EXHIBIT NO. ___(KJH-5)
DOCKET NO. UE-09___/UG-09___
2009 PSE GENERAL RATE CASE
WITNESS: KIMBERLY J. HARRIS

BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UE-09____** **Docket No. UG-09____**

FOURTH EXHIBIT (NONCONFIDENTIAL) TO THE
PREFILED DIRECT TESTIMONY OF
KIMBERLY J. HARRIS
ON BEHALF OF PUGET SOUND ENERGY, INC.

MAY 8, 2009

MAY 2007

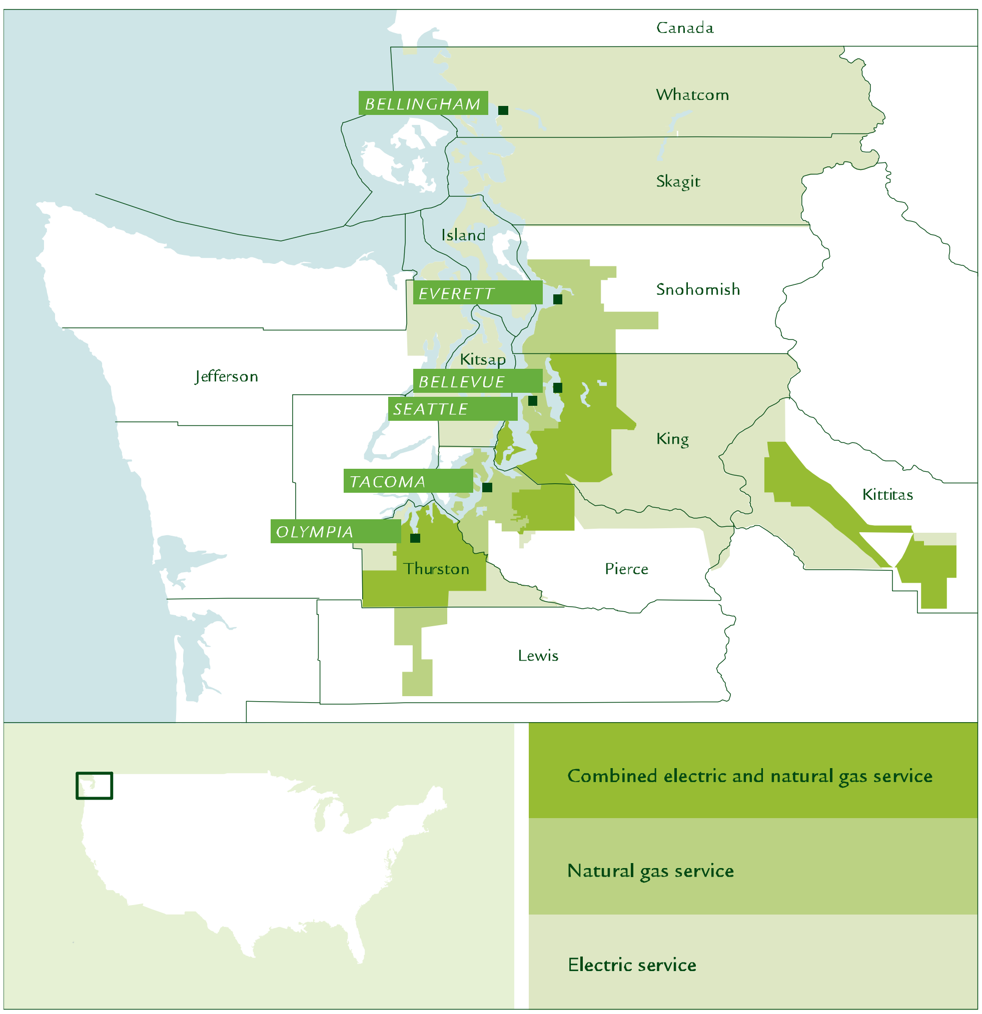
Integrated Resource Plan — Chapters 1-9

PSE PUGET SOUND ENERGY

The Energy To Do Great Things

About PSE

Puget Sound Energy is Washington State's largest and oldest electric and gas utility. We serve more than 1 million electric customers and approximately 700,000 natural gas customers. More than 3 million people reside within our 6,000-square-mile service area, which stretches from South Puget Sound north to the Canadian border, and from Central Washington's Kittitas Valley west to the Olympic Peninsula.



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2007 Integrated Resource Plan

Executive Summary

This Integrated Resource Plan describes how Puget Sound Energy can meet the growing energy needs of its customers with the lowest reasonable cost combination of resources over the next 20 years.

As we acquire resources to meet the needs of our vibrant community, we also strive to demonstrate the environmental values our customers and region demand. They expect no less of us than leadership in the development of responsible energy resources, and we expect no less of ourselves. Our goal is to identify solutions that are both cost effective *and* environmentally sound.

The resource portfolio presented here is the least carbon intense portfolio we have ever identified as being least cost. It includes aggressive investment in energy efficiency as a significant and cost-effective contribution to meeting resource need. It relies heavily on increased development of wind power and gas-fired generation. And we had concluded that adding new coal resources at this time is not in the best interests of our customers, even before Washington adopted a performance standard in May of 2007 that effectively bans development of new coal generation resources without carbon capture and sequestration. The new state law supports our conclusion that new coal resources would be too risky to develop at this time.

PSE faces significant resource acquisition needs in the coming years. At the same time, concern about greenhouse gas emissions and climate change is becoming a permanent part of the landscape of utility planning, which profoundly alters the risk profile of certain supply options. Increasing competition for available resources and technical expertise is also driving up projected portfolio costs. And finally, the number of viable resource alternatives, especially renewable resources, is far more limited than we would like. It is now clear that to fulfill our responsibilities, we will need to think and act creatively to obtain all the renewable resources we require.

This document explains how PSE developed the lowest reasonable cost portfolio for meeting our customers' growing resource needs. It describes key data and assumptions. It presents the rigorous quantitative analysis we used to assess risk and test possible portfolio combinations against scenarios that depict different futures that may develop over the 20-year planning horizon. It also describes the qualitative analysis we applied. Quantitative analysis alone is insufficient to fully describe current or future market realities. So, we incorporate our commercial experience, understanding, and close observation of developing market trends into our considerations as well.

Public participation played an important part in the development of this resource plan. Stakeholder meetings generated healthy debate, suggestions, and practical information that shaped both the way we constructed our analysis and the judgment we applied to the analytical results. We value this stakeholder relationship highly, and look forward to shaping the energy future of Washington state together.

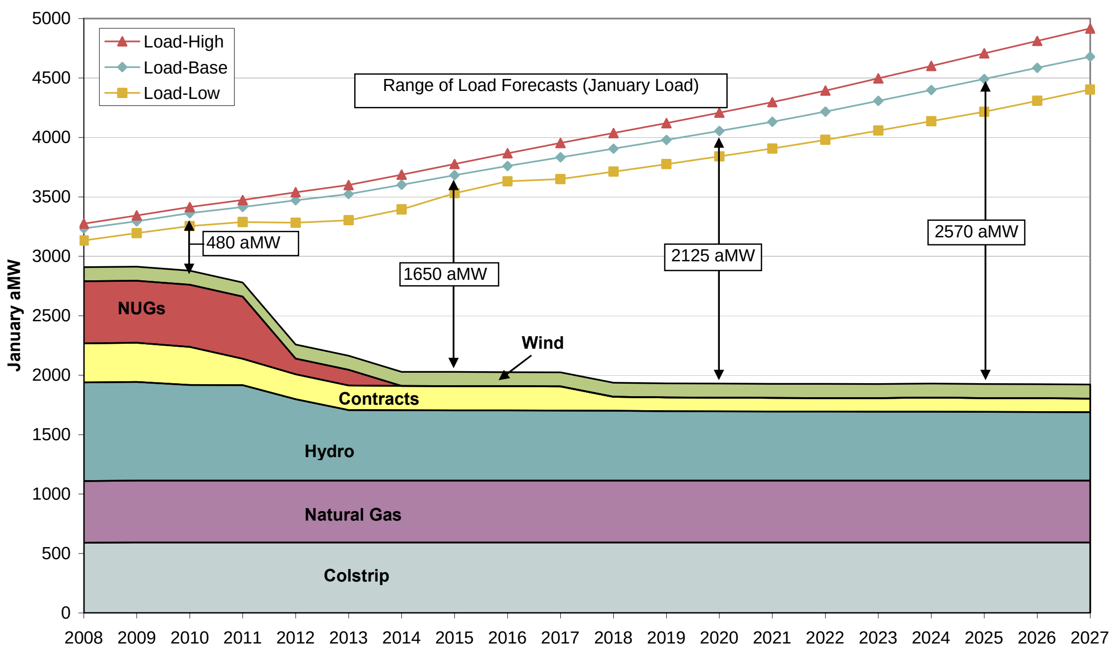
I. Resource Need: The Challenges We Face

Electric Resource Need

The combination of economic growth and expiring supply contracts means that PSE faces large electric resource needs in the years ahead. To meet the projected electric demand of our customers, we will need to replace, renew and acquire nearly 700 average Megawatts (aMW) of electric resources by 2011, more than 1,600 aMW by 2015, and 2,570 aMW by 2025, as Figure 1-1 below illustrates. This is the equivalent of adding enough electricity to power the city of Seattle for the next 20 years.

Figure 1-1

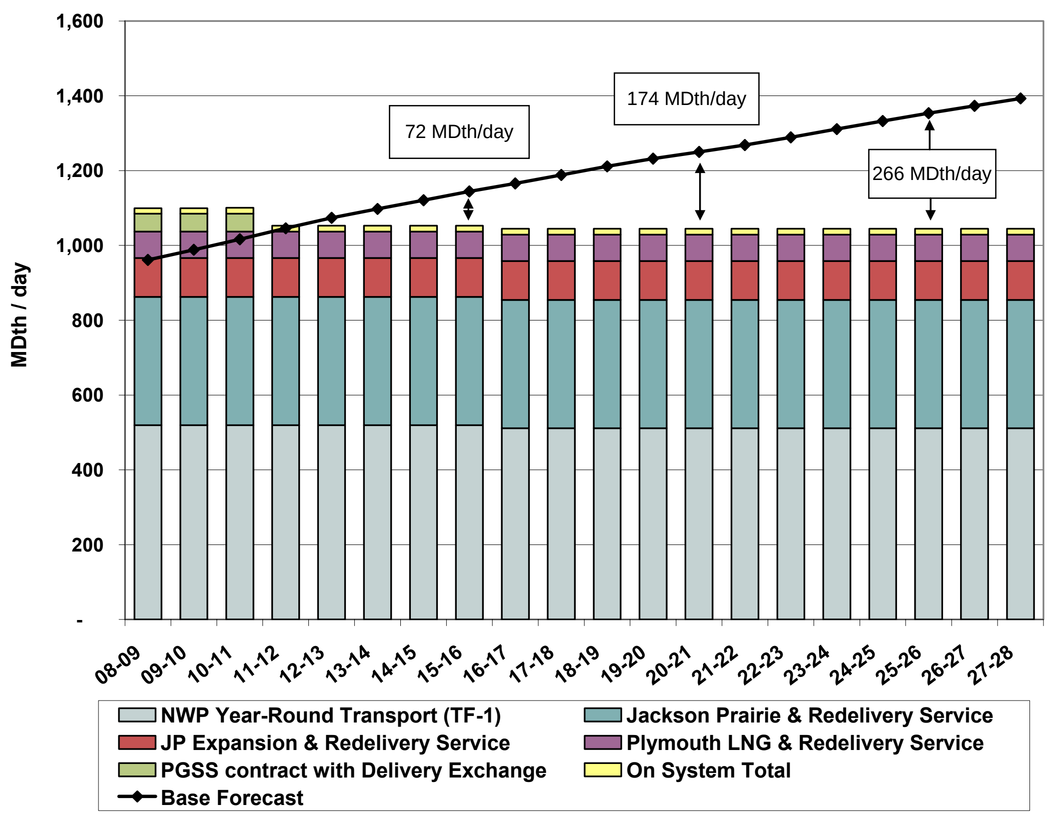
Electric Resource Need: Comparison of Projected Loads and Existing Resources



Resource Need for Gas Sales Service

PSE's retail natural gas resource need is also growing due to increasing demand and expiring contracts, but more gradually than electric needs due to the nature of the contracts. Although several agreements with Northwest Pipeline expire in coming years, the Company has unilateral rights to terminate or continue the contracts. Only one resource in our long-term retail natural gas portfolio terminates entirely. We currently have sufficient resources to meet projected peak-day requirements until the winter of 2011-2012.

Figure 1-2.
Gas Resource Need: Comparison of Projected Loads with Existing Resources

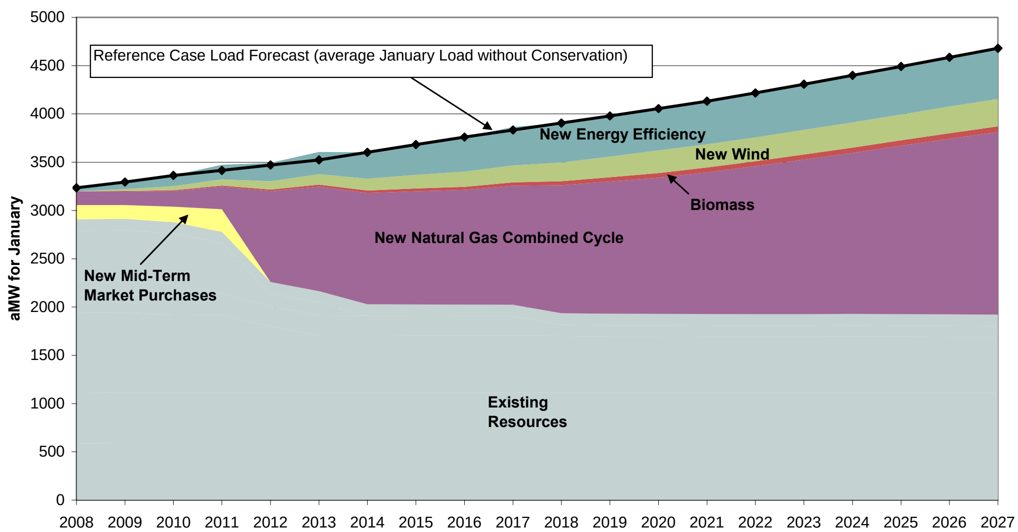


II. Meeting Electric Needs

Growing greener: more energy efficiency, more wind, and more natural gas-fired generation.

PSE's extensive analysis indicates that the portfolio shown below in Figure 1-3 is the lowest reasonable cost long-term resource strategy to pursue to meet our customers' growing demand for electricity. This strategy employs aggressive increases in demand-side resources (primarily energy efficiency), aggressive acquisition of wind resources in order to meet renewable portfolio standards, and gas-fired generation to make up the balance of energy needs that cannot reasonably be met through demand-side and renewable resources. In this plan, the "coal question" is largely put on hold until carbon sequestration becomes commercially viable.

Figure 1-3
Preferred Electric Resource Strategy, 2007 IRP



January Energy Additions aMW—Lowest Reasonable Cost Portfolio				
	2008	**2015**	**2020**	**2027**
DSM/Energy Efficiency	36	314	432	524
Wind	0	140	235	284
Biomass	0	29	49	59
Gas CCCT	142	1172	1410	1893
PBAs	148	0	0	0

January Capacity Additions MW				
	2008	**2015**	**2020**	**2027**
DSM/Energy Efficiency	36	314	432	524
Wind	0	550	921	1,112
Biomass	0	34	57	69
Gas CCCT	149	1,234	1,484	1,992
Duct Firing	20	167	200	269
SCCT	0	0	175	441
PBAs	148	0	0	0

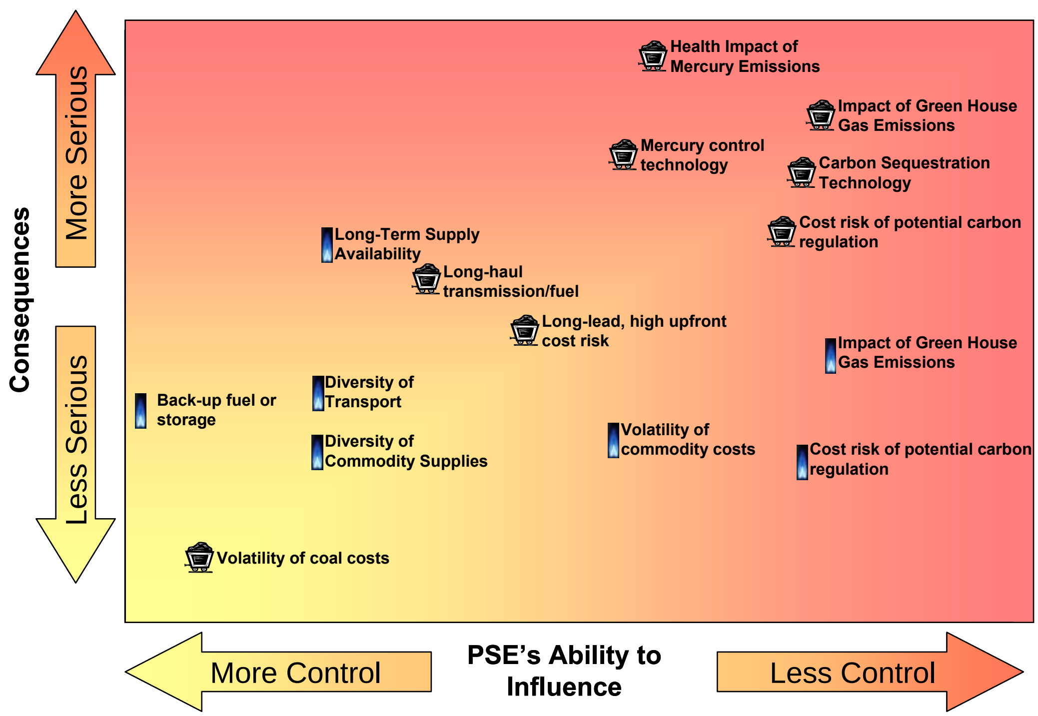
Why not coal?

Previous PSE resource plans suggested we should consider development of new coal resources to come online in approximately 2016. Since the 2005 resource plan was developed, however, market, regulatory, and legislative conditions have changed significantly. Activity at both federal and state levels suggests that cost consequences for the emission of carbon dioxide (CO_2) are likely in the future. Conditions have changed even since modeling for this plan began in October of 2006, as mentioned above, with Washington state adopting a new law in May of 2007 that bans new coal resources unless the CO_2 can be sequestered. Mercury emission standards are also becoming far more stringent, pushing the limits of technology. Mine mouth coal projects have no existing transmission solutions to the Interstate-5 (I-5) corridor. Transmission solutions are multi-billion dollar undertakings. The estimated cost of permitting, constructing, and operating coal plants has increased enormously. Simply stated, the commercial viability of coal resources has grown highly uncertain.

PSE's quantitative analysis supports the conclusion that the risk-reward relationship for coal is untenable at this time. Across the different planning scenarios we evaluated, addition of some mercury-emission-controlled coal late in the planning horizon was found to be marginally cost competitive in some futures and high cost in others. The results are so close, however, that one must be cautious about drawing conclusions based solely on the numbers. Our quantitative analysis highlights that carbon sequestration technology is key if coal risks are to be mitigated. At this time, permanent deep well geological sequestration of CO_2 is not a proven technology, nor is there a reliable estimate of when such technology may become commercially viable. Without commercially viable CO_2 sequestration, a reasoned balancing of costs and risks prefers gas-fired generation over coal. That is, if we constructed a coal plant without sequestration capabilities and found ourselves in a "green world" environment of high CO_2 costs, the negative economic consequences would be greater than if we constructed natural gas generators and found ourselves in a low-CO_2-cost future.

The qualitative considerations with respect to coal are an important component of this reasoning. Risks posed by coal appear to be more significant and less controllable than the risks of relying on more natural gas at present. Coal-fired generation poses potential risks to health and human welfare with mercury emissions and it emits twice the CO_2 of natural gas-fired generation; also, cost risks associated with impending future environmental regulations are significant with coal, such as potential legislation mentioned above that would prohibit utilities in Washington from acquiring coal resources unless CO_2 can be sequestered. There are clear risks as well with natural gas. At present, the kinds of risks posed by natural gas-fired generation appear to be less serious and more manageable than coal-fired generation risks. Figure 1-4 provides a graphical representation of the qualitative risk tradeoffs of coal versus natural gas-fired generation.

Figure1-4
Coal and Natural Gas: Comparison of Risks and Consequences



Available Alternatives

Energy efficiency, wind, and natural gas are the primary, commercially available resources that PSE can choose to meet future customer needs.

Energy efficiency. Energy efficiency is the primary component of a category called demand-side resources, which includes technologies like distributed generation and demand response. These resources enable us to make less energy do the same amount of work. Across all the planning scenarios tested, aggressive investment in demand-side resources was found to be cost competitive. The targets represent a significant increase over current program levels, to 28 aMW annually from 20 aMW.

Wind. Renewable portfolio standards recently established by Washington state require that the portfolios of utility providers contain an increasing proportion of renewable resources. For our region, renewables means wind, as it is the principal alternative capable of producing utility-scale generation. PSE developed, constructed, and began producing wind-generated power at our Hopkins Ridge and Wild Horse facilities even before the new standards were established. Competition for all wind resources will be fierce as a result of state requirements and global competition for resources. Recent action by the California Energy Commission to allow California utilities to acquire renewable resources at the Mid-C trading hub adds a significant competitor for northwest utilities. Accordingly, PSE will have to adopt an aggressive acquisition model to secure them.

Natural gas-fired generation. Natural gas becomes the lowest reasonable cost resource that is available in large enough quantities to meet base load and intermediate needs without proven carbon sequestration technology. This plan demonstrates that at this time natural gas is a better alternative than coal for meeting base load energy needs. There are several challenges with natural gas, such as diversity and security of supply, long-term availability, and demand-pull price risks. However, we judge such risks somewhat more manageable than coal risks.

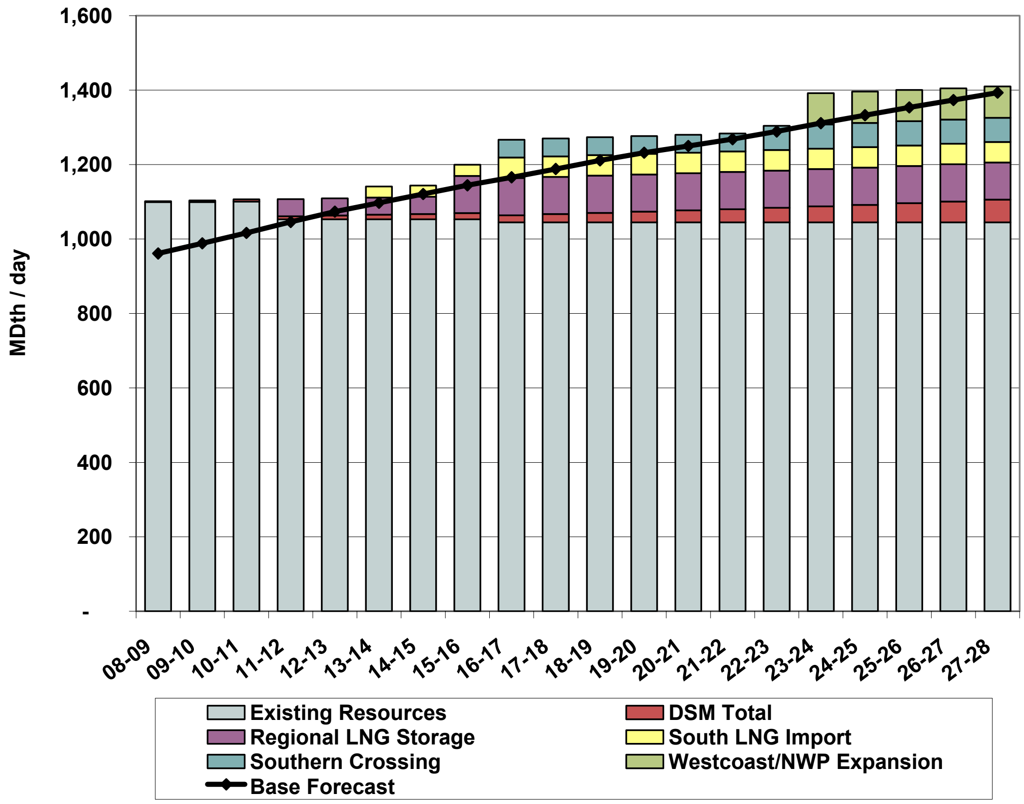
Other alternatives. Some biomass generation is included in the lowest reasonable cost portfolio strategy. Solar, geothermal, wave and tidal resources, however, remain largely research and development activities that merit ongoing interest and support; while they are capable of producing electric generation, they trail wind in their technical and commercial feasibility by at least a decade and perhaps much longer.

III. Meeting Gas Need

Long-term diversification is a goal.

PSE's gas resource strategy is geared toward long-term resource acquisition.

Figure 1-5
Recommended Gas Resource Additions



Winter Capacity Additions (MDth) - Reference Case Portfolio				
	2008	2015	2020	2027
DSM/Energy Efficiency	2	17	32	61
Regional LNG Storage	0	100	100	100
South LNG Import	0	30	55	55
Southern Crossing Pipeline	0	0	48	65
Westcoast/NWP Expansion	0	25	25	107

Evolving market conditions are pushing PSE to become more reliant on gas supplies originating in northern British Columbia. Seeking ways to diversify away from this concentration is important. The lowest reasonable cost resource strategy includes increasing our investment in gas demand-side programs, and seeking both liquefied natural gas (LNG) alternatives and opportunities to secure transportation and supplies from Alberta. In the early years of the 20-year planning horizon, we will investigate the possibility of participating in development of the regional infrastructure needed to make LNG a viable supply.

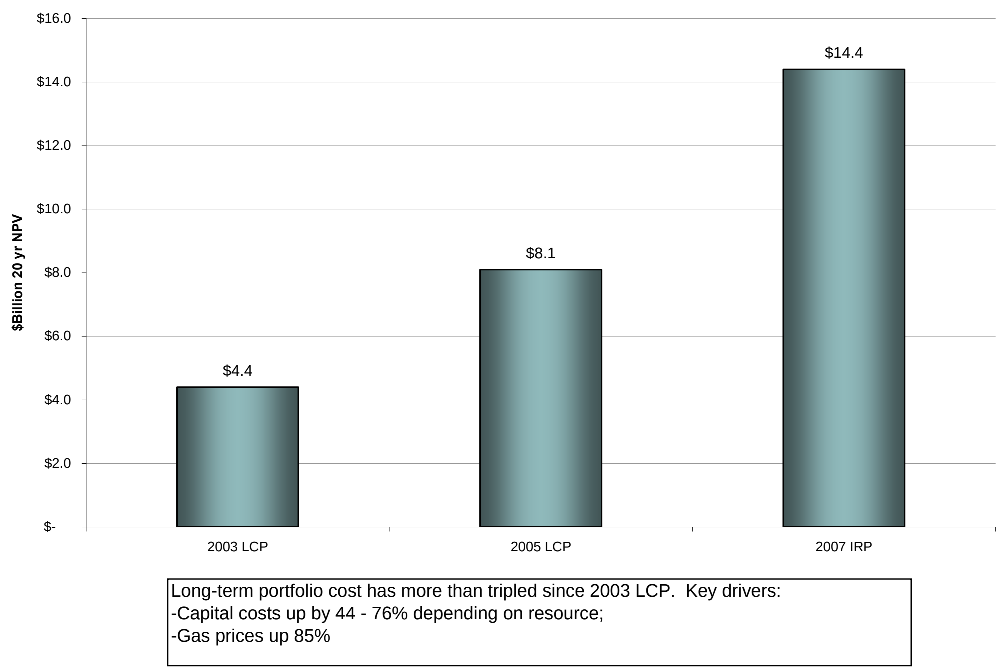
Development of facilities to support imported LNG in the Northwest is active, but outcomes are still uncertain. Even if such facilities are constructed, the role of LNG in Pacific Northwest markets is not clear in the face of growing global demand and competition for LNG. While a welcome source of supply diversity, the prices, terms, and conditions of imported supplies will determine whether LNG will be an appropriate addition to the long-term gas portfolio. PSE will continue to actively monitor LNG development prospects and participate when and where appropriate.

IV. Key Concerns

1. Future portfolio costs are rising significantly.

Projected fuel and construction costs have increased dramatically since PSE published its 2003 Least Cost Plan. As figure 1-6 below demonstrates, the net present value of the incremental 20-year portfolio cost has more than tripled in the past five years.

Figure 1-6
Rising Incremental Portfolio Costs



Two key factors are driving this increase: the all-in cost to complete new generation projects, and natural gas prices. With regard to all-in costs, PSE has been in the market making electric generation acquisitions for the past five years. We have been involved in extensive discussions with independent developers, vendors of key project components, and firms which provide engineering, procurement, and construction services. We have also acquired two wind projects in the mid stages of development and permitting, and negotiated contracts to design, build, and transfer them to us. We have also purchased two gas-fired combined-cycle projects and have had independent developers update estimates of the so-called “overnight cost” of building such projects from scratch. Two findings are abundantly clear: costs have risen substantially, and it’s virtually impossible today to get a reasonable “hard money” quote and firm delivery schedule to build a project of any significant size. These insights, combined with certain cost estimates published by industry groups, inform us about the real-world challenges of permitting and constructing resources today. This knowledge is applied to our planning assumptions. Accordingly, we find that the all-in cost of gas-fired combined cycle units has increased about 44% relative to the 2003 Least Cost Plan, the all-in cost of wind generation has grown by about 76%, and natural gas prices in our reference case have risen approximately 85%.

As coal has evolved as a less favored fuel alternative in the United States due to its environmental characteristics, pressure on natural gas prices increases. Competition for all available resources and the technical expertise required to place them in service is intensifying, supporting upward cost pressure throughout the resource supply chain.

2. The renewables challenge is formidable.

An estimated 4000 MW of additional wind generation will need to be acquired and placed in service by 2019 in order to meet Washington state’s renewable portfolio standard.[1] Wind will necessarily supply the bulk of the resources used to meet the requirement because wind has proven its ability to produce utility-scale power, because of the time it takes to fully develop projects, and because of the legal deadline established.

As discussed above, Oregon appears poised to adopt an even more aggressive renewable portfolio standard that will add greatly to the demand for renewable resources in the region. And California utilities have a huge appetite for renewable resources, and the state recently liberalized its procurement rules to allow California entities to compete at the Mid-C trading hub to acquire renewable resources based in the Pacific Northwest.

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[1] The estimated 4000 MW of wind power was derived by applying a 30% capacity factor to the CTED estimate of 1185 aMW that will be needed by 2020, see http://www.cted.wa.gov/DesktopModules/CTEDPublications/CTEDPublicationsView.aspx?tabID=0&ItemID=4109&MId=863&wversion=Staging

PSE must acquire additional renewable resources to meet state standards within the context of this regional rush. Translated into practical terms, this means PSE and its development industry partners will need to place one wind project into commercial service approximately every 18 months beginning in 2010, and do so in an extremely crowded marketplace.

The renewables challenge is enormous—not just for PSE, but for all utilities serving the state. To meet it will require a coordinated effort on a scale we have not seen before in the Northwest. Utilities, developers, key vendors, transmission providers, and regulators will need to engage in creative partnerships if we are to align critical processes to achieve the goals established for us by the people of Washington.

3. Addressing environmental impact will generate big changes in the future.

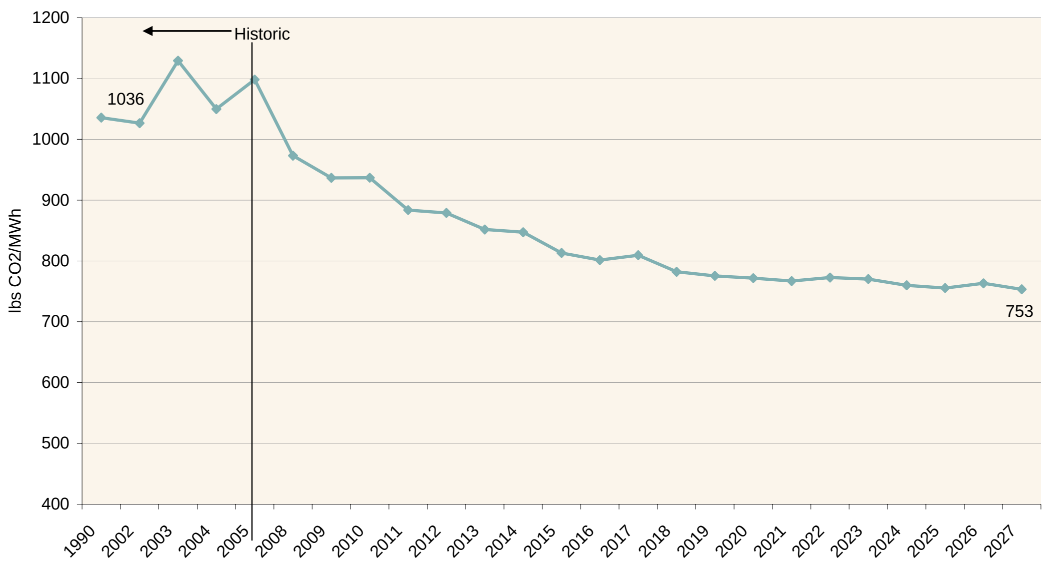
Concerns about climate change and the environmental impacts of energy production are becoming a permanent part of the utility planning landscape.

Since publication of our last long-term resource plan, the momentum for addressing these concerns via regulatory change has increased dramatically. Washington voters approved a renewable portfolio standard that requires utilities to acquire all cost-effective energy efficiency resources and meet 15% of load from renewable resources by 2020, joining 21 states with similar laws. The State Department of Ecology has initiated a rulemaking on mercury emissions that may make it impractical to build any form of coal generation in Washington. Finally, the state legislature passed and the governor signed a new law that caps emissions from new generating resources, regardless of where they are located, at 1,100 lbs. of CO_2 per megawatt hours (MWh). Given carbon sequestration is not commercially viable, this will prevent Washington utilities from acquiring new coal resources via ownership or long-term contracts. Additionally, this law requires the state to reduce total greenhouse gas emissions to 1990 levels by 2020.

PSE has been engaged in mitigating the long-term environmental impacts of meeting our customers' growing energy needs for many years. We have long been engaged in the aquatic and terrestrial management issues associated with hydro power generation. We have been a leader in designing avian protection programs around our electric transmission and distribution systems. We were early and effective adopters of energy efficiency measures, and we are regional leaders in the development of renewable wind power. In response to concerns about global warming, we have adopted a Greenhouse Gas Policy statement that is available on our website and in the Environmental Concerns appendix to this document. Our intent is to partner with our stakeholders, including customers and regulators, to meet the environmental challenges that confront us all.

The lowest reasonable cost portfolio identified in this IRP is the least carbon intense that has appeared in a PSE resource plan. The following chart illustrates that we expect the carbon intensity (CO_2 produced per megawatt hour of load) of meeting our customer's energy needs to decline significantly over time. The chart also illustrates the significant reduction in carbon intensity relative to the least cost portfolio from our 2005 plan. As newer, cleaner technology comes online over time, our carbon intensity will decline further. A comprehensive overview of climate change and greenhouse gas issues is included in the Environmental Concerns appendix to this plan.

Figure 1-7
PSE Carbon Dioxide Emission Rates Declining by 27% from 1990 Levels



By the end of the 20 year planning horizon, the Lowest Reasonable Cost portfolio will reduce the CO2 footprint passed on to our customers by 27% relative to 1990 carbon emission intensity levels.

V. Conclusion

PSE serves more than half of the people who live in Washington state. This IRP seeks to balance the growing energy needs of the region with concerns about the environmental impacts produced by power generation. It seeks to assess the risks and costs of different alternatives, and weigh them against different ways the future may develop. Its goal is to identify the lowest reasonable cost resource strategy that will meet our customers' needs.

The IRP provides useful guidance to the Company's demand-side and supply-side resource acquisition processes; however, it is a guide, not a prescriptive list for resource acquisition. It is based on high-level, generic assumptions about future market conditions and resource costs. Individual resource acquisitions must rely on judgment informed by specific information about specific resources. Such decisions will be informed by the strategy and the analytical and decision-making processes described here, but governed by actual market conditions.

Planning Environment

A high degree of uncertainty exists in the energy marketplace today for utility planners. New laws and regulations are being adopted, driven by concern about environmental impacts. Their final shape is still in flux, and their full implications are not yet fully understood. The cost of adding new resources is rising as overall demand for energy increases; in particular, demand for renewable resources and energy efficiency is rising. Regional transmission constraints continue to pose challenges, and so does integrating intermittent renewables such as wind. Here we describe the landscape in which we must make long-term resource decisions to meet the growing needs of our customers.

I. Changing Environmental Regulations

Changing environmental regulations in three areas are significantly influencing the options PSE has for meeting the needs of our customers. These are:

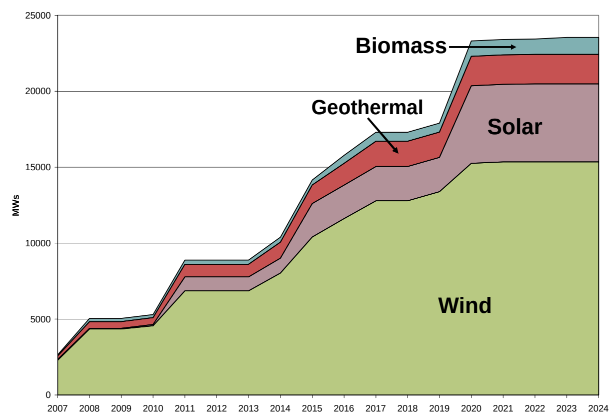
- Renewable Portfolio Standards
- Greenhouse Gas Emissions
- Mercury Emissions

Additional information on climate change, greenhouse gas emissions, and potential legislation may be found in Appendix C, along with a brief discussion of mercury emissions and related regulations. Here, we focus on the implications those regulations have on the marketplace in which we must operate.

A. Increasing Reliance on Renewable Portfolio Standards

Twenty-two states have passed legislation imposing a Renewable Portfolio Standard (RPS) on electric generation. As this IRP is being completed, Oregon is considering an RPS, and a Federal RPS is also a distinct possibility. These targets will significantly boost the renewable components of the regional generation base, and change the mix of generation technologies built over the next two decades. Figure 2-1 illustrates the magnitude of the additions required. Assuming that each state's RPS target will be met as currently written, nearly 30,000 MW of renewable generation will need to be added in the Western Electric Coordinating Council (WECC) over the next 20 years. The price and value of renewable alternatives will increase as a result, since there are finite limits on how many resources are feasible to develop in each state.

Figure 2-1. RPS Additions in WECC – Total



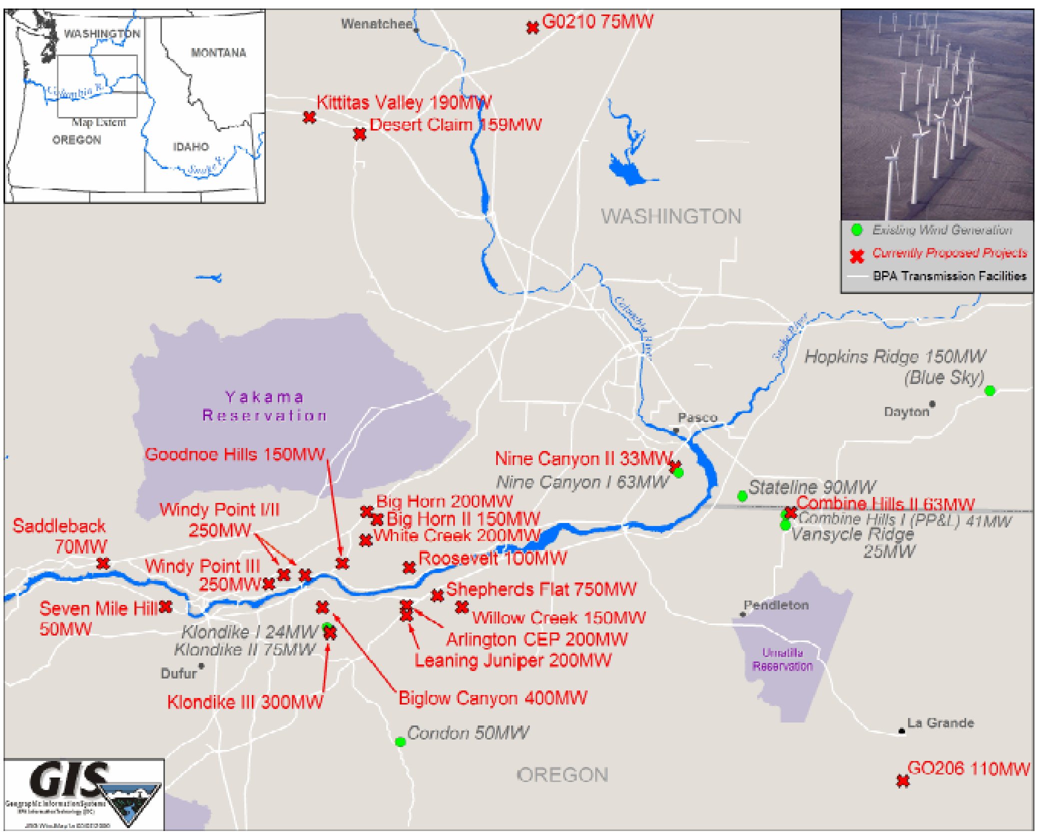
In the Pacific Northwest, wind is the primary renewable capable of generating utility-scale power. To meet the new requirements, Washington and Oregon together will have to add 10,500 MW of wind power by 2025. This means bringing four 150 MW wind farms online in the region every year from 2009 to 2025—enough to cover

90% of the surface area of Puget Sound. The total amount developed in the region may turn out to be even larger if California seeks to develop wind here to meet its need for renewable resources.

Precisely forecasting the amount of wind generation that will actually be constructed is difficult because Washington's RPS includes a complex financial cap. This cap may limit the quantity of wind and other renewable resources that utilities are required to acquire; whether the Oregon law will include similar caps is not yet clear.

The current and proposed wind projects that would interconnect with BPA's transmission facilities are shown in Figure 2-2 below. They total approximately 4000 MW—less than half of the requirements set forth by the Washington and proposed Oregon laws.

Figure 2-2
Current and Proposed Wind Project Interconnections to BPA Transmission Facilities



The field is crowded and will only become more so. Identifying enough locations for commercial wind development to satisfy RPS requirements will create increasing pressure in the marketplace. Demand for generators, developers, and skilled labor will also increase.

Summary of Washington's Renewable Portfolio Standard

Initiative 937 (the Energy Security Act) is Washington's Renewable Portfolio Standard. It was passed by voters in late 2006. The new law requires the state's electric utilities to meet the following targets:

- 3% of load from qualifying renewables by 2012;
- 9% of load from qualifying renewables by 2016;
- 15% of load from qualifying renewables by 2020;
- Penalty: $50/MWh for every MWh that a utility falls short;
- Cost Cap: total incremental renewable cost at 4% annual revenue requirement.

Regional and Neighboring States' Policy Activities

The actions of regional and neighboring states affect the energy markets in which we participate. In particular, California's actions have an enormous impact on renewable resources throughout the WECC region due to their early and aggressive policies and the sheer size of their markets. They have advanced a number of policy changes to support more renewable development.

Recently, FERC approved changes sought by the California Independent System Operator (CAISO) that altered the way certain transmission projects are financed in the state. The changes allow implementation of a "hybrid financing method" for smaller generators that will make it easier for them to access smaller projects. Previously, developers were responsible for the cost of building the transmission trunk lines that connected their new generation systems to the main grid; smaller renewable developers faced serious obstacles in obtaining the large amounts of financing required for transmission construction. Under the new model, utilities will now pay for trunk line construction and be reimbursed after connecting the additional smaller, renewable projects.

In considering CAISO's proposals, FERC acknowledged that renewable developers cannot generally locate their projects near favorable transmission lines, but instead must locate them where those renewable resources are available (such as windy or sunny spots).

RPS Impacts on Demand-side Resources

RPS and related policies will also increase pressure on demand-side resources in the marketplace, since most RPSs include demand-side as well as renewables requirements. This IRP calls for a significant increase in demand-side resources, and estimates expenditures of $2 billion for such resources over the 20-year planning horizon. In California, investor-owned utilities have budgeted to spend that amount *in the next two years alone* on energy efficiency.[1] The people who have the experience and skill to implement effective demand-side programs will be highly sought after as the region seeks to meet its goals.

B. State & Local Initiatives to Limit Green House Gas Emissions

Federal policy has yet to be set on climate change, but state and local initiatives to limit GHG emissions date back to June 2002, when Massachusetts adopted a 10% reduction of CO_2 for the state's coal-fired plants. These regulations took effect on January 1, 2006, and New Hampshire soon followed suit.

A cooperative effort among seven Northeastern states known as the Regional Greenhouse Gas Initiative (RGGI) mandates that electric utilities in the participating states reduce their emissions. The agreement caps power plant GHG emissions at 2005 levels from 2009 through 2014, then reduces them an additional 10% by 2019. Maryland will join RGGI in 2007. Together, these eight states account for one-eighth of the U.S. population and approximately 8% of the country's power generation.

State initiatives have also gained momentum in the West. Washington, Oregon, and California have proposed a number of emission reduction projects under the umbrella known as the West Coast Governors Global Warming Initiative. Currently, both Oregon

[1] California Public Utilities Commission Energy Efficiency California's Highest-Priority Resource, June 2006.

and Washington require new power plants to offset a certain portion of their anticipated CO_2 emissions. Similarly, the California Public Utility Commission (CPUC) requires that a "carbon adder" (an estimate of the cost of complying with future carbon emission limits) be used by the state's utilities when comparing the costs of alternative generation during their resource planning processes.

California was the first state to reach beyond the energy sector in order to reduce GHG emissions. In July 2002, the state enacted legislation requiring motor vehicles to reduce GHG emissions. In 2005, Governor Schwarzenegger signed an executive order committing the state to a program with goals to reach 2000 emission levels by 2010 and 1990 levels by 2020. Most notable is the California legislature's passage of AB 32 in August 2006. AB 32 establishes an economy-wide CO_2 cap that commits the state to reducing greenhouse gas emissions from all sources combined to 1990 levels by 2020. Specific measures are not mandated, but the bill directs the California Air Resources Board to develop regulations to achieve the required emissions reductions.

The passage of AB 32 in California and the limits set forth in the RGGI states mean that *approximately one-quarter of the U.S. population is now subject to state GHG emission limits.*

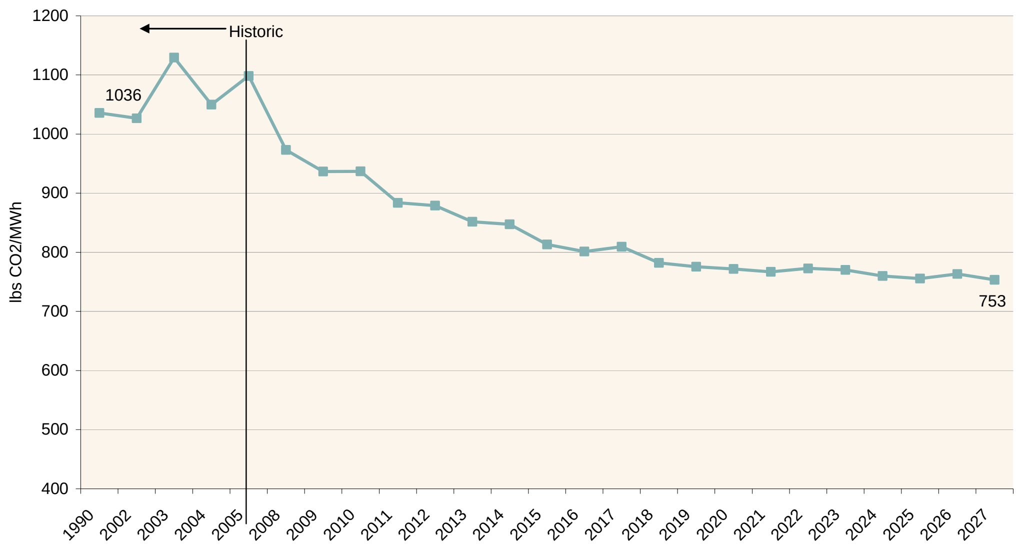
Local jurisdictions in the Pacific Northwest have also been developing their own climate policies, and Seattle has been one of the leading cities in this effort. In 2005, Mayor Greg Nickels launched the U.S. Mayors Climate Protection Agreement, which has enlisted over 330 municipalities in an agreement to reduce GHG emissions from their communities by 7% from 1990 levels, by 2012. Mayor Nickels also created the “Green Ribbon Commission on Climate Protection," which recommended ways for Seattle to achieve the 7% goal. King County announced this year that it joined the Chicago Climate Exchange.

In May 2007, after our analysis for this IRP was completed, Washington state adopted a new law regulating GHG emissions (Senate Bill 6001). The law has two key components that affect electric utilities. The first component is a set of guidelines pertaining to *emission rates* for CO_2 from new electric sources (whether owned or contracted). These guidelines state that any newly added electric resources must emit no more than 1,100 pounds of CO_2 per MWh. The second component sets goals to reduce *total* GHG *emissions* in the state to 1990 levels by 2020, 75% of 1990 levels by 2035, and 50% of 1990 levels by 2050.

The distinction between emission rates (carbon intensity) and total emissions is important to understand. “Carbon intensity” measures the amount of CO_2 produced per Megawatt hour of energy generated. “Total emissions” is the sum of *all* CO_2 produced by *all* of the energy that is generated. Even if carbon intensity is successfully reduced, total emissions may increase if greater overall energy production is required.

The carbon intensity of PSE’s resource portfolio is anticipated to decline significantly in the future under this IRP, as illustrated in Figure 2-3 below. Our carbon intensity falls to 753 lbs/MWh in 2027 from 1990 levels of 1,036 lbs/MWh. This means that PSE’s carbon footprint will decline by 27% over the planning horizon.

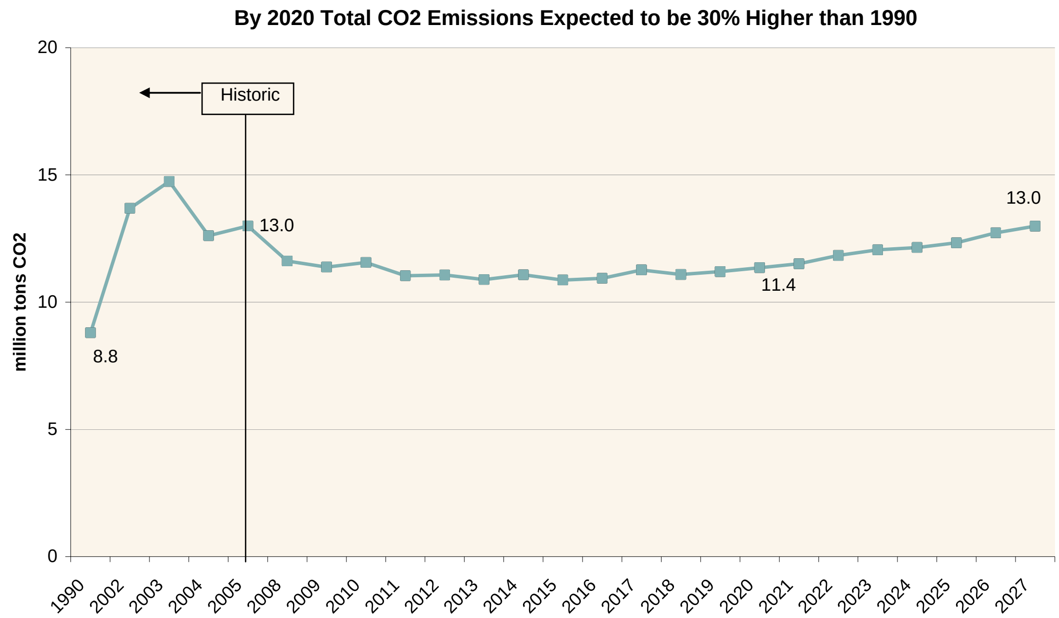
Figure 2-3
PSE Carbon Dioxide Emission Rates Declining by 27% from 1990 Levels



By the end of the 20 year planning horizon, the Lowest Reasonable Cost portfolio will reduce the CO2 footprint passed on to our customers by 27% relative to 1990 carbon emission intensity levels.

However, while PSE’s carbon footprint is declining, we also anticipate that the total number of customers—and thus the total amount of electricity we produce—will continue to grow. So even though the CO_2 emissions we produce per Megawatt hour will decline substantially, our total CO_2 emissions will increase. Figure 2-4 shows the total emissions we expect over the same time period. By 2020, total emissions are expected to be 30% higher than 1990 levels.

Figure 2-4
PSE Carbon Dioxide Total Emissions



The comparison of emission rates with total emissions shown above illustrates the importance of using emission rates for single-sector GHG regulation. Senate Bill 6001 identifies the transportation sector as the largest emitter of GHG in Washington state. There is an emerging risk that in the future, emissions from the transportation sector will be shifted to electric utilities through the use of plug-in electric hybrid vehicles. We have not performed an assessment of whether such a shift would increase or decrease total GHG emissions in Washington in this IRP, nor have we otherwise examined the potential impacts of plug-in vehicles. We will investigate the issue for our 2009 IRP. If PSE's load does increase as a result of plug-in hybrids, it would be even more unlikely that we could get back to 1990 total CO_2 emission levels, though we may be able to meet the emission rate cap of 1,100 lbs of CO_2/MWh.

C. Mercury Regulations

The Clean Air Mercury Rule (CAMR) enacted by the Environmental Protection Agency (EPA) in May 2005 permanently caps and reduces mercury emissions from coal-fired power plants. State and environmental group lawsuits are seeking to overturn the CAMR program in favor of stricter control requirements and limits on trading emissions (a mechanism that gives utilities a certain level of flexibility to comply with the cap). States, however, are moving beyond EPA in regulating mercury emissions from power plants. So far, sixteen have enacted or are working to enact programs more stringent than EPA.

In Idaho, coal-fired power plants will effectively be banned from the state under a mandate announced in August 2006 by Gov. Risch. Risch's executive order directs the state Department of Environmental Quality (DEQ) to initiate rulemaking with an eye toward opting out of CAMR. If approved by at least one house of the 2007 Legislature, the new DEQ rule will preclude any developer of coal-fired power plants from buying mercury emission credits from elsewhere and using them to operate in Idaho. With no coal-burning power plants currently in the state, Idaho's mercury emission budget is zero.

Oregon has also adopted a stricter standard than CAMR. In December 2006, the Oregon Environmental Quality Commission (DEQ) adopted a rule that limits mercury from new coal-fired power plants and mandates installation of mercury control technology by the state's only existing coal-fired plant. The Boardman plant, in eastern Oregon, is expected to reduce mercury emissions by 90% by July 1, 2012.

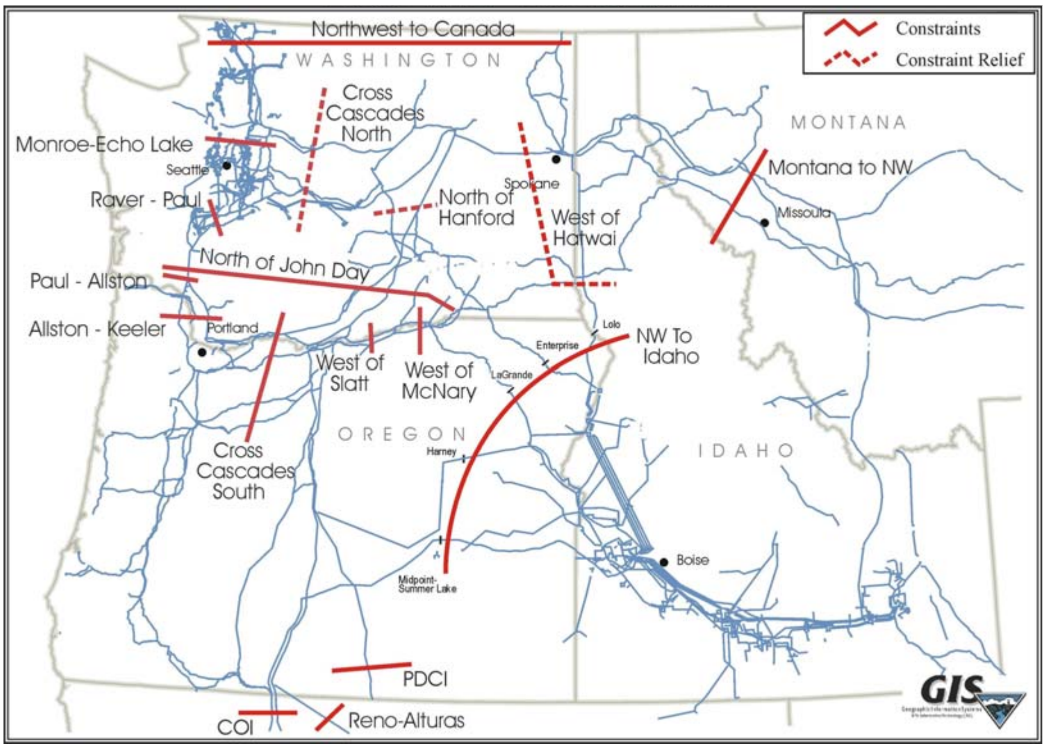
In October 2006, the Montana Board of Environmental Review approved a regulation to limit mercury emissions from coal-fired power plants. This, too, is more stringent than CAMR. Adopted with a 5-1 vote, the administrative rule (ARM 17.8.771) takes a two-tiered approach. It allows power plants burning lower-quality lignite coal to release more emissions than plants burning cleaner sub-bituminous coal. The new rule will cut mercury emissions by approximately 80%, and includes a cap-and-trade provision to help power plants meet their emissions-reductions targets. It also includes alternative emissions limits for plants that have tried to meet the new standards but have demonstrated that they cannot.

The Washington Department of Ecology (Ecology) is also drafting a mercury rule that is far more stringent than CAMR. The proposed standards would prohibit coal-based generators from participating in the national mercury emissions cap-and-trade program after 2012, effectively ending the future growth of clean coal in the state. The preliminary proposal would allow the continued operation of Transalta's existing pulverized coal facility in Centralia and might allow development of another 600 MW integrated gasification combined cycle (IGCC) facility, but would prohibit additional coal generation in Washington. Ecology isn't sure if opting out of the cap-and-trade program is the way to go; however, the agency is concerned about such a program creating mercury hotspots. Ecology has not been able to provide any information regarding studies about mercury sources in the state and their impacts to the local and regional environment, but is steadfast on this rulemaking.

II. Regional Transmission Constraints

PSE transports power from its origination point to our service territory over the regional transmission grid through contracts with various transmission providers. Physical and contractual limitations and lack of coordination within the regional transmission systems challenge PSE's ability to import resources from outside our service territory. The major constraints upon the regional transmission system are shown in Figure 2-5.

Figure 2-5
2005 Northwest Transmission Constraints



The intermittent nature of wind creates additional operating challenges for an electrical system. PSE has experienced wind resources that go from zero wind to full capacity and back down to zero within an hour. Variations of this magnitude create short-term operational issues, generally referred to as "wind integration," which is described more fully in the Wind Integration Appendix.

Over the next three years, as much as 2,400 MW of wind power is expected to come online in the Northwest region, for a total of nearly 3,800 MW by 2009. The Northwest Power and Conservation Council's Fifth Northwest Electric Power and Conservation Plan includes up to 6,000 MW of developable and potentially cost-effective wind power. This number represents only a portion of the 10,500 MW of renewable generation that we expect will be needed in Washington and Oregon. The Fifth Plan also calls for the development of a wind confirmation plan to resolve uncertainties surrounding wind power development.

The Northwest Wind Integration Action Plan was developed by many of the region's utility, regulatory, consumer, and environmental organizations and produced significant findings regarding the ability of the Northwest to accommodate future wind power development. The effort also identified issues that need to be resolved for wind power to achieve its full potential. The Action Plan made 16 recommendations intended to help resolve these issues. Of particular importance are actions addressing challenges associated with transmission marketing, planning, and expansion, and the limited market for control area services. A final action calls for the formation of a Northwest Wind Integration Forum to facilitate implementation of the Action Plan.

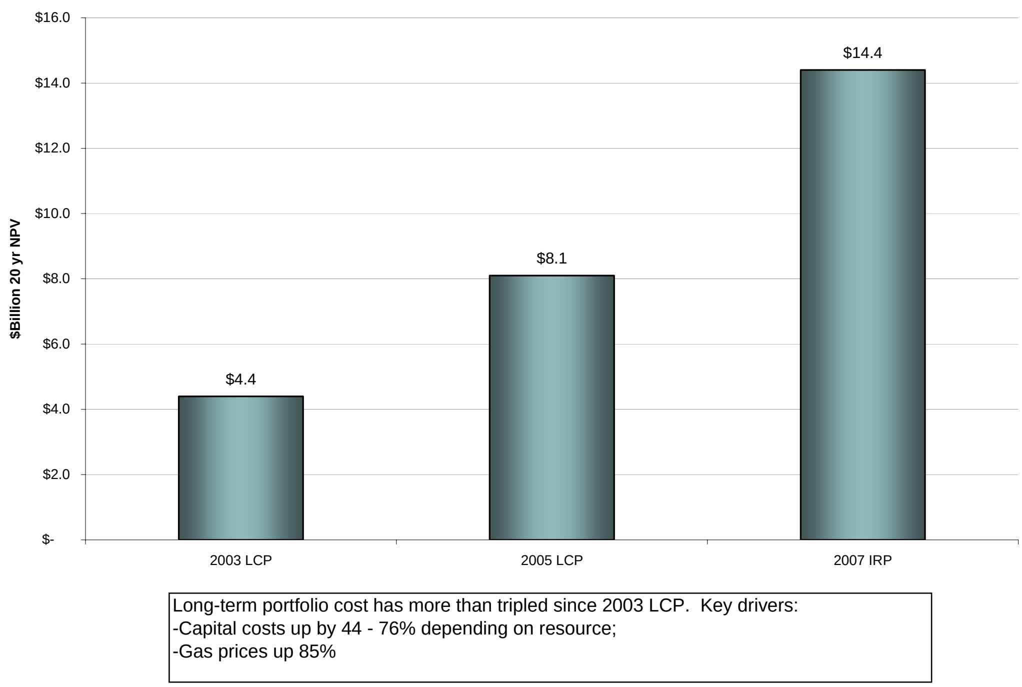
III. Resource Costs and Availability

In recent years the cost of adding new generation has risen sharply throughout the country and particularly here in the Northwest. PSE has a unique insight into these market trends since we have been active in the market through a series of solicitations and acquisitions over the past five years. A number of factors are influencing these cost trends.

A. Portfolio Cost Increase

Overall, PSE's long-term portfolio cost estimates have been increasing significantly over time. Figure 2-6 illustrates that our incremental portfolio cost has more than tripled since the 2003 LCP.[2] These figures compare the 20-year net present value of the portfolios for the 2003 and 2005 LCPs with the 2007 IRP.

Figure 2-6
Comparison of Incremental Portfolio Costs

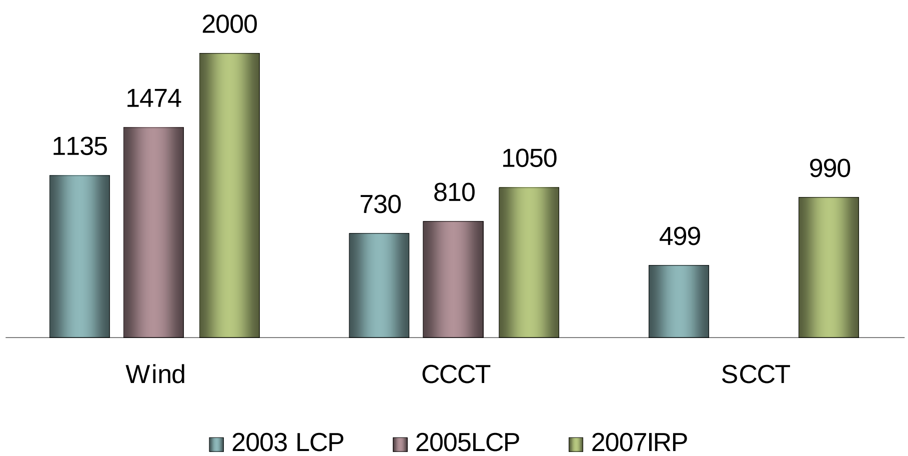


[2] Incremental portfolio cost here is measured as the variable costs associated with existing resources plus the fixed and variable costs of new resources.

B. Resource Cost Trends from Recent Market Solicitations

The cost of electric generation resources of all types has increased significantly over the past four years. PSE has experienced these shifting resource costs first-hand. The following chart illustrates the range of costs we experienced during the 2003 and 2005 RFP cycles.

Figure 2-7
Resource Cost Trends by Technology ($2007)



We have also experienced another sign of increasing pressure on the marketplace. During the 2005 RFP process, several renewable projects were withdrawn or scaled down by developers as a direct result of RPS requirements initiated by other states.

C. Global Demand for Generation Resources

The demand for energy resources is increasingly tied into an integrated global market, and high growth in certain regions is having a ripple effect in other regions. At this time, strong economic growth in China and India, and other growing economies in Asia, is having a pronounced effect on global prices for raw commodities, energy, and equipment and services related to construction of new generation facilities. Figure 2-8 illustrates the magnitude of that growth in terms of impacts on electricity consumed, based on data from the Department of Energy's, Energy Information Administration.[3] The figure shows that annual *growth* in electricity consumption in developing Asian economies is expected to nearly equal the *total* electricity consumed in the Northwest Power Pool

Data from the Energy Information Administration indicates that China, India, and other developing Asian economies will be adding the equivalent of more than 60% of the entire WECC load in generation every year. In other words, Asia is expected to build the equivalent of a new WECC-sized generation system every two years.

Figure 2-8
Annual Growth in Asia Nearly Equals Total Northwest Consumption
(kWh in Billions)

	2010	2015	2020	2025
Non-OECD Asia Electric Consumption:	4,713	5,896	7,154	8,513
Period-to-Period Change:		1,183	1,258	1,359
Average Annual Growth:		237	252	272
Northwest U.S. Consumption:	259	274	299	319

To a certain extent, the economic growth in Asian markets is simply displacing economic growth that might have occurred in Europe, Latin America, or other regions in previous years. However, the impact on the energy markets is somewhat unique because of the fact that China and India are growing from a minimal base into significant energy markets in an extremely rapid time frame. They now represent such a large economic opportunity for sectors such as clean coal technology, nuclear power, substation equipment, and wind turbine development, that the engineering, manufacturing and logistical capabilities of the world's largest OEMs are focusing heavily on these markets. As a result, other geographic regions are experiencing delays in manufacturing queues and delivery cycles that make it difficult to obtain equipment, and they are also experiencing upward pressure on prices.

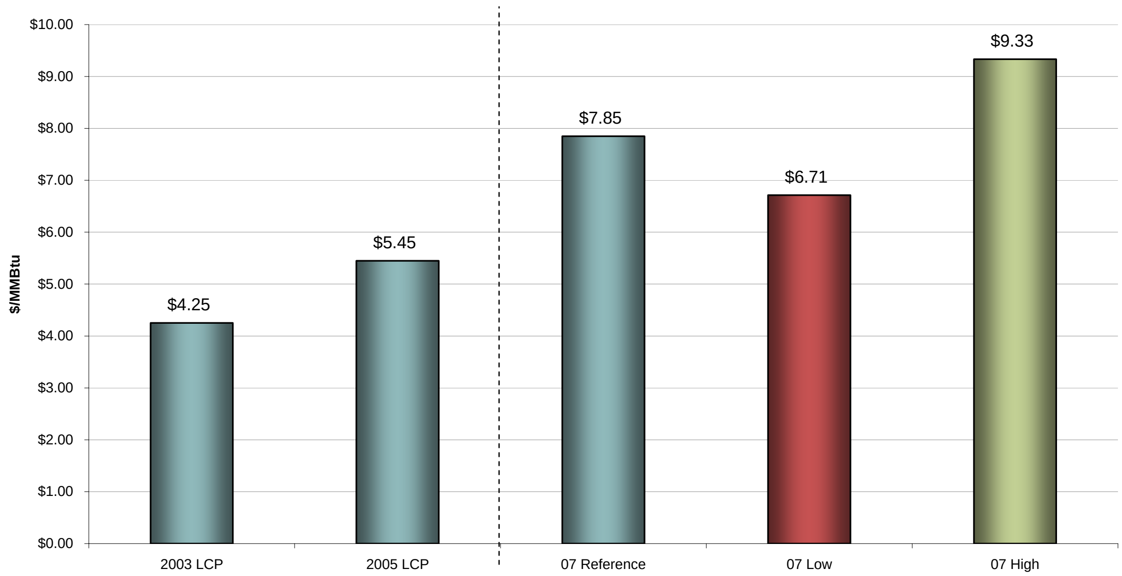
On a macro level, these pressures will continue for both equipment and key engineering skills, and they will continue to affect PSE.

[3] International Data: http://www.eia.doe.gov/oiaf/ieo/excel/ieoreftab_9.xls
U.S. Data: http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_72.xls

D. Gas Prices

Growing demand and increasing production costs have contributed to increases in natural gas prices. Since the 2003 LCP, gas prices have increased 85%. Even the low gas prices modeled in the 2007 IRP are 58% higher than reference case assumptions for the 2003 LCP.

Figure 2-9
Comparison of 20-year Levelized Gas Prices



Reference gas prices for the 2007 IRP are 85% than assumed in the 2003 Least Cost Plan.
Even low gas prices for the 2007 IRP are 58% higher than the reference case from the 2003 Least Cost Plan

We foresee increased reliance on natural gas as a fuel for electric generation, which will add to the upward pressure on overall portfolio costs. While current supplies and infrastructure are ample to meet existing and near-term needs, increased reliance on gas for electric generation (as well as continued growth of demand from gas sales customers) will require a significant increase in gas supplies, delivery pipelines, and storage facilities.

While cost-effective alternatives for expanding gas supplies are available, evaluating and acquiring the alternatives best suited to our needs while minimizing gas costs will continue to be a challenge. As our gas use increases, it will be important to maintain supply diversity. By making sure we establish and maintain effective connections with a variety of supply basins, we increase our ability to take advantage of price opportunities when and where they occur.

Imported liquefied natural gas (LNG) is expected to play a growing part in the continental and regional energy picture. The U.S. Energy Information Administration (EIA) projects LNG imports must increase from under one trillion cubic feet (Tcf) in 2004 to more than six Tcf by 2025 to meet projected continental demand. Recent technological developments and streamlined production, as well as higher prices in North America, have made the cost of LNG imports more competitive. More than 40 new terminals have been proposed to regulators, including four in Oregon and two in British Columbia. A regional LNG import facility would increase the diversity of PSE's gas supply portfolio as well as reduce our dependence on the gas pipeline network.

LNG importation, however, faces a host of hurdles including shipping and safety concerns, financing of import facilities, suitable location for terminals, and regulatory approval and permitting.

E. Long-Lead Resource Development Issues

"Long-lead" resources are those that take several years to engineer, site, and construct. Coal resources are the obvious—but not only—example. Most new, out-of-territory development projects fall into this category because of the length of time it takes to construct transmission facilities. High-head hydroelectricity from Alaska or British Columbia, geothermal power from eastern Idaho, and wind from Montana or Wyoming could all be described as long-lead resources.

Long-lead resources are subject to several risks that must be borne by the developer, or in some cases, by the utility sponsor. Siting and permitting can cost millions of dollars and take several years. Negotiation and development of long-haul transmission lines can take as long as 10 years. Direct construction can require up to four years for a coal plant, or two years for a gas plant. During all this time, capital must be expended, and interest costs continue to accumulate.

Electric utilities have historically undertaken such long-lead projects because they operated under a "regulatory compact" that helped to reassure them that prudently incurred expenditures would be recovered in the rate base. In the current planning environment, however, the size of the investments at risk are much larger and the potential exposure to different environmental scenarios is much less predictable than in the past. In addition, some long-lead alternatives now present the possibility of total success or total failure, with no spectrum of outcomes in between and huge amounts of money at stake. Commit to clean coal in hopes that carbon capture and sequestration will prove technically and commercially viable by the time siting and transmission issues have been fully negotiated—and if it does, you win. If it doesn't—or if environmental regulations change significantly—you lose big. In this high stakes planning environment, it becomes almost impossible for a utility to prudently make long-lead judgments until either technology or regulatory risks become more certain.

IV. Financial Considerations

In the course of developing our resource strategy, PSE considers how the selected resource portfolio and individual resources impact our incremental power costs and risk. The impact on our financial strength and credit are further evaluated during development of the annual strategic financial plan, and also when a specific resource is considered for purchase or contract. The following considerations and assumptions were used during this IRP analysis. For an in-depth discussion of the financial considerations that affect and influence resource acquisitions, see Appendix F.

- For evaluation of generic resources, both PPA contracts and natural gas fuel were priced at spot market without a risk management adder. This issue will be re-examined as we evaluate specific resource acquisitions.
- If the future coal market more closely resembles the natural gas market model, credit could become an issue for coal-fueled IGCC resources. This IRP does not include a credit adder for coal fuel.
- PSE could have a large capital need for resources concentrated over a few years prior to the time that NUG contracts expire in 2011-2012. While capital limitations during this time were not specifically analyzed in this IRP, we will need to examine the timing of replacement acquisitions to determine whether we have the financial strength to support rapid-owned resource additions.
- The timing of regulatory recovery is not explicitly modeled in the IRP, but this may become a consideration for specific resource acquisitions. For long-lead resources, and possibly transmission, PSE may need to pursue recovery of costs for construction work in progress. Short-term retail rate changes are another potential concern.
- Short-term power bridging agreements (PBAs) are used in this IRP to cover need until long-lead resources become available. PBAs may also be used to stagger resource additions to moderate the year-to-year financing requirements of owned resources. For the generic power bridging agreements analyzed in the portfolios, we computed an equity offset cost adder to account for the effect of imputed debt. A similar approach will be applied when evaluating specific power purchase agreements during the resource acquisition process.

V. Conclusion

The current planning environment for PSE is one that combines increasing uncertainty at a time when costs are also increasing, and the impact of being right or wrong is significant. Managing these challenges represents a significant opportunity for PSE to leverage its experience, insight, and personnel in a way that satisfies our customers, regulators and other stakeholders.

Key Analysis Components

Planning scenarios, portfolios, and price forecasts are key components of PSE's resource planning process. Using them allows us to evaluate the costs and risks associated with a multitude of possible futures, resource combinations, and the timing of resource additions. This chapter is organized in three sections.

I. Overview

A. Scenarios

Scenarios are different “pictures” of the future that allow us to incorporate fundamental changes for important issues that are observed today, but whose outcome is unknown. They depict different potential price-paths for different key variables that may occur as events unfold. These include uncertainty about energy policy, environmental issues, natural gas prices, and the performance of the national and regional economies. Changes in these factors affect the costs and risks associated with using different resources, and therefore inform the choices we make. The six electric and four natural gas scenarios PSE used in this analysis are described in this chapter.

B. Portfolios

A portfolio is a specified set of resources intended to meet the energy and operational requirements necessary to meet customer demands. Designing portfolios that contain different combinations of resources—and then modeling them within the context of each of the scenarios—provides us with insight into specific planning questions and the sensitivities and impacts of a wide range of decisions. PSE designed the electric portfolios in this IRP to provide insight into the effect of different levels of renewable energy in the portfolio, the cost and risk of different fuel choices, and the sensitivity of the timing of these key decisions. PSE’s electric analysis began with the 12 portfolios described in this chapter. Portfolios are not needed in the gas analysis, because we have an optimization model that mathematically solves for the lowest cost portfolio.

C. Price Forecasts

The individual electric and gas scenarios developed depict differing future economic conditions and regional power profiles. These conditions have different implications for resource costs, so price forecasts are developed for each of the scenarios. The appropriate price forecasts are then applied to each portfolio and evaluated for each scenario. Key assumptions included in the development of the price forecasts used are explained in the electric and gas sections of this chapter.

II. Electric Analysis Components

A. Electric Scenarios

PSE created six scenarios for our electric analysis to model a wide range of possible futures. These scenarios represent different potential price paths that may develop over the 20-year planning horizon. Figure 3-1, below, provides a high-level summary of the scenarios, followed by a more detailed explanation.

Figure 3-1
Electric Scenarios

Current Trends
Moderate Gas Prices
Low Carbon Costs
Moderate Load Growth

Green World
High Gas Prices
High Carbon Costs
Moderate- Load Growth

Low Growth
Low Gas Prices
Low Carbon Costs
Low Load Growth

Robust Growth
High Gas Prices
Low Carbon Costs
High Load Growth

Escalating Costs
Current Trends +
Increasing Capital Costs

Technology Improvement
Current Trends +
Declining Capital Costs
Heat Rate Efficiency Improvement

Current Trends

Current Trends represents PSE's reference case scenario. The input assumptions in this scenario include factors that can be observed today and seem likely to continue into the future. Because the reference case is used as a baseline for modifications made in the rest of the scenarios, it will be described in the greatest detail.

Resource costs. The estimated cost of generic resources is based on bids received in response to our formal 2005 Request for Proposals (RFP), along with information obtained during 2006 as part of the Company's ongoing market activity. Bid prices received were not firm and were occasionally revised upward. For long-term modeling purposes, the cost of resources is kept constant in real terms; in other words, the nominal cost rises at the same rate as inflation (a 2.5% annual inflation rate was assumed in this analysis). It is impossible to predict prices with certainty, but some forecasters, such as the U.S. Energy Information Agency (EIA), predict real resource costs will fall over time. Our recent market experience suggests costs are continuing to rise in nominal and real terms.

In general, the cost assumptions used in this reference case are higher than those used in the 2005 Least Cost Plan, and generally represent the "all-in" cost to deliver a resource to our customers. Such cost estimates are higher than cost estimates available from public sources, such as the EIA, which do not reflect "all-in" cost elements. Our real market data reflects our activity in the resource acquisition market during the past five years, and we apply that experience here. Our extensive discussions with developers, vendors of key project components, and firms that provide engineering, procurement, and construction services lead us to believe the estimates used here are appropriate and reasonable.

Heat rates. New equipment heat rates are expected to improve slightly over time, as they have in the past. PSE applies the improvements estimated by EIA to known current heat rates in the Current Trends scenario.

Regional demand growth. Demand growth varies by area in the Western Electric Coordinating Council (WECC). These regional demands affect PSE costs because we compete for resources from related pools. PSE uses estimates provided by the AURORA model developer EPIS, which are based on information from the Northwest Power and Conservation Council (NPCC) and the EIA. Annual demand growth in the region ranges from 2.5% in the southwest to 1% in the northwest according to these sources.

PSE demand growth. PSE-specific demand growth incorporates assumptions about regional demand growth, but also includes many factors specific to our service territory. Development of PSE demand forecasts is discussed in detail in Chapter 4. For this scenario, we assume our reference demand forecast.

Gas prices. Gas price forecasts are acquired from Global Insight, a respected worldwide economic consulting firm, which performs long-run fundamentals-based gas price forecasts. We review the assumptions that go into Global Insight's model and compare their resulting forecast with other forecasts for reasonableness. For the near term (five years), PSE uses forward marks that are currently available in the market. The forward marks reflect the price of gas being purchased today for future delivery. PSE uses forward marks for gas prices for the years 2008 through 2011, and thereafter applies Global Insight's long run reference forecast.

Emissions costs. Emissions costs, other than the capital and operating costs of certain pollution control equipment, are not a significant energy price factor today; however, in the near future, at least by 2009, we expect the federal government will institute new regulations regarding green house gases (CO_2 for modeling purposes.) At this time, the people with whom we work to track legislative and regulatory issues believe that the Bingaman-Domenici bill, based on the National Commission on Energy Policy[1], is a reasonable measure and a good proxy to use for assumptions concerning future green house gas regulation. The Current Trends scenario assumes a CO_2 charge of $7 per ton starting in 2012, and that the charge increases 5% per year thereafter (compared to inflation of 2.5% per year). The charge is assumed to apply to both new and existing resources. Charges for multi-pollutants are based on estimates provided by the Environmental Protection Agency[2] (EPA), and assume the Administration's "Clear Skies" initiative is enacted. Clear Skies is very similar to current EPA initiatives. Mercury regulation is not modeled directly as there is uncertainty about potential rules and costs; however, our analysis incorporates the cost of controlling mercury as part of the fixed cost for any new coal burning plants.

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[1] "Ending The Energy Stalemate – A Bipartisan Strategy to Meet America's Energy Challenges"; The National Commission on Energy Policy; December 2004.

[2] "Multi-Pollutant Analysis: Comparison Briefing"; U.S. Environmental Protection Agency; Office of Air and Radiation; October 2005.

Production tax credits. The Production Tax Credit (PTC) is one of many federal subsidies related to production of nuclear, oil, gas and alternative energy. The present PTC amounts to approximately $17 per MWh for ten years of production, and is indexed for inflation. Currently the PTC is scheduled to expire at the end of 2008. We expect it to be extended at least once to 2009, after which there is much uncertainty. This scenario assumes PTCs remain at the current rate through 2009, and drop to a $10 credit in 2010 and 2011, representing a 50% probability that the PTCs will be extended for another two years. PTCs are still assumed to be given to a project for 10 years after it is placed into service. As of 2012, this scenario assumes no further PTCs are available to new resource development.

Renewable portfolio standards. Renewable portfolio standards (RPSs) exist in 23 states and the District of Columbia, including most of the states in the WECC[3]. Each state defines renewable energy sources differently, has different timetables for implementation, and has different requirements for the percentage of load that must be supplied by renewables. To model these varying laws, we first identified the load forecast for each state in the model. Then we identified the benchmarks of each RPS (e.g. 3% in 2015, then 5% in 2020) and applied them to the load forecast for that state. No retirement of existing WECC renewable resources was provided for, which perhaps underestimates the number of new resources that need to be constructed. After existing and expected renewable energy resources were accounted for, new renewable energy resources were matched to the load to meet the RPS. With internal and external review for reasonableness, these resources are created in the AURORA database. The renewable energy technologies included wind, solar, biomass and geothermal. Estimates of potential production by states in the “Renewable Energy Atlas of the West” served to guide the creation of RPS resources. These vary considerably. For example, Arizona has little wind potential but great solar potential. For modeling purposes, some resources for Oregon and Washington are mixed because the area borders do not correspond to the political borders. Since Oregon is considering an RPS, PSE has applied the Washington RPS to both states.

Build constraints. The AURORA model, like all optimizing models, identifies the least cost resource and creates a large number of those units in the WECC on an economic basis. Often, as with coal, the unrestricted level is much greater than seems reasonable

[3] DOE website includes a summary of U.S. RPS requirements with links to more detailed information at
http://www.eere.energy.gov/states/maps/renewable_portfolio_states.cfm#chart

given current political and regulatory realities. Hence, we added constraints on coal technologies to reflect present-day trends and attitudes. Specific constraints include limiting conventional coal to the central states and only to meet each state's own load growth. Starting in 2014, the only coal technology assumed to be available in the WECC is IGCC that is carbon sequestration ready, but without actual carbon sequestration installed and operating.

Green World

The Green World scenario enables us to investigate the consequences of a future in which there are much higher emission costs, higher natural gas prices, and a corresponding lower demand for electricity because of price and social preference. The load growth rates for all areas in the WECC are reduced based on the low growth case for PSE's demand.

Gas prices. In the Green World scenario, gas prices are expected to be higher as developers of new generation resources move from coal to gas to satisfy legal requirements, driving up the demand, and thus the price of natural gas. The region will also see increased use of gas-fired generation as more intermittent renewable energy generation comes online (primarily wind and solar). The gas price forecast used is Global Insight's long run high forecast. Forward marks are used for the 2008-2009 period.

Emissions costs. Emission charges for CO_2 are much higher in the Green World scenario, rising from $7 per ton in 2012 for the Current Trends scenario to $24 per ton in 2012 for Green World. Quantitative values for the charges were estimated based on the Environmental Protection Agency report cited above. The specific case is legislation named "The Clean Power Act" which was introduced by Sen. Jeffords. Multi-pollutants costs are based on legislation introduced by Sen. Carper called the "Clean Air Planning Act."

Robust Growth

This scenario models the impact of more robust long-term economic growth than assumed in the reference case, which creates higher demand for energy in the region and in PSE's service territory.

Demand growth*.* Assumptions for the Robust Growth scenario include a high growth rate for demand in the WECC region and, more specifically, a 2% growth rate for PSE.

Natural gas prices. Gas prices reflect forward marks for years 2008 and 2009; Global Insight's long run high gas forecast has been applied to the remainder of the planning period. Robust growth assumes a higher gas price forecast than Current Trends, but the same emission costs, thus the all in cost of natural gas resources are relatively higher in Robust Growth than in Green World, which has the same gas price forecast but also the higher emission costs.

Low Growth

This scenario models the impact of weaker long-term economic growth than assumed in the reference case, which creates lower demand for energy in the region and PSE's service area.

Demand Growth**.** A low growth rate has been applied for the WECC region and a 1.3% growth rate has been applied for PSE.

Natural gas prices. In keeping with the lower level of demand, PSE assumes forward marks for gas prices for the years 2008 through 2009, and thereafter applies Global Insight's long run low forecast.

Technology Improvement

This scenario models a future in which technological advances have resulted in improvements to both the heat rate efficiency and the real capital cost of most generating resources. The magnitude of the improvements was identified using the EIA's *Annual Energy Outlook 2006*[4].

Resource costs and heat rates*.* Initial assumptions about costs and heat rates in this scenario are much more optimistic than what PSE is currently experiencing in the market for new resources. The improvements estimated by EIA were converted to percent changes and applied to PSE's resources to arrive at a corresponding 20-year forecast.

[4] "Assumptions to the Annual Energy Outlook 2006," Energy Information Agency; Report #: DOE/EIA-0554(2006); March 2006.

Another cost difference modeled in this scenario involves the simple cycle gas turbines used as peakers. Historically, the construction cost of a simple-cycle combustion turbine has been lower than the capital cost of a combined-cycle turbine; however, the heat rate for the simple cycle turbine is much higher. There is an economic trade-off between a more expensive, but more efficient, combined-cycle plant that would be used more often, versus a less expensive high-heat-rate turbine that would be used for peaking. The Current Trends scenario does not show this historic differential because current market data indicates such historical cost differentials have narrowed significantly. Greater historic pricing differentials are assumed in the Technology Improvement scenario.

Build constraints. For the AURORA modeling of the Technology Improvement scenario, the cost of new coal plants reflects IGCC with carbon capture and sequestration (CCS) in 2021.

Escalating Costs

In our Technology Improvement scenario, technology advancements drive down real resource costs in the future, ”all else” equal. But what if “all else” is not equal? What if costs continue to increase? The Escalating Cost scenario is a counterpoint to the optimistic Technology Improvement scenario. To develop technology cost input assumptions for this scenario, we relied again on EIA information, though indirectly.

Resource costs. EIA’s base case has a slight decrease in real costs over time. We applied the inverse of the magnitude of the base case change in costs to PSE’s starting costs to create a scenario with escalating costs. Overall, the impact is relatively small, at about a 5% real capital cost increase over 20 years.

Figure 3-2
Six Electric Analysis Scenarios

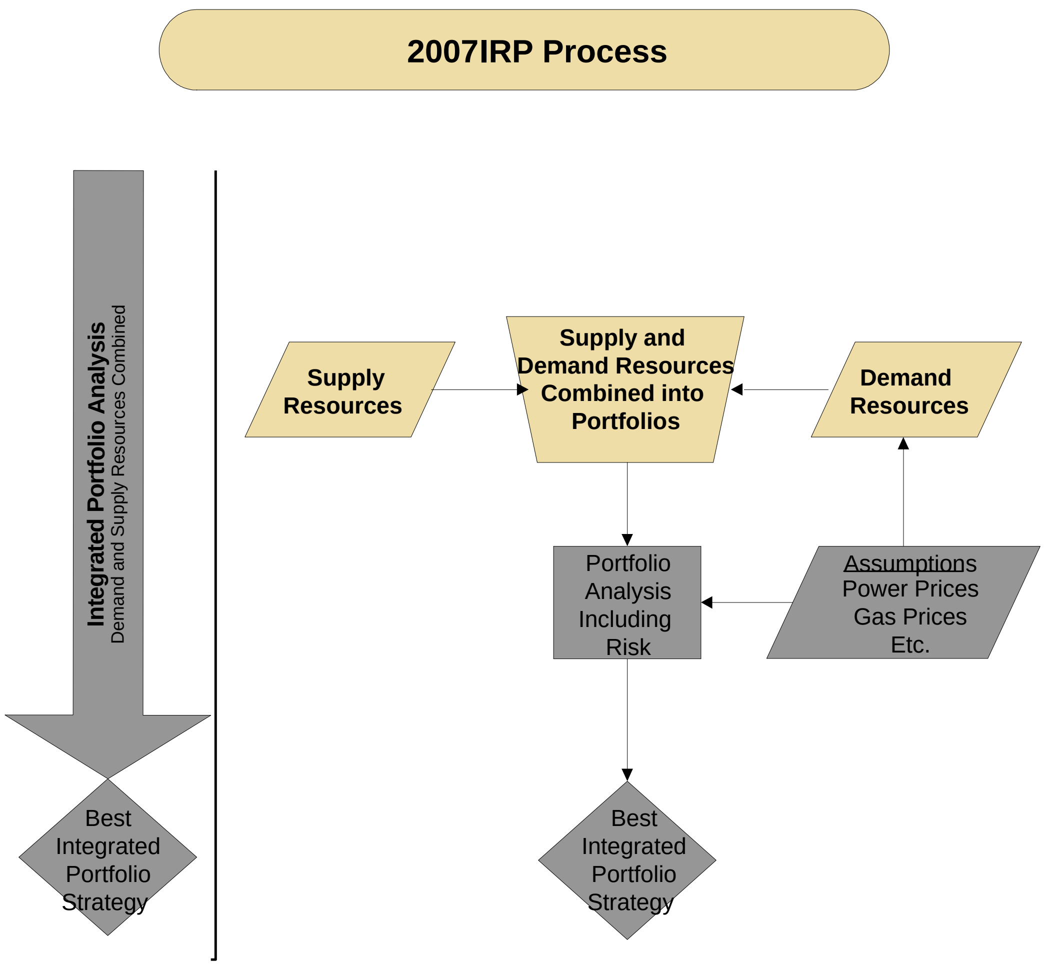
	Current Trends (Reference)	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Costs
Theme	Best estimate of current resource costs and characteristics, fuel prices, state laws and moderate federal environmental policies	Support for stronger environmental legislation at the federal level, with continuation of state level RPS	Lower regional and PSE demand load growth based on lower long-term economic growth.	Higher regional and PSE demand load growth based on higher long-term economic growth.	Optimistic outlook regarding technology development and deployment, as well as learning for thermal resources, based on EIA scenario.	Pessimistic view of technology development and deployment with increased costs and reduced availability.
WECC Demand (AURORA)	EPIS Averages CA: 1.97% SW: 2.5% PNW: 1% RM: 2%	Low Growth	Low Growth	High Growth	Reference	Reference
PSE Demand	Base 1.9%	Low 1.7%	Low 1.7%	High 2.2%	Reference	Reference
Gas Price	Forward marks for 2008-2011, and Global Insights long run fundamental forecast.	Forward marks for 2008-2009, and Global Insights long run high forecast.	Forward marks for 2008-2011, and Global Insights long run low forecast.	Forward marks for 2008-2009, and Global Insights long run high forecast.	Reference	Reference
Coal Price	Global Insights	Reference	Reference	Reference	Reference	Reference
Generic Resource Cost $/KW	PSE market based estimates with constant real costs for 20 years	Reference	Reference	Reference	Reference values adjusted per EIA Annual Energy Outlook 2006 (AEO2006) -0.25%/yr Mature -1.25%/yr New	PSE market based estimates with increasing real costs
Generic Resource Heat Rates	PSE Generic Heat Rates with EIA AEO2006 Reference case improvements	Reference	Reference	Reference	Adjustments per AEO2006 Advanced Technology side case	Reference

	Current Trends (Reference Case)	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Costs
Emissions CO2 (Nominal $/Ton)	"NCEP" (Bingaman) Start in 2012 with 5% annual nominal increase. 2012: $7.00 2020: $10.34 2027: $14.55	"Clean Power" (Jeffords) Start in 2012. Increasing per EPA (10/05) 2012: $ 24.81 2020: $45.35 2027: $70.68	Reference	Reference	Reference	Reference
Emissions SO2 (Nominal $/Ton)	Clear Skies (Bush) Start in 2010 2010: $978 2020: $2105 2027: $3306	"Clean Air Planning Act" (Carper) 2010: $1481 2020:$3191 2027: $5009	Reference	Reference	Reference	Reference
Emissions NOx (Nominal $/Ton)	Clear Skies Start in 2010 2010: $ 297 2020: $640 2027: $1006	"Clean Air Planning Act" (Carper) 2010: $5742 2020: $1522 2027: $1809	Reference	Reference	Reference	Reference
Production Tax Credits ($/MWH)	$19: 2008-2009 $10: 2010 - 2011 For all eligible technologies	Reference	Reference	Reference	Reference	Reference
RPS	Meet current state RPS through 2027. WA & OR meet RPS standards based on WA I-937	Reference	Reference	Reference	Reference	Reference
Build Constraints	**2012-2027:** IGCC + CCS ready Build to meet load growth only. 1 IGCC w CCS in CA.	Reference	Reference	Reference	**2012-2027:** IGCC + CCS ready Build to meet load growth only. **2021-2027:** IGCC with CCS	Reference

B. Electric Portfolios

Hypothetical portfolios used in this resource planning analysis were tested in the different planning scenarios detailed above. PSE performed an integrated analysis, meaning demand-side and supply side resources were combined and analyzed as one integrated portfolio. Portfolios were developed to ensure a robust analysis of all planning scenarios that could answer key planning questions. A significant amount of analysis went into selecting the demand- and supply-side resources for portfolio analysis, which is summarized below. Figure 3-3 illustrates how demand and supply resources are integrated into our portfolio analysis.

Figure 3-3
Constructing Integrated Portfolios



Demand-side Resource Alternatives

PSE utilized a comprehensive screening process to aggregate demand-side resources from a potential 1700+ individual energy efficiency and other demand side measures down to five “bundles.” This process is described in Chapter 5. Savings for all demand-side bundles resulted from energy efficiency, distributed generation, fuel conversion, and demand response measures. Demand response measures were used to calculate avoided peak demand rather than avoided annual energy requirements.

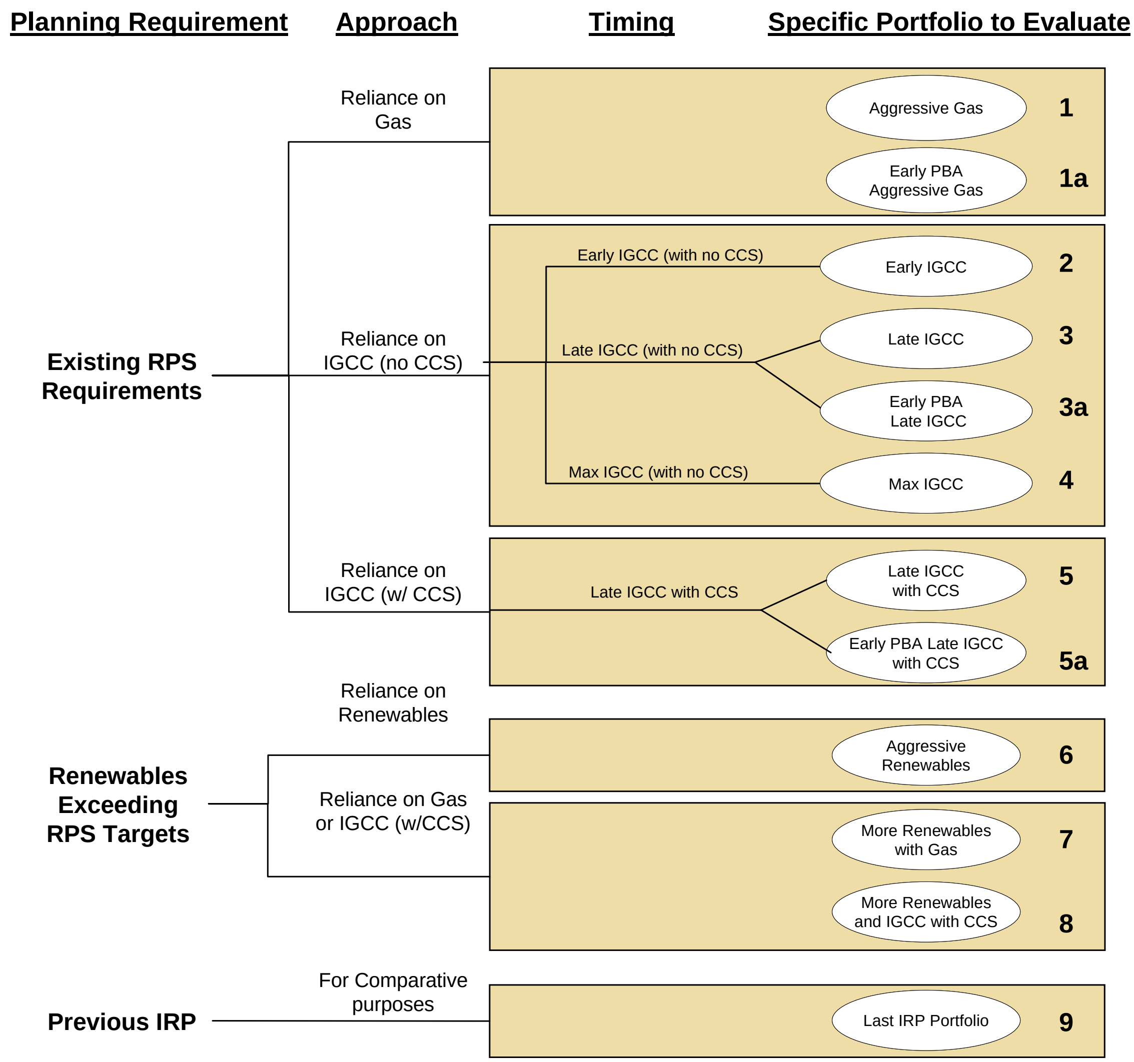
- Demand-side Bundle 1: The Current Trends bundle, which assumes avoided costs of $89.82 per MWh with total savings of 439 aMW.
- Demand-side Bundle 2: The High Avoided Costs bundle assumes avoided costs 25% higher than the Current Trends bundle for total savings of 464.5 aMW.
- Demand-side Bundle 3: The Low Avoided Costs bundle assumes avoided costs 10% lower than the Current Trends bundle for total savings of 419.9 aMW.
- Demand-side Bundle 4: The Low Growth bundle assumes avoided costs 14% lower than the Current Trends bundle and total savings of 404.4 aMW.
- Demand-side Bundle 5: The Green World bundle assumes avoided costs 14% higher than the Current Trends bundle for total savings of 450 aMW.

Supply-side Resource Alternatives

The supply-side alternatives for the resource portfolios are made up primarily of varying amounts of renewables, intermediate term power bridging agreements (PBAs), natural gas-fired combined cycle combustion turbines (CCCT), and coal-fueled integrated gasification combined cycle turbines (IGCC) with and without carbon capture and sequestration (CCS). Such portfolios introduce various resources at different times and in different quantities. Several include small changes in composition that stem from our desire to understand how certain assumptions might influence analytical results. For example, we wanted to find out how the use of short-term power bridging agreements (PBAs) affected expected costs for each of the different portfolios. PSE designed the portfolios to provide insight to how different levels of renewable energy requirements might evolve, what the cost and risk exposure to different fuel choices might be, and the sensitivity of results to the timing of these key decisions.

These alternatives are illustrated schematically in Figure 3-4.

Figure 3-4
Diagram of Electric Analysis Portfolio



Integrating Resources into Portfolios

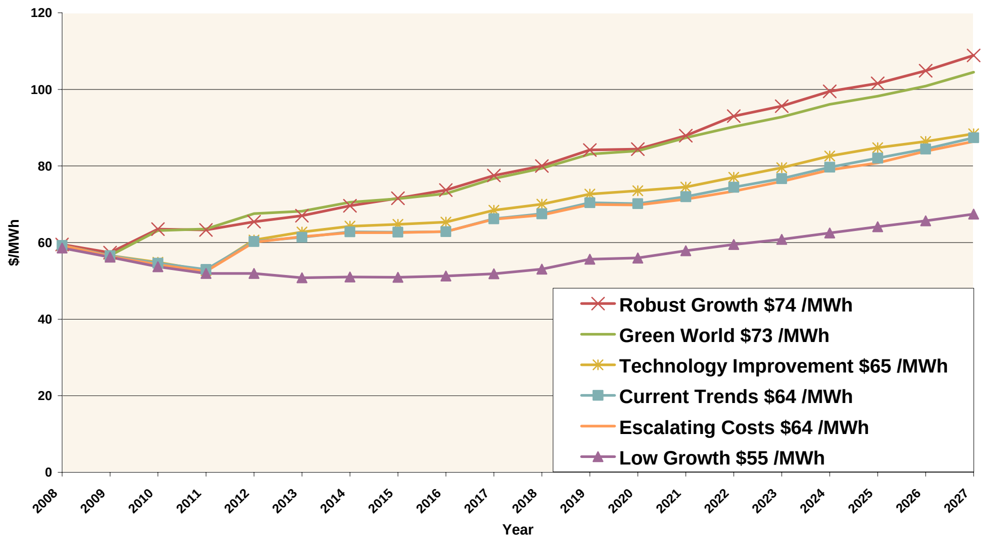
Integrated resource portfolios were generated by combining various demand-side bundles with the sets of supply-side elements. Rather than use all five demand-side resource bundles, we chose bundle 1 (Current Trends) along with bundles 2 and 4, which were the high and low cost bookends. This exercise is described in more detail in Chapter 5.

C. Electric Price Forecasts

The AURORA model was used to create separate electric market price forecasts for each of the six scenarios. The forecasts calculated by AURORA are based on specific economic, marketplace, and demand assumptions pertaining to each scenario. Different sets of input assumptions are designed to represent the different planning scenarios described above. A table summarizing key input assumptions is available in the Electric Analysis Appendix.

A comparison of the six electric price forecasts appears in Figure 3-5 below. Tables showing the monthly prices for all of the forecasted scenarios appear in the Electric Analysis Appendix.

Figure 3-5
Comparison of Annual Mid-C Price Forecasts for Six Electric Scenarios



Electric price forecasts are grouped tightly around one key input assumption: natural gas prices. Robust Growth and Green World prices are very similar, with levelized prices at $74/MWh and $73/MWh, respectively. Both use the same high gas price forecast. Current Trends, Technology Improvement, and Escalating Cost electric price forecasts are also tightly clustered in the range of $64-65/MWh. These scenarios also share a common gas price assumption. The electric price forecast for Low Growth is the lowest at $55/MWh, based on a low gas price assumption. While other input assumptions for PSE's portfolio analysis play a role, natural gas prices are the single largest determinant for the electric market price forecast. This result is consistent with natural gas-fired resources serving as the marginal market resource most of the time.

III. Gas Analysis Components

A. Gas Scenarios

Natural gas and electric resource planning analyses utilized consistent assumptions. Two kinds of studies were performed in our gas planning analysis. First, we performed gas resource planning analysis to meet the growing needs of our gas sales customers. Second, we performed a planning analysis on electric generation fuel requirements. The starting point for our generation fuel analysis was the gas load that results from the lowest reasonable cost electric portfolio. That is, after completing the electric analysis and selecting the lowest cost portfolio, we captured the gas usage from the electric dispatch model and applied our gas optimization model to these results. This allowed us to examine generation fuel use more closely than is possible in electric modeling alone.

Gas sales analysis was performed in the context of Current Trends, Green World, Robust Growth, and Low Growth planning scenarios. Technology Improvement and Escalating Costs were not replicated in the natural gas resource planning analysis, since those two scenarios are focused on factors mainly relevant to electric generation. The generation fuel requirements study was performed with Current Trends gas prices and the Current Trends dispatch of generation fuel.

Figure 3-6 summarizes the gas planning scenarios.

Figure 3-6
Gas Scenarios Summary Table

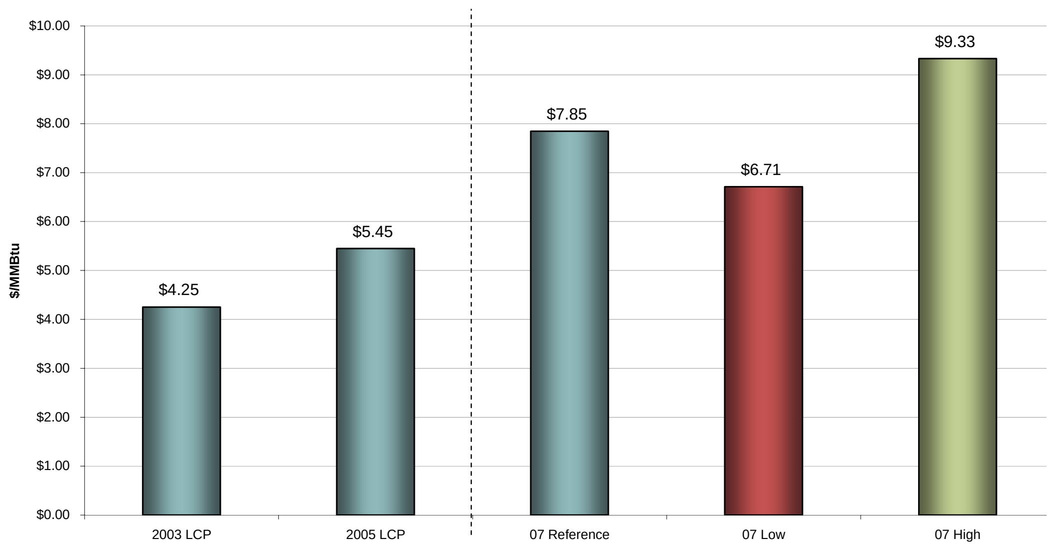
	Theme	Gas Demand	Gas Prices
Reference or Base Case	Current trends continue.	Base case customer growth and use/customer.	Mid-Prices: Global Insights Reference Case
Green World	National gas demand driven up, driving up prices.	Base case customer growth and use/customer.	High Prices: Global Insights High Scenario
Robust Growth	Local economy grows faster than expected.	High customer growth rate and higher use/customer.	High Prices: Global Insights High Scenario
Reduced Growth	Low regional and national economy.	Low customer growth rate and lower use/customer.	Low Prices: Global Insights Low Scenario
Generation Fuel Study	Current Trends Continue	Gas demand for generation fuel from lowest resaonable cost portfolio	Mid-Prices: Global Insights Reference Case

B. Gas Price Forecasts

As mentioned above in the scenario discussion, gas prices used for resource planning analysis were a combination of forward market prices, followed by fundamental forecasts. Fundamental forecasts were acquired from Global Insight, a well known macroeconomic and energy forecasting consultancy. Global Insights performs a comprehensive gas market analysis that includes regional, North American, and international factors (including Canadian markets and LNG imports).

Figure 3-7 below illustrates 20-year levelized gas prices, including forward market prices used in the resource planning analysis. Comparisons of gas prices from the 2003 and 2005 resource plans are also depicted. Figure 3-7 demonstrates that current market and forecast gas prices have increased significantly in the past four years.

Figure 3-7
Levelized Sumas Hub Gas Price Forecasts, 2008-2027



Reference gas prices for the 2007 IRP are 85% than assumed in the 2003 Least Cost Plan.
Even low gas prices for the 2007 IRP are 58% higher than the reference case from the 2003 Least Cost Plan

Demand Forecasts

Demand forecasting is a means of estimating the amount of energy that customers will use in the future. These forecasts project the "load" that the system will need to provide. Demand forecasts are one of two key determinants used to identify resource need. The second is an assessment of the Company's existing resources. "Resource need" is the gap between the two. The chapter is divided into three sections.

PSE performs a 20-year forecast of energy sales, customer counts, and peak demand each year. We use this forecast principally for planning long-term resource and delivery systems. Variations of the forecast may also be used to make annual revenue forecasts and operational plans. The 20-year horizon makes it possible to anticipate needs and develop timely responses. Annual updates provide for timely forecast revisions based on the most current information.

I. Methodology

The econometric method PSE employs to produce forecasts of energy demand uses historical data to explain changes in energy sales per customer and customer counts. Notable determinants include: regional and national economic growth, demographic changes, weather, prices, seasonality, and other customer usage and behavior factors. Known near-term load additions or deletions are also included.

The model is specified on electricity and/or gas as inputs into the production of various economic activities. For the residential sector, customer uses include space heating, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, and various other plug loads. For the commercial and industrial sectors, energy applications include heating, venting, and air conditioning (HVAC), lighting, computers, and other production processes.

Peak load forecasts are also developed by the application of econometric equations that relate observed monthly peak loads to weather-sensitive delivered sales for both residential and nonresidential sectors; deviations of actual peak hour temperature from normal peak temperature for the month; day of the week effects; and unique weather events such as a cold snap or El Nino.

A detailed discussion of the methodology used to produce the annual energy and hourly electric forecasts appears in the Load Forecasting Models Appendix.

Customers are divided into classes and service levels that use energy for certain specific purposes to forecast energy sales and customer counts:

- Electric customer classes include residential, commercial, industrial, streetlights, and resale.
- Gas customer classes include firm (residential, commercial, industrial, commercial large volume, and industrial large volume), interruptible (commercial and industrial interruptible), and transportation (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

To forecast peak load:

- Electric peak loads are calculated on an hourly basis, and projected for a winter normal and extreme peak design temperatures (normal: 23^{o} F; extreme: January 15^{o} F, February 15^{o} F, November 17^{o} F, and December 13^{o} F). These extreme peak design temperatures were established based on a one in 20 year return period (5% exceedence probability) developed from extreme value distributions of the 30 year historical minimum temperatures during the on-peak hours.
- Gas peak loads are calculated on a daily basis using a 52-heating degree as the design day temperature to represent its relevant peak. This planning standard is expected to meet or exceed 98% of historic peak day temperatures, and is described more fully in the Load Forecasting Models Appendix.

II. Key Assumptions

Economic activity and fuel prices have a significant effect on energy demand. Higher employment leads to greater energy demand by businesses and increases in the retail customer counts. Retail energy prices influence the type of fuel used to operate appliances, the amount used, and the choice of appliance efficiency levels in the long run. PSE used the following key assumptions about economic activity and fuel prices for the forecasts presented in this IRP.

A. Economic Growth

The Puget Sound area is a major commercial and manufacturing center in the Pacific Northwest with strong links to national and state economies. These links create jobs not only for directly affected industries, but also indirectly for supporting industries through multiplier effects. Accordingly, the performance of the national and state economies impacts PSE's service territory economy. PSE uses information and data generated by Global Insight, a global research firm specializing in economic analysis, as a resource for the U.S. macroeconomic assumptions.

National Economic Outlook

Global Insight's Third Quarter 2006, The US Economy: 30-Year Focus predicts that the nation's gross domestic product (GDP) will grow at an average rate of 2.8% per year over the next 25 years with only mild variations (trend growth). It projects that robust growth in equipment spending and advances in technology will result in higher productivity and efficiencies, even though the percentage of employed Americans will decline as the population ages. These national economic forecasts are summarized in Figure 4-1 below.

Figure 4-1
National U.S. Economic Outlook

	2006	2007	2010	2015	2020	2025	AARG*
Gross Domestic Product (in billions)	$ 11,417.0	$ 11,692.7	$ 12,822.4	$ 14,684.7	$ 16,949.9	$ 19,461.9	2.8%
Employment (in millions)	135.3	136.8	142.2	146.9	153.6	161.4	0.9%
Population (in millions)	299.6	302.3	310.3	323.7	337.1	350.8	0.8%

*AARG: average annual rate of growth

Global Insight's report anticipates near-term economic growth will be moderated by the Federal Reserve Board's interest rate policy to keep inflation low. Increases in consumption and business fixed investment are expected to offset slower employment growth, keeping U.S. economic growth steady over the long run. Real oil prices are also expected to decline near term, but to eventually rise because of rising costs to find, produce, process and distribute product in an environment in which new material is increasingly scarce. The forecast assumes a decline in the value of the dollar relative to other currencies, raising U.S. exports but increasing the cost of imported goods and services.

Regional Economic Outlook

During the next two decades, PSE expects employment in our service area to grow at an annual rate of 1.4% to 1.5%, compared to the 20-year historical rate of 2.5%. Factors contributing to the slower long-term growth in employment include slower national employment growth and an expectation that The Boeing Company's more efficient production processes will not generate the historical employment highs of 2000. Despite the slower rate of growth, we project local employers will create more than 600,000 jobs between 2006 and 2025, and the inflow of more than 800,000 new residents will increase the population of our service territory to about 4.5 million.

Between 2001 and 2003, the region experienced one of its worst recessions in the last 20 years, with employment declining in 2002 by about 2%. Employment boomed after that—particularly in the service sector—with the resurgence of Boeing in 2004, increased nonresidential construction, and higher exports due to a weaker dollar. This expansion is expected to continue in 2007 and 2008 though at a slower rate, led by increased hiring at Boeing (to ramp up production) and at Microsoft (for research and development). Most long-term employment growth is expected to come in the service sectors, including business services and computer industries, with variations by county. Smaller counties such as Island and Jefferson are expected to experience higher growth rates than King County, even though King will experience the highest absolute number of new jobs created. Figure 4-2 summarizes projected employment and population growth for PSE's service territory.

Figure 4-2
Economic Growth Assumptions for PSE Service Area

(in thousands)	2006	2007	2010	2015	2020	2025	AARG
Electric Service Area							
Employment	1,811.2	1,851.5	1,951.8	2,117.1	2,237.6	2,380.4	1.4%
Population	3,507.3	3,563.9	3,693.7	3,922.9	4,132.5	4,317.8	1.1%
Gas Service Area							
Employment	1,815.9	1,862.3	1,974.5	2,148.2	2,271.7	2,422.7	1.5%
Population	3,559.1	3,620.0	3,767.0	4,010.9	4,228.8	4,427.5	1.2%

B. Energy Prices

Retail energy prices—what customers pay—are included in the demand forecasts because they affect the efficiency level of newly acquired appliances, their frequency and level of use, and the type of energy source used to power them. The load forecast is an input into the resource planning process. Hence, the energy price forecasts draw on earlier information derived from internal and external sources.

Electricity

PSE projects that nominal retail electric rates will grow between 3.2% and 3.4% per year over the next 20 years. Near term, this forecast assumes rate increases resulting from our General Rate Cases and from Power Cost Only Rate Cases. To project long-term retail rates, we began with Global Insight's forecast of electric rates for the state and adjusted them to provide starting points in line with PSE's near-term forecast of retail rates.

PSE assumes that long-term real electricity prices (i.e., nominal prices adjusted for inflation) will be flat or will grow only moderately over time. This is due to competitive pressures resulting in moderating nominal costs, additional capacity in regions lacking sufficient energy supply, lower coal prices, and an increase in the efficiency of new generation technologies. Global Insight predicts that most new generation will come from gas-fired facilities, with small amounts from coal and wind. As the region increasingly relies on gas for new generation, marginal electric prices throughout the region will become similar while average electric price differentials across the region will gradually narrow.

Natural Gas

We expect the rise in nominal retail gas rates to equal the long-term rate of inflation: 1.8% to 2.1% per year over the next 20 years. In real terms, this means gas retail rates would remain virtually unchanged. Two components make up gas retail rates: the cost of gas and the cost of distribution, known as the distribution margin. The near-term forecast includes PSE's purchased gas adjustment of October 2006, and an increase due to a General Rate Case in 2007. Forecasted gas costs reflect Kiodex prices for 2006 to 2011, and Global Insight projections after that. The distribution margin is based on PSE's projection for the near term and Global Insight's for the longer term.

Figure 4-3 below summarizes electric and gas rate forecasts over the next 20 years.

Figure 4-3
Retail Rate Forecasts for Electric and Gas

(nominal)	2006	2007	2010	2015	2020	2025	AARG
Residential							
Electric, cent/kwh	7.19	8.31	9.41	10.48	11.63	13.05	3.2%
Natural Gas, $/therm	1.32	1.47	1.43	1.52	1.72	1.96	2.1%
Commercial							
Electric, cent/kwh	7.73	8.36	9.39	10.64	12.22	14.10	3.2%
Natural Gas, $/therm	1.23	1.36	1.30	1.37	1.55	1.77	2.0%
Industrial							
Electric, cent/kwh	7.28	7.88	8.86	10.03	11.68	13.66	3.4%
Natural Gas, $/therm	1.16	1.27	1.18	1.24	1.41	1.61	1.8%

C. Other Assumptions

Weather

The billed sales forecast is based on normal weather defined as the average weather using the last 30 years, ending in 2005.

Loss Factors

Based on current analysis, the electric loss factor was increased to 6.7% from 6.6%. The gas loss factor remains at 0.8% of total sales.

Major Accounts

Two major corporations in PSE's service area plan to add facilities starting in 2007 that will eventually increase consumption by 37 aMW. Completion of a planned water treatment plant in 2010 will add 14 aMW of consumption. A major residential development in Kittitas County is expected to add approximately 500 residential customers in the next few years.

III. Electric and Gas Demand Forecasts

Demand forecasts starting in 2008 serve as the basis for establishing system requirements in this resource plan. The charts and tables below incorporate existing demand-side resources (energy efficiency and conservation) prior to 2008, but do not include anticipated additional demand-side resources thereafter.

PSE analyzes several scenarios in order to capture the range of possible economic futures. Three scenarios were used to develop these forecasts. These scenarios are:

- The Base Case forecast assumes that the U.S. economy grows smoothly over time, with no major shocks or disruptions, at a rate of 2.8%.
- The High Case forecast assumes a faster GDP growth rate of 3.3%, a low inflation rate, and high productivity growth.
- The Low Case Forecast assumes a slower GDP growth rate of 2.3%, high inflation rates, and low productivity. It also assumes significant cutbacks in Boeing and Microsoft employment due to increased competition and regulations.

A. Electric Forecast

Figures 4-4 and 4-5 below map electric sales and peak growth forecasts for the Base Case, High Case, and Low Case over the 20-year planning horizon. The 2005 LCP base case is shown for comparison purposes. Highlights are discussed on the following pages.

Figure 4-4
Electric Sales Forecasts 2006-2025

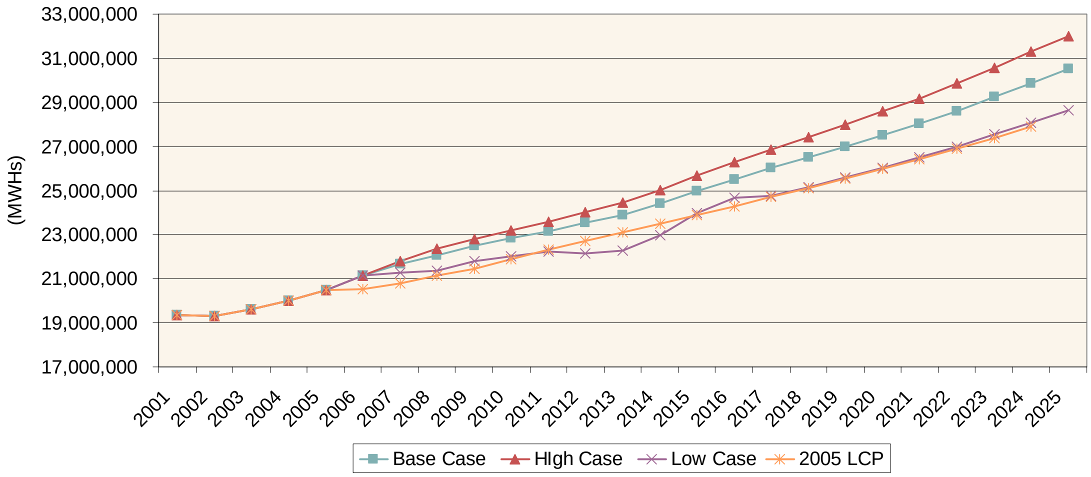
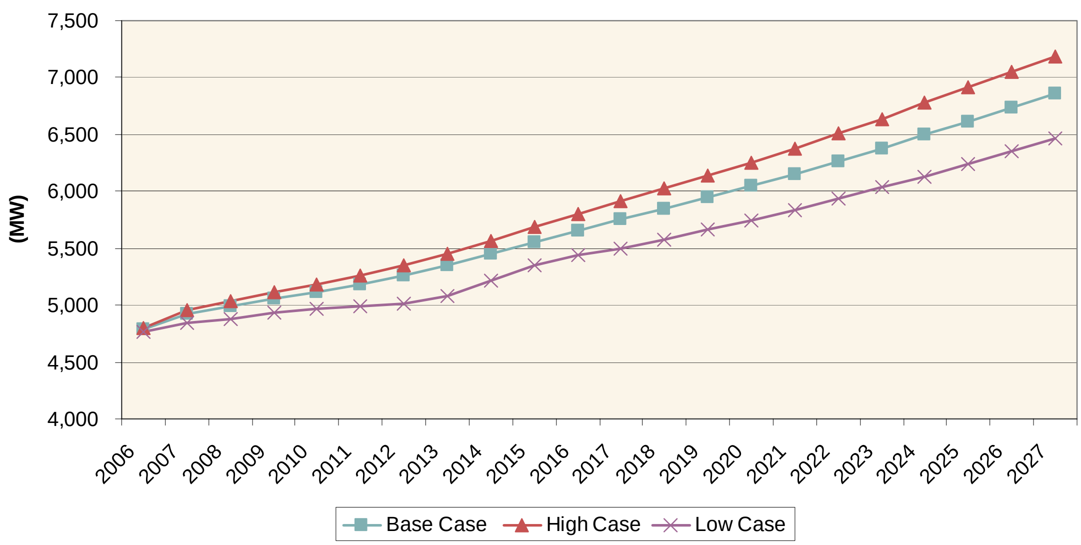


Figure 4-5
Electric Peak (Normal-23°F) Forecast



Electric Forecast Highlights (Base Case)

1. Electric sales are expected to grow at an average annual rate of 2% per year, from 2,412 aMW in 2006, to 3,483 aMW by 2025.

Driven by the area's vibrant economy over the last three years, we expect strong growth in loads to continue through 2007. The rate is then projected to moderate to 1.5% between 2008 and 2014 due to the moderate economic growth, before returning to slightly above 2% per year growth for the remainder of the period.

2. Commercial sales are expected to grow faster than residential sales, increasing from 49% of total sales in 2006 to 52% of total sales in 2025.

Billed sales related to nonmanufacturing employment are expected to grow the fastest in the future, while industrial sales are expected to continue to decline gradually as they have for the past decade (with the exception of 2001) due to declining manufacturing employment.

Slower growth in residential sales is caused by several factors: a projected increase in the rate of construction of multifamily housing, which uses less energy compared to single-family housing; the use of more efficient appliances; and the expectation that new single-family homes are likely to use gas for space and water heating. Residential retail energy price levels are higher, but grow at a slightly slower rate. All these are expected to produce declines in average residential use per customer of close to 1% per year in the forecast period. Residential sales as a percentage of total sales are projected to decline from 50% in 2006 to 47% in 2025.

3. The number of electric customers is predicted to grow at an average rate of 2% per year, reaching 1,500,647 by 2025.

Even though commercial customer growth rates are higher, the residential sector is expected to account for the majority of customer growth in absolute numbers. Currently, residential customers account for 88% of PSE's total customer base. Taking into account the increasing share of multifamily units over the next 20 years, we expect that percentage to decline by only a small amount.

4. Peak hourly loads for electric are expected to grow by 1.7% per year over the next 20 years to 6,616 MW from 4,792 MW, slower than the growth in billed energy.

Peak load growth is projected to grow more slowly than total energy use because residential sales (which place the most upward pressure on peak load events) are growing more slowly than commercial and industrial sales.

In general, compared to the forecast in the 2005 Least Cost Plan, the new forecast of energy load is higher by about 175 aMW by 2020, and grows at a slightly faster pace primarily due to higher customer growth and a slightly slower decline in residential use per customer than anticipated in 2005.

The following tables summarize electric demand forecast results.

Figure 4-6
Electric Sales Forecast Scenarios in aMW

	2006	2007	2010	2015	2020	2025	AARG
Scenarios							
Base Case	2,412	2,472	2,605	2,852	3,140	3,483	2.0%
High Case	2,412	2,486	2,649	2,929	3,262	3,654	2.2%
Low Case	2,412	2,430	2,515	2,736	2,972	3,268	1.6%
LCP 2005	2,345	2,375	2,499	2,727	2,966	N/A	1.7%

Figure 4-7
Electric Sales Forecasts by Class in aMW (Base Case)

	2006	2007	2010	2015	2020	2025	AARG
Base Case							
Total	2,412	2,472	2,605	2,852	3,140	3,483	2.0%
Residential	1,224	1,234	1,272	1,383	1,510	1,645	1.6%
Commercial	1,018	1,069	1,162	1,306	1,467	1,677	2.7%
Industrial	157	156	157	147	144	141	-0.6%
Others	12	13	14	16	18	20	2.6%

Figure 4-8
Electric Customer Count Forecast by Class (Base Case)

	2006	2007	2010	2015	2020	2025	AARG
Total	1,039,523	1,061,336	1,126,112	1,242,398	1,367,252	1,500,647	2.0%
Residential	918,109	936,970	992,445	1,091,598	1,197,430	1,309,252	1.9%
Commercial	114,840	117,652	126,583	142,996	161,148	181,670	2.4%
Industrial	3,800	3,803	3,775	3,735	3,704	3,670	-0.2%
Others	2,774	2,911	3,309	4,069	4,970	6,055	4.2%

Figure 4-9
Electric Peak Forecast (Base Case)

	2006	2007	2010	2015	2020	2025	AARG
Normal Peaks	4,792	4,924	5,116	5,557	6,047	6,616	1.7%
Extreme Peaks	5,228	5,376	5,590	6,081	6,624	7,256	1.7%
2005 LCP	4,719	4,751	4,945	5,307	5,687	N/A	1.3%

Figure 4-10
Residential Normalized Electric Use per Customer in MWh,
2007 compared to 2005 (Base Case)

	2006	2007	2010	2015	2020	2025	AARG
LCP 2005	11.068	10.824	10.331	9.905	9.745	N/A	-0.9%
LCP 2007	11.782	11.620	11.088	10.668	10.545	10.537	-0.8%

B. Gas Forecasts

Figures 4-11 and 4-12 below map the gas Base Case, High Case, and Low Case sales and peak day forecasts over the 20-year planning horizon. The 2005 LCP base case is shown for comparison purposes. Highlights are discussed on the following pages.

Figure 4-11
Gas Sales Forecast Scenarios, 2006-2025

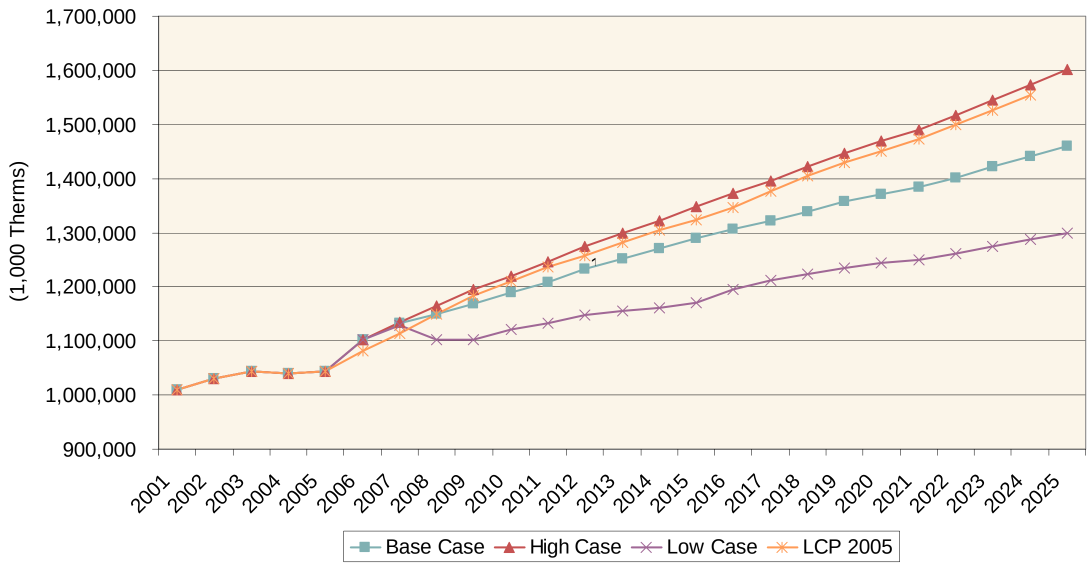
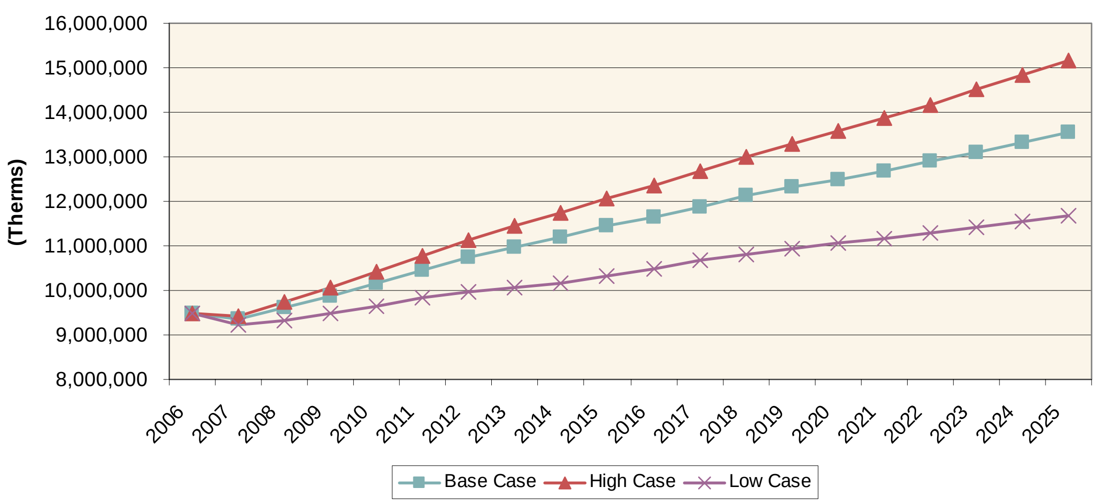


Figure 4-12
Gas Peak Day Forecast Scenarios, 2006-2025



Gas Forecast Highlights (Base Case)

1. Natural gas sales are expected to grow at an average rate of 1.5% per year over the next 20 years, to 1.46 billion therms from 1.1 billion therms in 2006 by 2025.

We expect a slightly faster growth rate in gas billed sales in the near term—over the next six years—as nominal gas prices remain flat or slightly lower; however, nominal gas price increases are expected to approximate the rate of inflation over the long term, which will slow the growth in sales for the remainder of the 20-year period.

While overall volume will increase, some sectors (industrial, interruptibles, and transportation) are expected to decline slightly, continuing a 10-year trend of slowing manufacturing employment and increasing retail prices. A slight decline in residential use per customer due to more efficient equipments and a projected increase in multifamily housing is offset by a steady increase in the number of customers.

2. Gas customer count is expected to increase at a rate of 2.2% per year in the next 20 years, reaching 1,085,323 by 2025.

This forecast reflects slower population growth (hence slower demand for housing) and a declining pool of potential conversion customers compared to the historical growth rate of about 3.3%.

Residential accounts are expected to increase at a rate of 2.2% per year over the next 20 years, and to represent 92% of our total customer base in 2025, as they do today.

While the number of potential conversion customers is expected to decline, this is expected to be offset by increasing penetration of gas into multifamily buildings (townhomes and condominiums) and new single-family homes.

Commercial sector accounts are expected to grow at an average annual rate of approximately 2.4% per year during the next two decades, and to continue to account for 7% of the overall customer base. New restrictions on the use of alternative fuels (especially oil) will contribute to a gradual decline in the growth rate of interruptible customers. We expect many of our current interruptible customers, especially those with smaller loads, will become all-firm customers or arrange for various combinations of firm, interruptible, and transportation services.

3. Peak-day firm gas requirements are expected to increase at an average rate of 1.9% per year over the next 20 years, from 9.4 million therms in 2006 to 13.5 million therms in 2025.

Gas peak-day growth rates are slightly higher than those for total billed sales because faster sales growth is predicted for the weather-sensitive residential sector for the first six years due to flat or slightly declining gas retail prices. The primary drivers of peak growth across all sectors are an expanding customer base and changes in use per customer. Rising base loads are contributing to peak demand because gas is increasingly being used for purposes other than heating (such as cooking, clothes drying, and fireplaces). This effect is slightly offset by higher appliance efficiencies, and by the increasing use of gas in multifamily housing, where per-customer use is lower.

The residential sector accounts for about 65% of the peak daily requirement; the commercial and industrial sectors account for 29% and 5%, respectively. Large-volume commercial and industrial customers are included in this forecast.

Compared to the gas peak day forecast produced in the 2005 Least Cost Plan, this forecast is higher for 2006, but slightly lower for later years due to higher projected retail prices.

The tables below summarize gas demand forecast results.

Figure 4-13
Gas Sales Forecast Scenarios

(in 1,000 therms)	2006	2007	2010	2015	2020	2025	AARG
Scenarios							
Base Case	1,102,835	1,133,454	1,188,846	1,290,536	1,371,050	1,460,106	1.5%
High Case	1,102,835	1,135,062	1,219,629	1,348,440	1,469,549	1,600,890	2.0%
Low Case	1,102,835	1,129,240	1,121,378	1,171,337	1,243,269	1,298,237	0.9%
LCP 2005	1,082,177	1,114,361	1,210,170	1,323,327	1,450,690	N/A	2.1%

Figure 4-14
Gas Sales Forecast by Class (Base Case)

(in 1,000 therms)	2006	2007	2010	2015	2020	2025	AARG
Total	1,102,835	1,133,454	1,188,846	1,290,536	1,371,050	1,460,106	1.5%
Residential	549,310	566,288	611,994	687,195	745,248	794,037	2.0%
Commercial	235,083	242,279	266,432	307,884	349,135	395,172	2.8%
Industrial	38,257	38,179	37,997	38,027	36,632	34,833	-0.5%
Interruptibles	74,058	87,098	71,884	62,117	49,836	43,812	-2.7%
Transportation	206,128	199,610	200,539	195,312	190,199	192,252	-0.4%

Figure 4-15
Gas Customer Count Forecasts by Class (Base Case)

	2006	2007	2010	2015	2020	2025	AARG
Total	715,116	736,368	797,710	902,039	999,675	1,085,323	2.2%
Residential	659,789	679,749	737,213	834,553	924,706	1,001,876	2.2%
Commercial	52,117	53,465	57,508	64,717	72,382	81,033	2.4%
Industrial	2,635	2,605	2,507	2,360	2,239	2,117	-1.1%
Interruptibles	452	429	362	289	229	178	-4.8%
Transportation	123	120	120	120	119	119	-0.2%

Figure 4-16
Gas Peak Day Forecast (Base Case)

(in 1,000 therms)	2006	2007	2010	2015	2020	2025	AARG
Total	9,482,914	9,363,205	10,164,268	11,444,406	12,499,946	13,535,248	1.9%
Residential	6,585,518	6,478,443	7,024,722	7,876,459	8,525,412	9,094,739	1.7%
Commercial	2,473,475	2,469,148	2,717,079	3,133,401	3,545,296	4,017,290	2.6%
Industrial	348,058	340,708	341,153	342,991	329,238	314,937	-0.5%
Losses	75,863	74,906	81,314	91,555	100,000	108,282	1.9%
LCP 2005	9,217,189	9,504,752	10,529,014	11,716,765	12,922,646	N/A	2.4%

Electric Resources

PSE provides electric services to more than a million customers in Washington state. Over the next 20 years those numbers will grow. That growth, combined with expiring resource contracts, means we will face substantial electric resource needs in coming years. This chapter reviews PSE's existing electric resources and the alternatives available to us. It outlines the methodology we used to analyze those alternatives, and it summarizes the key findings from the quantitative analysis. The chapter is divided into five sections.

I. Electric Resource Need

The combination of economic growth and expiring supply contracts means that PSE faces large electric resource needs in the years ahead. To meet the projected base load demand of our customers, we will need to acquire nearly 700 aMW of electric resources by 2011, more than 1,600 aMW by 2015, and 2,570 aMW by 2027, as Figure 5-1 below illustrates. This is the equivalent of adding enough electricity to power the city of Seattle for the next 20 years.

Figure 5-1
Electric Baseload Resource Need:
Comparison of Projected Loads and Existing Resources, 2008-2027

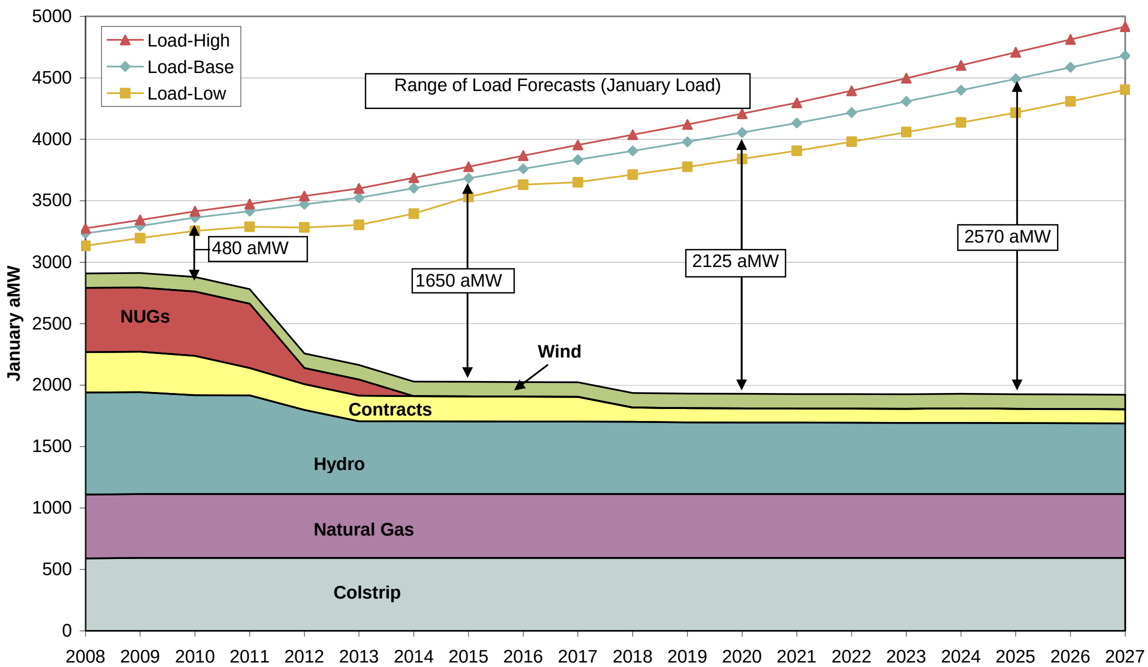
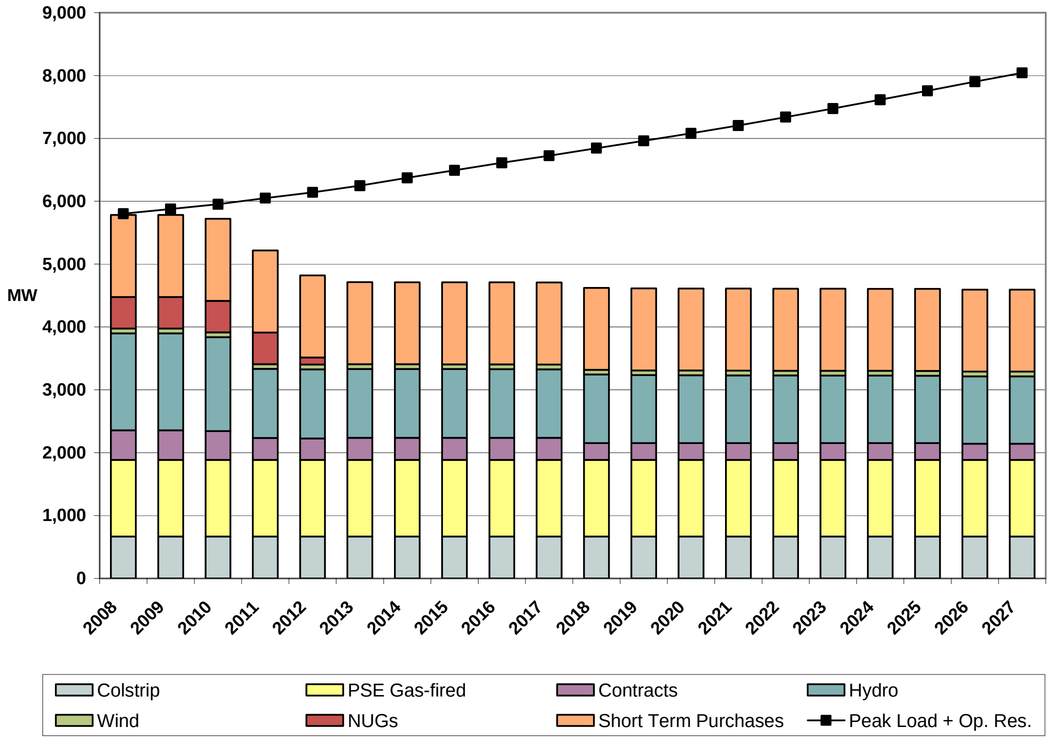


Figure 5-2
Electric Peak Capacity Resource Need:
Comparison of Projected Peak Loads with Existing Resources, 2008-2027



As the number of PSE customers increases each year, so do our peak load and base load energy demand. Figure 5-2 compares the forecasted load during the highest demand hour of the year to the peak capacity of existing resources and contracts. PSE is a winter peaking utility whose peaks are driven by temperature-dependent heating loads. The peak load forecast, therefore, includes both a forecast of the customer base and an estimate of how much power would be used at a temperature of 13 degrees Fahrenheit. The 13^{o}F represents a one in 20 year occurrence (5% exceedence probability) based on the 30 year historical data of minimum temperatures during the on-peak hours.

Electric resources are constrained by regional operating reserve requirements that, in effect, raise the peak resource requirement to take into account possible forced outages. The Western Electricity Coordinating Council (WECC) identifies this standard as the greater of the largest single contingency or 7% for thermal units plus 5% for hydro units.

Half of the reserve requirement must be provided as spinning (instantaneously available) reserves with the balance being carried as supplemental reserves.

Differences between Long-term and Short-term Peak Capacity Planning

Figure 5-2 describes long-term peak capacity needs, but it does not fully describe PSE's near-term capacity situation due to the different methods used to assess and address peak capacity.

During the past several winters PSE has met peak needs that are beyond the capacity of existing resources with a combination of short-term market product alternatives that have been more cost-effective than acquiring new generation. These include call options, energy exchanges, and the acquisition of additional cross-Cascades transmission capacity.

Long-term peak resource needs are plotted over the 20-year planning horizon using the December peak-load forecast compared to the existing resources available to meet those needs. Short-term peak needs planning is performed annually, and uses monthly estimates of peak loads and capacity for the winter period (November through February). Short-term planning also considers the transmission capacity of each transmission link the Company owns or leases, and the current marketplace conditions for day-ahead and month-ahead purchases.

Differences between the two methods result in observable differences in resource need estimates. For example, peak loads may be forecast to increase by 65 MW per year over the next 20 years, but only 50 MW for the coming December.

Extending the short-term methodology to cover long-term assessments of peak need is not practical. The transmission issues and short-term market conditions that inform near-term analyses are not possible to quantify over the long term in any meaningful way.

II. Existing Resources

This discussion of PSE's existing electric resources is divided into four parts.

- **Supply-side resources** encompass power generated by PSE-owned and contracted facilities, primarily hydropower, coal-fired plants, natural gas fueled turbines, and wind.
- **Demand-side resources** are contributions to the resource pool that are generated on the customer side of the meter, primarily through energy efficiency programs.
- **Green Power and small-scale renewables** discusses PSE's two customer renewable energy programs, one for customers who want additional renewable energy and one for customers producing power from small-scale renewables.
- **Regional transmission resources** describes the transmission system available to PSE to transport power to and across our service territory (as opposed to the local power distribution system owned and operated by PSE, which is discussed in Chapter 7).

A. Supply-side Resources

PSE's portfolio of supply-side generation resources is diversified both geographically and by fuel type (see Figure 5-3). Most of our gas-fueled resources are in western Washington, while the major hydroelectric contracted resources are in central Washington, outside our service area. The wind facilities are located in central and eastern Washington and the Colstrip coal facility is in eastern Montana.

Figure 5-3
Map of Supply-side Resources

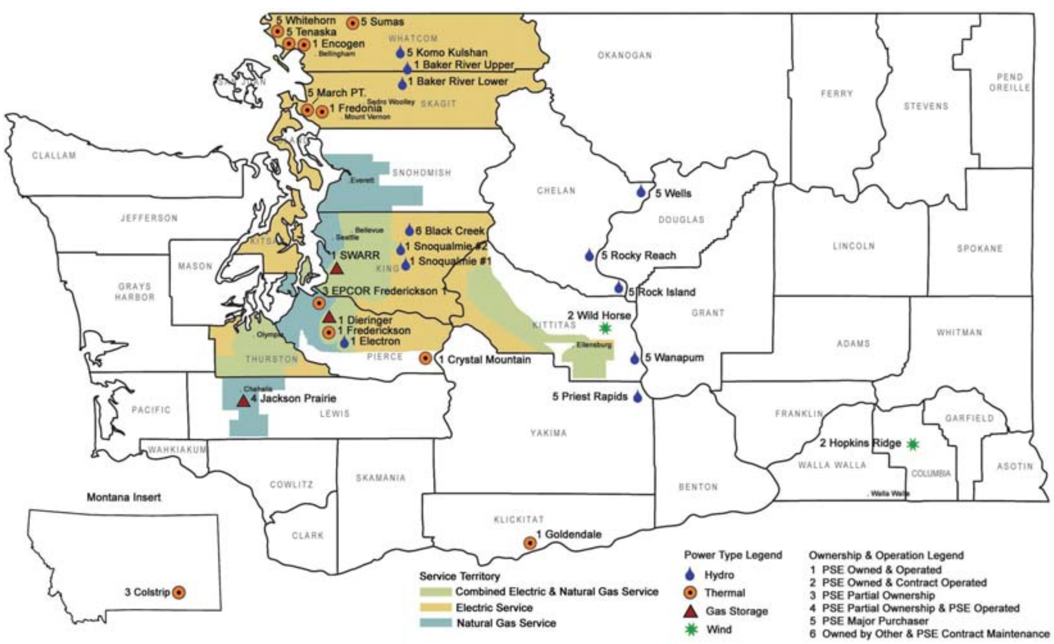


Figure 5-4

Expected Supply-side Resources for 2008

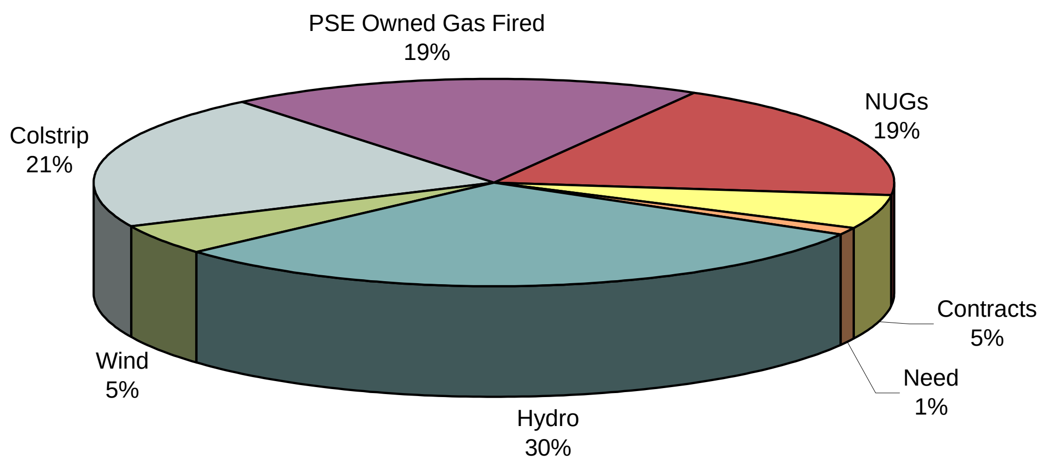


Figure 5-4 shows our supply-side sources annual availability of energy for 2008 under average (50-year) hydroelectric conditions. This figure shows the percent of annual electric resource base load need in 2008 based off of the annual load forecast. Hydroelectricity, which provides the largest supply percentage, includes both owned projects and long-term purchase contracts with mid-Columbia public utility districts (PUDs). Our share of the coal-fueled Colstrip plant makes up the next largest portion. Natural gas resources include nonutility generator (NUG) contracts, plus simple-cycle and combined-cycle combustion turbine plants that we both own and lease. Our Hopkins Ridge and Wild Horse wind-powered facilities provide 5% of our energy supply.

Hydroelectricity

Hydroelectric plants deliver approximately 32% of our annual energy generation or 810 aMW (aMW is the average number of megawatt-hours [MWh] over a specified time period; for example, 295,650 MWh generated over the course of one year is equivalent to 810 aMW, or 295,650 divided by 8,760 hours, which is the number of hours in a year). Hydro resources are very valuable because they can follow load (such as the mid-Columbia resources) and their cost is generally low compared to other sources of generation power. PSE owns hydro projects in western Washington and has long-term contracts with three PUDs that own large dams on the Columbia River in central

Washington. We also contract with smaller hydro generators. High precipitation levels generally allow more power to be generated; low-water years produce less power, so we must rely on more expensive self-generated or market sources to meet the load. This IRP analysis accounts for both seasonality and year-to-year variations in hydro production.

Figure 5-5
Existing Hydro Resources (2008)

PLANT	OWNER	PSE SHARE %	NAMEPLATE CAPACITY (MW)*	EXPIRATION DATE
Upper Baker River	PSE	100	105	n/a
Lower Baker River	PSE	100	85	n/a
Snoqualmie Falls and Electron	PSE	100	68	n/a
Total PSE-Owned			**258**	
Wells	Douglas Co. PUD	29.9	251	3/31/18
Rocky Reach	Chelan Co. PUD	38.9	493	11/1/11
Rock Island I & II	Chelan Co. PUD	50.0	272	6/7/12
Priest Rapids	Grant Co. PUD	4.31	39	Will tie to new FERC license
Wanapum	Grant Co. PUD	10.8	106	Will tie to new FERC license
Mid-Columbia Total			**1420**	
Total Hydro			**1678**	

*Nameplate capacity reflects PSE's share only.

Baker River Hydroelectric Project. Hydroelectric projects require a license from the Federal Energy Regulatory Commission (FERC) for construction and operation. These licenses normally are for periods of 30 to 50 years and then they must be renewed. PSE initiated relicensing for the Baker River Hydroelectric Project in March 2000, in advance of the existing license's expiration in 2006. A Settlement Agreement representing the consensus of 23 stakeholders was recommended to the FERC in 2004. All parties (federal and state resource agencies, three Native American tribes, Skagit County, several nongovernmental organizations and PSE) supported a 45-year license. We anticipate that, in 2007, FERC will issue a new license authorizing PSE to generate 707,600 MWh (average annual output) for a term of 30-45 years.

Snoqualmie Falls Hydroelectric Project. FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow us to generate an estimated 300,000 MWh per year, making this a reliable and cost-effective resource. The 2004 license requires significant enhancements to both the upper and lower power plants and the diversion dam, and to a number of public amenities such as parks. The new license is being challenged in federal court, the outcome of which cannot now be determined.

Mid Columbia Long-Term Purchased Power Contracts. PSE purchases a percentage of the output of five hydroelectric projects located on the middle stem of the Columbia River in Central Washington pursuant to long-term purchase power agreements with three PUDs (see Figure 5-5). In exchange, we pay the PUDs its proportionate share of operating expenses for the hydroelectric projects. The agreement with Douglas County PUD for the purchase of 29.9 % of the output of the Wells project expires in 2018. PSE executed new 20-year agreement with Chelan County PUD for the purchase of 25% of the output of the Rocky Reach and Rock Island projects. The new agreements will be in effect upon termination of the current agreements in 2011 and 2012, and will extend through October 2031. We also executed new agreements with Grant County PUD for a share of the output of the Wanapum and Priest Rapids developments. The terms of the agreements applied to Priest Rapids in November 2005 and will apply to Wanapum beginning November 2009. After that date, PSE will receive a combined share of power from both projects, which declines over time as the PUDs' loads increase. PSE's share of the Wanapum Development will remain at 10.8% until November 2009 and will be adjusted annually thereafter. Our share of the Priest Rapids Development declined to 4.3% in 2007. The new agreements with Grant County PUD will continue through the term of any new FERC license to be obtained by the PUD.

Wanapum and Priest Rapids Developments. PSE signed new contracts for a share of the electricity produced at these facilities in 2001. The terms applied to Priest Rapids as of November 1, 2005 and will apply to Wanapum beginning November 1, 2009. After that date we will receive a combined share of power from both projects rather than individual shares of each project.

White River Project. In January 2004, we stopped generating electricity at White River because relicensing and environmental expenses would have driven power costs well above available alternatives. We have arrangements with third parties to cover most ongoing postretirement costs, and we are working with interested groups to preserve the Lake Tapps reservoir for regional recreation and municipal water supply.

Coal

The coal-fueled generating plants located in Colstrip, Montana provide important baseload energy to PSE, and about 22% of our overall energy needs. PSE owns a 50% share in Colstrip 1 & 2, and a 25% share in Colstrip 3 & 4. The four coal-fired units are restoring their rated capacities by installing higher-efficiency turbine components by 2008. At that time, our share of the Colstrip output will total 566 aMW, an increase of 28 aMW. We also receive additional energy from Colstrip under a contract with NorthWestern Energy, which expires at the end of 2010.

Gas-fired Combined-cycle Combustion Turbines (CCCTs)

CCCTs improve output efficiency by generating additional energy from the heat produced by the original power-producing cycle of a simple-cycle combustion turbine. The nameplate capacity of our three CCCT resources is 570 MW. The **Goldendale** facility, in southern Washington, is our newest acquisition. Purchased in February 2007, it has a nameplate capacity of 277 MW. **Encogen**, our natural gas–fired cogeneration facility in Bellingham, Washington, provides steam to the adjacent Georgia-Pacific mill. To facilitate economic dispatch of the plant, an auxiliary boiler installed in August 2005 provides steam to the mill when market conditions warrant it. We also own 49.85% of **Frederickson 1**, a combined-cycle plant operated by EPCOR.

Wind Energy

The two wind projects described here represent PSE’s first ownership of utility-scale renewable energy, and supply 5% of our energy portfolio. So far we are the only Northwest utility to solely own and operate large wind-power facilities. **Hopkins Ridge**, located in Columbia County began generating energy in November 2005. **Wild Horse**, located in Kittitas County near Ellensburg, came online in December 2006. Combined, the two projects produce 125 aMW. Both projects have contributed to their respective local economies by providing permanent family-wage jobs, local supply and services procurement, and payment of production royalties to local landowners. In addition, these projects have increased the tax base, allowing local government to provide additional services (e.g., a new health clinic in Columbia County). Figure 5-6 presents details about our coal, CCCT, and wind resources.

Figure 5-6
Existing Coal, CCCT, and Wind Resources

POWER TYPE	UNITS	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)*
Coal	Colstrip 1 & 2	50%	310
Coal	Colstrip 3 & 4	25%	370
Total Coal			**680**
CCCT	Goldendale	100%	277
CCCT	Encogen	100%	170
CCCT	Frederickson	49.85%	133
Total CCCT			**570**
Wind	Hopkins Ridge	100%	149
Wind	Wild Horse	100%	229
Total Wind			**378**

*Nameplate capacity reflects PSE's share only.

Gas-fired Simple-cycle Combustion Turbines

Our four simple-cycle combustion turbine plants contribute a total of 606 MW of capacity. Details are shown in Figure 5-7. They provide important peaking capability, although they typically operate only a few days each year. These resources are not used for baseload energy when lower cost energy purchases are available, but were designed to provide winter peaking capacity and peak energy when market conditions warrant. A long-term financing lease for **Fredonia 3 & 4** expires in 2011. Our lease for **Whitehorn 2 & 3** expires in 2009, and we have executed an agreement to purchase the units when the lease ends.

Figure 5-7
Existing Simple-cycle Combustion Turbines

NAME	PSE OWNERSHIP	NAMEPLATE CAPACITY (MW)
Fredonia 1 & 2	100%	202
Fredonia 3 & 4	100%	110
Whitehorn 2 & 3	Leased	147
Frederickson	Leased	147
Total		**606**

*Nameplate capacity reflects PSE's share only.

Non-Utility Generators (NUGs)

Our NUG supply consists of cogeneration plants that use natural gas to supply electricity to us and steam to industrial "hosts" for their production processes. All three are located in Skagit and Whatcom counties, in the northern part of our service area. The combined nameplate capacity of these plants is 523 MW.

Tenaska Cogeneration. In 1991 we contracted to purchase the 224 aMW output, beginning in April 1994, from Tenaska Washington Partners, L.P., which owns and operates the project near Ferndale, Washington. We later bought out the project's existing long-term gas supply contracts, which contained fixed and escalating gas prices well above then current and projected future market prices. We thus became the principal natural gas supplier to the project, and power purchase prices under the Tenaska contract were revised to reflect market-based gas prices. This term of this agreement ends December 31, 2011.

Sumas Energy Cogeneration. In 1989 we contracted to purchase 133 aMW from Sumas Cogeneration Company, L.P., which owns and operates this project located in Sumas, Washington. Under its terms, this agreement ends April 16, 2013.

March Point Phases I & II. We have contracts through December 31, 2011 to purchase the full output of March Point Phase I & II from the March Point Cogeneration Company, which owns and operates these facilities. The plants are located at the Shell refinery in Anacortes, Washington and deliver a combined 145 aMW.

Other Long-term Contracts

Long-term contracts, which range in capacity up to 300 MW, consist of agreements with independent producers and other utilities. Fuel sources include hydro, gas, waste products, and system deliveries without a designated supply resource. Independent producers provided approximately 42 aMW, and utilities contributed approximately 110 aMW in 2006. This does not include short-term contracts (less than one year) negotiated by our energy trading group. These are summarized below in Figure 5-8.

NorthWestern Energy Company. This 20-year, unit-specific, purchased power contract is tied to Colstrip Unit 4. The contract, which expires in 2010, specifies capacity payments for each year, subject to reductions if specific performance is not achieved.

BPA – WNP-3 Bonneville Exchange Power. This is a system-delivery, not a unit-specific, purchased power contract. The agreement resulted from PSE claims against BPA resulting from its action to halt construction on nuclear project WNP-3, in which we had a 5% interest. Under the agreement, in effect until June 2017, PSE receives power from BPA according to a formula based on the average equivalent annual availability and cost factors of four surrogate nuclear plants similar in design to WNP-3. In 2006 this amounted to 44 aMW during the months January through April, November and December. The agreement provides for PSE to provide exchange energy from PSE combustion turbines, at PSE's cost, to BPA, if requested, during the months of January through April and September through December.

BPA Snohomish Conservation Contract. This agreement, which runs through February 2010, is a system-delivery, not a unit-specific, purchased power contract. Snohomish County PUD, Mason County PUD, and Lewis County PUD installed conservation measures in their service areas. PSE receives an amount of power equal to the amount saved over the expected 20-year life of the measures. BPA delivered this power through 2001, then delivery passed to Snohomish County PUD.

Powerex Purchase for Point Roberts. Powerex delivers electric power to our retail customers in Point Roberts, Washington. The Point Roberts load, which is physically isolated from our transmission system, connects to British Columbia Hydro's electric distribution facilities. We pay a fixed price for the energy during the term of the contract. This agreement ends in September 2007. PSE is currently in the process of renegotiating an extension with Powerex.

BPA Baker Replacement. Under a letter of intent signed with the U.S. Army Corps of Engineers (COE) for a 20-year agreement, PSE provides flood control for the Skagit River Valley. Early in the flood control period, we draft water from the Baker reservoir at the request of the COE. Then, during periods of high precipitation and runoff between October 15 and March 1, we store water in the Upper Baker reservoir and release it in a controlled manner to reduce downstream flooding. In return, we receive power from the BPA from November through February; this compensates for the lower generating capability caused by reduced head, due to the early drafting at the plant during the flood control months.

Pacific Gas & Electric Company (PG&E) Seasonal Exchange. Each calendar year we exchange 300 MW of capacity, together with 413,000 MWh of energy, on a one-for-one basis under this system-delivery purchased power contract. We provide power to PG&E

in June through September, and PG&E provides power to us November through February. (PSE is a winter-peaking utility, while PG&E is a summer-peaking utility.)

Canadian Entitlement Return. Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. Our benefits and obligations from this storage are based on the percentage of our participation in the Columbia River projects. Agreements with the Mid Columbia PUDs specify our share of the obligation to return one-half of the firm power benefits to Canada until the expiration of the PUD contracts or 2024, whichever occurs first. This is energy that we provide rather than receive, so it is a negative number (-58 MW in 2006).

Figure 5-8
Existing Long-term Contracts for Electric Power Generation

TYPE	NAME	TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)**
NUG	Tenaska		12/31/2011	245
NUG	Sumas		04/16/2013	133
NUG	March Point I		12/31/2011	80
NUG	March Point II		12/31/2011	65
Total NUG				**523**
Other Contracts	Northwestern Energy Company	Colstrip	12/29/2010	97
Other Contracts	BPA- WNP-3 Exchange	Various	6/30/2017	102
Other Contracts	Conservation Credit - SnoPUD	Hydro	2/28/2010	18
Other Contracts	Powerex/Pt.Roberts	Hydro	9/30/2007	3
Other Contracts	BPA Baker Replacement	Hydro	10/1/2007	7
Other Contracts	PG&E Seasonal Exchange-PSE	Thermal	Ongoing*	300
Other Contracts	Canadian EA	Hydro	12/31/2025	-58
Total Other				**469**
Independent Producers	Spokane Municipal Solid Waste	Biomass-QF	11/15/2011	18

TYPE	NAME	TYPE	CONTRACT EXPIRATION	NAMEPLATE CAPACITY (MW)**
Independent Producers	Twin Falls	Hydro	3/8/2025	14
Independent Producers	Koma Kulshan	Hydro	3/1/2037	11
Independent Producers	North Wasco	Hydro-QF	12/31/2012	5
Independent Producers	ORMAT	Heat Recovery	11/01/2028	5
Independent Producers	Nooksack Hydro	Hydro	11/30/2008*	3
Independent Producers	Puyallup Energy Recovery Co.(PERC)	Biomass-QF	4/18/2009	2
Independent Producers	Weeks Falls	Hydro	12/1/2022	3
Independent Producers	Hutchison Creek	Hydro-QF	9/30/2016	1
Independent Producers	Kingdom Energy-Sygitowicz	Hydro-QF	2/2/2014	0
Independent Producers	Port Townsend Paper	Hydro-QF	12/31/2008	0
Total Independent				**62**

*May be terminated with issuance of 5-year notice.
**Nameplate capacity reflects PSE's share only.

B. Demand-side Resources

Demand-side resources are generated or saved on the customer side of the meter. Energy efficiency, our primary demand-side resource, makes up a meaningful and increasing portion of PSE's energy portfolio. We have long supported cost-effective energy conservation. Between 1985 and 2005, these measures produced savings that gained approximately 310 aMW on an investment of $462 million. This is roughly equal to the annual output from our share of Colstrip 3 & 4--equivalent to the electricity used by about 230,000 homes. During the 2004-2005 tariff period, electric energy efficiency programs contributed 19.6 aMW to our resource needs, more than the annual amount of power supplied from our largest long-term contract with an independent producer, saving enough energy to power 30,000 homes.

In our April 2005 Least Cost Plan Update, PSE presented an extensive analysis of energy efficiency savings potential and its contribution to the Company's electric portfolio. In collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Least Cost Plan Advisory Group (LCPAG), these results were used to develop energy efficiency program targets for 2006 and 2007. A two-year stretch goal for energy savings of approximately 40 aMW by the end of 2007 was adopted. In addition, PSE also issued requests for proposals (RFPs) to acquire new electric and gas efficiency resources.

PSE's energy efficiency programs are designed to serve all customers—including residential, low-income, commercial, and industrial. Energy savings targets and the programs to achieve those targets are established every two years. The 2004-2005 biennial program period concluded at the end of 2005; current programs operate January 1, 2006 through December 31, 2007. A high-level summary is included in Figure 5-9.

PSE funds the majority of our electric energy efficiency programs using electric "Rider" funds collected from all customers. A portion of the funding takes place through arrangements with BPA to provide conservation and renewable discount (C&RD) credits. As with supply-side resources, we evaluate energy efficiency programs for their cost-effectiveness and suitability within a lowest reasonable cost strategy.

Current Electric Energy Efficiency Programs

The **Commercial and Industrial Retrofit Program** offers expert assistance and grants to help existing commercial and industrial customers use electric and natural gas more efficiently via cost-effective and energy efficient equipment, designs, and operations. This program produced the greatest gain in energy savings of all PSE efficiency programs in 2005, producing 5.27 aMW at a cost of $7,686,733. The retrofit program accounted for 32% of all electric savings in 2005. In 2006, the program savings declined, but it was again the dominant contributor to commercial program savings, contributing 4.74 aMW at a cost of $9,672,363 and comprising 25% of all electric energy efficiency savings.

The **Energy Efficient Lighting Program** offers instant rebates for residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. This program generated the greatest energy savings gains on the residential side in 2005, producing 2.65 aMW at a cost of $1,306,655. It accounted for 16% of all electric savings in 2005. In 2006, rebates for CFL Fixtures, Energy Star™ Washing Machines and Dishwashers, Refrigerator Decommissioning, and Energy Star™ Manufactured Homes combined for a savings of 6.6 aMW at a cost of $7,236,082. This very successful program accounted for 35% of all electric energy efficiency savings.

Figure 5-9
Annual Energy Efficiency Program Summary, 2005 & 2006
($millions, except MWh)

Tariff + C&RD Programs	2004 - 2005 Actual	’04-’05 2-Year Bdgt./Goal	‘04/’05 Actual vs. ‘04/’05 % Total	2006 Actual	’06-’07 2-Year Bdgt./Goal	’06 vs. ‘06/’07 % Total
Electric Program Costs*	$50.4	$52.2	104%	$28.7	$63.9	44.9%
Megawatt Hour Savings	344,606	343,080	100%	166,254	350,628	47.4%

* Does not include low-Income weatherization O&M funding of $300 thousand per year.

The year 2005 marked the end of a conservation tariff period spanning 2004 and 2005 that continued ongoing programs. Figure 5-9 shows 2004-2005 performance compared to two-year budget and savings goals for electric energy efficiency programs.

During 2004-2005, our electric energy efficiency programs saved a total of 39.3 aMW of electricity at a cost of $50.4 million. We surpassed our two-year savings goals while operating at a cost that was under budget. In 2006, electric energy efficiency programs saved 18.9 aMW of electricity at a cost of $28.7 million. It is also notable that, on average, costs of acquiring energy efficiency increased by approximately 16% from 2005 to 2006, although energy savings declined slightly.

In November 2005, we issued an “all-comers” RFP for energy efficiency resources to be added in 2006-2007. The RFP process is used to seek out and fill untapped market segments or add under-utilized energy efficiency technologies to complement our ongoing efforts. The results of that RFP process did not identify any significant new opportunities for additional electric energy efficiency. Of the 18 proposals received, 12 involved electric energy efficiency. One program, a multifamily weatherization direct installation program was selected.

C. Green Power and Small-scale Renewables

More PSE customers are participating in PSE’s customer renewable energy programs each year. The Green Power Program serves customers who want additional renewable energy, and the Customer Renewables Program serves customers who generate renewable energy on a small scale. Our customers find the Green Power and Customer Renewables programs to have value as well as social benefits. We embrace their use.

Green Power

PSE launched its Green Power program in 2001, after passage of a law requiring Washington state’s 16 largest electric utilities to allow customers to voluntarily purchase retail electric energy from qualified renewable energy resources (i.e., green power). Since then, the program has grown significantly—increasing to 17,426 subscribers who purchased 131,742 MWh in 2006 from 4,850 subscribers who purchased 8,563 MWh in 2002. (See Figure 5-11 for year-by-year totals.) The National Renewable Energy Laboratory recognized PSE as one of the top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants in 2005.

To supply green power, the Green Power Program purchases renewable energy credits, called green tags, from a variety of sources. The primary supplier is the Bonneville

Environmental Foundation (BEF), a nonprofit environmental organization in Portland, Oregon, which provides a portfolio of resources including wind, solar and biomass. The Green Power Program also purchases green tags directly from producers to support the development of new small renewable resources.

Figure 5-10 lists the resources constituting the Green Power portfolio.

Figure 5-10
Green Power Portfolio

Name	Resource	Location
Condon	Wind	Condon, OR
Stateline	Wind	Walla Walla, WA
Klondike	Wind	Sherman Co., OR
Klondike II	Wind	Sherman Co., OR
Nine Canyon	Wind	Kennewick, WA
Nine Canyon II	Wind	Kennewick, WA
Tillamook WTE	Bio	Tillamook, OR
Dry Creek LFG	Bio	Medford, OR
White Creek	Wind	Klickitat Co. WA
Small Solar	Solar	Various, OR, WA
Vander Haak	Bio	Lynden, WA
Grays Harbor Paper	Bio	Hoquiam, WA

Customers can purchase green power in 160 kWh blocks for $2 per block with a two-block minimum. In 2005, the Green Power Program introduced a large-volume green power rate, and also initiated several programs to increase business participation and encourage small-scale renewable energy projects within our region. The Green Power Program supports new resources by entering into agreements to purchase the green tags from these projects. The Customer Renewables Program has also directly paid for all or part of the installation of new solar demonstration projects, including a 1 kilowatt system on the Capitol building in Olympia and another solar project at the International Brotherhood of Electrical Workers office.

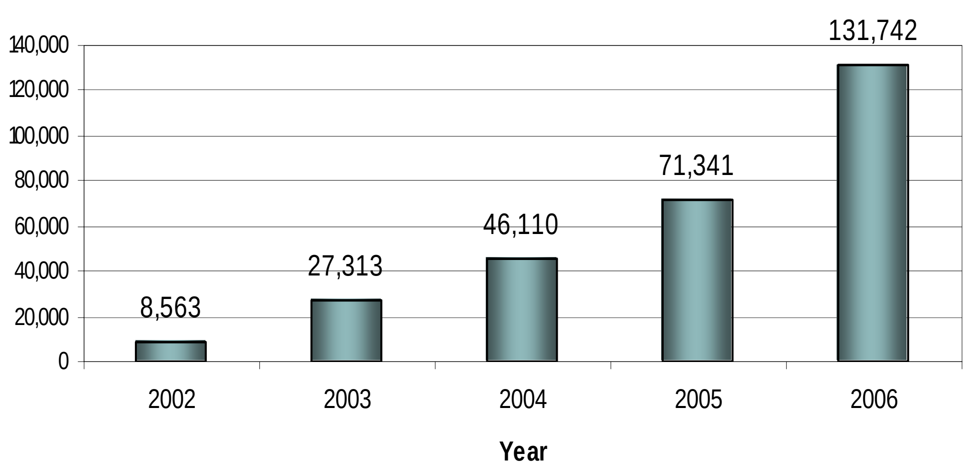
The large-volume green power rate—0.6 cent per kWh for customers who purchase more than 1,000,000 kWh annually—attracted seven customers by the end of its first year, including PSE's corporate offices in Bellevue. Two of these customers, Western Washington University and The Evergreen State University, use the program for 100% of their electric energy. Three more large-volume customers jointed the program in 2006.

Expanded efforts to increase participation have included exploring broader marketing techniques and projects. We entered into partnerships with Made in Washington stores, PCC Natural Markets, and Grounds for Change for residential campaigns, conducted direct mail campaigns, and advertised in business journals to reach the business and commercial communities. We also launched a formal recognition program for our large customers to support their actions.

Of our 17,426 Green Power subscribers at the end of 2006, 16,994 were residential customers and 432 were business customers. Cities with the most Green Power participants include Olympia with 2,120, Bellingham with 1,826, Bellevue with 1,009 and Kirkland with 817.

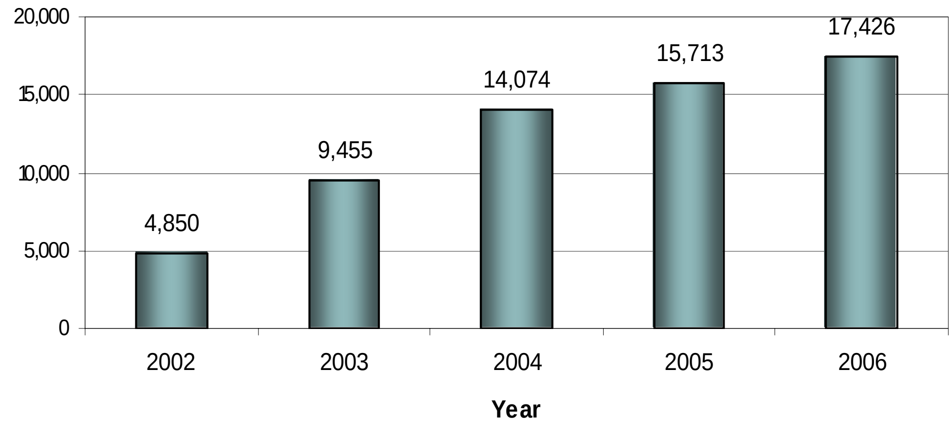
2006 marked the expiration of a three-year agreement with BEF for the purchase of green tags, which provided PSE with some surety on tag pricing and flexibility in adding small-scale resources to the program. In 2006, PSE issued an RFP for green tags, which resulted in a new three-year agreement, also with BEF.

Figure 5-11
Green Power Kilowatt-Hours Sold, 2002-2006



In 2006, the average purchase under Schedule 135 was 300 KWH per month. The average 2006 large volume purchase under Schedule 136 was 67,100 KWH per month. Figure 5-12 illustrates the number of subscribers by year.

Figure 5-12
Green Power Subscribers, 2002-2006

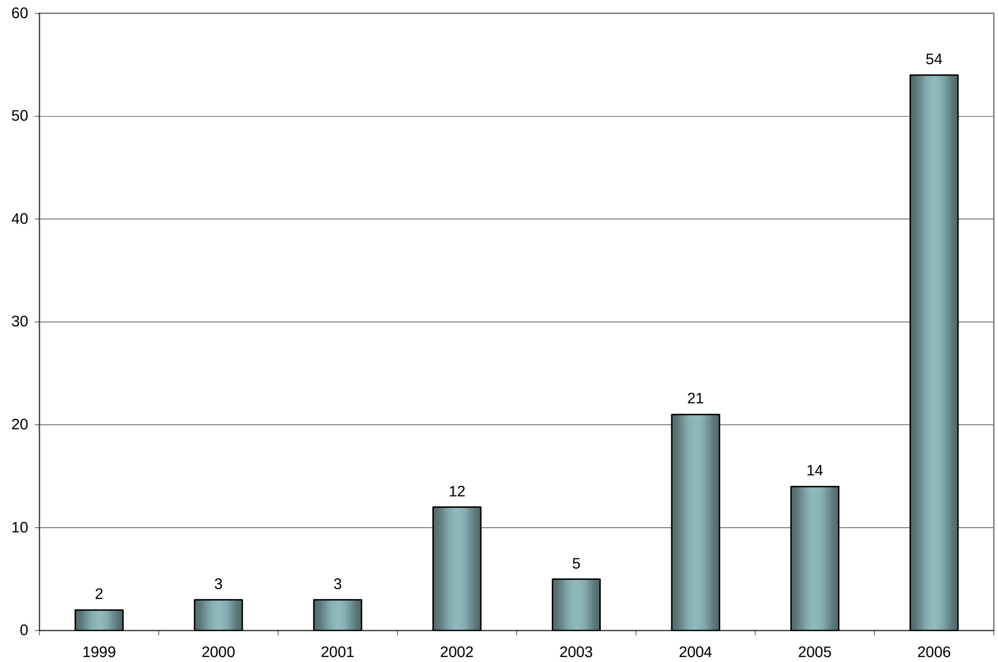


Customer Renewables Programs

PSE's net metering program, in place since 1999, provides a way for customers who generate their own renewable electricity to offset the electricity provided by PSE. The amount of electricity generated by the customer is subtracted from the amount of electricity provided by PSE, and the net difference is what the customer pays on a monthly basis. If the customer generates more electricity than PSE supplies, a KWh credit is carried over to the next month. The "banked" energy can be carried over until every April 30, when the account must be reset to zero according to state law.

Customer interest in small-scale renewables has increased significantly over the past three years, as Figure 5-13 below shows. In 2006, PSE added more than 50 new net metered customers for a total of 114.

Figure 5-13
Net Metered Customers Added per Year 1999-2006



The Customer Renewables Program also doubled the aggregate interconnected kilowatt capacity. The vast majority of systems are solar photovoltaic (PV) installations with an average generating capacity of 3.03 kW. Combined with our net metered small-scale hydroelectric generators and wind turbines, the overall average generating capacity of all net metered systems is 3.12 kW.

Figure 5-14
Net Metered Systems by Technology

Average System Capacity (kW)	Count	Technology	Aggregate Generating Capacity (kW)
3.97	3	Hybrid; solar/wind	11.91
5.67	3	Micro hydro	17.01
3.03	108	Solar array	327.24
Total	**114**		**356.16**

These small-scale renewable systems are distributed over a wide area of our service territory.

Figure 5-15
Net Metered Systems by County

County	Number of Net Meters
Whatcom	22
King	23
Jefferson	21
Skagit	15
Island	13
Kitsap	9
Thurston	9
Kittitas	1
Pierce	1

In June 2006, the interconnection capacity allowed under PSE's Net Metering Schedule 150 was increased to 100 kW, and the banking of accumulated kWh was extended to April 30 of the year after they were accumulated. Current initiatives include the following:

Residential Solar Rebate Program. The Customer Renewables residential solar rebate program began in 2004 in response to a 2003 rate case stipulation. Interconnected solar PV residential customers receive rebates of $525 to $600 per kilowatt of installed capacity; 44 customers took advantage of this program in 2006. The rebate rates are currently adjusted by county solar production factors within our service area.

Renewable Energy Advantage Program. In October 2006, PSE launched a Renewable Energy Advantage Program (REAP) in response to WAC 458-20-273. The program is voluntary for Washington state utilities, but we embraced the opportunity to participate because we have such a large and committed group of interconnected customers. Payments are made to interconnected electric customers who own and operate eligible renewable energy systems including solar PV, wind, or anaerobic digesters (the three micro hydro customers are not eligible under the current law). Annual amounts range from 15 cents to 18 cents per kWh produced by their system. PSE receives a state tax credit equal to the aggregate incentive payments made to customers. By the end of 2006, the Customer Renewables Program had enrolled 54 of our 81 eligible customers, and the first annual incentive payments were made. The tariff governing REAP, Schedule 151, along with its related agreement, was approved by the WUTC on October 6, 2006.

D. Regional Transmission Resources

PSE transports power from its origination point to our service area over the regional transmission grid through contracts with various transmission providers. This regional system is separate from the PSE-owned local delivery system through which we distribute power to customers (see Chapter 7, Delivery System Planning).

Physical and contractual limitations and lack of coordination within the regional transmission system severely constrain PSE's ability to promptly acquire generation outside our service territory. Of particular concern are the following.

- Transmission capacity constraints to the I-5 corridor
- A transmission planning process that is not well aligned with the resource acquisition process
- Multi-jurisdictional siting and permitting issues
- Diminished role of "rolled-in" ratemaking and funding, in favor of marginal cost pricing marginal user up-front funding

Unless these market structure and institutional factors are addressed in a timely manner, PSE will be challenged to acquire resources such as wind from the Columbia Gorge, gas plants within the state of Washington, coal plants from Montana, Wyoming, or Nevada, geothermal power from Idaho and Oregon, and hydroelectric power or biomass from British Columbia.

This section discusses constraints affecting use of the regional transmission grid, including PSE's current situation, the processes for adding new transmission capacity, current efforts to address regional transmission issues, and transmission needs related specifically to this IRP.

Current Situation

For the most part, PSE's owned and operated transmission system of 115 kV and 230 kV facilities have been developed to move power to customers. We do not have significant excess transmission capacity either across our service area or outside our service area. To bring power to our service area, PSE has typically contracted for transmission from the BPA.

Our local transmission system also interconnects with several utilities including BPA, Seattle City Light, Snohomish PUD, Tacoma Power, British Columbia Transmission Corporation, Chelan County PUD, Douglas County PUD, Grant County PUD and with purchasers of the Centralia project. Most of the interconnections are west of the Cascades.

Numerous developments have created pervasive congestion on the grid.

- Current load patterns are significantly different than those that existed when the grid was designed.
- Resource operations patterns have changed with the entrance of market participants other than utilities and the construction of new gas-fired generating sources, whose actual operation is market-driven and highly variable.
- Loads are growing more rapidly than transmission capability.
- The transmission industry is in the middle of considerable change, and with the recent 2005 Energy Policy Act (EPA) and the efforts of regional utilities to form ColumbiaGrid, it is unclear what the final Northwest transmission structure will look like.
- Almost all wind resources are located east of the Cascade Mountains in transmission-constrained areas.

Recent development of gas-fired generation and other intermittent resources like wind has made operation of the transmission system more challenging. The number of market transactions has also grown significantly, increasing the complexity of system operations and transmission system use. Consequently, the grid is now being utilized at near-full capability, and any forced outage or critical maintenance often places the grid in a “de-rated” condition.

New generation opportunities in PSE’s service area may be limited to natural gas projects and small-scale renewables as a result of these conditions. In order to diversify with coal or wind resources, PSE must look mostly to the east. However, bringing this new generation to PSE loads will require new transmission construction and possible construction of west-side gas-fired resources to provide wind integration services and other ancillary services needed to comply with new FERC/NERC system security requirements. Figure 5-16 lists the path constraints that directly affect PSE’s ability to import new generation.

Figure 5-16
List of Transmission Path Constraints Affecting PSE's Ability to Import

Transmission Path	Where Constrained
Along I-5 corridor	South of Allston
West through the Columbia River Gorge	McNary Slatt
Across the Cascades	Washington Oregon
From Montana to the NW	In Montana west of Garrison

New Generation

At present, generation planning and transmission planning are not performed in an integrated manner. BPA's current transmission system improvements are designed primarily to meet and maintain its current obligations, including an obligation to support load growth where contractually committed. Its policies with regard to new construction do not mesh well with the roughly 2-year cycles utilities follow for resource planning, integrated resource planning, resource acquisition, and RFPs. Without a specific request for service from the generation developer, BPA will not consider new upgrades, and its current policies require 100% advance funding in return for transmission credits for the entire cost of network upgrades. These policies make developers and utilities wary.

In 2005, BPA attempted to fund the McNary–John Day upgrade with advance funding, requiring the requesting parties to pre-pay the cost of the project. However, the project did not proceed due to lack of commitments to participate from BPA's power business line and interested parties, who are stuck in the permitting process and the processes of competitively acquiring a power purchase agreement.

BPA is reviewing its transmission services with the intention of addressing the limitations that current policies create. The organization is developing an evaluation and decision-making framework to address financing, contract value of anticipated future uses of facilities, future regional needs, risk assessment, and public process. PSE is hopeful that the new framework will be developed by the end of April 2007 and result in a transmission plan-of-service likely to have a high value to the region. Meanwhile, PSE continues to work closely with BPA to find a transmission solution for each new generation project. Nevertheless, the availability and cost of transmission will continue to be key factors in PSE's decision-making process for acquiring new resources.

Acquiring Long-Term Firm Transmission

The Northwest does not currently have a single regional body to coordinate transmission requests. Under current FERC rules, transmission providers sell long-term firm transmission through their Open Access Same-time Information System (OASIS). Resource developers must identify and apply to individual transmission providers to arrange for transportation of power.

Requesting transmission is a cumbersome process that involves multiple steps and the possibility of one or more lengthy studies. Completion of the process can take anywhere from a few months to several years.

If the new transmission requires service from multiple providers, the customer must make requests with each provider. Since the review processes may not match (e.g. one provider can offer immediate service while the other requires facility upgrades), the transmission customer may face the decision to sign up for one section of the transmission before securing rights for the entire route. In Order 890, FERC has taken a step toward fixing this problem. FERC requires transmission providers to work together to develop standards that will allow for coordination of these multiple requests.

Developers of new energy resources must be able to prove that they can bring their generation to load, or lenders will not finance their efforts. Lenders require proof of adequate transmission capacity at a reasonable price, or a clear and predictable process for developing and pricing new transmission. As a result of these requirements, the request queues for key existing transmission routes become overloaded with applications of varying certainty. After the developer has worked through the process and is offered a service agreement, the agreement must be executed, and significant payments made regardless of the resource project status, or the developers risks losing its place in the queue.

BPA and other transmission providers require customers to front the costs of network upgrades prior to undertaking the work. Once upgrades have been built, the transmission provider must recover the cost. Under current Long-term Generation Interconnection Agreements, the customer receives credits under the provider’s tariff rate until the total amount credited equals the total amount fronted by the customer. Under this model, PSE—the customer—pays for transmission facilities without receiving the asset benefits of ownership. This model also makes transmission upgrades essentially participantfunded without regard to the regional value created for all transmission network users—for example, enhanced off-system sales for legacy transmission customers.

Developing and Siting New Transmission

The processes involved in developing and siting new transmission are distinct from those used by transmission providers, but no less complex.

The Energy Policy Act of 2005, discussed in more detail in the Regional Transmission Resources Appendix, authorizes the Secretary of Energy to designate "national interest electric transmission corridors." Several western corridors have been identified, but the actual siting authority granted to FERC under the Act is yet to be defined and is limited, requiring the FERC to wait for states or regional groups to complete their analysis. For the time being, most transmission projects will continue to be sited under the current process.

The physical reality of electricity flow over long distance lines is that as generation flows to load, the energy crosses several flow paths (cut-planes) and multiple states. Because transmission facility siting lies with each state, lines crossing more than one state (coal and wind, for example) involve multiple, independent, and often disjointed state processes. In order to qualify for a new transmission contract, each of the affected paths must have sufficient available transmission capacity (ATC).

Again, no central permitting or siting authority exists, although some states have centralized authorities. To construct new transmission, developers must be prepared to work with multiple jurisdictions, observe differing processes for each jurisdiction at each level of government (local, state, and federal), anticipate local issues, and work around the absence of central citing or permitting authorities.

Early assessment of environmental conditions determines the level of permitting necessary to gain regulatory approval. Common regulatory permits at federal and state levels include SEPA/NEPA, Endangered Species (biological assessments), Army Corps of Engineers section 404 and 10 permits, Department of Fish/Wildlife HPA and the Department of Ecology NPDES. At the city or county level, common permitting needs are conditional use permits for shorelines, clearing and grading, critical area review, and right-of-way use.

In addition to these permits, consideration must be made as to whether tribal lands will be affected by proposed transmission line siting, necessitating land-use negotiations. Additionally, the company could be required to enter into long-term franchise agreements with local municipalities that are granting operating rights for facilities located in their rights-of-way.

Public involvement is a necessary ingredient in the planning and development phases of transmission projects. This involves informing, consulting, and involving affected and concerned stakeholders in many of the transmission provider's decisions. To compound the challenge, transmission projects usually offer regional system improvements but limited direct local benefits.

Routing of transmission lines can also require the use of corridors other than those available via municipal, county, or state rights-of-way in many cases. In these instances, easements from individual property owners are required. Because negotiation of these rights can become contentious and ultimately result in condemnation, careful consideration is critical. The use of condemnation can prove costly from a cost/schedule perspective and create community ill will.

Long-Term Regional Transmission Structure

The Northwest continues to function without a regional transmission organization, and without workable processes to align generation and transmission development and investment. Since the advent of open access transmission rules in 1996, regional entities have made a number of attempts to form regional transmission organizations such as IndeGO, RTO West, Grid West, Transmission Issues Group (TIG) and ColumbiaGrid. A summary history of these organizations and efforts is included in the Regional Transmission Resources Appendix.

Since PSE's 2005 LCP publication, Grid West and TIG have ceased operation, concluding that the organizations would not work. However, in light of the genuine need to resolve the region's transmission problems, a variety of interested regional parties have come together to form a new organization, ColumbiaGrid, to address critical transmission-related issues and search for solutions.

ColumbiaGrid

ColumbiaGrid is a nonprofit, Washington state membership corporation formed on March 31, 2006, to improve the operational efficiency, reliability, and planned expansion of the Northwest transmission grid. An independent board of directors was elected August 1, 2006. The board's term began on August 17, and they selected a president and chief executive officer effective December 11, 2006.

ColumbiaGrid will be given substantive responsibilities pursuant to a series of functional agreements with members and other qualified non-member parties. These agreements are being developed in a public process with broad participation. Work has been based on elements of BPA's October 2005 Integration Proposal, which combined elements of Grid West and TIG efforts.

The public process focuses on the design and implementation of near-term services and the design of additional longer-term responsibilities. Near-term services include transmission planning and expansion, reliability, and a common OASIS queue. Longer-term services may include adopting a regional flow-based analytical approach, long-term reliability initiatives, and regional transmission services. A Draft Planning and Expansion Functional Agreement was released on October 25, 2006, for public review and comment. The agreement was offered for signature on January 17, 2007 and was filed with the FERC on February 2. 2007.

The current Members of ColumbiaGrid are Avista Corp., BPA, Chelan County PUD, Grant County PUD, PSE, Seattle City Light, and Tacoma Power. All Northwest control area operators are welcome to join ColumbiaGrid as members.

Ultimately, in spite of all of the effort that has gone into the development of a regional transmission structure, the future of ColumbiaGrid is unknown, and the ability of ColumbiaGrid to assure the construction of transmission for commercial purposes does not exist. In short, there are still no comprehensive transmission solutions visible on the horizon.

Role and Limitations of BPA

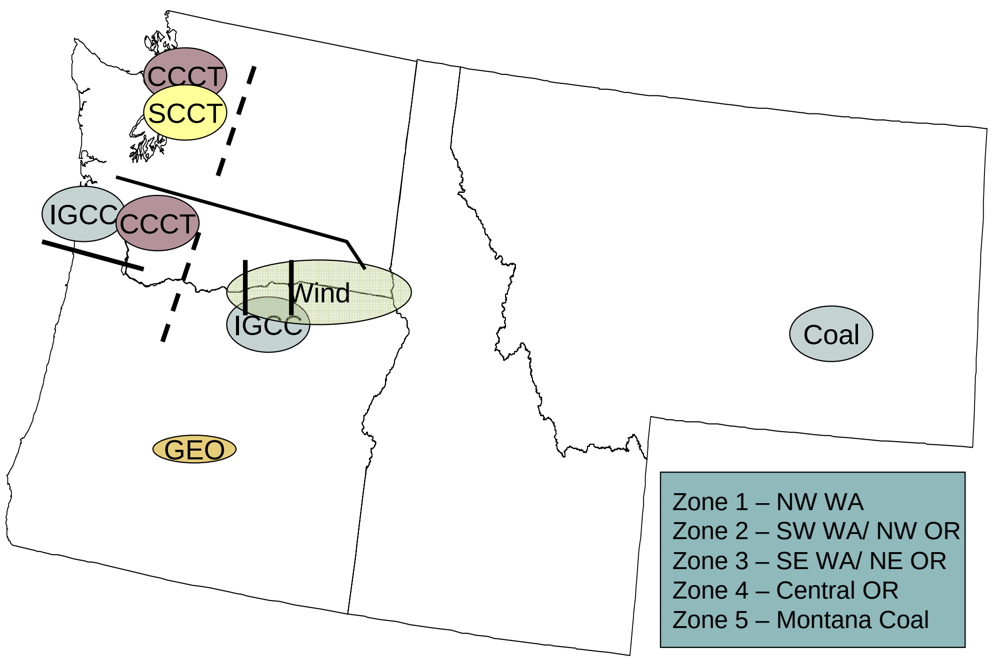
Since no regional entity has yet been established, BPA continues to be the only entity in the Northwest with the geographic scope and siting authority needed to approach building regional transmission. However, BPA does not currently have the borrowing authority to undertake major regional transmission expansion. BPA's scope is also limited by law and policy. Without BPA involvement, a major transmission solution will be difficult to organize.

In its 2006 Programs in Review process, BPA discussed its financial situation. The agency has a total of $4.45 billion in borrowing authority for all BPA projects, both power and transmission. It continues to seek mechanisms to extend its borrowing authority, including third party financing and creative debt management programs. Based on current projections, BPA expects its borrowing authority to extend to approximately 2013. BPA's existing capital plan includes capital dollars for reliability, NERC, WECC, environmental, and other compliance requirements; integration of new generating resources; congestion management; and the people and processes necessary to accomplish these projects. No money is targeted for economic transmission construction projects at this time.

Transmission Needs for New Resources

The map below shows the resource zones identified for location of possible resources in the 2007 IRP process.

Figure 5-17
Resource Zones for the 2007 IRP



Zone 1 (NW WA) indicates CCCT and SCCT plants in northwest Washington
Zone 2 (SW WA/NW OR) shows CCCT and IGCC plants in southwest Washington and northwest Oregon
Zone 3 (SE WA/NE OR) shows the Washington/Oregon boundary having wind resource in the Columbia Gorge and an IGCC plant around the Wallula area
Zone 4 (Central OR) shows geothermal resource in central Oregon
Zone 5 (Montana Coal) shows the Montana coal resource around the Colstrip area

For the purpose of modeling in this IRP, PSE has assumed that a regional transmission organization will not be established in time to facilitate transmission expansions that can be reflected in system-wide wheeling rates. PSE will continue to look for ways to work with BPA and other potential transmission providers to acquire the transmission needed for our resource additions.

Figure 5-18 table below shows PSE cost estimates for transmission upgrades related to the resources shown in the five zones above.

Figure 5-18
Cost Estimates for Transmission Upgrades Related to 2007 IRP
($Millions)

	Wind	GEO	Biomass	CCCT	SCCT	IGCC	Coal
Zone 1			0	0	0		
Zone 2			4	26		63	
Zone 3	16					62	
Zone 4		0					
Zone 5						374	374

Resource	Size (MW)
Wind	150
GEO	30
Biomass	40
CCCT	250
SCCT	150
IGCC	600
Coal	600

In order for us to continue to provide reliable power at a reasonable cost, we must take several steps to ensure that new energy supply can reach the Company's loads.

Short term. In the near term, PSE must focus on resources that are either located on the PSE system, already have transmission on the BPA system, or that exist where BPA is considering upgrades.

Long term. Based on a detailed analysis of BPA's current ATC availability, PSE anticipates that West of McNary and I-5 corridor transmission paths will need to be upgraded first. Both will require 500 kV line construction (i.e., McNary – John Day and Paul – Troutdale). PSE must continue to participate in regional efforts and actively work with BPA to create a stable, long-lasting transmission structure.

Other actions PSE should consider include:

- Retaining existing contract transmission rights
- Working with BPA to establish its new evaluation and decision-making framework—to determine the most effective paths to facilitate the integration of new generation and to create a feasible financing structure
- Investing to upgrade PSE-owned transmission paths

With the recent passage of the Washington State Renewable Portfolio Standard, I-937, there is increased urgency for PSE and other utilities in Washington to actively acquire and build renewable resources. Until new regional transmission lines are built, PSE might even rely on short-term transmission to transmit wind resources from the Columbia Gorge to our service territory.

III. Electric Resource Alternatives

The demand- and supply-side resource options considered for this IRP were informed by our close observation of developing market trends and information obtained from a variety of public resources such as the Northwest Power and Conservation Council (NPCC) and the Energy Information Administration (EIA). The resources discussed in this section are the ones most relevant to this IRP. A comprehensive list of alternatives and detailed information on their current development status is included in Appendix D, Electric Resource Alternatives.

Resource Alternatives Are Limited

Few commercially viable resources are available at this time; only four are currently capable of producing generation in quantities large enough to impact the significant need we face over the 20-year planning horizon. These are demand-side resources, wind, natural gas, and coal. Only two—coal and gas—produce baseload generation which can be counted on to provide energy at virtually any time. However, coal and gas also come with significant risks, which are explored in further detail below. Limited biomass and geothermal generation is possible; however, our experience in the marketplace indicates that such opportunities are few in number, small in scale and face challenging development issues.

Many technologies have not yet proven to be commercially viable—that is, able to economically generate power on a scale large enough to make meaningful contributions to meeting utility needs.

Tidal and wave. Technologies harnessing tidal and wave power to produce energy are still largely research and development efforts. PSE has been a supporter of two northwest ocean energy studies (one tidal assessment and one wave demonstration project) because we believe that tidal and wave resources merit further attention and monitoring; however, commercial production of such resources in the Northwest is not a current reality. While there has been much speculation about the potential for tidal and wave energy in the Puget Sound area, the initial estimates for energy generation at each location must be studied and validated during the preliminary permit process. Moreover, the extent and duration of associated cultural, recreational and environmental studies remains to be determined, and these studies may prove to be a significant hurdle for the successful commercial application of these technologies. We will continue to monitor the development of these resources.

Solar. While approaching commercial status in other parts of the United States, solar power is still emerging as a utility-scale resource in Washington state. PSE recently announced plans to develop a solar demonstration project at our Wild Horse wind facility. In addition to providing a small amount of renewable energy, the project affords us the opportunity to explore the potential benefits and challenges of solar generation in our state while encouraging local solar development.

Nuclear. Despite claims of pre-approved Nuclear Regulatory Commission designs, nuclear power faces considerable challenges. Development and construction costs are so much higher than the next highest base load resource option as to be prohibitive to all but a handful of the largest capitalized utilities. Additionally, permitting, public perception, and waste disposal pose substantial risks.

Hydro. There are few new hydroelectric generating opportunities in the region, and none without significant environmental and permitting risk. Furthermore, hydro is not included as an *eligible renewable resourc*e under Washington's renewable portfolio standard and therefore cannot be applied toward the fulfillment of our requirement. Further, recent federal court decisions seem to raise risks for existing large hydro projects.

Geothermal. There are few proven geothermal resources in our region. Because these resources are located outside Washington state (primarily in Idaho and Oregon), they face long-haul transmission issues to bring power from the point of generation to PSE's service territory.

Biomass. In addition to opportunity and generation output limitations, biomass is subject to fuel supply and fuel management risks.

B. Commercially Viable Resource Alternatives

Demand-side Resources

Demand-side resources include energy efficiency, fuel conversion, and distributed generation. All these alternatives enable us to make less energy do the same amount of work.

Energy efficiency is defined as a technology that demonstrates the same performance for a given task as competing technologies, but requires less energy to accomplish the task. Energy efficiency resources count toward meeting our energy efficiency requirement under the state's renewable portfolio standard (RPS).

Fuel conversion takes place when a customer switches from electricity to natural gas, particularly in the case of space and water heating. Electrical savings are gained from the reduction in electrical energy use.

Distributed generation refers to small-scale electricity generators located close to the source of the customer's load.

Wind

The RPS established by Washington state requires that an increasing portion of renewable resources make up the portfolio of the largest utility providers. For our region, renewables means wind. This is because wind is the primary eligible renewable resource, as defined by the RPS, that is capable of producing utility-scale generation. At the same time, renewable portfolio standards are being adopted in Oregon, California, and other states across the country, a reality that is expected to increase overall demand for wind resources throughout the region and the nation. As a result, competition for experienced wind developers, viable sites, and component parts is expected to be robust.

Wind is also an intermittent resource, meaning that we cannot be certain the wind will be blowing when our customers most need the power. Because of this, stand-by base load resources must be available to "fill the gaps." Further, integrating an intermittent generation source into the transmission system poses challenges of its own. For a detailed discussion of wind integration issues, refer to the Wind Integration Studies Appendix.

Finally, remote-location wind projects face long-haul transmission issues, resulting from increased demand on an already-constrained system. Many of these constraints are described in part D of Section II of this chapter.

Natural Gas

Natural gas fired generation has several benefits. First, a gas fired-generator can be located within our service territory, which avoids the costly transmission investments required for east-side resources. Gas-fired resources are dispatchable, meaning they can be turned on when needed to meet loads, unlike an intermittent resource like wind or run-of-the-river hydro. Different kinds of gas-fired generators also have varying degrees of ability to ramp up and down quickly in response to variations in loads and variations in wind generation. Gas plants are also more scalable and less capital intensive than coal plants and thus avoid some of the long-lead risks associated with the development of remote coal mines and coal plants. Also, natural gas resources have significantly lower emissions than coal resources.

However, natural gas resources do have drawbacks. There are concerns about long-term natural gas availability, especially as the region becomes increasingly dependent on natural gas for generation fuel. Lack of diversity in supply basins and lack of diversity in gas transportation alternatives are also of concern, as are long-term price risks and short-term market price volatility.

Coal

Coal is one of two viable commercially available base load resources in the Northwest capable of providing enough generation to reliably meet our growing long-term need. It offers a plentiful, low cost, stable fuel source, and valuable resource diversity. On the other hand, coal faces substantial risks related to cost, regulatory issues, long-haul transmission, and permitting and development. Further, with mercury emissions and twice the CO_2 emissions of natural gas, conventional coal poses potential risks to health and human welfare and the environment.

Since the 2005 resource plan was developed, market, regulatory, and legislative conditions have changed significantly regarding coal. Activity at both federal and state levels suggests that cost consequences for the emission of CO_2 are likely in the future. Conditions have even changed since modeling began in October 2006 for this plan, with adoption of a new law that bans new coal resources without carbon sequestration. Mercury emission standards are also becoming more stringent. Overall, the estimated cost of permitting, constructing, and operating coal plants has increased enormously, and the commercial viability of coal resources has grown more uncertain.

Carbon sequestration is a key technology to managing coal risks. Unfortunately, permanent deep well geological sequestration of CO_2 is not a proven technology, nor is there a reliable estimate of when such technology may become commercially viable. Further, there is no regulatory framework in place to address the risks associated with siting and permitting carbon sequestration projects, CO_2 transportation, injection and storage.

Developing a regulatory framework for carbon capture and sequestration (CCS) will be challenging. The Pacific Northwest Utilities Conference Committee's publication *PNUCC Principles for Global Climate Change Legislation,* dated February 28, 2007, includes the following list of key questions that need to be addressed.

- Immunity from potentially applicable criminal and civil environmental penalties
- Property rights, including the passage of title to CO_2 (including to the government) during transportation, injection and storage
- Government mandated caps on long-term CO_2 liability, insurance coverage for short-term CO_2 liability
- Licensing of CO2 transportation and storage operators, intellectual property rights related to CCS, and monitoring of CO_2 storage facilities

Ultimately, the cost risks associated with impending future environmental regulations will continue to be significant unless CO_2 can be sequestered. Likewise, cost risks associated with sequestration-related liability uncertainties will continue to be significant until uniform legal standards are developed to address them.

C. Commercially available capacity resources

Capacity resources supply physical electric power, or shave peak loads, at times of peak hourly demand. Alternatives are limited because the physical requirement to serve customers necessitates either a generator located on the west side of the Cascades or a firm transmission contract to transmit power from other geographical locations.

Demand Response

These resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. The acquisition of demand response resources may be based on reliability considerations, or economic or market objectives.

Call Options

The buyer of a call option pays an up-front premium to the seller in exchange for the right to take power at a specified time and price. Call options are generally purchased with less than a one year term due to the steep increases in prices resulting from long range price volatility and time value of money. PSE's experience is that these call options are a relatively expensive tool to meet peak load. In addition, the derivative nature of these contracts requires mark to market accounting. Additionally, to be most valuable to PSE, a call option is either purchased from a supplier on the west side of the Cascades or purchased along with firm transmission.

Gas Tolling Contract

The buyer of a gas tolling contract pays a fixed monthly amount based on the output capacity in exchange for the right to deliver and convert natural gas to electric power at a contract stated heat rate. In addition to the fixed capacity payment, the buyer pays a variable charge for each MWh of energy produced. Gas tolling contracts can be purchased at a range of heat rates. The lower heat rates are usually from combined cycle combustion turbines and the higher heat rates are from simple cycle combustion turbines. Tolling contracts are frequently available with terms of one to five years, and occasionally offered with longer terms. The gas tolling contract is sometimes referred to as a heat rate call option because of the right to take power by running the physical turbine once the market price of power and gas indicate that the gas tolling contract is economical. The gas tolling contract was used in this IRP to supply capacity in the years prior to 2014.

Natural Gas - Simple Cycle Combustion Turbines

One of the benefits of simple cycle combustion turbines is that they can be built in ten months or less. Moreover, they can be brought online quickly to serve peak need. While a simple cycle unit can be brought online more quickly than a combined cycle unit, which is what makes them more attractive from a capacity perspective, simple cycles are less efficient and have higher heat rates than combined cycles, rendering them more expensive to run. Additionally, these units have relatively high capital costs, and are subject to significant risks related to rising gas costs, and fuel supply and delivery diversity issues.

Natural Gas Fuel – Reciprocating Engine Generation

Like simple cycle combustion turbines, reciprocating engines can be built in ten months or less, and they can be brought online quickly to serve peak loads. Unlike gas turbines, reciprocating engines demonstrate consistent heat rate and output during all temperature conditions. Generally these units are small and are constructed in power blocks with multiple units. Reciprocating engines are less efficient than simple cycle combustion turbines, but the small size of the units allows a better match with peak loads thus increasing operating flexibility relative to the simple cycle combustion turbine.

IV. Electric Analytic Methodology

This section describes the quantitative analysis of electric demand- and supply-side alternatives. It explains how hypothetical portfolios were created to test a variety of key planning questions, and how these portfolios were evaluated under a wide range of potential scenarios. The resulting analysis allowed us to quantify how sensitive some of our conclusions were to the planning assumptions, and provided insight into how adding different types of generation would affect PSE ratepayers' costs. Among the critical questions we posed were the following:

- How sensitive are the demand-side portfolios to different levels of avoided costs?
- What are the key decision points and most important uncertainties in the long-term planning horizon, and when should we make those decisions?
- What is the impact if carbon sequestration technology cannot be proven commercially viable?
- What if PSE decides not to build any more coal generation?
- What is the impact of adopting IGCC technology earlier in the planning horizon rather than later?
- What if reliance on renewable energy alternatives is significantly increased?
- What is the carbon intensity under different planning assumptions?

Overview of Approach and Methodology

Electric analytic methodology followed the four basic steps illustrated in Figure 5-19. A detailed technical discussion of these models and methods is included in Appendix I, Electric Analysis.

Figure 5-19
Methodology Used to Analyze Demand- and Supply-side Portfolios

Step 1
Identify Available Portfolios and Resource Bundles
- Develop supply-side portfolios to test impact of key decision alternatives
  - Different technology types
  - Potential on-line dates
  - Commercial viability
- Develop alternate bundles of demand-side resources to determine potential
  - Screen demand-side bundles for technical and economic potential
  - Test alternate levels of avoided costs
  - Identify achievable potential

Step 2
Integrate and Test Supply and Demand Portfolios
- Combine supply and demand resources and test interactions
- Evaluate relative portfolio rankings by cost
- Identify key variables and quantify their impact

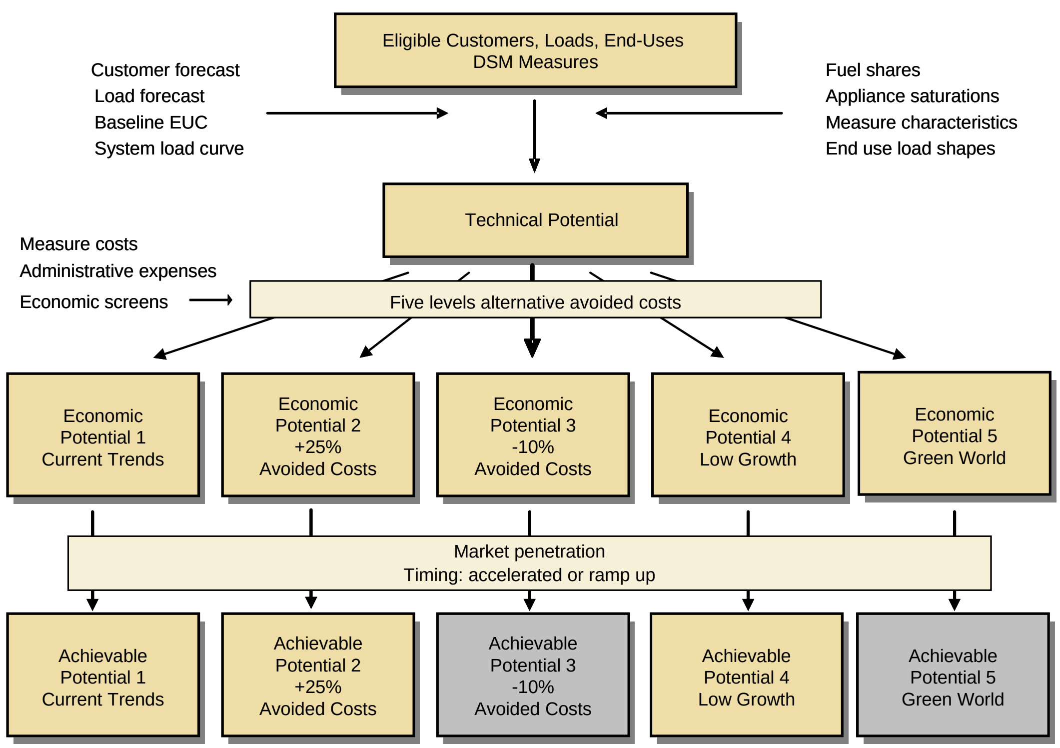
Step 3
Finalize Portfolios for Quantitative Analysis
- Add/subtract portfolios as appropriate to test key decisions

Step 4
Evaluate Risks and Sensitivities
- Compile portfolios for analysis
- Run Monte Carlo analysis

Step 1: Identify Available Resource Alternatives

Demand-side resources were first evaluated, and then combined into various bundles for integration with supply-side resource combinations. For PSE, demand-side resource alternatives include energy efficiency, fuel conversion, distributed generation, and demand response. Each involves different technologies, load impacts, and markets. To evaluate their unique characteristics and potential, we applied three distinct yet related screens. These three screens—for technical potential, economic potential, and achievable savings—are widely used in utility resource planning, consistent with the Northwest Power Planning and Conservation Council methodology, and with evaluation of energy efficiency resource potentials in general. After individual evaluation, demand-side resources were combined into bundles for further analysis. A more in-depth discussion of the demand-side resource evaluation and the development of the bundles used in our analysis process is provided in Appendix K.

Figure 5-20
General Methodology for Assessing Demand-Side Resource Potential



The first screen, for technical potential, assumed that all energy efficiency resource opportunities could be captured regardless of costs or market barriers. It produced an end-use forecast assuming “frozen” end-use efficiencies, and then calibrated it to PSE’s system load forecast. We then generated a second forecast that included all technically feasible demand-side measures. Technical energy efficiency resource potentials were then calculated as the difference between the forecasts.

The second screen, for economic potential, included only measures deemed to be cost effective based on a total resource cost test. Five levels of avoided costs were tested. The Current Trends, Green World, and Low Growth scenario electric price projections were used (with a planning adjustment), and in addition, we tested 10% below the adjusted Current Trends price projection and 25% above the adjusted Current Trends price projection. This wide range enabled us to test for behavior responses at different levels of avoided costs. This screening step resulted in five preliminary bundles containing different amounts of energy efficiency resources, and different estimated savings potentials for each level of avoided costs.

Finally, we screened out any resources not considered achievable. Establishing achievable potential largely relied on customer response to PSE’s past energy programs, the experience of other utilities offering similar programs, and review of the Northwest Power Planning and Conservation Council’s most recent energy efficiency potential assessment. For this IRP we assumed that economic electric energy efficiency potentials of 85% and 65% in existing buildings and new construction markets, respectively, are likely to be achievable over the planning period. The achievable potential was distributed over the planning period based on technical and market considerations.

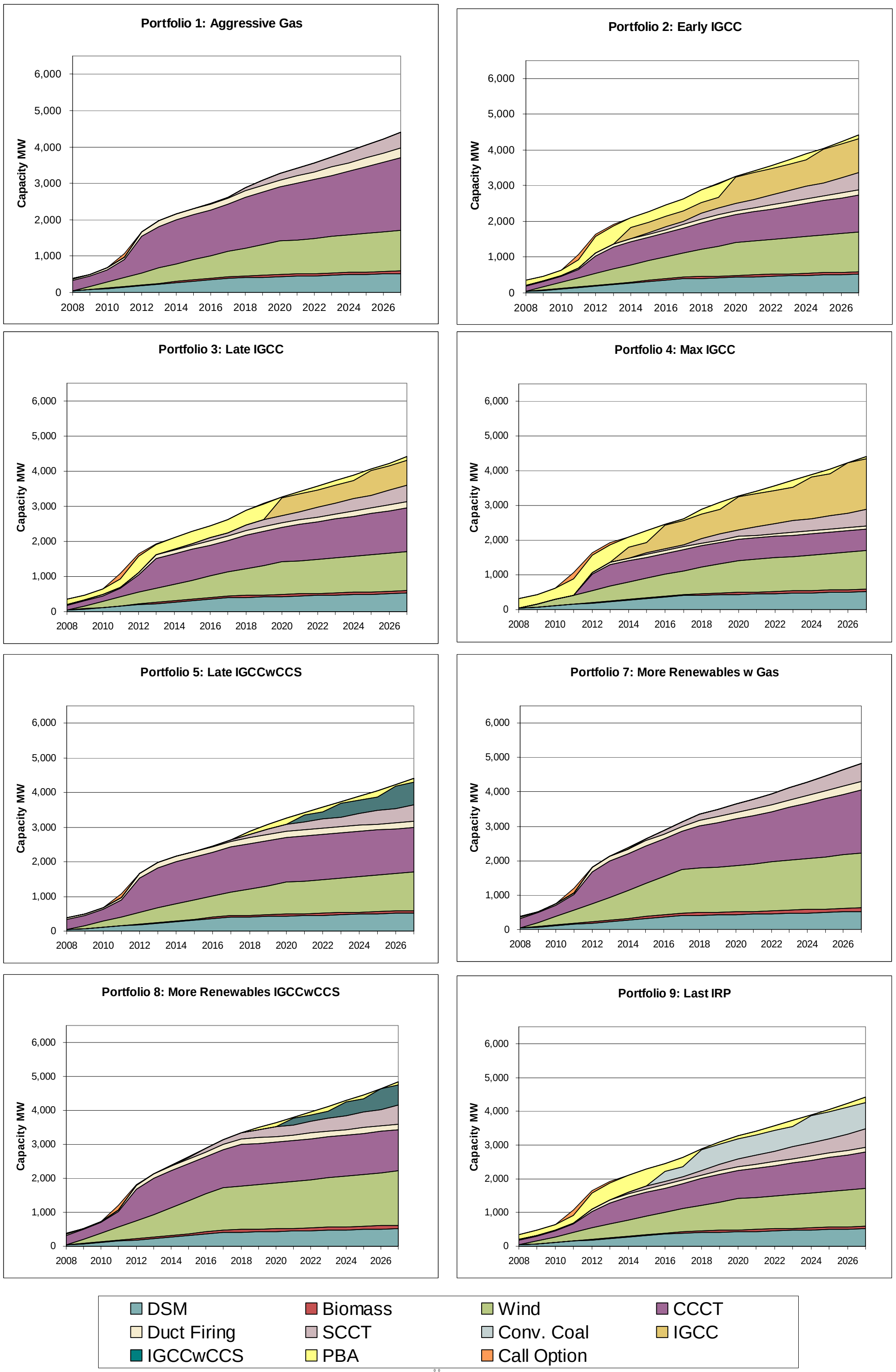
These three screens confirmed that the range of potential results was bounded by “bookends” representing the highest and lowest avoided costs (25% higher and 14% lower than the 2005 LCP). This allowed us to streamline our analysis by eliminating demand-side bundles 3 and 5 from our integrated analysis since all quantitative results from these two portfolios would be contained between the bookends.

Combinations of supply alternatives were constructed to provide analytical comparison groups composed of different renewable and thermal technologies. For example, combinations were constructed to test IGCC attractiveness with and without carbon sequestration, or to test heavy reliance on natural gas, or the aggressive use of renewables to meet future load requirements.

Step 2: Define and Test Integrated Portfolios

Each of the original eight supply combinations was matched with each of the three demand-side bundles, creating 24 integrated portfolios. Each of these 24 portfolios was then evaluated under each of the six planning scenarios, resulting in 144 portfolio-scenario combinations. On the next page, Figure 5-21 displays the capacity MW additions for the eight portfolios. More detailed information can be found in the Electric Analysis appendix.

Figure 5-21
Eight Initial Integrated Portfolios



Demand-side Bundle 1 (Current Trends) was based on the 2005 LCP estimate of avoided costs of $89.92 per MWh. Bundles 2 and 4 had higher and lower avoided costs. These were included to test whether they affected the cost rankings of the integrated portfolios. Our analysis of the 24 integrated portfolios across scenarios indicated that the relative rankings were essentially the same for all the energy efficiency portfolios. That is, the attractiveness of each portfolio basically did not shift depending on whether avoided costs equaled the 2005 LCP estimates, or were higher or lower. In the two cases that energy efficiency bundles affected relative rankings, the difference was so slight—less than 1/100 of 1%—it could be attributed to a rounding error. The relative rankings of all of the 144 portfolio-scenario combinations are shown in Figure 5-22.

Since rankings were unaffected by the level of energy efficiency resources, the final analyses focused on just one energy efficiency bundle. This further streamlined the analysis without affecting the quantitative conclusions. Demand-side Bundle 1 (Current Trends) was used in all subsequent analyses.

Figure 5-22
Relative Rankings of 144 Portfolio-Scenario Combinations
(24 portfolios across 6 scenarios)

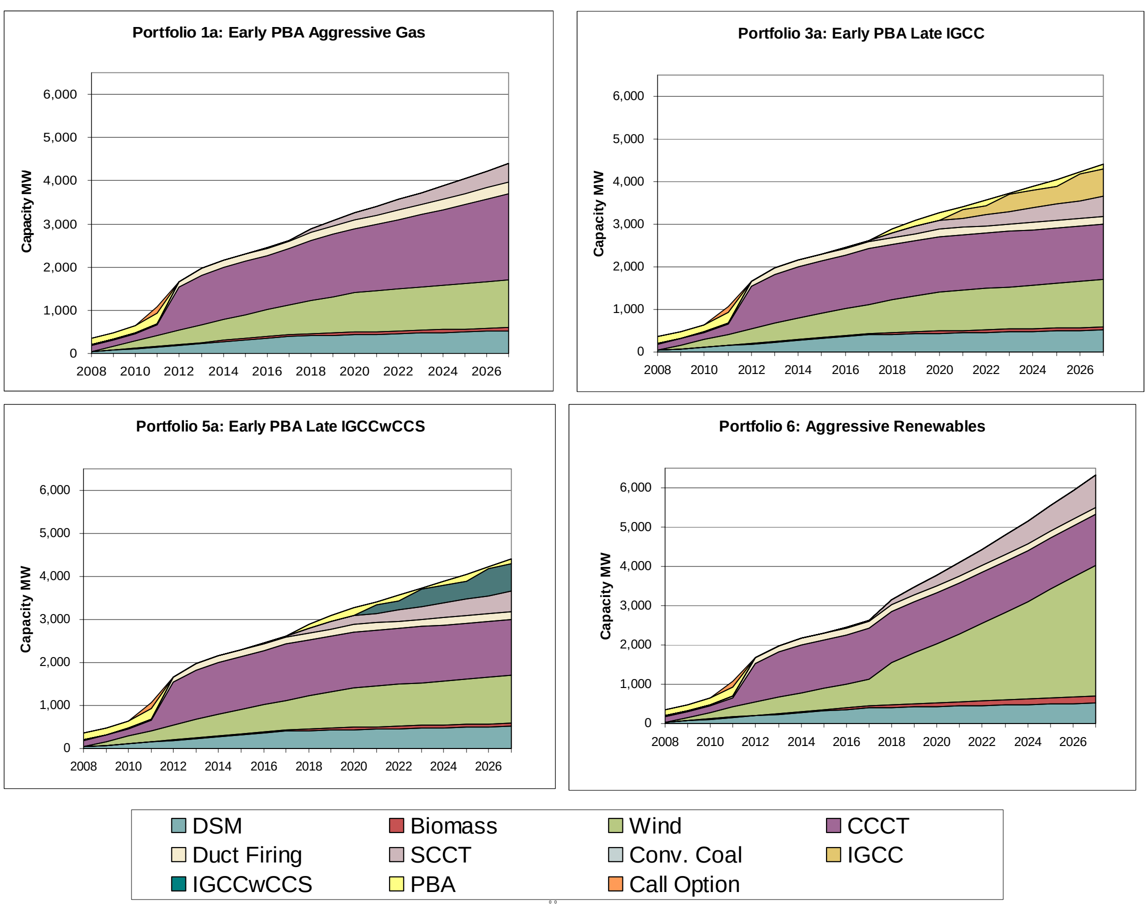
	1	2	3	4	5	7	8	9
	Aggressive Gas	**Early IGCC**	**Late IGCC**	**Max IGCC**	**Late IGCCwCCS**	**More Renew w Gas**	**More Renew w IGCCwCCS**	**Last IRP Portfolio**
Current Trends								
Low Growth DSM	2	3	1	4	6	7	8	5
Current Trends DSM	2	3	1	4	5	7	8	6
CT + 25% DSM	2	3	1	4	6	7	8	5
Green World								
Low Growth DSM	2	7	5	8	1	4	3	6
Current Trends DSM	2	7	5	8	1	4	3	6
CT + 25% DSM	2	7	5	8	1	4	3	6
Low Growth								
Low Growth DSM	1	5	2	8	4	3	7	6
Current Trends DSM	1	5	2	8	4	3	7	6
CT + 25% DSM	1	5	2	8	4	3	7	6
Robust Growth								
Low Growth DSM	6	2	3	1	5	8	7	4
Current Trends DSM	6	2	3	1	5	8	7	4
CT + 25% DSM	6	2	3	1	5	8	7	4
Technology Improvement								
Low Growth DSM	5	3	2	1	4	7	8	6
Current Trends DSM	5	3	2	1	4	7	8	6
CT + 25% DSM	5	3	2	1	4	7	8	6
Escalating Costs								
Low Growth DSM	1	4	2	6	3	7	8	5
Current Trends DSM	1	4	2	7	3	6	8	5
CT + 25% DSM	1	4	2	7	3	6	8	5

Lowest Cost Portfolio
2nd Lowest Cost Portfolio

Step 3: Finalize Portfolios for Quantitative Analysis

Examining the integrated portfolios raised a number of additional analytical questions that led us to construct four new supply portfolios as modifications of some of the original portfolios. These new portfolios have an “a” following the number to indicate an adjusted portfolio. These changes were made primarily to create equivalent comparisons of portfolios with the same amount of power bridging agreements (PBAs) in the early years. This allowed us to isolate the impacts of adding wind, gas, and IGCC with and without CCS over a comparable time horizon without having the results influenced by different levels of PBAs. The 12 final supply portfolios used in the analysis were able to provide a quantitative comparison of costs of all portfolios that contained equivalent amounts of PBAs in early years. The four new portfolios, along with their resource additions by year, are shown in Figure 5-23.

Figure 5-23
Four Additional Integrated Portfolios



Step 4: Complete Portfolio Analysis

After adding the four new portfolios, we tested them under all six scenarios. This enabled us to rank the 12 portfolios in each future. To fully understand risks associated with using expected gas prices, power prices, average hydro generation levels, and expected wind generation levels, we evaluated these variables using Monte Carlo analysis as we did in the 2003 and 2005 LCPs. The Monte Carlo analysis performed 100 iterations on each of the 12 integrated portfolio combinations for the Current Trends scenario. This provided quantitative backup for the risk evaluations. As we learned in the 2005 LCP and in subsequent RFP analyses, since the input variables and their probability distributions are the same for all portfolios (based on historical data), it is only necessary to perform the Monte Carlo analysis for one scenario to provide the analytic insight to support the risk assessment.

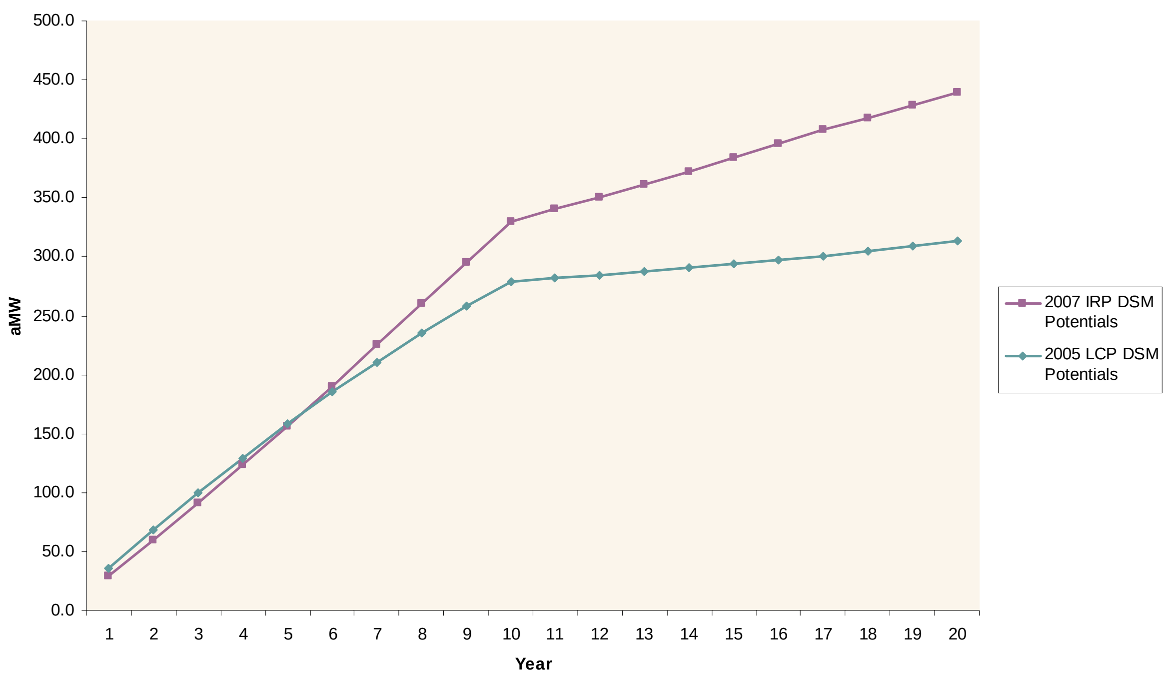
V. Quantitative Results and Insights

The quantitative results produced by this extensive analytical and statistical evaluation led to several key findings that guided the long-term resource strategy presented in this IRP. The data generated by the analysis are presented in the Electric Analysis appendix.

Key General Findings

1. Demand-side programs are projected to increase by approximately 40% over the last LCP. At their current level, these programs are not significantly affected by changes in assumed avoided costs.

Figure 5-24
2005 versus 2007 Demand-side Potentials



The demand-side resources in this plan represent an aggressive pursuit of cost-effective energy efficiency, fuel conversion, distributed generation, and demand response. The amount of cost-effective achievable demand-side resources is 40% greater than it was in the 2005 plan (Figure 5-24). Demand-side resources contribute 329 aMW to meeting the Company's energy need by 2017, and 438 aMW by 2027.

Near-term, the 2007 IRP guidance also represents a significant increase in energy efficiency resource acquisition for PSE. In the 2004-2005 biennial program cycle, PSE achieved 39 aMW of electric efficiency savings. For 2006-2007, the two-year target is 40 aMW. This guidance suggests a level of 56 aMW of meter-level savings for 2008-2009, an increase of 40% over current levels (Figure 5-25). This reflects higher levels of avoided costs and market penetration across all portfolios and scenarios.

Figure 5-25
Energy Efficiency Potential: Historical vs. Projected Short-term

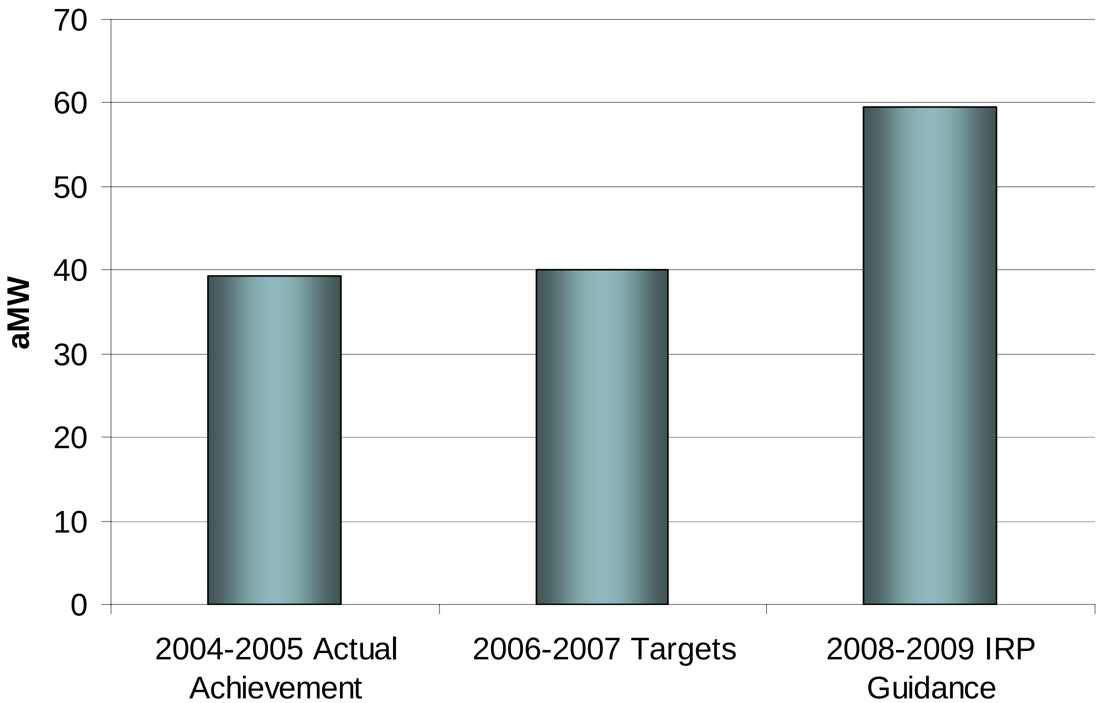
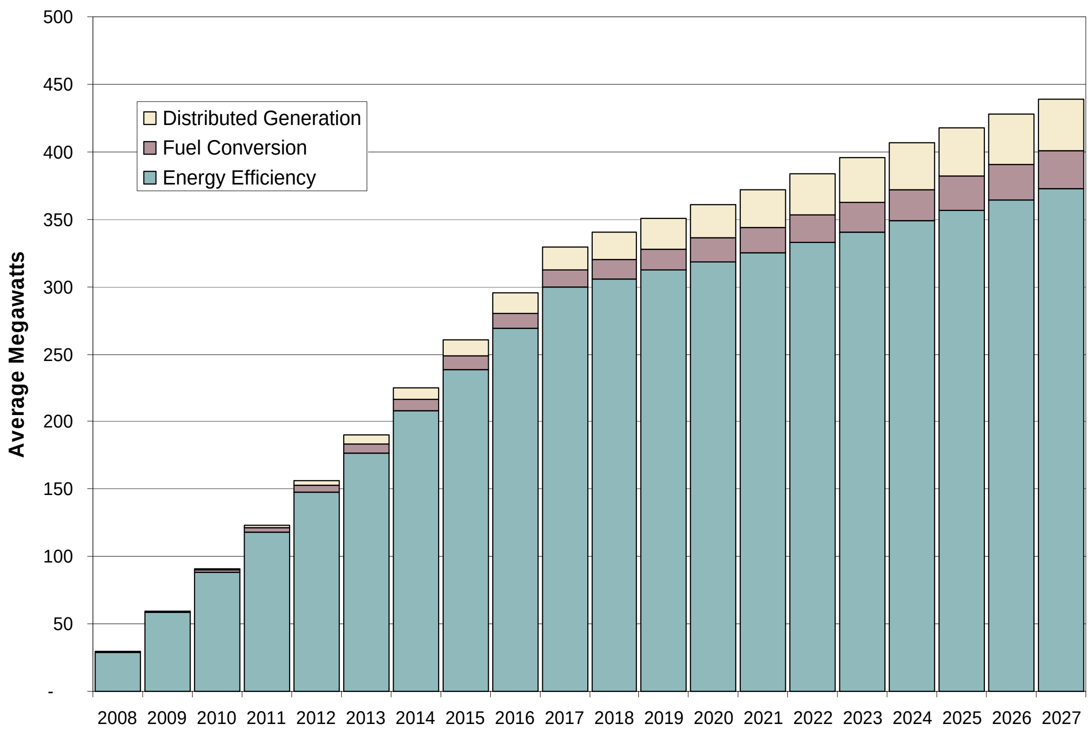


Figure 5-26 shows the breakdown of energy savings from demand-side resources by type of resource. Energy efficiency is by far the largest component at 372 aMW by 2027, with 299 aMW of that potential occurring by 2017, as all discretionary energy savings opportunities are accelerated into the first 10 years of the planning period. Fuel conversion and distributed generation resources account for 28 aMW and 38 aMW respectively by 2027. These are ramped in over time, reflecting the need to gain experience with customer acceptance and program design since they are new and untested resources for PSE. Fuel conversion also results in increased gas consumption of about 1.2 million decatherms, as part of the cost of gaining 28 aMW of electric savings. The 20-year achievable potential from demand response is 130 MW of peak capacity reduction.

Figure 5-26
Cumulative Annual Energy from Electric Demand-side Resources



Over the range of avoided cost scenarios considered, the difference between the highest and lowest cases was 60 aMW over 20 years. Compared to the Current Trends scenario used in the final portfolio analysis, the Current Trends +25% scenario yielded an additional 26 aMW, while the low growth scenario reduced the potential by 35 aMW. Figure 5-27 illustrates the 60 aMW range of achievable potentials between the avoided costs "bookends."

For the range of avoided costs considered, the achievable energy efficiency supply curve is a near vertical slope. Thus, changes in avoided costs did not significantly impact the potential for energy efficiency resources. Figure 5-28 shows the shape of the demand-side resource supply curve.

Figure 5-27
Range of Achievable Demand-side Potentials

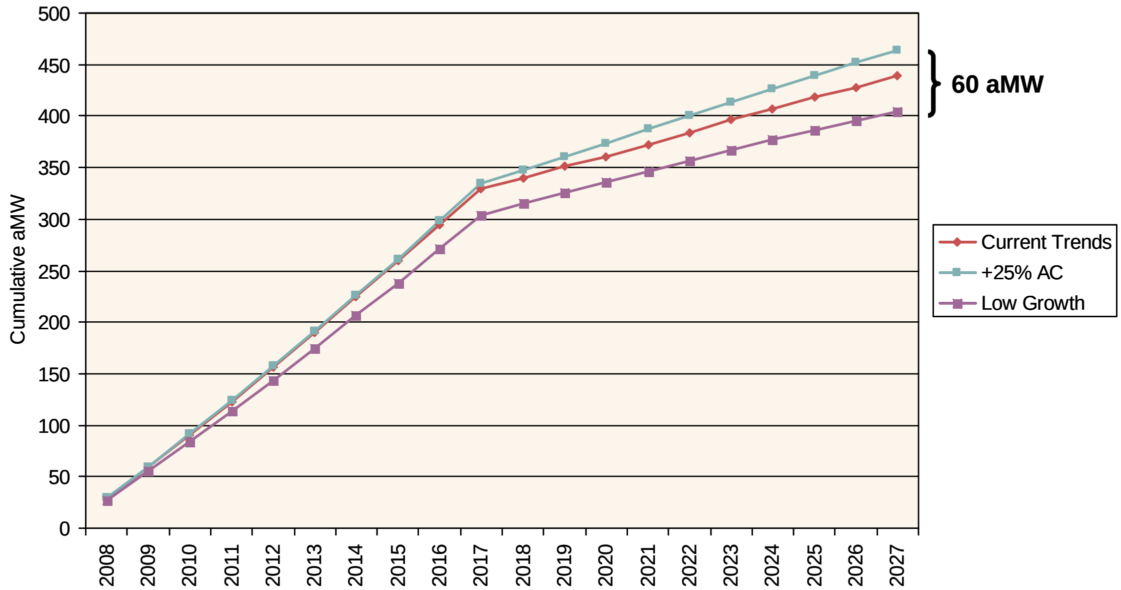
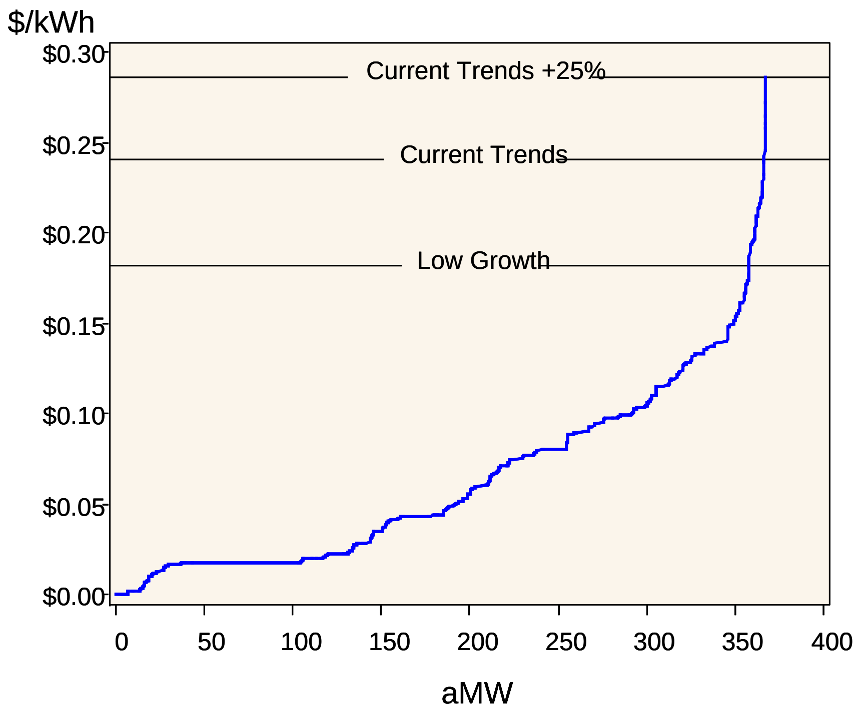


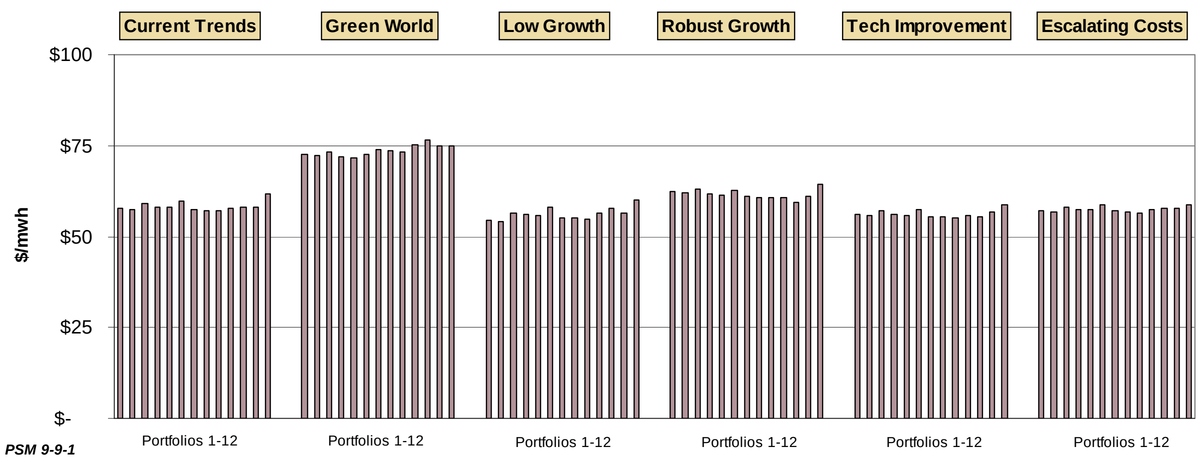
Figure 5-28
Supply Curve of Demand-side Potential



2. Total costs for all portfolios are very tightly grouped together.

The quantitative analysis found that cost differences between individual portfolios are small, so conclusions about which portfolio is best or second best must consider that the magnitude differentiating the “winner” is relatively small. There are two primary reasons for this tight grouping: (1) the differences in incremental portfolio additions are small compared to the larger relative size of the existing portfolio; and (2) most differences between portfolios involve choices occurring in the later half of the planning horizon. Due to discounting the out-year effects, this results in fairly small quantitative differences. The incremental cost per MWh for the different portfolios is shown in Figure 5-29.

Figure 5-29
Cost Differences between Portfolio-Scenario Combinations



3. The preferred portfolio varies considerably from scenario to scenario.

Figure 5-30 ranks the 12 portfolios in each of the six scenarios. These rankings demonstrate that in scenarios where gas prices are relatively high, portfolios with IGCC look better. In cases where natural gas prices are relatively lower, gas portfolios are better. When high environmental costs are added to high gas prices, as in the Green World scenario, the IGCC with carbon sequestration portfolio is preferred because it has the lowest emissions, low fuel prices, and stable supplies. If CCS is not available, however, aggressive gas portfolios would be the preferred choice.

Figure 5-30
Relative Rankings of 12 Portfolio-Scenario Combinations

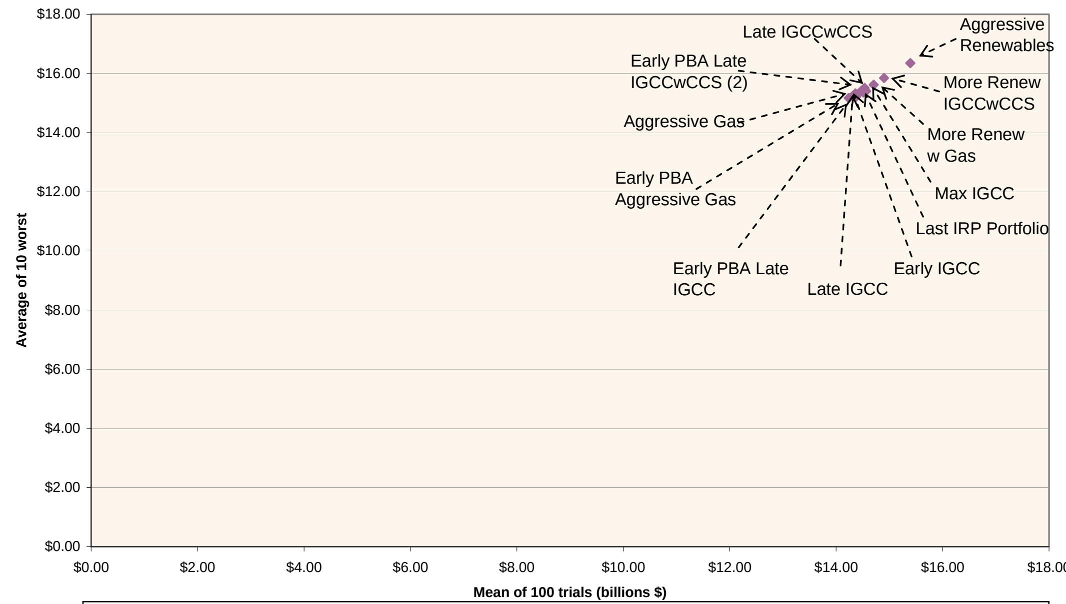
	1	1a	2	3	3a	4	5	5a	6	7	8	9
	Aggressive Gas	Early PBA Aggressive Gas	Early IGCC	Late IGCC	Early PBA Late IGCC	Max IGCC	Late IGCC w CCS	Early PBA Late IGCC w CCS	Aggressive Renew	More Renew w Gas	More Renew IGCC w CCS	Last IRP Portfolio
Current Trends	4	3	5	2	1	6	8	7	12	10	11	9
Green World	4	3	11	8	7	12	2	1	9	6	5	10
Low Growth	2	1	8	4	3	10	6	5	12	7	11	9
Robust Growth	9	8	2	4	3	1	7	6	12	11	10	5
Technology Improvement	8	5	4	3	1	2	7	6	12	10	11	9
Escalating Costs	3	2	7	4	1	9	6	5	12	10	11	8

Lowest Cost Portfolio
2nd Lowest Cost Portfolio

4. The worst portfolio outcomes are tightly grouped.

Figure 5-31 compares the cost-to-risk tradeoff of the different portfolios within the context of the Current Trends scenario. This graph plots the mean of the 100 trials from Monte Carlo and the average of the 10 worst trials (similar to the expected portfolio costs in finding 2). The risk results are tightly grouped.

Figure 5-31
Comparison of Cost/Risk Tradeoff
between Portfolios in the Current Trends Scenario

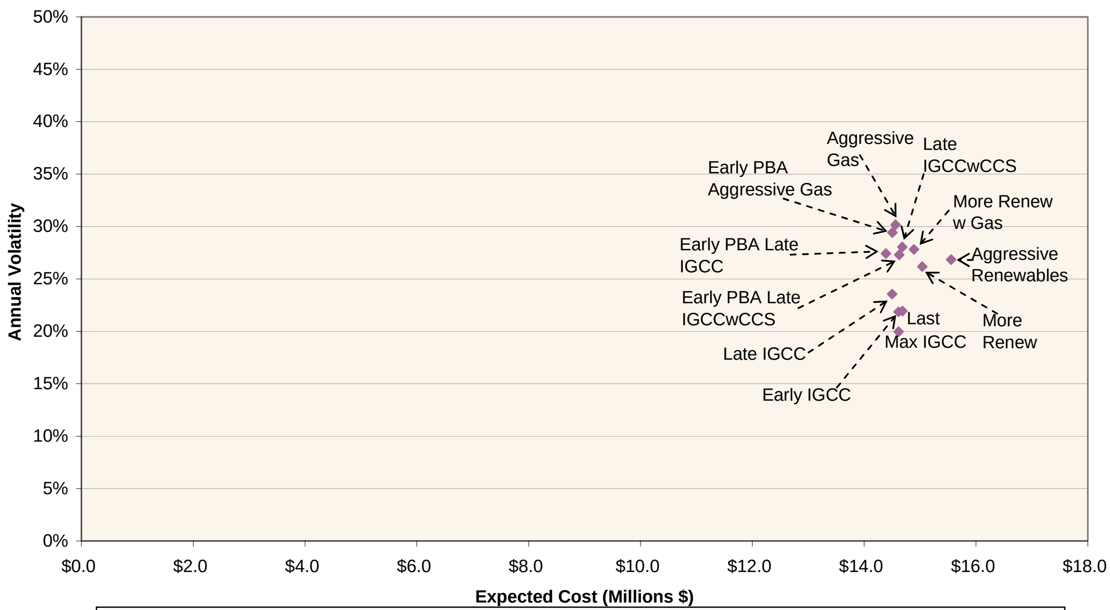


Risk is a measure of how bad costs might be with each portfolio.
Risk analysis for the IRP is performed by averaging the 10 worst cases from a 100-draw Monte Carlo analysis.

5. Annual volatility is dependent on fuel source.

The following chart shows that portfolios with more gas have more annual volatility, and portfolios with coal have less annual volatility. This is not surprising because the cost of coal fuel is relatively stable whereas gas prices are more variable. The addition of wind plants does not reduce volatility significantly, because more gas plants are needed to fill in for capacity need.

Figure 5-32
Comparison of Cost/Volatility Tradeoff between Portfolios in the Current Trends Scenario



Volatility is a measure of year-to-year variability in costs. It is an indicator of portfolios that would result in more or less stable rates over time. Volitility is estimated as the mean standard deviation of percentage changes in year-to-year costs in each each of the 100 Monte Carlo simulations.

Gas Resources

PSE provides gas service to approximately 700,000 customers in Washington state. This chapter describes the future resource needs of our gas sales customers, and our existing gas resources. It presents the alternatives available to meet long-term needs, introduces the methods we used to evaluate those alternatives, and summarizes the key results and findings of that analysis. Also included is a comparison of projected gas resources needed for electric generation fuel. The chapter is presented in six sections.

I. Gas Resource Need

Peak demand usage by our gas sales customers is projected to increase at an average rate of 1.9% per year over the next 20 years due to increasing employment and population growth in our service territory. (See Chapter 4 for a detailed discussion of the demand forecast.)

PSE holds firm pipeline transportation and peaking capacity that allows the Company to transport or otherwise deliver gas, on a firm basis, from points of receipt to customers. This capacity ensures that we can provide our customers with reliable and cost-effective gas supplies during the coldest expected weather, and over a range of expected scenarios. In addition, PSE maintains upstream pipeline capacity to ensure direct access to gas production areas and the inherent reliability that this brings. PSE also maintains a mix of on-system resources that assists in meeting peak demands and contributes to the reliability of the distribution system. Figure 6-1 illustrates our natural gas capacity need over the planning horizon under the three load forecast scenarios.

Figure 6-1
Gas Sales Resource Need 2008-2027:
Existing Resources Compared to Design Peak Day Gas Demands

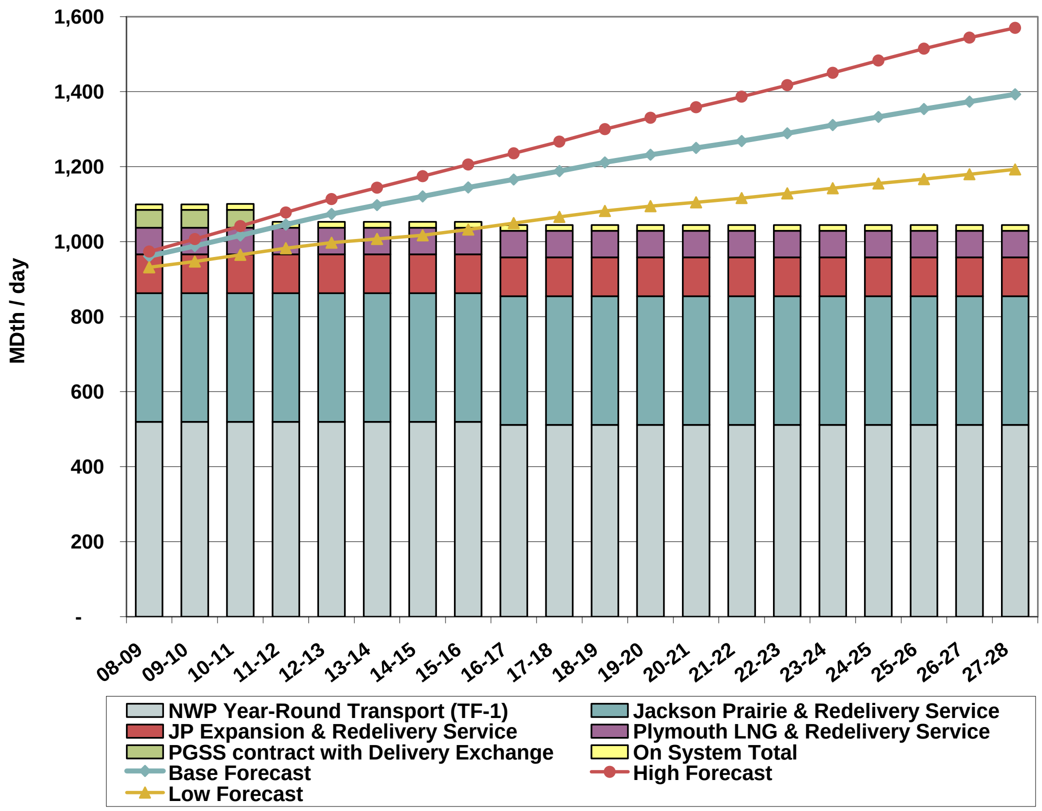


Figure 6-1 summarizes the balance between existing resources and projected peak day demand for direct sales customers. As shown, PSE has sufficient resources to meet the base (or expected) load forecast until the winter of 2012-2013. Under the high demand forecast, PSE will become deficit by the 2010-2011 heating season, and under the low demand forecast PSE will have sufficient resources to meet peak loads through the winter of 2016-2017.

We anticipated we would require additional delivery resources for the 2008-2009 heating season in the 2005 Least Cost Plan. The acquisition of 55 MDTh/day of firm pipeline capacity from Duke Energy Trading and Marketing (DETM) and the development of the Jackson Prairie expansion and redelivery service has added additional deliverability of 104 MDTh/day. This increased capacity is scheduled to come on-line in time for the 2008-2009 heating season and has extended the adequacy of PSE's peak supply resources.

II. Existing Gas Resources

A. Supply-side Resources

Supply-side gas resources include pipeline capacity, storage capacity, peaking capacity, and gas supplies.

Existing Pipeline Capacity

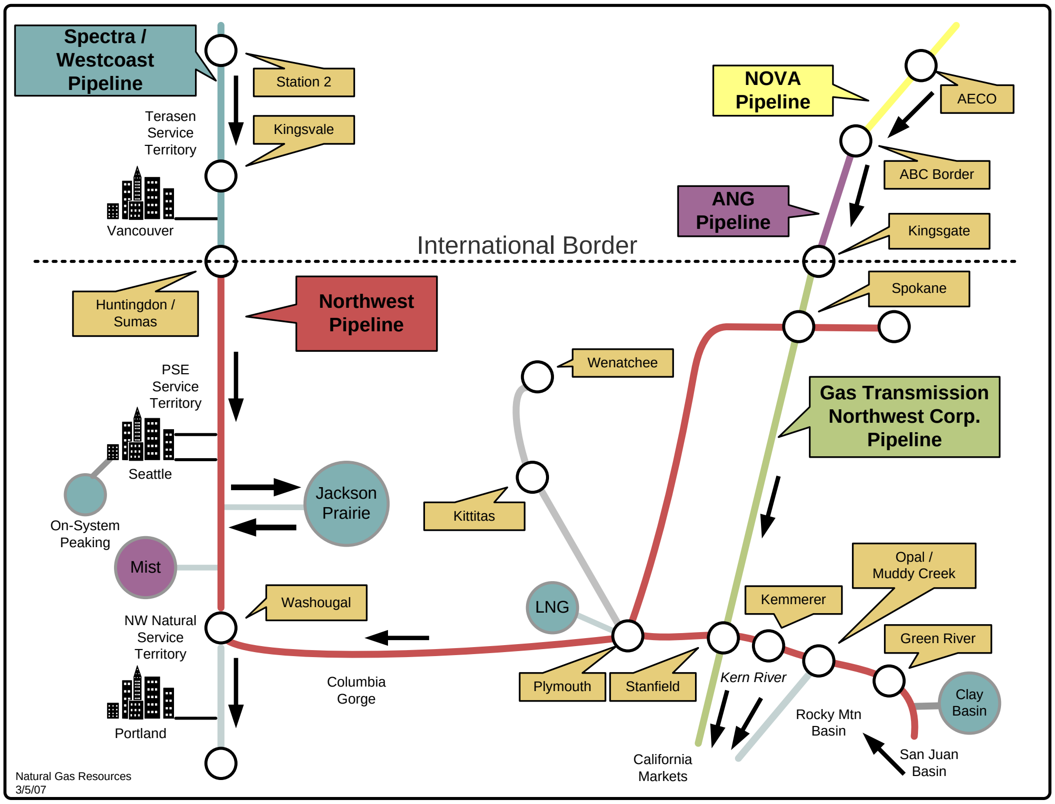
PSE holds firm pipeline transportation and peaking capacity that ensures we can provide customers with reliable and cost-effective gas supplies during the coldest expected weather and over a range of expected scenarios.

The two types of pipeline capacity are “direct connect,” which delivers supplies directly to PSE’s local distribution system from production areas, storage facilities or interconnections with other pipelines; and “upstream,” which delivers gas to the direct pipeline from remote production areas, market centers, and storage facilities. Figure 6-2 provides a general picture of the resources in the Pacific Northwest.

Direct-Connect Pipeline Capacity. All gas delivered to our gas distribution system is handled last by PSE’s only direct-connect pipeline, Northwest Pipeline (NWP). We hold 520,053 dekatherms per day (Dth/day) of NWP’s firm TF-1 transportation capacity, and 413,557 Dth/day of firm TF-2 capacity. TF-1 transportation contracts are firm contracts, available 365 days each year. TF-2 service on the other hand, is intended only for delivery of storage volumes during the winter heating season, and as such has significantly lower annual costs than the year-round service provided under TF-1.

Receipt points on the NWP contracts access supplies from four production regions: British Columbia, Alberta, the Rocky Mountain area, and the San Juan Basin. This provides valuable delivery point flexibility, including the ability to source gas from different regions on a day-to-day basis in some contracts.

Figure 6-2
PSE Gas Transportation Map



System reliability and supply dependability are ongoing concerns, and NWP has consistently met these challenges. For example, in 2003 NWP experienced two pipeline failures on its 26-inch Washington mainline. Following the second failure, NWP notified customers that it was idling a 268-mile segment of the pipeline between Sumas and Washougal, which temporarily reduced capacity by about 360,000 Dth/day. However, no customers were affected by this reduction, nor was there any decrease in transportation volumes. Even during cold snaps in January 2004 and 2005, NWP met its customers' firm service requirements.

NWP worked with the Office of Pipeline Safety (OPS) to restore 131,000 Dth/day of capacity by the end of June 2004. In addition, NWP filed an application with the Federal Energy Regulatory Commission (FERC) to replace the contractual capacity of the 26-inch pipeline with a new, larger-diameter pipe and additional compression by November 2006.

PSE reviewed the NWP Capacity Replacement Project proposal, compared it to other proposals, and concluded it was the most cost-effective solution to retain the region's access to gas supplies. Completed on-budget ($333 million) in December 2006, the project restored and replaced the capacity, flexibility, and reliability of the original facilities.

Upstream Pipeline Capacity. To transport gas supply from production basins or trading hubs to the NWP system, PSE holds capacity on several upstream pipelines. Figure 6-3 summarizes our direct-connect and upstream pipeline capacity position.

Figure 6-3
Existing Pipeline Capacity Position (Dth/Day)

Pipeline/Receipt Point	Note	Total	Year of Expiration			
			2008	2009	2010	Other
Direct Connect						
NWP/Westcoast Interconnect (Sumas)	1	259,761	58,000	128,705		18,056 (2016) 55,000 (2018)
NWP/GTN Interconnect (Spokane)	1	75,936	-	75,936	-	
NWP/various Rockies	1	184,356	43,848	139,892		8,056 (2016)
Total TF-1		520,053	101,848	344,533	26,112	55,000
NWP/Jackson Prairie	1,2	-	343,057	-	-	
NWP/Plymouth LNG	1,2	-	70,500	-	-	
Total TF-2		413,557	413,557	-	-	
Total Capacity to City Gate		**933,610**	**515,405**	**344,533**	**26,112**	**55,000**
Upstream Capacity						
TCPL-Alberta/from AECO to TCPL-BC Interconnect (A-BC Border)	3	80,000				
TCPL-BC/from TCPL-Alberta to TCPL-GTN Interconnect (Kingsgate)	4	80,000				
TCPL-GTN/from TCPL-BC Interconnect to NWP Interconnect (Spokane)	5	65,392	-	-	-	65,392 (2023)
TCPL-GTN/from TCPL-BC Interconnect to NWP Interconnect (Stanfield)	5,6	25,000	-	-	-	25,000 (2023)
Westcoast/from Station 2 to NWP Interconnect (Sumas)	4,7	95,000	-	-	-	25,000 (2014) 55,000 (2018) 15,000 (2019)
Total Upstream Capacity	**8**	**345,392**				

Notes:

1) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.*
2) *TF-2 service is intended only for redelivery of storage volumes during the winter heating season, and as such has significantly lower annual costs than the year-round service provided under TF-1.*
3) *Converted to approximate Dth per day from contract stated in gigajoules per day.*
4) *Converted to approximate Dth per day from contract stated in cubic meters per day.*
5) *TCPL-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.*
6) *Capacity can alternatively be used to deliver additional volumes to Spokane.*
7) *The Westcoast contracts contain a right of first refusal upon expiration.*
8) *Upstream capacity is not necessary for supplies acquired at interconnects in the Rockies and for some of the supplies available at Sumas.*

Firm and Interruptible Capacity. Firm pipeline transportation capacity carries the right, but not the obligation, to transport up to a maximum daily quantity (MDQ) of gas from one or more receipt points to one or more delivery points in accordance with the pipeline's published tariff (which is approved by FERC or the Canadian National Energy Board). The tariff defines the scope of service, which includes the number of days that the transportation service is available, along with the rates, rate adjustment procedures, and other operating terms and conditions. Firm transportation capacity requires a fixed payment, whether or not that capacity is used.

Firm capacity on NWP and GTN may be "released" and remarketed to third parties under the FERC-approved pipeline tariffs. Firm capacity on Westcoast can also be remarketed under recently instituted "streamlined capacity assignment" provisions. PSE aggressively releases capacity when we have a surplus and when market conditions make such transactions favorable for our customers. We also use the capacity release market to access additional firm capacity when it is available.

Interruptible service is subordinate to the rights of shippers who hold and use firm transportation capacity; when firm shippers do not use their pipeline capacity, they may release it for limited periods of time. Interruptible service is available to PSE from NWP under TI-1 rate schedules, but has a limited role in PSE's resource portfolio because it cannot be relied on to meet peak demand. The rate for interruptible capacity is negotiable, and is typically billed as a variable charge.

Existing Storage Resources

PSE's natural gas storage capacity is a significant component of our gas resource portfolio. It confers advantages that not only improve system flexibility, but create significant cost savings for both the system and customers.

- Ready access to an immediate and controllable source of firm gas supply enables us to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to a pooling point makes it possible for us to store gas that was purchased but not consumed during off-peak seasons, and to buy additional gas during the lower-demand summer season at significant cost savings.
- Combining storage capacity with seasonal TF-2 transportation allows us to eliminate the need to contract for year-round pipeline capacity to meet winter-only demand.

PSE also uses storage to balance city-gate gas receipts with the actual loads of our gas transportation customers. Industrial and commercial customers who elect gas transportation service (rather than gas sales service) make nominations directly or through marketer-agents to move city-gate gas deliveries to their respective meters. When these customers or marketers have imbalances between scheduled and actual gas consumption, our storage capacity allows us to manage these imbalances on a daily basis.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie storage, in Lewis County, is an aquifer-driven storage field designed to deliver large quantities of gas over a relatively short period of time. Clay Basin in northeastern Utah provides supply-area storage and a winter gas supply. Figure 6-4 presents details about our storage capacity.

Figure 6-4
Existing Gas Storage Position

	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Expiration Date
Jackson Prairie – Owned (1)	7,310,436	147,334	294,667	N/A
Jackson Prairie – NWP SGS-2F (2)	1,181,021	24,195	48,390	2006
Jackson Prairie – NWP SGS-2F (3)	140,622	3,352	6,704	2006
Clay Basin	13,419,000	55,900	111,825	2013/19
Total	**22,051,079**		**454,882**	

Notes:

1) *Storage capacity at 12/31/2006. Storage capacity will continue to grow due to current expansion of the process.*
2) *NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.*
3) *Obtained through capacity release market.*

Jackson Prairie Storage. PSE uses Jackson Prairie and the associated NWP TF-2 transportation capacity primarily to meet the intermediate peaking requirements of core customers—that is, to meet seasonal load requirements, balance daily load, and eliminate the need to contract for year-round pipeline capacity to meet winter-only demand. We have 343,057 Dth/day of TF-2 transportation capacity from Jackson Prairie.

PSE, NWP, and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, operated under FERC authorizations. In addition to firm daily deliverability and firm seasonal capacity, we have access to deliverability and seasonal capacity through a contract for SGS-2F storage service from NWP and from a third party through the capacity release market. The NWP contract is automatically renewed each year on October 31, but we have the unilateral right to terminate the agreement with one year's notice. We have interruptible withdrawal rights of up to 58,000 Dth/day, plus interruptible transportation service.

To meet growing peaking requirements, the three owners of Jackson Prairie are currently increasing deliverability from 884,000 Dth/day to 1,196,000 Dth/day. Our share of this expansion, 104,000 Dth/day, is expected to cost $15 million and be in service by November 2008.

Clay Basin Storage. Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This depleted gas reservoir stores gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 13,419,000 Dth and withdraw up to 111,825 Dth/day under a FERC-regulated agreement.

We use Clay Basin as a pooling point for purchased gas, and as a partial supply backup in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. This supply provides a reliable source throughout the winter, including on-peak days; it also provides a partial hedge to price spikes in this region. Gas from Clay Basin is delivered to PSE's system (and other markets) using firm TF-1 transportation.

Treatment of Storage Cost. Similar to firm pipeline capacity, firm storage arrangements require a fixed charge whether or not the storage service is used. Charges for Clay Basin service (and the non-PSE-owned portion of Jackson Prairie service) are billed to PSE pursuant to FERC-approved tariffs, and recovered from customers through a purchased gas adjustment (PGA), while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base rates. We pay a variable charge for gas injected into and withdrawn from Clay Basin.

Existing Peaking Supply and Capacity Resources

Firm access to other resources provides supplies and capacity for peaking requirements or short-term operational needs. Liquefied natural gas (LNG) storage, LNG satellite storage, vaporized propane-air (LP-Air) and a peak gas supply service (PGSS) provide firm gas supplies on short notice for relatively short periods of time. Generally a last resort due to their relatively higher variable costs, these sources typically meet extreme peak demand during the coldest hours or days. LNG, PGSS, and LP-Air do not offer the flexibility of other supply sources.

Figure 6-5
Existing Peaking Gas Resources

	Storage Capacity (Dth)	Injection Capacity (Dth/Day)	Withdrawal Capacity (Dth/Day)	Transport Tariff
Plymouth LNG	241,700	1,208	70,500	TF-2
Gig Harbor LNG (1)	5,250 10,500 (06-07) 15,750 (10-11)	1,500 3,000 (06-07)	2,000 3,000 (06-07) 4,000 (08-09) 5,250 (10-11)	On-system
Swarr LP-Air	128,440	16,680 (2)	10,000	On-system
PGSS	NA	NA	48,000	City-gate delivered, via TF-1 or commercial arrangement
Total	**375,390**	**19,388**	**131,500**	

Notes:
1) *Withdrawal capacity will grow as the load on the distribution system grows, allowing more supply to be absorbed.*
2) *Swarr holds 1.24 million gallons. At a refill rate of 111 gallons/minute, it takes 7.7 days to refill, or 16,680 Dth/day.*

Plymouth LNG. NWP owns and operates an LNG storage facility located at Plymouth, Washington, which provides a gas liquefaction, storage, and vaporization service under its LS-1 and LS-2F tariffs. PSE's long-term contract provides for seasonal storage with an annual contract quantity (ACQ) of 241,700 Dth, liquefaction with an MDQ of 1,208 Dth/day, and a withdrawal MDQ of 70,500 Dth/day. The ratio of injection and withdrawal rates means that it can take over 200 days to fill to capacity, but only 3-1/2 days to empty. Therefore we use LS-1 service to meet needle-peak demands, with LS-1 gas delivered to PSE's city gate using firm TF-2 transportation.

Gig Harbor LNG. In the Gig Harbor area, a new satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of our distribution system. The facility receives, stores, and vaporizes LNG that has been liquefied at other LNG facilities; the LNG comes by tanker truck from third-party providers. Because the LNG source is outside our distribution system, this facility represents an incremental supply source and is therefore included in the peak day resource stack, even though the plant was justified based on distribution capacity need. Daily deliverability is limited by hourly deliverability, total storage capacity, and the ability of the distribution system to absorb the supply. Although this facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in our service territory since it allows gas supply from pipeline interconnects or other storage to be diverted elsewhere.

A second tank, substantially completed in the fall of 2006, doubles on-site storage capacity and increases operational flexibility (one tank can be filled while the other is used). A possible third tank has space allocated but no installation date has been projected. It will cost substantially more than the second tank because of additional site preparation requirements, so any expansion decision will be based on distribution capacity need rather than supply need.

Swarr LP-Air. The Swarr LP-Air facility has a net storage capacity of 128,440 Dth equivalent, and can vaporize approximately 30,000 Dth/day—a little over four days of supply at maximum capacity. Swarr connects to PSE's distribution system, requiring no upstream pipeline capacity. We typically use it to meet extreme hourly or daily peak demand, or to supplement distribution pressures during pressure declines on NWP. We operate this facility to meet peak early morning and evening demand periods; given its operational flow characteristics, it is highly unlikely we will operate it for more than eight hours per day. Therefore, for peak-day planning purposes we consider this facility capable of supplying only 10,000 Dth/day.

Third-party Suppliers. Under our PGSS agreements, PSE can call on third-party gas supplies during peak periods for up to 12 days during the winter season. Currently, these amount to 48,000 Dth/day at a price tied to the replacement cost of distillate oil. The supply would be delivered to PSE city gates from Sumas on a firm basis through TF-1 capacity (when such capacity is not needed for other supplies) or by a commercial exchange agreement with a third party. The PGSS agreement expires after the 2011-2012 heating season, and renewal options are uncertain at this time.

Existing Gas Supplies

PSE maintains a policy of sourcing gas supplies from a variety of geographically diverse supply basins. Currently, we maintain pipeline capacity access to producing regions in the Rockies and San Juan, British Columbia, and Alberta. By avoiding concentration in one market, we increase reliability; if a supplier defaults, we can source the needed gas from another place along the pipeline. We can also mitigate price volatility somewhat; our capacity rights on NWP provide some flexibility to buy from the lowest-cost basin.

Price and delivery terms tend to be very similar across supply basins, though shorter-term prices at individual supply hubs may "separate" due to pipeline capacity shortages.

This separation cycle can last one to three years and is alleviated when additional pipeline infrastructure is constructed. We expect generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in the cost of transportation.

We have always purchased our supply at market hubs or pooling points. In the Rockies, the transportation receipt point is Opal; but alternate points, such as gathering system interconnects with NWP, allow some purchases directly from producers as well as from gathering and processing firms. In fact, we have a number of supply arrangements with major producers in the Rockies to purchase supply at or close to the wellhead, or point of production. Adding pipeline transportation capacity on Westcoast and ANG/Nova to our portfolio has increased our ability to access supply at the wellhead in Canada as well.

Gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. We meet average loads with a mix of long-term (more than two years) and short-term (two years or less) gas supply contracts. Long-term and medium-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. We also contract for seasonal baseload firm supply, typically for the winter months. Forward-month transactions supplement baseload transactions, particularly for November through March; we estimate average load requirements for upcoming months and enter into month-long transactions to balance load. We balance daily positions using storage (from Jackson Prairie), day-ahead purchases, and off-system sales transactions. Our markets are liquid, so long-term contracts do not offer significant advantages (other than reliability) at this time. We will continue to monitor gas markets to identify trends and opportunities to fine-tune our contract policies.

Like many local distribution companies (LDCs), PSE is somewhat at a buying disadvantage because of our very low load-factor market compared to industrial and power-generation markets, which may make access to additional supply more difficult over time. Therefore, our policy is to hold long-term contracts that cover at least 50% of our annual sales volumes.

Figure 6-6 summarizes PSE’s long-term gas contracts as of March 2007. Termination dates are spread out over a number of years. We will renew, extend, or replace contracts as they expire.

Figure 6-6
Existing Long-term Gas Supply Contracts

Contract	Basin	Winter Volume (Dth/d)	Summer Volume (Dth/d)	Primary Term Start Date	Primary Term Termination Date
Contract 1	**System**	**750**	**750**	05/15/1985	
Contract 2	BC/Sumas	10,000	10,000	11/01/2004	10/31/2008
Contract 3	BC/Sumas	20,000	20,000	11/01/2004	10/31/2009
Contract 4	BC/Sumas	10,000	10,000	11/01/2004	10/31/2009
Contract 5	BC/Stn 2	10,000	10,000	11/01/2004	10/31/2009
Contract 6	BC/Sumas	0	10,000	11/01/2007	03/31/2010
Contract 7	BC/Stn 2	0	10,000	10/01/2007	04/30/2010
Subtotal	**BC**	**50,000**	**70,000**		
Contract 8	Alberta	20,000	20,000	11/01/2004	10/31/2008
Contract 9	Alberta	10,000	10,000	11/01/2004	10/31/2009
Contract 10	Alberta	0	10,000	10/01/2006	04/30/2010
Contract 11	Alberta	0	10,000	10/01/2006	04/30/2010
Contract 12	Alberta	0	10,000	02/01/2007	04/30/2010
Subtotal	**Alberta**	**30,000**	**60,000**		
Contract 13	Rockies	30,000	30,000	05/01/2006	03/31/2008
Contract 14	Rockies	10,000	10,000	04/01/2005	10/31/2009
Contract 15	Rockies	10,000	10,000	04/01/2005	10/31/2010
Contract 16	Rockies	30,000	20,000	11/01/2004	10/31/2014
Contract 17	Rockies	0	10,000	10/01/2006	04/30/2010
Contract 18	Rockies	0	10,000	10/01/2006	04/30/2010
Subtotal	**Rockies**	**80,000**	**90,000**		
TOTAL		160,750	220,750		

Gas Futures Market

PSE began hedging our core gas portfolio in September 2002. At that time, hedge instruments—such as fixed-price physical transactions and fixed-price financial swap transactions—were the most effective means.

The delivery point for the New York Mercantile Exchange futures market is the Henry Hub in Louisiana. However, there can be a significant price variance between the Henry Hub and the physical locations of our supplies (the Rockies, British Columbia, and Alberta). To make a futures hedge fully effective, we would need an Exchange for Physical (EFP) transaction with another party to execute local delivery.

While an EFP is a viable hedging mechanism, its execution is rather complex. We have been able to negotiate much more simple, fixed-price physical agreements directly with regional suppliers. In addition, a liquid market has developed in over-the-counter financial derivatives for fixed-price and basis transactions. A master agreement governs these transactions, and the parties negotiate a range of contractual items including credit, netting, and cross-collateral terms. These transactions can be combined with our physical index-based purchase contracts, so financial derivatives work well within PSE's portfolio.

We will continue to evaluate all available hedging mechanisms to determine their applicability to our portfolio, particularly to balance the advantages to our customers of market prices with fixed supplies.

B. Existing Demand-side Resources

PSE has provided demand-side resources (that is, resources generated on the customer side of the meter) since 1993. Energy efficiency measures installed through 2005 have saved a cumulative total of 1,403,922 Dth in 2005 – more than half of which has been achieved since 2002. Through 1998, these programs primarily served residential and low-income customers. In 1999 we expanded to add commercial and industrial customer facilities. We have spent more than $17 million for natural gas conservation programs since 1993. PSE's energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of our 2001 General Rate Case.

In our April 2005 Least Cost Plan Update, we presented an extensive analysis of energy efficiency savings potential and its contribution to our electric and gas resource portfolios. In collaboration with key external stakeholders represented in the Conservation Resource Advisory Group (CRAG) and Least Cost Plan Advisory Group (LCPAG), we used the results to develop a two-year energy savings stretch target of approximately 420,000 Dth by the end of 2007 through program offerings to all customer classes.

Current Gas Energy Efficiency Programs

PSE's energy efficiency savings targets and the programs to achieve those targets are established every two years. Our current gas energy efficiency programs are authorized to operate January 1, 2006 through December 31, 2007. Programs engage all customer sectors and deliver a cost-effective resource. The majority of these programs are funded with electric “rider” and gas “tracker” funds collected from all customers.

2005 marked the end of a conservation tariff period spanning 2004 and 2005 that continued ongoing programs. Figure 6-7 shows how PSE has performed in the 2004 – 2005 tariff period compared to two-year budget and savings goals. The programs saved a total of 634,268 Dth, enough for 7500 homes, and exceeded our two-year savings goal of 500,000 Dth. 2004 - 2005 savings were achieved at a cost of $7,285,121. It is also important to note that 2006 actual savings decreased slightly and costs more than doubled. Our 2004 – 2005 achievement includes about two million therms of savings from commercial spray heads which represented a unique opportunity that could not be replicated in 2006 – 2007. While we are always seeking such prospects through both internal channels and our RFP process, at the present time, we have not yet uncovered a similar opportunity of such magnitude. After considering the effect of the spray head program on savings achievement in 2004 - 2005, our 2006 - 2007 levels track in alignment with our previous accomplishments.

Figure 6-7
Annual Gas Energy Efficiency Program Summary

Tariff Programs	2004- 2005 Actuals	’04–‘05 Budget/ Goal	’04 vs. ‘04/05 % Total	2006 Actual	’06 – ’07 2- Year Budget/ Goal	’06 vs. ’06/’07 % Total
Gas Program Costs*	$7,285,121	$9,106,000	41.7%	$6,759,062	$12,802,000	52.8%
Dth Savings	634,268	501,348	57.7%	237,724	420,000	56.6%

** Does not include low-income weatherization O&M funding of $297,000 per year.*

PSE’s **Commercial/Industrial Retrofit Program** achieves energy savings through improvements to HVAC systems, boilers, and process gas modifications – such as efficiency gains in radiator steam trap systems. In 2006 these efforts netted savings totaling 888,532 therms at a cost of $2,433,674; this program was the second largest generator of energy efficiency savings.

The **Energy-efficient Gas Furnace** program generated the most energy efficiency savings on the residential side. PSE customers and builders who installed a 90%+ efficient furnace received rebates; the program saved 248,399 therms at a cost of $933,970, accounting for 10% of all gas savings in 2006

In November 2005, we issued an "all-comers" RFP for energy efficiency resources to be added in 2006-2007. The RFP process is used to seek out and fill untapped market segments or add under-utilized energy efficiency technologies to complement our ongoing efforts. The results of that RFP process did not identify any significant new opportunities for additional natural gas energy efficiency. Out of 18 proposals received, six involved natural gas energy efficiency of which two were implemented.

III. Gas Resource Alternatives

The gas resource alternatives presented in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies we use in our daily conduct of business to minimize costs.

As PSE's existing NWP transportation contracts expire periodically over the next several years, we can consider a number of alternatives including new pipeline projects, LNG and natural gas underground storage projects, LNG import facilities, and additional demand-side energy efficiency programs. Our review and analysis focuses on natural gas alternatives for the winter of 2012-2013 and beyond, since PSE has sufficient capacity until that time.

A. Pipeline Capacity Alternatives

Direct-Connect Pipeline Capacity Alternatives

PSE's exclusive reliance on NWP to connect to upstream natural gas supplies is a matter of geography, not preference, and this situation is not likely to change in the near term. Potential sponsors have shown little interest in the construction of new pipelines because the challenges are so significant. New pipelines would have to build around or over the Cascade Range or the Columbia River Gorge to access anything but British Columbia–sourced gas, and so far new construction cannot compete financially with the inherently lower cost of expanding or rebuilding infrastructure in an existing right-of-way.

PSE retains the unilateral right to cancel NWP contracts upon one year's notice, so pending contract expirations in 2008, 2009, and 2016 create opportunities to make alternative resource decisions; however, future expansions of NWP, even though incrementally priced, will likely be our most cost-effective alternative.

In meeting customer loads, PSE strives to balance low cost and reliability with "reliability in diversity"; that is, acquiring multiple alternate routes for our supply so that when one source becomes economically less advantageous, others are available. Our current pipeline transportation capacity accesses four market hubs:

- Sumas provides 260 MDth, or 50% of our current supply. This includes 95 MDth of upstream capacity to Station 2.
- The Rockies and San Juan combine to provide 184 MDth, or 35% of current supply.
- AECO provides 76 MDth, or 15% of current supply. This includes 80 MDth of upstream capacity to AECO.

We have some concerns about relying on Sumas for half of the transportation capacity to our city gate. In recent years, producers and marketers have shown a preference to market and sell gas at the AECO hub rather than at Sumas or Station 2. The AECO hub is more liquid and the prices less volatile than Sumas because it has access to the Northwest and California, as well as Chicago and other midwestern areas.

The attractiveness of the AECO hub over Sumas is demonstrated by the recent completion of the Ellhwa pipeline (200 MDth/day), which was built to move gas from the gathering area that normally feeds Station 2 eastward to a tie-in with the TransCanada's Alberta pipeline system and thus to the AECO hub, and also the failure of Westcoast pipeline capacity holders to renew their contracts for capacity from T-South to Huntingdon (Sumas). Currently, approximately 50% of the Westcoast pipeline capacity is not under long term contract. In addition, it is likely that future supplies from the North Slope and/or the Mackenzie delta would be interconnected to AECO rather than Westcoast.

On the other hand, completion of the Kitimat or another northern B.C. LNG import facility would tend to firm up supplies at Sumas. Also, expansion of the NWP segment between Sumas and PSE's city gate is probably the lowest-cost alternative for increased access to any market hub. A decision to expand access to the Sumas hub would have to be balanced with the dangers of increased reliance on Sumas.

For economic reasons, PSE may need to rely on NWP to move incremental gas supplies from Sumas to the city gate, but at least one upstream pipeline alternative discussed in the next section—Southern Crossing + Inland Pacific Connector—would help diversify how the gas gets to Sumas.

Expansion of NWP pipeline capacity through the Columbia Gorge to Stanfield, and to the Rockies hubs, would be relatively expensive. Opportunities to acquire existing capacity are limited.

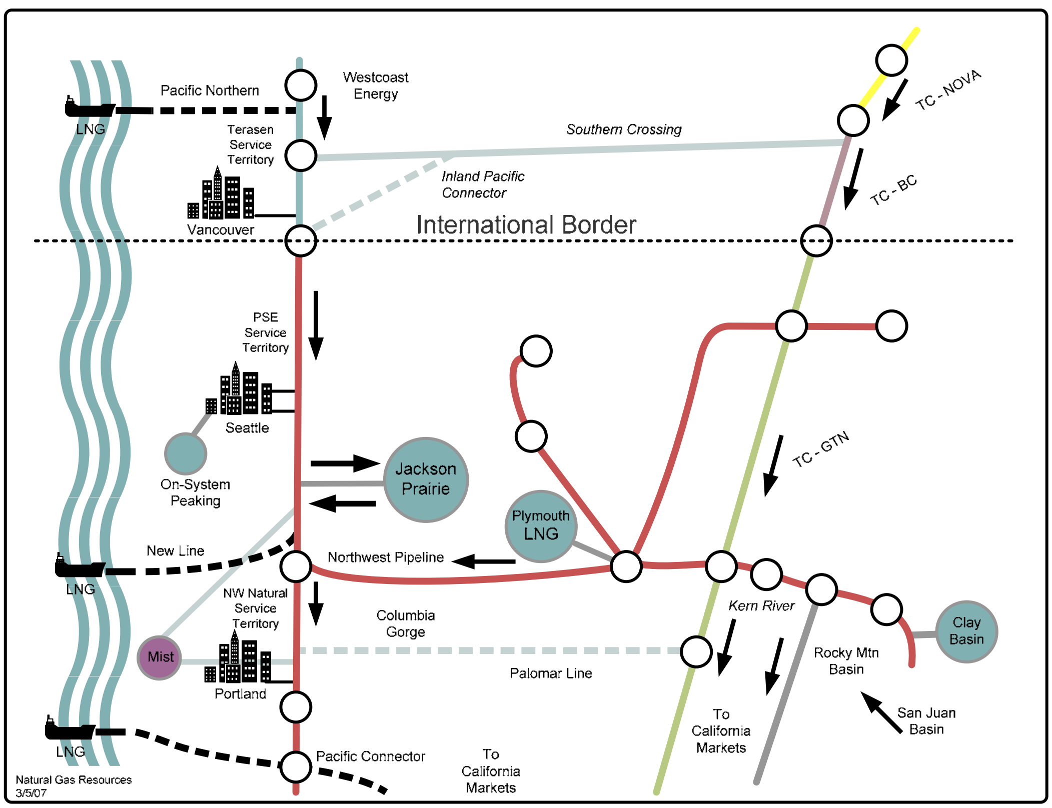
The direct-connect pipeline alternatives considered in this IRP analysis are summarized below.

Figure 6-8
Direct-Connect Pipeline Alternatives Analyzed

Name	Description
NWP - Sumas to PSE city gate	Expansions considered only in conjunction with upstream pipeline/supply expansion alternatives (Southern Crossing, additional Westcoast capacity, or access to a northern BC LNG import facility).
NWP - Washougal to PSE city gate	Expansion considered in conjunction with assumed LNG import terminal south of PSE service territory.

Figure 6-9 shows the location of these pipelines and LNG import terminals, and other pipeline and storage alternatives. Additional details are provided in Figure 6-2 (PSE Gas Transportation Map).

Figure 6-9
PSE Gas Transportation Map Showing Supply Alternatives



Upstream Pipeline Capacity Alternatives

In some cases, a tradeoff exists between buying gas at one point, and buying capacity to enable purchase at an upstream point closer to the supply basin. PSE has faced this tradeoff with our supply purchases at the Canadian import points of Sumas and Kingsgate.

We hold Gas Transmission Northwest (GTN) capacity from Kingsgate (Canadian border) south to NWP. Previous analyses led us to acquire approximately 80,000 Dth/day of upstream pipeline capacity on TransCanada's Alberta system (TCPL-Alberta) and TransCanada's British Columbia system (TCPL-BC). This enabled us to purchase gas directly from suppliers at the very liquid AECO trading hub and transport it to Kingsgate on a firm basis.

We also acquired 40,000 Dth/day of capacity on Westcoast Pipeline from Station 2 to Huntingdon, B.C. (Sumas) in 2003, and an additional 55 MDth of firm capacity in 2006. This upstream capacity accesses supplies at Station 2, adding supply diversity and hedging against Sumas price spikes.

Two potential upstream pipeline expansion alternatives that would further diversify supplies or enhance access to more liquid market hubs are modeled in the IRP analysis.

Figure 6-10
Upstream Pipeline Alternatives Analyzed

Name	Description
Station 2 to Sumas	Expansion of Westcoast considered to increase access to gas supply at Station 2 and an assumed northern BC LNG import terminal.
Southern Crossing Pipeline	Expansion of the existing Terasen gas pipeline across southern BC, a new lateral connecting to Huntingdon BC (Sumas), plus a commensurate expansion of the capacity on TCPL-Alberta and TCPL-BC as well as to NWP from Sumas to PSE's city gate.

Acquiring additional capacity on Westcoast would increase access to Station 2 supplies, but concerns about Station 2's liquidity and supply would have to be addressed.

The Southern Crossing alternative includes (1) PSE participation in the existing (or an expansion of the existing) Terasen pipeline across southern B.C., and (2) a new connector pipeline connects this pipeline to Huntingdon B.C. (Sumas). Acquisition of this capacity, as well as additional capacity on the TCPL-Alberta and TCPL-BC lines, would improve access to the AECO trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on B.C.-sourced supply.

A proposed Palomar pipeline (from NWP's Grants Pass lateral to GTN) offers an alternative route for AECO/Rockies gas that bypasses NWP through the gorge. Extending the line to a Columbia River LNG importing facility would provide access to the California market without using NWP. Although this pipeline was not part of our IRP modeling, we will monitor its progress.

B. Storage and Peaking Capacity Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie storage facility, and we also contract for capacity at the Clay Basin storage facility located in northeastern Utah through 2013 and 2020.

The current capacity expansion project at Jackson Prairie will increase PSE's peak deliverability by approximately 104 MDth/day, and increase our storage capacity portion by about 2,100 MDth. Completion isn't expected until 2012, though we anticipate increased deliverability by the fall of 2008. Previous expansions of Jackson Prairie have proven to be the least expensive way to meet our firm load growth, but no further expansions appear feasible.

The region's other underground storage project, the Mist storage project near Portland, Oregon, does not appear to be a viable alternative. It has relatively high costs and limited firm access to our city gate.

In this IRP analysis, PSE evaluated participation in a regional LNG storage facility as an alternative for meeting peak supply needs.

Figure 6-11
Peaking Storage Alternatives Analyzed

Name	Description
Regional LNG Storage Facility	To be cost effective, such a facility should be located to allow firm exchange delivery to PSE's city gate. The returns to scale of LNG storage imply that joint participation would be attractive. These analyses assume a 10-day supply at full deliverability.

C. Gas Supply Alternatives

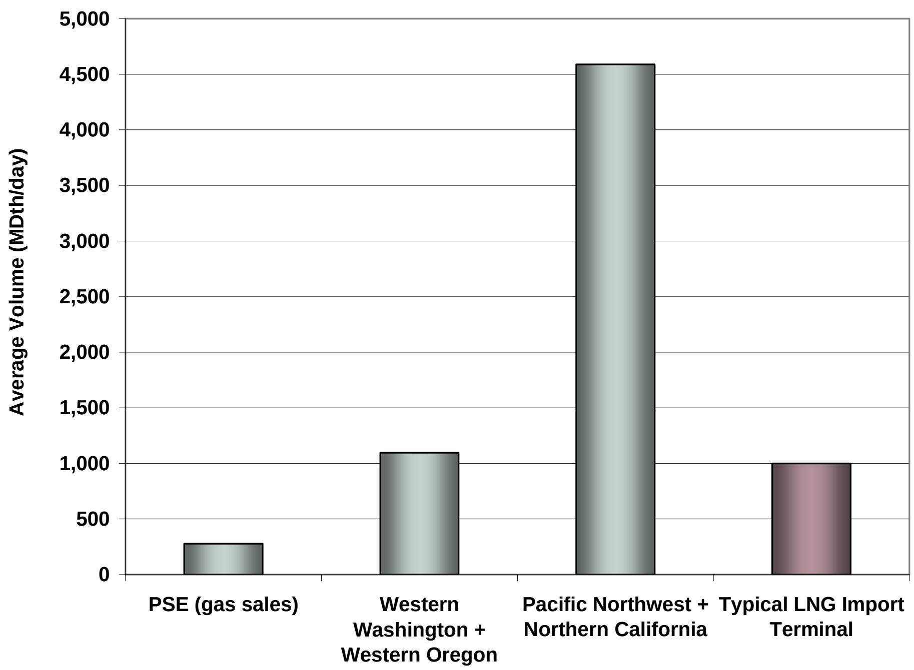
PSE's current pipeline contracts give us access to four regional supply basins that put us in a strong position to meet incremental load increases with additional reliable and economical capacity: the Rockies and the San Juan basin, British Columbia, and Alberta. It is likely that prices will remain competitive, as we see a focus on reserve development. For these reasons, one alternative modeled in this IRP assumes the current mix of term contracts and spot purchases—with Sumas and Station 2 supplies assumed to be limited and supply at AECO and the Rockies assumed to be sufficient.

Current and long-term views on natural gas availability suggest slower growth in supply and higher growth in demand going forward. Since supply scarcity can cause high and volatile pricing, PSE carefully monitors projects and resources that will ensure stable future supplies.

Two major pipelines have been proposed to transport gas from the Arctic to the North American markets, but both projects are too distant to provide short- or medium-term relief. The Alaska Natural Gas Transmission System would transport natural gas from the North Slope through Canada and to Chicago, and provide 4.5 Bcf/day between 2013 and 2015. The Mackenzie Valley Pipeline would transport natural gas from the Tablus, Parsons Lake, and Niglintgak fields to the northern border of Alberta and eventually deliver 800 Mcf/day.

While there currently are no LNG import terminals on the west coast, LNG imports could significantly increase the availability of gas in the region[1]. For example, Figure 6-12 compares the annual import volume of a typical LNG import terminal (capacity of one billion cubic feet per day {Bcf}) with the projected annual demand for 2010-2011 for PSE gas sales, for western Washington and western Oregon, and for combined demand from the Pacific Northwest (including BC) and northern California (including Pacific Gas & Electric). As shown, a typical LNG import terminal could nearly supply the full requirements of western Washington and western Oregon.

Figure 6-12
Comparison of Projected Annual Demand for 2010-11 with Capacity of Typical LNG Import Terminal



As demonstrated by Figure 6-12, an LNG import facility must be located to have access to relatively large market areas such as the Pacific Northwest plus northern California.

[1] The first LNG import project on the west coast of the North America expected to become operational is Sempra LNG's Costa Azul project on the Baja Peninsula of Mexico. Deliveries from the project are expected to begin in 2008, some of which will be transported into southern California.

At today's gas prices, LNG can be competitively transported, stored, and marketed. Major oil and gas companies recognize that LNG can both help alleviate the potential future supply scarcity, and provide an opportunity to market "stranded" reserves. To date, they have proposed more than 50 terminals, at least seven of them in Oregon, Washington, and British Columbia. Many experts believe that significant LNG imports into North America will be required to balance supply and demand in the future.

LNG production costs are well within current and anticipated market prices. LNG projects typically have low exploration and technology risks, and high capital costs. Projects generally require an experienced sponsor with a strong balance sheet, a secure source of natural gas, a large immediate market or an extensive infrastructure capable of consuming the entire output, and long-term off-take agreements to support the project's financing costs.

Siting domestic regasification terminals will be challenging. They must be large enough to capture economies of scale. Models of the North American gas market indicate that introducing incremental imported LNG at any location lowers or at least stabilizes prices throughout the market. Additionally, depending on location, imported LNG could displace some of the current supply for a given region—freeing up that supply for other markets. Whatever the location, however, import and regasification projects have the potential to relieve near-term supply scarcity and price volatility.

For this IRP, we considered two hypothetical regional LNG import terminals shown in Figure 6-13:

- South LNG Import—connected to the NWP system south of our service territory and assumed to require incremental NWP capacity construction north to PSE's service territory
- North LNG Import—connected to the Westcoast system in B.C. and requiring Westcoast T-South capacity and NWP capacity to deliver to the PSE system.

Costs and other commercial terms of purchase agreements are undetermined, but we assumed that the LNG itself would be priced at the AECO index plus a small demand charge (at the regasification plant outlet/pipeline interconnect).

Figure 6-13
Gas Supply Alternatives Analyzed

Name	Description
Northern LNG Import Interconnected with Westcoast Pipeline	Interconnects with Westcoast pipeline, flows over T-South transport to Sumas and then on existing or incremental NWP capacity to PSE.
Southern LNG Import Interconnected with NWP south of PSE service territory	Flows over NWP north to PSE on incremental transport capacity.
Conventional Gas Supply Purchase Contracts	Assume current mix of term contracts and spot purchases. Sumas and Station 2 supplies assumed limited. Supply at AECO and Rockies assumed to be sufficient.

D. Demand-side Resource Alternatives

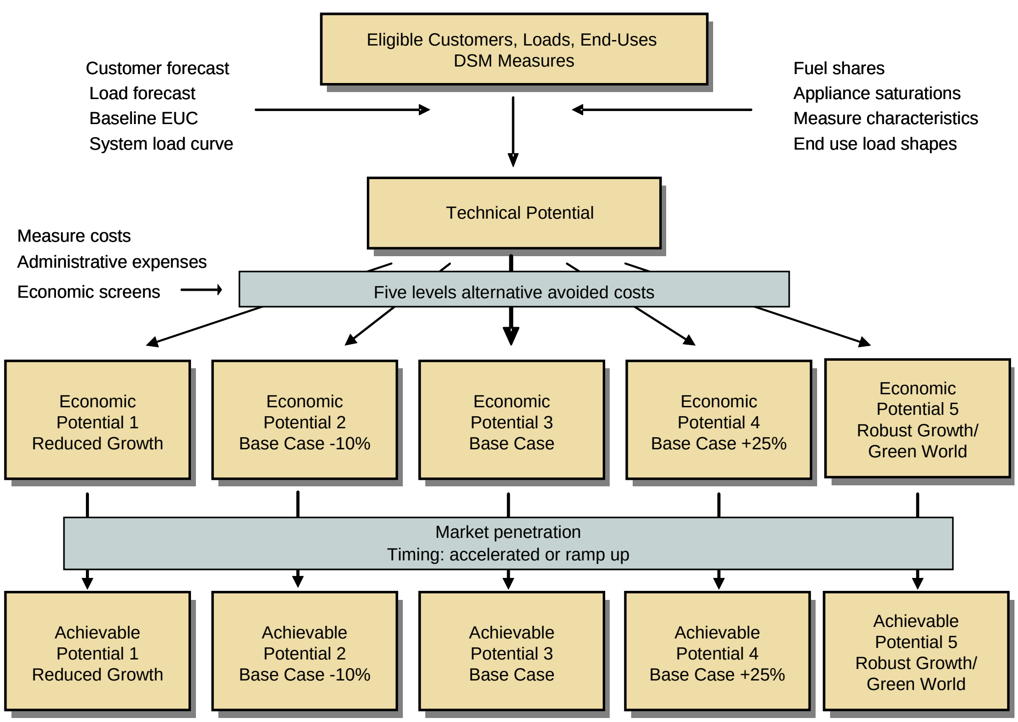
This IRP used a different evaluation than the 2005 LCP to analyze the cost-effectiveness of demand-side resources. The 2005 plan used SENDOUT® to test the cost-effectiveness of specific programs and to select programs to be included in each scenario; sets of increasingly expensive efficiency programs were added until SENDOUT rejected programs as not cost-effective.

In this IRP, the various bundles were pre-screened as discussed below, and then input into SENDOUT to confirm or “double-check” the cost effectiveness of the bundles. With only minor differences, the program bundles developed earlier were found to be cost-effective.

Gas demand-side resources were evaluated and combined into various bundles for integration with the supply-side analysis. The general approach to estimating the potentials for all demand-side categories was fundamentally the same: each individual type was screened for technical potential, economic potential, achievable implementation level, and achievable savings. The three screens are widely used in utility resource planning, consistent with the Northwest Power Planning and Conservation Council methodology, and with evaluation of energy efficiency resource potentials in general. Using them enables us to address the different technologies, load impacts, and markets that occur for each type of demand-side resource. After individual evaluation, demand-side resources were combined into bundles for further analysis.

The first screen, for technical potential, assumed that all energy efficiency resource opportunities could be captured regardless of costs or market barriers. It produced an end-use forecast assuming “frozen” end-use efficiencies, and then calibrated it to PSE’s system load forecast. We then generated a second forecast that included all technically feasible demand-side measures. Technical energy efficiency resource potentials were then calculated as the difference between the forecasts.

Figure 6-14
General Methodology for Assessing Demand-side Resource Potential



The second screen, for economic potential, included only measures deemed to be cost effective based on a total resource cost test. Five levels of avoided costs were used. We started with a base case, “economic potential 3.” “Economic potential 1” assumed avoided costs of base case -14%. “Economic potential 2” assumed avoided costs equal to the base case -10%. “Economic potential 4” assumed avoided costs 25% higher than the base case. Note that “economic potential 5” - Robust Growth/Green World - used the same, higher avoided cost.

This wide range enabled us to test for sensitivity of energy efficiency resource potential to different levels of avoided costs. This resulted in five bundles containing different amounts of energy efficiency resources for each level of avoided costs.

Finally, we screened out any resources not considered achievable. Establishing achievable potentials largely relied on customer response to PSE's past energy efficiency programs, the experience of other utilities offering similar programs, and review of the Northwest Power and Conservation Council's most recent electric energy efficiency potential assessment. For this IRP we assumed that economic energy-efficiency potentials of 75% and 55% in existing buildings and new construction markets, respectively, are likely to be achievable over the planning period.

IV. Gas Analytic Methodology

In order to estimate PSE's gas needs over the next 20 years, we compare peak-day demand forecasts with our current resources. We then use planning tools, optimization analyses, and scenarios, along with input assumptions, to determine the most-reasonable-cost portfolio of gas resources to meet our increasing service demands over the 20-year planning period.

Our analytical approach for analyzing and selecting the lowest cost supply portfolio for gas resources is different from the approach used for the electric portfolio analysis discussed earlier in Chapter 5. In general, analysis of the gas supply and demand system is less complex than analysis of the electrical supply system. The network of gas supply areas and market hubs, the pipeline transportation system, storage facilities, and demand areas lends itself to analysis using linear programming (LP) optimization models. In a single run, a LP model can determine the portfolio of resources that will minimize costs over the planning horizon, based on a set of assumptions regarding resource alternatives, resource costs, demand growth, and gas prices. This approach eliminates the need to develop alternative supply portfolios and to compare the resulting costs and other impacts to select the portfolio with the lowest reasonable cost.

A. Optimization Analysis Tools

PSE enhanced its ability to model gas resources for long-term planning and long-term gas resource acquisition activities for the 2005 LCP. The Company acquired SENDOUT and VectorGas™ from New Energy Associates in August of 2004. SENDOUT is a widely used model that helps identify the long-term least cost combination of resources to meet stated loads using a linear programming model. SENDOUT has the capability to integrate demand side resources alongside supply-side resources in determining the optimal resource portfolio. The linear programming approach is a helpful analytical tool to help guide decisions, but it is important to acknowledge this technique provides the model with "perfect foresight," meaning the theoretical results would not really be achievable. For example, the model knows the exact load and price for every day throughout a winter period, and can therefore minimize cost in a way that would not be possible in the real world. Real-world decisions must be made where numerous critical factors about the future will always be uncertain. Linear programming analysis provides helpful but not perfect information to guide decisions.

Because decisions must be made in the context of uncertainty about the future, PSE acquired VectorGas along with SENDOUT. VectorGas is an add-in product that facilitates the ability to model gas price and load (driven by weather) uncertainty into the future. VectorGas uses a Monte Carlo approach in combination with the linear programming approach in SENDOUT. This additional modeling capability will provide additional information to decision-makers under conditions of uncertainty. These new tools provide valuable enhancements to the robustness of the Company's long-term resource planning and acquisition activities. See the Gas Analysis Appendix for a more complete description of SENDOUT and VectorGas, as well as details of the various modeling inputs.

Monte Carlo analysis of physical supply risk indicates that a portfolio that meets our design-day peak forecast is sufficient, in an otherwise normal-temperature winter, to meet our obligations under a variety of possible conditions. Monte Carlo analysis of the optimal portfolio also indicates that the timing of certain resource additions is highly sensitive to Base Case assumptions.

B. Static Optimization Analysis

As described in Chapter 3, PSE selected four gas sales scenarios to examine the impact of different future demand and price scenarios on resource planning. The key to scenario analysis is understanding how different resources perform across a variety of conditions. Scenario analysis clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable only under a wide range of future circumstances.

PSE used SENDOUT to identify the optimal portfolio in each scenario. Supply-side resource alternatives generally were consistent across the scenarios. As discussed above, we developed energy efficiency programs for each of the three gas price scenarios. The appropriate level of energy efficiency was used in each resource planning scenario. For Robust Growth and Green World, for example, we included higher-cost efficiency programs based on the high gas price scenario. The gas planning analysis thereby necessarily focuses on where to buy gas, how to transport it to customers, and how to best utilize storage facilities to minimize the cost of meeting customer loads.

C. Monte Carlo Analysis on Base Case Portfolio

We performed two kinds of Monte Carlo analysis to test different dimensions of uncertainty. The first tested how a specific portfolio (in this case, the optimal portfolio derived from the static Base Case analysis) performs under price-induced and temperature-induced demand uncertainty. Examining the performance of a specific scenario helps determine financial and physical risk because it estimates cost variability. This can be particularly helpful when comparing two portfolios with similar expected costs but different cost risk profiles, which would not be evident in the traditional static analysis.

We used Monte Carlo analysis on 100 daily price and temperature scenarios—or draws—for the 20-year planning horizon. Each price draw started with the Reference Case (prices and weather are related in the underlying analysis that generates each scenario). For details of SENDOUT and VectorGas analyses, see Appendix J.

D. Monte Carlo Analysis Including Resource Optimization

The Monte Carlo analysis described above used optimal resources from the static Base Case analysis to examine how that portfolio would perform physically and financially. Another Monte Carlo analysis examined the robustness of that same portfolio by creating 100 scenarios of daily prices and demands for 20 years, then calculating the optimal portfolio to meet each of the 100 scenarios—again starting with Reference Case prices. This generated probability distributions for each potential resource addition. A static analysis often overemphasizes the importance of the “optimal” portfolio. Analysis showed how resource additions in the Base Case optimal portfolio are sensitive to the underlying price and demand assumptions.

V. Natural Gas Analysis: Results and Key Findings

PSE analyzed four planning scenarios for gas sales. This section compares resulting annual average gas costs and relevant differences between the resource addition alternatives that were considered, including energy efficiency programs.

A. Comparison of Resulting Average Annual Portfolio Costs

Figure 6-15 should be read with caution. It is not a projection of average purchased gas adjustment rates. The costs are based on a theoretical construct of highly incrementalized resource availability. Additionally, average portfolio costs include items that are not included in the PGA. These include rate-base costs related to Jackson Prairie storage and costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. Also, the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.

Figure 6-15
Cost Projections for Gas Scenarios

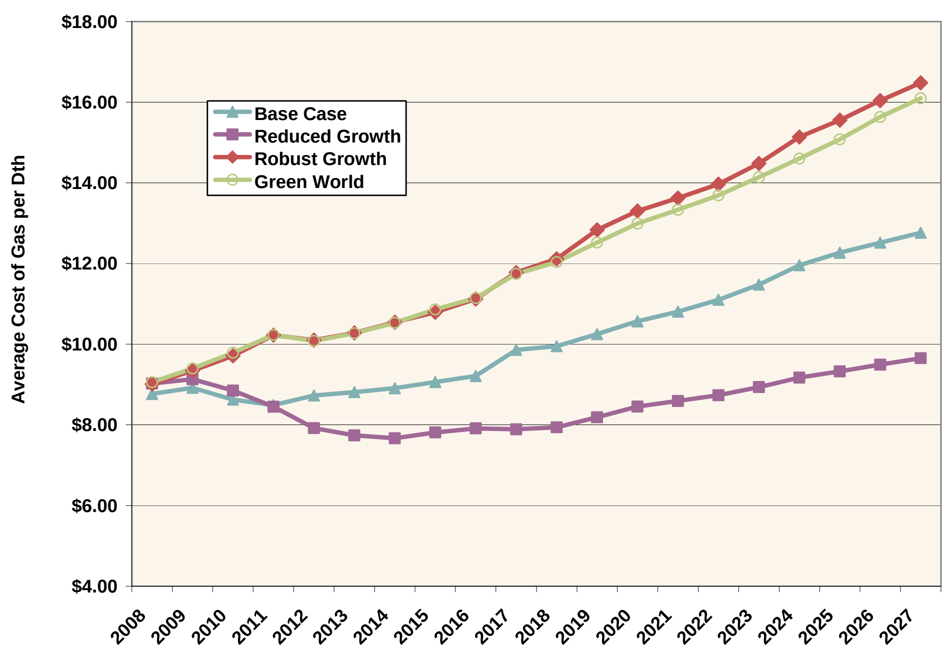


Figure 6-15 shows that average optimized portfolio costs follow expectations. Reference Case costs are about $8.76/Dth in 2008 and increase to about $12.70/Dth by 2027. Robust Growth costs are the highest of the four scenarios. Green World costs are somewhat lower, reflecting moderate load growth rather than the high load growth assumed for the Robust Growth scenario. Robust Growth costs are higher because of slightly higher average fixed costs—that is, the increase in fixed gas supply costs to meet the higher load growth is greater than the corresponding increase in volumes.

The Reduced Growth scenario has the lowest average portfolio costs, reflecting its low gas price and low load growth assumptions.

B. Comparison of Resource Additions

Differences in resource additions are generally driven by load growth. The exception is demand-side resources; they are influenced more directly by the gas price forecast than supply resources because by their nature they avoid commodity costs. However, the absolute level of efficiency programs is also affected by load growth assumptions. Optimal resource additions across scenarios are presented below by resource type.

Pipeline Capacity Additions

We considered two types of pipeline additions: upstream transportation alternatives that would interconnect with NWP (our direct-connect pipeline) at Sumas and at Washougal, and expansions of NWP capacity sufficient to deliver upstream gas to PSE's city gates.

Three pipeline alternatives were considered:

- Expanded Westcoast Pipeline capacity for delivery of gas from Station 2 and from the North LNG import facility.
- The Pacific Connector in conjunction with gas from the proposed South LNG facility; this alternative also includes enhancements of NWP's Grants Pass Lateral and the expansion of NWP from Washougal to PSE's city gate.
- The Southern Crossing/Inland Pacific Connector alternative that would increase supply diversity by connecting to the AECO hub instead of Sumas or Station 2; it

incorporates corresponding expansions of the TransCanada-Alberta and TransCanada-B.C. pipelines as well as NWP from Sumas to PSE's city gate.

Figure 6-16 summarizes the pipeline resources selected across the different planning scenarios. A limited expansion of Westcoast Pipeline capacity (25 MDth/day) in 2011 was selected in all scenarios except Reduced Growth. This expansion allows Sumas supply, purchased at either Sumas or Station 2 and transported to Sumas via Westcoast Pipeline, to match the existing delivery capacity of NWP from Sumas to PSE's city gate (260MDth/day). Further expansions of Westcoast capacity were not selected until 2018 in Robust Growth, and 2023 in the other scenarios. Since none of the scenarios selected the North LNG facility, these Westcoast expansions would be used to transport gas from Station 2.

Selected expansions of the Pacific Connector matched expansion of the South LNG—it was selected in all scenarios, although in relatively small amounts in Reduced Growth.

The Southern Crossing/Inland Pacific Connector was selected relatively late (beyond 2016) in all scenarios except Robust Growth. Its relatively high cost (because of the need to acquire capacity on four pipeline segments) does not make it attractive unless there is a compelling reason to diversify supplies away from Station 2 and Sumas.

Figure 6-16
Results of Pipeline Transportation Analysis

	Reference Case	Reduced Growth	Robust Growth	Green World
Westcoast (Sation 2 Sumas)				
2011	25MDth/d	-	25MDth/d	25MDth/d
2018	25MDth/d	-	100MDth/d	25MDth/d
2023	107MDth/d	65MDth/d	200MDth/d	98MDth/d
Pacific Connector (Pacific Connector & Grants Pass Lateral)				
2013	30MDth/d	5MDth/d	55MDth/d	40MDth/d
2016	55MDth/d	6MDth/d	55MDth/d	55MDth/d
2023	55MDth/d	23MDth/d	55MDth/d	55MDth/d
Southern Crossing/Inland Pacific Connector (TCAB, TCBC, SC & NWP)				
2011	-	-	20MDth/d	-
2016	48MDth/d	4MDth/d	83MDth/d	29MDth/d
2018	48MDth/d	-	120MDth/d	29MDth/d
2022	65MDth/d	-	137MDth/d	46MDth/d
2023	65MDth/d	-	193MDth/d	46MDth/d

Storage Additions

This analysis considered a single storage resource because PSE is currently participating in a relatively large expansion (104 MDth/day delivery) of the Jackson Prairie storage project scheduled to come on line in 2008. The alternative considered is a new LNG storage project in British Columbia. This northern location would facilitate a commercial exchange agreement to facilitate low-cost gas transportation. All scenarios selected this option, assumed to provide a 10-day supply at up to 100 MDth/day, as shown in Figure 6-17.

Figure 6-17
Results of Regional LNG Storage Analysis

	Reference Case	Reduced Growth	Robust Growth	Green World
2011	46MDth/d	6MDth/d	70MDth/d	37MDth/d
2015	100MDth/d	100MDth/d	100MDth/d	100MDth/d
2022	100MDth/d	100MDth/d	100MDth/d	100MDth/d

The results indicate that PSE's strategy should include consideration an LNG storage facility. However, since the SENDOUT analysis generally limited the initial project size to approximately 50 MDth/day in 2011 (the first year it was assumed to be available), a deliverability of 50 MDth/day, with later increases, may be an appropriate assumption.

Supply Additions

PSE will continue to rely on acquiring natural gas from creditworthy and reliable suppliers at major market hubs or production areas. For our SENDOUT model, we assumed continuation of our geographically diverse, long-term supply contracts (currently about two-thirds of annual requirements) throughout the planning horizon. The optimal portfolio would contain additional gas supply from various supply basins or trading locations, along with optimal utilization of existing and new capacity. The majority of this additional supply would likely be acquired under short-term contracts (one month to two years) at market price, as is the standard in the industry.

Supply additions considered included imported LNG supply terminals built at two locations. North LNG in northern British Columbia would connect to the pipeline system near Station 2, requiring transportation via the Westcoast system to Sumas, then on NWP to PSE's city gates; all scenarios assumed a maximum PSE supply of 150 MDth/day.

A South LNG import facility located in southern Oregon would connect to the existing NWP Grants Pass lateral and the GTN pipeline at Malin, and interconnect with other pipelines via the proposed Pacific Connector Gas Pipeline. The entire project could be in service by late 2011 with a capacity of about 1,000 MDth/day. We assumed PSE availability of 55 MDth/day, based on preliminary estimates of delivery capacity available via the Grants Pass Lateral and the NWP mainline to our city gate. Commodity prices for both the North and South LNG facilities were assumed to be the AECO index.

As shown in Figure 6-18, the South LNG alternative was selected in all scenarios, although in relatively small amounts in the Reduced Growth scenario. North LNG imports were rejected across all scenarios. This is not surprising, since North LNG supplies would likely require transportation on three pipelines (resulting in rate-stacking).

Figure 6-18
Results of LNG Import Terminal Analysis

	Reference Case	Reduced Growth	Robust Growth	Green World
South LNG Alternative				
2013	30MDth/d	5MDth/d	55MDth/d	45MDth/d
2016	55MDth/d	6MDth/d	55MDth/d	55MDth/d
2022	55MDth/d	23MDth/d	55MDth/d	55MDth/d
North LNG Alternative				
2013	-	-	-	-
2016	-	-	-	-
2022	-	-	-	-

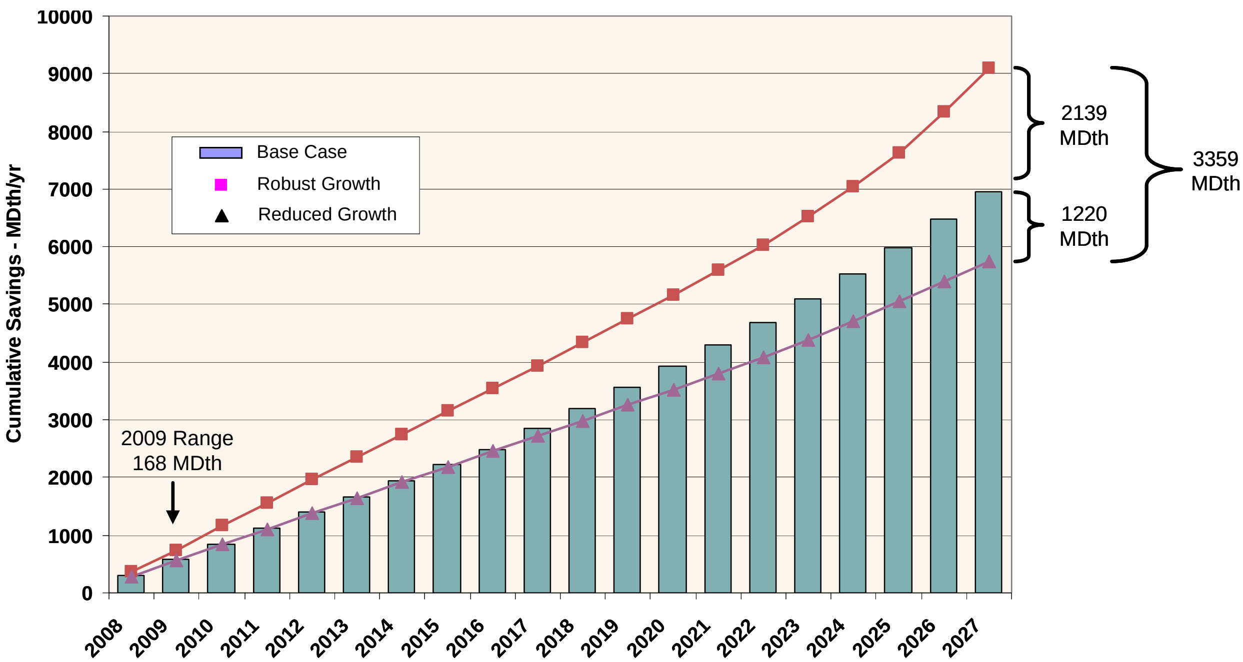
Assumptions about commodity cost pricing and supply terms will have a significant impact on the cost effectiveness of LNG imports. This analysis indicates that we should closely evaluate proposed LNG import terminals located to the south of PSE's service territory as more information becomes available, and continue to monitor development of other regional LNG import facilities.

Energy Efficiency Additions

As discussed earlier, in this IRP the various demand-side bundles were pre-screened and then input into SENDOUT to confirm or "double-check" the cost effectiveness of the bundles. With only minor differences, the program bundles developed in the screening analysis were found to be cost-effective.

Demand-side bundles demonstrated sensitivity to avoided costs, as illustrated in Figure 6-15. During the first two years the range is relatively tight, varying by 168 MDth between the Reduced Growth and the Robust Growth Bundles in 2009; by 2027, the difference increases to 3,359 MDth. In 2027, the variance between the Base Case and Robust Growth Bundles was 2,139 MDth, while the Reduced Growth Bundle differed from the Base Case Bundle by 1,220 MDth.

Figure 6-19
Gas Energy Efficiency Price Sensitivities



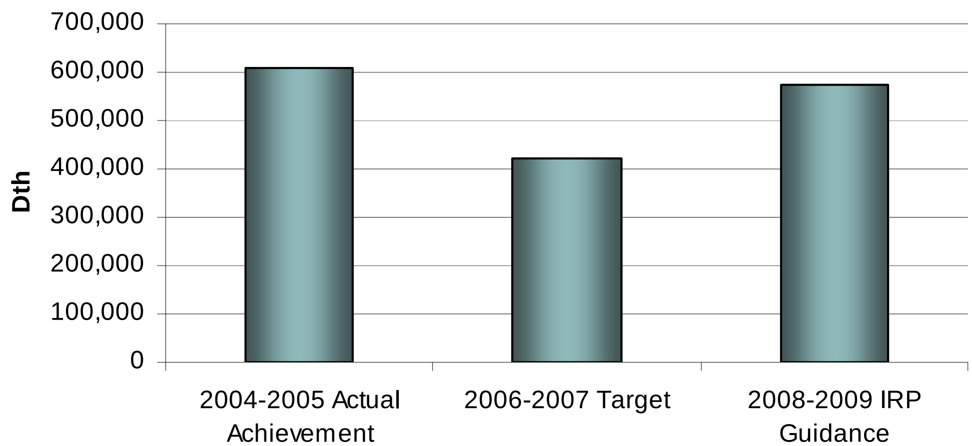
This 2007 IRP analysis revealed a seemingly counterintuitive effect in the magnitude of gas energy efficiency potentials compared to the previous plan. That is, the amount of achievable energy efficiency resources selected by the SENDOUT analysis in this plan is 1,611 MDth less than the previous plan, despite the higher gas price projections. The reduction is mainly due to the technical potential for energy efficiency being 3,114 MDth less in 2007 than 2005 (pre-SENDOUT economic potentials should not be compared due to changes in methodology). In 2007, we refined our assumptions about baseline end-use consumptions, savings, costs, and applicability of individual measures, which in turn reduced the magnitude of technical potential compared to 2005. However, the market penetration assumptions used to estimate achievable potential in 2007 are more aggressive than those used in the previous plan, which partly offset the reduction in technical potentials.

Figure 6-20
2005 - 2007 Technical and Achievable Energy Efficiency Potential Comparison

Year	Technical Potential (Dth)	SENDOUT® Results (Dth)
2005	38,223,912	8,576,600
2007	35,109,051	6,965,000

Figure 6-21 further compares our previous energy efficiency accomplishments, current target, and our new level of guidance. In the short term, this IRP guidance includes 576,000 Dth of energy efficiency savings for the 2008-2009 period. This is an increase of 37% over current 2006 – 2007 targets. It is slightly less than the savings achieved in 2004 – 2005, which included large savings from the unique, one-time commercial spray heads project.

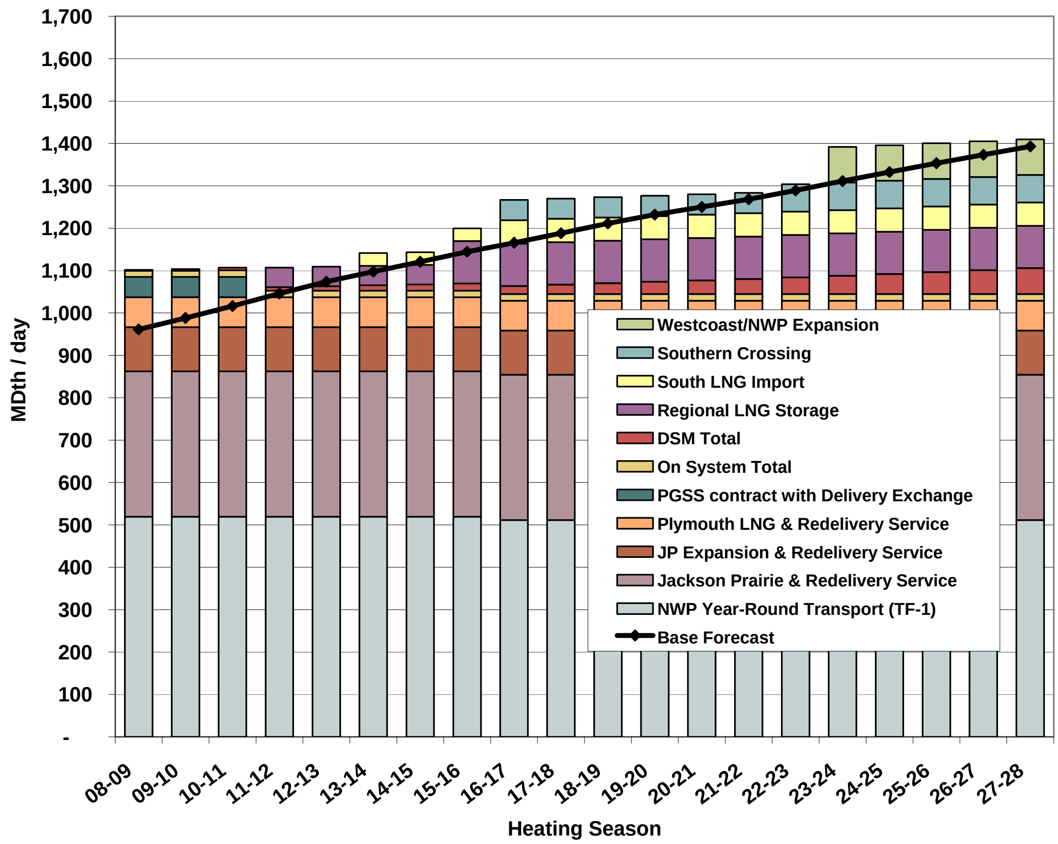
Figure 6-21
Short-term Comparison of Gas Energy Efficiency



C. Complete Picture: Base Case

A complete picture of the Base Case optimal resource portfolio is presented below in Figure 6-22. Additional Scenario results are included in the Gas Analysis Appendix.

Figure 6-22
Preferred Gas Portfolio, 2007 IRP

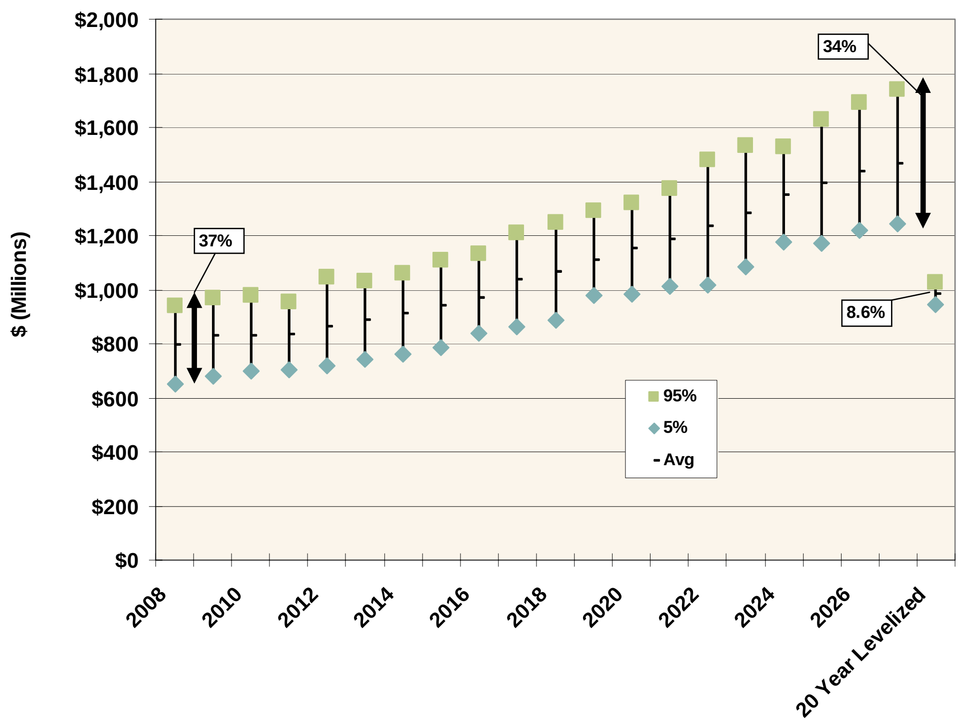


D. Results of Monte Carlo Analysis on Base Case Portfolio

As noted above, we used the Monte Carlo capabilities of Vector Gas to examine the effects of temperature-induced load uncertainty and price uncertainty on the Optimal Base Case portfolio. In this analysis, daily temperatures affect both load and daily gas prices. The Monte Carlo analysis was performed using 100 draws. Each of the 100 draws results in 20 years worth of daily prices and loads.

Figure 6-23 illustrates the nominal mean, and the 5th and 95th percentiles of total portfolio costs on an annual basis, along with the 20-year levelized results.

Figure 6-23
Annual and 20-Year Levelized Cost and Variability



As shown, the annual variability of total portfolio costs among the Monte Carlo draws is fairly consistent at over the 20 year time horizon (roughly 34% to 37%). It is important to note that the variability of the 20 year levelized costs is much lower at about 8.6%. The key take-away from a review of the Monte Carlo portfolio cost analysis is that measuring risk in the long term tends to dampen the effects of variability, thus short-term measures of risk in the context of the long-term analysis should also be considered.

Monte Carlo analysis on the Base Case optimal portfolio also provided information on the physical robustness of the optimal portfolio. This provides a reasonable test of whether the Company's planning standard of using normal weather with one design peak day per year creates a portfolio that will meet firm demands under a wide range of different temperature conditions. Results indicate that the Base Case portfolio, based on PSE's planning standard, will meet firm demands in 93% of the draws.

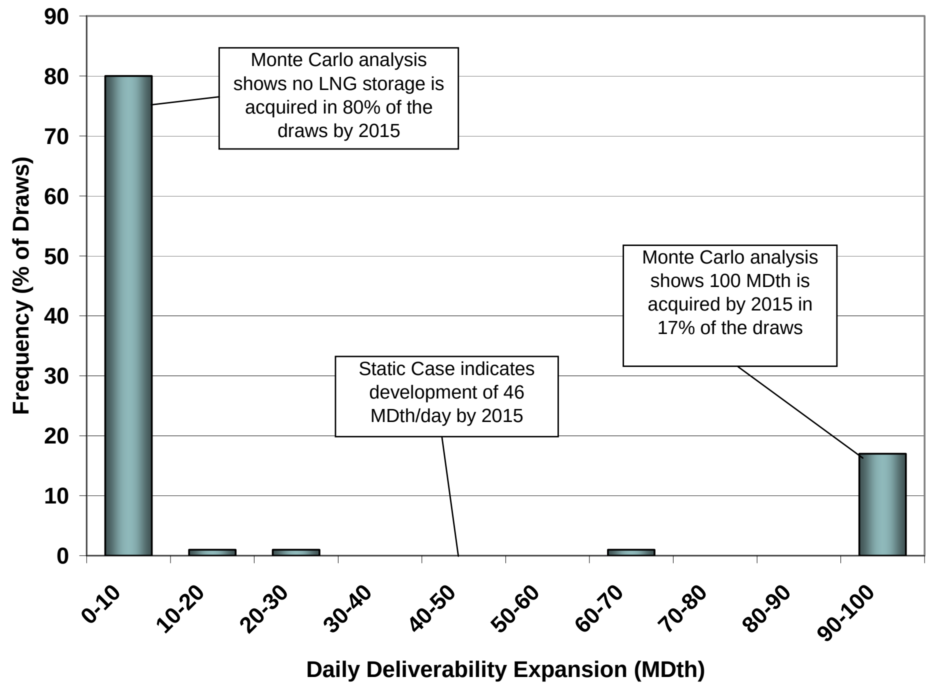
A Monte Carlo analysis was also done to test the sensitivity of resource additions in the Base Case scenario. Analyses were done on three specific resource addition decisions; the regional LNG storage alternative, the results of both the Southern and the Northern LNG import supply terminals, and the Southern Crossing/Inland Pacific connector pipeline alternative. The following tables will compare results from the static Base Case with the mean results from the resource optimization Monte Carlo analysis along with probability distributions for each of the resources.

The expansion of the Westcoast pipeline capacity by 25 MDth to allow supply of 260 MDth/day of gas at Sumas was selected in all 100 of the draws in 2011. The Northern LNG alternative at Kitimat was not selected in any of the 100 draws at any time in the analyses.

Monte Carlo Optimization Results—Regional LNG Storage

The regional LNG storage alternative included in the static analysis appears to be sensitive to the specific underlying assumptions. The frequency distribution of how the regional LNG storage alternative is selected across the 100 scenarios by the year 2015 is shown in Figure 6-24. The Monte Carlo analysis demonstrates that in 17% of the 100 draws, the full regional LNG storage deliverability of 100 MDth/day is developed by 2015, while in 80% of the draws no regional LNG storage is included.

Figure 6-24
Frequency Distribution of Regional LNG Storage Development by 2015

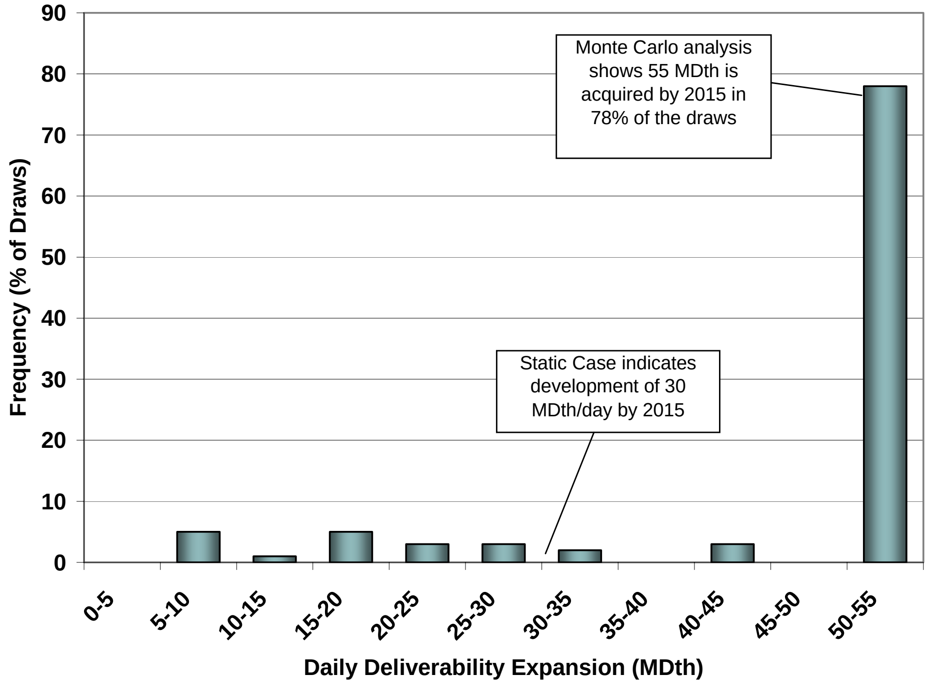


The Monte Carlo analysis indicates that the decision to acquire regional LNG storage capacity, while attractive in the static analysis, should be analyzed in greater detail as the Company proceeds to study the various capacity expansion alternatives.

Monte Carlo Optimization Results—Southern LNG Import Supply

Figure 6-25 illustrates the frequency distribution for the Southern LNG Import Supply and shows results of the static Base Case analysis. As shown, in 78% of the Monte Carlo scenarios, Import LNG was selected as part of the optimal resource portfolio. In the static analyses, the optimum quantity to be selected was about 30 MDth/day. These results support the conclusion that PSE should carefully consider the Southern LNG alternative as more information becomes available. As noted earlier, however, the specific terms and conditions of a long-term LNG import supply contract is the key determinant of the attractiveness of LNG imports.

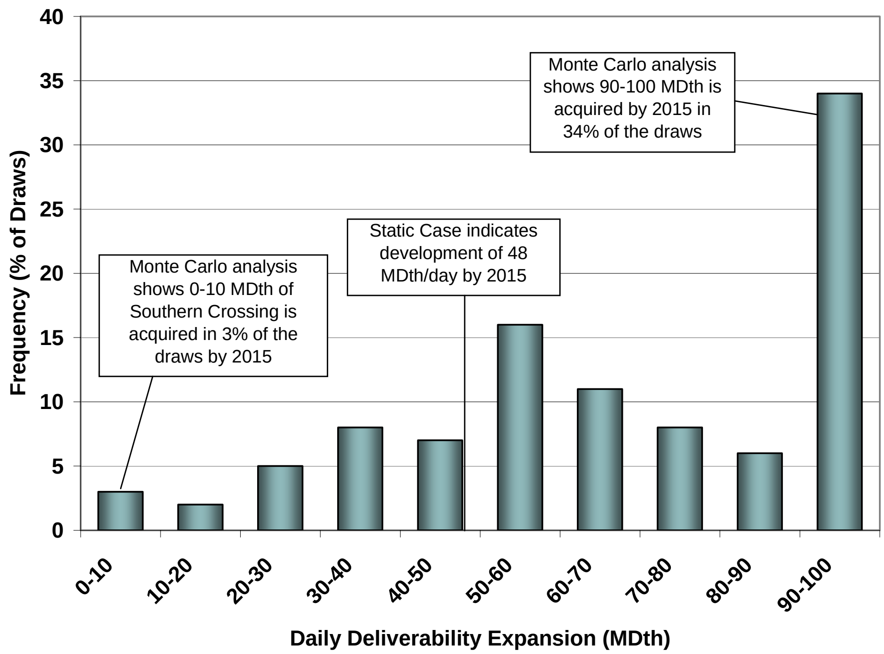
Figure 6-25
Frequency Distribution for South LNG Import Development by 2015



Monte Carlo Optimization Analysis—Southern Crossing/Inland Pacific Connector

We also found that the Southern Crossing/Inland Pacific Connector results appear to be highly sensitive to weather and gas price input assumptions. Figure 6-26 shows the frequency distribution for the Southern LNG Import Supply results as well as the results of the static Base Case analysis. In 34% of the Monte Carlo scenarios, a capacity of 90 to 100 MDth/day was selected for the Southern Crossing alternative. The static analyses indicated that the optimum level for development by 2015 was about 48 MDth.

Figure 6-26
Frequency Distribution for Southern Crossing Pipeline Development by 2015



Monte Carlo Optimization Analysis—Summary Conclusion

Monte Carlo analysis in the resource optimization approach provides information about the sensitivity of the optimality of resource additions to underlying assumptions of price and demand variability. As with the static optimization analysis, results of the Monte Carlo analysis will not provide the answer as to what kind of resources should be added to the portfolio at different times. Rather, this analysis will provide additional information to help support the Company's efforts to make informed resource acquisition decisions.

E. Key Findings

This analytical and statistical evaluation led to several key findings that will guide PSE not only as we develop our resource strategy over the 20-year planning horizon but also as we consider specific resources for the next two years.

1. PSE should investigate expanding gas energy efficiency programs.

Expanding these offerings will be challenging.

- We are doing greater amounts of gas energy efficiency compared to our previous achievements.
- We need to review gas prices frequently in order to understand what scenario is in operation.
- Long term (20 years), there is some risk that pursuing a Base Case energy efficiency strategy and ending up in a Robust or Reduced Growth Scenario future would cause PSE to under/over acquire energy efficiency, respectively. However, in the short term, the variance in the range of energy efficiency potential is only 168 MDth.

2. Investigate participation in a jointly owned LNG storage facility located to take advantage of locational displacement for low-cost withdrawal transportation to our service area.

This alternative appears to be a feasible and low-cost alternative to meet future peak load growth. Our core gas portfolio has a relatively low capacity factor (annual average volume divided by peak day loads). In general, we have sufficient pipeline capacity to deliver the total annual requirements but will need additional peak day delivery capacity starting in 2012. Acquiring firm year-around pipeline capacity is a relatively expensive alternative for meeting peak day loads.

3. Monitor the development of regional LNG import facilities.

Based on these analyses, acquisition of gas supplies from an LNG import terminal located south of PSE's service area appears to be a beneficial way to increase peak supply capacity and diversify of supply sources. It appears that it is feasible to cost-effectively develop some limited transportation capacity from the Jordan Cove site to PSE's city gate. At this time the terms for supply of gas to the LNG terminal have not been developed nor has PSE had the opportunity to discuss what form such a supply agreement might take. The final terms and conditions of the gas supply agreement will largely determine the attractiveness of this alternative.

4. Seek to develop additional long-term gas supply agreements for purchase of Sumas and Station 2 gas.

Fully 50% of PSE direct connect pipeline capacity is from Sumas to the PSE city gate. We are concerned that it is becoming more difficult to negotiate long-term gas supply agreements (up to 3 years) with gas producers and marketers at either Sumas or Station 2. Producers and marketers appear reluctant to make additional investments in new gas production facilities in northern British Columbia and they are electing to transport gas eastward to gain access to the AECO market hub. The AECO hub is more liquid than Sumas or Station 2 and has pipeline access to the Chicago and other mid-west markets. We will need to diversify our sources of supply away from Sumas and Station 2 if we have ongoing difficulties in purchasing gas at these hubs.

5. Consider increasing access to the AECO market hub in order to maintain diversity of supply.

The Southern Crossing/Inland Pacific Connector is a feasible alternative to increased dependence on gas supplies from northern BC. It also appears to be the highest cost of the four main alternatives evaluated as part of this analysis; however, the Southern Crossing alternative has the dual benefits of increasing peak day capacity as well as diversifying gas supplies by increasing access to the AECO hub.

6. The growth in the need for generation fuel will outpace the growth in need for gas sales.

The increase in both peak capacity and annual volumes of gas for generation fuel will exceed the increases in need for the gas sales portfolio. (See Section VI of this chapter.)

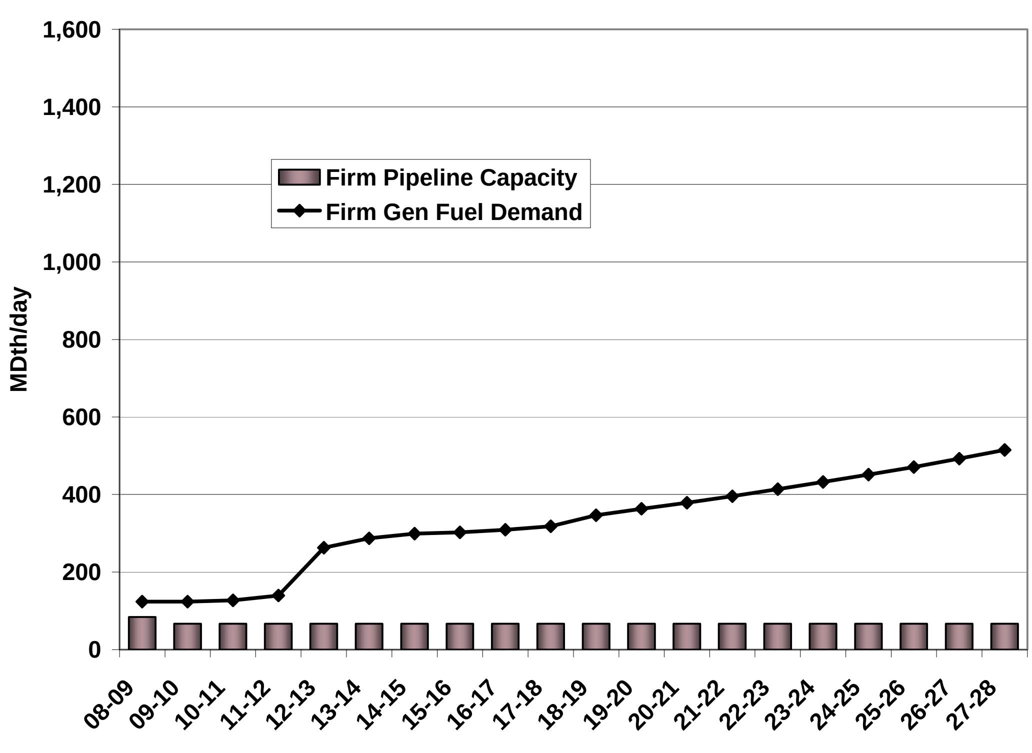
VI. Gas for Electric Generation

As discussed earlier in Chapter 5, all the electric portfolios evaluated in the electric analysis include relatively high amounts of gas fired generation. Selecting the best sources of supply, purchasing and hedging this gas, transporting and potentially storing it will be an important issue for the Company to deal with over the next several years. The following discussion uses the Aggressive Gas Portfolio 1-a, as discussed in Chapter 5, as the basis for determining gas resource needs for generation fuel.

A. Need for Gas for Electric Generation

The existing gas for electric generation firm peak supply portfolio and projected peak day need based on the gas requirements from Portfolio 1A are shown in Figure 6-27.

Figure 6-27
Gas for Generation Resource Need 2008-2027:
Existing Resources Compared to Design Peak-day Gas Demands



B. Existing Gas Resources for Power Generation

We also have firm pipeline transportation capacity for delivery of fuel to our gas-fired generation plants. Figure 6-28 summarizes that capacity.

Figure 6-28
Power Generation Gas Pipeline Capacity (Dth/Day)

Direct Connect Capacity						
Plant	**Transporter**	**Service**	**Capacity**	**Primay Path**	**Primary Term End**	**Renewal Right**
Whitehorn	Cascade Natural Gas	Firm	(1)	Westcoast/CNG Intereconnect (Sumas) to plant	12/31/2000	Yr to Yr
Tenaska	Cascade Natural Gas	Firm	(1)	Westcoast/CNG Intereconnect (Sumas) to plant	12/31/2000	Yr to Yr
Encogen	Cascade Natural Gas	Firm	(1)	NWP-Bellingham to plant	6/30/2008	Yr to Yr
Fredonia	Cascade Natural Gas	Firm	(1)	NWP-Sedro Wooley to plant	7/31/2021	Yr to Yr
Freddy1	NWP	Firm	21,747	Westcoast/NWP Interconnect (Sumas) to Plant	9/30/2018	Yr to Yr
Goldendale Generating Station	NWP	Firm	45,000	Westcoast/NWP Interconnect (Sumas) to Everett (3)	9/30/2018	Yr to Yr

Upstream Capacity						
Plant	**Transporter**	**Service**	**Capacity**	**Primay Path**	**Primary Term End**	**Renewal Right**
Various	Westcoast	Frim	22,000 (2)	Station 2 to Westcoast/NWP Interconnect (Sumas)	10/31/2014	Yes
Various	NWP	Firm (4)	16,884	Rockies to Bellingham	3/31/2008	No
Various	NWP	Firm	6,600	Westcoast/NWP Interconnect (Sumas) to Bellingham	6/30/2008	Yes

Notes:
(1) Plant Requirements
(2) Converted to approximate Dth/day from contract stated in cubic meters/day
(3) Gas is moved from Everett to Goldendale pursuant to flex provisions pursuant to NWP agreement and displacement agreement with PSE Gas Sales
(4) Capacity Held by a third party, controlled by PSE via grandfathered agreement

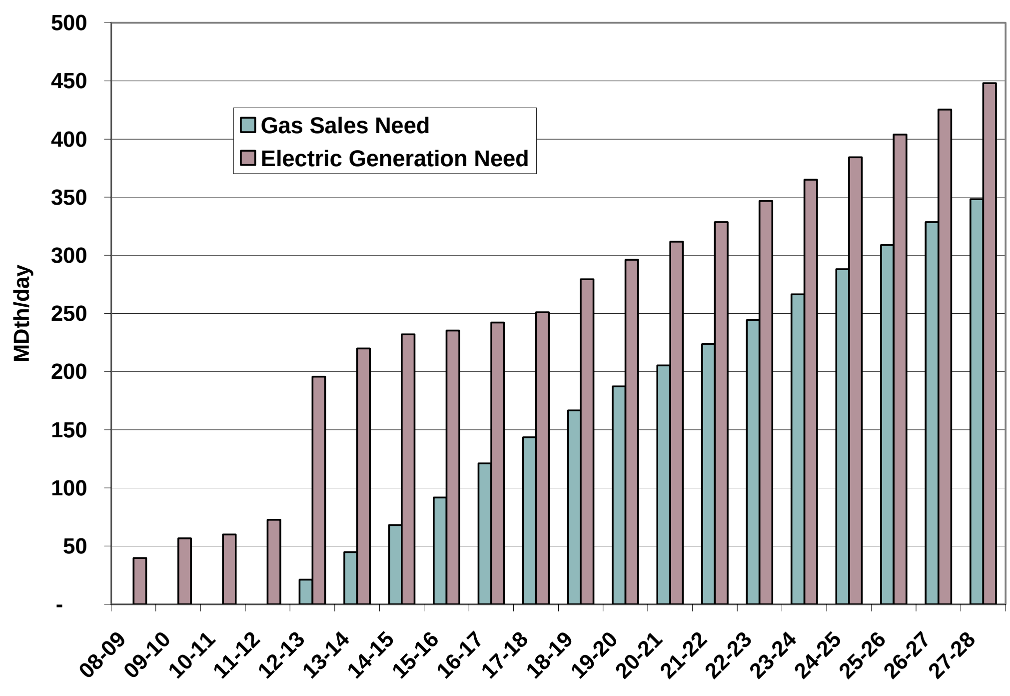
We have firm pipeline capacity to serve our combined cycle generating plants (Freddy1, Goldendale and Encogen). Several of our combustion turbine generation units (Whitehorn, Fredonia, and Frederickson) have backup fuel-oil firing capability and thus do not require firm pipeline capacity. The Tenaska generating facility also has backup fuel-oil firing capability.

C. Capacity Need for Gas Sales Compared to Electric Generation Gas Need

It is helpful to compare the projected need for peak day gas delivery capacity for electrical generation with the needs for the gas sales portfolio. (Note that the needs for the gas sales portfolio are shown in Figure 6-1.)

Figure 6-29 shows a comparison of the peak capacity needs of electric Portfolio 1A with the needs of the gas sales portfolio.

Figure 6-29
Comparison of Peak Day Need
for Gas Sales Portfolio and Electric Portfolio 1A



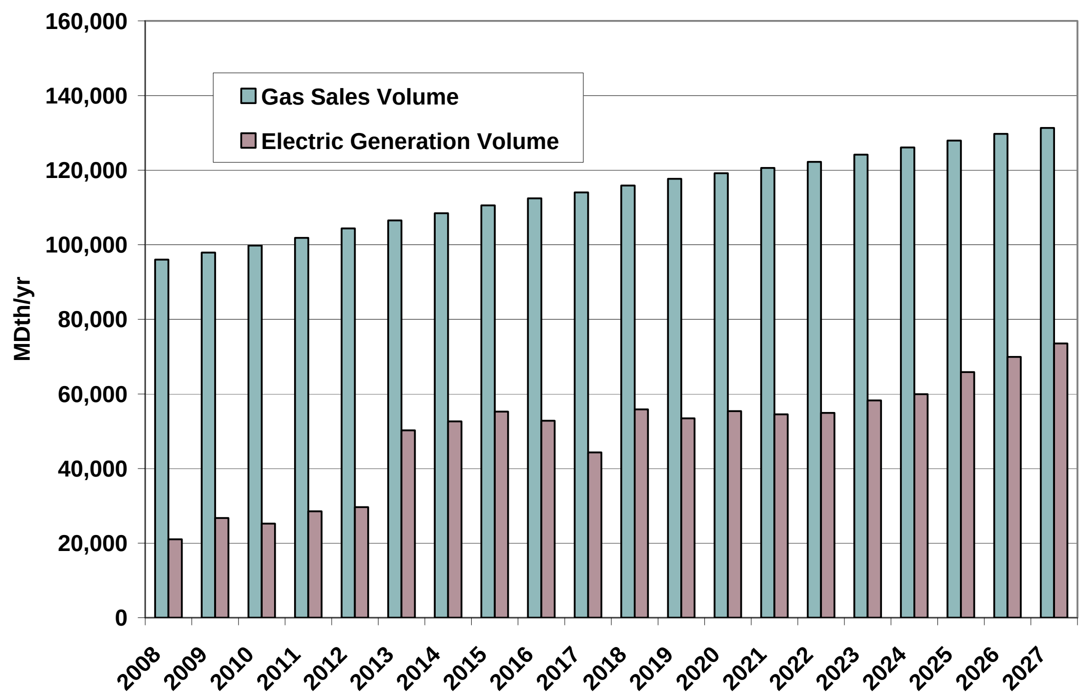
Note that the needs for electric generation are more immediate and increases more rapidly than the need for gas sales reflecting the addition of gas fuel generation in Portfolio 1A.

Developing long term plans to supply gas for generation is difficult since arranging for gas transportation is highly dependent on the specific location of the generating plants. For example, a location near a gas trading hub such as Sumas or with access to a gas storage facility greatly reduces the need for additional pipeline capacity.

While the gas required for electric generation is anticipated to increase faster than for the gas sales portfolio, the overall requirements are less than for gas sales and are projected to remain so over the 20-year planning horizon.

Figure 6-30 compares the annual volume of gas load forecasted for the gas sales portfolio and the gas required for electrical generation.

Figure 6-30
Projected Annual Gas Volumes Compared:
Gas Sales vs. Electric Portfolio 1A



Delivery System Planning

PSE manages two types of delivery systems. One is company-owned and delivers electricity and natural gas *within* our local service territory to more than 1.6 million customers. The other is "merchant-based" and involves arrangements made with outside companies and organizations to transport power and natural gas *to* our service territory. The two are governed by different rules and planned under separate processes and toolkits. This chapter deals with planning for the PSE-owned delivery system within our service territory. Merchant-based delivery systems are discussed in Chapter 5, Electric Resources. This chapter is organized in five parts.

Our delivery planning process is designed to balance safety, cost, and operational requirements while incorporating consideration of environmental management, regulatory requirements, and changing customer demands; its purpose is to identify the most cost-effective solutions to the needs that we face. Safety, capacity, and reliability are our most important performance criteria. Simply put: How will we safely and continuously deliver enough energy through the pipes or wires to meet the demand on the other end? We must operate the system as safely and efficiently as possible on a year-by-year, day-by-day and even hour-by-hour basis. We must accomplish needed maintenance and improvements as cost effectively as possible. And we must anticipate future needs so that infrastructure will be in place to meet that need when it arrives. Our goal is to fulfill these responsibilities at the lowest reasonable cost.

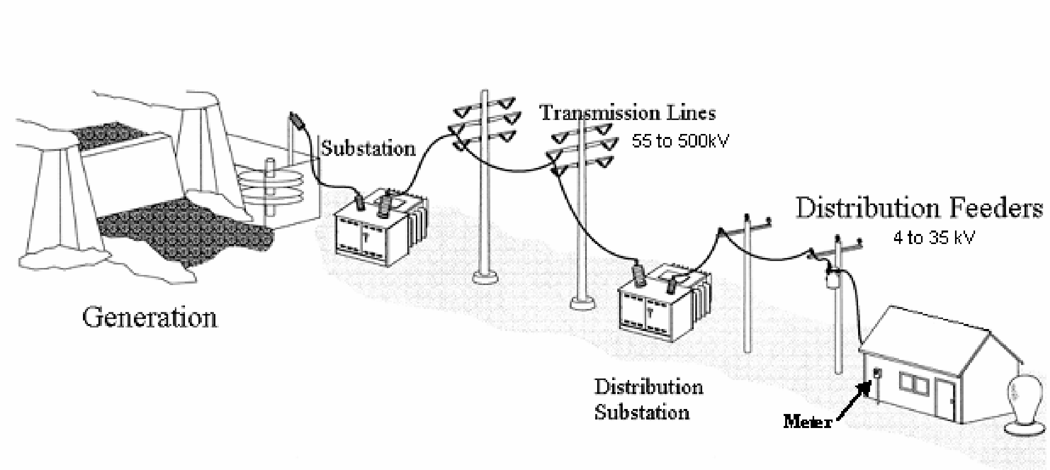
I. System Mechanics and 5-year Infrastructure Plan

To understand the delivery system planning process, it is helpful to understand the mechanics of how gas and electric delivery systems work.

A. Electric Delivery Systems

Electricity is transported from power generators to consumers over wires and cables, using a wide range of voltages and capacities. The voltage at the generation site must be stepped up to high levels for efficient transmission over long distances (generally 55 to 500 kilovolts). Substations receive this power and reduce the voltage to levels appropriate for travel over local distribution lines (between 4 and 34.5 kV). Finally, transformers at the customer's site reduce the voltage to levels suitable for the operation of lights and appliances (under 600 volts). Wires and cables in the system carry electricity from one place to another. Substations and transformers change its voltage to the appropriate level. Circuit breakers prevent overloads and meters measure how much power is used.

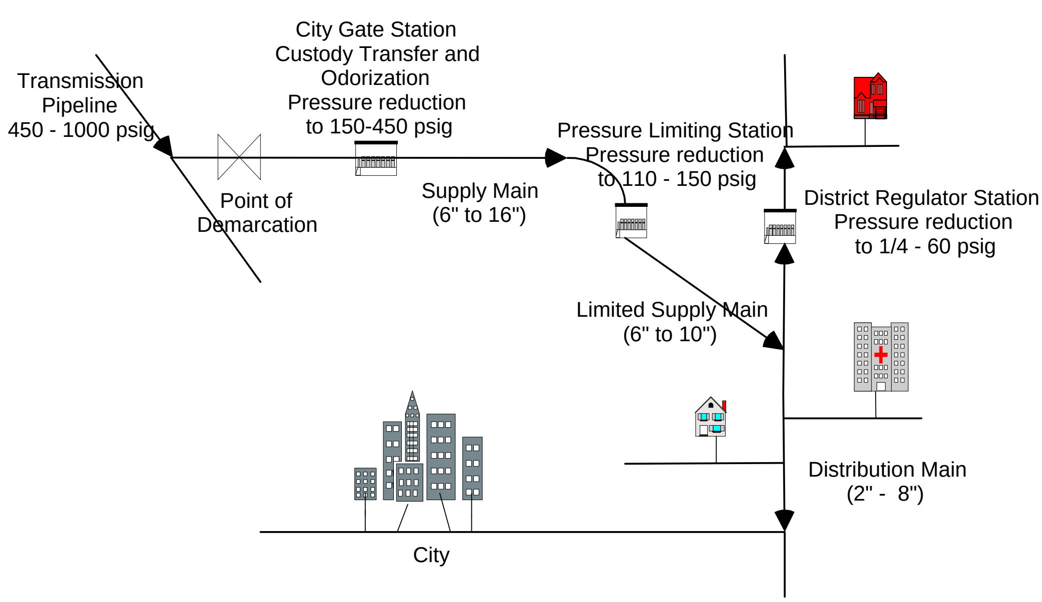
Figure 7-1
Electric Delivery System



B. Natural Gas Delivery Systems

Natural gas is transported at a variety of pressures through pipes of a variety of sizes. Large transmission pipelines deliver gas to city gate stations at high pressures, generally 450 to 1,000 pounds per square inch gauge (psig). There pressure is reduced to 150-450 psig for travel through supply main pipelines to district regulator stations which further reduce the pressure to less than 60 psig. From this point the gas flows through a network of piping (mains and services) to a meter set assembly at the customer's site. At the customer's site, the pressure is reduced to what is appropriate for the operation of their equipment (0.25 psig for a stove or furnace) and the gas is metered to determine how much is used. As gas flows through the distribution system, the system pressure will drop due to friction. This friction and resulting pressure drop depends on the diameter, material, roughness and length of the pipe that is used; it is also impacted by the type and number of fittings that are included in the system. As a result, each of these items is carefully considered when designing the system.

Figure 7-2
Gas Delivery System



C. PSE's Existing Delivery System

The table below summarizes the transmission and distribution infrastructure owned and operated by PSE as of December 31, 2006.

Figure 7-3
PSE-owned Transmission and Distribution System

Electric	Gas
Customers: 1,039,372	Customers: 712,974
Service territory: 4,500 square miles	Service territory: 2,800 square miles
Substations: 358	City gate stations: 39
Miles of transmission line: 2,630	Pressure regulating stations: 755
Miles of overhead distribution line: 10,417	Miles of pipeline: 11,554
Miles of underground distribution line: 9,356	Transmission pipeline pressure: 450-1,000 psig
Transmission line voltage: 55-500 kV	Supply Main pressure: 150–450 psig
Distribution line voltage: 4-34.5 kV	Distribution pipeline pressure: 45-60 psig
Customer site voltage: less than 600 V	Customer meter pressure: 0.25 psig

D. 5-year Infrastructure Plan

The maps and lists that follow show PSE's proposed 5-year infrastructure plan for meeting predicted capacity and reliability needs. The plan is reviewed annually; it remains dynamic. As the plan year gets closer, we refine plan projections based on new developments or information, and perform additional analyses to reveal and evaluate additional alternatives. The plan may change as a result of these investigations.

Figure 7-4
Map of Electric Substation Construction Plans, 2007–2011

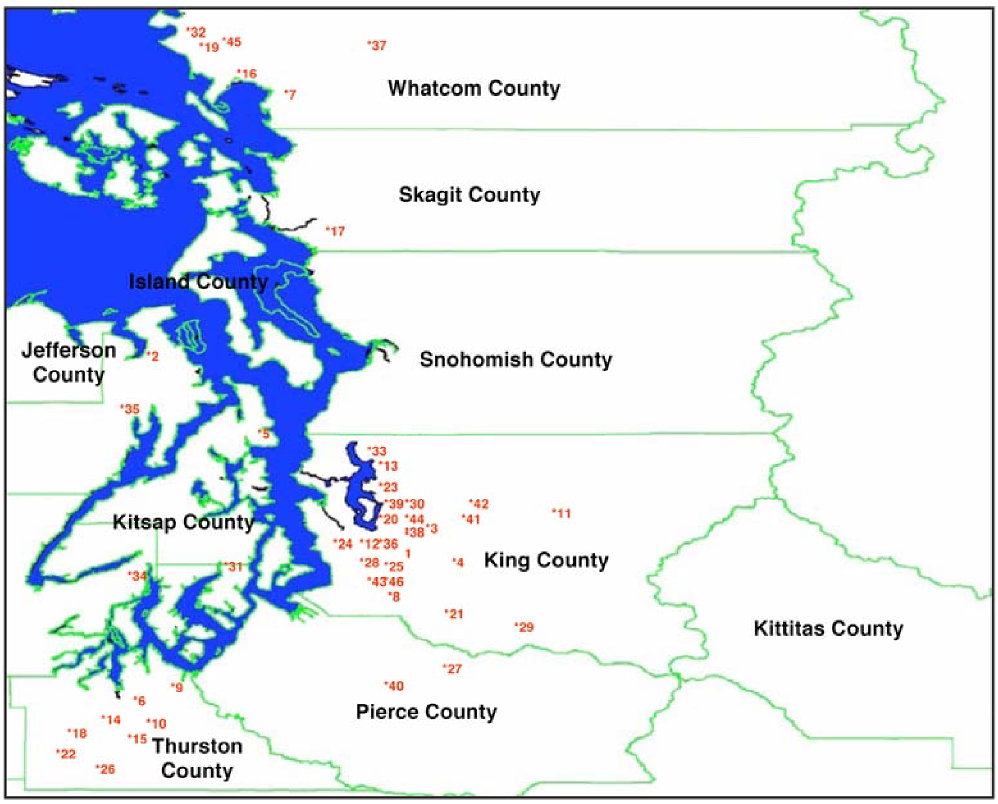


Figure 7-5
List of Electric Substation Construction Plans, 2007-2011

No	Year	Substation	County	Description
1	2007	Serwold	Kitsap	Construct new 115 kV substation with 25 MVA transformer
2	2007	Boeing Aerospace	King	Purchase and rebuild existing 115kV substation. Install new 115 kV, 25 MVA transformer.
3	2007	Chimacum	Jefferson	Construct new 115 kV substation with 25 MVA transformer
4	2007	Christopher	King	Install second 115 kV, 25 MVA transformer
5	2007	Glencarin	King	Construct new 115 kV substation with 25MVA transformer
6	2007	Kingston	Kitsap	Construct new 115 kV substation with 25 MVA transformer
7	2007	Prine Bank #2	Thurston	Install second 115 kV, 25 MVA transformer
8	2007	Sehome	Whatcom	Replace existing transformer with 115 kV, 25 MVA transformer
9	2007	Weyerhaeuser	King	Install second 115 kV, 25 MVA transformer
10	2007	Friendly Grove	Thurston	Replace existing transformer with 115 kV, 25 MVA transformer
11	2007	Plum Street	Thurston	Rebuild existing 55 kV substation to 115 kV. Replace existing transformer with 115 kV, 20 MVA transformer.
12	2007	Mt. Si	King	Construct new 115 kV substation with 25 MVA transformer.
13	2007	Paccar Bank #2	King	Install second 115 kV, 25 MVA transformer
14	2008	Juanita Sub #2	King	Install second 115 kV, 25 MVA transformer
15	2008	Browne	Thurston	Construct new 115 kV substation with 25 MVA transformer
16	2008	Capital	Thurston	Rebuild existing 55 kV substation to 115 kV. Replace existing transformer with 115kV, 25 MVA transformer.
17	2008	Laurel	Whatcom	Construct new 115 kV substation with 25 MVA transformer
18	2008	Eaglemont	Skagit	Construct new 115 kV substation with 25 MVA transformer
19	2008	Thurston	Thurston	Rebuild existing 55 kV substation to 115 kV. Replace existing transformers with two 115 kV, 25 MVA transformers.
20	2008	State St	Whatcom	Replace existing transformer with 115 kV, 25 MVA transformer
21	2008	Factoria Bank 2	King	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer.
22	2008	Four Corners	King	Construct new 115 kV substation with 25 MVA transformer
23	2008	Longmire Bank # 2	Thurston	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer
24	2008	Bridle Trails Bank #2	King	Install second 115 kV, 25 MVA transformer
25	2009	Freeway	King	Replace existing transformer with 115kV, 25 MVA transformer
26	2009	Kent Bank #3	King	Install third 115 kV, 25 MVA transformer.
27	2009	Spurgeon	Thurston	Construct new 115 kV substation with 25 MVA transformer
28	2009	Buckley	Pierce	Replace existing transformer with 115 kV, 25 MVA transformer
29	2009	Segale	King	Construct new 115 kV substation with 25 MVA transformer
30	2009	Greenwater	King	Replace existing transformer with 115 kV, 25 MVA transformer
31	2009	Ardmore	King	Construct new 115 kV substation with 25 MVA transformer
32	2009	Bethel	Kitsap	Construct new 115 kV substation with 25 MVA transformer
33	2009	Semiahmoo	Whatcom	Construct new 115 kV substation with 25 MVA transformer
34	2009	Vitulli Bank # 3	King	Rebuild existing 115 kV substation. Install third 115kV, 25 MVA transformer.
35	2010	Fletcher	Kitsap	Construct new 115 kV substation with 25 MVA transformer

No	Year	Substation	County	Description
36	2010	Lakeland	Jefferson	Construct new 115 kV substation with 25 MVA transformer
37	2010	Renton Junction Bank #3	King	Install third 115 kV, 25 MVA transformer
38	2010	Wiser Lake	Whatcom	Construct new 115 kV substation with 25 MVA transformer
39	2010	President Park Bank #2	King	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer.
40	2011	Center Bank #2	King	Install second 115 kV, 25 MVA transformer.
41	2011	Cumberland	Pierce	Replace existing transformer with 115 kV, 25 MVA transformer
42	2011	Goodes Corner Bank #2	King	Install second 115 kV, 25 MVA transformer
43	2011	Grand Ridge	King	Construct new 115 kV substation with 25 MVA transformer
44	2011	Lake Holm	King	Construct new 115 kV substation with 25 MVA transformer
45	2011	Northrup Bank #2	King	Rebuild existing 115 kV substation. Install second 115 kV, 25 MVA transformer.
46	2011	Whatcom	Whatcom	Construct new 115 kV substation with 25 MVA transformer
47	2011	Krain Corner	Pierce	Install 115 kV, 25 MVA transformer at existing 115 kV Switching Station

Figure 7-6
Map of Gas System Infrastructure Plans 2007-2011

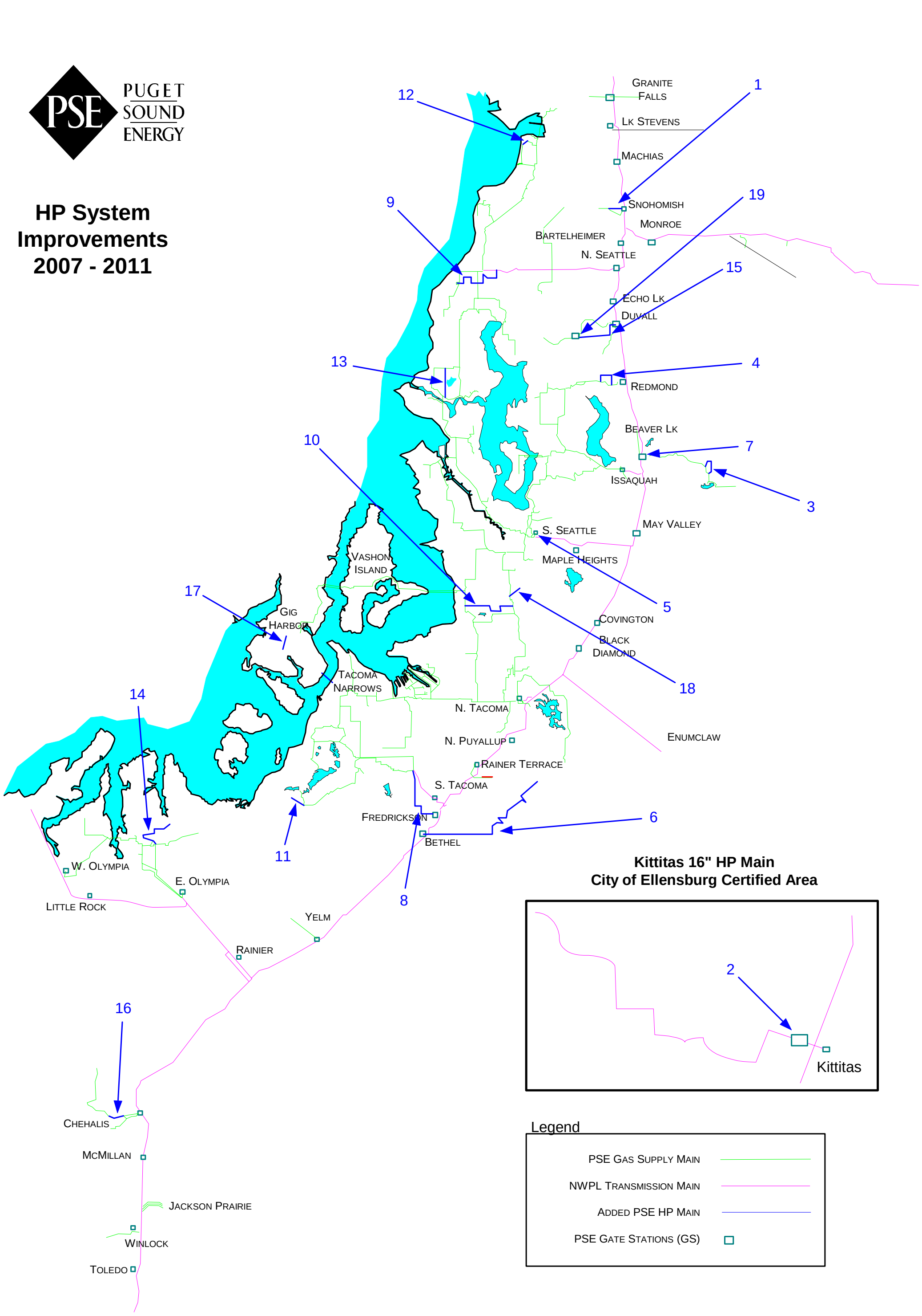


Figure 7-7
List of Gas System Infrastructure Plans 2007-2011

Number	Year	Name of Project	City	Job Description
1	2007	Snohomish	Snohomish	Install ~11,000 feet of 8" HP to replace 4" HP out of Snohomish GS
2	2007	Kittitas Gate Station	Kittitas	Install new higher capacity Kittitas GS and pressure increase lateral to 500 psig
3	2007	Snoqualmie Ph. III	Snoqualmie	Install ~11,500 feet of 12" HP to replace 4" HP on the Beaver Lake GS lateral to North Bend
4	2007	Union Hill Rd. Ph. III	Redmond	Install ~ 8500 feet of 16" HP to connect completed phases I and II ON Bellevue Redmond HP loop
5	2007	S. Seattle Gate Station	Seattle	Rebuild existing S. Seattle GS1376 and 8" Renton Supply DR.
6	2008-2010	Bethel Supply	Bethel	Install 12" HP Bethel GS to serve Cascadia and reinforce areas along the route
7	2008	Beaver Lake Gate Station 2498	Beaver Lake	Rebuild/replace existing GS2498 as required by future flow demands
8	2008	Fredrickson HP Lateral	Fredrickson	Install 12" HP from existing Fredrickson GS to location downstream of S Tacoma TBS.
9	2008	Greenwood Ph. III	Seattle	Install ~25,300 feet of 16" HP from N Seattle TBS to the Fremont and N Seattle LS laterals
10	2008	Kent Black Diamond Ph. II	Kent	Install ~ 27,000 feet of 16" HP from the end of Ph 1b to the Vashon Lateral
11	2009	Dupont HP Extension	Dupont	Extend ~8000 feet of 8" HP from the existing Dupont Supply
12	2009	Everett Supply Loop	Everett	Install 12" HP to connect the two HP Laterals in the Everett area
13	2009	Greenlake Lateral	Seattle	Install ~17,000 feet of 16" HP from the north to the south part of Greenlake Loop, Install new LS at the south loop end
14	2009	N. Lacey Supply	Lacey	Extend ~24,000 feet of 8" HP from existing 12" HP
15	2009	Woodinville Ph. III	Woodinville	Install ~ 26,400 feet of 16" HP from the Woodinville/Duvall GS to DR2134, Investigate new LS installation
16	2009	Chehalis	Chehalis	Replace ~6000 feet of 4" HP with 8" HP and retire 6 DR's, downrate remaining 4" HP to IP
17	2010	Gig Harbor HP Extension from LNG	Gig Harbor	Install 8" HP to southern Gig Harbor supplied from the Gig Harbor LNG facility
18	2011	Renton 8" HP Reinforcement	Renton	Install ~2500 feet of 8" HP to replace 4" HP to DR2521 in the Renton area
19	2011	Woodinville Limit Station	Woodinville	Install new LS off of Duval GS and increase new Woodinville Ph III lateral pressure to 400 psig.

II. Changes and Challenges

Aging infrastructure, changes in the industry and increasing sensitivity to energy costs, electric system reliability and environmental impact make planning delivery systems an evolving and complicated process. The planning process itself is subject to increasing scrutiny following the Northeast and upper Midwest blackout of 2003. Pipeline safety regulations are changing. Throughout the industry, infrastructure investments are rising as infrastructure nears the end of its usable life, and in response to the industry's limited spending during the push for utility deregulation (when facility ownership and cost recovery were uncertain). These changes, combined with the region's strong growth rate and our commitment to keeping gas and electric networks flexible enough to meet changing operating conditions and future needs, are resulting in significant delivery system investments by PSE.

A. General Infrastructure Needs

Electrical and gas equipment installed many years ago is now part of an aging infrastructure. Some components of our gas delivery system have been operating since 1889, and some electric-related equipment since 1917. We review the performance and reliability of these systems continually to ensure safe and reliable operation and to reduce leaks and outages. We have developed programs and processes to maintain existing facilities and add new components as necessary. In addition, aging cast iron mains, bare steel mains, power poles, underground cables, substation transformers and circuit breakers are being systematically replaced under multiyear replacement programs. Finally, we make investments to respond to changing conditions and needs. Annual performance issues for smaller distribution systems can often be resolved within a year or two, but large distribution or transmission issues take much longer to resolve. For example, securing substations and transmission facilities can take more than a decade.

B. Changing Regulations

The blackouts that affected the Northeast and Midwest in 2003 continue to generate changes for electric utilities. New regulations, mandated by The Energy Policy Act of 2005 and developed by the North American Electric Reliability Council (NERC), will go into effect June 1, 2007. Triggered by concern about the electrical grid's reliability, they move the industry into an era in which system planning, performance and operating requirements are mandated and take place under increasing scrutiny. More than 83 out of 107 proposed standards are expected to be adopted. The Federal Energy Regulatory Commission (FERC) selected NERC as the nation's Electric Reliability Organization (ERO). Per the Act, the ERO will be responsible for enforcing the new standards. The Western Electric Coordinating Council (WECC) is working with NERC to implement the new requirements; PSE is preparing to comply fully with them.

The Pipeline Safety Improvement Act (PSIA) of 2002 enacted stricter pipeline integrity requirements for the natural gas industry. As a result, PSE implemented its own transmission integrity management program in 2005 in order to comply with the act and to place additional focus on the transmission pipelines.

Last December, the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 was signed into law. The Act reauthorizes and amends the Department of Transportation's pipeline safety programs, and directs the Pipeline and Hazardous Materials Safety Administration to implement a distribution integrity management program (DIMP). Under the rule, concepts from the PSIA of 2002 will be applied to place additional focus on natural gas distribution systems. We anticipate the need to develop and implement our own DIMP by the end of 2009.

C. Right-of-way Issues

We anticipate that right-of-way issues will become more challenging in the future. The cost and effort to acquire these new rights-of-way is rising, and communities are increasingly concerned about their impacts. For these reasons, PSE strives to maximize our use of existing company-owned and public rights-of-way before considering creation of new ones. When we must seek new acquisitions, we believe it is crucial to seek input from the communities and jurisdictions they will affect before finalizing line routing and design. Maintenance of rights-of-way is an ongoing responsibility, and PSE is implementing more stringent vegetation standards for certain right-of-way corridors in accordance with new NERC requirements.

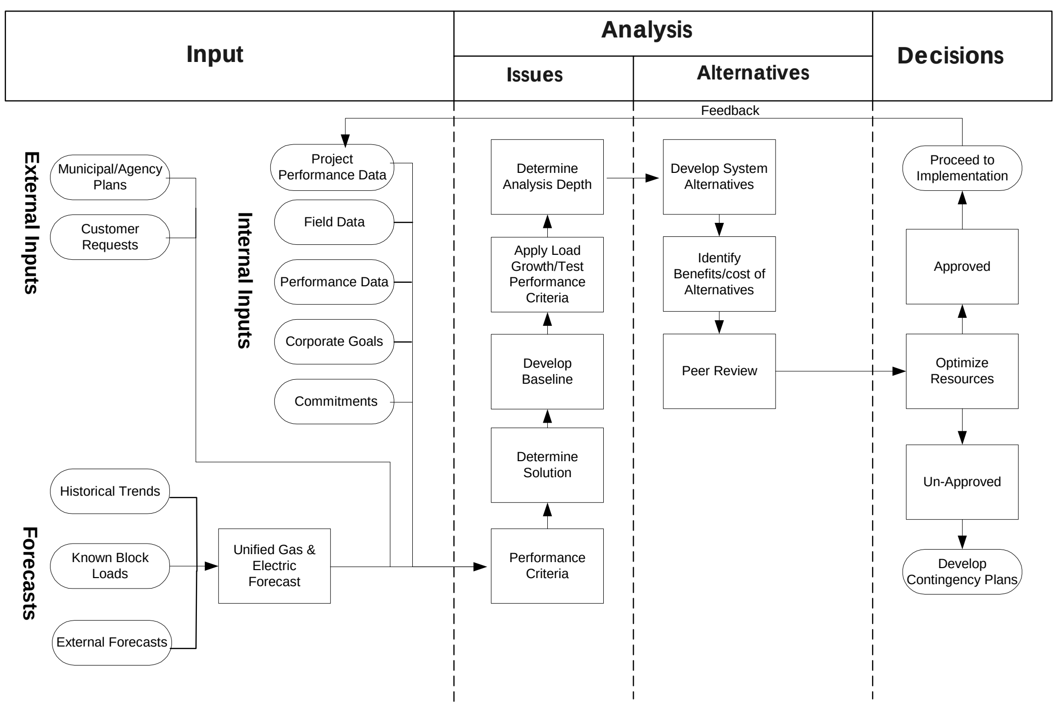
D. Emerging Alternatives

PSE is closely watching the development of new technologies that offer "non-wires" solutions to transmission and distribution challenges. Distributed energy resources technology has the potential to increase capacity on the system by incorporating power that is generated closer to, or at, the customer's location. It has promise, despite a variety of operating characteristics and complexities that must be addressed before it can be reliably integrated into the larger delivery system. Also, regardless of a customer's ability to self-produce generation, PSE must maintain a system equipped to meet use and capacity requirements if the distributed resource is unable to meet the customer's needs. See Section 5 of this chapter for a more detailed discussion of emerging alternatives.

III. Planning Process

The goal of the delivery system planning process is to find cost-effective ways to meet constituent needs. The process begins with an analysis of the current situation and an understanding of the existing operational and reliability challenges. Planning considerations (inputs) include both internal and external factors, load forecasts, customer expectations, and the impact of one energy type on the other. An analysis is conducted to identify alternatives that will address the challenge. Benefits and costs are then forecasted for each alternative that meets the performance criteria. Lastly, planners select and plan for the alternative that best balances customer needs, company economic parameters, and local and regional plan integration. Figure 7-8 diagrams the planning process.

Figure 7-8
Diagram of Delivery System Planning Process



A. Inputs

Internal planning considerations, or inputs, include system performance, company goals and commitments, and load forecasts.

PSE gathers system performance information from field charts, remote telemetry units, supervisory control and data acquisition equipment (SCADA), employees, and customers. Some information is analyzed over multiple years rather than a single year to normalize the effect of variables that can change significantly from year to year, such as weather. For near-term load forecasting at the local city, circuit, or neighborhood level, we use system peak-load and customer growth trends augmented by permitted construction activity for the next two years. For longer-term forecasting we use a corporate econometric forecasting method, which includes population growth and employment data by county (see Chapter 3).

External inputs include regulations, municipal and utility improvement plans, and customer feedback.

Reviewing municipal and utility improvement plans regularly enables us to minimize costs by scheduling upgrades or installation of new infrastructure when the ground is already being impacted by other construction work. We coordinate with other utilities whenever possible, and we work with other outside entities as well to find mutually beneficial schedules. Although our intent is to fully use existing assets before adding new ones, sometimes cost advantages can be gained from early installation for future needs.

PSE collects customer feedback in many ways. We continually investigate customer complaints and track ongoing service issues as they are communicated to us. Customers receive follow-up correspondence to discuss their concern, as well as plans for resolution. This communication provides valuable information that field data or statistical modeling may not have revealed. We also conduct customer surveys to seek out general information regarding customer expectations and possible specific concerns. The feedback from a January 2004 survey of electric customers who were affected by two large storms provided tremendous information that helped validate customer expectations and caused us to refine some of our plans. PSE is reviewing its response to the unprecedented storms of December 2006 to identify additional opportunities for improvement.

B. Performance Criteria

PSE primarily categorizes system needs as "capacity" and "reliability." These performance criteria lie at the heart of our planning process, and along with state and federal requirements provide the foundation for planning our infrastructure improvements.

Figure 7-9
Performance Criteria for Electric and Gas Delivery Systems

Electric delivery system performance criteria are defined by:	Gas delivery system performance criteria are defined by:
Safety and compliance	Safety and compliance
The temperature at which the system is expected to perform	The temperature at which the system is expected to perform
The nature of service and level of reliability that each type of customer is contracted for	The nature of service each type of customer is contracted for (interruptible vs. firm)
The minimum voltage that must be maintained in the system	The minimum pressure that must be maintained in the system
The maximum voltage acceptable in the system	The maximum pressure acceptable in the system
The cost customers are willing to pay for target levels of performance	The cost customers are willing to pay for target levels of performance
The interconnectivity with other utility systems and resulting requirements	

Modeling Tools

PSE relies on many different tools during the planning process to help identify and weigh the benefits of alternative actions. To evaluate both our gas and electric system performance, we use sophisticated modeling software that incorporates field data, including real-time information. Figure 7-10 provides a brief list of these tools, the planning considerations (inputs) that go into each, and the results (outputs) that they produce.

Figure 7-10
Summary of Delivery System Planning Tools

Tool	Use	Inputs	Outputs
Advantica SynerGEE	Network Modeling	Gas and Electric distribution infrastructure and load characteristics	Predicted system performance
Power World Simulator - Power Flow	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
PSS/E Power Flow & Stability	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
PSLF Power Flow & Stability	Network Modeling	Electric transmission infrastructure and load/generation characteristics	Predicted system performance
Probabilistic Spreadsheet	Probabilistic Analysis	Outage history, equipment failure probabilities	Outage savings based on probability of occurrence
Estimated Unserved Energy	Unserved Energy	Growth/load at specific conditions, annual load profile	Annual unserved energy, O&M costs as a result, value of service in cost terms
Investment Decision Optimization Tool (iDOT)	Project Data Storage & Portfolio Optimization	Project scope, budget, justification, alternatives and benefits; Resources/financial constraints	Optimized project portfolio, benefit cost ratio for each project, project scoping document
Area Investment Model (AIM)	Financial Analysis	Project costs, 8760 load data; and load growth scenarios	NPV; Income statement; Load Growth vs Capacity comparisons; EUE

PSE's gas system model is one of the largest integrated system models in the United States. It uses an Advantica SynerGEE software application that is continually updated to reflect new customer loads and system and operational changes. The accuracy of its results is validated by comparing them to actual system performance data. This model helps predict capacity constraints and subsequent system performance on a variety of degree days and under a variety of load growth scenarios. Where issues surface, the model can be used to evaluate alternatives and their effectiveness in resolving the issues. We augment these alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads.

For our electric distribution system, PSE also uses Advantica SynerGEE software. Here, the feeder system is modeled regionally rather than as a single large model. This is due to the limited connectivity between regions and the complexities with the management of a single large system model. Again, we use the model to evaluate system performance and predict capacity constraints on a variety of degree days and under a variety of load growth scenarios. As software capability improves, we hope to unify our gas and electric models. This will help us meet our customers' energy needs better by increasing our ability to take advantage of cost-effective fuel-switching opportunities where our electric and natural gas service territories overlap.

Modeling begins with building a digital map of the infrastructure and its operational characteristics. For gas, these include the diameter, roughness and length of the pipe, connecting equipment, regulating station equipment and operating pressure. For electric infrastructure, these include conductor cross-sectional area, resistance, length, construction type, connecting equipment, transformer equipment and voltage settings. Next, we identify customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system (CLX) or actual circuit readings. Finally, we vary temperature conditions, types of customers (interruptible vs. firm), time of peak daily usage, and the status of components (valves or switches closed or open) to model scenarios of infrastructure or operational adjustments to find the optimal solution to a given issue.

To simulate the performance of the electric transmission system, PSE uses three different programs: Power World Simulator, PSS/E (from Power Technologies Inc.), and PSLF (from General Electric). These simulation programs use a transmission system model that spans 11 western states, 2 provinces in western Canada and parts of northern Mexico. The power flow and stability data for these models is collected, coordinated, and distributed through regional organizations including Northwest Power Pool (NWPP) and Western Electricity Coordinating Council (WECC), one of 8 regional reliability organizations under the North American Reliability Corporation (NERC). These power system study programs support PSE's planning process and facilitate demonstration of compliance with reliability performance standards set forth by WECC and NERC. We are discontinuing use of the Managing and Utilizing System Transmission (MUST) program, another PTI product, because its capability to study the system's ability to move power from one area to another under various conditions is included in the Power World Simulator program.

C. System Alternatives

A variety of approaches are available to address delivery system capacity and reliability issues. Each alternative has its own costs, benefits, challenges and risks. These alternatives include the following.

Figure 7-1
Alternatives for Addressing Delivery System Capacity and Reliability Issues

Electric
· Add energy source
    Substation
· Strengthen feed to local area
    New conductor
    Replace conductor
· Improve existing facility
    Substation modification
    Expanded right-of-way
    Uprate system
    Rebalance load
    Modify automatic switching scheme
· Load Reduction
    Distributed Energy Resource
    Fuel Switching
    Conservation
    Load control equipment
    Possible new tarriffs
· Do nothing

Gas
· Add energy source
    City-gate station
    District regulator
· Strengthen feed to local area
    New high pressure main
    New intermediate pressure main
    Replace main
· Improve existing facility
    Regulation equipment modification
    Uprate system
· Load Reduction
    Fuel Switching
    Conservation
    Load Control Equipment
    Possible new tarriffs
· Do nothing

When issues are short term, like peaking events or meeting needs until a construction project is finished, energy flow can be managed temporarily with some of the same alternatives. Examples include:

- Temporary adjustment of regulator station operating pressure, as executed through PSE's Cold Weather Action Plan.
- Temporary adjustment of substation transformer operating voltage, as done using load tap changers to alter turn ratios.
- Automatic capacitor bank switching to optimize VAR consumption and maintain adequate voltage.
- Temporary siting of mobile equipment such as compressed natural gas injection vehicles, liquid natural gas injection vehicles, mobile substations, and portable generation.

D. Optimizing Value

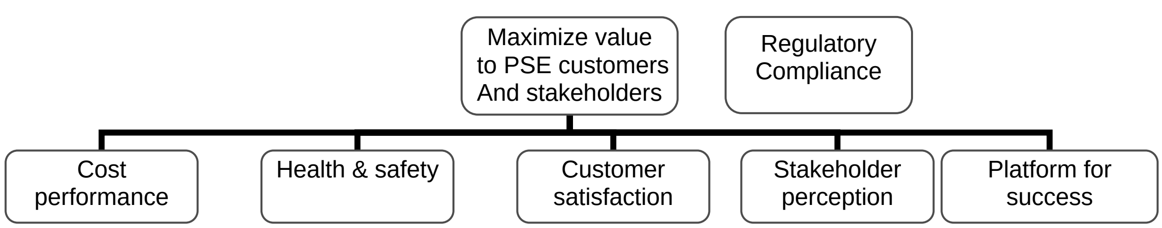
Making prudent investment decisions for hundreds of our gas and electric projects requires an objective way to synthesize, analyze, and optimize projects to maximize value to the company, customers, and the community. For this purpose, we use value-based budget prioritization.

In 2005, we updated the T&D Asset Investment Optimization System to better reflect our objectives, strategy and goals in light of the changing business environment, and to more efficiently and accurately quantify the value of projects, justify funding needs, prioritize projects, and account for risk and uncertainty. Formal "value modeling" refines and integrates existing tools to prioritize projects based on a measure of project value. Project value is estimated by simulating project impacts over the asset life or duration of maintenance funding and applying multi-attribute utility theory. The model we use, Investment Decision Optimization Tool (iDOT), identifies—from any portfolio of possible delivery system capital and maintenance projects, and any constraints on budget-year costs—the set of projects that will create maximum value.

Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on service provider contracts. As projects move through detailed scoping, cost estimates are refined. Planners use Area Investment Model (AIM) software to calculate a wide range of financial performance indicators for each project—including net present value and rate of return—as well as future revenue potential from capacity gained by a particular solution. This allows further comparisons for infrastructure that will be in service for 30–50 years.

The diagram below shows PSE's benefit structure to evaluate delivery system projects.

Figure 7-12
Benefit Structure to Evaluate Delivery System Projects



IV. Case Studies

To illustrate the planning process through example, we describe four situations and show how PSE addressed them.

A. Chehalis High-Pressure Gas Distribution System

PSE currently serves the Chehalis and Centralia areas with approximately 30,000 feet of 6" and 20,000 feet of 4" high-pressure (HP) pipeline from the Chehalis Gate Station. This one-way system has no alternate supply at present. The Chehalis/Centralia growth rate since 2000 has averaged 1% per year. The long-term plan for this area has been to replace the high-pressure pipe with large- diameter pipe when growth justified the replacement.

During the investigation we found that, in addition to the capacity issues, a number of older regulator stations fed from this line needed to be rebuilt or eliminated. We sought a solution that would address the capacity and maintenance issues at the same time.

Three projects were proposed:

A. Replace 20,000 feet of existing 4" HP pipe with 8" HP pipe, which would eliminate 16 small regulator stations.
B. Replace about 5,000 feet of existing 4" HP pipe with 8" HP pipe, which would eliminate 3 small regulator stations.
C. Replace about 5,000 feet of existing 4" HP with 8" HP pipe (in a different location), which would eliminate 5 small regulator stations.

All three were evaluated via the planning process to determine which would provide the most value, and therefore represent the best solution.

Project (A) lacked a positive benefit-to-cost ratio because customer growth in the area did not justify 20,000 feet of new 8" HP pipeline. It provided excess future capacity and too few near-term benefits. The cost savings from retiring 16 regulator stations and connecting them to the 4" pipe was not enough to justify such a large expenditure for a limited number of customers.

Project (B) had a positive benefit-to-cost ratio due to the reduced footage (5,000 feet versus 20,000 feet). It could handle the area's increased growth for many years and would eliminate 3 regulator stations.

Project (C), however, had the highest benefit-to-cost ratio. The 5,000 feet of pipe to be replaced retired more of the unmaintainable regulator stations (5 as opposed to 3) with as little replacement pipe as possible—yet still provided for an acceptable amount of future growth. Therefore we funded project (C) to be completed no later than 2008.

When the system reaches its capacity in the future, we will propose replacing another optimized section of 4" HP pipe with 8" HP—probably about 5,000 feet in 2014 or 2015. Completing projects in this manner optimizes costs; reduces the amount of underutilized pipe for the short term; funds current needs; and reduces the risks from incorrectly estimated future load growth.

Figure 7-13
Chehalis High-Pressure Gas Distribution System Alternatives

Alternatives	Capital	NPV 30 Yr	Comments
Project (A) – 20,000' of 8" HP and eliminate 16 regulator stations	$5.6M in 2007 Equal to timed projects below	($4.9M) $560k Capital Cost Avoidance & $12.8k Maintenance Cost Avoidance	Not selected – negative benefit/cost ratio. Increased capacity not needed until later.
Project (B) – 5,000' of 8" HP and eliminate 3 regulator stations	$1.4M in 2007 and $3.2M in 2011 (conservative date)	($1.2M) $105 Capital Cost Avoidance & $2.4k Maint. Cost Avoidance	Not selected - less benefit than version 3.
Project (C) – 5,000' of 8" HP and eliminate 5 regulator stations	$1.4M in 2007 and $3.2M in 2011 (conservative date)	($1.2M) $175k Capital Cost Avoidance & $4k Maint. Cost Avoidance	Selected version – best benefit/cost ratio.

B. Hansville Peninsula Electric Distribution System

The north Kitsap County electric system has experienced capacity issues. PSE began serving the Hansville Peninsula in 1980 via a cable resting on the floor of the Port Gamble Bay water passage between Port Gamble and Little Boston. The Hansville area experienced annual customer growth of 0.5% and a predicted capacity problem by 2005.

We used SynerGEE to model growth and to predict when system capacity would begin to adversely affect performance.

We looked at various options including installing a new underwater cable. However, new facilities could take years to study, design, and permit, so we began planning temporary solutions to prevent overuse and possible failure of the cable—which would leave approximately 2,000 customers without service. As a result, we installed a temporary generator at Hansville that operates during colder days, but this is merely a bridging solution that does not meet the long-term needs of this area. We considered three alternatives in our efforts to identify a long-term solution to this capacity issue:

A. An underwater transmission cable with a substation on the Hansville Peninsula, with costs ranging from $15 to $20 million.
B. A second distribution submarine cable at an estimated cable cost of about $4 million plus additional costs.
C. A new distribution substation and related transmission line, at a cost of about $5 to $7 million. In addition to providing capacity to the peninsula, the new substation would provide future capacity to the town of Kingston.

Alternative (A) was eliminated due to its cost. Alternative (B) meets near-term and long-term demand in Hansville, but does not provide additional capacity for the Kingston area and has more unknown costs for construction and engineering of underground cable. Alternative (C) was selected and is scheduled for completion in 2007. Its estimated cost was approximately equal to alternative (B) but without any additional cost unknowns, and it would provide greater capacity. The temporary generator will still be needed until the substation is completed.

Figure 7-14
Hansville Electric Distribution System Alternatives

Alternatives	Capital	NPV 30 Yr	Comments
Transmission Underwater cable	$15-$20 M	N.A.	Is not cost competitive
Second Distribution underwater cable	$4 M	($6.5M)	Too many cost unknowns to be a viable alternative
Kingston Substation	$5-$7 M	($4.7M)	Least cost alternative with more capacity than the distribution underwater cable

C. Puyallup Intermediate Pressure (IP) System Uprate

IP System #058 is PSE's natural gas distribution system serving the north Puyallup area. Its 300 miles of IP pipes, serving 22,000 customers, currently operate at a maximum allowable operating pressure (MAOP) of 45 psig. Since 2000, customer growth has averaged 2% per year. Using this growth rate and SynerGEE forecasting, we predicted that IP System #058 need would exceed capacity by the 2006-2007 winter season. As a result, more than 800 gas customers would experience outages at 15°F and more than 4,600 customers would experience outages on a design day (10°F). While cold-weather actions would ensure service continuity during the winter of 2006-2007, a more permanent and robust infrastructure solution was needed.

Four alternatives were evaluated to reinforce this area of our natural gas system:

A. IP main replacement-reinforcement alternative—replace more than 45,000 feet of existing 2" and 4" pipe with 6" pipe, install 8,500 feet of 4" pipe, and install 6,000 feet of 6" pipe.
B. HP extension I—install more than 19,000 feet of 8" HP main from the North Puyallup Gate Station and install two district regulators (DR).
C. HP extension II—extend more than 16,500 feet of 8" HP main from an existing 6" HP system and install two DRs.
D. Uprate IP System #058 from 45 psig to 60 psig MAOP.

Option (A) would meet the capacity need until 2012 and cost about $4 million. Option (B) would meet the capacity need until 2011 at an estimated cost of $7.5 million. Option (C) would also meet the capacity need until 2011, but at an estimated cost of $5.3 million. Option (D) would cost about $2.8 million and meet capacity needs until 2014. This option had a larger benefit-to-cost ratio: It was almost 50% less than the other options and would meet capacity concerns for more years. The uprate work began in 2006 and is scheduled to be completed in 2007. We also looked at combinations of alternatives, but from a long-range perspective no combination would be economically feasible and adequately handle growth without including the IP uprate solution.

Figure 7-16
Puyallup System Uprate Alternatives

Alternatives	Capital	NPV 30 Yr	Comments
IP replacement-reinforcement	$4.44M	($3.7M)	Not selected. Meets capacity requirements until 2012.
HP extension I	$7.50M	($6.3M)	Not selected. Meets capacity requirements until 2011.
HP extension II	$5.31M	($4.4M)	Not selected. Meets capacity requirements until 2011.
IP system uprate	$2.82M	($2.0M)	Selected option, least cost solution. Meets capacity requirements until 2014.

V. Emerging Alternatives

In the last 20 years, electricity consumption has increased 2.0% to 2.5% annually in North America. During this time, transmission infrastructure expansions have not taken place at an equivalent rate to match the increasing consumption. As a result, the strain on the transmission system is being felt throughout North America, including the Pacific Northwest, where the main grid transmission system has operated at or near capacity due to a lack of substantial transmission construction between 1987 and 2003.

PSE and the region's utilities have a vested interest in finding an optimal solution to this problem, and we are studying several emerging alternatives to meet today's transmission and distribution challenges. They include distributed energy, demand-response alternatives, and the development of a "smart grid."

A. Distributed Energy Resources

Distributed energy is a way of incorporating small-scale generation into the grid close to where the power is used. Many such sources exist: internal combustion engines, fuel cells, gas turbines and micro-turbines, hydro and micro-hydro applications, photovoltaics, wind energy, solar energy, and waste/biomass. The challenge for the delivery system is how to integrate this power into a system that was designed to transport power from large generating plants located far away.

For much of the 20th century, small-scale customer-based generation could not compete economically with centralized, utility-owned power plants, but those economics have begun to change. Though not yet cheaper than the conventional system in most cases, an increasing variety of customers find small-scale solutions desirable. Some industrial customers want to meet their heating and electrical needs with one system. Hospitals and computer-based internet service firms now require higher levels of power quality and would suffer significant consequences if a service interruption were to occur. Some customers want renewable or green power.

The formal name for distributed energy solutions is distributed energy resources (DER). It includes all technologies in distributed generation (DG), distributed power (DP) and demand-response applications. Unlike the conventional system through which power generally flows in one direction, DER configurations allow power to travel in both directions: Customers who generate electricity for their own use (or have back-up generators standing by) can sell power back to the grid. PSE already has more than 100 such "interconnected" customers. Demand-response applications build two-way communications into the system that enable customers and the company to calibrate actual usage much more closely.

Although a host of regulatory, business practice, technical and market barriers continue to challenge the full-scale implementation of DER technology, PSE believes that it has the potential to provide cost-effective, appropriate and meaningful solutions. We are already incorporating DER elements into our planning process, and have developed guidelines to identify projects most likely to serve as the lowest reasonable cost solution. To ensure no adverse effects on our customers, we require that such solutions be as reliable as traditional "wires-based" projects.

PSE has already implemented some DER solutions, and we are testing others to find out if they can provide benefits that justify their costs.

The Hansville Penninsula project outlined in the Case Studies section of this chapter uses distributed generation to meet the capacity needs of customers while a permanent infrastructure solution is constructed. When the existing submarine cable that supplies electricity to the area approaches its design capacity, the temporary generator is operated. This supplies the additional power needed and protects the cable from failing until the new substation and transmission line are completed.

At Crystal Mountain, PSE implemented a distributed resource peak shaving strategy in 1999 that enabled us to defer a costly traditional system upgrade. The load in the area (which included the Crystal Mountain and Greenwater substations) was projected to increase from 5.9 to 11.2 MVA by 2006-2007. A traditional upgrade was estimated to cost $2.5 million. PSE refurbished a 2.4 MVA diesel standby generator located nearby, tested it to prove both concept and feasibility, and placed it in service to meet the need.

PSE began testing a conservation voltage reduction pilot program in 2006 in conjunction with the Northwest Energy Efficiency Alliance (NEEA). The homes of 10 customers in two locations were fitted with meters capable of monitoring energy usage at the residence and transmitting that information back to PSE every 15 minutes over telephone lines. On alternate days, PSE reduced substation transformer control voltage from a range of 123 to a range of 119 volts. This results in a feeder voltage reduction of 3%. Two-way communication helped us determine whether the reduced voltage adversely affected any customers. Preliminary results from Phase 1 of the study are favorable, indicating 2%

energy savings at both pilot locations with no adverse effects. The NEEA will proceed in getting approval to begin Phase 2.

In its 2006 General Rate Case filing, PSE proposed refinements to our existing Schedule 93 commercial/industrial customer demand buyback tariff, a residential voluntary critical peak pricing pilot, and a voluntary community load curtailment pilot. We will work with the Conservation Resources Advisory Group to finalize design and evaluation plans for demand-response pilots. We will then file for tariffs and approval from the WUTC, initiate an internal implementation process, and recruit and finalize pilot participants. The pilots will then be installed and will collect data through 2009.

B. Modernizing the Grid

Smart grid is a movement to integrate intelligent devices and new technologies into the electrical grid to optimize the system to a degree not possible with existing infrastructure. It is less well developed than DER technologies, but has the potential to integrate all parts of the electric power system—production, transmission, and distribution—in ways that would be extremely beneficial.

- Such a grid would be self-healing, meaning sophisticated grid monitors and controls will anticipate and instantly respond to system problems in order to avoid or mitigate power outages and power quality problems.
- Such a grid would be more secure from physical and cyber threats, because it will be better able to identify and respond to man-made or natural disruptions.
- Such a grid would support widespread use of distributed energy resources, meaning standardized power and communications interfaces will allow customers to interconnect fuel cells, renewable generation, and other small-scale generation on a simple “plug and play” basis.
- Such a grid would enable customers to better control the appliances and equipment in their homes and businesses; the grid will be able to communicate with energy management systems in smart buildings for greater control over energy use and costs.

PSE is monitoring and researching smart grid devices, and participating with various governmental, regional, industry and utility groups in workshops and summits. When these devices become commercially available, we will integrate them into our cost-benefit analysis.

C. DER-related Industry and Regulatory Activity

PSE is monitoring and evaluating DER developments at the federal, state, and utility levels on an ongoing basis. Recent activity includes the following.

Federal and state agencies have taken some steps to address the technical, permitting, interconnection, and regulatory barriers identified in the National Renewables Energy Laboratories (NREL) report issued in May 2000.

The Department of Energy (DOE) established the Electric Distribution Program to work with federal, state, industry, laboratory and university groups on program planning, research, development demonstration and deployment of DER. The program supports a wide variety of distribution grid modernization initiatives and summits.

The DOE's Distributed Energy Resource program has implemented a Distributed Energy Resource Strategic Plan that promotes "next generation" clean, efficient, reliable, and affordable DER technologies.

FERC initiated a Notice of Proposed Rulemaking in July 2003 designed to finalize the standardization of small-generator interconnection agreements and procedures. (This followed FERC's Advance Notice of Proposed Rulemaking and the National Association of Regulatory Utilities Commission's [NARUC] June 2002 release of draft interconnection agreements and procedures.) In October 2003, NARUC published the model agreement for Interconnection and Parallel Operation of Small Distributed Generation Resources as an information tool and to serve as a catalyst for DER interconnection proceedings.

The Institute of Electric and Electronic Engineers (IEEE) is developing specific and voluntary DER standards. IEEE Standard 1547-2003, Standards for Distributed Resource Interconnection with the Electric Power Systems, was established and approved by the IEEE board in June 2003. The IEEE Standards Coordinating Committee is currently drafting and establishing technical guidelines for interconnecting electric power sources greater than 10 MVA with the transmission grid. The IEEE Distributed Resources

Integration working group has issued a draft paper on the impact of DER on utilities. DER should become easier for small customers to implement as many of these standards become finalized and approved.

BPA, which owns and operates approximately three-quarters of the electrical transmission system in the Pacific Northwest, holds Non-Wires Solutions (NWS) Roundtable meetings, in which PSE and other organizations participate. The group—utilities, regulators, renewable resource advocates, environmental interest groups, industrial energy users, Native American tribes and independent power generators—considers broad, regional approaches to employing non-wires solutions.

Choosing a Strategy

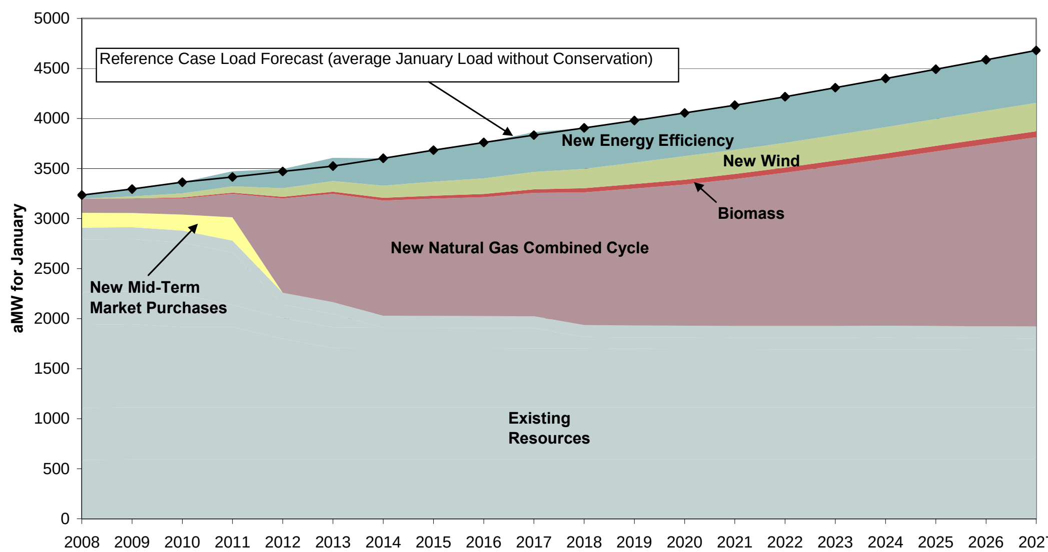
A great deal of material is described in detail in this document. Much of the information is technical and quantitative in nature, including the data, assumptions, and inputs developed, the methodology used, and many of the analytical results. Some of it is qualitative in nature, including information about marketplace conditions, choices about possible futures to model, and assessments of the current regulatory climate.

In this chapter, we want to take a step back and look at the big picture. We want to synthesize the two types of information, and in so doing, explain the reasoning PSE used to choose the lowest reasonable cost portfolios recommended in this integrated resource plan.

I. Electric Resource Strategy

In PSE's judgment, the lowest reasonable cost electric resource strategy to pursue at this time includes aggressive investment in energy efficiency as a significant and cost-effective contribution to meeting resource need. It relies heavily on increased development of wind power to meet renewable portfolio standards. And it relies on gas-fired generation to make up the balance of energy needs that cannot reasonably be met through demand-side and renewable resources.

Figure 8-1
Preferred Electric Resource Strategy, 2007 IRP



January Energy Additions aMW—Lowest Reasonable Cost Portfolio				
	2008	2015	2020	2027
DSM/Energy Efficiency	36	314	432	524
Wind	0	140	235	284
Biomass	0	29	49	59
Gas CCCT	142	1172	1410	1893
PBAs	148	0	0	0

January Capacity Additions MW				
	2008	2015	2020	2027
DSM/Energy Efficiency	36	314	432	524
Wind	0	550	921	1,112
Biomass	0	34	57	69
Gas CCCT	149	1,234	1,484	1,992
Duct Firing	20	167	200	269
SCCT	0	0	175	441
PBAs	148	0	0	0

A. Framing the Analysis

To arrive at this strategy, PSE assessed need over the next 20 years. We constructed scenarios that represented different possible ways the future might develop. We created hypothetical portfolios containing different combinations of resources to meet that need. Finally, we evaluated the portfolios within the context of the different scenarios to find out how they behaved with regard to cost and risk. The assumptions, inputs, and data used to construct these components, and the methodology used to analyze them are explained in the body of this report.

Six scenarios were constructed for the electric analysis; all included greenhouse gas emissions costs, as we believe these to be likely by 2009. Figure 8-2 summarizes the highlights of the different scenarios. These scenarios made it possible for us to investigate significant "what if" questions about the future.

- *Current Trends*. What if current economic, marketplace and regulatory trends continue into the future?

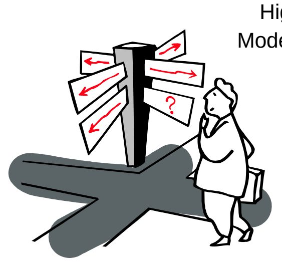
- *Green World*. How would higher-than-currently-expected charges for greenhouse gas emissions affect portfolio performance?
- *Low Growth*. What if projected economic growth in the region does not meet expectations?
- *Robust Growth*. What if economic growth exceeds current expectations?
- *Technology Improvement*. What if technological advances improve both heat rates and capital costs?
- *Escalating Costs*. What if these technological advances take place, but cost more than current optimistic projections?

Figure 8-2
Electric Scenarios

Current Trends
Moderate Gas Prices
Low Carbon Costs
Moderate Load Growth

Green World
High Gas Prices
High Carbon Costs
Moderate- Load Growth

Low Growth
Low Gas Prices
Low Carbon Costs
Low Load Growth



Robust Growth
High Gas Prices
Low Carbon Costs
High Load Growth

Escalating Costs
Current Trends +
Increasing Capital Costs

Technology Improvement
Current Trends +
Declining Capital Costs
Heat Rate Efficiency Improvement

Constructing different portfolios enabled us to compare the costs and risks associated with varying combinations of resources. All included significant emphasis on demand-side resources and sufficient renewable resources to meet RPS standards, but they differed in significant ways that allowed us to explore questions such as the following.

- How would portfolios that relied primarily on gas-fired generation compare to those that incorporated coal?
- What if coal were added sooner, rather than later?
- What was the effect of using power bridging agreements (PBAs)?
- How did increasing the amount of renewables affect results?

Altogether, we tested twelve different portfolios against the six scenarios. In the end, each portfolio's performance was ranked in each scenario, as summarized below.

Figure 8-3
Relative Rankings of 12 Portfolio-Scenario Combinations

	1	1a	2	3	3a	4	5	5a	6	7	8	9
	Aggressive Gas	**Early PBA Aggressive Gas**	**Early IGCC**	**Late IGCC**	**Early PBA Late IGCC**	**Max IGCC**	**Late IGCC w CCS**	**Early PBA Late IGCC w CCS**	**Aggressive Renew**	**More Renew w Gas**	**More Renew IGCC w CCS**	**Last IRP Portfolio**
Current Trends	4	3	5	2	1	6	8	7	12	10	11	9
Green World	4	3	11	8	7	12	2	1	9	6	5	10
Low Growth	2	1	8	4	3	10	6	5	12	7	11	9
Robust Growth	9	8	2	4	3	1	7	6	12	11	10	5
Technology Improvement	8	5	4	3	1	2	7	6	12	10	11	9
Escalating Costs	3	2	7	4	1	9	6	5	12	10	11	8

Lowest Cost Portfolio
2nd Lowest Cost Portfolio

B. Narrowing the Field: The Portfolio Screening Process

To eliminate the less favorable candidates, we applied a series of screens to the quantitative analysis. This screening process is illustrated in Figure 8-4. The quantitative analysis process and results are discussed in Chapter 5.

It is important to note that the results of the quantitative analysis are close enough that we must be cautious about drawing conclusions based solely on the numbers. While the costs are indeed close, we believe it is incumbent upon us to define the lowest cost portfolio and to provide an explanation of how we came to that conclusion.

1. *Portfolios that failed to rank 4th or higher on at least one scenario were eliminated.* Portfolios that failed to demonstrate some measure of economic advantage were considered less attractive and did not pass the screen.

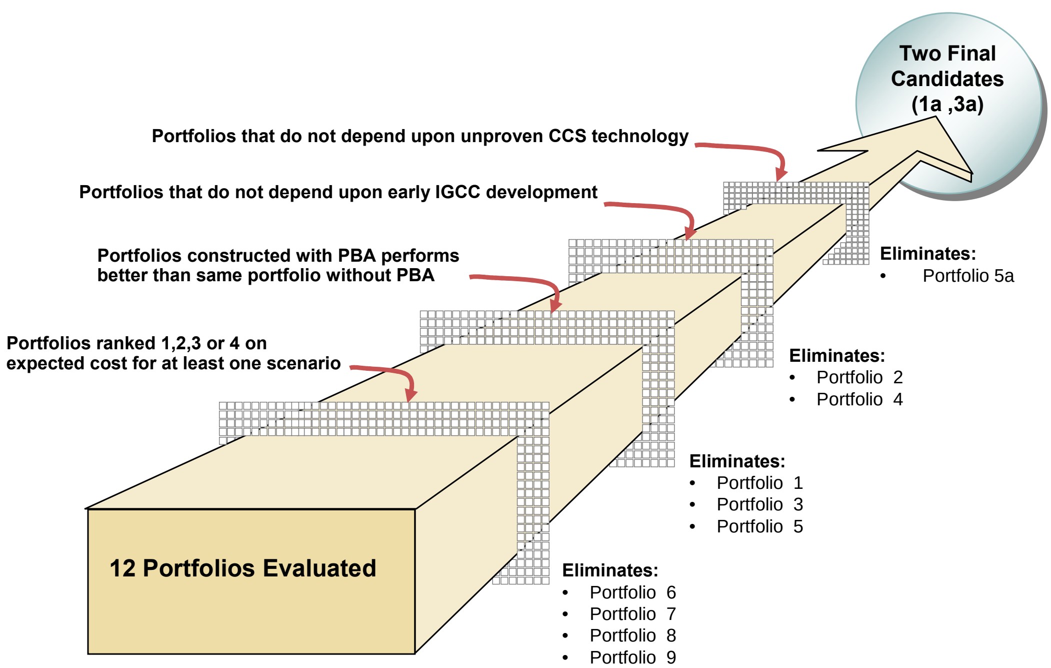
2. *Portfolios constructed without PBAs did not perform as well as the same portfolio with PBAs.* The hypothetical portfolios with and without PBAs were originally evaluated in order to normalize the comparisons between "lumpy" generation additions over the planning horizon. Under current market conditions, PBAs are

priced below the cost of new resources, which gives them an additional advantage. Portfolios without PBAs were screened out at this stage because of this advantage.

3. *Portfolios that rely on early IGCC development were eliminated.* The earliest proposed on-line date for any IGCC to appear in the region is 2014. Given the uncertainty surrounding federal regulation—and especially state legislation that may effectively prevent development of new coal resources (including IGCC)—we do not believe it is realistic to assume such plants can be brought on line so quickly. So, only portfolios featuring later stage IGCC development passed this screen.

4. *All coal projects without carbon capture and sequestration (CCS) capability were eliminated*. These projects were originally included in order to quantify the risks and trade-offs associated with CCS. At this time, it is not at all clear when—or if—CCS technology will become commercially available. Once it does, significant legal and regulatory hurdles will still need to be overcome. Portfolios that included CCS were screened out on the basis that such technology is not yet commercially available.

Figure 8-4
Electric Portfolio Screening Process



C. Final Candidate Evaluations

When the screening process was complete, two candidates remained. Both incorporated aggressive demand-side measures early in the planning horizon in order to capture the greatest benefit. Both added additional wind resources to meet RPS standards. And both relied on adding gas-fired resources to meet remaining need until late in the planning period. At 2020, they diverge in the following way.

- Portfolio 1a continues reliance on gas-fired generation to meet rising needs.
- Portfolio 3a adds contributions from coal-fired IGCC plants late in the planning horizon.

The decision presents a judgment call: If *Green World* scenario conditions emerge—with higher costs for greenhouse gas emissions—reliance on natural gas generation (Portfolio 1a) is lower cost than a portfolio including IGCC (Portfolio 3a), given that carbon sequestration is not commercially viable. Similarly, Portfolio 1a performs better in the Low Growth scenario that has a low natural gas price assumption. If the *Current Trends* scenario emerges—with relatively lower carbon costs—then the lower cost portfolio is the one that contains late IGCC (Portfolio 3a). Similarly, Portfolio 3a performs better in the Robust Growth scenario than Portfolio 1a, because of the lower relative carbon costs.

In order to explore the risks involved in this choice, we posed two further questions: What would be the cost consequences of committing to one or the other portfolio in both of the scenarios? And, how likely is it that market conditions will be more like the Green World scenario than the Current Trends scenario? We narrowed the scope to a comparison between Current Trends and Green World to focus on the specific risks that seem to drive results between additional coal and no coal—the relative difference between all-in coal costs (including carbon) and natural gas costs. This narrowing of focus is a reasonable simplification given our earlier explanation that the results of the analysis are too close to rely solely on quantitative results.

The cost of commitment. Figure 8-5 shows the comparison of cost risk across the two scenarios. If we implemented the aggressive gas portfolio (1a) in anticipation of Green World market conditions and Current Trends conditions prevailed, the net present value cost to the portfolio would be $117 million. On the other hand, if we pursued IGCC without carbon sequestration being viable and Green World conditions prevailed, the net present value cost to the portfolio would be $174 million. This told us that the scenario risk associated with coal in the form of IGCC represented in portfolio 3a was larger than the risk in the aggressive gas portfolio 1a.

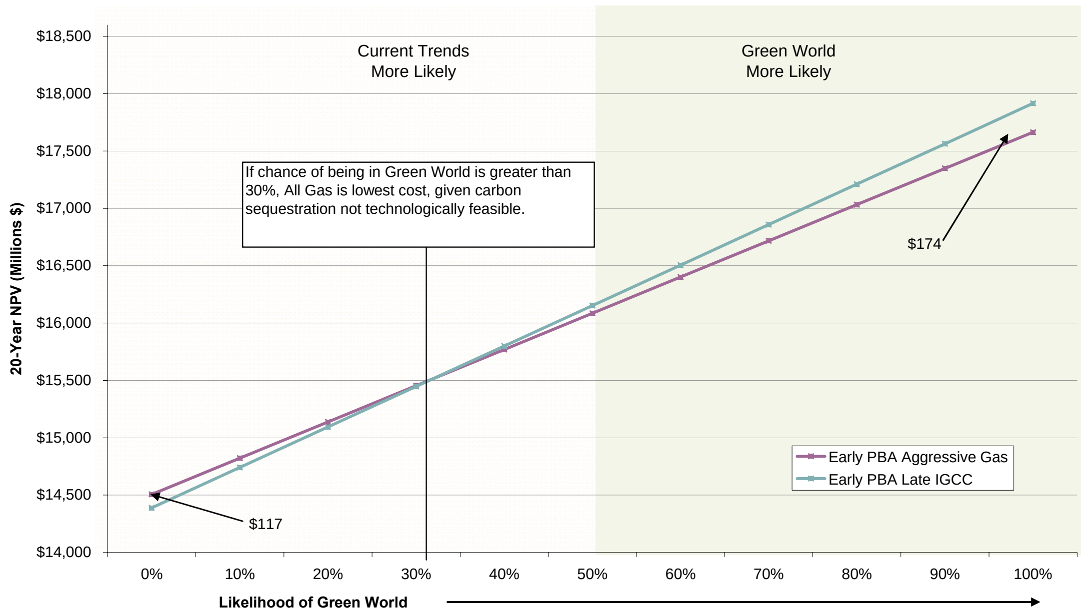
Figure 8-5
Comparison of Lowest cost portfolios across Scenarios (Millions $)

Lowest Cost Portfolios Across Different Scenarios		
	Early PBA Aggressive Gas	Early PBA Late IGCC
Current Trends	$ 14,506	$ 14,389
Green World	$ 17,664	$ 17,490

Difference From Lowest Cost		
	Early PBA Aggressive Gas	Early PBA Late IGCC
Current Trend	$ 117	$ -
Green World	$ -	$ 174

How likely is it that a Green World future will emerge? Assigning a probability to future market conditions is a very subjective exercise. However, Green World market conditions would make the difference between resource strategies relative to Current Trends. Since we do not know the likelihood of one potential future versus another, a better question is at what probability level would it make a difference? Figure 8-6 illustrates the probabilistic “tipping point” between two portfolios in the *Green World* and *Current Trends* scenarios. The end points tie to Figure 8-5: if Current Trends is the future, the cost difference between the two portfolios is $117 million NPV (net present value); if Green World is the future, the difference is $174 million NPV. The figure below illustrates the probability level at which the gas portfolio (1a) becomes lower cost than the IGCC portfolio (5a). The tipping point is 30%. Thus, if the probability of *Green World* is greater than 30%, then the heavy gas portfolio (1a) is preferred. If the probability of *Green World* is less than 30%, then reliance on the IGCC portfolio is preferred. Again, given present-day uncertainty surrounding federal and state legislation regarding greenhouse gas emissions, it seems possible that the 30% threshold may be exceeded.

Figure 8-6
Relative Risk Trade-off of Green World vs. Current Trends



D. Conclusion

In our judgment, the quantitative analysis supports a finding that portfolio 1a—which relies on aggressive investment in energy efficiency, aggressive addition of wind resources to meet renewables targets, and gas-fired generation to meet the balance of base load need—is the lowest reasonable cost resource strategy for PSE to pursue at this time. This is supported by the qualitative considerations described in the Executive Summary and by the new Washington state law precluding new coal generation without carbon sequestration.

Should CCS technology prove viable, we will reassess the trade-offs between gas and coal. PSE is actively monitoring—and will continue to monitor— activities at a number of utilities that are now looking closely at carbon sequestration. Based on our current analysis and assessment of the industry, we believe that by 2012, we may know enough to determine if CCS technology will be commercially viable by 2021. If that turns out to be true, 2012 would be the earliest we could re-examine the coal question. The primary driver for this will be the time at which CCS technology becomes commercially viable.

E. Near-term Marketplace Conditions

Although this integrated resource plan is essentially a strategic document, it is clear that several marketplace realities will confront us as we begin to acquire the resources needed to meet demand. They are worth noting here, as they will affect the tactical decisions we make as the acquisition process unfolds.

Renewables Will Require Aggressive Pursuit

Wind is currently the only renewable resource in the region capable of producing commercial-scale quantities of power. Assuming that 90% of the renewable portfolio standards established by Washington voters in 2006 will be met by wind resources, the state's utilities will need to add approximately 5000 MW of wind resources by 2027. PSE's share would be approximately 1100 MW. In practical terms, this means PSE and its development partners will need to place one wind project into commercial service approximately every 18 months beginning in 2010.

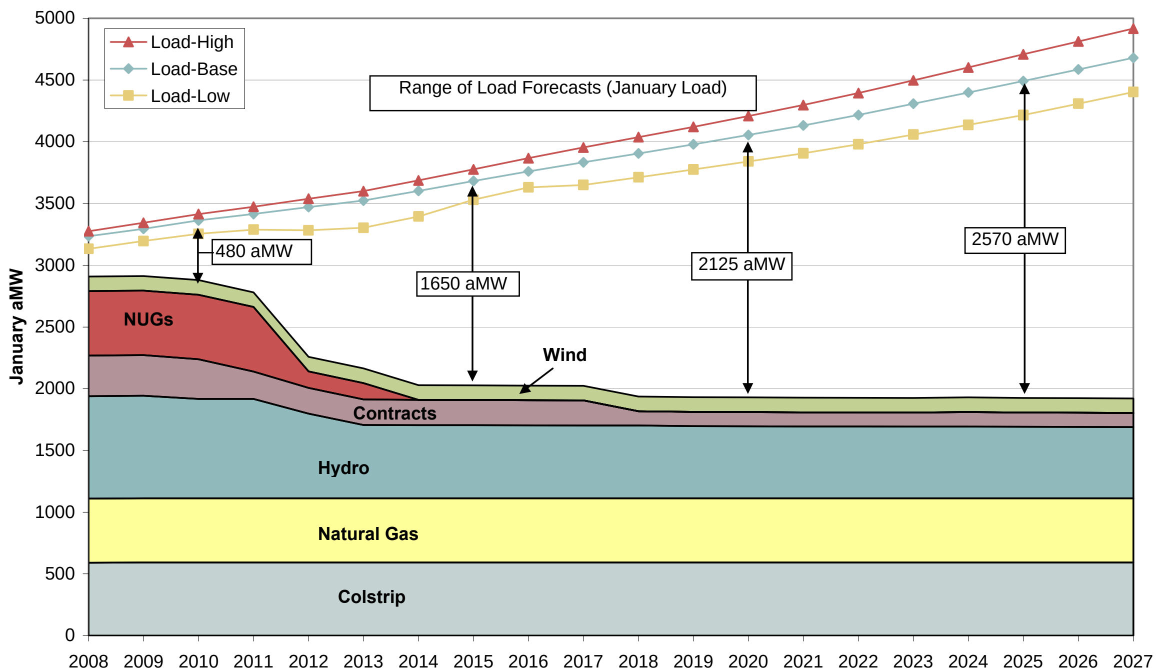
We will have to accomplish this in an extremely crowded marketplace. California recently empowered its utilities to seek renewable resources in the region; Oregon is poised to pass ambitious renewable portfolio standards; and many other western states (including Nevada, Arizona, New Mexico, and Colorado) have also established renewable standards. Demand for suitable wind sites and other renewables will be fierce in the Northwest and the West, and PSE will need to act aggressively in the marketplace to be able to meet our obligations.

All parties—utilities, developers, key vendors, transmission providers, and regulators—need to understand the size of the renewables challenge. Meeting RPS targets will require creative, coordinated efforts on a scale we have not seen before in the Northwest.

The Pace of Resource Acquisition Will Continue

PSE faces large electric resource needs in coming years due to a combination of economic growth and expiring contracts, as illustrated in Figure 8-7. We will need to acquire nearly 500 aMW of electric resources by 2010, more than 1,600 aMW by 2015, and nearly 2,600 aMW by 2025 in order to meet customer demands. This means that PSE will need to add a 150 MW wind plant, as previously mentioned, and a new 250 MW gas plant every eighteen months to two years. Thus, we see the current treadmill of resource planning, acquisition, and regulatory cost recovery continuing throughout the planning horizon.

Figure 8-7
Electric Resource Need



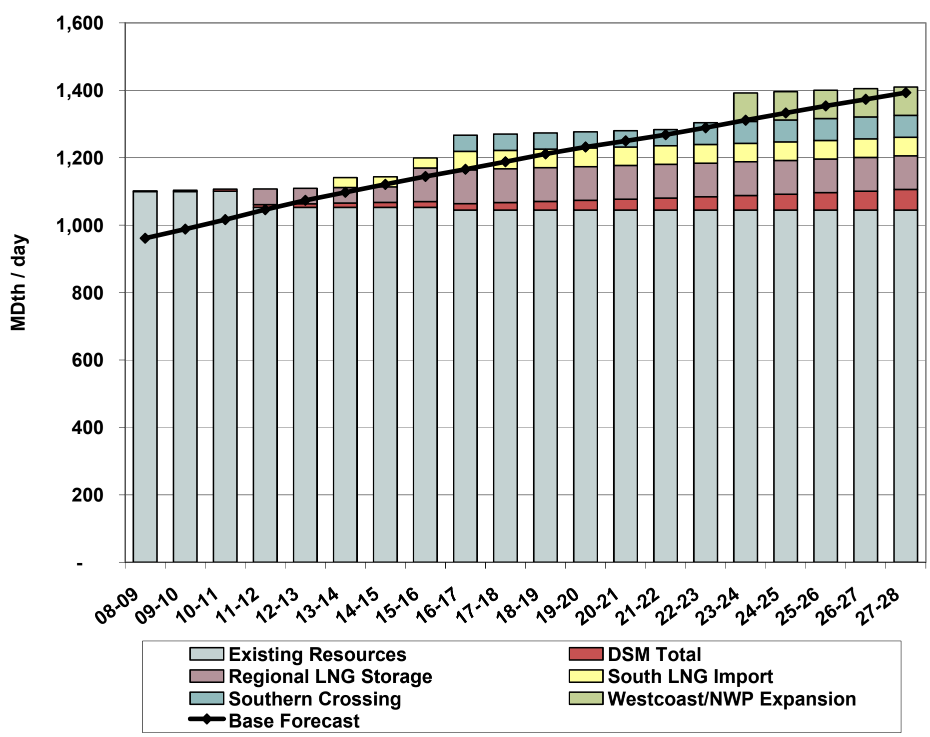
II. Gas Resource Strategy

PSE's retail natural gas resource need is growing more gradually than our electric resource need. Sufficient capacity resources are on-line and under development to meet needs through the winter of 2011-2012. We believe that the lowest reasonable cost strategy for meeting projected demand is the portfolio shown below. It includes cost-effective energy-efficiency measures as well as three supply-side alternatives that appear to be both feasible and cost-effective:

- participation in a regional LNG storage facility
- purchase of gas from a LNG import facility
- participation in an expansion of the Southern Crossing pipeline

Beyond approximately 2023 additional pipeline capacity is a feasible alternative to meet customer needs through 2027. Existing and prospective resources are both shown in Figure 8-8.

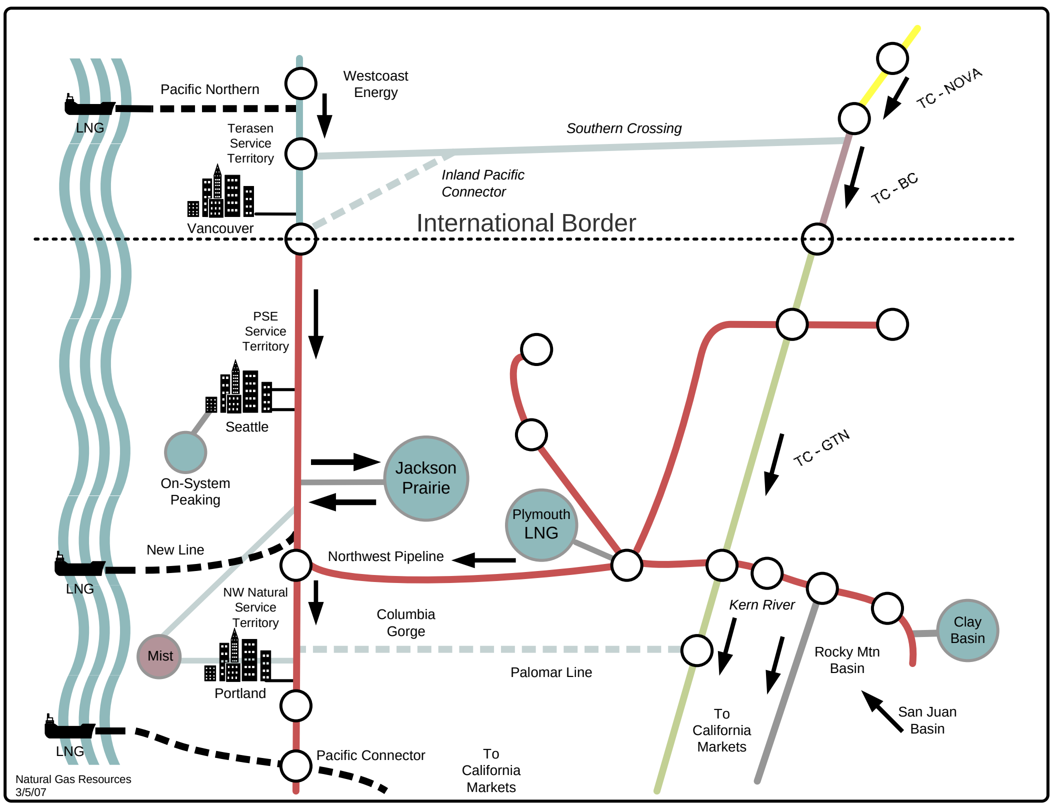
Figure 8-8
Lowest Reasonable Cost Portfolio - Gas Sales Customers



Winter Capacity Additions (MDth) - Reference Case Portfolio				
	2008	2015	2020	2027
DSM/Energy Efficiency	2	17	32	61
Regional LNG Storage	0	100	100	100
South LNG Import	0	30	55	55
Southern Crossing Pipeline	0	0	48	65
Westcoast/NWP Expansion	0	25	25	107

The location of these supply alternatives is shown on the regional gas transportation map in Figure 8-9.

Figure 8-9
Location of Gas Supply Resource Alternatives



Gas planning analysis focuses on where to buy gas, how to transport it to customers, how to best utilize storage facilities and the impacts of potential energy efficiency programs to minimize the cost of meeting customer loads. The network of supply areas and market hubs, the pipeline transportation system, storage facilities, and demand areas lends itself to analysis using linear programming models, so identifying the lowest reasonable cost portfolio for retail gas resources is somewhat more straightforward than electric analysis.

We began by developing demand forecasts and comparing these with existing resources to identify need. We created a set of assumptions regarding resource costs and gas prices (these are explained in Chapter 6, Gas Resources). Then we developed alternatives to address our primary needs: pipeline capacity, storage, energy efficiency, and supplies. Once these elements were in place, we were able to use a linear programming model to identify the portfolio that would minimize costs over the planning horizon.

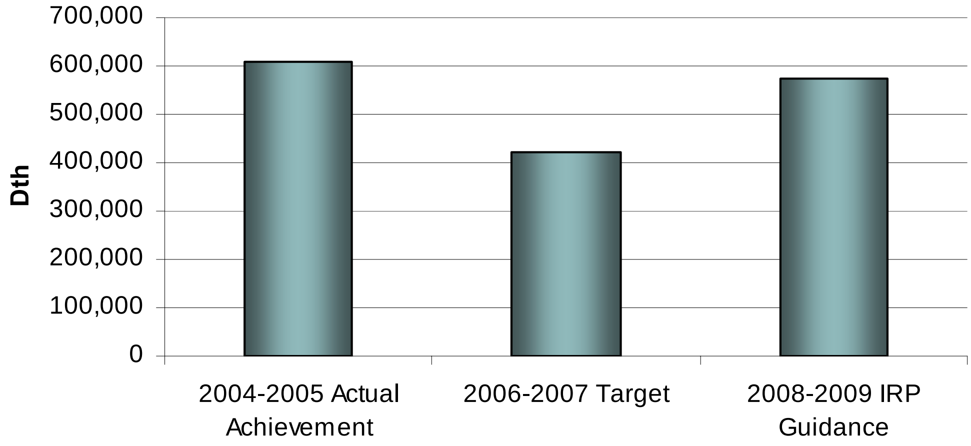
Four scenarios were also developed in order to investigate the effect different possible futures might have on gas prices and demand. The Base Case assumed present trends continue and gas prices stay in the middle of the range. A Green World scenario assumed higher prices due to increased demand for natural gas. Robust Growth assumed high customer growth rates and therefore higher demand and prices. Low Growth assumed lower growth and prices. Monte Carlo analysis enabled us to test how sensitive optimal resource additions were to these assumptions about price and demand.

Gas Resource Additions

Demand-Side Resources

Figure 8-10 compares our previous energy efficiency accomplishments, our current target, and our new level of guidance based on the results of this analysis. In the short term, this IRP guidance includes 576,000 Dth of energy efficiency savings for the 2008-2009 period. This is an increase of 37% over current 2006 – 2007 targets. It is slightly less than the savings achieved in 2004 – 2005, which included large savings from the unique, one-time commercial spray heads project.

Figure 8-10
Short-term Comparison of Gas Energy Efficiency



Supply-Side Resources

Direct-connect pipelines move gas from upstream sources to PSE's local distribution system. At this time, there are no practical alternatives to our current supplier, Northwest Pipeline (NWP). Future expansions of NWP, even though incrementally priced, will be our most cost-effective alternative for the present.

To address further storage and peaking needs, participation in a regional LNG storage facility was found to be the lowest reasonable cost alternative. In general, we have sufficient pipeline capacity to deliver total annual requirements; we require additional capacity mainly at peak usage times. Further expansion of the Jackson Prairie storage facility is not economically practical. Investing in development of a regional storage facility that is able to utilize low-cost redelivery service is a relatively less expensive solution than acquiring firm year-around pipeline capacity to meet peak day loads.

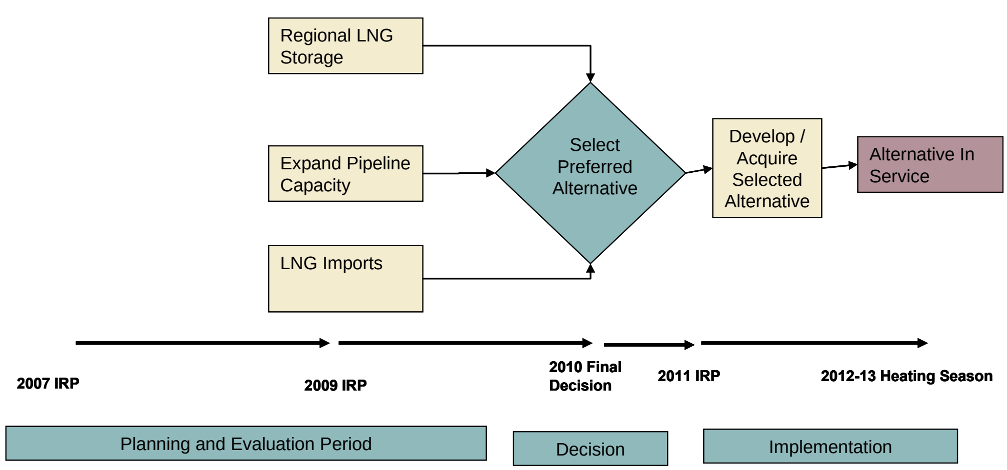
For gas supply needs, a South LNG import terminal located in southern Oregon was selected in all scenarios as a cost-effective way to increase peak supply capacity as well as to diversify sources of supply. In conjunction, development of some limited transportation capacity from the Jordan Cove site to PSE's city gate also appears economically feasible. Ultimately, the attractiveness of this alternative will be determined in large part by the final terms and conditions of any gas supply agreement arranged in association with it. The other LNG import facility evaluated in the analyses is the proposed Kitimat facility located on the north B.C. coast. The optimal portfolio also contains additional gas supplies from various supply basins or trading locations.

The upstream pipeline capacity alternative recommended in this portfolio required a judgment call on PSE's part. Going strictly by the numbers, the analysis recommended that the lowest cost alternative was limited expansion of the Westcoast Pipeline capacity, which would increase our capacity to transport gas purchased at Sumas and Station 2. However, we have some serious concerns about increasing our reliance on those markets. Sumas is already the source of 50% of PSE's gas supplies, and in recent years producers and marketers have shown a marked preference for moving their activities to the AECO hub. Because of AECO's access to Chicago and other Midwestern markets (in addition to California and the Northwest), its market is more liquid and its prices less volatile than Sumas.

Although the Southern Crossing/Inland Pacific Connector alternative recommended here has a relatively higher cost, it offers the significant advantage of enabling PSE to diversify our supply sources by decreasing our dependence on Sumas and northern B.C. gas supplies, and increasing our access to the more liquid AECO hub.

Figure 8-11 shows the decision path and timing necessary to acquire resources for the projected capacity need in 2012-13.

Figure 8-11
Natural Gas Sales Decision Path



Action Plans

PSE's main objective is to pursue acquisition of both demand- and supply-side resources that will accrue long-term benefits to our customers. The short-term, two-year electric and gas plans presented in sections I and II of this chapter outline specific actions to be taken by the utility in implementing the long-range integrated resource plans discussed in this 2007 IRP. Section III reports on the efforts PSE has made to address the Action Plan items in the 2005 Least Cost Plan.

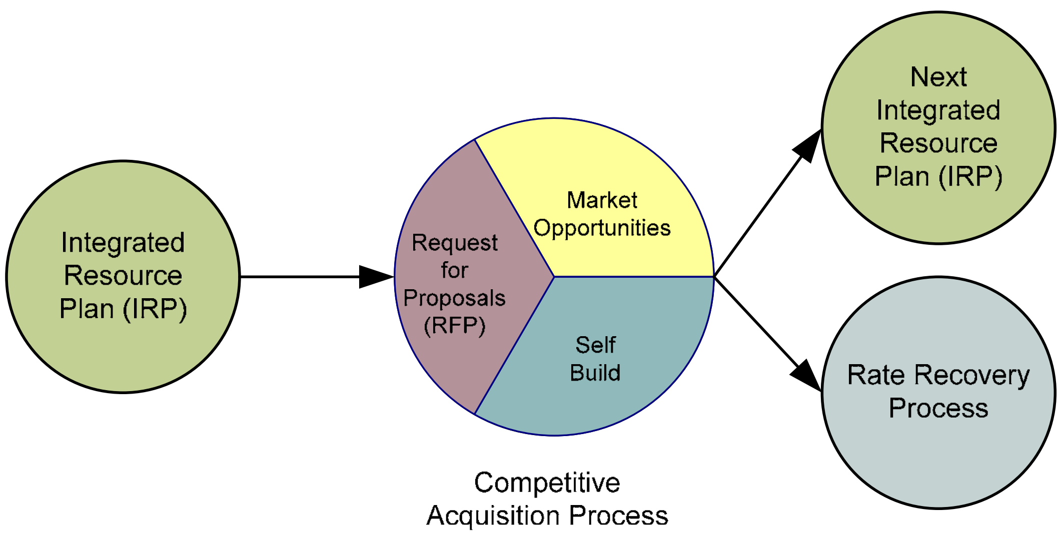
Developing the Integrated Resource Plan is an important exercise that gives PSE a structured opportunity to:

- *Think Broadly.* To consider different futures and understand implications those different futures might have on alternative resource strategies.
- *Consider Different Perspectives.* To obtain input from stakeholders that have a variety of experienced, informed perspectives about long-term energy markets, environmental issues, and other issues related to resource planning.
- *Make Reasoned Judgments.* To combine robust quantitative analysis and non-quantitative factors (reasoned qualitative analysis) into clear, well-supported conclusions that will help meet customer demands at the lowest reasonable cost.
- *Inform the Resource Acquisition Process.* To develop and refine analytical approaches and information that will assist the resource acquisition processes.
- *Communicate.* To describe the market conditions we face, and our thinking about the implications these conditions have for the resource decisions that must be made.

In some states, Integrated Resource Planning is nearly synonymous with resource acquisition analysis. In Washington state, the IRP informs the acquisition processes rather than providing a shopping list of resources to acquire. Analysis in this IRP relies on generic resources to explore strategic issues, such as the risk of coal-fired generation. Resource acquisition processes follow through with specific information about specific resources. The primary function of the IRP, beyond simply meeting regulatory requirements, is to inform our resource acquisition process.

Figure 9-1 illustrates the connection between the IRP and activity related to resource acquisitions. It shows how the IRP directly informs the formal RFP process. In Washington, the formal RFP process for demand-side and supply-side resources is just one source of information for making acquisition decisions. Market opportunities outside the RFP and self-build (or PSE demand-side resource programs) must also be considered when making prudent resource acquisition decisions. Figure 9-1 also illustrates that the acquisition process itself informs subsequent IRPs. As shown below, the IRP's primary purpose is to inform the acquisition process; it is not a substitute for the resource-specific analysis done to support specific acquisitions.

Figure 9-1
Relationship between the IRP and the Acquisition Process



I. 2007 Electric Resources Action Plan

The conclusions drawn from this Integrated Resource Plan analysis support the following actions with regard to electric resources.

Demand-side Resources

PSE will work toward significantly increasing our electric demand-side resource programs, mainly energy efficiency programs. We will work with external stakeholders in the CRAG process to develop program goals, targets, and tariff filings to implement this strategy. Such processes will rely on updated avoided cost inputs and more specific assessments of achievability based on specific programs that are designed.

Wind and Other Renewables

PSE will continue working toward meeting obligations under Washington's renewable portfolio standard. We will develop and begin implementing strategies to move deeper into the development process for renewables. Additionally, we will continue to remain active in exploring cost-effective opportunities as they appear during the formal RFP process and to other market opportunities that may present themselves.

Base Load Thermal Resources

PSE will take an opportunistic approach to filling the remaining resource needs with a combination of purchased power agreements and/or natural gas-fueled power plants. We will look to meet resource needs through the formal RFP process, seek opportunities to acquire resources through bilateral negotiations, and consider self-build natural gas alternatives. PSE will also actively monitor and participate in policy, regulatory, and technology developments affecting the viability of new coal resources.

II. 2007 Natural Gas Resources Action Plan

The conclusions drawn from this Integrated Resource Plan analysis support the following actions with regard to gas resources.

Gas Demand-side Resources

PSE is looking for opportunities to increase our gas programs where it is feasible. We will work with external stakeholders in the CRAG process to develop program goals, targets, and tariff filings to acquire cost effective and achievable energy efficiency savings. Such processes will rely on updated avoided cost inputs and more specific assessments of achievability based on specific programs that are designed.

Capacity Alternatives

PSE will continue working with others in the region to identify and more fully define regional LNG peaking opportunities. We will also continue to monitor transportation capacity alternatives that are tied to potential regional LNG import facilities. Additionally, we will monitor potential pipeline alternatives that could increase supply diversity.

Supply Alternatives: Imported LNG

PSE will work with other regional market participants to help determine if an LNG import facility in the region would be commercially viable, cost effective, and otherwise desirable for the market. If so, we will take reasonable actions to help encourage and/or participate in such development to benefit our customers.

Generation Fuel Planning

Increasing reliance on natural gas-fired generation creates issues, some of which may be quite different than concerns for meeting needs of gas sales customers. PSE will define and prioritize these issues, develop plans for investigating potential solutions, and commence implementation of such solutions as appropriate. We will discuss such activity with our IRPAG members and other stakeholders to the extent that such discussions do not compromise our ability to achieve commercial benefits for our customers.

III. Report on 2005 Action Plan

This section reviews the efforts PSE has made to address the Action Plan items included in the Company's 2005 Least Cost Plan. Those items are shown in bold type, subsequent PSE efforts appear below in regular type

A. Electric Resource Acquisition Activities

Actions related to resources expected to come online between 2006 and 2011 are designated "near-term," and those related to resources expected to come online between 2012 and 2025 are designated "long-term."

Energy Efficiency (Near-term)

Develop new electric and gas energy efficiency savings targets for 2006-2007 informed by Least Cost Plan analyses, and file new program tariffs with the Washington Utilities and Transportation Commission (WUTC) by the end of 2005.

In our April 2005 Least Cost Plan Update, PSE presented an extensive analysis of energy efficiency savings potential and its contribution to the Company's electric portfolio. In collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG), these results were used to develop energy efficiency program targets for 2006 and 2007. A two-year stretch goal for contributions of approximately 40 aMW by the end of 2007 was adopted.

Initiate an energy efficiency resource acquisition Request for Proposal (RFP) process that complies with regulatory requirements. This RFP will address the following: 1) long lead times due to 2006-2007 targets and program commitments needing to be made before the RFP process can be completed; and 2) development of a "targeted" RFP, focused on specific markets and/or technologies that complement PSE's programs.

In November 2005, PSE issued an "all-comers" RFP for acquisition of energy efficiency resources, consistent with 2005 Least Cost Plan findings of a short-term need for electric energy resources (with energy efficiency included as a least-cost option), as well as with WAC 480-107 requirements. The Energy Efficiency RFP process was run in parallel with the RFPs for wind and all generation resources.

In December 2005, PSE received bids for 18 efficiency projects, of which 12 involved electric energy efficiency totaling 6.7 aMW, and two involved electric demand response programs. These bids underwent an extensive evaluation process, focusing on cost-effectiveness, technical merits, compatibility with existing PSE programs, and the risk of not delivering projects as proposed. The evaluation process was completed in March 2006, resulting in the selection of a short list of six proposed projects. The results of this evaluation process have been reviewed with the CRAG. Below is a brief summary of the status for each of the short-listed electric projects.

- *Multi-Family Comprehensive Energy Efficiency* provides weatherization, lighting, and water heating measures to multifamily complexes. The project contract was awarded to ECOS Consulting and program implementation began in August 2006.
- *Refrigerator Recycling* proposal is on hold pending further review.
- Manufactured Home Heat Pump Replacement project is no longer being considered due to cost effectiveness concerns.
- *Two Demand Response* programs (one residential, one commercial) will be pursued in collaboration with the CRAG, as agreed upon by PSE, WUTC staff, and other parties in PSE's 2006 General Rate Case (Docket No. UE-060266 and UG-060267)

Fuel Conversion (Near-term)

Complete evaluation of single-family and multi-family fuel choice pilots, and explore the feasibility of further developing fuel conversion programs, with input from regulators and stakeholders.

PSE completed a pilot study of single family home fuel conversion in 2005. Evaluation of the pilot yielded favorable results for cost-effective savings for nearly all measures in the program. However, the magnitude of energy savings was not significant enough to defer investments in electrical distribution infrastructure due to capacity reduction. PSE's research into fuel conversion for existing multi-family structures found it was not cost-effective except in some larger units on a case by case basis. However, fuel-choice for new construction may hold more promise.

Demand Management (Near-term)

Explore the feasibility of implementing one or more demand-response pilots, with input from regulators and stakeholders.

PSE proposed four demand response pilot programs in its 2006 rate case filing and, per agreement with Commission staff and other stakeholders, agreed to withdraw these proposed pilots from the rate case filing. In the agreement demand response pilots would be pursed through the CRAG. We are currently in the process of working with the CRAG to develop appropriate pilots.

Green Power Program and Small-scale Renewable Generation (Near-term)

By the end of 2005, develop a two-year goal for the Green Power program covering the 2006-2007 period.

The 2006 goal for the Green Power Program was to sell 120,000 MWh of green power to customers in the same year. The program exceeded the goal, selling 131,000 MWh of green power in 2006. The 2007 goal is to sell 200,000 MWh of green power to customers.

Continue to encourage small-scale solar or other renewable energy demonstration projects.

PSE has continued to support the installation of small-scale solar projects through net metering arrangements, a residential rebate program, and the newly implemented Renewable Energy Advantage Program (REAP). In addition, PSE continues to provide grants for small-scale renewable energy demonstration projects. Under this program, solar installations were added to the Washington State Capitol building and the Vashon Institute for Environmental Research and Education, in 2005; and Redmond High School in 2006. A project at Washington Middle School entered the planning phases in 2006.

New Electric Resources (Near-term)

Initiate a competitive solicitation process for new electric energy resources by filing a draft RFP and accompanying materials with the WUTC within 90 days following submittal of this Least Cost Plan.

PSE released a request for proposals from all generation sources in December 2005. A final short list was selected in August 2006.

In December of 2006, PSE also released an RFP for a 500 kW solar demonstration facility, which would be the largest in the Pacific Northwest. Eleven proposals from local, national and international bidders were received. A contractor was selected in March 2007. Construction of the project is expected to take place this summer, leading to substantial completion by September 2007.

We completed acquisition of 277-MW natural gas-fired combined cycle plant located in Goldendale, WA in February 2006.

We completed a lease buyout of Whitehorn Units 3 and 4 effective February 2009.

Negotiations and contractual arrangements are underway with the remaining short listed projects selected from PSE's 2005 All Source RFP solicitation.

Negotiations are underway with two renewable biomass projects.

PSE is currently looking to leverage our wind development expertise to move further up the development chain for procurement of wind assets. The goal is to pursue the most promising wind projects in the region that may be in various stages of development.

Complete contractual arrangements and construct the Wild Horse and Hopkins Ridge wind projects.

The Hopkins Ridge wind facility entered commercial service in November 2005 and has produced over 400,000 megawatt-hours of renewable energy for PSE's customers with a project availability of over 98%. The Wild Horse wind facility entered commercial service in December 2006 and has produced over 60,000 megawatt-hours of renewable energy. Combined, the two projects produce approximately 125 aMW of electrical capacity.

Implement the Colstrip turbine upgrade to increase project efficiency (PSE's share of the additional project generation is 25 aMW).

The turbine upgrade projects have been completed on Units 1 and 4. Work on Unit 3 will occur this spring and on Unit 2 in the spring of 2008. Output on both Units 1 and 4 met the contract performance requirements and PSE is receiving about 4 MW additional output from Unit 1 and about 8 to 10 additional MW of output from Unit 4.

New Electric Resources (Long-term)

Explore contract renewal discussions with expiring cogeneration projects to maintain resource availability.

Only one of the three cogeneration projects participated in PSE's 2005 RFP solicitation. The proposed offer was determined to be commercially attractive and was ultimately selected to PSE's short list for further negotiation. PSE has been in active discussions separately with the two remaining cogeneration projects with regard to their proposed restructuring of their existing contracts. In each case, PSE's analysis has indicated that the proposed restructure contains significant commercial and regulatory risk to its customers.

Explore feasibility, partnering opportunities, and transmission alternatives for remote-located coal-fueled and renewable generation.

As coal has become increasingly risky, there was no need to follow-up on devoting significant resources to this effort.

Seek opportunities for emergent technologies including biomass, geothermal, and integrated gasification combined cycle (IGCC).

PSE is actively in negotiations with two biomass projects. Additionally, we short listed one geothermal project from our 2005 All Source RFP solicitation.

IGCC has been tabled until carbon capture and sequestration becomes viable.

B. Natural Gas Resource Acquisition Activities

Energy Efficiency

Develop new gas energy efficiency savings targets for 2006-2007, informed by Least Cost Plan analyses, and file new program tariffs with the WUTC by the end of 2005.

In our April 2005 Least Cost Plan Update, PSE presented an extensive analysis of energy efficiency savings potential and its contribution to the Company's electric portfolio. In collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG), these results were used to develop energy efficiency program targets for 2006 and 2007. A two-year stretch goal for contributions of approximately 420,000 decatherms by the end of 2007 was adopted.

New Natural Gas Resources

Work with Jackson Prairie co-owners to explore deliverability expansion, and work with Northwest Pipeline on related seasonal transportation.

In response to the ongoing growth in natural gas peak day demand requirements in the region and individual requirements of the owners, the owners of Jackson Prairie Storage Project (Northwest Pipeline, Puget Sound Energy, and Avista Corporation) authorized PSE, as the Project Operator, to examine the feasibility of expanding the deliverability of the Project. PSE's analysis in the previous Least Cost Plan and in contemporaneous studies indicated that additional Jackson Prairie deliverability (combined with appropriately priced redelivery service) was the least cost resource. In June 2006, the application for Certificate of Public Convenience and Necessity was filed with FERC for the Jackson Prairie Deliverability Expansion. The Project requested authorization to increase the deliverability from 884,000 Dth per day to 1,196,000 Dth per day. In February 2007, the Project received approval from FERC. The $43.8 million project will be developed over a two year period. PSE's share of this expansion is 104,000 Dth per day and is expected to cost $14.6 million. Major expansion activity slated for 2007 includes drilling of five wells at approximately $1 million each.

Northwest Pipeline (NWP) was asked to determine the availability of any additional firm pipeline capacity from the Jackson Prairie receipt point. NWP identified the availability of approximately 185,000 Dth per day north flow capacity from Jackson Prairie. After public posting of this information, PSE negotiated the acquisition of north-flow TF-1 capacity sufficient to accommodate the incremental 104,000 Dth per day of PSE's additional deliverability and to support additional Jackson Prairie capacity acquired through a release. PSE negotiated a demand charge of 60% of the maximum rate in the five winter months and full demand charge in seven summer months; zero if not used. The 110,700 Dth per day discounted capacity (commencing November 1, 2008 for a 20 year term) was posted for bid in early March 2007, in compliance with the FERC requirement. Following the closure of the auction, the capacity was awarded to PSE. As a condition of the transaction, PSE extended the primary term of selected service agreements with NWP; PSE retained the unilateral evergreen rights under these agreements.

Investigate specific locations for possible conventional and satellite liquefied natural gas (LNG) storage facilities and refine cost estimates for these facilities.

PSE continues to consider the use of LNG plant of any type to solve supply and/or distribution capacity shortfalls.

Consider acquisition of delivered bridging peak-supply resources and (discounted) long-term Northwest Pipeline transportation capacity.

PSE has recently identified a potential delivered peak supply resource (Regional LNG peaking) and has evaluated that option in this IRP.

Since the last plan, PSE has acquired for gas customers 55,000 Dth per day of long term firm transportation at a substantial discount from Duke Energy Trading & Marketing. In addition, PSE has secured an additional 45,000 Dth per day of deeply discounted long-term firm transportation for power generation. PSE has also secured 110,700 Dth per day of long-term discounted seasonal firm transportation to support the Jackson Prairie Deliverability Expansion commencing in 2008.

Continue monitoring developments at the Sumas, Station 2 and AECO markets, and investigate upstream transportation alternatives.

PSE has continued to participate in the gas supply markets available in the Pacific Northwest. It is generally expected that while periodic pricing conditions will favor one producing basin, over the long-run capacity will be developed that will drive equilibrium in prices from one basin to another. PSE remains actively engaged in dialogue with pipelines, developers, and other market participants to explore additional upstream transportation options.

Continue to monitor development and opportunities related to imported LNG in the region.

PSE continues to monitor proposed LNG Import Terminals in the Pacific Northwest and British Columbia. There are eight facilities in the region in various stages of pre-development: 1) Kitimat LNG located in Kitimat, B.C.; 2) Bradwood Landing located in Bradwood, Oregon; 3) Jordon Cove located in Coos Bay, Oregon; 4) Port Westward located in Port St. Helens, Oregon; 5) Skipanon located in Warrenton, Oregon; 6) Gray's Harbor located in Gray's Harbor, Washington; 7) Tansy Point, located in Warrenton, Oregon; and 8) Prince Rupert, located in Prince Rupert, B.C. While some of these proposed projects have made more progress then others in PSE's view there is no clear leader. Many industry observers question whether a LNG import terminal in the Pacific Northwest will be viable. Figure 9-2 summarizes the eight proposed facilities.

Figure 9-2
Summary of Eight Proposed LNG Import Terminals

Project Name and Sponsors	Location and C.O.D	Capital Cost	Capacity (Storage) Deliverability (Thru-put)	LNG Supply	Pipeline Connections	Regulatory / Permit Status
Kitimat Kitimat LNG Rosemary Boulton,Pres. Ilene Schmaltz,VP Mrktg **Galveston LNG:** Alfred Sorenson,CEO	Kitimat, BC Q4-2010	$500 million ($US) (terminal) $1 Billion ($US) P/L)	2 tanks x 160,000 m^{3} = 6.8 Bcf 600 /MMcf day (nominal) 1.0 Bcf / day (peak)	Letter of Intent) with LNG Ltd. Of Australia for 1.8M metric ton/yr. (25% of req'd) signed Sept.2006 .	via Pacific Trails P/L to Westcoast P/L at Station 4b Summit Lake. (Pac. Trail is 50/50 partnership of Galveston LNG and Pacific Northern P/L)	Terminal - Fully permitted Aug.2006 P/L – in prelimdesign Application to BC Util.Comm expected mid 2007
Bradwood Landing Northern Star Natural Gas LLC W.S. (Si) Garrett,CEO Paul Soanes, Pres. Gary Coppedge,VP Dev.	Bradwood, Oregon (Mile 38 on the Columbia River) Q4-2010	$580 million (terminal) $150 million (pipeline) (Secured added funding of $100M –mid 2006)	2 tanks x 160,000 m^{3} = 6.8 Bcf 1.0 Bcf / day (nominal) 1.3 Bcf / day (peak)	Unknown (Recent affiliation with Clearwater LNG project off-shore of Oxnard, CA may provide market diversity for suppliers.)	via Bradwood Landing P/L to interconnect with NWP at Kelso,Wa, also connect to NWN-Mist Storage (and on to GTN via Palomar), and to PGE Pt.Westward/ Beaver plant	FERC Certificate Application for terminal (CP06-365) and P/L(CP06-366)– June 2006
Jordan Cove Energy Projects Development LLC Bob Braddock, Proj.Mgr Elliot Trepper Fort Chicago Energy Partners LP & Guy Turcotte, Chrmn Stephen H.White Pres/CEO	Coos Bay, Oregon Q4-2011	$500 million (terminal) $800 million (pipeline)	2 tanks x 160,000 m^{3} = 6.8 Bcf 1.0 Bcf / day (nominal) 1.2 Bcf / day (peak)	unknown (It is expected that the sell-out of the P/L open season will attract major suppliers, including BP)	via Pacific Connector P/L to interconnect with NWP GrantsPass Lateral and to misc. S.Oregon LDC connects and to GTN, Tuscarora and PG&E at Malin	NEPA/FERC Prefiling – (PF06-25)-- April 2006 FERC Certificate Application for terminal and P/L – planned for Q2 07
Port Westward **Port Westward LNG:** Spiro Vassilopolos	Port St. Helens, Oregon	$400 – 525 million (terminal only)	400,000 m^{3} (2 tanks) 700 MMcf/d average 1.25 MMcf/d peak	unknown	2 lines proposed 24-30 inch to Mist 32 inch to line from Beaver to NWP at Kelso	NEPA/FERC Prefiling - 2006
Skipanon	Warrenton , Oregon (Port of	$500 million	2 tanks x 160,000 m^{3} = 6.8 Bcf	unknown	line to NWP at Kelso	NEPA/FERC Prefiling – expected

LNG Development Co **Peter Hansen** (formerly Calpine)	Astoria)		1.0 Bcf / day (nominal) 1.2 Bcf / day (pk)			mid 2007
Gray's Harbor **Sempra:** Darcel Hulse	Gray's Harbor Washington	unknown	360,000 m^3 (2 tanks) 1 Bcf/d	unknown	70 miles from terminal to NWP just north of Chehalis.	Unknown
Tansy Point **Warrenton Fiber**	Tansy Point Warrenton, Oregon	unknown	unknown	unknown	unknown	Unknown
Prince Rupert **Westpac LNG:**	Prince Rupert British Columbia	$C400 million	1 tank x 160,000 m^3 = 3.4 Bcf 300 MMcf / day (nominal) 500 MMcf / day (peak)	unknown	unknown	Unknown

C. Existing Electric Resource Activities

Conduct plant engineering, environmental studies, geotechnical exploration, and preliminary construction to implement the terms of the Baker Hydroelectric Project Settlement Agreement.

The original FERC license for the Baker Hydroelectric Project expired in April 2006. We are currently operating the project under annual licenses issued by the FERC, pending issuance of a new long-term license, anticipated in 2007.

PSE continues to perform early implementation of certain Settlement Agreement conditions, including construction of new upstream and downstream fish passage facilities. Additionally, we continue to evaluate and design a powerhouse expansion for Lower Baker that will enable compliance with minimum instream flow and down-ramping requirements.

Prepare environmental and historic resource management plans; conduct engineering for plant improvements; consult with resource agencies; and begin

construction activities, all to implement the terms of the 2004 Snoqualmie Falls Hydroelectric Project license.

Design and consultation activities toward construction of major features at the Snoqualmie Falls Hydroelectric Project continue. Such features include a new diversion dam, intakes, and upgrades to the Plant 1 and Plant 2 powerhouses.

Additionally, we are in early consultation with affected stakeholders to address a proposed minor license amendment that would modify the design of the new diversion dam for enhanced flood reduction benefits and incorporate other minor modifications as a result of continuing design and value engineering activities.

Continue contract renewal discussions with the Mid-Columbia PUDs.

PSE recently executed a new 20-year agreement with PUD No. 1 of Chelan County and will begin taking deliveries upon expiration of our current Rocky Reach and Rock Island contracts in 2011 and 2012, respectively.

In 2005, we began taking delivery from PUD No. 2 of Grant County for output from its Priest Rapids Development under the terms and conditions of a new power purchase agreement executed in 2001. We will begin taking deliveries from the PUD's Wanapum Development under the terms and conditions of the 2001 agreement upon the expiration of our current Wanapum contract in late 2009.

We continue to take delivery from PUD No. 1 of Douglas County for output from its Wells Hydroelectric Project under a power purchase agreement that expires in 2018.

D. Analytical and Process Improvements

Demand Forecasting

Refine the long-term geographic area energy and peak load with weather sensitivity, and other key economic factors.

The development of population and economic forecasts by county allowed us to create county level customer counts forecasts by class, thus differentiating customer growth by county. Annual growths in the use per customer by county and class are still the same as for the service territory, but the levels are different based on historical average ratios of use per customer for each county to the total service territory for each of the customer classes. These ratios are a function of fuel saturations, seasonal variations, weather, and mix of customer classes within each county. Peak loads thus vary by county also because of the different mix of customer classes and their energy usage.

Electric Resource Analytics

Explore modifications to PSE's electric portfolio analysis tool to increase flexibility.

In the 2005 LCP we used two portfolio analysis tools, one for supply portfolios and then one to analyze demand-side resources against one selected portfolio. One improvement that was made was to integrate the modeling of demand-side resources into one model. This increased the efficiency of the process and allowed us to perform stochastic analysis of demand-side resources as well as consider them with multiple supply-side portfolios.

Include appropriate consideration of imputed debt, credit requirements, and risk management in evaluating potential new resource acquisitions.

A discussion of the way PSE considers financial issues such as imputed debt, credit requirements and risk management in evaluating potential new resource acquisitions is included Appendix F (Financial Considerations).

Gas Resource Analytics

Incorporate refinements to Sendout/Vector Gas to analyze fixed, banded and market priced gas supply pricing options to support development of long-term hedging strategies.

Refinements to the Sendout/VectorGas analyses to support changes in the long-term hedging strategies were not deemed necessary because only relatively minor updates to PSE's hedging strategies were made.

Conduct additional studies of the potential efficiency of joint LDC/generation fuel planning, including Monte Carlo analysis.

Sendout was used to evaluate the cost-effectiveness of firm pipeline capacity to serve the newly acquired Goldendale Generating Station. These analyses included evaluation of pipeline as well as storage alternatives.

Re-examine design day planning criteria based on updated demand forecast and resource cost assumptions.

Review of the gas design day planning criteria was deferred, as we await review/update of the electric extreme peak hour methodology and temperature criteria. Any further review/update will be done in conjunction with further review of the electric planning standard.

E. Portfolio Operations and Risk Management

Expand long-term gas-for-power risk management capability.

In the 2006 General Rate Case, the WUTC approved the Company's acquisition of an additional line of credit dedicated specifically to augment our commodity hedging practices. For the power portfolio this will improve our ability to more actively and aggressively manage the gas for power portfolio exposure.

Develop operation and analytic methods for integrating wind into PSE's electric portfolio.

Wind projects will typically reside in either PSE's or BPA's control area. The control area operator is responsible for meeting NERC mandated reliability criteria. Projects that reside in the BPA control area are subject to BPA generation imbalance charges. The imbalance charges are derived from the difference between the forecasted hourly generation and the actual generation, and applied in a gradation format. PSE has effectively managed these imbalance charges through minimization of the forecasted and actual generation deviation primarily through utilization of state of the art forecasting technology.

PSE developed analytical models to determine the wind integration costs associated with projects in PSE's control area. As empirical data becomes available, we will analyze this information to either validate or adjust the theoretical values.

Complete development and implementation of the Long-Term Energy Cost Risk Management Strategy to address the risks of both long-term power cost and long-term PGA gas cost.

The Company has completed the research and development work necessary to implement the recommendations from the Long-Term Energy Cost Risk Management strategy. This work included a thorough bench-marking of industry best practices with respect to energy commodity hedging and a significant amount of market research of PSE's customers. The results of these analyses indicates that the industry standard for hedging strategies is currently between on and three years. With the WUTC's recent approval of a dedicated line of credit to augment both the Company's power and natural gas hedging strategies, we are proceeding to develop a revised hedging strategy and acquire the line of credit necessary to support these.

As part of developing the Long-Term Energy Cost Risk Management Strategy, study the value placed by PSE customers on lowering energy price volatility in retail power and gas bills.

As part of our Long Term Energy Cost Risk Management Strategy, the Company undertook several components of market research. We completed in-person interviews, small-sample size focus groups and a web-based survey to better understand customer preferences and trade-offs of rate stability, volatility and cost. From this research we were able to ascertain that about 85% of our gas customers, and 80% of our electric customers surveyed in the focus groups prefer a three-year period of stable rates.

Enhance and better integrate portfolio and risk management systems.

PSE is currently in the process of implementing an integrated portfolio and risk management system.

F. Policy, Regulatory, and Legislative Initiatives

Energy Efficiency

Participate in 2007-2009 Bonneville Power Administration (BPA) Rate Case process to secure a fair share of BPA conservation funding for PSE and other investor-owned utilities.

Work to address regulatory and financial disincentives to utilities for implementing demand-side management.

Develop a recommended approach to address key issues related to demand-response programs, including a cost effectiveness methodology and a cost recovery mechanism.

PSE proposed a performance incentive mechanism for Electric Energy Efficiency and a revenue decoupling mechanism for natural gas. The Commission subsequently ordered the adoption of the Electric Energy Efficiency performance incentive mechanism, but not the gas decoupling proposal.

PSE assessed the cost effectiveness of demand response in this IRP through hourly analysis of peak demand reduction and hourly avoided costs. We performed our economic screening of resources on an hourly basis. Avoided costs of hourly resources were compared against the cost of a winter peak call option through 2012. Starting in 2013, it was valued against the cost of building a single cycle combustion turbine.

Cost Recovery Mechanism. As part of PSE's agreement with Commission staff and other parties to withdraw demand response from our rate case, it was agreed that we could recover the cost of demand response pilot programs through the existing conservation tariff rider. Recovery of costs for any additional programs will be determined by the Company with input from Commission staff and stakeholders prior to filing tariffs for such programs.

New Electric Resources

Participate in ongoing regional efforts to evaluate the costs and risks of transmission for new resources located outside PSE's service territory.

BPA has begun a process, under the Regional Dialog heading, to begin the regional effort to evaluate how to get transmission constructed for economic purposes. PSE generation side is participating in both the planning discussion and the discussion on how to fund new transmission.

Continue to participate in the development and determination of the benefits of a regional transmission organization as well as explore other opportunities to improve transmission availability and access in the region.

PSE is an active member of ColumbiaGrid, which was formed to improve the operational efficiency, reliability and planned expansion of the Northwest transmission grid.

Remain active in appropriate regional initiatives like the Puget Sound Climate Protection Advisory Committee.

CPAC was discontinued in Jan 2005.

Explore the development of a corporate greenhouse gas (GHG) policy for shareholders and customers.

PSE has developed a corporate greenhouse gas policy. To review this policy, as well as a discussion of cost and other related issues, please refer to Environmental Concerns Appendix.

Actively participate in legislative discussions about a Renewable Portfolio Standard for Washington.

PSE participated in legislative discussions about a Renewable Portfolio Standard for Washington prior to the passage of I-937.

Continue to participate in regional initiatives exploring transmission and resource adequacy standards.

PSE has participated in the regional resource adequacy forums that develop recommended energy and capacity standards. The Company has also followed and begun implementation of the Electric Reliability Organization process that essentially provided NERC/WECC enforcement capabilities. Processes are in place to implement the over 900 reliability related requirements that resulted from that process.

Pursue, as necessary, regulatory mechanisms to address financial impediments and disincentives associated with resource acquisitions that are consistent with the Least Cost Plan.

As part of the Least Cost Plan Rulemaking, in 2005 PSE recommended to the WUTC a regulatory mechanism that addresses the financial impediments and disincentives associated with resource acquisitions. As part of that rulemaking, stakeholders discussed the potential advantages and disadvantages of incorporating some form of Commission approval for integrated resource plans. PSE suggested that public interest could benefit from regulatory approval that occurs *before* utilities use society's scarce resources to develop or acquire new energy. Prior to the resource acquisition decision process, there is not enough information available to make a decision, meaning there is little to "approve." Our proposed change would provide all stakeholders an opportunity to provide meaningful input to the resource decision process. In terms of process timing, the new process should come after the IRP and RFP processes, when all meaningful information will be available, but before significant resources are committed to a particular resource. PSE provided a proposal for optional proceedings through which:

- a utility could seek Commission approval of the prudence of a utility's determination of resource need and resource acquisition strategy prior to implementation of an acquisition plan and associated financial commitments.
- particularly with respect to long lead-time resources, a utility could seek Commission approval of decisions to proceed with various phases of a project along the way. Such approval might or might not include commencement of recovery of costs expended as of that point in the project development.
- stakeholders would be provided an opportunity to provide direct feedback to the resource acquisition process decision, rather than just far upstream in the information gathering process and long after the decision is made and utilities are seeking recovery of costs.

As part of its 2006 General Rate Case, PSE recommended to the WUTC a regulatory mechanism that addresses the financial impediments and disincentives associated with the massive costs of transmission investments related to generation resource acquisitions. PSE proposed a new regulatory mechanism to track known and measurable depreciation expense for transmission and distribution investments the Company makes between general rate cases. As proposed, depreciation expenses would be recovered through a surcharge added onto existing tariff schedules. The surcharge would be based on the incremental depreciation expense of natural gas and electric transmission and distribution investment over and above the depreciation expense reflected in existing rates. There would be an annual true-up. The mechanism would allow for recovery of investments in new plants between rate cases, but would not provide for recovery on the investments. The Company will invest $444 million and approximately $500 million in energy (electricity and natural gas) delivery infrastructure during 2006 and 2007, respectively. While customers will benefit from investments in this transmission and distribution plant as soon as the infrastructure is put into service, the Company will not recover the depreciation expense it incurs or any return on its invested capital until the conclusion of its next general rate case following the plant's in-service date. The Commission has in prior orders recognized that it is appropriate to address earnings attrition when there is a growing mismatch between revenues, expenses and rate base. The Company faces such circumstances due to regulatory lag and therefore its depreciation tracker or "known and measurable" rate base adjustment proposals are appropriate. PSE performed detailed attrition studies that demonstrate earnings attrition, thus justifying the mechanism.

G. System Planning

Evaluate opportunities for lower-cost, innovative solutions, which facilitate an appropriate level of system performance at the best long-term cost (such as the TreeWatch and Silicone Injection initiatives).

PSE has continued to fund lower-cost, innovative solutions such as the Tree Watch and Silicon Injection initiatives, which provide system performance at a lower cost. In 2007, the Tree Watch program will continue as an O&M program specifically focused on the transmission corridors in order to remove danger trees that threaten transmission and high voltage distribution facilities, as well as distribution circuits. Also, the cable remediation program will continue to use silicon injection to help remediate more cables in 2007.

Continue to evaluate distributed resources technologies and consider their impact to both gas and electric distribution systems.

PSE strives to incorporate distributed resources (DR) elements into its distribution system facilities planning processes, and is modifying DR screening tools to identify projects with the highest probability of serving the least cost capacity deferral alternative. Currently, we're monitoring and evaluating DR developments at the federal, state and utility levels. PSE continues to search for opportunities to implement DR and adopt effective and workable solutions already developed by the industry.

Continue to evaluate how aging assets are likely to impact system performance and develop remediation plans.

Electric. PSE has several electric system programs to address aging substation, transmission line, and distribution line infrastructure. The primary equipment asset focus of these programs based on reliability is:

- Distribution underground cable systems,
- Transmission and distribution line poles and switches, and
- Substation transformers, circuit-breakers, regulators, circuit-switchers, relays, and batteries.

System performance is reviewed on an annual basis by reviewing the information that is collected by maintenance crews, and through an equipment failure reporting process. Existing equipment remediation programs are modified and new programs developed as required based on new impacts identified during the review process.

Gas. Portions of PSE's gas assets are nearing the end of their useful life and are in need of replacement. PSE has implemented a programmatic approach to the replacement of aging facilities in order to manage impacts to system performance and customers. Examples of these efforts include specific programs targeting the replacement of cast iron and bare steel pipe, both of which are susceptible to increased leakage over time. Gas leakage can directly affect gas reliability and safety depending on the proximity to the customer and the duration a gas main is out of service, so that it can be repaired. The Cast Iron Program will be complete in June 2007 and the Bare Steel program will be complete by the end of 2014.

Continue to develop system models and other technologies that facilitate more accurate, customer- and time-sensitive system evaluations regarding system performance (i.e. Stoner SynerGEE implementation, supervisory control and data acquisition (SCADA), and Automated Meter Reading).

PSE has continued developing and enhancing the system models for the electric and gas infrastructures to be used in analyzing the system capability to serve new and existing customers. The Supervisory Control and Data Acquisition (SCADA) system is being expanded each year to help monitor and control the electrical infrastructure.

Key Definitions and Acronyms

Abbreviation	Meaning
ACQ	annual contract quantities
AECO	gas hub in Alberta, Canada
AFUDC	allowance for funds used during construction
AIM	Area Investment Model, used to calculate financial performance indicators for projects
AMR	Automated Meter Reading
ANOPR	advance notice of proposed rulemaking
ATC	available transmission capacity
AURORA	One of the two models PSE uses for integrated resource planning, which uses the western power market to produce hourly electricity price forecasts of potential future market conditions
BACT	best available control technology (required of new power plants and those with major modifications)
BcF	billion cubic feet
BEF	Bonneville Environmental Foundation
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CAMR	clean air mercury rule (requires that coal plants reduce at least 30% of their mercury emissions by 2010, and at least 70% by 2018)
CCCT	combined cycle combustion turbines (see Appendix D)
CCS	carbon capture and sequestration
CCX	Chicago Climate Exchange
CDD	Contract Daily Demand
CDEAC	Clean and Diversified Energy Advisory Committee formed by the WGA to identify incentive-based, non-mandatory recommendations that would facilitate 30,000 megawatts of new clean and diverse energy by 2015, a 20% increase in energy efficiency by 2020 and adequate transmission for the region)
CFB	circulating fluidized bed (see FB)
CHP	combined heat and power plant (a more efficient use of non-renewable generation units because the CHP unit captures waste heat and uses it)
C/I	commercial/industrial
CLX	PSE's customer service information system
COE	U.S. Army Corps of Engineers
CNG	compressed natural gas
CPUC	California Public Utility Commission
CRAG	Conservation Resource Advisory Group
C&RD	BPA's conservation and renewables discount
CTED	Washington State Department of Community, Trade & Economic Development
CVR	conservation voltage reduction
DER	distributed energy resources

iii. Key Definitions and Acronyms

Abbreviation	Meaning
DETM	Duke Energy Trading and Marketing
DG	distributed generation. Small modular, decentralized, grid-connected or off-grid energy systems located near where energy is used
DIMP	Distribution integrity management program implemented by the Pipeline and Hazardous Materials Safety Administration
DOE	Department of Energy
DP	distributed power
DR	demand response (see Appendix D)
DR	district regulators
DSM	Demand Side Management
EA	environmental assessment
EFP	exchange for physical
EIA	U.S. Energy Information Agency
EITF	Emerging Issues Task Force (see Appendix F, section B)
EO	Executive Order (of Governor Christine Gregoire outlining goals for addressing climate change)
EPA	Energy Policy Act
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERO	Electric Reliability Organization
ESP	electrostatic precipitator
EV	expected value (see Appendix J, section B)
FASB	Financial Accounting Standards Boards (see Appendix F, section B)
FB	fluidized bed (technology that mixes coal and an inert bed material such as sand in a combustor or boiler)
FEED	Front End Engineering Design (a study to develop the design envelope for IGCC; see IGCC section in Appendix D)
FEIR	Final Environmental Impact Report (filed by Cape Wind offshore wind farm)
FERC	Federal Energy Regulatory Commission
FF	fabric filter
GCM	general circulation models
GDP	gross domestic product
GHG	greenhouse gas
GP	Georgia Pacific
GTG	gas turbine generator (see CCTC section of Appendix D)
GTN	Gas Transmission Northwest
HAP	hazardous air pollutants
HC	Hadley Centre (model used to calculate hydro availability change)
HDD	heating degree days
HELM	Hourly electric load model (used to develop a 2002 demand profile, which was replaced by PSE's hourly load profile of electric demand). See Appendix H, section 3.
HP	high-pressure
HRSG	heat recovery steam generator (see CCCT section of Appendix D)
HVAC	heating, ventilation and air conditioning

iii. Key Definitions and Acronyms

Abbreviation	Meaning
ICNU	Industrial Customers of Northwest Utilities
iDOT	Investment Optimization Tool to identify a set of projects that will create maximum value
IEEE	Institute of Electric and Electronic Engineers
IGCC	integrated gasification combined cycle (generally refers to a model in which syngas from a gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier)
IP	intermediate pressure
IPCC	Intergovernmental Panel on Climate Change
IPP	Independent power producers
IRP	Integrated Resource Plan
IRPAG	Integrated Resource Plan Advisory Group
ISO	independent system operator
JISAO	Joint Institute for the Study of Atmosphere & Ocean
JP	Jackson Prairie
LCP	least cost plan (IRP)
LCPAG	Least Cost Plan Advisory Group (IRPAG)
LDC	local distribution company
LFG	landfill gas
LNP	liquefied natural gas
LOLP	loss of load probability
LP	linear program (see Appendix J, section A)
LP-Air	vaporized propane air
L/R Bal	load/resource balance (demand/availability)
MCFC	molten carbonate fuel cells
MDQ	maximum daily quantity
MEPA	Massachusetts Environmental Policy Act
MPI	Max Plank Institute Model
MSW	municipal solid waste
MUST	Managing & Utilizing System Transmission
NAAQS	National Ambient Air Quality Standards (set by the EPA, which enforces the Clean Air Act, for six criteria pollutants: sulfur oxides, nitrogen dioxide, particulate matter, ozone, carbon monoxide and lead)
NARUC	National Association of Regulatory Utility Commissions
NAS	National Academy of Sciences
NCEP	National Commission on Energy Policy
NEEA	Northwest Energy Efficiency Alliance
NERC	North American Electric Reliability Council
NGCC	natural gas combined cycle
NPCC	Northwest Power and Conservation Council
NPP	nuclear power plant (a thermal power station in which the heat source is one or more nuclear reactors)
NRDC	National Resources Defense Council
NREL	National Renewables Energy Laboratories
NSPS	new source performance standards (new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction)

iii. Key Definitions and Acronyms

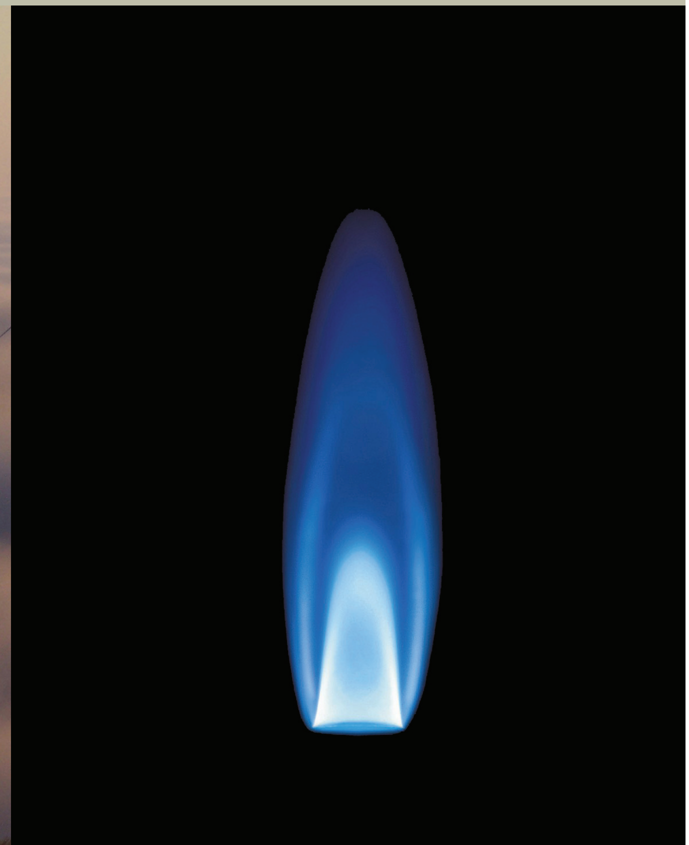
Abbreviation	Meaning
NTAC	Northwest Transmission Assessment Committee (established in 2003 to approach transmission issues from a perspective influenced by both commercial and reliability needs)
NUG	nonutility generator
NWIGU	Northwest Industrial Gas Users
NWP	Northwest Pipeline (only pipeline directly to west WA)
NWPCC	Northwest Power Planning & Conservation Council
NWPP	Northwest Power Pool
NWS	BPA's None-wire Solutions Roundtable
NYMEX	New York Mercantile Exchange
OASIS	Open Access Same-Time Information System
OPS	Office of Pipeline Safety
OSU	Oregon State University
P	probability
PAFC	phosphoric acid fuel cells
PBA	power bridging agreement (designates PPAs that bridge the period until long-lead resources or transmission can be developed)
PC	pulverized coal (technology that grounds coal into fine powder that is mixed with air and blown into the boiler furnace to be burned)
PCA	power cost adjustment (electric)
PCORC	power cost only rate case
PEM	proton exchange membrane fuel cells
PFBC	pressurized fluid bed combustion (the boiler uses FB technology at elevated operating pressures to produce heat for steam production and pressurized gas to drive a gas turbine)
PGA	purchased gas adjustment
PG&E	Pacific Gas & Electric
PGSS	peak gas supply service
PHMSA	Pipeline & Hazardous Materials Safety Administration
PM	particulate matter
portfolio	specific mix of generic power resources
PPA	purchased power agreement (a bilateral wholesale or retail power short term or long term contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point).
PPM	parts per million
PSE	Puget Sound Energy
PSIA	Pipeline Safety Improvement Act
PSIG	pounds per square inch gauge
PSM	portfolio screening model (one of the two models PSE uses for integrated resource planning, which tests electric supply and demand portfolios to evaluate PSE's long-term revenue requirements for incremental portfolio)
PTC	production tax credit
PTI	Power Technologies, Inc.
PUD	public utility district
PV	photovoltaic
REAP	Renewable Energy Advantage Program

iii. Key Definitions and Acronyms

Abbreviation	Meaning
REC	renewable energy credit
RFP	request for proposal
RGGI	Regional Greenhouse Gas Initiative; a cooperative effort between northeast states mandating electric utility emissions reductions
RMATS	Rocky Mountain Area Transmission Study (see Appendix E)
RPS	renewable portfolio standard (mandates 3% renewables by 2012, 9% by 2016 and 15% by 2020))
RTO	regional transmission organization
SCADA	supervisory control and data acquisition
SCCT	Simple cycle combustion turbine (see Appendix D, section C)
scenario	consistent set of data assumptions to define a specific future; takes holistic approach to uncertainty analysis
SCGT	simple cycle gas turbines
SCPC	super critical pulverized coal (see PC)
SENDOUT	PSE's model used to help identify the long-term least cost combination of gas resources to meet stated loads.
SOFC	solid oxide fuel cells
STG	steam turbine generator (see Appendix D)
TCPL-Alberta	TransCanada's Alberta System
TCPL-British Columbia	TransCanada's British Columbia System
T&D	transmission and distribution
TIG	Transmission Issues Group
TRC	total resource cost
UCPC	ultra critical pulverized coal (see PC)
USEIA	U.S. Energy Information Agency
VectorGas	facilitates the ability to model price and load uncertainty
WECC	Western Electric Coordinating Council
WGA	Western Governors' Association (see Appendix E)
WUTC	Washington Utilities and Transportation Commission

MAY 2007

Integrated Resource Plan — Appendices



PSE PUGET SOUND ENERGY
The Energy To Do Great Things

Appendices

2007 Integrated Resource Plan

Public Participation

PSE is committed to public involvement in the planning process. Stakeholder meetings generated valuable constructive feedback during this planning cycle, and the suggestions and practical information we received from both organizations and individuals helped to guide the development of this 2007 Integrated Resource Plan. We wish to thank all who participated.

As of the date this plan draft was filed with the WUTC, seven formal Integrated Resource Plan Advisory Group (IRPAG) meetings, five Conservation Resource Advisory Group (CRAG) meetings, and dozens of informal meetings and communications have taken place. Stakeholders who actively participated in one or more meetings include WUTC staff, the Public Counsel, Northwest Industrial Gas Users, Northwest Pipeline, conservation and renewable resource advocates, the Northwest Power and Conservation Council, project developers, other utilities and the Washington State Department of Community, Trade and Economic Development (CTED).

This appendix briefly describes the purpose of the IRPAG and CRAG, and summarizes the formal meetings held to date. We especially want to thank those who attended these meetings for the time and energy they invested, and we encourage their continued participation. The IRPAG covers all elements of the IRP, while the CRAG focuses on energy efficiency and demand-side resources. While these two groups meet separately, they have many members in common.

I. Integrated Resource Planning Advisory Group (IRPAG)

PSE works with external stakeholders through an informal group referred to as the Integrated Resource Plan Advisory Group (IRPAG). The IRPAG is the primary means of satisfying the requirements of WAC 480-100/90-238 for public involvement. During the development of the 2007 IRP, PSE engaged the IRPAG in two ways, in a series of structured IRPAG meetings and in individual meetings with various IRPAG members.

As part of the formal IRPAG meetings, we presented and discussed each building block in developing the IRP, often stepping through significant levels of detailed analysis. Additionally, we invited several guest speakers to talk about relevant topics, such as carbon sequestration, regional LNG import developments, and regional resource adequacy. IRPAG meetings are open to all comers, including individual customers and other utilities.

In addition to the more structured IRPAG meetings, PSE met with individual IRPAG members, on a one-on-one basis. Such meetings have proven to be very productive, allowing a freer flow of ideas that would have been difficult to achieve in a group setting. PSE has found the combination of one-on-one meetings followed by a group meeting to be particularly helpful in generating feedback.

Our discussions with IRPAG members provide new avenues for broadening the scope of information available to us in our planning process. Additionally, our interactions with IRPAG members enhance our thinking by bringing a variety of perspectives to the process. PSE has found the IRPAG process to be valuable and will continue to work toward improving upon our success.

II. Conservation Resources Advisory Group (CRAG)

The CRAG was formally established as part of the settlement of PSE's 2001 General Rate Case, which the WUTC approved in Docket No. UE-11570 and UG-011571. The group specifically works with PSE on development of energy efficiency plans, targets and budgets. The CRAG consists of ratepayer representatives, regulators, and energy efficiency policy organizations, including the following stakeholder groups:

- WUTC staff
- Public Counsel, Attorney General's Office
- Industrial Customers of Northwest Utilities (ICNU)
- Northwest Industrial Gas Users (NWIGU)
- NW Energy Coalition and Natural Resources Defense Council
- Energy Project (representing Low Income Agencies)
- Washington State Department of Community, Trade and Economic Development
- Customer representatives from commercial, industrial and institutional sectors (Microsoft, Kemper Development, King County)

The CRAG participated in the development of the PSE's 2007 IRP and energy efficiency program review through a series of formal meetings in which they reviewed and offered feedback on the assessment of all demand-side resources (energy efficiency, fuel conversion, and demand response). Many members also participated in other aspects of the IRP advisory process as well.

No significant concerns about the IRP demand-side potential results have been expressed. Issues with the highest level of interest included avoided costs; the cost-effectiveness screen used to determine economic potential; and the rationale and assumptions used to estimate achievable resource potential. Looking ahead, the CRAG will likely focus on how the 2007 IRP results are factored into demand-side savings targets, and programs and budgets for 2008–2009.

III. Summary of IRPAG and CRAG Meetings

A. CRAG Meeting, September 28, 2005

This meeting covered future gas price forecasts, end-of-year forecasts for PSE's 2004–2005 energy efficiency programs, energy efficiency targets and barriers, 2006–2007 energy efficiency program highlights, a program evaluation update, and the Green Utility Assessment.

B. IRPAG Kick-off Meeting, February 16, 2006

This meeting included an overview of the new IRP rule, a discussion of the new gas price forecast model (PSE switched from CERA to Global Insight), a look at our new planning process, an overview of our work plan for the 2007 IRP, and updates on the 2005 All Source and Energy Efficiency RFPs. The natural gas resources group presented an acquisition update; our vice president of energy efficiency introduced PSE's Green Utility Assessment project; and the meeting closed with our vice president of energy resources leading a discussion about PSE's need and the current planning environment.

C. IRPAG Meeting, April 20, 2006

Our supply-side and energy efficiency acquisition teams shared details about our 2005 All Source and Energy Efficiency RFP processes, and a status update for each RFP. Representatives from Kitimat LNG, Jordan Cove and Northern Star/Bradwood discussed the LNG situation in our region and presented information about their respective projects. PSE's green power group updated our Green Utility Assessment project. The meeting closed with up with a look at the draft 2007 IRP work plan and a discussion of next steps.

D. IRPAG Meeting, June 22, 2006

PSE's vice president of energy resources opened the meeting with a discussion of the current planning environment. An overview of our IRP development process followed, including an opportunity to discuss PSE's analytic approach and the questions we should answer in the current IRP. PSE distributed a draft outlining the resources we planned to explore and the scenarios we planned to test. This meeting included an update from the 2005 All Source and Energy Efficiency RFP teams. Our natural gas resources manager summarized the status of our Jackson Prairie expansion project.

Climate Trust presented an informational overview of climate change and the role of project-based emissions reductions. The Northwest Power and Conservation Counsel discussed resource adequacy in the Pacific Northwest.

E. IRPAG Meeting, October 26, 2006

This meeting began with an overview of changes to our planning process since the 2005 LCP, which have affected demand resource analysis, risk metrics, and the application of Monte Carlo analysis. This was followed by a review of our electric analytic process, assumptions, and scenarios. Copies of our draft scenario matrix were distributed, and we summarized PSE's gas analytic process, alternatives, and scenarios. PSE's acquisition team offered a brief look at our 2005 All Source RFP short list.

The meeting ended with a presentation by the Big Sky Carbon Sequestration Partnership about current carbon sequestration technology, and efforts to test this technology in a trial situation.

F. CRAG Meeting, November 3, 2006

Topics for this meeting included PSE energy efficiency staff reassignments; an update on the RFP process; a summary of energy efficiency residential and commercial programs; end-of-year forecasts for electric and gas savings; a program evaluation update; a discussion of potential demand response programs and objectives; and a discussion of topics for future meetings.

G. IRPAG Meeting, December 8, 2006

The meeting convened with a status report on our planning process. We presented draft electric scenario results and an overview of our electric planning adjustment for demand resources (adjustment equals portfolio cost minus market cost). We also discussed electric capacity load and resources for PSE and the region. A brief discussion of avoided capacity cost wrapped up the planning portion of this meeting.

PSE's acquisition team delivered a status update on the 2005 All Source RFP short list, as well as more details about the Goldendale and Whitehorn transactions. We shared information about our proposed Wild Horse solar project and the resulting solar RFP, followed by a general overview of solar technologies.

H. CRAG Meeting, December 8, 2006

This meeting provided a more comprehensive background on demand response potential programs and issues; a more detailed look at the methodology for estimating achievable potentials for gas and electric energy efficiency; fuel conversion; distributed generation potential; a discussion of analytical methodology; and the role of the IRP among other program target considerations.

I. CRAG Technical Workshop, January 4, 2007

We discussed draft demand-side resource potential results for the 2007 IRP.

J. IRPAG Meeting: January 18, 2007

A discussion of PSE's 2006 demand forecast model and results opened the meeting. Our analysts shared information about PSE's electric and capacity needs over the planning period. We briefly touched on our electric modeling process, requested feedback on our portfolios (as well as the resource strategy questions that we will answer with those portfolios), and an overview of our demand resource assumptions. On the gas side, we discussed our load-resource balance, the current supply situation and outlook, and supply expansion alternatives.

PSE's resource acquisition manager presented a status update on the seven projects selected from our 2005 All Source RFP. This included the Goldendale acquisition, which is subject to the bankruptcy process, and a brief look at next steps for the acquisition team once RFP negotiations are concluded. A quick report on the 2007 Solar RFP brought the meeting to a close with a look at highlights from the January 11th bidders meeting and an overview of the process timeline.

K. CRAG Meeting, January 18, 2007

This meeting reviewed the final results for demand-side resource potentials to be incorporated into the 2007 IRP, and an update on developments in demand-response potential programs.

L. IRPAG Meeting: March 1, 2007

This meeting began with an update from our Resource Acquisition team. The Resource Planning group followed with a summary of our initial IRP conclusions and key findings, with the caveat that we were still involved in the process of reviewing the results. The quantitative results of the electric, gas and DSM analyses were presented. The meeting concluded with an overview of PSE's new GHG Policy and goals.

M. IRPAG Meeting: April 26, 2007

This meeting began with an overview of our 2007 IRP findings. Stakeholders were encouraged to provide feedback on the current plan, and to make suggestions for the next planning process.

Legal Requirements

PSE is submitting this IRP pursuant to state regulations contained in WAC 480-100-238 regarding electric resource planning, and WAC 480-90-238 regarding natural gas resource planning. Tables B-1 and B-2 delineate the regulatory requirements for electric and natural gas integrated resource plans, and identify the chapters of this plan that address each requirement.

This IRP is the product of a robust analysis that considered a wide range of future risks and uncertainties. We believe this plan meets applicable statutory requirements, and seek a letter from the WUTC accepting this filing.

Figure B-1
Electric Integrated Resource Plan Regulatory Requirements

STATUTORY/REGULATORY REQUIREMENT	CHAPTER
WAC 480-100-238 (3) (a) A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses.	• Chapter 4, Demand Forecasts
WAC 480-100-238 (3) (b) An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	• Chapter 5, Electric Resources
WAC 480-100-238 (3) (c) An assessment of a wide range of conventional and commercially available nonconventional generating technologies.	• Chapter 5, Electric Resources
WAC 480-100-238 (3) (d) An assessment of transmission system capability and reliability, to the extent such information can be provided consistent with applicable laws.	• Chapter 7, Delivery System Planning
WAC 480-100-238 (3) (e) A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using the criteria specified in WAC 480-100-238 (2) (b), Lowest reasonable cost.	• Chapter 5, Electric Resources • Appendix I, Electric Analysis

WAC 480-100-238 (3) (f) Integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and projected future needs at the lowest reasonable cost to the utility and its ratepayers.	• Chapter 5, Electric Resources • Chapter 8, Choosing a Strategy
WAC 480-100-238 (3) (g) A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.	• Chapter 9, Action Plans
WAC 480-100-238 (3) (h) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.	• Chapter 9, Action Plans
WAC 480-100-238 (4) Timing. Unless otherwise ordered by the commission, each electric utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.	• 2007 Integrated Resource Plan Work Plan filed with the WUTC May 30, 2006 • Chapter 9, Action Plans
WAC 480-100-238 (5) Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.	• Public Participation Appendix

Figure B-2
Gas Integrated Resource Plan Regulatory Requirements

STATUTORY/REGULATORY REQUIREMENT	CHAPTER
WAC 480-90-238 (3) (a) A range of forecasts of future natural gas demand in firm and interruptible markets for each customer class that examine the effect of economic forces on the consumption of natural gas and that address changes in the number, type and efficiency of natural gas end-uses.	• Chapter 4, Demand Forecasts
WAC 480-90-238 (3) (b) An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements.	• Chapter 6, Natural Gas Resources
WAC 480-90-238 (3) (c) An assessment of conventional and commercially available nonconventional gas supplies.	• Chapter 6, Natural Gas Resources
WAC 480-90-238 (3) (d) An assessment of opportunities for using company-owned or contracted storage.	• Chapter 6, Natural Gas Resources
WAC 480-90-238 (3) (e) An assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	• Chapter 6, Natural Gas Resources
WAC 480-90-238 (3) (f) A comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness.	• Chapter 6, Natural Gas Resources
WAC 480-90-238 (3) (g) The integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.	• Chapter 6, Natural Gas Resources • Chapter 8, Choosing a Strategy

WAC 480-90-238 (3) (h) A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.	• Chapter 9, Action Plans
WAC 480-90-238 (3) (i) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.	• Chapter 9, Action Plans
WAC 480-90-238 (4) Timing. Unless otherwise ordered by the commission, each natural gas utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.	• 2007 Integrated Resource Plan Work Plan filed with the WUTC May 30, 2006 • Chapter 9, Action Plans
WAC 480-90-238 (5) Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.	• Public Participation Appendix

Environmental Matters

This appendix contains a wide range of information that relates to the environmental concerns PSE faces and seeks to address.

1. PSE Greenhouse Gas Policy

Many scientists and policymakers believe climate change may prove to be the most important business issue of the 21st century. The question for many business leaders is no longer "Is there human-caused climate change?" but (1) "How intense will the impacts be?" and (2) "What are feasible and economically viable solutions to the intensity of those impacts?"

Based on the level of federal activity surrounding climate change and the momentum the issue is gaining elsewhere, both at the local level and as an ever-increasing number of U.S. companies abandon the view that more research on climate change is needed before reducing GHGs is warranted, it is apparent that climate change legislation is moving in the direction from being almost "unthinkable" to being a "strong possibility." Additionally, as recent as December 1, 2006 the leaders of public utility commissions in California, Oregon, Washington, and New Mexico signed a pact agreeing to collaborate on strategies to fight climate change. In it, they agree that their "regulatory oversight ensures that the utilities operate in a manner that protects the environment and human health and safety, and protects ratepayers from economic risks of failure to plan for future regulation of emissions that cause climate change."

PSE realizes the importance of assuming leadership in devising new strategies to address climate change, even before such measures are mandated. As a first step, PSE has developed a climate change policy. The policy provides a guiding sense of the challenges we face, our obligation as a utility, and the solutions we see are feasible. Our climate change policy statement appears on the next page.

Greenhouse Gas Policy Statement

Puget Sound Energy (PSE) recognizes and concurs with the growing concern that increased atmospheric concentrations of greenhouse gases contribute to climate change and that such change can have global adverse economic and social consequences. While motor vehicles and the transportation industry emit a significant amount of all such greenhouse gases, PSE also recognizes that most of the world still relies on fossil fuels for much of its electric power and heating needs. Further, affordable electric power is essential to the long term growth and income prospects for the peoples of the world, including the PSE service territory. Accordingly, it is crucial that climate change policies balance a number of competing short-term and long-term interests to moderate the growth in greenhouse gas emissions while encouraging growth of the economy.

PSE believes that climate change is a very important issue that requires careful analysis and reasoned responses from policy makers. To that end, PSE advocates a national strategy that achieves both short-term measures designed to lessen the growth of greenhouse gas emissions and long-term strategies that will ultimately manage greenhouse gas emissions to appropriate levels in a cost-effective, scientifically sound, and sustainable fashion. In furtherance of the strategy that reduces near-term growth of greenhouse gases, PSE's policy is to take cost-effective measures to mitigate and/or offset greenhouse gas emissions from our energy activities while maintaining a dependable, cost-effective and diverse energy portfolio mix that will sustain our customers' needs now and into the future. The specific near-term strategies PSE will continue to explore and implement include the following:

1. Pursuit of a diverse energy portfolio mix of resources that includes renewable generation;
2. A Pledge to work with our partners in the utility industry, state government and national government to explore and evaluate opportunities to reduce greenhouse gas emissions;
3. Continue and develop a strong energy efficiency program;
4. Support the advancement of scientific understanding of climate change;
5. Support a market-based national system (e.g., "cap and trade" or carbon tax) or sub-national system that covers a large enough area to prove cost effective and useful;
6. A call for the removal of barriers and disincentives to the advancement of the aforementioned recommendations (e.g., governmental facilitation of transmission from renewable energy projects), and
7. Government incentives that will foster the development of renewable generation and other greenhouse gas reducing technologies.

Energy drives the economy. Sustainable energy is an essential component of sustainable development. Global and national problems ultimately require global and national solutions. However, PSE believes it is taking and will continue to take appropriate steps to meet the goal of providing cost effective and reliable energy while decreasing the impact on climate change through the implementation of these measures.

PSE's Emissions

During 2006, PSE's total electric retail load of 21,099,045 aMW was served from a supply portfolio of owned and purchased resources. Since 2002, we have voluntarily undertaken an inventory of the greenhouse gas (GHG) emissions associated with our portfolio. This inventory follows the protocol established by the World Resource Institute GHG Protocol (GHG Protocol). The most recent data indicate that PSE's total GHG emissions (direct and indirect) from its electric supply portfolio in 2005 were 12,999,051 tons (CO_2e). Approximately 54.3% of these emissions (7,058,313 tons) are associated with PSE's ownership and contractual interests in the 2200 MW Colstrip, Montana coal-fired steam electric generation facility.

PSE first acquired interest in the Colstrip, Montana coal-fired steam electric generation facility in 1975 and currently owns a percentage interest in each of the four units (PPLM is the Facility operator). Colstrip is a significant part of the diversified portfolio we own and/or operate for our customers. It has been and remains an important element of the overall generation and supply mix essential to meet the ongoing needs of our customers reliably and cost-effectively. However, our overall resource strategy demonstrates a concerted effort to meet customer needs with a diversified mix of supply options that includes significant energy efficiency efforts, increased renewable generation, and hydro and gas-fired generation.

Our Goal: Reduce Emission Intensity

With ongoing development of state and federal initiatives intended to address climate change, the challenge to develop strategic solutions is more complicated than ever. However, PSE believes that now is the time to act. Consequently, PSE is proposing to meet its own portfolio emissions goals that will adhere to the objectives stated in the Greenhouse Gas Policy Statement.

It is clear that the performance standards passed by California and proposed by Washington are very stringent compared to actions being taken elsewhere in the nation, but because PSE relies on the California interchange, we will participate directly in the impacts produced by them. For this reason and for the reasons presented in our policy, PSE is proposing a goal to meet the California standard of capping emission rates on new resources at an estimated 1100 lbs. of CO_2/MWh. Furthermore, we will adopt a carbon emission goal to not exceed that 1100 lbs. of CO_2/MWh for the entire portfolio, on a 5-year rolling average. We anticipate we will meet this standard through significant investments in energy efficiency programs, additional investments in renewables, and the use of highly efficient combined-cycle natural gas-fired plants.

2. Climate Change Overview

PSE has been active in environmental issues such as conservation and renewable resources for some time, and we believe it is the responsibility of both companies and individuals to take action now to address global warming.

In 2006, the popular media brought the issue of climate change to the forefront. Although PSE's 2005 Least Cost Plan did not explicitly discuss the impact of climate change on our Company's operations, we implicitly recognized the issue in our 2006 Current Momentum and Green World scenarios, which included carbon charges based on cap-and-trade regimes set forth by the National Commission on Energy Policy (NCEP) and the McCain-Lieberman proposal.

We explicitly recognize these concerns in our 2007 IRP. The basic reference case, called Current Trends, includes a carbon charge based on the NCEP proposal; and our Green World scenario incorporates substantial increases to emission charges. In addition to modeling possible legislative outcomes, PSE is actively engaged in forming a consensus on reasonable legislation such as that proposed by Senator Bingaman.

Discussions of climate change can be both complex and contentious. This appendix attempts to explain facts as simply as possible, describe the connections (global, regional, PSE, and customers), and present good science and reasonable public policies. Much of this explanation is based on information from the Climate Impacts Group at the University of Washington; the book *The Weather Makers* by Tim Flannery (© 2005, Atlantic Monthly Press); and the Intergovernmental Panel on Climate Change, Fourth Assessment Report of February 2007.

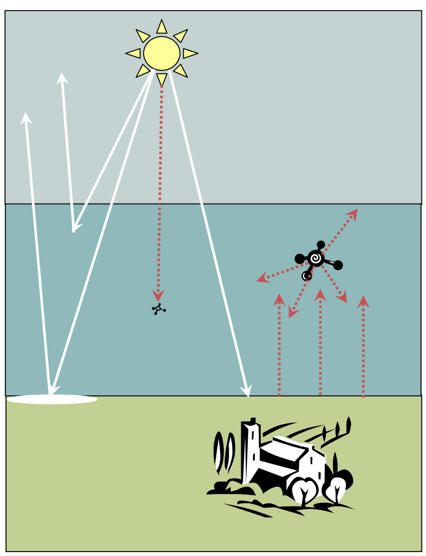
Understanding climate change can be simplified into three questions: What is the greenhouse gas effect? What do we know about CO_2 levels historically and currently? What evidence do we have that temperatures are increasing over time? We then consider possible impacts worldwide, on the Northwest, and on PSE—particularly the effect of temperature on precipitation and electric demand. We conclude with measures PSE currently supports to make a difference.

I. What is the Greenhouse Effect?

Solar radiation hits Earth in waves of different lengths. The smaller ones are x-rays and ultraviolet rays. Next are the most common wavelengths, visible light. Larger waves include infrared and various radio waves. Solar radiation can be reflected back into space by the atmosphere and by Earth—particularly when it hits the white icecaps. Molecules in the atmosphere absorb some radiation, but most is absorbed by Earth (Figure C-1).

The greenhouse effect focuses on visible light waves that pass through the atmosphere, are absorbed by the planet, and are then re-emitted as infrared radiation (heat). A common example is the south side of a house—light absorbed during the day is emitted as warm infrared radiation when the sun goes down. Its longer wavelength allows it to be captured by greenhouse gases (CO_2 and methane are the most common) and emitted again into the atmosphere.

Figure C-1
The Greenhouse Effect



- Radiation from Sun – mostly visible light, plus IR, UV, others.
  - Reflected by atmosphere
  - Reflected by earth (ice)
  - Absorbed by atmosphere
  - Absorbed by earth (most)
- IR Radiation (heat) Emitted from Earth
  - GHGs absorb IR in atmosphere, then re-emit back to Earth
- Higher Temps result from greater levels of GHGs

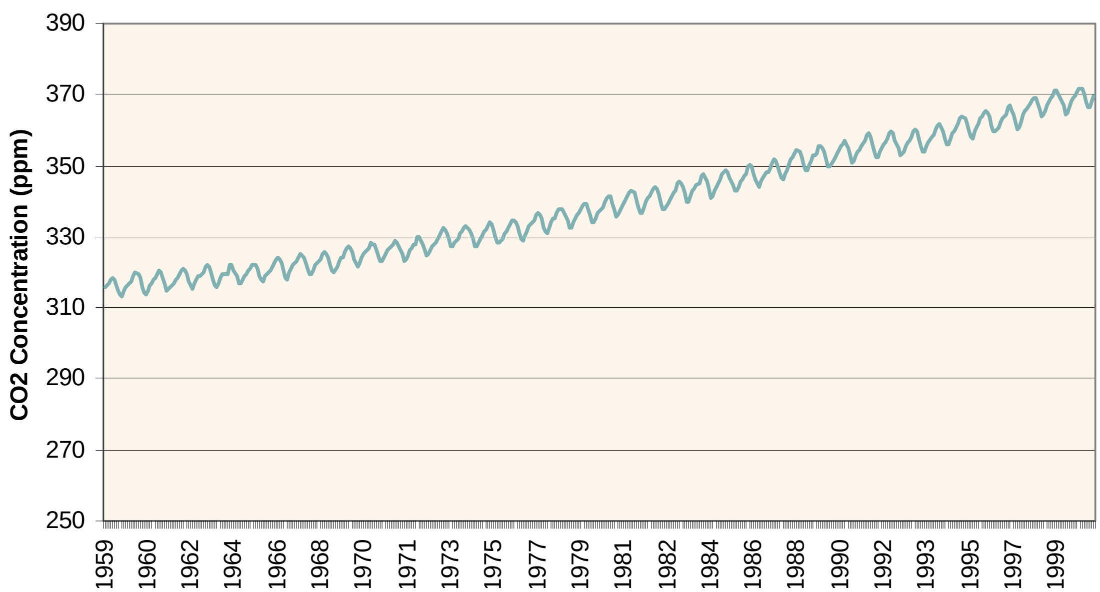
More CO_2 in the atmosphere means more infrared radiation stays in the Earth's atmosphere and less escapes back into space. This leads to higher atmospheric temperatures—also known as global warming.

II. What do we know about CO_2 levels?

There are two sources of historical CO_2 measurements. The first uses ancient evidence such as air bubbles trapped in icecaps up to thousands of years old. These indicate that CO_2 concentrations have fluctuated, dropping down to 160 parts per million (ppm) during the coldest periods and rising as high as 280 ppm during warm periods. Just before the industrial revolution (c. 1800),[1] the level of atmospheric CO_2 was at the 280 ppm level.

The other source, direct measurement, has only been possible for a few decades. A well-known set of data was collected near Hawaii, far from any large sources of CO_2 emissions. Figure C-2 shows two effects. First, the sinusoidal wave is the earth's annual cycle: Atmospheric CO_2 rises in fall/winter when grasses decompose and trees shed their leaves, releasing CO_2; it declines in spring/summer as plants grow and absorb CO_2. In addition to these semiannual variations, the graph clearly shows increasing CO_2 over time. In 1958 the CO_2 level was up to 315 ppm, and it is currently close to 370 ppm.

Figure C-2
Atmospheric CO_2 Concentration 1959 - 1999



[1] *The Weather Makers*, page 29.

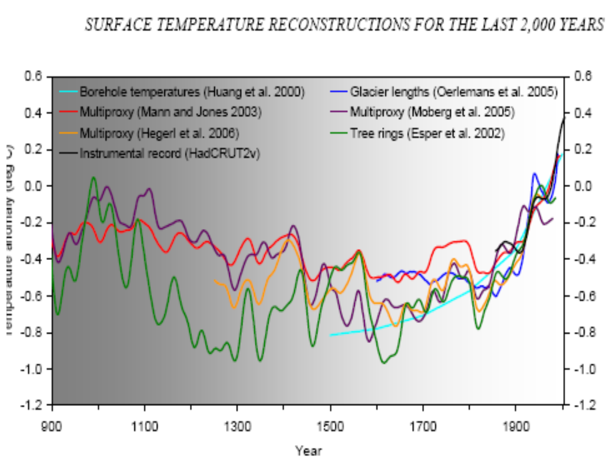
III. What evidence do we have that atmospheric temperatures are increasing?

Determining temperatures during ancient times is not an exact science. Many studies have looked back hundreds of years and a few have looked back 2,000 years. Without direct measurements, scientists use proxy indicators such as documentary and historical evidence, tree rings, marine proxies, ice cores, etc. One study in particular (Mann, 2003) has become a captive of politics, used as key evidence by former Vice President Al Gore and attacked in 2006 by former House Energy Committee Chair Joe Barton (R-TX).

In an effort to rise above partisan politics, The House Committee on Science asked the National Academy of Sciences (NAS) to review available studies to determine both variations of and certainty about Earth's temperature over the last 2,000 years. The NAS study concluded that the older the time period considered, the less certain the results. "Very little confidence" can be assigned (at this time) to results older than 900 years. However, it can be said with a "high level of confidence" that temperatures over the last 20 years are higher than during any period over the last 400 years.

The latter conclusion is based on the fact that results from many different studies, using different and unrelated methodologies, converge over time. These scientific analyses create a compelling body of evidence that global warming is occurring.

Figure C-3
Consensus on Warming, June 2006



"I think this report shows the value of Congress handling scientific disputes by asking scientists to give us guidance. The report clearly lays out a scientific consensus position on the historic temperature record. One element of that consensus is that the past few decades have been the hottest in at least 400 years."

Science Committee Chairman
Sherwood Boehlert (R-NY)

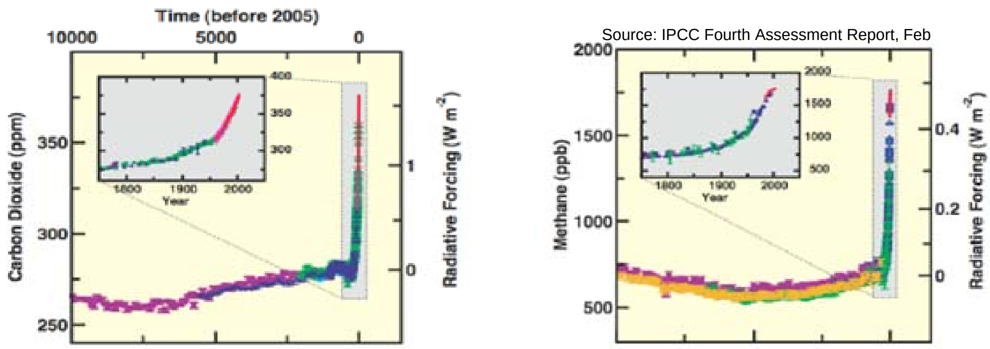
IV. Global Scientific View

In February 2007, the Intergovernmental Panel on Climate Change (IPCC) published its *Fourth Assessment Report* based on the results of earlier studies and six years of research. Its Working Group I, composed of scientists from around the world, made the following conclusions in the section "The Physical Science Basis"[2]:

- Global atmospheric concentrations of carbon dioxide, methane and nitrous oxide have increased markedly as a result of human activities since 1750, and now far exceed pre-industrial values determined from ice cores spanning many thousands of years (see Figure C-4).
- Global increases in carbon dioxide concentration are due primarily to fossil fuel use and land-use change, while those of methane and nitrous oxide are primarily due to agriculture.
- Warming of the climate system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice, and rising global mean sea level (see Figure C-5).
- Most of the observed increase in globally averaged temperatures since the mid-20th century is *very likely* due to the observed increase in anthropogenic greenhouse gas concentrations. This is an advance since the 2001 conclusion that "most of the observed warming over the last 50 years is *likely* to have been due to the increase in greenhouse gas concentrations."
- Discernible human influences now extend to other aspects of climate, including ocean warming, continental-average temperatures, temperature extremes, and wind patterns.

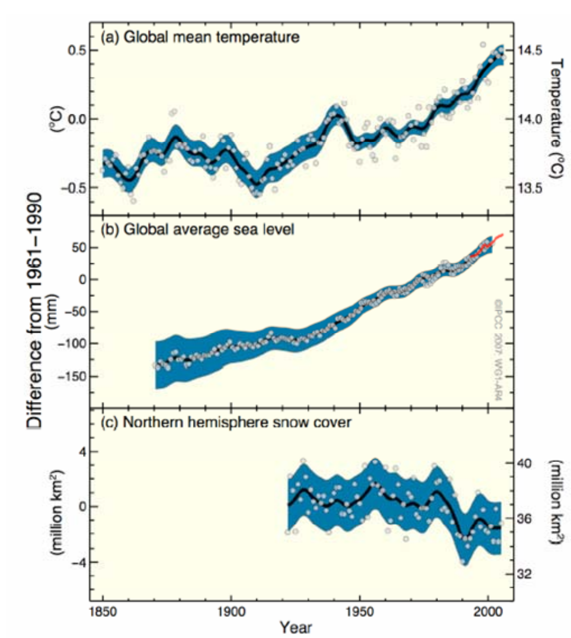
[2] "Climate Change 2007: The Physical Science Basis," Intergovernmental Panel on Climate Change, February 2007; http://www.ipcc.ch.

Figure C-4
Changes in Carbon Dioxide and Methane from Ice Cores



Source: IPCC Fourth Assessment Report, Feb

Figure C-5
Changes in Temperature, Sea Level and Snow Cover



Higher Temperature

Higher Sea Level

Less Snow Cover

Source: IPCC, Fourth Assessment Report, Feb 2007

V. Long-term Impact on the Northwest

Scientists are studying recent trends and using various models to consider the impact of climate change on the Northwest. Two particular areas interest utilities: changes in temperature, which affect energy loads; and changes in stream flows, which affect the seasonality and availability of hydro-generated electricity. Other issues—such as irrigation, water flows for fish, and flood control—are also factors since they may take priority over power generation.

A. Temperature

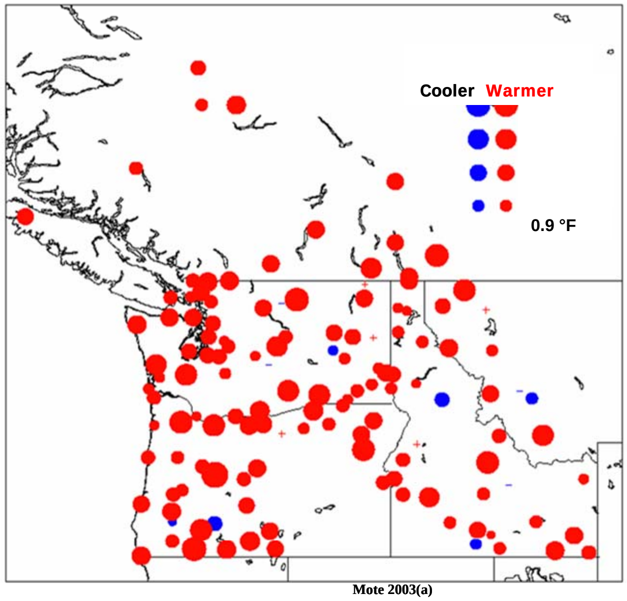
According to the Climate Impacts Group at the University of Washington,[3] "At nearly all stations in the Northwest, the temperature trends have been positive over the 1930 to 2005 period of record." The Climate Impacts Group formulated a number of conclusions:

- Minimum temperatures rose faster than maximum temperatures.
- Most temperature trends showed increases of 0.1 to 0.4 degrees Fahrenheit per decade.
- Trends for urban areas were very similar to trends for rural areas.
- The warming trend is much higher since 1960, compared to the 1930–1960 period.
- The single warmest year was 1934.
- The warmest 5-year period was 2001-2005.
- The warmest 10-year period was 1996-2005.
- The warmest 20-year period was 1986-2005.
- The regional warming trend is about the same as the global land average.

Figure C-6 shows the trends for numerous data stations throughout the Northwest. Red circles indicate warming trends; blue circles indicate cooling trends; the size of the circle represents the magnitude of the change observed. The map graphically demonstrates the overall increase in temperatures in our region.

[3] "Energy-relevant Impacts of Climate Change in the Pacific Northwest," Philip Mote, Eric Salathe, and Cynthia Peacock, July 2006.

Figure C-6
Temperature Trends Since 1920



- Over 100 meteorlogical stations in the Pacific Northwest
- Covering all climates
- Nearly all show increased temperatures

Source: CIG, UW, July 2006

B. Precipitation

Precipitation trends are not as clear as temperature trends. Known meteorological phenomena such as El Nino and the Pacific Decadal Oscillation can be large enough to be the primary cause of variability. As recently as 2004-2005, scientists have not been able to link any change in precipitation to human activities.[4]

C. Stream Flows

Even though precipitation may be constant on an annual basis, the warming trend will reduce snowpack and hence alter runoff timing. In general, lower snowpack means higher winter stream flows, since less precipitation stays frozen. This leads to reduced stream flows in late spring and summer.[5]

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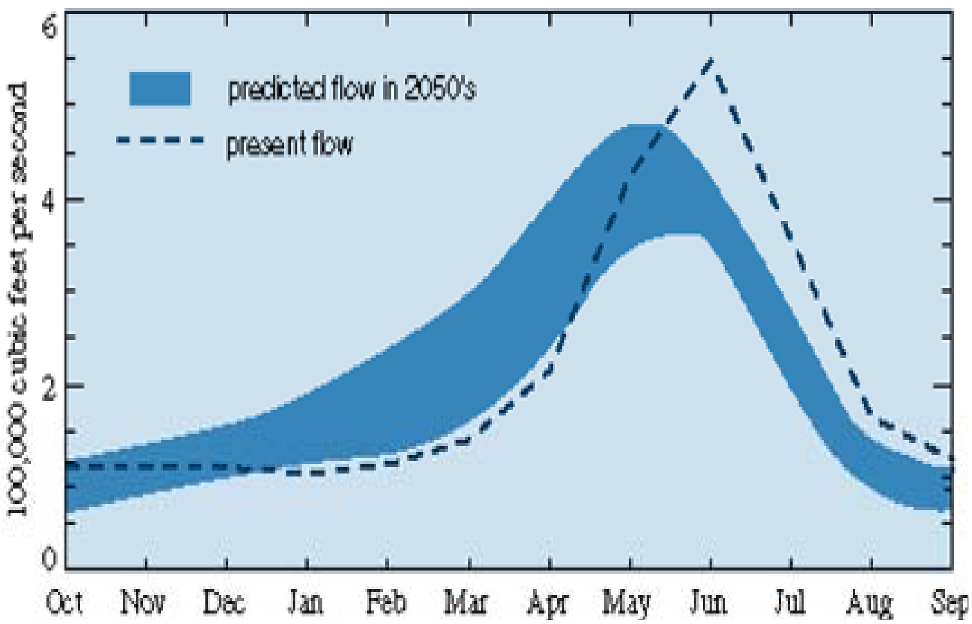
[4] Ibid, page 3.
[5] Ibid, page 4.

Seasonal shifts in stream flow can have a direct effect on hydro generation—depending on storage capacity and other priorities including flood control, fish spawning support, and irrigation. Changes in stream flow will not affect all uses equally, as various state and regional policies (legislative, executive, and judicial) have set specific water use priorities.

Figure C-7 depicts simulated stream flow for the Columbia River at The Dalles, Oregon using predictions for the climate in 2050. Flows increase in December through April, and decrease in May through September.

Figure C-7
Hydro: Winter Increase, Summer Decrease



Naturalized Columbia River flow - the Dalles, OR. Source: CIG, UW, July 2006

D. Wind

Wind along the Columbia Gorge is primarily caused by a temperature difference between the hot inland area and the cool coastal area. Under some climate change scenarios, the temperature difference between the two areas decreases, which would reduce wind speed. The Climate Impacts Group models currently do not show this reduction.[6]

[6] Ibid, page 10.

VI. Climate Change Impact on Puget Sound Energy

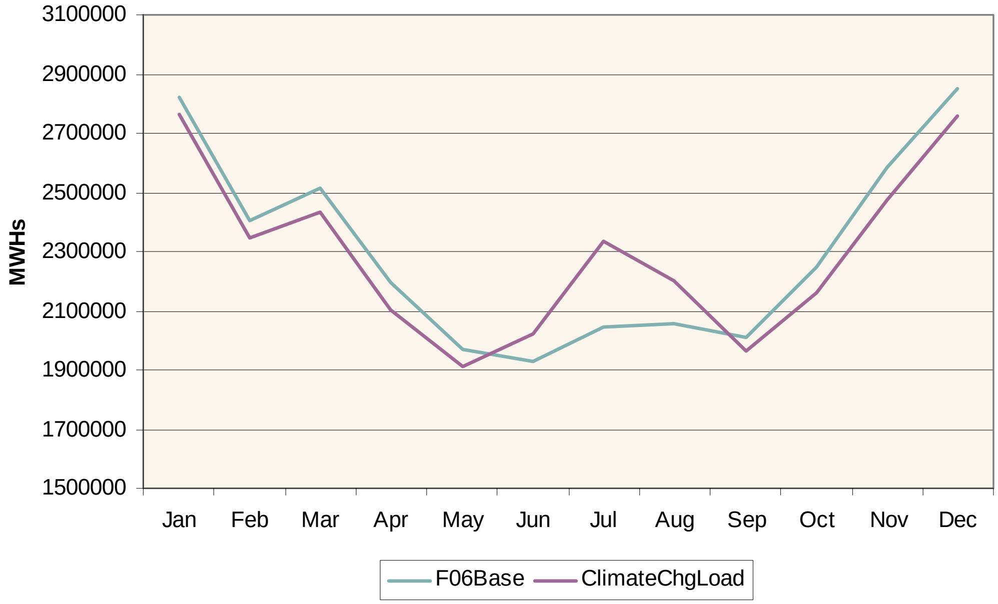
The 2007 IRP covers a 20-year period, while climate change scientists consider much longer periods (50 or 100 years). The discussion below compares the monthly load/resource balance for 2020 under current conditions and under climate change conditions.

A. Demand for Electricity

Consumption of energy is highly dependent on weather. Electric loads rise with drops in temperatures, primarily due to home heating demands. Electric loads also increase with higher summer temperatures, due to air conditioning demand. The Climate Impacts Group's latest projections of the impact of climate change for the Pacific Northwest showed an average temperature increase of about 2 degrees Fahrenheit by 2020 from current normal weather (this varies by month). From these data we developed heating and cooling degree days by month, and input them as normal weather for 2020 to 2027. We also assumed a slow change to these new averages, and thus extrapolated current values to the warmer values between 2007 and 2020.

Figure C-8 shows the impact on forecasted loads by 2020. Overall annual loads with climate change are lower—by 0.5% to 1%—compared to base case loads. Winter loads are lower by 2% to 4%, and summer loads are higher by 10% to 15%. However, PSE will continue to be a winter-peaking utility; winter loads will still be higher than summer loads.

Figure C-8
Climate Change Impact on Forecasted PSE Loads (2020)



B. Supply of Hydro Power

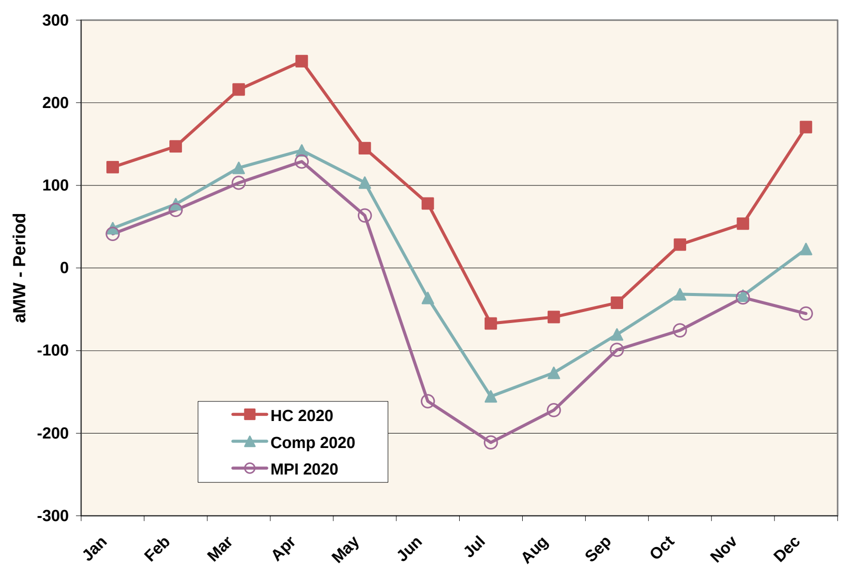
To estimate the change in hydro availability from our Mid-Columbia and Westside hydro resources, we analyzed generation data for specific resources provided by the Northwest Power and Conservation Council, which used a number of national models.[7] Downscaled hydrologic and temperature data for the Northwest was obtained from the Joint Institute for the Study of Atmosphere and Ocean Climate Impacts Group at the University of Washington. The data was derived primarily from two general circulation models, the Hadley Centre model (HC) and the Max Planck Institute model (MPI). Three sets of hydrological data were produced for operating years 2020 and 2040. Each is a downscaled and bias-adjusted set of water conditions generated using output from a

[7] A complete description of the NPCC analyses can be found in appendix N of the May 2005 Power Plan: http://www.nwcouncil.org/energy/powerplan/plan/Appendix%20N%20(Effects%20of%20Climate%20Change).pdf

particular global model. The first two sets of water conditions were derived from the HC and MPI models, and the third set was derived from a combination of model runs.

In Figure C-9, the results for PSE's hydro generation using the three model results shows little annual change in total generation, but more generation in winter months and less generation in summer and fall. These results indicate a slightly better load/resource balance in winter, as warmer temperatures decrease load and less snow increases winter stream flow. However, summer load rises and available hydro power decreases.

Figure C-9
Climate Change Impact on PSE Hydro Generation (2020)



C. Solutions and Actions Supported by Puget Sound Energy

There is no single or simple solution to climate change. Atmospheric CO_2 levels are already much higher than just a few decades ago, and the expected economic growth of developing countries will accelerate near-term increases. Nevertheless, the United States can provide leadership over the next 50 years by adopting a number of low-cost strategies for all aspects of the economy that produce CO_2.

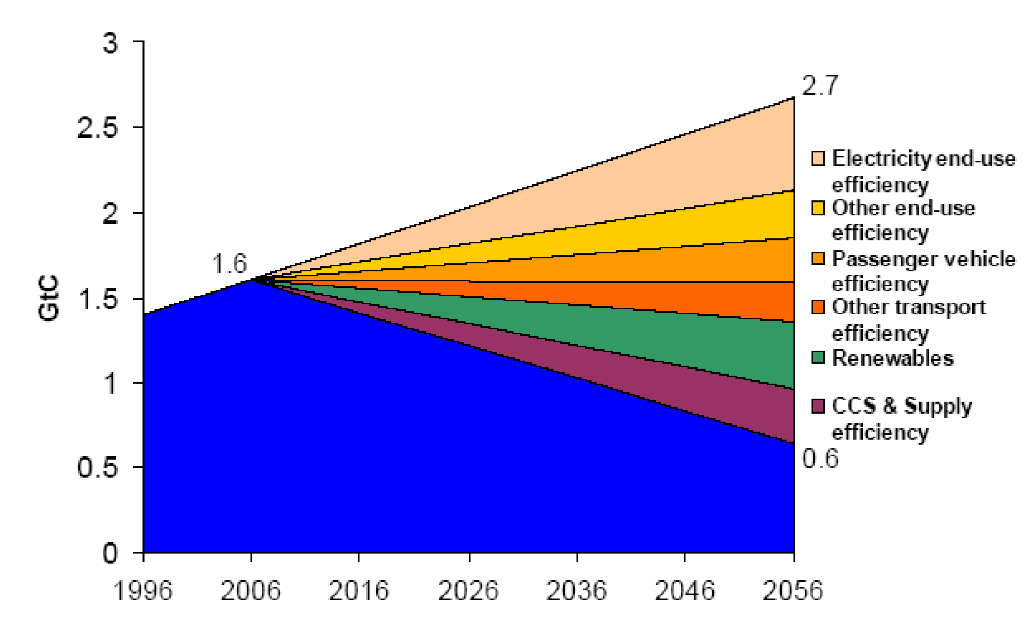
In December 2004, the National Commission on Energy Policy (NCEP) published a report entitled “Ending the Energy Stalemate—A Bipartisan Strategy to Meet America’s Energy Challenges.” NCEP developed a set of recommendations that "offers a balanced and comprehensive approach to the economic, national security, and environmental challenges that the energy issues present to our nation." Climate change and the resulting CO_2 charge are only part of one section out of six sections: Enhancing Oil Security; Reducing Risks from Climate Change; Improving Energy Efficiency; Expanding Energy Supplies; Strengthening Energy-Supply Infrastructure; and Developing Better Energy Technologies for the Future. The comprehensive policy indicates that since “energy” permeates all aspects of American life, national policies should as well.

Focusing on CO_2 reduction, Robert Socolow and Stephen Pacala[8] developed a framework of multiple strategies to stabilize atmospheric CO_2.[9] Their “stabilization wedges” for various energy programs would provide equal impact from reduced emissions, thereby creating a common unit to compare different strategies. This framework then allows policy makers and planners to fairly compare different options such as increasing automobile fuel efficiency and increasing the development of wind resources.

The Natural Resources Defense Council (NRDC) adapted the strategy to the U.S. situation and developed the scenario illustrated in Figure C-10. The United States currently produces about 1.6 gigatons of carbon per year; under the status quo, the level will increase to 2.67 gigatons per year. Under multiple strategies, it would be possible to lower the annual output to 0.6 gigatons per year.[10]

[8] Carbon Mitigation Initiative, www.princeton.edu/~cmi.
[9] “A Plan to Keep Carbon in Check,” Robert Socolow and Stephen Pacala, Scientific American, September 2006.
[10] “An Action Plan to Reduce U.S. Global Warming Pollution,” Daniel Lashof and David Hawkins, National Resources Defense Council, July 27, 2006.

Figure C-10
NRDC Strategic Framework for Stabilizing Atmospheric CO_2



The NRDC came to several conclusions relating to the framework:

- Stabilizing atmospheric CO_2 is a realizable goal.
- The solution will require a mix of strategies from different sectors of the economy.
- The tools are available today.
- Success requires both political acceptability and technological reasonableness.

PSE is contributing to the solution through a number of ongoing efforts discussed in this 2007 IRP. They include a leading energy efficiency services program that currently saves about 20 average megawatts per year, or enough electricity to serve over 15,000 homes. In December 2006 we completed our second large wind farm, giving us wind-generated capacity equal to about 5% of PSE's annual electric load. Our number of solar net metered customers rose from 60 to 110 in 2006 alone.

On the federal policy side, we continue to support policies and legislation that help move America to solve the climate change problem. Even though we own part of a coal plant in Montana, and face continued load growth that may have to be met with fossil fuels, we are always seeking ways to mitigate our carbon footprint.

D. Carbon Sequestration

We are tracking and using technologies such as integrated gasification combined cycle plants, which use coal and other fuels yet can capture and sequester carbon. We are part of the Big Sky Carbon Sequestration Partnership based in Bozeman, Montana, which is investigating numerous sequestration technologies for effectiveness and cost.[11] Carbon sequestration can be terrestrial or geologic.

Terrestrial carbon sequestration uses natural methods for returning carbon to the soil and plants at the surface level. Soil contains CO_2 sequestered by plants, but overgrazing reduces the ability of plants to perform this function; improved pasture management can increase soil CO_2. Crops also sequester carbon in the soil, but the tilling process releases it back into the atmosphere. Agricultural practices that reduce tilling have led to an increased level of carbon in the soil. Afforestation projects—growing trees to capture and hold carbon until the wood decomposes or is combusted—require long-term management to ensure that the carbon stays sequestered. Overall, while agriculture is responsible for a small portion of America's contribution to climate change, it can also be part of the solution.

Geologic sequestration involves pumping CO_2 deep into the ground, where it reacts with rocks to form an inert compound. There are numerous opportunities for carbon capture and sequestration (CCS). For example, oil companies have practiced "enhanced oil recovery" for 30 years—pumping CO_2 produced by the refining process into their wells to improve oil recovery. Companies in the Northwest are currently testing wells drilled deep into the saline aquifer. Pumped CO_2, in an aqueous state, reacts with basalt to form inert calcite. Costs for this type of geologic sequestration have not yet been determined; however, large-scale CCS will require significant infrastructure investments.

[11] Big Sky Carbon Partnership, Montana State University, Bozeman, MT; http://www.bigskyco2.org.

3. Fossil Fuel Emissions

The electric industry, due to its combustion of coal and natural gas, is implicated in certain adverse environmental impacts. Currently, there is no requirement nor is there a mechanism to measure and account for the social, environmental and public health costs of producing electricity from coal or natural gas resources that affect the environment in these manners—what economists call "external costs." Some studies even suggest that if the market accurately reflected these costs, certain plants, particularly old coal burners, would be shut down because the price of power they generated would be too high for the market to bear. This section briefly describes the atmospheric emissions produced by coal and natural gas combustion.

Coal

Combustion of coal by electric utilities is a major source of regional sulfur dioxide (SO_2), nitrogen oxides (NOx), and carbon dioxide (CO_2) emissions. It also produces carbon monoxide (CO), particulate matter (PM), and hazardous air pollutants (HAPs).

Carbon dioxide is the principal greenhouse gas (GHG) created when coal is combusted. Although methane is a much more potent GHG than CO_2, it is released in far smaller quantities. Nationwide, it is currently estimated that utilities are responsible for approximately 40% of all GHG emissions, with the majority of those emissions coming from coal-fired generation. On average, a modern coal plant with a capacity of 500 MW emits approximately 3.7 MM tons of CO_2 per year.

Mercury emissions from power plants are also an important issue, both nationally and regionally. Presently, coal-fired power plants are the largest source of mercury emissions in the United States, emitting approximately 48 tons of mercury per year[12].

[12] Source: EPA 1999 Utility Mercury Survey

Natural Gas

Relatively, natural gas burns much cleaner than coal and has less overall environmental issues. Its combustion generates virtually no SO_2, about half the CO_2 per Btu produced by coal, and much lower PM and HAPs. Further, combustion technologies today permit the extraction of a much larger fraction of the heat energy than even 15 years ago. However, natural gas combustion may generate NOx and CO in quantities comparable to or greater than coal burning.

4. Regulatory and Policy Activity

Limits on emissions of greenhouse gas (GHG) in the United States have gained significant political momentum in 2006. While the federal government thus far has failed to address the issue, states, local governments and corporations have been taking action. As a result, a patchwork of GHG policies and regulations are adding significant challenges to long-term resource planning for utilities. This section outlines regulations and policies that may have future impacts on our operations.

I. Federal Policies

The United States has not ratified the Kyoto Protocol and has yet to enact GHG regulation, but Congress has moved closer to establish national regulation. In June 2005, the Senate passed a "Sense of the Senate" resolution (SA 866) supporting a "national program of mandatory, market-based limits on emissions of greenhouse gases." In 2006, the Senate Energy Committee conducted extensive hearings on the design of such a program, leading the chairman of the committee, Sen. Pete Domenici, and the ranking Democratic member of the committee, Sen. Jeff Bingaman, to publish a white paper on the subject entitled "Design Elements of a Mandatory Market-Based Greenhouse Gas Regulatory System." In the House of Representatives, the House Appropriations Committee voted to accept an amendment to the Interior and Environment Appropriations bill calling for a "Sense of the Congress" resolution on climate change. That resolution calls for "mandatory market-based limits and incentives to slow, stop and reverse the growth of GHG emissions in a manner that will not significantly harm the United States economy."

On January 3, 2007 Sen. Harry Reid (Senate Majority Leader) sent a memo to Senate Democrats outlining the chamber's legislative agenda in ten specific areas, including global warming. Based on the schedule outlined by Senator Reid it appears that Senate Democrats are targeting to have global warming/energy independence legislation on the floor in the spring 2007. Because PSE anticipates an aggressive year in the federal legislature on climate, many of the federal proposals and related climate change activities from the last two years are summarized below.

A. Design Elements of a Mandatory Market-Based Greenhouse Gas Regulatory System

In February 2006, Senators Domenici and Bingaman introduced this climate change white paper to frame key questions and components for creating a national mandatory market-based greenhouse gas program. The paper sets the stage for legislation that will be introduced in 2007. A draft bill has been circulated to key stakeholders. The bill favors economy-wide emissions; "upstream," rather than "downstream" allowance requirements; and the sale, rather than the grant, of emissions allowances. An upstream regulatory approach means that fossil fuel suppliers would be required to own emission allowances commensurate with the CO_2 content of the fuels they sell. This would capture almost all sources of emissions and would stimulate a wider range of emissions reduction responses. Emission reduction targets may thus be achieved at a lower cost than would be the case under a program such as the McCain-Lieberman proposal described below.

In April, more than 70 industry groups, nongovernmental organizations, and labor unions responded to Representatives John Dingell and Rick Boucher with diverse ideas on how to craft legislation to mandate caps on carbon dioxide emissions. Dingell, who chairs the House Energy and Commerce Committee, and Boucher, who heads its Subcommittee on Energy and Air Quality, sought input as part of an effort to develop climate change legislation. To support this effort, the committee has conducted 11 hearings featuring testimony from more than 50 witnesses, including former Vice President Al Gore. In a February letter written by Dingell and Boucher, the energy panel sought input on how a bill might affect the economy, which industry sectors should be covered, and a suggested timetable for congressional action.

B. Climate Stewardship and Innovation Act of 2005 (S. 280)

The bill is modeled on previous proposals by Senators John McCain and Joseph Lieberman to cap GHG emissions as part of an emissions trading program that was defeated on the Senate floor in 2003 and 2005. However, the Senators have modified the latest legislation, the Climate Stewardship and Innovation Act, to include more flexibility for industry to comply with the mandated reductions by allowing them to seek offsets earned from other green projects and by allowing emissions trading in international carbon markets. The new proposal also calls for deeper, sustained cuts in U.S. emissions than previous ones. Total greenhouse gas emissions would be gradually reduced 2% per year after 2012 until they are brought about one-third below current levels in 2050. The bill measure would put in place a U.S. cap-and-trade program for emissions beginning in

2012 that would cover key industry sectors including the power industry, petroleum refiners and importers, and chemical manufacturers that generate greenhouse gases such as carbon dioxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

C. Global Warming Pollution Reduction Act (S. 309)

Senator Bernie Sanders introduced a bill in January that calls for cutting U.S. GHG emissions 80% below 1990 levels, by 2050. The bill, co-sponsored by Senate Environment and Public Works Committee Chairwoman Barbara Boxer, calls for a gradual reduction in U.S. GHG emissions, first by reducing emissions to 1990 levels, by 2020. Cuts would be further reduced by 80% of those 1990 levels over the successive three decades. The measure also would provide the Environmental Protection Agency with the authority to take additional regulatory action to further reduce U.S. emissions if the legislation, along with international efforts, fail to hold global greenhouse gas emissions at 450 parts per million. That is the level that many scientists view as the tipping point for severe global climate changes.

D. Electric Utility Cap-and-Trade Act (S. 317)

Senators Dianne Feinstein and Thomas Carper introduced a bill in January that would cap GHG emissions from power plants at 2001 levels in 2015, and require an additional 1% reduction each year through 2020. The Electric Utility Cap-and-Trade Act, which would allow for emissions trading, would also require further emissions cuts of 1.5% each year after 2020. Initially, the bill would allocate 85% of emissions credits directly to utilities. By 2016, 30% of the credits would be auctioned, and by 2036, 100% of the credits would be auctioned, with 80% of the auction proceeds going to developing low-emissions technology. The bill also would allow power companies to comply with emissions reduction targets by offsetting emissions reductions outside the power industry.

E. Kerry-Snowe Global Warming Reduction Act (S. 485)

Senators John Kerry and Olympia Snowe introduced a bill in February that would cut U.S. GHG emissions 65% from 2000 levels by 2050, an approach they said represents a middle ground between other proposals calling for deeper or more modest emissions cuts. The Kerry-Snowe Global Warming Reduction Act calls for freezing emissions of carbon dioxide and other U.S. GHG in 2010. The United States would then begin gradual, steady cuts of 1.5% per year over the following decade, a 2.5% annual cut each year beginning in 2020, and a 3.5% annual cut between 2030 and 2050 to reach the 65% target.

F. Climate Stewardship Act (HR. 620)

Representatives John Olver and Wayne Gilchrest introduced the first House legislation in the 110th Congress in January that calls for capping and reducing U.S. GHG emissions through an emissions trading scheme. The legislation calls for establishing a U.S. cap-and-trade program for emissions beginning in 2012. The House bill is the companion measure to the Senate climate proposal (S. 280) introduced January 12 by Senators McCain and Lieberman. The Olver-Gilchrest Climate Stewardship Act would cover the electric power, transportation, industrial, and commercial sectors and would set up a "feasible and effective" emissions trading scheme to reduce carbon dioxide and other greenhouse gas emissions over multiple decades. The targets for reducing GHG emissions in the Olver-Gilchrest proposal are modeled after those in the McCain-Leiberman bill, which calls for cutting emissions back to 2004 levels by 2012 and deeper cuts by mid-century.

II. State & Local Initiatives to Limit GHG Emissions

While federal policy has yet to be set, state and local initiatives to limit GHG emissions date back to June 2002, when Massachusetts adopted a 10% reduction of CO_2 limits for the state's coal-fired plants. These limits took effect on January 1, 2006. New Hampshire followed suit soon thereafter.

A. In the Northeast

The Regional Greenhouse Gas Initiative (RGGI), a cooperative effort between seven northeastern states, mandates that electric utilities reduce their emissions. This interstate agreement caps GHG emissions from power plants in the participating states at 2005 levels from 2009 through 2014, then cuts allowed GHG emissions by 10% by 2019. In April 2006, Maryland's governor signed legislation requiring the state to join RGGI in 2007. All together, the 8 states in RGGI account for one-eighth of the US population and approximately 8% of the country's power generation.

B. In the West

State initiatives to limit GHG emission have also gained momentum in the West. Washington, Oregon, and California have proposed a number of emission reduction projects under the umbrella known as the West Coast Governor's Global Warming Initiative. Currently, both Oregon and Washington require that new power plants offset a certain portion of their anticipated CO_2 emissions. Similarly, the California Public Utility Commission (CPUC) requires that a "carbon adder," an estimate of the cost of complying with future carbon emission limits, be used by the states' utilities in their resource planning process when comparing the costs of alternative generation.

California was the first state to move beyond the focus on the power sector as a source of GHG emissions. In July 2002, California enacted legislation to reduce GHG emissions from motor vehicles. In 2005, Gov. Arnold Schwarzenegger signed an executive order committing the state to a program of GHG emission limits that will reach 2000 emission levels by 2010 and 1990 levels by 2020. Most notably, however, is the passage by the California legislation of AB 32 in August 2006. With the passage of AB 32, California became the first state in the nation to adopt an economy-wide cap on CO_2. The bill commits California to cutting statewide greenhouse gas emissions to 1990 levels by

2020. Although AB 32 does not mandate specific measures to reduce greenhouse gas emissions, the bill directs the California Air Resources Board to develop regulations to achieve the required emissions reductions. With the passage of AB 32 in California and the limits set forth in the RGGI states, approximately one-quarter of the U.S. population is now subject to state GHG emission limits.

In December 2006, members of the California, Oregon and Washington public utility commissions committed their agencies to exploring the development and implementation of greenhouse gas emissions standards for new long-term power supplies. President Michael R. Peevey of the California Public Utilities Commission; Mark Sidran, chairman of the Washington Utilities and Transportation Commission; Lee Beyer, chairman of the Oregon Public Utility Commission; and Chairman Ben R. Lujan of the New Mexico Public Regulation Commission signed a special document in the presence of more than 200 witnesses at the Joint West Coast Public Utilities Commissions Workshop on Energy Efficiency. This agreement states that the four commissions recognize the need to "mitigate the adverse impacts of climate change resulting from continued reliance on fossil fuels." The regulators also agree that they have the obligation to ensure that utilities protect the environment and human health and safety, and to protect ratepayers from the economic risks of failing to plan for future regulation of emissions that cause climate change. The agencies are to direct their staffs to provide annual work plans and summaries of progress starting in 2007. The California PUC is already working on a CO_2 emissions standard and will issue a final decision in early 2007 in compliance with the new law passed as Senate Bill 1368. This bill forbids long-term investments in power plants with greenhouse gas emissions in excess of those produced by a combined-cycle natural gas power plant.

C. In the Northwest

On November 7, 2006, Washington voters narrowly approved a ballot measure that mandates an increase in the investment in and production of renewable energy resources. Initiative 937, the Clean Energy Initiative (I-937), requires that by 2020, large public and private utilities obtain 15% of their electricity from renewable resources such as wind, solar, and biomass. The first requirement will be 3% in 2012, increasing to 9% by 2016 and reaching its final target of 15% by 2020. With the acquisition of Hopkins Ridge and Wild Horse, PSE comfortably meets the first Renewables Portfolio Standard (RPS) target in 2012 and would likely meet the 2016 target based on its internal goal of meeting 10% of its load with renewable energy by 2013. PSE will need to continue to acquire renewable resources to meet the 2020 target. The Oregon legislature is also considering a Renewables Portfolio Standard. Under Oregon Senate Bill 838 (SB 838), 25% of Oregon's electricity would come from clean renewable energy sources by 2025. Given the ambitious targets, it is anticipated that further amendments to the bill and the RPS policy will be made as it makes its way through the legislative process.

Washington state Gov. Christine Gregoire signed an executive order on February 7, 2007 that outlines her administration's goals for addressing climate change. The executive order (EO) establishes a series of measurable targets and goals that are intended, according to the EO, to reduce Washington's contribution to global climate pollution, grow Washington's clean energy economy, and move Washington towards energy independence.

In April the Washington State Legislature approved S.B. 6001 to establish state goals to reduce greenhouse gas emissions. The governor signed the legislation on May 3. This legislation calls for statewide reductions of GHG emissions to 1990 levels by 2020 and to 50% below 1990 levels by 2050. Beginning July 1, 2008, public and private utilities are required to comply with a greenhouse gas emissions performance standard. The standard would be the lower of 1,100 pounds of greenhouse gas per megawatt-hour, or an amount determined by the Washington Department of Community, Trade, and Development, which would measure greenhouse gas emissions for all industrial sectors. The governor is also required to report to the Legislature by December 31, 2007, on the costs of providing tax incentives to encourage utilities to upgrade equipment to reduce carbon dioxide emissions. The legislation also allows use of ratepayer funds to reduce or mitigate the effects of greenhouse gases and requires the governor to provide a report to legislators on the possible benefits of providing tax breaks for utilities to encourage greenhouse gas emissions reduction.

Local jurisdictions in the Pacific Northwest have also been developing their own climate policies. In 2005, Seattle Mayor Greg Nickels launched the U.S. Mayors Climate Protection Agreement, which has enlisted over 330 municipalities that have agreed to reduce GHG emissions from their community by 7% from 1990 baseline levels by 2012. Mayor Nickels also created the "Green Ribbon Commission on Climate Protection," which recommended ways for Seattle to achieve the 7% goal. Seattle has been one of the leading cities behind this effort, and has since developed a list of recommendations for achieving that goal. Similarly, King County announced this year that it joined the Chicago Climate Exchange (CCX).

III. Mercury

On May 18, 2005, the Environmental Protection Agency (EPA) enacted the Clean Air Mercury Rule (CAMR) which will permanently cap and reduce mercury emissions from coal-fired power plants. State and environmental group lawsuits are seeking to overturn the CAMR program in favor of stricter control requirements and limits on trading emissions, a mechanism that gives utilities a certain level of flexibility to comply with the cap. States, however, are moving beyond the EPA in regulating mercury emissions from power plants. So far, 16 states have enacted or are working to enact programs more stringent than EPA.

In Idaho, coal-fired power plants will effectively be banned from the state under a mandate announced August 9 by Gov. Risch. Risch signed an executive order directing the state's Department of Environmental Quality (DEQ) to initiate rulemaking with an eye toward opting out of EPA's Clean Air Mercury Rule (CAMR). If approved by at least one house of the 2007 Legislature, the DEQ rule would preclude any developer of coal-fired power plants from buying mercury emission credits from elsewhere and using them to operate in Idaho. With no coal-burning power plants currently in the state, Idaho's mercury emission budget is zero.

Oregon has also adopted a rule more stringent than CAMR. In December 2006, the Oregon Environmental Quality Commission (DEQ) adopted a rule to limit mercury from new coal-fired power plants and mandate installation of mercury control technology by the state's only existing coal-fired plant. The existing Boardman plant, in eastern Oregon, is expected to reduce mercury emissions by 90% by July 1, 2012.

In October 2006, the Montana Board of Environmental Review approved a regulation to limit mercury emissions from coal-fired power plants that is also more stringent than CAMR. Adopted on a 5-1 vote, the administrative rule (ARM 17.8.771) takes a two-tiered approach to reducing mercury emissions, allowing power plants burning lower-quality lignite coal to release more emissions than plants burning cleaner sub-bituminous coal. The new rule will cut mercury emissions by about 80%, and includes a cap-and-trade provision to help power plants meet their emissions-reductions targets, as well as alternative emissions limits for plants that have tried to meet the new standards but have demonstrated that they cannot.

In Washington, the Department of Ecology (Ecology) is also drafting a mercury rule that is far more stringent than CAMR. If Ecology's proposed rules are adopted, the development of new clean-coal power plants in Washington may also be curtailed. The proposed state standards would prohibit coal-based generators from participating in the national mercury emissions cap-and-trade program after 2012. The preliminary proposal would allow the continued operation of Transalta's existing pulverized coal facility in Centralia and might allow development of another 600 MW integrated gasification combined cycle (IGCC) facility, but would prohibit additional coal generation in Washington. Ecology isn't sure if opting out of the cap-and-trade program is the best solution, but the agency is concerned about the program creating mercury hotspots. Ecology has not been able to provide any information regarding studies from mercury sources in the state and their impacts to the local and regional environment, but is steadfast on this rulemaking.

Electric Resource Alternatives

This section is designed to provide a brief overview of technology alternatives for electric power generation. It encompasses mature technologies but emphasis is placed on new methods of power generation with near- and mid-term commercial viability.

All data has been gathered from public sources except where noted, and in these instances is non-sensitive PSE data. It should be noted that many data sources are the manufacturers themselves, who may provide optimistic availability, cost, and production figures.

I. Demand-side Measures (DSM)

A. Energy Efficiency

Energy efficiency is defined as a technology that demonstrates the same performance for a given task as competing technologies, but requires less energy to accomplish the task.

Discretionary Measures

PSE refers to all energy efficiency improvements and upgrades to existing construction as "discretionary measures." This may include bringing building components up to or beyond code levels, or the early replacement of existing technologies such as lighting or appliances. Similar measures exist for new construction, and are discussed below under Lost Opportunities.

Lost Opportunity

Lost opportunities refer to the moment when a customer is making a decision about acquiring new equipment. Once the purchasing decision is made, there will not be another opportunity to influence the decision towards an energy efficient technology. When new buildings are being built, the construction phase is the best time to install the most efficient measures. Also, when a customer needs to purchase new equipment, savings can be gained by purchasing high-efficiency models.

Lighting

Switching from highly inefficient incandescent lighting to fluorescent lighting can result in significant savings. Lighting measures for typical household applications are categorized by use: low (1 hr/day), medium (2.5 hr/day), and high (4 hr/day) represent frequency of use.

Heating, Ventilation, and Air-Conditioning (HVAC)

Measures associated with the HVAC system improve the overall heating and cooling loads on a building. They include both lost opportunity measures, such as a high efficiency DX cooling package, as well as discretionary measures such as programmable thermostats. Discretionary measures can impact all types of cooling or heating equipment.

Building Envelope

"Building envelope" measures improve the thermal performance of a building's walls, floor, ceiling or windows. The baseline technology and the energy efficiency upgrades are discussed below. Building envelope energy efficiency measures include insulation (ceiling/roof, wall, and floor) and windows.

Domestic Hot Water

In addition to a more efficient water heating system, any equipment measures that require less hot water are also included in the domestic hot water measures below.

Plug Load

ENERGY STAR® rated plug-in loads reduce the overall electric load of a household compared to standard equipment. This measure identifies the specific plug-in equipment. The following list includes both typical household entertainment equipment and home-office equipment. Office equipment such as computers, monitors, and printers can all be ENERGY STAR® classified, indicating lower energy use than conventional equipment. Savings is achieved, in part, because the machine is equipped with a standby mode.

B. Fuel Conversion

When customers switch from electricity to natural gas, particularly in the case of space and water heating, electrical savings are gained from the reduction in electrical energy use.

Fuel conversion measures, specifically water heaters, space heaters, zone heaters, ranges and dryers, fall under the Lost-Opportunity Equipment category, as described above.

C. Distributed Generation

Distributed generation refers to small-scale electricity generators located close to the source of the customer's load.

Non-renewable Distributed Generation

Combined Heat and Power. Combined heat and power (CHP) plants are a more energy-efficient use of non-renewable generation units. A CHP starts with a standard non-renewable generator, but improves the overall utility by capturing the waste heat produced by the generator. For example, a typical spark-ignition engine has an electrical efficiency of only about 35%. The “lost” energy is primarily waste heat. A CHP unit captures much of this waste heat and uses it for space heating or domestic hot water. Thus, there are cost savings for the water heating in addition to electricity generation. Three-engine generator technologies are considered for use with CHP: reciprocating engines, micro-turbines and fuel cells.

Renewable Distributed Generation

Renewable generation encompasses all generation that uses a renewable energy source for the fuel; in other words, a fossil fuel is not consumed. There are two main categories of renewable generation: biomass and clean energy.

Biomass. Sometimes referred to as “resource recovery,” biomass is used as the fuel to drive a generator. The source of the biomass can vary, but can be broadly categorized into “industrial biomass” or “anaerobic digesters.”

Clean Energy. Generation that is achieved without the consumption of a hydrocarbon fuel. The two main sources for clean energy are wind and solar photovoltaics (PV).

D. Demand Response

Demand-response (or demand-responsive) resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility’s supply cost. Acquisition of demand-response resources may be based on either reliability considerations or economic/market objectives. Objectives of demand response may be met through a broad range of price-based (e.g., time-varying rates and interruptible tariffs) or incentive-based (e.g., direct load control, demand buy-back, and dispatchable stand-by generation) strategies. In this assessment, we considered five demand-response options: Direct Load Control, Critical Peak Pricing, Curtailable Rates, Demand Buyback and Distributed Standby Generation.

II. Solar Energy

Solar energy is the direct harnessing of the sun's energy and largely divides itself into the photovoltaic and thermal segments. Although the technology has been around for several decades, it is an emerging technology today in terms of cost and commercial maturity.

A. Photovoltaics

Description of Technology

Photovoltaic (PV) cells directly convert sunlight into electricity and represent the overwhelming majority of installations. PV currently comes in two major types, crystalline silicon and thin-films.

While the price of crystalline silicon PV has increased over the last couple of years due to competition for high-grade silicon with microchips, thin-film prices have fallen. Thin-film costs are approximately 50 cents per watt less than multi-crystalline. Thin-film panels are flexible, light-weight and non-glossy, resulting in their preferred use for building integrated photovoltaics.

Silicon panels remain more efficient than thin-films and thus have roughly half the footprint for the same power output. Thin-film panels have had a reputation for degrading performance over time, but now both technologies will come with manufacturer warranties guaranteeing their power curve for 20 to 25 years. Both types of PV panels generate DC power and require an inverter to switch to AC power, typically with 80% efficiency.

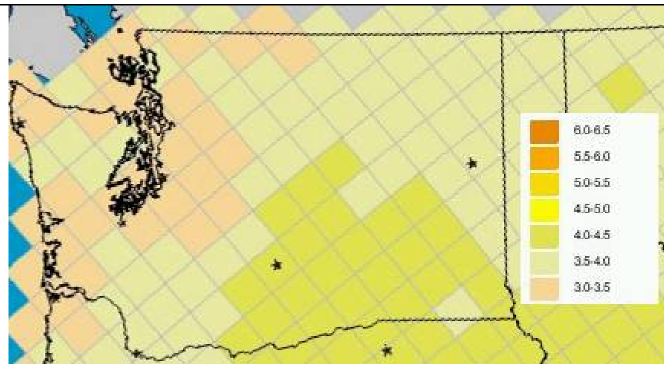
Opportunities in Puget Sound Region

In the Seattle area, average sunlight is around 3.6 kWh / m^2 / day (11% CF), contrasting with the eastern half of Washington where sunlight is significantly better at around 4.7 kWh / m2 / day (15% CF).[1]

[1] PV Watts, flat plate fixed at latitude for Seattle and Yakima and Frank Vignola, Univ. of Oregon

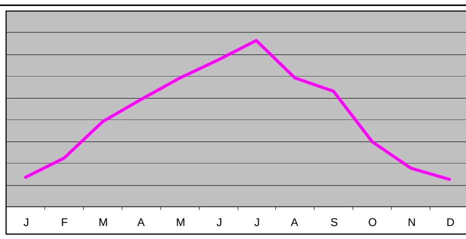
Figure D-1
Sunlight Averages for Washington State

Currently, solar projects are not eligible for Production Tax Credits, but are eligible for a 30% Investment Tax Credit provided that the solar assets are not "utility property." The 30% ITC reverts to a 10% ITC after 2008. Washington state recently passed legislation that provides a solar production incentive ranging from $150-$430/MWh but that is capped at $2,000 per project and a total of $25,000 / year.[2] Solar projects receive 5 year MACRS and are exempt from Washington sales tax.

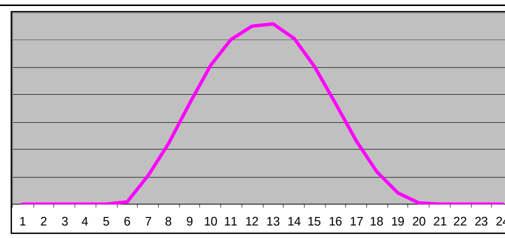


Source: National Renewable Energy Laboratories (NREL)

Figure D-2
Washington State Solar Irradiance



Annual Energy Shape (% by month)



Daily Energy Shape (% by Hour)

Notable Companies

Multi-crystalline Manufacturers: Sharp, Kyocera, BP, SCHOTT, REC, QCell

Thin-Film Manufacturers: Uni-Solar, First Solar, Nanosolar

Developers: Powerlight, SunEdison, URS, SolarWorld

Figure D-3
Solar Photovoltaic Key Metrics

Capital Cost w/o subsidies ($/kW)	Levelized Cost ($/MWh)	Typical Installation Size (kW)	Expected Life (years)
$7,000 – $9,000	$300 - 700	3 – 3,000	20 – 25

[2] DSIRE, http://www.dsireusa.org/

B. Thermal and Concentration Technologies

Technology Description

While solar thermal and concentrating technologies are less mature forms of solar generation, they may offer lower levelized costs in the long term. Generally, these technologies are best suited for commercial or utility scale installations. While there are several different types of solar thermal technology, they share a common characteristic of only being able to utilize direct sunlight, unlike photovoltaics, which can use both direct and diffuse sunlight. This reduces the solar energy they can harness in Washington state by about 30%. All such systems track the sun on at least one axis.

Figure D-4
Solar Thermal and Concentration Technologies

Solar Thermal Troughs - A parabolic mirrored trough concentrates energy onto a receiver pipe to heat oil and transports it to a turbine for power generation. The world's leading 300 MW SEGS facility in California uses solar troughs. Since the SEGS plants were built in the 1980s, no other plants were built until the last two years, when APS and Nevada Power both built a trough system. This technology has the potential to add thermal storage. There have been persistent problems with oil leaking from the receiver pipes at the SEGS facilities and with keeping the mirrors clean and properly focused. The two new systems hopefully resolve these problems.	
Dish-Engine Systems – Dish engine systems are comprised of a dish of mirrors that concentrate sunlight onto an engine or high-efficiency bank of photovoltaic cells. The largest system to date is a bank of six 25 kW dish-engines (total 150kW) at Sandia National Labs. San Diego Gas & Electric and Southern California Edison both signed 500 MW PPA agreements, but it is unclear if the facilities will ultimately be built.	
Concentrating Photovoltaics – Concentrating photovoltaics typically use a plastic lens to focus solar energy on a small PV cell and thus can greatly reduce the number of PV cells needed. The added heat has reduced the efficiency of the cells in some applications. The system pictured here is a 25 kW Amonix concentrating system built in 2006 in Nevada.	

Notable Companies

Manufacturers: Solargenix (formerly Duke Solar), Sterling Energy Systems (SES), Amonix, JX Crystals (local), Infinia (local)

Note that the following figures are still highly academic and based on studies of the technology, not actual commercial experience.

Figure D-5
Solar Trough Key Metrics

	Capital Cost ($/kW)	Levelized Cost ($/MWh)	Typical Installation Size (kW)	Expected Life (years)
Solar Trough[3]	$5,194	$315	25,000	20
Dish-Engine	Unavailable	Unavailable	Unavailable	Unavailable
Concentrating PV	Unavailable	Unavailable	Unavailable	Unavailable

[3] Morse Associates, Inc. for Medicine Hat, Alberta with 5.11 kWh of DNI (Yakima has about 4.0 kWh of DNI). The relationship of power production is less than linear with the solar energy, but as been treated as linear for simplicity.

III. Biomass

The term biomass generally applies to a fuel source (or feedstock) rather than a specific generation technology. Biomass fuels are combustible organic materials which can vary dramatically in form. Biomass fuel sources, as well as the generation technologies, are widely diverse. Biomass fuels include but are not limited to wood residues, spent pulping liquor, agricultural field residues, municipal solid waste, animal manure, and landfill and wastewater treatment plant gas. Biomass resources and power generation technologies are listed in the tables below.

Figure D-6
Biomass Fuel Resources

General Classification Biomass Type	Brief Description
Forest Products:	
- Forest Residue - Mill Residue - Pulping Chemical Recovery	- Logging slash and forest thinning - Wood chips, shavings, sander dust and other large bulk wood waste - Spent pulping liquor used in chemical pulping of wood
Agricultural Resources:	
- Crop Residues - Energy Crops - Animal Waste	- Residues obtained after each harvesting cycle of commodity crops - Crops grown specifically for use as feedstocks in energy generation processes, includes hybrid poplar, hybrid willow, and switchgrass - Combustible gas obtained by anaerobic decomposition of animal manure
Urban Resources:	
- Municipal Solid Waste - Landfill Gas / Wastewater Treatment	- Organic component of municipal solid waste - Combustible gas obtained by anaerobic decomposition of organic matter in landfills and wastewater treatment plants

Figure D-7
Biomass Conversion Technology Types[4]

Technology	Conversion Process Type	Major Biomass Feedstock	Energy or Fuel Produced
Direct Combustion	Thermochemical	wood agricultural waste municipal solid waste residential fuels	heat steam electricity
Gasification	Thermochemical	wood agricultural waste municipal solid waste	low or medium-Btu producer gas
Pyrolysis	Thermochemical	wood agricultural waste municipal solid waste	synthetic fuel oil (biocrude) charcoal
Anaerobic Digestion	Biochemical (anaerobic)	animal manure agricultural waste landfills wastewater	medium Btu gas (methane)
Ethanol Production	Biochemical (aerobic)	sugar or starch crops wood waste pulp sludge grass straw	ethanol
Biodiesel Production	Chemical	rapeseed soy beans waste vegetable oil animal fats	biodiesel
Methanol Production	Thermochemical	wood agricultural waste municipal solid waste	methanol

There is a wide array of technologies for converting biomass into power, fuel or heat. New and existing technology for using wood fuel effectively to produce power generation can be generally classified as direct combustion, co-firing, and gasification.

Direct combustion is the oldest and most proven technology. Most of today's biomass power plants are direct-fired systems, similar to most fossil fuel-fired power plants. The biomass fuel is burned in a boiler to produce high-pressure steam. This steam is then introduced into a steam turbine generator. While steam generation technology is very dependable and proven, its efficiency is limited. Biomass power boilers are typically in the

[4] http://egov.oregon.gov/ENERGY/RENEW/Biomass/BiomassHome.shtml

20 to 50 MW range. The small capacity plants tend to be lower in efficiency because of economic trade-offs. Typical plant efficiencies are in the low 20% range.

Co-firing involves substituting biomass for a portion of coal in an existing power plant furnace. It is the most economic near-term option for introducing new biomass power generation. Because much of the existing power plant equipment can be used without major modifications, co-firing is far less expensive than building a new biomass power plant. Compared to the coal it replaces, biomass reduces sulfur dioxide, nitrogen oxides, and other air emissions. After "tuning" the boiler for peak performance, there is little or no loss in efficiency from adding biomass. This allows the energy in biomass to be converted to electricity with the high efficiency (in the 33% to 37% range) of a modern coal-fired power plant.

Gasification is the process of heating wood in an oxygen-starved environment until volatile pyrolysis gases (carbon monoxide and hydrogen) are released from the wood. Depending on the final use of the typically low-energy wood gas, the gases can be mixed with air or pure oxygen for complete combustion and the heat that is produced can be transferred to a boiler for energy distribution. Otherwise, the gases can be cooled, filtered, and purified to remove tars and particulates and used as fuel for internal combustion engines, microturbines, and gas turbines. The use of pure biomass gas in a combustion turbine is in early research. Biomass IGCC and fluidized bed technologies have been experimented with, but they are not yet commercially viable.

Figure D-8
Biomass Power Technology Types[5]

Biomass Type	Technology	Size
Solid Fuels (agricultural, MSW, Forest residue, mill residue)	Direct fired / steam turbine or Direct co-fire with coal	5, 10, 25, 50, 100 (MW) 7.5, 15, 30 (MW)
Biogas/Manure	IC-engine	65, 130, 650 (kW)
Biogas/Landfill	IC-engine	1, 5 (MW)

As shown in Figure D-8 above, biomass generation can range from very small scale to utility scale power production. The diverse biomass fuel types and technology choices make biomass a complex resource to analyze for an electrical generation resource. There are many factors and determinates to consider before choosing biomass

[5] http://www.westgov.org/wga/initiatives/cdeac/Biomass-full.pdf

generation. Providing cost estimates for wood energy systems requires flexibility and a technical understanding that costs fluctuate widely depending on the site requirements and present site capabilities.

Like most combustion technologies, biomass generation's high energy cost is largely driven by the cost of the fuel itself. The technology also has a high capital cost, and is only half as efficient as a combined cycle gas turbine of similar size.

Biomass is a widely distributed resource. Fuel competition and transportation costs typically preclude the construction of power plants of greater than 50 MW capacities. Most future power plants fueled by dry biomass resources are likely to be in the range of 15 to 30 MW. The local market for available supply of wood may limit the benefits of burning wood fuel. Hauling wood biomass from outside a 50-mile radius is usually not economical. A rigorous life-cycle analysis is also necessary to fully understand the fuel supply chain. Initial costs of wood biomass generation facilities are typically 50% greater than that of a fossil fuel generation system due to the fuel handling and storage system requirements.

Biomass power is reliable baseload electric power. Biomass plants cannot easily perform load-following, and cannot be routinely dispatched due to the inherent limitations of a combustion/steam-cycle power plant. The necessity of a larger-sized boiler and the need for a waste-handling plant involve 1.5 to 4 times the investment cost of oil-fired package boilers.

The difficulties of fuel handling, boiler maintenance and ash disposal are labor and equipment intensive. Biomass plants require 10 to 20 times the staff per MW of a natural gas-fueled power plant, including the dedicated fuel infrastructure personnel.

Obvious benefits may be gained by burning wood residues to reduce a manufacturer's fuel oil and electricity bill. These benefits may be offset by high capital costs, low plant efficiency, and increased maintenance levels. Of course, the economics of wood waste energy generation becomes more attractive as traditional fuel prices increase.

There are 45 potential biomass sources in Washington state, according to a December 2005[6], report, "Biomass Inventory and Bioenergy Assessment: An Evaluation of Organic Material Resources for Bioenergy Production in Washington State." Categories included

[6] http://www.pacificbiomass.org/documents/WA_BioenergyInventoryAndAssessment_200512.pdf

field residues, animal manures, forestry residues, food packing/processing waste, and municipal wastes. The report states that Washington has an annual production of over 16.9 million tons of underutilized dry equivalent biomass, which is capable of producing, via assumed combustion and anaerobic digestion, approximately 1,769 MW of electrical power. Looking to just forestry resources (mostly mill residues and pulping recovery) the totals are approximately 945 MW. This study does not consider economic or commercial issues. Therefore, these results seem to be extremely aggressive and the report is based on the absolute potential, not viable or economic potential.

In June 2005, the Energy Trust of Oregon, Inc. received 25 proposals in response to a RFP seeking biomass electrical generation projects[7]. Eligible resources included landfill gas, wood waste from mills or forests, dairy manure, waste gas from sewage treatment, and other biomass sources. The 25 projects totaled 91 MW of gross nameplate capacity.

During PSE's 2004 and 2006 RFP cycles, three proposals for biomass cogeneration totaling 100 MW were received and evaluated. In the last several years, the region has seen the construction of only one biomass facility. Considering the impact of the Washington state RPS and the potential demand for diverse renewable resources, biomass may look more economically attractive as the demand grows.

Additional References:

- http://www.fpl.fs.fed.us/tmu/wood_for_energy/wood_for_energy.html
- http://www.nwcouncil.org/energy/powerplan/plan/Default.htm
- http://www1.eere.energy.gov/biomass/
- http://www.nrel.gov/biomass/
- http://www.eia.doe.gov/oiaf/analysispaper/biomass/
- http://www.calbiomass.org/

[7] http://www.energytrust.org/RR/bio/index.html

IV. Fuel Cells

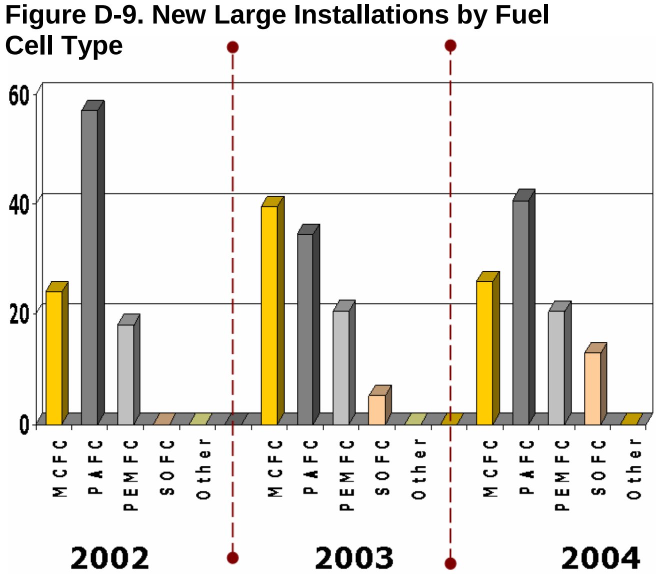
Fuel cells have been touted for their potential as an alternative to the internal combustion engine, but are examined here predominantly for their application in stationary power generation. Despite its reputation with many types of renewable technologies, the United States remains a dominant fuel cell developer. The market for large fuel cell generation (>10 kW) is dominated by four types of cells: phosphoric acid, solid oxide, proton membrane exchange and molten carbonate. Prices remain uncompetitive at around \$2500 per kW on the low end, although DOE has set a target of \$400 per kW by 2010.[8]

A. Phosphoric Acid Fuel Cells (PAFC)

PAFC technology was the first to market and remains the most common. PAFC cells are limited to stationary applications as they are large, heavy, expensive, and slow to start. Their advantages in maturity and lifespan, however, have given PAFC the largest market share in stationary applications. PAFC fuel cells are predominantly manufactured by United Technologies and Fuji.

B. Proton Exchange Membrane Fuel Cells

Figure D-9. New Large Installations by Fuel Cell Type



Source: Fuel Cell Today

PEM fuel cells are generally thought to be the technology of choice for mobile applications, but have more limited roles in stationary situations. PEM fuel cells operate at much lower temperatures and have a long lifespan, but require an expensive platinum catalyst. PEM cells are very sensitive to fuel impurities and require pure hydrogen. Ballard Power Systems of Vancouver, B.C. is a world leader in PEMFC development, although many auto manufacturers also conduct their own PEM research.

[8] DOE http://www.fossil.energy.gov/programs/powersystems/fuelcells/

Ballard recently introduced a stand-alone 1 kW unit for sale in Japan that includes a natural gas reformer and co-generates hot water and power.

C. Molten Carbonate Fuel Cells

Molten carbonate fuel cells (MCFC) operate at much higher temperatures, but also much higher efficiencies than phosphoric acid fuel cells. The higher temperature of molten-carbonate fuel cells functions as an internal reformer and allows it to internally reform a variety of gasses, but also lengthens start-up and shut-down. Among the world's largest MCFCs is a 1 MW, two-year demo plant in Renton, WA at the South Wastewater Treatment Plant. In their 2004 Q4 report, the demo reported efficiencies of 43% to 44% on both natural gas (supplied by PSE) and digester gas from wastewater.[9] The Environmental Protection Agency provided approximately $12.5 million of the $22 million project cost.

D. Solid Oxide Fuel Cells

Solid oxide fuel cells (SOFC) operate at higher temperatures than MCFCs, and accept an even wider variety of fuels.[10] In addition, the high temperature precludes the need for noble metal catalysts, reducing costs.[11] SOFC technology is still in early stages of development but is expected to have an increasingly important role in stationary applications. Figure D-9 shows the number of new large scale fuel cell projects by technology type and the rise of SOFC starting in 2003. Cogeneration systems are particularly attractive with solid oxide cells, due to the high operating temperature. See Figure D-10, next page.

[9] King Country http://dnr.metrokc.gov/wtd/fuelcell/docs/0504_Report-2.pdf
[10] E-sources http://www.e-sources.com/fuelcell/fcexpln.html
[11] CEA, http://www.cea.fr/gb/publications/Clefs44/an-clefs44/clefs4453a.html

Figure D-10
Fuel Cell Operating Temperatures and Efficiencies

Fuel Cell Type	Development Stage	Projected Efficiency (w/ heat recover)	Operating Temp. (°C)	Lifespan (hrs)	Fuels
Phosphoric Acid	Commercial	35%	175-200	40,000 - 60,000	Hydrogen
Proton Exchange Membrane (PEMFC)	Demonstration	35-45%	60-100	40,000	Hydrogen
Molten Carbonate (MCFC)	Demonstration	50% (85%)	600-800	5,000-20,000	Hydrogen Methane Natural Gas
Solid Oxide (SOFC)	R&D	50-60% (80-85%)	600-1000	20,000	Hydrogen Methane Natural Gas

Sources: [12] [13] [14] [15] [16]

[12] DOE, http://www.eere.energy.gov/hydrogenandfuelcells/fuelcells/pdfs/fc_comparison_chart.pdf
[13] Avista Labs, http://www.avistalabs.com/fuelcells_spectr.asp
[14] Exergy, http://www.exergy.se/ftp/cng97fc.pdf
[15] Siemens http://www.siemenswestinghouse.com/en/fuelcells/technology/chp/index.cfm
[16] Dr. Karl Kordesch, http://www.electricauto.com/fc_compare.html

V. Water Based Generation

Water based generation can be broken into four distinct categories; river hydroelectricity, wave energy, tidal energy and ocean thermal conversion.

A. Hydroelectricity

Large scale impoundment and diversion hydroelectricity is the backbone of power generation in the Pacific Northwest. However, large-scale projects are now difficult to build because of their large capital costs, regulatory burdens and environmental concerns.

Smaller scale hydroelectricity, on the other hand, has received attention due to its somewhat smaller implementation barriers. The Department of Energy defines “small” hydropower as generation capacity less than 30 MW, while “micro” hydropower refers to anything less than 100 kW.[17] In one example, Crown Hill Farm in Oregon successfully installed 25 kW of micro-hydro capacity. To do so, they invested $100,000 and dealt with 12 government bureaus over the course of 18 months.[18]

B. Tidal Energy

For the purpose of this brief, river in-stream energy and tidal energy are viewed as equivalent. The Electric Power Research Institute (EPRI) is seeking funding to identify potential river in-stream energy development locations along many major U.S. rivers. In addition, river in-stream energy conversion equipment will likely be quite similar to the tidal energy conversion devices currently under development.

The roots of tidal energy are closely related to the development of wind energy resources. Both technologies rely upon a multi-blade rotor to supply rotational energy to a generator. As with wind turbines, a speed increaser is required due to the physical limitations of the generator size and rotor diameters.

Most tidal energy development appears to be centered on the conventional “open” turbine that is very similar to the contemporary wind turbines: a “ducted” turbine where

[17] DOE, http://www.eere.doe.gov/RE/hydropower.html
[18] Oregen DOE http://egov.oregon.gov/ENERGY/CONS/BUS/docs/CrownHill.pdf

the turbine blades are enclosed within a venturi shape, or a hybrid Gorlov design with its characteristic spiral shaped turbine blades.

Figure D-11
Examples of Tidal Turbine Designs

When compared to wind turbines, tidal energy has two unique advantages: its predictable nature; and the possibility of using smaller rotor diameters for the same power output (owing to the mass flow density differences between air and water.) Tidal generation, however, is not expected to have a significantly greater capacity credit than wind since the load over time will not correlate with high load hours. Tidal currents are also bi-directional, which requires some of these turbine designs to pivot 180º to generate energy when the tidal current reverses its direction on the following tide cycle.

Because commercial scale tidal energy plants consist of multiple units, they could pose a significant risk to marine life. Each unit may incorporate one or more turbines and require its own anchoring and power transmission system, both of which could impact the local aquatic environment. Underwater construction challenges, local and federal permitting processes, and access to grid interconnection points also must be resolved at each tidal energy location before the tidal energy plant can proceed to commercial scale and become viable as a renewable energy resource.

Nationally, EPRI reports that 29 preliminary permits have been filed with the Federal Regulatory Energy Commission (FERC) for tidal energy projects. Of these, FERC has granted preliminary permits to only the Roosevelt Tidal Energy Project by Verdant Power, the San Francisco Bay Project by Golden Gate Energy, and the Tacoma Narrows Project by Tacoma Power.

The Roosevelt Tidal Energy Project near Roosevelt Island, New York, installed the first two of six generating units on December 11 and 12, 2006. One of these units will be used for testing, while the other appears to be performing near or above its expected capacity of 33 kW. Over 5,000 kWh of energy was generated by the second unit and provided to a local supermarket through December of 2006. The deployment of the remaining four units was expected within 90 days of the December 12th installation, following a review of the associated fish monitoring data to reveal the potential impacts to fish in the area.

In accordance with FERC's preliminary permit, Golden Gate Energy recently filed its second six-month progress report on the San Francisco Bay Project.[19] Citing examples of progress in understanding the scope and implementation of required studies, the report referred to a series of meetings with the San Francisco Bay Conservation and Development Commission and Pacific Gas and Electric Company. The report also stated that Oceana—Golden Gate Energy's parent company—has executed an agreement with the U.S. Naval Surface Warfare Center to install a demonstration project in the United States using Oceana's patent pending technology. The test project would be installed within the United States by late 2007 or 2008.

Likewise, Tacoma Power filed its first six-month progress report on July 31, 2006. The utility recently issued an RFP to initiate Phase II activities outlined in its preliminary permit. Among those activities, Tacoma Power must first determine whether to proceed with the installation of a pilot tidal energy unit in the Tacoma Narrows. If appropriate, the utility will then move forward with the necessary site engineering and consultation to address environmental concerns, and secure the necessary permits for the installation of the pilot unit during Phase III. If the pilot unit provides favorable results, Tacoma Power may proceed with its application for a formal FERC permit to install the commercial tidal energy plant. The utility estimates the plant will have an annual energy production of 120,000 MWh.

Currently, nine preliminary permits for various tidal energy locations throughout the Puget Sound area have been issued by FERC or are awaiting approval. Tacoma Power holds the initial preliminary permit granted by FERC for a location within Puget Sound near

[19] Recurring progress reports are a requirement to maintain preliminary permit status.

Point Evans in the Tacoma Narrows. FERC awarded the remaining preliminary permits for the balance of the desirable tidal energy locations throughout Puget Sound to Snohomish County Public Utility District. The locations within the Puget Sound are as follows:

Figure D-12
FERC Preliminary Permits for Tidal Energy Locations within Puget Sound

FERC ID#	Location	Developer	Estimated Annual Output[20]	Equivalent Wind Farm (30% CF)
12687	Deception Pass	Snohomish Co. PUD	20,700 MWh	7.9 MW
12688	Rich Passage	Snohomish Co. PUD	8,560 MWh	3.3 MW
12689	Spieden Channel	Snohomish Co. PUD	32,470 MWh	12.4 MW
12690	Admiralty Inlet	Snohomish Co. PUD	146,200 or 75,600 MWh[21]	55.6 MW
12691	Agate Passage	Snohomish Co. PUD	340 kW[22]	0.3 MW
12692	San Juan Channel	Snohomish Co. PUD	33,270 MWh	12.7 MW
12698	Guemes Channel	Snohomish Co. PUD	28,500 MWh	10.8 MW
12612	Tacoma Narrows	Tacoma Power	120,000 MWh	45.7 MW

A map of the various locations within Puget Sound appears on the next page.

[20] The estimated annual outputs are as reported in the preliminary permit applications submitted to FERC.
[21] The estimated annual output by Snohomish County PUD for the Admiralty Inlet location depends on the transect where the turbines are installed within Admiralty Inlet. The Point Wilson to Admiralty Head transect was estimated at 146,200 MWh and the Bush Point to Nodule Point transect was estimated at 75,600 MWh.
[22] Snohomish County PUD did not report an estimated annual output for the Agate Passage location.

Figure D-13
Puget Sound Tidal Energy Locations with FERC Preliminary Permits

A small, ducted tidal energy device was deployed at an ecological preserve located at the southeastern corner of Vancouver Island in British Columbia. The majority of the funding for this project was provided by EnCana™, a natural gas and oil provider with locations in both Canada and the United States. Pearson College provided the host site for the project, and both the government and parks departments of British Columbia provided the necessary permits. Although the exact size of the tidal power turbine is not clear to us, we do know the turbine was supplied by Clean Current Power Systems, and it charges the batteries used to power a lighthouse and associated buildings, as shown in the following illustration.

Figure D-14
Artist's Rendering of EnCana™ Tidal Project at Vancouver Island

The Electric Power Research Institute's (EPRI) estimated summary of the economics for a full installation at the Tacoma Narrows is provided in Figure D-15. It is important to note that no commercial installations exist and these estimates are highly theoretical.

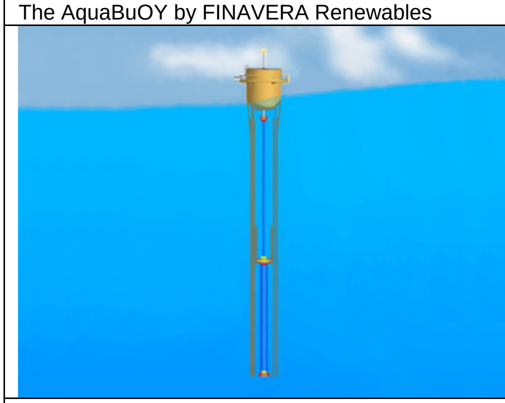
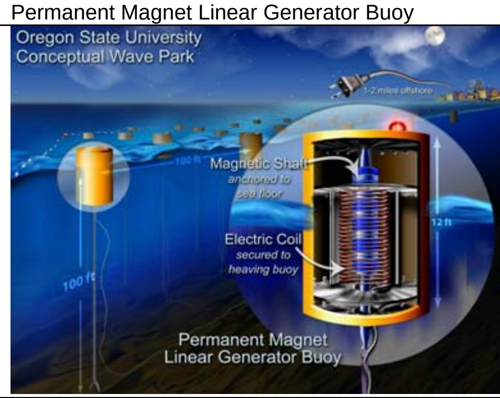
Figure D-15
Tacoma Narrows Tidal Plant Cost Estimates

Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
$2,200 / kW	$90	16,000	20	30 %

C. Wave Energy

Wave energy devices appear to be at a much earlier stage of development than tidal devices, thus the range of developmental wave energy equipment is much more diverse. For space considerations, this technical brief focuses on four of these technologies. These include three devices that directly convert the rise and fall of a wave into electrical energy and an air driven power turbine that extracts energy from the airflow caused by oscillating columns of water.

Figure D-16
Examples of Wave Energy Conversion Devices

<table>
<tr><td>The AquaBuOY by FINAVERA Renewables</td><td>Oregon State University (OSU)
Permanent Magnet Linear Generator Buoy</td></tr>
<tr><td></td><td>
</td></tr>
<tr><td></td><td></td></tr>
<tr><td>The Pelamis Wave Energy Converter
by Ocean Power Delivery LTD.</td><td>The Land Installed Marine Power Energy Transmitter
(LIMPET) by Wavegen®</td></tr>
<tr><td></td><td></td></tr>
</table>

The AquaBuOY, the Permanent Magnet Linear Generator Buoy and the Pelamis devices effectively use the vertical movement of the wave itself to generate electricity.

The AquaBuOY makes use of two hose pumps that alternately produce streams of water that impinge upon a small Pelton style wheel contained within the body of the buoy. The Pelton wheel is connected directly to a small generator where the rotation of the common shaft results in electrical power.

The Permanent Magnet Linear Generator Buoy also rides over the crest of the waves, but uses the vertical motion to move a magnet through the center of a small generator. The movement of the magnet through the copper windings in the core of the generator produces electrical energy each time the buoy rises or falls.

The Pelamis is the most sophisticated and commercially mature of wave energy equipment, as it uses the motion of the waves to pressurize a hydraulic system. Electrical energy is produced as the flow of oil through the hydraulic system rotates hydraulic motors attached to electrical generators. The key features of the Pelamis design are large cylindrical floats that attach directly to the hydraulic rams within a power module. Each power module is located between a pair of floats and the positions of the hydraulic rams within the power module allow the Pelamis device to convert both the vertical and horizontal movement of the floats into electrical energy.

The LIMPET relies upon wave action to initiate airflow through a turbine attached to an engineered structure located at either an on-shore or off-shore location with substantial wave activity. This structure consists of a series of inclined, open chambers with one end submerged in the sea. The wave action results in oscillating water columns inside the structure, that both expel air as the wave impinges upon the structure, then create a vacuum as the water columns drop during the subsequent trough before the next wave arrives. This, in turn, necessitates a bi-directional air driven power turbine to capture the energy of the air as it is both expelled and drawn back into the engineered structure.

Both the AquaBuOY and the Permanent Magnet Linear Generator Buoy have proposed applications within the Pacific Northwest, while the Pelamis and LIMPET devices are installed off of the north coast of Portugal and the Isle of Islay off the west coast of Scotland, respectively. Of these, the Pelamis site in Portugal has the highest reported installed capacity of 2.25 MW, followed by the 500 kW installed capacity of the LIMPET site on the Isle of Islay.

The maximum capacities for both the AquaBuOY and the Oregon State University (OSU) Permanent Magnet Linear Generator are reported to be the same, at 250 kW per buoy. However, the local conditions at each wave energy site heavily impact the expected capacities, as demonstrated by the four unit AquaBuOY pilot plant planned for Makah Bay. It has reported a per buoy capacity of 36 kW, for a total installed capacity of 144 kW. OSU will continue the development of its Permanent Magnet Linear Generator Buoy, and plans to contribute to the development of an open access wave energy park located along the west coast of Oregon. There, both OSU and other manufacturers of wave energy devices will be able to deploy their equipment, measure its power generation, and perform the field testing necessary to perfect their designs and improve efficiency.

Aside from the obvious design differences, it is also important to recognize another distinct difference between tidal energy and wave energy: Unlike tidal currents, which are influenced by the lunar cycle, wave energy is derived from the waves themselves. These waves result from wind acting upon the surface of the sea, local water depth, and sea bed conditions. The wind, being the most variable among these three factors, is also influenced by the combined effects of sunlight and barometric pressure. In this regard, wave energy power production is harder to schedule than tidal power, but will likely have a similar contribution to capacity.

While wave energy technology is perceived to have less potential impact on marine life than its tidal energy counterpart, it still faces similar challenges. As with tidal energy plants, commercial scale wave energy plants will have multiple units, with sophisticated anchoring and power transmission systems. This means each plant will have its own potential impact to the local aquatic environment. Underwater construction challenges, the permitting processes with both local and federal agencies, and access to grid interconnection points must also be resolved at each potential wave energy location before the wave energy plant can proceed to commercial scale and become a viable renewable energy resource.

EPRI's estimated summary of the economics for a full commercial installation off the Oregon Coast using a Pelamis machine is provided in Figure D-17. It is important to note that no commercial installations exist, and these estimates are highly theoretical.

Figure D-17
Pelamis Wave Energy Plant Cost Estimates

Capital Cost ($/kW)	Levelized Cost ($/MWh)	Commercial Installation Size (kW)	Expected Life (years)	Typical Capacity Factor
$2611 / kW	$116/MWh	90,000	15	40 %

VI. Waste to Energy Technologies

Waste to energy technology refers to methods of generating heat and power from energy that would otherwise be lost. This includes the collection and use of landfill gas, the incineration of solid waste, and the capture of energy lost in industrial processes. All forms of waste to energy technology are considered green, albeit to varying degrees.

A. Landfill Gas (LFG)

The Environmental Protection Agency (EPA) requires the collection of landfill gas (LFG) at nearly all U.S. landfills. They can sell the LFG, or use it to generate electricity. Nearly three quarters of the 421 U.S. landfills choose to utilize the gas to generate electricity, including five facilities in Washington, generating 1097 MW and 15 MW, respectively. Roughly every million tons of municipal solid waste provides enough gas for 0.8 MW of generation. King County has nearly 33 million tons of unused waste in candidate landfills, enough for 26 MW of generation.[23]

LFG is comprised of approximately 50% methane, and 50% CO_2, with trace amounts of other gasses. Although combustion of this gas does result in a net increase of greenhouse gasses, it is considered a renewable energy and qualifies for some renewable portfolio standards. BMW recently joined a long list of multinational companies using LFG when it converted the gas turbines in its South Carolina factory to be LFG compatible. The turbines had previously been mothballed due to the cost of natural gas.[24]

[23] EPA LMOP Database, http://www.epa.gov/landfill/proj/xls/lmopdata.xls
[24] Wasteage, http://wasteage.com/mag/waste_gas/index.html

B. Incineration of Municipal Solid Waste (MSW)

Only 14.7% of U.S. municipal solid waste (i.e. common trash) is directly incinerated, from which about 2,500 MW are generated nationwide. The primary reason for incineration is the reduction (up to 90% by volume) of the waste to be landfilled.[25] Seattle area firm WRSI refers to its incineration technology as "Thermal Recycling," as the company does not landfill any of its residues. In nations with limited space, incineration is more common. For example, Singapore incinerates 90% of its municipal solid waste.[26]

Figure D-18. Emissions Control Improvements

	1992 % of Waste Total	1999 % of Waste Total
Cadmium	35.9%	0.8%
Mercury	17.5%	1.3%
Arsenic	1.2%	1.0%
Chrmomium	9.3%	0.2%
Nickel	1.8%	0.3%
Lead	5.5%	0.1%
Particulates	0.3%	<.1%
Nitrogen Oxides	0.2%	0.2%
Sulphur Dioxide	0.1%	<.1%
Dioxins and Furans [a]	57.3%	4%[b]

[a] I-TEG : International Toxic Equivalent. This is derived as the sum of the Toxic Equivalent Factor (TEF) of all the dioxins and furans present in a mixture. The TEF for each compound is its relative toxicity in relation to the most toxic dioxin 2,3,7,8 - tetrachlorodibenzo-p-dioxin (TCDD)

[b] 1998 Data

Source: UK emissions in detail 1999, National Atmospheric Emissions Inventory

Historically, the public has fairly intensely opposed incineration, predominantly because of environmental concerns. For example, efforts to build a Seattle-area incineration facility were halted in the late 1980s. Although we've seen significant improvements in emissions control technologies since then (see Figure D-18), public opposition remains strong. In fact, some environmental groups suggest that the need for a steady incinerator fuel supply may provide an impetus to limit or actually reverse recycling efforts.

C. Reverse Polymerization

Reverse Polymerization is a process by which microwaves bombard solid waste in a low-oxygen environment and generate hydro-carbons. The hydro-carbons can then be used to either generate electricity, or be refined for industrial uses. This process can be applied to plastics, but is most commonly discussed in relation to tire disposal. Tires have a higher heat-content than coal and generally have a negative fuel cost.[27]

[25] EPA, http://www.epa.gov/cleanenergy/muni.htm
[26] UN Environment Program, http://www.unep.or.jp/ietc/estdir/pub/msw/sp/sp5/sp5_1.asp
[27] EPA, http://www.epa.gov/epaoswer/non-hw/muncpl/tires/faq.htm

The key advantage of reverse polymerization over incineration is the ability to recover the tire's carbon black and steel. This allows for 100% recycling of the tire. In regards to the results, this is similar to tire pyrolysis, although pyrolysis is not currently commercially viable. Reverse polymerization is in early deployment, and is also not yet commercial. Environmental Waste International, a leading developer, lists its TR-3000 unit, which has a consumption of 3,000 tires per day, as having a net annual output of 5,610 MWh (about 700 kW capacity) of electricity, 3,770 tons of carbon black and 1,000 tons of scrap steel. Efficiencies are designed to increase with scale.

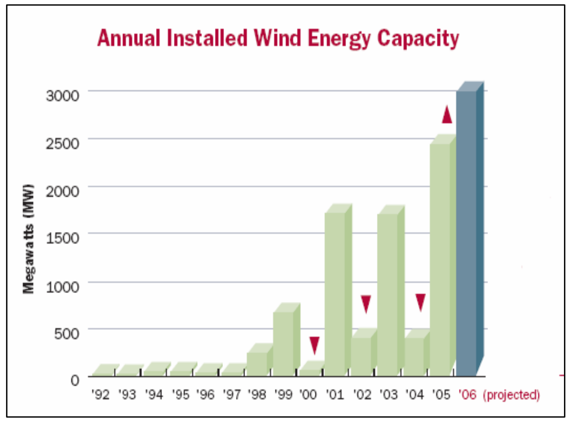
D. Waste Heat Recovery

Waste heat recovery projects typically harness exhaust heat to generate power. Recovery projects tend to be small in scope (less than 10 MW), as facilities with significant volumes of waste heat generally incorporated heat recovery into the original design. Specifics such as heat rates, availability and costs are highly project specific, depending on the volume and method of heat recovery. PSE has signed a letter of intent with ORMAT, an industry leader, for a 5 MW recovery system from the waste heat from turbines used for gas compression. ORMAT has identified roughly 600 turbines nationally as potential projects, for a total potential value of 932 MW. Similarly, ORMAT has identified 500 MW of waste energy available at cement factories.[28]

[28] Ormat, 2005, http://www.energy.wsu.edu/ftp-ep/pubs/events/geothermal/Buchanan_Targets.pdf

VII. Wind Energy

Figure D-19
Annual Installed Wind Capacity



Wind energy is the lowest cost alternative energy technology in the United States, and capacity is growing rapidly, as shown in Figure D-19. In 2006, the total installed wind energy capacity in the United States exceeded 11,000 MW, trailing only Spain and Germany in cumulative capacity, while being first in the world for capacity additions. Recent extension of the Production Tax Credit (PTC) to the end of 2008 should continue this trend. With the recent development and commercial operation of the Hopkins Ridge and Wild Horse wind farms, PSE has a strong familiarity with wind energy. This section addresses onshore wind technology as well as the potential for offshore wind farms.

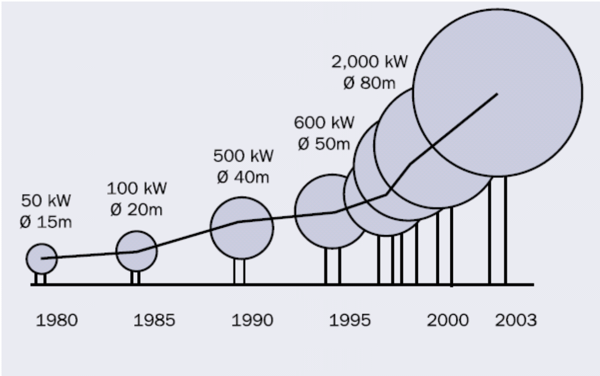
A. *Onshore Wind Power Trends*

The Danish Wind Industry notes three trends in grid connected turbines:

- The growth in size, height and capacity of turbines
- Increases in efficiency
- Decreased investment costs

Although the cost of turbines has risen in the last few years (a short-term spike driven by robust demand and limitations on manufacturing and supply logistics), all three of these trends have held true long term. This cost spike may extend because of Washington state's new Renewable Portfolio Standard (I-937), but is expected to return to its historical trend as manufacturing catches up to demand.

Figure D-20
Growth in Wind Turbine Capacity



Wind turbines, towers and blades are all growing in size, driven by relatively fixed O&M costs, a desire to reduce incremental construction cost, and the presence of stronger and more stable winds at higher rotor hub heights. Better designs, materials, and manufacturing are improving the efficiency and reliability of ever-increasing turbine sizes. At Hopkins Ridge, first-year project availability exceeded 98%.

The distribution of U.S. wind energy suggests that future projects will be located in the Midwest and West. Since 2000, 91% of wind generation has been installed west of the Mississippi River.[29] The extension of the federal PTC until 2008 suggests that 2007 and 2008 will again be "boom" years for wind power, with the American Wind Energy Association projecting over 3,000 MW of new installations.

B. Offshore Wind Generation

The world's first offshore wind project was built in Denmark in 1991, north of the island of Lolland. The 4.9 MW project has performed flawlessly. Now more than 20 offshore projects are in operation, with four more under construction and 18 in the planning stage. The world's largest offshore wind project, Horns Reef, was completed in 2003, with 80 Vestas 2.0 MW turbines totaling 160 MW of capacity.[30] Cape Wind (Figure D-21), a hotly debated project near Cape Cod in Nantucket Sound, could be the first U.S. offshore wind farm in operation by 2010[31]. However, two projects planned off of Long Island (Bluewater

[29] Henwood Energy Database, 2005
[30] Danish Wind Industry Association, 2003, http://www.windpower.org/en/pictures/offshore.htm
[31] Cape Wind, 2007, www.capewind.org

and LIPA Offshore) are close behind. NREL's goal is to lower costs to $50 per MWh by 2012, at which time they expect to utilize new 5 MW turbines installed in shallow water (less than 15 meters).

Figure D-21. Simulated view of Cape Wind turbines from 5.2 miles

Source: Cape Wind

Offshore wind farms benefit from stronger, more stable winds, but have higher capital and operating costs. Offshore turbines may also have higher capacities than their onshore cousins due to modified gearboxes with higher rotation rates and greater noise (prohibitive on shore). Currently, there is no land lease fee for building wind turbines in federal waters, where all turbines for the Cape Wind project are located. The U.S. Army Corps of Engineers, the final authority for permitting, issued a largely positive Draft Environmental Impact Study for Cape Wind in 2004.[32] It reported minimal impacts on marine and bird life, as well as minimal water and noise pollution. Cape Wind filed its Final Environmental Impact Report (FEIR) on February 15, 2007 with the Massachusetts Environmental Policy Act (MEPA) office.

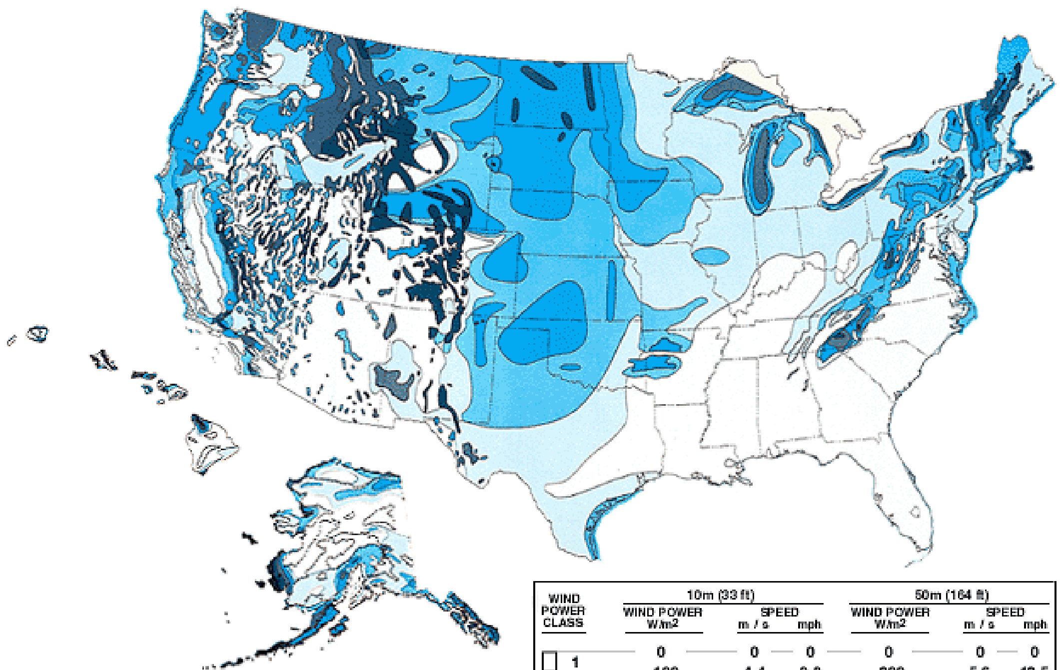
In general, offshore wind power is hoped to have less community resistance, although The Alliance to Protect Nantucket Sound, an energized opposition group comprised of prominent politicians, has formed in response to Cape Wind. Greenpeace and many other environmental groups have endorsed offshore wind energy, particularly Cape Wind.[33] It is unclear what kind of impact offshore farms will have on real estate values. Onshore studies in the United Kingdom have indicated that there is an initial negative impact to residential property values near wind farms, although this impact largely disappeared two years into operations.[34] European experience suggests that a decrease in property values may be offset, at least in part, by an increased tourism industry.

[32] Army Corp of Engineers, 2004, http://www.nae.usace.army.mil/projects/ma/ccwf/deis.htm
[33] Cape Wind, 2005, http://www.capewind.org/article47.htm
[34] Royal Institute of Surveyors, UK, 2003, http://www.rics.org/NR/rdonlyres/66225A93-840F-49F2-8820-0EBCCC29E8A4/0/Windfarmsfinalreport.pdf

An alternative with potentially fewer citizen objections is deep water wind farms. The European Commission is funding a pilot project in which two 5.0 MW REPower wind turbines were installed in the Scottish region of the North Sea at the Talisman Beatrice project in 2006.[35]

As indicated in Figure D-23 the coast of Washington state has strong winds, which may make it a potential site for offshore wind power projects. However, it remains to be determined whether such technology will become commercially viable and acceptable to the community.

Figure D-22. Available US Wind Energy



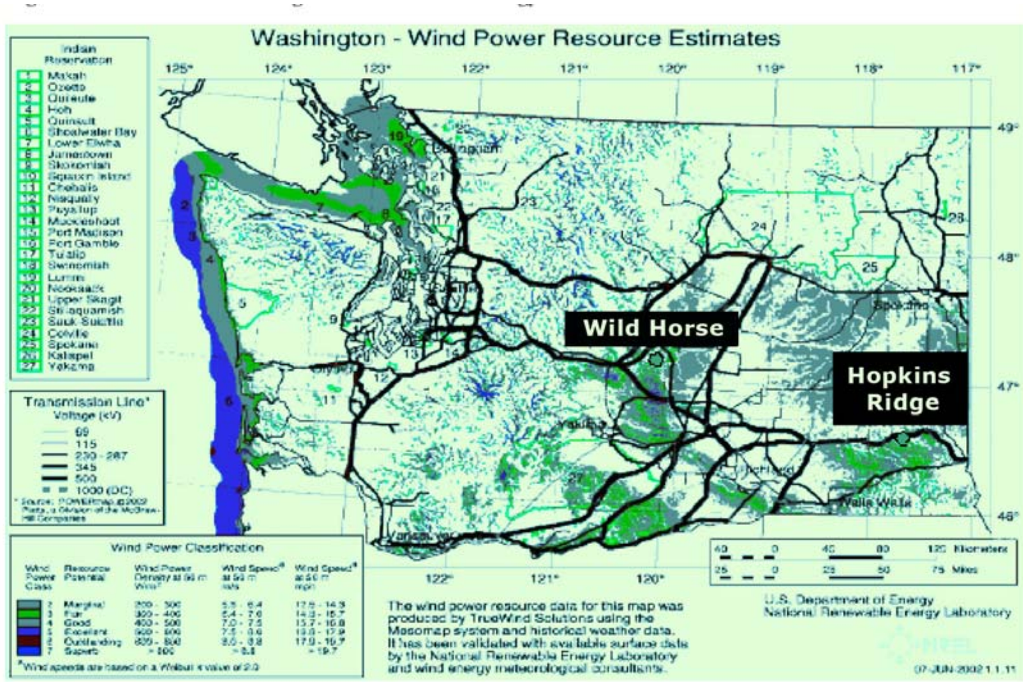
WIND POWER CLASS	10m (33 ft) WIND POWER W/m2	10m (33 ft) SPEED m/s	10m (33 ft) SPEED mph	50m (164 ft) WIND POWER W/m2	50m (164 ft) SPEED m/s	50m (164 ft) SPEED mph
	0	0	0	0	0	0
1	100	4.4	9.8	200	5.6	12.5
2	150	5.1	11.5	300	6.4	14.3
3	200	5.6	12.5	400	7.0	15.7
4	250	6.0	13.4	500	7.5	16.8
5	300	6.4	14.3	600	8.0	17.9
6	400	7.0	15.7	800	8.8	19.7
7	1000	9.4	21.1	2000	11.9	26.6

RIDGE CREST ESTIMATES (LOCAL RELIEF > 1000 FT)

Source: NREL

[35] Royal Institute of Technology in Stockholm, http://www.kth.se/forskning/pocket/project.asp?id=22466

Figure D-23
Available Washington State Wind Energy



Source: NREL

VIII. Geothermal

Despite over 100 years of history, the worldwide geothermal generation capacity is only around 8,000 MW, of which the United States has the largest national share at 2,700 MW.[36] Some countries such as Iceland (170 MW) and the Philippines (1909 MW) generate large portions of their power from geothermal sources[37], but the technology is inherently limited by geology. Development of geothermal power in the United States is concentrated in California, with the remaining capacity in Nevada, Hawaii and Utah.

Geothermal power captures heat from inside the earth using one of four methods:

- Dry Steam Plants utilize hydrothermal steam from the earth directly in turbines. This was the first type of geothermal power generation technology, but is limited by the number of sites that offer very hot (greater than 235°C) hydrothermal fluids that are predominantly steam.[38]
- Flash Steam Plants operate similarly to dry steam plants but use low pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high temperature geothermal sources (greater than 182°C).[39]
- Binary Cycle Power Plants can use lower temperature (107°C to 182°C) hydrothermal fluids to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, without even steam emissions. The majority of new geothermal installations are likely to be binary cycle systems due to emissions and the greater number of potential sites.[40]
- While the United States is not currently exploring hot dry rock technology, Japan, England, France, Germany and Belgium are looking into it.[41] It involves the drilling of deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.

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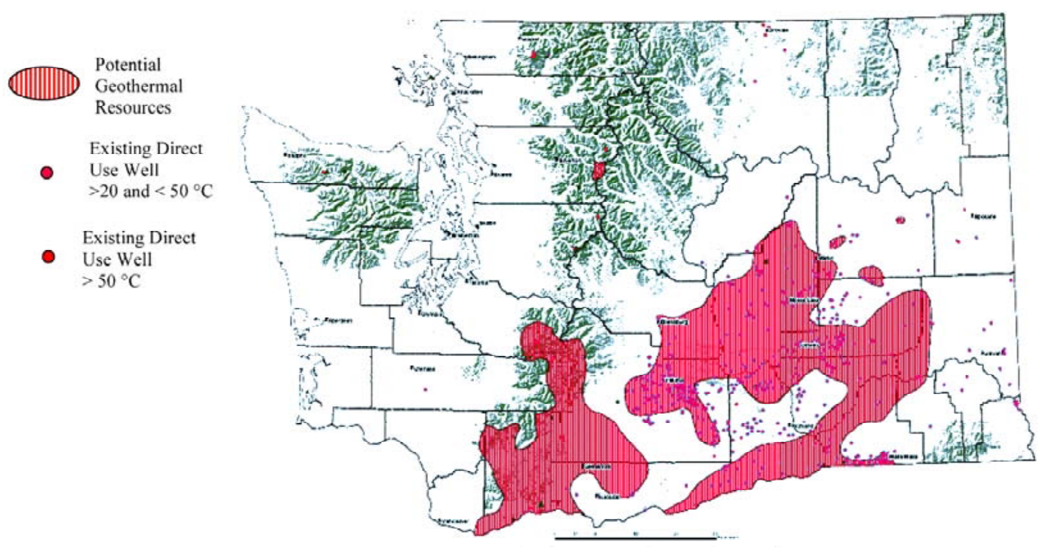
[36] EERE, http://www.eere.energy.gov/consumerinfo/factsheets/geothermal.html
[37] IGA 2000, http://iga.igg.cnr.it/geoworld/geoworld.php?sub=elgen
[38] Renewable Energy Policy Project http://www.crest.org/geothermal/geothermal_brief_power_technologyandgeneration.html
[39] EERE, http://www.eere.energy.gov/consumerinfo/factsheets/geothermal.html
[40] Ibid
[41] Geothermal Education Office, 2000, http://geothermal.marin.org/pwrheat.html

Geothermal depletion is a concern that leads many to question whether geothermal power is truly a renewable resource. Continued aggressive use of a geothermal well can lead to temperature and pressure reductions. The Geysers complex of geothermal installations in northern California decreased in output from over 1,800 MW in the late 1980s to around 1,000 MW in 2001. Economic modeling of 20 to 30 years of production is standard.[42] In addition, although SO_x and CO_2 emissions are very low, they are both present in both dry and flash steam plants as part of the geothermal fluid.

One of the primary challenges with geothermal power generation is handling the corrosive and scaling elements present in geothermal fluids. Research is ongoing with heat exchanger linings and acid resistant cements. In addition, there are efforts to extract commercial products such as zinc or high purity silica from geothermal fluids to offset costs.[43]

Figure D-24
Geothermal Potential in Washington



Source: DOE EERE, 2003

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[42] Geothermal.org, 2002, http://www.geothermal.org/articles/California.pdf
[43] Lawrence Livermoore National Labs, 2004, http://www.geothermal.org/DOE_presentations/BRUTON_L.PPT

Dr. Gordon Bloomquist of Washington State University, a specialist in geothermal energy, believes there is between 200 and 300 MW of geothermal potential in Washington state, notably around Mt. Baker, Mt. Adams and the Yakima Nation. He also notes that test wells in Oregon and British Columbia have identified geothermal fluids in excess of 500°C, and says there is no reason to believe that Washington state lacks geothermal resources.

IX. Coal

There are three principal technologies available for utilizing coal, and other solid fuels, in the production of electricity. Two of these technologies, pulverized fuel boilers and fluidized bed boilers, combust fuel to produce heat. The heat boils water to produce steam, which in turn drives a steam turbine-generator to produce electricity. When fueled with coal, these are referred to as "conventional coal" technologies. The third technology, gasification, converts any carbon-containing material into a synthesis gas (syngas) composed primarily of carbon monoxide and hydrogen. This syngas can be used to fuel the generation of electricity or steam.

A. Pulverized Coal

With pulverized coal (PC) technology, the coal is ground into a fine powder that is mixed with air and blown into the boiler furnace to be burned. The resulting heat is then used to produce steam. Fuel efficiency can be improved by increasing the temperature and pressure of the steam generated in the boiler. Current designs utilize steam pressures of 2500 psi and greater.

Supercritical boilers produce steam in excess of 3200 psi. Such boilers were introduced in the United States in the 1970s, but were plagued by metallurgical problems due to high operating temperatures and pressures. More recently, supercritical PC units (SCPC) have been operated successfully in Europe and Japan and have begun to re-emerge in North America. To further improve efficiency, ultra-supercritical PC units (UCPC), operating at even higher pressures, are now available.

Most coal boilers operating in the United States today use PC technology. PC boilers are also used to burn petroleum coke and other solid fuels. Boiler designs are available in a range of sizes from units producing less than 100 MW to those exceeding 1000 MW, powered by a single PC boiler. In addition to increasing boiler efficiency, vendors and equipment suppliers have improved combustion and post-combustion pollution control equipment to meet increasingly stringent emission reduction requirements.

B. Fluidized Bed

Fluidized bed (FB) technologies mix coal and an inert bed material, such as sand, in a combustor or boiler. The mixture of particles is suspended by an upward flow of air and burns producing heat to generate steam. Increasing air flow affects the fluid-like flow of the particles, resulting in a fixed, bubbling or circulating bed. Limestone may be added to the bed material to help capture sulfurous gases that are released as the coal is burned. High heat transfer in the boiler occurs with lower combustion temperatures, resulting in lower levels of NOx formation than in PC boilers. Post-combustion technologies may also be used to further lower air emissions.

FB boilers burn a wide variety of solid fuels in addition to coal and petroleum coke. The Jacksonville Electric Authority Demonstration Project is the largest single FB boiler built to date. It produces approximately 250 MW net.

The pressurized fluidized bed combustion (PFBC) boiler utilizes fluidized bed technology at elevated operating pressures to produce heat for steam production and hot pressurized exhaust gases that may be used to drive a combustion turbine. In the early 1990s, Ohio Edison built a demonstration PFBC plant to power a 55 MW steam turbine[44] and a 15 MW combustion turbine. Although the PFBC offers the promise of higher energy production efficiency, there has been no further commercial development of PFBC technology in the United States.

C. Gasification

Coal and other solid or waste fuels have been gasified to create liquid or gaseous fuels for more than 100 years. In the 1800s crude coal gasification provided gas for lighting streets and homes. During World War II, Germany gasified coal to produce fuel for airplanes and tanks. South Africa has gasified its indigenous coal supply to create liquid and gas fuels since the 1950s, and these plants continue to operate today.

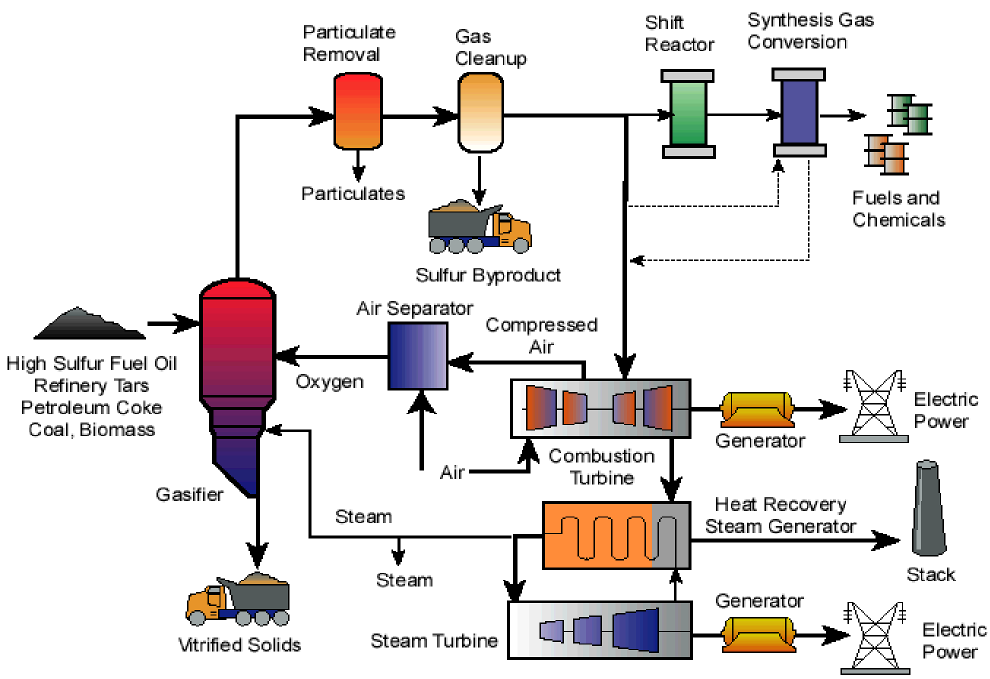
Coal gasification uses a partial oxidation process to produce a low to medium Btu (100-450 Btu per SCF) syngas, which can be fired in a boiler to produce steam to drive a steam turbine generator or may be substituted for natural gas in combustion turbines. In the partial oxidation reaction, there is insufficient oxygen present to convert all of the carbon in the fuel to carbon dioxide. When available oxygen is reduced, less heat is released from the coal and gaseous products appear. These products include hydrogen, carbon monoxide and methane (CH4), all of which contain potential chemical energy.

[44] The US DOE funded 35% of the cost of this project

Integrated Gasification Combined Cycle (IGCC)

The integrated gasification combined cycle process teams a gasifier with combined cycle equipment. While the extent of integration may vary, depending upon the gasification and combustion turbine equipment selected, IGCC generally refers to a model in which syngas from the gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier. Additionally, heat from the gasifier is coupled with exhaust from the combustion turbine to generate steam, which is used to drive a steam turbine-generator to produce additional electricity. This use of combustion turbine exhaust heat to generate steam that powers a steam turbine generator is a configuration known as combined cycle. This design has been widely used with natural gas and distillate fuels since the 1980s.

Figure D-25
The Coal Gasification Process



Source: Gasification Technologies Council (w ww.gasification.org)

The combination of coal gasification and combustion turbine technologies was first successfully demonstrated in the United States for electric power production on a commercial scale at the 100 MW Cool Water Demonstration Project in Daggett, California. This plant was operated successfully by Texaco, Bechtel, General Electric, and EPRI from 1984 to 1989 and was then decommissioned. A number of additional demonstration projects were developed in the 1980s and 1990s.

Commercial Availability

To date, the application of gasification for electric power production using IGCC has been limited to demonstration projects. While there are a number of vendors and technologies, their experience with different ranks of coal varies. The table below identifies the experience of major technology vendors with different types of U.S. coal.

Figure D-26
Gasification Technology Experience

	Fuel Type					
Technology Vendor	Lignite	Sub-Bituminous	Bituminous-Illinois Basin	Bituminous-Appalachian	Anthracite & Other Bituminous	Petroleum Coke
Allied Syngas - BGL	D	T	D	D		T
ConocoPhillips E-Gas	T	MM	MM	T		MM
General Electric (Texaco)	T	T	D	MM	MM	MM
KBR Transport Reactor	T	T	T			
Sasol-Lurgi	MM	MM	D	D	MM	
Shell	T	T	T	T	MM	MM
Siemens (Sustec)	D	T			D	

Key:
T = Tested
D = Demonstrated at 500 TPD or more
MM = Operated over 1 Millions Tons

Source: Lukes Consulting

To encourage commercialization of IGCC, major technology licensors have formed “alliances” with engineering and construction firms to provide design and construction on a turnkey basis, with guarantees for construction duration and cost. These alliances would also provide guarantees for initial operating performance, if employed under operating service agreements. To obtain such guarantees, a buyer must select a design fuel type and proceed with a Front End Engineering Design (FEED) study to develop the design envelope. Each alliance requires a specific FEED study before negotiating the contract and guarantees. Each FEED study is reported to cost more than $10 million.

There are currently two operating, commercial-size, coal-based IGCC power plants in the United States. The 262 MWe[45] Wabash River IGCC repowering project in Indiana commenced operation in October 1995[46]. Tampa Electric’s 250 MWe Polk Power Station IGCC project in Florida commenced operation in September 1996[47]. Additionally, there are two operating, commercial-sized IGCC power plants in Europe and one coal gasification project in the United States which provides feedstock for Eastman Chemicals in Kingsport, Tennesee.

The increase in cost and price volatility of natural gas has generated renewed interest in IGCC for electric power production. American Electric Power Company, Duke Energy (formerly Cinergy), Excelsior Energy and Energy Northwest have announced feasibility studies for commercial-scale IGCC facilities. NRG Energy recently proposed an IGCC facility in response to a New York Power Authority RFP. PSE has also received proposals from independent power developers for IGCC facilities.

D. Estimated Cost of Current Coal Technologies[48]

There is currently debate within the electric power industry regarding the costs and reliability of IGCC technology versus “conventional coal combustion” technologies. The

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[45] MWe is the abbreviation for megawatt electric. In this case MWe is used to indicate that the gasified coal is used to fuel a gas turbine, thus producing electric power.
[46] The Wabash River IGCC project uses the E-Gas gasification technology, which was acquired by ConocoPhillips in 2003.
[47] The Polk Power Station uses the Texaco gasification technology, which was acquired by GE Energy in 2004.
[48] This discussion is based on costs related to permitting, planning, design, construction and commissioning of the “power island” which begins at the point of receipt of the coal fuel at the plant site and ends with the generator step-up transformers before connection of the plant to a substation and the high voltage transmission system. The cost of interest during construction, or AFUDC, is not included.

installed cost of a power island using a pulverized coal (PC) boiler ranges between $2,400 per KW to $2,800 per KW in current dollars. Circulating fluidized bed (CFB) plants are in the same range; however, larger plants (over 250 MW) must be built in modules due to the size limits of available CFB boilers. IGCC plants are estimated to cost 15% to 20% more to construct than PC units of equal size.

Further, the gasification train of IGCC projects is less reliable than the power generation equipment of PC and atmospheric FB boilers. Without a spare gasifier, the equivalent availability of an IGCC unit is projected to be 85% while new PC units commonly attain over 90% equivalent availability. The reliability of the electricity-producing combined cycle plant can be increased to over 90% if the facility is designed to use both syngas and natural gas.

IGCC vendors are under pressure to reduce both the cost and down-time of their products. It is expected that IGCC unit costs will become similar to PC unit costs as more plants are built. IGCC plants will also be modular, in units of 250 MW to 300 MW, to take advantage of existing combustion turbine technology. The reliability of modular CFB or IGCC plants will likely be higher than that of a single boiler, single turbine PC unit.

The cost of a new coal plant is highly affected by siting factors: availability of electric transmission interconnection, availability of water and rail, and other infrastructure. Such costs may eliminate the cost differences between technologies. The cost of development, permitting and preliminary design can range from $20 million to $50 million without assurance that the plant can be built.

E. Environmental Climate

Major electric generating plants are subject to federal and state permitting laws and regulations covering air and water emissions, water use, waste management and pollution prevention. Additionally, state and local land use and zoning laws may govern site selection, and may also affect other plant siting issues, economic impacts or operating requirements. In the Pacific Northwest, the states of Washington, Oregon and Montana have created special regulation to manage the process of permitting major electric generating plants.

The Federal Clean Air Act applies to any electric generating facility and covers six Criteria Pollutants and more than 180 Hazardous Air Pollutants (HAPs). Of the HAPs, it is usually only Mercury and Nickel[49] that affect plant permitting and require specific control devices as part of the plant design, though many others must be analyzed during the permitting process. The EPA enforces the Clean Air Act and has set National Ambient Air Quality Standards (NAAQS) for six Criteria Pollutants: Sulfur Oxides, Nitrogen Dioxide, Particulate Matter, Ozone, Carbon Monoxide and Lead.

The federal Clean Air Mercury Rule (CAMR) requires that existing and new coal plants reduce at least 30% of their mercury emissions by 2010, and at least 70% by 2018. This rule is designed to permanently cap and reduce mercury emissions from coal-fired power plants. To date, 16 states have enacted or are in the process of enacting more restrictive mercury controls. Washington state's Department of Ecology is currently drafting such a rule.

Additionally, while the federal government has not addressed the issue of greenhouse gases (GHGs), states and local governments have been taking action. 2006 has seen a surge in political activity regarding GHG emission limits. As a result, a patchwork of local GHG policies and regulations has been developed, creating significant challenges for utility planning.

Carbon dioxide (CO_2) emissions from power generators are not currently regulated at the state or federal level; however, Washington and many other states currently require actual or economic mitigation of CO_2 emissions from new plants. PSE believes limits on CO_2 emissions will be imposed in the future and must be considered in the evaluation of future resources. See the Regulatory and Policy Activity chapter of the Environmental Concerns appendix for more information about possible future legislation.

New power plants (and major modifications to existing power plants) must employ Best Available Control Technology (BACT) and meet the New Source Performance Standards (NSPS) established by the EPA before receiving a permit to begin construction. What constitutes BACT is a function of the equipment and fuel to be utilized and the local and regional air quality. BACT is determined on a case-by-case basis, taking into account energy, environmental and economic impacts, and costs. Competition among equipment vendors, combined with pressure from plant owners and regulators have caused the BACT process to result in significant reductions in permitted emission levels. At present, the rate of change in BACT for gasification is far more rapid than for PC and FB units. Current EPA regulations and policy do not require that IGCC be included when

[49] Mercury and Nickel are subject to recent EPA rule-making to set emission limits.

performing BACT analyses for new PC and FB units; however, the permitting processes in many states do require such comparison. In February 2006, EPA revised its regulations to clarify that combustion turbines and combined cycle plants that receive 75% or more of their heat input from synthetic coal gas are subject to the same rules as utility steam boilers (40 CFR 60, Subpart Da) rather than the rules (Subpart KKKK) covering combustion turbines.

For more information about local and federal environmental regulations and related environmental issues, see Chapter 2, Planning Environment, and the Environmental Concerns Appendix, where PSE's Greenhouse Gas Policy can be found.

F. Emission Control Technologies

A significant difference between PC, FB and IGCC technologies is how, where in the process cycle, and how effectively Criteria Pollutants and HAPs are controlled. Conventional coal plants built recently include specialized, highly efficient pollution control equipment to reduce the emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx) and particulates. Some older plants have also added such pollution control devices and the federal Clean Air Interstate Rule is expected to significantly increase the number of existing plants with retrofitted pollution control equipment by 2010.

IGCC vendors claim greater capture rates for sulfur dioxide, nitrogen oxides and particulates because pollutant removal is performed prior to the introduction of the syngas fuel into the combustion turbine. In PC and FB boilers, these pollutants are captured during or after coal combustion. Vendors of conventional boilers have responded to these claims by continuing to offer equipment designs with lower emission rates. Nonetheless, some states are requiring the inclusion of gasification in the evaluation of BACT as part of the New Source Review process required for air permit application.

The following discussion focuses on the typical pollutants and HAPs that must be considered in converting coal to electricity. Because of the wide variety of proprietary gasification system designs, the process flow and equipment described may vary somewhat in configuration; however, all use the same basic steps.

Particulate Matter

Particulate matter refers to inorganic impurities in the coal in the form of fine ash.

Figure D-27
Particulate Matter Controls

PC and FB units	Particulate matter is captured using an electro-static precipitator (ESP) or a fabric filter (FF), also called a bag-house, to clean flue gases after they exit the boilers. ESPs were the first control devices applied to existing PC boilers. ESPs or FFs are used in the construction of all new PC and FB designs. Current performance requirements for ESPs and FFs are 0.02 lbs per MMBtu of heat input (about 0.2 lbs per MWh) or less in flue gases released to the atmosphere.
IGCC	Particulates are separated by gravity from the raw syngas in the gasifier. They exit the gasifier as slag or other similar solids. Additional removal of fine particulates takes place in candle filters in the raw syngas clean-up equipment between the gasifier and the combustion turbine. Current performance requirements are less than 0.01 Lbs per MMBtu or 0.1 Lbs. per MWh.

Sulfur Dioxide (SO_2)

All coal contains sulfur. It ranges from less than 1% by weight in some western U.S. coals to more than 6% in some mid-western coals. Petroleum coke, the waste product from the refining process, contains most of the sulfur from the original crude oil supply, which may be 4% by weight or more.

Figure D-28
Sulfur Dioxide Controls

PC units	Scrubbers are employed downstream of the boiler to mix an alkaline material, such as lime, with boiler exhaust gases to capture sulfur compounds. Some older scrubber designs also capture particulate matter (fly ash), eliminating the need for a separate ESP or FF. Scrubber designs fall into two broad categories: dry and wet. Dry scrubbers: Flue gas heat evaporates water media used to supply the alkaline material, leaving a dry alkali-sulfur compound. Particulate control equipment, normally placed after the scrubber, captures this dry product. Wet scrubbers: Particulate control occurs ahead of the scrubber. In such case, the alkali-sulfur product is a slurry with a chemical composition similar to natural gypsum. If transportation cost can be minimized, the scrubber product can be dried and sold for wall board manufacture.
FB units	Most FB units use an alkaline material as part of the bed. Before leaving the boiler, the alkali captures the sulfurous gas released during combustion and is then captured by the particulate control equipment, normally an FF. A polishing scrubber, similar to the main scrubbers on a PC unit, can be added to further reduce the amount of sulfur that leaves the stack in flue gases.
IGCC	The raw syngas that leaves the gasifier contains carbonyl sulfide (COS), which is converted to hydrogen sulfide (H2S) through electrolysis. Acid gas clean-up equipment then removes the H2S. Between the gasifier and the sulfur removal, the syngas is cooled in heat exchangers that use recovered heat to generate additional steam for the steam turbine. A sulfur recovery system may be added after the acid gas clean-up to recover sulfur as a salable by-product, either as elemental sulfur or as sulfuric acid.

Current SO_2 performance requirements for both PC and FB units require removal of more than 99% of the sulfur in the coal, yielding an emission level of 0.1 lbs per MMBtu (about 1 lbs per MWh) or less in the flue gases released into the atmosphere.

Current SO_2 performance requirements for gasification systems require removal of 99.5% of the sulfur in the coal, yielding an emission level as low as 0.03 lbs per MMBtu (less than 0.3 lbs per MWh) or less in the flue gases released into the atmosphere. In order to effectively capture mercury, the SO_2 emission level must be below 0.01 lbs per MMBtu before reaching the mercury absorber equipment. This requires use of a proprietary acid gas clean-up process, such as Selexol.

Nitrogen Oxides

Figure D-29
Nitrogen Oxide Controls

PC units	Nitrogen oxides (NOx) can be reduced in the PC boiler during combustion of the coal using Low NOx Burners, which reduce combustion temperatures, thereby affecting the amount of NOx produced. Over-fire air is used with Low NOx Burners to further cool the fireball in the furnace and reduce NOx production. Ammonia (NH3) can be injected into the PC boiler flue gas as it leaves the boiler to reduce NOx. A catalyst can be employed to aid in the chemical reaction between NH3 and NOx, that results in formation of water (H2O) and elemental nitrogen (N2). When a catalyst is used, this is called Selective Catalytic Reduction (SCR). Without a catalyst, it is known as Selective Non-Catalytic Reduction (SNCR).
FB units	In FB boilers, NOx is reduced in the combustor by keeping the combustion temperatures lower and may be further reduced by the addition of SCR or SNCR technology in the flue gas stream after the boiler.
IGCC	There is no NOx produced in the oxygen blown gasification process. The only NOx production occurs during the syngas combustion in the combustion turbine. NOx emission levels below 0.03 Lbs per MMBtu can be obtained with normal combustion practices using water and N2 (from the air separation plant) injection into the combustors of the combustion turbine with the syngas. Even lower levels, down to 0.01 Lbs per MMBtu or lower may be obtained by addition of SCR equipment to the combustion turbine exhaust. This requires extremely low levels of SO2 in the syngas stream to the combustion turbine.

Current NOx performance requirements for both PC and FB units is an emission level of 0.07 Lbs per MMBtu (about 0.7 Lbs per MWh) or less in the flue gases released to the atmosphere.

IGCC projects currently being permitted are being asked to review whether use of SCR equipment is BACT.

Mercury

As previously discussed, the federal Clean Air Mercury Rule (CAMR) will require that all coal-burning power plants reduce their mercury emissions beginning in 2010. Much research and demonstration of sorbent injection and other techniques to remove mercury from PC and FB unit flue gasses has taken place in the past five years, but no technology has been confirmed to provide long-term mercury removal for all types of coal and all boiler designs.

The Tennessee Eastman coal gasification facility has demonstrated success in removing mercury to non-detectable levels using sorbent beds during its syngas clean-up processes. The plant has been in operation generating chemical feedstocks since 1984. This sorbent bed technology should facilitate mercury removal at levels high enough to meet the requirements of CAMR.

Carbon Dioxide

Although carbon dioxide (CO_2) is not currently regulated as an air pollutant, there is keen interest in developing technologies to economically remove it from flue gases. Washington is one of several states that requires mitigation of carbon dioxide emissions from new power plants. The technology for carbon dioxide capture in the gas clean-up portion of the IGCC is clearly more developed than is post-combustion capture of carbon dioxide from either a PC or FB boiler. However, effective methods of permanent sequestration, other than injection for enhanced oil recovery in specific locations, is not commercially developed and readily accessible. A July 2006 study for the Environmental Protection Agency found that adding carbon capture technology to various IGCC designs increased the cost of electricity by 25% to 40%. The estimated increase in the cost of energy from a supercritical PC unit was as much as 65%. Not only does carbon capture involve the capital and operating costs of additional equipment, it also increases parasitic plant energy use significantly. This study and others available in the public literature caution that IGCC design and cost information is more sensitive to both the specifics of the site and the type of coal to be used than a PC unit. The limited development of carbon dioxide sequestration technologies and sites, however, limits the current ability of both IGCC and conventional coal technologies to “solve” the GHG problem.

Carbon capture

Very limited demonstration of amine-based CO2 capture systems have been demonstrated on flue gas slipstreams of PC and FB systems. Research is also underway to produce more cost-effective systems using ammonia-based or other processes, but no systems are currently available for full-scale CO2 removal from PC or FB units. Further, preliminary estimates indicate that such systems could increase the cost of electricity by 60% or more.

The use of “oxy-fuel” combustion practices, which uses an air separation plant to deliver O_2, rather than air, for the combustion process is being developed for PC units. This could be used in new designs or retro-fit to existing PC units. Using oxy-fuel techniques yields a flue gas stream of nearly pure CO_2, eliminating the need to separate the CO_2 from the other gases, primarily nitrogen, in the flue gas stream. There has been no demonstration of this technology except in pilot projects and no good estimates of cost.

Separation of CO_2 in the gasification process has been demonstrated using the water shift reaction to convert carbon monoxide (CO) and water into CO_2 and elemental hydrogen (H_2) as the fuel gas. However, combustion turbines that can utilize H_2 are being developed but are not currently available -- research is on-going by several combustion turbine producers.

Carbon Sequestration

Terrestrial carbon sequestration utilizes natural methods for returning carbon to the soil and plants at the surface level. Soil contains CO_2, which is sequestered by the plants. But overgrazing reduces the plants’ ability to perform their function. Improved pasture management can increase the amount of CO_2 in the soil. Crops also sequester carbon in the soil, but the tilling process releases it back into the atmosphere. Agriculture practices that reduce tilling have been shown to increase the level of carbon in the soil. Afforestation is the growing of trees that will capture carbon and hold it until the wood decomposes or is combusted. Hence, long term management of afforestation projects is necessary to insure that the carbon stays sequestered. Overall, while agriculture is responsible for a small portion of America’s contribution to climate change, it can still be part of the solution.

Geologic sequestration involves pumping CO_2 deep into the ground, where it reacts with the rocks to form an inert compound. There are numerous opportunities for carbon capture and sequestration (CCS). For example, for 30 years oil companies have practiced "enhanced oil recovery" whereby they pump CO_2 from the refining process into the wells to improve the recovery of oil. In the Northwest, testing is currently underway with wells drilled deep into the saline aquifer where the pressure is also very high. The pumped CO_2, in an aqueous state, reacts with the mafic rock (basalt) to form the inert calcite. The economic cost of the geologic sequestration has not been determined at this time; however, significant infrastructure investments are necessary in order to accomplish CCS on a large scale.

PSE participates in the Big Sky Carbon Sequestration Partnership based in Bozeman, MT, which is investigating numerous sequestration technologies for effectiveness and cost[50].

Water Use

Because IGCC units utilize both gas turbines and steam turbines for electricity production, consumptive water use is typically about one-third less than that of similarly-sized PC or FB units. IGCC units use smaller steam turbines, requiring less condenser cooling water.

Solid Wastes

PC, FB and IGCC units all produce solid waste products that can be marketed or disposed of as solid waste. The types of products produced vary by technology and design. The ability to market these products is largely a function of plant location and bulk material transportation costs.

[50] Big Sky Carbon Partnership, Montana State University, Bozeman, MT; http://www.bigskyco2.org/

X. Natural Gas

A. Combined-cycle Combustion Turbines

A combined-cycle combustion turbine (CCCT) power plant consists of one or more gas turbine generators (GTG) equipped with heat recovery steam generators (HRSG) to capture heat from the gas turbine exhaust. Steam produced in the HRSG powers a steam turbine generator (STG) to produce additional electric power. Use of the otherwise wasted heat in the turbine exhaust gas results in high thermal efficiency compared to other combustion based technologies. CCCT plants currently entering service can convert about 50% of the chemical energy of natural gas into electricity.

A single-train CCCT plant consists of one GTG, HRSG, and STG (or 1x1 configuration). Using “F-class” combustion turbines - the most common technology in use for large CCCT plants - this configuration can produce about 270 MW of capacity. Plants can also be configured using two or even three GTGs and a HRSG feeding a single, proportionally larger STG. Larger plant sizes result in economies of scale for construction and operation, and designs using multiple GTGs provide improved part-load efficiency. A 2x1 configuration using F-class technology will produce about 540 MW of capacity. Other plant components include a switchyard for electrical interconnection, cooling towers for cooling the STG condenser, a water treatment facility and control and maintenance facilities.

Additional peaking capacity can be obtained by use of various power augmentation features, including inlet air chilling and duct firing (direct combustion of natural gas in the HRSG). For example, an additional 20 MW to 50 MW can be gained from a single-train plant by use of duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base CCCT plant, the incremental cost is low and the additional electrical output can be valuable during peak load periods.

GTGs can operate on either gaseous or liquid fuels. Pipeline natural gas is the fuel of choice because of historically low and relatively stable prices, deliverability and low air emissions. Distillate fuel oil can be used as a backup fuel.

Because of high thermal efficiency, low initial cost, high reliability, relatively low gas prices and low air emissions, CCCTs have been the new resource of choice for bulk power generation for well over a decade. Other attractive features include significant operational flexibility, the availability of relatively inexpensive power augmentation for peak period operation and relatively low carbon dioxide production.

Proximity to natural gas mainlines and high voltage transmission is the key factor affecting the siting of new CCCT plants. Secondary factors include water availability, ambient air quality and elevation.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of any power generation technology using fossil fuel. The carbon dioxide production of a CCCT plant on a unit output basis is much lower than that of other fossil fuel technologies.

B. Peaking Power Plants[51]

Peaking power plants, also known as peaker plants, are power plants that generally run only when there is a high demand, known as peak demand, for electricity. In contrast, base load power plants operate continuously, stopping only for maintenance or unexpected outages. Intermediate plants operate between these extremes, curtailing their output in periods of low demand, such as during the night. Base load and intermediate plants are used preferentially to meet electrical demand because the lower efficiencies of peaker plants make them more expensive to operate.

The time that a peaker plant operates may be many hours a day or as little as a few hours per year. It depends on the loading condition of the region's electrical grid. It is expensive to build an efficient power plant, so if a peaker plant is only going to be run for a short and variable time, it does not make economic sense to make it as efficient as a base load power plant. In addition, the equipment and fuels used in base load plants are

[51] References for peaking power plant information
http://www.simplecyclepowerplants.com/
http://en.wikipedia.org/wiki/Gas_turbine
http://www.energysolutionscenter.org/DistGen/Tutorial/TutorialFrameSet.htm
http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf
http://www.energysolutionscenter.org/DistGen/Tutorial/TutorialFrameSet.htm
http://en.wikipedia.org/wiki/Reciprocating_engine
http://www.energy.ca.gov/distgen/equipment/reciprocating_engines/reciprocating_engines.html
http://www.cat.com/cda/layout?m=37508&x=7
http://www.eere.energy.gov/de/gas_fired/
http://www.wartsila.com/,en,solutions,applicationdetail,application,F00F72F1-9579-47E6-B6BD-60A0E42943A4,B0B76B09-FEAF-497D-9D59-BA2EC30AFB1E,,.htm

often unsuitable for use in peaker plants because the fluctuating conditions would severely strain the equipment. For these reasons, nuclear, geothermal, waste-to-energy, coal and biomass plants are rarely, if ever, operated as peaker plants.

Peaker plants are generally gas turbines that burn natural gas. A few burn distillate fuel, but it is usually more expensive than natural gas, so its use is limited. However, many peaker plants are able to use distillate fuel as a backup. The thermodynamic efficiency of gas turbine peaker power plants ranges from 20% to 40%, with about 30% to 35% being average for a new plant. The most efficient gas turbine plants are generally used for load cycling, cogeneration projects, or are intended to be operated for longer periods than usual. Reciprocating engines are sometimes used for smaller peaker plants.

C. Simple Cycle Combustion Turbines (SCCT)

Simple cycle combustion turbines in the power industry require smaller capital investment than coal, nuclear or even combined cycle natural gas plants and can be designed to generate small or large amounts of power. Also, the actual construction process can take as little as several weeks to a few months, compared to years for base load power plants. Their other main advantage is the ability to be turned on and off within minutes, supplying power during peak demand. Since they are less efficient than combined cycle plants, they are usually used as peaking power plants, which operate anywhere from several hours per day to a couple dozen hours per year, depending on the electricity demand and the generating capacity of the region. In areas with a shortage of base load and load following power plant capacity, a gas turbine power plant may regularly operate during most hours of the day and even into the evening. A typical large simple cycle combustion turbine may produce 75 MW to 180 MW of power and have 35% to 40% thermal efficiency. The most efficient turbines have reached 46% efficiency.

The modern power combustion turbine is a high-technology package that is comprised of a compressor, combustor, power turbine, and generator. In a combustion turbine, a large volume of air is compressed to high pressure in a multistage compressor. Fuel is then added to the high-pressure air and combusted. The combustion gases from the combustion chambers power an axial turbine that drives the compressor and the generator. In this way, the combustion gases in a combustion turbine power the turbine directly, rather than requiring heat transfer to a water/steam cycle to power a steam turbine, as in the steam plant. The latest combustion turbine designs use a turbine inlet temperature of 1,500°C (2,730°F) and compression ratios as high as 30:1 (for aeroderivatives) giving thermal efficiencies of 35% or more for a simple-cycle combustion turbine.

D. Reciprocating Engine Systems

Reciprocating engines are piston-driven electrical power generation systems ranging from a few kilowatts to over 15 MW. Reciprocating engine technology has improved dramatically over the past three decades because of economic and environmental pressures for power density improvements (more output per unit of engine displacement), increased fuel efficiency, and reduced emissions.

The reciprocating, or piston-driven, engine is a widespread and well-known technology. Also called internal combustion engines, reciprocating engines require fuel, air, compression, and a combustion source to function. Depending on the ignition source, they generally fall into two categories: (1) spark-ignited engines, typically fueled by gasoline or natural gas, and (2) compression-ignited engines, typically fueled by diesel oil fuel.

Almost all engines used for power generation are four-stroke and operate in four cycles (or stokes). The four-stroke, spark-ignited reciprocating engine has intake, compression, power, and exhaust cycles. In the intake phase, as the piston moves down in its cylinder, the intake valve opens, and the upper portion of the cylinder fills with fuel and air. When the piston returns upward in the compression cycle, the spark plug emits a spark to ignite the fuel-air mixture. This controlled reaction, or "burn," forces the piston down, thereby turning the crank shaft and producing power. In the exhaust phase, the piston moves back up to its original position, and the spent mixture is expelled through the open exhaust valve.

The compression-ignition engine operates in the same manner, except the introduction of diesel fuel at an exact instant ignites in an area of highly compressed air-fuel mixture at the top of the piston. In diesel units, the air and fuel are introduced separately with fuel injected after the air is compressed by the piston in the engine. As the piston nears the top of its movement, a spark is produced that ignites the mixture (in most diesel engines, the mixture is ignited by the compression alone).

Dual fuel engines use a small amount of diesel pilot fuel in lieu of a spark to initiate combustion of the primarily natural gas fuel. The pressure of the hot, combusted gases drives the piston down the cylinder. Energy in the moving piston is translated to rotational energy by a crankshaft. As the piston reaches the bottom of its stroke, the exhaust valve opens and the exhaust is expelled from the cylinder by the rising piston.

Commercially available reciprocating engines for power generation range from 0.5 kW to 16.5 MW. Reciprocating engines can be used in a variety of applications because of their small size, low unit cost, and useful thermal output. They offer moderate capital cost, easy start-up, proven reliability, good load-following characteristics, and heat recovery potential. Possible applications for reciprocating engines include continuous or prime power generation, peak shaving, backup power, premium power, remote power, standby power, and mechanical drive use. When properly treated, the engines can run on fuel generated by waste treatment (methane) and other biofuels.

XI. Nuclear

A nuclear power plant (NPP) is a thermal power station in which the heat source is one or more nuclear reactors. Nuclear power is the controlled use of the nuclear fission reaction to release energy for work including propulsion, heat, and the generation of electricity. Nuclear energy is produced when a fissile material, such as uranium-235 (U^{235}), is concentrated such that nuclear fission takes place in a controlled chain reaction and creates heat—which is used to boil water, produce steam, and drive a steam turbine to generate electricity[52].

Nuclear fuel production for light water reactors begins with concentrating the U^{235} fraction of natural uranium to the desired enrichment. The enriched uranium is reacted with oxygen to produce uranium oxide. This is fabricated into pellets, which are then stacked and sealed into zirconium tubes to form a fuel rod. Fuel rods are assembled into fuel assemblies - bundles of rods arranged to accommodate neutron absorbing control rods and to facilitate removal of the heat produced by the fission process. Nuclear fuel is a highly concentrated and readily transportable form of energy, freeing nuclear power plants from fuel-related geographic constraints[53].

Operating nuclear units in the United States are based on light water reactor technology developed in the 1950s. Future nuclear plants are expected to use advanced designs employing passively operated safety systems and factory-assembled standardized modular components. These features are expected to result in improved safety, reduced cost and greater reliability. Though preliminary engineering is complete, construction and operation of a demonstration project is required before the technology can be considered commercial. Electricity industry interest in participating in one or more commercial-scale demonstrations of advanced technology is increasing. But even if demonstration plant development moves ahead in the next several years, lead times are such that advanced technology is unlikely to be fully commercial until about 2015. This suggests the earliest operation of fully commercial advanced plants would be around 2020. Also needed for public acceptance of new nuclear development is a fully operational spent nuclear fuel disposal system. Though spent fuel disposal technology is available and the Yucca Mountain site is under development, the timing of commercial operation remains uncertain.

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[52] http://en.wikipedia.org/wiki/Nuclear_power
[53] Northwest Power Planning Council

Nuclear plants could be attractive under conditions of sustained high natural gas prices and aggressive greenhouse gas control. Other factors favoring nuclear generation would be failure to develop economic means of reducing or sequestering the CO2 production of coal based generation, and difficulty expanding transmission to access new wind or coal resources.

Nuclear energy uses an abundant, widely distributed fuel, and mitigates the greenhouse effect if used to replace fossil-fuel-derived electricity. Lately, there has been renewed interest in nuclear energy from national governments due to economic and environmental concerns. Other reasons for interest include increased oil prices, new passively safe designs of plants, and the low emission rate of greenhouse gas.

Nuclear power plants are base load stations, which work best when the power output is constant (although boiling water reactors can come down to half power at night). Their units range in power from about 40 MW to over 1200 MW. New units under construction in 2005 are typically in the range 600 MW to 1200 MW. As of 2006, new nuclear power plants are under construction in several Asian countries, as well as in Argentina, Russia, Finland, Bulgaria, Ukraine, and Romania.

Nuclear power is highly controversial, enough so that the building of new commercial nuclear power plants in the United States has ceased - at least temporarily. Under recent legislation intended to jump-start development, Congress is offering more than $8 billion in subsidies and loan guarantees for the first few new plants that get built. Constellation Energy Inc. has publicly identified two sites for development. A consortium of utilities called NuStart Energy Development LLC is in the application and development process for two new plants. Also, Dominion Resources Inc. and Southern Company are each considering new plants.[54]

Almost all the advantages and disadvantages of commercial nuclear power are disputed in some degree by the advocates for and against nuclear power. The use of nuclear power is controversial because of the problem of storing radioactive waste for indefinite periods, the potential for possibly severe radioactive contamination by accident or sabotage, and the possibility that its use in some countries could lead to the proliferation of nuclear weapons. Proponents believe that these risks are small and can be further reduced by the technology in the new reactors. Disposal of spent fuel and other nuclear waste is claimed by some as an advantage of nuclear power, claiming that the waste is

[54] "Power Producers Rush to Secure Nuclear Sites: First to Develop Plans Could Tap $8 Billion In Federal Subsidies" WSJ 1/29/2007

small in quantity compared to that generated by competing technologies, and the cost of disposal small compared to the value of the power produced. Others list it as a disadvantage, claiming that the environment cannot be adequately protected from the risk of future leakages from long-term storage.

The cost benefits of nuclear power are also in dispute. It is generally agreed that the capital costs of nuclear power are high and the cost of the necessary fuel is low compared to other fuel sources. Proponents claim that nuclear power has low running costs, and opponents claim that the numerous safety systems required significantly increase running costs.

New Plant Costs[55]

There has been little hard evidence of recent U.S. nuclear developments from which reasonable cost estimates can be made. However, the table below contains current information from the Northwest Power and Conservation Council that can shed some light on international nuclear developments. Please note that these figures reflect "overnight" costs as opposed to "all-in" costs, meaning that they assume the plant could be acquired overnight and thus, no interest or related development cost risks are assessed for the seven to ten year development period.

Figure D-30
Nuclear Plant Capital Costs

Plant Name	Location	COD	"Overnight" Cost (in 2002 dollars)
Genkai 3	Japan	1994	$2818/kW
Genkai 4	Japan	1997	$2218/kW
Onagawa	Japan	2002	$2409/kW
KK6	Japan	1996	$2020/kW
KK7	Japan	1997	$1790/kW
Yonggwang 5&6	Korea	2004/5	$1800/kW
Olkiluoto 3	Finland	2010-2011	$2500-3000/kW

As Figure D-30 illustrates, the average "overnight" cost of the seven recently-built units is $2,130 per kW in 2002 dollars. These figures do not reflect the impact of escalation to 2007 dollars. Further, they do not reflect the impact of nuclear fuel cost increases, which have risen significantly since 2002.

[55] The information provided in this section has been adapted from a Northwest Power and Conservation Council presentation titled "Costs and Prospects for New Nuclear Reactors", which was developed and presented by Jim Harding in February 2007.

XII. PPAs and PBAs

A purchased power agreement (PPA) is a bilateral wholesale or retail power contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point. PPAs may be long term (up to or greater than 15 years) or short term (less than two years) in nature, and can be shaped to provide peak power.

PSE also uses the term "power bridging agreements" (PBAs) to designate PPAs that bridge the period until long-lead resources or transmission can be developed. Over our 20-year planning horizon, PSE's load-resource balance demonstrates an immediate and continually growing need for new resources. Certain desirable resources may not be immediately available or may require new transmission before becoming viable. PBAs allow us the option to bridge our need before such longer-lead resources are online. PBAs also allow us to directly test delaying a resource.

Regional Transmission Resources

The following is a summary of attempts to address long-term regional transmission planning and expansion issues discussed in Chapter 5, Electric Resources.

I. Regionally-based Efforts

A. Northwest Transmission Assessment Committee (NTAC)

The Northwest Transmission Assessment Committee (NTAC) was established in 2003 to approach transmission issues from a perspective influenced by both commercial and reliability needs. NTAC continues to function as an open forum to address forward-looking planning and development for the Northwest Power Pool (NWPP) area transmission system.

NTAC subcommittees continue to study congested paths of interest to participants. They have studied and continue to study the Puget Sound area, the Montana to Northwest path, the Pacific Northwest/Canada to Northern California path, and the SE Washington/NE Oregon area. They also perform various reliability studies.

NTAC is also reviewing the Northern Lights proposal, from Fort McMurray, Alberta to Celilo. Follow-up work on the Pacific Northwest/Canada to Northern California study performed by NTAC has been picked up by Pacific Gas and Electric Company (PG&E).

B. Pacific Northwest/Canada to Northern California

This transmission project is intended to be operational by 2013. It is the natural outgrowth of the NTAC study completed in May 2006 exploring the possibility of transmitting renewable resources from Canada and Northwestern US to California. PG&E is taking the next step; they intend to formulate and go through all the stages of the WECC process. This proposed transmission project is intended to provide three main benefits:

- Access to significant incremental renewable resources in Canada and the Pacific Northwest.
- Regional transmission reliability improvement.
- Opportunities for market participants to use the facilities

C. The Rocky Mountain Area Transmission Study (RMATS)

RMATS has identified projects for both short- and long-term improvements. One of the RMATS recommendations was for export projects beyond that footprint, which included the Montana to the Northwest path. The RMATS work has been picked up by others, including the planning for the Frontier Line and Wyoming Infrastructure Authority.

D. Northwest Wind Integration Action Plan

The Northwest Power and Conservation Council and BPA have co-sponsored development of a Northwest Wind Integration Action Plan. The plan will identify and commit participants to regional steps to cost-effectively integrate large amounts of wind power and other intermittent renewable resources into the Northwest power system. The Council's 5th Power Plan calls for 6,000 megawatts of new wind generation over the next 20 years. The Transmission Expansion and Planning Committee has developed transmission plans to integrate the addition of 6,000 megawatts of wind.

E. Involvement of Western State Governors

The Western Governors' Association (WGA) continues to respond to issues regarding transmission. The WGA formed the Clean and Diversified Energy Advisory Committee (CDEAC) and charged it with the task of identifying incentive-based, non-mandatory recommendations that would facilitate 30,000 megawatts of new clean and diverse energy by 2015, a 20 percent increase in energy efficiency by 2020 and adequate transmission for the region. From the CDEAC report the Western Governors adopted numerous recommendations regarding transmission, including

- encouraging federal agencies to collaborate with Western states and regional organizations on facility siting and infrastructure planning,
- encouraging proactive, transparent, stakeholder-driven regional transmission expansion planning, defer to existing regional and sub-regional processes that meet such standards, and reform imbalance penalties to allow for greater use of the existing transmission system.

- supporting reforms in the U.S. Federal Energy Regulatory Commission's Open Access Transmission Tariff to implement the recommendations of the CDEAC that promote (a) regional transmission planning expansion and (b) expanded use of the existing transmission grid by reforming imbalance penalties.

II. The Energy Policy Act of 2005 (EPAct)

The EPAct addressed the difficulties of siting major new transmission facilities by authorizing the Secretary of Energy to designate “national interest electric transmission corridors” where there is major transmission congestion. EPAct allows applicants seeking to build transmission within these corridors to seek construction permits from the FERC under certain conditions. While most transmission projects will continue to be sited by states under state law, EPAct granted the FERC this important supplemental siting authority. FERC has proposed rules on transmission siting that will govern the issuance of construction permits by the FERC for projects that meet the statutory criteria.

In order to know what geographic areas FERC has authority to issue construction permits, FERC first had to determine where there was congestion. The U. S. Department of Energy was charged with the task of performing a study of congestion around the nation.

Department of Energy (DOE) National Electric Transmission Congestion Study
This is the first congestion study, published in August 2006, performed by the DOE (or Department), in response to EPAct. The study suggested that the Department now has to focus greater attention on the need to maintain, upgrade and build major transmission lines. The study primarily examines transmission congestion in many areas of the Nation of both the Eastern and Western Interconnections. From PSE IRP perspectives, it is relevant to focus on the Western region.

The Department categorizes three classes of congestion areas which warrant further Federal attention:

- Critical Congestion Areas - Where solutions to remedy existing or growing congestion problems are seriously needed. Southern California has been identified as such an area.

- Congestion Areas of Concern - Where a major congestion problem exists or may be emerging, but additional information and analyses are needed to confirm. Seattle–Portland and San Francisco Bay areas are identified as Areas of Concern.
- Conditional Congestion Areas - Where some congestion might exist, but significant congestion could result if major new generation resources were to be developed without the addition of more transmission capacity. These areas are potential locations for large-scale development of wind, coal and nuclear generation capacity to serve distant load centers. The Montana-Wyoming (coal and wind) has been identified as one such area of interest.

The Department believes that it may be appropriate to designate one or more National Corridors to facilitate relief of transmission congestion for the Critical Congestion Areas. However, it will also consider designating National Corridors to relieve congestion in Congestion Areas of Concern and Conditional Congestion Areas.

The study also explains that the states of Washington and Oregon are no longer peaking in winter only. Rapid population growth has led to summer air conditioning loads, and economic trends have shifted away from manufacturing toward a more service-based economy. With these developments, the Pacific Northwest faces a growing need for more transmission capacity to support market transactions and protect system reliability.

Financial Considerations

Financial considerations play a part in resource planning and acquisition because, in order to fulfill our responsibilities, PSE requires continuous access to capital markets on reasonable terms, available credit to operate the business, and the capability to execute risk management strategies.

Section I, Primary Considerations, discusses the most important of these considerations:

- the company's credit rating and how it affects the cost of credit for financing and risk management activities
- imputed debt cost associated with purchased power agreements (PPAs) and how it affects that credit rating
- financial considerations that were applied to this IRP analysis.

Section II, Further Considerations, contains:

- a detailed discussion of imputed debt issues
- summaries of relevant changes in financial accounting standards
- a description of risk management activities
- an explanation of the production tax credit and other tax incentives applied to certain resources

I. Primary Considerations

A. Credit Rating Significance

In general, financing for ongoing operations and new capital requirements comes from funds generated internally through operating cash flows, and from funds raised externally from both the debt and equity capital markets. PSE's historic reliance on purchased power does not generate cash flow, which other utilities generate from the recovery of depreciation of owned resources through rates charged to customers. Without this source of cash inflow, PSE expects to be a net borrower in order to fund the growth and maintenance of our transmission and distribution system, and the purchase of new resources. As such, continuous access to debt and equity capital markets is critical to PSE's successful execution of our capital spending plans.

To attract adequate and reasonable external debt financing, we must maintain an attractive credit and investment profile. Credit ratings are the primary measure used by investors to compare the creditworthiness of different companies. Moody's Investors Service and Standard and Poor's (S&P) are two of the major credit rating agencies.

PSE currently carries the lowest investment-grade credit rating (BBB-/Baa3). The rating affects the company in several ways. Generally, it makes our debt costs higher than they would be at a stronger rating; it limits our access to financial markets during periods of economic downturn or market stress (like credit market events, power cost fluctuations, regulatory, tax and political changes, wholesale market developments, and force majeure actions); and it provides limited cushion from a potential downgrade to non-investment grade status. Specifically related to resource planning, PSE's current rating

- increases the cost of borrowed funds used to finance capital expenditures like infrastructure improvements and new generation facilities
- limits the amount of unsecured credit extended by counterparties with whom we arrange for PPAs
- increases the cost of long-term PPAs, since providers will want compensation for the credit risk inherent in a long-term purchase contract.

Improving our credit rating to is a key part of our financial strategy. A stronger credit rating would give us better access to capital markets and a lower cost of capital, which directly benefit customers through lower rates over time. It would increase our ability to access long-term fuel supply contracts. And it would increase our ability to access physical and financial hedging products that are a part of risk management.

PSE has taken substantial steps to strengthen the company's capital structure and achieve a higher credit rating. Since 2001, we have raised over $500 million in new equity in three separate offerings. We have refinanced callable high-cost preferred stock and long-term debt, and increased our bank credit lines from $375 million to $700 million. Through this balanced approach to managing our debt portfolio, growing equity through the sale of stock, and retaining earnings, we plan to continue strengthening PSE's financial position, which we expect will lead to a higher credit rating over time.

B. Credit, Liquidity, and Risk Management

All energy transactions contain credit risk. PSE uses risk management strategies to reduce volatility in power and natural gas costs, manage unused capacity, and mitigate power costs through increasing the value of dispatching natural gas–fired electric generation plants. Execution of these risk management strategies, as well as executing future PPAs, requires credit.

In the energy industry, credit risk is defined as the potential loss resulting from a counterparty's failure to perform under one or more agreements for the purchase or sale of an energy service, energy product, or derivative thereof. Credit risk is typically calculated as the sum of amounts currently due and the replacement value of the energy under a given contract.

Firms with higher credit ratings are typically granted larger unsecured credit lines and are also able to transact with more counterparties compared to lower-rated companies. Since lower-rated firms tend to receive relatively smaller unsecured credit lines, they may be forced to rely on secured credit backed by collateral. Common forms of security used in the energy industry include cash collateral, and letters of credit issued by financial institutions such as commercial or investment banks. Posting collateral reduces liquidity and increases costs.

PSE uses liquidity facilities to fund its ongoing working capital needs. As of December 31, 2006, its facilities provided credit availability of around $700 million through an unsecured $500 million revolving credit line and a $200 million accounts receivable securitization arrangement. Credit available through the accounts receivable securitization program varies from around $150 million to $200 million, depending on accounts receivable and unbilled revenue balances. Given that these facilities are sized and are intended to be used primarily to fund working capital needs, they are typically not considered a source of credit to support energy credit risk. Instead, the Company relies on open trade credit from energy trading counterparties and a new credit facility established specifically to support energy hedging strategies.

Open trade credit provided by our energy trading counterparties helps address energy credit risk. Generally however, credit limits offered by these counterparties may be increased or decreased at any time; they vary in response to changes in the perceived risk of transacting with PSE.

During 2004 we informally surveyed the major counterparties with whom we execute these strategies to better understand the relationship between the Company's S&P and Moody's ratings and the unsecured credit lines provided. That survey indicated that an improved credit rating could expand our ability to enter into hedging transactions. On the other hand, a non–investment grade rating would significantly impair the company's risk management activities. Contracting parties would constrain open credit and would likely require collateral to maintain transacting activity. A downgrade would also trigger requirements to post collateral under several of our hedging instruments. While we might be able to access additional credit or equity to cover cash requirements, our weakened financial condition would significantly increase the cost of such capital and reduce liquidity.

In the January 2007 General Rate Case order, the WUTC approved recovery of hedging costs through the power cost adjustment (PCA) mechanism by including those costs in the Power Cost Baseline Rate. Specifically, the WUTC approved recovery of costs associated with establishing and maintaining liquidity facilities that support the company's hedging activities. In early 2007 the Company established a $350 million credit facility specifically dedicated to supporting hedging activities. The facility includes a $175 million accordion feature which could allow the facility to grow to $525 million subject to approval by the bank syndicate. This facility enables the Company to provide letters of credit or to make cash draws for the purpose of providing collateral required in excess of open trade credit as trading positions change in value with market pricing or credit standing movements over time. While recovery of credit costs through the PCA is an improvement, it does not change the importance of PSE's credit rating in implementing hedging strategies as a lower credit rating would simultaneously restrict open trade credit and increase costs under the hedging credit facility.

C. Purchased Power Agreements and Imputed Debt

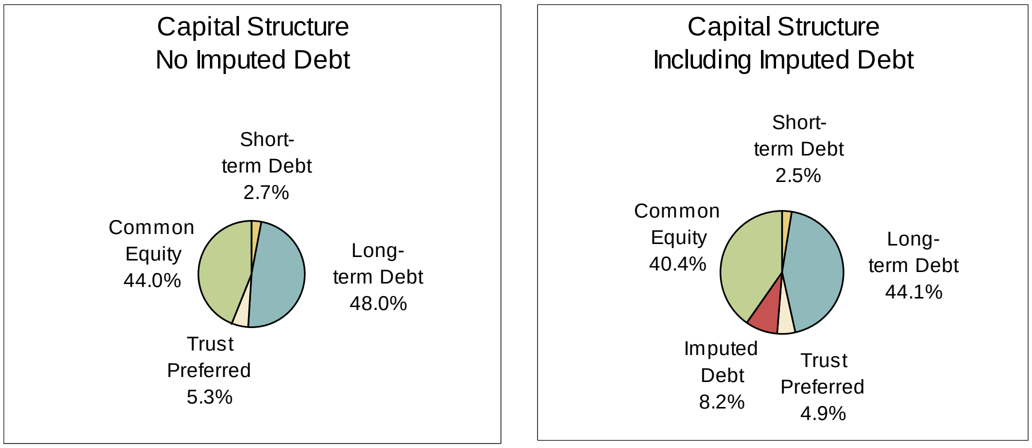
The extent of our reliance on PPAs increases the challenge of strengthening our credit rating. Rating agencies view electric utility PPAs as fixed commitments that affect a company's ability to cover debt obligations. Consequently, the agencies calculate (impute) debt associated with the capacity portion of payments made under these agreements.

PPAs are a useful resource strategy because they are an alternative to the risk and expense associated with new plant development, construction, and operation; however, they are not a physical asset and do not have an equity component. Therefore PPAs generally do not contribute to earnings, and related payments are viewed as a fixed obligation, similar to the interest on a bond. Applying imputed debt to PPAs decreases interest coverage ratios and is thus a negative factor in determining credit rating. Unless this imputed debt is offset by increased equity, it increases leverage in the balance sheet and reduces credit quality.

Our reliance on PPAs added more than $425 million of imputed debt to PSE's year-end 2006 capital structure used in credit metrics analysis. Since the publication of our 2005 plan, S&P has modified its methodology: rather than a flat 10% imputed interest and discount rate, it bases the rate on a company's cost of debt. In 2006, PSE's discount rate changed from 10% to 7.7%, which increased our imputed debt by more than $37 million. A majority of our energy and capacity supply comes from PPAs, so this change puts significant downward pressure on our credit rating. We have been working with the rating agencies since the early 1990s to convey that our imputed debt is somewhat mitigated by the low-cost structure of hydro-based contracts from the Mid-Columbia public utility districts.

As Figure F-1 shows, including $425 million of imputed debt in the capital structure allowed by the WUTC in the 2007 General Rate Case reduces the equity component from 44% to 40.4%.

Figure F-1
Capital Structure With and Without Imputed Debt



Regulatory Treatment of Imputed Debt

Public utility commissions in California and Florida have recognized the impact of imputed debt on utility credit ratios

A literature search as of January 2007 indicates no changes in what was reported in the 2005 Least Cost Plan for Florida and California regulatory treatment of imputed debt. A December 2004 California Public Utilities Commission ruling on imputed debt or debt equivalence of PPAs (Decision 04-12-047) stated:

> We decline to adopt a formal debt equivalence policy. However, we do recognize that debt equivalence associated with PPAs can affect utility credit ratios, credit ratings, and capital structure. Credit rating agencies have long recognized debt equivalence as a risk factor and we have and will continue to reflect the impact of such risk in establishing a fair and reasonable ROE and in approving a balanced ratemaking capital structure. In that regard, we have identified information that the utilities should provide in their annual cost of capital applications to enable us to better assess debt equivalence risks. Our goal is to provide the utilities with a fair and reasonable ROE and ratemaking capital structure that, among other matters, support investment-grade credit ratings.

The Florida Public Service Commission ruled in March 2004 (Docket 031093-EQ) that Florida Power and Light could account for imputed debt and make an equity adjustment to reduce the price paid for power purchased from small qualifying facilities. PSE has reviewed the major dockets at the Florida PSC web site, and has not found any evidence that would suggest any changes in their policy since 2004.

> We have repeatedly found that consideration of any application of an equity adjustment should be evaluated on a case-by-case basis. We have reviewed FPL's petition, the cited S&P article, and past Commission decisions regarding the application of an equity adjustment in general, and for purposes of determining capacity payments under a Standard Offer Contract, in particular. At our request, FPL provided additional support for its position in the form of a second S&P report dated October 21, 2003. In this report, S&P indicates that it applies a 30% risk factor in its evaluation of purchased power obligations as part of its determination of the consolidated credit profile of FPL Group. Based on the above, we believe it is appropriate in this instance for FPL to make an equity adjustment as stated in the determination of capacity payments in its Standard Offer Contract.

D. Financial Considerations Applied to This IRP

In the course of developing our resource strategy, PSE considers how the selected resource portfolio and individual resources impact our incremental power costs and risk. In addition the impact on our financial strength and credit, and conversely whether our financial situation supports the resource choices, are further evaluated further during development of the annual strategic financial plan and also when a specific resource is considered for purchase or contract. The following considerations and assumptions were used during this IRP analysis.

- PSE could have a large capital need for resources concentrated over a few years prior to the time that NUG contracts expire in 2011-2012. While capital limitations during this time were not specifically analyzed in this IRP, we will need to examine the timing of replacement acquisitions to determine whether we have the financial strength to support rapid-owned resource additions.
- Short-term power bridging agreements (PBAs) are used in this IRP to cover need until long-lead resources become available. PBAs may also be used to stagger resource additions to moderate the year-to-year financing requirements of owned resources. For the generic power bridging agreements analyzed in the portfolios, we computed an equity offset cost adder to account for the effect of imputed debt. A similar approach will be applied when evaluating specific power purchase agreements during the resource acquisition process.
- The timing of regulatory recovery is not explicitly modeled in the IRP, but this may become a consideration for specific resource acquisitions. For long-lead resources, and possibly transmission, PSE may need to pursue recovery of costs for construction work in progress. Short-term retail rate changes are another potential concern.
- For evaluation of generic resources, both PPA contracts and natural gas fuel were priced at spot market without a risk management adder. This issue will be re-examined as we evaluate specific resource acquisitions.
- If the future coal market more closely resembles the natural gas market model, credit could become an issue for coal-fueled IGCC resources. This IRP does not include a credit adder for coal fuel.

II. Further Financial Considerations

A. Further Detail: Purchased Power Agreements and Imputed Debt

PPA Advantages and Disadvantages

PPAs provide PSE with an opportunity to avoid construction risk. Depending on the terms, a PPA may also avoid performance risk. If the terms are "take-or-pay," we do not avoid performance risk because we pay whether or not the power is delivered. A "take-and-pay" PPA contract has less performance risk because we pay only when the power is available. While this risk mitigation is good, PPAs have some of the same risks as ownership and can also increase risk. As with plant ownership, PPAs can create an earnings lag when the full amount of the PPA cost is not allowed to be recovered through a power cost adjustment (PCA) mechanism until the next Power Cost Only Rate Case. PPAs can have increased risk compared to ownership due to loss of operational flexibility and counterparty risk.

With some PPAs, PSE does not have the operational flexibility to displace the contract when power is available in the market at lower prices. While a fixed-price PPA provides stability for the price of that power, it may not contribute to the lowest portfolio cost of all power needs. Plant ownership provides the operational flexibility of choosing to maintain and run the plant in a way that maximizes the plant's useful life. PPA sellers, on the other hand, choose the maintenance schedule that is best for them and could offer their plant at current fair market value, giving PSE the choice of buying the plant outright. That opportunity to purchase the plant provides some flexibility to a PPA, but there is a perception that purchasing the plant means PSE is paying for the facility twice—once by purchasing the power through the PPA and once again at contract termination.

We can report mostly good experiences for counterparty risk, as our counterparties have fulfilled their commitment to deliver. But this is not always true, and could change in the future. For example, the provider of a contract for firm gas supply defaulted and PSE received only partial compensation for the cost of replacement gas. In 2006, at the request of the PPA suppliers, PSE was asked to consider restructuring two fixed-price PPAs because the seller is experiencing financial distress in the later years of the contract. Mitigation of counterparty risk is managed through credit relationships and limits.

Imputed Debt Methodologies

Utilities have used PPAs in the past as an alternative to the risk and expense of new plant development, construction, and operation. However, entering into long-term PPAs creates fixed obligations that can increase a utility's financial risks.

Both Moody's Investors Service and Standard & Poor's (S&P) use a quantitative methodology to calculate the risk of PPAs and the impact of that risk on the creditworthiness of electric utilities. The methodologies, while different from one another, were designed to make a fair comparison between electric utilities that own and generate power vs. utilities that contract for power.

In general, imputed debt is described in the 1994 update of S&P 1992 Corporate Finance Criteria:

> To analyze the financial impact of purchased power, S&P employs the following financial methodology. The net present value of future annual capacity payments (discounted at 10%), multiplied by a "risk factor" (which in PSE's case is 30%) represents a potential debt equivalent—the off-balance sheet obligation that a utility incurs when it enters into a long-term purchase power contract.

PSE's IRP, and our screening of potential resource acquisitions, includes a cost of equity to neutralize the reduction in credit quality from imputed debt for all PPAs. As described previously, the debt rating agencies consider long-term take-or-pay and take-and-pay contracts equivalent to long-term debt; hence there is a cost associated with issuing equity to rebalance the company's debt/equity ratio. Imputed debt in the IRP is calculated using a similar methodology to that applied by S&P. The calculation begins with the determination of the fixed obligations that are equal to the actual demand payments, if so defined in the contract, or 50% of the expected total contract payments. This yearly fixed obligation is then multiplied by a risk factor. PSE's current contracts have a risk factor of 30%, a change that occurred in May 2004. Prior to this change, PSE contracts had risk factors between 15% and 40%. Imputed debt is the sum of the present value, using a 7.7% discount rate (the company's current average cost of long-term debt), and a mid-year cash flow convention of this risk-adjusted fixed obligation. The cost of imputed debt is the return on the amount of equity that would be acquired to offset the level of imputed debt to maintain the Company's capital and interest coverage ratios.

Imputed Debt's Effect on Capital Structure

Figures F-2 and F-3 show that the financial ratios with imputed debt are eroding PSE's financial strength as measured by the credit rating agencies. Total capitalization is approximately equal to year-end 2006, but the percentage mix of debt and equity is as allowed in the January 2007 General Rate Case order from the WUTC.

Figure F-2
Illustrative Base Case Excluding Imputed Debt

Capital Component	Illustrative Amount	Capital Structure	Cost Rate	Pre-tax WACC	WACC	After-tax WACC
Short-term Debt	$128,655	2.70%	6.66%	0.18%	0.18%	0.12%
Long-term Debt	$2,287,200	48.00%	6.64%	3.19%	3.19%	2.07%
Trust Preferred	$252,545	5.30%	8.54%	0.45%	0.45%	0.29%
Imputed Debt						
Common Equity	$2,096,600	44.00%	10.40%	7.04%	4.58%	4.58%
Total	$4,765,000	100.00%		10.86%	8.40%	7.06%

Figure F-3
Illustrative Base Case Including Imputed Debt

Capital Component	Illustrative Amount	Capital Structure	Cost Rate	Pre-tax WACC	WACC	After-tax WACC
Short-term Debt	$128,655	2.48%	6.66%	0.17%	0.17%	0.11%
Long-term Debt	$2,287,200	44.07%	6.64%	2.93%	2.93%	1.90%
Trust Preferred	$252,545	4.87%	8.54%	0.42%	0.42%	0.27%
Imputed Debt	**$425,000**	8.19%	7.70%	0.63%	0.63%	0.41%
Common Equity	$2,096,600	40.40%	10.40%	6.46%	4.20%	4.20%
Total	$5,190,000	100.00%		10.60%	8.35%	6.90%

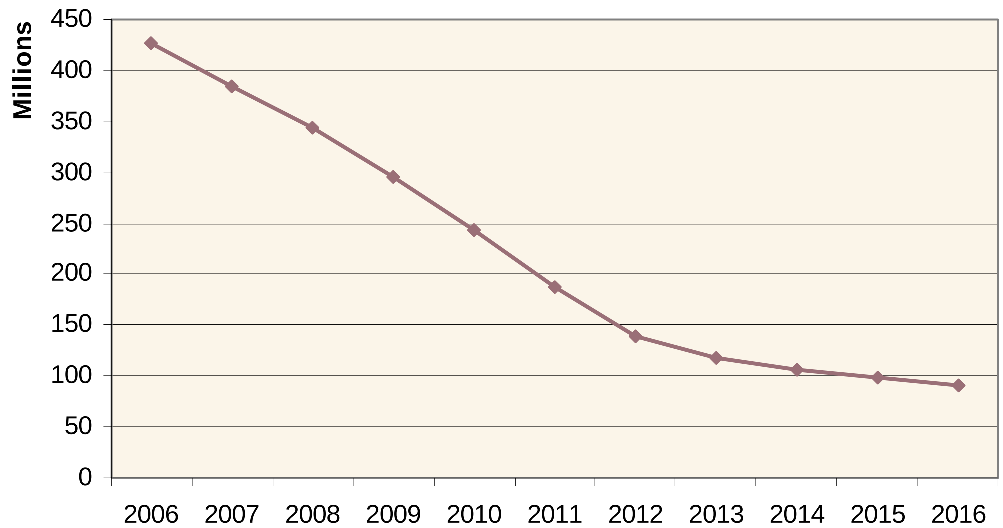
The pretax interest coverage ratio is reduced from over 2.7 to less than 2.5, and the ratio of debt to capital is increased from 57% to over 60%.

Figure F-4
Financial Ratios With and Without Imputed Debt

	No Imputed Debt	**Includes Imputed Debt**
Weighted Return on Equity	4.58%	4.20%
Tax impact	/ 65%	/ 65%
Pre-tax Weighted ROE	= 7.05%	= 6.46%
Cost of Debt	+ 3.82%	+ 4.15%
Pre-tax Cost of Capital	= 10.87%	= 10.61%
Cost of Debt	/ 3.82%	/ 4.15%
Pre-tax Interest Coverage	**2.85 x**	**2.56 x**
S&P Benchmark for "BBB" rating	2.4x - 3.5x	2.4x - 3.5x
Ratio Debt to Capital	**56.0%**	**59.6%**
S&P Benchmark for "BBB" rating	52% to 62%	52% to 62%

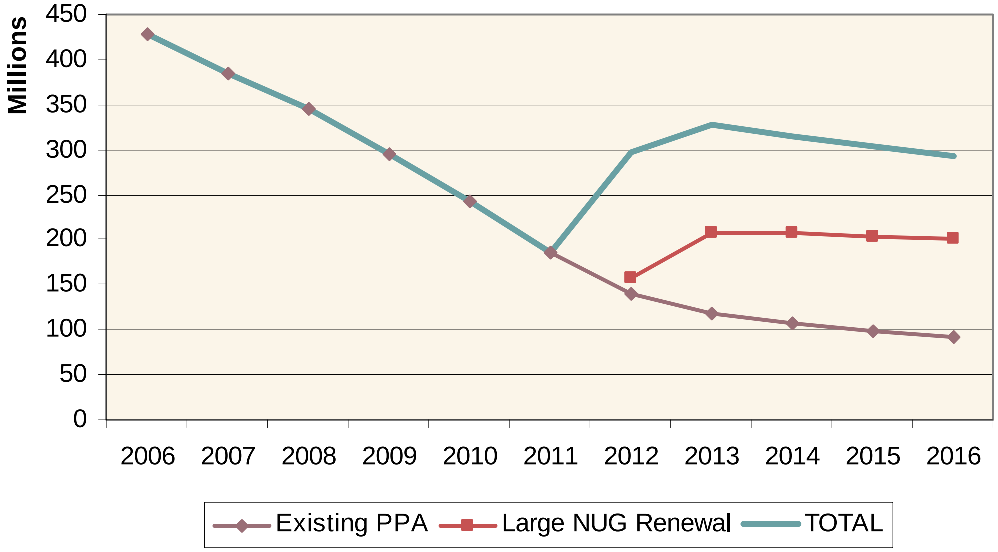
PSE has a number of PPAs outstanding, with termination dates from 2010 through 2037. In aggregate, these PPAs resulted in imputed debt of approximately $425 million in 2006. Figure F-5 reflects existing contracts, including the 20-year PPA with Chelan County PUD that begins in 2011, but excludes imputed debt associated with possible renewal of a number of PPAs that expire between 2011 and 2019.

Figure F-5
Imputed Debt, Existing PPAs



PSE has several large contracts with four large nonutility generators (NUGs) in northwestern Washington that expire between 2011 and 2013. If we were to replace these expiring contracts with new 20-year contracts, priced at the Aurora forecast prices, the imputed debt could increase to about $325 million in 2013. This is likely a low estimate, because prices for fixed-rate contracts generally have a forward premium and a credit premium that would increase contract payments. In addition, the estimate may also be low because it does not include imputed debt from possible contracts for power from renewable resources and possible power bridging agreements (PBAs) that may be used to partially fill the near-term resource need. Figure F-6 illustrates future imputed debt under these circumstances.

Exhibit F-6
Imputed Debt with Selected Contracts Replaced at Market Prices



B. Accounting Changes

Purchased Power and Lease Accounting

The Financial Accounting Standards Board (FASB) Emerging Issues Task Force (EITF) issued EITF 01-8 in 2001. EITF 01-8 gives criteria to determine whether an arrangement should be accounted for as a lease under FASB Statement 13, “Accounting for Leases.” Power supply agreements in which PSE has the right to control the use of the underlying property, plant or equipment may be considered a lease for accounting purposes and will thus require lease accounting. Such right to control is to be assessed with respect to, among other things, the amount of power PSE may purchase from the generating facility; PSE’s right to control access to the underlying property, plant, or equipment; and the relevant contract pricing structure. These determinations may lead to lease accounting under the agreements.

Derivative and Hedge Accounting

In June 1998, the FASB issued Statement 133 (FAS 133), "Accounting for Derivative Instruments and Hedging Activities," which established accounting and reporting standards for derivative contracts and hedging activities. The purpose of FAS 133 is to improve the quality of financial reporting by requiring that contracts with comparable characteristics be accounted for similarly. FAS 133 has the potential to increased volatility of reported earnings due to the requirement to record the unrealized gains and losses from derivatives on a company's books. In April 2003, the FASB issued Statement 149 (FAS 149), an amendment to FAS 133 that clarified the definition of derivatives and the implementation of this statement for financial instruments. If certain criteria are met as defined in FAS 133 or FAS 149, then PSE may be required to mark-to-market the agreement and record the mark-to-market effect either in the equity section of the balance sheet or in the income statement. Depending on the mark-to-market accounting, it may adversely impact PSE's cost of equity and corporate credit rating, and the ultimate cost of the PPA to PSE customers.

Variable Interest Entities

In December 2003, the FASB issued a revision to Interpretation 46 (FIN 46), "Consolidation of Variable Interest Entities." Consolidated financial statements are to include subsidiaries in which the enterprise has a controlling financial interest. That requirement has usually been applied to subsidiaries in which an enterprise has a majority voting interest, but in many circumstances the enterprise's consolidated financial statements do not include variable interest entities with which it has similar relationships. The primary objective of FIN 46R is to provide guidance on the identification of and the financial reporting for entities over which control is achieved through means other than voting rights—such entities are known as variable interest entities. Depending on specified criteria, FIN 46 may require PSE to consolidate entities providing long-term PPAs. Such consolidation requires PPA suppliers to provide their detailed financial information to determinate the applicability of FIN 46 and, if necessary, consolidation of their financial statements. Depending on the capital structure of the PPA supplier, the consolidation may adversely impact PSE's corporate credit rating and the ultimate cost of the PPA to PSE customers.

C. Risk Management

Starting with the Western energy crisis, and continuing through the recent escalation in natural gas prices, energy markets have experienced substantial volatility. Consequently, market participants have taken steps to improve their risk management. This includes taking a more structured approach to managing price exposure, and the use of better modeling tools. The market offers a variety of fixed-priced contracts and financial instruments to hedge a company's price risk exposure.

PSE balances numerous risk factors when obtaining energy resources to meet customer load. We must analyze these factors to (1) deliver reliable energy when our customers demand it, (2) serve our customers at a reasonably low cost while mitigating price volatility, and (3) enhance the value of PSE's energy resources to reduce power and gas costs. PSE uses risk management strategies to reduce volatility in power and gas costs, manage unused capacity, and increase the operational flexibility of assets.

A variety of hedging tools can reduce price volatility for power customers. We engage in forward market fixed-price purchases (both in physical gas and power purchase contracts and through financial market derivatives) to lock in gas prices, to purchase power as needed, and to acquire winter-peaking capacity hedges. In addition, our resources give us the flexibility to store hydroelectric energy where possible, to dispatch and displace generation as market conditions provide economic signals, and to use transmission to move energy from resources to load.

Several factors limit our strategic options. Market liquidity is one, as there may not be sellers of the hedge transactions we seek. Market conditions may also make certain products very expensive. For example, an option contract such as a cal—which is the right, but not the obligation, to purchase energy at a predetermined price—might be a very attractive means to manage load variability risk. But in volatile markets, the cost might be prohibitive. Counterparty issues limit our options: We may not be able to obtain a range of financially strong counterparties to reduce the risk of default, and our own credit position can limit our ability to enter into hedging transactions.

With a higher credit rating, counterparties would extend us more open credit, thereby enabling us to expand our hedging capacity for the power and gas portfolios without incurring costs to post collateral and without increasing debt. This benefits customers, as the company gains increased hedging capacity, without additional credit costs. With a better credit rating, PSE anticipates counterparties would be willing to sell us more fixed-price supply or other hedge transactions, thereby expanding our hedging capability. We would continue to link hedging strategies to price signals, fundamental analysis, and risk analysis; but when prices are opportunistic we believe it is important to have the capacity and flexibility to hedge more and further forward in time.

D. Tax Incentives

Production Tax Credit

In December 2006, the federal production tax credit (PTC) for wind and other renewable energy technologies was extended for one additional year – through December 31, 2008. The PTC provides a $19 per megawatt-hour (MWh) or 1.9 cents per kilowatt-hour (kWh) tax credit for electricity generated over the first 10 years of a wind project's operation.

The bill also extended the 30% solar energy investment tax credit (ITC) for homeowners and businesses for one additional year, through the end of 2008.

Figure F-7
Production Tax Credits for Renewable Resources

Resource	PTC Rate	Term	Comments
(1) Wind	$19 / MWh	10 years	Extended through 12/31/2008 2006 Rate = $19 / MWh = 1.2981 * 1.5 ¢ / kwh
(2) Closed-loop biomass	$19 / MWh	10 years	
(3) Open-loop biomass	$10 / MWh	10 years	$10 = 50% * 1.5 * 1.2981
(4) Geothermal & Solar	$19 / MWh	5 years	For Solar projects, the 30% investment tax credit provides more incentive than the $19 / MWh PTC.
(5) Small irrigation power	$10 / MWh	5 years	
(6) Landfill gas power	$10 / MWh	5 years	
(7) Trash combustion facilities	$10 / MWh	5 years	

Source:
Federal Register March 31, 2006.
http://a257.g.akamaitech.net/7/257/2422/01jan20061800/edocket.access.gpo.gov/2006/pdf/E6-4668.pdf

PTCs add significantly to the economics of wind projects. The 2006 level of $19/MWh is equivalent to a customer rate, or revenue requirement, benefit to PSE customer payments of about $29/MWh in the first of year. The PTC rate escalates with inflation over time but only applies to the first 10 years of generation. With escalation and the 10-year term, the 20-year levelized reduction in customers' revenue requirement is about $23 / MWh. The following table illustrates the calculation for a hypothetical project producing 1 MWh:

Figure F-8
Application of Production Tax Credits to a Hypothetical Project

		MWh	PTC	Revenue Required
	1/1/2006	-	0	0
1	2006	1	$ 19.00[1]	29.23
2	2007	1	$ 20.00	30.77
3	2008	1	$ 20.00	30.77
4	2009	1	$ 21.00	32.31
5	2010	1	$ 21.00	32.31
6	2011	1	$ 22.00	33.85
7	2012	1	$ 23.00	35.38
8	2013	1	$ 23.00	35.38
9	2014	1	$ 24.00	36.92
10	2015	1	$ 24.00	36.92
11	2016	1	$ -	$ -
12	2017	1	$ -	$ -
13	2018	1	$ -	$ -
14	2019	1	$ -	$ -
15	2020	1	$ -	$ -
16	2021	1	$ -	$ -
17	2022	1	$ -	$ -
18	2023	1	$ -	$ -
19	2024	1	$ -	$ -
20	2025	1	$ -	$ -
8.4%	NPV	8.79		$ 199.43
	Levelized			**$ 22.68**

[1] 2006 Rate = $19 / MWh = 1.2981 * 1.5 ¢ / kwh. Future rates assume escalation of 2.5% per year. All PTC rates are rounded to the closest $1 / MWh or 0.1 ¢ / kwh.

Clean Coal Tax Incentives

The Energy Policy Act of 2005 created two ITCs for integrated coal gasification combined cycle (IGCC) and advanced combustion facilities. IGCC projects may receive a 20% credit, capped at $800 million. Other advanced coal-based projects may receive a 15% credit, capped at $500 million. The credits are available only to projects certified by the Secretary of Treasury, in consultation with the Secretary of Energy. In addition, the EPAct creates a 20% ITC for certified industrial gasification projects. The total amount of gasification credits allocable is limited to $350 million. A good summary of different elements of the EPAct affecting coal projects can be found at http://www.coal.org/PDFs/KeyCoalIncentives0705.pdf.

These three different tax incentives combine to total $1.65 billion of tax credits. The projects must be certified by the Secretary of Energy, before receiving credits. On November 30, 2006, the U.S. Department of Energy and the Internal Revenue Service allocated about $1 billion of tax credits for nine projects: three utility IGCC projects (totaling $400 million), two utility advanced coal projects (totaling $250 million), two industrial gasification projects, and two others that were not identified. The balance of about $650 million will be available for allocation in 2007. The 2007 application period closes on October 1, 2007. Energy Northwest applied for $107 million in tax credits for proposed private owners of their Pacific Mountain Energy Center (Kalama) project and was not mentioned as being selected.

Since the clean coal credits are expected to be used projects currently under development, this IRP assumed that tax credits would not be available to PSE for lowering the cost of IGCC plants.

PSE's Tax Credit Appetite

PSE's use of tax credits is limited by tax law to a maximum of 25% of what the Company would have otherwise paid; it is further limited because resulting current taxes cannot be reduced below the level of tax calculated via the alternative minimum tax methodology. Based on PSE's federal tax payments in 2003–2005, the appetite for tax credits for these years ranged from $17 million to over $21 million. The PTC expected in 2007 from the Hopkins Ridge and Wild Horse wind projects is about $21 million. Thus, under PSE's current taxable income, our two existing wind projects have filled our appetite for tax credits.

Even though the tax credit appetite is filled at this time, we have several alternatives to capture these incentive benefits.

- First, renewable energy received through PPAs should reflect the PTC in the PPA pricing.
- Second, as our earnings grow through time, additional tax credit appetite will arise and could be used to develop small renewable projects.
- Third, the PTC rules contain provisions for rolling forward the benefit 20 years if it cannot be used in the current year. This alternative approach would likely be considered for a smaller project with limited PTCs that may be able to be used by PSE in good earnings years. If benefits were passed through to customers when power is generated, then customer costs would increase by the carrying cost on the unused credit account.
- Fourth, the financial markets have developed hybrid financings that use tax equity investors who are able to use the tax credits. These hybrid financing structures were developed for government-owned utilities that pay no federal tax. We have investigated several hybrid structures and will continue to pursue those that make economic sense for our customers.

Wind Integration Studies

PSE currently operates two wind projects: one in BPA's control area (the Hopkins Ridge project) and one in PSE's control area (the Wild Horse project). Experience and analytical studies have helped us understand some of the economic and operating effects of increasing the wind portion of our resource portfolio, which have been incorporated in this IRP planning process.

The costs used, based on Phase 4 evaluations by Golden Energy Services (Golden) of wind costs for our power system, assume a significant portion of the wind generation will be connected directly to our system (probably more than will actually be interconnected). In brief, we estimate wind integration—which includes added regulation due to wind generation, shifts in operating reserve due to wind generation, intra-hourly wind generation variability and day-ahead wind generation variability—will cost $5.90/MWh in 2007, and will escalate at 2.5% per year.

The costs projected in this IRP incorporate some future uncertainty. However, they do not specifically incorporate the effects of two regional events that might affect costs: (1) a current study by BPA and the Northwest Power and Conservation Council on the impact of integrating large quantities of wind power into regional utilities systems, particularly services not currently included in utility open access transmission tariffs; and (2) the recently enacted Washington RPS, which will likely require adding more wind to the region's generating portfolios—and result in higher costs.

I. Managing Variable Output

Unlike other conventional generation resources, wind energy has a relatively high degree of short-term variability. Variability itself is not a key operational issue. Rather, we are concerned about the inability of forecasts to predict that variability.

To ensure our electric system meets industry reliability standards, we must effectively manage short-term uncertainty. Therefore, we will need to gain greater real-time operational flexibility from the non-wind portions of our power system. Most of this is currently provided by our contracted share of the five Mid-Columbia hydroelectric projects—flexibility we currently use to manage load, real-time underruns or overruns, protect against thermal resource outages, and maintain constant frequency within our service territory.

To supplement these Mid-Columbia projects, we can depend on the Baker River hydro plants and at times our simple-cycle combustion turbines. The Baker River plants offer considerable flexibility, especially with the new control systems and operating parameters required by the new project license. Also, at least four of our combustion turbines can be on-line quickly enough to add flexibility when needed.

II. Integration Studies Overview

While much has been written about wind generation, only in the last few years have coordinated attempts been made to identify and quantify the short-term operating effects of large-scale wind farms on utility power systems. In 2003, we asked Golden to help evaluate these operating effects on our power system. Its August 2003 report, *Short-term Operational Impacts of Wind Generation on the Puget Sound Energy Power System* (the Phase 1 report), presented its findings.

In December 2003, we asked Golden to (1) expand on the results of Phase 1, and (2) develop information to help us evaluate wind resource bids. This Phase 2 analysis (included as Appendix D to PSE's 2005 plan) built on Phase 1 using actual wind resource data from a Columbia Basin wind project, and simulated wind resource data developed in Phase 1 for a proposed wind project near Ellensburg, Washington. Phases 1 and 2 analyzed the effect on PSE of

- regulation due to wind generation
- shifts in operating reserve due to wind generation
- intra-hourly wind generation variability
- day-ahead wind generation variability

In late 2004, PSE asked Golden to expand on Phase 2 work using detailed historical wind generation data and associated wind generation forecasts from an operating Northwest wind farm. The goals for this Phase 3 included

- evaluate PSE's short-term wind integration costs using differing amounts of available hydro capacity
- quantify the benefits of developing more accurate short-term wind generation forecasts
- incorporate expanded datasets of historical Northwest regional power prices

In the fall of 2006, PSE asked Golden for additional wind integration cost studies incorporating our existing capacity from Hopkins Ridge and Wild Horse. We also asked for help in evaluating potential new wind resources for our IRP process. A primary goal of Phase 4 was to investigate benefits associated with acquiring wind generation capacity at different physical locations within the Northwest region. Another goal was to update the wholesale pricing assumptions used in Phase 3 to reflect higher natural gas prices.

Figure G-1 shows Phase 4 results: the cost of integrating various levels of wind power into the PSE system, and the effect of adding increasing amounts of wind generation to our system. Not all this wind power will be connected directly to our system, but this provided a conservative means of analyzing integration costs in light of current uncertainty.

Results show that the greater the amount of wind generation, the higher the cost per megawatt-hour (MWh). For example, generating 207.3 MW in 2015 would cost $6.39/MWh. If PSE generated 630 MW in that same year, the cost would rise to $7.81/MWh.

Figure G-1
Puget Sound Energy - Wind IRP Studies
2007 - 2016

Year	PSE Mid-C	Wind Capacity in the PSE Control Area					Wind Capacity in the PSE Control Area					Wind Capacity in the PSE Control Area				
	Net Capacity (MW)	Net Capacity (MW)	DA Cost ($/Mwh) 1400 MW	HA Cost ($/Mwh) 207.3 MW	Reg/O.R. ($/Mwh) 207.3 MW	Tot Cost ($/Mwh)	Net Capacity (MW)	DA Cost ($/Mwh) 1900 MW	HA Cost ($/Mwh) 360 MW	Reg/O.R. ($/Mwh) 360 MW	Tot Cost ($/Mwh)	Net Capacity (MW)	DA Cost ($/Mwh) 1900 MW	HA Cost ($/Mwh) 630 MW	Reg/O.R. ($/Mwh) 630 MW	Tot Cost ($/Mwh)
2007	967	207.3	2.44	2.38	0.16	4.98	360.0	2.58	2.55	0.16	5.28	630.0	0.00	0.16	0.00	0.16
2008	967	207.3	2.89	2.80	0.16	5.85	360.0	3.02	3.01	0.16	6.19	630.0	0.00	0.16	0.00	0.16
2009	951	207.3	2.98	2.83	0.16	5.98	360.0	3.13	3.05	0.16	6.34	630.0	0.00	0.16	0.00	0.16
2010	869	207.3	2.70	2.53	0.16	5.39	360.0	2.83	2.74	0.16	5.73	630.0	0.00	0.16	0.00	0.16
2011	839	207.3	2.52	2.34	0.16	5.01	360.0	2.65	2.54	0.16	5.35	630.0	0.00	0.16	0.00	0.16
2012	602	207.3	3.01	2.79	0.16	5.97	360.0	3.12	3.16	0.16	6.44	630.0	0.00	0.16	0.00	0.16
2013	540	207.3	3.13	3.00	0.16	6.29	360.0	3.20	3.44	0.16	6.80	630.0	0.00	0.16	0.00	0.16
2014	540	207.3	3.21	3.10	0.16	6.48	360.0	3.28	3.56	0.16	7.00	630.0	0.00	0.16	0.00	0.16
2015	540	207.3	3.21	3.02	0.16	6.39	360.0	3.27	3.47	0.16	6.90	630.0	0.00	0.16	0.00	0.16
2016	540	207.3	3.22	2.94	0.16	6.32	360.0	3.28	3.36	0.16	6.81	630.0	0.00	0.16	0.00	0.16

Figure G-2 demonstrates how we determined the integration costs we used in our analysis. We started with the Total Cost ($/MWh) from each level of wind. Then we assumed:

- a total of 207 MW generated during the first two years
- adding another wind plant in 2009 for a total of 360 MW (for four years)
- adding two more projects in 2013 for a total of 630 MW (for four years)

The last column "USE" presents a least-squares fit using a 2.5% escalation factor.

Figure G-2
Amount of Wind in PSE Control Area
(Total integration costs, BPA & PSE)

	207 MW	360 MW	630 MW		Cost Steps	USE Est @ 2.5%
2007	$ 4.98	$ 5.28	$ 5.66	---->	$ 4.98	$ 5.90
2008	$ 5.85	$ 6.19	$ 6.63	---->	$ 5.85	$ 6.05
2009	$ 5.98	$ 6.34	$ 6.79	---->	$ 6.34	$ 6.20
2010	$ 5.39	$ 5.73	$ 6.18	---->	$ 5.73	$ 6.35
2011	$ 5.01	$ 5.35	$ 5.79	---->	$ 5.35	$ 6.51
2012	$ 5.97	$ 6.44	$ 7.20	---->	$ 6.44	$ 6.68
2013	$ 6.29	$ 6.80	$ 7.68	---->	$ 7.68	$ 6.84
2014	$ 6.48	$ 7.00	$ 7.92	---->	$ 7.92	$ 7.01
2015	$ 6.39	$ 6.90	$ 7.81	---->	$ 7.81	$ 7.19
2016	$ 6.32	$ 6.81	$ 7.69	---->	$ 7.69	$ 7.37

III. Comparison of Studies

In early 2006, Brian Parsons of the National Renewable Energy Laboratory presented a paper entitled *Grid Impacts of Wind Power Variability: Recent Assessments from a Variety of Utilities in the United States*.[1] The paper summarized results from several studies conducted by other entities to quantify short-term effects, including regulation, hour-ahead (load following), and day-ahead (unit commitment) impacts.

While these categories match up fairly well with those analyzed in our Phase 4 study, the results may not be directly comparable due to differing wind penetration levels and utility resource portfolios. To make the results somewhat more consistent, PSE's Phase 4 costs are based on locating all the generation in our control area.

Figure G-3
Short-Term Operational Costs of Wind Generation on Large Utility Power Systems

Date	Study	Wind Capacity Penetration (%)	Total Operating Cost Impact ($/MWh)
May-03	Xcel-UWIG	3.5	$ 1.85
Sep-04	Xcel-MNDOC	15	$ 4.60
Jun-03	We Energies	4	$ 1.90
Jun-03	We Energies	29	$ 2.92
Jun-05	PacifiCorp	20	$ 4.60
Apr-06	Xcel-PSCo	10	$ 3.72
Apr-06	Xcel-PSCo	15	$ 4.97
Apr-06	Xcel-PSCo (2)	20	$ 8.87
Jan-07	PSE Phase 4	10	$ 5.50

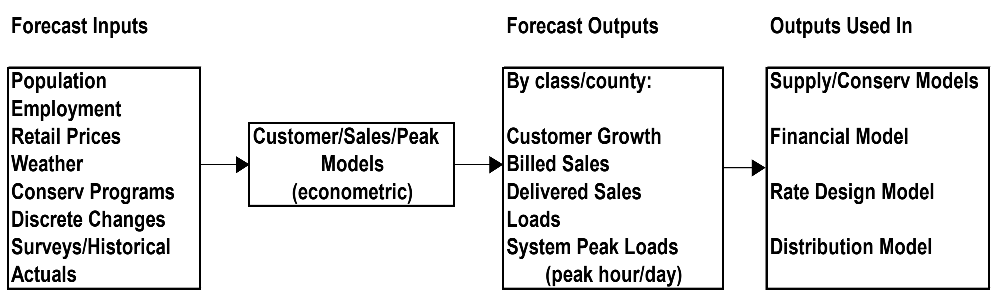
[1] Co-authored by Brian Parsons and Michael Milligan, National Renewable Energy Laboratory; J Charles Smith, Utility Wind Integration Group; Edgar DeMeo, Renewable Energy Consulting Services, Inc.; Brett Oakleaf, Xcel Energy; Kenneth Wolf, Minnesota Public Utilities Commission; and Matt Schuerger, Energy Systems.

Load Forecasting Models

This appendix provides a more detailed technical description of the three econometric methodologies used to forecast (a) billed energy sales, (b) customer counts, and (c) system peak loads for electricity and natural gas. It also describes the methodology used to project hourly distribution of electrical loads.

For the 2007 IRP, we updated our key forecast driver assumptions and re-estimated the main equations. Key enhancements to this model are the ability to develop monthly sales forecasts using actual weather over the last 30 years, and to project loads at the county level. The diagram below shows the overall structure of the analysis.

Figure H-1
Econometric Model for Forecasts
of Energy Sales, Customer Counts and Peak Loads



I. Electric and Gas Billed Sales and Customer Counts

The following use-per-customer and customer count equations were estimated using historical data from January 1990 to December 2005, depending on sector or class and fuel type. The billed sales forecast is based on the estimated equations, normal weather assumptions, rate forecasts, and forecast of various economic and demographic inputs.

$\mathbf{UsePerCust}_{c,m}$ = f(RetailRates$_{c,m}$, Weather$_{c,m}$, EcoDemo$_{c,m}$, MonDummies)
$\mathbf{CustCount}_{c,m}$ = f(EcoDemo$_{c,m}$, MonDummies)

$\mathbf{UsePerCust}_{c,m}$ = use (billed sales) per customer for class c, month m
$\mathbf{CustCount}_{c,m}$ = customer counts for class c, month m

RetailRates$_{c,m}$ = effective real retail rates for class c in polynomial distributed lag form of various lengths

Weather$_{c,m}$ = class-appropriate weather variable, cycle-adjusted HDD/CDD using base temperatures of 65, 60, 45, 35 for HDD and 75 for CDD; cycle-adjusted HDDs/CDDs are created to fit consumption period implied by the billing cycles

EcoDemo$_{c,m}$ = class-appropriate economic and demographic variables; variables could be income, household size, population, employment levels or growth, building permits

MonDummies = monthly binary variables

The billed sales forecast for each customer class is the product of use per customer and number of customers for each class, as defined above. Billed sales in a given month are defined as the sum of the billed sales across all customer classes.

BilledSales$_{c,m}$ = UsePerCust$_{c,m}$ x CustCount$_{c,m}$

Different functional forms were used depending on the customer class. We used a semi-log form for the electric residential use-per-customer equation, with explanatory variables (prices and demographic variables) entering in polynomial distributed lagged form. The length of the lag depends on the customer class equation (residential has the longest lags). We used a double-log form for the other sectors, again with explanatory variables entering in lagged form. Lagged explanatory variables in the equations account for short-term and long-term effects of changes in prices or economic variables on energy consumption. For gas, most of the use-per-customer equations have a linear form with prices or economic variables entering in polynomial distribution lagged form again.

Figure H-2, based on the estimated coefficients for the retail prices in the use-per-customer equations, provides computed long-term price elasticity for the major customer classes for electric and gas.

Figure H-2
Long-term Price Elasticity for Major Customer Classes

	Electric	Gas
Residential	-.16	-.11
Commercial	-.18	-.09
Industrial	-.19	-.12

All estimated price coefficients are also statistically significant.

Customer forecasts by county were generated by estimating an equation relating customer counts by class/county to population or employment levels in that county. We imposed a restriction on county-level forecasts so that the sum of forecasted customers across all counties equaled the total service area customer forecast. This projection is an input for the distribution planning process.

The billed sales forecast was further adjusted for discrete additions and deletions not accounted for in the forecast equations. These adjustments include known large additions/deletions or fuel switching, and schedule switching. Finally, total system loads were obtained by distributing monthly billed sales into cycle sales, then allocating the cycle sales into the appropriate calendar months using degree days as weights and adjusting each delivered sales for losses from transmission and distribution. This approach also enables us to compute the unbilled volumes each month.

II. Peak Load Forecasting

A. Electric Peak-hour Load Forecast

For electric, the peak hour for the normal and extreme design temperatures represent the relevant range of peak loads. An hourly regression equation provides "normal" and "extreme" peak loads for both residential and nonresidential sectors. Deviations of actual peak-hour temperature from normal peak temperature for the month, day of the week effects, and unique weather events such as a cold snap are modeled by the equation. We used monthly data from January 1991 to February 2004. The historical data includes a period when large industrial customers opted to leave firm customer classes to join the transportation-only rate class; the equation accounts for this change. Finally, we allow the impact of peak temperature on peak loads to vary by month. This permits different effects of residential and nonresidential loads on peak demand by season, with and without conservation. It also lets us account for the effects of different customer classes on peak loads. The functional form of the electric peak-hour equation is

Peak MW = $\sum_i a_i$ *Resid aMW*MoDum $_i$ + b*Non-Resid aMW
+ $\sum_{i \neq 7,8} c1_i$ *(Normal Mly Temp-Peak Hr Temp)*(WeathSensitv aMW)*MoDum $_i$
+ $\sum_{i = 7,8} c2_i$ *(Normal Mly Temp-Peak Hr Temp)*(Coml aMW)*MoDum $_i$
+ d*Sched48Dummy + $\sum_i e_i$ *WkDayDum $_i$ + f*ColdSnapDummy

where a, b, c1,c2, d, e, and f are coefficients to be estimated.

Peak MW = monthly system peak-hour load in MW
ResidaMW = residential delivered sales in the month in aMW
Non-ResidaMW = commercial plus industrial delivered sale in the month in aMW
MoDum = monthly dummy
Normal Mly Temp-Peak Hr Temp = deviation of actual peak-hour temperature from monthly normal temperature
WeathSensitv = residential plus a % of commercial delivered loads
Sched48Dummy = dummy variable for when customers in schedule 48 became transport
WkDayDum = day of the week dummy
ColdSnapDummy = 1 if the minimum temperature the day before peak day is less than 32 degrees

To obtain the normal and extreme peak load forecasts, we factor the appropriate design temperatures into the equation for either condition: 23°F for "normal" peak and 13°F for "extreme" peak in December.

B. Gas Peak-day Load Forecast

Gas peak day is assumed to be a function of weather-sensitive delivered sales, the deviation of actual peak-day average temperature from monthly normal average temperature, and other weather events. The following equation used monthly data from October 1996 to March 2004 to represent peak day firm requirements:

Peak DThm = a*FirmDThm + b*(Normal Mly Temp-Peak Day AvgTemp)*(Firm DThm)
+ c*ElNino + d*WinterDum + e*SummerDum + f*ColdSnapDummy

where a, b, c, d, e, and f are coefficients to be estimated.

Peak DThm = monthly system gas peak day load in decatherms
FirmDThm = monthly delivered loads by firm customers
Normal Mly Temp-Peak Day AvgTemp = deviation of actual peak-day average daily temperature from monthly normal temperature
ElNino = dummy for when ElNino is present during the winter
WinterDum, SummerDum = winter or summer dummy variable to account for seasonal effects
ColdSnapDummy = binary variable for when the peak occurred within a cold snap period lasting more than one day, multiplied by the minimum temperatures for the day

This formula for gas peak-day load accounts for changes in use per customer consistent with use-per-customer changes in the billed sales equation. The other advantage is the ability to account for the effects of conservation on peak loads, and for the contribution of customer classes to peak loads.

The design peak-day requirements for this forecast are based on meeting a 52 heating degree day (13°F average temperature for the day), based on the costs and benefits of meeting a higher or lower design day temperature. In the 2003 Least Cost Plan (LCP), we changed PSE’s gas supply peak-day planning standard from 55 heating degree days (HDD), which is equivalent to 10 degrees Fahrenheit or a coldest day on record standard, to 51 HDD, which is equivalent to 14 degrees Fahrenheit or a coldest day in 20 years standard. The Washington Utilities and Transportation Commission (WUTC) responded to the 2003 plan with an acceptance letter directing PSE to “analyze” the benefits and costs of this change and to “defend” the new planning standard in the 2005 LCP.

As discussed in our 2005 LCP, appendix I, PSE completed a detailed, stochastic cost-benefit analysis that considered both the value customers place on reliability of service and the incremental costs of the resources necessary to provide that reliability at various temperatures. This analysis determined that it would be appropriate to increase our planning standard from 51 HDD (14°F) to 52 HDD (13°F). PSE's gas planning standard is based on a detailed cost-benefit analysis that relies on the value our natural gas customers attribute to reliability and covers 98% of historical peak events. As such, it is unique to our customer base, our service territory, and the chosen form of energy. Thus, we use projected delivered loads by class and this design temperature to estimate gas peak-day load.

III. Hourly Electric Demand Profile

Because there is no way to store large amounts of electricity in a practical manner, the minute-by-minute interaction between electricity production and consumption is very important. For this reason, and for purposes of analyzing the effectiveness of different electric generating resources, an hourly profile of PSE electric demand is required.

We use our hourly (8,760 hours) load profile of electric demand for the IRP, our power cost calculation, and for other AURORA analyses. This hourly profile replaces a demand profile developed in 2002 with HELM (Hourly Electric Load Model). The new distribution uses actual observed temperatures, recent load data, the latest customer counts, and improved statistical modeling.

A. Data

We developed a representative distribution of hourly temperatures from January 1, 1950 to December 31, 2003. Actual hourly delivered electric loads between January 1, 1994 and December 16, 2004 were used to develop the statistical relationship between temperatures and loads for estimating hourly electric demand based on a representative distribution of hourly temperatures.

B. Methodology for Distribution of Hourly Temperatures

The above temperature data were sorted and ranked to provide two separate data sets:

- For each year, a ranking of hourly temperatures by month, coldest to warmest, over 54 years was used to calculate average monthly temperature.
- A ranking of the times when these temperatures occurred by month, coldest to warmest; these rankings were averaged to provide an expected time of occurrence.

Next we found the hours most likely to have the coldest temperatures (based on observed averages of coldest-to-warmest hour times) and matched them with average coldest-to-warmest temperatures by month. Sorting this information into a traditional time series then provides a representative hourly profile of temperature.

C. Methodology for Hourly Distribution of Load

For the time period January 1, 1994 to December 31, 2003, we used the statistical regression equation

$$\mathbf{Load}_h = \alpha_w + \beta_1 \text{*Load}_{h-1} + \beta_2 \text{*(Load}_{h-2} + \text{Load}_{h-3} + \text{Load}_{h-4}\text{)/3} + \beta_3 \text{*Month}_m \text{*temp}_h + \beta_4 \text{*Month}_m \text{*(temp}_h)^2 + \beta_5 \text{*Holiday} + \beta_6 \text{*Linear Trend} + \text{AR(1)}$$

w = 1 to 7 (weekday)
h = 1 to 24 (hours)
m = 1 to 12 (months)
Holiday = NERC holidays

to calculate load shape from the representative hourly temperature profile. The calendar variables for the load profile were derived to follow that of 2005.

Electric Analysis

This appendix presents details of the methods and models employed in PSE's electric resource analysis, and the data produced by that analysis.

1. Methods and Models

2. Data

1. Methods and Models

I. Methods

A. Planning Adjustment for Energy Efficiency Screening

PSE's planning team has developed a process that will directly incorporate demand resources into our portfolio analysis, as depicted in the diagram titled "2007 IRP Process" on page I-5 of this appendix. Integrating demand resources into our initial portfolio analysis achieves the kind of integrated resource planning called for in the rules set forth by the Washington Utilities and Transportation Commission (WUTC). It also allows us to examine the risk impacts of demand resources.

Demand resources are bundled into a manageable number of resources to effectively integrate them into the portfolio analysis. Bundling is performed using Quantec's cost effectiveness screening model, using a portfolio-based avoided cost approach. Quantec's model is capable of examining the benefit of demand resources based on hourly demands and hourly prices over a 20-year period, which amounts to more than 175,000 hourly data points for each of the 1700+ individual demand-resource measures.

i. Hourly "Prices" for Bundling and New Planning Adjustment Factor

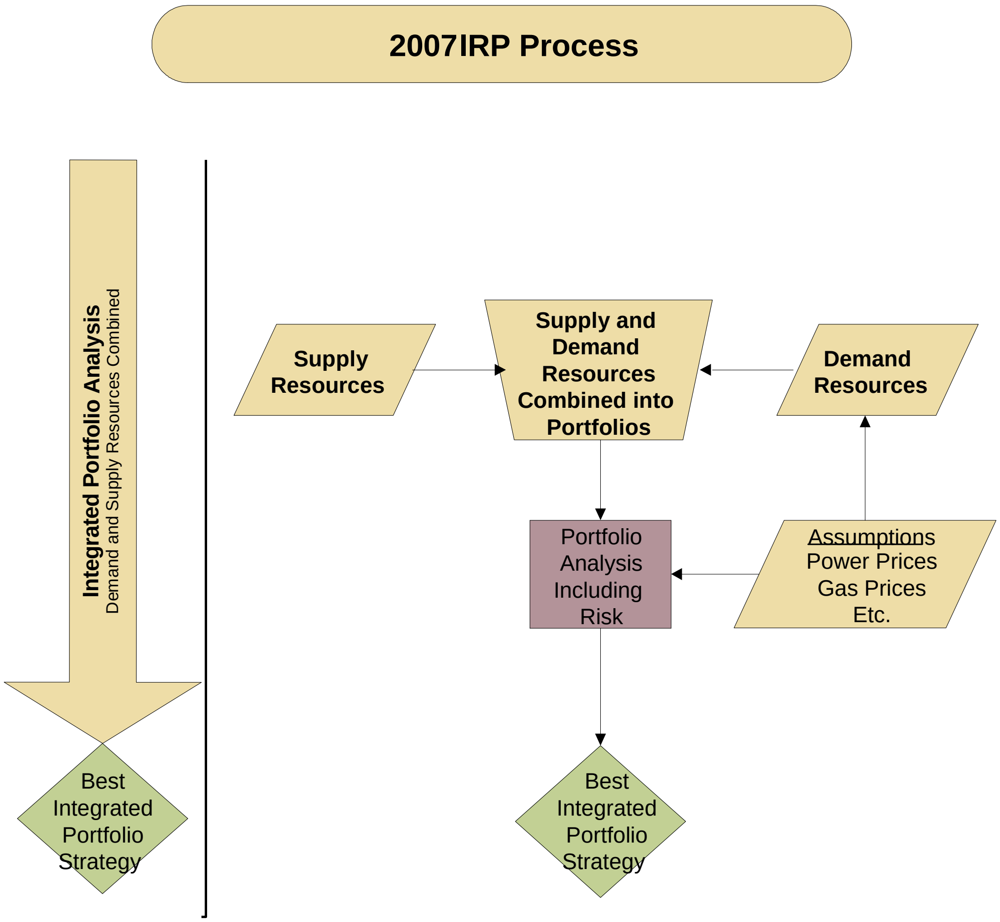
The hourly prices PSE provides to Quantec are based on Aurora price forecasts, and include adjustments consistent with PSE's cost effectiveness screening model. These include T&D benefits, system benefits charge, and line loss reduction. PSE has developed an additional adjustment called the "planning adjustment."

Our long-term planning standard calls for the Company to meet projected average energy requirements within each month of the year. It should be noted that this is not the same as stating that PSE will acquire resources as long as their cost is less than spot market (an approach more indicative of an energy marketer than a utility obligated to serve and manage risk). This IRP analysis indicates the incremental cost of PSE's 2005 LCP resource strategy is approximately 40% more costly than if the Company were to rely purely on spot market power. The "planning adjustment" is based on the portfolio strategy from the 2005 LCP, but with updated technology costs and characteristics, fuel prices, and power prices to reflect 2007 IRP assumptions. The difference between levelized spot prices and the levelized cost of the portfolio strategy is the planning adjustment. This adjustment provides a better estimate of the value energy efficiency would have in PSE's portfolio. For evaluating Demand Response, PSE provided Quantec an annual levelized cost of capacity resources. The all-in levelized number is calculated using $36.77 per KWyear, escalating annually during the first period of 2008 through 2013, and a levelized $90 per KW-year during the 2014 to 2027 period.

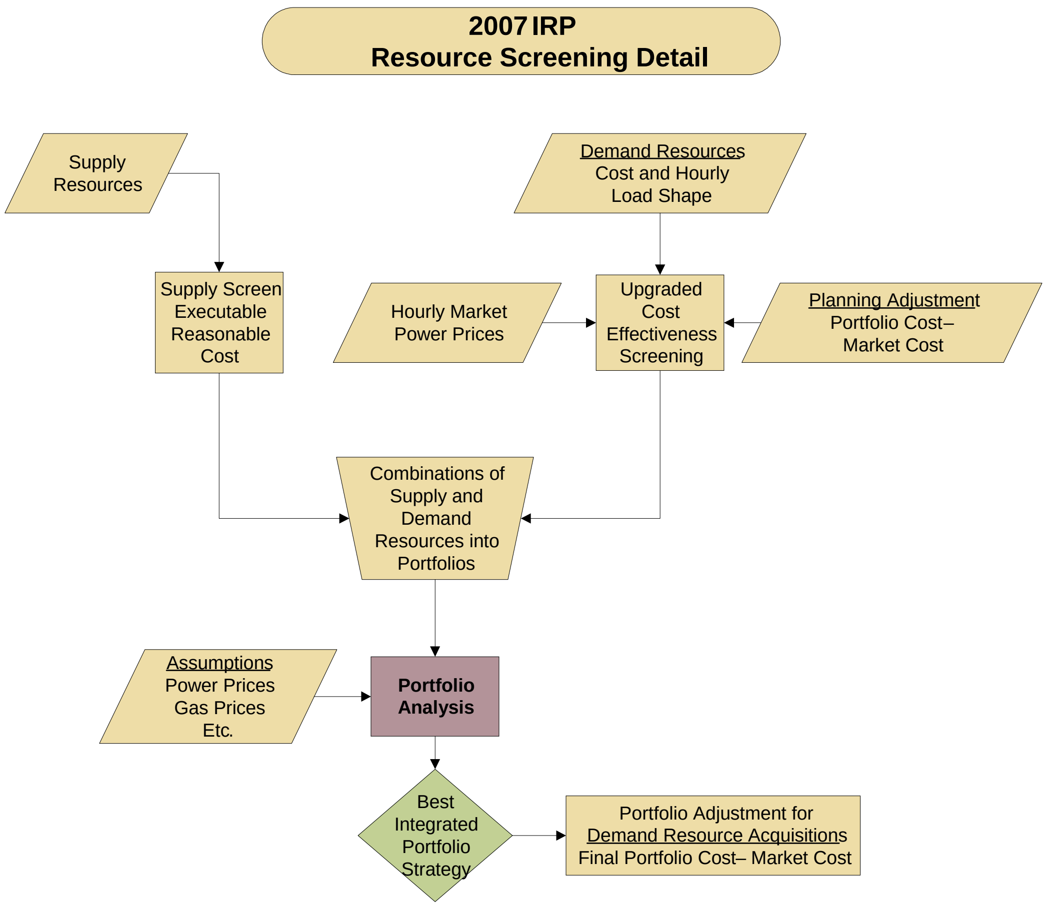
B. Diagrams of Process

PSE uses two models for integrated resource planning: AURORAxmp and the Portfolio Screening Model (PSM). AURORA analyzes the western power market to produce hourly electricity price forecasts of potential future market conditions, as described in Chapter 3. PSM tests electric supply and demand portfolios to evaluate PSE's long-term revenue requirements for the incremental portfolio. The followings diagrams show the methods used to quantitatively evaluate the lowest reasonable cost portfolio.

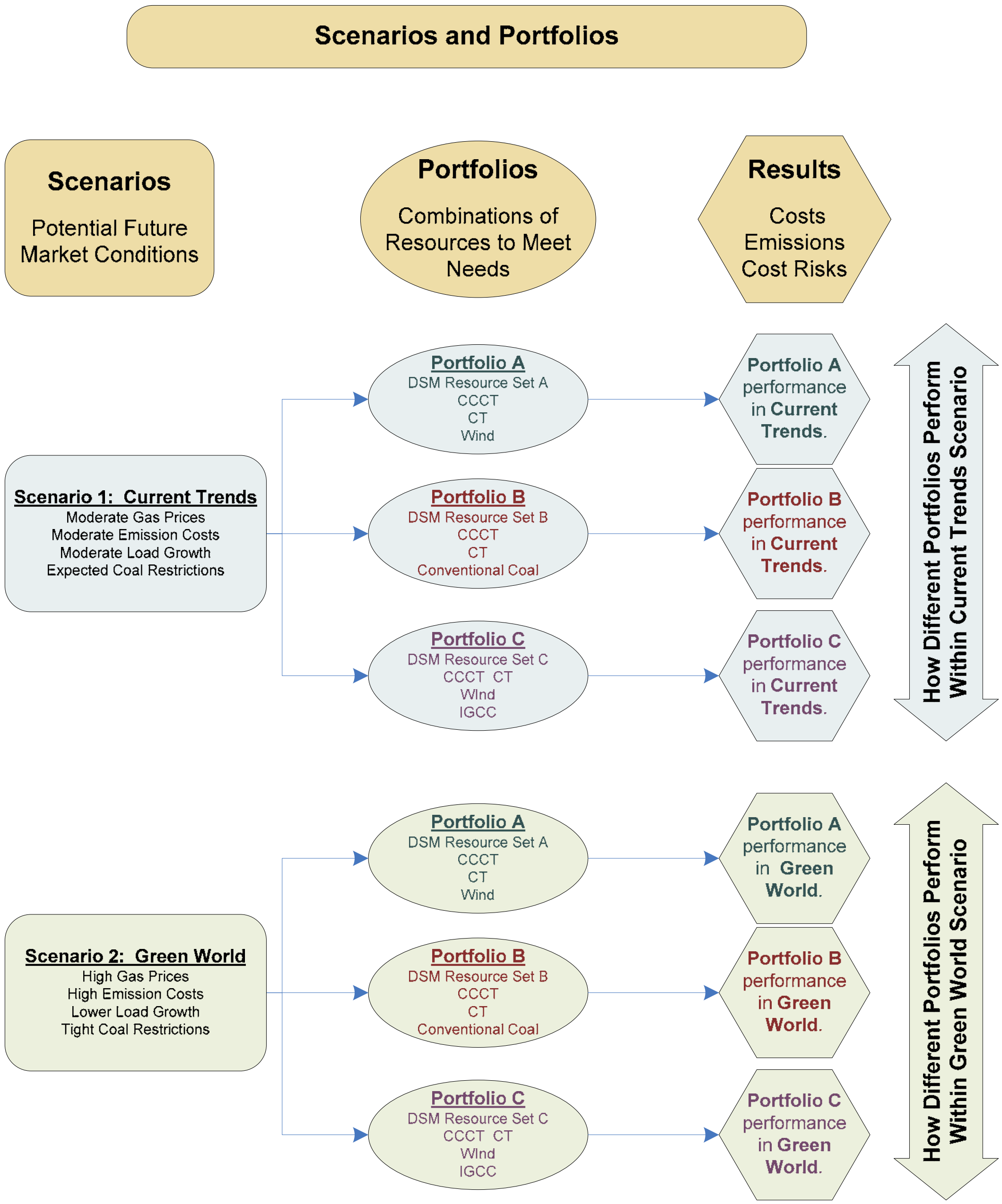
i. 2007 IRP Process



ii. Resource Screening



iii. Electric Resource Analysis



C. Risk Analysis

i. Scenarios

A description of the six scenarios can be found in Chapter 3, section 1, *Electric Analysis Components*. The monthly price output from these scenarios can be found in section 2 of this appendix.

ii. Portfolios

Below is a description of all 12 portfolios and the name that corresponds to the tables in section 2 of this appendix.

The key definitions and assumptions help to further define the portfolios:

- **Renewables**. Meet Washington's Renewable Portfolio Standards (RPS) of 3% by 2012, 9% by 2016 and 15% by 2020, and PSE's goal of 10% by 2013 with wind and biomass plants. In 2008, PSE meets slightly less than 5% of load with current wind resources (Wild Horse and Hopkins Ridge).
- **More Renewables**. Increase renewable energy development to 20% by 2017.
- **PBAs.** Power Bridging agreements used to balance energy need with short-term annual energy purchases that bridge the gap to long lead resources, limited to 500 MW.

Portfolio	Summary Description
1. Aggressive Gas	PSE meets Washington state RPS targets with wind and biomass plants. All other thermal requirements are met by gas-fired CCCT. No near-term PBAs.
1a. Early PBA Aggressive Gas	PSE meets Washington state RPS targets with wind and biomass plants. All other thermal requirements are met by gas-fired CCCT. PBAs used near-term.
2. Early IGCC	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT and IGCC capacity which is brought onine by 2014. A second IGCC plant comes online by 2020. PBAs used throughout.
3. Late IGCC	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT, and IGCC capacity (with no CCS) brought on line by 2020. PBAs used throughout.
3a. Early PBA Late IGCC	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT, and IGCC capacity (with no CCS) brought online by 2021. PBAs used near-term.
4. Max IGCC	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT and as many IGCC plants as PSE can bring online subject to the constraint of not exceeding more than 500 MW PBA at any time. First IGCC online in 2014, with the next online in 2016.
5. Late IGCC with CCS	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT and IGCC with CCS capacity brought online by 2021. No near-term PBAs
5a. Early PBA Late IGCC with CCS	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT and IGCC with CCS capacity brought online by 2021. PBAs used near-term
6. Aggressive Renewables	PSE meets Washington state RPS targets with wind and biomass plants. All other thermal requirements are met by gas-fired CCCT through 2017. Increased reliance on wind post-2018 in amount sufficient to offset thermal energy additions. PBAs used near-term.
7. More Renewables with Gas	PSE increases its renewables to meet 20% of load by 2017. All other thermal requirements are met by gas-fired CCCT.
8. More Renewables and IGCC with CCS	PSE increases its renewables to meet 20% of load by 2017. All other thermal requirements are met by gas-fired CCCT and IGCC with CCS capacity brought online by 2021.
9. Last IRP Portfolio	PSE meets Washington state RPS targets with wind and biomass plants. All other future load requirements met using the same portfolio construction as the 2005 IRP. Thermal requirements met by CCCT and Conventional Coal brought online by 2016.

iii. Probabilistic Analysis of Risk Factors

In addition to using scenarios to assess risk, this 2007 IRP continues to assess portfolio uncertainty through probabilistic Monte Carlo modeling in the Portfolio Screening model. It relies on Monte Carlo analysis to consider four uncertainty factors: market prices for natural gas, market prices for power, wind generation variability, and hydroelectric generation availability.

iv. Risk Measures

The results of the Monte Carlo simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10% of outcomes. This risk measure is the same as the risk measure used by NWPCC in its Fifth Power Plan. Additionally, we looked at annual volatility by measuring year to year changes in revenue requirements. Then we calculated the standard deviation of those year to year changes. The final measure of volatility is the average of the standard deviation across the simulations. It is important to recognize that this does not reflect actual expected rate volatility. The revenue requirement used for portfolio analysis does not include rate base and fixed cost recovery for existing assets.

II. Models

A. The AURORA Dispatch Model

i. Overview

PSE uses the AURORA model to estimate the market price of power used to serve its core customer load. The model is described below in general terms to explain how it operates, with further discussion of significant inputs and assumptions.

The following text was provided by EPIS, Inc. and edited by PSE.

> AURORA is a fundamentals-based program, meaning that it relies on factors such as the performance characteristics of supply resources, regional demand for power, and transmission, which drive the electric energy market. AURORA models the competitive electric market, using the following modeling logic and approach to simulate the markets: prices are determined from the clearing price of marginal resources. Marginal resources are determined by "dispatching" all of the resources in the system to meet loads in a least cost manner subject to transmission constraints. This process occurs for each hour that resources are dispatched. Resulting monthly or annual hourly prices are derived from that hourly dispatch.
>
> AURORA uses information to build an economic dispatch of generating resources for the market. Units are dispatched according to variable cost, subject to non-cycling and minimum-run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market-clearing price for the power they generate.

ii. Long Run Optimization

AURORA also has the capability to simulate the addition of new generation resources and the economic retirement of existing units through its long-term optimization studies. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable, unless reserve margin targets are selected; that is, when investors can recover fixed and variable costs with an acceptable return on investment. AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

iii. Use of Reserve Margin Targets

During the summer of 2006, EPIS, Inc. released a new version of AURORAxmp, along with an input database that included the necessary inputs to perform long-term studies using planning reserve margin targets. The model builds resources to meet target reserve margins and estimates the "capacity price payments necessary to support the marginal entrants supplying capacity to the system."[1]

PSE uses reserve margin targets at the pool level, which consists of the Northwest Power Pool territory. The overall pool reserve margin target is 15%. PSE tested capacity pool reserve margins at 0%, 5%, and 15%. A pool reserve margin of 15% best mitigated summer price spreads without increasing average prices unreasonably. Many U.S. regions plan for at least a 15% reserve margin.

Existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years.

B. Portfolio Screening Model

The Portfolio Screening Model (PSM) is a Microsoft Excel-based hourly dispatch simulation model the Company developed to evaluate incremental cost and risk for a wide variety of resource alternatives and portfolio strategies. The PSM calculates the

[1] EPIS, Inc., "Long-Term Studies Using Reserve Margins," from AURORAxmp electronic documentation, December 2005.

incremental portfolio costs of resources required to serve load. Incremental cost includes: (i) the variable fuel cost and emissions for PSE's existing fleet, (ii) the variable cost of fuel emissions and operations and maintenance for new resources, (iii) the fixed depreciation and capital cost of investments in new resources, (iv) the book cost and offsetting market benefit remaining at the end of the 20-year model horizon, and (v) the market purchases or sales in hours when resources are deficient or surplus to PSE's need.

PSM is a modeling tool that can

(i) quickly evaluate and compare results for a wide range and large number of alternative resource strategies;
(ii) calculate variable costs for all resources, including existing and new resources, as well as fixed costs for new resources (AURORA does not address fixed costs for new resources added to a utility's portfolio);
(iii) perform probabilistic analyses of several key uncertainty factors, including multiple correlations among uncertainty factors; and
(iv) address other topics, such as end effects for resource alternatives that have varying lives.

The primary input assumptions to the PSM are

(i) PSE's existing portfolio,
(ii) projected gas and power prices,
(iii) costs of generic resources,
(iv) financial assumptions such as cost of capital and escalation rates,
(v) variability of prices, and
(vi) a generic resource mix.

2. Data

I. Key Inputs and Assumptions

A. Aurora Inputs

Numerous assumptions are made to establish the parameters that define the optimization process. The first parameter is the geographic size of the market. In reality, the continental United States is divided into three regions, and electricity is not traded between these regions. The western-most region, called the Western Electricity Coordinating Council (WECC) includes the states of Washington, Oregon, California, Nevada, Arizona, Utah, Idaho, Wyoming, Colorado, and most of New Mexico and Montana. The WECC also includes British Columbia and Alberta, Canada, and the northern part of Baja California, Mexico. Electric energy is traded and transported to and from these foreign areas, but is not traded with Texas, for example.

For modeling purposes, the WECC is divided into 21 areas primarily by state and province, except for California which has eight areas, Nevada which has two areas, and Oregon and Washington which are combined. These areas approximate the actual economic areas in terms of market activity and transmission. The databases are organized by these areas and the economics of each area is determined uniquely.

Load forecasts are created for each area. These forecasts include the base year load forecast and an annual average growth rate. Since the demand for electricity changes over the year and during the day, monthly load shape factors and hourly load shape factors are included as well. All of these inputs vary by area: for example, the monthly load shape would show that California has a summer peak demand and the Northwest has a winter peak.

All generating resources are included in the resource database, along with characteristics of each resource, such as its area, capacity, fuel type, efficiency, and expected outages (both forced and unforced). Previously, the generating resource landscape experienced few changes; however, numerous plants are now under construction and many more are in the planning stage. PSE uses current knowledge of Northwest resources, and utilizes EPIS, Henwood, public sources (e.g., Cal-ISO, CEC, etc.) and private contacts to update the over 3,000 electric power resources in the West. The model incorporates resources that are under construction with expected online dates; however, because of uncertainties caused by numerous factors, PSE includes only new plants that will be completed by 2008.

Power Plants under Construction

Plant	Location	Fuel	Capacity (MW)	Online Date
Spring Canyon	CO	Wind	60	1/1/2006
Galena Geothermal	NV	Geothermal	20	11/14/2005
Stillwater 11	NV	Geothermal	26	12/31/2007
Nevada Solar One	NV	Solar	3.1	12/1/2006
Argonne Mesa	NM	Wind	90	12/1/2006
Caprock Wind	NM	Wind	80	5/1/2005
White Creek	WA	Wind	100	12/1/2007
Klondike Wind III	OR	Wind	247.5	12/2/2007
Gross Hydroelectric Reservoir Project	CO	Hydro	7.6	5/1/2007
Mint Farm Power Station	WA	Gas	285	6/1/2007
Allen GT2	NV	Gas	75	6/1/2006
Horseshoe Bend (Great Falls) Ranch Pit Wind	MT	Wind	9	3/1/2006
Hidden Hollow	ID	Landfill Gas	3	4/1/2006
Desert Peak 2	NV	Geothermal	15	6/1/2006
Soderglen	AB	Wind	70.5	8/1/2006
Kettles Hill WF 1-30 (Pincher Creek)	AB	Wind	63	7/31/2006
China Creek	BC	Hydro	6.5	1/1/2006
Brilliant Expansion	BC	Hydro	120	8/1/2006
Chin Chute Wind Power Project	AB	Wind	30	10/30/2006
Furry Creek Hydro Project	BC	Hydro	11	6/1/2004
Richard Burdett Geothermal	NV	Geothermal	30	11/14/2005
Miller Creek	BC	Hydro	33	3/1/2003

Many states in the WECC have passed statutes requiring Renewable Portfolio Standards (RPS) to support the development of renewable resources. Typically an RPS states that a specific percentage of energy consumed must be from renewable resources by a certain date (e.g., 10% by 2015). While these states have demonstrated clear intent for policy to support renewable energy development, they also provide pathways to avoid such strict requirements.

Coal prices were adopted from the August 2006 Global Insight price forecasts.

Water availability greatly influences the price of electric power in the Northwest. PSE assumes that hydro power generation is based on the average stream flows for the 50 historical years of 1929 to 1978. While there is also much hydro power produced in California and the Southwest (e.g., Hoover Dam), it does not drive the prices in those areas as it does in the Northwest. In those areas, the normal expected rainfall and hence, the average power production is assumed for the model. For sensitivity analysis, PSE can vary the hydro power availability, or combine a past year's water flow to a future year's needs.

Electric power is transported between areas on high voltage transmission lines. When the price in one area is higher than it is in another, electricity will flow from the low priced market to the high priced market (up to the maximum capacity of the transmission system), which will move the prices closer together. The model takes into account two important factors that contribute to the price: first, there is a cost to transport energy from one area to another, which limits how much energy is moved; and second, there are physical constraints on how much energy can be shipped between areas. The limited availability of high voltage transportation between areas allows prices to differ greatly between adjacent areas. EPIS updates the model to include known upgrades (e.g., Path 15 in California) but the model does not add new transmission "as needed."

B. Production Tax Credit and Renewable Portfolio Standard

i. Production Tax Credit Assumptions

Current federal production tax credit (PTC) legislation is effective through December 31, 2008. For modeling purposes, we continued PTCs at the current rate of $19 per MWh through 2009, and drop to a $10 per MWh credit in 2010 and 2011, representing a 50% probability that the PTCs will be extended for another two years. The PTCs are still assumed to be given to a project for 10 years after it is placed into service. The inflation adjuster will also be dropped. This suggestion allows for continued support for renewable energy while recognizing the fact that wind, in particular, has been heavily subsidized for a number of years. Another factor is the increasing number of states that have Renewable Portfolio Standards, which also leads to greater renewable energy capacity. While this may be a reasonable assumption, there is great uncertainty with respect to future PTCs and PSE will need to conduct additional sensitivity analyses for specific renewable resource proposals. Both wind and biomass receive the PTC; however, open-loop biomass only receives a partial PTC credit. For the purpose of modeling, we assumed open-looped Biomass is credited with half of the PTC.

ii. Renewable Portfolio Standard

As described above, a number of states in the WECC have Renewable Portfolio Standards, which determines the percentage of load that must be served with renewable resources. Each state has different rules regarding the definition of renewable energy sources, the timing of the standards, and the percentage of load that must be met.

In order to model these varying laws, we first need a load forecast for each state. The benchmarks of each RPS (e.g. 3% in 2015, then 5% in 2020) are identified and applied to the load forecast. After existing and expected renewable energy resources are accounted for, new renewable energy resources are matched to the load to meet the RPS. With internal and external review for reasonableness, these resources are created in the AURORA data base.

Important sources of information include: the AURORA data base for long run state load forecasts; summaries of the state RPSs from Lawrence Berkeley National Laboratory; and renewable resource potential for each state from the “Renewable Energy Atlas of the West.” Existing and expected renewable resources were identified in the AURORA data base, and updated with information from the Renewables Northwest Project and Global Energy Decisions' "New Entrants" data base.

New Mexico - The RPS requires 5% of retail sales to be renewable by 2006. RPS requirements increase by at least 1% a year, and utilities must reach 10% by January 1, 2011 and thereafter.

The Table below includes a brief overview of the RPS for each state in the WECC that has one. The "Standard" column offers a summary of the law, as provided by the Lawrence Berkeley National Laboratory (LBNL), and the "Notes for AURORA Modeling" column includes a description of the new renewable resources created to meet the law.

State	Standard (LBNL)	Notes for AURORA Modeling
Arizona	New Proposed RPS: 1.25% in 2006, increasing by 0.25% each year to 2.00% in 2009, then increasing by 0.5% a year to 5% in 2015, and increasing 1% a year to 14% in 2024, and 15% thereafter. Of that, 5% must come from distributed renewables in 2006, increasing by 5% each year to 30% by 2011 and thereafter. Half of distributed solar requirement must be from residential application; the other half from non-residential non-utility applications. No more than 10% can come from RECs, derived from non-utility generators that sell wholesale power to a utility.	Very little potential wind generation is available. Most of the requirement is met with central solar plants. The distributed solar (30%) is accounted for by assuming central renewable energy.
California	IOUs must increase their renewable supplies by at least 1% per year starting January 1, 2003, until renewables make up 20% of their supply portfolios. The 20% requirement must be reached no later than 2017, but utilities may not have to meet the requirement if SBC funds are exhausted before the requirement is met: costs of renewables over a to-be-determined market price must be paid for by the state's SBC fund. Although not required, major push to meet 20% level by 2010, with potential goal of 33% by 2020. IOUs do not need to make annual RPS purchases until they are creditworthy. CPUC can order transmission additions for meeting RPS under certain conditions.	The California Energy Commission created an outline of the necessary new resources by technology and location that could meet the 20% by 2017 goal. Technologies include wind, biomass, solar and geothermal in different areas of the state The renewable energy resources identified in the outline were incorporated into the model.
Colorado	Utilities that serve over 40,000 customers must have 3% of their electricity from eligible renewable energy from 2007 through 2010; 6% from 2011 through 2014; and 10% in 2015 and beyond. New and existing renewables are eligible. At least 4% of the RPS standard must be met by	The primary resource for Colorado is wind. The 4% solar requirement is modeled as central power only.

	solar, with half of the solar requirement from on-site solar systems. Utilities acquire renewables or RECs via competitive bidding.	
Montana	5% of sales (net of line losses) to retail customers in 2008 and 2009; 10% from 2010 to 2014; and 15% in 2015 and thereafter. At least 50 MW must come from community renewable energy projects during 2010 to 2014, increasing to 75 MW from 2015 onward. Utilities are to conduct RFPs for renewable energy or RECs and after contracts of at least 10 years in length, unless the utility can prove to the PSC the shorter-term contracts will provide lower RPS compliance costs over the long-term. Preference is to be given to projects that offer in-state employees or wages.	The primary source for Montana is wind. The community renewable resources are modeled as solar units of 50 MW then 25 MW.
Nevada	6% in 2005 and 2006 and increasing to 9% by 2007 and 2008, 12% by 2009 and 2010, 15% by 2011 and 2012, 18% by 2013 and 2012, ending at 20% in 2015 and thereafter. At least 5% of the RPS standard must be from solar (PV, solar thermal electric, or solar that offsets electricity, and perhaps even natural gas or propane) and not more than 25% of the required standard can be based on energy efficiency measures.	The Renewable Energy Atlas shows that considerable geothermal energy and solar energy potential exists. For modeling the resources are located in the northern and southern part of the state respectively, with the remainder made up with wind.
New Mexico	The Public Regulation Commission (PRC) passed an RPS rule on December 17, 2002, but the Legislature passed legislation in 2004 that is equivalent to the PRC rule. The RPS requires 5% of retail sales to be renewable by 2006. RPS requirements increase by at least 1% a year, and utilities must reach 10% by January 1, 2011 and thereafter.	New Mexico has a relatively large amount of wind generation currently for its small population. New resources are not required until 2015, at which time they are brought in as wind generation.
Oregon - Washington	Proposed Washington state RPS: 3% by 2012, 9% by 2016, 15% by 2020. Eligible resources include wind, solar, geothermal, biomass, tidal. Oregon officials have been discussing the need for an RPS, and the governor has proposed 25% by 2025.	The loads and existing renewable resources for Oregon and Washington were combined and the proposed Washington RPS was applied to the combined area. While the Washington RPS is yet to be voted on, it is expected to pass and some RPS legislation is expected from Oregon in the future. Further, the wind resources along the Columbia River may be in either state, but the model has them in Oregon. Modeled resources also included biomass in each state and geothermal in Oregon.

C. Generic Resource Costs and Characteristics

Generic Resource Costs	Units	CCCT 2008	SCCT 2008	Wind 2008	Coal SCPC 2008	IGCC 2008	IGCC + CCS 2008	Biomass 2008	Geothermal 2008
Capacity	*MW*	250 (40 DF)	100	150	500	500	500	40	25
Capital Cost	*$/KW*	1,050	990	2,000	2,600	3,001	4,295	2,200	3,449
O&M - Fixed	*$/kW-yr*	21	7	43	25	35	42	175	132
O&M - Variable	*$/MWh*	3	4	2	5	3	4	0	2
Availability	*%*	95%	95%	30%	90%	85%	85%	85%	95%
Heat Rate - GT	*Btu/kWh*	7,000	8,934	n/a	9,000	8,655	9,848	14,000	n/a
Heat Rate - Duct Firing	*Btu/kWh*	9,100	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Fuel Price	*$/MMBtu*	n/a	n/a	n/a				incl in FO&M	n/a
Fixed Gas Transportation	*$/Dth per day*	$0.50	$0.18	n/a	n/a	n/a	n/a		n/a
Fuel Basis Differential	*$/MWh*	$2.69	$3.43	n/a	n/a	n/a	n/a		n/a
Fuel Basis Differential - DF	*$/MWh*	$3.22						n/a	n/a
Electric Transmission - Fixed	*$/kW-yr*	$14.9	$4.0	$24.1	$97.5	$50.7	$50.7	$14.9	$68.54
Electric Transmission - Variable	*$/MWh*	$1.0	$0.0	$7.2	$1.4	$1.8	$1.8	$1.0	$1.78
Fixed Transmission Build	*$/kW-yr*	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed
Transmisssion Zone (% split)		1 & 2 (50%)	1 (100%)	3 (100%)	5 (100%)	2, 3 & 5 (33%)	2, 3 & 5 (33%)	1 & 2 (50%)	4 (100%)
Emissions:									
CO2	*ton/GWh*	385 (501 DF)	491	n/a	957	920	0		
SO2	*ton/GWh*	0.04 (0.06 DF)	0.05	n/a	0.32	0.3	0.3		
NOX	*ton/GWh*	0.00	0.00	n/a	0.56	0.13	0.13		
Hg									
Fixed Gas Transportation	*$/kW-yr*	30.66	4.70						

D. Wind Capacity Credit

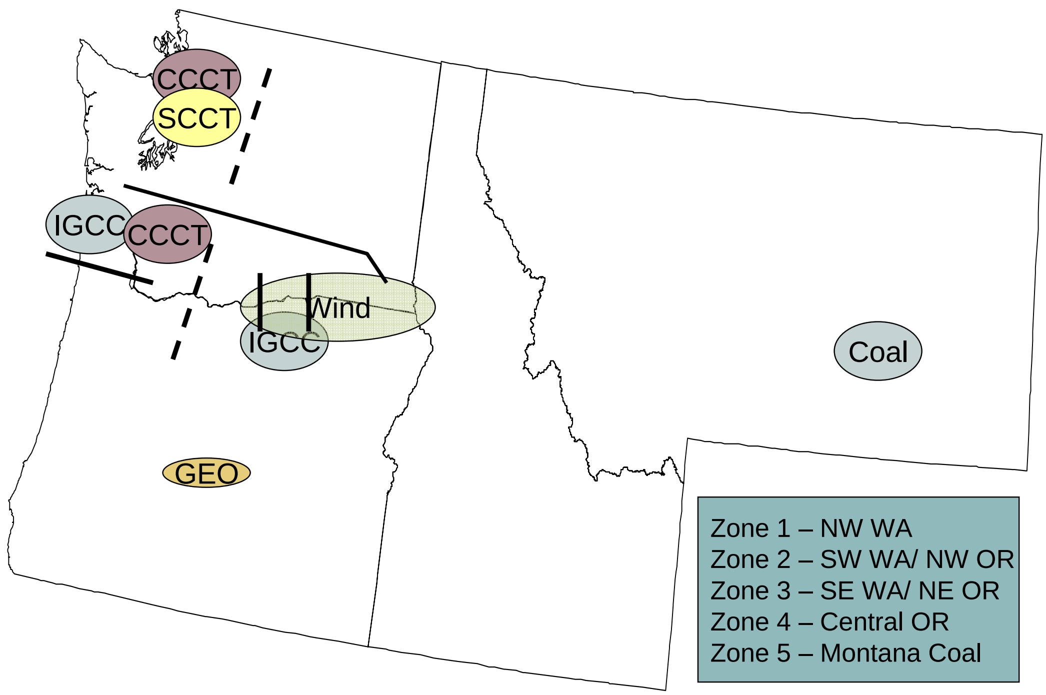
For the 2007 IRP, PSE is using 15% of plant name plate capacity for wind capacity credit when evaluating wind resources. We adopted the current recommendation that is being evaluated by the Pacific Northwest Resource Adequacy Forum in its pilot capacity adequacy standard, which was presented to the NWPCC on October 18, 2006.

E. Wind Profile

The following table provides information on zone 3 wind projects (see section F for zones). The January shape for peak capacity was derived by taking the average of these wind projects.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave	Factor
Avg % Energy (Zone 3)	29%	23%	43%	33%	40%	39%	40%	35%	32%	31%	27%	28%	400%	0.25
	7.1%	5.9%	10.8%	8.2%	9.9%	9.8%	10.1%	8.7%	8.0%	7.8%	6.8%	7.1%	100%	8.3%
Monthly aMW Factor	0.85	0.70	1.29	0.98	1.19	1.18	1.21	1.04	0.96	0.94	0.81	0.85	1.00	

F. Diagram of Transmission Zones



G. Monte Carlo Input Assumptions

The annual variability of power and gas prices, as well as the correlation between these variables, has been updated. Based on conversations with Horizon Wind Energy and with Global Energy Concepts, LLC, we updated the annual variability to 10%. The variability of hydroelectric generation and correlation with power prices was held at the same values used in the 2003 and 2005 Least Cost Plans.

The following table shows the Monte Carlo input assumptions.

	Variability and Distribution	Correlations		
		Gas Price	Power Price	Hydro
Gas Price	47% Log normal	1.0	.96	
Power Price	37% Log normal	.96	1.0	-.54
Mid-C Hydro	8% Normal		-.54	1.0
West Side Hydro	12% Normal		-.54	1.0
Wind	10% Normal			

II. Output

A. Aurora Electric Prices

Below is a series of tables with the AURORA price forecasts for the different scenarios.

Monthly Flat Mid-C Prices

(Nominal $/MWH)

Current Trends (CT)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.69	73.27	63.13	47.96	44.90	46.06	57.75	60.62	59.84	57.44	67.51	64.31	59.29
2009	65.35	70.62	60.67	46.52	42.55	43.51	54.19	56.98	57.22	54.37	66.34	61.55	56.65
2010	62.48	68.23	58.03	43.27	40.75	43.04	52.21	55.13	54.41	53.01	66.05	59.82	54.70
2011	61.34	67.06	56.98	41.67	38.99	41.16	49.12	53.14	52.69	51.58	64.91	57.83	53.04
2012	63.68	67.38	55.84	51.71	49.82	50.47	59.16	61.36	61.74	62.79	77.81	62.17	60.33
2013	64.89	68.59	56.87	53.55	51.15	50.51	60.61	63.78	64.69	63.40	74.77	64.56	61.45
2014	65.55	68.21	56.94	55.00	52.21	52.73	62.31	64.52	67.06	65.99	77.35	66.55	62.87
2015	64.77	66.79	56.61	54.91	52.41	53.77	62.32	64.59	67.25	66.23	77.54	65.99	62.77
2016	63.86	66.14	56.24	54.20	52.84	53.82	61.69	64.63	66.87	66.90	81.18	66.18	62.88
2017	67.44	67.79	58.63	57.29	55.97	57.08	66.00	68.34	69.72	71.71	86.03	69.00	66.25
2018	68.46	69.80	60.86	59.75	57.40	56.86	66.72	70.48	71.70	71.64	85.78	71.09	67.54
2019	71.50	71.38	62.15	62.66	59.77	58.96	70.10	73.39	74.76	75.53	89.82	75.22	70.44
2020	71.83	70.86	62.23	62.15	59.16	60.13	68.98	71.40	74.79	74.55	90.76	75.54	70.20
2021	76.30	75.98	67.04	63.78	58.56	58.83	67.57	70.40	73.59	73.89	96.33	82.08	72.03
2022	78.97	78.68	69.32	65.79	60.57	61.61	69.77	73.26	75.59	77.08	99.46	84.02	74.51
2023	81.78	80.50	71.15	67.43	62.97	63.11	72.29	75.82	77.17	80.33	102.85	85.50	76.74
2024	84.93	84.71	74.25	71.83	65.34	64.37	74.70	79.40	81.17	82.16	103.38	90.52	79.73
2025	86.92	87.47	76.67	73.41	66.83	66.87	77.67	80.66	83.94	84.76	106.81	93.33	82.11
2026	89.68	89.99	78.97	75.48	68.11	69.65	79.33	82.70	86.32	87.35	110.67	95.61	84.49
2027	92.28	92.60	82.29	77.96	69.99	72.71	82.33	85.87	88.74	90.17	115.79	98.53	87.44

Green World (GW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.08	72.35	62.31	47.52	44.08	44.70	57.30	60.24	59.25	56.91	66.83	63.68	58.60
2009	65.51	70.57	60.56	46.77	42.62	43.52	54.70	57.42	57.09	54.32	65.96	61.18	56.69
2010	64.43	66.60	56.33	54.20	50.90	53.23	65.05	67.10	66.70	65.17	81.81	66.70	63.18
2011	64.05	65.76	56.18	54.30	51.83	53.43	65.06	67.92	67.39	66.15	84.61	66.36	63.59
2012	67.25	68.68	57.21	58.54	58.28	58.87	70.55	71.91	69.17	72.07	89.80	68.54	67.57
2013	67.44	69.62	58.60	59.99	58.61	57.96	70.92	73.74	73.13	72.10	85.97	70.43	68.21
2014	68.61	70.02	58.70	62.17	60.95	61.48	74.62	76.40	75.81	75.57	89.57	72.49	70.53
2015	68.28	69.03	58.86	63.42	61.79	63.79	76.41	77.73	77.25	76.98	91.17	72.73	71.45
2016	69.03	68.82	59.12	64.50	62.61	65.10	77.09	80.29	77.60	78.58	96.76	74.28	72.81
2017	71.44	70.78	61.31	67.42	67.38	68.80	82.54	84.99	81.11	84.26	103.29	77.31	76.72
2018	73.75	73.63	64.62	71.43	70.03	69.15	85.19	88.69	84.63	86.08	104.18	80.89	79.36
2019	76.11	74.82	65.92	74.93	74.25	73.21	91.19	92.68	88.43	90.73	110.00	84.82	83.09
2020	78.10	74.00	65.88	75.78	73.54	74.56	92.06	92.91	88.56	91.14	113.51	87.19	83.94
2021	79.34	76.90	68.29	78.35	75.91	78.05	95.79	96.84	92.67	95.13	120.93	90.03	87.35
2022	82.09	79.16	70.45	80.92	79.40	82.11	97.43	100.14	94.82	99.79	124.53	91.88	90.23
2023	84.69	81.18	72.04	82.35	82.49	84.31	100.71	102.22	96.34	103.13	129.59	94.28	92.78
2024	88.12	85.30	76.13	87.32	85.30	83.95	104.62	106.58	101.95	105.51	129.00	99.72	96.13
2025	90.51	87.58	77.73	88.74	86.05	86.63	106.29	106.68	104.21	107.99	132.67	103.23	98.19
2026	93.14	89.95	79.89	90.29	88.81	90.10	109.13	109.28	106.72	110.47	137.14	105.34	100.86
2027	95.75	93.09	83.01	93.53	92.26	94.02	112.28	113.75	110.22	114.36	143.38	108.35	104.50

Low Growth (LG)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.08	72.35	62.31	47.52	44.08	44.70	57.30	60.24	59.25	56.91	66.83	63.68	58.60
2009	65.20	69.54	59.96	46.00	42.80	43.91	54.28	57.08	56.69	53.97	65.45	60.54	56.29
2010	61.41	66.44	56.21	42.77	40.37	42.58	52.06	54.44	53.81	52.18	64.40	58.58	53.77
2011	59.90	64.79	55.91	41.25	38.96	40.72	49.40	52.14	51.37	50.14	63.35	56.38	52.02
2012	55.14	57.16	47.31	44.56	43.40	44.32	51.67	52.34	52.51	53.90	67.53	53.54	51.95
2013	53.58	56.82	46.81	44.14	42.07	42.57	50.11	51.80	53.60	52.78	62.36	53.44	50.84
2014	53.42	55.63	45.96	44.12	42.67	43.31	50.79	51.78	54.16	53.65	63.45	54.01	51.08
2015	52.16	54.58	45.19	44.31	42.74	44.36	51.11	52.08	54.71	53.95	63.47	52.91	50.96
2016	51.57	53.46	45.03	44.15	43.23	44.74	51.20	53.11	54.28	54.66	66.82	53.25	51.29
2017	52.06	52.26	44.62	44.63	44.35	46.13	52.50	53.58	54.19	56.27	68.53	53.23	51.86
2018	53.35	53.97	46.62	46.32	45.41	45.97	53.66	54.97	56.09	56.51	68.96	55.34	53.10
2019	55.90	55.61	47.77	48.79	47.99	47.99	56.55	57.61	58.82	59.49	72.75	58.68	55.66
2020	55.78	55.23	48.01	49.52	47.07	49.08	57.08	57.90	58.85	60.18	74.20	58.96	55.99
2021	56.82	57.10	49.67	50.96	48.91	51.04	58.47	59.62	60.51	62.30	78.36	60.93	57.89
2022	59.00	58.30	50.75	51.81	50.68	52.43	59.85	61.90	62.15	64.43	80.68	62.14	59.51
2023	60.37	59.25	51.93	52.61	52.35	53.88	61.03	62.80	62.82	66.76	83.18	63.05	60.84
2024	62.03	62.24	54.04	55.17	53.60	53.71	62.95	64.29	65.73	67.63	83.05	65.92	62.53
2025	63.73	63.59	55.40	56.43	54.37	55.84	64.30	65.06	67.84	69.83	85.30	68.47	64.18
2026	65.42	65.00	56.68	57.77	55.91	57.68	64.92	65.81	69.37	71.38	88.05	70.20	65.68
2027	67.07	66.48	58.63	59.11	57.01	59.00	66.40	68.00	71.16	73.39	91.48	71.89	67.47

Robust Growth (RG)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.91	73.79	63.18	48.43	44.50	46.01	58.16	60.84	60.40	57.80	67.96	64.47	59.54
2009	66.05	71.55	61.09	47.53	43.45	44.82	55.53	58.01	57.75	54.97	66.81	62.04	57.47
2010	65.79	67.97	56.59	55.18	51.57	52.78	64.02	66.84	66.71	65.47	82.47	67.24	63.55
2011	64.96	66.87	56.00	55.05	52.29	52.94	63.57	66.74	66.04	65.88	83.34	66.48	63.35
2012	66.16	67.59	56.55	57.14	55.59	56.21	66.54	69.05	67.61	69.72	86.89	66.75	65.48
2013	66.84	68.00	57.79	59.70	57.33	56.82	68.92	72.21	71.43	71.41	84.87	69.28	67.05
2014	67.83	68.66	58.00	61.90	60.25	60.57	72.82	75.07	74.95	74.91	88.85	71.74	69.63
2015	68.52	68.67	58.77	63.94	61.93	63.84	76.14	77.93	77.07	77.23	92.09	72.80	71.58
2016	69.70	68.89	59.66	65.34	63.82	65.11	77.67	81.53	78.51	80.54	98.60	75.41	73.73
2017	72.81	70.80	61.86	68.70	68.08	69.16	82.82	85.77	81.79	85.60	104.61	78.31	77.53
2018	74.96	73.87	65.11	72.25	70.77	69.03	84.78	88.57	85.05	87.71	105.73	82.01	79.99
2019	78.01	76.24	66.71	76.20	74.00	72.79	90.49	93.13	89.75	93.04	112.28	87.30	84.16
2020	78.50	75.57	66.44	76.30	73.01	74.47	90.83	91.34	89.29	92.90	115.30	88.95	84.41
2021	80.04	77.68	68.80	78.63	76.19	77.83	94.10	96.15	93.27	97.18	122.70	92.30	87.91
2022	84.31	81.73	71.89	82.13	81.15	83.46	99.64	103.72	97.61	103.18	130.41	96.63	92.99
2023	87.46	83.51	73.96	84.29	83.92	84.98	103.07	105.86	98.97	107.29	134.79	98.85	95.58
2024	91.54	88.54	77.25	89.63	86.75	85.37	107.03	111.49	106.22	110.21	134.79	105.03	99.49
2025	93.60	90.44	79.44	91.38	87.95	88.94	109.02	110.44	108.24	113.25	138.26	107.69	101.55
2026	96.37	93.74	82.38	94.21	90.32	92.95	111.63	113.33	111.98	116.42	143.78	110.99	104.84
2027	98.74	96.33	85.20	97.24	94.70	97.39	116.25	120.35	115.19	120.70	151.06	113.06	108.85

Technology Improvement

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.69	73.27	63.13	47.96	44.90	46.06	57.75	60.62	59.84	57.44	67.51	64.31	59.29
2009	65.81	71.15	60.62	46.99	43.17	44.63	54.74	57.30	57.58	54.70	66.91	61.80	57.12
2010	63.05	67.96	58.70	43.78	41.36	43.95	52.71	55.34	55.17	53.41	66.34	60.05	55.15
2011	60.90	66.06	56.54	41.78	39.23	41.24	49.35	52.40	52.45	51.40	64.83	57.74	52.83
2012	64.62	67.42	55.94	52.57	50.44	51.10	60.02	61.96	61.94	63.44	78.54	63.50	60.96
2013	65.92	68.52	57.40	54.67	51.91	51.92	61.48	63.66	64.38	63.41	74.62	65.35	61.94
2014	66.42	68.33	56.85	55.67	53.52	53.87	63.00	64.30	65.72	65.15	76.47	66.65	63.00
2015	66.29	68.31	57.10	56.77	54.10	55.12	64.18	65.35	66.68	66.28	77.69	66.84	63.73
2016	66.08	67.52	57.16	56.78	54.33	55.58	63.76	66.31	66.13	66.83	81.06	67.65	64.10
2017	68.94	69.44	59.09	59.58	57.72	58.57	67.33	69.26	68.77	70.91	85.47	70.18	67.10
2018	70.39	71.76	62.07	61.34	59.00	58.61	68.04	70.93	70.62	71.45	85.64	72.48	68.53
2019	73.24	73.85	63.51	64.78	62.01	61.10	71.05	73.39	73.47	75.03	89.97	76.09	71.46
2020	74.12	73.36	63.54	65.44	61.29	62.25	72.70	73.46	73.37	75.51	92.24	77.50	72.06
2021	79.21	79.48	69.08	66.62	59.95	61.45	70.63	71.71	72.13	74.19	97.26	83.99	73.81
2022	82.09	82.83	72.19	69.02	62.60	64.10	72.50	74.96	74.59	77.59	100.93	86.49	76.66
2023	85.23	85.49	75.05	71.12	65.42	66.42	74.98	77.06	76.92	81.66	105.15	88.77	79.44
2024	88.54	89.99	78.54	75.04	67.90	66.98	77.16	79.90	80.83	82.74	105.47	93.26	82.20
2025	90.28	92.54	80.19	77.06	69.16	69.52	79.57	81.24	83.61	84.80	108.66	95.87	84.38
2026	92.29	94.82	82.55	78.62	71.04	71.73	81.23	82.84	85.60	86.49	111.48	97.26	86.33

Escalating costs

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.69	73.27	63.13	47.96	44.90	46.06	57.75	60.62	59.84	57.44	67.51	64.31	59.29
2009	65.30	70.07	60.32	46.60	42.85	44.03	54.23	56.91	56.80	54.16	66.06	60.84	56.51
2010	61.79	67.82	58.12	42.88	40.48	42.58	51.26	53.96	54.35	52.63	66.27	59.52	54.31
2011	60.62	65.86	56.99	41.28	38.86	41.18	48.83	52.08	52.09	51.18	64.66	57.14	52.56
2012	63.41	66.68	55.52	51.42	49.90	50.66	59.58	61.09	61.07	62.72	77.71	62.07	60.15
2013	64.87	68.28	57.24	53.64	50.78	51.11	61.23	63.12	64.81	63.54	75.58	64.77	61.58
2014	65.15	67.65	57.00	54.70	52.35	53.05	62.35	63.85	66.13	65.45	77.35	66.51	62.63
2015	64.61	66.86	56.13	54.69	52.62	53.90	62.77	64.26	66.50	65.87	77.87	65.54	62.63
2016	63.86	66.12	55.96	54.16	53.00	54.46	62.45	65.12	65.99	66.51	81.13	66.12	62.91
2017	67.05	68.07	58.25	57.03	56.60	57.32	66.41	68.37	68.66	71.24	86.20	68.43	66.14
2018	68.08	69.54	60.26	58.91	57.17	57.11	66.87	70.03	70.52	71.42	85.85	70.83	67.22
2019	70.36	71.37	61.58	61.99	59.68	59.79	69.95	72.44	73.45	74.47	89.98	74.59	69.97
2020	70.46	70.26	61.35	61.94	59.06	60.21	70.39	71.59	72.99	74.32	90.96	74.65	69.85
2021	75.41	75.20	66.37	63.27	57.85	59.20	68.33	69.86	71.78	73.12	95.57	80.56	71.38
2022	77.58	77.82	68.32	64.91	60.62	61.14	69.56	72.25	73.21	75.55	98.28	82.01	73.44
2023	80.75	80.02	70.58	66.54	62.85	63.41	72.24	74.84	74.80	79.34	102.46	84.00	75.99
2024	83.77	84.86	74.27	70.81	64.92	63.94	75.23	77.88	79.06	81.06	103.05	89.30	79.01
2025	84.95	87.06	75.95	72.64	66.25	66.36	77.17	78.75	81.65	82.99	105.04	91.40	80.85
2026	88.60	90.06	78.84	75.23	67.75	69.62	79.78	81.34	84.88	86.03	110.24	94.73	83.92
2027	90.68	92.53	81.71	77.09	69.79	72.01	81.79	84.06	87.40	88.98	114.77	97.05	86.49

B. Electric Demand-Side Screening Results

The results in the following tables were part of the bundles provided by Quantec. See Appendix K for a discussion of Quantec's methodology and analysis.

	Annual Energy Savings (aMW)				
	Bundle 1 Current Trends	Bundle 2 CT+25% AC	Bundle 3 CT-10% AC	Bundle 4 Low Growth	Bundle 5 Green World
2008	29.4	29.7	26.9	27.2	30.1
2009	59.6	60.4	54.7	55.2	61.1
2010	90.8	91.9	83.1	84.2	92.8
2011	123.2	124.1	113.2	113.7	125.4
2012	156.5	157.6	144.6	144.1	159.3
2013	190.1	191.1	177.0	174.8	193.2
2014	225.5	226.4	210.4	206.7	228.6
2015	260.5	261.6	243.5	238.6	263.9
2016	295.4	298.4	276.5	271.5	299.0
2017	329.7	334.7	309.0	304.4	333.6
2018	340.3	348.1	320.2	315.4	344.9
2019	350.9	361.2	331.3	325.8	356.1
2020	361.5	374.0	342.3	336.2	368.1
2021	372.2	387.0	353.5	346.4	380.0
2022	383.9	400.6	365.5	357.0	392.3
2023	395.9	414.3	377.4	367.5	404.9
2024	407.4	427.0	388.5	377.3	416.8
2025	418.0	439.5	398.9	386.3	427.8
2026	428.5	451.9	409.3	395.3	439.0
2027	439.0	464.5	419.9	404.4	450.0

January Energy Savings (aMW)					
	Bundle 1 Current Trends	Bundle 2 CT+25% AC	Bundle 3 CT- 10% AC	Bundle 4 Low Growth	Bundle 5 Green World
2008	35.9	36.5	32.7	32.7	37.0
2009	72.8	74.1	66.3	66.2	74.8
2010	111.1	112.8	100.9	101.0	113.7
2011	150.8	152.2	138.4	136.3	153.3
2012	191.1	192.7	176.8	172.6	194.1
2013	230.7	232.2	215.8	208.3	233.9
2014	272.2	273.8	255.9	245.2	275.5
2015	314.2	316.6	296.5	283.0	317.8
2016	356.9	363.2	337.4	323.6	360.6
2017	398.2	408.2	377.0	363.6	402.0
2018	409.7	424.0	389.3	376.3	414.2
2019	420.5	438.3	400.6	387.5	425.8
2020	431.5	452.3	412.2	398.6	438.9
2021	445.8	469.5	426.6	412.1	454.9
2022	459.8	485.7	440.5	424.7	469.8
2023	473.6	501.4	453.7	436.4	484.4
2024	486.8	515.7	465.7	447.0	498.0
2025	497.0	528.0	474.9	454.8	508.4
2026	509.8	543.1	487.3	465.5	522.0
2027	524.0	559.5	501.4	477.5	536.4

Total December Peak Reduction (MW)					
	Bundle 1 Current Trends	Bundle 2 CT+25% AC	Bundle 3 CT- 10% AC	Bundle 4 Low Growth	Bundle 5 Green World
2008	63.7	64.9	59.0	58.7	65.1
2009	133.5	136.0	124.4	123.5	136.3
2010	214.5	217.5	200.1	199.2	218.0
2011	307.3	310.1	290.2	285.1	310.7
2012	405.7	408.8	386.5	377.7	409.5
2013	483.3	486.4	463.7	449.1	487.1
2014	538.7	542.9	517.8	498.2	542.8
2015	602.9	608.8	580.7	557.2	607.7
2016	669.7	683.5	645.8	621.0	674.7
2017	734.8	756.0	709.0	683.1	739.9
2018	750.7	778.7	725.7	701.9	757.0
2019	775.1	808.2	750.3	725.9	782.6
2020	789.2	826.5	764.5	741.1	799.8
2021	811.0	853.1	785.1	761.9	824.1
2022	833.3	879.2	806.1	780.5	847.8
2023	857.8	906.9	828.4	799.5	873.9
2024	885.3	934.8	852.0	821.8	902.2
2025	907.3	958.8	870.6	838.8	924.5
2026	922.6	976.4	883.8	851.8	941.1
2027	946.7	1002.6	906.3	873.1	965.5

Total Costs (Thousands $)					
	Bundle 1 Current Trends	Bundle 2 CT+25% AC	Bundle 3 CT-10% AC	Bundle 4 Low Growth	Bundle 5 Green World
2008	$88,508	$97,372	$70,869	$66,563	$93,142
2009	$89,183	$99,721	$70,806	$67,650	$94,701
2010	$94,339	$103,818	$72,787	$72,278	$98,158
2011	$102,741	$108,930	$92,248	$74,844	$104,220
2012	$105,913	$113,030	$96,448	$78,468	$110,927
2013	$103,127	$106,935	$97,095	$72,932	$105,441
2014	$112,808	$118,105	$102,636	$79,549	$113,971
2015	$125,074	$135,956	$113,815	$92,964	$128,301
2016	$127,691	$164,748	$114,059	$111,660	$130,533
2017	$127,404	$168,006	$113,115	$113,481	$129,355
2018	$54,615	$96,886	$49,684	$57,174	$62,701
2019	$58,880	$93,870	$53,513	$56,811	$72,548
2020	$74,530	$101,216	$65,707	$64,720	$95,499
2021	$81,843	$100,341	$65,671	$62,636	$94,341
2022	$100,630	$120,617	$83,962	$80,808	$110,275
2023	$116,080	$142,289	$100,214	$89,057	$130,205
2024	$113,439	$136,875	$96,994	$87,036	$127,287
2025	$96,764	$131,528	$80,368	$71,247	$106,187
2026	$100,172	$130,932	$86,198	$74,811	$115,158
2027	$104,700	$128,956	$88,324	$75,463	$110,277

C. Electric Integrated Portfolio Results

Static Results from PSM using DSM Bundle 1 (Current Trends)

Portfolio		1	1a	2	3	3a	4	5	5a	6	7	8	9	
		Aggressive Gas	Early PBA Aggressive Gas	Early IGCC	Late IGCC	Early PBA Late IGCC	Max IGCC	Late IGCCwCCS	Early PBA Late IGCCwCCS	Aggresive Renewables	More Renew w Gas	More Renew w IGCCwCCS	Last IRP Portfolio	
Current Trends		$14,561	$14,506	$14,614	$14,502	$14,389	$14,616	$14,682	$14,626	$15,556	$14,891	$15,041	$14,685	*Millions $*
		$57.71	$57.49	$57.92	$57.48	$57.03	$57.93	$58.19	$57.97	$61.66	$59.02	$59.61	$58.20	*$/MWh*
		4	3	5	2	1	6	8	7	12	10	11	9	*Rank*
Green World		$17,710	$17,664	$18,355	$18,059	$17,916	$18,685	$17,536	$17,490	$18,282	$17,869	$17,751	$18,303	*Millions $*
		$72.55	$72.36	$75.19	$73.98	$73.39	$76.54	$71.84	$71.65	$74.89	$73.20	$72.71	$74.98	*$/MWh*
		4	3	11	8	7	12	2	1	9	6	5	10	*Rank*
Low Growth		$13,286	$13,230	$13,788	$13,492	$13,379	$14,077	$13,673	$13,616	$14,678	$13,752	$14,152	$13,816	*Millions $*
		$54.43	$54.20	$56.48	$55.27	$54.81	$57.67	$56.01	$55.78	$60.13	$56.33	$57.97	$56.60	*$/MWh*
		2	1	8	4	3	10	6	5	12	7	11	9	*Rank*
Robust Growth		$16,511	$16,457	$16,064	$16,152	$16,079	$15,786	$16,366	$16,316	$17,073	$16,685	$16,592	$16,177	*Millions $*
		$62.25	$62.04	$60.56	$60.89	$60.62	$59.51	$61.70	$61.51	$64.37	$62.90	$62.55	$60.99	*$/MWh*
		9	8	2	4	3	1	7	6	12	11	10	5	*Rank*
Technology Improvement		$14,166	$14,083	$14,049	$13,980	$13,903	$13,954	$14,160	$14,086	$14,851	$14,427	$14,456	$14,294	*Millions $*
		$56.15	$55.82	$55.68	$55.41	$55.11	$55.31	$56.12	$55.83	$58.86	$57.18	$57.30	$56.65	*$/MWh*
		8	5	4	3	1	2	7	6	12	10	11	9	*Rank*
Escalating Costs		$14,384	$14,329	$14,526	$14,398	$14,270	$14,571	$14,504	$14,449	$14,827	$14,634	$14,784	$14,543	*Millions $*
		$57.01	$56.79	$57.57	$57.06	$56.56	$57.75	$57.48	$57.27	$58.77	$58.00	$58.59	$57.64	*$/MWh*
		3	2	7	4	1	9	6	5	12	10	11	8	*Rank*

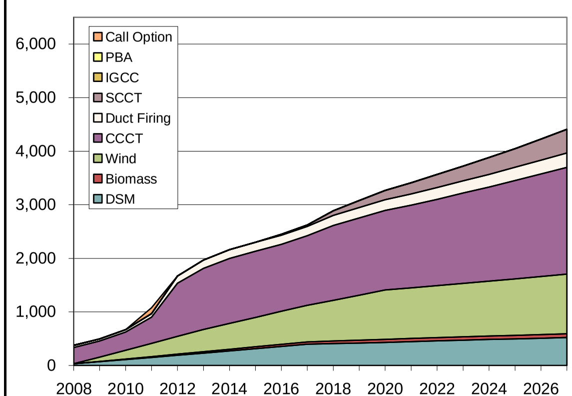
"Least Cost" Portfolio
Second "Least Cost" Portfolio
Third "Least Cost" Portfolio

Portfolio: Aggressive Gas
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW) 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2008-2017 Total Additions MW	Percent
CCCT	299		40	152	501	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	40		5	20	68	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	6	(6)									0	0%
Call Option				107	(107)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	381	116	172	408	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW) 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2008-2027 Total Additions MW	Percent
CCCT	99	45	43	62	67	73	68	82	78	78	1,992	45%
SCCT	60	46	42	34	35	33	40	31	44	49	441	10%
IGCC											0	0%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	13	6	6	8	9	10	9	11	10	11	269	6%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs											0	0%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($640)	($361)	($590)	($413)	($849)	($587)
Cost of Power Purchase	$3,160	$5,515	$2,617	$4,546	$2,465	$3,274
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$7,741	$6,674	$6,994	$8,184	$8,255	$7,492
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$432	$285	$612	$208	$291	$388
Expected Cost	$14,561	$17,710	$13,286	$16,511	$14,166	$14,384
Expected Cost $/MWh	$57.71	$72.55	$54.43	$62.25	$56.15	$57.01

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

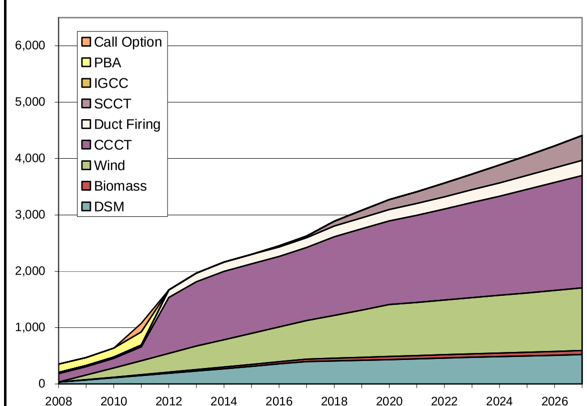
Mean	$14,400
Average of 10 Worst	$15,361
Annual Volatility	30%

Portfolio: Early PBA Aggressive Gas
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	746	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	101	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	(233)						0	0%
Call Option				153	(153)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	99	45	43	62	67	73	68	82	78	78	1,992	45%
SCCT	60	46	42	34	35	33	40	31	44	49	441	10%
IGCC											0	0%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	13	6	6	8	9	10	9	11	10	11	269	6%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs											0	0%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($650)	($371)	($602)	($419)	($865)	($597)
Cost of Power Purchase	$3,016	$5,366	$2,471	$4,387	$2,307	$3,125
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$7,830	$6,775	$7,086	$8,290	$8,346	$7,585
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$442	$295	$622	$214	$292	$398
Expected Cost	$14,506	$17,664	$13,230	$16,457	$14,083	$14,329
Expected Cost $/MWh	$57.49	$72.36	$54.20	$62.04	$55.82	$56.79

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

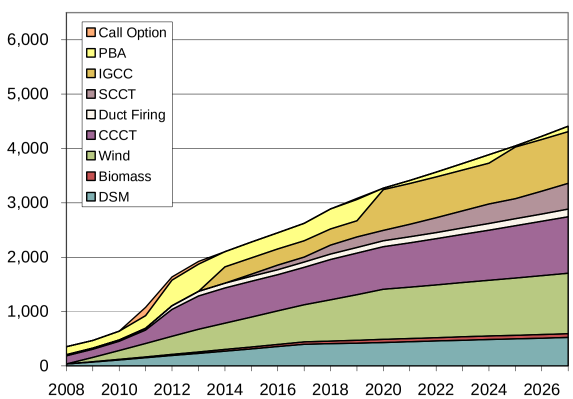
Mean	$14,342
Average of 10 Worst	$15,263
Annual Volatility	29%

Portfolio: Early IGCC
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	251	117	37	10	8	23	692	26%
SCCT								40	42	11	93	4%
IGCC							300				300	11%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	34	16	5	1	1	3	93	4%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	238	29	(220)	10	8	22	320	12%
Call Option				153	(93)	(7)	(52)				0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	560	285	181	174	173	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	50	23	21	31	34	37	34	41	39	39	1,039	24%
SCCT	70	29		39	41	40	46	8	51	57	475	11%
IGCC			450					200			950	22%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	7	3	3	4	5	5	5	6	5	5	140	3%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	47	22	(363)	30	32	34	33	(131)	37	37	98	2%
Call Option		21	(21)								0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($661)	($408)	($630)	($409)	($854)	($613)
Cost of Power Purchase	$2,057	$3,547	$1,616	$3,176	$1,678	$2,125
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,978	$9,024	$8,327	$9,443	$9,077	$8,831
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$371	$593	$822	($131)	$143	$366
Expected Cost	$14,614	$18,355	$13,788	$16,064	$14,049	$14,526
Expected Cost $/MWh	$57.92	$75.19	$56.48	$60.56	$55.68	$57.57

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

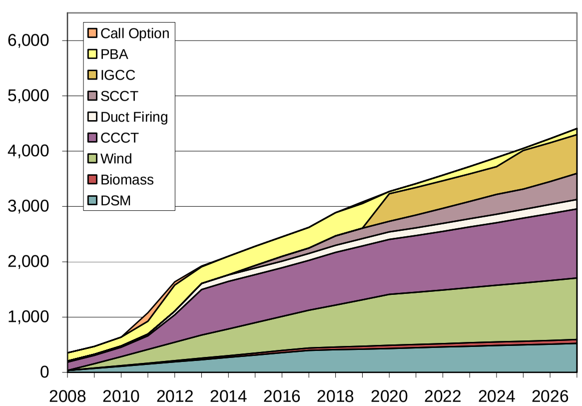
Mean	$14,508
Average of 10 Worst	$15,357
Annual Volatility	22%

Portfolio: Late IGCC
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	251	328	37	10	8	23	902	34%
SCCT							3	43	42	11	99	4%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	34	44	5	1	1	3	122	5%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	238	(171)	35	10	8	22	375	14%
Call Option				153	(93)	(46)	(13)				0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	560	285	178	177	173	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	50	23	21	31	34	37	34	41	39	39	1,250	28%
SCCT	70	21		40	41	39	47	8	51	57	474	11%
IGCC			500					200			700	16%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	7	3	3	4	5	5	5	6	5	5	169	4%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	47	22	(405)	29	32	35	32	(131)	37	37	110	2%
Call Option		29	(29)								0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($653)	($386)	($614)	($408)	($858)	($602)
Cost of Power Purchase	$2,300	$4,007	$1,833	$3,490	$1,828	$2,379
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,627	$8,335	$7,866	$9,157	$8,860	$8,453
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$359	$505	$753	($72)	$146	$350
Expected Cost	$14,502	$18,059	$13,492	$16,152	$13,980	$14,398
Expected Cost $/MWh	$57.48	$73.98	$55.27	$60.89	$55.41	$57.06

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

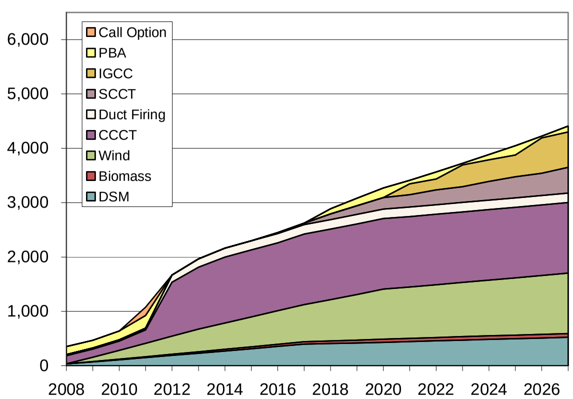
Mean	$14,373
Average of 10 Worst	$15,213
Annual Volatility	24%

Portfolio: Early PBA Late IGCC
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	746	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	101	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	(233)						0	0%
Call Option				153	(153)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT											1,297	29%
SCCT	79	54	50	16	48	16	53	46	21	64	473	11%
IGCC				200		200			250		650	15%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing											175	4%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	94	43	41	(112)	64	(100)	65	78	(139)	74	108	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($641)	($369)	($595)	($405)	($842)	($589)
Cost of Power Purchase	$2,763	$4,853	$2,254	$4,081	$2,171	$2,858
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,186	$7,482	$7,466	$8,631	$8,545	$7,987
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$213	$352	$602	($213)	$25	$197
Expected Cost	$14,389	$17,916	$13,379	$16,079	$13,903	$14,270
Expected Cost $/MWh	$57.03	$73.39	$54.81	$60.62	$55.11	$56.56

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

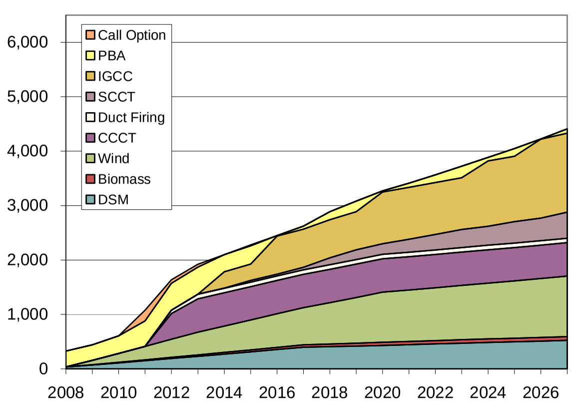
Mean	$14,296
Average of 10 Worst	$15,225
Annual Volatility	27%

Portfolio: Max IGCC
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT					471	142					613	23%
SCCT							3	30		15	48	2%
IGCC							300		400		700	27%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing					64	19					83	3%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	290	(6)	38	144	29	5	(184)	19	(324)	44	55	2%
Call Option				198	(134)	(12)	(52)	16	(16)		0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	326	116	165	471	560	285	178	177	173	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT											613	14%
SCCT	79	54	13	45	48	47	15	46	21	64	479	11%
IGCC			250				250		250		1,450	33%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing											83	2%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	94	43	(172)	59	64	69	(147)	78	(139)	74	78	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($700)	($456)	($678)	($443)	($880)	($654)
Cost of Power Purchase	$1,770	$3,081	$1,351	$2,836	$1,465	$1,822
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$9,381	$9,746	$8,858	$9,759	$9,332	$9,275
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$297	$716	$893	($351)	$33	$311
Expected Cost	$14,616	$18,685	$14,077	$15,786	$13,954	$14,571
Expected Cost $/MWh	$57.93	$76.54	$57.67	$59.51	$55.31	$57.75

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

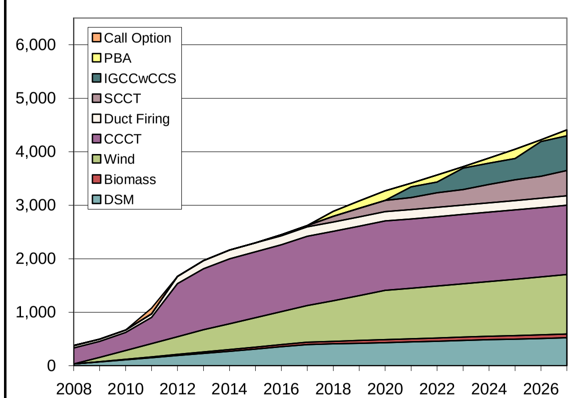
Mean	$14,628
Average of 10 Worst	$15,508
Annual Volatility	19%

Portfolio: Late IGCC with CCS
DSM Bundle: Current Trends

Supply Additions (Nameplate Capacity in MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2008-2017 Total Additions MW	Percent
CCCT	299		40	152	501	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCCwCCS											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	40		5	20	68	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	6	(6)									0	0%
Call Option				107	(107)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	381	116	172	408	592	298	195	136	152	172	2,622	100%

Supply Additions (Nameplate Capacity in MW)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2008-2027 Total Additions MW	Percent
CCCT											1,297	29%
SCCT	79	54	50	16	48	16	53	46	21	64	473	11%
IGCCwCCS				200		200			250		650	15%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing											175	4%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	94	43	41	(112)	64	(100)	65	78	(139)	74	108	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($631)	($359)	($584)	($398)	($825)	($579)
Cost of Power Purchase	$2,905	$4,941	$2,399	$4,239	$2,331	$3,006
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,263	$7,401	$7,538	$8,689	$8,583	$8,022
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$277	($45)	$666	($148)	$68	$237
Expected Cost	$14,682	$17,536	$13,673	$16,366	$14,160	$15
Expected Cost $/MWh	$58.19	$71.84	$56.01	$61.70	$56.12	$57.48

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

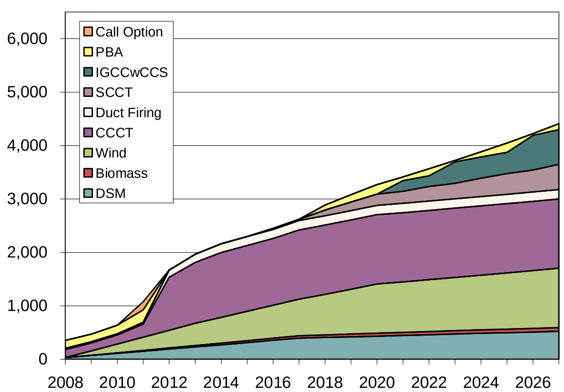
Mean	$14,586
Average of 10 Worst	$15,559
Annual Volatility	29%

Portfolio: Early PBA Late IGCC with CCS
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	746	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCCwCCS											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	101	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	(233)						0	0%
Call Option				153	(153)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT											1,297	29%
SCCT	79	54	50	16	48	16	53	46	21	64	473	11%
IGCCwCCS				200		200			250		650	15%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing											175	4%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	94	43	41	(112)	64	(100)	65	78	(139)	74	108	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($641)	($369)	($596)	($405)	($842)	($589)
Cost of Power Purchase	$2,762	$4,791	$2,252	$4,080	$2,171	$2,857
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,350	$7,505	$7,631	$8,794	$8,677	$8,115
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$287	($35)	$676	($138)	$77	$247
Expected Cost	$14,626	$17,490	$13,616	$16,316	$14,086	$14,449
Expected Cost $/MWh	$57.97	$71.65	$55.78	$61.51	$55.83	$57.27

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

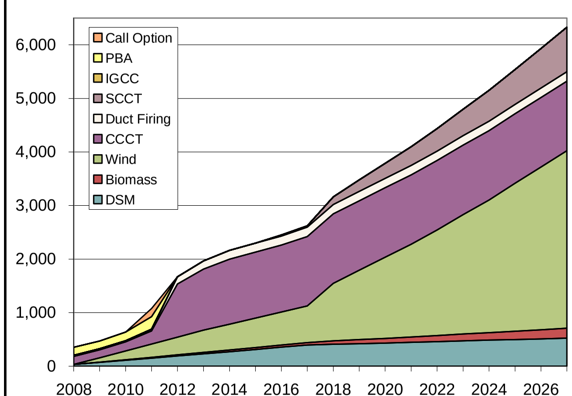
Mean	$14,530
Average of 10 Worst	$15,457
Annual Volatility	28%

Portfolio: Aggressive Renewables
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	746	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	101	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	(233)						0	0%
Call Option				153	(153)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT											1,297	20%
SCCT	116	72	66	69	73	74	79	77	88	93	833	13%
IGCC											0	0%
Wind	390	222	219	216	239	261	245	289	276	276	3,315	52%
Duct Firing											175	3%
Biomass	21	13	12	12	13	14	13	16	15	15	186	3%
PBAs											0	0%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	8%
Total	539	317	308	311	339	362	350	391	391	398	6,330	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($742,576)	($400,424)	($672,633)	($532,027)	($987,142)	($681,450)
Cost of Power Purchase	$2,695,490	$4,667,559	$2,197,627	$3,977,317	$2,121,598	$2,788,234
PPA Revenue Requirement	$980,107	$980,107	$980,107	$980,107	$980,107	$980,107
Generic Revenue Requirement	$8,877,237	$7,934,763	$8,204,274	$9,283,697	$9,146,116	$8,352,464
Variable Cost of Existing Fleet	$2,888,053	$4,617,739	$2,672,777	$3,004,881	$3,024,359	$2,837,233
End Effects	$857,909	$482,359	$1,295,839	$359,427	$566,169	$550,533
Expected Cost	$15,556,221	$18,282,102	$14,677,992	$17,073,403	$14,851,208	$14,827,121
Expected Cost $/MWh	$61.66	$74.89	$60.13	$64.37	$58.86	$58.77

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

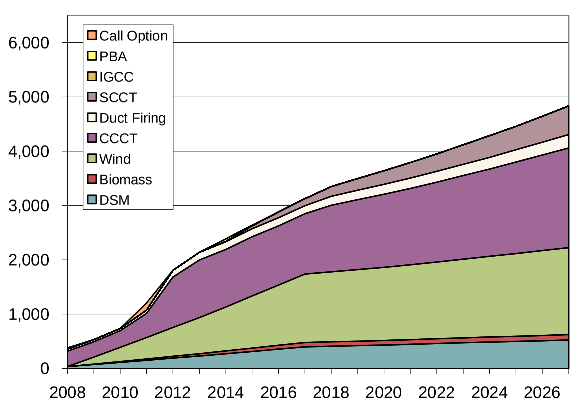
Mean	$15,472
Average of 10 Worst	$16,419
Annual Volatility	26%

Portfolio: More Renewables with Gas
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	283		24	136	485	132		32		19	1,110	35%
SCCT							5	48	54	22	129	4%
IGCC											0	0%
Wind		129	132	133	135	136	145	149	150	152	1,261	40%
Duct Firing	38		3	18	65	18		4		3	150	5%
Biomass		8	8	8	8	8	9	9	9	9	79	3%
PBAs	21	(21)					46	(36)	(10)		0	0%
Call Option				133	(131)	(2)					0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	13%
Total	378	153	206	468	603	331	247	249	246	245	3,127	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	115	61	60	59	64	70	65	79	74	75	1,834	38%
SCCT	52	37	33	35	37	34	42	32	46	51	529	11%
IGCC											0	0%
Wind	28	28	30	30	34	37	37	38	39	39	1,602	33%
Duct Firing	16	8	8	8	9	9	9	11	10	10	248	5%
Biomass	2	2	2	2	2	2	2	2	2	2	100	2%
PBAs											0	0%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	11%
Total	223	148	143	149	160	167	169	173	185	192	4,836	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($698)	($388)	($633)	($473)	($932)	($641)
Cost of Power Purchase	$2,866	$4,979	$2,353	$4,170	$2,252	$2,970
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,371	$7,376	$7,678	$8,789	$8,781	$8,059
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$485	$305	$702	$214	$322	$428
Expected Cost	$14,891	$17,869	$13,752	$16,685	$14,427	$14,634
Expected Cost $/MWh	$59.02	$73.20	$56.33	$62.90	$57.18	$58.00

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

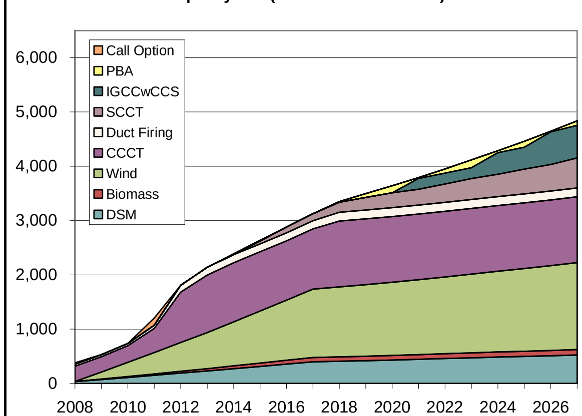
Mean	$14,753
Average of 10 Worst	$15,664
Annual Volatility	29%

Portfolio: More Renewables with IGCC w CCS
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	283		24	136	485	132	32			19	1,109	35%
SCCT								53	54	22	129	4%
IGCCwCCS											0	0%
Wind		129	132	133	135	136	145	149	150	152	1,261	40%
Duct Firing	38		3	18	65	18	4			3	150	5%
Biomass		8	8	8	8	8	9	9	9	9	79	3%
PBAs	21	(21)					16	(6)	(10)		0	0%
Call Option				133	(131)	(2)					0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	13%
Total	378	153	206	468	603	331	248	248	246	245	3,126	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	101										1,210	25%
SCCT	54	49	44	17	49	47	24	47	29	65	554	11%
IGCCwCCS				200			200		200		600	12%
Wind	28	28	30	30	34	37	37	38	39	39	1,602	33%
Duct Firing	14										163	3%
Biomass	2	2	2	2	2	2	2	2	2	2	100	2%
PBAs	14	58	57	(114)	61	67	(108)	75	(99)	71	82	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	11%
Total	223	148	143	149	160	167	169	173	185	192	4,835	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($693)	($388)	($632)	($461)	($913)	($637)
Cost of Power Purchase	$2,670	$4,522	$2,187	$3,932	$2,153	$2,764
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,811	$7,976	$8,148	$9,204	$9,055	$8,507
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$384	$42	$795	($68)	$157	$332
Expected Cost	$15,041	$17,751	$14,152	$16,592	$14,456	$14,784
Expected Cost $/MWh	$59.61	$72.71	$57.97	$62.55	$57.30	$58.59

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

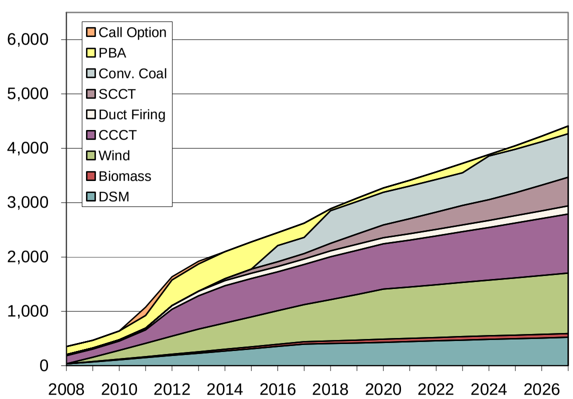
Mean	$15,902
Average of 10 Worst	$15,457
Annual Volatility	27%

Portfolio: Last IRP Portfolio
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	251	117	74	21	8	23	739	28%
SCCT							35	41	12	11	100	4%
Conv. Coal									300		300	11%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	34	16	10	3	1	3	100	4%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	238	29			(262)	22	260	10%
Call Option				153	(93)	(7)	(52)				0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	560	285	178	177	173	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	50	23	21	31	34	37	34	41	39	39	1,087	25%
SCCT	40	50	46	40	41	39	27	38	51	57	529	12%
Conv. Coal	300						200				800	18%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	7	3	3	4	5	5	5	6	5	5	147	3%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	(223)	22	20	29	32	35	(148)	39	37	37	140	3%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($668)	($402)	($631)	($419)	($868)	($618)
Cost of Power Purchase	$2,105	$3,725	$1,672	$3,233	$1,703	$2,175
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,896	$8,802	$8,218	$9,362	$9,132	$8,708
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$484	$581	$904	$16	$321	$461
Expected Cost	$14,685	$18,303	$13,816	$16,177	$14,294	$14,543
Expected Cost $/MWh	$58.20	$74.98	$56.60	$60.99	$56.65	$57.64

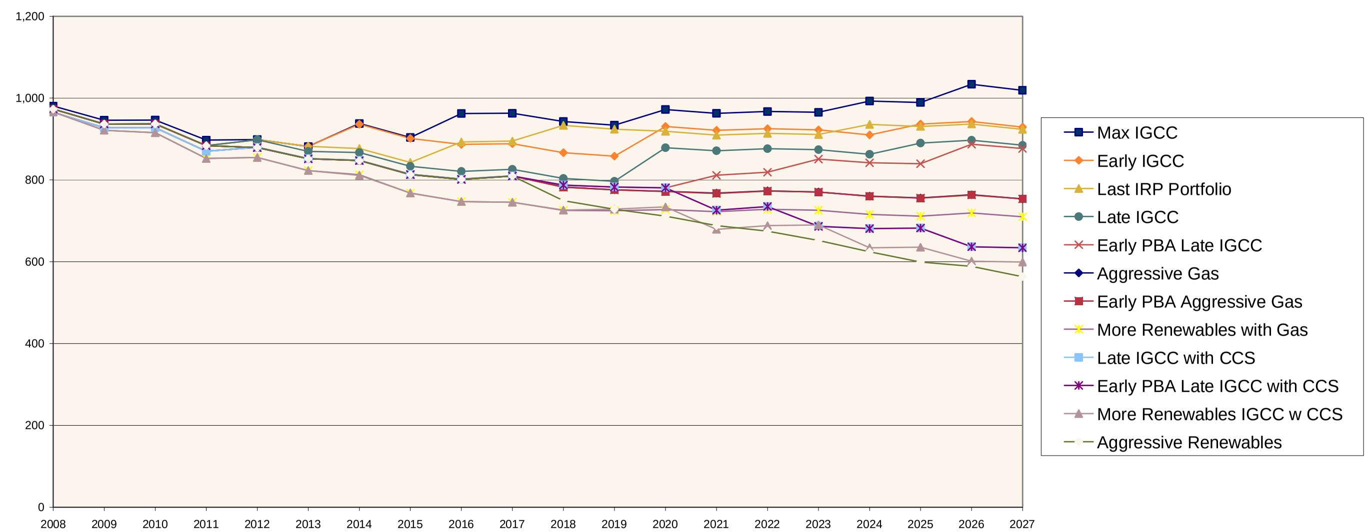
Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

Mean	$14,618
Average of 10 Worst	$15,438
Annual Volatility	22%

Total Emissions Intensity for Each Portfolio

Total Rate (lbs CO2/MWh)

	Aggressive Gas	Early PBA Aggressive Gas	Early IGCC	Late IGCC	Early PBA Late IGCC	Max IGCC	Late IGCC with CCS	Early PBA Late IGCC with CCS	Aggressive Renewables	More Renewables with Gas	More Renewables IGCC w CCS	Last IRP Portfolio
2008	965	973	973	973	973	981	965	973	973	966	966	973
2009	928	937	937	937	937	946	928	937	937	922	922	937
2010	927	937	937	937	937	946	927	937	937	916	916	937
2011	870	884	884	884	884	897	870	884	884	852	852	884
2012	880	879	898	898	879	899	880	879	879	855	855	898
2013	852	852	882	870	852	882	852	852	852	823	823	882
2014	848	847	936	867	847	938	848	847	847	813	811	877
2015	814	813	901	833	813	904	814	813	813	768	768	843
2016	802	801	887	821	801	962	802	801	801	747	747	893
2017	810	810	889	826	810	963	810	810	810	745	745	895
2018	783	782	867	804	787	943	788	787	749	725	726	933
2019	776	776	858	797	782	934	783	782	728	725	729	924
2020	772	772	930	879	781	972	781	781	712	728	734	919
2021	768	767	922	871	811	963	726	726	688	723	679	909
2022	773	773	925	876	819	967	735	735	675	728	688	914
2023	771	770	922	874	851	965	687	687	652	726	690	911
2024	760	760	910	863	842	993	681	681	624	716	634	936
2025	756	756	937	890	840	989	683	682	599	712	636	931
2026	764	763	943	897	887	1,034	637	636	589	719	601	937
2027	754	753	929	885	877	1,019	634	634	563	710	599	923



Gas Analysis

I. Analytical Models

In August 2004, PSE acquired SENDOUT® and VectorGas™ from New Energy Associates. SENDOUT is a widely used model that helps identify the long-term least cost combination of resources to meet stated loads. Avista, Cascade Natural Gas, and Terasen all use the SENDOUT model. VectorGas is an add-in that facilitates the ability to model price and load uncertainty. These valuable new tools enhance our ability to ensure robust long-term resource planning and acquisition activities. The following provides a description of SENDOUT and VectorGas followed by a detailed explanation of the uncertainty factors PSE modeled for VectorGas.

The SENDOUT and VectorGas software products are an integrated tool set for gas resource analysis. SENDOUT models the gas supply network and the portfolio of supply, storage, and transportation to meet demand requirements. VectorGas simulates uncertainties regarding weather and commodity prices using Monte Carlo methods. It then runs the SENDOUT portfolio over many draws to provide a probability distribution of results from which to make decisions.

A. SENDOUT

SENDOUT can operate in two different modes. It can be used to determine the optimal set of resources (energy efficiency, supply, storage, and transport) to minimize costs over a defined planning period. Alternatively, specific portfolios can be defined, and the model will determine the least cost dispatch to meet demand requirements for each portfolio. SENDOUT solves both problems using a linear program (LP). SENDOUT determines how a portfolio of resources (energy efficiency, supply, storage, and transport), including associated costs and contractual or physical constraints, should be added and dispatched to meet demand in a least-cost fashion. By using an LP, SENDOUT considers thousands of variables and evaluates tens of thousands of possible solutions, in order to generate the least cost solution. A standard dispatch considers the capacity level of all resources as given, and therefore performs a variable-cost dispatch. A resource mix dispatch can look at a range of potential capacity and size resources, including their capacities and fixed costs in addition to variable costs.

Energy Efficiency

SENDOUT provides a comprehensive set of inputs to model a variety of energy efficiency programs. Costs can be modeled at an overall program level or broken down into a variety of detailed accounts. The impact of efficiency programs on load can be modeled at the same detail level as demand. SENDOUT has the ability to optimize the size of energy efficiency programs on an integrated basis with supply-side alternatives in a long-run resource mix analysis.

Supply

SENDOUT allows a system to be supplied by either flowing gas contracts or a spot market. Specific physical and contractual constraints can be modeled, such as maximum flow levels and minimum flow percentages, on a daily, monthly, seasonal, or annual basis. SENDOUT uses standard gas contract costs; the rates may be changed on a monthly or daily basis.

Storage

SENDOUT allows storage sources (either leased or company owned, and either natural or production gas) to serve the system. Storage input data include the minimum or maximum inventory levels, minimum or maximum injection and withdrawal rates, injection and withdrawal fuel loss, *to* and *from* interconnects, and the period of activity (i.e., when the gas is available for injection or withdrawal). There is also the option to define and name volume-dependent injection and withdrawal percentage tables (ratchets), which can be applied to one or more storage sources.

Transportation

SENDOUT provides the means to model transportation segments to define flows, costs, and fuel loss. Flow values include minimum and maximum daily quantities available for sale to gas markets or for release. Cost values include standard fixed and variable transportation rates, as well as a per-unit cost generated for released capacity. Seasonal transportation contracts can also be modeled.

Demand

SENDOUT allows the user to define multiple demand areas, and it can compute a demand forecast by class based on weather.

B. VectorGas

Monte Carlo modeling set-up, simulation (running just the draws for weather and price inputs), and optimizations (running each of the draws through SENDOUT) is accomplished in the VectorGas module. In VectorGas, the assumptions for weather and price uncertainty are defined below. Scenario data from SENDOUT is exported to VectorGas, which produces simulations and generates optimizations.

Monte Carlo simulation is a statistical modeling method used to imitate the many possibilities that exist within a real-life system. By describing the expectation, variability, behavior, and correlation among potential events, it is possible through repeated random draws to derive a numerical landscape of the many potential futures. The goal of Monte Carlo is for this quantitative landscape to reflect both the magnitude and the likelihood of these events, thereby providing a risk-based viewpoint from which to base decisions.

Traditional optimization is deterministic. That is, the inputs for a given scenario are fixed (one value to one cell), and there is a single solution for this set of assumptions. Monte Carlo simulation allows the user to generate the inputs for optimization with hundreds or thousands of values (draws) for weather and price possibilities. VectorGas utilizes the SENDOUT network optimizer to provide a detailed dispatch for each Monte Carlo draw.

The advanced probability-based metrics yield a more insightful picture of the portfolio, and form the basis for risk-based resource decisions. The most common of these probability measures include: Expected Value (μ) - EV is then more meaningful than the traditional deterministic measure (total system costs, for example) for a normal scenario since it directly and proportionately captures the portfolio's response to the whole range of weather and price events. Variability (σ) – the level of variance for critical objectives (e.g., cost exposure) should be a key component when comparing portfolios. Probability (P) – measures the likelihood of a key event (10% to exceed $500 million in annual costs, for example).

Another application for Monte Carlo and optimization is to study the resource trade-off economics by optimally sizing the contract or asset level of various and competing resources for each draw. This can be especially helpful in determining the right resource mix that will lower expected costs. This mix of resources is difficult to identify using deterministic methods, since it is difficult to determine at which points various resources are better or worse.

Performing Monte-Carlo analysis in conjunction with the level of detail included in SENDOUT for long-term resource planning requires a considerable degree of computing power. In addition to the SENDOUT and VectorGas software, PSE also acquired additional hardware. VectorGas essentially runs on a server that is connected to five personal computers that are grid machines, all of which run the SENDOUT linear programming model. VectorGas creates the Monte Carlo draws. Then, through distributed processing, it sends each draw to one of the five grid computers. When the grid machines complete analysis of a Monte Carlo draw, results are posted back to VectorGas and another process job is sent to the grid machine. This is a flexible system that operates over PSE's IT network.

VectorGas Uncertainty Inputs

VectorGas's Monte Carlo analysis provides helpful information to guide long-term resource planning as well as to support specific resource acquisitions. Monte Carlo analysis is performed by creating a large number of price and temperature (and thus demand) scenarios that are analyzed in SENDOUT. Creating hundreds or thousands of reasonable scenarios of prices at each relevant supply basin with different temperatures requires a new and significant set of data inputs that are not required for a single static optimization model run. The following discussion identifies the uncertainty factors needed for VectorGas and explains the analysis used to define each factor.

Uncertainty Factors for VectorGas

The following is a list and brief description of each input needed for Vector Gas to create reasonable sets of scenarios:

- *Expected Monthly Heating Degree Days.* The expected summation of daily heating degree days (HDD) for each month is required. Daily heating degree days are calculated 65 minus the average daily temperature.
- *Standard Deviation of Monthly HDD.* A measure of variability in total monthly HDD that can be assigned a different value for every month.
- *Daily HDD Pattern.* Daily HDDs are derived by applying a historic daily HDD pattern to each monthly HDD draw. This daily pattern can be drawn independently from the monthly HDD level or can be set to reflect a different historic period in each month. Different months can have different daily pattern settings.
- *Expected Monthly Gas Price Draw.* The basis of determining prices each month, this measure can be considered the average of daily gas prices prior to factoring in effects of daily temperature.
- Standard Deviation of Monthly Price Draw: This is a measure of the variability of prices at each basin, such as at AECO. VectorGas uses standard deviation expressed in dollars. A different standard deviation can be assigned to each month for the planning period.
- *Temperature to Price Correlations at each Basin.* Ensures that a reasonable relationship exists between prices and temperatures in each Monte Carlo scenario. Linear/simple temperature to price correlation coefficients are used in VectorGas and a different value can be assigned to each month.
- *Price to Price Correlations between Basins.* Ensures reasonable relationships for prices between each basin for the Monte Carlo scenarios. Linear/simple temperature to price correlation coefficients are used in VectorGas.
- *Daily Price to Temperature Coefficients.* Daily temperatures drive changes from the monthly price draw. Daily price is modeled as an exponential function of daily temperature and has the ability to include a second level of sensitivity to model a price “blow-out” due to an extreme temperature.

Basis of Each Uncertainty Factor

Expected Monthly HDD. PSE is using the average monthly HDD for each month based on temperature data going back to January of 1950, in VectorGas. This period was chosen because it includes the period during which PSE has hourly temperature data with which to calculate HDD, and because it is consistent with the period used to establish the Company's gas peak day planning standard.

Standard Deviation of Monthly HDD. The standard deviation for each month was calculated using the monthly data back to 1950 noted above. That is, the standard deviation of monthly HDD totals was calculated.

Daily HDD Pattern. The daily HDD pattern for each month was prevented from varying randomly, independent of the monthly HDD draw. Preliminary analysis showed that randomly pairing monthly HDD levels with daily patterns can result in temperatures significantly colder than those recorded in history. To avoid overstating temperature variability, PSE applied the daily temperature pattern from the coldest month in the historical period. The next version of VectorGas is scheduled to have a matching feature to select the daily pattern from the period that best fits the monthly HDD draw—a feature included at PSE's request.

Expected Monthly Price Draw. The base or reference scenario gas price forecast was used as the expected monthly price draw in VectorGas for AECO, Sumas, Rockies, and San Juan price points.

Standard Deviation of Monthly Price Draw. Historical data was used to establish the range of variability for each price basin. Selecting a consistent time period for all four basins provides a reasonably consistent basis for calculating the standard deviation.

Temperature to Price Correlations. Historic price correlations for each supply basin to SeaTac HDD were calculated. There are a number of different ways such correlations could reasonably be calculated. For VectorGas, the correlation between HDD and prices was calculated based on daily temperatures and daily prices by season. Then the strongest positive seasonal correlation was selected. As one would expect, the correlations produced using this approach shows a positive, but weak correlation of prices at Sumas, AECO, Rockies, and San Juan to SeaTac temperatures.

Price Correlations between Basins. Similar to the price to weather correlations, price to price correlations were calculated seasonally. Price correlations between supply basins are strongly positive, which is to be expected given the infrastructure in the Pacific Northwest.

Temperature Effects on Daily Price-normal Variation. Deviations between daily price and monthly price draw in VectorGas are driven solely by daily HDD, which is a combination of the monthly HDD draw and daily shape, as noted above. Effects of daily temperatures are modeled as an exponential effect on prices, as daily temperature moves up and down relative to the average daily temperature. A different daily price/temperature factor was calculated for each month of the year and applied to the full 20-year period. To calculate the daily price-temperature factor, a target standard deviation of daily prices was selected. Then the factor estimated that, when applied to expected daily temperatures and the 20-year average monthly price, it would result in Vector Gas daily prices exhibiting the target standard deviation.

Temperature Effects on Daily Price-jump Statistics. The jump statistics to estimate a price blow-out require defining the temperature threshold at which such daily price events can occur, the probability of occurrence if that temperature threshold is exceeded, and the magnitude of the blow-out. Using daily price data back to 1999, the first step was to develop a definition of "price blow-out." Analysis of the data shows a few instances where daily prices exceed the daily average price by more than 40%. This was used as the definition of a blow-out event. The warmest temperature at which daily prices exceeded the average daily price for the month occurred at 21 HDD (39 degrees average daily temperature). The probability of a jump event occurring was calculated by examining the number of days that a jump event occurred at each basin, divided by the total number of days in the historic period with HDD at 21 HDD or higher. For example, during the period, there were 257 days where HDD was 21 HDD or greater. Daily prices were 40% or greater on 9 of those days. Thus, at the HDD threshold of 21 HDD, the probability of a jump event occurring was calculated to be 9/257= 3.5%. If the jump occurred, the magnitude was calculated as follows: When the spread between daily prices exceeded average daily prices by 40% or more, the average percentage increase was used. For Sumas, this was a jump multiplier of 1.53.

II. Analytical Results

Four planning scenarios were analyzed using the Sendout Model: the Base Case scenario (the reference case), Reduced Growth, Robust Growth, and Green World. A description of these scenarios is provided in Chapter 3. The optimal portfolios of supply and energy efficiency resources for each of the scenarios were identified using Sendout. The results of the analyses are shown in the following figures. The specific resource additions for each of these scenarios are described in Chapter 6, Section V.

Figure J-1
Base Case Optimal Portfolio

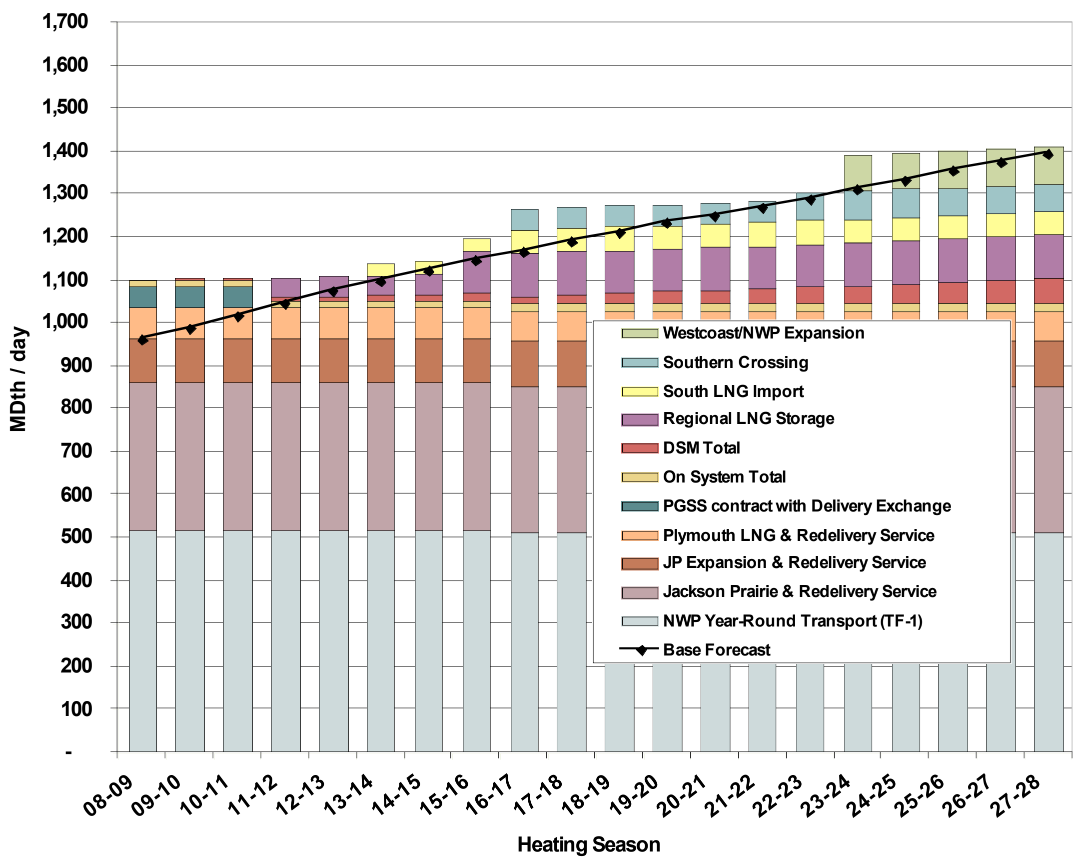


Figure J-2
Reduced Growth Optimal Portfolio

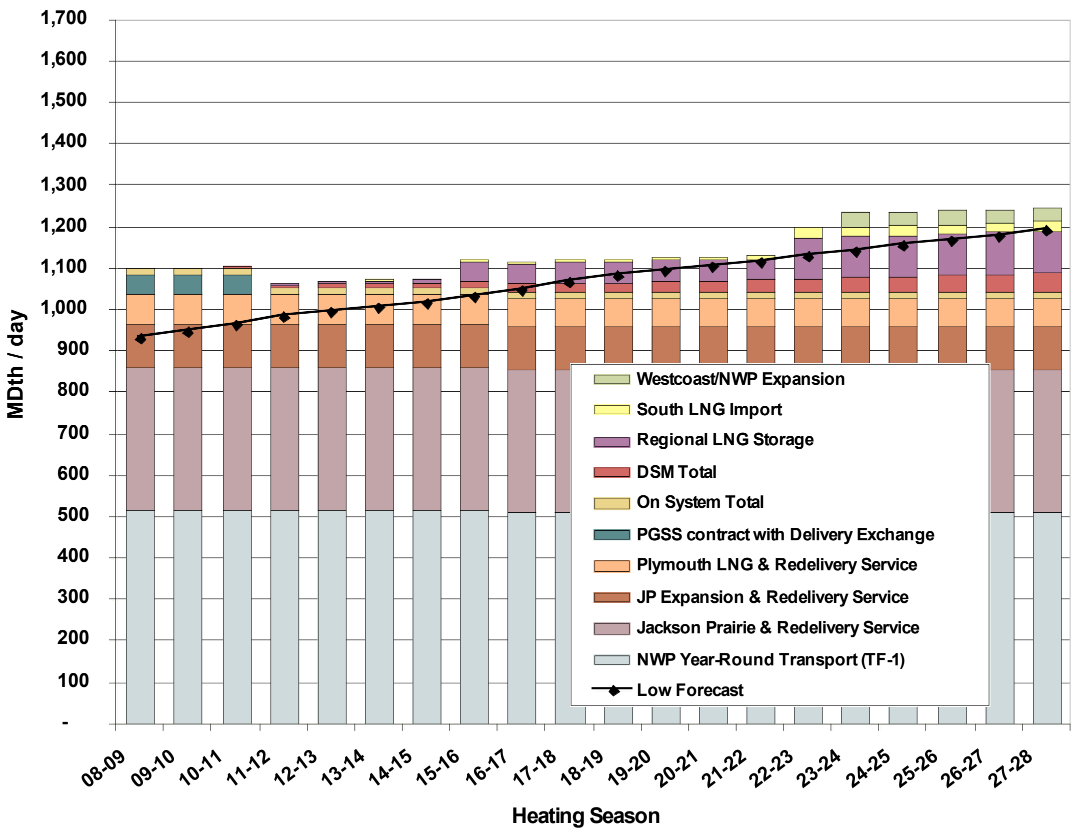


Figure J-3
Robust Growth Optimal Portfolio

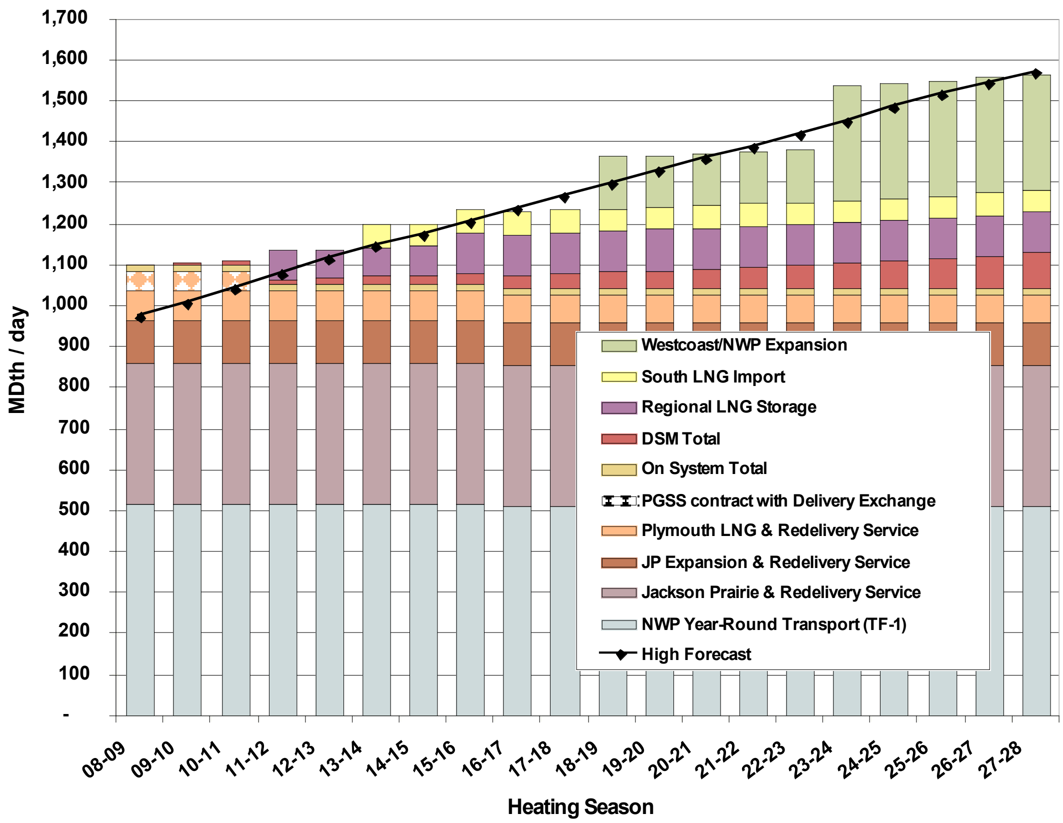
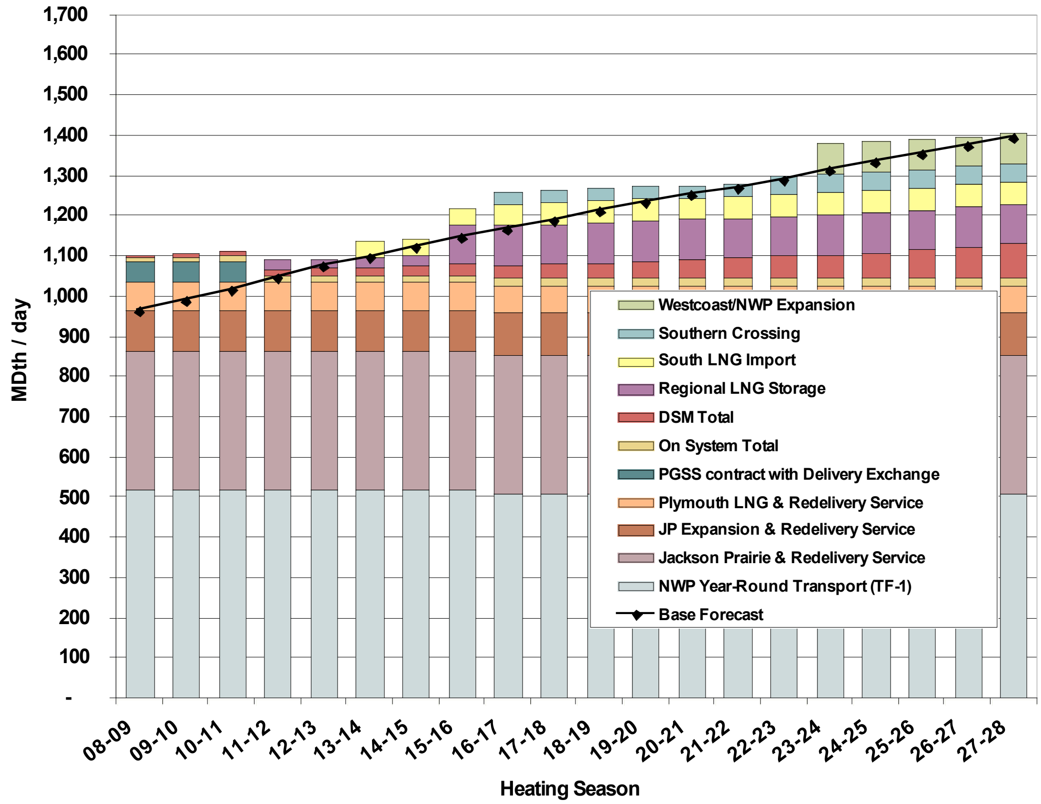


Figure J-4
Green World Optimal Portfolio



Final Report

Comprehensive Assessment of Demand-Side Resource Potentials (2008-2027)

Prepared for:
Puget Sound Energy

May 4, 2007

quantec *Raising the bar in analytics™*

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This study was a large and complex undertaking. New approaches had to be devised to meet its many conceptual and analytic challenges. It also required compilation of a large amount of data from multiple sources, including multiple departments within Puget Sound Energy. It would be difficult to overstate the contributions made by Puget Sound Energy's staff throughout the nine months of planning and research it took to complete this study—from formulating concepts to identification of appropriate data sources, to compilation of data, and to reviewing the results and providing constructive feedback. We are particularly grateful to Villamor Gamponia, Phillip Popoff, Aliza Seelig, Jay Jacobson, Bob Stolarski, Joel Jackman, Gurvinder Singh, Mary Smith and Eric Brateng.

We wish to thank Cal Shirley, Vice President for Energy Efficiency Services and William Hopkins, Manager of Strategic Planning and Research at Puget Sound Energy for their continual support. They offered invaluable insight and direction throughout the course of this project, while allowing us to exercise our independent judgment and to maintain our objectivity. Our project management team, Michael Wehling and Zac Yanez worked closely with us every step of the way. Without their active participation, generous assistance, and timely responses to our requests for information, we could not have met the many challenges of this study.

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Executive Summary

Overview

This report summarizes the results of an independent study of the potentials for electric and natural gas demand-side management (DSM) resources in Puget Sound Energy's (PSE's) service area from 2008 to 2027. The study was commissioned by PSE as part of its biennial integrated resource planning (IRP) process.

The study builds upon previous efforts and incorporates significant improvements with respect to scope of assessment and its methodology. As in previous studies, the focus of the assessment was on electric and natural gas energy efficiency potentials. The scope of the analysis for electric DSM resource potentials was expanded to include a full range of small-scale generation resources comprised of energy efficiency, demand response, fuel conversion, distributed generation, and emerging technologies for energy efficiency and distributed generation. Significant enhancements were also made in the methodology, particularly in technical characterization and economic valuation of resources. The methods used to evaluate the technical potentials for and cost-effectiveness of resources draw upon the best practices in the utility industry and are consistent with the methodology used by the Northwest Power Planning and Conservation Council in its assessment of regional conservation potentials in the Northwest.

Summary of the Results

The results of this study indicate cumulative "technical" energy conservation potentials of 799 average megawatts (aMW) of electric and 35 million Decatherms (Dth) of natural gas over the 20-year planning horizon from 2008 to 2027, from existing, mature energy efficiency and fuel conversion technologies (Exhibit 1).[1] Approximately 471 aMW of the electric and 11.2 million Dth of the natural gas conservation resources are expected to be cost effective, based on the total resource cost (TRC) criterion. Once normal market and program delivery constraints are taken into account, about 367 aMW (80%) and 6.9 million Dth (61%) of these resources may be reasonably achievable by the end of the 20-year planning period. An additional 54 aMW of energy savings are also expected to be achievable from emerging energy efficiency technologies (14 aMW) and existing and emerging distributed generation technologies (40 a MW).

The energy savings resulting from a full implementation of the identified demand-side resources represent 17% of total electric and 6% of gas loads in 2007, offsetting 38% and 21% of the projected 20-year growth in electric and gas demand.

In the electric sector, savings from *existing* energy efficiency technologies constitute the largest share (81%) of total savings potentials. The commercial sector accounts for the largest share of achievable electricity savings (168 aMW), followed by the residential sector with an achievable

[1] All energy savings presented in this report are at the customer meter and do not include "upstream" adjustments for T&D system losses which would increase energy savings by 6.7% for electric and 0.8% for gas.

savings potential of 157 aMW. An additional 17 aMW of electricity savings are projected to be available from the firm-load segment of the industrial sector. An additional 14 aMW of savings is expected to be achievable through the implementation of *emerging* electric energy-efficiency technologies, not include in the IRP. Discretionary resources (i.e. retrofit opportunities) account for 238 aMW (70%) of the electric and 3.2 million Dth (44%) of natural gas energy-efficiency resources. The remaining potentials are associated with "lost-opportunity" resources, namely new construction and normal replacement of existing equipment at the end of their normal life cycle.

Exhibit 1. Base-Case Electric Technical, Economic and Achievable Potentials by Resource

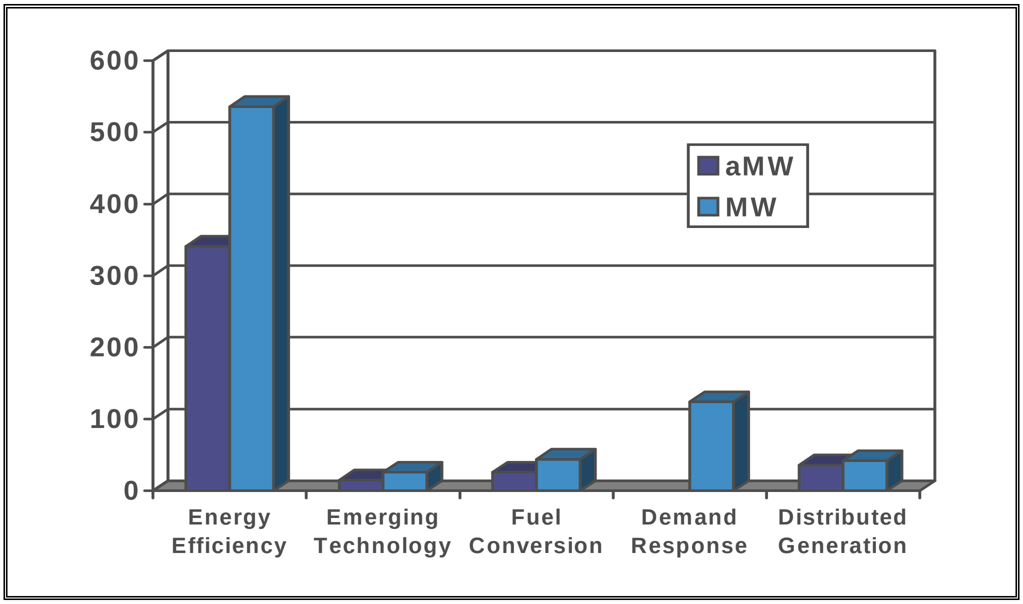
Resource	Technical Potential	Economic Potential	Achievable Potential
Electric Resources			
Energy Efficiency (aMW)	702	434	341
Energy Efficiency Emerging Technologies (aMW)	43	20	14
Fuel Conversion (aMW)	97	37	26
Demand Response (MW)	N/A	N/A	122
Distributed Generation (aMW)	N/A	N/A	36
Distributed Generation Emerging Technologies (aMW)	N/A	N/A	4
Total Energy Efficiency with Existing Technology			525
Total Energy Efficiency with Emerging Technology			543
Gas Resources			
Energy Efficiency (Dth)	35,109,050	11,181,275	6,919,508
Energy Efficiency Emerging Technologies (Dth)	526,124	464,183	377,898

Note: N/A indicates a potential was not calculated for this resource.

Conversion of residential space heating, water heating and appliances from electric to gas fuel are projected to provide the opportunity for acquiring an additional 26 aMW of electricity savings. Small-scale distributed generation technologies using fossil fuels (reciprocating engines, micro-turbines) and renewable sources (wind, solar, and biomass) are expected to offer additional load reductions of 40 aMW, about 4 aMW of which are expected to become available through emerging distributed generation technologies (Exhibit 2).

The identified electric demand-side management resources represent a significant contribution to PSE's future capacity requirements. As the results of this study suggest, if fully implemented, the energy savings from the identified resources are likely to reduce PSE's peak load by an equivalent of 648 MW by 2027, as measured at the meter. An additional reduction of 122 MW (at the meter) in peak capacity requirements may be achievable from demand-response options such as direct load control, demand buyback, curtailable tariffs, critical peak pricing and dispatchable standby generation. The combined effects of the peak impacts of energy-efficiency and demand-response resources may be expected to reduce PSE's 2027 peak capacity requirements by 11% (Exhibit 2). Additionally, due to the unique nature of DR resources, where two or more strategies can compete for the same customers and end uses, it is unlikely that all strategies can attain their individual potentials concurrently. Accounting for such interactions would lower the total available potential to 103 MW.

Exhibit 2. Year 20 Base-Case Electric Achievable Potential by Resource



Owing to the impacts of additional measures, particularly inclusion of emerging technologies, estimates of achievable electric energy efficiency potential are about 44 aMW (approximately 15%) higher than the 297 aMW from the 2005 assessment, or 30 aMW (10%) higher without emerging technologies. These results are largely in line with the regional estimates developed by the Northwest Power and Conservation Council. In its *5th Northwest Regional Electric Power and Conservation Plan*, the Council has estimated that 2,800 aMW of conservation is expected to be achievable regionally by the year 2025, which represents approximately 15% of the 2005 regional load. Based on the Council's "medium-case" forecast, regional conservation potentials represent slightly over 32% of the projected 6000 aMW growth in regional electricity demand from 2005 to 2025. Using 2005 as a basis for comparison, the achievable potentials identified in this study similarly amount to about 15% of PSE's 2005 load of 2,340 aMW. Based on the results of this study, by 2025 PSE is expected to account for approximately 14% of the regional load, and 12% of total regional achievable conservation potentials.[2]

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[2] Due to marked differences among local utilities in their customer mix, past conservation activity, load growth rate, and economic assumptions used in the determination of conservation potentials such as discount rates, a direct comparison between the regional and utility-specific estimates of conservation potentials is difficult, and may results in misleading conclusions.

The potentials for natural gas energy-efficiency resources are estimated at 7.3 million Dth, including 0.4 Dth from emerging technologies. The gas savings potentials are split almost evenly between discretionary and lost-opportunity resources. The majority of natural gas savings potentials are in the residential and commercial sectors, which together account for over 97% of total achievable energy-efficiency opportunities.

Achievable potentials for gas conservation are approximately 1,600 million Dth lower than those reported in the 2005 study, mainly as a result of lower technical potentials of 3,114 MDth due to updated end-use consumption indices based on new data, particularly in the residential sector. This difference is, however, mostly offset by the higher avoided costs and more aggressive market penetration assumptions.

Resource Costs

The total life-cycle costs for acquisition of the achievable potentials stand at approximately $1.1 billion for electric and $0.2 billion for gas resources in 2007 dollars, including 10% administrative expenses such as planning, program design, marketing, and on-going operation (Exhibit 3). Discretionary and lost-opportunity electric energy-efficiency savings from existing technologies account for the largest share (over 84%) of the total resource acquisition costs. The results of this assessment also show that the identified resources may be acquired at a weighted average levelized cost of $0.068 per kWh. Fuel conversion (at $0.03/kWh) and emerging energy-efficiency technologies (at $0.05/kWh) have the lowest levelized costs. Average levelized per-unit cost of conserved energy from energy-efficiency resources is estimated at or below $0.07 per kWh, and at a levelized per-unit cost of $0.76 per therm for gas resources (Exhibit 3). Distributed Generation has the highest levelized cost of energy (at $0.09/kWh).

Exhibit 3. Base-Case Resource Acquisition Costs (NPV and Levelized) by Resource

	Electric Resource		Natural Gas Resources	
Resource	20-Year NPV ($000)	Levelized Cost	20-Year NPV ($000)	Levelized Cost
Energy Efficiency	$ 929,762	$ 0.07 / kWh	$ 203,779	$ 0.76 / therm
Emerging Technologies	$ 21,378	$ 0.05 / kWh	$6,065	$ 0.34 / therm
Fuel Conversion	$ 21,314	$ 0.03 / kWh		
Demand Response	$ 73,881	$ 68 / kW		
Distributed Generation	$83,419	$ 0.09 / kWh		

Resource Availability under Alternative Scenarios

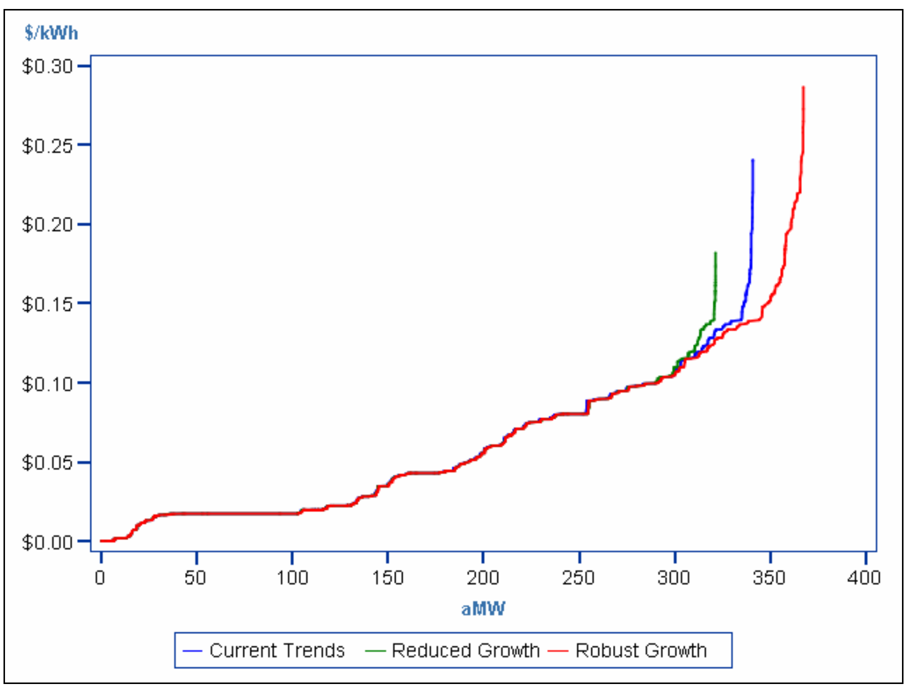
To provide additional perspective on future availability of DSM resources and to take into account uncertainties regarding future conditions in energy markets, resource potentials were estimated under alternative future scenarios with regard to their effect on resource costs. Five different scenarios were analyzed using a range of probable market prices. Estimates of energy efficiency potentials proved generally stable under various scenarios. In the electric sector, for example, a decline of nearly 20% from the highest to the lowest price scenarios was shown to result in a modest 6% decrease in energy efficiency potentials. (Exhibit 4). The results of the analysis indicates almost no effect on quantities of other DSM resources. This is largely due to the relatively low cost of many of the energy-efficiency measures.

Exhibit 4. Year 20 Electric Achievable Potential by Resource and Scenario

Resource	Base	Base + 25%	Base -10%	Green World	Low Growth
Average Avoided Cost ($/kWh)	$0.09	$0.11	$0.08	$0.10	$0.08
Energy Efficiency (aMW)	341.0	367.0	330.0	358.0	321.0
Emerging Technology (aMW)	14.0	15.0	14.0	14.0	14.0
Fuel Conversion (aMW)	26.0	26.0	25.7	26.0	22.0
Demand Response (MW)	124.0	124.0	124.0	124.0	124.0
Distributed Generation (aMW)	36.0	40.1	36.0	36.0	34.0
Distributed Generation + Emerging Tech (aMW)	40.1	40.1	40.1	36.0	40.1

Exhibit 5 shows how the electric energy-efficiency supply curve changes by scenario (the base-case book-ended by the highest and lowest scenarios). The curves are identical until about $0.11, at which point they begin to diverge. For example, if a horizontal line were drawn at $0.18, the amount of potential would vary significantly by scenario.

Exhibit 5. Electric Energy-Efficiency Supply Curves by Scenario



Examination of natural gas resources under alternative scenarios, however, indicates a more dramatic change in quantities in response to various price assumptions, particularly in energy efficiency based on existing technologies. As shown in Exhibit 6, achievable gas conservation potentials may be expected to grow by nearly 42% as a result of a 25% increase in prices above the base-case forecast. More extreme price fluctuations (for example from the low-growth scenario to 25% above the base-case) are likely to produce changes of nearly 72% in resource potentials. The impacts on fuel conversion options seem more moderate, since the base case is already high on the supply curve. For example, a 15% drop in avoided costs from the highest to the lowest case is shown to produce a less than 20% decline in the potentials for this resource. Price changes generally appear to have little effect on energy efficiency potentials from emerging technologies due to the relatively low per-unit costs of these resources (Exhibit 6).

Exhibit 6. Year 20 Gas Achievable Potential by Resource and Scenario (1000Dth)
(Represents Additional Gas Usage for Fuel Conversion)

Resource	Base	Base + 25%	Base -10%	Green World	Low Growth
Average Avoided Cost ($/therm)	$0.96	$1.20	$0.87	$1.13	$0.84
Energy Efficiency	69,195	97,926	64,843	90,308	56,989
Emerging Technology	3,779	3,530	3,807	3,692	3,675
Fuel Conversion	1,218	1,218	1,200	1,218	1,001

For gas energy efficiency, supply curves vary even more significantly than for electric. Exhibit 7 shows the base, low, and high scenarios and how much savings is attained for each at a given cost cutoff. At low costs, the high scenario actually provides lower savings than the other scenarios because some more efficient measures on the margin are included in this scenario. For example, although a high-efficiency gas furnace may have a low enough cost to pass in all scenarios, in the highest scenario, the premium-efficiency gas furnace passes the screen, and will be installed instead. The savings of this measure is greater, but the levelized cost is as well, so it is not included until higher up the supply curve, at which point the high scenario surpasses the other scenarios at a given cost cutoff.

Ramping and Deployment

For the purpose of incorporating the DSM resource potentials into the integrated resource plan, the identified electric resources were scheduled for deployment according to the timing of PSE’s resource requirements over the 20-year planning period. Given the forecast energy and capacity needs of PSE, all electric energy-efficiency and demand-response resources are scheduled for deployment during early years. Acquisition of other electric resources (fuel conversion and distributed generation) are assumed to begin slowly in the early years, then accelerate in the medium term, and level off over the latter parts of the period (Exhibit 8). Due to the common difficulties in marketing of natural gas conservation programs, natural gas conservation resources are assumed to be acquired at a rate of one-twentieth of the potential annually, without any acceleration.

Exhibit 7. Gas Energy-Efficiency Supply Curves by Scenario

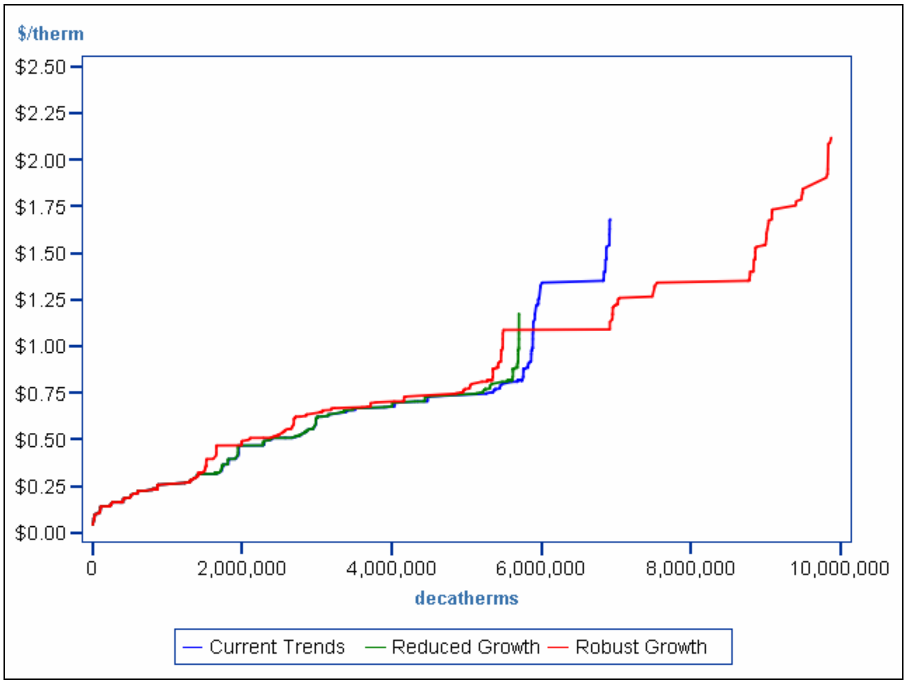
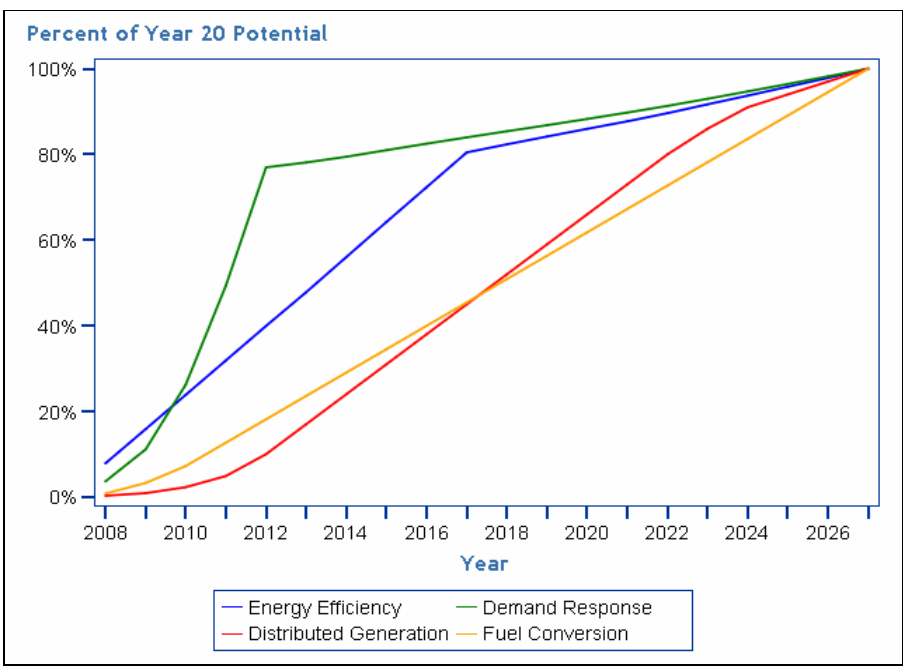


Exhibit 8. Assumed Timing of Electric DSM Resource Acquisition (Annual Rate as % of Total)



A full realization of the estimated achievable DSM potentials would require acquisition at the rate of approximately 21 aMW of electricity and 3.6 million therms per year over the 20-year planning period, assuming equal annual increments. These estimates are within a reasonable range of what PSE has been able to accomplish recently (19 aMW of electric and 2.4 million therms of natural gas savings in 2006). However, as more of the available potentials is exhausted over time, greater effort (and resources) would be needed to acquire the remaining potentials.

It is also important to note that achievable potentials represent fractions of economic potentials determined on the basis of the TRC criterion. The test is based on “total” cost of the resource, regardless of how it might be shared between the utility and program participants. Clearly, the higher the incentives paid by the utility, the greater the customers’ willingness to participate in DSM programs. The actual market penetration of DSM programs will therefore largely depend on incentives paid by the utility. This would, in turn, increase the cost burden borne by the utility, leading to higher rate impacts, with particular equity implications. These adverse effects may be at least partially mitigated by adopting alternative, low-cost resource acquisition strategies such as a greater emphasis on market transformation initiatives, promotion of new energy codes and standards, or programmatic efforts to improve compliance with existing codes.

1. Introduction

This study is a comprehensive attempt at identifying all electric and natural gas demand-side management (DSM) technologies and measures that are technically feasible, cost-effective and reasonably achievable in Puget Sound Energy's service area from 2008-2027. It is the third 20-year assessment commissioned by PSE in support of its biennial integrated resource planning (IRP) process. It builds upon the experiences of previous studies, expands their scope, and improves their methodologies in several important ways, including:

1. Extending the scope of the analysis to the full range of applicable DSM options including energy efficiency, electric-to-gas fuel conversion, demand response, small-scale distributed generation, dispatchable standby generation, and emerging energy-efficient and distributed generation technologies.

2. Incorporating additional measures including emerging energy-efficiency technologies and cost-saving innovations in distributed generation.

3. Using an economic screen to assess cost-effectiveness of individual measures and technologies based on the total resource cost (TRC) test criterion.

4. Evaluating resources at an hourly (rather than annual) level so that their unique energy and capacity impacts are fully taken into account. This procedure involved evaluating each measure based on its unique hourly load shape.

5. Updating end-use consumption indices for all sectors using the most recent data or estimating new indices through statistical regression techniques to disaggregate total annual consumption into its constituent end uses.

6. Revising the information on technology saturations to account for the effects of PSE's DSM activities since 2004 and resource acquisitions targeted for 2005 and 2006.

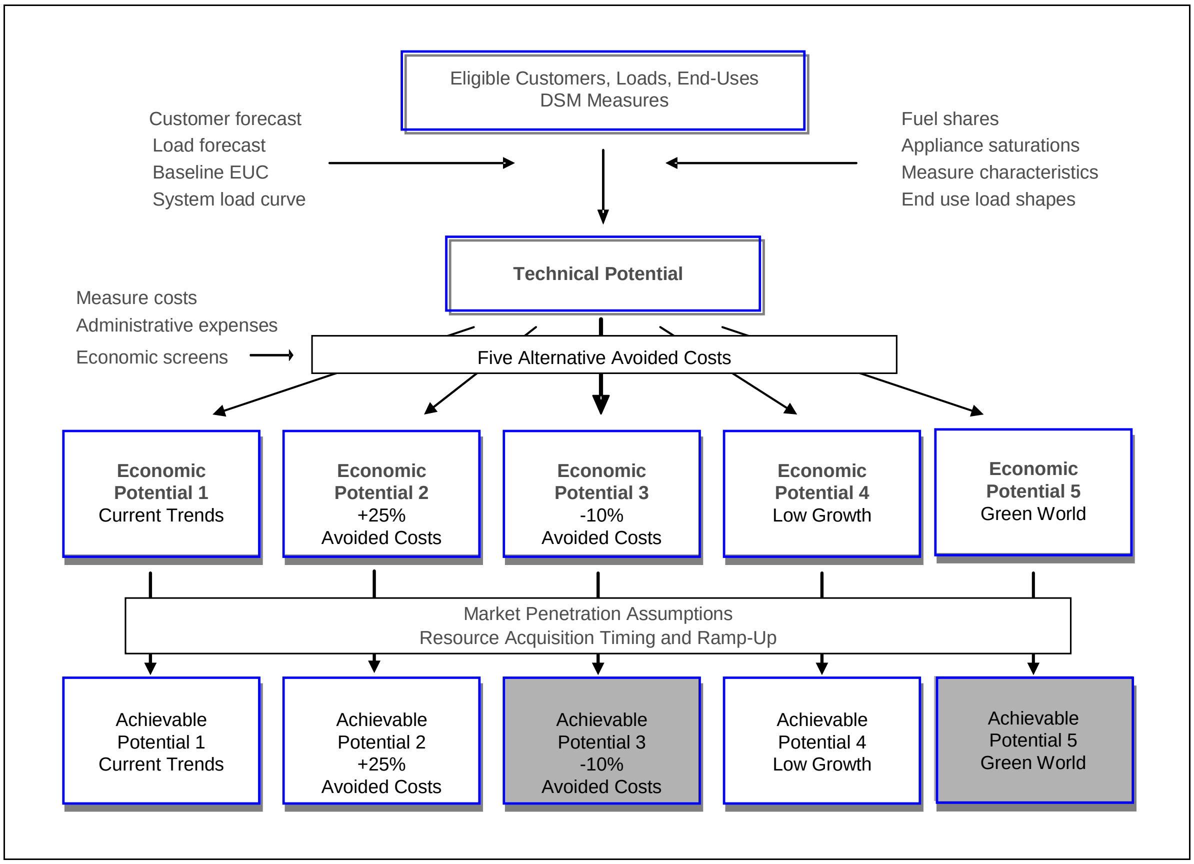
This study aims to characterize a broad range of DSM options and to provide reasonably reliable estimates of their magnitudes, costs, and the timing of their availability using the most recent data available. The conceptual framework and the analytic methods used in this study conform with standard practices in the utility industry and are consistent with the methods used by the Northwest Power Planning and Conservation Council ("the Council") in its assessment of region-wide conservation potentials.

General Approach

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

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

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



Consistent with the accepted industry standards, the approach in this study distinguishes among four distinct, yet related, definitions of resource potential that are widely used in utility resource planning: naturally occurring conservation, "technical potential," "economic potential," and "achievable potential." Naturally occurring conservation refers to gains in energy efficiency that occur as a result of normal market forces such as technological change, energy prices, market transformation efforts, and improved energy codes and standards. In this analysis, the market effects components of naturally occurring conservation are taken into account by explicitly incorporating changes to codes and standards and marginal efficiency shares in the development of the base-case forecasts.

Technical potential assumes that all demand-side resource opportunities may be captured, regardless of their costs or market barriers. For demand-side resources such as energy efficiency and fuel conversion, technical potentials further fall into two classes: “instantaneous” (retrofit) and “phased-in” (lost-opportunity) resources. It is important to note that the notion of “technical potentials” is less relevant to resources such as demand response and distributed generation—nearly all end-use loads may be subject to interruption or displacement by on-site generation from a strictly “technical” point of view. Economic potential represents a subset of technical potential consisting of only those measures that are deemed cost-effective based on a total resource cost test (TRC) criterion. For each measure, the test is structured as the ratio of the net present values of the measure’s benefits and costs. Only those measures with a benefit-to-cost ratio of equal or greater than 1.0 are deemed cost-effective and are retained.

Achievable potential is defined as that portion of economic potential that might be assumed to be achievable in the course of the planning horizon, given market barriers that may impede customer participation in demand-side management programs sponsored by the utility. The assumed levels of achievable potentials are meant to serve principally as planning guidelines. Ultimately, the actual levels of achievable opportunities will depend on the customers’ willingness and ability to participate in the demand-side programs, administrative constraints, and availability of an effective delivery infrastructure. Clearly, the customer’s willingness to participate in demand-side programs depends on the amount of incentive that is offered. Since the economic potentials in this analysis are based on a total resource cost perspective, it is implicitly assumed that PSE would bear the full cost of measures, which could raise equity concerns. Depending on the actual experience of various programs in the future, PSE may consider alternative, more efficient and cost-effective means such as market transformation and promotion of codes and standards, in order to capture portions of these resources.

A complete description of the each of the definitions of resource potentials and a discussion of methods used for their derivations are found in 7, Methodology.

Organization of this Report

This report is organized in seven sections. The next four sections (sections two through five) describe each individual resource analyzed in the study and present the results for each. Section six examines the effects of alternative economic scenarios on resource potentials. Section seven is devoted to a discussion of methodologies and assumptions used in evaluating various estimates of resource potentials. Additional technical information, descriptions of data and their sources are presented in the appendices to this document.

2. Energy Efficiency Resources

Scope

The principle objective in the analysis of energy efficiency potentials was to obtain reasonable and reliable estimates of long-run opportunities for energy-efficiency throughout PSE's service area. Energy-efficiency resource potentials for electricity and gas were analyzed for the residential, commercial, and industrial sectors. Six residential segments (existing and new construction single-family, multi-family, and manufactured homes) and 20 commercial segments (ten building types within the existing and new construction segments each) were considered. A comprehensive set of 145 unique electric and 61 unique gas measures—including 29 emerging electric and four emerging natural gas technologies—for all major end uses were analyzed. The results of the analysis for existing technology are described below, while emerging technology results are presented later in this section. A complete list of energy efficiency measures is provided in Appendix B.

Electric Resource Potentials

The results of this study indicate that there are 702[3] aMW of technically feasible electric energy efficiency potential (Technical Potential) by the end of the 20-year planning horizon in 2027 (Table 1). Approximately 434 aMW of these resources are cost-effective (Economic Potential) with an average levelized per unit cost of five (5) cents per kWh. Across all sectors, 341 aMW (nearly 80% of the economic potential) are deemed reasonably achievable (Achievable Potential). If fully deployed, the identified achievable potentials amount to nearly 10% of PSE's forecast load in 2027, and 30% of the projected load growth over the 20-year planning period.

Table 1. Cumulative (20-Year) Technical, Economic and Achievable Electric Energy Efficiency Potentials (aMW)

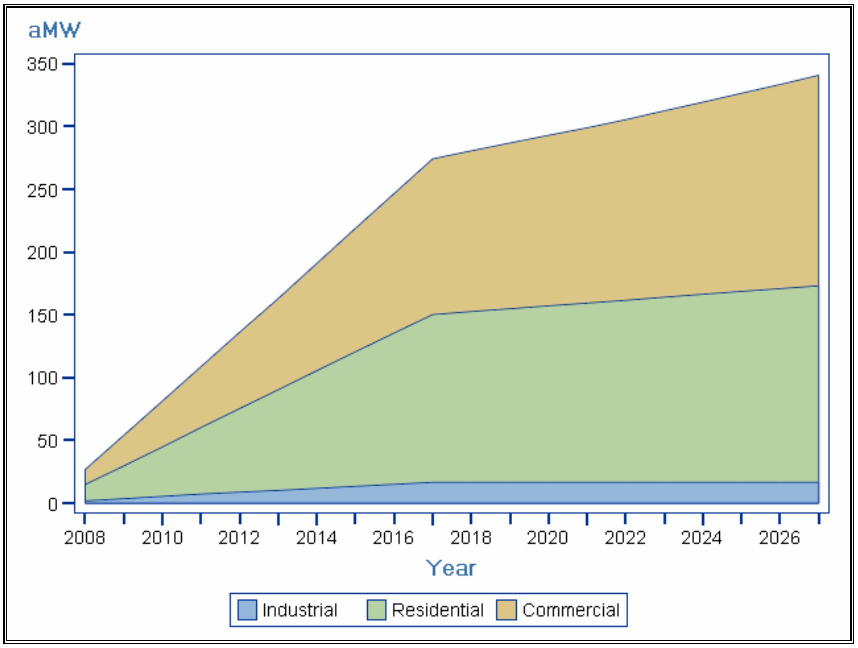
Sector	Technical Potential	Economic Potential	Achievable Potential	Achievable As Percent of Baseline Sales	Resource Cost Levelized $/kWh
Residential	310	196	157	9.3%	$0.05
Commercial	374	220	168	9.9%	$0.06
Industrial	19	19	17	9.9%	$0.03
Total	702	34	341	9.7%	$0.05

Nearly 95% (324 aMW) of the achievable potentials are in the commercial and residential sectors and 5% (17 aMW) in the industrial sector. Discretionary resources, i.e. those available

[3] All energy savings presented in this report are at the customer meter and do not include "upstream" adjustments for T&D system losses which would increase energy savings by 6.7% for electric and 0.8% for gas.

through immediate retrofit opportunities, constitute 70% (238aMW) of achievable electric potentials in the three sectors combined. All of the 17 aMW of achievable potentials in the industrial sector fall into the discretionary resource category. The large amounts of discretionary resources will allow PSE to accelerate its acquisition of energy-efficiency resources to meet its shorter term energy resource requirements. As illustrated in Figure 2, PSE is planning to pursue an aggressive acquisition strategy, seeking to obtain all discretionary[4] savings in the first ten years. All additional savings after the 10th year are from new construction and normal replacement of equipment in existing buildings.

Figure 2. Acquisition Schedule for Achievable Electric Savings by Year and Sector



Residential Sector

Achievable electric potential in the residential sector is expected to grow to 157 aMW over 20 years, corresponding to a 9.3% reduction in 2027 residential electric consumption. As shown in Figure 3, single family homes represent almost 75% (116 aMW) of total savings, followed by multifamily and manufactured homes. Additional savings of 25.2 aMW and 9.6 aMW are expected to be achievable in the multi-family and manufactured housing sectors. By far the largest (72%) of achievable saving opportunities in the residential sector are from lighting measures, owing primarily to the low cost of compact fluorescent lighting measures. Space heating and water heating applications account for the next two largest slices of achievable potentials, followed by plug loads and appliances such as energy-efficient refrigerators and freezers. (see Table 2 and Figure 4).

[4] Discretionary savings are those that can be acquired at any point during the planning horizon. These consist primarily of lighting, building shell, and water heating measures in existing buildings.

Table 2. Residential Sector Electric Energy Efficiency Potentials by End Use

End Use	Technical Potential (aMW)	Economic Potential (aMW)	Achievable Potential (aMW)
Central AC	2.1		
Freezer	2.1		
Heat Pump	11.6	5.0	4.0
Lighting	137.9	140.4	112.3
Plug Load	30.0	9.0	7.1
Refrigeration	12.0	12.3	10.0
Room AC	0.2		
Space Heat	65.8	22.7	18.2
Water Heat	48.5	6.3	4.9
Total	310.2	195.7	156.5

Commercial Sector

The commercial sector offers the largest opportunities for electric energy-efficiency improvement. The results of this study indicate that there are 168 aMW of cumulative achievable potentials in the commercial sector. Offices and educational facilities represent the largest shares (26% and 18% respectively) of the savings potential in the commercial sector. Considerable savings opportunities are expected to exist in the retail, groceries and dry-goods stores (31 aMW), health (14 aMW) and warehouse (16 aMW) segments of the commercial sector. Moderate amounts of savings are expected to be available in lodging facilities and restaurants. Together, these sectors are expected to offer 15 aMW of cumulative saving potentials. Approximately 20 aMW of savings are estimated for miscellaneous, un-classified commercial establishments (Figure 5). Lighting efficiency represents by far the largest portion of achievable potentials in the commercial sector, followed by HVAC, which accounts for approximately 40% of the achievable potentials (Table 3 and Figure 6).

Table 3. Commercial Sector Electric Energy Efficiency Potentials by End Use

End Use	Technical Potential (aMW)	Economic Potential (aMW)	Achievable Potential (aMW)
Cooling Chillers	32.6	17.9	13.6
Cooling DX	58.1	17.8	14.2
Cooling Heat Pump	18.6	4.9	3.9
HVAC Aux	1.4	1.4	0.9
Lighting	176.6	121.2	90.3
Plug Load	4.9	2.2	1.7
Refrigeration	10.9	9.7	7.6
Space Heat	61.4	39.6	31.6
Water Heat	9.3	4.9	3.9
Total	373.8	219.8	167.8

Industrial Sector

Technical and achievable electric and gas energy-efficiency potentials were estimated for all major end uses within 15 major industrial sectors in PSE's service territory. Achievable electric energy-efficiency potentials in the industrial sector are estimated at 17 aMW, representing approximately 10% of the total industrial load in 2027, at an average levelized per-unit cost of under 3 cents per kWh. The results of this study suggests that the identified savings tend to be evenly distributed among the eight industrial sectors, strongly correlated with their shares of PSE's industrial load (Figure 7). The majority of the savings in the industrial sector (57%) are attributable to efficiency gains in motor upgrades in air compression, pumping and air distribution applications. Small amounts of savings (3.2 aMW) are also available in facility improvements, primarily HVAC and lighting retrofits. Energy efficiency improvements in refrigeration and process cooling are also expected to generate an additional 2 aMW of savings in the industrial sector (Table 4 and Figure 8).

Table 4. Industrial Sector Electric Energy Efficiency Potentials by End Use

End Use	Technical Potential (aMW)	Economic Potential (aMW)	Achievable Potential (aMW)
HVAC	2.0	2.0	1.8
Lighting	1.6	1.6	1.4
Process Cooling	1.4	1.4	1.2
Process Motors Air Compression	3.2	3.2	2.8
Process Motors Fans	1.3	1.3	1.2
Process Motors Other	2.4	2.4	2.1
Process Motors Pumps	5.9	5.9	5.3
Process Motors Refrigeration	0.8	0.8	0.7
Total	18.6	18.6	16.6

Figure 3. Residential Achievable Electric Saving Potentials by Dwelling Type

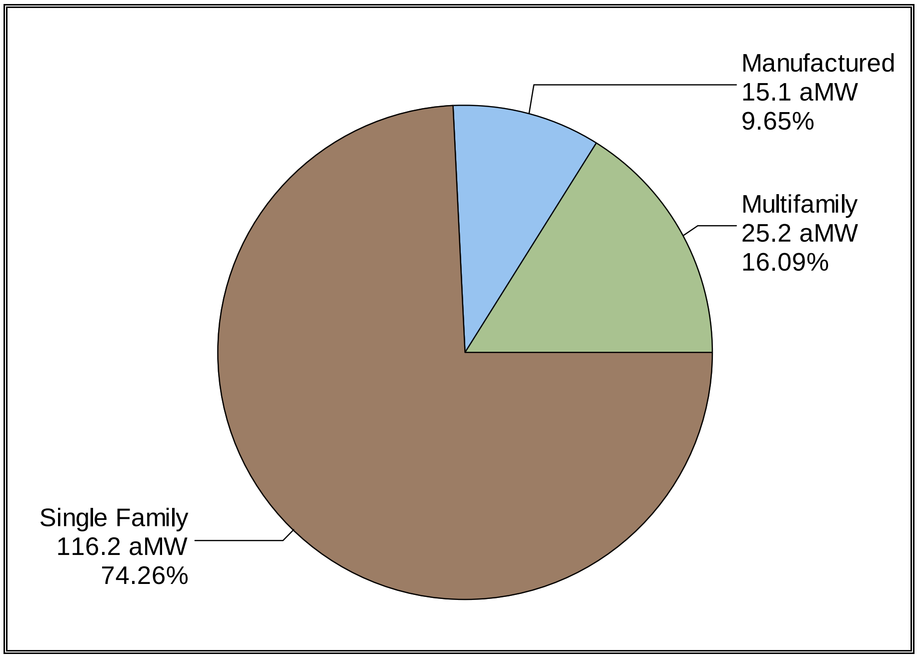


Figure 4. Residential Achievable Electric Saving Potentials by End Use

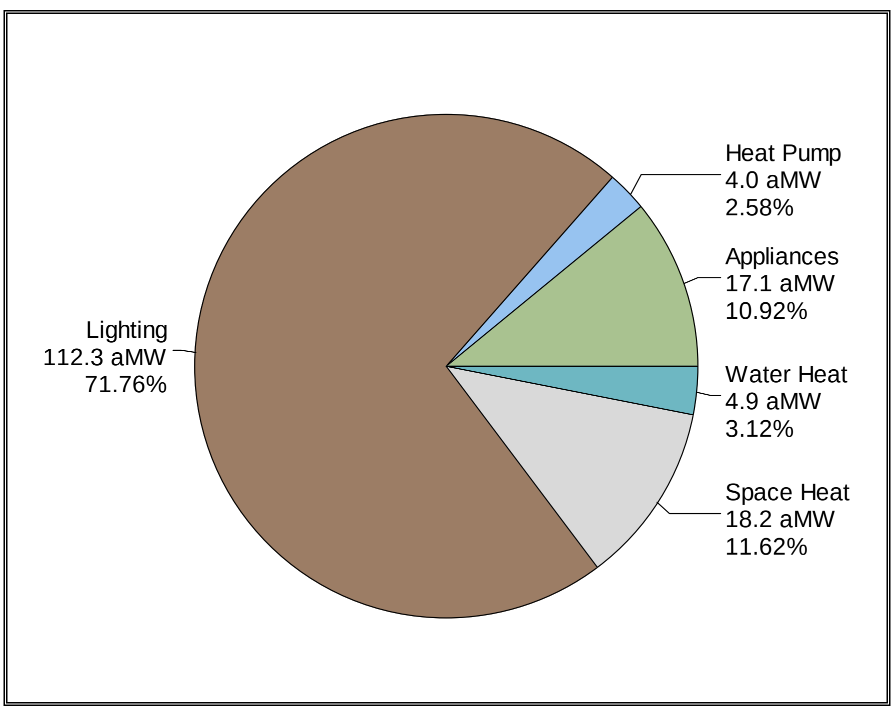


Figure 5. Commercial Sector Electric Achievable Potentials by Building Type

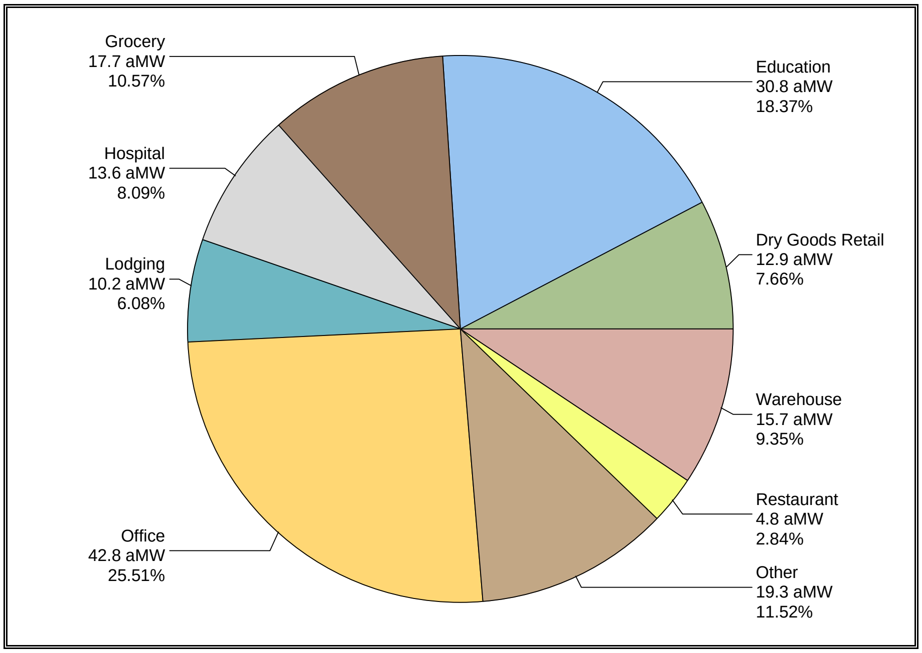


Figure 6. Commercial Sector Electric Achievable Potentials by End Use

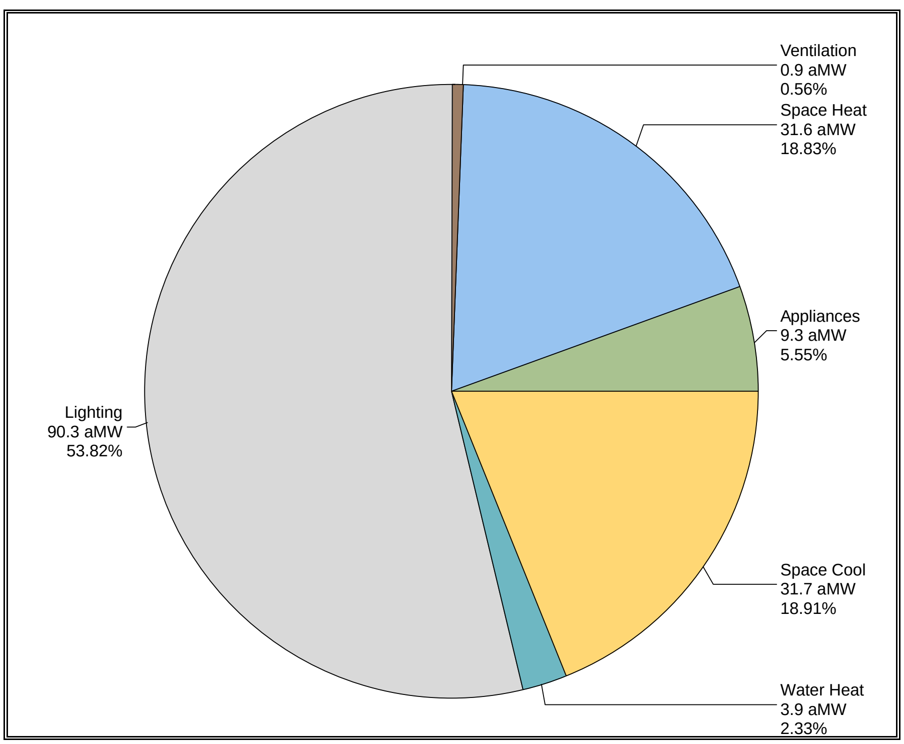


Figure 7. Industrial Sector Achievable Electric Potentials by Sector (NAICS)

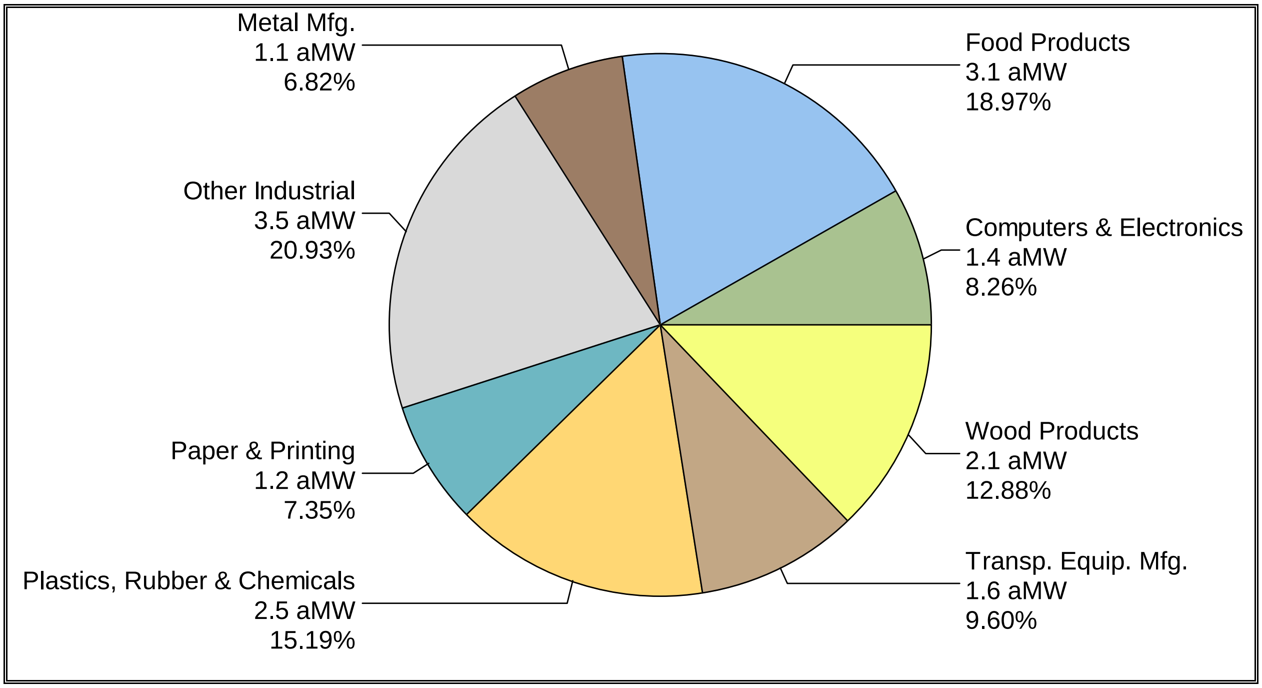
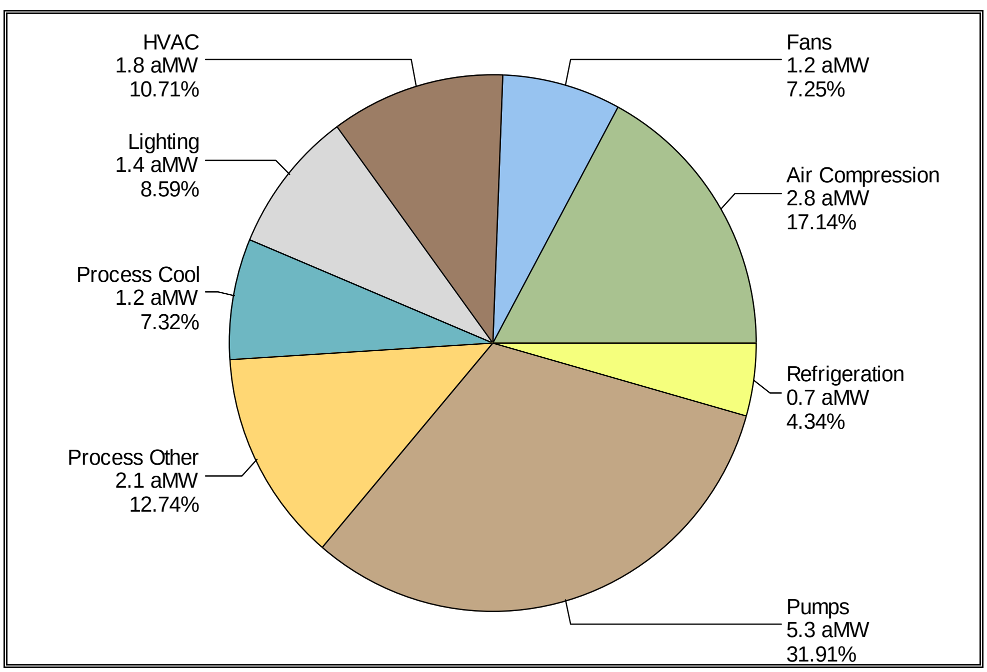


Figure 8. Industrial Sector Achievable Electric Potentials by End Use



Natural Gas Resource Potentials

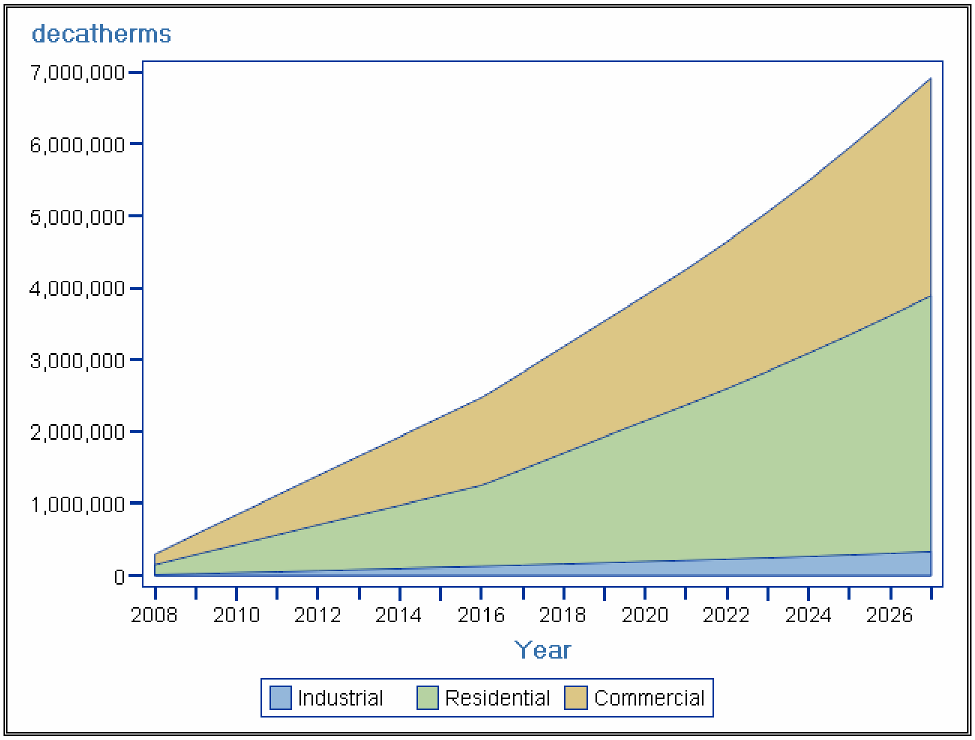
Table 5 shows the total decatherm (Dth) savings in the 20th year of the planning horizon by the type of potential. Across all sectors, cumulative natural gas savings potentials of nearly 70 million Dth are likely to be achievable over the planning horizon at a cost of 78 cents per therm or less. The estimated achievable potential represents about 32% of the technical and 62% of the economic potential. The residential and commercial sectors account for nearly 97% (10.7 million Dth) of the total achievable potential in all sectors. The industrial sector shows relatively small, though inexpensive, potentials for natural gas savings (Table 5).

Table 5. Cumulative (20-Year) Technical, Economic and Achievable Natural Gas Energy Efficiency Potentials (Dth)

Sector	Technical Potential	Economic Potential	Achievable Potential	Achievable As Percentage of Baseline Sales	Resource Cost ($/therm)
Residential	21,938,914	5,496,224	3,560,793	7.5%	$0.78
Commercial	12,732,958	5,247,873	3,030,831	4.4%	$0.53
Industrial	437,178	437,178	327,884	6.8%	$0.33
Total	35,109,050	11,181,275	6,919,508	5.3%	$0.65

Approximately 46% of the achievable natural gas savings potentials consist of retrofit measures and 54% are from lost opportunities. Due to the relatively large share of lost opportunity resources; and unique challenges in marketing of gas energy-efficiency programs, an aggressive, accelerated strategy does not appear feasible. It is, therefore, assumed that natural gas energy-efficiency resources would be acquired more gradually than electric resources. Achievable potentials for natural gas measures were assumed to begin at 55% (for existing buildings) and 35% (for new construction) of economic potentials during the early years of planning through 2016, and gradually ramp up to 75% and 55% for existing and new buildings respectively in the future.

Figure 9. Resource Acquisition Schedule Natural Gas Savings by Year and Sector



Residential Sector

Achievable natural gas savings potential in the residential sector grows to about 3.6 million Dth over 20 years. Figure 10 shows the distribution of this savings by home type. Because manufactured homes tend to have a higher saturation of electric equipment, these homes account for a smaller percentage of natural gas savings than they do for electric. There are far fewer natural gas end uses than electric, and only two prove to have cost-effective savings in the residential sector. Space heat accounts for over 60% of savings (Table 6 and Figure 11).

Table 6. Residential Sector Gas Energy Efficiency Potentials by End Use

End Use	Technical Potential (Dth)	Economic Potential (Dth)	Achievable Potential (Dth)
Space Heating	18,106,136	3,077,238	2,159,835
Water Heating	3,832,779	2,418,986	1,400,958
Total	21,938,914	5,496,224	3,560,793

Commercial Sector

Slightly over 3 million Dth of cumulative savings are expected to be achievable in this sector. Distribution of achievable natural gas savings across the ten modeled commercial segments are shown in Figure 12. Because the "Other" segment comprises the largest part of PSE's base year sales (over 30%), it is not surprising that it also represents the largest slice of potential, followed by office buildings with expected achievable potentials of nearly 0.5 million Dth. The largest amounts of achievable potentials are expected to be in energy-efficiency improvements in space heating and water heating, each accounting for approximately 1.5 million Dth of achievable potential (Table 7 and Figure 13).

Table 7. Commercial Sector Gas Energy Efficiency Potentials by End Use

End Use	Technical Potential (Dth)	Economic Potential (Dth)	Achievable Potential (Dth)
Cooking	152,067	23,088	17,316
Pool Heating	73,097	41,269	29,938
Space Heating	9,232,169	2,674,514	1,515,566
Water Heating	3,275,625	2,509,002	1,468,012
Total	12,732,958	5,247,874	3,030,831

Industrial Sector

Long-term cumulative achievable gas energy-efficiency potentials are estimated at 328,000 Dth. Food products and "other," unclassified industrials are the largest sources of achievable potential. With an average levelized per unit cost of under 33 cents per therm, energy-efficiency improvements in the industrial sector are the lowest cost gas savings. Food products and "other," unclassified industrial industries are the largest sources of achievable potential, combining for nearly 60% of the total (Figure 14). In the industrial sector, natural gas is almost exclusively used for process heating (boilers) and space heating. Nearly 80% of savings potentials are in boiler efficiency upgrades and 20% in space heating improvements (Table 8 and Figure 15).

Table 8. Industrial Sector Gas Energy Efficiency Potentials by End Use

End Use	Technical Potential (Dth)	Economic Potential (Dth)	Achievable Potential (Dth)
HVAC	89,470	89,470	67,103
Process Boiler	347,708	347,708	260,781
Total	437,178	437,178	327,884

Figure 10. Residential Sector Achievable Gas Potentials by Dwelling Type

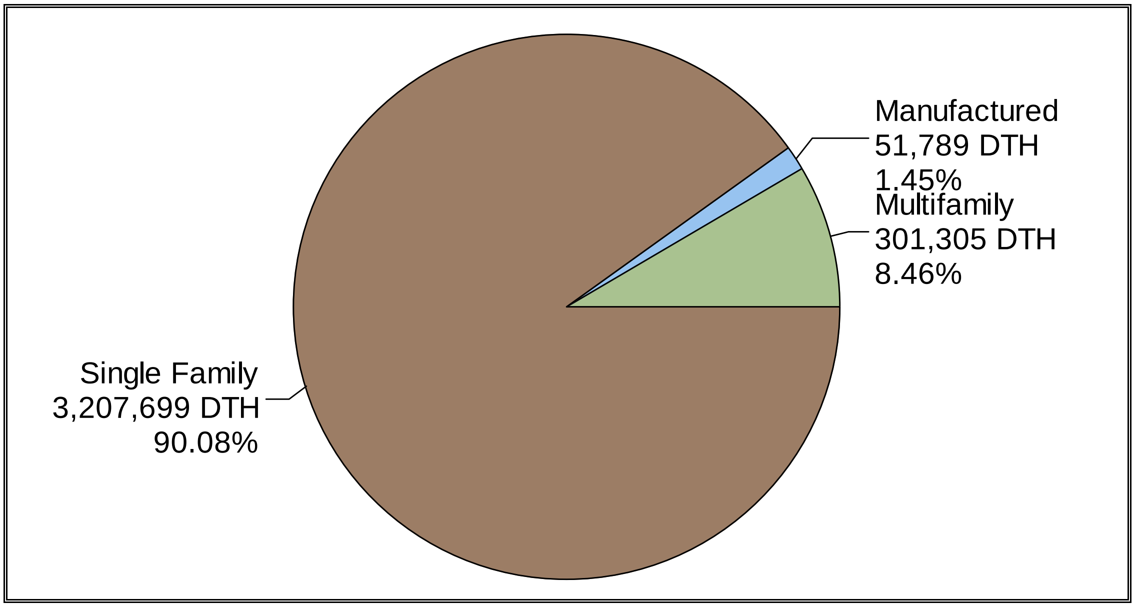


Figure 11. Residential Sector Achievable Gas Potentials by End Use

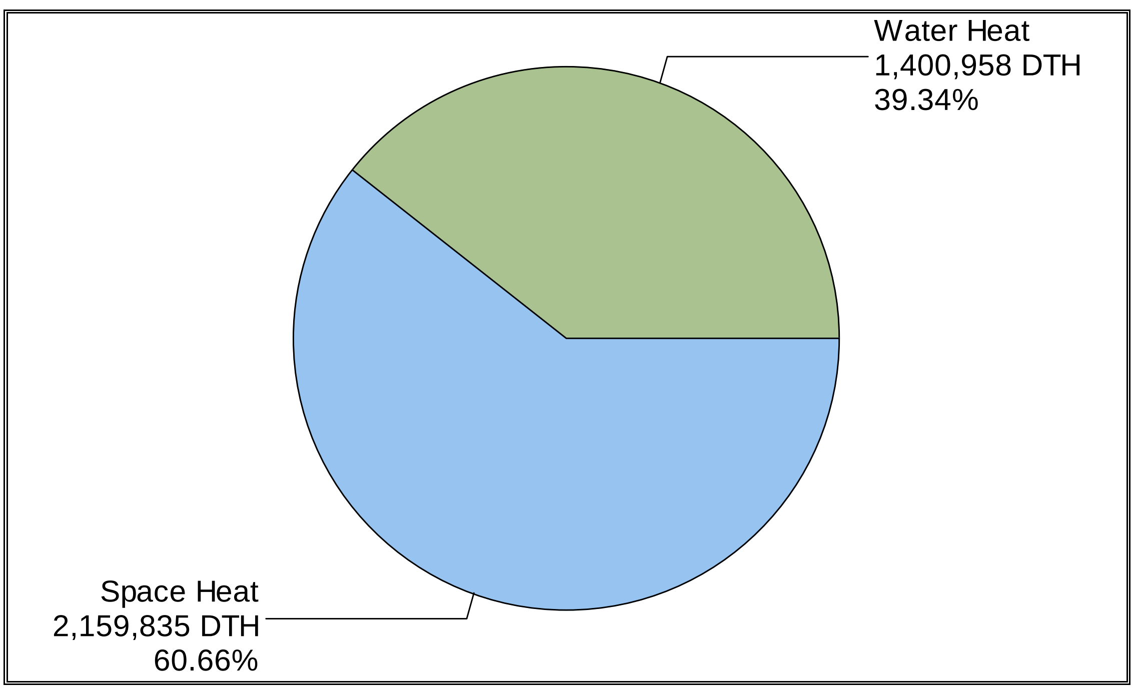


Figure 12. Commercial Sector Achievable Gas Potentials by Building Type

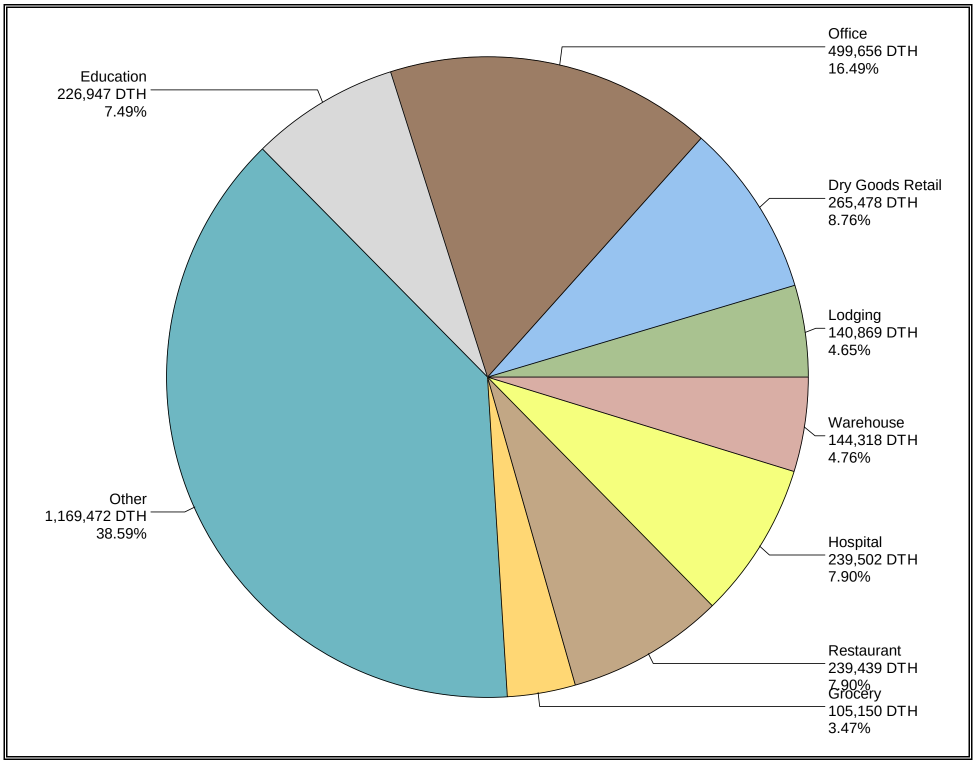


Figure 13. Commercial Sector Achievable Gas Potentials by End Use

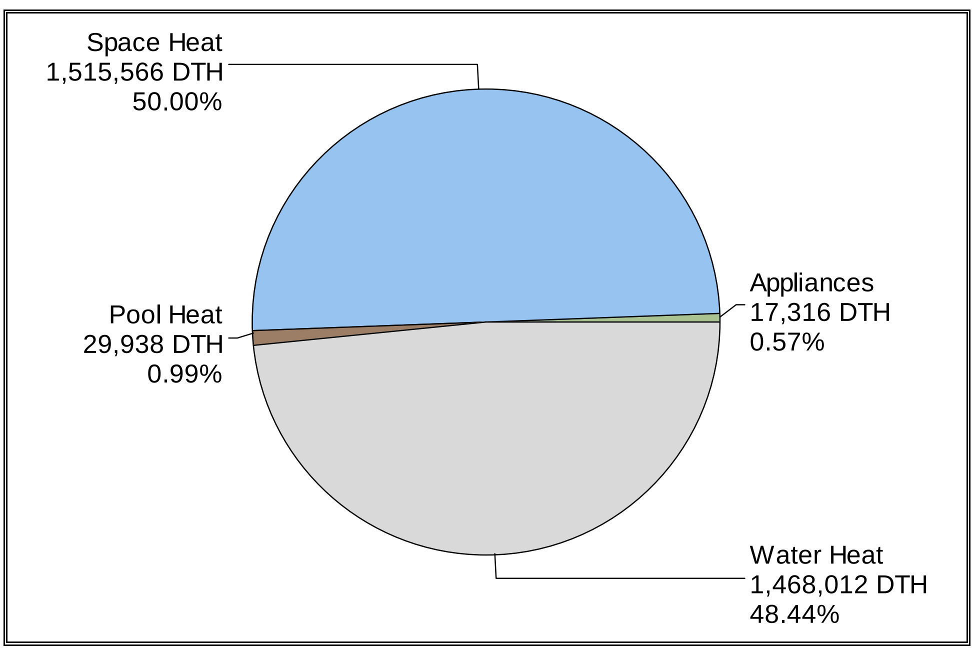


Figure 14. Industrial Sector Achievable Gas Potentials Industry

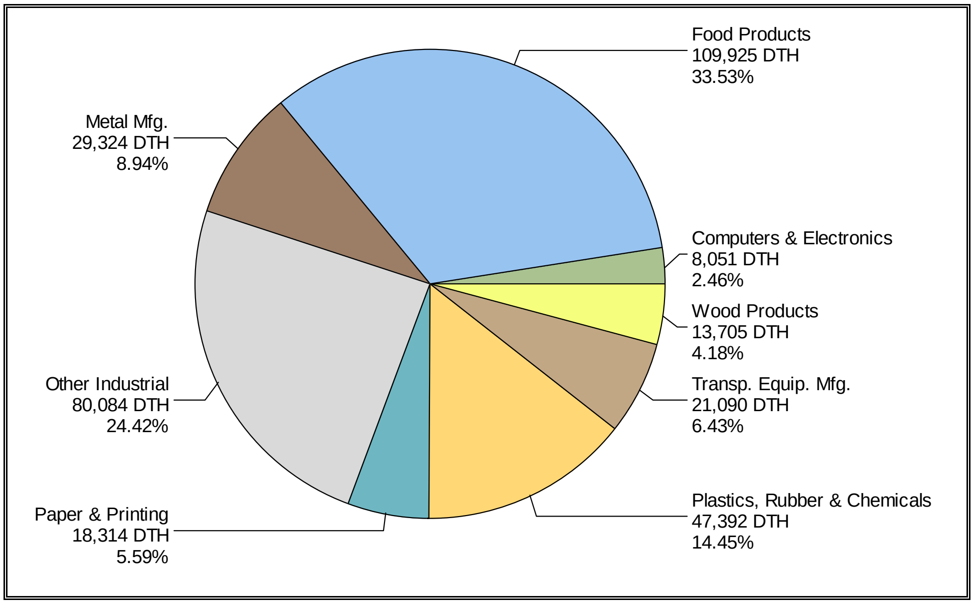
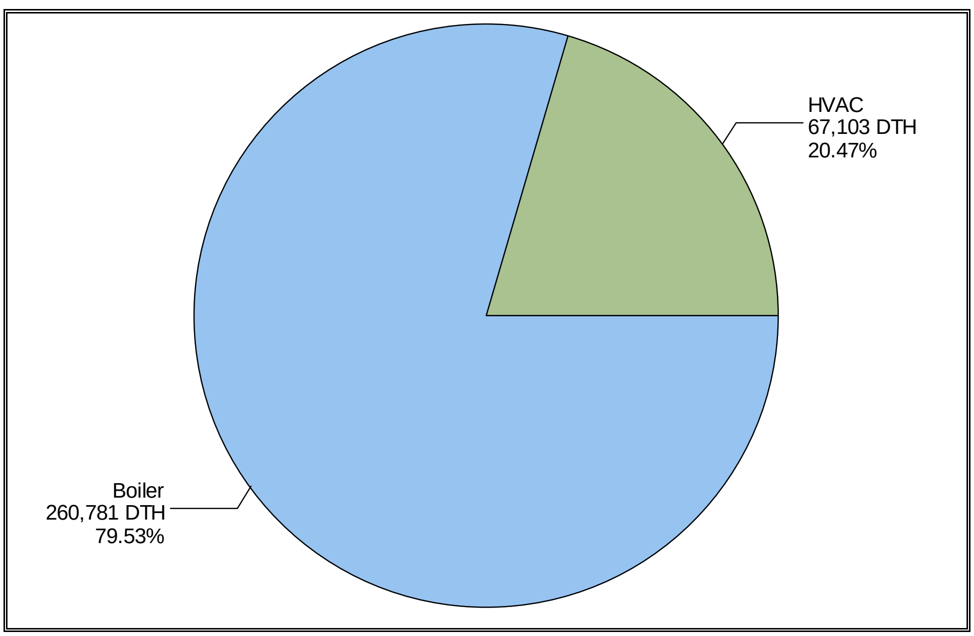


Figure 15. Industrial Sector Achievable Gas Potentials by End Use



Emerging Energy Efficiency Technologies

Scope of Analysis

In this study, explicit consideration was given to a number of emerging energy-efficiency technologies, including the deliberate modeling of conditions where new technologies gradually supplant existing ones. The emerging technology measures are energy-efficiency measures that are not readily available in the current market, but are expected to be so within the 20-year planning horizon. The potential energy savings from Emerging Technologies were not included in PSE's IRP.

The assessment of emerging technologies began with an initial list of 40 residential and 50 commercial measures. After applying several screens, the list was narrowed to a final set of 15 commercial and 13 residential measures. The first screen removed measures for which there was a lack of reliable quantitative data or that were otherwise inappropriate for PSE territory. Second, a rough economic screen was used to eliminate the highly expensive measures that had a levelized cost greater than $0.20/kWh as a first approximation of whether such measures were likely to be cost-effective. Finally, measures were screened for their stage of "market-readiness."[5] Measures that are now beginning to be introduced into the market are expected to become more commonplace and have a noticeable impact on energy use in about five years. There are also measures that are based of proven technologies, but for which no marketing or mass production has begun. These are expected to enter the market in about 10 years. Finally, there are those measures that represent a promising technology, but require more development and are thus not likely to have any market penetration for 15 years. Any measure that is not expected to penetrate the market in more than 15 years was not considered for this 20-year potential study. A table of these emerging technology measures is given in Chapter 7 and a more complete description is in Appendix A.

The emerging technology (ET) measures may or may not be competing with an existing measure. For example, LED white lighting would compete for market share with compact fluorescent lights (CFLs), where LEDs would gradually become more competitive over time. To account for this, the total number of energy-efficient fixtures installed would remain the same, but a portion of those fixtures with CFLs would decrease as the number of LEDs increased. Since LEDs are more efficient than CFLs, the overall savings potential would increase given the same number of fixtures. In other cases, the ET measures do not compete with existing measures and thus simply increase the overall savings potential as they are introduced.

Resource Potentials

Because there are no industrial ET measures and many of the measures in the commercial sector did not pass the cost-effectiveness threshold, the residential sector dominates the ET savings. Table 9 shows the year-20 achievable electric potential by sector and end use bundle. The largest

[5] "Emerging Energy Efficient Technologies and Practices for the Building Sector as of 2004," ACEEE, Davis Energy Group, and Marbek Resource Consultants, Report A042, October 2004.

potential appears in residential lighting, while there are also opportunities for HVAC measures in the commercial sector. For gas, the only cost-effective emerging technology measures are those applying to the heating end use. Again, most of the potential lies in the residential sector.

Table 9. Emerging Technology Electric and Gas Achievable Potentials (Year 20)

Sector	HVAC	Lighting	Other	Total
Electric (aMW)				
Residential	0.9	8.9	0.7	10.5
Commercial	3.3	0.2	0.1	3.6
Total Electric	4.1	9.2	0.8	14.0
Gas (Dth)				
Residential	332,320			332,320
Commercial	45,578			45,578
Total Gas	377,899			377,899

Figure 16 shows the annual savings by sector for electric ET measures. As can be seen, there is no ET savings until the first measures come online in year five. Due to PSE's aggressive approach in the first 10 years for electric resource acquisition, the slope of savings is greater from 2012 to 2016 than beyond, but savings continue to grow due to increased market acceptance. Figure 17 shows the gas measure savings (Dth) by year for each sector. The shape is much different than electric, due to the difference in resource acquisition strategies.

Figure 16. Emerging Technology Annual Electric Achievable Potential by Sector

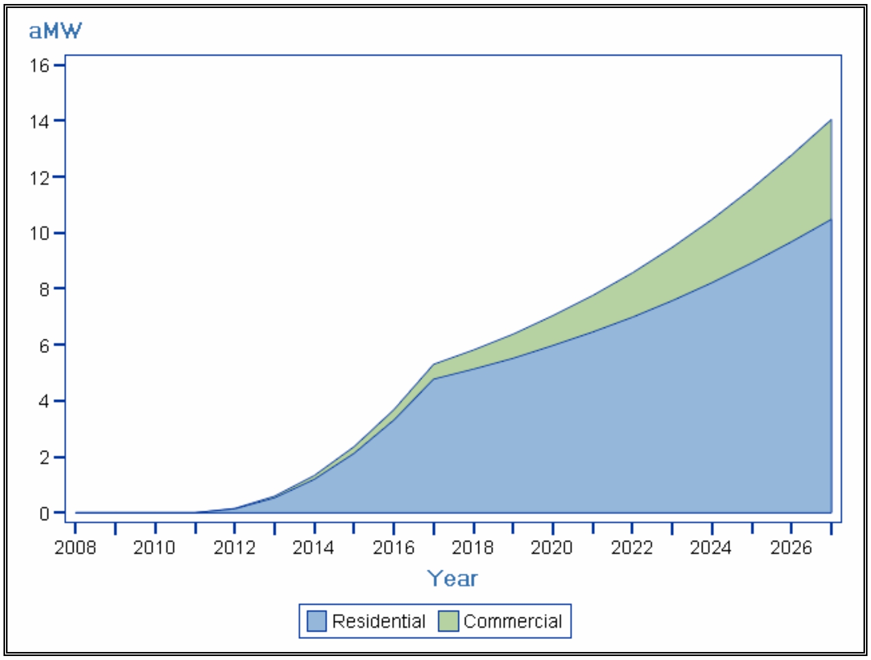
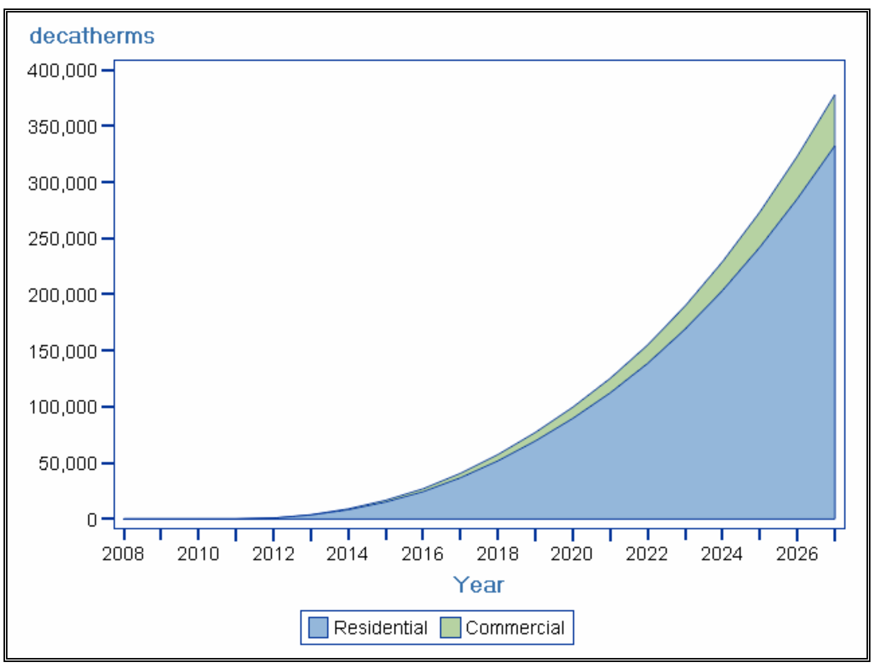


Figure 17. Emerging Technology Annual Gas Achievable Potential by Sector



3. Fuel Conversion Potentials

Scope

In the context of this study, “fuel conversion” refers to electricity saving opportunities involving substitution of natural gas for electricity through a replacement of space heating systems, water heating equipment and appliances. Fuel conversion potentials were examined for the residential single-family homes in parts of PSE’s service area where both electricity and gas are being served. Multi-Family and manufactured homes were not considered due to low saturation of natural gas in the existing stock, as well as technical and market constraints (for example venting issues and a high percentage of renters). Four end uses were considered: (1) space heating, (2) zonal heating, (3) water heating, and (4) appliances (clothes dryer and cooking range).

Methodology

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

1. Evaluate alternative technologies in terms of their life cycle costs (including full fixed installation and variable expenses) and benefits as measured in terms of the avoided cost value of displaced electricity

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

3. Establish cost-effectiveness of different technologies and “measure bundles” (economic potential)

4. Calculate achievable potential based on percentage of economic potential and assumed resource acquisition rate.

Measures Considered

The analysis of fuel conversion considered opportunities in four major end uses in single-family dwellings only: space heating, zonal heating, water heating and appliances (clothes dryer and cooking range). Applicable measures and their assumed technical specifications are shown in Table 10. Minimum efficiency thresholds for the gas equipment were set at the highest efficiency levels that met the cost-effective criteria in the gas energy efficiency potentials assessment. In other words, it was assumed that only the highest efficiency gas measures would be used in all conversions.

Examination of zonal (or room) heating assumed conversion to strictly similar gas-fired equipment such as gas wall heaters (rather than central systems). Dryers and cooking ranges were the only appliances considered in the study. Although the range of efficiencies for dryers tends to be narrow, a moisture sensor can be installed that will automatically shut off the dryer once the moisture level drops below a certain level. This can result in a 15% decrease in energy usage over a standard dryer, due to reduced run-time.[6] Similarly, there are minor differences in the efficiency level of ranges. However, a 20% energy savings can be achieved by using a convection oven.[7] A convection oven includes a fan within the oven cavity that results in air circulation around the food, increasing the overall heat transfer to the food. This allows for lowered oven temperatures and shortened cooking times. A fuller technical description of fuel conversion measures can be found in Appendix C.

Table 10. List of End Uses and Measures Used

End Use	Gas Measure	Electric Baseline
Space heating	90 AFUE condensing furnace	Electric furnace
	96 AFUE condensing furnace	
Zone heating	84% efficient wall heater	Electric wall/ baseboard
Water heating	EF=0.64 storage water heater	Electric water heater
	EF=0.82 tank-less water heater	
Appliances	Gas dryer w/ moisture sensor	Electric dryer w/ moisture sensor
	Convection gas range	Convection electric range

Gas Availability and Market Potentials

For the purpose of this study, it was assumed that the market potential would depend on two factors: (1) service availability and (2) customers' expressed interest and willingness to participate in a fuel conversion program.

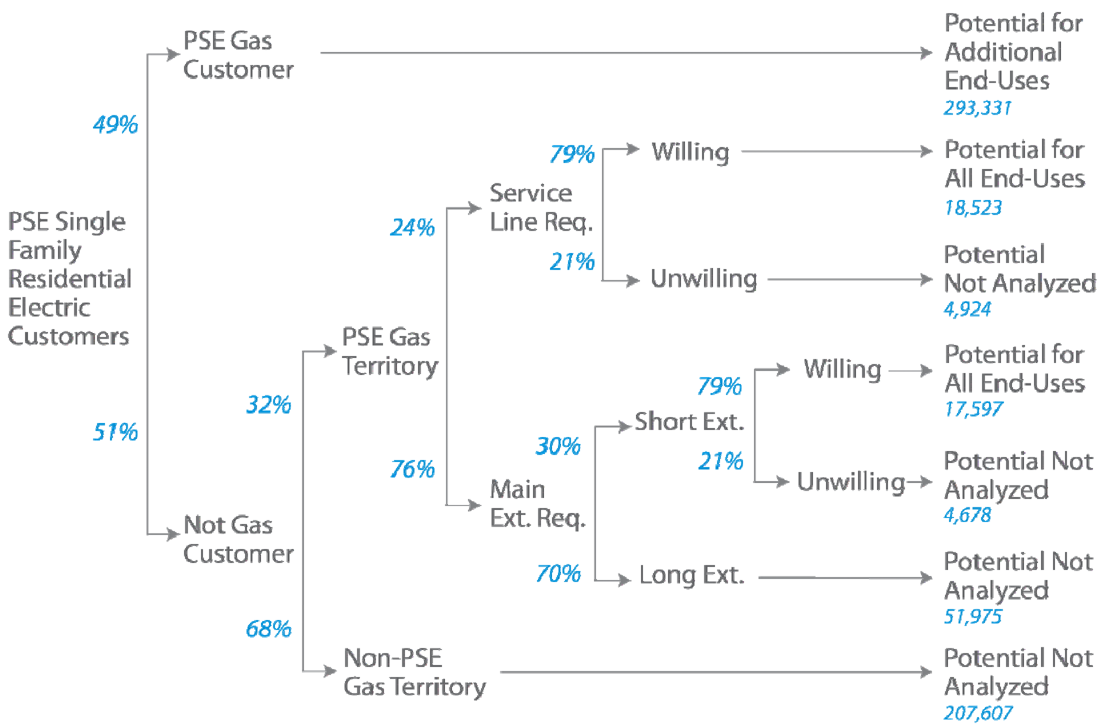
Gas availability and its implications in terms of service extension costs is an important consideration in determining the market and economic potentials for fuel conversion. Based on the most recent data available from PSE's 2004 Residential Energy Study (RES), PSE currently serves gas to approximately 49% of single-family homes in its electric service area (Figure 18). Since these customers use at least one or more piece of gas-using equipment, they are considered as candidates for only *additional* gas-using equipment, without imposing additional line extension costs. As shown in Figure 18, under the normal conversion scenario, these customers represent nearly three-quarters of the potential market (293,000 customers) for fuel conversion.

A relatively small proportion of the fuel conversion market potential is attributable to extension of service to new customers. The survey results have shown that about 32% of these customers are within PSE's gas service area. Based on the latest data available from PSE, delivery of gas service to these customers would require either a main extension (76%) or service line extension (24%). About 30% of customers in the former group may be served by short extensions.

[6] http://www.aceee.org/consumerguide/topwash.htm
[7] http://www.aceee.org/consumerguide/cooking.htm

Customer's willingness to participate in fuel conversion is a second major determinant of market potential for fuel conversion opportunities. Based on a recent survey of customers within PSE's gas service area, 79% of customers who are already on main or may be served with short line extensions expressed an interest in fuel conversion. This represents an additional market opportunity of 36,000 cases for implementation of *all* fuel conversion measures.[8]

Figure 18. Customers Available for Fuel Conversion



Conversion Costs and Benefits

To determine costs, only normal replacement was considered; that is, the assumed installed cost of the gas measure is incremental to that of the alternative electric measure. Thus, the cost to install a new gas furnace, for example, would include the cost of the gas unit itself, less the cost of the equivalent electric unit, plus any additional installation costs, including additional piping required to either extend the piping in the house (for current gas customers), or to deliver gas to the house (for electric-only customers), and gas fuel costs. For electric-only customers, connecting a house to the gas main is assumed to require either a service-line extension (no charge) or a short main extension (approximately $2000). Since it's expected that current electric customers would at least install a gas furnace, the cost to add the gas line to the house is only added to the furnace. Other end uses will have an additional cost only for interior piping ($200,

[8] The customer shares for the various branches in Figure 18 were derived from PSE Customer Information System and mapping of zip+4 census track codes to PSE's gas distribution system.

as determined through interviews with local HVAC contractors on PSE's Contract Referral Service List). Detailed assumptions on various cost elements are described in Appendix C.

Conversion costs were estimated based on electric and gas avoided costs and the assumed levels of unit energy consumption (UEC). The avoided cost benefits were calculated from a net present value of the first year electric ($/kWh) or gas ($/therm) avoided cost hourly data for the different end-use load shapes and measure lives. Electric UECs (kWh/yr) used in the energy-efficiency model for an existing single-family home were used for a baseline electric value. The equivalent gas UEC (therms/yr) was calculated from the electric usage for the water heater, range, and dryer, based on different efficiency levels for the different measures. For space heat, however, there was a significant disparity between the calculated gas UEC and that found from PSE tariffs. As a result, the tariff gas UEC was used for the stock gas heating measure (AFUE=80), with lower UECs calculated for high-efficiency furnaces. Zone heating UECs are assumed to be about 50% lower than in central units.

Calculation of benefits included avoided electric energy costs, avoided capacity costs ($35/kW/year through 2012 and $90/kW/yr after 2012), avoided transmission and distribution losses (6.7% for electricity and 0.8% for gas), and deferred T&D investment ($32/kW/yr). Since fuel conversion implies replacing an electric measure with a gas-fueled one, the true benefit needs to take this additional gas use into account.

Resource Potentials

To calculate the economic potential, the total resource cost (TRC) test was used to screen measures for cost-effectiveness. The economic screening was conducted assuming alternative bundles of measures, to account for cost savings resulting from joint installation of measures. All possible combinations of different bundling scenarios were considered in determining economic potentials. However, not all bundles are equally likely to be adopted. For new gas customers, it was assumed 5% will convert a space heater only, 80% will convert space and water heaters, 5% will convert space and water heaters and a range or dryer, and the remaining 5% will convert all four end uses. For existing gas customers, for which there are three possible end uses (water heater, range, dryer), it is assumed 85% will convert a water heater, 5% will convert two end uses (water + dryer or range) while 10% will convert all three. With zone heating, 5% will convert only a zone heater, 80% will convert a zone heater as well as a water heater, and 5% will convert a zone and water heater and one or two other end use(s) (dryer and/or range). These distributions are based on previous PSE experience. The TRC-based benefit/cost ratios for the different measures and bundles for the base case scenario is given with a 15% administration cost adder in Table 11 for electric-only and current gas customers. Only one end use (zonal heating) was not cost-effective in this scenario; however, the bundles including zonal heaters were.

Fuel conversion technical potentials were calculated by assuming that all measures for end uses for all willing customers are converted. At the meter, the technical potential was found to be 97 aMW for the base-case scenario. Acquisition of the indicated electricity savings would, however, result in an increased gas consumption at the meter of about 4,181,000 Dth in year 20 for the base-case scenario. Approximately 40% (36 aMW) of the technical potential was determined to be cost-effective after the application of economic screens.

Table 11. Measure Bundles for Electric-Only and Existing Gas Customers

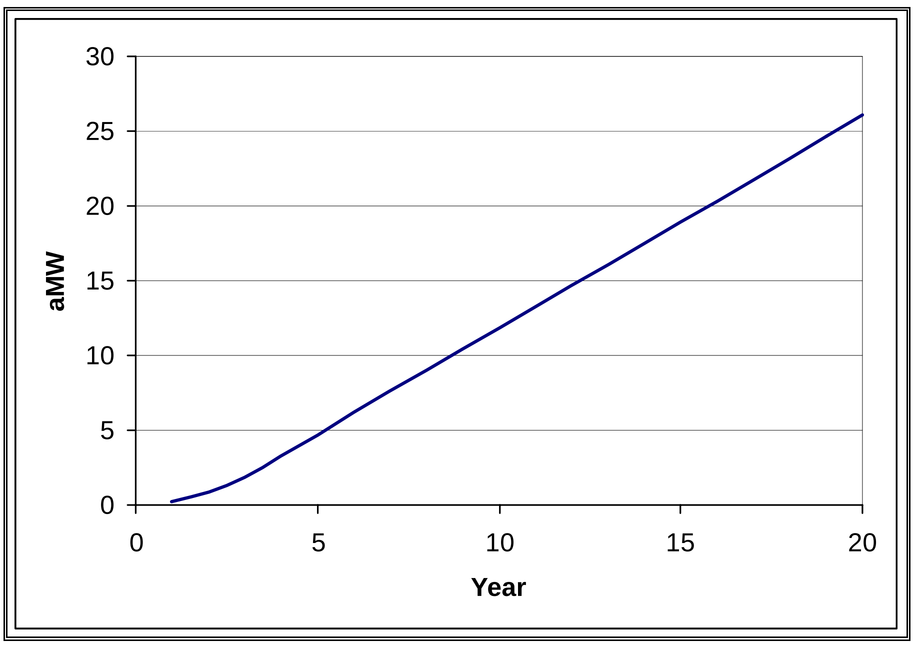
End Use	Measure//Measure Bundle	Cost ($)	Net Benefit ($)	Benefit/ Cost Ratio	Electric Savings (aMW)	Additional Gas Usage (1000 Dth)
Electric-Only Customers						
Space Heating	90 AFUE condensing furnace	1,840	2,504	1.4	0.2	10
	96 AFUE condensing furnace	2,243	2,817	1.3		
Space + Water	90 AFUE + 0.64 EF	2,369	3,887	1.6	7.5	495
Space + Water + Dryer	90 AFUE + 0.64 EF + moisture sensor	2,668	4,500	1.7	0.5	27
Space + Water + Range	90 AFUE + 0.64 EF + convection	2,714	4,239	1.6	0.5	27
Space + Water + Dryer + Range	90 AFUE + 0.64 EF + moisture sensor + convection	3,013	4,852	1.6	0.5	28
Existing Gas Customers						
Water Heating	EF=0.64 storage water heater	529	1,383	2.6	13	558
	EF=0.82 tank-less water heater	932	1,672	1.8		
Water + Dryer	0.64 EF + moisture sensor	828	1,996	2.4	0.5	20
Water + Range	0.64 EF + convection	874	1,734	2.0	0.5	20
Water + Dryer + Range	0.64 EF + moisture + convection	1,173	2,348	2.0	2.3	97
Zone Heating	84% efficient wall heater	1,725	957	0.6	0	0
Zone + Water	84% + 0.64 EF	2,254	2,340	1.0	0.3	17
Zone + Water + Dryer	84% + 0.64 EF + moisture sensor	2,553	2,953	1.2	0.01	0.6
Zone + Water + Range	84% + 0.64 EF + convection	2,599	2,691	1.0	0.01	0.6
Zone + Water Dryer + Range	84% + 0.64 EF + moisture + convection	2,898	3,304	1.1	0.02	1.3

The total achievable electric savings potential of fuel conversion in year 20 for the base case scenario was estimated at 26 aMW, which corresponds to an increase in gas use of 1,218,000 Dth, as measured at the meter. A summary of all potentials is given in Table 12. The achievable potential, by end use, is given in Table 11. In calculating the achievable potentials, it was assumed that 75% of the economic potential is likely to be achievable over the course of the planning period. As shown in Figure 19, deployment of fuel conversion resources would begin with a slow growth during the first three years, allowing for program development, and a strong, linear growth for the remainder of the planning horizon.

Table 12. Summary of Fuel Conversion Potentials

	Electric-Only Customers	Existing Gas Customers	Total
Technical Potential			
Electric Savings (aMW)	29	68	97
Additional Gas Usage (1000Dth)	2846	1335	4181
Economic Potential			
Electric Savings (aMW)	10	26	36
Additional Gas Usage (1000Dth)	547	1210	1757
Achievable Potential			
Electric Savings (aMW)	9	17	26
Additional Gas Usage (1000Dth)	501	717	1218

Figure 19. Assumed Ramp Rate for Fuel Conversion



4. Demand Response Potentials

Scope

Demand-response (or demand-responsive) resources (DR) are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. Acquisition of demand-response resources may be pursued for either reliability or economic/market objectives. These objectives may be met through a broad range of price-based (e.g., time-varying rates and interruptible tariffs) or incentive-based (e.g., direct load control, demand buyback, demand bidding, and dispatchable stand-by generation) strategies. In this assessment, five DR options were considered.

1. Direct Load Control

Direct load control (DLC) programs are designed to interrupt specific end-use loads at customer facilities through directed control by the utility. 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 usually 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. Typically, DLC programs are 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. Direct load control is assumed to be applicable to residential (space heating and water heating), large commercial and industrial customers (with loads larger than 250 kW), primarily through coordination with existing energy management systems. In the residential sector, space heating includes central forced air electric and heat pumps, assuming a 50% cycling strategy.

2. Dispatchable Standby Generation

Dispatchable standby generation involves an agreement between the utility and customers with existing on-site generation (generally back-up units), where the utility assumes responsibility for the operation, maintenance and fuel costs in exchange for the ability to dispatch the units for a pre-specified number of hours during system emergencies or high-price periods. Generally, the generating unit is a reciprocating diesel or dual-fuel engine. Given the pollution concerns of running a stationary diesel engine, there are limits to the number of hours in a year the engine can be operated. The Puget Sound Clean Air Agency allows a permitting exemption if the unit is less than 10 MMBtu/hr (~3000 kW) and runs for less than 500 hours per year. Given increased availability of bio-diesel fuel, it may be feasible to retrofit regular diesel stand-by generators to run on bio-diesel, thereby reducing greenhouse gas impacts of these units. Dispatchable standby generation programs are assumed to target multiple industrial and commercial sectors such as hospitals, hotels/motels, offices, warehouses and industrial high-tech facilities with generation units of 500 kW on average.

3. Curtailable Load Program

Curtailable load programs refer to contractual arrangements between the utility and its large customers who agree to curtail or interrupt their operations, in whole or in part, for a predetermined period when requested by the utility. In this study it was assumed that only those customers with a minimum monthly demand of at least 250 kW would be eligible for such a program. In most cases, mandatory participation is required once the customer enrolls in the program; however, the number of curtailment requests both in total as well as on a daily basis are limited by the terms of the contract.

Customers are generally not paid for individual events, but 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 strategies 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. PSE currently has a limited number of customers on interruptible tariffs.

4. Critical Peak Pricing

Critical peak (CPP) or extreme-day pricing refers to incentive-based, DR strategies that aim to reduce system demand by encouraging customers to curtail 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.

Under a CPP program, customers receive a discount on the 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 costs of participation. The basic rate structure is a time-of-use tariff where a rate with fixed prices for usage during different blocks of time (typically on- and off-peak prices by season). TOU rates are designed to reflect the typical costs of generating and delivering power during those time periods. When a critical peak pricing (CPP) element is added, the normal peak price under a TOU rate structure is replaced with a much higher event price, which is intended to reflect the utility’s higher cost of supply during critical peak events.

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. Residential and small commercial customers (<30 kW) are assumed to be eligible for this program.

5. Demand Buyback

Under demand buyback (DBB) 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 level of reduction is verified against an agreed upon baseline usage level. PSE operated a demand buy-back program in 2000 and 2001, but currently has no active participants.

Demand buyback is a mechanism that enables consumers to actively participate in electricity trading by offering to undertake changes in their normal patterns of consumption. Participation requires the flexibility to make changes to their normal electricity demand profile and 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 then can take the appropriate actions to manage their peak loads during the requested events. The strategy in this analysis targets the largest commercial and industrial customers (>250kW).

Methodology

Demand-response resources differ from other DSM options, particularly energy efficiency, in at least three important respects, which affect how DR potentials are calculated. First, they depend on customer choice. That is, they require that customers enroll in an on-going program (annually or periodically). Second, unlike energy-efficiency resources, demand response, by definition, affects the quality and availability of service to the customer albeit with the customer's consent. Finally, while energy-efficiency measures continue to provide savings over the normal life of the measure, the impacts of DR depend on the customer's ability and willingness to participate in individual events; and hence depend largely on program design features such as incentives levels, number of events, and whether the program is assumed to be mandatory or voluntary.

Demand-response 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. Recognizing this, the study employed a hybrid, "top-down"/"bottom-up" approach. As in the case of energy efficiency and fuel conversion, demand-response opportunities began with a "technical" assessment. However, the emphasis was on "market potential" as the determining factor in what is achievable. As illustrated graphically in Figure 20, the assessment involved four principal steps as follows.

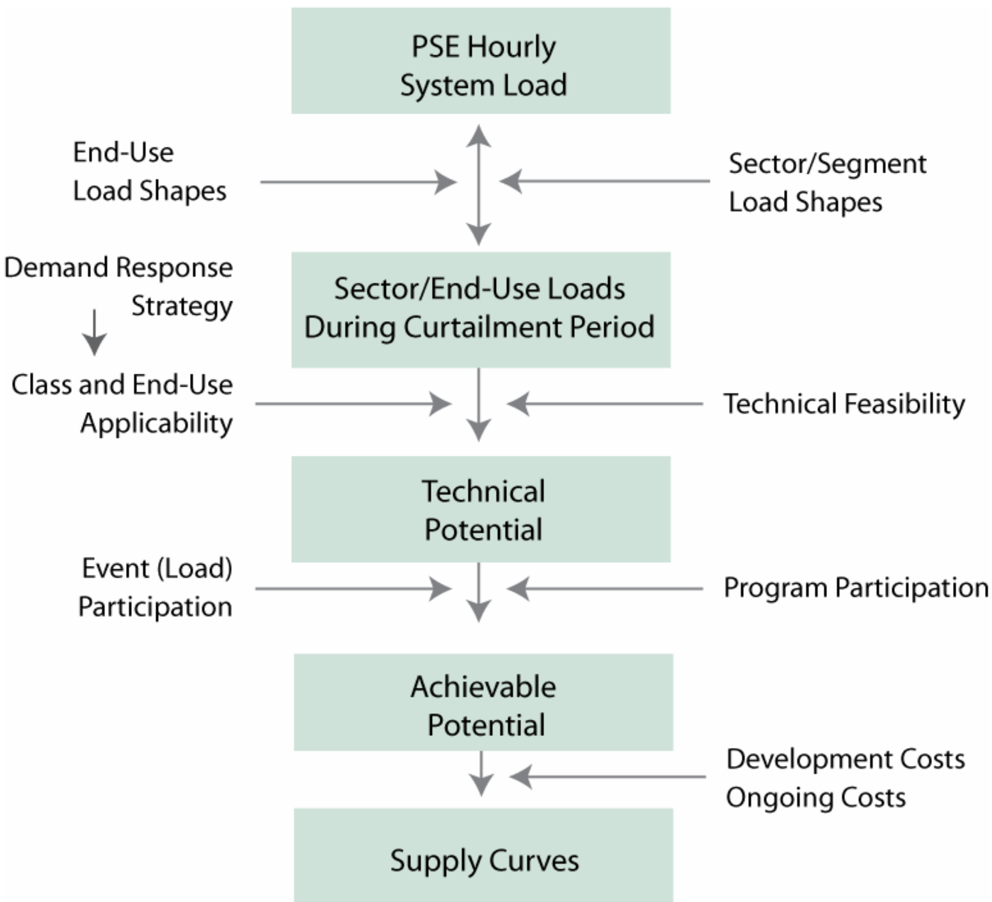
Estimating Total Load During Curtailment Periods. Using total energy sales by customer class and market sector in combination with end-use and sector hourly load profiles, the first step in the analysis was to calculate the class, sector and end-use loads during the likely curtailment periods. Maximum available loads for demand response were calculated based on the highest one-percentile (87 hours) of the system load duration curve.

Determining Technical Potentials. In all demand-response options, in general it may be technically feasible to shed all load during a demand-response event, but the potential would then equal system load, which is not useful for planning purposes and not possible for any single demand-response program. Therefore, technical potentials were estimated by adjusting total load to account for those customer classes and market segments deemed eligible for participation and the applicability and technical constraints of specific end uses. Technical potential is first estimated for the base year, then increased annually to 2027 by the annual peak forecast and assumes a 6.7% avoided line loss.

Estimating Achievable Potentials. Achievable potential is a subset of technical potential and takes into account the customers' ability and willingness to participate in DR programs subject to their unique business priorities, operating requirements, and economic (price) considerations. Estimates of achievable potential were derived by adjusting technical potential by two factors: expected rates of *program* participation, and expected rates of *event* participation. For each demand-response program, the assumed rates of program and event participation were derived based on the recent experiences of PSE, other utilities in the Northwest, other national utilities, and regional transmission organizations (RTOs) which have offered similar programs.

Development of Supply Curves. Finally, supply curves, which represents the quantity of resources (cumulative achievable MW) that can be achieved at or below the cost at any point, are developed using assumptions of development and ongoing costs for each DR strategy, as well as program attrition rates. The assumptions and data used in the analysis are described in greater detail in Appendix D.

Figure 20. General Methodology for Calculation of Demand Response Potentials



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Resource Potentials

The results of the technical potential assessment, as summarized in Table 13, show that in 2027, the highest *technical* potential can be found in residential water heating DLC and critical peak pricing, followed by curtailable load. Yet, due to significant market barriers; such as, customers being disinclined to enroll in programs which require significant behavioral changes, it is unlikely that a program can attain this level of load reduction. Table 14 provides an estimate of that portion of technical potential that is likely to be achieved, once actual market potentials for various strategies are taken into account. Program participation rates are based on experience of regional and national utilities in enrolling customers into demand response programs. Historically, the rates of acceptance by customers have been quite low.

The results indicate that residential water heating DLC and standby generation, with achievable potentials of 34 MW (0.5 percent of system peak) and 31 MW (0.5 percent of system peak) respectively, offer the largest opportunities for demand-response interventions. Achievable peak reductions from curtailable load are estimated at 25 MW, representing 0.4 percent of system peak. Opportunities resulting from critical peak pricing, DLC space heating and large C&I and demand buyback are expected to be relatively small. Because these results do not incorporate the interaction among programs or with energy efficiency, it is expected that the actual cumulative potentials would be somewhat lower than 122 MW although this may be used as an upper bound for planning purposes.

Table 13. Technical Potential (in 2027)

Sector	DLC – Water Heating	DLC - Space Heating	DLC – Large C&I	Demand Buyback	Curtailable Load	Critical Peak Pricing	Standby Generation
Industrial	-	-	18	48	48	-	-
Commercial	-	-	51	128	135	6	68
Residential	381	111	-	-	-	273	-
Total	**381**	**111**	**70**	**176**	**183**	**280**	**68**
Potential as % of PSE Peak	5.8%	1.7%	1.1%	2.7%	2.8%	4.2%	1.0%

Table 14 also displays the per-unit costs for each resource based on a dollar-per-kW-year basis. Standby generation, at $31/kW/year, is expected to be the least expensive option. Demand buyback though relatively inexpensive, at $46/kW/year, is much less reliable than standby generation due to the voluntary nature of the program and the rather low energy price forecasts for the foreseeable future. Curtailable load and critical peak pricing are both estimated at $50/kW/year, while the direct load control programs are all in the range of $100/kW/year due to the high cost of equipment and installation costs. These program costs can vary widely, depending on factors such as incentive levels and costs to recruit customers to participate in these programs.

Table 14. Achievable Potential (in 2027)

Sector	DLC – Water Heating	DLC – Space Heating	DLC – Large C&I	Demand Buyback	Curtailable Load	Critical Peak Pricing	Standby Generation
Industrial	-	-	1	1	6	-	-
Commercial	-	-	3	4	18	0	31
Residential	34	10	-	-	-	12	-
Total	34	10	5	5	25	13	31
Potential as % of PSE Peak	0.5%	0.2%	0.1%	0.1%	0.4%	0.2%	0.5%
Per-Unit Costs ($/kW-year)	$106	$95	$100	$46	$50	$50	$31

The supply curve is constructed from estimated achievable resource potentials and per-unit costs of each resource option. The demand response supply curve, shown in Figure 21, represents the quantity of each resource (cumulative achievable MW) that can be achieved at or below the cost at any point. Cumulative MW is created by summing the achievable potentials along the horizontal axis sequentially, in the order of their levelized costs. For example, the demand buyback program has 5 MW available, and its cost is the second lowest. Therefore, its quantity is added to the 31 MW of standby generation, showing that in total, 36 MW of resources are available at prices equal to or less than $46/kW. The dotted horizontal lines show PSE's total expected cost of capacity at various points in the planning horizon. Until 2012, it is expected that capacity will cost $67/kW/year, which includes $35 for generation capacity and $32 for the deferral value of transmission and distribution investments. After 2012, avoided capacity costs rise to $90, totaling $122/kW/year for capacity, rendering options such as direct load control cost-effective at that point.

Resource Acquisition Ramping Scenario

For demand response, it is expected that the all programs will ramp up at an increasing rate over the first 5 years of the planning period, such that only 5% of the total market potential will be in place in 2008, 35% in 2010, and 100% in year 2012, as shown in Figure 22. This five-year ramp-up is intended to coincide with PSE's projected timing of the need to build peaking resources. Additional resource potential will become available at the same rate as the growth in PSE's peak load.

Due to the unique nature of DR potentials, where two or more strategies can compete for the same customers and end uses, it is not likely that all strategies can attain their individual potentials concurrently. One way to account for such interactions is to rank the competing strategies by their levelized per-unit costs and assume that the lowest cost resources would be deployed first. For example, a 25% reduction in potentials for curtailable load and residential direct load control programs, and a 50% reduction in the C&I direct load control program would lower the total available potential to 103 MW.

Figure 21. Supply Curve for Demand-Response Options

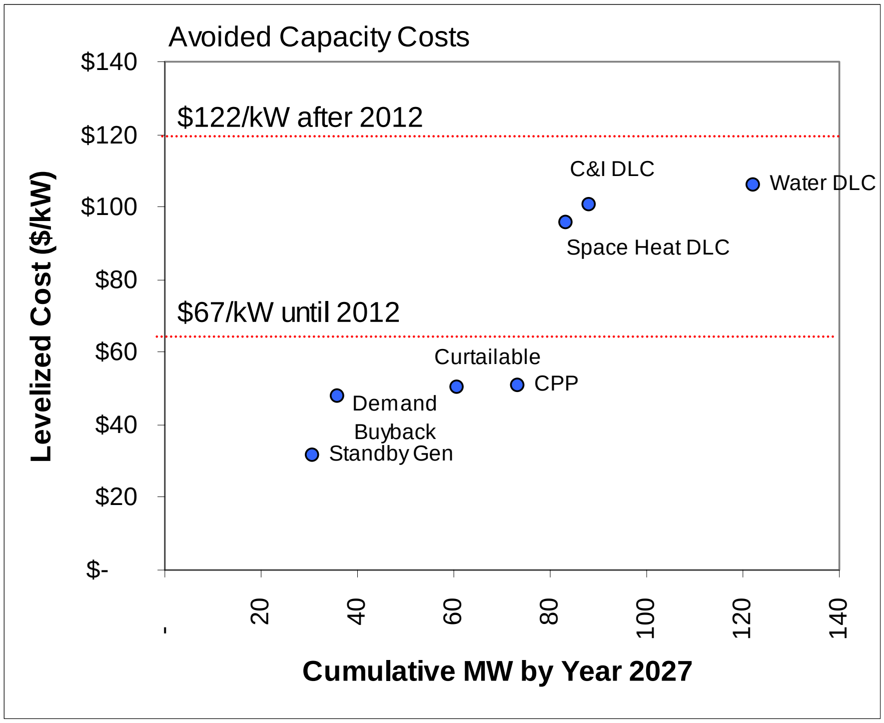
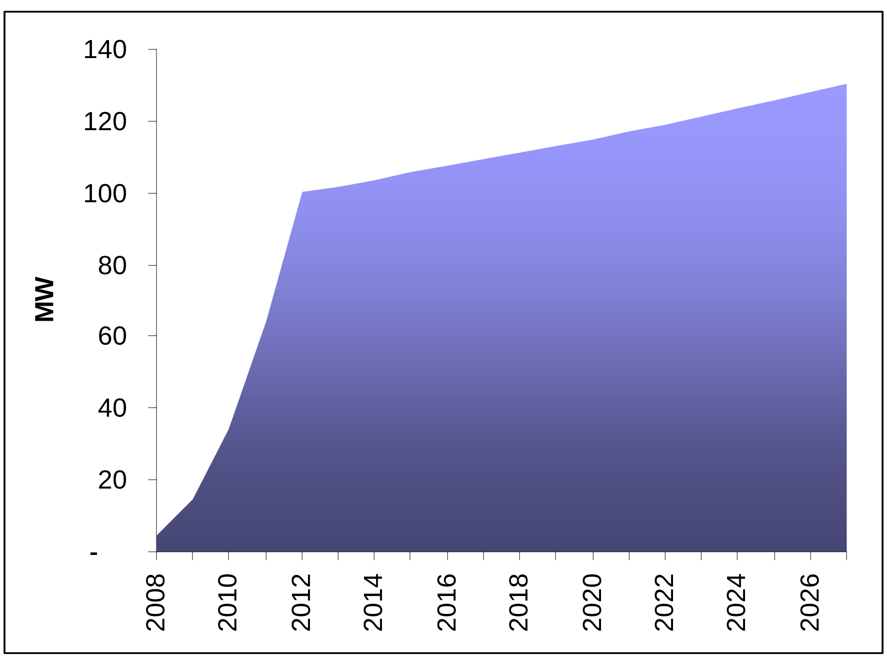


Figure 22. Demand-Response Ramping



5. Distributed Generation

Scope

Distributed generation (DG) encompasses all resources that generate electricity on-site at customers' facilities. For the purposes of this study, this type of power is used for baseline loads, but not as peak load reduction. Peak load reduction, or standby distributed generation, is treated under demand response. The DG technologies explored in this study fall into two primary categories: non-renewable generation and renewable generation. Only those technologies with less than five MW of rated capacity were considered as a demand-side resource.

Non-Renewable Generation

Non-renewable generation includes all technologies that require burning a hydrocarbon fuel, e.g., natural gas, in a generator to produce electricity. The three primary generator technologies are, in order of increasing cost, (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 as the electrolyte, although other types of fuel cells are now becoming commercially viable.

A more energy-efficient use of a standard non-renewable generation unit is as a combined heat and power (CHP) plant. CHP includes a standard non-renewable generator, but improves the overall utility by capturing the waste heat produced by the generator and using it for other purposes. 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 for space/water heating in addition to electricity being generated. All of the same generator technologies used for non-renewable generation are applicable for CHP, except that, in the case of fuel cells, not all types operate at a high enough temperature for efficient capture of the waste heat.

Renewable Generation

Renewable generation encompasses all generation that uses a renewable energy source. Three renewable energy sources are considered: (1) biomass, (2) wind, and (3) photovoltaics (PV). Biomass is further categorized into two subgroups: industrial biomass and anaerobic digesters. Industrial biomass includes the waste product from industries such as lumber mills or pulp and paper manufacturing, while anaerobic digesters create methane gas (biogas) by breaking down municipal solid waste, wastewater or dairy farm waste. The same generators used for non-renewable generation can be used with biomass, and may also be used in a CHP configuration. Industrial biomass is generally large scale, using generators such as steam or gas turbines of >1 MW capacity, while anaerobic digesters are coupled with smaller scale generators, such as reciprocating engines, microturbines or fuel cells.

The other renewable generation technologies are unique in that they do not require a hydrocarbon fuel for power generation and are thus zero-emission generators. For wind, a turbine is used to convert wind energy into electricity; photovoltaics (PV) convert solar radiation into electricity. These technologies do not create significant amounts of heat as a by-product, and thus are electricity-only technologies (not CHP).[9]

Methodology

Traditionally, when determining market potentials for energy-efficiency technologies, the first step is to calculate a "technical potential." This potential assumes all technologies will be adopted in all available applications, regardless of cost or other market barriers. However, for distributed generation technologies, determining a technical potential is not practical. From a purely "technical" point of view, DG can be implemented at any site, resulting in a technical potential of nearly 100%. This type of penetration is unrealistic, however,[10] and thus, for these technologies, only the "market" potential was calculated. The market potentials for different technologies were based, when available, on program successes in the Northwest and in other regions of the country. Details on the methodology for calculating market potentials for DG technology is discussed below.

Non-Renewable Generation

For the DG study, all non-renewable generation technologies include CHP. Standard non-renewable generation (without CHP) is only considered under standby distributed generation, a subset of demand response. In addition, natural gas is assumed to be the main fuel used, as it is throughout the year and is cleaner-burning than diesel[11].

Combined Heat and Power

CHP is assumed to always be utilized for two principal reasons:

1. Based on levelized cost comparison between the available technologies (reciprocating engines, microturbines, fuel cells) of similar capacities in non-CHP vs. CHP applications, the cost for CHP is uniformly less due to fuel savings in heating energy use.

2. Because CHP captures the otherwise waste heat of a stand-alone generator, the overall efficiency of a CHP system is greater. Thus, to make this DG resource portfolio as "green" as possible, all non-renewable generation includes CHP.

The market potential for CHP is based upon California's success of increasing CHP

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[9] Note that one can have a concentrated solar collector that does generate heat; however, those generally operate at much larger scales than are considered in this project, and are thus not discussed.

[10] See, for example, EEA Report No. B-REP-05-5427-013, Sept 2005.

[11] Depending on the metrics used, biodiesel could be considered clean burning, but storage issues make it less available than natural gas.

installations within the Self-Generation Incentive Program (SGIP). This program, funded by the investor-owned utilities of California, provides varying levels of incentives for individual customers to install various DG technologies. This program has been in effect since 2001. The results of SGIP was used as an expected generation outcome for the PSE base case, normalized by the PSE load compared to the load of the participating SGIP utilities. Since SGIP has been in effect for five years, this amount of generation achieved can occur for PSE after a similar five-year period. The three primary technologies (reciprocating engines, microturbines and fuel cells) were all included in SGIP and treated distinctly.

Renewable Generation

Wind

The results from California's SGIP were also used as a base for implementation of small-scale wind capacity (<1 MW). Note that in California, only four small-wind turbines have been adopted, so the sample size is quite small, but nevertheless representative of market penetration. Again, the capacities are normalized by the load ratio, as done with CHP.

Biomass

Industrial

Industrial biomass includes key industrial markets (e.g. lumber, food, pulp & paper) where sufficient internally generated biomass waste can be used for power generation. The projected growth in U.S. electricity generation from industrial biomass was used as the basis for growth in generation by biomass within PSE's industrial sector.[12] Again, the PSE industrial biomass growth is normalized by the ratio of the PSE industrial electrical load to the US load.

One weakness in this analysis is that the U.S. data does not differentiate between large- and small-scale generators. It is possible that much of this generation is larger than 5 MW. (A capacity of 1 MW was chosen as a typical generator size for relatively small scale applications.) To try to compensate for this, an upper limit on capacity was determined through a secondary study.[13] This work indicates that there are 268 MW of technical CHP potential in small-scale (<5 MW) industrial applications in Washington. Since PSE has 6.7% of the WA industrial sales, it is assumed to have a technical potential of 18 MW. This is taken as an upper limit of industrial biomass capacity.

Anaerobic Digesters

This category includes generators utilizing methane gas produced by dairy farms, municipal solid waste and wastewater treatment facilities. The capacity of 250 kW was chosen as a typical generator size. The type of unit used is variable (fuel cell, microturbine, reciprocating engine), and thus there is a wide range in associated cost. Generally, the generator is used in a CHP

[12] From Energy Information Administration (EIA).
[13] Energy and Environmental Analysis Report No. B-REP-04-5427-004r, Aug 2004.

application, where the captured heat is used to help maintain the digester at the necessary elevated temperatures. Although anaerobic digesters are included within California's SGIP, the availability of the users of these digesters are area-specific, and thus the SGIP was not used as a basis. Instead, the potential was based on information from the Washington Department of Community, Trade and Economic Development[14] and, in particular, the Northwest CHP Application Center[15] databases.

Photovoltaics

Similarly, SGIP's success with PV was not used in this study due to California's significantly different solar profile, and as such, the penetration under SGIP would likely over-predict what might be feasible in PSE territory. Instead, the market penetration rate of the Energy Trust of Oregon[16] within Portland General Electric's territory for the past four years is used as a basis for PSE. Given the similarity in PGE and PSE territories, the same growth is projected for PSE.

Technical Data

In order to determine the costs for the different technologies, an assumed capacity is used. For the three CHP technologies and wind, this assumed capacity is based on the weighted average of the units installed through California's SGIP. For PV, the average size of a typical array in Oregon is used.[17] Typical capacities for industrial biomass vary widely, and typically tend to be larger than other DG technologies. Thus, a 1 MW unit is used as a proxy. Finally, for anaerobic digesters, a rough average of existing and planned generators at various facilities with these digesters was used for the average capacity.[15] These values are summarized in Table 15 below. Also shown in the table is the fuel heat rate, measure life and capacity factors (CF) for the different generators. Heat rates are based on a weighted average of CHP units from the SGIP data. The measure life and CF were obtained from secondary published sources, except the CF for PV, wind and biomass. For PV and wind, the CF is based on PSE's experience, and for biomass, it is based on the actual capacity factor of the Renton Wastewater Treatment biomass unit.[15]

With these prototypical generating units, the associated costs and heat rates, if applicable, can be determined from literature values. For PV and biomass, the costs were based on a unit of the capacity given. 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 levelized cost of the technologies, based on adoption proportions in California is assumed. These costs are reported in Table 16. Administration costs of 10% of the capital expense are included in O&M cost. The heat rate can be used to calculate a fuel cost. Note that even though some of the references from which this cost information was obtained may be

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[14] Personal discussions with Tim Stearns, Senior Energy Policy Specialist, Washington Department of Community, Trade and Economic Development, June 2006.

[15] http://www.chpcenternw.org/

[16] Personal communication with Kacia Brockman of the Energy Trust of Oregon.

[17] "Oregon Photovoltaic Characterization," Prepared for the Energy Trust of Oregon by EMI, October 2003.

somewhat dated, the decrease in the cost of technology is roughly equivalent to the rate of inflation (2.5%). As a simplifying assumption, the 2007 costs are assumed to be the same as in the cited reference.

Table 15. Prototypical Generating Unit

Technology	Capacity (kW)	Fuel Heat Rate (MMBTU/MWh)	Measure Life (years)	Capacity Factor
Reciprocating Engine (RE)	419	4.8	20	0.9
Microturbine (MT)	183	7.4	15	0.95
Fuel Cell (FC)	696	5.8	10	0.95
Wind	663	N/A	25	0.15
Photovoltaics (PV)	0.65	N/A	25	0.12
Industrial Biomass	1,000	N/A	20	0.8
Anaerobic Digesters	250	N/A	15	0.8

Table 16. Costs for Technologies Considered (2007 Dollars)

Technology	Installed Cost ($000/MW)	Annual O&M Costs ($000/MW)	Heat Rate (MMBTU/MWh)
Reciprocating Engine (RE)	1,087	210	5.0
Microturbine (MT)	1,634	272	7.4
Fuel Cell (FC)	5,314	546	5.8
Wind	2,598	347	0
Photovoltaics (PV)	6,700	687	0
Industrial Biomass	1,600	272	0
Anaerobic Digesters	3,906	487	0

Market Potentials

The results of this analysis indicate a cumulative market potentials of 42.2 aMW from all DG technologies. The largest potentials are in reciprocating engine and micro-turbine CHP applications (23.9 aMW) and industrial biomass (10.1 aMW). An additional 6.1 aMW is also expected to be available through the installation of anaerobic digesters. The potential for renewables is small with a total of 0.11 aMW for wind and PV combined (Table 17).

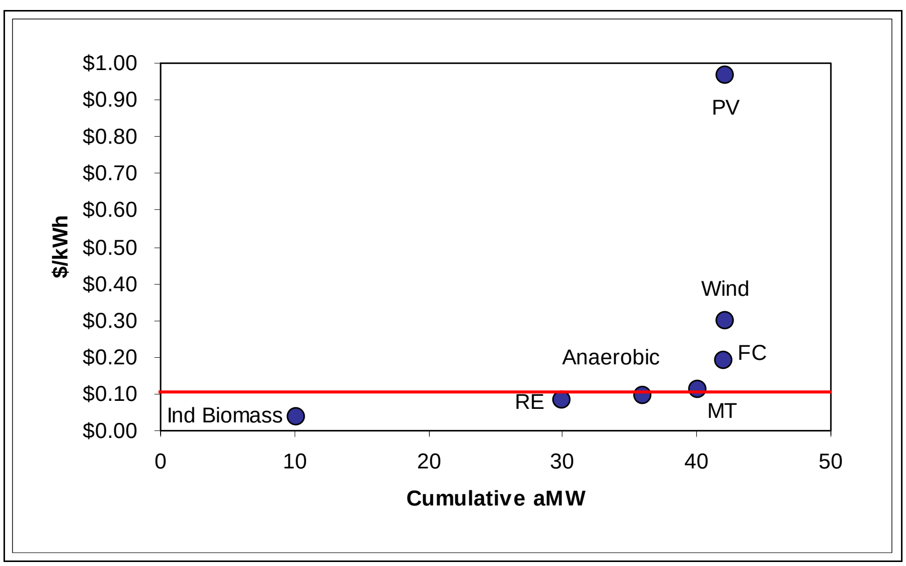
Table 17. Market Potential (aMW) for DG Technologies in Year 2027

Sector	Industrial Biomass	Reciprocating Engine	Anaerobic Digesters	Micro Turbine	Fuel Cell	Wind	Photo Voltaic	Total
Industrial	10.1	6.9	0.0	1.4	0.7	0.00	0.00	19.1
Commercial	0.0	12.9	6.1	2.7	1.3	0.03	0.04	23.1
Residential	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.1
Total	10.1	19.8	6.1	4.1	2.0	0.04	0.07	42.3
% of 2027 PSE sales	0.29%	0.56%	0.17%	0.12%	0.06%	0.00%	0.00%	1.2%
Levelized Cost ($/kWh)	$0.04	$0.08	$0.10	$0.11	$0.19	$0.30	$0.97	

Also shown in the table are the levelized costs ($/kWh), calculated using a nominal discount rate of 8.4%. These levelized costs were calculated from the total cost, and also include savings based on deferred transmission and distribution (T&D, $32/kW/yr) and avoided generation ($35/kW/yr through 2012 and $90/kW/yr after 2012).

As is made evident by their levelized costs, not all of these technologies are cost-effective. A cost cutoff, based on the levelized cost for a generic supply-side resource, was used to provide an economic screen. In other words, only technologies that are equal to or less than the cost of a generic supply-side resource are considered. This cutoff is $0.1104/kWh for the base case. Figure 23 gives the cumulative supply curve for the DG base case scenario, where the red line represents this cutoff. Thus, only industrial biomass, reciprocating engines, and anaerobic digesters are cost-effective, resulting in a total economic achievable potential of 36 aMW.

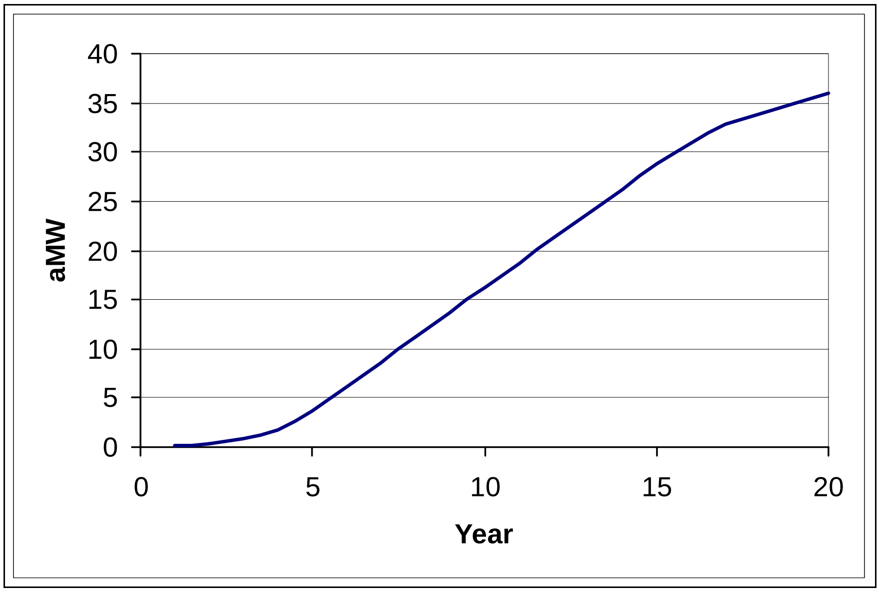
Figure 23. Cumulative Supply Curve for DG in Base Case Scenario



PV-Photovoltaics, FC- Fuel Cell, MT-Microturbine, RE-Reciprocating Engine

The assumed ramp rate of potential is given in Figure 24. This ramp rate allows for a slow buildup of programs over the first five years, significant growth in years 6-15, and a final slowdown in years 16-20 as most of the potential is realized.

Figure 24. Market Penetration Curve for All DG Technologies



Emerging Distributed Generation Technologies

Since a number of these technologies (specifically, PV, Wind, Microturbines and Fuel Cells) are continually developing, there is a good possibility that within the 20-year timeframe there will be significant technological advancements leading to a decrease in cost or increase in capacity factor (specifically for small wind). In addition, it is thought that CHP might break into the residential market, based on pilot programs in other parts of the country.[18] It is assumed that 2% of the total potential will be added to the residential sector.

To account for this, a separate DG resource bundle including an emerging technologies (ET) component was evaluated. This bundle assumes these technological changes will occur in year 10, resulting in a capital cost reduction of 50% (2007$) for PV, MT and FC. Anaerobic digesters, which can be run using a RE, MT or FC, have a 30% reduction in price, to account for the lack of price reduction with reciprocating engines. Wind turbines are assumed to have a 50% increase (to 23%) in the capacity factor, since smaller turbines, more suited to PSE territory, are beginning to be developed.

When emerging technologies assumptions are included, the penetration by sector changes, since CHP is now also within the residential sector (Table 18). However, the total potential is

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[18] For example, Climate Energy (www.climate-energy.com), has recently begun selling a CHP-RE unit for residential use in New England.

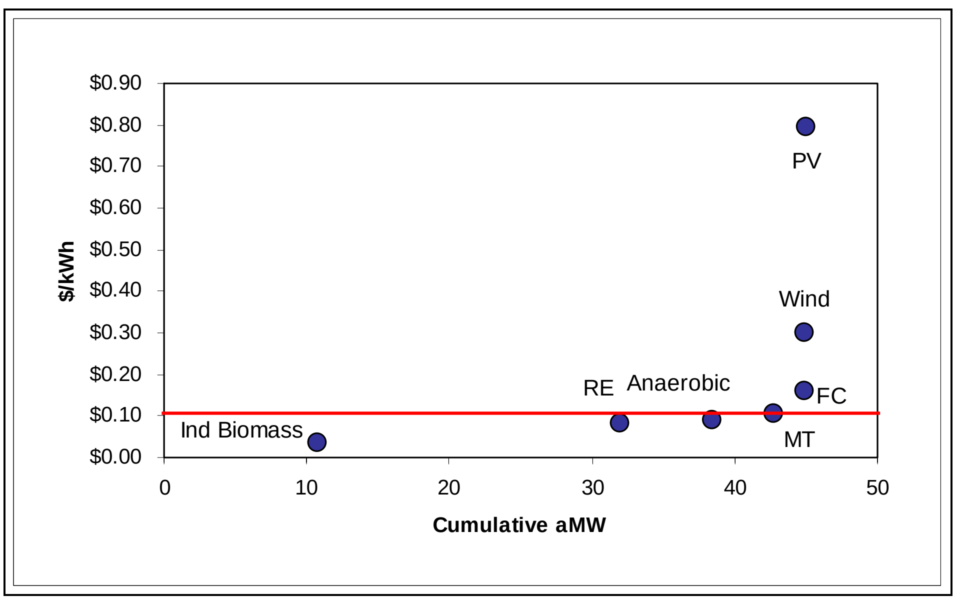
basically the same, though slightly higher, for the additional residential CHP and the increase in capacity factor for installations in years 10 and later for wind. Also included in this table are the levelized costs ($/kWh), calculated using a nominal discount rate of 8.4%.

Table 18. Market Potential (aMW) for DG+ET in Year 2027 Scenario by Sector

Sector	Industrial Biomass	RE	Anaerobic Digesters	MT	FC	Wind	PV	Total
Industrial	10.1	6.9	0.0	1.4	0.7	0.00	0.00	19.1
Commercial	0.0	12.9	6.1	2.7	1.3	0.03	0.04	23.1
Residential	0.0	1.1	0.0	0.1	0.1	0.01	0.04	1.3
Total	10.1	20.9	6.1	4.2	2.1	0.05	0.07	43.5
% of PSE Sales	0.29%	0.59%	0.17%	0.12%	0.06%	0.00%	0.00%	1.2%
Levelized Cost ($/kWh)	$0.04	$0.08	$0.09	$0.11	$0.16	$0.30	$0.79	

The levelized costs of some of technologies decrease with the emerging technology assumptions, as described above. With these reductions, CHP-MT will now fall below the economic cutoff. The total economic achievable potential for DG with ET increases to 40 aMW. The supply curve for DG with ET is given in Figure 25 below. The assumed ramp rate is the same as with the standard DG technology bundle.

Figure 25. Cumulative Supply Curve for DG + ET in Base Case Scenario



6. Resource Potentials Under Alternative Scenarios

In additional to the base case scenario, four additional scenarios for electric and gas potentials under alternative assumptions on future load growth and natural gas prices were considered: (1) current trends with a 10% decrease in avoided cost, (2) current trends with a 25% increase in avoided cost, (3) low growth, and (4) green world. (Natural gas scenario designations are shown in parentheses). Since these scenarios change the avoided cost, they only affect the economic potentials. The key assumptions underlying the five scenarios (gas indicated parenthetically) are:

1. ***Current Trends (Base Case)***
   a. Theme: best estimate of current resource costs and characteristics, fuel prices, state laws and moderate federal environmental policies
   b. Annual load growth: 1.6%
   c. Gas price: forward marks for 2008-2011, and Global Insights long-run fundamental forecast.
   d. Generic supply-side resource cost: $0.11/kWh
2. ***Current Trends + 25% (Base Case +25%)***
   a. Theme: upper bound on reference avoided costs
   b. Annual load growth: Upper bound on reference avoided costs
   c. Gas price: reference + 25%
   d. Generic supply-side resource cost: $0.14/kWh
3. ***Current Trends – 10% (/Base Case -10%)***
   a. Theme: lower bound on reference avoided costs
   b. Load growth: lower bound on reference avoided costs
   c. Gas price: reference – 10%
   d. Generic supply-side resource cost: $0.10/kWh
4. ***Low Growth (Reduced Growth)***
   a. Theme: lower regional and PSE load growth based on lower long-term economic growth
   b. Load demand: Low 1.3%
   c. Gas price: forward marks for 2008-2009, and Global Insights long run low forecast
   d. Generic supply-side resource cost: $0.09/kWh
5. ***Green World (Robust Growth)***
   a. Theme: support for stronger environmental legislation at the federal level, with continuation of state level RPS
   b. Load demand: lower
   c. Gas price: forward marks for 2008-2009, and Global Insights long run high case forecast.
   d. Generic supply-side resource cost: $0.13/kWh

Economic potentials for each of the five DSM resources under these scenarios were recalculated to reflect the effects of these scenarios on avoided costs. Total costs for each resource show the net-present value of the 20-year life cycle costs in 2007 dollars, based on a discount rate of 8.4%. Achievable potentials were then estimated using identical methodology as in the base case. The results are shown in Table 19 and

Table 20.

Table 19. Electric Achievable Resource Potentials Under Alternative Scenarios

Scenario	Energy Efficiency	Emerging Technology	Fuel Conversion	Demand Response	Distributed Generation	Distributed Generation Emerging Tech
Current Trends						
Potential	341 aMW	14 aMW	26.0 aMW	122 MW	36.0 aMW	40.1 aMW
Cost ($000)	$929,762	$21,378	$21,314	$73,881	$72,695	$ 83,419
Current Trends + 25%						
Potential	367 aMW	15 aMW	26.0 aMW	122 MW	40.1 aMW	40.1 aMW
Cost ($000)	$1,127,198	$22,947	$21,314	$73,881	$92,488	$ 91,063
Current Trends -10%						
Potential	330 aMW	14 aMW	25.7 aMW	122 MW	36.0 aMW	40.1 aMW
Cost ($000)	$841,791	$20,988	$20,917	$73,881	$70,355	$80,362
Low Growth						
Potential	321 aMW	14 aMW	22.0 aMW	122 MW	34.0 aMW	40.1 aMW
Cost ($000)	$766,316	$21,001	$17,673	$73,881	$60,864	$76,379
Green World						
Potential	358 aMW	14 aMW	26.0 aMW	122 MW	36.0 aMW	36.0 aMW
Cost ($000)	$1,029,508	$21,953	$21,314	$73,881	$79,156	$78,266

Table 20. Gas Achievable Potential Under Alternative Scenarios

Scenario	Energy Efficiency	Emerging Technology	Fuel Conversion (Additional Gas Use)
Base Case			
Achievable Potential (1000Dth)	69,195	3,779	1,218
Cost ($000)	$203,779	$6,065	$21,314
Base Case + 25%			
Achievable Potential (1000Dth)	97,926	3,530	1,218
Cost ($000)	$403,461	$5,819	$21,314
Base Case -10%			
Achievable Potential (1000Dth)	64,843	3,807	1,200
Cost ($000)	$171,600	$6,073	$20,917
Robust Growth/Green World			
Achievable Potential (1000Dth)	90,308	3,692	1,218
Cost ($000)	$352,399	$5,782	$21,314
Reduced Growth			
Achievable Potential (1000Dth)	56,989	3,675	1,001
Cost ($000)	$141,236	$5,684	$17,673

Price changes generally appear to have no appreciable effect on electric energy efficiency potentials, particularly for emerging technologies, due to the relatively low per-unit costs of these resources. Electric resource levels proved generally stable under all scenarios. For example, a decline of nearly 20% from the highest to the lowest price scenario was shown to result in a modest 6% decrease in potentials. The results of the analysis indicate almost no effect on quantities of demand response potentials.

Examination of natural gas resources under alternative scenarios (

Table 20) however, indicates a more dramatic change in quantities in response to various price assumptions, particularly in energy efficiency based on existing technologies. (Note that fuel conversion figures in

Table 20 indicate an increase in gas consumption and not a savings potential.) As shown in

Table 20, achievable gas conservation potentials may be expected to grow by nearly 42% as a result of a 25% increase in prices above the base-case forecast. More extreme price fluctuations (for example from the low-growth scenario to 25% above the base-case) are likely to produce changes of nearly 72% in resource potentials.

The impacts on fuel conversion options seem more moderate, since the base case is already high on the supply curve. For example, a 15% drop in avoided costs from the highest to the lowest case is shown to produce a less than 20% decline in the potentials for this resource.

7. Methodology for Estimating Potentials

1- Technical Potentials

Technical potential assumes that all demand-side resource opportunities may be captured, regardless of their costs or market barriers. For demand-side resources such as energy efficiency and fuel conversion, technical potentials further fall into two classes: “instantaneous” (retrofit) and “phased-in” (lost-opportunity) resources. The assessment of technical potentials in this study were based on an end-use modeling approach. Simply stated, the approach involves first producing an end-use level forecast assuming “frozen” end-use efficiencies, which is then calibrated to the Company’s system load forecast. A second forecast is then generated, taking into account the impacts of technically feasible demand-side measures. Technical resource potentials are then calculated as the difference between the two forecasts. The methodology underlying the estimation of technical potentials was based on an end-use modeling approach, consisting of two main steps as follows.

1. ***Baseline forecasts***. The development of an accurate baseline—including the present stock of equipment efficiency characteristics and expected changes in stock equipment efficiencies over the planning horizon due to codes, standards, and naturally-occurring conservation—was an essential step to accurately portray the size of conservation resources.
2. ***Estimation of technical, economic, and achievable potential***. The incorporation of technical measure data, economic analysis, and market constraints into the end use forecasting framework allowed the development of alternative scenarios that provided traditional estimates of technical, economic, and achievable potential.

Market Segmentation

The first step in segmentation was to determine the appropriate building types within each sector. These designations came from PSE’s end-use equipment survey for the residential sector, and from PSE’s classification of 2005 sales by building type for the commercial and industrial sectors. Next, appropriate end uses for each sector were determined and mapped to building types within each. Not all end uses within a sector were mapped to every building type (cooking was not mapped to warehouses, e.g.). Table 21 to Table 23 show the building types and end uses for both gas and electric for each sector.

Within each segment, inputs were analyzed separately for different construction vintages. For residential customers, four vintages were analyzed: homes built before 1980, from 1980 to 2000, from 2000 to 2007, and new construction over the planning horizon. For commercial customers, the three vintages were: buildings constructed before 1995, from 1995 to 2007, and new construction over the planning horizon. Industrial customers were split into two vintages: those constructed before 2007 and those constructed over the planning horizon.

Table 21. Residential Sector Dwelling Types and End-Uses

Residential Segments	Electric End Uses	Gas End Uses
Single Family	Space Heat	Space Heat
Multifamily	Heat Pump	Water Heat
Manufactured Home	Central AC	Cooking
	Room AC	Dryer
	Lighting	
	Water Heat	
	Refrigeration	
	Freezer	
	Cooking	
	Dryer	
	Plug Load	

Table 22. Commercial Sector Building Types and End-Uses

Commercial Segments	Electric End Uses	Gas End Uses
Office	Space Heat	Space Heat
Dry Goods Retail	Cooling Chillers	Water Heat
Restaurant	Cooling DX	Cooking
Grocery	Cooling Heat Pump	Pool Heat
Warehouse	HVAC Aux	
School	Lighting	
University	Water Heat	
Hospital	Refrigeration	
Hotel Motel	Cooking	
Other	Plug Load	

Table 23. Industrial Segments and End-Uses

Industrial Segments	Electric End Uses	Gas End Uses
Food Manufacturing	HVAC	HVAC
Wood Product Manufacturing	Indirect Boiler	Process - Boiler
Paper Manufacturing	Lighting	Process - Heat
Printing Related Support	Process Electro-Chemical	Process - Other
Chemical Manufacturing	Process Heat	
Petroleum and Coal Products	Process Other	
Plastics and Rubber Products	Process Cooling	
Nonmetallic Mineral Products	Process Motors - Fans	
Primary Metal Manufacturing	Process Motors - Pumps	
Fabricated Metal Products	Motors – Air Compression	
Industrial Machinery	Motors - Refrigeration	
Electrical Equipment Manufacturing	Process Motors - Other	
Transportation Equipment Manufacturing		
Computer Electronic Manufacturing		
Miscellaneous Manufacturing		

Baseline Forecasts

Before potentials could be estimated, an appropriate and accurate baseline end use forecast for each of PSE's fuels sectors needed to be created. The purpose of these baseline forecasts was to partition PSE's customers and sales by:

- Fuel: natural gas and electric
- Customer sector: residential, commercial, and industrial;
- Customer segments: dwellings, business types, and industries within the residential, commercial, and industrial sectors, respectively, for both existing and new construction vintages; and
- End uses: all major end uses applicable for each customer segment.

The breakdown of PSE's customers and sales into the three sectors was based on an analysis of detailed customer account information. Sales and customer forecasts were provided at the sector level, and 2005 sales data and PSE's Residential Appliance Saturation Survey (RASS) were used to distribute these forecasts into the various building types for each sector. For each customer segment, appropriate end uses were defined based on available data.

Once the appropriate segmentation was selected for each sector, baseline end-use forecasts were developed by combining current and forecasted customer counts with key market and equipment usage data. For commercial and residential sectors, the end-use-model-derived annual baseline end-use electricity consumption was calculated in each market segment as shown in equation (1) as follows:

$$EUSE_{ij} = \Sigma_e\, ACCTS_i * UPA_i * SAT_{ij} * FSH_{ij} * ESH_{ije} * EUI_{ije} \qquad (1)$$

where:

$EUSE_{ij}$ = total energy consumption for end use *j* in building type *i*;

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

UPA_i = the units per account in segment *i* (UPA_i is generally the average square feet per customer in commercial segments and 1.0 in residential dwellings);

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

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

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

EUI_{ije} = energy consumption per customer (per square foot for commercial) use by the equipment configuration *ije.*

Total annual consumption in each sector was then determined by summing $EUSE_{ij}$ across the end uses and customer segments. The key to ensuring accuracy of the baseline forecasts was to calibrate the end-use model estimates of total consumption to forecasted PSE sales in 2007. This calibration to base year sales was based on making appropriate adjustments to the data where necessary to conform to known information about customer counts, appliance and equipment saturations, and fuel shares from a variety of sources.

Due to the more complex nature of the industrial market, end uses, and equipment on the one hand, and the lack of reliable information on measure-specific saturations on the other, the breakdown of the industrial segments were analyzed using an alternative approach. Instead of using such detailed data, the total industrial loads were broken into major end uses within each class using data from the U.S. Department of Energy’s Energy Information Administration.

Based on the segmentation design and end use data, a baseline forecast is created for each fuel and sector combination. This forecast is then calibrated to each year of PSE’s econometric sales forecast so that potential estimates will be consistent with PSE’s expected sales. The baseline forecasts for electric and gas for each sector are shown in Figure 26 and Figure 27, respectively.

Figure 26. 20-Year Electric Sales Forecast by Sector

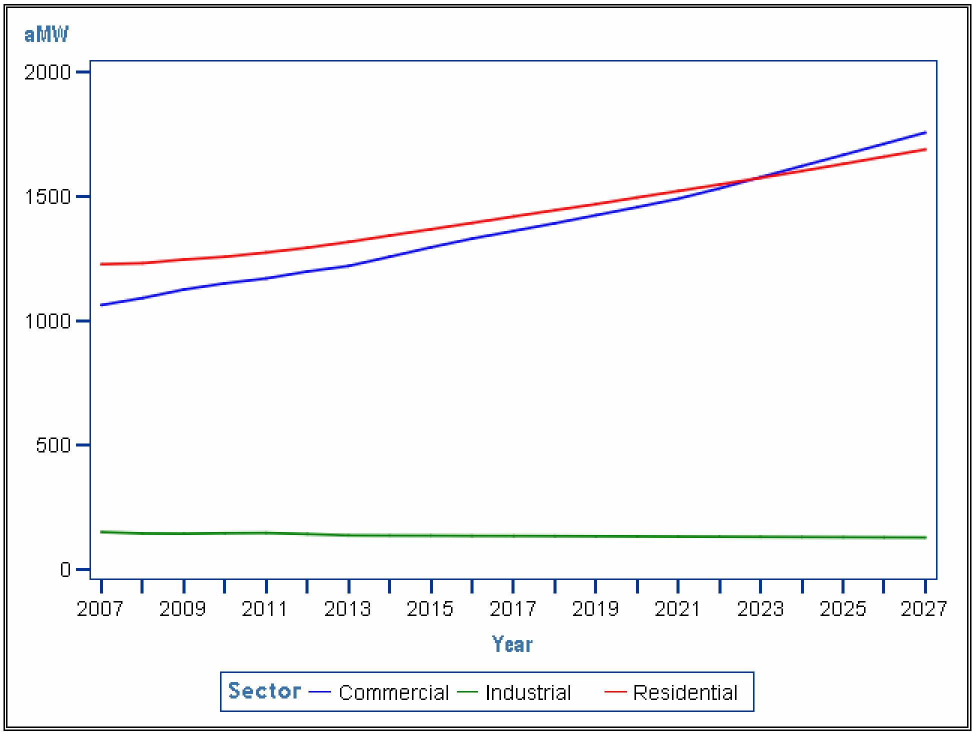
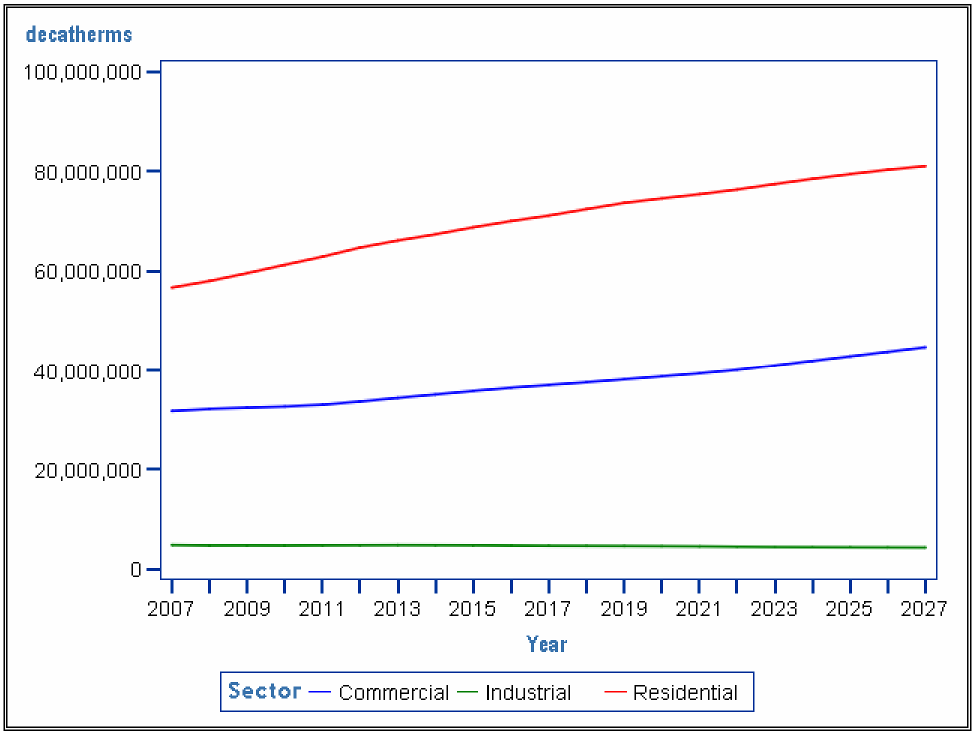


Figure 27. 20-Year Natural Gas Sales Forecast by Sector



Derivation of End-Use Consumption Estimates

Unit Energy Consumption (UEC) and End-Use Indices (EUI) are used to calibrate the End Use Forecasts for residential and commercial sectors, respectively. These represent the amount of energy that goes toward a specific end use in a year. The UEC is given in kWh or therms per year, while the EUI is given in kWh or therms per sq. ft. per year. The choice of UEC or EUI is critical to determine the overall EE potential. Baseline values are typically sourced from previous studies, by building simulation models, from statistical analysis, and/or from engineering experience, and are based on existing prototypical building types within the region. UECs are appropriate in the residential sector because of the homogeneity of energy use within each segment. However, due to the diversity within a particular segment of the commercial sector, UECs are not as appropriate and EUIs are used instead. Estimates of average square footages by commercial building segment were obtained from the 2003 Commercial Building Stock Assessment (CBSA) and PSE's 1994 Commercial End Use Survey.

Residential Sector

For the residential sector, the UECs and sources for single-family (SF) homes are given in Table 24 and Table 25 below for existing and new construction. The sources for the UECs are either from the 2005 IRP or from Conditional Demand Analysis (CDA). More details on the results of CDA analysis are given in Appendix G.

Table 24. Single-Family Electric UECs

End Use	UEC (kWh/yr)		Source
	Existing	New	
Central AC	384	370	Single-family conditional demand model
Cooking	890	761	PSE gas facilities extensions tariff - converted to electric.
Dryer	1275	868	Single-family conditional demand model or PSE gas extensions tariff - converted to electric.
Freezer	823	593	2005 IRP.
Heat Pump	4990	3272	2005 IRP
Lighting	2240	2240	2005 IRP
Plug Load	3389	3389	2005 IRP
Refrigeration	848	676	2005 IRP
Room AC	248	230	Multi-Family conditional demand model normalized by SF to MF number of occupants ratio.
Space Heat	8008	3817	2005 IRP
Water Heat	3510	2908	Single-family conditional demand model

Table 25. Single-Family Gas UECs

End Use	UEC (therms/yr)		Source
	Existing	New	
Cooking	50	43	PSE facilities extensions tariff.
Dryer	49	33	PSE facilities extensions tariff
Space Heat	670	515	Single-family Conditional demand model calibrated to existing use
Water Heat	259	304	Single-family conditional demand model calibrated to existing use

In the cases where the SF UEC was recalculated (not taken from the earlier IRP study), the UEC for multi-family and manufactured homes was found by normalizing the SF UEC by the ratio of the number of occupants or by square footage between it and the SF home. Otherwise, the source was the 2005 IRP, as for SF homes. Table 26 through 29 show the UEC values and their sources for each fuel, dwelling type and construction vintage.

Table 26. Multi-Family Electric UECs

End Use	UEC (kWh/yr)		Source
	Existing	New	
Central AC	212	205	Apply square footage ratio to SF UECs.
Cooking	670	574	Apply number of occupants ratio to SF UECs.
Dryer	960	654	Apply number of occupants ratio to SF UECs.
Freezer	599	431	2005 IRP
Heat Pump	1985	1302	MF new building type normalized by SF new and existing UECs
Lighting	1514	1514	2005 IRP
Plug Load	1534	1534	2005 IRP
Refrigeration	654	638	2005 IRP
Room AC	186	177	Multi-Family conditional demand model.
Space Heat	2773	1519	2005 IRP
Water Heat	2644	2191	Apply number of occupants ratio to SF UECs.

Table 27. Multi-Family Gas UECs

End Use	UEC (therms/yr)		Source
	Existing	New	
Cooking	36	30	PSE facilities extensions tariff. Apply number of occupants ratio to SF UECs.
Dryer	35	24	PSE facilities extensions tariff. Apply number of occupants ratio to SF UECs.
Space Heat	315	245	Calibrated SF conditional demand model UEC to MF new and existing use
Water Heat	184	216	Calibrated SF conditional demand model UEC to MF. Apply occupants ratio to SF UECs.

Table 28. Manufactured Home Electric UECs

End Use	UEC (kWh/yr)		Source
	Existing	New	
Central AC	531	433	Apply square footage ratio to SF UECs.
Cooking	747	639	Apply number of occupants ratio to SF UECs.
Dryer	1070	729	Apply number of occupants ratio to SF UECs.
Freezer	808	579	2005 IRP
Heat Pump	5320	3489	MH new building type normalized by SF new and existing UECs
Lighting	2227	2227	2005 IRP
Plug Load	1266	1266	2005 IRP
Refrigeration	854	680	2005 IRP
Room AC	208	208	Multi-Family conditional demand model normalized by MH to MF number of occupants ratio.
Space Heat	9184	4070	2005 IRP
Water Heat	2947	2441	Apply number of occupants ratio to SF UECs.

Table 29. Manufactured Home Gas UECs

End Use	UEC (therms/yr)		Source
	Existing	New	
Cooking	41	35	PSE facilities extensions tariff. Apply number of occupants ratio to SF UECs.
Dryer	40	27	PSE facilities extensions tariff. Apply number of occupants ratio to SF UECs.
Space Heat	405	311	Calibrated SF conditional demand model UEC to MF new and existing use
Water Heat	211	248	Calibrated SF conditional demand model UEC to MF. Apply occupants ratio to SF UECs.

Commercial Sector

For this study, the majority of the data is sourced from the PSE 2005 IRP as well as from professional engineering judgment. Table 30 and Table 31 represent the electric and gas EUIs for existing commercial buildings. Note that for the Gas EUIs, all the numbers are taken from the earlier IRP filing.

Table 30. Electric EUIs for Commercial Sector by Building Type (kWh/sq. ft. per Year)

Building Type	Space Heat	Cooling DX	Vent / HVAC Aux	Lighting	Water Heating	Cooking	Refrigeration	Misc. Equip
Office	4.5	6.5	2.3	5.0	0.3	-	-	1.6
Grocery	1.4	11.6	5.4	12.1	1.7	5.2	24.2	0.4
Retail	0.9	2.1	0.7	5.7	0.2	-	-	0.1
Restaurant	7.2	9.0	4.0	8.6	4.2	52.4	5.8	0.2
Warehouse	0.8	2.7	1.7	2.9	0.0	-	-	0.1
Hotel Motel	4.8	2.6	0.6	2.9	3.9	-	-	0.1
School	9.7	0.5	0.8	2.2	0.7	-	-	0.1
University	4.0	6.5	1.0	4.4	0.6	-	-	0.3
Hospital	4.6	15.5	2.7	10.2	2.1	-	-	0.5
Other	4.6	4.4	1.9	2.0	0.3	-	-	0.1

Sources: PSE 2005 IRP, except for all Water Heating end use, and Space Heat end use for Office and University building types (shaded blue), where engineering expertise determined an appropriate EUI based on analysis and previous project experience.

Table 31. Gas EUIs for Commercial Buildings by End Use (therms/sq. ft. per Year)

Building Type	Space Heat	Water Heating	Cooking	Pool Heat
Office	0.2	0.1	-	-
Grocery	0.2	0.3	0.7	-
Retail	0.1	0.0	-	-
Restaurant	0.1	0.8	1.7	-
Warehouse	0.1	0.0	-	-
Hotel Motel	0.1	0.8	-	0.11
School	0.2	0.3	0.0	0.17
University	0.3	0.4	0.0	0.14
Hospital	0.5	0.4	0.1	0.03
Other	0.2	0.2	-	-

Source: PSE 2005 IRP .

For new construction, most of the EUIs are identical except for lighting (electric) and pool heat (gas). The new EUIs reflect changes in building code requiring more efficient light fixtures and advances in pool heaters. The values for new construction are given in Table 32 below.

Table 32. EUIs for Commercial New Construction

Building Type	Lighting (kWh/yr)	Pool Heat (therms/yr)
Office	3.9	-
Grocery	9.6	-
Retail	4.4	-
Restaurant	7.5	-
Warehouse	2.4	-
Hotel Motel	2.8	0.06
School	1.9	0.03
University	4.0	0.05
Hospital	8.5	0.02
Other	1.7	-

Industrial Sector

In the industrial sector, a top-down approach was employed to allocate consumption to end uses. Industry-specific data were gathered to distribute the total building load into the major end uses within that industry. The percentage of load that falls into each end use is shown in Table 33 and Table 34, for electric and gas, respectively. The end-use breakout for the industrial building types was taken from the Energy Information Agency's 2002 Manufacturing Energy Consumption Survey (MECS).

Table 33. Industrial Electric Consumption by Industry Type and End Use

Industry Type	HVAC	Lighting	Indirect Boiler	Process Heat	Process Cool	Process Electro Chemical	Process Motors Fans	Process Motors Pumps	Process Motors Refrigeration	Process Motors Air Compression	Process Motors Other	Process Other	Other
Chemical Manufacturing	6%	4%	1%	3%	9%	18%	7%	15%	4%	16%	15%	0%	2%
Computer Electronic Manufacturing	29%	13%	0%	11%	9%	1%	5%	7%	1%	1%	9%	3%	11%
Electrical Equipment Manufacturing	17%	13%	0%	19%	4%	3%	4%	9%	3%	10%	10%	1%	8%
Fabricated Metal Products	10%	9%	0%	23%	3%	1%	6%	11%	3%	7%	17%	0%	9%
Food Manufacturing	7%	7%	1%	3%	25%	0%	4%	8%	15%	4%	19%	0%	7%
Industrial Machinery	18%	14%	0%	7%	3%	1%	7%	12%	3%	8%	19%	1%	7%
Miscellaneous Manufacturing	20%	15%	9%	9%	6%	0%	6%	3%	0%	5%	22%	0%	4%
Nonmetallic Mineral Products	6%	5%	0%	20%	3%	0%	8%	15%	4%	9%	23%	1%	4%
Paper Manufacturing	4%	4%	3%	2%	1%	2%	16%	25%	4%	4%	32%	0%	2%
Petroleum Coal Products	3%	2%	1%	6%	6%	0%	11%	20%	5%	13%	31%	0%	1%
Plastics Rubber Products	10%	8%	0%	15%	8%	0%	7%	13%	4%	9%	21%	1%	3%
Primary Metal Manufacturing	4%	3%	0%	28%	1%	31%	5%	3%	0%	5%	20%	0%	1%
Printing Related Support	18%	11%	0%	2%	4%	0%	7%	12%	3%	8%	19%	0%	14%
Transportation Equipment Manufacturing	19%	15%	0%	10%	5%	1%	5%	11%	3%	12%	12%	1%	4%
Wood Product Manufacturing	7%	7%	1%	5%	1%	0%	10%	18%	5%	11%	28%	0%	8%

Table 34. Industrial Gas Consumption by Industry Type and End Use

Industry Type	HVAC	Process Boiler	Process Heat	Process Other	Other
Chemical Manufacturing	2%	55%	35%	6%	2%
Computer Electronic Manufacturing	32%	41%	14%	2%	11%
Electrical Equipment Manufacturing	29%	12%	53%	0%	6%
Fabricated Metal Products	21%	16%	62%	1%	0%
Food Manufacturing	7%	51%	38%	5%	0%
Industrial Machinery	37%	18%	37%	3%	6%
Miscellaneous Manufacturing	33%	30%	27%	0%	10%
Nonmetallic Mineral Products	5%	3%	86%	0%	6%
Paper Manufacturing	4%	61%	26%	5%	5%
Petroleum Coal Products	1%	33%	60%	2%	4%
Plastics Rubber Products	19%	38%	29%	2%	11%
Primary Metal Manufacturing	7%	11%	80%	0%	2%
Printing Related Support	34%	20%	41%	2%	2%
Transportation Equipment Manufacturing	32%	26%	32%	2%	7%
Wood Product Manufacturing	13%	27%	49%	4%	7%

Measures Considered

For the residential and commercial sectors, the study began with a broad range of energy-efficiency measures for possible inclusion in the study. These measures were screened to include only measures that are commonly available, based on well-understood technology, and applicable to PSE's buildings and end uses. The industrial sector, in contrast, was based on general categories of process improvements. Table 35, Table 37, and Table 39 show the types of energy efficiency measures that were assessed in the residential, commercial, and industry sectors, respectively. Table 36 and Table 38 show the types of emerging technology measures that were assessed in the residential and commercial sectors, respectively. Equipment measures are those that replace end use equipment (e.g. high efficiency central air conditioners), while retrofit measures are those that reduce end use consumption without replacing end use equipment (insulation, e.g.) A complete list of all electric and gas measures, with descriptions, is given in Appendix A.

Table 35. Residential Energy-Efficiency Measures

End-Use	Measure Types
Heating and Cooling	• Retrofit: air-to-air heat exchangers; ceiling, wall (above and below grade), floor and rim joist insulation; insulated exterior doors; infiltration reduction; duct sealing and insulation; programmable thermostats; tune-up; windows; Northwest ENERGY STAR Manufactured and Single Family homes (shell measures included only). • Equipment:: high-efficiency heat pumps; high-efficiency central AC; ENERGY STAR room AC; high-efficiency gas furnaces.
Lighting	• Retrofit: CFLs; CFL fixtures.
Water Heating	• Retrofit: hot water pipe insulation; faucet aerators; low flow showerheads; temperature setback; ENERGY STAR dishwashers and clothes washers; solar water heaters; drain water heat recovery. • Equipment:: high efficiency water heaters; heat pump water heaters; solar water heaters.
Appliances	• Retrofit: removal of old (inefficient) appliances; ENERGY STAR DVD systems; ENERGY STAR digital set top receiver; ENERGY STAR HDTV; ENERGY STAR office equipment (copiers, monitors, printers and computers); external power adaptors; power strip with occupancy sensor. • Equipment:: ENERGY STAR freezers and refrigerators.

Table 36. Residential Emerging Technology Measures

End-Use	Measure Types
Heating and Cooling	• Retrofit: 'Check Me' and PTCS aerosol-based duct sealing; green roof (eco-roof); leak proof duct fittings; micro channel heat exchangers; small scale absorption cooling; solid state refrigeration cool chips (heat pump only). • Equipment:: advanced cold-climate heat pump
Lighting	• Retrofit: LED interior lighting.
Appliances	• Retrofit: advanced appliance motor (ECM) for a dryer; 1-Watt standby power; solid state refrigeration. • Equipment:: 1 kWh/day refrigerator.

Table 37. Commercial Energy Efficiency Measures

End Use	Measure Types
HVAC	• Retrofit: 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. • Equipment:: high-efficiency heat pumps; high-efficiency chillers and DX packages; high-efficiency gas furnace/boiler.
Lighting	• Retrofit: reduce power density; CFLs; continuous dimming and stepped dimming controls; occupancy sensors; refrigeration lighting and exit signs; integrated classroom lighting; bi-level control stairwell lighting; low-wattage ceramic metal halide; induction lighting.
Water Heating	• Retrofit: hot water pipe insulation; temperature setback; chemical dishwashing systems; demand controlled circulating systems; showerheads; faucet aerators; commercial clothes washers; chemical dishwashers.

End Use	Measure Types
	• Equipment:: high-efficiency water heaters (gas only); solar water heaters (electric and gas); and tank-less water heaters.
Refrigeration	• Retrofit: high-efficiency compressors; demand control defrost; humidistat controls; display case night covers; commissioning; strip curtains; floating condenser heads; case fans; reduced speed or cycling of evaporator fans.
Other	• Power burner fryer; solar pool/spa heating system; swimming pool/spa covers; optimized variable volume lab hood; ENERGY STAR office equipment (copiers, computers, monitors and printers); vending machines (optimization of controls and equipment).

Table 38. Commercial Emerging Technology Measures

End Use	Measure Types
HVAC	• Retrofit: active window insulation; automated building diagnostics SW; green roof; hotel key card room energy control system; leak proof duct fittings.
Lighting	• Retrofit: advanced HID lighting; advanced daylighting controls; cost-effective load shed ballast and controller; hospitality lighting; hybrid solar lighting; LED solid state white lighting; low-wattage ceramic metal halide; scotopic lighting;
Refrigeration	• Retrofit: high-efficiency fan w/ECM motors.
Other	• Under floor ventilation with low static pressure.

Again, due to the more complex nature of the industrial sector, the measures used are not at the same level of detail. Instead, the industrial measures are aggregates, such that often only one or two measures correspond to an end use. The savings and cost information were found by relying on available data from energy-efficiency programs in the Northwest and California, the Department of Energy, and market information on PSE's customers available from industrial accounts representatives.

Table 39. Industrial Conservation Measures

Electric Measure Types	Gas Measure Types
Lighting Improvements	Process Boiler Upgrades
Process Cooling Improvements	Process Boiler O&M
Fan System Improvements	Steam Distribution Systems
Pump System Improvements	HVAC Improvements
Air Compressor Improvements	
Air Compressor O&M	
Refrigeration Improvements	
Other Motor System Improvements	
HVAC Improvements	

Estimating Technical Potentials

As described in previous sections, once the baseline forecasts are established, the next step is estimating technical potential. This consists of creating an alternative forecast where all possible measures are installed, and subtracting this forecast from the baseline to calculate savings by end use, building type, sector, and fuel.

The following steps were required to develop the inputs underlying this alternative forecast scenario:

1. ***Determine measure impacts.*** The starting point in the assessment of measure impacts was the collection of a variety of inputs necessary to perform the analysis:

   Measure savings: The energy savings associated with a measure as a percentage of the total end-use consumption. Sources include engineering calculations, secondary data sources (case studies), previous 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 merchant websites (Lowes, Home Depot, Sears, Trane, etc.), DEER database, RS Means, and previous studies.

   Measure life: The expected lifetime of the measure. Sources include DEER database and previous studies.

   Measure applicability: A general term that encompasses a number of factors, including the technical feasibility of installation, the current or naturally occurring saturation of the measure, as well as factors to allocate the savings associated with mutually exclusive measures.

   For equipment measures, the savings were estimated based on a shift of all baseline shares to the highest efficiency level. That is, each of the efficiency levels has some baseline share associated with it. These shares include the impacts of federal codes and standards and the small penetration of high-efficiency equipment that occurs without market intervention. In the technical potential scenario, the baseline shares were overridden by shares where 100% of the new or replaced equipment goes to the highest efficiency level. The savings associated with equipment, then, are calculated as the difference between the baseline and equipment replacement scenarios. That is, the estimated savings are essentially an output of the end-use modeling process.

   For non-equipment (or “retrofit”) measures, the estimated savings are better characterized as an input to the model. More specifically, for each end use in each segment, the cumulative effect of the bundle of eligible measures was incorporated into the end-use model as a percentage adjustment to the usage associated with that segment and end-use combination.

   Where there is only one measure that affected an end use, this percentage adjustment would simply be the measure’s percentage savings. However, in nearly every instance in this study there were multiple measures affecting the end use, so a specific methodology was employed to assess the cumulative impacts of all the measures in the bundle.

Table 40. Measure Applicability Factors

	Measure Impact	Explanation	Sources
All Measures	Fuel Saturation	The percentage of customers that use a particular fuel (gas or electric) in PSE's territory for the specific end use (e.g., water heat, space heat, etc.).	• Residential-RES • Commercial-CBSA
	End-Use Saturation	The percentage of customers that have the specific end use. (If not all residential customers had a central AC unit, for example, the end-use saturation would be less than 100%.)	• Residential-RES • Commercial-CBSA
	Measure Share	Used to distribute the percentage of market shares for competing measures (e.g., solar water heater and heat pump water heater both have a 50% measure share of the market share).	• Engineering Judgment • Secondary Data Sources
	Measure Incomplete Factor	Represents the percentage of buildings that do not have the specific measure currently installed.	• 2003 PSE Data Tracking System • Engineering Judgment
	Technical Feasibility	Accounts for the percentage of buildings that can physically install the measure. A couple of factors that may affect this percentage include 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).	• Secondary Data Sources • Engineering Judgment
	Measure Interaction	Only considered for lighting. This percentage accounts for additional heating required by the HVAC system because of a reduction in heating produced by more energy-efficient lighting	• Energy Simulation Modeling (eQuest) • Engineering Judgment
Emerging Technology (ET) Measures and Those Measures Competing w/ ET	Year Introduced	Shows the year that the measure is expected to be commercially available (varies from five, to ten, 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: RES: Residential Energy Survey; CBSA: Commercial Building Stock Assessment; ACEEE 2004: Emerging Energy-Savings Technologies and Practices for the Buildings Sector as of 2004 (Report A042).

For the single measure case, Equation (2) below shows the basic equation for estimating *retrofit* or *new construction shell/plumbing measure* savings, where the impact is defined as a measure that changes the annual consumption of an end use without affecting the basic end-use equipment. The classic example of this is additional insulation in existing or new buildings. The insulation reduces consumption without changing the basic HVAC equipment in the building.

$$SAVE_{ijm} = EUI_{ije} * PCTSAV_{ijem} * APP_{ijem} \tag{2}$$

where:

$SAVE_{ijm}$ = annual energy savings for measure m for end use j in building type i;

EUI_{ije} = calibrated annual end-use energy consumption for the equipment configuration ije;

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

APP_{ijem} = a fraction that represents a combination of different factors that determine a measure's overall applicability, including the technical feasibility, existing measure saturation, end-use interaction, and any adjustments needed to allocate savings with other mutually-exclusive measures.

As stated previously, however, the study dealt almost exclusively with cases where multiple measures affected a single end use. In such instances, the assessment of cumulative impact had to account for the interaction among the various measures, a treatment referred to as "measure stacking." The primary means to account for stacking effects is to establish a rolling, reduced baseline that is applied iteratively as measures in the stack are assessed. This is shown in equations (3) through (5), where measures 1, 2, and 3 are applied to end use life:

$$SAVE_{ij1} = EUI_{ij\,e} * PCTSAV_{ije1} * APP_{ije1} \tag{3}$$
$$SAVE_{ij2} = (EUI_{ije} - SAVE_{ij1}) * PCTSAV_{ije2} * APP_{ije2} \tag{4}$$
$$SAVE_{ij3} = (EUI_{ije} - SAVE_{ij1} - SAVE_{ij2}) * PCTSAV_{ije3} * APP_{ije3} \tag{5}$$

The result of this process was that a measure's absolute savings as part of a bundle of measures was less than its savings on its own. These two measures of absolute savings were referred to as "stand-alone" and "stacked" savings. Note that a measure's order in the stack had an effect on its absolute savings. For this study, the order was based on ascending levelized cost of each measure, which ensured that the least expensive resources were incorporated first.

2. ***Estimate phased-in technical potential.*** Estimates of technical conservation potential were developed by incorporating the measure impacts into four alternative scenarios to the baseline forecast that reflect the four resource categories presented in the introductory section:

1) Equipment in existing construction
2) Retrofit measures in existing construction
3) Equipment in new construction
4) Shell and plumbing upgrades in new construction

As described above, for each of the equipment measure scenarios, the baseline efficiency shares were shifted from the baseline to 100% for the highest efficiency. In effect, any equipment either in new construction or replacement on burnout was shifted to the highest efficiency. For non-equipment measure scenarios, the measure impacts were incorporated to develop revised estimates of baseline consumption across all efficiency levels for a given end-use.

2- Economic Potential

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

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

where:

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

and

$$TRCCosts = MeasureCost$$

Benefits include the value of time- and seasonally-differentiated energy and capacity savings, transmission and local distribution cost savings, deferred-transmission system expansion costs and the conservation credit granted by the Northwest Power Act.[19] In order to capture the full value of time- and seasonally-differentiated impacts of each measure, a unique hourly benefits profile was calculated for each measure as the product of the measure's hourly end-use load

[19] The Pacific Northwest Power Planning and Conservation Act mandates that "the "estimated incremental system cost" of any conservation measure or resource shall not be treated as greater than that of any non-conservation measure or resource unless the incremental system cost of such conservation measure or resource is in excess of 110 per centum of the incremental system cost of the non-conservation measure or resource." [Northwest Power Act, §3(4)(D), 94 Stat. 2699.]

shape and hourly avoided costs. This approach in effect produces a unique hourly (8760) 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 and costs are calculated by discounting future streams at PSE's weighted average cost of capital. The basis and assumptions underlying the calculation of resource benefits and costs are summarized below.

Resource Benefit Components

- Avoided hourly generation (energy) costs: Variable, a function of measure load shape
- Avoided annual generation (capacity) costs: \$35/kW/year until 2012, and \$90/kW/year thereafter
- Avoided line losses: 6.7% for electricity and 0.8% for natural gas
- Avoided transmission system expansion costs: \$32/kW/year
- NW regional conservation credit: 10% (energy efficiency and demand response only)
- Discount Rate: weighted average cost of capital (8.4% per year)
- Administration Costs: 10% of measure costs

Resource Cost Components

- Capital measure costs: Variable by measure
- Installation labor costs: Variable by measure
- On-going O&M costs: Variable by measure
- Additional "other" fuel costs: Fuel conversion and distributed generation
- Discount Rate: weighted average cost of capital (8.4% per year)

There are three important considerations in interpreting the results of economic screening as it relates to the assessment of conservation potentials. First, the analysis is based on a total resource cost (TRC) perspective and as such no conclusions may be drawn as to how the measure costs might accrue to the utility and participants in energy efficiency programs. Indeed, it is implicitly assumed in the analysis that PSE would bear the full cost of measures. This consideration has important implications in terms of achievable potentials, since in most DSM programs the utility seldom pays the full incremental cost of the measure.

Second, the outcomes of the screening procedure described above depends 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. More important are the assumptions concerning the avoided costs. Clearly, as avoided costs change, so would the value of savings resulting from the installation of energy efficient technologies. So a measure failing the economic screen in earlier years of the planning period may become cost effective in later years if avoided costs increase. 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 economic screen within the context of the study, there could well be instances where the measure would be cost-effective.

3- Achievable Potential

Achievable potential is defined as that portion of economic potential that is expected to be reasonably achievable in the course of the planning horizon. Developing accurate estimates of achievable levels of conservation are a critical element in utility integrated resource planning. Understating achievable potential could lead to significant lost opportunities to the utility's resource acquisition process. On the other hand, if achievable potentials are overstated, unrealized conservation potentials would create gaps in the resource plan.[20]

Unfortunately, there are no standard methods for predicting actual levels of achievable potentials with certainty. In the majority of conservation potential studies, estimation of achievable potentials generally tends to be based on either arbitrary expectations of market penetration or the utility's past experience with energy efficiency programs. In the Northwest, for example, the Northwest Power and Conservation Council has historically assumed that 85% of the estimated economic potential is likely to be achievable.[21] In its 2004 IRP, PSE assumed that 50% of the economic potentials would be achievable.

In practice, levels of cost-effective conservation potentials that may be assumed achievable, depend on several factors, including customers' willingness to participate in conservation programs (or market potential), which is itself a function of incentive levels offered by the utility, energy prices, and non-price factors such as specific operational constraints that may prevent the customer from participating in conservation programs. It is, however, difficult to identify all such factors and to quantify their likely impacts without rigorous and systematic market studies.

In this study, we decided to rely on the experience and expert judgment of PSE's professional energy services staff. The energy services staff were surveyed in a modified Delphi framework to arrive at a consensus view on what would be a "reasonable" and "realistic" expectation for market penetration rates in various customer sectors and market segments. These estimates were developed by surveying PSE's energy services staff. Based on the results of this survey, summarized in Table 41, it was assumed that 85% and 65% of the economic electric energy efficiency potential in existing buildings and new construction markets respectively, are likely to be achievable in the course of the planning period. Achievable potentials for natural gas

[20] Accurate estimates of achievable potentials are particularly relevant in the context of Washington's Clean Energy Initiative, which directs utilities to pursue all cost-effective and "feasible" conservation with penalty provisions should utilities fail to meet such targets.

[21] The 85% figure might have its origin in Northwest's Hood River Conservation Project, a direct installation program implemented in Hood River, Oregon between 1983 and 1985. The project succeeded in achieving a market penetration of 85% of eligible households in the area. For a summary description of the project see Hood River Conservation Project Profile # 12, 1992, Bonneville Power Administration.

measures were assumed to begin at 55% (for existing buildings) and 35% (for new construction) of economic potentials during the early years of planning, and gradually ramp up to 75% and 55% for existing and new buildings respectively.

Rates for achievable potentials are assumed to be lower in the new construction market due mainly to issues concerning the concept of economically favorable “windows of opportunity” for equipment purchase decisions. The basic idea here is that the economic viability of investments in efficient equipment varies with the type and timing of construction activity. The size of economic windows varies depending on the specific equipment in question and on the timing of equipment purchase and installation. Although conservation resources in the new construction markets may be available at a lower cost than in retrofit markets, in order for the utility to intervene, it must synchronize its efforts with the normal cycle of new construction activity and act within limited windows of opportunity as they become available. This would require additional effort—and expenditures—for timely coordination with participants in the new construction market such as developers and A&A firms.

Table 41. 20 Year Market Penetration Rates by Fuel and Sector

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

The assumed levels of achievable potentials are meant to serve principally as planning guidelines. Ultimately, realizing these levels of demand-side opportunities will depend on the “market potentials” for various demand-side resources, which depend largely on factors beyond the Company’s control. Such factors include, among others, the customers’ willingness and ability to participate in the demand-side programs, administrative constraints, and availability of an effective delivery infrastructure. Clearly, the customer’s willingness to participate in demand-side programs depends on the amount of incentive that is offered. Depending on the actual experience of various programs in the future, PSE may consider alternative, more efficient and cost-effective means such as market transformation and promotion of codes and standards, in order to capture portions of these resources.

Appendix A: Measure Descriptions

Residential Electric Measure Descriptions

This section provides an overview of the selected energy-efficiency measure within the residential sector. The measures are categorized by end use. Discretionary (existing buildings) and Lost Opportunity- New Construction have many of the same measures within each end use and are thus grouped together. If significant differences in the TRC exist between the two applications, both TRCs will be given; otherwise, only an average TRC is given. Lost Opportunity—Equipment category includes additional measures and are given separately.. In addition, a description of emerging technologies is included at the end. A brief description of the current baseline technology and the energy measure is discussed. Percent savings and TRC are averaged over all applicable building types.

Lighting

Incandescent lighting is a highly inefficient light source; as such, significant savings can be gained by switching to fluorescent lighting.

Lighting measures for typical household applications are categorized by use: low (1 hr/day), medium (2.5 hr/day), and high (4 hr/day), representing frequency of use.

Table A–1. Residential Electric Lighting

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Lighting	CFL Lamps, Low Use	Incandescent 60W	9%	5.1
	CFL Lamps, Medium Use	Incandescent 60W	6%	9.4
	CFL Lamps, High Use	Incandescent 60W	43%	12.0
	CFL Fixtures, Low Use	Incandescent 2-60W	2%	0.7
	CFL Fixtures, Medium Use	Incandescent 2-60W	2%	1.7
	CFL Fixtures, High Use	Incandescent 2-60W	9%	2.7
	CFL Torchieres, Low Use	Incandescent Torchieres, 200W Halogen	1%	0.7
	CFL Torchieres, Medium Use	Incandescent Torchieres, 200W Halogen	1%	1.7
	CFL Torchieres, High Use	Incandescent Torchieres, 200W Halogen	3%	2.7

CFL Lamps, Torchieres and Fixtures

A 15W compact fluorescent light (CFL) can be a drop-in replacement for a 60W incandescent light, resulting in a 75% energy savings. Or, a 18W CFL torchiere can replace a 200W halogen—a 91% energy savings. A specific CFL fixture can also replace standard incandescent fixtures increasing the energy savings. The lighting usage is broken up such that high and low each constitute 20% of the total lighting while medium constitutes 60% of the total lighting.

Heating, Ventilation, and Air-Conditioning (HVAC)

Measures associated with the HVAC system improve the overall heating and cooling loads on the building. For residential buildings, only heating measures were considered, specifically those affecting the space heat and heat pump end uses.

Table A–2. Residential Electric HVAC

Category or End Use	Technology	Baseline	End-Use Percent Savings	TRC
Heat Pump or Space Heat	Air-to-Air Heat Exchangers	No Heat Exchanger	10%	0.2
	ENERGY STAR Home		36%	1.8
Heat Pump	“Check Me” Duct Sealing	No Duct Sealing	25%	2.2
	“Check Me” O&M Tune-Up	No Tune-Up	17%	1.3
Space Heat	Duct Insulation (R-8)	R-3	4%	1.3
	PTCS Duct Sealing	No Duct Dealing	14%	1.7
Envelope	Whole house air sealing		5%	0.6
	Insulated exterior entry doors	Non weather-stripped door	4%	0.3
	Insulation-Ceiling (R-38) Heat Pump	R-11	9%	0.9
	Insulation-Ceiling (R-38) Space Heat	R-11	9%	1.8
	Insulation-Floor (R-25) Heat Pump	R-0	11%	0.5
	Insulation-Floor (R-25) Space Heat	R-0	11%	1.0
	Insulation-Wall 2x4 (R-13)	R-0	10%	0.7
	Below Grade Insulation (R-11) Heat Pump	R-0	13%	0.6
	Below Grade Insulation (R-11) Space Heat	R-0	13%	1.2
	Insulation-Rim Joist (R-10)	R-0	2%	3.1
	ENERGY STAR Windows (Class 30)	Class 40	17%	0.5
	Spray-in Insulation R-26	R-13	30%	0.5

Air-to-Air Heat Exchangers

Advanced ventilation brings in fresh, outdoor air, but pre-heats the outside air with the warm exhaust air. Only for new construction.

ENERGY STAR Home

For manufactured or single-family homes, an ENERGY STAR rating exists to improve the overall efficiency of a home. Only for new construction.

Heat Pump Measures

Measures specific to residences using a heat pump.

"Check Me" Duct Sealing

Basically, by repairing and sealing leaky ducts, significant energy savings could be attained by ensuring the conditioned air is freely traveling to the occupied spaces. Only for existing homes.

"Check Me" O&M Tune-Up

For heat pumps, doing a certified maintenance will improve overall efficiency. Only for existing homes.

Space Heat Measures

Measures specific to residences using an electric furnace for their space heating needs.

Duct Insulation

Adding insulation (to R-8) around the ducts in the heating system will reduce heat loss to unconditioned spaces. Only for existing homes.

PTCS Duct Sealing

Basically, by repairing and sealing leaky ducts, significant energy savings could be attained by ensuring the conditioned air is freely traveling to the occupied spaces. Only for existing homes.

Building Envelope Measures

"Building envelope" measures improve the thermal performance of the building's walls, floor, ceiling or windows. The baseline technology and the energy-efficiency upgrades are discussed below. The building envelope energy-efficiency measures include insulation (ceiling/roof, wall, and floor) and windows. These measures result in saving for heat pump and space heat end uses. If they pass the economic screen under one end use but not the other, both TRCs are given.

Whole House Air Sealing

In existing buildings, air infiltration can account for 30% of a home's heating and cooling costs[1]. Windows, doors, attic, crawlspaces and outside walls contribute to air leakages. Sealing the air leaks improves overall heating and cooling losses. Only for existing homes.

Insulation—Exterior Doors

Insulated exterior entry doors with built-in weather-stripping to reduced air infiltration can decrease the heating and cooling costs.   Only for existing homes.

Ceiling/Roof Insulation

This measure represents an increase in R-value. Adding insulation in existing buildings increase the thermal performance and bring the resistance value closer/up to code. R-38 represents current code in the ceiling or roof. Only for existing homes.

Floor Insulation

Similar to ceiling insulation, this measure represent an increase in R-value. Increasing the thermal performance brings the resistance value closer/up to code. Currently, R-25 represents code for typical residential homes.   Only for existing homes.

Wall Insulation

The measure represent an increase in R-value thereby increasing the thermal performance of the building. In existing buildings, the type of construction dictates the level of increased R-value. Currently, R-13 represents code.   Only for existing homes.

Below Grade Insulation

Adding insulation to the basement or crawlspace walls increases the thermal performance of the concrete foundation. For existing construction the increased insulation R-value is from 0 to 11. Only for existing homes.

Rim Joist Insulation

Adding insulation to the rim joists around the basement or crawlspace walls increases the thermal performance of the basement. For existing construction the increased insulation R-value is from 0 to 10. Only for existing homes.

High-efficiency Windows

The efficiency of windows is rated by its Class, where a lower class number indicates a higher efficiency window. Higher performance windows can be achieved by using double-pane glass

[1] Source: U.S. Department of Energy – Air Sealing Spec Sheet by the Office of Building Technology, State and Community Programs.

with low-emissivity (low-e) films, and/or argon gas filling the gap between the panes. For existing homes, the measure represents an increase in performance by improving the Class from 40 to Class 30. This measure only applies to existing construction due to changes in the 2007 building code.

Spray-In Wall Insulation

This measure represents an increase in R-value, thereby increasing the thermal performance of the building. Spray-in insulation can improve the R-value of 2x4 wall insulation from R-13 to R-26. Only for new construction

Water Heat

In addition to a more efficient water heating system, any equipment measures that require less hot water are also included in the water heat measures below.

Table A–3. Residential Electric Water Heat

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC Retrofit	TRC New
Water Heat	ENERGY STAR Dishwasher (EF=0.58)	Standard Dishwasher (EF=0.52)	2%	1.9	1.6
	ENERGY STAR Clothes Washer (MEF=1.8)	Standard Clothes Washer (MEF=1.0)	13%	0.9	0.7
	Heat Pump Water Heater EF = 2.9	EF = 0.88	40%	0.8	0.7
	Solar Water Heater	EF = 0.93	40%	0.3	0.3
	Low-Flow Showerheads (2.5 GPM)	5.0 GPM	3%	4.0	2.4
	Hot Water Pipe Insulation R-4	R-0	1%	3.9	3.9
	Faucet Aerators (2.5 GPM)	4.5 GPM	1%	4.8	2.4
	Drain Water Heat Recovery (GFX)	No Heat Recovery	25%		2.5

ENERGY STAR Appliances

Upgrading to an ENERGY STAR-rated appliance, such as dishwasher or clothes washer, will reduce overall water needs.

Heat Pump Water Heater

Heat pump water heaters are more efficient than standard electric water heaters. This measure assumes an energy factor (EF) for heat pump water heaters of 2.9, an increase from 0.93, common for electric residential water heaters.

Solar Water Heater

A solar water heater is generally mounted on the roof of a building and is designed to use the sun to heat water rather than electricity or gas. A solar water heater helps offset the electric or gas water heating costs. Note that this is a passive process, not one that involves photovoltaic cells.

Low-Flow Showerheads

Low-flow shower heads use the same principle as faucet aerators to achieve a flow reduction of nearly 50%, lowering the flow rate to 2.5 gpm from 5.0 gpm.

Hot Water Pipe Insulation

Adding R-4 insulation around the pipes will decrease heat loss.

Faucet Aerators

Faucet aerators, by mixing water and air, lower the water flow from 5.0 gpm to 2.75 gpm. The faucet aerator creates a fine water spray with a screen that is inserted in the faucet head.

Drain Water Heat Recovery (GFX)

This measure is a essentially a gray water heat recovery system that works on the premise of recovering heat from waste water. For example, as hot water passes down the drain from a shower, heat is exchanged with incoming cold water from the water main thereby pre-heating incoming cold water to the water heater tank. Only for new construction.

Refrigeration

Table A–4. Residential Electric Refrigeration

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Refrigeration	Removal of Secondary Freezer	Base Secondary Freezer	100%	2.9

Removal of some appliances refers to a secondary appliance such as a garage refrigerator or freezer that is not considered a household necessity.

Plug Load

Plug-in loads that are purchased with an ENERGY STAR rating reduced the overall electric load of the household compared to standard equipment. This measure identifies the specific plug-in equipment. The following list includes both typical household entertainment equipment and home-office equipment. Office equipment such as computers, monitors, and printers can all be

ENERGY STAR-classified, indicating lower energy consumption than conventional equipment. This is, in part, achieved by allowing the machine to go into standby mode.

Table A–5. Residential Electric Plug Load

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Plug Load	Efficient high definition televisions	Standard HDTV	3%	0.4
	Efficient DVD systems	Standard DVD System	0.2%	>100
	Digital Set Top Receivers	Standard Receiver	0.2%	>100
	Office Equipment: Printers, ENERGY STAR or Better	Standard Printer	1.0%	>100
	Office Equipment: Monitors, ENERGY STAR or Better	Standard Monitor	1.0%	>100
	Office Equipment: Computer, ENERGY STAR or Better	Standard Computer	0.4%	>100
	Powerstrip with Occupancy Sensor	No Occupancy Sensor	1%	0.8
	External power adapters	No External Power Adapter	0.7%	0.6

ENERGY STAR Plug-In Equipment

Efficient high-definition televisions
Efficient DVD systems
Digital set top receivers
Printers, monitors, and computers

Power Strip with Occupancy Sensor

Energy saving products such as power strips with an occupancy sensor are found in workstations where power strips are commonly used. The sensor will turn on and off the power to all devices such as computers, desk lights, and audio equipment that are plugged into power strip based on occupancy within the work area.

External Power Adapters

External power adapters, also known as power supplies or battery chargers, convert high voltage AC electricity from the wall outlet to the low-voltage DC power. Typical electronic products such as like MP3 players, digital cameras, laptops, and cordless and mobile phones use power adapters. This measure is ENERGY STAR compliant and on average, 35 percent more efficient than conventional models.

Lost Opportunity–Equipment

In either existing or new construction, when new equipment needs to be purchased, savings can be gained by purchasing high-efficiency models.

Table A–6. Residential Electric Lost Opportunity—Equipment

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
HVAC	High Efficiency Heat Pump (13 SEER, 8.5 HSPF)	Standard Efficiency (13 SEER, 7.7 HSPF)	9%	1.2
	Premium Efficiency (13 SEER, 9.0 HSPF)	Standard Efficiency (13 SEER, 7.7 HSPF)	14%	0.3
	High Efficiency Central AC (14 SEER)	Standard Efficiency (13 SEER)	7%	0.1
	Premium Efficiency Central AC (16 SEER)	Standard Efficiency (13 SEER)	19%	0.05
	Advanced Efficiency Central AC (18 SEER)	Standard Efficiency (13 SEER)	28%	0.02
	ENERGY STAR Room AC (10.7 EER)	9.7 EER	9.4%	0.5
Appliances	ENERGY STAR Refrigerator	Standard Refrigerator	15%	1.3
	ENERGY STAR Freezer	Standard Freezer	10%	0.8

High/Premium-Efficiency Air-Source Heat Pump

A standard air-source heat pump has a SEER=13 and HSPF=7.7. A high-efficiency pump has SEER=13 and HSPF=8.5, and a premium-efficiency pump has SEER=13 and HSPF=9.0, with energy savings of 9% and 14%, respectively, over the standard. Note that this savings is only from the heating side.

High/Premium/Advanced-Efficiency Central AC

A standard central AC unit has a SEER=13. A high-efficiency unit has SEER=14, a premium-efficiency unit has SEER=16 and an advanced-efficiency unit has SEER=18, with energy savings of 7%, 19% and 28%, respectively, over the standard.

ENERGY STAR Equipment

Energy efficiency household equipment options are identified and have an ENERGY STAR rating for high efficiency compared to standard models.

ENERGY STAR Room AC (window) unit
ENERGY STAR Refrigerator
ENERGY STAR Freezer

Residential Electric Emerging Technology

These ET measures are energy-efficiency measures that are not readily available in the current market, but are expected to be so within the 20-yr planning horizon. The different ET measures are in varying stages of “market readiness,” and the potential study included the ET measures only after they become market-ready.

Lighting

Table A–7. Residential Electric Emerging Technology—Lighting

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Lighting	LED Lighting, High Use	Incandescent 60W	54%	3.7
	LED Lighting, Medium Use	Incandescent 60W	11%	0.9
	LED Lighting, High Use	Incandescent 60W	8%	2.3

LED Interior Lighting (White)

Light emitting diodes (LEDs) are solid-state devices that convert electricity to light, potentially with very high efficiency and long life. Recently, lighting manufacturers have been able to produce "cool" white LED lighting indirectly, using ultraviolet LEDs to excite phosphors that emit a white-appearing light. Replacement for incandescent lamps. Introduced in year five.

Plug Load

Table A–8. Residential Electric Emerging Technology—Plug Load

Category or End Use	Technology	Baseline	End-Use Percent Savings	TRC
Plug Load	One-Watt Standby Power	Four devices per home	10%	2.4
	Advanced Appliance Motor ECM	ENERGY STAR appliance	9%	0.4
Refrigeration	One kWh/day Refrigerator	Standard refrigerator	27%	1.8
	Solid State Refrigeration	ENERGY STAR Refrigerator	46%	0.6

One-Watt Standby Power

Standby power is the electricity used by electrical equipment when it is switched off, or not performing its main function. By minimizing this loss to 1 Watt or less can reduce this standby energy consumption by more than 50%. Introduced in year five.

Advanced Appliance Motor ECM

Applicable to ENERGY STAR appliances and dryers, electronically commutated motors (ECM) rely on electronics to provide precisely timed voltages to the coils, and use rotation position sensors for timing, resulting in greater efficiency than a standard motor. Applicable to any motor, particularly those used in dryers. Introduced in year five.

One kWh/day Refrigerator

Reducing the energy use of a refrigerator to less than 1 kWh/day will result in over 25% reduction in energy use from a baseline refrigerator. This measure is introduced in year 15.

Solid State Refrigeration "Cool Chips™"

Using thermoelectric devices to convert electricity for cooling (refrigeration) is only starting to become economical due to advances in efficiency levels. Introduced in year 15.

Heating, Ventilation, and Air-Conditioning (HVAC)

Table A–9. Residential Electric Emerging Technology—HVAC

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Heat Pump	Advanced Cold-Climate Heat Pump (16 SEER, 9.6 HSPF)	11 EER, 8.1 HSPF	17%	0.1
	Microchannel Heat Exchangers	11EER, 8.1 HSPF	5%	1.7
	Small Scale Absorption Cooling	11EER, 8.1 HSPF	14%	0.2
	Solid State Refrigeration Cool Chips	11EER, 8.1 HSPF	22%	0.5
Heat Pump or Space Heat	Aerosol-Based Duct Sealing	No sealing	14%	1.6
	Leak Proof Duct Fittings	Standard Duct Workmanship	17%	5.5
	Green Roof	Standard Roofing	13%	0.02

Advanced Cold-Climate Heat Pump

Cold-climate heat pumps are air-to-air heat pumps that have been optimized for colder climates. The performance of these heat pumps is expected to be approximately the same as ground-source heat pumps (GSHP). Introduced in year five.

Microchannel Heat Exchangers (Evaporator)

A microchannel heat exchanger allows for a longer dwell time for the air passing over it, as compared to a standard fit-tube heat exchanger. This results in an increase in heat exchanger effectiveness. Introduced in year 10.

Small Scale Absorption Cooling

The absorption cycle is a process by which a refrigeration effect is produced through the use of two fluids and a quantity of heat input, rather than electrical input, as in the vapor compression cycle. For applications above 32 degrees F, lithium bromide is used as the absorbent and water as the refrigerant. For applications below 32 degrees F, ammonia is used as the refrigerant and water as the absorbent. Introduced in year 15.

Solid State Refrigeration "Cool Chips™" for Heat Pumps

Using thermoelectric devices to convert electricity to cooling is only starting to become economical due to advances in efficiency levels. Introduced in year 15.

Aerosol-Based Duct Sealing

A significant amount of energy use in residential buildings is associated with duct losses due to leakage. This is an aerosol duct-sealing technology that seals holes in ducts up to ¼" in diameter from the inside by spraying atomized latex aerosol into a pressurized duct system. "Check Me" for heat pumps and "PTCS" for electric furnaces. Introduced in year five.

Green Roof

A green roof is a living roof that supports soil and plant growth. A series of carefully engineered layers are applied to the roof deck. These layers are watertight, lightweight and long-lasting. Green roofs can be incorporated into new and existing buildings as long as load requirements are met. They are suited for roofs that have slopes ranging up to 20 degrees and are most successful when sufficient attention has been paid to selecting plants that will thrive in the local climate and conditions. One of the most significant advantages is that a green roof can last up to three times longer than a standard roof. The added benefit of a green roof's ability to buffer temperature extremes improves a building's energy performance by dropping the temperatures on the roof 3-7 degrees, resulting in approximately a 10% reduction in cooling loads. Introduced in year five.

Leak-proof Duct Fittings

The majority of duct leakage in residential HVAC systems is due to improperly sealed connections between ductwork and fittings. Even when duct connections are initially well-sealed, leakage may increase over time. Although the use of mastics and mechanical fasteners is becoming more widespread, a low-cost, leak-proof system will help to transform the market. Introduced in year five.

Residential Gas Measure Descriptions

Percent savings and TRC are averaged over all applicable building types and the TRC is given for the base-case scenario averaged for both discretionary measures and lost opportunity-equipment measures, unless they differ significantly in which case both TRCs are given.

Heating, Ventilation, and Air-Conditioning (HVAC)

Measures associated with the HVAC system improve the overall heating and cooling loads on the building. Discretionary measures can impact all types of cooling or heating equipment. For residential buildings, only savings to the heating loads were considered.

Table A–10. Residential Gas HVAC

Category or End Use	Technology	Baseline	Percent End-Use Savings	TRC
Space Heat	Duct Insulation (R-8)	R-3	4%	0.8
	Duct Sealing	No Sealing	14%	1.1
	Exterior Door Insulation	Existing Door	4%	0.3
	Integrated Space & Water Heating	Standard Efficiency Furnace	13%	0.7
	Air-to-Air Heat Exchangers	No heat exchanger	10%	0.2
	ENERGY STAR Home (Single Family)		38%	0.7
	ENERGY STAR Home (Manufactured)		34%	1.5
Building Envelope	Whole House Air Sealing		6%	0.5
	Insulation - Roof / Ceiling (R-38)	R-11	9%	1.1
	Insulation – Floor (R-25)	R-0	11%	0.6
	Insulation – Wall (R-13)	R-0	10%	0.7
	Insulation – Rim Joist (R-10)	R-0	2%	0.3
	Below Grade Insulation (R-10)	R-0	13%	0.9

	Windows-High Efficiency (U=0.35)	Class 40	23%	0.7
	Spray-In Insulation (R-38)	R-19	30%	1.1

Duct Insulation

Insulating the ducts through which heated air travels will reduce energy loss in the unoccupied plenum space. The baseline value for this insulation is R-3, while the measure increases the insulation to R-8. Only for existing homes.

PTSC Duct Sealing

Basically, by repairing and sealing leaky ducts, significant energy savings could be attained by ensuring the conditioned air is freely traveling to the occupied spaces. Only for existing homes.

Insulation—Exterior Doors

Insulated exterior entry doors with built-in weather-stripping to reduced air infiltration can decrease the heating and cooling costs. Only for existing homes.

Integrated Space and Water Heating

This involves using a condensing furnace with a AFUE=90, compared to a standard efficiency AFUE=78. The condensed warm water from the space heating is used for water heat.

Air-to-Air Heat Exchangers

Advanced ventilation brings in fresh, outdoor air, but pre-heats the outside air with the warm exhaust air reducing the heating load otherwise required with incoming cold outside air. Only for new construction.

ENERGY STAR Home

For manufactured or single-family homes, an ENERGY STAR rating exists to improve the overall efficiency of a home. Only for new construction.

Building Envelope Measures

"Building envelope" measures improve the thermal performance of the building's walls, floor, ceiling or windows. The baseline technology and the energy efficiency upgrades are discussed below. The building envelope energy efficiency measures include insulation (ceiling/roof, wall, and floor) and windows.

Whole House Air Sealing

In existing buildings, air infiltration can account for 30% of a home's heating and cooling costs[2]. Windows, doors, attic, crawlspaces and outside walls contribute to air leakages. Sealing the air leaks improves overall heating and cooling losses. Only for existing homes.

Ceiling/Roof Insulation

This measure represents an increase in R-value. Adding insulation in existing buildings increase the thermal performance and bring the resistance value closer/up to code. R-38 represents current code in the ceiling or roof. Only for existing homes.

Floor Insulation

Similar to ceiling insulation, this measure represent an increase in R-value. Increasing the thermal performance brings the resistance value closer/up to code. Currently, R-25 represents code for typical residential homes. Only for existing homes.

Wall Insulation

The measure represent an increase in R-value thereby increasing the thermal performance of the building. In existing buildings, the type of construction dictates the level of increased R-value. Currently, R-13 represents code. Only for existing homes.

Rim Joist Insulation

Adding insulation to the rim joists around the basement or crawlspace walls increases the thermal performance of the basement. For existing construction the increased insulation R-value is from 0 to 10. Only for existing homes.

Below Grade Insulation

Adding insulation to the basement or crawlspace walls increases the thermal performance of the concrete foundation. For existing construction the increased insulation R-value is from 0 to 11. Only for existing homes.

High-efficiency Windows

The efficiency of windows is rated by its Class, where a lower class number indicates a higher efficiency window. Higher performance windows can be achieved by using double-pane glass with low-emissivity (low-e) films, and/or argon gas filling the gap between the panes. For existing homes, the measure represents an increase in performance by improving the Class from 40 to Class 30. This measure only applies to existing construction due to changes in the 2007 building code.

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[2] Source: U.S. Department of Energy – Air Sealing Spec Sheet by the Office of Building Technology, State and Community Programs.

Spray-In Wall Insulation

This measure represents an increase in R-value, thereby increasing the thermal performance of the building. Spray-in insulation can improve the R-value of 2x4 wall insulation from R-19 to R-38. Only for new construction.

Water Heat

In addition to a more efficient water heating system, any equipment measures that require less hot water are also included in the water heat measures below.

Table A–11. Residential Gas Water Heat

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Water Heat	Solar Water Heater	EF = 0.93	40%	0.2
	Low-Flow Showerheads (1.8 GPM)	2.5 GPM	3%	2.3
	Hot Water Pipe Insulation R-4	R-0	1%	1.9
	Faucet Aerators (1.8 GPM)	2.5 GPM	1%	3.1
	Tankless Water Heater (EF=0.82)	Storage Water Heater (EF=0.59)	20%	1.3
	Integrated Space and Water Heater	Standard Water Heater	5%	0.2
	ENERGY STAR Clothes Washer (MEF=1.8)	Standard Clothes Washer (MEF=1.0)	13%	0.6
	ENERGY STAR Dishwasher (EF=0.58)	Standard Dishwasher (EF=0.52)	4%	2.2
	Drain Water Heat Recovery (GFX)	No heat recovery	25%	2.5

Solar Water Heater

A solar water heater is generally mounted on the roof of a building and is designed to use the sun to heat water rather than electricity or gas. A solar water heater helps offset the electric or gas water heating costs. Note that this is a passive process, not one that involves photovoltaic cells.

Low-Flow Showerheads

Low-flow shower heads use the same principle as faucet aerators to achieve a flow reduction of nearly 50%, lowering the flow rate to 2.5 gpm from 5.0 gpm.

Hot Water Pipe Insulation

Adding R-4 insulation around the pipes will decrease heat loss. Only for existing construction.

Faucet Aerators

Faucet aerators, by mixing water and air, lower the water flow from 5.0 gpm to 2.75 gpm. The faucet aerator creates a fine water spray with a screen that is inserted in the faucet head.

Tankless Water Heater

If hot water usage is only sporadic, savings can be obtained by using an on-demand, or tankless hot water system. In this system, there is no water storage tank thereby reducing standby losses; rather, a high intensity heating element heats the flowing water when needed.

Integrated Space and Water Heating

This involves using a condensing furnace with high efficiency storage water heater. The condensed warm water from the space heating is used for water heat.

ENERGY STAR Appliance Measures

Two energy efficiency household appliance options are identified (clothes washer and dishwasher) and have an ENERGY STAR rating for high efficiency compared to standard models. Clothes washers reduce hot water use, which translates to energy savings. High-efficiency dishwashers improve the wash and dry cycles compared to standard models with a 20% increase in energy factor.

Drain Water Heat Recovery (GFX)

This measure is a essentially a gray water heat recovery system that works on the premise of recovering heat from waste water. For example, as hot water passes down the drain from a shower, heat is exchanged with incoming cold water from the water main thereby pre-heating incoming cold water to the water heater tank.

Lost Opportunity—Equipment

In either existing or new construction, when new equipment needs to be purchased, savings can be gained by purchasing high-efficiency models.

Table A–12. Residential Gas Lost Opportunity—Equipment

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
	High Water Heater (EF=0.64)	EF = 0.59	8%	2.3
Water Heat	High Efficiency Furnace (AFUE=80)	AFUE=78	3%	2.5
	Premium Efficiency Furnace (AFUE=90)	AFUE=78	13%	0.7
	Advanced Efficiency Furnace (AFUE=96)	AFUE=78	19%	0.2

	ENERGY STAR Dishwasher (EF=0.58)	Standard Dishwasher (EF=0.46)	4%	2.6
	ENERGY STAR Clothes Washer (MEF=1.8)	Standard Clothes Washer (MEF=1.0)	13%	0.6

High-Efficiency Storage Water Heater

A standard water heater has an energy factor (EF) of 0.59, while a high-efficiency water heater gas EF=0.64, resulting in an 8% energy savings.

High/Premium/Advanced-Efficiency Furnace

A standard central furnace has an AFUE=78. A high-efficiency unit has AFUE=80, a premium-efficiency unit has AFUE=90 and an advanced-efficiency unit has AFUE=96, with energy savings of 3%, 13% and 19%, respectively, over the standard.

ENERGY STAR Equipment

Energy efficiency household equipment options are identified and have an ENERGY STAR rating for high efficiency compared to standard models.

ENERGY STAR Clothes Washer
ENERGY STAR Dishwasher

Residential Gas Emerging Technology

These ET measures are energy-efficiency measures that are not readily available in the current market, but are expected to be so within the 20-yr planning horizon. The different ET measures are in varying stages of "market readiness," and the potential study included the ET measures only after they become market ready. All residential ET gas measures apply to the HVAC system.

Table A–13. Residential Gas Emerging Technology

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Space Heat	Aerosol-Based Duct Sealing	No sealing	19%	2.5
	Green Roof	Standard Roofing	13%	0.03
	Leak Proof Duct Fittings	Standard Duct Workmanship	17%	6.8

Aerosol-Based Duct Sealing

A significant amount of energy use in residential buildings is associated with duct losses due to leakage. This is an aerosol duct-sealing technology that seals holes in ducts up to ¼" in diameter from the inside by spraying atomized latex aerosol into a pressurized duct system. Introduced in year five.

Green Roof

A green roof is a living roof that supports soil and plant growth. A series of carefully engineered layers are applied to the roof deck. These layers are watertight, lightweight and long-lasting. Green roofs can be incorporated into new and existing buildings as long as load requirements are met. They are suited for roofs that have slopes ranging up to 20 degrees and are most successful when sufficient attention has been paid to selecting plants that will thrive in the local climate and conditions. One of the most significant advantages is that a green roof can last up to three times longer than a standard roof. The added benefit of a green roof's ability to buffer temperature extremes improves a building's energy performance by dropping the temperatures on the roof 3-7 degrees, resulting in approximately a 10% reduction in cooling loads. Introduced in year five.

Leak-proof Duct Fittings

The majority of duct leakage in residential HVAC systems is due to improperly sealed connections between ductwork and fittings. Even when duct connections are initially well-sealed, leakage may increase over time. Although the use of mastics and mechanical fasteners is becoming more widespread, a low cost, leak-proof system will help to transform the market. Introduced in year five.

Commercial Electric Measure Descriptions

This section provides an overview of the selected energy-efficiency measure within the commercial sector. The measures are categorized by end use. Discretionary (existing buildings) and Lost Opportunity- New Construction have many of the same measures within each end use and are thus grouped together. If significant differences in the TRC exist between the two applications, both TRCs will be given; otherwise, only an average TRC is given. Lost Opportunity—Equipment category includes additional measures and are given separately.. In addition, a description of emerging technologies is included at the end. A brief description of the current baseline technology and the energy measure is discussed. Percent savings and TRC are averaged over all applicable building types.

Lighting

Incandescent lighting is a highly inefficient light source; as such, significant savings can be gained by switching to light-emitting diodes (LEDs) or fluorescent lighting. In addition, lighting technologies have improved and so upgrades will save energy. Finally, electricity can be saved by simply not using the lights as much.

Table A–14. Commercial Electric Lighting

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC Existing	TRC New
Lighting	LED Exit Signs (5W)	CFL Exit Sign (16W)	1%	2.2	6.7
	LED Refrigeration Case Lights (10W)	Fluorescent Case Lights (34W)	12%	67.0	63.0
	Induction Lighting (55W)	Metal Halide (150W)	1%	0.5	0.5
	Bi-Level Control, Stairwell Lighting	Continuous Full Power Lighting in Stairways	2%	1.0	1.0
	Occupancy Sensor Control, Fluorescent	No Occupancy Sensor	5%	0.5	0.4
	Stepped Dimming Fluorescent Fixtures	No Dimming Controls	8%	1.0	1.9
	Continuous Dimming, Fluorescent Fixtures	No Dimming Controls	11%	2.2	4.1
	Integrated Lighting, Classrooms	1.2 W/sq. ft.	25%	0.5	0.5
	Reduce Interior Lighting Power Density Low Reduction (W/sq. ft.)		15%	2.6	5.4
	Reduce Interior Lighting Power Density High Reduction (W/sq. ft.)		27%	2.5	5.3

LED

Light-emitting diodes (LEDs) are highly efficient bulbs that can be used for refrigeration case lights and exit signs, a 70% energy savings over a fluorescent bulb. Currently, LEDs are not cost-effective to be used in general lighting applications.

Induction Lighting

A 100W incandescent lamp can be replaced by a 55 W induction lamp, a 45% energy savings per bulb. An induction lamp has an induction coil at its center powered by an electronic unit that produces a magnetic field that energizes a mercury electron-ion plasma material in the glass assembly surrounding the coil.

Bi-Level Control, Stairwell Lighting

Rather than having stairwell lighting continuously operating at full power, a bi-level control will use an occupancy sensor such that the lighting power is 50% during unoccupied times.

Occupancy Sensors

If a space is unoccupied for a designated amount of time, an occupancy sensor will turn off the lights. The lights will turn on again once the sensor detects a person has entered the space.

Stepped/Continuously Dimming

Rather than a light operating at full power, a dimming switch will allow light levels to vary from 0-100% brightness. A stepped dimming switch has several discrete levels of brightness, while a continuously dimming switch will allow variation throughout the range.

Integrated Lighting, Classrooms

Integrated lighting includes daylighting control, super T8 lights, and dimming controls.

Reduced Interior Lighting Power Density

A generic way to indicate improved efficiency lighting, whether it be by replacing an incandescent bulb with a fluorescent bulb, or a fluorescent bulb with a metal halide bulb, etc. A low reduction is of 15% in power density and between 25-40% for a high reduction .

Heating, Ventilation, and Air-Conditioning (HVAC)

Measures associated with the HVAC system improve the overall heating and cooling loads on the building. Discretionary measures can impact all types of cooling or heating equipment or be specific to a particular type of equipment.

Table A–15. Commercial Electric HVAC

Category or End Use	Technology	Baseline	Percent End-Use Savings	TRC Existing	TRC New
Cooling Chillers	Cooling Tower-Decrease Approach Temperature 6°F Δ T	10°F ΔT	8%	3.6	
	Direct Digital Control System-Installation	Pneumatic	10%	1.9	0.1
	Direct Digital Control System-Optimization	No Optimization	1%	0.1	
	Chilled Water / Condenser Water Settings-Optimization	EMS already installed - No Optimization	5%	1.3	1.4
	Chilled Water Piping Loop w/ VSD Control	3-way valves, with constant speed pump	12%	1.1	1.2
	Chiller-Water Side Economizer	No Economizer	10%	0.7	
	Cooling Tower-Two-Speed Fan Motor	Cooling Tower-One-Speed Fan Motor	14%	17.0	17.0
	Cooling Tower-VSD Fan Control	Cooling Tower-One-Speed Fan Motor	4%	2.6	2.7
	Pipe Insulation R-4	R-0	1%	6.5	6.6
	Retro-Commissioning		15%	0.5	0.2
	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Constant Ventilation	5%	0.4	0.6

Category or End Use	Technology	Baseline	Percent End-Use Savings	TRC Existing	TRC New
	Convert Constant Volume Air System to Variable Volume	Constant Volume Air System	12%	1.8	
	Chiller-Tune-Up / Diagnostics	No Tune-Up	10%	1.0	
Cooling DX	DX Package-Air Side Economizer	No Economizer	15%	4.5	
	Direct / Indirect Evaporative Cooling, Pre-Cooling		10%	0.6	0.7
	Terminal HVAC units-Occupancy Sensor Control	No Occupancy Sensor	35%	3.8	3.8
	Programmable Thermostat	No Programmable Thermostat	10%	11.0	
	Retro-Commissioning		15%	1.1	0.3
	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Constant Ventilation	5%	1.8	1.2
	DX Tune-Up / Diagnostics	No Tune-Up	10%	0.8	
	Convert Constant Volume Air System to Variable Volume	Constant Volume Air System	12%	3.9	
Cooling Heat Pump	Direct / Indirect Evaporative Cooling, Pre-Cooling		10%	0.6	0.7
	Programmable Thermostat	No Programmable Thermostat	10%	11.0	
	Retro-Commissioning		15%	1.1	0.3
	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Constant Ventilation	5%	1.0	1.2
Space Heat	Exhaust Air to Ventilation Air Heat Recovery	No Heat Recovery	20%	1.5	1.3
	Programmable Thermostat	No Programmable Thermostat	20%	6.7	
	Terminal HVAC units-Occupancy Sensor Control	No Occupancy Sensor	35%	16.0	16.0
	Retro-Commissioning		15%	0.9	0.2
	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	Constant Ventilation	10%	2.1	2.1
	Convert Constant Volume Air System to Variable Volume	Constant Volume Air System	12%	3.7	
HVAC	Duct Insulation (R-8)	R-3	3%	29.0	
	Duct Repair and Sealing (50% Reduction in Duct Lose)		1%	8.3	
Envelope	Windows-High Efficiency U = 0.35	U = 0.67	6%	2.8	9.0
	Insulation - Roof / Ceiling (R-19)	R-0	5%	0.8	
	Insulation - Floor (R-19)	R-0	3%	0.5	
HAVC Aux	Optimized Variable Volume Lab Hood Design		3%		4.5

Chiller-specific Measures

The two primary components of a chiller are the chiller itself (screw, centrifugal, or reciprocating) and the cooling tower. Chiller-specific measures can apply to the system itself, or to any of the sub-components.

Cooling Tower—Decrease Approach Temperature

The approach temperature is the difference between the tower water leaving and the wet-bulb temperatures. As a result, the cooling tower will be oversized but the chiller can be smaller. On an total energy usage basis, over-sizing a cooling tower requires less energy than a larger chiller. Only for existing construction.

Direct Digital Control System—Installation

Adding a direct digital control system allows for electronic remote control of all the building zones independently. The baseline equipment would have a pneumatic control. Only for existing construction.

Direct Digital Control System—Optimization

The optimization of the control system is upgrading a high-efficiency energy management system to a premium efficiency system.

Chilled Water/Condenser Water Settings—Optimization

As part of the entire direct digital control system, this measure optimizes the control of the chilled water temperature and/or flow settings.

Chilled Water Piping Loop with VSD Control

A VSD, or variable-speed drive, replaces a constant speed pump with 3-way valves. Varying the speed of the drive allows the pump to run at its optimal load; thus, minimizing its energy requirements.

Water-Side Economizer

This measure reflects the addition of a water-side economizer that consists of a coil attached to a condenser-water loop. The coil operates whenever a cooling load exists, and the outdoor conditions can produce condenser water colder than the mixed-air temperature. A water-side economizer is used if an outdoor-air economizer is not practical.   Only for existing buildings.

Cooling Tower-Two-Speed Fan Motor

Using a fan that can operate at two speeds, rather than one, allows for better optimization of the fan. A one-speed fan will cycle on and off to maintain tower set point, while a two speed fan will cycle between off, low speed and high speed to maintain the set point. Adding in the low-speed option uses less energy than a single, high speed fan.

Cooling Tower-VSD Fan Control

One step more sophisticated than the two-speed fan motor is the variable speed drive (VSD). A VSD drive is able to modulate the air flow so that the heat rejection exactly matches the load at the desired setpoint.

Pipe Insulation

The chilled water is carried through pipes between the cooling tower and chillers. Insulating these pipes minimizes heat loss.

DX Package/Cooling Heat Pump-specific Measures

A DX system, or direct-expansion air conditioning system is what is generally referred to as a “Central AC” unit. These measures may also apply to the cooling side of a heat pump.

Air-Side Economizer

An air-side economizer varies the proportion of outside air to return air to maintain the mixed air temperature set point.

Direct/Indirect Evaporative Cooling, Pre-Cooling

Including an evaporative cooler before the DX system will reduce the overall cooling load. A direct evaporative cooler is a low-energy system that evaporates water into the air stream, thus reducing the temperature of the air, but increasing the humidity. An indirect evaporative cooler uses a secondary air stream that is cooled by water and goes through a heat exchanger with the primary air stream, cooling it but not affecting the humidity. A direct/indirect system will cool the air stream first through an indirect cooler, then cool it further through a direct cooler.

Terminal HVAC Units—Occupancy Control

Including an occupancy sensor will ensure that the HVAC system only operated when the room is occupied. This measure is specific to hotel/motel buildings.

Programmable Thermostat

A programmable thermostat simply controls the set point temperatures automatically. This allows for lower energy use by ensuring the HVAC system is not running during low-occupancy hours.

Space Heat Measures

Measures applicable to any electric space heating system.

Exhaust Air to Ventilation Air Heat Recovery

The air that is exhausted out of a building during the heating season will be warmer than the air outside. Capturing some of this heat and transferring it to the incoming air lowers the overall heating load.

All HVAC Measures

Retro-Commissioning

"Retro-commissioning" is the process of optimizing the operation of an existing building through simple, low- or no-cost repairs and operational changes. For example, temperature controls will be set to operate only during occupied periods, ensuring that the ideal static pressure is being met for the fans.

Automatic Ventilation VFD Control

This measure allows the ventilation to only run only when CO_2 levels are above a specified level. Without it, the ventilation system would run constantly.

Tune-Up/Diagnostics

Simply put, this measure increases the overall efficiency of the HVAC equipment by doing any required maintenance or tune-up. The baseline building will have no tune-up performed. This measure has specific savings depending on what type of equipment is installed. Only for existing construction.

Convert Constant Volume Air System to Variable Volume

Similar to using VSD control, converting to a variable volume system will allow for the drives to operate at an optimal load level and thus, minimize energy consumption. The baseline building only runs at a single volume flow. Only for existing construction.

Duct Insulation

Packaged DX and heat-pump equipment is generally coupled with a ducting system inside the building. Insulating the ducts will reduce energy loss in the unoccupied plenum space. The baseline value for this insulation is R-3, while the measure increases the insulation to R-8. Only for existing construction.

Duct Repair and Sealing

Similar to duct insulation, this measure is applicable to building using packaged DX equipment or heat pumps. Basically, by repairing and sealing leaky ducts, significant energy savings could be attained by ensuring the conditioned air is traveling to the occupied spaces. Only for existing construction.

HVAC Aux. Measures

Measures specific to the HVAC ventilation or exhaust system.

Optimized Variable Volume Lab Hood Design

For buildings such as universities, schools, and hospitals that use lab hoods, a small savings can be obtained by using a variable, rather than constant, volume lab hood. By allowing the volumetric flow rate to vary will allow a constant speed through the duct, regardless of sash opening.

Building Envelope Measures

"Building envelope" measures improve the thermal performance of the building's floor and ceiling insulation and window efficiency. Insulation improvements are simply an increase in the "R-value" of the building envelope. The greater the R-value, the better the thermal performance. The baseline value for existing construction is assumed to be R-0, ensuring that the maximum savings are reflected. The efficiency of windows is rated by its "U-value," which is effectively 1/R-value. In other words, the smaller the U-value, the better the thermal performance. A U-value=1 indicates a single-pane, ¼", clear glass window. Higher performance windows can be achieved by using double-pane glass with low-emissivity (low-e) films, and/or argon gas filling the gap between the panes.

Windows—High-efficiency

This measure represents an increase in performance by changing the U-value from 0.67 to 0.35.

Ceiling/Roof Insulation

This measure represents an increase in R-value to current code values of R-19 in the roof or ceiling, for single-story buildings. Note that this measure is only cost-effective for the space heat end use (TRC=1.8). Only for existing construction.

Floor Insulation

Similar to ceiling/roof insulation, the measure represents an increase in R-value to current code levels of R-19 for the floor space. Only for existing construction.

Water Heat

In addition to a more efficient water heating system, any equipment measures that require less hot water fall under the auspices of water heat measures.

Table A–16. Commercial Electric Water Heat

Category or End Use	Technology	Baseline	Percent End-Use Savings	TRC
Water Heat	Faucet Aerators (1.6 GPM)	4.0 GPM	2%	4.4
	Low-Flow Spray Heads (1.6 GPM)	3.0 GPM	2%	3.5

	Low-Flow Showerheads (2.5 GPM)	5.0 GPM	2%	1.8
	Chemical Dishwashing System	High Temp Commercial Dishwasher	4%	1.9
	Water Cooled Refrigeration with Heat Recovery	No Heat Recovery	3%	0.9
	Commercial High Efficiency Clothes Washers	Commercial Standard Clothes Washer	23%	0.7
	Water Heater Temperature Setback (115 F)	140 F	15%	43.0
	Demand controlled Circulating Systems		5%	0.1
	Solar Water Heater	Standard Water Heater EF = 0.93	40%	0.5
	Hot Water Pipe Insulation (R-4)	No Insulation	5%	7.5

Faucet Aerators

Faucet aerators, by mixing water and air, lower the water flow from 4.5 gpm to 2.75 gpm. The faucet aerator creates a fine water spray with a screen that is inserted in the faucet head.

Low-Flow Spray Heads

Low-flow spray heads used the same principle as faucet aerators to achieve a flow reduction of nearly 50%, lowering the flow rate to 1.6 GPM from 3.0 GPM.

Low-Flow Showerheads

Low-flow shower heads use the same principle as faucet aerators to achieve a flow reduction of 50%, lowering the flow rate to 2.5 gpm from 5.0 gpm.

Chemical Dishwashing System

Instead of sanitizing the dishes with hot water, chemicals are used instead. This allows for a lower hot water temperature setting with the same cleaning result.

Water-Cooled Refrigeration with Heat Recovery

The heat that is extracted from a refrigeration unit can be recaptured for hot water requirements rather than dumped into the ambient.

Commercial High-Efficiency Clothes Washers

ENERGY STAR® clothes washers for commercial use.

Water Heater Temperature Setback

Often, the setpoint temperature on a hot water system is set higher than generally required. This measure reflects the savings obtained by reducing the setpoint temperature from 140°F to 115°F. Only for existing construction.

Demand-Controlled Circulating Systems

In order to ensure hot water demands are met, some buildings will have continuously circulating hot water systems resulting in energy loss through pipes. To reduce this loss, a demand-controlled circulating system can be installed to only circulate hot water when required.

Solar Water Heater

A solar water heater is generally mounted on the roof of a building and is designed to use the sun to heat water rather than electricity or gas. Note that this is a passive process, not one that involves photovoltaic cells.

Hot Water Pipe Insulation

Adding R-4 insulation around the pipes will decrease heat loss. Only for existing construction.

Refrigeration

Measures that improve refrigeration and/or freezer energy requirements are listed here.

Table A–17. Commercial Electric Refrigeration

Category or End Use	Technology	Baseline	Percent End-Use Savings	TRC
Refrigeration	Installation of Floating Condenser Head Pressure Controls	No Floating Condenser Head Pressure Controls	7%	11.0
	Anti-Sweat (Humidistat) Controls	No Anti-Sweat Controls	5%	39.0
	Refrigeration Compressor VSD retrofit	Constant Speed Drive	6%	2.4
	High Efficiency Case Fans	Standard Efficiency Case Fans	2%	0.3
	Night Covers for Display Cases	No Night Covers	6%	66.0
	Strip Curtains for Walk-Ins	No Strip Curtains	4%	6.0
	Reduced Speed or Cycling of Evaporator Fans		1%	0.5

Installation of Floating Condenser Head Pressure Controls

This technology allows more heat to be rejected through the condenser at low outside air temperatures, thereby increasing the compressor efficiency.

Anti-Sweat (Humidistat) Controls

An humidistat control allows the user to turn off refrigeration display case anti-sweat heaters off when ambient relative humidity is low enough that sweating will not occur. The baseline scenario without the control generally run these heaters continuously.

Refrigeration Compressor VSD Retrofit

A variable speed compressor modulates the motor speed in response to changes in load. When low-load conditions exist, the current to the compressor motor is decreased, decreasing the compressor work done on the refrigerant.

High-efficiency Case Fans

The fans used for circulating cool air in a refrigerated space can be upgraded to a higher efficiency.

Door/Cover Upgrade

There are two measures to reduce heat loss from a refrigerator or freezer unit by improving the barrier between the cold space and ambient air. These measures include night covers for display cases and strip curtains for walk-ins.

Reduced Speed or Cycling of Evaporator Fans

By allowing the evaporator fans to run less frequently or at a lower speed, the evaporator is run to fit the system need, rather than having the fans run continuously at high speed. Only for new construction.

Plug Load

Mostly applicable to office space, plug loads include any devices that do not have a secondary energy conversion use, like refrigeration or heating.

Table A–18. Commercial Electric Plug Load

Category or End Use	Technology	Baseline	Percent End-Use Savings	TRC
Plug Load	Office Computer Network Energy Management	Computers Left On	7%	8.6
	Office Equipment: Monitors, ENERGY STAR or Better	Standard Monitor	2%	0.2
	Office Equipment: Copiers, ENERGY STAR or Better	Standard Copier	1%	0.1
	Office Equipment: Printers, ENERGY STAR or Better	Standard Printer	1%	0.1
	Vending Machines- Controls	No Controls	1%	0.1
	Vending Machines- High Efficiency	Standard Vending Machine	2%	0.5

Lost Opportunity—Equipment

In either existing or new construction, when new equipment needs to be purchased, savings can be gained by purchasing high-efficiency models.

Table A–19. Commercial Electric Lost Opportunity—Equipment

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Cooling Chiller	High Efficiency (0.507 kW/ton)	Standard Efficiency (0.634 kW/ton)	20%	4.4
	Premium Efficiency (0.475 kW/ton)	Standard Efficiency (0.634 kW/ton)	25%	0.3
Cooling DX	High Efficiency (EER=11.3)	Standard Efficiency (EER=10.3)	9%	1.1
	Premium Efficiency (EER=12.2)	Standard Efficiency (EER=10.3)	16%	0.5

High/Premium-Efficiency Centrifugal Chiller

The efficiency of a standard chiller is around 0.634 kW/ton, but high-efficiency chillers with a rated efficiency of 0.507 kW/ton or premium-efficiency with 0.475 kw/ton efficiency are available, resulting in a 20% or 25% energy savings, respectively.

High/Premium-Efficiency DX Package

Increasing the Energy Efficiency Ratio (EER) of DX package chillers from 10.3 to 11.3 or 12.2 will save 9% and 16%, respectively, of the energy use.

Commercial Electric Emerging Technologies

These ET measures are energy-efficiency measures that are not readily available in the current market, but are expected to be so within the 20-yr planning horizon. The different ET measures are in varying stages of "market readiness," and the potential study included the ET measures only after they become market ready.

Lighting

Table A–20. Commercial Electric Emerging Technologies—Lighting

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Lighting	Advanced High Intensity Discharge (HID) Light Sources	400 Watt HID Probe-start Metal Halide Lamp	12%	4.2
	Advanced/Integrated Daylighting controls (ADCs) (10W)	General purpose (2) T8 w/ electronic ballast	8%	0.2
	Cost-Effective Load Shed Ballast and Controller	T8 lamps w/ load shed ballast dimmed at 30%, 100	1%	0.04
	Hospitality Bathroom Lighting	Standard bathroom light used as nightlight	2%	0.4
	Hybrid Solar Lighting	12 60W Fluorescent fixtures w 2 T8 lamps each	52%	0.4
	LED Solid State White Lighting	Incandescent (75 W)	6%	0.1
	Low Wattage Ceramic Metal Halide Lamps	100W Halogen-IR PAR lamps, 11 hrs/day, 4015 hrs/y	17%	0.7
	Scotopic (High CCT) Lighting	(2) 32W T8 Lamps w/ 3500K CCT, electronic ballast	17%	2.0

Advanced HID Light

Conventional high intensity discharge (HID) lamps use an electrical arc column across tungsten electrodes to produce light. Typically, the arc column uses 90% of the electric power, with the remaining 10% dissipated as electrode losses. Advanced HID lamps would shift some energy (infrared) from the arc to near UV or visible emission, improving efficiency. The goal is to raise lumens to 40% above current rate. Introduced in year 15.

Advanced/Integrated Daylighting Controls (ADCs)

In most office spaces, lighting has traditionally been designed to provide an equal amount of light for all occupant spaces; however, lighting may not be needed equally in all spaces. Part-time occupancy and natural daylight may eliminate lighting needs, and individual workers needs and expectations vary. Advanced lighting controls allow more flexibility in maintaining light levels for individual spaces. Introduced in year five.

Cost-effective Load Shed Ballast and Controller

This technology is an instant-start ballast that would receive a signal from a controller to dim lighting fixtures during peak demand periods. The controller would communicate with an outside source, such as a utility company or energy management system, and then send a signal to the ballast to dim lights. Introduced in year 15.

Hospitality Bathroom Lighting

One of the largest energy end-uses in hotels is bathroom lighting, largely due to guests leaving the bathroom light on as a night light. This new technology uses high intensity LEDs and motion sensors to efficiently provide a night light for hotel guests. The nightlight is an integrated unit that fits into a standard wall switch. Introduced in year five.

Hybrid Solar Lighting

Hybrid solar lighting combines roof-top sunlight collectors, light pipes and special luminaries that augment traditional fluorescent lighting with sunlight. Introduced in year 15.

LED Solid State White Lighting

Light emitting diodes (LEDs) are solid-state devices that convert electricity to light, potentially with very high efficiency and long life. Recently, lighting manufacturers have been able to produce "cool" white LED lighting indirectly, using ultraviolet LEDs to excite phosphors that emit a white-appearing light. Replacement for incandescent lamps. Introduced in year five.

Low-Wattage Ceramic Metal Halide Lamps

Advances in metal halide lamp technology have led to the production of ceramic metal halide (CMH) lamps that use ceramic rather than typical quartz arc tubes. Ceramic arc tubes can tolerate a higher temperature than quartz, resulting in improved quality of light color as desired in retail and other color-sensitive applications. CMH lamps represent an attractive alternative to halogen lamps commonly used in these applications due to longer lamp life and 50% less energy required. Introduced in year five.

Scotopic (High CCT) Lighting

Scotopic lighting (high correlated color temperatures) stimulates the eyes’ photoreceptors, increasing visual acuity. Scotopic lighting appears brighter to occupants even when light levels were reduced. Introduced in year five.

Heating, Ventilation, and Air-Conditioning (HVAC)

Table A–21. Commercial Electric Emerging Technologies—HVAC

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Cooling Chillers	Wireless Performace Monitoring, Diagnostics and Control	Standard BAS system	10%	0.5
	Active Window Insulation	No Window Treatment	21%	0.5
	Hotel Key Card Room Energy Control System	No Control	25%	1.4
	Leak Proof Duct Fittings	Standard Duct Workmanship	21%	20.7
	Green Roof	Standard Roofing	13%	0.05
Cooling DX	Active Window Insulation	No Window Treatment	21%	4.5
	Hotel Key Card Room Energy Control System	No Control	25%	1.9
	Leak Proof Duct Fittings	Standard Duct Workmanship	21%	36.0
	Green Roof	Standard Roofing	13%	0.09
Cooling Heat Pump	Active Window Insulation	No Window Treatment	21%	1.1
	Hotel Key Card Room Energy Control System	No Control	25%	2.4
	Leak Proof Duct Fittings	Standard Duct Workmanship	21%	36.0
	Green Roof	Standard Roofing	13%	0.09
Space Heat	Wireless Performace Monitoring, Diagnostics and Control	Standard BAS system	10%	1.1
	Hotel Key Card Room Energy Control System	No Control	25%	5.8
	Leak Proof Duct Fittings	Standard Duct Workmanship	21%	28.0
	Green Roof	Standard Roofing	13%	0.07
HVAC Aux	Underfloor Ventilation with Low Static Pressure	Standard Ventilation	20%	0.6

Wireless Performance Monitoring, Diagnostics and Control

These are second-generation building automation systems that allow for wireless optimization and operation of building systems such as HVAC through computerized monitoring and control software and interfaces. Applicable to Cooling Chillers and Space Heat end uses. Introduced in year 15.

Active Window Insulation

The use of an active window insulation (automated venetian blind) system as a daylighting strategy offers potential savings in cooling-related energy use. As part of a "smart" integrated system, automated blinds can provide dynamic control of daylight exposure in coordinating cooling requirements and current building operating conditions. Applicable all cooling end uses (chillers, heat pumps and DX). Introduced in year five.

Hotel Key Card Room Energy Control System

This is a key card system to control room HVAC and lighting during non-occupied periods. Occupancy is determined by the key card and/or additional sensors. The central system first sets temperature at a minimum level then gives control to the guest for temperature and lighting when the guest enters the room. New construction only. Introduced in year 10.

Leak-proof Duct Fittings

The majority of duct leakage in residential HVAC systems is due to improperly sealed connections between ductwork and fittings. Even when duct connections are initially well-sealed, leakage may increase over time. Although the use of mastics and mechanical fasteners is becoming more widespread, a low cost, leak-proof system will help to transform the market. Introduced in year five.

Green Roof

A green roof is a living roof that supports soil and plant growth. A series of carefully engineered layers are applied to the roof deck. These layers are watertight, lightweight and long-lasting. Green roofs can be incorporated into new and existing buildings as long as load requirements are met. They are suited for roofs that have slopes ranging up to 20 degrees and are most successful when sufficient attention has been paid to selecting plants that will thrive in the local climate and conditions. One of the most significant advantages is that a green roof can last up to three times longer than a standard roof. The added benefit of a green roof's ability to buffer temperature extremes improves a building's energy performance by dropping the temperatures on the roof 3-7 degrees, resulting in approximately a 10% reduction in cooling loads. Introduced in year five.

HVAC Aux. Measures

Under-floor Ventilation with Low Static Pressure

A process by which 100% outside air is introduced under the floor at a low velocity and a temperature slightly below desired room temperature. The occupants, office equipment, and external cooling loads warm the air. Introduced in year five.

Refrigeration

Table A–22. Commercial Electric Emerging Technologies—Refrigeration

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Refrigeration	Efficient Fan Motor Options	Standard Fan	14%	1.7

Efficient Fan Motor Options for Commercial Refrigeration

Fan and fan motors used in condensers and evaporators account for 20% of the annual energy use and operate at overall efficiencies as low as 7-15%. New axial fan blade designs enable improved fan performance, and advanced electric motors such as brushless DC or electronically commutated motors (ECM) offer motor performance solutions. Introduced in year five.

Commercial Gas Measure Descriptions

Percent savings and TRC are averaged over all applicable building types and the TRC is given for the base-case scenario averaged for both discretionary measures and lost opportunity-equipment measures, unless they differ significantly in which case both TRCs are given.

Space Heat

Table A–23. Commercial Gas Space Heat

Category or End Use	Technology	Baseline	Percent End-Use Savings	TRC
Space Heat	Boiler Economizer	No Economizer	10%	0.5
	Programmable Thermostat	No Programmable Thermostat	2%	3.0
	Exhaust Air to Ventilation Air Heat Recovery	No Heat Recovery	20%	0.7
	Convert Constant Volume Air System to VAV	Constant Volume Air System	12%	1.7
	Boiler Tune-Up	No Boiler Tune-Up	2%	0.3
	Duct Insulation (R-8)	R-3	2%	3.1
	Duct Repair and Sealing		2%	1.2
	Windows-High Efficiency (U=0.35)	U = 0.67	5%	0.7 existing 1.9 new
	Insulation - Roof / Ceiling (R-19)	R=0	10%	0.7
	Insulation – Floor (R-19)	R=0	5%	0.3
	Retro-Commissioning		15%	0.3
	Automated Ventilation VFD Control	Constant Ventilation	10%	0.99

Boiler Economizer

Similar to a condensing water heater, a boiler economizer captures heat that would otherwise be lost in the flue gas. In this case, the flue gas energy can be used to pre-heat the water entering the boiler.

Programmable Thermostat

A programmable thermostat simply controls the setpoint temperatures automatically. This allows for lower energy use by ensuring the heating system is not running during low-occupancy hours. Only for existing construction.

Exhaust Air to Ventilation Air Heat Recovery

The air that is exhausted out of a building during the heating season will be warmer than the air outside. Capturing some of this heat and transferring it to the incoming air lowers the overall heating load.

Convert Constant Volume Air System to Variable Volume

Converting to a variable volume system will allow for the drives to operate at an optimal load level and thus, minimize energy consumption. The baseline building system, as the measure name suggests, only runs at a single volume flow. Only for existing construction.

Boiler Tune-Up

Simply put, this measure increases the overall efficiency of the boiler by doing any required maintenance or tune-up. The baseline building will have no tune-up performed. Only for existing construction.

Duct Insulation

Heating systems are generally coupled with a ducting system inside the building. Insulating the ducts will reduce energy loss in the unoccupied plenum space. The baseline value for this insulation is R-3, while the measure increases the insulation to R-8. Only for existing construction.

Duct Repair and Sealing

Basically, by repairing and sealing leaky ducts, significant energy savings could be attained by ensuring the conditioned air is traveling to the occupied spaces. Only for existing construction.

Windows—High-efficiency

This measure represents an increase in performance by changing the U-value from 0.67 to 0.35.

Ceiling/Roof Insulation

The measure represents an increase in R-value to current code values of R-19 in the roof or ceiling for single-story buildings. Only for existing construction.

Floor Insulation

Similar to ceiling/roof insulation, the measure represents an increase in R-value to current code levels of R-19 for the floor space. Only for existing construction.

Retro-Commissioning

“Retro-commissioning” is the process of optimizing the operation of an existing building through simple, low- or no-cost repairs and operational changes. For example, temperature controls will be set to operate only during occupied periods, ensuring that the ideal static pressure is being met for the fans.

Automatic Ventilation VFD Control

This measure allows the ventilation to only run on an as-needed basis. Without it, the ventilation system would run constantly. With it, a CO_2 sensor will detect when ventilation is required, reducing the overall HVAC load.

Water Heat

In addition to a more efficient water heating system, any equipment measures that require less hot water fall under the auspices of water heat measures.

Table A–24. Commercial Gas Water Heat

Category or End Use	Technology	Baseline	Percent End-Use Savings	TRC
Water Heat	Faucet Aerators (1.6 GPM)	4.0 GPM	3%	13.0
	Low-Flow Spray Heads (1.6 GPM)	3.0 GPM	2%	3.0
	Low-Flow Showerheads (2.5 GPM)	5.0 GPM	2%	2.8
	Chemical Dishwashing System	High Temp Commercial Dishwasher	5%	1.3
	Tankless Hot Water System (EF=0.81)	EF=0.59	27%	3.3
	Commercial High Efficiency Clothes Washers	Commercial Standard Clothes Washer	35%	0.7
	Water Heater Temperature Setback (115° F)	140° F	5%	15.0
	Condensing Water Heater (EF=0.9)	EF=0.59	34%	3.5
	Solar Water Heater	EF=0.59	40%	0.8
	Pipe Insulation (R=4)	R=0	2%	6.2
	Demand controlled Circulating Systems		5%	0.2

Faucet Aerators

Faucet aerators, by mixing water and air, lower the water flow from 4.5 gpm to 2.75 gpm. The faucet aerator creates a fine water spray with a screen that is inserted in the faucet head.

Low-Flow Spray Heads

Low-flow spray heads used the same principle as faucet aerators to achieve a flow reduction of nearly 50%, lowering the flow rate to 1.6 gpm from 3.0 gpm.

Low-Flow Showerheads

Low-flow shower heads use the same principle as faucet aerators to achieve a flow reduction of 50%, lowering the flow rate to 2.5 gpm from 5.0 gpm.

Chemical Dishwashing System

Instead of sanitizing the dishes with hot water, chemicals are used instead. This allows for a lower hot water temperature setting with the same cleaning result.

Tankless Hot Water System

If hot water usage is only sporadic, savings can be obtained by using an on-demand, or tankless hot water system. In this system, there is not hot water storage tank, reducing standby losses; rather, a high intensity heating element heats the flowing water when needed. The energy factor can be increased from 0.59 to 0.81 with a tankless system.

Commercial High-Efficiency Clothes Washers

ENERGY STAR clothes washers for commercial use.

Water Heater Temperature Setback

Often, the setpoint temperature on a hot water system is set higher than generally required. This measure reflects the savings obtained by reducing the setpoint temperature from 140^{o}F to 115^{o}F. Only for existing construction.

Condensing Water Heater

Condensing water heaters recover much of the energy lost by water vapor leaving with the flue gases. A large or second heat exchanger that reduces the flue-gas temperature to the point where this water vapor condenses allows the water heater to capture this otherwise lost energy.

Solar Water Heater

A solar water heater is generally mounted on the roof of a building and is designed to use the sun to heat water rather than electricity or gas. Note that this is a passive process, not one that involves photovoltaic cells.

Hot Water Pipe Insulation

Adding R-4 insulation around the pipes will decrease heat loss.

Demand-Controlled Circulating Systems

In order to ensure hot water demands are met, some buildings will have continuously circulating hot water systems resulting in energy loss through pipes. To reduce this loss, a demand-controlled circulating system can be installed to only circulate hot water when required.

Cooking

Table A–25. Commercial Gas Cooking

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Cooking	Power Burner Fryer	Standard Fryer	5%	0.6
	Power Burner Oven	Standard Oven	5%	0.2

Power Burner Fryer/Oven

The power burner range is an improved atmospheric burner. The term "power" means that a blower drives gas and air flow to the burner. Gas and air are mixed in a plenum and the mixture is regulated to achieve more efficient combustion. During combustion, the flame moves sideways from the burner and impinges on a bowl made of low-carbon stainless steel located underneath the burner and increases the amount of radiant heat transmitted to the cooking utensil.

Pool Heat

Table A–26. Commercial Gas Pool Heat

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC Existing	TRC New
Pool Heat	Installation of Solar Pool/Spa Heating Systems		16%	1.1	0.6
	Installation of Swimming Pool / Spa Covers	No Cover	35%	12.0	8.2

Installation of Solar Pool/Spa Heating Systems

Using the energy from the sun to supplement the heat required for pool or spa heating systems can save 16% of the energy required.

Installation of Swimming Pool/Spa Cover

Simply covering a pool or spa when not in use can save 35% of the heating load.

Lost Opportunity—Equipment

In either existing or new construction, when new equipment needs to be purchased, savings can be gained by purchasing high-efficiency models.

Table A–27. Commercial Gas Lost Opportunity—Equipment

Category or End Use	Technology	Baseline	End Use Percent Savings	TRC
Water Heat	High Efficiency (EF=0.64)	Standard Efficiency (EF=0.59)	8%	13.0
	Premium Efficiency (EF=0.70)	Standard Efficiency (EF=0.59)	16%	3.4
	Premium Efficiency (EF=0.92)	Standard Efficiency (EF=0.59)	30%	4.8
Space Heat	High Efficiency (85%)	Standard Efficiency (75%)	12%	1.8

High/Premium-Efficiency Water Heater

The energy factor (EF) of a standard water heater is around 0.59, but high-efficiency water heaters can have an EF=0.64 or premium-efficiency with EF=0.70 are available, resulting in a 8% or 16% energy savings, respectively. For Hotel/Motel buildings, an even higher efficiency EF=0.92 water heater can be installed with a 30% savings.

High-Efficiency Gas Furnace/Boiler

A standard central boiler has an efficiency of approximately 75%, but a high-efficiency boiler can have an 85% efficiency, resulting in an energy savings of 12%.

Commercial Gas Emerging Technologies

These ET measures are energy-efficiency measures that are not readily available in the current market, but are expected to be so within the 20-yr planning horizon. The different ET measures are in varying stages of “market readiness,” and the potential study included the ET measures only after they become market ready. All ET gas measures are space heat measures.

Table A–28. Commercial Gas Emerging Technologies

Category or End Use	Technology	Baseline	Percent End-Use Savings	TRC
Space Heat	Wireless Performance Monitoring, Diagnostics and Control	Building with standard BAS system	10%	0.4
	Leak Proof Duct Fittings	Standard Duct Workmanship	15%	5.0
	Green Roof	Standard Roof	13%	0.03

Wireless Performance Monitoring, Diagnostics and Control

Second-generation building automation systems that allow for wireless optimization and operation of building systems such as HVAC through computerized monitoring and control software and interfaces. Introduced in year 15.

Leak-proof Duct Fittings

The majority of duct leakage in residential HVAC systems is due to improperly sealed connections between ductwork and fittings. Even when duct connections are initially well-sealed, leakage may increase over time. Although the use of mastics and mechanical fasteners is becoming more widespread, a low cost, leak-proof system will help to transform the market. Introduced in year five.

Green Roof

A green roof is a living roof that supports soil and plant growth. A series of carefully engineered layers are applied to the roof deck. These layers are watertight, lightweight and long-lasting. Green roofs can be incorporated into new and existing buildings as long as load requirements are met. They are suited for roofs that have slopes up to 20 degrees and are most successful when sufficient attention has been paid to selecting plants that will thrive in the local climate and conditions. One of the most significant advantages is that a green roof can last up to three times longer than a standard roof. The added benefit of a green roof's ability to buffer temperature extremes improves a building's energy performance by dropping the temperatures on the roof 3-7 degrees, resulting in approximately a 10% reduction in cooling loads. Introduced in year five.

Industrial Electric Measure Descriptions

In the tables, the End-Use Percent savings and TRC are averaged over all applicable building types for year 20 and the TRC is given for the base-case scenario.

. **Table A–28. Industrial Electric**

Category or End Use	Measure	End Use Percent Savings	TRC
Process	Cooling Improvements	7%	10.0
	Fan System Improvements	16%	10.0
	Pump System Improvements	38%	10.0
	Other Motor Improvements	10%	10.0
	Air Compressor Improvements	19%	13.0
	Air Compressor O&M	14%	7.7
	Refrigeration	7%	10.0
Building	Lighting	14%	4.6
	HVAC	11%	2.9

<u>Process-Related Measures</u>

Any measures to improve the industrial process, not specific to the building itself.

Process Cooling Improvements

Improvements that will decrease the energy required for process-related cooling. Examples would include avoid frost formation on evaporators, shutting of cooling water when not required, using economic thickness of insulation for low temperatures.

Fan System Improvements

Savings from variable-speed drives (VSD) and/or improvements to the design of the fan system, such as better fans, ducting and flow design.

Pump System Improvements

Similar to fan system improvements, with savings from a VSD and/or improvements to the overall pump system, such as better pumps, more efficient piping and eliminating unnecessary flows.

Other Motor Improvements

Improvements to motors not specific to fans or pumps. This would include using higher efficiency motors, improved rewind practices and correct motor sizing.

Air Compressor Improvements

Air compressor energy efficiency, used in the industrial process, can be improved by installing compressor air intakes in coolest locations, or using optimum-sized compressors, amongst others.

Air Compressor O&M

Changing operation and maintenance (O&M) procedures of an air compressor can improve the overall energy efficiency of a plant. Some O&M examples include reducing the pressure of compressed air to the minimum required, cooling compressor air intake with a heat exchanger or eliminating leaks.

Refrigeration Improvements

Refrigeration improvements can include isolating hot equipment from refrigerated area, using highest allowable temperature for refrigerated space or modify refrigeration system to operate at a lower pressure.

Building-Related Measures

Any measures to improve building itself, not specific to the industrial process.

Lighting Improvements

Any changes to overall illumination levels, use of natural lighting, or technology improvements to use more efficient bulbs or ballasts that will decrease the overall lighting energy consumption.

HVAC Improvements

There are many changes that can be made to reduce the energy consumption in HVAC control of a plant. Many are measures found in the commercial and residential lists. A sample of improvements include: air condition only space in use, install timers and/or thermostats, lower ceiling to reduce conditioned space, install or upgrade insulation on distribution system.

Industrial Gas Measure Descriptions

The measures percent savings and TRC are averaged over all industrial segments.

Table A–29. Industrial Gas

Category or End Use	Measure	End Use Percent Savings	TRC
Process	Boiler Upgrade	7%	7.0
	Boiler O&M	5%	4.6
	Steam Distribution	14%	10.0
Building	HVAC	11%	2.0

Process Boiler Upgrades

The boiler is generally used to create hot water. Savings can be found by installing a waste heat boiler to provide direct power or using flue gas heat to preheat boiler feedwater.

Process Boiler O&M

Such improvements would include reducing water temperature to the minimum required or replacing/cleaning filters.

Steam Distribution Systems

Any elimination in leaks or improved insulation to the ducting will reduce loss in a distribution system.

HVAC Improvements

There are many changes that can be made to reduce the energy consumption in HVAC control of a plant. Many are measures found in the commercial and residential lists. A sample of improvements include: install timers and/or thermostats, lower ceiling to reduce conditioned space, install or upgrade insulation on distribution system.

Fuel Conversion Measure Descriptions

For fuel conversion, four end uses were considered: Space Heating, Zone Heating, Water Heating and Appliances. The associated measures are given in the table below.

Table A–30. Fuel Conversion

End Use	Gas Measure
Space Heating	90 AFUE condensing furnace
	96 AFUE condensing furnace
Zone Heating	84% efficient wall heater
Water Heating	EF=0.64 storage water heater
	EF=0.82 tankless water heater
Appliances	Gas dryer w/ moisture sensor
	Convection gas range

For space and water heating, the first measure is the highest-efficiency measure that is cost-effective from the energy-efficiency scenario. However, within the fuel conversion cost-effectiveness screen, the higher-efficiency measures also pass. Since those measures are currently less commonly available, it is likely that the higher-efficiency measures will become phased in over time. Thus, over the first 10 years, the higher-efficiency space and water heaters are linearly increasing in market share from zero (year 1) to 50% (year 10) and maintained at 50% from years 11-20. Descriptions of these measures can be found in the residential gas energy-efficiency measure descriptions section.

Distributed Generation Measure Descriptions

Non-Renewable Generation

Combined Heat and Power

A more energy-efficient use of a non-renewable generation unit is as a combined heat and power (CHP) plant. CHP starts with a standard non-renewable generator, but improves the overall utility by capturing the waste heat produced by the generator. For example, a typical spark-ignition engine has an electrical efficiency of only about 35%. The “lost” energy is primarily waste heat. A CHP unit will capture much of this waste heat and use it for space heating or water heat. Thus, there are cost savings for the water heating in addition to electricity generation. Three engine generator technologies are considered for use with CHP: reciprocating engines, microturbines and fuel cells.

Reciprocating Engine (CHP-RE)

Reciprocating engines generate power by a compression/expansion cycle of a piston moving back and forth within a cylinder. The movement of the piston is driven by heating/cooling of the gas inside the cylinder. The linear movement of the piston drives a generator, creating electricity. In this study, only natural-gas fueled spark-ignition engines were considered. These spark-ignition engines can range in capacity from 1-5000 kW.

Microturbines (CHP-MT)

A microturbine (MT) is a small gas turbine. Natural gas is generally used, but a MT is known to be fairly flexible with the quality of fuel used, making them attractive for use with biogas. Microturbines range in capacity from 30-400 kW.

Fuel Cells (CHP-FC)

Fuel cells produce power electrochemically rather than by combustion. A fuel cell is composed of two electrodes separated by an electrolyte. The fuel (hydrogen) enters via one electrode while the air/O_2 enters the other. The hydrogen is split into its proton and electron components and is then driven in opposite directions, completing a circuit and creating a current. The only waste products are H_2O in this situation. However, due to the relative scarcity of H_2 gas, a reformer is often coupled with the fuel cell that transforms a hydrocarbon (e.g., methane) into H_2 for the fuel cell and also creates waste CO_2. There are several different types of fuel cells, most commonly used are PAFC (phosphoric acid fuel cell) and PEMFC (proton-exchange membrane fuel cell). PAFC are currently available in 200 kW units, and PEMFCs are generally in 150 kW units.

Renewable Generation

Renewable generation encompasses all generation that uses a renewable energy source for the fuel. In other words, a fossil fuel is not consumed. There are two main categories of renewable generation: biomass and clean energy.

Biomass

Sometimes referred to as “resource recovery,” biomass is used as the fuel to drive a generator. The source of the biomass can vary, but can be broadly categorized into “industrial biomass” or “anaerobic digesters.”

Industrial Biomass

Industrial Biomass refers to the waste-recovery used for generation found at industrial facilities, such as pulp and paper industry, lumber mills, etc. The waste products from these processes is combusted in a steam or gas turbine. The turbines are used in a CHP capacity, capturing the excess heat for space/water or process heating. Industrial biomass is generally large scale, >1 MW.

Anaerobic Digesters

Anaerobic digesters create methane gas by the breakdown of municipal solid waste, landfill gas or dairy farm waste. Any of the above CHP technologies (RE, MT or FC) can be used to combust this recovered methane to generate electricity required by the facility. The captured heat is fed back into the digester to maintain appropriate temperatures.

Clean Energy

This is generation that is achieved without the consumption of a hydrocarbon fuel. The two main sources for clean energy are wind, and solar photovoltaics (PV).

Wind

Wind energy is captured by rotors that spin and drive a turbine. Energy output is based on wind speed and swept area of the rotors. Thus, different sized rotors can be used to achieve different power requirements. Depending on time of day and time of year, energy output is variable. Wind turbines can range in size from <1 kW to >1 MW.

PV

Solar energy is often generated by use of photovoltaic (PV) cells. The conversion efficiency from sunlight to electricity is relatively low (~<20%) and highly dependent on weather conditions, time of day, and time of year, which can result in fairly low capacity factors. PV panels are modular and thus can come in a wide range of capacities.

Emerging Technologies

Since only technology classes are considered, emerging technologies do not change these categorizations. Rather, the ET scenario assumes price reductions (for PV, CHP-MT, CHP-FC, and anaerobic digesters), capacity factor increases (wind), and sector penetration (residential CHP added).

Measure Data Sources

Residential (Cost and Lifetime)

- Home Depot website
- Lowe’s website
- Sears website
- RS Means (labor cost)
- Deer database
- Previous studies (2003 PSE study, Tacoma Power potential study (2006))
- Cost data provided by PSE
- Engineering judgment

Commercial

- Deer database
- Trane
- Previous studies (2003 PSE study, Tacoma Power potential study (2006), MidAmerican Energy study (2005), GRE potential study (2006))
- Cost data provided by PSE
- Engineering judgment

Industrial

- Energy Information Administration: Manufacturing Energy Consumption Survey
- Office of Energy Efficiency and Renewable Energy (DOE-EERE) Office of Industrial Technologies: U.S. Industrial Electric Motor Systems Market Opportunities Assessment
- DOE-EERE Industrial Technologies Program: Industrial Assessment Centers Database

Appendix B: Energy Efficiency and Emerging Technologies: Inputs and Assumptions

Appendix B follows.

Table B-1. Residential Electric Measures

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Manufactured	Central_AC	Existing	Central AC - Advanced Technolgy	408.0828968			15	$1,125	28%
Manufactured	Central_AC	Existing	Central AC - High Efficiency	408.0828968			15	$225	7%
Manufactured	Central_AC	Existing	Central AC - Premium Efficiency	408.0828968			15	$688	19%
Manufactured	Central_AC	New	Central AC - Advanced Technolgy	422.40914			15	$1,125	28%
Manufactured	Central_AC	New	Central AC - High Efficiency	422.40914			15	$225	7%
Manufactured	Central_AC	New	Central AC - Premium Efficiency	422.40914			15	$688	19%
Manufactured	Dryer	Existing	Advanced Appliance Motor ECM	808.859336	100%	80%	14	$239	11%
Manufactured	Dryer	New	Advanced Appliance Motor ECM	678.4723584	100%	80%	14	$239	11%
Manufactured	Freezer	Existing	Freezer - Energy Star or better	561.6549503			15	$60	10%
Manufactured	Freezer	New	Freezer - Energy Star or better	559.4267898			18	$60	10%
Manufactured	Heat_Pump	Existing	ASHP - High Efficiency	4131.201203			20	$236	9%
Manufactured	Heat_Pump	Existing	ASHP - Premium Efficiency	4131.201203			20	$534	14%
Manufactured	Heat_Pump	Existing	Advanced Cold-Climate Heat Pump	4131.201203	100%	29%	20	$4,300	17%
Manufactured	Heat_Pump	Existing	Check Me O & M Tune-up	4131.201203	75%	90%	3	$225	17%
Manufactured	Heat_Pump	Existing	CheckMe! Heat Pump Duct Sealing	4131.201203	93%	50%	20	$850	25%
Manufactured	Heat_Pump	Existing	ES Windows (Class 30)	4131.201203	85%	95%	25	$2,300	17%
Manufactured	Heat_Pump	Existing	Insulation-Ceiling	4131.201203	90%	5%	25	$765	9%
Manufactured	Heat_Pump	Existing	Insulation-Floor	4131.201203	92%	88%	25	$1,400	11%
Manufactured	Heat_Pump	Existing	Insulation-Wall 2x4	4131.201203	15%	75%	25	$1,660	10%
Manufactured	Heat_Pump	Existing	Micro Channel Heat Exchangers (Evaporator)	4131.201203	100%	75%	18.4	$145	5%
Manufactured	Heat_Pump	Existing	Small Scale Absorption Cooling	4131.201203	100%	14%	20	$3,000	18%
Manufactured	Heat_Pump	Existing	Solid State refrigeration cool chips for heat pumps	4131.201203	100%	29%	18.4	$2,000	26%
Manufactured	Heat_Pump	Existing	Whole house air sealing	4131.201203	93%	90%	10	$300	5%
Manufactured	Heat_Pump	New	ASHP - High Efficiency	3124.262035			20	$236	9%
Manufactured	Heat_Pump	New	ASHP - Premium Efficiency	3124.262035			20	$534	14%
Manufactured	Heat_Pump	New	Advanced Cold-Climate Heat Pump	3124.262035	100%	29%	20	$4,300	17%
Manufactured	Heat_Pump	New	Air-to-Air Heat Exchangers	3124.262035	85%	20%	15	$1,440	10%
Manufactured	Heat_Pump	New	ES Labeled - New Manufactured Housing	3124.262035	95%	70%	23	$1,100	34%
Manufactured	Heat_Pump	New	Leak Proof Duct Fittings	3124.262035	100%	90%	30	$160	17%
Manufactured	Heat_Pump	New	Micro Channel Heat Exchangers (Evaporator)	3124.262035	100%	75%	18.4	$145	5%
Manufactured	Heat_Pump	New	Small Scale Absorption Cooling	3124.262035	100%	14%	20	$3,000	9%
Manufactured	Heat_Pump	New	Solid State refrigeration cool chips for heat pumps	3124.262035	100%	29%	18.4	$2,000	18%
Manufactured	Lighting	Existing	CFL Fixtures, High Use	2164.03587	65%	95%	10	$60	9%
Manufactured	Lighting	Existing	CFL Fixtures, Low Use	2164.03587	75%	95%	10	$60	2%
Manufactured	Lighting	Existing	CFL Fixtures, Medium Use	2164.03587	70%	95%	10	$60	2%
Manufactured	Lighting	Existing	CFL Lamps, High Use	2164.03587	65%	95%	6	$5	43%
Manufactured	Lighting	Existing	CFL Lamps, Low Use	2164.03587	75%	95%	12	$5	9%
Manufactured	Lighting	Existing	CFL Lamps, Medium Use	2164.03587	70%	95%	8	$5	6%
Manufactured	Lighting	Existing	CFL Torchieries, High Use	2164.03587	65%	95%	8	$90	3%
Manufactured	Lighting	Existing	CFL Torchieries, Low Use	2164.03587	75%	95%	8	$90	1%
Manufactured	Lighting	Existing	CFL Torchieries, Medium Use	2164.03587	70%	95%	8	$90	1%
Manufactured	Lighting	Existing	LED Interior Lighting (White), High Use	2164.03587	100%	50%	10	$28	54%
Manufactured	Lighting	Existing	LED Interior Lighting (White), Low Use	2164.03587	100%	50%	10	$28	11%
Manufactured	Lighting	Existing	LED Interior Lighting (White), Medium Use	2164.03587	100%	50%	10	$28	8%
Manufactured	Lighting	New	CFL Fixtures, High Use	2164.03587	55%	95%	10	$60	9%
Manufactured	Lighting	New	CFL Fixtures, Low Use	2164.03587	70%	95%	10	$60	2%
Manufactured	Lighting	New	CFL Fixtures, Medium Use	2164.03587	60%	95%	10	$60	2%
Manufactured	Lighting	New	CFL Lamps, High Use	2164.03587	55%	95%	6	$5	43%
Manufactured	Lighting	New	CFL Lamps, Low Use	2164.03587	70%	95%	12	$5	9%
Manufactured	Lighting	New	CFL Lamps, Medium Use	2164.03587	60%	95%	8	$5	6%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Manufactured	Lighting	New	CFL Torchieries, High Use	2164.03587	55%	95%	8	$90	3%
Manufactured	Lighting	New	CFL Torchieries, Low Use	2164.03587	70%	95%	8	$90	1%
Manufactured	Lighting	New	CFL Torchieries, Medium Use	2164.03587	60%	95%	8	$90	1%
Manufactured	Lighting	New	LED Interior Lighting (White), High Use	2164.03587	100%	50%	10	$28	54%
Manufactured	Lighting	New	LED Interior Lighting (White), Low Use	2164.03587	100%	50%	10	$28	11%
Manufactured	Lighting	New	LED Interior Lighting (White), Medium Use	2164.03587	100%	50%	10	$28	8%
Manufactured	Plug_Load	Existing	1-Watt Standby Power	1933.842831	100%	21%	7	$120	14%
Manufactured	Plug_Load	Existing	Advanced Appliance Motor ECMs, (2) Other	1933.842831	100%	80%	14	$1,082	10%
Manufactured	Plug_Load	Existing	Digital set top Receivers	1933.842831	80%	100%	6	$0	0%
Manufactured	Plug_Load	Existing	Efficient DVD systems	1933.842831	70%	100%	7	$0	0%
Manufactured	Plug_Load	Existing	Efficient high definition televisions	1933.842831	95%	100%	8	$250	5%
Manufactured	Plug_Load	Existing	Office Equipment: Computer, Energy Star or Better	1933.842831	65%	100%	4	$0	1%
Manufactured	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	1933.842831	50%	100%	4	$0	2%
Manufactured	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	1933.842831	85%	100%	5	$0	2%
Manufactured	Plug_Load	Existing	Power supply transformer/converter - External pow	1933.842831	90%	100%	15	$47	1%
Manufactured	Plug_Load	Existing	Powerstrip with Occupancy Sensor	1933.842831	100%	100%	20	$90	1%
Manufactured	Plug_Load	New	1-Watt Standby Power	1933.842831	100%	21%	7	$120	14%
Manufactured	Plug_Load	New	Advanced Appliance Motor ECMs, (2) Other	1933.842831	100%	80%	14	$1,082	10%
Manufactured	Plug_Load	New	Digital set top Receivers	1933.842831	80%	100%	6	$0	0%
Manufactured	Plug_Load	New	Efficient DVD systems	1933.842831	70%	100%	7	$0	0%
Manufactured	Plug_Load	New	Efficient high definition televisions	1933.842831	95%	100%	8	$250	5%
Manufactured	Plug_Load	New	Office Equipment: Computer, Energy Star or Better	1933.842831	65%	100%	4	$0	1%
Manufactured	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	1933.842831	50%	100%	4	$0	2%
Manufactured	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	1933.842831	85%	100%	5	$0	2%
Manufactured	Plug_Load	New	Power supply transformer/converter - External pow	1933.842831	90%	100%	15	$47	1%
Manufactured	Plug_Load	New	Powerstrip with Occupancy Sensor	1933.842831	100%	100%	20	$90	2%
Manufactured	Refrigeration	Existing	1 kWh/day Refrigerator	660.1565818	100%	90%	18	$160	27%
Manufactured	Refrigeration	Existing	Refrigerator, Energy Star or better	660.1565818			18	$80	15%
Manufactured	Refrigeration	Existing	Removal of Old Refrigerator	660.1565818	100%	2%	7	$200	100%
Manufactured	Refrigeration	Existing	Solid state refrigeration (cool chips ™)	660.1565818	100%	90%	19	$860	52%
Manufactured	Refrigeration	New	1 kWh/day Refrigerator	657.2166478	100%	90%	18	$160	27%
Manufactured	Refrigeration	New	Refrigerator, Energy Star or better	657.2166478			18	$80	15%
Manufactured	Refrigeration	New	Solid state refrigeration (cool chips ™)	657.2166478	100%	90%	19	$860	40%
Manufactured	Room_AC	Existing	Room AC - Energy Star	192.4457643			12	$33	9%
Manufactured	Room_AC	New	Room AC - Energy Star	204.0696333			12	$33	9%
Manufactured	Space_Heat	Existing	Duct Insulation	6971.605182	20%	50%	25	$300	3%
Manufactured	Space_Heat	Existing	ES Windows (Class 30)	6971.605182	85%	95%	25	$2,300	17%
Manufactured	Space_Heat	Existing	Insulation-Ceiling	6971.605182	90%	5%	25	$765	9%
Manufactured	Space_Heat	Existing	Insulation-Floor	6971.605182	92%	88%	25	$1,400	11%
Manufactured	Space_Heat	Existing	Insulation-Wall 2x4	6971.605182	15%	75%	25	$1,660	10%
Manufactured	Space_Heat	Existing	PTCS Duct Sealing	6971.605182	50%	50%	20	$1,000	9%
Manufactured	Space_Heat	Existing	Whole house air sealing	6971.605182	93%	90%	10	$300	5%
Manufactured	Space_Heat	New	Air-to-Air Heat Exchangers	3067.951106	85%	20%	15	$1,440	10%
Manufactured	Space_Heat	New	ES Labeled - New Manufactured Housing	3067.951106	95%	70%	23	$1,100	34%
Manufactured	Space_Heat	New	Leak Proof Duct Fittings	3067.951106	100%	90%	30	$160	17%
Manufactured	Water_Heat	Existing	Energy Star Clothes Washer	2635.123624	50%	95%	14	$600	13%
Manufactured	Water_Heat	Existing	Energy Star Dishwasher	2635.123624	20%	75%	13	$45	2%
Manufactured	Water_Heat	Existing	Faucet Aerators	2635.123624	55%	95%	5	$5	1%
Manufactured	Water_Heat	Existing	Heat Pump Water Heater	2635.123624	95%	65%	10	$1,750	40%
Manufactured	Water_Heat	Existing	Hot Water Pipe Insulation	2635.123624	62%	75%	15	$8	1%
Manufactured	Water_Heat	Existing	Low-Flow Showerheads	2635.123624	45%	95%	7	$20	3%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Manufactured	Water_Heat	Existing	Solar Water Heater	2635.123624	95%	45%	15	$5,500	40%
Manufactured	Water_Heat	New	Energy Star Clothes Washer	2294.708748	50%	98%	14	$600	13%
Manufactured	Water_Heat	New	Energy Star Dishwasher	2294.708748	20%	75%	13	$45	2%
Manufactured	Water_Heat	New	Faucet Aerators	2294.708748	45%	100%	5	$5	1%
Manufactured	Water_Heat	New	Heat Pump Water Heater	2294.708748	95%	65%	10	$1,750	40%
Manufactured	Water_Heat	New	Low-Flow Showerheads	2294.708748	45%	95%	7	$20	2%
Manufactured	Water_Heat	New	Solar Water Heater	2294.708748	95%	45%	15	$5,500	40%
Multi_Family	Central_AC	Existing	Central AC - Advanced Technolgy	175.4174762			15	$1,125	28%
Multi_Family	Central_AC	Existing	Central AC - High Efficiency	175.4174762			15	$225	7%
Multi_Family	Central_AC	Existing	Central AC - Premium Efficiency	175.4174762			15	$688	19%
Multi_Family	Central_AC	New	Central AC - Advanced Technolgy	205.5508698			15	$1,125	28%
Multi_Family	Central_AC	New	Central AC - High Efficiency	205.5508698			15	$225	7%
Multi_Family	Central_AC	New	Central AC - Premium Efficiency	205.5508698			15	$688	19%
Multi_Family	Dryer	Existing	Advanced Appliance Motor ECM	725.8048846	100%	80%	14	$239	11%
Multi_Family	Dryer	New	Advanced Appliance Motor ECM	608.8061668	100%	80%	14	$239	11%
Multi_Family	Freezer	Existing	Freezer - Energy Star or better	417.3812341			15	$60	10%
Multi_Family	Freezer	New	Freezer - Energy Star or better	417.3812341			15	$60	10%
Multi_Family	Heat_Pump	Existing	ASHP - High Efficiency	1541.643376			20	$236	9%
Multi_Family	Heat_Pump	Existing	ASHP - Premium Efficiency	1541.643376			20	$534	14%
Multi_Family	Heat_Pump	Existing	Advanced Cold-Climate Heat Pump	1541.643376	100%	29%	20	$4,300	17%
Multi_Family	Heat_Pump	Existing	CheckMe Aerosol-Based Duct Sealing	1541.643376	100%	19%	25	$450	19%
Multi_Family	Heat_Pump	Existing	ES Windows (Class 30)	1541.643376	85%	85%	30	$1,760	17%
Multi_Family	Heat_Pump	Existing	Insulated exterior entry doors with built-in weather-s	1541.643376	75%	100%	10	$300	4%
Multi_Family	Heat_Pump	Existing	Insulation-Wall 2x4	1541.643376	15%	75%	30	$624	10%
Multi_Family	Heat_Pump	Existing	Micro Channel Heat Exchangers (Evaporator)	1541.643376	100%	75%	18.4	$145	5%
Multi_Family	Heat_Pump	Existing	Small Scale Absorption Cooling	1541.643376	100%	14%	20	$2,000	18%
Multi_Family	Heat_Pump	Existing	Solid State refrigeration cool chips for heat pumps	1541.643376	100%	29%	18.4	$1,000	26%
Multi_Family	Heat_Pump	Existing	Whole house air sealing	1541.643376	100%	90%	10	$650	5%
Multi_Family	Heat_Pump	New	ASHP - High Efficiency	1165.88315			20	$236	9%
Multi_Family	Heat_Pump	New	ASHP - Premium Efficiency	1165.88315			20	$534	14%
Multi_Family	Heat_Pump	New	Advanced Cold-Climate Heat Pump	1165.88315	100%	29%	20	$4,300	17%
Multi_Family	Heat_Pump	New	Air-to-Air Heat Exchangers	1165.88315	85%	75%	15	$1,440	10%
Multi_Family	Heat_Pump	New	Green Roof	1165.88315	100%	25%	30	$19,700	13%
Multi_Family	Heat_Pump	New	Leak Proof Duct Fittings	1165.88315	100%	90%	30	$160	17%
Multi_Family	Heat_Pump	New	Micro Channel Heat Exchangers (Evaporator)	1165.88315	100%	75%	18.4	$145	5%
Multi_Family	Heat_Pump	New	Small Scale Absorption Cooling	1165.88315	100%	14%	20	$2,000	9%
Multi_Family	Heat_Pump	New	Solid State refrigeration cool chips for heat pumps	1165.88315	100%	29%	18.4	$1,000	18%
Multi_Family	Lighting	Existing	CFL Fixtures, High Use	1471.240718	65%	95%	10	$60	9%
Multi_Family	Lighting	Existing	CFL Fixtures, Low Use	1471.240718	75%	95%	10	$60	2%
Multi_Family	Lighting	Existing	CFL Fixtures, Medium Use	1471.240718	70%	95%	10	$60	2%
Multi_Family	Lighting	Existing	CFL Lamps, High Use	1471.240718	65%	95%	6	$5	43%
Multi_Family	Lighting	Existing	CFL Lamps, Low Use	1471.240718	75%	95%	12	$5	9%
Multi_Family	Lighting	Existing	CFL Lamps, Medium Use	1471.240718	70%	95%	8	$5	6%
Multi_Family	Lighting	Existing	CFL Torchieries, High Use	1471.240718	65%	95%	8	$90	3%
Multi_Family	Lighting	Existing	CFL Torchieries, Low Use	1471.240718	75%	95%	8	$90	1%
Multi_Family	Lighting	Existing	CFL Torchieries, Medium Use	1471.240718	70%	95%	8	$90	1%
Multi_Family	Lighting	Existing	LED Interior Lighting (White), High Use	1471.240718	100%	50%	10	$28	54%
Multi_Family	Lighting	Existing	LED Interior Lighting (White), Low Use	1471.240718	100%	50%	10	$28	11%
Multi_Family	Lighting	Existing	LED Interior Lighting (White), Medium Use	1471.240718	100%	50%	10	$28	8%
Multi_Family	Lighting	New	CFL Fixtures, High Use	1471.240718	55%	95%	10	$60	9%
Multi_Family	Lighting	New	CFL Fixtures, Low Use	1471.240718	70%	95%	10	$60	2%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Multi_Family	Lighting	New	CFL Fixtures, Medium Use	1471.240718	60%	95%	10	$60	2%
Multi_Family	Lighting	New	CFL Lamps, High Use	1471.240718	55%	95%	6	$5	43%
Multi_Family	Lighting	New	CFL Lamps, Low Use	1471.240718	70%	95%	12	$5	9%
Multi_Family	Lighting	New	CFL Lamps, Medium Use	1471.240718	60%	95%	8	$5	6%
Multi_Family	Lighting	New	CFL Torchieries, High Use	1471.240718	55%	95%	8	$90	3%
Multi_Family	Lighting	New	CFL Torchieries, Low Use	1471.240718	70%	95%	8	$90	1%
Multi_Family	Lighting	New	CFL Torchieries, Medium Use	1471.240718	60%	95%	8	$90	1%
Multi_Family	Lighting	New	LED Interior Lighting (White), High Use	1471.240718	100%	50%	10	$28	54%
Multi_Family	Lighting	New	LED Interior Lighting (White), Low Use	1471.240718	100%	50%	10	$28	11%
Multi_Family	Lighting	New	LED Interior Lighting (White), Medium Use	1471.240718	100%	50%	10	$28	8%
Multi_Family	Plug_Load	Existing	1-Watt Standby Power	2344.293072	100%	21%	7	$120	9%
Multi_Family	Plug_Load	Existing	Advanced Appliance Motor ECMs, (2) Other	2344.293072	100%	80%	14	$1,082	8%
Multi_Family	Plug_Load	Existing	Digital set top Receivers	2344.293072	80%	100%	6	$0	0%
Multi_Family	Plug_Load	Existing	Efficient DVD systems	2344.293072	70%	100%	7	$0	0%
Multi_Family	Plug_Load	Existing	Efficient high definition televisions	2344.293072	95%	100%	8	$250	4%
Multi_Family	Plug_Load	Existing	Office Equipment: Computer, Energy Star or Better	2344.293072	65%	100%	4	$0	0%
Multi_Family	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	2344.293072	50%	100%	4	$0	1%
Multi_Family	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	2344.293072	85%	100%	5	$0	1%
Multi_Family	Plug_Load	Existing	Power supply transformer/converter - External pow	2344.293072	90%	100%	15	$47	1%
Multi_Family	Plug_Load	Existing	Powerstrip with Occupancy Sensor	2344.293072	100%	100%	20	$90	2%
Multi_Family	Plug_Load	New	1-Watt Standby Power	2344.293072	100%	21%	7	$120	9%
Multi_Family	Plug_Load	New	Advanced Appliance Motor ECMs, (2) Other	2344.293072	100%	80%	14	$1,082	8%
Multi_Family	Plug_Load	New	Digital set top Receivers	2344.293072	80%	100%	6	$0	0%
Multi_Family	Plug_Load	New	Efficient DVD systems	2344.293072	70%	100%	7	$0	0%
Multi_Family	Plug_Load	New	Efficient high definition televisions	2344.293072	95%	100%	8	$250	4%
Multi_Family	Plug_Load	New	Office Equipment: Computer, Energy Star or Better	2344.293072	65%	100%	4	$0	0%
Multi_Family	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	2344.293072	50%	100%	4	$0	1%
Multi_Family	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	2344.293072	85%	100%	5	$0	1%
Multi_Family	Plug_Load	New	Power supply transformer/converter - External pow	2344.293072	90%	100%	15	$47	1%
Multi_Family	Plug_Load	New	Powerstrip with Occupancy Sensor	2344.293072	100%	100%	20	$90	2%
Multi_Family	Refrigeration	Existing	1 kWh/day Refrigerator	550.7538215	100%	90%	18	$160	27%
Multi_Family	Refrigeration	Existing	Refrigerator, Energy Star or better	550.7538215			18	$80	15%
Multi_Family	Refrigeration	Existing	Removal of Old Refrigerator	550.7538215	100%	1%	7	$200	100%
Multi_Family	Refrigeration	Existing	Solid state refrigeration (cool chips ™)	550.7538215	100%	90%	19	$860	52%
Multi_Family	Refrigeration	New	1 kWh/day Refrigerator	639.7255077	100%	90%	18	$160	27%
Multi_Family	Refrigeration	New	Refrigerator, Energy Star or better	639.7255077			18	$80	15%
Multi_Family	Refrigeration	New	Solid state refrigeration (cool chips ™)	639.7255077	100%	90%	19	$860	40%
Multi_Family	Room_AC	Existing	Room AC - Energy Star	169.1600191			12	$33	9%
Multi_Family	Room_AC	New	Room AC - Energy Star	172.5398786			12	$33	9%
Multi_Family	Space_Heat	Existing	Duct Insulation	2215.543912	20%	25%	30	$245	3%
Multi_Family	Space_Heat	Existing	ES Windows (Class 30)	2215.543912	85%	85%	30	$1,760	17%
Multi_Family	Space_Heat	Existing	Insulated exterior entry doors with built-in weather-s	2215.543912	75%	100%	10	$300	4%
Multi_Family	Space_Heat	Existing	Insulation-Wall 2x4	2215.543912	15%	75%	30	$624	10%
Multi_Family	Space_Heat	Existing	PTCS Aerosol-Based Duct Sealing	2215.543912	100%	19%	25	$450	9%
Multi_Family	Space_Heat	Existing	PTCS Duct Sealing	2215.543912	50%	25%	20	$630	9%
Multi_Family	Space_Heat	Existing	Whole house air sealing	2215.543912	100%	90%	10	$650	5%
Multi_Family	Space_Heat	New	Air-to-Air Heat Exchangers	1258.240321	85%	75%	15	$1,440	10%
Multi_Family	Space_Heat	New	Green Roof	1258.240321	100%	50%	30	$19,700	13%
Multi_Family	Space_Heat	New	Leak Proof Duct Fittings	1258.240321	100%	90%	30	$160	17%
Multi_Family	Water_Heat	Existing	Energy Star Clothes Washer	2368.757886	52%	85%	14	$600	13%
Multi_Family	Water_Heat	Existing	Energy Star Dishwasher	2368.757886	20%	80%	13	$45	2%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Multi_Family	Water_Heat	Existing	Faucet Aerators	2368.757886	50%	95%	5	$5	1%
Multi_Family	Water_Heat	Existing	Heat Pump Water Heater	2368.757886	95%	65%	10	$1,750	40%
Multi_Family	Water_Heat	Existing	Hot Water Pipe Insulation	2368.757886	62%	70%	15	$8	1%
Multi_Family	Water_Heat	Existing	Low-Flow Showerheads	2368.757886	45%	95%	7	$20	3%
Multi_Family	Water_Heat	Existing	Solar Water Heater	2368.757886	95%	45%	15	$5,500	40%
Multi_Family	Water_Heat	New	Energy Star Clothes Washer	2057.847911	52%	97%	14	$600	13%
Multi_Family	Water_Heat	New	Energy Star Dishwasher	2057.847911	20%	80%	13	$45	2%
Multi_Family	Water_Heat	New	Faucet Aerators	2057.847911	40%	100%	5	$5	1%
Multi_Family	Water_Heat	New	Heat Pump Water Heater	2057.847911	95%	65%	10	$1,750	40%
Multi_Family	Water_Heat	New	Low-Flow Showerheads	2057.847911	45%	95%	7	$20	2%
Multi_Family	Water_Heat	New	Solar Water Heater	2057.847911	95%	45%	15	$5,500	40%
Single_Family	Central_AC	Existing	Central AC - Advanced Technolgy	314.8976925			15	$1,125	28%
Single_Family	Central_AC	Existing	Central AC - High Efficiency	314.8976925			15	$225	7%
Single_Family	Central_AC	Existing	Central AC - Premium Efficiency	314.8976925			15	$688	19%
Single_Family	Central_AC	New	Central AC - Advanced Technolgy	372.6103485			15	$1,125	28%
Single_Family	Central_AC	New	Central AC - High Efficiency	372.6103485			15	$225	7%
Single_Family	Central_AC	New	Central AC - Premium Efficiency	372.6103485			15	$688	19%
Single_Family	Dryer	Existing	Advanced Appliance Motor ECM	963.4708986	100%	80%	14	$239	11%
Single_Family	Dryer	New	Advanced Appliance Motor ECM	808.1607564	100%	80%	14	$239	11%
Single_Family	Freezer	Existing	Freezer - Energy Star or better	573.8991968			15	$60	10%
Single_Family	Freezer	New	Freezer - Energy Star or better	573.8991968			15	$60	10%
Single_Family	Heat_Pump	Existing	ASHP - High Efficiency	3874.648182			20	$236	9%
Single_Family	Heat_Pump	Existing	ASHP - Premium Efficiency	3874.648182			20	$534	14%
Single_Family	Heat_Pump	Existing	Advanced Cold-Climate Heat Pump	3874.648182	100%	29%	20	$4,300	17%
Single_Family	Heat_Pump	Existing	Below Grade Insulation	3874.648182	85%	70%	20	$1,200	13%
Single_Family	Heat_Pump	Existing	Check Me O & M Tune-up	3874.648182	70%	90%	3	$225	17%
Single_Family	Heat_Pump	Existing	CheckMe Aerosol-Based Duct Sealing	3874.648182	100%	19%	25	$750	19%
Single_Family	Heat_Pump	Existing	CheckMe! Heat Pump Duct Sealing	3874.648182	93%	50%	20	$1,000	25%
Single_Family	Heat_Pump	Existing	ES Windows (Class 30)	3874.648182	85%	95%	30	$3,101	17%
Single_Family	Heat_Pump	Existing	Insulation-Ceiling	3874.648182	80%	90%	30	$720	9%
Single_Family	Heat_Pump	Existing	Insulation-Floor	3874.648182	92%	92%	30	$1,350	11%
Single_Family	Heat_Pump	Existing	Insulation-Rim Joist	3874.648182	75%	60%	30	$80	2%
Single_Family	Heat_Pump	Existing	Insulation-Wall 2x4	3874.648182	15%	75%	30	$1,064	10%
Single_Family	Heat_Pump	Existing	Micro Channel Heat Exchangers (Evaporator)	3874.648182	100%	75%	18.4	$145	5%
Single_Family	Heat_Pump	Existing	Small Scale Absorption Cooling	3874.648182	100%	14%	20	$3,000	18%
Single_Family	Heat_Pump	Existing	Solid State refrigeration cool chips for heat pumps	3874.648182	100%	29%	18.4	$2,000	26%
Single_Family	Heat_Pump	Existing	Whole house air sealing	3874.648182	93%	90%	10	$650	5%
Single_Family	Heat_Pump	New	ASHP - High Efficiency	2930.24126			20	$236	9%
Single_Family	Heat_Pump	New	ASHP - Premium Efficiency	2930.24126			20	$534	14%
Single_Family	Heat_Pump	New	Advanced Cold-Climate Heat Pump	2930.24126	100%	29%	20	$4,300	17%
Single_Family	Heat_Pump	New	Air-to-Air Heat Exchangers	2930.24126	85%	75%	15	$1,440	10%
Single_Family	Heat_Pump	New	Green Roof	2930.24126	100%	25%	30	$19,500	13%
Single_Family	Heat_Pump	New	Leak Proof Duct Fittings	2930.24126	100%	90%	30	$160	17%
Single_Family	Heat_Pump	New	Micro Channel Heat Exchangers (Evaporator)	2930.24126	100%	75%	18.4	$145	5%
Single_Family	Heat_Pump	New	NW ES Homes - Site Built	2930.24126	90%	100%	27	$1,350	38%
Single_Family	Heat_Pump	New	Small Scale Absorption Cooling	2930.24126	100%	14%	20	$3,000	9%
Single_Family	Heat_Pump	New	Solid State refrigeration cool chips for heat pumps	2930.24126	100%	29%	18.4	$2,000	18%
Single_Family	Heat_Pump	New	Spray in insulation - BIBS or icynene 2*4 Wall	2930.24126	100%	75%	30	$2,511	30%
Single_Family	Lighting	Existing	CFL Fixtures, High Use	2176.807147	65%	95%	10	$60	9%
Single_Family	Lighting	Existing	CFL Fixtures, Low Use	2176.807147	75%	95%	10	$60	2%
Single_Family	Lighting	Existing	CFL Fixtures, Medium Use	2176.807147	70%	95%	10	$60	2%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Single_Family	Lighting	Existing	CFL Lamps, High Use	2176.807147	65%	95%	6	$5	43%
Single_Family	Lighting	Existing	CFL Lamps, Low Use	2176.807147	75%	95%	12	$5	9%
Single_Family	Lighting	Existing	CFL Lamps, Medium Use	2176.807147	70%	95%	8	$5	6%
Single_Family	Lighting	Existing	CFL Torchieries, High Use	2176.807147	65%	95%	8	$90	3%
Single_Family	Lighting	Existing	CFL Torchieries, Low Use	2176.807147	75%	95%	8	$90	1%
Single_Family	Lighting	Existing	CFL Torchieries, Medium Use	2176.807147	70%	95%	8	$90	1%
Single_Family	Lighting	Existing	LED Interior Lighting (White), High Use	2176.807147	100%	50%	10	$28	54%
Single_Family	Lighting	Existing	LED Interior Lighting (White), Low Use	2176.807147	100%	50%	10	$28	11%
Single_Family	Lighting	Existing	LED Interior Lighting (White), Medium Use	2176.807147	100%	50%	10	$28	8%
Single_Family	Lighting	New	CFL Fixtures, High Use	2176.807147	55%	95%	10	$60	9%
Single_Family	Lighting	New	CFL Fixtures, Low Use	2176.807147	70%	95%	10	$60	2%
Single_Family	Lighting	New	CFL Fixtures, Medium Use	2176.807147	60%	95%	10	$60	2%
Single_Family	Lighting	New	CFL Lamps, High Use	2176.807147	55%	95%	6	$5	43%
Single_Family	Lighting	New	CFL Lamps, Low Use	2176.807147	70%	95%	12	$5	9%
Single_Family	Lighting	New	CFL Lamps, Medium Use	2176.807147	60%	95%	8	$5	6%
Single_Family	Lighting	New	CFL Torchieries, High Use	2176.807147	55%	95%	8	$90	3%
Single_Family	Lighting	New	CFL Torchieries, Low Use	2176.807147	70%	95%	8	$90	1%
Single_Family	Lighting	New	CFL Torchieries, Medium Use	2176.807147	60%	95%	8	$90	1%
Single_Family	Lighting	New	LED Interior Lighting (White), High Use	2176.807147	100%	50%	10	$28	54%
Single_Family	Lighting	New	LED Interior Lighting (White), Low Use	2176.807147	100%	50%	10	$28	11%
Single_Family	Lighting	New	LED Interior Lighting (White), Medium Use	2176.807147	100%	50%	10	$28	8%
Single_Family	Plug_Load	Existing	1-Watt Standby Power	5179.286913	100%	21%	7	$120	8%
Single_Family	Plug_Load	Existing	Advanced Appliance Motor ECMs, (2) Other	5179.286913	100%	80%	14	$1,082	4%
Single_Family	Plug_Load	Existing	Digital set top Receivers	5179.286913	80%	100%	6	$0	0%
Single_Family	Plug_Load	Existing	Efficient DVD systems	5179.286913	70%	100%	7	$0	0%
Single_Family	Plug_Load	Existing	Efficient high definition televisions	5179.286913	95%	100%	8	$250	2%
Single_Family	Plug_Load	Existing	Office Equipment: Computer, Energy Star or Better	5179.286913	65%	100%	4	$0	0%
Single_Family	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	5179.286913	50%	100%	4	$0	1%
Single_Family	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	5179.286913	85%	100%	5	$0	1%
Single_Family	Plug_Load	Existing	Power supply transformer/converter - External pow	5179.286913	90%	100%	15	$47	0%
Single_Family	Plug_Load	Existing	Powerstrip with Occupancy Sensor	5179.286913	100%	100%	20	$90	1%
Single_Family	Plug_Load	New	1-Watt Standby Power	5179.286913	100%	21%	7	$120	8%
Single_Family	Plug_Load	New	Advanced Appliance Motor ECMs, (2) Other	5179.286913	100%	80%	14	$1,082	4%
Single_Family	Plug_Load	New	Digital set top Receivers	5179.286913	80%	100%	6	$0	0%
Single_Family	Plug_Load	New	Efficient DVD systems	5179.286913	70%	100%	7	$0	0%
Single_Family	Plug_Load	New	Efficient high definition televisions	5179.286913	95%	100%	8	$250	2%
Single_Family	Plug_Load	New	Office Equipment: Computer, Energy Star or Better	5179.286913	65%	100%	4	$0	0%
Single_Family	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	5179.286913	50%	100%	4	$0	1%
Single_Family	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	5179.286913	85%	100%	5	$0	1%
Single_Family	Plug_Load	New	Power supply transformer/converter - External pow	5179.286913	90%	100%	15	$47	0%
Single_Family	Plug_Load	New	Powerstrip with Occupancy Sensor	5179.286913	100%	100%	20	$90	0%
Single_Family	Refrigeration	Existing	1 kWh/day Refrigerator	655.8284793	100%	90%	18	$160	27%
Single_Family	Refrigeration	Existing	Refrigerator, Energy Star or better	655.8284793			18	$80	15%
Single_Family	Refrigeration	Existing	Removal of Old Refrigerator	655.8284793	100%	10%	7	$200	100%
Single_Family	Refrigeration	Existing	Solid state refrigeration (cool chips ™)	655.8284793	100%	90%	19	$860	52%
Single_Family	Refrigeration	New	1 kWh/day Refrigerator	653.5074788	100%	90%	18	$160	27%
Single_Family	Refrigeration	New	Refrigerator, Energy Star or better	653.5074788			18	$80	15%
Single_Family	Refrigeration	New	Solid state refrigeration (cool chips ™)	653.5074788	100%	90%	19	$860	40%
Single_Family	Room_AC	Existing	Room AC - Energy Star	222.308448			12	$33	9%
Single_Family	Room_AC	New	Room AC - Energy Star	222.308448			12	$33	9%
Single_Family	Space_Heat	Existing	Below Grade Insulation	6181.398559	85%	70%	20	$1,200	13%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Single_Family	Space_Heat	Existing	Duct Insulation	6181.398559	20%	50%	30	$376	4%
Single_Family	Space_Heat	Existing	ES Windows (Class 30)	6181.398559	85%	95%	30	$3,101	17%
Single_Family	Space_Heat	Existing	Insulation-Ceiling	6181.398559	80%	90%	30	$720	9%
Single_Family	Space_Heat	Existing	Insulation-Floor	6181.398559	98%	75%	30	$1,350	11%
Single_Family	Space_Heat	Existing	Insulation-Rim Joist	6181.398559	75%	60%	30	$80	2%
Single_Family	Space_Heat	Existing	Insulation-Wall 2x4	6181.398559	15%	75%	30	$1,064	10%
Single_Family	Space_Heat	Existing	PTCS Aerosol-Based Duct Sealing	6181.398559	100%	19%	25	$750	9%
Single_Family	Space_Heat	Existing	PTCS Duct Sealing	6181.398559	50%	50%	20	$1,000	25%
Single_Family	Space_Heat	Existing	Whole house air sealing	6181.398559	93%	90%	10	$650	5%
Single_Family	Space_Heat	New	Air-to-Air Heat Exchangers	2982.257473	85%	75%	15	$1,440	10%
Single_Family	Space_Heat	New	Green Roof	2982.257473	100%	50%	30	$19,500	13%
Single_Family	Space_Heat	New	Leak Proof Duct Fittings	2982.257473	100%	90%	30	$160	17%
Single_Family	Space_Heat	New	NW ES Homes - Site Built	2982.257473	90%	100%	27	$1,350	38%
Single_Family	Space_Heat	New	Spray in insulation - BIBS or icynene 2*4 Wall	2982.257473	100%	75%	30	$2,511	30%
Single_Family	Water_Heat	Existing	Energy Star Clothes Washer	3139.220119	45%	100%	14	$600	13%
Single_Family	Water_Heat	Existing	Energy Star Dishwasher	3139.220119	20%	90%	13	$45	2%
Single_Family	Water_Heat	Existing	Faucet Aerators	3139.220119	55%	95%	5	$5	1%
Single_Family	Water_Heat	Existing	Heat Pump Water Heater	3139.220119	95%	70%	10	$1,750	40%
Single_Family	Water_Heat	Existing	Hot Water Pipe Insulation	3139.220119	62%	75%	15	$8	1%
Single_Family	Water_Heat	Existing	Low-Flow Showerheads	3139.220119	45%	95%	7	$20	3%
Single_Family	Water_Heat	Existing	Solar Water Heater	3139.220119	95%	45%	15	$5,500	40%
Single_Family	Water_Heat	New	Drain Water Heat Recovery (GFX)	2733.763884	95%	65%	15	$460	25%
Single_Family	Water_Heat	New	Energy Star Clothes Washer	2733.763884	45%	100%	14	$600	13%
Single_Family	Water_Heat	New	Energy Star Dishwasher	2733.763884	20%	90%	13	$45	2%
Single_Family	Water_Heat	New	Faucet Aerators	2733.763884	45%	100%	5	$5	1%
Single_Family	Water_Heat	New	Heat Pump Water Heater	2733.763884	95%	70%	10	$1,750	40%
Single_Family	Water_Heat	New	Low-Flow Showerheads	2733.763884	45%	95%	7	$20	2%
Single_Family	Water_Heat	New	Solar Water Heater	2733.763884	95%	45%	15	$5,500	40%

Table A-2. Residential Gas Measures

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Manufactured	Space_Heat	Existing	Advanced Efficiency - Condensing Furnace	370			18	$950	19%
Manufactured	Space_Heat	Existing	Duct Insulation	370	20%	50%	25	$300	3%
Manufactured	Space_Heat	Existing	ES Windows (Class 30)	370	85%	75%	25	$2,300	25%
Manufactured	Space_Heat	Existing	High Efficiency Condensing Furnace	370			18	$40	3%
Manufactured	Space_Heat	Existing	Insulation-Ceiling	370	90%	55%	25	$765	9%
Manufactured	Space_Heat	Existing	Insulation-Floor	370	40%	40%	25	$1,400	11%
Manufactured	Space_Heat	Existing	Insulation-Wall 2x4	370	15%	100%	25	$1,660	10%
Manufactured	Space_Heat	Existing	PTCS Duct Sealing	370	30%	50%	20	$1,000	9%
Manufactured	Space_Heat	Existing	Premium Efficiency - Condensing Furnace	370			18	$600	13%
Manufactured	Space_Heat	Existing	Whole house air sealing	370	40%	90%	10	$300	6%
Manufactured	Space_Heat	New	Advanced Efficiency - Condensing Furnace	319			18	$950	19%
Manufactured	Space_Heat	New	Air-to-Air Heat Exchangers	319	85%	20%	15	$1,440	10%
Manufactured	Space_Heat	New	ES Labeled - New Manufactured Housing	319	95%	100%	23	$1,100	34%
Manufactured	Space_Heat	New	High Efficiency Condensing Furnace	319			18	$40	3%
Manufactured	Space_Heat	New	Leak Proof Duct Fittings	319	95%	90%	30	$160	17%
Manufactured	Space_Heat	New	Premium Efficiency - Condensing Furnace	319			18	$600	13%
Manufactured	Water_Heat	Existing	Energy Star Clothes Washer	223	50%	100%	14	$600	13%
Manufactured	Water_Heat	Existing	Energy Star Dishwasher	223	36%	100%	13	$50	4%
Manufactured	Water_Heat	Existing	Faucet Aerators	223	55%	95%	5	$5	1%
Manufactured	Water_Heat	Existing	HE Storage Water Heater	223			13	$70	8%
Manufactured	Water_Heat	Existing	Hot Water Pipe Insulation	223	62%	50%	10	$8	1%
Manufactured	Water_Heat	Existing	Low-Flow Showerheads	223	45%	95%	7	$20	3%
Manufactured	Water_Heat	Existing	Solar Water Heater	223	95%	45%	15	$5,500	40%
Manufactured	Water_Heat	Existing	Tankless Water Heater	223	90%	30%	13	$450	20%
Manufactured	Water_Heat	New	Energy Star Clothes Washer	264	50%	100%	14	$600	13%
Manufactured	Water_Heat	New	Energy Star Dishwasher	264	36%	100%	13	$50	4%
Manufactured	Water_Heat	New	Faucet Aerators	264	45%	100%	5	$5	1%
Manufactured	Water_Heat	New	HE Storage Water Heater	264			13	$70	8%
Manufactured	Water_Heat	New	Low-Flow Showerheads	264	45%	95%	7	$20	2%
Manufactured	Water_Heat	New	Solar Water Heater	264	95%	45%	15	$5,500	40%
Manufactured	Water_Heat	New	Tankless Water Heater	264	90%	30%	13	$450	20%
Multi_Family	Space_Heat	Existing	Advanced Efficiency - Condensing Furnace	289			18	$950	19%
Multi_Family	Space_Heat	Existing	Duct Insulation	289	20%	25%	30	$245	3%
Multi_Family	Space_Heat	Existing	ES Windows (Class 30)	289	85%	75%	30	$1,760	27%
Multi_Family	Space_Heat	Existing	High Efficiency Condensing Furnace	289			18	$40	3%
Multi_Family	Space_Heat	Existing	Insulated exterior entry doors with built-in weather-stripping	289	60%	100%	10	$300	4%
Multi_Family	Space_Heat	Existing	Insulation-Wall 2x4	289	15%	60%	30	$624	10%
Multi_Family	Space_Heat	Existing	Integrated Space and Water Heating	289	95%	10%	20	$1,300	13%
Multi_Family	Space_Heat	Existing	PTCS Aerosol-Based Duct Sealing	289	100%	19%	25	$450	19%
Multi_Family	Space_Heat	Existing	PTCS Duct Sealing	289	75%	50%	20	$630	9%
Multi_Family	Space_Heat	Existing	Premium Efficiency - Condensing Furnace	289			18	$600	13%
Multi_Family	Space_Heat	Existing	Whole house air sealing	289	40%	90%	10	$486	6%
Multi_Family	Space_Heat	New	Advanced Efficiency - Condensing Furnace	251			18	$950	19%
Multi_Family	Space_Heat	New	Air-to-Air Heat Exchangers	251	85%	75%	15	$1,440	10%
Multi_Family	Space_Heat	New	Green Roof	251	100%	50%	30	$19,700	13%
Multi_Family	Space_Heat	New	High Efficiency Condensing Furnace	251			18	$40	3%
Multi_Family	Space_Heat	New	Integrated Space and Water Heating	251	95%	30%	20	$1,300	13%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Multi_Family	Space_Heat	New	Leak Proof Duct Fittings	251	95%	90%	30	$160	17%
Multi_Family	Space_Heat	New	Premium Efficiency - Condensing Furnace	251			18	$600	13%
Multi_Family	Water_Heat	Existing	Energy Star Clothes Washer	194	52%	100%	14	$600	13%
Multi_Family	Water_Heat	Existing	Energy Star Dishwasher	194	35%	100%	13	$50	4%
Multi_Family	Water_Heat	Existing	Faucet Aerators	194	50%	95%	5	$5	1%
Multi_Family	Water_Heat	Existing	HE Storage Water Heater	194			13	$70	8%
Multi_Family	Water_Heat	Existing	Hot Water Pipe Insulation	194	62%	25%	10	$8	1%
Multi_Family	Water_Heat	Existing	Integrated Space and Water Heating	194	95%	25%	20	$1,200	5%
Multi_Family	Water_Heat	Existing	Low-Flow Showerheads	194	45%	95%	7	$20	3%
Multi_Family	Water_Heat	Existing	Solar Water Heater	194	95%	45%	15	$5,500	40%
Multi_Family	Water_Heat	Existing	Tankless Water Heater	194	90%	50%	13	$450	20%
Multi_Family	Water_Heat	New	Energy Star Clothes Washer	230	52%	100%	14	$600	13%
Multi_Family	Water_Heat	New	Energy Star Dishwasher	230	35%	100%	13	$50	4%
Multi_Family	Water_Heat	New	Faucet Aerators	230	40%	100%	5	$5	1%
Multi_Family	Water_Heat	New	HE Storage Water Heater	230			13	$70	8%
Multi_Family	Water_Heat	New	Integrated Space and Water Heating	230	95%	25%	20	$1,200	5%
Multi_Family	Water_Heat	New	Low-Flow Showerheads	230	45%	95%	7	$20	2%
Multi_Family	Water_Heat	New	Solar Water Heater	230	95%	45%	15	$5,500	40%
Multi_Family	Water_Heat	New	Tankless Water Heater	230	90%	50%	13	$450	20%
Single_Family	Space_Heat	Existing	Advanced Efficiency - Condensing Furnace	614			18	$950	19%
Single_Family	Space_Heat	Existing	Below Grade Insulation	614	85%	70%	20	$1,200	13%
Single_Family	Space_Heat	Existing	Duct Insulation	614	20%	50%	30	$376	4%
Single_Family	Space_Heat	Existing	ES Windows (Class 30)	614	85%	75%	30	$3,101	17%
Single_Family	Space_Heat	Existing	High Efficiency Condensing Furnace	614			18	$40	3%
Single_Family	Space_Heat	Existing	Insulation-Ceiling	614	80%	90%	30	$720	9%
Single_Family	Space_Heat	Existing	Insulation-Floor	614	40%	40%	30	$1,350	11%
Single_Family	Space_Heat	Existing	Insulation-Rim Joist	614	75%	60%	30	$80	2%
Single_Family	Space_Heat	Existing	Insulation-Wall 2x4	614	15%	75%	30	$1,064	10%
Single_Family	Space_Heat	Existing	Integrated Space and Water Heating	614	95%	25%	20	$1,300	13%
Single_Family	Space_Heat	Existing	PTCS Aerosol-Based Duct Sealing	614	100%	19%	25	$750	19%
Single_Family	Space_Heat	Existing	PTCS Duct Sealing	614	30%	50%	20	$1,000	25%
Single_Family	Space_Heat	Existing	Premium Efficiency - Condensing Furnace	614			18	$600	13%
Single_Family	Space_Heat	Existing	Whole house air sealing	614	40%	90%	10	$650	6%
Single_Family	Space_Heat	New	Advanced Efficiency - Condensing Furnace	528			18	$950	19%
Single_Family	Space_Heat	New	Air-to-Air Heat Exchangers	528	85%	75%	15	$1,440	10%
Single_Family	Space_Heat	New	Green Roof	528	100%	50%	30	$19,500	13%
Single_Family	Space_Heat	New	High Efficiency Condensing Furnace	528			18	$40	3%
Single_Family	Space_Heat	New	Integrated Space and Water Heating	528	95%	35%	20	$1,300	13%
Single_Family	Space_Heat	New	Leak Proof Duct Fittings	528	95%	90%	30	$160	17%
Single_Family	Space_Heat	New	NW ES Homes - Site Built	528	90%	40%	26.7	$3,656	38%
Single_Family	Space_Heat	New	Premium Efficiency - Condensing Furnace	528			18	$600	13%
Single_Family	Space_Heat	New	Spray in insulation - BIBS or icynene 2*6 Wall	528	100%	75%	30	$2,511	30%
Single_Family	Water_Heat	Existing	Energy Star Clothes Washer	273	45%	100%	14	$600	13%
Single_Family	Water_Heat	Existing	Energy Star Dishwasher	273	30%	100%	13	$50	4%
Single_Family	Water_Heat	Existing	Faucet Aerators	273	55%	95%	5	$5	1%
Single_Family	Water_Heat	Existing	HE Storage Water Heater	273			13	$70	8%
Single_Family	Water_Heat	Existing	Hot Water Pipe Insulation	273	62%	50%	10	$8	1%
Single_Family	Water_Heat	Existing	Integrated Space and Water Heating	273	95%	50%	20	$1,200	5%
Single_Family	Water_Heat	Existing	Low-Flow Showerheads	273	45%	95%	7	$20	3%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Single_Family	Water_Heat	Existing	Solar Water Heater	273	95%	45%	15	$5,500	40%
Single_Family	Water_Heat	Existing	Tankless Water Heater	273	90%	60%	13	$450	20%
Single_Family	Water_Heat	New	Drain Water Heat Recovery (GFX)	323	95%	50%	15	$400	25%
Single_Family	Water_Heat	New	Energy Star Clothes Washer	323	45%	100%	14	$600	13%
Single_Family	Water_Heat	New	Energy Star Dishwasher	323	30%	100%	13	$50	4%
Single_Family	Water_Heat	New	Faucet Aerators	323	45%	100%	5	$5	1%
Single_Family	Water_Heat	New	HE Storage Water Heater	323			13	$70	8%
Single_Family	Water_Heat	New	Integrated Space and Water Heating	323	95%	50%	20	$1,200	5%
Single_Family	Water_Heat	New	Low-Flow Showerheads	323	45%	95%	7	$20	2%
Single_Family	Water_Heat	New	Solar Water Heater	323	95%	45%	15	$5,500	40%
Single_Family	Water_Heat	New	Tankless Water Heater	323	90%	60%	13	$450	25%

Table A-3. Commercial Electric Measures

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Dry_Goods_Retail	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	1.16084	95%	75%	10	$0.24	$0.05
Dry_Goods_Retail	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	1.16084	45%	95%	10	$0.23	$0.05
Dry_Goods_Retail	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	1.16084	75%	90%	15	$0.38	$0.12
Dry_Goods_Retail	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	1.16084	65%	98%	3	$0.09	$0.10
Dry_Goods_Retail	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	1.16084			20	$0.50	$0.25
Dry_Goods_Retail	Cooling_Chillers	Existing	Chiller-Water Side Economizer	1.16084	95%	45%	20	$0.59	$0.10
Dry_Goods_Retail	Cooling_Chillers	Existing	Convert Constant Volume Air System to VAV	1.16084	15%	85%	15	$0.19	$0.12
Dry_Goods_Retail	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	1.16084	98%	70%	15	$0.07	$0.08
Dry_Goods_Retail	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	1.16084	75%	95%	15	$0.04	$0.14
Dry_Goods_Retail	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	1.16084	90%	95%	15	$0.06	$0.04
Dry_Goods_Retail	Cooling_Chillers	Existing	Direct Digital Control System-Installation	1.16084	20%	60%	10	$0.15	$0.10
Dry_Goods_Retail	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	1.16084	99%	100%	5	$0.12	$0.01
Dry_Goods_Retail	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	1.16084			20	$0.15	$0.20
Dry_Goods_Retail	Cooling_Chillers	Existing	Insulation - Floor	1.16084	95%	60%	20	$0.47	$0.02
Dry_Goods_Retail	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	1.16084	90%	75%	20	$0.47	$0.03
Dry_Goods_Retail	Cooling_Chillers	Existing	Pipe Insulation	1.16084	50%	65%	20	$0.03	$0.01
Dry_Goods_Retail	Cooling_Chillers	Existing	Retro-Commisioning	1.16084	85%	92%	3	$0.27	$0.15
Dry_Goods_Retail	Cooling_Chillers	Existing	Windows-High Efficiency	1.16084	85%	80%	30	$0.23	$0.10
Dry_Goods_Retail	Cooling_Chillers	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	1.22194	95%	75%	10	$0.24	$0.05
Dry_Goods_Retail	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	1.22194	45%	95%	10	$0.23	$0.05
Dry_Goods_Retail	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	1.22194	75%	90%	15	$0.38	$0.12
Dry_Goods_Retail	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	1.22194			20	$0.50	$0.25
Dry_Goods_Retail	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	1.22194	10%	95%	15	$0.04	$0.14
Dry_Goods_Retail	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	1.22194	80%	95%	15	$0.06	$0.04
Dry_Goods_Retail	Cooling_Chillers	New	Direct Digital Control System-Optimization	1.22194	99%	100%	5	$0.12	$0.01
Dry_Goods_Retail	Cooling_Chillers	New	Green Roof	1.22194	100%	25%	40	$15.00	$0.13
Dry_Goods_Retail	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	1.22194			20	$0.15	$0.20
Dry_Goods_Retail	Cooling_Chillers	New	Leak Proof Duct Fittings	1.22194	100%	49%	30	$0.07	$0.21
Dry_Goods_Retail	Cooling_Chillers	New	Pipe Insulation	1.22194	50%	100%	20	$0.03	$0.01
Dry_Goods_Retail	Cooling_Chillers	New	Retro-Commisioning	1.22194	85%	92%	3	$1.00	$0.15
Dry_Goods_Retail	Cooling_Chillers	New	Windows-High Efficiency	1.22194	85%	80%	30	$0.08	$0.10
Dry_Goods_Retail	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	1.97186	95%	75%	10	$0.48	$0.05
Dry_Goods_Retail	Cooling_DX	Existing	Convert Constant Volume Air System to VAV	1.97186	15%	85%	15	$0.48	$0.12
Dry_Goods_Retail	Cooling_DX	Existing	DX Package-Air Side Economizer	1.97186	85%	10%	10	$0.39	$0.15
Dry_Goods_Retail	Cooling_DX	Existing	DX Tune-Up / Diagnostics	1.97186	85%	98%	3	$0.20	$0.10
Dry_Goods_Retail	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	1.97186	90%	50%	10	$0.73	$0.10
Dry_Goods_Retail	Cooling_DX	Existing	Duct Insulation	1.97186	20%	65%	20	$0.03	$0.03
Dry_Goods_Retail	Cooling_DX	Existing	Duct Repair and Sealing	1.97186	50%	65%	20	$0.04	$0.01
Dry_Goods_Retail	Cooling_DX	Existing	High Efficiency DX Package	1.97186			20	$0.50	$0.09
Dry_Goods_Retail	Cooling_DX	Existing	Insulation - Floor	1.97186	95%	60%	20	$0.47	$0.02
Dry_Goods_Retail	Cooling_DX	Existing	Insulation - Roof / Ceiling	1.97186	90%	75%	20	$0.47	$0.03
Dry_Goods_Retail	Cooling_DX	Existing	Premium Efficiency DX Package	1.97186			20	$0.75	$0.16
Dry_Goods_Retail	Cooling_DX	Existing	Programmable Thermostat	1.97186	48%	100%	10	$0.05	$0.10
Dry_Goods_Retail	Cooling_DX	Existing	Retro-Commisioning	1.97186	85%	92%	3	$0.27	$0.15
Dry_Goods_Retail	Cooling_DX	Existing	Windows-High Efficiency	1.97186	85%	80%	30	$0.23	$0.05
Dry_Goods_Retail	Cooling_DX	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.11564	95%	75%	10	$0.24	$0.05
Dry_Goods_Retail	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.11564	90%	50%	10	$0.73	$0.10
Dry_Goods_Retail	Cooling_DX	New	Green Roof	2.11564	100%	25%	40	$15.00	$0.13
Dry_Goods_Retail	Cooling_DX	New	High Efficiency DX Package	2.11564			20	$0.50	$0.09
Dry_Goods_Retail	Cooling_DX	New	Leak Proof Duct Fittings	2.11564	100%	49%	30	$0.07	$0.21
Dry_Goods_Retail	Cooling_DX	New	Premium Efficiency DX Package	2.11564			20	$0.75	$0.16
Dry_Goods_Retail	Cooling_DX	New	Retro-Commisioning	2.11564	85%	92%	3	$1.00	$0.15
Dry_Goods_Retail	Cooling_DX	New	Windows-High Efficiency	2.11564	85%	80%	30	$0.08	$0.05
Dry_Goods_Retail	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.01300	95%	75%	10	$0.24	$0.05
Dry_Goods_Retail	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.01300	90%	50%	10	$0.73	$0.10
Dry_Goods_Retail	Cooling_HeatPump	Existing	Duct Insulation	2.01300	20%	65%	20	$0.03	$0.03
Dry_Goods_Retail	Cooling_HeatPump	Existing	Duct Repair and Sealing	2.01300	50%	65%	20	$0.04	$0.01

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Dry_Goods_Retail	Cooling_HeatPump	Existing	Insulation - Floor	2.01300	95%	60%	20	$0.47	$0.02
Dry_Goods_Retail	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	2.01300	90%	75%	20	$0.47	$0.03
Dry_Goods_Retail	Cooling_HeatPump	Existing	Programmable Thermostat	2.01300	48%	100%	10	$0.05	$0.10
Dry_Goods_Retail	Cooling_HeatPump	Existing	Retro-Commisioning	2.01300	85%	92%	3	$0.27	$0.15
Dry_Goods_Retail	Cooling_HeatPump	Existing	Windows-High Efficiency	2.01300	85%	80%	30	$0.23	$0.05
Dry_Goods_Retail	Cooling_HeatPump	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.06461	95%	75%	10	$0.24	$0.05
Dry_Goods_Retail	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.06461	90%	50%	10	$0.73	$0.10
Dry_Goods_Retail	Cooling_HeatPump	New	Green Roof	2.06461	100%	25%	40	$15.00	$0.13
Dry_Goods_Retail	Cooling_HeatPump	New	Leak Proof Duct Fittings	2.06461	100%	49%	30	$0.07	$0.21
Dry_Goods_Retail	Cooling_HeatPump	New	Retro-Commisioning	2.06461	85%	92%	3	$1.00	$0.15
Dry_Goods_Retail	Cooling_HeatPump	New	Windows-High Efficiency	2.06461	85%	80%	30	$0.08	$0.05
Dry_Goods_Retail	Lighting	Existing	Advanced High Intensity Discharge (HID) Light Sources	4.63565	100%	6%	4	$0.07	$0.10
Dry_Goods_Retail	Lighting	Existing	Advanced/Integrated Daylighting controls (ADCs)	4.63565	100%	66%	20	$2.50	$0.12
Dry_Goods_Retail	Lighting	Existing	Bi-Level Control, Stairwell Lighting	4.63565	98%	95%	7	$0.10	$0.02
Dry_Goods_Retail	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	4.63565	90%	60%	18	$0.44	$0.10
Dry_Goods_Retail	Lighting	Existing	Induction Lighting	4.63565	99%	25%	25	$0.59	$0.01
Dry_Goods_Retail	Lighting	Existing	LED Exit Signs	4.63565	98%	100%	25	$0.12	$0.01
Dry_Goods_Retail	Lighting	Existing	LED Solid State White Lighting	4.63565	100%	7%	6	$1.76	$0.01
Dry_Goods_Retail	Lighting	Existing	Low Wattage Ceramic Metal Halide Lamps	4.63565	100%	6%	7	$1.34	$0.14
Dry_Goods_Retail	Lighting	Existing	Occupancy Sensor Control, Fluorescent	4.63565	95%	85%	14	$0.58	$0.01
Dry_Goods_Retail	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	4.63565	75%	98%	7	$0.26	$0.15
Dry_Goods_Retail	Lighting	Existing	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	4.63565	90%	85%	7	$0.48	$0.25
Dry_Goods_Retail	Lighting	Existing	Scotopic (High CCT) Lighting	4.63565	100%	13%	15	$0.55	$0.16
Dry_Goods_Retail	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	4.63565	85%	60%	18	$0.70	$0.08
Dry_Goods_Retail	Lighting	New	Advanced High Intensity Discharge (HID) Light Sources	4.31466	100%	6%	4	$0.07	$0.18
Dry_Goods_Retail	Lighting	New	Advanced/Integrated Daylighting controls (ADCs)	4.31466	100%	66%	20	$2.50	$0.12
Dry_Goods_Retail	Lighting	New	Bi-Level Control, Stairwell Lighting	4.31466	98%	95%	7	$0.10	$0.03
Dry_Goods_Retail	Lighting	New	Continuous Dimming, Fluorescent Fixtures	4.31466	90%	60%	18	$0.22	$0.10
Dry_Goods_Retail	Lighting	New	Induction Lighting	4.31466	99%	25%	25	$0.59	$0.01
Dry_Goods_Retail	Lighting	New	LED Exit Signs	4.31466	98%	100%	25	$0.04	$0.01
Dry_Goods_Retail	Lighting	New	LED Solid State White Lighting	4.31466	100%	7%	6	$1.76	$0.01
Dry_Goods_Retail	Lighting	New	Low Wattage Ceramic Metal Halide Lamps	4.31466	100%	6%	7	$1.34	$0.25
Dry_Goods_Retail	Lighting	New	Occupancy Sensor Control, Fluorescent	4.31466	95%	85%	14	$0.58	$0.01
Dry_Goods_Retail	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	4.31466	75%	98%	7	$0.12	$0.15
Dry_Goods_Retail	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	4.31466	90%	85%	7	$0.22	$0.25
Dry_Goods_Retail	Lighting	New	Scotopic (High CCT) Lighting	4.31466	100%	13%	15	$0.55	$0.16
Dry_Goods_Retail	Lighting	New	Stepped Dimming Fluorescent Fixtures	4.31466	85%	60%	18	$0.35	$0.08
Dry_Goods_Retail	Plug_Load	Existing	Office Computer Network Energy Management	0.14599	33%	100%	4	$0.00	$0.06
Dry_Goods_Retail	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	0.14599	65%	100%	4	$0.01	$0.01
Dry_Goods_Retail	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	0.14599	60%	100%	4	$0.01	$0.02
Dry_Goods_Retail	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	0.14599	62%	100%	4	$0.02	$0.01
Dry_Goods_Retail	Plug_Load	Existing	Vending Machines- Controls	0.14599	85%	95%	3	$0.02	$0.01
Dry_Goods_Retail	Plug_Load	Existing	Vending Machines- High Efficiency	0.14599	85%	100%	14	$0.02	$0.02
Dry_Goods_Retail	Plug_Load	New	Office Computer Network Energy Management	0.14599	33%	100%	4	$0.00	$0.06
Dry_Goods_Retail	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	0.14599	65%	100%	4	$0.01	$0.01
Dry_Goods_Retail	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	0.14599	60%	100%	4	$0.01	$0.02
Dry_Goods_Retail	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	0.14599	62%	100%	4	$0.02	$0.01
Dry_Goods_Retail	Plug_Load	New	Vending Machines- High Efficiency	0.14599	85%	100%	14	$0.02	$0.02
Dry_Goods_Retail	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.90868	95%	75%	15	$0.28	$0.10
Dry_Goods_Retail	Space_Heat	Existing	Convert Constant Volume Air System to VAV	0.90868	15%	85%	15	$0.19	$0.12
Dry_Goods_Retail	Space_Heat	Existing	Duct Insulation	0.90868	20%	65%	20	$0.01	$0.03
Dry_Goods_Retail	Space_Heat	Existing	Duct Repair and Sealing	0.90868	50%	65%	20	$0.01	$0.01
Dry_Goods_Retail	Space_Heat	Existing	Insulation - Floor	0.90868	95%	60%	20	$0.47	$0.05
Dry_Goods_Retail	Space_Heat	Existing	Insulation - Roof / Ceiling	0.90868	90%	75%	20	$0.47	$0.10
Dry_Goods_Retail	Space_Heat	Existing	Programmable Thermostat	0.90868	48%	100%	10	$0.15	$0.20
Dry_Goods_Retail	Space_Heat	Existing	Retro-Commisioning	0.90868	85%	92%	3	$0.27	$0.15
Dry_Goods_Retail	Space_Heat	Existing	Windows-High Efficiency	0.90868	85%	80%	30	$0.23	$0.10
Dry_Goods_Retail	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.90868	95%	75%	15	$0.28	$0.10

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Dry_Goods_Retail	Space_Heat	New	Green Roof	0.90868	100%	25%	40	$15.00	$0.13
Dry_Goods_Retail	Space_Heat	New	Leak Proof Duct Fittings	0.90868	100%	49%	30	$0.07	$0.21
Dry_Goods_Retail	Space_Heat	New	Retro-Commisioning	0.90868	85%	92%	3	$1.00	$0.15
Dry_Goods_Retail	Space_Heat	New	Windows-High Efficiency	0.90868	85%	80%	30	$0.08	$0.10
Dry_Goods_Retail	Water_Heat	Existing	Commercial Washers	0.16921	95%	90%	8	$1.45	$0.35
Dry_Goods_Retail	Water_Heat	Existing	Demand controlled Circulating Systems	0.16921	98%	60%	15	$1.56	$0.05
Dry_Goods_Retail	Water_Heat	Existing	Faucet Aerators	0.16921	20%	100%	10	$0.00	$0.02
Dry_Goods_Retail	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.16921	95%	85%	15	$0.02	$0.05
Dry_Goods_Retail	Water_Heat	Existing	Low-Flow Showerheads	0.16921	25%	100%	10	$0.01	$0.01
Dry_Goods_Retail	Water_Heat	Existing	Solar Water Heater	0.16921	95%	45%	15	$1.89	$0.40
Dry_Goods_Retail	Water_Heat	Existing	Water Heater Temperature Setback	0.16921	50%	100%	10	$0.01	$0.15
Dry_Goods_Retail	Water_Heat	New	Commercial Washers	0.16921	95%	90%	8	$1.45	$0.35
Dry_Goods_Retail	Water_Heat	New	Demand controlled Circulating Systems	0.16921	98%	60%	15	$1.56	$0.05
Dry_Goods_Retail	Water_Heat	New	Faucet Aerators	0.16921	20%	100%	10	$0.00	$0.02
Dry_Goods_Retail	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.16921	95%	85%	15	$0.02	$0.05
Dry_Goods_Retail	Water_Heat	New	Low-Flow Showerheads	0.16921	25%	100%	10	$0.01	$0.01
Dry_Goods_Retail	Water_Heat	New	Solar Water Heater	0.16921	95%	45%	15	$1.89	$0.40
Grocery	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.39459	95%	25%	10	$0.32	$0.05
Grocery	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	6.39459	45%	95%	10	$0.17	$0.05
Grocery	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	6.39459	75%	90%	15	$0.49	$0.12
Grocery	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	6.39459	65%	98%	3	$0.12	$0.10
Grocery	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	6.39459			20	$0.65	$0.25
Grocery	Cooling_Chillers	Existing	Chiller-Water Side Economizer	6.39459	95%	45%	20	$0.59	$0.10
Grocery	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	6.39459	98%	70%	15	$0.11	$0.08
Grocery	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	6.39459	75%	95%	15	$0.04	$0.14
Grocery	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	6.39459	90%	95%	15	$0.08	$0.04
Grocery	Cooling_Chillers	Existing	Direct Digital Control System-Installation	6.39459	20%	60%	10	$0.20	$0.10
Grocery	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	6.39459	99%	100%	5	$0.12	$0.01
Grocery	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	6.39459			20	$0.20	$0.20
Grocery	Cooling_Chillers	Existing	Insulation - Floor	6.39459	50%	60%	20	$0.48	$0.02
Grocery	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	6.39459	15%	75%	20	$0.48	$0.03
Grocery	Cooling_Chillers	Existing	Pipe Insulation	6.39459	50%	65%	20	$0.01	$0.01
Grocery	Cooling_Chillers	Existing	Retro-Commisioning	6.39459	85%	92%	3	$0.27	$0.15
Grocery	Cooling_Chillers	Existing	Windows-High Efficiency	6.39459	90%	80%	30	$0.21	$0.05
Grocery	Cooling_Chillers	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.73115	95%	25%	10	$0.32	$0.05
Grocery	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	6.73115	45%	95%	10	$0.17	$0.05
Grocery	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	6.73115	75%	90%	15	$0.49	$0.12
Grocery	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	6.73115			20	$0.65	$0.25
Grocery	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	6.73115	10%	95%	15	$0.04	$0.14
Grocery	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	6.73115	80%	95%	15	$0.08	$0.04
Grocery	Cooling_Chillers	New	Direct Digital Control System-Optimization	6.73115	99%	100%	5	$0.12	$0.01
Grocery	Cooling_Chillers	New	Green Roof	6.73115	100%	25%	40	$15.00	$0.13
Grocery	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	6.73115			20	$0.20	$0.20
Grocery	Cooling_Chillers	New	Leak Proof Duct Fittings	6.73115	100%	49%	30	$0.07	$0.21
Grocery	Cooling_Chillers	New	Pipe Insulation	6.73115	50%	100%	20	$0.01	$0.01
Grocery	Cooling_Chillers	New	Retro-Commisioning	6.73115	85%	92%	3	$1.00	$0.15
Grocery	Cooling_Chillers	New	Windows-High Efficiency	6.73115	90%	80%	30	$0.07	$0.05
Grocery	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	10.86217	95%	25%	10	$0.44	$0.05
Grocery	Cooling_DX	Existing	DX Package-Air Side Economizer	10.86217	95%	10%	10	$0.29	$0.15
Grocery	Cooling_DX	Existing	DX Tune-Up / Diagnostics	10.86217	85%	98%	3	$0.25	$0.10
Grocery	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	10.86217	90%	50%	10	$0.94	$0.10
Grocery	Cooling_DX	Existing	Duct Insulation	10.86217	20%	65%	20	$0.01	$0.03
Grocery	Cooling_DX	Existing	Duct Repair and Sealing	10.86217	50%	65%	20	$0.04	$0.01
Grocery	Cooling_DX	Existing	High Efficiency DX Package	10.86217			20	$0.50	$0.09
Grocery	Cooling_DX	Existing	Insulation - Floor	10.86217	50%	60%	20	$0.48	$0.02
Grocery	Cooling_DX	Existing	Insulation - Roof / Ceiling	10.86217	15%	75%	20	$0.48	$0.03
Grocery	Cooling_DX	Existing	Premium Efficiency DX Package	10.86217			20	$0.81	$0.16
Grocery	Cooling_DX	Existing	Programmable Thermostat	10.86217	45%	100%	10	$0.07	$0.10

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Grocery	Cooling_DX	Existing	Retro-Commisioning	10.86217	85%	92%	3	$0.27	$0.15
Grocery	Cooling_DX	Existing	Windows-High Efficiency	10.86217	90%	80%	30	$0.21	$0.05
Grocery	Cooling_DX	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	11.65420	95%	25%	10	$0.32	$0.05
Grocery	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	11.65420	90%	50%	10	$0.94	$0.10
Grocery	Cooling_DX	New	Green Roof	11.65420	100%	25%	40	$15.00	$0.13
Grocery	Cooling_DX	New	High Efficiency DX Package	11.65420			20	$0.50	$0.09
Grocery	Cooling_DX	New	Leak Proof Duct Fittings	11.65420	100%	49%	30	$0.07	$0.21
Grocery	Cooling_DX	New	Premium Efficiency DX Package	11.65420			20	$0.81	$0.16
Grocery	Cooling_DX	New	Retro-Commisioning	11.65420	85%	92%	3	$1.00	$0.15
Grocery	Cooling_DX	New	Windows-High Efficiency	11.65420	90%	80%	30	$0.07	$0.05
Grocery	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	11.08877	95%	25%	10	$0.32	$0.05
Grocery	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	11.08877	90%	50%	10	$0.94	$0.10
Grocery	Cooling_HeatPump	Existing	Duct Insulation	11.08877	20%	65%	20	$0.01	$0.03
Grocery	Cooling_HeatPump	Existing	Duct Repair and Sealing	11.08877	50%	65%	20	$0.04	$0.01
Grocery	Cooling_HeatPump	Existing	Insulation - Floor	11.08877	50%	60%	20	$0.48	$0.02
Grocery	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	11.08877	15%	75%	20	$0.48	$0.03
Grocery	Cooling_HeatPump	Existing	Programmable Thermostat	11.08877	45%	100%	10	$0.07	$0.10
Grocery	Cooling_HeatPump	Existing	Retro-Commisioning	11.08877	85%	92%	3	$0.27	$0.15
Grocery	Cooling_HeatPump	Existing	Windows-High Efficiency	11.08877	90%	80%	30	$0.21	$0.05
Grocery	Cooling_HeatPump	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	11.37309	95%	25%	10	$0.32	$0.05
Grocery	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	11.37309	90%	50%	10	$0.94	$0.10
Grocery	Cooling_HeatPump	New	Green Roof	11.37309	100%	25%	40	$15.00	$0.13
Grocery	Cooling_HeatPump	New	Leak Proof Duct Fittings	11.37309	100%	49%	30	$0.07	$0.21
Grocery	Cooling_HeatPump	New	Retro-Commisioning	11.37309	85%	92%	3	$1.00	$0.15
Grocery	Cooling_HeatPump	New	Windows-High Efficiency	11.37309	90%	80%	30	$0.07	$0.05
Grocery	Lighting	Existing	Advanced High Intensity Discharge (HID) Light Sources	9.99595	100%	6%	4	$0.14	$0.09
Grocery	Lighting	Existing	Bi-Level Control, Stairwell Lighting	9.99595	98%	95%	7	$0.10	$0.02
Grocery	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	9.99595	90%	2%	8	$0.39	$0.15
Grocery	Lighting	Existing	Induction Lighting	9.99595	99%	25%	25	$0.63	$0.01
Grocery	Lighting	Existing	LED Exit Signs	9.99595	98%	100%	25	$0.09	$0.01
Grocery	Lighting	Existing	LED Refrigeration Case Lights	9.99595	85%	100%	12	$0.02	$0.18
Grocery	Lighting	Existing	LED Solid State White Lighting	9.99595	100%	7%	6	$3.63	$0.01
Grocery	Lighting	Existing	Low Wattage Ceramic Metal Halide Lamps	9.99595	100%	6%	7	$2.78	$0.13
Grocery	Lighting	Existing	Occupancy Sensor Control, Fluorescent	9.99595	95%	85%	7	$0.52	$0.02
Grocery	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	9.99595	75%	98%	7	$0.26	$0.15
Grocery	Lighting	Existing	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	9.99595	90%	85%	7	$0.48	$0.25
Grocery	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	9.99595	85%	60%	8	$0.62	$0.11
Grocery	Lighting	New	Advanced High Intensity Discharge (HID) Light Sources	9.39438	100%	6%	4	$0.14	$0.09
Grocery	Lighting	New	Bi-Level Control, Stairwell Lighting	9.39438	98%	95%	7	$0.10	$0.03
Grocery	Lighting	New	Continuous Dimming, Fluorescent Fixtures	9.39438	90%	2%	8	$0.20	$0.15
Grocery	Lighting	New	Induction Lighting	9.39438	99%	25%	25	$0.63	$0.01
Grocery	Lighting	New	LED Exit Signs	9.39438	98%	100%	25	$0.03	$0.01
Grocery	Lighting	New	LED Refrigeration Case Lights	9.39438	85%	100%	12	$0.02	$0.18
Grocery	Lighting	New	LED Solid State White Lighting	9.39438	100%	7%	6	$3.63	$0.01
Grocery	Lighting	New	Low Wattage Ceramic Metal Halide Lamps	9.39438	100%	6%	7	$2.78	$0.13
Grocery	Lighting	New	Occupancy Sensor Control, Fluorescent	9.39438	95%	85%	7	$0.52	$0.02
Grocery	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	9.39438	75%	98%	7	$0.12	$0.15
Grocery	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	9.39438	90%	85%	7	$0.22	$0.25
Grocery	Lighting	New	Stepped Dimming Fluorescent Fixtures	9.39438	85%	60%	8	$0.31	$0.11
Grocery	Plug_Load	Existing	Office Computer Network Energy Management	0.40243	33%	100%	4	$0.00	$0.07
Grocery	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	0.40243	65%	100%	4	$0.01	$0.01
Grocery	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	0.40243	60%	100%	4	$0.01	$0.02
Grocery	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	0.40243	62%	100%	4	$0.01	$0.01
Grocery	Plug_Load	Existing	Vending Machines- Controls	0.40243	75%	95%	3	$0.01	$0.01
Grocery	Plug_Load	Existing	Vending Machines- High Efficiency	0.40243	85%	100%	14	$0.02	$0.02
Grocery	Plug_Load	New	Office Computer Network Energy Management	0.40243	33%	100%	4	$0.00	$0.07
Grocery	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	0.40243	65%	100%	4	$0.01	$0.01
Grocery	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	0.40243	60%	100%	4	$0.01	$0.02

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Grocery	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	0.40243	62%	100%	4	$0.01	$0.01
Grocery	Plug_Load	New	Vending Machines- High Efficiency	0.40243	85%	100%	14	$0.02	$0.02
Grocery	Refrigeration	Existing	Anti-Sweat (Humidistat) Controls	22.84253	45%	100%	12	$0.02	$0.05
Grocery	Refrigeration	Existing	Compressor VSD retrofit	22.84253	90%	60%	10	$0.41	$0.06
Grocery	Refrigeration	Existing	Efficient Fan Motor Options for Commercial Refrigeration	22.84253	100%	40%	9	$1.16	$0.14
Grocery	Refrigeration	Existing	High Efficiency Case Fans	22.84253	92%	100%	16	$1.16	$0.02
Grocery	Refrigeration	Existing	Installation of Floating Condenser Head Pressure Controls	22.84253	38%	100%	14	$0.12	$0.07
Grocery	Refrigeration	Existing	Night Covers for Display Cases	22.84253	90%	100%	5	$0.01	$0.06
Grocery	Refrigeration	Existing	Strip Curtains for Walk-Ins	22.84253	25%	100%	4	$0.05	$0.04
Grocery	Refrigeration	New	Anti-Sweat (Humidistat) Controls	22.84253	45%	100%	12	$0.02	$0.05
Grocery	Refrigeration	New	Efficient Fan Motor Options for Commercial Refrigeration	22.84253	100%	40%	9	$1.16	$0.14
Grocery	Refrigeration	New	High Efficiency Case Fans	22.84253	92%	100%	16	$1.16	$0.02
Grocery	Refrigeration	New	Installation of Floating Condenser Head Pressure Controls	22.84253	38%	100%	14	$0.12	$0.07
Grocery	Refrigeration	New	Night Covers for Display Cases	22.84253	90%	100%	5	$0.01	$0.06
Grocery	Refrigeration	New	Reduced Speed or Cycling of Evaporator Fans	22.84253	75%	100%	5	$0.09	$0.01
Grocery	Refrigeration	New	Strip Curtains for Walk-Ins	22.84253	25%	100%	4	$0.05	$0.04
Grocery	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	1.33587	95%	25%	15	$0.28	$0.10
Grocery	Space_Heat	Existing	Duct Insulation	1.33587	20%	65%	20	$0.01	$0.03
Grocery	Space_Heat	Existing	Duct Repair and Sealing	1.33587	50%	65%	20	$0.01	$0.01
Grocery	Space_Heat	Existing	Insulation - Floor	1.33587	50%	60%	20	$0.48	$0.05
Grocery	Space_Heat	Existing	Insulation - Roof / Ceiling	1.33587	15%	75%	20	$0.48	$0.10
Grocery	Space_Heat	Existing	Programmable Thermostat	1.33587	45%	100%	10	$0.15	$0.20
Grocery	Space_Heat	Existing	Retro-Commisioning	1.33587	85%	92%	3	$0.27	$0.15
Grocery	Space_Heat	Existing	Windows-High Efficiency	1.33587	90%	80%	30	$0.21	$0.06
Grocery	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	1.33587	95%	25%	15	$0.28	$0.10
Grocery	Space_Heat	New	Green Roof	1.33587	100%	25%	40	$15.00	$0.13
Grocery	Space_Heat	New	Leak Proof Duct Fittings	1.33587	100%	49%	30	$0.07	$0.21
Grocery	Space_Heat	New	Retro-Commisioning	1.33587	85%	92%	3	$1.00	$0.15
Grocery	Space_Heat	New	Windows-High Efficiency	1.33587	90%	80%	30	$0.07	$0.06
Grocery	Water_Heat	Existing	Demand controlled Circulating Systems	1.69795	98%	60%	15	$1.16	$0.05
Grocery	Water_Heat	Existing	Faucet Aerators	1.69795	20%	100%	10	$0.00	$0.02
Grocery	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	1.69795	95%	85%	15	$0.01	$0.05
Grocery	Water_Heat	Existing	Low Flow Spray Heads	1.69795	45%	100%	5	$0.01	$0.01
Grocery	Water_Heat	Existing	Low-Flow Showerheads	1.69795	25%	100%	10	$0.00	$0.01
Grocery	Water_Heat	Existing	Solar Water Heater	1.69795	95%	45%	15	$0.95	$0.40
Grocery	Water_Heat	Existing	Water Cooled Refrigeration with Heat Recovery	1.69795	95%	85%	8	$0.09	$0.03
Grocery	Water_Heat	Existing	Water Heater Temperature Setback	1.69795	55%	100%	10	$0.01	$0.15
Grocery	Water_Heat	New	Demand controlled Circulating Systems	1.69795	98%	60%	15	$1.16	$0.05
Grocery	Water_Heat	New	Faucet Aerators	1.69795	20%	100%	10	$0.00	$0.02
Grocery	Water_Heat	New	Hot Water (SHW) Pipe Insulation	1.69795	95%	85%	15	$0.01	$0.05
Grocery	Water_Heat	New	Low Flow Spray Heads	1.69795	45%	100%	5	$0.01	$0.01
Grocery	Water_Heat	New	Low-Flow Showerheads	1.69795	25%	100%	10	$0.01	$0.01
Grocery	Water_Heat	New	Solar Water Heater	1.69795	95%	45%	15	$0.95	$0.40
Grocery	Water_Heat	New	Water Cooled Refrigeration with Heat Recovery	1.69795	95%	85%	8	$0.09	$0.03
Hospital	Cooling_Chillers	Existing	Active Window Insulation	8.55084	100%	20%	15	$1.45	$0.21
Hospital	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	8.55084	95%	5%	10	$0.44	$0.05
Hospital	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	8.55084	45%	95%	10	$0.10	$0.05
Hospital	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	8.55084	75%	90%	15	$0.68	$0.12
Hospital	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	8.55084	65%	98%	3	$0.17	$0.10
Hospital	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	8.55084			20	$0.90	$0.25
Hospital	Cooling_Chillers	Existing	Chiller-Water Side Economizer	8.55084	95%	45%	20	$0.59	$0.10
Hospital	Cooling_Chillers	Existing	Convert Constant Volume Air System to VAV	8.55084	15%	85%	15	$0.35	$0.12
Hospital	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	8.55084	98%	70%	15	$0.16	$0.08
Hospital	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	8.55084	75%	95%	15	$0.04	$0.14
Hospital	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	8.55084	90%	95%	15	$0.11	$0.04
Hospital	Cooling_Chillers	Existing	Direct Digital Control System-Installation	8.55084	20%	60%	10	$0.27	$0.10
Hospital	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	8.55084	90%	100%	5	$0.12	$0.01
Hospital	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	8.55084			20	$0.27	$0.20

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Hospital	Cooling_Chillers	Existing	Insulation - Floor	8.55084	40%	60%	20	$0.43	$0.02
Hospital	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	8.55084	17%	75%	20	$0.43	$0.03
Hospital	Cooling_Chillers	Existing	Pipe Insulation	8.55084	50%	65%	20	$0.01	$0.01
Hospital	Cooling_Chillers	Existing	Retro-Commisioning	8.55084	85%	92%	3	$0.27	$0.15
Hospital	Cooling_Chillers	Existing	Windows-High Efficiency	8.55084	65%	80%	30	$0.10	$0.01
Hospital	Cooling_Chillers	Existing	Wireless Performance Monitoring, Diagnostics and Control	8.55084	100%	30%	10	$0.50	$0.10
Hospital	Cooling_Chillers	New	Active Window Insulation	8.78378	100%	20%	15	$1.45	$0.21
Hospital	Cooling_Chillers	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	8.78378	95%	5%	10	$0.44	$0.05
Hospital	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	8.78378	45%	95%	10	$0.10	$0.05
Hospital	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	8.78378	75%	90%	15	$0.68	$0.12
Hospital	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	9.00088			20	$0.90	$0.25
Hospital	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	8.78378	10%	95%	15	$0.04	$0.14
Hospital	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	8.78378	80%	95%	15	$0.11	$0.04
Hospital	Cooling_Chillers	New	Direct Digital Control System-Optimization	8.78378	90%	100%	5	$0.12	$0.01
Hospital	Cooling_Chillers	New	Green Roof	8.78378	100%	25%	40	$15.00	$0.13
Hospital	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	9.00088			20	$0.27	$0.20
Hospital	Cooling_Chillers	New	Leak Proof Duct Fittings	8.78378	100%	49%	30	$0.07	$0.21
Hospital	Cooling_Chillers	New	Pipe Insulation	8.78378	50%	100%	20	$0.01	$0.01
Hospital	Cooling_Chillers	New	Retro-Commisioning	8.78378	85%	92%	3	$1.00	$0.15
Hospital	Cooling_Chillers	New	Windows-High Efficiency	8.78378	65%	80%	30	$0.03	$0.01
Hospital	Cooling_Chillers	New	Wireless Performance Monitoring, Diagnostics and Control	8.78378	100%	30%	10	$0.50	$0.10
Hospital	Cooling_DX	Existing	Active Window Insulation	14.69131	100%	20%	15	$0.44	$0.21
Hospital	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	14.69131	95%	5%	10	$0.09	$0.05
Hospital	Cooling_DX	Existing	Convert Constant Volume Air System to VAV	14.69131	15%	85%	15	$0.35	$0.12
Hospital	Cooling_DX	Existing	DX Package-Air Side Economizer	14.69131	35%	10%	10	$0.17	$0.15
Hospital	Cooling_DX	Existing	DX Tune-Up / Diagnostics	14.69131	85%	98%	3	$0.35	$0.10
Hospital	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	14.69131	90%	50%	10	$1.31	$0.10
Hospital	Cooling_DX	Existing	Duct Insulation	14.69131	20%	65%	20	$0.01	$0.03
Hospital	Cooling_DX	Existing	Duct Repair and Sealing	14.69131	50%	65%	20	$0.04	$0.01
Hospital	Cooling_DX	Existing	High Efficiency DX Package	14.52487			20	$0.50	$0.09
Hospital	Cooling_DX	Existing	Insulation - Floor	14.69131	40%	60%	20	$0.43	$0.02
Hospital	Cooling_DX	Existing	Insulation - Roof / Ceiling	14.69131	17%	75%	20	$0.43	$0.03
Hospital	Cooling_DX	Existing	Premium Efficiency DX Package	14.52487			20	$0.90	$0.16
Hospital	Cooling_DX	Existing	Programmable Thermostat	14.69131	55%	100%	10	$0.09	$0.10
Hospital	Cooling_DX	Existing	Retro-Commisioning	14.69131	85%	92%	3	$0.27	$0.15
Hospital	Cooling_DX	Existing	Windows-High Efficiency	14.69131	65%	80%	30	$0.10	$0.05
Hospital	Cooling_DX	New	Active Window Insulation	15.20808	100%	20%	15	$1.45	$0.21
Hospital	Cooling_DX	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	15.20808	95%	5%	10	$0.44	$0.05
Hospital	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	15.20808	90%	50%	10	$1.31	$0.10
Hospital	Cooling_DX	New	Green Roof	15.20808	100%	25%	40	$15.00	$0.13
Hospital	Cooling_DX	New	High Efficiency DX Package	15.58398			20	$0.50	$0.09
Hospital	Cooling_DX	New	Leak Proof Duct Fittings	15.20808	100%	49%	30	$0.07	$0.21
Hospital	Cooling_DX	New	Premium Efficiency DX Package	15.58398			20	$0.90	$0.16
Hospital	Cooling_DX	New	Retro-Commisioning	15.20808	85%	92%	3	$1.00	$0.15
Hospital	Cooling_DX	New	Windows-High Efficiency	15.20808	65%	80%	30	$0.03	$0.05
Hospital	Cooling_HeatPump	Existing	Active Window Insulation	14.82788	100%	20%	15	$1.45	$0.21
Hospital	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	14.82788	95%	5%	10	$0.44	$0.05
Hospital	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	14.82788	90%	50%	10	$1.31	$0.10
Hospital	Cooling_HeatPump	Existing	Duct Insulation	14.82788	20%	65%	20	$0.01	$0.03
Hospital	Cooling_HeatPump	Existing	Duct Repair and Sealing	14.82788	50%	65%	20	$0.04	$0.01
Hospital	Cooling_HeatPump	Existing	Insulation - Floor	14.82788	40%	60%	20	$0.43	$0.02
Hospital	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	14.82788	17%	75%	20	$0.43	$0.03
Hospital	Cooling_HeatPump	Existing	Programmable Thermostat	14.82788	55%	100%	10	$0.09	$0.10
Hospital	Cooling_HeatPump	Existing	Retro-Commisioning	14.82788	85%	92%	3	$0.27	$0.15
Hospital	Cooling_HeatPump	Existing	Windows-High Efficiency	14.82788	65%	80%	30	$0.10	$0.05
Hospital	Cooling_HeatPump	New	Active Window Insulation	15.20808	100%	20%	15	$1.45	$0.21
Hospital	Cooling_HeatPump	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	15.20808	95%	5%	10	$0.44	$0.05
Hospital	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	15.20808	90%	50%	10	$1.31	$0.10

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Hospital	Cooling_HeatPump	New	Green Roof	15.20808	100%	25%	40	$15.00	$0.13
Hospital	Cooling_HeatPump	New	Leak Proof Duct Fittings	15.20808	100%	49%	30	$0.07	$0.21
Hospital	Cooling_HeatPump	New	Retro-Commisioning	15.20808	85%	92%	3	$1.00	$0.15
Hospital	Cooling_HeatPump	New	Windows-High Efficiency	15.20808	65%	80%	30	$0.03	$0.05
Hospital	HVAC_Aux	New	Optimized Variable Volume Lab Hood Design	2.59698	98%	95%	10	$0.01	$0.02
Hospital	Lighting	Existing	Advanced High Intensity Discharge (HID) Light Sources	8.76044	100%	6%	4	$0.12	$0.02
Hospital	Lighting	Existing	Advanced/Integrated Daylighting controls (ADCs)	8.76044	100%	66%	20	$2.50	$0.08
Hospital	Lighting	Existing	Bi-Level Control, Stairwell Lighting	8.76044	98%	95%	7	$0.10	$0.03
Hospital	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	8.76044	90%	20%	8	$0.38	$0.13
Hospital	Lighting	Existing	Induction Lighting	8.76044	99%	25%	25	$0.15	$0.01
Hospital	Lighting	Existing	LED Exit Signs	8.76044	98%	100%	25	$0.05	$0.01
Hospital	Lighting	Existing	LED Solid State White Lighting	8.76044	100%	7%	6	$3.17	$0.10
Hospital	Lighting	Existing	Low Wattage Ceramic Metal Halide Lamps	8.76044	100%	6%	7	$2.43	$0.03
Hospital	Lighting	Existing	Occupancy Sensor Control, Fluorescent	8.76044	95%	85%	7	$0.51	$0.04
Hospital	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	8.76044	75%	98%	7	$0.26	$0.15
Hospital	Lighting	Existing	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	8.76044	90%	85%	7	$0.48	$0.25
Hospital	Lighting	Existing	Scotopic (High CCT) Lighting	8.76044	100%	13%	15	$0.55	$0.19
Hospital	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	8.76044	85%	60%	8	$0.61	$0.10
Hospital	Lighting	New	Advanced High Intensity Discharge (HID) Light Sources	8.34295	100%	6%	4	$0.12	$0.02
Hospital	Lighting	New	Advanced/Integrated Daylighting controls (ADCs)	8.34295	100%	66%	20	$2.50	$0.10
Hospital	Lighting	New	Bi-Level Control, Stairwell Lighting	8.34295	98%	95%	7	$0.10	$0.03
Hospital	Lighting	New	Continuous Dimming, Fluorescent Fixtures	8.34295	90%	20%	8	$0.19	$0.13
Hospital	Lighting	New	Induction Lighting	8.34295	99%	25%	25	$0.15	$0.01
Hospital	Lighting	New	LED Exit Signs	8.34295	98%	100%	25	$0.02	$0.01
Hospital	Lighting	New	LED Solid State White Lighting	8.34295	100%	7%	6	$3.17	$0.10
Hospital	Lighting	New	Low Wattage Ceramic Metal Halide Lamps	8.34295	100%	6%	7	$2.43	$0.03
Hospital	Lighting	New	Occupancy Sensor Control, Fluorescent	8.34295	95%	85%	7	$0.51	$0.04
Hospital	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	8.34295	75%	98%	7	$0.12	$0.15
Hospital	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	8.34295	90%	85%	7	$0.22	$0.25
Hospital	Lighting	New	Scotopic (High CCT) Lighting	8.34295	100%	13%	15	$0.55	$0.19
Hospital	Lighting	New	Stepped Dimming Fluorescent Fixtures	8.34295	85%	60%	8	$0.31	$0.10
Hospital	Plug_Load	Existing	Office Computer Network Energy Management	0.51066	33%	100%	4	$0.00	$0.06
Hospital	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	0.51066	65%	100%	4	$0.04	$0.01
Hospital	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	0.51066	60%	100%	4	$0.06	$0.02
Hospital	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	0.51066	62%	100%	4	$0.11	$0.01
Hospital	Plug_Load	Existing	Vending Machines- Controls	0.51066	80%	95%	3	$0.01	$0.01
Hospital	Plug_Load	Existing	Vending Machines- High Efficiency	0.51066	85%	100%	14	$0.02	$0.02
Hospital	Plug_Load	New	Office Computer Network Energy Management	0.51066	33%	100%	4	$0.00	$0.06
Hospital	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	0.51066	65%	100%	4	$0.04	$0.01
Hospital	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	0.51066	60%	100%	4	$0.06	$0.02
Hospital	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	0.51066	62%	100%	4	$0.11	$0.01
Hospital	Plug_Load	New	Vending Machines- High Efficiency	0.51066	85%	100%	14	$0.02	$0.02
Hospital	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.47640	95%	5%	15	$0.28	$0.10
Hospital	Space_Heat	Existing	Convert Constant Volume Air System to VAV	4.47640	15%	85%	15	$0.35	$0.12
Hospital	Space_Heat	Existing	Duct Insulation	4.47640	20%	65%	20	$0.01	$0.03
Hospital	Space_Heat	Existing	Duct Repair and Sealing	4.47640	50%	65%	20	$0.00	$0.01
Hospital	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	4.47640	95%	5%	20	$1.00	$0.20
Hospital	Space_Heat	Existing	Insulation - Floor	4.47640	40%	60%	20	$0.43	$0.05
Hospital	Space_Heat	Existing	Insulation - Roof / Ceiling	4.47640	17%	75%	20	$0.43	$0.10
Hospital	Space_Heat	Existing	Programmable Thermostat	4.47640	55%	100%	10	$0.15	$0.20
Hospital	Space_Heat	Existing	Retro-Commisioning	4.47640	85%	92%	3	$0.27	$0.15
Hospital	Space_Heat	Existing	Windows-High Efficiency	4.47640	65%	80%	30	$0.10	$0.06
Hospital	Space_Heat	Existing	Wireless Performance Monitoring, Diagnostics and Control	4.47640	100%	30%	10	$0.50	$0.10
Hospital	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.47640	95%	5%	15	$0.28	$0.10
Hospital	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	4.47640	95%	5%	20	$0.93	$0.15
Hospital	Space_Heat	New	Green Roof	4.47640	100%	25%	40	$15.00	$0.13
Hospital	Space_Heat	New	Leak Proof Duct Fittings	4.47640	100%	49%	30	$0.07	$0.21
Hospital	Space_Heat	New	Retro-Commisioning	4.47640	85%	92%	3	$1.00	$0.15

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Hospital	Space_Heat	New	Windows-High Efficiency	4.47640	65%	80%	30	$0.03	$0.06
Hospital	Space_Heat	New	Wireless Performance Monitoring, Diagnostics and Control	4.47640	100%	30%	10	$0.50	$0.10
Hospital	Water_Heat	Existing	Chemical Dishwashing System	2.09602	90%	80%	10	$0.03	$0.04
Hospital	Water_Heat	Existing	Commercial Washers	2.09602	95%	90%	8	$0.22	$0.10
Hospital	Water_Heat	Existing	Demand controlled Circulating Systems	2.09602	85%	60%	15	$0.68	$0.05
Hospital	Water_Heat	Existing	Faucet Aerators	2.09602	20%	100%	10	$0.01	$0.02
Hospital	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	2.09602	75%	85%	15	$0.01	$0.05
Hospital	Water_Heat	Existing	Low-Flow Showerheads	2.09602	25%	100%	10	$0.03	$0.04
Hospital	Water_Heat	Existing	Solar Water Heater	2.09602	95%	45%	15	$3.01	$0.40
Hospital	Water_Heat	Existing	Water Heater Temperature Setback	2.09602	85%	100%	10	$0.00	$0.15
Hospital	Water_Heat	New	Chemical Dishwashing System	2.09602	90%	80%	10	$0.03	$0.04
Hospital	Water_Heat	New	Commercial Washers	2.09602	95%	90%	8	$0.22	$0.10
Hospital	Water_Heat	New	Demand controlled Circulating Systems	2.09602	85%	60%	15	$0.68	$0.05
Hospital	Water_Heat	New	Faucet Aerators	2.09602	20%	100%	10	$0.01	$0.02
Hospital	Water_Heat	New	Hot Water (SHW) Pipe Insulation	2.09602	75%	85%	15	$0.01	$0.05
Hospital	Water_Heat	New	Low-Flow Showerheads	2.09602	25%	100%	10	$0.03	$0.04
Hospital	Water_Heat	New	Solar Water Heater	2.09602	95%	45%	15	$3.01	$0.40
Hotel_Motel	Cooling_Chillers	Existing	Active Window Insulation	1.43044	100%	20%	15	$1.45	$0.21
Hotel_Motel	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	1.43044	95%	10%	10	$0.46	$0.05
Hotel_Motel	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	1.43044	45%	95%	10	$0.12	$0.05
Hotel_Motel	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	1.43044	75%	90%	15	$0.71	$0.12
Hotel_Motel	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	1.43044	65%	98%	3	$0.18	$0.10
Hotel_Motel	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	1.42821			20	$0.95	$0.25
Hotel_Motel	Cooling_Chillers	Existing	Chiller-Water Side Economizer	1.43044	35%	45%	20	$0.59	$0.10
Hotel_Motel	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	1.43044	98%	70%	15	$0.17	$0.08
Hotel_Motel	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	1.43044	75%	95%	15	$0.04	$0.14
Hotel_Motel	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	1.43044	90%	95%	15	$0.11	$0.04
Hotel_Motel	Cooling_Chillers	Existing	Direct Digital Control System-Installation	1.43044	20%	60%	10	$0.29	$0.10
Hotel_Motel	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	1.43044	85%	100%	5	$0.12	$0.01
Hotel_Motel	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	1.42821			20	$0.29	$0.20
Hotel_Motel	Cooling_Chillers	Existing	Hotel Key Card Room Energy Control System	1.43044	100%	90%	15	$0.33	$0.25
Hotel_Motel	Cooling_Chillers	Existing	Insulation - Floor	1.43044	50%	60%	20	$0.21	$0.02
Hotel_Motel	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	1.43044	30%	75%	20	$0.21	$0.03
Hotel_Motel	Cooling_Chillers	Existing	Pipe Insulation	1.43044	50%	65%	20	$0.03	$0.01
Hotel_Motel	Cooling_Chillers	Existing	Retro-Commisioning	1.43044	85%	92%	3	$0.27	$0.15
Hotel_Motel	Cooling_Chillers	Existing	Windows-High Efficiency	1.43044	55%	80%	30	$0.48	$0.07
Hotel_Motel	Cooling_Chillers	Existing	Wireless Performance Monitoring, Diagnostics and Control	1.43044	100%	30%	10	$0.50	$0.10
Hotel_Motel	Cooling_Chillers	New	Active Window Insulation	1.46712	100%	20%	15	$1.45	$0.21
Hotel_Motel	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	1.46712	45%	95%	10	$0.12	$0.05
Hotel_Motel	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	1.46712	75%	90%	15	$0.71	$0.12
Hotel_Motel	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	1.50338			20	$0.95	$0.25
Hotel_Motel	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	1.46712	10%	95%	15	$0.04	$0.14
Hotel_Motel	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	1.46712	80%	95%	15	$0.11	$0.04
Hotel_Motel	Cooling_Chillers	New	Direct Digital Control System-Optimization	1.46712	85%	100%	5	$0.12	$0.01
Hotel_Motel	Cooling_Chillers	New	Green Roof	1.46712	100%	25%	40	$15.00	$0.13
Hotel_Motel	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	1.50338			20	$0.29	$0.20
Hotel_Motel	Cooling_Chillers	New	Hotel Key Card Room Energy Control System	1.46712	100%	90%	15	$0.33	$0.25
Hotel_Motel	Cooling_Chillers	New	Leak Proof Duct Fittings	1.46712	100%	49%	30	$0.07	$0.21
Hotel_Motel	Cooling_Chillers	New	Pipe Insulation	1.46712	50%	100%	20	$0.03	$0.01
Hotel_Motel	Cooling_Chillers	New	Retro-Commisioning	1.46712	85%	92%	3	$1.00	$0.15
Hotel_Motel	Cooling_Chillers	New	Windows-High Efficiency	1.46712	55%	80%	30	$0.16	$0.07
Hotel_Motel	Cooling_Chillers	New	Wireless Performance Monitoring, Diagnostics and Control	1.46712	100%	30%	10	$0.50	$0.10
Hotel_Motel	Cooling_DX	Existing	Active Window Insulation	2.45383	100%	20%	15	$0.23	$0.21
Hotel_Motel	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.45383	95%	10%	10	$0.12	$0.05
Hotel_Motel	Cooling_DX	Existing	DX Package-Air Side Economizer	2.45383	35%	10%	10	$0.20	$0.15
Hotel_Motel	Cooling_DX	Existing	DX Tune-Up / Diagnostics	2.45383	85%	98%	3	$0.37	$0.10
Hotel_Motel	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.45383	90%	50%	10	$1.38	$0.10
Hotel_Motel	Cooling_DX	Existing	Duct Insulation	2.45383	20%	65%	20	$0.01	$0.03

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Hotel_Motel	Cooling_DX	Existing	Duct Repair and Sealing	2.45383	50%	65%	20	$0.04	$0.01
Hotel_Motel	Cooling_DX	Existing	High Efficiency DX Package	2.42603			20	$0.50	$0.09
Hotel_Motel	Cooling_DX	Existing	Hotel Key Card Room Energy Control System	2.45383	100%	90%	15	$0.33	$0.25
Hotel_Motel	Cooling_DX	Existing	Insulation - Floor	2.45383	50%	60%	20	$0.21	$0.02
Hotel_Motel	Cooling_DX	Existing	Insulation - Roof / Ceiling	2.45383	30%	75%	20	$0.21	$0.03
Hotel_Motel	Cooling_DX	Existing	Premium Efficiency DX Package	2.42603			20	$0.92	$0.16
Hotel_Motel	Cooling_DX	Existing	Programmable Thermostat	2.45383	45%	100%	10	$0.10	$0.10
Hotel_Motel	Cooling_DX	Existing	Retro-Commisioning	2.45383	85%	92%	3	$0.27	$0.15
Hotel_Motel	Cooling_DX	Existing	Terminal HVAC units-Occupancy Sensor Control	2.45383	90%	75%	15	$0.30	$0.35
Hotel_Motel	Cooling_DX	Existing	Windows-High Efficiency	2.45383	55%	80%	30	$0.48	$0.05
Hotel_Motel	Cooling_DX	New	Active Window Insulation	2.54015	100%	20%	15	$1.45	$0.21
Hotel_Motel	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.54015	90%	50%	10	$1.38	$0.10
Hotel_Motel	Cooling_DX	New	Green Roof	2.54015	100%	25%	40	$15.00	$0.13
Hotel_Motel	Cooling_DX	New	High Efficiency DX Package	2.60293			20	$0.50	$0.09
Hotel_Motel	Cooling_DX	New	Hotel Key Card Room Energy Control System	2.54015	100%	90%	15	$0.33	$0.25
Hotel_Motel	Cooling_DX	New	Leak Proof Duct Fittings	2.54015	100%	49%	30	$0.07	$0.21
Hotel_Motel	Cooling_DX	New	Premium Efficiency DX Package	2.60293			20	$0.92	$0.16
Hotel_Motel	Cooling_DX	New	Retro-Commisioning	2.54015	85%	92%	3	$1.00	$0.15
Hotel_Motel	Cooling_DX	New	Terminal HVAC units-Occupancy Sensor Control	2.54015	80%	75%	15	$0.30	$0.35
Hotel_Motel	Cooling_DX	New	Windows-High Efficiency	2.54015	55%	80%	30	$0.16	$0.05
Hotel_Motel	Cooling_HeatPump	Existing	Active Window Insulation	2.47664	100%	20%	15	$1.45	$0.21
Hotel_Motel	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.47664	95%	10%	10	$0.46	$0.05
Hotel_Motel	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.47664	90%	50%	10	$1.38	$0.10
Hotel_Motel	Cooling_HeatPump	Existing	Duct Insulation	2.47664	20%	65%	20	$0.01	$0.03
Hotel_Motel	Cooling_HeatPump	Existing	Duct Repair and Sealing	2.47664	50%	65%	20	$0.04	$0.01
Hotel_Motel	Cooling_HeatPump	Existing	Hotel Key Card Room Energy Control System	2.47664	100%	90%	15	$0.33	$0.25
Hotel_Motel	Cooling_HeatPump	Existing	Insulation - Floor	2.47664	50%	60%	20	$0.21	$0.02
Hotel_Motel	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	2.47664	30%	75%	20	$0.21	$0.03
Hotel_Motel	Cooling_HeatPump	Existing	Programmable Thermostat	2.47664	45%	100%	10	$0.10	$0.10
Hotel_Motel	Cooling_HeatPump	Existing	Retro-Commisioning	2.47664	85%	92%	3	$0.27	$0.15
Hotel_Motel	Cooling_HeatPump	Existing	Windows-High Efficiency	2.47664	55%	80%	30	$0.48	$0.05
Hotel_Motel	Cooling_HeatPump	New	Active Window Insulation	2.54015	100%	20%	15	$1.45	$0.21
Hotel_Motel	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.54015	90%	50%	10	$1.38	$0.10
Hotel_Motel	Cooling_HeatPump	New	Green Roof	2.54015	100%	25%	40	$15.00	$0.13
Hotel_Motel	Cooling_HeatPump	New	Hotel Key Card Room Energy Control System	2.54015	100%	90%	15	$0.33	$0.25
Hotel_Motel	Cooling_HeatPump	New	Leak Proof Duct Fittings	2.54015	100%	49%	30	$0.07	$0.21
Hotel_Motel	Cooling_HeatPump	New	Retro-Commisioning	2.54015	85%	92%	3	$1.00	$0.15
Hotel_Motel	Cooling_HeatPump	New	Windows-High Efficiency	2.54015	55%	80%	30	$0.16	$0.05
Hotel_Motel	Lighting	Existing	Advanced High Intensity Discharge (HID) Light Sources	2.77856	100%	6%	4	$0.04	$0.19
Hotel_Motel	Lighting	Existing	Bi-Level Control, Stairwell Lighting	2.77856	98%	95%	7	$0.10	$0.03
Hotel_Motel	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	2.77856	90%	2%	19	$0.19	$0.02
Hotel_Motel	Lighting	Existing	Hospitality Bathroom Lighting	2.77856	100%	2%	10	$0.18	$0.02
Hotel_Motel	Lighting	Existing	Induction Lighting	2.77856	99%	25%	25	$0.33	$0.01
Hotel_Motel	Lighting	Existing	LED Exit Signs	2.77856	98%	100%	25	$0.06	$0.01
Hotel_Motel	Lighting	Existing	LED Solid State White Lighting	2.77856	100%	7%	6	$0.93	$0.15
Hotel_Motel	Lighting	Existing	Low Wattage Ceramic Metal Halide Lamps	2.77856	100%	6%	7	$0.71	$0.26
Hotel_Motel	Lighting	Existing	Occupancy Sensor Control, Fluorescent	2.77856	90%	85%	15	$0.26	$0.01
Hotel_Motel	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	2.77856	75%	98%	7	$0.26	$0.15
Hotel_Motel	Lighting	Existing	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	2.77856	90%	85%	7	$0.48	$0.25
Hotel_Motel	Lighting	Existing	Scotopic (High CCT) Lighting	2.77856	100%	13%	15	$0.55	$0.02
Hotel_Motel	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	2.77856	85%	60%	19	$0.31	$0.01
Hotel_Motel	Lighting	New	Advanced High Intensity Discharge (HID) Light Sources	2.75607	100%	6%	4	$0.04	$0.19
Hotel_Motel	Lighting	New	Bi-Level Control, Stairwell Lighting	2.75607	98%	95%	7	$0.10	$0.03
Hotel_Motel	Lighting	New	Continuous Dimming, Fluorescent Fixtures	2.75607	90%	2%	19	$0.10	$0.02
Hotel_Motel	Lighting	New	Hospitality Bathroom Lighting	2.75607	100%	2%	10	$0.18	$0.02
Hotel_Motel	Lighting	New	Induction Lighting	2.75607	99%	25%	25	$0.33	$0.01
Hotel_Motel	Lighting	New	LED Exit Signs	2.75607	98%	100%	25	$0.02	$0.01
Hotel_Motel	Lighting	New	LED Solid State White Lighting	2.75607	100%	7%	6	$0.93	$0.15

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Hotel_Motel	Lighting	New	Low Wattage Ceramic Metal Halide Lamps	2.75607	100%	6%	7	$0.71	$0.26
Hotel_Motel	Lighting	New	Occupancy Sensor Control, Fluorescent	2.75607	90%	85%	15	$0.26	$0.01
Hotel_Motel	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	2.75607	75%	98%	7	$0.12	$0.15
Hotel_Motel	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	2.75607	90%	85%	7	$0.22	$0.25
Hotel_Motel	Lighting	New	Scotopic (High CCT) Lighting	2.75607	100%	13%	15	$0.55	$0.02
Hotel_Motel	Lighting	New	Stepped Dimming Fluorescent Fixtures	2.75607	85%	60%	19	$0.15	$0.01
Hotel_Motel	Plug_Load	Existing	Office Computer Network Energy Management	0.09942	33%	100%	4	$0.00	$0.05
Hotel_Motel	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	0.09942	65%	100%	4	$0.00	$0.01
Hotel_Motel	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	0.09942	60%	100%	4	$0.00	$0.02
Hotel_Motel	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	0.09942	62%	100%	4	$0.01	$0.01
Hotel_Motel	Plug_Load	Existing	Vending Machines- Controls	0.09942	75%	95%	3	$0.01	$0.01
Hotel_Motel	Plug_Load	Existing	Vending Machines- High Efficiency	0.09942	85%	100%	14	$0.02	$0.02
Hotel_Motel	Plug_Load	New	Office Computer Network Energy Management	0.09942	33%	100%	4	$0.00	$0.05
Hotel_Motel	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	0.09942	65%	100%	4	$0.00	$0.01
Hotel_Motel	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	0.09942	60%	100%	4	$0.00	$0.02
Hotel_Motel	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	0.09942	62%	100%	4	$0.01	$0.01
Hotel_Motel	Plug_Load	New	Vending Machines- High Efficiency	0.09942	85%	100%	14	$0.02	$0.02
Hotel_Motel	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.73023	95%	10%	15	$0.28	$0.10
Hotel_Motel	Space_Heat	Existing	Duct Insulation	4.73023	20%	65%	20	$0.01	$0.03
Hotel_Motel	Space_Heat	Existing	Duct Repair and Sealing	4.73023	50%	65%	20	$0.01	$0.01
Hotel_Motel	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	4.73023	95%	5%	20	$1.00	$0.20
Hotel_Motel	Space_Heat	Existing	Hotel Key Card Room Energy Control System	4.73023	100%	90%	15	$0.33	$0.25
Hotel_Motel	Space_Heat	Existing	Insulation - Floor	4.73023	50%	60%	20	$0.21	$0.05
Hotel_Motel	Space_Heat	Existing	Insulation - Roof / Ceiling	4.73023	30%	75%	20	$0.21	$0.10
Hotel_Motel	Space_Heat	Existing	Programmable Thermostat	4.73023	45%	100%	10	$0.15	$0.20
Hotel_Motel	Space_Heat	Existing	Retro-Commisioning	4.73023	85%	92%	3	$0.27	$0.15
Hotel_Motel	Space_Heat	Existing	Terminal HVAC units-Occupancy Sensor Control	4.73023	90%	75%	15	$0.20	$0.35
Hotel_Motel	Space_Heat	Existing	Windows-High Efficiency	4.73023	55%	80%	30	$0.48	$0.06
Hotel_Motel	Space_Heat	Existing	Wireless Performance Monitoring, Diagnostics and Control	4.73023	100%	30%	10	$0.50	$0.10
Hotel_Motel	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	4.73023	95%	5%	20	$0.93	$0.15
Hotel_Motel	Space_Heat	New	Green Roof	4.73023	100%	25%	40	$15.00	$0.13
Hotel_Motel	Space_Heat	New	Hotel Key Card Room Energy Control System	4.73023	100%	90%	15	$0.33	$0.25
Hotel_Motel	Space_Heat	New	Leak Proof Duct Fittings	4.73023	100%	49%	30	$0.07	$0.21
Hotel_Motel	Space_Heat	New	Retro-Commisioning	4.73023	85%	92%	3	$1.00	$0.15
Hotel_Motel	Space_Heat	New	Terminal HVAC units-Occupancy Sensor Control	4.73023	80%	75%	15	$0.20	$0.35
Hotel_Motel	Space_Heat	New	Windows-High Efficiency	4.73023	55%	80%	30	$0.16	$0.06
Hotel_Motel	Space_Heat	New	Wireless Performance Monitoring, Diagnostics and Control	4.73023	100%	30%	10	$0.50	$0.10
Hotel_Motel	Water_Heat	Existing	Commercial Washers	3.80473	95%	90%	8	$0.22	$0.10
Hotel_Motel	Water_Heat	Existing	Demand controlled Circulating Systems	3.80473	98%	60%	15	$0.78	$0.05
Hotel_Motel	Water_Heat	Existing	Faucet Aerators	3.80473	20%	100%	10	$0.01	$0.02
Hotel_Motel	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	3.80473	95%	85%	15	$0.03	$0.05
Hotel_Motel	Water_Heat	Existing	Low Flow Spray Heads	3.80473	55%	100%	5	$0.01	$0.01
Hotel_Motel	Water_Heat	Existing	Low-Flow Showerheads	3.80473	25%	100%	10	$0.05	$0.05
Hotel_Motel	Water_Heat	Existing	Solar Water Heater	3.80473	95%	45%	15	$2.64	$0.40
Hotel_Motel	Water_Heat	Existing	Water Heater Temperature Setback	3.80473	10%	100%	10	$0.01	$0.15
Hotel_Motel	Water_Heat	New	Commercial Washers	3.80473	95%	90%	8	$0.22	$0.10
Hotel_Motel	Water_Heat	New	Demand controlled Circulating Systems	3.80473	98%	60%	15	$0.78	$0.05
Hotel_Motel	Water_Heat	New	Faucet Aerators	3.80473	20%	100%	10	$0.01	$0.02
Hotel_Motel	Water_Heat	New	Hot Water (SHW) Pipe Insulation	3.80473	95%	85%	15	$0.03	$0.05
Hotel_Motel	Water_Heat	New	Low Flow Spray Heads	3.80473	55%	100%	5	$0.01	$0.01
Hotel_Motel	Water_Heat	New	Low-Flow Showerheads	3.80473	25%	100%	10	$0.05	$0.05
Hotel_Motel	Water_Heat	New	Solar Water Heater	3.80473	95%	45%	15	$2.64	$0.40
Office	Cooling_Chillers	Existing	Active Window Insulation	3.58631	100%	20%	15	$1.45	$0.21
Office	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	3.58631	95%	75%	10	$0.29	$0.05
Office	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	3.58631	45%	95%	10	$0.16	$0.05
Office	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	3.58631	75%	90%	15	$0.45	$0.12
Office	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	3.58631	65%	98%	3	$0.11	$0.10
Office	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	3.58072			20	$0.60	$0.25

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Office	Cooling_Chillers	Existing	Chiller-Water Side Economizer	3.58631	50%	45%	20	$0.59	$0.10
Office	Cooling_Chillers	Existing	Convert Constant Volume Air System to VAV	3.58631	15%	85%	15	$0.23	$0.12
Office	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	3.58631	98%	70%	15	$0.11	$0.08
Office	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	3.58631	75%	95%	15	$0.04	$0.14
Office	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	3.58631	90%	95%	15	$0.07	$0.04
Office	Cooling_Chillers	Existing	Direct Digital Control System-Installation	3.58631	20%	60%	10	$0.18	$0.10
Office	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	3.58631	85%	100%	5	$0.12	$0.01
Office	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	3.58072			20	$0.18	$0.20
Office	Cooling_Chillers	Existing	Insulation - Floor	3.58631	20%	60%	20	$0.33	$0.02
Office	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	3.58631	5%	75%	20	$0.33	$0.03
Office	Cooling_Chillers	Existing	Pipe Insulation	3.58631	50%	65%	20	$0.00	$0.01
Office	Cooling_Chillers	Existing	Retro-Commisioning	3.58631	85%	92%	3	$0.27	$0.15
Office	Cooling_Chillers	Existing	Windows-High Efficiency	3.58631	99%	80%	30	$0.44	$0.09
Office	Cooling_Chillers	New	Active Window Insulation	3.67826	100%	20%	15	$1.45	$0.21
Office	Cooling_Chillers	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	3.67826	95%	75%	10	$0.29	$0.05
Office	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	3.67826	45%	95%	10	$0.16	$0.05
Office	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	3.67826	75%	90%	15	$0.45	$0.12
Office	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	3.76918			20	$0.60	$0.25
Office	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	3.67826	10%	95%	15	$0.04	$0.14
Office	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	3.67826	80%	95%	15	$0.07	$0.04
Office	Cooling_Chillers	New	Direct Digital Control System-Optimization	3.67826	85%	100%	5	$0.12	$0.01
Office	Cooling_Chillers	New	Green Roof	3.67826	100%	25%	40	$15.00	$0.13
Office	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	3.76918			20	$0.18	$0.20
Office	Cooling_Chillers	New	Leak Proof Duct Fittings	3.67826	100%	49%	30	$0.07	$0.21
Office	Cooling_Chillers	New	Pipe Insulation	3.67826	50%	100%	20	$0.00	$0.01
Office	Cooling_Chillers	New	Retro-Commisioning	3.67826	85%	92%	3	$1.00	$0.15
Office	Cooling_Chillers	New	Windows-High Efficiency	3.67826	99%	80%	30	$0.15	$0.09
Office	Cooling_DX	Existing	Active Window Insulation	6.15208	100%	20%	15	$0.14	$0.21
Office	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.15208	95%	75%	10	$0.10	$0.05
Office	Cooling_DX	Existing	Convert Constant Volume Air System to VAV	6.15208	15%	85%	15	$0.10	$0.12
Office	Cooling_DX	Existing	DX Package-Air Side Economizer	6.15208	25%	10%	10	$0.26	$0.15
Office	Cooling_DX	Existing	DX Tune-Up / Diagnostics	6.15208	85%	98%	3	$0.23	$0.10
Office	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	6.15208	90%	50%	10	$0.87	$0.10
Office	Cooling_DX	Existing	Duct Insulation	6.15208	20%	65%	20	$0.02	$0.03
Office	Cooling_DX	Existing	Duct Repair and Sealing	6.15208	50%	65%	20	$0.04	$0.01
Office	Cooling_DX	Existing	High Efficiency DX Package	6.08238			20	$0.50	$0.09
Office	Cooling_DX	Existing	Insulation - Floor	6.15208	20%	60%	20	$0.33	$0.02
Office	Cooling_DX	Existing	Insulation - Roof / Ceiling	6.15208	5%	75%	20	$0.33	$0.03
Office	Cooling_DX	Existing	Premium Efficiency DX Package	6.08238			20	$0.79	$0.16
Office	Cooling_DX	Existing	Programmable Thermostat	6.15208	52%	100%	10	$0.06	$0.10
Office	Cooling_DX	Existing	Retro-Commisioning	6.15208	85%	92%	3	$0.27	$0.15
Office	Cooling_DX	Existing	Windows-High Efficiency	6.15208	99%	80%	30	$0.44	$0.05
Office	Cooling_DX	New	Active Window Insulation	6.36848	100%	20%	15	$1.45	$0.21
Office	Cooling_DX	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.36848	95%	75%	10	$0.29	$0.05
Office	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	6.36848	90%	50%	10	$0.87	$0.10
Office	Cooling_DX	New	Green Roof	6.36848	100%	25%	40	$15.00	$0.13
Office	Cooling_DX	New	High Efficiency DX Package	6.52589			20	$0.50	$0.09
Office	Cooling_DX	New	Leak Proof Duct Fittings	6.36848	100%	49%	30	$0.07	$0.21
Office	Cooling_DX	New	Premium Efficiency DX Package	6.52589			20	$0.79	$0.16
Office	Cooling_DX	New	Retro-Commisioning	6.36848	85%	92%	3	$1.00	$0.15
Office	Cooling_DX	New	Windows-High Efficiency	6.36848	99%	80%	30	$0.15	$0.05
Office	Cooling_HeatPump	Existing	Active Window Insulation	6.20927	100%	20%	15	$1.45	$0.21
Office	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.20927	95%	75%	10	$0.29	$0.05
Office	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	6.20927	90%	50%	10	$0.87	$0.10
Office	Cooling_HeatPump	Existing	Duct Insulation	6.20927	20%	65%	20	$0.02	$0.03
Office	Cooling_HeatPump	Existing	Duct Repair and Sealing	6.20927	50%	65%	20	$0.04	$0.01
Office	Cooling_HeatPump	Existing	Insulation - Floor	6.20927	20%	60%	20	$0.33	$0.02
Office	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	6.20927	5%	75%	20	$0.33	$0.03

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Office	Cooling_HeatPump	Existing	Programmable Thermostat	6.20927	52%	100%	10	$0.06	$0.10
Office	Cooling_HeatPump	Existing	Retro-Commisioning	6.20927	85%	92%	3	$0.27	$0.15
Office	Cooling_HeatPump	Existing	Windows-High Efficiency	6.20927	99%	80%	30	$0.44	$0.05
Office	Cooling_HeatPump	New	Active Window Insulation	6.36848	100%	20%	15	$1.45	$0.21
Office	Cooling_HeatPump	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.36848	95%	75%	10	$0.29	$0.05
Office	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	6.36848	90%	50%	10	$0.87	$0.10
Office	Cooling_HeatPump	New	Green Roof	6.36848	100%	25%	40	$15.00	$0.13
Office	Cooling_HeatPump	New	Leak Proof Duct Fittings	6.36848	100%	49%	30	$0.07	$0.21
Office	Cooling_HeatPump	New	Retro-Commisioning	6.36848	85%	92%	3	$1.00	$0.15
Office	Cooling_HeatPump	New	Windows-High Efficiency	6.36848	99%	80%	30	$0.15	$0.05
Office	HVAC_Aux	New	Under floor Ventilation with Low Static Pressure	2.19566	100%	22%	15	$0.70	$0.20
Office	Lighting	Existing	Advanced High Intensity Discharge (HID) Light Sources	4.12969	100%	6%	4	$0.06	$0.05
Office	Lighting	Existing	Advanced/Integrated Daylighting controls (ADCs)	4.12969	100%	66%	20	$2.50	$0.08
Office	Lighting	Existing	Bi-Level Control, Stairwell Lighting	4.12969	98%	95%	7	$0.10	$0.02
Office	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	4.12969	90%	60%	11	$0.39	$0.16
Office	Lighting	Existing	Cost Effective Load Shed Ballast and Controller	4.12969	100%	80%	15	$1.57	$0.01
Office	Lighting	Existing	Hybrid Solar Lighting	4.12969	100%	22%	15	$7.19	$0.52
Office	Lighting	Existing	Induction Lighting	4.12969	99%	25%	25	$0.18	$0.01
Office	Lighting	Existing	LED Exit Signs	4.12969	98%	100%	25	$0.08	$0.01
Office	Lighting	Existing	LED Solid State White Lighting	4.12969	100%	7%	6	$1.54	$0.02
Office	Lighting	Existing	Low Wattage Ceramic Metal Halide Lamps	4.12969	100%	6%	7	$1.18	$0.07
Office	Lighting	Existing	Occupancy Sensor Control, Fluorescent	4.12969	90%	85%	9	$0.52	$0.08
Office	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	4.12969	75%	98%	7	$0.26	$0.15
Office	Lighting	Existing	Reduce Interior Lighting Power Density 35% Reduction (W/sqft)	4.12969	90%	85%	7	$0.48	$0.25
Office	Lighting	Existing	Scotopic (High CCT) Lighting	4.12969	100%	13%	15	$0.55	$0.24
Office	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	4.12969	85%	60%	11	$0.63	$0.12
Office	Lighting	New	Advanced High Intensity Discharge (HID) Light Sources	3.86134	100%	6%	4	$0.06	$0.05
Office	Lighting	New	Advanced/Integrated Daylighting controls (ADCs)	3.86134	100%	66%	20	$2.50	$0.01
Office	Lighting	New	Bi-Level Control, Stairwell Lighting	3.86134	98%	95%	7	$0.10	$0.03
Office	Lighting	New	Continuous Dimming, Fluorescent Fixtures	3.86134	90%	60%	11	$0.20	$0.16
Office	Lighting	New	Cost Effective Load Shed Ballast and Controller	3.86134	100%	80%	15	$1.57	$0.01
Office	Lighting	New	Hybrid Solar Lighting	3.86134	100%	22%	15	$7.19	$0.52
Office	Lighting	New	Induction Lighting	3.86134	99%	25%	25	$0.18	$0.01
Office	Lighting	New	LED Exit Signs	3.86134	98%	100%	25	$0.03	$0.01
Office	Lighting	New	LED Solid State White Lighting	3.86134	100%	7%	6	$1.54	$0.02
Office	Lighting	New	Low Wattage Ceramic Metal Halide Lamps	3.86134	100%	6%	7	$1.18	$0.07
Office	Lighting	New	Occupancy Sensor Control, Fluorescent	3.86134	90%	85%	9	$0.52	$0.04
Office	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	3.86134	75%	98%	7	$0.12	$0.15
Office	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	3.86134	90%	85%	7	$0.22	$0.35
Office	Lighting	New	Scotopic (High CCT) Lighting	3.86134	100%	13%	15	$0.55	$0.24
Office	Lighting	New	Stepped Dimming Fluorescent Fixtures	3.86134	85%	60%	11	$0.31	$0.12
Office	Plug_Load	Existing	Office Computer Network Energy Management	1.55216	33%	100%	4	$0.01	$0.09
Office	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	1.55216	65%	100%	4	$0.03	$0.01
Office	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	1.55216	60%	100%	4	$0.09	$0.02
Office	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	1.55216	62%	100%	4	$0.10	$0.01
Office	Plug_Load	Existing	Vending Machines- Controls	1.55216	85%	95%	3	$0.01	$0.00
Office	Plug_Load	Existing	Vending Machines- High Efficiency	1.55216	85%	100%	14	$0.01	$0.00
Office	Plug_Load	New	Office Computer Network Energy Management	1.55216	33%	100%	4	$0.01	$0.09
Office	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	1.55216	65%	100%	4	$0.03	$0.01
Office	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	1.55216	60%	100%	4	$0.09	$0.02
Office	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	1.55216	62%	100%	4	$0.10	$0.01
Office	Plug_Load	New	Vending Machines- High Efficiency	1.55216	85%	100%	14	$0.01	$0.00
Office	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.50000	95%	75%	15	$0.28	$0.10
Office	Space_Heat	Existing	Convert Constant Volume Air System to VAV	4.50000	15%	85%	15	$0.23	$0.12
Office	Space_Heat	Existing	Duct Insulation	4.50000	20%	65%	20	$0.02	$0.03
Office	Space_Heat	Existing	Duct Repair and Sealing	4.50000	50%	65%	20	$0.01	$0.01
Office	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	4.50000	95%	5%	20	$1.00	$0.20
Office	Space_Heat	Existing	Insulation - Floor	4.50000	20%	60%	20	$0.33	$0.05

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Office	Space_Heat	Existing	Insulation - Roof / Ceiling	4.50000	5%	75%	20	$0.33	$0.10
Office	Space_Heat	Existing	Programmable Thermostat	4.50000	52%	100%	10	$0.15	$0.20
Office	Space_Heat	Existing	Retro-Commisioning	4.50000	85%	92%	3	$0.27	$0.15
Office	Space_Heat	Existing	Windows-High Efficiency	4.50000	99%	80%	30	$0.44	$0.20
Office	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.50000	95%	75%	15	$0.28	$0.10
Office	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	4.50000	95%	5%	20	$0.93	$0.15
Office	Space_Heat	New	Green Roof	4.50000	100%	25%	40	$15.00	$0.13
Office	Space_Heat	New	Leak Proof Duct Fittings	4.50000	100%	49%	30	$0.07	$0.21
Office	Space_Heat	New	Retro-Commisioning	4.50000	85%	92%	3	$1.00	$0.15
Office	Space_Heat	New	Windows-High Efficiency	4.50000	99%	80%	30	$0.15	$0.20
Office	Water_Heat	Existing	Demand controlled Circulating Systems	0.30125	85%	60%	15	$1.05	$0.05
Office	Water_Heat	Existing	Faucet Aerators	0.30125	20%	100%	10	$0.00	$0.02
Office	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.30125	35%	85%	15	$0.00	$0.05
Office	Water_Heat	Existing	Low-Flow Showerheads	0.30125	25%	100%	10	$0.00	$0.01
Office	Water_Heat	Existing	Solar Water Heater	0.30125	95%	45%	15	$1.54	$0.40
Office	Water_Heat	Existing	Water Heater Temperature Setback	0.30125	45%	100%	10	$0.01	$0.15
Office	Water_Heat	New	Demand controlled Circulating Systems	0.30125	85%	60%	15	$1.05	$0.05
Office	Water_Heat	New	Faucet Aerators	0.30125	20%	100%	10	$0.00	$0.02
Office	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.30125	35%	85%	15	$0.00	$0.05
Office	Water_Heat	New	Low-Flow Showerheads	0.30125	25%	100%	10	$0.01	$0.01
Office	Water_Heat	New	Solar Water Heater	0.30125	95%	45%	15	$1.54	$0.40
Other	Cooling_Chillers	Existing	Active Window Insulation	2.42207	100%	20%	15	$1.45	$0.21
Other	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.42207	95%	50%	10	$0.19	$0.05
Other	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	2.42207	45%	95%	10	$0.14	$0.05
Other	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	2.42207	75%	90%	15	$0.30	$0.12
Other	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	2.42207	65%	98%	3	$0.08	$0.10
Other	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	2.42207			20	$0.40	$0.25
Other	Cooling_Chillers	Existing	Chiller-Water Side Economizer	2.42207	90%	45%	20	$0.59	$0.10
Other	Cooling_Chillers	Existing	Convert Constant Volume Air System to VAV	2.42207	15%	85%	15	$0.16	$0.12
Other	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	2.42207	98%	70%	15	$0.07	$0.08
Other	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	2.42207	75%	95%	15	$0.04	$0.14
Other	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	2.42207	90%	95%	15	$0.05	$0.04
Other	Cooling_Chillers	Existing	Direct Digital Control System-Installation	2.42207	20%	60%	10	$0.12	$0.10
Other	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	2.42207	98%	100%	5	$0.12	$0.01
Other	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	2.42207			20	$0.12	$0.20
Other	Cooling_Chillers	Existing	Insulation - Floor	2.42207	55%	60%	20	$0.44	$0.02
Other	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	2.42207	35%	75%	20	$0.44	$0.03
Other	Cooling_Chillers	Existing	Pipe Insulation	2.42207	50%	65%	20	$0.01	$0.01
Other	Cooling_Chillers	Existing	Retro-Commisioning	2.42207	85%	92%	3	$0.27	$0.15
Other	Cooling_Chillers	Existing	Windows-High Efficiency	2.42207	75%	80%	30	$0.14	$0.02
Other	Cooling_Chillers	New	Active Window Insulation	2.48805	100%	20%	15	$1.45	$0.21
Other	Cooling_Chillers	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.48805	95%	50%	10	$0.19	$0.05
Other	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	2.48805	45%	95%	10	$0.14	$0.05
Other	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	2.48805	75%	90%	15	$0.30	$0.12
Other	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	2.48805			20	$0.40	$0.25
Other	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	2.48805	10%	95%	15	$0.04	$0.14
Other	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	2.48805	80%	95%	15	$0.05	$0.04
Other	Cooling_Chillers	New	Direct Digital Control System-Optimization	2.48805	98%	100%	5	$0.12	$0.01
Other	Cooling_Chillers	New	Green Roof	2.48805	100%	25%	40	$15.00	$0.13
Other	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	2.48805			20	$0.12	$0.20
Other	Cooling_Chillers	New	Leak Proof Duct Fittings	2.48805	100%	49%	30	$0.07	$0.21
Other	Cooling_Chillers	New	Pipe Insulation	2.48805	50%	100%	20	$0.01	$0.01
Other	Cooling_Chillers	New	Retro-Commisioning	2.48805	85%	92%	3	$1.00	$0.15
Other	Cooling_Chillers	New	Windows-High Efficiency	2.48805	75%	80%	30	$0.05	$0.02
Other	Cooling_DX	Existing	Active Window Insulation	4.11425	100%	20%	15	$0.32	$0.21
Other	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.11425	95%	50%	10	$0.32	$0.05
Other	Cooling_DX	Existing	Convert Constant Volume Air System to VAV	4.11425	15%	85%	15	$0.16	$0.12
Other	Cooling_DX	Existing	DX Package-Air Side Economizer	4.11425	75%	10%	10	$0.23	$0.15

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Other	Cooling_DX	Existing	DX Tune-Up / Diagnostics	4.11425	85%	98%	3	$0.16	$0.10
Other	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	4.11425	90%	50%	10	$0.58	$0.10
Other	Cooling_DX	Existing	Duct Insulation	4.11425	20%	65%	20	$0.01	$0.03
Other	Cooling_DX	Existing	Duct Repair and Sealing	4.11425	50%	65%	20	$0.04	$0.01
Other	Cooling_DX	Existing	High Efficiency DX Package	4.11425			20	$0.50	$0.09
Other	Cooling_DX	Existing	Insulation - Floor	4.11425	55%	60%	20	$0.44	$0.02
Other	Cooling_DX	Existing	Insulation - Roof / Ceiling	4.11425	35%	75%	20	$0.44	$0.03
Other	Cooling_DX	Existing	Premium Efficiency DX Package	4.11425			20	$0.71	$0.16
Other	Cooling_DX	Existing	Programmable Thermostat	4.11425	32%	100%	10	$0.04	$0.10
Other	Cooling_DX	Existing	Retro-Commisioning	4.11425	85%	92%	3	$0.27	$0.15
Other	Cooling_DX	Existing	Windows-High Efficiency	4.11425	75%	80%	30	$0.14	$0.05
Other	Cooling_DX	New	Active Window Insulation	4.41425	100%	20%	15	$1.45	$0.21
Other	Cooling_DX	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.41425	95%	50%	10	$0.19	$0.05
Other	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	4.41425	90%	50%	10	$0.58	$0.10
Other	Cooling_DX	New	Green Roof	4.41425	100%	25%	40	$15.00	$0.13
Other	Cooling_DX	New	High Efficiency DX Package	4.41425			20	$0.50	$0.09
Other	Cooling_DX	New	Leak Proof Duct Fittings	4.41425	100%	49%	30	$0.07	$0.21
Other	Cooling_DX	New	Premium Efficiency DX Package	4.41425			20	$0.71	$0.16
Other	Cooling_DX	New	Retro-Commisioning	4.41425	85%	92%	3	$1.00	$0.15
Other	Cooling_DX	New	Windows-High Efficiency	4.41425	75%	80%	30	$0.05	$0.05
Other	Cooling_HeatPump	Existing	Active Window Insulation	4.20008	100%	20%	15	$1.45	$0.21
Other	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.20008	95%	50%	10	$0.19	$0.05
Other	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	4.20008	90%	50%	10	$0.58	$0.10
Other	Cooling_HeatPump	Existing	Duct Insulation	4.20008	20%	65%	20	$0.01	$0.03
Other	Cooling_HeatPump	Existing	Duct Repair and Sealing	4.20008	50%	65%	20	$0.04	$0.01
Other	Cooling_HeatPump	Existing	Insulation - Floor	4.20008	55%	60%	20	$0.44	$0.02
Other	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	4.20008	35%	75%	20	$0.44	$0.03
Other	Cooling_HeatPump	Existing	Programmable Thermostat	4.20008	32%	100%	10	$0.04	$0.10
Other	Cooling_HeatPump	Existing	Retro-Commisioning	4.20008	85%	92%	3	$0.27	$0.15
Other	Cooling_HeatPump	Existing	Windows-High Efficiency	4.20008	75%	80%	30	$0.14	$0.05
Other	Cooling_HeatPump	New	Active Window Insulation	4.30777	100%	20%	15	$1.45	$0.21
Other	Cooling_HeatPump	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.30777	95%	50%	10	$0.19	$0.05
Other	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	4.30777	90%	50%	10	$0.58	$0.10
Other	Cooling_HeatPump	New	Green Roof	4.30777	100%	25%	40	$15.00	$0.13
Other	Cooling_HeatPump	New	Leak Proof Duct Fittings	4.30777	100%	49%	30	$0.07	$0.21
Other	Cooling_HeatPump	New	Retro-Commisioning	4.30777	85%	92%	3	$1.00	$0.15
Other	Cooling_HeatPump	New	Windows-High Efficiency	4.30777	75%	80%	30	$0.05	$0.05
Other	HVAC_Aux	New	Optimized Variable Volume Lab Hood Design	1.84570	98%	95%	10	$0.01	$0.02
Other	Lighting	Existing	Advanced High Intensity Discharge (HID) Light Sources	1.72088	100%	6%	4	$0.29	$0.22
Other	Lighting	Existing	Advanced/Integrated Daylighting controls (ADCs)	1.72088	100%	66%	20	$2.50	$0.12
Other	Lighting	Existing	Bi-Level Control, Stairwell Lighting	1.72088	98%	95%	7	$0.10	$0.03
Other	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	1.72088	90%	60%	26	$0.37	$0.07
Other	Lighting	Existing	Induction Lighting	1.72088	99%	25%	25	$0.28	$0.01
Other	Lighting	Existing	LED Exit Signs	1.72088	98%	100%	25	$0.07	$0.01
Other	Lighting	Existing	LED Solid State White Lighting	1.72088	100%	7%	6	$1.46	$0.01
Other	Lighting	Existing	Low Wattage Ceramic Metal Halide Lamps	1.72088	100%	6%	7	$1.42	$0.31
Other	Lighting	Existing	Occupancy Sensor Control, Fluorescent	1.72088	80%	85%	21	$0.49	$0.06
Other	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	1.72088	75%	98%	7	$0.26	$0.15
Other	Lighting	Existing	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	1.72088	90%	85%	7	$0.48	$0.25
Other	Lighting	Existing	Scotopic (High CCT) Lighting	1.72088	100%	13%	15	$0.55	$0.11
Other	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	1.72088	85%	60%	26	$0.59	$0.05
Other	Lighting	New	Advanced High Intensity Discharge (HID) Light Sources	1.63596	100%	6%	4	$0.07	$0.22
Other	Lighting	New	Advanced/Integrated Daylighting controls (ADCs)	1.63596	100%	66%	20	$2.50	$0.05
Other	Lighting	New	Bi-Level Control, Stairwell Lighting	1.63596	98%	95%	7	$0.10	$0.03
Other	Lighting	New	Continuous Dimming, Fluorescent Fixtures	1.63596	90%	60%	26	$0.18	$0.07
Other	Lighting	New	Induction Lighting	1.63596	99%	25%	25	$0.28	$0.01
Other	Lighting	New	LED Exit Signs	1.63596	98%	100%	25	$0.02	$0.01
Other	Lighting	New	LED Solid State White Lighting	1.63596	100%	7%	6	$1.86	$0.01

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Other	Lighting	New	Low Wattage Ceramic Metal Halide Lamps	1.63596	100%	6%	7	$0.13	$0.31
Other	Lighting	New	Occupancy Sensor Control, Fluorescent	1.63596	80%	85%	21	$0.49	$0.05
Other	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	1.63596	75%	98%	7	$0.12	$0.15
Other	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	1.63596	90%	85%	7	$0.22	$0.25
Other	Lighting	New	Scotopic (High CCT) Lighting	1.63596	100%	13%	15	$0.55	$0.11
Other	Lighting	New	Stepped Dimming Fluorescent Fixtures	1.63596	85%	60%	26	$0.30	$0.05
Other	Plug_Load	Existing	Office Computer Network Energy Management	0.08595	33%	100%	4	$0.01	$0.07
Other	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	0.08595	65%	100%	4	$0.04	$0.01
Other	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	0.08595	60%	100%	4	$0.07	$0.02
Other	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	0.08595	62%	100%	4	$0.11	$0.01
Other	Plug_Load	Existing	Vending Machines- Controls	0.08595	85%	95%	3	$0.01	$0.01
Other	Plug_Load	Existing	Vending Machines- High Efficiency	0.08595	85%	100%	14	$0.01	$0.02
Other	Plug_Load	New	Office Computer Network Energy Management	0.08595	33%	100%	4	$0.01	$0.07
Other	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	0.08595	65%	100%	4	$0.04	$0.01
Other	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	0.08595	60%	100%	4	$0.07	$0.02
Other	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	0.08595	62%	100%	4	$0.11	$0.01
Other	Plug_Load	New	Vending Machines- High Efficiency	0.08595	85%	100%	14	$0.01	$0.02
Other	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.47640	95%	50%	15	$0.28	$0.10
Other	Space_Heat	Existing	Convert Constant Volume Air System to VAV	4.47640	15%	85%	15	$0.16	$0.12
Other	Space_Heat	Existing	Duct Insulation	4.47640	20%	65%	20	$0.01	$0.03
Other	Space_Heat	Existing	Duct Repair and Sealing	4.47640	50%	65%	20	$0.01	$0.01
Other	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	4.47640	95%	5%	20	$1.00	$0.20
Other	Space_Heat	Existing	Insulation - Floor	4.47640	55%	60%	20	$0.44	$0.05
Other	Space_Heat	Existing	Insulation - Roof / Ceiling	4.47640	35%	75%	20	$0.44	$0.10
Other	Space_Heat	Existing	Programmable Thermostat	4.47640	32%	100%	10	$0.15	$0.20
Other	Space_Heat	Existing	Retro-Commisioning	4.47640	85%	92%	3	$0.27	$0.15
Other	Space_Heat	Existing	Windows-High Efficiency	4.47640	75%	80%	30	$0.14	$0.06
Other	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.47640	95%	50%	15	$0.28	$0.10
Other	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	4.47640	95%	5%	20	$0.93	$0.15
Other	Space_Heat	New	Green Roof	4.47640	100%	25%	40	$15.00	$0.13
Other	Space_Heat	New	Leak Proof Duct Fittings	4.47640	100%	49%	30	$0.07	$0.21
Other	Space_Heat	New	Retro-Commisioning	4.47640	85%	92%	3	$1.00	$0.15
Other	Space_Heat	New	Windows-High Efficiency	4.47640	75%	80%	30	$0.05	$0.06
Other	Water_Heat	Existing	Commercial Washers	0.30027	95%	90%	8	$0.44	$0.35
Other	Water_Heat	Existing	Demand controlled Circulating Systems	0.30027	98%	60%	15	$0.93	$0.05
Other	Water_Heat	Existing	Faucet Aerators	0.30027	20%	100%	10	$0.00	$0.02
Other	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.30027	95%	85%	15	$0.01	$0.05
Other	Water_Heat	Existing	Low-Flow Showerheads	0.30027	25%	100%	10	$0.01	$0.02
Other	Water_Heat	Existing	Solar Water Heater	0.30027	95%	45%	15	$2.58	$0.40
Other	Water_Heat	Existing	Water Heater Temperature Setback	0.30027	60%	100%	10	$0.01	$0.15
Other	Water_Heat	New	Commercial Washers	0.30027	95%	90%	8	$0.44	$0.35
Other	Water_Heat	New	Demand controlled Circulating Systems	0.30027	98%	60%	15	$0.93	$0.05
Other	Water_Heat	New	Faucet Aerators	0.30027	20%	100%	10	$0.00	$0.02
Other	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.30027	95%	85%	15	$0.01	$0.05
Other	Water_Heat	New	Low-Flow Showerheads	0.30027	25%	100%	10	$0.01	$0.02
Other	Water_Heat	New	Solar Water Heater	0.30027	95%	45%	15	$2.58	$0.40
Restaurant	Cooling_Chillers	Existing	Active Window Insulation	4.95063	100%	20%	15	$1.45	$0.21
Restaurant	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.95063	95%	5%	10	$0.18	$0.05
Restaurant	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	4.95063	45%	95%	10	$0.32	$0.05
Restaurant	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	4.95063	75%	90%	15	$0.29	$0.12
Restaurant	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	4.95063	65%	98%	3	$0.07	$0.10
Restaurant	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	4.95063			20	$0.38	$0.25
Restaurant	Cooling_Chillers	Existing	Chiller-Water Side Economizer	4.95063	95%	45%	20	$0.59	$0.10
Restaurant	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	4.95063	98%	70%	15	$0.07	$0.08
Restaurant	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	4.95063	75%	95%	15	$0.04	$0.14
Restaurant	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	4.95063	90%	95%	15	$0.05	$0.04
Restaurant	Cooling_Chillers	Existing	Direct Digital Control System-Installation	4.95063	20%	60%	10	$0.11	$0.10
Restaurant	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	4.95063	99%	100%	5	$0.12	$0.01

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Restaurant	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	4.95063			20	$0.11	$0.20
Restaurant	Cooling_Chillers	Existing	Insulation - Floor	4.95063	95%	60%	20	$0.45	$0.02
Restaurant	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	4.95063	90%	75%	20	$0.45	$0.03
Restaurant	Cooling_Chillers	Existing	Pipe Insulation	4.95063	50%	65%	20	$0.02	$0.01
Restaurant	Cooling_Chillers	Existing	Retro-Commisioning	4.95063	85%	92%	3	$0.27	$0.15
Restaurant	Cooling_Chillers	Existing	Windows-High Efficiency	4.95063	85%	80%	30	$0.14	$0.05
Restaurant	Cooling_Chillers	New	Active Window Insulation	5.21119	100%	20%	15	$1.45	$0.21
Restaurant	Cooling_Chillers	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	5.21119	95%	5%	10	$0.18	$0.05
Restaurant	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	5.21119	45%	95%	10	$0.32	$0.05
Restaurant	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	5.21119	75%	90%	15	$0.29	$0.12
Restaurant	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	5.21119			20	$0.38	$0.25
Restaurant	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	5.21119	10%	95%	15	$0.04	$0.14
Restaurant	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	5.21119	80%	95%	15	$0.05	$0.04
Restaurant	Cooling_Chillers	New	Direct Digital Control System-Optimization	5.21119	99%	100%	5	$0.12	$0.01
Restaurant	Cooling_Chillers	New	Green Roof	5.21119	100%	25%	40	$15.00	$0.13
Restaurant	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	5.21119			20	$0.11	$0.20
Restaurant	Cooling_Chillers	New	Leak Proof Duct Fittings	5.21119	100%	49%	30	$0.07	$0.21
Restaurant	Cooling_Chillers	New	Pipe Insulation	5.21119	50%	100%	20	$0.02	$0.01
Restaurant	Cooling_Chillers	New	Retro-Commisioning	5.21119	85%	92%	3	$1.00	$0.15
Restaurant	Cooling_Chillers	New	Windows-High Efficiency	5.21119	85%	80%	30	$0.05	$0.05
Restaurant	Cooling_DX	Existing	Active Window Insulation	8.40938	100%	20%	15	$0.21	$0.21
Restaurant	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	8.40938	95%	5%	10	$0.14	$0.05
Restaurant	Cooling_DX	Existing	DX Package-Air Side Economizer	8.40938	55%	10%	10	$0.53	$0.15
Restaurant	Cooling_DX	Existing	DX Tune-Up / Diagnostics	8.40938	85%	98%	3	$0.15	$0.10
Restaurant	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	8.40938	90%	50%	10	$0.55	$0.10
Restaurant	Cooling_DX	Existing	Duct Insulation	8.40938	20%	65%	20	$0.01	$0.03
Restaurant	Cooling_DX	Existing	Duct Repair and Sealing	8.40938	50%	65%	20	$0.04	$0.01
Restaurant	Cooling_DX	Existing	High Efficiency DX Package	8.40938			20	$0.50	$0.09
Restaurant	Cooling_DX	Existing	Insulation - Floor	8.40938	95%	60%	20	$0.45	$0.02
Restaurant	Cooling_DX	Existing	Insulation - Roof / Ceiling	8.40938	90%	75%	20	$0.45	$0.03
Restaurant	Cooling_DX	Existing	Premium Efficiency DX Package	8.40938			20	$0.70	$0.16
Restaurant	Cooling_DX	Existing	Programmable Thermostat	8.40938	45%	100%	10	$0.04	$0.10
Restaurant	Cooling_DX	Existing	Retro-Commisioning	8.40938	85%	92%	3	$0.27	$0.15
Restaurant	Cooling_DX	Existing	Windows-High Efficiency	8.40938	85%	80%	30	$0.14	$0.05
Restaurant	Cooling_DX	New	Active Window Insulation	9.02257	100%	20%	15	$1.45	$0.21
Restaurant	Cooling_DX	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	9.02257	95%	5%	10	$0.18	$0.05
Restaurant	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	9.02257	90%	50%	10	$0.55	$0.10
Restaurant	Cooling_DX	New	Green Roof	9.02257	100%	25%	40	$15.00	$0.13
Restaurant	Cooling_DX	New	High Efficiency DX Package	9.02257			20	$0.50	$0.09
Restaurant	Cooling_DX	New	Leak Proof Duct Fittings	9.02257	100%	49%	30	$0.07	$0.21
Restaurant	Cooling_DX	New	Premium Efficiency DX Package	9.02257			20	$0.70	$0.16
Restaurant	Cooling_DX	New	Retro-Commisioning	9.02257	85%	92%	3	$1.00	$0.15
Restaurant	Cooling_DX	New	Windows-High Efficiency	9.02257	85%	80%	30	$0.05	$0.05
Restaurant	Cooling_HeatPump	Existing	Active Window Insulation	8.58481	100%	20%	15	$1.45	$0.21
Restaurant	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	8.58481	95%	5%	10	$0.18	$0.05
Restaurant	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	8.58481	90%	50%	10	$0.55	$0.10
Restaurant	Cooling_HeatPump	Existing	Duct Insulation	8.58481	20%	65%	20	$0.01	$0.03
Restaurant	Cooling_HeatPump	Existing	Duct Repair and Sealing	8.58481	50%	65%	20	$0.04	$0.01
Restaurant	Cooling_HeatPump	Existing	Insulation - Floor	8.58481	95%	60%	20	$0.45	$0.02
Restaurant	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	8.58481	90%	75%	20	$0.45	$0.03
Restaurant	Cooling_HeatPump	Existing	Programmable Thermostat	8.58481	45%	100%	10	$0.04	$0.10
Restaurant	Cooling_HeatPump	Existing	Retro-Commisioning	8.58481	85%	92%	3	$0.27	$0.15
Restaurant	Cooling_HeatPump	Existing	Windows-High Efficiency	8.58481	85%	80%	30	$0.14	$0.05
Restaurant	Cooling_HeatPump	New	Active Window Insulation	8.80494	100%	20%	15	$1.45	$0.21
Restaurant	Cooling_HeatPump	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	8.80494	95%	5%	10	$0.18	$0.05
Restaurant	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	8.80494	90%	50%	10	$0.55	$0.10
Restaurant	Cooling_HeatPump	New	Green Roof	8.80494	100%	25%	40	$15.00	$0.13
Restaurant	Cooling_HeatPump	New	Leak Proof Duct Fittings	8.80494	100%	49%	30	$0.07	$0.21

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Restaurant	Cooling_HeatPump	New	Retro-Commisioning	8.80494	85%	92%	3	$1.00	$0.15
Restaurant	Cooling_HeatPump	New	Windows-High Efficiency	8.80494	85%	80%	30	$0.05	$0.05
Restaurant	Lighting	Existing	Bi-Level Control, Stairwell Lighting	7.59584	98%	95%	7	$0.10	$0.02
Restaurant	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	7.59584	90%	2%	16	$0.40	$0.10
Restaurant	Lighting	Existing	Cost Effective Load Shed Ballast and Controller	7.59584	100%	80%	15	$1.61	$0.01
Restaurant	Lighting	Existing	Induction Lighting	7.59584	99%	25%	25	$0.24	$0.01
Restaurant	Lighting	Existing	LED Exit Signs	7.59584	98%	100%	25	$0.16	$0.01
Restaurant	Lighting	Existing	LED Refrigeration Case Lights	7.59584	85%	100%	12	$0.02	$0.07
Restaurant	Lighting	Existing	LED Solid State White Lighting	7.59584	100%	7%	6	$2.70	$0.16
Restaurant	Lighting	Existing	Occupancy Sensor Control, Fluorescent	7.59584	95%	85%	13	$0.53	$0.00
Restaurant	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	7.59584	75%	98%	7	$0.26	$0.15
Restaurant	Lighting	Existing	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	7.59584	90%	85%	7	$0.48	$0.25
Restaurant	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	7.59584	85%	60%	16	$0.64	$0.08
Restaurant	Lighting	New	Bi-Level Control, Stairwell Lighting	7.30932	98%	95%	7	$0.10	$0.03
Restaurant	Lighting	New	Continuous Dimming, Fluorescent Fixtures	7.30932	90%	2%	16	$0.20	$0.10
Restaurant	Lighting	New	Cost Effective Load Shed Ballast and Controller	7.30932	100%	80%	15	$1.61	$0.01
Restaurant	Lighting	New	Induction Lighting	7.30932	99%	25%	25	$0.00	$0.01
Restaurant	Lighting	New	LED Exit Signs	7.30932	98%	100%	25	$0.05	$0.01
Restaurant	Lighting	New	LED Refrigeration Case Lights	7.30932	85%	100%	12	$0.02	$0.07
Restaurant	Lighting	New	LED Solid State White Lighting	7.30932	100%	7%	6	$2.70	$0.16
Restaurant	Lighting	New	Occupancy Sensor Control, Fluorescent	7.30932	95%	85%	13	$0.53	$0.00
Restaurant	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	7.30932	75%	98%	7	$0.12	$0.15
Restaurant	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	7.30932	90%	85%	7	$0.22	$0.25
Restaurant	Lighting	New	Stepped Dimming Fluorescent Fixtures	7.30932	85%	60%	16	$0.32	$0.08
Restaurant	Plug_Load	Existing	Office Computer Network Energy Management	0.22583	33%	100%	4	$0.00	$0.07
Restaurant	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	0.22583	65%	100%	4	$0.01	$0.01
Restaurant	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	0.22583	60%	100%	4	$0.02	$0.02
Restaurant	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	0.22583	62%	100%	4	$0.04	$0.01
Restaurant	Plug_Load	Existing	Vending Machines- Controls	0.22583	80%	95%	3	$0.02	$0.01
Restaurant	Plug_Load	Existing	Vending Machines- High Efficiency	0.22583	85%	100%	14	$0.03	$0.02
Restaurant	Plug_Load	New	Office Computer Network Energy Management	0.22583	33%	100%	4	$0.00	$0.07
Restaurant	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	0.22583	65%	100%	4	$0.01	$0.01
Restaurant	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	0.22583	60%	100%	4	$0.02	$0.02
Restaurant	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	0.22583	62%	100%	4	$0.04	$0.01
Restaurant	Plug_Load	New	Vending Machines- High Efficiency	0.22583	85%	100%	14	$0.03	$0.02
Restaurant	Refrigeration	Existing	Anti-Sweat (Humidistat) Controls	5.48107	45%	100%	12	$0.02	$0.05
Restaurant	Refrigeration	Existing	Compressor VSD retrofit	5.48107	90%	60%	10	$0.41	$0.06
Restaurant	Refrigeration	Existing	Efficient Fan Motor Options for Commercial Refrigeration	5.48107	100%	40%	9	$1.16	$0.14
Restaurant	Refrigeration	Existing	High Efficiency Case Fans	5.48107	92%	100%	16	$1.16	$0.02
Restaurant	Refrigeration	Existing	Installation of Floating Condenser Head Pressure Controls	5.48107	38%	100%	14	$0.12	$0.07
Restaurant	Refrigeration	Existing	Night Covers for Display Cases	5.48107	90%	100%	5	$0.01	$0.06
Restaurant	Refrigeration	Existing	Strip Curtains for Walk-Ins	5.48107	25%	100%	4	$0.05	$0.04
Restaurant	Refrigeration	New	Anti-Sweat (Humidistat) Controls	5.48107	45%	100%	12	$0.02	$0.05
Restaurant	Refrigeration	New	Efficient Fan Motor Options for Commercial Refrigeration	5.48107	100%	40%	9	$1.16	$0.14
Restaurant	Refrigeration	New	High Efficiency Case Fans	5.48107	92%	100%	16	$1.16	$0.02
Restaurant	Refrigeration	New	Installation of Floating Condenser Head Pressure Controls	5.48107	38%	100%	14	$0.12	$0.07
Restaurant	Refrigeration	New	Night Covers for Display Cases	5.48107	90%	100%	5	$0.01	$0.06
Restaurant	Refrigeration	New	Reduced Speed or Cycling of Evaporator Fans	5.48107	75%	100%	5	$0.09	$0.01
Restaurant	Refrigeration	New	Strip Curtains for Walk-Ins	5.48107	25%	100%	4	$0.05	$0.04
Restaurant	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	7.06793	95%	5%	15	$0.28	$0.10
Restaurant	Space_Heat	Existing	Duct Insulation	7.06793	20%	65%	20	$0.03	$0.03
Restaurant	Space_Heat	Existing	Duct Repair and Sealing	7.06793	50%	65%	20	$0.01	$0.01
Restaurant	Space_Heat	Existing	Insulation - Floor	7.06793	95%	60%	20	$0.45	$0.05
Restaurant	Space_Heat	Existing	Insulation - Roof / Ceiling	7.06793	90%	75%	20	$0.45	$0.10
Restaurant	Space_Heat	Existing	Programmable Thermostat	7.06793	45%	100%	10	$0.15	$0.20
Restaurant	Space_Heat	Existing	Retro-Commisioning	7.06793	85%	92%	3	$0.27	$0.15
Restaurant	Space_Heat	Existing	Windows-High Efficiency	7.06793	85%	80%	30	$0.14	$0.03
Restaurant	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	7.06793	95%	5%	15	$0.28	$0.10

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Restaurant	Space_Heat	New	Green Roof	7.06793	100%	25%	40	$15.00	$0.13
Restaurant	Space_Heat	New	Leak Proof Duct Fittings	7.06793	100%	49%	30	$0.07	$0.21
Restaurant	Space_Heat	New	Retro-Commisioning	7.06793	85%	92%	3	$1.00	$0.15
Restaurant	Space_Heat	New	Windows-High Efficiency	7.06793	85%	80%	30	$0.05	$0.03
Restaurant	Water_Heat	Existing	Chemical Dishwashing System	4.10206	90%	80%	10	$0.20	$0.07
Restaurant	Water_Heat	Existing	Demand controlled Circulating Systems	4.10206	98%	60%	15	$2.13	$0.05
Restaurant	Water_Heat	Existing	Faucet Aerators	4.10206	20%	100%	10	$0.01	$0.02
Restaurant	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	4.10206	95%	85%	15	$0.02	$0.05
Restaurant	Water_Heat	Existing	Low Flow Spray Heads	4.10206	30%	100%	5	$0.02	$0.05
Restaurant	Water_Heat	Existing	Low-Flow Showerheads	4.10206	25%	100%	10	$0.00	$0.00
Restaurant	Water_Heat	Existing	Solar Water Heater	4.10206	95%	45%	15	$2.21	$0.40
Restaurant	Water_Heat	Existing	Water Cooled Refrigeration with Heat Recovery	4.10206	95%	85%	8	$0.09	$0.03
Restaurant	Water_Heat	Existing	Water Heater Temperature Setback	4.10206	80%	100%	10	$0.01	$0.15
Restaurant	Water_Heat	New	Chemical Dishwashing System	4.10206	90%	80%	10	$0.20	$0.07
Restaurant	Water_Heat	New	Demand controlled Circulating Systems	4.10206	98%	60%	15	$2.13	$0.05
Restaurant	Water_Heat	New	Faucet Aerators	4.10206	20%	100%	10	$0.01	$0.02
Restaurant	Water_Heat	New	Hot Water (SHW) Pipe Insulation	4.10206	95%	85%	15	$0.02	$0.05
Restaurant	Water_Heat	New	Low Flow Spray Heads	4.10206	30%	100%	5	$0.02	$0.05
Restaurant	Water_Heat	New	Low-Flow Showerheads	4.10206	25%	100%	10	$0.01	$0.00
Restaurant	Water_Heat	New	Solar Water Heater	4.10206	95%	45%	15	$2.21	$0.40
Restaurant	Water_Heat	New	Water Cooled Refrigeration with Heat Recovery	4.10206	95%	85%	8	$0.09	$0.03
School	Cooling_Chillers	Existing	Active Window Insulation	0.28718	100%	20%	15	$1.45	$0.21
School	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.28718	95%	25%	10	$0.22	$0.05
School	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	0.28718	45%	95%	10	$0.07	$0.05
School	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	0.28718	75%	90%	15	$0.34	$0.12
School	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	0.28718	65%	98%	3	$0.08	$0.10
School	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	0.28718			20	$0.45	$0.25
School	Cooling_Chillers	Existing	Chiller-Water Side Economizer	0.28718	70%	45%	20	$0.59	$0.10
School	Cooling_Chillers	Existing	Convert Constant Volume Air System to VAV	0.28718	15%	85%	15	$0.17	$0.12
School	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	0.28718	98%	70%	15	$0.08	$0.08
School	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	0.28718	75%	95%	15	$0.04	$0.14
School	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	0.28718	90%	95%	15	$0.05	$0.04
School	Cooling_Chillers	Existing	Direct Digital Control System-Installation	0.28718	20%	60%	10	$0.14	$0.10
School	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	0.28718	92%	100%	5	$0.12	$0.01
School	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	0.28718			20	$0.14	$0.20
School	Cooling_Chillers	Existing	Insulation - Floor	0.28718	40%	60%	20	$0.47	$0.02
School	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	0.28718	20%	75%	20	$0.47	$0.03
School	Cooling_Chillers	Existing	Pipe Insulation	0.28718	50%	65%	20	$0.02	$0.01
School	Cooling_Chillers	Existing	Retro-Commisioning	0.28718	85%	92%	3	$0.27	$0.15
School	Cooling_Chillers	Existing	Windows-High Efficiency	0.28718	65%	80%	30	$0.12	$0.04
School	Cooling_Chillers	Existing	Wireless Performance Monitoring, Diagnostics and Control	0.28718	100%	30%	10	$0.50	$0.10
School	Cooling_Chillers	New	Active Window Insulation	0.30229	100%	20%	15	$1.45	$0.21
School	Cooling_Chillers	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.30229	95%	25%	10	$0.22	$0.05
School	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	0.30229	45%	95%	10	$0.07	$0.05
School	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	0.30229	75%	90%	15	$0.34	$0.12
School	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	0.30229			20	$0.45	$0.25
School	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	0.30229	10%	95%	15	$0.04	$0.14
School	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	0.30229	80%	95%	15	$0.05	$0.04
School	Cooling_Chillers	New	Direct Digital Control System-Optimization	0.30229	92%	100%	5	$0.12	$0.01
School	Cooling_Chillers	New	Green Roof	0.30229	100%	25%	40	$15.00	$0.13
School	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	0.30229			20	$0.14	$0.20
School	Cooling_Chillers	New	Leak Proof Duct Fittings	0.30229	100%	49%	30	$0.07	$0.21
School	Cooling_Chillers	New	Pipe Insulation	0.30229	50%	100%	20	$0.02	$0.01
School	Cooling_Chillers	New	Retro-Commisioning	0.30229	85%	92%	3	$1.00	$0.15
School	Cooling_Chillers	New	Windows-High Efficiency	0.30229	65%	80%	30	$0.04	$0.04
School	Cooling_Chillers	New	Wireless Performance Monitoring, Diagnostics and Control	0.30229	100%	30%	10	$0.50	$0.10
School	Cooling_DX	Existing	Active Window Insulation	0.48781	100%	20%	15	$0.09	$0.21
School	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.48781	95%	25%	10	$0.14	$0.05

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
School	Cooling_DX	Existing	Convert Constant Volume Air System to VAV	0.48781	15%	85%	15	$0.17	$0.12
School	Cooling_DX	Existing	DX Package-Air Side Economizer	0.48781	35%	10%	10	$0.11	$0.15
School	Cooling_DX	Existing	DX Tune-Up / Diagnostics	0.48781	85%	98%	3	$0.18	$0.10
School	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	0.48781	90%	50%	10	$0.65	$0.10
School	Cooling_DX	Existing	Duct Insulation	0.48781	20%	65%	20	$0.01	$0.03
School	Cooling_DX	Existing	Duct Repair and Sealing	0.48781	50%	65%	20	$0.04	$0.01
School	Cooling_DX	Existing	High Efficiency DX Package	0.48781			20	$0.50	$0.09
School	Cooling_DX	Existing	Insulation - Floor	0.48781	40%	60%	20	$0.47	$0.02
School	Cooling_DX	Existing	Insulation - Roof / Ceiling	0.48781	20%	75%	20	$0.47	$0.03
School	Cooling_DX	Existing	Premium Efficiency DX Package	0.48781			20	$0.73	$0.16
School	Cooling_DX	Existing	Programmable Thermostat	0.48781	38%	100%	10	$0.05	$0.10
School	Cooling_DX	Existing	Retro-Commisioning	0.48781	85%	92%	3	$0.27	$0.15
School	Cooling_DX	Existing	Windows-High Efficiency	0.48781	65%	80%	30	$0.12	$0.05
School	Cooling_DX	New	Active Window Insulation	0.52338	100%	20%	15	$1.45	$0.21
School	Cooling_DX	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.52338	95%	25%	10	$0.22	$0.05
School	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	0.52338	90%	50%	10	$0.65	$0.10
School	Cooling_DX	New	Green Roof	0.52338	100%	25%	40	$15.00	$0.13
School	Cooling_DX	New	High Efficiency DX Package	0.52338			20	$0.50	$0.09
School	Cooling_DX	New	Leak Proof Duct Fittings	0.52338	100%	49%	30	$0.07	$0.21
School	Cooling_DX	New	Premium Efficiency DX Package	0.52338			20	$0.73	$0.16
School	Cooling_DX	New	Retro-Commisioning	0.52338	85%	92%	3	$1.00	$0.15
School	Cooling_DX	New	Windows-High Efficiency	0.52338	65%	80%	30	$0.04	$0.05
School	Cooling_HeatPump	Existing	Active Window Insulation	0.49799	100%	20%	15	$1.45	$0.21
School	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.49799	95%	25%	10	$0.22	$0.05
School	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	0.49799	90%	50%	10	$0.65	$0.10
School	Cooling_HeatPump	Existing	Duct Insulation	0.49799	20%	65%	20	$0.01	$0.03
School	Cooling_HeatPump	Existing	Duct Repair and Sealing	0.49799	50%	65%	20	$0.04	$0.01
School	Cooling_HeatPump	Existing	Insulation - Floor	0.49799	40%	60%	20	$0.47	$0.02
School	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	0.49799	20%	75%	20	$0.47	$0.03
School	Cooling_HeatPump	Existing	Programmable Thermostat	0.49799	38%	100%	10	$0.05	$0.10
School	Cooling_HeatPump	Existing	Retro-Commisioning	0.49799	85%	92%	3	$0.27	$0.15
School	Cooling_HeatPump	Existing	Windows-High Efficiency	0.49799	65%	80%	30	$0.12	$0.05
School	Cooling_HeatPump	New	Active Window Insulation	0.51076	100%	20%	15	$1.45	$0.21
School	Cooling_HeatPump	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.51076	95%	25%	10	$0.22	$0.05
School	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	0.51076	90%	50%	10	$0.65	$0.10
School	Cooling_HeatPump	New	Green Roof	0.51076	100%	25%	40	$15.00	$0.13
School	Cooling_HeatPump	New	Leak Proof Duct Fittings	0.51076	100%	49%	30	$0.07	$0.21
School	Cooling_HeatPump	New	Retro-Commisioning	0.51076	85%	92%	3	$1.00	$0.15
School	Cooling_HeatPump	New	Windows-High Efficiency	0.51076	65%	80%	30	$0.04	$0.05
School	HVAC_Aux	New	Optimized Variable Volume Lab Hood Design	0.73197	98%	95%	10	$0.01	$0.02
School	HVAC_Aux	New	Under floor Ventilation with Low Static Pressure	0.73197	100%	22%	15	$0.70	$0.20
School	Lighting	Existing	Advanced High Intensity Discharge (HID) Light Sources	1.96057	100%	6%	4	$0.03	$0.07
School	Lighting	Existing	Advanced/Integrated Daylighting controls (ADCs)	1.96057	100%	66%	20	$2.50	$0.12
School	Lighting	Existing	Bi-Level Control, Stairwell Lighting	1.96057	98%	95%	7	$0.10	$0.03
School	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	1.96057	90%	45%	24	$0.35	$0.16
School	Lighting	Existing	Cost Effective Load Shed Ballast and Controller	1.96057	100%	80%	15	$1.41	$0.01
School	Lighting	Existing	Hybrid Solar Lighting	1.96057	100%	22%	15	$3.24	$0.52
School	Lighting	Existing	Induction Lighting	1.96057	99%	25%	25	$0.09	$0.01
School	Lighting	Existing	Integrated Lighting, Classrooms	1.96057	98%	75%	8	$0.94	$0.25
School	Lighting	Existing	LED Exit Signs	1.96057	98%	100%	25	$0.03	$0.01
School	Lighting	Existing	LED Solid State White Lighting	1.96057	100%	7%	6	$0.70	$0.01
School	Lighting	Existing	Low Wattage Ceramic Metal Halide Lamps	1.96057	100%	6%	7	$0.53	$0.10
School	Lighting	Existing	Occupancy Sensor Control, Fluorescent	1.96057	75%	85%	20	$0.42	$0.04
School	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	1.96057	75%	98%	7	$0.26	$0.15
School	Lighting	Existing	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	1.96057	90%	85%	7	$0.48	$0.25
School	Lighting	Existing	Scotopic (High CCT) Lighting	1.96057	100%	13%	15	$0.55	$0.24
School	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	1.96057	85%	45%	24	$0.56	$0.12
School	Lighting	New	Advanced High Intensity Discharge (HID) Light Sources	1.89688	100%	6%	4	$0.03	$0.07

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
School	Lighting	New	Advanced/Integrated Daylighting controls (ADCs)	1.89688	100%	66%	20	$2.50	$0.05
School	Lighting	New	Bi-Level Control, Stairwell Lighting	1.89688	98%	95%	7	$0.10	$0.03
School	Lighting	New	Continuous Dimming, Fluorescent Fixtures	1.89688	90%	45%	24	$0.18	$0.16
School	Lighting	New	Cost Effective Load Shed Ballast and Controller	1.89688	100%	80%	15	$1.41	$0.01
School	Lighting	New	Hybrid Solar Lighting	1.89688	100%	22%	15	$3.24	$0.52
School	Lighting	New	Induction Lighting	1.89688	99%	25%	25	$0.09	$0.01
School	Lighting	New	Integrated Lighting, Classrooms	1.89688	98%	75%	8	$0.94	$0.25
School	Lighting	New	LED Exit Signs	1.89688	98%	100%	25	$0.01	$0.01
School	Lighting	New	LED Solid State White Lighting	1.89688	100%	7%	6	$0.70	$0.01
School	Lighting	New	Low Wattage Ceramic Metal Halide Lamps	1.89688	100%	6%	7	$0.53	$0.10
School	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	1.89688	75%	98%	7	$0.12	$0.15
School	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	1.89688	90%	85%	7	$0.22	$0.35
School	Lighting	New	Scotopic (High CCT) Lighting	1.89688	100%	13%	15	$0.55	$0.24
School	Lighting	New	Stepped Dimming Fluorescent Fixtures	1.89688	85%	45%	24	$0.28	$0.12
School	Plug_Load	Existing	Office Computer Network Energy Management	0.10981	33%	100%	4	$0.00	$0.07
School	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	0.10981	65%	100%	4	$0.01	$0.01
School	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	0.10981	60%	100%	4	$0.06	$0.02
School	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	0.10981	62%	100%	4	$0.06	$0.01
School	Plug_Load	Existing	Vending Machines- Controls	0.10981	75%	95%	3	$0.00	$0.01
School	Plug_Load	Existing	Vending Machines- High Efficiency	0.10981	85%	100%	14	$0.01	$0.02
School	Plug_Load	New	Office Computer Network Energy Management	0.10981	33%	100%	4	$0.00	$0.07
School	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	0.10981	65%	100%	4	$0.01	$0.01
School	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	0.10981	60%	100%	4	$0.06	$0.02
School	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	0.10981	62%	100%	4	$0.06	$0.01
School	Plug_Load	New	Vending Machines- High Efficiency	0.10981	85%	100%	14	$0.01	$0.02
School	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	9.49571	95%	25%	15	$0.28	$0.10
School	Space_Heat	Existing	Convert Constant Volume Air System to VAV	9.49571	15%	85%	15	$0.17	$0.12
School	Space_Heat	Existing	Duct Insulation	9.49571	20%	65%	20	$0.01	$0.03
School	Space_Heat	Existing	Duct Repair and Sealing	9.49571	50%	65%	20	$0.00	$0.01
School	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	9.49571	95%	5%	20	$1.10	$0.20
School	Space_Heat	Existing	Insulation - Floor	9.49571	40%	60%	20	$0.47	$0.05
School	Space_Heat	Existing	Insulation - Roof / Ceiling	9.49571	20%	75%	20	$0.47	$0.10
School	Space_Heat	Existing	Programmable Thermostat	9.49571	38%	100%	10	$0.15	$0.20
School	Space_Heat	Existing	Retro-Commisioning	9.49571	85%	92%	3	$0.27	$0.15
School	Space_Heat	Existing	Windows-High Efficiency	9.49571	65%	80%	30	$0.12	$0.06
School	Space_Heat	Existing	Wireless Performance Monitoring, Diagnostics and Control	9.49571	100%	30%	10	$0.50	$0.10
School	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	9.49571	95%	25%	15	$0.28	$0.10
School	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	9.49571	95%	5%	20	$1.00	$0.15
School	Space_Heat	New	Green Roof	9.49571	100%	25%	40	$15.00	$0.13
School	Space_Heat	New	Leak Proof Duct Fittings	9.49571	100%	49%	30	$0.07	$0.21
School	Space_Heat	New	Retro-Commisioning	9.49571	85%	92%	3	$1.00	$0.15
School	Space_Heat	New	Windows-High Efficiency	9.49571	65%	80%	30	$0.04	$0.06
School	Space_Heat	New	Wireless Performance Monitoring, Diagnostics and Control	9.49571	100%	30%	10	$0.50	$0.10
School	Water_Heat	Existing	Chemical Dishwashing System	0.66314	90%	80%	10	$0.02	$0.04
School	Water_Heat	Existing	Demand controlled Circulating Systems	0.66314	98%	60%	15	$0.45	$0.05
School	Water_Heat	Existing	Faucet Aerators	0.66314	20%	100%	10	$0.01	$0.02
School	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.66314	10%	85%	15	$0.01	$0.05
School	Water_Heat	Existing	Low Flow Spray Heads	0.66314	30%	100%	5	$0.00	$0.01
School	Water_Heat	Existing	Low-Flow Showerheads	0.66314	25%	100%	10	$0.02	$0.02
School	Water_Heat	Existing	Solar Water Heater	0.66314	95%	45%	15	$1.93	$0.40
School	Water_Heat	Existing	Water Heater Temperature Setback	0.66314	20%	100%	10	$0.00	$0.15
School	Water_Heat	New	Chemical Dishwashing System	0.66314	90%	80%	10	$0.02	$0.04
School	Water_Heat	New	Demand controlled Circulating Systems	0.66314	98%	60%	15	$0.45	$0.05
School	Water_Heat	New	Faucet Aerators	0.66314	20%	100%	10	$0.01	$0.02
School	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.66314	10%	85%	15	$0.01	$0.05
School	Water_Heat	New	Low Flow Spray Heads	0.66314	30%	100%	5	$0.00	$0.01
School	Water_Heat	New	Low-Flow Showerheads	0.66314	25%	100%	10	$0.01	$0.02
School	Water_Heat	New	Solar Water Heater	0.66314	95%	45%	15	$1.93	$0.40

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
University	Cooling_Chillers	Existing	Active Window Insulation	3.58072	100%	20%	15	$1.45	$0.21
University	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	3.58072	95%	25%	10	$0.44	$0.05
University	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	3.58072	45%	95%	10	$0.05	$0.05
University	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	3.58072	75%	90%	15	$0.68	$0.12
University	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	3.58072	65%	98%	3	$0.17	$0.10
University	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	3.58072			20	$0.90	$0.25
University	Cooling_Chillers	Existing	Chiller-Water Side Economizer	3.58072	95%	45%	20	$0.59	$0.10
University	Cooling_Chillers	Existing	Convert Constant Volume Air System to VAV	3.58072	15%	85%	15	$0.35	$0.12
University	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	3.58072	98%	70%	15	$0.16	$0.08
University	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	3.58072	75%	95%	15	$0.04	$0.14
University	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	3.58072	90%	95%	15	$0.11	$0.04
University	Cooling_Chillers	Existing	Direct Digital Control System-Installation	3.58072	20%	60%	10	$0.27	$0.10
University	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	3.58072	85%	100%	5	$0.12	$0.01
University	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	3.58072			20	$0.27	$0.20
University	Cooling_Chillers	Existing	Insulation - Floor	3.58072	40%	60%	20	$0.30	$0.02
University	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	3.58072	17%	75%	20	$0.30	$0.03
University	Cooling_Chillers	Existing	Pipe Insulation	3.58072	50%	65%	20	$0.03	$0.01
University	Cooling_Chillers	Existing	Retro-Commisioning	3.58072	85%	92%	3	$0.27	$0.15
University	Cooling_Chillers	Existing	Windows-High Efficiency	3.58072	65%	80%	30	$0.32	$0.04
University	Cooling_Chillers	Existing	Wireless Performance Monitoring, Diagnostics and Control	3.58072	100%	30%	10	$0.50	$0.10
University	Cooling_Chillers	New	Active Window Insulation	3.76918	100%	20%	15	$1.45	$0.21
University	Cooling_Chillers	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	3.76918	95%	25%	10	$0.44	$0.05
University	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	3.76918	45%	95%	10	$0.05	$0.05
University	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	3.76918	75%	90%	15	$0.68	$0.12
University	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	3.76918			20	$0.90	$0.25
University	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	3.76918	10%	95%	15	$0.04	$0.14
University	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	3.76918	80%	95%	15	$0.11	$0.04
University	Cooling_Chillers	New	Direct Digital Control System-Optimization	3.76918	85%	100%	5	$0.12	$0.01
University	Cooling_Chillers	New	Green Roof	3.76918	100%	25%	40	$15.00	$0.13
University	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	3.76918			20	$0.27	$0.20
University	Cooling_Chillers	New	Leak Proof Duct Fittings	3.76918	100%	49%	30	$0.07	$0.21
University	Cooling_Chillers	New	Pipe Insulation	3.76918	50%	100%	20	$0.03	$0.01
University	Cooling_Chillers	New	Retro-Commisioning	3.76918	85%	92%	3	$1.00	$0.15
University	Cooling_Chillers	New	Windows-High Efficiency	3.76918	65%	80%	30	$0.11	$0.04
University	Cooling_Chillers	New	Wireless Performance Monitoring, Diagnostics and Control	3.76918	100%	30%	10	$0.50	$0.10
University	Cooling_DX	Existing	Active Window Insulation	6.08238	100%	20%	15	$0.12	$0.21
University	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.08238	95%	25%	10	$0.21	$0.05
University	Cooling_DX	Existing	Convert Constant Volume Air System to VAV	6.08238	15%	85%	15	$0.35	$0.12
University	Cooling_DX	Existing	DX Package-Air Side Economizer	6.08238	98%	10%	10	$0.08	$0.15
University	Cooling_DX	Existing	DX Tune-Up / Diagnostics	6.08238	85%	98%	3	$0.35	$0.10
University	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	6.08238	90%	50%	10	$1.31	$0.10
University	Cooling_DX	Existing	Duct Insulation	6.08238	20%	65%	20	$0.01	$0.03
University	Cooling_DX	Existing	Duct Repair and Sealing	6.08238	50%	65%	20	$0.04	$0.01
University	Cooling_DX	Existing	High Efficiency DX Package	6.08238			20	$0.50	$0.09
University	Cooling_DX	Existing	Insulation - Floor	6.08238	40%	60%	20	$0.30	$0.02
University	Cooling_DX	Existing	Insulation - Roof / Ceiling	6.08238	17%	75%	20	$0.30	$0.03
University	Cooling_DX	Existing	Premium Efficiency DX Package	6.08238			20	$0.90	$0.16
University	Cooling_DX	Existing	Programmable Thermostat	6.08238	28%	100%	10	$0.09	$0.10
University	Cooling_DX	Existing	Retro-Commisioning	6.08238	85%	92%	3	$0.27	$0.15
University	Cooling_DX	Existing	Windows-High Efficiency	6.08238	65%	80%	30	$0.32	$0.05
University	Cooling_DX	New	Active Window Insulation	6.52589	100%	20%	15	$1.45	$0.21
University	Cooling_DX	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.52589	95%	25%	10	$0.44	$0.05
University	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	6.52589	90%	50%	10	$1.31	$0.10
University	Cooling_DX	New	Green Roof	6.52589	100%	25%	40	$15.00	$0.13
University	Cooling_DX	New	High Efficiency DX Package	6.52589			20	$0.50	$0.09
University	Cooling_DX	New	Leak Proof Duct Fittings	6.52589	100%	49%	30	$0.07	$0.21
University	Cooling_DX	New	Premium Efficiency DX Package	6.52589			20	$0.90	$0.16
University	Cooling_DX	New	Retro-Commisioning	6.52589	85%	92%	3	$1.00	$0.15

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
University	Cooling_DX	New	Windows-High Efficiency	6.52589	65%	80%	30	$0.11	$0.05
University	Cooling_HeatPump	Existing	Active Window Insulation	6.20927	100%	20%	15	$1.45	$0.21
University	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.20927	95%	25%	10	$0.44	$0.05
University	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	6.20927	90%	50%	10	$1.31	$0.10
University	Cooling_HeatPump	Existing	Duct Insulation	6.20927	20%	65%	20	$0.01	$0.03
University	Cooling_HeatPump	Existing	Duct Repair and Sealing	6.20927	50%	65%	20	$0.04	$0.01
University	Cooling_HeatPump	Existing	Insulation - Floor	6.20927	40%	60%	20	$0.30	$0.02
University	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	6.20927	17%	75%	20	$0.30	$0.03
University	Cooling_HeatPump	Existing	Programmable Thermostat	6.20927	28%	100%	10	$0.09	$0.10
University	Cooling_HeatPump	Existing	Retro-Commisioning	6.20927	85%	92%	3	$0.27	$0.15
University	Cooling_HeatPump	Existing	Windows-High Efficiency	6.20927	65%	80%	30	$0.32	$0.05
University	Cooling_HeatPump	New	Active Window Insulation	6.36848	100%	20%	15	$1.45	$0.21
University	Cooling_HeatPump	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	6.36848	95%	25%	10	$0.44	$0.05
University	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	6.36848	90%	50%	10	$1.31	$0.10
University	Cooling_HeatPump	New	Green Roof	6.36848	100%	25%	40	$15.00	$0.13
University	Cooling_HeatPump	New	Leak Proof Duct Fittings	6.36848	100%	49%	30	$0.07	$0.21
University	Cooling_HeatPump	New	Retro-Commisioning	6.36848	85%	92%	3	$1.00	$0.15
University	Cooling_HeatPump	New	Windows-High Efficiency	6.36848	65%	80%	30	$0.11	$0.05
University	HVAC_Aux	New	Optimized Variable Volume Lab Hood Design	0.95098	95%	95%	10	$0.02	$0.04
University	HVAC_Aux	New	Under floor Ventilation with Low Static Pressure	0.95098	100%	22%	15	$0.70	$0.20
University	Lighting	Existing	Advanced High Intensity Discharge (HID) Light Sources	3.99065	100%	6%	4	$0.05	$0.05
University	Lighting	Existing	Advanced/Integrated Daylighting controls (ADCs)	3.99065	100%	66%	20	$2.50	$0.04
University	Lighting	Existing	Bi-Level Control, Stairwell Lighting	3.99065	98%	95%	7	$0.10	$0.03
University	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	3.99065	90%	60%	23	$0.33	$0.15
University	Lighting	Existing	Cost Effective Load Shed Ballast and Controller	3.99065	100%	80%	15	$1.32	$0.01
University	Lighting	Existing	Cost Effective Load Shed Ballast and Controller	3.99065	100%	80%	15	$0.79	$0.01
University	Lighting	Existing	Hybrid Solar Lighting	3.99065	100%	22%	15	$6.49	$0.52
University	Lighting	Existing	Induction Lighting	3.99065	99%	25%	25	$0.13	$0.01
University	Lighting	Existing	LED Exit Signs	3.99065	98%	100%	25	$0.02	$0.01
University	Lighting	Existing	LED Solid State White Lighting	3.99065	100%	7%	6	$1.39	$0.04
University	Lighting	Existing	Low Wattage Ceramic Metal Halide Lamps	3.99065	100%	6%	7	$1.07	$0.07
University	Lighting	Existing	Occupancy Sensor Control, Fluorescent	3.99065	75%	85%	19	$0.44	$0.06
University	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	3.99065	75%	98%	7	$0.26	$0.15
University	Lighting	Existing	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	3.99065	90%	85%	7	$0.48	$0.25
University	Lighting	Existing	Scotopic (High CCT) Lighting	3.99065	100%	13%	15	$0.55	$0.23
University	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	3.99065	85%	60%	23	$0.53	$0.11
University	Lighting	New	Advanced High Intensity Discharge (HID) Light Sources	3.89242	100%	6%	4	$0.05	$0.05
University	Lighting	New	Advanced/Integrated Daylighting controls (ADCs)	3.89242	100%	66%	20	$2.50	$0.12
University	Lighting	New	Bi-Level Control, Stairwell Lighting	3.89242	98%	95%	7	$0.10	$0.03
University	Lighting	New	Continuous Dimming, Fluorescent Fixtures	3.89242	90%	60%	23	$0.17	$0.15
University	Lighting	New	Cost Effective Load Shed Ballast and Controller	3.89242	100%	80%	15	$1.48	$0.01
University	Lighting	New	Cost Effective Load Shed Ballast and Controller	3.89242	100%	80%	15	$1.32	$0.01
University	Lighting	New	Hybrid Solar Lighting	3.89242	100%	22%	15	$6.49	$0.52
University	Lighting	New	Induction Lighting	3.89242	99%	25%	25	$0.13	$0.01
University	Lighting	New	LED Exit Signs	3.89242	98%	100%	25	$0.01	$0.01
University	Lighting	New	LED Solid State White Lighting	3.89242	100%	7%	6	$1.39	$0.04
University	Lighting	New	Low Wattage Ceramic Metal Halide Lamps	3.89242	100%	6%	7	$1.07	$0.07
University	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	3.89242	75%	98%	7	$0.12	$0.15
University	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	3.89242	90%	85%	7	$0.22	$0.25
University	Lighting	New	Scotopic (High CCT) Lighting	3.89242	100%	13%	15	$0.55	$0.23
University	Lighting	New	Stepped Dimming Fluorescent Fixtures	3.89242	85%	60%	23	$0.26	$0.11
University	Plug_Load	Existing	Office Computer Network Energy Management	0.30817	33%	100%	4	$0.00	$0.08
University	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	0.30817	65%	100%	4	$0.00	$0.01
University	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	0.30817	60%	100%	4	$0.02	$0.02
University	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	0.30817	62%	100%	4	$0.02	$0.01
University	Plug_Load	Existing	Vending Machines- Controls	0.30817	75%	95%	3	$0.00	$0.01
University	Plug_Load	Existing	Vending Machines- High Efficiency	0.30817	85%	100%	14	$0.01	$0.02
University	Plug_Load	New	Office Computer Network Energy Management	0.30817	33%	100%	4	$0.00	$0.08

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
University	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	0.30817	65%	100%	4	$0.00	$0.01
University	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	0.30817	60%	100%	4	$0.02	$0.02
University	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	0.30817	62%	100%	4	$0.02	$0.01
University	Plug_Load	New	Vending Machines- High Efficiency	0.30817	85%	100%	14	$0.01	$0.02
University	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.00000	95%	25%	15	$0.28	$0.10
University	Space_Heat	Existing	Convert Constant Volume Air System to VAV	4.00000	15%	85%	15	$0.35	$0.12
University	Space_Heat	Existing	Duct Insulation	4.00000	20%	65%	20	$0.01	$0.03
University	Space_Heat	Existing	Duct Repair and Sealing	4.00000	50%	65%	20	$0.00	$0.01
University	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	4.00000	95%	5%	20	$1.00	$0.20
University	Space_Heat	Existing	Insulation - Floor	4.00000	40%	60%	20	$0.30	$0.05
University	Space_Heat	Existing	Insulation - Roof / Ceiling	4.00000	17%	75%	20	$0.30	$0.10
University	Space_Heat	Existing	Programmable Thermostat	4.00000	28%	100%	10	$0.15	$0.20
University	Space_Heat	Existing	Retro-Commisioning	4.00000	85%	92%	3	$0.27	$0.15
University	Space_Heat	Existing	Windows-High Efficiency	4.00000	65%	80%	30	$0.32	$0.06
University	Space_Heat	Existing	Wireless Performance Monitoring, Diagnostics and Control	4.00000	100%	30%	10	$0.50	$0.10
University	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	4.00000	95%	25%	15	$0.28	$0.10
University	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	4.00000	95%	5%	20	$0.93	$0.15
University	Space_Heat	New	Green Roof	4.00000	100%	25%	40	$15.00	$0.13
University	Space_Heat	New	Leak Proof Duct Fittings	4.00000	100%	49%	30	$0.07	$0.21
University	Space_Heat	New	Retro-Commisioning	4.00000	85%	92%	3	$1.00	$0.15
University	Space_Heat	New	Windows-High Efficiency	4.00000	65%	80%	30	$0.11	$0.06
University	Space_Heat	New	Wireless Performance Monitoring, Diagnostics and Control	4.00000	100%	30%	10	$0.50	$0.10
University	Water_Heat	Existing	Chemical Dishwashing System	0.61619	90%	80%	10	$0.01	$0.04
University	Water_Heat	Existing	Demand controlled Circulating Systems	0.61619	98%	60%	15	$0.31	$0.05
University	Water_Heat	Existing	Faucet Aerators	0.61619	20%	100%	10	$0.00	$0.02
University	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.61619	75%	85%	15	$0.02	$0.05
University	Water_Heat	Existing	Low-Flow Showerheads	0.61619	25%	100%	10	$0.01	$0.02
University	Water_Heat	Existing	Solar Water Heater	0.61619	95%	45%	15	$3.42	$0.40
University	Water_Heat	Existing	Water Heater Temperature Setback	0.61619	20%	100%	10	$0.00	$0.15
University	Water_Heat	New	Chemical Dishwashing System	0.61619	90%	80%	10	$0.01	$0.04
University	Water_Heat	New	Demand controlled Circulating Systems	0.61619	98%	60%	15	$0.31	$0.05
University	Water_Heat	New	Faucet Aerators	0.61619	20%	100%	10	$0.00	$0.02
University	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.61619	75%	85%	15	$0.02	$0.05
University	Water_Heat	New	Low-Flow Showerheads	0.61619	25%	100%	10	$0.01	$0.02
University	Water_Heat	New	Solar Water Heater	0.61619	95%	45%	15	$3.42	$0.40
Warehouse	Cooling_Chillers	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	1.51207	95%	2%	10	$0.09	$0.05
Warehouse	Cooling_Chillers	Existing	Chilled Water / Condenser Water Settings-Optimization	1.51207	45%	95%	10	$0.10	$0.05
Warehouse	Cooling_Chillers	Existing	Chilled Water Piping Loop w/ VSD Control	1.51207	75%	90%	15	$0.14	$0.12
Warehouse	Cooling_Chillers	Existing	Chiller Tune-Up / Diagnostics	1.51207	65%	98%	3	$0.03	$0.10
Warehouse	Cooling_Chillers	Existing	Chiller-Centrifugal, VSD Control, 300 tons	1.51207			20	$0.18	$0.25
Warehouse	Cooling_Chillers	Existing	Chiller-Water Side Economizer	1.51207	95%	45%	20	$0.59	$0.10
Warehouse	Cooling_Chillers	Existing	Cooling Tower-Decrease Approach Temperature	1.51207	98%	70%	15	$0.03	$0.08
Warehouse	Cooling_Chillers	Existing	Cooling Tower-Two-Speed Fan Motor	1.51207	75%	95%	15	$0.03	$0.14
Warehouse	Cooling_Chillers	Existing	Cooling Tower-VSD Fan Control	1.51207	90%	95%	15	$0.02	$0.04
Warehouse	Cooling_Chillers	Existing	Direct Digital Control System-Installation	1.51207	20%	60%	10	$0.05	$0.10
Warehouse	Cooling_Chillers	Existing	Direct Digital Control System-Optimization	1.51207	92%	100%	5	$0.12	$0.01
Warehouse	Cooling_Chillers	Existing	High Efficiency Centrifugal Chiller, 300 ton	1.51207			20	$0.05	$0.20
Warehouse	Cooling_Chillers	Existing	Insulation - Floor	1.51207	50%	60%	20	$0.45	$0.02
Warehouse	Cooling_Chillers	Existing	Insulation - Roof / Ceiling	1.51207	15%	75%	20	$0.45	$0.03
Warehouse	Cooling_Chillers	Existing	Pipe Insulation	1.51207	50%	65%	20	$0.00	$0.01
Warehouse	Cooling_Chillers	Existing	Retro-Commisioning	1.51207	85%	92%	3	$0.27	$0.15
Warehouse	Cooling_Chillers	Existing	Windows-High Efficiency	1.51207	100%	80%	30	$0.09	$0.05
Warehouse	Cooling_Chillers	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	1.59165	95%	2%	10	$0.09	$0.05
Warehouse	Cooling_Chillers	New	Chilled Water / Condenser Water Settings-Optimization	1.59165	45%	95%	10	$0.10	$0.05
Warehouse	Cooling_Chillers	New	Chilled Water Piping Loop w/ VSD Control	1.59165	75%	90%	15	$0.14	$0.12
Warehouse	Cooling_Chillers	New	Chiller-Centrifugal, VSD Control, 300 tons	1.59165			20	$0.18	$0.25
Warehouse	Cooling_Chillers	New	Cooling Tower-Two-Speed Fan Motor	1.59165	10%	95%	15	$0.03	$0.14
Warehouse	Cooling_Chillers	New	Cooling Tower-VSD Fan Control	1.59165	80%	95%	15	$0.02	$0.04

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Warehouse	Cooling_Chillers	New	Direct Digital Control System-Optimization	1.59165	92%	100%	5	$0.12	$0.01
Warehouse	Cooling_Chillers	New	Green Roof	1.59165	100%	25%	40	$15.00	$0.13
Warehouse	Cooling_Chillers	New	High Efficiency Centrifugal Chiller, 300 ton	1.59165			20	$0.05	$0.20
Warehouse	Cooling_Chillers	New	Leak Proof Duct Fittings	1.59165	100%	49%	30	$0.07	$0.21
Warehouse	Cooling_Chillers	New	Pipe Insulation	1.59165	50%	100%	20	$0.00	$0.01
Warehouse	Cooling_Chillers	New	Retro-Commisioning	1.59165	85%	92%	3	$1.00	$0.15
Warehouse	Cooling_Chillers	New	Windows-High Efficiency	1.59165	100%	80%	30	$0.03	$0.05
Warehouse	Cooling_DX	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.56848	95%	2%	10	$0.23	$0.05
Warehouse	Cooling_DX	Existing	DX Package-Air Side Economizer	2.56848	45%	10%	10	$0.16	$0.15
Warehouse	Cooling_DX	Existing	DX Tune-Up / Diagnostics	2.56848	85%	98%	3	$0.07	$0.10
Warehouse	Cooling_DX	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.56848	90%	50%	10	$0.26	$0.10
Warehouse	Cooling_DX	Existing	Duct Insulation	2.56848	20%	65%	20	$0.01	$0.03
Warehouse	Cooling_DX	Existing	Duct Repair and Sealing	2.56848	50%	65%	20	$0.04	$0.01
Warehouse	Cooling_DX	Existing	High Efficiency DX Package	2.56848			20	$0.50	$0.09
Warehouse	Cooling_DX	Existing	Insulation - Floor	2.56848	50%	60%	20	$0.45	$0.02
Warehouse	Cooling_DX	Existing	Insulation - Roof / Ceiling	2.56848	15%	75%	20	$0.45	$0.03
Warehouse	Cooling_DX	Existing	Premium Efficiency DX Package	2.56848			20	$0.62	$0.16
Warehouse	Cooling_DX	Existing	Programmable Thermostat	2.56848	42%	100%	10	$0.02	$0.10
Warehouse	Cooling_DX	Existing	Retro-Commisioning	2.56848	85%	92%	3	$0.27	$0.15
Warehouse	Cooling_DX	Existing	Windows-High Efficiency	2.56848	100%	80%	30	$0.09	$0.05
Warehouse	Cooling_DX	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.75576	95%	2%	10	$0.09	$0.05
Warehouse	Cooling_DX	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.75576	90%	50%	10	$0.26	$0.10
Warehouse	Cooling_DX	New	Green Roof	2.75576	100%	25%	40	$15.00	$0.13
Warehouse	Cooling_DX	New	High Efficiency DX Package	2.75576			20	$0.50	$0.09
Warehouse	Cooling_DX	New	Leak Proof Duct Fittings	2.75576	100%	49%	30	$0.07	$0.21
Warehouse	Cooling_DX	New	Premium Efficiency DX Package	2.75576			20	$0.62	$0.16
Warehouse	Cooling_DX	New	Retro-Commisioning	2.75576	85%	92%	3	$1.00	$0.15
Warehouse	Cooling_DX	New	Windows-High Efficiency	2.75576	100%	80%	30	$0.03	$0.05
Warehouse	Cooling_HeatPump	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.62206	95%	2%	10	$0.09	$0.05
Warehouse	Cooling_HeatPump	Existing	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.62206	90%	50%	10	$0.26	$0.10
Warehouse	Cooling_HeatPump	Existing	Duct Insulation	2.62206	20%	65%	20	$0.01	$0.03
Warehouse	Cooling_HeatPump	Existing	Duct Repair and Sealing	2.62206	50%	65%	20	$0.04	$0.01
Warehouse	Cooling_HeatPump	Existing	Insulation - Floor	2.62206	50%	60%	20	$0.45	$0.02
Warehouse	Cooling_HeatPump	Existing	Insulation - Roof / Ceiling	2.62206	15%	75%	20	$0.45	$0.03
Warehouse	Cooling_HeatPump	Existing	Programmable Thermostat	2.62206	42%	100%	10	$0.02	$0.10
Warehouse	Cooling_HeatPump	Existing	Retro-Commisioning	2.62206	85%	92%	3	$0.27	$0.15
Warehouse	Cooling_HeatPump	Existing	Windows-High Efficiency	2.62206	100%	80%	30	$0.09	$0.05
Warehouse	Cooling_HeatPump	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	2.68929	95%	2%	10	$0.09	$0.05
Warehouse	Cooling_HeatPump	New	Direct / Indirect Evaporative Cooling, Pre-Cooling	2.68929	90%	50%	10	$0.26	$0.10
Warehouse	Cooling_HeatPump	New	Green Roof	2.68929	100%	25%	40	$15.00	$0.13
Warehouse	Cooling_HeatPump	New	Leak Proof Duct Fittings	2.68929	100%	49%	30	$0.07	$0.21
Warehouse	Cooling_HeatPump	New	Retro-Commisioning	2.68929	85%	92%	3	$1.00	$0.15
Warehouse	Cooling_HeatPump	New	Windows-High Efficiency	2.68929	100%	80%	30	$0.03	$0.05
Warehouse	Lighting	Existing	Advanced High Intensity Discharge (HID) Light Sources	2.47310	100%	6%	4	$0.03	$0.26
Warehouse	Lighting	Existing	Bi-Level Control, Stairwell Lighting	2.47310	98%	95%	7	$0.10	$0.02
Warehouse	Lighting	Existing	Continuous Dimming, Fluorescent Fixtures	2.47310	90%	2%	16	$0.20	$0.06
Warehouse	Lighting	Existing	Induction Lighting	2.47310	99%	25%	25	$0.47	$0.01
Warehouse	Lighting	Existing	LED Exit Signs	2.47310	98%	100%	25	$0.05	$0.01
Warehouse	Lighting	Existing	Low Wattage Ceramic Metal Halide Lamps	2.47310	100%	6%	7	$0.68	$0.37
Warehouse	Lighting	Existing	Occupancy Sensor Control, Fluorescent	2.47310	80%	85%	12	$0.26	$0.14
Warehouse	Lighting	Existing	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	2.47310	75%	98%	7	$0.26	$0.15
Warehouse	Lighting	Existing	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	2.47310	90%	85%	7	$0.48	$0.40
Warehouse	Lighting	Existing	Stepped Dimming Fluorescent Fixtures	2.47310	85%	60%	16	$0.31	$0.04
Warehouse	Lighting	New	Advanced High Intensity Discharge (HID) Light Sources	2.34303	100%	6%	4	$0.03	$0.26
Warehouse	Lighting	New	Bi-Level Control, Stairwell Lighting	2.34303	98%	95%	7	$0.10	$0.03
Warehouse	Lighting	New	Continuous Dimming, Fluorescent Fixtures	2.34303	90%	2%	16	$0.10	$0.06
Warehouse	Lighting	New	Induction Lighting	2.34303	99%	25%	25	$0.47	$0.01
Warehouse	Lighting	New	LED Exit Signs	2.34303	98%	100%	25	$0.02	$0.01

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Warehouse	Lighting	New	Low Wattage Ceramic Metal Halide Lamps	2.34303	100%	6%	7	$0.68	$0.37
Warehouse	Lighting	New	Occupancy Sensor Control, Fluorescent	2.34303	80%	85%	12	$0.26	$0.14
Warehouse	Lighting	New	Reduce Interior Lighting Power Density 15% Reduction (W/sqft)	2.34303	75%	98%	7	$0.12	$0.15
Warehouse	Lighting	New	Reduce Interior Lighting Power Density 25% Reduction (W/sqft)	2.34303	90%	85%	7	$0.22	$0.40
Warehouse	Lighting	New	Stepped Dimming Fluorescent Fixtures	2.34303	85%	60%	16	$0.16	$0.04
Warehouse	Plug_Load	Existing	Office Computer Network Energy Management	0.14216	33%	100%	4	$0.00	$0.08
Warehouse	Plug_Load	Existing	Office Equipment: Copiers, Energy Star or Better	0.14216	65%	100%	4	$0.02	$0.01
Warehouse	Plug_Load	Existing	Office Equipment: Monitors, Energy Star or Better	0.14216	60%	100%	4	$0.05	$0.02
Warehouse	Plug_Load	Existing	Office Equipment: Printers, Energy Star or Better	0.14216	62%	100%	4	$0.06	$0.01
Warehouse	Plug_Load	Existing	Vending Machines- Controls	0.14216	85%	95%	3	$0.01	$0.00
Warehouse	Plug_Load	Existing	Vending Machines- High Efficiency	0.14216	85%	100%	14	$0.02	$0.01
Warehouse	Plug_Load	New	Office Computer Network Energy Management	0.14216	33%	100%	4	$0.00	$0.08
Warehouse	Plug_Load	New	Office Equipment: Copiers, Energy Star or Better	0.14216	65%	100%	4	$0.02	$0.01
Warehouse	Plug_Load	New	Office Equipment: Monitors, Energy Star or Better	0.14216	60%	100%	4	$0.05	$0.02
Warehouse	Plug_Load	New	Office Equipment: Printers, Energy Star or Better	0.14216	62%	100%	4	$0.06	$0.01
Warehouse	Plug_Load	New	Vending Machines- High Efficiency	0.14216	85%	100%	14	$0.02	$0.01
Warehouse	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.77186	95%	2%	15	$0.28	$0.10
Warehouse	Space_Heat	Existing	Duct Insulation	0.77186	20%	65%	20	$0.01	$0.03
Warehouse	Space_Heat	Existing	Duct Repair and Sealing	0.77186	50%	65%	20	$0.00	$0.01
Warehouse	Space_Heat	Existing	Insulation - Floor	0.77186	50%	60%	20	$0.45	$0.05
Warehouse	Space_Heat	Existing	Insulation - Roof / Ceiling	0.77186	15%	75%	20	$0.45	$0.10
Warehouse	Space_Heat	Existing	Programmable Thermostat	0.77186	42%	100%	10	$0.15	$0.20
Warehouse	Space_Heat	Existing	Retro-Commisioning	0.77186	85%	92%	3	$0.27	$0.15
Warehouse	Space_Heat	Existing	Windows-High Efficiency	0.77186	100%	80%	30	$0.09	$0.01
Warehouse	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.77186	95%	2%	15	$0.28	$0.10
Warehouse	Space_Heat	New	Green Roof	0.77186	100%	25%	40	$15.00	$0.13
Warehouse	Space_Heat	New	Leak Proof Duct Fittings	0.77186	100%	49%	30	$0.07	$0.21
Warehouse	Space_Heat	New	Retro-Commisioning	0.77186	85%	92%	3	$1.00	$0.15
Warehouse	Space_Heat	New	Windows-High Efficiency	0.77186	100%	80%	30	$0.03	$0.01
Warehouse	Water_Heat	Existing	Demand controlled Circulating Systems	0.02543	98%	60%	15	$0.65	$0.05
Warehouse	Water_Heat	Existing	Faucet Aerators	0.02543	20%	100%	10	$0.00	$0.02
Warehouse	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.02543	92%	85%	15	$0.00	$0.05
Warehouse	Water_Heat	Existing	Low-Flow Showerheads	0.02543	25%	100%	10	$0.00	$0.03
Warehouse	Water_Heat	Existing	Solar Water Heater	0.02543	95%	45%	15	$0.60	$0.40
Warehouse	Water_Heat	Existing	Water Heater Temperature Setback	0.02543	50%	100%	10	$0.00	$0.15
Warehouse	Water_Heat	New	Demand controlled Circulating Systems	0.02543	98%	60%	15	$0.65	$0.05
Warehouse	Water_Heat	New	Faucet Aerators	0.02543	20%	100%	10	$0.00	$0.02
Warehouse	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.02543	92%	85%	15	$0.00	$0.05
Warehouse	Water_Heat	New	Low-Flow Showerheads	0.02543	25%	100%	10	$0.01	$0.03
Warehouse	Water_Heat	New	Solar Water Heater	0.02543	95%	45%	15	$0.60	$0.40

Table A-4. Commercial Gas Measures

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Dry_Goods_Retail	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.12	95%	90%	15	$0.28	10%
Dry_Goods_Retail	Space_Heat	Existing	Boiler Economizer	0.12	95%	40%	20	$0.59	10%
Dry_Goods_Retail	Space_Heat	Existing	Convert Constant Volume Air System to VAV	0.12	15%	80%	15	$0.19	12%
Dry_Goods_Retail	Space_Heat	Existing	Duct Insulation	0.12	20%	65%	20	$0.01	2%
Dry_Goods_Retail	Space_Heat	Existing	Duct Repair and Sealing	0.12	50%	65%	20	$0.04	2%
Dry_Goods_Retail	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.12			20	$0.10	12%
Dry_Goods_Retail	Space_Heat	Existing	Insulation - Floor	0.12	95%	60%	20	$0.47	5%
Dry_Goods_Retail	Space_Heat	Existing	Insulation - Roof / Ceiling	0.12	90%	75%	20	$0.47	10%
Dry_Goods_Retail	Space_Heat	Existing	Programmable Thermostat	0.12	48%	100%	10	$0.01	2%
Dry_Goods_Retail	Space_Heat	Existing	Retro-Commisioning	0.12	85%	92%	3	$0.27	15%
Dry_Goods_Retail	Space_Heat	Existing	Windows-High Efficiency	0.12	75%	75%	30	$0.23	7%
Dry_Goods_Retail	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.12	95%	90%	15	$0.28	10%
Dry_Goods_Retail	Space_Heat	New	Boiler Economizer	0.12	95%	40%	20	$0.59	10%
Dry_Goods_Retail	Space_Heat	New	Green Roof	0.12	100%	10%	40	$15.00	13%
Dry_Goods_Retail	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.12			20	$0.10	12%
Dry_Goods_Retail	Space_Heat	New	Leak Proof Duct Fittings	0.12	100%	40%	30	$0.09	15%
Dry_Goods_Retail	Space_Heat	New	Retro-Commisioning	0.12	85%	92%	3	$1.00	15%
Dry_Goods_Retail	Space_Heat	New	Windows-High Efficiency	0.12	75%	75%	30	$0.08	7%
Dry_Goods_Retail	Water_Heat	Existing	Commercial Washers	0.03	80%	5%	8	$0.22	35%
Dry_Goods_Retail	Water_Heat	Existing	Condensing Water Heater	0.03	95%	45%	13	$0.08	34%
Dry_Goods_Retail	Water_Heat	Existing	Demand controlled Circulating Systems	0.03	98%	60%	15	$1.56	5%
Dry_Goods_Retail	Water_Heat	Existing	Faucet Aerators	0.03	20%	100%	10	$0.00	3%
Dry_Goods_Retail	Water_Heat	Existing	High-Efficiency Water Heater	0.03			13	$0.03	8%
Dry_Goods_Retail	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.03	95%	85%	15	$0.02	2%
Dry_Goods_Retail	Water_Heat	Existing	Low-Flow Showerheads	0.03	25%	100%	10	$0.01	1%
Dry_Goods_Retail	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.03			13	$0.05	16%
Dry_Goods_Retail	Water_Heat	Existing	Solar Water Heater	0.03	95%	45%	15	$1.89	40%
Dry_Goods_Retail	Water_Heat	Existing	Tankless Water Heater	0.03	95%	25%	15	$0.12	27%
Dry_Goods_Retail	Water_Heat	Existing	Water Heater Temperature Setback	0.03	25%	100%	10	$0.02	5%
Dry_Goods_Retail	Water_Heat	New	Commercial Washers	0.03	80%	5%	8	$0.22	35%
Dry_Goods_Retail	Water_Heat	New	Condensing Water Heater	0.03	95%	45%	13	$0.06	34%
Dry_Goods_Retail	Water_Heat	New	Demand controlled Circulating Systems	0.03	98%	60%	15	$1.56	5%
Dry_Goods_Retail	Water_Heat	New	Faucet Aerators	0.03	20%	100%	10	$0.00	3%
Dry_Goods_Retail	Water_Heat	New	High-Efficiency Water Heater	0.03			13	$0.03	8%
Dry_Goods_Retail	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.03	95%	85%	15	$0.02	2%
Dry_Goods_Retail	Water_Heat	New	Low-Flow Showerheads	0.03	25%	100%	10	$0.01	1%
Dry_Goods_Retail	Water_Heat	New	Premium Efficency Storage Water Heater	0.03			13	$0.05	16%
Dry_Goods_Retail	Water_Heat	New	Solar Water Heater	0.03	95%	45%	15	$1.89	40%
Dry_Goods_Retail	Water_Heat	New	Tankless Water Heater	0.03	95%	55%	15	$0.12	27%
Grocery	Cooking	Existing	Power Burner Fryer	0.36	90%	100%	15	$0.21	4%
Grocery	Cooking	Existing	Power Burner Oven	0.36	90%	100%	15	$0.53	4%
Grocery	Cooking	New	Power Burner Fryer	0.36	90%	100%	15	$0.21	2%
Grocery	Cooking	New	Power Burner Oven	0.36	90%	100%	15	$0.53	2%
Grocery	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.20	95%	90%	15	$0.28	10%
Grocery	Space_Heat	Existing	Boiler Economizer	0.20	95%	40%	20	$0.59	10%
Grocery	Space_Heat	Existing	Duct Insulation	0.20	20%	65%	20	$0.01	2%
Grocery	Space_Heat	Existing	Duct Repair and Sealing	0.20	50%	65%	20	$0.06	2%
Grocery	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.20			20	$0.11	12%
Grocery	Space_Heat	Existing	Insulation - Floor	0.20	50%	60%	20	$0.48	5%
Grocery	Space_Heat	Existing	Insulation - Roof / Ceiling	0.20	15%	75%	20	$0.48	10%
Grocery	Space_Heat	Existing	Programmable Thermostat	0.20	70%	100%	10	$0.02	2%
Grocery	Space_Heat	Existing	Retro-Commisioning	0.20	85%	92%	3	$0.27	15%
Grocery	Space_Heat	Existing	Windows-High Efficiency	0.20	75%	75%	30	$0.21	5%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Grocery	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.20	95%	90%	15	$0.28	10%
Grocery	Space_Heat	New	Boiler Economizer	0.20	95%	40%	20	$0.59	10%
Grocery	Space_Heat	New	Green Roof	0.20	100%	10%	40	$15.00	13%
Grocery	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.20			20	$0.11	12%
Grocery	Space_Heat	New	Leak Proof Duct Fittings	0.20	100%	40%	30	$0.11	15%
Grocery	Space_Heat	New	Retro-Commisioning	0.20	85%	92%	3	$1.00	15%
Grocery	Space_Heat	New	Windows-High Efficiency	0.20	75%	75%	30	$0.07	5%
Grocery	Water_Heat	Existing	Condensing Water Heater	0.30	95%	45%	13	$1.14	34%
Grocery	Water_Heat	Existing	Demand controlled Circulating Systems	0.30	98%	60%	15	$1.16	5%
Grocery	Water_Heat	Existing	Faucet Aerators	0.30	20%	100%	10	$0.00	3%
Grocery	Water_Heat	Existing	High-Efficiency Water Heater	0.30			13	$0.02	8%
Grocery	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.30	95%	85%	15	$0.01	2%
Grocery	Water_Heat	Existing	Low Flow Spray Heads	0.30	45%	100%	5	$0.01	1%
Grocery	Water_Heat	Existing	Low-Flow Showerheads	0.30	25%	100%	10	$0.01	1%
Grocery	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.30			13	$0.03	16%
Grocery	Water_Heat	Existing	Solar Water Heater	0.30	95%	45%	15	$0.95	40%
Grocery	Water_Heat	Existing	Tankless Water Heater	0.30	95%	25%	15	$0.43	27%
Grocery	Water_Heat	Existing	Water Heater Temperature Setback	0.30	40%	100%	10	$0.01	5%
Grocery	Water_Heat	New	Condensing Water Heater	0.30	95%	45%	13	$0.83	34%
Grocery	Water_Heat	New	Demand controlled Circulating Systems	0.30	98%	60%	15	$1.16	5%
Grocery	Water_Heat	New	Faucet Aerators	0.30	20%	100%	10	$0.00	3%
Grocery	Water_Heat	New	High-Efficiency Water Heater	0.30			13	$0.02	8%
Grocery	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.30	95%	85%	15	$0.01	2%
Grocery	Water_Heat	New	Low Flow Spray Heads	0.30	45%	100%	5	$0.01	1%
Grocery	Water_Heat	New	Low-Flow Showerheads	0.30	25%	100%	10	$0.01	1%
Grocery	Water_Heat	New	Premium Efficency Storage Water Heater	0.30			13	$0.03	16%
Grocery	Water_Heat	New	Solar Water Heater	0.30	95%	45%	15	$0.95	40%
Grocery	Water_Heat	New	Tankless Water Heater	0.30	95%	55%	15	$0.43	27%
Hospital	Cooking	Existing	Power Burner Fryer	0.05	90%	100%	15	$0.04	4%
Hospital	Cooking	Existing	Power Burner Oven	0.05	90%	100%	15	$0.09	4%
Hospital	Cooking	New	Power Burner Fryer	0.05	90%	100%	15	$0.04	4%
Hospital	Cooking	New	Power Burner Oven	0.05	90%	100%	15	$0.09	4%
Hospital	Pool_Heat	Existing	Installation of Solar Pool/Spa Heating Systems	0.02	98%	95%	10	$0.02	16%
Hospital	Pool_Heat	Existing	Installation of Swimming Pool / Spa Covers	0.02	25%	100%	5	$0.00	35%
Hospital	Pool_Heat	New	Installation of Solar Pool/Spa Heating Systems	0.02	98%	95%	10	$0.02	16%
Hospital	Pool_Heat	New	Installation of Swimming Pool / Spa Covers	0.02	25%	100%	5	$0.00	35%
Hospital	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.47	95%	40%	15	$0.28	10%
Hospital	Space_Heat	Existing	Boiler Economizer	0.47	95%	40%	20	$0.59	10%
Hospital	Space_Heat	Existing	Boiler Tune-Up	0.47	45%	90%	3	$0.05	2%
Hospital	Space_Heat	Existing	Convert Constant Volume Air System to VAV	0.47	15%	80%	15	$0.35	12%
Hospital	Space_Heat	Existing	Duct Insulation	0.47	20%	65%	20	$0.03	2%
Hospital	Space_Heat	Existing	Duct Repair and Sealing	0.47	50%	65%	20	$0.13	2%
Hospital	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	0.47	95%	10%	20	$1.00	20%
Hospital	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.47			20	$0.13	12%
Hospital	Space_Heat	Existing	Insulation - Floor	0.47	40%	60%	20	$0.43	5%
Hospital	Space_Heat	Existing	Insulation - Roof / Ceiling	0.47	17%	75%	20	$0.65	10%
Hospital	Space_Heat	Existing	Programmable Thermostat	0.47	55%	100%	10	$0.06	2%
Hospital	Space_Heat	Existing	Retro-Commisioning	0.47	85%	92%	3	$0.27	15%
Hospital	Space_Heat	Existing	Windows-High Efficiency	0.47	75%	75%	30	$0.27	4%
Hospital	Space_Heat	Existing	Wireless Performance Monitoring, Diagnostics and Control	0.47	100%	30%	10	$0.50	10%
Hospital	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.47	95%	40%	15	$0.28	10%
Hospital	Space_Heat	New	Boiler Economizer	0.47	95%	40%	20	$0.59	10%
Hospital	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	0.47	85%	10%	20	$0.93	15%
Hospital	Space_Heat	New	Green Roof	0.47	100%	10%	40	$15.00	13%
Hospital	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.47			20	$0.13	12%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Hospital	Space_Heat	New	Leak Proof Duct Fittings	0.47	100%	40%	30	$0.24	15%
Hospital	Space_Heat	New	Retro-Commisioning	0.47	85%	92%	3	$1.00	15%
Hospital	Space_Heat	New	Windows-High Efficiency	0.47	75%	75%	30	$0.12	4%
Hospital	Space_Heat	New	Wireless Performance Monitoring, Diagnostics and Control	0.47	100%	30%	10	$0.50	10%
Hospital	Water_Heat	Existing	Condensing Water Heater	0.39	95%	45%	13	$0.39	34%
Hospital	Water_Heat	Existing	Demand controlled Circulating Systems	0.39	85%	60%	15	$0.68	5%
Hospital	Water_Heat	Existing	Faucet Aerators	0.39	20%	100%	10	$0.01	3%
Hospital	Water_Heat	Existing	High-Efficiency Water Heater	0.39			13	$0.01	8%
Hospital	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.39	75%	85%	15	$0.01	2%
Hospital	Water_Heat	Existing	Low-Flow Showerheads	0.39	25%	100%	10	$0.03	4%
Hospital	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.39			13	$0.11	16%
Hospital	Water_Heat	Existing	Solar Water Heater	0.39	95%	45%	15	$3.01	40%
Hospital	Water_Heat	Existing	Tankless Water Heater	0.39	95%	10%	15	$0.25	27%
Hospital	Water_Heat	Existing	Water Heater Temperature Setback	0.39	60%	100%	10	$0.01	5%
Hospital	Water_Heat	New	Condensing Water Heater	0.39	95%	45%	13	$0.28	34%
Hospital	Water_Heat	New	Demand controlled Circulating Systems	0.39	85%	60%	15	$0.68	5%
Hospital	Water_Heat	New	Faucet Aerators	0.39	20%	100%	10	$0.01	3%
Hospital	Water_Heat	New	High-Efficiency Water Heater	0.39			13	$0.01	8%
Hospital	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.39	75%	85%	15	$0.01	2%
Hospital	Water_Heat	New	Low-Flow Showerheads	0.39	25%	100%	10	$0.03	4%
Hospital	Water_Heat	New	Premium Efficency Storage Water Heater	0.39			13	$0.11	16%
Hospital	Water_Heat	New	Solar Water Heater	0.39	95%	45%	15	$3.01	40%
Hospital	Water_Heat	New	Tankless Water Heater	0.39	95%	25%	15	$0.25	27%
Hotel_Motel	Cooking	Existing	Power Burner Fryer	0.06	90%	100%	15	$0.04	4%
Hotel_Motel	Cooking	Existing	Power Burner Oven	0.06	90%	100%	15	$0.11	4%
Hotel_Motel	Cooking	New	Power Burner Fryer	0.06	90%	100%	15	$0.04	4%
Hotel_Motel	Cooking	New	Power Burner Oven	0.06	90%	100%	15	$0.11	4%
Hotel_Motel	Pool_Heat	Existing	Installation of Solar Pool/Spa Heating Systems	0.09	98%	95%	10	$0.07	16%
Hotel_Motel	Pool_Heat	Existing	Installation of Swimming Pool / Spa Covers	0.09	25%	100%	5	$0.01	35%
Hotel_Motel	Pool_Heat	New	Installation of Solar Pool/Spa Heating Systems	0.06	98%	95%	10	$0.07	16%
Hotel_Motel	Pool_Heat	New	Installation of Swimming Pool / Spa Covers	0.06	25%	100%	5	$0.01	35%
Hotel_Motel	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.08	95%	90%	15	$0.28	10%
Hotel_Motel	Space_Heat	Existing	Boiler Economizer	0.08	35%	40%	20	$0.59	10%
Hotel_Motel	Space_Heat	Existing	Boiler Tune-Up	0.08	45%	90%	3	$0.06	2%
Hotel_Motel	Space_Heat	Existing	Duct Insulation	0.08	20%	65%	20	$0.01	2%
Hotel_Motel	Space_Heat	Existing	Duct Repair and Sealing	0.08	50%	65%	20	$0.03	2%
Hotel_Motel	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	0.08	95%	50%	20	$1.00	20%
Hotel_Motel	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.08			20	$0.10	12%
Hotel_Motel	Space_Heat	Existing	Insulation - Floor	0.08	50%	60%	20	$0.21	5%
Hotel_Motel	Space_Heat	Existing	Insulation - Roof / Ceiling	0.08	30%	75%	20	$0.21	10%
Hotel_Motel	Space_Heat	Existing	Programmable Thermostat	0.08	70%	100%	10	$0.01	2%
Hotel_Motel	Space_Heat	Existing	Retro-Commisioning	0.08	85%	92%	3	$0.27	15%
Hotel_Motel	Space_Heat	Existing	Windows-High Efficiency	0.08	75%	75%	30	$0.48	4%
Hotel_Motel	Space_Heat	Existing	Wireless Performance Monitoring, Diagnostics and Control	0.08	100%	30%	10	$0.50	10%
Hotel_Motel	Space_Heat	New	Boiler Economizer	0.08	35%	40%	20	$0.59	10%
Hotel_Motel	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	0.08	85%	95%	20	$0.93	15%
Hotel_Motel	Space_Heat	New	Green Roof	0.08	100%	10%	40	$15.00	13%
Hotel_Motel	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.08			20	$0.10	12%
Hotel_Motel	Space_Heat	New	Leak Proof Duct Fittings	0.08	100%	40%	30	$0.07	15%
Hotel_Motel	Space_Heat	New	Retro-Commisioning	0.08	85%	92%	3	$1.00	15%
Hotel_Motel	Space_Heat	New	Windows-High Efficiency	0.08	75%	75%	30	$0.16	4%
Hotel_Motel	Space_Heat	New	Wireless Performance Monitoring, Diagnostics and Control	0.08	100%	30%	10	$0.50	10%
Hotel_Motel	Water_Heat	Existing	Condensing Water Heater	0.65	95%	45%	13	$0.51	34%
Hotel_Motel	Water_Heat	Existing	Demand controlled Circulating Systems	0.65	98%	60%	15	$0.78	5%
Hotel_Motel	Water_Heat	Existing	Faucet Aerators	0.65	20%	100%	10	$0.01	3%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Hotel_Motel	Water_Heat	Existing	High-Efficiency Water Heater	0.65			13	$0.01	8%
Hotel_Motel	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.65	95%	85%	15	$0.02	2%
Hotel_Motel	Water_Heat	Existing	Low Flow Spray Heads	0.65	55%	100%	5	$0.01	1%
Hotel_Motel	Water_Heat	Existing	Low-Flow Showerheads	0.65	25%	100%	10	$0.07	5%
Hotel_Motel	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.65			13	$0.24	30%
Hotel_Motel	Water_Heat	Existing	Solar Water Heater	0.65	95%	45%	15	$2.64	40%
Hotel_Motel	Water_Heat	Existing	Tankless Water Heater	0.65	95%	10%	15	$0.89	27%
Hotel_Motel	Water_Heat	Existing	Water Heater Temperature Setback	0.65	5%	100%	10	$0.01	5%
Hotel_Motel	Water_Heat	New	Condensing Water Heater	0.65	95%	45%	13	$0.37	34%
Hotel_Motel	Water_Heat	New	Demand controlled Circulating Systems	0.65	98%	60%	15	$0.78	5%
Hotel_Motel	Water_Heat	New	Faucet Aerators	0.65	20%	100%	10	$0.01	3%
Hotel_Motel	Water_Heat	New	High-Efficiency Water Heater	0.65			13	$0.01	8%
Hotel_Motel	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.65	95%	85%	15	$0.02	2%
Hotel_Motel	Water_Heat	New	Low Flow Spray Heads	0.65	55%	100%	5	$0.01	1%
Hotel_Motel	Water_Heat	New	Low-Flow Showerheads	0.65	25%	100%	10	$0.07	5%
Hotel_Motel	Water_Heat	New	Premium Efficency Storage Water Heater	0.65			13	$0.24	30%
Hotel_Motel	Water_Heat	New	Solar Water Heater	0.65	95%	45%	15	$2.64	40%
Hotel_Motel	Water_Heat	New	Tankless Water Heater	0.65	95%	25%	15	$0.89	27%
Office	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.19	95%	90%	15	$0.28	10%
Office	Space_Heat	Existing	Boiler Economizer	0.19	50%	40%	20	$0.59	10%
Office	Space_Heat	Existing	Boiler Tune-Up	0.19	45%	90%	3	$0.08	2%
Office	Space_Heat	Existing	Convert Constant Volume Air System to VAV	0.19	15%	80%	15	$0.23	12%
Office	Space_Heat	Existing	Duct Insulation	0.19	20%	65%	20	$0.02	2%
Office	Space_Heat	Existing	Duct Repair and Sealing	0.19	50%	65%	20	$0.04	2%
Office	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	0.19	95%	50%	20	$1.00	20%
Office	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.19			20	$0.10	12%
Office	Space_Heat	Existing	Insulation - Floor	0.19	20%	60%	20	$0.33	5%
Office	Space_Heat	Existing	Insulation - Roof / Ceiling	0.19	5%	75%	20	$0.33	10%
Office	Space_Heat	Existing	Programmable Thermostat	0.19	52%	100%	10	$0.01	2%
Office	Space_Heat	Existing	Retro-Commisioning	0.19	85%	92%	3	$0.27	15%
Office	Space_Heat	Existing	Windows-High Efficiency	0.19	75%	75%	30	$0.44	10%
Office	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.19	95%	90%	15	$0.28	10%
Office	Space_Heat	New	Boiler Economizer	0.19	50%	40%	20	$0.59	10%
Office	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	0.19	85%	95%	20	$0.93	15%
Office	Space_Heat	New	Green Roof	0.19	100%	10%	40	$15.00	13%
Office	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.19			20	$0.10	12%
Office	Space_Heat	New	Leak Proof Duct Fittings	0.19	100%	40%	30	$0.10	15%
Office	Space_Heat	New	Retro-Commisioning	0.19	85%	92%	3	$1.00	15%
Office	Space_Heat	New	Windows-High Efficiency	0.19	75%	75%	30	$0.15	10%
Office	Water_Heat	Existing	Condensing Water Heater	0.08	95%	45%	13	$0.13	34%
Office	Water_Heat	Existing	Demand controlled Circulating Systems	0.08	85%	60%	15	$1.05	5%
Office	Water_Heat	Existing	Faucet Aerators	0.08	20%	100%	10	$0.00	3%
Office	Water_Heat	Existing	High-Efficiency Water Heater	0.08			13	$0.02	8%
Office	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.08	35%	85%	15	$0.00	2%
Office	Water_Heat	Existing	Low-Flow Showerheads	0.08	25%	100%	10	$0.00	1%
Office	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.08			13	$0.03	16%
Office	Water_Heat	Existing	Solar Water Heater	0.08	95%	45%	15	$1.54	40%
Office	Water_Heat	Existing	Tankless Water Heater	0.08	95%	25%	15	$0.04	27%
Office	Water_Heat	Existing	Water Heater Temperature Setback	0.08	35%	100%	10	$0.01	5%
Office	Water_Heat	New	Condensing Water Heater	0.08	95%	45%	13	$0.09	34%
Office	Water_Heat	New	Demand controlled Circulating Systems	0.08	85%	60%	15	$1.05	5%
Office	Water_Heat	New	Faucet Aerators	0.08	20%	100%	10	$0.00	3%
Office	Water_Heat	New	High-Efficiency Water Heater	0.08			13	$0.02	8%
Office	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.08	35%	85%	15	$0.00	2%
Office	Water_Heat	New	Low-Flow Showerheads	0.08	25%	100%	10	$0.00	1%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Office	Water_Heat	New	Premium Efficency Storage Water Heater	0.08			13	$0.03	16%
Office	Water_Heat	New	Solar Water Heater	0.08	95%	45%	15	$1.54	40%
Office	Water_Heat	New	Tankless Water Heater	0.08	95%	55%	15	$0.04	27%
Other	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.23	95%	40%	15	$0.28	10%
Other	Space_Heat	Existing	Boiler Economizer	0.23	90%	40%	20	$0.59	10%
Other	Space_Heat	Existing	Boiler Tune-Up	0.23	45%	90%	3	$0.07	2%
Other	Space_Heat	Existing	Convert Constant Volume Air System to VAV	0.23	15%	80%	15	$0.16	12%
Other	Space_Heat	Existing	Duct Insulation	0.23	20%	65%	20	$0.01	2%
Other	Space_Heat	Existing	Duct Repair and Sealing	0.23	50%	65%	20	$0.07	2%
Other	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	0.23	95%	50%	20	$1.00	20%
Other	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.23			20	$0.16	12%
Other	Space_Heat	Existing	Insulation - Floor	0.23	55%	60%	20	$0.44	5%
Other	Space_Heat	Existing	Insulation - Roof / Ceiling	0.23	35%	75%	20	$0.44	10%
Other	Space_Heat	Existing	Programmable Thermostat	0.23	32%	100%	10	$0.04	2%
Other	Space_Heat	Existing	Retro-Commisioning	0.23	85%	92%	3	$0.27	15%
Other	Space_Heat	Existing	Windows-High Efficiency	0.23	75%	75%	30	$0.24	5%
Other	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.23	95%	40%	15	$0.28	10%
Other	Space_Heat	New	Boiler Economizer	0.23	90%	40%	20	$0.59	10%
Other	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	0.23	85%	50%	20	$0.93	15%
Other	Space_Heat	New	Green Roof	0.23	100%	10%	40	$15.00	13%
Other	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.23			20	$0.16	12%
Other	Space_Heat	New	Leak Proof Duct Fittings	0.23	100%	40%	30	$0.09	15%
Other	Space_Heat	New	Retro-Commisioning	0.23	85%	92%	3	$1.00	15%
Other	Space_Heat	New	Windows-High Efficiency	0.23	75%	75%	30	$1.53	5%
Other	Water_Heat	Existing	Commercial Washers	0.19	80%	5%	8	$0.55	35%
Other	Water_Heat	Existing	Condensing Water Heater	0.19	95%	45%	13	$0.14	34%
Other	Water_Heat	Existing	Demand controlled Circulating Systems	0.19	98%	60%	15	$0.93	5%
Other	Water_Heat	Existing	Faucet Aerators	0.19	40%	100%	10	$0.00	3%
Other	Water_Heat	Existing	High-Efficiency Water Heater	0.19			13	$0.02	8%
Other	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.19	95%	40%	15	$0.01	2%
Other	Water_Heat	Existing	Low-Flow Showerheads	0.19	25%	100%	10	$0.01	2%
Other	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.19			13	$0.03	16%
Other	Water_Heat	Existing	Solar Water Heater	0.19	95%	45%	15	$2.58	40%
Other	Water_Heat	Existing	Tankless Water Heater	0.19	95%	25%	15	$0.22	27%
Other	Water_Heat	Existing	Water Heater Temperature Setback	0.19	40%	100%	10	$0.01	5%
Other	Water_Heat	New	Commercial Washers	0.19	80%	5%	8	$0.55	35%
Other	Water_Heat	New	Condensing Water Heater	0.19	95%	45%	13	$0.10	34%
Other	Water_Heat	New	Demand controlled Circulating Systems	0.19	98%	60%	15	$0.93	5%
Other	Water_Heat	New	Faucet Aerators	0.19	40%	100%	10	$0.00	3%
Other	Water_Heat	New	High-Efficiency Water Heater	0.19			13	$0.01	8%
Other	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.19	95%	40%	15	$0.01	2%
Other	Water_Heat	New	Low-Flow Showerheads	0.19	25%	100%	10	$0.01	2%
Other	Water_Heat	New	Premium Efficency Storage Water Heater	0.19			13	$0.02	16%
Other	Water_Heat	New	Solar Water Heater	0.19	95%	45%	15	$2.58	40%
Other	Water_Heat	New	Tankless Water Heater	0.19	95%	55%	15	$0.22	27%
Restaurant	Cooking	Existing	Power Burner Fryer	0.93	85%	100%	15	$0.79	8%
Restaurant	Cooking	Existing	Power Burner Oven	0.93	85%	100%	15	$1.97	8%
Restaurant	Cooking	New	Power Burner Fryer	0.93	85%	100%	15	$0.79	4%
Restaurant	Cooking	New	Power Burner Oven	0.93	85%	100%	15	$1.97	4%
Restaurant	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.14	95%	90%	15	$0.28	10%
Restaurant	Space_Heat	Existing	Boiler Economizer	0.14	95%	40%	20	$0.59	10%
Restaurant	Space_Heat	Existing	Duct Insulation	0.14	20%	65%	20	$0.03	2%
Restaurant	Space_Heat	Existing	Duct Repair and Sealing	0.14	50%	65%	20	$0.02	2%
Restaurant	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.14			20	$0.26	12%
Restaurant	Space_Heat	Existing	Insulation - Floor	0.14	95%	60%	20	$0.45	5%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Restaurant	Space_Heat	Existing	Insulation - Roof / Ceiling	0.14	90%	75%	20	$0.45	10%
Restaurant	Space_Heat	Existing	Programmable Thermostat	0.14	70%	100%	10	$0.01	2%
Restaurant	Space_Heat	Existing	Retro-Commisioning	0.14	85%	92%	3	$0.27	15%
Restaurant	Space_Heat	Existing	Windows-High Efficiency	0.14	75%	75%	30	$0.14	3%
Restaurant	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.14	95%	90%	15	$0.28	10%
Restaurant	Space_Heat	New	Boiler Economizer	0.14	95%	40%	20	$0.59	10%
Restaurant	Space_Heat	New	Green Roof	0.14	100%	10%	40	$15.00	13%
Restaurant	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.14			20	$0.26	12%
Restaurant	Space_Heat	New	Leak Proof Duct Fittings	0.14	100%	40%	30	$0.15	15%
Restaurant	Space_Heat	New	Retro-Commisioning	0.14	85%	92%	3	$1.00	15%
Restaurant	Space_Heat	New	Windows-High Efficiency	0.14	75%	75%	30	$0.05	3%
Restaurant	Water_Heat	Existing	Chemical Dishwashing System	0.82	90%	100%	10	$0.31	5%
Restaurant	Water_Heat	Existing	Condensing Water Heater	0.82	95%	45%	13	$0.75	34%
Restaurant	Water_Heat	Existing	Demand controlled Circulating Systems	0.82	98%	60%	15	$2.13	5%
Restaurant	Water_Heat	Existing	Faucet Aerators	0.82	20%	100%	10	$0.02	3%
Restaurant	Water_Heat	Existing	High-Efficiency Water Heater	0.82			13	$0.04	8%
Restaurant	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.82	95%	85%	15	$0.02	2%
Restaurant	Water_Heat	Existing	Low Flow Spray Heads	0.82	30%	100%	5	$0.04	5%
Restaurant	Water_Heat	Existing	Low-Flow Showerheads	0.82	25%	100%	10	$0.01	0%
Restaurant	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.82			13	$0.06	16%
Restaurant	Water_Heat	Existing	Solar Water Heater	0.82	95%	45%	15	$2.21	40%
Restaurant	Water_Heat	Existing	Tankless Water Heater	0.82	95%	25%	15	$1.11	27%
Restaurant	Water_Heat	Existing	Water Heater Temperature Setback	0.82	10%	100%	10	$0.03	5%
Restaurant	Water_Heat	New	Chemical Dishwashing System	0.82	90%	100%	10	$0.31	5%
Restaurant	Water_Heat	New	Condensing Water Heater	0.82	95%	45%	13	$0.54	34%
Restaurant	Water_Heat	New	Demand controlled Circulating Systems	0.82	98%	60%	15	$2.13	5%
Restaurant	Water_Heat	New	Faucet Aerators	0.82	20%	100%	10	$0.02	3%
Restaurant	Water_Heat	New	High-Efficiency Water Heater	0.82			13	$0.04	8%
Restaurant	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.82	95%	85%	15	$0.02	2%
Restaurant	Water_Heat	New	Low Flow Spray Heads	0.82	30%	100%	5	$0.04	5%
Restaurant	Water_Heat	New	Low-Flow Showerheads	0.82	25%	100%	10	$0.01	0%
Restaurant	Water_Heat	New	Premium Efficency Storage Water Heater	0.82			13	$0.06	16%
Restaurant	Water_Heat	New	Solar Water Heater	0.82	95%	45%	15	$2.21	40%
Restaurant	Water_Heat	New	Tankless Water Heater	0.82	95%	55%	15	$1.11	27%
School	Cooking	Existing	Power Burner Fryer	0.02	90%	100%	15	$0.10	4%
School	Cooking	Existing	Power Burner Oven	0.02	90%	100%	15	$0.25	4%
School	Cooking	New	Power Burner Fryer	0.02	90%	100%	15	$0.10	4%
School	Cooking	New	Power Burner Oven	0.02	90%	100%	15	$0.25	4%
School	Pool_Heat	Existing	Installation of Solar Pool/Spa Heating Systems	0.10	98%	95%	10	$0.31	16%
School	Pool_Heat	Existing	Installation of Swimming Pool / Spa Covers	0.10	25%	100%	5	$0.02	35%
School	Pool_Heat	New	Installation of Solar Pool/Spa Heating Systems	0.02	98%	95%	10	$0.30	16%
School	Pool_Heat	New	Installation of Swimming Pool / Spa Covers	0.02	25%	100%	5	$0.01	35%
School	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.18	95%	90%	15	$0.28	10%
School	Space_Heat	Existing	Boiler Economizer	0.18	70%	40%	20	$0.59	10%
School	Space_Heat	Existing	Boiler Tune-Up	0.18	45%	90%	3	$0.04	2%
School	Space_Heat	Existing	Convert Constant Volume Air System to VAV	0.18	15%	80%	15	$0.17	12%
School	Space_Heat	Existing	Duct Insulation	0.18	20%	65%	20	$0.03	2%
School	Space_Heat	Existing	Duct Repair and Sealing	0.18	50%	65%	20	$0.08	2%
School	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	0.18	95%	50%	20	$1.00	20%
School	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.18			20	$0.39	12%
School	Space_Heat	Existing	Insulation - Floor	0.18	40%	60%	20	$0.47	5%
School	Space_Heat	Existing	Insulation - Roof / Ceiling	0.18	20%	75%	20	$0.47	10%
School	Space_Heat	Existing	Programmable Thermostat	0.18	38%	100%	10	$0.01	2%
School	Space_Heat	Existing	Retro-Commisioning	0.18	85%	92%	3	$0.27	15%
School	Space_Heat	Existing	Windows-High Efficiency	0.18	75%	75%	30	$0.12	4%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
School	Space_Heat	Existing	Wireless Performance Monitoring, Diagnostics and Control	0.18	100%	30%	10	$0.50	10%
School	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.18	95%	90%	15	$0.28	10%
School	Space_Heat	New	Boiler Economizer	0.18	70%	40%	20	$0.59	10%
School	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	0.18	85%	95%	20	$0.93	15%
School	Space_Heat	New	Green Roof	0.18	100%	10%	40	$15.00	13%
School	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.18			20	$0.39	12%
School	Space_Heat	New	Leak Proof Duct Fittings	0.18	100%	40%	30	$0.10	15%
School	Space_Heat	New	Retro-Commisioning	0.18	85%	92%	3	$1.00	15%
School	Space_Heat	New	Windows-High Efficiency	0.18	75%	75%	30	$0.04	4%
School	Space_Heat	New	Wireless Performance Monitoring, Diagnostics and Control	0.18	100%	30%	10	$0.50	10%
School	Water_Heat	Existing	Condensing Water Heater	0.12	95%	45%	13	$0.29	34%
School	Water_Heat	Existing	Demand controlled Circulating Systems	0.12	98%	60%	15	$0.45	5%
School	Water_Heat	Existing	Faucet Aerators	0.12	20%	100%	10	$0.01	3%
School	Water_Heat	Existing	High-Efficiency Water Heater	0.12			13	$0.01	8%
School	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.12	9%	85%	15	$0.01	2%
School	Water_Heat	Existing	Low Flow Spray Heads	0.12	30%	100%	5	$0.00	1%
School	Water_Heat	Existing	Low-Flow Showerheads	0.12	25%	100%	10	$0.02	2%
School	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.12			13	$0.01	16%
School	Water_Heat	Existing	Solar Water Heater	0.12	95%	45%	15	$1.93	40%
School	Water_Heat	Existing	Tankless Water Heater	0.12	95%	10%	15	$0.16	27%
School	Water_Heat	Existing	Water Heater Temperature Setback	0.12	10%	100%	10	$0.01	5%
School	Water_Heat	New	Condensing Water Heater	0.12	95%	45%	13	$0.21	34%
School	Water_Heat	New	Demand controlled Circulating Systems	0.12	98%	60%	15	$0.45	5%
School	Water_Heat	New	Faucet Aerators	0.12	20%	100%	10	$0.01	3%
School	Water_Heat	New	High-Efficiency Water Heater	0.12			13	$0.01	8%
School	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.12	9%	85%	15	$0.01	2%
School	Water_Heat	New	Low Flow Spray Heads	0.12	30%	100%	5	$0.00	1%
School	Water_Heat	New	Low-Flow Showerheads	0.12	25%	100%	10	$0.02	2%
School	Water_Heat	New	Premium Efficency Storage Water Heater	0.12			13	$0.01	16%
School	Water_Heat	New	Solar Water Heater	0.12	95%	45%	15	$1.93	40%
School	Water_Heat	New	Tankless Water Heater	0.12	95%	25%	15	$0.16	27%
University	Cooking	Existing	Power Burner Fryer	0.02	90%	100%	15	$0.06	4%
University	Cooking	Existing	Power Burner Oven	0.02	90%	100%	15	$0.14	4%
University	Cooking	New	Power Burner Fryer	0.02	90%	100%	15	$0.06	4%
University	Cooking	New	Power Burner Oven	0.02	90%	100%	15	$0.14	4%
University	Pool_Heat	Existing	Installation of Solar Pool/Spa Heating Systems	0.10	98%	95%	10	$0.20	16%
University	Pool_Heat	Existing	Installation of Swimming Pool / Spa Covers	0.10	25%	100%	5	$0.02	35%
University	Pool_Heat	New	Installation of Solar Pool/Spa Heating Systems	0.04	98%	95%	10	$0.20	16%
University	Pool_Heat	New	Installation of Swimming Pool / Spa Covers	0.04	25%	100%	5	$0.01	35%
University	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.26	95%	90%	15	$0.28	10%
University	Space_Heat	Existing	Boiler Economizer	0.26	95%	40%	20	$0.59	10%
University	Space_Heat	Existing	Boiler Tune-Up	0.26	45%	90%	3	$0.02	2%
University	Space_Heat	Existing	Convert Constant Volume Air System to VAV	0.26	15%	80%	15	$0.35	12%
University	Space_Heat	Existing	Duct Insulation	0.26	20%	65%	20	$0.04	2%
University	Space_Heat	Existing	Duct Repair and Sealing	0.26	50%	65%	20	$0.06	2%
University	Space_Heat	Existing	Exhaust Air to Ventilation Air Heat Recovery	0.26	95%	50%	20	$1.00	20%
University	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.26			20	$0.15	12%
University	Space_Heat	Existing	Insulation - Floor	0.26	40%	60%	20	$0.30	5%
University	Space_Heat	Existing	Insulation - Roof / Ceiling	0.26	17%	75%	20	$0.48	10%
University	Space_Heat	Existing	Programmable Thermostat	0.26	28%	100%	10	$0.04	2%
University	Space_Heat	Existing	Retro-Commisioning	0.26	85%	92%	3	$0.27	15%
University	Space_Heat	Existing	Windows-High Efficiency	0.26	75%	75%	30	$0.32	4%
University	Space_Heat	Existing	Wireless Performance Monitoring, Diagnostics and Control	0.26	100%	30%	10	$0.50	10%
University	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.26	95%	90%	15	$0.28	10%
University	Space_Heat	New	Boiler Economizer	0.26	95%	40%	20	$0.59	10%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
University	Space_Heat	New	Exhaust Air to Ventilation Air Heat Recovery	0.26	85%	95%	20	$0.93	15%
University	Space_Heat	New	Green Roof	0.26	100%	10%	40	$15.00	13%
University	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.26			20	$0.15	12%
University	Space_Heat	New	Leak Proof Duct Fittings	0.26	100%	40%	30	$0.11	15%
University	Space_Heat	New	Retro-Commisioning	0.26	85%	92%	3	$1.00	15%
University	Space_Heat	New	Windows-High Efficiency	0.26	75%	75%	30	$0.11	4%
University	Space_Heat	New	Wireless Performance Monitoring, Diagnostics and Control	0.26	100%	30%	10	$0.50	10%
University	Water_Heat	Existing	Condensing Water Heater	0.27	95%	45%	13	$0.64	34%
University	Water_Heat	Existing	Demand controlled Circulating Systems	0.27	98%	60%	15	$0.31	5%
University	Water_Heat	Existing	Faucet Aerators	0.27	20%	100%	10	$0.00	3%
University	Water_Heat	Existing	High-Efficiency Water Heater	0.27			13	$0.01	8%
University	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.27	75%	85%	15	$0.02	2%
University	Water_Heat	Existing	Low-Flow Showerheads	0.27	25%	100%	10	$0.02	2%
University	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.27			13	$0.09	16%
University	Water_Heat	Existing	Solar Water Heater	0.27	95%	45%	15	$3.42	40%
University	Water_Heat	Existing	Tankless Water Heater	0.27	95%	10%	15	$0.29	27%
University	Water_Heat	Existing	Water Heater Temperature Setback	0.27	10%	100%	10	$0.00	5%
University	Water_Heat	New	Condensing Water Heater	0.27	95%	45%	13	$0.47	34%
University	Water_Heat	New	Demand controlled Circulating Systems	0.27	98%	60%	15	$0.31	5%
University	Water_Heat	New	Faucet Aerators	0.27	20%	100%	10	$0.00	3%
University	Water_Heat	New	High-Efficiency Water Heater	0.27			13	$0.01	8%
University	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.27	75%	85%	15	$0.02	2%
University	Water_Heat	New	Low-Flow Showerheads	0.27	25%	100%	10	$0.02	2%
University	Water_Heat	New	Premium Efficency Storage Water Heater	0.27			13	$0.09	16%
University	Water_Heat	New	Solar Water Heater	0.27	95%	45%	15	$3.42	40%
University	Water_Heat	New	Tankless Water Heater	0.27	95%	25%	15	$0.29	27%
Warehouse	Space_Heat	Existing	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.12	95%	90%	15	$0.28	10%
Warehouse	Space_Heat	Existing	Boiler Economizer	0.12	95%	40%	20	$0.59	10%
Warehouse	Space_Heat	Existing	Duct Insulation	0.12	20%	65%	20	$0.05	2%
Warehouse	Space_Heat	Existing	Duct Repair and Sealing	0.12	50%	65%	20	$0.05	2%
Warehouse	Space_Heat	Existing	High Efficiency Gas Furnace /Boiler	0.12			20	$0.08	12%
Warehouse	Space_Heat	Existing	Insulation - Floor	0.12	50%	60%	20	$0.45	5%
Warehouse	Space_Heat	Existing	Insulation - Roof / Ceiling	0.12	15%	75%	20	$0.45	10%
Warehouse	Space_Heat	Existing	Programmable Thermostat	0.12	42%	100%	10	$0.01	2%
Warehouse	Space_Heat	Existing	Retro-Commisioning	0.12	85%	92%	3	$0.27	15%
Warehouse	Space_Heat	Existing	Windows-High Efficiency	0.12	75%	75%	30	$0.09	1%
Warehouse	Space_Heat	New	Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	0.12	95%	90%	15	$0.28	10%
Warehouse	Space_Heat	New	Boiler Economizer	0.12	95%	40%	20	$0.59	10%
Warehouse	Space_Heat	New	Green Roof	0.12	100%	10%	40	$15.00	13%
Warehouse	Space_Heat	New	High Efficiency Gas Furnace /Boiler	0.12			20	$0.08	12%
Warehouse	Space_Heat	New	Leak Proof Duct Fittings	0.12	100%	40%	30	$0.16	15%
Warehouse	Space_Heat	New	Retro-Commisioning	0.12	85%	92%	3	$1.00	15%
Warehouse	Space_Heat	New	Windows-High Efficiency	0.12	75%	75%	30	$0.03	1%
Warehouse	Water_Heat	Existing	Condensing Water Heater	0.04	95%	45%	13	$0.20	34%
Warehouse	Water_Heat	Existing	Demand controlled Circulating Systems	0.04	98%	60%	15	$0.65	5%
Warehouse	Water_Heat	Existing	Faucet Aerators	0.04	20%	100%	10	$0.00	3%
Warehouse	Water_Heat	Existing	High-Efficiency Water Heater	0.04			13	$0.01	8%
Warehouse	Water_Heat	Existing	Hot Water (SHW) Pipe Insulation	0.04	92%	85%	15	$0.00	2%
Warehouse	Water_Heat	Existing	Low-Flow Showerheads	0.04	25%	100%	10	$0.01	3%
Warehouse	Water_Heat	Existing	Premium Efficency Storage Water Heater	0.04			13	$0.02	16%
Warehouse	Water_Heat	Existing	Solar Water Heater	0.04	95%	45%	15	$0.60	40%
Warehouse	Water_Heat	Existing	Tankless Water Heater	0.04	95%	25%	15	$0.12	27%
Warehouse	Water_Heat	Existing	Water Heater Temperature Setback	0.04	40%	100%	10	$0.01	5%
Warehouse	Water_Heat	New	Condensing Water Heater	0.04	95%	45%	13	$0.15	34%
Warehouse	Water_Heat	New	Demand controlled Circulating Systems	0.04	98%	60%	15	$0.65	5%

Building Type	End Use	Vintage	Measure Name	Base Usage	Incomplete Factor	Technical Feasibility	Measure Life	Per Unit Cost	Energy Savings
Warehouse	Water_Heat	New	Faucet Aerators	0.04	20%	100%	10	$0.00	3%
Warehouse	Water_Heat	New	High-Efficiency Water Heater	0.04			13	$0.01	8%
Warehouse	Water_Heat	New	Hot Water (SHW) Pipe Insulation	0.04	92%	85%	15	$0.00	2%
Warehouse	Water_Heat	New	Low-Flow Showerheads	0.04	25%	100%	10	$0.01	3%
Warehouse	Water_Heat	New	Premium Efficency Storage Water Heater	0.04			13	$0.02	16%
Warehouse	Water_Heat	New	Solar Water Heater	0.04	95%	45%	15	$0.60	40%
Warehouse	Water_Heat	New	Tankless Water Heater	0.04	95%	55%	15	$0.12	27%

Table A-5. Industrial Electric Measures

Building Type	End Use	Vintage	Measure Name	Base Usage	Measure Life	Per Unit Cost	Energy Savings
Chemical_Mfg	HVAC	Existing	HVAC Improvements	51,895	12	$2,627	11%
Chemical_Mfg	Lighting	Existing	Lighting Improvements	38,275	10	$1,856	19%
Chemical_Mfg	Process_Cool	Existing	Process Cooling Improvements	75,514	15	$453	4%
Chemical_Mfg	Process_Motors_AirComp	Existing	Air Compressor Improvements	142,288	15	$3,220	19%
Chemical_Mfg	Process_Motors_AirComp	Existing	Air Compressor O&M	142,288	2	$640	15%
Chemical_Mfg	Process_Motors_Fans	Existing	Fan System Improvements	61,127	15	$1,543	17%
Chemical_Mfg	Process_Motors_Other	Existing	Other Motor System Improvements	137,151	15	$2,138	10%
Chemical_Mfg	Process_Motors_Pumps	Existing	Pump System Improvements	133,555	15	$7,681	38%
Chemical_Mfg	Process_Motors_Refrig	Existing	Refrigeration Improvements	39,553	15	$237	4%
Computer_Electronic_Mfg	HVAC	Existing	HVAC Improvements	109,535	12	$5,545	11%
Computer_Electronic_Mfg	Lighting	Existing	Lighting Improvements	49,050	10	$1,077	9%
Computer_Electronic_Mfg	Process_Cool	Existing	Process Cooling Improvements	34,423	15	$413	8%
Computer_Electronic_Mfg	Process_Motors_AirComp	Existing	Air Compressor Improvements	4,017	15	$65	13%
Computer_Electronic_Mfg	Process_Motors_AirComp	Existing	Air Compressor O&M	4,017	2	$18	15%
Computer_Electronic_Mfg	Process_Motors_Fans	Existing	Fan System Improvements	17,290	15	$295	11%
Computer_Electronic_Mfg	Process_Motors_Other	Existing	Other Motor System Improvements	34,231	15	$294	6%
Computer_Electronic_Mfg	Process_Motors_Pumps	Existing	Pump System Improvements	27,420	15	$1,357	33%
Computer_Electronic_Mfg	Process_Motors_Refrig	Existing	Refrigeration Improvements	4,366	15	$52	8%
Electrical_Equipment_Mfg	HVAC	Existing	HVAC Improvements	50,597	12	$2,561	11%
Electrical_Equipment_Mfg	Lighting	Existing	Lighting Improvements	38,326	10	$2,044	21%
Electrical_Equipment_Mfg	Process_Cool	Existing	Process Cooling Improvements	13,081	15	$157	8%
Electrical_Equipment_Mfg	Process_Motors_AirComp	Existing	Air Compressor Improvements	29,388	15	$715	20%
Electrical_Equipment_Mfg	Process_Motors_AirComp	Existing	Air Compressor O&M	29,388	2	$132	15%
Electrical_Equipment_Mfg	Process_Motors_Fans	Existing	Fan System Improvements	12,625	15	$345	18%
Electrical_Equipment_Mfg	Process_Motors_Other	Existing	Other Motor System Improvements	28,327	15	$534	13%
Electrical_Equipment_Mfg	Process_Motors_Pumps	Existing	Pump System Improvements	27,585	15	$1,649	40%
Electrical_Equipment_Mfg	Process_Motors_Refrig	Existing	Refrigeration Improvements	8,169	15	$98	8%
Fabricated_Metal_Products	HVAC	Existing	HVAC Improvements	53,821	12	$2,725	11%
Fabricated_Metal_Products	Lighting	Existing	Lighting Improvements	50,175	10	$1,282	10%
Fabricated_Metal_Products	Process_Cool	Existing	Process Cooling Improvements	18,419	15	$111	4%
Fabricated_Metal_Products	Process_Motors_AirComp	Existing	Air Compressor Improvements	37,026	15	$621	14%
Fabricated_Metal_Products	Process_Motors_AirComp	Existing	Air Compressor O&M	37,026	2	$167	15%
Fabricated_Metal_Products	Process_Motors_Fans	Existing	Fan System Improvements	32,105	15	$576	12%
Fabricated_Metal_Products	Process_Motors_Other	Existing	Other Motor System Improvements	91,393	15	$864	6%
Fabricated_Metal_Products	Process_Motors_Pumps	Existing	Pump System Improvements	58,116	15	$2,926	34%
Fabricated_Metal_Products	Process_Motors_Refrig	Existing	Refrigeration Improvements	15,701	15	$94	4%
Food_Mfg	HVAC	Existing	HVAC Improvements	41,726	12	$2,112	11%
Food_Mfg	Lighting	Existing	Lighting Improvements	39,978	10	$2,434	24%
Food_Mfg	Process_Cool	Existing	Process Cooling Improvements	150,716	15	$5,426	24%
Food_Mfg	Process_Motors_AirComp	Existing	Air Compressor Improvements	23,268	15	$612	22%
Food_Mfg	Process_Motors_AirComp	Existing	Air Compressor O&M	23,268	2	$105	15%
Food_Mfg	Process_Motors_Fans	Existing	Fan System Improvements	22,664	15	$676	20%
Food_Mfg	Process_Motors_Other	Existing	Other Motor System Improvements	117,853	15	$2,230	13%
Food_Mfg	Process_Motors_Pumps	Existing	Pump System Improvements	49,559	15	$3,118	42%
Food_Mfg	Process_Motors_Refrig	Existing	Refrigeration Improvements	88,843	15	$3,198	24%

Building Type	End Use	Vintage	Measure Name	Base Usage	Measure Life	Per Unit Cost	Energy Savings
Industrial_Machinary	HVAC	Existing	HVAC Improvements	32,702	12	$1,656	11%
Industrial_Machinary	Lighting	Existing	Lighting Improvements	24,329	10	$1,160	19%
Industrial_Machinary	Process_Cool	Existing	Process Cooling Improvements	5,793	15	$35	4%
Industrial_Machinary	Process_Motors_AirComp	Existing	Air Compressor Improvements	13,596	15	$313	19%
Industrial_Machinary	Process_Motors_AirComp	Existing	Air Compressor O&M	13,596	2	$61	15%
Industrial_Machinary	Process_Motors_Fans	Existing	Fan System Improvements	11,789	15	$304	17%
Industrial_Machinary	Process_Motors_Other	Existing	Other Motor System Improvements	33,561	15	$580	12%
Industrial_Machinary	Process_Motors_Pumps	Existing	Pump System Improvements	21,341	15	$1,242	39%
Industrial_Machinary	Process_Motors_Refrig	Existing	Refrigeration Improvements	5,766	15	$35	4%
Miscellaneous_Mfg	HVAC	Existing	HVAC Improvements	28,093	12	$1,422	11%
Miscellaneous_Mfg	Lighting	Existing	Lighting Improvements	20,135	10	$113	2%
Miscellaneous_Mfg	Process_Cool	Existing	Process Cooling Improvements	8,252	15	$25	2%
Miscellaneous_Mfg	Process_Motors_AirComp	Existing	Air Compressor Improvements	7,184	15	$89	10%
Miscellaneous_Mfg	Process_Motors_AirComp	Existing	Air Compressor O&M	7,184	2	$15	7%
Miscellaneous_Mfg	Process_Motors_Fans	Existing	Fan System Improvements	7,686	15	$95	8%
Miscellaneous_Mfg	Process_Motors_Other	Existing	Other Motor System Improvements	30,946	15	$121	3%
Miscellaneous_Mfg	Process_Motors_Pumps	Existing	Pump System Improvements	4,371	15	$196	30%
Miscellaneous_Mfg	Process_Motors_Refrig	Existing	Refrigeration Improvements	50	15	$0	2%
Nonmetallic_Mineral_Products	HVAC	Existing	HVAC Improvements	33,828	12	$1,713	11%
Nonmetallic_Mineral_Products	Lighting	Existing	Lighting Improvements	26,273	10	$2,032	31%
Nonmetallic_Mineral_Products	Process_Cool	Existing	Process Cooling Improvements	18,848	15	$113	4%
Nonmetallic_Mineral_Products	Process_Motors_AirComp	Existing	Air Compressor Improvements	51,147	15	$1,207	20%
Nonmetallic_Mineral_Products	Process_Motors_AirComp	Existing	Air Compressor O&M	51,147	2	$230	15%
Nonmetallic_Mineral_Products	Process_Motors_Fans	Existing	Fan System Improvements	44,349	15	$1,173	18%
Nonmetallic_Mineral_Products	Process_Motors_Other	Existing	Other Motor System Improvements	126,248	15	$2,269	12%
Nonmetallic_Mineral_Products	Process_Motors_Pumps	Existing	Pump System Improvements	80,281	15	$4,727	39%
Nonmetallic_Mineral_Products	Process_Motors_Refrig	Existing	Refrigeration Improvements	21,689	15	$130	4%
Paper_Mfg	HVAC	Existing	HVAC Improvements	34,710	12	$1,757	11%
Paper_Mfg	Lighting	Existing	Lighting Improvements	33,625	10	$711	8%
Paper_Mfg	Process_Cool	Existing	Process Cooling Improvements	12,778	15	$77	4%
Paper_Mfg	Process_Motors_AirComp	Existing	Air Compressor Improvements	31,733	15	$736	19%
Paper_Mfg	Process_Motors_AirComp	Existing	Air Compressor O&M	31,733	2	$143	15%
Paper_Mfg	Process_Motors_Fans	Existing	Fan System Improvements	136,592	15	$3,546	17%
Paper_Mfg	Process_Motors_Other	Existing	Other Motor System Improvements	270,424	15	$4,725	12%
Paper_Mfg	Process_Motors_Pumps	Existing	Pump System Improvements	216,615	15	$12,645	39%
Paper_Mfg	Process_Motors_Refrig	Existing	Refrigeration Improvements	34,493	15	$207	4%
Petroleum_Coal_Products	HVAC	Existing	HVAC Improvements	9,623	12	$487	11%
Petroleum_Coal_Products	Lighting	Existing	Lighting Improvements	7,384	10	$235	13%
Petroleum_Coal_Products	Process_Cool	Existing	Process Cooling Improvements	16,723	15	$100	4%
Petroleum_Coal_Products	Process_Motors_AirComp	Existing	Air Compressor Improvements	38,195	15	$573	13%
Petroleum_Coal_Products	Process_Motors_AirComp	Existing	Air Compressor O&M	38,195	2	$172	15%
Petroleum_Coal_Products	Process_Motors_Fans	Existing	Fan System Improvements	33,119	15	$700	14%
Petroleum_Coal_Products	Process_Motors_Other	Existing	Other Motor System Improvements	94,279	15	$1,179	8%
Petroleum_Coal_Products	Process_Motors_Pumps	Existing	Pump System Improvements	59,952	15	$2,776	31%
Petroleum_Coal_Products	Process_Motors_Refrig	Existing	Refrigeration Improvements	16,197	15	$97	4%
Plastics_Rubber_Products	HVAC	Existing	HVAC Improvements	99,399	12	$5,032	11%
Plastics_Rubber_Products	Lighting	Existing	Lighting Improvements	81,323	10	$2,766	14%

Building Type	End Use	Vintage	Measure Name	Base Usage	Measure Life	Per Unit Cost	Energy Savings
Plastics_Rubber_Products	Process_Cool	Existing	Process Cooling Improvements	82,726	15	$993	8%
Plastics_Rubber_Products	Process_Motors_AirComp	Existing	Air Compressor Improvements	85,143	15	$1,802	18%
Plastics_Rubber_Products	Process_Motors_AirComp	Existing	Air Compressor O&M	85,143	2	$383	15%
Plastics_Rubber_Products	Process_Motors_Fans	Existing	Fan System Improvements	73,826	15	$1,729	16%
Plastics_Rubber_Products	Process_Motors_Other	Existing	Other Motor System Improvements	210,163	15	$3,138	10%
Plastics_Rubber_Products	Process_Motors_Pumps	Existing	Pump System Improvements	133,642	15	$7,462	37%
Plastics_Rubber_Products	Process_Motors_Refrig	Existing	Refrigeration Improvements	36,105	15	$433	8%
Primary_Metal_Mfg	HVAC	Existing	HVAC Improvements	3,412	12	$173	11%
Primary_Metal_Mfg	Lighting	Existing	Lighting Improvements	2,734	10	$82	12%
Primary_Metal_Mfg	Process_Cool	Existing	Process Cooling Improvements	761	15	$5	4%
Primary_Metal_Mfg	Process_Motors_AirComp	Existing	Air Compressor Improvements	4,272	15	$185	36%
Primary_Metal_Mfg	Process_Motors_AirComp	Existing	Air Compressor O&M	4,272	2	$19	15%
Primary_Metal_Mfg	Process_Motors_Fans	Existing	Fan System Improvements	4,571	15	$185	27%
Primary_Metal_Mfg	Process_Motors_Other	Existing	Other Motor System Improvements	18,404	15	$528	19%
Primary_Metal_Mfg	Process_Motors_Pumps	Existing	Pump System Improvements	2,599	15	$223	57%
Primary_Metal_Mfg	Process_Motors_Refrig	Existing	Refrigeration Improvements	30	15	$0	4%
Printing_Related_Support	HVAC	Existing	HVAC Improvements	22,793	12	$1,154	11%
Printing_Related_Support	Lighting	Existing	Lighting Improvements	14,257	10	$201	6%
Printing_Related_Support	Process_Cool	Existing	Process Cooling Improvements	5,617	15	$101	12%
Printing_Related_Support	Process_Motors_AirComp	Existing	Air Compressor Improvements	9,831	15	$151	13%
Printing_Related_Support	Process_Motors_AirComp	Existing	Air Compressor O&M	9,831	2	$44	15%
Printing_Related_Support	Process_Motors_Fans	Existing	Fan System Improvements	8,524	15	$137	11%
Printing_Related_Support	Process_Motors_Other	Existing	Other Motor System Improvements	24,267	15	$185	5%
Printing_Related_Support	Process_Motors_Pumps	Existing	Pump System Improvements	15,431	15	$749	32%
Printing_Related_Support	Process_Motors_Refrig	Existing	Refrigeration Improvements	4,169	15	$75	12%
Transportation_Equipment_Mfg	HVAC	Existing	HVAC Improvements	82,120	12	$4,157	11%
Transportation_Equipment_Mfg	Lighting	Existing	Lighting Improvements	64,293	10	$1,685	10%
Transportation_Equipment_Mfg	Process_Cool	Existing	Process Cooling Improvements	19,412	15	$116	4%
Transportation_Equipment_Mfg	Process_Motors_AirComp	Existing	Air Compressor Improvements	51,771	15	$912	15%
Transportation_Equipment_Mfg	Process_Motors_AirComp	Existing	Air Compressor O&M	51,771	2	$233	15%
Transportation_Equipment_Mfg	Process_Motors_Fans	Existing	Fan System Improvements	22,241	15	$422	13%
Transportation_Equipment_Mfg	Process_Motors_Other	Existing	Other Motor System Improvements	49,902	15	$524	7%
Transportation_Equipment_Mfg	Process_Motors_Pumps	Existing	Pump System Improvements	48,594	15	$2,498	34%
Transportation_Equipment_Mfg	Process_Motors_Refrig	Existing	Refrigeration Improvements	14,391	15	$86	4%
Wood_Product_Mfg	HVAC	Existing	HVAC Improvements	22,023	12	$1,115	11%
Wood_Product_Mfg	Lighting	Existing	Lighting Improvements	23,312	10	$243	4%
Wood_Product_Mfg	Process_Cool	Existing	Process Cooling Improvements	2,059	15	$12	4%
Wood_Product_Mfg	Process_Motors_AirComp	Existing	Air Compressor Improvements	37,071	15	$1,247	28%
Wood_Product_Mfg	Process_Motors_AirComp	Existing	Air Compressor O&M	37,071	2	$167	15%
Wood_Product_Mfg	Process_Motors_Fans	Existing	Fan System Improvements	32,144	15	$890	18%
Wood_Product_Mfg	Process_Motors_Other	Existing	Other Motor System Improvements	91,505	15	$1,541	11%
Wood_Product_Mfg	Process_Motors_Pumps	Existing	Pump System Improvements	58,188	15	$4,319	49%
Wood_Product_Mfg	Process_Motors_Refrig	Existing	Refrigeration Improvements	15,720	15	$94	4%

Table A-6. Industrial Gas Measures

Building Type	End Use	Vintage	Measure Name	Base Usage	Measure Life	Per Unit Cost	Energy Savings
Chemical_Mfg	HVAC	Existing	HVAC Improvements	56	12	$35	11%
Chemical_Mfg	Process_Boiler	Existing	Process Boiler O&M	1,581	2	$31	5%
Chemical_Mfg	Process_Boiler	Existing	Process Boiler Upgrades	1,581	15	$173	7%
Chemical_Mfg	Process_Boiler	Existing	Steam Distribution Systems	1,581	15	$277	14%
Computer_Electronic_Mfg	HVAC	Existing	HVAC Improvements	169	12	$104	11%
Computer_Electronic_Mfg	Process_Boiler	Existing	Process Boiler O&M	220	2	$4	5%
Computer_Electronic_Mfg	Process_Boiler	Existing	Process Boiler Upgrades	220	15	$24	7%
Computer_Electronic_Mfg	Process_Boiler	Existing	Steam Distribution Systems	220	15	$39	14%
Electrical_Equipment_Mfg	HVAC	Existing	HVAC Improvements	118	12	$73	11%
Electrical_Equipment_Mfg	Process_Boiler	Existing	Process Boiler O&M	47	2	$1	5%
Electrical_Equipment_Mfg	Process_Boiler	Existing	Process Boiler Upgrades	47	15	$5	7%
Electrical_Equipment_Mfg	Process_Boiler	Existing	Steam Distribution Systems	47	15	$8	14%
Fabricated_Metal_Products	HVAC	Existing	HVAC Improvements	371	12	$228	11%
Fabricated_Metal_Products	Process_Boiler	Existing	Process Boiler O&M	282	2	$5	5%
Fabricated_Metal_Products	Process_Boiler	Existing	Process Boiler Upgrades	282	15	$31	7%
Fabricated_Metal_Products	Process_Boiler	Existing	Steam Distribution Systems	282	15	$49	14%
Food_Mfg	HVAC	Existing	HVAC Improvements	271	12	$167	11%
Food_Mfg	Process_Boiler	Existing	Process Boiler O&M	2,014	2	$39	5%
Food_Mfg	Process_Boiler	Existing	Process Boiler Upgrades	2,014	15	$220	7%
Food_Mfg	Process_Boiler	Existing	Steam Distribution Systems	2,014	15	$353	14%
Industrial_Machinary	HVAC	Existing	HVAC Improvements	327	12	$201	11%
Industrial_Machinary	Process_Boiler	Existing	Process Boiler O&M	158	2	$3	5%
Industrial_Machinary	Process_Boiler	Existing	Process Boiler Upgrades	158	15	$17	7%
Industrial_Machinary	Process_Boiler	Existing	Steam Distribution Systems	158	15	$28	14%
Miscellaneous_Mfg	HVAC	Existing	HVAC Improvements	224	12	$138	11%
Miscellaneous_Mfg	Process_Boiler	Existing	Process Boiler O&M	201	2	$4	5%
Miscellaneous_Mfg	Process_Boiler	Existing	Process Boiler Upgrades	201	15	$22	7%
Miscellaneous_Mfg	Process_Boiler	Existing	Steam Distribution Systems	201	15	$35	14%
Nonmetallic_Mineral_Products	HVAC	Existing	HVAC Improvements	156	12	$96	11%
Nonmetallic_Mineral_Products	Process_Boiler	Existing	Process Boiler O&M	94	2	$2	5%
Nonmetallic_Mineral_Products	Process_Boiler	Existing	Process Boiler Upgrades	94	15	$10	7%
Nonmetallic_Mineral_Products	Process_Boiler	Existing	Steam Distribution Systems	94	15	$16	14%
Paper_Mfg	HVAC	Existing	HVAC Improvements	183	12	$113	11%
Paper_Mfg	Process_Boiler	Existing	Process Boiler O&M	2,868	2	$56	5%
Paper_Mfg	Process_Boiler	Existing	Process Boiler Upgrades	2,868	15	$314	7%
Paper_Mfg	Process_Boiler	Existing	Steam Distribution Systems	2,868	15	$503	14%
Petroleum_Coal_Products	HVAC	Existing	HVAC Improvements	39	12	$24	11%
Petroleum_Coal_Products	Process_Boiler	Existing	Process Boiler O&M	1,556	2	$30	5%
Petroleum_Coal_Products	Process_Boiler	Existing	Process Boiler Upgrades	1,556	15	$170	7%
Petroleum_Coal_Products	Process_Boiler	Existing	Steam Distribution Systems	1,556	15	$273	14%
Plastics_Rubber_Products	HVAC	Existing	HVAC Improvements	950	12	$586	11%
Plastics_Rubber_Products	Process_Boiler	Existing	Process Boiler O&M	1,901	2	$37	5%
Plastics_Rubber_Products	Process_Boiler	Existing	Process Boiler Upgrades	1,901	15	$208	7%
Plastics_Rubber_Products	Process_Boiler	Existing	Steam Distribution Systems	1,901	15	$333	14%
Primary_Metal_Mfg	HVAC	Existing	HVAC Improvements	169	12	$104	11%

Building Type	End Use	Vintage	Measure Name	Base Usage	Measure Life	Per Unit Cost	Energy Savings
Primary_Metal_Mfg	Process_Boiler	Existing	Process Boiler O&M	272	2	$5	5%
Primary_Metal_Mfg	Process_Boiler	Existing	Process Boiler Upgrades	272	15	$30	7%
Primary_Metal_Mfg	Process_Boiler	Existing	Steam Distribution Systems	272	15	$48	14%
Printing_Related_Support	HVAC	Existing	HVAC Improvements	127	12	$78	11%
Printing_Related_Support	Process_Boiler	Existing	Process Boiler O&M	76	2	$1	5%
Printing_Related_Support	Process_Boiler	Existing	Process Boiler Upgrades	76	15	$8	7%
Printing_Related_Support	Process_Boiler	Existing	Steam Distribution Systems	76	15	$13	14%
Transportation_Equipment_Mfg	HVAC	Existing	HVAC Improvements	360	12	$222	11%
Transportation_Equipment_Mfg	Process_Boiler	Existing	Process Boiler O&M	295	2	$6	5%
Transportation_Equipment_Mfg	Process_Boiler	Existing	Process Boiler Upgrades	295	15	$32	7%
Transportation_Equipment_Mfg	Process_Boiler	Existing	Steam Distribution Systems	295	15	$52	14%
Wood_Product_Mfg	HVAC	Existing	HVAC Improvements	157	12	$97	11%
Wood_Product_Mfg	Process_Boiler	Existing	Process Boiler O&M	336	2	$7	5%
Wood_Product_Mfg	Process_Boiler	Existing	Process Boiler Upgrades	336	15	$37	7%
Wood_Product_Mfg	Process_Boiler	Existing	Steam Distribution Systems	336	15	$59	14%

Appendix C: Fuel Conversion: Inputs and Assumptions

Appendix C follows.

Table C-1. Residential Fuel Conversion Measures--Single Family

End Use	Gas Measure	Electric Baseline	Electricity Use Data: kWh/yr.	W/ T&D Savings	kBtu/yr.	AnnualCost	Equip Cost	Measure Life
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	Electric Furnace	8,008	8,583	27,331	$649	$1,400	18
	Condensing Furnace, 90 AFUE		8,008	8,583	27,331	$649	$1,400	18
	Condensing Furnace, 96 AFUE		8,008	8,583	27,331	$649	$1,400	18
Zone Heating	Wall heater 84% eff	Elec baseboard	4,004	4,292	13,666	$324	$500	15
Water Heating	Storage Water Heater, 50 gal., EF=.59	Electric Water Heater, 50 gal.	3,510	3,762	11,980	$230	$190	13
	Storage Water Heater, 50 gal., EF=.64		3,510	3,762	11,980	$230	$190	13
	Tankless water heater EF=0.82		3,510	3,762	11,980	$230	$190	13
Appliances	Gas Dryer, 6.5 cuft	Electric Dryer, 6.5 cuft	1,275	1,367	4,352	$103	$300	14
	Gas Dryer w/ Moisture Sens., 7.0 cuft	Electric dryer w/ moisture sens, 7.0cuft	1,084	1,162	3,699	$88	$450	14
	Standard Gas Range, Free-Standing, 30"	Electric Range, 30"	890	954	3,038	$72	$330	18
	Convection Gas Range, Free-Standing, 30"	Convection Electric range, 30"	712	763	2,430	$58	$1,050	18

End Use	Gas Measure	Electric Baseline	Gas Conversion Data: Therms/yr.	w/T&D savings	kBtu/yr.	AnnualCost	Equip Cost	Piping & Labor	Installed Cost w/ labor	Installed Cost Main Ext	Measure Life
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	Electric Furnace	625	630	62,465	$775	$2,000	$700	$2,700	$2,700	18
	Condensing Furnace, 90 AFUE		555	560	55,525	$689	$2,300	$700	$3,000	$3,000	18
	Condensing Furnace, 96 AFUE		521	525	52,055	$645	$2,650	$700	$3,350	$3,350	18
Zone Heating	Wall heater 84% eff	Elec baseboard	297	300	29,745	$369	$1,500	$500	$2,000		15
Water Heating	Storage Water Heater, 50 gal., EF=.59	Electric Water Heater, 50 gal.	203	205	20,287	$252	$430	$0	$430		13
	Storage Water Heater, 50 gal., EF=.64		187	189	18,702	$232	$450	$0	$450		13
	Tankless water heater EF=0.82		146	147	14,596	$181	$800	$0	$800		13
Appliances	Gas Dryer, 6.5 cuft	Electric Dryer, 6.5 cuft	49	49	4,901	$61	$360	$0	$360		14
	Gas Dryer w/ Moisture Sens., 7.0 cuft	Electric dryer w/ moisture sens, 7.0cuft	42	42	4,166	$52	$510	$0	$510		14
	Standard Gas Range, Free-Standing, 30"	Electric Range, 30"	50	50	4,999	$62	$330	$0	$330		18
	Convection Gas Range, Free-Standing, 30"	Convection Electric range, 30"	40	40	3,999	$50	$1,150	$0	$1,150		18

NOTES:
Cost of electricity is $.08/kWh; cost of gas is $1.24/therm;
T&D Savings is 6.7% for electric, 0.8% for gas;
Admin. adder is 15%;
Discount rate is 8.4%;
Service line cost is $0 (no charge) for a 1600 square foot home (S&WH);
Main Extension Cost is $2,000 for a 50' extension for a 2000 square foot home (S&WH);
In-house fuel line cost is $200;
Source for Electricity Use Data is 2001 Electric End Use Model;
Labor is included for Space/Zone Heating .

Table C-2. Technical Potential

	Number of Customers			
End Use	**PSE Gas**	**Svc Line Only**	**Main Ext.**	**Total**
All	293,331	18,523	17,597	329,451
Space Heat	0	4,013	3,813	7,826
Water Heat	42,017	18,523	17,597	78,137
Dryer	246,266	18,523	17,597	282,386
Range	202,026	18,523	17,597	238,146
Zone Heat	9,945	0	0	9,945

	Electric Savings (kWh/yr.)			
End Use	**PSE Gas**	**Svc Line Only**	**Main Ext.**	**Total (aMW)**
Space Heat	0	34,448,097	32,725,971	7.7
Water Heat	158,069,379	69,684,598	66,200,932	33.6
Dryer	286,056,615	21,515,864	20,440,245	37.4
Range	154,171,931	14,135,451	13,428,793	20.7
Zone Heat	42,679,293	0	0	4.9
			Total (kWh/yr.)	913,557,171
			Total (aMW)	104.3

	Gas Usage--90 AFUE Furnace, 0. 64 EF Water Heater (therms/yr.)			
End Use	**PSE Gas**	**Svc Line Only**	**Main Ext.**	**Total (Dth)**
Space Heat	0	2,246,457	2,134,153	438,061
Water Heat	7,921,221	3,492,056	3,317,481	1,473,076
Dryer	10,342,644	777,926	739,036	1,185,961
Range	8,144,019	746,695	709,366	960,008
Zone Heat	2,982,039	0	0	298,204
			Total (therms/yr.)	43,553,094
			Total (Dth/yr.)	4,355,309

	Gas Usage--96 AFUE Furnace, 0.82 EF Water Heater (therms/yr.)			
End Use	**PSE Gas**	**Svc Line Only**	**Main Ext.**	**Total (Dth)**
Space Heat	0	2,106,054	2,000,768	410,682
Water Heat	6,182,416	2,725,507	2,589,254	1,149,718
Dryer	10,342,644	777,926	739,036	1,185,961
Range	8,144,019	746,695	709,366	960,008
Zone Heat	2,982,039	0	0	298,204
			Total (therms/yr.)	40,045,724
			Total (Dth/yr.)	4,004,572

Table C-3. Economic Screen: Base Case Avoided Costs and Service Line

		NPV Avoided Cost (2008 Base Year)		Service Line Extension					
End Use	Gas Measure	Elec Avoided Cost ($/kWh)	Gas Avoided Cost ($/therm)	First Yr. Cost ($)	First Yr. Cost + Admin ($)	Elec. Benefit ($)	Elec.--Gas Benefit ($)	Benefit/Cost	Benefit/Cost w/Admin.
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	**$0.85**	**$9.0**	$ 1,300	$ 1,495	$ 7,514	$ 1,878	1.4	1.3
	Condensing Furnace, 90 AFUE	**$0.85**	**$9.0**	$ 1,600	$ 1,840	$ 7,514	$ 2,504	1.6	1.4
	Condensing Furnace, 96 AFUE	**$0.85**	**$9.0**	$ 1,950	$ 2,243	$ 7,514	$ 2,817	1.4	1.3
Zone Heating	Wall heater 84% eff	**$0.76**	**$8.1**	$ 1,500	$ 1,725	$ 3,375	$ 957	0.6	0.6
Water Heating	Storage Water Heater, 50 gal., EF=.59	**$0.70**	**$7.0**	$ 440	$ 506	$ 2,700	$ 1,271	2.9	2.5
	Storage Water Heater, 50 gal., EF=.64	**$0.70**	**$7.0**	$ 460	$ 529	$ 2,700	$ 1,383	3.0	2.6
	Tankless water heater EF=0.82	**$0.70**	**$7.0**	$ 810	$ 932	$ 2,700	$ 1,672	2.1	1.8
Appliances	Gas Dryer, 6.5 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 1,083	$ 721	2.8	2.4
	Gas Dryer w/ Moisture Sens., 7.0 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 920	$ 613	2.4	2.1
	Standard Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 200	$ 230	$ 868	$ 439	2.2	1.9
	Convection Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 300	$ 345	$ 694	$ 351	1.2	1.0
Bundles									
Space + Water Heat	90 AFUE + 0.64			$ 2,060	$ 2,369	$ 10,214	$ 3,887	1.9	1.6
Space + Dryer	90 AFUE + ms			$ 1,860	$ 2,139	$ 8,435	$ 3,117	1.7	1.5
Space + Range	90 AFUE + conv			$ 1,900	$ 2,185	$ 8,208	$ 2,856	1.5	1.3
Space + H2O + Dryer	90 AFUE + 0.64 + ms			$ 2,320	$ 2,668	$ 11,134	$ 4,500	1.9	1.7
Space + H2O + Range	90 AFUE + 0.64 + conv			$ 2,360	$ 2,714	$ 10,908	$ 4,239	1.8	1.6
Space + Dryer + Range	90 AFUE + ms + conv			$ 2,160	$ 2,484	$ 9,129	$ 3,469	1.6	1.4
All	90 + 0.64 + ms + conv			$ 2,620	$ 3,013	$ 11,829	$ 4,852	1.9	1.6
H2O + Dryer	0.64 + ms			$ 720	$ 828	$ 3,620	$ 1,996	2.8	2.4
H2O + Range	0.64 + conv			$ 760	$ 874	$ 3,394	$ 1,734	2.3	2.0
H2O + Dryer + Range	0.64+ ms+ conv			$ 1,020	$ 1,173	$ 4,315	$ 2,348	2.3	2.0
Zone + water heat	84% + 0.64			$ 1,960	$ 2,254	$ 6,075	$ 2,340	1.2	1.0
zone + water + dryer	84 % + 0.64 + ms			$ 2,220	$ 2,553	$ 6,995	$ 2,953	1.3	1.2
zone + water + range	84% + 0.64 + conv			$ 2,260	$ 2,599	$ 6,769	$ 2,691	1.2	1.0
zone + water + dryer + range	84% + 0.64 + ms+ conv			$ 2,520	$ 2,898	$ 7,689	$ 3,304	1.3	1.1
w/ tankless H2O & 96 AFUE									
Space + Water Heat	96 + 0.82			$ 2,760	$ 3,174	$ 10,214	$ 4,489	1.6	1.4
Space + H2O + Dryer	96 + 0.82 + ms			$ 3,020	$ 3,473	$ 11,134	$ 5,102	1.7	1.5
Space + H2O + Range	96 + 0.82 + conv			$ 3,060	$ 3,519	$ 10,908	$ 4,841	1.6	1.4
All	96 + 0.82 + ms + conv			$ 3,320	$ 3,818	$ 11,829	$ 5,454	1.6	1.4
H2O + Dryer	0.82 + ms			$ 1,070	$ 1,231	$ 3,620	$ 2,285	2.1	1.9
H2O + Range	0.82 + conv			$ 1,110	$ 1,277	$ 3,394	$ 2,024	1.8	1.6
H2O + Dryer + Range	0.82 + ms + conv			$ 1,370	$ 1,576	$ 4,315	$ 2,637	1.9	1.7

Table C-4. Economic Screen: Base Case Main Extension

		Main Extension				
End Use	Gas Measure	First Yr. Cost ($)	First Yr. Cost + Admin ($)	Elec.--Gas Benefit ($)	Benefit/ Cost	Benefit/Cost w/Admin.
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	$ 3,300	$ 3,795	$ 1,878	0.6	0.5
	Condensing Furnace, 90 AFUE	$ 3,600	$ 4,140	$ 2,504	0.7	0.6
	Condensing Furnace, 96 AFUE	$ 3,950	$ 4,543	$ 2,817	0.7	0.6
	Using 90 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,060	$ 4,669	$ 5,204	1.3	1.1
	Space + Dryer	$ 3,860	$ 4,439	$ 3,117	0.8	0.7
	Space + Range	$ 3,900	$ 4,485	$ 3,198	0.8	0.7
	Space + H2O + Dryer	$ 4,320	$ 4,968	$ 6,124	1.4	1.2
	Space + H2O + Range	$ 4,360	$ 5,014	$ 5,898	1.4	1.2
	Space + Dryer + Range	$ 4,160	$ 4,784	$ 4,119	1.0	0.9
	All	$ 4,620	$ 5,313	$ 6,819	1.5	1.3
	Using 96 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,760	$ 5,474	$ 5,517	1.2	1.0
	Space + Dryer	$ 4,210	$ 4,842	$ 3,738	0.9	0.8
	Space + Range	$ 4,250	$ 4,888	$ 3,512	0.8	0.7
	Space + H2O + Dryer	$ 5,020	$ 5,773	$ 6,438	1.3	1.1
	Space + H2O + Range	$ 4,510	$ 5,187	$ 4,432	1.0	0.9
	Space + Dryer + Range	$ 5,320	$ 6,118	$ 7,132	1.3	1.2
	All	$ 4,520	$ 5,198	$ 7,155	1.6	1.4

Table C-5. Economic Customer Count: Base Case

End Use	% Bundle Adoption	Measures	Number of Customers: PSE Gas	Svc Line Only	Main Ext.	Total
Space Heat + Additional End Uses	5%	space heat	0	4013	0	4013
	80%	space + water	0	4013	3813	7826
	5%	space + water + dryer	0	4013	3813	7826
	5%	space + water + range	0	4013	3813	7826
	5%	All	0	4013	3813	7826
Zone Heat + Additional End Uses	5%	zone heat	0	0	0	0
	80%	zone + water	9945	0	0	9945
	5%	zone + water + dryer	9945	0	0	9945
	5%	zone + water + range	9945	0	0	9945
	5%	zone + all	9945	0	0	9945
Water Heat + Additional End Uses	3%	water + dryer	42017			42017
	3%	water + range	42017			42017
	85%	water only	42017			42017
	10%	water + dryer + range	42017			42017

Table C-6. Economic Potential: Base Case

	Number of Customers		
Measures	**PSE Gas**	**Svc Line Only**	**Main Ext.**
space heat		201	0
space + water		3211	3050
space + water + dryer		201	191
space + water + range		201	191
All		201	191
zone heat	0		
zone + water	7956		
zone + water + dryer	497		
zone + water + range	497		
zone + all	497		
water + dryer	1050		
water + range	1050		
water only	35714		
water + dryer + range	4202		

	Electric Savings (kWh/yr.)		
Measures	**PSE Gas**	**Svc Line Only**	**Main Ext.**
space heat		1,722,405	0
space + water		39,637,681	37,656,118
space + water + dryer		2,710,454	2,574,953
space + water + range		2,630,496	2,498,992
All		2,863,595	2,720,438
zone heat	0		
zone + water	64,074,367		
zone + water + dryer	4,582,241		
zone + water + range	4,384,114		
zone + all	4,961,708		
water + dryer	5,171,875		
water + range	4,753,340		
water only	134,358,972		
water + dryer + range	23,893,920		
		Total (aMW)	38.9

	Gas Usage--90 AFUE Furnace, 0. 64 EF Water Heater (therms/yr.)		
Measures	**PSE Gas**	**Svc Line Only**	**Main Ext.**
space heat		112,323	0
space + water		2,402,483	2,282,378
space + water + dryer		158,583	150,655
space + water + range		158,245	150,334
All		166,673	158,340
zone heat	0		
zone + water	3,885,539		
zone + water + dryer	263,730		
zone + water + range	262,891		
zone + all	283,775		
water + dryer	242,146		
water + range	240,375		
water only	6,733,038		
water + dryer + range	1,137,960		
		Total (Dth)	1878947

	Gas Usage--96 AFUE Furnace, 0.82 EF Water Heater (therms/yr.)		
Measures	**PSE Gas**	**Svc Line Only**	**Main Ext.**
space heat		105,303	0
space + water		2,157,285	2,049,438
space + water + dryer		143,258	136,096
space + water + range		142,920	135,775
All		151,348	143,782
zone heat	0		
zone + water	3,556,291		
zone + water + dryer	243,152		
zone + water + range	242,313		
zone + all	263,197		
water + dryer	198,676		
water + range	196,905		
water only	5,255,054		
water + dryer + range	964,080		
		Total (Dth):	1608487

Table C-7. Economic Screen AC: -10% Scenario Avoided Costs and Service Line

		NPV Avoided Cost (2008 Base Year)		Service Line Extension					
End Use	**Gas Measure**	**Elec Avoided Cost ($/kWh)**	**Gas Avoided Cost ($/therm)**	**First Yr. Cost ($)**	**First Yr. Cost + Admin ($)**	**Elec. Benefit ($)**	**Elec.--Gas Benefit ($)**	**Benefit/Cost**	**Benefit/Cost w/Admin.**
	Standard Furnace, 80 AFUE, 60 kBtu	**$0.85**	**$9.0**	$ 1,300	$ 1,495	$ 6,782	$ 1,710	1.3	1.1
Space Heating	Condensing Furnace, 90 AFUE	**$0.85**	**$9.0**	$ 1,600	$ 1,840	$ 6,782	$ 2,273	1.4	1.2
	Condensing Furnace, 96 AFUE	**$0.85**	**$9.0**	$ 1,950	$ 2,243	$ 6,782	$ 2,555	1.3	1.1
Zone Heating	Wall heater 84% eff	**$0.76**	**$8.1**	$ 1,500	$ 1,725	$ 3,047	$ 871	0.6	0.5
	Storage Water Heater, 50 gal., EF=.59	**$0.70**	**$7.0**	$ 440	$ 506	$ 2,437	$ 1,152	2.6	2.3
Water Heating	Storage Water Heater, 50 gal., EF=.64	**$0.70**	**$7.0**	$ 460	$ 529	$ 2,437	$ 1,252	2.7	2.4
	Tankless water heater EF=0.82	**$0.70**	**$7.0**	$ 810	$ 932	$ 2,437	$ 1,512	1.9	1.6
	Gas Dryer, 6.5 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 980	$ 655	2.5	2.2
Appliances	Gas Dryer w/ Moisture Sens., 7.0 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 833	$ 557	2.1	1.9
	Standard Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 200	$ 230	$ 783	$ 397	2.0	1.7
	Convection Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 300	$ 345	$ 627	$ 318	1.1	0.9
Bundles									
Space + Water Heat	90 AFUE + 0.64			$ 2,060	$ 2,369	$ 9,219	$ 3,525	1.7	1.5
Space + Dryer	90 AFUE + ms			$ 1,860	$ 2,139	$ 7,616	$ 2,830	1.5	1.3
Space + Range	90 AFUE + conv			$ 1,900	$ 2,185	$ 7,409	$ 2,591	1.4	1.2
Space + H2O + Dryer	90 AFUE + 0.64 + ms			$ 2,320	$ 2,668	$ 10,053	$ 4,082	1.8	1.5
Space + H2O + Range	90 AFUE + 0.64 + conv			$ 2,360	$ 2,714	$ 9,846	$ 3,843	1.6	1.4
Space + Dryer + Range	90 AFUE + ms + conv			$ 2,160	$ 2,484	$ 8,242	$ 3,148	1.5	1.3
All	90 + 0.64 + ms + conv			$ 2,620	$ 3,013	$ 10,679	$ 4,400	1.7	1.5
H2O + Dryer	0.64 + ms			$ 720	$ 828	$ 3,271	$ 1,809	2.5	2.2
H2O + Range	0.64 + conv			$ 760	$ 874	$ 3,064	$ 1,570	2.1	1.8
H2O + Dryer + Range	0.64+ ms+ conv			$ 1,020	$ 1,173	$ 3,897	$ 2,127	2.1	1.8
Zone + water heat	84% + 0.64			$ 1,960	$ 2,254	$ 5,484	$ 2,123	1.1	0.9
zone + water + dryer	84 % + 0.64 + ms			$ 2,220	$ 2,553	$ 6,318	$ 2,680	1.2	1.0
zone + water + range	84% + 0.64 + conv			$ 2,260	$ 2,599	$ 6,111	$ 2,441	1.1	0.9
zone + water + dryer + range	84% + 0.64 + ms+ conv			$ 2,520	$ 2,898	$ 6,944	$ 2,998	1.2	1.0
w/ tankless H2O & 96 AFUE									
Space + Water Heat	96 + 0.82			$ 2,760	$ 3,174	$ 9,219	$ 4,067	1.5	1.3
Space + H2O + Dryer	96 + 0.82 + ms			$ 3,020	$ 3,473	$ 10,053	$ 4,624	1.5	1.3
Space + H2O + Range	96 + 0.82 + conv			$ 3,060	$ 3,519	$ 9,846	$ 4,385	1.4	1.2
All	96 + 0.82 + ms + conv			$ 3,320	$ 3,818	$ 10,679	$ 4,942	1.5	1.3
H2O + Dryer	0.82 + ms			$ 1,070	$ 1,231	$ 3,271	$ 2,069	1.9	1.7
H2O + Range	0.82 + conv			$ 1,110	$ 1,277	$ 3,064	$ 1,830	1.6	1.4
H2O + Dryer + Range	0.82 + ms + conv			$ 1,370	$ 1,576	$ 3,897	$ 2,387	1.7	1.5

Table C-8. Economic Screen AC: -10% Scenario Main Extension

End Use	Gas Measure	Main Extension: First Yr. Cost ($)	First Yr. Cost + Admin ($)	Elec.--Gas Benefit ($)	Benefit/ Cost	Benefit/Cost w/Admin.
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	$ 3,300	$ 3,795	$ 1,710	0.5	0.5
	Condensing Furnace, 90 AFUE	$ 3,600	$ 4,140	$ 2,273	0.6	0.5
	Condensing Furnace, 96 AFUE	$ 3,950	$ 4,543	$ 2,555	0.6	0.6
	Using 90 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,060	$ 4,669	$ 4,710	1.2	1.0
	Space + Dryer	$ 3,860	$ 4,439	$ 2,830	0.7	0.6
	Space + Range	$ 3,900	$ 4,485	$ 2,900	0.7	0.6
	Space + H2O + Dryer	$ 4,320	$ 4,968	$ 5,544	1.3	1.1
	Space + H2O + Range	$ 4,360	$ 5,014	$ 5,337	1.2	1.1
	Space + Dryer + Range	$ 4,160	$ 4,784	$ 3,733	0.9	0.8
	All	$ 4,620	$ 5,313	$ 6,170	1.3	1.2
	Using 96 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,760	$ 5,474	$ 4,992	1.0	0.9
	Space + Dryer	$ 4,210	$ 4,842	$ 3,388	0.8	0.7
	Space + Range	$ 4,250	$ 4,888	$ 3,182	0.7	0.7
	Space + H2O + Dryer	$ 5,020	$ 5,773	$ 5,826	1.2	1.0
	Space + H2O + Range	$ 4,510	$ 5,187	$ 4,015	0.9	0.8
	Space + Dryer + Range	$ 5,320	$ 6,118	$ 6,452	1.2	1.1
	All	$ 4,520	$ 5,198	$ 6,474	1.4	1.2

Table C-9. Economic Customer Count AC: -10% Scenario

End Use	% Bundle Adoption	Measures	Number of Customers: PSE Gas	Svc Line Only	Main Ext.	Total
Space Heat + Additional End Uses	5%	space heat	0	4013	0	4013
	80%	space + water	0	4013	3813	7826
	5%	space + water + dryer	0	4013	3813	7826
	5%	space + water + range	0	4013	3813	7826
	5%	All	0	4013	3813	7826
Zone Heat + Additional End Uses	5%	zone heat	0	0	0	0
	80%	zone + water	0	0	0	0
	5%	zone + water + dryer	9945	0	0	9945
	5%	zone + water + range	0	0	0	0
	5%	zone + all	9945	0	0	9945
Water Heat + Additional End Uses	3%	water + dryer	42017			42017
	3%	water + range	42017			42017
	85%	water only	42017			42017
	10%	water + dryer + range	42017			42017

Table C-10. Economic Potential AC: -10% Scenario

	Number of Customers		
Measures	**PSE Gas**	**Svc Line Only**	**Main Ext.**
space heat		201	0
space + water		3211	3050
space + water + dryer		201	191
space + water + range		201	191
All		201	191
zone heat	0		
zone + water	0		
zone + water + dryer	497		
zone + water + range	0		
zone + all	497		
water + dryer	1050		
water + range	1050		
water only	35714		
water + dryer + range	4202		

	Electric Savings (kWh/yr.)		
Measures	**PSE Gas**	**Svc Line Only**	**Main Ext.**
space heat		1,722,405	0
space + water		39,637,681	37,656,118
space + water + dryer		2,710,454	2,574,953
space + water + range		2,630,496	2,498,992
All		2,863,595	2,720,438
zone heat	0		
zone + water	-		
zone + water + dryer	4,582,241		
zone + water + range	-		
zone + all	4,961,708		
water + dryer	5,171,875		
water + range	4,753,340		
water only	134,358,972		
water + dryer + range	23,893,920		
		Total (aMW)	31.1

	Gas Usage--90 AFUE Furnace, 0. 64 EF Water Heater (therms/yr.)		
Measures	**PSE Gas**	**Svc Line Only**	**Main Ext.**
space heat		112,323	0
space + water		2,402,483	2,282,378
space + water + dryer		158,583	150,655
space + water + range		158,245	150,334
All		166,673	158,340
zone heat	0		
zone + water	-		
zone + water + dryer	263,730		
zone + water + range	-		
zone + all	283,775		
water + dryer	242,146		
water + range	240,375		
water only	6,733,038		
water + dryer + range	1,137,960		
		Total (Dth)	1464104

	Gas Usage--96 AFUE Furnace, 0.82 EF Water Heater (therms/yr.)		
Measures	**PSE Gas**	**Svc Line Only**	**Main Ext.**
space heat		105,303	0
space + water		2,157,285	2,049,438
space + water + dryer		143,258	136,096
space + water + range		142,920	135,775
All		151,348	143,782
zone heat	0		
zone + water	-		
zone + water + dryer	243,152		
zone + water + range	-		
zone + all	263,197		
water + dryer	198,676		
water + range	196,905		
water only	5,255,054		
water + dryer + range	964,080		
		Total (Dth):	1228627

Table C-11. Economic Screen AC: +25% Scenario Avoided Costs and Service Line

End Use	Gas Measure	NPV Avoided Cost (2008 Base Year) Elec Avoided Cost ($/kWh)	NPV Avoided Cost (2008 Base Year) Gas Avoided Cost ($/therm)	Service Line Extension First Yr. Cost ($)	First Yr. Cost + Admin ($)	Elec. Benefit ($)	Elec.--Gas Benefit ($)	Benefit/Cost	Benefit/Cost w/Admin.
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	**$0.85**	**$9.0**	$ 1,300	$ 1,495	$ 9,344	$ 2,298	1.8	1.5
	Condensing Furnace, 90 AFUE	**$0.85**	**$9.0**	$ 1,600	$ 1,840	$ 9,344	$ 3,081	1.9	1.7
	Condensing Furnace, 96 AFUE	**$0.85**	**$9.0**	$ 1,950	$ 2,243	$ 9,344	$ 3,473	1.8	1.5
Zone Heating	Wall heater 84% eff	**$0.76**	**$8.1**	$ 1,500	$ 1,725	$ 4,194	$ 1,172	0.8	0.7
Water Heating	Storage Water Heater, 50 gal., EF=.59	**$0.70**	**$7.0**	$ 440	$ 506	$ 3,357	$ 1,571	3.6	3.1
	Storage Water Heater, 50 gal., EF=.64	**$0.70**	**$7.0**	$ 460	$ 529	$ 3,357	$ 1,710	3.7	3.2
	Tankless water heater EF=0.82	**$0.70**	**$7.0**	$ 810	$ 932	$ 3,357	$ 2,072	2.6	2.2
Appliances	Gas Dryer, 6.5 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 1,339	$ 887	3.4	3.0
	Gas Dryer w/ Moisture Sens., 7.0 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 1,138	$ 754	2.9	2.5
	Standard Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 200	$ 230	$ 1,080	$ 544	2.7	2.4
	Convection Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 300	$ 345	$ 864	$ 435	1.5	1.3
Bundles									
Space + Water Heat	90 AFUE + 0.64			$ 2,060	$ 2,369	$ 12,700	$ 4,792	2.3	2.0
Space + Dryer	90 AFUE + ms			$ 1,860	$ 2,139	$ 10,482	$ 3,835	2.1	1.8
Space + Range	90 AFUE + conv			$ 1,900	$ 2,185	$ 10,208	$ 3,517	1.9	1.6
Space + H2O + Dryer	90 AFUE + 0.64 + ms			$ 2,320	$ 2,668	$ 13,838	$ 5,545	2.4	2.1
Space + H2O + Range	90 AFUE + 0.64 + conv			$ 2,360	$ 2,714	$ 13,564	$ 5,227	2.2	1.9
Space + Dryer + Range	90 AFUE + ms + conv			$ 2,160	$ 2,484	$ 11,346	$ 4,270	2.0	1.7
All	90 + 0.64 + ms + conv			$ 2,620	$ 3,013	$ 14,702	$ 5,981	2.3	2.0
H2O + Dryer	0.64 + ms			$ 720	$ 828	$ 4,495	$ 2,464	3.4	3.0
H2O + Range	0.64 + conv			$ 760	$ 874	$ 4,220	$ 2,146	2.8	2.5
H2O + Dryer + Range	0.64+ ms+ conv			$ 1,020	$ 1,173	$ 5,358	$ 2,899	2.8	2.5
Zone + water heat	84% + 0.64			$ 1,960	$ 2,254	$ 7,551	$ 2,882	1.5	1.3
zone + water + dryer	84 % + 0.64 + ms			$ 2,220	$ 2,553	$ 8,689	$ 3,636	1.6	1.4
zone + water + range	84% + 0.64 + conv			$ 2,260	$ 2,599	$ 8,414	$ 3,317	1.5	1.3
zone + water + dryer + range	84% + 0.64 + ms+ conv			$ 2,520	$ 2,898	$ 9,552	$ 4,071	1.6	1.4
w/ tankless H2O & 96 AFUE									
Space + Water Heat	96 + 0.82			$ 2,760	$ 3,174	$ 12,700	$ 5,544	2.0	1.7
Space + H2O + Dryer	96 + 0.82 + ms			$ 3,020	$ 3,473	$ 13,838	$ 6,298	2.1	1.8
Space + H2O + Range	96 + 0.82 + conv			$ 3,060	$ 3,519	$ 13,564	$ 5,980	2.0	1.7
All	96 + 0.82 + ms + conv			$ 3,320	$ 3,818	$ 14,702	$ 6,733	2.0	1.8
H2O + Dryer	0.82 + ms			$ 1,070	$ 1,231	$ 4,495	$ 2,826	2.6	2.3
H2O + Range	0.82 + conv			$ 1,110	$ 1,277	$ 4,220	$ 2,507	2.3	2.0
H2O + Dryer + Range	0.82 + ms + conv			$ 1,370	$ 1,576	$ 5,358	$ 3,261	2.4	2.1

Table C-12. Economic Screen AC: +25% Scenario Main Extension

End Use	Gas Measure	Main Extension: First Yr. Cost ($)	First Yr. Cost + Admin ($)	Elec.--Gas Benefit ($)	Benefit/ Cost	Benefit/Cost w/Admin.
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	$ 3,300	$ 3,795	$ 1,834	0.6	0.5
	Condensing Furnace, 90 AFUE	$ 3,600	$ 4,140	$ 2,531	0.7	0.6
	Condensing Furnace, 96 AFUE	$ 3,950	$ 4,543	$ 2,879	0.7	0.6
	Using 90 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,060	$ 4,669	$ 5,887	1.5	1.3
	Space + Dryer	$ 3,860	$ 4,439	$ 3,285	0.9	0.7
	Space + Range	$ 3,900	$ 4,485	$ 3,395	0.9	0.8
	Space + H2O + Dryer	$ 4,320	$ 4,968	$ 7,025	1.6	1.4
	Space + H2O + Range	$ 4,360	$ 5,014	$ 6,751	1.5	1.3
	Space + Dryer + Range	$ 4,160	$ 4,784	$ 4,532	1.1	0.9
	All	$ 4,620	$ 5,313	$ 7,889	1.7	1.5
	Using 96 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,760	$ 5,474	$ 6,236	1.3	1.1
	Space + Dryer	$ 4,210	$ 4,842	$ 4,017	1.0	0.8
	Space + Range	$ 4,250	$ 4,888	$ 3,743	0.9	0.8
	Space + H2O + Dryer	$ 5,020	$ 5,773	$ 7,374	1.5	1.3
	Space + H2O + Range	$ 4,510	$ 5,187	$ 4,881	1.1	0.9
	Space + Dryer + Range	$ 5,320	$ 6,118	$ 8,238	1.5	1.3
	All	$ 4,520	$ 5,198	$ 8,306	1.8	1.6

Table C-13. Economic Customer Count AC: +25% Scenario

End Use	% Bundle Adoption	Measures	Number of Customers: PSE Gas	Svc Line Only	Main Ext.	Total
Space Heat + Additional End Uses	5%	space heat	0	4013	0	4013
	80%	space + water	0	4013	3813	7826
	5%	space + water + dryer	0	4013	3813	7826
	5%	space + water + range	0	4013	3813	7826
	5%	All	0	4013	3813	7826
Zone Heat + Additional End Uses	5%	zone heat	0	0	0	0
	80%	zone + water	9945	0	0	9945
	5%	zone + water + dryer	9945	0	0	9945
	5%	zone + water + range	9945	0	0	9945
	5%	zone + all	9945	0	0	9945
Water Heat + Additional End Uses	3%	water + dryer	42017			42017
	3%	water + range	42017			42017
	85%	water only	42017			42017
	10%	water + dryer + range	42017			42017

Table C-14. Economic Potential AC: +25% Scenario

Measures	Number of Customers: PSE Gas	Svc Line Only	Main Ext.
space heat		201	0
space + water		3211	3050
space + water + dryer		201	191
space + water + range		201	191
All		201	191
zone heat	0		
zone + water	7956		
zone + water + dryer	497		
zone + water + range	497		
zone + all	497		
water + dryer	1050		
water + range	1050		
water only	35714		
water + dryer + range	4202		

Measures	Electric Savings (kWh/yr.): PSE Gas	Svc Line Only	Main Ext.
space heat		1,722,405	0
space + water		39,637,681	37,656,118
space + water + dryer		2,710,454	2,574,953
space + water + range		2,630,496	2,498,992
All		2,863,595	2,720,438
zone heat	0		
zone + water	64,074,367		
zone + water + dryer	4,582,241		
zone + water + range	4,384,114		
zone + all	4,961,708		
water + dryer	5,171,875		
water + range	4,753,340		
water only	134,358,972		
water + dryer + range	23,893,920		
		Total (aMW)	38.9

Measures	Gas Usage--90 AFUE Furnace, 0. 64 EF Water Heater (therms/yr.): PSE Gas	Svc Line Only	Main Ext.
space heat		112,323	0
space + water		2,402,483	2,282,378
space + water + dryer		158,583	150,655
space + water + range		158,245	150,334
All		166,673	158,340
zone heat	0		
zone + water	3,885,539		
zone + water + dryer	263,730		
zone + water + range	262,891		
zone + all	283,775		
water + dryer	242,146		
water + range	240,375		
water only	6,733,038		
water + dryer + range	1,137,960		
		Total (Dth)	1878947

Measures	Gas Usage--96 AFUE Furnace, 0.82 EF Water Heater (therms/yr.): PSE Gas	Svc Line Only	Main Ext.
space heat		105,303	0
space + water		2,157,285	2,049,438
space + water + dryer		143,258	136,096
space + water + range		142,920	135,775
All		151,348	143,782
zone heat	0		
zone + water	3,556,291		
zone + water + dryer	243,152		
zone + water + range	242,313		
zone + all	263,197		
water + dryer	198,676		
water + range	196,905		
water only	5,255,054		
water + dryer + range	964,080		
		Total (Dth):	1608487

Table C-15. Economic Screen: Green World Scenario Avoided Costs and Service Line

		NPV Avoided Cost (2008 Base Year)		Service Line Extension					
End Use	Gas Measure	Elec Avoided Cost ($/kWh)	Gas Avoided Cost ($/therm)	First Yr. Cost ($)	First Yr. Cost + Admin ($)	Elec. Benefit ($)	Elec.--Gas Benefit ($)	Benefit/Cost	Benefit/Cost w/Admin.
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	**$0.85**	**$9.0**	$ 1,300	$ 1,495	$ 8,107	$ 1,834	1.4	1.2
	Condensing Furnace, 90 AFUE	**$0.85**	**$9.0**	$ 1,600	$ 1,840	$ 8,107	$ 2,531	1.6	1.4
	Condensing Furnace, 96 AFUE	**$0.85**	**$9.0**	$ 1,950	$ 2,243	$ 8,107	$ 2,879	1.5	1.3
Zone Heating	Wall heater 84% eff	**$0.76**	**$8.1**	$ 1,500	$ 1,725	$ 3,628	$ 955	0.6	0.6
Water Heating	Storage Water Heater, 50 gal., EF=.59	**$0.70**	**$7.0**	$ 440	$ 506	$ 3,011	$ 1,383	3.1	2.7
	Storage Water Heater, 50 gal., EF=.64	**$0.70**	**$7.0**	$ 460	$ 529	$ 3,011	$ 1,510	3.3	2.9
	Tankless water heater EF=0.82	**$0.70**	**$7.0**	$ 810	$ 932	$ 3,011	$ 1,839	2.3	2.0
Appliances	Gas Dryer, 6.5 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 1,210	$ 795	3.1	2.7
	Gas Dryer w/ Moisture Sens., 7.0 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 1,028	$ 676	2.6	2.3
	Standard Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 200	$ 230	$ 983	$ 485	2.4	2.1
	Convection Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 300	$ 345	$ 787	$ 388	1.3	1.1
Bundles									
Space + Water Heat	90 AFUE + 0.64			$ 2,060	$ 2,369	$ 11,118	$ 4,041	2.0	1.7
Space + Dryer	90 AFUE + ms			$ 1,860	$ 2,139	$ 9,135	$ 3,207	1.7	1.5
Space + Range	90 AFUE + conv			$ 1,900	$ 2,185	$ 8,894	$ 2,918	1.5	1.3
Space + H2O + Dryer	90 AFUE + 0.64 + ms			$ 2,320	$ 2,668	$ 12,146	$ 4,716	2.0	1.8
Space + H2O + Range	90 AFUE + 0.64 + conv			$ 2,360	$ 2,714	$ 11,905	$ 4,428	1.9	1.6
Space + Dryer + Range	90 AFUE + ms + conv			$ 2,160	$ 2,484	$ 9,922	$ 3,594	1.7	1.4
All	90 + 0.64 + ms + conv			$ 2,620	$ 3,013	$ 12,933	$ 5,104	1.9	1.7
H2O + Dryer	0.64 + ms			$ 720	$ 828	$ 4,039	$ 2,186	3.0	2.6
H2O + Range	0.64 + conv			$ 760	$ 874	$ 3,798	$ 1,897	2.5	2.2
H2O + Dryer + Range	0.64+ ms+ conv			$ 1,020	$ 1,173	$ 4,826	$ 2,573	2.5	2.2
Zone + water heat	84% + 0.64			$ 1,960	$ 2,254	$ 6,639	$ 2,465	1.3	1.1
zone + water + dryer	84 % + 0.64 + ms			$ 2,220	$ 2,553	$ 7,668	$ 3,141	1.4	1.2
zone + water + range	84% + 0.64 + conv			$ 2,260	$ 2,599	$ 7,426	$ 2,852	1.3	1.1
zone + water + dryer + range	84% + 0.64 + ms+ conv			$ 2,520	$ 2,898	$ 8,454	$ 3,528	1.4	1.2
w/ tankless H2O & 96 AFUE									
Space + Water Heat	96 + 0.82			$ 2,760	$ 3,174	$ 11,118	$ 4,719	1.7	1.5
Space + H2O + Dryer	96 + 0.82 + ms			$ 3,020	$ 3,473	$ 12,146	$ 5,394	1.8	1.6
Space + H2O + Range	96 + 0.82 + conv			$ 3,060	$ 3,519	$ 11,905	$ 5,106	1.7	1.5
All	96 + 0.82 + ms + conv			$ 3,320	$ 3,818	$ 12,933	$ 5,782	1.7	1.5
H2O + Dryer	0.82 + ms			$ 1,070	$ 1,231	$ 4,039	$ 2,515	2.4	2.0
H2O + Range	0.82 + conv			$ 1,110	$ 1,277	$ 3,798	$ 2,227	2.0	1.7
H2O + Dryer + Range	0.82 + ms + conv			$ 1,370	$ 1,576	$ 4,826	$ 2,903	2.1	1.8

Table C-16. Economic Screen: Green World Scenario Main Extension

End Use	Gas Measure	Main Extension: First Yr. Cost ($)	First Yr. Cost + Admin ($)	Elec.--Gas Benefit ($)	Benefit/ Cost	Benefit/Cost w/Admin.
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	$ 3,300	$ 3,795	$ 1,834	0.6	0.5
	Condensing Furnace, 90 AFUE	$ 3,600	$ 4,140	$ 2,531	0.7	0.6
	Condensing Furnace, 96 AFUE	$ 3,950	$ 4,543	$ 2,879	0.7	0.6
	Using 90 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,060	$ 4,669	$ 5,542	1.4	1.2
	Space + Dryer	$ 3,860	$ 4,439	$ 3,207	0.8	0.7
	Space + Range	$ 3,900	$ 4,485	$ 3,317	0.9	0.7
	Space + H2O + Dryer	$ 4,320	$ 4,968	$ 6,570	1.5	1.3
	Space + H2O + Range	$ 4,360	$ 5,014	$ 6,328	1.5	1.3
	Space + Dryer + Range	$ 4,160	$ 4,784	$ 4,345	1.0	0.9
	All	$ 4,620	$ 5,313	$ 7,357	1.6	1.4
	Using 96 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,760	$ 5,474	$ 5,890	1.2	1.1
	Space + Dryer	$ 4,210	$ 4,842	$ 3,907	0.9	0.8
	Space + Range	$ 4,250	$ 4,888	$ 3,666	0.9	0.8
	Space + H2O + Dryer	$ 5,020	$ 5,773	$ 6,919	1.4	1.2
	Space + H2O + Range	$ 4,510	$ 5,187	$ 4,694	1.0	0.9
	Space + Dryer + Range	$ 5,320	$ 6,118	$ 7,705	1.4	1.3
	All	$ 4,520	$ 5,198	$ 7,735	1.7	1.5

Table C-17. Economic Customer Count: Green World Scenario

End Use	% Bundle Adoption	Measures	Number of Customers: PSE Gas	Svc Line Only	Main Ext.	Total
Space Heat + Additional End Uses	5%	space heat	0	4013	0	4013
	80%	space + water	0	4013	3813	7826
	5%	space + water + dryer	0	4013	3813	7826
	5%	space + water + range	0	4013	3813	7826
	5%	All	0	4013	3813	7826
Zone Heat + Additional End Uses	5%	zone heat	0	0	0	0
	80%	zone + water	9945	0	0	9945
	5%	zone + water + dryer	9945	0	0	9945
	5%	zone + water + range	9945	0	0	9945
	5%	zone + all	9945	0	0	9945
Water Heat + Additional End Uses	3%	water + dryer	42017			42017
	3%	water + range	42017			42017
	85%	water only	42017			42017
	10%	water + dryer + range	42017			42017

Table C-18. Economic Potential: Green World Scenario

	Number of Customers		
Measures	PSE Gas	Svc Line Only	Main Ext.
space heat		201	0
space + water		3211	3050
space + water + dryer		201	191
space + water + range		201	191
All		201	191
zone heat	0		
zone + water	7956		
zone + water + dryer	497		
zone + water + range	497		
zone + all	497		
water + dryer	1050		
water + range	1050		
water only	35714		
water + dryer + range	4202		

	Electric Savings (kWh/yr.)		
Measures	PSE Gas	Svc Line Only	Main Ext.
space heat		1,722,405	0
space + water		39,637,681	37,656,118
space + water + dryer		2,710,454	2,574,953
space + water + range		2,630,496	2,498,992
All		2,863,595	2,720,438
zone heat	0		
zone + water	64,074,367		
zone + water + dryer	4,582,241		
zone + water + range	4,384,114		
zone + all	4,961,708		
water + dryer	5,171,875		
water + range	4,753,340		
water only	134,358,972		
water + dryer + range	23,893,920		
		Total (aMW)	38.9

	Gas Usage--90 AFUE Furnace, 0. 64 EF Water Heater (therms/yr.)		
Measures	PSE Gas	Svc Line Only	Main Ext.
space heat		112,323	0
space + water		2,402,483	2,282,378
space + water + dryer		158,583	150,655
space + water + range		158,245	150,334
All		166,673	158,340
zone heat	0		
zone + water	3,885,539		
zone + water + dryer	263,730		
zone + water + range	262,891		
zone + all	283,775		
water + dryer	242,146		
water + range	240,375		
water only	6,733,038		
water + dryer + range	1,137,960		
		Total (Dth)	1878947

	Gas Usage--96 AFUE Furnace, 0.82 EF Water Heater (therms/yr.)		
Measures	PSE Gas	Svc Line Only	Main Ext.
space heat		105,303	0
space + water		2,157,285	2,049,438
space + water + dryer		143,258	136,096
space + water + range		142,920	135,775
All		151,348	143,782
zone heat	0		
zone + water	3,556,291		
zone + water + dryer	243,152		
zone + water + range	242,313		
zone + all	263,197		
water + dryer	198,676		
water + range	196,905		
water only	5,255,054		
water + dryer + range	964,080		
		Total (Dth):	1608487

Table C-19. Economic Screen: Low Growth Scenario Avoided Costs and Service Line

		NPV Avoided Cost (2008 Base Year)		Service Line Extension					
End Use	**Gas Measure**	**Elec Avoided Cost ($/kWh)**	**Gas Avoided Cost ($/therm)**	**First Yr. Cost ($)**	**First Yr. Cost + Admin ($)**	**Elec. Benefit ($)**	**Elec.--Gas Benefit ($)**	**Benefit/Cost**	**Benefit/Cost w/Admin.**
	Standard Furnace, 80 AFUE, 60 kBtu	**$0.85**	**$9.0**	$ 1,300	$ 1,495	$ 6,484	$ 1,590	1.2	1.1
Space Heating	Condensing Furnace, 90 AFUE	**$0.85**	**$9.0**	$ 1,600	$ 1,840	$ 6,484	$ 2,134	1.3	1.2
	Condensing Furnace, 96 AFUE	**$0.85**	**$9.0**	$ 1,950	$ 2,243	$ 6,484	$ 2,405	1.2	1.1
Zone Heating	Wall heater 84% eff	**$0.76**	**$8.1**	$ 1,500	$ 1,725	$ 2,992	$ 856	0.6	0.5
	Storage Water Heater, 50 gal., EF=.59	**$0.70**	**$7.0**	$ 440	$ 506	$ 2,392	$ 1,115	2.5	2.2
Water Heating	Storage Water Heater, 50 gal., EF=.64	**$0.70**	**$7.0**	$ 460	$ 529	$ 2,392	$ 1,215	2.6	2.3
	Tankless water heater EF=0.82	**$0.70**	**$7.0**	$ 810	$ 932	$ 2,392	$ 1,474	1.8	1.6
	Gas Dryer, 6.5 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 959	$ 637	2.5	2.1
Appliances	Gas Dryer w/ Moisture Sens., 7.0 cuft	**$0.75**	**$7.3**	$ 260	$ 299	$ 815	$ 542	2.1	1.8
	Standard Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 200	$ 230	$ 754	$ 381	1.9	1.7
	Convection Gas Range, Free-Standing, 30"	**$0.89**	**$8.5**	$ 300	$ 345	$ 603	$ 304	1.0	0.9
Bundles									
Space + Water Heat	90 AFUE + 0.64			$ 2,060	$ 2,369	$ 8,876	$ 3,349	1.6	1.4
Space + Dryer	90 AFUE + ms			$ 1,860	$ 2,139	$ 7,299	$ 2,675	1.4	1.3
Space + Range	90 AFUE + conv			$ 1,900	$ 2,185	$ 7,088	$ 2,438	1.3	1.1
Space + H2O + Dryer	90 AFUE + 0.64 + ms			$ 2,320	$ 2,668	$ 9,691	$ 3,890	1.7	1.5
Space + H2O + Range	90 AFUE + 0.64 + conv			$ 2,360	$ 2,714	$ 9,480	$ 3,653	1.5	1.3
Space + Dryer + Range	90 AFUE + ms + conv			$ 2,160	$ 2,484	$ 7,902	$ 2,980	1.4	1.2
All	90 + 0.64 + ms + conv			$ 2,620	$ 3,013	$ 10,295	$ 4,195	1.6	1.4
H2O + Dryer	0.64 + ms			$ 720	$ 828	$ 3,207	$ 1,757	2.4	2.1
H2O + Range	0.64 + conv			$ 760	$ 874	$ 2,996	$ 1,520	2.0	1.7
H2O + Dryer + Range	0.64+ ms+ conv			$ 1,020	$ 1,173	$ 3,810	$ 2,061	2.0	1.8
Zone + water heat	84% + 0.64			$ 1,960	$ 2,254	$ 5,384	$ 2,072	1.1	0.9
zone + water + dryer	84 % + 0.64 + ms			$ 2,220	$ 2,553	$ 6,199	$ 2,613	1.2	1.0
zone + water + range	84% + 0.64 + conv			$ 2,260	$ 2,599	$ 5,988	$ 2,376	1.1	0.9
zone + water + dryer + range	84% + 0.64 + ms+ conv			$ 2,520	$ 2,898	$ 6,803	$ 2,918	1.2	1.0
w/ tankless H2O & 96 AFUE									
Space + Water Heat	96 + 0.82			$ 2,760	$ 3,174	$ 8,876	$ 3,879	1.4	1.2
Space + H2O + Dryer	96 + 0.82 + ms			$ 3,020	$ 3,473	$ 9,691	$ 4,421	1.5	1.3
Space + H2O + Range	96 + 0.82 + conv			$ 3,060	$ 3,519	$ 9,480	$ 4,183	1.4	1.2
All	96 + 0.82 + ms + conv			$ 3,320	$ 3,818	$ 10,295	$ 4,725	1.4	1.2
H2O + Dryer	0.82 + ms			$ 1,070	$ 1,231	$ 3,207	$ 2,015	1.9	1.6
H2O + Range	0.82 + conv			$ 1,110	$ 1,277	$ 2,996	$ 1,778	1.6	1.4
H2O + Dryer + Range	0.82 + ms + conv			$ 1,370	$ 1,576	$ 3,810	$ 2,320	1.7	1.5

Table C-20. Economic Screen: Low Growth Scenario Main Extension

End Use	Gas Measure	Main Extension First Yr. Cost ($)	First Yr. Cost + Admin ($)	Elec.--Gas Benefit ($)	Benefit/ Cost	Benefit/Cost w/Admin.
Space Heating	Standard Furnace, 80 AFUE, 60 kBtu	$ 3,300	$ 3,795	$ 1,590	0.5	0.4
	Condensing Furnace, 90 AFUE	$ 3,600	$ 4,140	$ 2,134	0.6	0.5
	Condensing Furnace, 96 AFUE	$ 3,950	$ 4,543	$ 2,405	0.6	0.5
	Using 90 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,060	$ 4,669	$ 4,526	1.1	1.0
	Space + Dryer	$ 3,860	$ 4,439	$ 2,675	0.7	0.6
	Space + Range	$ 3,900	$ 4,485	$ 2,737	0.7	0.6
	Space + H2O + Dryer	$ 4,320	$ 4,968	$ 5,340	1.2	1.1
	Space + H2O + Range	$ 4,360	$ 5,014	$ 5,129	1.2	1.0
	Space + Dryer + Range	$ 4,160	$ 4,784	$ 3,552	0.9	0.7
	All	$ 4,620	$ 5,313	$ 5,944	1.3	1.1
	Using 96 AFUE Furnace **Bundles**					
	Space + Water Heat	$ 4,760	$ 5,474	$ 4,798	1.0	0.9
	Space + Dryer	$ 4,210	$ 4,842	$ 3,220	0.8	0.7
	Space + Range	$ 4,250	$ 4,888	$ 3,009	0.7	0.6
	Space + H2O + Dryer	$ 5,020	$ 5,773	$ 5,612	1.1	1.0
	Space + H2O + Range	$ 4,510	$ 5,187	$ 3,824	0.8	0.7
	Space + Dryer + Range	$ 5,320	$ 6,118	$ 6,216	1.2	1.0
	All	$ 4,520	$ 5,198	$ 6,239	1.4	1.2

Table C-21. Economic Customer Count: Low Growth Scenario

End Use	% Bundle Adoption	Measures	Number of Customers: PSE Gas	Svc Line Only	Main Ext.	Total
Space Heat + Additional End Uses	5%	space heat	0	4013	0	4013
	80%	space + water	0	4013	0	4013
	5%	space + water + dryer	0	4013	3813	7826
	5%	space + water + range	0	4013	3813	7826
	5%	All	0	4013	3813	7826
Zone Heat + Additional End Uses	5%	zone heat	0	0	0	0
	80%	zone + water	0	0	0	0
	5%	zone + water + dryer	9945	0	0	9945
	5%	zone + water + range	0	0	0	0
	5%	zone + all	9945	0	0	9945
Water Heat + Additional End Uses	3%	water + dryer	42017			42017
	3%	water + range	42017			42017
	85%	water only	42017			42017
	10%	water + dryer + range	42017			42017

Table C-22. Economic Potential: Low Growth Scenario

	Number of Customers		
Measures	PSE Gas	Svc Line Only	Main Ext.
space heat		201	0
space + water		3211	0
space + water + dryer		201	191
space + water + range		201	191
All		201	191
zone heat	0		
zone + water	0		
zone + water + dryer	497		
zone + water + range	0		
zone + all	497		
water + dryer	1050		
water + range	1050		
water only	35714		
water + dryer + range	4202		

	Electric Savings (kWh/yr.)		
Measures	PSE Gas	Svc Line Only	Main Ext.
space heat		1,722,405	0
space + water		39,637,681	-
space + water + dryer		2,710,454	2,574,953
space + water + range		2,630,496	2,498,992
All		2,863,595	2,720,438
zone heat	0		
zone + water	-		
zone + water + dryer	4,582,241		
zone + water + range	-		
zone + all	4,961,708		
water + dryer	5,171,875		
water + range	4,753,340		
water only	134,358,972		
water + dryer + range	23,893,920		
		Total (aMW)	26.8

	Gas Usage--90 AFUE Furnace, 0. 64 EF Water Heater (therms/yr.)		
Measures	PSE Gas	Svc Line Only	Main Ext.
space heat		112,323	0
space + water		2,402,483	-
space + water + dryer		158,583	150,655
space + water + range		158,245	150,334
All		166,673	158,340
zone heat	0		
zone + water	-		
zone + water + dryer	263,730		
zone + water + range	-		
zone + all	283,775		
water + dryer	242,146		
water + range	240,375		
water only	6,733,038		
water + dryer + range	1,137,960		
		Total (Dth)	1235866

	Gas Usage--96 AFUE Furnace, 0.82 EF Water Heater (therms/yr.)		
Measures	PSE Gas	Svc Line Only	Main Ext.
space heat		105,303	0
space + water		2,157,285	-
space + water + dryer		143,258	136,096
space + water + range		142,920	135,775
All		151,348	143,782
zone heat	0		
zone + water	-		
zone + water + dryer	243,152		
zone + water + range	-		
zone + all	263,197		
water + dryer	198,676		
water + range	196,905		
water only	5,255,054		
water + dryer + range	964,080		
		Total (Dth):	1023683

Table C-23. Achievable Potential Base Case Scenario: Gas Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
water + dryer (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	16071	25893	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	1891	3046	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	7956	179	288	398	398	398	398	398	398	398
zone + water + dryer (# cust)	497	6	9	12	12	12	12	12	12	12
zone + water + range	497	6	9	12	12	12	12	12	12	12
zone + all (# cust)	497	11	18	25	25	25	25	25	25	25
water heat elec (kWh)	1,117,872	4,471,486	9,874,532	17,327,009	24,779,487	32,231,964	39,684,441	47,136,918	54,589,395	62,041,873
dryer elec (kWh)	42,993	171,971	379,770	666,388	953,007	1,239,625	1,526,244	1,812,862	2,099,481	2,386,100
range elec (kWh)	28,245	112,981	249,500	437,802	626,105	814,407	1,002,709	1,191,011	1,379,313	1,567,615
zone heat (kWh)	13,439	53,757	118,713	208,307	297,902	387,496	477,091	566,685	656,280	745,874
total elec (kWh)	1,202,549	4,810,195	10,622,515	18,639,507	26,656,500	34,673,492	42,690,484	50,707,477	58,724,469	66,741,461
water heat gas (th)	59,562	236,285	517,847	901,850	1,281,494	1,656,781	2,027,709	2,394,279	2,756,491	3,114,345
dryer gas (th)	1,653	6,611	14,599	25,618	36,636	47,654	58,672	69,691	80,709	91,727
range gas (th)	1,586	6,346	14,013	24,589	35,165	45,741	56,317	66,893	77,469	88,045
zone gas (th)	998	3,994	8,819	15,475	22,131	28,787	35,443	42,099	48,755	55,410
total gas (th)	63,799	253,235	555,278	967,531	1,375,426	1,778,963	2,178,141	2,572,961	2,963,423	3,349,527

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
water + dryer (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	35714	35714	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	4202	4202	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	398	398	398	398	398	398	398	398	398	398
zone + water + dryer (# cust)	12	12	12	12	12	12	12	12	12	12
zone + water + range	12	12	12	12	12	12	12	12	12	12
zone + all (# cust)	25	25	25	25	25	25	25	25	25	25
water heat elec (kWh)	69,494,350	76,946,827	84,399,304	91,851,781	99,304,258	106,756,736	114,209,213	121,661,690	129,114,167	136,566,644
dryer elec (kWh)	2,672,718	2,959,337	3,245,955	3,532,574	3,819,192	4,105,811	4,392,430	4,679,048	4,965,667	5,252,285
range elec (kWh)	1,755,917	1,944,219	2,132,521	2,320,824	2,509,126	2,697,428	2,885,730	3,074,032	3,262,334	3,450,636
zone heat (kWh)	835,469	925,063	1,014,658	1,104,252	1,193,847	1,283,441	1,373,036	1,462,630	1,552,225	1,641,819
total elec (kWh)	74,758,454	82,775,446	90,792,439	98,809,431	106,826,423	114,843,416	122,860,408	130,877,400	138,894,393	146,911,385
water heat gas (th)	3,467,841	3,821,336	4,174,832	4,528,328	4,881,823	5,235,319	5,588,815	5,942,310	6,295,806	6,649,302
dryer gas (th)	102,745	113,764	124,782	135,800	146,819	157,837	168,855	179,873	190,892	201,910
range gas (th)	98,621	109,197	119,772	130,348	140,924	151,500	162,076	172,652	183,228	193,804
zone gas (th)	62,066	68,722	75,378	82,034	88,690	95,346	102,002	108,658	115,314	121,970
total gas (th)	3,731,273	4,113,019	4,494,765	4,876,510	5,258,256	5,640,002	6,021,748	6,403,494	6,785,239	7,166,985

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

Table C-24. Achievable Potential Base Case Scenario: Electric-Only Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat (# cust)	201	90	145	201	201	201	201	201	201	201
space + water	6261	2817	4539	6261	6261	6261	6261	6261	6261	6261
space + water + dryer	391	176	284	391	391	391	391	391	391	391
space + water + range	391	176	284	391	391	391	391	391	391	391
All	391	176	284	391	391	391	391	391	391	391
space heat elec (kWh)	458,601	1,834,402	4,050,971	7,108,308	10,165,645	13,222,982	16,280,319	19,337,656	22,394,993	25,452,330
water heat elec (kWh)	195,727	782,909	1,728,924	3,033,772	4,338,620	5,643,468	6,948,316	8,253,164	9,558,012	10,862,860
dryer elec (kWh)	6,361	25,445	56,192	98,601	141,010	183,419	225,828	268,237	310,646	353,055
range elec (kWh)	4,179	16,717	36,917	64,779	92,640	120,502	148,364	176,226	204,088	231,950
total electric (kWh)	664,868	2,659,474	5,873,004	10,305,460	14,737,916	19,170,372	23,602,828	28,035,284	32,467,740	36,900,195
space heat gas (th)	31,798	126,893	279,622	489,620	698,956	907,629	1,115,640	1,322,989	1,529,675	1,735,698
water heat gas (th)	10,429	41,371	90,669	157,904	224,376	290,084	355,030	419,212	482,632	545,288
dryer gas (th)	245	978	2,160	3,790	5,421	7,051	8,681	10,312	11,942	13,572
range gas (th)	235	939	2,073	3,638	5,203	6,768	8,333	9,898	11,463	13,027
total gas (th)	42,706	170,181	374,525	654,953	933,956	1,211,533	1,487,684	1,762,410	2,035,711	2,307,586

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat (# cust)	201	201	201	201	201	201	201	201	201	201
space + water	6261	6261	6261	6261	6261	6261	6261	6261	6261	6261
space + water + dryer	391	391	391	391	391	391	391	391	391	391
space + water + range	391	391	391	391	391	391	391	391	391	391
All	391	391	391	391	391	391	391	391	391	391
space heat elec (kWh)	28,509,667	31,567,004	34,624,341	37,681,678	40,739,015	43,796,352	46,853,689	49,911,026	52,968,363	56,025,700
water heat elec (kWh)	12,167,709	13,472,557	14,777,405	16,082,253	17,387,101	18,691,949	19,996,797	21,301,645	22,606,493	23,911,341
dryer elec (kWh)	395,464	437,873	480,282	522,691	565,100	607,509	649,918	692,327	734,736	777,145
range elec (kWh)	259,811	287,673	315,535	343,397	371,259	399,120	426,982	454,844	482,706	510,568
total electric (kWh)	41,332,651	45,765,107	50,197,563	54,630,019	59,062,475	63,494,931	67,927,387	72,359,843	76,792,299	81,224,754
space heat gas (th)	1,941,059	2,146,420	2,351,781	2,557,142	2,762,503	2,967,864	3,173,225	3,378,586	3,583,947	3,789,308
water heat gas (th)	607,181	669,075	730,968	792,861	854,754	916,648	978,541	1,040,434	1,102,327	1,164,221
dryer gas (th)	15,203	16,833	18,463	20,093	21,724	23,354	24,984	26,615	28,245	29,875
range gas (th)	14,592	16,157	17,722	19,287	20,852	22,416	23,981	25,546	27,111	28,676
total gas (th)	2,578,035	2,848,485	3,118,934	3,389,383	3,659,833	3,930,282	4,200,732	4,471,181	4,741,630	5,012,080

Table C-25. Achievable Potential Base Case Scenario: All Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat elec (kWh)	458,601	1,834,402	4,050,971	7,108,308	10,165,645	13,222,982	16,280,319	19,337,656	22,394,993	25,452,330
water heat elec (kWh)	1,313,599	5,254,395	11,603,456	20,360,781	29,118,107	37,875,432	46,632,757	55,390,082	64,147,408	72,904,733
dryer elec (kWh)	49,354	197,417	435,962	764,989	1,094,017	1,423,044	1,752,072	2,081,100	2,410,127	2,739,155
range elec (kWh)	32,425	129,698	286,417	502,581	718,745	934,909	1,151,073	1,367,237	1,583,401	1,799,565
zone heat (kWh)	13,439	53,757	118,713	208,307	297,902	387,496	477,091	566,685	656,280	745,874
total electric (kWh)	1,867,417	7,469,669	16,495,519	28,944,967	41,394,416	53,843,864	66,293,312	78,742,760	91,192,209	103,641,657
space heat gas (th)	31,798	126,893	279,622	489,620	698,956	907,629	1,115,640	1,322,989	1,529,675	1,735,698
water heat gas (th)	69,990	277,656	608,516	1,059,754	1,505,870	1,946,865	2,382,739	2,813,492	3,239,123	3,659,633
dryer gas (th)	1,897	7,589	16,759	29,408	42,057	54,705	67,354	80,002	92,651	105,299
range gas (th)	1,821	7,284	16,087	28,227	40,368	52,509	64,650	76,790	88,931	101,072
zone heat (th)	998	3,994	8,819	15,475	22,131	28,787	35,443	42,099	48,755	55,410
total gas (th)	106,505	423,417	929,803	1,622,484	2,309,382	2,990,495	3,665,825	4,335,372	4,999,134	5,657,113

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat elec (kWh)	28,509,667	31,567,004	34,624,341	37,681,678	40,739,015	43,796,352	46,853,689	49,911,026	52,968,363	56,025,700
water heat elec (kWh)	81,662,058	90,419,384	99,176,709	107,934,034	116,691,359	125,448,685	134,206,010	142,963,335	151,720,661	160,477,986
dryer elec (kWh)	3,068,182	3,397,210	3,726,238	4,055,265	4,384,293	4,713,320	5,042,348	5,371,376	5,700,403	6,029,431
range elec (kWh)	2,015,729	2,231,892	2,448,056	2,664,220	2,880,384	3,096,548	3,312,712	3,528,876	3,745,040	3,961,204
zone heat (kWh)	835,469	925,063	1,014,658	1,104,252	1,193,847	1,283,441	1,373,036	1,462,630	1,552,225	1,641,819
total electric (kWh)	116,091,105	128,540,553	140,990,002	153,439,450	165,888,898	178,338,347	190,787,795	203,237,243	215,686,691	228,136,140
space heat gas (th)	1,941,059	2,146,420	2,351,781	2,557,142	2,762,503	2,967,864	3,173,225	3,378,586	3,583,947	3,789,308
water heat gas (th)	4,075,022	4,490,411	4,905,800	5,321,189	5,736,578	6,151,967	6,567,356	6,982,744	7,398,133	7,813,522
dryer gas (th)	117,948	130,597	143,245	155,894	168,542	181,191	193,840	206,488	219,137	231,785
range gas (th)	113,213	125,354	137,494	149,635	161,776	173,917	186,057	198,198	210,339	222,480
zone heat (th)	62,066	68,722	75,378	82,034	88,690	95,346	102,002	108,658	115,314	121,970
total gas (th)	6,309,308	6,961,503	7,613,699	8,265,894	8,918,089	9,570,284	10,222,479	10,874,675	11,526,870	12,179,065

Table C-26. Achievable Potential Base Case Scenario: Annual Cost ($)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat	$ 105,373	$ 319,576	$ 520,443	$ 725,535	$ 733,219	$ 740,902	$ 748,586	$ 756,269	$ 763,952	$ 771,636
water heat	$ 197,975	$ 616,521	$ 1,029,687	$ 1,470,470	$ 1,520,681	$ 1,570,892	$ 1,621,103	$ 1,671,314	$ 1,721,525	$ 1,771,737
dryer	$ 13,617	$ 40,850	$ 65,813	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 15,711	$ 47,134	$ 75,938	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742
zone heat	$ 5,790	$ 17,370	$ 27,984	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599
total	$ 338,466	$ 1,041,450	$ 1,719,866	$ 2,430,123	$ 2,488,018	$ 2,545,912	$ 2,603,807	$ 2,661,701	$ 2,719,596	$ 2,777,491
Monthly cost (1000$)	$ 28.21	$ 86.79	$ 143.32	$ 202.51	$ 207.33	$ 212.16	$ 216.98	$ 221.81	$ 226.63	$ 231.46

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319
water heat	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948
dryer	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742
zone heat	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599
total	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385
Monthly cost (1000$)	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28

Table C-27. Achievable Potential Avoided Cost -10% Scenario: Gas Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
water + dryer (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	16071	25893	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	1891	3046	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water + dryer (# cust)	497	6	9	12	12	12	12	12	12	12
zone + water + range	0	0	0	0	0	0	0	0	0	0
zone + all (# cust)	497	11	18	25	25	25	25	25	25	25
water heat elec (kWh)	1,107,072	4,428,289	9,779,138	17,159,620	24,540,101	31,920,583	39,301,065	46,681,546	54,062,028	61,442,509
dryer elec (kWh)	42,993	171,971	379,770	666,388	953,007	1,239,625	1,526,244	1,812,862	2,099,481	2,386,100
range elec (kWh)	28,179	112,716	248,914	436,773	624,633	812,493	1,000,352	1,188,212	1,376,071	1,563,931
zone heat (kWh)	1,120	4,480	9,893	17,359	24,825	32,291	39,758	47,224	54,690	62,156
total elec (kWh)	1,179,364	4,717,456	10,417,714	18,280,140	26,142,566	34,004,992	41,867,418	49,729,844	57,592,270	65,454,696
water heat gas (th)	58,986	234,003	512,844	893,137	1,269,114	1,640,775	2,008,120	2,371,149	2,729,862	3,084,259
dryer gas (th)	1,653	6,611	14,599	25,618	36,636	47,654	58,672	69,691	80,709	91,727
range gas (th)	1,586	6,346	14,013	24,589	35,165	45,741	56,317	66,893	77,469	88,045
zone gas (th)	83	333	735	1,290	1,844	2,399	2,954	3,508	4,063	4,618
total gas (th)	62,309	247,292	542,191	944,633	1,342,759	1,736,569	2,126,063	2,511,241	2,892,102	3,268,648

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
water + dryer (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	35714	35714	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	4202	4202	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water + dryer (# cust)	12	12	12	12	12	12	12	12	12	12
zone + water + range	0	0	0	0	0	0	0	0	0	0
zone + all (# cust)	25	25	25	25	25	25	25	25	25	25
water heat elec (kWh)	68,822,991	76,203,472	83,583,954	90,964,436	98,344,917	105,725,399	113,105,880	120,486,362	127,866,844	135,247,325
dryer elec (kWh)	2,672,718	2,959,337	3,245,955	3,532,574	3,819,192	4,105,811	4,392,430	4,679,048	4,965,667	5,252,285
range elec (kWh)	1,751,790	1,939,650	2,127,510	2,315,369	2,503,229	2,691,088	2,878,948	3,066,807	3,254,667	3,442,527
zone heat (kWh)	69,622	77,089	84,555	92,021	99,487	106,953	114,420	121,886	129,352	136,818
total elec (kWh)	73,317,122	81,179,548	89,041,974	96,904,400	104,766,826	112,629,252	120,491,677	128,354,103	136,216,529	144,078,955
water heat gas (th)	3,434,339	3,784,420	4,134,501	4,484,581	4,834,662	5,184,742	5,534,823	5,884,904	6,234,984	6,585,065
dryer gas (th)	102,745	113,764	124,782	135,800	146,819	157,837	168,855	179,873	190,892	201,910
range gas (th)	98,621	109,197	119,772	130,348	140,924	151,500	162,076	172,652	183,228	193,804
zone gas (th)	5,172	5,727	6,282	6,836	7,391	7,945	8,500	9,055	9,609	10,164
total gas (th)	3,640,877	4,013,107	4,385,337	4,757,566	5,129,796	5,502,025	5,874,255	6,246,484	6,618,714	6,990,943

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

Table C-28. Achievable Potential Avoided Cost -10% Scenario: Electric-Only Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat (# cust)	201	90	145	201	201	201	201	201	201	201
space + water	6261	2817	4539	6261	6261	6261	6261	6261	6261	6261
space + water + dryer	391	176	284	391	391	391	391	391	391	391
space + water + range	391	176	284	391	391	391	391	391	391	391
All	391	176	284	391	391	391	391	391	391	391
space heat elec (kWh)	458,601	1,834,402	4,050,971	7,108,308	10,165,645	13,222,982	16,280,319	19,337,656	22,394,993	25,452,330
water heat elec (kWh)	195,727	782,909	1,728,924	3,033,772	4,338,620	5,643,468	6,948,316	8,253,164	9,558,012	10,862,860
dryer elec (kWh)	6,361	25,445	56,192	98,601	141,010	183,419	225,828	268,237	310,646	353,055
range elec (kWh)	4,179	16,717	36,917	64,779	92,640	120,502	148,364	176,226	204,088	231,950
total electric (kWh)	664,868	2,659,474	5,873,004	10,305,460	14,737,916	19,170,372	23,602,828	28,035,284	32,467,740	36,900,195
space heat gas (th)	31,798	126,893	279,622	489,620	698,956	907,629	1,115,640	1,322,989	1,529,675	1,735,698
water heat gas (th)	10,429	41,371	90,669	157,904	224,376	290,084	355,030	419,212	482,632	545,288
dryer gas (th)	245	978	2,160	3,790	5,421	7,051	8,681	10,312	11,942	13,572
range gas (th)	235	939	2,073	3,638	5,203	6,768	8,333	9,898	11,463	13,027
total gas (th)	42,706	170,181	374,525	654,953	933,956	1,211,533	1,487,684	1,762,410	2,035,711	2,307,586

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat (# cust)	201	201	201	201	201	201	201	201	201	201
space + water	6261	6261	6261	6261	6261	6261	6261	6261	6261	6261
space + water + dryer	391	391	391	391	391	391	391	391	391	391
space + water + range	391	391	391	391	391	391	391	391	391	391
All	391	391	391	391	391	391	391	391	391	391
space heat elec (kWh)	28,509,667	31,567,004	34,624,341	37,681,678	40,739,015	43,796,352	46,853,689	49,911,026	52,968,363	56,025,700
water heat elec (kWh)	12,167,709	13,472,557	14,777,405	16,082,253	17,387,101	18,691,949	19,996,797	21,301,645	22,606,493	23,911,341
dryer elec (kWh)	395,464	437,873	480,282	522,691	565,100	607,509	649,918	692,327	734,736	777,145
range elec (kWh)	259,811	287,673	315,535	343,397	371,259	399,120	426,982	454,844	482,706	510,568
total electric (kWh)	41,332,651	45,765,107	50,197,563	54,630,019	59,062,475	63,494,931	67,927,387	72,359,843	76,792,299	81,224,754
space heat gas (th)	1,941,059	2,146,420	2,351,781	2,557,142	2,762,503	2,967,864	3,173,225	3,378,586	3,583,947	3,789,308
water heat gas (th)	607,181	669,075	730,968	792,861	854,754	916,648	978,541	1,040,434	1,102,327	1,164,221
dryer gas (th)	15,203	16,833	18,463	20,093	21,724	23,354	24,984	26,615	28,245	29,875
range gas (th)	14,592	16,157	17,722	19,287	20,852	22,416	23,981	25,546	27,111	28,676
total gas (th)	2,578,035	2,848,485	3,118,934	3,389,383	3,659,833	3,930,282	4,200,732	4,471,181	4,741,630	5,012,080

Table C-29. Achievable Potential Avoided Cost -10% Scenario: All Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat elec (kWh)	458,601	1,834,402	4,050,971	7,108,308	10,165,645	13,222,982	16,280,319	19,337,656	22,394,993	25,452,330
water heat elec (kWh)	1,302,799	5,211,198	11,508,062	20,193,392	28,878,721	37,564,051	46,249,381	54,934,710	63,620,040	72,305,370
dryer elec (kWh)	49,354	197,417	435,962	764,989	1,094,017	1,423,044	1,752,072	2,081,100	2,410,127	2,739,155
range elec (kWh)	32,358	129,433	285,831	501,552	717,274	932,995	1,148,716	1,364,438	1,580,159	1,795,880
zone heat (kWh)	1,120	4,480	9,893	17,359	24,825	32,291	39,758	47,224	54,690	62,156
total electric (kWh)	1,844,232	7,376,929	16,290,718	28,585,600	40,880,482	53,175,364	65,470,246	77,765,128	90,060,009	102,354,891
space heat gas (th)	31,798	126,893	279,622	489,620	698,956	907,629	1,115,640	1,322,989	1,529,675	1,735,698
water heat gas (th)	69,415	275,374	603,514	1,051,041	1,493,490	1,930,860	2,363,150	2,790,361	3,212,494	3,629,547
dryer gas (th)	1,897	7,589	16,759	29,408	42,057	54,705	67,354	80,002	92,651	105,299
range gas (th)	1,821	7,284	16,087	28,227	40,368	52,509	64,650	76,790	88,931	101,072
zone heat (th)	83	333	735	1,290	1,844	2,399	2,954	3,508	4,063	4,618
total gas (th)	105,014	417,473	916,717	1,599,587	2,276,715	2,948,102	3,613,747	4,273,651	4,927,813	5,576,234

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat elec (kWh)	28,509,667	31,567,004	34,624,341	37,681,678	40,739,015	43,796,352	46,853,689	49,911,026	52,968,363	56,025,700
water heat elec (kWh)	80,990,699	89,676,029	98,361,359	107,046,689	115,732,018	124,417,348	133,102,678	141,788,007	150,473,337	159,158,667
dryer elec (kWh)	3,068,182	3,397,210	3,726,238	4,055,265	4,384,293	4,713,320	5,042,348	5,371,376	5,700,403	6,029,431
range elec (kWh)	2,011,602	2,227,323	2,443,044	2,658,766	2,874,487	3,090,209	3,305,930	3,521,651	3,737,373	3,953,094
zone heat (kWh)	69,622	77,089	84,555	92,021	99,487	106,953	114,420	121,886	129,352	136,818
total electric (kWh)	114,649,773	126,944,655	139,239,537	151,534,419	163,829,301	176,124,182	188,419,064	200,713,946	213,008,828	225,303,710
space heat gas (th)	1,941,059	2,146,420	2,351,781	2,557,142	2,762,503	2,967,864	3,173,225	3,378,586	3,583,947	3,789,308
water heat gas (th)	4,041,521	4,453,494	4,865,468	5,277,442	5,689,416	6,101,390	6,513,364	6,925,338	7,337,312	7,749,286
dryer gas (th)	117,948	130,597	143,245	155,894	168,542	181,191	193,840	206,488	219,137	231,785
range gas (th)	113,213	125,354	137,494	149,635	161,776	173,917	186,057	198,198	210,339	222,480
zone heat (th)	5,172	5,727	6,282	6,836	7,391	7,945	8,500	9,055	9,609	10,164
total gas (th)	6,218,913	6,861,592	7,504,271	8,146,949	8,789,628	9,432,307	10,074,986	10,717,665	11,360,344	12,003,023

Table C-30. Achievable Potential Avoided Cost -10% Scenario: Annual Cost ($)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat	$ 105,373	$ 319,576	$ 520,443	$ 725,535	$ 733,219	$ 740,902	$ 748,586	$ 756,269	$ 763,952	$ 771,636
water heat	$ 196,348	$ 611,453	$ 1,021,222	$ 1,458,381	$ 1,508,179	$ 1,557,977	$ 1,607,776	$ 1,657,574	$ 1,707,373	$ 1,757,171
dryer	$ 13,617	$ 40,850	$ 65,813	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 15,679	$ 47,038	$ 75,783	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528
zone heat	$ 482	$ 1,447	$ 2,332	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217
total	$ 331,499	$ 1,020,363	$ 1,685,593	$ 2,382,437	$ 2,439,919	$ 2,497,401	$ 2,554,883	$ 2,612,364	$ 2,669,846	$ 2,727,328
Monthly cost (1000$)	$ 27.62	$ 85.03	$ 140.47	$ 198.54	$ 203.33	$ 208.12	$ 212.91	$ 217.70	$ 222.49	$ 227.28

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319
water heat	$ 1,806,969	$ 1,806,969	$ 1,806,969	$ 1,806,969	$ 1,806,969	$ 1,806,969	$ 1,806,969	$ 1,806,969	$ 1,806,969	$ 1,806,969
dryer	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528
zone heat	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217
total	$ 2,784,810	$ 2,784,810	$ 2,784,810	$ 2,784,810	$ 2,784,810	$ 2,784,810	$ 2,784,810	$ 2,784,810	$ 2,784,810	$ 2,784,810
Monthly cost (1000$)	$ 232.07	$ 232.07	$ 232.07	$ 232.07	$ 232.07	$ 232.07	$ 232.07	$ 232.07	$ 232.07	$ 232.07

Table C-31. Achievable Potential Avoided Cost +25% Scenario: Gas Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
water + dryer (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	16071	25893	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	1891	3046	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	7956	179	288	398	398	398	398	398	398	398
zone + water + dryer (# cust)	497	6	9	12	12	12	12	12	12	12
zone + water + range	497	6	9	12	12	12	12	12	12	12
zone + all (# cust)	497	11	18	25	25	25	25	25	25	25
water heat elec (kWh)	1,117,872	4,471,486	9,874,532	17,327,009	24,779,487	32,231,964	39,684,441	47,136,918	54,589,395	62,041,873
dryer elec (kWh)	42,993	171,971	379,770	666,388	953,007	1,239,625	1,526,244	1,812,862	2,099,481	2,386,100
range elec (kWh)	28,245	112,981	249,500	437,802	626,105	814,407	1,002,709	1,191,011	1,379,313	1,567,615
zone heat (kWh)	13,439	53,757	118,713	208,307	297,902	387,496	477,091	566,685	656,280	745,874
total elec (kWh)	1,202,549	4,810,195	10,622,515	18,639,507	26,656,500	34,673,492	42,690,484	50,707,477	58,724,469	66,741,461
water heat gas (th)	59,562	236,285	517,847	901,850	1,281,494	1,656,781	2,027,709	2,394,279	2,756,491	3,114,345
dryer gas (th)	1,653	6,611	14,599	25,618	36,636	47,654	58,672	69,691	80,709	91,727
range gas (th)	1,586	6,346	14,013	24,589	35,165	45,741	56,317	66,893	77,469	88,045
zone gas (th)	998	3,994	8,819	15,475	22,131	28,787	35,443	42,099	48,755	55,410
total gas (th)	63,799	253,235	555,278	967,531	1,375,426	1,778,963	2,178,141	2,572,961	2,963,423	3,349,527

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
water + dryer (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	35714	35714	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	4202	4202	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	398	398	398	398	398	398	398	398	398	398
zone + water + dryer (# cust)	12	12	12	12	12	12	12	12	12	12
zone + water + range	12	12	12	12	12	12	12	12	12	12
zone + all (# cust)	25	25	25	25	25	25	25	25	25	25
water heat elec (kWh)	69,494,350	76,946,827	84,399,304	91,851,781	99,304,258	106,756,736	114,209,213	121,661,690	129,114,167	136,566,644
dryer elec (kWh)	2,672,718	2,959,337	3,245,955	3,532,574	3,819,192	4,105,811	4,392,430	4,679,048	4,965,667	5,252,285
range elec (kWh)	1,755,917	1,944,219	2,132,521	2,320,824	2,509,126	2,697,428	2,885,730	3,074,032	3,262,334	3,450,636
zone heat (kWh)	835,469	925,063	1,014,658	1,104,252	1,193,847	1,283,441	1,373,036	1,462,630	1,552,225	1,641,819
total elec (kWh)	74,758,454	82,775,446	90,792,439	98,809,431	106,826,423	114,843,416	122,860,408	130,877,400	138,894,393	146,911,385
water heat gas (th)	3,467,841	3,821,336	4,174,832	4,528,328	4,881,823	5,235,319	5,588,815	5,942,310	6,295,806	6,649,302
dryer gas (th)	102,745	113,764	124,782	135,800	146,819	157,837	168,855	179,873	190,892	201,910
range gas (th)	98,621	109,197	119,772	130,348	140,924	151,500	162,076	172,652	183,228	193,804
zone gas (th)	62,066	68,722	75,378	82,034	88,690	95,346	102,002	108,658	115,314	121,970
total gas (th)	3,731,273	4,113,019	4,494,765	4,876,510	5,258,256	5,640,002	6,021,748	6,403,494	6,785,239	7,166,985

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

Table C-32. Achievable Potential Avoided Cost +25% Scenario: Electric-Only Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat (# cust)	201	90	145	201	201	201	201	201	201	201
space + water	6261	2817	4539	6261	6261	6261	6261	6261	6261	6261
space + water + dryer	391	176	284	391	391	391	391	391	391	391
space + water + range	391	176	284	391	391	391	391	391	391	391
All	391	176	284	391	391	391	391	391	391	391
space heat elec (kWh)	458,601	1,834,402	4,050,971	7,108,308	10,165,645	13,222,982	16,280,319	19,337,656	22,394,993	25,452,330
water heat elec (kWh)	195,727	782,909	1,728,924	3,033,772	4,338,620	5,643,468	6,948,316	8,253,164	9,558,012	10,862,860
dryer elec (kWh)	6,361	25,445	56,192	98,601	141,010	183,419	225,828	268,237	310,646	353,055
range elec (kWh)	4,179	16,717	36,917	64,779	92,640	120,502	148,364	176,226	204,088	231,950
total electric (kWh)	664,868	2,659,474	5,873,004	10,305,460	14,737,916	19,170,372	23,602,828	28,035,284	32,467,740	36,900,195
space heat gas (th)	31,798	126,893	279,622	489,620	698,956	907,629	1,115,640	1,322,989	1,529,675	1,735,698
water heat gas (th)	10,429	41,371	90,669	157,904	224,376	290,084	355,030	419,212	482,632	545,288
dryer gas (th)	245	978	2,160	3,790	5,421	7,051	8,681	10,312	11,942	13,572
range gas (th)	235	939	2,073	3,638	5,203	6,768	8,333	9,898	11,463	13,027
total gas (th)	42,706	170,181	374,525	654,953	933,956	1,211,533	1,487,684	1,762,410	2,035,711	2,307,586

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat (# cust)	201	201	201	201	201	201	201	201	201	201
space + water	6261	6261	6261	6261	6261	6261	6261	6261	6261	6261
space + water + dryer	391	391	391	391	391	391	391	391	391	391
space + water + range	391	391	391	391	391	391	391	391	391	391
All	391	391	391	391	391	391	391	391	391	391
space heat elec (kWh)	28,509,667	31,567,004	34,624,341	37,681,678	40,739,015	43,796,352	46,853,689	49,911,026	52,968,363	56,025,700
water heat elec (kWh)	12,167,709	13,472,557	14,777,405	16,082,253	17,387,101	18,691,949	19,996,797	21,301,645	22,606,493	23,911,341
dryer elec (kWh)	395,464	437,873	480,282	522,691	565,100	607,509	649,918	692,327	734,736	777,145
range elec (kWh)	259,811	287,673	315,535	343,397	371,259	399,120	426,982	454,844	482,706	510,568
total electric (kWh)	41,332,651	45,765,107	50,197,563	54,630,019	59,062,475	63,494,931	67,927,387	72,359,843	76,792,299	81,224,754
space heat gas (th)	1,941,059	2,146,420	2,351,781	2,557,142	2,762,503	2,967,864	3,173,225	3,378,586	3,583,947	3,789,308
water heat gas (th)	607,181	669,075	730,968	792,861	854,754	916,648	978,541	1,040,434	1,102,327	1,164,221
dryer gas (th)	15,203	16,833	18,463	20,093	21,724	23,354	24,984	26,615	28,245	29,875
range gas (th)	14,592	16,157	17,722	19,287	20,852	22,416	23,981	25,546	27,111	28,676
total gas (th)	2,578,035	2,848,485	3,118,934	3,389,383	3,659,833	3,930,282	4,200,732	4,471,181	4,741,630	5,012,080

Table C-33. Achievable Potential Avoided Cost +25% Scenario: All Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat elec (kWh)	458,601	1,834,402	4,050,971	7,108,308	10,165,645	13,222,982	16,280,319	19,337,656	22,394,993	25,452,330
water heat elec (kWh)	1,313,599	5,254,395	11,603,456	20,360,781	29,118,107	37,875,432	46,632,757	55,390,082	64,147,408	72,904,733
dryer elec (kWh)	49,354	197,417	435,962	764,989	1,094,017	1,423,044	1,752,072	2,081,100	2,410,127	2,739,155
range elec (kWh)	32,425	129,698	286,417	502,581	718,745	934,909	1,151,073	1,367,237	1,583,401	1,799,565
zone heat (kWh)	13,439	53,757	118,713	208,307	297,902	387,496	477,091	566,685	656,280	745,874
total electric (kWh)	1,867,417	7,469,669	16,495,519	28,944,967	41,394,416	53,843,864	66,293,312	78,742,760	91,192,209	103,641,657
space heat gas (th)	31,798	126,893	279,622	489,620	698,956	907,629	1,115,640	1,322,989	1,529,675	1,735,698
water heat gas (th)	69,990	277,656	608,516	1,059,754	1,505,870	1,946,865	2,382,739	2,813,492	3,239,123	3,659,633
dryer gas (th)	1,897	7,589	16,759	29,408	42,057	54,705	67,354	80,002	92,651	105,299
range gas (th)	1,821	7,284	16,087	28,227	40,368	52,509	64,650	76,790	88,931	101,072
zone heat (th)	998	3,994	8,819	15,475	22,131	28,787	35,443	42,099	48,755	55,410
total gas (th)	106,505	423,417	929,803	1,622,484	2,309,382	2,990,495	3,665,825	4,335,372	4,999,134	5,657,113

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat elec (kWh)	28,509,667	31,567,004	34,624,341	37,681,678	40,739,015	43,796,352	46,853,689	49,911,026	52,968,363	56,025,700
water heat elec (kWh)	81,662,058	90,419,384	99,176,709	107,934,034	116,691,359	125,448,685	134,206,010	142,963,335	151,720,661	160,477,986
dryer elec (kWh)	3,068,182	3,397,210	3,726,238	4,055,265	4,384,293	4,713,320	5,042,348	5,371,376	5,700,403	6,029,431
range elec (kWh)	2,015,729	2,231,892	2,448,056	2,664,220	2,880,384	3,096,548	3,312,712	3,528,876	3,745,040	3,961,204
zone heat (kWh)	835,469	925,063	1,014,658	1,104,252	1,193,847	1,283,441	1,373,036	1,462,630	1,552,225	1,641,819
total electric (kWh)	116,091,105	128,540,553	140,990,002	153,439,450	165,888,898	178,338,347	190,787,795	203,237,243	215,686,691	228,136,140
space heat gas (th)	1,941,059	2,146,420	2,351,781	2,557,142	2,762,503	2,967,864	3,173,225	3,378,586	3,583,947	3,789,308
water heat gas (th)	4,075,022	4,490,411	4,905,800	5,321,189	5,736,578	6,151,967	6,567,356	6,982,744	7,398,133	7,813,522
dryer gas (th)	117,948	130,597	143,245	155,894	168,542	181,191	193,840	206,488	219,137	231,785
range gas (th)	113,213	125,354	137,494	149,635	161,776	173,917	186,057	198,198	210,339	222,480
zone heat (th)	62,066	68,722	75,378	82,034	88,690	95,346	102,002	108,658	115,314	121,970
total gas (th)	6,309,308	6,961,503	7,613,699	8,265,894	8,918,089	9,570,284	10,222,479	10,874,675	11,526,870	12,179,065

Table C-34. Achievable Potential Avoided Cost +25% Scenario: Annual Cost ($)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat	$ 105,373	$ 319,576	$ 520,443	$ 725,535	$ 733,219	$ 740,902	$ 748,586	$ 756,269	$ 763,952	$ 771,636
water heat	$ 197,975	$ 616,521	$ 1,029,687	$ 1,470,470	$ 1,520,681	$ 1,570,892	$ 1,621,103	$ 1,671,314	$ 1,721,525	$ 1,771,737
dryer	$ 13,617	$ 40,850	$ 65,813	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 15,711	$ 47,134	$ 75,938	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742
zone heat	$ 5,790	$ 17,370	$ 27,984	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599
total	$ 338,466	$ 1,041,450	$ 1,719,866	$ 2,430,123	$ 2,488,018	$ 2,545,912	$ 2,603,807	$ 2,661,701	$ 2,719,596	$ 2,777,491
Monthly cost (1000$)	$ 28.21	$ 86.79	$ 143.32	$ 202.51	$ 207.33	$ 212.16	$ 216.98	$ 221.81	$ 226.63	$ 231.46

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319
water heat	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948
dryer	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742
zone heat	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599
total	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385
Monthly cost (1000$)	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28

Table C-35. Achievable Potential Avoided Cost Green World Scenario: Gas Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
water + dryer (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	16071	25893	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	1891	3046	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	7956	179	288	398	398	398	398	398	398	398
zone + water + dryer (# cust)	497	6	9	12	12	12	12	12	12	12
zone + water + range	497	6	9	12	12	12	12	12	12	12
zone + all (# cust)	497	11	18	25	25	25	25	25	25	25
water heat elec (kWh)	1,117,872	4,471,486	9,874,532	17,327,009	24,779,487	32,231,964	39,684,441	47,136,918	54,589,395	62,041,873
dryer elec (kWh)	42,993	171,971	379,770	666,388	953,007	1,239,625	1,526,244	1,812,862	2,099,481	2,386,100
range elec (kWh)	28,245	112,981	249,500	437,802	626,105	814,407	1,002,709	1,191,011	1,379,313	1,567,615
zone heat (kWh)	13,439	53,757	118,713	208,307	297,902	387,496	477,091	566,685	656,280	745,874
total elec (kWh)	1,202,549	4,810,195	10,622,515	18,639,507	26,656,500	34,673,492	42,690,484	50,707,477	58,724,469	66,741,461
water heat gas (th)	59,562	236,285	517,847	901,850	1,281,494	1,656,781	2,027,709	2,394,279	2,756,491	3,114,345
dryer gas (th)	1,653	6,611	14,599	25,618	36,636	47,654	58,672	69,691	80,709	91,727
range gas (th)	1,586	6,346	14,013	24,589	35,165	45,741	56,317	66,893	77,469	88,045
zone gas (th)	998	3,994	8,819	15,475	22,131	28,787	35,443	42,099	48,755	55,410
total gas (th)	63,799	253,235	555,278	967,531	1,375,426	1,778,963	2,178,141	2,572,961	2,963,423	3,349,527

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
water + dryer (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	35714	35714	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	4202	4202	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	398	398	398	398	398	398	398	398	398	398
zone + water + dryer (# cust)	12	12	12	12	12	12	12	12	12	12
zone + water + range	12	12	12	12	12	12	12	12	12	12
zone + all (# cust)	25	25	25	25	25	25	25	25	25	25
water heat elec (kWh)	69,494,350	76,946,827	84,399,304	91,851,781	99,304,258	106,756,736	114,209,213	121,661,690	129,114,167	136,566,644
dryer elec (kWh)	2,672,718	2,959,337	3,245,955	3,532,574	3,819,192	4,105,811	4,392,430	4,679,048	4,965,667	5,252,285
range elec (kWh)	1,755,917	1,944,219	2,132,521	2,320,824	2,509,126	2,697,428	2,885,730	3,074,032	3,262,334	3,450,636
zone heat (kWh)	835,469	925,063	1,014,658	1,104,252	1,193,847	1,283,441	1,373,036	1,462,630	1,552,225	1,641,819
total elec (kWh)	74,758,454	82,775,446	90,792,439	98,809,431	106,826,423	114,843,416	122,860,408	130,877,400	138,894,393	146,911,385
water heat gas (th)	3,467,841	3,821,336	4,174,832	4,528,328	4,881,823	5,235,319	5,588,815	5,942,310	6,295,806	6,649,302
dryer gas (th)	102,745	113,764	124,782	135,800	146,819	157,837	168,855	179,873	190,892	201,910
range gas (th)	98,621	109,197	119,772	130,348	140,924	151,500	162,076	172,652	183,228	193,804
zone gas (th)	62,066	68,722	75,378	82,034	88,690	95,346	102,002	108,658	115,314	121,970
total gas (th)	3,731,273	4,113,019	4,494,765	4,876,510	5,258,256	5,640,002	6,021,748	6,403,494	6,785,239	7,166,985

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

Table C-36. Achievable Potential Avoided Cost Green World Scenario: Electric-Only Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat (# cust)	201	90	145	201	201	201	201	201	201	201
space + water	6261	2817	4539	6261	6261	6261	6261	6261	6261	6261
space + water + dryer	391	176	284	391	391	391	391	391	391	391
space + water + range	391	176	284	391	391	391	391	391	391	391
All	391	176	284	391	391	391	391	391	391	391
space heat elec (kWh)	458,601	1,834,402	4,050,971	7,108,308	10,165,645	13,222,982	16,280,319	19,337,656	22,394,993	25,452,330
water heat elec (kWh)	195,727	782,909	1,728,924	3,033,772	4,338,620	5,643,468	6,948,316	8,253,164	9,558,012	10,862,860
dryer elec (kWh)	6,361	25,445	56,192	98,601	141,010	183,419	225,828	268,237	310,646	353,055
range elec (kWh)	4,179	16,717	36,917	64,779	92,640	120,502	148,364	176,226	204,088	231,950
total electric (kWh)	664,868	2,659,474	5,873,004	10,305,460	14,737,916	19,170,372	23,602,828	28,035,284	32,467,740	36,900,195
space heat gas (th)	31,798	126,893	279,622	489,620	698,956	907,629	1,115,640	1,322,989	1,529,675	1,735,698
water heat gas (th)	10,429	41,371	90,669	157,904	224,376	290,084	355,030	419,212	482,632	545,288
dryer gas (th)	245	978	2,160	3,790	5,421	7,051	8,681	10,312	11,942	13,572
range gas (th)	235	939	2,073	3,638	5,203	6,768	8,333	9,898	11,463	13,027
total gas (th)	42,706	170,181	374,525	654,953	933,956	1,211,533	1,487,684	1,762,410	2,035,711	2,307,586

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat (# cust)	201	201	201	201	201	201	201	201	201	201
space + water	6261	6261	6261	6261	6261	6261	6261	6261	6261	6261
space + water + dryer	391	391	391	391	391	391	391	391	391	391
space + water + range	391	391	391	391	391	391	391	391	391	391
All	391	391	391	391	391	391	391	391	391	391
space heat elec (kWh)	28,509,667	31,567,004	34,624,341	37,681,678	40,739,015	43,796,352	46,853,689	49,911,026	52,968,363	56,025,700
water heat elec (kWh)	12,167,709	13,472,557	14,777,405	16,082,253	17,387,101	18,691,949	19,996,797	21,301,645	22,606,493	23,911,341
dryer elec (kWh)	395,464	437,873	480,282	522,691	565,100	607,509	649,918	692,327	734,736	777,145
range elec (kWh)	259,811	287,673	315,535	343,397	371,259	399,120	426,982	454,844	482,706	510,568
total electric (kWh)	41,332,651	45,765,107	50,197,563	54,630,019	59,062,475	63,494,931	67,927,387	72,359,843	76,792,299	81,224,754
space heat gas (th)	1,941,059	2,146,420	2,351,781	2,557,142	2,762,503	2,967,864	3,173,225	3,378,586	3,583,947	3,789,308
water heat gas (th)	607,181	669,075	730,968	792,861	854,754	916,648	978,541	1,040,434	1,102,327	1,164,221
dryer gas (th)	15,203	16,833	18,463	20,093	21,724	23,354	24,984	26,615	28,245	29,875
range gas (th)	14,592	16,157	17,722	19,287	20,852	22,416	23,981	25,546	27,111	28,676
total gas (th)	2,578,035	2,848,485	3,118,934	3,389,383	3,659,833	3,930,282	4,200,732	4,471,181	4,741,630	5,012,080

Table C-37. Achievable Potential Avoided Cost Green World Scenario: All Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat elec (kWh)	458,601	1,834,402	4,050,971	7,108,308	10,165,645	13,222,982	16,280,319	19,337,656	22,394,993	25,452,330
water heat elec (kWh)	1,313,599	5,254,395	11,603,456	20,360,781	29,118,107	37,875,432	46,632,757	55,390,082	64,147,408	72,904,733
dryer elec (kWh)	49,354	197,417	435,962	764,989	1,094,017	1,423,044	1,752,072	2,081,100	2,410,127	2,739,155
range elec (kWh)	32,425	129,698	286,417	502,581	718,745	934,909	1,151,073	1,367,237	1,583,401	1,799,565
zone heat (kWh)	13,439	53,757	118,713	208,307	297,902	387,496	477,091	566,685	656,280	745,874
total electric (kWh)	1,867,417	7,469,669	16,495,519	28,944,967	41,394,416	53,843,864	66,293,312	78,742,760	91,192,209	103,641,657
space heat gas (th)	31,798	126,893	279,622	489,620	698,956	907,629	1,115,640	1,322,989	1,529,675	1,735,698
water heat gas (th)	69,990	277,656	608,516	1,059,754	1,505,870	1,946,865	2,382,739	2,813,492	3,239,123	3,659,633
dryer gas (th)	1,897	7,589	16,759	29,408	42,057	54,705	67,354	80,002	92,651	105,299
range gas (th)	1,821	7,284	16,087	28,227	40,368	52,509	64,650	76,790	88,931	101,072
zone heat (th)	998	3,994	8,819	15,475	22,131	28,787	35,443	42,099	48,755	55,410
total gas (th)	106,505	423,417	929,803	1,622,484	2,309,382	2,990,495	3,665,825	4,335,372	4,999,134	5,657,113

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat elec (kWh)	28,509,667	31,567,004	34,624,341	37,681,678	40,739,015	43,796,352	46,853,689	49,911,026	52,968,363	56,025,700
water heat elec (kWh)	81,662,058	90,419,384	99,176,709	107,934,034	116,691,359	125,448,685	134,206,010	142,963,335	151,720,661	160,477,986
dryer elec (kWh)	3,068,182	3,397,210	3,726,238	4,055,265	4,384,293	4,713,320	5,042,348	5,371,376	5,700,403	6,029,431
range elec (kWh)	2,015,729	2,231,892	2,448,056	2,664,220	2,880,384	3,096,548	3,312,712	3,528,876	3,745,040	3,961,204
zone heat (kWh)	835,469	925,063	1,014,658	1,104,252	1,193,847	1,283,441	1,373,036	1,462,630	1,552,225	1,641,819
total electric (kWh)	116,091,105	128,540,553	140,990,002	153,439,450	165,888,898	178,338,347	190,787,795	203,237,243	215,686,691	228,136,140
space heat gas (th)	1,941,059	2,146,420	2,351,781	2,557,142	2,762,503	2,967,864	3,173,225	3,378,586	3,583,947	3,789,308
water heat gas (th)	4,075,022	4,490,411	4,905,800	5,321,189	5,736,578	6,151,967	6,567,356	6,982,744	7,398,133	7,813,522
dryer gas (th)	117,948	130,597	143,245	155,894	168,542	181,191	193,840	206,488	219,137	231,785
range gas (th)	113,213	125,354	137,494	149,635	161,776	173,917	186,057	198,198	210,339	222,480
zone heat (th)	62,066	68,722	75,378	82,034	88,690	95,346	102,002	108,658	115,314	121,970
total gas (th)	6,309,308	6,961,503	7,613,699	8,265,894	8,918,089	9,570,284	10,222,479	10,874,675	11,526,870	12,179,065

Table C-38. Achievable Potential Avoided Cost Green World Scenario: Annual Cost ($)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat	$ 105,373	$ 319,576	$ 520,443	$ 725,535	$ 733,219	$ 740,902	$ 748,586	$ 756,269	$ 763,952	$ 771,636
water heat	$ 197,975	$ 616,521	$ 1,029,687	$ 1,470,470	$ 1,520,681	$ 1,570,892	$ 1,621,103	$ 1,671,314	$ 1,721,525	$ 1,771,737
dryer	$ 13,617	$ 40,850	$ 65,813	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 15,711	$ 47,134	$ 75,938	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742
zone heat	$ 5,790	$ 17,370	$ 27,984	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599
total	$ 338,466	$ 1,041,450	$ 1,719,866	$ 2,430,123	$ 2,488,018	$ 2,545,912	$ 2,603,807	$ 2,661,701	$ 2,719,596	$ 2,777,491
Monthly cost (1000$)	$ 28.21	$ 86.79	$ 143.32	$ 202.51	$ 207.33	$ 212.16	$ 216.98	$ 221.81	$ 226.63	$ 231.46

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319	$ 779,319
water heat	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948	$ 1,821,948
dryer	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742	$ 104,742
zone heat	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599	$ 38,599
total	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385	$ 2,835,385
Monthly cost (1000$)	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28	$ 236.28

Table C-39. Achievable Potential Avoided Cost Low Growth Scenario: Gas Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
water + dryer (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	473	762	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	16071	25893	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	1891	3046	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water + dryer (# cust)	497	6	9	12	12	12	12	12	12	12
zone + water + range	0	0	0	0	0	0	0	0	0	0
zone + all (# cust)	497	11	18	25	25	25	25	25	25	25
water heat elec (kWh)	1,107,072	4,428,289	9,779,138	17,159,620	24,540,101	31,920,583	39,301,065	46,681,546	54,062,028	61,442,509
dryer elec (kWh)	42,993	171,971	379,770	666,388	953,007	1,239,625	1,526,244	1,812,862	2,099,481	2,386,100
range elec (kWh)	28,179	112,716	248,914	436,773	624,633	812,493	1,000,352	1,188,212	1,376,071	1,563,931
zone heat (kWh)	1,120	4,480	9,893	17,359	24,825	32,291	39,758	47,224	54,690	62,156
total elec (kWh)	1,179,364	4,717,456	10,417,714	18,280,140	26,142,566	34,004,992	41,867,418	49,729,844	57,592,270	65,454,696
water heat gas (th)	58,986	234,003	512,844	893,137	1,269,114	1,640,775	2,008,120	2,371,149	2,729,862	3,084,259
dryer gas (th)	1,653	6,611	14,599	25,618	36,636	47,654	58,672	69,691	80,709	91,727
range gas (th)	1,586	6,346	14,013	24,589	35,165	45,741	56,317	66,893	77,469	88,045
zone gas (th)	83	333	735	1,290	1,844	2,399	2,954	3,508	4,063	4,618
total gas (th)	62,309	247,292	542,191	944,633	1,342,759	1,736,569	2,126,063	2,511,241	2,892,102	3,268,648

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
water + dryer (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water + range (# cust)	1050	1050	1050	1050	1050	1050	1050	1050	1050	1050
water only (# cust)	35714	35714	35714	35714	35714	35714	35714	35714	35714	35714
water + dryer + range (# cust)	4202	4202	4202	4202	4202	4202	4202	4202	4202	4202
zone heat (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water (# cust)	0	0	0	0	0	0	0	0	0	0
zone + water + dryer (# cust)	12	12	12	12	12	12	12	12	12	12
zone + water + range	0	0	0	0	0	0	0	0	0	0
zone + all (# cust)	25	25	25	25	25	25	25	25	25	25
water heat elec (kWh)	68,822,991	76,203,472	83,583,954	90,964,436	98,344,917	105,725,399	113,105,880	120,486,362	127,866,844	135,247,325
dryer elec (kWh)	2,672,718	2,959,337	3,245,955	3,532,574	3,819,192	4,105,811	4,392,430	4,679,048	4,965,667	5,252,285
range elec (kWh)	1,751,790	1,939,650	2,127,510	2,315,369	2,503,229	2,691,088	2,878,948	3,066,807	3,254,667	3,442,527
zone heat (kWh)	69,622	77,089	84,555	92,021	99,487	106,953	114,420	121,886	129,352	136,818
total elec (kWh)	73,317,122	81,179,548	89,041,974	96,904,400	104,766,826	112,629,252	120,491,677	128,354,103	136,216,529	144,078,955
water heat gas (th)	3,434,339	3,784,420	4,134,501	4,484,581	4,834,662	5,184,742	5,534,823	5,884,904	6,234,984	6,585,065
dryer gas (th)	102,745	113,764	124,782	135,800	146,819	157,837	168,855	179,873	190,892	201,910
range gas (th)	98,621	109,197	119,772	130,348	140,924	151,500	162,076	172,652	183,228	193,804
zone gas (th)	5,172	5,727	6,282	6,836	7,391	7,945	8,500	9,055	9,609	10,164
total gas (th)	3,640,877	4,013,107	4,385,337	4,757,566	5,129,796	5,502,025	5,874,255	6,246,484	6,618,714	6,990,943

NOTE: Percentages of space heat adoption: (1) zone heat--10%; (2) zone + water--5%; (3) zone + water + dryer--2.5%; (4) zone + water + range--2.5%; (5) zone + all--5%.

Table C-40. Achievable Potential Avoided Cost Low Growth Scenario: Electric-Only Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat (# cust)	201	90	145	201	201	201	201	201	201	201
space + water	3211	1445	2328	3211	3211	3211	3211	3211	3211	3211
space + water + dryer	391	176	284	391	391	391	391	391	391	391
space + water + range	391	176	284	391	391	391	391	391	391	391
All	391	176	284	391	391	391	391	391	391	391
space heat elec (kWh)	275,401	1,101,602	2,432,705	4,268,709	6,104,712	7,940,716	9,776,720	11,612,724	13,448,727	15,284,731
water heat elec (kWh)	115,429	461,714	1,019,619	1,789,142	2,558,666	3,328,189	4,097,712	4,867,236	5,636,759	6,406,283
dryer elec (kWh)	6,361	25,445	56,192	98,601	141,010	183,419	225,828	268,237	310,646	353,055
range elec (kWh)	4,179	16,717	36,917	64,779	92,640	120,502	148,364	176,226	204,088	231,950
total electric (kWh)	401,370	1,605,479	3,545,432	6,221,230	8,897,028	11,572,826	14,248,624	16,924,422	19,600,220	22,276,018
space heat gas (th)	19,095	76,202	167,920	294,029	419,740	545,053	669,969	794,486	918,606	1,042,328
water heat gas (th)	6,150	24,398	53,472	93,123	132,324	171,075	209,376	247,227	284,628	321,579
dryer gas (th)	245	978	2,160	3,790	5,421	7,051	8,681	10,312	11,942	13,572
range gas (th)	235	939	2,073	3,638	5,203	6,768	8,333	9,898	11,463	13,027
total gas (th)	25,725	102,518	225,625	394,580	562,687	729,947	896,359	1,061,923	1,226,639	1,390,507

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat (# cust)	201	201	201	201	201	201	201	201	201	201
space + water	3211	3211	3211	3211	3211	3211	3211	3211	3211	3211
space + water + dryer	391	391	391	391	391	391	391	391	391	391
space + water + range	391	391	391	391	391	391	391	391	391	391
All	391	391	391	391	391	391	391	391	391	391
space heat elec (kWh)	17,120,735	18,956,738	20,792,742	22,628,746	24,464,750	26,300,753	28,136,757	29,972,761	31,808,764	33,644,768
water heat elec (kWh)	7,175,806	7,945,330	8,714,853	9,484,377	10,253,900	11,023,424	11,792,947	12,562,471	13,331,994	14,101,517
dryer elec (kWh)	395,464	437,873	480,282	522,691	565,100	607,509	649,918	692,327	734,736	777,145
range elec (kWh)	259,811	287,673	315,535	343,397	371,259	399,120	426,982	454,844	482,706	510,568
total electric (kWh)	24,951,817	27,627,615	30,303,413	32,979,211	35,655,009	38,330,807	41,006,605	43,682,403	46,358,201	49,033,999
space heat gas (th)	1,165,652	1,288,976	1,412,301	1,535,625	1,658,949	1,782,273	1,905,597	2,028,921	2,152,246	2,275,570
water heat gas (th)	358,080	394,581	431,082	467,583	504,084	540,585	577,086	613,588	650,089	686,590
dryer gas (th)	15,203	16,833	18,463	20,093	21,724	23,354	24,984	26,615	28,245	29,875
range gas (th)	14,592	16,157	17,722	19,287	20,852	22,416	23,981	25,546	27,111	28,676
total gas (th)	1,553,527	1,716,548	1,879,568	2,042,588	2,205,609	2,368,629	2,531,649	2,694,670	2,857,690	3,020,711

Table C-41. Achievable Potential Avoided Cost Low Growth Scenario: All Customers

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat elec (kWh)	275,401	1,101,602	2,432,705	4,268,709	6,104,712	7,940,716	9,776,720	11,612,724	13,448,727	15,284,731
water heat elec (kWh)	1,222,501	4,890,003	10,798,757	18,948,762	27,098,767	35,248,772	43,398,777	51,548,782	59,698,787	67,848,792
dryer elec (kWh)	49,354	197,417	435,962	764,989	1,094,017	1,423,044	1,752,072	2,081,100	2,410,127	2,739,155
range elec (kWh)	32,358	129,433	285,831	501,552	717,274	932,995	1,148,716	1,364,438	1,580,159	1,795,880
zone heat (kWh)	1,120	4,480	9,893	17,359	24,825	32,291	39,758	47,224	54,690	62,156
total electric (kWh)	1,580,734	6,322,934	13,963,147	24,501,371	35,039,595	45,577,819	56,116,043	66,654,267	77,192,490	87,730,714
space heat gas (th)	19,095	76,202	167,920	294,029	419,740	545,053	669,969	794,486	918,606	1,042,328
water heat gas (th)	65,136	258,401	566,316	986,260	1,401,438	1,811,850	2,217,496	2,618,376	3,014,490	3,405,838
dryer gas (th)	1,897	7,589	16,759	29,408	42,057	54,705	67,354	80,002	92,651	105,299
range gas (th)	1,821	7,284	16,087	28,227	40,368	52,509	64,650	76,790	88,931	101,072
zone heat (th)	83	333	735	1,290	1,844	2,399	2,954	3,508	4,063	4,618
total gas (th)	88,033	349,810	767,816	1,339,214	1,905,447	2,466,516	3,022,422	3,573,163	4,118,741	4,659,155

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat elec (kWh)	17,120,735	18,956,738	20,792,742	22,628,746	24,464,750	26,300,753	28,136,757	29,972,761	31,808,764	33,644,768
water heat elec (kWh)	75,998,797	84,148,802	92,298,807	100,448,812	108,598,817	116,748,822	124,898,828	133,048,833	141,198,838	149,348,843
dryer elec (kWh)	3,068,182	3,397,210	3,726,238	4,055,265	4,384,293	4,713,320	5,042,348	5,371,376	5,700,403	6,029,431
range elec (kWh)	2,011,602	2,227,323	2,443,044	2,658,766	2,874,487	3,090,209	3,305,930	3,521,651	3,737,373	3,953,094
zone heat (kWh)	69,622	77,089	84,555	92,021	99,487	106,953	114,420	121,886	129,352	136,818
total electric (kWh)	98,268,938	108,807,162	119,345,386	129,883,610	140,421,834	150,960,058	161,498,282	172,036,506	182,574,730	193,112,954
space heat gas (th)	1,165,652	1,288,976	1,412,301	1,535,625	1,658,949	1,782,273	1,905,597	2,028,921	2,152,246	2,275,570
water heat gas (th)	3,792,419	4,179,001	4,565,583	4,952,165	5,338,746	5,725,328	6,111,910	6,498,491	6,885,073	7,271,655
dryer gas (th)	117,948	130,597	143,245	155,894	168,542	181,191	193,840	206,488	219,137	231,785
range gas (th)	113,213	125,354	137,494	149,635	161,776	173,917	186,057	198,198	210,339	222,480
zone heat (th)	5,172	5,727	6,282	6,836	7,391	7,945	8,500	9,055	9,609	10,164
total gas (th)	5,194,405	5,729,655	6,264,904	6,800,154	7,335,404	7,870,654	8,405,904	8,941,154	9,476,404	10,011,654

Table C-42. Achievable Potential Avoided Cost Low Growth Scenario: Annual Cost ($)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
space heat	$ 63,279	$ 191,913	$ 312,538	$ 435,701	$ 440,315	$ 444,929	$ 449,543	$ 454,158	$ 458,772	$ 463,386
water heat	$ 184,246	$ 573,766	$ 958,279	$ 1,368,493	$ 1,415,222	$ 1,461,951	$ 1,508,680	$ 1,555,409	$ 1,602,138	$ 1,648,867
dryer	$ 13,617	$ 40,850	$ 65,813	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 15,679	$ 47,038	$ 75,783	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528
zone heat	$ 482	$ 1,447	$ 2,332	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217
total	$ 277,303	$ 855,013	$ 1,414,745	$ 2,002,715	$ 2,054,058	$ 2,105,401	$ 2,156,744	$ 2,208,088	$ 2,259,431	$ 2,310,774
Monthly cost (1000$)	$ 23.11	$ 71.25	$ 117.90	$ 166.89	$ 171.17	$ 175.45	$ 179.73	$ 184.01	$ 188.29	$ 192.56

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
space heat	$ 468,000	$ 468,000	$ 468,000	$ 468,000	$ 468,000	$ 468,000	$ 468,000	$ 468,000	$ 468,000	$ 468,000
water heat	$ 1,695,596	$ 1,695,596	$ 1,695,596	$ 1,695,596	$ 1,695,596	$ 1,695,596	$ 1,695,596	$ 1,695,596	$ 1,695,596	$ 1,695,596
dryer	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777	$ 90,777
range	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528	$ 104,528
zone heat	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217	$ 3,217
total	$ 2,362,117	$ 2,362,117	$ 2,362,117	$ 2,362,117	$ 2,362,117	$ 2,362,117	$ 2,362,117	$ 2,362,117	$ 2,362,117	$ 2,362,117
Monthly cost (1000$)	$ 196.84	$ 196.84	$ 196.84	$ 196.84	$ 196.84	$ 196.84	$ 196.84	$ 196.84	$ 196.84	$ 196.84

Sources

(Note: all costs are installed costs; all administrative costs are 15%)

Furnace	www.indoorclimate.com
Electric Furnace:	UBHA-14J11NF 10kW
Gas Furnace: 80 AFUE	UGPK07EAUER max 75k BTU
Gas Furnace: 90 AFUE	UGRA06EAME 60k BTU
Gas Furnace: 96 AFUE	incremental cost over AFUE 90 from EE measure list
$700 for piping the gas line : PSE Website	

Clothes Dryer	www.sears.com
Electric:	Whirlpool WED5320SQ
Gas:	Whirlpool WGD5320SQ
Electric w/ Moisture Sensor:	Whirlpool WED5820SW
Gas w/ Moisture Sensor:	Whirlpool WGD5820SW

Range	www.sears.com
30" Standard Electric:	Kenmore 71054
30" Standard Gas Range:	Kenmore 91064
30" Convection Electric Range	GE JBP84KKCC
30" Gas Convection Range:	Maytag MGR5875QDW

Water Heater	www.sears.com
Electric	Kenmore 32656
EF=0.59	Kenmore 33976
EF=0.63	Kenmore 33154
Tankless	http://www.tanklesswaterheaters.com/

Gas And Electric Rates	
Electric Rate:	http://www.pse.com/InsidePSE/ratesDocs/summ_elec_prices_2006_10_01.pdf
Gas Rate:	http://www.pse.com/InsidePSE/ratesDocs/summ_gas_prices_2006_10_01.pdf

UECs for electric dryer/cooking:	PSE gas tarrif information
UECs for space/water heating:	EndUse Forecaster Model

Appendix D: Demand Response: Methodology, Inputs and Assumptions

Data Sources

This study required compilation of a large and complex 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 forecasts and usage data available from PSE. For other data, the most recent regional data were used. Specific data elements and their respective sources are listed in Table D–1.

Table D–1. Data Sources

Data	Sources
Hourly System Load Profile	• PSE 2005 hourly profile
End-Use Shares and Load Shapes	• Calibrated ForecastPro end-use percentages • Northwest Conservation and Planning Council & ELCAP load shapes (1999)
End-Use and Appliance Saturations	• PSE Residential Appliance Saturation Surveys (RASS) • Commercial Building Stock Assessment • Northwest Energy Efficiency Alliance, 2002
Demand Response Impact Estimates	• PSE Experience • California Energy Commission • Edison Electric Institute (EEI) • Peak Load Management Alliance (PLMA) • Various RTO and utility reports
Costs	• PSE Experience • California Energy Commission • Various utility reports

Load Analysis

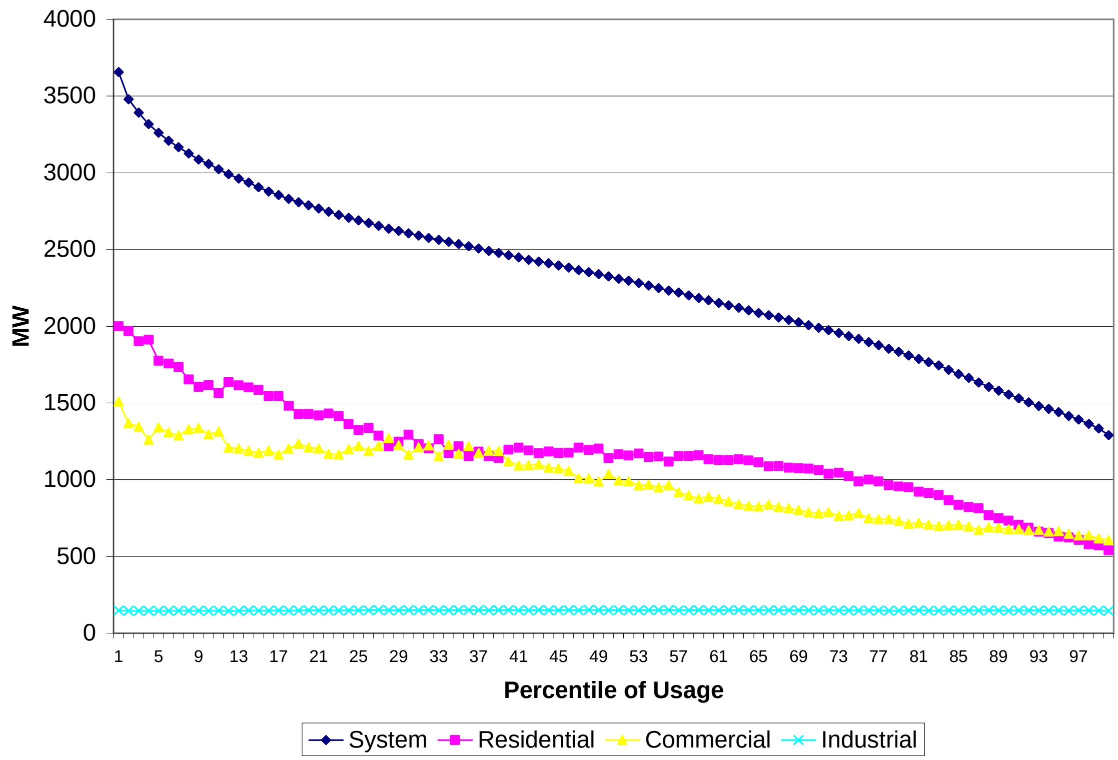
To estimate the quantity of potential available for demand-responsive resources, the first step was to conduct a thorough analysis of system loads, breaking them down into customer class (or sector), market segments, and finally, end-use loads. Using hourly (8760) load profiles, the data could be summarized to estimate average loads during likely curtailment periods.

The first step of this process was to define customer sectors, market segments, and applicable end uses, similarly to the energy-efficiency study. System loads were disaggregated into three sectors: (1) residential, (2) commercial, and (3) industrial. The commercial sector was further broken down into eleven segments consisting of the following:

Education	Food Stores
Hospitals	Hotels/Motels
Other Health	Miscellaneous
Offices	Public Assembly
Restaurants	Retail
Warehouses	

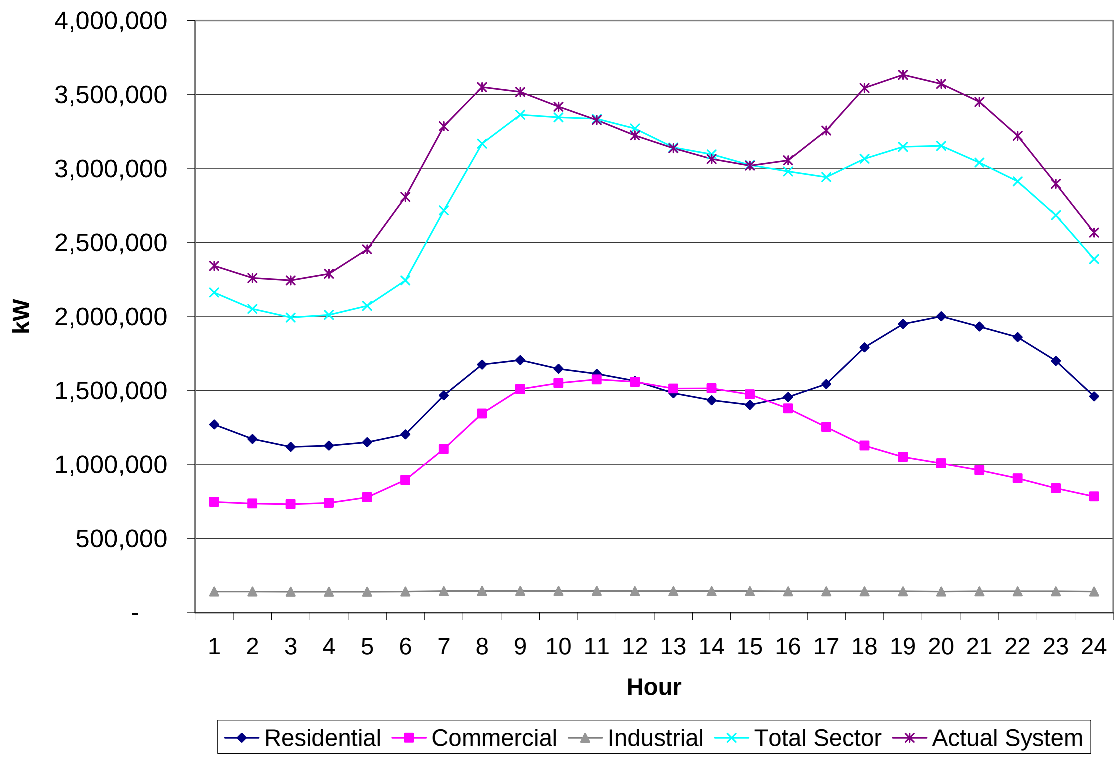
Using the system hourly shape for 2005, Figure D–1 displays the load duration curve representing the average demand (MW) during each percentile of hours in the year. The top 87 (top 1%) hours for the system have an average demand of 3650 MW, of which 2000 is residential load, 1500 is commercial load and 150 is industrial load. The various sectors were calculated using total energy sales by sector, and sector hourly load profiles.

Figure D–1. Load Duration Curve (Average 2005 MW by Percentile of Usage)



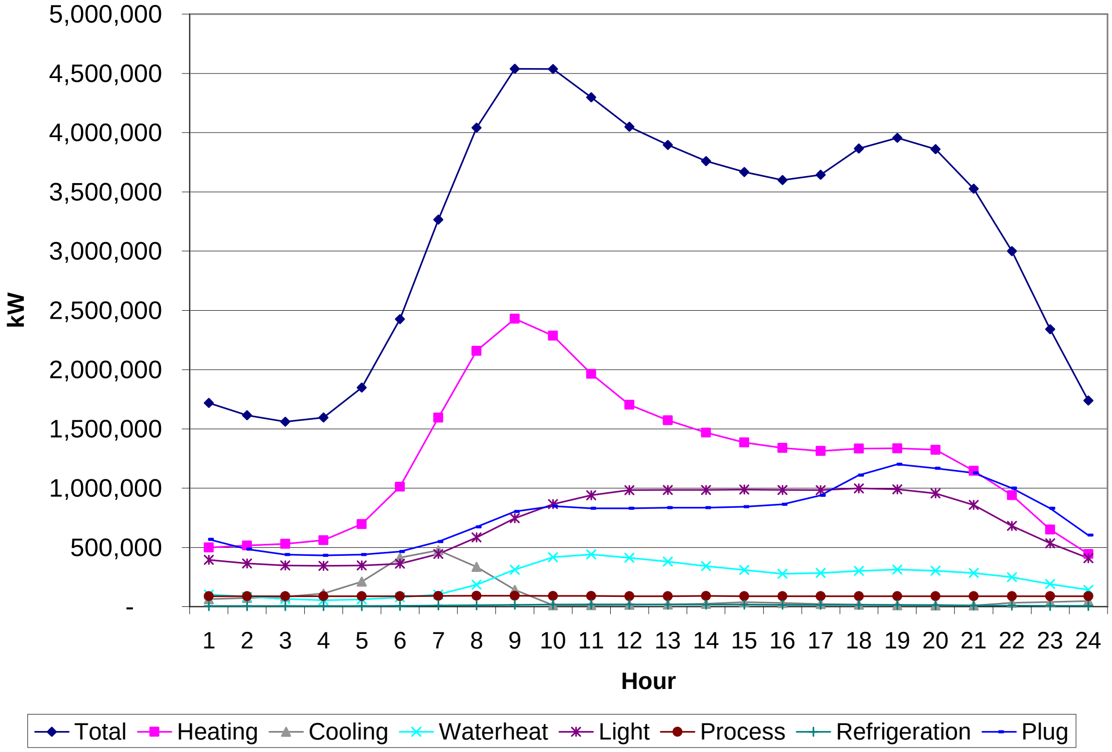
Because PSE is a winter-peaking utility, the winter period is most important for demand response, as curtailments will primarily happen during on-peak weekday periods. Figure D–2 shows the load, for each hour on the average winter weekday, for each sector. The small difference between the “Total Sector” line (which represents the sum of the sectors) and the “Actual System” is primarily a function of differences in the hourly sector shapes, which came from secondary data.

Figure D–2. Average Winter Weekdays—All Sectors



These sector-level analyses were then broken down into the various end uses using end-use saturation data from PSE surveys and base-case energy-efficiency potential results of the portion of energy sales by end use. Figure D–3 shows the end-use breakdown (across all sectors).

Figure D–3. Average Winter Weekdays—All End Uses



Finally, the analyses shown above produce the end-use and sector-specific loads for the most likely curtailment periods. For all program strategies, the top 87 hours of winter are used (which correspond with the top 1% of the load duration curve), except for demand buyback, which would be offered more frequently, and therefore corresponds with the top 175 hours of winter. The following table provides the total sector results for the top 87 and 175 hours of winter, including 6.7% line losses.

Table D–2. Top Hours of Winter, by Sector

Sector	Top 87 Winter	Top 175 Winter
Residential	2,131,404	2,105,573
Education	319,147	293,245
Food Stores	18,217	18,050
Hospitals	21,711	21,353
Hotels/Motels	67,001	66,001
Other Health	14,692	14,238
Misc	479,870	459,245
Offices	297,931	286,027
Assembly	34,580	33,130
Restaurants	22,723	22,105
Retail	197,445	193,461
Warehouses	135,299	129,985
Industrial	156,297	155,865

Methodology for Estimating Technical Potential

For demand response generically, it may be technically feasible to shed all load during a demand-response event, but potential would then equal system load, which is not useful for planning purposes, and not possible for any single DRR strategy. Therefore, technical potential for a DRR strategy adjusts total load to account for those sectors and segments that are eligible for participation, and the applicability and technical constraints of specific end uses. Technical potential is first estimated for the base year, then increased annually to 2027 by the annual peak forecast.

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

$$TP_s = \sum TP_{sce} \qquad (1)$$

and

$$TP_{sce} = LE_{cs} \times LI_{se} \qquad (2)$$

where

LE_{cs} (load applicability) represents the percent of customer class loads that are applicable for strategy (*s*), and

LI_{se} (load impact) is the percentage reduction in end-use load (*e*) resulting from strategy (*s*).

Load applicability (LE_{cs}) thresholds are established by calculating the percent of load by customer sector and market segment that meet load criteria for each strategy. Table D–3 outlines the portion of load that is applicable for program strategies, using secondary data from regional sources.

Table D–3. Sector Applicability, by Program

Program Name/Sector	DLC - Water Heating	DLC - Space Heating	DLC - Large C&I	Demand Buyback	Curtailable Rates	Critical Peak Pricing	Standby Generation
Residential	100%	100%	-	-	-	100%	-
Education	-	-	19%	50%	50%	2%	-
Food Stores	-	-	27%	70%	70%	5%	-
Hospitals	-	-	-	-	-	-	-
Hotels/Motels	-	-	5%	12%	12%	19%	-
Other Health	-	-	23%	60%	60%	-	-
Miscellaneous	-	-	-	-	-	-	100%
Offices	-	-	19%	50%	50%	10%	-
Assembly	-	-	8%	20%	20%	-	-
Restaurants	-	-	-	-	-	-	-
Retail	-	-	-	-	-	-	-
Warehouses	-	-	15%	40%	40%	-	-
Industrial	-	-	30%	80%	80%	-	-
Eligibility	Residential	Large C&I - >250 kW with EMS	Large C&I - >250 kW with EMS	Large C&I - >250 kW	Large C&I - >250 kW	Residential and some small commercial sectors	Non-targeted sectors

Estimates of maximum load impacts (i.e., percentage reduction of end use or total load) resulting from various demand response strategies (LI_{se}), are derived from the commercial and industrial Enhanced Automation Study sponsored by the California Energy Commission, studies by Lawrence Berkeley National Laboratories (e.g., Goldman, 2004), and the experiences of PSE and other utilities with similar DR programs. Table D–4 outlines these inputs and assumptions. The final row provides the technical assumptions.

Table D–4. Technical Load Impacts (Percentage Reduction)

Program Name/Sector	DLC - Water Heating	DLC - Space Heating	DLC - Large C&I	Demand Buyback	Curtailable Rates	Critical Peak Pricing	Standby Generation
End Use	Hot Water	Space Heating	All End Uses	All End Uses	All End Uses	All End Uses	All End Uses
Residential	90%	12%	-	-	-	10%	-
Education	-	-	22%	22%	22%	10%	-
Food Stores	-	-	20%	20%	20%	10%	-
Hospitals	-	-	-	-	-	-	-
Hotels/Motels	-	-	20%	20%	20%	10%	-
Other Health	-	-	8%	8%	8%	-	-
Misc	-	-	-	-	-	-	11%
Offices	-	-	32%	32%	32%	10%	-
Assembly	-	-	20%	20%	20%	-	-
Restaurants	-	-	-	-	-	-	-
Retail	-	-	-	-	-	-	-
Warehouses	-	-	30%	30%	30%	-	-
Industrial	-	-	30%	30%	30%	10%	-
Technical Assumptions	90% technical ability.	90% technical ability, 50% cycling; 27% of electric heating load is central heat and heat pumps.	Total curtailable load based on Goldman (2004)–National Trends, by sector. If not mentioned, unclassified was used.			10% from flat CPP program (2003 Statewide Pricing Pilot by Charles River Associates–Zone 2 Inland).	Corresponds with technical potential similar to Portland General Electric territory.

Methodology for Estimating Achievable Potential

Achievable potential is the subset of technical potential that may reasonably be implemented, taking into account the customers' ability and willingness to participate in load reduction programs, subject to their price/value considerations, unique (business) priorities, and operating requirements. Market levels of potential are derived by adjusting technical potentials by two factors: expected rates of *program* (sign-up) and *event* participation. Assumed rates of program and event participation were estimated based on the recent experiences of PSE, other utilities in the Northwest, other national utilities, and Regional Transmission Organizations (RTOs) which have offered similar programs.

Achievable potential (A*P*) is calculated as the product of technical potential, sector program participation (sign-up) rates (PP_c), and expected event participation (EP_c) rates thus:

$$AP_s = TP_{sc} \times PP_c \times EP_c \tag{3}$$

Rates of program sign-up and event participation were estimated using the experience of regional and national programs and that of PSE, and shown in Table D–5.

Table D–5. Program Sign-up and Event Participation

	DLC - Water Heating	DLC - Space Heating	DLC - Large C&I	Demand Buyback	Curtailable Rates	Critical Peak Pricing	Standby Generation
Program Participation	10%	10%	8%	25%	15%	5%	50%
Event Participation	90%	90%	90%	12%	90%	90%	90%
NOTES	Residential only; 10% Program participation based on FPL On Call program, and Mid American and Duke. Event participation assumed to be less than all– i.e., 90%.		PSE 03 Sectors >250kW and only 38% with EMS systems (CBSA 05); Participation: Florida Power and Light C&I On Call has less than 1% of all customers. Because our figures already account for those not eligible, we have assumed a 7.5% base; event participation is assumed to be less than all– i.e., 90%.	IEA DSM 2006 provides a low of 4% participation; Goldman 2002– average portion of customers enrolled in DR programs is 30%; we use a medium-high figure. Event participation is based on 2001-2002 PSE program experience.	National participation ranges from slightly greater than 0% (ISO NE) of customers to 30% (NYISO 29%, Duke 14%). We used the midpoint. Duke: 90%+ compliance; CEC: 90+% compliance.	Program participation: current programs in the nation have very low participation– the base is 5%. (We reviewed seven programs with the range having a maximum of 3%.) Event participation is assumed to be less than all– i.e., 90%.	Portland General Electric includes the ability to dispatch as required in contract. Currently, the focus is on new equipment installations, rather than retrofit, due to the additional cost.

Methodology for Estimating Per-unit Costs

Demand response strategies vary significantly with respect to both type and level of costs. Applicable resource acquisition costs for DR generally fall into two categories: (1) fixed program expenses such as infrastructure, administration, maintenance and data acquisition; and (2) variable costs. Further, variable costs also fall into two categories: costs that vary by the number of customers (e.g., hardware costs) and those that vary by kW reduction (primarily incentives).

In developing estimates of per-unit costs, all program costs were first allocated annually over the expected program life cycle (20 years), and then discounted by a real cost of capital at 5.8% to estimate the per-kilowatt levelized costs for each resource (based on achievable potential). Additionally, attrition rates were used to account for program turnover (15% for residential DLC and CPP programs and 10% for C&I DLC and Curtailment).[3] Table D–6 outlines the development (up-front investment) and annual costs for the three categories of cost inputs: per-kW, per-customer, and program administration.

[3] Attrition rate of 10% approximates a 10-year program life and 15% approximates a 7-year life, which roughly corresponds to the average rate of housing turnover.

Table D–6. Cost Inputs

Frequency	DLC - Water Heating	DLC - Space Heating	DLC - Large C&I	Demand Buyback	Curtailable Rates	Critical Peak Pricing	Standby Generation
Variable Costs – Per Customer							
Development	$300	$300	-	-	$1,200	-	-
Annual	$35	$35	-	-	-	$57	-
Variable Costs – Per kW							
Development	-	-	-	-	-	-	$175
Annual	-	-	$95	$20	$48	-	$13
Fixed Program Expenses							
Development	$300,000	$300,000	$100,000	$300,000	$300,000	$492,000	$300,000
Annual	$50,000	$50,000	$50,000	$100,000	$100,000	$100,000	$100,000
COST NOTES	• Variable costs per customer include $300 in DLC equipment and $35 per year, which includes incentives and communications. • Fixed program expenses assume $300,000 in billing system set-up, marketing and internal administration, with $50,000 each year in administration (equal to 0.5 FTE).	• Variable costs per customer include $300 in DLC equipment and $35 per year, which includes incentives and communications. • Fixed program expenses assume $300,000 in billing system set-up, marketing and internal administration, with $50,000 each year in administration (equal to 0.5 FTE).	• Costs based on EnerNOC Bid of $95/kW for annual costs. • Assumes reduced start-up costs due to external contractor costs included in EnerNOC bid.	• Assumes no required hardware and incentives paid on a per event/per MWh basis, based on costs from 2001-2002 program experience ($16K of incentives between 2001 and 2003, with an average reduction of 840kW). • Fixed program expenses assume $300,000 in billing system set-up, marketing and internal administration, with $50,000 each year in administration (equal to 0.5 FTE).	• Development: Per Customer of $500 for marketing and $700 for equipment and installation. • Incentive of $48 ($4/kWMonth: PG&E pays $3-$7/kWMonth, SCE pays $7/kWMonth, Wisconsin pays $3.3/kWMonth, Mid-American pays $3.3, Duke pays $3.5/kW-Month). • Fixed program expenses assume $300,000 in billing system set-up, marketing and internal administration, with $50,000 each year in administration (equal to 0.5 FTE)	• Annual customer costs include $12 for meter reading, $42 in hourly load profiles, $2.5 in PAR3 Messaging. • Program costs are based on PSE CPP Pilot Attachment A - June 2006. • Development costs include $25K for fixed MCC costs, $200K for billing system, $75K for meter data warehouse, $192K for recruiting (excludes $66K for evaluation). • Annual costs of $100K for marketing (actual was $112).	• Installation costs of $175 per kW and O&M of $5/kW from PGE Standby Generation program. • Annual per kW costs also include $8/kW in fuel assuming 100 hours/year, 20 gallons per hour of fuel for 500 kW unit, $2/gallon fuel. • Fixed program expenses assume $300,000 in billing system set-up, marketing and internal administration, with $50,000 each year in administration (equal to 0.5 FTE).

20-year Results

Finally, a ramping assumption was created to account for the increasing acceptance by customers and increased expertise of PSE with DR programs; 5% of base-year potential would be achieved in 2008, 15% in 2009, 35% in 2010, 65% in 2011 and 100% by 2012. The peak capacity forecast was used to increase potential for all subsequent years.

Table D–7. Achievable Potential, kW

kW	DLC - Water Heating	DLC - Space Heating	DLC - Large C&I	Demand Buyback	Curtailable Rates	Critical Peak Pricing	Standby Generation
1	1,336	388	183	206	964	490	1,200
2	4,062	1,180	557	626	2,931	1,492	3,648
3	9,597	2,789	1,316	1,478	6,924	3,524	8,619
4	18,045	5,243	2,474	2,779	13,019	6,626	16,205
5	28,133	8,174	3,857	4,333	20,298	10,331	25,266
6	28,549	8,295	3,914	4,397	20,598	10,483	25,639
7	29,038	8,437	3,981	4,472	20,951	10,663	26,078
8	29,600	8,601	4,058	4,559	21,356	10,869	26,583
9	30,154	8,762	4,134	4,644	21,755	11,073	27,080
10	30,691	8,918	4,207	4,727	22,143	11,270	27,563
11	31,214	9,070	4,279	4,807	22,520	11,462	28,032
12	31,730	9,220	4,350	4,887	22,893	11,652	28,496
13	32,264	9,375	4,423	4,969	23,278	11,848	28,975
14	32,810	9,533	4,498	5,053	23,672	12,048	29,466
15	33,378	9,698	4,575	5,141	24,082	12,257	29,976
16	33,985	9,875	4,659	5,234	24,520	12,480	30,521
17	34,612	10,057	4,745	5,331	24,972	12,710	31,084
18	35,248	10,242	4,832	5,429	25,431	12,944	31,656
19	35,896	10,430	4,921	5,529	25,898	13,181	32,237
20	36,549	10,620	5,010	5,629	26,370	13,421	32,824

Appendix E: Distributed Generation: Inputs and Assumptions

Appendix E follows.

Table E-1. Distributed Generation Base Case Scenario: CHP (Natural Gas)

	% Penetration (by MW)				2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CHP (Natural gas)	Res	Com	Ind											Levelized Cost
Recip Engine	0%	65%	35%											
				MW	0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
				aMW	0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
				Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
				O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
				Fuel ($/kW)	$ 312	$ 301	$ 292	$ 277	$ 285	$ 287	$ 289	$ 292	$ 296	$ 309
				Lump sum ($)	$ 106,249	$ 237,544	$ 567,394	$ 1,092,595	$ 2,191,755	$ 3,294,699	$ 3,905,981	$ 4,525,960	$ 5,162,231	$ 5,908,582
Microturbine	0%	65%	35%											
				MW	0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
				aMW	0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
				Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
				O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
				Fuel ($/kW)	$ 487	$ 469	$ 455	$ 432	$ 444	$ 447	$ 451	$ 455	$ 461	$ 482
				Lump sum ($)	$ 31,043	$ 69,114	$ 164,857	$ 316,715	$ 635,300	$ 952,684	$ 1,124,904	$ 1,299,789	$ 1,479,666	$ 1,693,277
Fuel Cell	0%	65%	35%											
				MW	0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
				aMW	0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
				Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
				O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
				Fuel ($/kW)	$ 380	$ 366	$ 355	$ 338	$ 347	$ 349	$ 352	$ 356	$ 360	$ 377
				Lump sum ($)	$ 38,798	$ 79,792	$ 187,234	$ 350,758	$ 692,721	$ 976,247	$ 1,030,547	$ 1,085,844	$ 1,143,010	$ 1,212,802

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	.		
CHP (Natural gas)												Gen SS Resource	$0.10	$/kWh
Recip Engine														
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01			
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%	
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087			
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345			
	Fuel ($/kW)	$ 313	$ 324	$ 336	$ 339	$ 349	$ 358	$ 368	$ 378	$ 386	$ 394			
	Lump sum ($)	$ 6,580,051	$ 7,363,294	$ 8,198,835	$ 8,922,516	$ 9,764,658	$ 10,274,939	$ 10,712,607	$ 10,699,778	$ 11,183,057	$ 11,681,788	Levelized Cost	$0.08	$/kWh
Microturbine														
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32			
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%	
	Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634			
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135			
	Fuel ($/kW)	$ 488	$ 505	$ 524	$ 529	$ 544	$ 558	$ 574	$ 589	$ 601	$ 614			
	Lump sum ($)	$ 1,883,941	$ 2,108,857	$ 2,349,800	$ 2,556,464	$ 2,799,429	$ 2,969,080	$ 3,118,636	$ 3,176,230	$ 3,411,163	$ 3,751,916	Levelized Cost	$0.11	$/kWh
Fuel Cell														
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07			
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%	
	Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314			
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403			
	Fuel ($/kW)	$ 381	$ 394	$ 410	$ 413	$ 425	$ 436	$ 448	$ 460	$ 470	$ 479			
	Lump sum ($)	$ 1,310,352	$ 1,420,722	$ 1,597,668	$ 1,810,243	$ 2,193,905	$ 2,378,106	$ 2,326,048	$ 2,135,871	$ 2,184,527	$ 2,234,955	Levelized Cost	$0.20	$/kWh

NOTES: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%

Table E-2. Distributed Generation Base Case Scenario: Renewables

Renewable		% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Small Wind	30%	70%	0%											
					MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
					aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
					Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
					O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
					Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
	PV	50%	50%	0%											
					MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
					aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
					Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
					O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
					Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass															
	Industrial	0%	0%	100%											
					MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
					aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
					Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
					O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
					Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
	Anaerobic Digester	0%	100%	0%											
					MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
					aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
					Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
					O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
					Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

Renewable			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost	
	Small Wind													
		MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26		
		aMW	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	Capacity Factor	15%
		Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598		
		O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600		
		Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.32 $/kWh
	PV													
		MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61		
		aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%
		Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700		
		O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800		
		Lump sum ($)	$ 319,554	$ 320,270	$ 320,987	$ 321,703	$ 322,419	$ 278,143	$ 233,764	$ 144,290	$ 144,597	$ 144,904	Levelized Cost	$1.03 $/kWh
Biomass														
	Industrial													
		MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67		
		aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%
		Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600		
		O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600		
		Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04 $/kWh
	Anaerobic Digester													
		MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57		
		aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%
		Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906		
		O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013		
		Lump sum ($)	$ 2,655,332	$ 2,706,223	$ 2,757,115	$ 2,808,006	$ 2,858,897	$ 2,674,790	$ 2,483,413	$ 2,114,833	$ 2,527,034	$ 3,362,160	Levelized Cost	$0.10 $/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation Base Case Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	1.0	2.1	4.2	7.2	10.1	13.1	16.1	19.0
aMW	0.1	0.3	0.8	1.8	3.6	6.1	8.6	11.2	13.7	16.2
Total Cost	$ 277,140	$ 585,748	$ 1,384,151	$ 2,622,883	$ 5,201,787	$ 7,496,205	$ 8,257,319	$ 9,027,130	$ 9,813,232	$ 10,709,415
Fuel ($/MMBTU)	$ 7.87	$ 7.59	$ 7.36	$ 7.00	$ 7.18	$ 7.24	$ 7.30	$ 7.37	$ 7.46	$ 7.80

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	22.0	24.9	27.9	30.8	33.8	36.3	38.4	39.7	41.0	42.2
aMW	18.7	21.2	23.8	26.3	28.8	31.0	32.8	33.8	34.9	36.0
Total Cost	$ 11,530,715	$ 12,463,790	$ 13,449,163	$ 14,322,675	$ 15,314,648	$ 15,502,722	$ 15,596,778	$ 14,811,957	$ 15,749,841	$ 17,126,101
Fuel ($/MMBTU)	$ 7.89	$ 8.17	$ 8.49	$ 8.56	$ 8.80	$ 9.04	$ 9.28	$ 9.53	$ 9.73	$ 9.93

Table E-3. Distributed Generation + Emerging Technologies Base Case Scenario: CHP (Natural Gas)

CHP (Natural gas)	% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Recip Engine	5%	63%	32%											
				MW	0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
				aMW	0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
				Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
				O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
				Fuel ($/kW)	$ 312	$ 301	$ 292	$ 277	$ 285	$ 287	$ 289	$ 292	$ 296	$ 309
				Lump sum ($)	$ 106,249	$ 237,544	$ 567,394	$ 1,092,595	$ 2,191,755	$ 3,294,699	$ 3,905,981	$ 4,525,960	$ 5,162,231	$ 5,908,582
Microturbine	5%	63%	32%											
				MW	0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
				aMW	0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
				Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
				O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
				Fuel ($/kW)	$ 487	$ 469	$ 455	$ 432	$ 444	$ 447	$ 451	$ 455	$ 461	$ 482
				Lump sum ($)	$ 31,043	$ 69,114	$ 164,857	$ 316,715	$ 635,300	$ 952,684	$ 1,124,904	$ 1,299,789	$ 1,479,666	$ 1,693,277
Fuel Cell	5%	63%	32%											
				MW	0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
				aMW	0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
				Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
				O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
				Fuel ($/kW)	$ 380	$ 366	$ 355	$ 338	$ 347	$ 349	$ 352	$ 356	$ 360	$ 377
				Lump sum ($)	$ 38,798	$ 79,792	$ 187,234	$ 350,758	$ 692,721	$ 976,247	$ 1,030,547	$ 1,085,844	$ 1,143,010	$ 1,212,802

CHP (Natural gas)		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost	
												Gen SS Resource	$0.11 $/kWh
Recip Engine													
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01		
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087		
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345		
	Fuel ($/kW)	$ 313	$ 324	$ 336	$ 339	$ 349	$ 358	$ 368	$ 378	$ 386	$ 394		
	Lump sum ($)	$ 6,580,051	$ 7,363,294	$ 8,198,835	$ 8,922,516	$ 9,764,658	$ 10,274,939	$ 10,712,607	$ 10,699,778	$ 11,183,057	$ 11,681,788	Levelized Cost	$0.08 $/kWh
Microturbine													
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32		
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%
	Inst costs ($/kW)	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053		
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135		
	Fuel ($/kW)	$ 488	$ 505	$ 524	$ 529	$ 544	$ 558	$ 574	$ 589	$ 601	$ 614		
	Lump sum ($)	$ 1,690,201	$ 1,915,117	$ 2,156,060	$ 2,362,724	$ 2,605,690	$ 2,794,714	$ 2,963,644	$ 3,054,451	$ 3,256,171	$ 3,527,731	Levelized Cost	$0.11 $/kWh
Fuel Cell													
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07		
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%
	Inst costs ($/kW)	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423		
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403		
	Fuel ($/kW)	$ 381	$ 394	$ 410	$ 413	$ 425	$ 436	$ 448	$ 460	$ 470	$ 479		
	Lump sum ($)	$ 995,550	$ 1,092,983	$ 1,235,430	$ 1,396,257	$ 1,672,111	$ 1,817,500	$ 1,808,565	$ 1,704,636	$ 1,753,292	$ 1,803,720	Lev Cost	$0.16 $/kWh

NOTES: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Table E-4. Distributed Generation + Emerging Technologies Base Case Scenario: Renewables

Renewable		% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Small Wind	30%	70%	0%											
					MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
					aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
					Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
					O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
					Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
	PV	50%	50%	0%											
					MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
					aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
					Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
					O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
					Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass															
	Industrial	0%	0%	100%											
					MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
					aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
					Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
					O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
					Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
	Anaerobic Digester	0%	100%	0%											
					MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
					aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
					Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
					O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
					Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

Renewable			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost	
	Small Wind													
		MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26		
		aMW	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	Capacity Factor	15%
		Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	CF after Year 10	23%
		O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600		
		Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.30 $/kWh
	PV													
		MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61		
		aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%
		Inst costs ($/kW)	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315		
		O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800		
		Lump sum ($)	$ 207,705	$ 208,421	$ 209,137	$ 209,854	$ 210,570	$ 182,272	$ 153,872	$ 96,355	$ 96,662	$ 96,969	Levelized Cost	$0.79 $/kWh
Biomass														
	Industrial													
		MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67		
		aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%
		Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600		
		O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600		
		Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04 $/kWh
	Anaerobic Digester													
		MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57		
		aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%
		Inst costs ($/kW)	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354		
		O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013		
		Lump sum ($)	$ 2,333,647	$ 2,384,539	$ 2,435,430	$ 2,486,321	$ 2,537,213	$ 2,385,274	$ 2,226,065	$ 1,912,631	$ 2,269,687	$ 2,989,925	Levelized Cost	$0.09 $/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation + Emerging Technologies Base Case Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	1.1	2.3	4.7	7.9	11.2	14.4	17.7	21.0
aMW	0.1	0.4	0.9	2.0	4.0	6.8	9.6	12.4	15.2	18.0
Total Cost	$ 308,183	$ 654,862	$ 1,549,007	$ 2,939,598	$ 5,837,087	$ 8,448,889	$ 9,382,223	$ 10,326,919	$ 11,292,898	$ 12,402,692
Fuel ($/MMBTU)	$ 7.87	$ 7.59	$ 7.36	$ 7.00	$ 7.18	$ 7.24	$ 7.30	$ 7.37	$ 7.46	$ 7.80

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	24.2	27.5	30.7	34.0	37.3	40.0	42.4	43.8	45.2	46.6
aMW	20.9	23.7	26.5	29.3	32.1	34.5	36.5	37.7	38.9	40.1
Total Cost	$ 12,899,231	$ 14,057,222	$ 15,283,538	$ 16,363,714	$ 17,598,653	$ 18,007,919	$ 18,303,074	$ 17,664,205	$ 18,748,665	$ 20,281,597
Fuel ($/MMBTU)	$ 7.89	$ 8.17	$ 8.49	$ 8.56	$ 8.80	$ 9.04	$ 9.28	$ 9.53	$ 9.73	$ 9.93

Table E-5. Distributed Generation Base Case -10% Scenario: CHP (Natural Gas)

CHP (Natural gas)		% Penetration (by MW) Res	Com	Ind	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Recip Engine		0%	65%	35%										
	MW				0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
	aMW				0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
	Inst costs ($/kW)				$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
	O&M ($/MW)				$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
	Fuel ($/kW)				$ 312	$ 301	$ 292	$ 277	$ 285	$ 287	$ 289	$ 292	$ 296	$ 309
	Lump sum ($)				$ 104,189	$ 231,588	$ 552,631	$ 1,062,694	$ 2,129,110	$ 3,187,378	$ 3,753,143	$ 4,326,736	$ 4,914,991	$ 5,602,319
Microturbine		0%	65%	35%										
	MW				0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
	aMW				0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
	Inst costs ($/kW)				$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
	O&M ($/MW)				$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
	Fuel ($/kW)				$ 487	$ 469	$ 455	$ 432	$ 444	$ 447	$ 451	$ 455	$ 461	$ 482
	Lump sum ($)				$ 30,412	$ 67,289	$ 160,333	$ 307,552	$ 616,103	$ 919,796	$ 1,078,067	$ 1,238,738	$ 1,403,901	$ 1,599,425
Fuel Cell		0%	65%	35%										
	MW				0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
	aMW				0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
	Inst costs ($/kW)				$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
	O&M ($/MW)				$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
	Fuel ($/kW)				$ 380	$ 366	$ 355	$ 338	$ 347	$ 349	$ 352	$ 356	$ 360	$ 377
	Lump sum ($)				$ 38,562	$ 79,109	$ 185,541	$ 347,328	$ 685,535	$ 963,937	$ 1,013,015	$ 1,062,992	$ 1,114,650	$ 1,177,672

CHP (Natural gas)		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
												Gen SS Resource L	$0.10	$/kWh
Recip Engine														
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01			
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%	
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087			
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345			
	Fuel ($/kW)	$ 313	$ 324	$ 336	$ 339	$ 349	$ 358	$ 368	$ 378	$ 386	$ 394			
	Lump sum ($)	$ 6,222,253	$ 6,942,783	$ 7,710,382	$ 8,377,307	$ 9,150,846	$ 9,597,162	$ 9,975,895	$ 9,918,401	$ 10,360,043	$ 10,815,592	Levelized Cost	$0.08	$/kWh
Microturbine														
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32			
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%	
	Inst costs ($/kW)	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053			
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135			
	Fuel ($/kW)	$ 488	$ 505	$ 524	$ 529	$ 544	$ 558	$ 574	$ 589	$ 601	$ 614			
	Lump sum ($)	$ 1,774,296	$ 1,979,994	$ 2,200,117	$ 2,389,388	$ 2,611,330	$ 2,761,379	$ 2,892,874	$ 2,936,781	$ 3,158,955	$ 3,486,475	Levelized Cost	$0.11	$/kWh
Fuel Cell														
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07			
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%	
	Inst costs ($/kW)	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423			
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403			
	Fuel ($/kW)	$ 381	$ 394	$ 410	$ 413	$ 425	$ 436	$ 448	$ 460	$ 470	$ 479			
	Lump sum ($)	$ 1,269,310	$ 1,372,487	$ 1,541,639	$ 1,747,704	$ 2,123,498	$ 2,300,361	$ 2,241,543	$ 2,046,242	$ 2,090,122	$ 2,135,597	Levelized Cost	$0.18	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Table E-6. Distributed Generation Base Case -10% Scenario: Renewables

Renewable	% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Small Wind	30%	70%	0%											
				MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
				aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
				Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
				O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
				Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
PV	50%	50%	0%											
				MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
				aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
				Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
				O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
				Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass														
Industrial	0%	0%	100%											
				MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
				aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
				Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
				O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
				Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
Anaerobic Digester	0%	100%	0%											
				MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
				aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
				Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
				O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
				Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

Renewable		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
Small Wind														
	MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26			
	aMW	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	Capacity Factor	15%	
	Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	CF after Year 10	23%	
	O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600			
	Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.30	$/kWh
PV														
	MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61			
	aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%	
	Inst costs ($/kW)	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315			
	O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800			
	Lump sum ($)	$ 319,554	$ 320,270	$ 320,987	$ 321,703	$ 322,419	$ 278,143	$ 233,764	$ 144,290	$ 144,597	$ 144,904	Levelized Cost	$0.97	$/kWh
Biomass														
Industrial														
	MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67			
	aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%	
	Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600			
	O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600			
	Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04	$/kWh
Anaerobic Digester														
	MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57			
	aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%	
	Inst costs ($/kW)	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354			
	O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013			
	Lump sum ($)	$ 2,655,332	$ 2,706,223	$ 2,757,115	$ 2,808,006	$ 2,858,897	$ 2,674,790	$ 2,483,413	$ 2,114,833	$ 2,527,034	$ 3,362,160	Levelized Cost	$0.10	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation Base Case -10% Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	1.0	2.1	4.2	7.2	10.1	13.1	16.1	19.0
aMW	0.1	0.3	0.8	1.8	3.6	6.1	8.6	11.2	13.7	16.2
Total Cost	$ 275,080	$ 579,792	$ 1,369,388	$ 2,592,981	$ 5,139,142	$ 7,388,884	$ 8,104,481	$ 8,827,906	$ 9,565,993	$ 10,403,152
Fuel ($/MMBTU)	$ 7.09	$ 6.83	$ 6.62	$ 6.30	$ 6.46	$ 6.51	$ 6.57	$ 6.63	$ 6.71	$ 7.02

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	22.0	24.9	27.9	30.8	33.8	36.3	38.4	39.7	41.0	42.2
aMW	18.7	21.2	23.8	26.3	28.8	31.0	32.8	33.8	34.9	36.0
Total Cost	$ 11,172,917	$ 12,043,279	$ 12,960,710	$ 13,777,466	$ 14,700,837	$ 14,824,944	$ 14,860,065	$ 14,030,580	$ 14,926,827	$ 16,259,904
Fuel ($/MMBTU)	$ 7.10	$ 7.36	$ 7.64	$ 7.71	$ 7.92	$ 8.13	$ 8.35	$ 8.58	$ 8.76	$ 8.94

Table E-7. Distributed Generation + Emerging Technologies Base Case -10% Scenario: CHP (Natural Gas)

CHP (Natural gas)	% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Recip Engine	5%	63%	32%											
				MW	0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
				aMW	0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
				Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
				O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
				Fuel ($/kW)	$ 281	$ 271	$ 263	$ 250	$ 256	$ 258	$ 260	$ 263	$ 266	$ 278
				Lump sum ($)	$ 104,189	$ 231,588	$ 552,631	$ 1,062,694	$ 2,129,110	$ 3,187,378	$ 3,753,143	$ 4,326,736	$ 4,914,991	$ 5,602,319
Microturbine	5%	63%	32%											
				MW	0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
				aMW	0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
				Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
				O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
				Fuel ($/kW)	$ 438	$ 422	$ 409	$ 389	$ 399	$ 403	$ 406	$ 410	$ 415	$ 434
				Lump sum ($)	$ 30,412	$ 67,289	$ 160,333	$ 307,552	$ 616,103	$ 919,796	$ 1,078,067	$ 1,238,738	$ 1,403,901	$ 1,599,425
Fuel Cell	5%	63%	32%											
				MW	0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
				aMW	0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
				Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
				O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
				Fuel ($/kW)	$ 342	$ 330	$ 320	$ 304	$ 312	$ 314	$ 317	$ 320	$ 324	$ 339
				Lump sum ($)	$ 38,562	$ 79,109	$ 185,541	$ 347,328	$ 685,535	$ 963,937	$ 1,013,015	$ 1,062,992	$ 1,114,650	$ 1,177,672

CHP (Natural gas)		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
												Gen SS Resource	$0.10	$/kWh
Recip Engine														
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01			
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%	
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087			
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345			
	Fuel ($/kW)	$ 281	$ 291	$ 303	$ 305	$ 314	$ 322	$ 331	$ 340	$ 347	$ 354			
	Lump sum ($)	$ 6,222,253	$ 6,942,783	$ 7,710,382	$ 8,377,307	$ 9,150,846	$ 9,597,162	$ 9,975,895	$ 9,918,401	$ 10,360,043	$ 10,815,592	Levelized Cost	$0.08	$/kWh
Microturbine														
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32			
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%	
	Inst costs ($/kW)	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053			
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135			
	Fuel ($/kW)	$ 439	$ 455	$ 472	$ 476	$ 489	$ 503	$ 516	$ 530	$ 541	$ 552			
	Lump sum ($)	$ 1,580,556	$ 1,786,254	$ 2,006,377	$ 2,195,648	$ 2,417,591	$ 2,587,013	$ 2,737,883	$ 2,815,002	$ 3,003,964	$ 3,262,290	Levelized Cost	$0.10	$/kWh
Fuel Cell														
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07			
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%	
	Inst costs ($/kW)	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423			
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403			
	Fuel ($/kW)	$ 343	$ 355	$ 369	$ 372	$ 382	$ 393	$ 403	$ 414	$ 423	$ 431			
	Lump sum ($)	$ 954,508	$ 1,044,748	$ 1,179,402	$ 1,333,719	$ 1,601,703	$ 1,739,755	$ 1,724,060	$ 1,615,007	$ 1,658,887	$ 1,704,362	Levelized Cost	$0.15	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Table E-8. Distributed Generation + Emerging Technologies Base Case -10% Scenario: Renewables

		% Penetration (by MW)				2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Renewable		Res	Com	Ind											
	Small Wind	30%	70%	0%											
					MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
					aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
					Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
					O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
					Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
	PV	50%	50%	0%											
					MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
					aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
					Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
					O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
					Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass															
	Industrial	0%	0%	100%											
					MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
					aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
					Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
					O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
					Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
	Anaerobic Digester	0%	100%	0%											
					MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
					aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
					Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
					O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
					Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost	
Renewable														
	Small Wind													
		MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26		
		aMW	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	Capacity Factor	15%
		Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598		
		O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600		
		Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.30 $/kWh
	PV													
		MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61		
		aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%
		Inst costs ($/kW)	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315		
		O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800		
		Lump sum ($)	$ 207,705	$ 208,421	$ 209,137	$ 209,854	$ 210,570	$ 182,272	$ 153,872	$ 96,355	$ 96,662	$ 96,969	Levelized Cost	$0.79 $/kWh
Biomass														
	Industrial													
		MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67		
		aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%
		Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600		
		O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600		
		Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04 $/kWh
	Anaerobic Digester													
		MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57		
		aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%
		Inst costs ($/kW)	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354		
		O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013		
		Lump sum ($)	$ 2,333,647	$ 2,384,539	$ 2,435,430	$ 2,486,321	$ 2,537,213	$ 2,385,274	$ 2,226,065	$ 1,912,631	$ 2,269,687	$ 2,989,925	Levelized Cost	$0.09 $/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation + Emerging Technologies Base Case -10% Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	1.1	2.3	4.7	7.9	11.2	14.4	17.7	21.0
aMW	0.1	0.4	0.9	2.0	4.0	6.8	9.6	12.4	15.2	18.0
Total Cost	$ 305,492	$ 647,081	$ 1,529,720	$ 2,900,534	$ 5,755,245	$ 8,308,680	$ 9,182,549	$ 10,066,644	$ 10,969,894	$ 12,002,577
Fuel ($/MMBTU)	$ 7.09	$ 6.83	$ 6.62	$ 6.30	$ 6.46	$ 6.51	$ 6.57	$ 6.63	$ 6.71	$ 7.02

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	24.2	27.5	30.7	34.0	37.3	40.0	42.4	43.8	45.2	46.6
aMW	20.9	23.7	26.5	29.3	32.1	34.5	36.5	37.7	38.9	40.1
Total Cost	$ 12,431,788	$ 13,507,849	$ 14,645,402	$ 15,651,429	$ 16,796,743	$ 17,122,441	$ 17,340,600	$ 16,643,380	$ 17,673,443	$ 19,149,959
Fuel ($/MMBTU)	$ 7.10	$ 7.36	$ 7.64	$ 7.71	$ 7.92	$ 8.13	$ 8.35	$ 8.58	$ 8.76	$ 8.94

Table E-9. Distributed Generation Base Case + 25% Scenario: CHP (Natural Gas)

CHP (Natural gas)	% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Recip Engine	0%	65%	35%											
				MW	0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
				aMW	0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
				Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
				O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
				Fuel ($/kW)	$ 390	$ 376	$ 365	$ 347	$ 356	$ 359	$ 362	$ 365	$ 370	$ 387
				Lump sum ($)	$ 111,399	$ 252,433	$ 604,302	$ 1,167,349	$ 2,348,367	$ 3,563,003	$ 4,288,076	$ 5,024,021	$ 5,780,329	$ 6,674,239
Microturbine	0%	65%	35%											
				MW	0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
				aMW	0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
				Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
				O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
				Fuel ($/kW)	$ 608	$ 586	$ 568	$ 540	$ 555	$ 559	$ 564	$ 569	$ 576	$ 603
				Lump sum ($)	$ 32,621	$ 73,677	$ 176,167	$ 339,623	$ 683,293	$ 1,034,904	$ 1,241,994	$ 1,452,416	$ 1,669,079	$ 1,927,908
Fuel Cell	0%	65%	35%											
				MW	0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
				aMW	0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
				Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
				O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
				Fuel ($/kW)	$ 475	$ 458	$ 444	$ 422	$ 433	$ 437	$ 441	$ 445	$ 450	$ 471
				Lump sum ($)	$ 39,389	$ 81,500	$ 191,468	$ 359,333	$ 710,686	$ 1,007,023	$ 1,074,375	$ 1,142,974	$ 1,213,909	$ 1,300,628

CHP (Natural gas)		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
												Gen SS Resource L	$0.14	$/kWh
Recip Engine														
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01			
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%	
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087			
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345			
	Fuel ($/kW)	$ 391	$ 405	$ 420	$ 424	$ 436	$ 448	$ 460	$ 472	$ 482	$ 492			
	Lump sum ($)	$ 7,474,545	$ 8,414,570	$ 9,419,967	$ 10,285,539	$ 11,299,187	$ 11,969,383	$ 12,554,388	$ 12,653,220	$ 13,240,593	$ 13,847,280	Levelized Cost	$0.10	$/kWh
Microturbine														
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32			
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%	
	Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634			
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135			
	Fuel ($/kW)	$ 609	$ 631	$ 655	$ 661	$ 680	$ 698	$ 717	$ 736	$ 751	$ 767			
	Lump sum ($)	$ 2,158,053	$ 2,431,015	$ 2,724,009	$ 2,974,154	$ 3,269,677	$ 3,488,332	$ 3,683,038	$ 3,774,851	$ 4,041,683	$ 4,415,518	Levelized Cost	$0.13	$/kWh
Fuel Cell														
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07			
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%	
	Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314			
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403			
	Fuel ($/kW)	$ 476	$ 493	$ 512	$ 517	$ 531	$ 545	$ 560	$ 575	$ 587	$ 599			
	Lump sum ($)	$ 1,412,955	$ 1,541,309	$ 1,737,738	$ 1,966,590	$ 2,369,925	$ 2,572,469	$ 2,537,311	$ 2,359,942	$ 2,420,538	$ 2,483,349	Levelized Cost	$0.21	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Table E-10. Distributed Generation Base Case + 25% Scenario: Renewables

Renewable		% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Small Wind	30%	70%	0%											
					MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
					aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
					Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
					O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
					Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
	PV	50%	50%	0%											
					MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
					aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
					Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
					O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
					Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass															
	Industrial	0%	0%	100%											
					MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
					aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
					Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
					O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
					Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
	Anaerobic Digester	0%	100%	0%											
					MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
					aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
					Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
					O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
					Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

Renewable			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost	
	Small Wind													
		MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26		
		aMW	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	Capacity Factor	15%
		Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598		
		O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600		
		Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.30 $/kWh
	PV													
		MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61		
		aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%
		Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700		
		O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800		
		Lump sum ($)	$ 319,554	$ 320,270	$ 320,987	$ 321,703	$ 322,419	$ 278,143	$ 233,764	$ 144,290	$ 144,597	$ 144,904	Levelized Cost	$0.97 $/kWh
Biomass														
	Industrial													
		MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67		
		aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%
		Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600		
		O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600		
		Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04 $/kWh
	Anaerobic Digester													
		MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57		
		aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%
		Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906		
		O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013		
		Lump sum ($)	$ 2,655,332	$ 2,706,223	$ 2,757,115	$ 2,808,006	$ 2,858,897	$ 2,674,790	$ 2,483,413	$ 2,114,833	$ 2,527,034	$ 3,362,160	Levelized Cost	$0.10 $/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation Base Case + 25% Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	1.1	2.3	4.7	7.9	11.2	14.4	17.7	21.0
aMW	0.1	0.4	0.9	2.0	4.0	6.8	9.6	12.4	15.2	18.0
Total Cost	$ 314,911	$ 674,313	$ 1,597,225	$ 3,037,259	$ 6,041,693	$ 8,799,413	$ 9,881,408	$ 10,977,606	$ 12,100,409	$ 13,402,979
Fuel ($/MMBTU)	$ 9.84	$ 9.48	$ 9.20	$ 8.75	$ 8.98	$ 9.05	$ 9.13	$ 9.21	$ 9.33	$ 9.75

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	24.2	27.5	30.7	34.0	37.3	40.0	42.4	43.8	45.2	46.6
aMW	20.9	23.7	26.5	29.3	32.1	34.5	36.5	37.7	38.9	40.1
Total Cost	$ 14,583,263	$ 15,946,080	$ 17,394,304	$ 18,659,852	$ 20,118,854	$ 20,685,498	$ 21,121,597	$ 20,540,250	$ 21,849,060	$ 23,707,110
Fuel ($/MMBTU)	$ 9.86	$ 10.22	$ 10.61	$ 10.70	$ 11.00	$ 11.30	$ 11.60	$ 11.91	$ 12.16	$ 12.42

Table E-11. Distributed Generation + Emerging Technologies Base Case + 25% Scenario: CHP (Natural Gas)

CHP (Natural gas)	% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Recip Engine	5%	63%	32%											
				MW	0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
				aMW	0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
				Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
				O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
				Fuel ($/kW)	$ 390	$ 376	$ 365	$ 347	$ 356	$ 359	$ 362	$ 365	$ 370	$ 387
				Lump sum ($)	$ 111,399	$ 252,433	$ 604,302	$ 1,167,349	$ 2,348,367	$ 3,563,003	$ 4,288,076	$ 5,024,021	$ 5,780,329	$ 6,674,239
Microturbine	5%	63%	32%											
				MW	0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
				aMW	0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
				Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
				O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
				Fuel ($/kW)	$ 608	$ 586	$ 568	$ 540	$ 555	$ 559	$ 564	$ 569	$ 576	$ 603
				Lump sum ($)	$ 32,621	$ 73,677	$ 176,167	$ 339,623	$ 683,293	$ 1,034,904	$ 1,241,994	$ 1,452,416	$ 1,669,079	$ 1,927,908
Fuel Cell	5%	63%	32%											
				MW	0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
				aMW	0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
				Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
				O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
				Fuel ($/kW)	$ 475	$ 458	$ 444	$ 422	$ 433	$ 437	$ 441	$ 445	$ 450	$ 471
				Lump sum ($)	$ 39,389	$ 81,500	$ 191,468	$ 359,333	$ 710,686	$ 1,007,023	$ 1,074,375	$ 1,142,974	$ 1,213,909	$ 1,300,628

CHP (Natural gas)		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
												Gen SS Resource	$0.14	$/kWh
Recip Engine														
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01			
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%	
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087			
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345			
	Fuel ($/kW)	$ 391	$ 405	$ 420	$ 424	$ 436	$ 448	$ 460	$ 472	$ 482	$ 492			
	Lump sum ($)	$ 7,474,545	$ 8,414,570	$ 9,419,967	$ 10,285,539	$ 11,299,187	$ 11,969,383	$ 12,554,388	$ 12,653,220	$ 13,240,593	$ 13,847,280	Levelized Cost	$0.10	$/kWh
Microturbine														
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32			
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%	
	Inst costs ($/kW)	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053			
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135			
	Fuel ($/kW)	$ 609	$ 631	$ 655	$ 661	$ 680	$ 698	$ 717	$ 736	$ 751	$ 767			
	Lump sum ($)	$ 1,964,314	$ 2,237,275	$ 2,530,269	$ 2,780,414	$ 3,075,937	$ 3,313,966	$ 3,528,047	$ 3,653,071	$ 3,886,691	$ 4,191,333	Levelized Cost	$0.13	$/kWh
Fuel Cell														
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07			
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%	
	Inst costs ($/kW)	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423			
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403			
	Fuel ($/kW)	$ 476	$ 493	$ 512	$ 517	$ 531	$ 545	$ 560	$ 575	$ 587	$ 599			
	Lump sum ($)	$ 1,098,154	$ 1,213,571	$ 1,375,501	$ 1,552,604	$ 1,848,130	$ 2,011,863	$ 2,019,828	$ 1,928,707	$ 1,989,303	$ 2,052,114	Levelized Cost	$0.18	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Table E-12. Distributed Generation + Emerging Technologies Base Case + 25% Scenario: Renewables

Renewable		% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Small Wind	30%	70%	0%											
					MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
					aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
					Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
					O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
					Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
	PV	50%	50%	0%											
					MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
					aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
					Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
					O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
					Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass															
	Industrial	0%	0%	100%											
					MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
					aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
					Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
					O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
					Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
	Anaerobic Digester	0%	100%	0%											
					MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
					aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
					Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
					O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
					Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

Renewable			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost	
	Small Wind													
		MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26		
		aMW	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	Capacity Factor	15%
		Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	CF after Year 10	23%
		O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600		
		Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.30 $/kWh
	PV													
		MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61		
		aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%
		Inst costs ($/kW)	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315		
		O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800		
		Lump sum ($)	$ 207,705	$ 208,421	$ 209,137	$ 209,854	$ 210,570	$ 182,272	$ 153,872	$ 96,355	$ 96,662	$ 96,969	Levelized Cost	$0.79 $/kWh
Biomass														
	Industrial													
		MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67		
		aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%
		Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600		
		O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600		
		Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04 $/kWh
	Anaerobic Digester													
		MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57		
		aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%
		Inst costs ($/kW)	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354		
		O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013		
		Lump sum ($)	$ 2,333,647	$ 2,384,539	$ 2,435,430	$ 2,486,321	$ 2,537,213	$ 2,385,274	$ 2,226,065	$ 1,912,631	$ 2,269,687	$ 2,989,925	Levelized Cost	$0.09 $/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation + Emerging Technologies Base Case + 25% Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	1.1	2.3	4.7	7.9	11.2	14.4	17.7	21.0
aMW	0.1	0.4	0.9	2.0	4.0	6.8	9.6	12.4	15.2	18.0
Total Cost	$ 314,911	$ 674,313	$ 1,597,225	$ 3,037,259	$ 6,041,693	$ 8,799,413	$ 9,881,408	$ 10,977,606	$ 12,100,409	$ 13,402,979
Fuel ($/MMBTU)	$ 9.84	$ 9.48	$ 9.20	$ 8.75	$ 8.98	$ 9.05	$ 9.13	$ 9.21	$ 9.33	$ 9.75

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	24.2	27.5	30.7	34.0	37.3	40.0	42.4	43.8	45.2	46.6
aMW	20.9	23.7	26.5	29.3	32.1	34.5	36.5	37.7	38.9	40.1
Total Cost	$ 14,067,838	$ 15,430,656	$ 16,878,879	$ 18,144,428	$ 19,603,430	$ 20,221,615	$ 20,709,257	$ 20,216,269	$ 21,436,720	$ 23,110,690
Fuel ($/MMBTU)	$ 9.86	$ 10.22	$ 10.61	$ 10.70	$ 11.00	$ 11.30	$ 11.60	$ 11.91	$ 12.16	$ 12.42

Table E-13. Distributed Generation Green World Scenario: CHP (Natural Gas)

	% Penetration (by MW)													
CHP (Natural gas)	**Res**	**Com**	**Ind**		**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**
Recip Engine	0%	65%	35%											
				MW	0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
				aMW	0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
				Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
				O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
				Fuel ($/kW)	$ 312	$ 301	$ 334	$ 331	$ 325	$ 333	$ 343	$ 353	$ 363	$ 382
				Lump sum ($)	$ 106,248	$ 237,545	$ 588,747	$ 1,150,135	$ 2,280,520	$ 3,468,772	$ 4,190,175	$ 4,939,233	$ 5,721,855	$ 6,633,651
Microturbine	0%	65%	35%											
				MW	0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
				aMW	0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
				Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
				O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
				Fuel ($/kW)	$ 487	$ 469	$ 521	$ 516	$ 507	$ 520	$ 535	$ 550	$ 565	$ 596
				Lump sum ($)	$ 31,043	$ 69,114	$ 171,400	$ 334,348	$ 662,502	$ 1,006,027	$ 1,211,993	$ 1,426,434	$ 1,651,160	$ 1,915,470
Fuel Cell	0%	65%	35%											
				MW	0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
				aMW	0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
				Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
				O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
				Fuel ($/kW)	$ 380	$ 366	$ 407	$ 403	$ 396	$ 406	$ 418	$ 429	$ 442	$ 466
				Lump sum ($)	$ 38,798	$ 79,792	$ 189,684	$ 357,358	$ 702,903	$ 996,214	$ 1,063,145	$ 1,133,249	$ 1,207,202	$ 1,295,972

		2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**Levelized Cost**		
CHP (Natural gas)												Gen SS Resource L	$0.13	$/kWh
Recip Engine														
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01			
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%	
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087			
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345			
	Fuel ($/kW)	$ 394	$ 413	$ 433	$ 444	$ 456	$ 469	$ 481	$ 494	$ 508	$ 521			
	Lump sum ($)	$ 7,512,415	$ 8,520,763	$ 9,597,735	$ 10,611,149	$ 11,660,157	$ 12,368,431	$ 12,982,927	$ 13,109,421	$ 13,786,583	$ 14,487,847	Levelized Cost	$0.10	$/kWh
Microturbine														
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32			
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%	
	Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634			
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135			
	Fuel ($/kW)	$ 615	$ 644	$ 675	$ 693	$ 712	$ 731	$ 750	$ 771	$ 791	$ 813			
	Lump sum ($)	$ 2,169,658	$ 2,463,557	$ 2,778,485	$ 3,073,935	$ 3,380,294	$ 3,610,618	$ 3,814,362	$ 3,914,651	$ 4,208,998	$ 4,611,816	Levelized Cost	$0.14	$/kWh
Fuel Cell														
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07			
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%	
	Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314			
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403			
	Fuel ($/kW)	$ 480	$ 503	$ 527	$ 541	$ 556	$ 571	$ 586	$ 602	$ 618	$ 635			
	Lump sum ($)	$ 1,417,299	$ 1,553,490	$ 1,758,129	$ 2,003,939	$ 2,411,330	$ 2,618,242	$ 2,586,466	$ 2,412,271	$ 2,483,166	$ 2,556,826	Levelized Cost	$0.21	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Table E-14. Distributed Generation Green World Scenario: Renewables

		% Penetration (by MW)													
Renewable		Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Small Wind	30%	70%	0%											
					MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
					aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
					Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
					O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
					Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
	PV	50%	50%	0%											
					MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
					aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
					Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
					O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
					Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass															
	Industrial	0%	0%	100%											
					MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
					aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
					Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
					O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
					Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
	Anaerobic Digester	0%	100%	0%											
					MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
					aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
					Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
					O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
					Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

Renewable			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
	Small Wind														
		MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26			
		aMW	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	Capacity Factor	15%	
		Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598			
		O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600			
		Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.30	$/kWh
	PV														
		MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61			
		aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%	
		Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700			
		O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800			
		Lump sum ($)	$ 319,554	$ 320,270	$ 320,987	$ 321,703	$ 322,419	$ 278,143	$ 233,764	$ 144,290	$ 144,597	$ 144,904	Levelized Cost	$0.97	$/kWh
Biomass															
	Industrial														
		MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67			
		aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%	
		Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600			
		O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600			
		Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04	$/kWh
	Anaerobic Digester														
		MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57			
		aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%	
		Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906			
		O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013			
		Lump sum ($)	$ 2,655,332	$ 2,706,223	$ 2,757,115	$ 2,808,006	$ 2,858,897	$ 2,674,790	$ 2,483,413	$ 2,114,833	$ 2,527,034	$ 3,362,160	Levelized Cost	$0.10	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation Green World Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	1.0	2.1	4.2	7.2	10.1	13.1	16.1	19.0
aMW	0.1	0.3	0.8	1.8	3.6	6.1	8.6	11.2	13.7	16.2
Total Cost	$ 277,139	$ 585,748	$ 1,405,503	$ 2,680,422	$ 5,290,552	$ 7,670,279	$ 8,541,513	$ 9,440,403	$ 10,372,856	$ 11,434,484
Fuel ($/MMBTU)	$ 7.87	$ 7.59	$ 8.42	$ 8.34	$ 8.20	$ 8.41	$ 8.66	$ 8.90	$ 9.15	$ 9.65

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	22.0	24.9	27.9	30.8	33.8	36.3	38.4	39.7	41.0	42.2
aMW	18.7	21.2	23.8	26.3	28.8	31.0	32.8	33.8	34.9	36.0
Total Cost	$ 12,463,080	$ 13,621,259	$ 14,848,063	$ 16,011,308	$ 17,210,148	$ 17,596,214	$ 17,867,097	$ 17,221,600	$ 18,353,366	$ 19,932,159
Fuel ($/MMBTU)	$ 9.95	$ 10.42	$ 10.92	$ 11.22	$ 11.51	$ 11.83	$ 12.14	$ 12.47	$ 12.81	$ 13.15

Table E-15. Distributed Generation + Emerging Technologies Green World Scenario: CHP (Natural Gas)

	% Penetration (by MW)				2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CHP (Natural gas)	Res	Com	Ind											
Recip Engine	5%	63%	32%											
				MW	0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
				aMW	0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
				Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
				O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
				Fuel ($/kW)	$ 312	$ 301	$ 334	$ 331	$ 325	$ 333	$ 343	$ 353	$ 363	$ 382
				Lump sum ($)	$ 106,248	$ 237,545	$ 588,747	$ 1,150,135	$ 2,280,520	$ 3,468,772	$ 4,190,175	$ 4,939,233	$ 5,721,855	$ 6,633,651
Microturbine	5%	63%	32%											
				MW	0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
				aMW	0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
				Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
				O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
				Fuel ($/kW)	$ 487	$ 469	$ 521	$ 516	$ 507	$ 520	$ 535	$ 550	$ 565	$ 596
				Lump sum ($)	$ 31,043	$ 69,114	$ 171,400	$ 334,348	$ 662,502	$ 1,006,027	$ 1,211,993	$ 1,426,434	$ 1,651,160	$ 1,915,470
Fuel Cell	5%	63%	32%											
				MW	0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
				aMW	0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
				Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
				O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
				Fuel ($/kW)	$ 380	$ 366	$ 407	$ 403	$ 396	$ 406	$ 418	$ 429	$ 442	$ 466
				Lump sum ($)	$ 38,798	$ 79,792	$ 189,684	$ 357,358	$ 702,903	$ 996,214	$ 1,063,145	$ 1,133,249	$ 1,207,202	$ 1,295,972

		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
CHP (Natural gas)												Gen SS Resource	$0.13	$/kWh
Recip Engine														
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01			
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%	
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087			
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345			
	Fuel ($/kW)	$ 394	$ 413	$ 433	$ 444	$ 456	$ 469	$ 481	$ 494	$ 508	$ 521			
	Lump sum ($)	$ 7,512,415	$ 8,520,763	$ 9,597,735	$ 10,611,149	$ 11,660,157	$ 12,368,431	$ 12,982,927	$ 13,109,421	$ 13,786,583	$ 14,487,847	Levelized Cost	$0.10	$/kWh
Microturbine														
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32			
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%	
	Inst costs ($/kW)	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053			
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135			
	Fuel ($/kW)	$ 615	$ 644	$ 675	$ 693	$ 712	$ 731	$ 750	$ 771	$ 791	$ 813			
	Lump sum ($)	$ 1,975,919	$ 2,269,817	$ 2,584,745	$ 2,880,196	$ 3,186,554	$ 3,436,252	$ 3,659,370	$ 3,792,872	$ 4,054,007	$ 4,387,631	Levelized Cost	$0.13	$/kWh
Fuel Cell														
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07			
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%	
	Inst costs ($/kW)	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423			
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403			
	Fuel ($/kW)	$ 480	$ 503	$ 527	$ 541	$ 556	$ 571	$ 586	$ 602	$ 618	$ 635			
	Lump sum ($)	$ 1,102,498	$ 1,225,752	$ 1,395,892	$ 1,589,953	$ 1,889,535	$ 2,057,636	$ 2,068,984	$ 1,981,036	$ 2,051,931	$ 2,125,591	Levelized Cost	$0.18	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Table E-16. Distributed Generation + Emerging Technologies Green World Scenario: Renewables

Renewable		% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Small Wind	30%	70%	0%											
					MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
					aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
					Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
					O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
					Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
	PV	50%	50%	0%											
					MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
					aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
					Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
					O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
					Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass															
	Industrial	0%	0%	100%											
					MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
					aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
					Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
					O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
					Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
	Anaerobic Digester	0%	100%	0%											
					MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
					aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
					Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
					O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
					Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

Renewable			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
	Small Wind														
		MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26			
		aMW	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	Capacity Factor	15%	
		Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	CF after Year 10	23%	
		O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600			
		Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.30	$/kWh
	PV														
		MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61			
		aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%	
		Inst costs ($/kW)	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315			
		O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800			
		Lump sum ($)	$ 207,705	$ 208,421	$ 209,137	$ 209,854	$ 210,570	$ 182,272	$ 153,872	$ 96,355	$ 96,662	$ 96,969	Levelized Cost	$0.79	$/kWh
Biomass															
	Industrial														
		MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67			
		aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%	
		Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600			
		O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600			
		Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04	$/kWh
	Anaerobic Digester														
		MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57			
		aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%	
		Inst costs ($/kW)	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354			
		O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013			
		Lump sum ($)	$ 2,333,647	$ 2,384,539	$ 2,435,430	$ 2,486,321	$ 2,537,213	$ 2,385,274	$ 2,226,065	$ 1,912,631	$ 2,269,687	$ 2,989,925	Levelized Cost	$0.09	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation + Emerging Technologies Green World Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	1.0	2.1	4.2	7.2	10.1	13.1	16.1	19.0
aMW	0.1	0.3	0.8	1.8	3.6	6.1	8.6	11.2	13.7	16.2
Total Cost	$ 277,139	$ 585,748	$ 1,405,503	$ 2,680,422	$ 5,290,552	$ 7,670,279	$ 8,541,513	$ 9,440,403	$ 10,372,856	$ 11,434,484
Fuel ($/MMBTU)	$ 7.87	$ 7.59	$ 8.42	$ 8.34	$ 8.20	$ 8.41	$ 8.66	$ 8.90	$ 9.15	$ 9.65

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	22.0	24.9	27.9	30.8	33.8	36.3	38.4	39.7	41.0	42.2
aMW	18.7	21.2	23.8	26.3	28.8	31.0	32.8	33.8	34.9	36.0
Total Cost	$ 12,141,395	$ 13,299,574	$ 14,526,378	$ 15,689,623	$ 16,888,463	$ 17,306,697	$ 17,609,750	$ 17,019,398	$ 18,096,019	$ 19,559,924
Fuel ($/MMBTU)	$ 9.95	$ 10.42	$ 10.92	$ 11.22	$ 11.51	$ 11.83	$ 12.14	$ 12.47	$ 12.81	$ 13.15

Table E-17. Distributed Generation Low Growth Scenario: CHP (Natural Gas)

CHP (Natural gas)	% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Recip Engine	0%	65%	35%											
				MW	0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
				aMW	0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
				Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
				O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
				Fuel ($/kW)	$ 312	$ 301	$ 292	$ 277	$ 242	$ 238	$ 235	$ 236	$ 238	$ 237
				Lump sum ($)	$ 106,248	$ 237,545	$ 567,395	$ 1,092,591	$ 2,097,499	$ 3,113,148	$ 3,620,269	$ 4,146,790	$ 4,681,398	$ 5,194,099
Microturbine	0%	65%	35%											
				MW	0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
				aMW	0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
				Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
				O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
				Fuel ($/kW)	$ 487	$ 469	$ 455	$ 432	$ 377	$ 372	$ 367	$ 369	$ 371	$ 370
				Lump sum ($)	$ 31,043	$ 69,114	$ 164,857	$ 316,714	$ 606,416	$ 897,049	$ 1,037,349	$ 1,183,594	$ 1,332,318	$ 1,474,328
Fuel Cell	0%	65%	35%											
				MW	0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
				aMW	0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
				Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
				O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
				Fuel ($/kW)	$ 380	$ 366	$ 355	$ 338	$ 295	$ 290	$ 287	$ 288	$ 290	$ 289
				Lump sum ($)	$ 38,798	$ 79,792	$ 187,234	$ 350,758	$ 681,909	$ 955,422	$ 997,774	$ 1,042,351	$ 1,087,855	$ 1,130,847

CHP (Natural gas)		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
												Gen SS Resource L	$0.09	$/kWh
Recip Engine														
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01			
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%	
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087			
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345			
	Fuel ($/kW)	$ 239	$ 248	$ 258	$ 262	$ 266	$ 270	$ 274	$ 279	$ 284	$ 289			
	Lump sum ($)	$ 5,734,423	$ 6,375,180	$ 7,054,841	$ 7,674,120	$ 8,304,047	$ 8,605,394	$ 8,841,715	$ 8,660,757	$ 9,017,436	$ 9,383,819	Levelized Cost	$0.07	$/kWh
Microturbine														
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32			
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%	
	Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634			
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135			
	Fuel ($/kW)	$ 372	$ 386	$ 402	$ 408	$ 414	$ 421	$ 428	$ 435	$ 443	$ 451			
	Lump sum ($)	$ 1,624,803	$ 1,806,055	$ 1,999,230	$ 2,173,900	$ 2,351,834	$ 2,457,457	$ 2,545,312	$ 2,551,384	$ 2,747,521	$ 3,047,717	Levelized Cost	$0.09	$/kWh
Fuel Cell														
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07			
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%	
	Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314			
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403			
	Fuel ($/kW)	$ 291	$ 302	$ 314	$ 319	$ 324	$ 329	$ 334	$ 340	$ 346	$ 352			
	Lump sum ($)	$ 1,213,353	$ 1,307,380	$ 1,466,445	$ 1,667,045	$ 2,026,365	$ 2,186,600	$ 2,111,446	$ 1,901,984	$ 1,936,118	$ 1,971,365	Levelized Cost	$0.18	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Table E-18. Distributed Generation Low Growth Scenario: Renewables

Renewable		% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Small Wind	30%	70%	0%											
					MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
					aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
					Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
					O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
					Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
	PV	50%	50%	0%											
					MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
					aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
					Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
					O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
					Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass															
	Industrial	0%	0%	100%											
					MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
					aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
					Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
					O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
					Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
	Anaerobic Digester	0%	100%	0%											
					MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
					aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
					Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
					O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
					Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

Renewable			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost	
	Small Wind													
		MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26		
		aMW	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	Capacity Factor	15%
		Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598		
		O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600		
		Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.30 $/kWh
	PV													
		MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61		
		aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%
		Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700		
		O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800		
		Lump sum ($)	$ 319,554	$ 320,270	$ 320,987	$ 321,703	$ 322,419	$ 278,143	$ 233,764	$ 144,290	$ 144,597	$ 144,904	Levelized Cost	$0.97 $/kWh
Biomass														
	Industrial													
		MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67		
		aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%
		Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600		
		O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600		
		Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04 $/kWh
	Anaerobic Digester													
		MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57		
		aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%
		Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906		
		O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013		
		Lump sum ($)	$ 2,655,332	$ 2,706,223	$ 2,757,115	$ 2,808,006	$ 2,858,897	$ 2,674,790	$ 2,483,413	$ 2,114,833	$ 2,527,034	$ 3,362,160	Levelized Cost	$0.10 $/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation Low Growth Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	0.9	1.9	3.9	6.6	9.4	12.1	14.8	17.5
aMW	0.1	0.3	0.8	1.7	3.4	5.8	8.2	10.6	12.9	15.3
Total Cost	$ 208,403	$ 453,124	$ 1,076,830	$ 2,058,121	$ 3,982,083	$ 5,810,828	$ 6,557,190	$ 7,328,895	$ 8,111,168	$ 8,864,819
Fuel ($/MMBTU)	$ 7.87	$ 7.59	$ 7.36	$ 7.00	$ 6.10	$ 6.01	$ 5.94	$ 5.97	$ 6.01	$ 5.98

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	20.3	23.0	25.7	28.5	31.2	33.5	35.5	36.7	37.8	39.0
aMW	17.7	20.1	22.5	24.9	27.2	29.3	31.0	32.0	33.0	34.0
Total Cost	$ 9,654,558	$ 10,575,508	$ 11,547,284	$ 12,440,173	$ 13,346,974	$ 13,615,844	$ 13,787,784	$ 13,209,488	$ 13,804,707	$ 14,513,688
Fuel ($/MMBTU)	$ 6.03	$ 6.25	$ 6.50	$ 6.60	$ 6.70	$ 6.81	$ 6.93	$ 7.04	$ 7.17	$ 7.30

Table E-19. Distributed Generation + Emerging Technologies Low Growth Scenario: CHP (Natural Gas)

CHP (Natural gas)	% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Recip Engine	5%	63%	32%											
				MW	0.07	0.20	0.51	1.08	2.20	3.74	5.28	6.82	8.36	9.90
				aMW	0.06	0.18	0.46	0.97	1.98	3.37	4.75	6.14	7.53	8.91
				Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087
				O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345
				Fuel ($/kW)	$ 312	$ 301	$ 292	$ 277	$ 242	$ 238	$ 235	$ 236	$ 238	$ 237
				Lump sum ($)	$ 106,248	$ 237,545	$ 567,395	$ 1,092,591	$ 2,097,499	$ 3,113,148	$ 3,620,269	$ 4,146,790	$ 4,681,398	$ 5,194,099
Microturbine	5%	63%	32%											
				MW	0.01	0.04	0.10	0.21	0.43	0.74	1.04	1.34	1.64	1.95
				aMW	0.01	0.04	0.09	0.20	0.41	0.70	0.99	1.27	1.56	1.85
				Inst costs ($/kW)	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634	$ 1,634
				O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135
				Fuel ($/kW)	$ 487	$ 469	$ 455	$ 432	$ 377	$ 372	$ 367	$ 369	$ 371	$ 370
				Lump sum ($)	$ 31,043	$ 69,114	$ 164,857	$ 316,714	$ 606,416	$ 897,049	$ 1,037,349	$ 1,183,594	$ 1,332,318	$ 1,474,328
Fuel Cell	5%	63%	32%											
				MW	0.01	0.02	0.05	0.10	0.21	0.35	0.50	0.64	0.79	0.93
				aMW	0.01	0.02	0.05	0.10	0.20	0.33	0.47	0.61	0.75	0.89
				Inst costs ($/kW)	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314	$ 5,314
				O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403
				Fuel ($/kW)	$ 380	$ 366	$ 355	$ 338	$ 295	$ 290	$ 287	$ 288	$ 290	$ 289
				Lump sum ($)	$ 38,798	$ 79,792	$ 187,234	$ 350,758	$ 681,909	$ 955,422	$ 997,774	$ 1,042,351	$ 1,087,855	$ 1,130,847

CHP (Natural gas)		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost	
												Gen SS Resource	$0.09 $/kWh
Recip Engine													
	MW	11.44	12.98	14.52	16.06	17.61	18.93	20.03	20.69	21.35	22.01		
	aMW	10.30	11.69	13.07	14.46	15.84	17.03	18.02	18.62	19.21	19.81	Capacity Factor	90%
	Inst costs ($/kW)	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087	$ 1,087		
	O&M ($/MW)	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345	$ 101,345		
	Fuel ($/kW)	$ 239	$ 248	$ 258	$ 262	$ 266	$ 270	$ 274	$ 279	$ 284	$ 289		
	Lump sum ($)	$ 5,734,423	$ 6,375,180	$ 7,054,841	$ 7,674,120	$ 8,304,047	$ 8,605,394	$ 8,841,715	$ 8,660,757	$ 9,017,436	$ 9,383,819	Levelized Cost	$0.07 $/kWh
Microturbine													
	MW	2.25	2.55	2.85	3.16	3.46	3.72	3.94	4.07	4.20	4.32		
	aMW	2.14	2.42	2.71	3.00	3.29	3.53	3.74	3.86	3.99	4.11	Capacity Factor	95%
	Inst costs ($/kW)	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053	$ 1,053		
	O&M ($/MW)	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135	$ 108,135		
	Fuel ($/kW)	$ 372	$ 386	$ 402	$ 408	$ 414	$ 421	$ 428	$ 435	$ 443	$ 451		
	Lump sum ($)	$ 1,431,063	$ 1,612,316	$ 1,805,490	$ 1,980,160	$ 2,158,094	$ 2,283,091	$ 2,390,320	$ 2,429,605	$ 2,592,530	$ 2,823,532	Levelized Cost	$0.09 $/kWh
Fuel Cell													
	MW	1.08	1.22	1.37	1.51	1.66	1.78	1.89	1.95	2.01	2.07		
	aMW	1.02	1.16	1.30	1.44	1.58	1.69	1.79	1.85	1.91	1.97	Capacity Factor	95%
	Inst costs ($/kW)	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423	$ 3,423		
	O&M ($/MW)	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403	$ 14,403		
	Fuel ($/kW)	$ 291	$ 302	$ 314	$ 319	$ 324	$ 329	$ 334	$ 340	$ 346	$ 352		
	Lump sum ($)	$ 898,552	$ 979,641	$ 1,104,207	$ 1,253,059	$ 1,504,570	$ 1,625,994	$ 1,593,963	$ 1,470,748	$ 1,504,882	$ 1,540,129	Levelized Cost	$0.15 $/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Table E-20. Distributed Generation + Emerging Technologies Low Growth Scenario: Renewables

Renewable		% Penetration (by MW) Res	Com	Ind		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
	Small Wind	30%	70%	0%											
					MW	0.00	0.00	0.01	0.01	0.03	0.04	0.06	0.08	0.10	0.12
					aMW	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.02
					Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598
					O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600
					Lump sum ($)	$ 2,263	$ 4,592	$ 10,760	$ 20,124	$ 39,562	$ 55,036	$ 56,606	$ 58,176	$ 59,747	$ 61,317
	PV	50%	50%	0%											
					MW	0.00	0.01	0.01	0.03	0.06	0.10	0.15	0.19	0.23	0.27
					aMW	0.00	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03
					Inst costs ($/kW)	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700	$ 6,700
					O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800
					Lump sum ($)	$ 13,498	$ 27,026	$ 63,082	$ 117,217	$ 229,964	$ 315,973	$ 316,689	$ 317,405	$ 318,121	$ 318,838
Biomass															
	Industrial	0%	0%	100%											
					MW	0.04	0.11	0.29	0.62	1.27	2.15	3.04	3.93	4.81	5.70
					aMW	0.03	0.09	0.23	0.50	1.01	1.72	2.43	3.14	3.85	4.56
					Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600
					O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600
					Lump sum ($)	$ 71,112	$ 146,465	$ 344,578	$ 648,816	$ 1,278,168	$ 1,800,631	$ 1,899,571	$ 1,998,512	$ 2,097,452	$ 2,196,392
	Anaerobic Digester	0%	100%	0%											
					MW	0.02	0.07	0.17	0.37	0.76	1.29	1.82	2.35	2.88	3.41
					aMW	0.02	0.05	0.14	0.30	0.61	1.03	1.45	1.88	2.30	2.73
					Inst costs ($/kW)	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906	$ 3,906
					O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013
					Lump sum ($)	$ 99,779	$ 201,739	$ 472,178	$ 881,471	$ 1,731,864	$ 2,400,875	$ 2,451,766	$ 2,502,658	$ 2,553,549	$ 2,604,441

Renewable			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Levelized Cost		
	Small Wind														
		MW	0.13	0.15	0.17	0.19	0.20	0.22	0.23	0.24	0.25	0.26			
		aMW	0.02	0.03	0.03	0.03	0.04	0.04	0.04	0.05	0.05	0.05	Capacity Factor	15%	
		Inst costs ($/kW)	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	$ 2,598	CF after Year 10	23%	
		O&M ($/MW)	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600	$ 87,600			
		Lump sum ($)	$ 62,888	$ 64,458	$ 66,028	$ 67,599	$ 69,169	$ 63,198	$ 57,002	$ 43,040	$ 43,713	$ 44,386	Levelized Cost	$0.30	$/kWh
	PV														
		MW	0.32	0.36	0.40	0.44	0.49	0.52	0.55	0.57	0.59	0.61			
		aMW	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	Capacity Factor	12%	
		Inst costs ($/kW)	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315	$ 4,315			
		O&M ($/MW)	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800	$ 16,800			
		Lump sum ($)	$ 207,705	$ 208,421	$ 209,137	$ 209,854	$ 210,570	$ 182,272	$ 153,872	$ 96,355	$ 96,662	$ 96,969	Levelized Cost	$0.79	$/kWh
Biomass															
	Industrial														
		MW	6.59	7.47	8.36	9.25	10.13	10.89	11.53	11.91	12.29	12.67			
		aMW	5.27	5.98	6.69	7.40	8.11	8.71	9.22	9.52	9.83	10.13	Capacity Factor	80%	
		Inst costs ($/kW)	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600	$ 1,600			
		O&M ($/MW)	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600	$ 111,600			
		Lump sum ($)	$ 2,295,332	$ 2,394,273	$ 2,493,213	$ 2,592,153	$ 2,691,093	$ 2,552,992	$ 2,400,757	$ 1,997,346	$ 2,039,749	$ 2,082,152	Levelized Cost	$0.04	$/kWh
	Anaerobic Digester														
		MW	3.94	4.47	5.00	5.53	6.06	6.51	6.89	7.12	7.34	7.57			
		aMW	3.15	3.57	4.00	4.42	4.85	5.21	5.51	5.69	5.88	6.06	Capacity Factor	80%	
		Inst costs ($/kW)	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354	$ 3,354			
		O&M ($/MW)	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013	$ 96,013			
		Lump sum ($)	$ 2,333,647	$ 2,384,539	$ 2,435,430	$ 2,486,321	$ 2,537,213	$ 2,385,274	$ 2,226,065	$ 1,912,631	$ 2,269,687	$ 2,989,925	Levelized Cost	$0.09	$/kWh

NOTE: Red indicates levelized cost is less than cost of generic resource; all admin. costs are 10%.

Distributed Generation + Emerging Technologies Low Growth Economic Market Potential and Cost

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
MW	0.1	0.4	1.1	2.3	4.7	7.9	11.2	14.4	17.7	21.0
aMW	0.1	0.4	0.9	2.0	4.0	6.8	9.6	12.4	15.2	18.0
Total Cost	$ 308,182	$ 654,863	$ 1,549,008	$ 2,939,592	$ 5,713,948	$ 8,211,703	$ 9,008,956	$ 9,831,553	$ 10,664,717	$ 11,469,260
Fuel ($/MMBTU)	$ 7.87	$ 7.59	$ 7.36	$ 7.00	$ 6.10	$ 6.01	$ 5.94	$ 5.97	$ 6.01	$ 5.98

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
MW	24.2	27.5	30.7	34.0	37.3	40.0	42.4	43.8	45.2	46.6
aMW	20.9	23.7	26.5	29.3	32.1	34.5	36.5	37.7	38.9	40.1
Total Cost	$ 11,794,466	$ 12,766,307	$ 13,788,974	$ 14,732,755	$ 15,690,447	$ 15,826,752	$ 15,858,858	$ 15,000,339	$ 15,919,402	$ 17,279,428
Fuel ($/MMBTU)	$ 6.03	$ 6.25	$ 6.50	$ 6.60	$ 6.70	$ 6.81	$ 6.93	$ 7.04	$ 7.17	$ 7.30

Appendix F: Other Data

Table F-1. Residential Electric: Sales Forecast (MWh)

Year	Island	Jefferson	King	Kitsap	Kittitas	Pierce	Skagit	Thurston	Whatcom	Total
2007	361,790	207,614	4,955,160	1,337,557	116,127	1,194,076	523,011	1,238,838	808,729	10,742,901
2008	361,587	212,169	4,972,105	1,329,392	118,693	1,213,752	521,716	1,241,452	808,332	10,779,199
2009	364,579	219,604	5,028,433	1,335,697	122,307	1,247,612	524,666	1,251,468	814,392	10,908,758
2010	367,566	228,257	5,048,638	1,342,287	126,499	1,269,741	528,749	1,268,982	824,124	11,004,842
2011	375,221	236,264	5,079,305	1,375,888	131,078	1,287,413	536,487	1,294,647	838,566	11,154,867
2012	383,416	242,918	5,104,852	1,414,970	135,539	1,311,924	544,926	1,332,012	853,741	11,324,298
2013	391,910	249,967	5,155,822	1,452,605	139,252	1,340,557	555,111	1,369,868	870,861	11,525,953
2014	400,300	257,135	5,230,961	1,489,629	142,514	1,370,177	565,760	1,405,502	889,158	11,751,136
2015	408,373	263,352	5,311,631	1,529,289	145,819	1,395,992	573,552	1,439,865	904,129	11,972,002
2016	416,694	268,899	5,394,033	1,570,689	149,301	1,421,463	579,898	1,476,546	916,075	12,193,598
2017	424,839	274,579	5,481,710	1,610,539	151,647	1,448,874	586,849	1,513,707	928,549	12,421,292
2018	432,443	280,225	5,569,323	1,647,819	152,556	1,476,572	593,857	1,547,281	941,118	12,641,195
2019	439,796	285,743	5,655,006	1,684,756	153,299	1,503,908	600,463	1,579,044	953,240	12,855,256
2020	447,852	291,751	5,748,090	1,725,116	154,319	1,533,609	607,866	1,614,148	966,745	13,089,495
2021	455,732	297,660	5,837,183	1,765,595	155,318	1,562,183	614,826	1,649,094	979,758	13,317,349
2022	463,530	302,753	5,937,066	1,795,807	157,975	1,588,915	625,346	1,677,312	996,524	13,545,230
2023	471,553	307,993	6,039,821	1,826,888	160,709	1,616,415	636,169	1,706,342	1,013,771	13,779,661
2024	479,780	313,367	6,145,191	1,858,759	163,513	1,644,614	647,268	1,736,110	1,031,457	14,020,059
2025	488,289	318,924	6,254,182	1,891,726	166,413	1,673,783	658,748	1,766,902	1,049,751	14,268,719
2026	496,973	324,596	6,365,411	1,925,370	169,373	1,703,551	670,463	1,798,326	1,068,420	14,522,484
2027	505,741	330,323	6,477,710	1,959,338	172,361	1,733,605	682,292	1,830,052	1,087,269	14,778,690

Table F-2. Residential Electric: Housing Type Allocation

Year	County	Multi_Family	Manufactured	Single_Family
2007	Island	0.108765443	0.111785764	0.779448793
2008	Island	0.108151076	0.110293164	0.78155576
2009	Island	0.107536709	0.108800564	0.783662728
2010	Island	0.106922342	0.107307963	0.785769695
2011	Island	0.106307975	0.105815363	0.787876662
2012	Island	0.105693608	0.104322763	0.789983629
2013	Island	0.105079241	0.102830162	0.792090596
2014	Island	0.104464874	0.101337562	0.794197564
2015	Island	0.103850508	0.099844961	0.796304531
2016	Island	0.103236141	0.098352361	0.798411498
2017	Island	0.102621774	0.096859761	0.800518465
2018	Island	0.102007407	0.09536716	0.802625433
2019	Island	0.10139304	0.09387456	0.8047324
2020	Island	0.100778673	0.09238196	0.806839367
2021	Island	0.100164306	0.090889359	0.808946334
2022	Island	0.09954994	0.089396759	0.811053302
2023	Island	0.098935573	0.087904159	0.813160269
2024	Island	0.098321206	0.086411558	0.815267236
2025	Island	0.097706839	0.084918958	0.817374203
2026	Island	0.097096311	0.083452139	0.819486616
2027	Island	0.096489598	0.082010658	0.821604487
2007	Jefferson	0.074661914	0.179485281	0.745852806
2008	Jefferson	0.074438662	0.177708559	0.74785278
2009	Jefferson	0.07421541	0.175931836	0.749852754
2010	Jefferson	0.073992158	0.174155114	0.751852728
2011	Jefferson	0.073768906	0.172378392	0.753852702
2012	Jefferson	0.073545654	0.17060167	0.755852676
2013	Jefferson	0.073322402	0.168824948	0.75785265
2014	Jefferson	0.07309915	0.167048225	0.759852624
2015	Jefferson	0.072875898	0.165271503	0.761852599
2016	Jefferson	0.072652646	0.163494781	0.763852573
2017	Jefferson	0.072429394	0.161718059	0.765852547
2018	Jefferson	0.072206142	0.159941337	0.767852521
2019	Jefferson	0.07198289	0.158164614	0.769852495
2020	Jefferson	0.071759639	0.156387892	0.771852469
2021	Jefferson	0.071536387	0.15461117	0.773852443
2022	Jefferson	0.071313135	0.152834448	0.775852417
2023	Jefferson	0.071089883	0.151057726	0.777852392
2024	Jefferson	0.070866631	0.149281004	0.779852366
2025	Jefferson	0.070643379	0.147504281	0.78185234
2026	Jefferson	0.07042083	0.145748705	0.783857443
2027	Jefferson	0.070198983	0.144014024	0.785867688
2007	King	0.317806712	0.038269385	0.643923903
2008	King	0.319520124	0.037886344	0.642593532
2009	King	0.321233537	0.037503303	0.64126316
2010	King	0.322946949	0.037120262	0.639932789
2011	King	0.324660362	0.036737221	0.638602418
2012	King	0.326373774	0.03635418	0.637272046
2013	King	0.328087186	0.035971139	0.635941675

Year	County	Multi_Family	Manufactured	Single_Family
2014	King	0.329800599	0.035588097	0.634611304
2015	King	0.331514011	0.035205056	0.633280932
2016	King	0.333227424	0.034822015	0.631950561
2017	King	0.334940836	0.034438974	0.63062019
2018	King	0.336654248	0.034055933	0.629289818
2019	King	0.338367661	0.033672892	0.627959447
2020	King	0.340081073	0.033289851	0.626629076
2021	King	0.341794486	0.03290681	0.625298704
2022	King	0.343507898	0.032523769	0.623968333
2023	King	0.34522131	0.032140728	0.622637962
2024	King	0.346934723	0.031757687	0.621307591
2025	King	0.348648135	0.031374646	0.619977219
2026	King	0.35037001	0.030996224	0.618649697
2027	King	0.352100388	0.030622368	0.617325016
2007	Kitsap	0.188934162	0.105278847	0.705786991
2008	Kitsap	0.18882082	0.105030947	0.706148233
2009	Kitsap	0.188707477	0.104783047	0.706509475
2010	Kitsap	0.188594135	0.104535148	0.706870718
2011	Kitsap	0.188480792	0.104287248	0.70723196
2012	Kitsap	0.188367449	0.104039348	0.707593203
2013	Kitsap	0.188254107	0.103791448	0.707954445
2014	Kitsap	0.188140764	0.103543549	0.708315687
2015	Kitsap	0.188027421	0.103295649	0.70867693
2016	Kitsap	0.187914079	0.103047749	0.709038172
2017	Kitsap	0.187800736	0.102799849	0.709399415
2018	Kitsap	0.187687394	0.10255195	0.709760657
2019	Kitsap	0.187574051	0.10230405	0.710121899
2020	Kitsap	0.187460708	0.10205615	0.710483142
2021	Kitsap	0.187347366	0.10180825	0.710844384
2022	Kitsap	0.187234023	0.10156035	0.711205626
2023	Kitsap	0.187120681	0.101312451	0.711566869
2024	Kitsap	0.187007338	0.101064551	0.711928111
2025	Kitsap	0.186893995	0.100816651	0.712289354
2026	Kitsap	0.186780721	0.100569359	0.712650779
2027	Kitsap	0.186667516	0.100322674	0.713012388
2007	Kittitas	0.055613926	0.205505592	0.738880482
2008	Kittitas	0.055805529	0.206328364	0.737866107
2009	Kittitas	0.055997132	0.207151136	0.736851732
2010	Kittitas	0.056188735	0.207973908	0.735837357
2011	Kittitas	0.056380339	0.20879668	0.734822982
2012	Kittitas	0.056571942	0.209619452	0.733808607
2013	Kittitas	0.056763545	0.210442224	0.732794232
2014	Kittitas	0.056955148	0.211264996	0.731779856
2015	Kittitas	0.057146751	0.212087768	0.730765481
2016	Kittitas	0.057338354	0.212910539	0.729751106
2017	Kittitas	0.057529958	0.213733311	0.728736731
2018	Kittitas	0.057721561	0.214556083	0.727722356
2019	Kittitas	0.057913164	0.215378855	0.726707981
2020	Kittitas	0.058104767	0.216201627	0.725693605
2021	Kittitas	0.05829637	0.217024399	0.72467923
2022	Kittitas	0.058487973	0.217847171	0.723664855

Year	County	Multi_Family	Manufactured	Single_Family
2023	Kittitas	0.058679577	0.218669943	0.72265048
2024	Kittitas	0.05887118	0.219492715	0.721636105
2025	Kittitas	0.059062783	0.220315487	0.72062173
2026	Kittitas	0.05925501	0.221141344	0.71960878
2027	Kittitas	0.059447862	0.221970295	0.718597255
2007	Pierce	0.172345989	0.116429175	0.711224836
2008	Pierce	0.16972604	0.116029065	0.714244896
2009	Pierce	0.16710609	0.115628954	0.717264956
2010	Pierce	0.164486141	0.115228843	0.720285015
2011	Pierce	0.161866192	0.114828733	0.723305075
2012	Pierce	0.159246243	0.114428622	0.726325135
2013	Pierce	0.156626294	0.114028512	0.729345195
2014	Pierce	0.154006344	0.113628401	0.732365254
2015	Pierce	0.151386395	0.113228291	0.735385314
2016	Pierce	0.148766446	0.11282818	0.738405374
2017	Pierce	0.146146497	0.112428069	0.741425434
2018	Pierce	0.143526548	0.112027959	0.744445493
2019	Pierce	0.140906598	0.111627848	0.747465553
2020	Pierce	0.138286649	0.111227738	0.750485613
2021	Pierce	0.1356667	0.110827627	0.753505673
2022	Pierce	0.133046751	0.110427517	0.756525733
2023	Pierce	0.130426802	0.110027406	0.759545792
2024	Pierce	0.127806853	0.109627295	0.762565852
2025	Pierce	0.125186903	0.109227185	0.765585912
2026	Pierce	0.122620661	0.108828535	0.768617932
2027	Pierce	0.120107025	0.108431339	0.771661961
2007	Skagit	0.158953321	0.132543092	0.708503587
2008	Skagit	0.160140236	0.133170256	0.706689508
2009	Skagit	0.161327152	0.133797419	0.704875429
2010	Skagit	0.162514067	0.134424582	0.70306135
2011	Skagit	0.163700983	0.135051746	0.701247271
2012	Skagit	0.164887899	0.135678909	0.699433193
2013	Skagit	0.166074814	0.136306072	0.697619114
2014	Skagit	0.16726173	0.136933235	0.695805035
2015	Skagit	0.168448645	0.137560399	0.693990956
2016	Skagit	0.169635561	0.138187562	0.692176877
2017	Skagit	0.170822476	0.138814725	0.690362798
2018	Skagit	0.172009392	0.139441889	0.68854872
2019	Skagit	0.173196307	0.140069052	0.686734641
2020	Skagit	0.174383223	0.140696215	0.684920562
2021	Skagit	0.175570138	0.141323379	0.683106483
2022	Skagit	0.176757054	0.141950542	0.681292404
2023	Skagit	0.17794397	0.142577705	0.679478325
2024	Skagit	0.179130885	0.143204868	0.677664246
2025	Skagit	0.180317801	0.143832032	0.675850168
2026	Skagit	0.181512581	0.144461942	0.674040945
2027	Skagit	0.182715277	0.14509461	0.672236566
2007	Thurston	0.192496214	0.131222859	0.676280927
2008	Thurston	0.192226823	0.129714718	0.678058458
2009	Thurston	0.191957433	0.128206578	0.67983599
2010	Thurston	0.191688042	0.126698437	0.681613521

Year	County	Multi_Family	Manufactured	Single_Family
2011	Thurston	0.191418652	0.125190296	0.683391053
2012	Thurston	0.191149261	0.123682155	0.685168584
2013	Thurston	0.19087987	0.122174014	0.686946116
2014	Thurston	0.19061048	0.120665873	0.688723647
2015	Thurston	0.190341089	0.119157732	0.690501179
2016	Thurston	0.190071698	0.117649591	0.69227871
2017	Thurston	0.189802308	0.11614145	0.694056242
2018	Thurston	0.189532917	0.114633309	0.695833774
2019	Thurston	0.189263527	0.113125168	0.697611305
2020	Thurston	0.188994136	0.111617027	0.699388837
2021	Thurston	0.188724745	0.110108887	0.701166368
2022	Thurston	0.188455355	0.108600746	0.7029439
2023	Thurston	0.188185964	0.107092605	0.704721431
2024	Thurston	0.187916573	0.105584464	0.706498963
2025	Thurston	0.187647183	0.104076323	0.708276494
2026	Thurston	0.187378178	0.102589724	0.710058498
2027	Thurston	0.18710956	0.101124359	0.711844985
2007	Whatcom	0.248544376	0.129586595	0.621869029
2008	Whatcom	0.251691307	0.129909522	0.618399171
2009	Whatcom	0.254838238	0.130232449	0.614929313
2010	Whatcom	0.257985168	0.130555376	0.611459455
2011	Whatcom	0.261132099	0.130878303	0.607989597
2012	Whatcom	0.26427903	0.131201231	0.60451974
2013	Whatcom	0.26742596	0.131524158	0.601049882
2014	Whatcom	0.270572891	0.131847085	0.597580024
2015	Whatcom	0.273719822	0.132170012	0.594110166
2016	Whatcom	0.276866752	0.132492939	0.590640309
2017	Whatcom	0.280013683	0.132815866	0.587170451
2018	Whatcom	0.283160614	0.133138793	0.583700593
2019	Whatcom	0.286307545	0.13346172	0.580230735
2020	Whatcom	0.289454475	0.133784647	0.576760877
2021	Whatcom	0.292601406	0.134107574	0.57329102
2022	Whatcom	0.295748337	0.134430502	0.569821162
2023	Whatcom	0.298895267	0.134753429	0.566351304
2024	Whatcom	0.302042198	0.135076356	0.562881446
2025	Whatcom	0.305189129	0.135399283	0.559411589
2026	Whatcom	0.308368847	0.135722982	0.555963121
2027	Whatcom	0.311581694	0.136047455	0.55253591

Table F-3. Residential Electric: Customer Count Forecast

Year	Island	Jefferson	King	Kitsap	Kittitas	Pierce	Skagit	Thurston	Whatcom	Total
2007	30,080	15,669	447,701	102,153	9,424	93,560	47,473	100,462	81,771	928,292
2008	30,572	16,283	456,860	103,248	9,796	96,715	48,159	102,380	83,118	947,132
2009	31,058	16,981	465,549	104,522	10,171	100,168	48,800	103,987	84,377	965,613
2010	31,636	17,833	472,274	106,125	10,628	103,002	49,690	106,535	86,272	983,996
2011	32,471	18,558	477,749	109,375	11,073	105,008	50,693	109,283	88,264	1,002,474
2012	33,315	19,159	482,141	112,943	11,494	107,449	51,703	112,900	90,233	1,021,337
2013	34,110	19,748	487,790	116,141	11,825	109,981	52,759	116,304	92,199	1,040,858
2014	34,843	20,315	494,975	119,113	12,103	112,427	53,779	119,343	94,151	1,061,050
2015	35,582	20,828	503,176	122,413	12,397	114,673	54,581	122,391	95,843	1,081,883
2016	36,352	21,293	511,743	125,892	12,711	116,934	55,264	125,678	97,251	1,103,117
2017	37,096	21,761	520,535	129,201	12,914	119,297	55,977	128,957	98,664	1,124,401
2018	37,810	22,239	529,567	132,368	13,009	121,741	56,721	131,994	100,134	1,145,583
2019	38,518	22,715	538,624	135,564	13,094	124,205	57,449	134,931	101,595	1,166,694
2020	39,226	23,194	547,536	138,822	13,183	126,668	58,162	137,941	103,043	1,187,776
2021	39,940	23,678	556,346	142,162	13,276	129,103	58,863	141,010	104,491	1,208,867
2022	40,770	24,162	565,226	144,768	13,468	131,725	59,785	143,703	106,653	1,230,259
2023	41,502	24,596	575,370	147,366	13,710	134,089	60,858	146,282	108,567	1,252,339
2024	42,257	25,043	585,835	150,046	13,959	136,528	61,965	148,943	110,542	1,275,117
2025	43,030	25,501	596,547	152,790	14,214	139,024	63,098	151,666	112,563	1,298,433
2026	43,817	25,968	607,464	155,586	14,474	141,568	64,253	154,442	114,623	1,322,194
2027	44,618	26,442	618,566	158,429	14,739	144,156	65,427	157,264	116,718	1,346,360

Table F-4. Residential Electric: Efficiency Shares

bName	nName	fName	Stock	Standard	High	Premium	Super_Premium
Manufactured	Central_AC	Electric	0.5	0.4	0.07	0.02	0.01
Manufactured	Cooking	Electric	0.95	0.05			
Manufactured	Cooking	Gas	1				
Manufactured	Freezer	Electric	0.95	0.03	0.02		
Manufactured	Heat_Pump	Electric	0.5	0.4	0.09	0.01	
Manufactured	Lighting	Electric	1				
Manufactured	Other	Electric	1				
Manufactured	Plug_Load	Electric	1				
Manufactured	Refrigeration	Electric	0.6	0.2	0.20		
Manufactured	Room_AC	Electric	0.59	0.34	0.07		
Manufactured	Space_Heat	Electric	1				
Manufactured	Space_Heat	Gas	1				
Manufactured	Water_Heat	Electric	0.1	0.9			
Manufactured	Water_Heat	Gas	1				
Multi_Family	Central_AC	Electric	0.5	0.4	0.07	0.02	0.01
Multi_Family	Cooking	Electric	0.95	0.05			
Multi_Family	Cooking	Gas	1				
Multi_Family	Freezer	Electric	0.95	0.03	0.02		
Multi_Family	Heat_Pump	Electric	0.5	0.4	0.09	0.01	
Multi_Family	Lighting	Electric	1				
Multi_Family	Other	Electric	1				
Multi_Family	Plug_Load	Electric	1				
Multi_Family	Refrigeration	Electric	0.6	0.2	0.20		
Multi_Family	Room_AC	Electric	0.5	0.48	0.02		
Multi_Family	Space_Heat	Electric	1				
Multi_Family	Space_Heat	Gas	1				
Multi_Family	Water_Heat	Electric	0.13	0.87			
Multi_Family	Water_Heat	Gas	1				
Single_Family	Central_AC	Electric	0.5	0.4	0.07	0.02	0.01
Single_Family	Cooking	Electric	0.9	0.1			
Single_Family	Cooking	Gas	1				
Single_Family	Freezer	Electric	0.95	0.03	0.02		
Single_Family	Heat_Pump	Electric	0.5	0.4	0.09	0.01	
Single_Family	Lighting	Electric	1				
Single_Family	Other	Electric	1				
Single_Family	Plug_Load	Electric	1				
Single_Family	Refrigeration	Electric	0.6	0.2	0.20		
Single_Family	Room_AC	Electric	0.59	0.34	0.07		
Single_Family	Space_Heat	Electric	1				
Single_Family	Space_Heat	Gas	1				
Single_Family	Water_Heat	Electric	0.1	0.9			
Single_Family	Water_Heat	Gas	1				
Manufactured	Dryer	Electric	0.65	0.35			
Multi_Family	Dryer	Electric	0.65	0.35			
Single_Family	Dryer	Electric	0.65	0.35			
Manufactured	Dryer	Gas	1				
Multi_Family	Dryer	Gas	1				
Single_Family	Dryer	Gas	1				

Table F-5. Residential Electric: Price Forecast ($/kWh)

Year	Res Price Deflator	Single_Family Average Price	Single_Family Marginal Price	Multi_Family Average Price	Multi_Family Marginal Price	Manufactured Average Price	Manufactured Marginal Price
2007	100.00	0.082077944	0.082077944	0.082077944	0.082077944	0.082077944	0.082077944
2008	102.36	0.084414096	0.084414096	0.084414096	0.084414096	0.084414096	0.084414096
2009	104.88	0.087790591	0.087790591	0.087790591	0.087790591	0.087790591	0.087790591
2010	107.71	0.091554894	0.091554894	0.091554894	0.091554894	0.091554894	0.091554894
2011	110.85	0.093935517	0.093935517	0.093935517	0.093935517	0.093935517	0.093935517
2012	114.08	0.096867362	0.096867362	0.096867362	0.096867362	0.096867362	0.096867362
2013	117.62	0.099707646	0.099707646	0.099707646	0.099707646	0.099707646	0.099707646
2014	121.21	0.102322788	0.102322788	0.102322788	0.102322788	0.102322788	0.102322788
2015	124.71	0.105251369	0.105251369	0.105251369	0.105251369	0.105251369	0.105251369
2016	128.31	0.108591229	0.108591229	0.108591229	0.108591229	0.108591229	0.108591229
2017	132.26	0.110620979	0.110620979	0.110620979	0.110620979	0.110620979	0.110620979
2018	136.58	0.113769415	0.113769415	0.113769415	0.113769415	0.113769415	0.113769415
2019	141.23	0.116712043	0.116712043	0.116712043	0.116712043	0.116712043	0.116712043
2020	146.18	0.119451071	0.119451071	0.119451071	0.119451071	0.119451071	0.119451071
2021	151.34	0.122219831	0.122219831	0.122219831	0.122219831	0.122219831	0.122219831
2022	156.72	0.125117083	0.125117083	0.125117083	0.125117083	0.125117083	0.125117083
2023	162.33	0.127931168	0.127931168	0.127931168	0.127931168	0.127931168	0.127931168
2024	168.17	0.130756568	0.130756568	0.130756568	0.130756568	0.130756568	0.130756568
2025	174.23	0.133600241	0.133600241	0.133600241	0.133600241	0.133600241	0.133600241
2026	180.50	0.136505757	0.136505757	0.136505757	0.136505757	0.136505757	0.136505757
2027	187.00	0.139474462	0.139474462	0.139474462	0.139474462	0.139474462	0.139474462

Table F-6. Residential Electric: Gas Price Forecast ($/therm)

Year	Single_Family Average Price	Single_Family Marginal Price	Multi_Family Average Price	Multi_Family Marginal Price	Manufactured Average Price	Manufactured Marginal Price
2007	1.3307	1.3307	1.3307	1.3307	1.3307	1.3307
2008	1.2888	1.2888	1.2888	1.2888	1.2888	1.2888
2009	1.2620	1.2620	1.2620	1.2620	1.2620	1.2620
2010	1.2547	1.2547	1.2547	1.2547	1.2547	1.2547
2011	1.0679	1.0679	1.0679	1.0679	1.0679	1.0679
2012	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019
2013	1.1765	1.1765	1.1765	1.1765	1.1765	1.1765
2014	1.2432	1.2432	1.2432	1.2432	1.2432	1.2432
2015	1.2686	1.2686	1.2686	1.2686	1.2686	1.2686
2016	1.2059	1.2059	1.2059	1.2059	1.2059	1.2059
2017	1.2473	1.2473	1.2473	1.2473	1.2473	1.2473
2018	1.3553	1.3553	1.3553	1.3553	1.3553	1.3553
2019	1.4501	1.4501	1.4501	1.4501	1.4501	1.4501
2020	1.5398	1.5398	1.5398	1.5398	1.5398	1.5398
2021	1.6220	1.6220	1.6220	1.6220	1.6220	1.6220
2022	1.6560	1.6560	1.6560	1.6560	1.6560	1.6560
2023	1.6911	1.6911	1.6911	1.6911	1.6911	1.6911
2024	1.7260	1.7260	1.7260	1.7260	1.7260	1.7260
2025	1.7435	1.7435	1.7435	1.7435	1.7435	1.7435
2006	1.7611	1.7611	1.7611	1.7611	1.7611	1.7611
2007	1.7790	1.7790	1.7790	1.7790	1.7790	1.7790

Table F-7. Residential Gas: Sales Forecast (therms)

Year	King	Kittitas	Lewis	Pierce	Snohomish	Thurston	Total
2007	339,248,910	271,497	3,409,890	104,819,463	87,792,538	30,745,696	566,287,994
2008	347,164,551	277,859	3,489,458	107,263,446	89,839,868	31,462,484	579,497,667
2009	356,582,541	285,418	3,584,131	110,171,621	92,275,280	32,315,469	595,214,459
2010	366,636,961	293,487	3,685,199	113,276,511	94,875,677	33,226,146	611,993,981
2011	376,397,338	301,311	3,783,316	116,290,640	97,399,172	34,110,259	628,282,036
2012	387,395,851	310,107	3,893,893	119,687,289	100,240,998	35,106,696	646,634,833
2013	395,858,363	316,876	3,978,978	122,300,356	102,426,812	35,873,275	660,754,659
2014	403,306,261	322,839	4,053,862	124,599,839	104,350,427	36,547,842	673,181,070
2015	411,705,251	329,568	4,138,304	127,193,086	106,520,455	37,308,551	687,195,214
2016	419,285,057	335,647	4,214,506	129,533,290	108,479,271	37,994,995	699,842,766
2017	425,869,103	340,931	4,280,696	131,566,026	110,181,073	38,591,228	710,829,057
2018	433,619,110	347,142	4,358,612	133,958,905	112,183,582	39,293,152	723,760,503
2019	441,103,850	353,139	4,433,864	136,269,700	114,117,081	39,971,010	736,248,643
2020	446,498,477	357,467	4,488,104	137,934,742	115,510,154	40,459,431	745,248,376
2021	451,553,601	361,526	4,538,930	139,494,920	116,815,719	40,917,075	753,681,771
2022	457,196,757	366,056	4,595,665	141,236,814	118,273,593	41,428,014	763,096,899
2023	463,778,201	371,337	4,661,831	143,268,625	119,974,311	42,023,991	774,078,296
2024	470,035,341	376,360	4,724,736	145,200,266	121,591,270	42,590,578	784,518,551
2025	475,738,269	380,926	4,782,062	146,961,977	123,066,534	43,107,329	794,037,097
2026	480,952,853	385,101	4,834,478	148,572,833	124,415,471	43,579,830	802,740,565
2027	485,329,949	388,606	4,878,476	149,924,977	125,547,762	43,976,445	810,046,215

Table F-8. Residential Gas: Housing Type Allocation

Year	County	Multi_Family	Manufactured	Single_Family
2007	King	0.3875	0.0250	0.5876
2008	King	0.3893	0.0246	0.5861
2009	King	0.3912	0.0243	0.5846
2010	King	0.3930	0.0239	0.5831
2011	King	0.3948	0.0236	0.5816
2012	King	0.3967	0.0233	0.5801
2013	King	0.3985	0.0229	0.5785
2014	King	0.4004	0.0226	0.5770
2015	King	0.4022	0.0222	0.5755
2016	King	0.4041	0.0219	0.5740
2017	King	0.4059	0.0215	0.5725
2018	King	0.4078	0.0212	0.5710
2019	King	0.4096	0.0209	0.5695
2020	King	0.4115	0.0205	0.5680
2021	King	0.4133	0.0202	0.5665
2022	King	0.4151	0.0198	0.5650
2023	King	0.4170	0.0195	0.5635
2024	King	0.4188	0.0191	0.5620
2025	King	0.4207	0.0188	0.5605
2026	King	0.4225	0.0185	0.5590
2027	King	0.4244	0.0181	0.5575
2007	Kittitas	0.0556	0.2055	0.7389
2008	Kittitas	0.0558	0.2063	0.7379
2009	Kittitas	0.0560	0.2072	0.7369
2010	Kittitas	0.0562	0.2080	0.7358
2011	Kittitas	0.0564	0.2088	0.7348
2012	Kittitas	0.0566	0.2096	0.7338
2013	Kittitas	0.0568	0.2104	0.7328
2014	Kittitas	0.0570	0.2113	0.7318
2015	Kittitas	0.0571	0.2121	0.7308
2016	Kittitas	0.0573	0.2129	0.7298
2017	Kittitas	0.0575	0.2137	0.7287
2018	Kittitas	0.0577	0.2146	0.7277
2019	Kittitas	0.0579	0.2154	0.7267
2020	Kittitas	0.0581	0.2162	0.7257
2021	Kittitas	0.0583	0.2170	0.7247
2022	Kittitas	0.0585	0.2178	0.7237
2023	Kittitas	0.0587	0.2187	0.7227
2024	Kittitas	0.0589	0.2195	0.7216
2025	Kittitas	0.0591	0.2203	0.7206
2026	Kittitas	0.0593	0.2211	0.7196
2027	Kittitas	0.0594	0.2220	0.7186
2007	Lewis	0.1220	0.1950	0.6830
2008	Lewis	0.1220	0.1950	0.6830
2009	Lewis	0.1220	0.1950	0.6830
2010	Lewis	0.1220	0.1950	0.6830
2011	Lewis	0.1220	0.1950	0.6830
2012	Lewis	0.1220	0.1950	0.6830
2013	Lewis	0.1220	0.1950	0.6830

Year	County	Multi_Family	Manufactured	Single_Family
2014	Lewis	0.1220	0.1950	0.6830
2015	Lewis	0.1220	0.1950	0.6830
2016	Lewis	0.1220	0.1950	0.6830
2017	Lewis	0.1220	0.1950	0.6830
2018	Lewis	0.1220	0.1950	0.6830
2019	Lewis	0.1220	0.1950	0.6830
2020	Lewis	0.1220	0.1950	0.6830
2021	Lewis	0.1220	0.1950	0.6830
2022	Lewis	0.1220	0.1950	0.6830
2023	Lewis	0.1220	0.1950	0.6830
2024	Lewis	0.1220	0.1950	0.6830
2025	Lewis	0.1220	0.1950	0.6830
2026	Lewis	0.1220	0.1950	0.6830
2027	Lewis	0.1220	0.1950	0.6830
2007	Pierce	0.2383	0.0823	0.6794
2008	Pierce	0.2371	0.0819	0.6810
2009	Pierce	0.2359	0.0815	0.6826
2010	Pierce	0.2347	0.0811	0.6843
2011	Pierce	0.2335	0.0806	0.6859
2012	Pierce	0.2322	0.0802	0.6876
2013	Pierce	0.2310	0.0798	0.6892
2014	Pierce	0.2298	0.0794	0.6908
2015	Pierce	0.2286	0.0789	0.6925
2016	Pierce	0.2274	0.0785	0.6941
2017	Pierce	0.2262	0.0781	0.6957
2018	Pierce	0.2250	0.0777	0.6974
2019	Pierce	0.2238	0.0772	0.6990
2020	Pierce	0.2226	0.0768	0.7006
2021	Pierce	0.2213	0.0764	0.7023
2022	Pierce	0.2201	0.0760	0.7039
2023	Pierce	0.2189	0.0756	0.7055
2024	Pierce	0.2177	0.0751	0.7072
2025	Pierce	0.2165	0.0747	0.7088
2026	Pierce	0.2153	0.0743	0.7104
2027	Pierce	0.2141	0.0739	0.7121
2007	Snohomish	0.2698	0.0695	0.6607
2008	Snohomish	0.2708	0.0674	0.6618
2009	Snohomish	0.2718	0.0653	0.6628
2010	Snohomish	0.2729	0.0632	0.6639
2011	Snohomish	0.2739	0.0612	0.6650
2012	Snohomish	0.2749	0.0591	0.6660
2013	Snohomish	0.2759	0.0570	0.6671
2014	Snohomish	0.2769	0.0549	0.6682
2015	Snohomish	0.2779	0.0528	0.6692
2016	Snohomish	0.2789	0.0508	0.6703
2017	Snohomish	0.2800	0.0487	0.6714
2018	Snohomish	0.2810	0.0466	0.6724
2019	Snohomish	0.2820	0.0445	0.6735
2020	Snohomish	0.2830	0.0424	0.6746
2021	Snohomish	0.2840	0.0403	0.6756
2022	Snohomish	0.2850	0.0383	0.6767

Year	County	Multi_Family	Manufactured	Single_Family
2023	Snohomish	0.2861	0.0362	0.6778
2024	Snohomish	0.2871	0.0341	0.6788
2025	Snohomish	0.2881	0.0320	0.6799
2026	Snohomish	0.2891	0.0301	0.6810
2027	Snohomish	0.2901	0.0282	0.6820
2007	Thurston	0.1925	0.1312	0.6763
2008	Thurston	0.1922	0.1297	0.6781
2009	Thurston	0.1920	0.1282	0.6798
2010	Thurston	0.1917	0.1267	0.6816
2011	Thurston	0.1914	0.1252	0.6834
2012	Thurston	0.1911	0.1237	0.6852
2013	Thurston	0.1909	0.1222	0.6869
2014	Thurston	0.1906	0.1207	0.6887
2015	Thurston	0.1903	0.1192	0.6905
2016	Thurston	0.1901	0.1176	0.6923
2017	Thurston	0.1898	0.1161	0.6941
2018	Thurston	0.1895	0.1146	0.6958
2019	Thurston	0.1893	0.1131	0.6976
2020	Thurston	0.1890	0.1116	0.6994
2021	Thurston	0.1887	0.1101	0.7012
2022	Thurston	0.1885	0.1086	0.7029
2023	Thurston	0.1882	0.1071	0.7047
2024	Thurston	0.1879	0.1056	0.7065
2025	Thurston	0.1876	0.1041	0.7083
2026	Thurston	0.1874	0.1026	0.7101
2027	Thurston	0.1871	0.1011	0.7118

Table F-9. Residential Gas: Customer Count Forecast

Year	King	Kittitas	Lewis	Pierce	Snohomish	Thurston	Total
2007	394,178	462	4,492	125,958	104,809	38,848	668,748
2008	406,022	476	4,627	129,743	107,959	40,016	688,843
2009	417,332	489	4,756	133,357	110,966	41,130	708,030
2010	428,296	502	4,881	136,861	113,882	42,211	726,632
2011	439,235	515	5,006	140,357	116,791	43,289	745,192
2012	450,305	528	5,132	143,893	119,733	44,380	763,971
2013	461,655	541	5,261	147,520	122,751	45,498	783,226
2014	473,269	555	5,394	151,231	125,838	46,643	802,929
2015	484,996	569	5,527	154,978	128,956	47,799	822,825
2016	496,626	582	5,660	158,694	132,049	48,945	842,556
2017	507,816	595	5,788	162,270	135,024	50,048	861,540
2018	518,767	608	5,912	165,769	137,936	51,127	880,120
2019	529,136	620	6,031	169,082	140,693	52,149	897,711
2020	538,823	632	6,141	172,178	143,268	53,103	914,144
2021	547,779	642	6,243	175,040	145,650	53,986	929,339
2022	556,554	652	6,343	177,844	147,983	54,851	944,227
2023	565,749	663	6,448	180,782	150,428	55,757	959,827
2024	575,010	674	6,553	183,741	152,890	56,670	975,540
2025	582,226	713	6,579	187,422	156,341	57,684	990,967
2026	589,000	754	6,598	191,004	159,726	58,664	1,005,747
2027	595,087	797	6,609	194,404	162,973	59,583	1,019,453

Table F-10. Residential Gas: Efficiency Shares

bName	nName	fName	Stock	Standard	High	Premium	Super_Premium
Manufactured	Cooking	Gas	0.95	0.05			
Manufactured	Cooking	Electric	1				
Manufactured	Other	Gas	1				
Manufactured	Space_Heat	Gas	0.5	0.385	0.075	0.03	0.01
Manufactured	Space_Heat	Electric	1				
Manufactured	Water_Heat	Gas	0.1	0.68	0.22		
Manufactured	Water_Heat	Electric	1				
Multi_Family	Cooking	Gas	0.95	0.05			
Multi_Family	Cooking	Electric	1				
Multi_Family	Other	Gas	1				
Multi_Family	Space_Heat	Gas	0.5	0.385	0.075	0.03	0.01
Multi_Family	Space_Heat	Electric	1				
Multi_Family	Water_Heat	Gas	0.13	0.76	0.11		
Multi_Family	Water_Heat	Electric	1				
Single_Family	Cooking	Gas	0.9	0.1			
Single_Family	Cooking	Electric	1				
Single_Family	Other	Gas	1				
Single_Family	Space_Heat	Gas	0.5	0.385	0.075	0.03	0.01
Single_Family	Space_Heat	Electric	1				
Single_Family	Water_Heat	Gas	0.1	0.68	0.22		
Single_Family	Water_Heat	Electric	1				
Manufactured	Dryer	Gas	0.48	0.52			
Multi_Family	Dryer	Gas	0.48	0.52			
Single_Family	Dryer	Gas	0.48	0.52			
Manufactured	Dryer	Electric	1				
Multi_Family	Dryer	Electric	1				
Single_Family	Dryer	Electric	1				

Table F-11. Residential Gas: Price Forecast ($/therm)

Year	Single_Family Average Price	Single_Family Marginal Price	Multi_Family Average Price	Multi_Family Marginal Price	Manufactured Average Price	Manufactured Marginal Price
2007	1.3307	1.3307	1.3307	1.3307	1.3307	1.3307
2008	1.2888	1.2888	1.2888	1.2888	1.2888	1.2888
2009	1.2620	1.2620	1.2620	1.2620	1.2620	1.2620
2010	1.2547	1.2547	1.2547	1.2547	1.2547	1.2547
2011	1.0679	1.0679	1.0679	1.0679	1.0679	1.0679
2012	1.1019	1.1019	1.1019	1.1019	1.1019	1.1019
2013	1.1765	1.1765	1.1765	1.1765	1.1765	1.1765
2014	1.2432	1.2432	1.2432	1.2432	1.2432	1.2432
2015	1.2686	1.2686	1.2686	1.2686	1.2686	1.2686
2016	1.2059	1.2059	1.2059	1.2059	1.2059	1.2059
2017	1.2473	1.2473	1.2473	1.2473	1.2473	1.2473
2018	1.3553	1.3553	1.3553	1.3553	1.3553	1.3553
2019	1.4501	1.4501	1.4501	1.4501	1.4501	1.4501
2020	1.5398	1.5398	1.5398	1.5398	1.5398	1.5398
2021	1.6220	1.6220	1.6220	1.6220	1.6220	1.6220
2022	1.6560	1.6560	1.6560	1.6560	1.6560	1.6560
2023	1.6911	1.6911	1.6911	1.6911	1.6911	1.6911
2024	1.7260	1.7260	1.7260	1.7260	1.7260	1.7260
2025	1.7435	1.7435	1.7435	1.7435	1.7435	1.7435
2026	1.7611	1.7611	1.7611	1.7611	1.7611	1.7611
2027	1.7790	1.7790	1.7790	1.7790	1.7790	1.7790

Table F-12. Residential Gas: Electric Price Forecast ($/kWh)

Year	Res Price Deflator	Single_Family Average Price	Single_Family Marginal Price	Multi_Family Average Price	Multi_Family Marginal Price	Manufactured Average Price	Manufactured Marginal Price
2007	100.00	0.082077944	0.082077944	0.082077944	0.082077944	0.082077944	0.082077944
2008	102.36	0.084414096	0.084414096	0.084414096	0.084414096	0.084414096	0.084414096
2009	104.88	0.087790591	0.087790591	0.087790591	0.087790591	0.087790591	0.087790591
2010	107.71	0.091554894	0.091554894	0.091554894	0.091554894	0.091554894	0.091554894
2011	110.85	0.093935517	0.093935517	0.093935517	0.093935517	0.093935517	0.093935517
2012	114.08	0.096867362	0.096867362	0.096867362	0.096867362	0.096867362	0.096867362
2013	117.62	0.099707646	0.099707646	0.099707646	0.099707646	0.099707646	0.099707646
2014	121.21	0.102322788	0.102322788	0.102322788	0.102322788	0.102322788	0.102322788
2015	124.71	0.105251369	0.105251369	0.105251369	0.105251369	0.105251369	0.105251369
2016	128.31	0.108591229	0.108591229	0.108591229	0.108591229	0.108591229	0.108591229
2017	132.26	0.110620979	0.110620979	0.110620979	0.110620979	0.110620979	0.110620979
2018	136.58	0.113769415	0.113769415	0.113769415	0.113769415	0.113769415	0.113769415
2019	141.23	0.116712043	0.116712043	0.116712043	0.116712043	0.116712043	0.116712043
2020	146.18	0.119451071	0.119451071	0.119451071	0.119451071	0.119451071	0.119451071
2021	151.34	0.122219831	0.122219831	0.122219831	0.122219831	0.122219831	0.122219831
2022	156.72	0.125117083	0.125117083	0.125117083	0.125117083	0.125117083	0.125117083
2023	162.33	0.127931168	0.127931168	0.127931168	0.127931168	0.127931168	0.127931168
2024	168.17	0.130756568	0.130756568	0.130756568	0.130756568	0.130756568	0.130756568
2025	174.23	0.133600241	0.133600241	0.133600241	0.133600241	0.133600241	0.133600241
2026	180.50	0.136505757	0.136505757	0.136505757	0.136505757	0.136505757	0.136505757
2027	187.00	0.139474462	0.139474462	0.139474462	0.139474462	0.139474462	0.139474462

Table F-13. Commercial Electric: Sales Forecast (MWh)

Year	Island	Jefferson	King	Kitsap	Kittitas	Pierce	Skagit	Thurston	Whatcom	Total
2007	209,272	92,453	5,459,274	731,811	69,111	575,126	512,468	937,332	720,905	9,307,752
2008	215,146	96,479	5,571,389	749,978	71,302	599,356	530,766	968,775	752,670	9,555,862
2009	223,281	102,860	5,728,535	767,170	73,457	625,759	551,035	994,099	787,577	9,853,774
2010	227,206	106,397	5,866,386	774,373	74,409	648,726	559,970	1,013,056	802,333	10,072,856
2011	228,546	108,910	5,963,785	783,195	75,205	668,939	565,193	1,040,656	809,865	10,244,295
2012	233,872	114,050	6,085,516	800,151	77,244	691,534	579,924	1,071,576	833,741	10,487,606
2013	238,263	118,906	6,143,116	833,097	78,297	705,389	591,396	1,120,258	852,779	10,681,503
2014	248,479	124,157	6,275,010	875,219	81,152	735,220	612,984	1,166,946	886,373	11,005,541
2015	258,709	129,315	6,423,014	913,238	83,662	766,490	634,959	1,207,890	919,757	11,337,035
2016	267,203	134,025	6,567,290	945,080	85,681	794,900	654,695	1,243,190	950,915	11,642,979
2017	273,949	137,861	6,696,798	976,571	87,553	816,943	668,884	1,278,880	975,583	11,913,022
2018	281,263	141,179	6,829,612	1,012,051	89,382	837,552	680,400	1,316,074	995,056	12,182,569
2019	289,166	144,655	6,975,958	1,046,384	91,231	860,358	693,057	1,350,350	1,015,532	12,466,691
2020	296,478	148,125	7,122,011	1,079,189	92,855	883,537	705,937	1,384,150	1,036,430	12,748,714
2021	303,820	151,747	7,275,555	1,113,892	94,545	907,856	719,498	1,421,252	1,058,632	13,046,797
2022	312,826	156,147	7,464,368	1,154,845	96,763	936,787	736,509	1,465,160	1,086,018	13,409,424
2023	322,625	160,952	7,670,292	1,199,565	99,237	967,584	755,028	1,512,902	1,115,916	13,804,102
2024	331,763	165,510	7,887,543	1,233,541	102,048	994,989	776,413	1,555,753	1,147,523	14,195,085
2025	340,837	170,037	8,103,270	1,267,279	104,839	1,022,203	797,649	1,598,304	1,178,909	14,583,326
2026	350,059	174,638	8,322,521	1,301,568	107,676	1,049,861	819,231	1,641,549	1,210,806	14,977,908
2027	359,230	179,213	8,540,566	1,335,668	110,497	1,077,366	840,694	1,684,557	1,242,529	15,370,319

Table F-14. Commercial Electric: Building Type Allocation

Year	County	Dry_Goods_Retail	Grocery	Office	Restaurant	Warehouse	Hospital	Hotel_Motel	School	University	Other
2007	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2008	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2009	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2010	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2011	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2012	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2013	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2014	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2015	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2016	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2017	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2018	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2019	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2020	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2021	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2022	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2023	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2024	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2025	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2026	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2027	Island	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2007	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2008	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2009	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2010	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2011	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2012	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2013	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2014	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2015	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2016	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2017	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2018	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2019	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2020	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2021	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2022	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2023	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2024	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2025	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2026	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2027	Jefferson	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2007	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2008	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2009	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2010	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2011	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2012	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2013	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2014	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072

Year	County	Dry_Goods_Retail	Grocery	Office	Restaurant	Warehouse	Hospital	Hotel_Motel	School	University	Other
2015	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2016	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2017	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2018	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2019	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2020	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2021	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2022	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2023	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2024	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2025	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2026	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2027	King	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2007	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2008	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2009	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2010	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2011	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2012	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2013	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2014	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2015	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2016	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2017	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2018	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2019	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2020	Kitsap	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
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2018	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2019	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2020	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2021	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2022	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2023	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2024	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2025	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2026	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072
2027	Whatcom	0.13938135	0.016426108	0.196171211	0.016889866	0.090233298	0.029209034	0.046458726	0.133441328	0.016916007	0.314873072

Table F-15. Commercial Electric: Customer Count Forecast

Year	Island	Jefferson	King	Kitsap	Kittitas	Pierce	Skagit	Thurston	Whatcom	Total
2007	4,121	2,856	52,238	12,448	1,925	10,262	7,985	12,950	11,678	116,463
2008	4,204	2,962	53,640	12,599	1,955	10,668	8,136	13,233	11,929	119,326
2009	4,261	3,055	54,941	12,838	1,991	11,083	8,274	13,695	12,131	122,270
2010	4,359	3,199	56,049	13,113	2,045	11,454	8,488	14,099	12,486	125,291
2011	4,457	3,347	56,787	13,703	2,080	11,727	8,687	14,794	12,818	128,400
2012	4,610	3,466	57,531	14,278	2,138	12,123	8,931	15,284	13,214	131,575
2013	4,764	3,583	58,447	14,787	2,188	12,544	9,182	15,702	13,609	134,805
2014	4,902	3,700	59,536	15,245	2,232	12,960	9,432	16,100	14,017	138,125
2015	5,029	3,808	60,739	15,761	2,282	13,326	9,640	16,571	14,387	141,542
2016	5,169	3,904	62,012	16,352	2,332	13,677	9,818	17,072	14,690	145,026
2017	5,316	4,002	63,362	16,913	2,381	14,054	10,004	17,523	14,998	148,553
2018	5,456	4,102	64,754	17,461	2,426	14,448	10,200	17,979	15,322	152,147
2019	5,592	4,203	66,162	18,026	2,471	14,848	10,398	18,465	15,653	155,817
2020	5,733	4,307	67,592	18,609	2,518	15,256	10,599	18,955	15,990	159,559
2021	5,878	4,413	69,051	19,217	2,567	15,666	10,802	19,458	16,334	163,387
2022	6,024	4,521	70,656	19,740	2,587	16,086	11,075	19,912	16,726	167,327
2023	6,170	4,631	72,374	20,220	2,650	16,478	11,344	20,396	17,133	171,395
2024	6,320	4,744	74,136	20,712	2,715	16,879	11,621	20,893	17,550	175,568
2025	6,474	4,859	75,943	21,217	2,781	17,290	11,904	21,402	17,977	179,847
2026	6,632	4,978	77,795	21,734	2,849	17,712	12,194	21,924	18,416	184,233
2027	6,794	5,099	79,692	22,264	2,918	18,144	12,491	22,458	18,865	188,726

Table F-16. Commercial Electric: Efficiency Shares

bName	nName	fName	Stock	Standard	High	Premium
Dry_Goods_Retail	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
Dry_Goods_Retail	Cooling_DX	Electric	0.515	0.456	0.023	0.007
Dry_Goods_Retail	Cooling_HeatPump	Electric	0.515	0.485		
Dry_Goods_Retail	Lighting	Electric	0.700	0.300		
Dry_Goods_Retail	Other	Electric	1.000			
Dry_Goods_Retail	Plug_Load	Electric	1.000			
Dry_Goods_Retail	Space_Heat	Electric	1.000			
Dry_Goods_Retail	Space_Heat	Gas	1.000			
Dry_Goods_Retail	HVAC_Aux	Electric	0.550	0.450		
Dry_Goods_Retail	Water_Heat	Electric	0.700	0.300		
Dry_Goods_Retail	Water_Heat	Gas	1.000			
Grocery	Cooking	Electric	1.000			
Grocery	Cooking	Gas	1.000			
Grocery	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
Grocery	Cooling_DX	Electric	0.515	0.456	0.023	0.007
Grocery	Cooling_HeatPump	Electric	0.515	0.485		
Grocery	Lighting	Electric	0.700	0.300		
Grocery	Other	Electric	1.000			
Grocery	Plug_Load	Electric	1.000			
Grocery	Refrigeration	Electric	0.950	0.050		
Grocery	Space_Heat	Electric	1.000			
Grocery	Space_Heat	Gas	1.000			
Grocery	HVAC_Aux	Electric	0.550	0.450		
Grocery	Water_Heat	Electric	0.700	0.225	0.075	
Grocery	Water_Heat	Gas	1.000			
Hospital	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
Hospital	Cooling_DX	Electric	0.515	0.456	0.023	0.007
Hospital	Cooling_HeatPump	Electric	0.515	0.485		
Hospital	Lighting	Electric	0.700	0.300		
Hospital	Other	Electric	1.000			
Hospital	Plug_Load	Electric	1.000			
Hospital	Space_Heat	Electric	1.000			
Hospital	Space_Heat	Gas	1.000			
Hospital	HVAC_Aux	Electric	0.550	0.450		
Hospital	Water_Heat	Electric	0.700	0.300		
Hospital	Water_Heat	Gas	1.000			
Hotel_Motel	Cooking	Electric	1.000			
Hotel_Motel	Cooking	Gas	1.000			
Hotel_Motel	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
Hotel_Motel	Cooling_DX	Electric	0.515	0.456	0.023	0.007
Hotel_Motel	Cooling_HeatPump	Electric	0.515	0.485		
Hotel_Motel	Lighting	Electric	0.700	0.300		
Hotel_Motel	Other	Electric	1.000			
Hotel_Motel	Plug_Load	Electric	1.000			
Hotel_Motel	Space_Heat	Electric	1.000			
Hotel_Motel	Space_Heat	Gas	1.000			
Hotel_Motel	HVAC_Aux	Electric	0.550	0.450		
Hotel_Motel	Water_Heat	Electric	0.700	0.300		
Hotel_Motel	Water_Heat	Gas	1.000			
Office	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
Office	Cooling_DX	Electric	0.515	0.456	0.023	0.007
Office	Cooling_HeatPump	Electric	0.515	0.485		

bName	nName	fName	Stock	Standard	High	Premium
Office	Lighting	Electric	0.700	0.300		
Office	Other	Electric	1.000			
Office	Plug_Load	Electric	1.000			
Office	Space_Heat	Electric	1.000			
Office	Space_Heat	Gas	1.000			
Office	HVAC_Aux	Electric	0.550	0.450		
Office	Water_Heat	Electric	0.700	0.300		
Office	Water_Heat	Gas	1.000			
Other	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
Other	Cooling_DX	Electric	0.515	0.456	0.023	0.007
Other	Cooling_HeatPump	Electric	0.515	0.485		
Other	Lighting	Electric	0.700	0.300		
Other	Other	Electric	1.000			
Other	Plug_Load	Electric	1.000			
Other	Space_Heat	Electric	1.000			
Other	Space_Heat	Gas	1.000			
Other	HVAC_Aux	Electric	0.550	0.450		
Other	Water_Heat	Electric	0.700	0.300		
Other	Water_Heat	Gas	1.000			
Restaurant	Cooking	Electric	1.000			
Restaurant	Cooking	Gas	1.000			
Restaurant	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
Restaurant	Cooling_DX	Electric	0.515	0.456	0.023	0.007
Restaurant	Cooling_HeatPump	Electric	0.515	0.485		
Restaurant	Lighting	Electric	0.700	0.300		
Restaurant	Other	Electric	1.000			
Restaurant	Plug_Load	Electric	1.000			
Restaurant	Refrigeration	Electric	0.950	0.050		
Restaurant	Space_Heat	Electric	1.000			
Restaurant	Space_Heat	Gas	1.000			
Restaurant	HVAC_Aux	Electric	0.550	0.450		
Restaurant	Water_Heat	Electric	0.700	0.300		
Restaurant	Water_Heat	Gas	1.000			
School	Cooking	Electric	1.000			
School	Cooking	Gas	1.000			
School	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
School	Cooling_DX	Electric	0.515	0.456	0.023	0.007
School	Cooling_HeatPump	Electric	0.515	0.485		
School	Lighting	Electric	0.700	0.300		
School	Other	Electric	1.000			
School	Plug_Load	Electric	1.000			
School	Space_Heat	Electric	1.000			
School	Space_Heat	Gas	1.000			
School	HVAC_Aux	Electric	0.550	0.450		
School	Water_Heat	Electric	0.700	0.300		
School	Water_Heat	Gas	1.000			
University	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
University	Cooling_DX	Electric	0.515	0.456	0.023	0.007
University	Cooling_HeatPump	Electric	0.515	0.485		
University	Lighting	Electric	0.700	0.300		
University	Other	Electric	1.000			
University	Plug_Load	Electric	1.000			
University	Space_Heat	Electric	1.000			
University	Space_Heat	Gas	1.000			

bName	nName	fName	Stock	Standard	High	Premium
University	HVAC_Aux	Electric	0.550	0.450		
University	Water_Heat	Electric	0.700	0.300		
University	Water_Heat	Gas	1.000			
Warehouse	Cooling_Chillers	Electric	0.515	0.456	0.023	0.007
Warehouse	Cooling_DX	Electric	0.515	0.456	0.023	0.007
Warehouse	Cooling_HeatPump	Electric	0.515	0.485		
Warehouse	Lighting	Electric	0.700	0.300		
Warehouse	Other	Electric	1.000			
Warehouse	Plug_Load	Electric	1.000			
Warehouse	Space_Heat	Electric	1.000			
Warehouse	Space_Heat	Gas	1.000			
Warehouse	HVAC_Aux	Electric	0.550	0.450		
Warehouse	Water_Heat	Electric	0.700	0.300		
Warehouse	Water_Heat	Gas	1.000			

Table F-17. Commercial Electric: Price Forecast ($/kWh)

Year	Price Deflator	Commercial Average Price	Commercial Marginal Price
2007	100.00	0.081388597	0.081388597
2008	102.36	0.082873068	0.082873068
2009	104.88	0.085172869	0.085172869
2010	107.71	0.087751835	0.087751835
2011	110.85	0.090333153	0.090333153
2012	114.08	0.093322358	0.093322358
2013	117.62	0.096312153	0.096312153
2014	121.21	0.09917074	0.09917074
2015	124.71	0.102442729	0.102442729
2016	128.31	0.106263368	0.106263368
2017	132.26	0.108721831	0.108721831
2018	136.58	0.112553447	0.112553447
2019	141.23	0.116251341	0.116251341
2020	146.18	0.119817245	0.119817245
2021	151.34	0.123525091	0.123525091
2022	156.72	0.127512594	0.127512594
2023	162.33	0.131502778	0.131502778
2024	168.17	0.135635484	0.135635484
2025	174.23	0.139906254	0.139906254
2026	180.50	0.144311497	0.144311497
2027	187.00	0.148855449	0.148855449

Table F-18. Commercial Electric: Gas Price Forecast ($/therm)

Year	Commercial Average Price	Commercial Marginal Price
2007	1.2325	1.2325
2008	1.1908	1.1908
2009	1.1603	1.1603
2010	1.1493	1.1493
2011	0.9571	0.9571
2012	0.9885	0.9885
2013	1.0610	1.0610
2014	1.1256	1.1256
2015	1.1474	1.1474
2016	1.0790	1.0790
2017	1.1179	1.1179
2018	1.2239	1.2239
2019	1.3163	1.3163
2020	1.4030	1.4030
2021	1.4800	1.4800
2022	1.5104	1.5104
2023	1.5419	1.5419
2024	1.5731	1.5731
2025	1.5862	1.5862
2026	1.5995	1.5995
2027	1.6129	1.6129

Table F-19. Commercial Electric: Number of Electric Meters Per Building

Year	Dry_Goods_Retail	Grocery	Office	Restaurant	Warehouse	Hospital	Hotel_Motel	School	University	Other
2007	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2008	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2009	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2010	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2011	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2012	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2013	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2014	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2015	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2016	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2017	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2018	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2019	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2020	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2021	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2022	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2023	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2024	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2025	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2026	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685
2027	1.13694382	1	1.140333321	1.038285929	1.140127233	2.489337961	1.300638839	1.628339	2	1.290374685

Table F-20. Commercial Electric: Average Square Footage by Building Type

Year	Dry_Goods_Retail	Grocery	Office	Restaurant	Warehouse	Hospital	Hotel_Motel	School	University	Other
2007	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2008	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2009	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2010	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2011	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2012	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2013	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2014	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2015	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2016	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2017	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2018	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2019	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2020	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2021	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2022	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2023	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2024	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2025	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2026	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699
2027	6421	8637	9525	4699	15284	14803	12772	22241	32392	10699

Table F-21. Commercial Gas: Sales Forecast (therms)

Year	King	Kittitas	Lewis	Pierce	Snohomish	Thurston	Total
2007	197,758,361	135,648	4,763,833	53,699,238	45,627,047	15,824,539	317,808,666
2008	200,347,590	137,544	4,826,134	54,404,474	46,223,712	16,032,714	321,972,167
2009	201,924,125	138,733	4,864,045	54,834,489	46,586,823	16,159,748	324,507,962
2010	203,384,614	139,820	4,899,180	55,232,599	46,923,258	16,277,315	326,856,786
2011	205,564,142	141,395	4,951,640	55,825,885	47,425,608	16,452,387	330,361,058
2012	209,628,266	144,270	5,049,492	56,931,026	48,362,755	16,778,315	336,894,124
2013	214,143,587	147,453	5,158,205	58,158,600	49,404,108	17,140,313	344,152,266
2014	218,419,363	150,468	5,261,150	59,321,083	50,390,199	17,483,121	351,025,385
2015	222,808,614	153,558	5,366,845	60,514,395	51,402,345	17,835,011	358,080,768
2016	226,875,584	156,418	5,464,781	61,620,037	52,340,183	18,161,041	364,618,043
2017	230,318,873	158,837	5,547,687	62,556,018	53,134,351	18,437,029	370,152,795
2018	233,766,758	161,262	5,630,704	63,493,307	53,929,541	18,713,411	375,694,984
2019	237,483,919	163,876	5,720,209	64,503,790	54,786,810	19,011,373	381,669,976
2020	241,203,028	166,487	5,809,762	65,514,737	55,644,556	19,309,462	387,648,032
2021	244,982,832	169,134	5,900,781	66,542,077	56,516,319	19,612,367	393,723,511
2022	249,418,095	172,228	6,007,593	67,747,350	57,539,319	19,967,699	400,852,284
2023	254,862,007	176,014	6,138,698	69,226,501	58,795,075	20,403,739	409,602,034
2024	260,608,409	180,006	6,277,091	70,787,754	60,120,632	20,863,967	418,837,860
2025	266,325,274	183,955	6,414,789	72,340,597	61,439,475	21,321,652	428,025,743
2026	272,051,662	187,910	6,552,717	73,896,027	62,760,515	21,780,099	437,228,931
2027	277,782,775	191,869	6,690,758	75,452,741	64,082,645	22,238,924	446,439,711

Table F-22. Commercial Gas: Building Type Allocation

Year	County	Dry_Goods_Retail	Grocery	Office	Restaurant	Warehouse	Hospital	Hotel_Motel	School	University	Other
2007	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2008	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2009	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2010	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2011	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2012	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2013	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2014	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2015	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2016	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2017	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2018	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2019	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2020	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2021	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2022	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2023	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2024	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2025	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2026	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2027	King	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2007	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2008	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2009	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2010	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2011	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2012	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2013	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2014	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2015	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2016	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2017	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2018	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2019	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2020	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2021	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2022	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2023	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2024	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2025	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2026	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2027	Kittitas	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2007	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2008	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2009	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2010	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2011	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2012	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2013	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2014	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562

Year	County	Dry_Goods_Retail	Grocery	Office	Restaurant	Warehouse	Hospital	Hotel_Motel	School	University	Other
2015	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2016	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2017	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2018	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2019	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2020	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2021	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2022	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2023	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2024	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2025	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2026	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2027	Lewis	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2007	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2008	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2009	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2010	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2011	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2012	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2013	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2014	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2015	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2016	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2017	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2018	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2019	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2020	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2021	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2022	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2023	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2024	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2025	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2026	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2027	Pierce	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2007	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2008	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2009	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2010	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2011	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2012	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2013	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2014	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2015	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2016	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2017	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2018	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2019	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2020	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2021	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2022	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2023	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2024	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562

Year	County	Dry_Goods_Retail	Grocery	Office	Restaurant	Warehouse	Hospital	Hotel_Motel	School	University	Other
2025	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2026	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2027	Snohomish	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2007	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2008	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2009	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2010	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2011	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2012	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2013	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2014	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2015	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2016	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2017	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2018	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2019	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2020	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2021	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2022	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2023	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2024	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2025	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2026	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562
2027	Thurston	0.145696974	0.020869955	0.186576654	0.098459064	0.069155103	0.040393462	0.012136739	0.022468863	0.007489621	0.396753562

Table F-23. Commercial Gas: Customer Count Forecast

Year	King	Kittitas	Lewis	Pierce	Snohomish	Thurston	Total
2007	32,447	41	914	9,225	7,682	3,161	53,470
2008	33,251	42	936	9,453	7,873	3,239	54,794
2009	34,048	43	959	9,680	8,062	3,317	56,108
2010	34,830	44	981	9,902	8,247	3,393	57,397
2011	35,635	45	1,003	10,131	8,437	3,471	58,722
2012	36,455	46	1,026	10,364	8,631	3,551	60,074
2013	37,295	47	1,050	10,603	8,830	3,633	61,458
2014	38,172	48	1,075	10,852	9,038	3,718	62,904
2015	39,074	50	1,100	11,108	9,251	3,806	64,390
2016	39,977	51	1,126	11,365	9,465	3,894	65,878
2017	40,887	52	1,151	11,624	9,681	3,983	67,377
2018	41,804	53	1,177	11,885	9,898	4,072	68,889
2019	42,722	54	1,203	12,145	10,115	4,162	70,401
2020	43,645	55	1,229	12,408	10,334	4,251	71,923
2021	44,593	57	1,256	12,677	10,558	4,344	73,485
2022	45,583	58	1,284	12,959	10,793	4,440	75,117
2023	46,612	59	1,312	13,251	11,036	4,540	76,811
2024	47,671	60	1,342	13,553	11,287	4,644	78,557
2025	48,650	62	1,364	13,904	11,593	4,775	80,348
2026	49,646	63	1,386	14,264	11,907	4,910	82,176
2027	50,645	64	1,408	14,628	12,226	5,048	84,019

Table F-24. Commercial Gas: Efficiency Shares

bName	nName	fName	Stock	Standard	High	Premium
Dry_Goods_Retail	Other	Gas	1.000			
Dry_Goods_Retail	Space_Heat	Electric	1.000			
Dry_Goods_Retail	Space_Heat	Gas	0.370	0.600	0.030	
Dry_Goods_Retail	Water_Heat	Electric	1.000			
Dry_Goods_Retail	Water_Heat	Gas	0.700	0.225	0.045	0.030
Grocery	Other	Gas	1.000			
Grocery	Space_Heat	Electric	1.000			
Grocery	Space_Heat	Gas	0.370	0.600	0.030	
Grocery	Water_Heat	Electric	1.000			
Grocery	Water_Heat	Gas	0.700	0.225	0.045	0.030
Hospital	Cooking	Electric	1.000			
Hospital	Cooking	Gas	0.950	0.050		
Hospital	Other	Gas	1.000			
Hospital	Pool_Heat	Gas	1.000			
Hospital	Space_Heat	Electric	1.000			
Hospital	Space_Heat	Gas	0.370	0.600	0.030	
Hospital	Water_Heat	Electric	1.000			
Hospital	Water_Heat	Gas	0.700	0.225	0.045	0.030
Hotel_Motel	Other	Gas	1.000			
Hotel_Motel	Pool_Heat	Gas	1.000			
Hotel_Motel	Space_Heat	Electric	1.000			
Hotel_Motel	Space_Heat	Gas	0.370	0.600	0.030	
Hotel_Motel	Water_Heat	Electric	1.000			
Hotel_Motel	Water_Heat	Gas	0.700	0.225	0.045	0.030
Office	Other	Gas	1.000			
Office	Space_Heat	Electric	1.000			
Office	Space_Heat	Gas	0.370	0.600	0.030	
Office	Water_Heat	Electric	1.000			
Office	Water_Heat	Gas	0.700	0.225	0.045	0.030
Other	Other	Gas	1.000			
Other	Space_Heat	Electric	1.000			
Other	Space_Heat	Gas	0.370	0.600	0.030	
Other	Water_Heat	Electric	1.000			
Other	Water_Heat	Gas	0.700	0.225	0.045	0.030
Restaurant	Cooking	Electric	1.000			
Restaurant	Cooking	Gas	0.950	0.050		
Restaurant	Other	Gas	1.000			
Restaurant	Space_Heat	Electric	1.000			
Restaurant	Space_Heat	Gas	0.370	0.600	0.030	
Restaurant	Water_Heat	Electric	1.000			
Restaurant	Water_Heat	Gas	0.700	0.225	0.045	0.030
School	Other	Gas	1.000			
School	Pool_Heat	Gas	1.000			
School	Space_Heat	Electric	1.000			
School	Space_Heat	Gas	0.370	0.600	0.030	
School	Water_Heat	Electric	1.000			
School	Water_Heat	Gas	0.700	0.225	0.045	0.030
University	Cooking	Electric	1.000			
University	Cooking	Gas	0.950	0.050		
University	Other	Gas	1.000			
University	Pool_Heat	Gas	1.000			
University	Space_Heat	Electric	1.000			

bName	nName	fName	Stock	Standard	High	Premium
University	Space_Heat	Gas	0.370	0.600	0.030	
University	Water_Heat	Electric	1.000			
University	Water_Heat	Gas	0.700	0.225	0.045	0.030
Warehouse	Other	Gas	1.000			
Warehouse	Space_Heat	Electric	1.000			
Warehouse	Space_Heat	Gas	0.370	0.600	0.030	
Warehouse	Water_Heat	Electric	1.000			
Warehouse	Water_Heat	Gas	0.700	0.225	0.045	0.030
Hotel_Motel	Cooking	Electric	1.000			
Hotel_Motel	Cooking	Gas	0.950	0.050		
School	Cooking	Electric	1.000			
School	Cooking	Gas	0.950	0.050		
Grocery	Cooking	Electric	1.000			
Grocery	Cooking	Gas	0.950	0.050		

Table F-25. Commercial Gas: Price Forecast ($/therm)

Year	Commercial Average Price	Commercial Marginal Price
2007	1.2325	1.2325
2008	1.1908	1.1908
2009	1.1603	1.1603
2010	1.1493	1.1493
2011	0.9571	0.9571
2012	0.9885	0.9885
2013	1.0610	1.0610
2014	1.1256	1.1256
2015	1.1474	1.1474
2016	1.0790	1.0790
2017	1.1179	1.1179
2018	1.2239	1.2239
2019	1.3163	1.3163
2020	1.4030	1.4030
2021	1.4800	1.4800
2022	1.5104	1.5104
2023	1.5419	1.5419
2024	1.5731	1.5731
2025	1.5862	1.5862
2026	1.5995	1.5995
2027	1.6129	1.6129

Table F-26. Commercial Gas: Electric Price Forecast ($/kWh)

Year	Price Deflator	Commercial Average Price	Commercial Marginal Price
2007	100.00	0.081388597	0.081388597
2008	102.36	0.082873068	0.082873068
2009	104.88	0.085172869	0.085172869
2010	107.71	0.087751835	0.087751835
2011	110.85	0.090333153	0.090333153
2012	114.08	0.093322358	0.093322358
2013	117.62	0.096312153	0.096312153
2014	121.21	0.09917074	0.09917074
2015	124.71	0.102442729	0.102442729
2016	128.31	0.106263368	0.106263368
2017	132.26	0.108721831	0.108721831
2018	136.58	0.112553447	0.112553447
2019	141.23	0.116251341	0.116251341
2020	146.18	0.119817245	0.119817245
2021	151.34	0.123525091	0.123525091
2022	156.72	0.127512594	0.127512594
2023	162.33	0.131502778	0.131502778
2024	168.17	0.135635484	0.135635484
2025	174.23	0.139906254	0.139906254
2026	180.50	0.144311497	0.144311497
2027	187.00	0.148855449	0.148855449

Table F-27. Commercial Gas: Number of Gas Meters Per Building

Year	Dry_Goods_Retail	Grocery	Office	Restaurant	Warehouse	Hospital	Hotel_Motel	School	University	Other
2007	1	1	1	1	1	1	1	1	1	1
2008	1	1	1	1	1	1	1	1	1	1
2009	1	1	1	1	1	1	1	1	1	1
2010	1	1	1	1	1	1	1	1	1	1
2011	1	1	1	1	1	1	1	1	1	1
2012	1	1	1	1	1	1	1	1	1	1
2013	1	1	1	1	1	1	1	1	1	1
2014	1	1	1	1	1	1	1	1	1	1
2015	1	1	1	1	1	1	1	1	1	1
2016	1	1	1	1	1	1	1	1	1	1
2017	1	1	1	1	1	1	1	1	1	1
2018	1	1	1	1	1	1	1	1	1	1
2019	1	1	1	1	1	1	1	1	1	1
2020	1	1	1	1	1	1	1	1	1	1
2021	1	1	1	1	1	1	1	1	1	1
2022	1	1	1	1	1	1	1	1	1	1
2023	1	1	1	1	1	1	1	1	1	1
2024	1	1	1	1	1	1	1	1	1	1
2025	1	1	1	1	1	1	1	1	1	1
2026	1	1	1	1	1	1	1	1	1	1
2027	1	1	1	1	1	1	1	1	1	1

Table F-28. Commercial Gas: Average Square Footage by Building Type

Year	Dry_Goods_Retail	Grocery	Office	Restaurant	Warehouse	Hospital	Hotel_Motel	School	University	Other
2007	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2008	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2009	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2010	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2011	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2012	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2013	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2014	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2015	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2016	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2017	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2018	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2019	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2020	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2021	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2022	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2023	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2024	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2025	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2026	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000
2027	33000	16000	30000	5000	66000	9000	26000	39000	66000	18000

Table F-29. Industrial Electric: Sales Forecast (MWh)

Year	Industrial
2007	1,314,446
2008	1,264,681
2009	1,254,988
2010	1,274,408
2011	1,282,529
2012	1,242,275
2013	1,196,442
2014	1,189,451
2015	1,186,576
2016	1,180,342
2017	1,177,324
2018	1,172,608
2019	1,166,488
2020	1,160,423
2021	1,153,479
2022	1,147,354
2023	1,141,885
2024	1,136,499
2025	1,131,324
2026	1,125,671
2027	1,120,690

Table F-30. Industrial Electric: Building Type Allocation

Year	Food Mfg	Wood Product Mfg	Paper Mfg	Printing Related Support	Chemical Mfg	Petroleum Coal Products	Plastics Rubber Products	Nonmetallic Mineral Products	Primary Metal Mfg	Fabricated Metal Products	Industrial Machinery	Electrical Equipment Mfg	Transportation Equipment Mfg	Computer Electronic Mfg	Miscellaneous Mfg
2007	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2008	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2009	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2010	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2011	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2012	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2013	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2014	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2015	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2016	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2017	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2018	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2019	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2020	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2021	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2022	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2023	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2024	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2025	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2026	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%
2027	6.78%	8.68%	1.31%	7.61%	1.71%	0.78%	2.97%	3.52%	0.95%	5.49%	11.77%	5.47%	7.54%	3.69%	31.74%

Table F-31. Industrial Electric: Customer Count Forecast

Year	Industrial
2007	3,802
2008	3,802
2009	3,802
2010	3,802
2011	3,802
2012	3,802
2013	3,802
2014	3,802
2015	3,802
2016	3,802
2017	3,802
2018	3,802
2019	3,802
2020	3,802
2021	3,802
2022	3,802
2023	3,802
2024	3,802
2025	3,802
2026	3,802
2027	3,802

Table F-32. Industrial Electric: Load Allocation by Building Type

Year	Food Mfg	Wood Product Mfg	Paper Mfg	Printing Related Support	Chemical Mfg	Petroleum Coal Products	Plastics Rubber Products	Nonmetallic Mineral Products	Primary Metal Mfg	Fabricated Metal Products	Industrial Machinery	Electrical Equipment Mfg	Transportation Equipment Mfg	Computer Electronic Mfg	Miscellaneous Mfg
2007	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2008	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2009	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2010	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2011	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2012	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2013	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2014	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2015	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2016	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2017	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2018	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2019	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2020	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2021	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2022	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2023	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2024	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2025	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2026	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%
2027	13.07%	9.04%	3.56%	3.08%	4.83%	0.75%	9.47%	6.07%	0.28%	9.30%	6.66%	5.17%	10.16%	4.50%	14.04%

Table F-33. Industrial Gas: Sales Forecast (therms)

Year	Industrial
2007	49,033,697
2008	48,123,643
2009	48,234,060
2010	48,028,038
2011	48,411,544
2012	48,643,427
2013	48,868,308
2014	48,716,974
2015	48,519,827
2016	47,895,274
2017	47,312,668
2018	47,137,658
2019	46,877,308
2020	46,526,645
2021	46,090,061
2022	45,399,275
2023	44,883,716
2024	44,606,476
2025	44,363,677
2026	44,139,225
2027	43,909,362

Table F-34. Industrial Gas: Building Type Allocation

Year	Food Mfg	Wood Product Mfg	Paper Mfg	Printing Related Support	Chemical Mfg	Petroleum Coal Products	Plastics Rubber Products	Nonmetallic Mineral Products	Primary Metal Mfg	Fabricated Metal Products	Industrial Machinery	Electrical Equipment Mfg	Transportation Equipment Mfg	Computer Electronic Mfg	Miscellaneous Mfg
2007	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2008	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2009	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2010	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2011	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2012	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2013	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2014	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2015	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2016	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2017	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2018	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2019	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2020	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2021	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2022	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2023	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2024	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2025	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2026	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%
2027	8.87%	5.78%	0.79%	6.17%	2.79%	0.26%	1.58%	4.60%	1.28%	10.15%	10.77%	6.01%	7.88%	2.59%	30.48%

Table F-35. Industrial Gas: Customer Count Forecast

Year	Industrial
2007	31,917
2008	31,917
2009	31,917
2010	31,917
2011	31,917
2012	31,917
2013	31,917
2014	31,917
2015	31,917
2016	31,917
2017	31,917
2018	31,917
2019	31,917
2020	31,917
2021	31,917
2022	31,917
2023	31,917
2024	31,917
2025	31,917
2026	31,917
2027	31,917

Table F-36. Industrial Gas: Load Allocation by Building Type

Year	Food Mfg	Wood Product Mfg	Paper Mfg	Printing Related Support	Chemical Mfg	Petroleum Coal Products	Plastics Rubber Products	Nonmetallic Mineral Products	Primary Metal Mfg	Fabricated Metal Products	Industrial Machinery	Electrical Equipment Mfg	Transportation Equipment Mfg	Computer Electronic Mfg	Miscellaneous Mfg
2007	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2008	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2009	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2010	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2011	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2012	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2013	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2014	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2015	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2016	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2017	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2018	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2019	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2020	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2021	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2022	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2023	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2024	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2025	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2026	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%
2027	24.44%	4.95%	2.57%	1.60%	5.55%	0.86%	5.42%	10.10%	2.25%	12.63%	6.66%	1.68%	6.10%	0.96%	14.22%

Appendix G: Conditional Demand Analysis

Conditional demand analysis (CDA) was the methodology used for deriving end-use unit energy consumption (UEC) indices in the residential sector. CDA is a statistical regression technique used for disaggregating total consumption into constituent end uses. The analysis typically relies on periodic (annual, daily or hourly) data, structural characteristic, household demographics, appliance saturations, and weather. The generic specification for a CDA model is as follows:

kWh Use = f(Structural Characteristics, Demographics, Appliance Saturation, Weather, Vintage)

Structural characteristics and household demographics are typically represented as categorical or binary variables; while appliance saturations are often represented as binary variables with a value of 1 indicating the presence of the appliance and 0 indicating otherwise. Information on weather is generally entered in terms of heating and cooling degree days (HDD and CDD).

Data Development

The Residential Energy Study (RES), conducted on 5,575 residential customers in 2003-2004 was the primary source of data on household demographics and appliance stock. The survey data was collated with daily kWh consumption histories for 2,488 (94%) gas customers and 3,368 (85%) electric customers with complete surveys. Due to data quality problems in the surveys and missing values for some of the critical variables, 5,316 cases were retained in the final analysis, comprised of 2,659 gas and 3,943 electric customers.

As a first step in preparation of the data, the daily consumption histories were merged with the survey data. Next, the daily temperature was compiled into this database by mapping information from 11 weather stations in PSE’s service area to the surveys by ZIP Code. The 11 weather stations used were: Bellingham, Everett, Olympia, Port Angeles, Renton, SeaTac, Seattle, Tacoma (McChord AFB), Toledo, Wenatchee, and Yakima. From the average daily temperature data, cooling degree days (CDD) with bases of 65° and 70°F, and heating degree days (HDD) with bases of 60° and 65°F were calculated.

The compiled database was then thoroughly examined using statistical screening procedures to identify any data quality problems such as missing values, outliers and other anomalies such as inconsistent survey responses. The data screening and validation process led to the elimination of 15 % of the electric cases and 29% of the gas cases in the database. The data screening process and the disposition of the final database is summarized below.

Electric Accounts

- Total number of cases: 3343
- Cases passing quality screens: 2834 (85%)
- Cases with incomplete usage data: 195 (6%)
- Vacancies: 140 (4%)

- Inconsistent survey response: 94 (3%)
- Bad or missing square footage: 79 (2%)

Gas Accounts

- Total number of cases: 2405
- Cases passing quality screens: 1716 (71%)
- Cases with incomplete usage data: 347 (14%)
- Inconsistent survey response: 222 (9%)
- Bad or missing square footage: 70 (3%)
- Vacancies : 48 (2%)

Composition of the Final Database

Once the survey and consumption data were screened and validated, all relevant variables were compiled into one database and merged with weather data. The final database included the following key variables:

Consumption Data

- Hourly, daily and monthly kWh and therms usage by year (2003-2005)
- Total number of billing days by year
- Maximum usage by year
- Coefficient of variation of usage by year
- Energy use intensity (kWh/ft^2, therms/ft^2)

End Use/Appliance Stock Variables

- Gas/electric heating
- Gas/electric water heating
- Gas/electrically heated spa
- Gas/electric heated pool
- Electric/gas dryer (only if home did not have gas heating/water heating)
- Electric/gas cooking (only if home did not have gas heating/water heating)
- Gas fireplace (only if home did not have gas heating/water heating)
- Electric AC

Home Characteristics & Occupant Data

- Square footage of home
- Number of heated rooms
- Number of bathrooms
- Number of occupants

Data Modeling

Separate conditional demand models were specified and estimated by fuel (electricity and gas) and dwelling type (single-family gas and multi-family) and vintage (new, or post-2000, construction, and existing, or pre-2000, structures). Due to the small sample of manufactured homes in the survey, this segment of the residential market was not analyzed separately. Instead, the single family results for various end-uses were calibrated to manufactured homes, using total consumption and occupancy for the adjustment. The final specification of the regression models by fuel and dwelling type are shown below.

Electric Conditional Demand Model Specification and Results

Single-Family

$$DAILYKWH_{it} = \beta_1 ELECTRICHEAT*HDD65_{it} + \beta_2 ELECTRICHEAT*SQFT_i + \beta_3 HEATPUMP*(HDD60 + CDD70)_{it} + \beta_4 ELECTRICWATERHEAT * TOTOCC_i + \beta_5 ELECTRICWATERHEAT * HDD65_{it} + \beta_6 ELECTRICDRYER_i + \beta_7 CENTRAL\_AC*CDD70_{it} + \beta_8 ELECTRICHEAT * VPRE1980_i + \beta_9 ELECTRICHEAT * V1980\text{-}2000_i + \beta_{10} ELECTRICHEAT * VPOST\ 2000_i + \beta_{11} ELECTRICWATERHEAT_i + \varepsilon_{it} \quad (1)$$

where,

$DAILYKWH_{it}$ = Daily kWh for customer *i* and day *t;*

$ELECTRICHEAT_i$= 1 if customer *i* has electric space heating, 0 otherwise;

$HEATPUMP_i$= 1 if customer *i* has a heat pump, 0 otherwise;

$ELECTRICWATERHEAT_i$= 1 if customer *i* has electric water heating, 0 otherwise;

$ELECTRICDRYER_i$ = 1 if customer *i* has an electric dryer, 0 otherwise;

$CENTRAL\_AC_i$ = 1 if customer *i* has a central air conditioner, 0 otherwise;

$SQFT_i$= Heated square footage of home for customer *i;*

$HDD60_i$ = Heating degree days (base 60°F) for customer *i* and day *t;*

$HDD65_i$ = Heating degree days (base 65°F) for customer *i* and day *t;*

$CDD70_i$ = Cooling degree days (base 70°F) for customer *i* and day *t;*

$TOTOCC_i$= Number of occupants in home for customer *i;*

$VPRE1980_i$= 1 if home was built before 1980 for customer *i;*

$V1980\_2000_i$= 1 if home was built between 1980 and 2000 for customer *i;*

$VPOST2000_i$= 1 if home was built after 2000 for customer *i;* and

ε_{it} = Error term for customer *i* and day *t;*

The estimated parameters and the associated t-tests of statistical significance are shown in Table G–1. All estimated parameters are statistically significant at a 99% confidence level.

Table G–1. Electric Single-Family Conditional Demand Model Results

Variable	Parameter Estimate	T-test
$R^2 = 0.40$		
Intercept	24.32	410.3
Elecheathdd	1.36	179.3
Elecheatsqft	0.006	63.0
heatpumpdd60_70	1.71	174.4
Elecwhocc	5.00	166.5
Elecwhhdd	0.56	109.6
Elecdry	1.76	26.7
Centralcdd	2.58	81.1
elecheat_pre80	-10.92	-59.1
elecheat_80_00	-16.09	-78.1
elecheat_post00	-24.3	-54.4
Elecwh	-10.50	-92.7

Multifamily

$$DAILYKWH_{it}= \beta_1 ELECTRICHEAT*HDD65_{it}+ \beta_2 ELECTRICHEAT*SQFT_i + \beta_3 HEATPUMP*(HDD60 + CDD70)_{it} + \beta_4 ELECTRICWATERHEAT * TOTOCC_i + \beta_5 ELECTRICWATERHEAT * HDD65_{it} + \beta_6 ELECTRICDRYER_i + \beta_7 CENTRAL\_AC*CDD70_{it} + \beta_8 ELECTRICHEAT * VPRE1980_i + \beta_9 ELECTRICHEAT * V1980\text{-}2000_i + \beta_{10} ELECTRICHEAT * VPOST\ 2000_i + \beta_{11} ELECTRICWATERHEAT_i + \varepsilon_{it} \quad (2)$$

where,

$DAILYKWH_{it}$ = Daily kWh for customer *i* and day *t;*

$ELECTRICHEAT_i$= 1 if customer *i* has electric space heating, 0 otherwise;

$HEATPUMP_i$= 1 if customer *i* has a heat pump, 0 otherwise;

$ELECTRICWATERHEAT_i$= 1 if customer *i* has electric water heating, 0 otherwise;

$ELECTRICDRYER_i$ = 1 if customer *i* has an electric dryer, 0 otherwise;

$CENTRAL\_AC_i$ = 1 if customer *i* has a central air conditioner, 0 otherwise;

$SQFT_i$= Heated square footage of home for customer *i;*

$HDD60_i$ = Heating degree days (base 60°F) for customer *i* and day *t;*

$HDD65_i$ = Heating degree days (base 65°F) for customer *i* and day *t;*

$CDD70_i$ = Cooling degree days (base 70°F) for customer *i* and day *t;*

$TOTOCC_i$= Number of occupants in home for customer i;

$VPRE1980_i$= 1 if home was built before 1980 for customer i;

$V1980\_2000_i$= 1 if home was built between 1980 and 2000 for customer i;

$VPOST2000_i$= 1 if home was built after 2000 for customer i; and

ε_{it} = Error term for customer i and day t;

The estimated parameters and the associated t-tests of statistical significance are shown in Table G–2. All estimated parameters are statistically significant at a 99% confidence level.

Table G–2. Electric Multifamily Conditional Demand Model Results

Variable	Parameter Estimate	T-test
R^2 = 0.40		
Intercept	16.73	133.1
elecheathdd	0.17	16.9
elecheatsqft	0.0018	22.4
heatpumpdd60_70	2.14	60.8
elecwhocc	4.66	92.4
elecwhhdd	0.82	83.9
centralcdd	2.67	15.8
roomcdd	1.34	8.9
elecheat_pre80	3.80	24.6
elecheat_80_00	-0.73	-5.5
elecheat_post00	-1.66	-4.8
elecwh	-12.79	-64.7

Because of high co-linearity between electric water heat and its interactions with HDD and occupants, the sign on the water heat indicator is wrong. However, when the final UECs are obtained the total water heat UEC is still reasonable.

Gas Model Specification and Results

Single-Family

$$DAILYTHERMS_{it} = \beta_1 GASSPA_i + \beta_2 GASDRYER_i + \beta_3 GASCOOKING_i + \beta_4 GASFIREPLACE_i + \beta_5 GASHEAT * SQFT_i + \beta_6 GASHEAT * HDD65_{it} + \beta_7 GASWATERHEAT * TOTOCC_i + \beta_8 GASHEAT * VPRE1980_i + \beta_9 GASHEAT * V1980\text{-}2000_i + \beta_{10} GASHEAT * VPOST\ 2000_i + \varepsilon_{it} \quad (3)$$

where,

$DAILYTHERMS_{it}$ = Daily therms for customer *i* and day *t;*

$GASSPA_i$ = 1 if customer *i* has a gas heated spa, 0 otherwise;

$GASDRYER_i$ = 1 if customer *i* has a gas dryer, 0 otherwise;

$GASCOOKING_i$ = 1 if customer *i* has a gas stove/oven, 0 otherwise;

$GASFIREPLACE_i$ = 1 if customer *i* has a gas fireplace, 0 otherwise;

$GASHEAT_i$= 1 if customer *i* has gas space heating, 0 otherwise;

$GASWATERHEAT_i$= 1 if customer *i* has gas water heating, 0 otherwise;

$SQFT_i$= Heated square footage of home for customer *i;*

$HDD65_{it}$ = Heating degree days (base 65°F) for customer *i* and day *t;*

$TOTOCC_i$= Number of occupants in home for customer *i;*

$VPRE1980_i$= 1 if home was built before 1980 for customer *i*, 0 otherwise;

$V1980\_2000_i$= 1 if home was built between 1980 and 2000 for customer *i*, 0 otherwise;

$VPOST2000_i$= 1 if home was built after 2000 for customer *i*, 0 otherwise; and

ε_{it} = Error term for customer *i* and day *t*.

The estimated parameters and the associated t-tests of statistical significance are shown in Table G–3. All estimated parameters are statistically significant at a 99% confidence level.

Table G–3. Estimated Parameters (Single-Family)

Variable	Parameter Estimate	T-test
R^2 = .80		
GASSPA	0.27	21.9
GASDRY	0.14	27.9
GASCOOK	0.20	50.0
GASFP	0.21	48.4
GASHEATSQFT	0.00024	108.5
GASHEATHDD	0.14	746.5
GASWHOCC	0.22	214.3
GASHEAT_pre80	-0.77	-139.0
GASHEAT_80_00	-0.96	-150.3
GASHEAT_post00	-1.22	-117.6

Multifamily

$$DAILYTHERMS_{it} = \beta_1 GASDRYER_i + \beta_2 GASCOOKING_i + \beta_3 GASFIREPLACE_i + \beta_4 GASHEAT * AVGHDD65_{it} + \beta_5 GASWATERHEAT * TOTOCC_i + \beta_6 GASHEAT * VPRE1980_i + \beta_7 GASHEAT * V1980\text{-}2000_i + \beta_8 GASHEAT * VPOST\ 2000_i + \varepsilon_{it} \quad (4)$$

where,

$DAILYTHERMS_{it}$ = Daily therms for customer i and day t;

$GASDRYER_i$ = 1 if customer i has a gas dryer, 0 otherwise;

$GASCOOKING_i$ = 1 if customer i has a gas stove/oven, 0 otherwise;

$GASFIREPLACE_i$ = 1 if customer i has a gas fireplace, 0 otherwise;

$GASHEAT_i$= 1 if customer i has gas space heating, 0 otherwise;

$GASWATERHEAT_i$= 1 if customer i has gas water heating, 0 otherwise;

$AVGHDD65_i$ = Heating degree days (base 65°F) for customer i and day t;

$TOTOCC_i$= Number of occupants in home for customer i;

$VPRE1980_i$= 1 if home was built before 1980 for customer i, 0 otherwise;

$V1980\_2000_i$= 1 if home was built between 1980 and 2000 for customer i, 0 otherwise;

$VPOST2000_i$= 1 if home was built after 2000 for customer i, 0 otherwise; and
ε_{it} = Error term for customer i and day t.

The estimated parameters and the associated t-tests of statistical significance are shown in Table G–4. All estimated parameters are statistically significant at a 99% confidence level.

Table G–4. Estimated Parameters (Multifamily)

Variable	Parameter Estimate	T-test
R^2 = .70		
GASDRY	0.12	6.4
GASCOOK	0.12	13.4
GASFP	0.30	29.3
GASHEATHDD	0.08	121.9
GASWHOCC	0.40	96.0
GASHEAT_pre80	-0.19	-13.2
GASHEAT_80_00	-0.30	-22.9
GASHEAT_post00	-0.45	-15.9

Derivation of End-Use Consumption (UEC) Indices

Once the conditional demand models parameters were estimated, the average use per end-use customer was derived by multiplying the estimated coefficients by the average values of the independent variables in the model to obtain UECs. In the case of CDD- and HDD-independent variable interactions, long-run heating and cooling degree days were used instead of the actual values.[4] The procedures for calculation of average use per customer and UECs for each vintage (*v*) are analytically shown below.

Electric UECs

$$AverageUsePerCustomer\_SPACEHEAT_v = \beta_5 {*} ELECTRICHEAT {*} SQFT\_AVG_v + \beta_6 {*} ELECTRICHEAT {*} LRHDD65\_AVG_v + \beta_8 {*} ELECTRICHEAT\_VPRE1980\_AVG_v + \beta_9 {*} ELECTRICHEAT\_V1980\text{-}2000\_AVG_v + \beta_{10} {*} ELECTRICHEAT {*} VPOST\ 2000\_AVG_v \quad (5)$$

$$AverageUsePerCustomer\_WATERHEAT_v = \beta_7 {*} ELECTRICWATERHEAT {*} TOTOCC\_AVG_v \quad (6)$$

$$AverageUsePerCustomer\_DRYER_v = \beta_2 {*} ELECTRICDRYER\_AVG_v \quad (7)$$

$$\mathrm{UEC}_{ve} = AverageUsePerCustomer_{ve} \,/\, Enduse\ Saturation_{ve} \quad (8)$$

[4] Normal heating degree days are base 65, from NOAA “normal” from 1970-2000.

Single-Family Electric

Table G–5. Single-Family Electric Averages by Vintage

Variable	Overall	Pre 1980	1980-2000	Post 2000
Elecheathdd	1.94	2.16	1.69	0.97
Elecheatsqft	242.4	260.8	224.4	114.3
heatpumpdd60_70	0.40	0.42	0.38	0.15
Elecwhocc	0.91	1.10	0.73	0.29
Elecwhhdd	4.78	6.06	3.40	1.79
Elecdry	0.84	0.86	0.83	0.83
Centralcdd	0.08	0.07	0.09	0.11
elecheat_pre80	0.09	0.17	0	0
elecheat_80_00	0.05	0	0.13	0
elecheat_post00	0.003	0	0	0.07
Avg Daily Use	*32.2*	*33.2*	*31.6*	*25.8*
2003 HDD	*4746*	*4721*	*4782*	*4844*
NORMAL HDD	*5042*	*5053*	*5025*	*5034*
2003 CDD	*234*	*246*	*217*	*220*
NORMAL CDD	*152*	*159*	*141*	*143*
Elecwh	0.37	0.47	0.26	0.13
Elecheat	*0.15*	*0.17*	*0.13*	*0.07*
Heatpump	*0.04*	*0.05*	*0.04*	*0.02*
Centac	*0.13*	*0.11*	*0.16*	*0.18*
Roomac	*0.05*	*0.05*	*0.04*	*0.11*

Table G–6. Single-Family Electric UEC and Average Use Per Customer—Contribution of Individual Coefficients

	AVERAGE USE PER CUSTOMER				UEC			
Variable	Overall	pre80	80-00	post 00	Overall	pre80	80-00	post 00
elecheathdd	1023	1145	878	498	6847	6857	6819	6832
elecheatsqft	512	551	474	242	3428	3302	3681	3317
heatpumpdd60_70	251	264	236	94	5778	5780	5805	5476
Elecwhocc	1658	2007	1327	529	4514	4303	5061	3925
Elecwhhdd	1037	1324	734	380	2824	2839	2800	2815
Elecdry	543	553	532	531	642	642	642	642
Centralcdd	51	45	57	66	384	410	365	370
elecheat_pre80	-345	-665	0	0	-2306	-3987	0	0
elecheat_80_00	-319	0	-757	0	-2136	0	-5874	0
elecheat_post00	-28	0	0	-647	-187	0	0	-8880
Elecwh	-1407	-1786	-1004	-517	-3831	-3831	-3831	-3831

Table G–7. Single-Family Electric UEC and Average Use Per Customer—End Use Totals

Enduse	AVERAGE USE PER CUSTOMER				UEC			
	Overall	Pre80	80-2000	Post20 00	Overall	Pre80	80-2000	Post 2000
HEATING	844	1030	596	92	5647	6172	4626	1268
BASE LOAD	8877	8877	8877	8877	8877	8877	8877	8877
WATER HEAT	1288	1544	1056	392	3507	3311	4030	2908
DRYER	543	553	532	531	642	642	642	642
CENTRAL AC	51	45	57	66	384	410	365	370
HEAT PUMP	251	264	236	94	5778	5780	5805	5476
TOTAL	11853	12313	11354	10053				

Table G–8. Multifamily Electric Averages by Vintage

Variable	Overall	Pre 1980	1980-2000	Post 2000
Elecheathdd	9.03	9.58	8.61	7.77
Elecheatsqft	791.4	853.7	761.7	1267.5
heatpumpdd60_70	0.11	0.37	0.06	0
Elecwhocc	1.65	1.77	1.55	0.99
Elecwhhdd	10.97	11.44	10.45	7.77
Elecdry	0.012	0.015	0.017	0
Centralcdd	0.015	0.041	0.007	0.044
elecheat_pre80	0.180	0.753	0	0
elecheat_80_00	0.336	0	0.676	0
elecheat_post00	0.023	0	0	0.588
Avg Daily Use	*26.19*	*30.74*	*24.87*	*21.88*
2003 HDD	*4656*	*4641*	*4652*	*4828*
NORMAL HDD	*5006*	*5008*	*5004*	*5015*
2003 CDD	*216*	*330*	*146*	*358*
NORMAL CDD	*148*	*139*	*149*	*218*
Elecwh	0.86	0.89	0.82	0.59
Elecheat	0.71	0.75	0.68	0.59
Heatpump	0.013	0.044	0.006	0
Centac	0.024	0.018	0.035	0
Roomac	0.023	0.046	0.017	0.044

Table G–9. Multifamily Electric UEC and Average Use Per Customer—Contribution of Individual Coefficients

Variable	AVERAGE USE PER CUSTOMER				UEC			
	Overall	pre80	80-00	post 00	Overall	pre80	80-00	post 00
elecheathdd	600	638	572	499	845	847	847	848
elecheatsqft	529	570	509	847	745	757	753	1440
heatpumpdd60_70	92	288	47	0	6825	6543	7816	NA
Elecwhocc	2817	3018	2647	1693	3281	3381	3240	2880
Elecwhhdd	3548	3713	3382	2430	4133	4161	4140	4134
Elecdry	8	6	17	0	341	358	477	NA
Centralcdd	5	9	3	13	226	187	199	292
elecheat_pre80	249	1045	0	0	351	1387	0	0
elecheat_80_00	-90	0	-181	0	-127	0	-268	0
elecheat_post00	-14	0	0	-357	-20	0	0	-608
Elecwh	-4007	-4165	-3812	-2743	-4667	-4667	-4667	-4667

Table G–10. Multifamily Electric UEC and Average Use Per Customer—End Use Totals

Enduse	AVERAGE USE PER CUSTOMER				UEC			
	Overall	pre80	80-00	post 00	Overall	pre80	80-00	post 00
HEATING	1273	2253	900	988	1794	2991	1332	1681
BASE LOAD	6107	6107	6107	6107	6107	6107	6107	6107
WATER HEAT	2358	2566	2217	1379	2747	2875	2714	2347
DRYER	8	6	17	0	341	358	477	NA
CENTRAL AC	5	9	3	13	226	187	199	292
HEAT PUMP	92	288	47	0	6825	6543	7816	NA
TOTAL	9843	11228	9290	8487				

Gas UECs

Once the conditional demand models are run, the average use per customer is derived by multiplying the coefficients by their averages. In the case of the HDD space heat interaction variable, long run heating degree days were used in place of the actual 2003 averages. The detailed average-use-per-customer calculations for each end use and vintage (v) was calculated as follows:

$$AverageUsePerCustomer\_SPACEHEAT_v = \beta_5 * GASHEAT * SQFT\_AVG_v + \beta_6 * GASHEAT * LRHDD65\_AVG_v + \beta_8 * GASHEAT\_VPRE1980\_AVG_v + \beta_9 * GASHEAT\_V1980\text{-}2000\_AVG_v + \beta_{10} * GASHEAT * VPOST\ 2000\_AVG_v \quad (9)$$

$$AverageUsePerCustomer\_WATERHEAT_v = \beta_7 * GASWATERHEAT * TOTOCC\_AVG_v \quad (10)$$

$$AverageUsePerCustomer\_COOKING_v = \beta_3 * GASCOOKING\_AVG_v \quad (11)$$

$$AverageUsePerCustomer\_FIREPLACE_v = \beta_4 * GASFIREPLACE\_AVG_v \quad (12)$$

$$AverageUsePerCustomer\_SPA_v = \beta_1 * GASSPA\_AVG_v \quad (13)$$

$$AverageUsePerCustomer\_DRYER_v = \beta_2 * GASDRYER\_AVG_v \quad (14)$$

UECs for vintage *v* and end use *e* are obtained from the average use per customer by dividing by the end-use saturation as follows:

$$UEC_{ve} = AverageUsePerCustomer_{ve} / Enduse\ Saturation_{ve} \quad (15)$$

Single-Family Gas

Table G–11. Single-Family Gas Averages by Vintage

Variable	Overall	Pre 1980	1980-2000	Post 2000
GASSPA	0.02	0.01	0.03	0.05
GASDRY	0.16	0.14	0.18	0.22
GASCOOK	0.30	0.28	0.34	0.43
GASFP	0.22	0.14	0.29	0.55
GASHEATSQFT	1788	1711	1927	1688
GASHEATHDD	11.6	11.5	11.7	11.0
GASWHOCC	2.4	2.1	2.7	3.1
GASHEAT_pre80	0.48	0.90	0	0
GASHEAT_80_00	0.36	0	0.89	0
GASHEAT_post00	0.04	0	0	0.84
Avg Daily Use	*2.1*	*2.0*	*2.1*	*2.1*
2003 HDD	*4,787*	*4,722*	*4,677*	*4,788*
NORMAL HDD	*4,991*	*4,988*	*4,975*	*5,005*
GasHeat	0.89	0.90	0.89	0.84
GasWH	0.86	0.80	0.95	0.97

Table G–12. Single-Family Gas UEC and Average Use Per Customer—Contribution of Individual Coefficients

	AVERAGE USE PER CUSTOMER				UEC			
Variable	Overall	pre80	80-00	post 00	Overall	pre80	80-00	post 00
GASSPA	2	1	3	5	100	100	100	100
GASDRY	8	7	9	11	50	50	50	50
GASCOOK	22	20	24	31	72	72	72	72
GASFP	17	11	22	42	77	77	77	77
GASHEATSQFT	156	149	168	147	175	166	189	176
GASHEATHDD	633	637	633	594	709	707	711	709
GASWHOCC	193	169	222	253	224	212	235	260
GASHEAT_pre80	-136	-254	0	0	-152	-281	0	0
GASHEAT_80_00	-124	0	-311	0	-139	0	-349	0
GASHEAT_post00	-18	0	0	-372	-20	0	0	-444

Table G–13. Single-Family Gas UEC and Average Use Per Customer—End Use Totals

Variable	AVERAGE USE PER CUSTOMER				UEC			
	Overall	pre80	80-00	post 00	Overall	pre80	80-00	post 00
SPACE HEAT	511	533	490	369	572	591	551	441
WATER HEAT	193	169	222	253	224	212	235	260
COOKING	22	20	24	31	72	72	72	72
FIREPLACE	17	11	22	42	77	77	77	77
SPA	2	1	3	5	100	100	100	100
DRYER	8	7	9	11	50	50	50	50
TOTAL	752	740	770	711				

Multifamily Gas

Table G–14. Multifamily Gas Averages by Vintage

Variable	Overall	Pre 1980	1980-2000	Post 2000
GASDRY	0.09	0.02	0.11	0.10
GASCOOK	0.41	0.57	0.25	0.76
GASFP	0.37	0.12	0.47	0.66
GASHEATHDD	7.3	6.9	8.1	3.8
GASWHOCC	1.2	0.5	1.4	1.3
GASHEAT_pre80	0.18	0.56	0	0
GASHEAT_80_00	0.33	0	0.64	0
GASHEAT_post00	0.04	0	0	0.30
Avg Daily Use	*1.1*	*0.9*	*1.3*	*1.1*
2003 HDD	*4,595*	*4,510*	*4,643*	*4,561*
NORMAL HDD	*4,943*	*4,878*	*4,976*	*4,958*
GasHeat	0.58	0.56	0.64	0.30
GasWH	0.66	0.38	0.80	0.72

Table G–15. Multifamily Gas UEC and Average Use Per Customer—Contribution of Individual Coefficients

Variable	AVERAGE USE PER CUSTOMER				UEC			
	Overall	Pre80	80-2000	Post 2000	Overall	Pre80	80-2000	Post 2000
GASDRY	4	1	5	4	42	42	42	42
GASCOOK	18	25	11	34	44	44	44	44
GASFP	41	13	52	72	109	109	109	109
GASHEATHDD	228	218	253	119	397	390	398	397
GASWHOCC	170	71	208	193	257	184	261	268
GASHEAT_pre80	-12	-39	0	0	-22	-70	0	0
GASHEAT_80_00	-37	0	-70	0	-64	0	-111	0
GASHEAT_post00	-6	0	0	-50	-10	0	0	-165

Table G–16. Multifamily Gas UEC and Average Use Per Customer—End Use Totals

End Use	AVERAGE USE PER CUSTOMER				UEC			
	Overall	Pre80	80-2000	Post 2000	Overall	Pre80	80-2000	Post 2000
SPACE HEAT	173	179	182	70	301	320	287	232
WATER HEAT	170	71	208	193	257	184	261	268
COOKING	18	25	11	34	44	44	44	44
FIREPLACE	41	13	52	72	109	109	109	109
DRYER	4	1	5	4	42	42	42	42
TOTAL	405	288	458	373				

Calibration and Final UEC Calculations

The final electric and gas UECs by home type and vintage are summarized in Tables G–17 and G–18. The estimated UECs were calibrated to total annual consumption levels to ensure consistency with the PSE load forecast. In the case of major end uses, such as electric space heating, cooling and water heating, the UECs from the conditional demand models were used directly.

For some end uses, such as cooking, PSE facilities rate tariff conditional demand estimates were substituted for the 2006 conditional demand results. Generally, the 2006 conditional demand estimates provided refinements to the existing PSE facilities rate tariff and the 2001 end-use survey conditional demand estimates. The 2001 and 2006 UECs were compared to other utility and national studies to cross-check each conditional demand model estimate.

The gas UECs from the conditional demand models were all used directly for modeling of conservation potentials—except for cooking, which was too high in 2006 compared to 2001 and other studies. Gas conditional demand model average use per customer was compared to the actual average use per customer by home type, which was available from PSE. The model UECs were considerably lower in the model sample compared to the actual averages. In fact, the single family model usage of 751 kWh was compared to the 2003 actual 877 kWh overall number from PSE. The usages for all single-family UECs were scaled up about 17% to account for this difference. A similar approach was followed for manufactured homes and multifamily homes.

Since the single-family (SF) models were the most reliable, and the multifamily sample sizes were small, only the space heat conditional demand UEC was used for multifamily homes. In order to obtain manufactured home and multifamily UECs, the average number of occupants was used to ratio down the SF water heating, cooking, and drying UECs.

Table G–17. Final Electric UECs

End Use	Vintage	Single-Family	Manufactured	Multifamily	UEC Source
Central AC	Existing	384	531	212	Conditional Demand 2006
Central AC	New	370	433	205	Conditional Demand 2006
Cooking	Existing	890	747	670	Conditional Demand 2001 (PSE Facilities Extensions Rate Tariff converted to electric)
Cooking	New	761	639	574	Conditional Demand 2001 (PSE Facilities Extensions Rate Tariff converted to electric)
Dryer	Existing	1275	1070	960	Conditional Demand 2001 (PSE Facilities Extensions Rate Tariff converted to electric)
Dryer	New	868	729	654	Conditional Demand 2001 (PSE Facilities Extensions Rate Tariff converted to electric)
Freezer	Existing	823	808	599	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Freezer	New	593	579	431	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Heat Pump	Existing	4990	5320	1985	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Heat Pump	New	3272	3489	1302	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Lighting	Existing	2240	2227	1514	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Lighting	New	2240	2227	1514	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Plug Load	Existing	3389	1266	1534	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Plug Load	New	3389	1266	1534	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Refrigeration	Existing	848	854	654	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Refrigeration	New	676	680	638	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Room AC	Existing	248	208	186	Conditional Demand 2006
Room AC	New	230	208	177	Conditional Demand 2006
Space Heat	Existing	8008	9184	2773	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Space Heat	New	3817	4070	1519	Conditional Demand 2001 (2004 UEC - PSE 2001 End-use Survey)
Water Heat	Existing	3510	2947	2651	Conditional Demand 2006
Water Heat	New	2908	2441	2191	Conditional Demand 2006

Table G–18. Final Gas Base UECs

End Use	Vintage	Single-Family	Manufactured	Multifamily	UEC Source
Cooking	Existing	50	41	36	Conditional Demand 2001 (PSE Facilities Extensions Rate Tariff)
Cooking	New	43	35	30	Conditional Demand 2001 (PSE Facilities Extensions Rate Tariff)
Dryer	Existing	49	40	35	Conditional Demand 2006
Dryer	New	33	27	24	Conditional Demand 2006
Space Heat	Existing	670	405	315	Conditional Demand 2006
Space Heat	New	515	311	245	Conditional Demand 2006
Water Heat	Existing	259	211	184	Conditional Demand 2006
Water Heat	New	304	248	216	Conditional Demand 2006