Appendix A: Fuel Price Forecast

INTRODUCTION

Since the millennium, the trend for fuel prices has been one of uncertainty and volatility. The price of crude oil was $25 a barrel in January of 2000. In July 2008 it averaged $127, even approaching $150 some days. Natural gas prices at the wellhead averaged $2.37 per million Btu in January 2000. In June 2008, the average wellhead price of natural gas averaged $12.60. Even Powder River Basin coal prices, which have traditionally been relatively stable, increased by about 50 percent in 2008. Fuel prices weakened significantly during later in 2008, but remain high by standards of the 1980s and 1990s.

Fuels are not the only commodities that have experienced a period of very high prices; metals, concrete, plastics, and other construction materials have all experienced increased prices in the last few years. Factors contributing to higher commodity prices in general, and to fuel prices in particular, include: rapid world economic growth, declining value of the dollar, slow response of conventional energy supplies to higher prices, continuing conflict in the Middle East, uncertainty about the direction of climate change policy, and changing commodity market dynamics.

The relative contribution of these factors to increased prices is uncertain, as is the direction of change for many of them. Conventional sources of oil and natural gas in North America are expected to be difficult to expand significantly. Growth in supplies, therefore, will increasingly depend on the development of unconventional sources and liquefied natural gas (LNG) imports. With the higher natural gas prices of recent years and technological improvements in drilling, nonconventional supplies of natural gas have expanded rapidly. A significant amount of LNG import capability has been added and has contributed significant new supplies in times of high prices. Both of these sources are expanding, but all new investments in energy infrastructure are controversial. In addition, the investments can be slowed by large uncertainties concerning energy climate change policies.

At the same time, high prices have also brought about changes on the demand side of the market. High prices encourage conservation in the sense of using less, and they also create incentives to invest in energy-efficient technologies. Such responses to high prices set in motion the forces to reduce prices. Over time, these cycles are likely to reach higher high points and higher low points, forming a series of upward-stepping cycles. Investments in new supplies and energy efficiency also tend to follow these cycles. Expectations that prices will fall from high points in the cycle make consistent investments in supply and energy efficiency less robust.

Accurately forecasting future fuel prices is an impossible task. The history of such forecasts is that even long-term forecasts tend to assume that current conditions will, to a large extent, continue. During periods of high fuel prices, forecasts tend to increase, and during periods of low prices, they tend to decrease. The Council's practice has been to recognize the inherent uncertainty and build power plans that minimize the risk from price forecasts that turn out to be wrong.

DEALING WITH UNCERTAINTY AND VOLATILITY

In spite of their uncertainty, fuel prices are an important consideration for electricity planning. Fuel prices affect both the demand for, and the cost of, electricity. As an important determinant of electricity cost, they also affect the cost-effective amount of efficiency improvement through the avoided cost of alternative generation resources. The uncertainty and volatility of fuel prices create risks for the Northwest power system. These risks and others are addressed in the Council's electricity planning.

The range of trend forecasts discussed here represents only one aspect of fuel price uncertainty addressed in the Council's power plan. The low to high trend forecasts of fuel prices are meant to reflect current analysis and views on the likely range of future prices, but the plan's analysis also considers variations expected to occur around those trends. In the Fifth Power Plan this additional volatility was only applied to natural gas prices. This was because oil prices are insignificant as either a demand alternative to electricity or a generation fuel. Coal prices are a significant determinant of electricity costs because of existing coal-fired generation, and coal is also a potential future source of energy. However, coal prices had not experienced the same level of uncertainty and volatility as oil and natural gas prices, and were therefore not considered to be a major source of risk and uncertainty. The Council is considering adding additional analysis of coal price risk for the Sixth Power Plan.

The plan reflects three distinct types of uncertainty in natural gas prices: (1) uncertainty about long-term trends, (2) price excursions due to disequilibrium of supply and demand that may occur over a number of years, and (3) short-term and seasonal volatility due to such factors as temperatures, storms, or storage levels. The forecasts discuss only the first uncertainty. Shorter-term variations are addressed in the Council's portfolio model analysis.

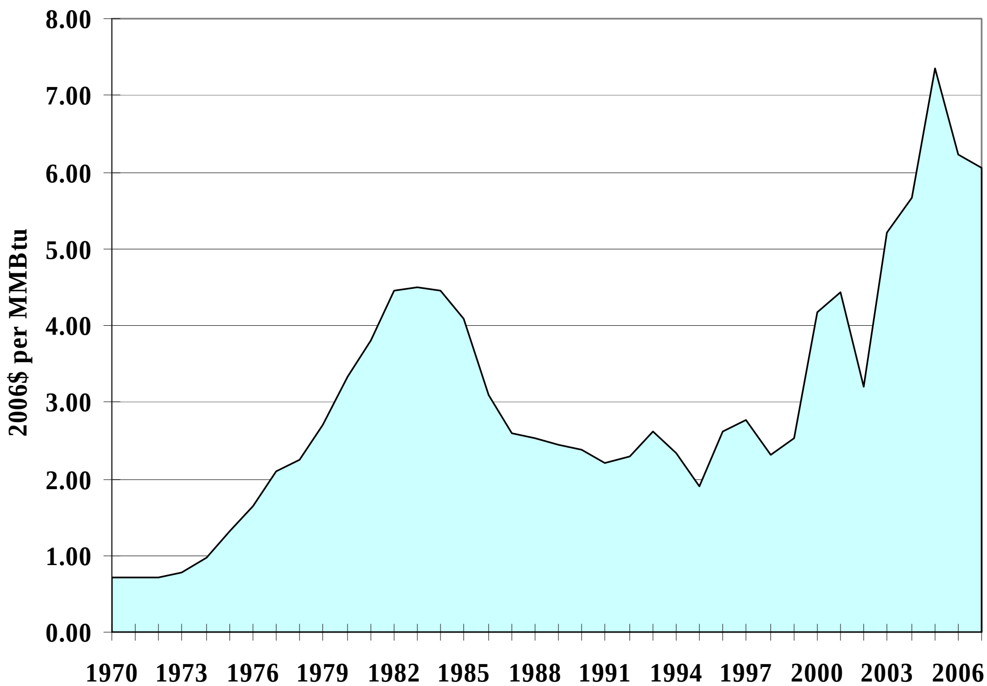
There are additional uncertainties to the cost of fuel from the effects of climate policies, such as CO2 costs from taxes or a cap and trade structure. These additional costs are explicitly treated in the Council's portfolio model and affect the cost of using various fuels, but are not a part of the commodity prices discussed in this document.

NATURAL GAS

Background

The Council's forecast of natural gas prices starts with a national level commodity price, the average natural gas wellhead price of the lower-48 states. A look at the past behavior of these prices gives perspective for the forecasts. Figure A-1 shows wellhead natural gas prices (in constant 2006 dollars per million Btu) from 1980 through 2007. Following deregulation of natural gas markets in the late 1980s, prices fell to nearly \$2.30 and remained near that level for all of the 1990s. After 2000, prices began to increase rapidly and became highly volatile. By 2007 the wellhead price of natural gas averaged \$6, nearly three times the levels of the 1990s. In some months since 2000, prices have reached over \$10 as they responded to the effects of hurricanes, storage levels, oil prices, and other market effects. With this historical context, it is difficult to predict future natural gas prices with any certainty.

Figure A-1: Historical Wellhead Natural Gas Price



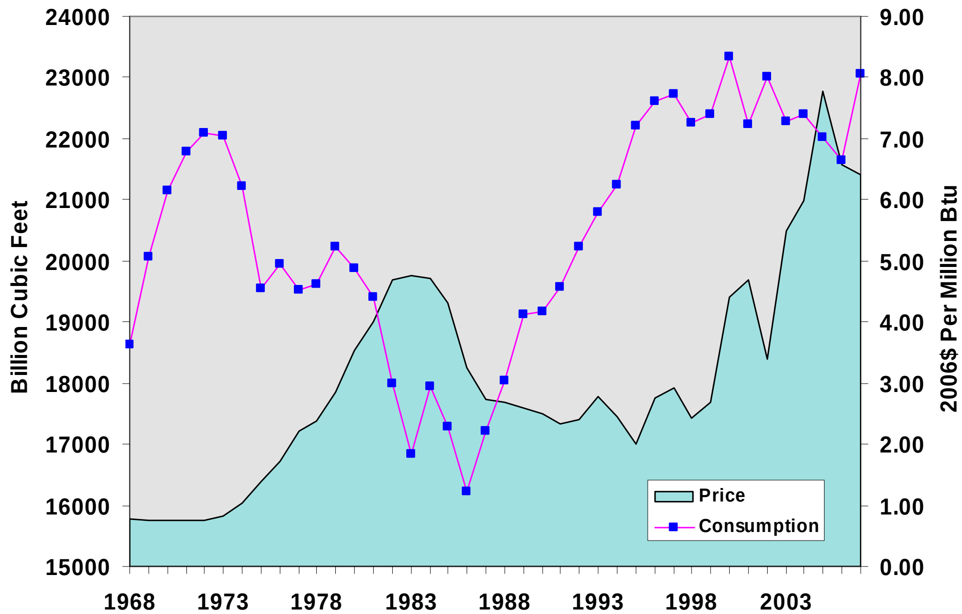
The Council's forecast of natural gas prices is informed by national level forecasts of prices from other organizations that specialize in analysis of fuel commodity markets. Such forecasts rely on estimates of the fundamentals of supply, demand, and the transportation capacity to move natural gas from supply sources to demand locations. Nevertheless, these forecasts are far from stable over time since they tend to respond to the most recent conditions, which can change drastically. The variation of forecasts from various organizations helps scale the uncertainty between the high and low forecasts. However, the range is also informed by analysis of long term trends in prices and analysis of how prices respond to changing conditions over long periods of time.

Forecasting future fuel prices is particularly difficult following large changes in markets, which is the case with the natural gas market since 2000. It requires sorting out temporary influences from longer-term factors that are expected to persist into the future. For example, regulation of natural gas supplies dampened the supply response to the growing demand for natural gas in the early 1980s, leading to rapid price escalation. Regulatory incentives to find new natural gas supplies, but not increase production from existing supplies, resulted in a slow supply response, but also created large new supplies in the longer term. When natural gas was deregulated in the late 1980s, prices collapsed due to the so-called "gas bubble" and remained low throughout the 1990s. During this time, low prices were expected to continue for many years and estimates of the cost of finding new natural gas were low.

By the end of the 1990s, the more permanent effects of deregulated natural gas supplies were becoming clear. Companies no longer held large inventories of proven reserves and as excess reserves declined, prices became more volatile. This volatility was exacerbated by the development of spot and futures trading markets. Without significant changes to natural gas market regulation, this volatility is expected to be a long-term feature of these markets. As noted earlier, that volatility is reflected in the Council's power plan, but this forecast addresses only a range of long-term price trends around which such volatility will occur. For example, the portfolio model includes short periods of time where prices can substantially exceed the high trend price forecast.

It is important to understand that the collapse of prices in the late 1980s was not all due to a supply bubble; there was also a significant reduction in natural gas use. During the two decades prior to 1970, natural gas use had grown rapidly as supplies expanded and natural gas pipeline expansion made the supplies available to users. However, as natural gas prices escalated during the 1970s (more than quadrupling), demand for natural gas dropped precipitously. Similarly, as prices dropped following deregulation and remained low during the 1990s, demand grew, but failed to return to its previous 1973 high level until 1995. Figure A-2 shows these patterns. Also evident in Figure A-2 is the moderating effect of recent natural gas price increases on natural gas use since 2000.

Figure A-2: Historical Natural Gas Prices and Consumption



Price Forecasts

U.S. Natural Gas Commodity Prices

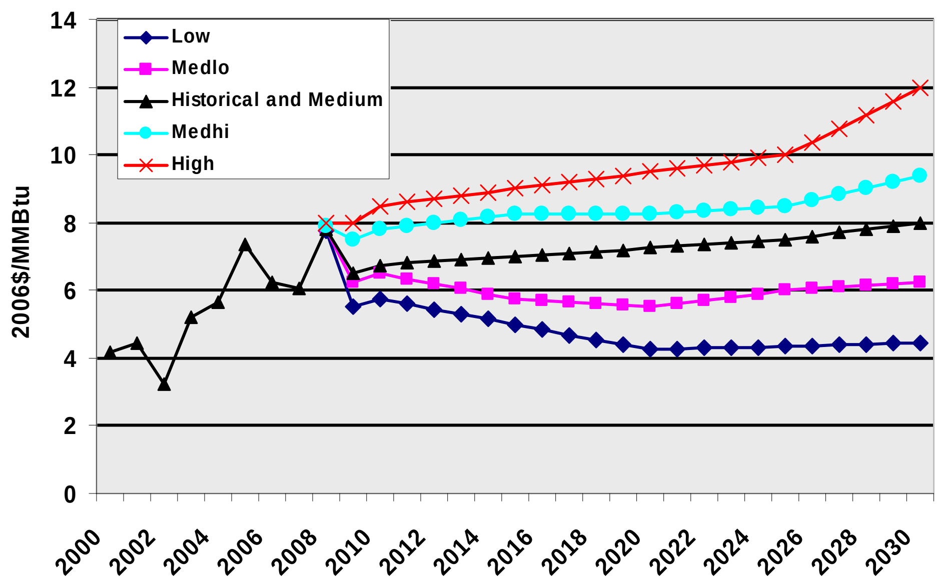
There are several characteristics of the recent price increases that have implications for the future long-term trends in natural gas price. On the supply side, it has become clear that conventional natural gas supplies are increasingly difficult to expand. This does not mean that supply will not be able to expand. Recently, there have been significant increases in nonconventional supplies of natural gas, such as coal-bed methane and shale deposits like the Barnett Shale in North Texas. It is estimated that such nonconventional supplies of natural gas now account for half of U.S. natural gas production. Production from nonconventional sources has been made feasible by improved drilling and production technologies, but these are also more expensive. For example, development of new shale natural gas supplies is estimated to cost between $7 and $8 dollars per million Btu.

Another factor with implications for the long-term trend of natural gas prices is on the demand side of the equation. The significant reduction in demand during the 1970s was partly due to the ability to switch industrial uses of natural gas to alternative fuels. With today's climate concerns, the use of oil and coal are becoming constrained and limit the ability of industries (including power generation) to reduce natural gas use as prices increase. Further, the response to climate concerns and regulations is expected to increase the demand for natural gas. Examples include electric vehicles, where the electricity generation is likely to require increased amounts of natural gas, and biofuels, where natural gas is required to produce ammonia fertilizer to grow biofuel crops and provide process heat to refine the biofuels.

Cycles will continue in the future as markets develop and respond to changing supply and demand conditions. However, the view expressed in the central part of the Council's natural gas price forecast range is that the trend through these future cycles will be upward. Given that the market appears to be starting from a high point in a commodity cycle, most of the forecast range includes decreases from recent levels. However, trend prices do not fall back to the $2.30 natural gas prices of the 1990s, even in the lowest price forecast.

Figure A-3 shows the range of U.S. wellhead price forecasts proposed for the Sixth Power Plan. As shown in the graph, natural gas prices doubled between 2000 and the estimated 2008 price. Not shown is the doubling of prices in 2000 from the previous few years. Thus, 2008 prices are expected to be four times their levels from 10 years ago.

Figure A-3: U.S. Wellhead Natural Gas Price Forecast Range



The medium case forecast shows prices declining to $7 (in 2006 prices) by 2015, and then trending upward slowly, reaching $8.00 by 2030. Note that $7 is a higher natural gas price than any historical year except 2005, which was affected by Hurricanes Katrina and Rita, and 2008, which included oil prices that reached nearly $150 per barrel in the early summer months. Nevertheless, these prices represent the current expectations of many experts in the fuel markets, including many of the members of the Council's Natural Gas Advisory Committee.

The high and low forecasts are intended to be extreme views of possible future prices from today's context. The high case prices increase to $10 until 2025 and then increase to nearly $12 by 2030. The Council's forecasts assume that more rapid world economic growth will lead to higher energy prices, even though the short-term effects of a rapid price increase can adversely impact the economy. For long-term trend analysis, the stress on prices from increased need to expand energy supplies is considered the dominant relationship. The high natural gas scenario assumes rapid world economic growth. This scenario might be consistent with very high oil prices, high environmental concerns that limit use of coal, limited development of world LNG capacity, and slower improvements in drilling and exploration technology, combined with the high cost of other commodities and labor necessary for natural gas development. It is a world where both alternative sources of energy and opportunities for demand reductions are very limited.

The low case assumes slow world economic growth which reduces the pressure on energy supplies. It is a future where world supplies of natural gas are made available through aggressive development of LNG capacity, favorable nonconventional supplies and the technologies to develop them, and low world oil prices providing an alternative to natural gas use. The low case would also be consistent with a scenario of more rapid progress in renewable electric generating technologies, thus reducing the demand for natural gas. In this case, the normal increases in natural gas use in response to lower prices would be limited by aggressive carbon-control policies. It is a world with substantial progress in efficiency and renewable technologies, combined with more stable conditions in the Middle East and other oil and natural gas producing areas.

The intermediate cases are variations on the medium case that are considered reasonably likely to occur. The medium-high case would contain elements of the high scenario, however not to the same degree. Similarly, the medium-low case would contain some of the more optimistic factors described for the low case.

In reality, prices may at various times in the future resemble any of the forecast range. Such cycles in natural gas prices, as well as shorter-term volatility, are captured in the Council's Regional Portfolio Model. Table A-1 shows the range of natural gas price trend forecasts for selected years. In the Council's portfolio analysis, however, prices at any given time may fall anywhere within, or even outside, the range shown in Table A-1.

Table A-1: U.S. Wellhead Natural Gas Price Forecasts (2006 Dollars Per Million Btu)

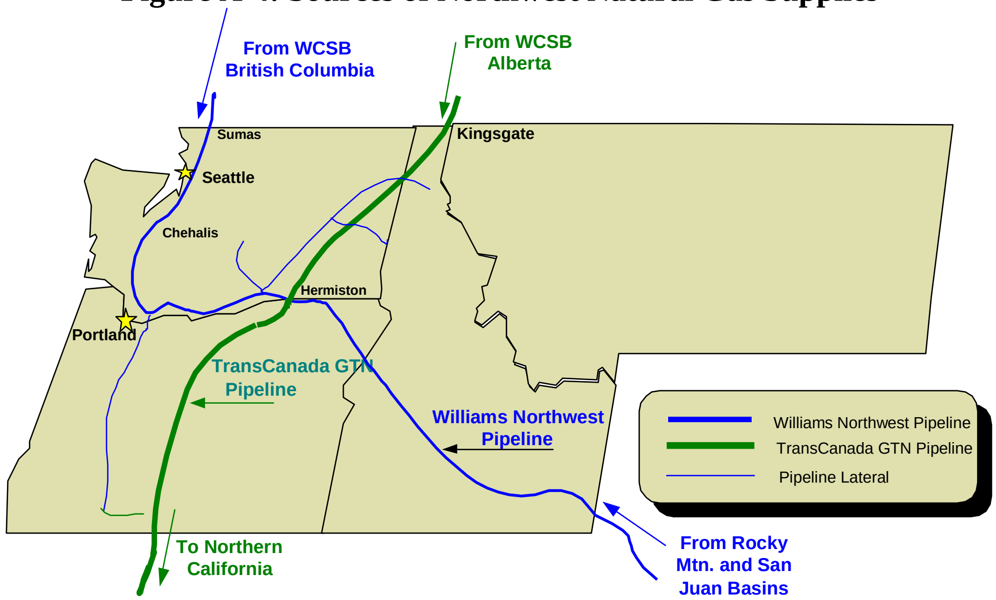
	Low	Medium Low	Medium	Medium High	High
2007			6.06		
2010	5.75	6.50	6.75	7.80	8.50
2015	5.00	5.75	7.00	8.25	9.00
2020	4.25	5.50	7.25	8.25	9.50
2025	4.35	6.00	7.50	8.50	10.00
2030	4.45	6.25	8.00	9.40	12.00
Growth Rates					
2007-15	-2.36%	-0.64%	1.83%	3.94%	5.08%
2007-30	-1.33%	0.14%	1.22%	1.93%	2.89%

Northwest Natural Gas Supplies and Price

Given a forecast of U.S. level commodity prices, the next step is to estimate the cost of natural gas within the Pacific Northwest region and the rest of the Western United States. This is necessary because there is significant regional variation in natural gas prices.

Natural gas supplies for the Pacific Northwest come from two sources: the Western Canada Sedimentary Basin in Alberta and Northeastern British Columbia, and the U. S. Rocky Mountains. Natural gas from these areas is delivered into the region by two pipelines. The Williams Northwest Pipeline delivers supplies from the U.S. Rocky Mountains as well as down from Sumas at the B.C. border. The other pipeline is TransCanada Gas Transmission Northwest, which brings supplies from Alberta, through the Northwest and on down to the California border. Figure A-4 illustrates the Northwest's natural gas delivery system.

Figure A-4: Sources of Northwest Natural Gas Supplies



In the past, the Northwest has been fortunate to be linked to expanding natural gas supply areas that had limited transmission to other areas. This resulted in natural gas prices in the region that are lower than most other areas of the country. In recent years, the ability of WCSB to expand production has decreased and it is projected that imports from that area to the U.S. are unlikely to be able to meet growing natural gas demand in the future. A more optimistic view of the ability of Western Canada to continue providing natural gas to the region would recognize that there is substantial coal bed and shale gas potential in the WSCB that could be developed. Further the internal demand for natural gas for oil sands development, could be substantially replaced by liquefaction of petroleum coke (a by product of oil sands refining), development of nuclear technologies to provide electricity and steam for oil sands production and processing, or cogeneration of electricity from natural gas use.

The Rocky Mountain supply area is still a growing production area, however, and its prices are still relatively low. New pipelines from the Rockies to the east are likely to reduce the price advantage of Rockies natural gas unless supplies expand even faster than pipeline capacity. The pipeline capacity to bring Rockies gas to the Northwest is constrained and will need to be expanded for the Northwest to be able to access growing Rockies supplies. There are active proposals to expand pipeline capacity from the Rockies to the Northwest. The Sunstone pipeline would bring gas from the Opal hub in Wyoming to Stanfield in eastern Oregon, and the Blue Bridge project would expand pipeline capacity from Stanfield to western Oregon. Two other pipeline proposals, Bronco and Ruby, would bring natural gas from Opal to the Oregon-California border at Malin. There are also proposals for expanding pipelines from the Rockies to Southern California and to the East.

Liquefied natural gas (LNG) is another potential source of future natural gas supplies. There are currently three proposed LNG import terminals in the region: Bradwood Landing and Oregon LNG near the mouth of the Columbia River, and Jordan Cove LNG in Coos Bay, Oregon. Each of these has the potential to supplement natural gas supplies to the Pacific Northwest in the future, but it is doubtful if more than one of these proposals will be built. Each would involve some pipeline construction and expansion to deliver natural gas into the Northwest's pipeline systems.

Another potential for increasing Northwest natural gas supplies is a proposed pipeline to bring natural gas from Alaska through Canada and into the Pacific Northwest. Alternative proposals for such a pipeline have been vying for support for several years. At best, completion of an Alaskan pipeline is probably 10 years in the future.

There is general agreement that natural gas will have to play an important role in electricity supplies for the Council's planning horizon. The cost of that natural gas will depend on the demand for natural gas and the supply and deliverability to the region. The deliverability of natural gas depends not only on access to supplies and pipeline capacity, but also on storage capability and other natural gas peaking resources like line pack, LNG storage, and interruptible demand.

The growing use of natural gas for electricity generation will require increased coordination between the electricity and natural gas industries. This is particularly true for natural gas used for peaking generation or ancillary services. Natural gas is currently scheduled on a daily basis, but electricity is scheduled on an hourly basis with constant adjustment to actual demands through load following and regulation services. Increasing amounts, and perhaps different forms, of natural gas flexibility within the day may be required as the use of natural gas increases for providing flexibility and ancillary services for the electricity sector.

In order to plan for the region's electricity needs, the Council must forecast natural gas prices, not only in the Northwest, but also in other areas of the West. To do this, the Council has developed relationships among the various natural gas pricing hubs in the West. Most relevant to the Northwest are prices at the AECO-NIT pricing hub in Alberta, the Sumas hub on the Washington-B.C. border, and the Rocky Mountain hub.

Figure A-5 shows the medium case forecasts for average wellhead prices, and prices at the Henry Hub, Sumas, AECO, and the Rocky Mountains trading hubs. Henry Hub, Louisiana is the pricing point for the New York Mercantile Exchange spot and futures markets for natural gas. Table A-2 shows the values for selected years. Figure A-6 shows the basis differentials between Henry Hub and the three regional pricing hubs. A negative basis differential means that local prices are lower than the Henry Hub price. Historical relationships that were estimated among natural gas pricing hubs are used to predict future basis differentials. Consistent monthly or seasonal differences are captured in the relationships, but differentials are likely to change over the future in ways not reflected in these estimates. These changes will relate to pipeline expansions, shifts in demand, and expansions of supply that will occur at different times and rates. The forecasts will not capture these shifting factors directly, but the wide range of price forecasts and variations in those forecasts captured in the Portfolio Model will help measure the risks posed by such variations.

The forecast basis differentials reflect an expectation that Northwest natural gas prices will continue to be lower than prices in the Gulf of Mexico (Henry Hub) area. This is consistent with growing Rocky Mountain production, stable Canadian production, and future pipeline capacity from Alaska. Development of LNG import capability within the region would also help keep Northwest supplies robust and prices more moderate, but in reality, these relative prices could shift in the future. Rapid development of LNG import capacity in the Gulf of Mexico and development of shale-based natural gas in Texas, Oklahoma, Arkansas, and the Appalachian Basin have the potential to shift regional price relationships and possibly reduce the Northwest's price advantage.

Figure A-5: Medium Case Natural Gas Price Forecasts at Northwest Hubs

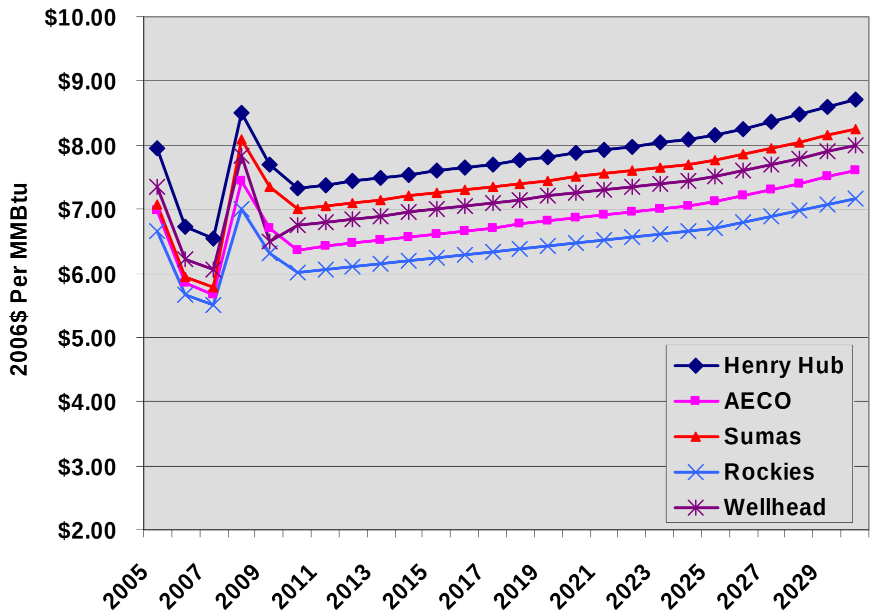
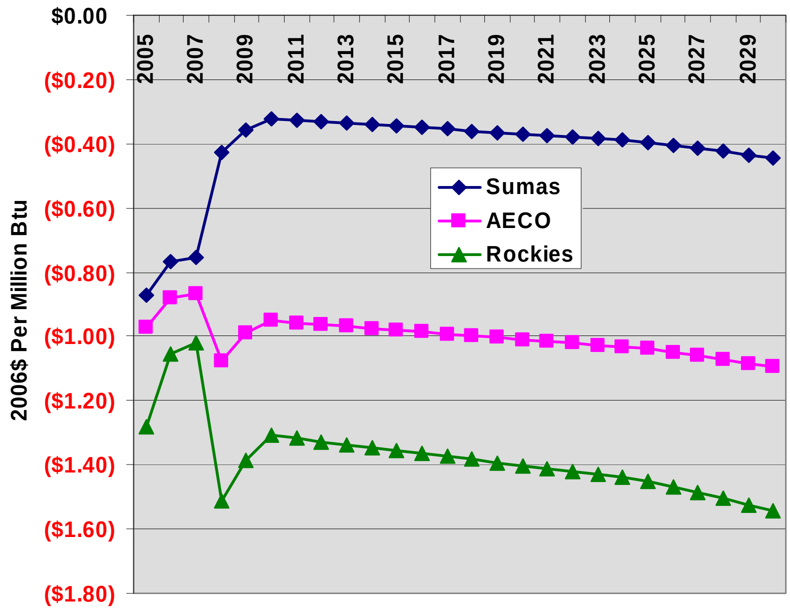


Table A-2: Medium Case Prices Natural Gas Price Forecasts at Northwest Hubs (2006 Dollars Per Million Btu)

	Wellhead	Henry Hub	AECO	Sumas	Rockies
2007	$6.06	$6.53	$5.67	$5.78	$5.51
2010	$6.75	$7.32	$6.37	$7.00	$6.01
2015	$7.00	$7.60	$6.62	$7.25	$6.24
2020	$7.25	$7.87	$6.86	$7.50	$6.47
2025	$7.50	$8.15	$7.11	$7.75	$6.70
2030	$8.00	$8.70	$7.60	$8.26	$7.16
Growth Rates					
2007-15	1.83%	1.90%	1.95%	2.87%	1.56%
2007-30	1.22%	1.25%	1.29%	1.56%	1.14%

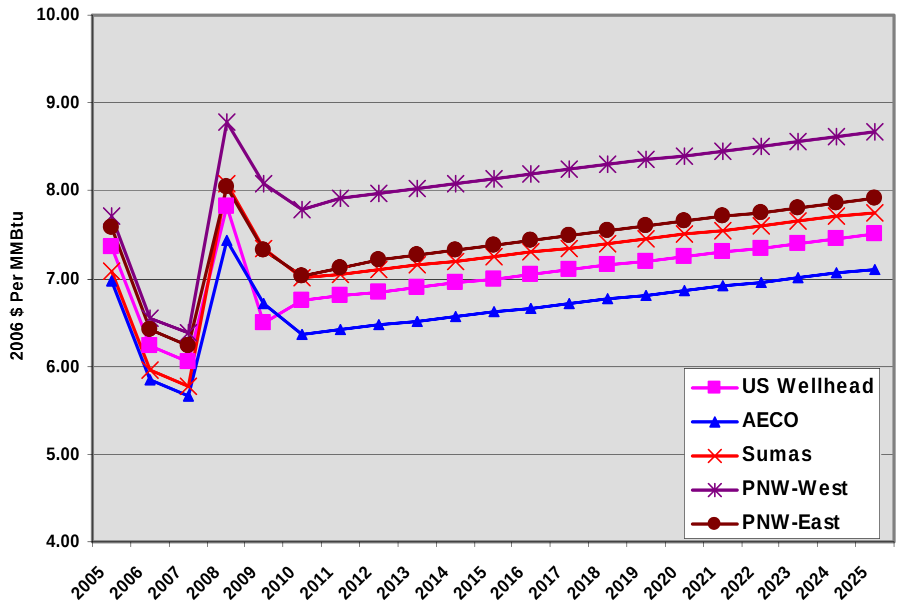
Figure A-6: Medium Case Basis Differentials From Henry Hub Prices



Forecasts of natural gas delivered to specific parts of the region are based on the forecasts of hub prices at Sumas, AECO, and the Rockies plus estimated costs of transporting the fuel via regional pipelines. Pipeline costs include three general types of cost: capacity charges, commodity charges, and in-kind fuel costs. Capacity costs are by far the largest component of the transportation cost, and they are considered to be fixed costs. Existing users of natural gas are assumed to pay rolled-in pipeline capacity costs, but future power plants are assumed to pay incremental capacity costs, which reflect new pipeline capacity costs that escalate in real terms over time. The rate of escalation varies with the forecast case. Pipeline commodity and in-kind fuel charges are small and are a variable cost of natural gas, along with the cost of the gas itself.

Figure A-7 shows the medium case forecast of delivered natural gas prices for east and west of the Cascade Mountains compared to regional hub and wellhead prices. The cost of delivering natural gas from regional pricing hubs results in delivered prices that are similar in magnitude to Henry Hub prices. In addition to delivered natural gas prices for electric generation, the Council also forecasts retail natural gas prices to residential, commercial, and industrial users. More detailed price forecasts for each case appear in the appendix tables.

Figure A-7: Incremental Natural Gas Prices Delivered to Regional Generation Facilities



OIL

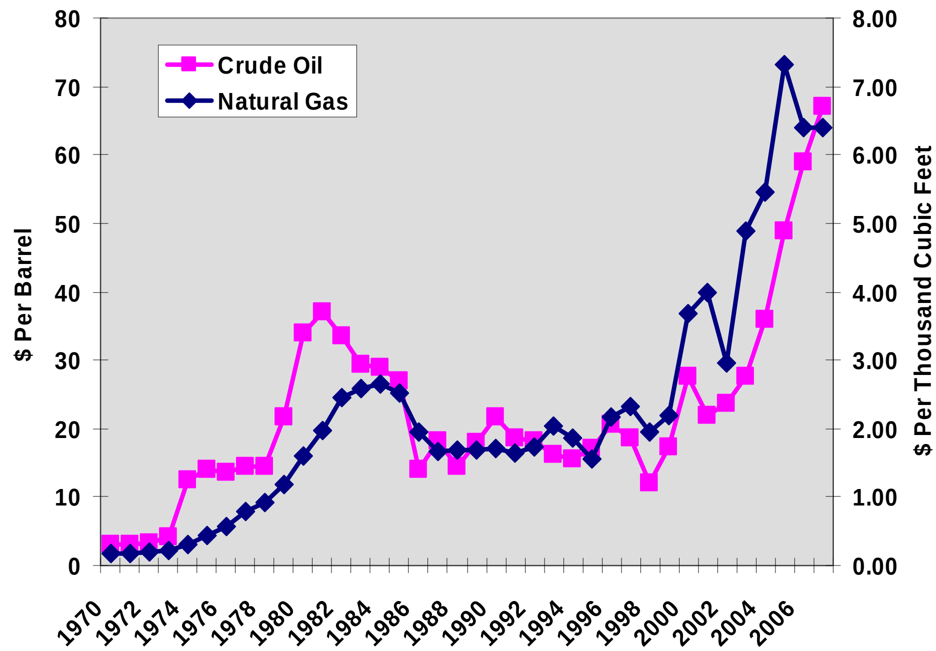
Background

Forecasts of oil prices play a less direct role in the Council's Power Plan than natural gas prices. Oil is not a significant fuel for electricity generation, nor is it an important competitor with electricity in end-use applications. However, oil prices do have an influence on natural gas prices and other energy sources. The relationship is not exact, but as shown in Figure A-8, crude oil and natural gas commodity prices do tend to move together in the long-term. Oil is most significant as a transportation fuel. In that role, oil prices enter into determining delivered coal prices at various points in the West. This is due to the reliance on diesel fuel to run the trains that deliver coal from supply areas in Wyoming and Montana.

In the middle of 2008, world oil prices reached the highest level ever recorded. The price of $150 for a barrel of oil, experienced some days in 2008, was four times the previous highest average price for a year in 1981. Even adjusting the prices to equivalent year dollars, the prices in mid-2008 were double the previous peak. However, the $150 prices did not last long. Prices have recently fallen to below $50 a barrel, but are still well above historical levels.

The factors contributing to these high oil prices are very similar to the factors listed as affecting high natural gas prices. Strong world economic growth, declining value of the dollar, unrest in the Middle East, 2005 hurricane damage, and declining domestic oil supplies. The large increases in oil prices since 2004 have changed many forecasters' views of the probable range of future oil prices.

Figure A-8: Historical Comparison of Crude Oil and Wellhead Natural Gas Prices



Oil Price Forecast Range

The oil price forecast proposed here is dramatically different from the forecast included in the Council's Fifth Power Plan. The lowest case forecast in this paper is higher than the medium forecast in the last plan. The entire forecast range, shown in Figure A-9, is much wider, reflecting increased uncertainty about future oil prices, especially on the high side of the range.

The medium forecast of world oil prices, defined as refiners' acquisition cost of imported oil, varies between $65 and $75 dollars per barrel (2006 dollars), somewhat higher than prices at the end of 2008, which were partially influenced by the global financial crisis and recession. Prices generally fall following a period of extremely high prices as new sources of supply, substitution of other energy sources, and reduced demand bring markets into balance. However, as oil production increases, more expensive sources of oil are required so that over time, prices ratchet upward. Uncertainty about oil supplies and their costs, the effects of new technologies on supplies and uses, climate policies, and political factors in oil producing countries create large uncertainties about future oil prices, and therefore, a large range of price forecasts.

The high price case is unlikely in the long term because of the alternative supplies and reductions in use that are likely to occur at such high prices. There are still ample supplies of conventional oil in the world, but its production is currently restricted by turmoil in the Middle East and the immaturity of the economies of former Soviet Union states. On the demand side, very high oil prices will stimulate improved efficiency and possibly reduced economic growth. In the years following the high oil prices of the 1970s and early 1980s, the energy intensity of the U.S. economy decreased by half, from 18.0 trillion Btu per billion dollars of Gross Domestic Product (2000$) in 1970, to 8.8 in 2007 (see Figure A-10). As the world continues to tackle the climate change issue, improved efficiency and expanded use of renewable energy sources will grow and further reduce the demand for oil in the long run. Uncertainty about the amount of supply and demand adjustments and their costs contribute to the wide range of possible future oil prices.

Figure A-9: World Oil Prices: History and Forecast

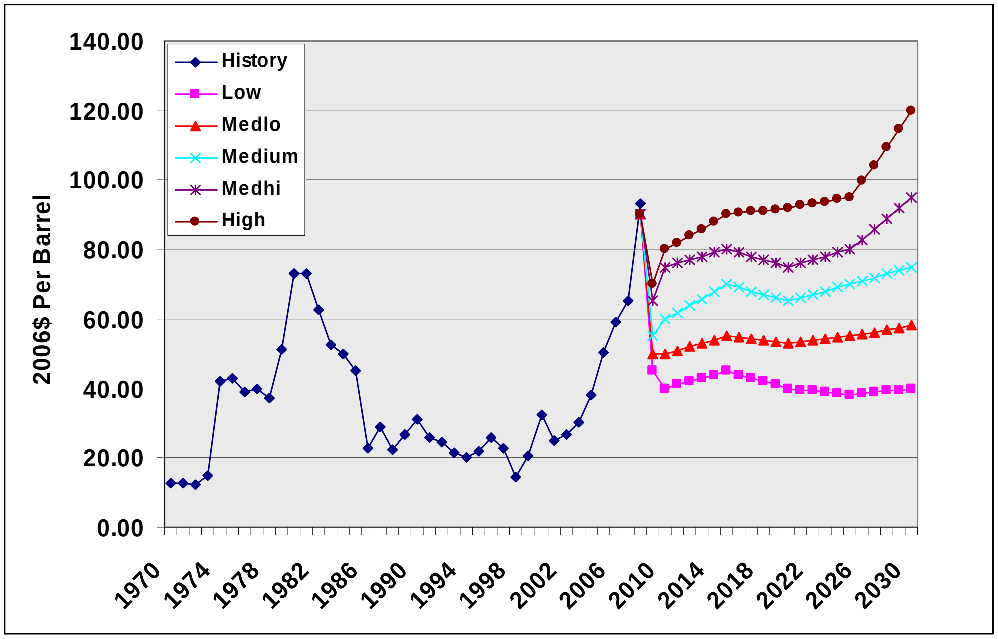
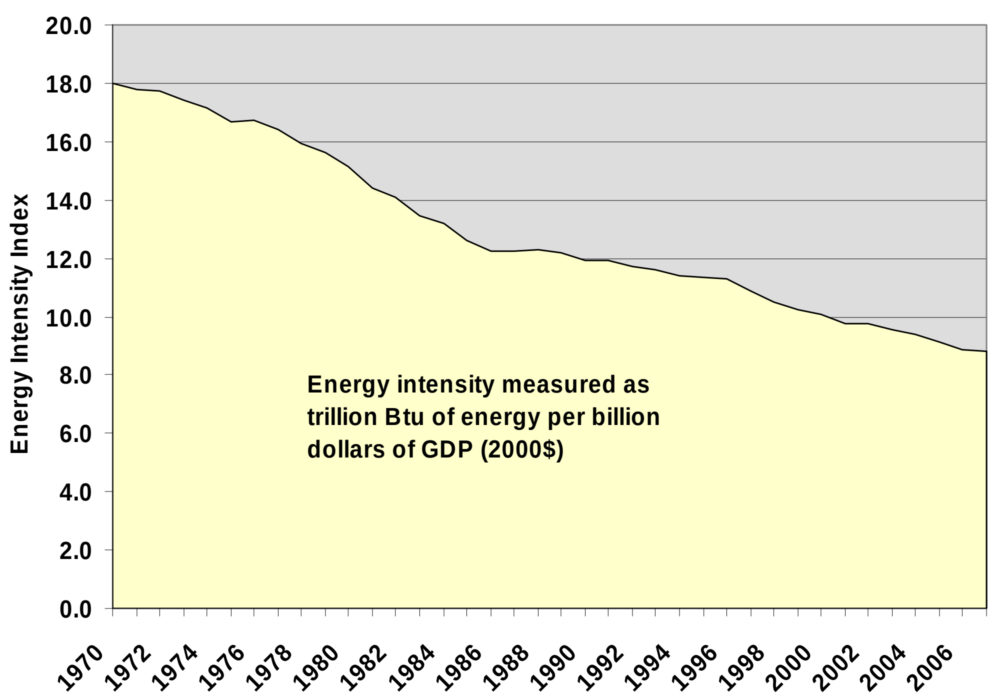


Figure A-10: Total U.S. Energy Use Per Dollar of Gross Domestic Product



The low case is also considered unlikely from today's perspective even though it is slightly higher than prices experienced during the 1990s. This scenario might be consistent with rapid progress in efficiency and renewable resources, combined with a growing ability of the Middle East and former Soviet Union states to produce their oil resources. In addition, the low case would require substantial progress in reducing the use of carbon fuels as a result of aggressive climate change policies.

The medium-low and medium-high cases are variations around the medium forecast. In the past, the Council has considered these cases to be nearly as likely as the medium case. However, given the fact that these forecasts are being prepared in the context of a very high price period, and the historical fact that forecasts done in such time periods tend to overstate future prices, the medium-low case may be more likely than the medium-high case.

Table A-3 shows the values of the forecast range for selected years. The estimated 2008 value is based on prices through September and futures market expectations for the rest of the year.

Table A-3: World Oil Price Forecast Range (2006 Dollar Per Barrel)

	Low	Medium Low	Medium	Medium High	High
2007			$65.29		
2008			$90.00		
2010	$40.00	$50.00	$60.00	$75.00	$80.00
2015	$45.00	$55.00	$70.00	$80.00	$90.00
2020	$40.00	$53.00	$65.00	$75.00	$92.00
2025	$38.00	$55.00	$70.00	$80.00	$95.00
2030	$40.00	$58.00	$75.00	$95.00	$120.00
Growth Rates					
2007-15	-4.54%	-2.12%	0.88%	2.57%	4.09%
2007-30	-2.11%	-0.51%	0.60%	1.64%	2.68%

As in the case of natural gas, oil commodity prices are used to estimate future oil product prices at the wholesale and retail level. The refiner wholesale prices of heavy and light oil products are based on refinery costs and a simple profit maximization calculation. Retail price forecasts are based on simple historical relationships between wholesale oil product prices (residual and distillate oils) and retail prices. These prices are shown in the appendix tables.

COAL

Coal Commodity Prices

Coal is a plentiful energy source in the United States. Coal resources, like natural gas, are measured in many different forms. The EIA reports several of these.[1] One measure is "demonstrated reserve base," which measures coal more likely to be mined based on seam thickness and depth. EIA estimates that the 1997 U.S. demonstrated reserve base of coal is 508 billion short tons. Only 275 billion short tons of these resources are considered "recoverable" due to inaccessibility or losses in the mining process. This is still a large supply of coal relative to the current production of about 1.1 billion short tons a year.

About half of the demonstrated reserve base of coal, 240 billion short tons, is located in the West. Western coal production has been growing due to several advantages it has over Appalachian and interior deposits. Western coal, especially Powder River Basin coal, is cheaper

[1] U.S. Energy Information Administration, U.S. Coal Reserves: 1997 Update, February 1999.

to mine due to its relatively shallow depths and thick seams. More important, Western coal is lower in sulfur content. Use of low-sulfur coal supplies has been an attractive way to help utilities meet increased restrictions on sulfur dioxide emissions under the 1990 Clean Air Act Amendments that took effect on January 1, 2000. The other characteristic that distinguishes most Western coal from Eastern and interior supplies is its Btu content. Western coal is predominately sub-bituminous coal with an average heat content of about 17 million Btu's per short ton. In contrast, Appalachian and interior coal tends to be predominately higher grade bituminous coal with heat rates averaging about 24 million Btu per short ton. Another drawback of some Western coal is a relatively high arsenic content, which will require more expensive treatment for removal under stricter environmental rules.

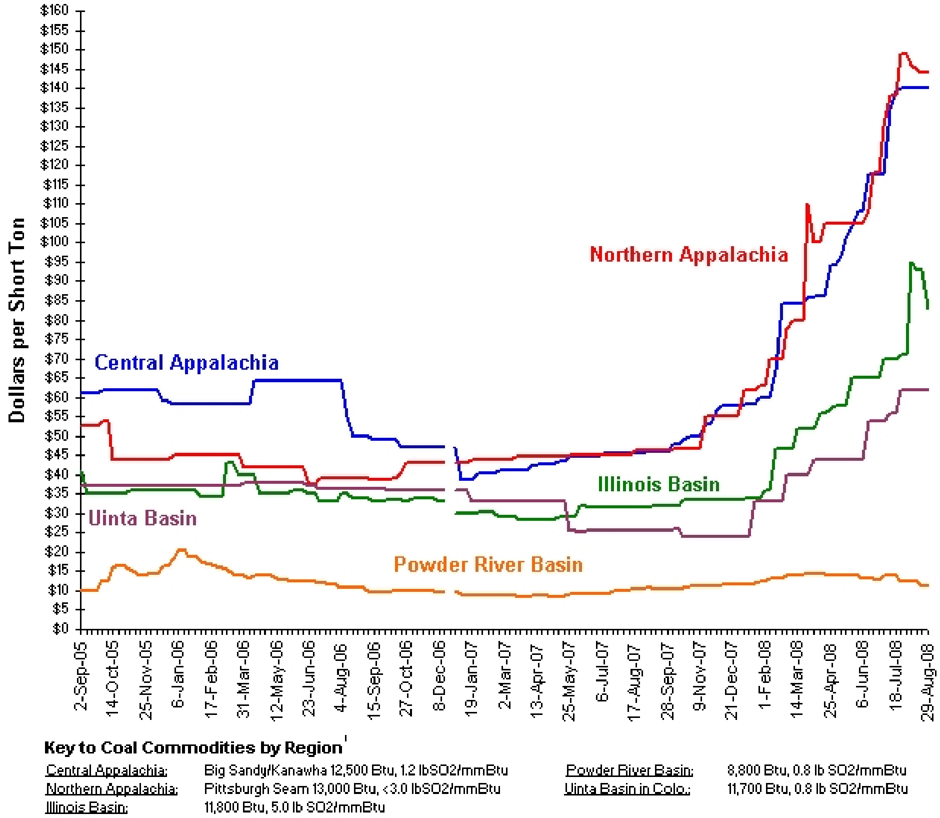
Western coal production in 2007 was 612 million short tons, with 74 percent of that production coming from Wyoming (454 million short tons). The second largest state producer was Montana at 43 million tons. Colorado, New Mexico, North Dakota and Utah produced between 24 and 36 million short tons each, and Arizona produced about 8 million short tons.[2]

Productivity increases have been rapid, especially in Western coal mines. As a result, mine-mouth coal prices have decreased over time. In constant dollars, Western mine-mouth coal prices declined by an average of 1.6 percent per year between 1985 and 2005. Expiring higher-priced long-term contracts have also contributed to declining coal prices.

Most of the coal used in the Pacific Northwest comes from the Power River Basin in Wyoming and Montana. As noted above, the cost of Power River Basin coal is very low relative to other coal. Figure A-11 shows historical coal cost from various supply areas. Additional forecast details are shown in the appendix tables.

[2] U.S. Energy Information Administration, Annual Coal Report, September 2008.

Figure A-11: Coal Price Trends from Major Supply Areas



Source: U.S. Department of Energy, Energy Information Administration

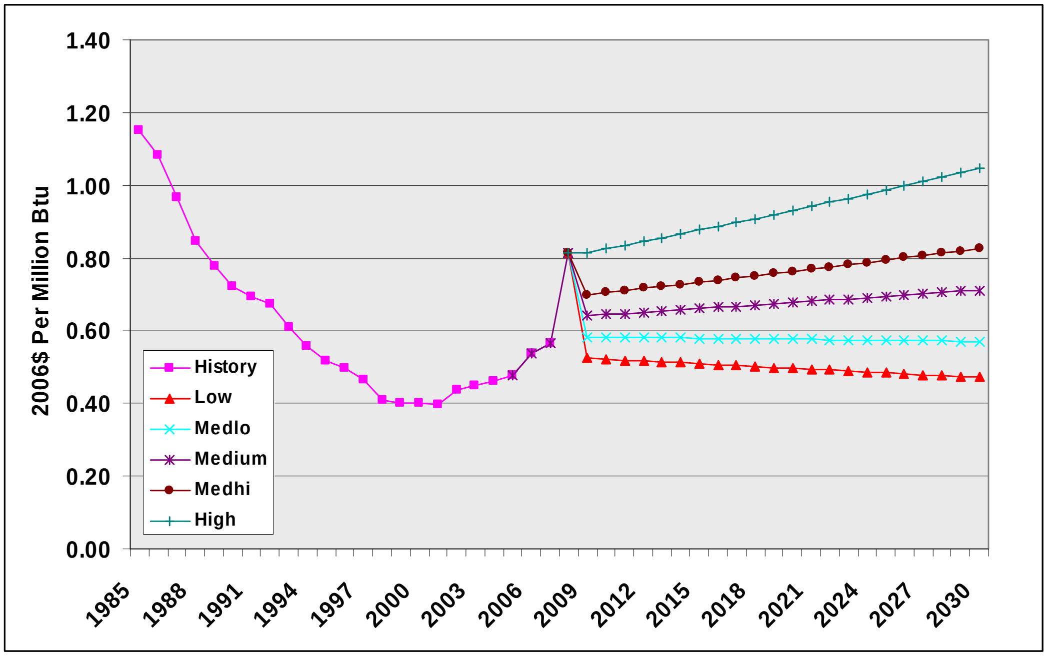
Coal Price Forecast

The forecast cost of coal to the Pacific Northwest is based on projected Powder River Basin coal prices. These forecasts are simple price growth rate assumptions from 2010 to 2030 with varying degrees of recovery from recent price increases by 2010. Table A-4 demonstrates these assumptions. Figure A-12 shows the resulting forecast range.

Table A-4: Coal Price Assumptions (2006 Dollars Per Million Btu)

	Low	Medium Low	Medium	Medium High	High
2007			$0.56		
2010	$0.52	$0.58	$0.64	$0.70	$0.83
2015	$0.51	$0.58	$0.66	$0.73	$0.88
2020	$0.50	$0.58	$0.68	$0.76	$0.93
2025	$0.48	$0.57	$0.69	$0.79	$0.99
2030	$0.47	$0.57	$0.71	$0.83	$1.05
Growth Rates					
2007-15	-1.29%	0.32%	1.98%	3.33%	5.65%
2007-30	-0.78%	0.05%	1.01%	1.67%	2.73%

Figure A-12: Range of Powder River Basin Coal Price Forecasts

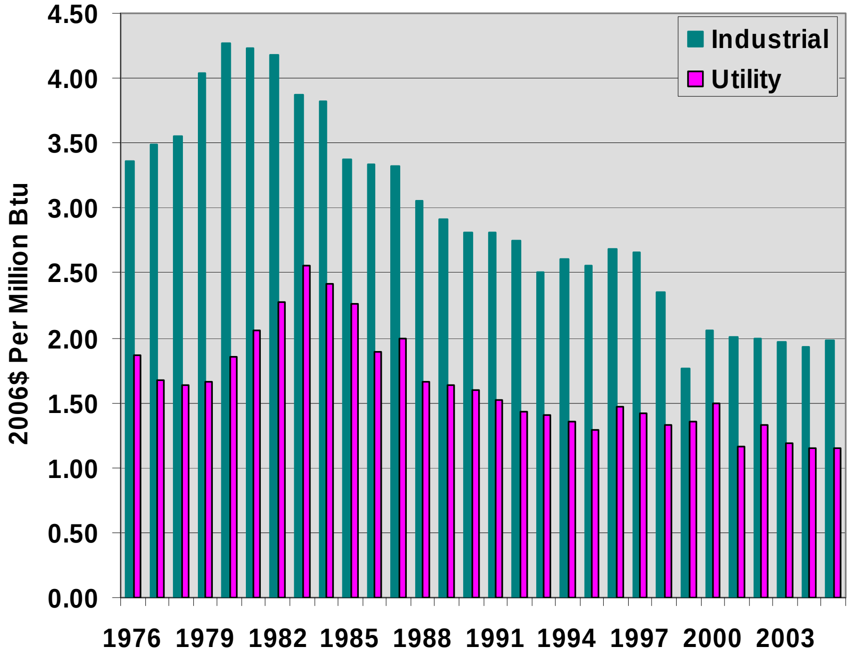


The price of coal delivered to northwest electric generators and industries is very dependent on transportation distances and costs. In addition, delivered costs may have very different time trends from mine-mouth costs due to long-term coal supply contracts. Figure A-13 shows Pacific Northwest delivered industrial and utility sector coal prices from 1976 to 2005.[3] Coal prices increased during the late 1970s with other energy prices, but after the early 1980s declined steadily until 2000 when they increased slightly in response to increased commodity prices and increased use, both domestically and for export. On average, regional industrial coal prices decreased at an annual rate of 3 percent between 1980 and 2005. Regional utility coal prices have followed a similar pattern of decline, although utility prices were delayed a few years in following industrial prices downward. This may have been due to longer-term coal contracts for the coal-fired electric generating plants.

Delivered coal prices to utilities in various locations of the Northwest and West are forecast based on the commodity price forecast. These forecasts are based on a simple relationship of the distance in miles from the Power River Basin to various locations, the cost of unit train shipment of coal per ton-mile, and an adjustment of the shipment cost to reflect the forecast of changes in transportation diesel fuel, a significant factor in the shipment costs.

[3] U.S. Energy Information Administration

Figure A-13: Utility and Industrial Coal Prices in the Pacific Northwest



Appendix A1: Medium Case Fuel Price Forecast Tables

Table A1-1: Natural Gas Prices at Key Hubs and Northwest Generators
2006$/MMBtu
Medium Case

Year	Henry Hub Natural Gas Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2005	7.95	6.98	7.08	7.70	7.58
2006	6.72	5.84	5.95	6.56	6.42
2007	6.53	5.67	5.78	6.38	6.24
2008	8.51	7.44	8.09	8.77	8.04
2009	7.70	6.71	7.34	8.07	7.33
2010	7.32	6.37	7.00	7.79	7.02
2011	7.38	6.42	7.05	7.91	7.12
2012	7.43	6.47	7.10	7.97	7.22
2013	7.48	6.52	7.15	8.03	7.27
2014	7.54	6.57	7.20	8.08	7.32
2015	7.60	6.62	7.25	8.14	7.37
2016	7.65	6.66	7.30	8.19	7.44
2017	7.71	6.71	7.35	8.24	7.49
2018	7.76	6.76	7.40	8.29	7.55
2019	7.82	6.81	7.45	8.35	7.60
2020	7.87	6.86	7.50	8.40	7.65
2021	7.93	6.91	7.55	8.46	7.70
2022	7.98	6.96	7.60	8.51	7.76
2023	8.04	7.01	7.65	8.56	7.81
2024	8.09	7.06	7.70	8.62	7.86
2025	8.15	7.11	7.75	8.67	7.91
2026	8.26	7.21	7.85	8.77	8.01
2027	8.36	7.30	7.95	8.88	8.11
2028	8.48	7.40	8.05	8.98	8.22
2029	8.59	7.50	8.15	9.09	8.32
2030	8.70	7.60	8.26	9.19	8.43

Table A1-2: Wellhead and Retail Natural Gas Prices
2006$/MMBtu
Medium Case

Year	U.S. Wellhead Prices	Regional Retail Natural Gas Prices			
		Residential	Commercial	Industrial	Utility Average
2005	7.36	12.66	11.16	8.26	7.64
2006	6.23	11.53	10.03	7.12	6.49
2007	6.06	11.36	9.86	6.95	6.31
2008	7.83	13.13	11.63	9.12	8.40
2009	6.50	11.80	10.30	8.19	7.67
2010	6.75	12.05	10.55	8.02	7.35
2011	6.80	12.10	10.60	8.07	7.43
2012	6.85	12.15	10.65	8.12	7.49
2013	6.90	12.20	10.70	8.18	7.55
2014	6.95	12.25	10.75	8.23	7.60
2015	7.00	12.30	10.80	8.28	7.65
2016	7.05	12.35	10.85	8.33	7.70
2017	7.10	12.40	10.90	8.38	7.75
2018	7.15	12.45	10.95	8.43	7.81
2019	7.20	12.50	11.00	8.48	7.86
2020	7.25	12.55	11.05	8.53	7.91
2021	7.30	12.60	11.10	8.58	7.96
2022	7.35	12.65	11.15	8.63	8.02
2023	7.40	12.70	11.20	8.68	8.07
2024	7.45	12.75	11.25	8.74	8.12
2025	7.50	12.80	11.30	8.79	8.17
2026	7.60	12.90	11.40	8.89	8.27
2027	7.70	13.00	11.50	8.99	8.37
2028	7.80	13.10	11.60	9.09	8.48
2029	7.90	13.20	11.70	9.19	8.58
2030	8.00	13.30	11.80	9.30	8.69

Table A1-3: World Oil Prices and Retail Oil Product Prices
2006$/MMBtu
Medium Case

Year	World Oil Prices	Industrial Residual Oil Price	Industrial	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price	Average Commercial Oil Price	Average Residential Oil Price	Utility Residual Oil Price	Utility Distillate Oil Price
2005	50.40	6.95	12.55	12.25	7.22	12.04	11.90	14.94	0.00	11.56
2006	59.02	8.22	14.20	13.89	8.49	13.69	13.55	16.60	0.00	13.22
2007	65.29	9.15	15.41	15.08	9.41	14.90	14.74	17.80	0.00	14.42
2008	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	55.00	7.63	13.43	13.12	7.90	12.92	12.78	15.82	0.00	12.45
2010	60.00	8.37	14.39	14.07	8.63	13.88	13.73	16.79	0.00	13.41
2011	61.88	8.64	14.75	14.43	8.91	14.24	14.09	17.15	0.00	13.77
2012	63.82	8.93	15.12	14.80	9.20	14.61	14.46	17.52	0.00	14.14
2013	65.81	9.22	15.51	15.18	9.49	15.00	14.85	17.90	0.00	14.52
2014	67.87	9.53	15.91	15.57	9.80	15.39	15.24	18.30	0.00	14.92
2015	70.00	9.84	16.31	15.97	10.11	15.80	15.65	18.71	0.00	15.33
2016	68.97	9.69	16.12	15.78	9.96	15.61	15.45	18.51	0.00	15.13
2017	67.96	9.54	15.92	15.58	9.81	15.41	15.25	18.32	0.00	14.94
2018	66.96	9.39	15.73	15.39	9.66	15.22	15.06	18.12	0.00	14.74
2019	65.97	9.25	15.54	15.21	9.52	15.03	14.88	17.93	0.00	14.55
2020	65.00	9.10	15.35	15.02	9.37	14.84	14.69	17.75	0.00	14.37
2021	65.97	9.25	15.54	15.21	9.52	15.03	14.88	17.93	0.00	14.55
2022	66.96	9.39	15.73	15.39	9.66	15.22	15.06	18.12	0.00	14.74
2023	67.96	9.54	15.92	15.58	9.81	15.41	15.25	18.32	0.00	14.94
2024	68.97	9.69	16.12	15.78	9.96	15.61	15.45	18.51	0.00	15.13
2025	70.00	9.84	16.31	15.97	10.11	15.80	15.65	18.71	0.00	15.33
2026	70.97	9.99	16.50	16.16	10.25	15.99	15.83	18.90	0.00	15.52
2027	71.96	10.13	16.69	16.34	10.40	16.18	16.02	19.08	0.00	15.71
2028	72.96	10.28	16.88	16.53	10.55	16.37	16.21	19.28	0.00	15.90
2029	73.97	10.43	17.08	16.73	10.70	16.57	16.40	19.47	0.00	16.09
2030	75.00	10.58	17.28	16.92	10.85	16.76	16.60	19.67	0.00	16.29

Table A1-4: Coal Price Forecasts
2006$/MMBtu
Medium Case

			Selected Regional Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	West WA/OR	East WA/OR	Idaho	Montana	Utah	Wyoming
2005	0.48	2.11	1.40	1.22	0.82	0.78	0.67	0.58
2006	0.54	2.08	1.43	1.25	0.87	0.83	0.72	0.64
2007	0.56	2.09	1.45	1.27	0.89	0.85	0.75	0.66
2008	0.82	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.64	1.98	1.45	1.28	0.94	0.90	0.81	0.73
2010	0.64	2.17	1.52	1.35	0.97	0.93	0.82	0.74
2011	0.65	2.15	1.52	1.34	0.97	0.93	0.83	0.74
2012	0.65	2.15	1.52	1.35	0.97	0.93	0.83	0.75
2013	0.65	2.16	1.52	1.35	0.97	0.94	0.83	0.75
2014	0.66	2.16	1.53	1.35	0.98	0.94	0.84	0.75
2015	0.66	2.16	1.53	1.36	0.98	0.94	0.84	0.76
2016	0.66	2.15	1.53	1.35	0.98	0.95	0.84	0.76
2017	0.67	2.15	1.53	1.36	0.99	0.95	0.84	0.76
2018	0.67	2.16	1.53	1.36	0.99	0.95	0.85	0.76
2019	0.67	2.16	1.54	1.36	0.99	0.96	0.85	0.77
2020	0.68	2.16	1.54	1.37	1.00	0.96	0.85	0.77
2021	0.68	2.18	1.55	1.37	1.00	0.96	0.86	0.78
2022	0.68	2.18	1.55	1.38	1.00	0.97	0.86	0.78
2023	0.69	2.18	1.56	1.38	1.01	0.97	0.87	0.78
2024	0.69	2.19	1.56	1.38	1.01	0.97	0.87	0.79
2025	0.69	2.19	1.56	1.39	1.01	0.98	0.87	0.79
2026	0.70	2.20	1.57	1.39	1.02	0.98	0.88	0.79
2027	0.70	2.20	1.57	1.39	1.02	0.98	0.88	0.80
2028	0.70	2.20	1.57	1.40	1.02	0.99	0.88	0.80
2029	0.71	2.21	1.58	1.40	1.03	0.99	0.89	0.80
2030	0.71	2.21	1.58	1.41	1.03	0.99	0.89	0.81

Appendix A2: Low Case Fuel Price Forecast Tables

Table A2-1: Natural Gas Prices at Key Hubs and Northwest Generators
2006$/MMBtu
Low Case

Year	Henry Hub Natural Gas Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2005	7.95	6.98	7.08	7.70	7.58
2006	6.72	5.84	5.95	6.56	6.42
2007	6.53	5.67	5.78	6.38	6.24
2008	8.46	7.39	8.04	8.72	7.99
2009	7.07	6.15	6.77	7.49	6.76
2010	6.22	5.38	6.00	6.77	6.02
2011	6.04	5.22	5.84	6.67	5.90
2012	5.87	5.07	5.68	6.53	5.80
2013	5.71	4.92	5.53	6.37	5.65
2014	5.55	4.78	5.38	6.22	5.50
2015	5.39	4.64	5.24	6.08	5.36
2016	5.21	4.48	5.08	5.91	5.21
2017	5.04	4.33	4.93	5.75	5.05
2018	4.88	4.18	4.77	5.60	4.92
2019	4.72	4.04	4.63	5.45	4.77
2020	4.56	3.90	4.49	5.30	4.63
2021	4.58	3.92	4.51	5.32	4.65
2022	4.61	3.94	4.53	5.34	4.67
2023	4.63	3.96	4.55	5.36	4.69
2024	4.65	3.98	4.57	5.38	4.71
2025	4.67	4.00	4.59	5.40	4.73
2026	4.69	4.02	4.61	5.42	4.75
2027	4.72	4.04	4.63	5.44	4.76
2028	4.74	4.06	4.65	5.46	4.78
2029	4.76	4.08	4.67	5.48	4.80
2030	4.78	4.10	4.69	5.50	4.82

Table A2-2: Wellhead and Retail Natural Gas Prices
2006$/MMBtu
Low Case

Year	U.S Wellhead Price	Regional Retail Natural Gas Prices			
		Residential	Commercial	Industrial	Utility Average
2005	7.36	12.66	11.16	8.26	7.64
2006	6.23	11.53	10.03	7.12	6.49
2007	6.06	11.36	9.86	6.95	6.31
2008	7.78	13.08	11.58	9.07	8.35
2009	5.50	10.80	9.30	7.49	7.09
2010	5.75	11.05	9.55	7.01	6.33
2011	5.59	10.90	9.39	6.85	6.20
2012	5.44	10.74	9.24	6.69	6.06
2013	5.29	10.59	9.09	6.54	5.91
2014	5.14	10.45	8.94	6.39	5.76
2015	5.00	10.30	8.80	6.24	5.61
2016	4.84	10.14	8.64	6.08	5.46
2017	4.69	9.99	8.49	5.92	5.30
2018	4.54	9.84	8.34	5.77	5.15
2019	4.39	9.69	8.19	5.62	5.00
2020	4.25	9.55	8.05	5.48	4.86
2021	4.27	9.57	8.07	5.50	4.88
2022	4.29	9.59	8.09	5.52	4.90
2023	4.31	9.61	8.11	5.54	4.92
2024	4.33	9.63	8.13	5.56	4.94
2025	4.35	9.65	8.15	5.58	4.96
2026	4.37	9.67	8.17	5.60	4.98
2027	4.39	9.69	8.19	5.62	5.00
2028	4.41	9.71	8.21	5.64	5.02
2029	4.43	9.73	8.23	5.66	5.04
2030	4.45	9.75	8.25	5.68	5.06

Table A2-3: World Oil Prices and Retail Oil Products Prices
2006$/MMBtu
Low Case

Year	World Oil Prices	Industrial Residual Oil Price	Industrial	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price	Average Commercial Oil Price	Average Residential Oil Price	Utility Residual Oil Price	Utility Distillate Oil Price
2005	50.40	6.95	12.55	12.25	7.22	12.04	11.90	14.94	0.00	11.56
2006	59.02	8.22	14.20	13.89	8.49	13.69	13.55	16.60	0.00	13.22
2007	65.29	9.15	15.41	15.08	9.41	14.90	14.74	17.80	0.00	14.42
2008	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	45.00	6.15	11.51	11.22	6.42	11.00	10.87	13.90	0.00	10.52
2010	40.00	5.41	10.55	10.27	5.68	10.04	9.91	12.94	0.00	9.56
2011	40.95	5.55	10.73	10.45	5.82	10.22	10.10	13.12	0.00	9.74
2012	41.93	5.70	10.92	10.64	5.96	10.41	10.28	13.31	0.00	9.93
2013	42.93	5.84	11.11	10.83	6.11	10.60	10.47	13.50	0.00	10.12
2014	43.95	6.00	11.31	11.02	6.26	10.80	10.67	13.70	0.00	10.32
2015	45.00	6.15	11.51	11.22	6.42	11.00	10.87	13.90	0.00	10.52
2016	43.95	6.00	11.31	11.02	6.26	10.80	10.67	13.70	0.00	10.32
2017	42.93	5.84	11.11	10.83	6.11	10.60	10.47	13.50	0.00	10.12
2018	41.93	5.70	10.92	10.64	5.96	10.41	10.28	13.31	0.00	9.93
2019	40.95	5.55	10.73	10.45	5.82	10.22	10.10	13.12	0.00	9.74
2020	40.00	5.41	10.55	10.27	5.68	10.04	9.91	12.94	0.00	9.56
2021	39.59	5.35	10.47	10.20	5.62	9.96	9.84	12.86	0.00	9.48
2022	39.19	5.29	10.39	10.12	5.56	9.88	9.76	12.78	0.00	9.41
2023	38.79	5.23	10.31	10.04	5.50	9.80	9.68	12.71	0.00	9.33
2024	38.39	5.17	10.24	9.97	5.44	9.73	9.61	12.63	0.00	9.25
2025	38.00	5.12	10.16	9.89	5.38	9.65	9.53	12.56	0.00	9.18
2026	38.39	5.17	10.24	9.97	5.44	9.73	9.61	12.63	0.00	9.25
2027	38.79	5.23	10.31	10.04	5.50	9.80	9.68	12.71	0.00	9.33
2028	39.19	5.29	10.39	10.12	5.56	9.88	9.76	12.78	0.00	9.41
2029	39.59	5.35	10.47	10.20	5.62	9.96	9.84	12.86	0.00	9.48
2030	40.00	5.41	10.55	10.27	5.68	10.04	9.91	12.94	0.00	9.56

Table A2-4: Coal Price Forecasts
2006$/MMBtu
Low Case

Year	Western Minemouth Prices	Regional Industrial Price	Selected Regional Electricity Generation Coal Prices					
			West WA/OR	East WA/OR	Idaho	Montana	Utah	Wyoming
2005	0.48	2.11	1.40	1.22	0.82	0.78	0.67	0.58
2006	0.54	2.08	1.43	1.25	0.87	0.83	0.72	0.64
2007	0.56	2.09	1.45	1.27	0.89	0.85	0.75	0.66
2008	0.82	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.52	1.83	1.31	1.15	0.81	0.78	0.69	0.61
2010	0.52	1.98	1.37	1.20	0.84	0.80	0.70	0.62
2011	0.52	2.02	1.39	1.21	0.84	0.80	0.70	0.61
2012	0.52	2.02	1.39	1.21	0.84	0.80	0.69	0.61
2013	0.51	2.01	1.38	1.21	0.83	0.80	0.69	0.61
2014	0.51	2.01	1.38	1.21	0.83	0.79	0.69	0.61
2015	0.51	2.01	1.38	1.20	0.83	0.79	0.69	0.60
2016	0.51	1.99	1.37	1.20	0.82	0.79	0.68	0.60
2017	0.50	1.99	1.37	1.19	0.82	0.78	0.68	0.60
2018	0.50	1.99	1.36	1.19	0.82	0.78	0.68	0.60
2019	0.50	1.98	1.36	1.19	0.82	0.78	0.68	0.59
2020	0.50	1.98	1.36	1.19	0.81	0.78	0.67	0.59
2021	0.49	1.98	1.36	1.18	0.81	0.78	0.67	0.59
2022	0.49	1.98	1.36	1.18	0.81	0.77	0.67	0.59
2023	0.49	1.98	1.35	1.18	0.81	0.77	0.67	0.58
2024	0.49	1.98	1.35	1.18	0.80	0.77	0.66	0.58
2025	0.48	1.97	1.35	1.18	0.80	0.77	0.66	0.58
2026	0.48	1.98	1.35	1.17	0.80	0.76	0.66	0.58
2027	0.48	1.97	1.35	1.17	0.80	0.76	0.66	0.57
2028	0.48	1.97	1.34	1.17	0.80	0.76	0.65	0.57
2029	0.47	1.97	1.34	1.17	0.79	0.76	0.65	0.57
2030	0.47	1.97	1.34	1.16	0.79	0.75	0.65	0.57

Appendix A3: Medium-Low Case Fuel Price Forecast Tables

Table A3-1: Natural Gas Prices at Key Hubs and Northwest Generators
2006$/MMBtu
Medlo Case

Year	Henry Hub Natural Gas Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2005	7.95	6.98	7.08	7.70	7.58
2006	6.72	5.84	5.95	6.56	6.42
2007	6.53	5.67	5.78	6.38	6.24
2008	8.48	7.41	8.06	8.74	8.01
2009	7.53	6.56	7.19	7.92	7.18
2010	7.04	6.12	6.75	7.53	6.77
2011	6.87	5.97	6.59	7.44	6.65
2012	6.70	5.81	6.44	7.30	6.55
2013	6.54	5.67	6.29	7.14	6.40
2014	6.37	5.52	6.14	7.00	6.26
2015	6.22	5.38	6.00	6.85	6.11
2016	6.16	5.33	5.94	6.80	6.07
2017	6.11	5.28	5.89	6.75	6.02
2018	6.05	5.23	5.84	6.70	5.99
2019	6.00	5.18	5.79	6.65	5.94
2020	5.94	5.13	5.74	6.60	5.89
2021	6.05	5.23	5.84	6.70	5.99
2022	6.16	5.33	5.94	6.80	6.09
2023	6.27	5.42	6.04	6.90	6.19
2024	6.38	5.52	6.14	7.01	6.29
2025	6.49	5.63	6.25	7.11	6.40
2026	6.55	5.68	6.30	7.16	6.45
2027	6.60	5.72	6.35	7.22	6.50
2028	6.66	5.77	6.40	7.27	6.55
2029	6.71	5.82	6.45	7.32	6.60
2030	6.77	5.87	6.50	7.37	6.65

Table A3-2: Wellhead and Retail Natural Gas Prices
2006$/MMBtu
Medlo Case

Year	U.S Wellhead Price	Regional Retail Natural Gas Prices			
		Residential	Commercial	Industrial	Utility Average
2005	7.36	12.66	11.16	8.26	7.64
2006	6.23	11.53	10.03	7.12	6.49
2007	6.06	11.36	9.86	6.95	6.31
2008	7.80	13.10	11.60	9.09	8.37
2009	6.25	11.55	10.05	8.01	7.52
2010	6.50	11.80	10.30	7.77	7.10
2011	6.34	11.65	10.14	7.61	6.96
2012	6.19	11.49	9.99	7.45	6.82
2013	6.04	11.34	9.84	7.30	6.67
2014	5.89	11.20	9.69	7.15	6.52
2015	5.75	11.05	9.55	7.01	6.38
2016	5.70	11.00	9.50	6.95	6.33
2017	5.65	10.95	9.45	6.90	6.28
2018	5.60	10.90	9.40	6.85	6.23
2019	5.55	10.85	9.35	6.80	6.18
2020	5.50	10.80	9.30	6.75	6.13
2021	5.60	10.90	9.40	6.85	6.23
2022	5.69	11.00	9.50	6.95	6.33
2023	5.79	11.10	9.60	7.05	6.43
2024	5.90	11.20	9.70	7.16	6.54
2025	6.00	11.30	9.80	7.26	6.64
2026	6.05	11.35	9.85	7.31	6.69
2027	6.10	11.40	9.90	7.36	6.74
2028	6.15	11.45	9.95	7.41	6.79
2029	6.20	11.50	10.00	7.46	6.85
2030	6.25	11.55	10.05	7.52	6.90

Table A3-3: World Oil Prices and Retail Oil Product Prices
2006$/MMBtu
Medlo Case

Year	World Oil Prices	Industrial Residual Oil Price	Industrial	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price	Average Commercial Oil Price	Average Residential Oil Price	Utility Residual Oil Price	Utility Distillate Oil Price
2005	50.40	6.95	12.55	12.25	7.22	12.04	11.90	14.94	0.00	11.56
2006	59.02	8.22	14.20	13.89	8.49	13.69	13.55	16.60	0.00	13.22
2007	65.29	9.15	15.41	15.08	9.41	14.90	14.74	17.80	0.00	14.42
2008	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	50.00	6.89	12.47	12.17	7.16	11.96	11.82	14.86	0.00	11.48
2010	50.00	6.89	12.47	12.17	7.16	11.96	11.82	14.86	0.00	11.48
2011	50.96	7.03	12.65	12.36	7.30	12.14	12.01	15.05	0.00	11.67
2012	51.94	7.18	12.84	12.54	7.44	12.33	12.20	15.24	0.00	11.86
2013	52.94	7.32	13.03	12.73	7.59	12.52	12.39	15.43	0.00	12.05
2014	53.96	7.47	13.23	12.92	7.74	12.72	12.58	15.62	0.00	12.25
2015	55.00	7.63	13.43	13.12	7.90	12.92	12.78	15.82	0.00	12.45
2016	54.59	7.57	13.35	13.05	7.84	12.84	12.70	15.75	0.00	12.37
2017	54.19	7.51	13.27	12.97	7.78	12.76	12.63	15.67	0.00	12.29
2018	53.79	7.45	13.20	12.89	7.72	12.69	12.55	15.59	0.00	12.21
2019	53.39	7.39	13.12	12.82	7.66	12.61	12.47	15.52	0.00	12.14
2020	53.00	7.33	13.05	12.74	7.60	12.53	12.40	15.44	0.00	12.06
2021	53.39	7.39	13.12	12.82	7.66	12.61	12.47	15.52	0.00	12.14
2022	53.79	7.45	13.20	12.89	7.72	12.69	12.55	15.59	0.00	12.21
2023	54.19	7.51	13.27	12.97	7.78	12.76	12.63	15.67	0.00	12.29
2024	54.59	7.57	13.35	13.05	7.84	12.84	12.70	15.75	0.00	12.37
2025	55.00	7.63	13.43	13.12	7.90	12.92	12.78	15.82	0.00	12.45
2026	55.59	7.71	13.54	13.23	7.98	13.03	12.89	15.94	0.00	12.56
2027	56.18	7.80	13.66	13.35	8.07	13.15	13.01	16.05	0.00	12.67
2028	56.78	7.89	13.77	13.46	8.16	13.26	13.12	16.17	0.00	12.79
2029	57.39	7.98	13.89	13.58	8.25	13.38	13.24	16.28	0.00	12.90
2030	58.00	8.07	14.01	13.69	8.34	13.50	13.35	16.40	0.00	13.02

Table A3-4: Coal Price Forecasts
2006$/MMBtu
Medlo Case

Year	Western Minemouth Prices	Regional Industrial Price	Selected Regional Electricity Generation Coal Prices					
			West WA/OR	East WA/OR	Idaho	Montana	Utah	Wyoming
2005	0.48	2.11	1.40	1.22	0.82	0.78	0.67	0.58
2006	0.54	2.08	1.43	1.25	0.87	0.83	0.72	0.64
2007	0.56	2.09	1.45	1.27	0.89	0.85	0.75	0.66
2008	0.82	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.58	1.91	1.38	1.22	0.88	0.84	0.75	0.67
2010	0.58	2.07	1.45	1.27	0.90	0.86	0.76	0.68
2011	0.58	2.08	1.45	1.28	0.90	0.86	0.76	0.68
2012	0.58	2.08	1.45	1.27	0.90	0.86	0.76	0.68
2013	0.58	2.08	1.45	1.27	0.90	0.86	0.76	0.68
2014	0.58	2.08	1.45	1.27	0.90	0.86	0.76	0.67
2015	0.58	2.08	1.45	1.27	0.90	0.86	0.76	0.67
2016	0.58	2.07	1.44	1.27	0.90	0.86	0.76	0.67
2017	0.58	2.07	1.44	1.27	0.90	0.86	0.76	0.67
2018	0.58	2.07	1.44	1.27	0.90	0.86	0.76	0.67
2019	0.58	2.07	1.44	1.27	0.90	0.86	0.75	0.67
2020	0.58	2.07	1.44	1.27	0.89	0.86	0.75	0.67
2021	0.58	2.07	1.44	1.27	0.90	0.86	0.75	0.67
2022	0.58	2.07	1.44	1.27	0.89	0.86	0.75	0.67
2023	0.57	2.07	1.44	1.27	0.89	0.86	0.75	0.67
2024	0.57	2.07	1.44	1.27	0.89	0.86	0.75	0.67
2025	0.57	2.07	1.44	1.27	0.89	0.86	0.75	0.67
2026	0.57	2.07	1.44	1.27	0.89	0.86	0.75	0.67
2027	0.57	2.07	1.44	1.27	0.89	0.85	0.75	0.67
2028	0.57	2.07	1.44	1.26	0.89	0.85	0.75	0.67
2029	0.57	2.07	1.44	1.26	0.89	0.85	0.75	0.67
2030	0.57	2.07	1.44	1.26	0.89	0.85	0.75	0.67

Appendix A4: Medium-High Case Fuel Price Forecast Tables

Table A4-1: Natural Gas Prices at Key Hubs and Northwest Generators
2006$/MMBtu
Medhi Case

Year	Henry Hub Natural Gas Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2005	7.95	6.98	7.08	7.70	7.58
2006	6.72	5.84	5.95	6.56	6.42
2007	6.53	5.67	5.78	6.38	6.24
2008	8.59	7.51	8.16	8.85	8.11
2009	8.34	7.28	7.92	8.66	7.91
2010	8.48	7.41	8.06	8.87	8.08
2011	8.58	7.49	8.14	9.03	8.21
2012	8.67	7.58	8.23	9.13	8.36
2013	8.77	7.67	8.32	9.23	8.45
2014	8.87	7.76	8.41	9.32	8.54
2015	8.98	7.85	8.51	9.42	8.63
2016	8.98	7.85	8.51	9.43	8.65
2017	8.98	7.85	8.51	9.43	8.65
2018	8.98	7.85	8.51	9.43	8.66
2019	8.98	7.85	8.51	9.44	8.66
2020	8.98	7.85	8.51	9.44	8.66
2021	9.03	7.90	8.56	9.49	8.71
2022	9.09	7.95	8.61	9.55	8.77
2023	9.14	8.00	8.66	9.60	8.82
2024	9.20	8.05	8.71	9.66	8.87
2025	9.25	8.10	8.76	9.71	8.93
2026	9.44	8.27	8.93	9.90	9.11
2027	9.64	8.44	9.11	10.08	9.29
2028	9.84	8.62	9.29	10.27	9.47
2029	10.04	8.80	9.47	10.46	9.66
2030	10.25	8.99	9.66	10.66	9.85

Table A4-2: Wellhead and Retail Natural Gas Prices
2006$/MMBtu
Medhi Case

Year	U.S Wellhead Price	Regional Retail Natural Gas Prices			
		Residential	Commercial	Industrial	Utility Average
2005	7.36	12.66	11.16	8.26	7.64
2006	6.23	11.53	10.03	7.12	6.49
2007	6.06	11.36	9.86	6.95	6.31
2008	7.90	13.20	11.70	9.19	8.47
2009	7.50	12.80	11.30	8.91	8.26
2010	7.80	13.10	11.60	9.09	8.42
2011	7.89	13.19	11.69	9.18	8.53
2012	7.98	13.28	11.78	9.27	8.64
2013	8.07	13.37	11.87	9.36	8.73
2014	8.16	13.46	11.96	9.46	8.83
2015	8.25	13.55	12.05	9.55	8.92
2016	8.25	13.55	12.05	9.55	8.93
2017	8.25	13.55	12.05	9.55	8.93
2018	8.25	13.55	12.05	9.55	8.93
2019	8.25	13.55	12.05	9.55	8.93
2020	8.25	13.55	12.05	9.55	8.93
2021	8.30	13.60	12.10	9.60	8.98
2022	8.35	13.65	12.15	9.65	9.04
2023	8.40	13.70	12.20	9.70	9.09
2024	8.45	13.75	12.25	9.75	9.14
2025	8.50	13.80	12.30	9.81	9.20
2026	8.67	13.98	12.47	9.98	9.37
2027	8.85	14.15	12.65	10.16	9.55
2028	9.03	14.33	12.83	10.34	9.74
2029	9.21	14.52	13.01	10.53	9.93
2030	9.40	14.70	13.20	10.72	10.12

Table A4-3: World Oil Prices and Retail Oil Product Prices
2006$/MMBtu
Medhi Case

Year	World Oil Prices	Industrial Residual Oil Price	Industrial	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price	Average Commercial Oil Price	Average Residential Oil Price	Utility Residual Oil Price	Utility Distillate Oil Price
2005	50.40	6.95	12.55	12.25	7.22	12.04	11.90	14.94	0.00	11.56
2006	59.02	8.22	14.20	13.89	8.49	13.69	13.55	16.60	0.00	13.22
2007	65.29	9.15	15.41	15.08	9.41	14.90	14.74	17.80	0.00	14.42
2008	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	65.00	9.10	15.35	15.02	9.37	14.84	14.69	17.75	0.00	14.37
2010	75.00	10.58	17.28	16.92	10.85	16.76	16.60	19.67	0.00	16.29
2011	75.97	10.72	17.46	17.11	10.99	16.95	16.79	19.86	0.00	16.48
2012	76.96	10.87	17.65	17.29	11.14	17.14	16.98	20.05	0.00	16.67
2013	77.96	11.02	17.84	17.48	11.29	17.33	17.17	20.24	0.00	16.86
2014	78.97	11.17	18.04	17.68	11.44	17.53	17.36	20.43	0.00	17.06
2015	80.00	11.32	18.24	17.87	11.59	17.73	17.56	20.63	0.00	17.25
2016	78.97	11.17	18.04	17.68	11.44	17.53	17.36	20.43	0.00	17.06
2017	77.96	11.02	17.84	17.48	11.29	17.33	17.17	20.24	0.00	16.86
2018	76.96	10.87	17.65	17.29	11.14	17.14	16.98	20.05	0.00	16.67
2019	75.97	10.72	17.46	17.11	10.99	16.95	16.79	19.86	0.00	16.48
2020	75.00	10.58	17.28	16.92	10.85	16.76	16.60	19.67	0.00	16.29
2021	75.97	10.72	17.46	17.11	10.99	16.95	16.79	19.86	0.00	16.48
2022	76.96	10.87	17.65	17.29	11.14	17.14	16.98	20.05	0.00	16.67
2023	77.96	11.02	17.84	17.48	11.29	17.33	17.17	20.24	0.00	16.86
2024	78.97	11.17	18.04	17.68	11.44	17.53	17.36	20.43	0.00	17.06
2025	80.00	11.32	18.24	17.87	11.59	17.73	17.56	20.63	0.00	17.25
2026	82.80	11.73	18.77	18.40	12.00	18.26	18.09	21.17	0.00	17.79
2027	85.69	12.16	19.33	18.95	12.43	18.82	18.64	21.73	0.00	18.35
2028	88.69	12.60	19.91	19.52	12.87	19.40	19.22	22.30	0.00	18.92
2029	91.79	13.06	20.50	20.11	13.33	19.99	19.81	22.90	0.00	19.52
2030	95.00	13.53	21.12	20.72	13.80	20.61	20.42	23.52	0.00	20.14

Table A4-4: Coal Price Forecasts
2006$/MMBtu
Medhi Case

Year	Western Minemouth Prices	Regional Industrial Price	Selected Regional Electricity Generation Coal Prices					
			West WA/OR	East WA/OR	Idaho	Montana	Utah	Wyoming
2005	0.48	2.11	1.40	1.22	0.82	0.78	0.67	0.58
2006	0.54	2.08	1.43	1.25	0.87	0.83	0.72	0.64
2007	0.56	2.09	1.45	1.27	0.89	0.85	0.75	0.66
2008	0.82	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.70	2.08	1.52	1.36	1.00	0.97	0.87	0.79
2010	0.70	2.25	1.59	1.41	1.03	0.99	0.89	0.80
2011	0.71	2.21	1.58	1.40	1.03	0.99	0.89	0.81
2012	0.72	2.21	1.58	1.41	1.04	1.00	0.89	0.81
2013	0.72	2.22	1.59	1.42	1.04	1.00	0.90	0.82
2014	0.73	2.22	1.60	1.42	1.05	1.01	0.91	0.82
2015	0.73	2.23	1.60	1.43	1.05	1.02	0.91	0.83
2016	0.74	2.23	1.60	1.43	1.06	1.02	0.92	0.83
2017	0.75	2.23	1.61	1.44	1.06	1.03	0.92	0.84
2018	0.75	2.24	1.62	1.44	1.07	1.03	0.93	0.85
2019	0.76	2.24	1.62	1.45	1.08	1.04	0.93	0.85
2020	0.76	2.25	1.63	1.45	1.08	1.04	0.94	0.86
2021	0.77	2.27	1.64	1.46	1.09	1.05	0.95	0.86
2022	0.78	2.27	1.64	1.47	1.10	1.06	0.95	0.87
2023	0.78	2.28	1.65	1.48	1.10	1.06	0.96	0.88
2024	0.79	2.29	1.66	1.48	1.11	1.07	0.97	0.88
2025	0.79	2.29	1.66	1.49	1.11	1.08	0.97	0.89
2026	0.80	2.31	1.67	1.50	1.12	1.08	0.98	0.90
2027	0.81	2.31	1.68	1.50	1.13	1.09	0.99	0.90
2028	0.81	2.32	1.69	1.51	1.13	1.10	0.99	0.91
2029	0.82	2.33	1.69	1.52	1.14	1.10	1.00	0.92
2030	0.83	2.33	1.70	1.52	1.15	1.11	1.01	0.92

Appendix A5: High Case Fuel Price Forecast Tables

Table A5-1: Natural Gas Prices at Key Hubs and Northwest Generators
2006$/MMBtu
High Case

Year	Henry Hub Natural Gas Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2005	7.95	6.98	7.08	7.70	7.58
2006	6.72	5.84	5.95	6.56	6.42
2007	6.53	5.67	5.78	6.38	6.24
2008	8.70	7.60	8.26	8.95	8.22
2009	8.69	7.59	8.24	8.99	8.23
2010	9.25	8.10	8.76	9.59	8.79
2011	9.36	8.20	8.86	9.75	8.93
2012	9.47	8.29	8.96	9.87	9.08
2013	9.58	8.39	9.06	9.98	9.18
2014	9.69	8.49	9.16	10.08	9.28
2015	9.80	8.59	9.26	10.19	9.39
2016	9.91	8.69	9.36	10.30	9.50
2017	10.02	8.79	9.46	10.41	9.60
2018	10.13	8.89	9.56	10.51	9.71
2019	10.24	8.99	9.66	10.62	9.82
2020	10.36	9.09	9.76	10.73	9.92
2021	10.46	9.18	9.86	10.84	10.02
2022	10.57	9.28	9.96	10.95	10.13
2023	10.68	9.38	10.06	11.05	10.23
2024	10.79	9.48	10.16	11.16	10.34
2025	10.91	9.58	10.27	11.27	10.45
2026	11.32	9.95	10.64	11.66	10.82
2027	11.74	10.33	11.03	12.06	11.22
2028	12.18	10.72	11.43	12.47	11.62
2029	12.64	11.13	11.84	12.90	12.05
2030	13.11	11.56	12.28	13.35	12.48

Table A5-2: Wellhead and Retail Natural Gas Prices
2006$/MMBtu
High Case

Year	U.S Wellhead Price	Regional Retail Natural Gas Prices			
		Residential	Commercial	Industrial	Utility Average
2005	7.36	12.66	11.16	8.26	7.64
2006	6.23	11.53	10.03	7.12	6.49
2007	6.06	11.36	9.86	6.95	6.31
2008	8.00	13.30	11.80	9.30	8.57
2009	8.00	13.30	11.80	9.29	8.58
2010	8.50	13.80	12.30	9.81	9.13
2011	8.60	13.90	12.40	9.90	9.25
2012	8.70	14.00	12.50	10.01	9.37
2013	8.80	14.10	12.60	10.11	9.48
2014	8.90	14.20	12.70	10.21	9.58
2015	9.00	14.30	12.80	10.31	9.68
2016	9.10	14.40	12.90	10.41	9.79
2017	9.20	14.50	13.00	10.51	9.89
2018	9.30	14.60	13.10	10.62	10.00
2019	9.40	14.70	13.20	10.72	10.10
2020	9.50	14.80	13.30	10.82	10.21
2021	9.60	14.90	13.40	10.92	10.31
2022	9.70	15.00	13.50	11.02	10.41
2023	9.80	15.10	13.60	11.13	10.52
2024	9.90	15.20	13.70	11.23	10.62
2025	10.00	15.30	13.80	11.33	10.73
2026	10.37	15.68	14.17	11.71	11.11
2027	10.76	16.06	14.56	12.10	11.50
2028	11.16	16.46	14.96	12.51	11.91
2029	11.57	16.87	15.37	12.93	12.33
2030	12.00	17.30	15.80	13.37	12.77

Table A5-3: World Oil Prices and Retail Oil Product Prices
2006$/MMBtu
High Case

Year	World Oil Prices	Industrial Residual Oil Price	Industrial	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price	Average Commercial Oil Price	Average Residential Oil Price	Utility Residual Oil Price	Utility Distillate Oil Price
2005	50.40	6.95	12.55	12.25	7.22	12.04	11.90	14.94	0.00	11.56
2006	59.02	8.22	14.20	13.89	8.49	13.69	13.55	16.60	0.00	13.22
2007	65.29	9.15	15.41	15.08	9.41	14.90	14.74	17.80	0.00	14.42
2008	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2009	70.00	9.84	16.31	15.97	10.11	15.80	15.65	18.71	0.00	15.33
2010	80.00	11.32	18.24	17.87	11.59	17.73	17.56	20.63	0.00	17.25
2011	81.91	11.60	18.60	18.23	11.87	18.09	17.92	21.00	0.00	17.62
2012	83.86	11.89	18.98	18.60	12.16	18.47	18.29	21.37	0.00	17.99
2013	85.86	12.18	19.36	18.98	12.45	18.85	18.67	21.76	0.00	18.38
2014	87.90	12.49	19.76	19.37	12.75	19.25	19.07	22.15	0.00	18.77
2015	90.00	12.80	20.16	19.77	13.06	19.65	19.47	22.55	0.00	19.18
2016	90.40	12.85	20.24	19.84	13.12	19.73	19.54	22.63	0.00	19.25
2017	90.79	12.91	20.31	19.92	13.18	19.80	19.62	22.71	0.00	19.33
2018	91.19	12.97	20.39	20.00	13.24	19.88	19.69	22.78	0.00	19.40
2019	91.60	13.03	20.47	20.07	13.30	19.96	19.77	22.86	0.00	19.48
2020	92.00	13.09	20.54	20.15	13.36	20.03	19.85	22.94	0.00	19.56
2021	92.59	13.18	20.66	20.26	13.45	20.15	19.96	23.05	0.00	19.67
2022	93.19	13.27	20.77	20.37	13.53	20.26	20.08	23.17	0.00	19.79
2023	93.79	13.36	20.89	20.49	13.62	20.38	20.19	23.28	0.00	19.90
2024	94.39	13.44	21.00	20.60	13.71	20.49	20.31	23.40	0.00	20.02
2025	95.00	13.53	21.12	20.72	13.80	20.61	20.42	23.52	0.00	20.14
2026	99.54	14.21	21.99	21.58	14.47	21.48	21.29	24.39	0.00	21.01
2027	104.31	14.91	22.91	22.49	15.18	22.40	22.20	25.30	0.00	21.93
2028	109.29	15.65	23.87	23.43	15.91	23.36	23.15	26.26	0.00	22.88
2029	114.52	16.42	24.87	24.43	16.69	24.36	24.15	27.27	0.00	23.89
2030	120.00	17.23	25.93	25.47	17.49	25.42	25.20	28.32	0.00	24.94

Table A5-4: Coal Price Forecasts
2006$/MMBtu
High Case

Year	Western Minemouth Prices	Regional Industrial Price	Selected Regional Electricity Generation Coal Prices					
			West WA/OR	East WA/OR	Idaho	Montana	Utah	Wyoming
2005	0.48	2.11	1.40	1.22	0.82	0.78	0.67	0.58
2006	0.54	2.08	1.43	1.25	0.87	0.83	0.72	0.64
2007	0.56	2.09	1.45	1.27	0.89	0.85	0.75	0.66
2008	0.82	2.45	1.74	1.55	1.15	1.12	1.00	0.92
2009	0.82	2.21	1.65	1.48	1.12	1.09	0.99	0.91
2010	0.83	2.37	1.71	1.53	1.15	1.11	1.01	0.92
2011	0.84	2.34	1.71	1.53	1.16	1.12	1.01	0.93
2012	0.85	2.35	1.72	1.54	1.17	1.13	1.02	0.94
2013	0.86	2.36	1.73	1.55	1.18	1.14	1.03	0.95
2014	0.87	2.37	1.74	1.56	1.19	1.15	1.04	0.96
2015	0.88	2.38	1.75	1.57	1.20	1.16	1.05	0.97
2016	0.89	2.38	1.75	1.58	1.21	1.17	1.06	0.98
2017	0.90	2.39	1.76	1.59	1.22	1.18	1.08	0.99
2018	0.91	2.40	1.78	1.60	1.23	1.19	1.09	1.00
2019	0.92	2.41	1.79	1.61	1.24	1.20	1.10	1.01
2020	0.93	2.42	1.80	1.62	1.25	1.21	1.11	1.03
2021	0.94	2.44	1.81	1.63	1.26	1.22	1.12	1.04
2022	0.95	2.45	1.82	1.65	1.27	1.23	1.13	1.05
2023	0.96	2.46	1.83	1.66	1.28	1.25	1.14	1.06
2024	0.98	2.47	1.84	1.67	1.30	1.26	1.15	1.07
2025	0.99	2.48	1.85	1.68	1.31	1.27	1.17	1.08
2026	1.00	2.51	1.87	1.70	1.32	1.28	1.18	1.09
2027	1.01	2.53	1.89	1.71	1.33	1.30	1.19	1.11
2028	1.02	2.54	1.90	1.72	1.35	1.31	1.20	1.12
2029	1.04	2.55	1.91	1.73	1.36	1.32	1.22	1.13
2030	1.05	2.56	1.92	1.75	1.37	1.33	1.23	1.14

Appendix A6: Fuel Price Forecasting Model

INTRODUCTION

This paper describes the fuel price forecasting model that is used for the Council's Sixth Power Plan. The model consists of several worksheets linked together in an EXCEL "workbook". The Excel model is in Q:\TM\FUEL\MODF\FUELMOD7(2) for the draft forecasts in December 2008.

The model includes forecasts of natural gas, oil, and coal prices. These prices are forecast for fuel commodity prices, wholesale, and retail level prices. Retail fuel prices for various demand sectors are derived from forecasts of basic energy commodity prices; that is, the average wellhead price of natural gas, the world price of oil, and Powder River Basin (PRB) minemouth coal prices. These energy commodity prices are forecast by several organizations that specialize in energy market forecasting. Thus basic energy commodity price trends can be based on a variety of forecasts which helps define a range of possible futures based on much more detailed modeling and analysis than the Council has the resources to accomplish alone. The prices of oil, natural gas, and coal are not explicitly linked to one another. Rather, the relationships should be considered by the analyst in developing fuel price scenarios.

Retail prices are derived from the basic energy commodity prices. The approach for doing this varies by type of fuel and region. Where possible these additional costs, or markups, are based on historical relationships among energy costs to various geographic areas and economic sectors.

The degree of detail devoted to each fuel depends on its relative importance to electricity planning. For example, natural gas is a very important determinant of both electricity demand and the cost of electricity generation from gas-fired plants. As a result, the natural gas forecasting approach is significantly more detailed than oil or coal. Oil plays a smaller role in competition with electricity use and for electricity generation and receives less attention. Coal plays little role in determining electricity demand, but is an important fuel for electricity generation. It is treated briefly in the model using assumed annual growth rates of minemouth prices in the PRB, which is the primary source of coal for the region. The delivered price of coal to various locations is estimated based on distance and an estimated cost per ton-mile for unit coal trains escalated for changes in the cost of diesel fuel.

These Commodity price forecasts are developed in a separate workbook called "Fuel Price FC Develop.xls" and then copied into the fuel price model. WOPFC, NGFC, and COALFC are tabs in the FUELMOD7(1) Excel Workbook where forecasts of world oil prices, natural gas wellhead prices, and PRB coal prices, respectively, are entered.

Historical regional retail price data for each fuel are kept on separate Excel files called OIL.XLS, GAS.XLS, and COAL.XLS. These spreadsheets contain historical retail price data by state and consuming sector from the "State Energy Price and Expenditure Report" compiled by the U.S. Energy Information Administration (EIA). In addition, they contain consumption data from the "State Energy Data Report", also published by EIA. State level prices are weighted by consumption levels to estimate regional prices. The spreadsheets convert the prices to constant or real dollars.

In FUELMOD7(2), the tab labeled "Deflation" contains implicit deflators for U.S. Gross Domestic Product (GDP). In cell D5, the user can specify what year constant dollars the forecasts will be expressed in. Labels for columns throughout the model are created here and used for reference in other tabs.

MAIN is the tab in FUELMOD7(2) where a model forecast is set up. The scenario (L, ML, M, MH, or H) is selected from a drop down menu in cell B2. The forecast for the chosen scenario is selected by the model from the WOPFC, NGFC, and COALFC tabs. Commodity prices feed into the further tabs that develop regional wholesale and retail fuel prices. Main also compares the model estimates of industrial residual oil prices, interruptible gas prices, and coal prices: a burner-tip cost comparison. Other parameters and scenario varying assumptions also appear in this tab. The varying scenario parameters and their cell locations are as follows:

Scenario Name	B2
Wellhead Natural Gas Price	B9:B59
World Oil Price	C9:C59
Real Growth Rate of Incremental Pipeline Costs	H68:L68
Firm Natural Gas Supply Share	H70:L70

The separate tabs in FUELMOD7(2) are described in the Appendix, which is a printout of the first tab ("DOC") in the model. The model structure is described in more detail below for each fuel type.

Natural Gas Model

The natural gas price forecasting component is far more detailed than the oil or coal components. This is not only because natural gas is currently the strongest competitor to electricity, but also because of the lack of reliable historical price information for large industrial and electric utility gas purchases.

There are twelve separate worksheets for natural gas price model. These worksheets are described in the "DOC" tab of FUELMOD7(2), which is reproduced as Attachment A6-1 to this documentation.

Commodity Prices

The forecasts start from forecasts of average annual lower-48 wellhead natural gas prices. Annual wellhead prices are converted to monthly wellhead prices using an econometric relationship that estimates systematic monthly patterns in prices. Monthly wellhead prices are comverted to Henry Hub spot prices using another econometric relationship. Basis differentials from the Henry Hub prices to various pricing hubs in the West are then estimated based on Henry Hub prices. The pricing hubs included in the model are AECO-NIT in Alberta, Sumas at the B.C. and Washington border, U.S. Rocky Mountains, Permian, and San Juan.

The commodity price equations were reestimated by Chris Collier in the summer of 2008.[1] The original equations were estimated for the Fifth Power Plan by Terry Morlan.[2] The latter included equations for prices to electricity generators discussed in the next section.

Seasonal variations were captured in the hub price equations by including Fourier series in some of the equations. The Fourier series equations that were used in the regressions are:

S1 =SIN((2*3.14159*1 *Month)/12)
S2= SIN((2*3.14159*2 *Month)/12)
C1= COS((2*3.14159*1 *Month)/12)
C2= COS((2*3.14159*2 *Month)/12)

Where Month = what number of month in the year is it. Example: January =1, February= 2,..., Dec.=12

Annual Wellhead to Monthly Wellhead

The first step in the forecasting process was to find a relationship between annual wellhead prices and monthly wellhead prices that would provide the ability to forecast monthly wellhead price. The U.S. Energy Information Administration (EIA) provides wellhead data (both monthly and annually) since 1973, but when determining relationships only data starting from January 1989 was used. In January 1989, deregulation of the natural gas market occurred which allowed prices to more accurately reflect natural gas market forces. When running a regression in order to determine the relationship between the annual and monthly prices the Fourier series played an important role. Table A6-1 shows the estimated equation and fit statistics.

The estimated relationship is used to determine monthly wellhead prices is:

Wellhead Monthly= -.00497+ 1.000651 * Annual Wellhead + C1 * 0.201547+ C2 * 0.131491

Where: Wellhead Monthly = The monthly wellhead price of natural gas
Annual Wellhead = The annual wellhead price of natural gas
C1 = A fourier series with highest value in winter
C2 = A fourier series with low values in shoulder months

This equation results in a better estimation of monthly wellhead prices, given a forecast of annual wellhead prices. There were no dummy variables included in this regression because the

[1] Chris Collier. “Natural Gas Forecast”. August 2008.
[2] “Developing Basis Relationships Among Western Natural Gas Pricing Points”. Northwest Power and Conservation Council. 2004.

annual wellhead prices is an average of the twelve months in the year therefore, any one time events are already picked up.

Table A6-1: Monthly Wellhead Price as a Function of Annual Wellhead Price

Regression Statistics						
Multiple R	0.954957					
R Square	0.911943					
Adjusted R Square	0.910763					
Standard Error	0.58542					
Observations	228					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	3	795.0336287	265.0112	773.2671	7.4532E-118	
Residual	224	76.76843926	0.342716			
Total	227	871.802068				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-0.00497	0.07830	-0.0635	95%	-0.159262805	0.149319
Annual Wellhead	1.000651	0.02086	47.96393	0%	0.959538585	1.041763
C1(Fourier Series)	0.201547	0.05483	3.675874	0%	0.093498869	0.309594
C2(Fourier Series)	0.131491	0.05483	2.398173	2%	0.023443069	0.239539

Monthly Wellhead to Monthly Henry Hub Spot Price

Unlike the majority of natural gas hubs in the United States, Henry Hub is traded on the New York Mercantile Exchange (NYMEX) and is the most important natural gas trading hub in the United States. Data for Henry Hub spot prices is very accessible and Henry Hub prices factor into regional natural gas prices because Henry Hub is the main hub in the United States. That being, it was imperative that to find a close relationship between monthly wellhead prices and monthly Henry Hub spot prices.

When attempting to find a relationship between Monthly Wellhead Prices and Monthly Henry Hub Spot Prices, two dummy variables were used. The first dummy variable is a replication of the dummy variable used to adjust for outlier months. The second dummy variable used in order to adjust for the prices increases caused by Hurricanes Katrina and Rita in 2005.

The estimated relationship is:

HH= .1237 + 1.1029 * Wellhead monthly + 1.3809 * D1 + 1.5201 * D2

Where: HH = the Henry Hub Spot Price

D1 = Dummy Variable for Outlier Months: Outlier Months are: 1,2,3 1996; 11,12, 2000; 1, 2001; 2, 3, 2003

D2= Dummy Variable for Extreme Weather Katrina: Katrina months are: 8,9,10,11,12, 2005

Table A6-2 shows regression results. The value of the R-squared indicates that the equation is able to explain 97 percent of the month to month variation of the Henry Hub prices about their mean.

Table A6-2: Henry Hub Spot Price as a Function of Wellhead Price

Regression Statistics						
Multiple R	0.98644074					
R Square	0.97306534					
Adjusted R Square	0.97270461					
Standard Error	0.3892528					
Observations	228					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	3	1226.145	408.7152	2697.474	1.85E-175	
Residual	224	33.93997	0.151518			
Total	227	1260.085				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-0.12372615	0.053171	-2.32695	2%	-0.228505	-0.018946975
Wellhead Monthly	1.10296041	0.015038	73.34706	0%	1.0733272	1.132593579
D1(Outliers)	1.38094005	0.141527	9.757431	0%	1.1020454	1.659834715
D2 (Katrina)	1.52019919	0.18272	8.319845	0%	1.1601298	1.880268532

AECO

The AECO- NIT trading hub is located in southeast Alberta, Canada and is the primary trading hub for natural gas produced in the Western Canada Sedimentary Basin (WCSB). Prices at the AECO trading hub tend to be lower than natural gas prices at Henry Hub because the WSCB has been a growing supply area with limited pipeline capacity to export natural gas. AECO plays an important roll in northwest natural gas prices because a large portion of the region's natural gas supply comes from the WCSB.

AECO price data was not available before January of 1995. Since that time AECO prices averaged $.86 less than Henry Hub Prices. The relationship between AECO and Henry Hub prices are estimated from January 1995 to December 2007. The equation is:

AECO = -0.5305+ 0.89564 * Henry Hub -1.44438 * D1 - 0.79599 * D2+ 0.3425 * D3

Where: AECO = natural gas price at the AECO-NIT hub;
Henry Hub = Henry Hub natural gas price;
D1= Dummy Variable due to harsh winter months (Months are 1,2,3, 12, 1996);
D2= Dummy Variable for Hurricane Katrina (Months are 8,9,10,11,12, 2005; 1, 2006);
D3 = Dummy for the opening of the Alliance pipeline in December 2000 (All months after December 2000).

The addition of the Alliance Pipeline capacity is estimated to have raised AECO prices an average of $.34. This is assumed to affect future prices therefore; D3 is carried over into the forecasting period. Table A6-3 shows the detailed estimation results.

Table A6-3: AECO Prices as a function of Henry Hub Prices

Regression Statistics						
Multiple R	0.984038					
R Square	0.968331					
Adjusted R Square	0.967492					
Standard Error	0.411699					
Observations	156					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	4	782.5753	195.6438	1154.269	4.653E-112	
Residual	151	25.59389	0.169496			
Total	155	808.1692				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-0.5305	0.07774	-6.82408	0%	-0.684101754	-0.3769
Henry Hub	0.89564	0.024143	37.09798	0%	0.847939198	0.943341
D1(Winter)	-1.44438	0.244074	-5.9178	0%	-1.926623922	-0.96214
D2(Hurricane)	-0.79599	0.219869	-3.62029	0%	-1.230403991	-0.36157
D3 Pipeline	0.342524	0.100763	3.399292	0%	0.143436072	0.541613

Rockies

The U.S. Rocky Mountain area is another major source of natural gas supplies to the Pacific Northwest. The natural gas hub used in this analysis is named Opal. It is the main hub located in the Rocky Mountain area and supplies natural gas to the east and the west. The Rockies are a rapidly growing supply area and many new pipeline proposals, if implemented, will greatly affect natural gas prices. Since the deregulation of the natural gas market in 1989, Rockies prices averaged $.80 less than Henry Hub prices. Recently, new pipeline proposals have been announced in an attempt to move growing Rocky Mountain natural gas supplies out of that region.

When estimating the relationship between Rockies and Henry Hub prices the same dummy variables as used in the earlier fuel price forecasting model were included, but an additional dummy variable incorporated to adjusted for the depressed Rockies prices that occurred during 2007 due to pipeline capacity constraints. The pipeline capacity constraint created an excess supply of natural gas causing a disconnect between the two hubs and significantly depressing Rockies prices because of excess supply. Also, in this relationship the Fourier series picked up consistent monthly patterns that were significant.

The estimated equation relating Rockies natural gas prices to Henry Hub prices is as follows:

$$\text{Rockies} = -0.0603 + 0.829485 * \text{Henry Hub} + .1279 * S1 + .0981 * C1 - 1.7675 * D1 + .2176 * D2 - 1.01625 * D3 - 2.2327 * D4$$

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Where: Rockies = The Rocky Mountain natural gas price at Opal;
Henry Hub= Henry Hub natural gas price;
S1 = Fourier series (see page 3);
C1 = Fourier series (see page 3);
D1 = Dummy for months 1, 2, 3 1996;
D2 = Dummy for months in 1998 through 2001;
D3 = Dummy for depressed Rockies prices in 2002-03;
D4 = Dummy for depressed Rockies prices in 2007 for pipeline constraints (Months: 3, 4, 5, 6, 7, 8, 9, 10, 11, 2007).

Table A6-4 shows the detailed estimation results. The Rockies are important to monitor because prices will vary with the growth in supply relative to additions to the pipeline capacity to move natural gas out of the region.

Table A6-4: Rockies as a Function of Henry Hub Prices

Regression Statistics						
Multiple R	0.978661					
R Square	0.957777					
Adjusted R Square	0.956433					
Standard Error	0.400115					
Observations	228					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	7	798.9267	114.1324	712.917	2.3E-147	
Residual	220	35.22026	0.160092			
Total	227	834.147				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	-0.06029	0.051794	-1.16398	25%	-0.16236	0.041789
Henry Hub	0.829485	0.011997	69.13946	0%	0.80584	0.853129
S1	0.127993	0.037871	3.379753	0%	0.053358	0.202629
C1	0.098133	0.038034	2.58014	1%	0.023175	0.17309
D1(1996)	-1.7675	0.235826	-7.49495	0%	-2.23227	-1.30273
D2(98-01)	0.217687	0.066249	3.28587	0%	0.087122	0.348251
D3(2002-03)	-1.01625	0.109772	-9.25786	0%	-1.23259	-0.79991
D4(2007)	-2.23276	0.144406	-15.4617	0%	-2.51736	-1.94817

San Juan

The San Juan market area is focused on Colorado and New Mexico. The San Juan prices tend to be similar to Rockies prices in relation to Henry Hub prices. However, the San Juan prices were not affected in 2007 by pipeline capacity constraints which caused the depression of the Rockies prices. When determining the relationship between San Juan prices and Henry Hub prices the same dummy variables were used in the earlier fuel price forecasting model.

The estimated equation for the San Juan natural gas price as a function of the Henry Hub price is shown below. The detailed estimation statistics are shown in Table A6-5.

San Juan = 0.1701+ 0.8243 * HH - 1.9103 * D1 + 0.5721 * D2 - 0.40914 * Drockies + 0.0747 * S2 + 0.0786 * C1

Where: San Juan = the San Juan price for natural gas
HH = the Henry Hub prices for natural gas
D1 = when Henry Hub prices were abnormally high
D2 = a dummy adjusting for the energy crisis (DRockies is a dummy adjusting for pipeline capacity constraint during 2002 and early 2003)

Table A6-5: San Juan Price as a Function of Henry Hub Prices

Regression Statistics						
Multiple R	0.988726					
R Square	0.97758					
Adjusted R Square	0.976971					
Standard Error	0.30209					
Observations	228					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	6	879.3847	146.5641	1606.039	3.3E-179	
Residual	221	20.16804	0.091258			
Total	227	899.5527				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.170197	0.036777	4.627815	0%	0.097718	0.242675
HH	0.82437	0.008732	94.4071	0%	0.807162	0.841579
D1(1996)	-1.91035	0.177006	-10.7926	0%	-2.25919	-1.56152
D2(2000-2001)	0.572165	0.181015	3.160868	0%	0.215428	0.928902
Drockies	-0.40914	0.076544	-5.34521	0%	-0.55999	-0.25829
S2	0.074781	0.028426	2.630784	1%	0.018762	0.130801
C1	0.078688	0.02875	2.736927	1%	0.022028	0.135348

In 2003 when the regressions for the fuel price forecasting model were run, San Juan prices averaged $.37 below Henry Hub prices. Since 2003, the difference between the two hubs has become larger. From 2003-2007, San Juan prices averaged $ 1.01 less than Henry Hub prices, but the gap between the two hubs has since retreated. Using the estimated equation from 2008-2030 San Juan prices averaged $.88 less than Henry Hub prices.

Permian

The Permian basin pricing point is located in West Texas and supplies natural gas for Arizona and Southern California. Similar to San Juan hub prices, Permian basin prices averaged $ .20 less than Henry Hub prices during 1998-2003, but since 2003 Permian basin prices have averaged roughly $.75 less than Henry Hub spot prices. In this relationship, the same two dummy variables were used as in the earlier fuel price forecasting model but with the addition of a fourier series to capture regular cyclical patterns.

The estimated equation for the Permian Basis natural gas price as a function of the Henry Hub price is shown below. The detailed estimation statistics are shown in Table A6-6.

Permian = 0.1782 + 0.8552 * Henry Hub + 0.0601 * S2 + 0.5228 * D1 - 1.2478 * D2

Where: Permian = the Permian natural gas price
Henry Hub = the Henry Hub spot price
S2 = a Fourier series (see page 2)
D1 = a dummy variable for abnormal Henry Hub prices
D2 = a dummy variable for depressed Rockies prices due to the Kern River pipeline expansion

Table A6-6: Permian Price as a function of Henry Hub Prices

Regression Statistics						
Multiple R	0.994125					
R Square	0.988285					
Adjusted R Square	0.988074					
Standard Error	0.224765					
Observations	228					
ANOVA						
	df	SS	MS	F	Significance F	
Regression	4	950.3557	237.5889	4702.928	5.2E-214	
Residual	223	11.26582	0.050519			
Total	227	961.6215				
	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	0.178285	0.027076	6.584636	0%	0.124928	0.231643
Henry Hub	0.855245	0.006455	132.4937	0%	0.842525	0.867966
S2	0.060191	0.021149	2.846038	0%	0.018513	0.101869
D1 (1996)	0.522843	0.067973	7.691945	0%	0.388892	0.656794
D2 (2003)	-1.24789	0.131264	-9.50667	0%	-1.50656	-0.98921

During 2008-2030, the estimated equation forecasts Permian prices to be on average $ .64 below Henry Hub prices.

Sumas

The estimated equation for the Sumas hub is different from the rest of the relationships that were found because Sumas prices are assumed to be related to prices at AECO and the Rockies. The Sumas natural gas hub is located in Sumas, Washington and has been an important factor in regional prices. It is the entry point for WCSB gas from British Columbia into Western Washington. Since Sumas is the entry point for WCSB gas, it is expected that Sumas prices will have a close relationship with AECO prices. Sumas hub prices will also be related to Rockies prices since the Williams pipeline connects Sumas and the Rockies region. The equation below was estimated on monthly data from January 1995 to December 2007 on a monthly basis, but some outlier observations in the data were left out. Due to depressed Rockies prices in 2007, a dummy variable was added to adjust for that one time event. Specifically, November 1996 through January 1997 and the same months in the 2000-2001 energy crisis were left out of the estimate.

The estimated equation for the Sumas hub natural gas price as a function of the Rockies and AECO prices is shown below. The detailed estimation statistics are shown in Table A6-7.

Sumas = 0.0140 + 0.1462 * Rockies + 0.8812 * AECO + 1.0570 * D1 +6.6626 * D3 + .7950 * D4

Where: Sumas = the Sumas natural gas price
Rockies = the Rockies natural gas price
AECO = the AECO natural gas prices
D1 = a dummy variable for the winter of 1996-97
D3 = a dummy for November and December 2000
D4 = a dummy for depressed Sumas prices since 2007

Table A6-7: Sumas Price as a Function of AECO and Rockies Prices

Regression Statistics						
Multiple R	0.989085					
R Square	0.978289					
Adjusted R Square	0.977565					
Standard Error	0.38353					
Observations	156					
ANOVA						
	df	SS	MS	F	Significance F	
Regression	5	994.193758	198.8388	1351.77	8.7E-123	
Residual	150	22.06426511	0.147095			
Total	155	1016.258023				
	Coefficients	Standard Error	t Stat	P-value	Lower 95%	Upper 95%
Intercept	0.014037	0.060378078	0.23249	0.816474	-0.10526	0.133339
Rockies	0.146183	0.050933668	2.870066	0.004697	0.045543	0.246823
Aeco	0.881218	0.046601013	18.90985	1.52E-41	0.789139	0.973297
D1	1.056978	0.237214521	4.45579	1.63E-05	0.588265	1.525691
D3	6.662592	0.276408041	24.10419	1.88E-53	6.116436	7.208748
D4	0.794977	0.185935755	4.275546	3.38E-05	0.427585	1.162368

Electric Generator Prices

The Aurora Model uses estimates of the price that will be paid by electric generators for natural gas. These prices are organized by supply areas that mostly coincide with states in the West. The exceptions are California and Nevada, which are divided into north and south, and the Pacific Northwest is divided into 4 areas that don't coincide with state boundaries.

The data for natural gas prices to electric generators by state is from the Energy Information Administration. For several states in the West this data is thin and not representative of market price relationships. In these cases, equations that attempt to relate state electric generator natural gas prices to a nearby trading hub's prices fail. Reasonably good relationships were attained for Arizona, New Mexico, Colorado, and Nevada. Separate electric generator natural gas prices were available for northern and southern California from Natural Gas Week, and reasonable relationships were estimated for those. The estimated equation for Nevada is used for Southern Nevada, and Northern Nevada is estimated using a method described later in the Appendix.

The methods for the Pacific Northwest areas are discussed in a later section.

California South

Southern California gets its natural gas supplies from the Permian area and, since 1992, from the Rockies. The opening of the Kern River Pipeline in 1992 brought Rockies natural gas to Southern California and changed the pricing. The equation below was estimated on data since April 1992 and excludes the period of the West Coast energy crisis in 2000-01 from the observations. Table A6-7 shows the detailed regression results.

CA_S = 0.328 + 0.782 * PERM + 0.203 * ROCK - 0.737 * D96SCA

Where: CA_S the Southern California natural gas price to utilities
D96SCA = dummy for the first half of 1996
PERM and ROCK = Permian and Rockies natural gas prices

Table A6-7: Southern California Price as a Function of Permian and Rockies Prices

Dependent Variable: CA_S				
Method: Least Squares				
Date: 04/15/04 Time: 13:23				
Sample: 1992:04 2000:08 2001:08 2003:11				
Included observations: 129				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.327675	0.058711	5.581203	0.0000
PERM	0.781839	0.043682	17.89829	0.0000
ROCK	0.203339	0.052878	3.845470	0.0002
D96SCA	-0.736620	0.101784	-7.237071	0.0000
R-squared	0.944423	Mean dependent var		2.655116
Adjusted R-squared	0.943090	S.D. dependent var		0.959815
S.E. of regression	0.228972	Akaike info criterion		-0.079915
Sum squared resid	6.553538	Schwarz criterion		0.008762
Log likelihood	9.154506	F-statistic		708.0507
Durbin-Watson stat	0.767842	Prob(F-statistic)		0.000000

California North

Northern California receives natural gas from the WCSB and from the Rockies. The following equation was estimated on data from January 1995 through November 2003. The period of the West Coast energy crisis was omitted from the observations. Figure A6-8 shows the detailed regression results.

CA_N = 0.436 + 0.581 * AECO + 0.463 * ROCK

Where: CA_N = the Northern California natural gas price
AECO and ROCK are as defined earlier

Table A6-8: Northern California Price as a Function of AECO and Rockies Prices

Dependent Variable: CA_N				
Method: Least Squares				
Date: 04/15/04 Time: 13:46				
Sample: 1995:01 2000:10 2001:07 2003:11				
Included observations: 99				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.435619	0.090815	4.796752	0.0000
AECO	0.581218	0.061551	9.442896	0.0000
ROCK	0.463417	0.076812	6.033145	0.0000
R-squared	0.906084	Mean dependent var		2.665657
Adjusted R-squared	0.904128	S.D. dependent var		1.148937
S.E. of regression	0.355748	Akaike info criterion		0.800648
Sum squared resid	12.14947	Schwarz criterion		0.879288
Log likelihood	-36.63210	F-statistic		463.0958
Durbin-Watson stat	0.687154	Prob(F-statistic)		0.000000

Nevada

Utility natural gas price data was only available for the entire state of Nevada, but the north would not be significantly influenced by Permian prices and the south not by AECO prices. Nevada is likely dominated by Southern Nevada (the Las Vegas area); and Southern Nevada is similar to Southern California. It can receive natural gas from the Permian basin or the Rockies. Northern Nevada is likely to be affected by AECO and Rockies, and AECO prices did show significance in the estimated equations for Nevada. The details of the equation below are contained in Table A6-9. The months from June 2001 through October 2002 were eliminated from the estimation. The equation is used for only Southern Nevada. Northern Nevada prices are estimated using the methods described in a later section.

NV = 0.798 + 0.468 * PERM + 0.370 * AECO - 0.869 * D96_97

Where: NV = utility natural gas prices in Nevada
AECO and PERM are as defined earlier
D96_97 = a dummy variable for November/December, 1996 and January, 1997

Table A6-9: Nevada Price as a Function of Permian and Rockies Prices

Dependent Variable: NV				
Method: Least Squares				
Date: 04/21/04 Time: 16:10				
Sample: 1995:01 2000:10				
Included observations: 70				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.798370	0.086816	9.196139	0.0000
PERM	0.468088	0.068439	6.839446	0.0000
AECO	0.370051	0.065829	5.621396	0.0000
D96_97	-0.869152	0.151518	-5.736297	0.0000
R-squared	0.894748	Mean dependent var		2.462147
Adjusted R-squared	0.889964	S.D. dependent var		0.666755
S.E. of regression	0.221174	Akaike info criterion		-0.124293
Sum squared resid	3.228570	Schwarz criterion		0.004192
Log likelihood	8.350259	F-statistic		187.0230
Durbin-Watson stat	1.391586	Prob(F-statistic)		0.000000

Arizona

Arizona can access natural gas from the Permian and San Juan Basins via the El Paso and Transwestern pipelines. Arizona utility prices of natural gas are therefore based on the prices in these basins. The equation estimated is as follows:

AZ = 1.003 + 0.309 * PERM + 0.596 * SJ + 2.06 * D96_97

Where: AZ = the Arizona price of natural gas to electric utilities
PERM and SJ = Permian and San Juan prices
D96_97 = a dummy variable for Nov. and Dec. 1996 and Jan. 1997

The detailed estimation results are shown in Table A6-10

Table A6-10: Arizona Price as a Function of Permian and San Juan Prices

Dependent Variable: AZ				
Method: Least Squares				
Date: 04/19/04 Time: 14:15				
Sample: 1989:01 2003:08				
Included observations: 176				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1.002582	0.080535	12.44894	0.0000
PERM	0.308772	0.127064	2.430056	0.0161
SJ	0.596317	0.139524	4.273942	0.0000
D96_97	2.061088	0.262927	7.839012	0.0000
R-squared	0.853227	Mean dependent var		3.195625
Adjusted R-squared	0.850667	S.D. dependent var		1.157051
S.E. of regression	0.447126	Akaike info criterion		1.250512
Sum squared resid	34.38652	Schwarz criterion		1.322569
Log likelihood	-106.0451	F-statistic		333.2937
Durbin-Watson stat	1.224515	Prob(F-statistic)		0.000000

New Mexico

The situation in New Mexico is very similar to Arizona. The equation below determines New Mexico prices based on Permian and San Juan prices. Table A6-11 shows the detailed estimation results.

NM = 0.546 + 0.598 * PERM + 0.300 * SJ

Where NW = New Mexico natural gas prices and other variables are a defined earlier

Table A6-11: New Mexico Price as a Function of Permian and San Juan Prices

Dependent Variable: NM				
Method: Least Squares				
Date: 04/19/04 Time: 14:36				
Sample: 1989:01 2003:08				
Included observations: 176				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	0.546146	0.038924	14.03098	0.0000
PERM	0.597776	0.061494	9.720824	0.0000
SJ	0.299599	0.067418	4.443900	0.0000
R-squared	0.957544	Mean dependent var		2.738460
Adjusted R-squared	0.957054	S.D. dependent var		1.044997
S.E. of regression	0.216560	Akaike info criterion		-0.204998
Sum squared resid	8.113411	Schwarz criterion		-0.150955
Log likelihood	21.03979	F-statistic		1950.921
Durbin-Watson stat	0.974070	Prob(F-statistic)		0.000000

Colorado

The equation for Colorado is as follows, with the detailed estimation results shown in Table A6-12.

CO = 1.163 + 0.730 * SJ - 0.899 * D_ROCKIES + 3.755 * D05_97

Where CO = the Colorado natural gas price to electric utilities
D05_97 = a dummy for May 1997
And other variables are as defined earlier

Table A6-12: Coloado Price as a Function of San Juan Prices

Dependent Variable: CO				
Method: Least Squares				
Date: 04/15/04 Time: 11:08				
Sample: 1989:01 2003:08				
Included observations: 176				
Variable	Coefficient	Std. Error	t-Statistic	Prob.
C	1.162658	0.070299	16.53879	0.0000
SJ	0.730307	0.027868	26.20580	0.0000
D_ROCKIES	-0.898657	0.135828	-6.616119	0.0000
D05_97	3.754979	0.391006	9.603368	0.0000
R-squared	0.817955	Mean dependent var		2.834136
Adjusted R-squared	0.814779	S.D. dependent var		0.905629
S.E. of regression	0.389758	Akaike info criterion		0.975884
Sum squared resid	26.12874	Schwarz criterion		1.047940
Log likelihood	-81.87775	F-statistic		257.6064
Durbin-Watson stat	1.492502	Prob(F-statistic)		0.000000

Other Areas

For some areas included in the Aurora model, it was not possible to estimate meaningful relationships between natural gas prices to utilities and trading hub prices. These areas included Utah, Wyoming, Northern Nevada, British Columbia, Alberta, and the Pacific Northwest areas. This is due to the nature of the utility gas price data, which is thin and displays little relationship to trading hub markets.

For these areas, the model uses estimated historical differentials or estimates of pipeline costs to estimate delivered costs to the demand areas. The methods for each area are described below.

Rocky Mountain States

The current method for calculating utility natural gas prices in Utah, Wyoming, Northern Nevada, Alberta and British Columbia assumes a starting differential for each area from its most likely pricing hub (See Table A6-13). The pipeline reservation cost is assumed to be $.50 for existing customers. For new power plants these costs are assumed to be $.62 and escalate over time reflecting real pipeline capacity cost growth. This growth in incremental pipeline fixed costs amounts to a 32 percent increase over existing rolled-in cost by 2030. The rate of real growth in pipeline capacity costs after 2007 varies by forecast scenario (See Table A6-14).

Table A6-13: Starting Pipeline Delivery Costs by State (2000$/MMBtu)

State	Hub
Utah	Rockies
Wyoming	Rockies
Northern Nevada	AECO
British Columbia	Sumas
Alberta	AECO

Table A6-14: Escalation of Incremental Pipeline Capacity Cost Post 2006 (%/Yr.)

Scenario	Escalation Rate
Low	- 0.1 %
Medium Low	0.1 %
Medium	0.3 %
Medium High	0.5 %
High	0.7 %

Pacific Northwest Areas

There are four separate areas modeled for the Pacific Northwest. These include Western Oregon and Washington, Eastern Oregon and Washington, Southern Idaho, and Western Montana. The delivery cost of natural gas to these areas is based on more detailed estimates of pipeline delivery costs from pricing hubs in the Northwest. The estimation of natural gas cost to the four PNW areas are based on the following relationships to market trading points. In the case of Western Oregon and Washington the related trading hub is assumed to be Sumas. In the case of Eastern Oregon and Washington (including Northern Idaho) and Western Montana it is assumed to be AECO. Southern Idaho is related to prices in the Rocky Mountains. The calculation takes the following general form.

Delivered Cost = Hub Price / (1 - in-kind fuel charge) + pipeline capacity reservation cost / plant capacity factor + pipeline commodity charge

Where: The in-kind fuel charge is a percent of the purchase price. Pipeline capacity cost is calculated for both existing and incremental capacity cost, which includes real growth that varies by scenario. The pipeline commodity charge is a variable cost per million Btu of fuel shipped.

The values used for pipeline delivery and capacity cost are described below. The assumption in the plan is that new power plants are likely to be required to subscribe to incrementally priced pipeline capacity. It was also assumed that these costs would escalate in real terms over time as shown in Table A6-14.

Tables A6-15a and A6-15b show the various transportation components, their column number in the COMPONENTS worksheet, and the current value or range of values in the model. Tables A6-16a and A6-16b show which adjustments are applied to calculate the various industrial and electric utility gas price forecasts from the national wellhead forecast. The “a” tables are for the

West side of Oregon and Washington, and the "b" tables are for the East side of Oregon and Washington and Northern Idaho. Estimates for Southern Idaho are based on the Western Oregon and Washington delivery costs (Northwest Pipeline), and Western Montana estimates are based on the Eastern Oregon and Washington delivery costs from AECO.

Table A6-15a: Natural Gas Delivery Cost from Sumas to West-Side PNW

Cost Component	**Components Column**	**Constant Costs (2000$/MMBtu)**	**Scenario Variant**				
			L	ML	M	MH	H
Pipeline Capacity							
Firm Rolled-In	B	$.33					
Firm Incremental	C	$.51 in 2012 + growth	-.1%	.1%	.3%	.5%	.7%
Capacity release	D	$.28					
Plant Capacity Factor cf		85 Percent					
Pipeline Commodity	E	$.03					
Pipeline Fuel	$D$42	1.99 %					
LDS Distribution							
Firm	F	$.20					
Interruptible Adj.	K	- $.05					
Firm Supply Premium	G	0%					

Table A6-16a: Cost Adjustments Applied for Specific West-Side Natural Gas Prices.

Equation	Natural Gas Product	Calculation
	Industrial Sector	
[1]	Pipeline Firm	Sumas/(1-D42)+(B/cf+E+G+F)*cd
[2]	Pipeline Interruptible	Equation[1] + K
[3]	LDC Served	Wellhead Price + average historical retail difference
	Utility Sector	
[4]	Existing Firm	Sumas/(1-D42)+(B/cf+E+G)*cd
[5]	New Firm	Sumas/(1-D42)+(C/cf+E+G)*cd
[6]	Interruptible	Equation[4] + K
	Variable Fuel Costs	
[7]	New firm e.g.	Sumas/(1-D47)+(E*cd
	Fixed Fuel Costs	
[8]	New firm e.g.	[(f*G)+(C*cd) * hr*8.76/(1000)
cd is conversion from 2000$ to year dollars of the forecast (2006$ currently)		
hr is the heat rate of a gas-fired power generation plant		
cf is the capacity factor of a gas-fired power generation plant		
f is the share of fuel supply that is purchase on a firm basis		

(Capital letters correspond to the Components Column in Table A6-15a.)

The formulas shown in Tables A6-15a and A6-15b may need some translation. For example, equation [5] shows how the incremental cost of firm pipeline capacity on the west side of the region is calculated. It starts with the price at Sumas and increases it to account for the in-kind fuel charge of 1.99 percent on Northwest Pipeline which is contained in cell $D$42. Then the firm incremental pipeline capacity costs (column C) (divided by the capacity factor of the power generating plant), the pipeline commodity charge (column E), and any firm supply premium (column G) are added to the cost. These latter charges are contained in the model in year 2000 dollars so they can be converted to the year dollars chosen for the forecast, in this case, 2006 dollars. The term “cd” is a conversion factor from 2000 to 2006 year dollars. The values in Tables A6-15a and A6-15b have already been converted to 2006 dollars.

The calculation of generator firm incremental natural gas prices is shown a different way in Tables A6-17a and A6-17b.

Table A6-15b: Natural Gas Delivery Cost from AECO to East-Side PNW

Cost Component	Markup Column	Constant Costs (2006$/MMBtu)	Scenario Variant				
			L	ML	M	MH	H
Pipeline Capacity							
Firm Rolled-In	O	$.32					
Firm Incremental	P	$.47 in 2020 + growth	-.1%	.1%	.3%	.5%	.7%
Capacity Release	Q	$.33					
Plant Capacity Factor		85 Percent					
Pipeline Commodity	R	$.01					
Pipeline Fuel	$D$43	1.91 %					
LDS Distribution							
Firm	S	$.20					
Interruptible Adj.	X	- $.05					
Firm Supply Premium	T	0%					

Table A6-16b: Cost Adjustments Applied for Specific East-Side Natural Gas Prices.

Equation	Natural Gas Product	Calculation
	Utility Sector	
[9]	Existing Firm	AECO/(1-D43)+(O/cf+R+T)*cd
[10]	New Firm	AECO/(1-D43)+(P/cf+r+t)*cd
[11]	Interruptible	Wellhead Price + average historical difference
	Variable Fuel Costs	
[12]	New firm e.g.	AECO/(1-D43) + R * cd)
	Fixed Fuel Costs	
[13]	New firm e.g.	[(f*T)+(P*cd)]*hr*8.76/(1000)
cd is conversion from 2000$ to year dollars of the forecast (2006$ currently)		
hr is the heat rate of a gas-fired power generation plant		
cf is the capacity factor of a gas-fired power generation plant		
f is the share of fuel supply that is purchase on a firm basis		

(Capital letters correspond to the Components Column in Table A6-16b.)

Table A6-71a: Derivation of West-Side Firm Utility Gas Price
2006$/MMBtu

	Derivation of West-Side Firm Utility Gas Price									
Medium 11/21/2008	2006$/MMBtu									
	US Wellhead Price	Henry Hub Price	Sumas Delta	Sumas Price	Firm Supply Premium	Pipeline Fuel Charge	Incremental Transport Cost	Pipeline Commodity Charge	Utility Gas Price	Total Delivery Cost
			(+)		(+)	(+)	(+)	(+)		
2005	7.36	7.95	-0.87	7.08	0.00	0.14	0.45	0.03	7.70	0.63
2006	6.23	6.72	-0.77	5.95	0.00	0.12	0.45	0.03	6.56	0.60
2007	6.06	6.53	-0.75	5.78	0.00	0.12	0.45	0.03	6.38	0.60
2008	7.83	8.51	-0.43	8.09	0.00	0.16	0.49	0.03	8.77	0.69
2009	6.50	7.70	-0.36	7.34	0.00	0.15	0.55	0.03	8.07	0.73
2010	6.75	7.32	-0.32	7.00	0.00	0.14	0.62	0.03	7.79	0.79
2011	6.80	7.38	-0.33	7.05	0.00	0.14	0.69	0.03	7.91	0.86
2012	6.85	7.43	-0.33	7.10	0.00	0.14	0.70	0.03	7.97	0.88
2013	6.90	7.48	-0.34	7.15	0.00	0.15	0.70	0.03	8.03	0.88
2014	6.95	7.54	-0.34	7.20	0.00	0.15	0.70	0.03	8.08	0.88
2015	7.00	7.60	-0.35	7.25	0.00	0.15	0.71	0.03	8.14	0.88
2016	7.05	7.65	-0.35	7.30	0.00	0.15	0.71	0.03	8.19	0.89
2017	7.10	7.71	-0.36	7.35	0.00	0.15	0.71	0.03	8.24	0.89
2018	7.15	7.76	-0.36	7.40	0.00	0.15	0.71	0.03	8.29	0.89
2019	7.20	7.82	-0.36	7.45	0.00	0.15	0.71	0.03	8.35	0.90
2020	7.25	7.87	-0.37	7.50	0.00	0.15	0.72	0.03	8.40	0.90
2021	7.30	7.93	-0.37	7.55	0.00	0.15	0.72	0.03	8.46	0.90
2022	7.35	7.98	-0.38	7.60	0.00	0.15	0.72	0.03	8.51	0.91
2023	7.40	8.04	-0.38	7.65	0.00	0.16	0.72	0.03	8.56	0.91
2024	7.45	8.09	-0.39	7.70	0.00	0.16	0.73	0.03	8.62	0.91
2025	7.50	8.15	-0.39	7.75	0.00	0.16	0.73	0.03	8.67	0.92
2026	7.60	8.26	-0.40	7.85	0.00	0.16	0.73	0.03	8.77	0.92
2027	7.70	8.36	-0.41	7.95	0.00	0.16	0.73	0.03	8.88	0.92
2028	7.80	8.48	-0.42	8.05	0.00	0.16	0.73	0.03	8.98	0.93
2029	7.90	8.59	-0.43	8.15	0.00	0.17	0.74	0.03	9.09	0.93
2030	8.00	8.70	-0.44	8.26	0.00	0.17	0.74	0.03	9.19	0.94

Table A6-17b: Derivation of East-Side Firm Utility Gas Price
2006$/MMBtu

	Derivation of East-Side Firm Utility Gas Price							
	2006$/MMBtu							
	AECO Delta (+)	AECO Price	Firm Supply Premium (+)	Pipeline Fuel Charge (+)	Incremental Transport Cost (+)	Pipeline Commodity Charge (+)	Utility Gas Price	Total Delivery Cost
2005	-0.97	6.98	0.00	0.13	0.45	0.01	7.57	0.60
2006	-0.88	5.84	0.00	0.11	0.45	0.01	6.41	0.57
2007	-0.87	5.67	0.00	0.11	0.45	0.01	6.24	0.57
2008	-1.08	7.44	0.00	0.14	0.45	0.01	8.04	0.61
2009	-0.99	6.71	0.00	0.13	0.48	0.01	7.33	0.62
2010	-0.95	6.37	0.00	0.12	0.52	0.01	7.02	0.65
2011	-0.96	6.42	0.00	0.12	0.56	0.01	7.11	0.70
2012	-0.96	6.47	0.00	0.12	0.62	0.01	7.22	0.75
2013	-0.97	6.52	0.00	0.12	0.62	0.01	7.27	0.75
2014	-0.97	6.57	0.00	0.13	0.62	0.01	7.32	0.75
2015	-0.98	6.62	0.00	0.13	0.62	0.01	7.37	0.75
2016	-0.99	6.66	0.00	0.13	0.63	0.01	7.43	0.77
2017	-0.99	6.71	0.00	0.13	0.63	0.01	7.48	0.77
2018	-1.00	6.76	0.00	0.13	0.64	0.01	7.55	0.78
2019	-1.00	6.81	0.00	0.13	0.64	0.01	7.60	0.79
2020	-1.01	6.86	0.00	0.13	0.64	0.01	7.65	0.79
2021	-1.02	6.91	0.00	0.13	0.65	0.01	7.70	0.79
2022	-1.02	6.96	0.00	0.13	0.65	0.01	7.75	0.79
2023	-1.03	7.01	0.00	0.13	0.65	0.01	7.80	0.79
2024	-1.03	7.06	0.00	0.13	0.65	0.01	7.86	0.80
2025	-1.04	7.11	0.00	0.14	0.65	0.01	7.91	0.80
2026	-1.05	7.21	0.00	0.14	0.66	0.01	8.01	0.80
2027	-1.06	7.30	0.00	0.14	0.66	0.01	8.11	0.81
2028	-1.07	7.40	0.00	0.14	0.66	0.01	8.21	0.81
2029	-1.08	7.50	0.00	0.14	0.66	0.01	8.32	0.82
2030	-1.10	7.60	0.00	0.15	0.66	0.01	8.42	0.82

Fixed and Variable Natural Gas Costs

The Council's resource planning models require utility gas prices in terms of their fixed and variable components. For the Pacific Northwest, the model forecasts these based on the components described in Table A6-17a and A6-17b. Natural gas prices at regional hubs, pipeline fuel costs, and pipeline commodity charges are variable costs. That is, they can be avoided if electricity is not generated. The major fixed cost for natural gas is the pipeline reservation charge. It accounts for most of the transportation cost of natural gas. The pipeline reservation cost is divided by the plants capacity factor, currently set to .85, to get the correct cost per million Btu of fuel consumed. The other fixed cost is any premium that must be paid to secure firm gas supply. This is currently set to zero in the forecasts. Fixed costs are expressed in dollars per kilowatt per year, instead of dollars per million Btu.

The forecasts of natural gas prices to electric generators outside of the Pacific Northwest also have to be expressed in terms of fixed and variable costs. However, for these areas to forecasting approach does not explicitly include the components relied on to calculate the Pacific Northwest fixed and variable costs. The natural gas prices in these areas relied on either estimated equations of relationships to pricing hubs, or on average differences in costs observed historically. However, these differences include more than just pipeline transportation costs. Some differences for example are negative reflecting various market forces. A different approach is required in these cases.

To calculate the fixed and variable components of the non-PNW a little different assumption had to be made. In order to simplify the process, and not end up with zero capital costs for regions with state electric generators prices lower than hub prices, it was assumed that the fixed costs of pipeline capacity was the same for all areas. For existing generators, it was assumed to be $.50. For incremental generators is was assumed to be $.62, escalating at the scenario varying rates shown in Table A6-14.

Retail Prices

Residential and commercial sector retail natural gas prices are based on historical prices compared to wellhead prices. For historical years the difference between wellhead prices and retail prices are calculated. For forecast years, the projected difference is added to the wellhead price forecast. The differences, or markups, can be projected from historical trends, other forecasting models, or judgement.

Gas prices for small industrial gas users that rely on local gas distribution companies to supply their gas are forecast in the same manner as residential and commercial users. However, large firm or interruptible customers, whether industrial or electric utility, must be handled with a different method. This is because there is no reliable historical price series for these gas users to base a simple markup on. For these customers, the difference between wellhead and end user prices is built up from a set of transportation cost components appropriate to the specific type of gas use. These components for four areas of the Northwest are developed in the worksheet COMPONENTS.

To forecast the firm and interruptible prices for industrial gas users that secure their own supplies and transportation, calculations similar to those for power generators are used. Industrial firm gas users have been assumed to pay rolled-in rates. Interruptible users pay interruptible pipeline capacity charges. It is also assumed that industrial users will have to pay either firm or interruptible distribution charges to a local gas distribution company. As discussed above, gas prices for industrial gas users that obtain their gas supplies through their local distribution company can be forecast from national wellhead prices and historical relationships to reported retail prices. All of the specific adjustments that are applied to the other industrial and utility users are captured implicitly by this method.

Oil Model

The oil price forecasting model first estimates the refiner price of distillate and residual oil based on the assumed world price for crude oil. This is done using a very simple model of refinery economics[3]. Retail prices of oil products for the industrial, residential, and commercial sectors are then calculated by adding markups based on the historical difference between calculated refiner wholesale prices and actual retail prices.

The simple model of refiner economics considers the cost of crude oil, the cost of refining crude oil into heavy and light oil products, and the value of those products in the market. It assumes that refiners will decide on their production mix so that their profits will be maximized. That is, the difference between the revenue received from sale of products and the costs of crude oil and refining it into products will be maximized.

The underlying assumptions are as follows:

Refining costs:

Simple refining
- $2.15 per barrel in 2000 dollars.
- Saudi light yields 47 % heavy oil.
- 3 percent energy penalty.

Complex refining
- $5.38 per barrel in 2000 dollars.
- yield 100 percent light oil.
- 12 percent energy penalty, about 6-8 percent above simple refining.

Desulpherization
- $3.91 per barrel in 2000 dollars.
- 4 to - 8 percent energy penalty.
- Assumed not to be necessary in NW.

Profit Equations:

<u>Simple refinery</u>

Revenue = $.47H + .53L$
Cost = $C + .03C + 2.15$
Profit = $(.47H + .53L) - (C + .03C + 2.15)$

Where: .47 is residual oil output share.

[3] This refinery model evolved from the old Council fuel price forecasting method developed by Energy Analysis and Planning, Inc. That company has evolved into Economic Insight Inc.

.53 is distillate oil output share.
H is residual oil wholesale price.
L is distillate oil wholesale price.
C is cost of crude oil
.03 is the energy penalty for simple refining.
2.15 is the refining cost per barrel.

<u>Complex refinery</u>

Revenue = L
Cost = C + .12C + 5.38
Profit = L - (C + .12C + 5.38)

<u>Equilibrium Condition:</u> Profit from heavy products equals profit from light products at the margin.

$$.47H + .53L - C - .03C - 2.15 = L - C - .12C - 5.38$$

<u>Solve for product prices:</u>

$$.47H + .53L - L = .03C - .12C - 5.38 + 2.15$$
$$.47(H - L) = -.09C - 3.23$$
$$(H - L) = -.1915C - 6.8723$$

Using $L = C + .12C + 5.38$ gives

$$H = -.1915C - 6.8723 + C + .12C + 5.38$$

$$H = .9285C - 1.5133$$ (Equation for residual oil price as a function of crude oil price.)

The simple refinery model thus gives the estimates of residual oil (heavy) and distillate oil (light) prices based on the assumed crude oil prices. Distillate wholesale prices equals 112 percent of the crude oil price plus $5.38 (in 2000 dollars) per barrel. Residual oil wholesales price equals 93 percent of the crude oil price less $1.51

Historically based markups are added to get retail prices for residual and distillate oil for the commercial, industrial and utility sectors. The two oil products prices and then consumption weighted to get an average oil price for the sector. The residential sector does not use residual oil so only a distillate retail price is calculated.

Coal Model

The coal model consists of two tabs in FUELMOD7(1). One tab calculates total coal costs at various locations in the West. A second tab calculates only the variable costs of coal for electricity generation.

Coal costs delivered to the Northwest, for example, are based on PRB minemouth prices with delivery costs added. PRB minemouth price forecasts are based on the last year of available prices, adjusted to an estimated trend level starting point a few years into the forecast period. These trend levels vary by forecast case. Once estimated trend levels are reached a simple annual real price growth rate is added, which also varies by forecast case.

Total delivered costs are estimated for industrial coal users in the Northwest, and for electricity generation in various areas of the West. Industrial prices are based on historical differences between Northwest industrial coal prices and PRB minemouth prices. In the forecast these differences are escalated for diesel fuel cost increases. Electricity generation coal costs are estimated for areas in WECC based on distance from the PRB, unit car rail costs per ton-mile, and an escalation factor for diesel fuel costs.

Currently the coal prices are forecast in 2000 constant dollars. The prices in the COALFC tab are entered in 2000 dollars, and the regional coal prices are estimated in 2000 dollars and then converted to the year dollars of the other forecasts. In the Sixth Power Plan these are 2006 constant dollars.

ATTACHMENT A6-1

--GUIDE TO FUEL PRICE FORECASTING MODEL PAGES

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--
DOC- -- -Describes files in the forecast model
--
Deflation- -- -The Deflation worksheet contains implicit GDP deflators and uses them to generate a series of conversion factors to convert from nominal to 2000 dollars. It is set up to enter the year-dollars the user wants the model to work in and creates a conversion factor (cd) to convert from 2000$ to the chosen year dollars. It also create labels that are put in various places in the model to reflect the year dollars being used.
--
NGFC- ---Contains historical wellhead natural gas prices in various units, and the forecast range of wellhead prices. The forecast of natural gas prices must be done in the year dollars chosen for the reports in the Deflation tab. The forecasts, as well as oil and coal forecasts, are developed in a separate spreadsheet called "Fuel Price FC Develop 090308.xls".
--
WOPFC- ---Contains historical world oil prices in various units, and the forecast range of world oil prices. The world oil prices are defined as refiners acquisition prices of imported oil. As in the case of the wellhead gas price forecast, the forecast of world oil prices must be done in the year dollars chosen for the reports in the Deflation tab.
--
COALFC----Contains forecasts of Wyoming/Montana fuel prices for a short historical period and low through high forecasts for prices. Coal price forecasts, unlike natural gas and oil, must be done in year 2000 dollars.
--
MAIN- -- -MAIN is where most of the controls for a forecast run are set. Cell B2 contains a drop down menu for choice of the forecast scenario. When the user picks a scenario, the worksheet inserts the appropriate natural gas, oil, and coal prices from the NGFC, WOPFC, and COALFC tabs. Cell E3 contains the run date. At the bottom of the worksheet, is a section where scenario varying parameters are chosen to fit the scenario. The right side of the worksheet contains a summary of burner-tip prices for oil, natural gas, and coal.
--
NG West Annual- ---This worksheet develops forecasts of natural gas prices at various pricing points throughout the West. The major pricing hubs (orange highlights) are averages of values calculated in the NG West Monthly tab. Equations then relate annual major hub prices to prices in specific WECC locations. The year dollars are automatically adjusted in this worksheet, including changes to the parameters in the basis equations.
--
Basis Equations----This tab contains econometric relationship among natural gas pricing hubs at Henry Hub and various points in the West. It includes an equation to convert annual wellhead prices to monthly wellhead prices, and an equation to estimate monthly Henry Hub prices based on the monthly wellhead price forecast. It includes assumed values for differentials where equations are not estimated
--
NGWest Monthly----This tab creates monthly Hub prices from the U.S. wellhead price forecast using the equations in the Basis Equations tab.
--
COMPONENTS----This worksheet develops delivered natural gas prices for Pacific Northwest large users. The delivery costs are built up from shipping cost components. Price estimates are developed for firm and interruptible customers, and for existing and new customers. New customers are expected to pay incremental pipeline capacity costs. These delivered prices are developed separately for the West and East sides of the PNW.

--

HistRetail----This contains historical prices for retail natural gas and oil products. The prices run from 1980 to 2005. These prices are used to calibrate markups from wholesale fuel prices to retail prices by sector (used in RES_COM, INDUST, and OILMOD) for input to the demand forecasting models.

--

RES_COM- -- -This sheet calculates Residential & Commercial retail natural gas prices for the residential and commercial sectors. Retail prices are estimated from wholesale prices using markup assumptions that come form the HistRetail worksheet

--

INDUST- -- -This sheet calculates delivered industrial natural gas prices for industrial consumers. It includes estimates for direct purchasers from the pipeline, both firm and interruptible, and also for industrial users that purchase from the LDC (Local Distribution Company).

--

NWUTIL- -- -This worksheet develops natural gas prices for electric generators in four subareas of the PNW. There are estimates for Existing firm supplies, for new incremental supplies, and for interruptible supplies. The costs are separated into fixed and variable costs using the components contained in the COMPONENTS worksheet.

--

Aurora Monthly- -- -Develops monthly fixed and variable natural gas prices for electric generators at Aurora Model pricing points throughout the West (WECC).

--

C$ NWUtil- -- -This sheet displays the derivation of utility delivered natural gas prices. It is more easily understood than the NWUTIL sheet.

--

GASSUM- ---Summary table for gas price forecasts, linked to the individual
-- sector worksheets.

--

OILMOD- ---The oil model estimates refiner cost of residual and distillate products based on the refiner acquisition cost of imported oil from the WOPFC worksheet. The refiner product prices are based on a very simple profit maximization model of refiner operations. The worksheet goes on to estimate sectoral retail prices for distillate and residual oil based on markups from the historical relationships in the HistRetail worksheet.

--

OilSum----This sheet contains a summary of the oil price forecasts.

--

COAL(Total)- ---This sheet contains a coal price forecasting model. The basic forecast of price is for PRB minemouth price, which is simply based on alternative growth rates that are specified for each forecast case in the MAIN tab. The model then calculates delivered coal prices for each Western Aurora model region. Delivered prices are based on a standard cost per ton-mile of commodity using a unit train, combined with the estimated number of miles from mine mouth to an particular area. The percent change in diesel prices weighted by the share share of delivery cost that is due to the propulsion energy requirements (25%), adjusts the delivery costs so that they roughly reflect changes in oil prices.

--

COAL(Variable)----Same as COAL(Total) except that only inlcudes variable delivery costs.

--

Tables--Develops tables to be included in forecast document appendices

--

Graphs--Miscellaneous graphs to assess the forecast and describe results

--

NOTE: Columns with Red block at top need to be input during forecast period.

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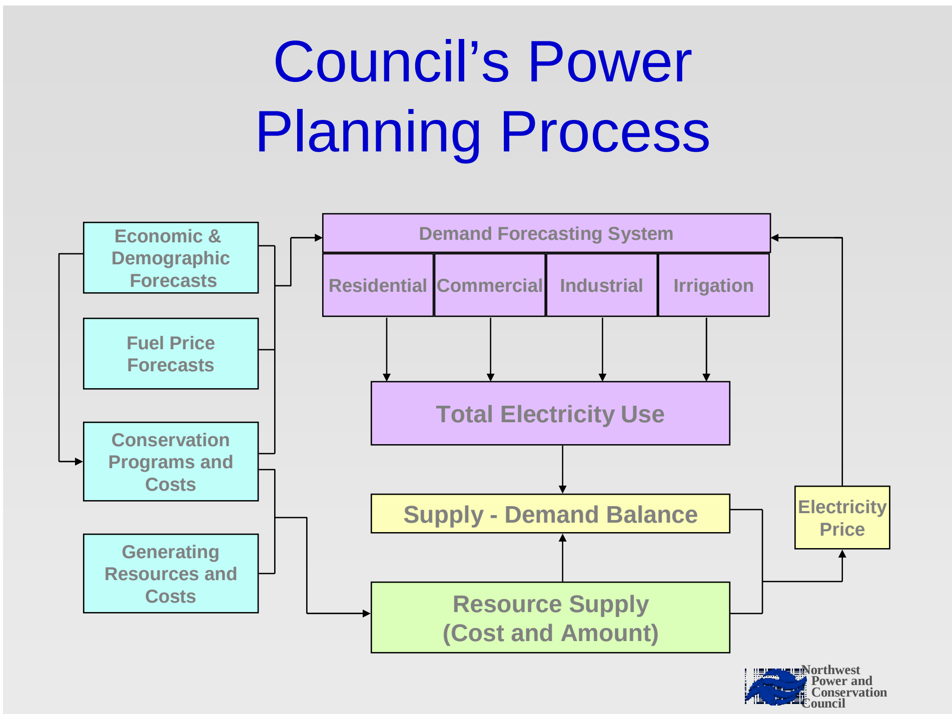
Appendix B: Economic Forecast

ROLE OF THE ECONOMIC FORECAST

A 20-year forecast of demand for electricity is one of the requirements of the Northwest Power Act (Public Law 96-501, Sec. 4(e)(3)(D)). A detailed demand forecast is used in planning future conservation potential, electricity market clearing price projections, as well as in the Council's own resource risk assessments. To better capture the impact of future uncertainties, the Council develops a forecast of future demand for energy that identifies not just one trend but a range of trends. The demand forecast range is determined by a consistent set of assumptions about uncertainties in future economic and demographic activities in the region, the trajectory of fossil fuel and electricity prices, and legislative and market responses to climate change.

The figure below depicts the Council's power planning process. The planning process starts with economic and demographic assessments and then adds fuel and electricity price forecasts to create a forecast for electricity demand. The demand forecast looks at energy use by sector to predict monthly load for electricity generators. The Northwest load forecast, along with the forecast for load outside the Northwest, is used in forecasting wholesale electricity prices. Northwest load is used in the Council's Regional Portfolio Model (RPM) to create least-cost, low-risk resource options for the region.

The demand forecast is also used extensively to develop the conservation supply curves. The key economic drivers for the conservation supply curves are identical to the economic drivers of the demand forecast.



BACKGROUND

Economic Growth Assumptions

The national economic models driving the regional forecast of the draft Sixth Power Plan were updated as of the first quarter 2009. Given the long-term nature of the Council's power plan, the current recession and impact of the federal economic stimulus package were not modeled in detail. However, pace of economic activity was reduced to capture impact of recession on energy consumption. Also, over the next 20 years, economic policy initiatives responding to climate change will affect the regional economy and regional demand for energy. These policy changes have not been explicitly incorporated into the Council's economic assumptions or demand forecast for electricity.

Many things determine the load forecast, and energy demand is influenced by both long-term and short-term factors. Long-term variables may be economic circumstances, life-style choices, demographic changes, or socio-economic trends that take decades to develop and fade. Energy demand is also affected by short-term factors, such as weather conditions or changes in income. The combination of all these conditions determines the demand for energy.

ECONOMIC DRIVERS OF RESIDENTIAL DEMAND

The number of dwellings is a key driver of energy demand in the residential sector. Residential demand begins with the number of units, including single family, multifamily, and manufactured homes. This demand is forecast to grow at 1.3 percent annually from 2010-2030. The current (2008) stock of 5.7 million homes is expected to grow to 7.6 million by 2030, or approximately 83,000 new homes per year.

Another factor affecting residential demand for electricity is life-style trends. As more homes are linked to the internet and the saturation rate for air-conditioning appliances and electronic equipment increases, demand for electricity in the residential sector increases. Over 80 percent of all new homes in the region now have central air conditioning. This compares to 7-8 percent of housing stock with central air conditioning in the 1980s. Another change is the growth rate in home electronics, which has been phenomenal at over 6 percent per year since 2000, and which is expected to continue to increase.

In the residential sector, electricity demand is driven by space heating and cooling, as well as refrigeration, cooking, washing, and a new category called Information, Communication and Entertainment (ICE). This new category includes all portable devices that must be charged, such as laptop computers and cell phones, as well as larger, more energy-intensive televisions and gaming devices. As the regional population grows, and with it the number of homes, demand for these services and appliances will also increase. The energy efficiency of appliances as dictated by state and federal standards, which appliances consumers buy, and how they use them, affect energy demand, as well.

The “number of homes” category is driven by regional population, house size, and composition of the population. The region’s population increased from about 8.9 million in 1985 to about 13 million by 2007, and is projected to grow to over 16 million by 2030 at an annual rate of 1.3 percent.

The following figure reflects the expected population change in each of the four states.

Figure B-1: Population Forecast (000)

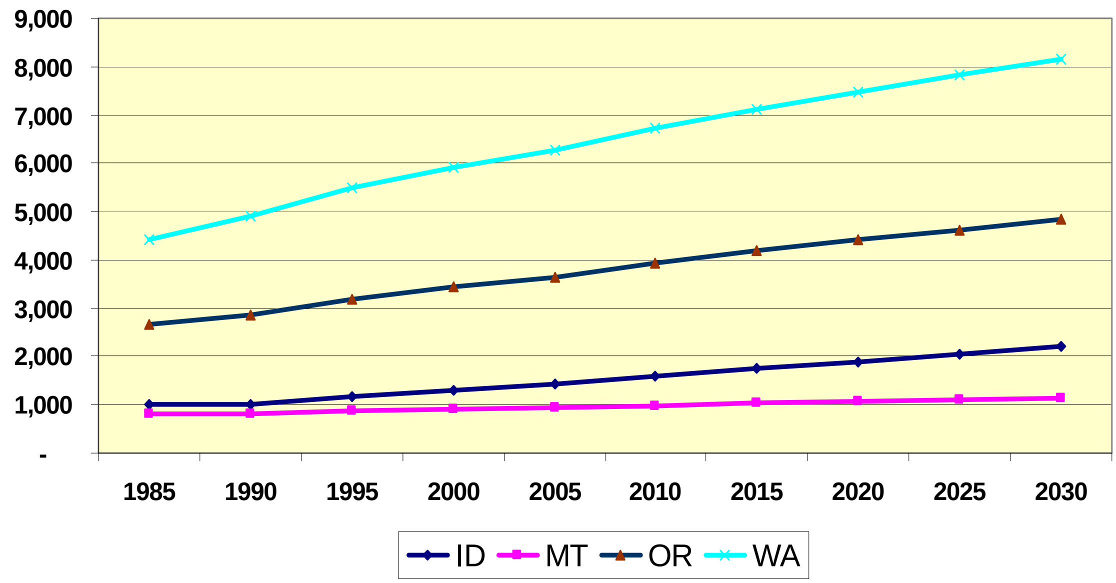


Table B-1: Population in the Region (000)

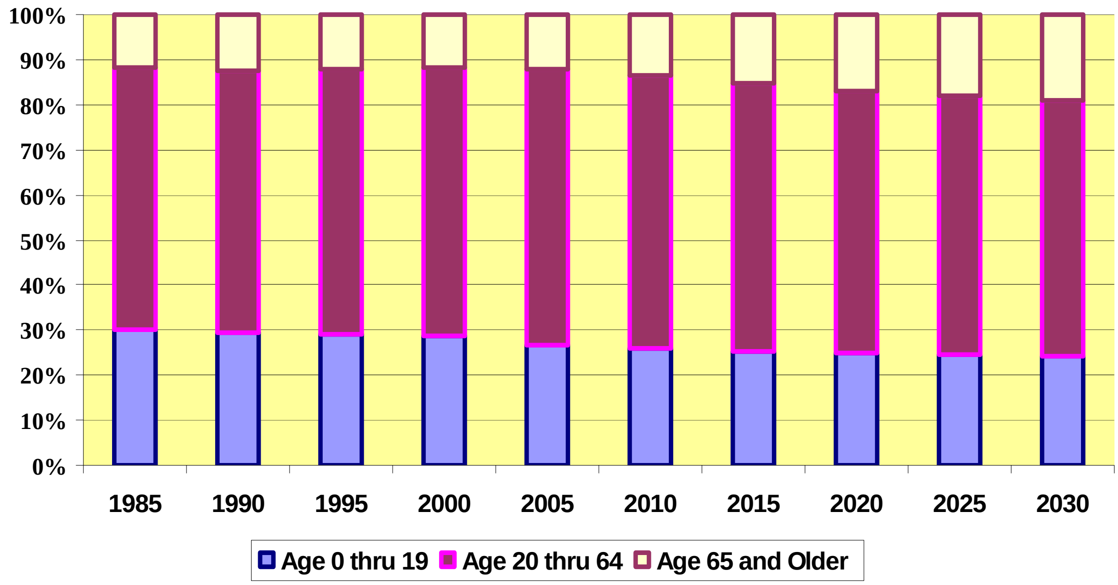
State	1985	2007	2010	2015	2030	Annual Growth rates[1] 1985-2007	Annual Growth rates[1] 2010-2030
ID	993	1,504	1,603	1,746	2,195	1.9%	1.6%
MT	821	959	989	1,032	1,135	0.7%	0.7%
OR	2,674	3,754	3,920	4,178	4,826	1.6%	1.0%
WA	4,406	6,480	6,731	7,100	8,170	1.8%	1.0%
4 states	8,894	12,698	13,244	14,056	16,326	1.6%	1.1%

Table B-2: Composition of Regional Population (000)

	1985	2007	2010	2015	2030
Population Age 0 thru 19	2,673	3,339	3,414	3,540	3,954
Population Age 20 thru 64	5,161	7,776	8,043	8,369	9,266
Population Age 65 & Older	1,060	1,583	1,787	2,148	3,107

[1] Important note: This appendix uses average annual growth rates as summary figures when comparing the historic and forecast periods for many economic drivers and fuel prices. The average annual growth rate is sensitive to the base year values used in calculating the annual growth rates. For a more accurate picture of the year-by-year growth in economic drivers and prices, additional information for each state is available from the companion Excel worksheet available from Council's website. This companion data can provide a more accurate picture of historic and future growth.

Figure B-2: Composition of Population Forecast (000)



Population

The region's population is changing and reflects demographic shifts seen throughout the United States. In 1985, 30 percent of the region's population was younger than 19. This age group has been growing at about 1 percent per year, but it is forecast to grow more slowly for the next two decades, at around 0.7 percent annually. As a percentage of the total population, it is projected to represent about 24 percent of the population by 2030. This generation represents consumers who have grown up with ICE technologies, the fastest-growing segment of residential electricity demand.

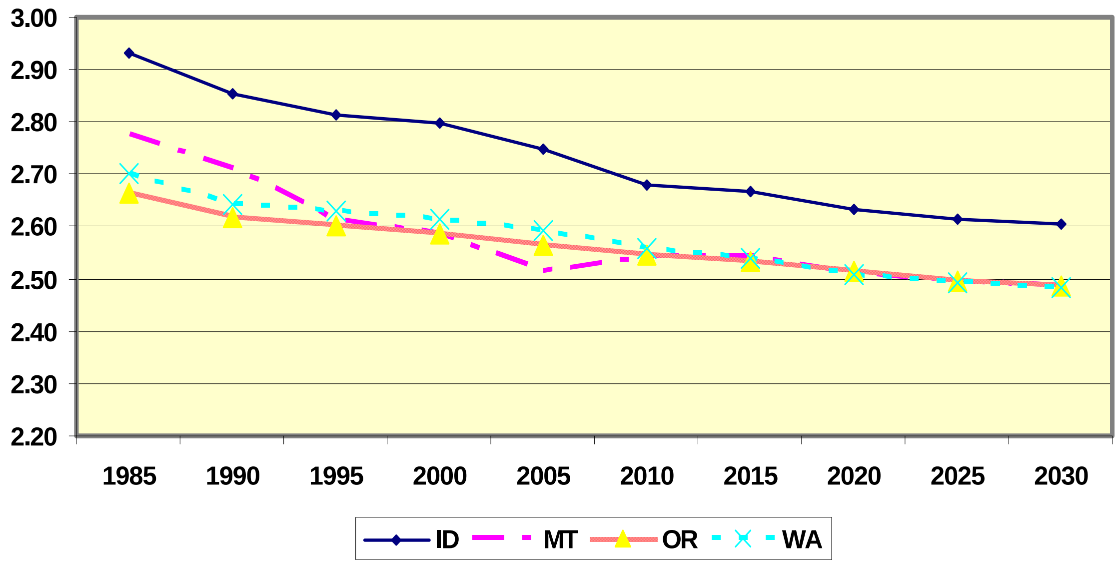
The 20-to-64 year-old age group, representing the working group, has grown from about 5 million in 1985 to about 7.7 million in 2007, and is projected to grow to over 9 million by 2030. This age group has been growing at 1.9 percent per year, but its growth rate is expected to be significantly reduced as more and more baby boomers retire. This demographic category plays a critical role in regional employment, demand for homes, major capital equipment, and goods and services.

The fastest-growing population segment is people over 64, the "retirees." They represented about 12 percent of the population in 1985, and by 2030 they are expected to represent about 20 percent of the region's population. This segment is expected to grow almost 3 percent per year over the next 20 years, at almost three times the growth rate of the total population. This trend has affected the commercial sector in many ways, and the increase in the number of businesses catering to elders is one example. In 2005, the Bureau of Labor Statistics and county business patterns show there were over 3,200 businesses in the region offering elder care services. Such businesses had more than 100,000 employees and occupied about 60 million square feet of space. If the current trends continue, by 2030 an additional 50 million square feet of space would be needed for elder care. The demand from this business is tracked in the commercial section of the model. However, the region lacks a good understanding of the demand from this particular market segment, so the Sixth Power Plan recommends pursuing better data on the energy consumption pattern of this sector.

Housing Stock

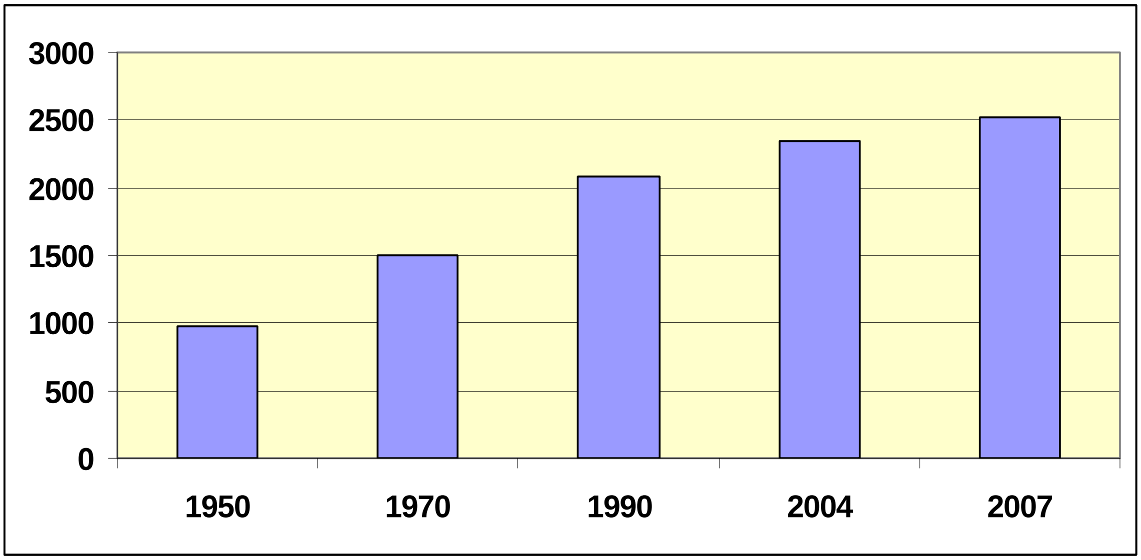
While the regional population has been increasing, the number of occupants per household has been declining. In 1985, the average household size was about 2.95 persons per household, and by 2030 it is expected to go down to 2.6 persons per household, resulting in the number of homes growing at a faster rate than the population.

Figure B-3: Declining Household Size (People per Household)



While the number of occupants per household has declined, the square footage of homes has been increasing. According to the U.S. Bureau of Census's annual survey of new homes, the average single-family house completed in 2007 had 2,521 square feet, 801 more square feet than homes in 1977. Going back to the 1950s, the average square footage of a new single-family home was about 983 square feet. Over the past five decades, the average home size has grown by more than 250 percent. In 2007, 38 percent of new single-family homes had four or more bedrooms, almost twice the number of bedrooms in most homes built 20 years ago. In addition, 90 percent of these new homes had air conditioning. These changes have meant an increased demand for space conditioning and lighting.

Figure B-4: Growing Average Size of New Single Family Homes



The increase in the average size of homes has not been limited to single-family residences. The average square footage of multi-family units completed and built for sale in 2007 was 1,577 square feet, 217 square feet more than in 1999. It is difficult to predict the future trends in house size. However, if the movement toward a more sustainable lifestyle gains momentum, housing size may decline as the number of single-occupant households increases and the population ages.

In absolute terms, the number of single-family housing has been growing at a faster pace than the overall population. Between 1985 and 2007, the population grew at 1.6 percent per year and the number of homes grew at 1.9 percent per year. As incomes increased and as more people purchased homes, the number of households grew at a rate faster than the rate of population growth.

Figure B-5: Number of Single-Family Homes (000) Stock

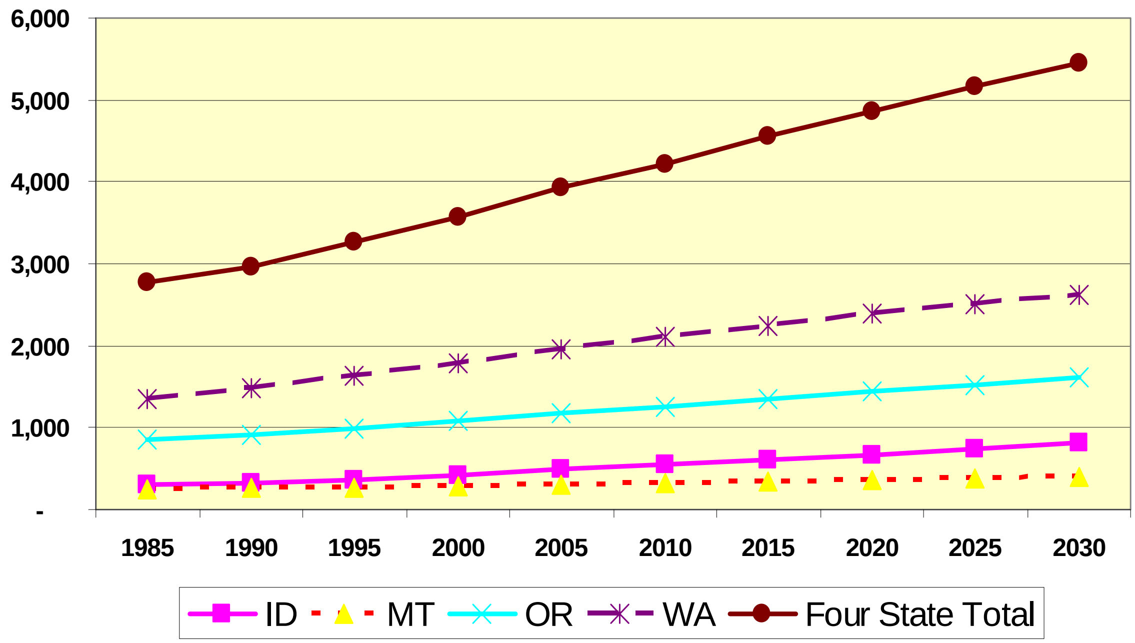
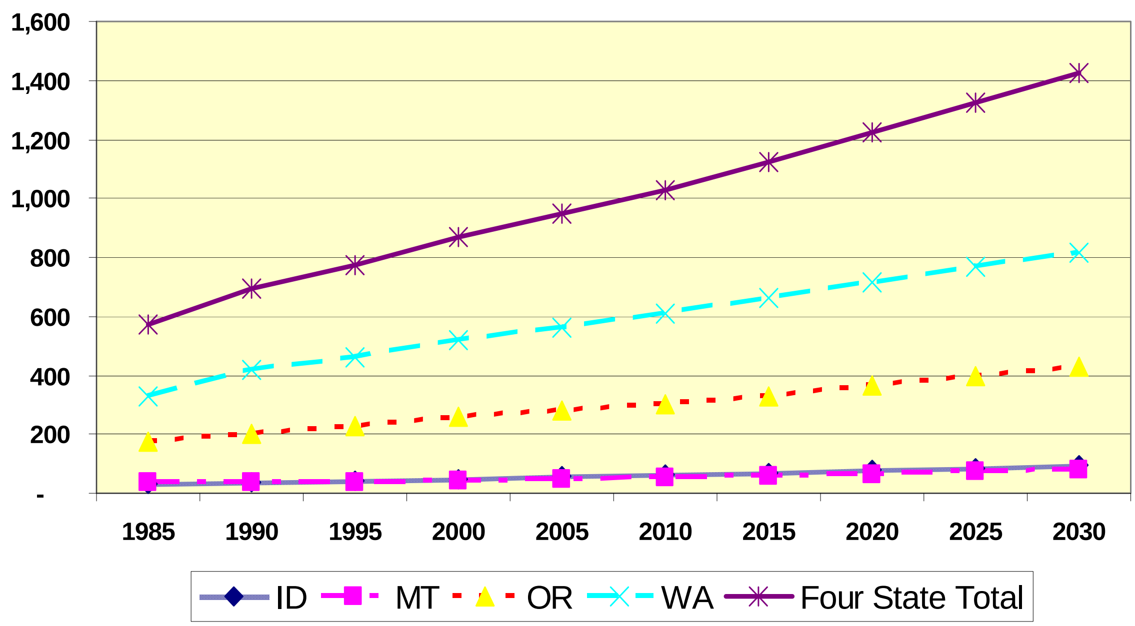
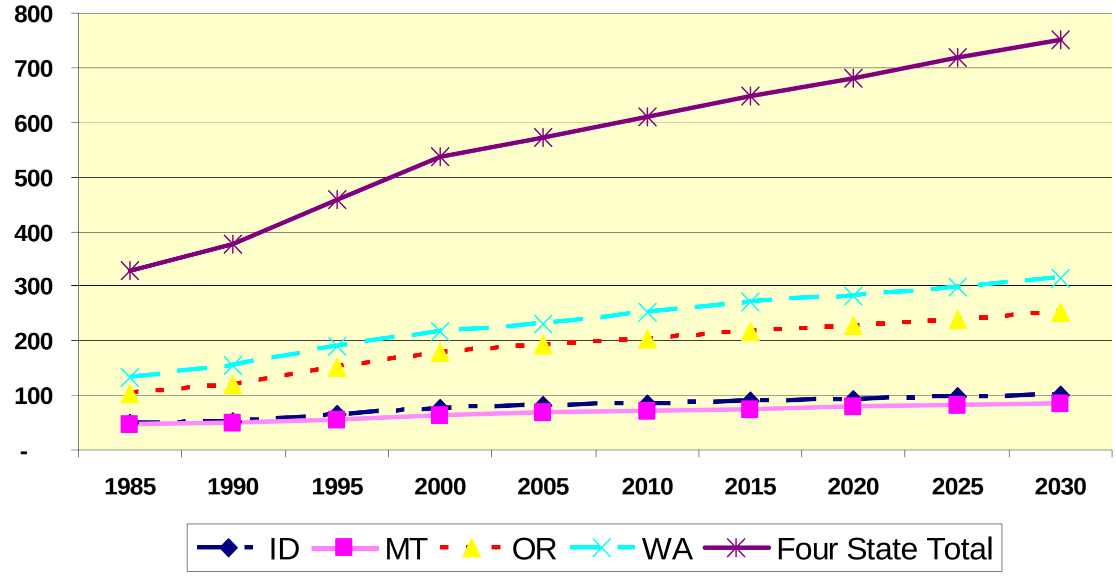


Figure B-6: Number of Multi-Family Homes (000) Stock



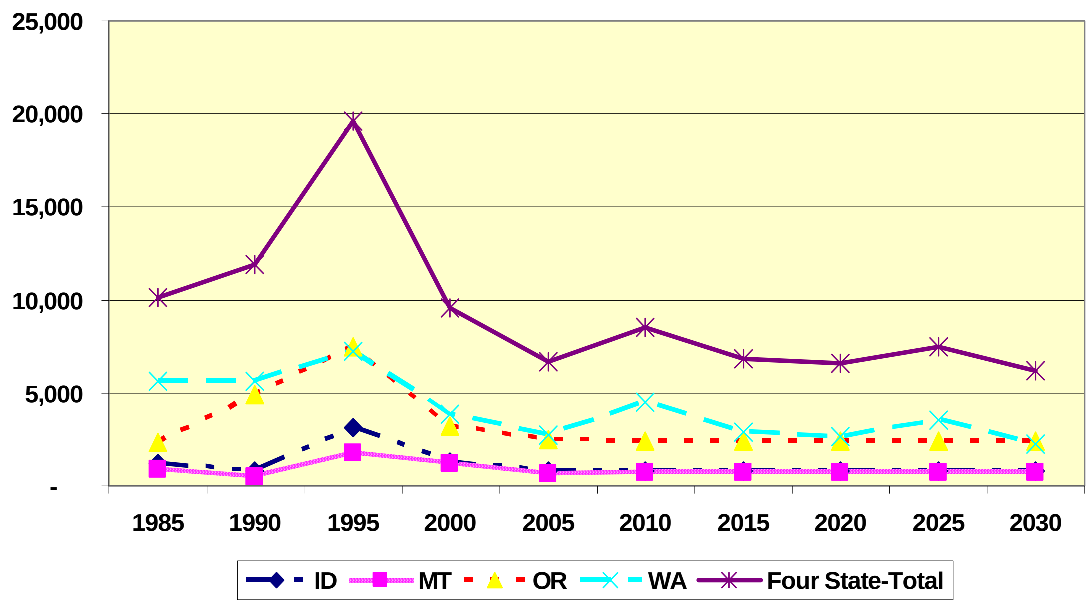
A housing sub-sector that has *not* been growing as fast is manufactured housing. The factors determining demand for this type of housing are income, price of land, and the number of newlywed and low-income populations. Manufactured homes tend to be less-expensive housing options, so an increase in per capita income in the region has slowed demand for these homes. The price of manufactured housing has also increased, although significantly less than stick-built homes.

Figure B-7: Number of Manufactured Homes (000) Stock



Although manufactured housing typically represents about 10 percent of new homes in the region, they represent about 30 percent of electrically heated new homes. Recognizing this high percentage of electrically heated homes, the Manufactured Housing Acquisition Program was established in 1992. The incentive program, supported by the Council, the Bonneville Power Administration, state energy offices, electric utilities, and manufacturers, paid manufacturers the incremental cost to add efficiency measures to each new home. New manufactured homes peaked in 1995 after this program ended. For now, the stock of manufactured homes is projected to increase, although at a slower rate.

Figure B-8: New Manufactured Homes per Year



The overall composition of housing stock has been changing to favor multi-family homes. Single-family homes (defined as a detached single-family home or a multi-plex unit of up to 4 units) has been losing market share. Single-family homes represented 75 percent of homes in the region in 1985, but by 2007 they represented 72 percent of housing stock. By 2030, the forecast is for single-family homes to decline to about 71 percent. Multi-family homes (defined as housing with greater than four units) represented 16 percent of residential housing stock in 1985, 17 percent by 2007, and is projected to be about 20 percent by 2030. Manufactured homes have had a 9-10 percent market share and are projected to retain this status.

Table B-3: Average Annual Number of New Homes

	1985-2000	2001-2008	2010-2030
Single-Family			
Idaho	7,390	12,544	13,148
Montana	2,070	3,620	3,702
Oregon	14,459	17,789	18,124
Washington	28,237	32,364	27,069
Four State Total	52,157	66,317	62,043
Multi-Family			
Idaho	901	1,423	1,504
Montana	551	1,001	1,347
Oregon	5,660	4,510	6,086
Washington	12,762	9,206	10,188
Four State Total	19,873	16,141	19,126
Manufactured Home			
Idaho	1,818	870	837
Montana	1,161	775	714
Oregon	4,983	2,424	2,404
Washington	5,609	3,138	3,157
Four State Total	13,571	7,208	7,111

Each year during 1985-2008, an average of 54,000 new single-family, 19,500 multi-family, and 12,000 new manufactured homes were added to the existing stock. Starting in 2000, each year has seen a dramatic increase in new single-family home additions. Rising income levels in the region and the increased availability of credit caused a shift from multi-family to single-family home ownership. In 2005, more than 87,000 new single-family homes were added in the region. This increase in the number of single-family houses caused a substantial increase in the price of housing. In the 2010-2030 period, the Council anticipates a return to more historic levels of growth. A slow down in new single-family home additions is already evident. The forecast predicts an increase in multi-family homes in the region. The impact of the current recession on new residential construction was incorporated in the revised forecast using Global Insight's short-term economic forecast of March 2009.

Figure B-9: New Single Family Home Additions

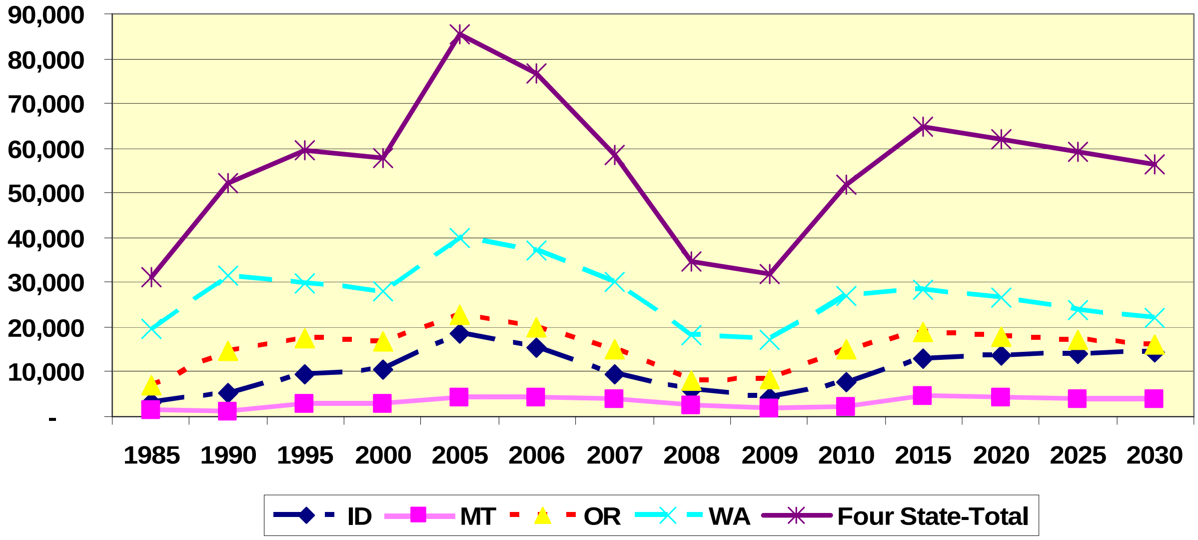
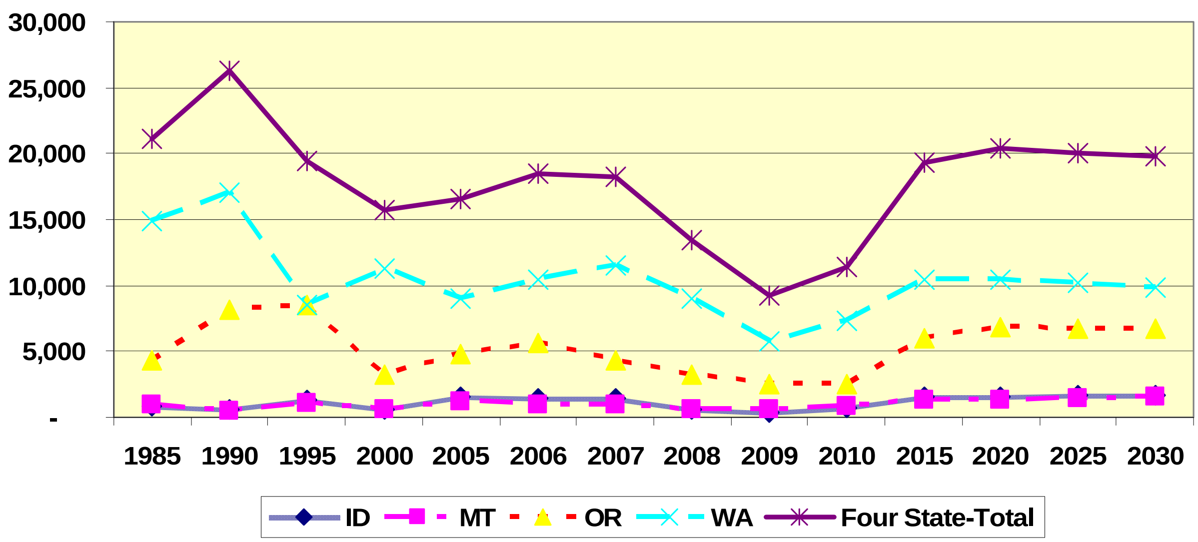


Figure B-10: New Multi-family Additions



In summary, the key driver for demand for electricity consumption in the residential sector is the number of residential units. The following table presents the existing residential units for select years.

Table B-4: Historic and forecast residential units (1000s)

Regional Summary	1985	2007	2015	2020	2030
Single Family	2,767	4,066	4,534	4,850	5,436
Multi Family	571	984	1,107	1,208	1,408
Other Family	329	585	649	681	752

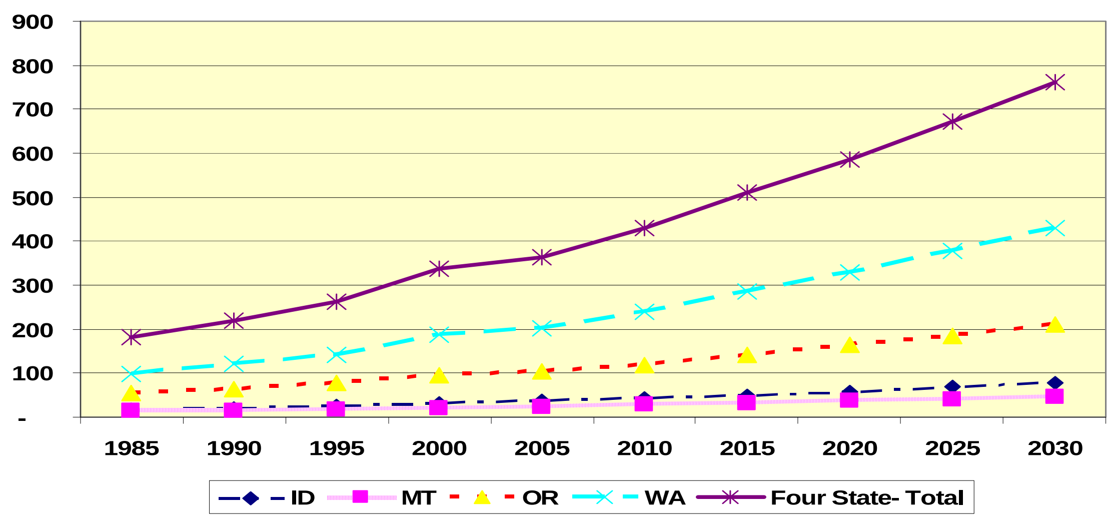
Personal Income

Personal income is another economic driver of energy demand. Energy consumption is elastic, so a decline in personal income causes a short-term reduction in demand. Regional personal income, both in total and on a per-capita basis, has been on the upswing and is projected to continue, although at a slower rate. The following table shows the growth rate, in constant dollars, for personal income in the four states. It should be noted that the impact of the 2008 recession has not been incorporated into these personal income projections.

Table B-5: Growth Rate Personal Income (2000 constant dollars)

	1985-2007	2010-2030
Idaho	3.9%	3.1%
Montana	2.7%	2.4%
Oregon	3.3%	2.9%
Washington	3.8%	2.9%
Four State- Total	3.6%	2.9%

Figure B-11: Personal Income
(Billions in 2000 constant dollars)



Number of Energy-using Appliances in the Average Residence

Energy-using appliances also affect energy demand in the residential sector, and the penetration rate of appliances is a key driver of demand. One group of devices that has experienced significant growth in the residential sector has been home electronics (ICE). Very few sources track the penetration rate of this end-use at the regional level, so the following analysis draws on national-level data.

Information Communication and Entertainment

The explosive growth of these devices has been global, fueled in part by the rapid expansion of the Internet. In a not too distant past, the typical appliances in a typical home consisted of one or two refrigerators; a water heater; perhaps a freezer; some form of space-heating appliance; a cooking appliance; lighting fixtures; and, rarely, an air-conditioning unit. Entertainment appliances were usually limited to a color television and a stereo system.

An average home today has all these appliances, as well as a whole range of ICE devices. Some ICE devices provide services that were once performed outside the home, such as printing pictures or reports. Other ICE devices connect people to the outside world and social networks, and some ICE devices provide entertainment. ICE devices, to a great extent, have removed the boundary between office work and home life. The line between home and work life is increasingly less pronounced as more and more people are able to conduct office work from home.

ICE end-uses are numerous and vary from household to household, depending on the life-style and demographic characteristics of the household. The following table is a partial list of ICE end-uses. The consumption figures are estimates and combine the various duty cycles of the devices.

Table B-6: Partial Listing of ICE Devices and Estimated Annual Consumption[2]

Home Office/Communication Devices	KWh/year	Home Entertainment Devices	KWh/year
Desktop PC	264	Home Theater systems	115
Laptop PC	74	TV- CRT	126
Monitors	68	TV-LCD	108
Inkjet Printer	21	TV-Plasma	281
Laser Printer	97	TV-Projection	237
Scanners	45	Digital Cable box	159
Copiers	51	Digital Satellite Receiver	125
Broadband Devices	79	Digital Video Recorder	264
Home Router	53	DVD players	34
Chargers	13.1	Game Systems	

U.S. national shipment data for 1997-2006 show that the shipment of laptop computers increased at an annual rate of 16 percent.[3] For the same period, desk top computer shipments increased at a rate of 3 percent annually. Meanwhile, the traditional analog color television was declining at 13 percent per year. In 1997, about 400,000 digital televisions (LCD, plasma, and projection) were shipped, and by 2006 the volume of shipment reached over 21 million units.

At the same time that the number and type of home televisions were increasing, television screen size also increased. For example, in 1999, over 83 percent of residential televisions were less than 32 inches, and about 5 percent were larger than 46 inches. In 2008, over 30 percent of

[2] Pacific Gas and Electric Company, Emerging Technologies Program Application Assessment Report #0513 Consumer Electronics: Market Trends, Energy Consumption, and Program Recommendations 2005-2010, Issued: December 2006

[3] Appliance Magazine data for U.S. manufacturers

televisions are now over 46 inches and only 14 percent are less than 32 inches.[4] As screen size increases, so does energy consumption. A 32-inch or less television consumes about 172 kilowatt hours per year compared to the 283 (or more) kilowatt hours that televisions with 46-inch or wider screens consume.

Figure B-12: Growth in Computer Sales

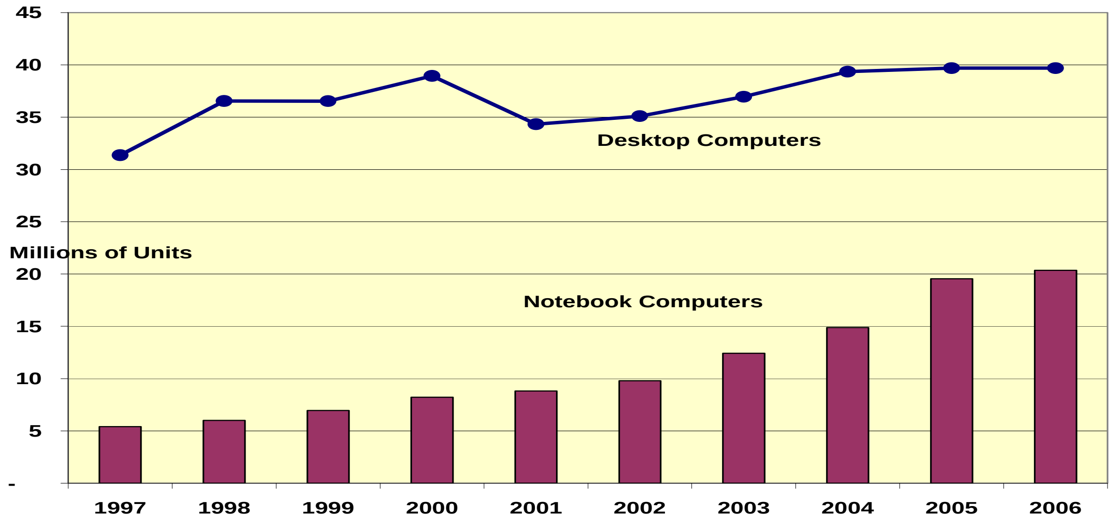
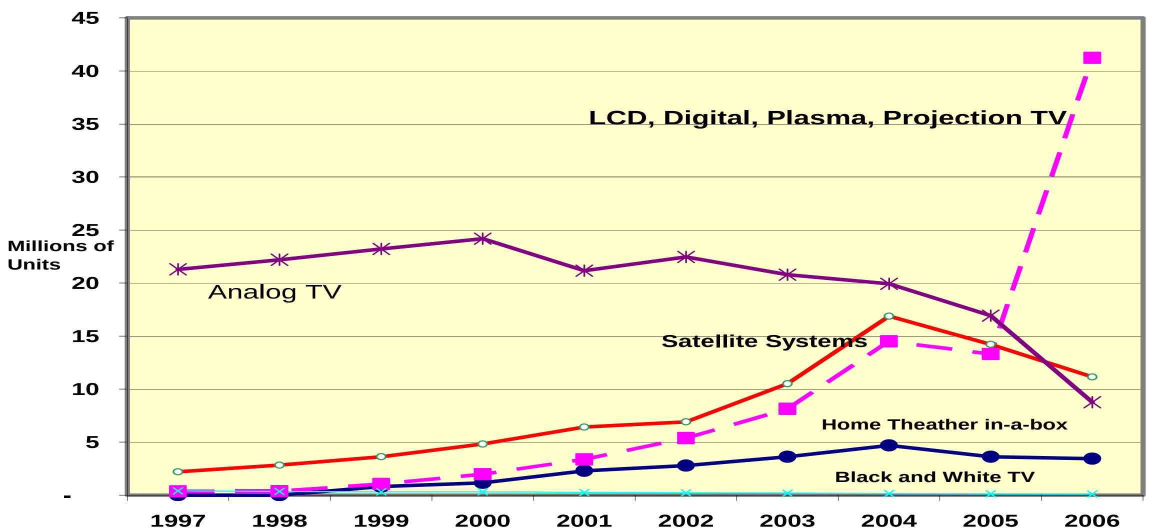


Table B-7: Annual Growth Rate in Shipment of Entertainment Equipment

	1997-2006
Home Theater-In-a-Box	23%
LCD, Digital, Plasma, Projection TV	69%
Satellite Systems	17%
Televisions, Black & White (Monochrome)	-14%
Televisions, Color, Analog	-13%

Figure B-13: Annual Shipment of TVs and Satellite Systems



[4] 2008 study conducted for Northwest Power and Conservation Council by ECOS consulting.

Demand for Air Conditioning

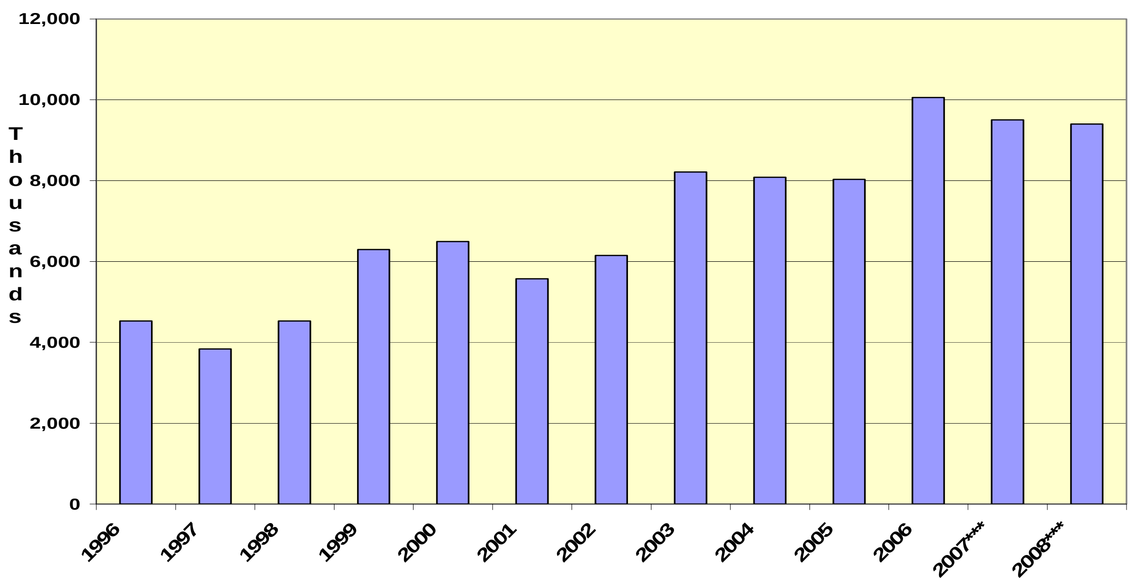
Residential air conditioning has grown rapidly in the region. The market penetration of air conditioning by Northwest homeowners was relatively low, about 10-20 percent, during the 1980s and 1990s. Air conditioning use has been increasing significantly in recent years. This shift in demand can be attributed to warmer summer temperatures, reduced prices of air-conditioning units, and the number of new people moving into the region who are accustomed to using air-conditioning in their previous homes. The following table shows that in 2000, about 40,000 room air conditioning units were shipped to the region. Five years later, the figure had increased to about 140,000. State-specific figures are not available at this writing, but if the national trends are any indication, the volume of room air conditioning units in 2006 would show a significant increase.

Table B-8: Shipment of Room Air Conditions to the Region (number)

	2000	2001	2002	2003	2004	2005	Annual Growth Rate
Idaho	5,300	5,400	7,500	13,000	13,600	9,998	14%
Montana	4,200	4,900	8,000	12,400	15,300	7,926	14%
Oregon	15,800	17,300	21,100	39,800	58,700	55,469	29%
Washington	16,200	27,300	32,600	45,300	90,700	66,163	33%

The increase in room air-conditioning has not been a regional phenomenon. Similar trends can be seen in national figures. Between 1997 and 2006, room air-conditioning sales grew at an annual rate of 11 percent, almost 10 times the population growth rate. Sales increased from about 4 million units in 1997 to about 10 million units in 2006. The sales volume for room air-conditioning depends on summer temperatures, which is evident from the high sales volume in 2006--one of the hottest years on record.

Figure B-14: Recent Trends in Nationwide Shipment of Room Air Conditioners [5]



[5] -Association of Home Appliance Manufacturers data. 2007 and 2008 are forecasts.

ECONOMIC DRIVERS OF THE COMMERCIAL SECTOR

The key economic driver for the commercial sector's energy demand is the square footage needed for commercial enterprises. In modeling this sector, the space requirement of thousands of business activities was calculated and aggregated into 17 different building types.

Methodology in Estimating Commercial Floor Space Requirements

The key driver for the commercial sector is the stock square footage required to conduct business activities in designated building types. To calculate this square footage, a simple model was developed that uses the number of employees per business activity and median square footage per building type. The following analytic steps were taken:

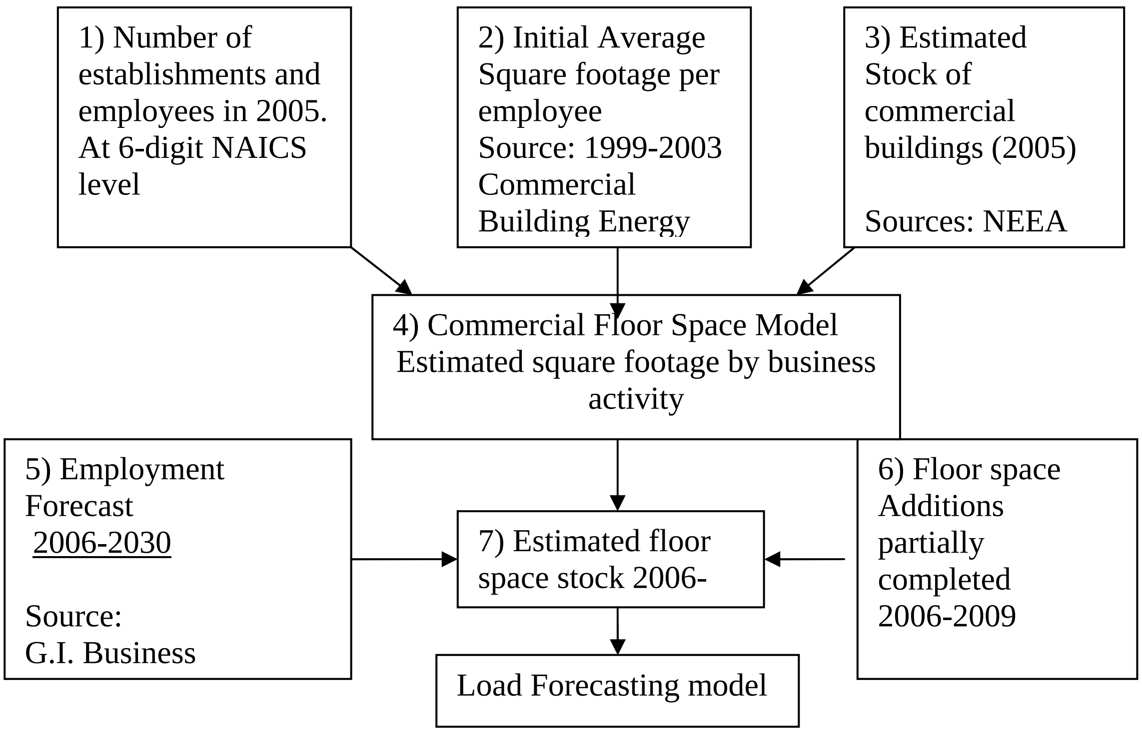
1. The number of establishments[6] and employees in 2005 (at 6-digit NAICS[7] code level) was obtained from the Bureau of Labor Statistics. This enabled a detailed investigation of the type of business activities and the number of employees for each business type. Each business activity was assigned one of the 17 commercial building types used in load forecasting and conservation assessment.
2. The median square footage per main-shift employees (the hours of 8 a.m.-5 p.m.) for various business activities reported as part of Commercial Building Energy Consumption Surveys (CBEC) was obtained from the Department of Energy.
3. CBEC micro data (individual site data) for 1992-2003 for more than 21,000 buildings was used to calculate the median square footage per employee and the number of hours of operation for various establishments.
4. The percent of "major" occupation categories engaged in a business activity (at 4-digit NAICS) was obtained from the Bureau of Labor Statistics. http:/stat.bls.gov/oes/home.htm
5. An estimate of existing floor space stock and the demolition rate by building type was obtained from the Commercial Building Stock Analysis (NEEA 2004).
6. Floor space additions for each building type for 2002-2005 was obtained from F.W. Dodge and used to augment the 2001 building floor space stock to create an assessment of the existing floor space in 2005. This floor space stock was reduced by calculated demolitions during 2002-2005.
7. An initial estimate of 2005 square footage requirements for each business activity was estimated using the following factors:
    a. The assigned building type
    b. Median square footage per employee
    c. Number of employees
    d. Percent of business activity engaged in an occupation
8. The estimated 2005 floor space stock for each business activity was adjusted so that the total square footage for that building type is close to the benchmark floor space stock in 2005.

[6] Establishment - A single physical location where business is conducted or where services or industrial operations are performed.

[7] NAICS - North American Industrial Classification System

9. Future floor space requirements were forecast by applying the annual growth rate in employment in each business activity to Global Insight's forecast (at state, and 4-digit NAICS code level), and to the 2005 floor space requirements for that business activity.
10. For each year, the new floor space requirements across business activities were aggregated by building type, and for each building type, a portion of floor stock is estimated to be demolished.
11. To capture the construction projects that are partially complete for 2006-2009, the Council replaced its model's estimate for the square footage additions with those reported by F.W. Dodge for construction projects in the pipeline.
12. For years 2006-2030, the estimated commercial floor space stock is fed into the demand forecasting model.

Figure B-15: Analytic Steps in Forecasting Floor Space for Each State



The Northwest Energy Efficiency Alliance's (NEEA) market research report[8] estimated that in 2001 the total commercial floor space in the Pacific Northwest was 2.4 billion square feet. Taking these estimates, and the new floor space additions for 2001-2005 from F.W. Dodge, staff estimated the commercial building stock in the region to be about 2.7 billion square feet in 2005. Roughly 300 million square feet were added between 2001 and 2005 and an estimated 60 million square feet were demolished.

[8] "Assessment of the Commercial Building Stock in the Pacific Northwest" March 2004,

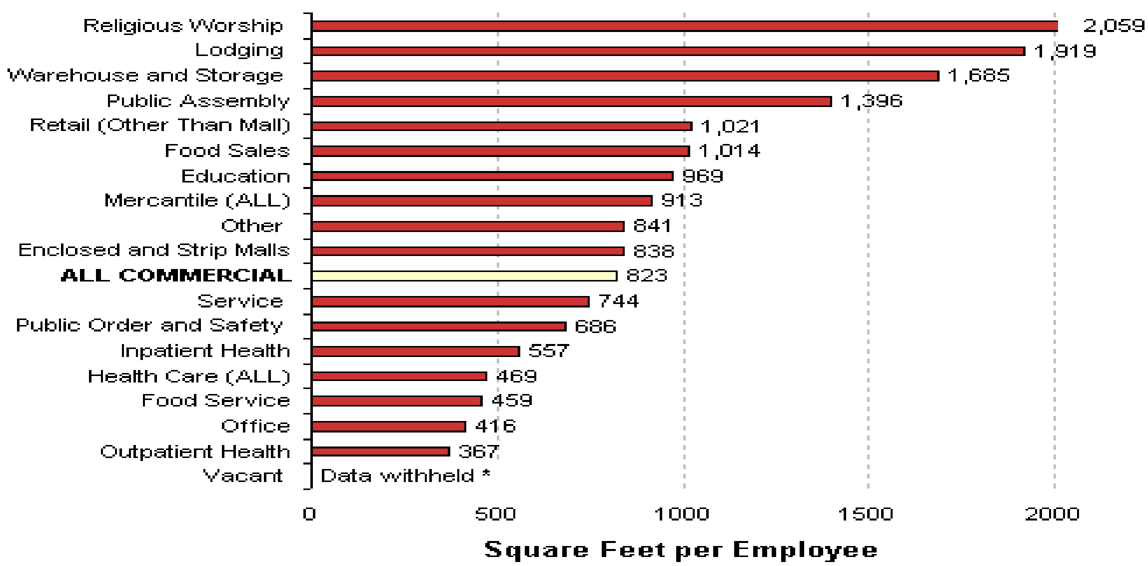
Table B-9: 2005 Commercial Building Stock (1,000,000 SQF)

	Idaho	Montana	Oregon	Washington	Total
Office (3 types)	27	34	104	340	504
Retail (4 types)	29	25	156	289	500
K-12	26	21	38	152	237
University	13	8	20	77	118
Hotel	16	25	52	69	162
Hospital	7	5	20	37	68
Hospital Other (Elder Care)	17	10	32	75	133
Restaurant	3	4	15	25	48
Grocery	8	6	9	32	55
Grocery Other	3	2	4	13	22
Warehouse	26	19	131	156	331
Assembly	17	11	43	130	202
Other	36	21	82	251	391
Total	230	192	705	1,645	2,772

Square Footage Per Employee

Using the Department of Energy's Commercial Building Energy Consumption survey data (micro-data from a national survey of over 21,000 commercial buildings surveyed between 1992 and 2003), we estimate the median square footage per employee for various business activities. A graphic example of the initial square footage per employee used in the model (from CBECS 1999) is shown here.

Figure B-16: Median square footage per employee



Note: "Mercantile (ALL)" includes both "Retail (Other Than Mall)" and "Enclosed and Strip Malls"; "Health Care (ALL)" includes both "Inpatient Health" and "Outpatient Health".
* Relative Standard Error (RSE) greater than 50 percent or fewer than 20 buildings sampled.
Source: Energy Information Administration, 1999 Commercial Buildings Energy Consumption Survey.

Calibration to Benchmark Year Stock

The floor space estimates were then compared with the actual floor space figures by state and building type for 2005. The 2001 commercial building stock assessment had categorized a large portion of the building stock, nearly 20 percent, to the "other" category. To better understand the nature of this category of buildings, a detailed model was developed to estimate floor space requirements for various business activities. Through this analysis, the amount of floor space that was designated as “other” was reduced and assigned to the appropriate floor space types for “office,” “warehouse,” or “assembly.” This enables us to have a better estimate of the conservation potential of these commercial enterprises and the demand forecast for the region.

Table B-10 shows the estimated share of building stock before and after the detailed analysis of business activities. Other building types now represent about 5 percent of building stock. An increase in the share of office, warehouse, and assembly buildings can be observed.

Table B-10: Percent of Commercial Floor Space by Building Type

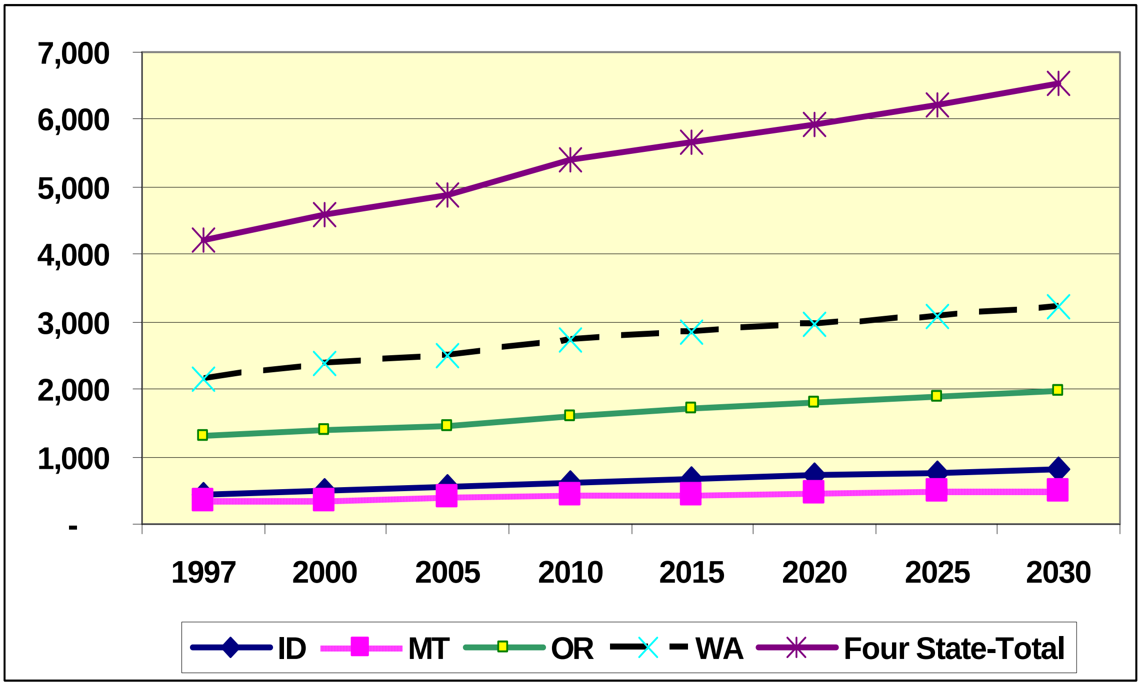
	Initial Market Segmentation	Final Market Segmentation
Office	18.2%	24.1%
Retail	18.0%	18.1%
Hospital	2.5%	2.5%
Hospital Other	4.8%	4.8%
Hotel	5.9%	6.3%
Restaurant	1.7%	1.8%
Grocery	2.0%	2.0%
Grocery Other	0.8%	0.8%
K-12	8.6%	8.9%
University	4.3%	4.4%
Warehouse	11.9%	12.0%
Assembly	7.3%	9.2%
Other	14.1%	5.1%

Other sources of information used for verifying the results of the analysis were the grocery and supermarket data that NEEA had purchased. This data confirmed that grocery store square footage developed by our model was within 2 percent of actual floor space data.

Forecasting Commercial Floor Space Requirements

A model forecasting the square footage requirements of the commercial sector was developed and calibrated to the known square footage data for 2005. Then, using Global Insight’s business demographic forecast of employment, the Council was able to forecast the square footage requirement for commercial buildings. The following figures show the historic and forecast commercial employment totals in the region, and then broken down by major business activity. Between 2010 and 2030, the overall commercial employment is expected to grow at an annual rate of 1.1 percent, with total commercial employment growing from 5.1 million in 2007 to about 6.5 million by 2030.

Figure B-17: Commercial Employment Projection (thousands)



Changing Composition of Commercial Sector

The employment market share of business activities in the commercial sector has not been constant. Over the past 10 years, some business sectors have increased their market share, while other sectors experienced a declining market share. For example, businesses engaged in health care, information technologies, professional and technical services, and wholesale trade services have increased their market share, while government and retail trade have reduced their market share. The historic and forecast trends are presented in the following table.

Table B-11: Percent Market Share of Employment

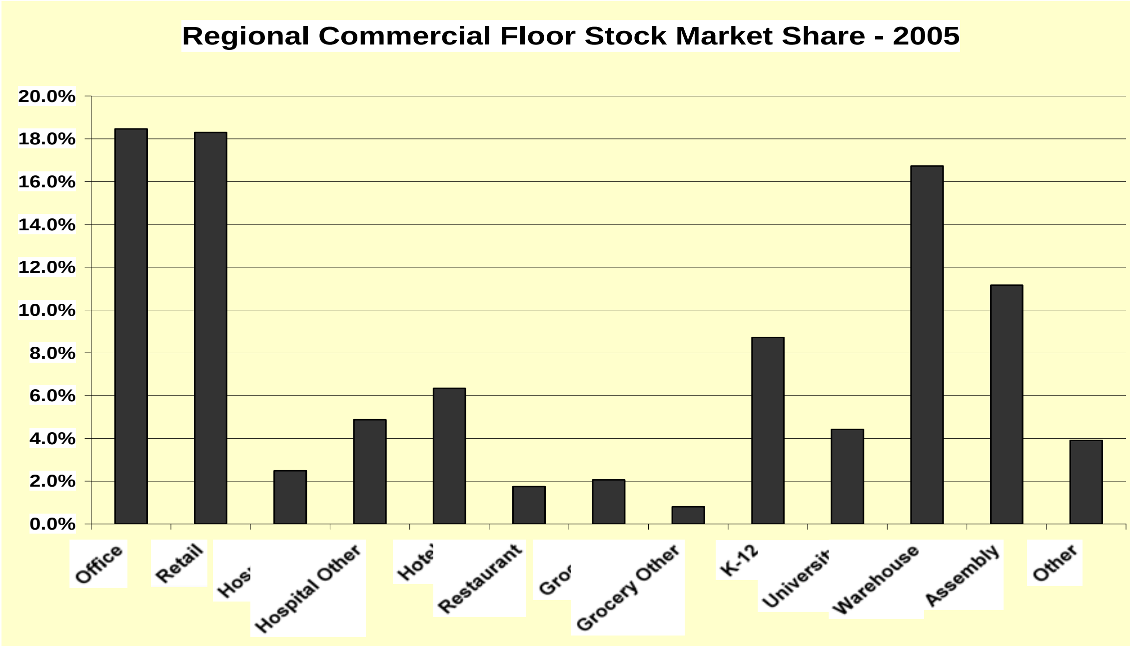
	1997	2007	2030
Businesses with Increasing Employment Market Share			
Health Care and Social Assistance	10.8	11.7	12.5
Administrative and Support and Waste Management	5.4	6.1	9.7
Information	2.9	3.1	3.7
Construction	6.4	7.4	7.8
Professional, Scientific, and Technical Services	5.1	5.5	7.4
Wholesale Trade	5.5	5.0	5.4
Businesses with Declining or stable Market Share			
Government Employees	21.3	20.0	18.0
Retail Trade	13.8	13.1	10.7
Accommodation and Food Services	9.6	9.4	7.8
Transportation and Warehousing	3.9	3.4	3.5
Other Services (except Public Administration)	4.4	3.9	3.5
Finance and Insurance	4.0	4.1	3.4
Real Estate and Rental and Leasing	2.2	2.2	1.9
Arts, Entertainment, and Recreation	1.6	1.7	1.7
Educational Services	1.5	1.7	1.6
Management of Companies and Enterprises	1.4	1.4	1.3
Utilities	0.4	0.3	0.2
Total Employment in Commercial Activities (000)	4,222	5,117	6,531

To establish the relationship between floor space requirements and the number of employees, data from the Commercial Building Stock Analysis (NEEA 2004) was used to estimate the existing floor space stock and the demolition rate by building type in 2004. It was then used to estimate the commercial floor space stock in 2005. The following figures show the estimated commercial floor space stock in 2005. These estimates, along with the data on the number of employees, were used to forecast floor space requirements.

Table B-12: Commercial Floor Space Stock 2005 (millions SQF)

Building type	Idaho	Montana	Oregon	Washington	Total
Office	29	36	100	340	505
Retail	29	26	155	290	500
hospital	7	5	20	37	68
Hospital Other	17	9	32	75	133
Hotel	18	27	57	72	173
Restaurant	4	5	15	24	48
Grocery	8	6	10	32	56
Mini Marts	3	2	4	13	22
K-12	27	21	38	152	238
University	13	9	20	78	121
Warehouse	35	21	131	272	457
Assembly	25	31	95	155	305
Other	11	9	31	56	107
Total	225	207	708	1,596	2,735

Figure B-18: Regional Commercial Floor Stock Market Share (2005)



The floor space stock in each year is the sum of new floor space additions and retirements from the floor space in that year. The forecast for floor space additions for each state and the region is shown in the following figure. The Council's Sixth Power Plan forecasts about 900 million square feet of new floor space. A large portion of this will be in warehouse space, office space, K-12 schools, and elder care facilities.

Table B-13: 2010-2030 New Commercial Floor Space Additions (millions of SQF)

	Idaho	Montana	Oregon	Washington	Region
Large Off	6.87	5.63	17.38	64.12	94.00
Medium Off	3.10	2.54	7.83	28.89	42.35
Small Off	3.63	2.97	9.19	33.90	49.69
Big Box-Retail	2.11	1.37	8.46	10.13	22.06
Small Box-Retail	3.89	2.53	15.62	18.70	40.75
High End-Retail	0.97	0.63	3.91	4.68	10.19
Anchor-Retail	1.88	1.22	7.54	9.03	19.67
K-12	6.62	4.73	6.71	34.33	52.39
University	3.99	1.62	4.98	20.18	30.78
Warehouse	24.61	8.33	65.04	177.32	275.30
Supermarket	0.89	0.52	1.05	3.03	5.48
Mini Mart	1.20	0.33	0.55	2.51	4.59
Restaurant	2.06	1.31	4.48	6.55	14.40
Lodging	3.96	1.86	7.02	9.38	22.23
Hospital	2.50	0.84	5.50	7.73	16.57
Other Health*	10.06	4.40	11.06	39.17	64.68
Assembly	21.30	8.44	31.60	31.45	92.79
Other	8.42	6.35	17.56	23.37	55.70
Total	108.05	55.63	225.47	524.46	913.61

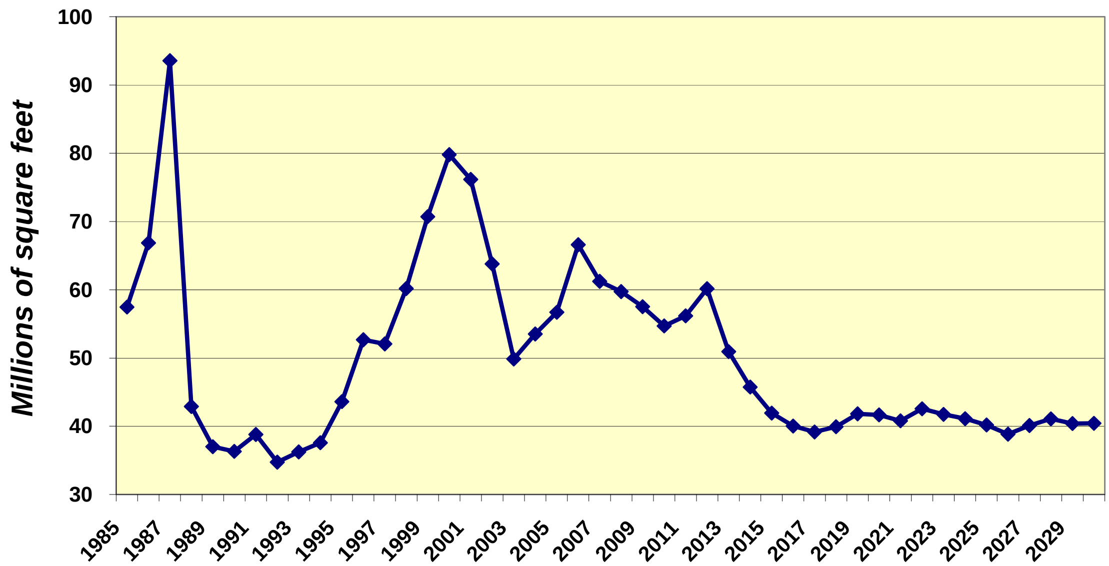
*- elder care facilities

Commercial Floor Space Additions

The overall pattern of floor space additions for the commercial sector is presented in the following graph. A quick review of the historic data shows the cyclical nature of commercial floor space additions. The sharp increase in late 1980s is followed by a significant slow down in the early 1990s. The late 1990s indicate a sharp increase in new construction activities. The 2000-2002 recession slowed construction activities. In 2005, another wave of commercial construction took place. Due to the long construction time for commercial activities, it would typically take a year or two for construction activities to reflect the economy. The slow down in construction activities due to the current recession would be reflected in the level of new commercial construction activities after a few years. The current forecast indicates that it would be at least 2011-2012 before commercial construction activities increase.

The long-term forecast projects a slow down in floor space additions, from 60 million square feet per year to about 40 million square feet. The forecast for future floor space additions does not show a wide swing in construction activities in the sector. However, there are different patterns of floor space additions, depending on the building category.

Figure B-19: Total Commercial Floor Space Additions (Northwest Region)

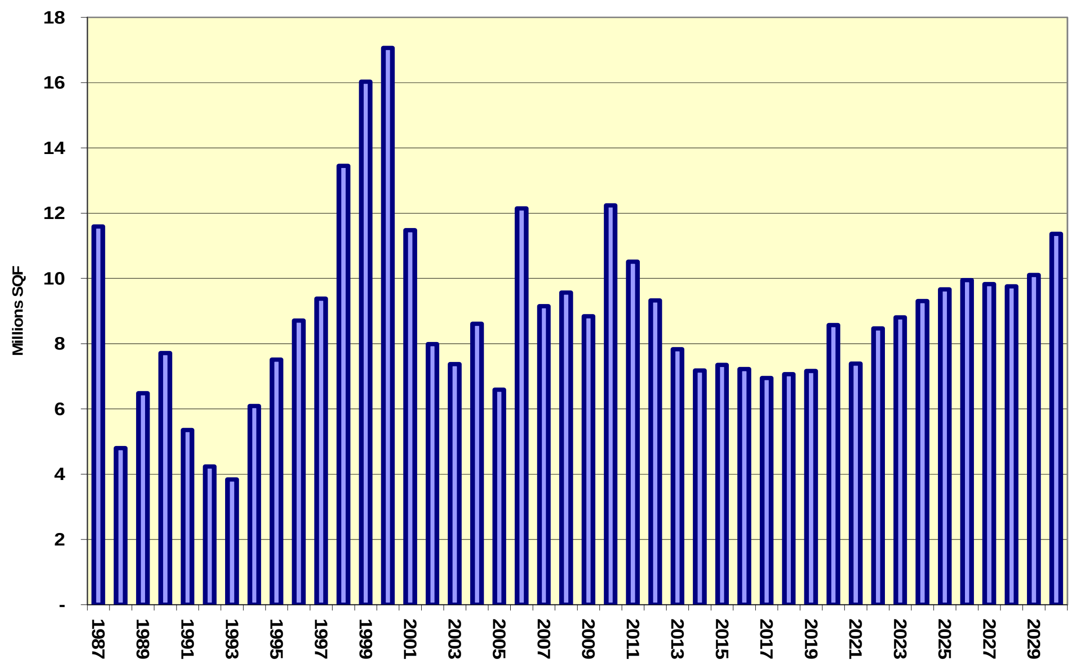


Patterns of Commercial Floor Space Additions

Commercial floor space additions typically show a cyclical pattern of overbuilding followed by high occupancy and demand for more space. This is especially true for the more speculative building types such as office or retail. A brief review of commercial floor space additions for 1987-2030 shows the different patterns of floor space additions for office, retail, warehouse, K-12 schools, and elder care facilities. An increase in office space additions, declining retail space requirements, substantial increases in new warehouse space, and declining K-12 school floor space requirements are forecast.

Office space requirements suggest a decline in new office space additions for 2012-2014, followed by a stable period from 2015-2019. Starting with 2020, the Council forecasts an escalation of commercial office construction activities.

Figure B-20: Pattern of Office Space Addition



A decrease in retail floor space requirements and new retail space additions are expected to decline over the forecast period. This decrease reflects slower population growth and the move to e-commerce. Retail space additions peaked in 2005-2006. In the 2010-2030 period, retail commercial floor space is forecast to average around 4 million square feet per year.

A decrease in retail space requirement is off-set by an increase in demand for warehouse space. The increase in warehouse space reflects the expanding market for e-commerce.

Figure B-21: Pattern of Retail Space Addition

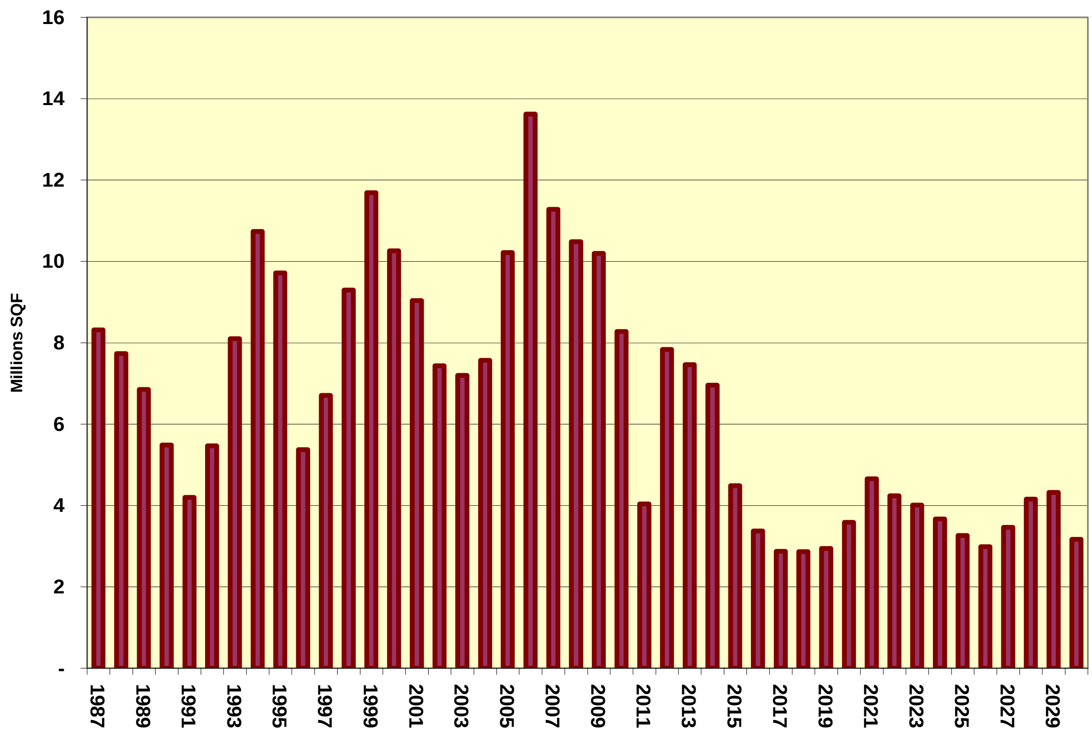
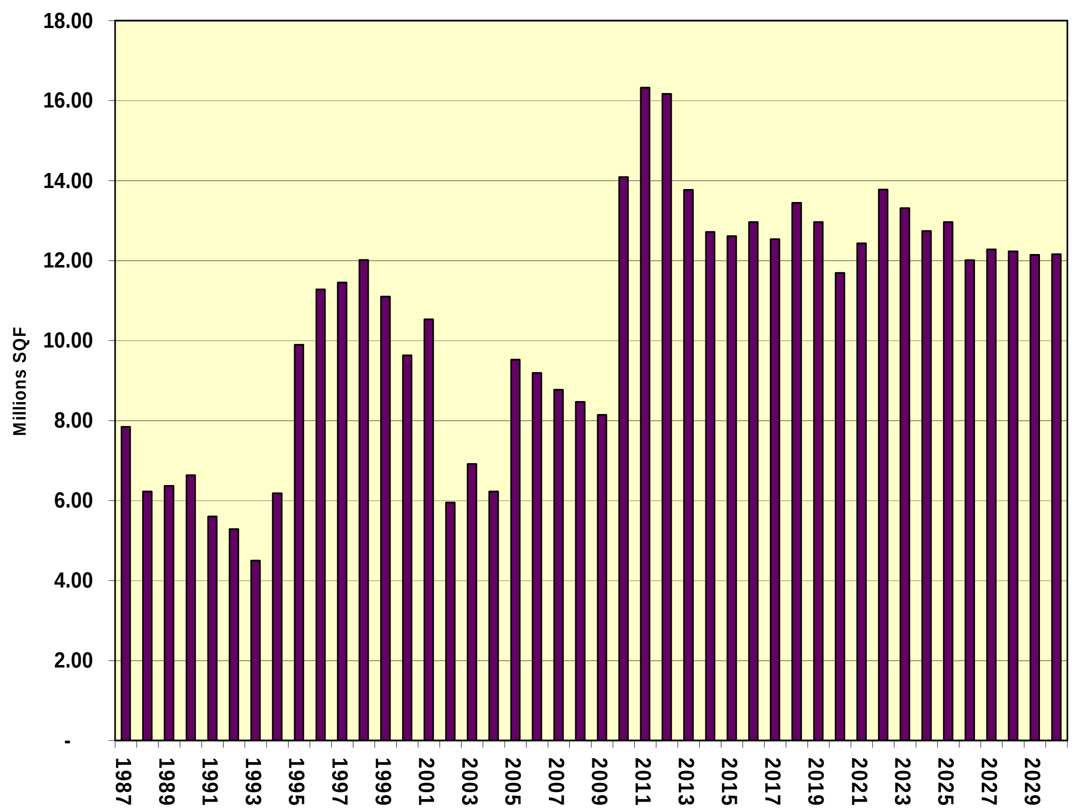
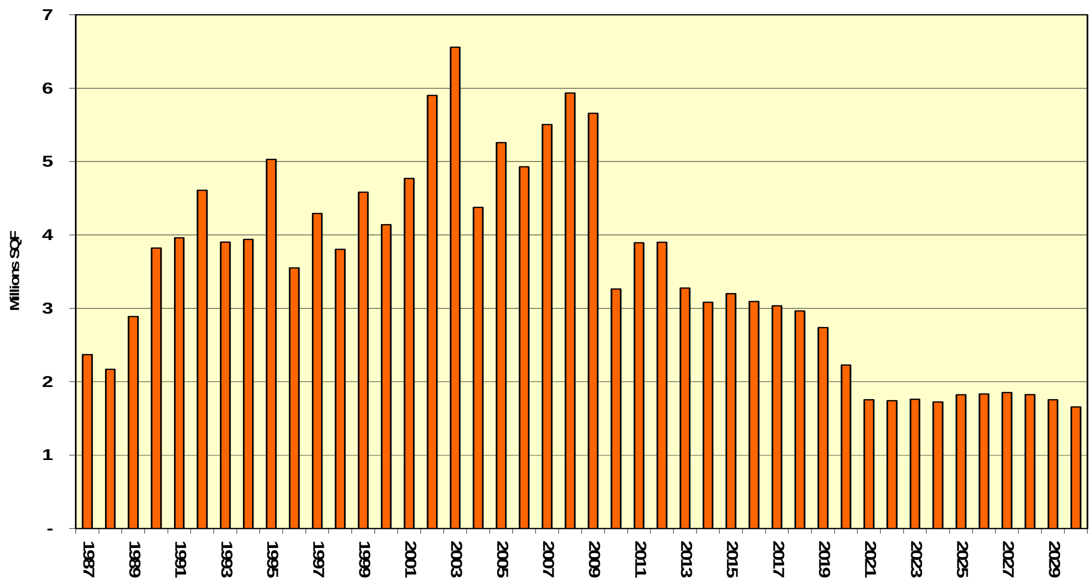


Figure B-22: Pattern of Warehouse Floor Space Addition



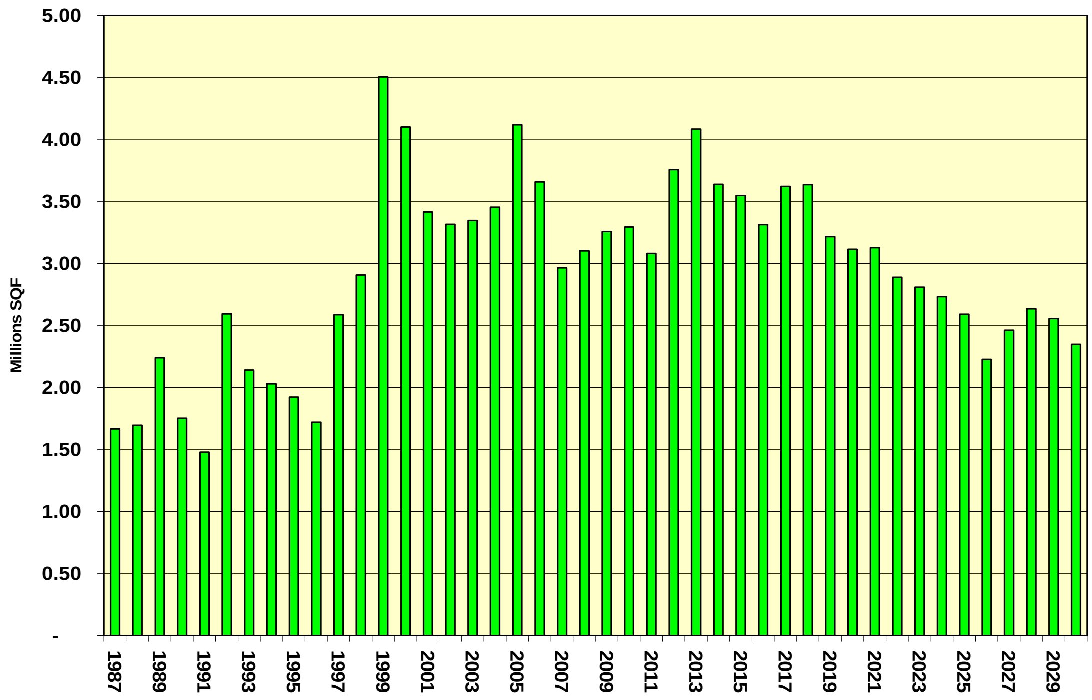
The demand for the schools and elder care are driven by the demographic changes facing the region. Population in the region is growing at a slower rate and a larger population is at retirement age. The pattern of floor space additions for K-12 schools reflects the declining share of the under 19 population. Between 1985 and 2007, the regional population of this age group increased by 666,000. But between 2010 and 2030, this population group is forecast to grow by about 540,000 people. The floor space requirement forecast for K-12 schools is expected to decline in two steps. From 2011-2018 the forecast for floor space additions is for about 3-4 million square feet per year. From 2020-2030, the forecast goes down to less than 2 million square feet per year.

Figure B-23: Pattern of Floor Space Addition for K-12 Schools



The elderly population, 65 and older, is increasing from about one million in 1985 to about 1.5 million in 2007, and to over 3 million by 2030. This more than doubling of population is forecast to increase the demand for special elder care facilities. In the 2011-2018 period, new floor space for these facilities is forecast to increase by about 3.5-4.0 million square feet per year. After 2020, the forecast for new floor space drops to 2.5 to 3.0 million square feet per year.

Figure B-24: Pattern of Floor Space Addition for Elder Care Facilities



Commercial Floor Space Stock

Commercial floor space stock is projected to increase from 2.9 billion square feet to about 3.9 billion square feet over the 2007-2030 period. Sectors showing the greatest increase in floor space additions are large office, warehouse, and other health (elder care) facilities. Warehouse floor space shown here does not include self-storage facilities or warehouses associated with manufacturing facilities.

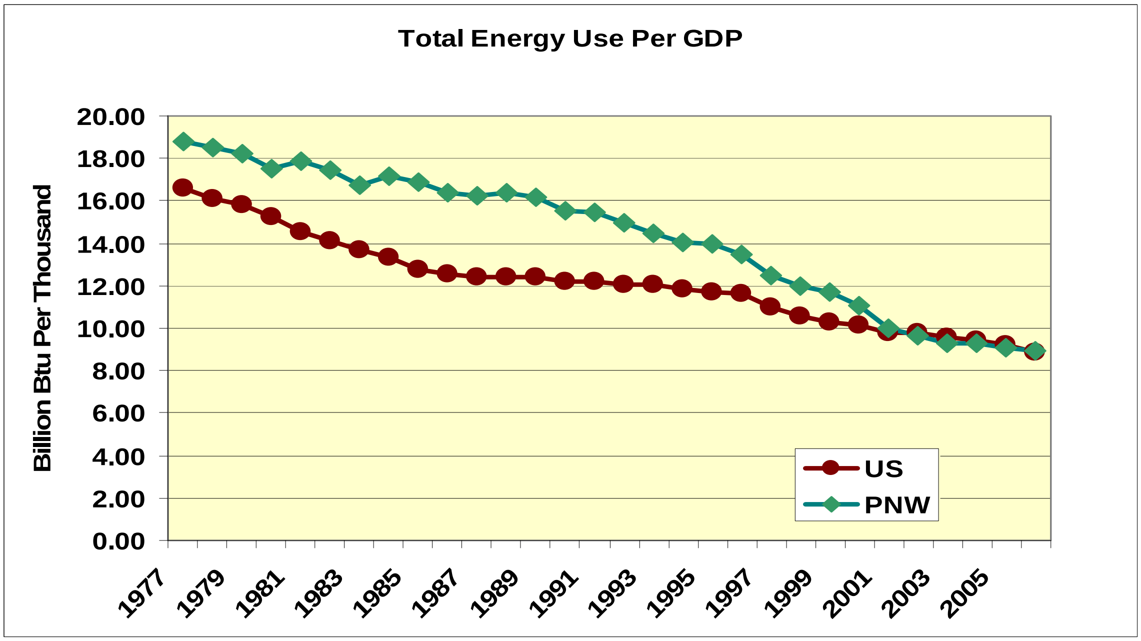
Table B-14: Regional Commercial Floor Space Stock (millions sqf)

Regional Summary	1985	2007	2015	2020	2030	2007-2030 Addition	Market share 2007-2030
Large Office	190	266	303	321	369	103	10%
Medium Office	49	120	136	145	166	46	4%
Small Office	90	141	160	170	195	54	5%
Big Box-Retail	20	125	139	143	152	27	3%
Small Box-Retail	171	231	257	264	280	49	5%
High End-Retail	44	58	64	66	70	12	1%
Anchor-Retail	98	111	124	127	135	24	2%
K-12	155	248	280	294	312	64	6%
University	77	123	139	147	159	36	4%
Warehouse	170	349	452	515	641	292	28%
Supermarket	43	55	57	58	60	5	0%
Mini Marts	5	22	24	25	27	5	0%
Restaurant	36	48	55	58	63	15	1%
Lodging	116	169	184	188	196	27	3%
Hospital	39	67	77	81	87	20	2%
Other Health (Elder Care)	85	144	172	188	215	71	7%
Assembly	123	211	252	272	312	101	10%
Other	240	420	457	471	496	76	7%
Total	1,751	2,908	3,332	3,533	3,935	1027	100%

ECONOMIC DRIVERS FOR INDUSTRIAL SECTOR DEMAND

Demand for energy in the industrial sector is driven by the demand for goods and products produced in the region. Historically, demand for electricity in the industrial sector was dominated by a few large energy-intensive industries. However, the regional mix of industries has been changing toward less electricity and energy-intensive industries, and the region's industries now resemble the rest of the country. The following figure tracks total energy use per dollar of GDP (constant dollars) for the nation and the Northwest. Since 1960, there has been a trend toward less energy use in this sector. During the 1980s and 1990s, industries in the Northwest used significantly more energy for every dollar of output they produced. Since 2002, however, the intensity of energy use for both the region and nation has been identical.

Figure B-25: Change in National and Regional Energy Intensity



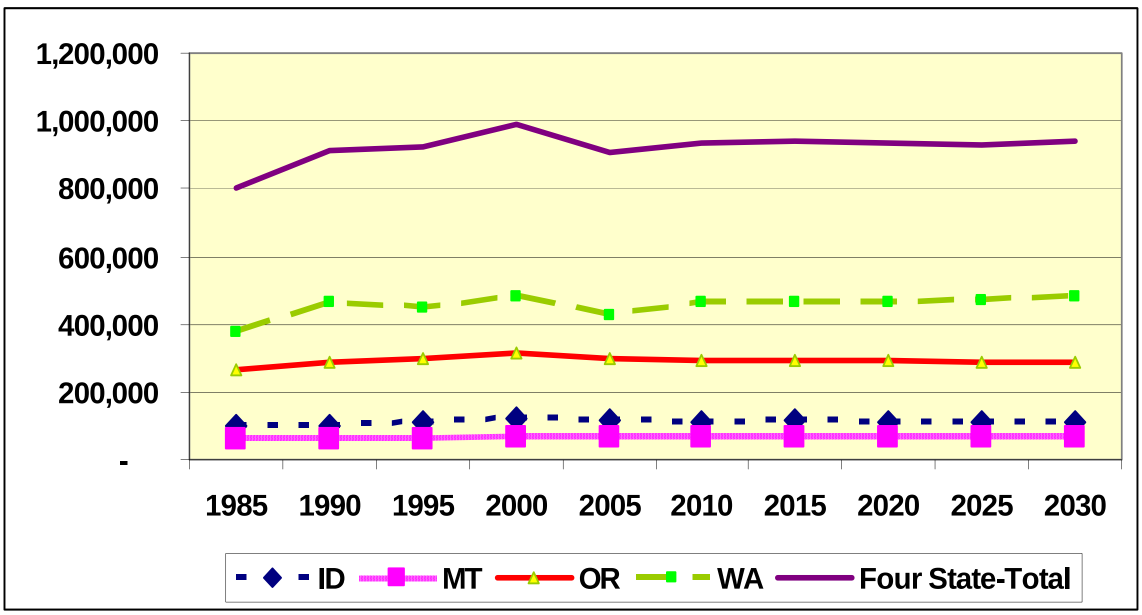
Projected Employment Growth

The demand forecast model tracks 21 distinct industries. The demand for energy consumed in each industry is forecast using the estimated growth in the product output in that industry. Output in each industry is forecast based on the projected employment in the industry and the average productivity of employees. Productivity is measured in terms of dollars of output per number of employees. Industrial employment has been on the decline, but that decline is projected to slow. The following figure shows the number of industrial employees for 2000, 2002, 2007, and 2030. Industrial employment peaked at about 730,000 in 2000, but it declined significantly during the 2000-2002 period to about 650,000. Industrial employment has been growing slowly; by 2007 it reached 650,000, and by 2030 it is forecast to go slightly above the year 2000 employment level. The composition of industrial employment is also forecast to change: lumber, apparel, rubber, and transportation industries are projected to lose employment, while food, fabricated metals, and printing industries are forecast to experience an increase in employment. In total, industrial employment is forecast to grow at an average annual rate of 0.3 percent per year for the 2007-2030 period.

Table B-15: Number of Industrial Employment

Industry	2000	2002	2007	2030	2007-2030 Change
Food & Tobacco	91,458	87,078	87,184	91,119	3,935
Lumber	77,229	68,820	69,190	59,211	(9,978)
Paper	25,091	22,513	20,622	21,520	897
Textiles	5,853	5,119	4,351	4,594	243
Apparel	7,610	6,413	6,259	3,067	(3,193)
Leather	1,518	1,591	1,570	420	(1,151)
Furniture	23,065	21,074	23,756	33,267	9,511
Printing	103,422	98,275	111,067	174,656	63,589
Chemicals	14,002	13,140	13,618	14,077	459
Fabricated Metals	45,474	40,124	47,439	57,990	10,552
Petroleum Products	3,785	4,079	3,979	3,059	(920)
Rubber	20,846	18,584	19,920	14,951	(4,969)
Stone, Clay, etc.	18,283	17,116	20,596	23,381	2,784
Machines & Computer	139,945	119,982	116,760	110,113	(6,648)
Transport Equipment	112,824	93,113	98,204	64,236	(33,968)
Electric Equipment	8,381	7,238	8,851	11,043	2,192
Other Manufacturing	30,197	29,628	32,259	48,695	16,436
Total	728,983	653,887	685,625	735,398	49,773

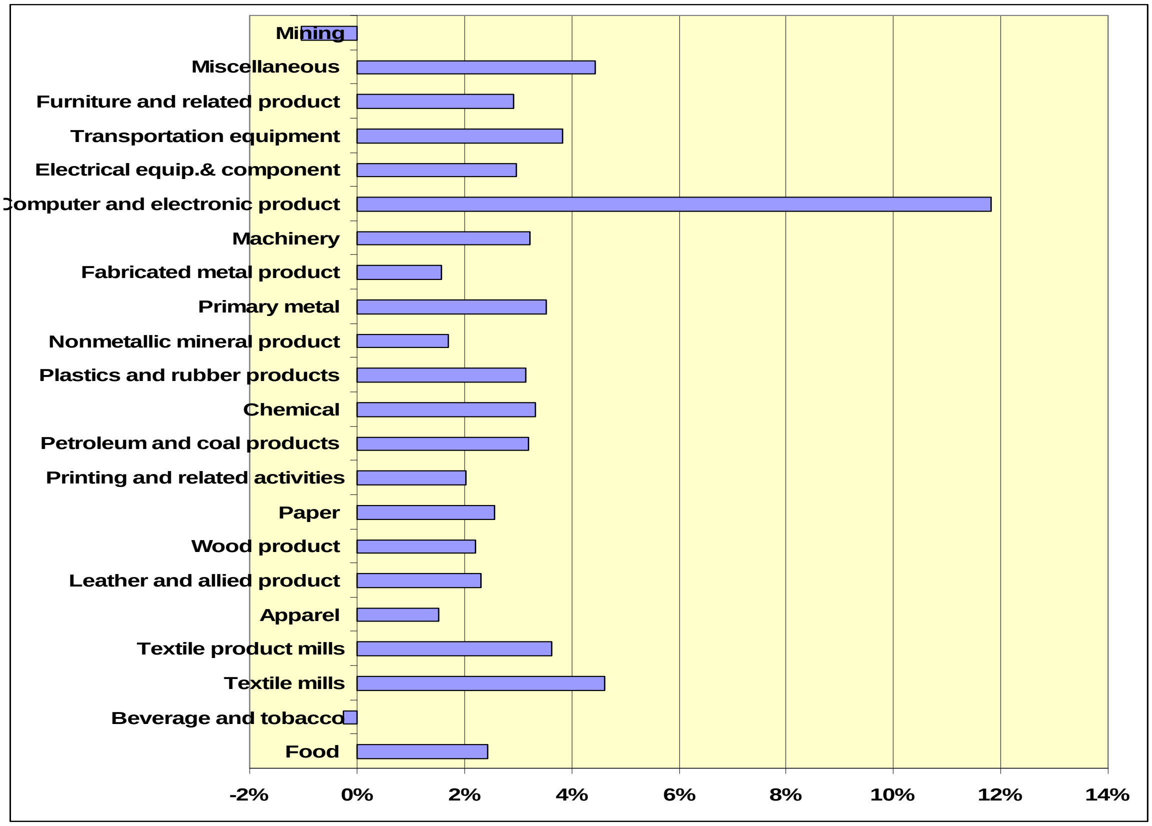
Figure B-26: Employment in Manufacturing Sectors (number)



Industrial Output

Industrial output is calculated using industrial employment and output per employee (defined as productivity). The U.S. Bureau of Labor Statistics tracks labor productivity, measured as dollars of output (constant dollars) per unit of labor. The following figure shows the labor productivity index. In most industries, gains in labor productivity have been in excess of 2 percent, with some industries, such as machines and computers, exceeding 10 percent per year. In this analysis, long-term productivity in the manufacturing of machines and computers was capped to 3 percent, reflecting the productivity of a matured industry.

Figure B-27: National Growth Rate of Labor Productivity 1997-2005



It should be noted that if information on regional labor productivity were available, it would have been used in this analysis. Also, it should be noted that Council staff is currently reviewing a recently completed bottom-up industrial analysis, and the finding from that analysis will be incorporated in the final Sixth Power Plan.

The following table shows the dollar value of industrial output, which drives demand for this sector.

Table B-16: Regional Industrial Output (billions of $2000)

	1985	2007	2015	2020	2030
Food & Tobacco	4.15	5.20	6.31	7.19	8.65
Textiles	0.07	0.21	0.28	0.38	0.65
Apparel	0.23	0.16	0.15	0.14	0.12
Lumber	9.79	4.52	5.94	6.09	6.11
Furniture	0.27	1.19	1.69	2.13	3.30
Paper	2.76	3.08	4.00	4.78	6.38
Printing	2.44	1.25	1.65	1.95	2.90
Chemicals	1.42	1.58	2.01	2.39	3.15
Petroleum Products	0.55	1.39	1.62	1.80	1.97
Rubber	0.27	1.44	1.70	1.89	2.12
Leather	0.04	0.05	0.04	0.04	0.02
Stone, Clay, etc.	0.53	1.79	2.18	2.48	3.21
Aluminum	0.32	0.45	0.54	0.64	0.97
Fabricated Metals	1.20	3.46	4.55	5.25	6.62
Machines & Computer	2.43	42.62	47.70	55.46	74.41
Electric Equipment	0.36	0.95	1.32	1.62	2.36
Transport Equipment	6.32	11.81	15.30	16.20	18.53
Other Manufacturing	0.38	1.92	3.03	4.02	7.17
Agriculture	4.93	12.80	16.64	19.83	27.62

Two other sectors are included in the industrial demand for electricity: custom data centers and direct service industries. The demand for electricity from direct service industries is based on projections provided in the BPA White Book 2008 and data from the Chelan Public Utility District. Detailed discussions on the methodology and forecast for both custom data centers and direct service industries are in the demand forecast appendix C.

ECONOMIC DRIVERS FOR OTHER SECTORS

Irrigation

Demand for electricity for irrigation is linked to agricultural output. A forecast of agricultural output in constant dollars is provided in a state forecast conducted in October, 2008, by Global Insight. Agricultural output in the region is forecast to increase from about $13 billion in 2007 to about $20 billion in 2020, and about $28 billion by 2030.

Transportation

In the current analysis, demand for electricity in the transportation sector is limited to public transportation, such as the Tri-met transportation system or electric buses. The economic driver for this mode of transportation is personal income in the region. The regional income is forecast to grow at an annual rate of 2.9 percent per year, from $399 billion dollars (2000 constant dollars) in 2007 to $763 billion dollars (2000 constant dollars) in 2030.

As part of the sensitivity analysis, the Council will estimate the demand for electricity from plug-in hybrid electric vehicles (PHEV). The key economic driver for the demand for PHEV is the forecast demand for new vehicles, a percentage of which is assumed to be plug-in hybrids. A forecast of new vehicles is provided by Global Insight's October 2008 regional forecast. The market share of PHEVs will depend on consumer consideration of the PHEV purchase price, available incentives, cost of gasoline, and the price of alternative vehicles. A discussion of demand for plug-in hybrid electric vehicles is in the demand forecast appendix C.

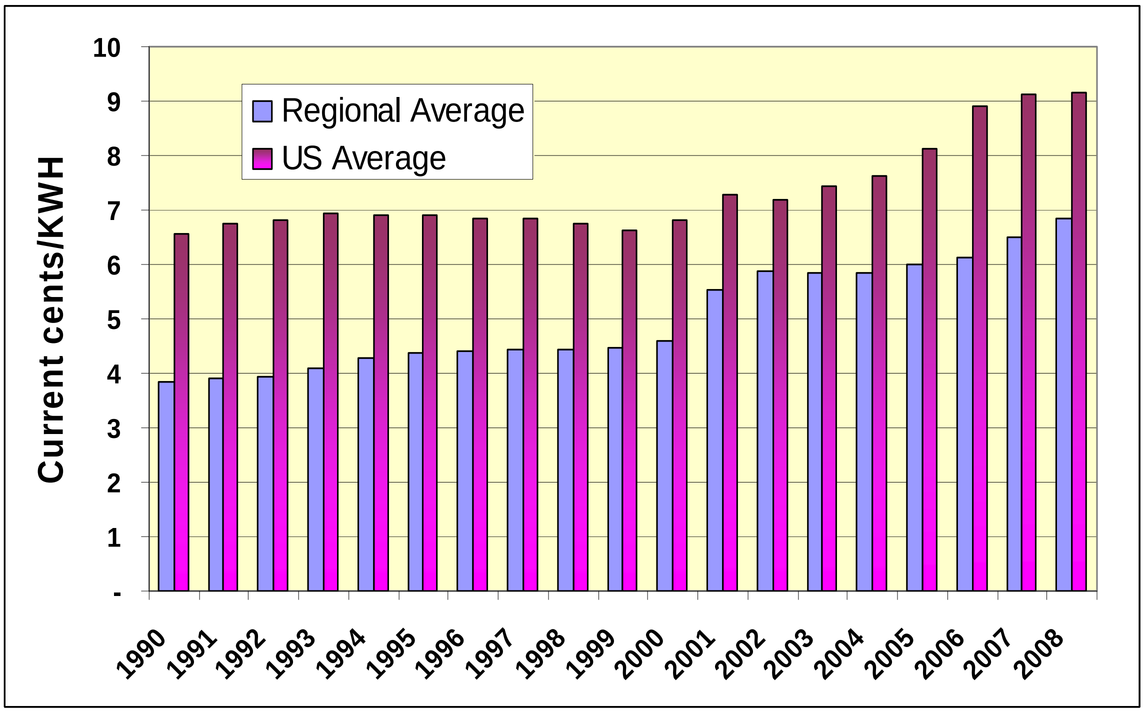
OTHER ASSUMPTIONS

Electricity Prices

Another factor affecting demand for electricity is its price. There are significant differences in electricity prices across the region and among different utilities in the region. To analyze these price differences, the Council used published historic average prices for electricity and other fuel. The average price of electricity is calculated for each sector and each state as the ratio of revenue from the sale of electricity (in megawatt hour sales) to that sector.

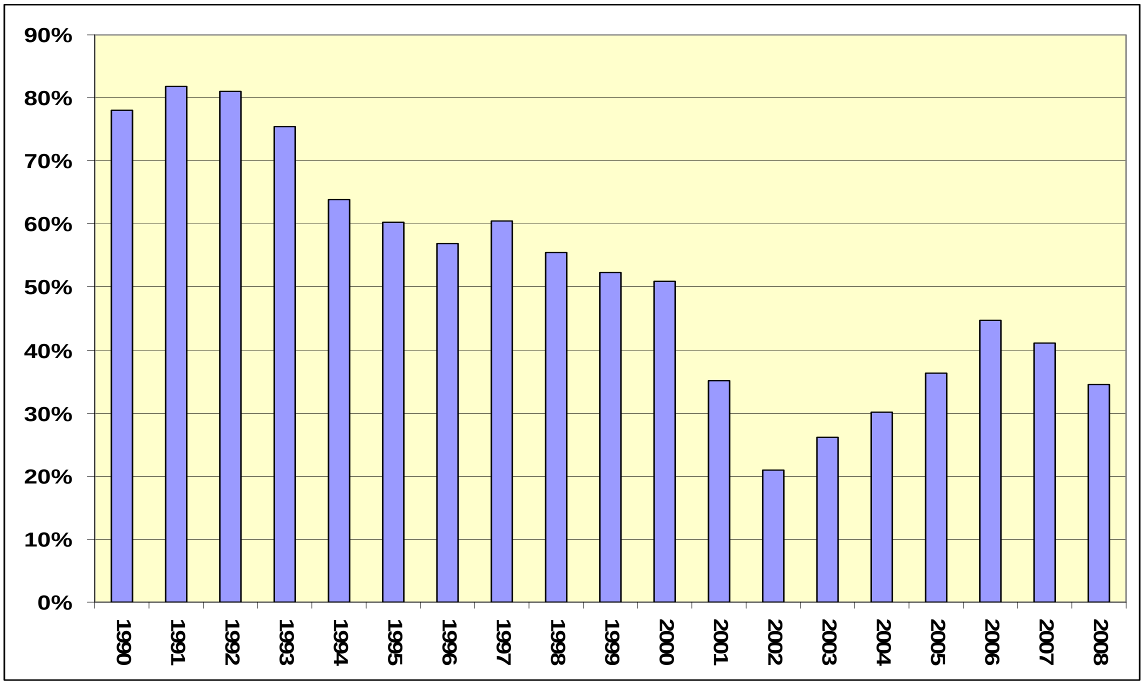
Historically, electricity prices in the Northwest have been lower than the national average. This lower price had attracted more energy-intensive industries to the region. However, since the energy crisis in 2000, the price of electricity has been on the rise both regionally and nationally. In the Northwest, it has been growing at a higher rate compared to the nation.

Figure B-28: Comparison of NW Regional Electricity Price to US Average Price



The average electricity price in the nation was about 50-80 percent higher than the regional average price during the1990-2000 period. The difference between these prices narrowed after the energy crisis of 2000-2001, and the region experienced a dramatic loss of industrial load. However, the difference between regional and national prices is growing again due to the increase in oil and gas prices. The national price of electricity has been increasing at a higher rate than the regional price, resulting in a growing discrepancy between regional and national prices.

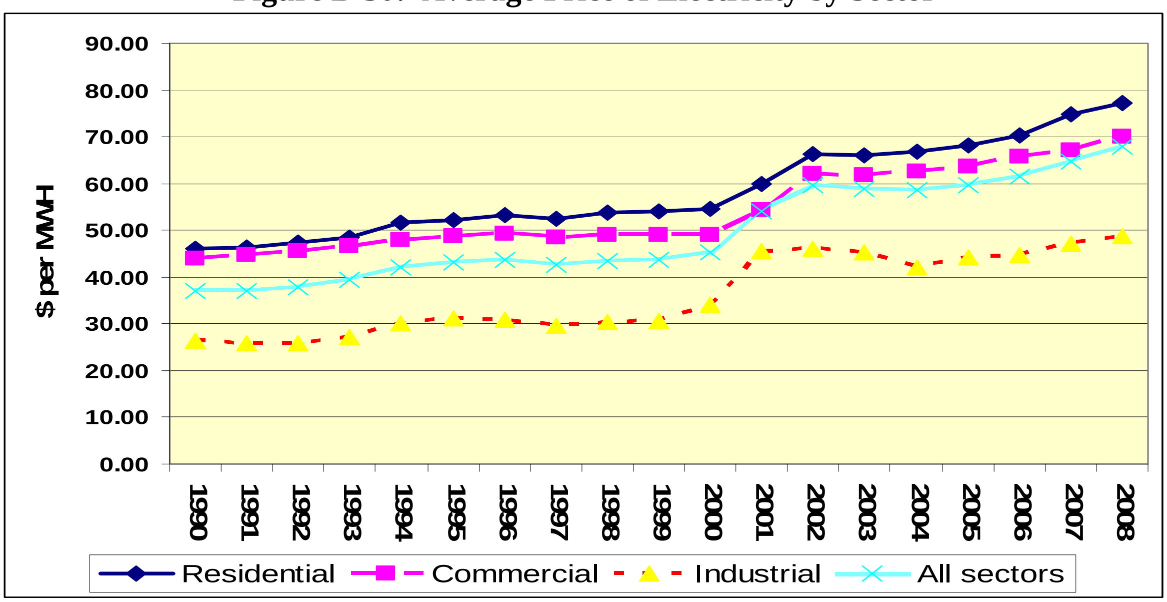
Figure B-29: Difference Between National and Regional Average Price of Electricity



Variations in Price by Sector

The average price of electricity varies across sectors. Typically, residential customers pay a higher price (in part due to higher distribution costs allocated to the residential sector) while commercial and industrial customers typically pay lower rates.

Figure B-30: Average Price of Electricity by Sector



The growth rate of electricity prices across sectors has not been constant over time. During 1990-2000, rate increases were fairly modest. In the late 1990s and early 2000s, the need for new capacity, plus the increase in fuel prices, contributed to an increase in the growth rate of the average price of electricity. During 1990-2000, the nominal price of electricity grew at an average annual rate of 2 percent, with industrial prices growing at a higher rate. Adjusted for inflation, the price of electricity was flat between 1990 and 2000. Since 2000, the growth rate for electricity prices (adjusted for an average inflation rate of 2.5 percent) has been increasing at about twice the inflation rate, growing at an average annual rate of 5.2 percent. The real growth in regional electricity prices was about 3 percent, and nationally around 1.2 percent.

Table B-17: Average Annual Growth Rate in Electricity Prices

Northwest	Residential	Commercial	Industrial	All sectors
1990-2000	1.7	1.1	2.6	2.0
2000-2008	4.4	4.6	4.5	5.2
US				
1990-2000	0.5	0.1	-0.2	0.4
2000-2008	3.2	3.4	4.4	3.7

Forecast of Electricity Prices

Typically, the price of electricity is determined through a regulatory approval process, with utilities bringing a rate proposal to their regulatory body, board of directors or city council, to seek approval of future rates. Rates are dependant on the anticipated cost of serving customers and the level of sales. Sales are determined either for a future period or for a past period. The approved rates should cover the variable *and* fixed-cost components of serving the customers.

The methodology used for forecasting future electricity prices in the Sixth Power Plan is similar to the methodology used for forecasting other fuel prices such as gas, oil, and coal. A fuel price forecast starts with a national or regional base price and then modifies the base price through the addition of delivery charges to calculate regional prices. In forecasting retail electricity prices, a similar approach is used. Starting with a forecast of the wholesale price at the Mid-C, transmission and delivery charges, plus other incremental fixed costs that are not reflected in market clearing, are added. Examples of these incremental fixed costs include the cost of conservation investments or the cost of meeting renewable portfolio standards (RPS).

Electricity Price Estimation Methodology

A three-step process was used to calculate the retail electricity prices for each state.

Step 1: For each state, the average price of electricity in 2007, measured as the average revenue per megawatt hour of sales, is calculated. The 2007 wholesale market price for Mid-C market is calculated. The difference between the average retail price of electricity and the wholesale price at Mid-C is treated as a proxy for transmission and distribution cost additions.

Note that the transmission and distribution charges calculated here are simply proxies for the actual transmission and distribution charges (shown in the following table under the column labeled -Proxy Non-generation costs). At this point, it is assumed that these charges will stay constant in real terms over the forecast horizon.

Table B-18: Components of Retail Rate

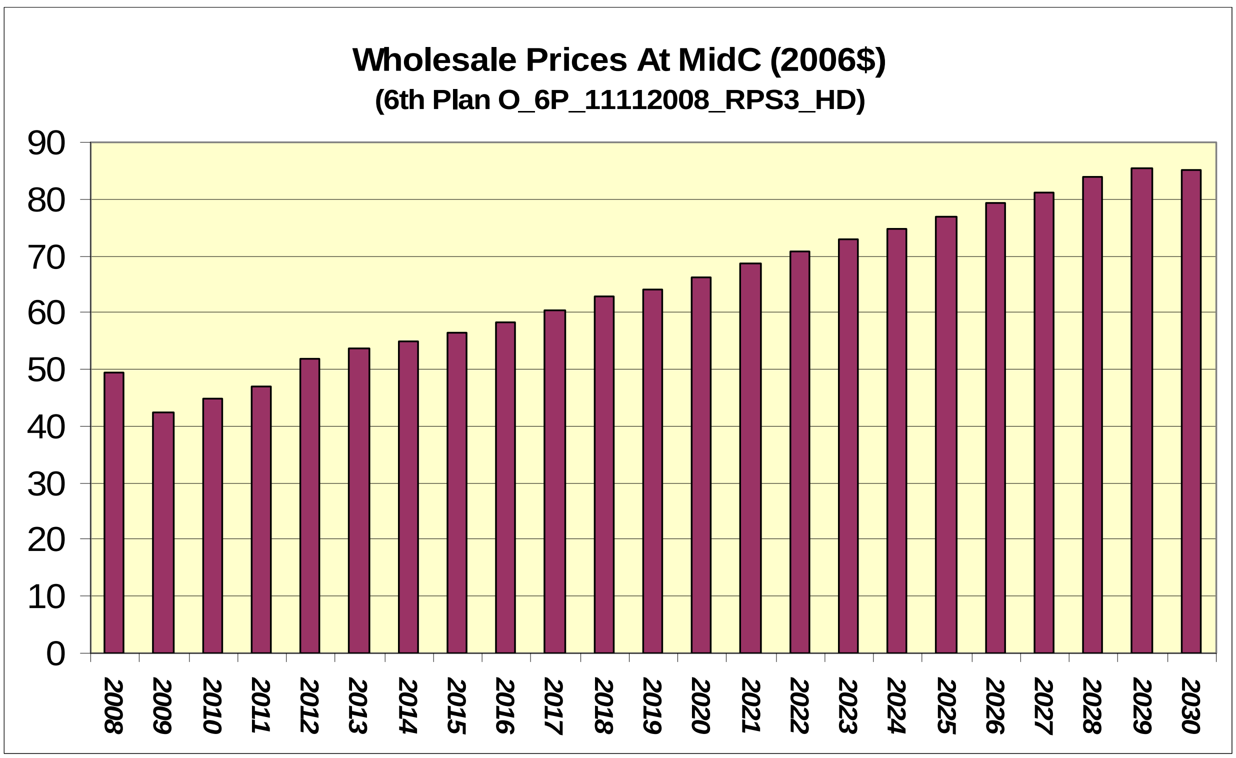
State	Average Retail Price of Electricity 2007 $/MWH	Wholesale Price Forecast for Mid C * 2007 $/MWH	Proxy Non-generation Costs 2007 $/MWH
IDAHO	50.63	45.34	5.03
MONTANA	75.06	45.34	29.46
OREGON	69.96	45.34	24.36
WASHINGTON	64.12	45.34	18.52

*- based on Aurora run 6th Plan 03-13-2008 RPS HCAPTL HD

Step 2: The forecast of wholesale market prices for 2008-2030, derived from the Council's production costing model "AURORA^{xmp}," is used as the base wholesale price for electricity. The AURORA^{xmp} model produces wholesale market clearing prices for a given forecast load and fuel prices, taking into account the operating characteristics of generation plants and the transmission system in the western United States. The AURORA^{xmp} model produces wholesale price forecasts for many markets in the West. For the retail electricity price analysis, the Mid-C wholesale price forecast was selected as the base market hub.

The following graph shows the forecast electricity price at Mid-C for the scenario that is currently used to calculate retail electricity rates. Wholesale prices at Mid-C are projected to grow at an average annual rate of 3.3 percent for the 2010-2030 period. For a more detailed discussion on wholesale price forecast, please see appendix D of the 6th Plan.

Figure B-31: Wholesale Price of Electricity at Mid C



Step 3: Calculate additional costs to meet RPS standards.

RPS targets vary by state. In order to calculate additional electricity rate increases incurred by utilities for added resources to meet RPS targets, it is assumed that the costs of committed RPS resources are already reflected in the rates. Therefore, any additional costs would be due to the new RPS resources.

To estimate new RPS resource requirements, state or utility RPS obligations for a given year are calculated. The RPS obligation is calculated as the load forecast multiplied by the RPS target percent. If the committed RPS is above incremental RPS, no new RPS resources would be built in that year; otherwise, new RPS resources are built.

There are different resource mix options for new RPS resources that need to be built. The following table shows the Council's current assumption on how the uncommitted/new RPS resources are going to be built.

Table B-19: Assumed Market Share of New RPS Resources

	Montana	Oregon	Washington
Biomass	25.0 percent	20.0 percent	20.0 percent
Geothermal		10.0 percent	
Hydro			
Solar Photovoltaic (Load-side)		5.0 percent	5.0 percent
Solar Thermal			
Wind	75 percent	65.0 percent	75.0 percent

Each renewable generation technology has its own set of costs, including transmission and integration costs. At the moment, however, incremental transmission costs are not included in this analysis.

Interaction of RPS and Conservation: Conservation achievements reduce loads, and by reducing a utility's load, a utility's RPS target is likewise reduced. In this analysis, we calculated the rate impact of RPS with *and* without incremental conservation. Preliminary analysis indicates that, given current load forecasts and committed RPS, the region can meet RPS requirements without any new RPS resources in significant amounts until 2012.

Table B-20: Cumulative New RPS Qualifying Resources Needed (MWa)

	Without Conservation			With 200 MWa / Yr Conservation target		
	MT	OR	WA	MT	OR	WA
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0
2010	1	0	0	0	0	0
2011	16	0	0	15	0	0
2012	31	0	0	30	0	0
2013	38	23	6	37	2	0
2014	46	34	144	44	3	108
2015	54	48	324	52	4	272
2016	54	59	490	52	5	419
2017	55	180	662	52	115	568
2018	56	515	839	53	439	720
2019	56	583	1023	53	494	876
2020	57	654	1214	54	551	1035
2021	58	746	1243	54	626	1049
2022	59	836	1272	55	698	1063
2023	60	929	1302	55	772	1078
2024	61	1027	1334	56	850	1095
2025	62	1130	1368	57	931	1115
2026	63	1164	1403	58	953	1134
2027	64	1196	1441	58	972	1158
2028	65	1231	1479	59	994	1182
2029	66	1267	1518	60	1018	1206
2030	67	1305	1559	61	1044	1232

To calculate the effect on rates, above-market costs for RPS resources are calculated and are assumed to be recovered from target customers. For each state, using Mid-C market prices from step 1 and the levelized total cost of renewable generation technologies, total above-market costs are calculated and recovered from qualified ratepayers. For Montana, the above-market costs are recovered from Northwest customers. For the state of Washington, the RPS is applicable to 84 percent of state load, and must be met by both public and private utilities. For the state of Oregon, three different target rates are given, and the above-market costs are recovered from these target customers.

The following table shows the average rate impact of RPS with and without conservation targets. The average rate increase from RPS for the 2010-2030 period is about 1$/MWh for Montana, $3 dollars/MWH for Oregon, and about $2 per MWH for Washington, averaged over a 20-year period. On an annual basis, incremental cost increases are higher, as shown in the following table. The average rate increase for consumers in these states is similar regardless of whether or not conservation was achieved. Conservation targets lower the growth of new load but they do not significantly lower the RPS requirements.

Table B-21: Rate Impact from meeting RPS (2006 $/MWH)

	Without Conservation			With Conservation		
	MT	OR	WA	MT	OR	WA
2008	0.00	0.00	0.00	-	-	-
2009	0.00	0.00	0.00	-	-	-
2010	0.02	0.00	0.00	0.01	-	-
2011	0.50	0.00	0.00	0.49	-	-
2012	0.94	0.00	0.00	0.95	-	-
2013	1.14	0.22	0.02	1.15	0.02	-
2014	1.30	0.32	0.50	1.33	0.03	0.40
2015	1.45	0.43	1.05	1.49	0.04	0.95
2020	1.41	4.46	3.13	1.46	4.19	3.01
2025	1.37	6.84	3.17	1.44	6.55	3.03
2030	1.34	7.11	3.25	1.42	6.78	3.10
Average 2010-2030	1.14	3.47	1.96	1.18	3.22	1.86

Step 4: Calculate additional costs to meet conservation targets.

The next step in the analysis includes the incremental cost of conservation programs. However, this step of the analysis cannot be completed until the conservation target levels are known. The calculation of incremental costs of meeting conservation targets will be conducted after determining the optimized conservation-acquisition targets.

Forecast for Electricity Prices by Sector

The estimated price of electricity by sector is presented in the following tables. For the residential sector, the annual real growth rate in electricity prices is expected to be in the 1.5-2.0 percent per year for the 2010-2030 period. It should be noted that these forecasts are at the state level, and within each state, some electric utility rates may be higher or lower than the figures presented here. Also, some utilities may have significantly higher rate increases than these average state-wide figures would indicate.

Table B-22: Price of Electricity for Residential Customers ($2006/MWH)

	Oregon	Washington	Idaho	Montana
1985	74	60	68	74
1990	67	62	69	77
1995	70	63	68	77
2000	69	60	63	76
2005	75	68	65	84
2010	79	70	61	85
2015	85	76	66	92
2020	93	83	71	96
2030	114	101	88	114
Annual Growth				
1985-2000	-0.3%	0.0%	-0.3%	0.1%
2000-2007	2.9%	3.9%	0.3%	2.7%
2010-2030	1.8%	1.8%	1.9%	1.5%

Table B-23: Price of Electricity for Commercial Customers ($2006/MWH)

	Oregon	Washington	Idaho	Montana
1985	81	57	65	67
1990	67	56	60	65
1995	64	59	57	68
2000	60	55	50	61
2005	67	65	56	77
2010	70	63	49	77
2015	76	69	54	84
2020	84	76	58	88
2030	105	94	76	106
Annual Growth				
1985-2000	-1.3%	-0.2%	-1.2%	-0.4%
2000-2007	3.2%	3.6%	-0.3%	3.5%
2010-2030	2.0%	2.0%	2.2%	1.6%

Table B-24: Price of Electricity for Industrial Customers ($2006/MWH)

	Oregon	Washington	Idaho	Montana
1985	56	34	42	40
1990	44	34	37	40
1995	44	38	36	44
2000	42	39	37	47
2005	50	44	40	50
2010	47	45	36	55
2015	53	51	41	61
2020	61	57	46	66
2030	82	75	63	83
Annual Growth				
1985-2000	-1.3%	0.6%	-0.6%	0.7%
2000-2007	4.8%	3.2%	-0.1%	8.1%
2010-2030	2.8%	2.6%	2.8%	2.1%

Other Fuel Prices

The demand for electricity is not only affected by the price of electricity, but also the price of alternative fuels. If the price of electricity relative to natural gas is decreasing, one would expect the consumption of electricity to increase and natural gas to decrease. Consumers could substitute natural gas for electricity, and or decrease their demand for natural gas. Consumer's fuel choices are influenced by relative fuel prices. Demand for electricity is affected by the competition between alternative fuels.

This section covers the current assumptions for the retail prices of natural gas and electricity. For each fuel, a base price and a regional delivery charge is calculated. The base, or wholesale commodity, price for each fuel is from the Council's fuel price forecast, discussed in Appendix A. Delivery charges vary by sector and state. Historic and forecast prices for the three main kinds of fuel are shown in the following table. To put the fuel on a comparable basis, prices are shown in constant 2006 dollars per million Btu.

Table B-25: Oregon Sector Level Fuel Prices ($2006/mmBTU)

Sector and Fuel	1985	2000	2007	2010	2020	2030	2010-2030 growth rate
Residential Electricity	21.72	20.22	24.64	23.14	27.30	33.35	1.8%
Residential Natural Gas	10.65	9.24	13.67	14.48	15.20	19.63	1.5%
Residential Oil	11.08	11.57	21.20	22.68	19.43	26.59	0.8%
Commercial Electricity	23.68	17.60	21.91	20.50	24.63	30.67	2.0%
Commercial Natural Gas	9.60	7.37	11.56	12.36	12.91	16.99	1.6%
Industrial Electricity	16.33	12.23	16.94	13.87	17.94	23.96	2.8%
Industrial Natural Gas	7.36	5.61	8.68	9.48	9.79	13.39	1.7%

Table B-26: Washington Sector Level Fuel Prices ($2006/mmBTU)

Sector and Fuel	1985	2000	2007	2010	2020	2030	2010-2030 growth rate
Residential Electricity	17.64	17.64	23.07	20.53	24.27	29.56	1.8%
Residential Natural Gas	10.05	8.06	13.50	14.31	15.02	19.42	1.5%
Residential Oil	12.29	13.02	20.33	21.80	18.48	25.50	0.8%
Commercial Electricity	16.73	16.11	20.62	18.48	22.20	27.49	2.0%
Commercial Natural Gas	8.30	6.78	12.04	12.84	13.43	17.59	1.6%
Industrial Electricity	9.86	11.36	14.16	13.10	16.77	22.04	2.6%
Industrial Natural Gas	7.25	4.51	9.54	10.33	10.71	14.45	1.7%

Table B-27: Idaho Sector Level Fuel Prices ($2006/mmBTU)

Sector and Fuel	1985	2000	2007	2010	2020	2030	2010-2030 growth rate
Residential Electricity	19.95	18.53	18.90	17.90	20.69	25.93	1.9%
Residential Natural Gas	10.40	7.19	11.04	11.85	12.35	16.34	1.6%
Residential Oil	11.54	10.39	21.32	22.79	19.56	26.74	0.8%
Commercial Electricity	19.15	14.55	14.21	14.31	17.06	22.30	2.2%
Commercial Natural Gas	8.59	6.27	10.27	11.07	11.51	15.37	1.7%
Industrial Electricity	12.18	10.70	10.60	10.64	13.35	18.58	2.8%
Industrial Natural Gas	6.83	4.60	8.94	9.74	10.07	13.71	1.7%

Table B-28: Montana Sector Level Fuel Prices ($2006/mmBTU)

Sector and Fuel	1985	2000	2007	2010	2020	2030	2010-2030 growth rate
Residential Electricity	21.80	22.32	26.94	24.89	28.15	33.39	1.5%
Residential Natural Gas	7.63	6.91	9.73	10.53	10.93	14.70	1.7%
Residential Oil	12.54	9.85	19.69	21.16	17.79	24.70	0.8%
Commercial Electricity	19.77	17.98	22.83	22.60	25.84	31.08	1.6%
Commercial Natural Gas	8.07	6.76	9.54	10.34	10.72	14.46	1.7%
Industrial Electricity	11.63	13.64	23.53	16.02	19.20	24.42	2.1%
Industrial Natural Gas	7.46	8.51	9.58	10.38	10.76	14.50	1.7%

On average, the growth rate in fuel prices is anticipated to be slower in the forecast period than they were historically, in part due to extraordinary high prices experienced in 2008. Natural gas price increases are expected to be lower in the forecast period than they were in the historic period. However, the year-by-year increase in prices presents a more accurate picture of change in the cost of fuel. The year-by-year data on fuel prices is available in the companion Excel workbook. The following graphs show the historic and forecast fuel prices for each state.

Figure B-32: Oregon Sectoral Fuel Prices ($ 2006/MMBTU)

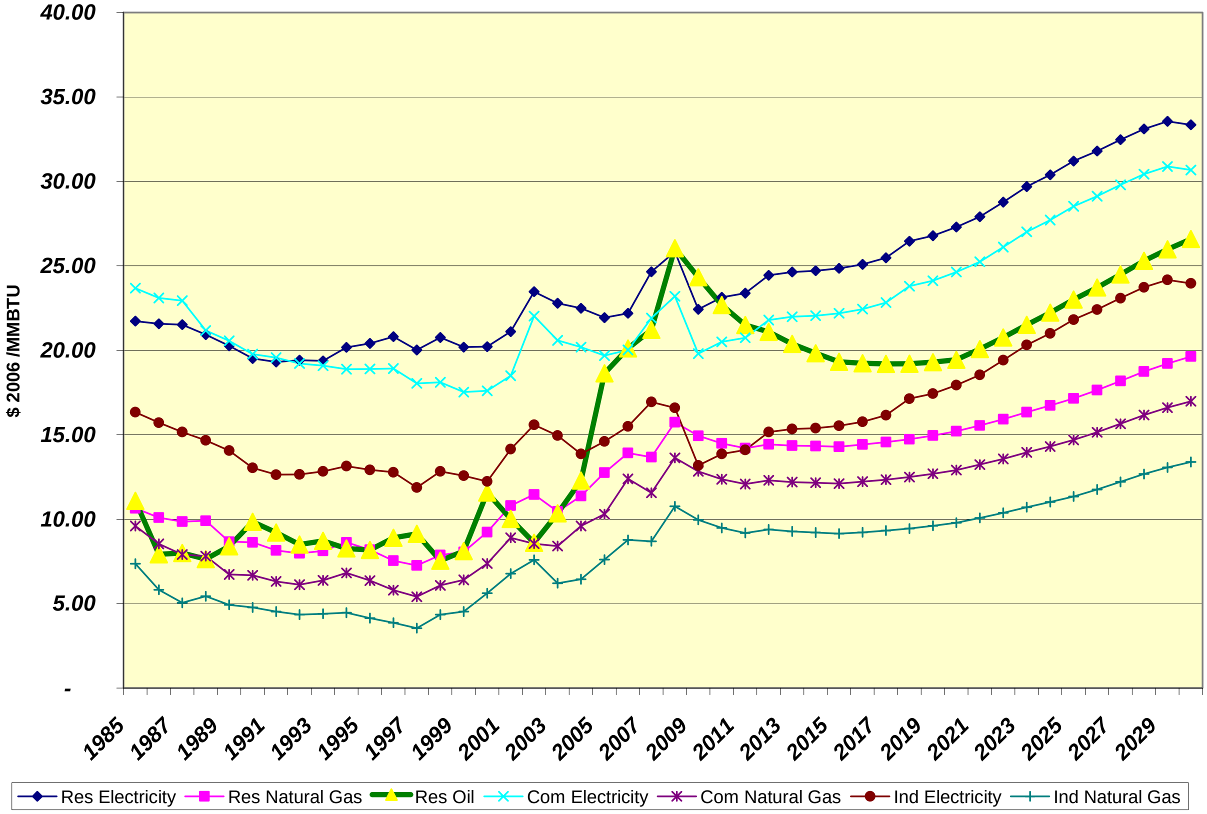


Figure B-33: Washington Sectoral Fuel Prices ($ 2006/MMBTU)

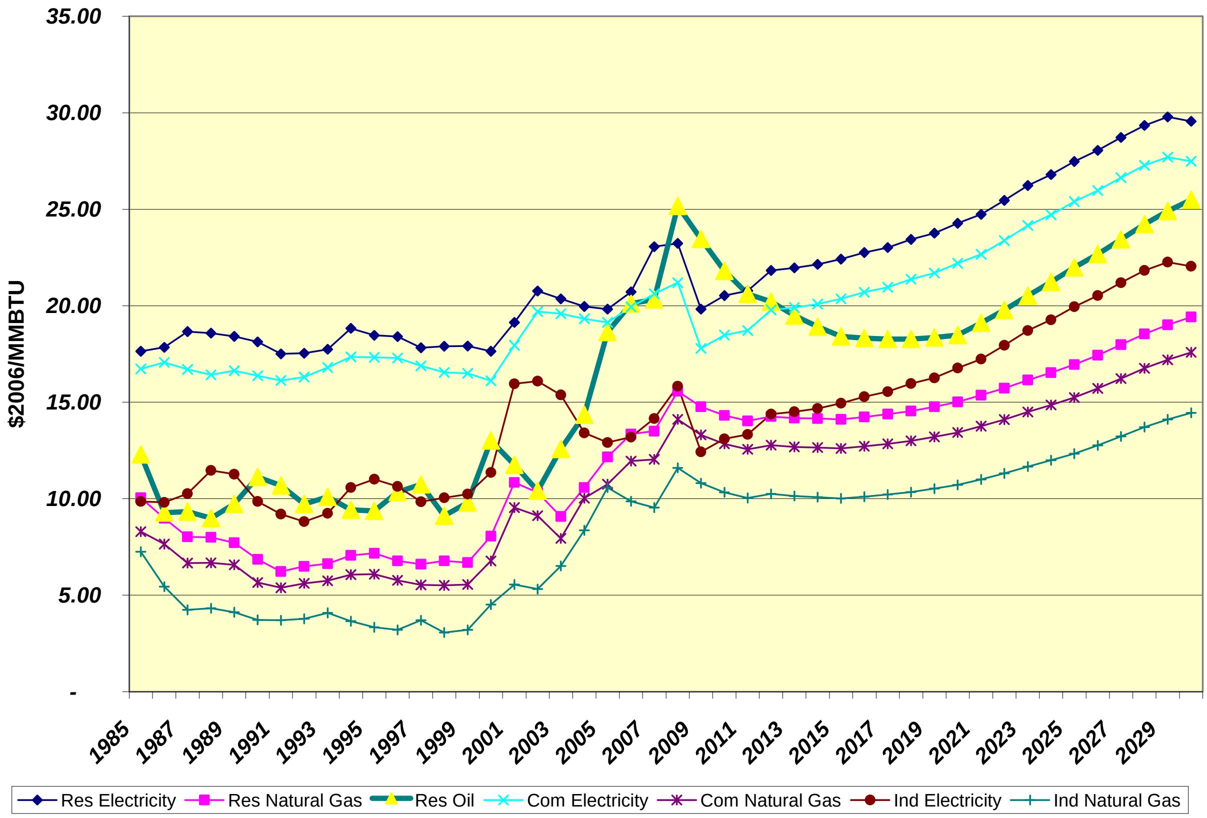


Figure B-34: State of Idaho Sectoral Fuel Prices ($ 2006/MMBTU)

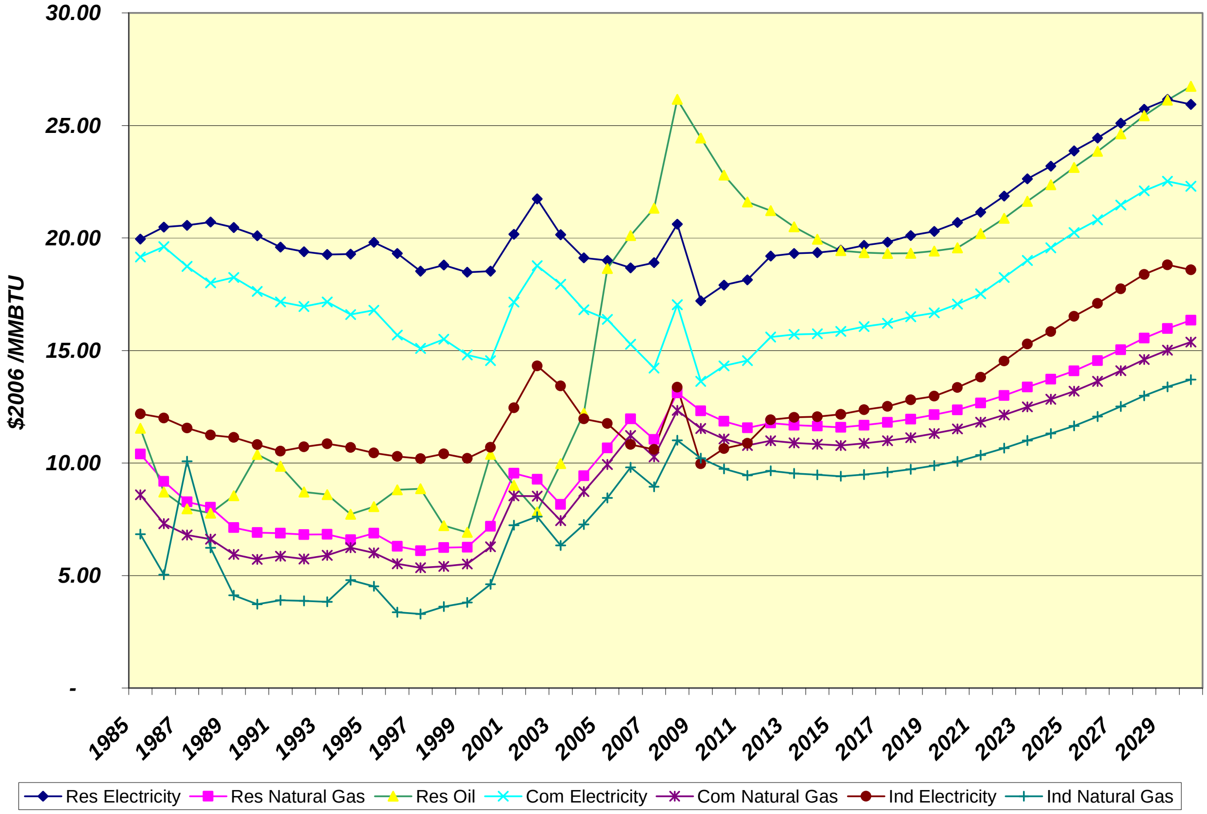


Figure B-35: State of Montana Sectoral Fuel Prices ($ 2006/MMBTU)

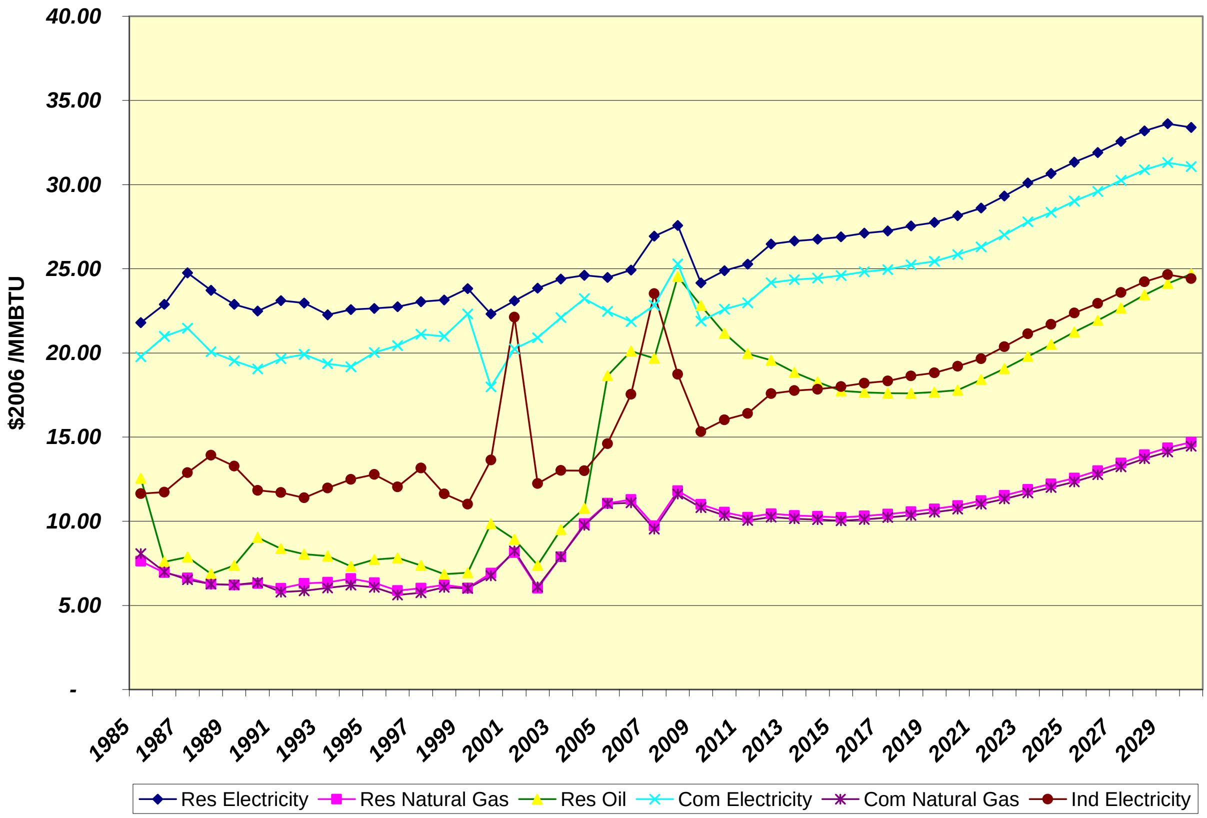


Table B-29: Growth Rate in Retail Electricity Price

Price of Electricity (2006 $/ MWH)	1985-2007	2000-2007	2010-2030
Oregon-Single Family	0.6%	2.9%	1.8%
Oregon-Commercial	-0.4%	3.2%	2.0%
Oregon-Industrial	0.2%	4.8%	2.8%
Washington-Single Family	1.2%	3.9%	1.8%
Washington-Commercial	1.0%	3.6%	2.0%
Washington-Industrial	1.7%	3.2%	2.6%
Idaho-Single Family	-0.2%	0.3%	1.9%
Idaho-Commercial	-1.3%	-0.3%	2.2%
Idaho-Industrial	-0.6%	-0.1%	2.8%
Montana-Single Family	1.0%	2.7%	1.5%
Montana-Commercial	0.7%	3.5%	1.6%
Montana-Industrial	3.3%	8.1%	2.1%

SUMMARY OF ECONOMIC DRIVERS FOR THE SIXTH POWER PLAN

The following summary table shows the annual growth rate for the historic and forecast period for each state and the region. In general, the key economic drivers reflect a slow down in economic growth for 2010-2030.

Table B-30: Historic and Forecast of Annual Growth Rate by Sector

		Oregon		Washington		Idaho		Montana		Region	
Sector	Business/Building type	1985-2007	2010-2030	1985-2007	2010-2030	1985-2007	2010-2030	1985-2007	2010-2030	1985-2007	2010-2030
Residential	Single Family	1.6%	1.3%	1.9%	1.2%	2.4%	2.1%	0.9%	1.1%	1.8%	1.3%
(Number of	Multi Family	2.4%	1.8%	2.6%	1.5%	2.5%	2.1%	1.6%	2.1%	2.5%	1.6%
household stock)	Other Family	3.0%	1.1%	2.7%	1.1%	2.5%	0.9%	1.9%	0.9%	2.7%	1.0%
Commercial	Large Office	2.0%	1.2%	1.3%	1.4%	5.7%	1.6%	0.3%	1.3%	1.5%	1.4%
(square footage	Medium Office	4.6%	1.2%	3.9%	1.4%	8.6%	1.6%	2.7%	1.3%	4.1%	1.4%
Stock)	Small Office	2.5%	1.2%	1.8%	1.4%	6.3%	1.6%	0.7%	1.3%	2.1%	1.4%
	Big Box-Retail	8.6%	0.9%	8.6%	0.6%	13.0%	1.0%	8.6%	0.9%	8.8%	0.7%
	Small Box-Retail	1.1%	0.9%	1.3%	0.6%	4.5%	1.0%	1.2%	0.9%	1.4%	0.7%
	High End-Retail	1.1%	0.9%	1.0%	0.6%	4.5%	1.0%	1.2%	0.9%	1.2%	0.7%
	Anchor-Retail	0.4%	0.9%	0.4%	0.6%	4.2%	1.0%	0.5%	0.9%	0.6%	0.7%
	K-12	3.5%	0.7%	1.9%	0.9%	3.3%	0.9%	1.1%	0.9%	2.2%	0.9%
	University	3.6%	1.0%	1.8%	1.0%	2.9%	1.2%	1.8%	0.7%	2.1%	1.0%
	Warehouse	2.6%	1.8%	4.3%	3.3%	3.9%	3.0%	1.3%	1.7%	3.3%	2.7%
	Supermarket	0.6%	0.5%	0.9%	0.4%	3.2%	0.5%	1.0%	0.4%	1.1%	0.4%
	Mini Mart	6.4%	0.6%	6.2%	0.8%	9.2%	1.5%	6.6%	0.6%	6.7%	0.9%
	Restaurant	1.1%	1.2%	1.4%	1.1%	3.7%	2.1%	1.0%	1.3%	1.4%	1.2%
	Lodging	1.6%	0.6%	2.2%	0.6%	2.4%	1.0%	0.7%	0.3%	1.7%	0.6%
	Hospital	3.7%	1.1%	1.9%	0.9%	3.0%	1.5%	2.3%	0.7%	2.5%	1.0%
	Other Health	3.6%	1.2%	2.0%	1.8%	2.1%	2.0%	2.9%	1.7%	2.4%	1.7%
	Assembly	3.6%	2.3%	2.1%	0.9%	3.2%	3.5%	1.7%	2.5%	2.5%	1.6%
	Other	3.7%	0.8%	2.3%	0.4%	3.4%	0.9%	1.5%	1.2%	2.6%	0.6%
Industrial	Food & Tobacco	2.0%	2.6%	0.9%	2.1%	-0.5%	1.5%	1.4%	2.5%	1.0%	2.2%
(output)	Textiles	1.6%	5.4%	7.1%	5.2%	13.9%	6.3%	16.1%	8.0%	4.8%	5.5%
	Apparel	-1.7%	-0.8%	-1.3%	-1.9%	-2.6%	-2.3%	-4.6%	2.9%	-1.6%	-1.4%
	Lumber	-4.0%	0.8%	-2.9%	1.7%	-2.8%	1.6%	-2.8%	0.8%	-3.4%	1.2%
	Furniture	7.7%	4.1%	6.5%	5.5%	8.1%	4.7%	6.4%	4.6%	7.1%	4.9%
	Paper	0.1%	2.7%	0.8%	3.8%	0.2%	0.5%	0.7%	4.9%	0.5%	3.4%
	Printing	-2.2%	2.9%	-3.2%	4.7%	-3.6%	2.3%	-5.6%	2.4%	-3.0%	3.9%
	Chemicals	5.4%	3.3%	-1.3%	2.9%	0.4%	2.5%	3.0%	5.9%	0.5%	3.1%
	Petroleum Products	-2.5%	1.9%	6.3%	1.4%	3.3%	5.4%	-2.7%	2.5%	4.3%	1.5%
	Rubber	9.3%	1.5%	9.4%	1.7%	1.3%	2.0%	9.3%	2.9%	7.9%	1.6%
	Leather	2.1%	-3.9%	2.1%	-5.1%	-0.3%	-6.4%	-5.3%	-3.7%	1.4%	-4.5%
	Stone, Clay, etc.	5.9%	2.6%	6.2%	2.9%	4.7%	3.2%	2.4%	2.6%	5.7%	2.8%
	Aluminum	4.0%	1.0%	1.3%	4.4%			-4.6%	3.8%	1.5%	3.8%
	Other Primary Metals	4.0%	5.0%	1.3%	4.4%	12.0%	7.8%	-4.6%	3.8%	3.1%	5.0%
	Fabricated Metals	3.7%	2.8%	6.0%	2.9%	5.0%	4.2%	6.8%	4.2%	4.9%	3.0%
	Machines & Computer	15.8%	2.1%	7.6%	3.1%	19.0%	3.1%	14.9%	3.6%	13.9%	2.5%
	Electric Equipment	0.9%	4.3%	8.0%	4.0%	2.3%	3.6%	-1.9%	4.7%	4.6%	4.1%
	Transport Equipment	2.7%	4.0%	2.8%	1.2%	9.3%	3.0%	5.8%	5.1%	2.9%	1.5%
	Other Manufacturing	8.3%	5.9%	6.6%	5.9%	12.2%	7.4%	8.3%	6.6%	7.6%	6.1%
Mining	Mining	4.9%	2.0%	4.2%	-0.1%	7.1%	5.3%	3.7%	2.5%	3.9%	2.8%
Agriculture	Agriculture	4.3%	4.9%	3.8%	2.1%	3.8%	3.7%	6.9%	3.0%	4.4%	3.5%
Transportation *	Passenger	3.3%	2.9%	3.8%	2.9%	3.2%	3.1%	2.7%	2.4%	3.6%	2.9%
	Freight	3.1%	3.7%	3.3%	3.4%	5.6%	5.6%	2.4%	2.9%	3.3%	3.8%
	Off Road	1.4%	0.5%	1.4%	-1.0%	-0.5%	-0.4%	1.7%	0.8%	1.5%	-0.3%

ALTERNATIVE ECONOMIC SCENARIOS

Because future economic conditions are highly uncertain, the forecasts encompass a wide range of possibilities for future economic growth. The demand forecast includes three alternative sets of economic drivers. In the medium case, discussed earlier, the key economic drivers project a healthy regional economy (albeit with a slower growth path than in the recent past). In addition to the Plan case, two alternative scenarios are considered, one representing a low-economic-growth scenario and the other a high-growth projection of the future.

The low-growth scenario reflects a future with slow economic growth, weak demand for fossil fuel, declining fuel prices, a slow down in labor productivity, and a low inflation rate. On the other hand, the high-case scenario assumes faster economic growth, stronger demand for energy, higher prices for fossil fuel, sustained growth in labor productivity, and a higher inflation rate.

In all scenarios it is assumed that climate change concerns, demand for cleaner fuel, and a national cap-and-trade or a CO_2 tax push fuel prices higher. Cost of CO_2 emissions is assumed to start at $8 dollars per tons in 2012 and climb to about $27 dollars by 2020 and by the end of forecast period, 2030, to reach $47 dollars per ton.

To estimate the low and high range for each key variable for each year, the base value for the driver was multiplied by an annual factor that increases the value (for the high case) or reduces it (for the low case). For example, if the medium case value for new floor space additions for warehouses were 100,000 square feet, for the low-growth scenario the 100,000 square feet is lowered by 9 percent, and for the high-growth scenario it is increased by 20 percent. The 9 percent and 20 percent figures are averages; the actual percentage values used in the model vary by year. The following two figures show the range of percent change from the medium case scenario for each commercial building type and each industry. Similar methodology is used in developing each key economic driver.

Figure B-36: Range of Percent Change from Medium Case - for Commercial Buildings

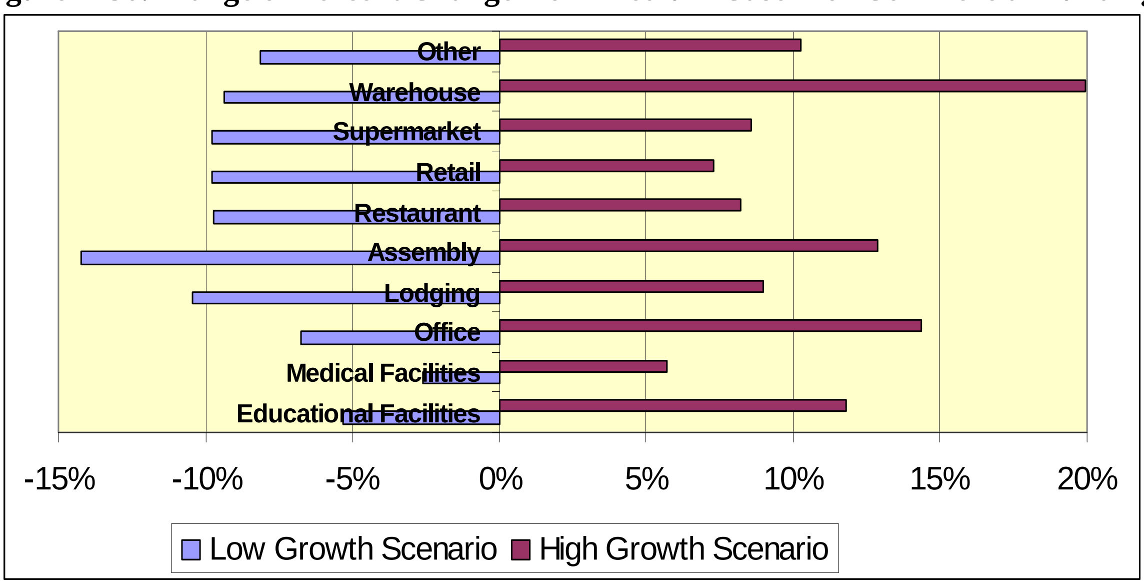
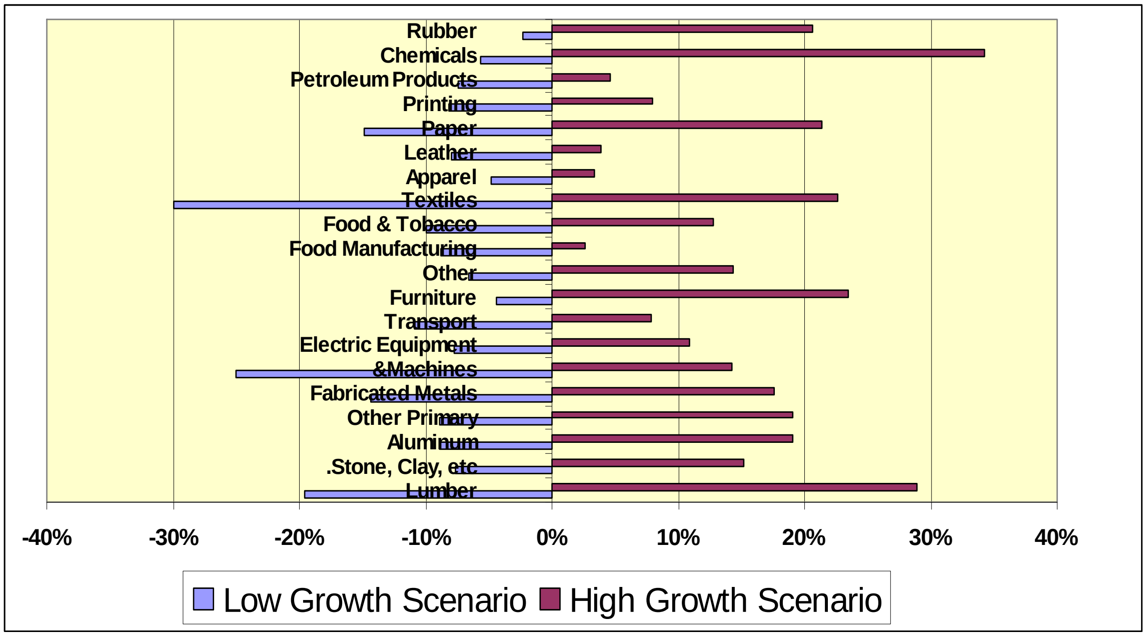


Figure B-37: Range of Percent Change from Medium Case- for Industrial Sectors



The average annual growth rates presented above are summary values. The demand forecasting system, however, uses the year-by-year values rather than the annual average values. The source of the range forecast used in the Sixth Power Plan, is Global Insight's long-term national forecast, October 2008.

The following table shows the growth rate for each sector at a more aggregate level. The price range for oil, natural gas, and coal are based on the Council's Sixth Power Plan.

Table B-31: Historic, Medium Case and Alternative Growth Rates

	1985-2007	2010-2030	2010-2030	2010-2030
Key economic driver for each sector	**Actual**	**Low Case**	**Medium Case**	**High Case**
Population	1.6%	0.6%	1.1%	2.2%
Residential Units	1.9%	0.6%	1.3%	2.2%
Commercial Floor space	2.3%	0.9%	1.5%	1.9%
Manufacturing Output $	4.1%	2.3%	3.0%	3.9%
Agriculture Output $	4.4%	3.0%	3.9%	5.0%
Light Vehicle Sales		0.5%	1.4%	2.2%
Electricity Prices		**Low Case**	**Medium Case**	**High Case**
Inflation rate	2.2%	3.5%	1.9%	1.7%
Average Annual growth rate in Price(2008-2030)*				
Oil Prices	1.7%	-1%	1%	2.0%
Natural Gas Prices	1.8%	-1.3%	0.9%	1.7%
Coal Prices	-4.8%	-0.5%	0.5%	1.2%

* Fuel price assumptions are consistent with the Council's fuel price and electricity price forecast.

Additional Details: A companion Excel workbook containing details on the economic drivers is available from Council's website.

Appendix C: Demand Forecast

ENERGY DEMAND

Background

It has been 26 years, a mere generation, since the Council released its first power plan in 1983. Since then, the region's energy environment has undergone many changes. In the decade prior to the Northwest Power Act, regional electricity load was growing at 3.5 percent per year and load (excluding the direct service industries) grew at an annual rate of 4.3 percent. In 1970, regional load was about 11,000 average megawatts, and during that decade demand grew by about 4,700 average megawatts. During the 1980s, load growth slowed significantly but continued to grow at about 1.5 percent per year, experiencing load growth of about 2,300 average megawatts. In the 1990s, another 2,000 average megawatts was added to the regional load, making load growth in the last decade of 20th century about 1.1 percent. Since 2000, regional load has declined. As a result of the energy crisis of 2000-2001 and the recession of 2001-2002, regional load decreased by 3,700 average megawatts between 2000 and 2001. Loss of many of the aluminum and chemical companies that were direct service industries contributed to this load reduction. Since 2002, however, regional load has been on an upswing, growing at an annual rate of 2.5 percent. This growth has been driven by increasing demand from commercial and residential sectors. Figure C-1 and Table C-1 track the regional electricity sales from 1970-2007.

Figure C-1: Total and Non-DSI Regional Electricity Sales (MWa)

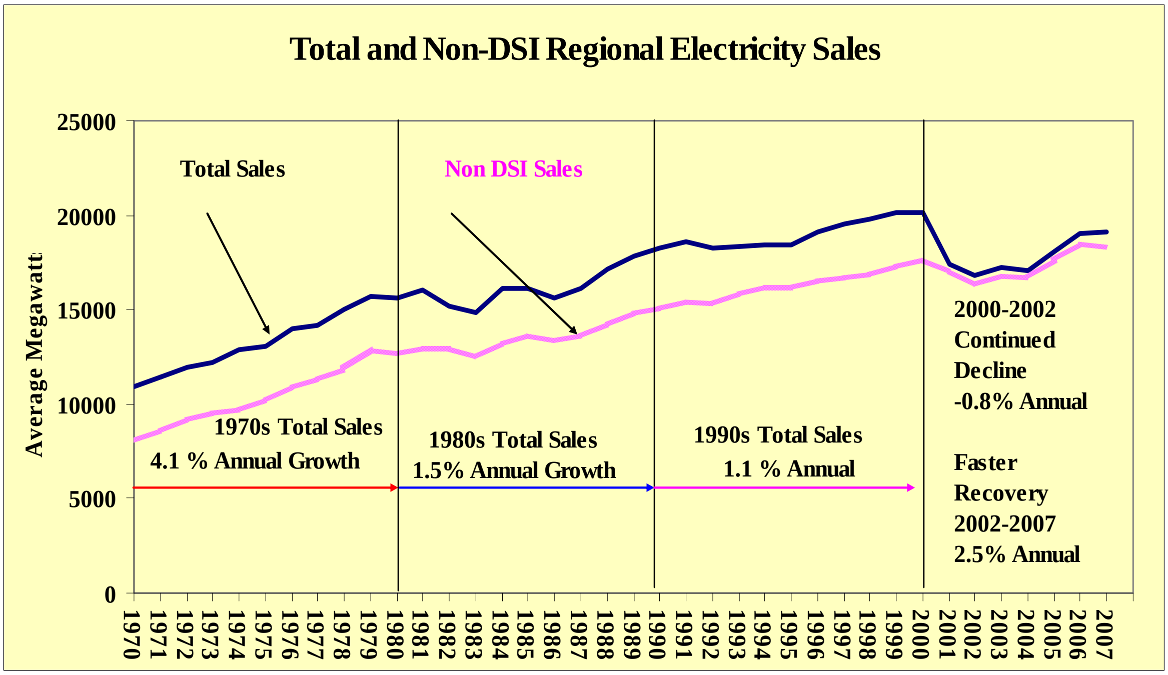


Table C-1: Total and Non-DSI Regional Electricity Sales

Annual Growth	Total Sales	Non DSI
1970-1979	4.1%	5.2%
1980-1989	1.5%	1.7%
1990-1999	1.1%	1.5%
2000-2007	-0.8%	0.5%
2002-2007	2.5%	2.2%

The dramatic decrease in the growth of electricity demand shown in Table C-1 was not due to a slowdown in economic growth in the region. The region added more population and more jobs between 1980 and 2000 than it did between 1960 and 1980. The decrease in demand was the result of a move to less energy-intensive activities. As shown in Table C-2, electric intensity in terms of use per capita increased between 1980 and 1990, but has been declining since 1990. This shift reflects industry changes, increasing electricity prices, and regional and national conservation efforts.

Table C-2: Changing Electric Intensity of the Regional Economy

Year	Non-DSI Electricity Use Per Capita (MWa / Thousand Persons)
1980	1.64
1990	1.71
2000	1.61
2006	1.51

For the most part, the upswing in load since 2002 has been due to growth in residential- and commercial-sector sales. By the end of 2007, the residential sector had added about 888 average megawatts to load, the commercial sector 285 average megawatts, while the industrial sector lost 337 megawatts.

In the past two decades, the region's population has grown from roughly 9 million in 1985 to more than 12.6 million in 2007. This growth rate surpasses the national population growth rate by almost 40 percent. Typically, this level of increase in population would put significant pressure on the electricity demand. However, due to regional conservation investments and a shift to less energy-intensive industries, the region's demand for electricity has remained stable. For example, during the years 1990-2007, the U.S. population grew at an annual rate of 0.9 percent, while residential demand for electricity grew at 2.4 percent. In the Northwest, the average growth rate in population was 1.3 percent, while the residential demand for electricity grew at an annual rate of 1.4 percent, a full percentage point below the national average. Similar patterns can be observed in the commercial sector.

Demand Forecast Methodology

When the Council was formed, growth in electricity demand was considered the key issue for planning. The region was beginning to see some slowing of its historically rapid growth of electricity use, and it began to question the future of several proposed nuclear and coal generating plants. To respond to these changes, it was important that the Council's demand forecasting system (DFS) be able to determine the causes of changing demand growth and the extent and composition of future demand trends. Simple historical trends, used in the past, were no longer reliable indicators of future demand.

In addition, the Northwest Power Act requires the Council to consider conservation a resource, and to evaluate it along with new generation. So, the DFS analysis also needs to support a detailed evaluation of energy efficiency improvements and their effects on electricity demand.

Rather than identifying trends in aggregate or electricity consumption by sector, the Council developed a forecasting system that incorporates end-use details of each consuming sector (residential, commercial, industrial). Forecasting with these models requires detailed separate economic forecasts for all the sectors represented in the demand models. The models also required forecasts of demographic trends, electricity prices, and fuel prices.

As Western electricity systems became more integrated through deregulated wholesale markets, and as capacity issues began to emerge, it became clear that the Council needed to understand the pattern of electricity demand over seasons, months, and hours of the day. The load shape forecasting system (LSFS) was developed to do this. The model identifies what kinds of equipment are contributing to demand and how much electricity they are using, which helps build the hourly shape of demand.

These new detailed approaches of the DFS and LSFS were expensive and time consuming to develop, and were not used in the Fifth Power Plan. Although the Northwest Power Act still requires a 20-year forecast of demand, changes in the electricity industry have meant a greater focus on the short-term energy landscape. Rather than large-scale nuclear and coal plants, popular in the early 1980s, other resources that do not take as long to plan and develop are being chosen and built, so the need to analyze their impact on the power system is critical. In addition, the Council's centralized planning role is less clear as a restructured wholesale electricity market relies more on competitively developed resources.

The focus of the Council's power planning activity now includes evaluating the performance of more a competitive power market, and how the region should acquire conservation in this new market. The Council is also concerned about the ability of competitive wholesale power markets to provide adequate and reliable power supplies, which has implications for demand forecasting.

One of the most significant issues facing the region's power system today is that the pattern of electricity demand has changed. The question is not only if we have energy to meet annual demand, but whether we have adequate capacity to meet times of peak demand. The Pacific Northwest now resembles the rest of the West, which has always been capacity constrained. The region can now expect peak prices during Western peak demand periods. In response, the Sixth Power Plan is focused on shorter-term electricity demand.

Additionally, the region is no longer independent of the entire Western U.S. electricity market. Electricity prices and the adequacy of supply are now determined by West-wide electricity conditions. The Council uses the AURORA® electricity market model, which requires assumptions about demand growth for all areas of the Western-integrated electricity grid.

Given all these changes, the demand forecast needs to be able to analyze short-term, temporal patterns of demand and expanded geographic areas. As well, any forecast must address the effect of energy-efficiency improvements on the power system. Finding new ways to assess conservation potential, or to encourage its adoption without explicit estimates of the electricity likely to be saved, is a significant issue for regional planning.

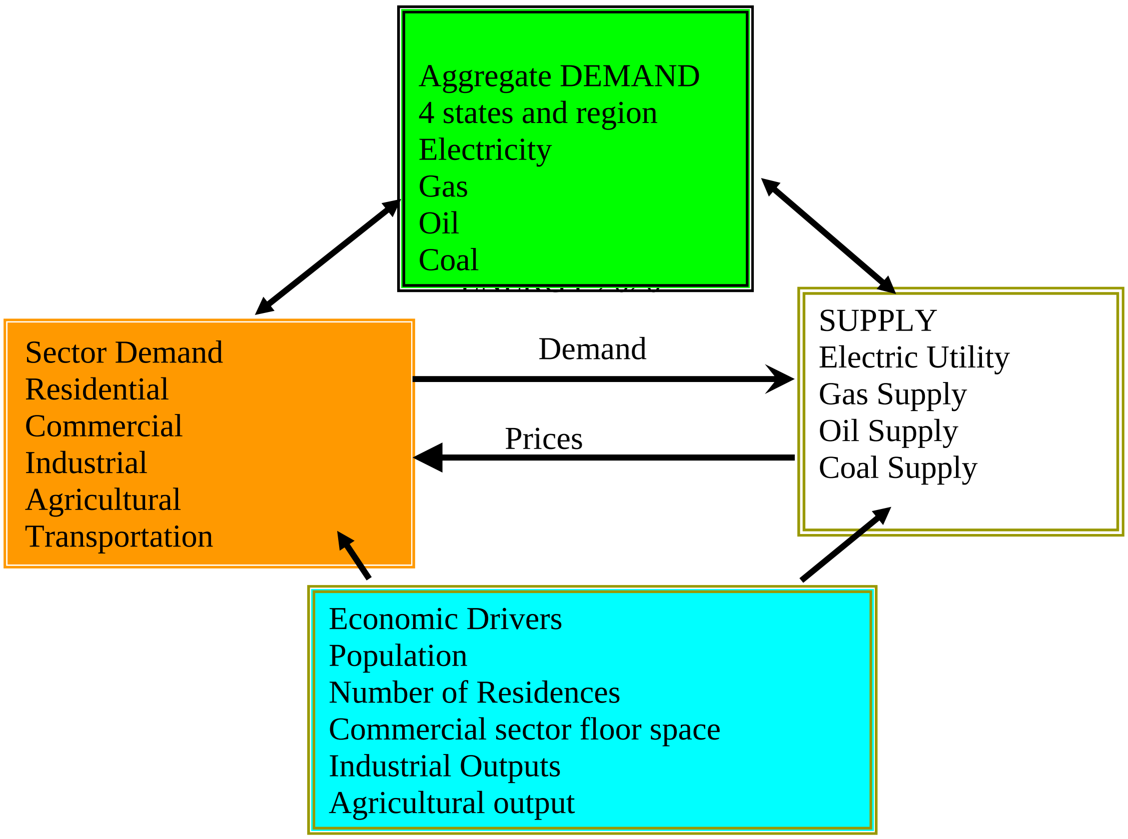
Previous Council forecasts for individual sectors have been quite accurate. The level of residential consumption was overestimated by an average of 0.6 percent. Commercial consumption was underestimated by an average of 0.9 percent, and industrial consumption, excluding direct service industries (DSI), was overestimated by an average of 3.6 percent. Long-term forecasts did not depart seriously from actual electricity consumption, so the Fifth Power Plan relied on earlier forecast trends for non-DSI electricity demand. However, the Sixth Power Plan updates the demand forecasting system.

New Demand Forecasting Model for the Sixth Plan

The 2000-2001 Western energy crisis created renewed interest in demand forecasting, and the Northwest's changing load shape has created a particular concern about capacity supply. In order to forecast these peaks, the Council relies on end-use forecasting models. For its Sixth Power Plan, the Council selected a new end-use forecasting and policy analysis tool. The new demand forecasting system (DFS), based on the Energy 2020 model, generates forecasts for electricity, natural gas, and other fuel.

The Energy 2020 model is fully integrated and includes fuel, sectors, and end-use load. The Council uses Energy 2020 to forecast annual and peak load for electricity as well as for other fuel. The following flow-chart provides an overview of the Energy 2020 model.

Figure C-2: Overview of Council's Long Term Forecasting Model



The DFS is calibrated to total demand for electricity, natural gas, oil, and a range of other fuel. The data for calibration is obtained from the Energy Information Administration's State Energy Demand System (SEDS). Annual consumption data for each sector and state is available for years 1960-2006. To add the year 2007, additional information from monthly electricity sales reports for electricity, natural gas, and oil consumption was used. The Energy 2020 model used detailed information from the previous version of the DFS to create a bridge between the old Council modeling system and the new modeling system.

The basic version of Energy 2020 was expanded to make sure that the DFS can meet the needs of conservation resource planning. The number of sectors and end-uses was increased. In the residential sector, three building types, four different space-heating technologies, and two different space-cooling technologies were tracked. Demand was tracked for electricity for 12 end-uses in the residential sector. New end-uses were added, like information, communication, and entertainment (ICE) devices, which in earlier forecasts did not have a major share of electricity consumption in homes. Technology trade-off curves were updated with new cost and efficiency data.

In the commercial sector, the model was expanded to forecast load for 18 different commercial building types. Forecasts for commercial floor space development made sure that the economic drivers of the demand forecast for electricity and the economic drivers for the conservation resource assessment were identical.

The industrial sector of the model was updated with new regional energy consumption data. The work on the industrial sector is ongoing and the results of a recent analysis on industrial demand for electricity will be added to the demand forecast.

The load shape forecasting system was updated with the best available data on end-use load shape to forecast peak demand, including monthly peaks. This will enable the Council to demonstrate a closer link among the demand forecasting system, the hydro modeling, and the Regional Portfolio Model (RPM).

Demand Forecast

The Council's medium or "Plan" case predicts electricity demand to grow from about 19,000 average megawatts in 2007 to 25,000 average megawatts by 2030. The average annual rate of growth over that period in this forecast is about 1.3 percent per year. This level of growth does not take into account expected demand reductions due to new conservation measures. This rate is consistent with the Council's Fifth Power Plan growth rate, which was projected to grow by 1.4 percent per year from 2000 to 2025. The winter peak demand for power is projected to grow from about 34,000 megawatts in 2010 to around 37,000 megawatts by 2030, at an average annual growth rate of 0.75 percent. The summer peak demand for power is projected to grow from 28,000 megawatts in 2010 to 35,000 megawatts by 2030, at an annual growth rate of 1.1%.

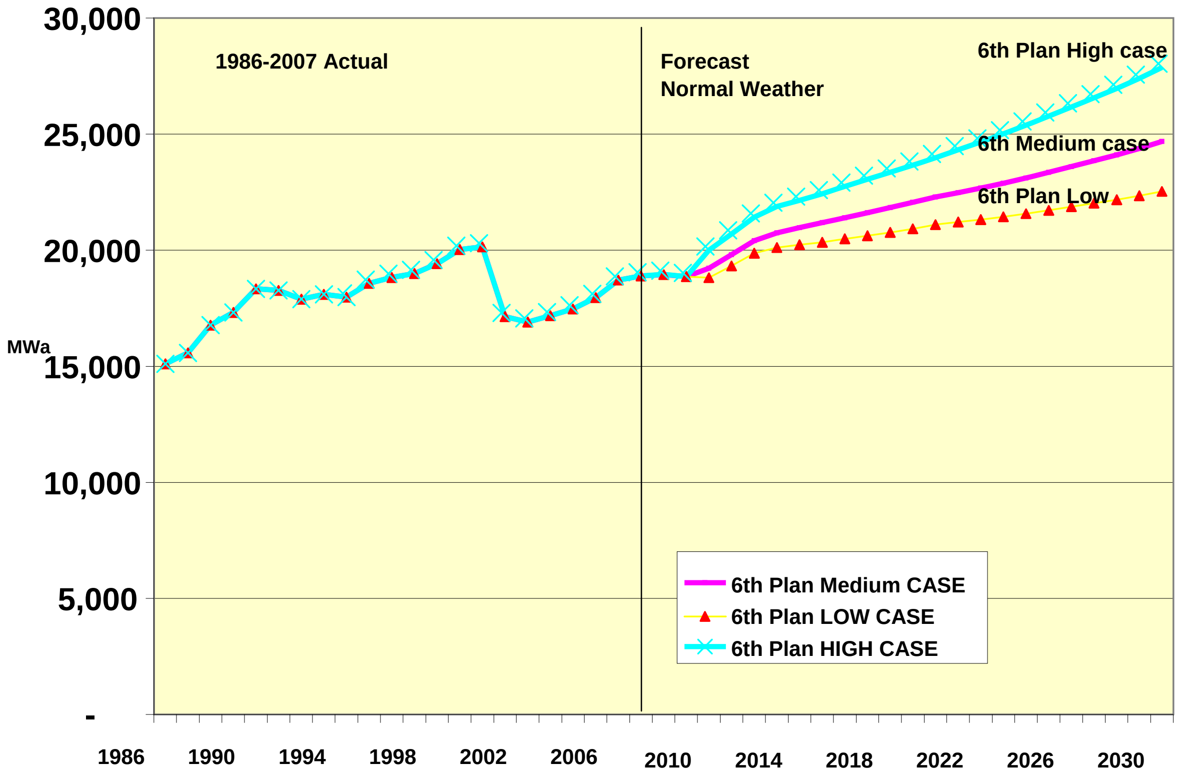
Total non-DSI consumption of electricity is forecast to grow from about 18,000 average megawatts in 2007 to over 19,000 average megawatts by 2010 and close to 25,000 average megawatts by 2030. This is an average annual growth rate of 1.3 percent for the years 2010-2030. The following table shows the forecast for each sector in the medium case. Each sector's forecast is discussed in separate subsections of this appendix.

Table C-3: Medium Case Sector Forecast of Annual Energy MWa

	2007 Actual	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Residential	7,432	7,554	8,452	9,765	1.1%	1.3%
Commercial	6,106	6,537	8,201	8,767	2.3%	1.5%
Industrial Non-DSI	3,725	3,648	3,952	4,277	0.8%	0.8%
DSI	764	693	818	818	1.7%	0.8%
Irrigation	802	728	781	958	0.7%	1.4%
Transportation	64	65	83	94	2.5%	1.9%
Total Non-DSI	18,130	18,531	21,470	23,860	1.5%	1.3%
Total	18,893	19,224	22,288	24,678	1.5%	1.3%

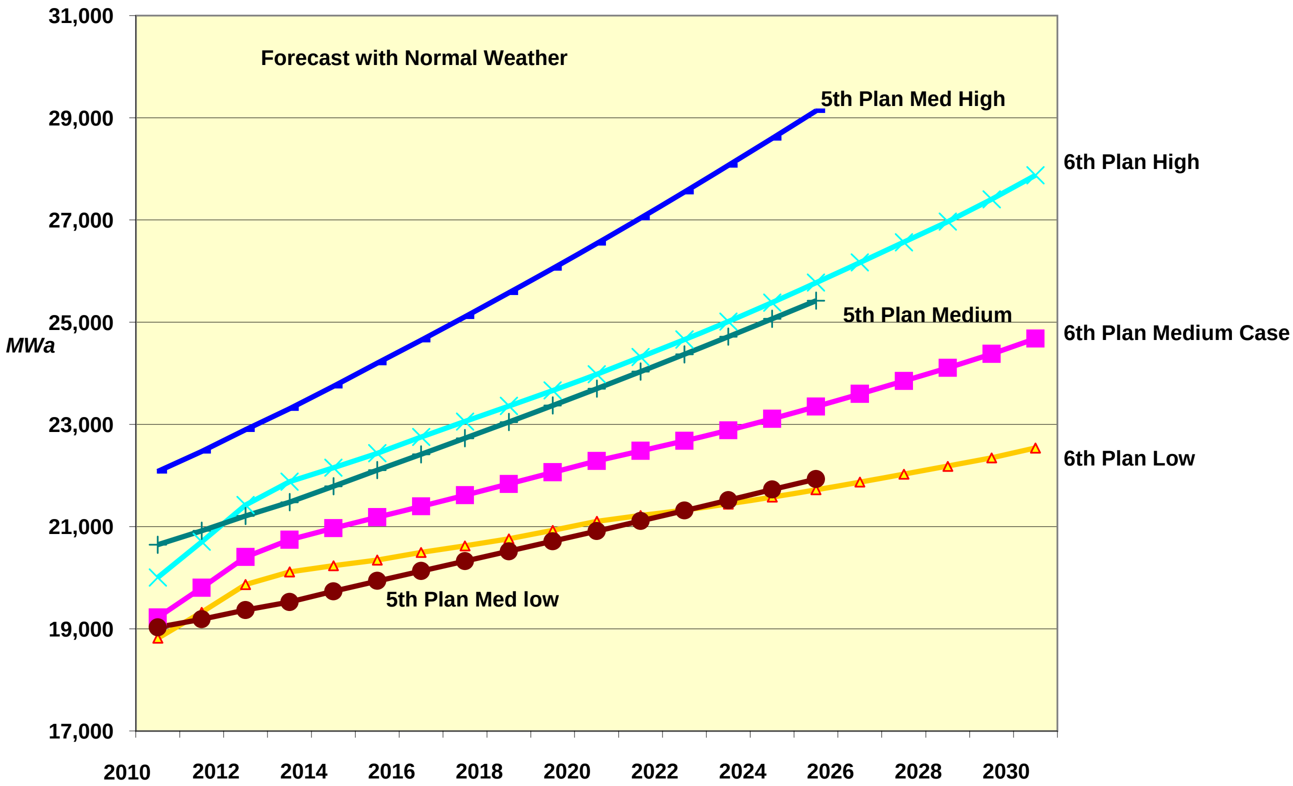
The medium case electricity demand forecast predicts that the region's electricity consumption will grow, absent any conservation, by about 5,500 average megawatts by 2030, an average annual increase of over 270 average megawatts. The projected growth reflects increased electricity use by the residential and commercial sectors and reduced growth in the industrial sector, particularly by energy-intensive industries. Higher electricity and natural gas prices have had a tremendous impact on the region's industrial makeup. As a result of the 2000-2001 energy crisis and the recession of 2001-2002, the region lost about 3,500 megawatts of industrial demand, which it has not regained. The region is projected to surpass the 2000 level of demand by 2013. However, the depth of the 2008 recession may delay this recovery.

Figure C-3: Sixth Power Plan Range of Demand Forecasts (MWa)



Comparing the Fifth Power Plan projections with actual consumption, regional demand was in the range of the plan's medium to medium-high forecast. The Sixth Power Plan forecasts are lower than the Fifth Power Plan; by 2025 the two forecasts differ by about 2000 average megawatts.

Figure C-4: Comparison of Fifth and Sixth Demand Forecast

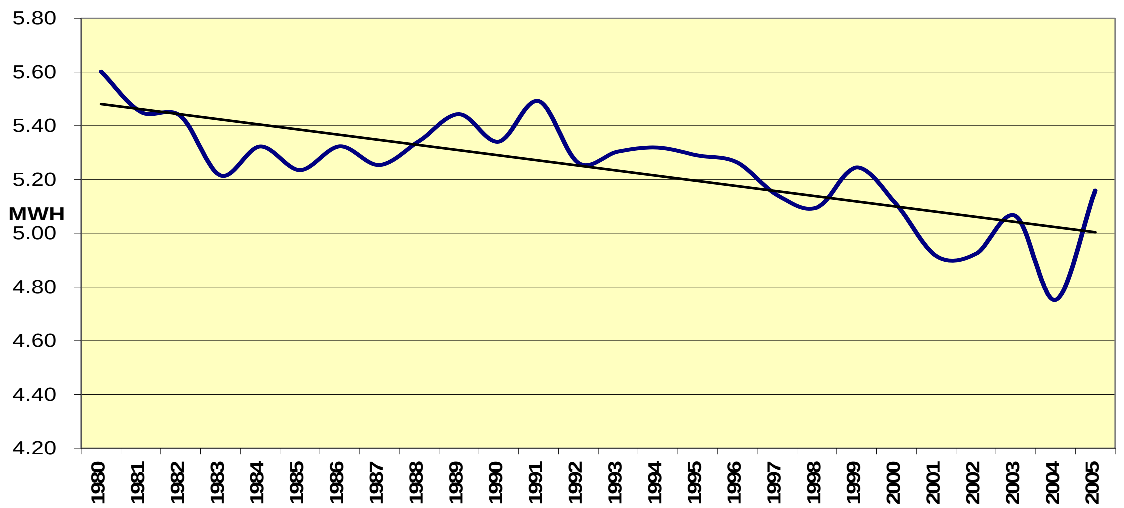


Residential Sector Demand

History

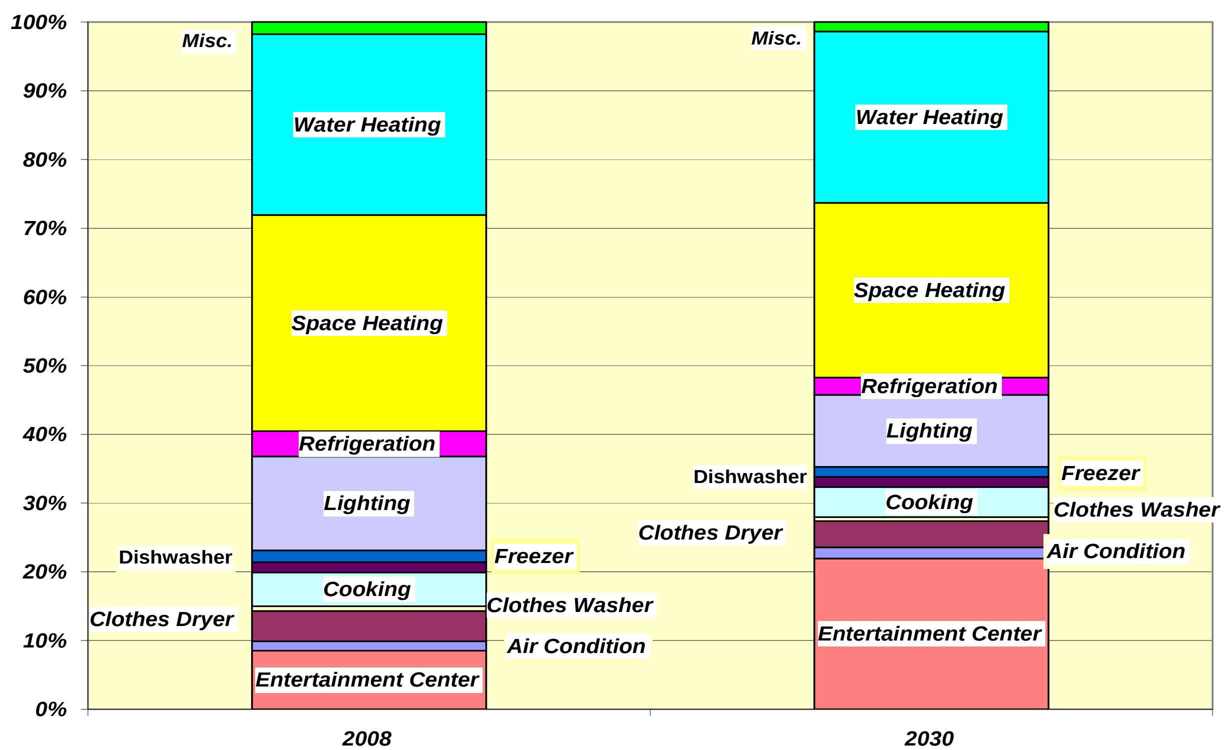
Demand for electricity in the residential sector grew from 5,350 average megawatts in 1986 to about 7,400 average megawatts in 2007. Although residential demand for electricity has been increasing, the per capita consumption of electricity in the residential sector was declining or stable until about 2005 when per capita electricity consumption began to grow. Improved building codes and more efficient appliances helped to keep the consumption level down. Per capita consumption (adjusted for weather) for the region, as well as the overall trend, is shown in the following graph.

Figure C-5: Change in Residential Per Capita Consumption



The drop in residential per capita consumption of electricity is even more significant when considering the tremendous increase in home electronics that did not even exist 25 years ago. The demand for information, communication, and entertainment (ICE) appliances has sky-rocketed and is expected to continue. The following graph shows the share of residential sector electricity consumption by end-use. The share of air-conditioning and ICE doubles between 2008 and 2030.

Figure C-6: Breakdown of Residential Electricity Consumption by End-use



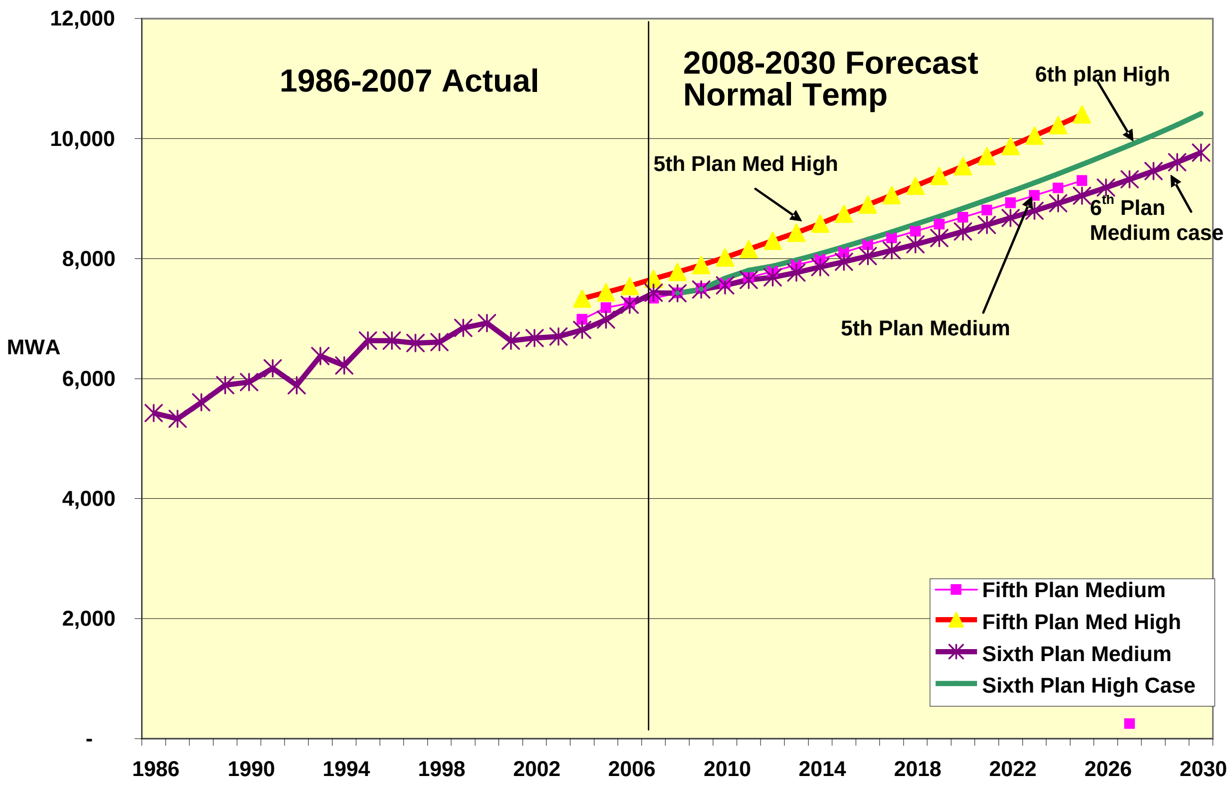
Residential Demand Forecast

For the medium case scenario, residential electricity consumption is forecast to grow by 1.3 percent between 2010 and 2030. This growth rate is consistent with the levels anticipated in the Fifth Power Plan, which estimated the growth rate for the residential sector to be 1.36 percent per year between the years 2000 and 2025. The draft Sixth Power Plan predicts that for 2008-2030, residential sector demand will increase by an average of about 100 megawatts per year. This forecast does not incorporate the effect of new conservation investments.

Figure C-6 compares the medium and high range of the residential consumption forecast to historical data and the forecasts from the Council's Fifth Power Plan. The draft Fifth Power Plan medium case residential demand forecast for 2010 is 36 average megawatts higher than the Sixth Power Plan's forecast for that same year. By 2025, the medium case residential forecast is 250 average megawatts lower than the forecast level in the Fifth Power Plan for the same year.

Note: There is a companion Excel workbook with the load forecasts under the Fifth and Sixth Power Plans.

Figure C-7: Forecast Residential Electricity Sales Compared to Fifth Plan Forecasts

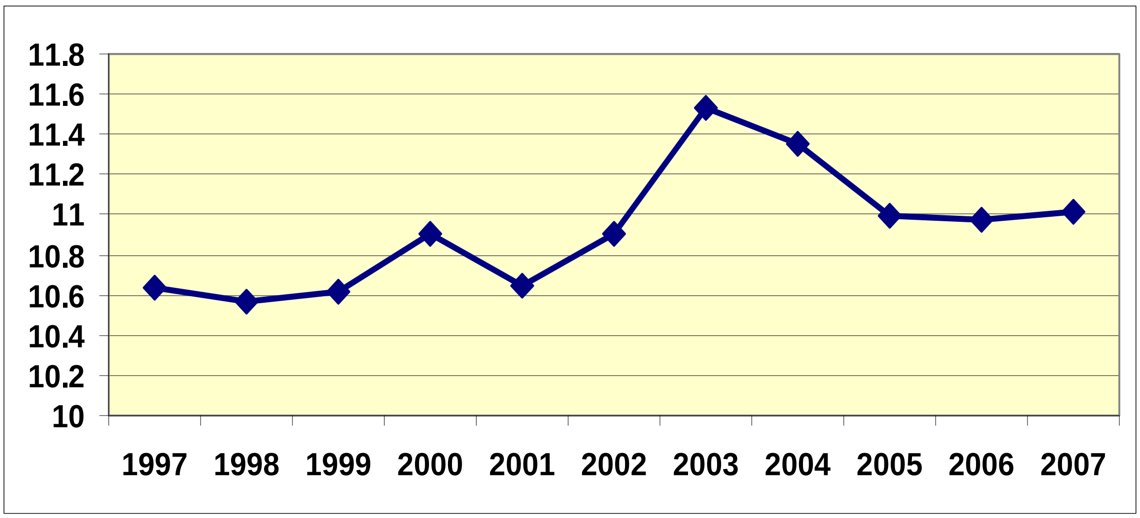


Commercial Sector Demand

History

Electricity demand in the commercial sector has increased regionally and nationally. In 1986, demand in the commercial sector of the region was about 4,000 average megawatts and by 2007 this sector required more than 6,000 average megawatts. Electricity intensity in the sector has also increased. Electricity intensity in the commercial sector is measured in kilowatt hours used per square foot. In 1997, the commercial sector's average electricity intensity was about 10.6 kilowatt hours per square foot. By 2003, it had increased to about 11.6 kilowatt hours per square foot. Since 2003, however, the intensity of electricity use in the commercial sector has been declining or has remained stable. The commercial sector also includes street lighting, traffic lights and load from municipal public facilities such as sewer treatment facilities.

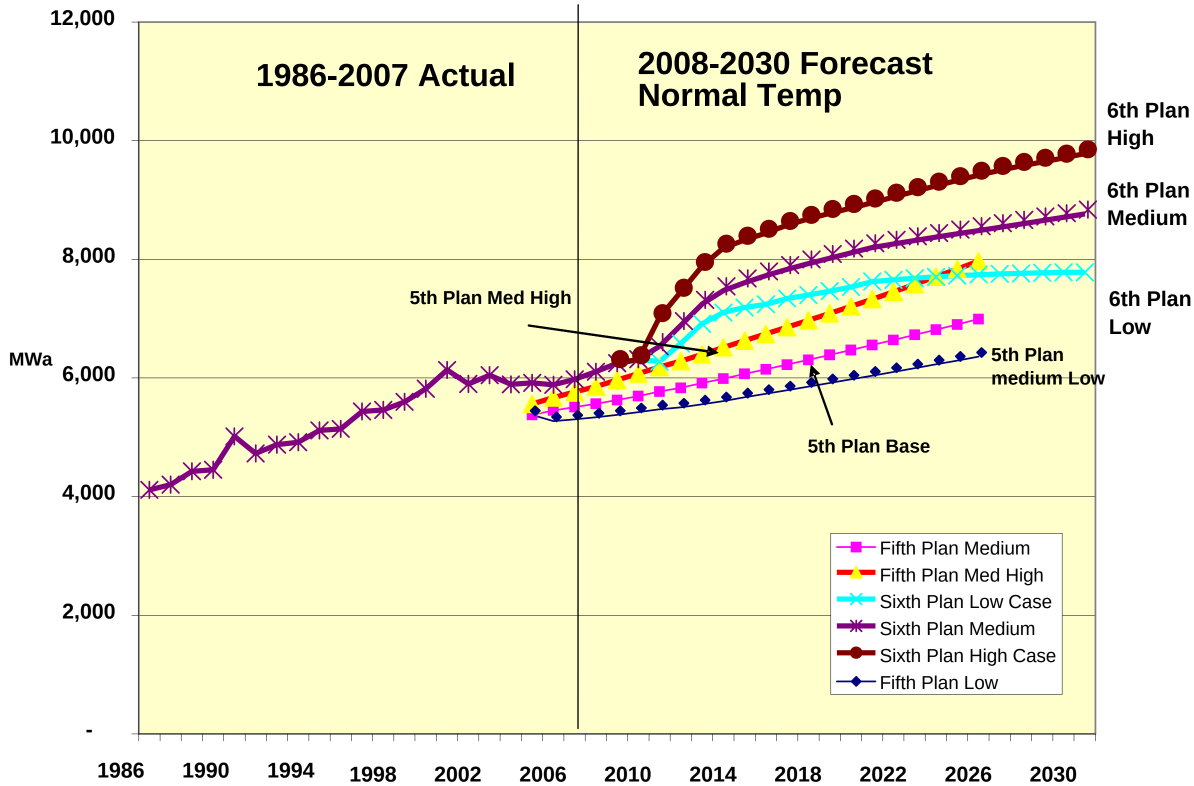
Figure C-8: Electricity Intensity in the Commercial Sector (kWh/SQF)



Commercial Demand Forecast

Commercial sector electricity consumption is forecast to grow by 1.5 percent per year between 2010 and 2030. During this period, demand is expected to grow from 6,500 average megawatts to about 8,800 average megawatts. This rate of increase is higher than the 1.18 percent per year that was forecast in the Fifth Power Plan. The following figure illustrates the forecast. Compared to the Fifth Power Plan forecast of commercial electricity use, the Sixth Power Plan trends have been adjusted upward to reflect underestimations of commercial demand. The forecast for 2025 is about 1,600 average megawatts higher than the 2025 medium forecast in the Fifth Power Plan. On average, this sector's predicted demand adds about 120 average megawatts per year during 2010 and 2030.

Figure C-9: Forecast Commercial Electricity Sales Compared to the Fifth Plan Forecasts



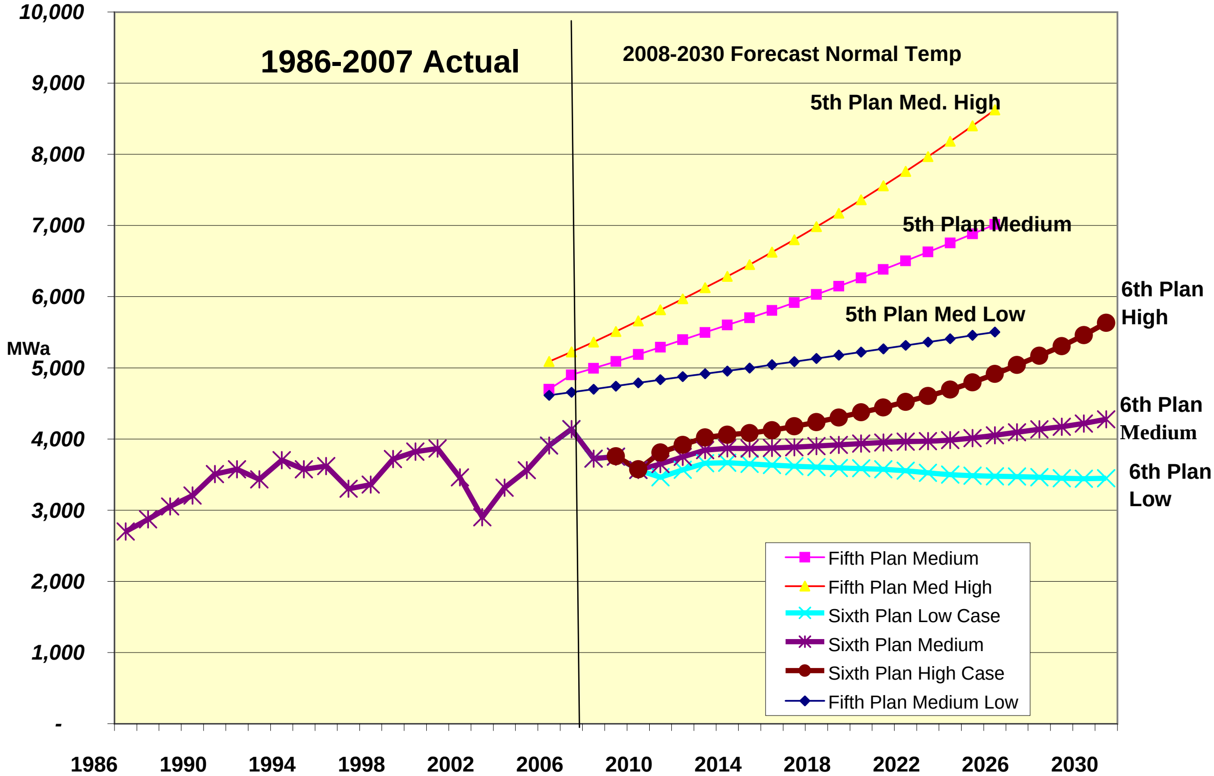
Non-DSI Industrial Sector

Industrial electricity demand is difficult to confidently forecast. It differs from residential and commercial sector demand where energy is used mostly for buildings and is reasonably uniform and easily related to household growth and employment. By contrast, industrial electricity use is extremely varied, and demand tends to be concentrated in relatively few very large, often specialized, uses instead of spread among many relatively uniform uses.

The non-DSI industrial sector demand is dominated by pulp and paper, food processing, chemical, primary metals other than aluminum, and lumber and wood products industries. Many of these industries have declined or are experiencing slow growth. These traditional resource-based industries are becoming less important to regional electricity demand forecasts, while new industries, such as semiconductor manufacturing, are growing faster and commanding a growing share of the industrial-sector load.

In the draft Sixth Power Plan, non-DSI industrial consumption is forecast to grow at 0.8 percent annually. Electricity consumption in this sector is forecast to grow from 3,700 average megawatts in 2007 to 4,300 in 2030. The non-DSI industries' demand peaked in 1999 reaching 4,000 average megawatts. Starting with the 2000-2001 energy crisis and the recession that followed, non-DSI consumption went down to about 3,700 average megawatts by the start of 2008.

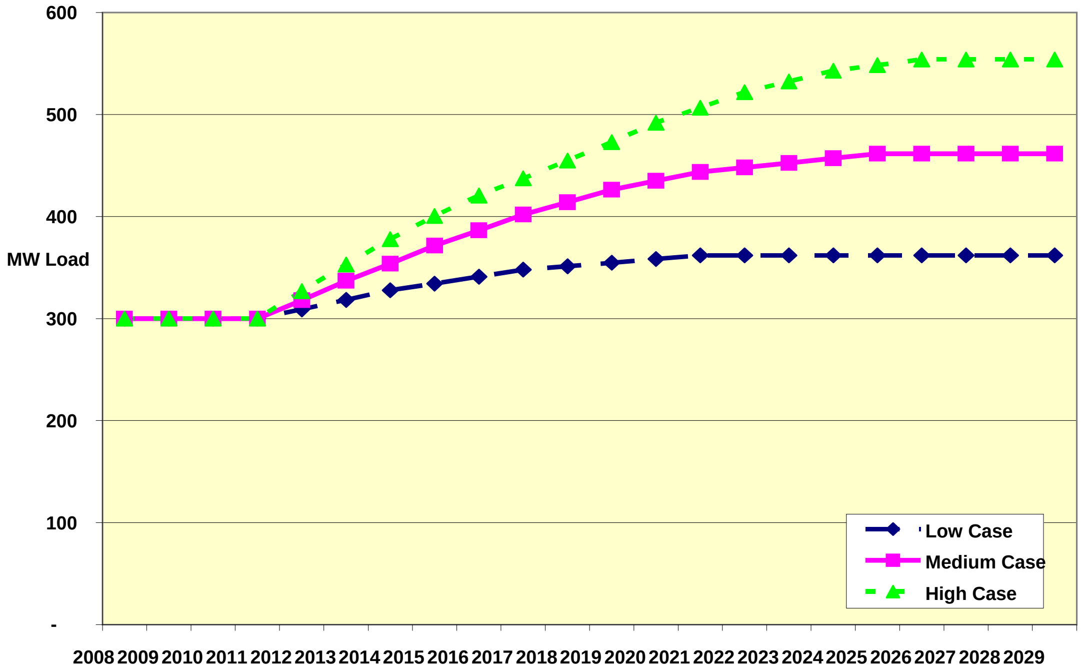
Figure C-10: Forecast Industrial Non-DSI Electricity Sales Compared To the Fifth Plan



Custom Data Centers

The non-DSI industrial load sector includes custom data centers. These centers are also known as data "farms" and "service centers" and support Internet services like the well-known Amazon.com or Google.com. These businesses do not manufacture a tangible product, but because they are typically on an industrial rate schedule and because of their size, they are categorized as industrial load. The region currently provides about 300 average megawatts to these types of businesses. The demand for services from this sector is forecast to increase by about 7 percent per year. However, there are many opportunities to increase energy efficiency in custom data centers. As a result, the demand forecast for these centers is adjusted to an annual growth rate of about 3 percent. Background and additional assumptions on custom data centers is presented at the end of this appendix.

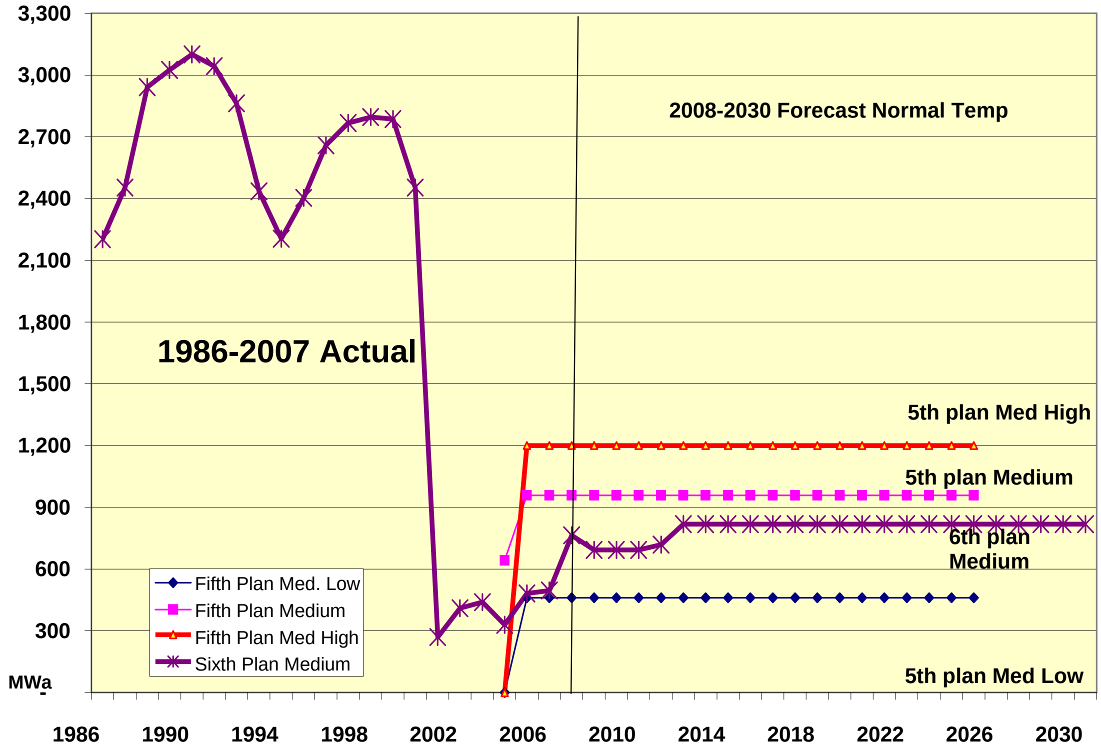
Figure C-11: Projected Load (MW) from Custom Data Centers



Aluminum (DSIs)

Historically, direct service industries (DSIs) have been industrial plants that purchased their electricity directly from the Bonneville Power Administration. They have played an integral role in the development of the region's hydroelectric system, for this industrial sector grew as the region's hydroelectric system grew. The vast majority of companies in this category are aluminum smelters. When all of the region's 10 aluminum smelters were operating at capacity, they could consume about 3,150 average megawatts of electricity. However, after the power crisis of 2000-2001, many smelters shut down permanently. Currently, only a few pot lines operate in the region, consuming about 750 megawatts of power. In the Fifth Power Plan, the Council developed models to forecast electricity consumption by DSI customers. In the draft Sixth Power Plan, a simplified forecast assumes that DSI consumption will be stable at around 818 average megawatts for the forecast period. This total includes power provided by Chelan County PUD to Alcoa's Intalco plant.

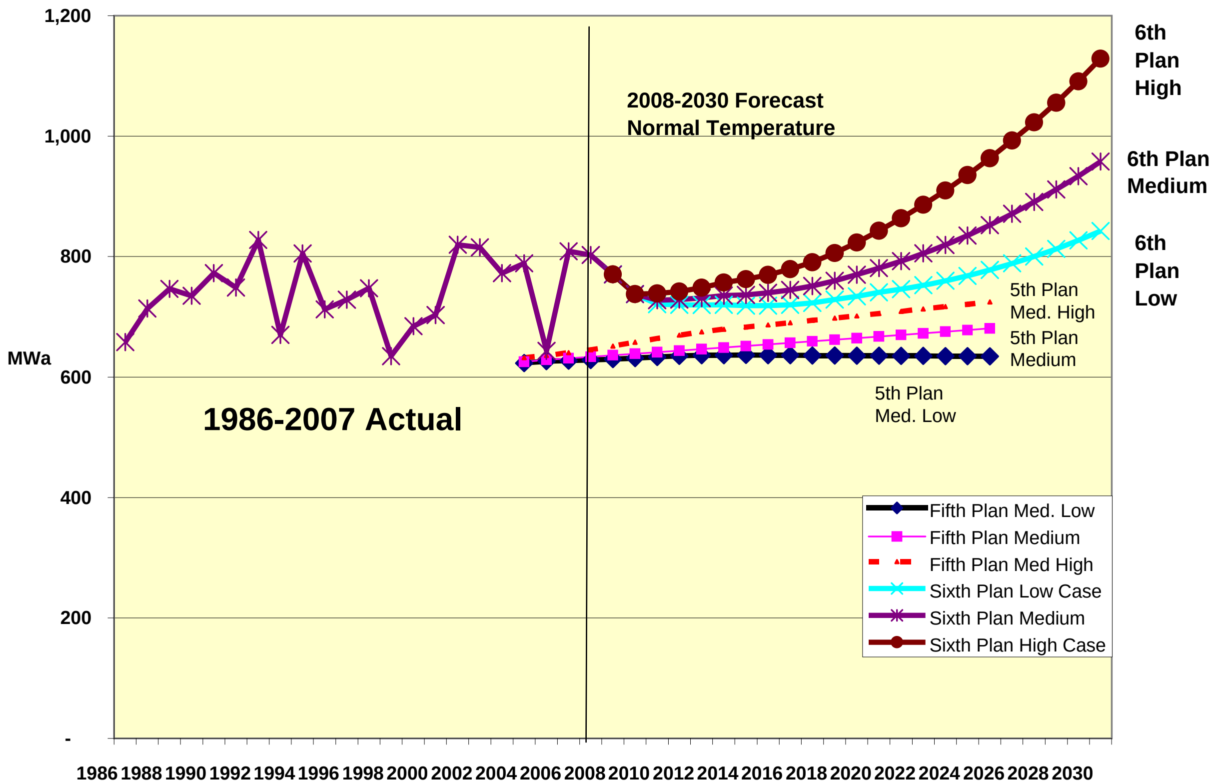
Figure C-12: Forecast DSI Electricity Sales Compared to the Fifth Plan Forecasts



Irrigation

Regional irrigation load is relatively small compared to the residential, commercial, and industrial sectors. Irrigation averaged about 740 average megawatts per year between 1986 and 2007 with little trend development discernable among the wide fluctuations that reflect year-to-year weather and rainfall variations. The electricity consumption in this sector is forecast to grow at 1.4 percent annually for the forecast period, slightly above its historic 1986-2007 growth rate. The main factor influencing demand for irrigation is precipitation. The main economic driver for this sector is the demand for agricultural products requiring irrigation. Agricultural output is forecast to grow at an average annual rate of 3-4 percent in the 2010-2030 period. Demand for electricity for food product manufacturing (fruits, meats, and dairy) is included in the industrial sector forecast.

Figure C-13: Irrigation Class, Electricity Sales Compared to the Fifth Power Plan Forecasts



The historic growth rate for the years 1986-2007 was about 0.95 percent per year. In the draft Sixth Power Plan, the irrigation sector is forecast to grow at an annual rate of 0.7 percent for 2010-2020, and at faster growth rate between 2020-2030. If projected increases in summer temperatures are realized, the need for irrigation to support agricultural crops could increase.

Regional data on irrigation load has been difficult to obtain. An action item for the Sixth Power Plan might be to establish a reporting mechanism to the Council so that irrigation load can be followed more frequently and accurately.

Transportation Demand

The use of electricity in the transportation sector, consisting mainly of mass transit systems in major metropolitan cities in the region, typically has been estimated to be about 60 average megawatts. The plug-in electric vehicle could be a growing segment of this sector. The Council's preliminary analysis indicates that demand from plug-in electric vehicles could add 100-550 average megawatts to regional electricity use. In the sensitivity section of the draft Sixth Power Plan, the effect of plug-in electric vehicles will be included in the analysis.

Demand History and Forecast by State

In the past, the Council's demand forecast was available at the regional level. In the draft Sixth Power Plan, state-level forecasts are also available. A brief review of the historic growth rate and forecast growth rate for each state is presented in the following graph and table. Demand has been growing faster in Oregon and Idaho compared to Washington and Montana. The 2000-2001 energy crisis and the closure of DSIs in Washington, Montana, and Oregon caused a substantial drop in industrial load. Residential demand for electricity has been growing at an average annual rate of 1.4-2.2 percent per year. Commercial demand has been growing at 0.4-2.2 percent per year. Industrial demand has had a negative growth rate in all states except Idaho. Idaho industrial load has been growing at 2.7 percent per year in the 1986-2007 period.

Figure C-14: Historic and Forecast Demand for Electricity (MWa)

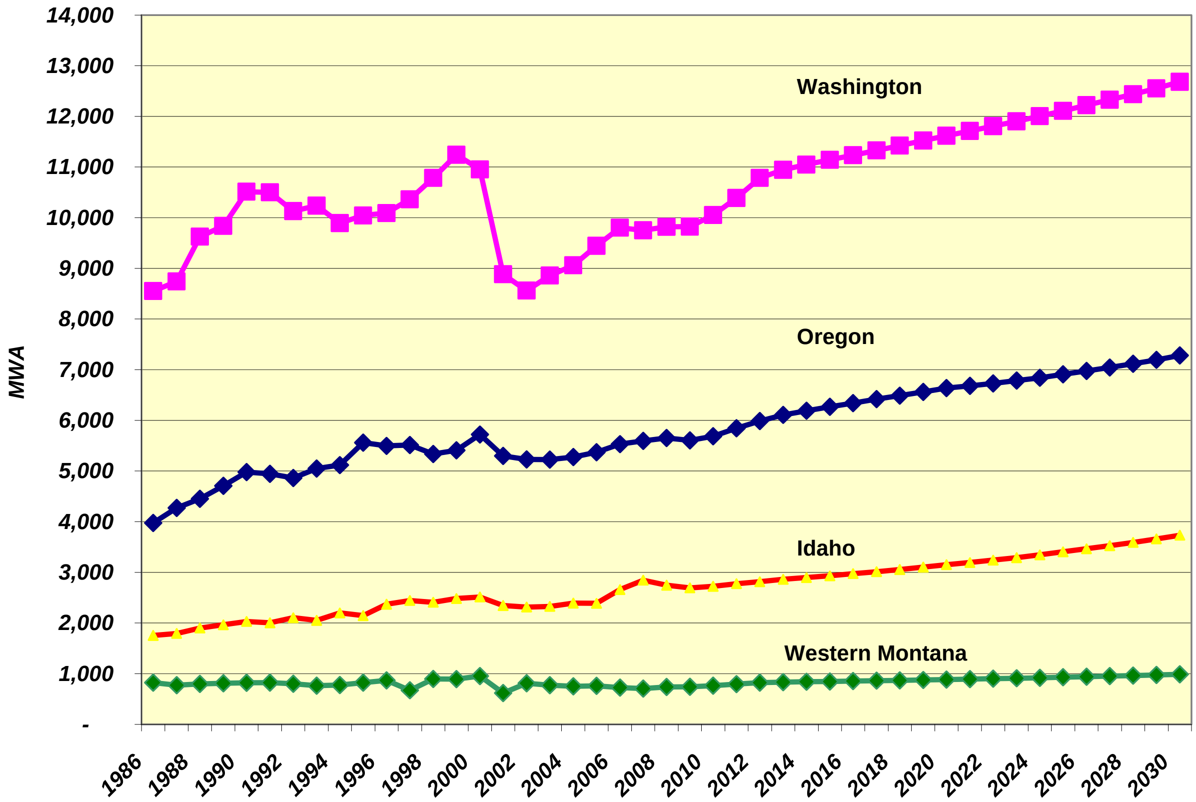


Table C-4: Average Annual Growth Rate[1] in Demand for Electricity

	Oregon	Washington	Idaho	Western Montana	Region
1986-2007	1.64%	0.63%	2.32%	-0.73%	1.64%
2010-2020	1.56%	1.46%	1.46%	1.48%	1.56%
2010-2030	1.24%	1.17%	1.59%	1.28%	1.24%

Monthly Pattern of Demand

Demand is not evenly distributed throughout the year. In the Northwest, demand for electricity is higher in the winter and summer and lower in spring and fall. The historic demand for electricity for the region shows a "W"-shaped profile. Approximately 9-10 percent of annual

[1] Caution is warranted when interpreting the average annual growth rate. The average annual growth rate is sensitive to medium year values. Additional information on annual demand for each state is available in the companion Excel worksheet available on the Council's website, and will provide a more accurate picture of historic and future growth.

electricity in the region is consumed in the winter months of January and December. In the shoulder months (March through June, and September through November) monthly energy consumption is about 8 percent. In summer months, it is slightly above 8 percent. Similar patterns can be observed in each one of the four states, with electricity demand in Idaho slightly higher in summer and slightly lower than the regional average in winter months.

Figure C-15: Monthly Pattern of Demand for Electricity

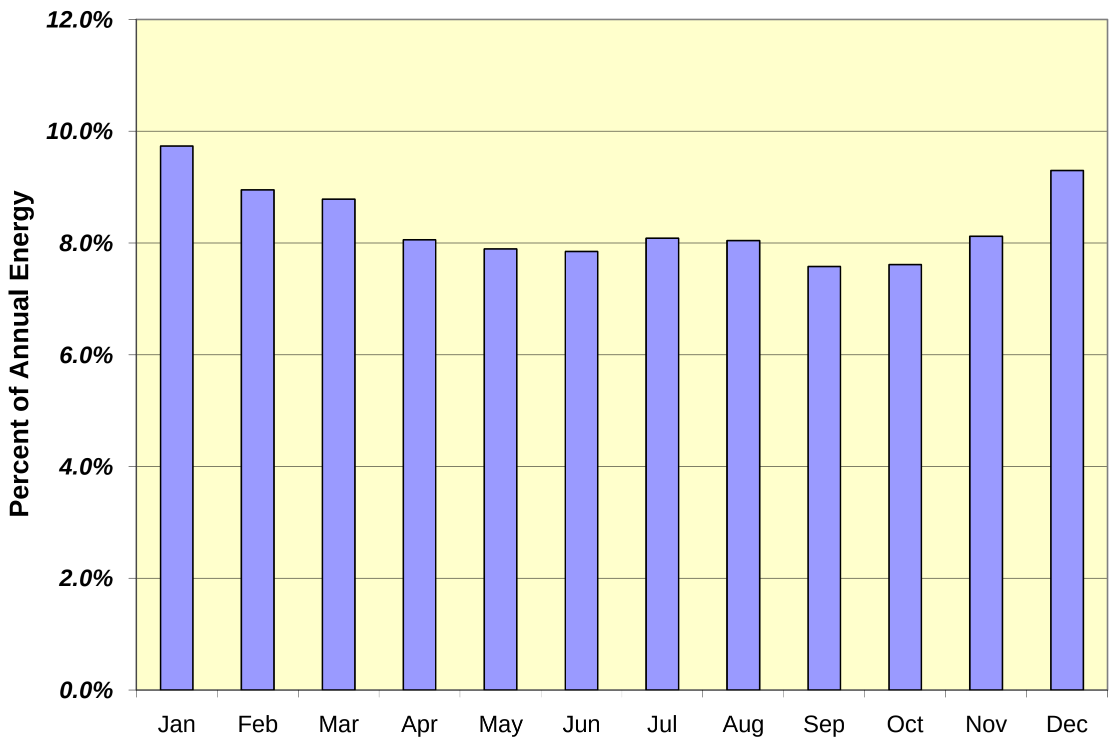


Table C-5: Monthly Pattern of Demand for Electricity

	ID	MT	OR	WA	Region
Dec	9%	9%	9%	9%	9%
January	9%	10%	10%	10%	10%
July	10%	8%	8%	8%	8%
Aug	9%	8%	8%	8%	8%

In order to make sure there are sufficient resources available to meet demand, it is necessary to forecast the timing of peak load.

REGIONAL PEAK LOAD

As discussed in Appendix B of the draft Six Power Plan, the temporal pattern of demand and its peaks are becoming more important. The region was once constrained by average annual energy supplies. Today, the region is more likely to be constrained by sustained-peaking capability.

To better forecast the temporal pattern of demand and hourly load, generators may have to development of two sets of models:

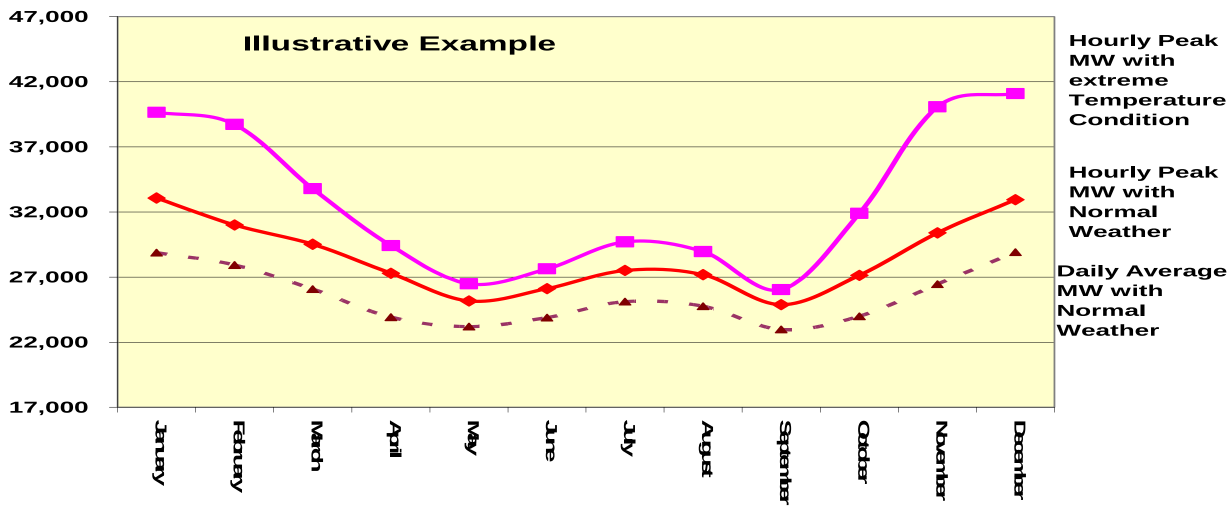
- A short-term load forecasting model that projects 3-5 years into the future on an hourly basis. The short-term model is used for the resource adequacy analysis.
- A long-term load forecasting model that projects 20 years into the future on a monthly basis.

This appendix discusses the long-term forecasting model.

Seasonal Variation in Load

Regional load has significant seasonal variability driven by temperature changes. Although the Northwest is a winter-peaking region, there can be a significant range in winter load. Illustrating this, the following graph measures three examples of load. The dashed line shows the daily average megawatts of energy under normal weather conditions. Winter daily energy demand is about 28,000 megawatts, and summer average demand is about 24,000 megawatts. With normal weather, the peak-hour load in winter reaches over 33,000 megawatts, and the summer peak increases to about 28,000 megawatts. If weather conditions are extreme, then the hourly load can increase substantially and has reached more than 41,000 in winter and more than 30,000 in the summer.

Figure C-16: Range of Variation in Load



Demand Versus Load

The demand forecast figures presented earlier were for customer demand and did not include transmission and distribution losses. This energy loss from transmission and distribution varies depending on temperature conditions and the mix of sectors. Higher temperatures means a greater loss of energy. Transmission and distribution losses also increase as the regional load shifts to the residential or commercial sector. Large industrial customers like the DSIs typically have lower losses because they can receive power at the transmission level. The following table shows the projected annual load and sales for the region.

Table C-6: Annual Demand and Loads (MWa)

	Annual Demand	Annual Load		Annual Demand	Annual Load
2009	18,861	21,261	**2020**	22,288	25,124
2010	19,224	21,670	**2021**	22,482	25,342
2011	19,803	22,322	**2022**	22,677	25,563
2012	20,405	23,000	**2023**	22,884	25,796
2013	20,742	23,381	**2024**	23,111	26,051
2014	20,969	23,637	**2025**	23,352	26,323
2015	21,186	23,881	**2026**	23,599	26,601
2016	21,399	24,122	**2027**	23,851	26,885
2017	21,616	24,367	**2028**	24,108	27,175
2018	21,834	24,613	**2029**	24,381	27,482
2019	22,062	24,870	**2030**	24,678	27,817

Resource Adequacy and Peak Forecast

To make sure adequate resources are available to meet load under the range of variations shown in Table C-6, regional resource adequacy guidelines have been established. These guidelines do not focus on peak load for a single hour, but rather use the concept of a sustained-peak period (SPP). Sustained-peak period is defined as an 18-hour period over three consecutive days. The sustained-peak load for adequacy assessment is determined in the short-term forecasting model. A discussion on the development and application of short-term can be found in the Resource Adequacy Forum, February 5, 2007 Technical Committee Meeting.[2]

Peak Load Forecast Methodology (Long-term Model)

One approach to forecasting temporal demand is to use historical monthly and hourly patterns. In the Fourth Power Plan, the Council used an extremely detailed hourly electricity demand forecasting model to estimate future hourly demand patterns. The methodology used in the draft Sixth Power Plan is similar to the Fourth Power Plan approach, in which the detailed hourly demand for numerous end-uses and sectors built the model's load profile.

In the draft Sixth Power Plan, monthly demand patterns for specific end-uses were used to create a cumulative regional load forecast. Hourly load profiles for each end-use were mapped against the system load profile and an end-use specific load shape factor (LSF) was calculated. This tells us which end-use is contributing to the peak and by how much. The calculation for LSF is done on a monthly basis. This method allows the Council's model to make specific forecasts for end-uses that are increasing like air conditioning or ICE technologies.

The load shape factors currently used by the Council were gathered from the best available data, but they should be updated. An action item for the Sixth Power Plan is to update the load shape for various end-uses.

[2] http://www.nwcouncil.org/energy/resource/meetings/2007/02/20507%20Tech%20Short%20Term%20Loads.pdf

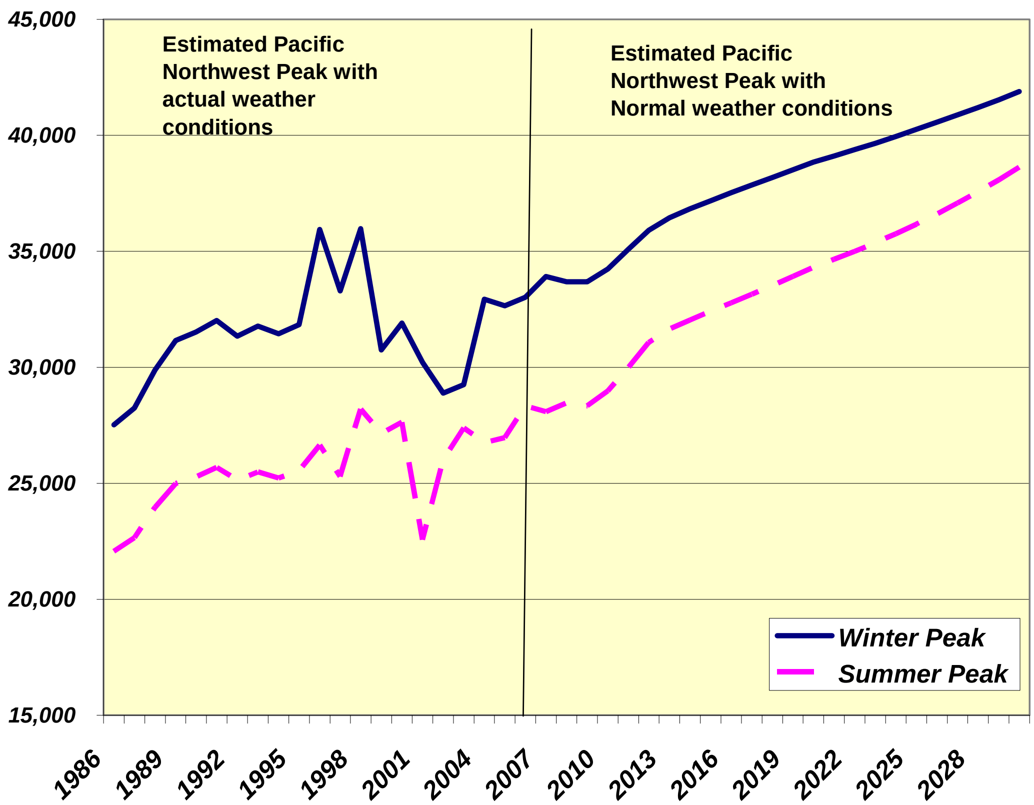
Regional Peak Load Forecasts

The regional peak load is expected to grow from about 34,000 megawatts in 2010 to around 42,000 megawatts by 2030 at an average annual growth rate of 1.0 percent. With no climate change scenarios, the region is expected to remain winter peaking until near the end of the planning horizon. Figure C-17 shows the forecast peak load for winter and summer months under different scenarios. Note that the estimated peak load for 2007 reflects the actual peak temperatures for 2007. However, the peak load forecasts for 2010, 2020, and 2030 are based on normal weather conditions. The forecast of peak load suggests that the region's winter and summer peak loads become close by the end of forecast period, about 3,000 MW apart. The growth rate for the summer peak is higher than the winter peak. The growth rate for the winter peak is 1.0 percent per year compared to the summer peak growth rate of 1.5 percent.

Table C-7: Total Summer and Winter Peak Load Forecasts MW

	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Medium - Winter	33,908	34,243	38,842	41,885	1.3%	1.0%
Medium - Summer	28,084	28,976	34,313	38,630	1.7%	1.5%

Figure C-17: Peak Load Demand for Electricity (MW)



The growth rate of summer and winter peak load depends on the growth rate of the economy in general. In the high-growth scenario, the summer peak grows at 1.8 percent per year. In the low-growth scenario, the summer peak grows at 1.1 percent per year. The winter peak load in the region could increase from about 34,000 megawatts in 2007 to about 46,000 megawatts in

2030. The summer peak load is forecast to grow at a faster rate, 1.1-1.8 percent per year, increasing from about 28,000 megawatts in 2007 to about 43,000 megawatts by 2030.

Table C-8: Total Summer and Winter Peak Load Forecasts MW

	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - Winter	33,908	33,795	37,109	39,060	0.9%	0.7%
Low - Summer	28,084	28,229	32,462	35,357	1.4%	1.1%
Medium - Winter	33,908	34,243	38,842	41,885	1.3%	1.0%
Medium - Summer	28,084	28,976	34,313	38,630	1.7%	1.4%
High - Winter	33,908	35,416	41,481	46,552	1.6%	1.4%
High - Summer	28,084	30,232	36,876	43,413	2.0%	1.8%

Residential Sector

Peak load for the residential sector during the winter season is estimated to increase from about 19,700 megawatts in 2007 to about 23,000 megawatts by 2030, an annual growth rate of about 0.8 percent per year. This growth rate is slower than forecast growth rate for energy demand in the residential sector. During the summer peak, high demand by the residential sector is anticipated to increase by 0.8-2.2 percent per year, depending on the economic growth scenario.

Table C-9: Residential Summer and Winter Peak Load Forecasts MW

Residential	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	19,721	19,797	20,925	22,708	0.6%	0.7%
Low - July	8,438	8,960	10,427	13,082	1.5%	1.9%
Medium - January	19,721	19,688	21,400	23,128	0.8%	0.8%
Medium - July	8,438	8,921	10,604	13,257	1.7%	2.0%
High - January	19,721	20,000	22,353	24,611	1.1%	1.0%
High - July	8,438	9,032	10,979	13,918	2.0%	2.2%

Commercial Sector

Peak load for the commercial sector during the winter season is estimated to increase from about 5,700 megawatts in 2007 to about 8,500 megawatts by 2030, an annual growth rate of 1.7 percent per year. The summer season peak loads in this sector are projected to grow from 9,000 megawatts in 2007 to about 13,000 megawatts in 2030, or about 1.5 percent per year. This growth rate is consistent with the growth rate in the annual energy use forecast for this sector.

Table C-10: Commercial Summer and Winter Peak Load Forecasts MW

Commercial	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	5,705	5,875	7,252	7,400	2.1%	1.2%
Low - July	9,035	9,221	11,336	11,600	2.1%	1.2%
Medium - January	5,705	6,142	7,903	8,522	2.6%	1.7%
Medium - July	9,035	9,644	12,182	13,040	2.4%	1.5%
High - January	5,705	6,699	8,810	9,777	2.8%	1.9%
High - July	9,035	10,396	13,254	14,470	2.5%	1.7%

Industrial Sector

The load profile of the industrial sector is typically flat, with little hourly or seasonal variation. In the winter, the estimated industrial sector contribution to the electricity system's peak is anticipated to be about 4,900 megawatts in 2007, increasing to about 5,500 megawatts by 2030. During the summer season, the industry's contribution to the region's peak use is slightly greater than its contribution to winter peak demand because the regional summer peak usually occurs during mid-day working hours, whereas the system winter peak occurs during either early morning or early evening.

Table C-11: Industrial Summer and Winter Peak Load Forecasts MW

Industrial	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	4,933	4,511	4,771	4,632	0.6%	0.1%
Low - July	7,720	7,098	7,439	7,585	0.5%	0.3%
Medium - January	4,933	4,728	5,190	5,543	0.9%	0.8%
Medium - July	7,720	7,336	8,011	8,921	0.9%	1.0%
High - January	4,933	4,916	5,733	7,079	1.5%	1.8%
High - July	7,720	7,557	8,778	11,037	1.5%	1.9%

Irrigation Sector

Agricultural crops are not irrigated in the winter, so the irrigation sector does not contribute to the winter system peak. However, this sector can contribute significantly to the system peak in the summer. The estimated contribution of the irrigation sector to the 2007 summer peak was about 2,400 megawatts. Peak-load demand is projected to grow to about 2,900 megawatts by 2030.

Table C-12: Irrigation Summer and Winter Peak Load Forecasts MW

Irrigation	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	-	-	-	-		
Low - July	2,412	2,176	2,237	2,539	0.3%	0.8%
Medium - January	-	-	-	-		
Medium - July	2,412	2,196	2,359	2,886	0.7%	1.4%
High - January	-	-	-	-		
High - July	2,412	2,229	2,545	3,402	1.3%	2.1%

Street Lighting and Public Facilities

This sector consists of street lighting, traffic lights, and water and sewer facilities. The energy forecast for this sector is typically combined with the commercial sector demand. In 2007, this sector contributed an estimated 837 megawatts to the summer peak and by 2030, this sector's share of summer peak is projected to grow to about 1,000 megawatts. This sector is projected to grow at 1.1 percent per year between 2010 and 2030.

Table C-13: Irrigation Summer and Winter Peak Load Forecasts MW

	2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2010-2030
Low - January	780	815	914	1,008	1.2%	1.1%
Low - July	837	873	979	1,079	1.1%	1.1%
Medium - January	780	815	914	1,008	1.2%	1.1%
Medium - July	837	873	979	1,079	1.1%	1.1%
High - January	780	815	914	1,008	1.2%	1.1%
High - July	837	873	979	1,079	1.1%	1.1%
Low - January	780	815	914	1,008	1.2%	1.1%

ELECTRICITY DEMAND GROWTH IN THE WEST

Electricity demand is analyzed not only by sector but by geographic region. The Council's AURORA^{xmp} electricity market model requires energy and peak load forecasts for 16 areas, four of which are forecast by the Council's demand forecast model and 12 for other areas in the Western U.S., Canada, and Mexico. Council staff projected both energy and peak demand growth in nine of these 12 areas (those in the U.S.) based on 2008-2017 forecasts submitted to the FERC (EIA Form 714) by electric utilities. The forecast for Alberta for the same years was based on the forecast by the Alberta Electric System Operator (AESO).[3] The Council's forecast for British Columbia was based on a forecast BC Hydro submitted to the Western Electricity Coordinating Council (WECC) for the period 2010-2017, supplemented by data from the British Columbia Transmission Corporation (BCTC)[4] for 2007 and interpolation for 2008 and 2009. The forecast load for northern Baja California in Mexico was based on the forecast submitted to WECC for 2010-2017, the 2006 load previously used by AURORA, and interpolated values for 2007-2009.

AURORA requires area load projections for each year to 2053, so Council staff extended the forecasts past 2017 by calculating a rolling average of most areas for the past five years. For the Arizona and New Mexico areas, the load from 2021 through 2027 was projected to grow at the same rate as the projected population growth in each state. After 2027, load was projected to continue to grow at the 2027 rate. The load for northern Baja California was similarly projected, except that the population growth rate for New Mexico was used for 2021-2027 (population projections for Baja California were unavailable).

[3] http://www.aeso.ca/downloads/Future_Demand_and_Energy_Outlook_(FC2007_-_December_2007).pdf
[4] http://www.bctc.com/NR/rdonlyres/C6E06392-7235-4F39-ADCD-D58A70D493C7/0/2006controlareaload.xls

Table C-14: Naming Convention for Aurora Areas

Area Name	Short Area Name
Pacific NW Eastside	PNWE
California North	CAN
California South	CAS
British Columbia	BC
Idaho South	IDS
Montana East	MTE
Wyoming	WY
Colorado	CO
New Mexico	NM
Arizona	AZ
Utah	UT
Nevada North	NVN
Alberta	AB
Mexico Baja CA North	BajaN
Nevada South	NVS
Pacific NW Westside	PNWW

AURORA's model information covers a large and diverse area. Figure C-18 shows the 2010 projected demand for energy.

Figure C-18: 2010 Projected Electricity Load by AURORA Area (MWa)

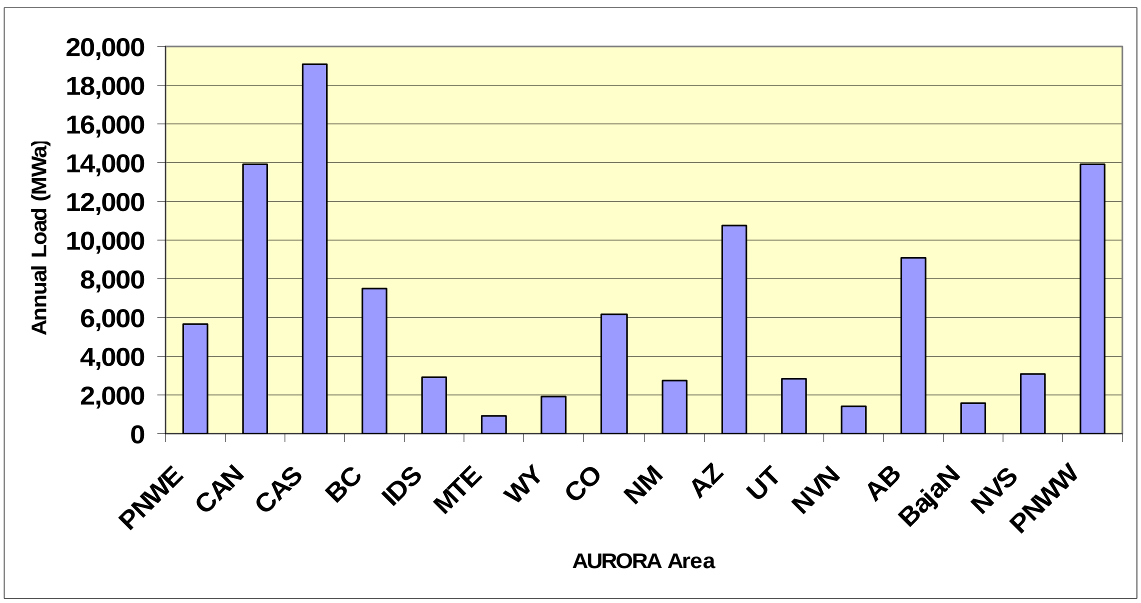


Figure C-19 shows the 2008-2027 projected growth rates for demand in the 16 geographic areas. The figure shows the projected growth rates for areas that are expected to experience demand increases of less than 1 percent and areas that are forecast to experience demand increases of nearly 4 percent. The highest projected rates of change are the geographic areas of Alberta, Canada, and northern Baja California, followed by Arizona and southern Nevada. The lowest rates are for northern California, southern California, and northern Nevada, all anticipated to grow at less than 1 percent by 2027. The four Pacific Northwest areas have projected load growth rates in the mid-range of the WECC area, at about 1.6 percent by 2030. These areas include: the eastern portions of Oregon and Washington, the northern part of Idaho (PNWE), southern Idaho (IDS), eastern Montana (MTEa), and the western portions of Oregon and Washington (PNWW).

Figure C-19: Per Cent Annual Growth 2008-27 by AURORA Area (MWa)

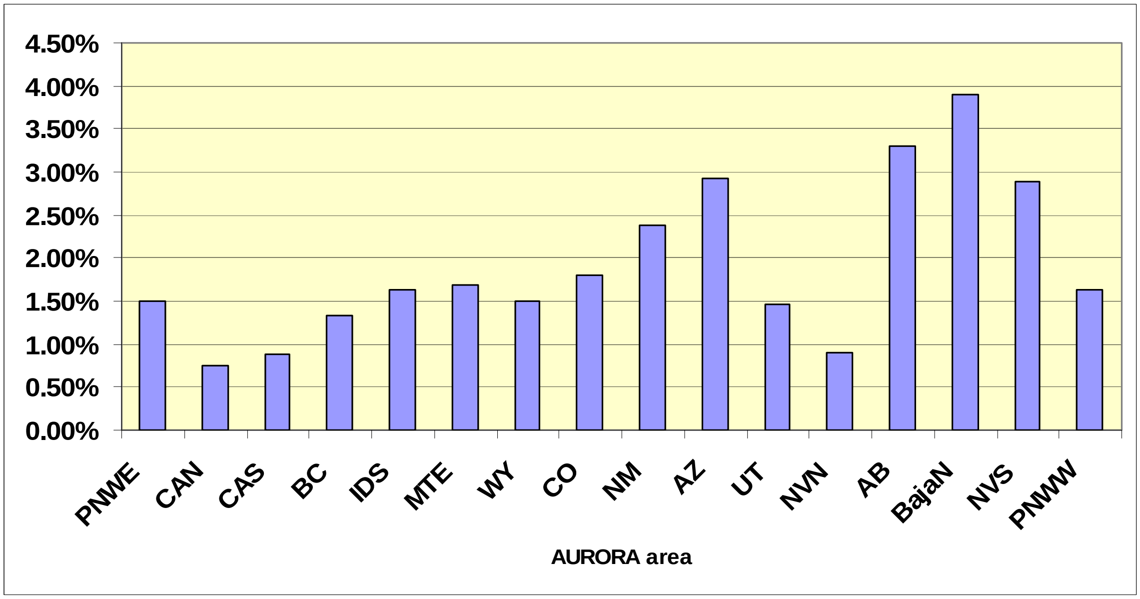


Figure C-20: 2010 Projected Peak Load by AURORA Area (MW)

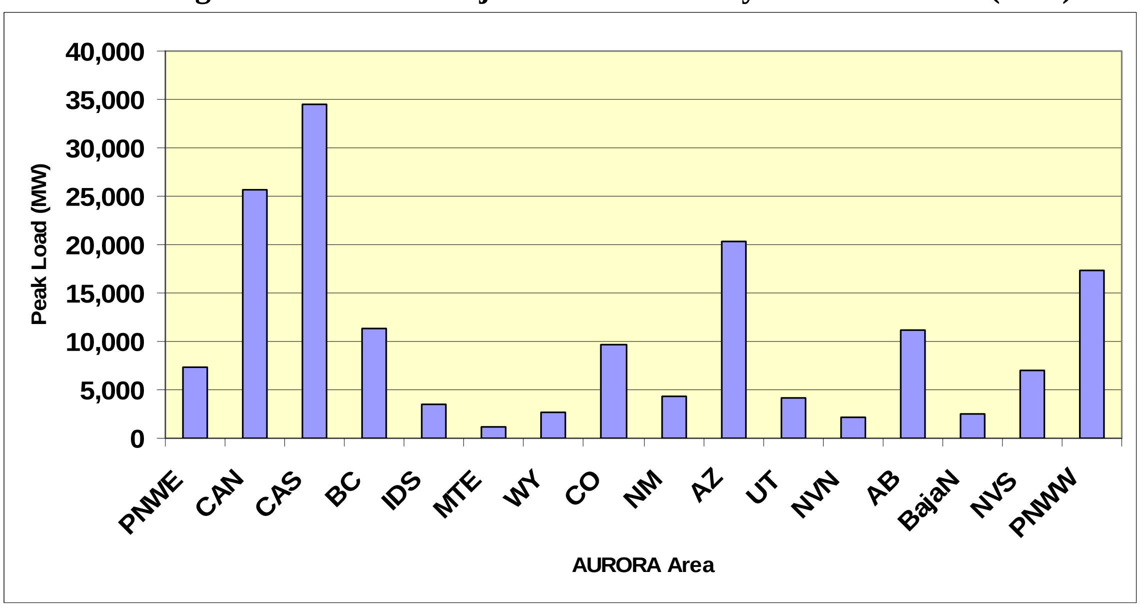


Figure C-18 shows the 2010 projected peak load by AURORA area. The figure demonstrates a wide range in projections of peak demand among geographic areas. It is important to note that these projections are non-coincident (individual utility) peaks, and while six of the areas (PNWE, BC, MTEa, WY, AB, and PNWW, totaling about 51,000 megawatts) are winter peaking, the rest of WECC, totaling about 114,000 megawatts, are summer-peaking areas. The WECC area as a whole is summer peaking.

SPECIAL TOPICS

This section describes the impact of custom data centers and plug-in hybrid electric vehicles (PHEV) on demand. The effects of PHEV on demand will be treated as a sensitivity analysis.

Estimating Electricity Demand in Data Centers

Background on Trends in Data Center Load

A brand new load type has emerged as recently as 2000. Large data centers have been attracted to the Northwest because of its low electricity prices and moderate climate, meaning fewer storms and power interruptions.

What is a Data Center?

"Data center" is a generic term used to describe a number of different types of facilities that house digital electronic equipment for Internet-site hosting, electronic storage and transfer, credit card and financial transaction processing, telecommunications, and other activities that support the growing electronic information-based economy.[5] In general, data centers can be categorized into these two main categories:

- Custom data centers, such as Google, Yahoo, and Microsoft sites in the Grant County PUD and Northern Wasco County PUD. These data centers are typically very large, consisting of thousands of servers and representing a significant demand for power. They are usually sited close to transmission facilities and are typically charged industrial retail rates by their local utility.

- Hidden data centers, like those in business offices, may include a small separate office or closet with a few servers, or larger server facilities with hundreds of servers. These data centers are called "hidden data centers" because they are part of existing commercial businesses. They are usually in urban settings and are typically charged commercial retail electric rates by their local utility.

Tracking load from data centers (especially custom data centers) is important because their growth rate has been swift, and their size generally creates a large demand. The Council currently estimates that the region has about 300 average megawatts of connected load used by custom data centers, and another 300 average megawatts of load that can be attributed to hidden data centers. If national projected trends for non-custom servers holds true, the load from these data centers can increase by 50 percent by the year 2011.

National Picture: Research conducted nationally for the EPA[6] in 2005 shows that electricity sales for servers and data centers was about 6,200 average megawatts or about 1.5 percent of total U.S. retail electricity sales. This estimated level of electricity consumption is more than the electricity consumed by the nation's color televisions, and is similar to the amount of electricity consumed by approximately 5.8 million average U.S. households (or about 5 percent of the total U.S. housing stock). The energy use of the nation's servers and data centers in 2006 is estimated

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[5] http://www.gulfcoastchp.org/Markets/Commercial/DataCenters

[6] Report to Congress on Server and Data Center Energy Efficiency Public Law 109-431

to be more than double the electricity consumed for this purpose in 2000. The power and cooling infrastructure that supports IT equipment in data centers also uses significant energy, and accounts for 50 percent of the total electricity consumption of these centers. Among the different types of data centers, the nation's largest (enterprise-class facilities used by the banking industry or the airline industry) and most rapidly growing data centers use more than one-third (38 percent) of the electricity from this sector.

This total does not yet include the load of larger custom server sites. No detailed estimates for load from these types of data centers exist. However, Lawrence Berkeley Labs conservatively estimates the demand of these sites to be about 900 average megawatts nationally. In total, 1.7 percent of national retail electric sales can be attributed to servers and data centers.

Regional Picture: To estimate the total load for servers and data centers in the region, the Council assumed that the region's demand from these sites is similar to the nation's demand. To verify this assumption, the percent of each state's gross state product generated by information-intensive industries (such as Internet-service providers and financial institutions) was calculated. Then, the same percentage at the national level was calculated and the two figures compared. The analysis showed that the information-intensive industries' contribution to the GSP is similar to the contribution of the same industries nationally. The region as a whole is similar to the nation in the contribution of information-intensive industries to the regional economy. The analysis showed that in the Northwest, 1.47 percent of total electricity sales, or about 285 average megawatts, can be attributed to servers and data centers.

This estimate excludes custom data centers attracted to the region by access to fiber optic networks, low electricity prices, and a moderate climate. The Council contacted utilities serving these customers for more information. Preliminary estimates put the custom data centers' consumption at about 300 average megawatts of connected load. Typically, custom data centers project their future peak power requirements and the local utility then sizes the distribution facilities to those requirements. Conversations with utilities indicate that the full load would occur over several years rather than immediately.

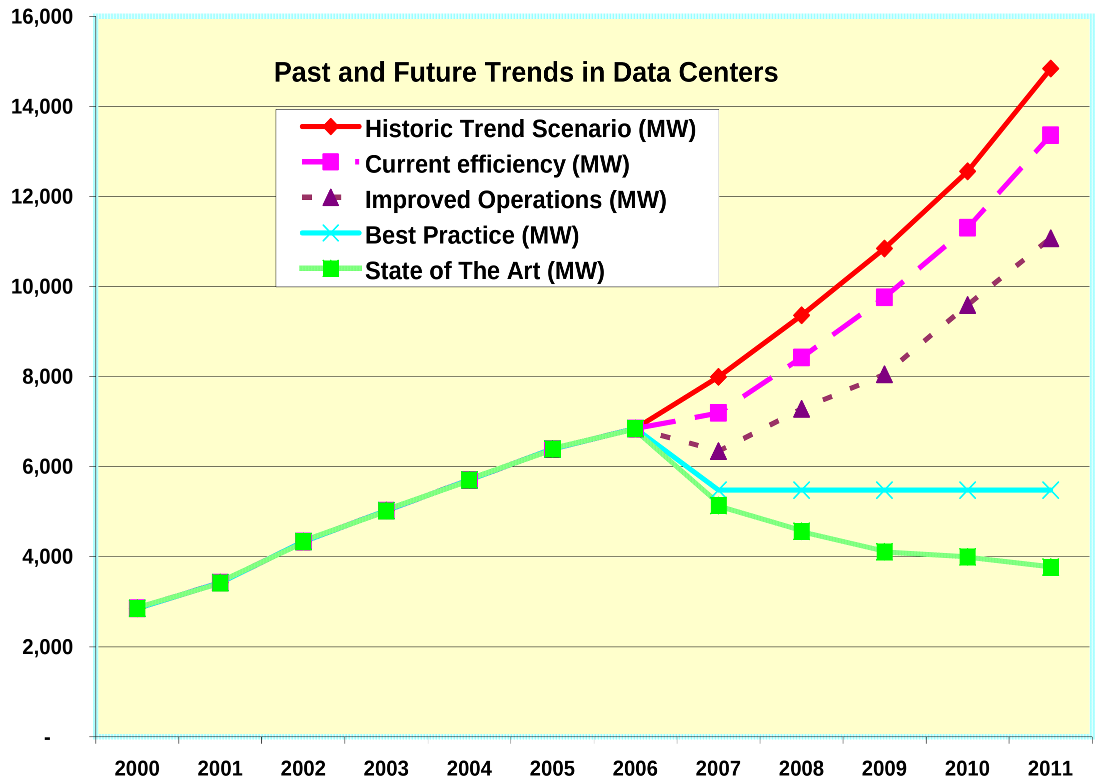
Future Trends: Nationally, electricity sales to server operations have grown suddenly and rapidly. By 2010, the number of total U.S. installed servers is expected to increase from 5.6 million in 2000 to over 15 million servers. This phenomenal sales growth highlights the impact of servers and data centers on demand. But there are also many opportunities to reduce this sector's demand. In the EPA study mentioned earlier, three different energy-efficiency scenarios were explored:

- The "**improved operation**" scenario includes energy-efficiency improvements beyond current efficiency trends that are essentially operational changes and require little or no capital investment. This scenario represents the "low-hanging fruit" that can be harvested simply by operating the existing capital stock more efficiently. An example of low-hanging fruit is isolating hot and cold isles in the data center, thus reducing air-conditioning demand. Potential savings from this category of improved energy efficiency: 30 percent.

- The "**best practice**" scenario represents the efficiency gains that can be obtained through the more widespread adoption of practices and technologies used in the most energy-efficient facilities in operation today. Potential savings from this category of improved energy efficiency: 70 percent.

- The "**state-of-the-art**" scenario identifies the maximum energy-efficiency savings that could be achieved using available technologies. This scenario assumes that U.S. servers and data centers will be operated at the maximum possible energy efficiency using only the most efficient technologies and the best management practices available. Potential savings from this category of improved energy efficiency: 80 percent.

Figure C-21: National Forecast for Demand from Data Centers



If regional trends follow national trends, load from non-custom servers will increase from its current 285 average megawatts to about 570 average megawatts. Load for custom data centers may also double by 2010. However, there are indications that this projected doubling may not occur. Growth-limiting factors include technological improvements like the use of "virtualization" (using one server to do the job of many), the use of alternative storage technologies, better power management, as well as other limiting factors such as access to water for cooling needs, limitations on tax incentives, and limitations on below-market electricity rates.

Conservation Opportunities: Significant conservation opportunities may be available, depending on the type of data center. For example, installing the proper size of cooling equipment can significantly reduce consumption. Cooling technologies for server equipment may help the industry maintain, rather than increase, the cost of custom data centers. Currently, we do not have a good baseline assessment of the installed cooling equipment in hidden and custom data centers. An action item for the Sixth Power Plan would be to establish such a baseline.

Methodology for Estimating Custom Data Center Loads

Load for non-custom (hidden) data centers is imbedded in the commercial sector load forecast and is not separately estimated. Load for custom data centers is forecast separately using the following method:

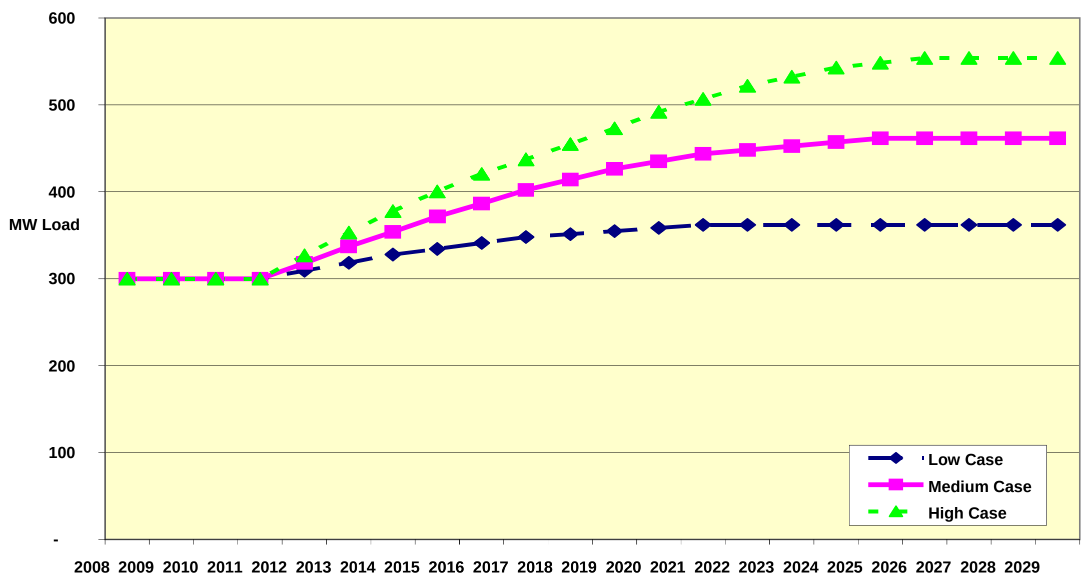
Load for this type of data center in 2008 was estimated. Two trends were then considered. The first trend reflects the increase of demand for services from this sector at a rate of 3 -10 percent per year (3 percent for a low-growth scenario, 7 percent for a medium-growth scenario, and 10 percent for a high-growth scenario). The second trend is the potential improvement in energy efficiency in data centers. Three alternative scenarios for potential improvement in energy efficiency were considered. The medium growth scenario assumed that improvements in energy efficiency start at about 1 percent per year in 2012, increasing gradually to 7 percent per year by 2026. The low-growth scenario assumed that energy-efficiency improvements would be on a slower trajectory, starting at about 1 percent in 2015, and ramping up to about 3 percent by 2022. The high-growth scenario assumed a more rapid growth path for energy-efficiency improvements, starting at 1 percent per year in 2012, increasing to 7 percent by 2020, and 10 percent by 2026. The combination of load growth factors and improvement in energy efficiency result in a flat load growth for the data centers in the later parts of the forecast period. The assumed improvements in energy efficiency presented here are market-driven and are not considered as part of the Council's conservation potential.

The year-by-year growth in demand and improvement in efficiency for the medium case scenario is shown in the following table. The following graph shows the projected load for alternative energy efficiency and load-growth scenarios. It is assumed that the current estimated connected load of 300 average megawatts would be sufficient to meet the load from custom data centers until 2012.

Table C-15: Medium Case Trends in Data Center Loads

	Growth in Demand	Increase in Efficiency	Load MWa
2008-2011	0%	0%	300
2012	7%	-1%	318
2013	7%	-1%	337
2014	7%	-2%	354
2015	7%	-2%	372
2016	7%	-3%	386
2017	7%	-3%	402
2018	7%	-4%	414
2019	7%	-4%	426
2020	7%	-5%	435
2021	7%	-5%	444
2022	7%	-6%	448
2023	7%	-6%	453
2024	7%	-6%	457
2025-2030	7%	-6%	462

Figure C-22: Projected Load (MW) from Custom Data Centers



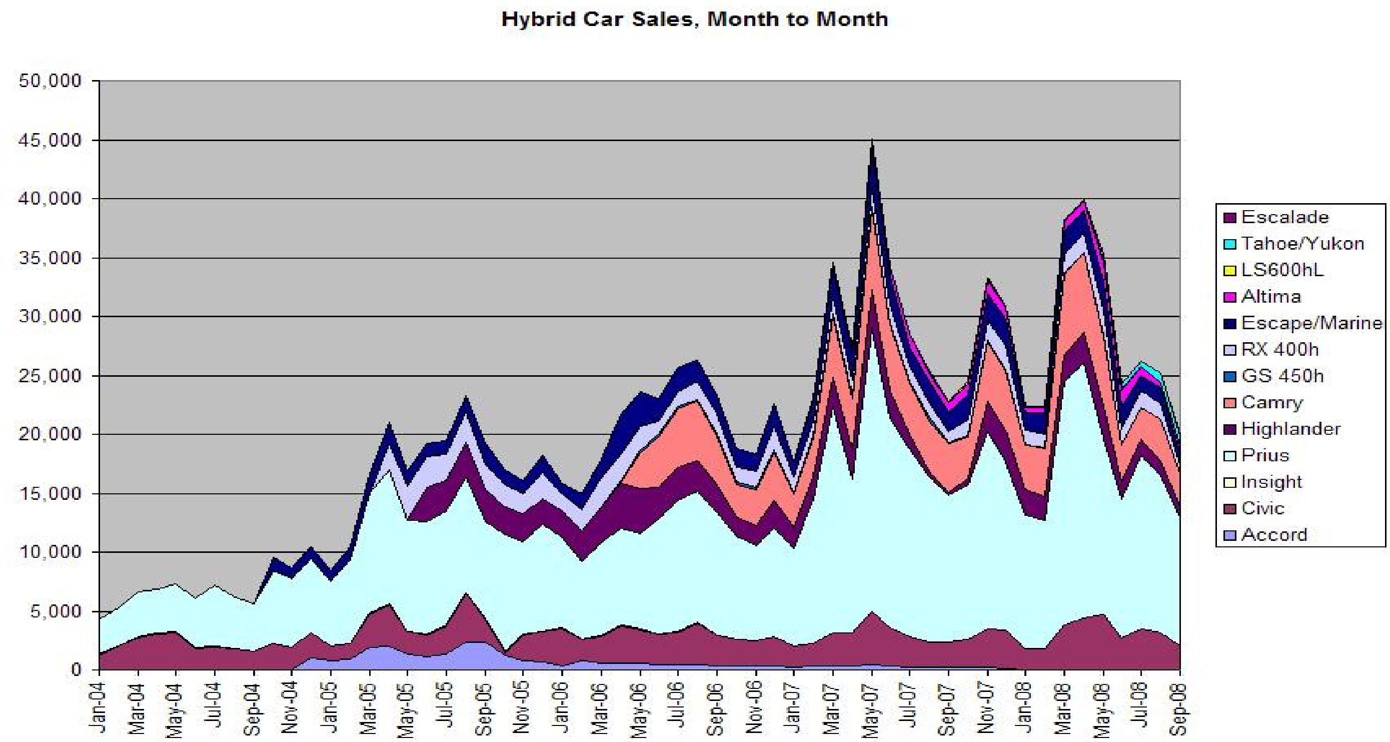
Future Trends for Plug-in Hybrid Electric Vehicles

Background

Concern for the environment and volatile gasoline prices have created unprecedented interest in alternative fuel and hybrid vehicles. Hybrid vehicles have been available in the U.S. market since 2000 in limited quantities. The hybrid vehicles offered today are powered by internal-combustion engines, with batteries that recharge during driving, and an electric motor to assist with power demand. Hybrids do not need to be plugged in, yet they deliver exceptional mileage compared to their gas-only counterparts. Hybrids are considered environmentally friendly alternatives to traditional internal-combustion vehicles.

Hybrid vehicle sales did not increase substantially until after 2004. According to R. L. Polk and Co., nationwide sales of new hybrid vehicles increased from about 84,000 in 2004 to about 200,000 in 2005; to 250,000 in 2006; and to about 350,000 in 2007. However, in 2008, hybrid vehicle sales were plagued by the same problems as conventional vehicles sales. In 2008, new hybrid vehicle sales declined for the first time due to the housing crisis, credit crunch, and declining fuel prices. Cumulative sales for January through September 2008 were 2 percent lower than the comparable period in 2007.

Figure C-23: Nationwide Sales of Hybrids 2004-Sep 2008



Source: R. L. Polk and Co. Hybrid Car Sales, September 2008

Hybrid vehicles usually cost more than comparable conventional vehicles, but they produce significantly lower CO2 emissions. To reduce the lifetime cost of these vehicles, state, federal, and local governments have offered incentives in the form of direct reduced fees (such as registration fees) and tax credits. In the Northwest, Oregon and Washington offer tax incentives for PHEV purchases. Government agencies in Washington, Oregon, and Idaho are required to reduce the petroleum consumption of their fleets by increasing the fuel economy of the vehicles they purchase, and by reducing the number of miles driven by each employee. In the state of Washington, beginning January 1, 2009, new passenger cars, light-duty trucks, and medium-duty passenger vehicles that are dedicated alternative fuel vehicles (AFVs) are exempt from the state sales and use taxes. Washington agencies must take all reasonable actions to achieve a 20 percent reduction in petroleum use in all state and privately owned vehicles used for state business by September 1, 2009. In Oregon, the Department of Energy offers two income tax credits for alternative and hybrid vehicles for both residents and business owners. Oregon residents are eligible for a residential energy tax credit of up to $1,500 toward the purchase of qualified AFVs.

Potential Effects on Electricity Demand

Factory-made plug-in hybrid electric vehicles are not currently available to the public. Consumer demand for hybrid vehicles can give us a window into the potential demand for plug-in electric vehicles. More information about marketplace acceptance of these vehicles is needed to be able to forecast their effect on the region's demand. A "what if" analysis was conducted to get an estimate of their potential effect on electricity demand.

According to R. L. Polk and Co., there is a strong relationship between the customer's previously owned vehicle and the size and type of a newly purchased hybrid vehicle, including plug-in hybrids. To analyze the effect of plug-in electric vehicles on electricity demand, the Council used Global Insight's October 2008 forecast scenarios for the total number of new light vehicles. The following table shows the projected new light vehicle sales in the four Northwest states. Three growth rates in new light vehicles and three for penetration rates were considered.

Table C-16: Projected New Light Vehicles (000)

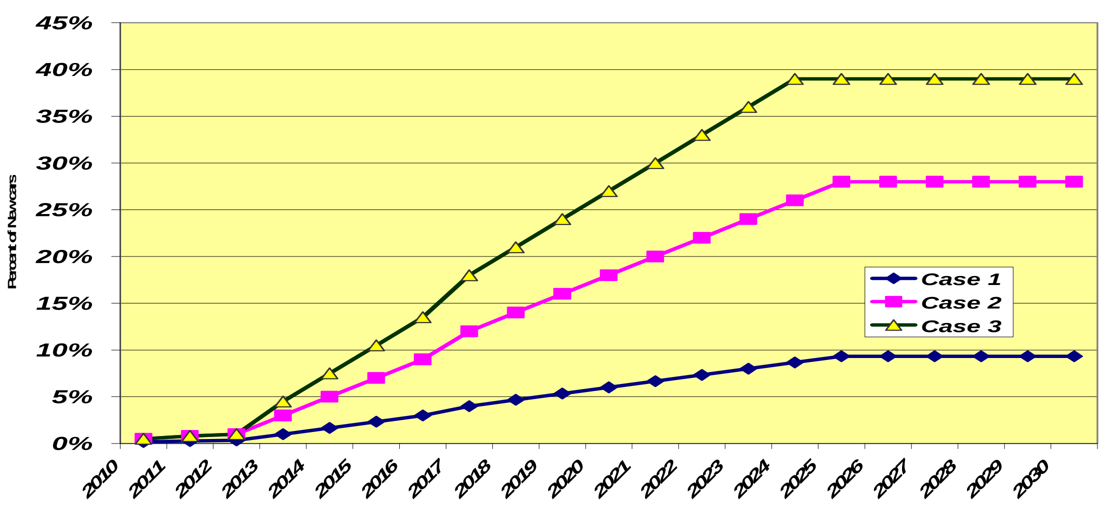
	Case 1	Case 2	Case 3
2010	481	606	560
2011	513	620	591
2012	537	627	616
2013	543	632	629
2014	548	636	641
2015	561	639	659
2016	564	640	673
2017	565	643	90
2018	571	649	706
2019	568	658	718
2020	560	665	730
2021	553	669	749
2022	549	675	755
2023	545	681	762
2024	543	688	774
2025	543	696	791
2026	543	704	806
2027	543	710	819
2028	542	717	837
2029	543	724	856
2030	543	732	878

The penetration rate for plug-in electric vehicles will be limited. The case 1 scenario assumes a 0.5 percent penetration rate for 2010. By 2030, it is assumed that 28 percent of new light vehicles will be plug-in hybrids. In the high-penetration scenario, case 3, it is assumed that 39 percent of new vehicles will be plug-in electric by 2030. In the low-penetration scenario, case 1, plug-in electric vehicles are assumed to represent 9 percent of the new car market by 2030.

Table C-17: Penetration Rate and Cumulative Number of PHEVs in the Region (000)

	Case 1	Case 2	Case 3	Case 1	Case 2	Case 3
2010	0.2%	0.5%	0.5%	1	3	3
2011	0.3%	0.8%	0.8%	2	7	8
2012	0.3%	1.0%	1.0%	4	13	14
2013	1.0%	3.0%	4.5%	9	31	42
2014	1.7%	5.0%	7.5%	19	61	90
2015	2.3%	7.0%	10.5%	32	104	157
2016	3.0%	9.0%	13.5%	49	159	244
2017	4.0%	12.0%	18.0%	71	235	359
2018	4.7%	14.0%	21.0%	98	324	496
2019	5.3%	16.0%	24.0%	128	426	654
2020	6.0%	18.0%	27.0%	162	541	833
2021	6.7%	20.0%	30.0%	199	669	1034
2022	7.3%	22.0%	33.0%	239	811	1257
2023	8.0%	24.0%	36.0%	282	966	1502
2024	8.7%	26.0%	39.0%	329	1135	1770
2025	9.3%	28.0%	39.0%	380	1320	2042
2026	9.3%	28.0%	39.0%	431	1506	2316
2027	9.3%	28.0%	39.0%	481	1694	2593
2028	9.3%	28.0%	39.0%	532	1884	2873
2029	9.3%	28.0%	39.0%	583	2077	3155
2030	9.3%	28.0%	39.0%	633	2272	3441

Figure C-24: Assumed Market Penetration Rates for New PHEV



Plug-in hybrid electric vehicles were assumed to have an average energy requirement of 0.3 KWh/mile. The analysis focused on a composite of three types of cars: a compact sedan, a mid-size sedan, and a mid-size SUV ranging from 0.26 to 0.46 KWh/mile to create a "typical" PHEV. For this composite vehicle, a Lithium-ion battery sized to 10 kilowatt hours is assumed to power the vehicle. It was also assumed that the energy efficiency of the vehicle would improve at a rate of 5 percent per year.

These vehicles are assumed to travel 33 miles per day, the current average. The battery recharge profile for PHEVs is important in order to estimate their demand on the electric grid. It was assumed that 95 percent of cars would be charged between 7 p.m. and 7 a.m., and 5 percent of the vehicles would be charged between 8 a.m. and 6 p.m. Recharging at 110 volt, 15 amp was assumed to take eight hours or less; at 220 volt, 30 AMP, the vehicle would be charged in less than two hours. The current average efficiency of gasoline-powered fleet vehicles is assumed to be 20.2 MPG and improving to 35 MPG by 2020. Based on these assumptions, electricity demand for each scenario was projected. The following figure shows the annual energy and peak and off-peak demand requirements of plug-in hybrid vehicles in the Northwest.

Given these assumptions, plug-in electric vehicles are forecast to increase the regional load between 100 to 550 average megawatts by 2030. The increase in load would be gradual and would have a minimal impact on regional load in the first 5 to 10 years of introduction into the market. Their impact on system load would be greater during off-peak hours, given the recharge assumption. It is projected that off-peak loads would increase by 200-1,000 megawatts. The impact of PHEVs on system peak is projected to be much smaller, 5-25 megawatts, given the assumption that only 5 percent of vehicles will recharge during the peak period.

Figure C-25: Projected Load from Plug-in Hybrid Vehicles

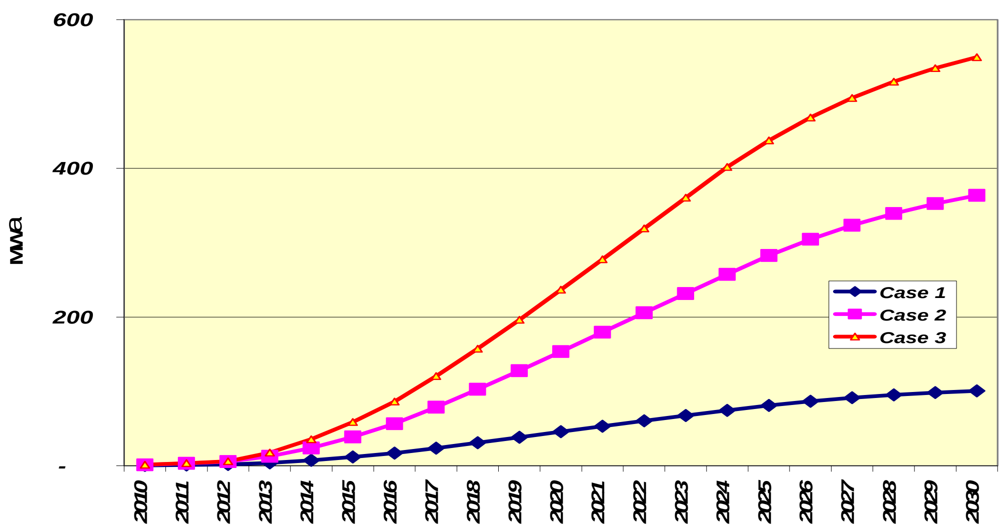
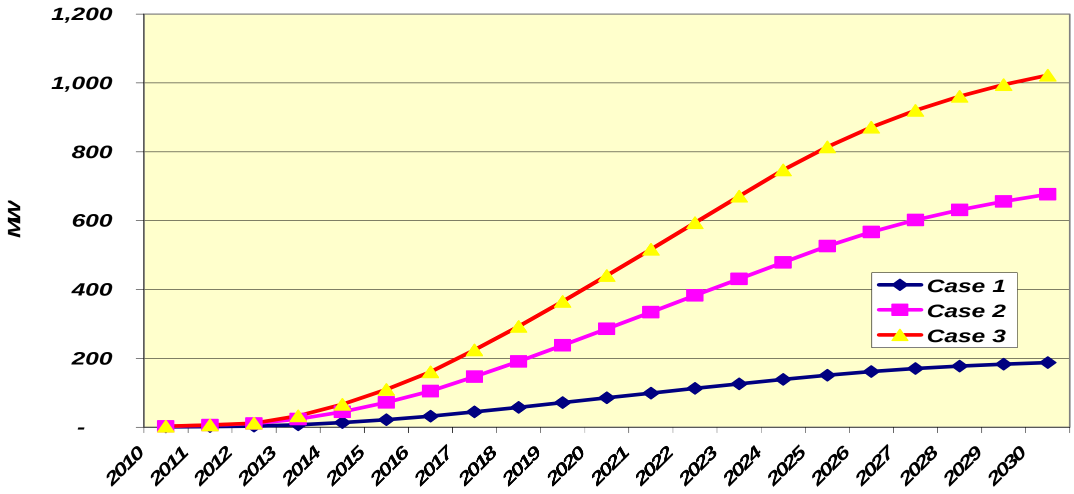


Figure C-26: Project Off-peak Load from Plug-in Hybrid Vehicles



Appendix D: Electricity Price Forecast Preliminary Draft

INTRODUCTION

The Council prepares and periodically updates a 20-year forecast of wholesale electric power prices. This forecast is used to establish benchmark capacity and energy costs for conservation and generating resource assessments for the Council's power plan. The forecast establishes the mean value electricity market price for the Council's portfolio risk model and is used for the ProCost model used by the Regional Technical Forum to assess the cost-effectiveness of conservation measures. The Council's price forecast is also used by other organizations for assessing resource cost-effectiveness, developing resource plans and for other purposes.

The Council uses the AURORA$^{xmp®}$ Electric Market Model[1] to forecast wholesale power prices. AURORA$^{xmp®}$ provides the ability to incorporate assumptions regarding forecast load growth, future fuel prices, new resource costs, capacity reserve requirements, climate control regulation and renewable portfolio standard resource development into its forecasts of future wholesale power prices. The forecasting model, once updated and otherwise set up for the forecast, is also used to support the analysis of issues related to power system composition and operation, such as the effectiveness of greenhouse gas control policies.

A preliminary forecast is prepared early in the development of the power plan to guide resource assessments and to provide an initial basis for the demand forecast and the portfolio analysis. The preliminary forecast described in this appendix. Prior to adoption of the final plan, the

[1] The AURORA^{xmp} Electric Market Model, available from EPIS, Inc (http://www.epis.com/).

forecast will be rerun using the final fuel price forecast, assumptions regarding resources, demand forecast and portfolio recommendations.

FINDINGS

Load serving entities in the Pacific Northwest depend on the wholesale marketplace to match their customer's ever changing demand for electricity with an economical supply. The wholesale power market promotes the efficient use of the region's generating resources by assuring that the resources with the lowest operating cost are serving the demand in the region. In the long-run, the performance of the wholesale power market, and the prices determined in the marketplace, largely depend on the balance between the region's generating resources and demand for electricity. On the supply-side, there are three primary factors that are likely to influence the wholesale power market over the current planning period: (1) the future price of natural gas; (2) the future price of carbon dioxide (CO_2) allowances associated with climate control regulation; and (3) the future path of renewable resource development associated with the region's Renewable Portfolio Standards (RPS).

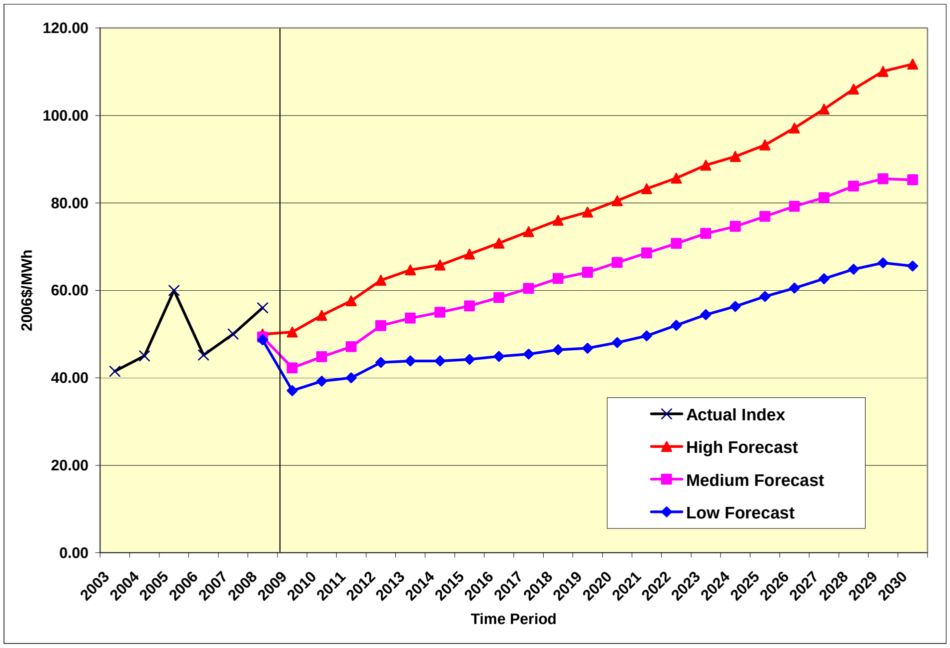
Natural gas-fired generating units are often the marginal generating unit, and determine the wholesale price of electricity during most hours of the year. The cost of natural gas fuel is the major component of the variable cost of operation for a combined-cycle plant and therefore the largest component of the marginal cost of electricity for any hour that a combined-cycle plant is on the margin. To establish a plausible range for the future long-term trend of wholesale power prices in the Pacific Northwest, the Council has forecast wholesale power prices using its low, medium, and high forecasts of fuel prices described in Appendix A.

The Council's forecast of expected CO2 allowance prices begins in 2012 at a price of $8 per short ton of CO_2 emitted, increases to $27 per ton in 2020, and to $47 per ton in 2030. Uncertainties regarding future climate control regulation and its impact on future resource development in the region are discussed more fully in Chapter 10.

Three of the four Northwest states (Montana, Oregon and Washington) have enacted renewable portfolio standards. There has been a rapid pace of renewable resource development in Pacific Northwest in recent years and the region's utilities appear to be well positioned to meet their RPS targets. The Council has forecast an expected build-out of renewable resources associated with state RPS and British Columbia energy policy in the western U.S. as a whole. By 2030, the cumulative capacity of the RPS build-out includes: 17,000 MW from wind plants; 4,000 MW from concentrating solar plants; 3,000 MW from solar photovoltaic plants; and roughly 1,000 MW each from geothermal, biomass, and small hydro plants.

Under "medium" fuel price and carbon dioxide (CO2) emission price assumptions, wholesale power prices at the Mid-Columbia trading hub are projected to increase from $45 per megawatt-hour (MWh) in 2010 to $85 per MWh in 2030. For comparison, Mid-Columbia wholesale power prices averaged $56 per MWh in 2008 (in real 2006 dollars). Figure D-1 compares the forecast range of Mid-Columbia wholesale power prices to actual prices during the 2003 through 2008 period.

Figure D-1: Forecast Range of Annual Mid-Columbia Wholesale Power Prices



The Council's wholesale power price forecasts are projections of the long-term trend of future wholesale power prices. Short-term electricity price risk, due to such factors as disequilibrium of supply and demand, and seasonal volatility due to hydro conditions are not reflected in the long-term trend forecasts. This short-term price volatility is modeled in the Regional Portfolio Model that the Council uses to inform its development of the Power Plan.

Pacific Northwest electricity prices tend to exhibit a seasonal pattern associated with spring runoff in the Columbia River Basin. The Council's forecast of monthly on-peak and off-peak wholesale power prices exhibits an average seasonal hydroelectric trend during each year of the planning period. Figure D-2 shows the medium forecast of Mid-Columbia monthly on-peak and off-peak power prices. The forecast show a narrowing of the difference between on-peak and off-peak power prices over the planning period. Table D-1 shows the forecast values for selected years.

Figure D-2: Medium Forecast of Mid-Columbia Wholesale Power Prices

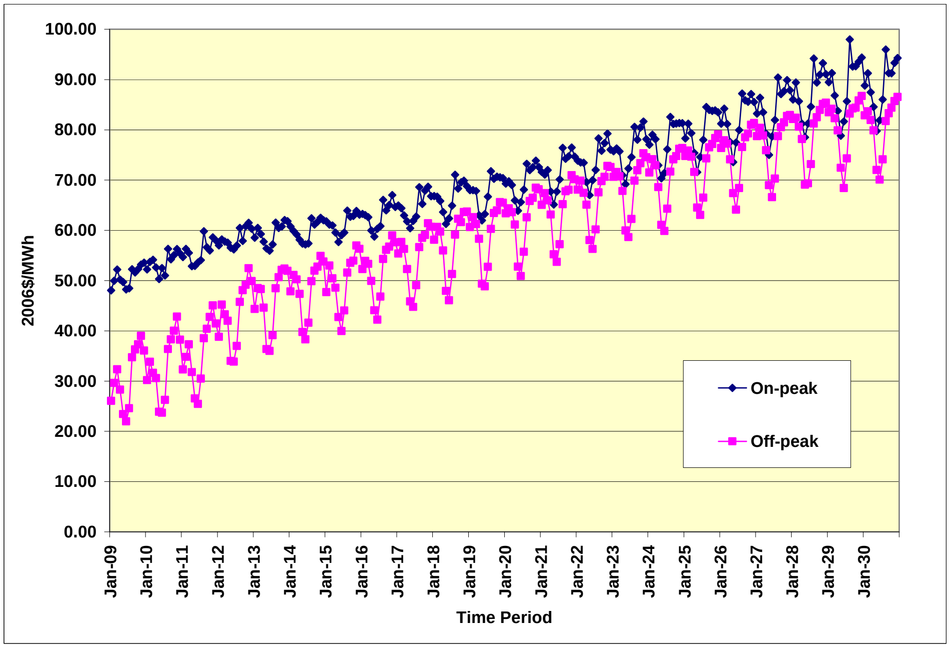


Table D-1: Forecast of Mid-Columbia Wholesale Power Prices

	On-Peak	Off-Peak	Average
Actual 2008	62.00	49.00	56.00
2010	54.00	33.00	45.00
2015	61.00	50.00	56.00
2020	70.00	62.00	66.00
2025	80.00	73.00	77.00
2030	89.00	81.00	85.00
Growth Rates			
2010-2020	2.61%	6.30%	3.93%
2020-2030	2.43%	2.62%	2.51%

The range of trend forecasts discussed here represents only one aspect of the uncertainty addressed in the Council's power plan. The low to high trend forecasts are meant to reflect current analysis and views on the likely range of future prices, but the plan's analysis also considers variations expected to occur around those trends. The plan reflects three distinct types of uncertainty in wholesale electricity prices: (1) uncertainty about long-term trends, (2) price excursions due to disequilibrium of supply and demand that may occur over a number of years, and (3) short-term and seasonal volatility due to such factors as temperatures, storms, or storage levels. These forecasts discuss only the first uncertainty. Shorter-term variations are addressed in the Council's portfolio model analysis.

APPROACH AND ASSUMPTIONS

The Council uses the AURORA$^{xmp®}$ Electric Market Model to forecast wholesale electricity prices for the Pacific Northwest.[2] The AURORA^{xmp} model projects future wholesale power market prices based on model inputs that determine the underlying supply and demand conditions in the future. Key inputs to the AURORA^{xmp} model include forecasts of future electricity demand, inventories of existing electricity generating plants, forecasts of construction costs for new electricity generating plants, and forecasts of future fuel prices for electricity generating plants. Given the forecast of future electricity demand and the set of drivers of future electricity supply, the model then uses economic logic to project future resource additions and market-clearing wholesale electricity prices.

Many of the inputs to the AURORA^{xmp} model are described in chapters or appendices of Sixth Power Plan. Chapters 2 and 3 of the Plan describe the demand forecast. Chapter 6 describes the new generating resources assumptions. This section of Appendix D describes inputs to the

The forecast is developed in a two-step process. First, using AURORA^{xmp} long-term resource optimization logic, a forecast of resource additions and retirements is developed. In the second step, the forecasted resource mix is then dispatched on an hourly basis to serve forecast loads. The variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period establishes the forecast price.

The Council recently updated its AURORA^{xmp} software to version 8.4.

The Council updated many of the key inputs used in the AURORA^{xmp} model for the electricity price forecast. [Recognize that the electricity price forecast does not yet incorporate draft plan resources for the PNW]

Demand Growth

To forecast future wholesale price of electricity, we need to know the regional demand for electricity as well as demand from other regions in the Western U.S., Canada and Mexico that form the WECC region. Electricity demand is analyzed not only by sector but by geographic region. The Council's AURORAxmp electricity market model requires energy and peak load forecasts for 16 areas, four of which are forecast by the Council's demand forecast model and 12 for other areas in the Western U.S., Canada, and Mexico. Council staff projected both energy and peak demand growth in nine of these 12 areas (those in the U.S.) based on 2008-2017 forecasts submitted to the FERC (EIA Form 714) by electric utilities. The forecast for Alberta for the same years was based on the forecast by the Alberta Electric System Operator (AESO).3 The Council's forecast for British Columbia was based on a forecast BC Hydro submitted to the Western Electricity Coordinating Council (WECC) for the period 2010-2017, supplemented by data from the British Columbia Transmission Corporation (BCTC)4 for 2007 and interpolation for 2008 and 2009. The forecast load for northern Baja California in Mexico was based on the forecast submitted to WECC for 2010-2017, the 2006 load previously used by AURORA, and interpolated values for 2007-2009.

[2] Available from EPIS, Inc. (www.epis.com).
[3] http://www.aeso.ca/downloads/Future_Demand_and_Energy_Outlook_(FC2007_-_December_2007).pdf
[4] http://www.bctc.com/NR/rdonlyres/C6E06392-7235-4F39-ADCD-D58A70D493C7/0/2006controlareaload.xls

AURORA requires area load projections for each year to 2053, so Council staff extended the forecasts past 2017 by calculating a rolling average of most areas for the past five years. For the Arizona and New Mexico areas, the load from 2021 through 2027 was projected to grow at the same rate as the projected population growth in each state. After 2027, load was projected to continue to grow at the 2027 rate. The load for northern Baja California was similarly projected, except that the population growth rate for New Mexico was used for 2021-2027 (population projections for Baja California were unavailable).

Firm Capacity Standards

The AURORA^{xmp} model provides the capability to perform long-term system expansion studies. Each study provides a build-out of system resources that is optimized to economically supply energy to the system while maintaining a firm capacity standard. The firm capacity standard represents a requirement that a region's generating resources provide enough firm capacity to meet the region's peak demand plus a specified margin for reliability considerations. The model uses two input parameters to simulate achievement of a region's firm capacity standard. The first parameter is a planning reserve margin target specified for each region. The second parameter is a firm capacity credit specified for each type of generating resource.

Planning Reserve Margin Targets

The Council has configured AURORA^{xmp} to simulate power plant dispatch in 16 load-resource zones that make up the WECC electric reliability area. Reserve margin targets can be specified for each load-resource zone, for an aggregation of load-resource zones called an operating pool, or for both. The Council has specified planning reserve margin targets for two operating pools: (1) the Pacific Northwest region, which has 4 load-resource zones; and (2) the California Independent System Operator (CAISO), which has 2 load-resource zones. The remaining 8 load-resource zones are given individual reserve margin targets.

For the CAISO and 8 stand-alone zones, the planning reserve margin target was set at 15 percent. For the Pacific Northwest, the Council configured AURORA^{xmp} to reflect the capacity standard of the Pacific Northwest Power Supply Adequacy Forum. The adequacy forum has determined that reserve margin targets of 25 percent in winter and 19 percent in summer correspond to an overall system loss-of-load probability of 5 percent. These reserve margin targets cannot, however, be input directly into AURORA^{xmp}.

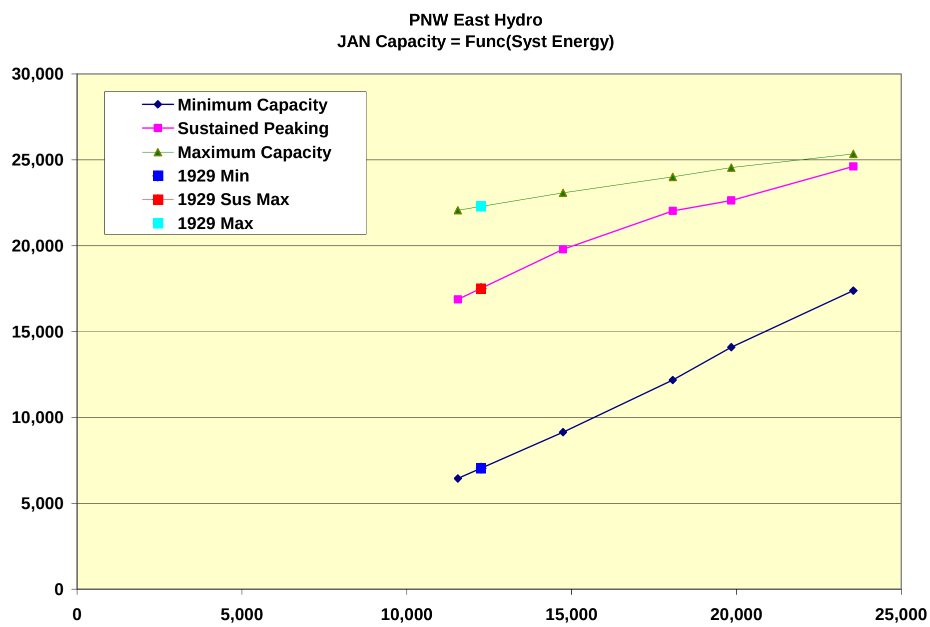
The adequacy forum targets reflect a specific set of resource and load assumptions that cannot be easily replicated in AURORA^{xmp}. For example, the adequacy forum winter reserve margin target is based on consideration of the highest average demand for a three-day 18-hour sustained peak period, while the AURORA^{xmp} targets are based on consideration of the single highest hour of demand. For electricity price forecasting purposes, the Council converted the adequacy forum's multiple-hour capacity reserve margin targets to an equivalent single-hour target. Adjustments were also made to reflect consistent treatment of spot market imports, hydro conditions and flexibility, and independent power producer generation. The equivalent single-hour winter capacity reserve margin for the Northwest is 18 percent. Conversion of the adequacy forum's capacity reserve margin targets does not reflect a change in the adequacy standard, but rather an adjustment to approximate the complex Northwest standards using the simpler reserve parameters available in AURORA^{xmp}. Both the forum's target and the target used in AURORA^{xmp} reflect an overall loss-of-load probability of 5 percent for the Northwest.

Firm Capacity Credit

The second input parameter used to simulate achievement of a region's firm capacity standard is the firm capacity credit specified for each type of generating resource. The firm capacity credit is often referred to as resource type's peak contribution or its expected availability at the time of peak demand. For a generating resource that is fully dispatchable, the peak contribution is determined by its expected forced outage rates. The Council uses a firm capacity credit for coal-fired and natural-gas fired resources in the range of 90 to 95 percent of installed capacity. For variable wind and solar resources, the Council has estimated the expected output at the time of peak demand. The Council uses a firm capacity credit of 5 percent for wind resources adopted by the Reliability Forum, and an provisional value of 30 percent for solar resources. For the Pacific Northwest's hydro resources, the Council uses a winter single-hour firm capacity credit of 82 percent on installed capacity for east-side hydro and 83 percent for west-side hydro. 95 percent is used for other load resource areas.

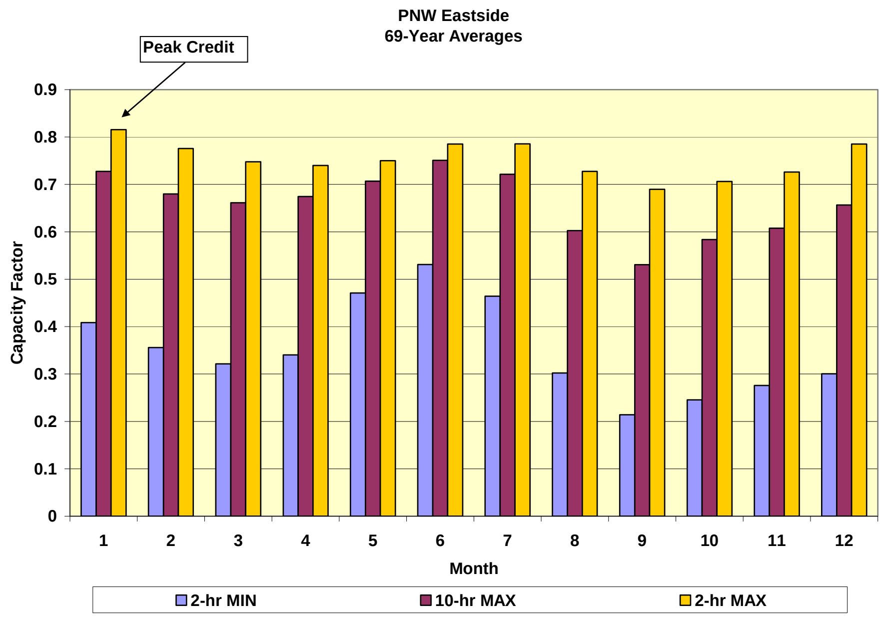
The firm capacity credits for Pacific Northwest hydro resources are based on sustained peaking studies conducted for the Pacific Northwest Power Supply Adequacy Forum. Figure D-3 shows the January peaking capability of Pacific Northwest east-side hydro resources as a function of monthly energy output. On the horizontal axis, the average monthly energy output of these hydro resources can be seen to range from 11,000 to 24,000 average megawatts. On the vertical axis, the curve at the top of the chart represents the two-hour sustained peak output of these hydro resources across the range of monthly output (or stream flow conditions). For example, given 1929 modified streamflows and a monthly energy output of 12,000 MWa, the east-side hydro resources would be expected to provide roughly 22,000 MW of firm capacity over a two-hour peak period.

Fig D-3: PNW East Hydro
JAN Capacity = Func(Sy at Energy)



The Council has calculated the two-hour sustained firm capacity credit for both east-side and west-side hydro resources by month for each of the 69 calendar years in the Pacific Northwest streamflow record. Figure D-4 shows the two-hour firm capacity credit for east-side hydro resources by month. For hydro modeling in AURORA^{xmp}, the Council uses the January values of 82 percent of installed capacity for east-side hydro resources and 83 percent for west-side hydro resources.

Figure D-4: PNW Eastside Hydropower, 69-Year Average



Existing Resources

[Portions of this section are yet to be completed]

New Resource Options

[Portions of this section are yet to be completed]

Pacific Northwest Hydro Modeling

Pacific Northwest modified streamflow data is available for the period September 1928 through August 1998. The Council uses its GENESYS model to estimate the hydroelectric generation that would be expected from this streamflow record given today's level of river system development and environmental protection. To simulate Pacific Northwest hydroelectric generation in AURORA^{xmp} , annual average capacity factors are calculated for the hydro resources located in three load-resource zones: Pacific Northwest Eastside; Pacific Northwest Westside; and Idaho South . Figure D-5, shows the annual capacity factors of the Pacific Northwest Eastside hydro resources given the modified streamflow record for the period January 1929 through December 1997. The 69-year average capacity factor is 44 percent of nameplate capacity.

Figure D-5: Annual capacity factor of Pacific Northwest Eastside hydropower resources

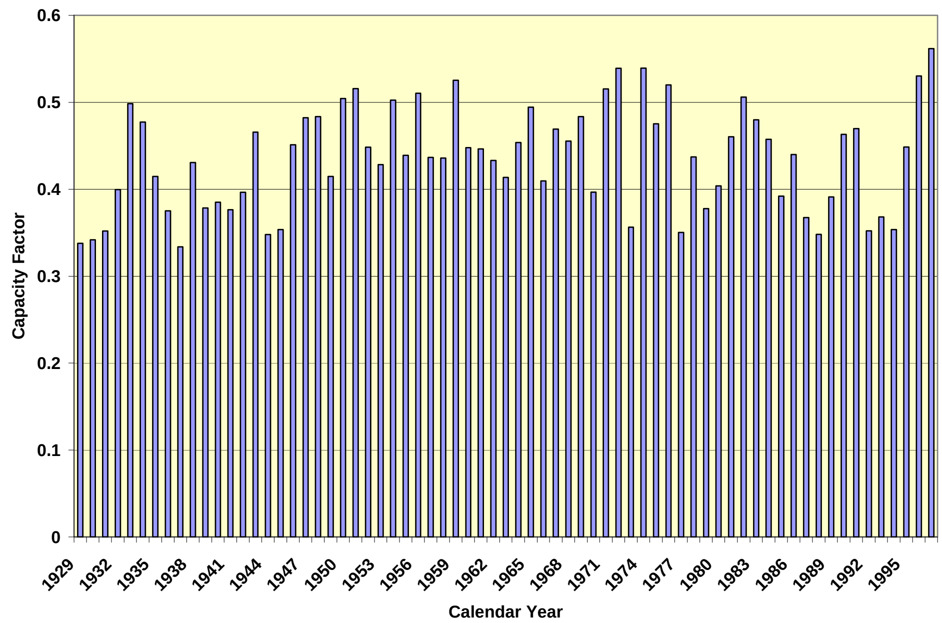
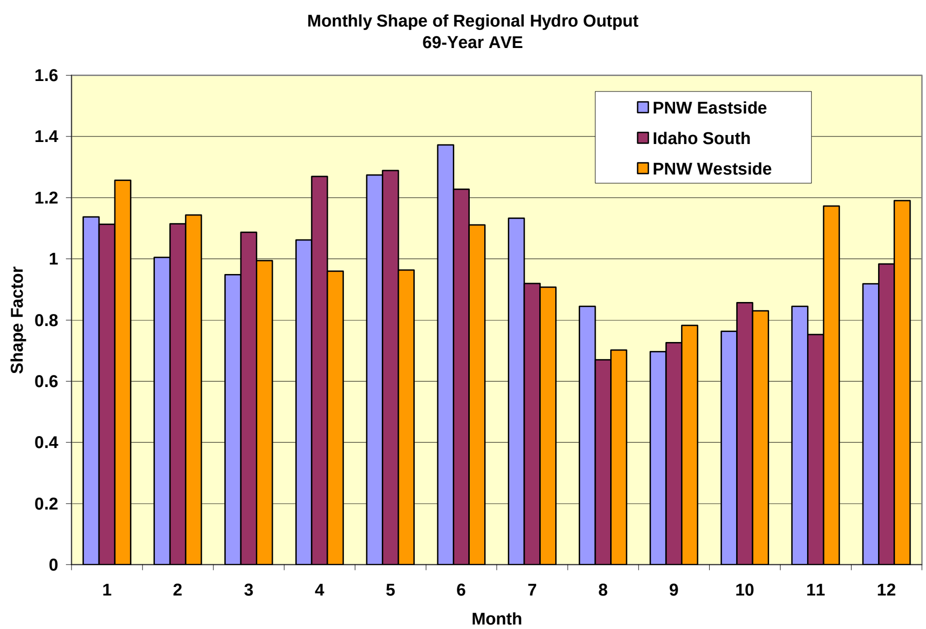


Figure D-6: Monthly Shape of Regional Hydro Output, 69 Year Avg.



State Renewable Portfolio Standards

Renewable resource portfolio standards targeting the development of certain types and amounts of resources have been adopted by eight states within the WECC; four (Colorado, Oregon, Montana, and Washington) since adoption of the Fifth Power Plan. In addition, British Columbia has adopted an energy plan with conservation and renewable energy goals equivalent to an aggressive RPS. The key characteristics of the state renewable portfolio standards and the B.C. Energy Plan are summarized in Table 3.

As discussed later in this paper, forced development of low variable-cost renewable resources can have potentially significant effects on wholesale power prices. Thus, assumptions must be made regarding the types of renewable resources that will be developed and the success in achieving the targets. For the Fifth Power Plan power price forecast, states that had enacted renewable portfolio standards were assumed to meet 75 percent of their target levels of renewable resource development.[5] Additional resources corresponding to the estimated levels of development from the Oregon and Montana system benefit charge programs were also included. Because of much greater public concern regarding greenhouse gas control, expanded initiatives for renewable resource development, prospects for even more aggressive RPS in some states, and indications that utilities will be able to achieve the initial target levels of development in many RPS states, 100 percent achievement of RPS targets was assumed for the base case of this forecast. Furthermore, because of the potentially significant effect of RPS acquisitions on wholesale prices, a more thorough assessment of the expected resource development effects of the various state RPS efforts was undertaken for this forecast.

Fuel Prices

The Council forecasts the cost of coal delivered to each load-resource zone defined in its electricity market model. The delivered coal cost is the sum of the mine-mouth price of Powder River Basin (PRB) coal, plus the variable cost of transporting PRB coal to each load-resource zone. The Council issued its current forecast of PRB coal prices on September 11, 2007. The variable costs of transportation are based on average transportation rates for PRB coal and average shipment distances from Wyoming to each load-resource zone.

Natural gas prices from the Council's recently revised fuel price forecast are used for this power price forecast. With the exception of Idaho and Montana, the assumptions used to convert natural gas commodity prices into delivered load-resource area prices for AURORA^{xmp} are those used for the Fifth Power Plan. The approaches used to estimate Idaho and Montana natural gas prices were revised to better reflect the factors controlling gas prices in those two states.

Carbon Dioxide Emission Prices

A number of industrialized nations are taking action to limit the production of carbon dioxide and other greenhouse gasses. Within the United States, a number of states, including Washington and Oregon, have initiated efforts to control carbon dioxide production. It appears that the Region could see control policy enacted at the federal, West-wide, or state level.

It is unlikely that reduction in carbon dioxide production can be achieved without cost. Consequently, future climate control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing. A cap and trade allowance system appears to have been a successful approach to SO2 control and may be used again for CO_2 production control. Alternatively, a carbon tax has the benefit of simpler administration and perhaps fewer opportunities for manipulation. It is also unclear where in the carbon production chain – the source, conversion, or use – a control policy would be implemented. It is unclear what share of total carbon production the power generation sector would bear or what would be done with any

[5] States with enacted legislation at the time of the Fifth Power Plan include: Arizona, California, Nevada, and New Mexico.

revenues generated by a tax or trading system. It is unclear which ratepayer sector will pay for which portion of any costs associated with a control mechanism.

The Council's studies use a fuel carbon content tax as a proxy for the cost of CO_2 control, whatever the means of implementation. When considered as an uncertainty, studies represent carbon control policy as a penalty (dollars per ton CO_2) associated with burning natural gas, oil, and coal.

The CO_2 allowance cost values used for this forecast are described in Appendix I.

Carbon Dioxide Emission Performance Standards

As described in Chapter 10, California, Montana, Oregon and Washington have established carbon dioxide emission performance standards for new baseload generating plants. The intent of the Oregon and Washington standards is to limit the CO_2 production of new baseload facilities to that of a contemporary combined-cycle gas turbine power plant fuelled by natural gas (about 830 lbCO2/MWh). The California standard is less restrictive, allowing production of 1100 lbCO2/MWh - a level that would allow baseload operation of many of the simple-cycle aeroderivative gas turbines installed in that state, or alternatively, require sequestration of about 50% of the CO2 production of a coal-fired plant. Although the 1100 lbCO2/MWh California standard was adopted by Washington as the initial standard, it seems likely that the Washington standard will be reduced in administrative review to a level approximating 830 lbCO2/MWh as the legislation clearly states that the standard is intended to represent the average rate of emissions of new natural gas combined-cycle plants. The Montana standard does not set an explicit carbon dioxide production limit, but rather mandates capture and sequestration of 50 percent of the carbon dioxide production of any new coal-fired generating facility subject to approval of the state Public Service Commission. Additionally, the BC Energy Plan requires any new interconnected fossil fuel generation in the province to have zero net greenhouse gas emissions.

The BC Energy Plan requirement was approximated in AURORA^{xmp} by limiting new coal-fired resource options within the BC load-resource area to integrated gasification combined-cycle (IGCC) plants with CO_2 separation and sequestration.[6] The four state performance standards, in effect preclude new coal-fired plants serving utilities within the four states (investor-owned utilities only in Montana), unless the facility can be provided with carbon separation and sequestration for 40 to 50 percent of the uncontrolled carbon dioxide production of the plant. The state performance standards are difficult to simulate because contractual paths are not modeled in AURORA^{xmp}. The state performance standards were approximated by limiting new coal-fired resource options within the California, Oregon, and Washington load-resource areas to IGCC plants with CO_2 separation and sequestration and by constraining new conventional coal resource options in peripheral areas to amounts sufficient only to meet native load. In addition, new conventional coal was precluded in Idaho because of the current moratorium on conventional coal development in that state. The Montana policy that new coal plants capture and sequester 50 percent of CO_2 emissions was not incorporated in this study.

[6] Because the cost and performance estimates for the technology have not yet been developed by Council staff, new combined-cycle units available to the B.C. load-resource area did not include CO_2 separation and sequestration.

Initial runs showed some new economically driven coal resource development in some load-resource areas not subject to performance standards. However, subsequent runs incorporating the revised carbon allowance cost forecast showed no new coal development within the entire WECC area. Coal-fired units were subsequently removed from the available set of new resources to expedite later runs.

WHOLESALE POWER PRICE FORECASTS

The Council's forecast of Mid-Columbia trading hub electricity prices, levelized for the period 2010 through 2029, is $62.40 per megawatt-hour (in year 2006 dollars).[7] This is a 60 percent increase from the base case forecast of the Fifth Power Plan (levelized value of $38.90 per megawatt-hour). Table D-2 shows the forecast values for selected years.

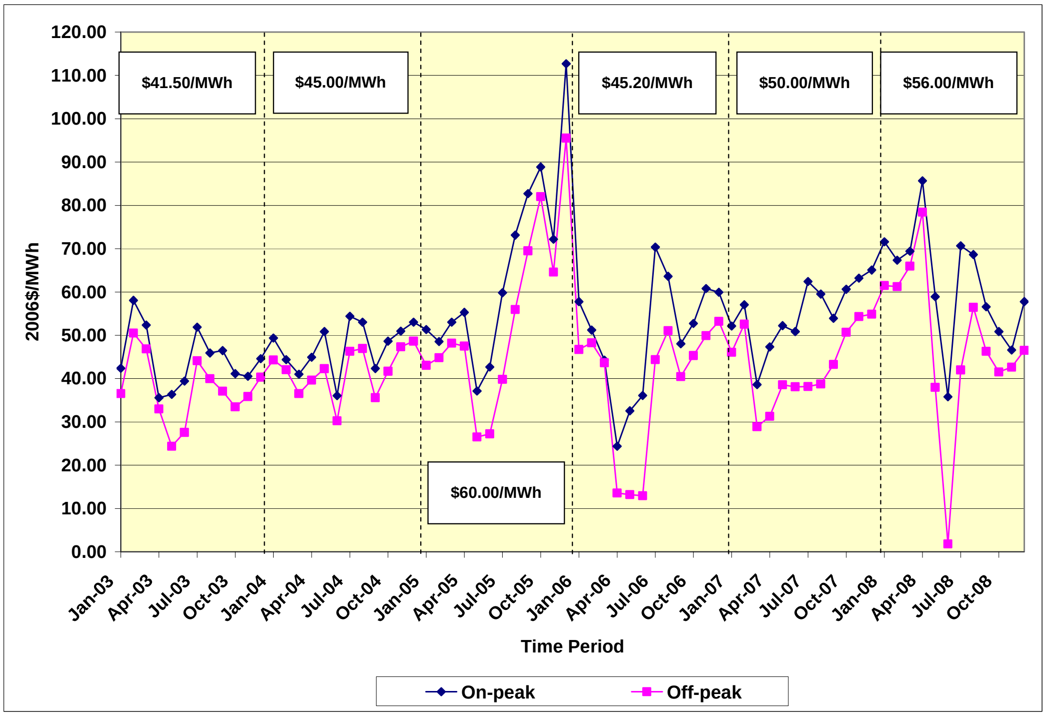
Table D-2: Forecast of Mid-Columbia Wholesale Power Prices ($2006)

	On-Peak	Off-Peak	Average
Actual 2008	62.00	49.00	56.00
2010	54.00	33.00	45.00
2015	61.00	50.00	56.00
2020	70.00	62.00	66.00
2025	80.00	73.00	77.00
2030	89.00	81.00	85.00
Growth Rates			
2010-2020	2.61%	6.30%	3.93%
2020-2030	2.43%	2.62%	2.51%

The following figure shows actual average monthly on- and off-peak prices (in $2006) at the Mid-Columbia trading for the period 2003 through 2008.

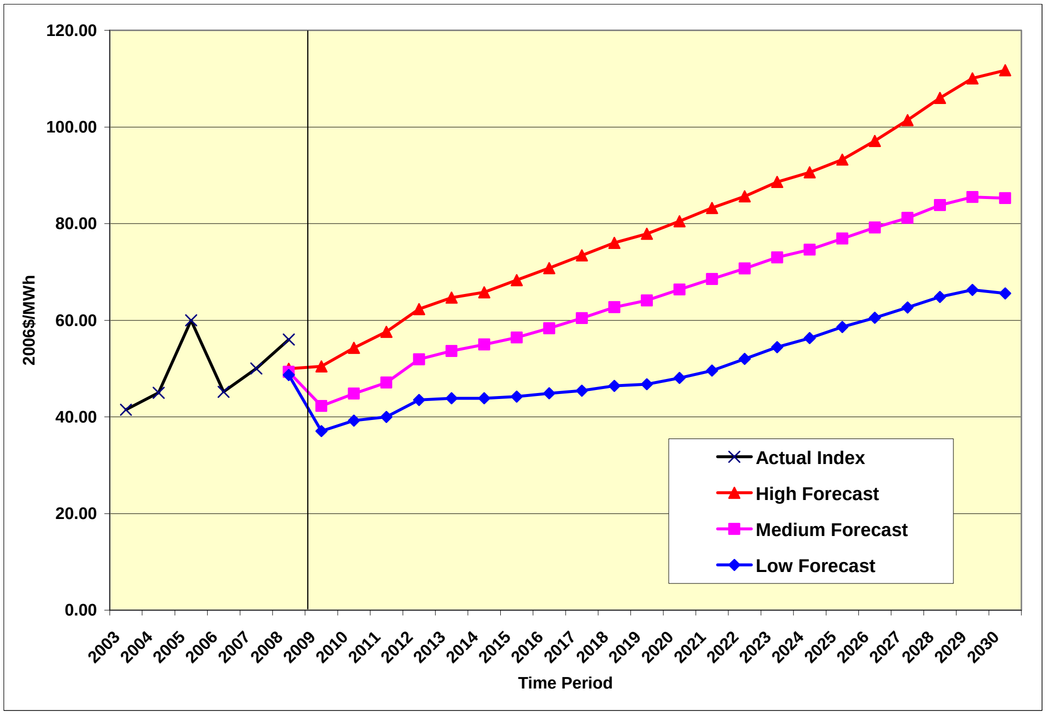
[7] All dollar values appearing in this paper are in year 2006 dollars unless otherwise indicated.

Figure-D-7: Actual 2003 -2008 Mid-Columbia Wholesale Power Prices



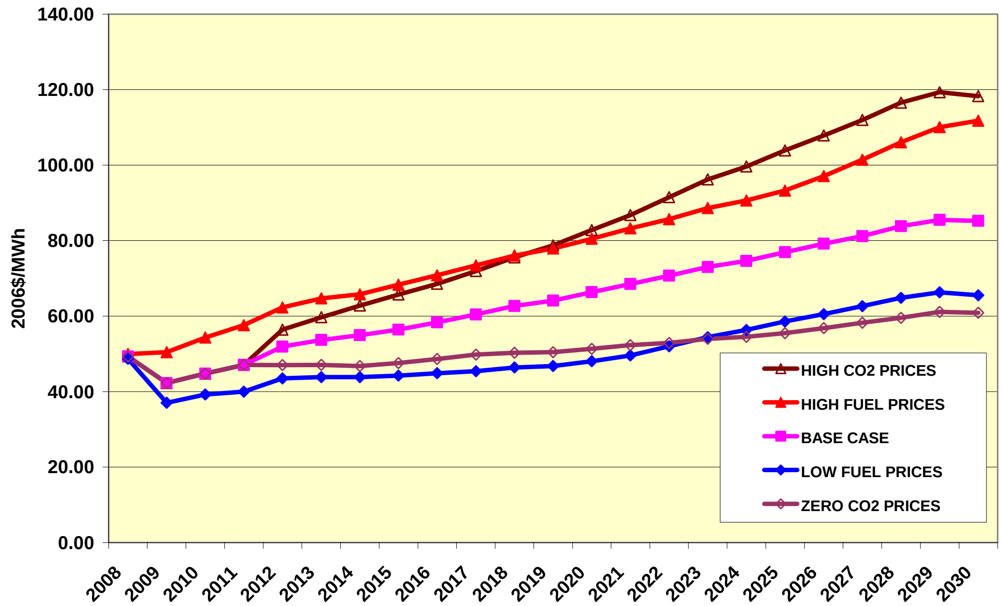
The monthly data exhibit a wide range of variation. The highest average on-peak price for the period was nearly $113 per MWh in December 2005. The lowest average on-peak price was $24 per MWh in April 2006. Annual average Mid-C prices ranged from a low of $41.50 per MWh in 2003 to a high of $60.00 per MWh in 2005.

Figure D-8: Comparison of Actual and Forecast Mid-Columbia Wholesale Power Prices



Uncertainty regarding future CO2 emissions prices and future natural gas prices could dramatically change the long-term trend forecast for wholesale power prices. We attempted to bracket the future trajectory of Mid-Columbia wholesale power prices using scenario analysis. We modeled high and low fuel price cases and high and low CO2 emissions price cases. We did not consider the potential combination of these sensitivity cases. Explain the input ranges???

Figure D-9: High and Low Mid-Columbia Wholesale Power Price Forecasts

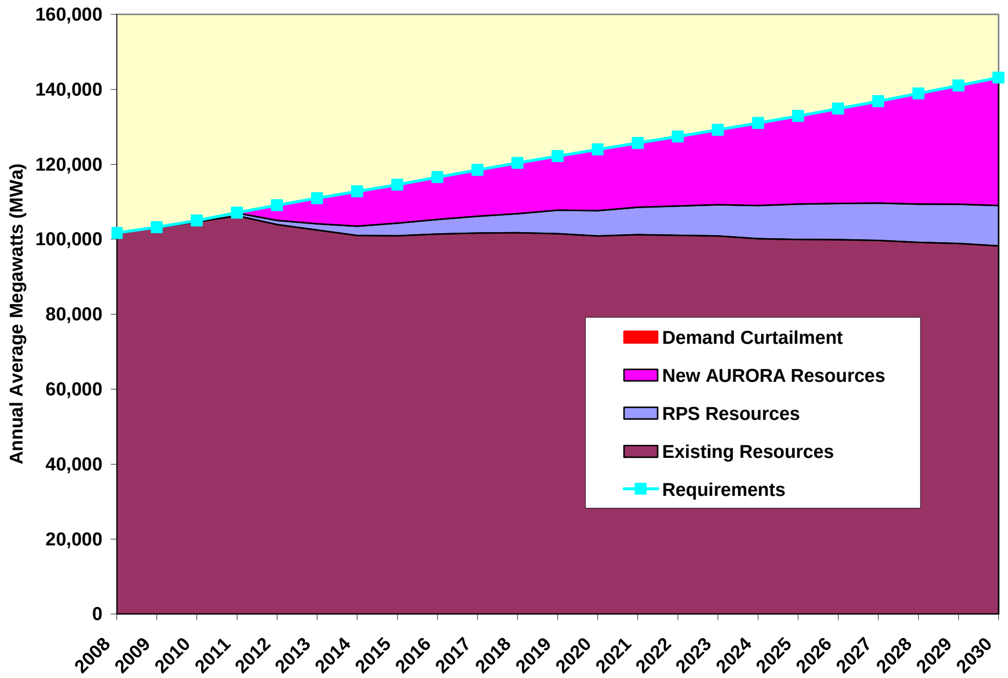


Underlying Market Fundamentals

Another way to assess the reasonableness of the wholesale power price forecast is to examine the underlying supply and demand fundamentals. Figure D-10 show the underlying annual energy load-resource balance for the Western Electricity Coordinating Council area.[8] Existing resources are shown at the bottom, "forced" RPS resource additions (discussed above) are shown as the middle wedge, and finally, modeled resource additions are shown at the top.

[8] The load-resource balance is based on the economic dispatch of the resources, not the theoretical availability the resources.

Figure D-10: WECC Annual Energy Load-Resource Balance

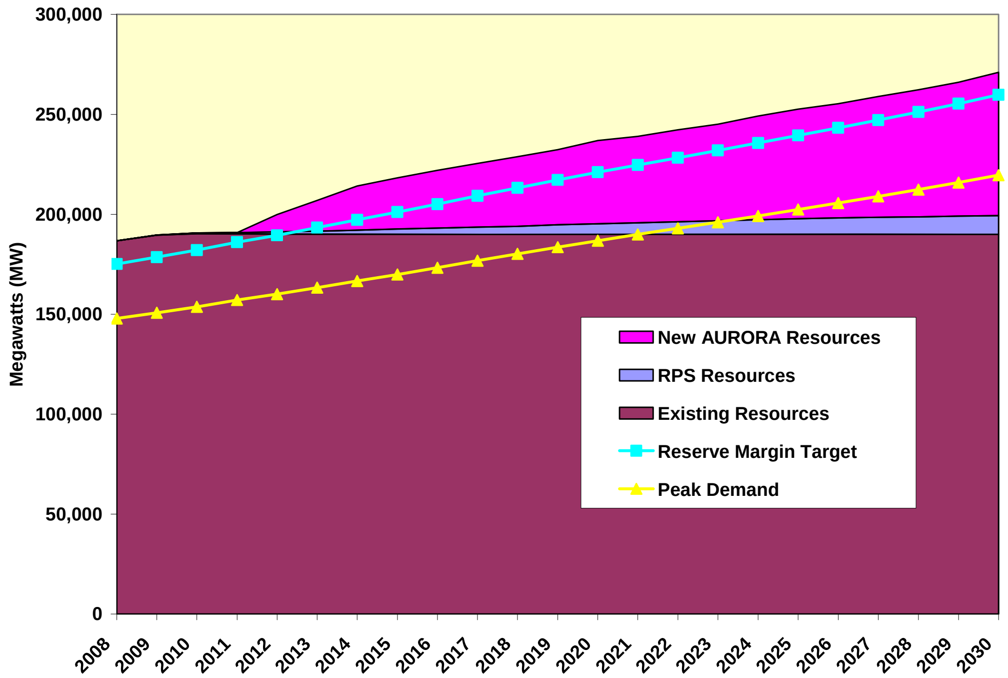


The modeled resource additions are comprised primarily of natural gas-fired combined-cycle combustion turbines. The combined-cycle turbines not only help to fill the WECC's energy deficit, but also satisfy the targeted planning reserve margins. The model's selection of resources capable of making significant contributions to meeting peak hour demand is partly due to fact that a significant part of the energy requirement is being met by "forced" RPS resources that tend to make a low contribution to meeting peak hour demand.

Figure - ??? show the underlying capacity load-resource balance by year for the Western Electricity Coordinating Council area. The figure shows the small contribution of "forced" RPS resource additions and the large contribution of "modeled" resource additions towards meeting peak hour demand.

It also shows that the model has built to a capacity surplus on a WECC wide basis. This is due to our configuration of the planning reserve margin targets. The configuration forces the model to meet planning reserve margin targets at the level of individual load-resource zones and pools. In other words, the model adds resources, in part, to fill capacity deficits at the zone and pool levels. At the WECC wide level, the sum of resource capacity contributions is greater than the need due to non-coincident hourly peaks.

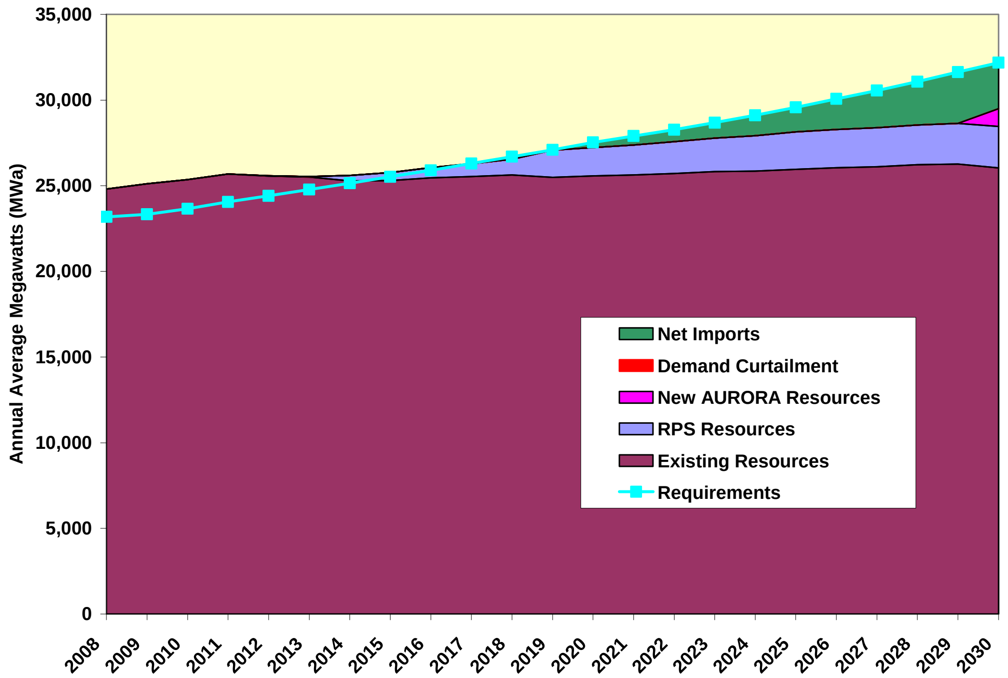
Figure D-11: WECC Annual Capacity Load-Resource Balance



The modeled addition of natural gas-fired combined-cycle combustion turbines has a significant impact on the forecasted energy load-resource balance for the Pacific Northwest. At the sub-WECC level, energy imports and exports become an important consideration. Figure - ??? shows the underlying annual energy load-resource balance for the Northwest load-resource pool.[9] Existing resources, assuming normal hydro conditions, are shown at the bottom, “forced” RPS resource additions are shown as the middle wedge, and finally, energy imports from other zones and modeled resource additions comprise the top two wedges. In the model, the region’s current energy and capacity surpluses put it in the position of being able to take advantage of the excess capacity built in other areas of the WECC to meet future energy needs. This is a logical model result, it is not a recommended resource portfolio for the region.

[9] The load-resource balance is based on the economic dispatch of the resources, not the theoretical availability the resources.

Figure D-12: Pacific Northwest Annual Energy Load-Resource Balance



Forecast of Retail Electricity Prices

Typically, the price of electricity is determined through a regulatory approval process, with utilities bringing a rate proposal to their regulatory body, board of directors or city council, to seek approval of future rates. Rates are dependant on the anticipated cost of serving customers and the level of sales. Sales are determined either for a future period or for a past period. The approved rates should cover the variable *and* fixed-cost components of serving the customers.

The methodology used for forecasting future electricity prices in the Sixth Power Plan is similar to the methodology used for forecasting other fuel prices such as gas, oil, and coal. A fuel price forecast starts with a national or regional base price and then modifies the base price through the addition of delivery charges to calculate regional prices. In forecasting retail electricity prices, a similar approach is used. Starting with a forecast of the wholesale price at the Mid-C, transmission and delivery charges, plus other incremental fixed costs that are not reflected in market clearing, are added. Examples of these incremental fixed costs include the cost of conservation investments or the cost of meeting renewable portfolio standards (RPS).

Retail Rates Estimation Methodology

A three-step process was used to calculate the retail electricity prices for each state.

Step 1: For each state, the average price of electricity in 2007, measured as the average revenue per megawatt hour of sales, is calculated. The 2007 wholesale market price for Mid-C market is calculated. The difference between the average retail price of electricity and the wholesale price at Mid-C is treated as a proxy for transmission and distribution cost additions.

Note that the transmission and distribution charges calculated here (shown in the following table under the column labeled -Proxy Non-generation costs) are simply proxies for the actual transmission and distribution charges. At this point, it is assumed that these charges will stay constant in real terms over the forecast horizon.

Table D-3: Components of Retail Rate

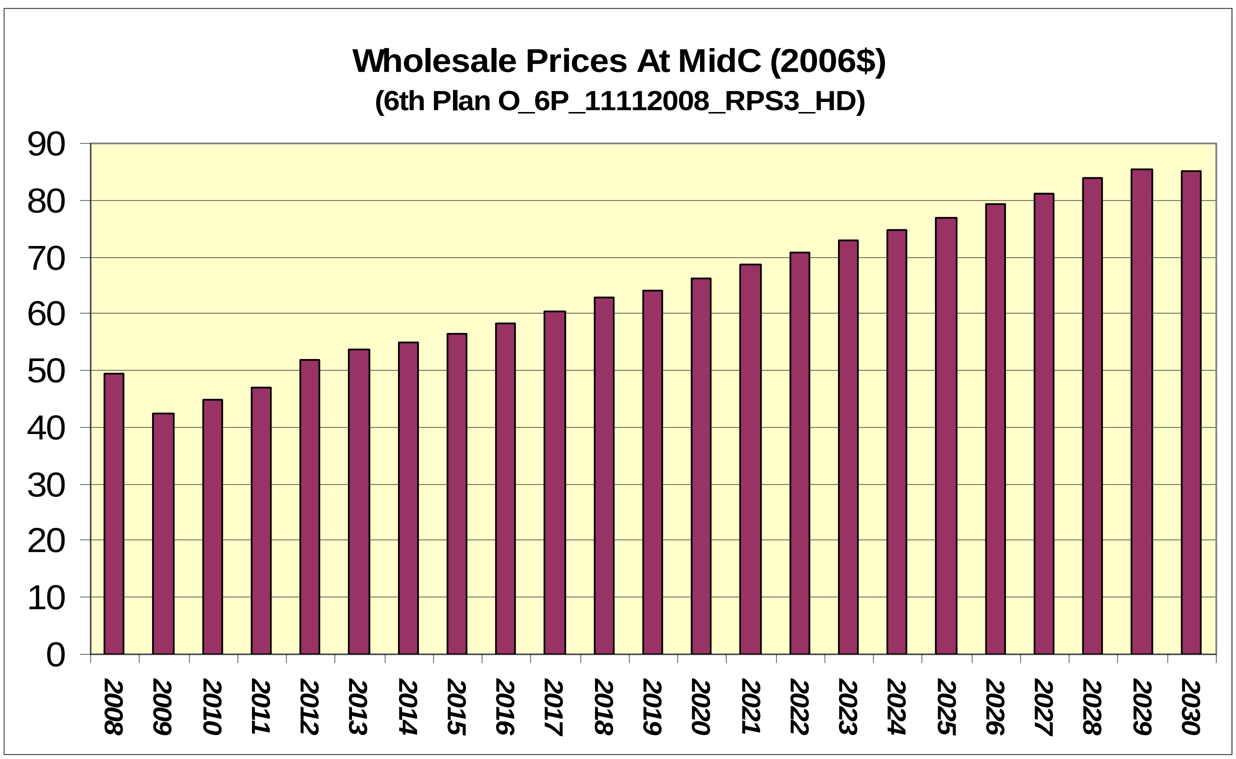
State	Average Retail Price of Electricity 2007 $/MWH	Wholesale Price Forecast for Mid C * 2007 $/MWH	Proxy Non-generation costs 2007 $/MWH
IDAHO	50.63	45.34	5.03
MONTANA	75.06	45.34	29.46
OREGON	69.96	45.34	24.36
WASHINGTON	64.12	45.34	18.52

*- based on Aurora run 6th Plan 03-13-2008 RPS HCAPTL HD

Step 2: The Interim Base Case forecast of wholesale market prices for 2008-2030, is used as the base wholesale price for electricity. The AURORA^{xmp} model produces wholesale price forecasts for many markets in the West. For the retail electricity price analysis, the Mid-C wholesale price forecast was selected as the base market hub.

The following graph shows the forecast electricity price at Mid-C for the scenario that is currently used to calculate retail electricity rates. Wholesale prices at Mid-C are projected to grow at an average annual rate of 3.3 percent for the 2010-2030 period.

Figure D-13: Wholesale Price of Electricity at Mid C



Step 3: Calculate additional costs to meet RPS standards.

RPS targets vary by state. In order to calculate additional electricity rate increases incurred by utilities for added resources to meet RPS targets, it is assumed that the costs of committed RPS resources are already reflected in the retail rates in 2007. Therefore, any additional costs would be due to the new RPS resources.

To estimate new RPS resource requirements, state or utility RPS obligations for a given year are calculated. The RPS obligation is calculated as the load forecast multiplied by the RPS target percent. If the committed RPS is above incremental RPS, no new RPS resources would be built in that year; otherwise, new RPS resources are built.

There are different resource mix options for new RPS resources that need to be built. The following table shows the Council's current assumption on how the uncommitted/new RPS resources are going to be built.

Table D-4: Assumed Market Share of New RPS Resources

	Montana	Oregon	Washington
Biomass	25.0 percent	20.0 percent	20.0 percent
Geothermal		10.0 percent	
Hydro			
Solar Photovoltaic (Load-side)		5.0 percent	5.0 percent
Solar Thermal			
Wind	75 percent	65.0 percent	75.0 percent

Each renewable generation technology has its own set of costs, including transmission and integration costs. At the moment, however, incremental transmission costs are not included in this analysis.

Interaction of RPS and Conservation: Conservation achievements reduce loads, and by reducing a utility's load, a utility's RPS target is likewise reduced. In this analysis, we calculated the rate impact of RPS with *and* without incremental conservation. Preliminary analysis indicates that, given current load forecasts and committed RPS, the region can meet RPS requirements without any new RPS resources in significant amounts until 2012.

Table D-5: Cumulative New RPS Qualifying Resources Needed (MWa)

Cumulative New RPS Qualifying Resources Needed (MWa)								
	Without Conservation			With 200 MWa /Yr Conservation target				
	MT	OR	WA		MT	OR	WA	
2008	0	0	0		0	0	0	
2009	0	0	0		0	0	0	
2010	1	0	0		0	0	0	
2011	16	0	0		15	0	0	
2012	31	0	0		30	0	0	
2013	38	23	6		37	2	0	
2014	46	34	144		44	3	108	

2015	54	48	324		52	4	272	
2016	54	59	490		52	5	419	
2017	55	180	662		52	115	568	
2018	56	515	839		53	439	720	
2019	56	583	1023		53	494	876	
2020	57	654	1214		54	551	1035	
2021	58	746	1243		54	626	1049	
2022	59	836	1272		55	698	1063	
2023	60	929	1302		55	772	1078	
2024	61	1027	1334		56	850	1095	
2025	62	1130	1368		57	931	1115	
2026	63	1164	1403		58	953	1134	
2027	64	1196	1441		58	972	1158	
2028	65	1231	1479		59	994	1182	
2029	66	1267	1518		60	1018	1206	
2030	67	1305	1559		61	1044	1232	

To calculate the effect on rates, above-market costs for RPS resources are calculated and are assumed to be recovered from target customers. For each state, using Mid-C market prices from step 1 and the levelized total cost of renewable generation technologies, total above-market costs are calculated and recovered from qualified ratepayers. For Montana, the above-market costs are recovered from Northwest customers. For the state of Washington, the RPS is applicable to 84 percent of state load, and must be met by both public and private utilities. For the state of Oregon, three different target rates are given, and the above-market costs are recovered from these target customers.

The following table shows the average rate impact of RPS with and without conservation targets. The average rate increase from RPS for the 2010-2030 period is about 1$/MWh for Montana, $3 dollars/MWH for Oregon, and about $2 per MWH for Washington, averaged over a 20-year period. On an annual basis, incremental cost increases are higher, as shown in the following table. The average rate increase for consumers in these states is similar regardless of whether or not conservation was achieved. Conservation targets lower the growth of new load but they do not significantly lower the RPS requirements.

Table D-6: Rate Impact from meeting RPS (2006 $/MWH)

	Without Conservation			With Conservation		
	MT	**OR**	**WA**	**MT**	**OR**	**WA**
2008	0.00	0.00	0.00	-	-	-
2009	0.00	0.00	0.00	-	-	-
2010	0.02	0.00	0.00	0.01	-	-
2011	0.50	0.00	0.00	0.49	-	-
2012	0.94	0.00	0.00	0.95	-	-
2013	1.14	0.22	0.02	1.15	0.02	-
2014	1.30	0.32	0.50	1.33	0.03	0.40
2015	1.45	0.43	1.05	1.49	0.04	0.95
2020	1.41	4.46	3.13	1.46	4.19	3.01

2025	1.37	6.84	3.17	1.44	6.55	3.03
2030	1.34	7.11	3.25	1.42	6.78	3.10
Average 2010-2030	1.14	3.47	1.96	1.18	3.22	1.86

Step 4: Calculate additional costs to meet conservation targets.

The next step in the analysis includes the incremental cost of conservation programs. However, this step of the analysis cannot be completed until the conservation target levels are known. The calculation of incremental costs of meeting conservation targets will be conducted after determining the optimized conservation-acquisition targets.

Table D-7: Mid-Columbia Wholesale Power Price Forecast (2006$/MWh)

Month	On-peak	Off-peak	Flat		Month	On-peak	Off-peak	Flat
Jan-2020	69.29	63.37	66.81		**Jan-2025**	78.29	74.78	76.82
Feb-2020	69.74	64.37	67.45		**Feb-2025**	81.22	75.88	78.93
Mar-2020	69.03	63.59	66.63		**Mar-2025**	79.32	74.64	77.26
Apr-2020	65.95	61.13	63.91		**Apr-2025**	75.39	71.61	73.79
May-2020	63.91	52.75	58.99		**May-2025**	71.58	64.53	68.62
Jun-2020	65.58	50.90	59.38		**Jun-2025**	74.61	63.06	69.47
Jul-2020	68.09	55.72	62.90		**Jul-2025**	77.99	66.50	73.18
Aug-2020	73.24	62.56	68.53		**Aug-2025**	84.53	74.32	80.03
Sep-2020	71.97	65.81	69.37		**Sep-2025**	83.94	76.50	80.80
Oct-2020	72.56	66.46	70.00		**Oct-2025**	83.76	77.16	80.99
Nov-2020	73.87	68.47	71.47		**Nov-2025**	83.89	78.35	81.43
Dec-2020	72.56	68.15	70.71		**Dec-2025**	83.49	79.10	81.65
Jan-2021	71.61	65.06	68.72		**Jan-2026**	81.22	76.36	79.18
Feb-2021	71.08	67.38	69.50		**Feb-2026**	84.22	77.91	81.51
Mar-2021	71.98	65.96	69.45		**Mar-2026**	81.16	77.24	79.43
Apr-2021	67.72	63.15	65.79		**Apr-2026**	77.56	74.09	76.09
May-2021	65.14	55.20	60.76		**May-2026**	73.56	67.40	70.84
Jun-2021	67.71	53.73	61.81		**Jun-2026**	77.47	64.08	71.82
Jul-2021	70.11	57.21	64.70		**Jul-2026**	79.95	68.42	75.12
Aug-2021	76.41	65.21	71.47		**Aug-2026**	87.19	76.57	82.51
Sep-2021	74.25	67.76	71.51		**Sep-2026**	85.88	78.50	82.76
Oct-2021	74.74	68.06	71.79		**Oct-2026**	85.56	79.27	82.92
Nov-2021	76.45	70.95	74.13		**Nov-2026**	87.09	81.00	84.38
Dec-2021	74.68	70.14	72.77		**Dec-2026**	85.50	81.36	83.77
Jan-2022	73.86	68.09	71.32		**Jan-2027**	83.21	78.74	81.24
Feb-2022	73.50	69.87	71.95		**Feb-2027**	86.38	80.37	83.80
Mar-2022	73.43	67.47	70.93		**Mar-2027**	83.48	78.87	81.55
Apr-2022	69.58	65.11	67.69		**Apr-2027**	79.27	75.92	77.85
May-2022	67.00	58.04	63.05		**May-2027**	75.01	68.99	72.36
Jun-2022	69.99	56.30	64.21		**Jun-2027**	78.66	66.60	73.57
Jul-2022	72.02	60.18	66.80		**Jul-2027**	81.93	70.29	77.05
Aug-2022	78.30	67.55	73.79		**Aug-2027**	90.39	78.72	85.25
Sep-2022	75.83	69.78	73.27		**Sep-2027**	87.11	80.53	84.33
Oct-2022	77.36	70.65	74.40		**Oct-2027**	87.69	81.47	84.95
Nov-2022	79.25	72.81	76.53		**Nov-2027**	89.89	82.74	86.87
Dec-2022	76.07	72.58	74.61		**Dec-2027**	87.87	82.93	85.80
Jan-2023	75.72	70.65	73.48		**Jan-2028**	86.03	82.14	84.32
Feb-2023	76.31	71.61	74.30		**Feb-2028**	89.39	82.41	86.42
Mar-2023	75.69	70.73	73.61		**Mar-2028**	85.66	80.62	83.55
Apr-2023	70.93	67.82	69.55		**Apr-2028**	81.21	78.15	79.85
May-2023	69.19	59.97	65.33		**May-2028**	78.52	69.08	74.56
Jun-2023	72.30	58.64	66.53		**Jun-2028**	81.25	69.36	76.23
Jul-2023	74.57	62.26	69.14		**Jul-2028**	84.61	73.17	79.57
Aug-2023	80.57	69.87	76.08		**Aug-2028**	94.19	81.25	88.77
Sep-2023	78.02	71.94	75.46		**Sep-2028**	89.41	82.47	86.48
Oct-2023	80.44	73.35	77.31		**Oct-2028**	90.97	83.94	87.87
Nov-2023	81.65	75.34	78.99		**Nov-2028**	93.25	85.14	89.83
Dec-2023	78.12	74.53	76.54		**Dec-2028**	91.05	85.40	88.56
Jan-2024	77.04	71.51	74.72		**Jan-2029**	89.45	83.48	86.95
Feb-2024	79.01	74.13	76.93		**Feb-2029**	91.30	84.18	88.25
Mar-2024	78.11	72.95	75.84		**Mar-2029**	86.84	82.27	84.92
Apr-2024	72.93	68.59	71.10		**Apr-2029**	83.79	79.88	82.05
May-2024	70.34	61.06	66.45		**May-2029**	78.83	72.44	76.15
Jun-2024	71.41	59.86	66.28		**Jun-2029**	81.63	68.41	76.05
Jul-2024	76.12	64.29	71.16		**Jul-2029**	85.66	74.30	80.65
Aug-2024	82.55	71.66	77.98		**Aug-2029**	97.98	83.20	91.78
Sep-2024	81.15	74.10	78.02		**Sep-2029**	92.58	84.24	88.87
Oct-2024	81.24	74.76	78.52		**Oct-2029**	92.64	84.42	89.20
Nov-2024	81.34	76.22	79.17		**Nov-2029**	93.54	85.82	90.28
Dec-2024	81.31	76.35	79.13		**Dec-2029**	94.38	86.74	91.01

Appendix E: Conservation Supply Curve Development

OVERVIEW

This Appendix provides an overview of the Council general methodology for estimating the conservation resource potential in the region and describes the major sources of information used to prepare that analysis. It also provides links to spreadsheets containing the detailed input assumptions and specific source data used for each of the measures in the Council's conservation supply curves.

The Council estimates costs and savings for over 1400 measures. These costs and savings are used to develop supply curves of conservation potential available by year. The supply curves represent the amount of conservation available at different cost levels. Costs are expressed as TRC Net levelized costs so they can be compared to the costs of power purchases and the costs of new resource development.[1] The Council uses an in-house model called ProCost to calculate TRC Net levelized cost. The following sections describe the "global" inputs and methodology used by the Council in its assessment of regional conservation resource potential.

Cost-Effectiveness Methodology Used in the Portfolio Analysis Model

As with all other resources, the Council uses its Resource Portfolio Model (RPM) to determine how much conservation is cost-effective to develop.[2] The RPM is designed to compare resources, including conservation on a "generic" level. That is, it does not model a specific combined cycle gas or wind project nor does it model specific conservation measures or programs. In the case of conservation, the model uses two separate supply curves. These supply curves, one for discretionary resources and a second for lost opportunity resources, depict the amount of savings achievable at varying costs. The savings in these two supply curves are allocated to "on-peak" and "off-peak" periods for each quarter of the year to capture the daily and seasonal effect of changes in wholesale market prices on the value of conservation. This allocation of savings to time periods is a summation of the time-based shape of the collective savings of the individual measures in each of these supply curves.

The cost-effectiveness methodology used in the conservation assessment considers the time-based value of the savings, and the non-power system costs and benefits of each conservation measure to estimate how much of the identified savings potential is cost-effective based on an estimate of forecast power prices and forecast value of transmission and distribution capacity deferred. Run time constraints limit the number of conservation programs the RPM can

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[1] "TRC Net Levelized Cost" is computed based on all costs minus all benefits regardless of which sponsor incurs the cost or accrues the benefits. TRC Net Levelized Cost includes all applicable costs and all benefits. In addition to energy system costs and benefits, TRC Net Levelized Cost includes non-energy, other-fuel, O&M, periodic-replacement and risk-mitigation benefits and costs. TRC Net Levelized Cost corresponds to TRC B/C ratios with regard to the costs and benefits included. Benefits are subtracted from costs, then levelized over the life of the program.

[2] The Act defines regional cost-effectiveness as follows: "Cost-effective", when applied to any measure or resource referred to in this chapter, means that such measure or resource must be forecast to be reliable and available within the time it is needed, and to meet or reduce the electric power demand, as determined by the Council or the Administrator, as appropriate, of the consumers of the customers <u>at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative measure or resource</u>, or any combination thereof. (Emphasis added). Under the Act the term "system cost" means an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and such quantifiable environmental costs and benefits as are directly attributable to such measure or resource. The Council has interpreted the Act's provisions to mean that in order for a conservation measure to be cost-effective the discounted present value of all of the measure's benefits should be compared to the present value of all of its costs.

consider. The RPM cannot consider individual programs for every measure and every specific load shape, and perform a measure-specific benefit-cost ratio for each sub-component of conservation. So the Council simplifies the set of conservation measures available to the portfolio model. The Council uses "adjusted" levelized costs to incorporate the transmission and distribution system benefits for the aggregate benefits of the collective set of conservation measures. The Council adjusts the levelized costs of the measures to reflect the transmission and distribution value of the collective savings in both the lost-opportunity and discretionary supply curves. The RPM compares this supply curve of available conservation and adjusted levelized costs to the model's "estimates" of forecast short-term power market prices. The RPM then tests how much conservation to develop, along with other resources, that provides least-cost and least risk plans.

The Costs of Conservation

The costs included in the Council's analyses are the sum of the total installed cost of the measure, and any operation and maintenance costs, or savings, associated with ensuring the measure's proper functioning over its expected life. If the use of an electric efficiency measure increases or decreases the use of another fuel, such as improving the efficiency of lighting in a commercial building may increase the use of natural gas for heating, the cost or savings of these impacts are included in the analysis.

The Value of Conservation

Part of the value of a kilowatt-hour saved is the value it would bring on the wholesale power market and part of its value comes from deferring the need to add distribution and/or transmission system capacity. This means that the marginal "avoided cost" varies not only by the time of day and the month of the year, but also through time as new generation, transmission and distribution equipment is added to the power system. The Council's cost-effectiveness methodology starts with detailed information about when the conservation measure produces savings and how much of these savings occur when distribution and transmission system loads are at their highest. That is, each measure's annual savings are evaluated for their effects on the power system over the 8760 hours in a year.[3]

The Northwest's highest demand for electricity occurs during the coldest winter days, usually during the early morning or late afternoon. Savings during these peak periods reduce the need for distribution and transmission system expansion. Electricity saved during these periods is also more valuable than savings at night during spring when snow melt is filling the region's hydroelectric system and the demand for electricity is much lower. However, since the Northwest electric system is linked to the West Coast wholesale power market, the value of the conservation is no longer determined solely by regional resource cost and availability.

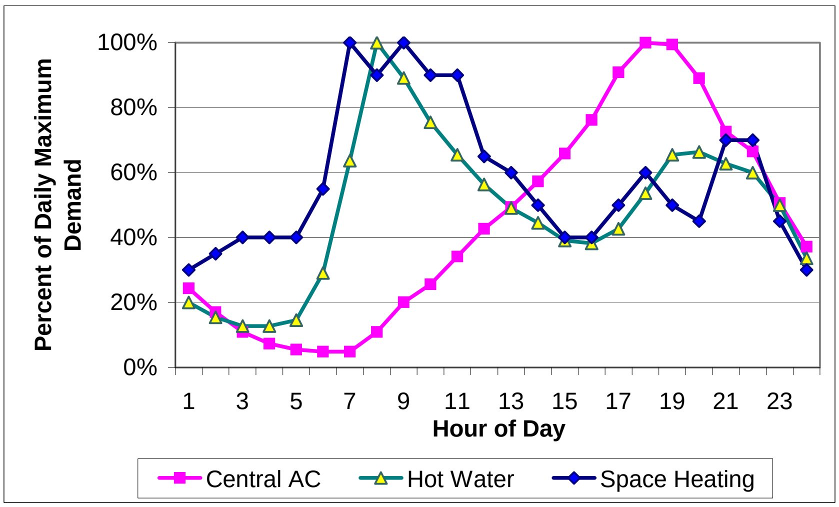
[3] To simplify this analysis the Council divides each day and week into four time segments representing high, medium high, medium and low demand hours, resulting in four price "periods" per day for each month for a total of 48 prices per year.

Value of Energy Saved

Given the interconnected nature of the West, regional wholesale power prices reflect the significant demand for summer air conditioning in California, Nevada and the remainder of the desert Southwest. Consequently, wholesale power prices are as high as or higher during the peak air conditioning season in July and August than they are when the Northwest system peak demand occurs in the winter. Consequently, a kilowatt-hour saved in a commercial building in the afternoon in the Pacific Northwest may actually displace a kilowatt-hour of high-priced generation in Los Angeles on a hot August day. Whereas a kilowatt-hour saved in street lighting might displace a low-cost imported kilowatt-hour on a night in November.

As noted previously, in addition to its value in offsetting the need for generation during the hours it occurs, conservation also reduces the need to expand local power distribution system capacity. Figure E-1 shows typical daily load shape of conservation savings for measures that improve the efficiency of space heating, water heating and central air conditioning in typical new home built in Boise. The vertical axis indicates the ratio (expressed as a percent) of each hour's electric demand to the maximum demand for that end use during over the course of the entire day. The horizontal axis shows the hour of the day, with hour "0" representing midnight.

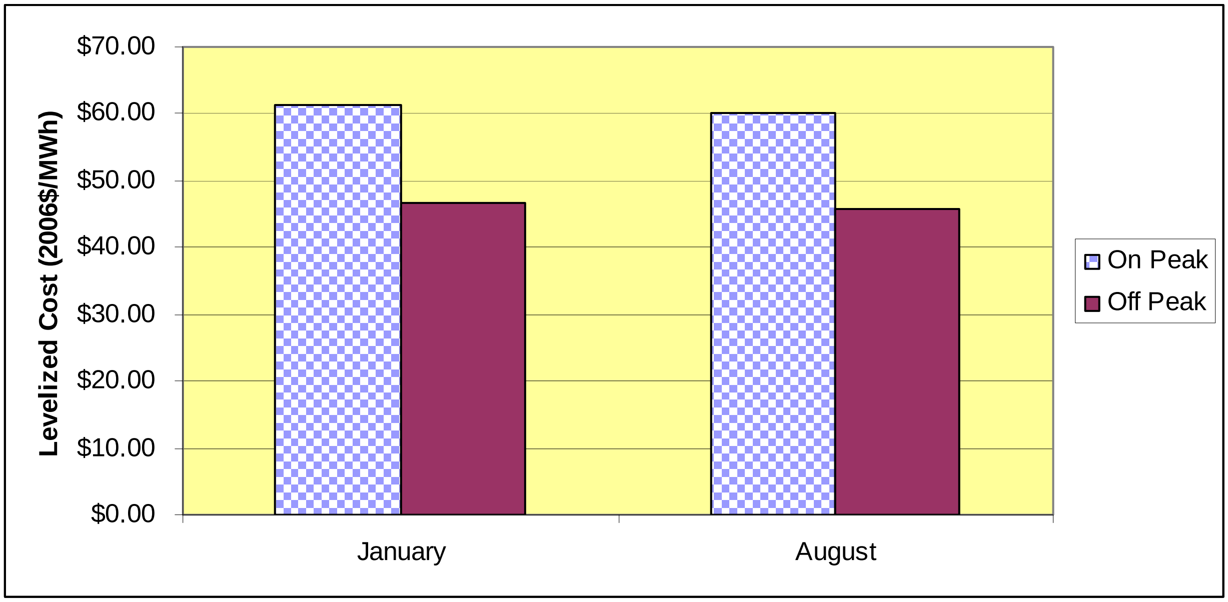
Figure E-1: Hour Load Profile for Residential Central Air Conditioning Water Heating and Space Heating Conservation Savings



As can be seen from inspecting Figure E-1, water heating savings increase in the morning when occupants rise to bathe and cook breakfast, then drop while they are away at work and rise again during the evening. Space heating savings also exhibit this "double-hump" pattern. In contrast, central air conditioning savings increase quickly beginning in the early afternoon, peaking in late afternoon and decline again as the evening progresses and outside temperatures drop.

The Council's forecast of future hourly wholesale market power prices vary over the course of typical summer and winter days. Figure E-2 shows the average levelized "on peak" and "off peak" wholesale market prices at Mid-C for January and August. As can be seen from Figure E-2, "on-peak" savings are far more valuable than those that occur "off-peak" during the summer or during the winter.

Figure E-2: Forecast Levelized "On" and "Off-Peak" Wholesale Power Market Prices for January and August at Mid Columbia Trading HUB



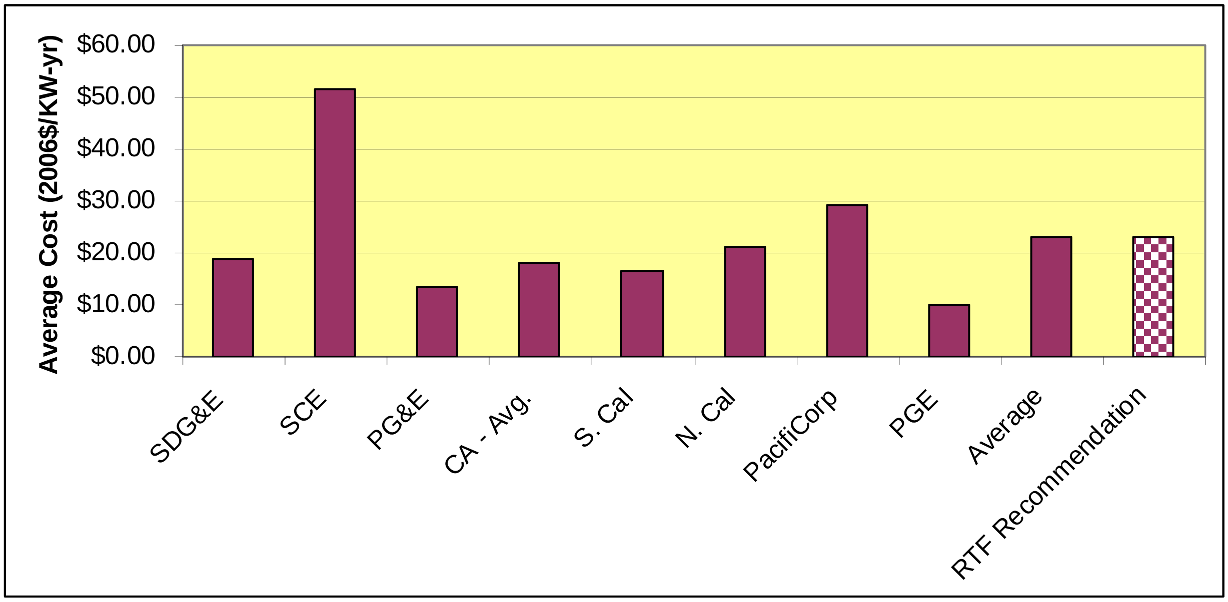
In order to capture this differential in benefits, the Council computes the weighted average time-differentiated value of the savings of each conservation measure based on its unique conservation load shape. Each month's savings are valued at the avoided cost for that time period based on the daily and monthly load shape of the savings. The weighted value of the all time period's avoided costs establishes the cost-effectiveness limit for a particular end use.

Forecast of future wholesale power market prices are subject to considerable uncertainty. Therefore, in order to determine a more "robust" estimate of a measure's cost-effectiveness it should be tested against a range of future market prices. The Council currently uses its "base case" AURORA model forecast of future wholesale market prices to determine conservation cost-effectiveness. However, in order to reflect the uncertainty of future market prices rather than a single market price forecast the Council adjusts the AURORA market price forecast to incorporate the value that conservation provides as a hedge against future market price volatility. The derivation of this value is described fully in Chapter 9 of the Sixth Plan.

Value of Deferred Transmission and Distribution Capacity

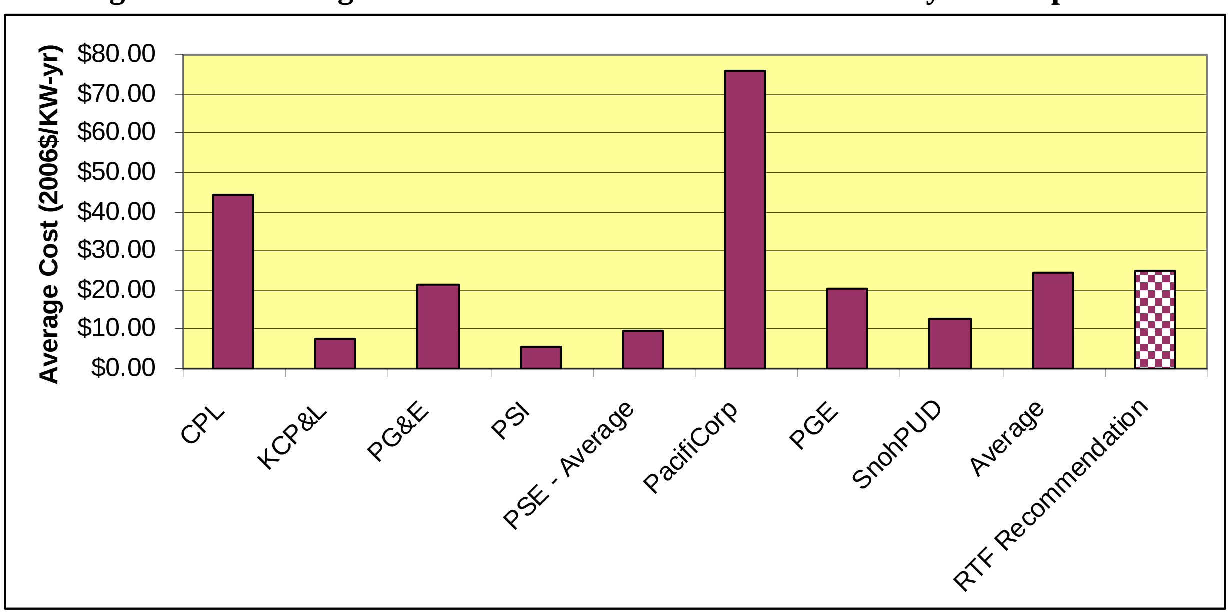
In addition to its value in offsetting the need for generation, conservation also reduces the need to expand local power distribution system capacity. The next step used to determine conservation's cost effectiveness is to determine whether the installation of a particular measure will defer the installation or expansion of local distribution and/or transmission system equipment. The Council recognizes that potential transmission and distribution systems cost savings are highly dependent upon local conditions. However, the Council relied on data obtained by its Regional Technical Forum (RTF) to develop a representative estimate of avoided transmission and distribution costs. Figure E-3 presents data for the avoided cost of transmission system expansion and Figure E-4 presents data for the avoided cost of distribution system expansion.

Figure E-3: Average Avoided Cost of Deferred Transmission System Expansion



After reviewing this data the RTF recommended a value of $23/kW-yr for "representative" of avoided transmission system expansion cost and $25/kW-yr as "representative" of avoided cost of distribution system expansion. The Council adopted the RTF recommended value for distribution system avoided cost. However, because the value of avoiding the transmission system investments is already included in the wholesale market prices produced by the AURORA model the Council did not use the RTF estimate of the benefits of deferring transmission system expansion so as to avoid double counting.

Figure E-4: Average Avoided Cost of Deferred Distribution System Expansion



As discussed above, due to the interconnected nature of the West coast wholesale power market, conservation measures that reduce consumption during the on peak hours are the most valuable, even though the region has significant peaking resources from the hydro-system. In contrast, throughout most of the Northwest region measures conservation measures that reduce peak demand during the winter heating season are of more value to the region's local distribution systems and to its wholesale transmission system.[4] This is because these systems must be designed and built to accommodate "peak demand" which occurs in winter. If a conservation measure reduces demand during these periods of high demand it reduces the need to expand distribution and transmission system capacity.

In order to determine the benefits a conservation measure might provide to the region's transmission and distribution system it is necessary to estimate how much that measure will reduce demand on the power system when regional loads are at their highest. The same conservation load shape information that was used to estimate the value of avoided market purchases was also used to determine the "on-peak" savings for each conservation measure.

Value of Non-Power System Benefits

In addition to calculating the regional wholesale power system and local distribution system benefits of conservation the Council analysis of cost-effectiveness takes into account a measure's other non-power system benefits. For example, more energy efficient clothes washers and dishwashers save significant amounts of water as well as electricity. Similarly, some industrial efficiency improvements also enhance productivity or improve process control while others may reduce operation and maintenance costs. Therefore, when a conservation measure or activity provides non-power system benefits, such benefits should be quantified (e.g., gallons of water savings per year and where possible an estimate of the economic value of these non-power system benefits should be computed. These benefits are added to the Council's estimate of the value of energy savings to the wholesale power system and the local electric distribution systems when computing total system/societal benefits.

Regional Act Credit

The Northwest Power Act directs the Council and Bonneville to give conservation a 10 percent cost advantage over sources of electric generation. The Council does this by adding 10 percent to the AURORA model forecast of wholesale market power prices and to its estimates of capital costs savings from deferring electric transmission and distribution system expansion. Since the Council's Resource Portfolio Model (RPM) does not address the Act's credit for conservation, the levelized cost of conservation in the supply curves are adjusted downward so that this credit is reflected in its comparison of conservation with other resources.

Financial Input Assumptions

The present value cost of conservation is determined by who pays for it. The RTF was asked to provide recommendations on the anticipated "cost-sharing" between utilities and consumers. Staff also developed estimates of the cost of capital and equity used to pay for conservation based on the mix of consumers in each of the major sectors. Tables E-1 through E-4 show the financial assumptions used in the economic analysis of conservation opportunities in each of the four major economic sectors.

[4] Some areas of the region now experience both summer and winter peaks of almost equal magnitude due to increased use of air conditioning.

Table E-1: Residential Sector Financial Input Assumptions

Sponsor Parameters	Customer	Wholesale Electric	Retail Electric	Natural Gas
Real After-Tax Cost of Capital	3.90%	4.40%	4.90%	5.00%
Financial Life (years)	15	1	1	1
Sponsor Share of Initial Capital Cost	35%	20%	45%	0%
Sponsor Share of Annual O&M	100%	0%	0%	0%
Sponsor Share of Periodic Replacement Cost	100%	0%	0%	0%
Sponsor Share of Administrative Cost	0%	50%	50%	0%
Last Year of Non-Customer O&M & Period Replacement		20		

Table E-2: Commercial Sector Financial Input Assumptions

Sponsor Parameters	Customer	Wholesale Electric	Retail Electric	Natural Gas
Real After-Tax Cost of Capital	6.70%	4.40%	4.90%	5.00%
Financial Life (years)	20	1	1	1
Sponsor Share of Initial Capital Cost	35%	10%	55%	0%
Sponsor Share of Annual O&M	100%	0%	0%	0%
Sponsor Share of Periodic Replacement Cost	100%	0%	0%	0%
Sponsor Share of Admin Cost	0%	50%	50%	0%
Last Year of Non-Customer O&M & Period Replacement		20		

Table E-3: Industrial Sector Financial Input Assumptions

Sponsor Parameters	Customer	Wholesale Electric	Retail Electric	Natural Gas
Real After-Tax Cost of Capital	7.60%	4.40%	4.90%	5.00%
Financial Life (years)	20	1	1	1
Sponsor Share of Initial Capital Cost	35%	10%	55%	0%
Sponsor Share of Annual O&M	100%	0%	0%	0%
Sponsor Share of Periodic Replacement Cost	100%	0%	0%	0%
Sponsor Share of Admin Cost	0%	50%	50%	0%
Last Year of Non-Customer O&M & Period Replacement		20		

Table E-4: Agriculture Sector Financial Input Assumptions

Sponsor Parameters	Customer	Wholesale Electric	Retail Electric	Natural Gas
Real After-Tax Cost of Capital	7.60%	4.40%	4.90%	5.00%
Financial Life (years)	5	1	1	1
Sponsor Share of Initial Capital Cost	35%	10%	55%	0%
Sponsor Share of Annual O&M	100%	0%	0%	0%
Sponsor Share of Periodic Replacement Cost	100%	0%	0%	0%
Sponsor Share of Admin Cost	0%	50%	50%	0%
Last Year of Non-Customer O&M & Period Replacement		20		

RESIDENTIAL SECTOR

Residential Sector Definition and Coverage

For the Council's conservation analysis the residential sector includes single family, multifamily and manufactured homes buildings. Single family buildings are defined as all structures with four or fewer separate dwelling units, including both attached and detached homes. Multifamily structures include all housing with five our more dwelling units, up to four stories in height.[5] Manufactured homes are dwellings regulated by the US Department of Housing and Urban Development (HUD) construction and safety standards (USC Title 42, Chapter 70). Modular homes, which are regulated by state codes, are considered single family dwellings.

One of primary inputs into the residential sector conservation assessment is the number of units that each conservation measure or measure bundle could be applied to in the region. Space conditioning savings are a function of both the characteristics of the structure and the climatic conditions where the home is located. Therefore, the Council's assessment includes estimates of the number of new and existing dwelling units of each type (i.e., single family, multifamily, manufactured homes) in nine different climate zones. The Council defines climate zones by specific combinations of heating and cooling degree days. Table E-5 shows the nine climate zones in the region.

Measure Bundles

Nearly 60 individual residential-sector measures are analyzed in the Sixth Power Plan. In the case of heat pumps and central air conditioning three measures were consolidated into a single bundle of related measures. Two levels of efficiency above the current federal minimum standards were tested, HSPF 8.5/SEER 14 and HSPF 9.0/SEER 14. For purposes of analytical expediency it was assumed that when a high efficiency heat pump was installed it would also undergo commissioning to ensure it functions properly and that it would have controls installed to optimize its operation. In addition, it was also assumed that in the case of existing homes the duct system would be sealed and in the case of new homes the duct system would be located inside the conditioned space or be sealed. As a result "duct sealing" and "heat pump commissioning and controls" are not identified separated in the supply curve, but are bundled with "heat pump efficiency upgrades" and "heat pump conversions." These measure bundles do not and should not dictate the way measures are bundled for programmatic implementation.

Table E-5: Regional Heating and Cooling Climate Zones

Climate Zone	Heating Degree Days	Cooling Degree Days
Climate Zone: Heating 1 - Cooling 1	< 6000	<300
Climate Zone: Heating 1 - Cooling 2	< 6000	> 300 - 899
Climate Zone: Heating 1 - Cooling 3	< 6000	> 900
Climate Zone: Heating 2 - Cooling 1	6000 - 7499	<300
Climate Zone: Heating 2 - Cooling 2	6000 - 7499	> 300 - 899
Climate Zone: Heating 2 - Cooling 3	6000 - 7499	> 900
Climate Zone: Heating 3 - Cooling 1	> 7500	<300
Climate Zone: Heating 3 - Cooling 2	> 7500	> 300 - 899
Climate Zone: Heating 3 - Cooling 3	> 7500	> 900

Measures are also consolidated into three types of application modes. These modes are new, natural replacement and retrofit. The new mode applies primarily to new buildings or new equipment. The natural replacement mode applies to subsystems and equipment within buildings that are replaced on burnout, at the end of their useful life, or at the time of remodel of

[5] The conservation potential for water heating, lighting, appliances and consumer electronics in high rise multifamily dwellings (i.e., those covered by non-residential codes) are included in the residential sector. However, the savings from building shell and HVAC improvements in high rise multifamily buildings is not included in the Council's assessment of regional conservation potential due to lack of data.

the building or system within a building. Examples of this mode include appliance and water heater replacements and conversions of electric forced air furnaces to air source heat pumps are assumed to take place when the existing furnace needs to be replaced. Retrofit mode is used where a measure or a building subsystem upgraded, replaced or retired before the end of its useful life. The installation of insulation, window replacements and installation of ductless heat pumps to provide higher efficiency supplemental space conditioning are all examples of retrofit measures.

There are three reasons to distinguish the new, natural replacement and retrofit application modes. First, costs and savings can be different by application mode. Second, in the case of new and natural replacement, the available stock for the measure depends on the forecast of new additions and replacement rate for equipment. These opportunities are tracked separately over course of the forecast period and limit the annual availability of conservation opportunities. Third, the Council's portfolio model treats new and natural replacement applications as lost-opportunity measures that can only be captured at the time of construction or natural replacement.

Measure costs, savings, applicability, and achievability estimates are identified separately for each of the new, natural replacement and retrofit application modes. The Council analyzes measure costs and savings on an incremental basis. Measure cost is the incremental cost over what would be done absent the measure or program. The same is true for savings. Incremental measure costs and savings can be different depending on the application mode. For example, incremental costs of high performance windows in a new application only include the additional cost of the windows required by code. In a retrofit application, the labor cost of removing and replacing the existing window are added to the measure cost.

Overview of Methods

Measure costs and savings are developed at a level of detail compatible with data availability, expected variance in measure costs and savings, the diversity of measure applications and practical limitations on the number of measures that can be analyzed. Costs and savings are based both on engineering estimates as well as estimates based on results from the operation of existing programs. Savings potential is the product of savings per unit and the forecast of number of units that the measure is applicable to. For the residential sector measures the unit of measure is a function of the measure type. Most measures apply to a fraction of the building stock in a particular building type. For example, insulation measures are a function of the number of households with electric heat, refrigerator efficiency improvements are a function of the number of refrigerators that are replaced or purchase new each year and the potential savings from ductless heat pumps are function of the number of single family homes with zonal electric heating systems.

For every measure or practice analyzed, there are four major methodological steps to go through. These steps establish baseline conditions, measure applicability, and measure achievability. For the residential-sector conservation measures, each of these is treated explicitly for each measure bundle.

Baseline Characteristics

Baseline conditions are estimated from current conditions for existing buildings and systems. Estimates of current conditions and characteristics of the building stock come from several sources. Key among these are the market research projects of the Northwest Energy Efficiency Alliance (NEEA), selected studies from utilities, Energy Trust of Oregon, and other sources.

For new buildings, new and replacement equipment, baseline conditions are estimated from a combination of surveys of new buildings, state and local building energy codes and federal and state appliance efficiency standards. The most recent survey data used is from the NEEA New Single Family and New Multifamily Buildings Characteristics studies completed in 2007 which looked at buildings built in the 2003-2004. Codes and standards are continually being upgraded. The baseline assumptions used in the Sixth Power Plan are those that were adopted at the end of 2008, with a few exceptions. Some of these include standards that are adopted now but with effective dates that occur in the future. For such codes or standards, both savings estimates and the demand forecast reflect the effective dates of adopted standards. Baseline characteristics for major appliances (washers, dishwashers, refrigerators and freezers) are the national sales weighted average efficiency levels. This data was obtained from the American Home Appliance Manufacturer's Association (AHAM). Cost data for appliances was obtained from an analysis of the Oregon Residential Energy Tax Credit data and Internet searches. Heating, cooling, insulation and window cost were obtained from an analysis of program data from Puget Sound Energy and the Energy Trust of Oregon.

Measure Applicability

Measure applicability reflects several major components. First is the technical applicability of a measure. Technical applicability includes what fraction of the stock the measure applies to. Technical applicability can be composed of several factors. These include the fraction of stock that the measure applies to, overlap with mutually exclusive measures and the existing saturation of the measure. Existing measure saturation reflects the fraction of the applicable stock that has already adopted the measure and for which savings estimates do not apply. There are hundreds of applicability assumptions in the residential-sector conservation assessment. Applicability assumptions by measure appear in the three supply curve summary workbooks. Table E-6 shows the measures covered by each of these three workbooks.

Measure Achievability

The Council assumes that only a portion of the technically available conservation can be achieved. Ultimate achievability factors are limited to 85 percent of the technically available conservation over the twenty-year forecast period. In addition to a limit of 85 percent, the Council considers near-term achievable penetration rates for bundles of conservation measures. Several factors are used to estimate near-term achievability rates. Recent experience with region wide conservation program accomplishments is one key factor. But in addition to historic experience, the Council also considers a bottom-up approach to estimate near-term achievability.

In the bottom-up approach, the Council estimates near-term achievability rates of each bundle of conservation measures based on the characteristics of the measures in the bundle being described
In the bottom-up approach, the Council estimates near-term achievability rates of each bundle of conservation measures based on the characteristics of the measures in the bundle being described
and consideration of likely delivery mechanisms. This detailed bottom-up approach is a new

element in the Sixth Power Plan. In the Sixth Plan, the Council uses a suite of typical ramp rates to reflect near-term penetration rates. For example, measures involving emerging technology might start out at low penetration rates and gradually increase to 85 percent penetration. Measures suitable for implementation by a building code or a federal equipment standard might increase rapidly to 85 percent penetration in new buildings and major remodels. Measures requiring new delivery mechanisms might ramp up slowly. Simple measures with well-established delivery channels, like efficient shower heads, might take only half a dozen years to fully implement. Whereas retrofit measures in complex markets might take 20 years to reach full penetration. Assumptions for the bottom-up approach are detailed in the conservation supply curve workbooks shown in Table E-6 below.

Table E-6: Measures Covered in Residential Supply Curve Summary Worksheets

Measures	Worksheet Name
New and existing lighting Clothes washers and dryers Dishwashers Refrigerators and Freezers Microwaves and ovens High efficiency water heaters, including heat pump water heaters Showerheads Waste water heat recovery Solar water heating Solar photovoltaic	PNWResDHWLight&ApplianceCurve_6thPlanv1_3.xls
Thermal Envelop Improvements (insulation, windows, air sealing) High Efficiency heat pumps (upgrades and system conversions) High Efficiency air conditioners (Room AC and Central AC) Duct Efficiency (sealing and interior ductwork) Heat pump commissioning and controls Ductless heat pumps	PNWResSpaceConditioningCurve_6thPlanv1_5.xls
Televisions Set Top Boxes Desktop computers Desktop computer monitors	PNWConsumerElectronicsSupplyCurve_6thPlanv1_3.xls

Physical Units

The conservation supply curves are developed primarily by identifying savings and cost per unit and estimating the number of applicable and achievable units that the measure can be deployed on. In the residential sector analysis, the applicable unit estimates for space conditioning, water heating, lighting and appliances are based on the number of existing housing units and forecast of future housing growth from the Council's Demand Forecasting Model. The housing units from the forecasting model were allocated to climate zones based on the population weighted average heating and cooling degrees for each county in the region. The housing unit data and zone allocations are all contained in the spreadsheet entitled "PNWResSectorSupplyCurveUnits_6thPlan.xls." The estimates of physical units available include the number of units available annually. For example, for new buildings, the estimate of available new building stock is taken from the Council's baseline forecast for annual additions by building type. Similarly for equipment replacement measures the annual stock available is taken from estimates of the turnover rate of the equipment in question. For retrofit measures, the annual stock availability is a fraction of the estimated stock remaining at the end of the forecast period.

The number of applicable and achievable units for consumer electronics were derived from national and regional sales data and forecast for televisions, set top boxes and desktop computers and monitors. The estimates of physical units for these products are embedded in the consumer electronics supply curve workbooks cited in Table E-6.

Guide to the Residential Conservation Workbooks

Table E-7 provides a cross-walk between the measures included in the Council's assessment of regional conservation potential in the residential sector and the name of the individual workbooks. The most recent version of these workbooks are posted on the Council's website and are available for downloading.

Table E-7: Residential Sector Supply Curve Input Workbooks

File Scope	File Name
Lighting - Existing	EStarLighting_ExistingFY09v1_1.xls
Lighting - New	EStarLighting_NewFY09v1_0.xls
Refrigerator	EStarRefrigeratorFY09v1_0.xls
Dishwasher	EStarResDishwasherFY09v1_0.xls
Freezer	EStarResFreezersFY09v1_0.xls
Window AC Upgrades	EStarRoomACFY09v1_0.xls
Clothes Washers and Dryers - Single Family	EStarWasher_DryerSingleFamily_FY09v1_1.xls
Clothes Washers and Dryers - Multifamily	EStarWasher_DryerMultifamily_FY09v1_0.xls
Marginal Cost and Load Shape Date File (needed to run Procost models to update cost-effectiveness)	MC_and_LoadShape_6P.xls
Residential Appliance, Lighting and Domestic Water Heating Supply Curve for Draft 6th Plan	PNWResDHWLight&ApplianceCurve_6thPlanv1_5.xls
Residential Supply Curve Housing and Appliance Units	PNWResSectorSupplyCurveUnits_6thPlan.xls
Residential Space Conditioning Supply Curve	PNWResSpaceConditioningCurve_6thPlanv1_5.xls
New and Existing Single Family & Manufactured Home HVAC Conversions and Upgrades to High Efficiency Heat Pumps	ResDHP&HPConversions_UpgradesFY09v1_4.xls
Showerhead	ResDHW_2_0gpmShowerheads_FY09v1_0.xls
Efficient Water Heater Tanks and Heat Pump Water Heaters	ResDHWFY09v1_1.xls
Waste Water Heat Recovery	ResDHWHeatRecoveryFY09v1_1.xls
New Multifamily Thermal Shell	ResNewMF_wAdvancedLightingsqftFY09v1_2.xls
New Manufactured Home Thermal Shell	ResNewMH_wAdvancedLightingsqftFY09v1_2.xls
New Single Family Thermal Shell	ResNewSF_wAdvancedLightingsqftFY09v1_2.xls
Microwaves and Ovens	ResOven_MicrowaveFY09v1_0.xls
Residential Sector Supply Curve Summary	ResSectorConAsmnt_070109Summary.xls
Multifamily Weatherization	ResWxMF_w/AdvancedLightingsqftFY09v1_2.xls
Manufactured Home Weatherization	ResWxMH_w/AdvancedLightingsqftFY09v1_2.xls
Single Family Weatherization	ResWxSF_w/AdvancedLightingsqftFY09v1_2.xls
Solar Domestic Water Heating	SolarDHW_FY09v1_0.xls
Solar Photovoltaic	SolarPV_FY09v1_0.xls
Consumer Electronics (Televisions, Set-top-Boxes, Computers & Monitors)	PNWConsumerElectronicsSupplyCurve_6thPlanv1_3.xls
Climate Zone Assignments by State and County	PNWClimateZones_6thPlan.xls
Housing Foundation Types	PNWFoundTypes-_6thPlan.xls

COMMERCIAL SECTOR

Commercial Sector Definition and Coverage

For the Council’s conservation analysis the commercial sector includes non-residential buildings except for industrial, as well as non-building economic activities such as street and highway lighting, outdoor area lighting, municipal sewage treatment, and water supply systems.

Commercial building floor area is one of the key drivers of the commercial conservation assessment. Floor area estimates are driven by economic forecasts of business activity, employment, demographics, and other factors such as floor area per employee. The development of the commercial floor area and load forecasts is described in Appendix C. The commercial building sector is categorized into 11 economic activity types and 18 separate building types. These building types are listed in Table E-8.

Table E-8: Building Types Covered in Commercial Supply Curve Summary Worksheets

Primary Activity	Council Building Type	Gross Floor Area in Square Feet	Number of Stories	Note, Comment, or Example
Office	Large Office	> 100,000	Any	
Office	Medium Office	20,000 to 100,000	Any	
Office	Small Office	< 20,000	Any	
Retail	Big Box	> 50,000	1	Includes some Grocery
Retail	Small Box	<50,000	1	
Retail	High End	< 20,000	1	High lighting density
Retail	Anchor	> 50,000	>1	
Education	K-12	Any	Any	
School	University	Any	Any	University, community college
Warehouse	Warehouse	Any	Any	Excludes refrigerated warehouse
Retail Food	Supermarket	> 5000	Any	
Retail Food	MiniMart	< 5000	Any	
Restaurant	Restaurant	Any	Any	Fast food, sit-down, café & bar
Lodging	Lodging	Any	Any	Hotel, motel & residential care
Health Care	Hospital	Any	Any	Medical, surgical, psychiatric
Health Care	Other Health	Any	Any	Outpatient health, labs, ambulance
Assembly	Assembly	Any	Any	Churches, museums, airports, stadiums, etc.
Other	Other	Any	Any	Parking lots, fire protection, car wash, gasoline , cemetery, air traffic control

Estimates of existing stock by building type and vintage cohort are based on data from the Commercial Building Stock Assessments from 2001 and 2004, construction data from F.W. Dodge, and other sources. Figure E-5 identifies floor area estimates for the 18 building types for 2010. Figure E-6 shows total historic and base case forecast commercial floor area for the period 1987 through 2029. Figure E-7 shows annual additions to commercial floor space for the same period. The year-by-year forecast of floor area by building type, employment and population used to estimate future stock is in the workbook Commercial Forecast 6P.xls identified in table E-11. The file also contains a detailed mapping of economic activity types to building types. Economic activity definitions are base on the North American Industry Classification System (NAICS) codes.

Figure E-5: Commercial Floor Area by Building Type for 2010

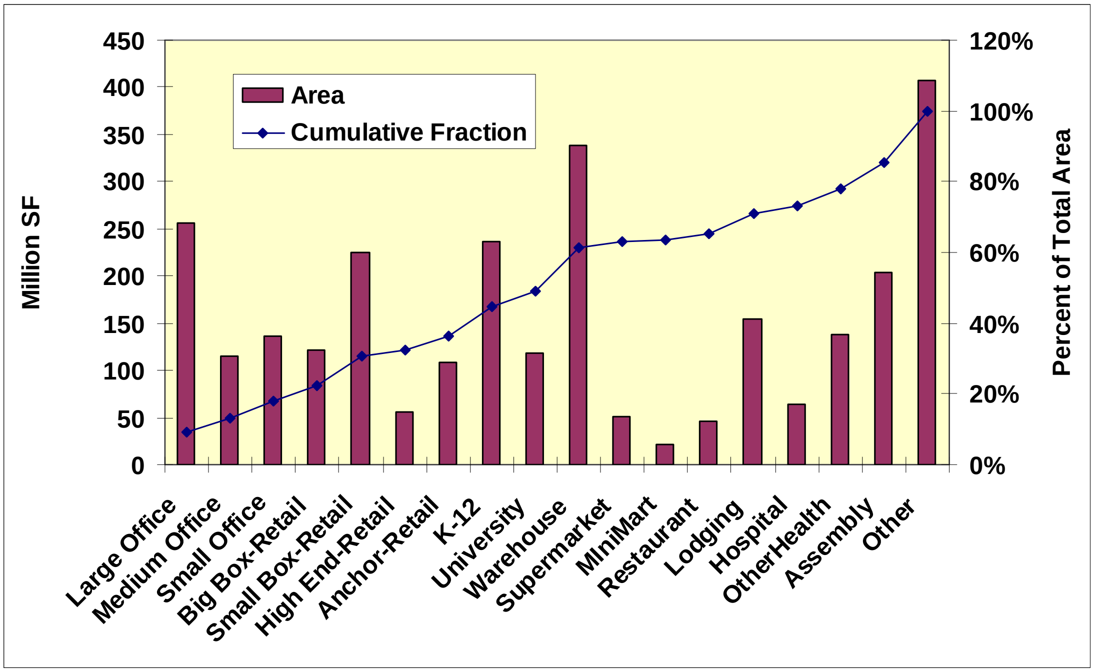


Figure E-6: Total Commercial Floor Area 1987-2029

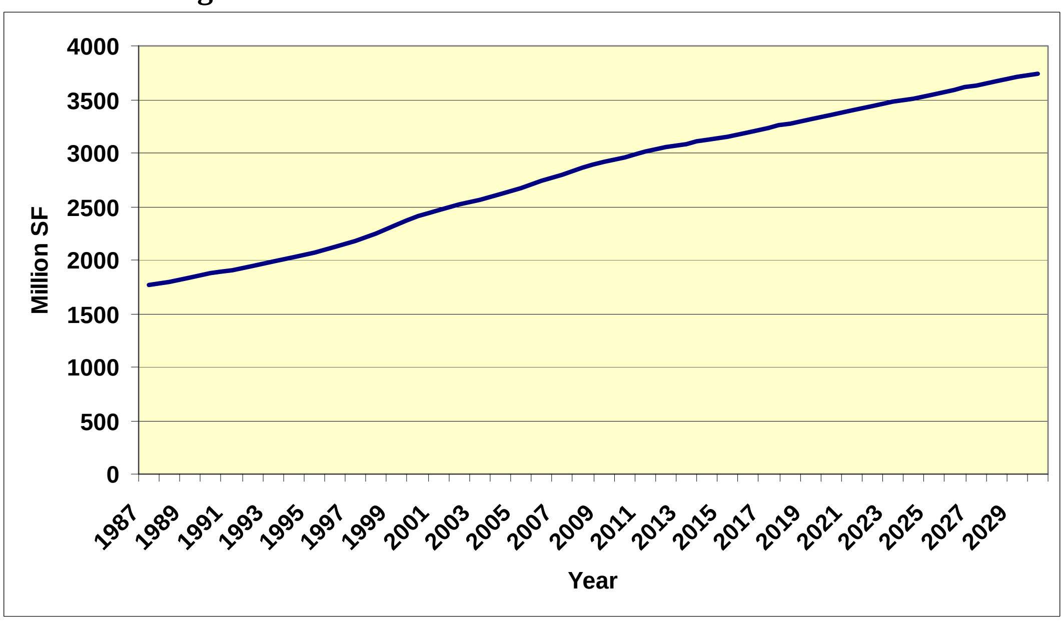
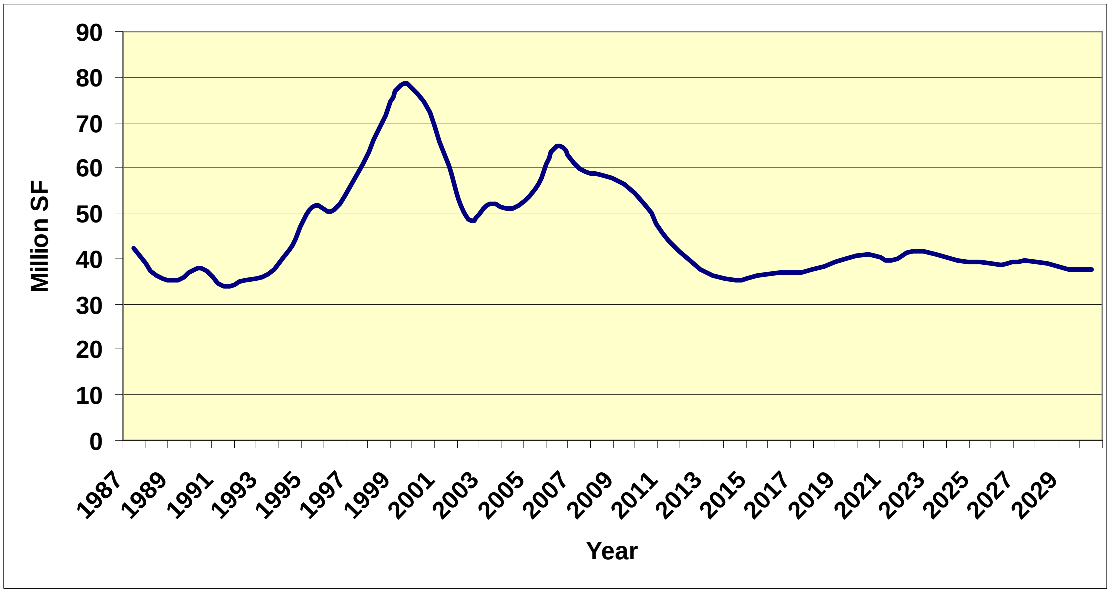


Figure E-7: Annual Commercial Floor Area Additions 1987-2029



Measure Bundles

Over 250 individual commercial-sector measures are analyzed in the Sixth Power Plan. These measures are consolidated into 45 bundles of related measures. The measure bundles are chosen primarily for analytical expediency. For example, measures that reduce interior lighting power density (LPD) are bundled together. Measures that reduce lighting hours through occupancy sensors are bundled separately. Measures that reduce interior lighting through daylighting are also bundled separately. Measure bundles do not always correspond to the way measures are bundled for programmatic implementation.

Measures are also consolidated into three types of application modes. These modes are new, natural replacement and retrofit. The new mode applies primarily to new buildings or new equipment. The natural replacement mode applies to subsystems and equipment within buildings that are replaced on burnout, at the end of their useful life, or at the time of remodel of the building or system within a building. Retrofit mode is used where a measure or a building subsystem is replaced or retired before the end of its useful life.

There are three reasons to distinguish the new, natural replacement and retrofit application modes. First, costs and savings can be different by application mode. Second, in the case of new and natural replacement, the available stock for the measure depends on the forecast of new additions and replacement rate for equipment. These opportunities are tracked separately over course of the forecast period and limit the annual availability of conservation opportunities. Third, the Council's portfolio model treats new and natural replacement applications as lost-opportunity measures that can only be captured at the time of construction or natural replacement.

Measure costs, savings, applicability, and achievability estimates are identified separately for each of the new, natural replacement and retrofit application modes. The Council analyzes measure costs and savings on an incremental basis. Measure cost is the incremental cost over what would be done absent the measure or program. The same is true for savings. Incremental measure costs and savings can be different depending on the application mode. For example, incremental costs for high performance T8 fluorescent lamps and ballasts in a new application only include the additional cost above standard T8 lamps and ballast. But in a retrofit application, the cost of removing and disposing of existing tubes and ballast are added to the measure cost.

Table E-10 lists the commercial sector measure bundles, a short description of the measures, the number of measures in each bundle and the technical energy savings potential by 2029 in each bundle by application mode.

Table E-10: Commercial Sector Measure Bundles

				Technical Potential in MWa by Year 2029			
Measure Bundle	**End Use**	**Number of Measures in Bundle**	**Measure Description**	**New**	**Natrual Replacement**	**Retrofit**	**Total**
Lighting Power Density	Lighting	54	Lamp, ballast and fixture improvements to lighting power density	51	354	38	443
Daylighting with Skylights	Lighting	6	Skylights with lighting controls	16	0	0	16
Daylighting with Windows	Lighting	6	Perimeter daylighting controls	3	12	0	15
Lighting Controls Interior	Lighting	6	Occupancy controls for areas not required by code such as open office, warehouse aisle, classrooms	6	65	8	79
Exit Signs	Lighting	2	LED and electroluminescent "Exit" signs	0	0	0	0
Premium HVAC Equipment	HVAC	4	HVAC equipment more efficient than applicable code or standard practice	8	31	0	39
Variable Speed Chiller	HVAC	2	Variable speed chillers	1	14	0	15
Controls Commission Complex HVAC	HVAC	20	Commissioning on HVAC systems in buildings with complex HVAC systems	10	0	124	134
Package Roof Top Optimization and Repair	HVAC	8	Suite of measures and control strategies for buildings served by package roof top HVAC units	4	8	16	29
Low Pressure Distribution Complex HVAC	HVAC	2	Dedicated Outside Air or Underfloor Air distribution systems in buildings with complex HVAC systems	6	0	0	6
Demand Control Ventilation	HVAC	5	Fan control strategies, DCV and Fleet Strategy DOAS with heat recovery in simple HVAC systems	4	4	14	22
ECM Motors on Variable Air Volume Boxes	HVAC	2	Electically Commutated Motors on Variable Air Volume Boxes	3	9	0	12
Evaporative Assist Cooling	HVAC	0	Evaporative Assist Cooling	0	0	0	0
Windows	HVAC	39	Windows and glazing more efficiecnt that code or standard practice	3	8	22	33
Roof Insulation	HVAC	2	Add insulation during re-roofing	0	3	0	3
Duct Sealing and Repair	HVAC	0	Sealing and repair of ductwork in unconditioned spaces	0	0	0	0
Efficienct fans, pumps and drives	HVAC	0	Variable speed fans, pumps and drives, pump and fan system efficiencies and demand control	0	0	0	0
Exterior Building Lighting	Ext Lighting	4	Effiicient façade, walkway, area and decorative exterior lighting, such as LED	0	67	0	67
Integrated Building Design	Multi	13	Multiple measures applied in integrated design practice	61	0	0	61
Street and Roadway Lighitng	Ext Lighting	2	Efficient street and roadway lighting, LED and induction	8	42	0	51
Parking Lighting	Ext Lighting	2	Efficient parking lot and garage lighting and controls	1	38	0	38
LED Traffic Lights	Ext Lighting	1	LED traffic signals	0	0	0	0
Signage	Ext Lighting	1	LED advertizing signs	0	5	0	5
Municipal Sewage Treatment	Process	10	Suite of measures for sewage treatment	0	0	27	27
Municipal Water Supply	Process	5	Suite of measures for water supply systems	0	0	13	13
Network PC Power Management	Process	1	Control of a networked computer's advanced energy management systems	0	0	40	40
Packaged Refrigeration Equipment	Process	20	Efficient refrigerators and freezers, beverage merchandizers, ice makers and vending machines	52	0	0	52
Commercial Clothes Washers	Process	0	Clotheswashers more efficient than federal standard	0	0	0	0
Cooking Equipment	Process	0	Efficient cooking equipment such as hot food holders, grills, fryers and steam tables	0	0	0	0
Office Equipment	Process	2	Efficient Desktop PC and Efficient Monitor	0	0	0	0
Computer Servers and IT	Process	2	Consolidation & virtualization & upgrade of servers in embedded server rooms in buildings	0	0	88	88
DCV Restaurant Hood	Process	1	Demand control ventilation systems for large restaurant hoods	0	0	4	4
DCV Parking Garage	Process	1	Demand control ventilation systems for parking garages	0	0	0	0
Grocery Refrigeration Bundle	Process	12	Grocery store refrigeration measures	0	0	68	68
Plug Load Sensor	Process	1	Occupancy controls for task lighting and other ancillary loads in offices	0	0	0	0
Premium Fume Hood	Process	1	Effiicient fume hoods in labs	21	0	0	21
Pre-Rinse Spray Wash	Process	1	Low-flow pre-rinse spray valves for restaurant kitchens, cafeterias, and food-serving	0	0	2	2
Total		**238**		**258**	**662**	**462**	**1382**

Overview of Methods

Measure costs and savings are developed at a level of detail compatible with data availability, expected variance in measure costs and savings, the diversity of measure applications and practical limitations on the number of measures that can be analyzed. Costs and savings are based both on engineering estimates as well as estimates based on results from the operation of existing programs. Savings potential is the product of savings per unit and the forecast of number of units that the measure is applicable to. For most of the commercial sector measures, building floor area, by building type, is the primary unit of measure. Most measures apply to a fraction of the building stock in a particular building type. In addition to building floor area, several of the measure potential estimates are based on forecast of equipment stock, equipment turnover rates, equipment sales data, population, and process capacity.

For every measure or practice analyzed, there are four major methodological steps to go through. These steps establish baseline conditions, measure applicability, and measure achievability. For the commercial-sector conservation measures, each of these is treated explicitly for each measure bundle.

Baseline Characteristics

Baseline conditions are estimated from current conditions for existing buildings and systems. Estimates of current conditions and characteristics of the building stock come from several sources. Key among these are the Pacific Northwest Commercial Building Stock Assessment (CBSA), the national Commercial Building Energy Consumption Survey (CBECS), market research projects of the Northwest Energy Efficiency Alliance (NEEA), selected studies from utilities, Energy Trust of Oregon, and other sources.

For new buildings, new and replacement equipment, baseline conditions are estimated from a combination of surveys of new buildings, state and local building energy codes and federal and state appliance efficiency standards. The most recent survey data used is from the NEEA New Buildings Characteristics study completed in 2008 which looked at buildings built in the 2002-2004. Codes and standards are continually being upgraded. The baseline assumptions used in the Sixth Power Plan are those that were adopted at the end of 2008, with a few exceptions. Some of these include standards that are adopted now but with effective dates that occur in the future. For such codes or standards, both savings estimates and the demand forecast reflect the effective dates of adopted standards.

Measure Applicability

Measure applicability reflects several major components. First is the technical applicability of a measure. Technical applicability includes what fraction of the stock the measure applies to. Technical applicability can be composed of several factors. These include the fraction of stock that the measure applies to, overlap with mutually exclusive measures and the existing saturation of the measure. Existing measure saturation reflects the fraction of the applicable stock that has already adopted the measure and for which savings estimates do not apply. There are hundreds of applicability assumptions in the conservation assessment. Applicability assumptions and source references are detailed in the workbooks for each measure bundle.

Measure Achievability

The Council assumes that only a portion of the technically available conservation can be achieved. Ultimate achievability factors are limited to 85 percent of the technically available conservation over the twenty-year forecast period. In addition to a limit of 85 percent, the Council considers near-term achievable penetration rates for bundles of conservation measures. Several factors are used to estimate near-term achievability rates. Recent experience with region wide conservation program accomplishments is one key factor. But in addition to historic experience, the Council also considers a bottom-up approach to estimate near-term achievability.

In the bottom-up approach, the Council estimates near-term achievability rates of each bundle of conservation measures based on the characteristics of the measures in the bundle being described and consideration of likely delivery mechanisms. This detailed bottom-up approach is a new element in the Sixth Power Plan. In the Sixth Plan, the Council uses a suite of typical ramp rates to reflect near-term penetration rates. For example, measures involving emerging technology might start out at low penetration rates and gradually increase to 85 percent penetration. Measures suitable for implementation by a building code or a federal equipment standard might increase rapidly to 85 percent penetration in new buildings and major remodels. Measures requiring new delivery mechanisms might ramp up slowly. Simple measures with well-established delivery channels, like efficient shower heads, might take only half a dozen years to fully implement. Whereas retrofit measures in complex markets might take 20 years to reach full penetration.

Assumptions for the bottom-up approach are detailed in the conservation supply curve workbooks. The worksheet “ACHIEV” in the workbook ComMaster contains all the achievability assumptions by measure bundle.

Physical Units

The conservation supply curves are developed primarily by identifying savings and cost per unit and estimating the number of applicable and achievable units that the measure can be deployed on. In the commercial sector analysis, the applicable units estimates come from several sources. For measures in buildings, the units are primarily floor area with applicable characteristics. These data come primarily from the Commercial Building Stock Assessment (CBSA). For some of the equipment measures, additional unit data from utility surveys of characteristics, national data from Commercial Building Energy Consumption Survey (CBECS), equipment sales data, census data, and many others.

The estimates of physical units available include the number of units available annually. For example, for new buildings, the estimate of available new building stock is taken from the Council’s baseline forecast for annual additions by building type. Similarly for equipment replacement measures the annual stock available is taken from estimates of the turnover rate of the equipment in question. For retrofit measures, the annual stock availability is a fraction of the estimated stock remaining at the end of the forecast period. The estimates of physical units available are called stock models and are embedded in the measure bundle workbooks. The worksheets that contain the stock models are identified by the prefix “SC”.

Guide to the Commercial Conservation Workbooks

There are about 50 Excel workbooks used to develop the commercial-sector conservation assessment. In addition there are dozens of outside sources of data which are referenced. The Council workbooks are available from the Council website.[6] Supporting data sources are identified in the workbooks and the key supporting data from these sources is summarized in the

[6] http://www.nwcouncil.org/energy/powerplan/6/supplycurves/default.htm

Council workbooks. All outside source data is cited in the workbooks or otherwise made available to the extent it is not proprietary.

Figure E-8 describes the main components and structure of the commercial conservation assessment workbooks. The workbooks and brief descriptions of their purpose are listed in Table E-11.

Figure E-8: Main Components and Structure of the Commercial Conservation Assessment Workbooks

ProCost Measure Workbooks: These workbooks contain the detailed analysis for all the measures. Generally there is one workbook for each bundle of similar or related measures.

Naming convention starts with PC (For example: PC-ECMVAV-6P-D1.xls means is the ProCost workbook for the measure Electronically Commutated Motors on VAV systems, 6th Plan, Draft 1)

These files contain the ProCost engine used for cost-effectiveness analysis. They also contain the supporting analysis of measure cost and savings as well as links to data used to support the analysis. They also contain supply curves for the measure bundle.

Basic layout as follows:

SC worksheets: Calculates supply curve total savings potential by cost bin by year. Uses output data from MData worksheets along with unit forecasts from floor space sheet and achievability rates from ComMaster. Usually there are several SC worksheets for new, retrofit and natural-replacement applications since cost and savings and units are different for each application.

ProData worksheet: Control panel for ProCost analysis.

MData worksheets: Measure data sheets. Measure level inputs and outputs for ProCost. Normalized to floor area with one to several hundred permutations of costs and savings. At least two permutations of the MData tab exist in each sheet. One is for the "measure" level which represent costs and savings for an individual measure. This provides the cost and savings estimates for individual measures regardless of the measure's applicability. The other is the "regional" level which includes costs and savings weighted for applicability across the region. ProCost output by measure ends up here too and is passed to the supply curve sheets to develop supply curves. Inputs to MData are usually harvested from MMap tab.

MMap worksheet: Measure Map. Used to assign costs and savings inputs to each application and permutation of the measure. Feeds MData worksheets.

Notes and Sources worksheet Contains notes, savings calculations and links to sources.

Supporting worksheets: A variety of supporting worksheets, documentation and administrative notes are also included.

6PSummary: Summarizes key input assumptions, sources and calculation methodology.

ComMaster

Contains measure list, links to all supporting files and sheets for other administrative functions.

Contains key characteristics common among measures used to calculate savings estimates. Includes measure applicability (APPLIC), baseline penetration (BASE), applicable vintage cohort (STOCK), achievability rates (ACHIEV), fuel saturations, equipment saturations and other key characteristics (CHAR) used in the analysis by building occupancy type and application (New, Retro or Natural Replacement (NR)) . Also includes common variables, labels (VAR & Labels) and other administrative functions.

ComFloorAreaForecast.xls (or similar name)

Output from regional forecast model. Supply curve estimates are driven primarily by floor space estimates, equipment count or population. File contains stock estimates relevant to the measures by building occupancy type, state and vintage.

MC_AND_ LOADSHAPE

Contains avoided cost and shape of savings data. Called by ProCost.

SUPPLYCURVEBUNDLER

Bundles all measures into supply curves by cost bin and year for input to portfolio model.

Table E-11: List of Commercial-Sector Workbooks

File Name	File Description
Com_Master	Master Workbook for Commercial Sector Conservation
ComLighting_v2008-D2	Support file for lighting power density measure workbook
Commercial Forecast 6P	Floor area and population forecast
InteractionsBldgType01082004-	Space Heat and Cooling Interaction Factors for Lighting Savings
MC_AND_LOADSHAPE_6P	Marginal Cost and Load Shape Data File
PC-Cooking-6P-D1	Measure workbook: Cooking
PC-DCVGarage-6P-D1	Measure workbook: Demand Control Ventilation Parking Garage
PC-DCVHood-6P-D1	Measure workbook: Demand Control Ventilation Restaurant
PC-DemandControlVent-6P-D4	Measure workbook: Demand Control Ventilation for HVAC
PC-DuctSeal-6P-D1	Measure workbook: Duct Sealing
PC-ECMVAV-6P-D4	Measure workbook: ECM Motors in Variable Air Volume HVAC
PC-EvapAssist-6P-D1	Measure workbook: Evaporative Assist Cooling
PC-Exit Sign-6P-D2	Measure workbook: Exit Signs
PC-ExtLight-6P-D1	Measure workbook: Exterior Building Lighting
PC-FanPumpDrive-6P-D1	Measure workbook: Adjustable Drives for Fans & Pumps
PC-FumeHood-6P-D1	Measure workbook: Efficient Lab Fume Hood
PC-Grocery-6P-D3	Measure workbook: Grocery Store Measures
PC-HVACControls-6P-D4	Measure workbook: Controls Commission Complex HVAC
PC-HVACEQUIP-6P-D7	Measure workbook: Premium HVAC Equipment
PC-IntDesign-6P-D1	Measure workbook: Integrated Building Design
PC-Lighting Controls Interior-6p-	Measure workbook: Lighting Controls Interior
PC-Lodging-6P-D1	Measure workbook: Lodging-Specific Measures
PC-LowPressureDist-6P-D1	Measure workbook: Low Pressure Distribution Complex HVAC
PC-LPDPackage-6P-D16	Measure workbook: Lighting Power Density Interior
PC-NetworkPC Power	Measure workbook: Network PC Power Management
PC-OfficeEquip-6P-D1	Measure workbook: Office Equipment
PC-Pack Refrig Equip-6P-D3	Measure workbook: Refrigerators, freezers, ice makers,
PC-PackRTOptimize-6P-D6	Measure workbook: Package Roof Top Optimization and Repair
PC-Parking Lighting-6P-D1	Measure workbook: Parking Lighting
PC-PlugLoadSensor-6P-D1	Measure workbook: Plug Load Sensor
PC-ReRoof-6P-D1	Measure workbook: Roof Insulation
PC-ServerRooms and IT-6P-D1	Measure workbook: Computer Server Room Efficiency
PC-SideDaylight-6P-D1	Measure workbook: Day Lighitng Control - Windows
PC-Singage-6P-D1	Measure workbook: LED Signage
PC-Spray Head-6P-D1	Measure workbook: Pre-Rinse Spray Valve
PC-StreetRoadway-6P-D2	Measure workbook: Street and Roadway Lighting
PC-TopDaylightNew-6P-D5	Measure workbook: Day Lighting Control - Skylights
PC-Traffic Signals-6P-D1	Measure workbook: LED Traffic Signals
PC-VSDChiller-6P-D3	Measure workbook: Variable Speed Chillers
PC-Wastewater-6P-D1	Measure workbook: Municipal Wastewater
PC-WaterSupply-6P-D3	Measure workbook: Municipal Water Supply
PC-Windows-6P-D10	Measure workbook: Windows
ProCostFinAssumptions_Sector	Financial Assumptions
SupplyCurveBundlerLO	Bundles all Lost-Opportunity Measures into Supply Curves
SupplyCurveBundlerRetro	Bundles all Retrofit Measures into Supply Curves

The main workbook is named ComMaster. ComMaster contains the master measure list, the measure bundles, common assumptions used throughout the analysis and links to the ProCost measure files where detailed measure-specific analysis resides. The reference data in ComMaster are primarily in matrices by measure bundle and building type. The reference data in the ComMaster file are listed and described in Table E-12.

Table E-12: Reference Data in ComMaster Workbook

Sheet Name	Contents
Overview	Overview of model structure
MLIST	Master List of measure bundles
FILES	List and links to measure-level files. Plus housekeeping.
APPLIC	Applicability factor for the measure. Fraction of stock the measure applies to.
BASE	Baseline penetration of measure. Estimated fraction of stock where the measure is already in place.
STOCK	Vintage cohort that the measure applies to.
TURN	Turnover rate for stock to which measure applies.
ACHIEVE	Achievable rate of acquisition for measure bundles by year
CODE	Tables developed to estimate regional baseline penetration for various elements of energy codes by jurisdiction
CHAR	Key characteristics for stock by vintage cohort and building subtype. Used to develop regional application of meas
FLOOR	Floor area forecast summary used to develop data in CHAR
VARS	List of variables used in the CHAR tab and elsewhere in the files.
Labels	Map of building types labels from different sources.
Lookup	Lookup table for vintage cohort
EUI	Reference EUI from various sources including CBECS & CBSA.

INDUSTRIAL SECTOR

Overview

The Sixth Plan Industrial Supply Curve (ISC) conservation assessment was prepared by a contractor, Strategic Energy Group (SEG) with guidance from Council staff and an advisory group. The assessment includes an Excel workbook, referred to as the Measure Analysis Tool, which contains industrial load data, measure data, conservation supply curves and documentation. There is another Excel workbook, referred to as the NPCC Supply Curve Generator, which converts measure costs and savings data to conservation supply curves for input to the Council's Resource Portfolio Model. The contractor also prepared documentation of the development of the analysis, the Measure Analysis Tool, and a detailed description of the modeling of a subset of the measures referred to as System Optimization Measures.

In addition to these major components, the assessment includes a rich dataset of sources referred to as the Industrial Data Catalogue and a guide to that catalogue. Finally, the project also developed a detailed database on motor loads at industrial facilities in the Northwest. This is called the Northwest Industrial Motor Database.

Industrial Sector Overview and Coverage

The Council's industrial sector analysis covers most of the region's non-DSI industries plus refrigerated warehouse storage. The assessment does not include savings estimates for the direct-service industries. Nor does it cover savings potential in the information technology sector (IT). These two subsectors were beyond the scope of the industrial assessment.

Structure of the Analysis

The conservation assessment model is structured differently that the Council's assessments in other sectors. The ISC model uses estimates of energy savings as a fraction of load by end use by industry.

First, data were collected on electricity use by industry by state. These data came from a variety of sources primarily utility-provided reports. But other sources were considered too including data supplied by individual plants, proprietary datasets and publicly-available data. These data were calibrated to industrial load data reported by state to EIA. Then the consumption estimates were split into estimates of electricity use by major process end use. Then energy conservation measures (ECMs) are applied to the use by end use estimates as a percent savings with associated costs. Finally, factors for measure applicability, measure interaction, and achievability rates over time are applied. A detailed summary of the structure of the assessment is available in the document entitled “ISC Model Review R4”.

Guide to the Industrial Sector Workbooks and Data

Table E-13 identifies the key workbooks and files that comprise the industrial conservation assessment.

Table E-13: List of Industrial Sector Workbooks

Item	Description
Measure Analysis Tool	Excel workbook containing the major elements of the industrial sector characterization, the estimates of end use splits and the details on the energy conservation measures
Description of Measure Analysis Tool	Description of the structure and development of the Measure Analysis Tool
NPCC Supply Curve Generator	Excel workbook which translates the costs and savings from the Measure Analysis Tool into supply curve data for the Regional Portfolio Model. Uses ProCost to develop TRC Net levelized costs consistent with estimates in other sectors
Documentation on System Optimization Measures	Excel workbook containing detailed derivation of costs, savings and measure applicability for a suite of measures related to system optimization of key industrial processes
Systems Whole Plant Optimization Overview	Description of the system optimization and whole plant measure bundles, the input assumptions, and supporting sources
Industrial Data Catalogue and Guide	Large database of industrial data sources. A compilation of published and unpublished resource assessments, market and technology reports, datasets, case studies and guidebooks focused on industrial energy efficiency and energy management. The files include N electronic collection of these resources
Northwest Industrial Motor Database	Information on motors that collected over 20 years by the Industrial Assessment Center (IAC) at Oregon State University (OSU). The Northwest Industrial Motor Database includes a database of a total of 22,514 records, each with detailed motor application data.

AGRICULTURAL SECTOR

Overview

The Sixth Power Plan’s assessment of conservation potential in the agriculture sector covers irrigation hardware system efficiency improvements, irrigation water management (scientific irrigation scheduling) and diary farm milk processing. Consistent with the conservation assessments in prior plan’s the largest potential savings in the agriculture sector are available through irrigation hardware system efficiency improvements, including reducing system operating pressures, reducing system leaks and improving pump efficiency. The next largest savings in this sector come from improved water management practices followed by dairy milk processing savings. This is the first Council plan to estimate savings from irrigation water management and diary milk production.

Measure Bundles

Seven generic irrigation hardware system efficiency improvements and three "operation and maintenance"(e.g., gasket and nozzle replacement) measures are analyzed in the Sixth Power Plan. Irrigation water management practices were considered as a bundled measure consisting of moisture monitoring hardware and software. Four individual, non-interactive measures were considered for improving the energy efficiency of dairy milking barns and milk processing.

Overview of Methods

The irrigation hardware efficiency measures were evaluated using savings derived from an engineering spreadsheet model that simulates the energy use of a center pivot system using alternative pump efficiencies, static and dynamic head, annual water throughput and system leakage rates. Each hardware efficiency measure's savings were estimated based on water supplied by a well of average depth and water supplied by a deep well for each of the Northwest states. Data on well depth, amount of water applied, average pump size and irrigated acreage served by each type of irrigation system were drawn from the most recent USDA Farm and Ranch Survey. All data used from this survey are shown in the "IrrgAgHardwareSupplyCurve_6Pv1_1.xls."

Irrigation water management savings were estimated using a spreadsheet developed by the Columbia Basin Ground Water Management Association (GAMA). This spreadsheet was modified to reflect the average water savings achieved in Bonneville's evaluation of irrigation water management. This evaluation documented the average water savings from scientific irrigation water management as well as the cost of carrying out improved practices. Dairy efficiency improvements were based on detailed audits and retrofits of 30 dairies in New York carried our by the New York State Energy Research and Development Administration (NYSERDA).

Baseline Characteristics

Baseline conditions for irrigation hardware system efficiency improvements were estimated from the USDA Farm and Ranch survey and discussions with Bonneville and utility staff with in-depth experience working with farmers on these systems. Baseline characteristics (i.e., the average amount of water applied by crop type and acreage) for irrigation water management in the Columbia Basin Project was provided by GAMA. Dairy efficiency in the region was assumed to parallel that found by NYSERDA.

Measure Applicability and Measure Achievability

No quantitative study has been conducted in the region to determine the current saturation and remaining opportunities for improvement in either irrigation system hardware or on diaries. Therefore, judgment, based on discussions with Bonneville and utility program staff served as the basis estimating the remaining number of systems and diaries in the region that could carry out cost-effective energy efficiency improvements. Where quantitative data was available (e.g.

the acreage irrigated with high pressure systems) this data was used to size the remaining opportunities for savings.

Physical Units

The conservation supply curves are developed primarily by identifying savings and cost per unit and estimating the number of applicable and achievable units that the measure can be deployed on.   In the irrigation sector analysis, the applicable unit estimates for irrigated acreage, system types and annual water application were drawn from the USDA Farm and Ranch Survey. GAMA provided data on the acreage and crop types present in Columbia Basin Project. The estimate of current diary production in the region also comes from the USDA and the US Department of Commerce. Staff developed a forecast of future milk production growth in the region using historical trends.

The three workbooks containing the Agriculture Sector conservation resource assessment are downloadable from the web. These are:

- Irrigation Hardware System Efficiency Improvements - IrrgAgHardwareSupplyCurve_6Pv1_1.xls

- Irrigation Water Management - SIS_SupplyCurve_6thPlanv1_1.xls

- Diary Efficiency Improvement - DairySupplyCurve_6thPlanv1_1.xls

DISTRIBUTION SYSTEM

Overview

The Sixth Power Plan includes a conservation potential assessment on the region’s electric distribution system. The assessment is based on a study completed in 2007 by R.W. Beck for the Northwest Energy Efficiency Alliance (NEEA).

Structure of the Analysis

The distribution system conservation assessment uses savings estimates from measured data on 33 utility feeders, and analytical methods developed by RW Beck in the NEEA study. Costs and savings for four major measures were identified and applied to a descriptive data set of the region’s distribution system. The dataset contains system loads by customer class, substation counts, feeders counts, customer counts and climate zones for 137 regional utilities used to generate the units estimates.   Table E-14 below identifies the key workbooks and data used in the analysis.

Table E-14 identifies the key workbooks and files that comprise the distribution system conservation assessment.

Table E-14: List of Agriculture Sector Workbooks

Item	Description
NPPC Supply Curve	Excel workbook used to generate the supply curves with documentation
Supporting Data	Excel workbook containing the data on distributions systems and the key factors for the savings estimates
Distribution Efficiency Initiative	2007 RW Beck Study for NEEA. Findings from this study were used to develop the conservation supply curves

Appendix F: Model Conservation Standards

INTRODUCTION

As directed by the Northwest Power Act, the Council has designed model conservation standards to produce all electricity savings that are cost-effective for the region. The standards are also designed to be economically feasible for consumers, taking into account financial assistance from the Bonneville Power Administration and the region's utilities.

In addition to capturing all cost-effective power savings while maintaining consumer economic feasibility, the Council believes the measures used to achieve the model conservation standards should provide reliable savings to the power system. The Council also believes actions taken to achieve the standards should maintain, and possibly improve upon the occupant amenity levels (e.g., indoor air quality, comfort, window areas, architectural styles, and so forth) found in typical buildings constructed before the first standards were adopted in 1983.

The Council has adopted six model conservation standards. These include the standard for new electrically heated residential buildings, the standard for utility residential conservation programs, the standard for all new commercial buildings, the standard for utility commercial conservation programs, the standard for conversions, and the standard for conservation programs not covered explicitly by the other model conservation standards[1].

THE MODEL CONSERVATION STANDARDS FOR NEW ELECTRONICALLY HEATED RESIDENTIAL AND COMMERCIAL BUILDINGS

The region should acquire all electric energy conservation measure savings from new residential and new commercial buildings that have a benefit-to-cost ratio greater than one when compared

[1] This chapter supersedes the Council's previous model conservation standards and surcharge methodology.

to the Council's forecast of future regional power system cost[2]. The Council believes that at least 85 percent of all regionally cost-effective savings in new residential and commercial buildings are practically achievable. The Council finds that while significant progress has been made toward improving the region's residential and commercial energy codes these revised codes will not capture all regionally cost-effective savings in these sectors. The Council's analysis indicates that further improvements in existing residential and commercial energy codes would be both cost-effective to the regional power system and economically feasible for consumers.

The Council is committed to securing all regionally cost-effective electricity savings from new residential and commercial buildings. The Council believes this task can be accomplished best through a combination of continued enhancements and enforcement of state and local building codes and the development and deployment of effective regional market transformation efforts. Bonneville and the region's utilities should support these actions. The Council has established four model conservation standards affecting new buildings. These standards are set forth below:

New Site Built Electrically Heated Residential Buildings and New Electrically Heated Manufactured Homes

The model conservation standard for new single-family and multifamily electrically heated residential buildings is as follows: New site built electrically heated residential buildings are to be constructed to energy-efficiency levels at least equal to those that would be achieved by using the illustrative component performance paths displayed in Table E-1for each of the Northwest climate zones[3]. New electrically heated manufactured homes regulated under the National Manufactured Housing Construction and Safety Standards Act of 1974. 42 USC §5401 et seq. (1983) are to be built to energy-efficiency levels at least equal to those that would be achieved by using the illustrative component performance paths displayed in Table E-2 for each of the Northwest climate zones. The Council finds that measures required to meet these standards are commercially available, reliable and economically feasible for consumers without financial assistance from Bonneville.

It is important to remember that these illustrative paths are provided as benchmarks against which other combinations of strategies and measures can be evaluated. Tradeoffs may be made among the components, as long as the overall efficiency and indoor air quality of the building are at least equivalent to a building containing the measures listed in Tables F-1 and F-2.

[2] The term "system cost" means an estimate of all direct costs of a measure or resource over its effective life, including, if applicable, the cost of distribution and transmission to the consumer and, among other factors, waste disposal costs, end-of-cycle costs, and fuel costs (including projected increases), and such quantifiable environmental costs and benefits as the Administrator determines, on the basis of a methodology developed by the Council as part of the plan, or in the absence of the plan by the Administrator, are directly attributable to such measure or resource. [Northwest Power Act, §3(4)(B), 94 Stat. 2698-9.]

[3] The Council has established climate zones for the region based on the number of heating degree-days as follows: Zone 1: less than 6,000 heating degree days; Zone 2: 6,000-7,499 heating degree days; and Zone 3: over 7,500 heating degree days.

Utility Conservation Programs for New Residential Buildings

The model conservation standard for utility conservation programs for new residential buildings is as follows: Utilities should implement programs that are designed to capture all regionally cost-effective space heating, water heating and appliance energy savings. Efforts to achieve and maintain a goal of 85 percent of regionally cost-effective savings should continue as long as the program remains regionally cost-effective. In evaluating the program's cost-effectiveness, all costs, including utility administrative costs and financial assistance payments, should be taken into account. This standard applies to site-built residences and to residences that are regulated under the National Manufactured Housing Construction and Safety Standards Act of 1974. 42 USC §5401 et seq. (1983).

There are several ways utilities can satisfy the model conservation standard for utility conservation programs for new residential buildings. These are:

1. Support the adoption and/or continued enforcement of an energy code for site-built residential buildings that captures all regionally cost-effective space heating, water heating and appliance energy savings.

2. Support the revision of the National Manufactured Housing Construction and Safety Standards for new manufactured housing so that this standard captures all regionally cost-effective space heating, water heating and appliance energy savings.

3. Implement a conservation program for new electrically heated residential buildings. Such programs may include, but are not limited to, state or local government or utility sponsored market transformation programs (e.g., Energy Star), financial assistance, codes/utility service standards or fees that achieve all regionally cost-effective savings, or combinations of these and/or other measures to encourage energy-efficient construction of new residential buildings and the installation of energy-efficient water heaters and appliances, or other lost-opportunity conservation resources.

Table F-1: Illustrative Paths for Model Conservation Standard for New Site Built Electrically Heated Residential Buildings

	Climate Zone		
Component	**Zone 1**	**Zone 2**	**Zone 3**
Ceilings			
• Attic	R-49 (U-0.020)[a,b]	R-49 (U-0.020)[a,b]	R-49 (U-0.020)[a,b]
• Vaults	R-38 (U-0.027)	R-38 (U-0.027)	R-38 (U-0.027)
Walls			
• Above Grade[c]	R-21 Advanced (U-0.051)	R-21 Advanced (U-0.051)	R-21 Advanced (U-0.051)
• Below Grade[d]	R-21	R-21	R-21
Floors			
• Crawlspaces and Unheated Basements	R-30 (U-0.029)	R-30 (U-0.029)	R-30 (U-0.029)
• Slab-on-grade - Unheated[e]	R-10 Full Under Slab	R-10 Full Under Slab	R-10 Full Under Slab
• Slab-on-grade - Heated	R-10 Full Under Slab w/R-5 Thermal Break	R-10 Full Under Slab w/R-5 Thermal Break	R-10 Full Under Slab w/R-5 Thermal Break
Glazing[f,g]	R-3.33 (U-0.30)	R-3.33 (U-0.30)	R-3.33 (U-0.30)
Exterior Doors	R-5 (U-0.19)	R-5 (U-0.19)	R-5 (U-0.19)
Thermal Infiltration Rate[h]	0.35 ach	0.35 ach	0.35 ach
Ventilation and Indoor Air Quality[i]	ASHRAE Standard 62.2-2007 with Heat Recovery Ventilation		
Service Water Heater[j]	Energy Factor = 2.2		
Hardwired Lighting	Maximum Lighting Power Density - 0.6 Watts/sq.ft.		
Space Conditioning System	Minimum Heating Season Performance Factor (HSPF) - 9.0 Minimum Seasonal Energy Efficiency Rating (SEER) -14.0		

[a] R-values listed in this table are for the insulation only. U-factors listed in the table are for the full assembly of the respective component and are based on the methodology defined in the *Super Good Cents Heat Loss Reference—Volume I: Heat Loss Assumptions and Calculations and Super Good Cents Heat Loss Reference—Volume II—Heat Loss Coefficient Tables*, Bonneville Power Administration (October 1988).

[b] Attics in single-family structures in all zones shall be framed using techniques to ensure full insulation depth to the exterior of the wall. Attics in multifamily buildings in all zones shall be insulated to nominal R-38 (U-0.031).

[c] All walls are assumed to be built using advanced framing techniques (e.g., studs on 24-inch centers, insulated headers above doors and windows, and so forth) that minimize unnecessary framing materials and reduce thermal short circuits

[d] Only the R-value is listed for below-grade wall insulation. The corresponding heat-loss coefficient varies due to differences in local soil conditions and building configuration. Heat-loss coefficients for below-grade insulation should be taken from the Super Good Cents references listed in footnote “a” for the appropriate soil condition and building geometry.

[e] Only the R-value is listed for slab-edge insulation. The corresponding heat-loss coefficient varies due to differences in local soil conditions and building configuration. Heat-loss coefficients for slab-edge insulation should be taken from the Super Good Cents references listed in footnote “a” for the appropriate soil condition and building geometry and assuming a thermally broken slab.

[f] U-factors for glazing shall be determined, certified and labeled in accordance with the National Fenestration Rating Council (NFRC) Product Certification Program (PCP), as authorized by an independent certification and inspection agency licensed by the NFRC. Compliance shall be based on the Residential Model Size. Product samples used for U-factor determinations shall be production line units or representative of units as purchased by the consumer or contractor.

[g] Glazing area is not limited if all building shell components meet reference case maximum U-factors and minimum R-values. Reference case glazing area equal to15 percent of conditioned floor area shall be used in thermal envelope component tradeoff calculations.

[h] Assumed air changes per hour (ach) used for determination of thermal losses due to air leakage without heat recovery ventilation..

[i] The dwelling shall have a heat recovery mechanical ventilation system that is sized to comply with the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 62.2-2007*, Ventilation and Acceptable Indoor Air Quality in Low-rise Residential Buildings.*

.[j] Water Heater Energy Factor (EF) varies by tank capacity. EF shown is for 50 gallon nominal tank capacity. EF may be adjusted higher or lower based on actual nominal water heater tank capacity.

Table F-2: Illustrative Paths for the Model Conservation Standard for New Electrically Heated Manufactured Homes

	Climate Zone		
Component	**Zone 1**	**Zone 2**	**Zone 3**
Ceilings			
• Attic	R-49[a] (U-0.023)	R-49 (U-0.023)	R-49 (U-0.023)
• Vaults	R-38 (U-0.030)	R-38 (U-0.030)	R-38 (U-0.030)
Walls			
• Above Grade	R-21 Advanced (U-0.050)	R-21 Advanced (U-0.050)	R-21 Advanced (U-0.050)
Floors			
• Crawlspaces	R-33 (U-0.032)	R-33 (U-0.032)	R-33 (U-0.032)
Glazing[b,c]	R-3.33 (U-0.30)	R-3.33 (U-0.30)	R-3.33 (U-0.30)
Exterior Doors	R-5 (U-0.19)	R-5 (U-0.19)	R-5 (U-0.19)
Thermal Infiltration Rate[d]	0.35 ach	0.35 ach	0.35 ach
Overall Conductive Heat Loss Rate (Uo)	0.047	0.047	0.047
Ventilation and Air Quality[e]	ASHRAE Standard 62.2-2007		
Service Water Heater[f]	Energy Factor = 2.2		
Hardwired Lighting	Maximum Lighting Power Density - 0.6 Watts/sq.ft.		
Space Conditioning System	Minimum Heating Season Performance Factor (HSPF) - 9.0 Minimum Seasonal Energy Efficiency Rating (SEER) - 14.0		

[a] R-values listed in this table are for the insulation only. U-factors listed in the table are for the full assembly of the respective component and are based on the methodology defined in the *Super Good Cents Heat Loss Reference for Manufactured Homes —*

[b] U-factors for glazing shall be determined, certified and labeled in accordance with the National Fenestration Rating Council (NFRC) Product Certification Program (PCP), as authorized by an independent certification and inspection agency licensed by the NFRC. Compliance shall be based on the Residential Model Size. Product samples used for U-factor determinations shall be production line units or representative of units as purchased by the consumer or contractor.

[c] Glazing area is not limited if all building shell components meet reference case maximum U-factors and minimum R-values. Reference case glazing area equal to15 percent of conditioned floor area shall be used in thermal envelope component tradeoff calculations.

[d] Assumed air changes per hour (ach) used for determination of thermal losses due to air leakage.

[e] The dwelling shall have a heat recovery mechanical ventilation system that is sized to comply with the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 62.2-2007*, Ventilation and Acceptable Indoor Air Quality in Low-rise Residential Buildings.*

[f] Water Heater Energy Factor (EF) varies by tank capacity. EF shown is for 50 gallon nominal tank capacity. EF may be adjusted higher or lower based on actual nominal water heater tank capacity.

New Commercial Buildings

The American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. Standard 90.1 (ASHRAE Standard 90.1) is the reference standard in the United States for construction of new commercial buildings. ASHRAE Standard 90.1 is under continuous revision. The Council finds that measures required to meet the current version, ASHRAE Standard 90.1-2007, are commercially available, reliable and economically feasible for consumers without financial assistance from Bonneville. The Council also finds that the measures required to meet the ASHRAE Standard 90.1-2007 do not capture all regionally cost-effective savings.

Furthermore, the Council finds that commercial building energy standards adopted by the four states in the region contain many energy efficiency provisions that exceed ASHRAE Standard 90.1 provisions; produce power savings that are cost-effective for the region and are economically feasible for customers. Those state or locally adopted efficiency provisions that are superior to ASHRAE Standard 90.1 should be maintained. In addition, efforts should be made by code setting jurisdictions to adopt the most efficient provisions of ASHRAE Standard 90.1 or existing local codes so long as those provisions satisfy the conditions for model conservation standards set forth in the Regional Act.

Therefore, the model conservation standard for new commercial buildings is as follows: New commercial buildings and existing commercial buildings that undergo major remodels or renovations are to be constructed to capture savings equivalent to those achievable through constructing buildings to the better of 1) the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 90.1-2007 -- Energy Standard for Buildings Except Low-Rise Residential Buildings (IESNA cosponsored; ANSI approved; Continuous Maintenance Standard), I-P Edition and addenda or subsequent revision to ASHRAE Standard 90.1, or 2) the most efficient provisions of existing commercial building energy standards promulgated by the states of Idaho, Montana, Oregon and Washington so long as those provisions reflect geographic and climatic differences within the region, other appropriate considerations, and are designed to produce power savings that are cost-effective for the region and economically feasible for customers taking into account financial assistance made available from Bonneville.

As with the residential model conservation standard, flexibility is encouraged in designing paths to achieve the commercial model conservation standards. The Council will consult with the Administrator, States, and political subdivisions, customers of the Administrator, and the public to assist in determining which provisions of existing standards are the most efficient, and provide clear code language, are easily enforced and meet the conditions for model conservation standards set forth in the Regional Act.

Utility Conservation Programs for New Commercial Buildings

The model conservation standard for utility conservation programs for new commercial buildings is as follows: Utilities should implement programs that are designed to capture all regionally cost-effective electricity savings in new commercial buildings. Efforts to achieve and maintain a goal of 85 percent of regionally cost-effective savings in new commercial buildings should continue as long as the program remains regionally cost-effective. In evaluating the program's cost-effectiveness all costs, including utility administrative costs and financial assistance payments, should be taken into account.

There are several ways utilities can satisfy the model conservation standard for utility conservation programs for new commercial buildings. These are:

1. Support the adoption and/or continued enforcement of an energy code for new commercial buildings that captures all regionally cost-effective electricity savings.

2. Implement a conservation program that is designed to capture all regionally cost-effective electricity savings in new commercial buildings. Such programs may include, but are not limited to, state or local government or utility marketing programs, financial assistance, codes/utility service standards or fees that capture all the regionally cost-effective savings or combinations of these and/or other measures to encourage energy-efficient construction of new commercial buildings or other lost-opportunity conservation resources.

Buildings Converting to Electric Space Conditioning or Water Heating Systems

The model conservation standard for existing residential and commercial buildings converting to electric space conditioning or water heating systems is as follows: State or local governments or utilities should take actions through codes, service standards, user fees or alternative programs or a combination thereof to achieve electric power savings from such buildings. These savings should be comparable to those that would be achieved if each building converting to electric space conditioning or electric water heating were upgraded to include all regionally cost-effective electric space conditioning and electric water heating conservation measures.

Conservation Programs not Covered by Other Model Construction Standards

This model conservation standard applies to all conservation actions except those covered by the model conservation standard for new electrically heated residential buildings, the standard for utility conservation programs for new residential buildings, the standard for all new commercial buildings, the standard for utility conservation programs for new commercial buildings and the standard for electric space conditioning and electric water heating system conversions. This model conservation standard is as follows: All conservation actions or programs should be implemented in a manner consistent with the long-term goals of the region's electrical power system. In order to achieve this goal, the following objectives should be met:

1. Conservation acquisition programs should be designed to capture all regionally cost-effective conservation savings in a manner that does not create lost-opportunity resources. A lost-opportunity resource is a conservation measure that, due to physical or institutional characteristics, will lose its cost-effectiveness unless actions are taken now to develop it or hold it for future use.

2. Conservation acquisition programs should be designed to take advantage of naturally occurring "windows of opportunity" during which conservation potential can be secured by matching the conservation acquisitions to the schedule of the host facilities. In industrial plants, for example, retrofit activities can match the plant's scheduled downtime or equipment replacement; in the commercial sector, measures can be installed at the time of renovation or remodel.

3. Conservation acquisition programs should be designed to secure all measures in the most cost-efficient manner possible.

4. Conservation acquisitions programs should be targeted at conservation opportunities that are not anticipated to be developed by consumers.

5. Conservation acquisition programs should be designed to ensure that regionally cost-effective levels of efficiency are economically feasible for the consumer.

6. Conservation acquisition programs should be designed so that their benefits are distributed equitably.

7. Conservation acquisition programs should be designed to maintain or enhance environmental quality. Acquisition of conservation measures that result in environmental degradation should be avoided or minimized.

8. Conservation acquisition programs should be designed to enhance the region's ability to refine and improve programs as they evolve.

SURCHARGE RECOMMENDATION

The Council does not recommend that the model conservation standards be subject to surcharge under Section 4(f) (2) of the Act.

The Council expects that Bonneville and the region's utilities will accomplish conservation resource development goals established in this Plan. If Council recommendations on the role of Bonneville are adopted, utility incentives to pursue all cost-effective conservation should improve. Fewer customers would be dependent on Bonneville for load growth and those that are would face wholesale prices that reflect the full marginal cost of meeting load growth. However, while these changes would lessen the rationale for a surcharge, the Council recognizes that they would not eliminate all barriers to utility development of programs to capture all cost-effective conservation.

The Council recognizes that while conservation represents the lowest life cycle cost option for meeting the region's electricity service needs, utilities face real barriers to pursuing its development aggressively. In particular, because of the current economic conditions, some utilities are experiencing significantly slower or negative load growth. Investments in conservation, like any other resource acquisition, will increase utility cost and place additional upward pressure on rates. Furthermore, there is some uncertainty regarding how public utilities will respond to Bonneville's implementation of rate designs that will result in at least some portion of their loads exposed to cost of new resources. Bonneville has committed to ensure that the "public system" meet its share of the Sixth Plan's conservation targets. It is working with its customers to put in place programs and rate structures that designed to achieve this objective. However, should an individual utility fail to meet its share of the regional conservation goal, then Bonneville may need the ability to recover the cost of securing those savings. In this instance the Council may wish to recommend that the Administrator be granted the authority to place a surcharge on that customers rates to recover those costs.

The Council intends to continue to track regional progress toward the Plan's conservation goals and will review this recommendation, should accomplishment of these goals appear to be in jeopardy.

Surcharge Methodology

Section 4(f)(2) of the Northwest Power Act provides for Council recommendation of a 10-percent to 50-percent surcharge on Bonneville customers for those portions of their regional loads that are within states or political subdivisions that have not, or on customers who have not, implemented conservation measures that achieve savings of electricity comparable to those that would be obtained under the model conservation standards. The purpose of the surcharge is twofold: 1) to recover costs imposed on the region's electric system by failure to adopt the model conservation standards or achieve equivalent electricity savings; and 2) to provide a strong incentive to utilities and state and local jurisdictions to adopt and enforce the standards or comparable alternatives. The surcharge mechanism in the Act was intended to ensure that Bonneville's utility customers were not shielded from paying the full marginal cost of meeting load growth. As stated above, the Council does not recommend that the Administrator invoke the surcharge provisions of the Act at this time. However, the Act requires that the Council's plan set forth a methodology for surcharge calculation for Bonneville's administrator to follow.

Should the Council alter its current recommendation to authorize the Bonneville administrator to impose surcharges, the method for calculation is set out below.

Identification of Customers Subject to Surcharge

The administrator should identify those customers, states or political subdivisions that have failed to comply with the model conservation standards for utility residential and commercial conservation programs.

Calculation of Surcharge

The annual surcharge for non-complying customers or customers in non-complying jurisdictions is to be calculated by the Bonneville administrator as follows:

1. If the customer is purchasing firm power from Bonneville under a power sales contract and is not exchanging under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of all firm power purchased from Bonneville under the power sales contract for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

2. If the customer is not purchasing firm power from Bonneville under a power sales contract, but is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is 10 percent of the cost to the customer of the power purchased (or deemed to be purchased) from Bonneville in the exchange for that portion of the customer's load in jurisdictions not implementing the model conservation standards or comparable programs.

If the customer is purchasing firm power from Bonneville under a power sales contract and also is exchanging (or is deemed to be exchanging) under a residential purchase and sales agreement, the surcharge is: a) 10 percent of the cost to the customer of firm power purchased under the power sales contract; plus b) 10 percent of the cost to the customer of power purchased from Bonneville in the exchange (or deemed to be purchased) multiplied by the fraction of the utility's exchange load originally served by the utility's own resources[4].

Evaluation of Alternatives and Electricity Savings

A method of determining the estimated electrical energy savings of an alternative conservation plan should be developed in consultation with the Council and included in Bonneville's policy to implement the surcharge.

[4] This calculation of the surcharge is designed to eliminate the possibility of surcharging a utility twice on the same load. In the calculation, the portion of a utility's exchange resource purchased from Bonneville and already surcharged under the power sales contract is subtracted from the exchange resources before establishing a surcharge on the exchange load.

Appendix G: MCS Cost-effectiveness for Residences

INTRODUCTION

This appendix provides an overview of the method and data used to evaluation the regional cost-effectiveness and consumer economic feasibility of the Council's Model Conservation Standards for New Electrically Heated Residential Buildings. The first section describes the methodology, cost and savings assumptions used to establish the efficiency level that achieves all electricity savings that are cost-effective to the region's power system. The second section describes the methodology and assumptions used to determine whether the regionally cost-effective efficiency levels are economically feasible for new homebuyers in the region.

REGIONAL COST EFFECTIVENESS

Base Case Assumptions

Since the Council first promulgated its model conservation standards for new residential constructions in 1983 all of the states in the region have revised their energy codes. Consequently, many of the conservation measures included in the Council's original standards have now been incorporated into state regulations. In addition, some of the measures identified in prior Council Power Plan's as being regionally cost-effective when installed in new manufactured homes are now required by federal regulation.[1] This analysis assumes that the "base case" construction practices in the region comply with existing state codes and federal standards. However, since not all of the energy codes in the region are equally stringent this analysis uses the less restrictive measure permitted by code for each building component (e.g., walls, windows, doors, etc.). Table G-1 shows the levels of energy efficiency assumed for new site built and manufactured homes built to existing state codes and federal standards.

[1] The energy efficiency of new manufactured homes are regulated under the National Manufactured Housing Construction and Safety Standards Act of 1974. 42 USC §5401 et seq. (1983) which also pre-empts state regulation of their construction.

Table G-1: Base Case Efficiency Level Assumptions

Component	Site Built Homes	Manufactured Homes
Attic	R38 Standard Framing	R38 Intermediate Framing
Door	R5	R5
Floor	R30	R22
Infiltration	0.35 Air changes per hour	0.35 Air changes per hour
Joisted Vault	R30	R19
Slab-on-Grade (F-Value/linear foot of perimeter)	R10	Not Applicable
Trussed Vault	R38	R19
Wall	R19 Standard Framing	R19
Wall Below Grade (Interior)	R21	Not Applicable
Slab-below-Grade (F-Value/lin.ft. perimeter)	R10	Not Applicable
Window	Class 35 (U<0.35)	Class 50 (U<0.50)

Measure Cost Assumptions

The cost data for new site built homes used in the Council's analysis were obtained from a 1994 survey of new residential construction costs prepared for Bonneville and cost estimates provided to the Regional Technical Forum based on program data from the Energy Trust of Oregon and Mission Valley Power.[2] These costs were converted to year 2006 dollars using the GDP Deflator. Costs include a 20 percent markup for builder overhead and profit. Table G-2 provides a summary of the incremental costs used in the analysis for site built homes.

[2] Frankel, Mark, Baylon, D. and M. Lubliner 1995. Residential Energy Conservation Evaluation: Cost-Effectiveness of Energy Conservation Measures in New Residential Construction in Washington State. Washington State Energy Office, Olympia, WA. and the Bonneville Power Administration, Portland, OR.

Table G-2: Incremental Cost of New Site Built Residential Space Heating Conservation Measures

Conservation Measure	Incremental Installed Cost (2006$/sq.ft.)
Wall R19 Standard Framing	Base
Wall R21 Advanced Framing	$0.15
Wall R21 Standard Framing + R5 Foam	$0.87
Wall R30 Stressed Skin Panel	$1.19
Wall R38 Double Wall	$0.61
Attic R38 Standard Framing	Base
Attic R49 Advanced Framing	$0.39
Attic R60 Advanced Framing	$0.39
Vault R30 (Joisted)	Base
Vault R38 (Joisted w/High Density Insulation)	$0.62
Vault R50 Stressed Skin Panel	$2.18
Underfloor R30	Base
Underfloor R38 (Truss joist)	$0.41
Window Class 35 (U<0.35)	Base
Window Class 30 (U<0.30)	$0.89
Window Class 25 (U<0.25)	$2.00
Exterior Door R5	Base
Slab-On-Grade R10 Perimeter, down 2 ft	Base
Slab-On-Grade R10 Perimeter, down 4 ft	$.27
Slab-On-Grade R10 Full Under Slab w/R5 TB	$0.81
Below-Grade Wall R21 Interior	Base
Below-Grade Wall R21 Interior + R5 Foam	$0.87

Cost for new manufactured home energy efficiency improvements were obtained from regional manufacturers, insulation and window.[3] Table G-3 summarizes this same information for manufactured homes. These cost assume a manufacturer markup on material costs of 200 percent to cover labor and production cost and profit as well as and a retailer markup of 35 percent.

[3] Davis, Robert, D. Baylon and L. Palmiter, 1995 (draft report). *Impact Evaluation of the Manufactured Housing Acquisition Program (MAP).* Bonneville Power Administration, Portland, OR.

Table G-3: Incremental Cost of New Manufactured Home Residential Space Heating Conservation Measures

Conservation Measure	Incremental Installed Cost (2006$/sq.ft)
Wall R19 Standard Framing	Base
Wall R21 Standard Framing	$0.17
Attic R19	Base
Attic R25	$0.10
Attic R30	$0.10
Attic R38	$0.15
Attic R49	$0.23
Vault R19	Base
Vault R25	$0.10
Vault R30	$0.10
Vault R38	$0.15
Underfloor R22	Base
Underfloor R33	$0.18
Underfloor R44	$0.18
Window Class 35 (U<0.35)	Base
Window Class 30 (U<0.30)	$0.89
Window Class 25 (U<0.25)	$2.00
Exterior Door R5	$4.54

Energy Use Assumptions

The Council used an engineering simulation model, SEEM©, that is an improved version of the SUNDAY© simulation that has been calibrated to end-use metered space heating for electrically heated homes built across the region.[4] Thermal shell savings were computed for each measure based on the “economic” optimum order of application. This was done by first computing the change in heat loss rate (UA) that resulted from the application of each measure. The incremental cost of installing each measure was then divided by this “delta UA” to establish a measure’s benefit-to-cost ratio (i.e., dollars/delta UA). The SEEM© simulation model was then used to estimate the space heating and space cooling energy savings that would result from the applying all measures starting with those that had the largest benefit-to-cost ratios. Savings were estimated for three typical site built single family homes and three typical manufactured homes. Table G-4 provides a summary of the component areas for each of these six homes.

[4] Palmiter, L., I. Brown and M. Kennedy 1988. *SUNDAY Calibration*. Bonneville Power Administration, Portland, OR.

Table G-4: Prototypical Home Component Dimensions

	Site Built Homes			Manufactured Homes		
Component	1344 sq.ft.	2200 sq.ft.	2268 sq.ft.	924 sq.ft.	1568 sq.ft.	2352 sq.ft.
Attic	1344	1784	1344	924	1568	2352
Door	40	40	40	40	40	40
Floor over Crawlspace	1,344	1,784	0	924	1,568	2,352
Volume	10,752	18,700	22,848	7,392	12,544	18,816
Slab-on-Grade (F-Value/lin.ft. perimeter)	-	-	140	-	-	-
Wall (Above Grade)	969	1,805	1,064	1,125	1,108	1,234
Wall Below Grade (Interior)	-	-	962	-	-	-
Slab-below-Grade (F-Value/lin.ft. perimeter)	-	-	148	-	-	-
Window	175	365	376	116	196	294

Five locations, Seattle, Portland, Boise, Spokane and Kalispell were selected to represent the range of climates found across the region. The SEEM© simulation model was run using the most recent (version 3) Typical Meteorological Year weather files for each of these locations. The savings produced by each measure across all five locations were then weighted together based on the share of new housing built in each location to form the three climate zones used by the Council. Table G-5 shows the weights used.

Table G-5: Location Weights Used to Establish Northwest Heating Zones

Location	Portland	Seattle	Boise	Spokane	Kalispell
Heating Zone 1	20%	50%	15%	15%	0%
Heating Zone 2	0%	0%	10%	85%	5%
Heating Zone 3	0%	0%	0%	0%	100%

In order to determine whether a measure is regionally cost-effective the Council then compared to cost of installing each measure with the value of the energy savings it produced over its lifetime. The value of all conservation savings vary by time of day and season of the year based on the market prices for electricity across the West and the impact of the savings on the need to expand the region's transmission and distribution system.

Tables G-6 through G-8 show the results of the cost-effectiveness analysis for each heating climate zone for site built homes and Tables G-9 through G-11 show the results of the cost-effectiveness analysis for new manufactured homes. All measures with a benefit/cost (B/C) ratio of 1.0 or larger are considered regionally cost-effective.

Table G-6: Regional Cost-Effectiveness Results for Site Built Homes in Heating Zone 1

1344 sq. ft				2200 sq. ft				2688 sq. ft			
Measure	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**
WINDOW CL30	298	156	1.7	WINDOW CL30	644	326	1.7	WINDOW CL30	644	336	1.7
INFILTRATION @ 0.20 ACH w/HRV	1027	672	1.4	INFILTRATION @ 0.20 ACH w/HRV	1784	1100	1.4	INFILTRATION @ 0.20 ACH w/HRV	2281	1344	1.5
ATTIC R49 ADVrh	524	520	0.9	ATTIC R49 ADVrh	723	690	0.9	ATTIC R49 ADVrh	602	520	1.0
WINDOW CL25	321	349	0.8	WINDOW CL25	713	730	0.9	SLAB R10-FULL	1078	1088	0.9
WALL R21 INT+R5	749	988	0.7	WALL R21 INT+R5	1459	1840	0.7	WINDOW CL25	729	753	0.9
FLOOR R38 STD w/12"Truss	335	552	0.5	FLOOR R38 STD w/12"Truss	454	733	0.5	BGWALL R21	117	146	0.7
ATTIC R60 ADVrh	138	520	0.2	ATTIC R60 ADVrh	190	690	0.2	WALL R21 INT+R5	802	1084	0.7
WALL 8" SSPANEL	213	1150	0.2	WALL 8" SSPANEL	382	2142	0.2	ATTIC R60 ADVrh	121	520	0.2
WALL R33 DBL	24	590	0.0	WALL R33 DBL	45	1099	0.0	WALL 8" SSPANEL	199	1262	0.1
								WALL R33 DBL	25	647	0.0

Table G-7: Regional Cost-Effectiveness Results for Site Built Homes in Heating Zone 2

1344 sq. ft				2200 sq. ft				2688 sq. ft			
Measure	**Savings (kWh/yr)**	**Installed Cost**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**
WINDOW CL30	392	156	2.2	WINDOW CL30	830	326	2.3	WINDOW CL30	836	336	2.2
INFILTRATION @ 0.20 ACH w/HRV	1349	672	1.8	INFILTRATION @ 0.20 ACH w/HRV	2309	1100	1.9	INFILTRATION @ 0.20 ACH w/HRV	2956	1344	1.9
ATTIC R49 ADVrh	692	520	1.2	ATTIC R49 ADVrh	940	690	1.2	ATTIC R49 ADVrh	762	520	1.3
WINDOW CL25	402	349	1.0	WINDOW CL25	878	730	1.1	SLAB R10-FULL	1331	1088	1.1
WALL R21 INT+R5	933	988	0.8	WALL R21 INT+R5	1805	1840	0.9	WINDOW CL25	900	753	1.1
FLOOR R38 STD w/12"Truss	435	552	0.7	FLOOR R38 STD w/12"Truss	594	733	0.7	BGWALL R21	144	146	0.9
ATTIC R60 ADVrh	183	520	0.3	ATTIC R60 ADVrh	251	690	0.3	WALL R21 INT+R5	1025	1084	0.8
WALL 8" SSPANEL	289	1150	0.2	WALL 8" SSPANEL	519	2142	0.2	ATTIC R60 ADVrh	162	520	0.3
WALL R33 DBL	33	590	0.0	WALL R33 DBL	61	1099	0.0	WALL 8" SSPANEL	272	1262	0.2
								WALL R33 DBL	34	647	0.0

Table G-8: Regional Cost-Effectiveness Results for Site Built Homes in Heating Zone 3

1344 sq. ft				2200 sq. ft				2688 sq. ft			
Measure	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**
WINDOW CL30	466	156	2.6	WINDOW CL30	989	326	2.7	WINDOW CL30	1006	336	2.7
INFILTRATION @ 0.20 ACH w/HRV	1610	672	2.1	INFILTRATION @ 0.20 ACH w/HRV	2751	1100	2.2	INFILTRATION @ 0.20 ACH w/HRV	3522	1344	2.3
ATTIC R49 ADVrh	823	520	1.4	ATTIC R49 ADVrh	1115	690	1.4	ATTIC R49 ADVrh	898	520	1.5
WINDOW CL25	473	349	1.2	WINDOW CL25	1019	730	1.2	SLAB R10-FULL	1567	1088	1.3
WALL R21 INT+R5	1096	988	1.0	WALL R21 INT+R5	2100	1840	1.0	WINDOW CL25	1060	753	1.2
FLOOR R38 STD w/12"Truss	523	552	0.8	FLOOR R38 STD w/12"Truss	708	733	0.9	BGWALL R21	170	146	1.0
ATTIC R60 ADVrh	220	520	0.4	ATTIC R60 ADVrh	297	690	0.4	WALL R21 INT+R5	1223	1084	1.0
WALL 8" SSPANEL	356	1150	0.3	WALL 8" SSPANEL	641	2142	0.3	ATTIC R60 ADVrh	198	520	0.3
WALL R33 DBL	41	590	0.1	WALL R33 DBL	76	1099	0.1	WALL 8" SSPANEL	345	1262	0.2
								WALL R33 DBL	43	647	0.1

Table G-9: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 1

924 sq. ft				1568 sq. ft				2352 sq. ft			
Measure	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**
WINDOW CL35	676	135	4.5	WINDOW CL35	1078	228	4.2	WINDOW CL35	1579	343	4.1
FLOOR R33	465	163	2.5	FLOOR R33	806	276	2.6	FLOOR R33	1213	415	2.6
WINDOW CL30	230	103	2.0	WINDOW CL30	406	175	2.1	WINDOW CL30	619	263	2.1
VAULT R30	95	47	1.8	ATTIC R30	171	79	1.9	ATTIC R30	261	118	2.0
ATTIC R30	94	47	1.8	VAULT R30	171	79	1.9	VAULT R30	261	118	2.0
DOOR R5	324	211	1.4	DOOR R5	347	211	1.5	DOOR R5	353	211	1.5
WALL R21 ADV	256	195	1.2	WALL R21 ADV	281	192	1.3	WALL R21 ADV	320	214	1.3
ATTIC R38	66	70	0.8	ATTIC R38	164	118	1.2	ATTIC R38	252	178	1.3
WINDOW CL25	159	231	0.6	WINDOW CL25	394	392	0.9	WINDOW CL25	604	588	0.9
VAULT R38	40	70	0.5	VAULT R38	98	118	0.7	VAULT R38	152	178	0.8
ATTIC R49	53	105	0.5	ATTIC R49	126	178	0.6	ATTIC R49	192	266	0.6
FLOOR R44	53	163	0.3	FLOOR R44	109	276	0.4	FLOOR R44	186	415	0.4

Table G-10: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 2

924 sq. ft				1568 sq. ft				2352 sq. ft			
Measure	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**
WINDOW CL35	894	135	5.9	WINDOW CL35	1367	228	5.3	WINDOW CL35	1969	343	5.1
FLOOR R33	614	163	3.3	FLOOR R33	1065	276	3.4	FLOOR R33	1593	415	3.4
WINDOW CL30	304	103	2.6	WINDOW CL30	532	175	2.7	WINDOW CL30	811	263	2.7
VAULT R30	127	47	2.4	ATTIC R30	224	79	2.5	ATTIC R30	342	118	2.6
ATTIC R30	126	47	2.4	VAULT R30	224	79	2.5	VAULT R30	342	118	2.6
DOOR R5	434	211	1.8	DOOR R5	456	211	1.9	DOOR R5	463	211	1.9
WALL R21 ADV	336	195	1.5	WALL R21 ADV	374	192	1.7	WALL R21 ADV	424	214	1.8
ATTIC R38	93	70	1.2	ATTIC R38	217	118	1.6	ATTIC R38	333	178	1.7
WINDOW CL25	222	231	0.8	WINDOW CL25	524	392	1.2	WINDOW CL25	798	588	1.2
VAULT R38	56	70	0.7	VAULT R38	129	118	1.0	VAULT R38	202	178	1.0
ATTIC R49	74	105	0.6	ATTIC R49	162	178	0.8	ATTIC R49	246	266	0.8
FLOOR R44	74	163	0.4	FLOOR R44	145	276	0.5	FLOOR R44	237	415	0.5

Table G-11: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 3

924 sq. ft				1568 sq. ft				2352 sq. ft			
Measure	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**	**Measure**	**Savings (kWh/yr)**	**Installed Cost**	**Benefit/ Cost Ratio**
WINDOW CL35	1073	135	7.1	WINDOW CL35	1636	228	6.3	WINDOW CL35	2362	343	6.1
FLOOR R33	739	163	4.0	FLOOR R33	1276	276	4.1	FLOOR R33	1908	415	4.1
WINDOW CL30	365	103	3.1	WINDOW CL30	641	175	3.2	WINDOW CL30	975	263	3.3
VAULT R30	151	47	2.9	ATTIC R30	270	79	3.0	ATTIC R30	411	118	3.1
ATTIC R30	151	47	2.9	VAULT R30	270	79	3.0	VAULT R30	411	118	3.1
DOOR R5	523	211	2.2	DOOR R5	549	211	2.3	DOOR R5	556	211	2.3
WALL R21 ADV	407	195	1.9	WALL R21 ADV	448	192	2.1	WALL R21 ADV	508	214	2.1
ATTIC R38	117	70	1.5	ATTIC R38	263	118	2.0	ATTIC R38	402	178	2.0
WINDOW CL25	280	231	1.1	WINDOW CL25	631	392	1.4	WINDOW CL25	962	588	1.5
VAULT R38	70	70	0.9	VAULT R38	154	118	1.2	VAULT R38	241	178	1.2
ATTIC R49	94	105	0.8	ATTIC R49	195	178	1.0	ATTIC R49	296	266	1.0
FLOOR R44	94	163	0.5	FLOOR R44	179	276	0.6	FLOOR R44	286	415	0.6

Once the cost-effective level of the thermal shell was established the Council tested the cost-effectiveness of improving the efficiency of the homes space conditioning system. This was done by applying running the SEEM© model with higher performance heat pumps, improved duct systems, including moving all duct work and HVAC system inside the conditioned space, and carrying out heat pump commissioning and controls to ensure the system operated as designed. The average costs of these measures are shown in Table G-12. All of measures listed in Table G-12 are regionally cost-effectiveness, with total resource cost benefit-to-cost ratio greater than 1.0.

Table G-12: Heating System Efficiency Improvements

HVAC System Efficiency Improvements	Incremental Cost (2006$)
PTCS Heat Pump Commissioning	$225
PTCS - Duct Sealing	$300
PTCS-Interior Ducts & HVAC	$350
Air Source Heat Pump - Baseline (HSPF 7.7/SEER 13)	$3,880
Air Source Heat Pump - (HSPF 8.5/SEER 14)	$5,790
Air Source Heat Pump - Baseline (HSPF 9.0/SEER 14)	$6,900

In addition to space conditioning system efficiency improvements, recent changes to state energy codes have included lighting efficiency improvements. National model codes also include minimum lighting efficiency requirements. Therefore, the Council also analyzed lighting efficiency improvements. Four levels of efficiency, including baseline lighting power densities were reviewed for cost-effectiveness. It was assumed that all of these levels could be achieved with higher efficacy lighting technologies (compact fluorescent, LEDs) without reducing lumen levels. The estimated cost of these improvements is show in Table G-13.

Reduction in lighting power densities interact with the space heating and cooling needs of a home. Therefore, to properly estimate the net savings from these lighting reductions the SEEM© model was run to calculate the space heating and cooling loads after their implementation. All of the lighting levels shown in Table G-13 are regionally cost-effective, with total resource cost benefit-to-cost ratios greater than 1.0.

Table G-13: Lighting System Efficiency Improvements and Cost

Efficiency Level	Lighting Power Density (Watts/sq.ft.)	Cost/sq.ft.
Baseline	1.75	
Energy Star	1.00	$0.11
Advanced	0.75	$0.17
Full	0.60	$0.23

The 5th Plan's Model Conservation Standards did not cover water heating. Higher efficiency tanks have been available for decades and with the anticipated availability of heat pump water heaters, there is now a potentially cost-effective technology to reduce water heating consumption by as much as half. The estimated average cost and savings assumed for improving water heating efficiency are shown in Table G-14. Using these cost and savings, all of the water heating measures shown in Table G-14 are regionally cost-effective, with total resource cost benefit-to-cost ratios greater than 1.0.

Table G-14: Water Heating System Efficiency Improvements and Cost

Water Heating System Type	DHW System Cost (2006$)	DHW Use (kWh/yr)
EF 0.90	$649	3,655
EF 0.92	$669	3,576
EF 0.94	$746	3,500
EF 2.2	$1,450	1,499

The Council's Model Conservation Standards are "performance based" and not prescriptive standards. That is, many different combinations of energy efficiency measures can be used to meet the overall performance levels called for in the standards. In order to translate the regional cost-effectiveness results into "model standards" the Council calculates the total annual space conditioning, water heating and lighting use of a "reference building" that meets the Council's standards so that its efficiency can be compared to the same building built with some other combination of measures. Table G-15 shows the maximum annual energy budget for space conditioning, water heating and lighting use permitted under the draft sixth Plan's model standards "reference" case requirements for site built and manufactured homes for each of the region's three heating climate zones. These "performance budgets" incorporate all of the conservation measures shown in Tables G-6 through G-14 that have a benefit-to-cost ratio of 1.0 or higher on a total resource cost basis.

Table G-15: Draft Sixth Plan Model Conservation Standards Annual Space Conditioning, Water Heating and Lighting Budgets[5]

	Site Built Homes (kWh/sq.ft./yr)	Manufactured Homes (kWh/sq.ft/yr)
Heating Zone 1	2.87	2.54
Heating Zone 2	4.27	3.54
Heating Zone 3	5.15	4.10

The Council compared the requirements underlying the performance shown in Table G-15 for site built homes with the requirements of state energy codes in the region. It also compared the requirements underlying the performance shown in Table G-15 with the requirements of regional Energy Star® site built and manufactured home program specifications. This comparison, revealed that none of the region's energy codes nor the Energy Star® program specifications met the Model Conservation Standards goal of capturing all regionally cost-effective electricity savings. It therefore appears that further strengthening of these codes and program specifications is required. The following section addresses the question of whether these higher levels of efficiency would be economically feasible for consumers.

CONSUMER ECONOMIC FEASIBILITY

The Act requires that the Council's Model Conservation Standards be "economically feasible for consumers" taking into account any financial assistance made available through Bonneville and the region's utilities. In order to determine whether the performance standards set forth in Table G-15 met this test the Council developed a methodology that allowed it to compare the life cycle cost of home ownership, including energy costs, of typical homes with increasing levels of

[5] Annual space conditioning, water heating and lighting use for a typical 2250 sq.ft. site built home and 1750 sq.ft. manufactured home. Both homes are assumed to have air source heat pumps with a minimum HSPF 9.0/SEER 14, heat pump water heater and maximum lighting power density of 0.6 Watts/sq.ft.

energy efficiency built into them. This section describes this methodology and results of this analysis.

The life cycle cost of home ownership is determined by many variables, such as the mortgage rate, downpayment amount, the marginal state and federal income tax rates of the homebuyer, retail electric rates, etc. The value of some of these variables, such as property and state income tax rates are known, but differ across state or utility service areas or differ by income level. For example, homebuyers in Washington state pay no state income tax, while those in Oregon pay upwards of 9% of their income in state taxes. Since home mortgage interest payments are deductible, Oregon homebuyers have a lower "net" interest rate than do Washington buyers. The value of other variables, such as mortgage rates and the fraction of a home's price that the buyer pays as a downpayment are a function of income, credit worthiness, market conditions and other factors. Consequently, it is an extreme oversimplification to attempt to represent the economic feasibility of higher levels of efficiency using the "average" of all of these variables as input assumptions.

In order to better reflect the range of conditions individual new homebuyers might face the Council developed a model that tested over a 1500 different combinations of major variables that determine a specific consumer's life cycle cost of home ownership for each heating climate zone. Table G-16 lists these variables and the data sources used to derive the actual distribution of values used.

Table G-16: Data Sources and Variables Used in Life Cycle Cost Analysis

Variable	Data Source
Average New Home Price	Federal Housing Finance Board
Mortgage Interest Rates	Federal Housing Finance Board & Mortgage Bankers Association
Downpayment	Federal Housing Finance Board
Private Mortgage Insurance Rates	Mortgage Bankers Association
Retail Electric Rates	Energy Information Administration
Retail Gas Rates	Energy Information Administration
Retail Electric and Gas Price Escalation Rates	Council Draft 6th Plan Forecast
Federal Income Tax Rates	Internal Revenue Service
State Income and Property Tax Rates	ID, MT, OR & WA State Departments of Revenue
Adjusted Gross Incomes	Internal Revenue Service
Home owners insurance	Online estimates from Realtor.com

A "Monte Carlo" simulation model add-on to EXCEL© called Crystal Ball© was used to select specific values for each of these variables from the distribution of each variable. Each combination of values was then to use to compute the present value of a 30-year (360 month) stream of mortgage principal and interest payments, insurance premiums, property taxes and energy cost for a new site built or manufactured home built to increasing levels of thermal efficiency. Figures G-1 through G-6 show the distributions used for each of the major financial input assumptions to the life cycle cost analysis.

Figure G-1: Distribution of Nominal Mortgage Rates

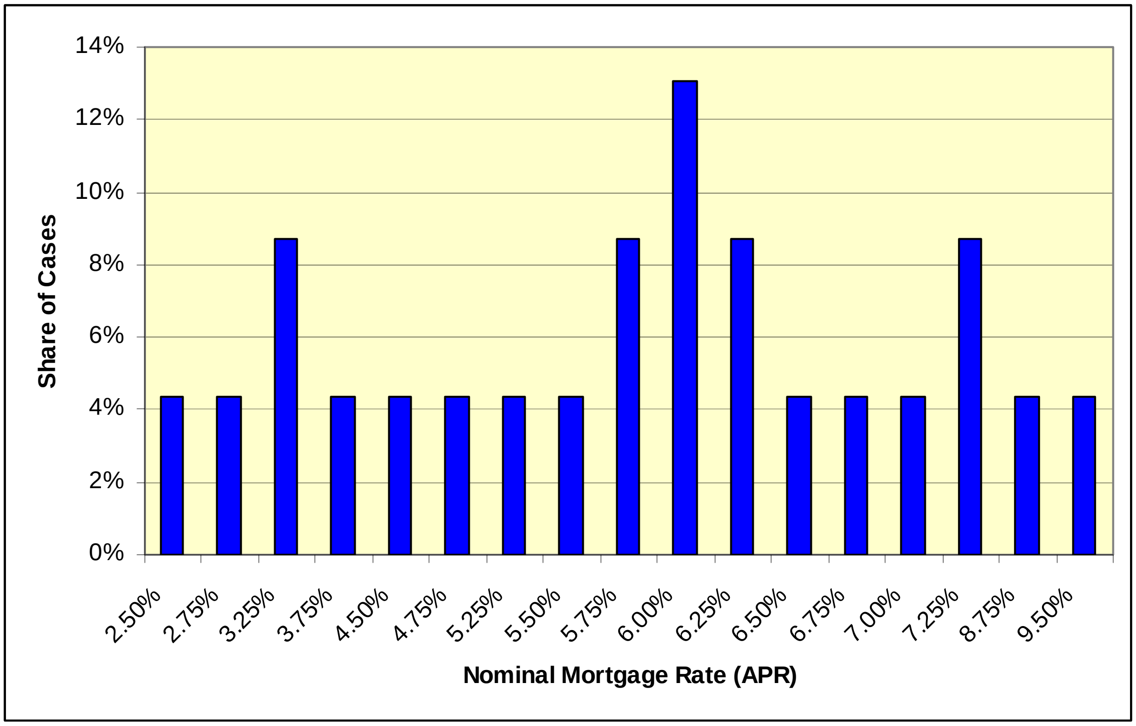


Figure G-2: Distribution of Downpayment Amounts

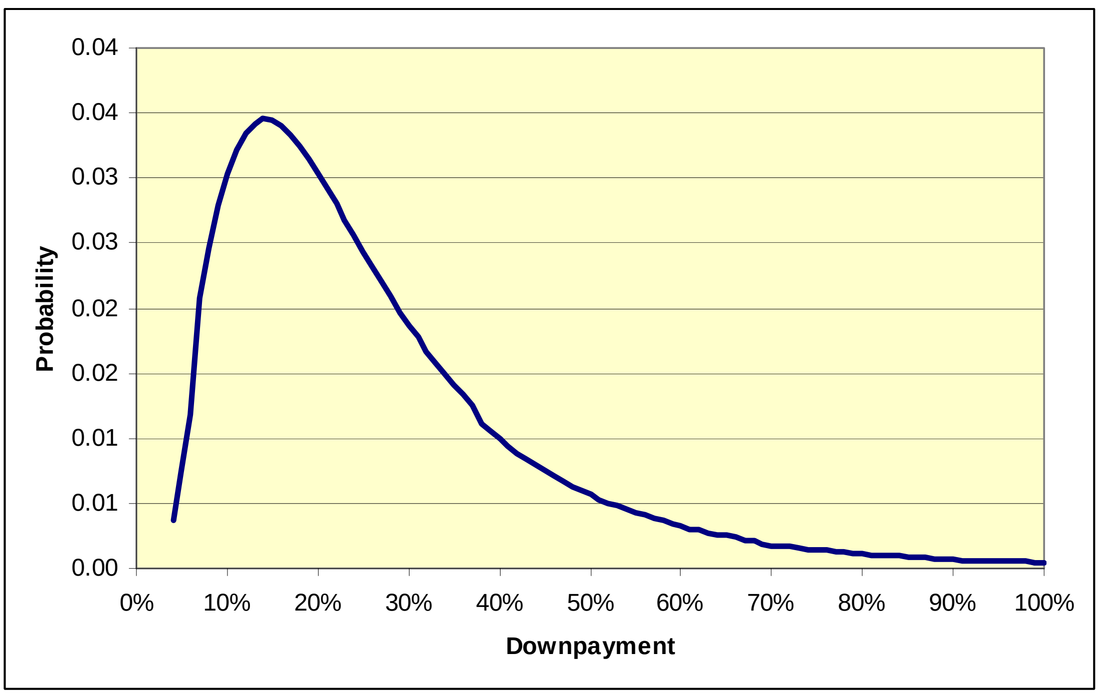


Table G-17: Distribution of Marginal State and Federal Income Tax Rates

	Idaho			Montana			Oregon			Washington		
Adjusted Gross Income	Federal Tax Rate	State Income Tax Rate	Share of Returns	Federal Tax Rate	State Income Tax Rate	Share of Returns	Federal Tax Rate	State Income Tax Rate	Share of Returns	Federal Tax Rate	State Income Tax Rate	Share of Returns
Under $10,000	10%	5.1%	20.0%	10%	3.0%	24.4%	10%	7.0%	18.6%	10%	0.0%	16.8%
$10,000 Under $20,000	15%	7.1%	19.3%	15%	5.0%	20.8%	15%	9.0%	18.1%	15%	0.0%	16.1%
$20,000 Under $30,000	15%	7.8%	15.0%	15%	6.0%	14.2%	15%	9.0%	14.4%	15%	0.0%	13.7%
$30,000 Under $50,000	18%	7.8%	19.6%	18%	8.0%	18.0%	19%	9.0%	19.5%	20%	0.0%	19.8%
$50,000 Under $75,000	25%	7.8%	13.6%	25%	9.0%	12.1%	25%	9.0%	14.1%	25%	0.0%	15.5%
$75,000 Under $100,000	25%	7.8%	5.7%	25%	10.0%	4.6%	25%	9.0%	6.8%	25%	0.0%	8.1%
$100,000 Under $150,000	28%	7.8%	3.2%	28%	11.0%	2.4%	28%	9.0%	4.3%	28%	0.0%	5.5%
$150,000 Under $200,000	28%	7.8%	0.9%	29%	11.0%	0.8%	29%	9.0%	1.3%	29%	0.0%	1.5%
$200,000 Under $500,000	33%	7.8%	0.9%	33%	11.0%	0.8%	33%	9.0%	1.3%	33%	0.0%	1.5%
$500,000 Under $1,000,000	35%	7.8%	0.2%	35%	11.0%	0.1%	35%	9.0%	0.2%	35%	0.0%	0.3%
$1,000,000 and Over	35%	7.8%	0.1%	35%	11.0%	0.0%	35%	9.0%	0.1%	35%	0.0%	0.2%

Figure G-3: Property Tax Rates by State

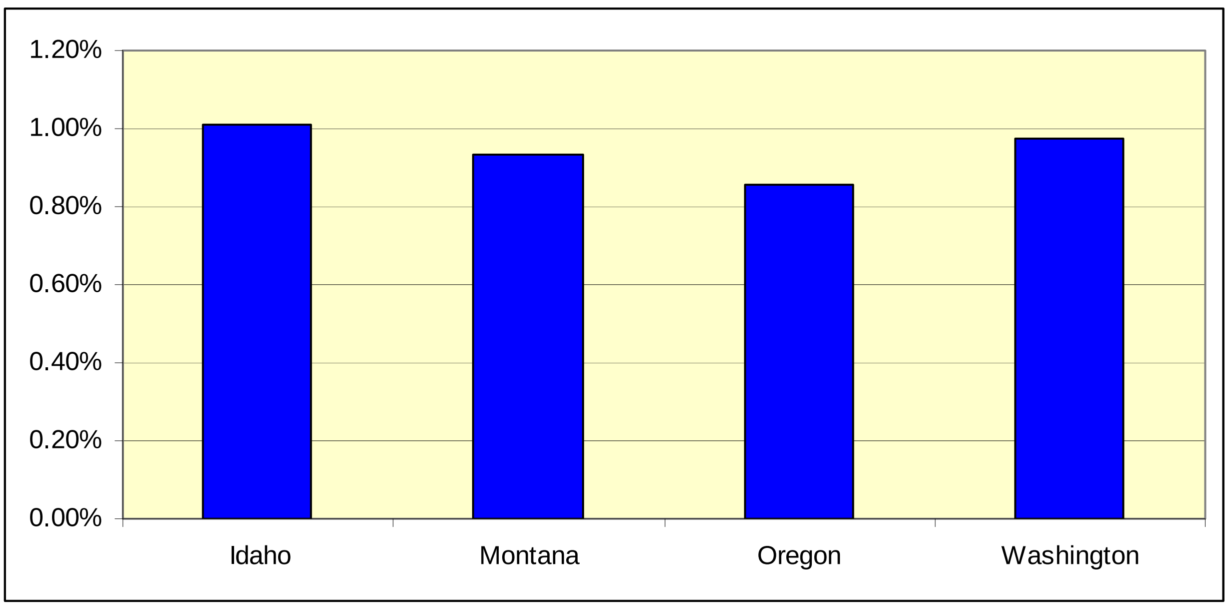


Figure G-4: Base Year Retail Electric Rates by Climate Zone

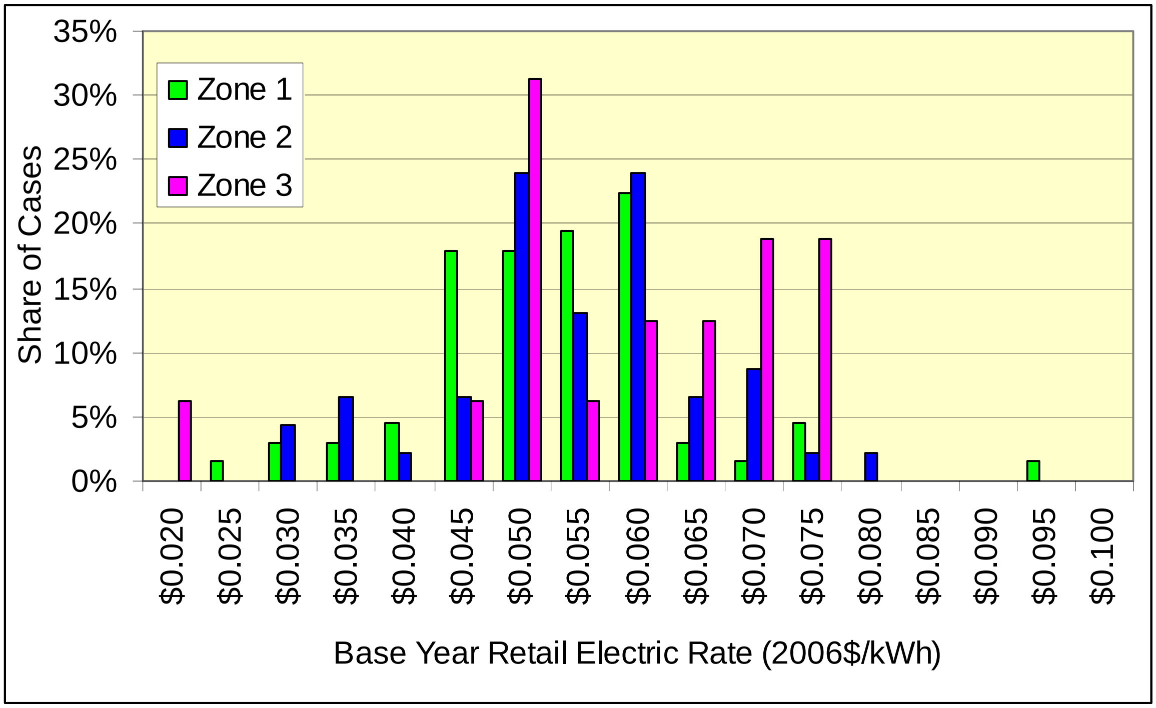
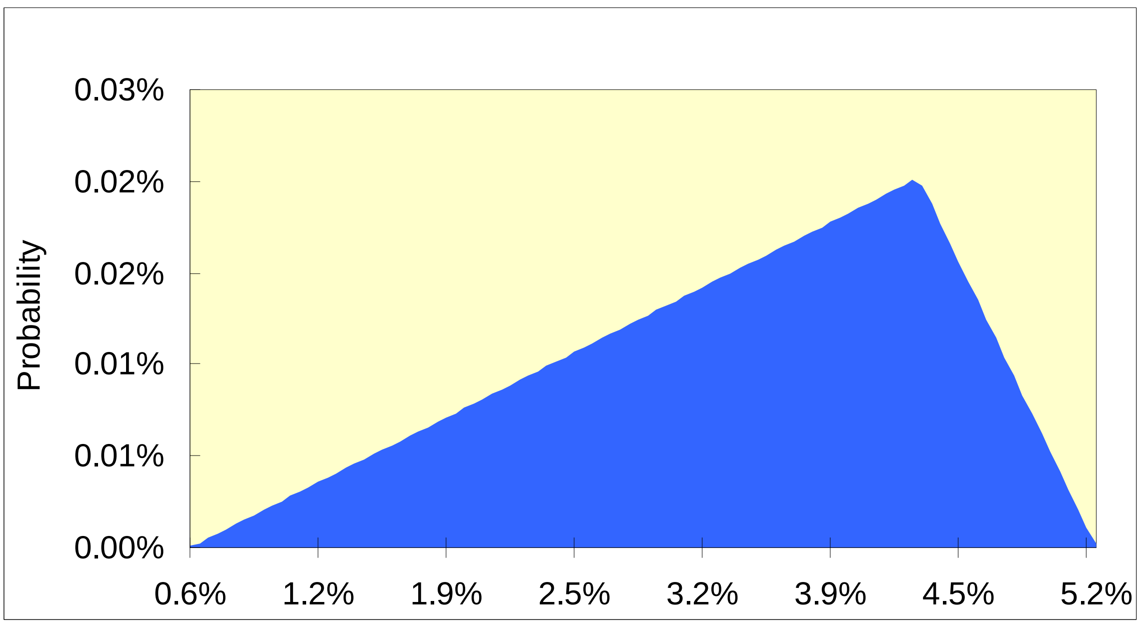


Figure G-5: Nominal Escalation Rates for Retail Electricity Prices - All Climate Zones



The incremental costs of conservation measures described in the prior section on regional cost-effectiveness were used in the life cycle cost calculations. Annual space heating and cooling energy use was computed for four heating system types using the system efficiency assumptions shown in Table G-12 and the water heating and lighting use shown in Tables G13 and G-14.

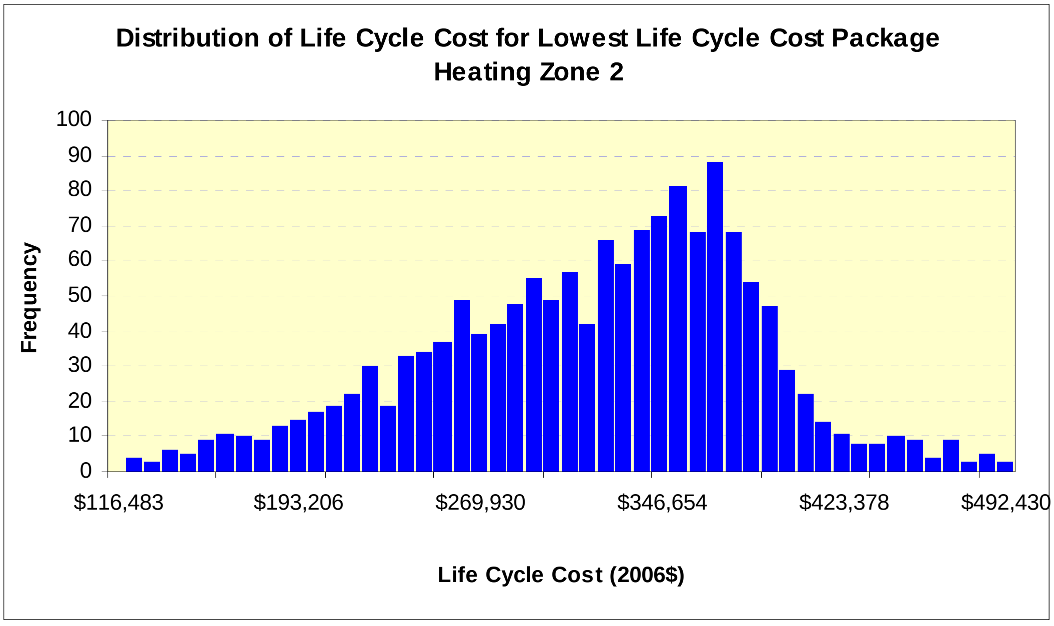
The life cycle cost simulation model used the same 1,500 combinations of input assumptions for each level of energy efficiency tested. As a result, the Council could compare the distribution of 1,500 different life cycle cost results for a home built to incrementally higher levels of efficiency, rather than just single cases. This allowed the Council to consider how "robust" a conclusion one might draw regarding the economic feasibility of each measure.

Figure G-6 illustrates a typical distribution of net present value results for one the lowest life cycle cost package identified for Heating Zone 2. The graph plots the life cycle cost value of a conservation package (i.e., thermal shell, space conditioning system, water heating system and lighting system) costs and energy use over the term of the mortgage on the horizontal (x) axis. The frequency of obtaining a given life cycle cost is plotted on the vertical (y) axis.

The simulation model was set up to seek out the lowest life cycle cost path to comply with current codes. In this case, the model was only permitted to select different electric space conditioning systems. That is, it was not allowed to choose improvements in thermal shell, water heating, lighting or duct system efficiency. Table G-18 shows the mean life cycle cost, first cost and energy use of for each of the regions three heating zones for new single-family homes and for new manufactured homes.

Once the "base case" homes life cycle cost was established the model was set up to seek out the lowest life cycle cost package of measures by selecting various combinations of thermal shell improvements, space conditioning systems, duct system efficiencies and lighting and water heating system efficiency improvements. Table G-19 shows the mean life cycle cost, first cost and annual energy use for the package that performed best across all 1500 different combinations of financial inputs.

Figure G-6: Illustrative Distribution of Life Cycle Cost Results



Finally, the simulation model was run to determine the life cycle cost of the package for each heating zone that includes all measures that were found to regionally cost-effective to the power system. Table G-20 shows the mean life cycle cost, first cost and annual energy use for these packages for each climate zone.

A comparison of the energy use for the lowest life cycle cost packages shown in Table G-19 with the life cycle cost of the packages containing all regionally cost-effective measures shown in Table G-20 reveals that across all climate zones and building types, life cycle costs are higher for those packages containing all regionally cost-effective measures.

Table G-18: Lowest Life Cycle Minimally Code Compliant Packages (Base Case)

	Life Cycle Cost - 30 yrs		**First Cost**		**Total Use (kWh/yr)**	
	Single Family	Manufactured Home	Single Family	Manufactured Home	Single Family	Manufactured Home
Zone 1	$314,247	$99,749	$2,297	$8,732	17,575	10,131
Zone 2	$324,608	$104,167	$2,297	$8,732	19,551	14,528
Zone 3	$255,368	$103,076	$2,297	$8,732	26,752	17,158

Table G-19: Lowest Life Cost Cycle Packages (Economically Feasible)

	Life Cycle Cost - 30 yrs		**First Cost**		**Total Use (kWh/yr)**	
	Single Family	Manufactured Home	Single Family	Manufactured Home	Single Family	Manufactured Home
Zone 1	$307,500	$93,705	$10,899	$10,908	9,265	5,431
Zone 2	$315,460	$95,623	$10,899	$10,904	10,462	7,165
Zone 3	$242,302	$91,231	$10,899	$11,107	12,453	8,173

Table G-20: All Regionally Cost-Effective Packages (MCS)

	Life Cycle Cost - 30 yrs		**First Cost**		**Total Use (kWh/yr)**	
	Single Family	Manufactured Home	Single Family	Manufactured Home	Single Family	Manufactured Home
Zone 1	$308,254	$94,593	$12,068	$11,617	6,449	4,334
Zone 2	$316,107	$96,303	$12,068	$11,617	9,776	6,204
Zone 3	$242,780	$91,658	$12,068	$11,617	11,714	7,170

Table G-21 shows differences in the buildings shell between the lowest life cycle cost packages and the packages that contain all regionally cost-effective measures. A review of Table G-21 reveals that the only difference in the thermal shell is in the level of attic insulation and air sealing.

Table G-21: Comparison of Thermal Shell Measures in Lowest Life Cycle Cost Packages and All Regionally Cost-Effective Packages

Component	Regionally Cost-Effective (All Zones)	Minimum Life Cycle Cost (All Zones)
Wall – Above Grade	R21 Advanced Framing	R21 Advanced Framing
Wall – Below Grade	R19	R19
Attic	R49 Advanced	R38 STD
Vault	R30	R30
Floor	R30	R30
Window	Class 25	Class 25
Door	R5	R5
Slab	R10 Full Under Slab	R10 Full Under Slab
Wall – Ext. Below grade	R10	R10
Infiltration	Air Sealing w/HRV	Current Practice

Table G-22 shows the differences in the space conditioning, water heating and lighting system efficiency components between the lowest life cycle cost packages and the packages containing all regionally cost-effective measures. As can be seen in Table G-22 the only difference between the lowest life cycle cost package and the package containing all regionally cost-effective measures is the minimum efficiency requirements for the heat pump space conditioning system.

Table G-22: Comparison of Space Conditioning, Water Heating and Lighting Measures in Lowest Life Cycle Cost Packages and All Regionally Cost-Effective Packages

Component	Regionally Cost-Effective	Minimum Life Cycle Cost
HVAC System	HSPF 9.0/SEER 14 Heat Pump	HSPF 7.7/SEER 13 Heat Pump
Duct System	Interior Ducts	Interior Ducts
Water Heater	Heat Pump	Heat Pump
Lighting	0.6 Watts/sq.ft.	0.6 Watts/sq.ft.

Appendix H: Demand Response

INTRODUCTION

The Council's definition of demand response (DR) is voluntary and temporary change in consumers' use of electricity when the power system is stressed. The change in use is usually a reduction, but there could be situations in which an increase in use would relieve stress on the power system and would qualify as DR.

Demand response is similar to conservation in that it occurs on the consumer's side of the meter. However, while conservation is an increase in efficiency that reduces energy use while leaving consumers' levels of service unchanged, demand response is a change in use of electricity at particular times that may change quality or level of service and may in some cases actually increase energy use overall.

This appendix reviews the treatment of demand response in the Council's Fifth Power Plan, reviews progress in understanding and implementation of demand response since the Fifth Plan, and describes the work on demand response in the Sixth Power Plan

DEMAND RESPONSE IN THE COUNCIL'S FIFTH POWER PLAN

The Council's Fifth Power Plan[1] was the first of the Council's plans to consider demand response as a resource.[2] The Plan explained that concern with demand response rises from a disconnect between power system costs and consumers' prices. While costs of providing electricity vary with power system circumstances that change from hour to hour and season to season, electricity consumers seldom see prices that reflect these "real time" costs. This disconnect leads to higher consumption at high cost times than is optimal, with overinvestment in peaking capacity.

The Fifth Power Plan examined two general categories of options to remedy the disconnect, pricing and programs.

Pricing Options

The Fifth Plan outlined the main categories of retail pricing options that have been proposed for incenting demand response. The objective of these options is to give consumers prices that more closely approximate actual system costs through the hours of the year, leading consumers to reduce their usage appropriately when system costs are high. The Fifth Plan described three main categories of time sensitive pricing structures and their advantages and disadvantages:

Real time prices vary with demand and supply conditions as they develop, so that consumers receive efficient signals to guide their usage decisions. Since real time prices will often vary from one hour to the next, they require meters that record hourly use and that can notify customers of the hourly changes in prices. These meters were less common when the Fifth Plan was being developed than they are now, but they are still an obstacle to universal use of real time prices. Real time prices can convey the most accurate reflection of electricity costs as events occur, but they can also be the most volatile of pricing structure, and that volatility has been a concern for many customers and regulators.

Time of use prices are set based on expected costs of serving loads in specified seasons and times of day. Time of use prices are set for a year or more at a time, so are less volatile than real time prices, but they are inherently less able to reflect the unexpected demand and supply situations that occur and that represent the greatest opportunities for demand response to benefit the power system. In short, time of use rates raise less concerns among regulators and ratepayers, but they have less potential benefits.

Critical peak prices can be viewed as a compromise between real time prices and time of use prices. Critical peak prices are usually set at mutiples (4-6 times) ordinary retail rates, but are only in force for a small part of the year, typically 1% of all hours (87 hours/year), limiting volatility in customers' bills. At the same time, critical peak prices have some of the efficiency

[1] The Fifth Power Plan is posted at http://www.nwcouncil.org/energy/powerplan/5/Default.htm, with Chapter 4 on DR at http://www.nwcouncil.org/energy/powerplan/5/(04)%20Demand%20Response.pdf and Appendix H on DR at http://www.nwcouncil.org/energy/powerplan/5/Appendix%20H%20(Demand%20Response).pdf.

[2] According to the strict legal definitions of the Northwest Power Act, demand response is probably not a "resource" but a component of "reserves." For ease of exposition, the Plan refers to demand as a resource in the sense of the general definition of the word - "a source of supply or support."

potential of real time prices, because utilities can call critical peak price events when the system is most in need of demand response (with previous notice, commonly 24 hours).

Program Options

The 5th Power Plan described the main categories of program alternatives to pricing policies to achieve demand response. These program alternatives all involve some form of compensation to customers willing to modify their use, or allow the utility to modify their use, of power when it benefits the power system:

Interruptible contracts have been used for many years to help utilities manage the risk of unexpected problems. For a discount in the customer's underlying price, the utility has the right to cut service to the customer when necessary. The discount and terms of interruption vary.

Direct control has also been used for many years, typically applied to air conditioners. The customer is typically compensated with a seasonal discount in exchange for the utility's right to reduce air conditioning service for a specified number of times during the season.

Demand buyback has been used in the Pacific Northwest and elsewhere to enable customers who were unwilling to make the commitment called for by interruptible contracts or direct control programs to play a part in demand response. Customers participating in demand buyback programs respond on a day-ahead basis to offers from the utility or system operator of payment for load reduction. Typically the utility announces what it is willing to pay for load reduction the next day and the customer responds with an amount of reduction it is willing to make for that level of compensation. The utility notifies customers whose reductions will be compensated usually the afternoon of the day before reductions are needed.

Emergency generation installed in such facilities as hospitals, data centers and office buildings can be dispatched by the local utility, subject to environmental limitations. Arrangements between the utility and the owners of emergency generation can be anything acceptable to both parties, but may include a reservation or capacity payment and an energy payment when the generator is operated.

Estimate of Potential Demand Response

The Fifth Power Plan reviewed DR experience in the Pacific Northwest and elsewhere in the U.S. While the Pacific Northwest pursued some kinds of demand response during the 2000-01 West Coast electricity market crisis, historically the hydroelectric system of our region had made it relatively easy to meet our regional peak demands without demand response. By contrast, elsewhere in the U.S. the costs of meeting peak loads were closely related to building more thermal generation, at higher costs, creating incentives to consider demand side alternatives, i.e. demand response. As a result, demand response experience was generally more common outside the Pacific Northwest.

The Fifth Power Plan made a very simple estimation of the possible size of the demand response, arriving at about 1,600 megawatts[3] by a set of conservative assumptions, and the Plan used 2,000

[3] Page H-13, Appendix H of the Fifth Power Plan

megawatts as the basis for its portfolio analysis of the effect of demand response on long run cost and risk. These estimates matched rules of thumb and experience from around the country, which suggested that demand response potential in the range of 5 per cent of peak load[4] was a reasonable target.

Estimates of Cost Effectiveness of Demand Response

The Plan's exploration of cost effectiveness measures of demand response examined three methods of estimating the generating cost avoided by demand response:

A simplistic estimate of the cost/MWh at an assumed number of hours of operation of a "stand-alone" peaking generator. This method resulted in estimates of $677/MWh to $1,179/MWh for generators running 100 hours/year, with higher costs for generators running fewer hours/year.[5]

The estimation of the incremental cost of electricity from peaking generators added to the existing system, with credit of operational savings and spot market sales from the new units. This estimation used the AURORA® model to simulate the operation of the interconnected power system of the entire Western U.S. along with the Canadian provinces of British Columbial and Alberta and the norther part of Baja California in Mexico. The resulting estimates of avoided cost ranged from $519/MWh to over $14,000/MWh, depending on hydro conditions and reserve margin assumptions.[6]

The simulation of the effect of demand response on the cost and risk of the power system over a range of 750 possible 20-year futures, using the Council's portfolio model. This simulation did not estimate avoided cost, but compared the cost and risk combinations of portfolios that included up to 2000 MW of demand response with fixed costs of $2260/MW-yr and variable costs of $150/MWh,[7] compared to portfolios with no demand response. The comparison showed substantial net reductions in both cost and risk when demand response was included in the portflios. These net benefits clearly indicate that demand response at these costs is cost effective.

The results of the different methods differed, but they all indicated that reductions in demand for electricity at appropriate times could avoid very significant costs, and in the case of the portfolio model method could reduce the financial risks to the system as well.

Action Plan

The Fifth Plan set a target of 500 MW of demand response to be achieved by 2009. This target was not based on detailed analysis of acquisition costs of demand response, since our experience with these costs was slim. Instead, the target was intended to encourage utilities and others in the region to gain experience with demand response, putting future programs and analysis on a firmer basis.

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[4] The system peak load has ranged up to 36,000 MW in the period 1992-2007, Five per cent of this would be 1800 MW.
[5] Page H-16, Appendix H of the Fifth Power Plan
[6] Table H-2, Appendix H of the Fifth Power Plan
[7] Page H-21, Appendix H of the Fifth Power Plan

Finally, the Fifth Plan also included eight action items for the region to accomplish by 2009:

1. Expand and refine existing programs.

2. Develop cost effectiveness methodology for demand response.

3. Incorporate demand response in utilities' integrated resource plans.

4. Evaluate the cost and benefits of improved metering and communication technologies.

5. Monitor cost and availability of emerging demand response technologies.

6. Explore ways to make price mechanisms more acceptable.

7. Transmission grid operators should consider demand response for the provision of ancillary services, on an equal footing with generation.

8. The Council will host several workshops to identify and coordinate efforts to accomplish these action items.

PROGRESS SINCE THE FIFTH PLAN

Action Plan Items

Since the release of the Council's Fifth Power Plan there have been a number of developments related to demand response. Several of these developments are related to the action items just listed:

Action Item 1. A number of existing demand response programs have been expanded. Idaho Power and PacifiCorp have expanded programs that allow them to interrupt air conditioning and irrigation. Portland General Electric has substantially increased the number of their customers' standby generators that PGE can dispatch when necessary.

Action Items 2, 6 and 8. Council staff held 3 workshops in 2005 and 2006. These workshops focused mainly on cost effectiveness methodology. Beginning in 2007 the Council, along with the Regulatory Assistance Project (RAP) and Lawrence Berkeley National Laboratory (LBNL),[8] formed the Pacific Northwest Demand Response Project (PNDRP).

The objective of the PNDRP is to provide suggestions to the region's regulators to help encourage the development of demand response. Consultation with the regulators resulted in narrowly focusing the topics to be taken up by the PNDRP: cost effectiveness methodology, pricing strategies, and the integration of demand response into transmission and distribution planning. By December of 2008 PNDRP had succeeded in agreeing on a set of cost effectiveness guidelines, and began to examine pricing strategies. These cost effectiveness guidelines provide an initial valuation framework for demand response resources and should be

[8] The participation of the RAP and LBNL is supported by the U.S. Department of Energy.

considered as a screening tool by state commissions and utilities in the Pacific Northwest. The cost effectiveness guidelines are at the end of this Appendix in Appendices H-1 and H-2.

The PNDRP is continuing work on pricing strategies in the spring of 2009.

Council staff is also working on incorporating risk into the evaluation of cost effectiveness of demand response, using the Council's portfolio model. Progress in this work is described below, in the "Portfolio analysis of demand response since the Fifth Plan" section.

Action Item 3. Utilities are including demand response in their integrated resource plans, and further expansions of demand response programs are planned.

Action Item 4. Portland General Electric and Idaho Power have begun to install advanced metering for all their customers.

Action Item 5. Council staff and others in the region have continued to monitor potential new demand response technologies. Perhaps the most significant development in this area is the growth of demand response aggregators. These aggregators are not really new technology, rather a combination of existing communication and control technology, together with a business model that calls makes the aggregator the intermediary between the utility and the customer when demand response is needed. The aggregator enlists customers, installs controls on selected equipment on the customers' premises, and guarantees reductions to utilities or system operators when needed. Utilities, both in our region and elsewhere, can "pay for performance" without developing all the program capability themselves, which is attractive to many utilities.

Action Item 7. In the last year or so the combination of increasing demand for electricity together with the necessity to accommodate increasing amounts of wind generation has focused attention on ancillary services, in particular regulation and load following.[9] Bonneville's balancing authority has been the one most affected by wind development in the region, and Bonneville has done significant analysis on the cost of incremental ancillary services. Bonneville also distributed a Request for Information (RFI) in August of 2008, asking for information on generation or loads that could provide regulation or load following to help integrate wind generation.

Achievement of 500 MW of demand response by 2009: The achievement of the 500 MW target for demand response developed by 2009 depends on how the megawatts are counted. Regional utilities have at least 700 megawatts of demand response acquired or planned by the end of 2009. Significant parts of this demand response are outside our region in the eastern part of PacifiCorp's service territory, though this demand response benefits the western part of PacifiCorp's system (in our region) as well. While we cannot precisely allocate the share of total demand response that is in our region, it is less than the 500 megawatts target.

Some of the details of these accomplishments are proprietary, but the major components are: reductions in air conditioning and irrigation by Idaho Power and PacifiCorp, curtailable

[9] More complete discussion of regulation and load following is in Chapter 11.

industrial loads, dispatchable standby generation by Portland General Electric,[10] and day-ahead demand buyback programs by PacifiCorp and Portland General Electric.

While our region as a whole is winter peaking, much of the 2005-2009 experience with demand response affects summer loads. However, even though summer demand response may not reduce the region's absolute peak loads it could have as much or more value than winter demand response. Analysis by the Adequacy Forum[11] suggests that summer peaking capacity may become short before winter peaking capacity. Further, regional spot prices for electricity, heavily influenced by summer peaking loads in California and the Southwest, already tend to be higher in the summer than in the winter. As a result, the experience with summer demand response programs has significant value for the region.

There have also been developments that were not anticipated by the Fifth Power Plan's action items. Several utilities have contracted estimates of supply curves for demand response.[12] This work, based on our current level of experience, cannot foresee all the demand response measures we will eventually discover, or foresee all the means of obtaining demand response we will eventually devise, but the estimates are steps forward in our understanding of demand response.

Portfolio Analysis of Demand Response since the Fifth Plan

Compared to no demand response, including demand response in the Fifth Plan reduced both cost and risk all along the "efficient frontier" of possible portfolios. Since the release of the Fifth Power Plan Council staff have conducted additional portfolio analysis of the effects of demand response. Much of this analysis explored the cost effectiveness of demand response. The work estimated combinations of fixed and variable costs that that result in power system costs and risks that are equivalent to no demand response at all.[13] At these combinations of costs, the costs of the demand response program just balance the reductions in other resource costs. These combinations of costs can be characterized as the "cost effectiveness frontier" and can be illustrated by Figure H-1.

[10] Other utilities have called on customers' standby generation on an ad hoc basis in special circumstances.
[11] See the 2008 Assessment at http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc
[12] Including Bonneville, PacifiCorp, Puget Sound Energy and Portland General Electric
[13] See Appendix H-3 for a detailed description of the work and findings.

Figure H-1 Cost Effectiveness Frontier of Demand Response

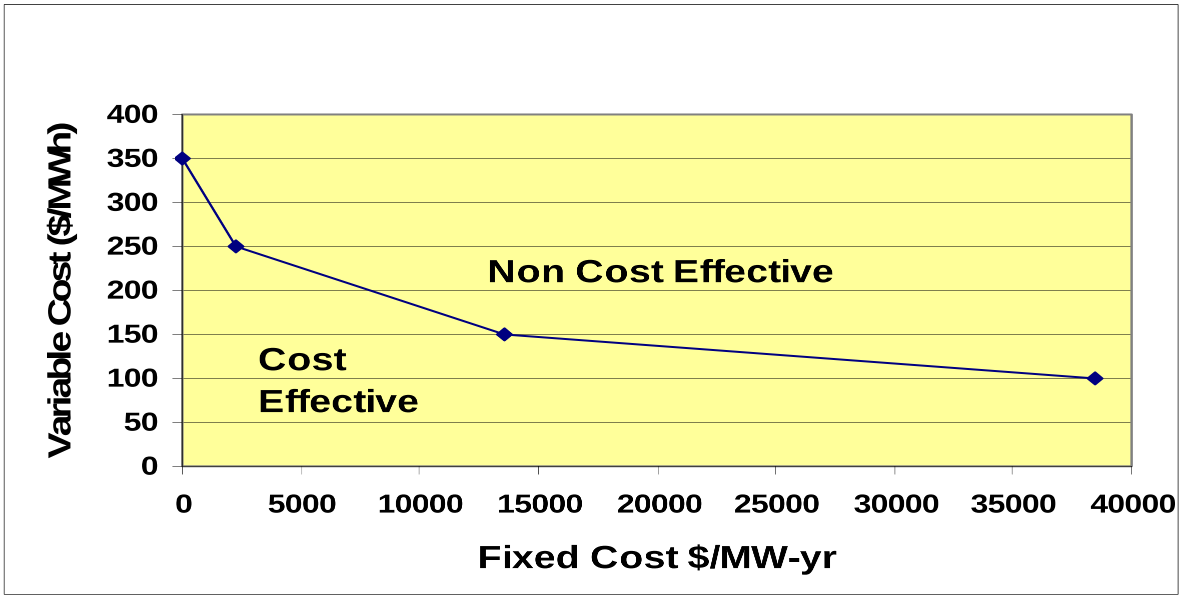

Figure H-1 shows combinations of fixed costs, graphed on the horizontal axis, and variable costs, graphed on the vertical axis. The cost effectiveness frontier divides all possible combinations of fixed and variable costs into two sets, combinations above the frontier and combinations below it. Combinations whose costs graph below the frontier are cost effective; that is, demand response with these costs reduces system costs and risks.

The cost effectiveness frontier offers some advantages to regulators and utility program designers, compared to alternative indicators of cost effectiveness. Since it is based on the Council's portfolio analysis, the effects of demand response not only on cost but also on risk are incorporated. The frontier takes into account the tradeoff between fixed costs and variable costs of demand response, and provides a rough measure of effectiveness that helps identify programs that are worthy of more detailed analysis.

But this cost effectiveness frontier has shortcomings. It represents a single, simplified "generic" demand response program that is available in all seasons at the same cost and capacity, and it is modeled in the portfolio as a resource to help the power system meet peak demand. As has been discussed earlier, we're coming to appreciate that demand response may be able to provide a range of services to the power system, from peak load service, to contingency reserves, to reguation and load following. Some loads may be able to provide more than one of these services. To reflect this world, several demand response programs will need to be simulated in the portfolio model. In addition, the portfolio model currently cannot simulate ancillary services, so the cost effectiveness frontier cannot reflect reflect benefits from ancillary services provided by demand response.

For the time being, the cost effectiveness frontier approach to identifying cost effective demand response is a work in progress, and is not proposed as a proven and mature measure for decision making.

DEMAND RESPONSE IN THE SIXTH PLAN

Estimation of Available Demand Response

The Fifth Power Plan used estimated short-term price elasticities to arrive at a very rough estimate of the potential size of the demand response resource.[14] The estimate was presented not as being accurate within 10 or 20 per cent, but as supporting the potential significance of a resource that we were just beginning to understand. While there is now more experience with demand response, there is still a great deal to learn about how much demand response is possible and how best to achieve it.

The concept of a supply curve for demand response is very attractive -- the region has worked (and still works) on supply curves for conservation, arranging conservation measures and programs in order of increasing costs, to help identify which measures are most attractive and to help identify where to draw the line for cost effectiveness. We'd like similar help with demand response, but some qualities of demand response make the estimation of supply curves for it more complicated:

1. The amount of available demand response varies with season, time of day, and power system conditions. For example, on an August afternoon customers can accept higher temperatures to reduce air-conditioning load, but that response is not available when there is little or no air-conditioning load, such as the cool night hours in most months.
2. Demand response can provide a variety of services to the power system (e.g. peak load service, contingency reserves, regulation, load following) as described later in this Appendix. Each of these services will have its own supply, which will vary over time. To estimate a supply curve for demand response to help meet peak loads we must consider whether some of the same customers and actions will be providing contingency reserves or load following services as well -- otherwise we run the risk of counting the same actions twice in separate supply curves.
3. The costs of demand response are more complex than those of conservation. The costs of conservation are generally fixed, as are the amount and schedule of energy savings. In contrast, demand response often comes with fixed and variable cost components, and requires a "dispatch" decision (by the utility or the customer) to reduce energy use at a particular time. The variable cost of demand response is the major factor in that decision.
4. Displaying demand response in the normal cost vs. quantity format of a supply curve requires some sort of aggregation of the fixed and variable costs into a single measure, such as the "average cost per megawatt of a demand response program that operates 100 hours per year." But a supply curve displaying such aggregated costs may distort critical information about a demand response program. In this example, depending on the variable cost of the program, it may or may not make sense to operate it the assumed 100 hours per year.
5. Estimates of conservation potential have depended on understanding the performance of "hardware" such as insulation and machinery, predictable by engineering analysis. Estimates of demand response, on the other hand, depend more on understanding the behavior of consumers exchanging comfort or convenience for compensation. This behavior is not so predictable without actual experience, which so far is quite limited.

[14] Page A-8, Chapter 4 of the Fifth Power Plan

6. The economics of demand response will be powerfully influenced by technological change, particularly the development of "Smart Grid" technologies,[15] which promise to make more and cheaper demand response available. Such technological change is impossible to predict in specifics, but it seems inevitable that there will be significant change over the next 20 years, and that the change will make demand response more attractive.

With the limited experience available now, a balance must be struck between the precision and the comprehensiveness of estimates of potential demand response. Precise estimates need to be limited to customers, end uses, and incentives where there is experience. These estimates necessarily exclude some possibilities that are virtually certain to have significant demand potential, eventually. Comprehensive estimates avoid this tendency to underestimate potential by including possibilities where there is less experience, but the estimates are therefore less precise.

Each of these approaches has its place. An estimate for a near-term implementation plan must focus on the "precise" end of this spectrum. An estimate for a long run planning strategy, such as the Council's, should focus on the "comprehensive" end. The long term goal should be to expand experience with various forms of demand response to the point that a precise estimate of available demand response is also comprehensive. It's fair to say this goal has been reached in the estimation of conservation potential, but has not yet been reached for demand response, at least for the region as a whole.

Studies of Potential

With these caveats about the limitations of estimating potential demand response based on limited experience, the regional discussions and analysis since the Fifth Power Plan have advanced our understanding of the resource. In our region, Bonneville, PacifiCorp, Portland General Electric, and Puget Sound Energy have contracted studies of potential.

Global Energy Partners and The Brattle Group performed Bonneville's study. The study estimated demand response available through 2020 and included direct load control of residential and small commerical customers, an "Emergency Demand Response"[16] program for medium and large commercial and industrial customers, capacity market options,[17] customers' participation in a market for ancillary services, and two pricing options. The study estimated potential demand response for each of theses options. The estimates took each option alone, with no attempt to estimate the interactions among them -- as a result, adding the estimates together risks double counting some demand response.

Council staff extended this study's results for direct load control, emergency demand response, and capacity market options proportionally to the entire region by assuming that these programs did not double count potential so that they could be summed. The upper end of the range of regional estimates resulting from this extension amounted to about 1.4% of peak load in the winter and 2.2% of peak load in the summer in 2020.

[15] See Appendix K
[16] Customers are offered payment for load reductions during system events, but are not penalized if their usage does not change.
[17] Customers are paid to commit to reduce loads when required by the power system, and receive additional payment when they are actually called to reduce load.

Puget Sound Energy (PSE) commissioned a study by Cadmus in 2009 that is still being revised. Preliminary results indicate that about demand response equal to about 3 per cent of 2029 forecast peak load will be available.

The studies of demand response potential for PacifiCorp and Portland General Electric had not been completed at the time the Draft Sixth Power Plan was written, but are expected soon. Their results may be available in time to include in the final version of the Sixth Power Plan.

Experience

In addition to estimates of demand response available in the future, there is considerable experience around the country with demand response that has been acquired or is in the last stages of acquisition by utilities and system operators. This experience gives some idea of the total amount of demand response that can be expected when utilities pursue it aggressively over a period of time.

In the Pacific Northwest, PacifiCorp has been quite active in acquiring demand response. By 2009, PacifiCorp expected to have over 500 megawatts of demand response, including direct load control of air conditioning and irrigation, dispatchable standby generation, and interruptible load. PacifiCorp also calls on demand buy back and "Power Forward."[18] These last two components are considered non-firm resources, but have combined to provide reductions in the 100 to 200 megawatts range in addition to the 500 megawatts of firm megawatts. The demand response, compared to PacifiCorp's forecasted peak load of 9,800 megawatts for 2009, means that PacifiCorp has more than 5 per cent of peak load in firm demand response, and another 1-2 per cent in non-firm demand response.

Idaho Power had about 60 megawatts of demand response in 2008, made up of direct load control of residential air conditioning and timers on irrigation pumps. The company is committeed to expand their demand response to 293 megawatts by 2013 by converting much of their irrigation demand response to dispatchable[19] and adding demand response from the commercial and industrial sectors. This level would be 7.7 per cent of their projected peak demand in 2013 of 3,800 megawatts. In the longer run the company is planning on reaching 500 megawatts of demand response by 2021, which would make demand response equal to 11.4 per cent of its 2021 forecasted peak demand of about 4,400 megawatts.

Portland General Electric expects to have 125 megawatts of dispatchable standby generation (DSG) in place by 2012. While this generation is licenced to operate 400 hours per year, PGE is using it to provide contingency reserves, which means it only operates when another resource is unexpectedly unavailable, or a much smaller number of hours per year. PGE also has received responses from a Request for Proposals (RFP) asking for proposals to provide demand response up to 50 megawatts by 2012. These responses make the company confident that it can actually secure 50 megawatts of new demand response by 2012. PGE also has 10 megawatts that is interruptible. The sum of these three resources, 185 megawatts, is equal to 4.1 per cent of the company's projected peak load of 4,500 megawatts in 2012.

[18] Power Forward is a program coordinated with the governor's office in Utah that makes public service announcements asking for voluntary reductions from the general public when the power system is stressed. Estimated response varies, but has been as much as 100 megawatts.

[19] Instead of having reductions on fixed schedules, some customers on Monday, some on Tuesday, etc., the company would be able to call on all of the participating customers at the same time when the need arises.

Elsewhere in the country, the New York Independent System Operator (NYISO) has been enlisting and using demand response in its operations for several years. The NYISO currently has about 2,300 megawatts of demand response participating in their programs. About 2,000 megawatts of that total are subject to significant penalties if they don't deliver promised reductions when called upon, so should be considered firm resources. About 300 megawatts of the total are voluntary and are better counted as nonfirm, although the typical response of these resources is around 70 per cent, according to NYISO staff. The 2,000 megawatts of firm demand response amount to about 5.9 per cent of the NYISO's expected 2009 peak load of 34,059 megawatts. Adding the expected 70 per cent of the 300 megawatts of non firm demand response would raise the expected total demand response to 2,210 megawatts, or 6.5 per cent of peak load.

The New England Independent System Operator (ISO) cites 1,678 megawatts of demand response without dispatchable standby generation and 2278 megawatts of demand response with dispatchable standby generation in 2007. These figures are 6.1 and 8.3 per cent of the ISO's average weather summer peak load of 27,400 megawatts, (winter 22,775 megawatts).[20]

PJM Interconnection is a Regional Transmission Organization that manages a wholesale market and the high-voltage transmission system for 13 mid-Atlantic Coast and Midwest states and the District of Columbia. PJM estimates 4,460 megawatts of demand response in its control area in 2008 compared to a forecasted peak load of 137,950 megawatts[21] or about 3.2 per cent of peak load. There may be some demand response in the utilities of states that have been recently added to PJM (Illinois, Ohio, Michigan, Kentucky) that is not included in this total.

California dispatched 1,200 MW of interruptible load on July 13, 2006 to help meet a record peak load of 50,270 MW. California had 1,200 megawatts more of DR available if it had been needed.[22] The 2,400 megawatts of total demand response used and available amounted to 4.8 per cent of actual peak load. By 2011 the three investor-owned utilities expect to have at least 3,500 megawatts of demand response available, or 6.5 per cent of the California Energy Commission's forecast of the three utilities' peak loads total for 2011 (53,665 megawatts).[23]

Portfolio Analysis of Demand Response in the Sixth Plan

In the development of the Council's Sixth Power Plan, the staff considered possible refinements in the treatment of demand response in the portfolio model. The Fifth Plan treated demand response very much like a peaking generator, with especially low fixed costs and high variable costs, but available at all times for as many hours per year as necessary. In fact most demand response is not available at all times (e.g. demand response from irrigation pumping is only available in the summer) and there is generally some fairly low number of hours that customers are willing to tolerate reduced service. To better reflect this reality, the Sixth Plan analyzed

[20] http://www.iso-ne.com/trans/rsp/2008/rsp08_final_101608_public_version.pdf Table 5-7 page 47, Table 5-8 page 49, and Table 3-3 pg 25

[21] http://www.pjm.com/documents/~/media/documents/presentations/pjm-summer-2008-reliability-assessment.ashx

[22] "Harnessing the Power of Demand How ISOs and RTOs Are Integrating Demand Response into Wholesale Electricity Markets" Markets Committee of the ISO/RTO Council October 16, 2007

[23] The California Energy Commission's forecast of the three utilities peak demands can be found at http://www.energy.ca.gov/2007publications/CEC-200-2007-015/CEC-200-2007-015-SF2.PDF, in the Form 4 table for each utility.

demand response programs that are only available seasonally and have a maximum number of hours per season they can be exercised.

The analysis also simulated more than one kind of demand resource program, which will allow examination of the effect of demand response programs with varying proportions of fixed and variable costs on system costs and risks.

Council Assumptions

Based on the studies of demand response potential and experience elsewhere described above, the Council adopted cost and availability assumptions for several demand response programs. For this analysis of long-term planning strategies, the assumptions lean more toward the comprehensive end of the "precise/comprehensive" spectrum. These assumptions were used in the regional portfolio model to analyze the impact on expected system costs and risk of alternative resource strategies. Accordingly, they can be regarded as achievable technical potential, with the portfolio model analysis determining the programs and amounts that are cost- and risk- effective.[24]

The Council based its assumptions in part on the evidence that demand response of at least 5 per cent of peak load has been accomplished by a number of utilities and system operators in periods of five to ten years, so that accomplishing a similar level of total demand response over 20 years in our region is reasonable. The total assumed potential brackets the 5 per cent level, depending on whether the dispatchable standby generation is included or not. Without dispatchable standby generation, the assumed potential is 1,550 megawatts in the winter and 1,750 megawatts in the summer (about 3.9 per cent and 4.4 per cent of the forecast 40,000 megawatt peak load forecast for 2030, respectively). With dispatchable standby generation the totals are 2,550 megawatts in the winter and 2,750 megawatts in the summer, or 6.4 per cent and 6.9 per cent of forecast peak load, respectively.

The assumptions are summarized in Table H-1. Two points are worth making about these assumptions: First, they include demand response that has already been achieved, amounting to more than 160 MW by 2009. Second, they include announced plans to acquire demand response by regional utilities amounting to more than 350 MW

While the Council regards these assumptions as reasonable for the region as a whole, each utility service area has its own characteristics that determine the demand response available in that area. Further, while the allocation of the total potential to individual components is reasonable, more experience could well support changes in the allocation.

For example, ALCOA has offered to provide reserves as part of its proposed contract with Bonneville that could provide from about 15 MW to over 300 MW of demand response, depending on how much aluminum production capacity is operating and the level of compensation. A complete potline (in the case of the ALCOA Ferndale plant, about 160 MW) can be reduced by about 10 per cent for an extended time (i.e. about 16 megawatts for a number of hours) or shut down entirely for at least an hour without the risk of the alumina "freezing" in the pots. If two or more potlines are operating, they can alternate shutting down for an hour, so that load can be reduced by about 160 megawatts on a continuous basis without freezing pots.

[24] For more information about the working of the portfolio model, see Chapter 6.

The alternating potlines would not have to be at the same plant – the result could be achieved by negotiating the cooperation of other smelter owners (e.g. Columbia Falls Aluminum) and other electricity suppliers to aluminum smelters (e.g. Chelan County Public Utility District).

Cold storage facilities for food are estimated to use about 140 MWa of energy in the region and could be interrupted briefly without compromising the quality and safety of food. These facilities have participated in demand response programs in other regions, with reductions in load of 50 per cent at peak load hours. The large thermal mass of food products stored in these facilities allows them to cut load for hours with minimal change in food temperatures. The same quality could also allow a form of energy storage by pre-cooling the product slightly below nominal temperatures if the power system has a temporary (i.e. a few minutes or hours) surplus of energy.

As the region gains more experience with as-yet-unexamined resources such as these, the Council will revise its assumptions on potential for demand response.

Table H-1: Demand Response Assumptions

Program	MW	Fixed Cost	Variable Cost or hours/year limit	Season available
Air Conditioning (Direct Control)	200	$60/kW-year	100 hours/year	Summer
Irrigation	200	$60/kW-year	100 hours/year	Summer
Space heat/Water Heat (Direct Control)	200	$100/kW-year	50 hours/year	Winter
Aggregators (Commercial)	450	$70/kW-year	$150/MWh 80 hours/year	Summer + Winter
Interruptible Contracts	450	$80/kW-year	40 hours/year	Summer + Winter
Demand Buyback	400	$10/kW-year	$150/MWh	All year
Dispatchable Standby Generation	1,000	$20-$40/kW-year	$175-300/MWh	All year

The resource programs examined were:

Direct load control for air conditioning. Direct control of air conditioners, by cycling or thermostat adjustment, is one of the most common DR programs across the country, and is most attractive in areas where electricity load peaks in the summer. The Pacific Northwest as a whole is still winter-peaking, but new forecasts show the region's summer peak load growing faster than winter peak load. PacifiCorp's Rocky Mountain Power division and Idaho Power already face summer-peaking load. The two utilities have acquired and exercised more than 100 peak megawatts of demand response from direct control of air conditioning. Most of those 100 megawatts are outside the Council's planning region, in Utah. Air conditioning is increasing in the region as a whole, as is the importance of the summer peak load in the region. The assumption for the portfolio model analysis is that there will be 200 megawatts of this resource in the region by 2030. Based on PacifiCorp's experience, the resource is assumed to cost $60 per kilowatt a year and to be limited to 100 hours per summer.

1. Irrigation. PacifiCorp and Idaho Power are currently reducing irrigation load by nearly 100 MW by scheduling controls. Both utilities are in the process of modifying their programs to give them more control of the resource, increasing the load reduction

available when the utilities need it. There is significant irrigation load elsewhere in the region as well. The assumption for the portfolio model analysis is that 200 MW of irrigation DR will be available by 2030. Based on PacifiCorp's experience, this resource is assumed to cost $60 per kilowatt a year, limited to 100 hours per summer. Since the adoption of these assumptions for the draft plan, the Council has learned that the planned acquisition of demand response from irrigation by Idaho Power alone would exceed 200 megawatts.

2. Direct load control of space heat and water heat. While there has been some experience with direct control of water heating in the region, experience with direct control of space heating is limited. The assumption for the portfolio model analysis is 200 megawatts, at $100 per kilowatt a year for a maximum of 50 hours per winter. These assumptions are informed by the Global Energy and Brattle Group study for Bonneville. The megawatt assumption is about half the study's estimate for residential and commercial direct control programs when the study's most optimistic result is extended from Bonneville's customers to the whole region.

3. Aggregators. Increasingly, aggregators facilitate demand response by acting as middlemen between utilities or system operators on the one hand and the ultimate users of electricity on the other. These aggregators are known by a variety of titles such as "demand response service providers" for the independent system operators in New York and New England and "curtailment service providers" for the PJM regional transmission organization. Aggregators could recruit demand response from loads already described here, in which case aggregators would not add to the total of available demand response. But in the Council's analysis, aggregators are assumed to achieve additional demand response by recruiting commercial and small industrial load that is not otherwise captured in the assumptions. This resource is assumed to be 450 megawatts. The assumed fixed costs of $70 a kilowatt per year and variable costs of $150 per megawatt hour are based on conversations with aggregators. The resource is assumed available for a maximum of 80 hours during the winter or summer.

4. Interruptible contracts. Interruptible contracts offer rate discounts to customers who agree to have their electrical service interrupted under defined circumstances. This is an old mechanism for reducing load in emergencies, although in some cases they became de facto discounts with no expectation that the utility would ever actually interrupt service. These contracts are usually arranged with industrial customers, and PacifiCorp has about 300 megawatts of interruptible load under such contracts. The assumption for the portfolio analysis is that 450 megawatts will be available by 2030 at a fixed cost of $80 a kilowatt per year, limited to 40 hours any time during the year. The costs of existing interruptible contracts are considered proprietary, so the Council's cost assumption is based on conversations with aggregators.

5. Demand buyback. Utilities with demand buyback programs offer to pay customers for reducing load for hours-long periods on a day-ahead basis. Early in the 2000-2001 energy crisis, Portland General Electric conducted a program that had significant participation. Other utilities were developing similar programs, but the idea of buying back power for several hours a day was overtaken by high prices in all hours, and deals were made that bought back power for months rather than hours (mostly from Direct

Service Industries). Since 2001, the most active buyback program has been PacifiCorp's program. Buyback programs still exist elsewhere in principle, but have not been maintained in a ready-to-use state. While this option could be replaced by expanded aggregator programs, the assumption for the Council's portfolio model analysis is that demand buyback programs with customers who deal directly with utilities (not through aggregators) could amount to 400 megawatts by 2030, at fixed costs of $10 a kilowatt per year and variable costs of $150 per megawatt hour available all year. These cost assumptions are based on the experience of Portland General Electric with its Demand Exchange program in 2000-2001.

Dispatchable standby generation. This resource is composed of emergency generators in office buildings, hospitals, and other facilities that need electric power even when the grid is down. The generators can also be used by utilities to provide contingent reserves, an ancillary service. Ancillary services are not simulated in the portfolio model, but dispatchable standby generation is nevertheless a form of demand response that has significant potential and cannot be overlooked. Portland General Electric has pursued this resource aggressively, taking over the maintenance and testing of the generators in exchange for the right to dispatch them as reserves when needed. PGE has 53 megawatts of dispatchable standby generation available in early 2009, and plans to have 125 megawatts by 2012. This potential will grow over time as more facilities with emergency generation are built and existing facilities are brought into the program. The Council assumes that at least 300 megawatts would be available in PGE's service territory by 2030, and that the rest of the region will have at least twice as much, for a total of about 1,000 megawatts by 2030. Based on Portland General Electric's program, cost assumptions are $20-$40 per kilowatt per year fixed cost and $175-$300 per megawatt hour variable cost, available all year.

The dispatchable standby generation component was not modeled by the regional portfolio model, since it is expected to be used for contingency reserves, which cannot be represented in the model. The other programs were simulated in the portfolio model, with schedules based on those in Table H-2. The air conditioning and irrigation programs were treated as one program, since their costs and dispatch constraints were identical. That program, the space and water heating program, the aggregators component, and the interruptible contracts component were modeled similarly. For each of these components, the portfolio model could try:

1. No demand response at all,

2. Demand response on the 2009-2019 schedule in Table H-2 followed by no additional demand response,

3. No demand response for 2009-2019 followed by demand response in 2019-2029 following the 2009-2019 schedule in Table H-2,

4. Demand response for 2009-2029 on the schedule in Table H-2.

Previous analysis with the portfolio model has shown the demand buyback program to consistently reduce costs and risks. It was modeled on the schedule shown in Table H-2.

Table H-2: Schedule of Demand Response Programs in the Regional Portfolio Model

Program	Megawatts										
	2009	2011	2013	2015	2017	2019	2021	2023	2025	2027	2029
AC and Irrigation	100	200	230	260	290	320	350	380	400	400	400
Space and Water Heat		10	20	30	40	50	70	90	120	160	200
Aggregators		20	60	100	150	200	250	300	350	400	450
Interruptible Contracts		50	100	150	200	250	300	350	400	450	450
Demand Buyback	70	100	130	160	190	220	250	290	340	370	400

Pricing Structures

The Council is not making assumptions now about the amount of demand response that might be available from pricing structures. There is no doubt that time-sensitive prices can reduce load at appropriate times, but the region does not yet appear to be ready for general adoption of these pricing structures. While hourly meters are becoming more common, most residential customers don't yet have them, which makes time-of-day pricing, critical peak pricing, peak time rebates, and real time prices unavailable to those customers for the time being. Many in the region are concerned that some customers will experience big bill increases with different pricing structures. There is also the potential for double counting between demand response programs and any pricing strucuture initiatives.

The Pacific Northwest Demand Response Project, co-sponsored by the Council and the Regulatory Assistance Project is taking up the subject of pricing structures as a means of achieving demand response in the spring of 2009. In addition, Idaho Power and Portland General Electric are launching pilot projects for time-sensitive electricity prices, which can be expected to provide valuable experience not only for those utilities but the region as a whole.

Providing Ancillary Services with Demand Response

Demand response has usually been regarded as an alternative to generation at peak load (or at least near peak load), which occur a few hours per year. Because demand response for this purpose is only needed a few hours a year, customers need to reduce their usage for only a few hours a year. The load whose reduction provides such demand response need not be year-round load, as long as the load is present during hours when system load is at or near peaks (the most familiar example is air conditioning load for summer-peaking systems).

But demand response can do more than help meet peak load. It can help provide ancillary services such as "contingency reserves" and "regulation and load following." Historically ancillary services have not been considered a problem in the Pacific Northwest, but as loads have grown, and especially as wind generation has increased, power system planners and operators have become more concerned about ancillary services (see Chapter 11 of this plan). Not all demand response can provide such services, since they have different requirements than meeting peak load.

Ancillary services are not simulated in the Council's portfolio model, so the potential value of demand response in this area will not be captured in the model's analysis. Nevertheless, the potential cannot be ignored, and the subject should be pursued as one of the demand response action items.

Contingency Reserves

In some respects providing contingency reserves with demand response is similar to meeting peak loads with demand response. In both cases load reductions of a few hours per year are likely to meet the system need.[25]

But in other respects providing contingency reserves requires somewhat different demand response than meeting peak loads. To provide contingency reserves during non-peak load hours, demand response will require reductions in end use loads that are present in those hours. For example, residential space heating cannot provide reserves in the summer; residential air conditioning cannot provide reserves in the winter; but commercial lighting and residential water heating can provide contingency reserves throughout the year.

Regulation and Load Following

Providing regulation and load following with demand response presents new requirements, compared to serving peak loads. Regulation is provided by generators that automatically respond to relatively small but quite rapid (in seconds) variations in power system loads and generation. Load following is provided by larger and slower adjustment in generator output in response to differences between the amount of prescheduled generation and the amount of load that actually occurs. Regulation and load following are needed in virtually every hour of the year, and require that generation be able to both increase and decrease.

Many customers who would be willing to provide demand response for meeting peak loads will not be available for regulation or load following. Providing regulation or load following with demand response would involve decreasing or increasing loads in virtually every hour.[26] Customers who are willing and able to decrease and increase use when the power system needs it will be harder to recruit than those who are willing and able only to decrease loads. Even if customers are asked only to decrease loads, many of them who could participate in, for example, a 100 hour per year demand response program that helps meet peak loads, will not be able participate in a load following program that requires thousands of actions per year.

While demand response that can provide regulation or load following will be a subset of all possible demand response, there may well be a useful amount. What kinds of loads make good candidates for this kind of demand response?

One example would be pumping for municipal water systems. Such systems don't pump continuously -- they fill reservoirs from which water is provided to customers as needed. The schedule of pumping can be quite flexible, as long as the reservoir level remains somewhere between specified minimum and maximum levels. For such a load, the water utility could specify the total amount of pumping for the next 24 hours based on its customers' expected usage, and allow the power system to vary the pumping over the period to help meet variation in the power system's loads (and variation of wind generation), as long as the total daily pumping

[25] Contingency reserves are only called to operate when unexpected problems make the regularly scheduled resource unavailable, which occurs infrequently. Further, utilities are required to restore reserves within 105 minutes, so that the reserves' hours of operation per occurrence are limited. The result is that actual calls on contingency reserves are likely to be a few hours per year.

[26] It may be possible to achieve an equivalent effect by a combination of loads that can make reductions when necessary together with generation that can make reductions when necessary. One such combination could be DR and wind machines.

requirement is satisfied. Presently, accomplishing this degree of coordination between the power system and its customers is probably not practical, but with the Smart Grid's promise of cheaper metering and communication and more automated control, it could become so.

Another example is the charging load for plug-in hybrid cars (PHEVs). Many parties have suggested this possibility, and the general outline of these cars' potential interaction with the power system is common to most proposals -- the PHEVs' individual batteries together act as a large storage battery for the power system whenever they are connected to the grid, at home, at work or elsewhere. This aggregate battery accepts electricity when the cost of electricity is low (e.g. at night) and gives electricity back to the system when the cost is high (e.g. hot afternoons or during cold snaps). The Smart Grid could coordinate[27] this exchange.[28]

Domestic water heating is yet another example of a load that could be managed to provide regulation or load following to the power system. In this case we have enough information to make a rough estimate of how much flexible reserve could be available. Current estimates of the region's total number of electric water heaters run in the 3.4 million range. If each of these heaters has heating elements of 4500 watts, the total connected load is about 15,300 megawatts. Of course water heaters are not all on at the same time, but load shape estimates suggest that the total water heating load on the system ranges from about 400 megawatts to about 5300 megawatts, depending on the season, day and hour.

In normal operation water heaters' heating elements come on almost immediately when hot water is taken from the tank, to heat the replacement (cold) water coming into the tank. But if the elements don't come on immediately, the water in the tank is stratified, hot at the top and cold at the bottom. Opening a hot water faucet continues to get hot water from the top of the tank until the original charge of hot water in the tank is gone. This means that heating the replacement water can be delayed (reducing loads) for some time without depriving water users of hot water. Based on the load shape estimates cited above, the maximum available reduction ranges from about 400 to about 5300 megawatts, depending on when it is needed.

But to provide regulation or load following, reductions aren't sufficient -- loads need also to be increased when the power system needs it. An example of such a condition is 4:00 AM during the spring runoff, when demand for electricity is low, river flows cannot be reduced, not much non-hydro generation is operating, and winds are increasing. System operators have too much energy and few good options – they can cut hydro generation by increasing spill, which loses revenue and can hurt fish, or they can require wind machine operators to feather their rotors, losing both market revenue and production tax credits.

Water heating can help absorb this temporary surplus of energy and make productive use of it. Water heating loads can be increased up to the maximum connected load, but the duration of the increase will be limited by the rise in water temperature above its normal setting that we allow. If, for example, we allow the temperature to rise from 120 degrees F to 135 degrees F, 3.4 million 50 gallon water heaters can accept 6198 megawatt hours of energy, store it (at the cost of

[27] A common assumption is that this coordination includes a requirement that the charge in the PHEV's battery at the end of the day is sufficient to get home. Even if requirement is not met, however, PHEV's have the ability to charge their own batteries, so they are not stranded.
[28] A more detailed description of how PHEVs could contribute to the power system is at Appendix K-1.

roughly 24 megawatt hours per hour higher standby losses) and return it to the system in the form of a reduction in hot water heating requirement in a later hour.[29]

There are other loads that have some sort of reservoir of "product," a reservoir whose contents can vary within an acceptable range. The "product" might be crushed rock, compressed and cooled air (in the process of air separation), stored ice (for commercial building air conditioning), pulped wood for paper making, or the like. This reservoir of "product" could allow the electricity customer to tolerate variation in his rate of electricity use to provide ancillary services to the power system, assuming that the customer receives adequate compensation.

There is an industrial plant in Texas that provides 10 megawatts of regulation to the Electricity Reliability Council of Texas (ERCOT) the independent system operator of the Texas interconnected power system. ERCOT's rules keep plant information confidential, but it is understood that the plant's process is electrochemical, and that its unique situation makes unlikely that many other plants could provide regulation to the power system.

[29] This rise could result from an increase in load of 6198 MW for an hour, or an increase in load of 3099 MW for two hours, etc. See Appendix K for a fuller description of providing reserves, load following and energy storage using water heaters.

Appendix H1: Demand Response

Guidelines for Cost-effectiveness Valuation Framework for Demand Response Resources in the Pacific Northwest - from the Pacific Northwest Demand Response Project

Background

In May 2007, the Pacific Northwest Demand Response Project (PNDRP) agreed to form several Working Groups to explore demand response (DR) issues in more detail (Cost-effectiveness, Pricing, and Integrating DR into Distribution System Planning and Investment). In July 2007, the Cost-Effectiveness Working Group met for a one-day workshop in Portland Oregon, which included presentations by a number of utilities on valuation approaches used for DR resources. In January 2008, draft guidelines for a DR Cost-effectiveness valuation framework were presented and discussed at a Working Group workshop.[1] In September 2008, the draft final guidelines were presented and discussed at a Working Group workshop; participants provided comments and suggestions. At that meeting, there was consensus among participants on the guidelines and that the final guidelines document should be provided to the Northwest Power and Conservation Council to be included as an Appendix in the Sixth Pacific Northwest Power and Conservation Plan. This document offers proposed guidelines for a cost-effectiveness valuation framework for Demand Response Resources that could be considered as a screening tool by state commissions and utilities in the Pacific Northwest.

Purpose

The primary purposes of a cost-effectiveness valuation framework for DR resources are to:

- Propose workable methods for state commissions, utilities and others to consider for valuing the benefits and costs of different types of DR resources in long-term resource planning;
- Provide methods that can be used in *ex ante* screening of DR programs for cost-effectiveness and to evaluate the treatment of a portfolio of DR resources/program options in an integrated utility resource plan;
- Document value of demand response for the purpose of rate setting.

Demand Response Resources

- Demand Response resources (DRR) are comprised of flexible, price-responsive customer loads that may be curtailed or shifted in the event of system emergencies and system operational needs or when wholesale market prices are high.
- It is useful to characterize Demand Response resources in terms of their "firmness" as a resource option from the perspective of the utility.
- Firm DSM Resources (Class 1)

[1] The Draft Guidelines were developed based on discussions among participants in the PNDRP Cost-effectiveness Working Group and our review of DR valuation studies and cost-effectiveness proceedings currently underway in other jurisdictions (see References).

- This class of DR resources allows either interruptions of electrical equipment or appliances that are directly controlled by the utility or are scheduled ahead of time. These resources can include such programmatic options as fully dispatchable programs (e.g. direct load control of air conditioning, water heating, space heating, commercial energy management system coordination) and scheduled firm load reductions (e.g. irrigation load curtailment, thermal energy storage).[2]

- "Non-firm" DSM resources (Class 3)
    - DR resources in this group are typically outside of the utility's direct control and include curtailable rate tariffs, time-varying prices (e.g., real-time pricing, critical peak pricing), demand buyback, or demand bidding programs.

Guidelines and Principles

1) Treat DR resources on par with alternative supply-side resources and include them in the utilities' integrated resource plans and transmission system plans.

2) Distinguish among DR programs with respect to their design purpose, dispatchability, response time, and relative certainty regarding load response (e.g., firmness).

3) In assessing cost-effectiveness of DR resources, it is important to account explicitly for all potential benefits, including avoided/deferred generation capacity costs, avoided energy costs, avoided T&D losses, deferred/avoided T&D grid system expansion, environmental benefits, system reliability benefits, and benefits to participating customers.

4) Incorporate the temporal and locational benefits of DR programs systematically (e.g. estimate avoided costs at hourly level, treat transmission congestion zones separately). Most of the benefits of DR resources are related to avoiding relatively low probability future events (e.g. unusually high peak demand or energy prices) in relatively few hours, whose occurrence could have significant economic consequences.

5) All DR program incentive and administration costs, costs of enabling technology, and participant costs should also be included. For DR programs in which customers have to voluntarily enroll, it can be assumed that total costs incurred by participants are less than or equal to the benefits, otherwise they would be unlikely to sign up and participate.[3]

6) DSM programs are often screened using a set of benefit-cost tests that compare and assess the benefits and costs from different perspectives (i.e., society, utility, participants,

[3] For participants, benefits include bill reductions and any financial incentives paid, tax credits (if available) and non-energy benefits; costs include capital and O&M costs associated with installation of DR enabling technologies, the value of service lost (e.g. reduced productivity and/or comfort), and transaction costs. As a practical matter, this means that for a voluntary DR program, utilities can assume that the benefit/cost values for the Participant Test are greater than one.

and non-participants).[4] These tests are not intended to be used individually or in isolation; results from the various tests should be compared and trade-offs between tests considered.[5] These benefit-cost tests may need to be modified and adapted in some areas to account for the distinctive characteristics and features of DR resources.

7) Utilities should consider conducting sensitivity analysis on key benefit and cost variables that have significant uncertainties which can have a major impact on program cost-effectiveness (see Appendix F-1A for examples of the proposed cost-effectiveness screening method).

8) Initiate and conduct DR pilot programs to assess market readiness, barriers to customer participation and to obtain information on customer performance that can be used to characterize the timing and duration of load impacts for long-term resource planning. Pilot programs need to include exercises of "non-firm" DR resources with a view to identifying a fraction of the resource that could be treated as firm for planning purposes.

Benefits of DR Resources

1) Avoided Generation Capacity Costs
    a. "Firm" DR resources, when directly incorporated into a utility's resource and reliability planning processes, can avoid the need for a relatively high heat rate generating capacity. The market value of that type of generating capacity will typically be based on a new natural gas-fired combustion turbine (CT).
    b. There is not a consensus on methods to determine the market value of new generating capacity avoided by a DR resource. Some parties in the Pacific Northwest have raised concerns about the appropriate way to value capacity when the region is long on power.[6] Moreover, market prices for new capacity are not widely available.
    c. In the interim, using a benchmarking method that estimates the costs of a new gas-fired CT as a proxy to derive the market value of avoided generation capacity is a reasonable approach for screening DR programs.[7] *These costs have typically been estimated to range between $50-85 per kW-year in the past, but recent increases in costs have resulted in estimates of over $100 per kW-year.*
    d. Estimates of hourly market prices for new generation capacity can be derived by allocating the estimated annual market price of generation capacity ($/kW-yr)

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[4] See *California Standard Practice Manual Economic Analysis of Demand Side Programs and Projects, October 2001* as one example. http://www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF
[5] PUCs and utilities may consider using the Total Resource Cost (TRC) or Societal Test as the primary test in screening DR programs.
[6] Similarly, in California, the investor-owned utilities have proposed to offset the present value of the total fixed costs of that new CT by the present value of the gross margins that the new CT capacity is expected to earn from selling energy when wholesale electricity market prices exceed variable costs. Other parties in California (e.g. industrial customers) disagree with the method proposed by the California utilities.
[7] In estimating CT costs, utilities should annualize total investment using a real economic carrying charge rate that takes into account return, income taxes, and depreciation, with O&M, ad valorem and payroll taxes, insurance, costs associated with obtaining firm gas transmission, and capital costs incurred to comply with existing environmental regulations including acquisition of offsets for criteria pollutants.

among the hours in each year, in proportion to the relative need for generation capacity in each hour. Utilities, regulators, and other stakeholders should agree on method(s) to allocate avoided generation capacity costs to specific time periods that is appropriate for the Pacific Northwest power system.[8]

e. Avoided T&D losses and Reserve margin -- The resulting estimates of generation capacity costs avoided by DR program should be adjusted upward to reflect the T&D line losses avoided by that DR resource capacity and the capacity planning reserve margin avoided by that DR program.[9]

f. The capacity benefits of a DR resource should also be adjusted for differences that reflect operational program constraints (e.g., limits on the months, days, and/or hours in which DR program events can be called; limits on maximum duration of program events, limits on number of consecutive days on which program events can be called) compared to the capacity value of a new CT (including limits on the use of a CT).

2) Avoided Energy Costs

a. DR resources typically result in load shifting from peak to off-peak periods or load curtailments in which customers forego consumption for relatively short time periods. Thus, DR resources also enable utilities to avoid energy costs.

b. Because utilities can always buy or sell electricity in the wholesale energy market, the expected wholesale market electricity price in each future time period is the relevant opportunity cost for estimating the value of electricity that will be avoided by a DR resource.

c. Avoided energy costs should be adjusted upward to reflect distribution system line losses that DR load reductions would avoid in event hours.

d. Avoided energy costs can be particularly important in evaluating DR programs from the participants' perspective as they tend to directly affect customer bills.

e. DR program events are most likely to be called in hours when prices are higher than expected; using expected hourly prices will tend to under-estimate actual electricity market prices in the hours in which an event-based DR program is called and will reduce loads.

f. Avoided energy costs may be estimated using several options: (1) wholesale energy prices averaged over the highest priced hours of a price forecast, and (2) stochastic methods (e.g., Monte Carlo simulations) that analyze the correlation between electricity prices and times that DR events are expected to occur and explicitly address the uncertainty in future loads, prices, hydro conditions in the Pacific Northwest regional utility system.

3) Deferred Investments in Transmission and/or Distribution System Capacity

a. The transmission and distribution system is comprised of three key elements: interties, local network transmission, and local distribution systems.

b. DR programs that provide highly predictable load reductions on short notice may allow utilities to defer and/or reduce transmission and/or distribution (T&D) capacity investments in specifically defined congested locations on the grid. This

[8] In California, the utilities have proposed allocating the annual market value of new CT capacity to individual hours in proportion to the loss of load expectation (LOLE) in each hour.

[9] T&D losses will typically be higher during peak periods compared to average values for T&D losses.

may lead to a reduction in a utility's projected T&D capital budget and thus avoid some T&D costs.[10]

   c. Utilities should consider one of two options in estimating avoided T&D costs: (1) develop a default avoided T&D cost which may be applied to DR programs that meet pre-established criteria regarding locational value and certainty of load reductions or (2) estimate avoided or deferred T&D capacity investments on a case specific basis.[11]
   d. The default avoided T&D costs can be calculated by using marginal costs associated with local transmission and distribution substation equipment, which is principally related to transformer capacity.[12]

4) Environmental Benefits (and Costs)
   a. DR resources have the potential to produce environmental benefits by avoiding emissions from peaking generation units as well as some potential conservation effects (i.e. through load curtailments, foregoing usage).
   b. Assessing the environmental impacts of DR resources depends primarily on the emissions profile of the utility's generation resource mix as well as participating customer's DR strategy (e.g., load curtailment vs load shifting vs onsite generation).
   c. For DR resources that result in load curtailments, a reasonable proxy for estimating the volume of greenhouse gas (GHG) emissions avoided by a DR resource is to base it on the operating and emission rate characteristics of a new CT.

5) Reliability Benefits
   a. DR resources can provide value in responding to system contingencies that compromise electric system operator's ability to sustain system level reliability and increase the likelihood and extent of forced outages.
   b. In the context of long-term resource planning, joint consideration of economic (avoided capacity and energy) benefits and reliability benefits is challenging. In an IRP plan, the value of DR hinges primarily on its ability to displace some portion of the utility's peak demand. Once DR resources are included in the utility's projected capacity resource mix, they become part of planned capacity and are no longer available for dispatch during system emergencies.

   c. Customers participating in emergency or other "non-firm" DR programs are not counted on as system resources for planning purposes; they represent an

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[10] The extent to which DR programs may defer or avoid specific T&D capital investments depends on: 1) the characteristics of the individual utility system, 2) the specific T&D investment proposed, 3) the characteristics of the customer load to be served by the proposed T&D investment, 4) the attributes of the proposed DR program, and 5) the level of uncertainty associated with the projected load impacts of the DR program.

[11] The specified criteria for DR programs are designed to limit application of avoided T&D costs to DR programs that: (1) are located in areas where load growth would result in need for additional delivery infrastructure, (2) are capable of addressing local delivery capacity needs, (3) have sufficient certainty of providing long-term reduction that the risk to utility of incurring after-the-fact distribution system replacement costs is modest, and (4) can be relied upon for local T&D equipment loading relief.

[12] Marginal T&D costs often include local T&D lines, towers and power poles, underground conduit and structures which are added as service is extended into new geographic areas; these costs are generally not related to peak demands in a specific area and are typically not avoided by a DR program.

additional resource for reliability assurance; distinct from "firm" DR programs that are counted among planned reserves.[13]

d. In assessing the value of these emergency-type DR programs, a reasonable proxy for monetizing the value of load curtailments is the product of the value of lost load (VOLL) with typical values between $3-5/kWh and the expected un-served energy (EUE).[14]

6) "Hard to quantify" benefits
   a. Some potential benefits of demand response are inherently difficult to quantify. Examples of "hard to quantify benefits" include: the long-term educational value of customers being exposed to and having a choice of how to respond to time-varying wholesale market prices or customer satisfaction in helping to avert system emergency. These non-quantifiable benefits are likely to be small but state PUCs may also want to consider them in assessing dynamic pricing (if appropriate).

DR Resource Costs

7) Program Administration Costs
   a. Utilities will incur initial and ongoing costs in operating DR programs. Incremental program costs attributable to DR resources can include program management, marketing, customer education, on-site hardware, customer event notification system upgrades, and payments to third party curtailment service providers that implement aspects of a DR program.

8) Customer costs
   a. Customer costs are defined as those costs incurred by the customer to participate in a DR program and can include investments in enabling technology to participate, developing a load response strategy, comfort/inconvenience costs, rescheduling costs for facility workers, or reduced product production.
   b. For a voluntary DR program, it is reasonable to assume that participant costs are less than or equal to the incentives offered by the program; otherwise most customers would not voluntarily chose to participate.[15] The exceptions are those customers who believe participation is the right thing to do, regardless of their personal costs

9) Incentive payments to participating customers
   a. Incentive payments are paid to customers participating in DR programs to encourage them to enroll initially and continue in the program. Incentives also

[13] Emergency DR programs provide incremental reliability benefits at times of unexpected shortfalls in reserves. When all available resources have been deployed and reserve margins still cannot be maintained, curtailments under an emergency DR program reduce the likelihood and extent of forced outages.

[14] Expected unserved energy (EUE) is a measure of the magnitude of a reserve shortfall which takes into account the change in the likelihood of curtailment (i.e. loss of load probability) and the amount of load at risk.

[15] One possible exception are those customers that are motivated by civic responsibility and believe that participation in a DR program and responding to a electric power system emergency are the "right thing" to do, regardless of their personal costs.

compensate customers for any reduction in the value of service that they would normally receive (e.g. higher household temperatures during an A/C cycling event or increased costs when a business shuts down some of its equipment when an emergency event is called).

b. For voluntary DR programs, in evaluating cost-effectiveness, it is reasonable to assume that total customer costs incurred by participants will be equal to the present value of incentives expected to be paid.[16]

10) Characterizing DR Resource Costs

a. It is reasonable to ramp up enrollment in DR programs over a multi-year period (e.g. 3-4 years) and to match the time horizon of DR costs and benefits (e.g. use expected life of DR enabling technology in assessing benefits).

b. In modeling DR program options, it is useful to categorize costs into fixed expenses (program development, ongoing administration, communication and data acquisition infrastructure) and variable costs (e.g. incentive payments to customers, participant acquisition costs, other program costs that vary with number of participants or the number of times that DR program events are called).).

11) Relationship between DR screening and portfolio analysis

a. A long-term resource plan that includes a portfolio analysis and accounts for the uncertainties in future loads, prices, and resources, is the preferred approach to fully value the benefits of DR resources

b. In screening DR resources and program concepts, it is also useful to establish cost-effectiveness thresholds that allow regulators and utilities to estimate whether a DR program is worthwhile to pursue.

References on DR Cost-effectiveness and Valuation

U.S. Department of Energy (2006). “Benefits of DR in Electricity Markets and Recommendations for Achieving them: A Report to U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005,” February 2006.

Quantec 2006. “Demand Response Proxy Supply Curves,” prepared for Pacificorp, September 8, 2006.

CPUC (2007). “Order Instituting Rulemaking Regarding Policies and Protocols for Demand Response Load Impact Estimates, Cost-effectiveness Methodologies, Megawatt Goals and Alignment with California System Operator Market Design Protocols,” OIR 07-01-041, Jan 25, 2007.

CPUC Energy Division (2008). *Draft Demand Response Cost-effectiveness Protocols.* April 4, 2008.

[16] It is reasonable to treat incentive payments in voluntary DR programs as compensation for any loss of service or out of pocket costs that participating customers expect to incur under the assumption that the customer would not participate if the incentive wasn’t sufficient to offset these costs.

Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company (2007). *Revised Straw Proposals For Demand Response Load Impact Estimation and Cost Effectiveness Evaluation*, September 10, 2007 (http://docs.cpuc.ca.gov/efile/REPORT/72728.pdf)

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Attachment H1-A

Examples of Cost Effectiveness Screening Methodology

We have constructed two prototypical demand response programs - a direct load control water heater program and a smart thermostat air conditioning program – in a spreadsheet-based tool to illustrate how the Cost Effectiveness screening methodology may be applied to specific demand response programs.[17] . The spreadsheet tool includes "typical" first-year values and compound annual growth rates for key model inputs on costs and load impacts; LBNL established "typical" values for key inputs based on our analysis of reference values (i.e., minimum, average, median, and maximum values) observed in pilot and full-scale DR program evaluations from the Pacific Northwest and a review of the DR program planning and evaluation literature. Users of the spreadsheet tool have the capability to change model inputs based on their assessment of appropriate model input values for DR programs under consideration and can use the Reference Values as a guide to the range of values observed in the Pacific Northwest.

Direct Load Control – Water Heater

This program targets single-family residential customers with standard-sized electric water heaters. A control switch is installed in each participant's home near the water heater circuit breaker, which is then controlled via a one-way pager signal to trip the relay on and off according to the received message. Curtailments are initiated during peak hours of winter weekdays (i.e., mornings and/or afternoons) and are not expected to exceed sixty hours each year (i.e., fifteen events at four hours/event). A sample of participants will also have interval meters installed to help program administrators document and verify the achieved level of demand savings during program events. We assume an average event performance rate of 95% for this DLC program (i.e., 5% of the customer switches fail to respond).

Figure H1-A-1 summarizes information on market penetration, aggregate load impacts, economic and reliability benefits, and costs of the DLC Water Heater program. The utility expects to ramp up the DR program over a seven-year period with the goal of achieving 30,000 participants. With per unit savings expected to be 1.0 kW during events, the program is anticipated to reduce the residential class peak demand by 1.6% when it reaches steady-state in year 7 (i.e., 2014). After 2014, the utility plans to add new participants to maintain aggregate peak demand savings. This will require the utility to enroll new participants to offset projected growth in peak demand (2.2% per year) and replace customers that move or drop out of the program. The utility expects that ~7% of the customers per year will be lost due to changes in electric service (5%) or removal from the program (2%). In terms of energy savings, it is anticipated that the water heater DLC program will have a small impact on energy usage during peak periods when events are called (60 kWh/unit-year), which is completely made up in the four-hour period following a curtailment.

The utility has budgeted $100,000 up-front to develop the program in year 1. The utility projects that customer acquisition costs are ~$25/customer for marketing and back-office costs, that cost and installation of the switch is $175/customer, and that load impact verification costs are $5/customer (e.g. cost and installation of a logger for a sample of customers). The utility will also offer customers an incentive for participating in events ($6.66/month bill credit for three months = $20/customer-year). The use of the one-way paging system is expected to cost the

[17] See spreadsheet entitled "DR_Cost_Effectiveness_Methodology_Model_Public~112508.xls"

utility $7/customer-year, while the utility believes it will incur $10/customer-year to inspect a sample of switches and loggers as well as perform any necessary service calls for these items of equipment. The cost to run the program every year is estimated to be $60,000/year. These costs are anticipated to grow by 2% per year after 2008.

Benefits from the program are derived from the avoided cost of energy, capacity and transmission and distribution, as well as environmental savings. No reliability benefits are calculated because this resource is considered “firm”, and thus is directly integrated into the planning process. The utility projects that in 2008 the value of avoided cost of peak and off-peak energy is 7.5 ¢/kWh and 4.5 ¢/kWh respectively, which is projected to increase at 2% per year. Environmental benefits are estimated to be $0.008/kW-year, increasing 2% annually. The first year avoided cost of capacity is set at $80/kW-year, and is expected to increase by 3% a year thereafter. T&D savings can be broken out into two pieces: line loss savings and reduced investment in plant. The utility has a secondary voltage level loss factor of 6%, thus any associated reduction in sales and peak demand means 106% of that electricity need not be generated and maintained for reserves, respectively. The utility has deemed that the average T&D cost savings associated with the program are $3/kW-year, which grows at an annual rate of 3%. Avoided capacity benefits account for ~95% of total benefits of the water heater DLC program. Because the DLC program is treated as a “firm” resource and is credited with avoiding and/or deferring a supply-side resource, we do not include additional reliability benefits.

Using these inputs and assuming the DLC water heater program is maintained for twenty years, the utility anticipates total program costs, on a present value basis using a discount rate of 8.8%, to be $19.63MM and program benefits to be $25.12MM. This water heater DLC program produces $5.49MM in net benefits with a TRC benefit-cost ratio of 1.28.

Our screening analysis tool can be utilized by utility planners and regulatory staff to conduct sensitivity analysis on key input values that might affect program cost-effectiveness. Input values that have the most significant impact on cost-effectiveness are the avoided cost of capacity and T&D (initial year value and assumed escalation rate). Lower program costs would also improve cost-effectiveness with assumed values for technology and back-office costs and program incentives having the most significant impact.

Figure H1-A-1 – Direct Load Control Water Heater Demand Response Program: Benefit-Cost Estimates

Year Index	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Utility System Characteristics																				
Forecasted Retail Sales (GWh)	23,000	23,460	23,929	24,408	24,896	25,394	25,902	26,420	26,948	27,487	28,037	28,598	29,170	29,753	30,348	30,955	31,574	32,206	32,850	33,507
Forecasted Peak Demand (MW)	4,000	4,088	4,178	4,270	4,364	4,460	4,558	4,658	4,761	4,865	4,972	5,082	5,194	5,308	5,425	5,544	5,666	5,791	5,918	6,048
Residential Retail Sales (GWh)	8,740	8,915	9,093	9,275	9,460	9,650	9,843	10,040	10,240	10,445	10,654	10,867	11,084	11,306	11,532	11,763	11,998	12,238	12,483	12,733
Residential Peak Demand (MW)	1,520	1,553	1,588	1,623	1,658	1,695	1,732	1,770	1,809	1,849	1,890	1,931	1,974	2,017	2,061	2,107	2,153	2,200	2,249	2,298
DR Program Characteristics																				
Number of New Participants (Units)	4,286	4,586	4,886	5,186	5,486	5,786	6,086	2,760	2,821	2,883	2,946	3,011	3,077	3,145	3,214	3,285	3,357	3,431	3,506	3,584
Number of Returning Participants (Units)	0	3,986	7,971	11,957	15,943	19,929	23,914	27,900	28,514	29,141	29,782	30,437	31,107	31,791	32,491	33,206	33,936	34,683	35,446	36,226
Number of Total Participants (Units)	4,286	8,571	12,857	17,143	21,429	25,714	30,000	30,660	31,335	32,024	32,728	33,448	34,184	34,936	35,705	36,490	37,293	38,114	38,952	39,809
Peak Period Energy Reduction (MWh)	244	489	733	977	1221	1466	1710	1748	1786	1825	1866	1907	1949	1991	2035	2080	2126	2172	2220	2269
Off-Peak Period Energy Increase (MWh)	244	489	733	977	1221	1466	1710	1748	1786	1825	1866	1907	1949	1991	2035	2080	2126	2172	2220	2269
Proportion of Class Retail Sales (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity Reduction (MW)	4.07	8.14	12.21	16.29	20.36	24.43	28.50	29.13	29.77	30.42	31.09	31.78	32.48	33.19	33.92	34.67	35.43	36.21	37.00	37.82
Proportion of Class Peak Demand (%)	0.3%	0.5%	0.8%	1.0%	1.2%	1.4%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%	1.6%
Benefits																				
Avoided Energy Cost Savings ($MM)	$0.01	$0.02	$0.02	$0.03	$0.04	$0.05	$0.06	$0.06	$0.07	$0.07	$0.07	$0.08	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10	$0.11
Avoided Capacity Cost Savings ($MM)	$0.35	$0.71	$1.10	$1.51	$1.94	$2.40	$2.89	$3.04	$3.20	$3.37	$3.54	$3.73	$3.93	$4.13	$4.35	$4.58	$4.82	$5.07	$5.34	$5.62
Avoided T&D System Cost Savings ($MM)	$0.01	$0.03	$0.04	$0.05	$0.07	$0.08	$0.10	$0.11	$0.11	$0.12	$0.13	$0.13	$0.14	$0.15	$0.15	$0.16	$0.17	$0.18	$0.19	$0.20
Environmental Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Reliability Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($MM)	***$0.37***	***$0.75***	***$1.16***	***$1.60***	***$2.05***	***$2.54***	***$3.05***	***$3.21***	***$3.38***	***$3.55***	***$3.74***	***$3.94***	***$4.14***	***$4.36***	***$4.59***	***$4.83***	***$5.08***	***$5.35***	***$5.63***	***$5.93***
Benefits - Present Value ($MM)	**$25.12**																			
Costs																				
Program Development Costs ($MM)	$0.10	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Customer Acquisition Costs ($MM)	$0.88	$0.96	$1.04	$1.13	$1.22	$1.31	$1.40	$0.65	$0.68	$0.71	$0.74	$0.77	$0.80	$0.83	$0.87	$0.91	$0.94	$0.98	$1.03	$1.07
Annual Program Administration Costs ($MM)	$0.06	$0.06	$0.06	$0.06	$0.06	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09
Annual Program Variable costs ($MM)	$0.16	$0.32	$0.49	$0.67	$0.86	$1.05	$1.25	$1.30	$1.36	$1.42	$1.48	$1.54	$1.60	$1.67	$1.74	$1.82	$1.89	$1.97	$2.06	$2.15
Total ($MM)	***$1.20***	***$1.34***	***$1.60***	***$1.86***	***$2.14***	***$2.43***	***$2.72***	***$2.02***	***$2.11***	***$2.19***	***$2.29***	***$2.38***	***$2.48***	***$2.58***	***$2.69***	***$2.80***	***$2.92***	***$3.04***	***$3.17***	***$3.30***
Costs - Present Value ($MM)	**$19.63**																			
Net Benefits ($MM)	***5.49***																			
Benefit Cost Ratio	***1.28***																			

Smart Thermostat – Air Conditioning Program

This smart thermostat program targets single-family residential customers with central air conditioning system. A smart thermostat is installed in each participant's home, replacing the existing thermostat, which is then controlled via a one-way pager signal to manage the set-point and cycling of the furnace. Curtailments are initiated during peak hours of summer (June - August) weekday afternoons and are not expected to exceed one-hundred twenty hours each year (i.e., thirty events of four hours/event). Due to the cycling strategy undertaken coupled with a customer's ability to override the set-point signal, it is assumed that about 65% of the households participate during events. A sample of participants will also have interval meters installed to help program administrators document and verify the achieved level of demand savings during program events.

Figure H1-A-2 summarizes projected market penetration, aggregate load impacts, economic and reliability benefits, and costs for the smart thermostat air conditioning program. The utility expects to ramp up the smart thermostat program over a seven-year period, with the goal of achieving 30,000 participants. With per unit savings expected to be 1.1 kW during events, the program is anticipated to reduce the residential class peak demand by 1.2% when it reaches a steady-state in year 7 (i.e., 2014). After 2014, the utility plans to add new participants to maintain aggregate peak demand savings. This will require the utility to enroll new participants to offset projected growth in peak demand (2.2% per year) and replace customers that move or drop out of the program. The utility expects that ~7% of the customers per year will be lost due to changes in electric service (5%) or removal from the program (2%)). The utility estimates that increasing set-points and cycling the air conditioner will have a measurable impact on energy consumption during events (132 kWh/unit-year). The utility also assumes that customers will take back about 50% of these energy savings during the four hour period following a curtailment.

The utility has budgeted $150,000 up-front to develop the program in year 1. The utility projects that customer acquisition costs are $30/customer for marketing and back-office costs, that cost and installation of the smart thermostat is $175/customer, and that load impact verification costs are $5/customer. Costs for the smart thermostat are assumed to decrease by 1.5% per year, due to technology improvements and greater market volumes. The utility will offer customers an incentive for participating in events ($7/month bill credit for three months = $21/customer-year). The use of the paging system is expected to cost $5/customer-year, while the utility believes it will incur $15/customer-year to inspect a sample of smart thermostats and interval meters as well as perform any necessary service calls for these items of equipment. The cost to run the program every year is estimated to be $65,000/year. These costs are anticipated to grow by 2% per year after 2008.

Benefits from the program are derived from the avoided cost of energy, capacity and transmission and distribution, as well as environmental savings (see discussion of water heater DR program). The avoided capacity costs account for ~90% of the total benefits.

Using these inputs and assuming the smart thermostat air conditioning program is maintained for twenty years, the utility anticipates total program costs, on a present value basis using a discount rate of 8.8%, to be $19.28MM and program benefits to be

$19.91MM. The TRC Benefit Cost ratio for this program would be slightly above 1.0 and is only marginally cost-effective.

Our screening analysis tool can be utilized by utility planners and regulatory staff to conduct sensitivity analysis on key input values that might affect program cost-effectiveness. Input values that have the most significant impact on cost-effectiveness are the avoided cost of capacity (initial year value and assumed escalation rate) and the assumed proportion of customers that participate and respond to events and don't override (e.g. we assume 65% participate). Lower program costs would also improve cost-effectiveness with assumed values for technology and back-office costs and program incentives having the most significant impact.

Figure H1-A-2 – Smart Thermostat Air Conditioning Demand Response Program: Benefit-Cost Estimate

Year Index	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Year	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Utility System Characteristics																				
Forecasted Retail Sales (GWh)	23,000	23,460	23,929	24,408	24,896	25,394	25,902	26,420	26,948	27,487	28,037	28,598	29,170	29,753	30,348	30,955	31,574	32,206	32,850	33,507
Forecasted Peak Demand (MW)	4,000	4,088	4,178	4,270	4,364	4,460	4,558	4,658	4,761	4,865	4,972	5,082	5,194	5,308	5,425	5,544	5,666	5,791	5,918	6,048
Residential Retail Sales (GWh)	8,740	8,915	9,093	9,275	9,460	9,650	9,843	10,040	10,240	10,445	10,654	10,867	11,084	11,306	11,532	11,763	11,998	12,238	12,483	12,733
Residential Peak Demand (MW)	1,520	1,553	1,588	1,623	1,658	1,695	1,732	1,770	1,809	1,849	1,890	1,931	1,974	2,017	2,061	2,107	2,153	2,200	2,249	2,298
DR Program Characteristics																				
Number of New Participants (Units)	4,286	4,586	4,886	5,186	5,486	5,786	6,086	2,760	2,821	2,883	2,946	3,011	3,077	3,145	3,214	3,285	3,357	3,431	3,506	3,584
Number of Returning Participants (Units)	0	3,986	7,971	11,957	15,943	19,929	23,914	27,900	28,514	29,141	29,782	30,437	31,107	31,791	32,491	33,206	33,936	34,683	35,446	36,226
Number of Total Participants (Units)	4,286	8,571	12,857	17,143	21,429	25,714	30,000	30,660	31,335	32,024	32,728	33,448	34,184	34,936	35,705	36,490	37,293	38,114	38,952	39,809
Peak Period Energy Reduction (MWh)	368	735	1103	1471	1839	2206	2574	2631	2689	2748	2808	2870	2933	2998	3063	3131	3200	3270	3342	3416
Off-Peak Period Energy Increase (MWh)	184	368	552	735	919	1103	1287	1315	1344	1374	1404	1435	1467	1499	1532	1565	1600	1635	1671	1708
Proportion of Class Retail Sales (%)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Capacity Reduction (MW)	3.06	6.13	9.19	12.26	15.32	18.39	21.45	21.92	22.40	22.90	23.40	23.92	24.44	24.98	25.53	26.09	26.66	27.25	27.85	28.46
Proportion of Class Peak Demand (%)	0.2%	0.4%	0.6%	0.8%	0.9%	1.1%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
Benefits																				
Avoided Energy Cost Savings ($MM)	$0.02	$0.04	$0.06	$0.09	$0.11	$0.14	$0.16	$0.17	$0.18	$0.18	$0.19	$0.20	$0.21	$0.22	$0.22	$0.23	$0.24	$0.25	$0.27	$0.28
Avoided Capacity Cost Savings ($MM)	$0.26	$0.54	$0.83	$1.14	$1.46	$1.81	$2.17	$2.29	$2.41	$2.53	$2.67	$2.81	$2.96	$3.11	$3.27	$3.45	$3.63	$3.82	$4.02	$4.23
Avoided T&D System Cost Savings ($MM)	$0.01	$0.02	$0.03	$0.04	$0.05	$0.06	$0.08	$0.08	$0.09	$0.09	$0.09	$0.10	$0.10	$0.11	$0.12	$0.12	$0.13	$0.14	$0.14	$0.15
Environmental Benefits ($MM)	$0.00	$0.00	$0.00	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.01	$0.02	$0.02	$0.02	$0.02	$0.02	$0.02
Reliability Benefits ($MM)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total ($MM)	***$0.29***	***$0.60***	***$0.92***	***$1.27***	***$1.63***	***$2.02***	***$2.42***	***$2.55***	***$2.68***	***$2.82***	***$2.96***	***$3.12***	***$3.28***	***$3.45***	***$3.63***	***$3.82***	***$4.02***	***$4.23***	***$4.45***	***$4.68***
Benefits - Present Value ($MM)	**$19.91**																			
Costs																				
Program Development Costs ($MM)	$0.15	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Customer Acquisition Costs ($MM)	$0.90	$0.95	$1.00	$1.04	$1.08	$1.13	$1.17	$0.52	$0.52	$0.53	$0.53	$0.54	$0.54	$0.54	$0.55	$0.55	$0.55	$0.56	$0.56	$0.56
Annual Program Administration Costs ($MM)	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.07	$0.08	$0.08	$0.08	$0.08	$0.08	$0.08	$0.09	$0.09	$0.09	$0.09	$0.09	$0.09
Annual Program Variable costs ($MM)	$0.18	$0.36	$0.55	$0.75	$0.95	$1.16	$1.39	$1.44	$1.51	$1.57	$1.64	$1.71	$1.78	$1.85	$1.93	$2.01	$2.10	$2.19	$2.28	$2.38
Total ($MM)	***$1.29***	***$1.37***	***$1.61***	***$1.86***	***$2.11***	***$2.36***	***$2.63***	***$2.04***	***$2.11***	***$2.18***	***$2.25***	***$2.32***	***$2.40***	***$2.48***	***$2.56***	***$2.65***	***$2.74***	***$2.84***	***$2.93***	***$3.04***
Costs - Present Value ($MM)	**$19.28**																			
Net Benefits ($MM)	***0.63***																			
Benefit Cost Ratio	***1.03***																			

Appendix H3: Translating Portfolio Analysis of Power System Planning into a Cost Effectiveness Limit for Demand Response

Ken Corum, Northwest Power and Conservation Council, prepared for the Pacific Northwest Demand Response Project, September 12, 2008

INTRODUCTION

Demand response (DR) is the temporary, voluntary reduction in use of electricity at times when the power system is stressed. Such stress results from events such as peak loads or the unexpected loss of transmission or generating facilities. Customers providing demand response usually receive some form of compensation.

Historically, demand response received little attention in the Pacific Northwest because our power system had a large component of hydroelectricity, whose flexibility allowed the power system to meet peak loads and other stressful conditions. Over time we have begun to outgrow the ability of the hydroelectricity to perform this service, and we have made other demands on that flexibility as well. In the not-too-distant future, regional utilities are likely to face decisions whether or not to build peaking generators[1] such as single cycle combustion turbines (SCCTs) to meet conditions once routinely handled by the flexibility of the hydroelectric system. Demand response can be an attractive alternative to these peaking generators.

Beginning in the Northwest Power and Conservation Council’s 5th Power Plan, released in early 2005, the Council has treated demand response as one of the alternatives to conventional generating plants in meeting regional loads. Over the same period, utilities have expanded their demand response programs and are considering further expansions. In the course of these developments it has become clear that a clear cost effectiveness criterion would be helpful in guiding development of demand response.

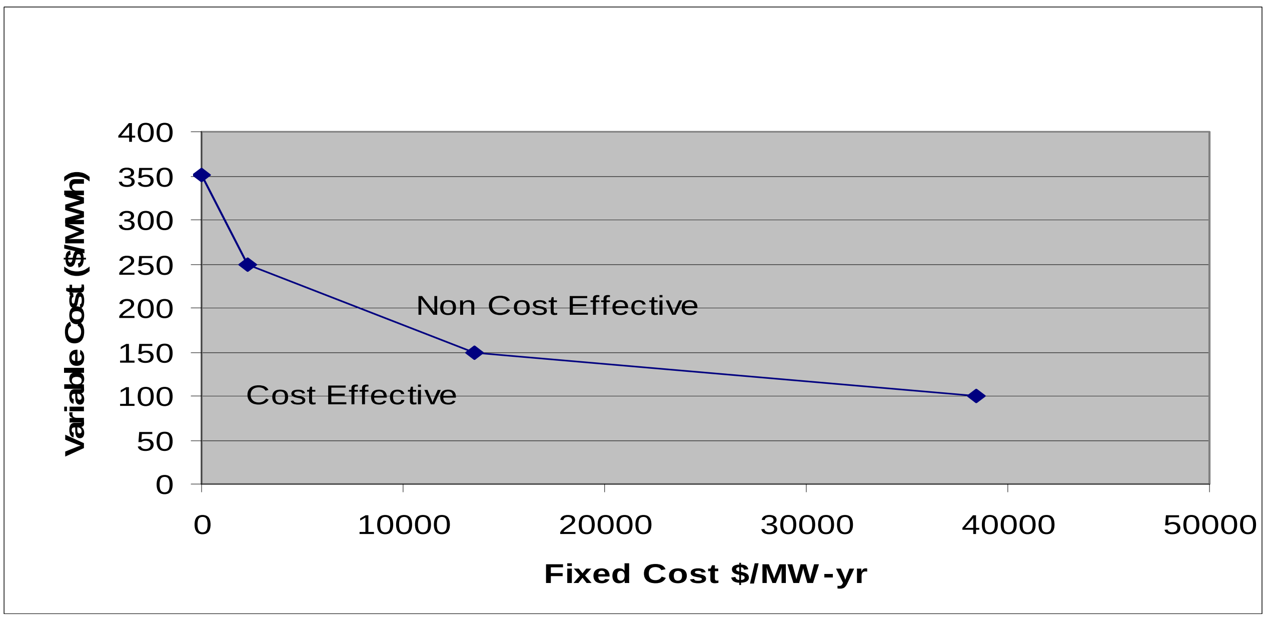
There is general agreement that the basic concept of this criterion should be “compare the cost of demand response to the costs avoided elsewhere in the power system.” But the complex interactions in the power system mean that we must decide how much detail is enough in the

[1] “Peaking” generators have relatively low capital costs and relatively high operating costs, making them attractive resources for meeting short, infrequent situations. Peakers have been rare in the Pacific Northwest until recently because the hydroelectric system has been able to meet those situations more economically.

estimation of "the costs avoided elsewhere." In estimating the power system costs avoided by demand response, there is a conflict between comprehensiveness and practical usefulness. While more detail may give more confidence that the estimate is accurate, incorporating more detail has a significant cost -- past some level of detail it becomes impractical for utility and regulator analysts to apply the estimation method to individual demand response options. The paper reviews three estimation methods of increasing complexity that illustrate the problem.

The paper then describes an attempt to resolve this conflict between comprehensiveness and practicality by translating the results of a very comprehensive analysis of avoided cost (the portfolio analysis used in the Council's planning) into a simple "cost effectiveness frontier" for DR. The cost effectiveness frontier for demand response would separate non cost effective combinations of fixed and variable costs from cost effective combinations, as demonstrated by the line in Figure H3-1. The frontier could serve as a simple screening mechanism to help identify programs that are likely to be cost effective in the long run. If a demand response program has a combination of fixed and variable costs that place it below and to the left of the frontier, it is a good candidate for further evaluation.

Figure H3-1: Cost Effectiveness Frontier



BACKGROUND: PREVIOUS APPROACHES

Using cost effectiveness as a guide for power system resource decisions requires the specification of a baseline set of resources and loads expected at planning points in the future. The baseline resources are then evaluated to estimate the cost that could be avoided if an increment of load[2] could be served with an alternative resource. This "avoided cost" is the standard against which alternative resources are measured; if an alternative resource is cheaper than the avoided cost, the alternative resource is cost effective relative to the baseline resource.

[2] The increment of load of interest here is of short duration (e.g. 50-200 hours per year), commonly at the times when the power system faces its highest loads.

"Stand-alone Peaker" Approach

The simplest approach to the estimation of avoided cost of an SCCT is to express the total cost of a SCCT in $/MWh terms by dividing its costs by the number of MWh it is assumed to produce. For example, a recent estimate of the annual fixed cost of a new[3] SCCT is $76/kW-yr. If we assume a conversion efficiency of 11,000 Btu/kWh, a natural gas price of $8.00/million Btu and we assume the peaker is built and operated to meet peak load or other stress conditions that last 100 hours/year, the cost of electricity produced in those hours by this generator is $.85/kWh[4]. If a demand response program allows us to avoid building and operating a new SCCT to serve this 100-hour load, that program is cost effective if it costs less than $.85/kWh.

While this approach has the advantage of simplicity, it does not consider some significant features of the power system. For example, a new peaker, even if it is built to meet a 100-hour condition, will likely run more than 100 hours per year, because the new unit will tend to be more efficient in converting fuel to electricity than some units which are already in the power system. Therefore the new unit would likely displace some of those units in some hours, reducing the operating cost of the whole system. The net cost of the new unit, taking into account this operating cost savings, is less than the "stand-alone" costs of the unit, and the cost avoided by not building the unit is likewise less than the estimate of the "stand-alone" approach. There are other interactions, such as the possibility of trade between utilities within our region, or between our region and others, that could affect the net cost of a new SCCT and would reinforce the point of this illustration -- ignoring the interaction of a new SCCT with the rest of the power system may introduce significant bias into the estimate of avoided cost.

Another significant concern that is not reflected in the "stand-alone" approach is that of uncertainty. Power systems are built and operated based on expectations about the future -- loads will grow at an expected rate, fuel prices will be in an expected range, weather will have an expected pattern. But expectations frequently turn out to be wrong, and power systems can be configured to be less vulnerable to these events. A "stand-alone" approach to estimating avoided cost cannot recognize this vulnerability and cannot discriminate between power system alternatives on this basis.

"System Simulation" Approach

The interaction between a new generator and the rest of the power system can be modeled with tools such as the AURORA© model, which simulates the operation of the entire "Western Interconnection," the power system from the Rockies to the Pacific, including the provinces of British Columbia and Alberta in Canada and the northern part of Baja California in Mexico. The Council and others use this model to forecast wholesale electricity prices and for other analysis. The model simulates the operation of generators based on the principle of dispatching lowest operating cost units first, subject to the ability to transmit the electricity from generator to load and other operating constraints.

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[3] From a long run planning perspective, both construction and operation costs are avoidable. In the shorter run, once an SCCT is built, its construction costs are sunk and only its costs of operation are avoidable.

[4] $76/100 + $8*11,000/1,000,000 = $.848/kWh. For perspective, the retail price of electricity to residential customers in this region averages $.07/kWh to $.08/kWh. That is, during the assumed 100 hours consumers see retail rates that are roughly 1/10 of the actual incremental cost of the energy they're using.

A tool such as AURORA can be used to estimate the avoided cost of a new generator by making two runs, a "base case" that includes the generator, and a "demand response case" that avoids the new generator by reducing load, evaluating the total cost change between the two runs. The result should capture the interaction between the new unit and existing units throughout the system, and thus provide a more comprehensive estimate of avoided cost than a "stand-alone" approach.

However, because modeling using AURORA cannot adequately reflect uncertainty, this approach cannot recognize the effect of resource choices on the power system's vulnerability to uncertainty. It shares this limitation of the "stand-alone" approach, as described above. In addition, AURORA and similar tools are costly, both in terms of license fees and in terms of committed human resources.

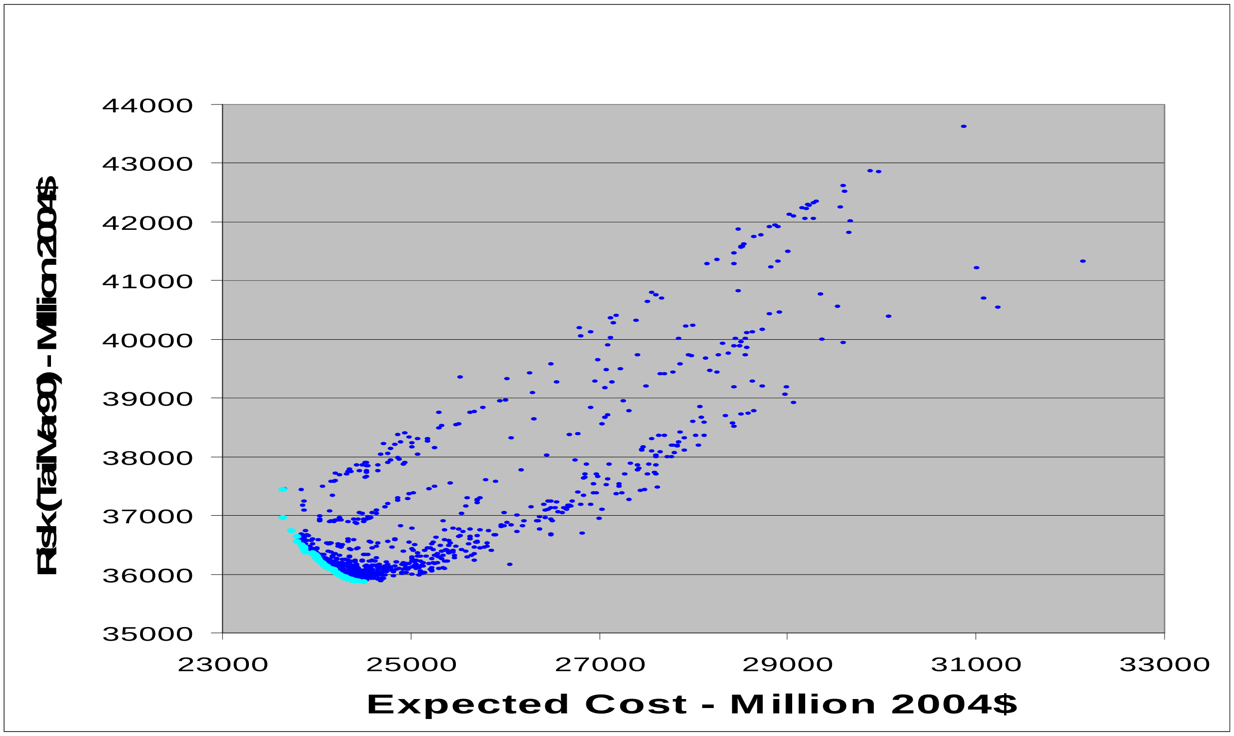
Council Portfolio Model

The Council's portfolio model was conceived and developed largely to incorporate uncertainty into power system planning. It is documented in detail at http://www.nwcouncil.org/energy/powerplan/plan/Default.htm. For the purposes of this paper, it is enough to know that the model simulates the development and operation of the region's power system, for several thousand potential resource portfolios. Each resource portfolio is evaluated over a set of 750 possible 20-year futures, which incorporates variation in fuel and electricity prices, demand for electricity, availability of hydroelectric power, generator outages, demand for electricity by aluminum smelters, CO_2 taxes, and incentives for electricity from renewable energy.

An important feature of the model is that while each simulation is based on a potential resource portfolio, the decisions to build and operate each resource are simulated within each future, based on the recent experience in that future. The effect is that the model simulations include "mistakes" in development, like overbuilding after a period of fast load growth, only to experience slow load growth in a succeeding period. The result of subjecting each portfolio to 750 futures is a set of 750 net present values (NPVs) of the costs of the system. Each portfolio thus has a distribution of NPVs that can be characterized by the distribution's mean and a measure of risk called TailVar90 (the mean of the highest 10 per cent of NPVs).

Each portfolio can then be represented as a point on a graph with expected costs on the horizontal axis and TailVar90 on the vertical axis. If the results for all the analyzed portfolios are plotted, the result is a "feasibility space," illustrated by the results of an analysis done for the Council's 5th Power Plan, shown in Figure H3-2.

Figure H3-2: Feasibility Space and Efficient Frontier



While all the points plotted in the feasibility space are possible, the lighter points at the lower-left boundary of the feasibility space (the "efficient frontier") are preferable to the rest -- the efficient frontier is made up of portfolios that minimize expected cost for each level of risk. For any portfolio not on the efficient frontier, it is possible to find a portfolio that reduces expected cost at the same risk, or reduces risk at the same expected cost, or reduces both expected cost and risk. Any decision-maker, regardless of their preferences for expected cost vs. risk, can find some point on the efficient frontier that is preferable to any point that is not on the frontier.[5]

The Council's portfolio model is arguably at the cutting edge of analytical design and comprehensive treatment of uncertainty in power planning. Its design also simulates the interaction of a new generator with the rest of the power system. As a result we can say that the portfolio model remedies the important shortcomings of the "stand-alone peaker" and "system simulation" approaches. But it does so at the cost of considerable complexity -- at the Council, the model uses ten personal computers coordinated by a server, and an analysis commonly requires several days' run time. In addition, acquiring the skills and understanding needed to exercise the model requires a considerable investment of time for the analyst.

In the face of these drawbacks, we decided to explore the possibility that the results of a limited number of runs of the portfolio model could be translated into simpler terms. The concept we developed is the "cost effectiveness frontier," illustrated in Figure H3-1. This frontier separates DR fixed and variable cost combinations that are cost effective, from combinations of costs that are not cost effective. For example, the combination of $10,000/MW-yr fixed cost and

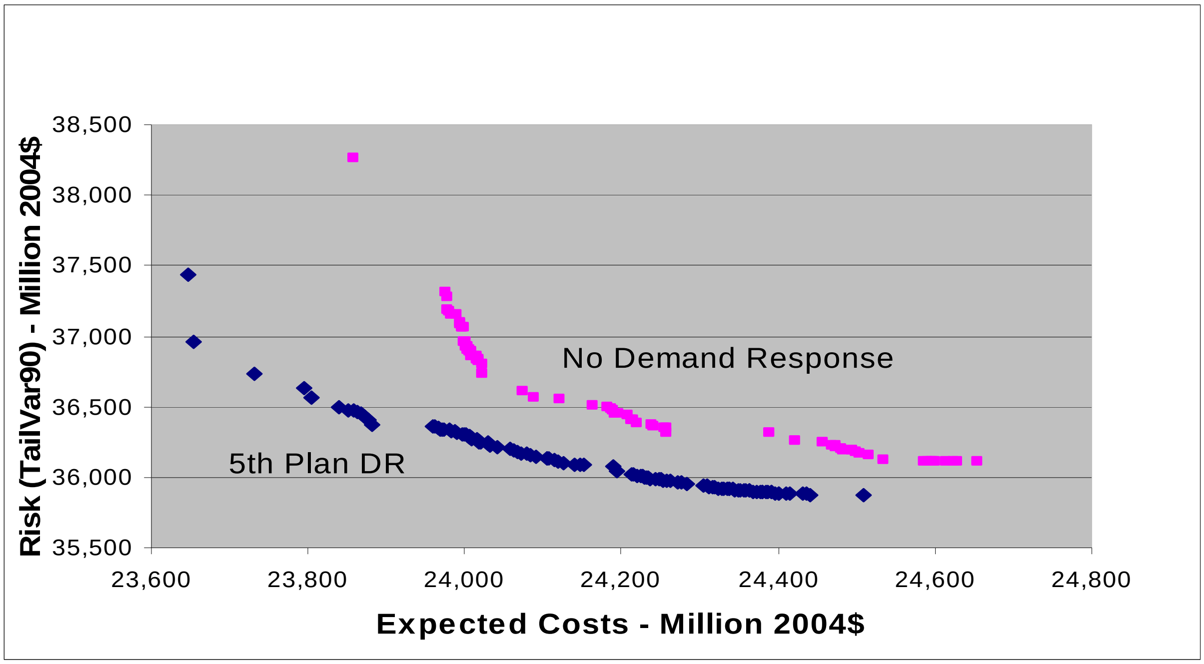
[5] While all decision-makers will prefer to be somewhere on the frontier, they will not prefer the same point on the frontier. Choosing among portfolios on the frontier requires trading expected cost for risk. These trades require subjective weighting of expected cost vs. risk. Different decision-makers will apply different weights and arrive at different portfolio choices.

$250/MWh variable cost is above the frontier, or non cost effective, while the combination of $20,000/MW-yr fixed cost and $100/MWh is below the frontier, or cost effective.[6]

TRANSLATION METHODOLOGY

How should we interpret the Council's portfolio analysis in terms of cost effectiveness? The analysis in the Council's 5th Power Plan indicated that demand response could reduce the expected cost and risk of the region's power system, while serving the same loads. The analysis in the Plan[7] assumed that 2000 MW of DR were phased in over the 20 year horizon, with the $2260/MW-yr and $150/MWh cost assumptions described above, in the "5th Plan DR" case and assumed no DR at all in the "No Demand Response" case. The results of the analysis are reproduced in Figure H3-3.

Figure H3-3: Effect of Demand Response on Efficient Frontier (Fig. H-4 in 5th Power Plan)



While the analysis is not structured as a conventional cost effectiveness analysis, Figure H3-3 illustrates that the 2000 MW resource analyzed in the 5th Power Plan is clearly cost effective, compared to no DR. That is, at every comparable level of risk, the 5th Plan DR case has lower expected cost than the No DR case. But the analysis does not tell us how high DR costs can be before the DR becomes not cost effective. We'd like to establish a cost effectiveness limit, analogous to those we have established for energy efficiency[8]. Such a limit would allow utilities,

[6] The cost effectiveness frontier has a shape that is similar to the efficient frontier illustrated in Figure 2. Each frontier separates a plane into two regions, but the planes represent different variables. The cost effectiveness frontier in Figure 1 separates combinations of fixed and variable costs into cost effective and non cost effective regions, while the efficient frontier in Figure 2 separates combinations of expected cost and risk into feasible (above the frontier) and infeasible (below the frontier) regions.

[7] Page 21 of Appendix H, Demand Response Assessment (http://www.nwcouncil.org/energy/powerplan/plan/Appendix%20H%20(Demand%20Response).pdf).

[8] For example, energy efficiency measures affecting residential lighting were estimated to have a cost effectiveness limit of $45/MWh or 4.5 cents/kWh (2000$) in the Council's 5th Power Plan. The cost effectiveness limit varies

regulators and others to estimate whether a DR program is worthwhile without repeating the portfolio analysis in the 5th Plan.

Let's first consider what such a limit would look like. The DR resource analyzed in the Plan is typical of most DR resources, in that it has both fixed ($/MW-yr) and variable $/MWh) components. This is in contrast to energy efficiency, whose costs and load reductions are fixed once an efficiency measure is installed. As a result of these differences between DR and energy efficiency, while a cost effectiveness limit for energy efficiency can be expressed as a levelized cost in $/MWh or cents/kWh, a cost effectiveness limit for DR needs to be expressed as a "frontier" combining both fixed and variable costs, such as was illustrated in Figure H3-1. DR programs or measures whose fixed and variable costs place them lower and to the left of the "cost effectiveness frontier" are cost effective.

How can we calculate a cost effectiveness frontier? Using the Council's portfolio model, we can simulate the effect of varying levels of DR costs on the expected costs and risks of the region's power system. Simulating the effect of higher DR costs would generate a "Test Case" frontier that is higher and to the right of the 5th Plan DR frontier. Successively higher DR costs would generate test case frontiers that are successively higher and further to the right of the 5th Plan DR frontier. At some level of DR costs, the test case frontier will coincide with the No Demand Response frontier <u>at some level of risk</u>.[9]

Since we can't expect any test case frontier to coincide with all points on the No Demand Response frontier, we must choose a point on the No Demand Response frontier as our target. For the present, we're choosing the least-risk portfolio (the far right point) on the frontier.[10] Our objective is to determine the levels of DR costs that result in test case frontiers that coincide with that point. That coincidence means that including DR in the resource portfolio at those costs no longer offers any advantage. Those DR costs are at the cost effectiveness limit.

An example should help clarify the analytical process we're proposing: We ran the portfolio model with the assumptions of the 5th Plan DR case, including DR's fixed cost at $2260/MW-yr, but raising the variable cost of DR from $150/MWh to $200/MWh. The test case in Figure H3-4 is labeled ($2260, $200) and the figure shows that the ($2260, $200) efficient frontier is between the "5th Plan" frontier and the "No DR" frontier. That is, at equal levels of risk the expected costs of portfolios that include DR at $200/MWh variable cost are higher than those that include DR at $150/MWh variable cost, but lower than portfolios that include no DR at all. Therefore, while DR at VC=$200/MWh is not as attractive as DR at VC=$150/MWh (fixed costs remaining at $2260/MW-yr) it is still cost effective compared to no DR.

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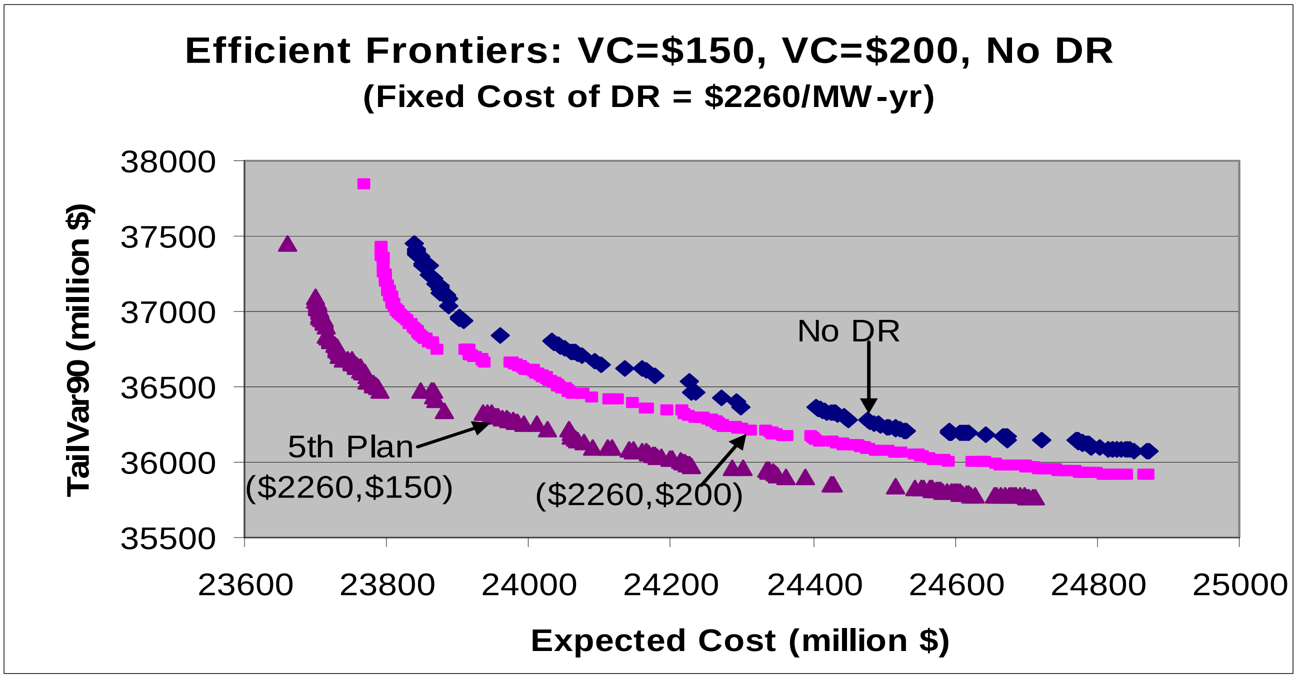
depending on the hourly distribution of the expected savings. See Table E-2 of Appendix E of the 5th Power Plan (http://www.nwcouncil.org/energy/powerplan/plan/Appendix%20E%20(Conservation%20Cost-Effectiveness%20Methodology).pdf for cost effectiveness limits for the full range of energy efficiency measures analyzed.

9 The coincidence could occur at more than one level of risk simultaneously, but is very unlikely to occur all along the efficient frontier simultaneously.

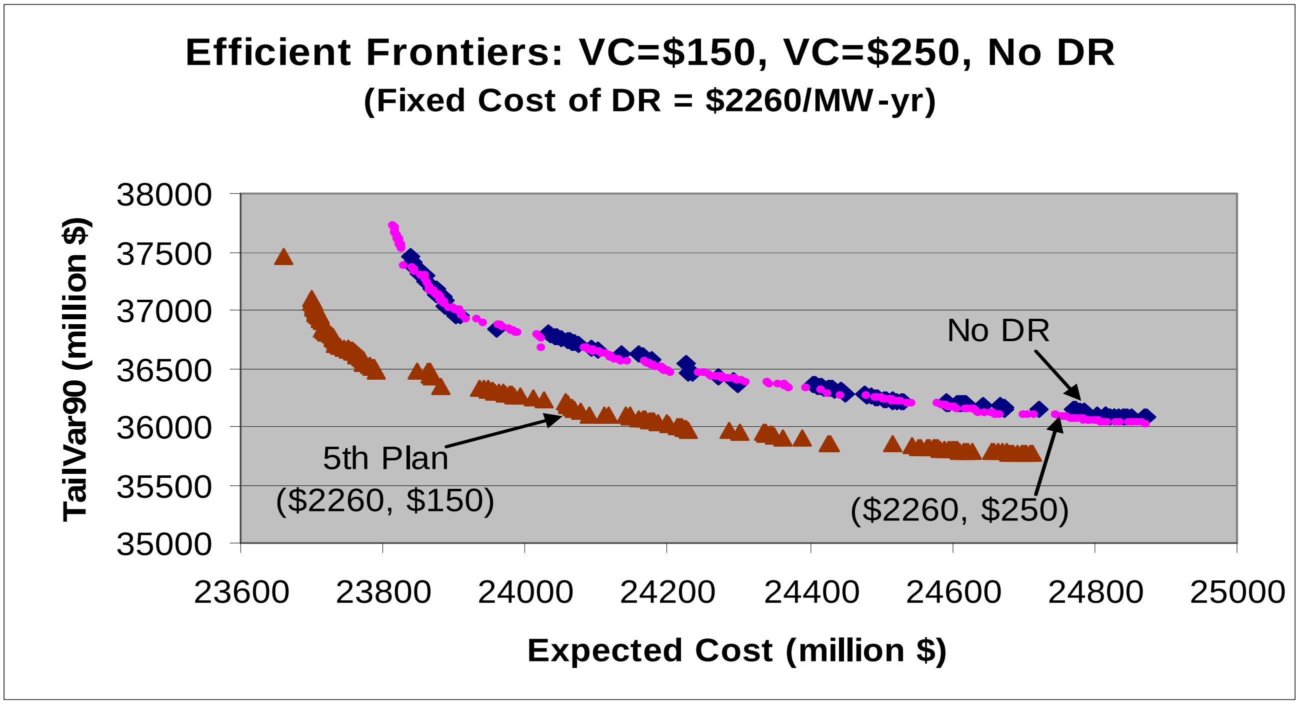
10 This choice can be revisited, but it is consistent with the Council's choice of the least-risk portfolio on the frontier for the implementation part of the 5th Power Plan.

Figure H3-4: Comparison of Efficient Frontiers (VC=$150, $200)



We then made another run of the portfolio model maintaining all assumptions except that DR's variable cost was raised further, to $250/MWh. Figure H3-5 shows that the test case ($2260, $250) efficient frontier is now roughly coincident with the "No DR" frontier (slightly lower at the right end of both frontiers). In other words, at these costs portfolios that include DR have essentially the same risk and expected costs as portfolios with no DR. Therefore, this combination of fixed and variable costs is at the limit of cost effectiveness, and the point ($2260, $250) is one point on the cost effectiveness frontier. This point is included in the frontier shown in Figure 1.

Figure H3-5: Comparison of Efficient Frontiers (VC=$150, $250)



Repeating this process with different combinations of fixed and variable costs will generate other points and trace the full shape of the cost effectiveness frontier. Figure H3-1 illustrates one plausible outcome of this process.

CAVEATS

While Figure H3-1 shows a cost effectiveness frontier that is plausible, the frontier should not be interpreted as a finished product. The goal of this paper is to describe a method to translate results of the Council's portfolio analysis into simpler terms. Even if the translation is valid, any limitations of the underlying portfolio analysis will compromise the quality of the resulting cost effectiveness frontier.

For example, the DR program analyzed in the 5th Power Plan was based on a "buyback" program and modeled very much like a peaking generator. There are demand response programs that are quite different (e.g. PacifiCorp's and Idaho Power's irrigation scheduling programs, which have fixed annual costs and have load reductions that are fixed in timing and amount). Development of portfolio analyses reflecting different forms of DR will give us more confidence in the underlying analysis, and will provide an opportunity to test the translation methodology for different DR programs.

Another feature of the 5th Power Plan analysis that should be recognized is that the model had no limits on the number of times per year that DR could be used. In fact, most real-world DR programs have limits on dispatches. We need to model DR with limited dispatches to increase our confidence in the cost effectiveness frontier we can derive from the portfolio model.

SUMMARY

The paper reviewed methods of estimating cost effectiveness of demand response (DR) and each method's strengths and limitations. The portfolio analysis used by the NW Power and Conservation Council in its long run planning is a comprehensive approach that accounts for resources' interactions with the rest of the power system, trade among the various regions of the Western Interconnection, and the effects of uncertainty on the value of each resource.

However, the portfolio analysis is complex and demanding of time and analytical resources, making the analysis impractical for use by utility program managers or regulatory staff. To make the results of the analysis more easily usable, we propose a translation of a series of portfolio analyses into a "cost effectiveness frontier" (Figure H3-1). This frontier separates combinations of fixed and variable costs of demand response into regions that are cost effective (combinations below the frontier) and not cost effective (combination above the frontier). At this stage of development we regard the frontier as a helpful screening aid, with potential for further development.

Appendix I: Generating Resources and Energy Storage Technologies - Background Information

INTRODUCTION

This appendix describes the development of the planning assumptions for new generating resources for use in preparing the Sixth Power Plan.

GENERAL APPROACH AND ASSUMPTIONS

Conventions

The following conventions are used in this Appendix and in Chapter 6 unless otherwise noted:

The price base year from which future changes in real costs are calculated is 2008

Costs are expressed in constant 2006 dollars

The technology base year from which future changes in technology are calculated is 2008

The scope of resource cost estimates includes the cost and losses of delivery to the wholesale receiving point of the local load-serving entity.

"Near-term" referes to the period 2010 - 2014; "Mid-term" to the period 2015-2019 and "Longer-term" to the period 2020 - 2029.

In calculating total investment cost, project costs are are assumed to be fixed (in real terms) at the first year of construction.

Levelized Costs

Comparative levelized lifecycle generating resource costs are provided in several locations in this plan. These are computed using the Council's MicroFin project revenue requirements model. MicroFin is also used to compute levelized capital costs for new resource options for the AURORA$^{xmp®}$ Electric Market Model and for the Council's Regional Portfolio Model. The operation of MicroFin is as follows:

Total project investment is calculated for the selected year of construction using the estimated project capital cost, plant capacity, cost escalation factors, construction cash flow estimates and the construction financing of the selected type of project developer (Consumer-owned utility, investor-owned utility and independent project developer financing options are available in MicroFin. Most resource costs reported in this plan assume investor-owned utility financing.

Annual capital-related costs (debt interest, debt principal, return on equity, recovery of equity, state and federal taxes) are calculated for the total project investment using the long-term financing characteristics and tax obligations of the selected type of developer. Financial incentives such as accelerated depreciation, investment tax credit and production tax credits are applied at this point.

Annual property tax and insurance payments are calculated based on depreciated plant value.

Annual energy production is calculated based on plant capacity and capacity factor.

Annual fixed fuel costs are calculated based on escalated fixed fuel costs and plant capacity. Annual variable fuel costs are based on escalated variable fuel costs, heat rate and energy production.

Annual fixed O&M costs are calculated based on escalated fixed O&M costs and plant capacity. Annual variable O&M costs are based on escalated variable O&M costs and energy production.

Annual emission costs are calculated based on fuel consumption, fuel carbon content, and forecast CO_2 allowance costs.

Annual transmission costs are calculated based on plant capacity and escalated unit transmission costs. Integration costs are calculated based on forecast integration costs and energy production.

The value of transmission losses is calculated based on total annual costs and the transmission loss factor.

The net present value for the initial year of service is calculated for each component of annual cost over the life of the project. The levelized annual cost stream yielding the same net present value is then calculated for each component. The discount rate used for the net present value and levelization is the weighted after-tax cost of capital for the selected type of project developer.

The resulting levelized cost components are converted to unit (per-megawatt-hour) values, discounted to the base year (2006 dollar values) and summed to yield total revenue requirements.

A copy of MicroFin, loaded with the resource, fuel financing and other assumptions used to calculate investment costs and project revenue requirements for this plan is available from the Council on request.

Capital Cost Estimates

The capital cost estimates for the reference power plants are based on published sources. These include costs reported in the media for planned projects, projects under construction and completed projects, and generic cost estimates for specific technologies and projects appearing in publically-available reports. Using this information, the Council develops an estimate of per kilowatt Total Project Costs for each reference plant. “Total Project Costs” (often referred to as “overnight” costs) are defined here as total direct and indirect costs of project development and construction and commissioning, exclusive of the costs of securing financing, and escalation and interest incurred during construction. Various financing assumptions can then be applied to the total project cost to yield total project investment costs.

The raw cost data used to develop reference plant cost estimates can represent different vintages, project scope and year dollars and may or may not include the costs of financing, escalation and interest during construction. In all cases it is necessary to normalize reported costs to common vintage, scope, year dollars and to overnight value. The information needed to make these adjustments is typically documented in technology assessments and feasibility studies. However, the needed information is often incomplete or entirely missing in media reports, necessitating assumptions. The general approach used to normalize costs is as follows; additional details regarding specific technologies are provided in the respective technology sections:

- Project capacity is adjusted to common metrics. For thermal projects this is net output under ISO conditions. Wind project costs are based on installed turbine capacity and utility-scale solar project costs are adjusted to net AC output.

- Reported estimates were screened and adjusted to represent a plant configuration broadly approximating the reference plant. Plants having configurations clearly unrepresentative of the reference plant were eliminated from the sample. For example, reported costs for simple-cycle combustion turbine plants of consisting of more than four units were omitted. In other cases, costs were increased or decreased to normalize major design characteristics. For example, the reported costs of thermal plants provided with dry cooling was adjusted down to represent the cost of plants employing evaporative cooling.

- Estimates were adjusted to include all owners' costs (project development, land, infrastructure and financing). Unless specifically noted in the reporting, cost estimates reported prior to completion are assumed to be overnight construction cost, exclusive of owner's costs. These were increased to account for owner's costs. Reported costs for completed plants are assumed to include all owners' costs.

- Costs reported for specific projects were adjusted to an average construction cost index for the Pacific Northwest states using the state adjustment factors of USACE (2008).

- Costs were adjusted to represent overnight costs. Cost estimates reported prior to completion are assumed to be overnight costs so were not adjusted other than conversion to constant (real) 2006 dollars. Reported costs for completed projects are assumed to be in as-expended (nominal) dollars including financing, and escalation and interest during construction. For these cases, the equivalent overnight total plant costs in year 2006 dollars are calculated using the Council's MicroFin project financing and levelization model.

Because of the substantial escalation in plant construction costs between 2004 and 2008 it is necessary to plot costs by vintage to gain a sense of typical 2008 base year costs and range of costs. Costs of completed plants or plants under construction are assumed to represent costs as of the initial year of construction. The vintage of costs reported for plants not yet under construction is assumed to be the year of publication. Some resources, particularly those where large sample sizes are available and plants tend to have relatively uniform characteristics yielded well-defined distributions. Figure I-14 (wind plants) is one such example. In cases with well-defined distributions, the representative 2008 base year cost was taken as the approximate average of 2008 costs and the range the range of normalized reported costs (less obvious outliers).

Other resources yielded poorly-defined distributions, because of small sample sizes, plants inherently of widely varying characteristics or for other reasons. An example is I-BIO-1, landfill gas energy recovery projects. In these cases, the selection of the reference plant base year cost was influenced by the source and apparent quality of individual samples and the shape of the HIS Cambridge Energy Research Associates Power Capital Cost Index[1] (converted to real terms).

Capital costs forecasts are based on the interaction of two factors - near-term declines resulting from contraction of the credit market and reduction in demand for goods since mid 2008, and, over the longer-term, the effect of technological improvements and economies of production, particularly for less-mature technologies. In general, capital costs (in real terms) are assumed to drop from mid-2008 highs to market equilibrium values by 2011. Market equilibrium values are

[1] http://www.cera.com/aspx/cda/public1/news/pressReleases/pressReleaseDetails.aspx?CID=10429

assumed to be the average of 2004 and 2008 capital costs (in 2006 constant year dollar values). Further declines resulting from technological advances and economies of production are based on rates observed in the years prior to 2004. These assumptions are described below for the various reference plants. The base year capital cost assumptions and capital cost forecasts for the various reference plants are provided in Table I-1. Selected cases are plotted in Figure I-1 to illustrate the changes through time.

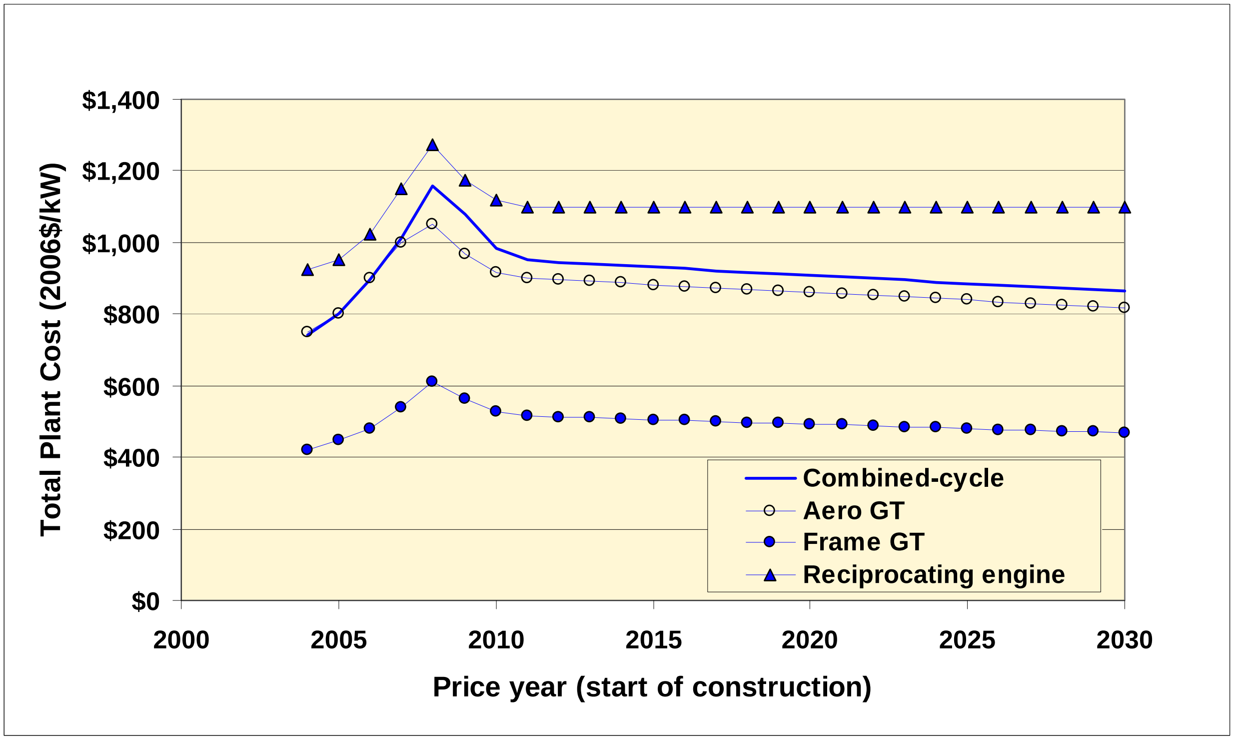
[The following table is yet to be completed]

Table I-1: Projected total plant cost (overnight, 2006 dollar values)

	Animal Waste	Combined-cycle	Geothermal	Landfill Gas	Reciprocating Engines	Wastewater Treatment	Wind
2008	$5,000	$1,160	$4,800	$2,349		$5,000	$2,100
2009	$4,600	$1,079	$4,400	$2,161		$4,600	$1,806
2010	$4,385	$982	$3,988	$2,060		$3,963	$1,725
2011	$4,314	$950	$3,850	$2,026		$3,750	$1,700
2012	$4,314	$945	$3,850	$2,026		$3,731	$1,692
2013	$4,314	$941	$3,850	$2,026		$3,713	$1,683
2014	$4,314	$936	$3,850	$2,026		$3,694	$1,675
2015	$4,314	$931	$3,850	$2,026		$3,676	$1,666
2016	$4,314	$927	$3,850	$2,026		$3,657	$1,658
2017	$4,314	$922	$3,850	$2,026		$3,639	$1,650
2018	$4,314	$917	$3,850	$2,026		$3,621	$1,641
2019	$4,314	$913	$3,850	$2,026		$3,603	$1,633
2020	$4,314	$908	$3,850	$2,026		$3,585	$1,625
2021	$4,314	$904	$3,850	$2,026		$3,567	$1,617
2022	$4,314	$899	$3,850	$2,026		$3,549	$1,609
2023	$4,314	$895	$3,850	$2,026		$3,531	$1,601
2024	$4,314	$890	$3,850	$2,026		$3,513	$1,593
2025	$4,314	$886	$3,850	$2,026		$3,496	$1,585
2026	$4,314	$881	$3,850	$2,026		$3,478	$1,577
2027	$4,314	$877	$3,850	$2,026		$3,461	$1,569
2028	$4,314	$873	$3,850	$2,026		$3,444	$1,561
2029	$4,314	$868	$3,850	$2,026		$3,426	$1,553

[The following figure is yet to be completed]

Figure I-1: Selected projections of total plant cost



Project Financing

Power plants can be constructed by investor-owned utilities, consumer-owned utilities and independent power project developers. Each of these entities uses different project financing mechanisms. The differing financing mechanisms and financial incentives available for some resources result in owner-specific total capital investment costs and annual capital service requirements for otherwise identical projects. In general, financing by consumer-owned utilities results in lower capital service requirement than financing by either investor-owned utilities or independent developers. The object of the Council's plan is to choose among types of resources rather than to recommend the development of specific resources. For this reason, a single type of resource developer is chosen to provide consistent comparisons of resource costs. Investor-owned utility financing is used as this basis in this power plan.

Plant investment costs are calculated using the Council's MicroFin model. MicroFin is a spreadsheet model used to calculate annual and levelized lifecycle minimum revenue requirements for various resource alternatives. Accelerated depreciation is normalized for investor-owned utility financing. Investment and production tax credits are credited as available against project costs. MicroFin is used by the Council to calculate levelized electricity costs for broad comparisons among resource alternatives, to calculate levelized fixed costs required to model new resource option in the AURORA$^{xmp®}$ model and to calculate the levelized cost of the the three phases of development and construction (Option, Early Construction and Committed Construction) required for the Regional Portfolio Model. Though investor-owned utility financing is used as the standard for this plan, MicroFin can also model typical consumer-owned utility financing and non-third party independent power developer financing. MicroFin is available from the Council on request.

The financing parameter values used in MicroFin are shown in Table I-2.

Table I-2: Assumptions regarding financing and other common parameters (Values are nominal unless stated)

	Municipal/ PUD	Investor-Owned Utility	Independent Power Producer
Federal Income Tax Rate	--	35%	35%
Federal Investment Tax Credit	--	See Incentives	See Incentives
FIT Recovery Period	--	See Incentives	See Incentives
State Income Tax Rate	--	5.9%	5.9%
State Investment Tax Credit	--	None	None
SIT Recovery Period	--	Same as federal	Same as federal
Property Tax	1.4%	1.4%	1.4%
Insurance	0.25%	0.25%	0.25%
Debt Term	Economic life	Economic life	15 years max
Equity return	--	Economic life	15 years max
Debt fraction - Development	100%	50%	0%
Debt fraction - Construction	100%	50%	60%
Debt fraction - Term	100%	50%	60%
Debt interest - Development	5.2%	7.3%	--
Debt interest - Construction	5.2%	7.3%	6.0%
Debt interest - Term	5.2%	7.3%	7.3%
Return on Equity - Development	--	11.0%	--
Return on Equity - Construction	--	11.0%	14.5%
Return on Equity - Term	--	11.0%	14.5%
Debt Financing Fee	2.0%	2.0%	2.0%
Discount Rate	4.4%	7.3%	7.7%
General Inflation Rate	2.0%	2.0%	2.0%

Incentives

Existing federal energy production tax credit and investment tax credit are assumed to apply to qualifying resources for their currently authorized term. Existing provisions for accelerated depreciation are assumed to continue indefinitely. Numerous complexities and options are present in the tax code with respect to these incentives and simplifications are made here, for example, the "tax credit appetite" of the developing entity is constrained only by the federal income tax incurred by this specific project. No conversions to investment tax credit are taken. Assumptions regarding federal incentives are provided in Table I-3.

Table I-3: Assumptions regarding federal incentives (2006 year dollar values)

Resource	PTC2 (Alternative to ITC)	ITC3 (Alternative to PTC)	Accelerated Depreciation Recovery Period3
Biomass (Open loop)	$9.85/MWh thru 2013	None	7-year
CHP4 (OL Biomass)	$9.85/MWh thru 20135	10% thru 20166	5-year
CHP4 (NG)	None	10% thru 20166	5-year
Geothermal	$19.70/MWh thru 2013	10% (no expiration date)	5-year
Hydropower7	$9.85/MWh thru 2013	None	20-year
Solar	$9.85/MWh thru 2013	30% thru 2016, 10% thereafter	5-year
Wind	$19.70/MWh thru 2012	None	5-year

State incentives represent within-region income transfers and are not considered in calculating project costs[8] to better represent true project costs.

Transmission

[Portions of this section are yet to be completed]

[2] The federal production tax credit is generally available for the first ten years of operation.
[3] Investment tax credit and accelerated depreciation may be limited to only a portion of total plant investment. In this plan the credits are assumed to apply to the entire investment.
[4] Including waste heat energy recovery.
[5] Denied if investment tax credit is taken (26 USC ¶ 48(c)(3)..
[6] Tests regarding size, net thermal efficiency and percentage energy to electrical and non-electrical loads apply to CHP facilities (26 USC ¶ 48(c)(3).
[7] Qualifications apply.
[8] This treatment is not entirely consistent with the treatment of state taxes. These also represent within-region income transfer. Omitting state taxes, however, would eliminate a fairly significant cost that is in-theory applicable to all resources.

Table I-4: Transmission lines to access remote resources

Line	Segments	Type	Capacity	Line Miles	Capital Cost (MM$)	Losses
MT Wind to ID	Townsend, MT - Midpoint, ID (MSTI)	Sgl ckt 500kV AC	1500 MW	415	1100	4.2%
MT Wind to OR/WA	Townsend, MT - Midpoint, ID (MSTI) Midpoint, ID - Hemmingway, ID (Gateway W. Seg 8) Hemmingway, ID - Boardman, OR (B2H)	Sgl ckt 500kV AC	1500 MW	844	2200	6.5%
AB Wind to OR/WA	Milo, AB - Grass Valley, OR (Northern Lights HVDC)	Sgl ckt +/- 500kV DC	2000 MW	615	1900	4.3%
NV Solar to ID	White R. Valley, NV - Thirtymile, NV (No proposal) Thirtymile, NV - Midpoint, ID (SWIP N.)	Sgl ckt 500kV AC	1500 MW	370	1000	4.0%
NV Solar to OR/WA	White R. Valley, NV - Thirtymile, NV (No proposal) Thirtymile, NV - Midpoint, ID (SWIP N.) Midpoint, ID - Hemmingway, ID (Gateway W. Seg 8) Hemmingway, ID - Boardman, OR (B2H)	Sgl ckt 500kV AC	1500 MW	800	2100	6.5%
WY Wind to ID	Aeolus, WY - Creston (Gateway W. Seg 2) Creston - Bridger (Gateway W. Seg 3) Bridger, WY - Populus, ID (Gateway W. Seg 4) Populus - Cedar Hill, ID (Gateway W. Seg 7)	Sgl ckt 500kV AC	1500 MW	470	1300	4.5%
WY Wind to OR/WA	Aeolus, WY - Creston (Gateway W. Seg 2) Creston - Bridger (Gateway W. Seg 3) Bridger, WY - Populus, ID (Gateway W. Seg 4) Populus - Cedar Hill (Gateway W. Seg 7) Cedar Hill - Hemmingway (Gateway W. Seg 9) Hemingway, ID - Boardman, OR (B2H line)	Sgl ckt 500kV AC	1500 MW	930	2400	7.0%

Integration Cost for Variable Resources

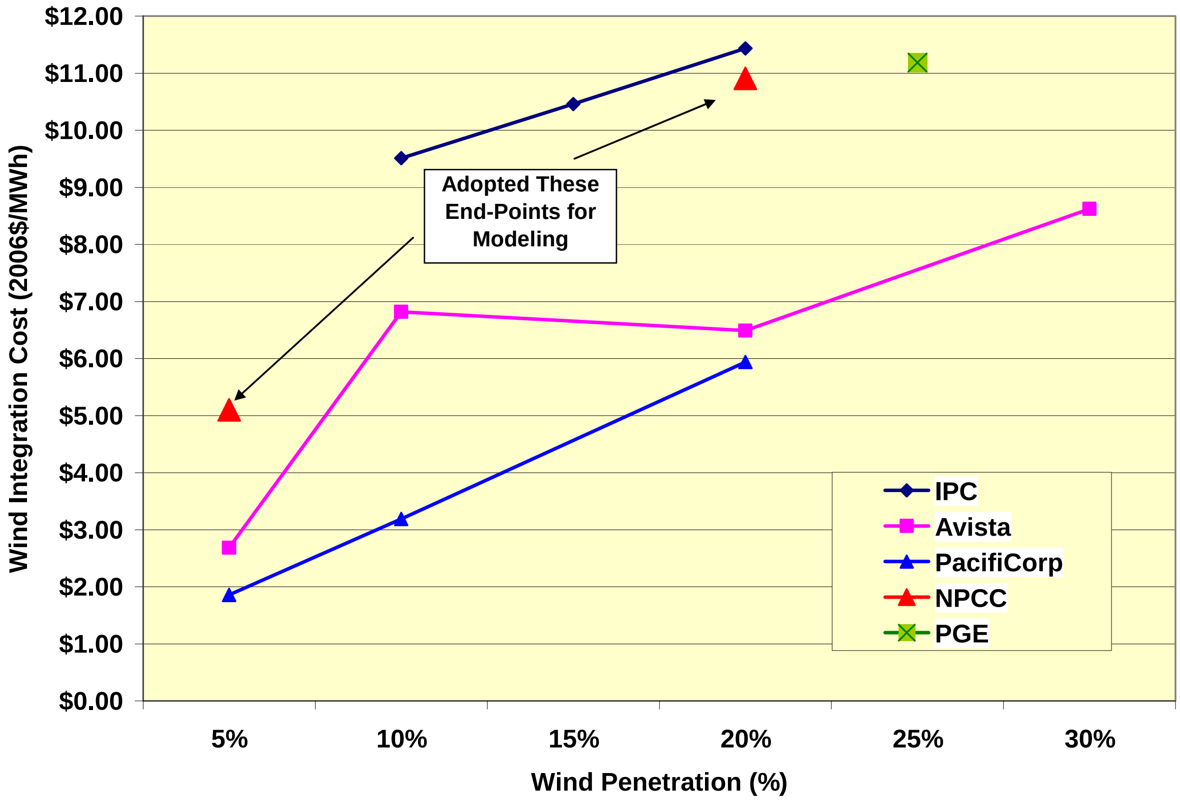
Balancing services (regulation and sub-hourly load-following) for integration of variable output renewable resources such as wind and solar are provided by reserving generating capacity for up-regulation ("up-reg") and for down-regulation ("down-reg"). Up-regulation capability is the ability to increase generation to offset unforecasted loss of variable resource output. Down-regulation is the ability to reduce generation to offset unforecasted increases in variable resource output. Unless the variable resource is not operating, or is operating at full output, up-regulation and down-regulation must be provided simultaneously.

The provision of balancing services incurs cost because of foregone revenues or savings. Reserving capacity for up-regulation incurs foregone revenue that would have been received if the reserved capacity could have been profitably dispatched into the market. Reserving capacity for down-regulation incurs cost if the variable cost of the reserved capacity is greater than the market value of power. For these reasons, the cost of providing balancing services is sensitive to the wholesale value of power and the resource used to provide the services. Moreover, the cost of providing balancing services is a function of the penetration of installed variable resource capacity compared to peak load.

Only capacity that which is technically and environmentally capable of rapidly responding to changes in load (flexible capacity) is suitable for providing balancing services. Hydro capacity, though technically extremely flexible and frequently used to provide balancing services, can result in consumption of water, a limited energy source, during periods of low market value. An optimal balancing resource is technically and environmentally capable of flexible operation and has variable operating costs close to the market value of power.

The cost of providing balancing services is best estimated with a system impact study where the costs of operating the system with and without a given amount of variable resources are compared. This type of analysis was not performed for estimating regional variable resource integration costs because of time and modeling considerations. Rather, an approximate relationship of within-hour balancing costs to wind penetration was subjectively developed from wind integration studies undertaken by various regional utilities (Figure I-2).

Figure I-2: Wind integration cost estimates as a function of wind penetration from various wind integration studies



The lower end-point of the proposed regional cost curve represents a cost of about $5.00 per MWh at 2% penetration (currently about 500 MW). The upper end-point represents a cost of $10.90 at 17% system penetration (currently about 6000 MW). For purposes of the initial resource assessment, wholesale price forecasts and resource portfolio model development, penetration (and therefore integration cost) was assumed to be a linear function of time. The forecast was rebased for the 2010 - 2029 planning period based on an estimated installed regional wind capacity through 2009 of 11%. This yields a 2010 integration cost of $8.85/MWh. The upper end of the integration cost curve ($10.90/MWh) was assumed to be reached in 2024, and run flat in real terms thereafter (Table I-5). Because the variable resource penetration rate and final penetration level resulting from the final resource portfolio may differ from these assumptions, this curve will be revisited prior to release of the final plan.

Table I-5: Forecast regulation and load-following cost and CO_2 allowance prices

	Regulation and Load-following ($/MWh)	CO2 Allowance Costs ($/tonCO2)
2010	$8.85	$0.00
2011	$8.99	$0.00
2012	$9.14	$8.05
2013	$9.29	$10.39
2014	$9.43	$13.00
2015	$9.58	$15.14
2016	$9.73	$16.93
2017	$9.87	$19.15
2018	$10.02	$21.70
2019	$10.17	$24.23
2020	$10.31	$26.76
2021	$10.46	$29.15
2022	$10.61	$31.79
2023	$10.75	$34.59
2024	$10.90	$36.85
2025	$10.90	$39.32
2026	$10.90	$41.23
2027	$10.90	$43.29
2028	$10.90	$45.67
2029	$10.90	$46.72

Carbon Dioxide Allowance Prices

A deterministic forecast of CO_2 allowance (or equivalent tax) prices is used for estimating the levelized electricity costs of fossil fuel resources for broad comparisons among resource alternatives. This series is also used in the AURORA$^{xmp®}$ model for forecasting wholesale power prices. Future carbon dioxide allowance prices are modeled as an uncertain variable in the Regional Portfolio Model (RPM), as described in Chapter 8. The deterministic forecast of CO_2 allowance prices (Table I-GEN-3) is the mean value of the probability distribution initially proposed for the RPM in late 2008. In response to comments from the Council's Generating Resources Advisory Committee, that proposed distribution was subsequently modified to move forward the year of 50% probability of some CO_2 allowance price. However, the deterministic time series used for MicroFin and AURORA$^{xmp®}$ studies was not updated to reflect the modified probability distribution. As a result, the values shown in Table I-GEN-3 for the mid-term period are slightly lower than the mean of the values used in the RPM for the draft plan. The difference is slight and is unlikely to significantly affect resource decisions. The forecasts will be reconciled for the final plan.

Carbon Dioxide Sequestration

Numerous possibilities exist for isolating carbon dioxide produced by fossil fuel combustion from the atmosphere for long periods of time. The CO_2 from coal-fired power generating facilities is an attractive target for sequestration because power plants are large stationary point sources of CO_2, and many plants are located within a feasible transportation distance from potential sequestration sites.

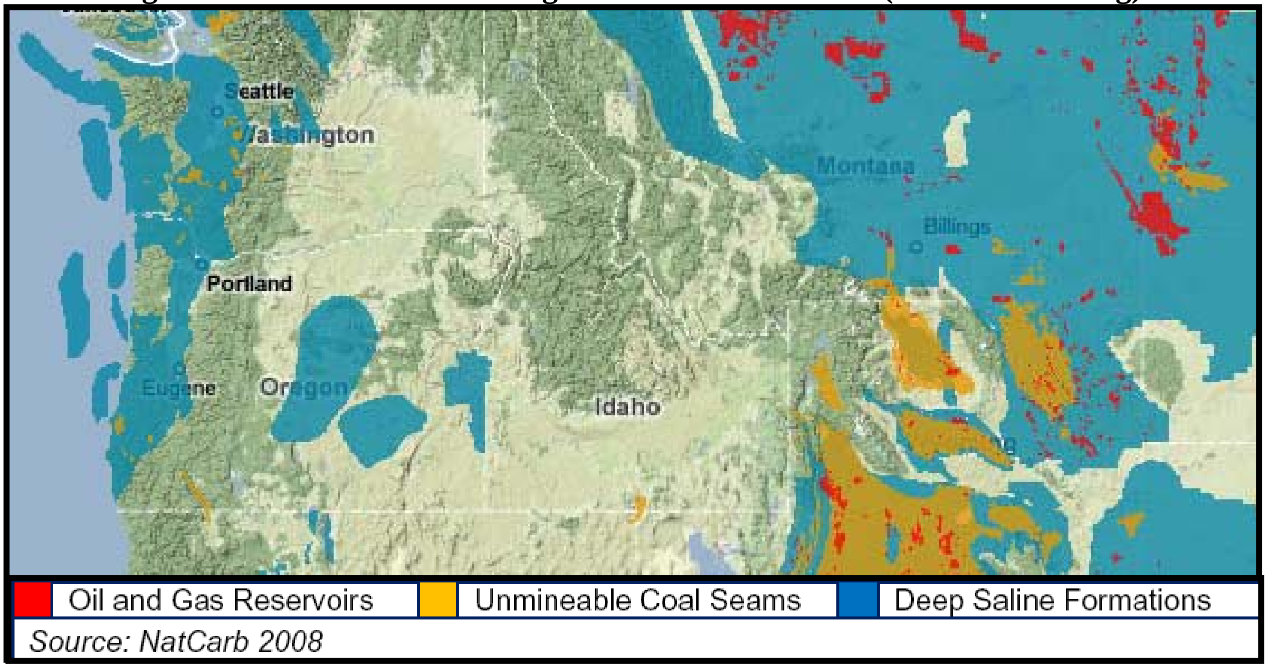
Proposals for long-term storage of CO_2 from power plant operation include deep oceanic injection and several geologic mechanisms. The general concept is to separate CO2 at the power plant into a relatively pure form, compress the CO_2 to a liquid state and transport the liquid to the sequestration facility by pipeline for injection. The pipeline operating pressure would be sufficient for injection without further compression at the sequestration facility.

Oceanic CO_2 injection, though feasible, is controversial because of potential impacts on the ocean environment and marine life. Pilot projects in Hawaii and Norway have been cancelled as a result. Certain marine treaties now prohibit storage of CO_2 in the water column or seabed (IEA, 2008a). Geologic sequestration options with Northwest potential are described below. The following discussion is compiled from EcoSecurities (2008), IEA (2004), IEA (2008a) and the Big Sky Carbon Sequestration Partnership (http://www.bigskyco2.org).

CO_2-enhanced oil recovery: Carbon dioxide enhanced oil recovery (CO_2-EOR) is an established process whereby CO_2 is injected into oil fields to enhance recovery of remaining oil. The CO_2 repressurizes the reservoir and promotes release of remaining oil through viscosity reduction and other means. CO_2-EOR has been in commercial use for about three decades and about 3% of current world oil production is recovered using this technology. CO_2 sequestration is incidental to current CO_2-EOR operations, the objective of which is profitably recovering oil. EOR operations undertaken for the purpose of CO_2 sequestration would not necessarily operate at a profit though the value of the recovered oil would help offset overall costs. An added complexity of a sequestration operation is the need to ensure long-term reservoir integrity. While natural gas and oil reservoirs are inherently of great integrity, developed fields are punctured with wells, that if improperly plugged, could release sequestered CO_2. It is believed that enhanced oil recovery using CO_2 could eventually be applied to most oil fields, though the CO_2 sequestration capacity of depleted oil fields is relatively small compared to CO_2 production from power generation facilities. Scattered oilfields are found in eastern Montana (Figure I-3) and additional opportunities in Alberta, Wyoming and the Dakotas may be within feasible CO_2 transportation distance.

CO_2-enhanced natural gas recovery: Carbon dioxide enhanced natural gas recovery (CO_2-EGR) is a method of augmenting natural gas recovery and of reducing drawdown-related subsidence by repressurizing depleted natural gas fields. CO_2 is denser and more viscous than methane at reservoir conditions so the remaining methane tends to float above the injected CO_2, Methane withdrawal would continue until excessively diluted with CO_2 breaking through the overlying methane layer. A commercial-scale EGR demonstration project is underway in the North Sea, however the technology is not fully developed. As with CO2-EOR, a major issue is ensuring long-term reservoir integrity. Though the CO_2 sequestration potential of EGR might be larger than that of EOR, the economics are less favorable because of the lower revenue from the recovered methane per ton of injected CO_2.

Figure I-3: Potential CO2 storage sites in the Northwest (www.natcarb.org)



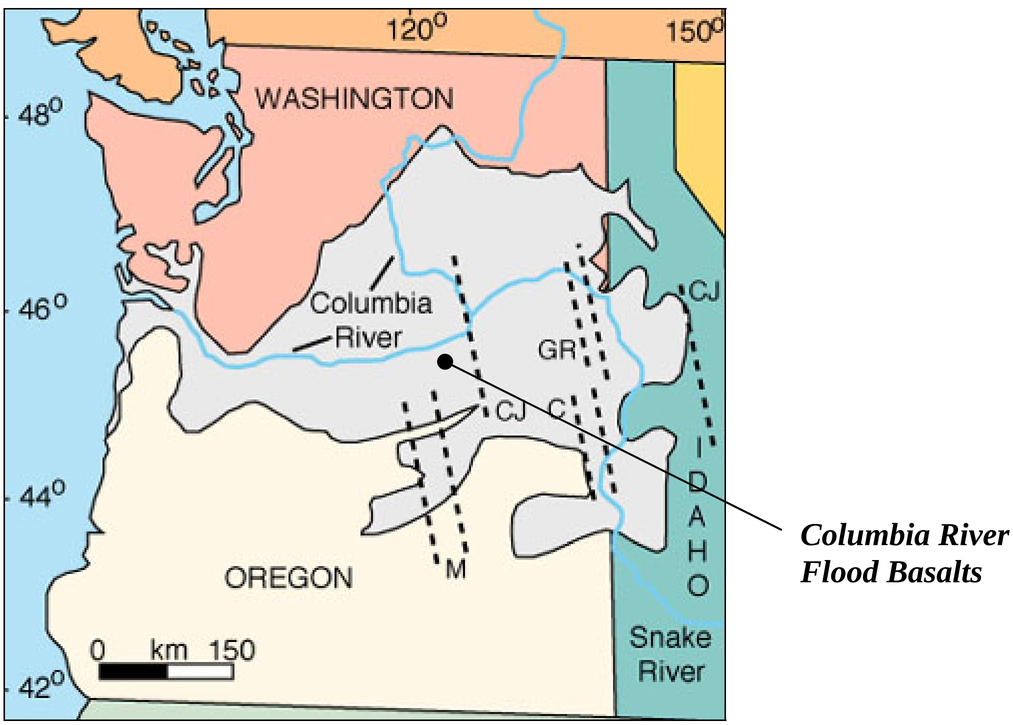
Depleted oil or gas fields: Carbon dioxide could be sequestered in depleted oil or gas fields using CO_2-EGR injection technology. The global theoretical potential for sequestering CO_2 in depleted oil and gas fields is of the same order of magnitude as for CO_2-EGR. Similar issues regarding resource integrity would be present and net cost would be higher because of the absence of byproduct oil or gas. Existing production wells could be repurposed for CO_2 injection.

CO_2-enhanced coal bed methane recovery (ECBM): Coal beds typically contain large amounts of methane-rich gas adsorbed to the coal. Because carbon dioxide is preferentially adsorbed to coal, injection of CO_2 into deep unmineable coal seams could sequester the CO_2 and produce methane as a marketable product. CO_2 is physically adsorbed to the coal, increasing confidence in long-term storage integrity. Coal measures potentially offering ECBM potential are scattered within the four states and a substantial area of potential is present in Wyoming (Figure I-3). The effectiveness and economic feasibility of enhanced coal bed methane recovery using CO_2 injection is promising but yet to be fully demonstrated.

Deep saline aquifers: Deep saline aquifers consisting of porous rocks saturated with brine are found throughout the world, many located in the same sedimentary basins from which coal and other fossil fuels are extracted. The brines are of high salt content and typically unsuitable for agricultural use or human consumption. If confined by underlying and overlying layers of restricted permeability these formations may be suitable for long-term storage of very large quantities of CO_2. Though initially accumulating under the cap rock, the injected CO2 is expected to eventually dissolve in the brine, promoting secure long-term storage. Deep saline formations are located below the coalfields of eastern Montana and between the Cascades and the coast (Figure I-3). The technical feasibility of CO_2 storage in deep saline aquifers has been demonstrated in the North Sea. Remaining questions relate to the amount of CO_2 that can be injected into a given aquifer volume, the long-term expansion and migration of the CO2 plume and the geochemical reactions expected to occur over time.

Flood basalt formations: The Columbia River flood basalts and possibly other basalt formations present a potential CO2 sequestration option of particular interest to the Northwest. Flood basalts consisting of several hundred individual flows, each tens to hundreds of feet in thickness cover the central Columbia Basin and extend to the Pacific along the course of the Columbia River (Figure I-4). Many of the individual flows consist of a fractured and highly porous upper layer and a dense impermeable lower layer. Carbon dioxide could be stored in the porous upper layer, trapped between the dense lower layers of the same flow and the adjacent overlying flow. Preliminary experiments indicate that carbon dioxide would be rapidly converted to solid carbonaceous minerals in the basaltic environment, ensuring permanent storage.

Figure I-4: Columbia River Flood basalts (Oregon State University)



The U.S. DOE Regional Carbon Sequestration Partnerships and the National Carbon Sequestration Database and Geographical Information System are assessing the potential for carbon sequestration for individual U.S. states and Canadian provinces. Results are published and periodically updated in the *Carbon Sequestration Atlas of the United States and Canada* (USDOE, 2008). The top section of Table I-6 shows the current estimates of technical sequestration potential for the four Northwest states for three types of formations potentially suitable for CO_2 sequestration. The values in this section are from the *Carbon Sequestration Atlas.* To provide perspective regarding this potential, the lower section of the table expresses the technical potential in terms of the number of years of CO_2 storage potential at the estimated CO_2

production rate from Northwest coal-fired power plants in 2005. Practical storage potential is likely to be much less than the theoretical potential. This suggests that though sequestration in oil and gas reservoirs and unminable coal seams is, in general, technically more advanced than sequestration in deep saline formations, and moreover, may yield marketable oil or gas to help offset sequestration costs, deep saline formations appear to be the principal candidate for sequestration of significant amounts of CO_2 over the long-term.

Table I-6: Theoretical storage potential of several Northwest CO_2 sequestration options

	Oil and Gas Reservoirs	Unmineable Coal Seams	Deep Saline Formations
Technical Potential (MM tonsCO2)			
ID	0	Not reported	Not reported
MT	1388	322	291,948 -1,087,714
OR	0	Not reported	18,400 - 73,600
WA	0	3080-3395	99,270 -397,077
Total	**1388**	**3402**	**409,617 -1,558,391**
Technical Potential (Years @ 2005 CO2 production rate)			
ID	0	--	--
MT	28	7	6000 - 22,000
OR	0	--	400 - 1500
WA	0	63 - 69	2000 - 8,000
Total	**28**	**70 - 76**	**8300 - 32,000**

The overall cost of carbon dioxide separation and sequestration includes the incremental capital and operating costs of the power plant facilities for separation and compression of CO_2, including the effects of additional electrical and steam loads on plant heat rate; the capital and operating costs of transporting the compressed, liquefied CO_2; and the capital and operating costs of the sequestration facility including long-term monitoring of reservoir integrity. The incremental costs and heat rate penalty for power plants with CO_2 separation are included in the description of the reference coal-fired power plants in the Assumptions for Reference Plants section of this Appendix.

The estimated cost of transporting CO2 from power plant to sequestration facility ranges from $1 - 8/tonne CO2 (0.90 - $7.20/ton) (EcoSecurities, 2008). The estimated cost of sequestering CO2 in depleted oil fields ranges from $0.50 - 4.00/tonne CO2 ($0.45 - $3.30/ton) and in depleted gas fields from $0.50 - 12.00/tonne CO2 ($0.45 - $10.90/ton) (EcoSecurities, 2008). Storage in deep saline aquifers is estimated to cost from $0.40 - 4.50/tonne CO2 ($0.36 - $4.10/ton) (EcoSecurities, 2008).

For purposes of this plan, CO2 transportation costs are assumed to average $4.00/ton CO2 - an approximation of the $1 - 8/tonne CO_2 range cited in EcoSecurities (2008). CO2 transportation is a mature technology and current cost estimates should be a reliable indicator of actual future costs. While appealing because of the potential revenue from recovered oil and gas, any serious attempt to reduce atmospheric releases of CO_2 would appear to quickly overwhelm the available capacity of partially depleted oil or gas fields in the Northwest. Sequestration in deep saline formations currently appears to be the most promising candidate for large-scale sequestration in the Northwest. The concept is in the early stages of development, however, and experience with developing technologies suggests that costs are bound to rise much higher than current estimates as the concept is commercialized. For this reason, for this plan the Council assumes CO_2 sequestration costs average $22.50/ton CO_2, the high end of the $15 - 25/tonne CO_2 overall North American cost range cited in IEA (2008a).

A commercial-scale deep saline sequestration facility in the Northwest is assumed to be available for operation no earlier than 2023. Given the research, development and demonstration needed to resolve remaining technical issues, the legal and institutional questions needing resolution and the development and construction time required for a commercial-scale CO2 sequestration facility and transportation pipelines, such a facility may not be feasible within the planning period.

ASSUMPTIONS FOR REFERENCE PLANTS

Landfill Gas

A landfill gas energy recovery plant uses the methane content of the gas produced as a result of the decomposition of landfill contents to generate electric power. The complete recovery system includes an array of collection wells, collection piping, gas cleanup equipment and one or more generator sets, usually using reciprocating engines. Typically, the gas collection system is installed as a requirement of landfill operation and the raw gas sold to the operator of the power plant.

Reference Plant: The reference plant consists of two 1.6 MW reciprocating engine generating unit fuelled by landfill gas. The scope includes gas processing equipment, engine-generator sets, powerhouse and maintenance structure and power generation site infrastructure.

Availability Parameters: Plant availability parameters are as follows:

Scheduled maintenance - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

Equivalent annual availability - 88%

Capacity Factor: Landfill gas energy recovery plants are assumed to operate at an annual capacity factor of 85%, based on CEC (2007).

***Unit Commitment Parameters*:** Landfill gas energy recovery plants operate as must-run units.

Heat rate: The heat rate of the reference plant is 10060 Btu/kWh. Heat rate is inversely correlated with engine capacity and is derived from the following capacity - heat rate relationship for small reciprocating engines, from Exhibit 3-10 of WGA (2006):

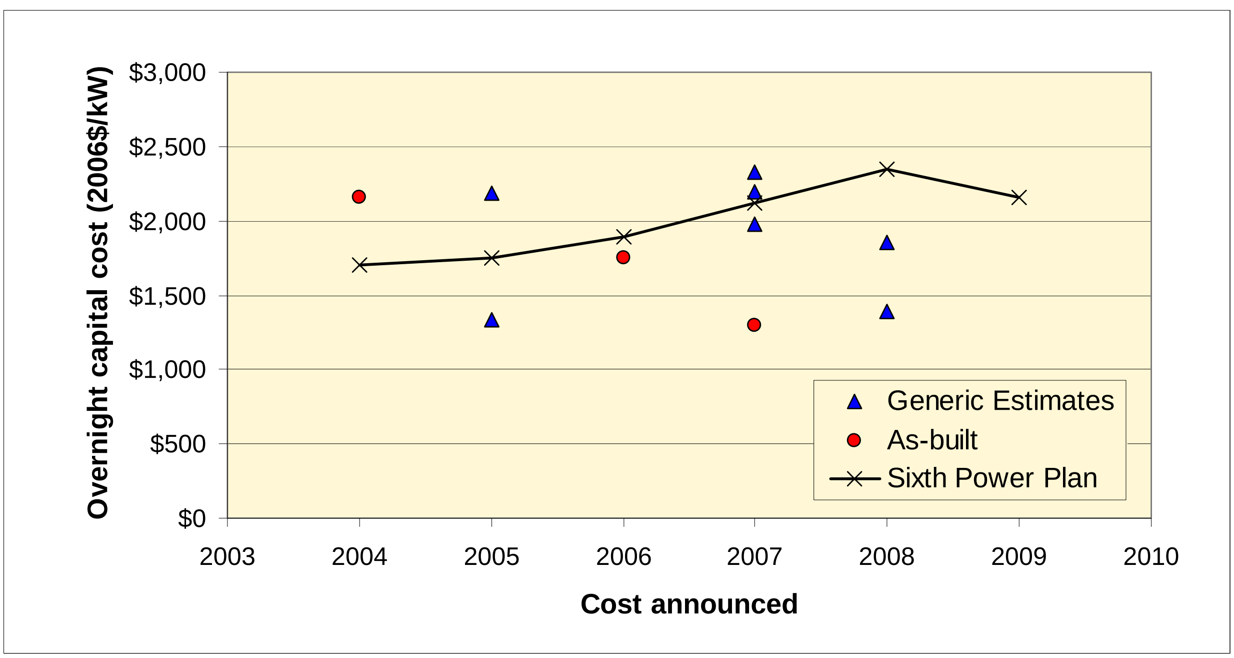
Heat Rate (HHV) = $10159x^{-0.0555}$

Where x is the plant capacity in megawatts

Total Plant Cost: The "overnight" total plant cost of the reference plant is $2350/kW installed capacity (2008 price year). This estimate is based on reported costs for three as-built plants. Four generic estimates of landfill plant development costs were also obtained. Three of these were range estimates consisting of low and high bound costs. These cost observations, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-5. The increase in capital costs from 2004 to 2008, clearly observed for most power generation technologies is not clearly evident here, particularly for the reported as-built costs. A possible reason may be that the built projects were of substantially different scopes (e.g., with or without the gas collection system) not reported. For this reason, the representative project cost estimate was based on a projection of the 2005 and 2007 generic costs cost, which together with the 2006 actual project cost seem to reasonably track observed power plant cost escalation during this period. Because landfill gas energy recovery projects were not modeled in the Regional Portfolio Model, capital cost uncertainty was not estimated.

The projected Total Plant Cost for landfill gas energy recovery plants is based on the forecast future cost of reciprocating engine generating plants. See Table I-1.

Figure I-5: Published costs of landfill gas energy recovery projects normalized to total plant costs



Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for a landfill gas energy recovery plant are those assumed for reciprocating engine power plants:

> **Development** (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 18 mo., 3% of total plant cost
>
> **Early Construction** (Final engineering, major equipment order, site preparation) - 9 mo., 9% of total plant cost
>
> **Committed Construction** (Delivery of major equipment, completion of construction and testing) - 6 mo., 88% of total plant cost

Fuel Cost: A typical business arrangement is for the power plant operator to purchase the raw landfill gas from the landfill operator. The landfill operator is responsible for installing and operating the wellfield and collection system. The published sources of information regarding landfill gas prices suggest a wide range. Lazard (2008) reports landfill gas fuel costs ranging from $1.50 to $3.00/MMBtu. The Idaho Statesman reports that Ada County collects $0.89/MMBtu plus 40% of REC and PTC credits for the Ada County Landfill Waste-to Energy plant. The effective fuel price (fuel plus 40% of the value of incentives) for the Ada plant 2007 was $1.50/MMBtu. Because the Ada price lies at the low end of the range reported by Lazard, a somewhat higher expected price, $2.00/MMBtu, is used for this plan is - higher than Ada county but towards the low end of the Lazard range.

Operating and maintenance costs: Operating and maintenance costs for landfill gas energy recovery plants were based on California Energy Commission estimates. The CEC estimates are consistent with other available estimates of the O&M costs of these plants when adjusted to comparable year dollars. Moreover, the CEC O&M costs are broken into fixed and variable components and exclude property tax and insurance, consistent with the Council's representative resource costs. Fixed O&M cost for landfill gas energy recovery ($26/kW/yr) is estimated to be 1.1% of the overnight capital cost described above. The 1.1% is based on the ratio of fixed O&M cost to overnight cost of Appendix B ("Economic Assumptions: Landfill Gas Fuel to Energy") of CEC (2007). The variable O&M cost ($19/MWh) was derived in a similar manner as 0.8% of total plant cost.

Economic Life: The economic lifetime of a landfill gas energy recovery plant is assumed to be 20 years; limited by the operating life of a reciprocating engine-generator and the productive life of a typical landfill.

Development potential: The remaining feasible development potential for landfill gas energy recovery facilities was derived from the U.S. EPA Landfill Methane Outreach Program database of candidate landfills for energy recovery[9]. EPA estimates of waste-in-place in candidate landfills in the four Northwest states were converted to estimated electricity production potential using values for gas generation potential and fuel energy content. From an assessment of landfill energy recovery potential in Oregon prepared for the Energy Trust of Oregon (ETO, 2005). The reference plant heat rate of 10,060 Btu/kWh was substituted for the more optimistic heat rate of 9000 Btu/kWh used in ETO study. This yielded a remaining undeveloped electric energy

[9] http://www.epa.gov/lmop/proj/index.htm

potential of 69 average megawatts (Table I-7). This estimate should be viewed as having considerable uncertainty. On one hand, emplaced waste will continue to increase during the planning period, even with aggressive reuse and recycling programs. On the other, the competing alternative of direct injection of landfill-derived gas into the natural gas system is less expensive than on-site generation of electric power.

Table I-7: Derivation of estimated undeveloped landfill gas energy recovery potential

	Waste in-place (tons)	Gas Generation Potential (MMscf/yr)	Fuel Energy (TBtu/yr)	Electric Energy (MWh/yr)	Developable Potential (MWa)
Idaho	2,000,000	400	0.18	17893	2
Montana	16,956,766	3391	1.53	151701	17
Oregon	25,022,845	5005	2.25	223862	26
Washington	23,656,412	4731	2.13	211638	24
Totals	**67636023**	**13527**	**6.09**	**605094**	**69**

Animal Waste Energy Recovery

The energy value of certain agricultural and food wastes can be recovered by processing the waste materials in anaerobic digesters. This yields a combustible gas that be used to fuel a thermal electric power generator. Reciprocating engine-generator sets are typically used for the power production. The most widely employed anaerobic digestion technology at present, uses animal manure in liquid or slurry form. The principal source of suitable feedstock is from manure handling systems at large concentrated animal feeding operations (CAFOs).

Reference Plant: The reference plant consists of a plug flow anaerobic digester supplied by liquid or slurry manure handling system at a large (500 head, or larger) CAFO dairy. The digester produces a low-Btu methane rich-gas that supplies an 850 kW reciprocating engine generating unit. Reject heat is recovered from the engine to maintain digester operating temperatures.

Availability: Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

Equivalent annual availability - 88%

***Unit Commitment Parameters*:** Animal waste energy recovery plants operate as must-run units.

Capacity Factor: Animal waste energy recovery plants are assumed to operate at an annual capacity factor of 75%, based on CEC (2007).

Heat rate: The heat rate of the reference plant is 10250 Btu/kWh. Heat rate is inversely correlated with engine capacity and is derived from the following capacity - heat rate relationship for small reciprocating engines, from Exhibit 3-10 of WGA (2006):

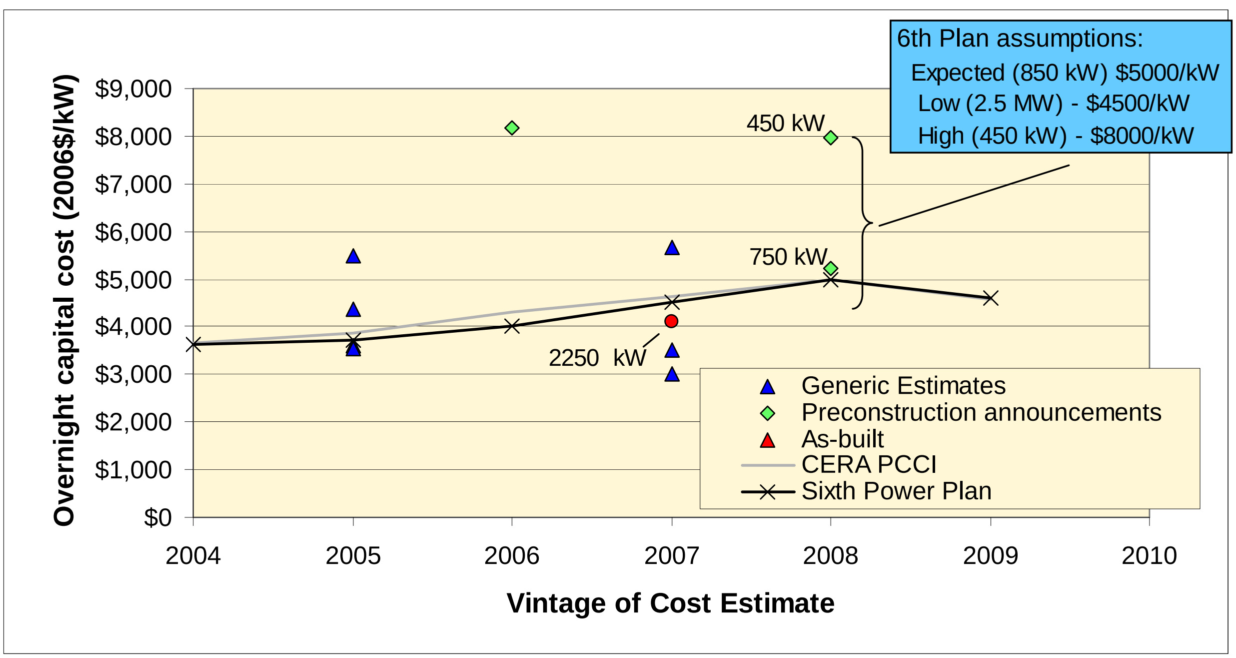
Heat Rate (HHV) = $10159x^{-0.0555}$

Where x is the plant capacity in megawatts

Total Plant Cost: The "overnight" total plant cost of the reference plant is $5000/kW installed capacity (2008 price year). This estimate is based on reported costs for 3 proposed and one completed plants and generic estimates from three sources. One of the generic sources provided a range estimate consisting of low and high bound costs and a second included estimates for a range of plant sizes. These observations were normalized as described in the Capital Cost Analysis subsection of this Appendix, and are plotted by vintage in Figure I-6. If the one 2006 extreme outlier is omitted, the distribution, though based on a limited sample size, is reasonably satisfying, with a wide range appearing to be primarily driven by installed capacity and to a lesser extent by the increased cost of manure handling facilities for joint plants serving several farms compared to on-farm plants. Costs rise increasingly rapidly as plant capacity declines. $5000/kW was chosen as the 2008 values for the reference (850 kW) plant with a range of $4500/kW for larger units (1 - 3 MW) and $8000 for smaller units (400 - 500kW). This resulting distribution is consistent with the general increase in power plant costs observed from 2004 through 2008 (represented by the CERA PCCI curve), the 2005 generic estimates (ETO, 2005) and the reported cost of the one completed plant from the sample (Bettencourt Dry Creek Dairy in Idaho).

The projected Total Plant Cost for is based on the forecast future cost index for reciprocating engine generating plants. See Table I-1.

Figure I-6: Published costs of animal manure energy recovery projects normalized to total plant costs



Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for an animal manure energy recovery plant are as follows:

> **Development** (Feasibility study, permitting, engineering) - 12 mo., 3% of total plant cost
>
> **Construction** (Equipment order, site preparation, delivery of equipment, completion of construction and testing) - 12 mo., 98% of total plant cost

Fuel Cost: Anaerobic digesters and associated power generation equipment serve as a solution to the challenging problem of disposing of large quantities of animal waste from large concentrated feeding operations. The value of the raw manure/fuel is assumed to be zero for this analysis. Depending on specific circumstances the raw manure might be considered to have a negative value.

Operating and Maintenance Cost: Fixed O&M cost for animal waste energy recovery is taken as 0.9% of capital cost, based on Table 6 ("AD Dairy") of CEC (2007). This yields $72/kW/yr for small (450 kW) facilities, $45/kW/yr for mid-range (850 kW) facilities and $41/kW/yr for large (2.5 MW) facilities.

Variable O&M cost for animal waste energy recovery is taken as 0.3% of capital cost, based on Table 6 ("AD Dairy") of CEC (2007). This yields $24/MWh for small facilities, $15/kW/yr for mid-range facilities and $14/kW/yr for large facilities.

Economic Life: The economic life of an animal waste energy recovery plant is assumed to be 15 years.

Development potential: The remaining feasible development potential for animal manure energy recovery facilities at dairy operations in the Northwest is estimated to be 61 MWa with a possible range of 51 to 108 MWa. The derivation of this estimate is shown in Table I-8. Potentially feasible operations and mature head are reported by EPA for the top ten states, including Idaho and Washington. These are operations of 500 head, or more and employing slurry or liquid manure handling systems. The Oregon data are from ETO, 2005, and are based on dairy farms of 500 head or more. The Oregon estimates do not appear to have been screened for use of slurry of liquid manure handling systems, so may be high. The expected energy production potential was estimated from head count using the 3 kWh per mature head per day, described as "realistic" in (ETO, 2005). The low end of the range is based on the value of 2.6 kWh/head-day assumed in EPA[10] and the high end was based on "optimistic" 5 kWh/head-day of ETO (2005).

[10] 38.5 ft^3 methane per cow-day using plug flow digesters (EPA, p.31) x 66 kWh/1000 ft^3 methane (EPA, p.32).

Table I-8: Derivation of estimated undeveloped animal manure energy recovery potential

	Feasible Operations	Mature Head at Feasible Operations (000)	Electric Generation Potential (MWa)	Operating and Committed Generation (MWa)	Developable Potential (MWa)
Idaho[11]	185	285	36	7.9	29
Montana[12]	--	--	--	--	--
Oregon[13]	32	114	14	0.5	14
Washington[11]	122	135	17	2.9	14
Totals	**339**	**534**	**67**	**11.3**	**57**

Wastewater Treatment Plant Energy Recovery

Sludge collected in the clarification stage of wastewater treatment is commonly processed to remove volatile organic materials in anaerobic digesters. Anerobic digestion produces a low-Btu gas consisting largely of methane and carbon-dioxide. This gas can be treated to remove moisture, siloxanes, hydrogen sulfide and other impurities and used to fuel a electric generating plant. Reject heat from the engine is used to maintain optimum digester temperature.

Reference Plant: The reference plant is an 850-kilowatt reciprocating engine generating unit fuelled by gas from the anaerobic digestors of a wastewater treatment plant. Reject engine heat is captured and used to maintain optimal digester temperatures. The estimated capital cost of the installation includes engine-generator, gas processing equipment, heat recovery equipment, interconnection equipment and associated infrastructure. The anaerobic digestors are assumed to be present.

Availability: Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 8%

Mean time to repair - Not estimated (stochastic outages not modeled)

Equivalent annual availability - 88%

***Unit Commitment Parameters*:** Animal waste energy recovery plants operate as must-run units.

Capacity Factor: Wastewater treatment plant energy recovery systems are assumed to operate at an annual capacity factor of 85%, based on CEC (2007)

Heat rate: The heat rate of the reference plant is 10250 Btu/kWh. Heat rate is inversely correlated with engine capacity and is derived from the following capacity - heat rate relationship for small reciprocating engines, from Exhibit 3-10 of WGA (2006):

Heat Rate (HHV) = $10159x^{-0.0555}$

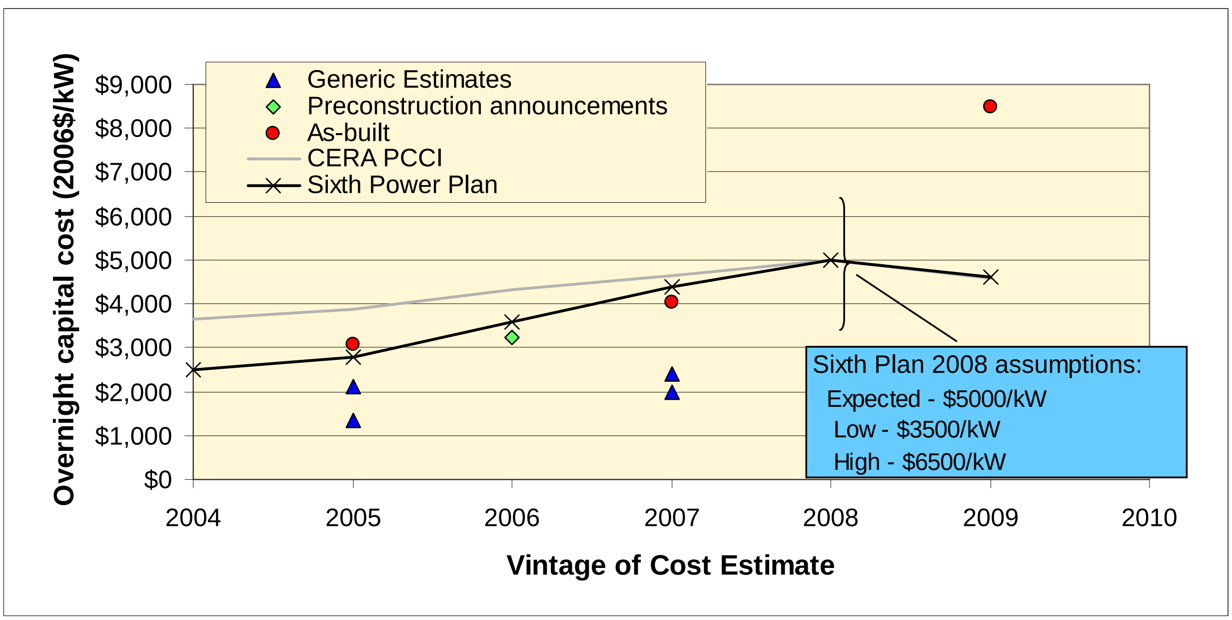
[11] U.S. Environmental Protection Agency (Undated)
[12] No estimates were located for Montana. The number of large confined dairy operations in Montana is thught to be small.
[13] Energy Trust of Oregon (2005)

Where x is the plant capacity in megawatts

Total Plant Cost: The "overnight" total plant cost of the reference plant is $5000/kW installed capacity (2008 price year). This estimate is based on reported costs for one proposed and two completed plants (a preconstruction and an as-built estimate is available for one of the latter). Generic estimates were obtained from three sources. One of the generic sources provided a range estimate consisting of low and high bound costs. These observations were normalized as described in the Capital Cost Analysis subsection of this Appendix, and are plotted by vintage in Figure I-7. The normalized preconstruction and as-built costs show much higher costs than do the generic estimates and much stronger escalation than do the generic costs or CERA Power Capital Cost Index. Because the underlying cost and plant configuration information is considered reliable and representative, the as-built and preconstruction estimates for 2005, 2006 and 2007 guided the development of the Sixth Power Plan 2004-09 values. The scope of the 2009 project is believed to be more extensive than a typical project hence the much higher cost. The range of uncertainty is +/- 30% of the reference 2008 cost, consistent with a "simplified" to "preliminary' quality estimate.

The projected Total Plant Cost (Table I-1) is based on the forecast future cost index for reciprocating engines.

Figure I-7: Published costs of wastewater treatment plant energy recovery projects normalized to total plant costs



Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for a wastewater treatment plant energy recovery plant are those assumed for reciprocating engine power plants:

> **Development** (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 18 mo., 3% of total plant cost

Early Construction (Final engineering, major equipment order, site preparation) - 9 mo., 9% of total plant cost

Committed Construction (Delivery of major equipment, completion of construction and testing) - 6 mo., 88% of total plant cost

Fuel Cost: The reference plant is applicable to a wastewater treatment facility already containing anaerobic sludge digesters and associated gas collection system. The fuel is therefore assumed to be free.

Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance for wastewater treatment plant energy recovery ($32/kW/yr) is taken as 0.8% of capital cost, based on Table 6 ("Biomass - WWTP") of CEC (2007). Variable O&M ($24/MWh) is taken as 0.6% of capital cost, based on Table 6 ("Biomass - WWTP") of CEC (2007).

Economic Life: The economic life of a wastewater treatment energy recovery plant is assumed to be 20 years; limited by the operating life of a reciprocating engine-generator.

Development potential: The remaining development potential for wastewater treatment energy recovery facilities in the Northwest is estimated to be about 12 MWa. This estimate is based on reported influent flow at waste treatment facilities in the four states that receive at least 5 MMgpd. (Appendix B of EPA, 2007). Total potential generation was calculated assuming production of 650 Btu/scf digester gas at a rate of 10,000 scf gas per MMgpd influent and energy conversion at a heat rate of 10,250 Btu/kWh. This yielded a total potential (developed and undeveloped) of 21 MWa, including the energy output of several facilities with operating generation not reported in EPA, 2007. Currently installed capacity at Northwest treatment facilities is capable of producing about 9 MWa. This was deducted from the total potential to yield the 12 MWa of undeveloped potential. Several trends could increase this potential. Future population growth will likely increase total regional influent production. This will increase the potential at plants included in the inventory on which the estimate is based, and may increase the number of candidate facilities (facilities receiving at least 5 MMgpd of influent, on average, and facilities using anaerobic sludge treatment). Also, larger plants will tend to employ larger power generation units which tend to be more efficient. Advances in reciprocating engine and other potentially suitable generating technologies will increase plant heat rates and therefore, the generation potential, and may also enhance the feasibility of developing energy recovery facilities at smaller treatment plants. On the other hand, some treatment facilities may choose to sell treated biogas to natural gas companies for injection into the natural gas network. However, this use of biogas, though requiring less capital investment that electric power generation, seems less likely for treatment plants, because some biogas would need to be substituted for recovered generating plant reject heat to maintain digester temperatures.

Table I-9: Derivation of estimated undeveloped wastewater treatment plant energy recovery potential

[Table to be supplied]

Woody Residue Power Plant

[Portions of this section are yet to be completed]

A woody residue steam-electric power plant converts the chemical energy of woody biomass to electric energy. Conventional plants are based on steam-electric generating technology and range in size from several to about 50 megawatts. Fluidized-bed boilers are increasingly used to provide flexibility to combust a wide variety of fuels, improve combustion efficiency and to facilitate air quality control. Small-scale modular plants are under development that could be periodically relocated to "follow the fuel" and thereby lower fuel transportation costs. Wood-fired power plants are often located at wood product plants providing both a source of residue fuel and a cogeneration steam load.

Reference Plant: The reference plant is a 25 MW steam-electric generating unit fuelled by forest thinning and other sources of woody residue. The plant includes fuel receiving, processing and storage facilities, a fluidized bed boiler, steam turbine-generator wet mechanical draft condenser cooling towers, electrical interconnection, site and supporting infrastructure. Stand-alone and cogeneration cases are described.

Availability: Plant availability parameters are as follows:

Scheduled maintenance outages - 35 days/yr

Equivalent forced outage rate - 7%

Mean time to repair - 40 hours

Equivalent annual availability - 84%

Capacity Factor: Plants serving a cogeneration load are assumed to be must-run. The default capacity factor used for must-run units is 80%. The historical energy production of woody residue plants in the Northwest indicates that annual average capacity factors of 80% or better are readily achievable for newer units.

Heat rate: The heat rate of the stand-alone plant is 15,500 Btu/kWh. The electrical heat rate (fuel charged to power) of the cogeneration plant is

***Unit Commitment Parameters*:** Woody residue plants are assumed to operate as must-run units.

Total Plant Cost:

Figure I-8: Published costs of woody residue power generation projects normalized to total plant costs

[Table to be supplied]

Development and Construction Schedule, Cash Flows: Development and construction schedule and cash flow assumptions for a woody residue steam electric plant are as follows:

Development (Feasibility study, permitting, geophysical assessment, preliminary engineering) - 24 mo., 2% of total plant cost

Early Construction (Final engineering, major equipment order, site preparation) - 12 mo., 47% of total plant cost

Committed Construction (Delivery of major equipment, completion of construction and testing) - 12 mo., 51% of total plant cost

Fuel Cost:

Operating and maintenance costs: Economic Life: The economic life of a stand-alone steam-electric plant fuelled by woody residue is assumed to be 20 years; limited by uncertainties regarding continued fuel supply availability.

Development potential:

Table I-10: Derivation of estimated undeveloped woody residue energy recovery potential

[Table to be supplied]

Geothermal

Reference Plant: The reference plant is a 40 megawatt (nominal) binary cycle plant comprised of three 13-megawatt (net) units. The plant is assumed to use closed loop organic Rankine cycle technology suitable for low geothermal fluid temperatures. The plant includes production and injection wells, geothermal fluid piping, power block, cooling towers, step-up transformers, switchgear and interconnection facilities and security, control and maintenance facilities. Wet cooling, resulting in higher plant efficiency, greater productivity and lower cost would likely be used at sites with sufficient water. Dry cooling could be employed at sites with insufficient cooling water availability, at additional cost and some sacrifice in efficiency and productivity.

Availability Parameters: Plant availability parameters are as follows:

Scheduled maintenance outages - 14 days/yr

Equivalent forced outage rate - 6.4%

Mean time to repair - 40 hours

Equivalent annual availability - 90%

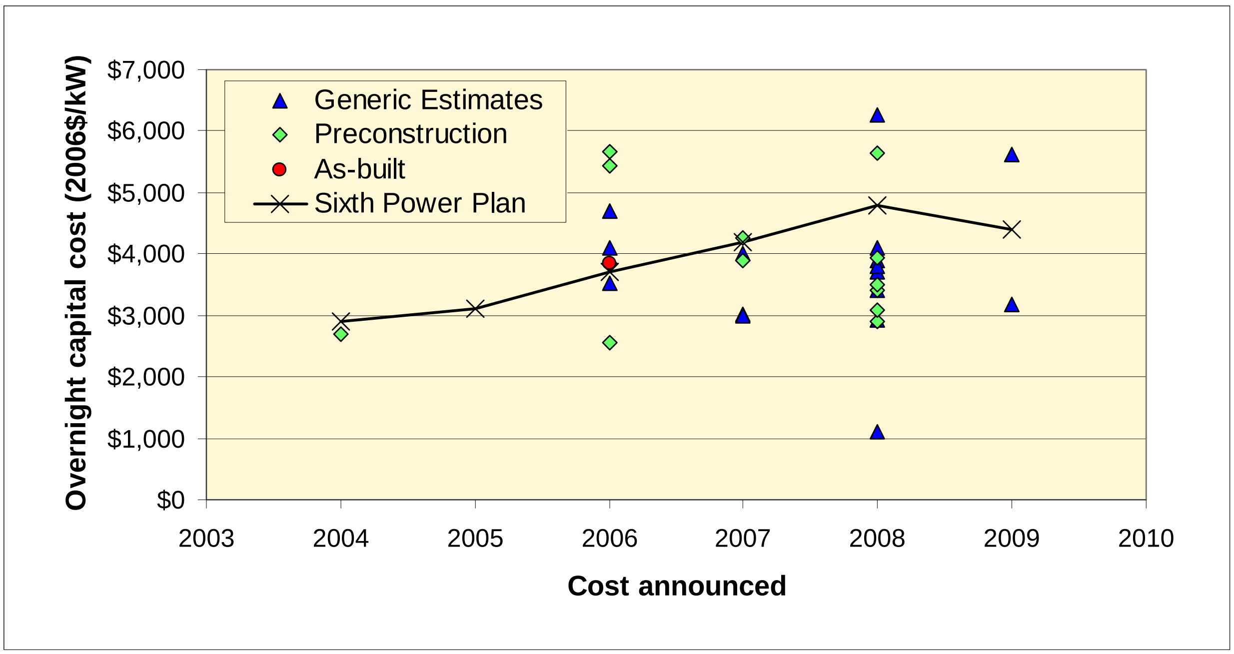
Capacity Factor: The average capacity factor over the life of the facility is assumed to be 90%.

Heat Rate: The average annual full load heat rate is 28,500 Btu/kWh, typical of an ORC binary plant operating on 300^{o}F geothermal fluid.

Unit Commitment Parameters**:** Geothermal plants are assumed to operate as must-run units.

Total Plant Cost: The "overnight" total plant cost of the reference geothermal plant is $4800/kW installed capacity (2008 price year). This estimate is based on a sample of 1 as-built plant costs and 12 published preconstruction estimates dating from 2004 through 2008 (including one preconstruction range estimate consisting of low and high bounded cost). Ten generic estimates of geothermal plant development costs were also obtained. Five of these were range estimates consisting of low and high bound costs and one included low, mid-range and high bound costs. Published costs, normalized as described in the Capital Cost Analysis subsection of this Appendix, are plotted by vintage in Figure I-9. A wide range in capital cost is evident and the general increase in power plant construction costs from 2004 through mid-2008 is poorly defined. The reference plant cost estimate of $4800/kW is based on a rough projection of average cost trends from 2004 through 2007 and lies on the high side of the 2008 cluster. The 2008 base year forecast does relate reasonably well to 2009 generic estimates (the 2009 estimates are a range estimate representing a low-temperature deep resource (high cost) and a higher temperature shallower resource (low cost). The cost uncertainty range of -33% ($3200) to +17% ($5600) is based on the range of 2008 vintage costs excluding the two extreme outlying values.

Figure I-9: Published costs of binary geothermal projects normalized to total plant costs



Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a geothermal plant are as follows:

> **Development** (Site option to completion of exploration) - 36 mo., 10% of total plant cost
>
> **Early Construction** (Wellfield confirmation and development) - 12 mo., 35% of total plant cost
>
> **Committed Construction** (Powerplant, pipelines and infrastructure) - 24 mo., 55% of total plant cost

Operating and Maintenance Cost: Estimated operating and maintenance costs for the reference plant are $175/kW/yr fixed plus $4.50/MWh variable. This estimate is derived from eight published sources containing estimates of geothermal plant operating and maintenance costs. Each source is associated with a capital cost estimate, allowing O&M costs to be estimated in terms of percentage of capital cost, a common approach. The O&M cost estimates were first adjusted to 2006 dollar values. Some estimates include both fixed and variable components, some are fixed only and others are in fully variable terms. Variable costs were converted to equivalent fixed values, assuming a 90% capacity factor. These were added to the fixed O&M component, if any, yielding total O&M cost in fixed terms, in 2006 year dollars. The resulting values were converted to percentages of total plant cost based on the associated normalized capital costs. This yielded an average value of 5% (omitting one extreme value associated with an unrepresentative low capital cost); $210/kW/yr using the capital cost of the reference plant. Fixed and variable components were derived from this estimate by assuming the variable component to be $4.50/MWh (the value from CEC, 2007). Deducting the fixed equivalent of $4.50/MWh at 90% capacity factor from $210/kW/yr yields the $175/kW/yr fixed component.

Economic Life: The economic life of a geothermal plant is assumed to be 30 years; limited by wellfield viability and equipment life.

Development Potential: A recent U.S. Geological Survey assessment of moderate and high temperature hydrothermal resources[14] yielded a mean total electricity generating potential with 95% confidence of 266 MWe[15] of from currently identified resources and 1103 MWe from currently undiscovered resources within the four Northwest states for a total of 1369 aMW of energy potentially available with high confidence. However, factors including the limited development in the Northwest to date, the high frequency of dry holes encountered during earlier attempts to develop Northwest geothermal projects, siting resistance encountered in earlier efforts to develop Northwest geothermal resources, the high risk and long lead time associated with the confirmation of geothermal resources and the relatively few sites currently under development all suggest that the Northwest resource potential during the period of this plan will be limited by development rate rather than ultimate availability. Based on geothermal development experience in Nevada, a state with similar types of geothermal resources as the Northwest, we assume that resources can be developed at a maximum rate of 14 MW per year in from 2011 through 2014, increasing to 24 MW per year, on average for the duration of the planning period. This would yield a maximum of 416 megawatts of hydrothermal resource over the term of the plan. At 90 percent capacity factor, this capacity would yield 374 average megawatts of energy. These assumptions are believed to be conservative and should be revisited at the biennial assessment of the 6th Plan when it is expected that additional Northwest geothermal development experience will be available.

Hydropower

[This section to be supplied]

[14] United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*. 2008.

[15] In this study, one MWe is defined as the capability of generating 8.77 GWh (one average megawatt) continuously for a period of 30 years.

Solar Photovoltaic Plant

[Portions of this section are yet to be completed]

Photovoltaics is conversion of solar radiation to electricity by the use of solid-state electronic devices (solar cells). Though photovoltaics have been widely employed for many years to supply power to small remote loads, larger-scale and grid-connected photovoltaic installations have been few in number and capacity because of the high cost of the technology and low productivity relative to alternatives. Over the past several years, strong public and political support has lead to attractive financial incentives and distributed grid-connected installations of a several kilowatts to several megawatts in installed capacity are becoming increasingly common. Utility-scale plants, 10 megawatts and larger and sited in optimal locations are appearing in Europe and the United States.

A wide variety of photovoltaic plant designs are possible with various combinations of cell, module and mounting design. A basic tradeoff is energy conversion efficiency vs. cost. Thin-film photovoltaic cells mounted on fixed racks results in a (relatively) low cost, rugged design. Conversion efficiency is low, however and thin-film cell output tends to deteriorate significantly over time. Efficiency and durability can be increased by use of single-crystalline cells mounted on single axis tracking devices. The ultimate in efficiency can be achieved by use of concentrating lenses focused on multijunction cells sensitive to a wide spectral range, mounted on fully automatic dual axis trackers. But each increase in efficiency comes at a greater cost, complexity and some sacrifice in reliability. Moreover, the most efficient designs, those employing concentrating devices, operate only on direct solar radiation so are more suitable for Southwestern locations where clear skies prevail.

Reference Plant: The reference plant is 20 megawatt (net AC output) plant using flat plate (non-concentrating) single crystalline modules mounted on automatic single-axis trackers. The 26 MW DC module output is converted to alternating current for grid interconnection using solid-state inverters. Inverter, cabling and transformer losses result in a net output of 20 MW AC. The plant also includes step-up transformers, switchgear and interconnection facilities and security, control and maintenance facilities. No storage is provided. The deployment strategy would include numerous individual plants at scattered locations within the better solar resource areas of the region. This would reduce simultaneous ramping due to cloud movement and reduce interconnection costs.

Capacity Factor: Annual and monthly average capacity factor were evaluated for five reference locations using the NREL Solar Advisor Model ((https://www.nrel.gov/analysis/sam/). Monthly average plant output and annual average capacity factors (ac rating to net ac output) are provided in Tables I-10 and illustrated in Figure I-10. Average hourly plant output for the Boise location is provided in Table I-11 and illustrated in Figure I-11.

The plant design assumptions use for this analysis are as follows:

Configuration - Flat plate, tracker-mounted, inverted to AC output, no storage

Array DC power - 25.3 MW (yielding nominal 20 MW AC output)

Modules - 12 x 10549 (126588) SunPower SPR-200-BLK(c-Si)

Mounting - Single-axis tracker

Inverters - (98) Xantrex GT250-480-POS

System degradation - 1%/yr, compounded

Internal derate factor - 84%, excluding inverter conversion efficiency

Overall performance ratio (dc rating > ac output) - 78%-79% (location-specific)

Table I-10: Estimated monthly net energy production (MWh) and annual capacity factors for utility-scale photovoltaic plant using flat plate single-crystalline modules on single-axis trackers (AC rating to net AC output)

	Billings, MT	Boise, ID	Burns, OR	Ely, NV	Yakima, WA
Jan	1722	1586	1722	2904	1255
Feb	2294	2244	2173	3083	1915
Mar	3566	3544	3323	4524	3391
Apr	3930	4404	4208	4914	3891
May	4977	5291	5180	5614	5245
Jun	5088	5656	5511	6121	5572
Jul	5837	6192	5859	6161	5941
Aug	5220	5637	5530	5461	5320
Sep	4059	4516	4421	5224	4258
Oct	2868	3389	3219	4086	2858
Nov	1905	1830	1540	2632	1279
Dec	1487	1421	1299	2579	1093
Annual	24.5%	26.4%	25.4%	30.4%	24.3%

Figure I-10: Estimated monthly net energy production for utility-scale photovoltaic plant using flat plate single-crystalline modules on single-axis trackers

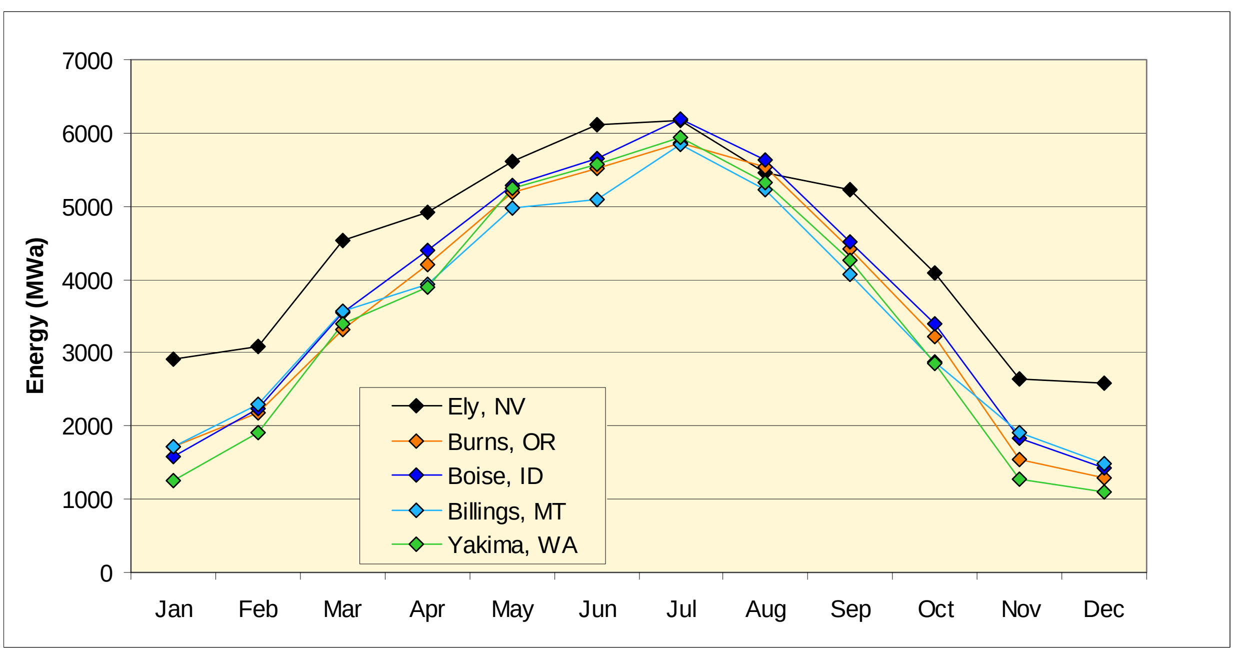
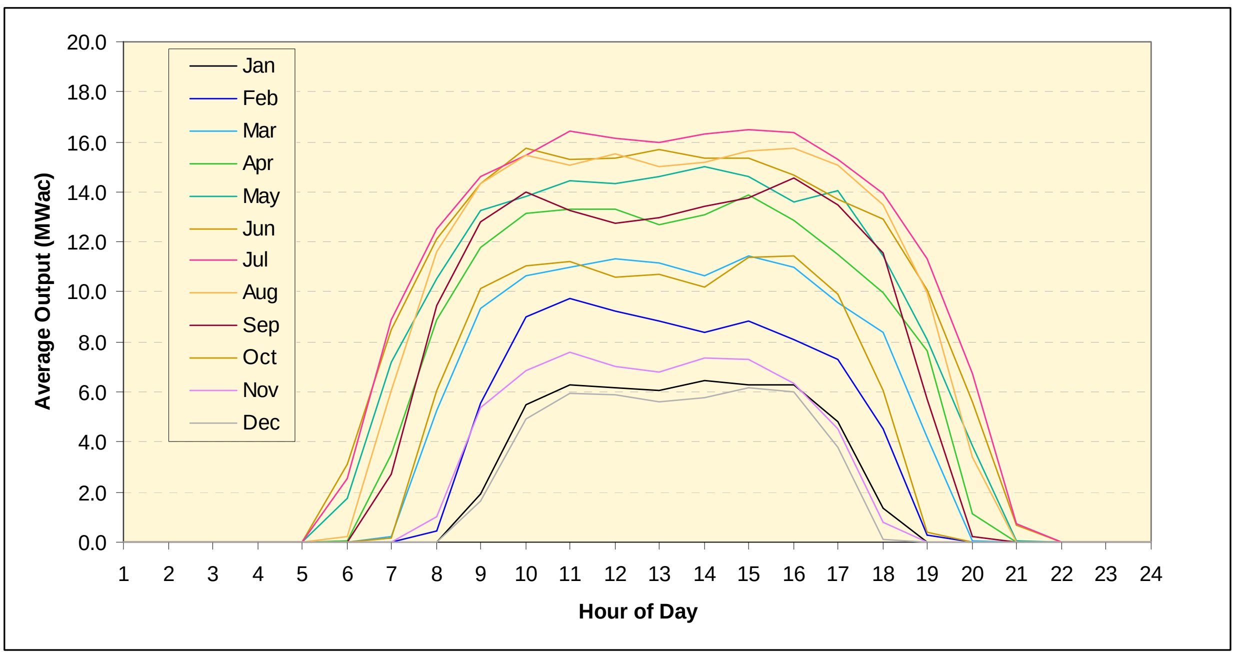


Table I-11: Estimated average hourly energy output by month (Boise location)

Hour	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
6	0.00	0.00	0.00	0.08	1.78	3.10	2.54	0.22	0.00	0.00	0.00	0.00
7	0.00	0.00	0.25	3.53	7.22	8.50	8.90	6.09	2.70	0.16	0.00	0.00
8	0.00	0.47	5.29	8.90	10.55	12.15	12.50	11.61	9.45	6.09	1.02	0.00
9	1.95	5.58	9.37	11.77	13.25	14.32	14.62	14.34	12.79	10.14	5.37	1.65
10	5.52	8.99	10.63	13.16	13.81	15.73	15.46	15.46	13.98	11.06	6.85	4.92
11	6.27	9.75	11.00	13.33	14.44	15.28	16.44	15.09	13.25	11.22	7.61	5.97
12	6.20	9.24	11.35	13.30	14.33	15.34	16.17	15.54	12.76	10.61	7.03	5.89
13	6.05	8.82	11.17	12.69	14.60	15.71	15.98	15.01	12.95	10.68	6.82	5.59
14	6.45	8.37	10.65	13.11	15.00	15.33	16.33	15.17	13.41	10.19	7.36	5.77
15	6.28	8.82	11.47	13.86	14.64	15.36	16.46	15.62	13.78	11.39	7.31	6.17
16	6.32	8.08	10.97	12.88	13.58	14.70	16.37	15.76	14.54	11.46	6.37	5.99
17	4.81	7.30	9.58	11.48	14.04	13.74	15.28	15.05	13.46	9.91	4.52	3.82
18	1.36	4.52	8.39	9.97	11.46	12.94	13.92	13.51	11.55	6.06	0.79	0.11
19	0.00	0.26	4.19	7.62	8.08	10.08	11.31	9.98	5.74	0.39	0.00	0.00
20	0.00	0.00	0.03	1.13	3.86	5.63	6.76	3.40	0.22	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.05	0.66	0.74	0.00	0.00	0.00	0.00	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Figure I-11: Estimated average hourly energy output by month (Boise location)



Firm Capacity Value:

Unit Commitment Parameters: Solar photovoltaic plants are assumed to operate as must-run units.

Total Plant Cost: The total plant cost of the reference plant is estimated to be $9000/kW for the 2008 price year on the basis of nominal AC plant rating (approximately $7000/kW for the DC plant rating , as more commonly reported in the press).

Figure I-12: Published costs of utility scale solar photovoltaic projects normalized to total plant costs

Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a geothermal plant are as follows:

> **Development** (Site acquisition, resource assessment, permitting, preliminary engineering) - 24 mo., 1% of total plant cost
>
> **Early Construction** (Final engineering, major equipment order) - 12 mo., 14% of total plant cost
>
> **Committed Construction** (Construction, testing) - 12 mo., 85% of total plant cost

Economic Life: The economic life of a utility-scale solar photovoltaic plant is assumed to be 25 years; limited by warranted cell lifetime. Maintenance costs are included to cover inverter replacement at 10 to 12 years.

Development Potential: The development potential for utility-scale photovoltaic plants was not assessed.

Concentrating Solar Power Plant

[Portions of this section are yet to be completed]

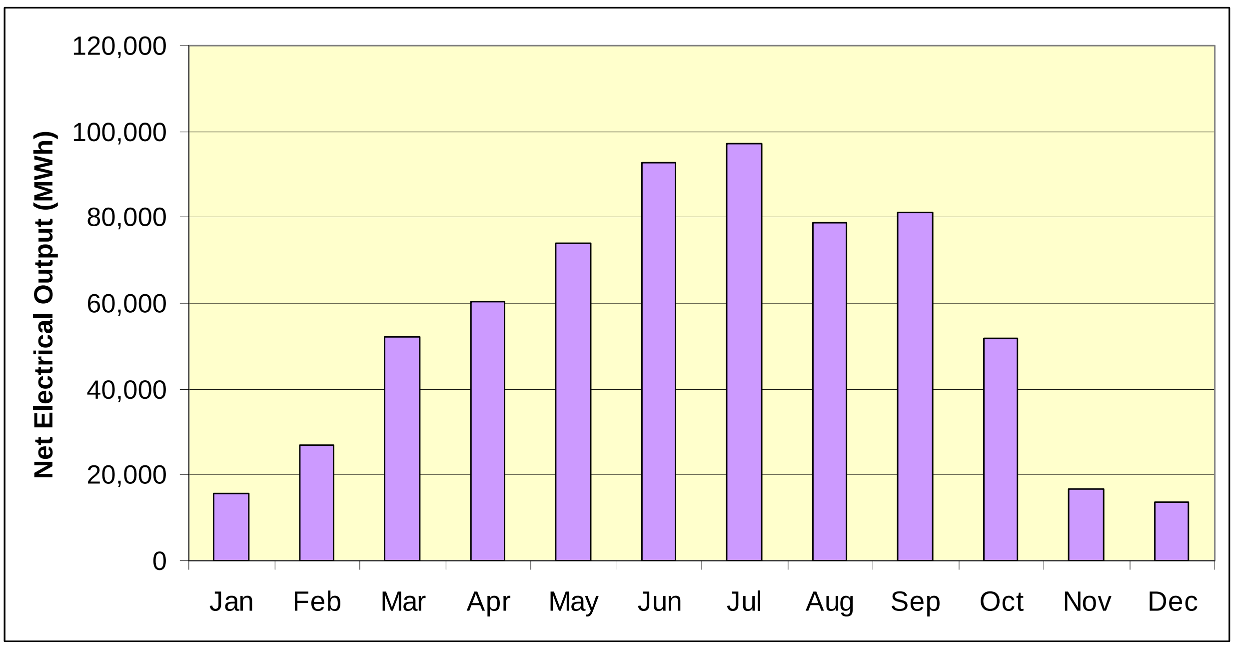
Parabolic trough concentrating solar thermal power plants are a commercially proven technology with over 20 years of operating history. Current plants use a synthetic oil primary heat transfer fluid and a supplementary natural gas boiler in the secondary (water) heat transfer loop for output stabilization and extended operation into the evening hours. Future plants are expected to benefit from higher collector efficiencies, higher operating temperatures (providing higher thermal efficiency and more economical storage) and economies of production.

Concentrating solar technologies (thermal and photovoltaic) require high direct normal solar irradiation for efficient operation. Though the most promising sites are in the desert southwest, potentially suitable areas are found in Bonneville's Nevada service territory (http://www.nrel.gov/csp/images/3pct_csp_nv.jpg) and some evidence suggests possible sites in extreme southeastern Oregon.

Reference Plant: The reference plant is a 200-megawatt parabolic trough concentrating solar thermal plant located in east-central Nevada in the vicinity of Ely. Power would be delivered to southern Idaho via the north segment of the proposed Southwest Intertie Project and thence to the Boardman area via portions of the proposed Gateway West and the Boardman-to-Hemmingway transmission projects. Higher temperature heat transfer fluids such as molten salt are expected to be available by the earliest feasible date for energization of the necessary transmission (ca. 2015). The reference plant is assumed to be equipped with thermal storage sufficient to support six to eight hours of full power operation and a 2.5x collector field. This would allowing output to be shifted to non-daylight hours, improve winter capacity factor, levelize output on intermittently cloudy days and impart some firm capacity value. No natural gas backup is provided since natural gas service is not available in the vicinity of the reference site[16].

Capacity Factor: Analysis using the NREL Solar Advisor Model ((https://www.nrel.gov/analysis/sam/) yields an annual average capacity factor of 35.5%. Output is highly seasonal, even with a collector field solar multiplier of 2.5 and eight hours of storage (Figure I -13).

Figure I-13: Estimated monthly net energy production for 200 MW parabolic trough plant with 2.5 solar multiplier and eight hours of storage located near Ely, NV



Firm Capacity Value:

***Unit Commitment Parameters*:** Concentrating solar thermal plants are assumed to operate as must-run units.

Total Plant Cost:

[16] The Ely vicinity was selected as a reference site because of the availability of reasonably favorable solar resource, suitable sites and the likelihood that the SWIP or a parallel transmission project would move forward. Subsequent analysis using the NREL Solar Advisor Model suggests possible alternatives including the Reno area with new transmission via the existing Alturas corridor. The Reno alternative may have somewhat better solar irradiation plus the advantage of natural gas service permitting use of natural gas backup.

Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a geothermal plant are as follows:

> **Development** (Site acquisition, resource assessment, permitting, preliminary engineering) - 24 mo., __% of total plant cost
>
> **Early Construction** (Final engineering, major equipment order) - 8 mo., __% of total plant cost
>
> **Committed Construction** (Construction, testing) - 20 mo., __% of total plant cost

Economic Life:

Development Potential:

Wind

Wind power is modeled by defining a reference wind plant then applying transmission assumptions appropriate to the location of the wind resource and the load center served. Plant capacity factors are adjusted to reflect the quality of the various wind resource areas. The combinations of wind resource areas, transmission and points of delivery considered are shown in Table I-12

Table I-12: Wind resource areas, load areas and transmission assumptions

Wind Resource Area >	Columbia Basin	Southern Idaho	Central Montana	Southern Alberta	Eastern Wyoming
Oregon and Washington Load Area	Point-to-Point		500kV AC Townsend, MT > Boardman, OR + Point-to-Point	+/-500kV DC Milo, AB > Buckley, OR + Point-to-Point	500kV AC Aeolus, WY > Boardman, OR + Point-to-Point
Southern Idaho Load Area		Point-to-Point	500kV Townsend, MT > Midpoint, ID + Point-to-Point		500kV AC Aeolus, WY > Cedar Hill, ID + Point-to-Point
Montana Load Area			Point-to-Point		

Reference Plant: The reference plant consists of conventional three blade wind turbine generators, in-plant electrical and control systems, interconnection facilities and on-site roads, meteorological towers and support facilities. The installed capacity is 100 MW.

Capacity Factor: The annual average capacity factor and monthly shape factors are shown in Table I-13. The annual capacity factors are from the Biennial Monitoring Report (NPCC, 2007) and the monthly shape factors were developed for the wholesale power price forecast of the Fifth Power Plan (NPCC, 2005). The capacity factors shown in Table I-13 are net at the plant interconnection and are derated for transmission losses to the point of wholesale delivery using the transmission loss factors described in the Transmission Assumptions subsection of the General Approach and Assumptions section.

Table I-13: Wind average annual capacity factors and monthly shape factors

Wind Resource Area >	Columbia Basin	Southern Idaho	Central Montana	Southern Alberta	Eastern Wyoming
Average annual capacity factor (net plant output)	32%	30%	38%	38%	38%
Monthly shape factors (average monthly output as fraction of annual capacity factor)					
Jan	1.03	1.19	1.61	1.61	1.61
Feb	0.90	1.39	1.57	1.57	1.57
Mar	1.07	1.07	1.02	1.02	1.02
Apr	1.07	1.05	0.84	0.84	0.84
May	1.21	0.94	0.77	0.77	0.77
Jun	1.07	0.71	0.73	0.73	0.73
Jul	1.11	0.56	0.35	0.35	0.35
Aug	1.07	0.61	0.42	0.42	0.42
Sep	0.94	0.72	0.52	0.52	0.52
Oct	0.73	0.74	1.00	1.00	1.00
Nov	0.85	1.59	1.30	1.30	1.30
Dev	0.96	1.43	1.88	1.88	1.88

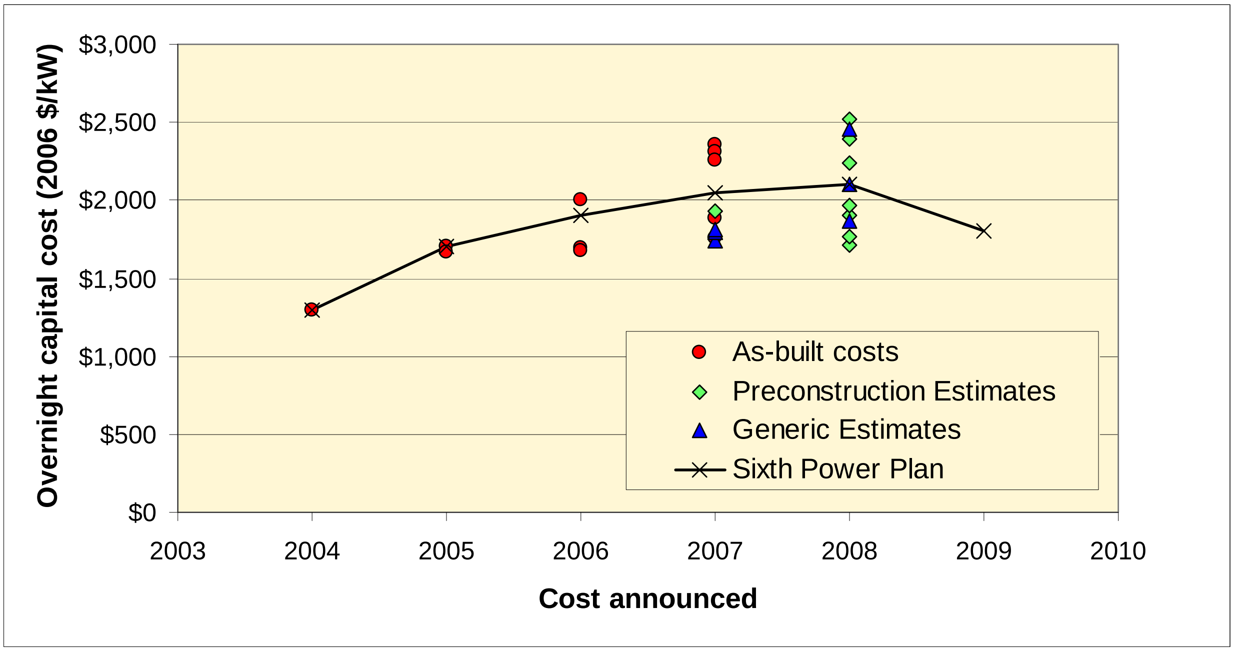
Firm Capacity Value: 5% of installed capacity as adopted by the Northwest Resource Adequacy Forum.

Unit Commitment Parameters**:** Wind power plants are assumed to operate as must-run units.

Total Plant Cost: The "overnight" total plant cost of the reference wind plant is $2100/kW installed capacity (2008 price year). This estimate is based on a sample of 11 reported as-built plant costs and 8 published preconstruction estimates from 2004 through 2008. Records of these costs were obtained from the Council's database of WECC wind plant development. Five generic estimates of wind plant development costs were also obtained. Two of these were range estimates consisting of low and high bound costs. Published costs, normalized as described in the Estimating Costs subsection of this Appendix, are plotted by vintage in Figure I-WND-1. The increase in construction costs from 2004 through mid-2008 is evident and approximated by the "Sixth Power Plan" curve. Analysis of the increase in wind plant costs during this period is provided in the Biennial Monitoring Report (NPCC, 2007).

A cost uncertainty range from -19% to +24% ($1700 to $2500 in 2008) is used for Regional Portfolio Model studies. The range is based on 2008 range of observations.

Figure I-14: Overnight total plant cost of wind projects



Total Plant Cost is forecast to decline 14% (real) from the 2008 price year to 2009, then to average of estimated 2004 and 2008 levels by 2011. Thereafter, TPC is assumed to decline at 0.5% per year, reflecting a 5% learning rate. See Table I- 1 and Figure I- 1.

Development and Construction Schedule, Cash Flows: The development and construction schedule and cash flow assumptions for a wind plant (exclusive of long-distance transmission, if any) are as follows:

Development (Site options to completion of resource assessment): - 24 mo., 5% of total plant cost

Early Construction (WTG order to first WTG shipment) - 12 mo., 16% of total plant cost

Committed Construction (WTG shipment to commercial service) - 18 mo., 79% of total plant cost

The development and construction schedule and cash flows for a wind resource requiring long-distance transmission is modeled in two phases. The first phase is coincidental development of the transmission line and 50% of the installed wind capacity potentially served by the transmission line. The transmission development schedule is controlling and the timing of wind capacity development is assumed to be such that the wind capacity enters service coincidental with the transmission line. The second phase is optional build-out of the remaining 50% of wind capacity potentially served by the transmission line in 250 MW increments.

Operating and Maintenance Cost: The variable O&M cost of $2.00/MWh is intended to represent land rent. Land rent is reported to typically range between 2 - 4% of the gross revenue from wind turbine generator (Wind Powering America, http://www.windpoweringamerica.gov/pdfs/wpa/34600_landowners_faq.pdf). $2.00 per MWh is approximately 2% of busbar revenue requirements at the current cost of wind. Because construction costs are expected to decline and variable O&M remains constant in the analysis, the low end value was selected. Fixed O&M costs are intended to include plant operation and maintenance costs and capital replacement costs, exclusive of property taxes and insurance. The estimated fixed O&M cost of $43/kW/yr is based on the fixed O&M cost for wind plants used for the Fifth Power Plan ($20/kWh/yr), escalated by observed 2004 - 2008 wind plant capital cost escalation (108% nominal). The resulting value was rounded to $40/kW/yr to yield overall annual O&M costs (including property taxes and insurance) of 2.5% of total plant cost. This percentage is within the range of 2 - 3.5% of total energy cost and 20 - 25% of total energy costs over the life of the plant cited in IEA, 2008b.

Integration cost: The forecast cost of supplying regulation and sub-hourly load-following services for operational integration is shown in Table I-GEN-3. The cost of longer-term shaping services is not included in the resource cost estimates of the plan.

Economic Life: The economic life of a wind plant is assumed to be 20 years.

Development Potential: The estimated development potential for the various blocks of wind is shown in Table I-14. Capacity and energy shown as "available" is estimated developable capacity in excess of operating and committed (under construction) capacity as of February 2009.

The Columbia Basin resource potential for delivery to western Oregon and Washington load centers is limited by new east - west transmission capacity that could be developed at current embedded transmission cost. This capacity is the sum of unconstructed projects with firm Bonneville transmission rights (estimated to be 1250 MW) and new capacity created by the West of McNary, Little Goose and I-5 Corridor reinforcements (approximately 4860 MW). This total was reduced by the capacity of unconstructed projects with announced long-term sales to California (these are assumed to hold firm transmission rights to California).

The Columbia basin potential for delivery to eastern Oregon and Washington load centers, and Idaho and Montana potential for local delivery are each assumed to be limited to a maximum penetration of 20% of forecast peak hourly load at the end of the planning period. This implies that the variable resource integration cost assumption described earlier is sufficient to cover integration costs to this level of penetration.

The remote resource blocks using new long-distance transmission were provisionally limited by the capacity of a single transmission circuit, pending initial development of the resource strategy (Chapter 9). In only one case (Low Conservation), did renewable resource development exceed the estimated availability of wind from sources not involving construction of new long-distance transmission. For this reason, further assessment of potential limits was not undertaken.

An issue needing further consideration is the prospect of additional long-term sales of Northwest wind to California utilities for compliance with California renewable portfolio standards. Various outcomes are possible, involving California renewable energy credit policy, the proposed increase in California renewable portfolio standard targets, current intertie capacity and the future competitiveness of Northwest wind vs. California and Southwestern solar from the perspective of California utilities.

Table I-14: Wind power development potential

Wind Resource Area	Load	Available Capacity (MW)	Available Energy (MWa)	Limiting Factors	Earliest Service
Columbia Basin	Westside OR/WA	4060	1300	New transmission to Westside @ embedded cost	2011
Westside OR/WA	Westside OR/WA	200	60	Allowance	2011
Columbia Basin	Eastside OR/WA	340	110	20% of 2029 peak load	2011
S. Idaho	S. Idaho	720	220	20% of 2029 peak load	2011
Montana	Montana	215	80	20% of 2029 peak load	2011
Montana	S. Idaho	1500	570	Per 500kV AC ckt	2015
Montana	OR/WA	1500	570	Per 500kV AC ckt	2015
Wyoming	S. Idaho	1500	570	Per 500kV AC ckt	2015
Wyoming	OR/WA	1500	570	Per 500kV AC ckt	2015
Alberta	OR/WA	2000	760	Per +/-500kV DC ckt	2015

Waste Heat Energy Recovery Cogeneration

Reference Plant: The reference plant is a 5 MW organic Rankine cycle (ORC) generating plant using dry cooling, operating on the gas turbine exhaust heat from a natural gas pipeline compressor station.

Capacity Factor: Energy-limited to 80%. Expected annual energy production for Trailblazer Pipeline Peetz compressor station is 27,600 MWh (3.15 MWa) (Colorado Energy News, 2009). The installed capacity at this station is 4 MW, giving a 79% capacity factor. This was rounded to 80% for the reference plant. A higher (90%) capacity factor is reported for the Northern Border Compressor Station #7 plant, though the load factor in pipelines serving the Midwestern market may be higher those of Western lines.

Development and Construction Schedule: The development and construction schedule (24 mo. Development, 12 mo. Early Construction, 12 mo. Construction) and corresponding cash flows (5% Development, 30% Early Construction, 65% Final Construction) was based on gas turbine assumptions, but with an extended development period reflecting the complexities of three-party development (third-party developer, pipeline owner and purchasing utility) and an extended early construction period including final engineering, major equipment order, site preparation and installation of compressor turbine exhaust diversion valves and ducting.

Fuel Price: Included in Operating and Maintenance cost

Heat Rate: The representative heat rate 38,000 Btu/kWh for an ORC plant operating with the reference plant assumptions (900^{o}F GT exhaust temperature, dry cooling) is based on the average annual performance of the ORC heat recovery project at the Northern Border Pipeline Compressor Station #7 (ORNL, 2007). Because the cost of the waste heat “fuel” is assumed to be a royalty payment based on electricity production, a heat rate assumption is not required for energy production cost calculations.

Unit Commitment Parameters**:** Waste heat energy recovery plants are assumed to operate as must-run units.

Total Plant Cost: Typical total plant cost is based on an typical installed cost of $2500/kW cited in Table 3 of INGAA (2008). An Owner's Cost allowance of 20% was added to the INGAA total plant cost and the resulting value adjusted to real 2006 dollars (assuming that the values in the INGAA report are 2008 dollar values). The resulting value was rounded to $2900/kW. The range of total plant costs were derived in a similar manner from the range cited in INGAA, yielding a range of $2300 - 2900/kW.

Total Plant Cost is forecast to decline 8% (real) from 2008 price year to 2009, then to average of estimated 2004 and 2008 levels by 2011. Thenceforth, TPC is assumed to decline at 0.5% per year, reflecting a 5% learning rate for organic Rankine cycle technology. See Figure I-1.

Operating and Maintenance Cost: Operating and maintenance costs (exclusive of property taxes and insurance) include plant O&M costs and payments to the pipeline owner for the use of the site and energy supply. INGAA, 2008 cites $0.005/kWh ($5/MWh) as typical pipeline company compensation and 0.002/kWh ($2/MWh) as a typical O&M cost . A range of possible O&M costs of $0.001 - 0.005/kWh ($1 - 5/MWh) is cited. The O&M costs were increased by 30% to account for general and administrative costs, and rounded up to the nearest dollar, yielding an expected total O&M cost of $8/MWh with a range of $7 to 13/MWh.

Economic Life: The economic life of a heat recovery cogeneration plant is assumed to be 20 years; limited by uncertainty regarding host facility viability.

Coal-fired Steam-electric Plant

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

Coal-fired Gasification Combined-cycle Plant

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

Natural Gas Combined-Cycle Gas Turbine

[Portions of this section are yet to be completed]

Technology:

Reference Plant: The reference plant is a single advanced "H-class" gas turbine generator and one steam turbine generator. The base-load capacity is 390 megawatts with an additional 25 megawatts of duct-firing power augmentation. Fuel is natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control. Condenser cooling is wet mechanical draft.

Availability: The availability parameters are those developed for the Fifth Power Plan:

Scheduled maintenance outages - 18 days/yr

Equivalent forced outage rate - 5%

Mean time to repair - 24 hours

Equivalent annual availability - 90% (of baseload rating)

The equivalent annual availability value should be reduced by 2.2% if using a "new and clean" capacity rating.

Heat Rate: The heat rate (7110 Btu/kWh) is based on the reported heat rate for the Port Westward plant (Mitsubishi MHI 501G , 6786 Btu/kWh, HHV) derated 2.1% for a maintenance-adjusted average lifecycle aging effects. The incremental heat rate of supplemental (duct fired) capacity is assumed to be 9500 Btu/kWh (Fifth Plan assumption).

Unit Commitment Parameters: Unit commitment parameters are used in the AURORA$^{xmp®}$ Electric Power Market Model for dispatchable units. Because AURORA$^{xmp®}$ is an hourly dispatch model, subhourly commitment capability is not modeled.

Minimum load - %

Minimum run time - hour

Minimum down time - hour

Ramp rate - greater than %/hr

Development and Construction Schedule: The development and construction schedule and associated cash flows used for the Regional Portfolio Model studies are as follows:

Phase	Definition	Duration	Cost (% of TPC)
Development (Option)	Site selection to EPC selection	24 mo	4%
Early Construction	Notice to Proceed to major foundations complete	12 mo	42%
Committed Construction	Receipt of major equipment to commercial service	18 mo	54%

These values were derived from values used in the Fifth Power Plan with the overall construction period extended to 30 months at the recommendation of the Council's Generating Resources Advisory Committee to reflect recent construction experience.

Fuel Price: Fuel price forecasts are described in Chapter 2 and Appendix A.

Economic Life: The economic lifetime of a combined-cycle plant is assumed to be 30 years.

Total Plant Cost: Total plant cost ($1160/kW for the 2008 price year) of baseload capacity (i.e., exclusive of the incremental cost of supplemental duct firing capacity) is based on the average of four normalized reported preconstruction estimates for projects scheduled for 2008 construction ($1100/kW). This average was adjusted upward by approximately 50% of the implied fuel savings value of advanced gas turbine technology ($120/kW). Figure I-NG-1 illustrates the 2008 preconstruction estimates and their relationship to earlier normalized construction, preconstruction and generic estimates dating from 2002 through 2007. The increase in construction cost from 2004 through 2007 is evident and approximated by the "Sixth Power Plan" curve. In developing the analysis represented in Figure I-15, reported plant costs were normalized to equivalent overnight development and construction cost in constant 2006 dollars[17]. Normalization adjustments include the following:

Reported site capacity was adjusted to vendor's nominal ISO baseload capacity as reported in Gas Turbine World (2007).

Reported costs were reduced in proportion to installed duct firing capability assuming that incremental duct firing capacity costs are 40% of incremental baseload capacity costs.

Reported costs for plants with 2x1x1[18] configuration were reduced 10% to reflect the added cost of a 1x1x1 plant. Plants of 3xGT configuration and larger were excluded from the sample.

Reported costs of plants with dry cooling were reduced 6% to reflect the added cost of dry cooling.

Reported as-built costs were assumed to include all owners' costs (development, land, infrastructure and financing). Reported preconstruction estimates were assumed to be overnight total construction cost, exclusive of owner's costs and were increased by 29% to account for owner's development costs. In as-built cases where specific owner's costs were explicitly cited as excluded, these were estimated as follows: Development - 2%, Land - 2%.

[17] Additional information regarding the development of the estimate of total plant cost is available on request.
[18] 2x1x1 - two gas turbines, one heat recovery steam generator and one steam turbine generator.

Reported as-built and preconstruction costs were adjusted to a average value for the Pacific Northwest states using the state adjustment factors of USACE (2008).

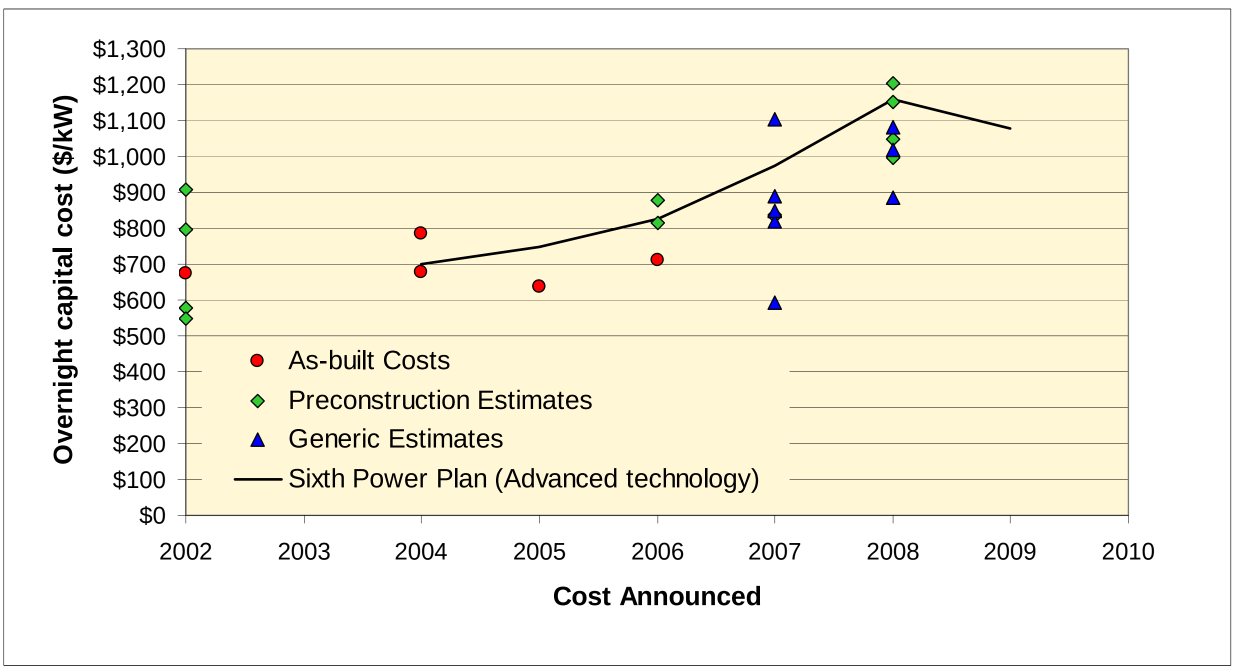
As-built costs were assumed to be nominal, including financing, and escalation and interest incurred during construction. Equivalent overnight total plant costs were back calculated, following the adjustments described above, using the Council's MicroFin cost model. Preconstruction costs were assumed to be overnight costs so did not require further adjustment other than to 2006 dollar values.

The incremental cost of power augmentation (duct firing) is assumed to be $465/kW for the 2008 price year assuming that the cost of incremental supplemental capacity is 40% of the incremental cost of baseload capacity.

A cost uncertainty range of +/- 30%, based on NETL (2007) is used for Regional Portfolio Model studies.

Total Plant Cost and Fixed Operating and Maintenance Costs are forecast to decline 7% (real) from the 2008 price year to 2009, then to average of estimated 2004 and 2008 levels by 2011. Thenceforth, these costs are assumed to decline at 0.5% per year, reflecting a 5% learning rate for gas turbine technology. See Table I-1 and Figure I- 1.

Figure I-15: Overnight total plant costs of combined-cycle power plants



Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance ($14/kW/yr) and variable O&M ($1.70/MWh) are based on values appearing in NETL (2007), escalated in proportion to the difference in the normalized combined-cycle capital cost of NETL (2007) and the Sixth Plan total plant cost described above.

Maximum Annual Development Rate: No constraints were initially placed on the regional maximum annual development rate for combined-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a potential maximum combined-cycle build rate of 415 MW (one unit) per two-year interval. This is an achievable rate, if needed.

Developable Potential: No constraints were initially placed on the cumulative development potential for combined-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a cumulative maximum of 830 MW (two units) of new combined-cycle gas turbine capacity. This amount would not be constrained by gas supply, other infrastructure or air quality constraints.

Natural Gas Simple-Cycle Gas Turbines

Technology: Air is pressurized, heated by burning liquid or gas fuel then expanded through a power turbine. The power turbine drives the compressor and an electric power generator. A simple-cycle gas turbine power plant typically consists of one to several gas turbine generator units, each consisting of an air compressor, fuel combustors, and power turbine coupled to an electric generator, skid-mounted as a modular unit. The generator sets are typically equipped with inlet air filters and exhaust silencers and are installed in acoustic enclosures. Lube oil, starting, fuel forwarding, and control systems complete the basic package. Water or steam injection, intercooling[19] or inlet air cooling can be used to increase power output. Basic nitrogen oxide control is accomplished by use of "low-NOx" combustors. Exhaust gas catalysts can further reduce nitrogen oxide and carbon monoxide production. Other plant components may include a switchyard, fuel gas compressors, a water treatment facility (if units are equipped with water or steam injection) and control and maintenance facilities. A fuel oil storage and supply system may be provided for backup fuel. A wide range of unit sizes is available, from less than 5 to greater than 170 megawatts.

Gas turbine designs include heavy industrial machines specifically designed for stationary applications ("frame" machines) and "aeroderivative" machines - lightweight aircraft engines adapted to stationary applications. The higher pressure (compression) ratios of aeroderivative machines result in a more efficient and compact unit than frame machines of equivalent output. Because of their lighter construction, aeroderivative machines provide superior operational flexibility including rapid black start capability, short run-up, rapid cool-down and overpower operating capability. Start times to full load of ten minutes or less allow these machines to provide "spinning" reserves without needing to be operating. Aeroderivative machines are highly modular and major maintenance is often accomplished by swapping out major components or the entire engine for a replacement, shortening maintenance outages. These attributes come at a price - industrial machines cost less on a per-kilowatt capacity basis and can be longer-lived. Both aeroderivative and industrial gas turbine technological development is strongly driven by military and aerospace gas turbine applications.

Reference Aeroderivative Simple-cycle Gas Turbine Plant

Reference Plant: The reference aeroderivative simple-cycle gas turbine plant consists of twin gas turbine generator sets of 47MW nominal capacity, ancillary equipment, a control building

[19] Chilling the compressed air between air compression stages.

and switchyard. Cost and performance characteristics are generally based on the General Electric LM6000PD Sprint. This design uses water spray injection intercooling in the two-stage compressor to increase mass flow and reduce second-stage compressor load, thereby increasing overall power output. Lifecycle average output is 45MW per unit under ISO conditions. Fuel is natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control.

Availability: Availability parameters are those of the Fifth Power Plan:

Scheduled maintenance outages - 10 days/yr

Equivalent forced outage rate - 3.6%

Mean time to repair - 80 hours

Equivalent annual availability - 94%

Unit Commitment Parameters**:** Unit commitment parameters are used in the AURORA$^{xmp®}$ Electric Power Market Model for dispatchable units. Because AURORA$^{xmp®}$ is an hourly dispatch model, subhourly commitment capability is not modeled.

Minimum load - 25%

Minimum run time - 1 hour

Minimum down time - 1 hour

Ramp rate - greater than 100%/hr

Development and Construction Schedule: The development and construction schedule and associated cash flows used for the Regional Portfolio Model studies are as follows:

Phase	Definition	Duration	Cost (% of TPC)
Development (Option)	Site selection to EPC selection	18 mo	5%
Early Construction	Notice to Proceed to major foundations complete	9 mo	50%
Committed Construction	Receipt of major equipment to commercial service	6 mo	45%

While the duration of the Development period and overall construction period remain at the values used for the Fifth Power Plan, the early construction period is shorted from 12 to 9 months and the Committed Construction Period extended by 3 months. Level cash flows are assumed for the Development Period. Construction cash flows are based on a right-skewed cash flow from Phung, 1978, maximized at the initial month of the committed construction period.

Fuel Price: Fuel price forecasts are described in Chapter 2 and Appendix A.

Heat Rate: The lifecycle average full load heat rate (9370 Btu/kWh, HHV) is based on the new and clean full load heat rate reported for a General Electric LM6000PD Sprint (9060 Btu/kWh) in Gas Turbine World (2007). The nominal heat rate derated 3.1% for inlet, exhaust, auxiliary load and transformer losses and 0.8% for maintenance-adjusted lifecycle aging effects.

Economic Life: The economic lifetime is assumed to be 30 years.

Total Plant Cost: Total plant cost ($1050/kW for the 2008 price year) was derived from an analysis of reported aeroderivative gas turbine costs including 13 reported preconstruction estimates, five reported costs at completion and six generic estimates dating from 2002 through 2008. The reference 2008 price year cost (representing a plant placed in-service in 2009) is an approximate average of normalized preconstruction estimates reported in 2008, exclusive of outliers. Figure I-16 illustrates the 2008 preconstruction estimates and their relationship to earlier normalized construction, preconstruction and generic estimates. The 2008 outlier is the San Francisco Potrero and SFO peaker projects. These projects have been bedeviled by delay and are proposed for challenging highly urban environments and for these reasons are not thought to be representative of future projects in the Northwest. The 2007 outlier is the average cost of five Southern California Edison peaking units - a project also confronting highly urban locations and delay. The increase in construction cost from 2004 through 2007 is evident and approximated by the "Sixth Power Plan" curve.

The values plotted in Figure I-2 are intended to represent equivalent overnight development and construction cost in constant 2006 dollars[20]. These values were derived from "raw" reported plant costs as follows:

Reported site capacity was adjusted to vendor's nominal ISO baseload capacity as reported in Gas Turbine World (2007).

Plants consisting of more than four units were excluded from the sample. The cost of projects consisting of a single unit were increased by 10%.

Reported as-built costs were assumed to include all owners' costs (development, land, infrastructure and financing). Reported preconstruction estimates were assumed to be overnight total construction cost, exclusive of owner's costs and were increased by 12% to account for owner's development costs.

Reported as-built and preconstruction costs were adjusted to a average value for the Pacific Northwest states using the state adjustment factors of USACE (2008).

As-built costs were assumed to be nominal, including financing, and escalation and interest incurred during construction. Equivalent overnight total plant costs were back calculated, following the adjustments described above, using the Council's MicroFin cost model.

[20] Additional information regarding the development of the estimate of total plant cost is available on request.

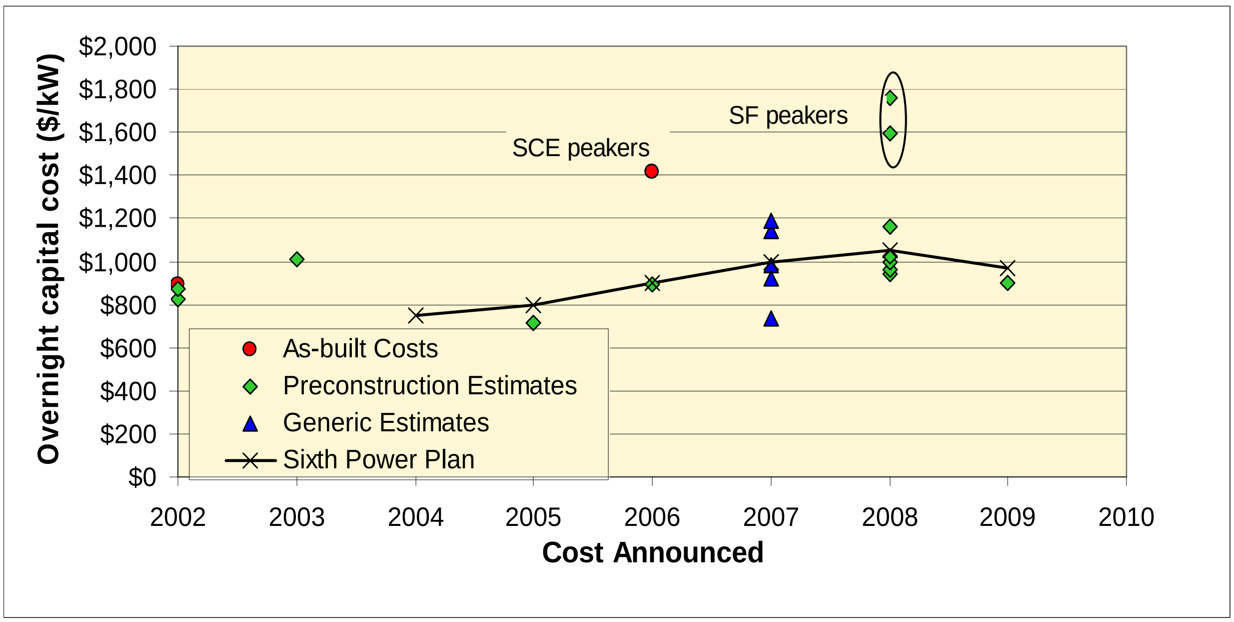
Preconstruction costs were assumed to be overnight costs so did not require further adjustment other than to 2006 dollar values.

A cost uncertainty range of +/- 30%, based on NETL (2007) is used for Regional Portfolio Model studies.

Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance ($14/kW/yr) and variable O&M ($4.00/MWh) are based on a rounded average of "Albany" and "Syracuse" GE7FA fixed O&M values (less property tax and insurance) and variable O&M values, respectively of Table A-3 of NERA (2007).

Cost Forecast: See discussion under Reference Combined-cycle Gas Turbine Plant and Figure I-3.

Figure I-16: Aeroderivative gas turbine generator total plant costs



Maximum Annual Development Rate: No constraints were initially placed on the regional maximum annual development rate for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a potential maximum simple-cycle build rate of 170 MW per two-year interval[21]. This is an achievable rate, if needed.

Developable Potential: No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a cumulative maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that would not be constrained by gas supply, other infrastructure or air quality constraints.

[21] The reference heavy duty simple-cycle gas turbine pant was used in the portfolio analysis, hence the capacity values of the portfolio analysis are multiples of the heavy duty reference plant capacity.

Reference Heavy-duty Simple-cycle Gas Turbine Plant

Reference Plant: The reference heavy-duty simple-cycle gas turbine plant consists of a single gas turbine generator set of 85MW nominal capacity, ancillary equipment, control building and switchyard. Cost and performance characteristics are generally based on the General Electric 7EA. Lifecycle average output is 81MW under ISO conditions. Fuel is natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include dry low-NOx combustors and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC control.

Availability: Availability parameters are those of the Fifth Power Plan:

Scheduled maintenance outages - 26 days/yr

Equivalent forced outage rate - 7%

Mean time to repair - 51 hours

Equivalent annual availability - 86%

***Unit Commitment Parameters*:** Unit commitment parameters are used in the AURORA$^{\underline{xmp}®}$ Electric Power Market Model for dispatchable units. Because AURORA$^{\underline{xmp}®}$ is an hourly dispatch model, subhourly commitment capability is not modelled.

Minimum load - 25%

Minimum run time - 1 hour

Minimum down time - 1 hour

Ramp rate - greater than 100%/hr

Development and Construction Schedule: See discussion under Reference Aeroderivative Simple-cycle Gas Turbine Plant

Fuel Price: Fuel price forecasts are described in Chapter 2 and Appendix A.

Heat Rate: The lifecycle average full load heat rate (11,960 Btu/kWh, HHV) is based on the new and clean full load heat rate reported for a General Electric MS7001EA (10,419 Btu/kWh) in Gas Turbine World (2007). The nominal heat rate derated 3.1% for inlet, exhaust, auxiliary load and transformer losses and 0.8% for maintenance-adjusted lifecycle aging effects.

Economic Life: The economic lifetime is assumed to be 30 years.

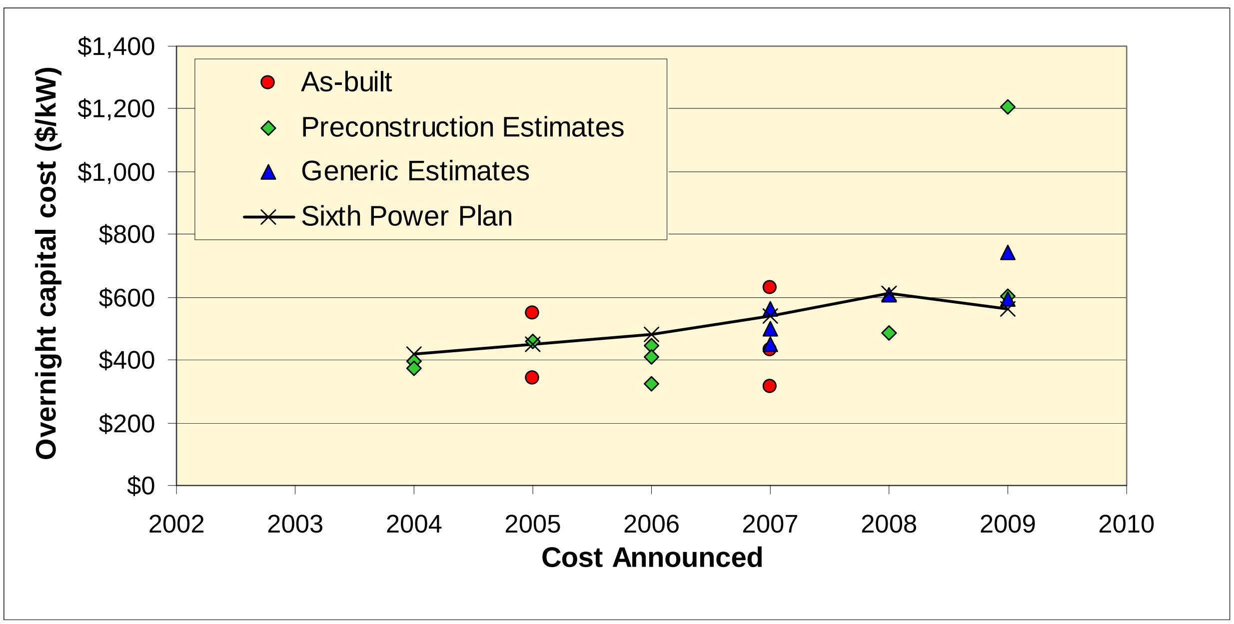
Total Plant Cost: Total plant cost ($610/kW for the 2008 price year) was derived from an analysis of reported heavy-duty gas turbine construction costs including 9 reported preconstruction estimates, five reported costs at completion and six generic estimates dating from 2004 through 2009 (Figure I-17). Though at the high end of the range of estimates announced in 2008, the reference 2008 price year cost (representing a plant placed in-service in 2009) is at the low-end of estimates announced in 2009 (both the generic and preconstruction estimates announced in 2009 are range estimates). It is not clear if the 2009 estimates assume a continuation of the 2004 - 08 construction cost escalation trend, and as a result are unrepresentatively high, or whether the 2008 examples are low. The cost estimates will be revisited in the Biennial Assessment.

The values plotted in Figure I-17 are intended to represent equivalent overnight development and construction cost in constant 2006 dollars[22]. These values were derived from "raw" reported plant costs as described in the reference aeroderivative simple-cycle plant discussion.

Operating and Maintenance Cost: Fixed O&M cost, exclusive of property tax and insurance ($4/kW/yr) and variable O&M ($1.00/MWh) are based on a rounded average of "Albany" and "Syracuse" GE7FA fixed O&M values (less property tax and insurance) and variable O&M values, respectively of Table A-3 of NERA (2007).

Cost Forecast: See discussion under Combined-cycle Gas Turbine and Figure I-3.

Figure I-17: Heavy-duty gas turbine generator total plant costs



Maximum Annual Development Rate: No constraints were initially placed on the regional maximum annual development rate for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a potential maximum simple-cycle build rate of 170 MW per two-year interval. This is an achievable rate, if needed.

Developable Potential: No constraints were initially placed on the cumulative development potential for simple-cycle gas turbine plants pending initial portfolio model results. The recommended (least risk) portfolio contains a cumulative maximum of 170 MW of new simple-cycle gas turbine capacity, an amount that would not be constrained by gas supply, other infrastructure or air quality constraints.

[22] Additional information regarding the development of the estimate of total plant cost is available on request.

Natural Gas Reciprocating Engine Plant

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

Advanced Nuclear Plant

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

Compressed Air Energy Storage

The following sources were used in the development of the discussion of compressed air energy storage:

Di Biasi (2009)

Mason (2009)

Nakhamkin (2007)

Nakhamkin, et. al. (2004)

Schainker, et. al. (2007)

Succar, Samir and Williams (2008)

Pumped Storage Hydropower

[Portions of this section are yet to be completed]

Technology:

Reference Plant:

VALUES UNDERLYING CHARTS OF CHAPTER 6

Figures 6-1A-C: Levelized Electricity Cost of Generating Options

Figures 6-1A-C depict the levelized cost of producing and delivering electricity from resources and technologies generally used to produce electricity on a base or intermediate load basis. The technologies and resources included in Figures 6-1A-C are those assumed to be available for commercial service by the respective time periods and permissible under current state law. Not included are emerging or prospective resources and technologies for which costs are speculative at this time.

The levelized costs of Figures 6-1A-C are calculated using the Council's MicroFin levelized cost workbook. The cost calculations use the reference plant assumptions and financing assumptions described in this appendix. Natural gas and coal cases use the medium case fuel price forecasts described in Appendix B. The values reflect investor-owned utility financing, transmission to a Pacific Northwest load-serving entity wholesale delivery point, CO_2 allowance costs at the mean values of the portfolio analysis and integration cost as described in this appendix. State and federal financial incentives are excluded, except accelerated depreciation. Actual project costs may differ because of site-specific conditions and different financing and timing. MicroFin, loaded with the assumptions of this plan is available on request for those seeking more detail or the opportunity to calculate costs under varying assumptions.

The values of Figure 6-1A are based on reference plants placed in service in 2015. Figure 6-1B values are based on plants placed in service in 2020 and Figure 6-1C values are based on plants placed in service in 2025.

[These values in these tables still need to be evaluated for consistency]

Table I-15: Levelized Electricity Cost of Energy Generating Options Available in the Near-term (2010-14)

Resource	Location	Capacity Factor	Plant Busbar	Integration	Transmission and Losses	Emissions	Total
Heat Recovery	PNW	80%	$51.49	$0.00	$3.54	$0.00	**$55**
Landfill Gas	PNW	85%	$73.32	$0.00	$3.63	$0.00	**$77**
Geothermal	PNW	90%	$76.28	$0.00	$3.57	$0.00	**$80**
Wind (MT Local)	MT	38%	$71.69	$9.84	$6.53	$0.00	**$88**
Combined Cycle	PNWE	80%	$72.52	$0.00	$4.02	$13.93	**$90**
New Hydro	PNW	50%	$90.72	$0.00	$5.52	$0.00	**$96**
Animal/Food Waste	PNW	75%	$97.06	$0.00	$4.39	$0.00	**$100**
Wind (Col Basin)	OR/WA	32%	$84.77	$9.84	$7.71	$0.00	**$101**
Wind (ID Local)	ID	30%	$90.29	$9.84	$8.20	$0.00	**$102**
Recip Engine	PNWE	80%	$90.30	$0.00	$4.27	$15.87	**$108**
Woody Residue	PNW	80%	$118.61	$0.00	$4.65	$0.00	**$109**
WWTP Biogas	PNW	85%	$122.16	$0.00	$4.58	$0.00	**$110**
Utility-scale PV	S. ID/OR	26%	$277.16	$9.89	$12.79	$0.00	**$113**

Table I-16: Levelized Electricity Cost of Energy Generating Options Available in the Mid-term (2015-19)

Resource	Location	Capacity Factor	Plant Busbar	Integration	Transmission and Losses	Emissions	Total
Heat Recovery	PNW	80%	$60.97	$0.00	$3.53	$0.00	**$65**
Landfill Gas	PNW	85%	$72.54	$0.00	$3.62	$0.00	**$76**
Geothermal	PNW	90%	$76.32	$0.00	$3.57	$0.00	**$80**
Wind (MT Local)	MT	38%	$69.97	$10.16	$6.50	$0.00	**$87**
Combined Cycle	PNWE	80%	$72.42	$0.00	$4.07	$16.24	**$93**

New Hydro	PNW	50%	$90.72	$0.00	$5.52	$0.00	**$96**
Animal/Food Waste	PNW	75%	$95.19	$0.00	$4.35	$0.00	**$100**
Wind (OR/WA)	OR/WA	32%	$82.72	$10.16	$7.67	$0.00	**$101**
Supercritical Coal (ID)	ID	85%	$60.36	$0.00	$4.14	$38.97	**$103**
Wind (ID Local)	ID	30%	$88.10	$10.16	$8.17	$0.00	**$106**
IGCC (ID)	ID	80%	$72.02	$0.00	$4.46	$36.84	**$113**
MT Wind > S. ID	MT	38%	$69.97	$10.16	$33.93	$0.00	**$114**
AB Wind > OR/WA	AB	38%	$69.97	$10.16	$40.35	$0.00	**$120**
Woody Residue	PNW	80%	$117.19	$0.00	$4.62	$0.00	**$122**
WWTP Biogas	PNW	85%	$120.17	$0.00	$4.54	$0.00	**$125**
MT Wind > OR/WA	MT	38%	$69.97	$10.16	$61.63	$0.00	**$142**
NV CSP > S. ID	NV	36%	$129.23	$0.00	$35.36	$0.00	**$165**
NV CSP > OR/WA	NV	36%	$129.23	$0.00	$73.92	$0.00	**$203**
Utility-scale PV	S. ID/OR	26%	$219.21	$10.18	$11.67	$0.00	**$241**

Table I-17: Levelized Electricity Cost of Energy Generating Options Available in the Long-term (2020-29)

Resource	Location	Capacity Factor	Plant Busbar	Integration	Transmission and Losses	Emissions	Total
Heat Recovery	PNW	80%	$59.66	$0.00	$3.51	$0.00	**$63**
Landfill Gas	PNW	85%	$71.80	$0.00	$3.60	$0.00	**$75**
Geothermal	PNW	90%	$76.37	$0.00	$3.58	$0.00	**$80**
Wind (MT Local)	MT	38%	$68.29	$10.27	$6.47	$0.00	**$85**
Combined Cycle	PNWE	80%	$71.96	$0.00	$4.09	$17.44	**$93**
New Hydro	PNW	50%	$90.73	$0.00	$5.52	$0.00	**$96**
Animal/Food Waste	PNW	75%	$93.38	$0.00	$4.32	$0.00	**$98**
Wind (OR/WA)	OR/WA	32%	$80.73	$10.27	$7.64	$0.00	**$99**
MT Wind > WA/OR via CTS	MT	38%	$68.29	$10.27	$21.39	$0.00	**$100**
UltraSupercritical Coal (ID)	ID	85%	$60.04	$0.00	$4.13	$38.67	**$103**
Wind (ID Local)	ID	30%	$85.98	$10.27	$8.13	$0.00	**$104**
IGCC (ID)	ID	80%	$104.62	$0.00	$4.25	$0.00	**$109**
Advanced Nuclear	PNW	85%	$68.29	$10.27	$33.88	$0.00	**$112**
MT Wind > S. ID	MT	38%	$70.49	$0.00	$4.49	$39.56	**$115**
AB Wind > OR/WA	AB	38%	$68.29	$10.27	$40.30	$0.00	**$119**
Woody Residue	PNW	80%	$116.33	$0.00	$4.60	$0.00	**$121**
WWTP Biogas	PNW	85%	$118.25	$0.00	$4.50	$0.00	**$123**
MT Wind > OR/WA	MT	38%	$68.29	$10.27	$61.55	$0.00	**$140**
IGCC (CSS) via CTS	MT	80%	$94.57	$0.00	$16.27	$30.16	**$141**
NV CSP > S. ID	NV	36%	$117.30	$0.00	$34.93	$0.00	**$152**
NV CSP > OR/WA	NV	36%	$117.30	$0.00	$73.23	$0.00	**$191**
Utility-scale PV	S. ID/OR	26%	$183.24	$10.29	$11.00	$0.00	**$205**

Figure 6-2: Levelized Fixed Cost of Firm Capacity Options

Figures 6-1A-C depict the levelized fixed cost of installed capacity for resources and technologies generally used primarily to provide firm capacity or ancillary services. The technologies and resources included are those assumed to be available for commercial service during the 20-year period of the plan. Not included are emerging or prospective resources and technologies for which costs are speculative at this time.

Table I-18: Levelized fixed cost of installed capacity for resources and technologies generally used primarily to provide firm capacity or ancillary services

Resource	Plant Capital & O&M	Fuel	Transmission and Losses	Total
Combined-cycle (Incremental duct firing)	$42.59	$31.40	$17.90	**$92**
Frame GT	$56.53	$52.29	$18.58	**$127**
Aeroderivative GT	$105.67	$40.96	$19.31	**$166**
Reciprocating Engine	$178.07	$35.77	$20.61	**$234**
Pumped Storage	$288.30	$19.24	$44.20	**$352**

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Appendix J: The Regional Portfolio Model

INTRODUCTION AND SUMMARY

Many of the assumptions and results of Regional Portfolio Model (RPM) are significant to the credibility of the Council's plan. Some of the more detailed of these are summarized in this appendix.

The appendix covers a host of disparate subjects and studies. For the most part, these can be read and understood independently. Where familiarity with other areas of the Plan is necessary, the reader is alerted to those prerequisites.

Most of this appendix is limited to descriptions of changes and enhancements the Council has implemented since the Fifth Power Plan. The Fifth Power Plan, especially Appendices L and P, describes many of the model's details. Most of these features are present in the current version of the model, and we will not repeat that material here.

Instead we start with the more apparent changes in the behavior of the model, such as the shift in expected cost and risk that have taken place since the Fifth Plan. We then dive more deeply into the details of enhancements to the model and evolution of concepts and data. Finally, we consider how uncertainty affects risk. Regression analysis allows us to see which sources of uncertainty make the largest contribution to risk and whether their contribution is loosely or more tightly related to risk. Some thoughts about the modeling of uncertainty conclude the appendix. The last section is really a reference for the first section, identifying the exact dates and circumstances when modifications to data and model logic occurred.

CHANGES SINCE THE FIFTH PLAN

The last section of this appendix provides a blow-by-blow account of the changes that staff introduced into the model to arrive at the calculator responsible for many of the Draft Plan's principal conclusions. These appear as a sequence of model revisions, starting with L801 and ending with L811.[1]

The next section presents a more concise overview of the changes that appear to have made larger changes to either the selection of portfolios or the nominal cost and risk levels. This introduction provides background for understanding the nominal changes in cost, risk, and cost-effective conservation levels appearing in subsequent sections.

[1] The studies require a significant amount of time and preparation, even after the simulation model is complete. The stable of computers require re-initialization, the optimization parameters must be re-estimated, sometimes multiple times, and verification of repeatability under alternative circumstances is necessary. Consequently, the "L" refers to "launch." The 800 series was chosen because this particular sequence of studies, or at least the logic and data they would use, began in 2008.

Overview of Data and Model Changes

Modeling for the Sixth Power Plan began in February 2008, when staff assembled load requirement, fuel price, and electricity price forecast updates and resource additions forthcoming since the Fifth Power Plan. The intent of this exercise was to provide an initial shake-down of data preparation procedures and to get a preliminary look at where the Sixth Power Plan might be headed. These results were presented at the April 16, 2008, Power Committee meeting in Whitefish, Montana. They resemble, to a large extent, the Council's Draft Resource Plan, although the level of conservation potential envisioned was much less than that which finally manifest in the Draft Plan.

Over the course of development, between February 2008 and early April 2009, Council staff created eleven models, each reflecting modifications to basic assumptions or logic. The list models and corresponding changes appear at the end of this appendix.

Study case L801, completed in late February 2008, introduced the data changes since the Fifth Power Plan. The version of the model used for the final Fifth Power Plan is L28. Apart from changes in the decision criterion for reserve target level and for the priority of market viability, there were no changes from the Fifth Plan L28 logic. Much like the Fifth Plan, the CO_2 penalty increased in steps, although the steps became \$50/ton and \$100/ton, instead of the \$15/ton and \$30/ton used in the Fifth Power Plan. The probability of occurrence also increased slightly. Models L802 and L803 introduced refinements to the CO_2 penalty assumptions, as well as numerous data refinements based on staff review. L803 was the basis of the April 16, 2008, Power Committee presentation.

The next change of significance to the cost and risk of the model was the introduction of the end-effect adjustment for carbon penalty. This adjustment, introduced in July 2008 with L804, resulted in a nominal increase of both cost and risk by a factor of three to four. The reasons for and specific calculation of the adjustment is the subject of a subsequent section in this appendix. This shift is illustrated in the next section.

The model L806, completed in early February 2009, was the next major revision to the model, and it incorporated what was intended to be all the data and logic changes that would be made for the staff's final resource portfolio recommendation. The original schedule called for adoption of the Draft Plan in April 2009. An intermediate version of the model, L805, was really a "restore point" for model development. Model L805 is a "known good" version of the model, before the addition of significant changes to construction cost logic. Besides incorporating construction cost logic changes, the L806 version uses the first careful update to load requirement, resource descriptions, and fuel price data. It incorporates the first representation for RPS resources. Unfortunately, the schedule of model development did not permit careful review of model changes, and several errors were introduced that were not discovered and corrected until L810.

Models L807, L808, and L809 represent incremental enhancements to the code and data. The energy adequacy target is moved about 2,500 MWa but with little effect on cost and risk. Hydrogeneration data is extended to the 70-year record in L809, but it is determine later that a significant amount of energy for hydro independents is missing under about 20 percent of the hydro conditions. This problem is corrected in L811.

L810 is significant because it reflects corrections due to an audit of logic and data that revealed the aforementioned problems. It is also significant because of a major load forecast revision. The load forecast increased by nearly 4,000 MW the on-peak loads in the winter, near-term. There was also a 3000MWa energy decrease by the end of the study. This substantially decreased the cost of the system.

L811 is the last revision and the basis for the draft plan. Besides cleanup of hydrogeneration data, this last version incorporates a revised CO2 penalty distribution that moves the expected arrival of some kind of penalty to earlier in the study period. Necessary changes and corrections to this version of the model appear at the end of the appendix. Staff has identified these since adopting L811 as the basis for the Draft Plan recommendations. Special studies have confirmed that these revisions should not have a major impact on the recommends based on L811.

A summary of the impacts of changes from L28 to L811 appears in the next section. The section also gives an estimate of the relative contribution of various changes to cost and risk.

Sources of Shifts in the Feasibility Space

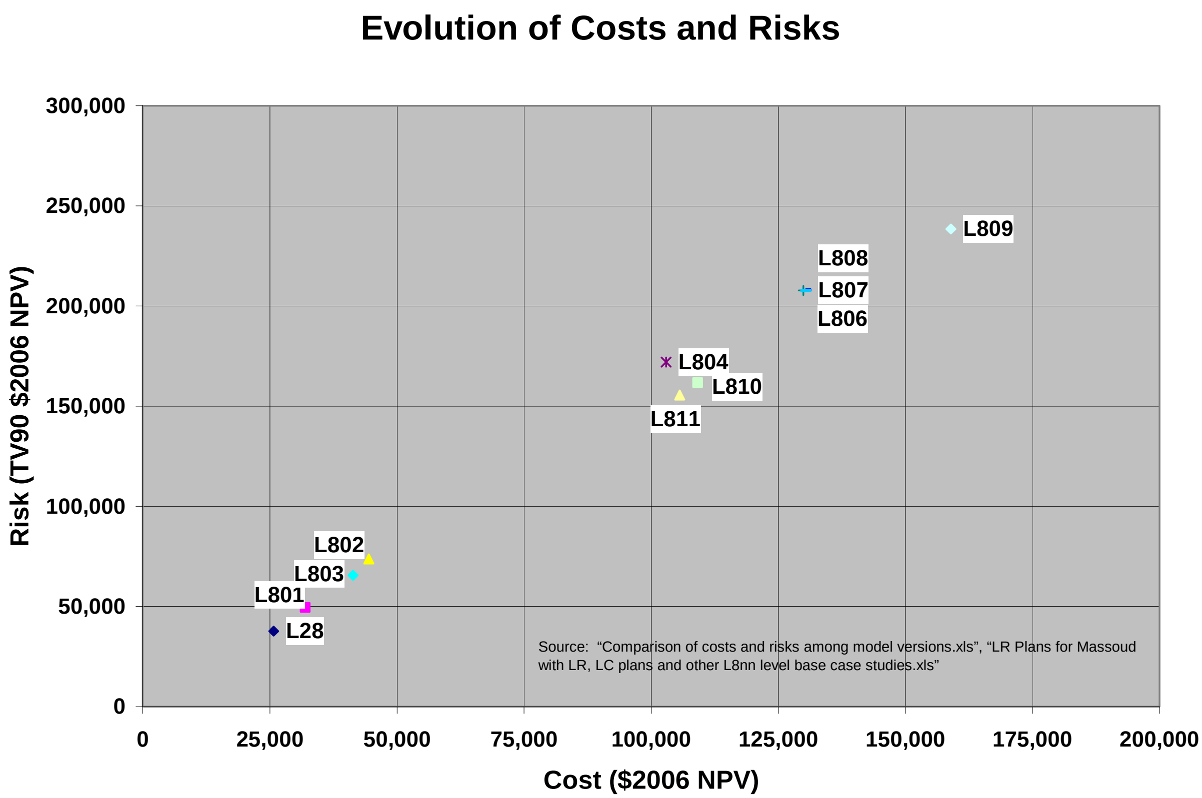
Figure J-1 shows how the feasibility space has moved since the Fifth Power Plan, which is identified by the point L28. The points in this figure are, in fact, the values of the least-risk plan from each model's base case feasibility space. The costs and risk of the feasibility space are subject to many factors, such as the expected value of and magnitude of uncertainty associated with assumptions, the kinds of costs considered, and the manner in which the costs are calculated. All of these factors have affected the costs and risks this figure presents.

The first three versions of the model, L801 through L803, incorporate data changes since the fifth power plan. It is at this point that the $100 per ton On CO2 penalty is introduced. The distribution of carbon penalty implemented in L803 appears in Figure J-2. Costs and risks increase about 70 percent to 41.4 billion cost and 65.5 billion risk from the fifth power plan levels of 24.5 billion expected cost and 35.9 billion risk. Without a more extensive analysis it is difficult to determine the specific sources responsible for these changes. The change from L802 to L803 seems to be primarily due to the introduction of a limit of $50 per ton on carbon penalty through the middle of the study.

In an effort to understand the contributions made by various sources, we can use a simple version of the regional portfolio model that has expected values for load growth, natural gas price, carbon penalty, and so forth. When we run this in a deterministic mode, we get some sense of the sensitivity of costs to the change and assumptions. Table J-1 indicates that the change in load assumptions contributed to the preponderance of costs change between L28 and L803.

With the introduction of the perpetuity factor in L804, costs increased by 150 percent. This change seems disproportionate at first glance. And even stream of cash flows over 20 years would have net present value of about 55 percent of the net present value of the same cash flows to perpetuity. As explained in the subsequent section, however, the perpetuity is applied only to costs subsequent to the imposition of carbon penalty. Consequently, the sample of costs extended to perpetuity calculation will typically be much higher than those prior to the arrival of a carbon penalty.

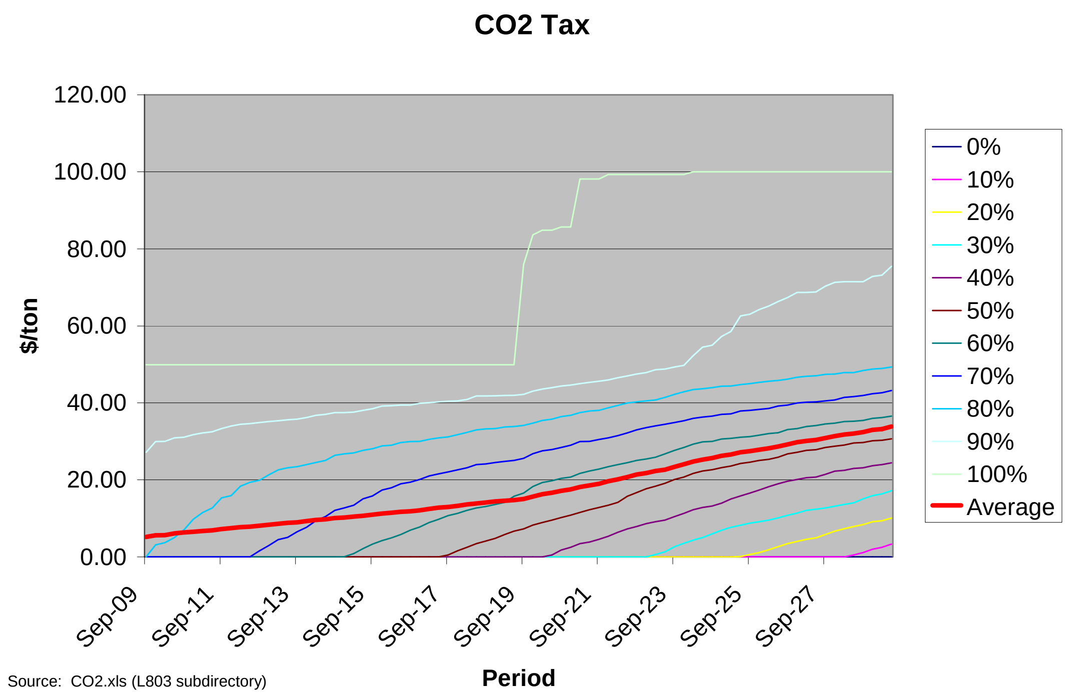
Figure J-1: Evolution of the Feasibility Space



The base case L806 was the first comprehensive update of all data for the sixth power plan. The cost data for base case L806 through L809, however, is suspect for the reasons described in the previous section. The values for base case L810 are reliable. We know that the very large drop in costs between L809 and L810, however, are primarily the result of a change in the load forecast.

Overall average cost and risk did not change significantly between L810 and L811. This is despite their having been numerous significant changes in data and code, including advancing the carbon dioxide penalty median likelihood from 2019 to 2012. The detailed chronology of all changes since the fifth power plan appear at the end of this appendix.

Figure J-2: Carbon Penalty in L803 (April 2008)



The Sources of Increased Conservation

The model has found significant amounts of conservation are cost effective. Much of the conservation has marginal cost above expected long-term market price. This section explains why this is true and identifies contributing factors.

First, it is helpful to understand how the model determines how much conservation will be added at each point in the study. There are two mechanisms responsible and they function in very different ways. The two mechanisms, which we now describe, are the cost-effectiveness threshold and the market adder.

Within each of the 750 futures, the model develops conservation energy in each study period up to the cost-effectiveness threshold. The cost-effectiveness threshold is related to wholesale electricity market prices, but it is not the same thing. Within each period, the cost-effectiveness threshold is compared against a supply curve for lost opportunity and discretionary conservation. Conservation is acquired by moving up the supply curve to progressively more expensive conservation until the model reaches the cost-effectiveness threshold. The cost for each program encountered on the supply curve is added to the cost of conservation already acquired. The model uses real levelized costs for conservation and all other resources.

Table J-1: Sensitivity of L803 to Various Factors

Fifth Power Plan without perpetuity	**24,059**
L803 plan NG price	**24,560**
L803 plan electricity price	**23,976**
L803 plan Loads	**39,715**
L803 CO2 penalty	**28,539**
All four L803 changes	**49,320**
Actual L803 Least-risk case	**41,364**

source: L811mini for illustrations L803.xls

The cost-effectiveness threshold differs from market price in several ways. To calculate the cost-effectiveness threshold, market prices need to be weighted according to the distribution of conservation energy. Also, because there is a lag between the time that a utility conservation budget is determined and the time when the conservation would actually be acquired, the market price of the model uses is an average of market prices over some recent history. Averaging market prices also reflects the fact that perceptions of future long-term market price tend to follow spot price, but recent history also factors into the perception. Another difference is the ratcheting of the cost-effectiveness threshold to reflect the non-decreasing nature of acquisition under changing codes, laws and standards. Finally, there is a "market adder" or premium above wholesale market price that the model will adjust to minimize cost and risk.

The market adder is the second mechanism by which the model determines how much conservation energy to acquire. When the model runs, it exposes each resource portfolio to 750 distinct futures. These futures include descriptions of, among other things, wholesale power market electricity price. Each future specifies hourly values for uncertainties over the 20 year study time period.

The means by which the model selects portfolios to examine is partially arbitrary and partially the product of some learning that takes place as the model acquires experience. In particular, the model tries a whole host of different market adders to see what improves the model success in reducing risk and cost. Of course, the model is also trying different combinations of other generation resources as it does so.

Consequently, the market adder is the results of the model's search process. As its name suggests, the market adder is simply fixed dollars per megawatt hour addition to (or subtraction from) the wholesale market price that the model will use in a particular resource portfolio to modify how far up the supply curve to go for cost-effective conservation in each period.

All of this preliminary is necessary because the model develops conservation using both of these mechanisms. Stochastic variation in electricity prices, with or without the effect of carbon penalties, results in higher levels of conservation acquisition. This is primarily due to the way that the cost-effectiveness threshold's work. Market adder's have greater influence if one selects resource portfolios that have greater risk mitigation value.

One way to characterize the factors that contribute to conservation development is to begin with a simple, deterministic forecast of wholesale electricity price. Using the Council's adopted electricity price forecast to access the supply curves for lost opportunity and discretionary conservation leads to about 4,641 MWa. Because the model adjusts electricity price according to the particular carbon future it selects, the electricity price forecast used for this estimate assumes no carbon penalty.

Stochastic variation in electricity price, assuming no carbon penalty, adds 278 MWa, bringing the total to 4,919 MWa. Stochastic variation electricity price is the result not only of uncertainty with respect to wholesale market price fundamentals, like natural gas price and the construction costs for combined cycle combustion turbines. It is also due to hydro generation variability, load growth excursions, and so forth. Stochastic variation increases acquisition for several reasons. Discretionary conservation has a single supply curves for the entire study. Variations around an expected value in any period will drive cost-effectiveness and acquisition to a high-water mark above that which an average would achieve. Lost opportunity conservation has a similar ratcheting mechanism in its cost effectiveness threshold, as described earlier.

Carbon penalty uncertainty has a direct impact on the wholesale market electricity price and, consequently, the cost effectiveness threshold. Introducing the carbon penalty uncertainty increases acquisition by 419 MWa, to 5,338 MWa. Because we handle this separately in the model, it is possible to cull the contribution from this source of uncertainty from the others mentioned above.

Finally, we have the effect of market price adders. At the least cost, high-risk end of the efficient frontier, the model finds $10 per megawatt hour adders for both lost opportunity and discretionary conservation cost effective. This increases acquisition by 189 MWa, to 5,527 MWa. On the other end of the efficient frontier, the model finds a $10 per megawatt hour adder for discretionary conservation and a $50 per megawatt hour adder for lost opportunity conservation cost effective. . This increases acquisition by 300 MWa, to 5,827 MWa, relative to the least-cost resource portfolio. The results are summarized in Table J-2.

Table J-2: Conservation Acquisition Factors

End of Study (average for non-deterministic)	Stochastic ?	Carbon Pen?	LO Add er	NLO Add er	Discretionary		Lost Opportunity		Total		Ref
					MWa	$/MWh	MWa	$/MWh	MWa	$/MWh	
Deterministic forecasts (0,0)	N	N	0	0	2,251	30.02	2,391	12.97	4,641	21.24	1
Stochastic without carbon (0,0)	Y	N	0	0	2,281	30.30	2,638	17.58	4,919	23.83	2
Stochastic with carbon (0,0)	Y	Y	0	0	2,515	35.15	2,824	21.04	5,338	27.00	3
Risk aversion - least-risk (10,50)	Y	Y	10	50	2,573	36.29	3,253	29.05	5,827	32.30	4
Deterministic, no carbon (10,10)	N	N	10	10	2,294	30.45	2,594	15.92	4,888	22.74	1
Deterministic, no carbon (10,50)	N	N	10	50	2,294	30.45	3,097	24.81	5,391	27.21	1
L811J LR Plan 1851 (10,10)	Y	N	10	10	2,408	32.77	2,788	19.50	5,197	25.73	5

Except for the deterministic cases, the values are averages over 750 futures.
L811, plan 1987_conservation_sensitivity 090720.xls, no market adders, no carbon, Council's electricity price forecast w/o carbon
L811, plan 1987 (now plan -0002), no market adders, without carbon
L811, plan 1987 (now plan -0001), no market adders, with carbon
L811, plan 1987 LR Plan
Feasibility Space L811J

Source: workbook "L811_conservation_sensitivity 090720.xls," worksheet "Table"

Some of the entries in Table J -2 will not be self-explanatory. Each row describes the results of a particular study. The name of the study has two numbers in parentheses at the end which indicate the market adders for lost opportunity and discretionary conservation, respectively. The next four columns represent the same kind of information, but in more structured form. The first column indicates whether this is the results of the stochastic simulation or deterministic estimate. The second column indicates whether there is a carbon penalty present. The third and fourth columns containing the market adders for lost opportunity (LO) or discretionary (NLO) conservation. The values to the right of these columns identify the average megawatts (energy) developed by the end of the study for the respective type of conservation and the average cost of the conservation. The values in the lighter font are estimates, interpolations of the model outputs that appear in darker font.

At the far right is a column that contains numbers which refer to the references at the bottom of the table. These references indicate where to find the corresponding model results.

ENHANCEMENTS TO THE MODEL

Below is an introduction to some of the logic enhancements introduced since the Fifth Power Plan.

Capacity and Costs Related to Capacity

Early in the process, staff and stakeholders recognized that construction cost uncertainty would be prominent in the Sixth Power Plan. When we consider uncertainty in construction costs, however, numerous other issues present themselves. Should uncertainty in construction costs be tied to the seasonal or long-term capability of a unit or to the original nameplate capacity? How do other costs vary? Is fixed operation and maintenance similarly affected? If we introduce the capability to adjust cost and capacity according to some random variable, we introduce the capability to vary according to a deterministic variable. Do we want to develop the capability to vary capacity, capability, fix costs associated with construction, and fixed costs associated with ongoing operations and maintenance?

Ultimately, we elected to provide all of these features in the revised model. These changes, moreover, suggested numerous other modifications that can be made with little or no additional development effort. Such changes include uncertainty in commercial availability of a new technology. This section describes most of the new features developed for the Sixth Power Plant.

The following is a summary of the sections that follow. These sections briefly describe the enhancements to Capability and Fixed Cost Representations:

- In the Fifth Power Plan, construction costs did not have the kind of detail that staff would have found ideal. Specifically, mothball in cancellation costs depend, in a sensitive fashion, on when the decision is made to defer or cancel construction. Enhancements for the Sixth Power Plan reflect those preferences.

- Internalized decision making, including decisions based on forward-going fixed costs, became not only preferable but in fact necessary.

- Enhancements provided for adjusting all fixed costs, including fixed operations and maintenance (FOM) and construction cost.

- Enhancements also provided for adjustable capacity due to seasonal effects and adjustment over the study, both for cost and for energy calculation purposes.

- Finally, staff anticipated that retirement logic would be useful not only to the evaluating the implications to coal-fired power generation due to carbon penalties, but also the retirement of less efficient gas-fired units in the situation where electricity prices fall. Subsequently, however, with the Generation Resource Advisory Committee (GRAC) suggested that utilities would retire power plants only when their public utility commissions deemed it appropriate. Power plants are almost always kept, because the discretionary fix costs become relatively small after the units have been constructed. Such plants provide insurance against unforeseeable excursions in loads or electricity prices.

In total, there about 16,388 combinations of new features and their interaction can be subtle. These are enumerated at the end of the section. The following describes some of the more prominent changes.

Before proceeding with the description of the enhancements, it may be useful to describe some of the features that it existed in the Fifth Power Plan.

Fixed Cost and Capability Treatment in the Fifth Power Plan

In the model, construction may begin in any period, subject to user specification. That is, the model permits additions to be made in every period, but the user must specify the maximum amount of each type of resource that may be added in that period. The schedule of these earliest construction start dates constitutes a significant portion of what we refer to as a "plan" or a "resource portfolio."

Cohorts are identical units that may begin construction at the same time. Units are identical in the sense that they have the same technology and fuel, and they face exactly the same costs and market prices. They have the same unit size. Cohorts exist because the model adds new capacity in multiples of some fixed unit size. At a given period, for example, a plan or portfolio may specify that only one unit may begin construction, only two units may begin construction, or some other pre-specified number may begin construction. Of course, because all cohorts face the same economic and adequacy circumstance, all cohorts have the same decision criterion outcome and will respond identically. It is the plan selected by the optimizer, therefore, that determines the amount (MW) of capability that will eventually become available for completion.

One feature that has not been used in either the Fifth Power Plan or the Sixth Power Plan is discretionary addition of resources by the model under favorable market conditions. The reason for excluding this option is probably obvious: the Council is tasked with producing a resource portfolio, including the timing and selection of resources. The feature that we're describing, however, leaves that decision to the market place. The selection of this feature, therefore, would be in a sense an abdication of the Council's role.

Nevertheless, if the user selects this feature, he or she must specify the maximum number of units that may be added in a particular period. Without that limitation, nothing would restrain the model from adding an arbitrary number of units whenever the market indicated that a single unit could make money.

The model partitions construction activities into three phases. There is an initial planning phase which is often quite long but typically costs only 1 or 2 percent of the overall project budget. In Council studies, the optimizer assumes that this phase has been completed and associates with a plan the cost of the initial planning for each resource in that portfolio. The decision criterion for construction is not use during this phase.

The second phase is an early construction phase, during which the decision criterion determines whether to continue with construction or two defer or cancel the unit. The third phase is a late construction phase, during which construction continues without regard to the decision criterion until the plant is completed and brought online. It is assumed that most of the money has been spent before the initiation of this third phase and that the best economic outcome at that point is to complete the plant.

In the Fifth Power Plan, the rate of expenditures during construction was the same for the early and the late phase. One of the enhancements for the Sixth Power Plan is the introduction of separate cost expenditure rates for the early in the late phase of construction. This provides more flexibility in stipulating construction costs.

Another feature of the original construction logic was a specification of whether all of the funds would be spent in the first period of a particular construction phase. It has been observed that very often, a project manager is called on to spend, up front, most of the money available for construction. These up-front expenses are for key components, often the initial or final payments on boilers or combustion turbines. These represent the majority of the cash flow. These decisions also mark the beginning of a new phase of construction. By providing the capability to represent this in the model's logic, we better capture the commitments that decision makers are bound to.

These existing features must be integrated with the new features. We will return to these considerations in the context of each feature.

More Detailed Specification of Construction Costs

In the model, deferral (mothballing) and cancellation can occur only during early construction phase. For the Fifth Power Plan, whether or not a deferral or cancellation decision was made early or later in this early phase had no impact on the cost. For the Sixth Power Plan, logic was modified to reflect the fact that mothballing and cancellation costs depend, in fact, on whether or not the decision is made in the first period of the early construction phase. It is generally thought that if a construction project is terminated or deferred early, the cost of cancellation and or of deferral would be considerably less.

We also note that there are a least two components of mothball costs – a fixed, one-time charge, and a period charge for each period in which the unit is mothballed. In the Fifth Power Plan, the model reflected only the latter. This is one area where no significant improvement has been made to our representations that the Six Power Plan. Unfortunately, recognition of the fixed component of mothball costs came only at the end of the development process. Also unfortunate is the fact that the fix costs appeared to dominate the variable costs. They can be as much as 32 times larger than the variable costs.

At a minimum, we need to study the treatment of fixed cost better before implementation. There are several unanswered questions that this aspect of cost raises. For example, is it applied again if construction restarts and then stops again?

Mothball and cancellation costs should be capitalized and amortized rather than expensed. To expense them would introduce distortions in economic value calculations, due to the use of real levelized costs and the assumption that costs prior to the end of the study are representative of life-cycle costs.

Note that there is no treatment of deferrals and cancellation during the planning and late construction phases. Our assumption is that planning and late construction activities are insensitive to decision criteria.

Finally we must give consideration to deferral and cancellation during any decisions about retirement of power plants. These are discussed separately in their own section below.

What is assumed throughout, however, is that any adjustments or escalation in the real cost of construction, deferral, or cancellation will be applied irrespective of whether those decisions are made during construction or retirement. In particular, the GRAC suggested that construction cost uncertainty and variability be applied to deferral and cancellation rates of cost acquisition.

Uncertainty in Construction Costs, Fixed O&M Cost, and Variable O&M Cost

For the Fifth Power Plan, we did not include uncertainty in construction costs or fixed and variable O&M. For the Six Power Plan, these are prescribed by external multipliers for each period. The multipliers differ from period to period. Moreover, each future has a distinct sequence of multipliers with strong correlation from one period to the next.

Application of the multipliers to construction costs will affect the real levelized cost over the life of the plant in every period. That is, the construction cost that is incurred is affected by the multiplier, and then a levelized value is present in each period of the economic life of the unit. This is not true, however, for fixed and variable operations and maintenance (O&M). Fixed and variable operations and maintenance (O&M) multipliers do affect their associated costs over time.

Consequences for the Algorithms

Because the multiplier effects fixed O&M costs only in the period to which they are applied, in contrast with construction cost which must be carried forward to subsequent periods, we do not need to store the information. We will carry along only information about the original variable O&M and fixed O&M rate. As their values are reported back for period costing, we apply the multipliers. Values are not stored. In fact, we don't even need to know for this purpose what the cohort fixed and variable O&M are. We do need that information, however, for the calculation of decision criteria.

As is true for the preceding section, any escalation in or adjustments specified by the user must be applied to these costs in each period.

Variation in construction and O&M cost, moreover, will apply to all cohorts in a given period equally. Because each cohort has identical operating and capacity characteristics, they must be treated identically with respect to these adjustments.

Economic Retirement

The treatment of economic retirement is new in the Six Power Plan. In the Fifth Power Plan, the model reflected a prescriptive loss of about 1000 MW of inefficient gas-fired generation in the region. In the Sixth Power Plan, however, we wanted the treatment to be not only more sophisticated but also to be sufficiently detailed to capture the impact on power plant economics due to the possible imposition of a carbon penalty.

Economic retirement is driven by decision criteria based on forward going fixed O&M cost. If the decision criterion is negative for a prescribed number of periods, the model effectively decommissions the unit.

In principle, this feature could be available for both existing, non-surrogate plants and for new candidates. Surrogate plants are as those that represent an equivalence class of dispatchable generation that have identical fuel type, heat rate, variable operation and maintenance costs, and fuel cost.

Providing for a decision criterion that is meaningful for new candidates, however, requires separate tracking of fixed O&M for every cohort. Each cohort will have, typically, different fixed cost requirements based on prior commitments and will therefore face different requirements for economic feasibility. The prospect of distinct commitments and fixed costs for each cohort also means a requirement for new logic to track and handle prior retirement decisions regarding costs and units. Specifically, when a new plant comes online, offsetting additive inverse of units and fixed O&M are added to a period at the end of the plant life. If the unit is retired early, however, these values need to be removed and replaced by the revised values.

For the initial version of this algorithm, therefore, the model excludes new resource candidates and existing resource surrogates. Retirement is only implemented for simple existing units. The rationale for this is that any specific existing resources that we suspect are candidates for retirement probably require of their own modeling. In addition, any new units should be much more efficient than existing units and should be among the last to be retired.

Consequences for the Algorithms

During the simulation, construction costs are subtracted from the period corresponding to the economic life of the unit. This permits annual fixed costs to simply be carried forward in added to current period costs. When the power plan reaches the period in which it is retired, the levelized fix costs are added to the costs for the subject period, which are negative, resulting in zero cost for subsequent periods.

One question is whether that costs which has been subtracted from the retirement period for a given cohort needs adjustment to reflect variation in construction costs. These would not be adjusted, however, assuming that capitalized construction costs, once fixed at the time of expenditure, would remain fixed. That is, the cost is determined when construction expenditures take place and is not affected by any subsequent variation in costs that other, new cohorts would face.

Another subtlety is that the decision criterion for retirement will be affected by fixed operation and maintenance costs, which in turn is determined by any escalator and by variations in plant capability and in the fixed O&M rate itself. Because the decision is based on a per kilowatt criterion, the capability of the unit should not be an issue, but the other factors remain. Moreover, many of the issues that pertain to mothballing and cancellation costs incurred during construction also affect retirement decisions.

Uncertainty about Commercial Availability

An important source of uncertainty for new technologies is their eventual commercial availability. Even if we are fairly confident that a technology is achievable, we have no assurance that it is achievable it costs that are competitive with other generation sources. In discussions with various advisors, the following representation seems to be the most promising.

At the beginning of each game, a random variable is selected for a new candidate that has uncertainty with respect to commercial availability. This random variable has as its value the year when commercial availability is achieved. It may be that this value is beyond the study horizon. In that case, the technology effectively is never commercially available.

As with other new candidates, cohorts can be constructed in any period the user specifies. The pregame logic, however, assigns a special status code to all periods before the commercial availability variable's period. This status code indicates that that cohort is not commercially available. This has the effect of causing the schedule to simply slip until the technology becomes available and the first period of planning or construction phase can begin.

Note that all cohorts are treated equally in this case. All cohorts will become available in the same period.

One question associated with this representation is whether there are costs incurred during periods in which the technology is not commercially available. Another question is whether there is some maximum number of periods of unavailability feasible for a specified technology. That is, will the technology lose its siting and licensing if it doesn't become commercially available within specified amount of time. I would guess that the answer to this question is yes, and I have reflected this in the current logic. I would also guess that that maximum amount of time could probably be taken as the maximum amount of time for mothballing during the construction of a power plant.

Finally, how do the deferral and cancellation cost due to commercial infeasibility comparable to the cancellation cost for construction? For the initial version of this feature, we have used the costs associate with the "first period" construction event. See the section, ***More Detailed Specification of Deferral and Cancellation Costs***, for details.

Integrated Forced Outage Rate

One of the deficiencies in representing new candidates has been the treatment of forced outages. As new units of a given technology are added, there is a diversification effect with respect to forced outages. We have not accounted for this, and in fact use only a block deration for forced outages of new candidates.

The objective of this new logic therefore is to provide cohort-specific forced outages. Of course, we would continue to provide forced outage adjustment through deration.

One of the benefits of handling forced outage rates internally would be reduced reliance on Crystal Ball random variables. Most of the 1100 random variables the Fifth Power Plan's model employs are for modeling forced outage rates associated with large, existing thermal units. Because our new planning flexibility function permits us to better treat existing power plants, the Crystal Ball random variables are replaced. Crystal ball provides only a seed value for the internal random number generator.

Consequences for the Algorithms

One means of producing these forced outage rates is through pre-calculation and storage. The purpose of the Crystal Ball random variable then would be merely to look up the values associated with each future, plant, period, and cohort. The Sixth Power Plan's drat plan model, however, uses the more computation intensive approach of recalculating outages for all cohorts of all plant at the beginning of each future.

Modeling subscribes to the following representation of failures and repairs. Overall power systems fail when a series of components fail. Each component is assumed to have failure rate with exponential distribution. For multiple component failures, the system will have a gamma distribution, which is determined by the Mean Time to Failure (MTTF). Similarly, we assume that the simple systems must be repaired before the restoration of the overall system is complete. Restoration will similarly have a gamma distribution determined by a Mean Time Before Repair (MTBR). Again, the components have exponential distribution. We assume one-half dozen simpler systems fail and require repair.

The forced outrage rate (FOR) is the ratio MTBR/(MTTF + MTBR), which will have a statistical beta distribution. Knowing the FOR and MTBR is adequate to computing all the other information necessary for specifying the distribution. These are therefore the required data for the model.

Because forced outages affect only period data, their values do not need to be retained for any subsequent calculations. They can be applied directly to the estimated energy for each cohort before the cohort energies are summed up to report back to the worksheet.

Variable Capacity

We want to prescribe variable capability of existing plants over time. These changes might vary by future as well as period, and they might change stochastically or deterministically. One significant application of this feature is representation of maintenance and planned outages.

There is a problem with doing this for surrogates and for new candidates. Surrogates represent a collection of existing plants. We currently do not have a good way of telling the model which cohort or plant within a collection to modify. Consequently, while we permit application of variable capacity to any kind of unit, in the case of surrogate units and new candidates, for this initial version, we apply the same adjustment to all units or cohorts implied or modeled within the collection. That is, the adjustment is simply applied to all output of the collection.

One issue is whether this adjustment affects decision criteria for new plants and for economic retirements. Because the economic feasibility of a plant is determined on a per-MW basis, this typically has no effect on the decision. If the variation is seasonal, however, the forecast capability is affected. This is the case with maintenance and for dispatchable resources subject to temperature-related performance. Consequently, an annual average over recent periods must be calculated for these purposes and incorporated into the decision criteria. Otherwise, we shall assume that variations in capability are unforeseeable and would therefore not affect the decision criteria.

Variable capability will, however, affect the adequacy calculation for the decision criterion. For this purpose we definitely need to have some average over recent periods to make of realistic estimates of contribution towards energy adequacy.

We assume that any adjustment to capacity does not affect fixed costs associated with construction investment. Adjustable capacity will, however, affect fixed operations and maintenance (O&M). A subsequent enhancement to the model will be permitting the user to specify whether or not this is the case.

For this adjustment, as well as other, we will provide a new capability to the model to permit that data be read cyclically. For example, assume a sequence of adjustments is specified for k periods, where k is less than the number of periods in the study. The model will return to the first period's adjustment for a value to use for the k+1 period. It will use the second period's adjustment for the k+2 period, and so forth.

New Utilities

We need transparency with respect to the responses of the model. We need to report back adjustments due to the other new features we are introducing.

- Forced outage rate, by cohort, plant, and period.
- Capability for regional act adequacy estimation. This will differ by future.
- Internal decision criteria estimation, by cohort, plant, and period. Relevant factors are prospective fuel and electricity price, regional adequacy, energy value, fixed O&M, and -- for new construction -- forward going construction costs.
- Fixed O&M adjustment by cohort, plant, and period.
- Capital costs by cohort, plant, and period.

We will need the breakdown by plant, cohort, and period. For new units, we will also need detailed information about the construction state of the unit.

Special auditing software now provides the ability to look not only at the value of ranges within the model's worksheet, but also the content of selected Visual Basic arrays. These arrays are used to store detailed information about the state value of each existing and new resource. These can be extracted in a number of formats, including those suitable for spinner graphs, pivot table, and other applications.

Input Variables and Feature Selection

The specification of options for the representation of fixed costs and capability appears in a relatively compact format next to each resource for which it applies. Below, in Figure J-3, the new capabilities and specification of new values are captured by the first row. The second row of variables in identical to what the Fifth Plan used, with the exception of the cell highlighted in yellow and using red font. There is a slight change in the interpretation of that value from what was previously used, as explained by a comment in that cell.

The overall specification of which of the 16,388 combination of features the model will use is encoded in an integer in the first column of the new row.

Figure J-3: Fixed Cost and Capability Specification

610 MW CC 030708

Option Selection (integer)	FOM (R $M/ MW/ period)	Late Constr Costs (RL $M/ MW/ Period^2)	Earliest Availability (Period)	Regional Share	Retirement mothball life (periods)	Retirement evaluation cost (RL $M/MWPeriod)	Decommisioning cost (RL $M/MWPeriod)	First Period Mothball Costs(RL $M/ MW/ Period)	First Period Cancellation Costs (RL $M/ MW/ Period^2)	Generation technology	Status	LT Fuel Price (Range name)	MTBR (weeks)	FOR [0...1]	Nameplate (MW) - required for cost calcs of existing units only
44144	0.013101	0.003000		100%				0.000029170	0	CCCT	New			0.05	378.3

Criterion Set ID	Planning Periods	Early Construction Periods	Late Construction Periods	Development Costs (RL $M/ MW/ Period^2)	Mothball Costs (RL $M/ MW/ Period)	Cancellation Costs (RL $M/ MW/ Period^2)	Early Constr Costs(RL $M/ MW/ Period^2)	CancelThreshold (	Const Cost Escl (.01=1%/period)	ResourceLife (periods)	OptionLife (periods)	Market-driven ramp rate (MW)	Planned Development Costs (RL $M/ MW/ Period^2)	Index
CCCT Criterion_004	0	4	6	0	0.00068613	0.0014288	0.003137106	-99999	0.000%	120	20	FALSE	0.00132581	0

Study ID	Availability	DHF(0=Dis	Fixed Ener	Fixed Cost ($/l	Fuel Set (ID	Heatrate (MMB	Planning Flexibility ID	Capacity ID (I	Cap_Decisior	Variable Cost	Hydro Structure ID	
1	(none)	0	(none)	(none)	PNW East N	7.1	CCCT-01 Annual_004	CCCT Capaci	0,6000,1500,(	1.82	(none)	12

Construction Cost Variation	1	1	1
Manifest Capability (MWa)	0.0	0.0	0.0
Cost ($M Real)	0.0	0.0	0.0
Energy(MWh)	0.0	0.0	0.0
Cost ($M)	0.0	0.0	0.0

In a separate location within the RPM, the user can specify with simple yes or no flags whether to use the particular option. The coding logic appears in Figure J-4.[2] The user may also need to decode a particular option selection from the integer. Figure J-5 illustrates the formula in the workbook that performs that function.

Figure J-4: Encoding the Selection of Options

	Option selection		Plant status (for data validation)
1	no	Use 2004 logic	Existing
2	no	FOM Variable (& differs each gam	Existing Aggr
4	no	VOM Variable (& differs each gam	New
8	no	Capability Variable?	
16	yes	Construction Cost Variable (& differs each game)?	
32	yes	Use Distinct Cost for Committed Construction?	
64	yes	Use Internal Decision Criterion?	
128	no	Economic Retirement Logic?	
256	no	Stochastic FOR?	
512	no	Stochastic Availability?	
1024	yes	Use Distinct Cost for Mothballing in First Period?	
2048	yes	Use Distinct Cost for Cancelling in First Period?	
4096	no	Capability Differs Each Game?	<== not currently in use
8192	no	Spend early construction phase cash in first period	
16384	no	Permit Market Additions	
32768	yes	Read construction costs from the internal array	
	35952		

Most of the variable inputs for fixed cost and capability representation in the model are self-evident. Because some of them are not, however, their description appears in Figure J-6, which is detail from the first row in Figure J-3. This particular example is for an existing surrogate natural-gas fired power plant. We have already discussed the first column.

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[2] At first glance, this figure suggests that a much larger number, 65536, are available. In fact, one option is not currently in use. Also, the selection of the 2004 logic excludes the use of other options, except for market additions and early use of all early construction funds in the first period of early construction.

Figure J-5: Decoding a Selection of Options

44144

		INVERSE	
0	1	FALSE	
1	2	FALSE	
2	4	FALSE	
3	8	FALSE	
4	16	TRUE	Construction Cost Variable (& differs each game)?
5	32	TRUE	Use Distinct Cost for Committed Construction?
6	64	TRUE	Use Internal Decision Criterion?
7	128	FALSE	
8	256	FALSE	
9	512	FALSE	
10	1024	TRUE	Use Distinct Cost for Mothballing in First Period?
11	2048	TRUE	Use Distinct Cost for Cancelling in First Period?
12	4096	FALSE	
13	8192	TRUE	Spend early construction phase cash in first period
14	16384	FALSE	
15	32768	TRUE	Read construction costs from the internal array

The remaining columns in Figure J-6 are described below.

FOM (R $M/ MW/ period) – fixed operation and maintenance cost – fixed operation and maintenance expressed in millions of dollars per megawatt per period. The final fixed O&M rate is subject to any escalation and variation multiplier.

Late Constr Costs (RL $M/ MW/ Period^2) – if the user specifies a distinct cost for construction during the late construction phase, the rate is specified here in real levelized millions of dollars per megawatt per period per period. This is a rate of cost accumulation (like an acceleration) during construction. By the end of construction, the total accumulated real levelized costs is carried forward to subsequent periods.

Earliest Availability (Period) – This is a stochastic variable used by the model when the user specifies uncertain commercial availability. The value of the stochastic variable indicates the earliest of that construction may begin.

Regional Share – Some units have a portion of their output dedicated to independent power producers (IPPs) and do not have firm contracts for regional use. If this is the case, only that chair of the output dedicated to the region will be used to determine the value of this resource to the region. The remaining energy will be supply to the wholesale power markets, but will not otherwise benefit the region.

Retirement mothball life (periods) – This indicates the number of periods during which retirement may be evaluated before the unit would be permanently decommissioned.

Retirement evaluation cost (RL $M/MWPeriod) – During the evaluation of the unit for potential retirement, retirement evaluation costs may accumulate. Those are stipulated here are in real levelized millions of dollars per megawatt per period. This cost appears in each period before decommissioning. This cost disappears after decommissioning.

Decommissioning cost (RL $M/MWPeriod) – Once the decision has been made to decommission the unit, some additional decommissioning cost may be necessary. That cost stipulated here is in real levelized millions of dollars per megawatt per period. This cost will be carried by the power plant over its remaining economic life.

First Period Mothball Costs(RL $M/ MW/ Period) – If, during early construction, deferral of the unit during the first period of early construction would incur a cost substantially less than deferral during subsequent periods, the first period cost may be stipulated here. The model will use this cost if the user specifies the selection of this option through the selection of flags identified earlier.

First Period Cancellation Costs (RL $M/ MW/ Period^2) – If, during early construction, cancellation of the unit during the first period of early construction would incur a cost substantially less than cancellation during subsequent periods, the first period cost may be stipulated here. The model will use this cost if the user specifies the selection of this option through the selection of flags identified earlier.

Generation technology – This specifies the generation resource's type of technology (SCCT, CCCT, Wind, etc.). Excel data validation restricts the selection to a specified list of technologies. Identifying the type of technology is necessary for the correct functioning of the decision criterion.

Status – The status of the unit indicates whether it is existing or new, and if it is existing, whether it is a surrogate unit or a simple unit. The status is used by the logic to determine whether or not a construction process is warranted and how the decision criterion, if any, needs to be implemented.

LT Fuel Price (Range name) – This specifies the range name of the long-term fuel price forecast. This information is used by the decision criterion to determine economic feasibility.

MTBR (weeks) – if the user specifies that the model should implement stochastic forced outages for this plant, the model requires both the forced outage rate and the Mean Time Before Repair for this unit. This is specified in weeks. See the discussion above for forced outage rate modeling for additional background.

FOR [0…1] – The forced outage rate is required for all units. If the user does not specify that the model implements stochastic forced outages, the model will derate a unit's capability deterministically by the forced outage rate. The value in this field should fly between zero and 1.0. For example if the forced outage rate is 5 percent, the value in this field should be 0.05.

Nameplate (MW) - required for cost calculations of existing units only – For existing units, the model only requires the capability of the unit (before forced outages) to determine energy generation. If there are fixed costs associated with the existing unit, however, such as fixed operation and maintenance, the nominal capacity is necessary to determine period cost. That nominal capacity is specified in this field.

New generation does not require this information. New generation takes its capability directly from the decision cells at the top of the worksheet. These typically are controlled by the optimizer.

Figure J-6: Detail of options in previous figure

															West 1
Option Selection (integer)	FOM (R $M/ MW/ period)	Late Constr Costs (RL $M/ MW/ Period^2)	Earliest Availability (Period)	Regional Share	Retirement mothball life (periods)	Retirement evaluation cost (RL $M/MWPeriod)	Decommisioning cost (RL $M/MWPeriod)	First Period Mothball Costs(RL $M/ MW/ Period)	First Period Cancellation Costs (RL $M/ MW/ Period^2)	Generation technology	Status	LT Fuel Price (Range name)	MTBR (weeks)	FOR [0…1]	Nameplate (MW) - required for cost calcs of existing units only
264										CCCT	Existing Aggr		0.143	0.05	1.00

The following illustration (Figure J-7) indicates how various representation options interact.

For the draft plan, many of the capabilities of the model went unused. For example, the GRAC suggested that a coal plant would never be retired for economic reasons. Consequently, staff decided to retain existing coal plants in the region's portfolio of resources unless a study explicitly called for their removal. Studies relied primarily on the models new features for representing variable costs, in particular variable construction and FOM costs, and stochastic forced outages.

Figure J-7: Impact of Modeling Choices on Various Costs

end of study dollars	FOM Adjustment on original capacity	FOM Adjustment on modified capacity	VOM Adjustment	Capacity Adjustment	Construction Cost Adjustment on original capacity	Construction Cost Adjustment on modified capacity	Commercial Availability	Stochastic FOR	Escalation rates		Use 2004 logic	FOM variable over study	FOM variable over study and over future	VOM variable over study	VOM variable over study and over futures	Capability variable over study	Capability variable over study and over futures	Construction Cost variable over study	Construction Cost variable over study and over fugures	Use Distinct Cost for Committed Construction	Use Internal Decision Criterion?	Stochastic Availability?	Use Distinct Cost for Mothballing in First Period?	Use Distinct Cost for Cancelling in First Period?	Initial capability Differs Each Game?	Spend early construction phase cash in first period	Permit Market Additions	Read construction costs from the internal array	After on-line	Economic Retirement Logic?	Stochastic FOR?
sunken development cost ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X										X				
development cost ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X								X	X			
mothball cost, first period variable ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
cancellation cost, first period variable ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
other mothball cost variable ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
other cancellation cost variable ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
mothball cost, first period fiXed ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
cancellation cost, first period fiXed ($)	1	1		X	X	X	2	2	X			1	1	1	1	X	X	X	X			X	X	X	X		X				
other mothball cost fiXed ($)	1	1		X	X	X	2	2	X		X	1	1	1	1	X	X	X	X			X	X	X	X		X				
other cancellation cost fiXed ($)	1	1		X	X	X	2	2	X		X	1	1	1	1	X	X	X	X			X	X	X	X		X				
early construction costs ($)	1	1		X	X	X	2	2	X		X	1	1	1	1	X	X	X	X			X	X	X	X	X	X	X			
late construction costs ($)	1	1		X	X	X	2	2	X		X	1	1	1	1	X	X	X	X	X	X							X			
FOM cost ($)	X	X		X												X	X						X	X	X	X		X		X	X
VOM cost ($)			X	X				3				X	X	X	X	X	X						X	X	X	X		X		X	X
fuel cost ($)				X				3								X	X						X	X	X	X		X		X	X

1 Because FOM only affects operations, and in particular, only affects costs after construction, this does not affect any construction costs.

2 Because these affect only operations, they do not affect any construction costs.

3 Stochast FOR affects variable cost, not fixed cost

Source: workbook "Relationship among variables.xls", worksheet "Sheet1"

RPS Modeling

As described in Chapter 8, renewable portfolio standards (RPS) have been adopted by states across the country. In the Pacific Northwest, the states of Washington, Oregon, and Montana have already implemented in RPS. Typically, and RPS specifies that a utility will meet a prescribed fraction of its total energy requirements with renewables according to a particular schedule that makes than 20 years in the future.

There are several challenges in modeling RPS requirements. First, these requirements apply to utilities within each state depending on the number of customers of or load served by the utility. Second, utilities typically may opt out of their requirements if acquisition of renewables would cause their revenue requirements to exceed by 4 percent their requirements otherwise.

Representing RPS standards with the regional portfolio model (RPM) introduces several more challenges. The RPM uses 750 distinct regional load forecasts. These regional load forecasts must somehow be allocated down to the utility level in order to determine a consistent RPS requirement. Moreover, the RPM has discretion to option wind and geothermal resources to reduce cost and risk to the region. Some rules for allocating any such wind or geothermal energy back to individual states, if not utilities, is necessary. This energy presumably would apply toward their RPS targets.

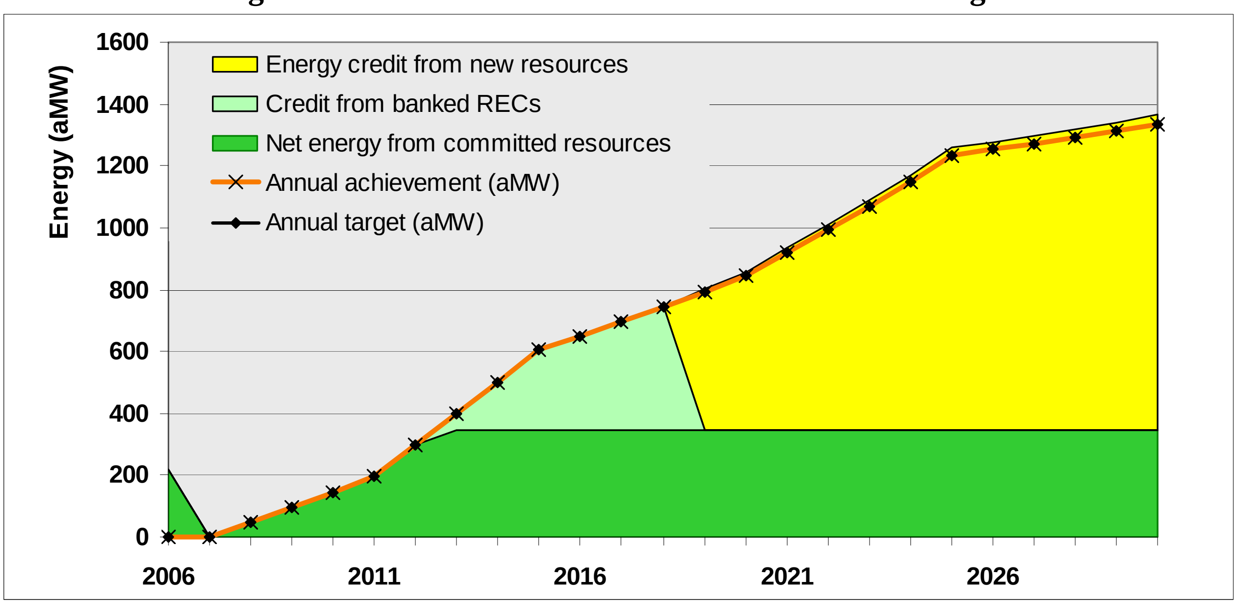
Finally, the Council has stipulated an amount of cost-effective renewable resource potential within the region. The model must have rules for determining when renewables are used to meet RPS requirements, when they are not used to meet RPS requirements and their renewable energy credits (RECs) may be sold, and whether the required RPS development would exceed the regional potential for cost effective renewables. If required RPS development would exceed this threshold, the model needs a rule for determining where the renewables would come from and what they're cost would be. Ideally, the cost of RPS renewables would match the cost of non-RPS renewables having identical technology and geographic placement, with the possible exception of REC value treatment.

Because of the very tight time constraints placed on development of the model's RPS representation, only a single pass at design was possible. The next section describes the representation used for the draft Sixth Power Plan. The subsequent section describes a number of enhancements that may be incorporated in the final Plan.

Draft Methodology

The logic in the RPM is based on a detailed analysis performed by Maury Galbraith and Jeff King in the fall of 2008.[3] These analyses estimate the amount of renewables already developed by each of the states. They also determine the mix of obligated utilities and their RPS requirements in the future. Finally they estimate of the REC credits that each state has acquired to date. The final forecast REC balance is illustrated in Figures J-8 through J-10, below.

Figure J-8: Forecast REC Balance for the State of Oregon



[3] See "RPS Estimates 100708.xls" and subsequently "RPS Estimates 021909.xls"

As these illustrations show, many utilities are banking REC credits acquired by building renewables in advance of requirements. These REC credits correspond to megawatt hours of energy generated in a given year surplus to requirements. The states of Washington, Oregon, and Montana all have different rules regarding how long the utility can bank its REC credits, however. In Oregon, REC credits never expire. In Washington, they expire after one year. Montana permits utilities to bank their credits for two years. Different states, therefore, will encounter a need for REC energy it significantly different points in time.

The RPM must track renewables development, banked REC credit balances, and load changes for each of the states. Moreover, it must maintain renewable acquisitions to meet nominal state targets. Finally, it must track cost for any such acquisitions.

Because the model must meet each state's RPS needs, even when other states are surplus renewables relative to their RPS targets, requirements may be larger than expected. That is, comparing the total obligated utilities' renewables to their total REC obligations will typically understate the net requirement.

The model begins by allocating wind energy to the three states. The first calculation in Figure J - 11 updates the amount of wind energy constructed by the model. There are two wind generation classes in this version of the model, representing units that do and do not get credit for selling their RECs. Because Montana is expected never to have RPS needs exceeding 100MWa, the RPM next tries to meet Montana's needs, up to that amount (the second calculation in Figure J-11). While Figure J-9 indicates Montana's requirement never goes over 50MWa, we must remember that this is a "most likely" forecast of loads, and loads may exceed the most likely case significantly in the model. If there is any additional wind energy added by the model, the energy is split between Oregon and Washington.

Next the model estimates the gross RPS requirement for each state. To do this, it uses a fixed estimate of the percentage of the region's load that each state's obligated utility load represents. This is about 3.3 percent for Montana, 27.2 percent for Oregon and 39.7 percent for Washington. The fraction of each state's obligated utility load that must be met with renewables increases over time and is typically stipulated only for three or four years, for example, 2015, 2020, and 2025. Straight line interpolation provides the model with estimates for the intervening years. For the first year in the RPM, Hydro year ending August 2010, this interpolation yields 10 percent for Montana's obligated to load, 3 percent for Oregon's obligated load, 2 percent for Washington's obligated load.

From the region's load, from the percentage of region load that each state's obligated utility load represents, and from the annual target percentage of obligated utility load that must be met by renewables, the model calculates the gross RPS target. For all three states, this initial target is about 30 average megawatts.

The next step is to compare the gross RPS target, the existing renewables, any wind generation allocated from the RPM's new wind additions, and the existing banked RECs. This is done for each state separately. In Figure J-12, the model first determines the gross RPS target for Montana as described in the preceding paragraph. The value is constrained to be non-decreasing, because it is unlikely that the state would decrease its requirement due to, for example, short-term load variation.

The estimates for existing renewables within each state are from the fall 2008 study of Maury Galbraith and Jeff King, mentioned earlier. They estimated that at that point in time, Montana had about a 65 average megawatts, Oregon had about 377 average megawatts, and Washington had 401 average megawatts of renewable energy.

The existing credits, existing renewable energy, and new, allocated renewable energy are netted from the gross requirements. The net requirement may be either positive or negative. If the balance is positive, in principle model could sell the RECs or carry the credit forward. Because of the value of the RECs to utility that is likely to need RPS renewables, this version of the model always carried the credit forward. Obviously, if the utility did not need the credits or the credits would expire before the utility could use the RECs, it would make more sense to sell the RECs. It appeared that Oregon and Washington RECs would have greater value to banked than sold. Montana would probably benefit from selling any RECs, but the renewable energy allocated by the model to Montana is already constrained to prohibit a large surplus. Consequently, this approach appeared to be a reasonable compromise.

Figure J-9: Forecast REC Balance for the State of Montana

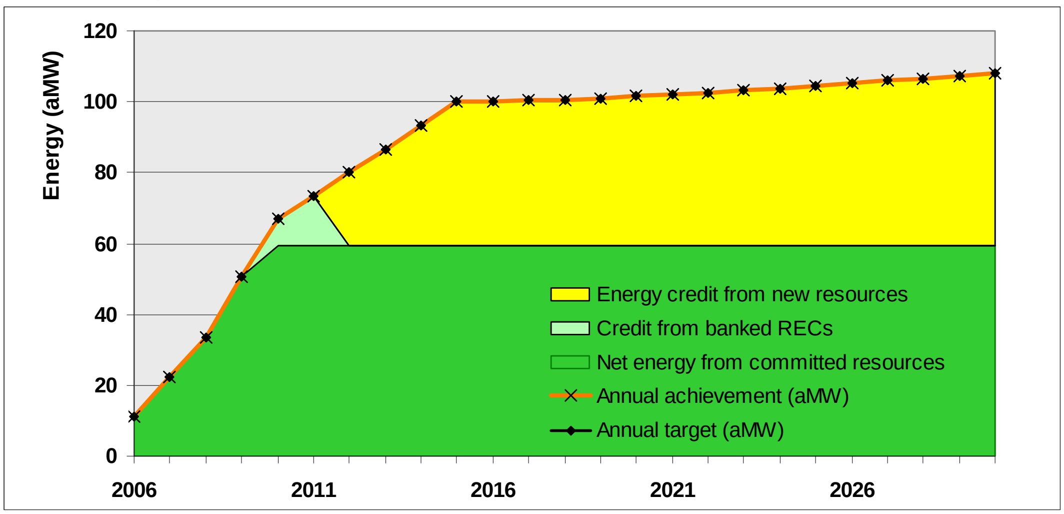


Figure J-10: REC Balance for the State of Washington

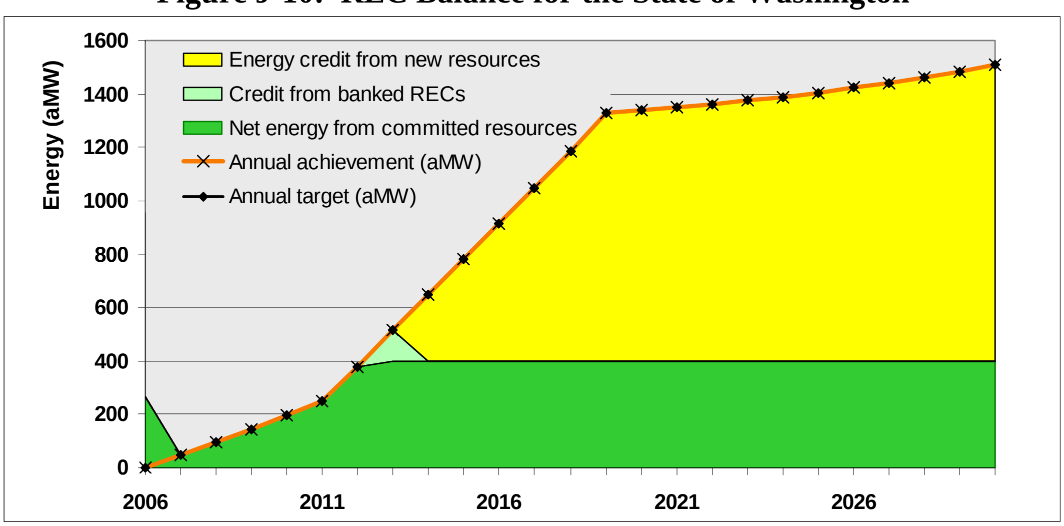


Figure J-11: Allocation of Obligations and Wind Renewable Energy

	N	O	P	Q	R	U	V	W	X
687									
688				**New RPS Resources**					
689									
690				New Wind Energy (MWa)	0		=(SUM(R573:U573)+SUM(R586:U586))/4		
691				Allocation to MT	0		=MIN(V690,100)		
692				Allocation to OR	0		=0.5*(V$690-V$691)		
693				Allocation to WA	0		=0.5*(V$690-V$691)		
694									
695				Load, less conservation (MWa)	21458		=-(V$324+V$326)		
696	MT obl ut requirement sales (MWa)			3.3%					
697				MT obl ut target (%)	10%				
698	OR obl ut requirement sales (MWa)			27.2%					
699				OR obl ut target (%)	3%				
700	WA obl ut requirement sales (MWa)			39.7%					
701				WA obl ut target (%)	2%				
702									
703			Source: "L8112 for illustrating RPS.xls"						
704									

The estimate of credits for each state is based on the in-service date of renewables in that state. In these early years, states are generally surplus to their RPS requirements and are therefore accumulating RECs.

If the state were deficit instead of surplus renewable energy, the model would add the energy and cost. For the case of Montana, this calculation appears in row 714 of Figure J-12.

Finally, the total RPS requirement for all three states is summed up in row 734 of Figure J-12. The estimate of regional cost for the RPS resources is taken from the cost of model wind resources. It remains around $90 a megawatt hour in $2006. The value of this energy is determined by the market price for electricity. These last estimates appear in rows 736 through 738 of Figure J-12.

Proposed Enhancements

There are several enhancements to the logic that the preceding narrative suggests. We expect to complete these enhancements for the final Sixth Power Plan resource portfolio.

First, the calculations described above are made once each year. This introduces a considerable lag between the time a wind resource is completed and when the region makes accommodations in its RPS requirements bookkeeping. This lag is responsible for the bumps that appear in Figure J-13, which is described and explained in chapter 8. More frequent recalculation of regional RPS requirements would eliminate this anomaly.

Second, allocation of renewable energy should be based on need, rather than on prescriptive factors. The current rule allocates energy first to Montana, with any remaining energy split between Oregon and Washington. In fact, we would expect that the states most in need of RPS energy would be the most likely to construct renewables. Consequently, any energy resulting from the model's selection of wind or geothermal should be allocated to states according to their respective requirements. We expect that the amount of RPS resource developed would also more closely correspond to the nominal RPS targets.

Third, the section ***Detailed Chronology of Model Changes*** of this appendix identifies an unresolved conceptual problem with modeling RPS costs. The construction costs for wind generation and geothermal are subject to uncertainty. In principle, there should be no difference between the costs of these generation resources and those renewables that are developed to meet RPS requirements. In the current modeling, however, these are disconnected. The RPS resources have a cost fixed at $90 per megawatt hour.

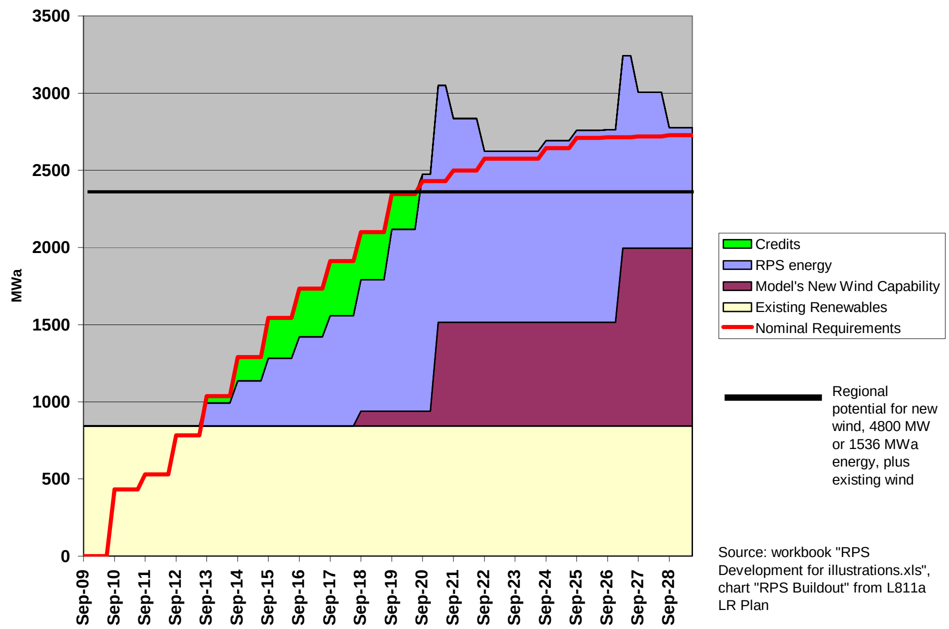
Resolving this inconsistency is not a simple challenge. (See Item 129 in the section, ***Detailed Chronology of Model Changes***, of this appendix.) Options include modification of the fixed cost and capability logic described earlier and extension of supply curve logic.

Because we are considering removing wind and geothermal from the model's selection, this third issue may become moot. It is noted elsewhere that we never observe the model developing wind or geothermal in advance of the RPS requirements. Consequently, unless we explicitly exclude the assumption of RPS acquisitions, the extra work being done by the model to evaluate wind and geothermal additions provides no additional information. If we remove wind and geothermal candidates, the problem of coordination of costs obviously disappears. We must still endeavor to capture construction uncertainty for the RPS resources, however.

Figure J-12: Detailed RPS Requirements Calculation

	P / Q	R	V
707	MT obl ut target (MWa busbar)	30.0	=MAX(V$695*$Q696*V697,R707)
708	MT resources (MWa busbar)	65.0	=R708
709	**MT new resources (MWa busbar)**		=V$691
710	MT credits remaining (MWa)	0.0	=R708+R710-R707
711	**MT net requirement (MWa)**		=V707-V708-V709-V710
712	Sell RECs*		
713	Carry forward credit*		=MAX(0,-V711)
714	Buy Renewables		**=MAX(0,V711)**
715			
716	OR obl ut target (MWa busbar)	30.0	=MAX(V$695*$Q698*V699,R716)
717	OR resources (MWa busbar)	377.0	=R717
718	**OR new resources (MWa busbar)**		=V$692
719	OR credits remaining (MWa)	1000.0	=R717+R719-R716
720	**OR net requirement (MWa)**		=V716-V717-V718-V719
721	Sell RECs*		
722	Carry forward credit*		=MAX(0,-V720)
723	Buy Renewables		**=MAX(0,V720)**
724			
725	WA obl ut target (MWa busbar)	30.0	=MAX(V$695*$Q700*V701,R725)
726	WA resources (MWa busbar)	401.0	=R726
727	**WA new resources (MWa busbar)**		=V$693
728	WA credits remaining (MWa)	1000.0	=R726+R728-R725
729	**WA net requirement (MWa)**		=V725-V726-V727-V728
730	Sell RECs*		
731	Carry forward credit*	1371.0	=MAX(0,-V729)
732	Buy Renewables		**=MAX(0,V729)**
733			
734	**Regional requirement (MWa busbar)**		**=V714+V723+V732**
735			
736	Regional energy on- and off-peak (MWh)	0.0	=IF(ISBLANK(V734),U736,V734*2016)
737	Regional total cost ($M)		=IF(ISBLANK(V$734),U737,($N$736*V714+$N$737*V723+$N$738*V732)*0.002016)
738	Regional on- and off-peak value($M)	0.0	=-V736*V$269/1000000
739			
740	Source: "L8112 for illustrating RPS.xls"		

Figure J-13: Development of RPS Resources in a Particular Study Future



Perpetuity Factor and End Effects

This section describes the adjustment made to costs to properly reflect the impact of carbon penalty on the economic value of generating resources. The model reports and uses NPV costs that have a special "perpetuity" adjustment. This adjustment accounts for the long-term effect of any carbon penalty, as the following paragraphs explain. The section describes the derivation and application of the adjustment, and it outlines enhancements for the final Plan studies.

Draft Methodology

As described in Appendix L of the Fifth Power Plan, the RPM uses real-levelized costs for power plant capital costs. Briefly, this spreads the construction costs of the plant evenly over its life. Spreading the cost in this manner matches the cost of construction with whatever benefits or value the plant produces. It is typical to assume that the economics of the plant beyond the study horizon are represented by the economics of operation and levelized cost within the study. Because of this, certain "end effects" are neutralized. These end effects are due to unequal economic lives of alternatives.

This all works fine, if we expect that the economics during the study represent economics beyond the study horizon. For example, if a plant is profitable during the study, we have no basis for assuming it would not be after the study horizon. If a plant is more profitable than an alternative during the study period, we expect it would be after the horizon.

Such is not the case, unfortunately, with a carbon penalty that appears during a study. Instead, we expect that the economics beyond the study horizon will resemble that ***subsequent*** to the arrival of the penalty. Consider a carbon penalty imposed during the last two years of a study. A plant placed into service five years before the end of the study carries the penalty for 2/5 of its life during the study. If the plant has a 20-year life, however, the penalty will apply for the remaining 15 years of its life, or 18/20 of its lifetime.

The model addresses this problem by extending all the costs in the study after that point in time when a carbon penalty appears. The model extends these costs, subsequent to any carbon penalty, in perpetuity. Portfolios can then be compared to determine the least cost and risk portfolios, but the resulting cost measures are difficult to describe in more familiar terms of revenue requirements or rates.

The following presents the economics of the problem and describes the solution implemented in the draft plan. A subsequent section outlines enhancements to this framework.

Problem 1

Consider the case of a coal plant that goes into service in 2012 and faces a carbon penalty in 2016. The gross value of this power plant is illustrated in Figure J-14. Figure J-14 is an illustration of a 20 year study that begins in 2001. The arrows correspond to dollar amounts of the annual value of energy in the market net of fuel and variable operating costs. After the carbon penalty appears, the gross value of this power plant is diminished because of the effective increase in the cost of fuel. For the time being, we will ignore the fixed costs associated with this power plant.

The problem with this situation is that if we present value these cash flows, it may well be the case that the value of the coal plant is overstated because we did not capture the cost of the carbon penalty over the remaining economic life of the plant. If the economics of the plant during the 20 year study, that is, between the years 2012 and 2020, are not representative of its lifecycle economics, we risk making a bad decision. Note that there are alternatives to meeting our energy requirements. Consequently, even a relatively small shift in the value associated with this coal plant may give rise to an improper ranking among alternatives.

Figure J-14: Study Gross Value for Coal Plant

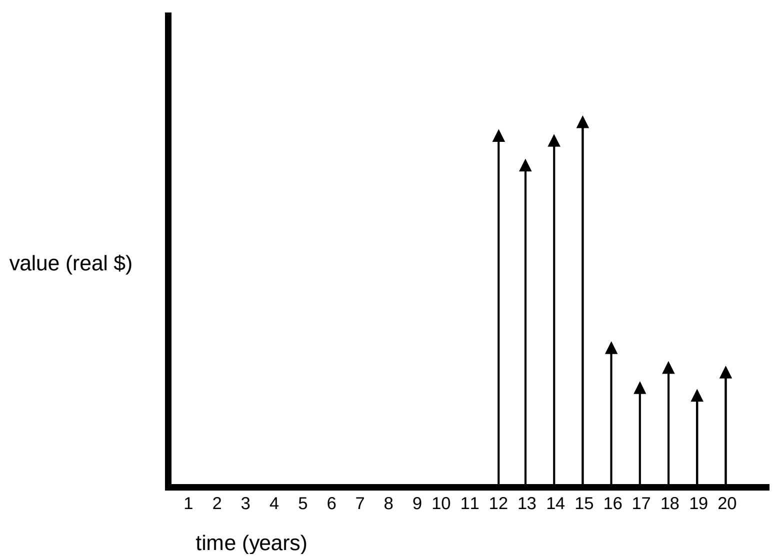
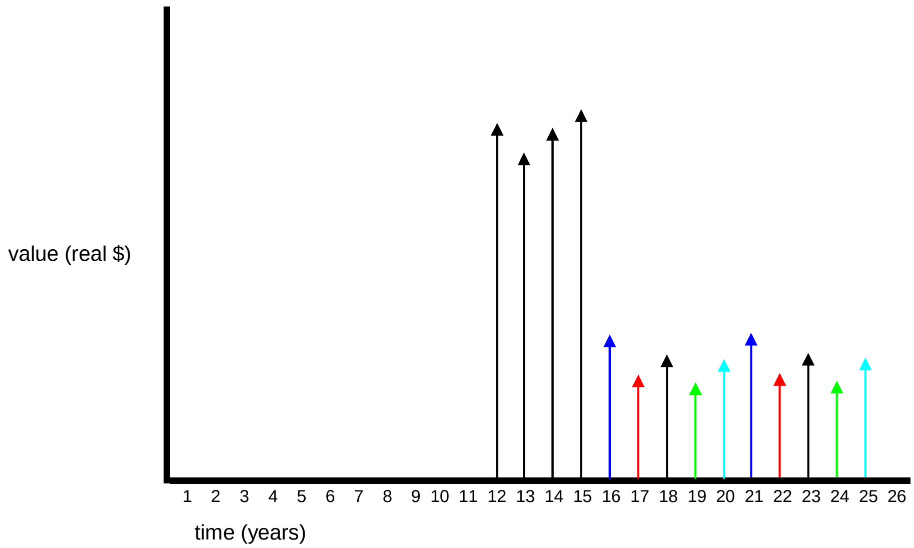


Figure J-15: Extension of Penalized Values



Solution 1

Clearly we need to capture the impact of the carbon penalty over the remaining economic life of this resource. One rather natural way of doing this is to assume that the economics of this resource beyond the study resembles the economics of the resource during the study, after the carbon penalty appears. In figure J-15, we extend the gross value after the carbon penalty appears by simply repeating the cycle of values. The values are color coded in this illustration to emphasize their cyclical nature.

Because we will be discounting cash flows to the beginning of the study, we note at this point that the net present value relationship between the cash flow in 2022 to that in 2017 is (Equation J-1)

Equation J-1

$$V_{2022} = \frac{1}{(1+d)^5} V_{2017} = \frac{1}{(1+d)^{(S-E+1)}} V_{2017}$$

where

V_{2017} is the present value of gross value in 2017

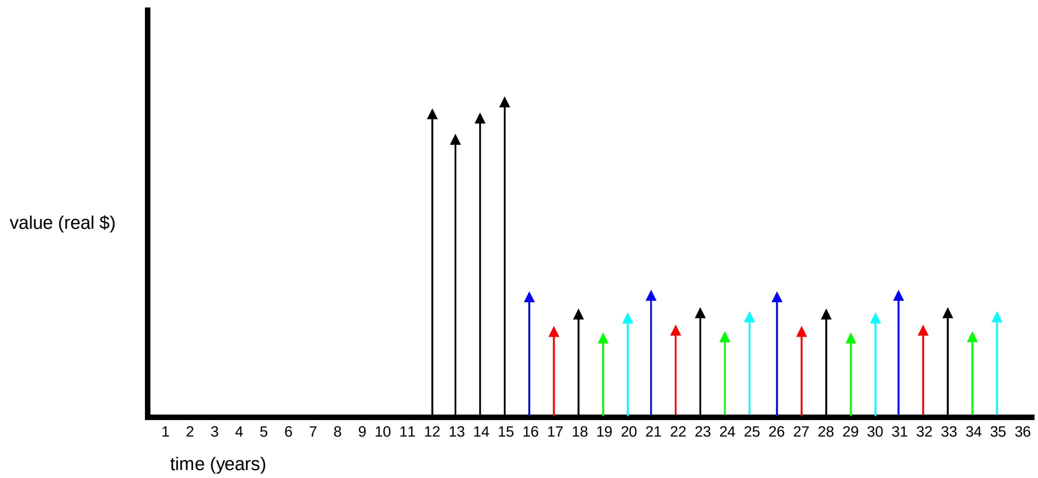
V_{2022} is the present value of gross value in 2022

d is the discount rate

S is the last year of the study

E is the year in which the carbon penalty arrives

Figure J-16: Extension of Values over Lifetime



The selection of the fifth power of the discount factor in the second term reflects the assumed cyclic nature of the values. Because the event occurs in period E and the study has S periods, the cycle length is equal to S-E+1, as the last term states.

Indeed, the same relationship holds between the cash flow in 2023 and 2018, 2024 and 2019, and so forth.

Of course, if we want lifecycle economics we have to extend this pattern over the remaining life of the plant, which we assume ends after 2035. Figure J-16, therefore, shows the extension of the cycle of values through that year.

Note that the relationship of the present value of the cash flow in 2027 to that in 2022 is the same as that between the cash flow in 2022 and 2017, namely Equation J-1. If we let the conversion factor in Equation J-1 be represented by the variable W, we see that the present value to 2017 of cash flows in 2017, 2022, 2027 and 2032 is (Equation J-2)

Equation J-2

$$
\begin{aligned}
&V_{2017} + V_{2017} \times W + V_{2017} \times W^2 + V_{2017} \times W^3 \\
&= V_{2017} \times (1 + W + W^2 + W^3)
\end{aligned}
$$

Again, the same relationship holds for corresponding subsequences beginning in 2016, 2018, 2019, and 2020.

To represent the present value of cash flows in 2016 through the end of the study back to the beginning of the study in 2001, we may write (Equation J-3)

Equation J-3

$$
\begin{aligned}
&NPV_{2001}(V_{2016}, \cdots V_{2020}) \\
&= \frac{V_{2016}}{(1+d)^{(2016-2001)}} + \frac{V_{2017}}{(1+d)^{(2017-2001)}} + \cdots + \frac{V_{2020}}{(1+d)^{(2020-2001)}}
\end{aligned}
$$

Consequently, if we denote (1+W+W2+W3) by G, the present value of cash flows in Figure J-16 from 2016 through 2035 back to the beginning of the study is (Equation J-4)

Equation J-4

$$
\begin{aligned}
&NPV_{2001}(V_{2016},\cdots V_{2035}) \\
&= \frac{V_{2016}}{(1+d)^{(2016-2001)}} \times G + \frac{V_{2017}}{(1+d)^{(2017-2001)}} \times G + \cdots + \frac{V_{2020}}{(1+d)^{(2020-2001)}} \times G \\
&= NPV_{2001}(V_{2016},\cdots V_{2020}) \times G
\end{aligned}
$$

Note that we have reduced the end effect associated with this extension of economics to a single multiplier of the present value of cash flows in the study subsequent to the carbon penalty.

Problem 2

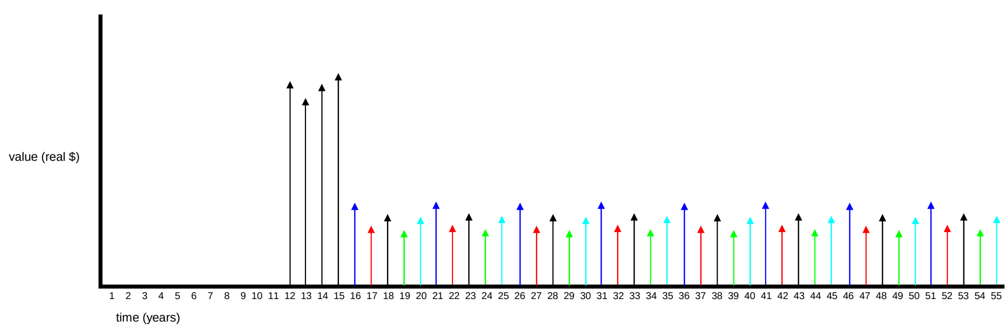
We immediately recognize some inadequacies in what we've done. First, the extension of the original cycle of post-penalty values typically is not an integral multiple of the length of the length of that cycle. Consequently, if it is not a multiple, then different numbers of terms would have to be added to distinct year's cash flows. Second, we would need to extend the fixed costs associated with this power plant in the same way to preserve its relation to the variable gross value.

More important, however, in a typical study we consider coal plants that come online in different years and possibly have different economic lifetimes. We also consider alternatives to coal plants that most definitely have different economic horizons. This means that choosing the economic life of any one of them would be arbitrary and could result in a poor comparison with other plants.

Solution 2

If we assume that the real cost and value associated with cash flows extended beyond the study horizon remain constant, as we have above, then for any positive discount rate extending the cycles indefinitely results in a convergence series. That is, at least mathematically it is meaningful to extend the study horizon to infinity. (See Figure J-17.) This has the advantage of avoiding the selection of any finite horizon, which as we have observed would he arbitrary and potentially misleading.

Figure J-17: Indefinite Extension



How do we interpret the extension of cash flows associated with our coal plant beyond its economic life? It is customary to assume replacement in kind. From a practical standpoint, contributions beyond the economic life of a typical power plant from replacements are de minimis.

The sum of an infinite series of powers of a variable is called the geometric series and has a particularly simple representation (See Equation J-5):

Equation J-5

$$\sum_{i=0}^{\infty} x^i = 1 + x + x^2 + x^3 + \cdots = \frac{1}{(1-x)}, \ 0 \le x < 1$$

As we saw before, the adjustment to the net present value of cash flows subsequent to the carbon penalty therefore consists of multiplication by a fixed constant (See Equation J-6).

Equation J-6

$$\begin{aligned}
&NPV_{2001}(V_{2016}, V_{2017}, \cdots, \infty) \\
&= \frac{V_{2016}}{(1+d)^{(2016-2001)}} \times \Pi + \frac{V_{2017}}{(1+d)^{(2017-2001)}} \times \Pi + \cdots + \frac{V_{2020}}{(1+d)^{(2020-2001)}} \times \Pi \\
&= NPV_{2001}(V_{2016}, \cdots V_{2020}) \times \Pi \\
&\text{where } \Pi \text{ is the "perpetuity factor," } \frac{1}{1\text{-}W} = \frac{1}{1\text{-}\left(1+d\right)^{(E-S-1)}}
\end{aligned}$$

If we want to use Excel's net present value function, =NPV(), a simple rearrangement of terms facilitates this. If A represents the net present value of cash flows prior to the carbon penalty, B represents the net present value of cash flows subsequent to the carbon penalty, and C represents cash flows over the entire study, we have Equation J-7:

Equation J-7

$$NPV_{2001}(V_{2016}, \cdots V_{2020}) = NPV_{2001}(V_{2001}, \cdots V_{2020}) - NPV_{2001}(V_{2001}, \cdots V_{2015})$$

So the net present value of all cash flows including the extension to infinity is simply

Equation J-8

$$\begin{aligned}
NPV_{2001}(V_{2001}, V_{2002}, \cdots \infty) &= NPV_{2001}(V_{2001}, \cdots V_{2015}) + \\
&\quad \left[NPV_{2001}(V_{2001}, \cdots V_{2020}) - NPV_{2001}(V_{2001}, \cdots V_{2015})\right] \times \Pi \\
&= \Pi \times NPV_{2001}(V_{2001}, \cdots V_{2020}) + (1-\Pi) \times NPV_{2001}(V_{2001}, \cdots V_{2015})
\end{aligned}$$

Finally, the Excel OFFSET () function helps us deal with the problem of a carbon penalty that can occur in any year (Equation J-9)

Equation J-9

$$\begin{aligned}
NPV_{2001}(V_{2001}, V_{2002}, \cdots \infty) &= \Pi \times NPV_{2001}(V_{2001}, \cdots V_{2020}) + \\
&\quad (1-\Pi) \times NPV_{2001}\left(\text{Offset}\left(\left[V_{2001}, \cdots V_{2020}\right], 0, 0, 1, E-1\right)\right)
\end{aligned}$$

Of course, we have to apply this not only to the variable and fixed costs of each plant, but to the net present value calculations associated with every cash flow in the model, including the costs of meeting electricity requirements. This means every place that the net present value formula

```
=8760/8064*NPV(dcrt,RC18:RC97)
```

appears, we need to replace it with a slight variation of the formula in Equation J-9:

```
=8760/8064*(p_fac*NPV(dcrt,RC18:RC97)+(1-p_fac)*IF(AND(CO2taxevent>1,CO2taxevent<81),
NPV(dcrt,OFFSET(RC18:RC97,0,0,1,CO2taxevent)),0))
```

where `CO2taxevent` is the period ***before*** which the penalty occurs, `8760/8064` is the conversion of standard periods to calendar periods (See Appendix L), and the perpetuity factor (p_fac) is the our constant Π:

```
=IF(AND(CO2taxevent>1,CO2taxevent<81),1/(1-(1+dcrt)^(CO2taxevent-80-1)),1/(1-(1+dcrt)^(-80))),
```
and **see note**[4]

Note also that this equation includes a test `IF(AND(CO2taxevent>1,CO2taxevent<81), …)` to see whether the carbon penalty occurs before the beginning of the study or after the end of the study (period 80) and makes the appropriate adjustment. This adjustment takes the entire study time period as representative of the future beyond the study horizon.[5]

This new formula occurs in 66 cells of the regional portfolio model. The impact on model execution time is on the order of 2 percent.

Proposed Enhancements

Part of the reason for going to real levelized costs in the first place is to avoid end effect calculations. Among the primary problems with end effect calculations is the sensitivity of the outcome to horizon-extension assumptions such as growth rate in fuel prices.

The approach laid out in this note suffers from the same deficiency. That is, if there is a carbon penalty in the last few periods the study, that small sample of years will be taken to represent the extension to infinity. The diversity of the 750 futures examined with the regional portfolio model should dampen this effect. That is, while there will be futures where the last few years of the study are extreme, they will not be correlated with the timing of the carbon penalty. The combination of extreme years and late carbon penalty will be rare. Moreover, the effect should be offset by futures in which the final years of the study are moderate. Nevertheless, we may see a much greater diversity in the distribution of costs associated with resource plans.

---

[4] This (yellow) is an error in the original implementation of this calculation. If CO2taxevent is the period ***before*** which the penalty occurs, period ***E***, CO2taxevent-80-1 should be CO2taxevent-80.
[5] Here again, we may have an issue. If real costs are generally increasing over time, perhaps some sample of the final costs should be used, not the entire study time period, to be consistent with our approach elsewhere. We return to this issue momentarily.

Another problem arises if the carbon penalty arises not in a single year, but gradually over several years. This is the kind of penalty behavior we might expect with an emission trading mechanism. Now the point where we begin the "penalty" phase of the calculation is unclear. Apart from extending the study from 20 to 30 or more years, we could choose a fixed number of years near the end of the study as representative. Of course, this brings us back the concerns raised in the preceding paragraph. Nevertheless, this approach is probably preferable to ignoring the effect beyond the study horizon.

A related problem is treatment of plant value in futures without a carbon penalty and in futures where a plant that goes into service after the CO_2 penalty event occurs. To illustrate the first situation, consider a plant that begins operation in the 16th year of a 20-year study. The costs and value of that operation should be carried forward in perpetuity, rather than assume that we will see the benefits and costs of that plant in only one-fourth (20-16+1)/20 of the future years.

Futures where a plant that goes into service after the CO_2 penalty event occurs have a similar problem. The plant's costs and benefits would be reflected in only a portion of the sample period used to represent the future beyond the study horizon, i.e., the last S-E+1 periods of the study. This would distort the benefits and costs of this plant relative to those that began service on or before the CO_2 penalty event.

To assure that the sample used for perpetuity estimates uses a significant number of periods near the end of the study and never a period during which a plant comes into service, we need to modify the calculation so that E is determined not by the CO_2 event alone, but by the latest occurrence of the CO_2 event and the completion of any power plant.

This will require, however, that we limit when a plant can come into service. For example, if a plant has not been brought on line by the fifth quarter prior to the end of the study, we could preclude it from doing so. This assures that periods of non-operational penalty are not used to represent the future. By limiting the periods when representational sampling may occur to, say, the beginning of hydro years, samples are guaranteed to have all four seasons. (Using arbitrary quarters results is certain quarters being over-sampled.) Finally, using a minimum of four quarters will stabilize results, in all cases except when carbon penalty arises in the last three quarters. Limit the arrival of carbon penalty to before the last four quarters would also help stabilize results.

The final selection for sampling (currently the event CO2TaxEvent) would then become

$$= \max(CO_2Penalty, \mathrm{int}(\max(PlantOnLine_i)/4)+4)$$

Modeling Energy-Limited Resources

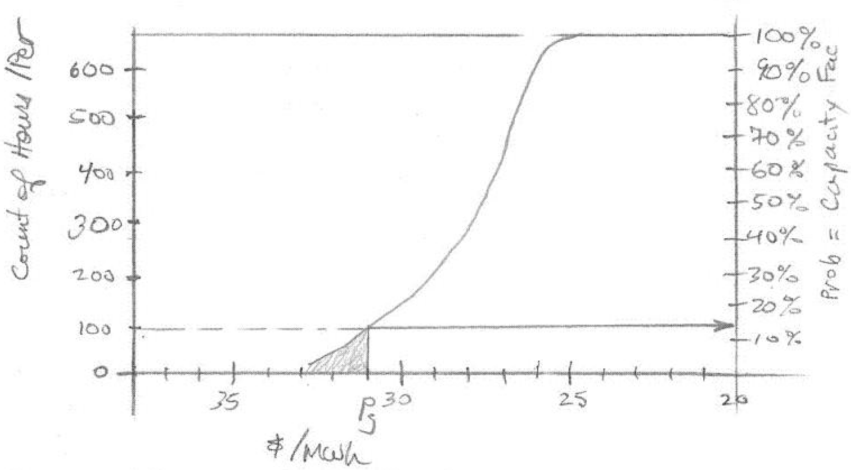
Chapter 5, ***Demand Response***, identifies resources that are available only a brief number of hours each year. The number range from 40 to 100 hours per year. To model this kind of resource, certain modifications to the RPM's standard algorithms was necessary.

As described in Appendix L of the Fifth Power Plan, the energy and value of dispatchable generation for a given period and subperiod are determined by a statistical description of hourly fuel and electricity market prices. The correlation between these is also important. The section entitled, ***Thermal Generation***, beginning on page L-26 of Appendix L to the Fifth Power Plan is prerequisite to following this discussion.

We begin with the review of the determination of value and energy for dispatchable resource. Figure J-18 illustrates the example where the price of fuel and heat rate are such that, above $31 per megawatt hour, this particular unit would dispatch given the electricity price duration curve in the illustration. The capacity factor corresponds to the number of hours of operation out of the number of hours in the sample, about 15 percent. Whenever it is cost effective to generate, the economic choice is to generate at full capacity, so we can consequently determine the amount of energy produced. The value of this generation is the shaded area to the left of the vertical line corresponding to $31 per megawatt hour.

Consider now a different electricity price duration curve that, given the same dispatch price, would result in 60 percent capacity factor for this unit. We have the situation in Figure J-19. We assume now, however, that this unit is constrained to run no more than 200 hours in a month, about 27 percent capacity factor. This constraint is represented by the horizontal line in Figure J-19. In this case, the economic choice for this unit is to run over that 200 highest value hours which result in the value corresponding to the shaded area beneath the horizontal line to the left of $31 per megawatt hour, as shown in Figure J-20. How do we calculate this result algorithmically?

Figure J-18: Price of Fuel Determines Energy Production



The answer to this problem is to determine an effective price p_g* that results in the capacity factor serving as our energy constraint. This effective price appears in Figure J-21.

Figure J-19: Constraint on Energy

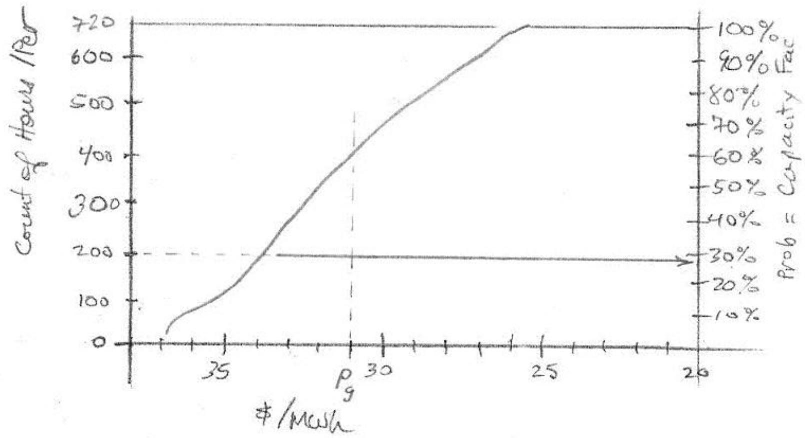


Figure J-20: Value Produced

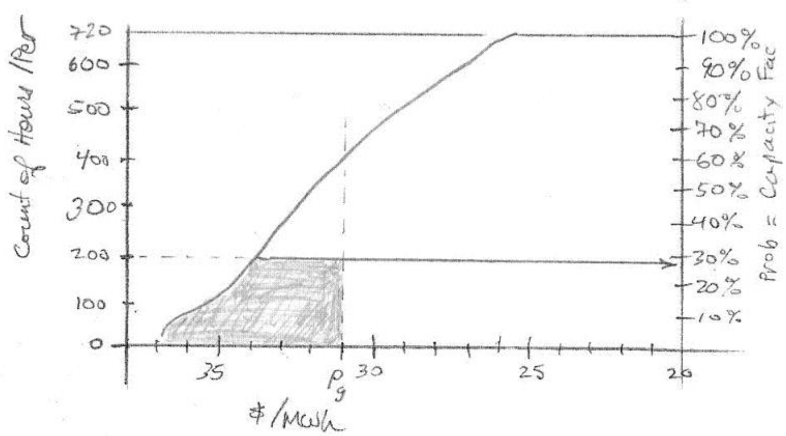
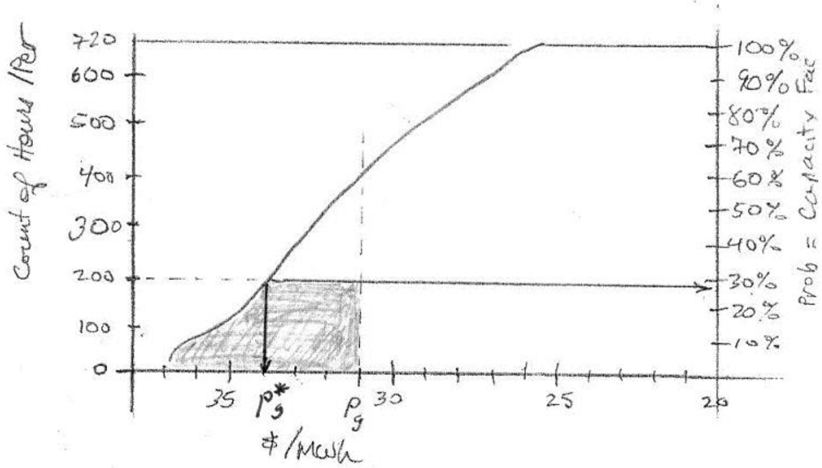


Figure J-21: Fuel Price Corresponding to Energy Constraint



It turns out that given the energy constraint, expressed as a specified capacity factor, the relationship between the average price of fuel and p_s^* is fixed. The model can estimate the relationship once, at the beginning of the simulation, and quickly update the value of p_s^* for each new period.

After that, the model simply compares p_s^* against the price of fuel in that period. If p_s^* is **greater than** the price of fuel, the hours and energy are constrained and the model uses p_s^* to determine the generation and value of the energy. If p_s^* is **less than** the price of fuel, the hours and energy are unconstrained and the model use the price of fuel to determine energy generation and value, as it normally does. The area corresponding to value is now the as used before, augmented by a square of value above the actual price of dispatch when energy is constrained.

Modeling Direct Use of Gas

The basic objective is to supply a specified amount of heat energy for a specific purpose at lowest cost, given constraints such as the existing heating system, the expected efficiency of heat pump models, and availability of natural gas. The potential for conversion, therefore, is determined by the size and thermal heat requirement for customers with the same constraint values.

To introduce the basic approach to modeling this situation, we restrict the technologies to resistance electric heat, electric heat pumps, and direct use of gas (DUG). The economics of these three technologies are as follows.

The annual cost for energy produced by the delivery of a constant thousand watts of thermal energy continuously over the course of a year from electric resistance heating is

Equation J–10

$$\frac{\$}{kW_t yr} = \frac{RL\$}{kW_t yr} + \frac{\$}{MW_e h} \bullet \frac{MW_e h}{kW_e yr} \bullet \frac{W_e}{W_t}$$

where

Equation J-11

$$\begin{aligned}
\$/kW_t yr &= \text{the annual cost for a kilowatt of thermal energy over a year} \\
RL\$/kW_t yr &= \text{the annual, real levelized cost of equipment} \\
&= \quad \text{sized to produce a kilowatt of thermal power} \\
\$/MW_e h &= \text{the wholesale price of electricity} \\
MW_e h/kW_e yr &= \text{the constant } 8760/1000 = 8.76 \\
W_t / W_e &= \text{conversion efficiency, also coefficient of performance (COP)}
\end{aligned}$$

For direct use of gas, the same quantity of thermal energy costs

Equation J-12

$$\frac{\$}{kW_t yr} = \frac{RL\$}{kW_t yr} + \frac{\$}{MMBTU_{t-in}} \bullet \frac{MMBTU_{t-in}}{kW_{t-in} yr} \bullet \frac{W_{t-in}}{W_{t-out}} + \frac{\$}{MW_e h} \bullet \frac{MW_e h}{kW_e yr} \bullet \left(\frac{W_e}{W_t}\right)_f$$

The new terms are

Equation J-13

$$\$/MMBTU_{t-in} = \text{the price of natural gas}$$

$$\frac{MMBTU_{t-in}}{kW_{t-in}yr} = \text{the constant } (8760 * 3413)/1000000 \approx 2.99$$

$$W_{t-out}/W_{t-in} = \text{conversion efficiency or COP for gas}$$

$$(W_e/W_t)_f = \text{annual electric energy, assumed constant, for fans, etc.}$$

As with the resistance heat equation, there are terms associated with the fixed installation costs and the use. The third term provides for the possible significant use of electricity for fans and circulators.

The figure for the amount of electric power required per unit of thermal power $(W_e / W_t)_f$ can be calculated from figures that are more familiar.

Equation J-14

$$\left(\frac{W_e}{W_t}\right)_f = \frac{MMBTU_{t-out}}{kW_{t-out}yr} \bullet \frac{W_{t-in}}{W_{t-out}} \bullet \frac{yr}{h} \bullet \frac{kW_e h / yr}{MMBTU_{t-in} / yr}$$

The first term on the right-hand side is the constant identified above. The second term is 1/COP of the gas appliance. The fourth and last term is the ratio of electrical energy to gas supplied to the unit in a year. Note that $(W_e / W_t)_f$ is typically less than one-half percent.

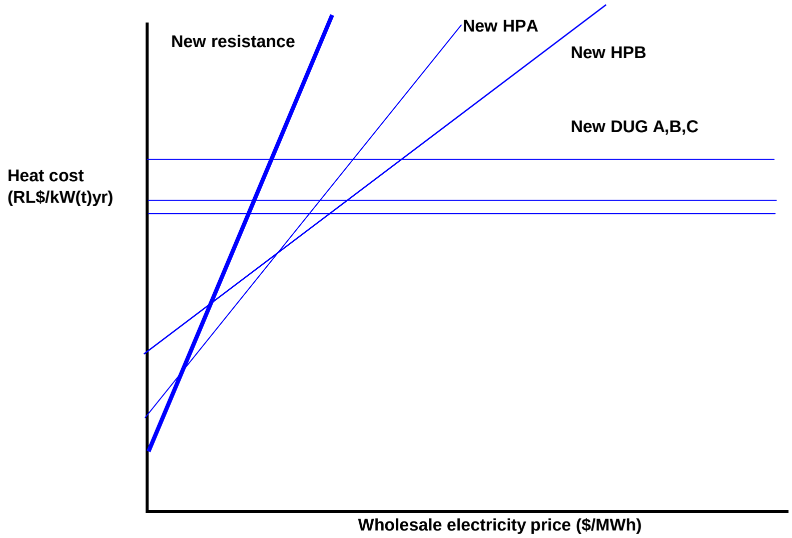
Finally, for a heat pump we obtain

Equation J-15

$$\frac{\$}{kW_t yr} = \frac{RL\$}{kW_t yr} + \frac{\$}{MW_e h} \bullet \frac{MW_e h}{kW_e yr} \bullet \frac{1}{\text{COP}}$$

The COP is defined to be Wt/ We, the number units of output thermal power produced by a unit of input electrical power. For heat pumps, values greater than one are typical.

Figure J-22: Conversions



Observe that, if the price of gas ($/MMBTU) is fixed, these three equations are linear functions of electricity price. For direct use of gas, in fact, the functions are just constants if ancillary electricity use for circulation is nil. There are several implications under this condition. First, if

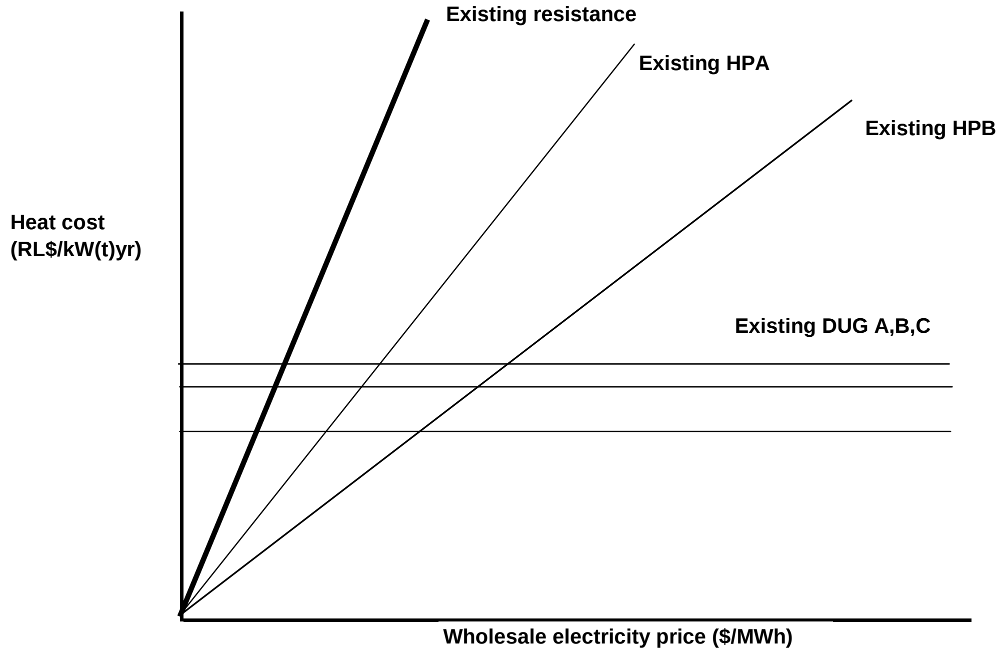
DUG electricity use is small, there is a minimum-cost DUG program, so no further analysis of DUG economics is necessary. Second, the programs may be illustrated by a set of screening curves that indicate which program is least-cost at each electricity price. Third, the cost of programs in place must be considered, and we assume they may be represented by the same set of lines, shifted down by the fixed cost. The program in place can be captured by the definition of market segments.

We assume that the entire segment pursues only the least-cost alternative. The least-cost alternative has an electric energy savings rate, although it may be negative. For example, if converting to electric resistance heat from a direct use of gas program, the savings rate would be minus 100 percent. The potential for the market segment and the savings rate for the segment's least-cost choice, therefore, gives us incremental resource contribution for this segment at this electricity price.

By totaling up the resource contributions across segments at each electricity price defines the supply curve for DUG at the assumed gas price. Alternative supply curves for other gas prices provide a complete suite of such curves, adequate to characterize the economic choice and performance for heating space and water over a range of electricity and gas prices.

Finally, because there are a finite number of points where the lines for a market segment's alternatives intersect, there are also a finite number of points that define the final, fixed-gas price supply curve. This would be the most efficient way to describe such curves.

Figure J-23: Existing Systems



ANALYSIS OF RISK

What appear to be the primary sources of risk in system cost studies? Understanding which uncertainties drive cost and risk is useful background to understanding the value of a resource portfolio.

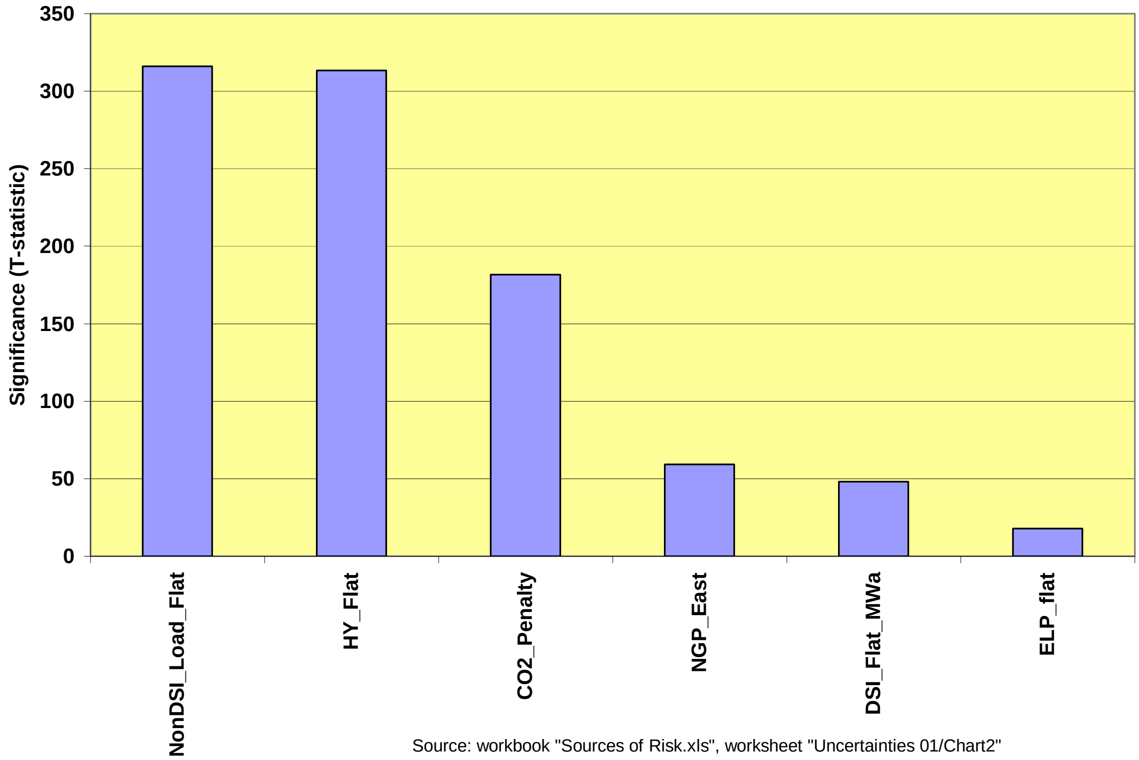
Regression Analysis

Detailed studies of the data produced by the RPM have produced insights into the cost risks of the region. A regression analysis on cost reveals the significance of and sensitivity to sources of uncertainty.

The term "significance" refers to the strength of the relationship between the uncertainty and cost. If we were to plot, for example, the time students study a subject and their scores on tests, we generally would not see a straight-line relationship. Instead there would be a cloud of points. The significance is a measure of how tightly the cloud clusters around the trend. It tells us how much of the result (test score) as explained by the variable (study). The sensitivity, on the other hand, is the slope of the trend. Significance (also called correlation) is an aspect of the data that is independent of sensitivity.

The result of the regression of quarterly costs on various factors appears in Figure J-24.

Figure J-24: Significance of Uncertainties



In Figure J-24, several variables appear that require description:

NonDSILoad_Flat – The amount of system energy load requirements (MWa) across on- and off-peak subperiods. These include energy required to meet losses for distribution and transmission but does not include energy supplied to direct service industries (DSIs, primarily aluminum smelters).

HY_flat – The energy generated by the hydroelectric system (MWa) across on- and off-peak subperiods.

CO2_Penalty – the carbon penalty ($2006/ton **e**$CO_2$) discussed throughout the Plan

NGP_East ($2006/MMBTU) – The cost of natural gas delivered to power plants east of the Cascades, where most of recent capacity additions have been made and future additions are likely.

DSI_Flat_MWa – Direct service industry (aluminum smelter) load requirements (MWa).

ELP_Flat – Electricity price ($2006/MWh), west of the Cascades, where the load centers predominate.

There are several things to note about this figure. We are attempting to predict RPM quarterly costs using only simple, statistically independent sources of uncertainties. This particular model explains about 90 percent of the variation in costs. The degree of significance tells us nothing, however, about the sensitivity of the costs to each variable. For that, we need Table J-3.

Table J-3: Sensitivity to Factors

	sensitivity				
NonDSI_Load_Flat	8.08	MW-mo	-or-	16284	MWh/mo
HY_Flat	-9.44	MW-mo	-or-	-19021	MWh/mo
CO2_Penalty	0.14	$/ton CO2			
NGP_East	0.05	$/MMBTU			
DSI_Flat_MWa	6.74	MW-mo	-or-	13582	MWh/mo
ELP_flat	-1.73	$/MWh			

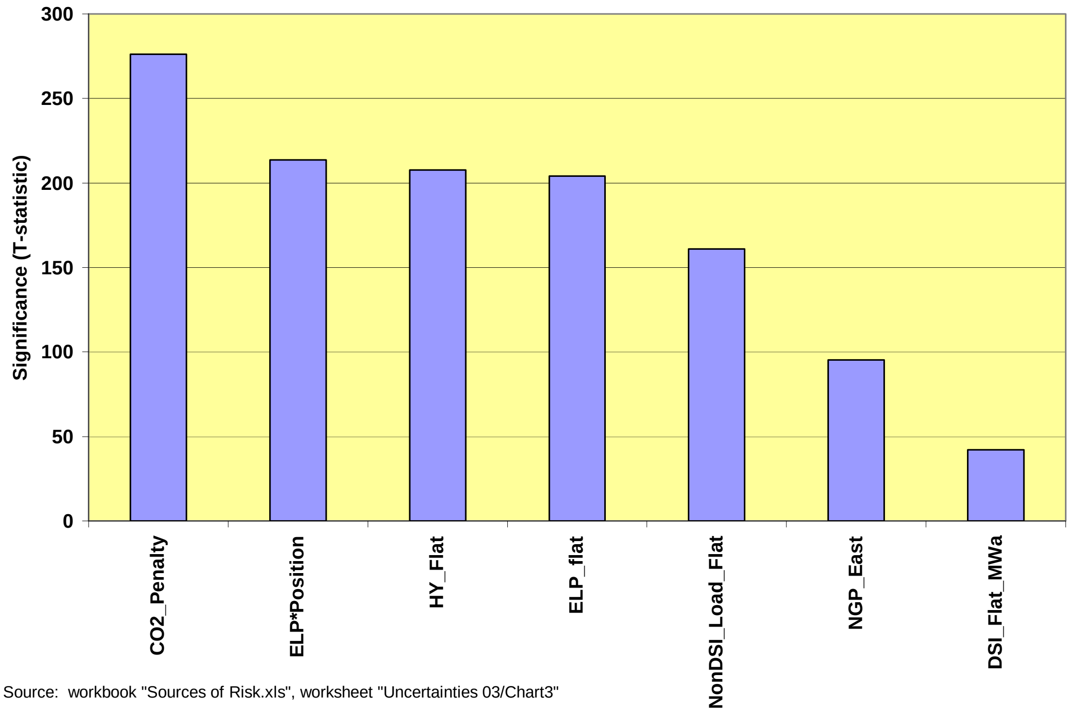
Source: workbook "Sources of Risk.xls", worksheet "Uncertainties 01"

Table J-3 tells us that a change in electricity requirements of about 16,284 MWh in a hydro quarter has the same average effect as does:

- a 19,021 MWh/hydro quarter decrease in hydrogeneration,
- a $0.14 /ton CO_2 penalty,
- an increase of $0.05/MMBTU in the price of natural gas,
- a 13,582 MWh/hydro quarter increase in DSI (aluminum smelter load), and
- a $1.73 decrease in the price of electricity

This last sensitivity seems a bit counter-intuitive, both because of its direction and its magnitude. Experience suggests that the price of electricity should be more influential. If we were to study the relationship between imports, electricity price, and cost, however, we would soon recognize the issue. If we are exporting power, higher electricity prices ***reduce*** cost because we can sell power we do not use at higher prices. Conversely, if we are importing power, higher electricity prices ***increase*** cost. Higher cost is therefore associated with regional energy imports and electricity price moving in the same direction.

Figure J-25: Revised Significance of Uncertainties



Source: workbook "Sources of Risk.xls", worksheet "Uncertainties 03/Chart3"

Consequently, we can improve the analysis by including an interaction term that is the product of electricity price and imports. Imports are not among our input variables, however. Consequently, we construct something we will call “position” from input variables that will stand in for imports. To describe position for a quarter in terms of the original variables, we use DSI and non-DSI regional electricity use, less hydrogeneration. This difference between load and hydrogeneration is, to a large extent, the net requirement the region must manage with thermal generation and market purchases.

The interaction term is just the mathematical product of position and electricity price. Adding this term to the model permits the model to reflect the movement of these variables in the same direction. Consider, for a moment, the following product:

$$\left(Q-\overline{Q}\right)\left(p_e-\overline{p_e}\right)$$

where

Q is the position (MWa)

$\overline{Q}$ is the average position

p_e is the price of electricity

$\overline{p_e}$ is the average price of electricity

If Q and p_e ***both move below*** their average, each term in negative and the product is positive. Similarly, if Q and p_e ***both move above*** their average, the product is again positive. The product is negative only when the two variables move in opposite directions. If we included this product in the regression, therefore, its significance would indicate that the ***coordinated movement*** of the variables explains higher cost.

We can, however, dispense with averages in the product, and use the product of the variables directly instead. If we distribute the multiplication across the product, the terms in the resulting series that include the averages are already picked up in the model. The product of the averages is picked up in the constant term of the model and the terms that are the product of each variable and the other's average are picked up by the variable's term in the model.

The result is the revised model appears in Figure J-25.

The addition of the interaction between electricity price and market exposure, the second bar in Figure J-25, increases the regression's descriptive power to 95 percent. It reduces the amount of "over specification" in the statistical model as well. If descriptive strength is achieved by simply adding more variables, we say the model is "over specified." This accounts for about 5 percent of the first model's performance and 4 percent of the revised model's power. We want over specification to be as small as possible if we want to really understand what is driving the results.

We see that electricity price and the price-position interaction are now much stronger. Carbon penalty, which has a direct impact of electricity price and the operation of thermal resources, is dominant. Our interaction term is the second most significant variable. Hydrogeneration and pure electricity price are tied for third place. The sensitivity to each variable appears below.

Table J-4: Revised Sensitivity with Interaction Term

	sensitivity				
CO2_Penalty	0.12	$/ton CO2			
ELP*Position	0.11	$			
HY_Flat	-15.19	MW-mo	-or-	-30,630	MWh/mo
ELP_flat	-0.08	$/MWh			
NonDSI_Load_Flat	15.39	MW-mo	-or-	31,029	MWh/mo
NGP_East	0.04	$/MMBTU			
DSI_Flat_MWa	10.11	MW-mo	-or-	20,374	MWh/mo

Source: workbook "Sources of Risk.xls", worksheet "Uncertainties 03"

How should we feel about high wholesale electricity prices? If we have a surplus, it is not so bad. The problem is, surplus and position are determined largely by hydrogeneration, over which we have little control.

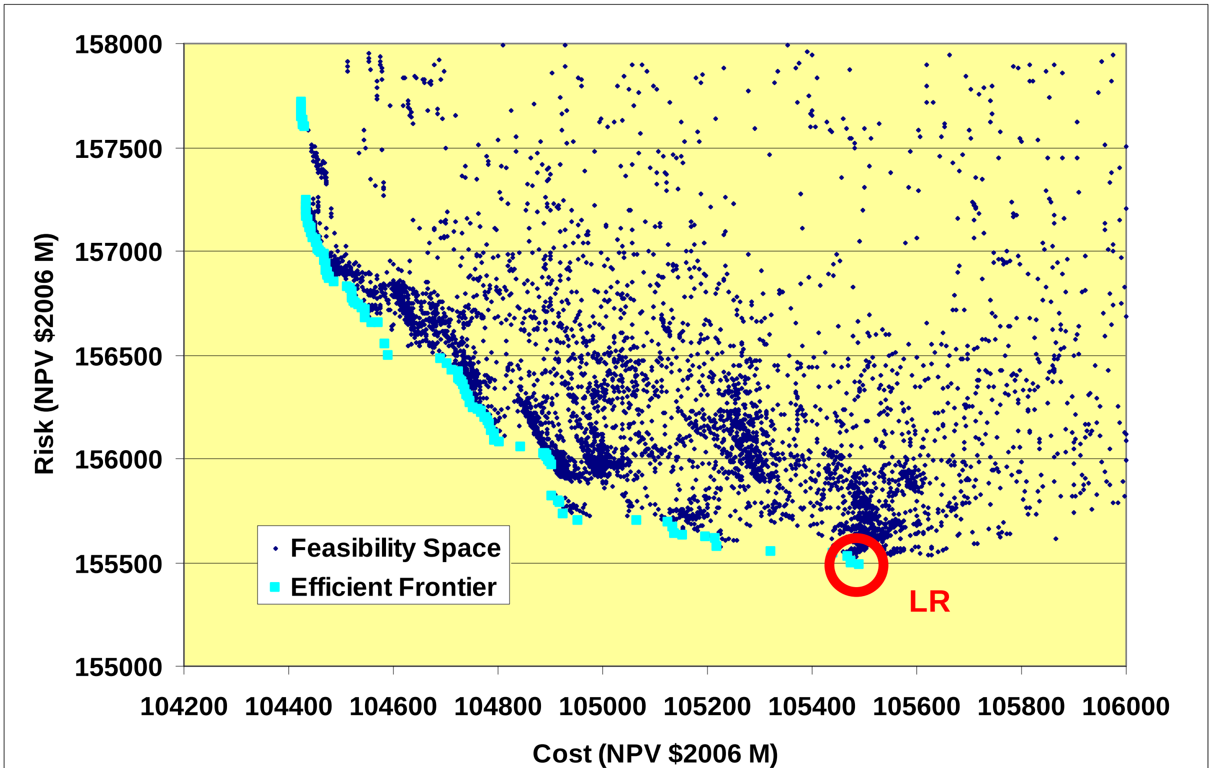
Carbon penalty invokes double punishment. It reduces regional thermal generation, increasing the likelihood the region will be exposed to the market. It also increases the cost of imported power.

This brief analysis underscores the potential for market exposure to affect cost and cost volatility. It provides an objective idea of how other variables contribute the cost results, as well. The next section illustrates these finding with specific examples.

Illustration with Selected Futures

Chapter 8 introduced the ideas of a feasibility space and its efficient frontier. The efficient frontier for in the $0-100/ton Penalty Case appears in Figure J-26. The particular plan we have chosen to illustrate our findings is the least-risk plan, identified by LR in Figure J-26. The schedule for the earliest construction of each resource in this plan appears in Figure J-27.

Figure J-26: The Efficient Frontier



Source: w orkbook "Analysis of Optimization Run_L811 090510 2101.xls", w orksheet "basecase"

Figure J-27: Least-Risk Portfolio (LR)

50	**Lost opportunity** conservation cost-effectiveness threshold over market ($2006/MWh)
3253	**Lost opportunity** conservation by end of study (MWa)
10	**Discretionary** conservation cost-effectiveness threshold over market ($2006/MWh)
2573	**Discretionary** conservation by end of study (MWa) assuming 160MWa/year limit
5827	**Total conservation (MWa)**

Cumulative MW, by earliest date to begin construction

	Dec-15	Dec-17	Dec-19	Dec-23	Dec-25
CCCT	0	**415**	**830**	**830**	**830**
SCCT	**170**	**170**	**170**	**170**	**170**
Geothermal	0	**52**	**104**	**156**	**169**
Wind	**1200**	**1200**	**3000**	**3000**	**3000**

Source: "Schedules for plan resources 090722.xls", worksheet "Schedules (2)"

We will be examining two situations to understand the risks associated with exposure to wholesale market prices. We will be particularly interested in how various resources differ in their ability to mitigate this kind of risk. We begin with a future that has among the highest cost outcomes, largely due to exposure to the market.

An obvious response to this risk might be to acquire enough resource that we minimize the likelihood of exposure to the market. Depending on the selection of resource, however, this can present its own risks. Some resources will create greater cost, for example, if wholesale electricity prices crash. We therefore consider a future where loads fall or remain flat, our new resources are surplus to our needs, and low market prices occur.

Market Exposure

To see how the market reliance affects costs, consider the future illustrated beginning in Figure J-28[6]. High gas price and electricity prices, combined with high carbon penalty, create a treacherous outcome for the least-risk portfolio. While the average cost, including carbon penalty, for this future is $105.6 billion NPV, this future costs $232.7 billion.

Because of the high load growth and hydrogeneration shortages in several years, the region is forced to purchase power under unfavorable circumstances. (See Figure J-29[7]) This occurs despite the construction and operation of the additional resources in the model's least-risk portfolio. While the region's energy adequacy metric shows a surplus from today's perspective, this future highlights the possibility that the region can nevertheless become exposed. The cost and rate excursions in Figure J-30 correspond directly to periods of low hydrogeneration and to high import levels of energy.

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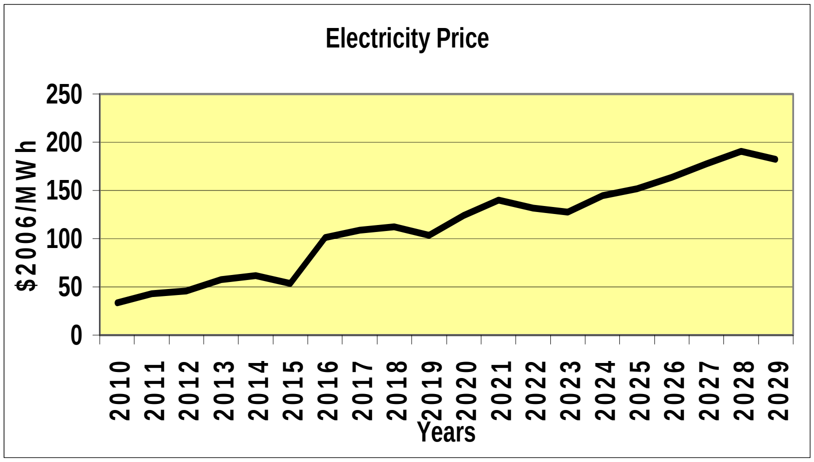
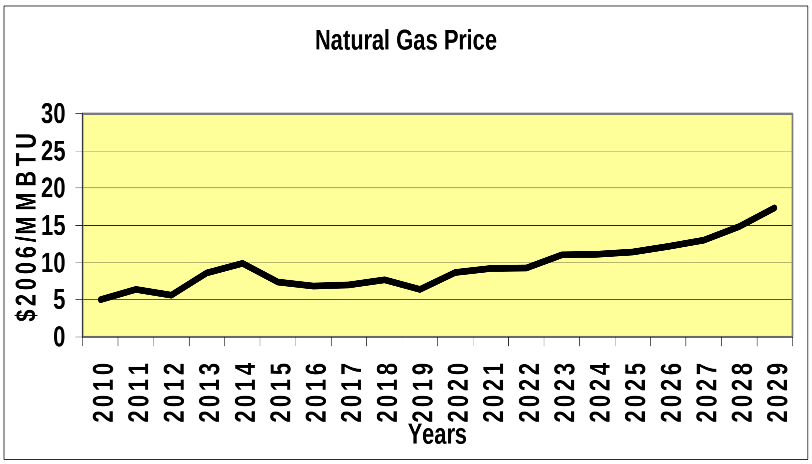
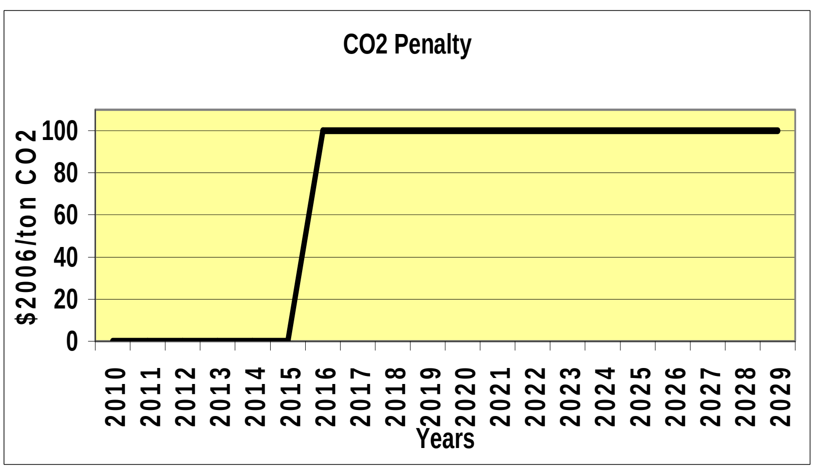
[6] This future, number 150, and all of the other 749 futures – and their impacts on resource portfolios – may be viewed by down-loading "spinner graphs" from the Council's website. This example is from the $0-100/ton Penalty Case least-risk portfolio spinner graph, http://www.nwcouncil.org/dropbox/Spinner_090811_1846%20L811%20LR%201987.zip

[7] As explained in Chapter 8, the model produces artificial spikes in RPS requirements due to the manor in which the model performs RPS accounting. These will not appear in the Final Plan.

Figure J-28: Elements of Future 150

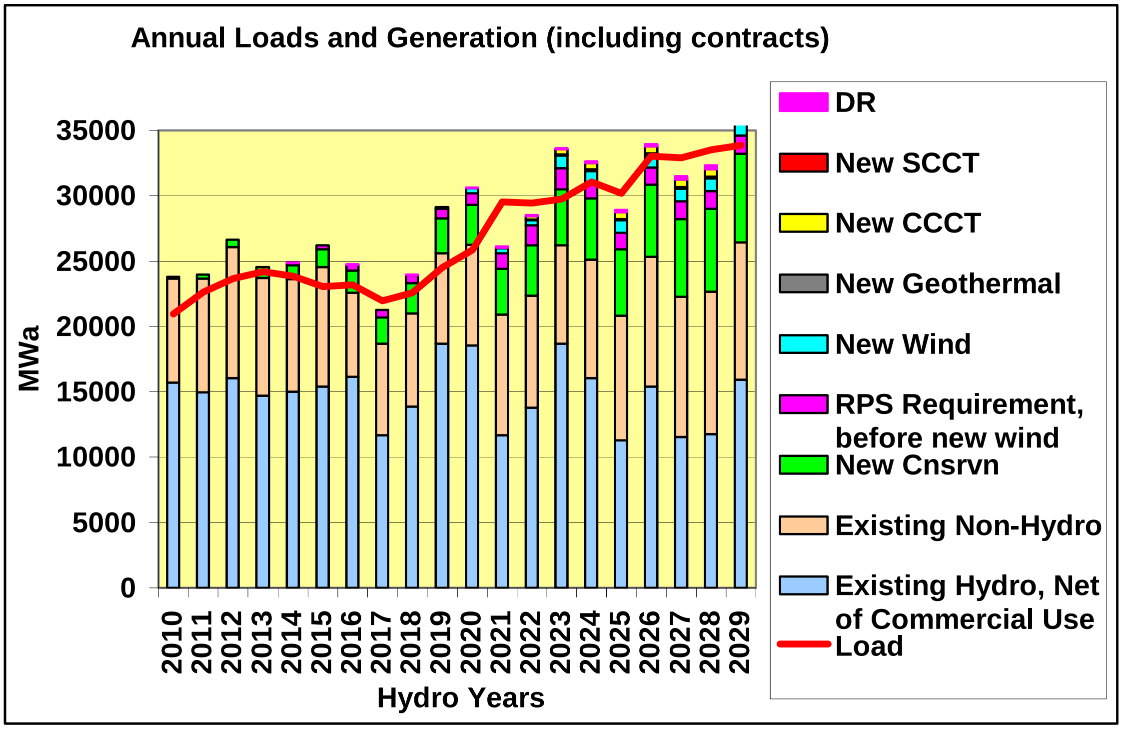


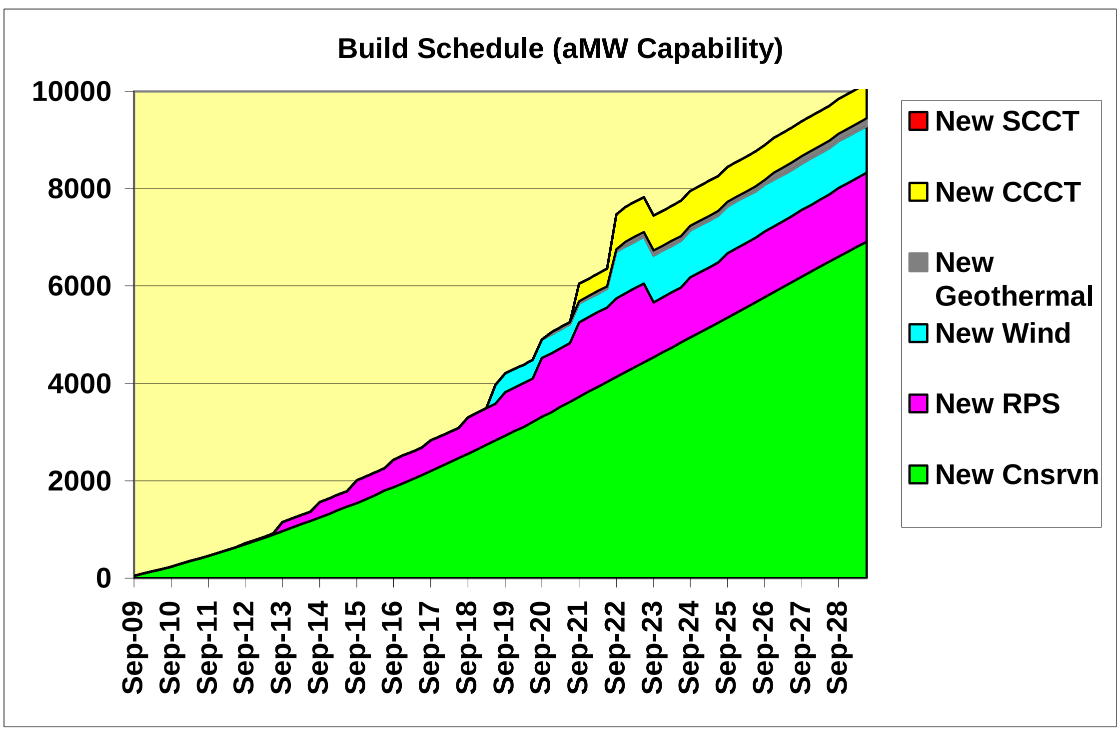




Source: Workbook "Spinner_090710_1402 L811 LR for illustrations.xls", worksheet "Future - Part 1 of 3"

Figure J-29: Loads, Operation, and Build Out

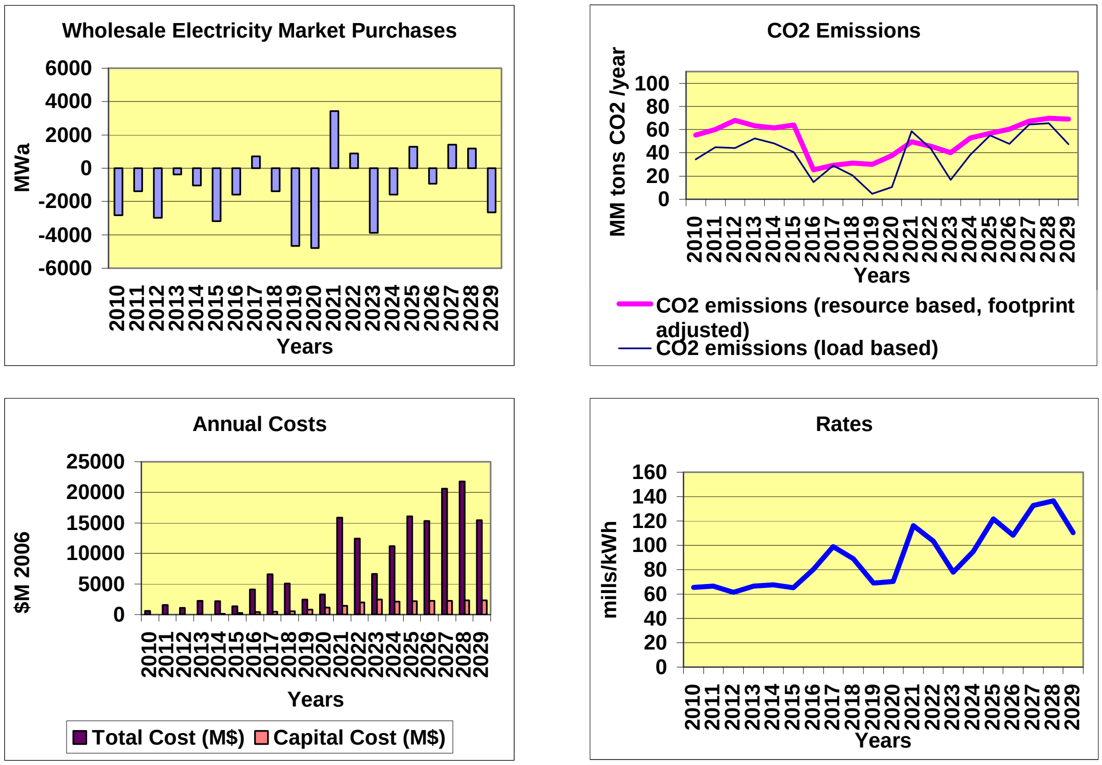




Source: Workbook "Spinner_090710_1402 L811 LR for illustrations.xls", worksheet "Future - Part 2 of 3"

Finally, Figure J-30 shows that when electricity prices remain high and the region needs power, the coal plants in the region will run. Without the coal plants, the regional CO_2 emission levels never exceed 35 million tons per year. Even with a \$100/ton carbon penalty, the CO_2 emission levels in the latter years of the study consistently run above today's levels.

Figure J-30: Other Consequences



Source: Workbook "Spinner_090710_1402 L811 LR for illustrations.xls", worksheet "Future - Part 2 of 3"

Conservation Investment in Depressed Power Markets

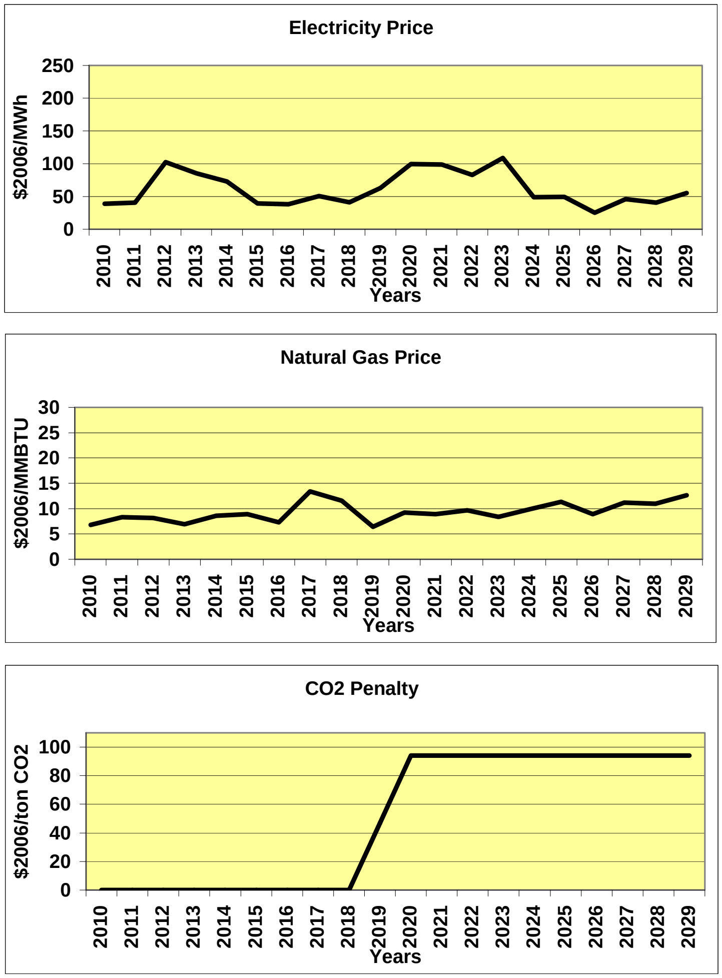
The least-risk plan supports higher levels of conservation and conventional resource development. The risk associated with high levels of capital investment in conservation and generation resources is that the region turns surplus and electricity prices fall. It is reasonable to wonder, what does such a future look like?

Selecting from among the lower load-growth futures, there are many in which load remains flat and electricity prices either hold or fall. Another future with $100/ton carbon penalty[8] provides some comparison with the last example. If instead, we were to consider a low-carbon future[9], thermal generation does not increase significantly, because electricity prices are low in both cases. The outcome costs about half of the average least-risk plan cost over futures. This would be considered a good outcome, economically, and therefore not one of particular interest from a risk perspective. The $100/ton carbon penalty future results in higher costs and is therefore more suitable to our scrutiny.

Beginning with Figure J-31, we have a future where natural gas and electricity prices remain about where they are today until the last quarter of the study. More significantly, load growth, illustrated in Figure J-32, is relatively flat. This results in significant surplus of resources in the out years, largely due to better-than-normal hydrogeneration conditions.

[8] Future 699.
[9] See, for example, future 106.

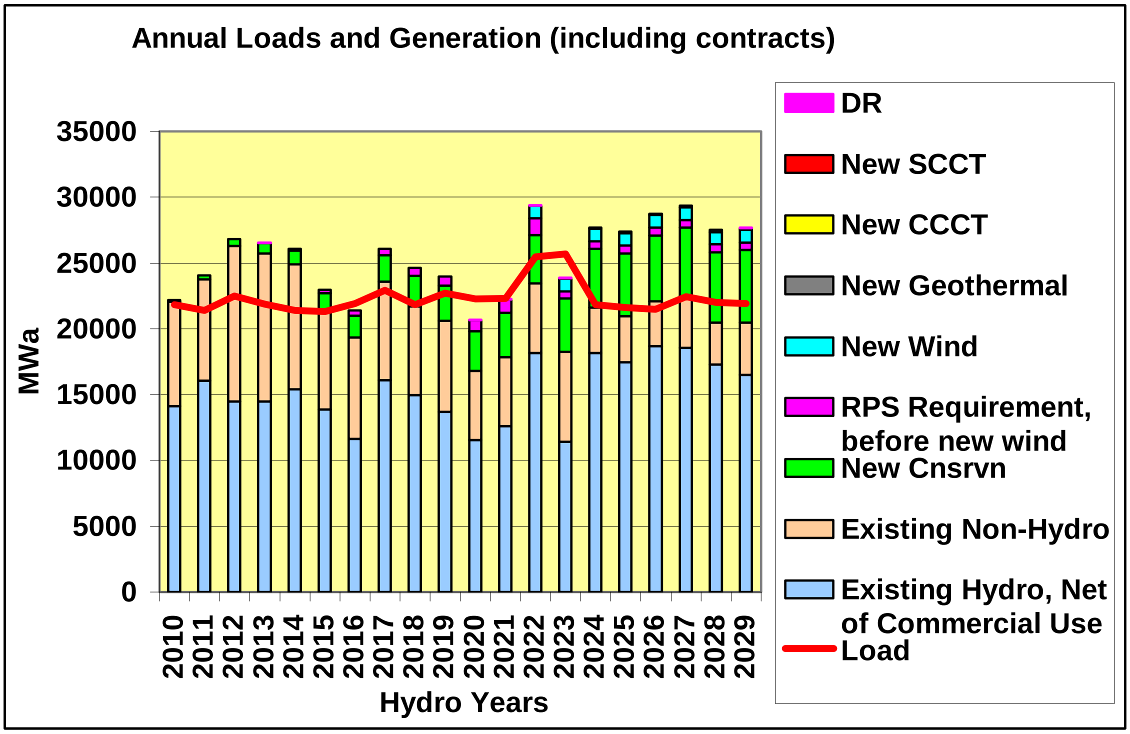
Figure J-31: Depressed Market 1/3

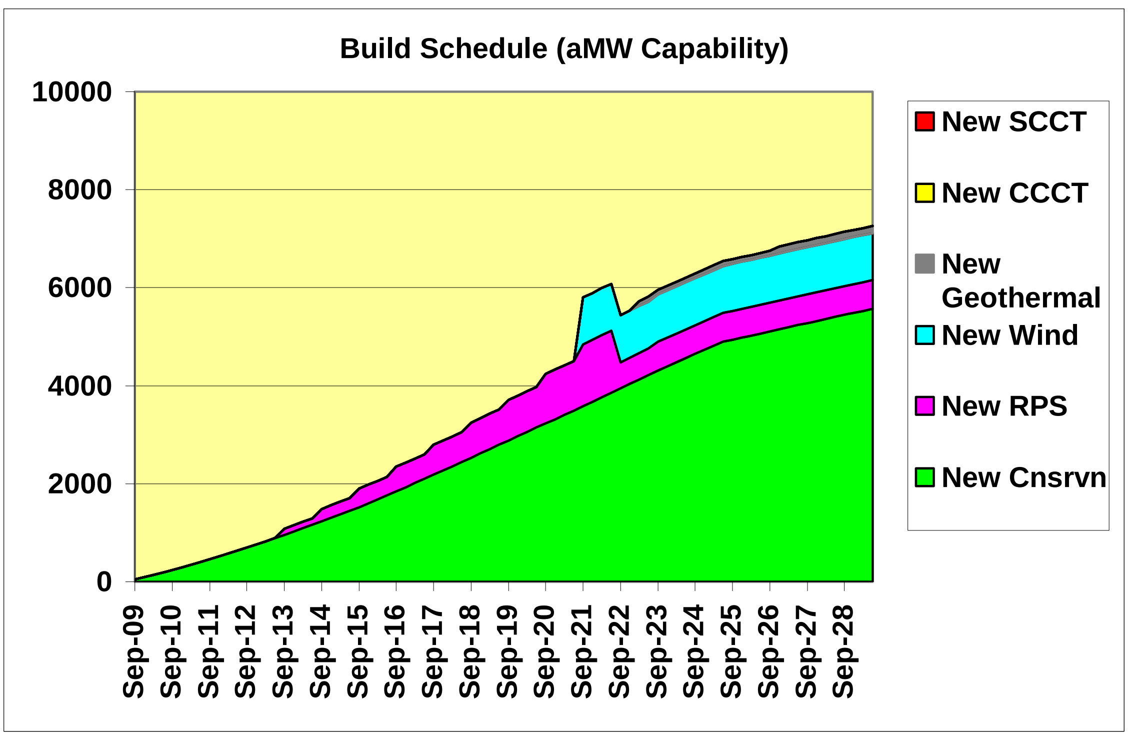


Source: Workbook "Spinner_090710_1402 L811 LR for illustrations.xls", worksheet "Future - Part 1 of 3"

In response to generally lower electricity prices and stronger natural gas prices, the region does not construct the combustion turbines that have been sited and licensed in the portfolio. Lower electricity prices result in little generation beyond the must-run renewable, nuclear, and gas-fired generation. Must-run gas-fired generation is mostly customer cogeneration installations and units necessary to provide for system stability. On an energy basis, the RPS and conservation that the region has built is surplus to its requirements in 14 of 20 years of the study.

Figure J-32: Depressed Markets, 2/3





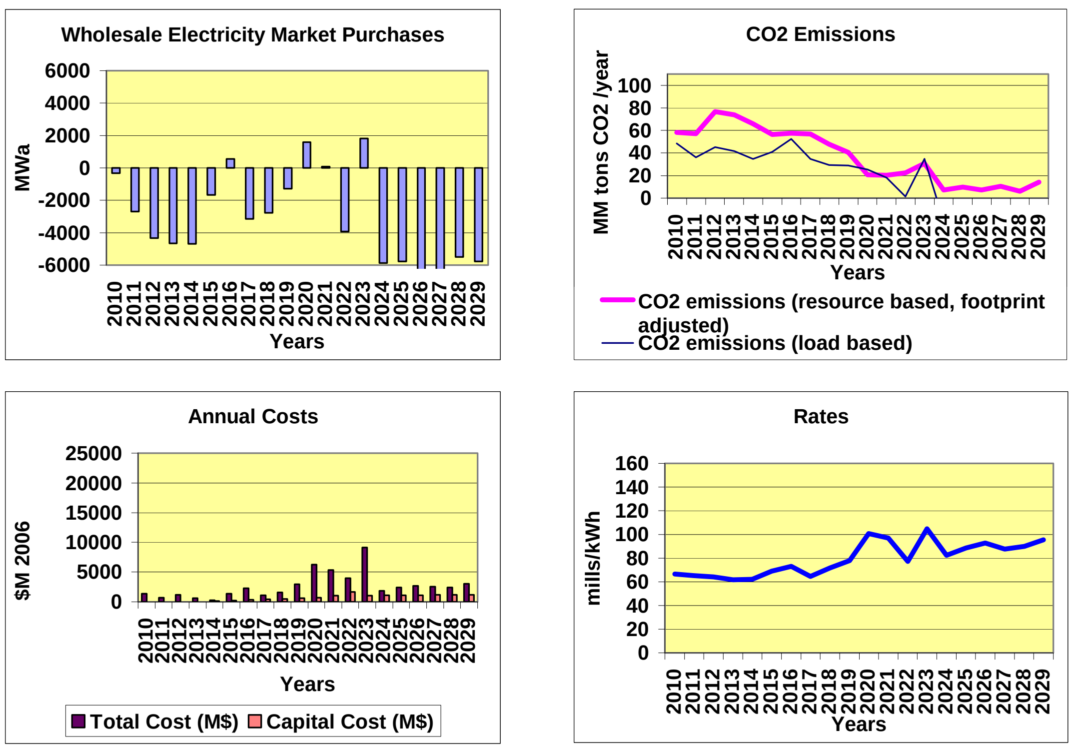
Source: Workbook "Spinner_090710_1402 L811 LR for illustrations.xls", worksheet "Future - Part 2 of 3"

Despite these extreme set of circumstances, the total cost of the system is $110.6 billion. This figure is less than 5 percent above the expected cost for the least-risk portfolio. Evident in Figure J-33 is reduced cost and rate variation and CO_2 emissions, as well.

The advantage of conservation and, to a lesser extent renewables, is low or zero operating cost. At any electricity price, these resources contribute some level of value. Figure J-33 shows that, while thermal generation is shut down, the region is still exporting surplus energy and reducing annual costs.

This benefit is essentially why there is a market adder for conservation. The region has seen that it is better to have slightly too many resources than too few. Most utility planners understand the value of keeping some capacity in reserve for unforeseeable circumstances. Examining the candidates for such a reserve in light of the observations above, conservation is expected to be the least expensive. It is the least expensive candidate precisely because it performs better in a low-risk portfolio. That is, it performs better when more resources are available and electricity prices are *expected* to be lower. In high price scenarios, of course, it performs no worse than thermal generation.

Figure J-33: Depressed markets, 3/3



Source: Workbook "Spinner_090710_1402 L811 LR for illustrations.xls", worksheet "Future - Part 2 of 3"

The Fifth Power Plan presented many examples of how a least-risk plan reduces rate and cost volatility and market exposure. Council studies have confirmed that the same kinds of behavior takes place in the efficient frontier of the Sixth Power Plan's plan case. The reader is encouraged to review the Fifth Plan for details.

GENERATION RESOURCES IN THE MODEL

This section discusses the existing generation resources in the portfolio model. That is, these are the resources common to all studies and expected to be present over the study horizon. Existing resources in the RPM are aggregated by heat rate, fuel type, and variable operations and maintenance (VOM) cost rates ($/MWh). The following table summarized the resources included in all draft plan studies, as well as the assumed aggregate unit capability, after discounting for planned and unplanned (forced) outages.

While it is not indicated here, a portion of certain plants may belong to independent power producers (IPPs). Those portions, however, appear explicitly Chapter 8.

Table J-5: Existing Resources

Name or Group Name	Group_ID	Aggr_Unit	MWaAnnual
18th Street (Springfield ICs, Springfield Gen Farm)	1000	West 3	9.1
Barber Dam	1017	Must Run	2.0
Basin Creek group	100	East 5	17.1
Beaver 1 - 7	1020	West 3	445.8
Beaver 8	1021	East 7	21.5
Bennett Mountain	1023	West 4	157.2
Bettencourt Dry Creek Dairy	1671	Must Run	2.2
Big Hanaford CC1A-1E	1028	West 1	222.4
Biglow Canyon I	1031	Must Run	37.7
Biomass One 1 & 2	1033	Must Run	22.6
Boardman	1044	Boardman	397.9
Boulder Park 1-6	1054	East 5	23.1
Box Canyon	1057	Must Run	0.3
Box Canyon 1 & 2	1059	Must Run	1.6
Broadwater	1064	Must Run	2.0
Bull Run No. 1 (Portland Hydro)	1069	Must Run	10.7
Bull Run No. 2 (Portland Hydro)	1070	Must Run	6.2
Bypass	1074	Must Run	3.0
Central Oregon Siphon	1085	Must Run	2.8
Centralia 1	1086	Centralia	607.6
Centralia 2	1087	Centralia	607.6
Chehalis Generating Facility	1089	West 1	466.4
City of Albany (Vine Street WTP)	1092	Must Run	0.2
Clearwater Hatchery (Dworshak)	1101	Must Run	0.5
Coffin Butte 1 - 5	1104	Must Run	5.0
Cogen II (D.R. Johnson) 1 & 2	1105	Must Run	7.2
Colstrip 1	1107	Colstrip 1&2	139.2
Colstrip 2	1108	Colstrip 1&2	139.2
Colstrip 3	1109	Colstrip 3&4	469.7
Colstrip 4	1110	Colstrip 3&4	617.4
Columbia Generating Station	1112	Must Run	1020.8
Combine Hills I	1115	Must Run	12.3
Condon	1119	Must Run	15.0
COPCO 1 (1 & 2)	1121	Must Run	12.6
COPCO 2 (1 & 2)	1122	Must Run	16.8
Covanta Marion	1126	Must Run	9.0
Cowiche Hydroelectric Project	1128	Must Run	1.0
Coyote Springs 1	1130	East 2	218.2
Coyote Springs 2	1131	East 2	233.2
Danskin (Evander Andrews) CT1	1136	East 6	150.2
Danskin group	104	East 7	81.3
Dietrich Drop	1148	Must Run	2.0
Don Plant (Simplot Pocatello)	1149	Must Run	6.3
Dry Creek	1152	Must Run	1.8
Dry Creek Landfill	1153	Must Run	3.1
Elkhorn Valley	1164	Must Run	30.0
Encogen 1-4	1169	Must Run	143.5
Everett Cogeneration Project	1171	Must Run	23.5
Evergreen Forest Products (Tamarack)	1172	Must Run	4.5

Name or Group Name	Group_ID	Aggr_Unit	MWaAnnual
Fall Creek 1 - 3	1173	Must Run	1.0
Fall River	1174	Must Run	6.0
Falls Creek	1175	Must Run	2.1
Farmers Irr. Dist. No. 2 (Copper Dam)	1178	Must Run	2.0
Farmers Irr. Dist. No. 3 (Peters Drive)	1179	Must Run	0.9
Foote Creek I	1185	Must Run	14.9
Foote Creek II	1186	Must Run	0.6
Foote Creek IV	1188	Must Run	6.1
Fossil Gulch	1195	Must Run	2.9
Frederickson 1	1198	West 4	79.8
Frederickson 2	1199	West 4	79.8
Frederickson Power 1	1200	West 1	241.3
Fredonia 1	1201	West 4	111.2
Fredonia 2	1202	West 4	111.2
Fredonia 3	1203	East 6	56.2
Fredonia 4	1204	East 6	55.2
Freres Lumber	1205	Must Run	9.0
Georgia-Pacific (Camas)	1211	Must Run	47.0
Georgia-Pacific (Wauna)	1212	Must Run	24.4
Glenns Ferry Cogeneration	1217	Must Run	8.8
Goldendale CC 1A & 1B	1219	East 2	219.1
Goodnoe Hills	1220	Must Run	28.2
Grays Harbor Energy Facility (Satsop)	1228	West 1	583.0
H.W. Hill (Roosevelt Biogas) 1 - 5	1234	Must Run	10.1
Hampton Lumber	1236	Must Run	6.5
Hay Canyon	1675	Must Run	30.3
Hazelton A	1240	Must Run	2.0
Hazelton B	1241	Must Run	3.0
Hermiston Generating Project CC1A & 1B	1246	East 2	208.5
Hermiston Generating Project CC2A & 2B	1247	East 2	208.5
Hermiston Power Project	1248	East 3	468.1
Hidden Hollow	1249	Must Run	1.5
Hopkins Ridge	1253	Must Run	47.0
Hoquiam Diesels	1254	Ignore	9.6
Horseshoe Bend	1255	Must Run	3.6
Horseshoe Bend Hydroelectric	1256	Must Run	6.0
Ingram Warm Springs Ranch B	1264	Must Run	0.6
Iron Gate	1267	Must Run	9.4
Jim Bridger 1	1271	Bridger	480.6
Jim Bridger 2	1272	Bridger	480.6
Jim Bridger 3	1273	Bridger	480.6
Jim Bridger 4	1274	Bridger	480.6
John H. Koyle (Koyle Ranch Hydroelectric) 1-3	1280	Must Run	1.0
Judith Gap	1281	Must Run	16.1
Kettle Falls Generating Station	1286	Must Run	47.9
Kettle Falls GT	1287	Must Run	6.2
Klamath Cogeneration Project	1290	East 1	424.0
Klamath Generation Peakers 1 & 2	1291	East 4	45.3
Klamath Generation Peakers 3 & 4	1292	East 4	45.3
Klondike I	1293	Must Run	7.2

Name or Group Name	Group_ID	Aggr_Unit	MWaAnnual
Klondike II	1294	Must Run	22.5
Klondike III	1295	Must Run	28.2
Koma Kulshan	1297	Must Run	8.0
Lancaster (Rathdrum CC)	1305	East 2	245.6
Lateral No. 10	1308	Must Run	1.0
Leaning Juniper	1310	Must Run	30.2
Little Wood River Ranch	1323	Must Run	1.0
Lower Low Line No. 2	1334	Must Run	1.4
LQ-LS Drains	1338	Must Run	0.9
Magic Dam	1342	Must Run	3.0
March Point 1 - 4	1344	Must Run	125.6
Marengo I	1345	Must Run	42.2
Marengo II	1346	Must Run	21.1
Meyers Falls	1354	Must Run	1.0
Middle Fork Irrigation District 1	1355	Must Run	0.3
Middle Fork Irrigation District 2	1356	Must Run	0.3
Middle Fork Irrigation District 3	1357	Must Run	2.0
Mile 28 (1 & 2)	1358	Must Run	1.0
Mink Creek	1367	Must Run	1.0
Mint Farm	1368	West 1	286.1
Mirror Lake (Hutchinson Creek)	1369	Must Run	0.5
Montana One (Colstrip Energy)	1372	Colstrip 3	11.7
Mora Canal Drop	1374	Must Run	0.9
Morrow Power	1376	East 6	22.7
N-32 (Northside Canal)	1387	Must Run	0.3
Nine Canyon	1394	Must Run	19.1
North Valmy 1	1399	Valmy	115.2
North Valmy 2	1400	Valmy	121.5
Northeast 1	1402	East 8	5.8
Northeast 2	1403	East 8	5.8
Olympic View 1 & 2	1411	West 4	5.2
Opal Springs	1413	Must Run	3.0
Owyhee Dam	1417	Must Run	1.0
Owyhee Tunnel No. 1	1418	Must Run	3.5
Plummer Forest Products	1437	Must Run	5.7
Port Westward CC1A & 1B	1443	West 1	382.1
Portneuf River	1445	Must Run	0.5
Potlatch (Lewiston) 1 - 4	1449	Must Run	53.3
Raft River I	1464	Must Run	12.5
Rathdrum 1	1467	East 6	77.7
Rathdrum 2	1468	East 6	77.7
River Road Generating Plant	1475	West 1	222.4
Rock Creek #1	1476	Must Run	1.0
Rock Creek #2	1477	Must Run	1.0
Rock River I	1481	Must Run	18.0
Ross Creek	1486	Must Run	0.1
Rough & Ready Lumber	1487	Must Run	1.1
Rupert Cogeneration	1490	Must Run	8.8
Savage Rapids Diversion	1498	Must Run	0.6
Short Mountain group	102	Must Run	2.4

Name or Group Name	Group_ID	Aggr_Unit	MWaAnnual
Shoshone/Shoshone II	1507	Must Run	0.5
Sierra Pacific (Aberdeen)	1510	Must Run	9.1
Sierra Pacific (Fredonia)	1511	Must Run	2.8
Skookumchuck	1515	Must Run	4.0
Slate Creek	1516	Must Run	2.2
South Dry Creek	1533	Must Run	0.3
St. Anthony	1545	Must Run	0.3
Stateline	1546	Must Run	90.1
Sumas Cogeneration Station	1556	Must Run	110.3
Tenaska Washington Partners Cogeneration Station	1571	West 2	219.8
Tiber-Montana	1579	Must Run	0.9
Tieton	1580	Must Run	7.1
Tuttle Ranch (Ravenscroft)	1588	Must Run	0.6
Twin Falls (TFHA)	1590	Must Run	6.0
Twin Reservoirs	1591	Must Run	0.5
Upriver	1605	Must Run	7.3
Vaagen Brothers Lumber	1606	Must Run	2.7
Vansycle Wind Energy Project	1608	Must Run	7.5
Wapato Drop 2 (#1)	1613	Must Run	1.5
Wapato Drop 3 (#1 - 2)	1614	Must Run	1.0
Weyerhaeuser (Springfield) 4 (WEYCO)	1637	Must Run	22.6
Wheat Field	1640	Must Run	29.0
Wheelabrator Spokane	1641	Must Run	20.8
White Creek	1643	Must Run	60.5
Whitehorn Generating Station 2	1650	West 4	79.8
Whitehorn Generating Station 3	1651	West 4	79.8
Wild Horse Wind	1653	Must Run	68.6
Wilson Lake	1657	Must Run	3.0
Wolverine Creek	1660	Must Run	18.1
Yellowstone Energy (BGI)	1668	Must Run	17.0

Many of the units, it may be noted, are assigned to the "must run" aggregate unit. The reasons for this assignment depend on the particular plant. Some of these are combined heat and power (CHP) installations owned by customers. Wind, geothermal, and most other renewables belong to his family, having virtually zero variable operating cost. Run of River Hydro, which is generally not dispatchable, and the Columbia Station nuclear power plant, which has very low operating cost, also belong to this category.

TREATMENT OF CAPACITY AND FLEXIBILITY

Because the emphasis of the RPM is cost, which is largely determined by energy surplus or deficiency, it is not well understood how the RPM treats capacity. There are two approaches to addressing this issue. The first is based on economic evaluation. That is, how does the model value resources that operate only a small number of hours? How does the model evaluate such resources for capacity expansion? The second deals with the energy aspect. How does the resource “contribute to peak load?” By this, we may mean how likely is the resource ***to be producing energy*** when energy requirements are greatest? Alternatively, we may mean how likely is the resource expected ***to be available*** to meet load when requirements are greatest?

The RPM uses the economic valuation approach. The RPM does not have the information it needs to determine either form of contribution to peak load. Instead, the Council relies on a model dedicated to that calculation, **Genesys**. It is certainly ***possible*** to estimate peak contribution from distributions in the RPM, but not without additional logic development.

Having said that, we believe there are reasons why the model has produced plans that meet peaking requirements. We return to this observation after discussing how the RPM implements the economic evaluation of capacity.

Understanding the RPM's economic treatment of capacity resources takes some explanation. To address uncertainty, the Regional Portfolio Model (RPM) requires high computer processing speed. Producing a single feasibility space may require several million twenty-year studies. The RPM achieves such speed by representing hourly variation in prices and requirements using statistical distributions. For example, distributions represent hourly data for loads, electricity prices, fuel prices, and so forth. Separate distributions represent on- and off-peak behavior over a hydro quarter. A hydro quarter is three months of a hydro year, beginning in September.

As described in the Fifth Power Plan[10], representing costs in this manner provides the same results that would an hourly dispatch model. The model accurately estimates, for example, the value of demand response programs operating over only the 80 highest-value hours.

Understanding the role of correlation in the RPM is central to understanding the treatment of capacity. Fuel cost is the product of fuel quantity and fuel price, summed over hours of operation. Cost depends, however, on whether hourly quantity moves in the same direction as hourly price. If we buy more fuel when fuel is expensive, it costs more. The correlation of these variables is therefore important.

Estimating fuels and operation cost in a conventional way would be difficult using distributions. It would be necessary to keep track of how the BTUs and the prices of fuels move. Fuel use depends on dispatch. Dispatch to meet loads, however, depends on the generation of other plants, in particular those that are cheaper to dispatch. The model would therefore need correlations among all fuel prices and quantities. Doing such bookkeeping for all the generators in the region would be near impossible.

Valuation costing gives us a simple way to estimate costs in the model. It uses the difference between the value of resources and the cost of serving loads in the electricity market[10]. The model does not need to track how fuel prices correlate among themselves. Instead, only the correlation between each resource's fuel price and electricity market price is required.

We also rely on the ***non-correlation*** of price and quantity to model several important resources. Cost or value, in this case, is just the product of average quantity and average price. This is the true for the value of **wind generation**, for example. Wind generation is not correlated to electricity price. Consequently, use of an average block representation of wind energy and average electricity price does not compromise the value estimate.

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[10] See the section entitled "Valuation Costing," beginning on page L-13 of Appendix L to the Fifth Power Plan.

We have also assumed it is true for **hydrogeneration**. Sustained peaking contribution is estimated from a trapezoidal approximation. Rates of energy delivery are therefore flat over on- and off-peak subperiods, as the name suggests. The RPM shapes HydSim sustained peaking energy flat into the 96 peak hours of the week. These peak hours define a certain subperiod in the model.

For dispatchable resources, however, fuel prices and electricity prices typically are correlated. The RPM also correctly reflects the economic value of such resources. Capacity resources, like simple cycle combustion turbines, are the example that interests us. In this case, it is change in average price for electricity, however, that drives value of new generation. If the system is short of energy on peak in certain seasons, electricity prices during those hours must increase. If price increases for enough hours, a simple-cycle combustion turbine creates enough value to cover its construction costs.[11]

Economic value therefore determines whether the model will build a power plant. Any value beyond that necessary to cover plant costs lowers the system cost, so the model would choose to add it.

This brings us back to the observation that the model seems to produce plans that meet energy peaking requirements. Traditional reliability and adequacy assessments of capacity requirements ignore fuel prices or operation costs. It is assumed that if the region needed capacity to meet an unforeseen circumstance, fuel price would not be an issue. If prices ***were*** considered, however, very high electricity prices would result. Of significance to us, the RPM would build more resources in this situation specifically to avoid exposure to these high prices.

The model will option the turbines under two distinct circumstances. These circumstances correspond to the two notions of "contribution to peak" introduced at the beginning of this note. Requirements and high electricity prices can happen on a regular or periodic basis, or they can happen due to unusual circumstances. High prices on a regular basis result in building peaking resources for the reasons given a few paragraphs above.

The model options and builds capacity resources for unusual situations also, by virtue of it being a risk mitigation model. A utility may want to build a turbine to mitigate risk. The utility may recognize circumstances can change from current conditions. It may think that the utility may not be able to access the market for peak energy when it needs to. Alternatively, it may think the market would be able to provide energy under such circumstances, but only at very high prices.

The model simulates these possibilities with very high electricity market prices in many futures. The model will option the turbine if the likelihood of this situation makes the optioning cost attractive. The model will build such a resource in futures where the region is likely to need them. The region will be likely to need them if proximal economic conditions warrant. That is, if a turbine would pay for itself today, it will probably pay for itself tomorrow, so build. Alternatively, the region will be likely to need them if regional adequacy is drifting lower. In this case, construction occurs irrespective of whether the model forecasts that the resource can cover its cost in the future.

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[11] If it increases too many hours, however, a combined cycle turbine will be cheaper. When the CCCT comes into service, it will lower electricity prices and displace the simple-cycle unit.

It may be surprising to discover that a resource needs to cover its costs in only one future to be optioned by the RPM. The plan, however, must belong to a risk-constrained portion of the efficient frontier. The risk metric is responsible for situation. Hypothetically, the model can reduce TailVaR_{90} if it can reduce the NPV of even a ***single*** future. Of course, this means that the NPV of all siting, licensing, planning, construction, and operation is recovered by eliminating the costs that would otherwise have occurred.

To conclude this discussion of energy peaking contribution, there is no guarantee that the model will always build plans that meet energy peaking requirements. Consequently, staff always evaluates recommended plans using the **Genesys** model. So far, however, we have never seen a situation where economic adequacy has failed to produce energy adequacy and to meet peaking requirements.

THOUGHTS ON INNOVATION AND REGULATORY INITIATIVES

Technological innovation can rewrite the economic rules of generating power. Legislative and regulatory initiatives can have and have had this effect. How does the Council's portfolio deal with such "game changers?"

While there is little chance of accurately forecasting innovations in markets, regulation, or power generation, the possible effects on power system cost are foreseeable. Studies can thereby discover and examine situations that deserve additional consideration for risk.

For example, consider the possibility of a technological breakthrough that makes solar photovoltaic generation cost effective for individual homeowners. If a large number of homeowners installed these systems, it is reasonable to expect utility residential load requirements would decline. Industrial requirements for energy-intensive purposes, such as metals and chemical refining, could increase but only until other regions or countries acquired the solar conversion technology. The utilities themselves would likely find a way to harness the technology in larger quantities and at even lower cost. Surplus utility generation would drive down wholesale power prices. Could it impact natural gas prices? Quite possibly. It is difficult to imagine, on the other hand, how this breakthrough would affect hydrogenation variability or power plant forced outages. In this manner, a solar photovoltaic breakthrough is interpreted in terms of the sources of uncertainty the Council's model already addresses.

These observations bear on the scale of and relationship among uncertainties included in studies.

Council studies reflect a larger scale of uncertainty than intuition might first suggest. This simply reflects the potential for a larger pool of contributing factors than history provides. Combining futures in unlikely ways, moreover, reveals how alternative sources of uncertainty can conspire to bring extraordinary risk. One needs to look no further for support of this approach than the current economic crisis. "Unlikely" coincidence of mortgage defaults was not a consideration in derivative valuation estimates. Once revealed, however, it is still incumbent on the Council to decide whether a particular combination of events is meaningful.

DETAILED CHRONOLOGY OF MODEL CHANGES

The Council used a particular implementation of the RPM to develop the Draft Plan, workbook L811.xls. This model is a descendent from the workbook that produced the resource portfolio adopted in the Fifth Power Plan. The following identifies the principal changes that have been made to since then.

Notes on L801

February 22, 2008

1. The model originates with L28.xls (L27a2.xls) (Friday, February 22, 2008)
2. Transferred over new expansion logic and energy reserve target (2000MWa) from l28an.xls. (Done Tuesday, March 25, 2008)
3. Date range modified to Sept 2009 to August 2029 (Friday, February 22, 2008)
4. Updating **contracts** from MSchilmoellerRegionalContracts_MJS_070823.xls, rows 85 and 88. Extrapolated beyond Aug CY2016 by repeating the pattern. (Friday, February 22, 2008)
5. Tested on WK1 in Turbo mode – OK (Friday, February 22, 2008)
6. **Natural gas prices** input (Wednesday, February 27, 2008)
7. **Aluminum prices** input (Monday, March 3, 2008)
8. **Coal prices** for Eastern coal (including new coal units) updated. Note that Centralia and Boardman remain the same. The cost for Centralia does not seem to correspond to Terry's "Western" coal price – Centralia is much more expensive. (Friday, March 14, 2008)
9. **Electricity Prices** input (Friday, March 14, 2008). I have not updated the volatilities, but having seasonal variation in volatility looks attractive.
10. **Electricity Loads** (Friday, March 14, 2008). I should verify my assumptions with Massoud. Looks like what he wound up giving me was merely CY Frozen Efficiency Sales. I confirmed this with on Monday.
11. **Conservation.** I created the curve generating code, Friday, March 14, 2008. Some selection of points (six from 11) was necessary, so I created a graph that permitted me to see how various selections worked. Entered into L801.xls Wednesday, March 19, 2008.
12. **Resources**
    a. Check existing against current surrogates. This remains a challenge.
        i. Received notebook with 142 resources, including capacity adjusted by POR, but not FOR, by ownership type (IPP, IOU, COU, PUD) and by whether or not it qualifies toward the RPS standard on 3/17/2008.
        ii. I completed a list of mismatches between old units in new units. There are 31 plants apparently missing from the current listing that appeared in the 5th Plan. There are 42 new plants.
        iii. Get the IPP breakdown (received 5:30PM Friday 3/21/2008)
        iv. Analyze Existing units by VOM and heat rate and complete new aggregation units.
    b. Get the RPS resources. (MG provided total MWa after FOR and POR by calendar year, 3/17/2008). Calculated consistent hydro quarter values Wednesday, March 19, 2008.
    c. Transfer existing and new RPM resource data to workbook
        i. Input Must Run (Done Tuesday, March 25, 2008)

ii. Input Special Treatment resources (Boardman, Bridger, Centralia, Colstrip 1&2+Hardin, Colstrip 3&4+Montana One, Corrette, and Valmy), including updated capabilities, VOM, and heat rate information.
iii. Input Aggregate plants (West 1-4, East 1-8)
iv. Performed calculation check on L801.xls version 3/25/2008 5:53PM on both non-turbo and turbo versions of CB2000. Everything is checking out. Made a backup copy of this version.

Had a Crystal Ball error when I tried to save before running in CB mode, to the effect that Operation could not be performed. Turned out most of the workers had multiple copies of Excel loaded.

v. Converted East 5 (formerly Waste) and East 8 to include VOM and FOR, respectively, including off-peak logic. Converted those and West 2 (formerly Encogen) to point to natural gas prices, and East 1 (dynamic FOR) and East 4 (static FOR) to point to the correct gas region. (All done Wednesday, March 26, 2008)

vi. Adjusted economics for IPP shares (done Wednesday, March 26, 2008)

vii. Updated coal plant fuel prices—No new information.

d. Characterize new generation. Received workbook on Friday, March 07, 2008. These had the wrong discount rate for calculation of real levelized cost, but the correction should be constant based on the economic life of the unit.
i. Computed economic life-specific discount rate adjustments
ii. Computed quarterly escalation rates and cash flow rates for the five project candidates.
iii. Forced outage rates missing, so I am assuming previous values. Checks out fine with Jeff; IGCC may decline from 10 percent to 7 percent.
iv. Elect to remove Class 6 wind. Remaining wind at 28 percent CF
v. Modified DR additions: 300MWa in 9/09, increasing 100MWa/yr

13. CO_2 penalty, PTC, RECs
a. probability of occurrence increased to more than 95 percent. Range increased to 50 and 100 $/ton CO2
b. No changes to PTC or REC modeling

14. Modify optimization assumptions
a. Fix energy RM target at 2000 MWa above critical water (keep a copy of the old model, in case things do not go according to plans).
b. Fix coal additions to zero
c. Constraints
i. earliest dates for additions
ii. rates of addition
iii. number of units permitted (min and max, by year)

Notes on L802

Wednesday, April 02, 2008 4:08:04 PM

15. Adjusted wind in the Must Run resource by the capacity factor (4/1/2008)

16. See observations in Staff Review of Data Assumptions 080331.doc (4/1/2008)
    a. Reduce potential addition of wind to 2900MW by EOS
    b. Remove non-viable smelters (remaining smelters are Winachee, Bellingham, Columbia Falls, and "perhaps" Goldendale. (Quotes added by Terry.)
    c. Revise CO_2 modeling, in particular the probabilities of a penalty before the beginning of the study and probability of occurrence during the study time period.
    d. Modify levelized costs for new resources
    e. Reduce seasonality of gas
    f. IPPs: remove Lancaster, correct Klamath Generation and Centralia IPP amounts

Notes on L803

17. Revised CO_2 logic for level to be max $50/ton prior to halfway point.

18. Lifted limits on CCCT and LO Conservation additions that the optimizer can test, restricted others.

19. Changed variable constraint levels.

Notes on L804

Thursday, July 10, 2008

Enhancements over L803 include

20. Implementation of HourDispatchC from NWPCCRisk07.xll (Copy of L804.xls)
21. Removal of doEvents from the subroutine subFindEq3 (Copy of L804.xls)
22. **Addition of end-effect logic for carbon penalty events**. (See ..\Plan 6 Studies\Model Development\CO2 tax end effect" subdirectory and notes) (Copy of L804.xls)
23. New vba modules for correspondence with current implementation of Olivia, including new naming convention and error handling dll. This required a slight modification to the "parameters" names in the workbook to include underscores for spaces and Hungarian notation. Strings in the initialization for the names had unnecessary leading "P_", too. (L804.xls)

Notes on L805

Tuesday, December 30, 2008

I have been making a lot of progress on the logic for the model, and it is time to start developing a model that will use the Plan 6 data. Consequently, L805 has

24. Loads from Massoud J., as developed in "Load forecast data for Portfolio model.xls", which is the workbook he gave me, and in "081230 FE Loads Data conversion workbook 01.xls" where I do the necessary aggregation and factoring. I am taking the results to wk1 with the much smaller workbook, "081230 Loads for the RPM.xls"
25. Natural gas prices from Terry Morlan, "Fuel Prices to Portfolio Model.xls" 119,808 B, 10-02-08 12:31:18, aggregated with C:\Backups\Plan 6 Studies\Data Development\Fuels and Aluminum\"081230 Natural Gas Prices Data conversion workbook 01.xls" 1,257,472 .a.. 12-30-08 21:50:22.
26. Electricity prices from Maury Galbraith according to a 1/5/2009 run. Modified the FERC price cap from $250/MWh to $400/MWh.
27. Construction cost uncertainty data, as presented to the December GRAC. I believe the final piece is the application of the stochastic variation to the overnight construction costs and a recap of what we did. Not sure whether to rehash the CERA sensitivity issues.

L805 is based on L804b (8:16PM ADT 11/4/2008 -- aka L804x, aka L804c), which I developed to present material on CO2 penalty, PTC viability, and Greentag (REC) value uncertainty to the GRAC. I performed extractions on this model, so it should be free of Excel 2003/CB2000 issues, but I will check. It contains the data used to prepare the December 2008 presentation to the Power Committee.

As always, these need to be added carefully on the workers under Excel 2000 and checked at each step. I just ran with the new load forecast, and everything seems to be running just fine. [12/30/2008 9:25:53 PM].

28. CO2: Take out forms, put in firm sales+purchases Tuesday, February 10, 2009 (Done)
29. On wk1, Used Application.RegisteredFunctions to source add-in resolution of names to NWPCCRisk07.xll

```
Sub test1()
Dim theArray As Variant
Dim i As Long, j As Long

theArray = Application.RegisteredFunctions
If IsNull(theArray) Then
   MsgBox "No registered functions"
Else
   For i = LBound(theArray) To UBound(theArray)
      For j = 1 To 3
         Worksheets("Sheet1").Cells(i, j). _
            Formula = theArray(i, j)
      Next j
   Next i
End If

End Sub
```

30. Application.RegisterXLL ("C:\Documents and Settings\Schilmoeller\Application Data\Microsoft\AddIns\NWPCCRisk07.xll")

31. Implemented West 1 using the new planning and flexibility template. Basically, I am now pointing at a new row for capability.

32. Installed my "InstallOrRemovePlant" utility. Using it pretty extensively.

33. Put in CO2 emissions calc for the IGCC (88 percent sequestration).

34. Brought over all existing, non-hydro plant data. Put in the new template for planning and flexibility, but have not started implementing the logic yet. I thought this would be a good place to stop and preserve a functioning copy, just in case.

Because significant changes to logic would be introduced at this point, and because I could verify that L805 was a working model, I did not perform any studies with L805 but instead chose it to serve as a "restore point," in case logic changes introduced instabilities that required my tracing back to a "known good" copy of the model.

Notes on L806

Tuesday, February 17, 2009

This workbook stems from a working copy of L805.xls. I am bringing over the Capacity and fixed cost logic from FixedCst_07.xls, and I thought it would be wise to have a reset point. **For principal data and logic changes, please consult the note "L805 Notes.doc"**

I did a substantial amount of work on my home computer, which runs Excel 2007. I ran the resulting workbook on WK1, and it worked in local mode, turbo mode, and under Optquest. Looks like our issues may not be as severe on the new Excel. I am deeming this workbook no longer infected. [2/19/2009 1:06:28 PM] Subsequent entry: I have discovered that now even workbooks saved under Excel 2003 do not create problems running under CB2000 on WK1. While I am delighted, I am mystified. I can only guess that, in the last six months or so, Microsoft has introduced changes to Excel 2003 which resolves these issues. [Tuesday, February 24, 2009]

There are workbooks with a host of suffixes in this subdirectory. Eventually, I may be able to clear out a bunch of this, but here is their meaning

- The suffix i refers to “infected” (or “ri” for “reinfected”), which means the workbooks have been saved under a non-Excel 2000 environment.
- The suffix s refers to “small”. At one point, I guessed that the problems we were having with worker performance were related to the large workbook size associated with the 750 futures’ worth of construction cost data for CCCT, SCCT, Wind, and IGCC. I pulled out the worksheet with the construction cost data and turned off the construction cost uncertainty feature.

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- After many crashes, I was concerned that I had introduced contamination into the workbook and “washed” the VBE modules.
- L806s2.xls is a smaller “s” version of the workbook with any object creation “set X = new Y” carefully disposed of by the end of the procedure or, in the case of the error-handling dll, at the end of each call to subAfterGame under certain conditions. The error-handling dll should not be re-created and destroyed within subAfterGame if the routine subAfterGame was called from Auto_open. This required some special logic.

It may, in fact, not be necessary to go through all these machinations for the error-handling dll. We did not see the workers create multiple instances of the workbooks under the service host earlier, when the creation of the error handler was accomplished with a simple “CeH as new ErrHandler” definition.

35. I will be transferring the object disposal in L806s2 to the original version L806.xls to proceed from here [Tuesday, February 24, 2009].

36. I am trimming the number of construction cost futures to 100 to reduce the bloat of the model. While hidden name objects in sheets could provide a more compact means of storage large numbers of random variables, I will not have the time to investigate and implement that approach. I believe 100 futures should provide sufficient variation for these initial runs. I also need to adjust the range of the CB random variable in cell R325C7 to act a seed in the selection of the futures. [Wednesday, February 25, 2009]

37. **Install variable RPS resources, including accounting for banks RPS credits**. The most current version of this nets out any wind already built and provides banking for surplus capacity. An alternate approach, perhaps suitable for MT or WA, is to sell RECs on the surplus amount. We are examining this.

    The amount of RPS is variable, reflecting changing loads from future to future, but in this version it is assumed that obligated utilities always meet their targets. Consequently, it banking credits are inadequate for compliance, the deficient state effectively buys RPS resource at 60-80 $/MWh. [Done]

An inconsistency exists in this version of the model. There is no consistency between the cost of wind the optimizer can choose – which is also subject to cost uncertainty – and the prescriptive price of RPS resource. This will be remedied in the next version of the model.

38. Check forced outages for existing plants. [Done] This reveals that the one plant using stochastic forced outages seems to have its output discounted by capacity deration instead.

39. Bring over supply curves. [Done] The modeling that Tom and Charlie wanted me to do with the new discretionary conservation is not possible at this time.

40. Install 5 DR programs (no fixed cost uncertainty) [Done]

41. Install new expansion for a CCCT. [Done]

42. Install (at least) three wind units. [Done] On closer inspection, these units differed only in whether 2011 or 2012 was the earliest availability and how much RPS/REC credit Jeff had assigned to them. I wound up using one wind unit, without REC credit. (See item 1 above)

43. Conventional coal and demand buyback are removed from among planning candidates. [Done]

44. We also have 10 conversions of exiting units to the new Fixed Cost format, to take advantage of FOR modeling. I removed approximately 1000 Crystal Ball decision cells previously used for this purpose. I implemented the new vfunFxdCstCap logic with ***West 1***, which is underway. [I did not go beyond conversion of West1, but returning to this is warranted.]

45. Include contributions for new resources into the adequacy calculation. This includes RPS resources. We also modify the target to reflect the fact that we are now discounting energy by FOR for planning purposes. [Done]

46. Implement internal decision criteria. [Done] The criterion logic is a hybrid, not entirely internal to the vfunFxdCstCap function. This was desirable because this function has not yet been ported to the XLL and would have to use a slower VBA function.

47. Reintroduce construction cost uncertainty. [Done] This was removed temporarily for diagnostic reasons. I have returned 100 futures instead of the full 750, however.

48. Constrain IGCC and wind according to their known availabilities. [Done] This is done in the optimizer input file.

49. Reinterpret the mothball and termination costs. [Done] Jeff recently clarified that the values he has given me are net present values, not real levelized values as the workbooks indicate. This comports with the size of these values. Jeff's initial thinking is that

cancellation costs should be capitalized and mothball costs should be expensed, but I am not sure. As an interim step, I levelized these NPVs and used them, which should lead to the right answers.

50. Re-estimate optimal packet size – I think we can facilitate this with messages from AfterSimulation macro. [Done] Smaller is better, down to 2 futures per packet. Latency rules.

51. Modified feasibility space illustration workbook to accommodate new resources. [Done]

52. Reduced options for smelters to Winachee. [Done]

53. Eliminated unused range names and indices. [Done]

54. Change lTopHeaderRow and lBottomHeaderRow to named ranges and replace logic for reading their value. Delete unused model parameters from the parameter list. [Done]

Note that I let L806 run for quite awhile, without using the output. The final output log is named simply Optquest.log, and its final plan is 6719. One of the things that we learned from this run is that the current range for risk is 207,500 $M (margin 242 $M) to 213,600 $M (margin 70 $M).

The least risk plan was:

Sim	Cnsrvn_Lost Opportunity	Cnsrvn_Dispatchable	DRAC	DRSH	DRAG	DRIN	CCCT_CY_Sep09	CCCT_CY_Dec13	CCCT_CY_Dec15	CCCT_CY_Dec17	CCCT_CY_Dec19	CCCT_CY_Dec21	CCCT_CY_Dec23	CCCT_CY_Dec25
1460	40	20	4	3	2	4	378	756	756	756	1512	7560	7560	7560

SCCT_CY_Sep09	SCCT_CY_Dec13	SCCT_CY_Dec15	SCCT_CY_Dec17	SCCT_CY_Dec19	SCCT_CY_Dec21	SCCT_CY_Dec23	SCCT_CY_Dec25	Wind_CY_Sep09	Wind_CY_Dec13	Wind_CY_Dec15	Wind_CY_Dec17	Wind_CY_Dec19	Wind_CY_Dec21	Wind_CY_Dec23	Wind_CY_Dec25
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

IGCC_CY_Sep09	IGCC_CY_Dec13	IGCC_CY_Dec15	IGCC_CY_Dec17	IGCC_CY_Dec19	IGCC_CY_Dec21	IGCC_CY_Dec23	IGCC_CY_Dec25	Wind2_CY_Sep09	Wind2_CY_Dec13	Wind2_CY_Dec15	Wind2_CY_Dec17	Wind2_CY_Dec19	Wind2_CY_Dec21	Wind2_CY_Dec23	Wind2_CY_Dec25
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Total Study Costs (Mean) (Std_Dev) (Median)	TailVaR90	LO_MWa: Mean	LO_Cst: Mean	NLO_MWa: Mean	NLO_Cst: Mean	Cnsv_MWa: Mean	Cnsv_Cst: Mean
129,917	207,742	2223	29.8	2239	17.5	4462	23.6

CO2AnnAvg2025:1	CO2AnnAvg2025:(std dev)	CO2AnnAvg2029:1	CO2AnnAvg2029:(std dev)	CostWOcarbon_penalty: Mean	NPVCarbonPenalty ($M): Mean
38,112,108	11,606,341	39,696,550	12,617,702	102,940	26,977

with the proviso that the RPS displaces most of our slightly more expensive wind, most of the time.

Notes on L807

Tuesday, March 03, 2009

The model L807 stems from L806, which has been running successfully for three days, now.

55. Energy adequacy target revised to -438 MWa from +2000 MWa. The latter number was out of date and should have been 466 MWa, per documentation that I did in response to Dick Adam's question, October 10, 2008. It has been revised farther south, because I am now explicitly considering FOR deration, consistent with the regional standard. [Done]
56. Add a calculation of CO_2, excluding sales and purchases. [Done]
57. Capture TailVar90 for Costs without carbon penalty and for 2025 and 2030 emission levels. Repeat these variables, but excluding sales and purchases, for good measure. [Done]
58. Revise the averaging periods for carbon emissions to three years, 9/25-8/25 and 9/26-8/29. The latter is constrained by 8/29 being the last end of the last quarter we explicitly model. Restate in millions of US tons. [Done]
59. Revisit the seed value for stochastic FOR calculations. Note that the algorithm uses integers, so real values between zero and one do not give us much. [Done] This resulted in a change to the algorithm.
60. Include a CO_2 adjustment for 400 MWa of natural gas fired generation that I am counting in must run. [Done]
61. Put buyback in for the full year. [Done]
62. Revise the discretionary conservation max number upward, because it is binding in the optimizations. [Done]
63. Check the rules for Oregon carrying forward RPS credits. [Done]
64. Pull out code for aggregators off-peak. Ken thinks this will be primarily businesses. Make it all-season. Per KC 3/5/2009. [Done]
65. Make Interruptible all-season. (Keep on-peak.) Per KC 3/5/2009. [Done]
66. Revised costs for IGCC and SCCT, according to Jeff's latest cost estimates. [Done]

Notes on L808

Thursday, March 05, 2009

Primarily fixes to logic. No new data.

67. Change the static variable back to simple local to address the discrepancy between multi- and single-machine results. [Done]
68. Resolve observation that costs were the same across alternative DR programs. [Done] It appears that capability for DR may not have been getting updated correctly. These fixes are detailed at the top of the module mod_PlanningFlex.

Notes on L809

Tuesday, March 17, 2009

69. Reinstitute imbalance charge that I removed in L806. I understand now that it is a special charge invoked only in those cases where we cannot balance the system. Both shortages and surpluses have costs, hence the absolute value on energy. [Done] Actually, this was still in place, although the way it was handled for on-peak was distinct from that for off peak. Reconciled the approaches.
70. Revise hydrogeneration data to 70-year record from the 50-year record. [Done] This includes redefinition of the range of the uniform distributions.
71. Modify electricity price in the presence of carbon penalty. . [Done]
72. Have decision criterion make more intelligent use of least cost alternative information. (See "C:\Backups\Plan 6 Studies\L808\Study of early turbines\Study of early turbines.doc") . [Done] It now evaluates only units in early construction with outstanding construction ahead. Note that I made an additional modification to dfunDecisionCriteria in module mod_PlanningFlex, captured in the model version in this subdirectory, during the run:

```
lCohortCand = lCohortCand + 1

If lCohortCand < R_lNumCohorts Then
   lCohortBeginPeriod = R_lCohortToPeriod(lCohortCand)
Else
   lCohortBeginPeriod = P_lNumPeriods + 1
End If
```

73. Increase constraint on discretionary conservation to 50MWa per quarter. [Done] I had observed that when constrained to levels below 35 MWa per quarter, the premium had no effect because cheap conservation was always available.

Notes on L810

Monday, April 06, 2009

74. Start working on the carbon study.
75. Removed the loss of 600MWa over the 2008 BiOp in hydrogeneration, which had been a vestige of the 5^{th} plan. John and Terry said to make it zero. [DONE]
76. Bring in new loads from Massoud [DONE].
77. Ported over the revised mod_RRP module, with module-level variable to control the step size of the search algorithm. Also made the cap in the price formulas in the workbook (row 218) implement the range name Emergency, so that it is always synchronized with the parameter for maximum price that is at the bottom of the worksheet, in the "Parameters" section. [DONE]
78. Correcting conservation formula references in the first year. [DONE]
79. Set the price cap to $325/MWh. [DONE] This results in a very small, but positive likelihood of hourly prices approaching $400/MWh.
80. Adding a cohort in Sept of 2011. [DONE]

81. Bring in new DR assumptions from Ken (yesterday). [DONE]

    Ken has asked me to lock in the AC through 2011. As the only remaining decision is to continue adding up to 400MW or stop at the 2011 values, which are 200MW, I am reducing the optimizer's decisions to those two choices. Optimization file and decision cells should be modified to reflect this.

    Schedule for Aggregators and Interruptible also changed. Aggregators converter to energy constrained from unconstrained.

    Discovered that the construction cost calculations I used were not correct when fixed cost were associated with periods that were not contiguous. Modified calculations in "Copy of 2008 DR Progress031609_mjs.xls".

82. Develop geothermal resource. [DONE]
83. Develop frame SCCT instead of aero derivative. [DONE]
84. Develop biomass resource. [DONE]
85. Develop nuclear resource. [DONE]
86. Develop MT wind I resource. [DONE]
87. Develop MT wind II resource. [DONE]
88. Insert decision cells with appropriate availability limits for these new resources. [DONE]
89. Add decision criteria for these new resources. [DONE]
90. Add assumption cell for arrival uncertainty of advanced nuclear commercialization. [DONE]

We then went through three aborted runs – as of this writing (4/8/2009 3:33:27 PM) – cleaning up errors with this new data, finding inconsistencies in other data, etc. Some of these are detailed below.

91. Reversed sign of operating costs for geothermal. [DONE]
92. Made the optioning periods and construction periods for the advanced nuclear. In the model, the siting and construction permits have a limited life. If the cohort has not entered committed construction by the time associated with the permit, the permit is cancelled and so is the plant. (This is true for irrespective of any delays that arrival uncertainty might introduce.) Jeff understood the permit clock to be in abeyance as long as there was some construction underway, so he selected permit lives of five years, even though early construction takes six years. We agreed to make the permit lives for nuclear equal to the sum of figures, i.e. eleven years. [DONE]

93. Corrected unresolved forecast name references. (OptQuest removed some forecast names that it thought were duplicates.) . [DONE]

94. Correct early- for late- construction cash flow error: This is a change to the Planning Flex logic. The early construction cash flow rate was being used for late construction instead of the late construction flow rate. This was largely responsible for MT imported wind being so inexpensive. [DONE]

95. Correct construction cost uncertainty disconnect. The new plants were not getting their adjustments, just a 1.0 multiplier. [DONE]

96. West 4 CCCT, Off-Peak, Period 1, (R897) is not tied to the off-peak electricity price. [DONE]

97. Woody Biomass (R302) decision criterion pointing at only one electricity price cell, an on-peak one at that, used the wrong number of hours. Needed FOR adjustment to capability here. [DONE]

98. Advanced Nuclear decision criterion wrong number of hours. Needed FOR adjustment to capability here. [DONE]

99. CCCT energy and valuation function (R491 NP & R972 FP) point to a single cell. Natural gas prices were tied to a single cell, as well. [DONE]

100. SCCT energy and valuation function (R507 NP & R978 FP) point to a single cell. Natural gas prices were tied to a single cell, as well. [DONE]

101. Biomass energy and valuation function (R614 NP & R996 FP) point to a single cell. [DONE]

102. Nuclear energy and valuation function (R627 NP & R1000 FP) point to a single cell. [DONE]

103. IGCC on-peak electricity price tied to 24-month average instead of on-peak price, FOR included in both on- and off-peak calculations, but it is not appropriate if we are using vfunFxdCapNCst to make that calculation. [DONE]

104. Increased Massoud/Jeff's RPS cost to $90/MWh to make them more comparable to wind, geothermal, and biomass. Insufficient time to coordinate RPS costs directly with the cost representations for these resources in the model. [DONE]

105. Reinstituted carbon uncertainty to recreate the basecase. [DONE]

106. Brought over Maury's new (4/6/2009) electricity price forecast. This is about $20/MWh lower in 2029 than his 2/6/2009 forecast. He expects to get another forecast to me before he leaves. [DONE]

107. Made corrections for PTC, RECs, and integration costs in all wind units, biomass, and geothermal. These all get PTC, although biomass gets only 1/2 of PTC. The integration cost for wind is now included with the VOM for all units. I am permitting REC credit for the new MT Wind units, but I believe the rest would get snapped up by utilities to meet their RPS standards. Consequently, they would have to retain their RECs instead of sell them. [DONE]

Notes on L811

Tuesday, March 31, 2009

See the end of this note on a history of the pedigree of the least-risk plan.

This model is spawned from L810e.xls, which in turn stems from L810new.xls (L810b.xls with RPS). L810e.xls has the most current conservation supply curves (see item 2 below) with a 160MWa/year constraint. It differs from the L810 base case, therefore, by a slightly different configuration of cohorts (see "L810a notes.doc") as well as the factors listed below.

108. Bring over the new BPAREGU.out file with correction for independents that I got from John on 3/24/2009. [DONE]

 That file, it turns out, is incomplete. It turned out not to have anything ***but*** hydro independents, had no breakdown for east and west side generation, like the BPAREGU file, etc. John gave me another BPAREGU.out file with correction for independents on 4/24/2009. (He actually sent two. Ignore the first one, which has results for a PNGC study.) [DONE]

109. Revise discretionary and lost op conservation. Limit to 160 MWa/year. Bring over the on- and off-peak energy contributions from the most recent studies. [DONE]

110. Revise the peak/off-peak distribution of conservation energy to 1.231:0.692 from 1.402:0.465. See calculations in "On- and Off-Peak Conservation 090428.xls" [DONE]

111. Change discount factor to 4.9 percent from 5.0 percent. **No, use 5.0 percent per Wally at staff meeting 2:30PM, Monday April 27.** [DONE]

112. Uncertain RPS development? **No, per staff meeting 2:30PM, Monday April 27. Howard will send me some information on higher opt-out rates with loads are lower, but Terry wants us to stick with what we have**. [DONE]

113. Reintroduce Bellingham/Ferndale and Columbia Falls. Modify their capacities and break Columbia Falls into two units with distinct electricity prices. [DONE]

114. Introduce a new carbon distribution, proposed by the GRAC, adopted 4/29/2009 by the staff, and reviewed by the Power Committee [DONE]

115. Revisit all the risk measures to be certain that they are getting properly updated. [DONE]

116. Return the rate metrics to operation. [DONE]

117. Limit geothermal to 13 MW unit per year for 2010 through 2014 and two 13 MW units annually for the remainder of the planning period, for a total of 455 MW of capacity, per Jeff King's 4/23/2009 memo. This is an adjustment to the *.opt file.

Addendum Tuesday, May 26, 2009

Cleaned up back reference in Geo01_01 decision cell and eliminated extra rows and columns. Saved.

Because the base case was disturbed by a power outage, it was restarted, resulting in multiple version of the least-risk plan. None of these differ significantly from the original, so we have stayed with it:

Plan D Discretionary demand response: none

50 Lost opportunity conservation cost-effectiveness threshold, premium over market ($2006/MWh)
3253 Lost opportunity conservation by end of study (MWa)*
10 Discretionary conservation cost-effectiveness threshold, premium over market ($2006/MWh)
2573 Discretionary conservation by end of study (MWa) assuming 160MWa/year limit
5827 Total conservation (MWa)

Cumulative MW, by earliest date to begin construction

	Dec-10	Dec-13	Dec-15	Dec-17	Dec-19	Dec-23	Dec-25
CCCT	0	0	0	**415**	**830**	**830**	**830**
SCCT	0	0	**170**	**170**	**170**	**170**	**170**
Geothermal	0	0	0	**52**	**104**	**156**	**169**
and the *larger* of							
Wind	0	0	**1200**	**1200**	**3000**	**3000**	**3000**
RPS* req	0	**317**	**1182**	**1968**	**2825**	**3959**	**4229**

Figure 1: Plan D in "Schedules for plan resources 090519.xls"

This was originally developed for a web conference, and we have consistently referred to it as the "least-risk plan." It has plan ID 1987, although we have to be careful, because another plan in the second run was also assigned that ID. Fortunately, it does not resemble ours. For example, the LO conservation receives only 20 mill/kWh adder. It is based on the workbook "Analysis of Optimization Run_L811 090502.xls." The second run of L811 (L8112) has a new least-risk plan, ID 189.

The extraction series we began, subdirectory C:\Backups\Plan 6\Studies\L811\L811 Extractions\Qtrly Rates, CO2, and others - LR+LC, has a slightly different least-risk plan from either of these, however. It matches Plan 2067 of the first L811 run and Plan 1 of the second run, L8112. It is evidently our best guess at the time of what the least-risk plan could look like. It has costs slightly lower ($20M) and risks slightly higher ($50M) than the improved least-risk run from L8112.

Proposed Changes for the Final Plan

Thursday, August 06, 2009

This model is spawned from L811.xls. Care was taken to assure that decision cells and forecast cells destroyed by the 5/2/2009 1:26PM power surge were replaced and no unresolved =REF# exist in decision cells.

118. Remove the DR demand buy-back (added 5/1/2009)

119. Add CB forecast cells for
   a. Wind Manifest, RPS requirement, RPS nominal target, and RPS requirement net of model wind
   b. other resource capacity manifest
   c. CO_2_penalty_wT

120. Modify the RPS calculation:
   d. Allocate wind generation according to need, not according to relative size of loads.
   e. Include the construction of geothermal toward net RPS requirements.
   f. Determine if it is desirable and, if so, whether there is some way of getting rid of the bumps.
   g. Investigate the use of FxdCapCst to model the construction cost uncertainty associated with RPS resources.

121. Introduce cost uncertainty for conservation.
122. Verify subAfterGame recalculation is correct:

```
'Clear price adjustment
With Sheet1
  For lMktSubIdx = 0 To P_lNumMktSubPeriods - 1
    P_lEntryPoint = 40
   .Range(.Cells(P_lPriceAdjRow(lMktSubIdx), P_lFirstCol), .Cells( _
            P_lPriceAdjRow(lMktSubIdx), P_lFirstCol + P_lNumPeriods - 1)) = 0
    P_lEntryPoint = 50
   .Range(.Cells(P_lPriceRow(lMktSubIdx), P_lFirstCol), .Cells( _
            P_lPriceRow(lMktSubIdx),   P_lFirstCol + P_lNumPeriods - 1)).Calculate
  Next lMktSubIdx
End With
```

123. Implement the most current rate calculation method. Verify with Massoud his rationale in arriving at 65 mills/kWh today.

124. Carbon penalty for Centralia: Now I believe this was never an issue. Perhaps I got confused because some relative referencing got absolute $ assignments by Olivia, but it was done correctly.

125. Check unqualified cell references, especially in SubAfterGame. (e.g., Sheet1.Range(Cells(….)) .) Remove.

126. Alternative implementation of the perpetuity factor, effective the last manifestation of capacity or CO_2 event, whichever is last.

127. Consider using "L811x2_LR3+.xls", because it has all the range names that I introduced 6/23/2009.

128. Ken and Massoud point out 7/1/2009 3:45:27 PM that discount rate is wrong, 4 percent instead of 5 percent. Performed a study, L811x

Tentative:

129. Make revised wind costs available to the RPS cost calculation. This is trickier than it sounds. Merely tying the annual cost to current construction cost would create an unfair comparison for wind, because wind's cost are locked in at construction. So to should the RPS.

We cannot use the PlanFlex logic because that has cohort timing that does not correspond to RPS additions. The easiest thing might be to do the cost accounting in the workbook, using a structure like supply curves. The real levelized prevailing construction cost rate would be locked in over the life of the commitment.

In any case, wind might be disadvantaged by possible construction delays, while RPS would not. Finally, I don't think it is really an issue, if the only question is timing. We know the costs, whatever they are, should be the same whether utilities built renewables for RPS purposes or cost purposes.

130. Add Supercritical Pulverized coal.
131. Evaluate the value of MT and WA selling RECs versus banking RPS credits.
132. We may want to review the ramp rates for CCCTs and other conventional resources, according to Jeff.

When you are done, we need a new sensitivity model. Bring over the assumption cells from L811's sensitivity model.

Appendix K: The Smart Grid

INTRODUCTION

Smart grid technology has the potential to bring revolutionary changes to the structure and operation of the power system. The technology could make make it possible for customers to participate in solving power system problems to an unprecedented degree. It could cut costs and improve reliability by giving system operators a level of understanding of the minute-by-minute state of the system, and an ability to make quick and effective adjustments in operation, that they have never had before. The changes could affect the power system from generation to transmission to distribution to consumption, and the potential range of change is often compared to that of the Internet.

COMPONENTS OF THE SMART GRID

The technologies that make up the smart grid can be grouped into three general categories: metering, communication, and intelligence and control.

Metering

The metering category includes a wide variety of devices such as: improved versions of utility meters that measure customers' use every few minutes or seconds; sensors in electrical equipment in consumers' houses or businesses; devices that sense load at many points in the transmission and distribution system; and sensors that read the chemical composition of cooling oil in substation transformers, warning of impending equipment failure. The increase in information on the state of the power system could be orders of magnitude, opening many possibilities for increasing the efficiency and reliability of the power system.

Communication

The enhanced data from improved metering must be communicated in order to be useful. That communication can be from the meter to the utility, from one part of the utility to another, or from the utility to customers. Communication technology continues to improve, both in capability and cost. The paths for communication across the power system range from copper wire and fiber optics to a variety of powerline carrier and wireless technologies. The preferred options are likely to vary depending on the particular application, and the relative advantages of the alternatives are still in flux.

Advanced utility meters could play a central role in communication, not only of customers' total use by time interval, but also in passing data from individual appliances and equipment inside the customers' houses and businesses. Such data can also move by such non-utility paths as the Internet.

Intelligence and Control

Improved collection and communication of data on the state of the power system does not guarantee improved operation of the system. The data must also be translated into information that guides decisions, and those decisions must be executed. This processing and execution may be simple and close to the data source, such as a single device in a clothes dryer that senses power system frequency and shuts down the dryer's heater when the frequency drops below a set level. Or it may be more complex; it could incorporate a real time price signal from the power system, current refrigeration equipment requirements, and adaptive control of multiple pieces of equipment to reduce demand for electricity in a grocery store. Or the processing may condense large amounts of hourly load data to summary differences in energy use that can be used to guide efficiency program strategy.

BENEFITS FROM THE SMART GRID

Predicting the long-term effect of these technologies is like predicting the effect of the Internet in 1990, before the introduction of web browsers such as Netscape Navigator.[1] However, significant benefits will likely come in three general areas: demand response, operational efficiency, and capital savings.

[1] The Pacific Northwest National Laboratory conducted a 2003 study of the potential benefits of GridWise technologies, which generally correspond to the smart grid definition used in this appendix. That study arrived at a range of estimates from $46 billion to $117 billion net present value over 20 years (http://www.pnl.gov/main/publications/external/technical_reports/PNNL-14396.pdf). The Rand Corporation conducted an independent study of the same topic in 2004, and arrived at an even wider range of benefits, $32 billion to $132 billion net present value over 20 years http://www.rand.org/pubs/technical_reports/2005/RAND_TR160.pdf). A study done now would probably not be able to narrow the range of benefits greatly.

Demand Response

Demand response is the temporary, voluntary change in electricity use when the power system is stressed. Demand response was first covered in the Fifth Power Plan and is treated in more detail in Chapter 5 and Appendix H of this plan. The general effect of smart grid technologies on demand response is to reduce its cost, increase its flexibility, and improve the verification of demand response. These technologies extend possibilities for demand response in a variety of ways:

1. The smart grid could send signals directly to customers' equipment, not only cycling air conditioners (as is done now) but also controlling such equipment as clothes dryers, water heaters, dishwashers and pool pumps. The extent of modification in each customer's pattern of electricity use could depend on the amount of stress the system faces and that customer's willingness to participate for compensation. The customer could also preprogram the response so that the equipment would respond automatically, unless he or she overrides the programmed response.

2. Devices that use an under-frequency signal to interrupt some appliance functions like clothes dryer heating, automatic defrosting of refrigerators, and water heating are very cheap when installed when the appliances are manufactured. This is a new kind of demand response, an almost instantaneous "last ditch" measure when other measures turn out to be inadequate and the alternative is rolling blackouts.

3. Sensor and communication equipment have helped create an industry of demand aggregators. These aggregators can pool and dispatch consumers' equipment to provide load reductions with response times, reliability, and numbers of megawatts that rival conventional generators.

4. Until now, demand response has mostly been seen as a means of providing peaking capacity and contingency reserves. However, if smart grid technology continues to develop, it could provide ancillary services such as regulation and load following. This possibility is described in more detail later in this appendix and in Appendix H on demand response.

Operational Efficiencies

The smart grid could also enable operational efficiencies in the power system. Advanced metering should reduce the cost of meter reading, of course, but meters with two-way communication should also reduce the cost and delay of locating outages. With appropriate control capability, connecting new customers and disconnecting old ones should be cheaper and quicker.

The smart grid could also make possible significant reductions in energy use. Traditionally, distribution feeders are operated well above 114 volts. This practice wastes energy, but maintains a voltage margin that protects appliances from damage that can occur if voltage drops below 114. Some smart grid technologies allow more precise control of voltage on distribution circuits, allowing voltage to be maintained closer to 114 without risking excursions below 114, reducing line losses and appliance energy use. This practice is documented at in Chapter 4 and Appendix E as “conservation voltage reduction.”

Energy Efficiency

In addition to the efficiencies in the operation of the power delivery system, the smart grid offers possible contributions to energy efficiency at the customer level. The smart grid can give customers more information about their electricity use, which could change how much energy they use or when they use it. It could also influence what appliances they buy.

Improving the quality of information available to efficiency program designers and managers is another potential benefit. Evaluating the effectiveness of efficiency programs has always been crucial, but difficult. The smart grid could make measured results at the customer level available in near real time. This offers great promise for understanding what works and for making improvements in programs quickly.

Capital Savings

The smart grid seems certain to allow existing resources to be used more intensively, reducing future investment requirements. For example, a substation transformer might serve one area with high loads during the day and then switch to serve a nearby area with high loads in the evening (“dynamic management of substation service”), avoiding the cost of a second transformer. Remote sensing and monitoring of line temperatures could also prevent excessive line sag, arcing to ground and the costs of outages and replacing transmission equipment.

NECESSARY DEVELOPMENTS

For smart grid technologies to realize their full potential, the following developments are needed:

Interoperability

Presently, many potential buyers of smart grid equipment have concerns about purchasing equipment that quickly becomes obsolete, concerns that discourage them from making the investment. To some extent, rapid technological advances make this unavoidable. But the risk can be reduced if, for example, meters purchased last year from manufacturer A and meters purchased this year from manufacturer B can both pass data over the same communication system. In that case, while last year’s meters might not be this year’s choice, they are still useful.

This is one example of the benefits of “interoperability,” the ability to use equipment of different designs and manufacturers together. Interoperability is recognized as a difficult and important issue. The Gridwise Architecture Council was formed several years ago to take up this problem and continues to work on it.

Simplified Participation by Consumers

While the smart grid will make a great deal more information available to utility operators and consumers, consumers have limited attention to give to understanding energy issues and making decisions on energy use. Consumers’ participation in demand response programs, for example, will need to be as simple as possible for them. Most consumers will not take time every day to monitor prices that change frequently, but they may be willing to spend time once to choose from a menu of automated responses to future prices. Utilities or aggregators for utilities that make participation easy for consumers will be able to tap those consumers' potential contributions to the economical development and operation of the power system.

Utility Operators' Experience with the Smart Grid and Consumers

Some smart grid technologies such as conservation and voltage reduction can be adopted by the utilities themselves so their evaluation by utilities should be relatively straightforward. However, many smart grid technologies like air conditioning cycling or critical peak pricing require consumer participation, which introduces an extra element of uncertainty to their evaluation. Until utilities and regulators have some experience with such technologies, they are unlikely to be widely adopted. Pilot programs and the experience gained from early adopters will help to encourage utilities to plan on these technologies as resource alternatives for the future.

THE SMART GRID OF THE FUTURE

Imagining what a smart grid would look like conveys a sense of the scale of change that is possible.

Meeting Peak Load

Spiking demand due to a summer heat wave could be mitigated by short interruptions in air conditioning, rotating among customers in a coordinated pattern so individual customers experience little or no change in their comfort. Other end uses such as refrigerator defrosting, clothes dryers, and swimming pool pumps could be included in a coordinated control strategy.

Notification and Location of Outages

The smart grid could notify utilities of system outages immediately, rather than receiving phone calls from customers (perhaps hours after the outage occurs). Smart meters could let the utility know very precisely where the problem is without requiring a repair crew to search it out.

Integration of Plug-in Hybrids

Plug-in hybrid electric vehicles (PHEV) could be combined and controlled to function as a storage battery for the power system. Many parties have suggested this possibility in which the combined PHEV batteries act as a large storage battery for the power system when they are connected to the grid, at home, at work or elsewhere. This aggregate battery accepts electricity when the cost of electricity is low, for instance at night, and gives electricity back to the system when the cost is high during hot afternoons or cold snaps.[2] The smart grid could coordinate[3] this exchange.

[2] One such description of how PHEV could contribute to the power system is at the Regulatory Assistance Project's web site www.raponline.org under the title "Plug-In Hybrid Vehicles, Wind Power, and the Smart Grid."

Water Heaters for Peak Load, Load Following, and Energy Storage

Smart grid technologies could help coordinate the use of water heaters to: 1) meet peak load; 2) provide regulation and/or load following services; and 3) store energy. In this case, there is enough data to estimate the range of benefits to the power system. For the sake of illustration, it is assumed that the whole resource is available. Although it is unlikely to have full participation, if smart grid controls are installed at the factory, it seems likely that eventually a large percentage of water heaters could be coordinated.

Currently, there are about 3.4 million electric water heaters in the region. If each heater has a heating element of 4,500 watts, the total connected load is about 15,300 megawatts. Of course, water heaters are not all on at the same time; load shape estimates suggest that the total water heating load on the system ranges from about 400 megawatts to about 5,300 megawatts, depending on the season, day, and hour.

Controlling Water Heaters to Meet Peak Load

In normal operation, the heating elements of a water heater come on almost immediately when hot water is taken from the tank, to heat the replacement (cold) water. But if the elements don't come on immediately, the water in the tank is stratified, hot at the top and cold at the bottom. Opening a hot water faucet continues to get hot water from the top of the tank until the original charge of hot water is gone. This means that heating the replacement water can be delayed, reducing load for some time without depriving water users of hot water. Based on the load shape estimates cited above, the maximum available reduction ranges from about 400 to about 5300 megawatts, depending on when it is needed.[4]

Smart grid technology could sense when water heaters are at risk of running out of hot water and begin heating replacement water, while also postponing heating in other water heaters that still have adequate reserves of hot water. Peak load could be reduced without depriving consumers of hot water when they want it. This reduction could be maintained for a few hours, after which all water heaters would be restored to normal operation, increasing total load while the average temperature in each heater is raised to its normal level. Figure K-1 illustrates the effect of reducing water-heating load on total load, and the recovery of water heaters when the load reduction is no longer needed.

In the figure, the 2010 forecast annual load was combined with 2002 weather to create hourly loads for 2010. Solid lines show the January 4, 2010 hourly forecast loads for both water heating ("WH") and "Total." The broken lines for "Modified Total" and "Modified WH" show the effect of reductions in water-heating load of 1,000, 1,300, and 900 megawatts for the hours between 7:00 a.m. and 10:00 a.m. These reductions would result from delaying reheating of hot water used in those hours. The broken lines then show increases of 700, 1,200, and 1,300 megawatts in the hours from 10:00 a.m. to 1:00 p.m. as water is reheated to return all water

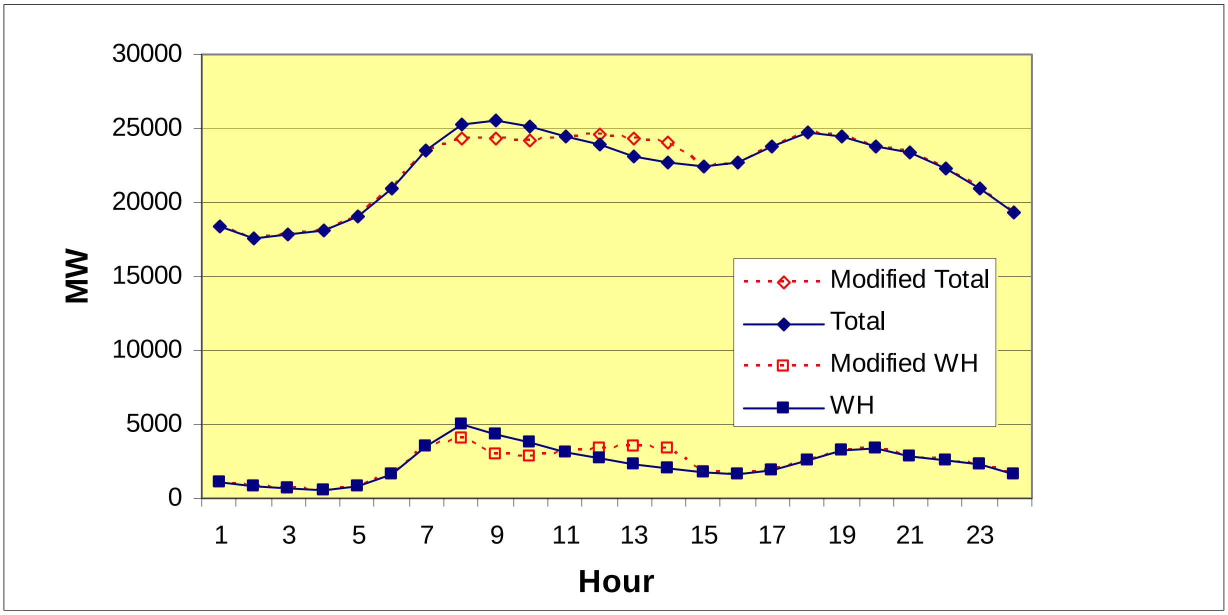
[3] A common assumption is that this coordination includes a requirement that the charge in the battery at the end of the day is sufficient to get home. Even if this requirement is not met, however, PHEV have the ability to charge their own batteries, so that they are not stranded.

4 Water heating load tends to be high when total load is high, so that the available water heating reductions to help meet peak total load are nearer to 5,300 megawatts than 400 megawatts.

heaters to their original average temperatures. The reductions could have been as much as the entire water-heating load, for example, 5,000 megawatts in hour 8 (7:00 a.m. to 8:00 a.m.).

The broken lines illustrate the expected pattern: a reduction in both water-heating and total load, followed by increased load as the water heaters require more energy to restore their original storage temperatures.

Figure K-1: Peak Reduction Illustration - Controlled Water Heaters



Controlling Water Heaters to Provide Regulation or Load Following

Energy users can help the power system by reducing load as shown in Figure K-1, but reductions alone are not enough to keep the system in balance; load must also be increased when the system needs it. These adjustments up or down are referred to as regulation or load following. Water heaters, unlike most other loads, are able not only to reduce load temporarily but can also temporarily increase load as well.

While water heaters are usually set to maintain water at 120 degrees Fahrenheit, they can operate at significantly higher temperatures, and were commonly set at 135 degrees before the energy crisis of the 1970s. Raising the storage temperature to, for example, 135 degrees does not increase the total number of gallons of hot water in the tank, but it does increase the total energy stored in those gallons. A mixing valve would ensure that enough cold water is added to the 135-degree water as it leaves the tank to make sure water at the tap never exceeds 120 degrees for safety concerns.

A water heater that is set at 135 degrees will provide more gallons of (mixed) 120-degree water than the same tank set at 120 degrees. Therefore, a water heater with appropriate controls and a mixing valve could accept extra energy from the power system, and store it in the form of higher-temperature water. Then when its hot water is used, the water heater could “return” the energy to the power system in the form of reduced load by heating replacement water only to the original 120-degree setting.

Smart grid technology could enable system operators to control water heaters in both directions in real time, as unscheduled variations in load or generation occur. Water-heating load could, in principle, increase up to the maximum connected load,[5] or decrease down close to zero, but the duration of the increases and decreases would be limited. The duration of load increases would be limited by the allowed rise in water temperature above its normal setting. The duration of load reductions will be limited by the reserves of heated water in the tanks.[6]

Fortunately, regulation and load following require both increases and decreases in load within the hourly operating schedule of the power system. These increases and decreases tend to balance each other over the operating hour. Therefore, these services do not usually require large net increases or decreases over several hours.

Controlling Water Heaters for Energy Storage

With smart grid controls and communication, water heaters could also act as virtual batteries, storing electricity generated at times when there is little or no demand for it, and releasing it when it has more value. An example of such a condition is 4:00 a.m. during the spring runoff, when demand for electricity is low, river flows cannot be reduced, not much non-hydro generation is operating, and winds are increasing. System operators have few good options – they can cut hydro generation by increasing spill, which loses revenue and can hurt fish, or they can require wind machine operators to feather their rotors, losing both market revenue and production tax credits.

In such conditions, water heaters could absorb extra energy by raising the temperature of stored water and return it to the system by reheating to a lower temperature later. If, for example, the temperature is raised from 120 degrees F. to 135 degrees F, 3.4 million 50-gallon water heaters can accept 6,198 megawatt hours[7] of energy and store it at the cost of roughly 24 megawatt-hours per hour from higher standby losses. Figure K-2 is similar to Figure K-1, except that January 2, 2010 loads are used. The “Modified WH” and “Modified Total” broken lines illustrate an increase of 3,099 megawatts in water heating and total load in each of the hours from 3:00 a.m. to 5:00 a.m. and reductions over the hours from 7:00 a.m. to 11:00 a.m. as the water heaters return to their original temperatures.[8]

In contrast to the pattern in Figure K-1 of reductions in load followed by increases, the pattern in Figure K-2 is the opposite -- increases in load as the water heaters absorb the energy to be stored, followed by decreases in load as fewer gallons of cold water need to be heated to 120 degrees.

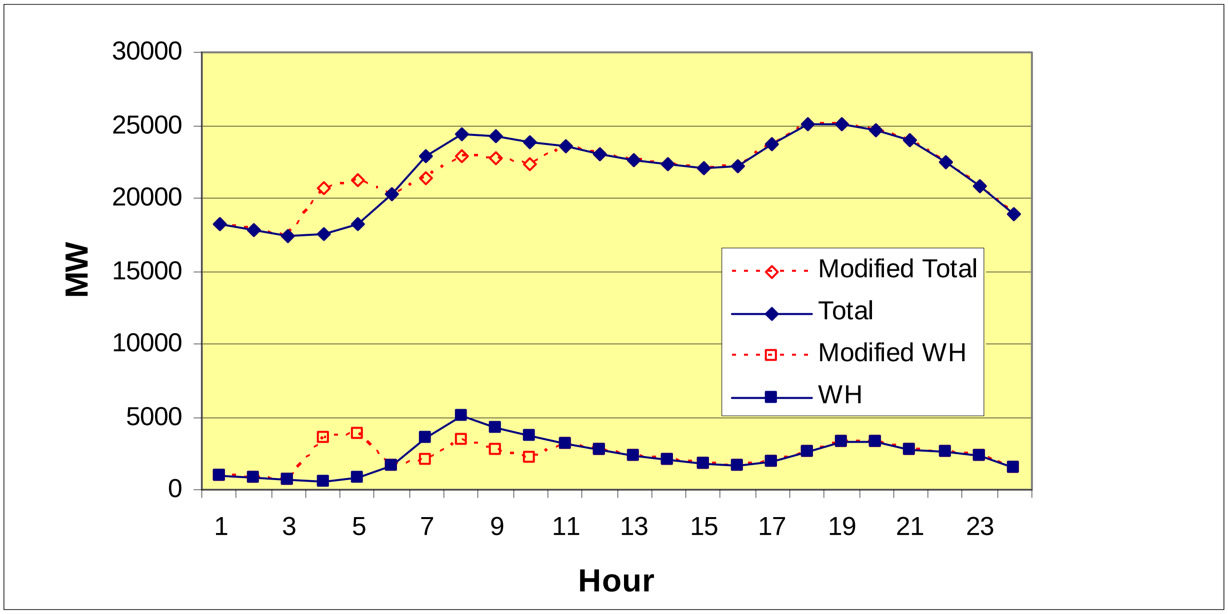
[5] This would imply an increase of 14,900 megawatts in hours when water-heater load is at its minimum (15,300 – 400) or 10,000 megawatts when load is at its maximum (15,300 – 5,300). As a practical matter, the system will never need this much load for regulation or load following, and calling on the full amount could well cause local distribution problems in any case. It’s enough to say that several thousand megawatts could be available.

[6] If consumers find themselves without hot water very often, they are likely to withdraw from the program.

[7] This rise could result from an increase in load of 6,198 megawatts for an hour, or an increase in load of 3,099 megawatts for two hours, etc. If we allow water temperatures to rise more, water heaters can provide more regulation or load following flexibility.

[8] The return of the energy to the system could be managed to occur later in the day (for example in the high-load hours from 5:00 p.m. to 9:00 p.m.) if that was more useful to the power system. The extra standby losses would amount to about 264 megawatt hours, or about 4.3 per cent of the stored energy.

Figure K-2: Energy Storage Illustration
Controlled Water Heaters



The practicality of water heating as a source of load following and/or energy storage depends on the cost of the sensors, communication, and controls that have been assumed in this illustration. It may be that the technology is already sufficiently developed to make load following with water heaters practical if it can be built into the heaters at the factory instead of retrofitted after the heaters are installed in customers's houses. In that case, the new federal administration's announced willingness to act aggressively on new appliance standards and to encourage smart grid technologies offers the opportunity to see this possibility become reality.

Appendix L: Climate Change and Power Planning

SUMMARY OF KEY FINDINGS

Climate change presents a daunting challenge for regional power planners. There are at least two ways in which climate can affect the power plan. First, warming trends will alter electricity demand and change precipitation patterns, river flows and hydroelectric generation. Second, policies enacted to reduce green house gases will affect future resource choices. There remains a great deal of uncertainty surrounding both of these issues. While climate change cannot be modeled with precision for the Pacific Northwest, it is possible to make general predictions about potential changes and, as a result, recommend policies and actions that could be adopted and implemented today to prepare for potential future impacts. This appendix describes the first of these issues, namely how climate change may affect demand for electricity and production of hydroelectric generation.

Global climate change models all seem to agree that temperatures will be higher but they disagree somewhat on levels of precipitation. Some models suggest that the Northwest will be drier while others indicate more precipitation in the long term. But all the models predict less snow and more rain during winter months, resulting in a smaller spring snowpack. Winter electricity demands would decrease with warmer temperatures, easing the Northwest's peak requirements. In the summer, demands driven by air conditioning and irrigation loads would rise and potentially force the region to compete with southern California for electricity resources.

All of these changes have implications for the region's major river system, the Columbia and its tributaries. More winter rain would likely result in higher winter river flows. Less snow means a smaller spring runoff volume, resulting in lower flows during summer months. This could lead to many potential impacts, such as:

- Putting greater flood control pressure on storage reservoirs and increasing the risk of winter flooding;
- Boosting winter production of hydropower when Northwest demands are likely to drop due to higher average temperatures;

- Reducing the size of the spring runoff and shifting its timing to slightly earlier in the year;
- Reducing late spring and summer river flows and potentially causing average water temperatures to rise;
- Jeopardizing fish survival, particularly salmon and steelhead, by reducing the ability of the river system to meet minimum flow and temperature requirements during spring, summer and fall migration periods;
- Reducing the ability of reservoirs to meet demands for irrigation water;
- Reducing summer power generation at hydroelectric dams when Northwest demands and power market values are likely to grow due to higher air conditioning needs in the Northwest and Southwest; and
- Affecting summer and fall recreation activities in reservoirs.

The potential effects of climate change on river flows and the operation of the hydroelectric system are still being refined but indications are that the region will see a slowly evolving shift in flow pattern. Analysis summarized in this appendix identifies the potential range of changes and the corresponding impacts to hydroelectric production. Some suggestions are made regarding actions that could be implemented to mitigate potential impacts to reliability and potential increases to fish mortality. However, due to the uncertainty surrounding the data and models used for climate change assessment, no actions (other than to continuing to monitor the research) are recommended in the near term.

The effects of the uncertainty surrounding a potential carbon penalty and other climate policies have been incorporated into the Councils portfolio analysis and have appropriately influenced the recommended resource strategy and action plan. Further details of that analysis are provided in Chapter 10 of the power plan.

BACKGROUND

Dozens of groups around the world are actively investigating global climate change and its potential impacts.[1] Most of these organizations have developed complex computer models used to forecast long-term changes in the Earth's climate. These models are used primarily to estimate effect of greenhouse gases on temperature and precipitation. The most sophisticated of these models are known as "general circulation models" or GCMs. They take into account the interaction of the atmosphere, oceans and land surfaces.[2] Each of these models has been "calibrated" to some degree and crosschecked against other such models to give us more confidence in their forecasting ability.

Scientists are confident about their projections of climate change for large-scale areas but are less confident about projections for small-scale areas. This is largely because computer models used

[1] http://stommel.tamu.edu/~baum/climate_modeling.html
[2] http://gcrio.org/CONSEQUENCES/fall95/mod.html

to forecast global climate change are still ill equipped to simulate how things may change at smaller scales. Forecasts on a global level are of little use to planners in the Northwest. Thus, a method of "downscaling" the output from these models has been developed.[3] This downscaled data matches better with hydrological data used to simulate the operation of the Columbia River Hydroelectric Power System. By using temperature and precipitation changes forecast by global climate models but downscaled for the Northwest, an adjusted set of potential future water conditions and temperatures can be generated. The adjusted water conditions can be used as input for power system simulation models, which can determine impacts of climate change to the Northwest hydroelectric power system. Temperature changes lead to adjustments in electricity demand forecasts.

There are at least 20 different global models that simulate future changes in temperature. Every one of these models, to varying degrees, projects a warming trend for the Earth. Each uses modern mathematical techniques to simulate changes in temperature as a function of atmospheric and other conditions. Like all fields of scientific study, however, there are uncertainties associated with assessing the question of global warming and, as we are often reminded, a computer model is only as good as its input assumptions. The effects of weather (in particular precipitation) and ocean conditions are still not well known and are often inadequately represented in climate models -- although all play a major role in determining our climate.

Scientists who work on climate change models are quick to point out that they are far from perfect representations of reality, and are probably not advanced enough for direct use in policy implementation. Interestingly, as computer climate models have become more sophisticated in recent years, the predicted increase in temperature has gotten smaller. Nonetheless, most climatologists concur that the warming trend is real and could have serious impacts worldwide.

TEMPERATURE AND HYDROLOGICAL CHANGES

For the Northwest, models show that potential impacts of climate change include a shift in the timing and perhaps the quantity of precipitation. They also show less snow in the winter and more rain, thus increasing natural river flows. Also, with warmer temperatures, the snowpack is projected to melt earlier, which would result in lower summer river flows. More discussion regarding these possible impacts and their implications is provided in the next section.

Preliminary downscaled hydrologic and temperature data for the Northwest was obtained from the Joint Institute for the Study of Atmosphere and Ocean (JISAO)[4] Climate Impacts Group[5] at the University of Washington. This preliminary data is for a single climate change scenario, which is a composite of results from several climate models used by the CIG and roughly represents an "expected" or average forecast. Results and conclusions provided in this Appendix reflect this preliminary composite data set.

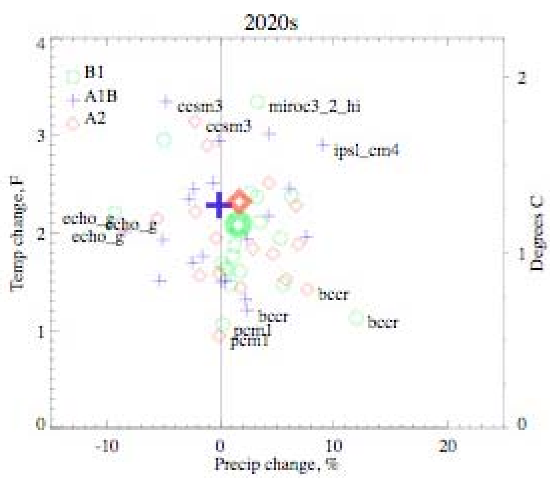
[3] Wood, A.W., Leung, L. R., Sridhar, V., Lettenmaier, Dennis P., no date: "Hydrologic implications of dynamical and statistical approaches to downscaling climate model surface temperature and precipitation fields."
[4] http://tao.atmos.washington.edu/main.html
[5] http://tao.atmos.washington.edu/PNWimpacts/index.html

The CIG has developed an improved set of data that incorporates a more detailed geographical scale and a wider range of scenarios but unfortunately, it is not yet available in a form that can be used in Council planning models. The CIG is currently adapting results from several of its climate scenarios for use by Council and Bonneville models. The expectation is that a representative subset of scenarios will be modified for Council analysis. This subset of scenarios should adequately represent the full range of projections from all 20 climate models used by the CIG. Council expects this new data to be available sometime this year.

A summary of temperature and precipitation change forecasts from the 20 global climate models used by the CIG (for the 2020 time period) is shown in Figure N-1. In that figure, the X-axis represents forecast change in precipitation and the Y-axis forecast change in temperature. Three conclusions can be drawn from the figure below; 1) each model shows a net temperature increase, 2) most but certainly not all models show a slight increase in annual precipitation, and 3) there is great variation in both the temperature and precipitation forecasts.

The climate change scenario used for Council analysis presented in this appendix falls somewhere near the center of all the points in Figure N-1. The forecast average annual temperature increase for the region is about 2 degrees Fahrenheit by 2030 and the annual average river volume is slightly lower than today.

Figure L-1: Temperature and Precipitation Change Forecasts[6]



Other caveats regarding the analysis in this appendix are specified below:

- Adjusted stream flows are based on the 1930 to 1998 water conditions.
- No correlation was assumed between temperature increases and river flows, that is, only a single monthly temperature increase was assumed for each water condition.

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[6] Borrowed from CIG Publication No. 145, Hamlet, Alan, F., July 3, 2001: "Effects of Climate Change on Water Resources in the Pacific Northwest: Impacts and Policy Implications," JISAO Climate Impacts Group, University of Washington.

- Operating guidelines (rule curves) for the hydro system were not adjusted (i.e. flood control was not adjusted for the change in spring runoff forecast nor were firm drafting limits re-optimized).

- Each water condition was given an equal likelihood of occurring.

- The analysis was designed to examine climate change impacts (electricity demand and river flows) for the year 2030 applied to today's power system.

Precipitation, Snow Pack and River Flows

Most global climate models indicate that the Northwest will become hotter across each month of the year. If this is true, then less precipitation will fall as snow in fall and winter months, thus reducing the amount of snowpack in the mountains. More rain in winter months means higher stream flows during those months. However, with a smaller snowpack, the spring runoff will correspondingly be less, translating into lower river flows in summer. In addition, the peak of the spring runoff is projected to occur as much as a month earlier. Figure L-2 shows monthly average river flows at The Dalles Dam based on the historical record from 1929 to 1998 and the effect of climate change to those flows (by 2045 to better illustrate the effect). Figure L-3 highlights the impact by plotting the change in average flow at The Dalles Dam by month.

While these changes are drastic, over 100,000 cubic feet per second in June, they are not expected to occur until 2045. As will be demonstrated in a later section, annual changes to temperature and consequently river flows from today through 2045 are expected to grow gradually and in a non-linear fashion (changes growing more rapidly later in the period). In fact, climate induced changes to annual river flow in the near term are difficult to detect due to the large natural variance in annual weather patterns.

Figure L-2: Average Unregulated Flow at The Dalles (2045)

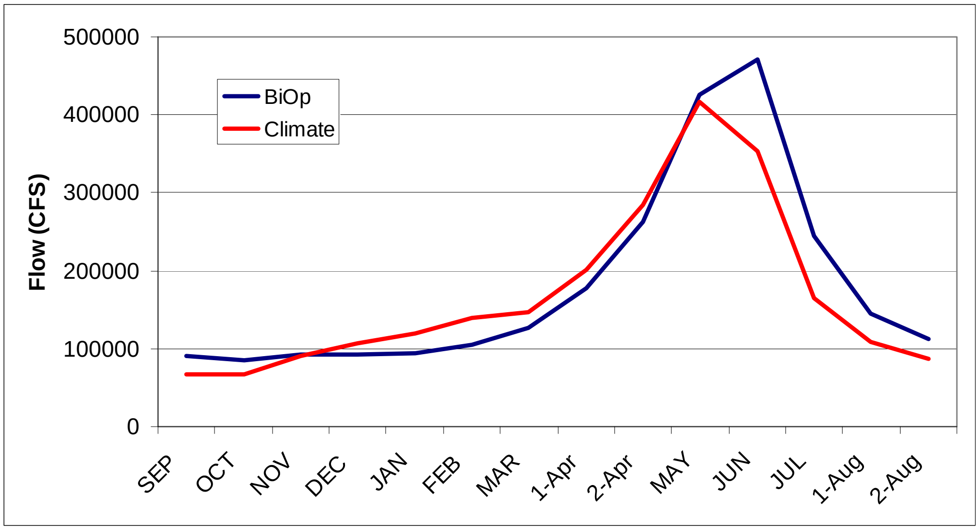
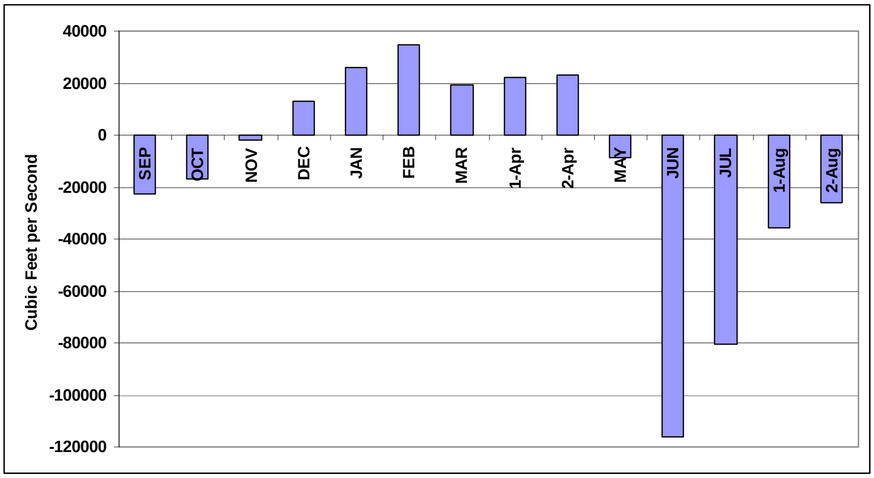


Figure L-3: Forecast Change in Unregulated Flow at The Dalles (2045)



Electricity Demand

There is a clear relationship between temperature and electricity demand. For electrically heated homes, as the temperature drops in winter months, electricity use goes up. Even for non-electrically heated homes, electricity use in winter tends to increase due to shorter daylight hours. Based on data from the Northwest Power Pool, for each degree Fahrenheit the temperature drops from normal, electricity demand increases by about 300 megawatts. This value has stayed fairly consistent over the past several years, in spite of the fact that a smaller percent of new homes are being built with electric heat. If this relationship holds true, then a two-degree increase in average temperature over winter months should translate into about a 600-megawatt decrease in electricity demand.

However, the Council does not rely on the Power Pool to estimate fluctuation in demand caused by temperature changes. The Council uses a recently developed load model to assess demand variations as a function of temperature. Results of that relationship are presented in Figures L-4 and L-5. Based on those results, a two-degree increase in the average monthly temperature for December results in about a 600 average-megawatt decrease in regional load – essentially the same conclusion that the Power Pool would make. However, that relationship doesn't hold up in January, when a two-degree increase in temperature yields just over a 400 average-megawatt decrease in load.

It should be noted that the Power Pool's rule-of-thumb temperature/load relationship is primarily focused on peak hourly loads and not on monthly average loads. For an average *monthly* increase in temperature of two degrees in winter months, the associated average *peak hourly* temperature will be higher. From Figure L-4, a two-degree increase in monthly temperature for December yields a peak hourly load decrease of just over 1,000 megawatts. If the Power Pool's relationship holds, this means that the average change in the peak hour temperature should be a little over three degrees.

Summer loads appear to be a little more sensitive to temperature than winter loads. Again using the results plotted in Figures L-4 and L-5, a slightly lower than three degree increase in the average July temperature (see Figure L-7) results in an average monthly load increase of over 1,000 average megawatts and a peak hour load increase of nearly 3,000 megawatts.

Figure L-4: Impact of an Annual 2-Degree Temperature Increase on Peak Loads

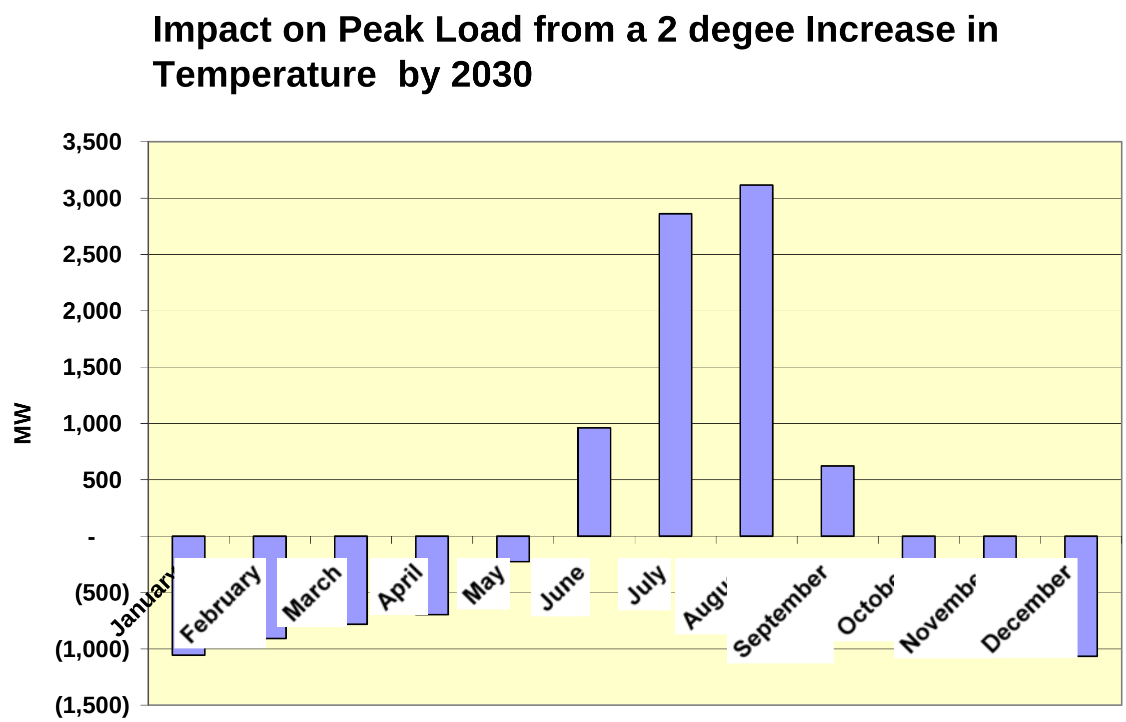
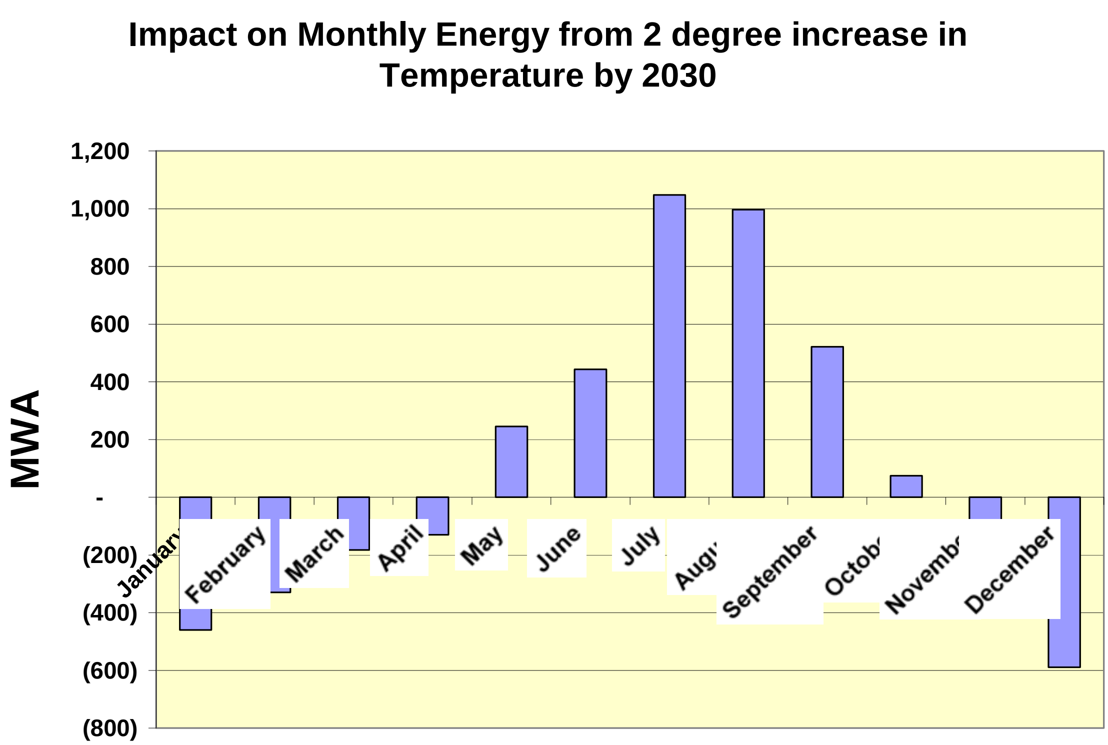
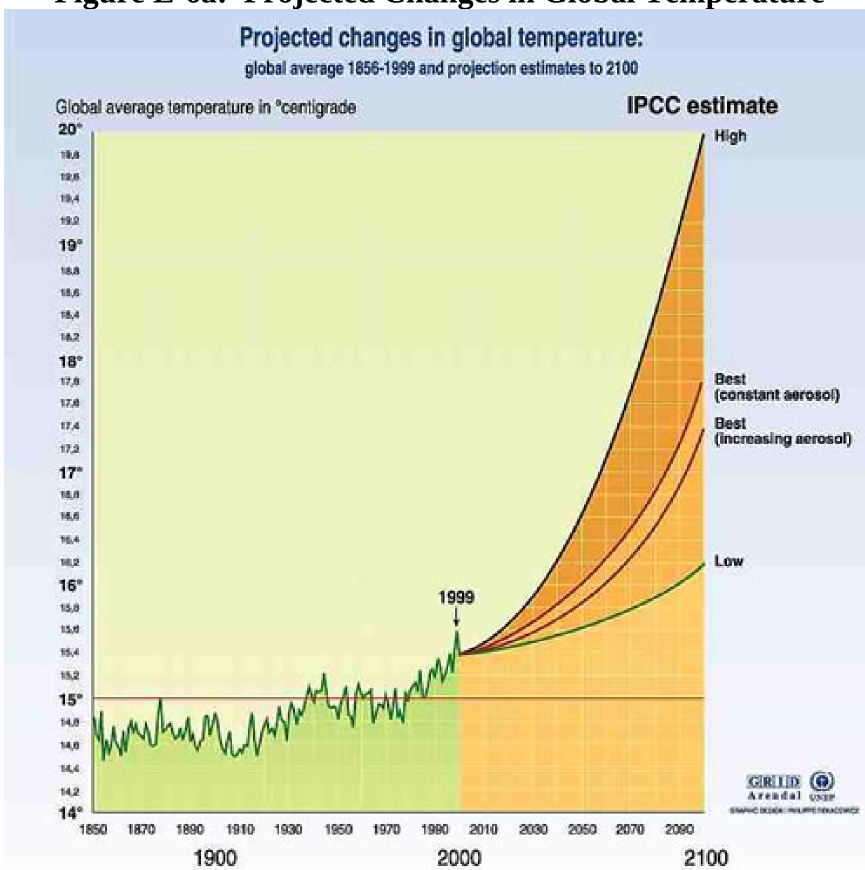


Figure L-5: Impact of an Annual 2-Degree Temperature Increase on Monthly Loads



Using preliminary data from the University of Washington, the projected increase in annual temperature caused by climate change was interpolated to be about 2 degrees Fahrenheit by 2030. However, this forecast temperature increase is not expected to grow linearly. Based on current data used in global climate models, it appears that climate induced temperature increases should grow gradually, as illustrated in Figure L-6a. This general trend for global temperature increase was used to derive a projected annual temperature change for the Northwest. Those results are shown in Figure L-6b. In addition, annual temperature increases are not distributed uniformly across each month of the year. Figure L-7 shows the monthly distribution of temperature change for an annual increase of 2 degrees.

Figure L-6a: Projected Changes in Global Temperature



Actual global temperatures are plotted on the graph for years 1856-1999 and IPCC estimates of temperature are plotted for years 1999-2100. Different lines on the graph between 1999 and 2100 indicate high, low, and best estimates of future temperature.

Courtesy GRIDA/UNEP

Figure L-6b: Projected Climate Induced Annual Temperature Change through 2030

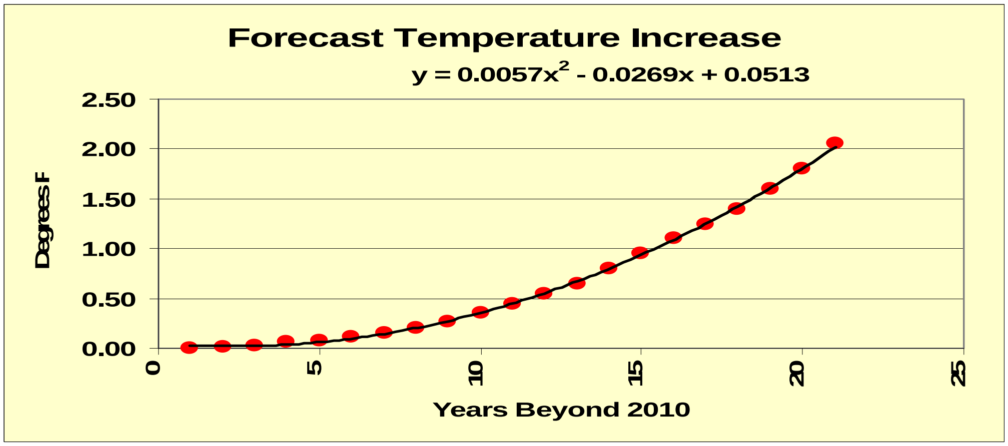
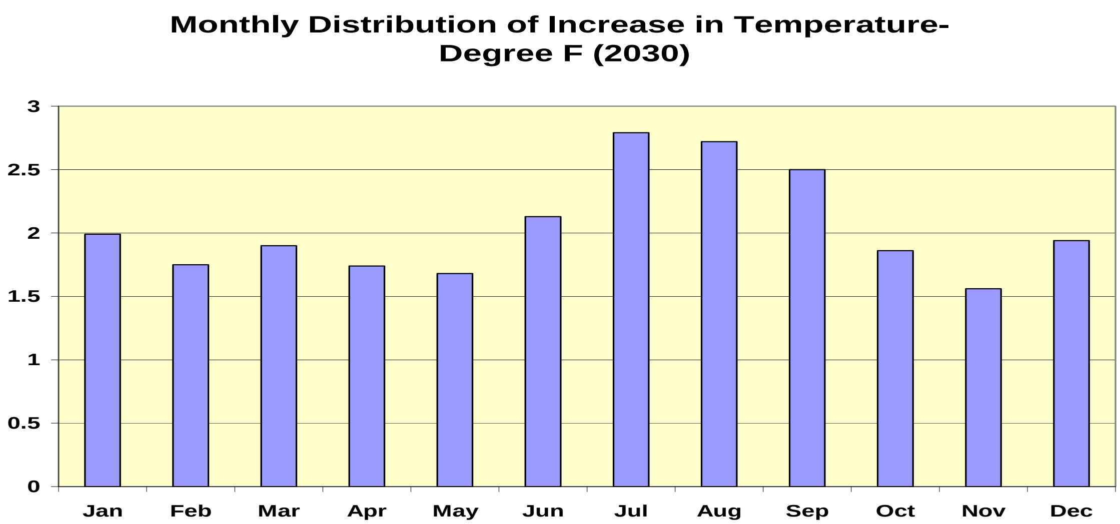


Figure L-7: Projected Changes in Monthly Average Temperatures by 2030



The projected increases in annual and monthly temperatures are converted to cooling and reduced heating degree days for each state. The cooling and heating degree days are measured as the average of annual cooling or heating degrees days for years 1985 through 2007. The cooling and heating degree days vary by state. For example, under normal conditions, the annual cooling degree day value for state of Idaho is about 531 degrees. In the preliminary climate change scenario, the normal cooling degree days is forecast to increase to 904 degrees by 2030. Each state's normal and 2030 forecast cooling and heating degree day values are shown in Table L-1 below. The summer cooling degree days is projected to increase at an average annual rate of 1.6 percent and the winter heating degree days is declining at an average annual rate of -0.3 percent.

Table L-1: Cooling/Heating Degree Days by State

	Cooling degree Days (Normal) (1985-2007)	Cooling degree Days (2030)	Heating degree Days (Normal) (1985-2007)	Heating degree Days (2030)
ID	531	904	6589	5788
MT	290	500	7826	6875
OR	271	468	4927	4328
WA	221	381	5277	4635

As a result of climate induced increases in temperatures, the annual demand for energy is forecast to increase by 120 average megawatts by 2030. However, that conclusion is somewhat misleading since the resulting January and December load is expected to decrease on the order of 400 to 600 average megawatts, while the July and August load is expected to increase by about 1,000 average megawatts for each month.

Regional summer peak load is projected to increase by over 3,000 megawatts by 2030, while the winter peak load is expected to decline by about 1,000 megawatts. The impact of temperature on summer and winter loads, especially peak hourly loads, is not equivalent because of the assumed penetration rate of air-conditioning and space heating. Air-conditioning penetration rates continue to increase over time, while the penetration rate of space heating is already at 100 percent.

Power planners have rarely had to concern themselves with summer problems because the Northwest has historically not been a summer peaking region and because of the great capacity of the hydroelectric system. Based on current assessments of power supply adequacy (Chapter 13), the existing power system can adequately supply additional climate induced demand but only in the near term. With continued demand growth, especially in summer, and increasing operating constraints on the hydroelectric system, it appears that by 2013 the region may be faced with an inadequate summer supply. Adding conservation and wind resources, as proposed by this power plan, extends the period of adequacy for the region and will give planners more time to assess climate impacts and actions to mitigate for them.

IMPACTS TO THE POWER SYSTEM

Methodology

To assess climate change impacts to the power system, the Council used two computer models. The first, GENESYS, simulates the physical operation of the hydroelectric and thermal resources in the Northwest. The second, AURORA©, forecasts electricity prices based on demand and resource supply in the West.

The GENESYS[7] computer model is a Monte Carlo program that simulates the operation of the northwest power system. It performs an economic dispatch of resources to serve regional demand. It assumes that surplus northwest energy may be sold out-of-region, if electricity prices are favorable. And, conversely, it will import out-of-region energy to maintain service to firm demands.

[7] See www.nwcouncil.org/GENESYS

The model splits the northwest region into eastern and western portions to capture the possible effects of cross-Cascade transmission limits. Inter-regional transmission is also simulated, with adjustments to intertie capacities, whenever appropriate, as a function of line loading. Outages on the cross-Cascade and inter-regional transmission lines are not modeled.

The important stochastic variables are hydro conditions, temperatures (as they affect electricity loads) and forced outages on thermal generating units. The model typically runs hundreds of simulations for one or more calendar years. For each simulation it samples hydro conditions, temperatures and the outage state of thermal generating units according to their probability of occurrence in the historic record.

The model also adjusts the availability of northern California imports based on temperatures in that region. Non-hydro resources and contractual commitments for import or export are part of the GENESYS input database, as are forecasted prices and costs and escalation rates.

Key outputs from the model include reservoir elevations, regulated river flows and hydroelectric generation. The model also keeps track of reserve violations and curtailments to service. Physical impacts of climate change are presented as changes in elevations and *regulated* flows due to the adjusted *natural* flows discussed earlier. Economic impacts are calculated by multiplying the change in hydroelectric generation with the forecasted monthly average electricity price.

Hydroelectric Generation and Cost

More rain in winter months means higher stream flows at a time when electricity demand is highest. This in combination with the fact that demand for electricity is likely to decrease due to warmer winter months, should ease the pressure on the hydroelectric system to meet winter electricity needs. In fact, excess water (water than cannot be stored) may be used to generate electricity that will displace higher-cost thermal resources or be sold to out-of-region buyers.

While the winter outlook appears to be better from a power system perspective, a more serious look at flood control operations is warranted. Some global climate models indicate not only more fall and winter precipitation in the Northwest but also a higher possibility of extreme weather events, including heavy rain. This should prompt the Corps of Engineers to examine the potential to reexamine flood control evacuations prior to January, when they currently begin. Evacuation of water stored in reservoirs during winter months for flood control purposes will add to hydroelectric generation and further reduce the need for thermal generation during that time.

However, any winter power benefits could be offset by summer problems. With a smaller snowpack, the spring runoff will correspondingly be less, translating into lower river flows. As mentioned earlier, lower flows (and less hydroelectric generation) may not be a Northwest problem now because of the excess hydroelectric system capacity. Except for some small portions of the Northwest, the region experiences its highest demand for electricity during winter months. However, as summer temperatures increase so will electricity demand due to anticipated increases in air-conditioning use. In addition, potentially growing constraints placed on the hydroelectric system for fish and wildlife benefits may further reduce summer peaking capability. It is also possible that summer air-quality constraints may be placed on Northwest fossil-fuel burning resources, which would also decrease the peaking capability. The projected increase in Northwest summer demand along with potential reductions in hydroelectric generation will force the Northwest to consider resource options for summer needs sooner rather than later.

Figure L-8 shows the expected average regulated flow changes in 2045 due to climate impacts. This chart is very similar to Figure L-3, which shows the expected differences in natural (or unregulated) flows. Hydroelectric generation is proportional to river flow, thus it is no surprise that the average change in hydroelectric generation for 2030 (as shown in Figure L-9) has the same monthly shape (note that the flow changes in Figure L-8 are for 2045 and the generation changes in Figure L-9 are for 2030). It should be noted that this analysis was performed without modifications to operating rule curves, such as flood control. The effect of this is to exaggerate the flow reductions in summer. By not adjusting flood control elevations in spring, reservoirs will be evacuated to a greater degree than necessary to protect for floods because the snowpack, in general, will be smaller. This results in reservoirs being emptier by the end of June, typically when flood control limits expire. To estimate the magnitude of this problem, one can compare the difference in end-of-June average elevation between the climate change case and the base case. On average, reservoirs will hold about 900,000 acre-feet less water in the climate change case. This translates into an average summer flow (July and August) of about 7,200 cubic feet per second. This means that spring flows would be lower and summer flows higher by about this much. However, the flows in Figure L-8 and the generation in Figure L-9 do not reflect this adjustment, nor does the assessment of cost later in this section. This omission should be corrected in future analyses.

Figure L-8: Projected Regulated Flow Changes at The Dalles Dam (2045)

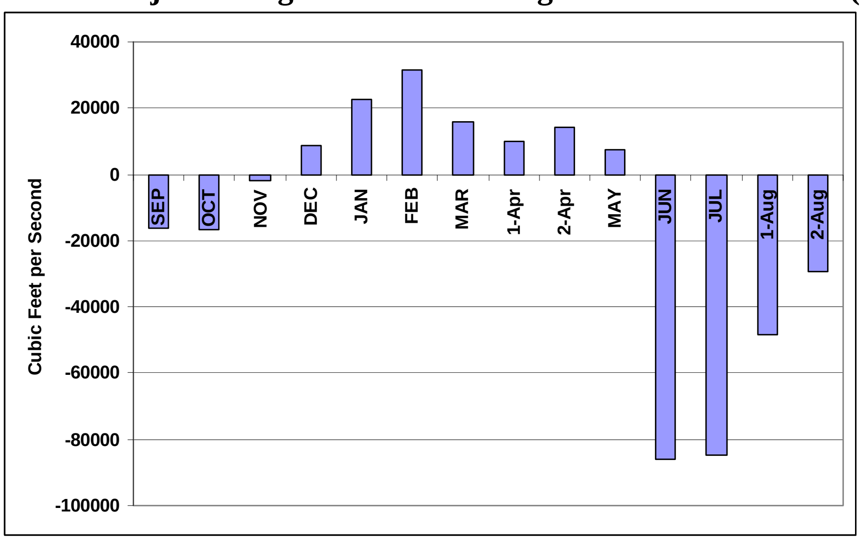
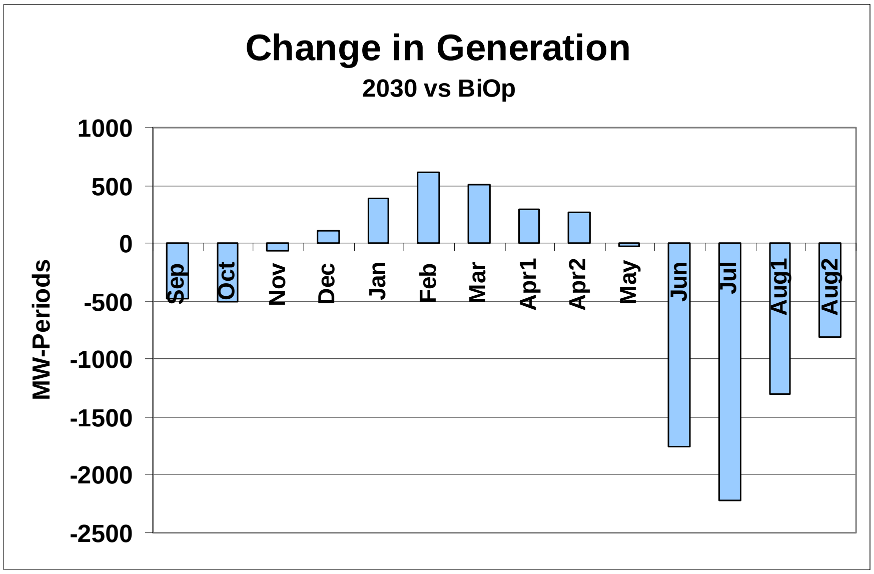
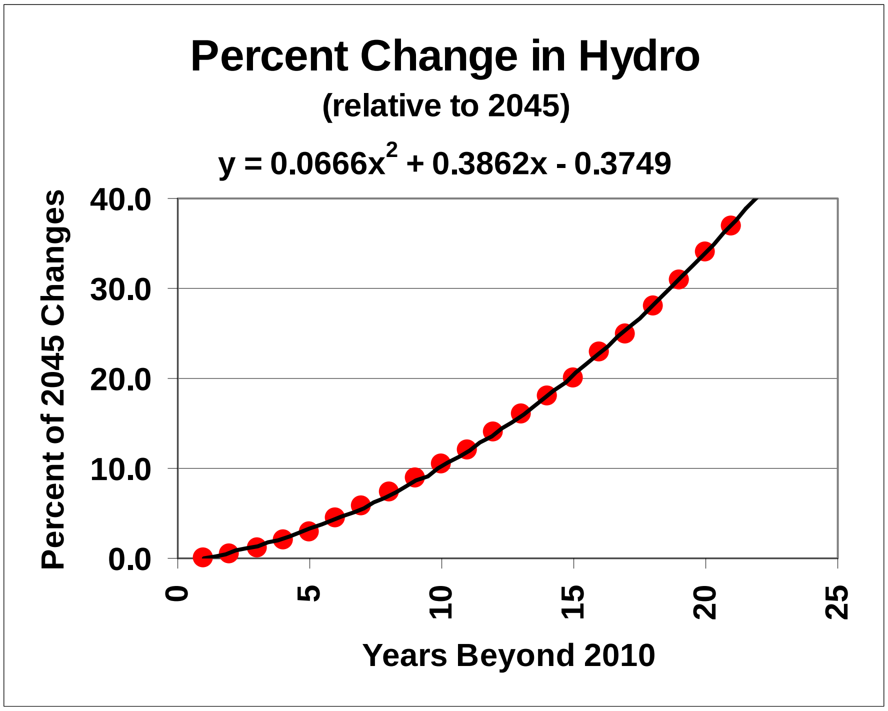


Figure L-9: Change in Hydroelectric Generation for 2030



As with projected temperature increases over time, river flow changes will also occur gradually. Figure L-10 illustrates the assumed changes to hydroelectric generation through 2030. It should be emphasized that the curve in Figure L-10 does not imply that hydroelectric generation will grow over time. What it does reflect is that portion of the 2045 change in generation that is expected in the years between 2010 and 2030. Climate change data that was actually analyzed was for the year 2045 and included the natural flow adjustments (as illustrated in Figure L-2). As with the temperature changes over time, an assumption was made that natural flow changes (and thus hydroelectric generation changes) would occur gradually. The generation changes in question are similar to those shown in Figure L-9 but reflect values for the year 2045. Figure L-10 indicates what percent of the 2045 change occurs in any given year, whether the (monthly) change is positive or negative. In fact, the data for Figure L-9 was derived by taking the average monthly generation changes for 2045 and applying a factor of about 37 percent (the value in Figure L-10 for year 2030).

Figure L-10: Projected Annual Hydroelectric Generation Change Relative to 2045



Using the above mentioned assumption regarding climate change impacts to hydroelectric generation, we derive the data for Figures L-11 and L-12. Those figures show the expected change in average hydroelectric generation for July and February over the study horizon period. By 2030, average February generation is expected to increase by about 600 average megawatts or about 4 percent. July generation is expected to decrease by about 2,200 average megawatts or about 17 percent.

Figure L11: Average Winter and Summer Hydroelectric Generation Change

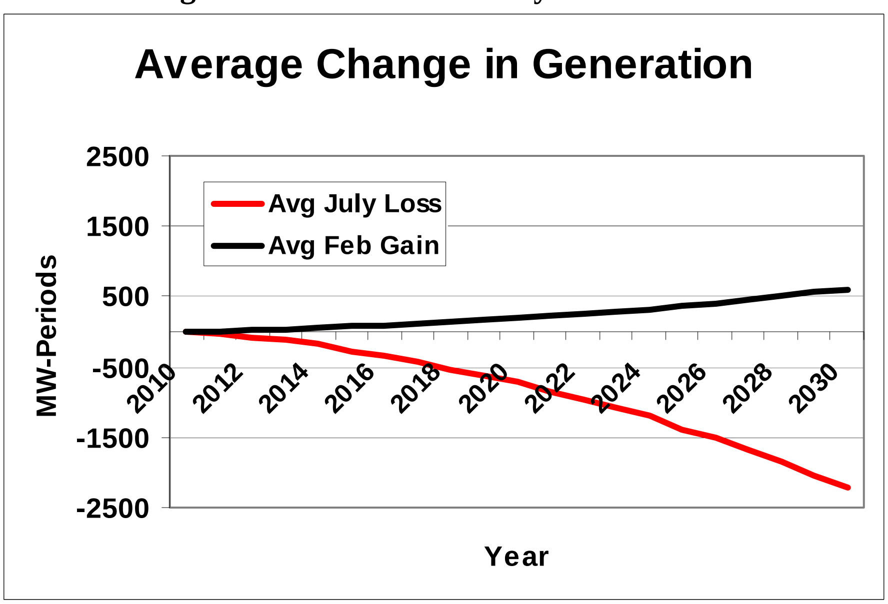
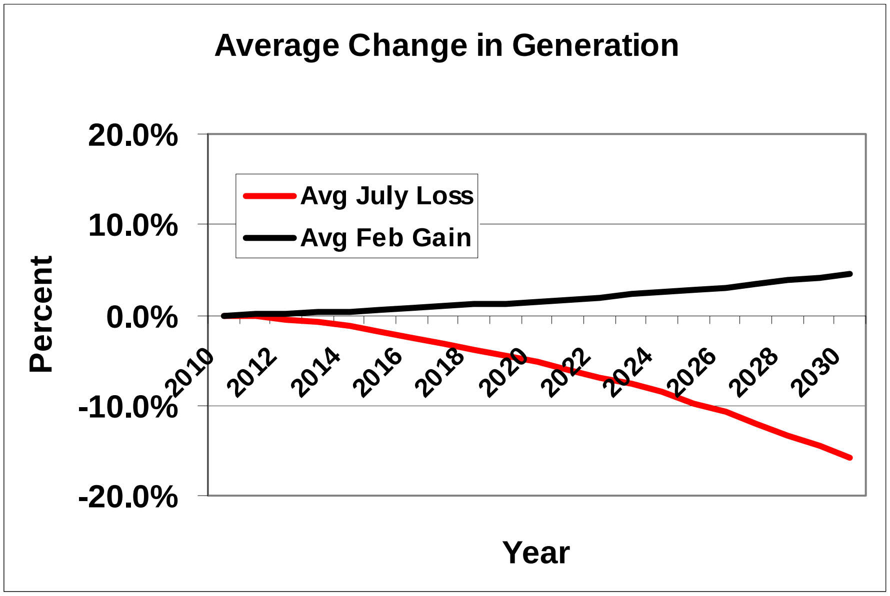


Figure L-12: Percent Annual Hydroelectric Generation Change



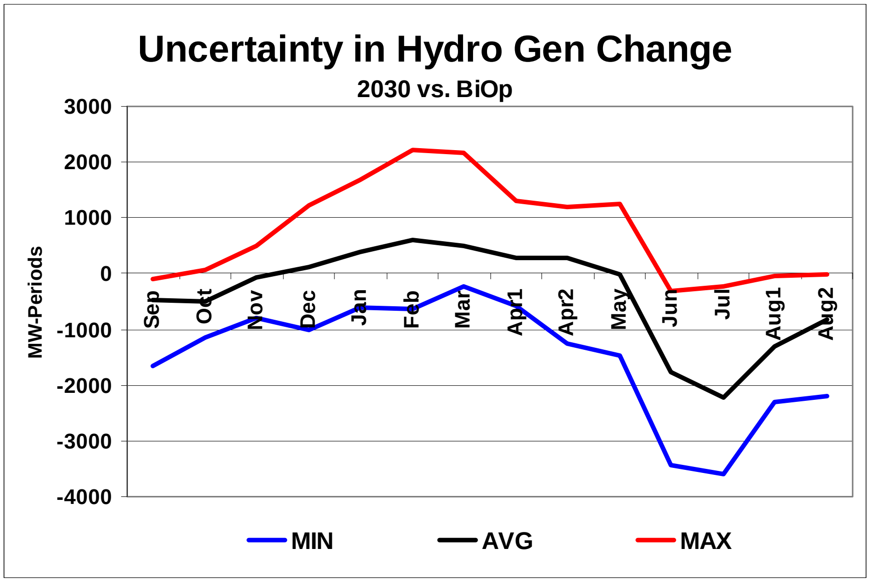
At the same time, winter demand is expected to decrease by about 600 average megawatts by 2030 while summer demand is expected to increase by about 1,000 average megawatts. Table L-2 summarizes these results, which when added together show a net load/resource balance increase of 1,200 average megawatts in winter and a net load/resource balance decrease of 3,220 average megawatts in summer. From an adequacy point of view, the winter season gets better while the summer becomes more stressed. In principle, these load/resource balance differences can be used to adjust the adequacy assessment calculations in Chapter 13. The net effect of doing so does not change the conclusion in that chapter, which is; that on an annual energy basis the region's power supply is adequate. A similar assessment of changes in winter and summer peaking reserve margins can be done and applied to the assessed values for peaking supply adequacy. This has not be done for a number of reasons but primarily because the climate change data used for this analysis is preliminary and is too uncertain to use for resource planning at this time.

Table L-2: Net Impacts to Energy Load/Resource Balance 2030 (MWa)

Changes to:	Winter	Summer
Generation	600	(2,220)
Demand	(600)	1,000
Net (G-D)	1,200	(3,220)

Assessing the true power system cost of climate change is difficult because in order to do so would require the development of two complete resource plans; one with climate change and one without. The Council's Portfolio Model does not currently have the capability to incorporate climate change impacts to hydroelectric generation and load as random variables. (This topic is discussed in more detail in the last section). However, an approximate power system cost can be made by assuming that changes in hydroelectric generation are prices at market values. Thus, months showing higher generation represent a net benefit to the region and months with lower generation represent a cost. In principle, generation changes for each month and for each water condition would be priced at the corresponding market electricity price (which varies by month and water condition). The uncertainty in the change in hydroelectric generation is illustrated in Figure L-13, which captures the minimum, maximum and average generation for each month.

Figure L-13: Uncertainty in Climate Induced Generation Change



In wet years, like the maximum curve in Figure L-13, the region stands to make money. And conversely in dry years, like the minimum curve, the region will likely have to purchase from the market to serve all of its loads. The average or expected cost of this scenario is on the order of \$120 million dollars for 2030 climate conditions (but priced at today's prices). Figure L-14 shows the monthly distribution of costs, which has a similar pattern as the generation change chart (Figure L-9) and the flow change chart (Figure L-8). Applying the minimum and maximum ranges for changes to hydroelectric generation yields the graph in Figure L-15, which shows the range of potential power system costs for this scenario.

Even though a power system cost can be estimated using these techniques, no serious conclusion can be drawn as to whether climate change will be an economic benefit or cost to the region. There remains too much uncertainty in the data to make that assessment. We can conclude, however, that the net benefit or cost is directly related to the total volume of water that flows through the hydroelectric system on an annual basis. That parameter appears to be more important in assessing costs than the volume of water that is shifted from summer to winter.

Figure L-14: Estimated Power System Cost of Climate Change

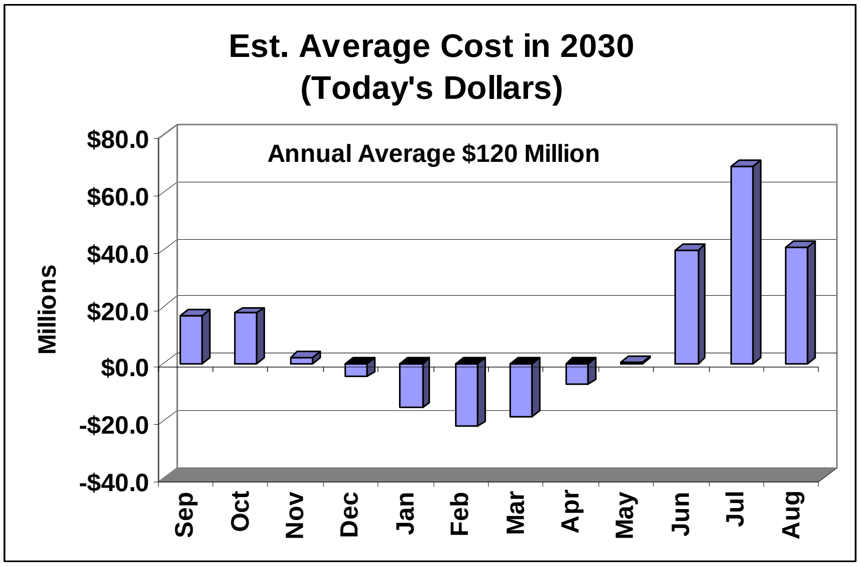
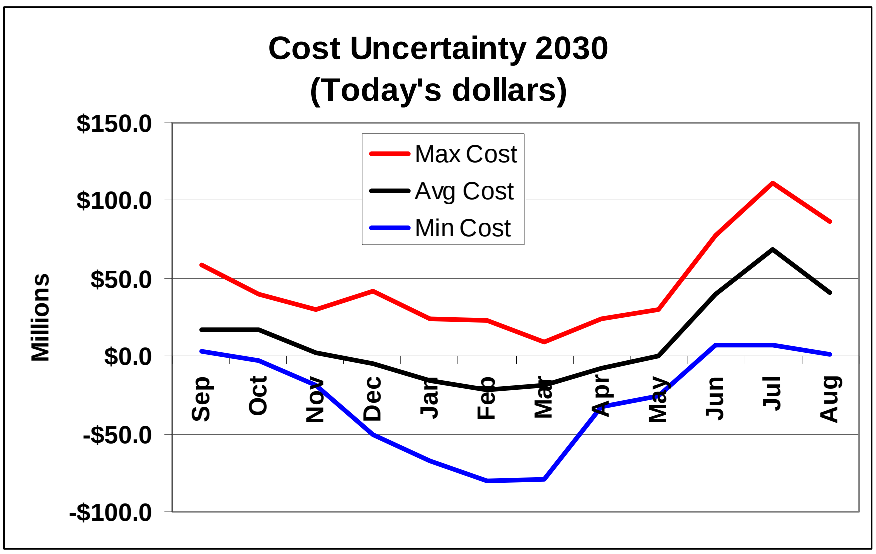


Figure L-15: Climate Change Cost Uncertainty



Other Impacts

Because river flows are likely to decrease is spring and summer, smolt (juvenile salmon) outmigration (journey to the ocean) and adult salmon returns will be affected. Lower river flows translate into lower river velocity and longer travel times to the ocean for migrating smolts. Lower river flows also mean that water temperature may increase, another factor contributing to smolt mortality.

Besides the impacts to river flows, hydroelectric generation and temperatures, climate change will affect the Northwest's interactions with other regions. Currently, both the Northwest and Southwest benefit from differences in climate. During the winter peak demand season in the Northwest, the Southwest generally has surplus capacity that can be imported to help with winter reliability. In the summer months, the opposite is true and some of the Northwest's hydroelectric capacity can be exported to help the Southwest meet its peak demand needs. This sharing of resources is cost effective for both regions.

Under a severe climate change scenario the Northwest could see increased summer demand with greatly decreased summer hydroelectric production. It is possible that the Northwest could find itself having to plan for summer peak needs as well as for winter peaks. In that case, the Northwest would no longer be able to share its surplus capacity with the Southwest. This would obviously have economic impacts in the Southwest where additional resources may be needed to maintain summer service. This would likely raise the value of late summer energy, thereby increasing the economic impact of climate change to the northwest.

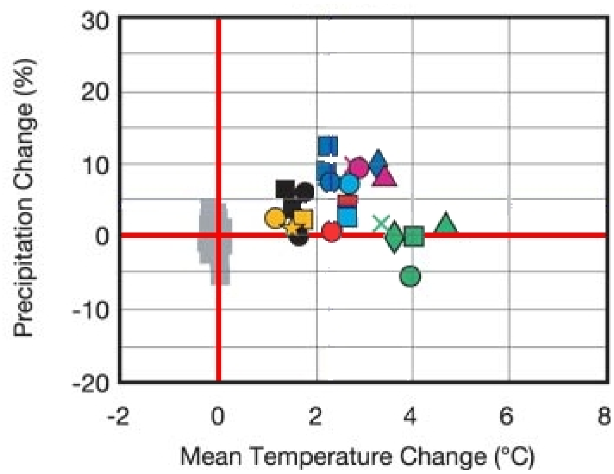
All of these impacts assume that no operational changes are made to the hydroelectric system. As described below in the section on mitigating actions, changes in the operation of the hydroelectric system may be significant. In which case, the impacts mentioned above may become better or worse. For example, if reservoirs were drafted deeper in summer months to make up for lost snowpack water, the increase in winter hydroelectric generation shown above would be reduced. A more realistic assessment of the physical and economic impacts must be done with an anticipated set of mitigating actions.

MODELING CLIMATE CHANGE AS A RANDOM VARIABLE

Ideally, climate change uncertainty and its impacts to hydroelectric generation and loads would be included as one of the random variables in the Council's Portfolio Model. Unfortunately, this cannot be done at this time for several reasons. First, the data required to do so is not available. Second, even if the data were available, the Portfolio Model is not equipped to accommodate it. Third, the relative likelihood of occurrence for each of the scenarios analyzed by the 20 Global Climate Models is not known.

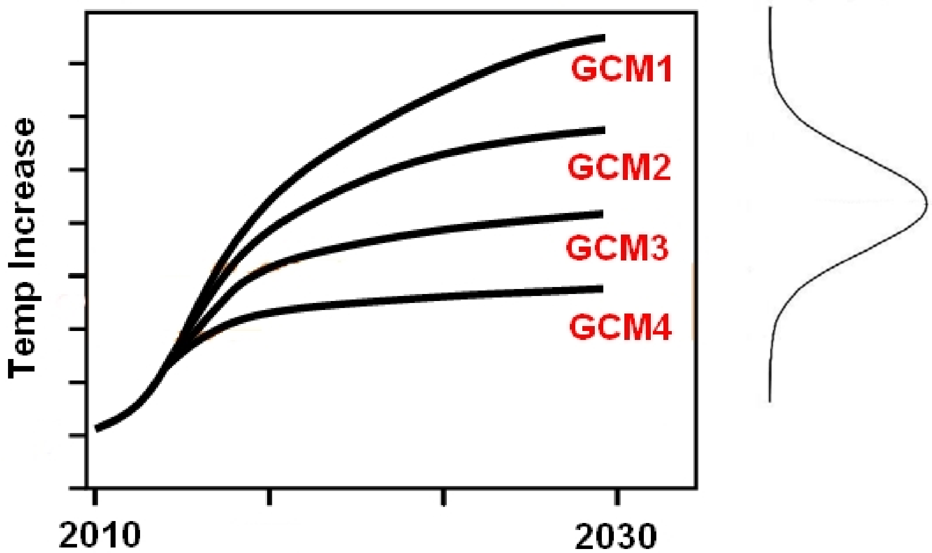
Figure L-16 below (similar to Figure L-1) plots the mean forecasted temperature and precipitation changes for a number of climate change scenarios. The data in Figure L-16 is not representative of analyses for the Northwest but rather is simply an illustration of the uncertainty surrounding these models. Each point in this graph represents the result of a single climate change scenario analysis for a particular future year. The gray area in this graph represents the normal uncertainty range for current climate conditions. Not surprisingly, the uncertainty in the climate change analyses (measured as the size of the spread of points) is much larger than the uncertainty surrounding current climate. As noted previously, all scenarios show a higher forecasted temperature but not all forecast higher precipitation.

Figure L-16: Temperature and Precipitation Changes for Various Models



Recall that the Portfolio Model is a Monte Carlo computer program that assesses average power system cost and economic risk for many different resource strategies (or plans). Each resource strategy is, in essence a potential supply curve for available new resources, including conservation, over the study horizon period. Each resource plan is examined over many different potential futures for the Northwest. Each future covers a 20-year period and draws from many random variables, including load, water conditions, electricity and fuel prices and carbon penalties to assess costs. In order to incorporate climate change uncertainty into the Portfolio Model as a random variable, the relative likelihood of occurrence for each climate scenario must be known. Then for each future examined, one particular climate change profile would be selected (i.e. one of the points in Figure L-16) as one of the many random variables used for that particular future. This concept is illustrated graphically in Figure L-17. In this figure, the mean forecasted temperature increase per year over a 20-year period is plotted for several different climate change scenarios (GCM1 through GCM4). In this example, a probability distribution is assigned to the set of scenarios, shown as the bell curve to the right of the graph. In this example, GCM2 and GCM3 are more likely to occur than GCM1 or GCM4 and thus they would be selected more often in the Monte Carlo simulation. Unfortunately, a probability distribution for climate change scenarios does not yet exist.

Figure L-17: Illustrative Probability Distribution for Climate Model Results



But that is not the only problem. Consider for a moment just a single climate change scenario. That scenario would provide a temperature change forecast and a river flow change forecast for a single future year. For the Portfolio Model, those forecasts would have to be provided for every year of the study horizon period, meaning that, in theory, the climate models would have to be run for every year between now and 2030. In practice, it may be possible to interpolate the results from a climate model run for 2030 back to today but we would need to understand how to do that interpolation (e.g., it will not likely be linear).

Furthermore, because the Portfolio Model draws from a 70-year water record to select the water condition for each calendar year simulated, that 70-year water record would have to be adjusted for all 20 years of the study period. Once a water condition is selected for a particular year, it becomes the "observed" set of natural flows. Additionally, all operating rule curves (flood control, refill curves and critical rule curves) associated with each set of water conditions would have to be adjusted accordingly. But in order to do so properly, a synthetic *forecast* for the "observed" water conditions must somehow be developed. Remember that in real life rule curves are calculated only knowing forecasts for anticipated river flows. Even though the adjusted river flows from climate model runs are technically forecasts, once the model chooses a particular water condition, it becomes the "observed" set. If related rule curves were based on that set of "observed" flows, the model would have perfect knowledge of what was coming and would not be a good representation of how the real world works.

And unfortunately, there are other data related problems that will have to be overcome in order to add climate change as a random variable to the Portfolio Model. Those problems relate to how load growth is calculated and how hydroelectric peaking capability is assessed. But in spite of these seemingly insurmountable hurdles, progress is being made. Bonneville is working on a method to develop a set of synthetic flow forecasts to be used to calculate adjusted rule curves. We have had discussions with the CIG about assigning probabilities to various climate change scenarios. Staff has had internal discussions about how climate change scenario results could be interpolated to fill in years of missing information. It is not clear at this time whether all of these problems can be resolved prior to the development of the next power plan but because climate change can have such a significant impact on the power supply, the Council recommends continued effort in this area.

RECOMMENDATIONS

The development of this power plan for the Northwest incorporates actions intended to addresses future uncertainties and their risks to service and to the economy. Such uncertainties include large fluctuations in electricity demand, fuel prices, changes in technology and increasing environmental constraints. The effects of climate change are twofold; 1) future temperature changes will affect electricity demand and hydroelectric generation and 2) policies directed at reducing green house gas emissions will affect resource operation and cost.

Though the physical effects of climate change remain imperfectly understood, the Council has examined them and recommends that research continue in this area. In terms climate policy, the Council has explicitly included assumptions regarding potential carbon penalties and renewable resource portfolio requirements into its Portfolio Model. A more detailed description of those policies and their impacts is provided in Chapter 10.

While no immediate actions regarding reservoir operations are indicated by this preliminary analysis of physical impacts of climate change, the region should begin to examine reservoir operations that could potentially mitigate those impacts. Some of those actions may include:

- Adjusting reservoir rule curves to assure that reservoirs are full by the end of June
- Allowing reservoirs to draft below current end-of-summer limits
- Negotiating with Canada to examine the potential for more summer releases from Canadian reservoirs
- Using increased winter streamflows to refill reservoirs
- Exploring the development of non-hydro resources to replace winter hydroelectric generation and to satisfy higher summer needs.

Appendix M: Integrating Fish & Wildlife and Power Planning

SUMMARY OF KEY FINDINGS

The Columbia River Basin hydroelectric system is a limited resource that is unable to completely satisfy the demands of all users under all circumstances.[1] Conflicts often arise that require policy makers to decide how to equitably allocate this resource. The Council's *Columbia River Basin Fish and Wildlife Program* and *Electric Power and Conservation Plan* must provide measures to "protect, mitigate, and enhance fish and wildlife affected by the development, operation, and management of [hydropower] facilities while assuring the Pacific Northwest an adequate, efficient, economical, and reliable power supply."

The Council's current assessment[2] indicates that the regional power supply can reliably provide actions specified to benefit fish and wildlife (and absorb the cost of those actions) while maintaining an adequate, efficient, economic and reliable energy supply. This is so even though the hydroelectric operations specified for fish and wildlife have a sizeable impact on power generation and cost. The power system has addressed this impact by acquiring conservation and generating resources, by developing resource adequacy standards, and by implementing strategies to minimize power system emergencies and events that might compromise fish operations.

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[1] Some of the many uses of the Columbia River hydroelectric system include flood control, power generation, irrigation, recreation, navigation and protection for fish and wildlife.
[2] See http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc.

On average, hydroelectric generation is reduced by about 1,170 average megawatts, relative to an operation without any constraints for fish and wildlife.3 For perspective, this energy loss represents about 10 percent of the hydroelectric system's firm generating capability4. It is difficult to assess the cost of this loss because mitigation actions taken specifically for this loss cannot be identified. The region has acquired conservation and other resources since 1981 for many different reasons, fish and wildlife impacts being only one. However, the cost of fish and wildlife operations to the power system can be approximated. Using a long-term amortized replacement resource cost, the fish and wildlife program cost to the power system is on the order of $300 million per year.

Sometimes, however, it becomes important to assess the cost of program measures using market prices. For example, Bonneville gets a credit for expenses made for non-power related operations. For this assessment, Bonneville appropriately uses market prices to determine its power purchase costs related to fish and wildlife operations. Using this approach, the annual average power system cost of the program is in the range of $450 million. In addition to operational costs, fish and wildlife related capital expenses and other program costs, while variable, are expected to average $287 million5 per year over the next 5 years. Bonneville estimates that replacing lost hydropower capability and funding direct fish and wildlife program expenditures have increased Bonneville's costs from $750 to $900 million per year. That amount represents about 20 percent of Bonneville's annual net revenue requirement.6 These impacts would definitely affect the adequacy, efficiency, economy and reliability of the power system, if they had been implemented over a short term. However, this has not been the case. Since 1981, the region has periodically amended fish and wildlife related hydroelectric system operations and, in each case, the power system has had time to adapt to these incremental changes.

Looking toward the future, there remain a number of uncertainties surrounding the operation of the hydroelectric system, which must be addressed in the development of the power plan. These uncertainties can have both positive and negative effects. For example, spillway weirs offer the potential to reduce bypass spill while providing the same or better passage survival. On the other hand, current bypass spill levels are under litigation and are likely to be increased. Climate change has the potential to alter river flows, which affect both power production and fish survival. The potential of dam removal or of operating reservoirs at lower elevations would further reduce power production. The Council recommends that the region continue to monitor fish and wildlife activities and to continue to develop better analytical methods to assess both power and biological impacts.

Outside of the Council's own power planning effort, there is no forum or process in the region to address long-term planning issues related to the integration of power planning and fish and wildlife operations. The Council would support the creation of an open forum where fish and wildlife managers and power planners could jointly explore strategies to improve both fish and

[3] The comparison study, which includes no actions for fish and wildlife, is represented by hydroelectric operations prior to 1980.
[4] Firm hydroelectric generating capability is about 11,900 average megawatts (2007 Bonneville White Book) and is based on the critical hydro year, which is currently defined to be the 1937 historical water year.
[5] Taken from Bonneville's 2008 Integrated Program Review, the capital budget estimate for the next five years represents the maximum cost; actual expenditures may be less.
[6] Bonneville's annual net revenue requirement is on the order of $3.5 billion (Bonneville's 2007 Annual Report).

wildlife benefits and hydroelectric power operations. In such a forum, synergistic effects between fish and wildlife operations and power planning could be examined.

INTRODUCTION: INTEGRATING THE FISH AND WILDLIFE PROGRAM AND POWER PLANNING UNDER THE NORTHWEST POWER ACT

The many storage and hydroelectric facilities built in the Columbia River Basin provide a number of benefits to the citizens of the Pacific Northwest and Canada. This includes the fact that, on average, the US portion of the hydroelectric system provides nearly 75 percent of the electricity needs for the northwest.[7] Development of the hydroelectric system, however, has also had adverse effects on salmon and steelhead and other native species of fish and wildlife in the basin. In the Northwest Power Act, Congress directed the Council to lead an on-going effort to find the best ways to operate the hydrosystem and further develop the region's power supply so as to improve the survival of fish and wildlife affected by the system while also meeting the region's growing electricity demands with the least-cost conservation and generating resources.[8]

The Northwest Power Act directs the Council to integrate planning for fish and wildlife and electric power resources in a recurring two-step process. The first step is to develop or amend the fish and wildlife program; the second is to include the fish and wildlife program in the power plan, developing a coordinated resource plan to accommodate the fish and wildlife requirements and meet any increasing demand for electricity. This is the Council's central fish and wildlife/power "integration" function under the Power Act, and yet it is largely ignored in the usual discussions of the relationship of the fish and wildlife program to the region's power system. Thus the first part of this appendix is devoted to explaining how the power planning process and the power system add least-cost resources over time to keep the electricity supply in balance while accommodating all the changes that affect that load/resource balance, including the effects of fish and wildlife operations.

The second part of this appendix discusses the costs of the fish/power integration, from a number of different viewpoints. For too long the integration of the fish and wildlife program and the power plan have been talked of *only* in terms of cost, and *only* in terms of the difference between current operations and operations without consideration for fish and wildlife, priced at current wholesale market electricity prices. This may be interesting information to know, as a theoretical opportunity cost and for understanding total effects on Bonneville revenues over time. It does not necessarily reflect actual costs to Bonneville and the region over time, which should take into account instead the costs of the resources actually added over time to replace the hydropower generation, which is the first set of costs addressed in this part. Identifying the cost of individual fish and wildlife program measures allows the Council to assess their power system value relative to their biological benefits. This helps the Council include in its fish and wildlife program cost-effective measures to achieve its biological goals. Also, the Bonneville Power

[7] Hydroelectric generation in the Pacific Northwest averages about 16,000 average megawatts and annual demand is about 21,000 average megawatts.

[8] The development and operation of the hydroelectric system also affects flood control, irrigation, navigation, recreation, water for municipal and industrial uses, Native American cultural resources, and water quality. All of these effects must be taken into account as the relevant agencies plan and operate the system. But the Power Act has a particular focus on the relationship between fish and wildlife and electrical energy, and so that is the focus here.

Administration receives a credit from the US Treasury for part of its expenses related to non-power operations, which includes fish and wildlife costs and is another important aspect of cost assessment. Finally, it is important to assess how the fish and wildlife program has affected Bonneville's revenue sources and electricity rates.

Finally, the third part of this appendix discusses future uncertainties that would affect the fish and wildlife program and the power supply. These include uncertainties and risks related to (1) possible future changes in the fish and wildlife program; (2) an evolving power system that must integrate different kinds of generating resources, which will put more stress on the hydroelectric system; (3) possible modifications in Columbia River Treaty operations; and (4) climate change effects on the amount and timing of runoff and on electricity demands that would pose problems for both fish and wildlife and power generation.

PART 1: POWER RESOURCE PLANNING TO ACCOMMODATE THE POWER SYSTEM EFFECTS OF THE FISH AND WILDLIFE PROGRAM

This part of the appendix is devoted to explaining how the power planning process and the power system add least-cost resources over time to keep the power supply in balance while accommodating all the changes that affect the load/resource balance, including the effects of the fish and wildlife operations.

Prior to the development of the first power plan, the Power Act directed the Council to call for recommendations and adopt the *Columbia River Basin Fish and Wildlife Program*. Prior to each five-year review of the regional power plan, the Council must first call for recommendations and amend the fish and wildlife program. Leading into the Sixth Power Plan, for example, the Council recently completed amendments to the fish and wildlife program, resulting in the *2009 Columbia River Basin Fish and Wildlife Program* (www.nwcouncil.org/fw/program).

In this first stage in the planning sequence, the Power Act requires the Council to adopt fish and wildlife program measures that will "protect, mitigate, and enhance fish and wildlife" affected by the development and operation of the basin's hydroelectric facilities, and to do so while also assuring the region an "adequate, efficient, economical, and reliable power supply." To this end the Council's fish and wildlife program contains, among other measures, mainstem flow and passage measures (such as bypass spill) that affect hydroelectric system operations. These flow and passage measures have evolved over time, differing with each new version of the program. The changing flow and passage measures alter power generation at the mainstem dams, shifting flows and generation from winter to spring and summer as reservoir storage operations have changed to benefit fish and wildlife, and reducing potential generation in spring and summer by increasing bypass spill at run-of-the-river dams to improve fish passage survival.

Each time the Council considers and adopts a revised fish and wildlife program, it must also assess how the revised program measures will affect the region's power supply, and then evaluate, albeit in a preliminary way, if it will be possible to accommodate these changes and still assure the region an adequate, efficient, economical, and reliable power supply. The power system evaluation at this stage is necessarily preliminary. This is because what will follow immediately will be a comprehensive power planning effort that will include, among many other tasks, assessing whether and how to adapt the power system and add resources to accommodate the effects on power supply of the revised fish and wildlife program.

The power plan process is then the second step in the integration of fish and wildlife program measures and power system expansion under the Northwest Power Act. As the Northwest Power Act describes the power planning process, the Council projects a range of electricity demand scenarios over the next 20 years, and then evaluates whether current electric power resources will be adequate to meet increasing demand under different future conditions. If not, the Council includes a plan for adding the lowest-cost new resources, including (as a first priority) cost-effective conservation. What's important here is that the Power Act makes the just-amended fish and wildlife program one element of the power plan. In part, this is because knowing the latest flow and passage operations of the fish and wildlife program is an important part of assessing the current generating capability of the hydroelectric system, and the amount of hydroelectric generation available is then one contributor to knowing the total generating capability of current regional power resources. The current resource capability is then compared to current and projected load demands, and the differences are noted. In that sense, a change in hydroelectric generation due to a change in operations for fish and wildlife is functionally the same, for the Council's power planning purposes, as an increase in electricity demand, altering the load-resource balance in ways Congress expected the Council to be concerned with and to address in the power plan.

The Council is then to develop a least-cost resource plan to deal with any projected load-resource gap, whether the result of a reduction in available resources (such as due to a change in operations for fish and wildlife or because of a change in some other existing resource) or an increase in electricity demand, or both (as has always been the case since 1980). The Power Act then obligates Bonneville to have an ongoing conservation program and acquire other resources, if necessary, consistent with the Council's power plan to meet its electricity demand obligations and "to assist in meeting the requirements of section 4(h) of this Act" -- that is, to meet the requirements of the Council's fish and wildlife program and Bonneville's corresponding obligation to protect, mitigate, and enhance fish and wildlife in a manner consistent with the Council's program and power plan.

This is not just an "energy" issue. New or revised fish and wildlife operations do alter the amount of overall energy that the hydropower system can produce, but they also alter the peaking capability of the hydroelectric system in winter and reduce the flexibility of the system to follow load and balance other variable resources, which is a growing issue with the regional power system. The Sixth Power Plan is looking at regional resource needs in all these categories -- energy, capacity, and flexibility. Changes in fish and wildlife operations are one source of effects on all three to take into account.

The last point to reemphasize is these fish and wildlife operations and these power system effects did not happen all at once, or all in one planning period. Flow and passage measures for fish and wildlife began with the "water budget" in the first Fish and Wildlife Program in 1982, and have changed and (largely) increased at every iteration of the program since then. Each successive power plan, and nearly thirty years of resource planning and resource acquisitions by Bonneville -- mostly conservation -- have accommodated those changes. Fish and wildlife operations have changed again since the Fifth Power Plan, and the main integration task the Council faces in this power plan is to how to deal with those and other effects on the region's load/resource balance in the next five and twenty years.

The 2009 Fish and Wildlife Program and Current Fish Operations

Fish and wildlife actions identified in the 2008 NOAA Fisheries FCRPS Biological Opinion have been recognized in the Council's 2009 Fish and Wildlife Program as the baseline for fish and wildlife operations in the near future. Current operations are actually a combination of flow and passage measures in the 2008 Biological Opinion and additional spill agreed to by the parties and ordered by the federal court in the Biological Opinion litigation, at least for this year.

The authors of the biological opinion attempted to use best available science to develop a least-harm hydroelectric project operations plan by assessing the magnitude of potential adverse effects on fish resulting from a wide range of operational scenarios. The biological effects of the operational scenarios were estimated using the NOAA Fisheries' COMPASS (Comprehensive Passage and Survival) model, designed specifically for the reaches of the Columbia and Snake rivers extending from Lower Granite Dam to Bonneville Dam.

These provisions have substantive effect with regard to the operation of the mainstem hydropower system in the Columbia and Snake rivers. The mainstem portion of the fish and wildlife program consists of two major types of actions to promote anadromous fish survival that will also affect the power supply: 1) storage reservoir operations to affect flows; and 2) bypass spill for fish passage. [9]

Reservoir Operations

The Biological Opinion/Fish and Wildlife Program operations call for federal storage reservoirs in the United States to be at, and not below, the maximum level specified for flood control operations in early April. This has the effect of requiring system operators to keep water levels behind these dams higher in winter and early spring than they would have (in most years) for an optimum power operation. Monthly flow objectives are then provided for both the Snake and Columbia rivers during a part of the juvenile and adult salmon migration season in spring and summer (April through August) and during the spawning season for Kootenai River white sturgeon below Libby Dam. The reservoir operation in spring largely works toward project refill while otherwise passing the snowmelt runoff downstream to try to achieve the flow objectives.

The fish and wildlife operations target reservoirs for refill by end of June. The Biological Opinion then specifies federal storage reservoirs to draft, up to limits specified in the opinion, in order to augment summer flows to aid in fish survival. This operation results in higher flows over this period than would be normal under a purely power-focused operation. For more than a decade, the federal agencies have also entered into supplemental operating agreements with B.C. Hydro to release water from Canadian storage projects to benefit fish migration in the U.S. in ways that would not occur under ordinary Columbia River Treaty operations. Finally, the operating agencies also release water in late fall and early winter to support chum flow spawning

[9] The Fish and Wildlife Program contains other measures that do not affect system operations, but which do require expenditures by Bonneville, including capital costs for fish passage and the direct cost of other fish and wildlife program actions. These elements of the program are described in more detail below. *See* the Council's 2009 Fish and Wildlife Program and NOAA Fisheries' 2008 Biological Opinion.

and rearing in the lower Columbia, and control operations in the mid-Columbia River to support fall Chinook spawning and rearing in the Hanford Reach.

The main effect of this operation on the power supply is to reduce the generating capability of the hydroelectric system over the winter, at the time of the region's peak loads, and to increase generation when runoff is passed through in the spring and when it is released from storage in the summer, generally producing surplus generation over native regional demand. There is not a one-to-one shift in energy production from winter to spring/summer because of bypass spill requirements.

Bypass Spill

Bypass spill is the re-routing of river flows away from turbine intakes and into fish passage and spillway systems. The survival of migrating juveniles diverted into fish passage systems and over spillways is considerably higher than fish survival rates through the turbines. The Fish and Wildlife Program and NOAA Fisheries Biological Opinion call for the eight federal dams on the lower Snake and Columbia rivers to divert part of their flows through fish bypass systems during spring and summer. As noted above, additional spill is occurring this year as a result of a court-approved agreement among the parties to the Biological Opinion litigation. It is not clear whether such additional bypass spill will be required in future years, therefore it was not assumed in the analysis.

Hydropower generation is reduced from what it would be without the spillways open. In nearly every year, the difference does not affect the firm power capability of the system, and instead reduces the amount of non-firm or surplus power available for sale on wholesale power markets. Surplus power sales are made to serve peak loads in the Southwest or to allow others to displace more expensive resources that also serve load in the region. The main effect of surplus sales at Bonneville is to generate revenue that helps to cover the cost of Bonneville's operation of the federal hydropower system, reducing Bonneville's debt to the Treasury, and covering its other costs. Spill can also reduce reactive support for the transmission system, which leads to reduced transmission capability and could potentially reduce system reliability.[10]

The Biological Opinion/Fish and Wildlife Program specify additional operational limitations, including turbine operating criteria and limits on how fast flows may be ramped up or down through changes in project discharge levels. These constraints have little effect on the total energy production of the system, but instead reduce the system's flexibility to follow load and accommodate varying wind output. These effects are difficult to model or estimate quantitatively, but are real nonetheless.

Modeling the Power System

As part of the power plan effort, the Council has to estimate the current generating capability of the hydroelectric system. Operations for fish and wildlife are only part of this effort, and must be combined with the runoff pattern (both amount and shape), with operational requirements and constraints for purpose of flood control (which are significant) and navigation, irrigation and

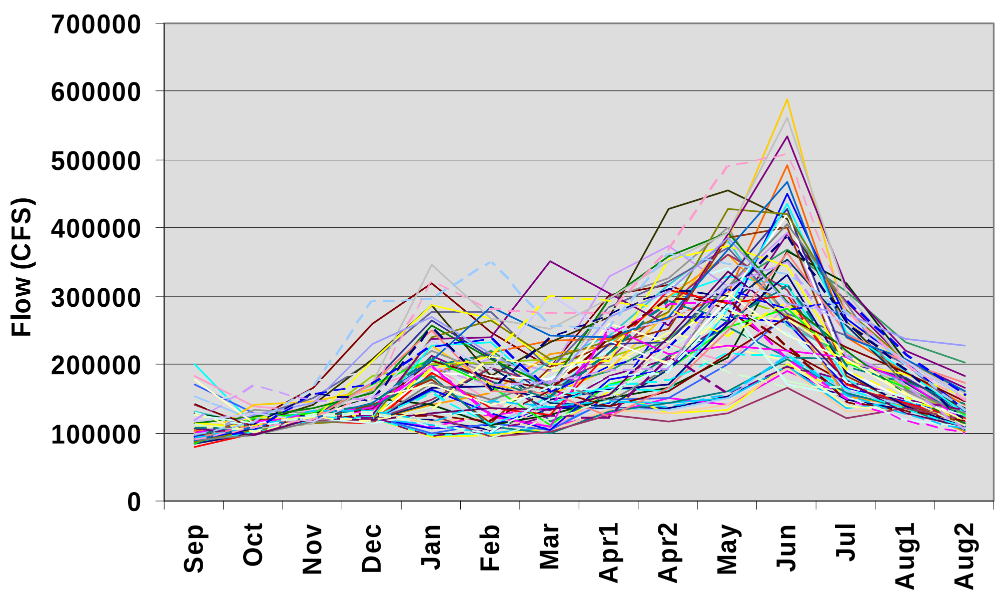
[10] See the Memorandum dated February 24, 1998, memorandum from John Fazio to the Council regarding the transmission impacts of drawing down John Day Reservoir and other fish and wildlife operations (Council document 98-3).

other non-power purposes (relatively minor on overall system operations), and power system objectives (i.e., load objectives). The end result is a series of monthly reservoir elevation and flow profiles, and then, especially, monthly generation patterns (bi-monthly in April and August). The modeling effort can be done on a planning basis, using different runoff patterns representing the 70-year historical water record (and the Council and Bonneville both do this), or on an "actual" basis, looking at a past year's actual runoff and generation (Bonneville does this).

The analysis of system operation and hydroelectric generation is performed with the GENESYS model.[11] The model simulates the operation of regional resources including hydroelectric facilities over many different future conditions. For the hydroelectric system, key outputs include regulated outflows, reservoir elevations, and generation. (Another output is cost, but that is addressed in the second part of the appendix.) GENESYS simulates both a monthly and hourly dispatch of available resources to meet regional load. In the monthly mode, it simulates the operation of individual hydroelectric facilities. In the hourly mode, however, the hydroelectric system is operated in aggregate and the peaking capability of that system is approximated using linear programming techniques.

This model is designed to address both energy (monthly and annual) needs and capacity (hourly) needs. The results depicted below are based on the use of GENESYS to analyze the operations outlined in the Council's Fish and Wildlife Program, consistent with those in NOAA Fisheries' 2008 Biological Opinion. Figures M-1 and M-2 show the range of outflows at Lower Granite and The Dalles dams for each of the 70 water conditions modeled. Figure M-3 shows the range of system generation in average megawatts by month and Figures M-4 through M-7 show the range of elevations by month at Libby, Hungry Horse, Grand Coulee and Dworshak dams.

Figure M-1: Flow at The Dalles



[11] See http://www.nwcouncil.org/genesys.

Figure M-2: Flow at Lower Granite

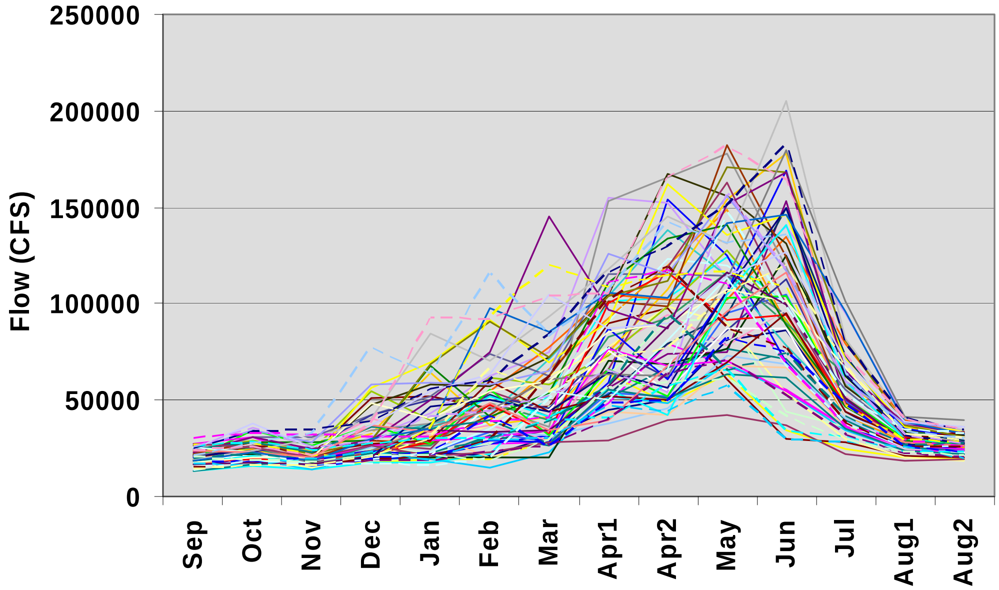


Figure M-3: Hydroelectric Generation

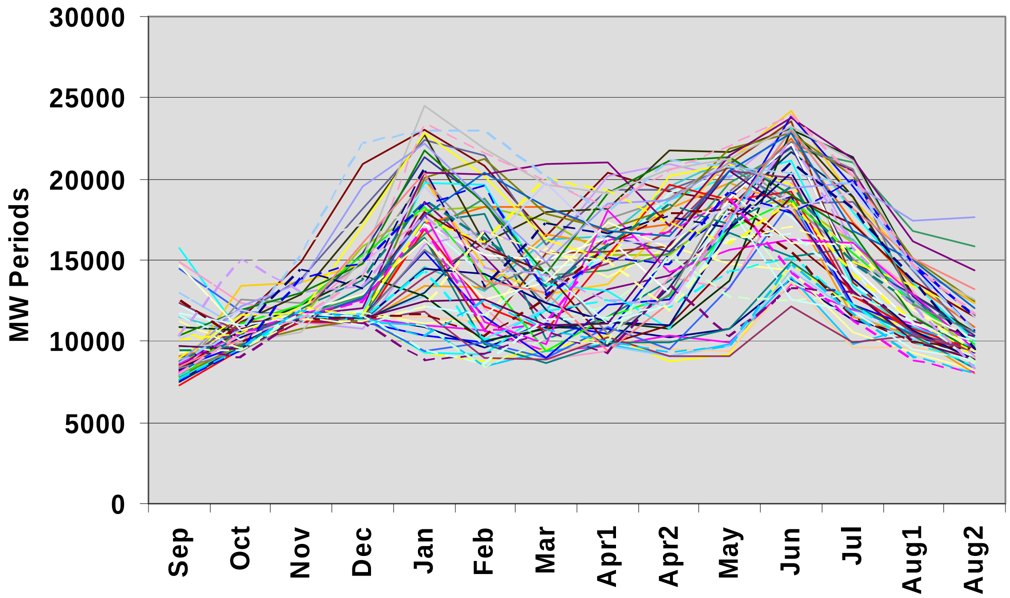


Figure M-4: Elevation at Libby Dam

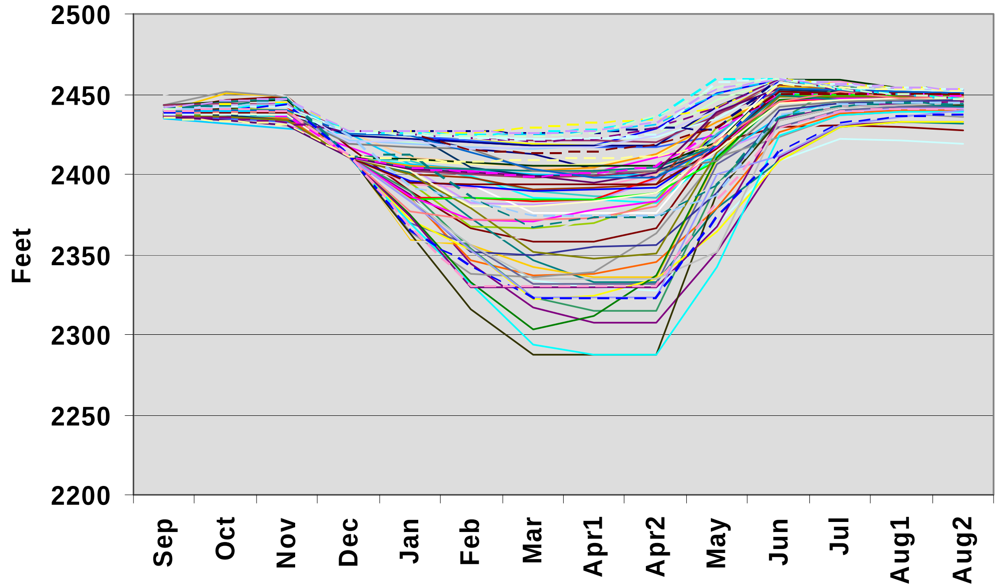


Figure M-5: Elevation at Hungry Horse Dam

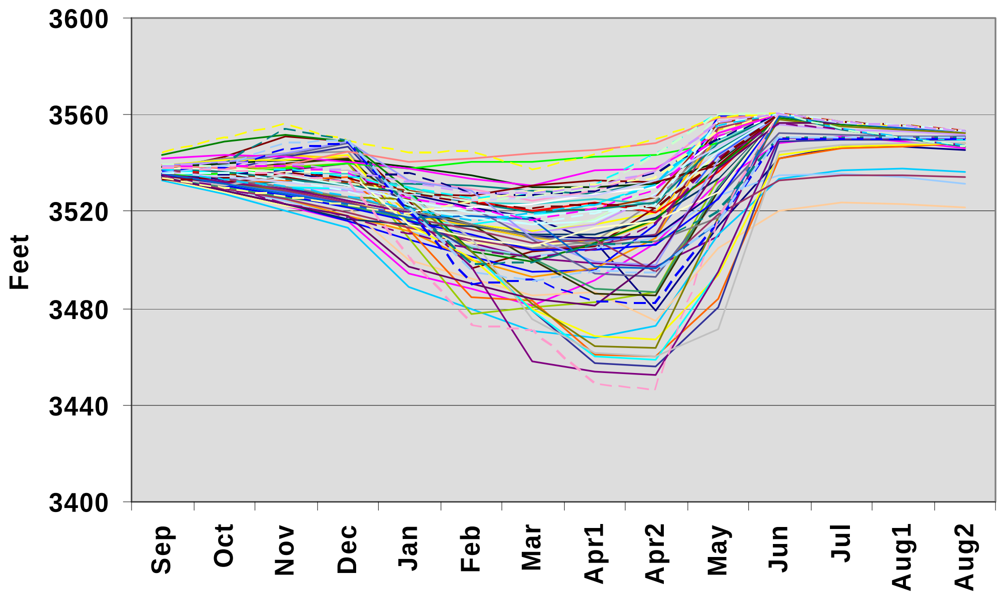


Figure M-6: Elevation at Grand Coulee Dam

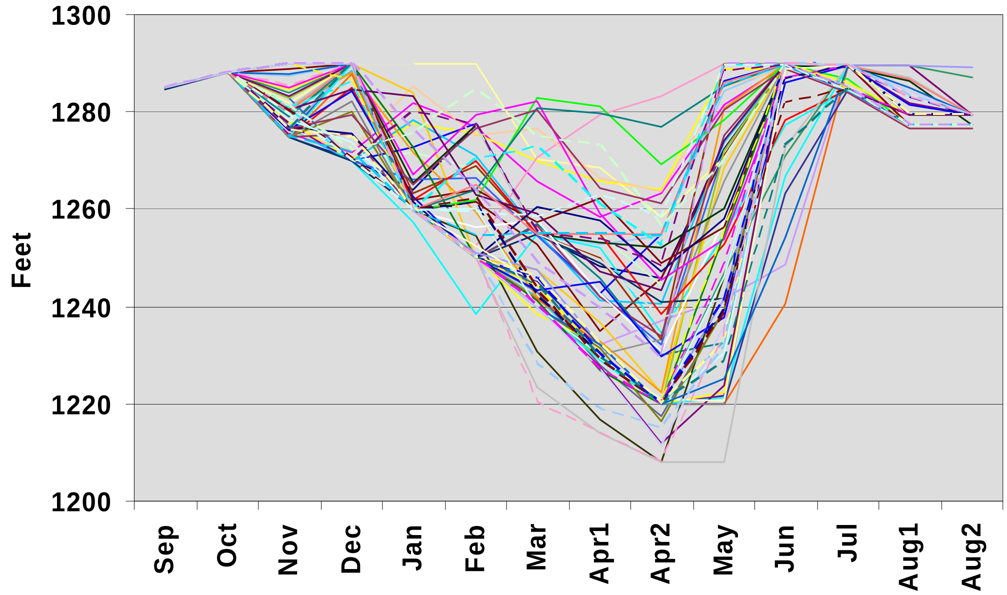
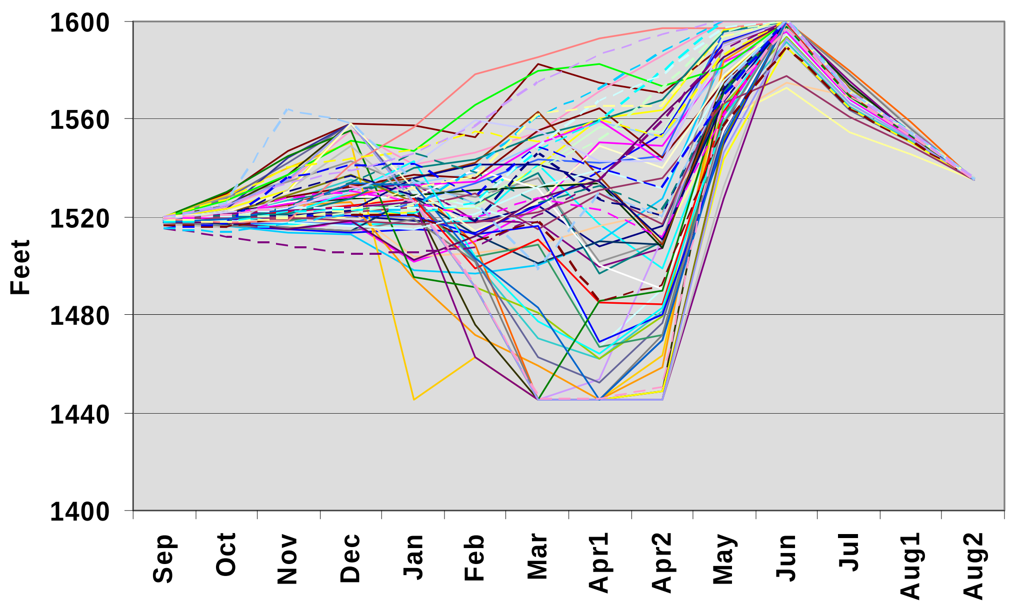


Figure M-7: Elevation at Dworshak Dam



For current resource planning purposes, of course, the more important information is the change in the firm power generating capability since the last iterations of the Fish and Wildlife Program (2003 Mainstem Amendments/2000 FCRPS Biological Opinion) and Power Plan (Fifth Power Plan, December 2004). We did not begin shifting flows and thus generation from winter to spring/summer just recently -- the fish and wildlife program was built to current levels from the original water budget in 1982, with major evolutions ever since. And resource planning and resource acquisitions have accommodated these changes in hydroelectric power production and peak capacity all along. For an historical perspective, however, it is important to note total changes in hydroelectric operations since before fish and wildlife measures were first adopted. This information is not important for resource planning or for fish and wildlife decision making, but it is useful for understanding the full magnitude of changes over time. The following charts display these differences.

Figure M-8: Average Outflow at The Dalles Dam

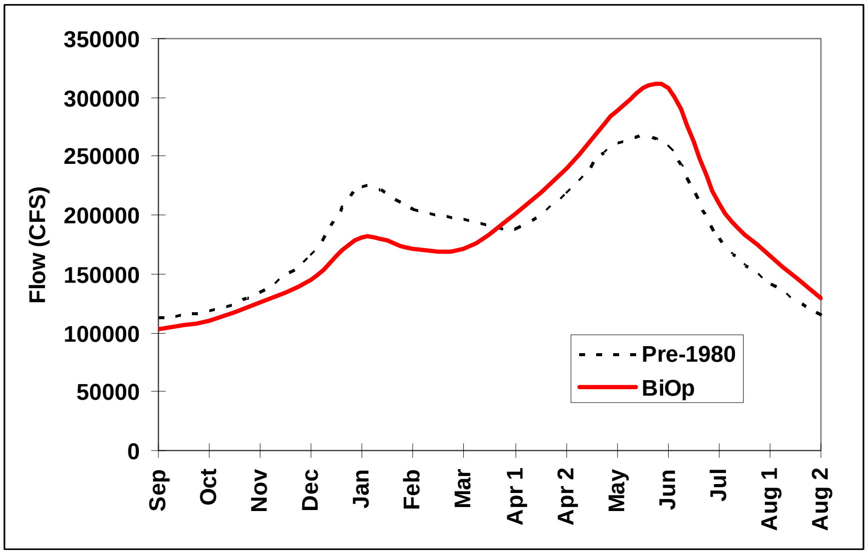
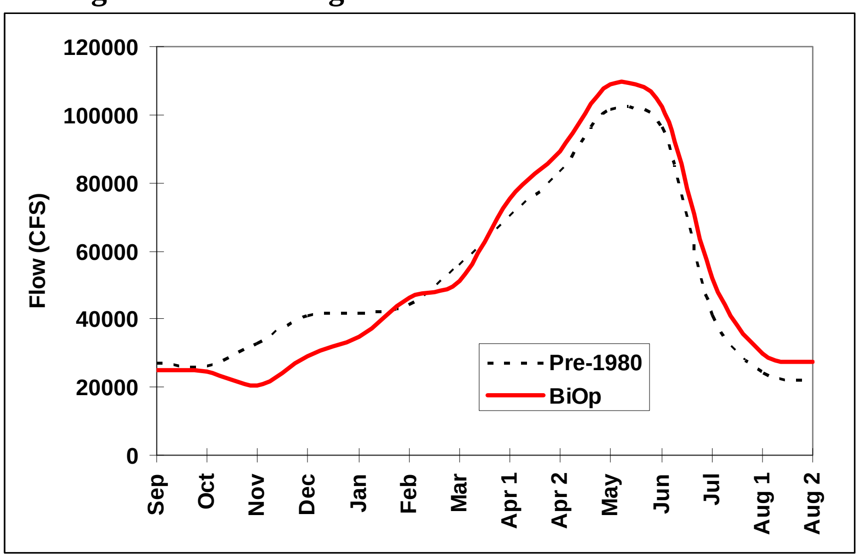


Figure M-9: Average Outflow at Lower Granite Dam



In order to reshape river flows, water in reservoirs that would have been used for power production during winter months is kept in storage for later release during spring and summer. The following four charts (Figures M-10 to M-13) show the average reservoir content for Libby, Hungry Horse, Grand Coulee and Dworshak dams, in units of thousands of second-foot days or KSFD (one KSFD is equal to about 2000 acre feet or 2 KAF). The pattern of keeping more water in these reservoirs during winter months is clearly apparent in these charts. Additional water is also released at these projects over the summer months, which leaves these reservoirs at lower elevations by the end of August or September. On average, Dworshak reservoir is 80 feet below full, Libby and Hungry Horse are 10 to 20 feet lower and Grand Coulee is between 10 and 12 feet lower by summer's end.

Figure M-10: Average Reservoir Content at Libby Dam

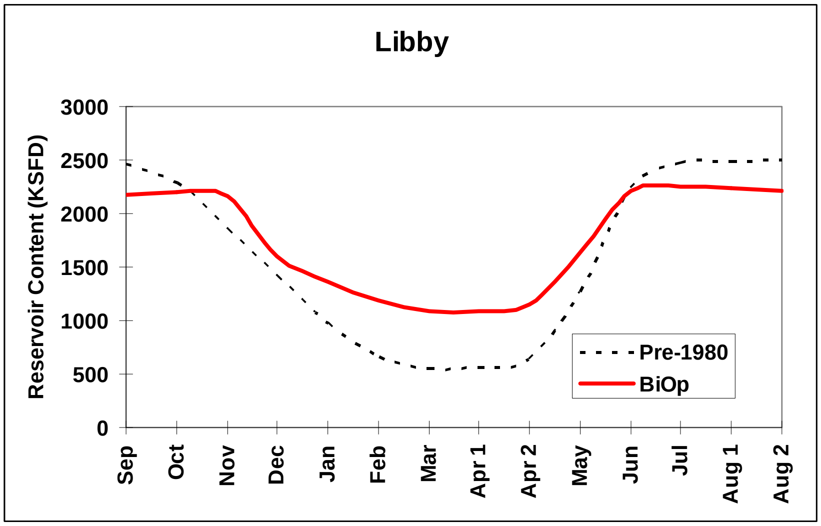


Figure M-11: Average Reservoir Content at Hungry Horse Dam

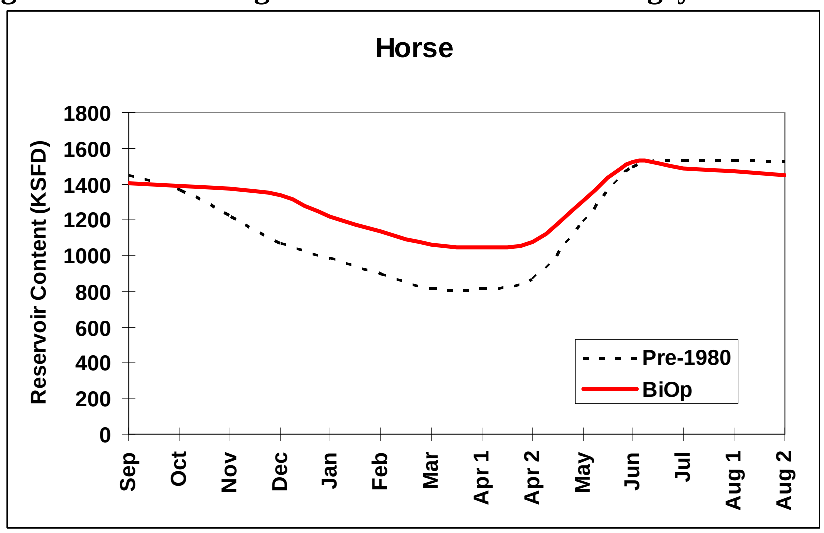


Figure M-12: Average Reservoir Content at Grand Coulee Dam

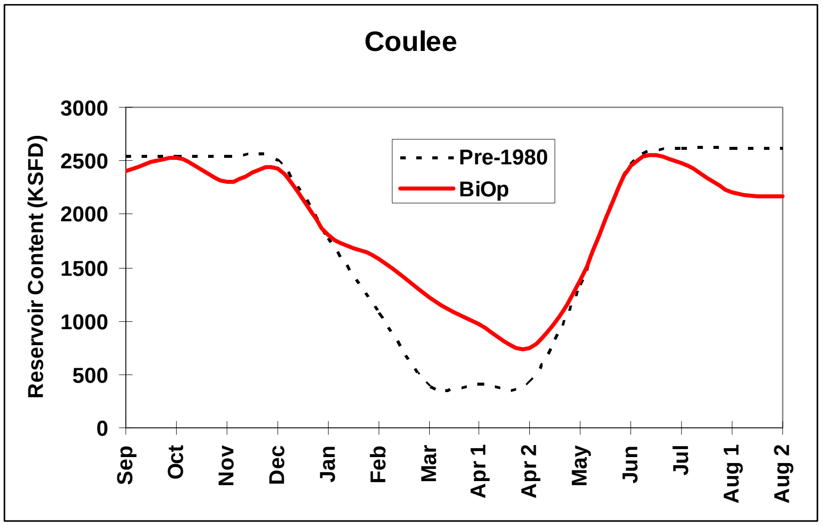
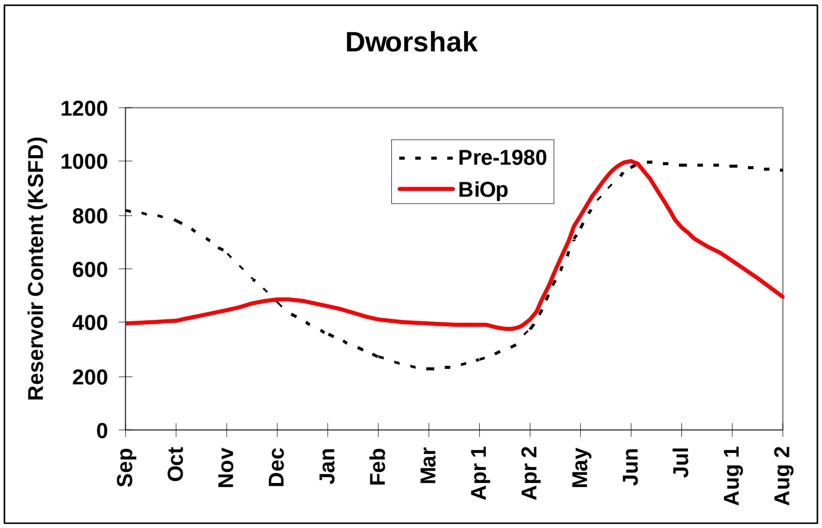


Figure M-13: Average Reservoir Content at Dworshak Dam

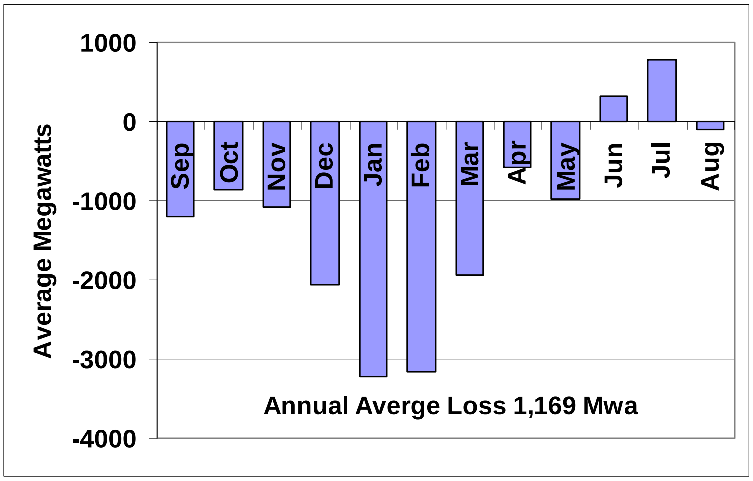


Council analysis indicates that, on average, implementation of the program will reduce hydroelectric generation by about 1,170 average megawatts, relative to an operation without any constraints for fish and wildlife.[12] For perspective, this energy loss represents about 10 percent of the hydroelectric system's firm generating capability.[13] Figure M-14 below shows the monthly average change in hydroelectric generation between current operations and a pre-1980 operation, which includes no fish and wildlife constraints.

[12] The comparison study, which includes no actions for fish and wildlife, is represented by hydroelectric operations prior to 1980.

[13] Firm hydroelectric generating capability is about 11,900 average megawatts (2007 Bonneville White Book) and is based on the critical hydro year, which is currently defined to be the 1937 historical water year.

Figure M-14: Change in Monthly Average Hydroelectric Generation since 1980



Resource Planning

As described above, the central purpose of the power plan is to assess the current and projected demand for electricity for the next 20 years, compare that to current resources (hydroelectric and other generation), and develop a plan for adding conservation and generating resources to avoid or close a resource/load gap. Addressing the firm power effects of the fish and wildlife program is just one part of that resource analysis. The relevant resource analysis and the plan to add resources are described in the main chapters of the Power Plan and in the Action Plan. No particular effort is made to assign certain resources to cover different reasons for a possible load/resource gap, so no particular effort can be made here to identify particular resources as the replacement resources for the reduction in hydroelectric generation due to fish and wildlife operations. The firm power effects of those operations are addressed through this method, however.

The resource planning effects of the fish and wildlife program, since the Fifth Power Plan was adopted, are relatively small compared to other aspects of the load/resource balance. For example, the annual average incremental loss of hydroelectric generation since 2005 due to fish operations is on the order of 20 average megawatts. In comparison, the Sixth Power Plan targets 1,200 average megawatts of conservation acquisitions over the next five years, which nearly covers all of the expected load growth of 1,500 average megawatts over that period.

Fish and wildlife operations, however, do not just have a firm power energy effect. As noted above, they also contribute to reductions in capacity and within-hour system flexibility. Capacity and flexibility adjustments that necessarily include addressing these effects and others are described in Chapter 11. Fish operations, especially bypass spill, also reduce the ability of the system to generate surplus power and thus additional revenue. The revenue effects are described below, in the section on costs.

Providing an Adequate Operation for Power and Fish

Bonneville and the other federal operating agencies implement the fish and wildlife operations, and the rest of the Fish and Wildlife Program, consistent with the Northwest Power Act, the federal Endangered Species Act, the project authorizations, and other applicable law. The hydroelectric operations to improve fish survival that are specified in the Council's Fish and Wildlife Program also become a part of the power plan. The power plan must be designed to provide both an adequate and reliable power supply and an adequate and reliable implementation of fish operations. The impacts of those operations are substantial and would definitely affect the adequacy and reliability of the power system, if implemented over a short period of time. However, this has not been the case. As described above, since 1980, the region has periodically amended fish and wildlife-related hydroelectric operations and in each case, the power system has had time to adapt to these incremental changes and has maintained an adequate and reliable power supply.

The Council staff produced a preliminary assessment of the impacts of fish operations on the adequacy and reliability of the power supply during the recent fish and wildlife program amendment process. A more detailed adequacy and reliability assessment is provided in this power plan. That assessment (Chapter 13) indicates that the regional power supply can reliably provide the actions specified to benefit fish and wildlife (and absorb their cost), respond to other challenges to the reliability and adequacy of the regional system described in that chapter, and maintain an adequate, efficient, economic, and reliable energy supply. Moving forward, the Council's resource adequacy standard provides a minimum threshold for resource development that minimizes the likelihood of curtailments to both power and fish operations.

It should be noted that prescribed mainstem operations for fish and wildlife are subject to change, because some of those operations are currently under litigation. The Council's assessment of the hydroelectric system's contribution to the region's power resources is based on current fish operations, as is the Council's conclusion that the current system can accommodate fish operations while maintaining an adequate and reliable supply. Some of those operations that could change in the near-term include:

- Increased spring and summer bypass spill

- Revisions to the Hungry Horse and Libby late summer/fall operation, or to other reservoir operations

- Potential changes to the Non-Power Uses Agreement under the Columbia River Treaty, which stores an additional 1 million acre feet of water for later release to support needs of fish

- Annual changes to other Columbia River Treaty supplemental agreements for non-power operations

- Potential reductions in bypass spill requirements upon installation and effective operation of spillway weirs

Whenever non-power operations are modified, resource planning and acquisition considerations may need to be reviewed, and the Council and Bonneville will need to undertake a new adequacy assessment. However, while the above mentioned actions may affect power generation to some degree, none of them would jeopardize the power supply's near-term adequacy. Longer-term changes, which might affect power supply adequacy, are discussed in the section entitled

"Dealing with an Uncertain Future" and include issues such as climate change, the expiration of the Canadian Treaty and dam removal.

In addition to the adequacy standard, power planners have become more cognizant of non-emergency situations, such as isolated low flow events, night-time over-generation conditions, and rapid load changes that have compromised fish operations in the past. Planners are actively developing operational protocols to address these situations and to alleviate the pressure to curtail fish operations. For example, the U.S. Army Corps of Engineers (Corps) describes how it intends to deal with these situations in its planned operations for fish passage for 2009 (Corps document number 1693-2, "2009 Spring Fish Operations Plan").

In spite of best laid plans, however, emergencies sometimes occur, and all utilities have contingency actions in place to avoid potential curtailments. We do not and cannot plan and build for 100% assurance of power system operations, nor the same for the operations specified for fish. What we can do is reduce the likelihood of emergencies to an acceptable level (mostly through adding sufficient resources to the system), and then have contingency plans in place to deal with power and fish emergencies in a comparable fashion.

Hydro flexibility is one method for dealing with power system emergencies. During periods of rapid load changes or the loss of a major resource or transmission line, reservoirs can be drafted below their normal operating elevations to sustain electricity service. This use of additional hydroelectric generation is often referred to as "hydro flexibility." Hydro flexibility is generally used during cold snaps or heat waves when no other resources are available, including imports from out of region. The additional water drafted to produce extra energy is replaced as soon as possible, even if energy must be imported. Most often reservoirs can recover and get back to required refill elevations. However, in the event that hydro flexibility can not be replaced by early spring, less water would be available for the spring flow operation for fish and wildlife augmentation. The power plan, resource additions, and in-season planning strategies should be designed to minimize situations when hydro flexibility cannot be replaced prior to the migration season.

Both bypass spill requirements and reduced mainstem reservoir operating limits imposed by the program limit the flexibility of the hydroelectric system. This is important because less flexibility means a reduced ability to meet peaking requirements, provide ancillary services, and integrate wind and other variable resources. Once system flexibility is used up, additional resources may need to be added along with variable generators to provide a reliable supply. This will clearly increase the cost of meeting renewable portfolio standards and may also increase carbon emissions. As discussed in Chapter 11, creative strategies for operating the system to balance renewable resources, and then careful planning to add least-cost resources to meet the system's capacity and flexibility requirements are key to preserving reliable implementation of fish and wildlife operations while maintaining power system reliability.

The biological opinion allows for curtailment of fish and wildlife operations during power system emergencies, as happened in the very low water year of 2001, but it does not specify an upper bound for such actions. It also includes comparable language that allows deviations from normal power system operations during rare occasions when emergency fish passage conditions occur.

Whenever the region's generating capability lags behind demand growth (as happened in the late 1990s), the risk of having to curtail fish and wildlife operations will increase. Using curtailment of fish and wildlife operations as a last-resort alternative during rare emergencies is allowed under the biological opinion language[14]. The key word in the previous sentence is "rare." Analysis showing a high frequency of curtailment to fish and wildlife operations would indicate that the power supply is not adequate. Curtailment of fish and wildlife operations cannot be used in lieu of acquiring resources to maintain an adequate regional power supply. In the same way, power system operations should not be jeopardized an inordinate amount to deal with fish emergencies.[15]

Physical and economic analysis of specific fish and wildlife measures can aid in the development of a fish and wildlife curtailment policy, in the event of a power emergency. It would be in the region's interest to have these policies in place prior to an emergency, in order to minimize the risk to fish. Action item F&W-2 (see the Action Plan) calls for the Council to work with fish and wildlife managers and regional power planners to develop contingency plans.

PART 2: ASSESSING COSTS

The second part of this appendix discusses the costs of the fish/power integration, from a number of different viewpoints. The costs of using the hydroelectric system to provide suitable conditions for fish and wildlife are largely assigned to the power system and its ability to generate revenue. Part of the purpose of the power plan is to accommodate these costs and the loss of generating capability that fish and wildlife measures may induce. This means acquiring additional resources, whenever needed, to maintain an acceptable level of adequacy, efficiency, economy, and reliability. To assess the "cost" of fish and wildlife operations, Bonneville, the Council, and others have been in the habit of comparing whatever are the current operations for fish and wildlife to a hydrosystem operation without fish and wildlife constraints, estimating the difference in generation per month, pricing that difference at whatever is the current market price for electricity, and summing the differences for each month to get a total net "cost" for those operations. Just as many others, inside and outside the Council, have objected to that practice, for a number of reasons. What has been missing, at least in part, has been a discussion as to precisely why cost information is important under the Northwest Power Act -- to what ends and for what decisions is cost information important. When that is done, the result is a set of conceptual categories for assessing costs, categories that require different information and different perspectives on costs.

As noted in the introduction, the focus here is to carefully describe the cost categories, and take the focus off the specific numbers. There are at least four different purposes for assessing the cost of fish and wildlife operations. First, the Council must assess the costs of the resources added to the power system to accommodate the change in hydropower generation due to fish and wildlife operations as well as meet load growth. Second, identifying the cost of individual fish and wildlife program measures allows the Council to assess the power system value of each measure relative to its biological benefits. Performing a strict cost-effectiveness analysis is impossible because absolute biological benefits are difficult to identify and value in terms of dollars. Nonetheless, this analysis at least allows the Council to group various measures into

[14] Reference the NOAA BiOp RPA number 8 here.
[15] Reference the NOAA BiOp RPA number 9 here.

broad categories, such as those that are very high cost and have very highly uncertain biological benefits. This may help the Council rule out certain measures to include its fish and wildlife program. Ideally, should two different measures provide the same biological benefits; the Council should choose to include the least costly one. Third, under section 4h(10)(C) of the Northwest Power Act, the Bonneville Power Administration receives a credit from the US Treasury for part of its expenses related to non-power operations. Finally, it is important to assess how the fish and wildlife program has affected overall revenues and electricity rates. The following sections describe in more detail these cost assessments and their purposes.

Assessing the Resource Cost Effects of Fish and Wildlife Operations

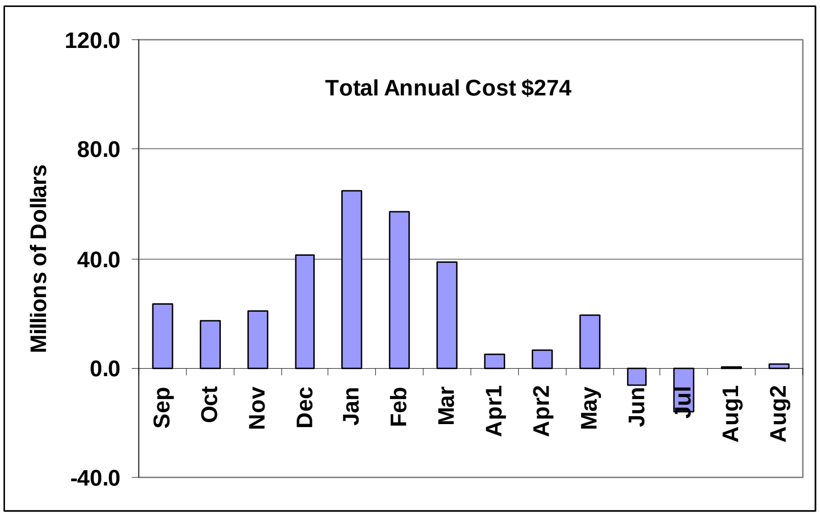
As described above, the power planning effect of a change in generation due to operations for fish and wildlife is how it affects the load-resource balancing and contributes to the resource acquisition strategies outlined in the Power Plan. Thus in this particular power plan setting, as in any other, the cost to the system of the latest changes in fish operations that affect the firm power energy and capacity of the system is the average cost of the resource acquisitions needed to make up the projected load-resource gap, the same as it is for addressing load growth and other resource changes. No particular added resource is tied to the fish operations part of the load-resource calculation. Looked at over the entirety of the Fish and Wildlife Program and the Power Plan, the federal power system is serving the “fish operations” part of Bonneville’s obligations at an average system cost, just as it serving all other aspects of Bonneville’s load obligations. In the main chapters of the Power Plan, the Council estimates the long-term average cost of resources added to the system to meet load obligations and reductions in supply capability due to non-power operations.

More precisely, the Power Act directs the Council to plan for the addition of the most cost-effective resources to address a gap between expected loads and current resources (again, *whatever* the reasons for the gap), with a priority for an ongoing program to add cost-effective conservation to avoid having to add other generating resources. This question is never looked at in isolation -- that is, one resource is added to make up for lost generation due to fish operations, while another resource is added to avoid or address load growth. Instead, the load-resource balance is looked at as a whole, deficiencies are identified and low-cost resources are added to fill those deficiencies. The average cost of those added resources is thus one way to determine the “cost” of accommodating the latest changes in fish and wildlife operations to the power system, at least those that affect the firm power resource balance, as well as accommodating (or avoiding) load growth. And looking at the system as a whole, the average system cost of meeting load obligations includes meeting the obligation to accommodate fish operations and still provide an adequate and reliable power supply.

For most of the life of the Council’s power planning efforts, the cost-effective available resources planned for addition, especially conservation, have cost significantly less than ongoing purchases of electricity at wholesale market prices. The same is true for the resources in the plan this time, again, mostly cost-effective conservation. The traditional “market price” calculation of the total effect on generation from fish and wildlife operations is essentially irrelevant to the power plan’s resource development efforts, and the Power Act’s provisions for accommodating the fish and wildlife program through resource planning and additions. Fish and wildlife operations have been incrementally decreasing the portion of firm power supply from hydropower generation since 1981, just as the Northwest has seen incrementally increasing demand for electricity over the same time period. The Council's power plan has been describing the least-cost resources to address those developments, and Bonneville and the region's utilities have been developing conservation measures and adding resources in that context to keep the power system adequate and reliable and as economical as those changes have allowed it to be. Part of those resource additions undoubtedly were added because of fish and wildlife operations and thus can be used to assess the replacement "cost" to the power system of the fish and wildlife program.

Unfortunately, this assessment is effectively impossible to do since we have not and do not distinguish resource acquisition for specific reasons. However, as a means to estimate the cost of the program, average resource replacement costs can be used and as a surrogate for those costs, Bonneville's Priority Firm Power Rate ($27 per megawatt-hour) can be used. Applying these costs to the average monthly energy losses in Figure M-14 yields the results in Figure M-15. The average annual cost of the fish and wildlife program is approximated to be in the range of $300 million. The cost in any particular year, however, can vary dramatically depending on water conditions (see the section below on cost uncertainty).

Figure M-15: Average Monthly Cost using Replacement Resource Cost



Finally, at any particular moment in time, the Council and Bonneville must be able to make the overall determination that the region's power supply is not just adequate and reliable, but also "economical." The Fish and Wildlife Program does add costs to the system, as expected under the Power Act, but maintaining an economical power system should not limit the development of the program. Power planners must assess reductions in the power supply due to program measures and develop a least-cost resource acquisition strategy to offset these deficiencies, just as they would for projected load growth. In the context of the Power Act, the power system remains "economical" when sufficient time is allowed to add least-cost resources in a reasonable manner and recover costs in a businesslike fashion. This is the process that has occurred since 1981 when the first fish and wildlife measures were implemented.

Relative Cost of Individual Fish and Wildlife Measures

The range of actual decision making is *not*, under the Northwest Power Act or the Endangered Species Act, the difference between current operations that include fish and wildlife measures and an operation that does not include fish and wildlife measures. Instead, at any particular moment in the last 30 years (and presumably in the foreseeable future), the range of active decision making has proven to be between current operations (as the base) and an indeterminate and evolving range of operations in either direction from that base (e.g., periodic adjustments in storage reservoir operations and dam operations affecting flow amounts and velocities; bypass spill increases or decreases, proposed or implemented, of a certain magnitude).

Within this range of actual fish and wildlife decision making -- that is, current operations to improve conditions for fish within a certain range of flow and spill changes -- it is important to know what would be the power system effects of a proposed or implemented change, and what would be the costs to the power system and ratepayers of dealing with that change. This is useful as a way of understanding the power system effects of a change just made in the Fish and Wildlife Program, or proposed to be made pending the next power plan.

It is particularly useful information to be able to compare the costs of proposed changes (and the benefits to be gained) against the costs and benefits of other possible actions. In theory, this sort of cost information allows for a cost-effectiveness comparison of the costs and benefits of different actions -- e.g., what would be the comparative benefits of different actions for fish and wildlife that could be done for the same cost? And vice versa -- how much is the difference in cost to get comparable survival benefits from actions that improve mainstem habitat conditions or tributary/estuary habitat conditions, assuming some comparable way of estimating survival benefits can also be used?

For this purpose, the short-term costs of any generation changes caused by an operational change related to fish and wildlife would be assessed using market electricity prices. This should include loss of revenue (or foregone revenues) for bypass spill operations. Assessing costs using market prices is used in this case only to compare and rank various fish and wildlife measures. These costs are not intended to represent the actual or true cost of the fish and wildlife program as a whole. The overall cost assessment (as described in a later section) should be based on long-term levelized resource replacement costs (as would the assessment of cost to meet a particular magnitude of future load growth).

However, to reiterate an earlier statement, the cost of the difference between current fish operations and no fish operations is irrelevant to current decision making. It is not a real opportunity under the current understandings of law and policy. However, what it might cost and what benefits might be gained, for example, by increasing or decreasing the percentage of the flow spilled at John Day Dam by 10% in mid-summer, or drafting a storage reservoir five feet less or more than before, or buying up a 100 cfs of water for in stream use, or various other actions, *is* relevant information that can inform decision makers of the comparative value of real choices.

As an example of the type of information that can be useful in developing a fish and wildlife program, Figures M-16 through M-19 show bypass spill costs by project and by month, assessed using market electricity prices. Figure M-16 illustrates the average cost of bypass spill by project. Overall, using market electricity prices, the total average cost for bypass spill is about $220 million per year, with $100 million for spring months and $120 million for summer months. As indicated in Figure M-16 above, spill at John Day, The Dalles and Bonneville dams makes up the majority of the total cost of bypass spill, both for spring and summer (see Figure

M-17 and M-18). On a monthly basis, bypass spill is most costly in July with an average cost of about $60 million per year (Figure M-19).

Figure M-16: Total Bypass Spill Costs

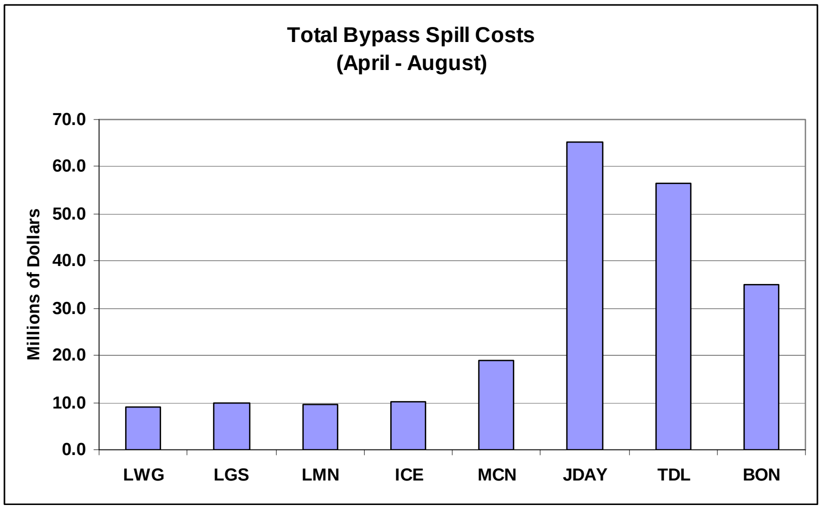


Figure M-17: Bypass Spill Costs (Spring Only)

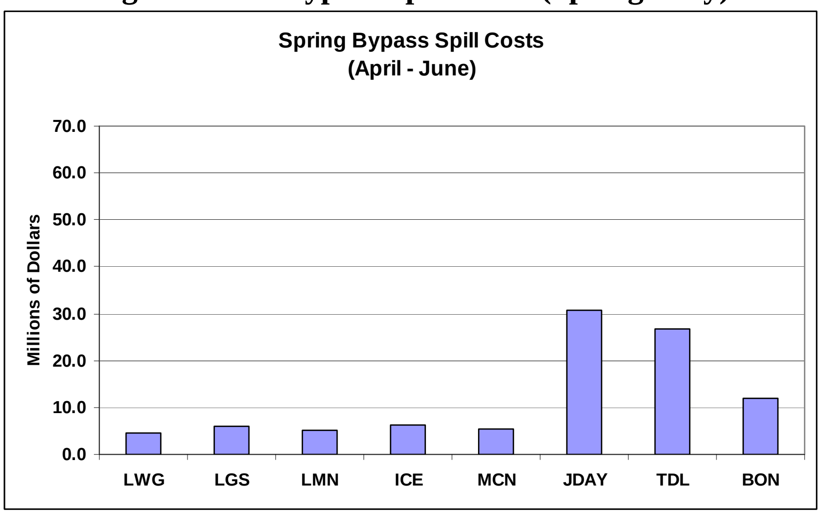


Figure M-18: Bypass Spill Costs (Summer Only)

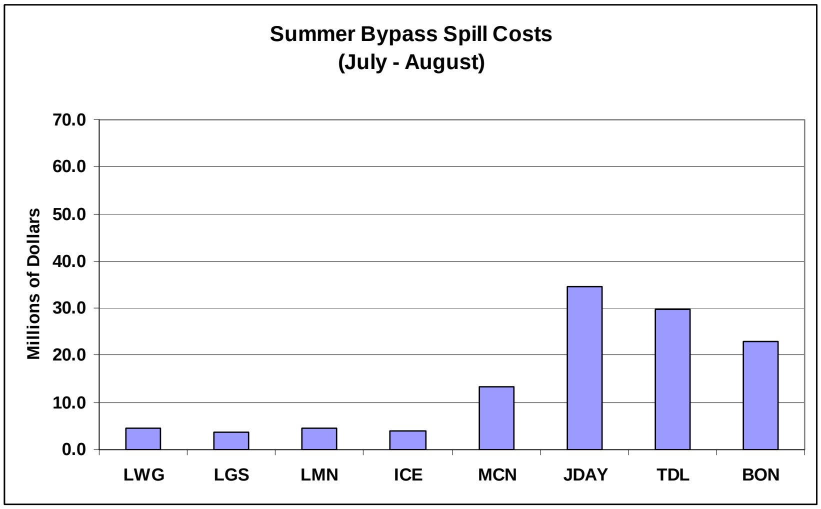
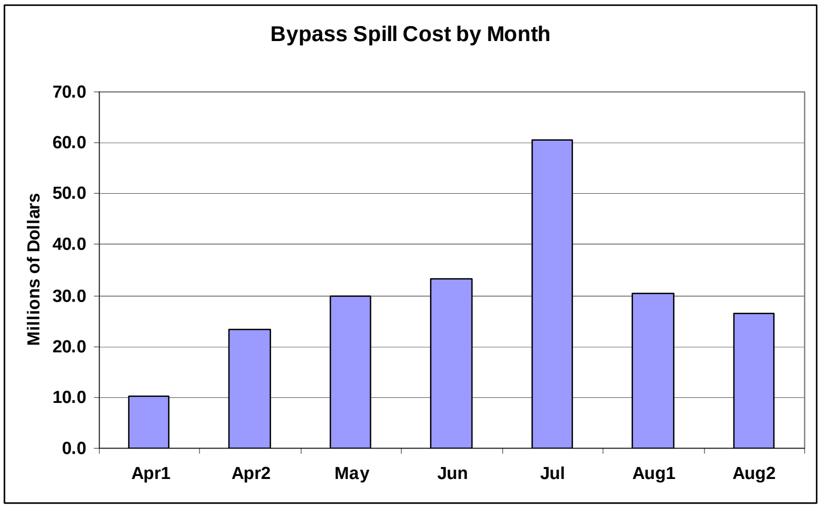


Figure M-19: Bypass Spill Costs by Month



Section 4h(10)(C) Credits

Section 4(h)(10)(C) of the Northwest Power Act provides that the amounts expended by Bonneville to address the effects of the dams on fish and wildlife are ultimately to be allocated among the various project purposes. The federal agencies agreed some time ago that the hydropower purpose should bear approximately 75% of such costs. Thus Bonneville's ratepayers are ultimately responsible for 75% of the costs of the actions to address the adverse effects of the projects on fish and wildlife.

Bonneville routinely pays 100% of the cost of a number of fish and wildlife actions, however. So, Bonneville has an understanding with the Treasury and the Office of Management and Budget (OMB) on a mechanism that will allow Bonneville to recoup the over-investment of the hydrosystem by crediting or offsetting against Bonneville's Treasury payment the non-power share (or approximately 25%) of such expenditures.

The understanding with Treasury/OMB applies to all expenditures or actual money paid by Bonneville for fish and wildlife purposes. As such, it also applies to Bonneville's direct expenditures, such as on habitat or production projects. Bonneville also expends money on power purchases throughout the year to meet instantaneous load requirements. And the understanding also extends to those power purchases Bonneville would not have had to make if it at that moment it could have generated more rather than store or spill water for fish purposes. *The understanding does not apply to, and no 4(h)(10)(C) credit is given for, foregone revenues, as these are not actual expenditures by Bonneville.*

The effect of the credit is to reduce Bonneville's annual Treasury payment, thus reducing the revenue requirement to cover costs that must be recovered in rates. How Bonneville determines and demonstrates that a power purchase is related to the fish and wildlife program is a matter for Bonneville and Treasury/OMB to agree to. For 4(h)(10)(C) credit purposes, Bonneville calculates energy purchase costs associated with fish and wildlife operations using market electricity prices but it does not include foregone revenue from loss of spring and summer sales due to bypass spill. This method of calculating costs is not a Fish and Wildlife Program or Power Plan issue for the Council, and the Council does not analyze or estimate the amount of the 4(h)(10)(C) credit in any year. However, the Council does support Bonneville's effort to account for and obtain the full amount of credit it is due.

Revenue and Rate Effects

As noted above, changes in system operations for fish and wildlife purposes have an effect on generation, and thus on power sales, and thus on Bonneville's revenue. Changes in generation patterns that affect the ability of the system to serve firm power loads will have an immediate revenue effect perhaps, but may not necessarily reduce revenues in the long-term. This is because the resource deficit is replaced in some way by other resources and may or may not have a *revenue* effect depending on how it is replaced. Resources added to replace lost hydroelectric capability will have cost impacts, of course, as do all conservation and generation resource additions and thus will have an impact on rates.

On the other hand, a significant portion of the operational requirements for fish -- and especially all or most of the spring and summer spill -- has an effect not on firm power but on the amount of nonfirm or surplus power the system is able to produce for sale on the wholesale power market. That, at the time spill occurs, the hydropower system ordinarily produces more than enough power to meet firm loads and also generate for surplus sales; if the system could spill less, the result would be more power for surplus market sales. These generation impacts do not necessarily require resource planning and resource acquisitions to meet load obligations -- instead, the primary if not the only "cost" effect is on revenue. (A change in the amount of surplus hydropower sales may also have an effect on carbon emissions, if such sales displace others' use of carbon-emitting resources.)

To date, no firm resources have been acquired to replace energy loss due to bypass spill requirements. This could change in the future because the region is quickly approaching a condition where summer capacity needs may outweigh winter or annual needs. When that happens, and resources are acquired to serve firm summer loads, then simply using market prices to assess spill cost would not be appropriate. For the present, using market prices to assess bypass spill costs is appropriate.

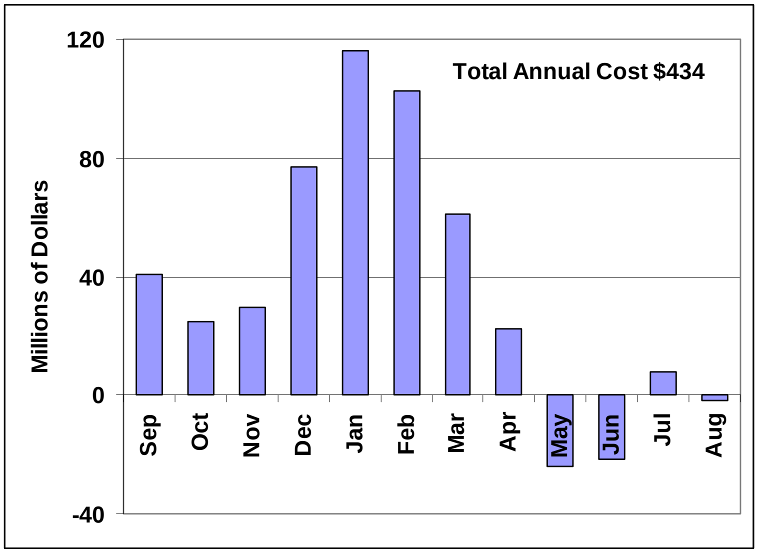
The real effect at Bonneville is to alter the relative level of contributions from (a) surplus sale revenues and (b) firm power rates in covering Bonneville's costs. The greater the surplus sale revenue, the less the contribution needs to be in rates, and vice versa. Bonneville will still collect the revenue and cover its costs -- the effect is to alter the allocation of those costs to different revenue streams.

In this perspective, this is a rate and revenue matter at Bonneville, not a Power Plan resource issue and not a Fish and Wildlife Program issue. The size of this revenue effect is routinely calculated for the entire difference between the revenue generated assuming current fish operations and the estimated revenue that might be generated assuming no fish operations, usually valued at market prices. Some find this a useful number to know, to understand the magnitude of the revenue/rate shifting effect over time, although the total amount is largely irrelevant in terms of having an effect on current decisions (and presumably overstates the rate impact of replacing the generation related to firm power, as Bonneville should have replaced this resource at an average system cost for the added resources, not at market prices).

In any event, this overall value is determined by first assessing the expected monthly secondary (or surplus) sales or market purchases for both current and pre-1980 operations over the entire range of potential water conditions. The secondary energy sales or purchases are converted to dollars by multiplying the associated energy by the expected monthly electricity price. The expected monthly electricity price will vary by water condition and by hydroelectric system generation. The monthly price is further adjusted to take into account peak and off-peak effects. Thus, a pattern of monthly electricity prices is created for each of the 70 water conditions analyzed. This matrix of electricity prices is multiplied by the matrix of energy sales or purchases for each case. The monthly cost or benefit is averaged across all water conditions and is then summed over all months to yield a total, which for this case is in the range of $450 million. On average, the power system cost is almost evenly divided between flow augmentation (average cost of about $230 million/year) and bypass spill (average cost of about $220 million/year).

Figure M-20 summarizes the average monthly cost of the fish and wildlife program relative to a pre-1980 operation. Positive values in Figure M-20 reflect regional costs and negative values represent benefits. Generally, the cost of a particular change in hydroelectric system operation is inversely proportional to the change in generation, so the pattern in Figure M-8 is similar but reversed from that in Figure M-14. In other words, an operation that causes a decrease in generation usually represents a cost to the system. However, this pattern is not exactly inversely proportional because cost depends on electricity prices and they depend on available generation. For example, May shows a decrease in average generation in Figure M-14 but in Figure M-20 it shows a net revenue increase. This is because a reduction in the available generation during that month causes electricity market prices to increase. Thus, even though less energy is available for sale, it is being sold at a higher price and produces higher revenues. A more detailed description of how cost is assessed is provided below.

Figure M-20: Average Monthly Cost using Market Prices



Bonneville also incurs a number of the other costs of implementing the Fish and Wildlife Program that must be covered through rates and surplus revenues. These include:

Capital Costs: These costs include the projected amortization, depreciation and interest payments for fish and wildlife-related capital investments by the Corps of Engineers and Bureau of Reclamation for which Bonneville is obligated to repay the power share to the US Treasury, as well as similar costs generated by direct capital investments by Bonneville. This includes construction and installation of fish bypass systems, turbine intake deflector screens, spillway weirs, fish collection systems, artificial production facilities, and land acquisition for habitat purposes.

Reimbursable/Direct Funding Costs: These costs include the hydroelectric system's share of operations and maintenance costs and other non-capital expenditures for fish and wildlife activities by the Corps of Engineers, Bureau of Reclamation and U.S. Fish & Wildlife Service that pre-dated the Northwest Power Act.

Direct Program Costs: These costs include expenditures for non-capital fish and wildlife activities consistent with the Council's Fish and Wildlife Program and elements of NOAA Fisheries' and the FWS' Biological Opinions. This includes funding for tributary and estuary habitat improvements, predation control, operations and maintenance costs for direct program investments in habitat and production activities, and monitoring, evaluation, research, and coordination projects. Bonneville estimates these expenditures will amount to $231 million per year[16] over the next five years. The direct program costs also include the costs of servicing the direct capital investments Bonneville has made and intends to make for fish and wildlife purposes. Bonneville estimates it will invest an average of $56 million per year over the next five years[17].

[16] The direct Program, 2008 BiOp and Fish Accord budget estimates for the next five years represent budget ceilings; actual expenditures may be less.
[17] Taken from Bonneville's 2008 Integrated Program Review, the capital budget estimate for the next five years represents the maximum cost; actual expenditures may be less.

The current power system has absorbed these costs and remains economical, although there are alternative ways of thinking about the economical criterion. One is whether the per-kilowatt-hour costs of the system have increased significantly in comparison to other regions. On this basis, the power system is clearly less economical than it was. However, in terms of absolute electricity cost, the Northwest still ranks as one of the lowest cost regions in the nation. Unfortunately, this aggregate assessment does not capture potential impacts on specific sectors of the economy. In particular, electricity-intensive industries, such as aluminum smelting, are proportionately harder hit by increases in electricity costs. In fact, most aluminum plants in the region have ceased operation due to high operating costs. Fish recovery costs have contributed to this, although in the current context, they are not the major contributor.

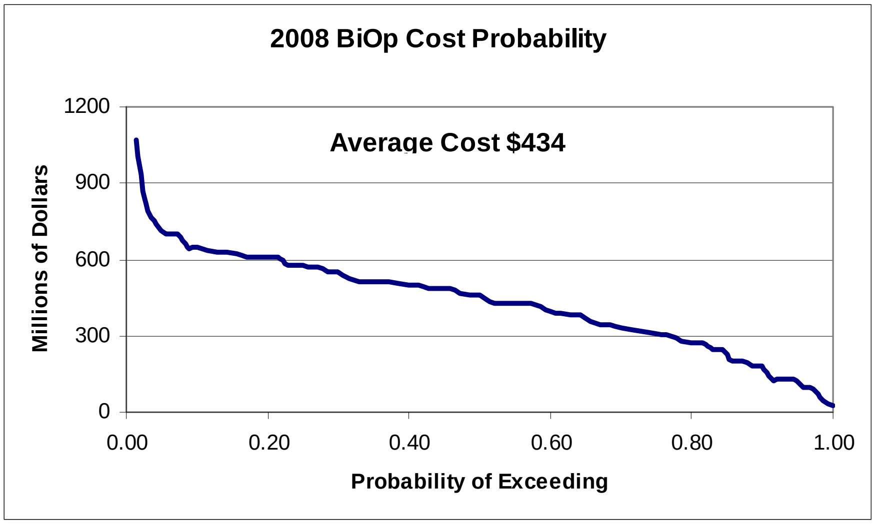
In aggregate, the region's power system has been assessed to be adequate both in terms of energy and capacity needs for at least the next five years.[18] That assessment shows that the balance between resources and loads is above the minimum thresholds defined in the Council's resource adequacy standard.[19] Those minimum thresholds, however, should not be mistaken as a resource planning targets. The types and amounts of resources the Northwest should acquire over and above the minimum thresholds must be assessed in an integrated resource planning process, so that other factors, such as economic risk, can be taken into account.

Cost Uncertainty

Although the average *power system operations* cost of the fish and wildlife program is about $450 million (*if* for convenience sake using market prices to represent the entirety of the operational effects; *but see* the discussion of replacement resource costs above), differences in water conditions from year-to-year result in a range of actual effects, and so costs can range from a high of about one billion dollars to a low of just several million dollars, as shown in Figure M-21. The likelihood of the region experiencing a cost greater than $600 million in any given year, however, is only about 20 percent. Similarly, the likelihood of a cost less than $300 million is also about 20 percent.

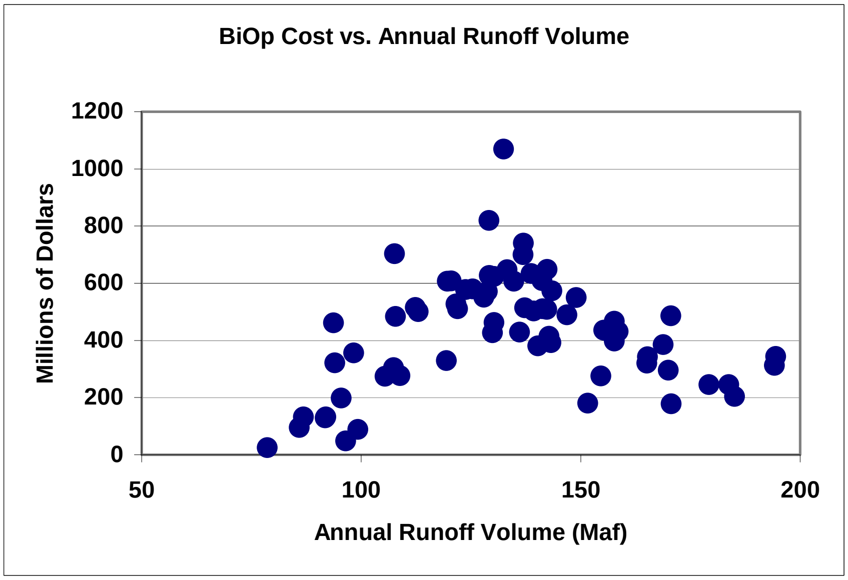
[18] See http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc.
[19] See http://www.nwcouncil.org/library/2008/2008-07.pdf.

Figure M-21: Range of Annual Cost for Fish and Wildlife Operations (2010 operating year, 2008 dollars compared to pre-1980 operations)



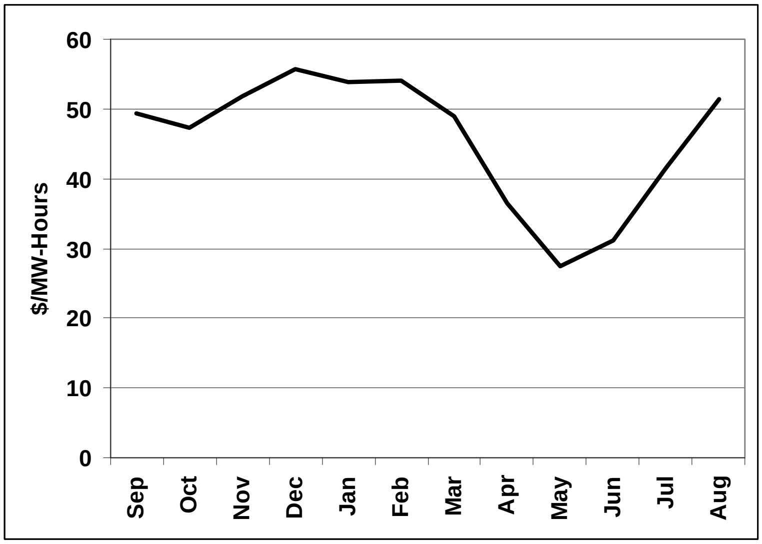
It is beneficial for planners to understand how these costs vary with water conditions. Figure M-22 plots the power system cost of the fish and wildlife program as a function of the annual runoff volume. Initially, one might think that costs would be greater in dry years since water is scarcer. However, the pattern of costs shown in Figure M-22 does not reflect that relationship. In that figure, costs are low in the dry years as well as the wet years and are highest for more average runoff conditions. In order to explain this apparently non-intuitive phenomenon we must describe in more detail the two major components of fish and wildlife operations, that is, flow augmentation and bypass spill.

Figure M-22: Cost as a function of Runoff Volume



Flow augmentation or holding water back during winter months for release in spring and summer, effectively moves hydroelectric generation from months with high electricity prices into months with lower prices (see Figure M-23). The amount of water that is shifted depends on the forecasted runoff volume. Generally more water is held in reservoirs for flow augmentation during dry years. In wet years, water must be evacuated by early spring for flood protection thus leaving less water in reservoirs for augmentation. Given this general observation, one would assume that fish and wildlife costs would be highest in the dry years and lowest in the wet years. However, electricity prices are affected by the availability of hydroelectric generation and in general are higher in years with low runoff volume. So, in some dry years, shifting water from winter months into summer months may actually cost less than in a year with average runoff conditions. But that is not the whole story. We must also remember that the costs in Figure M-22 also include the effects of bypass spill.

Figure M-23: Forecast Bulk Electricity Prices (Mid-Columbia, 2010 operating year, 2008 dollars)



Bypass spill is water that is routed around turbines to enhance survival of migrating smolts. It always represents a loss of generation and revenue. The cost of spill varies with water conditions and electricity prices. Generally, as the runoff volume increases, so does bypass spill because for some projects bypass spill is specified as a percentage of outflow. However, as runoff volumes begin to approach average conditions, spill is often limited by total dissolved gas supersaturation limits imposed under the Clean Water Act by the state water quality agencies. That is, once the absolute volume of spill causes gas levels to reach the gas limit, no more volume is spilled. At this point, bypass spill costs level off.

As runoff volumes continue to increase, however, bypass spill costs actually begin to decrease (illustrated in Figure M-24). That is because of a condition referred to as forced spill. When the hydraulic capacity at dams is exceeded, water in excess of that capacity must be spilled. This forced spill volume counts toward the required bypass spill and because forced spill would have occurred anyway, some of the bypass spill requirement is provided at no cost. For very wet years, forced spill can equal or sometimes even exceed the required bypass spill volume. The actual relationship between bypass spill cost and runoff volume is shown in Figure M-25 and its effect on the overall pattern of fish and wildlife costs (Figure M-21) is evident.

Figure M-24: Illustration of Bypass Spill Flow as a function of Outflow

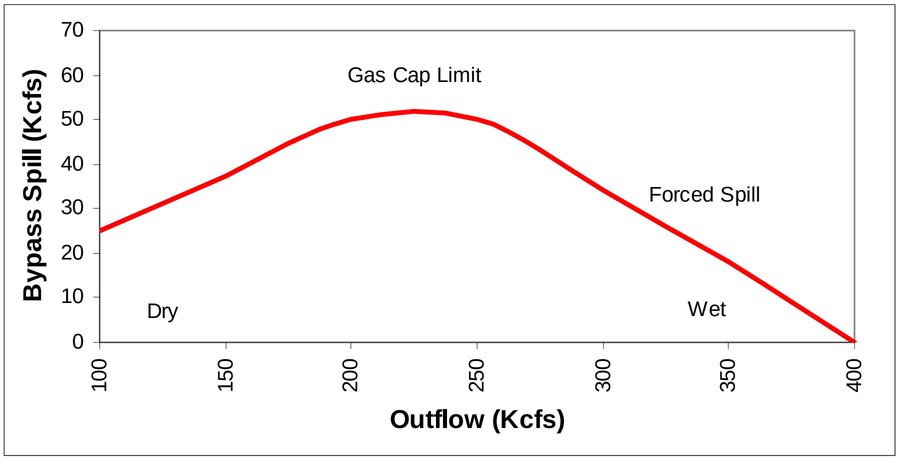
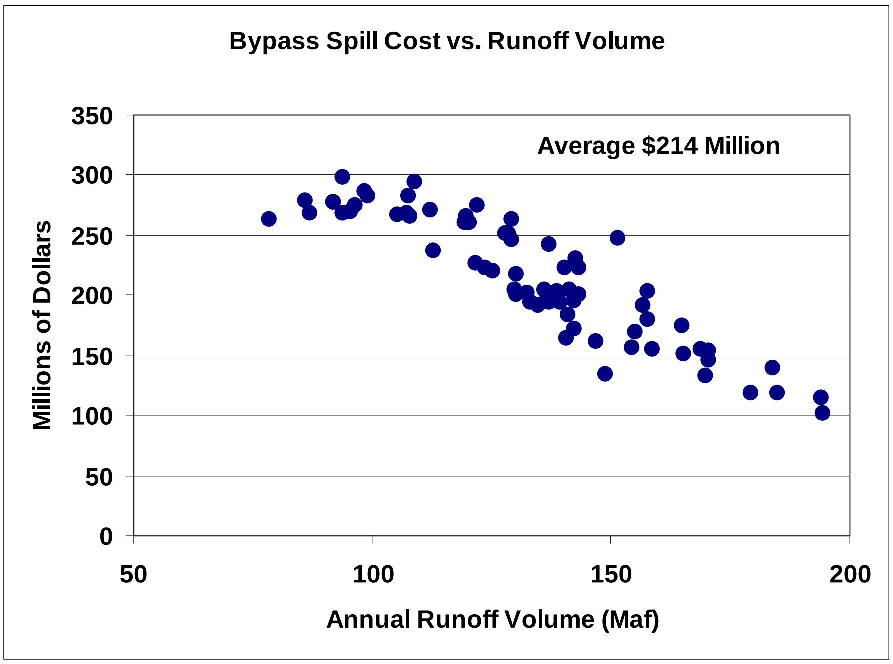


Figure M-25: Bypass Spill Cost as a function of Runoff Volume (2010 operating year, 2008 dollars)



PART 3: DEALING WITH AN UNCERTAIN FUTURE

Finally, even if we are able at present to integrate the needs of the river's fish and wildlife and the region's power supply adequately, the future holds a number of challenges for our continued ability to do so. These include the uncertainties and risks related to (1) possible further changes in the operations to benefit fish and wildlife; (2) an evolving power system that is integrating different kinds of generating resources than in the past, resources that put new and different requirements on the hydropower system; (3) possible modifications in Columbia River Treaty operations in the next decade, for both power and non-power reasons; and (4) climate change effects on the amount and shape of runoff and on electricity demands that will pose problems for both fish and wildlife and power generation. This part of the appendix addresses future uncertainty and risk.

The power plan has a 20-year planning horizon, which requires that potential future changes must be assessed in the hydroelectric system or fish and wildlife needs over that time period. The resource strategy developed in this power plan must be sufficiently robust to accommodate these potential changes in order to continue to provide desired fish conditions and an adequate and reliable power supply. The challenge is to identify the uncertain but possible areas of change, assess the possible range of effects and develop a set of actions to accommodate these changes. This implies that the power plan must be flexible and dynamic so that it can deal with uncertainties if and when they occur.

Likely categories for significant change include additional operations for fish, reduction in hydroelectric system flexibility due to increasing amounts of variable resources (such as wind), possible changes in the Columbia River Treaty, climate change**,** and potential bypass spill reductions associated with spillway weirs.

The Council along with other regional entities, including the Independent Economic Advisory Board[20] recently examined the interactions between fish and power operations and identified several important factors to be considered in the development of this plan:

- In the long term, hydroelectric generation could increase due to installation of spillway weirs at federal dams. Spillway weirs are designed to increase juvenile migrant passage survival while reducing the volume of bypass spill. Unfortunately, evaluation of the effectiveness of these weirs has been mixed and projections of future energy savings cannot be assumed at this time. The Council assumed no long-term increase in hydroelectric generation due to spillway weirs.

- There remains a great deal of uncertainty regarding the amount of future bypass spill, which is still being litigated. It is possible that long-term hydroelectric generation will decrease due to increased spill requirements, similar to the increased spill that a federal judge has required for 2009. However, quantifying this potential loss is difficult because of the possibility of future legal actions. The Council's set of current operations used to develop its resource strategy do not include additional bypass spill.

- Mainstem operations for fish and wildlife tend to reduce the hydroelectric system's flexibility and increase the cost of integrating wind resources. Flexibility of electricity supplies is vital to ensuring a reliable power system. Efforts are underway to quantify this loss of flexibility. Some, but not all, of the effects of this loss of flexibility were captured in the Council's analysis for the plan. However, the Council recommends continued regional participation in discussions and analysis of this issue.

- New water management strategies or development of new storage facilities would clearly affect hydroelectric generation in the long term. However, given the long lead time required to develop and implement these projects, it is not likely to happen in the short term, if at all. Thus the Council assumes that no new water management strategies or storage facilities will be implemented for the power plan analysis.

- Terrestrial and wetland habitat protection and restoration funded by the fish and wildlife program may create opportunities to develop carbon credits. Discussions of potential

[20] Reference IEAB report here.

benefits to the power system are just barely underway. No assumptions regarding potential future carbon credits for habitat development were included in the plan.

Other potential long-term changes may include additional or different operations for fish such as:

- Lower operating elevations during the migration season (e.g., John Day Dam at minimum operating pool elevation instead of minimum irrigation pool elevation);
- Additional volumes of water for flow augmentation (i.e., allowing reservoirs to be drafted deeper by summer's end);
- Different pattern of water releases during the migration season;
- Removal of one or more mainstem federal dams;
- Revised Columbia River Treaty operations;
- Revised use of non-treaty storage; and
- Changes to flood control operations

The potential effects of climate change show impacts to both power and fish. Current analysis indicates that the Northwest is likely to see higher winter river flows and lower summer flows. At the same time, winter demand for electricity should decrease and summer demand would increase with rising temperatures. This effect should ease the pressure on the hydroelectric system in winter but make it more difficult over summer months, especially with the addition of more and more variable resources. Also, current renewable portfolio standards have already affected resource acquisition strategies and will likely continue to do so if they are modified or replaced by federal legislation. Potential carbon tax or cap-and-trade mechanisms will also alter future resource plans.

Ongoing changes in power markets and westwide power integration may also bring changes to the way we use and value the power system (e.g. generation in summer may become more and more profitable). These kinds of changes present challenges for fish and wildlife operations, but may also present positive opportunities. For example, releasing more stored water during summer months not only increases revenues but also provides higher river flows for migrating smolts.

For this plan, long-term uncertainties already include load, fuel and electricity prices, runoff conditions and carbon penalties. Uncertainties not explicitly incorporated into resource plan development include the effects of climate change, modifications to fish operations or changes in the Columbia River Treaty. Because of difficulties in quantifying the range and magnitude of these latter uncertainties, it is best to assess these by means of sensitivity analysis. Studies can be performed to determine the potential effects of these changes, either independently or in combination. However, the magnitude of potential impacts must be considered in conjunction with the likelihood of occurrence, that is, a potential uncertainty may have a large impact but might be extremely unlikely. The region should continue to explore and analyze such scenarios to be better prepared should these unlikely events occur.

While there is much the Council can do as part of both the fish and wildlife program and the power planning process to analyze and respond to these long-term agencies, regional cooperation is also needed. Federal agencies have already formed several committees to deal with in-season operational issues affecting fish and power. For example, the Technical Management Team (TMT) consists of technical staff from federal, state, and tribal agencies that usually meet on a weekly basis during the fish migration seasons to assess the operation of the hydroelectric system. Requests for variations to those operations can be made and discussed at TMT meetings. Conflicts that cannot be resolved at the technical meetings are passed on to the Regional Implementation Oversight Group (RIOG), which consists of higher policy-level staff. This new process of resolving conflicts in proposed hydroelectric operations is untested.

While the existing committee structure is intended to solve in-season problems, no currently active process exists to address long-term planning issues related to both power planning and fish and wildlife operations. The Council encourages the creation of an open forum where fish and wildlife managers and power planners could jointly explore strategies to improve both fish and wildlife benefits and hydroelectric power operations. In such a forum, synergistic effects between fish and wildlife operations and power planning could be examined. For example, conservation savings in irrigation should also provide savings in water quantity and energy, which could benefit both in-stream flows for fish and reduce load on the power system. Also, the State of Washington is currently exploring options for new storage sites, which could benefit fish, power and irrigation. And finally, potential carbon emission mitigation benefits of actions to acquire or improve fish and wildlife habitat should be assessed.

Action Plan items F&W-1 (long-term planning forum); F&W-3 (analytical capability), F&W-4 (Columbia River Treaty), and F&W-5 (climate change) are intended to help the Council and the region to develop the tools needed to address these uncertainties.

Appendix N:Financial Assumptions and Discount Rate

INTRODUCTION AND SUMMARY

The Council uses a real discount rate of 5 percent for its analysis for the upcoming power plan. This is based on mid-term forecasts of the cost of capital to the entities or sectors examined. The sections below briefly review the need for a discount rate, the various approaches that have been taken in the literature and relied upon by the Council in the past, and the development of the specific values that are suggested to be used. The appendix also notes that, unlike other data in the power plan, which can be used directly by the various regional entities responsible for meeting loads, the discount rate used in the Council's analysis is a composite rate that will not be directly applicable to most of these entities making resource decisions. The approach to calculation of a discount rate is applicable, however.

The underlying financial assumptions were updated in January 2009, based on the then most-recent Global Insight long-term forecast. They will be reviewed again before the final analysis for the Power Plan.

BACKGROUND

Investment analysis, such as that for the Council's plan, typically has to compare projects with different time patterns of costs. A conservation project or a wind turbine installation, for example, is characterized by high fixed investment costs and low operating expenses. With initial capital costs repaid over time, the time pattern of costs for this type of investment will typically look generally flat over its lifetime. Contrast this with, for example, a combustion turbine investment, where the bulk of the cost is in the fuel rather than the fixed cost. With any escalation in real terms – above the general level of inflation – the biggest part of the lifetime cost will come in future years.

The discount rate is a fundamental piece of the Council's resource analysis for the power plan. The discount rate is the piece that tells us the rate of time preference we are applying to the analysis, that is, how much relative importance we give to costs and benefits in different years in the future. The discount rate is used to convert future costs or benefits to their present value. A higher discount rate reduces the importance of future effects more than a lower discount rate. All else equal, a higher discount rate would tend to value a combustion turbine over a wind project, for example, by disproportionately reducing the higher fuel costs in future years. On the other hand, a low discount rate would not reduce the effects of those future costs so much. A discount rate of 0 percent for example, would treat effects in all years, whether next year or 30 years from now, the same in terms of their impact on the investment decision taken now.

This notion of time preference is not, however, an abstract preference for the short term versus the long term. Time preference is directly tied to the concept of a market interest rate. Putting aside questions of risk temporarily, a dollar to be paid next year is less of a burden than a dollar this year. That is because one could invest less than a dollar today and, assuming sufficient return on that investment, use the proceeds to pay the dollar cost next year.

From the other side, a dollar benefit this year is more valuable than the same dollar benefit next year, because it can be turned into more than a dollar next year by investing it. The important point here is that dollars at different times in the future are not directly comparable values; they are apples and oranges. Applying a discount rate turns costs and benefits in different years into comparable values. Because the Council's analysis looks at annual cost streams of various resource types, discounting is required in order to calculate and fairly compare total costs of alternative policies.

Market interest rates embody the effect of everybody's rates of time preference. Individuals and businesses that value current consumption more than future consumption will tend to borrow, and those that value future consumption more will save. The net effect of this supply and demand for money is a major factor in setting the level of interest rates, as are the actions of the Federal Reserve in setting the federal funds rate and influencing inflation expectations through its actions on the aggregate money supply. Market interest rates also embody considerations of uncertainty of repayment, inflation uncertainty, tax status, and liquidity, which together account for most of the variations among observed interest rates.

Because of this overall relationship between rates of time preference and interest rates, the level of the discount rate should be related to the level of interest rates. The difficulty is in determining which interest rate is the appropriate one for the choices being made. There are three general approaches in the literature that can be used for this choice, which can be described as the regional consumer's perspective, the corporate perspective and the national perspective.

Finally, risk and uncertainty in capital project evaluation is sometimes treated by modifying the discount rate and sometimes by directly modifying the treatment of costs and benefits in the analysis. There are theoretical arguments in the economic literature on all sides of these issues. The Council's analysis evaluates project risk and uncertainty explicitly and does not incorporate it into the discount rate decision.

Regional Consumer's Perspective

The regional consumer's perspective looks at the after-income tax returns available to regional consumers to determine their rate of time preference. This perspective bypasses considerations of who, or what kind of entity, is making the investment decision and addresses the question for whom the investment is ultimately being made, regional utility customers in this case. The Council had taken this perspective in earlier plans and had examined a number of different kinds of interest rates that individuals earn or have to pay, ranging from savings accounts with negative real after-tax returns, through mortgages and stock and bond market returns, to the cost of credit card interest, which is quite high in real, after-tax terms. Generally, the Council had concluded that mortgages and stock and bond investments best represented the household consumer's rate of time preference.

Corporate Perspective

The corporate perspective addresses the perspective of who, or what kind of entity, is making the investment decision. It typically looks at a company's weighted cost of capital, adjusted for the deductibility of bond interest from corporate income taxes to the company, as the starting point for choosing a discount rate to evaluate investment decisions. With this approach, we would use a cost of capital roughly weighted by the types of financial entities represented by the utilities in the region (municipally financed, treasury financed, taxable-market financed and equity financed).

The literature on corporate investment decisions almost uniformly holds that the correct discount rate is the firm's tax-adjusted cost of capital. Broadly considered, this perspective uses the cost of capital to the entity making the investment decision. While most of the literature focuses on private corporate entities, this perspective is also applicable to entities with other forms of ownership, as long as they are externally financed. Using the corporate cost of capital as the discount rate will ensure that the decisions that are made maximize the value to the owners of the firm. This argument would also apply to publicly owned entities without stockholders.

There is a second argument in favor of this perspective that would also apply for those entities without stockholders or for those which have a focus on something other than owner wealth maximization. This argument holds that the majority of the investment decisions in the U.S. are made by private corporations that use this investment rule. To use another rule for a limited sector of the economy would distort investment patterns in the overall economy, either over-investing or under-investing, depending on whether the discount rate is lower or higher than appropriate.

This is the perspective that has been adopted (implicitly or explicitly) by the region's IOUs and the utility commissions who regulate them. With this perspective, Bonneville would use its cost of capital – treasury borrowing plus a markup – and the region's publicly owned utilities would use theirs – tax-exempt municipal bond borrowing. The Council uses the corporate perspective in preparing forecasts of future generating resource development and power prices, under the assumption that on-the-ground resource development decisions will be based on corporate discount rates.

National or Social Perspective

There is a third perspective, which might be called the "national consumer's" or the "social" perspective. This is similar to the regional consumer's perspective except that it looks at pre-tax returns/costs rather than after-tax returns/costs. From an overall social perspective, income taxes are a deliberately incurred device that, among other things, raises the cost of capital to individuals and most corporate entities[1]. This is sometimes combined with the corporate perspective in arguments that national government investments should adopt some form of the private sector's cost of capital as the discount rate, using, however, the pre-tax rather than the tax-adjusted cost (as the firm itself would use).

Risk and Uncertainty Issues

As mentioned earlier, variations in risk and uncertainty account for a major part of the differences among returns to various potential investments. It is important to try to capture these elements of potential investments in the analysis in some manner, and at the same time, not double count them by embodying them in both the discount rate and the rest of the analysis. The Council's resource analysis explicitly accounts for major uncertainties and risks, such as water conditions, load growth uncertainty, fuel prices, power market prices, CO2 mitigation requirements, and so forth.

APPROACH CHOSEN

In the Fifth Power Plan, the Council adopted the corporate perspective in setting the discount rate. This paper is recommending that the Council continue to use the corporate perspective in adopting a discount rate for use in the Sixth Power Plan. This approach is most frequently recommended in the economic literature and is widely used in the electric industry, as well as in other industries. It leads to a discount rate that aligns the decision about investing capital with the interest rates and cost of that capital to the entity making the investment decision.

For the Sixth Plan, this approach has been modified to include the effect of other investment decision makers, end-use consumers, as appropriate for the decision in question, rather than implicitly assuming that all decisions on resources are made by utilities. This will be described further below.

It should be noted that, unlike much of the analysis and data provided by the Council in its plans, which are directly useable by the entities acquiring resources, costs of capital and discount rates derived from them are specific to each entity. A composite rate, such as the Council uses, will not likely be appropriate for use by any particular utility, though the Council's approach to choosing a value should be useful and is recommended.

CONSIDERATIONS IN CHOOSING A SPECIFIC VALUE FOR THE COUNCIL'S PLAN

The plan will be completed in mid-late 2009, and the period over which it will be most relevant for decision making will be the succeeding five years, starting in 2010. Consequently, the analysis looks at forecast data for 2010 - 2014.

The approach in this appendix builds on two sets of assumptions. The first is the relative shares of future investment decisions made by different actors (BPA, publicly owned utilities, IOUs and residential and business customers). The second is a set of forecast data developed by Global

[1] This effect is partially mitigated by the reduction in income taxes afforded by the deductibility of interest payments mentioned above.

Insight, a national economic consulting firm, whose forecasts are used for various purposes by the Council.

The first set of assumptions looks at decision makers. Because the chosen approach looks at investment decision makers, and because a significant fraction of the conservation resource is expected to be paid for directly by consumers, we have made assumptions about the shares of the ultimate portfolio that will be made up of generation and conservation and the shares of the conservation decisions that will be made by consumers. Generation decisions will be made by utilities; conservation investment decisions will be made both by utilities, through purchase or rebate programs, and by consumers directly. An assumption has also been made about the share of the public agencies' new resource requirements that will be placed on Bonneville under the new contracts. That share will be evaluated at a Bonneville discount rate.

Plausible changes from the reference assumptions would affect the ultimate discount rate somewhat. Because of that both the reference assumptions and a range of assumption values have been examined. Both are shown in Table N-1 below. Moreover, the final calculated value, described later, has been rounded rather than an attempt being made to capture unrealistic precision.

Table N-1

Entity or Item	Reference Share	Range
BPA share of publics' generation needs	.20	.10-.30
Generation share of new resource	.60	.50-.70
Conservation share of new resource	.40	.50-.30
Utility share of conservation cost	.60	.50-.70
Consumer share of conservation cost	.40	.50-.30
Residential share of consumer conservation	.33	.30-.40
Business share of consumer conservation	.67	.70-60

The second set of assumptions consists of cost of capital estimates for the various decision-making entities described above. As noted, they are based on the most recent forecasts of financial variables as of January 2009 by Global Insight (these assumptions will be updated before the analysis for the final Power Plan). There are five basic inputs to the calculation from this forecast, all averaged over the years 2010-14: GDP deflator, used to convert to real terms, and nominal 30 year Treasury bond rates, 30 year new conventional mortgage rates, long-term AAA rated municipal bond rates and long-term Baa corporate bond rates. These values are shown in Table N-2 below:

Table N-2

Item	2010-14 Average
GDP deflator	2.04%
30 year Treasury	5.74%
30 year new conventional mortgage	7.07%
Long-term AAA municipal bond	5.39%
Long-term Baa corporate bond	7.63%

The discount rates that are used for the three major categories of retail load-serving entities (municipals/PUDs, coops and IOUs) are distinguished by their financing costs and estimates can be derived from the above values.

Municipal utilities and public utility districts are assumed to be able to borrow at AAA municipal bond rates, or 3.3 percent in real terms. Coops are able to finance at about 100 basis points above Treasury rates, implying a rate of 6.7 percent or 4.6 percent in real terms. Bonneville financing is about 90 basis points above Treasury rates for long-term borrowing, implying a rate of 4.5 percent in real terms.

The discount rates used by regional IOUs in recent integrated resource plans ranged between about 7.0 - 7.6 percent in nominal terms, or 5.0 - 5.2 in real terms, using the inflation rates assumed in the various IRPs[2]. They represent the tax-adjusted weighted average cost of capital (WACC) for the utilities and typically employ the allowed rate of return from the most recent rate case. They are substantially higher than the other entities' rates both because of the large equity component in their capital structures and because their credit ratings on debt are relatively weaker.

A composite value for the IOUs using the assumptions in this paper can be calculated using the current cost of equity, roughly averaged from the data, and a cost of debt based on the forecast cost of Baa debt, adjusted for its tax deductibility. This is necessary because the effective cost of the debt is lower because it is deductable for corporate income tax purposes, just as home mortgage debt is deductable for personal income tax purposes. This calculation would give 5.3 percent in real terms, similar to the range of values (5.0 - 5.2 percent) being used in the integrated resource plans of several of the IOUs using their own calculations and forecasts of inflation.

The approach for assessing decision making by consumers for the consumer-funded portion of the conservation is similar, though it looks mostly at different data. DOE has recently conducted a study on consumer discount rates[3] for the purpose of evaluating some proposed national lighting standards. On the residential side, they looked at a range of assets and borrowing sources available to individual consumers[4], weighted by their historic use based on the Federal Reserve Board's Survey of Consumer Finances over a recent 15-year period. Based on this historic data analysis, DOE calculated a real consumer discount rate of 5.6 percent. (More details of this calculation are in Section 8.2.7.1 of the DOE report cited in Footnote 4.)

We can also look at the Global Insight forecast data, which has been used for the previous calculations in this paper, though this forecasts a much more limited range of assets than the DOE data looked at. It has one series that can be taken as one kind of proxy for a consumer discount rate, the 30-year mortgage rate. That forecast rate, averaged over the period 2010-14 is 7.07 percent. Because mortgages are deductable for income-tax purposes, the net cost to consumers is lower. Assuming a 20 percent tax rate gives an after-tax mortgage cost of 5.66 percent or 3.5 percent in real terms. Because that is significantly less than the average calculated

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[2] To the extent they are explicit, the IOU IRPs use various inflation rates that are more or less different from the assumption in this paper. Where the calculation is explicit, the recent IOU discount rates are reported as ranging from 5.0 - 5.2 percent in real terms.

[3] http://www.eere.energy.gov/buildings/appliance_standards/residential/gs_fluorescent_incandescent_tsd.html

[4] Similarly to the approach used by Council in earlier plans, when it took a region consumer's perspective.

by DOE, primarily because of the tax deductibility effect for this particular asset, the final calculation will again use a range for this variable, along with the ranges for the others.

The last item that needs to be calculated is the discount rate for business consumers. DOE also estimated values for this, based on a different approach than they had used for residential consumers. They used the Capital Asset Pricing Model, a widely used approach in financial economics, to calculate the cost of equity for a large sample of commercial and industrial companies. Using the same data base from which the companies were drawn, they extracted estimates of cost of debt, debt/equity ratios and factors relevant to the calculation. Using an estimate of long-term Treasury rates of 5.5 percent (almost identical to the Global Insight forecast used here, 5.7 percent) and an inflation forecast of 2.3 percent (higher than that used here, 2.0 percent) they derive real industrial and commercial discount rates of 7.5 and 7.3 percent, respectively. (More details are available in Section 8.2.7.2 of the DOE paper cited in Footnote 4.)

In order to make the result somewhat more comparable to the calculations in this paper, the values can be recalculated using the Global Insight forecast of inflation, which has the effect of implying higher real interest rates. That calculation would yield industrial and commercial real discount rates of 7.8 and 7.6 percent respectively.

Note that use of such a rate for business decisions implies relatively unlimited access to capital, which is typically not the case. One approach to capital budgeting in the presence of limited capital is to simply rank projects by net present values; another is to deliberately raise the discount rate to ensure that only the projects that have the most immediate payoffs are pursued. These potential actions can be captured using a higher discount rate for business decisions, in a sensitivity analysis.

In addition to the range of values used for the decision-share assumptions, described earlier in the paper, the recommendation for a discount rate to use in the Council's analysis will be based on a range of real discount rates for business and residential consumer decisions. The final set of assumed values with their ranges is shown below in Table N-3, which partly recapitulates Table N-1. The output of the spreadsheets for the reference and high and low assumption calculations are reproduced in the Attachment. Note that in the calculation of the effect of the individual ranges, the low end is driven by assumptions that drive the result low, which may not necessarily be the low end of any particular range (sometimes the high assumption drives a lower discount rate), and similarly for the high range calculation.

Table N-3

Item	Value	Range
Inflation	2.0%	NA
Municipal/PUD real discount rate	3.3%	NA
Co-op real discount rate	4.6%	NA
IOU real cost of equity	8.8%	NA
IOU real cost of debt	5.5%	NA
IOU real discount rate (tax-adjusted)	5.3%	NA
BPA real discount rate	4.5%	NA
Residential consumer real discount rate	3.9%	3%-5%
Business consumer real discount rate	7.7%	7%-9%
Real discount rate for plan	4.9%	4.7%-5.5%

CONCLUSIONS

Taking account of the range of assumptions used, the Council has chosen a real discount rate of 5 percent be used in the Sixth Plan analysis. The Council expects that individual entities may well have different values at the point at which they actually make investment decisions.

Appendix N1: Attachment

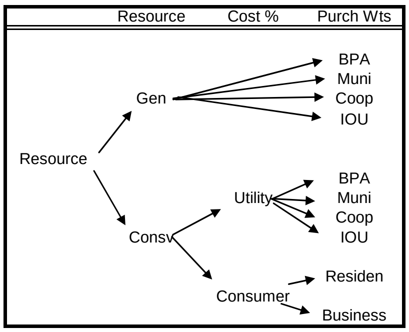
Figure N1-1: Reference Assumptions

Weighted Discount Rate Based on Global Insight 3Q08 Forecasts

Purchaser	Wtd Disc Rate	Real Disc Rate	Purchaser Weight	Consv Respon Share	Utility Res Respon Share	Regional Load Share
Muni	0.008	0.033	0.235	0.168	0.280	0.350
Co-op	0.003	0.046	0.067	0.048	0.080	0.100
IOU	0.025	0.053	0.462	0.330	0.550	0.550
BPA	0.003	0.045	0.076	0.054	0.090	
Residen Cust	0.002	0.039	0.053	0.132		
Business Cust	0.008	0.077	0.107	0.268		
Wtd avg	0.049		1.000	1.000	1.000	1.000

IOU WACC calc

Equity cost	0.11
Tax adj debt cost	0.0496
Debt ratio	0.5
WACC	0.079798
Real WACC	0.053



GI 4Q07 Fcsts 2010-14 avgs

GDP Deflator	0.0204
30 Yr Treasury	0.0574
30 Yr New Morgages	0.0707
AAA Munis	0.0539
Baa Corporate	0.0763

Other factors

BPA adder on 30 Yr Treasury	0.0090
Co-op adder on 30 Yr Treasury	0.0100
Tax-Adj Baa corp	0.0496

Assumptions

Corporate tax rate		0.35
Indivdividual tax rate		0.20
BPA share of publics' gen res respon		0.20
Gen share of future res		0.60
Consv share of future res	(CALC)	0.40
Consumer share of consv cost		0.40
Residen sector share of consv		0.33
Business sector share of consv	(CALC)	0.67
Residential real discount rate		0.039
Business real discount rate		0.077

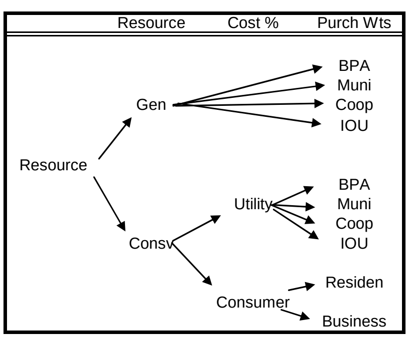
Figure N2-2: Assumptions that Drive Discount Rate Up

Weighted Discount Rate Based on Global Insight 3Q08 Forecasts

Purchaser	Wtd Disc Rate	Real Disc Rate	Purchaser Weight	Consv Respon Share	Utility Res Respon Share	Regional Load Share
Muni	0.006	0.033	0.184	0.123	0.245	0.350
Co-op	0.002	0.046	0.053	0.035	0.070	0.100
IOU	0.022	0.053	0.413	0.275	0.550	0.550
BPA	0.005	0.045	0.101	0.068	0.135	
Residen Cust	0.004	0.050	0.075	0.150		
Business Cust	0.016	0.090	0.175	0.350		
Wtd avg	0.055		1.000	1.000	1.000	1.000

IOU WACC calc

Equity cost	0.11
Tax adj debt cost	0.0496
Debt ratio	0.5
WACC	0.079798
Real WACC	0.053



GI 4Q07 Fcsts 2010-14 avgs

GDP Deflator	0.0204
30 Yr Treasury	0.0574
30 Yr New Morgages	0.0707
AAA Munis	0.0539
Baa Corporate	0.0763

Other factors

BPA adder on 30 Yr Treasury	0.0090
Co-op adder on 30 Yr Treasury	0.0100
Tax-Adj Baa corp	0.0496

Assumptions

Corporate tax rate		0.35
Indivdividual tax rate		0.20
BPA share of publics' gen res respon		0.30
Gen share of future res		0.50
Consv share of future res	(CALC)	0.50
Consumer share of consv cost		0.50
Residen sector share of consv		0.30
Business sector share of consv	(CALC)	0.70
Residential real discount rate		0.050
Business real discount rate		0.090

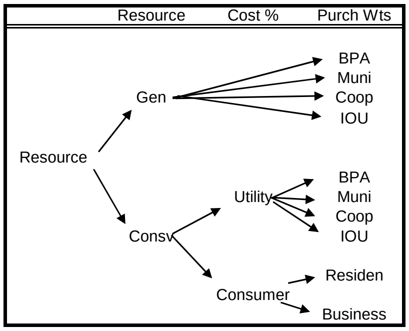
Figure N3-3: Assumptions that Drive Discount Rate Down

Weighted Discount Rate Based on Global Insight 3Q08 Forecasts

Purchaser	Wtd Disc Rate	Real Disc Rate	Purchaser Weight	Consv Respon Share	Utility Res Respon Share	Regional Load Share
Muni	0.009	0.033	0.287	0.221	0.315	0.350
Co-op	0.004	0.046	0.082	0.063	0.090	0.100
IOU	0.027	0.053	0.501	0.385	0.550	0.550
BPA	0.002	0.045	0.041	0.032	0.045	
Residen Cust	0.001	0.030	0.036	0.120		
Business Cust	0.004	0.070	0.054	0.180		
Wtd avg	0.047		1.000	1.000	1.000	1.000

IOU WACC calc

Equity cost	0.11
Tax adj debt cost	0.0496
Debt ratio	0.5
WACC	0.079798
Real WACC	0.053



GI 4Q07 Fcsts 2010-14 avgs

GDP Deflator	0.0204
30 Yr Treasury	0.0574
30 Yr New Morgages	0.0707
AAA Munis	0.0539
Baa Corporate	0.0763

Other factors

BPA adder on 30 Yr Treasury	0.0090
Co-op adder on 30 Yr Treasury	0.0100
Tax-Adj Baa corp	0.0496

Assumptions

Corporate tax rate		0.35
Indivdividual tax rate		0.20
BPA share of publics' gen res respon		0.10
Gen share of future res		0.70
Consv share of future res	(CALC)	0.30
Consumer share of consv cost		0.30
Residen sector share of consv		0.40
Business sector share of consv	(CALC)	0.60
Residential real discount rate		0.030
Business real discount rate		0.070

Appendix P: Calculation of Retail Rates and Customer Bills

In this analysis we present the methodology and the levelized average retail rates and bills for the least risk resource plan under various scenarios. The scenarios are defined in Chapter 9 of the Plan. These rates and bills reflect the impact of conservation investment, CO2 costs and other resource options for each scenario. It should be emphasized that the retail rate calculations presented here are a gross simplification of the detailed calculations and regulatory approval process that rates have to go through. Actual rate setting procedures and calculations will vary across utilities, class of customers and regulatory jurisdictions. The rate calculations presented here are averaged across all customer classes, so relative changes among classes are not reflected. The rates should, however, be valid for comparison across scenarios.

METHODOLOGY FOR ESTIMATING AVERAGE RETAIL RATES

To estimate the retail rates, dollars of revenue requirements are divided by the total retail sales of electricity. To calculate dollars of revenue requirements; the continuing fixed cost of the existing power system was added to the development and operational cost of the future power system. The cost of existing power system is assumed not to change, remaining at 2008 levels, in real terms over the planning horizon. This implicitly assumes that depreciation in cost of existing power system is equal to capital additions to maintain the existing power system. The future system costs consist of the capital cost of the new resources and the non-capital cost of the existing power system. The future system cost is the cost measured in the Resource Portfolio Model (RPM). The consumer's contribution to conservation measures is netted from the total system cost calculated in the Resource Portfolio Model. It should be noted that the average rates and bills shown below are an average of the rates and bills under 750 possible futures.

Estimating Existing Power System Cost:

The total regional revenue requirement for the power system in 2008 is reported to be $11.6 billion dollars. It was estimated that about 85 per cent of that requirement was due to fixed costs, which amounts to about $9.8 billion dollars per year. Figure P-1 illustrates the relative importance of this component; in the $0 to $100 per ton CO2 case it accounts for about 60 mills per kilowatt hour of the total retail rate.

Estimating Future Power System Cost:

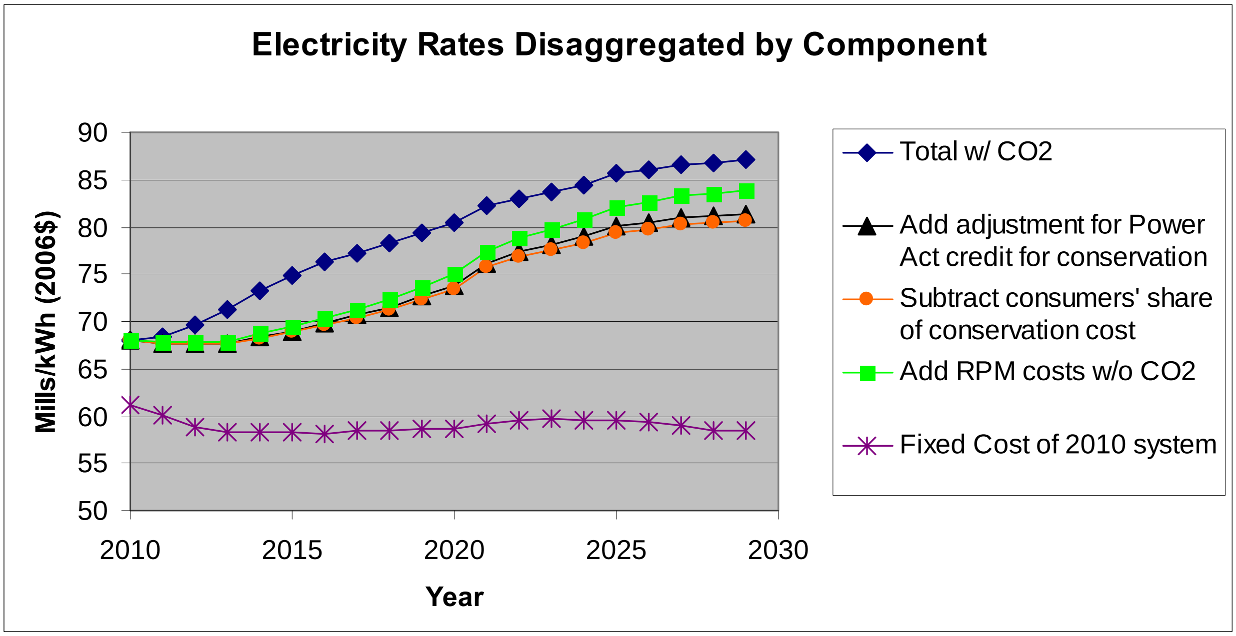
The cost of the future power system consists of levelized costs of conservation resources and capital and non-capital costs of other new resources selected in the Resource Portfolio Model. To translate conservation costs calculated in the RPM model, to conservation costs that should be included in the revenue requirement calculations, the levelized conservation costs[1] are adjusted for the 10 percent Regional Power Act Conservation credit, and reduced by the share of conservation costs paid for by the consumer, assumed to be 35% of the cost. Figure P-1 illustrates that the total costs simulated in the RPM account (excluding CO2 costs) for about 7 mills per kilowatt hour in 2010, rising to about 25 mills per kilowatt hour by 2029. Reducing revenue requirements by the consumers' share of conservation cost into account reduces rates by about 3 mills per kilowatt hour in 2029. Adding to revenue requirements to compensate for the Power Act's Conservation credit raises rates by about one mill per kilowatt hour in 2029.

Cost of CO2 Penalties

The default accounting of the total cost of new system includes cost of CO2 emissions. However, given uncertainty regarding the impact of CO2 costs on power system revenue requirements, the rate impacts are calculated with and without CO2 costs. To the extent that CO2 costs are included in the power system revenue requirement, they are in rates for the consumers served by the generators emitting the CO2, regardless of whether the generators are physically in the region or not. That is, CO2 emissions from power exported from the region are subtracted from CO2 emissions due to regional load and CO2 emissions from power imported to meet regional load are added to CO2 emissions due to regional load. The addition of CO2 costs as though they are paid on every ton of emissions raises rates by about 6 mills per kilowatt hour when added to the components already described above, as shown in Figure P-1.

[1] The conservation premium used to select the level of conservation acquisition does not change the cost of conservation resources and the levelized cost of conservation and the cash-flow of expensed conservation do not vary greatly if conservation acquisition levels are increasing smoothly and do not have significant jumps from one year to next.

Figure P-1: Average Retail Electricity Rates Disaggregated by Component ($0 to $100/ton CO2 Case)



Calculated Retail Rates

The above methodology, averaged across the 750 futures simulated by the Regional Portfolio Model, results in the annual and levelized retail rates for the period 2010 through 2029. The results in Tables P-1 and P-2 represent 13 scenarios defined in Chapter 9. The regional retail rate in 2008 across all sectors was estimated to be about 6.5 cents per kilowatt-hour or $65 dollars per megawatt hour of sales. As an illustrative example, the "$0 to $100 per ton CO2" case projects the rate to increase to about $68 per megawatt hour by 2010. By 2030 the case projects rates to be between $80 and $86 dollars per megawatt hours depending on whether CO2 penalties are paid on all emissions (Table P-1) or whether allowances are distributed to utilities free (Table P-2).

Calculated Monthly Bills

Representative residential bills are estimated beginning with the total revenue requirements calculated earlier, allocating the residential share of those annual revenue requirements (about 39 per cent) to the residential sector, dividing by the projected number of households in future years and dividing by 12 to arrive at monthly bills per household. The results of those calculations are shown in Tables P-3 and P-4.

The Excel workbook on which Tables P-1 through P-4 are based is posted on the Council's web site at: http://www.nwcouncil.org/energy/powerplan/6/Appendix_P_082409.xls

Table P-1: Average Electricity Rates for Least Risk Portfolios by Scenario - CO2 Costs in Rates (All rates are expressed in $2006/MWh (=mills/kWh))

	$0-$100 per ton CO2	Current Policy	Low Cons	Dam Removal	High Cons	Suspend Carbon Policy	No RPS	Retire Coal WO/CO2	Retire Coal W/CO2	$100/ton CO2	$20/ton CO2	PHEV	$0-$50 per ton CO2
Case Identifier	**L811**	**L811J**	**L811A**	**L811B**	**L811C**	**L811D**	**L811E**	**L811I**	**L811G**	**L811H**	**L811K**	**L811M**	**L811Q**
2010	67.96	67.90	67.86	67.96	68.04	67.91	67.96	67.88	67.91	87.89	73.24	67.95	67.93
2011	68.30	67.54	68.09	68.30	68.49	67.55	68.31	67.93	68.58	85.02	72.90	68.29	67.95
2012	69.63	67.30	69.34	69.63	69.86	67.32	69.66	67.96	70.02	84.88	72.59	69.61	68.57
2013	71.14	67.18	70.77	71.14	71.41	67.19	71.16	68.63	72.00	85.46	72.46	71.11	69.37
2014	73.05	67.82	72.61	73.07	73.41	67.50	72.89	70.27	74.61	86.39	72.99	73.00	70.82
2015	74.66	68.33	74.11	74.70	75.04	67.71	74.49	71.89	76.83	87.17	73.43	74.60	72.04
2016	76.07	68.94	75.39	76.14	76.56	68.00	75.74	73.92	79.17	87.25	74.01	75.98	73.07
2017	77.00	69.34	76.09	77.06	77.76	68.07	76.72	75.57	80.81	87.26	74.25	76.76	73.74
2018	77.85	69.73	76.79	77.98	78.72	68.06	77.17	77.22	82.26	87.42	74.69	77.56	74.40
2019	78.93	70.57	77.84	79.07	79.93	68.60	78.20	79.79	84.27	88.13	75.47	78.56	75.39
2020	79.97	71.58	78.82	83.38	81.03	68.76	78.78	82.42	86.20	88.47	76.23	79.57	76.39
2021	81.77	73.03	80.13	84.90	82.66	69.18	80.16	83.02	87.41	88.84	77.56	81.50	77.99
2022	82.49	73.84	80.57	85.57	83.30	69.75	80.32	83.78	88.01	89.55	78.44	82.16	78.87
2023	83.06	74.35	80.99	86.13	83.80	70.15	80.99	84.33	88.54	89.78	78.94	82.72	79.51
2024	83.74	74.66	81.52	86.89	84.24	70.42	81.53	84.85	89.13	90.53	79.32	83.43	80.02
2025	84.87	75.23	82.58	88.01	85.15	70.95	82.71	85.51	90.45	91.61	79.90	84.58	80.89
2026	85.33	75.37	83.12	88.65	85.48	71.12	83.24	85.90	91.18	92.43	80.09	85.13	81.20
2027	85.77	75.58	83.81	89.06	85.90	71.51	83.71	86.38	92.04	93.29	80.41	85.79	81.58
2028	85.98	75.51	84.06	89.46	86.01	71.75	84.06	87.06	92.99	94.08	80.46	85.82	81.60
2029	86.33	75.52	84.47	89.79	86.37	71.89	84.49	87.35	93.55	94.27	80.51	86.12	81.86
Levelized Rates	**$77.37**	**$70.80**	**$76.28**	**$78.70**	**$77.83**	**$68.87**	**$76.48**	**$77.03**	**$80.97**	**$88.44**	**$75.78**	**$77.20**	**$74.60**
Annual Rate of Growth	1.2%	0.5%	1.1%	1.4%	1.2%	0.3%	1.1%	1.3%	1.6%	0.4%	0.5%	1.2%	0.9%
% Δ from $0-$100/ton CO_2	-	-8.5%	-1.4%	1.7%	0.6%	-11.0%	-1.2%	-0.4%	4.65%	14.3%	-2.1%	-0.2%	-3.6%

Table P-2: Average Electricity Rates for Least Risk Plans by Scenario - CO2 Costs Not in Rates (All rates are expressed in $2006/MWh (=mills/kWh))

	$0-$100 per ton CO2	Current Policy	Low Cons	Dam Removal	High Cons	Suspend Carbon Policy	No RPS	Retire Coal WO/CO2	Retire Coal W/CO2	$100/ton CO2	$20/ton CO2	PHEV	$0-$50 per ton CO2
Case Identifier	**L811**	**L811J**	**L811A**	**L811B**	**L811C**	**L811D**	**L811E**	**L811I**	**L811G**	**L811H**	**L811K**	**L811M**	**L811Q**
2010	67.93	67.90	67.83	67.93	68.01	67.91	67.93	67.88	67.88	74.57	68.75	67.92	67.92
2011	67.64	67.54	67.42	67.64	67.83	67.55	67.65	67.93	67.92	72.28	68.23	67.63	67.61
2012	67.50	67.30	67.19	67.50	67.76	67.32	67.53	67.96	67.88	71.47	67.82	67.48	67.47
2013	67.47	67.18	67.03	67.47	67.81	67.19	67.49	68.63	68.46	71.77	67.71	67.43	67.44
2014	68.06	67.82	67.45	68.07	68.53	67.50	67.79	70.27	70.09	72.76	68.30	67.99	68.13
2015	68.67	68.33	67.83	68.71	69.24	67.71	68.29	71.89	71.76	74.55	68.90	68.59	68.74
2016	69.42	68.94	68.35	69.49	70.16	68.00	68.78	73.92	73.99	75.26	69.55	69.28	69.38
2017	70.22	69.34	68.74	70.29	71.32	68.07	69.58	75.57	76.07	75.91	70.00	69.88	69.91
2018	70.99	69.73	69.16	71.10	72.37	68.06	70.04	77.22	78.02	76.70	70.58	70.50	70.47
2019	72.12	70.57	70.11	72.27	73.69	68.60	71.11	79.79	80.71	77.71	71.47	71.54	71.43
2020	73.26	71.58	71.20	75.17	75.00	68.76	71.65	82.42	83.34	78.50	72.48	72.67	72.51
2021	75.51	73.03	72.79	77.09	76.92	69.18	73.29	83.02	85.07	79.43	74.15	75.07	74.28
2022	76.77	73.84	73.56	78.26	77.88	69.75	74.06	83.78	86.19	80.48	75.16	76.16	75.32
2023	77.46	74.35	73.92	78.87	78.40	70.15	74.89	84.33	86.71	81.27	75.81	76.85	76.06
2024	78.23	74.66	74.50	79.74	78.78	70.42	75.43	84.85	87.37	82.34	76.21	77.60	76.60
2025	79.24	75.23	75.53	80.81	79.60	70.95	76.49	85.51	88.73	84.25	76.86	78.65	77.41
2026	79.68	75.37	76.07	81.49	79.88	71.12	76.94	85.90	89.58	85.55	77.08	79.19	77.72
2027	80.14	75.58	76.89	81.91	80.29	71.51	77.42	86.38	90.49	86.48	77.34	79.99	78.12
2028	80.25	75.51	77.23	82.20	80.30	71.75	77.67	87.06	91.52	86.71	77.32	79.99	78.10
2029	80.39	75.52	77.44	82.29	80.43	71.89	77.87	87.35	91.92	86.91	77.38	79.96	78.24
Levelized Rates	**$72.51**	**$70.80**	**$70.75**	**$73.21**	**$73.17**	**$68.87**	**$71.30**	**$77.03**	**$78.28**	**$77.68**	**$71.79**	**$72.22**	**$71.78**
Annual Rate of Growth	0.8%	0.5%	0.7%	1.0%	0.8%	0.3%	0.7%	1.3%	1.5%	0.8%	0.6%	0.8%	0.7%
% Δ from $0-$100/ton CO_2	-	-2.4%	-2.4%	1.0%	0.9%	**-5.0%**	-1.7%	6.2%	8.0%	7.1%	-1.0%	-0.4%	-1.0%

Table P-3: Average Residential Bills for Least Risk Portfolios by Scenario - CO2 Cost in Rates
(Bills are expressed in 2006$/month/household)

	$0-$100 per ton CO2	Current Policy	Low Cons	Dam Removal	High Cons	Suspend Carbon Policy	No RPS	Retire Coal WO/CO2	Retire Coal W/CO2	$100/ton CO2	$20/ton CO2	PHEV	$0-$50 per ton CO2
Case Identifier	**L811**	**L811J**	**L811A**	**L811B**	**L811C**	**L811D**	**L811E**	**L811I**	**L811G**	**L811H**	**L811K**	**L811M**	**L811Q**
2010	72.18	72.15	72.21	72.18	72.15	72.15	72.19	72.10	72.13	93.39	77.81	72.18	72.16
2011	71.51	70.76	71.63	71.51	71.39	70.76	71.52	71.11	71.80	89.06	76.36	71.51	71.15
2012	71.79	69.49	72.10	71.79	71.54	69.48	71.81	70.07	72.19	87.57	74.92	71.81	70.71
2013	72.57	68.69	73.10	72.57	72.17	68.66	72.60	70.02	73.45	87.22	74.03	72.60	70.79
2014	73.85	68.80	74.67	73.87	73.34	68.41	73.69	71.05	75.44	87.39	73.94	73.91	71.64
2015	74.46	68.45	75.54	74.50	73.77	67.75	74.29	71.71	76.63	86.97	73.41	74.56	71.89
2016	75.22	68.54	76.58	75.29	74.43	67.50	74.90	73.14	78.31	86.32	73.39	75.35	72.32
2017	74.93	67.91	76.52	75.00	74.19	66.56	74.67	73.59	78.67	84.95	72.49	75.00	71.84
2018	74.95	67.62	76.84	75.07	74.10	65.87	74.30	74.39	79.22	84.16	72.16	75.06	71.71
2019	75.09	67.72	77.44	75.22	74.15	65.68	74.41	76.01	80.22	83.86	72.10	75.21	71.83
2020	75.48	68.22	78.25	78.69	74.48	65.37	74.37	77.93	81.43	83.50	72.30	75.68	72.23
2021	75.98	68.58	78.80	78.89	74.95	64.81	74.52	77.21	81.25	82.53	72.43	76.39	72.60
2022	75.69	68.57	78.65	78.50	74.94	64.59	73.71	76.96	80.77	82.15	72.39	76.15	72.51
2023	75.63	68.58	78.76	78.42	75.26	64.50	73.77	76.87	80.65	81.70	72.32	76.18	72.56
2024	75.99	68.84	79.17	78.78	75.78	64.65	73.96	77.12	80.80	82.02	72.59	76.66	72.84
2025	76.55	69.13	79.75	79.24	76.38	64.87	74.51	77.33	81.27	82.31	72.86	77.34	73.29
2026	76.91	69.38	80.09	79.67	76.77	65.11	74.87	77.72	81.62	82.85	73.14	77.87	73.61
2027	77.29	69.67	80.51	79.98	77.23	65.51	75.23	78.15	82.15	83.54	73.51	78.52	74.00
2028	77.87	70.03	80.87	80.73	77.78	66.10	75.91	79.17	83.30	84.65	73.98	79.00	74.43
2029	77.92	69.90	80.68	80.72	77.86	66.04	75.99	79.13	83.38	84.50	73.85	79.05	74.44
Levelized Rates	**$74.72**	**$69.14**	**$76.49**	**$75.89**	**$74.25**	**$67.17**	**$73.87**	**$74.42**	**$77.97**	**$85.60**	**$73.73**	**$75.05**	**$72.25**
Annual Rate of Growth	0.4%	-0.2%	0.6%	0.6%	0.4%	-0.4%	0.3%	0.5%	0.7%	-0.5%	-0.3%	0.5%	0.2%
% ∆ from $0-$100/ton CO_2	-	-7.5%	2.4%	1.6%	-0.6%	-10.1%	-1.1%	-0.4%	4.3%	14.6%	-1.3%	0.4%	-3.3%

Table P-4: Average Residential Bills for Least Risk Portfolios by Case - CO2 Cost Not in Rates (Bills are expressed in 2006$/month/household)

	$0-$100 per ton CO2	Current Policy	Low Cons	Dam Removal	High Cons	Suspend Carbon Policy	No RPS	Retire Coal WO/CO2	Retire Coal W/CO2	$100/ton CO2	$20/ton CO2	PHEV	$0-$50 per ton CO2
Case Identifier	**L811**	**L811J**	**L811A**	**L811B**	**L811C**	**L811D**	**L811E**	**L811I**	**L811G**	**L811H**	**L811K**	**L811M**	**L811Q**
2010	72.15	72.15	72.17	72.15	72.12	72.15	72.15	72.10	72.10	79.22	73.04	72.15	72.14
2011	70.81	70.76	70.93	70.81	70.71	70.76	70.82	71.11	71.11	75.69	71.47	70.82	70.80
2012	69.60	69.49	69.86	69.60	69.39	69.48	69.62	70.07	69.99	73.70	69.99	69.61	69.59
2013	68.83	68.69	69.24	68.83	68.53	68.66	68.85	70.02	69.84	73.24	69.18	68.85	68.83
2014	68.81	68.80	69.36	68.83	68.47	68.41	68.54	71.05	70.87	73.59	69.20	68.84	68.92
2015	68.49	68.45	69.14	68.53	68.07	67.75	68.11	71.71	71.58	74.37	68.88	68.56	68.61
2016	68.66	68.54	69.44	68.73	68.21	67.50	68.03	73.14	73.19	74.42	68.97	68.72	68.67
2017	68.34	67.91	69.12	68.40	68.04	66.56	67.73	73.59	74.05	73.85	68.34	68.28	68.11
2018	68.34	67.62	69.20	68.44	68.11	65.87	67.42	74.39	75.11	73.78	68.19	68.21	67.92
2019	68.61	67.72	69.75	68.75	68.36	65.68	67.67	76.01	76.82	73.87	68.28	68.50	68.06
2020	69.15	68.22	70.69	70.95	68.94	65.37	67.64	77.93	78.70	74.01	68.73	69.12	68.56
2021	70.14	68.58	71.55	71.62	69.74	64.81	68.10	77.21	79.03	73.70	69.23	70.35	69.14
2022	70.42	68.57	71.79	71.79	70.05	64.59	67.95	76.96	79.06	73.72	69.36	70.57	69.25
2023	70.48	68.58	71.84	71.77	70.37	64.50	68.15	76.87	78.90	73.81	69.44	70.72	69.38
2024	70.94	68.84	72.30	72.26	70.84	64.65	68.36	77.12	79.11	74.44	69.73	71.25	69.70
2025	71.39	69.13	72.85	72.70	71.33	64.87	68.82	77.33	79.60	75.48	70.06	71.85	70.10
2026	71.75	69.38	73.22	73.20	71.68	65.11	69.13	77.72	80.05	76.45	70.36	72.36	70.42
2027	72.15	69.67	73.79	73.52	72.13	65.51	69.50	78.15	80.64	77.20	70.67	73.14	70.82
2028	72.60	70.03	74.22	74.13	72.53	66.10	70.05	79.17	81.82	77.74	71.06	73.54	71.19
2029	72.50	69.90	73.91	73.96	72.47	66.04	69.99	79.13	81.78	77.66	70.94	73.35	71.12
Levelized Rates	**$70.08**	**$69.14**	**$70.98**	**$70.68**	**$69.86**	**$67.17**	**$68.93**	**$74.42**	**$75.32**	**$74.95**	**$69.81**	**$70.25**	**$69.56**
Annual Rate of Growth	0.0%	-0.2%	0.1%	0.1%	0.0%	-0.4%	-0.2%	0.5%	0.6%	-0.1%	-0.1%	0.1%	-0.1%
% Δ from $0-$100/ton CO_2	-	-1.3%	1.3%	0.9%	-0.3%	-4.2%	-1.6%	6.2%	7.5%	7.0%	-0.4%	0.2%	-0.7%

Analysis of Rate and Bill Differences among Cases

The tables can be used to contrast rates and bills among cases in almost infinite combinations, but a few illustrations should make it possible for regional analysts to pursue their interests using the tables. For example, consider the impact of a reduction in conservation potential:

We can compare the “\$0 to \$100 per ton CO2” case to the “Low Conservation” case, which reduces the availability of conservation by about 22%. Comparison of the “\$0 to \$100 per ton CO2” and “Low Conservation” columns of Tables P-2 and P-4 shows that rates decrease when conservation is reduced but bills increase. The disparity in impact on rates versus bills is because conservation reduces sales by a larger proportion than it reduces costs. The same results are shown graphically in Figures P-2 and P-3. The data shown in Figure P-2 are from the “\$0 to \$100 per ton CO2” and “Low Conservation” column in Table P-2 and the data shown in Figure P-3 are from the same columns in Table P-4.

Figure P-2 Average Electricity Rate Comparison - CO2 Costs Not in Rates

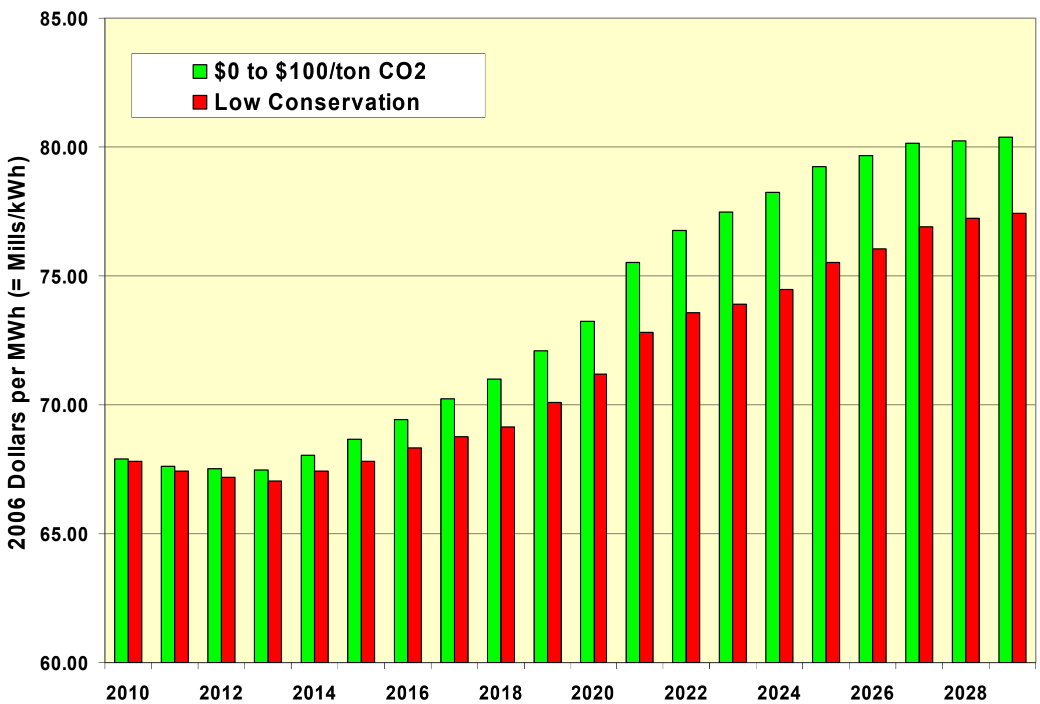
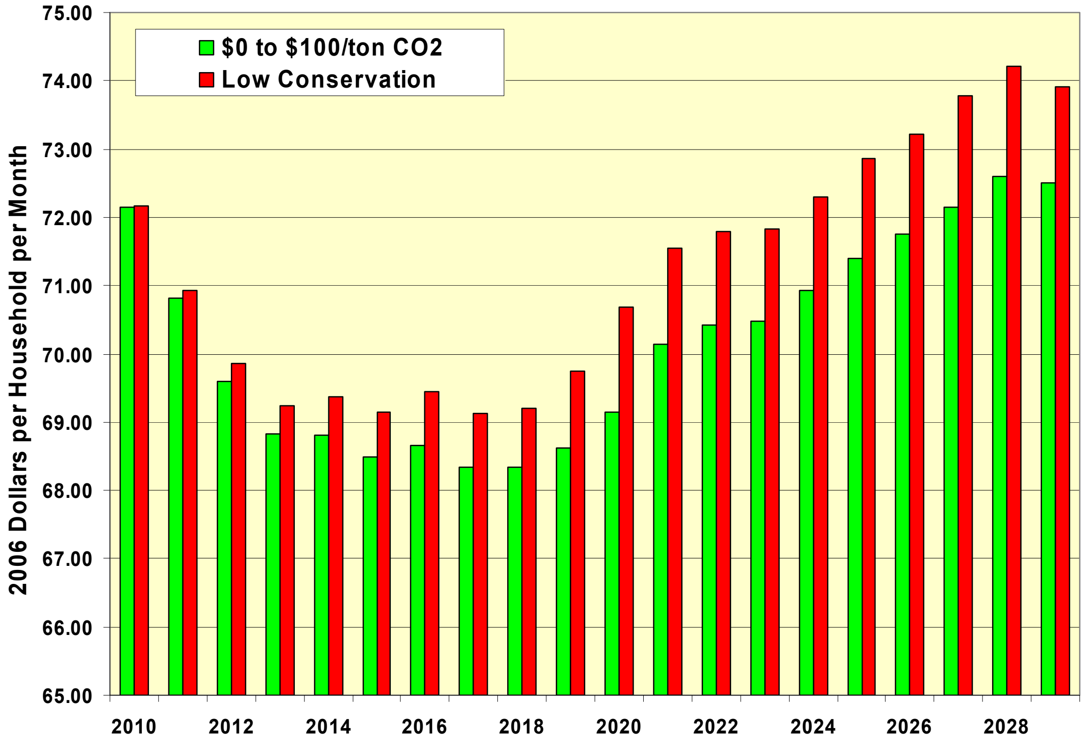


Figure P-3 Typical Residential Electricity Bill Comparison - CO2 Costs Not in Bills



Another illustration of potential analysis using Tables P-1 through P-4 (and the Excel workbook that lies behind them) is a comparison of the levelized rates and bills across the 13 scenarios included in the tables. Figure P-4 compares levelized rates across all scenarios, and Figure P-5 compares levelized bills, both with CO2 costs excluded from both rates and bills. Levelized rates (from Table P-2) range from a low of $70.75 per megawatt hour for the "Low Conservation" scenario to $78.28 per megawatt hour for the "Retire Existing Coal W/CO2" scenario. Levelized bills range from $67.17 for the "Suspend Carbon Policy" scenario to $75.32 for the "Retire Existing Coal W/CO2" scenario.

Figure P-4: Levelized Electricity Rates by Scenario - CO2 Costs Not in Rates

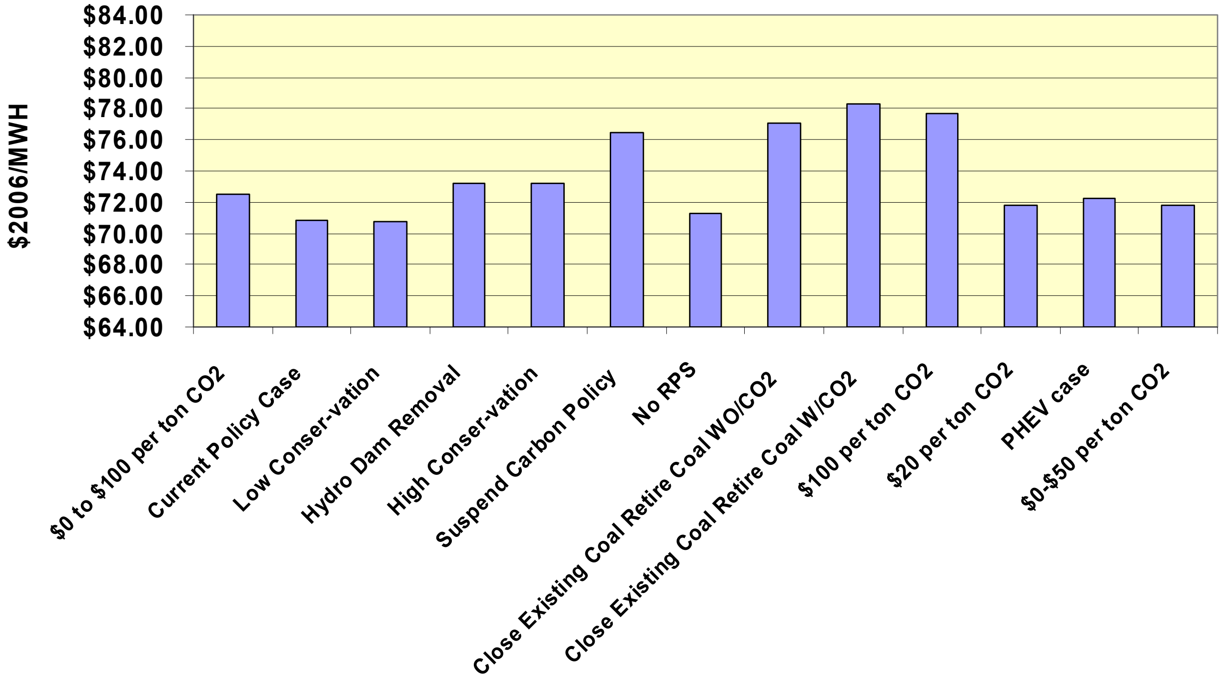


Figure P-5: Levelized Typical Residential Electricity Bills by Scenario - CO2 Costs Not in Bills