STP UNITS 3 and 4 COL DEIS
WEB REFERENCES
CHAPTER 9
PART 2

NextEra 2009 Solar Electric Generating Systems through
TCEQ 2008 Texas Water Quality Inventory

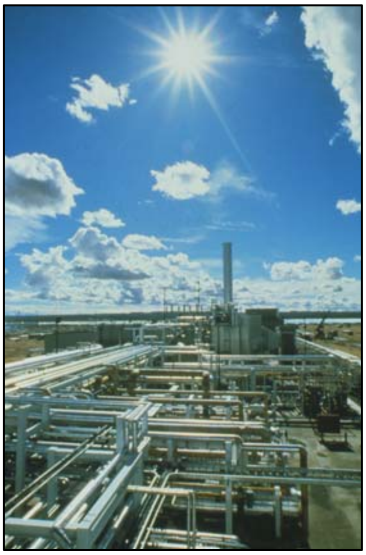
Please see Part 1 (in this ADAMS package) for Benson and Arnold 2001 Texas Bird Atlas through NETL 2007 Cost Performance Baseline for Fossil Fuel Plants.

Please see Part 3 (in this ADAMS package) for TCEQ 2009a Water Rights Database through Wade 2008 Groundwater Availability Modeling Section (end).

Solar Electric Generating Systems

FPL Energy.

The electricity generated at the Solar Electric Generating System (SEGS) could power more than 230,000 homes.



For more information about FPL Energy, go to our Web site at **www.FPLEnergy.com**

LETTING THE SUN SHINE IN

There's probably no better place to catch some rays than California's Mojave Desert, and the seven Solar Electric Generating Systems (SEGS) facilities accomplish that task, using state-of-the-art technology to collect solar power and convert it into useful energy.

The SEGS facilities -- located at Kramer Junction (SEGS III-VII) and Harper Lake (SEGS VIII, IX) in California -- are collectively known as the world's largest solar site with a generating capability of 310 megawatts.

CLEAN, RENEWABLE ENERGY FOR CALIFORNIA

FPL Energy co-owns and operates the SEGS facility, which represents a valuable part of the company's clean and renewable energy mix and provides a national showcase for solar technology.

The electricity generated at the SEGS sites could power more than 230,000 homes. The facilities cover more than 1,500 acres in the desert, and more than 900,000 mirrors capture and concentrate sunlight.

All the power produced at SEGS is purchased by Southern California Edison.

HELPING MEET PEAK POWER DEMANDS

The SEGS plants are designed as peaking power plants, supplying power during peak demand periods, particularly hot summer afternoons with high electrical use loads. This schedule is an ideal match for the SEGS plants, which operate at full power during these periods.

Generally, peak demand periods are also when pollution is at its worst. The SEGS plants help reduce pollution because they do not emit nitrogen oxide and carbon dioxide that contribute to smog and global warming.

Solar energy is a clean, renewable resource that is continuously supplied to the earth by the sun.

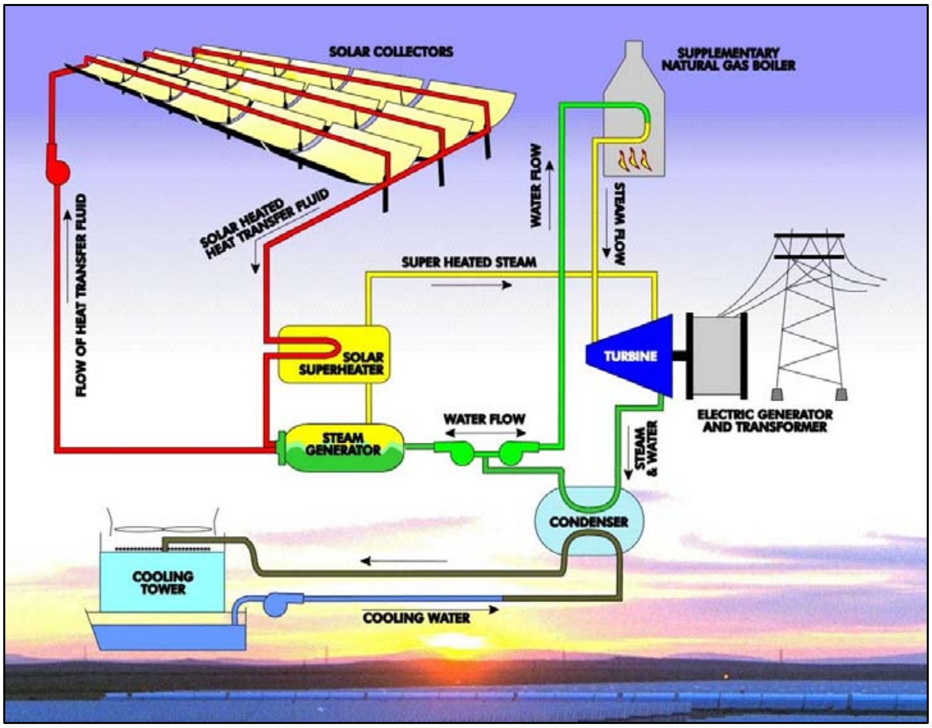
Solar Electric Generating Systems

HOW SEGS WORK

Solar collectors capture and concentrate sunlight to heat a synthetic oil called therminol, which then heats water to create steam.

The steam is piped to an onsite turbine-generator to produce electricity, which is then transmitted over power lines.

On cloudy days, the plant has a supplementary natural gas boiler. The plant can burn natural gas to heat the water, creating steam to generate electricity.



SEGS FACTS

- Seven solar facilities
- Located at Kramer Junction (SEGS III-VII) and Harper Lake (SEGS VIII, IX) in California
- 310 megawatts with FPL Energy ownership equivalent to approximately 150 megawatts
- Covers more than 1,500 acres in the desert
- More than 900,000 mirrors that capture and concentrate sunlight
- Offsets approximately 3,800 tons of pollutants annually that would have been produced if the electricity had been provided by fossil fuels, such as oil

Demand Forecast

INTRODUCTION AND SUMMARY

A 20-year forecast of electricity demand is a required component of the Council's Northwest Regional Conservation and Electric Power Plan.[1] Understanding growth in electricity demand is, of course, crucial to determining the need for new electricity resources and helping assess conservation opportunities. The Council has also had a tradition of acknowledging the uncertainty of any forecast of electricity demand and developing ways to reduce the risk of planning errors that could arise from this and other uncertainties in the planning process.

Electricity demand is forecast to grow from 20,080 average megawatts in 2000 to 25,423 average megawatts by 2025 in the medium forecast. The average annual rate of growth in this forecast is just less than 1 percent per year. This is slower demand growth than forecast in the Council's Fourth Power Plan, which grew at 1.3 percent per year from 1994 to 2015.

The slower demand growth primarily reflects reduced electricity use by the aluminum industry and other electricity intensive industries in the region. Forecasts of higher electricity and natural gas prices will fundamentally challenge energy intensive industries in the region.

The medium case electricity demand forecast means that the region's electricity needs would grow by 5,343 average megawatts by 2025, an average annual increase of 214 average megawatts. As a result of the 2000-01 energy crisis, the 2003 demand is expected to be nearly 2000 average megawatts lower than in 2000, making the annual growth rates and megawatt increases from 2003-2025 higher than from the 2000 base. The annual growth rate from 2003 to 2025 is 1.5 percent per year, with annual megawatt increases averaging 330.

Compared to the 2015 forecast of demand in the Council's Fourth Power Plan, the Fifth Plan forecast is 3,000 average megawatts lower. Nearly, two thirds of this difference is due to lower expectations for the region's aluminum smelters.

The most likely range of demand growth (between the medium-low and medium-high forecasts) is between 0.4 and 1.50 percent per year. However, the low to high forecast range recognizes that growth as low as -0.5 percent per year or as high as 2.4 percent per year is possible, although relatively unlikely. Table A-1 summarizes the forecast range.

[1] Public Law 96-501, Sec. 4(e)(3)(D)

Table A-1: Demand Forecast Range

	(Actual) 2000	2015	2025	Growth Rates 2000-2015	Growth Rates 2000-2025
Low	20,080	17,489	17,822	-0.92	-0.48
Medium Low	20,080	19,942	21,934	-0.05	0.35
Medium	20,080	22,105	25,423	0.64	0.95
Medium High	20,080	24,200	29,138	1.25	1.50
High	20,080	27,687	35,897	2.16	2.35

FORECASTING METHODS

The approach to the demand forecasts is significantly different from previous Council plans. For this plan, the Council has not used its Demand Forecasting System. Instead there are three separate approaches to the forecast in terms of methods and relationship to the Council's Fourth Power Plan. The methods differ for (1) the range of long-term non-direct service industry (non-DSI) forecasts from low to high; (2) for a monthly near-term medium case forecast; and (3) for a forecast of aluminum smelter and other direct service industry (DSI) demand.

The non-DSI forecasts generally rely on the forecasts from the Fourth Power Plan for their long-term demand trends. The decision to use the Fourth Power Plan forecast trends was based partly on an assessment of the accuracy of those forecasts over the five or six years since they were done.[2] The total demand forecasts tracked actual loads very closely between 1995 and 2000. The average percentage error in the forecast of electricity consumption for those years has been less than one half of a percent. Figure A-1 illustrates actual consumption compared to the medium, medium-low and medium-high forecasts through 2000. Figure A-1 also illustrates the ability of the model to simulate the period before 1995 when actual values of the main forecast drivers are used.

The forecasts for individual consuming sectors have also been quite accurate since the 1995 forecasts were done. The level of residential consumption was overforecast by an average of 0.6 percent. Commercial consumption was underforecast by an average of 0.9 percent, and industrial consumption, excluding DSIs, was overforecast by an average of 3.6 percent. Since there was little evidence that the long-term forecasts were departing seriously from actual electricity consumption, the Council decided to continue to rely on its earlier forecast trends for non-DSI electricity demand.

The medium case non-DSI forecast is developed in two stages. The first stage is a near-term monthly forecast of demand recovery from the recent energy crisis. The second stage is a long-term forecast of demand trends from 2005 to 2025.

[2] Northwest Power Planning Council. "Economic and Electricity Demand Analysis and Comparison of the Council's 1995 Forecast to Current Data." September 2001, Council Document 2001-23. http://www.nwcouncil.org/library/2001/2001-23.htm

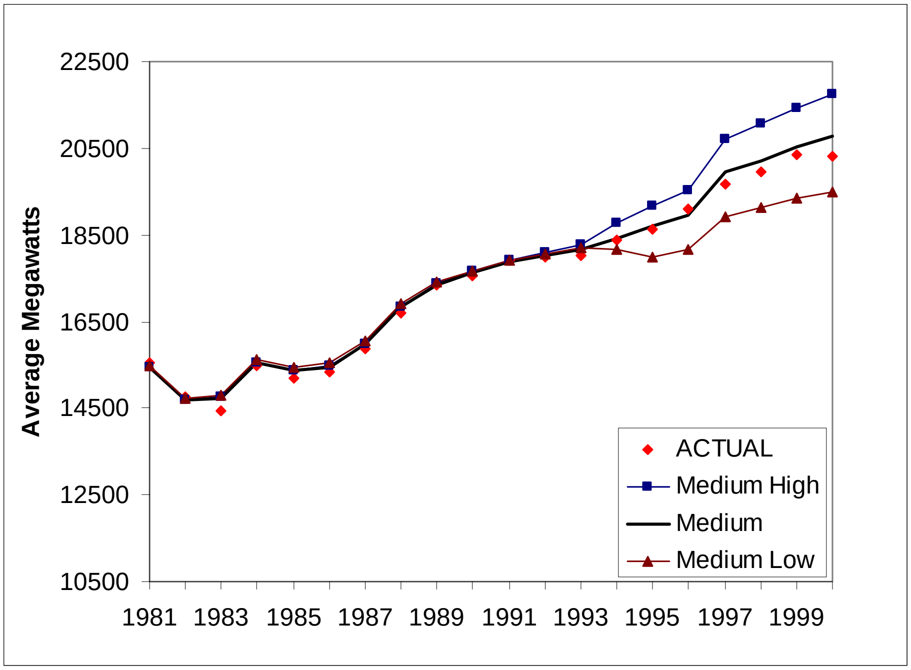


Figure A-1: Demand Forecast Versus Actual Consumption of Electricity

During late 2000 and 2001, electricity demand decreased dramatically in the region due to the electricity crisis, large increases in retail electricity rates, and an economic recession. The Council analyzed the components and causes of the 2000-2001 decline in electricity consumption in its assessment of the outlook for winter 2001-2002 electricity adequacy and reliability.[3] As illustrated in Figure A-2, nearly 60 percent of the reduction was due to closing down aluminum smelters, which make up the bulk of the DSI category. Therefore, a large part of the total medium forecast of demand recovery depends on specific assumptions about the return to operation of aluminum and other large industrial loads that were either bought out or shut down during 2001. The medium case forecast to 2005 addresses the recovery from this starting condition.

The medium case forecast of non-DSI demand recovery depends on assumptions about recovery from the economic recession and the effects of recent retail electricity price increases, although these effects are not modeled in any formal way. In general, the effects of higher retail electricity prices are assumed to dampen the effect of economic recovery on electricity use and slow the recovery of electricity demand. By 2005 non-DSI electricity demands are assumed to have nearly returned to a non-recession level, but that demand is lower than the Fourth Power Plan forecast due to some assumed permanent effects of higher electricity prices, as well as lasting efficiency improvements achieved during the crisis.

[3] Northwest Power Planning Council. "Analysis of Winter 2001-2002 Power Supply Adequacy." November 2001. Council Report 2001-28. http://www.nwcouncil.org/library/2001/2001-28.pdf

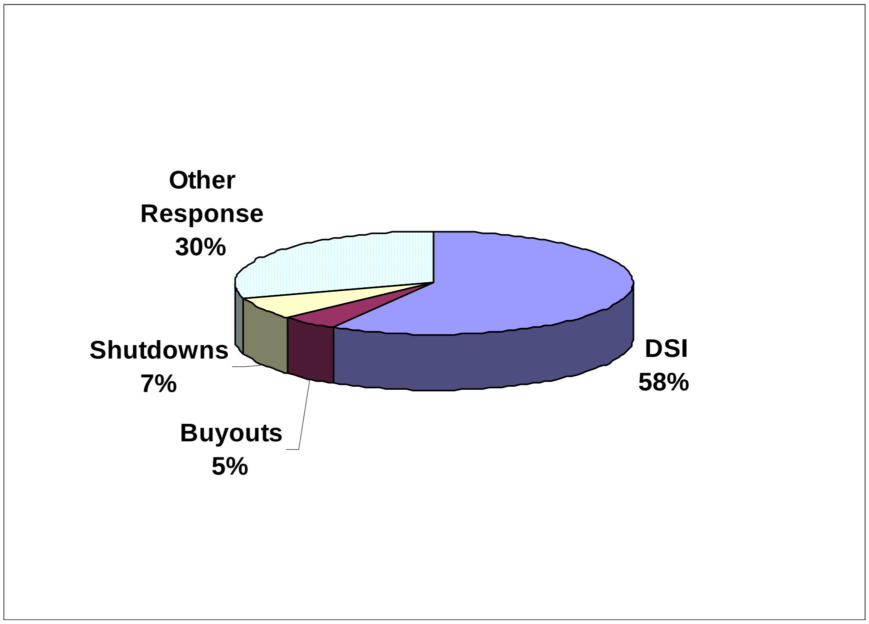


Figure A-2: Components of a 20 Percent Load Reduction From July 2000 to July 2001

The near-term medium forecasts are done on a monthly basis through 2005. The monthly forecasts through 2005 are done as electricity loads to facilitate tracking the forecast against actual load data as it becomes available. After 2005 the forecast is presented as electricity sales and is comparable to the range forecasts and to previous Council demand forecasts.

The range of long-term non-DSI forecasts is developed for the years following 2005. These four forecasts, as well as the medium case extension beyond 2005, depend on the growth rates of the corresponding forecasts in the Fourth Power Plan. The 2005 starting points for the range forecasts are estimated by applying Fourth Plan low to high case growth rates to an estimate of actual electricity demand in 2000 instead of the Fourth Plan forecasts for 2000. However, the relative pattern of growth for each case is adjusted to resemble the pattern of near-term medium case decreases in 2001 and recovery to 2005. After 2005, low to high case annual growth rates from the Fourth Plan were applied to the respective range of cases. This approach results in a narrower range of forecasts than the corresponding years' forecasts in the Fourth Power Plan.

The long-term forecasts should be viewed as estimates of future demand, unreduced for conservation savings beyond what would be induced by consumer responses to price changes. The Council has referred to these forecasts as "price effects" forecasts in the past. The shift from actual consumption to the price effects forecast is made in 2001. In the medium case, the only sector with any significant programmatic conservation by 2001 in the Fourth Power Plan was the residential sector. Residential sector consumption in 2001 has 191 average megawatts of programmatic conservation savings added to demand. This makes the decrease in residential consumption appear smaller in the forecast than actual consumption decreases are likely to be for 2001. Similar adjustments affect the higher growth cases for the other sectors as well.

The forecast of electricity demand by the region's aluminum smelters and the few other remaining industrial plants that were traditionally served directly by the Bonneville Power Administration (DSIs) are discussed separately. The forecast of aluminum smelter electricity use is an exception to reliance on the Fourth Plan forecast trends. Both the method of forecasting and the results are significantly different from the Fourth Power Plan.

DEMAND FORECAST

The medium-term monthly forecasts are presented in the form of monthly "load" forecasts. That is, the values include transmission and distribution losses. The long-term forecasts are presented as electricity sales, or electricity consumption at the end-use level, and therefore exclude transmission and distribution losses. The long-term forecasts of electricity demand are developed for individual consuming sectors such as residential, commercial, and industrial. The long-term forecasts are directly comparable to the demand forecasts presented in the Fourth Power Plan. Detailed tables of annual electricity demand forecasts by sector appear at the end of this appendix.

The forecast of demand for electricity by aluminum smelters is treated separately from the non-DSI demand. This reflects the large amount of electricity required by these plants combined with a growing uncertainty about their future operation in the region.

Non-DSI Forecasts

Near-Term Monthly Non-DSI Load Forecast

Figures 3a and 3b illustrate how the near-term forecasts of non-DSI loads are designed to track recovery back toward the forecast trends from the Council's Fourth Power Plan. In Figure A-3a the upper line is the Fourth Power Plan trend forecast converted to electricity loads with a monthly pattern added. The lower line shows the near-term monthly forecast of loads. The dashed vertical line separates actual monthly load data from the forecast. The recovery may be clearer in the corresponding annual numbers shown in Figure A-3b.

When the Council first developed a near-term forecast of load recovery in October 2001, it was expected that non-DSI loads would recover to near the Fourth Plan forecast levels by 2004. This is no longer the case, as shown in Figures 3a and 3b. There are two substantial reasons for the changes to the near-term load forecast since the earlier assessment. First, the anticipated rate of economic recovery has been slower than expected. Second, energy prices, which fell substantially in 2002, have increased again in 2003. Some of the increase is due to temporary conditions including strikes in the oil industry of Venezuela, concerns about the war in Iraq, a cold winter in the Eastern part of the country, and low runoff forecasts for the Pacific Northwest. However, other contributors to high energy prices may be indicative of longer-term trends. These include the reduced growth in natural gas supplies in spite of significant drilling activity and continued high retail prices for Bonneville's customers and the customers of investor-owned utilities as well.

As shown in Figure A-3b, instead of recovering to the long-term trend forecast from the Fourth Power Plan by 2004, the revised annual non-DSI load forecast remains below the Fourth Plan forecast in 2005. This difference, which amounts to 929 average megawatts, is considered to be a permanent reduction in electricity demand, and affects the long-term forecast as well. The reductions are focused in the industrial sector, where energy intensive businesses are vulnerable to the large price increases the region has suffered since 2001.

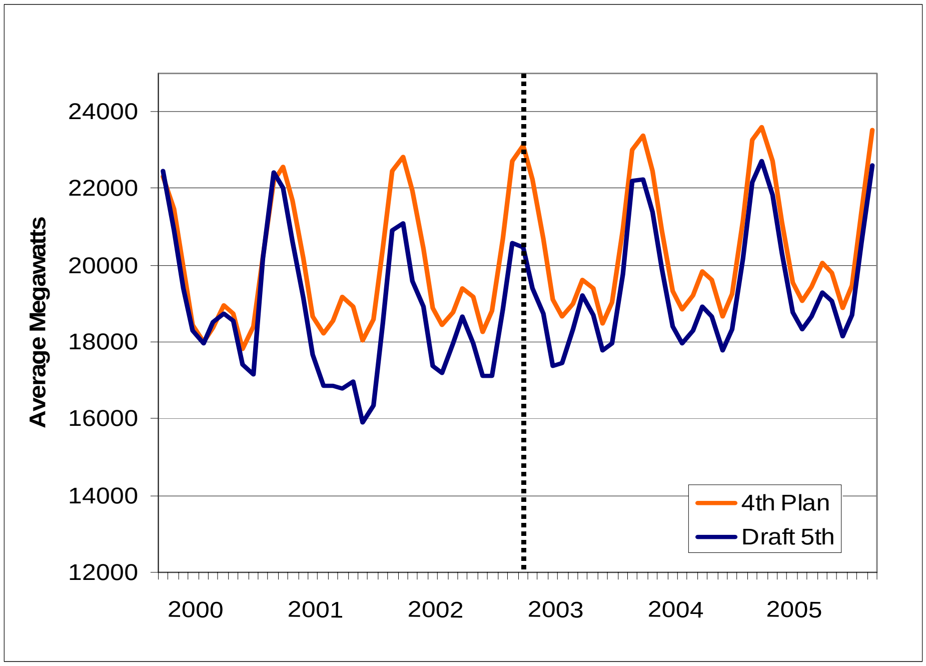


Figure A-3a: Comparison of Monthly Near-Term Forecast to the Fourth Power Plan

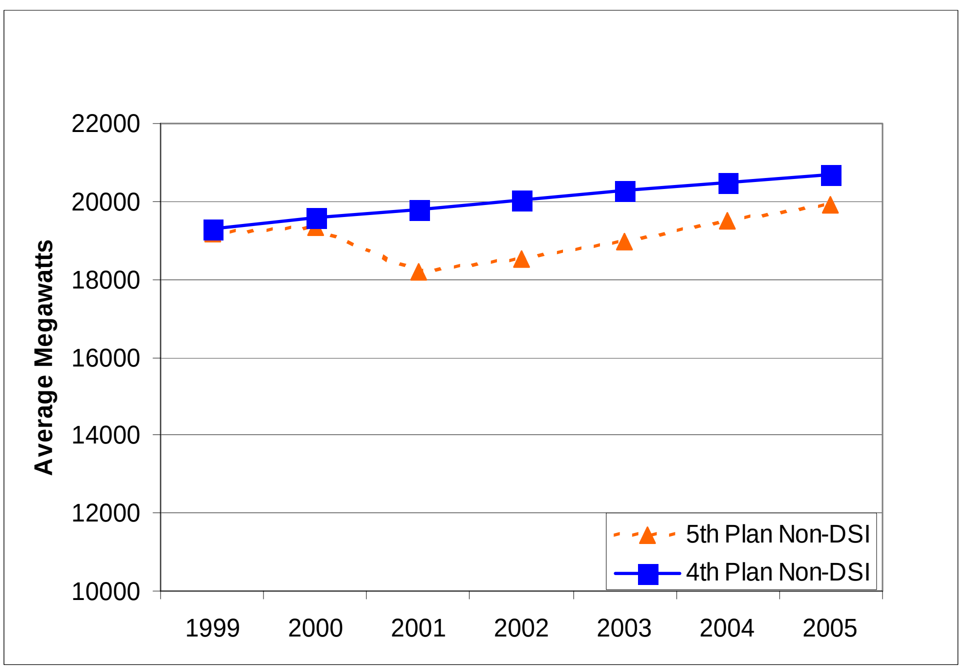


Figure A-3b: Comparison of Annual Near-Term Forecast to the Fourth Power Plan

Long-Term Forecasts of Non-DSI Demand

The range of long-term forecasts of total non-DSI electricity sales is shown in Figure A-4. In the medium forecast, non-DSI electricity consumption grows from 17,603 average megawatts in 2000 to 24,464 average megawatts by 2025. This is an increase of 1.33 percent, and 275 average megawatts, per year from 2000 to 2025. These growth indicators are lowered somewhat by the electricity crisis and recession in 2000-01. From 2005 to 2025 the average annual growth rate is 1.43 percent per year, with an average annual increase in consumption of 300 average megawatts.

Figure A-4 illustrates how the Fourth Plan demand forecast and the near-term and long-term forecasts for the Fifth Power Plan compare. The near-term forecast reflects the currently depressed electricity demand and then merges into the medium forecast. The other forecasts in the range appear as dashed lines that extend from 2005 to 2025. The Fourth Plan forecasts appear as solid lines that extend to 2015. Historical actual weather adjusted sales appears as a dotted line through the year 2000.

The range of forecasts indicates that actual future demands should fall within plus or minus 15 percent of the medium forecast in 2025 with fairly high probability. This is reflected in the medium-low to medium-high forecast range in Table A-2. However, under more extreme variations in circumstances they could vary by 30 to 40 percent from the medium forecast, as shown by the low to high forecast range.

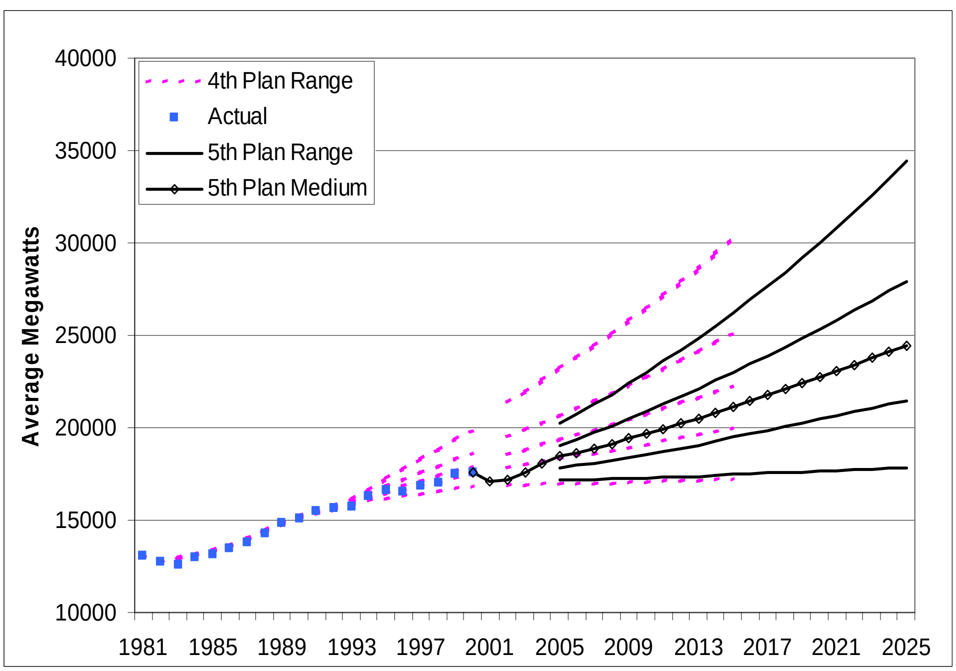


Figure A-4: Forecast Total Non-DSI Electricity Sales Compared to Fourth Plan Forecasts

Table A-2: Non-DSI Electricity Sales Forecast Range

				Growth Rates	
	2000	2015	2025	2000-15	2000-25
	(Actual)				
Low	17603	17489	17822	-0.04%	0.05%
Medium Low	17603	19482	21474	0.68%	0.80%
Medium	17603	21147	24464	1.23%	1.33%
Medium High	17603	23000	27937	1.80%	1.86%
High	17603	26187	34397	2.68%	2.72%

Maintaining growth rates from the Fourth Power Plan's demand forecasts after 2005 implicitly assumes that the underlying assumptions remain about the same in terms of their effects on growth in electricity demand. The main driving assumptions in the Fourth Power Plan demand forecasts were economic growth, fuel price assumptions, and electricity price forecasts.

We have not attempted to develop a new economic forecast. However, the Fourth Plan's economic forecasts were checked for obvious deviations from actual values since the forecasts were developed in 1995.[4] The most aggregate determinates of demand are: population, households, and total non-farm employment. The number of households is the key driver of residential electricity demand growth. Actual household growth has followed the medium household forecast from the Fourth Power Plan. Population growth also tracked the medium forecast until 2000 Census data showed an upward revision in regional population. The new population count placed 2000 regional population between the medium and medium-high forecasts.

Employment forecasts are more sensitive to economic conditions than population and households. The period of sustained rapid growth in the national and regional economies during the late 1990s exceeded the Fourth Plan forecast assumptions, which were representative of longer-term sustained growth possibilities. Non-manufacturing employment, which drives the commercial sector forecasts has been closer to the medium-high forecast through 2000, although state forecasts of non-manufacturing employment that were available when the assessment was done show its growth moderating and moving back toward the medium forecast. The current slowdown in economic activity likely will have moved non-manufacturing employment back to the medium forecast or below.

The effects of robust economic growth in the late 1990s are even more apparent in manufacturing sector employment. Actual manufacturing employment moved well above the medium-high forecast in 1997 and 1998 when there was a boom in transportation equipment employment (i.e. Boeing). State forecasts available in mid-2001 expected manufacturing employment to return to medium forecast levels for 2001-2003. With the development of a recession in the fall of 2001 the manufacturing employment has probably fallen below medium forecast levels. There were some offsetting errors within the individual manufacturing sectors. In particular, electronic and other electrical equipment employment has been above the medium-high case, while paper and allied products has been below the medium-low.

[4] Council Document 2001-23, sited above.

Future natural gas prices are expected to be higher in this power plan than in the Fourth Plan. Table A-3 below compares 4th plan gas price forecasts for 2015 to this plan's natural gas price forecasts. The 2015 medium natural gas price forecast for this plan is above the high case in the Fourth Plan; a 54 percent increase. Based on the Council's Load Forecasting Models, this would imply that electricity demand might be increased by 3 to 4 percent over the Fourth Plan forecasts if nothing else changed.

Table A-3: Natural Gas Price Forecasts for 2015 (2000 $ Per Million Btu)

	4th Plan Forecast	5th Plan Forecast
Low	$ 1.85	$ 2.75
Medium Low	$ 2.16	$ 3.40
Medium	$ 2.47	$ 3.80
Medium High	$ 3.09	$ 4.30
High	$ 3.71	$ 4.90

However, the effects of higher gas prices may be offset by higher electricity prices. It is difficult to compare retail electricity prices between the two forecasts because the old price forecasting models are no longer appropriate for price forecasting in a partially restructured electricity market. The new price model addresses only wholesale electricity prices. Future retail prices will reflect both wholesale market prices and utility-owned resource costs if the system remains mixed, as it is currently. It is clear that higher natural gas prices will have an effect on electricity prices, both through the cost of utility owned natural gas-fired generation and through the wholesale market price of electricity. Higher electricity prices have a larger downward effect on electricity consumption than the upward effect that a comparable increase in natural gas prices would have. In the end, it isn't clear whether the changes in natural gas and electricity prices would cause a net increase or decrease in electricity consumption.

Sector Forecasts

Total non-DSI consumption of electricity is forecast to grow from 17,603 average megawatts in 2000 to 24,464 average megawatts by 2025, an average yearly rate of growth of 1.33 percent. The year 2000 is used as the base year for the forecast and growth rate calculations. It is a more representative year for examining long-term trends in demand than 2001 or 2002 would be. Table A-4 shows the forecast for each consuming sector in the medium case. Each sector's forecast is discussed in separate sections below.

Table A-4: Medium Case Non-DSI Consumption Forecast (Average Megawatts)

	2000	2005	2010	2015	2020	2025	Growth Rates		
	(Actual)						2000-25	2000-15	2005-25
Total Non-DSI Sales	17,603	18,433	19,688	21,147	22,742	24,464	1.33	1.23	1.43
Residential	6,724	7,262	7,687	8,230	8,809	9,430	1.36	1.36	1.31
Commercial	5,219	5,453	5,771	6,146	6,556	6,993	1.18	1.10	1.25
Non-DSI Industrial	4,836	4,904	5,397	5,919	6,505	7,150	1.58	1.36	1.90
Irrigation	652	629	641	654	667	681	0.17	0.02	0.40
Other	172	185	191	198	204	211	0.82	0.93	0.66

Residential Sector

Residential electricity consumption is forecast to grow by 1.36 percent per year between 2000 and 2025. Figure A-5 illustrates the range of the residential consumption forecast, compared to historical data, and the forecasts from the Council's Fourth Power Plan. The medium case residential demand forecast for 2005 is 161 average megawatts lower than the Fourth Plan forecast for that year. The forecast growth of residential sector use of electricity is slightly less than the growth from 1986-1999 of 1.8 percent annually.

The medium residential forecast remains just below the Fourth Plan medium case. This adjustment reflects the fact that the Fourth Plan slightly over forecast actual residential sales between 1995 and 2000, and that there are expected to be some longer-term effects of utility and consumer efficiency investments in response to the electricity crisis and high prices of the last couple of years. The 2005 residential demand forecast is 161 megawatts lower than the Fourth Plan forecast for 2005, or a 2.2 percent reduction in the forecast consumption level.

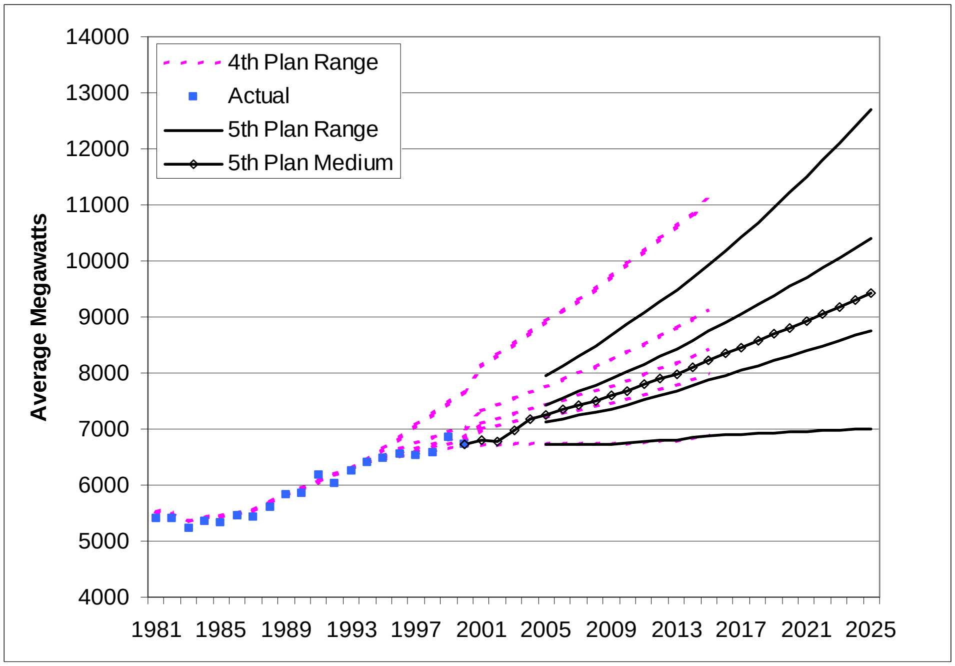


Figure A-5: Forecast Residential Electricity Sales Compared to Fourth Plan Forecasts

Although the near-term forecast shows a significant dip in residential consumption in 2001, the reduction in consumption is dampened significantly by making the adjustment to a "price effects" forecast in 2001. That is, the forecasts are intended to reflect what demand for electricity would be if new conservation programs are not implemented. The consumption levels before 2001 include the effects of conservation programs on electricity use, thus reducing consumption. The residential sector sales forecast is the only one affected by programmatic conservation in 2001 in the medium case of the Fourth Power Plan. The adjustment to eliminate the savings from conservation programs increased the residential electricity use forecast by 191 average megawatts in 2005.

It should be noted that the forecasts presented here have not been adjusted for the future effects of new building or appliance codes that have been put into effect since the Fourth Plan forecasts were done. These changes in minimum energy efficiency would reduce the future "price effects" forecast shown here. The analysis to make these adjustments has not been completed at this time.

Commercial Sector

Commercial sector electricity consumption is forecast to grow by 1.18 percent per year between 2000 and 2025, increasing from 5,219 to 6,993 average megawatts. Figure A-6 illustrates the forecast. Compared to the Fourth Power Plan forecast of commercial electricity use, the medium case has been adjusted upwards to reflect the fact that there has been a slight tendency to under forecast commercial demand since 1995. The forecast for 2005 is 325 average megawatts higher than the 2005 medium forecast in the Council's Fourth Power Plan.

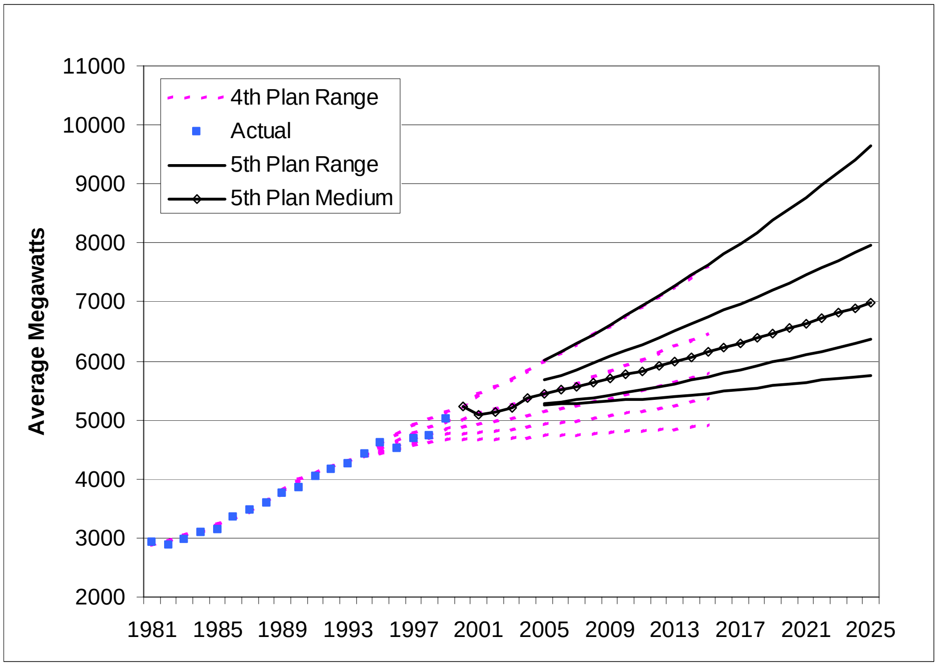


Figure A-6: Forecast Commercial Electricity Sales Compared to 4th Plan Forecasts

Comments in the residential section about the effects of new building and appliance efficiency codes apply to the commercial sector as well. In the medium commercial sector forecast, there is no adjustment made for conservation programs in shifting to the medium price effects forecast in 2001. The conservation program adjustment does affect the starting point for the medium-high and high forecast in 2005. It also affects the 4th plan forecast shown in the graph. The transition from a "sales" forecast to a "price effects" forecast is apparent in the high case, the upper line in Figure A-6. The near-term forecast dip in the medium case is the expected effect of recent price changes and economic recession.

The growth forecast for the commercial sector is for a significantly slower growth than in the past. Between 1986 and 1999 commercial electricity use grew at 3.1 percent per year.

Therefore, the forecast growth rate of 1.2 percent represents a big slowdown in commercial growth. This slowdown was present in the 4th power plan forecasts as well. But there has not been a significant under forecasting trend since the Fourth Plan forecast of commercial demand was done even though the region has experienced a robust growth cycle during these years. Figure A-7 shows the forecast compared to actual sales for 1994 through 1999. Although actual sales for 1995 and 1999 are above and at the medium-high, respectively, the other four years are at or below the medium case forecast.

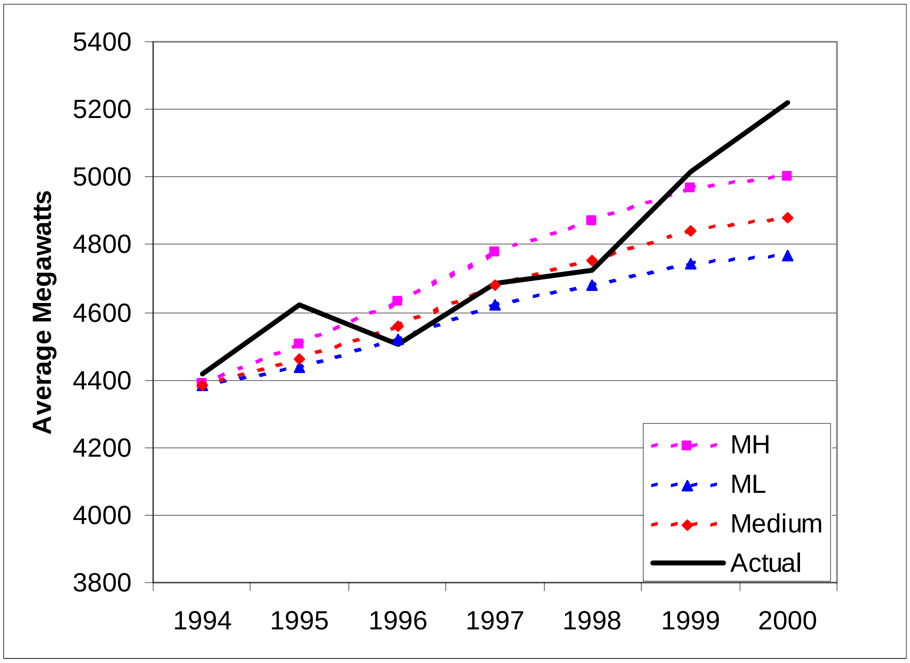


Figure A-7: Fourth Plan Commercial Forecast Performance

Several factors could help explain the forecast of slower growth of commercial electricity use. The underlying forecast of employment growth in the non-manufacturing sectors is significantly slower than historical growth. This alone could account for much of the decreased electricity demand growth forecast. In addition, the demand forecasting model accounts for building vintages and efficiency. As newer, more energy efficient, buildings that have been subject to building efficiency codes enter the stock and replace older buildings the electricity use per square foot of buildings will tend to decrease. Such factors may account for the decreased rate of growth of commercial electricity use, but the Council continues to evaluate the commercial forecasts to see if these forecasts might understate future commercial electricity needs. The Council would like to hear the views of utilities and the public on this issue.

Non-DSI Industrial Sector

Industrial electricity demand is difficult to forecast with much confidence. Unlike the residential and commercial sectors where energy use is predominately for buildings, and therefore reasonably uniform and easily related to household growth and employment, industrial electricity use is extremely varied. Further, the use tends to be concentrated in a relatively few very large users instead of spread among many relatively uniform users.

The direct service industries (DSIs) of Bonneville are treated separately in this discussion because this hand-full of plants (mainly aluminum smelters) accounts for nearly 40 percent of industrial electricity use. In addition, the future of these plants is highly uncertain. Large users in a few industrial sectors such as pulp and paper, food processing, chemicals, primary metals other than aluminum, and lumber and wood products dominate the remainder of the industrial sector's electricity use. Many of these sectors are declining or experiencing slower growth. These traditional resource based industries are becoming less important to the regional electricity demand while new industries, such as semiconductor manufacturing are growing faster.

Non-DSI industrial consumption is forecast to grow at 1.58 percent annually from 2000 to 2025 (see Figure A-8). Electricity consumption grows from 4,836 average megawatts in 2000 to 7,150 in 2025. The medium-high and medium-low forecasts are about 20 and 30 percent higher and lower than the medium forecast, respectively. This reflects the greater uncertainty in forecasting the industrial sector's electricity demand. In addition, the actual industrial consumption data is becoming more difficult to obtain as some consumers gain access to electricity supplies from independent marketers instead of their local distribution utility who must report their electricity sales.

The near-term forecast reflects a severe reduction of consumption in 2001 and 2002. Higher electricity prices are expected to continue to repress industrial electricity use. 2005 demand remains significantly, 1,022 average megawatts; lower than the 2005 forecast for Fourth power plan.

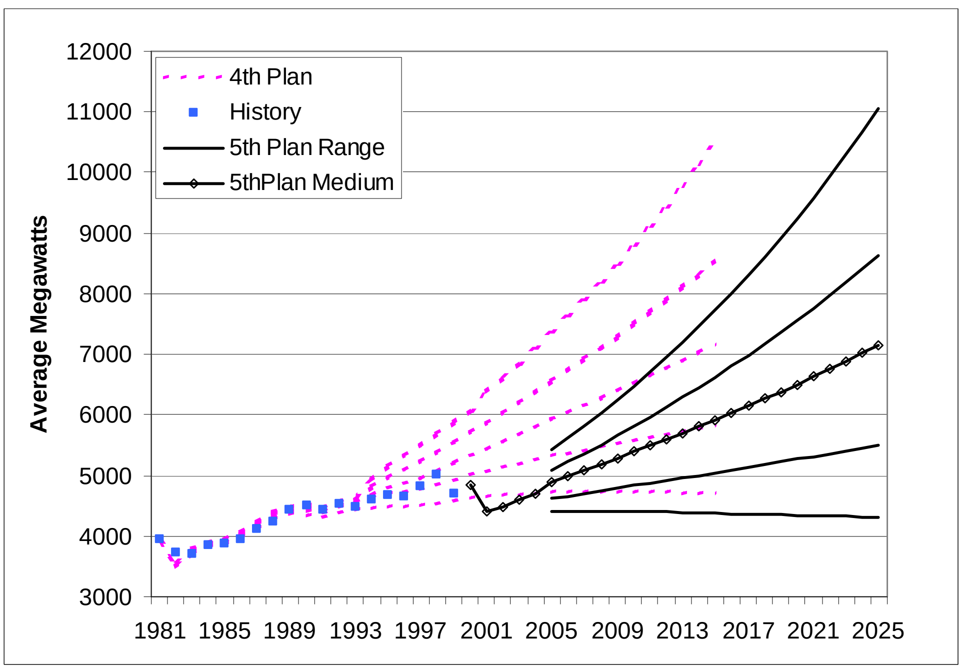


Figure A-8: Forecast Non-DSI Industrial Electricity Sales Compared to Fourth Plan Forecasts

Irrigation and Other Uses

Irrigation and other uses are relatively small compared to the residential, commercial and industrial sectors. Irrigation has averaged about 640 average megawatts between 1986 and 1999 with little trend discernable among the wide fluctuations that reflect year-to-year weather and rainfall variations. Other includes streetlights and various federal agencies that are served by Bonneville. It is relatively stable and averaged about 180 megawatts a year between 1986 and 1999.

Unlike most other sectors in the forecast, the irrigation forecast range has been changed substantially, although due to its small size it has little effect on total demand. Analysis showed that the average irrigation use over the past 20 years was substantially lower than where the medium forecast in the Fourth Plan started. The 2005 consumption was lowered to 629 average megawatts, compared to a Fourth Plan value of 700 average megawatts in that year. The forecast medium case, shown in Figure A-9, includes very little growth, as has been the case for the last 10 or more years. The range considers a high case growth of 0.7 percent a year and the low case considers that irrigation electricity use could decline by 0.8 percent annually. Substantial expansion of irrigated agriculture seems unlikely given the competing uses of the oversubscribed water in the Pacific Northwest.

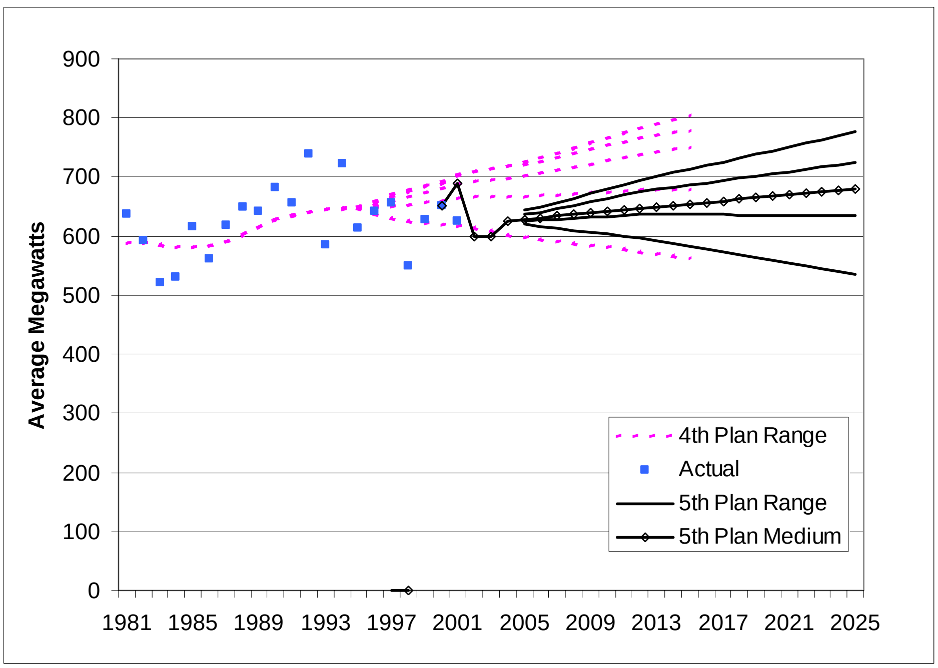


Figure A-9: Forecast Irrigation Electricity Sales Compared to Fourth Plan Forecasts

Other electricity use did not have a range associated with its forecast in the Fourth Power Plan. The other forecast is unchanged from the Fourth Plan forecast, growing at just under one percent annually.

Aluminum (DSIs)

Background

Direct Service Industries, or DSIs, refers to a group of industrial plants that have purchased electricity supplies directly from the Bonneville Power Administration. In the past, most of these plants obtained all of their electricity needs from Bonneville. Recently, many of these plants have diversified their electricity supplies, either by choice or because of reduced allocations from Bonneville. This discussion generally addresses the total electricity requirements of these industrial consumers regardless of source.

"DSIs" is often used interchangeably with aluminum smelters because aluminum smelters account for the vast bulk of this categories' electricity consumption. When all of the region's ten aluminum smelters were operating at capacity, they could consume about 3,150 average megawatts of electricity. Table A-5 shows the smelters, their locations, their aluminum production capacity and the amount of electricity they were capable of consuming at full operation.

Table A-5: Pacific Northwest Aluminum Plants

Owner	Plants	County	Capacity	Electricity Demand
			(M tons/yr.)	(MW)
Alcoa	Bellingham WA	Whatcom	282	457
Alcoa	Troutdale OR	Multnomah	130	279
Alcoa	Wenatchee WA	Chelan	229	428
Glencore	Vacouver WA	Clark	119	228
Glencore	Columbia Falls MT	Flathead	163	324
Longview Aluminum	Longview WA	Cowlitz	210	417
Kaiser	Mead WA	Spokane	209	390
Kaiser	Tacoma WA	Pierce	71	140
Golden Northwest	Goldendale WA	Klickitat	166	317
Golden Northwest	The Dalles OR	Wasco	84	167
Total			1663	3145

Source: Metal Strategies, LLC, *The Survivability of the Pacific Northwest Aluminum Smelters*, Redacted Version, February, 2001.

This amount of electricity is significant in the Pacific Northwest power system. The amount of power used by these aluminum plants in full operation could account for 15 percent of total regional electricity use. When operating, the electricity use of these plants tends to be very uniform over the hours of the day and night. However, the aluminum plants have faced increasing difficulty operating consistently over the past 20 years because of increased electricity prices and aluminum market volatility.

Aluminum smelting in the region started during the early 1940s to help build up for the war effort and to provide a market for the hydroelectric power production in the region. Smelting capacity was expanded throughout the 1960s and 1970s. Since then no new plants have been added, although improvements to the existing plants have resulted in some increases in smelting capacity. The 10 aluminum plants in the Pacific Northwest accounted for a significant share of the U.S., and even the world, aluminum smelting capacity. Before the millennium, the region's smelters accounted for 40 percent of the U.S. aluminum smelting capacity and about 6 to 7 percent of the world capacity. Their presence in the region is largely due to the historical availability of low priced electricity from the Federal Columbia River Power System. Aluminum smelting is extremely electricity intensive. Electricity accounts for about 20 percent of the total cost of producing aluminum worldwide and is therefore a critical factor in a plant's ability to compete in world aluminum markets. With increasing electricity prices this share is now substantially larger for the region's smelters, perhaps as much as one-third of costs.

Deteriorating Position of Northwest Smelters

The position of the region's aluminum smelters in the world market has been deteriorating since 1980. This is due to a combination of increased electricity prices, declining world aluminum prices and the addition of lower cost aluminum smelting capacity throughout the world.

Around 1980 the cost and availability of electricity supplies to the Pacific Northwest aluminum plants began to change dramatically. At the time, Bonneville supplied all of the smelters' electricity needs at very competitive prices. However, between 1979 and 1984 Bonneville's electricity prices increased nearly 500 percent. This is illustrated in Figure A-10, which shows Bonneville preference utility rates for electricity since 1940. The aluminum plants, along with other electricity consumers in the region, suddenly found themselves in a much less advantageous position with regard to electricity costs.

As the region's aging smelters have struggled to stay competitive in a world aluminum market, the conditions of their electricity service have also been changing. During the 1970s, the region's electricity demand began to outgrow the capability of the hydroelectric system. The fact that aluminum smelters had no preference access to the Federal hydroelectric energy meant that their electricity supplies were threatened. The Pacific Northwest Electric Power Planning and Conservation Act of 1980 (The Act) extended the DSI access to Federal power in exchange for the DSIs covering, for a time, the cost of the residential and small farm exchange for investor-owned utility customers. In addition, the DSIs were to provide a portion of Bonneville's reserve requirements through interruptibility provisions in their electricity service.

Over the years since the Act, the DSI service conditions and rates have changed in response to changing conditions. After the dramatic electricity price increases of 1980, smelters became more vulnerable to changing aluminum market conditions. Between 1986 and 1996 Bonneville implemented electricity rates for the aluminum plants that changed with changes in aluminum prices. These rates were intended to help the aluminum plants operate through difficult aluminum market conditions, and to help stabilize Bonneville's revenues. Until 1996, aluminum plants in the region bought all of their electricity from Bonneville, with the exception of one plant that acquired part of its electricity supply from a Mid-Columbia dam. In the 1996 rate case, aluminum plants chose to reduce the amount of energy they purchased from Bonneville to about 60 percent of their demand in order to gain greater access to a (then) very attractive wholesale power market. In the 2001 rate case, Bonneville further reduced the aluminum allocation to about 45 percent of smelters' potential demand, or about 1,425 megawatts. The aluminum smelters are now required to obtain over half of their electricity requirements in the wholesale electricity market or from other non-Bonneville sources.

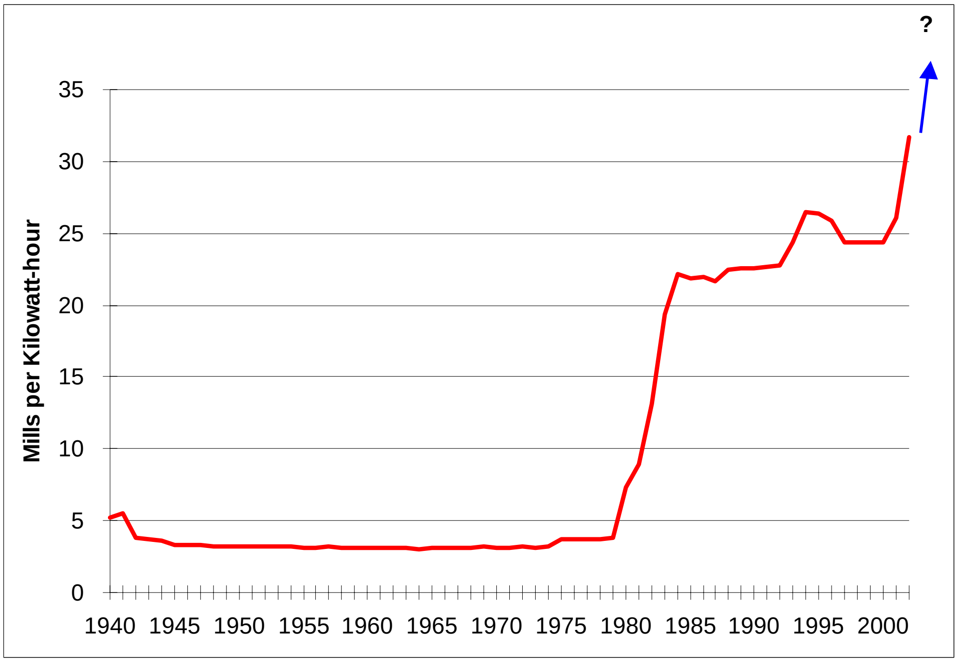
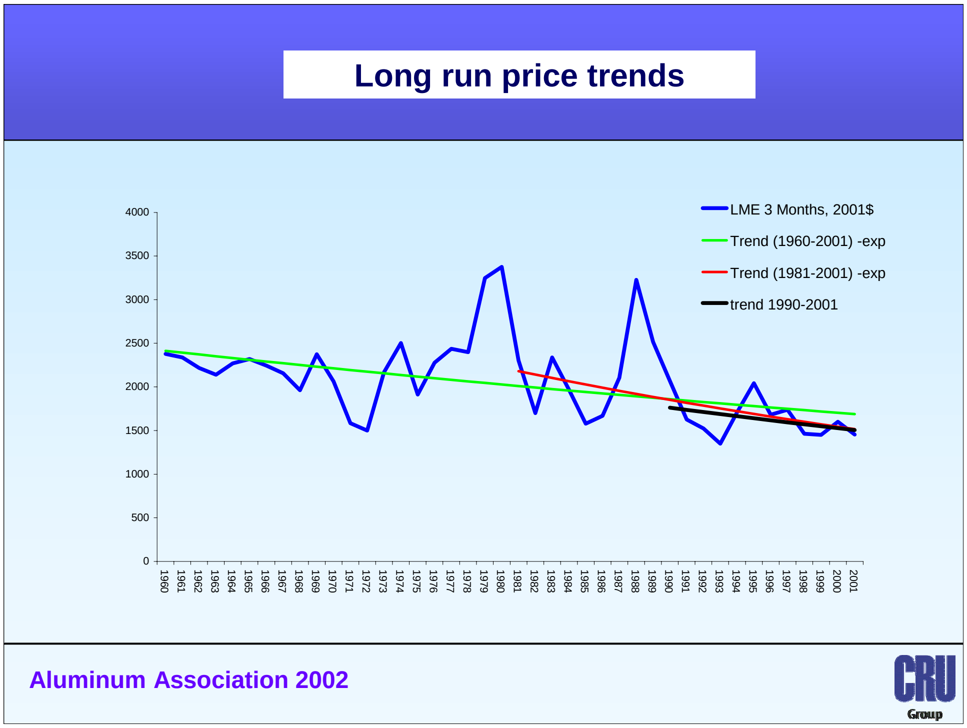


Figure A-10: Bonneville Power Administration Preference Rates

Most new world aluminum smelting capacity has been added outside of the traditional Western economies, often in countries where social agendas may be driving the capacity decisions as much as aluminum market fundamentals. The disintegration of the former Soviet Union and the liberalization of trade in China have had a significant effect on the development of a world aluminum market. The addition of more capacity over time and improving aluminum smelting technology is reflected in declining aluminum price trends. Figure A-11 shows aluminum prices from 1960 through 2001. Trends calculated over different time periods all show a consistent downward trend. On average, aluminum prices corrected for general inflation decreased by about 0.8 percent annually from 1960 to 2001. The downward trend is particularly pronounced from 1980 to the present.

The steady improvement in aluminum smelting technologies over time has meant that the region's smelters have tended to grow relatively less competitive in terms of their operating costs as new more efficient capacity has been added throughout the world. By investing in improved technology some of the region's smelters have been able to partially offset the effects of these declining cost trends. In addition, the worsening position of the region's aluminum smelters relative to other aluminum plants may have been partly offset by the decreasing capital costs and debt as older plants and equipment depreciate. Nevertheless, a growing share of the regional smelting capacity has become swing capacity. That is, plants could operate profitably during times of strong aluminum prices or low electricity prices, but tended to shut down during periods of less favorable market conditions.



Source: CRU International Ltd., Presentation to Aluminum Association 2002.

Figure A-11: Aluminum Price Trends

Caught in the pincers of decreasing aluminum prices and increasing electricity prices, many of the region's smelters have reached a critical point. Events since the spring of 2000, in both the electricity and aluminum markets, have had a dramatic effect on the region's aluminum plants. By mid-summer of 2001, all of the region's aluminum smelters had been shut down for normal production, either because of high electricity prices and poor aluminum market conditions or because Bonneville bought back the electricity to help meet an expected shortfall of electricity supplies and remarket the electricity at much higher market prices. The elimination of aluminum electricity load played a key role in avoiding electricity shortages in the summer of 2001 and the following winter.

Sharing of the savings from remarketing aluminum plants' electricity helped ease the financial strain on aluminum companies and their employees of a long shut down. During 2002 electricity prices in the wholesale market fell to low levels, but aluminum prices remained very low and only a few smelters found it desirable to partially return to production. In addition, Bonneville's rates have remained high. There does not appear to be much optimism for a quick recovery of aluminum prices. Some analysts expect the global aluminum market to remain in surplus until 2005.

Currently, three of the region's smelters have closed permanently, another is in bankruptcy proceedings and appears likely to close permanently, and others are in dire financial straits. During 2003 aluminum plants only consumed 423 average megawatts of electricity. Three plants that had partially reopened have cut back or suspended operations.

With aluminum market recovery uncertain, and with expected future electricity prices too high for most aluminum plants to operate profitably, future aluminum electricity use is expected to be much lower than in previous Council plans. The ability of aluminum plants to operate depends critically on the level of electricity prices. With the medium natural gas price assumptions, the Council currently forecasts long-term spot market electricity prices to be in the $30 to $40 per megawatt-hour range in year 2000 dollars (see Figure A-12). Few, if any, of the region's smelters would be able to operate with electricity prices at that level. It is unclear how much of the aluminum load Bonneville might serve in the future, but Bonneville's future electricity prices may also be higher than aluminum plants can afford except when aluminum prices are especially high.

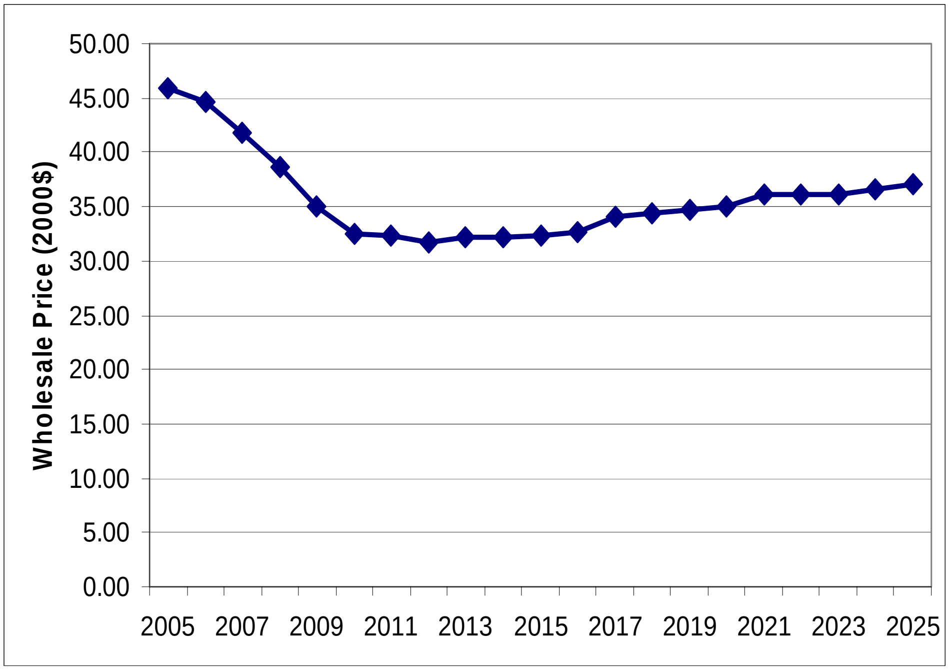


Figure A-12: Medium Case Wholesale Price Forecasts for Mid-Columbia Electricity

A Simple Model of Aluminum Electricity Demand

A simple model of Pacific Northwest aluminum plants was developed to relate the likelihood of existing aluminum plants operating to different levels of aluminum prices and electricity prices. Given an aluminum price, the model estimates what each aluminum plant in the Northwest could afford to pay for electricity given its other costs. Then, for a given electricity price, the electricity demand of the plants that can afford to operate make up the aluminum electricity demand in the region. Basic data for the model came from the July 2000 study cited as the source for Table A-5, advice from the Council's Demand Forecasting Advisory Committee, and comments on a draft aluminum forecast paper.[5]

[5] "Forecasting Electricity Demand of the Region's Aluminum Plants." Northwest Power Planning Council document 2002-20. December, 2002.

Figure A-13 illustrates the relative competitiveness of the seven remaining Northwest aluminum plants as represented in the model. (It is assumed that the other three smelters in Troutdale, Oregon, Longview, Washington, and Tacoma, Washington are permanently closed.) Figure A-13 shows the amount that each plant could afford to pay for electricity given an assumed aluminum price of $1,500 per ton[6] (about 67 cents a pound), which is about the average aluminum price over the past several years.

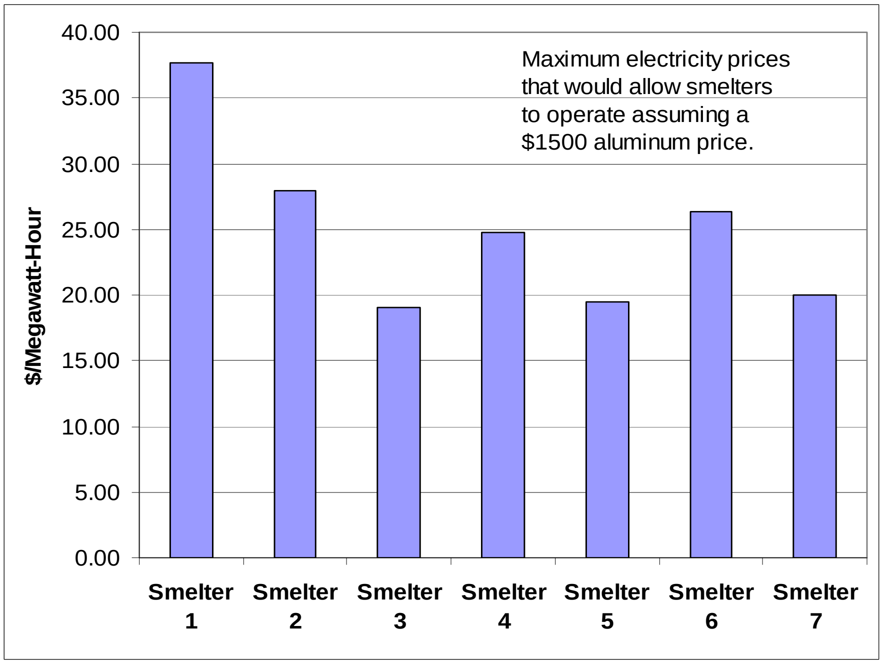


Figure A-13: Affordable Electricity Price Limits of PNW Aluminum Smelters At $1,500 Per Ton Aluminum Prices

One aluminum plant in the region is very efficient and is likely to operate under a wide range of electricity and aluminum prices. Three other smelters could pay around $25 a megawatt-hour for electricity if aluminum prices were $1,500 a tonne, which is higher than aluminum prices have averaged since 2000. The other smelters could only afford to operate at electricity prices near $20 per megawatt-hour.

There are some important limitations to this simple model. It is intended to represent whether aluminum plants would be willing to operate for an intermediate time period. The costs used in the model include an amount above the pure short-term operating costs to allow sufficient ongoing capital investments to maintain the plant's capability to produce. But the costs do not include sufficient returns on capital to justify the long-term operation of the plant.

Thus, the model does not address the question of when a plant would be likely to close permanently. In order to remain in operation, a plant would have to be able to recover sufficient funds during periods of high aluminum prices and low electricity prices to recover an adequate return on investment. However, as plants depreciate, or as they are sold at discounted prices, capital recovery becomes a smaller part of the decision, and strategic positioning in global

[6] "Tonne" refers to a metric ton, which contains 2,240 pounds.

markets may enable some plants to remain available for operation when conditions are attractive enough. The implicit assumption in the model is that if a plant can operate for the intermediate term under expected electricity and aluminum prices, then it will be able to recover sufficient returns during favorable cyclical market conditions to survive in the long term.

The model does not address the dynamics of temporary closures of aluminum plants or their return to operation. The dynamics of aluminum smelter operations are important considerations for assessing their potential value as demand-side reserves. The potential demand-side reserves that might be provided by aluminum plants include: very short-duration interruptions for system stability purposes; interruptions of up to four hours during extreme peak electricity price spikes; and long-term shut downs of several months to a year or more to address periods of poor hydroelectric conditions or other periods of significant generation capacity shortages. These issues will be addressed outside of the simple aluminum model described here. In the Council's portfolio risk model, aluminum plant closure, reserves, and reopening conditions are related to uncertain variations in electricity and aluminum prices. This will be discussed in more detail later.

Model Results

By varying the aluminum and electricity prices over a range of possible values, the simple model can be used to simulate expected aluminum electricity demands under varying conditions. Aluminum prices were varied between $1,050 and $2,250 per tonne in $100 increments. For each aluminum price, electricity prices were varied between $20 and $40 per megawatt-hour. This generated 91 different estimates of aluminum plant electricity demand under the varying aluminum and electricity combinations. Figure A-14 shows the results of this exercise.

A couple of bracketing points are evident. First, at aluminum prices below $1,150 per tonne, none of the Northwest aluminum plants can operate profitably at any electricity price between $20 and $40 per megawatt-hour. Aluminum prices have seldom been below $1,200 a ton (in 2002 prices) in the past 20 years. On the other extreme, all seven smelters could operate at aluminum prices above $2,050 per tonne for electricity prices up to $40 per megawatt-hour.

If past trends in aluminum prices continue, aluminum prices might decline at about one percent a year. That would mean that average aluminum prices might average less than $1,500 over the next 20 years. Of course, there will be considerable volatility around that trend. At this point in the Council's planning process, we do not have a range of future electricity prices that match the range of natural gas prices we are assuming for our analysis. Preliminary analysis with the medium natural gas price forecast shows that wholesale electricity prices under medium assumptions (see Figure A-12) could be between $35 and $40 per megawatt-hour over the long term. In those ranges of electricity and aluminum prices, it is unlikely that more than two aluminum plants could operate, and electricity demand by aluminum smelters in the region would be less than 900 megawatts.

The results in Figure A-14 include an assumption that one smelter will continue to have access to low cost mid-Columbia dam power for part of its electricity demand. Access to some lower cost supplies of electricity from Bonneville or other sources and further investments in smelter efficiency may improve the ability of some smelters to stay in operation. The simple aluminum model was used to see what effect an offer of 100 megawatts of electricity priced at $28 per megawatt-hour would have on smelter operations. Assuming an availability of such electricity supplies changes the model results for the 91 combinations of aluminum and electricity prices.

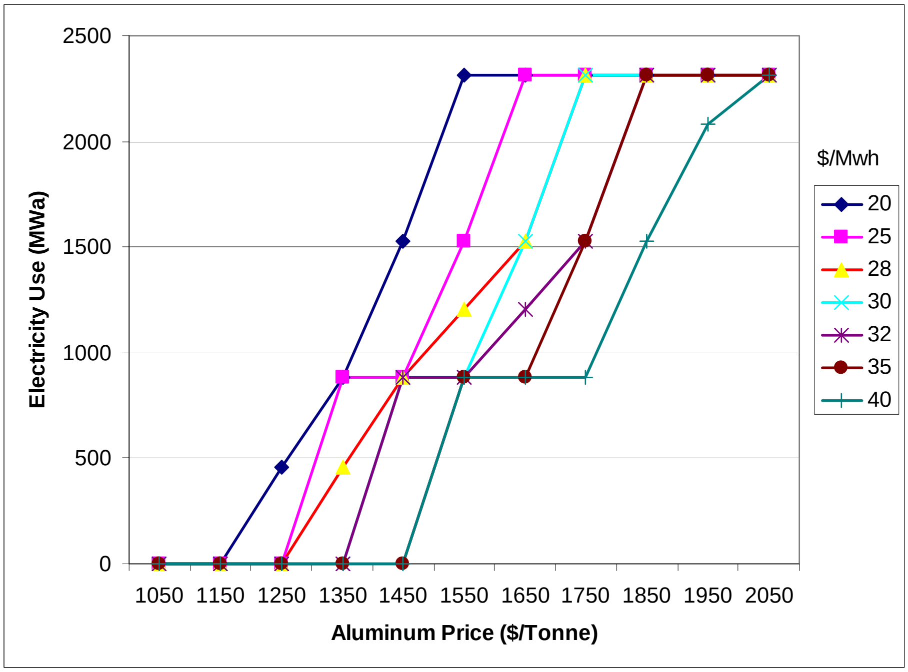


Figure A-14: Spectrum of Potential Aluminum Smelter Electricity Demands

In order to more easily illustrate these effects, an expected value of electricity demand was calculated for each assumed electricity market price. This was done by weighting electricity demand simulated at different aluminum prices by the percent of days in the last ten years that actual aluminum prices fell into that range. These expected electricity demands are shown in Figure A-15. Another way of characterizing an individual bar in Figure A-15 is that it is a weighted average of the electricity use in an individual line from Figure A-14.

Using just market electricity prices and the one mid-Columbia supply contract, expected smelter electricity demands ranged from 783 megawatts at $40 per megawatt-hour electricity prices to 2,138 megawatts at $20 electricity prices. This is shown in the left-most bar for each electricity price group in Figure A-15.

If smelters could arrange to purchase 100 megawatts of power priced at $28 per megawatt-hour, it is estimated to have a relatively small effect on expected aluminum operations (see the middle bars in Figure A-15). At market prices below $28 the expected electricity demand of aluminum smelters is actually reduced by the higher priced power supply. If market power prices were $40, the availability of 100 MW of power at $28 per megawatt-hour is estimated to increase the expected value of aluminum smelters' electricity demand of from 783 to 875 megawatts, a relatively small effect. If smelters could arrange a block of power at $20 (illustrated by the right-most bars in Figure A-15) the estimated increase in electricity demand at the $40 market price would be 314 megawatts. That increase is roughly the electricity demand of one additional smelter.

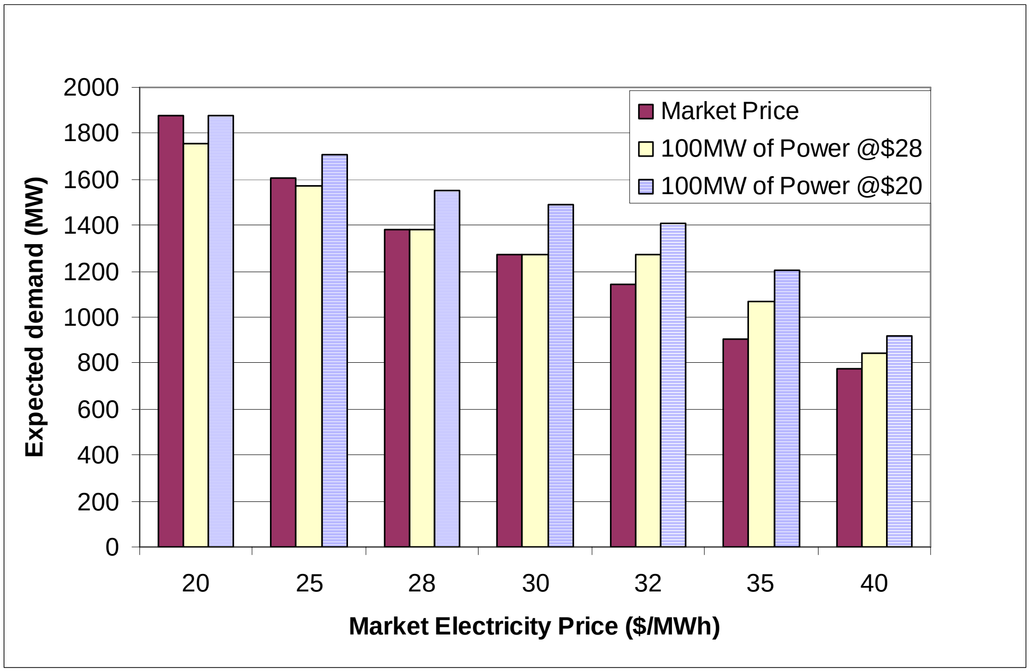


Figure A-15: Expected Aluminum Plant Electricity Demand (Effect of Special Electricity Supplies)

The analysis above addresses the question of whether the existing smelters in the region are likely to operate under different aluminum and electricity market conditions. It does not address the likelihood of permanent closure. Historically, older and less efficient smelters are not frequently closed permanently. Their depreciated capital costs allow them to operate when electricity and aluminum prices are attractive. They may provide an inexpensive option for aluminum supplies in tight aluminum markets. In addition, permanent closure may involve expensive site clean up.

The result is that the region might retain a large, but uncertain, electricity demand. If such a demand is required to be served when they need electricity, it can be very costly for their electricity supplier to maintain generating capacity to serve the potential demand. If serving the demand is optional, however, through either interruption agreements or the smelters purchasing available power in the market, it can have attractive features that may reduce electricity price volatility. The future of aluminum operations in the region may depend on the ability of aluminum plants to find, and get value for, their potential for complementing the power system in a competitive wholesale market.

Mid-Term Aluminum Demand Assumption

The Council is required to include in its power plans a 20-year forecast of demand. The Council is also increasing its focus on the nearer term for purposes of reliability and adequacy analysis. For these purposes, a specific forecast of total electricity demand is useful. And for that, specific assumptions about DSI demands are needed. This section presents such a best guess forecast, but it is important to keep the extreme uncertainty regarding this assumption in mind when evaluating reliability, adequacy, or long-term resource strategies.

Figure A-16 shows the assumed mid-term pattern of aluminum electricity demand through 2005 compared to the Council's assumption for the Fourth Power Plan. In the current forecast, electricity demand is assumed to recover to about 1,000 megawatts by 2005. This would be consistent with two aluminum smelters operating plus 60 average megawatts of non-aluminum DSI demand. If the aluminum model is reasonably accurate, and if electricity can be acquired for $30 to $35 per megawatt-hour, this implies that aluminum prices would have to recover to $1,450 to $1,550 per tonne by 2005. The higher end of that range is similar to average aluminum prices during the past 10 years. Although aluminum prices have risen to above $1,600 in the first four months of 2004, given recent trends and events in world aluminum markets, the range of $1,450 to $1,550 per tonne should be viewed as a reasonably optimistic assumption for future aluminum prices.

The forecast is significantly more pessimistic about aluminum plants' ability to operate than the Council's Fourth Power Plan. This is consistent with a prolonged period of low aluminum prices during 2001 through 2004, with higher forecasts of electricity prices. It also is more pessimistic about the ability of some smelters to survive a prolonged period of high electricity prices, poor aluminum prices, and uncertainty about electricity markets and contracts.

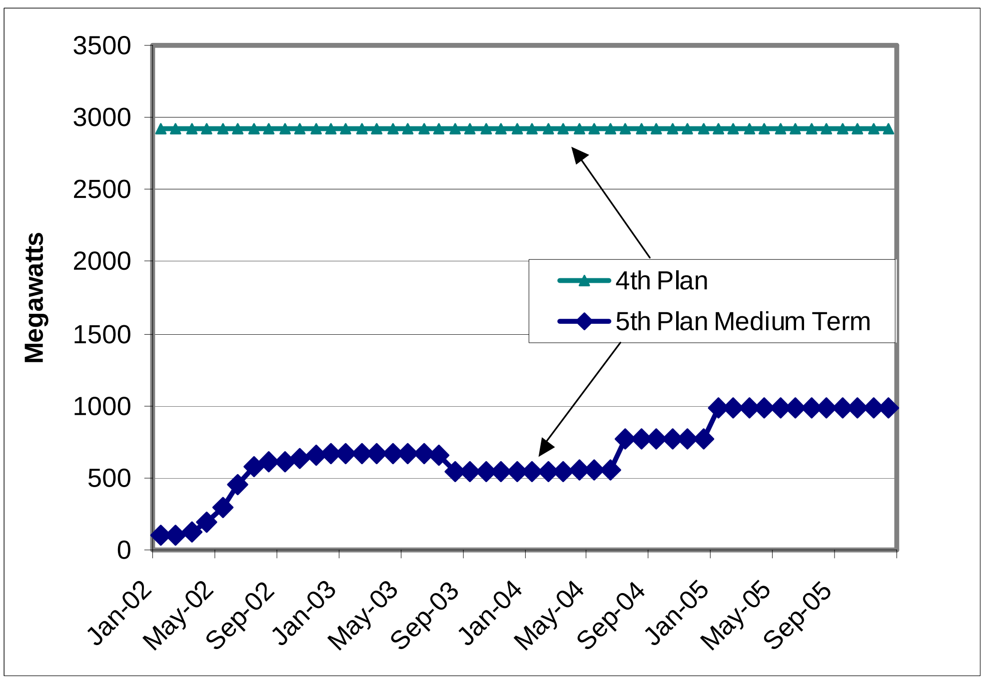


Figure A-16: Medium Case Assumptions for Aluminum Demand Recovery to 2005 (Comparison to 4th Plan Assumptions)

Long-Term Forecasts of Aluminum Smelter Electricity Demand

For the long-term medium forecast, the 2005 forecast level is extended to the end of the forecast in 2025. Figure A-17 shows the medium total DSI demand assumptions extended to 2025 compared to the forecasts in the Council's Fourth Power Plan. In this figure, non-aluminum DSI loads of 60 average megawatts have been added to the aluminum forecast. Again, this forecast does not imply that Bonneville will serve all of this DSI demand; it has been labeled DSI for convenience. The medium case is 1,260 average megawatts below the forecast in the Council's last power plan.

Although the loads after 2005 are shown as constant, we would actually expect them to be quite volatile around that trend. In addition, since aluminum prices are expected to trend downward over time, and natural gas prices upward, it may become increasingly difficult for regional smelters to operate as the future unfolds.

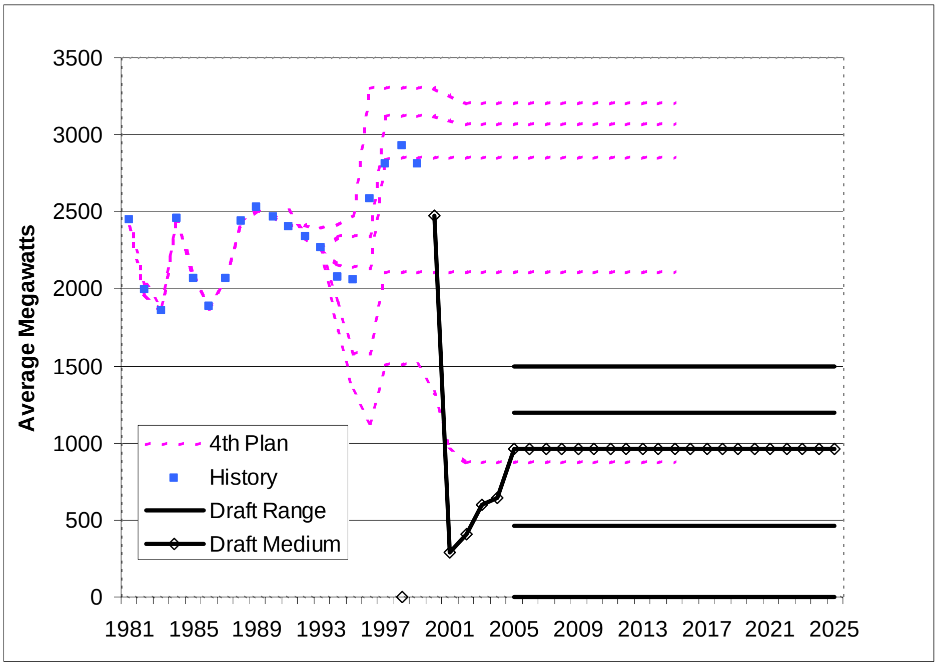


Figure A-17: Demand Assumptions for DSI Industries Compared to Fourth Plan Assumptions

In all previous power plans, the Council has assumed a range of DSI demands. The high DSI demand assumption was paired with the high economic assumptions and demand forecast. This pairing of aluminum and other forecasting assumptions was based on the theory that aluminum prices would be the key variable and that aluminum prices were likely to be positively correlated with rates of economic growth. For illustrative purposes, a similar approach has been used to develop a range of aluminum demand assumptions. Figure A-18 shows the aluminum demand assumptions included in each forecast case for the Council's Fourth Power Plan compared to the outlook now.

Only in the low forecast of the Fourth Power Plan was there a large reduction of aluminum demand. It was assumed that Bonneville or other relatively affordable power would be available to the aluminum plants. Thus, most of the plants were assumed to remain competitive, or at least operate as swing plants, in the medium case. Now the expectation is that only between zero and four of the region's smelters could survive to operate at significant capacity factors.

The expectation of higher electricity prices and rapid expansion of aluminum smelting capacity in China and other areas has changed the outlook for the region's smelters substantially. Aluminum prices are still important, but the cost of electricity has become a critical element for Northwest smelters. Since electricity prices are related to natural gas prices in the long-term, and high natural gas prices are associated with the high economic growth case, it is also reasonable to expect that lower aluminum demand could be associated with the higher economic growth cases. However, if high aluminum prices are still associated with higher economic growth, then it is possible that the high economic growth cases will favor aluminum plant operation given that electricity prices are not too high. In short, it is not clear how aluminum demand will be related to the economic growth conditions. The proposed solution to this dilemma is to forecast aluminum electricity demand separately from other demands for electricity.

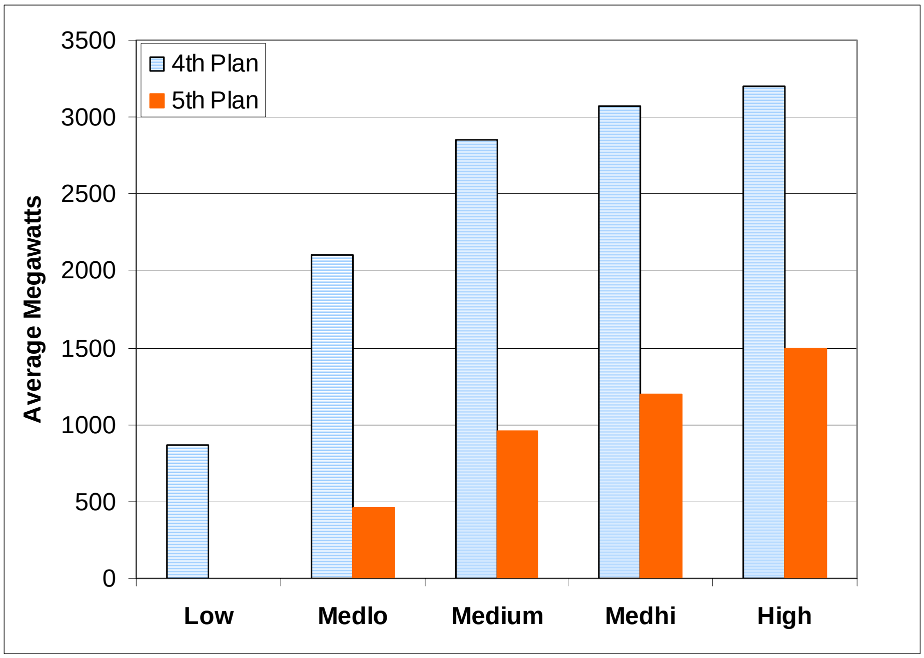


Figure A-18: Aluminum Electricity Demand Assumptions for 2005-2025 Compared to the Council's Fourth Power Plan

Therefore, the Council is modeling aluminum industry demands explicitly in its portfolio model.

Aluminum Demand in the Portfolio Analysis

Since aluminum demands are very significant in determining future electricity demands of the region, they are an important source of uncertainty that should be modeled and addressed directly in the Council's resource planning process. In developing the Fifth Power Plan, the Council modeled aluminum plants as uncertain loads that depend on aluminum prices and electricity prices. This was done using the Council's portfolio analysis model. The simple model described above was the basis for the relationship between aluminum electricity demand and electricity and aluminum prices developed for the portfolio model. As it simulated alternative futures, the portfolio model randomly selected different electricity prices and aluminum prices. These conditions were used to estimate the aluminum plants' demand for electricity.

However, the simulations contained in the portfolio model take into account, in addition to the basic cost information for each plant, assumptions about cost of shutting down and restarting plants and minimum down time and up time. For example, it is assumed that the decision to restart a plant would include the startup costs and that, if a plant were to reopen, it would remain open for at least 9 months. Similarly, a plant may not close immediately when current prices make it unprofitable, and once it does close it would likely remain closed for a period of at least 9 months. The portfolio model also assumes that if a plant does not operate for a five-year period, it will be permanently closed. The portfolio model goes beyond these calculations to consider the value of an aluminum plant interruption option to Bonneville or the regional power system.

The base case portfolio model simulations are less optimistic about the operation of the aluminum plants than the discrete assumptions described in the earlier section of this appendix. In 80 percent of the futures, aluminum electricity use was expected to be zero. The mean electricity demand for the plants decreased from about 100 average megawatts in the early years down to about 60 average megawatts in the later years. This compares to the medium discrete assumption of 958 average megawatts. There are futures examined in which aluminum loads vary between 800 and 1500 average megawatts although such futures are infrequent. If it were assumed that the region needed to stand ready to meet these loads, this is roughly consistent with the discrete range of DSI forecasts discussed above.

NEW DIMENSIONS OF COUNCIL DEMAND FORECASTING

Changing electricity markets are changing the planning requirements for the region. Electricity prices in the Pacific Northwest are related directly to demand and supply conditions, not just in the region, but also in the entire interconnected Western United States. In addition, electricity markets have been, and are expected to remain, volatile. Shortages and high prices will occur at specific times of the year and day depending on electricity demand, but can be prolonged in cases of poor hydroelectric conditions, such as occurred in 2001.

Evaluating electricity markets requires assumptions about demand growth in the entire West and some understanding of how the demand will vary across different seasons and across hours of the day. The following sections describe the simple approaches used to develop assumptions about future patterns of electricity consumption and predicted growth in demand throughout the rest of the West.

Patterns of Regional Electricity Consumption

One approach to forecasting temporal patterns of demand is to use the monthly and hourly patterns from the Fourth Power Plan. In the Fourth Power Plan, the Council used an extremely detailed hourly electricity demand forecasting model to estimate hourly demand patterns in the future. That model was not used for this forecast, but the hourly patterns remain similar. Another approach is to use historical patterns of demand. In practice, these approaches do not result in significantly different monthly patterns of consumption.

Whatever typical monthly shape is used, specific months can depart from the normal pattern depending on weather. Variability in consumption patterns due to weather events were considered in the portfolio planning model that addresses mitigation of risk and uncertainty in electricity markets. Typical monthly patterns provide a starting point for that analysis. The same is true for the peak demand forecast and the typical hourly patterns of demand.

Monthly Patterns of Regional Demand

Figure A-19 compares monthly patterns of regional demand in 1999 with patterns from the Council's Load Shape Forecasting System (LSFS) from the Fourth Power Plan simulation for 1995. The points on this graph indicate the monthly consumption of electricity compared to the annual average. These patterns have been adjusted to reflect only non-DSI demand. DSI demands, dominated by aluminum plants, tend to be seasonally flat.

The monthly patterns of both the actual and modeled demand reflect the higher electricity consumption in the winter with a secondary and smaller increase during the summer. Within that general pattern, there appear variations in specific months. The LSFS was based on a year in which there was a severe cold event in December. A particular year was chosen to design the model rather than an average over several years to preserve the variability in the load patterns. Averaging would have tended to flatten the hourly variation masking some of the potential volatility.

For purposes of this forecast, the 1999 pattern is used. Table A-6 shows the monthly demand shape in numerical terms.

Table A-6: Monthly Non-DSI Electricity Consumption Pattern

Month	Shape Factor
January	1.140
February	1.097
March	1.020
April	0.943
May	0.921
June	0.938
July	0.969
August	0.957
September	0.911
October	0.940
November	1.033
December	1.185

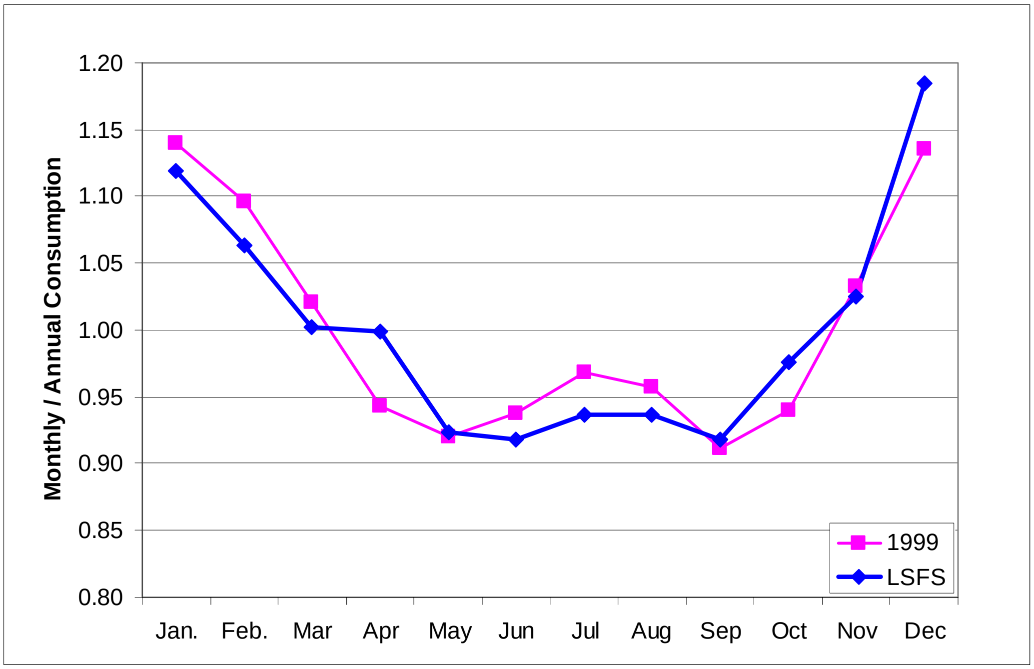


Figure A-19: Monthly Patterns of Non-DSI Electricity Use

Regional Peak Demand

Monthly regional peak demands are also taken from the Council's Load Shape Forecasting System. Figure A-20 shows average monthly consumption compared to monthly peak hour consumption. Peak demand is highest relative to average monthly demand in the winter months. For example, estimated January peak demand is 45 percent higher than the average demand for the month, whereas the peak August demand is only 21 percent higher than average August demand. The summer and winter peak demands occur at different times of the day. In June, July and August, peak demand hours are at 2:00 or 3:00 in the afternoon. The rest of the year peak demand occurs at 8:00 or 9:00 in the morning.

The ratio of average monthly demand to peak hour demand in a month is referred to as a "load factor." Over time the LSFS predicts that load factors will decline, especially during the winter months. That is, the peak hour demand will increase faster than the average monthly demand over time. Figure A-21 shows predicted load factors for 1995, 2005 and 2015 from the LSFS analysis of the Fourth Power Plan forecasts. The change in load factor is most pronounced in the winter months. Discussion with the Council's Demand Forecasting Advisory Committee indicated that utilities are experiencing increases in summer peak loads, probably due to an increasing presence of air conditioning in the region. In the future, the Council should investigate this trend further to see if the forecasted pattern needs to be modified to reflect a greater decrease in summer load factors.

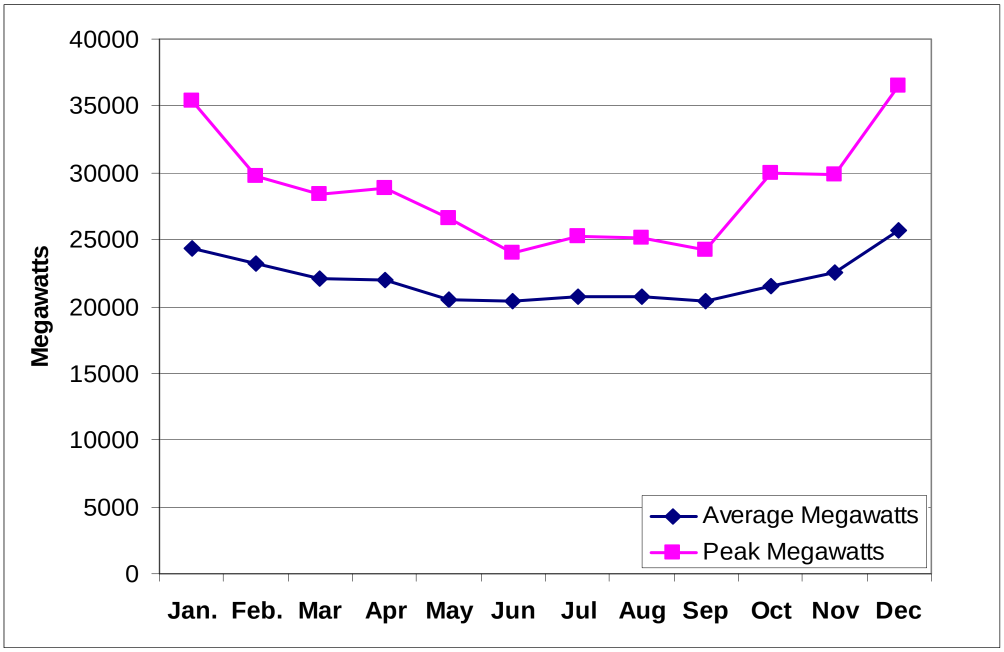


Figure A-20: Hourly Peak Demand Compared to Average Monthly Demand

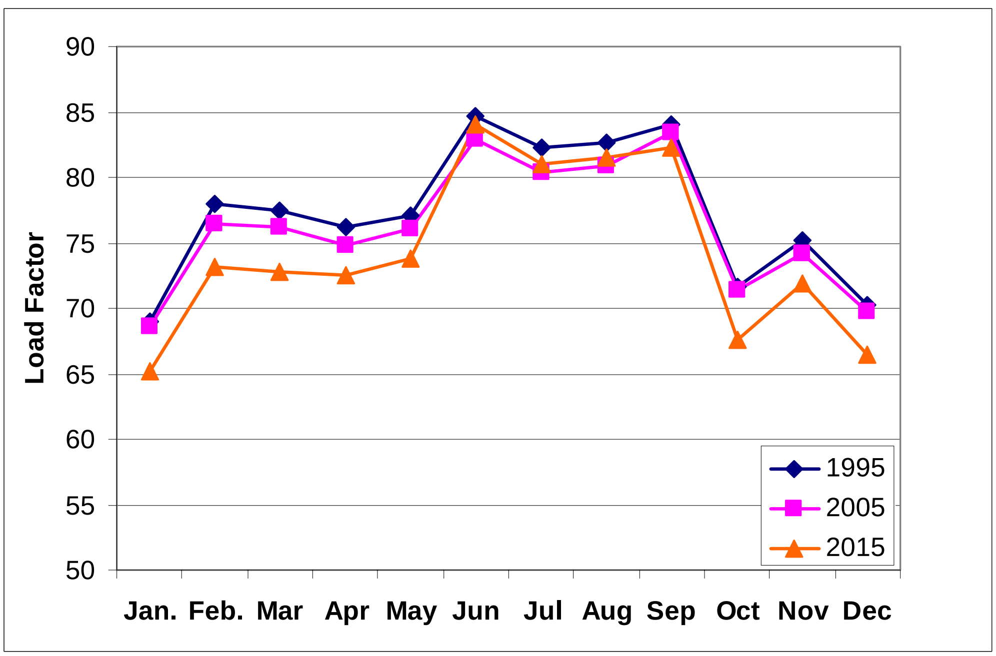


Figure A-21: Forecast of Electricity Demand Load Factors

Regional Hourly Demand Patterns

The LSFS forecasts hourly demand for 8,760 hours in the year. It does this for individual end uses within the commercial and residential sectors, for specific manufacturing sectors, and for irrigation. These hourly patterns are aggregated to obtain total hourly demand in the region. Figure A-22 illustrates hourly shapes for a typical winter weekday, a very cold winter weekday, and a summer weekday. Winter demand peaks in the morning and again in the evening. This pattern is driven largely by residential demand patterns, which are more variable across the hours of the day than the other sectors.

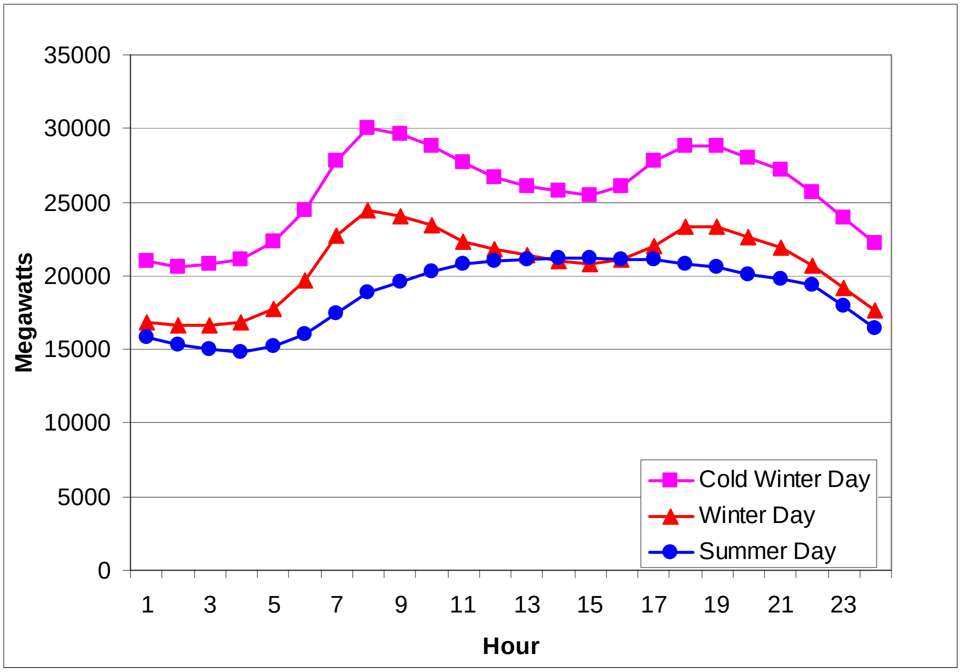


Figure A-22: Illustrative Hourly Demand Patterns in a Day

These hourly patterns of demand may be used in various ways to address analytical requirements. In the Fourth Power Plan, for example, they were aggregated into four distinct blocks of demand for a week. These included on-peak, shoulder, off-peak, and minimum load hours.[7] This was done to address sustained peaking requirements in the plan. By estimating an hourly pattern for 8,760 hours in a year, flexibility is provided to aggregate the demand patterns for different types of analysis.

Portfolio Model Analysis of Non-DSI Demand

The portfolio model goes beyond the typical demand trends and their normal seasonal and hourly patterns. It introduces random variations in loads. There are three types of variation considered. The model chooses among potential long-term trends encompassed in the range of demand forecasts discussed above as past Council plans have done. But the portfolio model also adds shorter-term excursions that reflect such events as business cycles and energy commodity price cycles, and very short-term variations such as would be caused by weather events.

Figure A-23 illustrates a few specific demand paths, from hundreds simulated, and compares them to the long-term range of non-DSI demand forecasts.

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[7] See "Draft Fourth Northwest Conservation and Electric Power Plan," Appendix D, p. D-36.

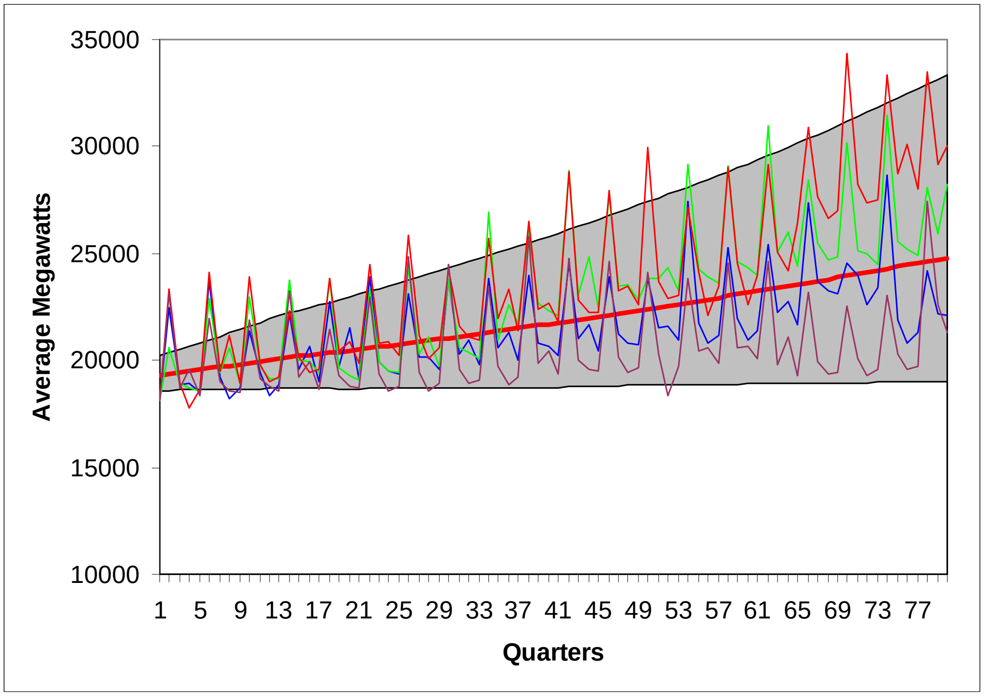


Figure A-23: Illustrative Non-DSI Demand Paths from the Portfolio Model Compared to the Trend Forecast Range

Electricity Demand Growth in the Rest of the West

In previous power plans, the Council has not concerned itself with demand growth in other parts of the West. However, as noted earlier, this is now an important consideration for analysis of future electricity prices in this region.

A simple approach was used to estimate electricity demand growth for other areas of the West. The areas used by the AURORA® electricity market model dictate the specific areas considered. The general approach used, although it varies for some areas, is to calculate future growth in electricity demand as a historical growth rate of electricity use per capita times a forecast of population growth rate for the area. The exceptions to this method were California, where forecasts by the California Energy Commission were used, the Pacific Northwest, and the Canadian provinces, where electricity demand forecasts were directly available from the National Energy Board.

Population forecasts for states are available from the U.S. Census Bureau web site. However, the Census forecasts were replaced by more recent state forecasts when they could be identified. For example, Nevada population forecasts were taken from the Nevada Department of Water Resources. There were two reasons for this. First, the AURORA® model distinguishes between Northern and Southern Nevada and Census forecasts were only available at the state level. Second, the Census Bureau forecast showed Nevada population growing at only .85 percent a year, whereas Nevada has recently been the fastest growing state in the nation with population growth in the neighborhood of 5 percent a year. Other population forecast sources used were the Colorado Department of Labor Affairs, the Arizona Department of Economic Security, Pacificorp's Integrated Resource Plan for Utah, and the Wyoming Department of Administration and Information.

Electricity consumption per capita varies substantially among the states in the West, as have their patterns of change over time. Figure A-24 shows electricity use per capita for Western states from 1960 to 1999. The most spectacular change is for Wyoming, which started out in 1960 with the lowest use per capita and grew to substantially higher than any other state. This may reflect significant heavy industrial growth in electricity intensive, but low employment, plants, oil and natural gas production, for example. The Pacific Northwest states are the highest per capita users of electricity, reflecting a past of very low electricity prices and a heavy presence of aluminum smelters. California is the lowest user of electricity per capita, followed by New Mexico, Utah and Colorado, which are all very similar to one another. Nevada and Arizona fall between these three states and the Pacific Northwest states.

The general pattern is substantial growth in electricity use per capita until about 1980. After 1980, most states' electricity use per capita levels off or actually declines. Exceptions to this pattern are Colorado, New Mexico, Arizona, and Utah where use per capita has slowed, but continued growing.

The Pacific Northwest was a special case. In AURORA®, the Pacific Northwest is divided into four areas; Western Oregon and Washington (west of the Cascade Mountains), Eastern Oregon and Washington combined with Northern Idaho, Southern Idaho, and Montana. The sum of these area forecasts should be consistent with the 20-year regional forecast discussed earlier. One approach would have been to share the regional demand forecast to areas based on historical shares. However, in order to recognize that areas within the Pacific Northwest have not grown uniformly, the forecast area growth rates were modified to reflect historical relative population growth in the four areas while maintaining consistency with the total regional population growth.

Table A-7 shows the forecast growth rates for the AURORA® demand areas. They are average annual growth rates from 2000 to 2025.

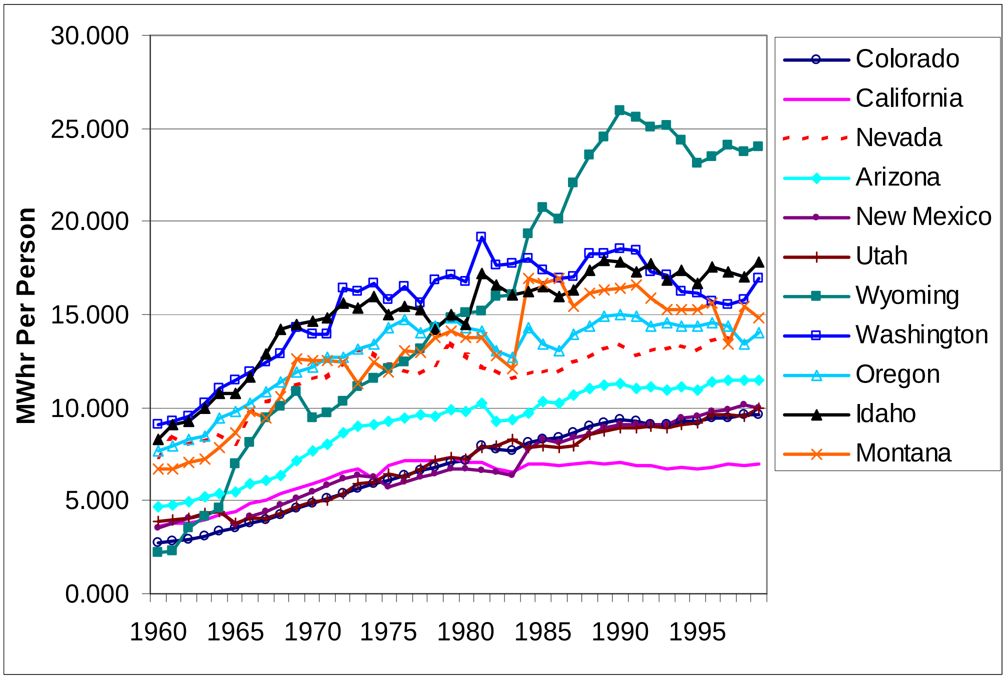


Figure A-24: State Electricity Use Per Capita: 1960 to 1999

Table A-7: Forecast Electricity Demand Growth Rates for Western Demand Areas

Area	Annual Growth Rate
PNW Western OR+WA	1.06
PNW Eastern OR+WA and Northern ID	0.42
PNW Southern ID	1.50
PNW MT	0.63
Northern CA	1.51
Southern CA	1.62
Northern NV	2.12
Southern NV	2.72
WY	0.62
UT	2.80
CO	2.34
NM	3.05
AZ	2.47
Alberta	1.59
British Columbia	1.39

FUTURE FORECASTING METHODS

At the time the Council was formed, growth in electricity demand was considered the key issue for planning. The region was beginning to see some slowing of the historically rapid growth of electricity use, and the future of several proposed nuclear and coal generating plants was in question. It was important for the Council's Demand Forecasting System (DFS) to determine the causes of changing demand growth and the extent and composition of future demand trends. Simple historical trends were no longer reliable. In addition, the requirement of the Northwest Power Act for a balanced consideration of both conservation and new generation placed another requirement on the DFS; it needed to support the detailed evaluation of improved efficiency opportunities and their effects on electricity demand.

These analytical requirements necessitated an extremely detailed approach to demand forecasting. Rather than identifying trends in aggregate or electricity consumption by sector, the Council developed a forecasting system that built demand forecasts from the end-use details of each consuming sector (residential, commercial, industrial). Forecasting with these models required detailed economic forecasts for all the sectors represented separately in the demand models. The models also required forecasts of demographic trends, electricity prices and fuel prices.

Before the last power plan update, a significant new component was added to the DFS. As Western electricity systems became more integrated through deregulated wholesale markets, and as capacity issues began to arise in the region, it became clear that we needed to understand the patterns of electricity demand over seasons, months and hours of the day. Therefore the Load Shape Forecasting System (LSFS) was developed. This model builds up the hourly shape of demand based on the underlying hourly shapes of electricity use by the different types of end-use equipment. It contains about the same detail as the DFS, but when multiplied by 8,760 hours per year, a one-year forecast can contain 400 million values.

The detailed approaches of the DFS and LSFS are expensive and time consuming. Major efforts are involved in collecting detailed end-use data, building the models, and maintaining and operating the systems. Neither the current planning issues, nor the available data and resources seem to support the continued use of the old demand forecasting approach. The Council developed an issue paper on forecasting methods in May 2001 to explore alternative approaches.[8] It was agreed that it was not possible for the Council to employ the forecasting models for the Fifth Power Plan. However, there was little consensus in the region about what changes should be made to the forecasting system for future Council planning.

The basic priorities for a demand forecast have changed. Although the Northwest Power Act still requires a 20-year forecast of demand, there are few decisions that need to be made today to meet growing electricity demands beyond the next five years. The lead-time required to put new generating resources in place has been reduced substantially from the large scale nuclear and coal plants that appeared to be desirable in the early 1980s. In addition, the restructuring of the wholesale electricity markets to rely more on competitively developed supplies means there is a less clear role for the Council's planning which focused on the type and timing of new resources to be acquired.

The focus of the Council's power activity has shifted to the evaluation of the performance of more competitive power markets and how to acquire conservation in the new market. The Council also has been concerned about the likelihood of competitive wholesale power markets

[8] Northwest Power Planning Council. "Council Demand Forecasting Issues." May 2001, Council document number 2001-13. http://www.nwcouncil.org/library/2001/2001-13.htm

providing adequate and reliable power supplies, which has three implications for demand forecasting. First, the focus is much shorter term. Adequacy and reliability depend on generating resources, including water conditions and their effects of hydroelectric generation, compared to loads. The question facing the region recently has been whether there is adequate capacity and energy to meet the coming winter demand. Second, the region is no longer independent of the entire Western U.S. electricity market. Electricity prices and adequacy of supply are now determined by West-wide electricity conditions. The AURORA® electricity market model that the Council is using requires assumptions about demand growth for all areas of the Western integrated electricity grid. Third, the temporal patterns of demand and peak demands matter more. The region is becoming more likely to be constrained by sustained peaking capability than average annual energy supplies, as it was in the past. Further, the rest of the West has always been capacity constrained and thus peak prices throughout the West can be expected during peak demand periods.

Thus, for purposes of demand forecasting, the requirements of the forecast are shifting to shorter term, temporal patterns, and expanded geographic areas. This implies that a different type of demand forecasting system may be useful for future Council planning. However, there remains the question of estimated potential efficiency gains in the use of electricity. To assess cost-effective conservation potential, the end-use detail of the old forecasting models would still be useful. But even if the Council still had the resources to use the old forecasting models, the detailed data necessary to update the models does not exist. Finding new ways of assessing conservation potential, or of encouraging its adoption without explicit estimates of the amount likely to be saved, is a significant issue for regional planning.

The forecasts presented in this paper are based on an extension of the previous Council plan and relatively simple approaches to expanding the geographic and temporal dimensions of the forecast. The Council needs to invest in new forecasting approaches for future power plans. One of the activities for the Council over the next several years will be to develop a new forecasting system that is better oriented to the available Council resources, to the current planning issues, and to the available data regarding electricity consumption and its driving variables. The Council welcomes suggested approaches and advice in this area.

Fifth Power Plan Demand Forecast D2
Medium Case

	2000 (Actual)	2005	2010	2015	2020	2025	Growth Rates 2000-2025	2000-2015	2005-2025
Total Sales	20080	19391	20646	22105	23701	25423	0.95	0.64	1.36
Non-DSI Sales	17603	18433	19688	21147	22742	24464	1.33	1.23	1.43
Residential	6724	7262	7687	8230	8809	9430	1.36	1.36	1.31
Commercial	5219	5453	5771	6146	6556	6993	1.18	1.10	1.25
Non-DSI Industrial	4836	4904	5397	5919	6505	7150	1.58	1.36	1.90
DSI Industrial	2477	958	958	958	958	958	-3.73	-6.13	0.00
Irrigation	652	629	641	654	667	681	0.17	0.02	0.40
Other	172	185	191	198	204	211	0.82	0.93	0.66

Total

	2000 (Actual)	2015	2025	Growth Rates 2000-2015	2000-2025
Low	20080	17489	17822	-0.92	-0.48
Medium Low	20080	19942	21934	-0.05	0.35
Medium	20080	22105	25423	0.64	0.95
Medium High	20080	24200	29138	1.25	1.50
High	20080	27687	35897	2.16	2.35

Non-DSI

	2000 (Actual)	2015	2025	Growth Rates 2000-2015	2000-2025
Low	17603	17489	17822	-0.04%	0.05%
Medium Low	17603	19482	21474	0.68%	0.80%
Medium	17603	21147	24464	1.23%	1.33%
Medium High	17603	23000	27937	1.80%	1.86%
High	17603	26187	34397	2.68%	2.72%

Total Demand

Weather Adjusted Sales Actual	YEAR	Revised Forecast Low	Medlo	Medium	Medhi	High
15533	1981					
14767	1982					
14448	1983					
15477	1984					
15194	1985					
15352	1986					
15872	1987					
16683	1988					
17356	1989					
17549	1990					
17903	1991					
17994	1992					
18021	1993					
18385	1994					
18647	1995					
19099	1996					
19685	1997					
19967	1998					
20487	1999					
20082	2000			20080		
17235	2001			17415		
	2002			17565		
	2003			18145		
	2004			18714		
	2005	17191	18284	19391	20220	21721
	2006	17200	18415	19621	20560	22227
	2007	17214	18558	19864	20921	22757
	2008	17228	18699	20103	21294	23314
	2009	17257	18858	20363	21679	23897
	2010	17297	19030	20646	22079	24507
	2011	17320	19189	20917	22476	25098
	2012	17353	19366	21209	22897	25714
	2013	17366	19527	21480	23307	26343
	2014	17430	19734	21789	23748	27001
	2015	17489	19942	22105	24200	27687
	2016	17522	20132	22415	24649	28406
	2017	17554	20324	22729	25108	29145
	2018	17586	20518	23048	25576	29907
	2019	17619	20714	23372	26053	30690
	2020	17652	20913	23701	26541	31497
	2021	17686	21113	24035	27039	32327
	2022	17719	21315	24374	27547	33181
	2023	17753	21519	24718	28066	34060
	2024	17787	21725	25068	28596	34966
	2025	17822	21934	25423	29138	35897
Growth Rate	2005-25	0.18%	0.91%	1.36%	1.84%	2.54%
Growth Rate	2000-25	-0.48%	0.35%	0.95%	1.50%	2.35%

Total Non-DSI Demand

Weather Adjusted Sales Actual	YEAR	Revised Forecast Low	Medlo	Medium	Medhi	High
13085	1981					
12774	1982					
12588	1983					
13019	1984					
13126	1985					
13467	1986					
13807	1987					
14248	1988					
14825	1989					
15084	1990					
15496	1991					
15653	1992					
15756	1993					
16310	1994					
16589	1995					
16519	1996					
16871	1997					
17034	1998					
17464	1999					
17605	2000			17603		
	2001			17129		
	2002			17152		
	2003			17545		
	2004			18072		
	2005	17191	17824	18433	19020	20221
	2006	17200	17955	18663	19360	20727
	2007	17214	18098	18906	19721	21257
	2008	17228	18239	19145	20093	21814
	2009	17257	18398	19405	20479	22397
	2010	17297	18570	19688	20879	23007
	2011	17320	18729	19959	21275	23598
	2012	17353	18906	20251	21696	24214
	2013	17366	19067	20521	22106	24843
	2014	17430	19274	20830	22547	25501
	2015	17489	19482	21147	23000	26187
	2016	17522	19672	21456	23449	26906
	2017	17554	19864	21770	23907	27645
	2018	17586	20058	22089	24375	28407
	2019	17619	20254	22413	24853	29190
	2020	17652	20453	22742	25341	29997
	2021	17686	20653	23076	25839	30827
	2022	17719	20855	23415	26347	31681
	2023	17753	21059	23760	26866	32560
	2024	17787	21265	24109	27396	33466
	2025	17822	21474	24464	27937	34397
Growth Rate	2005-25	0.18%	0.94%	1.43%	1.94%	2.69%
Growth Rate	2000-25	0.05%	0.80%	1.33%	1.86%	2.72%

Residential Demand

	Revised Forecast				
	Low	Medlo	Medium	Medhi	High
2000			6724		
2001	6397	6759	6797	6876	7093
2002	6642	6722	6784	6883	7162
2003	6857	6902	6987	7110	7462
2004	6837	7069	7183	7333	7767
2005	6728	7122	7262	7437	7955
2006	6728	7178	7340	7545	8124
2007	6735	7244	7428	7665	8305
2008	6731	7299	7505	7777	8484
2009	6734	7362	7589	7894	8673
2010	6747	7436	7687	8021	8876
2011	6768	7517	7789	8159	9077
2012	6793	7599	7896	8302	9280
2013	6801	7668	7986	8430	9472
2014	6838	7765	8103	8584	9688
2015	6878	7869	8230	8747	9918
2016	6890	7954	8343	8900	10167
2017	6902	8040	8457	9056	10423
2018	6915	8126	8573	9214	10684
2019	6927	8214	8690	9376	10952
2020	6940	8303	8809	9540	11227
2021	6952	8393	8930	9707	11509
2022	6965	8483	9052	9876	11798
2023	6977	8575	9176	10049	12094
2024	6990	8667	9302	10225	12398
2025	7002	8761	9430	10404	12709
Growth 2000-25	0.16%	1.06%	1.36%	1.76%	2.58%

Commercial Demand

	Revised Forecast				
	Low	Medlo	Medium	Medhi	High
2000			5219		
2001	5043	5064	5083	5184	5319
2002	5218	5240	5124	5248	5427
2003	5260	5281	5201	5348	5576
2004	5357	5377	5378	5560	5842
2005	5255	5274	5453	5670	6008
2006	5267	5306	5509	5763	6148
2007	5276	5338	5564	5858	6292
2008	5293	5378	5627	5965	6450
2009	5317	5425	5696	6075	6614
2010	5340	5472	5771	6184	6780
2011	5348	5507	5835	6284	6932
2012	5367	5558	5914	6398	7100
2013	5387	5611	5988	6514	7280
2014	5425	5676	6070	6631	7455
2015	5455	5735	6146	6743	7631
2016	5485	5795	6226	6856	7811
2017	5515	5855	6307	6972	7996
2018	5545	5916	6389	7089	8184
2019	5576	5978	6472	7209	8378
2020	5607	6040	6556	7330	8576
2021	5638	6103	6641	7454	8778
2022	5669	6166	6727	7580	8986
2023	5700	6231	6815	7707	9198
2024	5732	6295	6904	7837	9415
2025	5763	6361	6993	7969	9638
Growth 2000-25	0.40%	0.79%	1.18%	1.71%	2.48%

Industrial Non-DSI Demand

	Revised Forecast				
	Low	Medlo	Medium	Medhi	High
2000	4737	4770	4836	4833	4851
2001	4239	4303	4401	4454	4589
2002	4245	4344	4484	4567	4744
2003	4277	4411	4596	4710	4933
2004	4297	4469	4702	4850	5124
2005	4402	4616	4904	5092	5429
2006	4402	4657	4997	5225	5618
2007	4403	4700	5092	5365	5817
2008	4405	4743	5189	5511	6027
2009	4410	4789	5291	5662	6248
2010	4415	4836	5397	5818	6480
2011	4410	4878	5498	5970	6709
2012	4403	4918	5601	6128	6947
2013	4391	4957	5703	6287	7194
2014	4384	5000	5808	6453	7454
2015	4377	5044	5919	6626	7726
2016	4370	5088	6032	6803	8009
2017	4364	5133	6147	6985	8301
2018	4357	5178	6264	7172	8605
2019	4350	5224	6384	7364	8919
2020	4343	5270	6505	7561	9245
2021	4336	5316	6629	7763	9583
2022	4329	5363	6756	7970	9933
2023	4322	5410	6885	8184	10297
2024	4316	5458	7016	8403	10673
2025	4309	5506	7150	8627	11063
Growth 2000-25	-0.46%	0.52%	1.58%	2.34%	3.37%

DSI Demand

	Revised Forecast				
Year	Low	Medlo	Medium	Medhi	High
2000			2477		
2001			286		
2002			412		
2003			600		
2004			642		
2005	0	460	958	1200	1500
2006	0	460	958	1200	1500
2007	0	460	958	1200	1500
2008	0	460	958	1201	1500
2009	0	460	958	1201	1500
2010	0	460	958	1201	1500
2011	0	460	958	1201	1500
2012	0	460	958	1201	1500
2013	0	460	958	1201	1500
2014	0	460	958	1201	1500
2015	0	460	958	1201	1500
2016	0	460	958	1201	1500
2017	0	460	958	1201	1500
2018	0	460	958	1201	1500
2019	0	460	958	1201	1500
2020	0	460	958	1201	1500
2021	0	460	958	1201	1500
2022	0	460	958	1201	1500
2023	0	460	958	1201	1500
2024	0	460	958	1201	1500
2025	0	460	958	1201	1500
Growth 2000-25		-6.5%	-3.7%	-2.9%	-2.0%

Irrigation Demand

Year	Revised Forecast				
	Low	Medlo	Medium	Medhi	High
2000			652		
2001			690		
2002			600		
2003	593	598	600	606	610
2004	618	623	625	632	638
2005	621	626	629	636	643
2006	617	627	631	640	649
2007	613	628	634	645	656
2008	609	630	636	652	664
2009	606	632	639	658	672
2010	603	633	641	664	680
2011	600	635	644	670	687
2012	596	636	646	675	695
2013	592	636	649	679	701
2014	587	637	652	683	707
2015	582	636	654	687	713
2016	577	636	657	690	719
2017	572	636	659	694	726
2018	568	636	662	698	732
2019	563	636	665	702	738
2020	558	635	667	705	744
2021	554	635	670	709	751
2022	549	635	673	713	757
2023	544	635	675	717	763
2024	540	635	678	721	770
2025	535	635	681	725	777
Growth 2000-25	-0.79%	-0.11%	0.17%	0.42%	0.70%

Other

Year	Revised Forecast				
	Low	Medlo	Medium	Medhi	High
2000			172		
2001			158		
2002			160		
2003			160		
2004			184		
2005	185	185	185	185	185
2006	186	186	186	186	186
2007	188	188	187	188	188
2008	189	189	189	189	189
2009	190	190	190	190	190
2010	191	191	191	191	191
2011	193	193	193	193	193
2012	194	194	194	194	194
2013	195	195	195	195	195
2014	197	197	196	197	197
2015	198	198	198	198	198
2016	199	199	199	199	199
2017	201	201	200	201	201
2018	202	202	202	202	202
2019	203	203	203	203	203
2020	205	205	204	205	205
2021	206	206	206	206	206
2022	207	207	207	207	207
2023	209	209	208	209	209
2024	210	210	210	210	210
2025	211	211	211	211	211
Growth 2000-25	0.83%	0.83%	0.82%	0.83%	0.83%

Fuel Price Forecasts

INTRODUCTION

Fuel prices affect electricity planning in two primary ways. They influence electricity demand because oil and natural gas are substitute sources of energy for space and water heating, and other end-uses as well. Fuel prices also influence electricity supply and price because oil, coal, and natural gas are potential fuels for electricity generation. Natural gas, in particular, has become a cost-effective generation fuel when used to fire efficient combined-cycle combustion turbines. This second effect is the primary use of the fuel price forecast for the Council's Fifth Power Plan.

Traditionally, the Council has developed very detailed forecasts of electricity demand using models that are driven by economic, fuel price, and technological assumptions. For a number of reasons, the Council has chosen to retain many elements of its long-term demand forecasts from the Fourth Power Plan, making modifications as needed to reflect significant changes that might affect the long-term trend of electricity use. Therefore, the fuel price assumptions did not directly drive the demand forecasts of this power plan.

The fuel price forecasts do affect the expected absolute and relative cost of alternative sources of electricity generation. Through their effects on generation costs, they also largely determine the future expected prices of electricity.

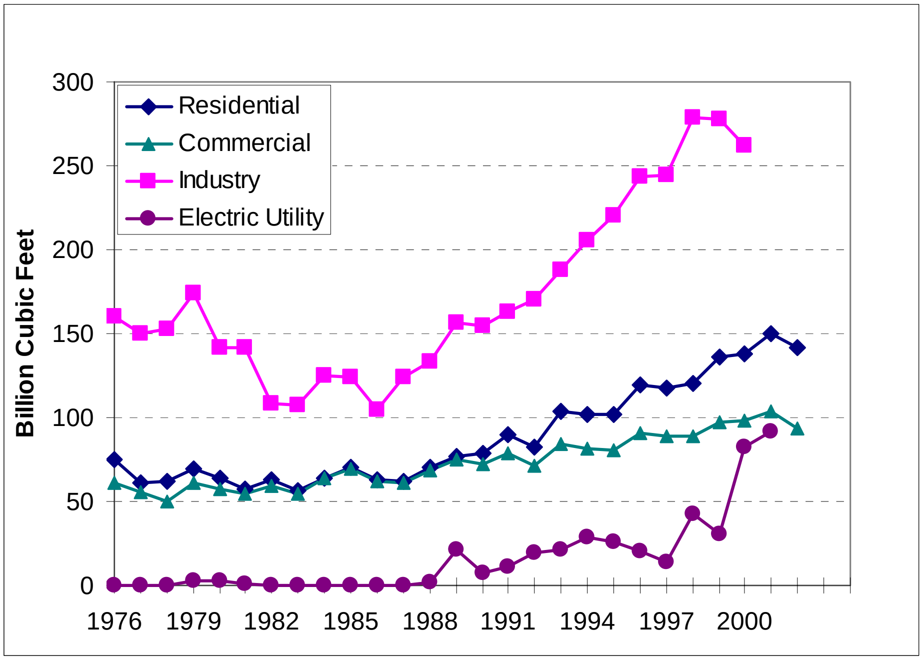
The forecast describes fuel price assumptions for three major sources of fossil fuels: natural gas, oil, and coal.

NATURAL GAS

Historical Consumption and Price

In 2000, the Pacific Northwest consumed 581 billion cubic feet (bcf) of natural gas. About 45 percent of this natural gas was used in the industrial sector, which included electricity generation by non-utility power plants. About a quarter of the natural gas use was in the residential sector and about 17 percent was in the commercial sector. In 2000, electric utilities consumed 83 bcf of natural gas, or about 14 percent of the regional total natural gas consumption. Utility natural gas consumption in 2000 was nearly three times the amount consumed in 1999, and it remained high in the early months of 2001. However, natural gas use for electricity generation was extraordinary in 2000 and early 2001 due to the electricity crisis in the West. Generating plants normally used only for extreme peak electricity needs were operated for much of the winter of 2000-2001. However, new gas-fired generation has been constructed and planned recently, which will increase normal levels of gas use for electricity generation.

The regional consumption of natural gas has grown rapidly over the last several years. Between 1986 and 2000 regional natural gas consumption grew 6.8 percent a year, more than doubling natural gas consumption over a 14-year period. Figure B-1 shows natural gas use by sector since 1976. After 1986, all sectors grew, but the industrial sector, which included independent electricity generation, accounted for nearly half of the increase in gas consumption and grew at a higher rate than residential and commercial use. Increasing electric utility use of natural gas is also apparent in Figure B-1.



Source: Energy Information Administration and NPCC calculations.

Figure B-1: Pacific Northwest Natural Gas Consumption

The rapid growth in natural gas use since 1986 coincided with a period of ample natural gas supplies and attractive prices, coupled with strong economic growth in the region. Figures 2a and 2b illustrate the Pacific Northwest natural gas prices and consumption since 1976 for the residential and industrial sectors. High natural gas prices and a severe economic downturn in the early to mid-1980s kept natural gas consumption low. However, following the deregulation of natural gas prices in the late 1980s, prices fell and demand began to grow rapidly. Natural gas displaced oil and other industrial fuels for economic and environmental reasons during this time. Higher electricity and oil prices for residential consumers combined with lower natural gas prices made natural gas a more attractive heating fuel for homes.

The most significant trend in natural gas markets has been the increasing use of natural gas for electricity generation. This is a relatively recent trend, but attracts a lot of attention because of expectations of rapid growth in the future. Figure B-1 shows some use of natural gas for electricity generation by electric utilities in the region since 1988. It increased recently, but is still a relatively small amount of the total natural gas used in the region. Non-utility electricity generators have used additional natural gas, but, until recently, the data did not allow it to be broken out from overall industrial sector natural gas use. Given the level of concern about natural gas supplies, and the potential for a greatly increased use for electricity generation, it is worth understanding the current and potential role of natural gas in electricity generation.

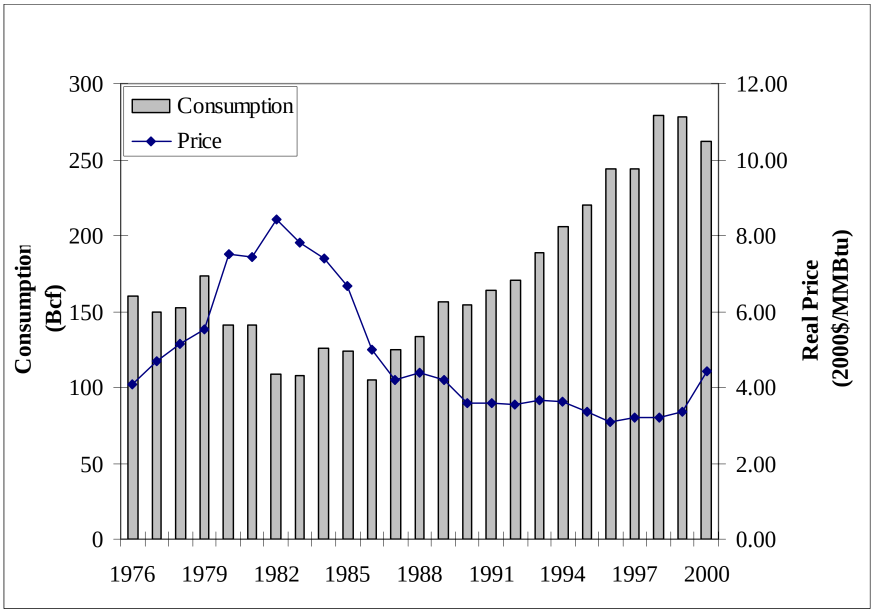


Figure B-2a: Pacific Northwest Industrial Natural Gas Consumption and Price

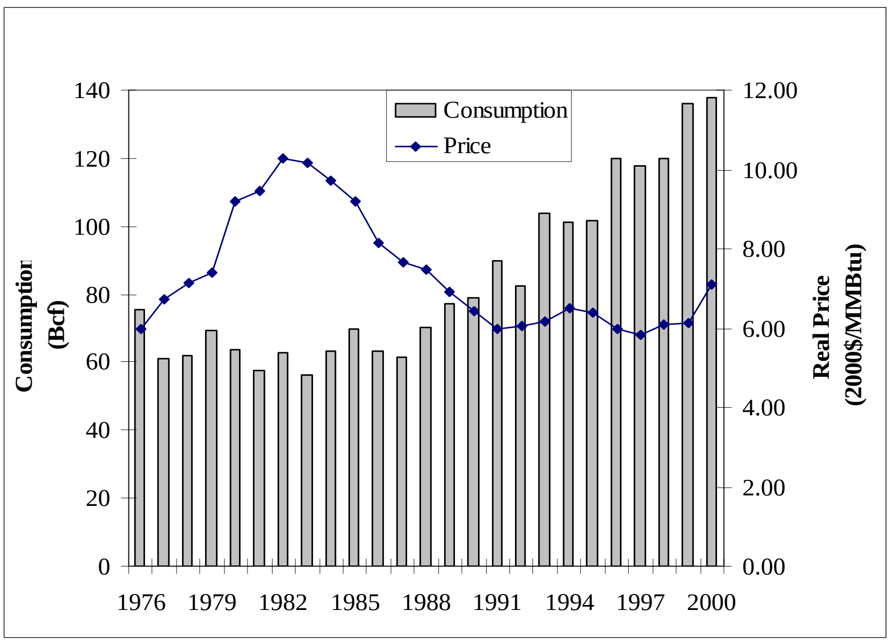


Figure B-2b: Pacific Northwest Residential Natural Gas Consumption and Price

Natural gas currently accounts for only 13 percent of the region's electricity generation capacity. In terms of average energy generated, the share is higher at 20 percent. That is because the hydroelectric capacity, which dominates the region's generating capacity, is limited in its annual production by the amount of water available so that its share of average generation is much lower than its capacity rating.

At the end of 1999 there were 38 plants that could generate electricity using natural gas with a combined generating capacity of 3,400 megawatts. Over half of this capacity (2,000 megawatts) had been built since 1990. Sixty percent of this capacity was owned by electric utilities and two-thirds of the capacity is located west of the Cascade Mountains. Many of these plants have the ability to burn other fuels such as wood waste, refinery gas, or oil.

If all of the plants using natural gas as their primary fuel were operating, they would be able to burn 668 million cubic feet of natural gas per day. Plants on the West side could burn as much as 476 million cubic feet per day. For perspective, this can be compared to the total capacity to deliver natural gas to the I-5 corridor on a peak day in 2004, which was estimated to be 3,760 million cubic feet per day.[1] If operated continuously for a year, the region's gas-fired generators in 1999 could burn 242 billion cubic feet of natural gas. This compares to an estimated 2001 total regional natural gas consumption of 670 billion cubic feet.

However, gas-fired generating plants in the region have not operated for a large part of the year, nor have they typically operated during peak natural gas demand events. This is partly due to the fact that in most years there is surplus hydroelectricity in the region. For example, utility-owned natural gas-fired generating plants in place at the end of 1999 had the capability to burn 141 billion cubic feet a year if operated at an 85 percent capacity factor on natural gas. However, as shown in Figure B-1, utilities only consumed 30 billion cubic feet of natural gas in 1999. In other words, utility-owned gas-fired generating facilities only consumed 20 percent of their capability in 1999. If the non-utility electricity generating capacity were assumed to operate at the same relative rate, they would have consumed only 14 billion cubic feet out of the 262 billion cubic feet of total industrial consumption in 1999.

In 2000, natural gas consumed for utility-owned electricity generation increased dramatically from 30 billion cubic feet in 1999 to 83 billion cubic feet. Non-utility generation from natural gas increased as well, but by a smaller percentage. This was not a result of additional gas-fired generation capacity being added in 2000. It was in response to the energy crisis of 2000 and the extremely high electricity prices that accompanied it. Existing gas-fired generation was operated far more intensively than normal because it was very profitable to do so.

Significant amounts of gas-fired generation have been added in the region since 2000. In 2001 an additional 1,176 megawatts of gas-fired generation capacity was put in service in the region, a 32 percent increase in gas-fired generation capacity. Another 1,330 megawatts was added in 2002, and an additional 1,560 megawatts in 2003. This new gas-fired generation will have a substantial impact on natural gas consumption in the region. According to the U.S. Energy Information Administration, the four Northwest states used 132 billion cubic feet of natural gas for electricity generation in 2003. This accounted for nearly a quarter of all natural gas consumption in the region.

In the past, most natural gas-fired electricity generation in the region has not operated on firm natural gas supplies and delivery. By buying interruptible service, the cost of natural gas could be reduced substantially. When interruptions came, during peak natural gas demand times, most of the plants, even if running, could switch to alternative fuels. Increasingly, new gas-fired generation plants are intended to operate at a high capacity factor and are more likely to use firm natural gas supplies and transportation.

The use of interruptible demand is a key feature in the ability of the natural gas industry to meet peak day demands for its product. Figure B-3 illustrates the role of interruptible consumers in meeting peak day natural gas demand.[2] The use of natural gas storage withdrawal and the injection

[1] 2004 Regional Resource Planning Study, Terasen Gas., July 2004.
[2] Based on Regional Resource Planning Study, BC Gas Utility Ltd., July 10, 2001.

of liquefied natural gas into pipelines are also used to meet peak requirements and help to increase the capacity utilization of natural gas pipelines.

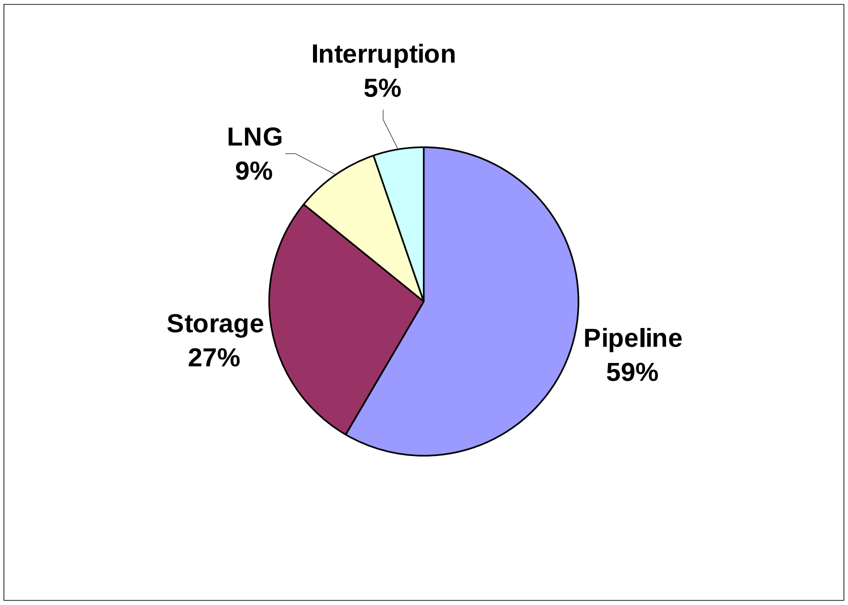


Figure B-3: Contributions to Peak Day Natural Gas Supplies

With a growing share of natural gas demand expected to be firm electricity generation, the share of interruptible demand may fall as a percent of total demand. This is likely to increase the value of other strategies for meeting peak gas demand such as storage and LNG injection. To the extent that increased gas-fired electricity generation turns out to add substantially to highly variable natural gas demand, the overall capacity factor of natural gas consumption would decrease. Lower capacity factors mean that, in general, the cost of natural gas on a per unit consumed basis could increase as fixed capacity costs are spread over a smaller amount of consumption per unit of capacity. This is not the only possibility, however. If many new gas-fired generating plants operate at a high capacity factor, or if they tend to operate more in the summer, they could have the opposite effect. They could partly offset the highly seasonal demand of the residential and commercial sectors, which peaks in the winter, and raise the overall capacity factor of the natural gas system.

In the summer of 2000, the use of natural gas-fired generation changed substantially on the West Coast. Poor hydroelectricity supplies and a growing electricity generating capacity shortage caused electricity prices to increase by a factor of 10 or more. The extremely high electricity prices made it attractive to burn gas for electricity generation; it was very profitable, and the electricity was badly needed to meet electricity demand. As a result, the use of natural gas on the West Coast for electricity generation increased dramatically. For example, it has been reported that California generators consumed 690 billion cubic feet of gas in 2000 compared to a normal consumption of 270 billion cubic feet.[3] Much of this increase in natural gas use began in the summer when natural gas use is typically lower and natural gas is injected into storage for use during the next winter heating season.

The problem created in natural gas markets may be some indication of the effects of the predicted growth of natural gas use for electricity generation in the future. In many regions, electricity use peaks in the summer. Growing use of natural gas for electricity generation has the potential to

[3] Natural Gas Week, Vol. 17, No. 18 (April 30,2001).

change the traditional seasonal patterns of natural gas storage and withdrawals. Less than expected storage injections in the summer and fall of 2000 led to concerns about natural gas shortages for the winter and pushed prices for natural gas to levels not seen since the early 1980s. This problem was especially severe in California, and combined with pipeline capacity strains, pushed prices in the West to several times historical levels.

However, the dramatic increase in the use of natural gas in existing generation plants in 2000 and early 2001 clearly had an exaggerated effect on natural gas markets and prices. Due to the sudden and severe shortage in electricity supplies and unprecedented electricity prices, the natural gas delivery system in the West was pushed far beyond normal operational patterns. Thus, the impacts on natural gas prices were more severe than should be expected from an orderly development of additional natural gas demands for electricity generation.

Although total natural gas consumption only recently returned to the levels of the early 1970s, substantial growth is now being projected due to growing plans for electricity generation. The U.S. Energy Information Administration is forecasting a growth in natural gas use of 1.4 percent per year for the next 20 years.[4] Residential and commercial natural gas use is projected to grow modestly at about 1 percent per year. Industrial sector use is projected to grow at 1.5 percent annually, but natural gas use for electricity generation is projected to grow by about 1.8 percent a year. The EIA forecasts would result in total U.S. natural gas consumption increasing from the current level of about 23 trillion cubic feet per year to 32 trillion cubic feet in 2025.

As an example of the possible effect of increased gas-fired electricity generation in the Pacific Northwest, complete reliance on natural gas-fired generation to meet a projected electricity demand growth of 1.0 percent a year for the next 20 years could add 217 billion cubic feet of natural gas consumption to the current 559 billion cubic feet per year. A modest 1.5 percent growth in other sectors' natural gas use could add another 147 billion cubic feet of new natural gas use in the region over the next 20 years. Meeting this demand would require continued expansion of natural gas supplies, pipeline capacity, and other elements of the natural gas delivery system, such as storage. Recent experience indicates that it will be increasingly difficult to expand North American natural gas production to meet increased demand. New sources of supply are likely to cost more and raise natural gas prices well above the levels enjoyed during the 1990s.

Natural Gas Resources

Natural gas is created by natural processes and is widespread. Most current recovery methods attempt to exploit natural geologic formations that are able to trap natural gas in concentrated pockets. However, natural gas occurs in more dispersed forms as well. Eventually, it is likely to become possible to recover natural gas from some of these formations. Coal bed methane is a good example. Substantial amounts of natural gas are often associated with coal deposits. In the last several years methods have developed, with some government incentives, to extract the natural gas from coal formations, and this coal bed methane has made substantial contributions to the natural gas supplies in the Rocky Mountain area. It now accounts for about 7.5 percent of U.S. natural gas production.[5] Expansion of natural gas supplies increasingly will have to move into these less conventional areas, increasing costs. The amount of increase depends a great deal on technological developments in the exploration and recovery field.

[4] U.S. Energy Information Administration, Annual Energy Outlook 2004.
[5] U.S. Geological Survey. "Coal-Bed Methane: Potential and Concerns." USGS Fact Sheet FS-123-00 (October 2000).

The availability of natural gas to meet growing demands is a key issue. Assessing natural gas resources is a confusing and difficult exercise. There is no absolute answer to the question of how much natural gas there is and how long it will last. Traditionally, the question has been approached on a North American basis, although Mexico has not traditionally played a large role. With the potential for increased use of liquefied natural gas (LNG) imports and exports, the market could become international, similar to current oil markets. Meanwhile, it may be instructive to look at North American natural gas resource estimates in a fairly traditional way.

There are two main categories of natural gas supplies. "Reserves" refers to natural gas that has been discovered and can be produced given the current technology and markets. Reserves are developed as needed by drilling wells in areas that are expected to hold natural gas producing potential. Reserves are often confused with the ultimate potential natural gas "resources," which is the second category of natural gas supplies. Natural gas "resources" are more speculative than reserves, and resource estimates are more uncertain. They are based on assessment of geologic structures, not direct drilling results. Resource estimates are speculative estimates of natural gas that could be developed with known technology and at feasible costs. Reserves are more like the amount of natural gas resource that has been developed and is available to be produced within a relatively short period. Reserves should be thought of as an inventory of natural gas to be produced and marketed within a few years.

Natural gas reserves have decreased relative to consumption levels since the deregulation of natural gas supplies and changes in Canadian export policies in the 1980s. Some have taken this decline as an indication that we are running out of natural gas. In reality, it is a result of reducing inventory holding costs as a response to increased competition. It is similar to the new approaches to other kinds of inventory in the modern economy where businesses hold down inventory storage time and costs. In Canada, it was also influenced by elimination of a rule that required Canada to have a 20-year reserve for Canada's internal natural gas demand before any natural gas could be exported. Canadian reserves are now closer to a 10-year supply.

So reserves are constantly being consumed and replaced. The relative rates of consumption and replacement vary with economic conditions and natural gas prices. During periods of low natural gas prices, consumption tends to increase and there is a reduced incentive to develop new reserves. Eventually, this leads to falling reserves and creates an upward pressure on prices such as the nation experienced recently. With the natural gas industry operating at narrower reserve margins, these cyclical patterns have become more severe and led to growing natural gas price volatility.

Another common error in assessing natural gas supplies is to assume that the estimates of ultimate natural gas resources are static. In reality, natural gas resource estimates have shown a tendency to increase over time as technology improves and new discoveries are made. To illustrate this point, note that in 1964 the Potential Gas Committee, which estimates natural gas resources, estimated potential natural gas resources to be 630 trillion cubic feet. By 1996, the nation had consumed more than 630 trillion cubic feet of natural gas. If the potential resource were a fixed limit, as many interpret it, we would have run out of natural gas by now. Instead the estimated potential remaining natural gas resource in 1996, at 1,038 trillion cubic feet excluding proved reserves, was actually higher than the estimate of what was remaining in 1964 in spite of over 30 years of continuing consumption. This does not mean that resource estimates will necessarily continue to increase in the future, but it illustrates the uncertain nature of natural gas resource estimates.

The Potential Gas Committee estimated that in 1996 the natural gas reserves and potential resources were 1,205 trillion cubic feet and noted that at then-current consumption rates, it would be a 63-year supply. A little different approach to estimating the years that the current estimated resource would last is to look at North American natural gas resource estimates and a predicted growing natural gas consumption to see how long those supplies would last. Table B-1 shows an estimate of remaining natural gas resources. Note that both of these calculations assume that potential natural gas resource estimates would not grow over time, as they have historically.

Table B-1: Remaining Natural Gas Resources in North America (Trillion Cubic Feet)

	Already Produced	Remaining Reserves	Remaining Resources
Lower 48 States	847	166	1,078-1,548
Alaska	0	0	237
Canada	103	51	559-630
Mexico	34	72	230-250
Total	984	289	2,104-2,665

Figure B-4 plots the growth in cumulative natural gas consumption into the future and identifies the years when the current resource estimate would be exhausted. The Mexican consumption of natural gas and its natural gas resources have been excluded from Figure B-4. U.S. and Canadian consumption is assumed to grow at 1.5 percent a year. Under these assumptions current estimated resources would last about 45 to 55 years. However, we should expect that the production of these resources will become increasingly difficult and expensive. If production rates cannot keep up with demand growth it will result in upward pressure on natural gas prices and increased volatility.

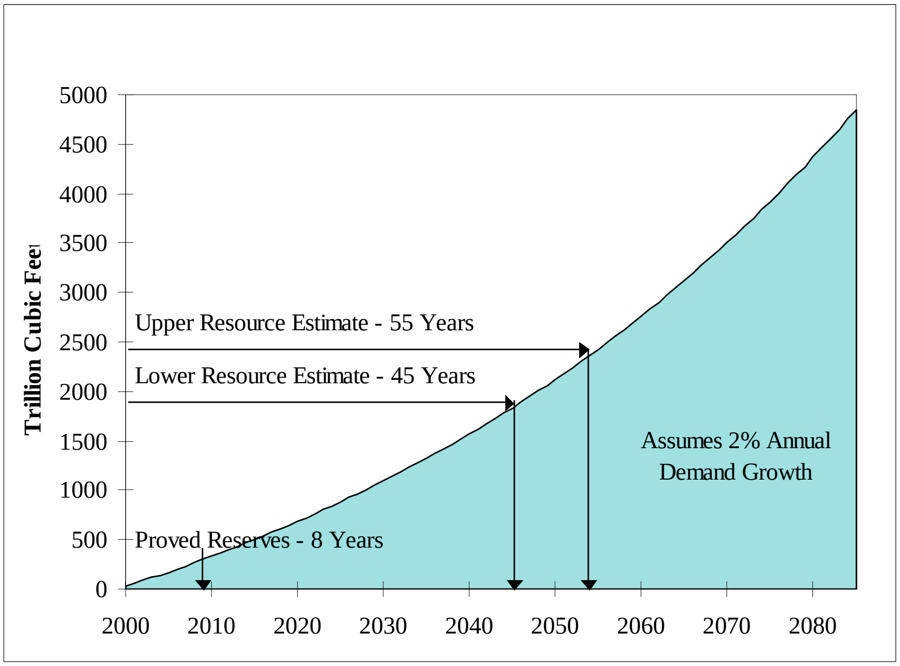


Figure B-4: Cumulative Natural Gas Production and Resources

However, based on past experience, the resource estimates are likely to increase over time in unpredictable ways. Some examples of potential changes will give some idea of what the future could hold in the longer term for natural gas resources. As in the case of oil, many natural gas resources lie outside of North America. Currently estimated conventional natural gas resources worldwide are 13,000 trillion cubic feet. As natural gas prices increase, the use of liquefied natural gas transportation will make these resources increasingly accessible to North America. In addition, natural gas occurs throughout nature in many forms. Besides coal bed methane, there are geopressurized brines and gas hydrates.[6] The ability to recover such sources is unknown at this point, but as new sources of gas are needed in the distant future, new technologies may facilitate some use of these resources. Gas hydrates, for example, are estimated to contain from 100,000 to 300,000,000 trillion cubic feet of natural gas resource.[7]

Natural Gas Delivery

Another important consideration in natural gas supply and cost is the capacity to transport the gas from the wells to the points of consumption. This involves gathering the gas from wells, processing the gas to remove liquids and impurities, moving the gas over long distances on interstate pipelines, and finally, distribution to individual consumers' homes and businesses.

Currently, U.S. natural gas supplies are largely domestic, supplemented by substantial imports from Canada. In 2001, the United States imported 3.75 trillion cubic feet of natural gas from Canada; and 1.1 trillion cubic feet of that were imported through Sumas and Kingsgate on the region's border with Canada, with a substantial amount of that gas destined for California markets.

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[6] U.S. Geological Survey. "Describing Petroleum Reservoirs of the Future." USGS Fact Sheet FS-020-97 (January 1997).

[7] U.S. Geological Survey. "Natural Gas Hydrates - Vast Resource, Uncertain Future." USGS Fact Sheet FS-021-01 (March 2001)

The sources of natural gas for the Pacific Northwest are the Western Canada Sedimentary Basin, in Alberta and Northeast British Columbia, and the U.S. Rocky Mountains. Two major interstate pipelines deliver natural gas into the Pacific Northwest region from Canada. Williams Northwest pipeline brings natural gas from British Columbia producing areas through Sumas, Washington where it receives gas from the Duke Westcoast pipeline in British Columbia. Williams Northwest pipeline also brings U.S. Rocky Mountain natural gas into the region from its other end. Thus, Williams Northwest is a bi-directional pipeline; it delivers gas from both ends toward the middle. The second interstate pipeline serving the region is the PG&E Gas Transmission Northwest (GTN) pipeline, which brings Alberta supplies through Kingsgate on the Idaho - British Columbia border. Much of the gas flowing on the GTN is destined for California. The GTN and Williams Northwest pipelines intersect near Stanfield, Oregon. The natural gas pipeline system serving the Pacific Northwest is illustrated in Figure B-5

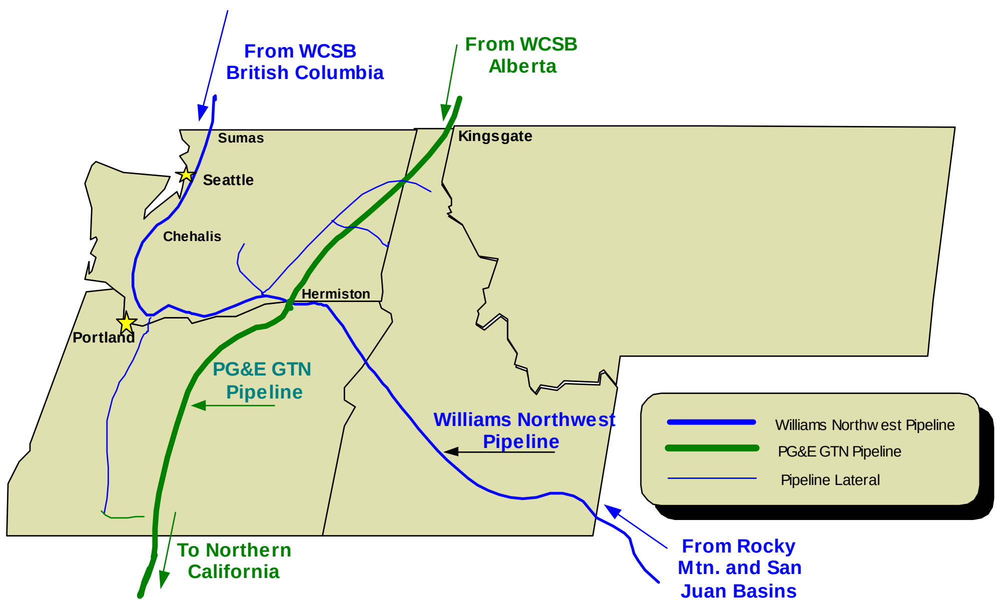


Figure B-5: Natural Gas Pipelines Serving the Pacific Northwest

The development of interstate pipeline capacity is based on the willingness of local distribution companies or other shippers of natural gas to subscribe to capacity additions. Historically, local gas distribution companies, the regulated utilities that serve core customers' natural gas demand, have owned much of the capacity on interstate pipelines. Because residential and commercial natural gas use varies seasonally and with temperatures, there is often pipeline capacity that is available for resale. Large industrial consumers and others who have some flexibility can acquire this capacity on a short term or capacity release basis. Interruptible consumers rely on this type of pipeline capacity, and it is typically available except on extremely cold winter days.

Growing natural gas demand results in pipeline capacity expansion as it is needed and as distributors or consumers are willing to pay for the capacity on an individual contractual basis. Interstate pipeline capacity is not expanded on a speculative basis based on someone's forecast of natural gas demand. Various expansions of pipeline capacity have been completed recently or are currently underway on both the Williams Northwest and the GTN systems, as well as on other pipelines throughout the West. Most of the entities committing to recent capacity expansions are electricity generators who are securing natural gas delivery capacity for proposed new electricity generating plants. Generating plant developers indicate that firm pipeline capacity is required in order to get financial backing for a new gas-fired combined cycle plant.

Over the long term, it should be expected that pipeline capacity will be expanded to deliver the necessary natural gas to regional consumers. In the short term, extremely unusual natural gas demands can place severe strain on pipeline delivery capacity, which can in turn cause serious natural gas price increases. This was the situation in the West in 2000-2001 when prices in California and the Northwest became disconnected from other U.S. prices.

Forecast Methods

Natural gas prices, as well as oil and coal prices, are forecast using an Excel spreadsheet model. The model does not address the basic supply and demand issues that underlie energy prices. Instead assumptions are made about the basic commodity price trends at a national or international level based on analysis of past price trends and market behavior, forecasts of other organizations that specialize in such analyses, and the advice of the Council's Natural Gas Advisory Committee. The model then converts the commodity price assumptions into wholesale prices in the Pacific Northwest and other pricing points in the West, and then adds transportation and distribution costs to derive estimates of retail prices to various end-use sectors.

Because natural gas is the primary end-use competitor for electricity, and because it is the electricity generation fuel of choice at this time, natural gas prices are forecast in more detail than oil and coal prices. Residential and commercial sector retail natural gas prices are based on historical retail 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 between retail and wellhead natural gas prices can be projected from historical trends, other forecasting models, or judgment.

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 natural gas consumers, 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 mark-up on. For these customers, the difference between wellhead and end-user prices is built from a set of transportation cost components and regional gas price differentials appropriate to the specific type of gas use.

The components include pipeline capacity costs, pipeline commodity costs, pipeline fuel use, local distribution costs, and regional wellhead price differentials. The latter is necessary because the driving assumption is a national average wellhead gas price. Wellhead prices in British Columbia, Alberta, and the Rocky Mountains gas supply areas, the traditional sources of gas for the Pacific Northwest, have historically been lower than national averages. The fuel price model and assumptions are described in more detail in Appendix B1.

Forecasts

U.S. Wellhead Prices

There are a number of different indicators of U.S. natural gas commodity prices. The Council's analysis utilizes two of these measures. One is the U.S. wellhead price series published by the U.S. Energy Information Administration. The other is the Henry Hub cash market price. A link between U.S. wellhead prices and the Henry Hub cash price is estimated to relate the two series for the Council's analysis.

Figure B-6 shows the history of U.S. wellhead natural gas prices from 1970 to 2002. After the deregulation of wellhead natural gas prices around 1986, natural gas prices fell dramatically to the $2.00 per million Btu range in year 2000 dollars. Since then, until 2000, natural gas prices varied between $1.60 and $2.40 in year 2000 prices. In 2000, natural gas prices shot up, reaching a peak of over $9.00 by January 2001 as measured by spot prices at the Henry Hub in Louisiana. Although the 2000 price spike created expectations of significantly higher natural gas prices in the future, prices fell rapidly during 2001 and by September 2001 had returned to near their post-deregulation average of $2.15 in year 2000 prices. Many industry participants warned that the lower prices in the winter of 2001-02 were due to extremely warm temperatures, high natural gas storage inventories, and reduced demand as a result of higher prices and an economic slowdown and that there remained an underlying shortage of natural gas supplies.[8] Indeed, in the spring of 2002 prices firmed up to above $3.00 and prices in March 2003 averaged $8.00, with much higher excursions on a daily basis.

Wellhead natural gas prices averaged $4.81 in 2003 in year 2000 dollars. Prices have remained high in 2004 even with adequate storage levels and mild summer weather. Natural gas prices have been supported at a high level by high world oil prices. After 2005 prices are expected to begin moderating, but remain well above price levels of the 1990s. After 2005, prices decrease over several years as supply and demand adjust to the new conditions. By 2015 medium case prices remain $1.35 higher than the Fourth Plan forecast. The range of the forecast is wider in 2015 than in the Fourth Power Plan and it is significantly higher. The low is above the medium forecast of the Fourth Power Plan, and the high is $1.22 higher than the previous plan's high forecast.

Table B-2 shows actual U.S. wellhead prices for 1999 through 2003, annual forecasts for 2004 and 2005, and forecasts in five-year intervals after 2005. The last row of Table B-2 shows the average annual growth rate of real wellhead prices from 1999 to 2025. 1999 was chosen as the base year for growth rates because its price is close to the average price between 1986 and 1999. The projected growth in prices has already occurred, however, and from current prices the entire forecast range decreases. Figure B-7 shows the forecast range compared to historical prices.

[8] Natural Gas Advisory Committee, February 28, 2002

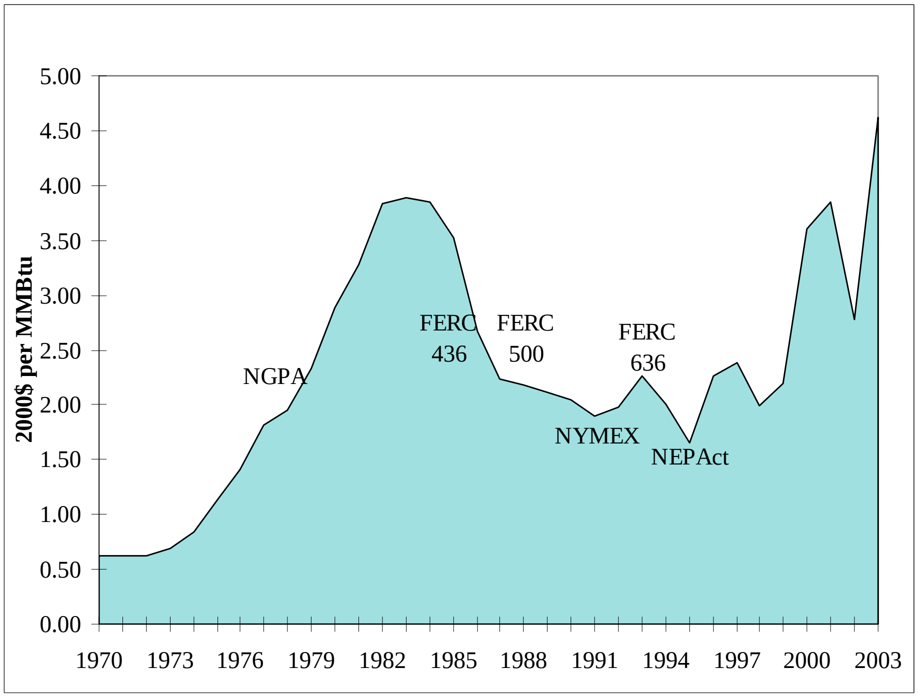


Figure B-6: History U.S. Wellhead Natural Gas Prices

Table B-2: U.S. Wellhead Natural Gas Prices (2000$ per million Btu)

Year	Low	Med-low	Medium	Med-high	High
1999			2.19		
2000			3.60		
2001			4.03		
2002			2.80		
2003			4.62		
2004	4.75	5.20	5.45	5.60	5.80
2005	4.50	4.90	5.30	6.00	6.35
2010	3.00	3.30	4.00	4.50	5.00
2015	2.75	3.40	3.80	4.30	4.90
2020	2.90	3.50	3.90	4.35	5.00
2025	3.00	3.50	4.00	4.50	5.10
1999-2025 Growth Rate	1.22	1.82	2.34	2.81	3.31

The reader should not be lured into complacency by the smooth appearance of these forecasted prices. Future natural gas prices are not expected to follow a smooth pattern as reflected in the forecasts; they will be cyclically volatile, but the forecasts only reflect expected averages. There is, in fact, reason to expect continued volatility in natural gas prices because competition has narrowed reserve margins in the industry, making prices more vulnerable to changes in demand due to weather or other influences.[9] The consequences of price volatility, and ways to mitigate its impact, will be addressed in the part of the power plan that addresses risk and uncertainty in regional resource planning.

The low case forecast reflects a situation where improved technology allows expanded natural gas supplies to occur with relatively moderate real price increases. Sources of natural gas would continue to be primarily from traditional natural gas sources and coal bed methane. Low oil prices provide strong competition in the industrial boiler fuel market to help keep natural gas prices low. Continuing declines in coal prices, coupled with improved environmental controls, may moderate the growth in natural gas reliance for electricity generation.

The high case reflects a scenario with less successful conventional natural gas supply expansion. In the high case, higher prices would mean a growing role for frontier supply areas and liquefied natural gas imports. High prices of oil and slower progress on environmental mitigation of the effects of burning coal leave natural gas in a state of higher demand growth.

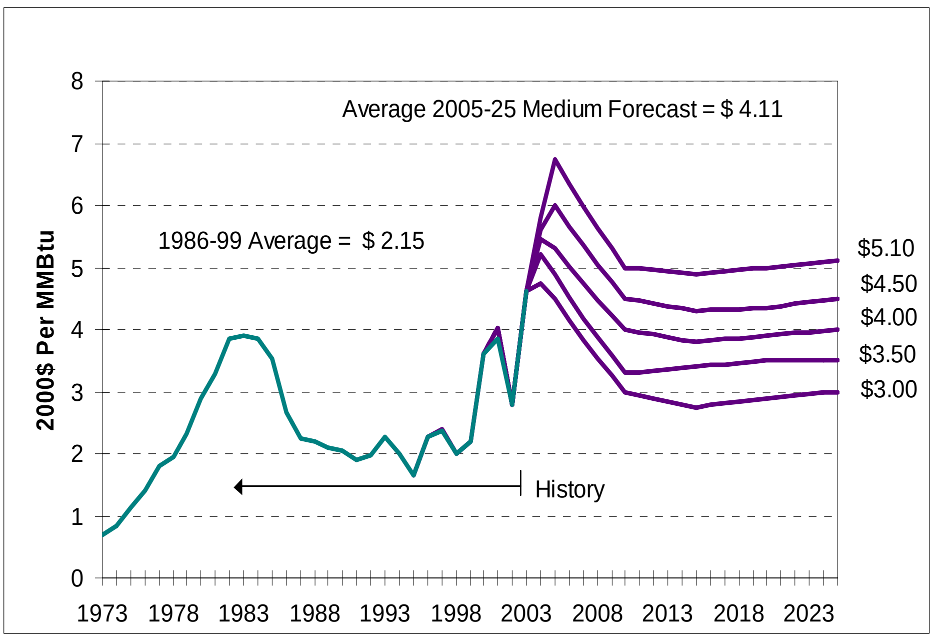
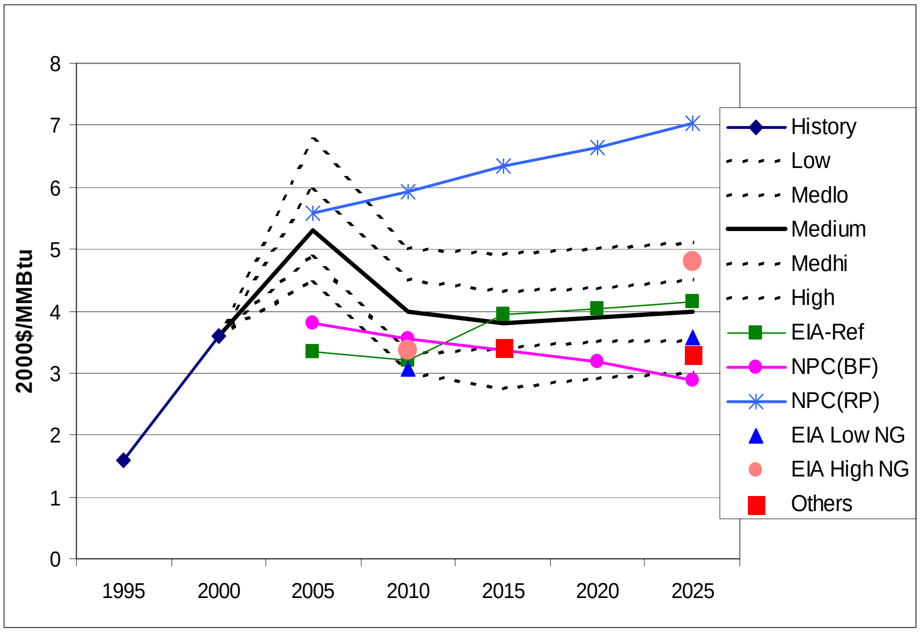


Figure B-7: U.S. Wellhead Prices: History and Forecast

Figure B-8 compares the Council's range of natural gas price forecasts to forecasts by some other organizations. A forecast in the U.S. Energy Information Administration's (EIA) Annual Energy Outlook 2004 is similar to the Council's medium forecast. The main difference is that EIA's forecast is lower in 2005 and 2010. EIA also has a high and low natural gas price forecast based on alternative assumptions about technological advances in natural gas exploration and production. These cases differ little from the reference forecast in 2010, but in 2025 the EIA high case is between the Council's medium-high and high forecasts. EIA's low price case falls between the Council's low and medium-low forecasts. EIA reviewed several other forecasts that were available to them. The average of these other forecasts is shown as "others" in Figure B-8 and falls between the Council's medium-low and low forecasts. These forecasts were likely done in early to mid 2003

[9] Natural Gas Advisory Committee, February 29, 2002

and may have been revised upward since then. Another recent forecast was done by the National Petroleum Council (NPC), which completed a comprehensive analysis of natural gas supplies and markets. The NPC study shows two futures, one called the "reactive path" (RP), and the other called the "balanced future" (BF). The reactive path scenario illustrates the consequences of poor natural gas policies. It results in prices well above the Council's high case. The balanced future case results in natural gas prices that generally fall between the Council's medium-low and low cases.



Sources: U.S. Energy Information Administration, *Annual Energy Outlook 2004*; National Petroleum Council. *Balancing Natural Gas Policy - Fueling the Demand of a Growing Economy*. September 25, 2003.

Figure B-8: Comparison of Natural Gas Price Forecasts

Regional Natural Gas Price Differences

As noted above, for the AURORA® model analysis of electricity supplies and pricing, a forecast of Henry Hub cash market prices is used as the U.S. commodity price. Figure B-9 shows the difference between the Henry Hub price of natural gas and the U.S. wellhead price from 1989 through 2003. Excluding the most extreme values, the difference averaged $0.23 per million Btu in year 2000 dollars. To forecast Henry Hub prices, an equation was estimated from monthly inflation-adjusted historical prices that relates the Henry Hub price to the U.S. wellhead natural gas price.

AURORA® also requires information about future natural gas and other fuel prices for several pricing points throughout the Western United States. In the draft fuel price forecast in April 2003 the Council used fixed real dollar adjustments between Henry Hub and the other pricing points in the West. In the final power plan, these constant adjustments have been replaced with estimated equations similar to the one used to adjust wellhead prices to Henry Hub prices.[10]

Natural gas commodity prices in the Pacific Northwest have typically been lower than national prices. Between 1990 and 2003, Canadian natural gas prices delivered to the Washington border at Sumas averaged $.62 per million Btu less than the national market index at Henry Hub, Louisiana. Prices at the Canadian border at Kingsgate have averaged about $.08 lower than the Washington

[10] See Council staff paper on "Developing Basis Relationships Among Western Natural Gas Pricing Points".

border price at Sumas. As shown in Figure B-10, however, these regional price differences have been extremely volatile. Figure B-10 shows monthly regional price differences from Henry Hub to Sumas and Kingsgate from 1990 through 2003. Occasionally, regional natural gas prices have even been above Henry Hub prices. In December of 2000, they were dramatically so, reflecting regional pipeline constraints caused, in part, by the electricity crisis in the West and the sudden increase in the use of natural gas to generate electricity. The average differences exclude the extreme values in the winter of 1995-96 and 2000-01.

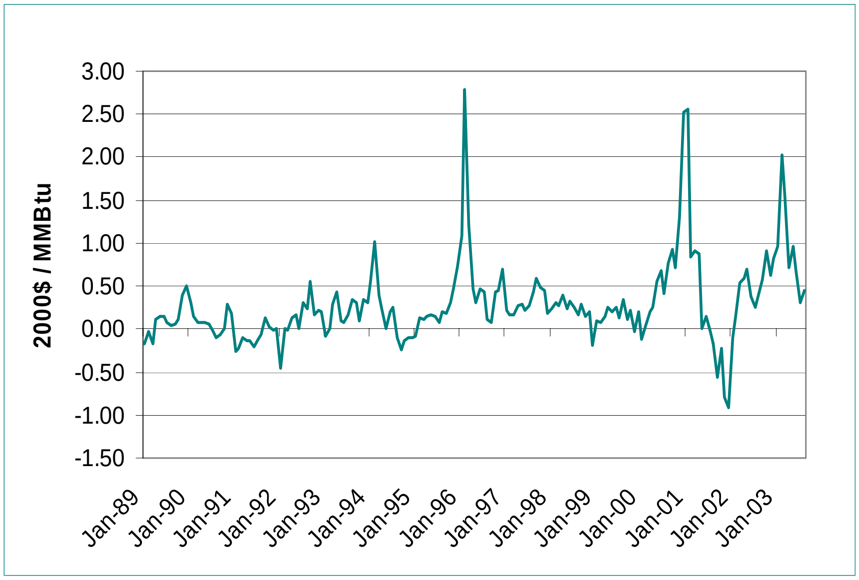


Figure B-9: Difference Between Henry Hub and U.S. Wellhead Natural Gas Prices

In addition to Canadian natural gas supplies through Sumas and Kingsgate, the Pacific Northwest receives natural gas supplies from the Rocky Mountain supply area on Williams Northwest Pipeline. Thus, Rocky Mountain natural gas supplies also play an important role in setting natural gas prices in the region. However, because of the direct competition among the various natural gas sources in the region, Rocky Mountain prices have generally tended to be similar to Canadian prices delivered into the region.

For purposes of forecasting regional natural gas prices in the eastern part of the region, a liquid pricing point in Alberta called the AECO-C hub is used as a focal point for regional natural gas prices. AECO-C prices have averaged $.81 per million Btu (2000$) less than Henry Hub prices since 1990. Prices in the western part of the region are estimated from Sumas prices at the Washington and British Columbia border. Sumas prices are estimated based on AECO and Rockies prices. The emerging natural gas pricing point in British Columbia is Station 2 in Northeastern British Columbia. However, there was insufficient historical data on Station 2 prices to estimate a relationship.

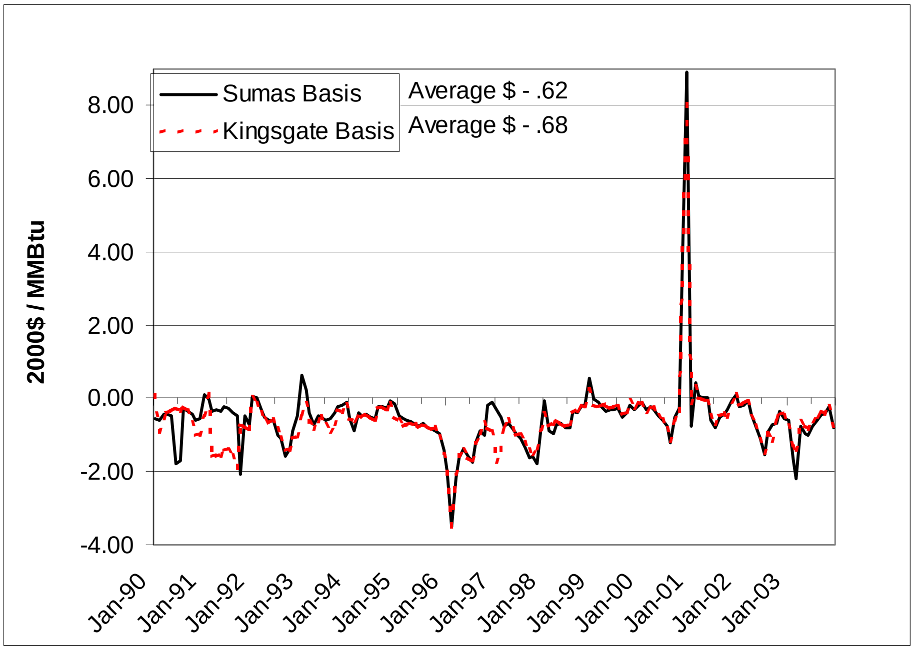


Figure B-10: Canadian Gas Price Differences from Henry Hub

Retail Prices

The forecast prices paid by regional consumers of natural gas are based on the U.S. and Canadian commodity prices described in the previous section. The exact method depends on the consuming sector being considered and will be explained below.

Figure B-11 shows the regional retail natural gas price forecasts for end-use sectors compared to the U.S. wellhead price forecast for the medium case. The residential and commercial forecasts are based on historical differences between regional retail price and U.S. wellhead prices. Industrial price forecasts are a weighted average of three different price estimates; direct-purchase firm gas, direct-purchase interruptible gas, and local distribution company-served industrial customers. Direct-puchase gas is gas supply that is purchased directly by industrial customers instead of from local gas distribution companies (LDCs). The ability of industrial users to purchase natural gas directly in the market began with natural gas deregulation in the mid-1980s. The effect on industrial prices is apparent in Figure B-11, where the average industrial price moves toward the utility and wellhead price and away from the utility-served residential and commercial prices during the 1980s. The differences between U.S. wellhead and regional retail prices are discussed further below.

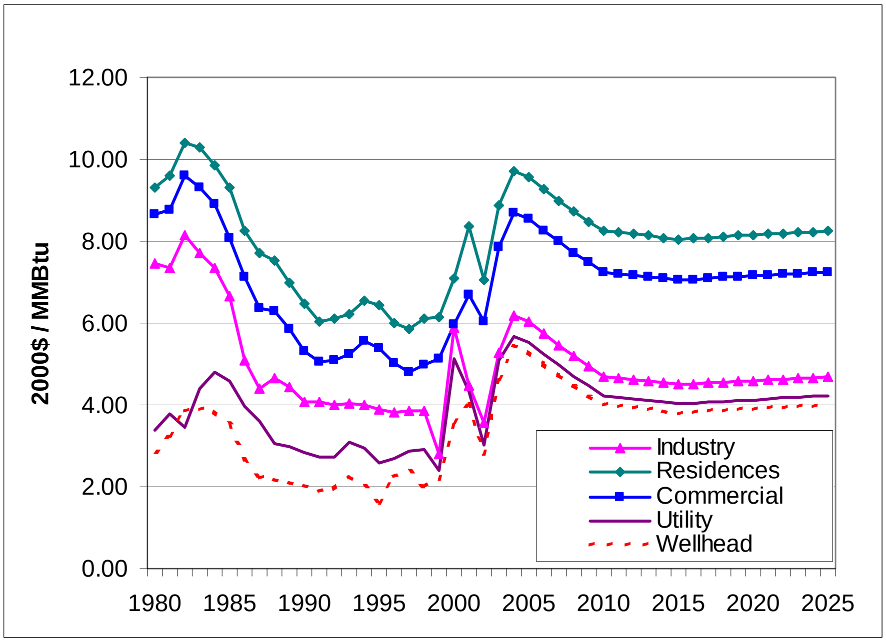


Figure B-11: Retail and Wellhead Prices History and Medium Forecast

Residential and commercial sector prices are based on observed differences from U.S. wellhead natural gas prices between 1989 and 2000. Figure B-12 shows that these differences declined during the 1980s. Since then, the differences have leveled off. The forecast assumes a $4.25 difference for residential and a $3.25 difference for commercial. These differences are held constant over the forecast period and across forecast cases.

As noted above, the industrial price shown in Figure B-11 is a blended price. The prices of the three components are derived in different ways. The LDC-provided prices are developed in the same way as residential and commercial prices. The forecast addition to U.S. wellhead prices to estimate LDC-provided retail prices starts at about $1.70, but unlike the residential and commercial adders, declines gradually over time. It does not, however, vary among forecast cases.

Directly purchased industrial natural gas prices are built from wellhead prices using estimates of the various components of gas supply and transportation costs. These components are described in detail in the Appendix B1, but Table B-3 shows, as an example, an estimate of regional industrial directly-purchased natural gas prices for 2010 in the medium case forecast. The example is a large, high-capacity-factor, industrial consumer. For electricity generators, natural gas and transportation costs are assumed to be different on the west and east side of the Cascade Mountains. There is no distinction applied to the industrial price forecasts; they are calculated using west side costs.

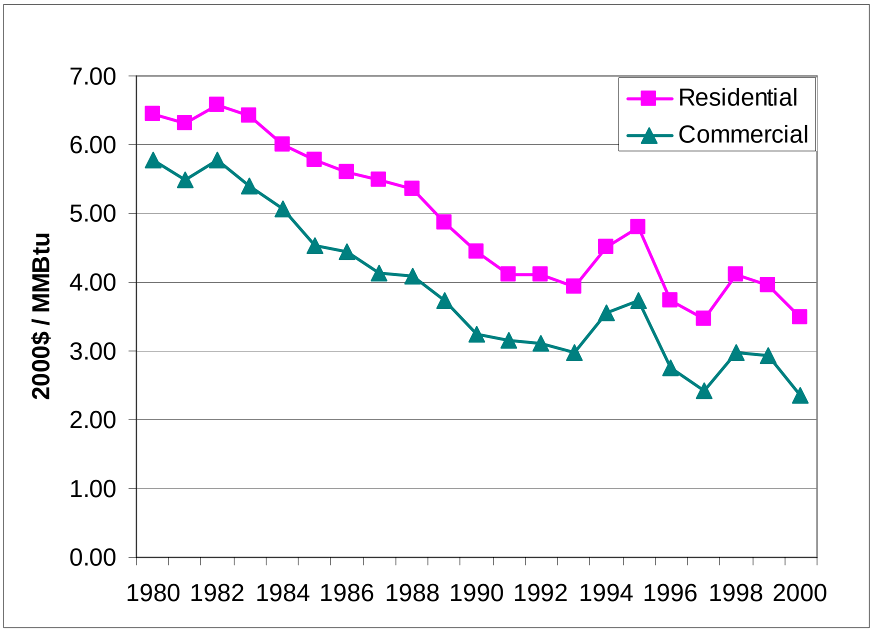


Figure B-12: Historical Difference Between Regional Residential and Commercial Retail Natural Gas Prices and U.S. Wellhead Prices

There is some disagreement whether a consumer who buys natural gas supplies on a firm basis would generally pay a premium for firm supplies. In this forecast, it is assumed that there is no premium. It is assumed that a large, high-capacity-factor industrial consumer would likely pay a negotiated rate for gas transportation by the local distribution utility and that there is no difference between firm or interruptible distribution service for such customers. This may only be the case for a customer with a potential to bypass the local distribution company, but the assumption about LDC transport cost only applies to industrial consumers and the forecast of industrial electricity demand in the Fifth Power Plan is not directly affected.

To combine the components into a blended price it is assumed that 30 percent of industrial natural gas consumption is purchased from the local distribution utility. The remaining 70 percent is purchased directly by industrial consumers. 90 percent of these direct purchases are assumed to be interruptible. It is assumed that a consumer that doesn't hold firm pipeline capacity will acquire released capacity or short-term firm capacity. In Figure B-11, the average difference between the U.S. wellhead price and the blended industrial users' price is small compared to the residential and commercial sectors. It is important to remember that the differences encompass a negative adjustment from Henry Hub commodity prices to AECO and Sumas, as described in the previous section.

Natural gas prices for electricity generators reflect the assumption that all electricity generators will buy their gas directly from suppliers rather than the local utility, and that generators will receive their gas supplies directly from interstate pipelines. Like industrial direct purchases, these purchases can be made on a firm or interruptible basis. In this forecast, it is assumed that all electric generator gas purchases are made on a firm transportation basis. Electric generator natural gas prices are calculated both in terms of average cost per million Btu, and in terms of fixed and variable natural gas costs. Again these assumptions are detailed in Appendix B1. Table B-4a shows an example of the calculation of natural gas costs for a new generating plant on the west side of the Cascade Mountains. Table B-4b shows the same derivation for a plant on the east side of the Cascade

Mountains. The examples are for the year 2010 in the medium forecast case. Appendix B3 shows annual natural gas price forecasts for the U.S. wellhead and retail prices for the residential, commercial, industrial and utility sectors for each forecast case. In addition, Appendix B2 shows similar information for electricity generators on the west and east side of the Cascade Mountains.

Table B-3: Estimation of 2010 Industrial Firm and Interruptible Direct-Purchase Natural Gas Cost (2000$/MMBtu)

Price Components	Price Adjustments	Firm	Interruptible
Henry Hub Price		$ 4.31	4.31
Sumas Price		3.77	3.77
In Kind Fuel Cost	+ 1.74%	3.84	3.84
Firm Pipeline Capacity (Rolled-in)	+ .28	4.12	
Interruptible Pipeline Capacity	+ .21		4.05
Pipeline Commodity Charge	$ + .04	4.16	4.09
Firm Supply Premium	$ + 0.0	4.16	
LDC Distribution Cost	+ .20	4.36	4.29

Table B-4a: Estimation of West Side Electric Generator Firm and Interruptible Natural Gas Cost (2000$/MMBtu)

Price Components	Price Adjustments	Firm	Interruptible
Henry-Hub Price		$ 4.31	$ 4.31
Sumas Price		3.77	3.77
In-Kind Fuel Charge	+ 1.74%	3.84	3.84
Firm Pipeline Capacity (Incremental)	$ + .56	4.40	
Interruptible Pipeline Capacity	$ + .21		4.05
Pipeline Commodity Charge	$ + .04	4.44	4.09
Firm Supply Premium	$ + .00	4.44	

Table B-4b: Estimation of East Side Electric Generator Firm and Interruptible Natural Gas Cost (2000$/MMBtu)

Price Components	Price Adjustments	Firm	Interruptible
Henry Hub Price		$ 4.31	$ 4.31
AECO Price		3.66	3.66
In-Kind Fuel Charge	+ 2.8%	3.76	3.76
Firm Pipeline Capacity (Incremental)	$ + .45	4.21	
Interruptible Pipeline Capacity	$ + .23		3.99
Pipeline Commodity Charge	$ + .01	4.22	4.00
Firm Supply Premium	$ + .00	4.22	

Inputs to the AURORA® model are configured differently, but they are based on the same underlying U.S. wellhead price forecast. Adjustment from U.S. wellhead prices to AURORA® market area prices are described in Appendix B1.

Treatment of Natural Gas Prices in the Portfolio Model

The discussion above described long-term trend forecasts for natural gas prices. These are important for the expected cost trends over the forecast horizon. However, the choice of generating and conservation resources also must consider volatility and risk inherent in natural gas prices. The Council's portfolio model assessed such price behavior and its affect on the cost and risk of alternative resource plans.

The portfolio model introduces additional kinds of variation into the analysis of natural gas prices to electricity generators in the region. Normal seasonal patterns are added to the annual trends, and random commodity price cycles are added with periods of extreme price variation. The result is an analysis of natural gas prices with much greater variation than the trend forecasts. Figure B-13 illustrates a sample of natural gas price futures evaluated in the portfolio model. The range of trend forecasts is shown as the shaded band. Clearly the portfolio analysis considers price excursions well outside the annual trend range, especially on the high price side.

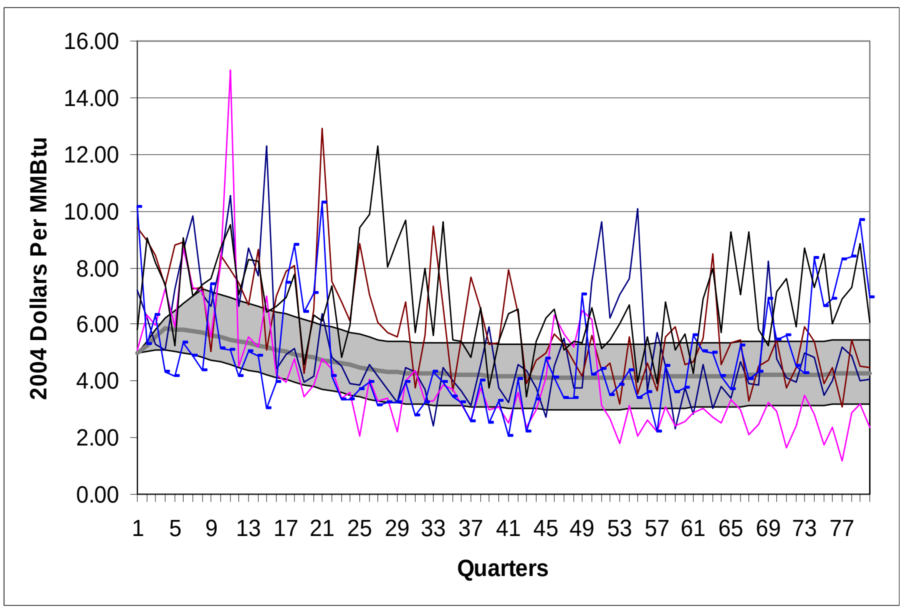


Figure B-13: Illustration of Natural Gas Price Futures in the Portfolio Model

OIL

Historical Consumption and Price

Oil products are playing a decreasing role in both electricity generation and in residential and commercial space heating in the Pacific Northwest. Figure B-14 shows that both distillate and residual oil consumption have generally been declining in all sectors since the mid-1970s.

To a large extent, declining oil consumption reflects growing natural gas use. Some increases in oil consumption are evident during the mid-1980s when natural gas prices were high. Substitution possibilities between natural gas and oil use in large industrial applications is a key feature of fuel markets. The substitution of oil for natural gas, for example, played an important role during 2001 in reducing high natural gas prices. In the Pacific Northwest, the displacement of industrial residual oil use is particularly dramatic as shown in Figure B-14.

In general, the price of oil products is determined by the world price of crude oil. Figure B-15 shows crude oil prices from 1978 to 2000 compared to refiner prices for residual oil and distillate oil. The differences are relatively stable with residual oil being priced lower than crude oil and distillate oil higher. On average, during this time period distillate oil was priced $1.00 per million Btu higher than crude oil. Residual oil was on average priced $.80 lower than crude oil. (Prices are in nominal dollars.) Retail prices of oil products follow very similar patterns, but at different levels.

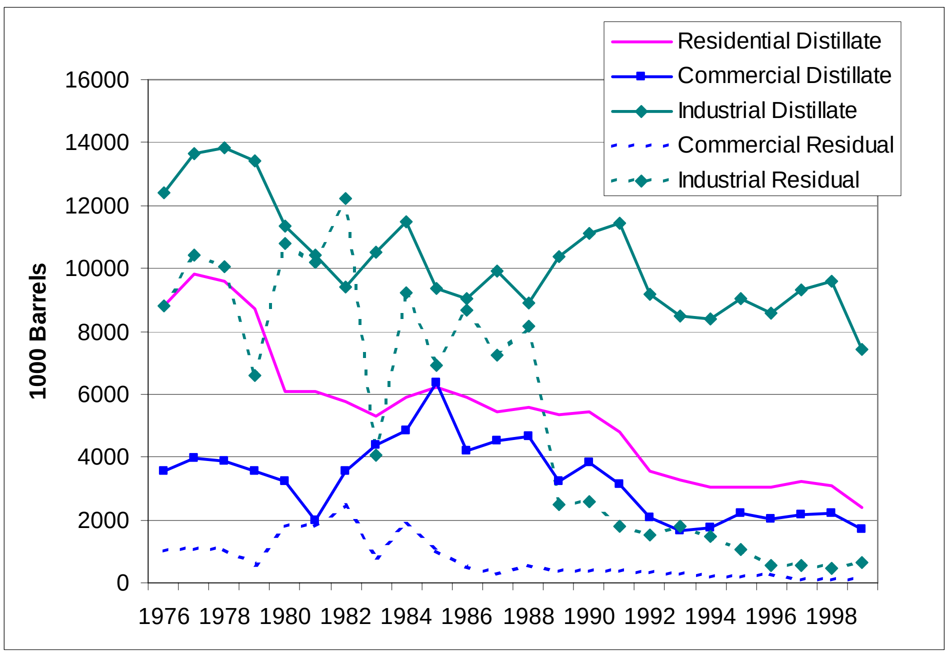


Figure B-14: Historical Oil Consumption in the Pacific Northwest

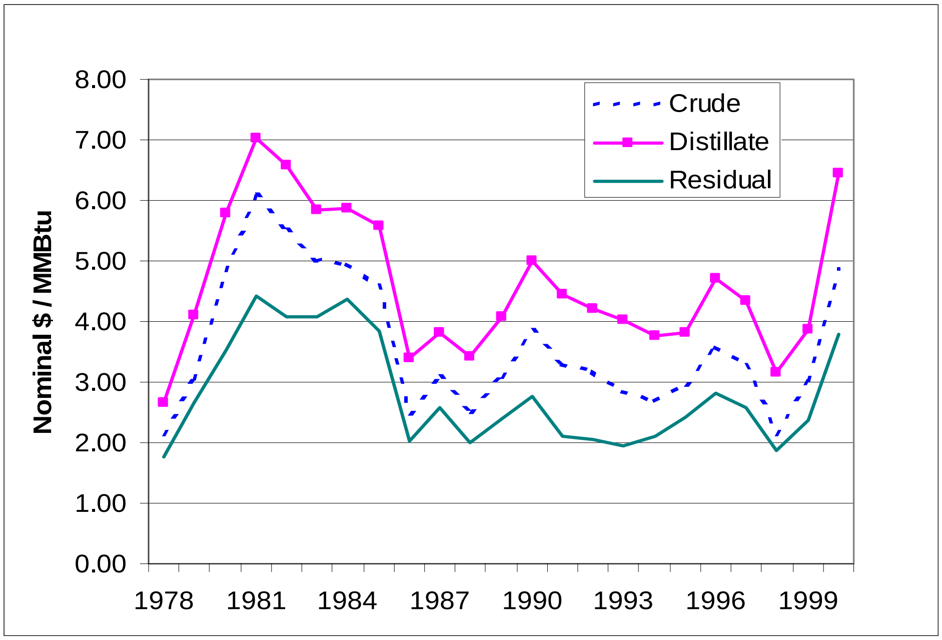


Figure B-15: Comparison of Crude Oil and Refiner Product Prices

Methods

The forecasts of oil prices are based on assumptions about the future world price of crude oil. Refiner prices of distillate and residual oil are derived from formulas relating product prices to crude oil prices and refining costs. The formulas are based on a conceptual model of refinery costs and assume profit-maximizing decisions by refiners regarding the mix of distillate and residual oil production. Appendix B1 describes this model in more detail.

Although the refinery model is very simple, and the refining cost estimates and energy penalties have not been changed since the early days of the Council's planning, the ability of the equations to simulate historical prices remains good. Figures 16a and 16b show a comparison of predicted residual oil and distillate oil prices, respectively, based on actual world crude oil prices, to actual prices from 1978 to 2000. The equations appear to be predicting well, especially after the mid-1980s.

Forecasts of retail oil prices to end-use sectors are based on historical differences between the refiner price estimates for residual and distillate oil and actual retail prices. These mark-ups are assumed constant over time and across alternative forecast cases.

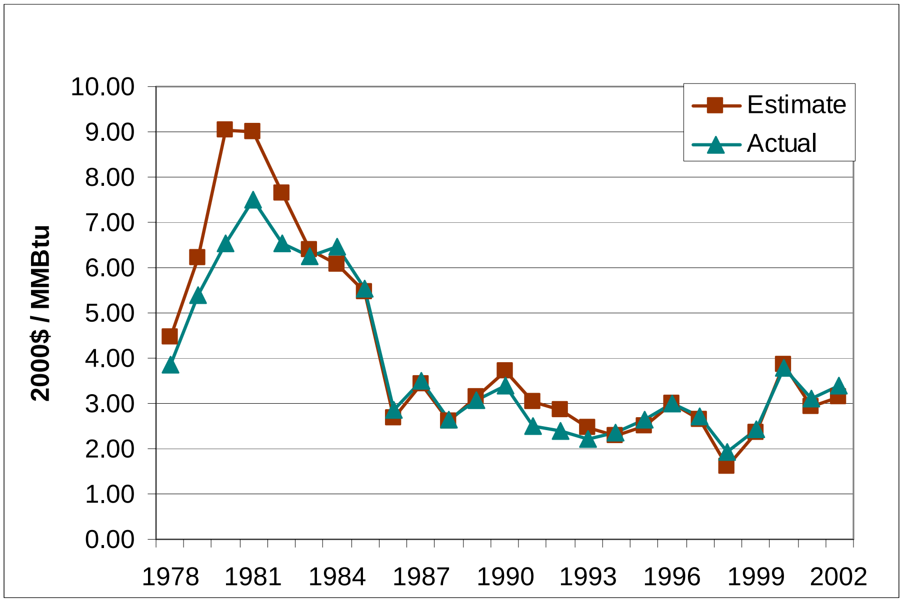


Figure B-16a: Comparison of Forecast and Actual Residual Oil Prices

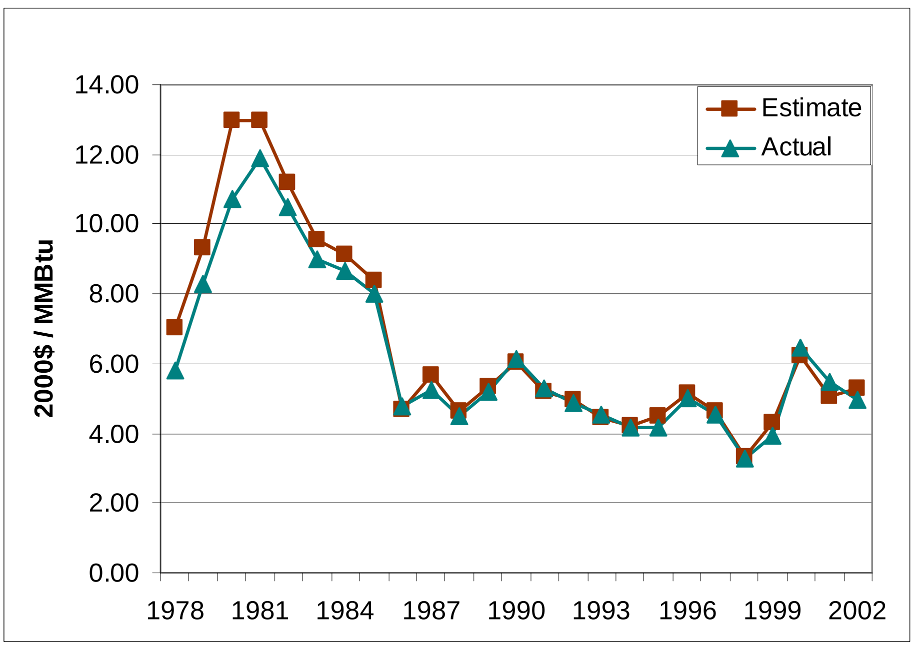


Figure B-16b: Comparison of Forecast and Actual Distillate Oil Prices

World Crude Oil Price Forecast

The situation in world oil markets is very different from natural gas markets. Oil has much more of a world market than natural gas because it is easier to transport. The world's proved reserves of oil are about 1,000 billion barrels. World consumption of oil in 2000 was 27 billion barrels (based on BP and USGS data). Oil reserves are dominated by the Middle East, which has 65 percent of the world's proven reserves. The Middle East's reserves can be produced at low cost, but the middle eastern countries and their partners in the Organization of Petroleum Exporting Countries (OPEC) attempt to limit production so that world oil prices remain in the range of $22 to $28 per barrel. Proven oil reserves in the Middle East are 80 times the actual production rate in 2000. As a result, world oil prices are likely to depend on OPEC actions for the duration of the forecast period.

Although fluctuating world oil demand, Middle East conflicts, lapses in OPEC production discipline, and other world events will result in volatile oil prices over time, we have assumed a range of stable average prices in the forecast. Figure B-17 shows historical world oil prices and the five forecast cases.

Since the mid-1980s, world oil prices have averaged $21 a barrel in year 2000 prices. However, they varied from a low of $12.49 per barrel in 1998 to $27.69 in 2000. During 2001 and 2002, prices averaged in the low $20 range. Table B-5 shows historical world oil prices and forecasts for individual years between 2000 and 2005 and in five-year increments thereafter. A number of factors have caused an increase in world oil prices in 2003 and 2004. These include the Iraq situation, strikes in Venezuela, and a lower value of the U.S. dollar. In 2003 world oil prices averaged $26.23 and they have moved substantially higher in 2004, at times nearing $50. The forecasts assume that oil prices this high are a temporary condition. After 2010 the medium-low to medium-high forecast range settles to the $23 to $29 dollar range.

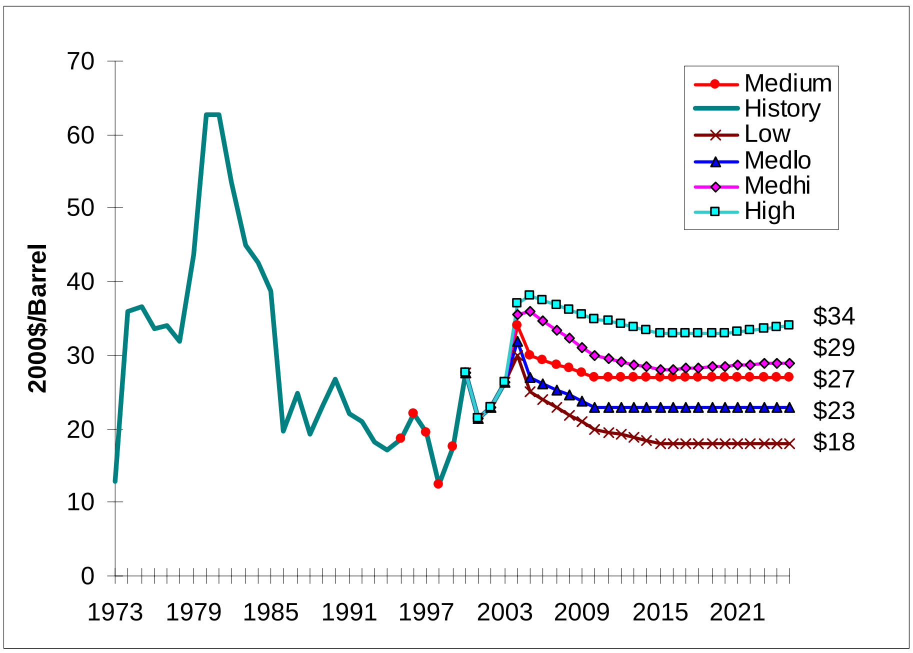


Figure B-17: World Oil Price: History and Forecasts

Table B-5: World Oil Price Forecasts (2000$ per MMBtu)

	Low	Medium-Low	Medium	Medium-High	High
2000			27.69		
2001			21.52		
2002			22.91		
2003			26.23		
2004	30.00	32.00	34.00	35.50	37.00
2005	25.00	27.00	30.00	36.00	38.00
2010	20.00	23.00	27.00	30.00	35.00
2015	18.00	23.00	27.00	28.00	33.00
2020	18.00	23.00	27.00	28.50	33.00
2025	18.00	23.00	27.00	29.00	34.00

The assumptions about future oil prices are based on observation and analysis of historical prices and on comparisons among forecasts made by other organizations that put substantial resources into the analysis of future oil price trends. Figure B-18 shows historical world oil prices for 1990, 1995 and 2000 compared to the forecast range and a range of other forecasts. The U.S. Energy Information Administration (EIA) is the source of the summary of other forecasts.[11] Figure B-18 shows EIA's forecast range and the average of 8 other forecasts that EIA compared to their own forecast. EIA's reference case forecast falls between our medium-low and medium cases after 2005. EIA's range is also consistent with our low to high range after 2005. The average of the 8 other forecasts falls between our low and medium-low forecasts. These other forecast did were done during 2003 and did not have the advantage of knowing about recent oil prices, so their 2005 forecasts are well below the Council's in the near term. Appendix B4 contains tables of annual forecasts for world oil prices and retail sector oil prices for each forecast case.

[11] U.S. Energy Information Administration, Annual Energy Outlook 2004.

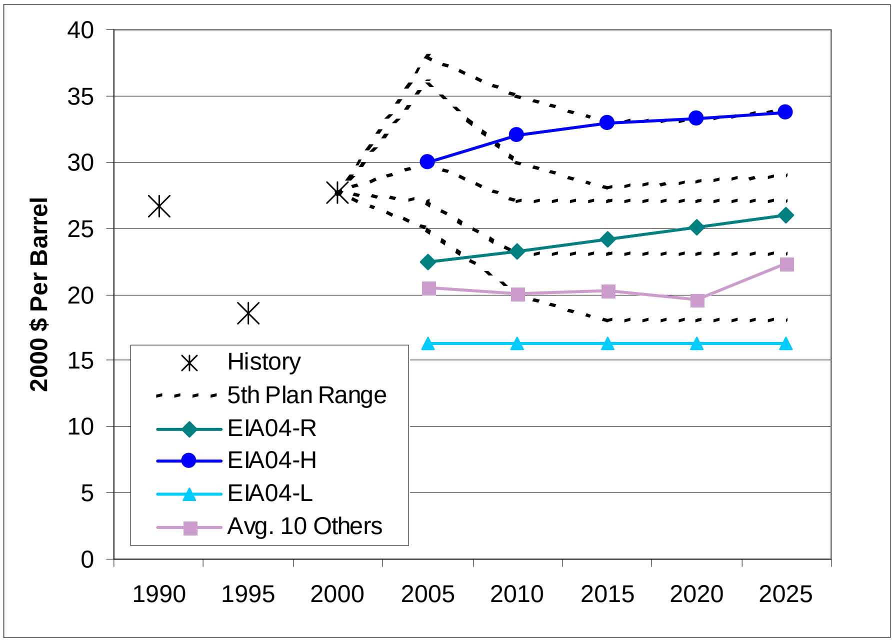


Figure B-18: Comparison to Other World Oil Price Forecasts

Consumer Prices

Using the methods described earlier, world oil price forecasts are converted to refiner prices of residual oil and distillate oil. Figure B-19 shows the forecast relationship among the prices of these refiner products for the medium case. A set of mark-ups is used to derive forecasts of retail prices for various products to end use sectors. These retail mark-ups, shown in Table B-6, are generally assumed constant over time and across forecast cases. The mark-ups are based on historical average price relationships during the 1980s and 1990s. Appendix B5 contains detailed tables for the oil price forecast.

Table B-6: Retail Mark-up Assumptions for Oil Products and Sectors

INDUSTRIAL SECTOR	
Residual Oil Over Refinery	$ .24
Distillate Oil Over Refinery	$ 1.00
UTILITY SECTOR	
Residual Oil Over Refinery	$ .24
Distillate Oil Over Refinery	$ .46
COMMERCIAL SECTOR	
Residual Oil Over Industrial	$ .05
Distillate Oil Over Industrial	$ -.42
RESIDENTIAL SECTOR	
Distillate Oil Over Industrial	$ 1.98

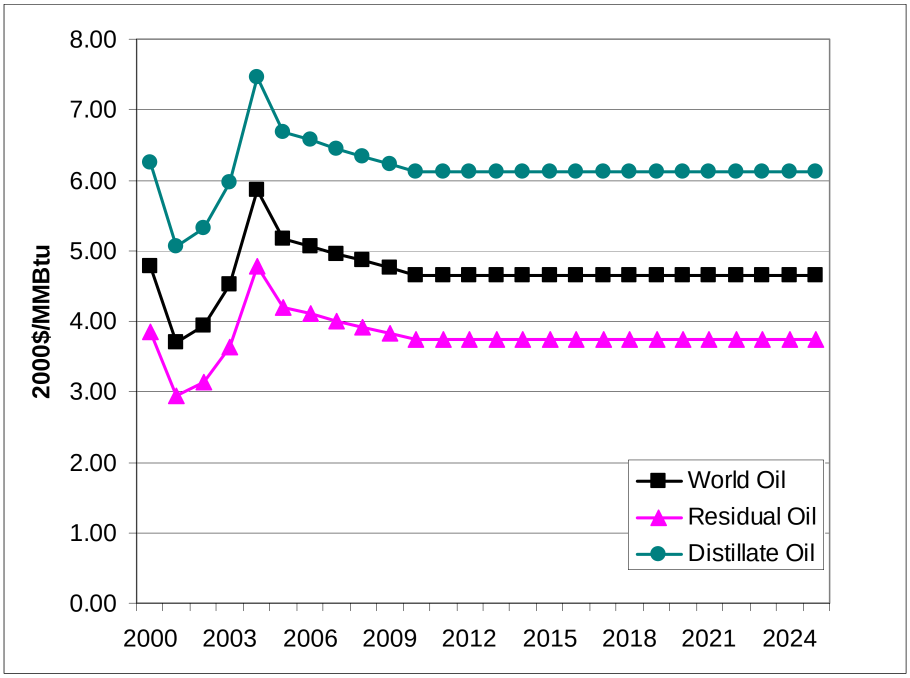


Figure B-19: Refiner Prices of Residual and Distillate Oil Compared to World Crude Oil Price (Medium Case)

COAL PRICE FORECASTS

Coal prices play little role in determining regional electricity demand. There are not many end uses where coal and electricity substitute for one another and coal consumption is relatively minor in the Pacific Northwest in any case. Coal as a percent of total industrial fuel purchases in the region in 1999 was 0.7 percent compared to 6.1 percent for the U.S. as a whole. Coal is also a relatively minor electricity generation fuel in the region compared to the U.S. In 1999, coal accounted for 14 percent of regional utility fuel purchases compared to 55 percent for the nation. Only Montana had a coal generation share similar to the US for electricity generation.

Nevertheless, coal may be an important alternative as an electricity generation fuel in the future. The trade-off is that while coal is a plentiful and relatively inexpensive domestic energy source, it also has substantial environmental impacts both during extraction and burning. Thus its future may depend on technological progress in emissions controls and policies with regard to air quality and global warming.

Coal resources, like natural gas, are measured in many different forms. The EIA reports several of these.[12] 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 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

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

interior deposits. Western coal is cheaper 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 SO_2 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.

Western coal production in 2000 was 510.7 million short tons. Two-thirds of that production came from Wyoming, 338.9 million short tons. The second largest state producer was Montana at 38.4 million tons. Colorado, New Mexico, North Dakota and Utah produced between 26 and 31 million short tons each, and Arizona produced about 13 million short tons.

Productivity increases have been rapid, especially in Western coalmines. As a result, mine-mouth coal prices have decreased over time. In constant dollars, Western mine-mouth coal prices declined by nearly 6 percent per year between 1985 and 2000. Expiring higher priced long-term contracts have also contributed to declining coal prices.

The price of delivered coal 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 B-20 shows Pacific Northwest delivered industrial and utility sector coal prices from 1976 to 1999.[13] Coal prices increased during the late 1970s with other energy prices, but since the early 1980s have declined steadily. On average, regional industrial coal prices decreased at an annual rate of 3.2 percent between 1980 and 1999. 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 generation plants in the region.

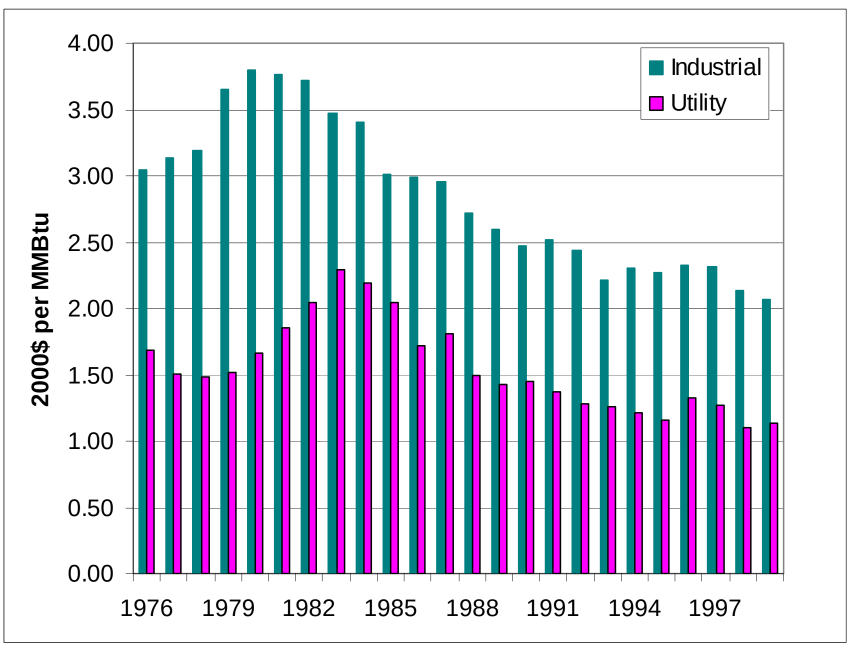


Figure B-20: Pacific Northwest Industrial and Utility Historical Coal Price Trends

[13] U.S. Energy Information Administration

Forecasts of coal prices rely on a very simple method. Different constant rates of price change for Western mine-mouth coal prices are assumed for the five forecast cases. The assumptions are shown in Table B-7. In all cases, the rapid declines in coal prices over the last 20 years are assumed to end. The medium case assumes stable prices. The lower cases assume slight decreases, and the higher cases slight increases. The EIA forecast of Western Coal prices grows at about the same rate as the Council's medium-high forecast.

Table B-7: Assumed Western Mine-mouth Coal Price Growth Rates

Forecast Case	Average Annual Rate of Growth
Low	- 0.8 %
Medium Low	- 0.5 %
Medium	0.0 %
Medium High	+ 0.5 %
High	+ 0.9 %

Delivered prices to Pacific Northwest industries and utilities are estimated by applying fixed mark-ups from Western mine-mouth prices to delivered prices. Because transportation costs are significant for coal, states that are farther away from the mines tend to have significantly higher delivered coal costs. Montana and Wyoming delivered costs, however, can be quite close to the mine-mouth price. Some coal-fired electricity generating plants are located at the mine and have little, if any, transportation cost. In more distant states, like Washington, the delivered cost can be more than 3 times the mine-mouth price. Table B-8 shows the additions to Western mine-mouth coal prices for the states in the West and the 2010 medium forecast of coal prices that result. Appendix B5 contains annual forecasts of coal prices for each of the forecast cases.

Table B-8: Derivation of State Electricity Generator Coal Prices, 2010 Medium Forecast (2000$ per Million Btu)

	Mark-up from Mine	Price Forecast
Western Mine-mouth		$ 0.51
Washington	$ + .99	1.50
Oregon	+ .53	1.05
Idaho	+ .45	.96
Montana	+ .01	.52
Utah	+ .62	1.13
Wyoming	+ .19	.70
Colorado	+ .47	.98
New Mexico	+ .86	1.37
Arizona	+ .82	1.33
Nevada	+.88	1.39

APPENDIX B1 - FUEL PRICE FORECASTING MODEL

Introduction

This Appendix describes the fuel price forecasting model that was used for the Council's Fifth Power Plan. The model consists of several worksheets linked together in an EXCEL "workbook."

The model includes forecasts of natural gas, oil and coal prices. Retail fuel prices for the various demand sectors are derived from the forecasts of basic energy commodity prices; that is, the world price of oil, the average wellhead price of natural gas, and Western mine-mouth coal prices. These energy prices are forecast by several organizations that specialize in energy market forecasting. Thus, basic energy price trends can be compared to 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 estimated by adding cost components to the basic energy commodity prices. Where possible these additional costs, or mark-ups, are based on historical relationships among energy costs to various sectors. Thus, the basic driving forces in the fuel price model are world oil price forecasts, wellhead natural gas price forecasts, coal price growth rates, and mark-ups to retail prices in various end-use sectors. In the case of natural gas, prices at various trading points in the West are estimated using equations describing the basis relationships among various locations.

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 in electricity generation and receives less attention. Coal plays little role in determining electricity demand and is treated very briefly in the model using assumed annual growth rates.

Model Components

Historical retail data for each fuel are kept on separate Excel files. 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. The spreadsheets convert the prices to real 2000 dollars and calculate consumption weighted average regional prices for each end-use sector. In addition, wholesale market price data is maintained in separate files.

Forecasts of world oil prices and natural gas wellhead prices are developed in the WOPFC and NGFC tabs, respectively, in the FUELMOD04 Excel Workbook. They take historical data, consistent with the historical fuel price worksheets described in the previous paragraph, and merge it with forecasts in five-year intervals. The worksheet interpolates between the five-year forecasts to get annual values. These tabs also contain previous Council forecasts and forecasts by other organizations for comparison purposes.

MAIN contains the forecasts of basic oil and gas commodity prices calculated in WOPFC and NGFC for a specific forecast case and any other scenario dependent assumptions and parameters. It also compares the model estimates of industrial residual oil prices, interruptible gas prices, and coal prices. Wellhead gas prices feed into the gas price model and world oil prices feed into the oil price model. MAIN contains the scenario controls and variables for the entire model. The varying scenario assumptions and their cell locations are as follows:

Scenario Name	B2
Wellhead Natural Gas Price	B30:B54
World Oil Price	C30:C54
Real Growth Rate of Incremental Pipeline Costs	D60
Coal Price Growth Rate	D61
Firm Natural Gas Supply Share	D62

The separate tabs in FUELMOD04 are described at the end of this appendix in a section entitled Model Components, which is a printout of the first tab ("DOC") in the model. The model structure is described in more detail below.

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.

The natural gas price forecasts begin with a forecast of average U.S. wellhead prices. These are used to estimate prices at other trading points throughout the West in the tab called NG West. In addition, state utility natural gas prices are estimated in NG West. Where supported by historical data, regression equations were estimated that relate these various natural gas prices. For a description of the data and estimations see Council staff paper "Developing Basis Relationships Among Western Natural Gas Pricing Points".

There are three separate worksheets for Pacific Northwest natural gas price forecasts by sector: INDUST, which contains industrial sector forecasts; NWUTIL which contains electricity generator forecasts; RES_COM which contains residential and commercial forecasts. A separate worksheet, COMPONENTS, supports the industrial and electricity generator price forecasts by accounting for the various components of cost that are incurred between the wellhead and the end-user. The worksheet GASSUM is simply a report that summarizes the natural gas price forecasts. The tabs 00$NWUtil and AURORA report fixed and variable cost of natural gas for electricity generators.

Residential and commercial sector gas prices are based on historical regional retail prices compared to U.S. 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 mark-ups, can be projected from historical trends, other forecasting models, or judgment.

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 electricity generators, 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 mark-up 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 are developed in the worksheet COMPONENTS.

The components include pipeline capacity costs, pipeline commodity costs, pipeline fuel use, local distribution costs, and firm gas supply premiums, if any. These adjustments are applied to AECO prices for the regional eastside prices, and to Sumas for the regional westside prices. Three types of pipeline capacity costs are used; incremental firm, rolled-in firm, and interruptible or capacity release. New electricity generation plants are assumed to require incremental firm pipeline capacity. The part of pipeline capacity costs that could not likely be recovered from the capacity release market becomes a part of fixed fuel costs.

Tables B1-1 and B1-2 show the various transportation components, their column location in the COMPONENTS worksheet, and the current value or range of values in the model. Table B1-1 applies to a large natural gas consumer on the west side of the Cascades and Table B1-2 applies to the same kind of consumer on the east side.

Table B1-1: West-Side Cost Components for Calculating Delivered Natural Gas Prices.

Cost Component	Components Column	Constant Costs (2000$/MMBtu)	Scenario Variant				
			L	ML	M	MH	H
U.S. Wellhead Price	B						
Henry Hub Price	C						
Sumas Price *	Q						
Pipeline Capacity Costs							
Firm Rolled-In	E	+ .28					
Firm Incremental	G	+.55 in 2006 + growth	-0.1	0.1	0.3	0.5	0.7
Released Capacity Cost *	I	+ .21					
Pipeline Commodity Cost	K	+ .04					
Pipeline In-Kind Fuel Cost *	E61	+ 1.74 %					
LDC Distribution Cost	M	+ .20					
Firm Supply Premium	N	+ 0.0					

* Summer and winter values are different from the averages show here

The resource planning models require utility gas prices in terms of their fixed and variable components. Variable costs include wellhead prices adjusted for regional differences, pipeline fuel costs, and pipeline commodity charges. These are costs that can be avoided if electricity is not generated. In addition, some portion of the pipeline capacity charge may be avoided through resale in the capacity release market. The share of firm pipeline capacity costs that can be recovered by resale in the capacity release market is a parameter in the model and is currently assumed to equal 10 percent. For example, if it were not possible to recover any pipeline capacity costs then they become fixed costs. The other potentially fixed cost is any premium that must be paid to secure firm gas supply, but this is currently assumed to be zero. Fixed costs are expressed in dollars per kilowatt per year, instead of dollars per million Btu.

Table B1-2: East-Side Cost Components for Calculating Delivered Natural Gas Prices.

Cost Component	Components Column	Constant Costs (2000$/MMBtu)	Scenario Variant				
			L	ML	M	MH	H
U.S. Wellhead Price	B						
Henry Hub Price	C						
AECO Price	P						
Pipeline Capacity Cost							
Firm Rolled-In	F	+ .29					
Firm Incremental	H	+.45 in 2007 + growth	-0.1	0.1	0.3	0.5	0.7
Released Capacity Cost *	J	+ .23					
Pipeline Commodity Cost	L	+ .01					
Pipeline In-Kind Fuel Cost *	F62	+ 2.80 %					
LDC Distribution Cost	M	+ .20					
Firm Supply Premium	N	+ 0.0					

* Summer and winter values are different from the averages show here

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.[14] Retail prices of oil products for the industrial, residential, and commercial sectors are then calculated by adding mark-ups 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 the 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\$.
- Saudi light yields 47 percent heavy oil.
- 3 percent energy penalty.

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

Desulpherization
- \$3.91 per barrel in 2000\$.
- 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.
.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.

[14]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.

2.15 is the refining cost per barrel.

Complex refinery

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

Equilibrium Condition: Profit from heavy products equals profit from light products at the margin.

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

Solve for product prices:

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

$$.47(H - L) = -.09C - 3.23$$

$$(H - L) = -.1915C - 6.8723$$

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 $5.38 (2000$) per barrel. Residual oil wholesales price equals 93 percent of the crude oil price less $1.51

Historically based mark-ups are added to get retail prices for residual and distillate oil for the commercial, industrial and utility sectors. The two oil products prices are 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 is a very simple approach. Average Western mine-mouth coal prices are forecast by applying assumed, scenario-specific, growth rates to a base year level. Regional utility and industry prices, and state-specific utility prices are forecast based on time- invariant differentials from western the mine-mouth prices.

Model Components (Tabs in the Excel Workbook)

DOC	-- Describes files in the forecast model
NGFC	-- Contains historical prices and the forecast range of wellhead gas prices. Scenarios are to be copied into MAIN for each case. Contains GDP deflators for converting historical to study year dollars.
WOPFC	-- Contains historical prices and the forecast range of world oil prices. Scenarios are to be copied into MAIN for each case.
MAIN	-- Contains drivers for forecast model and includes scenario varient values. (Avg. wellhead, world oil, GNP deflators etc. Displays boiler fuel relative gas, oil, coal prices
Basis	-- Contains regional basis differential assumptions for each scenario To be copied into MAIN for each scenario.
NG West	-- Develops forecasts of natural gas prices at major Western pricing points
Components	-- Combines the various components of pipeline and distribution cost, regional wellhead price difference, and other add-ons to the wellhead gas price. These adders are used in the INDUST and NWUTIL sheets.
RES_COM	-- Residential & Commercial gas price model, linked to MAIN wellhead prices by retail price differences.
INDUST	-- Industrial gas price model, linked to MAIN wellhead Large interruptible, Avg. transport, through LDC & Mixed
NWUTIL	-- PNW Utility gas price model, linked to MAIN wellhead Interruptible and Firm burner-tip
00$ NWUtil	-- Shows derivation of West-side and East-side Firm utility gas prices
AURORA	-- Develops fixed and variable natural gas prices for AURORA™ Model pricing points in the WECC
GASSUM	-- Summary table for gas price forecasts, linked to the individual sector worksheets.
OILMOD	-- Estimates retail oil prices for all sectors, linked to MAIN

world oil price forecasts.

OilSum -- Summary of retail oil price forecasts for residual and distillate in both midyear 2000 dollars and Jan 2000 dollars.

COALMOD -- Forecasts industrial coal prices based on exogenous growth rate read from MAIN.

Tables -- Develops tables to be included in forecast documents

FUELS -- Puts the fuel price forecasts in the format needed for input to demand forecasting models, converts to 1980 dollars

Export -- File to be exported for demand model inputs.

APPENDIX B2 - FORECAST TABLES FOR U.S. WELLHEAD AND REGIONAL MARKET PRICES

Table B2-1 - Medium
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Medium Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	5.45	5.12	5.21	5.85	5.66
2005	5.30	4.97	5.06	5.69	5.50
2006	5.01	4.68	4.78	5.45	5.22
2007	4.74	4.40	4.50	5.17	4.99
2008	4.48	4.14	4.24	4.91	4.72
2009	4.23	3.89	4.00	4.67	4.47
2010	4.00	3.66	3.77	4.43	4.23
2011	3.96	3.62	3.73	4.39	4.19
2012	3.92	3.58	3.69	4.35	4.15
2013	3.88	3.54	3.65	4.32	4.11
2014	3.84	3.50	3.61	4.28	4.07
2015	3.80	3.46	3.57	4.24	4.03
2016	3.82	3.48	3.59	4.26	4.05
2017	3.84	3.50	3.61	4.28	4.07
2018	3.86	3.52	3.63	4.30	4.10
2019	3.88	3.54	3.65	4.33	4.12
2020	3.90	3.56	3.67	4.35	4.14
2021	3.92	3.58	3.69	4.37	4.16
2022	3.94	3.60	3.71	4.39	4.18
2023	3.96	3.62	3.73	4.41	4.21
2024	3.98	3.64	3.75	4.44	4.23
2025	4.00	3.66	3.77	4.46	4.25

Table B2-2 - Low
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Low Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	4.75	4.41	4.52	5.14	4.93
2005	4.50	4.16	4.27	4.88	4.67
2006	4.15	3.81	3.92	4.58	4.33
2007	3.83	3.49	3.60	4.25	4.05
2008	3.53	3.19	3.30	3.95	3.74
2009	3.25	2.91	3.03	3.67	3.45
2010	3.00	2.65	2.77	3.41	3.19
2011	2.95	2.60	2.72	3.36	3.13
2012	2.90	2.55	2.67	3.31	3.08
2013	2.85	2.50	2.62	3.25	3.03
2014	2.80	2.45	2.57	3.20	2.98
2015	2.75	2.40	2.53	3.15	2.93
2016	2.78	2.43	2.55	3.18	2.96
2017	2.81	2.46	2.58	3.21	2.99
2018	2.84	2.49	2.61	3.24	3.02
2019	2.87	2.52	2.64	3.27	3.05
2020	2.90	2.55	2.67	3.30	3.08
2021	2.92	2.57	2.69	3.32	3.10
2022	2.94	2.59	2.71	3.34	3.12
2023	2.96	2.61	2.73	3.36	3.14
2024	2.98	2.63	2.75	3.38	3.16
2025	3.00	2.65	2.77	3.40	3.18

Table B2-3 - Medium-Low
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Medium Low Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	5.20	4.87	4.96	5.59	5.40
2005	4.90	4.57	4.67	5.29	5.09
2006	4.53	4.19	4.30	4.96	4.72
2007	4.18	3.84	3.95	4.61	4.42
2008	3.87	3.52	3.64	4.29	4.09
2009	3.57	3.23	3.34	3.99	3.78
2010	3.30	2.96	3.07	3.72	3.50
2011	3.32	2.98	3.09	3.74	3.52
2012	3.34	3.00	3.11	3.76	3.54
2013	3.36	3.02	3.13	3.78	3.57
2014	3.38	3.04	3.15	3.80	3.59
2015	3.40	3.06	3.17	3.82	3.61
2016	3.42	3.08	3.19	3.84	3.63
2017	3.44	3.10	3.21	3.86	3.65
2018	3.46	3.12	3.23	3.89	3.67
2019	3.48	3.14	3.25	3.91	3.69
2020	3.50	3.16	3.27	3.93	3.71
2021	3.50	3.16	3.27	3.93	3.71
2022	3.50	3.16	3.27	3.93	3.71
2023	3.50	3.16	3.27	3.93	3.72
2024	3.50	3.16	3.27	3.93	3.72
2025	3.50	3.16	3.27	3.93	3.72

Table B2-4 - Medium-High
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

Medium High Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	5.60	5.27	5.36	6.00	5.81
2005	6.00	5.67	5.76	6.40	6.23
2006	5.66	5.34	5.43	6.11	5.90
2007	5.35	5.02	5.11	5.80	5.62
2008	5.05	4.72	4.81	5.49	5.31
2009	4.77	4.43	4.53	5.21	5.02
2010	4.50	4.16	4.27	4.94	4.75
2011	4.46	4.12	4.23	4.91	4.71
2012	4.42	4.08	4.19	4.87	4.67
2013	4.38	4.04	4.15	4.83	4.63
2014	4.34	4.00	4.11	4.79	4.59
2015	4.30	3.96	4.07	4.76	4.55
2016	4.31	3.97	4.08	4.77	4.57
2017	4.32	3.98	4.09	4.78	4.58
2018	4.33	3.99	4.10	4.79	4.59
2019	4.34	4.00	4.11	4.81	4.61
2020	4.35	4.01	4.12	4.82	4.62
2021	4.38	4.04	4.15	4.85	4.65
2022	4.41	4.07	4.18	4.89	4.68
2023	4.44	4.10	4.21	4.92	4.72
2024	4.47	4.13	4.24	4.95	4.75
2025	4.50	4.16	4.27	4.99	4.79

Table B2-5 - High
Regional Electricity Generation Natural Gas Prices
(2000$ Per MMBtu)

High Case					
Year	U.S. Wellhead Price	AECO Price	Sumas Price	West-Side Delivered	East-Side Delivered
2000	3.60	3.37	5.98	6.58	3.77
2001	4.03	4.14	3.59	4.15	4.59
2002	2.80	2.57	2.65	3.18	2.97
2003	4.62	4.94	4.32	4.88	5.41
2004	5.80	5.47	5.56	6.20	6.02
2005	6.75	6.43	6.51	7.16	7.00
2006	6.36	6.03	6.12	6.81	6.62
2007	5.99	5.66	5.75	6.44	6.28
2008	5.64	5.31	5.40	6.09	5.92
2009	5.31	4.98	5.07	5.77	5.59
2010	5.00	4.67	4.77	5.46	5.27
2011	4.98	4.65	4.75	5.44	5.25
2012	4.96	4.63	4.73	5.42	5.24
2013	4.94	4.61	4.71	5.41	5.22
2014	4.92	4.59	4.69	5.39	5.20
2015	4.90	4.57	4.67	5.37	5.18
2016	4.92	4.59	4.69	5.40	5.21
2017	4.94	4.61	4.71	5.42	5.23
2018	4.96	4.63	4.73	5.45	5.26
2019	4.98	4.65	4.75	5.47	5.28
2020	5.00	4.67	4.77	5.50	5.30
2021	5.02	4.69	4.79	5.52	5.33
2022	5.04	4.71	4.81	5.55	5.35
2023	5.06	4.73	4.83	5.57	5.38
2024	5.08	4.75	4.85	5.59	5.40
2025	5.10	4.77	4.87	5.62	5.42

APPENDIX B3 - FORECAST TABLES FOR U.S. WELLHEAD AND REGIONAL RETAIL NATURAL GAS PRICES

Table B3-1 - Medium
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Medium Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	5.45	9.70	8.70	6.18	5.67
2005	5.30	9.55	8.55	6.02	5.52
2006	5.01	9.26	8.26	5.73	5.24
2007	4.74	8.99	7.99	5.45	4.97
2008	4.48	8.73	7.73	5.19	4.71
2009	4.23	8.48	7.48	4.94	4.46
2010	4.00	8.25	7.25	4.70	4.22
2011	3.96	8.21	7.21	4.66	4.18
2012	3.92	8.17	7.17	4.62	4.14
2013	3.88	8.13	7.13	4.58	4.10
2014	3.84	8.09	7.09	4.54	4.06
2015	3.80	8.05	7.05	4.50	4.02
2016	3.82	8.07	7.07	4.51	4.04
2017	3.84	8.09	7.09	4.53	4.06
2018	3.86	8.11	7.11	4.55	4.08
2019	3.88	8.13	7.13	4.57	4.10
2020	3.90	8.15	7.15	4.59	4.13
2021	3.92	8.17	7.17	4.61	4.15
2022	3.94	8.19	7.19	4.63	4.17
2023	3.96	8.21	7.21	4.65	4.19
2024	3.98	8.23	7.23	4.67	4.21
2025	4.00	8.25	7.25	4.68	4.23

Table B3-2 - Low
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Low Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	4.75	9.00	8.00	5.47	4.96
2005	4.50	8.75	7.75	5.22	4.70
2006	4.15	8.40	7.40	4.86	4.36
2007	3.83	8.08	7.08	4.53	4.04
2008	3.53	7.78	6.78	4.23	3.73
2009	3.25	7.50	6.50	3.95	3.45
2010	3.00	7.25	6.25	3.69	3.19
2011	2.95	7.20	6.20	3.64	3.14
2012	2.90	7.15	6.15	3.59	3.09
2013	2.85	7.10	6.10	3.54	3.04
2014	2.80	7.05	6.05	3.49	2.99
2015	2.75	7.00	6.00	3.44	2.94
2016	2.78	7.03	6.03	3.46	2.97
2017	2.81	7.06	6.06	3.49	3.00
2018	2.84	7.09	6.09	3.52	3.03
2019	2.87	7.12	6.12	3.55	3.06
2020	2.90	7.15	6.15	3.58	3.09
2021	2.92	7.17	6.17	3.60	3.11
2022	2.94	7.19	6.19	3.62	3.13
2023	2.96	7.21	6.21	3.64	3.15
2024	2.98	7.23	6.23	3.66	3.17
2025	3.00	7.25	6.25	3.68	3.19

Table B3-3 - Medium-Low
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Medium Low Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	5.20	9.45	8.45	5.92	5.42
2005	4.90	9.15	8.15	5.62	5.11
2006	4.53	8.78	7.78	5.24	4.75
2007	4.18	8.43	7.43	4.89	4.41
2008	3.87	8.12	7.12	4.57	4.08
2009	3.57	7.82	6.82	4.27	3.78
2010	3.30	7.55	6.55	4.00	3.50
2011	3.32	7.57	6.57	4.02	3.52
2012	3.34	7.59	6.59	4.03	3.54
2013	3.36	7.61	6.61	4.05	3.56
2014	3.38	7.63	6.63	4.07	3.58
2015	3.40	7.65	6.65	4.09	3.61
2016	3.42	7.67	6.67	4.11	3.63
2017	3.44	7.69	6.69	4.13	3.65
2018	3.46	7.71	6.71	4.15	3.67
2019	3.48	7.73	6.73	4.17	3.69
2020	3.50	7.75	6.75	4.19	3.71
2021	3.50	7.75	6.75	4.19	3.71
2022	3.50	7.75	6.75	4.18	3.71
2023	3.50	7.75	6.75	4.18	3.71
2024	3.50	7.75	6.75	4.18	3.71
2025	3.50	7.75	6.75	4.18	3.71

Table B3-4 - Medium-High
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

Medium High Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	5.60	9.85	8.85	6.33	5.83
2005	6.00	10.25	9.25	6.73	6.24
2006	5.66	9.91	8.91	6.39	5.91
2007	5.35	9.60	8.60	6.07	5.60
2008	5.05	9.30	8.30	5.77	5.29
2009	4.77	9.02	8.02	5.48	5.01
2010	4.50	8.75	7.75	5.21	4.73
2011	4.46	8.71	7.71	5.17	4.69
2012	4.42	8.67	7.67	5.12	4.65
2013	4.38	8.63	7.63	5.08	4.61
2014	4.34	8.59	7.59	5.04	4.58
2015	4.30	8.55	7.55	5.00	4.54
2016	4.31	8.56	7.56	5.01	4.55
2017	4.32	8.57	7.57	5.02	4.56
2018	4.33	8.58	7.58	5.03	4.57
2019	4.34	8.59	7.59	5.04	4.58
2020	4.35	8.60	7.60	5.04	4.59
2021	4.38	8.63	7.63	5.07	4.63
2022	4.41	8.66	7.66	5.10	4.66
2023	4.44	8.69	7.69	5.13	4.69
2024	4.47	8.72	7.72	5.16	4.72
2025	4.50	8.75	7.75	5.19	4.75

Table B3-5 - High
Pacific Northwest Retail Natural Gas Prices
(2000$ Per MMBtu)

High Case		Regional Retail Natural Gas Prices			
Year	U.S. Wellhead Price	Residential	Commercial	Industrial Average	Utility Average
2000	3.60	7.09	5.95	5.91	5.13
2001	4.03	8.38	6.68	4.49	4.32
2002	2.80	7.05	6.05	3.55	3.03
2003	4.62	8.87	7.87	5.29	5.10
2004	5.80	10.05	9.05	6.53	6.03
2005	6.75	11.00	10.00	7.49	7.01
2006	6.36	10.61	9.61	7.09	6.62
2007	5.99	10.24	9.24	6.71	6.25
2008	5.64	9.89	8.89	6.36	5.90
2009	5.31	9.56	8.56	6.03	5.56
2010	5.00	9.25	8.25	5.71	5.25
2011	4.98	9.23	8.23	5.69	5.23
2012	4.96	9.21	8.21	5.67	5.21
2013	4.94	9.19	8.19	5.65	5.19
2014	4.92	9.17	8.17	5.63	5.17
2015	4.90	9.15	8.15	5.61	5.16
2016	4.92	9.17	8.17	5.62	5.18
2017	4.94	9.19	8.19	5.64	5.20
2018	4.96	9.21	8.21	5.66	5.22
2019	4.98	9.23	8.23	5.68	5.24
2020	5.00	9.25	8.25	5.70	5.27
2021	5.02	9.27	8.27	5.72	5.29
2022	5.04	9.29	8.29	5.74	5.31
2023	5.06	9.31	8.31	5.76	5.33
2024	5.08	9.33	8.33	5.78	5.36
2025	5.10	9.35	8.35	5.80	5.38

APPENDIX B4 - FORECAST TABLES FOR WORLD OIL AND REGIONAL RETAIL OIL PRICES

Table B4-1 - Medium
Retail Oil Price Forecast

Medium Case		Industrial	Industrial	Average	Commercial	Commercial	Average	Average	Utility	Utility
Year	World Oil Price (00$/Bbl.)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Industrial Oil Price	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Commercial Oil Price	Residential Oil Price (00$/MMBtu)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	34.00	5.02	8.46	8.26	5.07	8.04	7.90	10.44	5.02	7.92
2005	30.00	4.43	7.69	7.50	4.48	7.27	7.14	9.67	4.43	7.15
2006	29.37	4.34	7.57	7.38	4.39	7.15	7.02	9.55	4.34	7.03
2007	28.76	4.25	7.45	7.27	4.30	7.03	6.90	9.43	4.25	6.91
2008	28.16	4.16	7.34	7.15	4.21	6.92	6.79	9.32	4.16	6.80
2009	27.57	4.07	7.23	7.04	4.12	6.81	6.68	9.21	4.07	6.69
2010	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2011	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2012	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2013	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2014	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2015	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2016	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2017	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2018	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2019	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2020	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2021	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2022	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2023	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2024	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2025	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58

Table B4-2 - Low
Retail Oil Price Forecast

Low Case		Industrial	Industrial	Average	Commercial	Commercial	Average	Average	Utility	Utility
Year	World Oil Price (00$/Bbl.)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Industrial Oil Price	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Commercial Oil Price	Residential Oil Price (00$/MMBtu)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	30.00	4.43	7.69	7.50	4.48	7.27	7.14	9.67	4.43	7.15
2005	25.00	3.69	6.73	6.55	3.74	6.31	6.19	8.71	3.69	6.19
2006	23.91	3.53	6.52	6.34	3.58	6.10	5.98	8.50	3.53	5.98
2007	22.87	3.38	6.32	6.15	3.43	5.90	5.78	8.30	3.38	5.78
2008	21.87	3.23	6.13	5.96	3.28	5.71	5.59	8.11	3.23	5.59
2009	20.91	3.09	5.94	5.78	3.14	5.52	5.41	7.92	3.09	5.40
2010	20.00	2.95	5.77	5.60	3.00	5.35	5.24	7.75	2.95	5.23
2011	19.58	2.89	5.69	5.52	2.94	5.27	5.16	7.67	2.89	5.15
2012	19.17	2.83	5.61	5.45	2.88	5.19	5.08	7.59	2.83	5.07
2013	18.77	2.77	5.53	5.37	2.82	5.11	5.00	7.51	2.77	4.99
2014	18.38	2.71	5.46	5.30	2.76	5.04	4.93	7.44	2.71	4.92
2015	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2016	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2017	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2018	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2019	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2020	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2021	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2022	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2023	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2024	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84
2025	18.00	2.66	5.38	5.22	2.71	4.96	4.86	7.36	2.66	4.84

Table B4-3 - Medium-Low
Retail Oil Price Forecast

Medium Low Case										
Year	World Oil Price (00$/Bbl.)	Industrial Residual Oil Price	Industrial Distillate Oil Price (00$/MMBtu)	Average Industrial Oil Price	Commercial Residual Oil Price	Commercial Distillate Oil Price (00$/MMBtu)	Average Commercial Oil Price	Average Residential Oil Price (00$/MMBtu)	Utility Residual Oil Price (00$/MMBtu)	Utility Distillate Oil Price
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	32.00	4.73	8.08	7.88	4.78	7.66	7.52	10.06	4.73	7.54
2005	27.00	3.99	7.12	6.93	4.04	6.70	6.57	9.10	3.99	6.58
2006	26.15	3.86	6.95	6.77	3.91	6.53	6.41	8.93	3.86	6.41
2007	25.32	3.74	6.79	6.61	3.79	6.37	6.25	8.77	3.74	6.25
2008	24.52	3.62	6.64	6.46	3.67	6.22	6.10	8.62	3.62	6.10
2009	23.75	3.51	6.49	6.31	3.56	6.07	5.95	8.47	3.51	5.95
2010	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2011	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2012	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2013	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2014	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2015	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2016	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2017	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2018	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2019	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2020	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2021	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2022	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2023	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2024	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81
2025	23.00	3.40	6.35	6.17	3.45	5.93	5.81	8.33	3.40	5.81

Table B4-4 - Medium-High
Retail Oil Price Forecast

Medium High Case		Industrial	Industrial	Average	Commercial	Commercial	Average	Average	Utility	Utility
Year	World Oil Price (00$/Bbl.)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Industrial Oil Price	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Commercial Oil Price	Residential Oil Price (00$/MMBtu)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	35.50	5.24	8.75	8.54	5.29	8.33	8.18	10.73	5.24	8.21
2005	36.00	5.32	8.85	8.64	5.37	8.43	8.28	10.83	5.32	8.31
2006	34.71	5.13	8.60	8.39	5.18	8.18	8.03	10.58	5.13	8.06
2007	33.47	4.94	8.36	8.16	4.99	7.94	7.80	10.34	4.94	7.82
2008	32.27	4.77	8.13	7.93	4.82	7.71	7.57	10.11	4.77	7.59
2009	31.11	4.59	7.91	7.71	4.64	7.49	7.35	9.89	4.59	7.37
2010	30.00	4.43	7.69	7.50	4.48	7.27	7.14	9.67	4.43	7.15
2011	29.59	4.37	7.61	7.42	4.42	7.19	7.06	9.59	4.37	7.07
2012	29.18	4.31	7.53	7.35	4.36	7.11	6.98	9.51	4.31	6.99
2013	28.78	4.25	7.46	7.27	4.30	7.04	6.91	9.44	4.25	6.92
2014	28.39	4.19	7.38	7.19	4.24	6.96	6.83	9.36	4.19	6.84
2015	28.00	4.13	7.31	7.12	4.18	6.89	6.76	9.29	4.13	6.77
2016	28.10	4.15	7.33	7.14	4.20	6.91	6.78	9.31	4.15	6.79
2017	28.20	4.16	7.35	7.16	4.21	6.93	6.80	9.33	4.16	6.81
2018	28.30	4.18	7.36	7.18	4.23	6.94	6.81	9.34	4.18	6.82
2019	28.40	4.19	7.38	7.20	4.24	6.96	6.83	9.36	4.19	6.84
2020	28.50	4.21	7.40	7.22	4.26	6.98	6.85	9.38	4.21	6.86
2021	28.60	4.22	7.42	7.23	4.27	7.00	6.87	9.40	4.22	6.88
2022	28.70	4.24	7.44	7.25	4.29	7.02	6.89	9.42	4.24	6.90
2023	28.80	4.25	7.46	7.27	4.30	7.04	6.91	9.44	4.25	6.92
2024	28.90	4.27	7.48	7.29	4.32	7.06	6.93	9.46	4.27	6.94
2025	29.00	4.28	7.50	7.31	4.33	7.08	6.95	9.48	4.28	6.96

Table B4-5 - High
Retail Oil Price Forecast

High Case		Industrial	Industrial	Average	Commercial	Commercial	Average	Average	Utility	Utility
Year	World Oil Price (00$/Bbl.)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Industrial Oil Price	Residual Oil Price	Distillate Oil Price (00$/MMBtu)	Commercial Oil Price	Residential Oil Price (00$/MMBtu)	Residual Oil Price	Distillate Oil Price (00$/MMBtu)
2000	27.70	4.09	7.25	7.06	4.14	6.83	6.70	9.23	4.09	6.71
2001	21.49	3.17	6.06	5.89	3.22	5.64	5.52	8.04	3.17	5.52
2002	22.81	3.37	6.31	6.14	3.42	5.89	5.77	8.29	3.37	5.77
2003	26.23	3.87	6.97	6.78	3.92	6.55	6.42	8.95	3.87	6.43
2004	37.00	5.46	9.04	8.83	5.51	8.62	8.47	11.02	5.46	8.50
2005	38.00	5.61	9.23	9.02	5.66	8.81	8.66	11.21	5.61	8.69
2006	37.38	5.52	9.11	8.90	5.57	8.69	8.54	11.09	5.52	8.57
2007	36.77	5.43	8.99	8.78	5.48	8.57	8.43	10.97	5.43	8.45
2008	36.17	5.34	8.88	8.67	5.39	8.46	8.31	10.86	5.34	8.34
2009	35.58	5.25	8.76	8.56	5.30	8.34	8.20	10.74	5.25	8.22
2010	35.00	5.17	8.65	8.45	5.22	8.23	8.09	10.63	5.17	8.11
2011	34.59	5.11	8.57	8.37	5.16	8.15	8.01	10.55	5.11	8.03
2012	34.19	5.05	8.50	8.29	5.10	8.08	7.93	10.48	5.05	7.96
2013	33.79	4.99	8.42	8.22	5.04	8.00	7.86	10.40	4.99	7.88
2014	33.39	4.93	8.34	8.14	4.98	7.92	7.78	10.32	4.93	7.80
2015	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2016	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2017	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2018	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2019	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2020	33.00	4.87	8.27	8.07	4.92	7.85	7.71	10.25	4.87	7.73
2021	33.20	4.90	8.31	8.11	4.95	7.89	7.75	10.29	4.90	7.77
2022	33.40	4.93	8.34	8.14	4.98	7.92	7.78	10.32	4.93	7.80
2023	33.60	4.96	8.38	8.18	5.01	7.96	7.82	10.36	4.96	7.84
2024	33.80	4.99	8.42	8.22	5.04	8.00	7.86	10.40	4.99	7.88
2025	34.00	5.02	8.46	8.26	5.07	8.04	7.90	10.44	5.02	7.92

APPENDIX B5 - FORECAST TABLES FOR WESTERN MINE-MOUTH AND REGIONAL DELIVERED COAL PRICES

Table B5-1 - Medium
Coal Price Forecasts
(2000$ Per MMBtu)

Medium Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2002	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2003	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2004	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2005	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2006	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2007	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2008	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2009	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2010	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2011	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2012	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2013	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2014	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2015	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2016	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2017	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2018	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2019	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2020	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2021	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2022	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2023	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2024	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70
2025	0.51	2.11	1.50	1.05	0.52	0.96	1.13	0.70

Table B5-2 - Low
Coal Price Forecasts
(2000$ Per MMBtu)

Low Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2002	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2003	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2004	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2005	0.49	2.09	1.48	1.03	0.50	0.94	1.11	0.68
2006	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2007	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2008	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2009	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2010	0.47	2.07	1.46	1.01	0.48	0.92	1.09	0.66
2011	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2012	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2013	0.46	2.06	1.45	1.00	0.47	0.91	1.08	0.65
2014	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2015	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2016	0.45	2.05	1.44	0.98	0.46	0.90	1.07	0.64
2017	0.45	2.05	1.44	0.98	0.46	0.90	1.07	0.64
2018	0.44	2.04	1.43	0.98	0.45	0.89	1.06	0.63
2019	0.44	2.04	1.43	0.97	0.45	0.89	1.06	0.63
2020	0.44	2.04	1.43	0.97	0.45	0.89	1.06	0.63
2021	0.43	2.03	1.42	0.97	0.44	0.88	1.05	0.62
2022	0.43	2.03	1.42	0.96	0.44	0.88	1.05	0.62
2023	0.43	2.03	1.42	0.96	0.44	0.88	1.05	0.62
2024	0.42	2.02	1.41	0.96	0.43	0.87	1.04	0.61
2025	0.42	2.02	1.41	0.95	0.43	0.87	1.04	0.61

Table B5-3 - Medium-Low
Coal Price Forecasts
(2000$ Per MMBtu)

Medium Low Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2002	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2003	0.51	2.11	1.50	1.04	0.52	0.96	1.13	0.70
2004	0.50	2.10	1.49	1.04	0.51	0.95	1.12	0.69
2005	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2006	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2007	0.50	2.10	1.49	1.03	0.51	0.95	1.12	0.69
2008	0.49	2.09	1.48	1.03	0.50	0.94	1.11	0.68
2009	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2010	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2011	0.49	2.09	1.48	1.02	0.50	0.94	1.11	0.68
2012	0.48	2.08	1.47	1.02	0.49	0.93	1.10	0.67
2013	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2014	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2015	0.48	2.08	1.47	1.01	0.49	0.93	1.10	0.67
2016	0.47	2.07	1.46	1.01	0.48	0.92	1.09	0.66
2017	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2018	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2019	0.47	2.07	1.46	1.00	0.48	0.92	1.09	0.66
2020	0.46	2.06	1.45	1.00	0.47	0.91	1.08	0.65
2021	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2022	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2023	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2024	0.46	2.06	1.45	0.99	0.47	0.91	1.08	0.65
2025	0.45	2.05	1.44	0.99	0.46	0.90	1.07	0.64

Table B5-4 - Medium-High
Coal Price Forecasts
(2000$ Per MMBtu)

Medium High Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.52	2.12	1.51	1.05	0.53	0.97	1.14	0.71
2002	0.52	2.12	1.51	1.05	0.53	0.97	1.14	0.71
2003	0.52	2.12	1.51	1.05	0.53	0.97	1.14	0.71
2004	0.52	2.12	1.51	1.06	0.53	0.97	1.14	0.71
2005	0.53	2.13	1.52	1.06	0.54	0.98	1.15	0.72
2006	0.53	2.13	1.52	1.06	0.54	0.98	1.15	0.72
2007	0.53	2.13	1.52	1.06	0.54	0.98	1.15	0.72
2008	0.53	2.13	1.52	1.07	0.54	0.98	1.15	0.72
2009	0.54	2.14	1.53	1.07	0.55	0.99	1.16	0.73
2010	0.54	2.14	1.53	1.07	0.55	0.99	1.16	0.73
2011	0.54	2.14	1.53	1.08	0.55	0.99	1.16	0.73
2012	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2013	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2014	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2015	0.55	2.15	1.54	1.09	0.56	1.00	1.17	0.74
2016	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2017	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2018	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2019	0.56	2.16	1.55	1.10	0.57	1.01	1.18	0.75
2020	0.57	2.17	1.56	1.10	0.58	1.02	1.19	0.76
2021	0.57	2.17	1.56	1.10	0.58	1.02	1.19	0.76
2022	0.57	2.17	1.56	1.11	0.58	1.02	1.19	0.76
2023	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77
2024	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77
2025	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77

Table B5-5 - High
Coal Price Forecasts
(2000$ Per MMBtu)

High Case			Selected State Electricity Generation Coal Prices					
Year	Western Minemouth Price	Regional Industrial Price	Washington	Oregon	Montana	Idaho	Utah	Wyoming
2000	0.51	2.11	1.65	1.09	0.71	0.00	1.39	0.81
2001	0.52	2.12	1.51	1.05	0.53	0.97	1.14	0.71
2002	0.52	2.12	1.51	1.06	0.53	0.97	1.14	0.71
2003	0.53	2.13	1.52	1.06	0.54	0.98	1.15	0.72
2004	0.53	2.13	1.52	1.07	0.54	0.98	1.15	0.72
2005	0.54	2.14	1.53	1.07	0.55	0.99	1.16	0.73
2006	0.54	2.14	1.53	1.07	0.55	0.99	1.16	0.73
2007	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2008	0.55	2.15	1.54	1.08	0.56	1.00	1.17	0.74
2009	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2010	0.56	2.16	1.55	1.09	0.57	1.01	1.18	0.75
2011	0.57	2.17	1.56	1.10	0.58	1.02	1.19	0.76
2012	0.57	2.17	1.56	1.10	0.58	1.02	1.19	0.76
2013	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77
2014	0.58	2.18	1.57	1.11	0.59	1.03	1.20	0.77
2015	0.59	2.19	1.58	1.12	0.60	1.04	1.21	0.78
2016	0.59	2.19	1.58	1.13	0.60	1.04	1.21	0.78
2017	0.60	2.20	1.59	1.13	0.61	1.05	1.22	0.79
2018	0.60	2.20	1.59	1.14	0.61	1.05	1.22	0.79
2019	0.61	2.21	1.60	1.14	0.62	1.06	1.23	0.80
2020	0.61	2.21	1.60	1.15	0.62	1.06	1.23	0.80
2021	0.62	2.22	1.61	1.15	0.63	1.07	1.24	0.81
2022	0.63	2.23	1.62	1.16	0.64	1.08	1.25	0.82
2023	0.63	2.23	1.62	1.16	0.64	1.08	1.25	0.82
2024	0.64	2.24	1.63	1.17	0.65	1.09	1.26	0.83
2025	0.64	2.24	1.63	1.18	0.65	1.09	1.26	0.83

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Wholesale Electricity Price Forecast

This appendix describes the wholesale electricity price forecast of Fifth Northwest Power Plan. This forecast is an estimate of the future price of electricity as traded on the wholesale, short-term (spot) market at the Mid-Columbia trading hub. This price represents the marginal cost of electricity and is used by the Council in assessing the cost-effectiveness of conservation and new generating resource alternatives. The price forecast is also used to estimate the cost implications of policies affecting power system composition or operation. A forecast of the future Western Electricity Coordinating Council (WECC) generating resource mix is also produced, as a precursor to the electricity price forecast. This resource mix is used to forecast the fuel consumption and carbon dioxide (CO_2) production of the future power system.

The next section describes the base case forecast results and summarizes the underlying assumptions. The subsequent section describes the modeling approach. The final section describes underlying assumptions in greater detail and the results of sensitivity tests conducted on certain assumptions. Costs and prices appearing in this appendix are in year 2000 dollars unless otherwise noted.

BASE CASE FORECAST

The base case wholesale electricity price forecast uses the Council's medium electricity sales forecast, medium fuel price forecast, average hydropower conditions, the new resource cost and performance characteristics developed for this plan, and the mean annual values of future CO_2 mitigation cost, renewable energy production tax credits and renewable energy credits of the portfolio analysis of this plan. These are summarized in Table C-1.

Table C-1: Summary of assumptions underlying the base case forecast

Hydropower	Average hydropower conditions Linear reduction of available Northwest hydropower by 450 MW 2005 through 2024
Fuel prices	5th Plan forecast, Medium case
Loads	5th Plan electricity sales forecast, Medium case, adjusted for 150 aMW/yr conservation, 200 aMW Direct Service Industry load and transmission and distribution losses
Northwest resources	Resources in service as of Q4 2004 Resources under construction as of Q4 2004 Retirements scheduled as of Q4 2004 75 percent of Oregon and Montana system benefit charge target acquisitions 50 percent of demand response potential by 2025
Other WECC resources	Resources in service as of Q1 2003 Resources under construction as of Q1 2003 Retirements scheduled as of Q1 2003 75 percent of state renewable portfolio standard and & system benefit charge target acquisitions 50 percent of demand response potential by 2025.

New resource options	610 MW natural gas-fired combined-cycle gas turbines 100 MW wind power plants - prime resource areas 100 MW wind power plants - secondary resource areas 400 MW coal-fired steam-electric plants 425 MW coal gasification combined-cycle plants 2x47 MW natural gas-fired simple-cycle gas turbines 100 MW central-station solar photovoltaic plants Montana First Megawatts 240 MW natural gas-fired combined-cycle plant Mint Farm 286 MW natural gas-fired combined-cycle plant Grays Harbor 640 MW natural gas-fired combined-cycle plant
Inter-regional transmission	2003 WECC path ratings Scheduled upgrades as of Q1 2003
Carbon dioxide penalty	Washington & Oregon: $0.87/ton CO_2 for 17% of production until exceeded by the mean annual values of the portfolio analysis. Other load-resource zones: The mean annual values of the portfolio analysis
Renewable resource incentives	Federal production tax credit at mean annual values of the portfolio analysis Green tag revenue at mean annual values of the portfolio analysis

The forecast Mid-Columbia trading hub price, levelized for the period 2005 through 2025 is $36.20 per megawatt-hour. In Figure C-1, the current forecast is compared to the base case ("Current Trends") forecast of the Draft 5th Power Plan (levelized value of $36.10 per megawatt-hour).

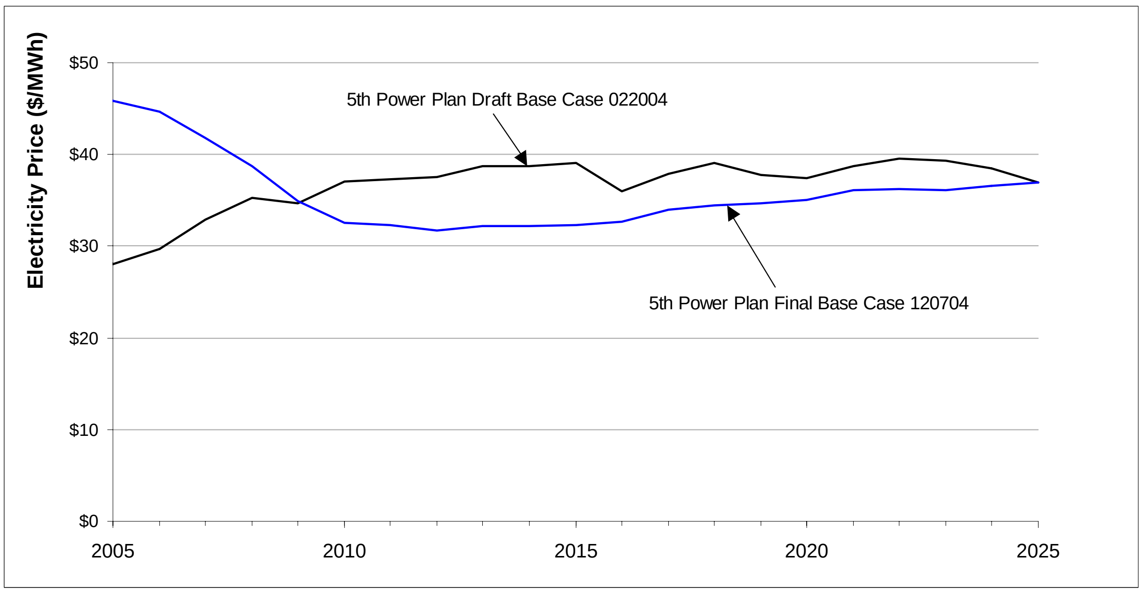

Figure C-1: Draft and final base case forecasts of average annual wholesale electricity prices at the Mid-Columbia trading hub

The final forecast prices decline from 2003 highs as gas prices decline, leveling off about 2012 as growing loads exhaust the current generating capacity and new capacity development ensues. Prices slowly increase through the remainder of the planning period under the influence of slowly increasing natural gas prices, new resource additions, declining renewable energy incentives and increasing CO_2 penalties. Not included in the forecast are likely episodic price excursions resulting from gas price volatility or poor hydro conditions.

The annual average prices of Figure C-1 conceal important seasonal price variation. Seasonal variation is shown in the plot of monthly average Mid-Columbia prices in Figure C-2. Also plotted in Figure C-2 are monthly average Northwest loads and monthly average Southern California loads. The winter-peaking character of Northwest loads (driven by lighting and heating loads) and the more pronounced summer-peaking character of the Southern California loads (driven by air conditioning and irrigation loads) are evident. A strong winter Mid-Columbia price peak, driven by winter peaking Northwest loads is present throughout the forecast. A secondary summer price peak is also present because spot market prices in the Northwest will follow Southwest prices as long as capacity to transmit electricity south is available on the interties. The summer Mid-Columbia price peak begins to increase in magnitude midway through the planning period as California loads grow relative to Northwest loads. The summer price peak increases the value of summer-peaking efficiency resources such as irrigation efficiency improvements.

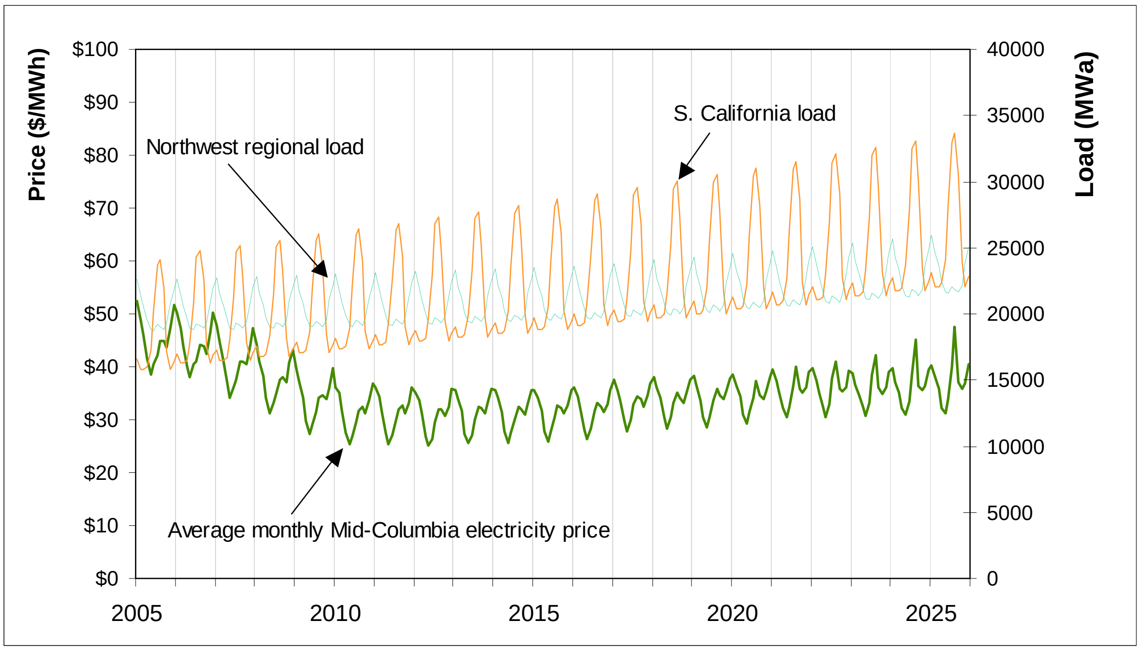

Figure C-2: Monthly wholesale Mid-Columbia prices compared to Northwest and Southwest load shapes

Daily variation in prices is significant as well, with implications for the cost-effectiveness of certain conservation measures. Typical daily price variation is shown in Figure C-3 - a snapshot of the hourly Mid Columbia forecast for a summer week.

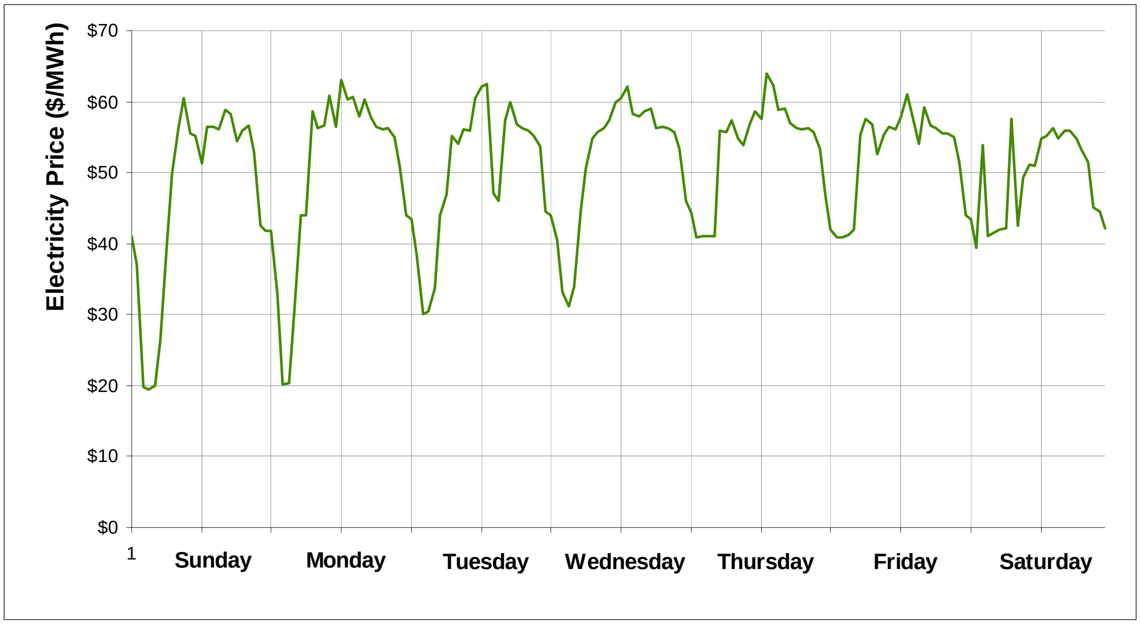

Figure C-3: Illustrative hourly prices (July 31- August 7, 2005)

The forecast annual average prices for the Mid-Columbia trading hub and for other Northwest load-resource zones is provided in Table C-1. Monthly and hourly price series are available from the Council on request.

Table C-1: Forecast annual average wholesale electricity prices for Northwest load-resource zones

Year	West of Cascades	Mid-Columbia (Eastside)	S. Idaho	E. Montana
2005	45.99	45.84	45.16	44.86
2006	44.84	44.68	45.16	44.86
2007	41.99	41.76	45.16	44.86
2008	38.93	38.71	45.16	44.86
2009	35.11	34.94	45.16	44.86
2010	32.65	32.52	45.16	44.86
2011	32.42	32.31	45.16	44.86
2012	31.85	31.75	45.16	44.86
2013	32.27	32.17	45.16	44.86
2014	32.25	32.15	45.16	44.86
2015	32.37	32.28	45.16	44.86
2016	32.76	32.66	45.16	44.86
2017	34.07	33.99	45.16	44.86
2018	34.54	34.46	45.16	44.86
2019	34.74	34.67	45.16	44.86
2020	35.12	35.05	45.16	44.86
2021	36.16	36.08	45.16	44.86
2022	36.25	36.18	45.16	44.86
2023	36.10	36.05	45.16	44.86
2024	36.58	36.52	45.16	44.86
2025	37.06	36.99	45.16	44.86

The base case forecast resource mix for the interconnected Western Electricity Coordinating Council (WECC) area is shown in Figure C-4. Factors affecting resource development through the 2005-2025 period include load growth, natural gas prices, generating resource technology improvement, continued renewable resource incentives and increasing probability of carbon dioxide production penalties. Principal additions between 2005 and 2025 include approximately 4600 megawatts of renewable resources resulting from state renewable portfolio standards and system benefit charges, 17,000 megawatts of combined-cycle plant, 20,000 megawatts of steam coal capacity, 22,000 megawatts of wind capacity and 9000 megawatts of coal gasification combined-cycle plant. Retirements include 1650 MW of steam coal, 1400 MW of gas combined-cycle and 1400 MW of gas steam units. The 2025 capacity mix includes 33 percent natural gas, 25 percent hydropower, 24 percent coal and 11 percent intermittent renewables (wind and solar). Not shown in the figure is about 9,000 megawatts of demand response capability assumed to be secured between 2007 and 2025.

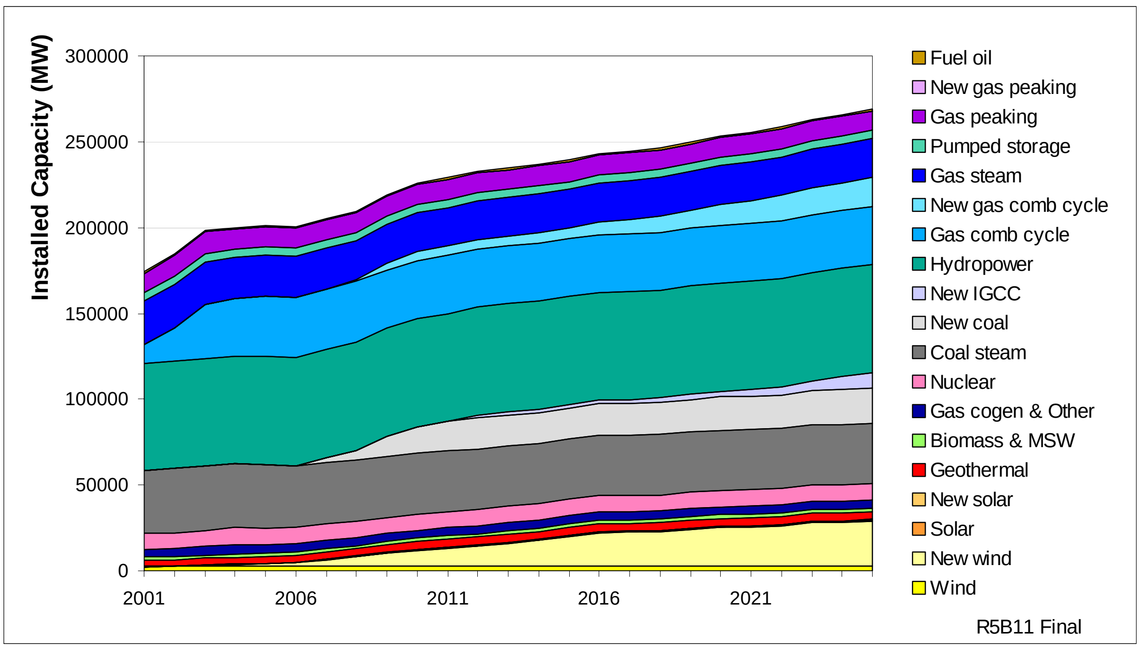

Figure C-4: Base case WECC resource mix

The Northwest resource mix is shown in Figure C-5. About 960 megawatts of renewables funded by state system benefit charges (modeled as wind) and 2900 additional megawatts of new, market-driven wind power are added during the period 2005-25 in addition to the 399 MW Port Westward combined-cycle plant, currently under construction. No capacity is retired. The regional capacity mix in 2025 includes 67 percent hydropower, 13 percent natural gas, 9 percent wind and 8 percent coal. Not shown in the figure is about 1,900 megawatts of demand response capability assumed to be secured between 2007 and 2025. Because the capacity addition logic used for this forecast uses deterministic fuel prices, loads, renewable production credits, CO_2 penalties and other values affecting resource cost-effectiveness, the resulting resource additions differ somewhat from the recommendations resulting from the more sophisticated risk analysis described in Chapter 7 of the plan.

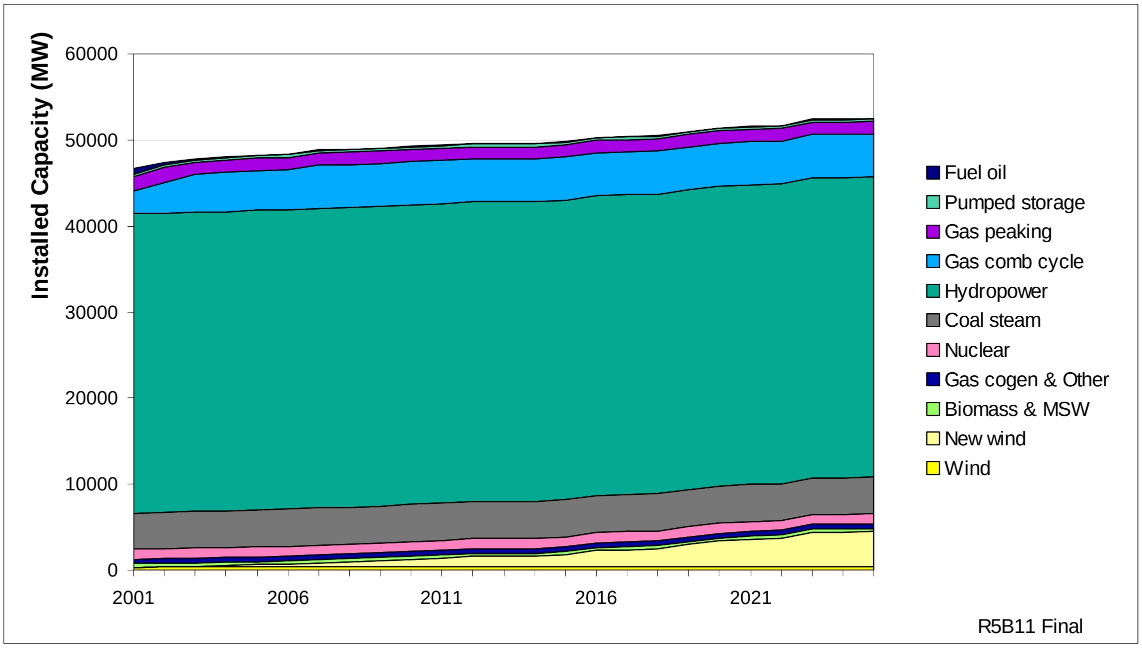

Figure C-5: Base case Pacific Northwest resource mix

Other base case results are summarized in Table C-3. Further detail can be found in the workbook PLOT R5B11 Final Base 012705.xls, posted in the Council's website dropbox.

APPROACH

The Council forecasts wholesale electricity prices using the AURORA$^{xmp®}$ electricity market model. Electricity prices are based on 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. A forecast is developed using the two-step process illustrated in Figure C-6. First, a forecast of capacity additions and retirements beyond those currently scheduled is developed using the AURORA$^{xmp®}$ long-term resource optimization logic. This is an iterative process, in which the net present value of possible resource additions and retirements are calculated for each year of the forecast period. Existing resources are retired if market prices are insufficient to meet the future fuel, operation and maintenance costs of the project. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, operation, maintenance and fuel including a return on the developer's investment and a dispatch premium. This step results in a future resource mix such as depicted for the base case in Figure C-4.

The electricity price forecast is developed in the second step, in which the mix of resources developed in the first step is 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.

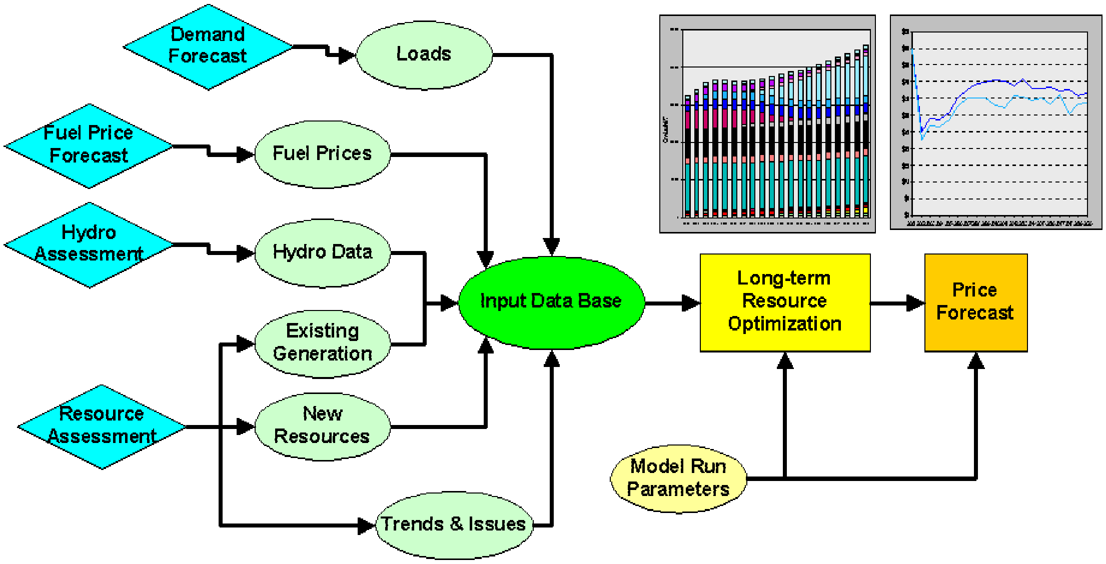

Figure C-6: Price forecasting process

As configured by the Council, AURORA$^{xmp®}$ simulates power plant dispatch in each of 16 load-resource zones comprising the WECC electric reliability area (Figure C-7). These zones are defined by transmission constraints and are each characterized by a forecast load, existing generating units, scheduled project additions and retirements, fuel price forecasts, load curtailment alternatives and a portfolio of new resource options. Transmission interconnections between the zones are characterized by transfer capacity, losses and wheeling costs. The demand within a load-resource zone may be served by native generation, curtailment, or by imports from other load-resource zones if economic, and if transmission transfer capability is available.

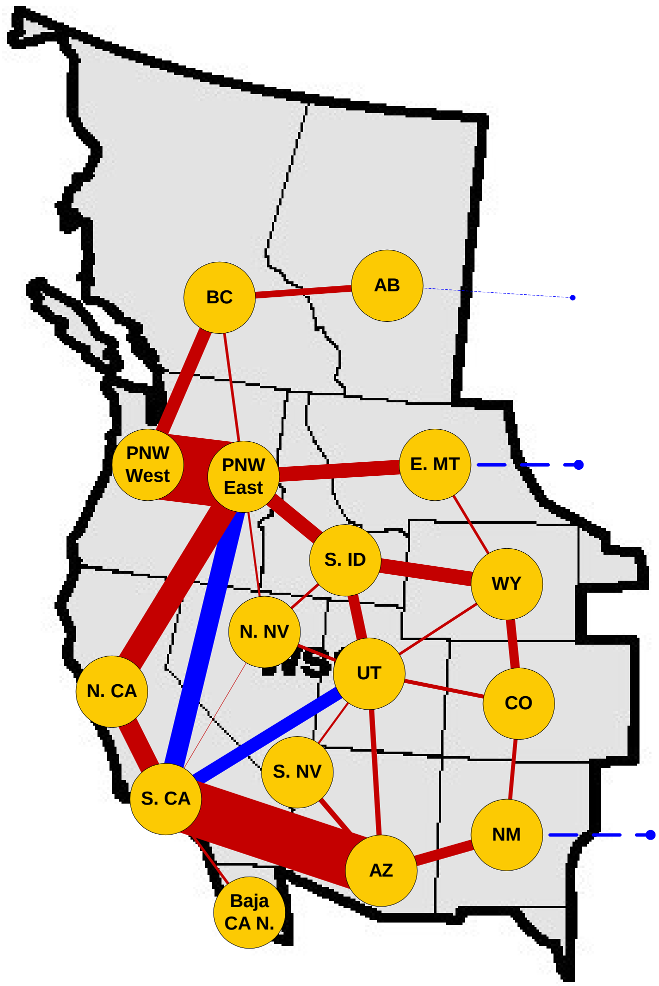

Figure C-7: Load-resource zones

DATA, ASSUMPTIONS AND SENSITIVITY ANALYSES

The data and assumptions underlying the electricity price forecast are developed by the Council with the assistance of its advisory committees (Appendix C-1). The base forecast is an expected value forecast using the medium case electricity sales forecast, the medium case forecast of fuel prices and average water conditions. Though possible future episodes of fuel price and hydropower volatility are not specifically modeled, water conditions and fuel prices are adjusted to compensate for the biasing effect of volatility on electricity prices. The base case forecast uses the mean annual values of federal renewable production tax credits, renewable energy credit revenues and possible future carbon dioxide penalties from the portfolio risk analysis.

Electricity Loads

The Council's medium case electricity sales forecast is the basis for the base case electricity price forecast for Northwest load-resource zones. Transmission and distribution losses are added and the effects of price-induced and programmatic conservation deducted to produce a load forecast. In the medium-case forecast, Northwest loads, including eastern Montana are forecast to grow at an average annual rate of approximately 0.7 percent per year from 20,875 average megawatts in 2005 to 23,850 average megawatts in 2025. Direct Service Industry loads average 200 megawatts in the medium case.

Total WECC load is forecast to grow at an annual average rate of 1.7 percent, from about 94,800 average megawatts in 2005 to 132,100 average megawatts in 2025. Most load-resource zones outside the Northwest are forecast to see more rapid load growth than Northwest areas (Table C-2). The approach used to forecast loads for load-resource zones outside the Northwest was to calculate future growth in electricity demand as the historical growth rate of electricity use per capita times a forecast of population growth rate for the area. Exceptions to this method were California, where forecasts by the California Energy Commission were used, and the Canadian provinces, where load forecasts are available from the National Energy Board.

Table C-2: Base loads and medium case forecast load growth rates[a]

Load-resource zone	2005 (Average Megawatts)	2025 (Average Megawatts)	Average Annual Load Growth, 2005-2025
PNW Eastside (WA & OR E. of Cascade crest, Northern ID & MT west of Continental Divide.	4695	5341	0.6 percent
PNW Westside (WA & OR W. of Cascade crest)	12832	14661	0.7 percent
Southern Idaho (~IPC territory)	2518	3022	0.9 percent
Montana E. (east of Continental Divide)	830	829	0.0 percent
Alberta	6023	8489	1.6 percent
Arizona	8513	13867	1.4 percent
Baja California Norte	1117	1883	2.6 percent
British Columbia	7798	10199	1.4 percent
California N. (N. of Path 15)	13842	18794	1.5 percent
California S. (S. of Path 15)	18431	25686	1.7 percent
Colorado	6011	9498	2.3 percent
Nevada N. (~ SPP territory)	1294	1941	2.0 percent
Nevada S. (~ NPC territory)	2586	4466	2.8 percent
New Mexico	3099	5670	3.1 percent
Utah	3256	5702	2.7 percent
Wyoming	1814	2046	0.6 percent
Total	**94847**	**132094**	**1.7 percent**

a) Load is forecast sales plus 8 percent transmission and distribution loss.

Sensitivity studies were run using the Council's medium-low and medium-high case electricity sales forecast to assess the implications of long-term load growth uncertainty on electricity prices and resource development. Growth rates for load-resource zones outside the Northwest were estimated by adjusting the medium-case long-term growth rates for each area by the percentile growth rate differences between the Northwest medium case (0.7%/yr) and medium-low case (0.1%/yr) and medium-high case (1.3%/yr), respectively.

As expected, the faster load growth of the medium-high load growth case result in higher electricity prices throughout the forecast period (Figure C-8). Beginning about 2017, the medium-high case prices climb rapidly away from the base case prices. This appears to result from accelerated development of natural gas combined-cycle plants at this time. It is likely that gas is selected over coal because of increasing CO_2 mitigation cost. Levelized Mid-Columbia prices are $37.70 per megawatt-hour, 4 percent higher than the base case.

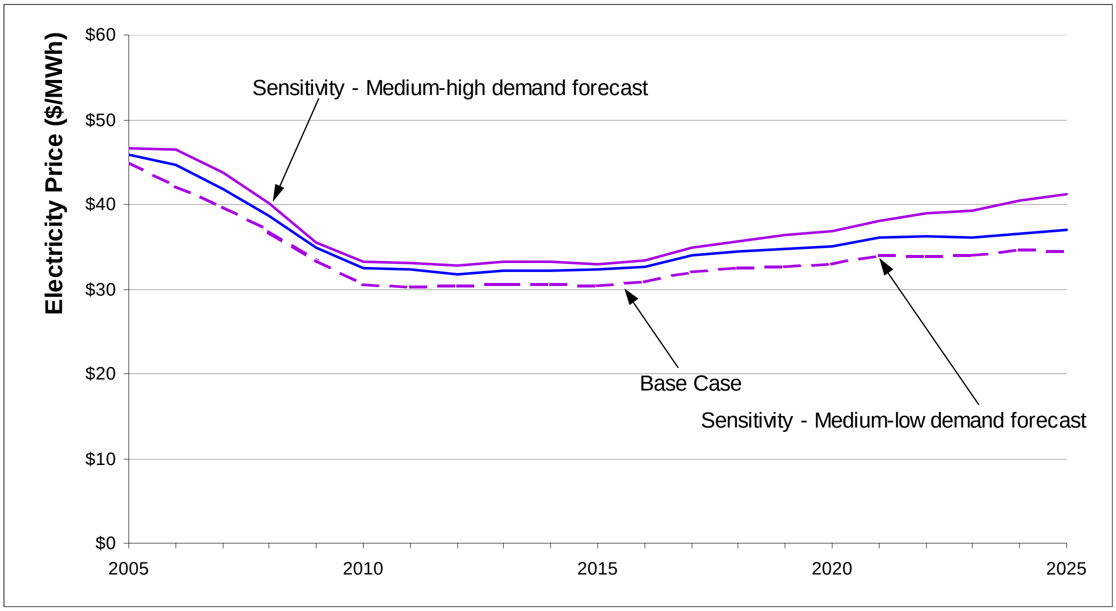

Figure C-8: Sensitivity of Mid-Columbia electricity price to load growth uncertainty

The medium-low case results in consistently lower Mid-Columbia prices (Figure C-8). Levelized Mid-Columbia prices are $34.30 per megawatt-hour, 5 percent lower than the base case.

Other results of the load sensitivity cases are summarized in Table C-3. Further detail can be found in the workbooks PLOT R5B11 Final MLDmd 033005.xls, PLOT R5B11 Final MHDmd 041005.xls, posted in the Council's website dropbox.

Fuel Prices

The Council's medium case fuel price forecast is used for the base case electricity price forecast. Coal prices are based on forecast Western mine-mouth coal prices, and natural gas prices are based on a forecast of U.S. natural gas wellhead prices. Basis differentials are added to the base prices to arrive at delivered fuel prices for each load-resource zone. Natural gas prices are further adjusted for seasonal variation. For example, the price of natural gas delivered to a power plant located in western Washington or Oregon is based on the annual average U.S. wellhead price forecast, adjusted by price differentials between wellhead and Henry Hub (Louisiana); Henry Hub and AECO hub (Alberta); AECO and (compressor) Station 2, British Columbia; and finally, Station 2 and western Washington and Oregon. A monthly adjustment is applied to the AECO - Station 2 differential. The fuel price forecasts and derivation of load-resource area prices are more fully described Appendix B.

In the medium case, the price of Western mine-mouth coal is forecast to hold at $0.51 per million Btu from 2005 through 2025 (constant 2000$). Average distillate fuel oil prices are forecast to stabilize at $6.58 by 2010, following a decline from $7.15 per million Btu in 2005. Price-driven North American exploration and development, increasing liquefied natural gas imports and demand destruction are expected to slowly force down average annual U.S. wellhead natural gas prices from $5.30 per million Btu in 2005 to a low of $3.80/MMBtu in 2015. The annual average price is then forecast to then rise slowly to $4.00 per million Btu in 2025 (2000$), capped by the expected cost of landed liquefied natural gas.

Forecast medium-case delivered prices for selected fuels are plotted in Figure C-9. Fuel prices are shown in Figure C-9 as fully variable (dollars per million Btu) to facilitate comparison. However, the price of delivered coal and natural gas is modeled as a fixed (dollars per kilowatt per year) and a variable (dollars per million Btu) component to differentiate costs, such as pipeline reservation costs that are fixed in the short-term.

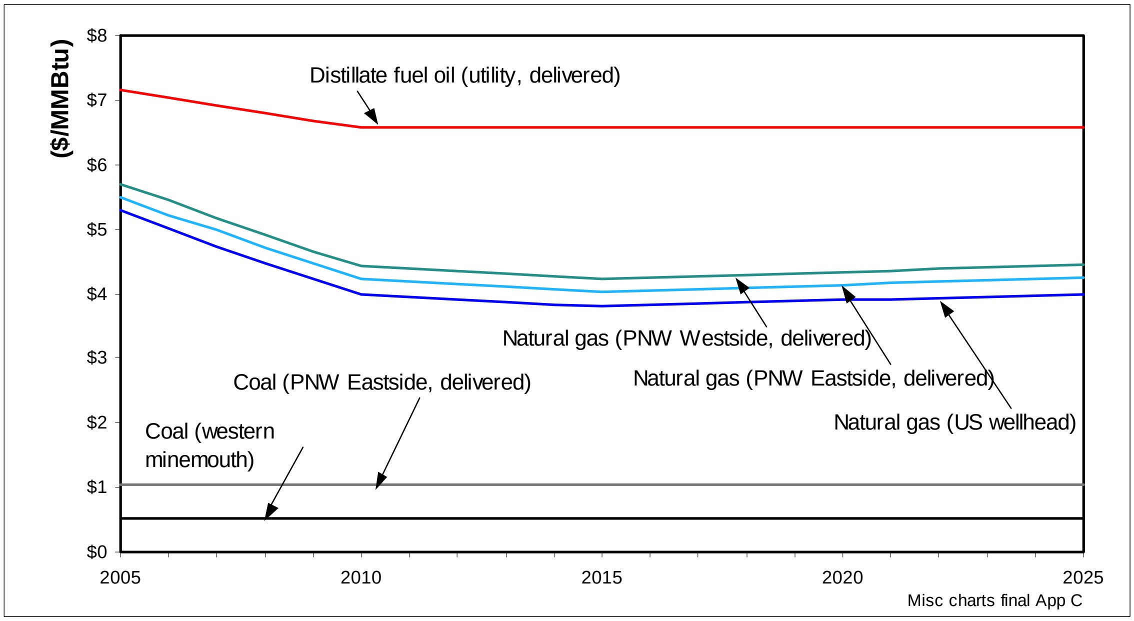

Figure C-9: Forecast prices for selected fuels - Medium Case

Sensitivity analyses were run using the Council's high case and low case fuel price forecasts to examine the effects of higher or lower fuel prices on the future resource mix and electricity prices. The high case and the low case fuel price forecasts for wellhead gas and minemouth coal are compared to the medium case forecasts in Figure C-10.

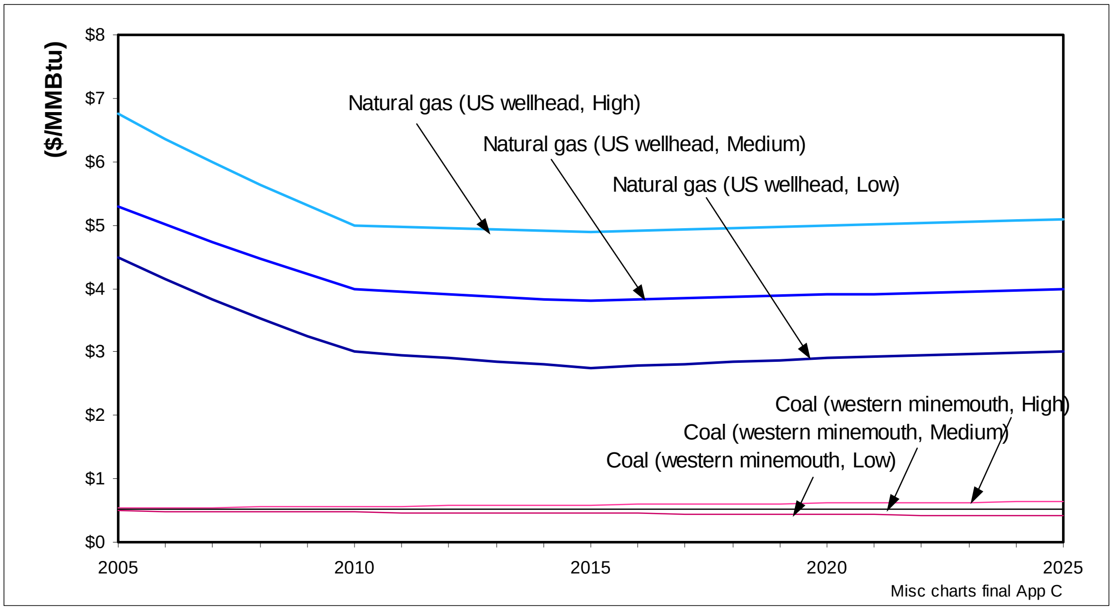

Figure C-10: Natural gas and coal price forecast cases

The low fuel price forecast results in levelized Mid-Columbia electricity prices of $29.80 per megawatt-hour, 18 percent lower than the base case. The lower price is evident throughout the forecast period, possibly as a manifestation of continued reliance on gas-fired combined-cycle power plants (Figure C-11). The 2025 resource mix (Table C-3) shows a shift away from new coal and wind to new gas-fired units. Also evident in Table C-3 is the substantial reduction in CO_2 production associated with the greater penetration of natural gas. If this were intended to be a scenario rather than a sensitivity case, the higher loads resulting from lower prices would offset a portion of the potential CO_2 reduction.

The high fuel price forecast results in levelized Mid-Columbia electricity prices of $39.60 per megawatt-hour, 9 percent higher than the base case. Prices are substantially higher in the near-term, but moderate toward base case values by 2015 as new coal-fired power plants supplement existing gas-fired capacity (Figure C-11). The 2025 resource mix (Table C-3) shows a strong shift to new conventional coal and IGCC plants and wind in lieu of new gas-fired capacity. Towards the end of the forecast period, increasing CO_2 mitigation costs result in electricity prices again rising above base case values.

Other results of the fuel price sensitivity cases are summarized in Table C-3. Further detail can be found in the workbooks PLOT R5B11 Final LoFuel 031705.xls, PLOT R5B11 Final HiFuel 031605.xls, posted in the Council's website dropbox.

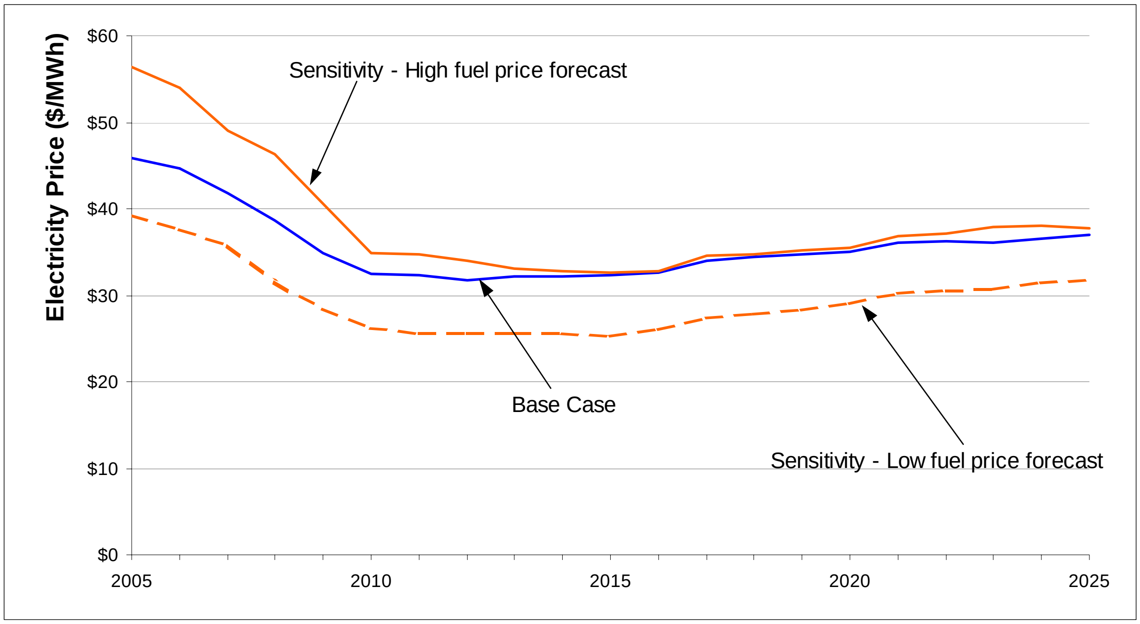

Figure C-11: Sensitivity of Mid-Columbia electricity price to fuel price uncertainty

Demand Response

Demand response is a change in the level or quality of service that is voluntarily accepted by the consumer, usually in exchange for payment. Demand response can shift load from peak to off-peak periods and reduce the cost of generation by shifting the marginal dispatch to more efficient or otherwise less-costly units. Demand response may also be used to reduce the absolute amount of energy consumed to the extent that end-users are willing to forego net electricity consumption in return for compensation. The attractiveness of demand response is not only its ability to reduce the overall cost of supplying electricity; it also rewards end users for reducing consumption during times of high prices and possible supply shortage. Demand response also offers many of the environmental benefits of conservation.

Though the understanding of demand response potential remains sketchy, preliminary analysis by the Council suggests that ultimately up to 16 percent of load might be offset at a cost of $50 to $400 per megawatt-hour through various forms of time-of-day pricing and negotiated agreements. For the base case forecast, we assume that 50 percent of this potential is secured, beginning in 2007 and ramping up to 2025. Similar penetration is assumed throughout WECC.

Existing Generating Resources

The existing power supply system modeled for the electricity price forecast consisted of the projects within the WECC interconnected system in service and under construction as of the first quarter of 2003. Three Northwest gas combined-cycle power plants for which construction was suspended, Grays Harbor, Mint Farm and Montana First Megawatts were included as new generating resource options. Projects having announced retirement dates were retired as scheduled.

New Generating Resource Options

When running a capacity expansion study, AURORA$^{xmp®}$ adds capacity when the net present value cost of adding a new unit is less than the net present market value of the unit. Because of study run time considerations, the number of available new resource alternatives is limited to those possibly having a significant effect on future electricity prices. Some resource alternatives such as gas combined-cycle plants and wind are currently significant and likely to remain so. Others, such as new hydropower or various biomass resources, are unlikely to be available in sufficient quantity to significantly influence future electricity prices. Some, such as coal gasification combined-cycle plants or solar photovoltaics do not currently affect power prices, but may so as the technology develops and costs decline. Resources such as new generation nuclear plants or wave energy plants were omitted because they are unlikely to be commercially mature during the forecast period. Others, such as gas-fired reciprocating generator sets were omitted because they are not markedly different from simple-cycle gas turbines with respect to their effect on future electricity prices. With these considerations in mind, the new resources modeled for this forecast included natural gas combined-cycle power plants, wind power, coal-fired steam-electric power plants, coal gasification combined-cycle plants, natural gas simple-cycle gas turbine generating sets and central-station solar photovoltaic plants.

Natural gas-fired combined cycle power plants

The high thermal efficiency, low environmental impact, short construction time and excellent operating flexibility of natural gas-fired combined-cycle plants lead to this technology becoming the "resource of choice" in the 1990s. In recent years, high natural gas prices have dimmed the attractiveness of combined-cycle plants and many projects currently operate at low load factors. Though technology improvements are anticipated to help offset high natural gas prices, the future role of this resource is sensitive to natural gas prices and global climate change policy. Higher gas prices could shift development to coal or windpower. More stringent carbon dioxide offset requirements might favor combined-cycle plants because of their proportionately lower carbon dioxide production. The representative natural gas combined-cycle power plant used for this forecast is a 2x1 (two gas turbines and one steam turbine) plant of 540 megawatts of baseload capacity plus 70 megawatts of power augmentation (duct-firing) capacity.

Wind power plants

Improved reliability, cost reduction, financial incentives and emerging interest in the hedge value of wind with respect to gas prices and greenhouse gas control policy have moved wind power from niche to mainstream over the past decade. The cost of wind power (sans financial incentives) is currently higher that that from gas combined-cycle or coal plants, but is expected to decline to competitive levels within several years. The future role of wind is dependent upon gas price, greenhouse gas policy, continued technological improvement, the cost and availability of transmission and shaping services and the availability of financial incentives. Higher gas prices increase the attractiveness of wind, particularly if there is expectation that coal may be subject to future CO_2 penalties. At current costs, it is infeasible to extend transmission more than several miles to integrate a wind project with the grid. This limits the availability of wind to prime resource areas close to the grid. As wind plant costs decline, feasible interconnection distances will extend, expanding wind power potential. Two cost blocks of wind in 100 MW plant increments were defined for this study - a lower cost block representing good wind resources and low shaping costs, and a higher cost block representing the next phase of wind development with somewhat less favorable wind (lower capacity factor) and higher shaping costs.

Coal-fired steam-electric power plants

No coal-fired power plants have entered service in the Northwest since the mid-1980s. However, relatively low fuel prices, improvements in technology and concerns regarding future natural gas prices have repositioned coal as a potentially economically attractive new generating resource. Conventional steam-electric technology would likely be the coal technology of choice in the near-term. Supercritical steam technology is expected to gradually penetrate the market and additional control of mercury emissions is likely to be required. The representative new coal-fired power plant defined for this forecast is a 400-megawatt steam-electric unit. Costs and performance characteristics simulate a gradual transition to supercritical steam technology over the planning period.

Coal-gasification combined-cycle power plants

Increasing concerns regarding mercury emissions and carbon dioxide production are prompting interest in advanced coal generation technologies promising improved control of these emissions at lower cost. Under development for many years, pressurized fluidized bed combustion and coal gasification apply efficient combined-cycle technology to coal-fired generation. This improves fuel use efficiency, improves operating flexibility and lowers carbon dioxide production. Coal gasification technology offers the additional benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration and optional co-production of hydrogen, liquid fuels or other petrochemicals. The low air emissions of coal gasification plants might open siting opportunities nearer load centers. A 425-megawatt coal-gasification combined-cycle power plant without CO2 separation and sequestration was modeled for the price forecast.

Natural gas-fired simple-cycle gas turbine generators

Gas turbine generators (simple-cycle gas turbines), reciprocating engine-generator sets, supplementary (duct) firing of combined-cycle plants are potentially cost-effective means of supplying peaking and reserve power needs. As described earlier, the Council also views demand response as a promising approach to meeting peaking and reserve power needs. Supplementary ("duct") firing of gas combined-cycle plants can also help meet peaking or reserve needs at low cost and is included in the generic combined-cycle plant described above. Additional requirements can be met by simple-cycle gas turbine or reciprocating generator sets. From a modeling perspective, the cost and performance of gas-fired simple-cycle gas turbines and gas-fired reciprocating engine-generator sets are sufficiently similar that only one need be modeled. The Council chose to model a twin-unit (2 x 47 megawatt) aeroderivative simple-cycle gas turbine generator set.

Central-station solar photovoltaics

Solar power is one of the most potentially attractive and abundant long-term power supply alternatives. Economical small-scale applications of solar photovoltaics are currently found throughout the region where it is costly to secure grid service, however for bulk, grid-connected supply, solar photovoltaics are currently much more expensive than other bulk supply alternatives. Because of the potential for significant cost reduction, the Council included a 100 MW central-station solar photovoltaic plant as a long-term bulk power generating resource alternative.

The cost and performance characteristics of these generating resource alternatives are further described in Chapter 5 and Appendix I.

Transmission

Transfer ratings between load-resource zones are based on the 2003 WECC path ratings plus scheduled upgrades to Path 15 between northern and southern California (since completed) and scheduled upgrades between the Baja California and southern California.

Renewable Energy Production Incentive

Federal, state and local governments for many years have provided incentives to promote various forms of energy production, including research and development grants and favorable tax treatment. A federal incentive that significantly affects the economics of renewable resource development is the renewable energy production tax credit (PTC) and the companion renewable energy production incentive (REPI) for tax-exempt entities. Enacted as part of the 1992 Energy Policy Act, and originally intended to help commercialize wind and certain biomass technologies, these incentives have been repeatedly renewed and extended, and currently amount to approximately $13 per megawatt hour (2004 dollars) when levelized over the life of a project. The incentive expired in at the end of 2003 but, in September 2004, was extended to the end of 2005, retroactive to the beginning of 2004. In addition, the scope of qualifying facilities was extended to forms of biomass, geothermal, solar and certain other renewable resources not previously qualifying. The long-term fate of these incentives is uncertain. The original legislation contains a provision for phasing out the credit as above-market resource costs are reduced. In addition, federal budget constraints may eventually force reduction or termination of the incentives. However, the incentives remain politically popular, as they encourage development that produces rural property tax revenues and revenue for local landowners on whose land wind turbines are sited. Moreover, the incentives serve as a crude carbon dioxide control mechanism in the absence of more comprehensive federal climate change policy.

Because of these uncertainties, future federal renewable energy production incentive was modeled as a stochastic variable in the portfolio risk analysis, as described in Chapter 6. The mean annual value from the portfolio risk analysis was used for the base case electricity price forecast and for all sensitivity cases (Figure C-12). Because of practical considerations, state and local financial incentives, such as sales and property tax exemptions, were not modeled.

Renewable Energy Credits

Power from renewable energy projects commands a market premium, manifested in the form of renewable energy credits (RECs, or "green tags"). The REC market is driven by the demand for green power products, the nascent demand for CO_2 offsets and by the demand for resources to meet state renewable portfolio standard obligations. The current market value of green tags for recently-developed windpower is reported to be $3 to $4 per megawatt-hour. Solar power commends higher tag prices and tag values for hydro, biomass and geothermal power are generally lower. Power from new projects commands higher tag values than that from existing projects. Future REC revenues were modeled as a stochastic variable in the portfolio risk analysis as described in Chapter 6. The mean annual REC value from the portfolio risk analysis (Figure C-12) was used for both wind and solar power in the base and sensitivity cases.

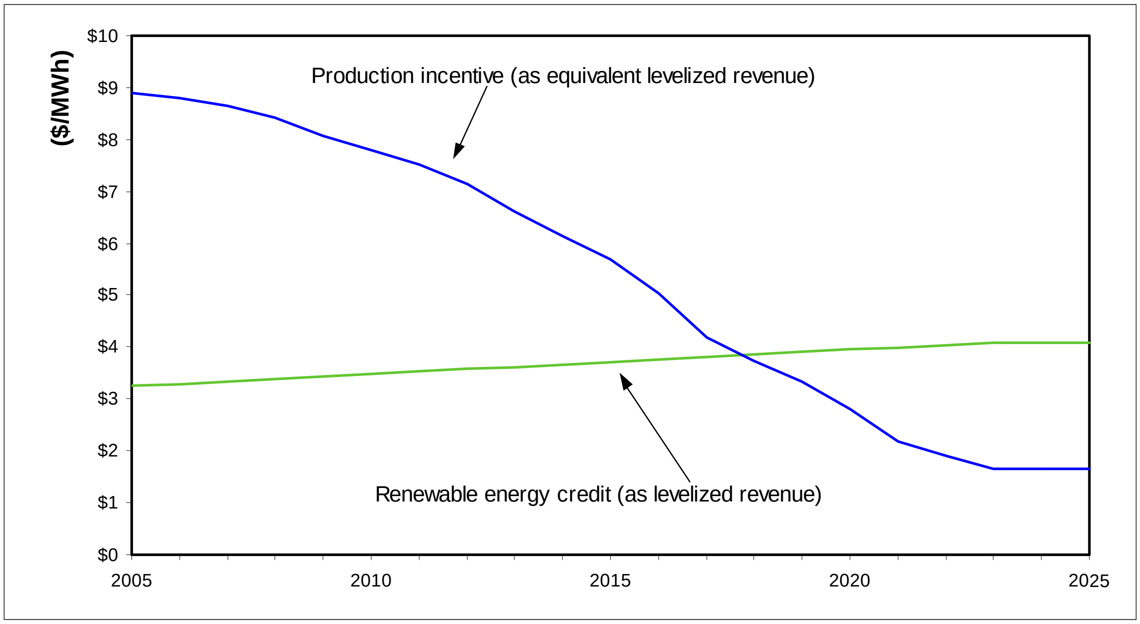

Figure C-12: Renewable energy incentives

Global Climate Change Policy

In the absence of federal initiatives, individual states are moving to establish controls on the production of carbon dioxide and other greenhouse gasses. Since 1997, Oregon has required mitigation of 17 percent of the carbon dioxide production of new power plants. Washington, in 2004 adopted CO_2 mitigation requirements for new fossil power plants exceeding 25 megawatts capacity. In Montana, the developer of the natural gas-fired Basin Creek Power Plant has agreed to mitigate CO_2 production to the Oregon requirements. California has joined with Washington and Oregon to develop joint policy initiatives leading to a reduction of greenhouse gas production.

Though it appears likely that CO_2 production from power generation facilities will be subject to increasing regulation over the period of this plan, the nature and timing of future controls is highly uncertain. For this reason, CO_2 mitigation costs were modeled in the portfolio risk analysis as a stochastic carbon tax. The probabilities and distributions used to derive the carbon tax for the portfolio analysis are described in Chapter 6. In the base case electricity price forecast, the mean annual value of the carbon tax from the portfolio risk analysis is applied to both existing and new generating resources. Unlike the portfolio analysis, the current Oregon mitigation requirements are applied to new resources developed in Washington or Oregon until this value is exceeded by the mean annual values from the portfolio analysis (Figure C-13).

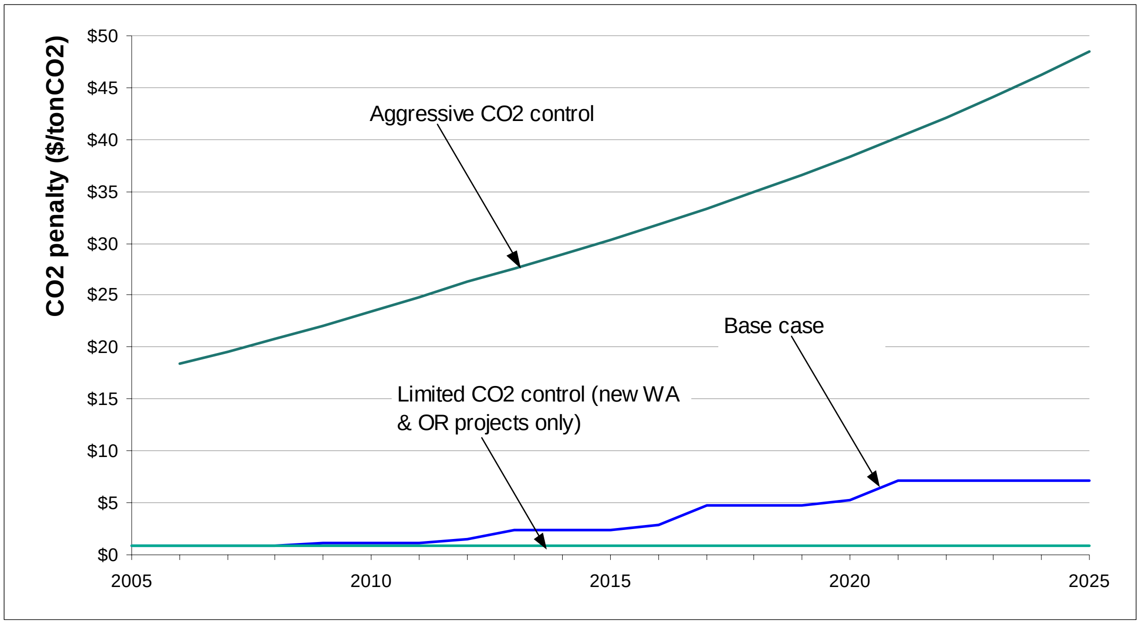

Figure C-13: CO_2 mitigation cost (as carbon tax)

Because of uncertainties regarding future CO_2 regulation, two sensitivity analyses were run. A limited CO_2 control case assumed that CO_2 mitigation continues to be required only in Oregon and Washington at a cost of $0.87 per ton CO_2 (approximately the current Oregon fixed payment option). Compared to the base case, this shifts future resource development from wind and natural gas combined-cycle plants to conventional and gasified coal (Table C-3). Additional older gas steam capacity is retired. The levelized Mid-Columbia price declines by 6 percent to $33.90 per megawatt-hour (Figure C-14). The most significant price reduction is experienced in the longer-term as the resource mix shifts from more expensive natural gas capacity to less expensive coal (Figure C-14). The additional new fossil capacity leads to a larger 2025 WECC system average CO_2 production factor of 0.576 lbCO_2/kWh, 14 percent greater than that of the base case value of 0.507 lb CO_2/kWh (Figure C-15). Cumulative WECC CO_2 production for the period 2005-25 increases by 7 percent.

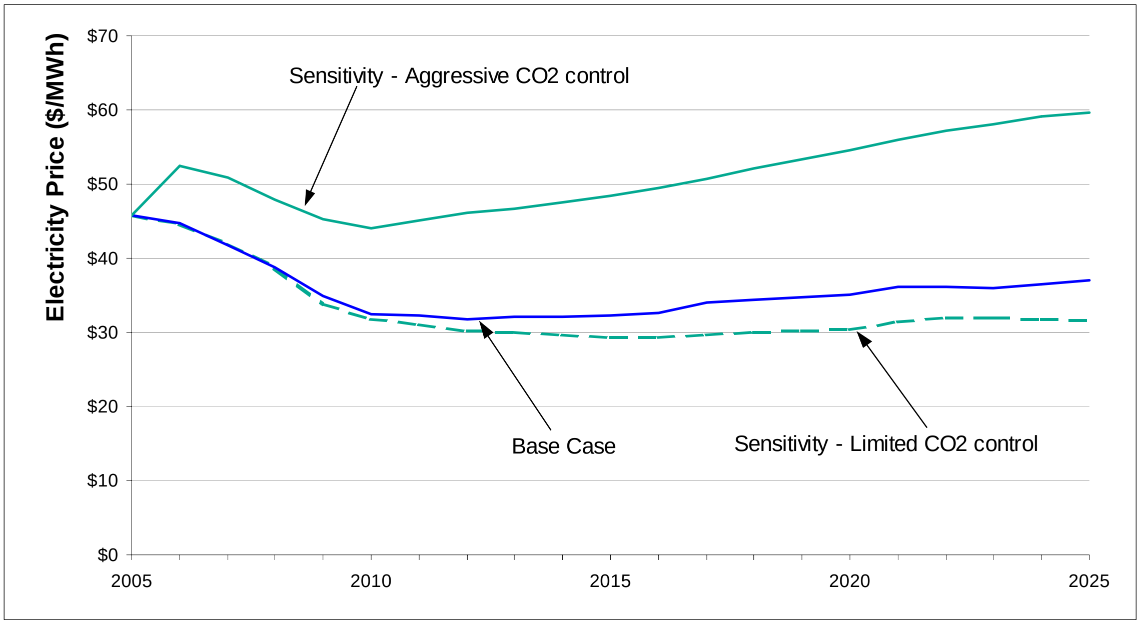

Figure C-14: Sensitivity of electricity price forecast to CO_2 mitigation cost

An aggressive CO_2 control effort was modeled by approximating the nationwide cap and trade program proposed in the McCain-Lieberman Climate Stewardship Act. McCain-Lieberman would implement capped and tradable emissions allowances for CO_2 and other greenhouse gasses. Reduction requirements would apply to large commercial, industrial and electric power sources. The proposal rejected by the Senate in a 43-55 vote in 2003 would have capped allowances at 2000 levels by 2010 and 1990 levels in 2016.

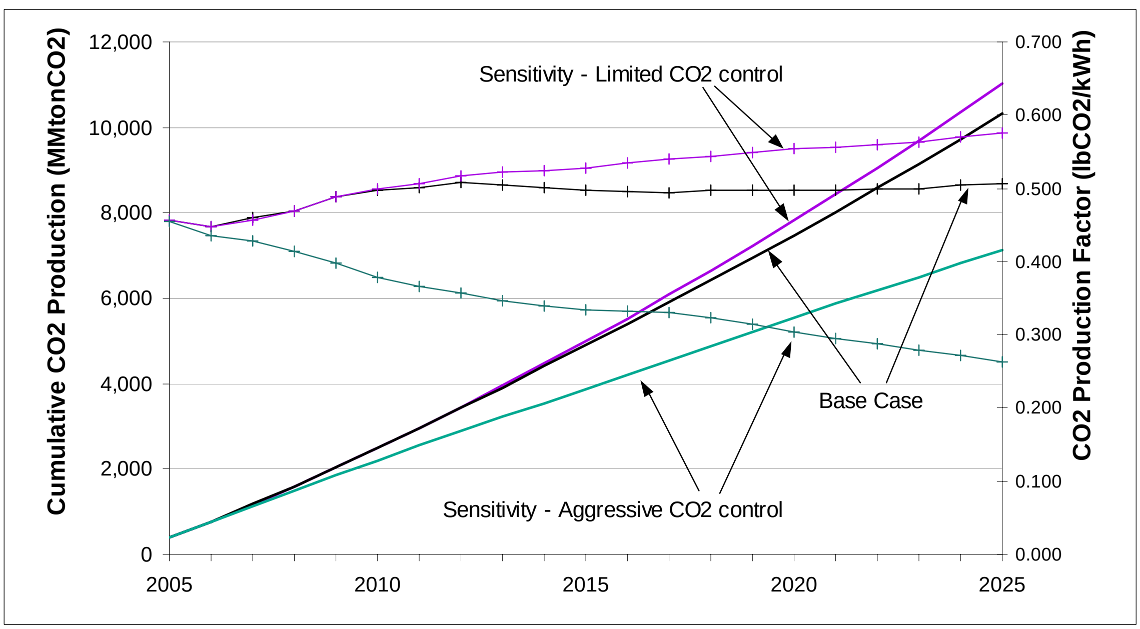

Figure C-15: Sensitivity of forecast WECC CO_2 production to CO_2 mitigation cost

The aggressive CO_2 control sensitivity case is based on the assumed enactment of federal regulation similar to the McCain-Lieberman proposal in 2006, with the year 2000 cap in effect in 2012. Model limitations require CO_2 mitigation cost to be treated as a carbon tax on fuel use rather than as a true cap and trade system. In this case, fuel carbon for existing and new projects is taxed at the equivalent of a forecast cost of CO_2 allowances required to achieve the proposed McCain-Lieberman cap[1]. The allowance costs needed to achieve the targeted reductions of the McCain-Lieberman proposal are highly uncertain but were the subject of a Massachusetts Institute of Technology (MIT) analysis[2]. The sensitivity study was based on the forecast CO_2 allowance costs of Case 5 of the MIT study, shifted back two years to coincide with the assumed 2012 Phase I implementation date. A market in banked allowances was assumed to develop on enactment in 2006 so any subsequent reduction in fuel carbon consumption is valued at an opportunity cost equivalent to the discounted forecast 2012 allowance cost. Oregon and Washington were assumed to continue their current mitigation standards at $0.87 per ton through 2006.

These assumptions result in a significant shift in the future resource mix compared to the base case. Wind and gas combined-cycle resource development is accelerated and additions of bulk solar photovoltaics appear near the end of the forecast. About 6 percent of existing coal capacity and 17 percent of existing gas steam capacity is retired over the forecast period. New coal development is entirely absent (Table C-3). The levelized forecast Mid-Columbia price is $50.10 per megawatt-hour, 38 percent higher than the base case value. Prices increase almost immediately, in 2006 because of the opportunity cost of bankable CO_2 allowances (Figure C-14). The assumed carbon tax is effective in reducing CO_2 production. The shift from coal and less efficient gas-fired capacity to wind, solar and more efficient gas capacity rapidly reduces the CO2 production factor. The 2025 WECC system wide CO_2 production factor is 0.264 lbCO_2/kWh, 48 percent lower than the base case value. Cumulative CO_2 production for the WECC area for the period 2005 - 25 is reduced by 31 percent from the base case forecast.

Because this case is a sensitivity analysis rather than a scenario, the results should be used with caution. If this case were cast as a scenario, other adjustments to assumptions would have to be included. For example, natural gas prices could be expected to increase more rapidly as a result of increased development of gas-fired generating capacity. Electrical loads could be expected to moderate as a result of higher prices and additional conservation would become cost-effective. Wind resources in addition to those included in these model runs might be available, though probably at higher cost than those currently represented. New nuclear resources are not included; it is possible that new-generation modular nuclear plants might produce electricity at lower cost than the marginal resources of this case.

Price Cap

Following a year of extraordinarily high electricity prices, the FERC implemented a floating WECC wholesale trading electricity price cap in June 2001. The original cap triggered when California demand rose to within 7 percent of supply. The cap itself was set for each occurrence based on the estimated production cost of the most-expensive California plant needed to serve

[1] As a further modeling simplification, the carbon tax was applied to all WECC areas, including British Columbia, Alberta and Baja California.

[2] Massachusetts Institute of Technology. Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal. June 2003.

load. This mitigation system was revised in July 2002 to a fixed cap of $250 per megawatt-hour, effective October 2002.

The base and sensitivity cases assume continuation of the $250/MWh wholesale price cap (year 2000 dollars, escalating with inflation). This cap undercuts several of the higher cost load curtailment and demand response blocks, curtailing peak period prices and reducing generation developed to meet peak period loads.

Table C-3: Base and sensitivity case results

Case	Changes from Base	Mid-Columbia Price Forecast ($/MWh)	Ave of top 10% of Monthly Prices ($/MWh)	2025 WECC coal (GW)	2025 WECC gas (GW)	2025 WECC wind & solar (GW)	2005-25 WECC CO_2 Production ($MMTCO_2$)	2025 WECC August Reserve Margin (%)	2025 PNW January L/R Balance (aMW)[3]
Base Case (Changes 2005 - 2025 shown in percent)									
Final Base	--	$36.20	$46.18	64.6 (75%)	89.7 (18%)	29.9 (570%)	10321 (154%)	11%	-14
Sensitivity Cases (Changes from base shown in percent)									
Medium-low demand forecast	NPCC Medium-low demand forecast case	$34.30 (-5 %)	$45.03 (-3%)	53.4 (-17 %)	82.0 (-9 %)	31.7 (+6 %)	9084 (-12 %)	18 %	3263
Medium-high demand forecast	NPCC Medium-high demand forecast case	$37.70 (+4 %)	$49.92 (+8 %)	74.6 (+16 %)	98.7 (+10 %)	40.0 (+10 %)	11,562 (+12 %)	6 %	-2808
Low fuel price forecast	NPCC Low fuel price forecast case	$29.80 (-18 %)	$39.47 (-15 %)	37.5 (-42 %)	114.2 (+27 %)	22.4 (-25 %)	9187 (-11 percent)	10 %	-471
High fuel price forecast	NPCC High fuel price forecast case	$39.60 (+9 %)	$57.12 (+24 %)	88.6 (+37 %)	66.1 (-26 %)	33.6 (+4 %)	11,074 (+7 %)	11 %	2356
Non-aggressive CO_2 control	$0.87/T CO_2 mitigation, WA & OR only	$33.90 (-6 %)	$46.64 (+1 %)	84.2 (+30 %)	70.2 (-22 %)	22.2 (-26 %)	11,028 (+7 %)	11 %	477
Aggressive CO_2 control	Immediate $0.87/T CO_2 offset in WA & OR Climate Stewardship Act enacted 2006, Ph I in 2012	$50.10 (+38 %)	$49.46 (+7 %)	34.5 (-47 %)	129.5 (+44 %)	44.8 (+50 %)	7126 (-31 percent)	15 %	2946

[3] Excluding demand response capability.

Appendix C1

MEMBERS OF THE GENERATING RESOURCES ADVISORY COMMITTEE

Name	Affiliation
Rob Anderson	Bonneville Power Administration
Peter Blood	Calpine Corporation
John Fazio	Northwest Power Planning Council
Stephen Fisher	Mirant Americas Energy Marketing
Mike Hoffman	Bonneville Power Administration
Clint Kalich	Avista Utilities
Eric King	Bonneville Power Administration
Jeff King	Northwest Power Planning Council
Mark Lindberg	Montana Economic Opportunity Office
Bob Looper	Summit Energy, LLC, representing State of Idaho
Jim Maloney	Eugene Water & Electric Board
Dave McClain	D.W. McClain & Associates representing Renewable Northwest Project
Alan Meyer	Weyerhaeuser Corp.
Mike Mikolaitis	Portland General Electric
Bob Neilson	Idaho National Environmental and Engineering Laboratory
Roby Roberts	PacifiCorp Power Marketing
Jim Sanders	Clark Public Utilities
David Stewart-Smith	Oregon Office of Energy
Tony Usibelli	Washington Office of Trade and Economic Development
Carl van Hoff	Energy Northwest
David Vidaver	California Energy Commission
Kevin Watkins	Pacific Northwest Generating Coop
Chris Taylor	Zilkha Renewable Energy

Conservation Acquisition Strategies

In chapter 7, the Council proposes to engage the region on the development of a strategic plan for conservation deployment. This appendix reviews the conservation potential in the region and proposes actions needed to reach near-term conservation acquisition targets presented in chapter 7. This appendix sets forth specific acquisition approaches for the target conservation measures in the residential, commercial, irrigation and industrial sectors that the region should consider in the development of a strategic conservation plan.

HOW MUCH CONSERVATION REMAINS TO BE DEVELOPED?

Table D-1 shows the amount of cost-effective and realistically achievable conservation savings potential by sector and end-use under the Council's medium wholesale electric price forecast. As can be see in Table D-1, the Council has identified about 2,800 average megawatts of conservation resources that could be developed during the next 20 years under these conditions.[1] This is enough energy to replace the output of about 18 single-unit combined cycle combustion turbine power plants, at about half the cost.[2] Almost 20 percent of this potential is in new and existing residential lighting. The next largest single source of potential savings, about 12 percent of the total, is in the non-aluminum industrial sector. The remaining large sources of potential savings are spread across residential water heating and laundry equipment and new and existing lighting and HVAC equipment in the commercial buildings.

[1] This is the total amount of cost-effective conservation achievable, given sufficient economic and political resources, over a 20-year period in the medium forecast.
[2] Based on a 305 megawatts single-unit combined-cycle gas-fired plant (270 megawatts baseload + 35 megawatts duct-firing) seeing service in 2005. For the 2005-2019 periods, under average conditions, such a plant would operate at an average capacity of 156 megawatts with a levelized cost of $45.20/megawatt-hour (2000$).

Table D-1: Achievable Conservation Potential

Sector and End-Use	Cost-Effective Savings Potential (MWa in 2025)[3]	Average Levelized Cost (Cents/kWh)[4]	Benefit/Cost Ratio[5]	Share of Savings (Percent)
Residential Compact Fluorescent Lights	530	1.7	2.3	19
Residential Heat Pump Water Heaters	200	4.3	1.1	7
Residential Clothes Washers	140	5.2	2.6	5
Residential Existing Space Conditioning - Shell	95	2.6	1.9	3
Residential Water Heaters	80	2.2	2.3	3
Residential HVAC System Conversions	70	4.3	2.1	3
Residential HVAC System Efficiency Upgrades	65	2.9	1.2	2
Residential New Space Conditioning - Shell	40	2.5	2	1
Residential Hot Water Heat Recovery	20	4.4	1.1	1
Residential HVAC System Commissioning	10	3.1	1.9	0.4
Residential Existing Space Conditioning - Duct Sealing	10	3.1	1.9	0.4
Residential Dishwashers	10	1.6	2.6	0.4
Residential Refrigerators	5	2.1	2.2	0.2
Commercial New & Replacement Lighting	221	1.3	8.6	8
Commercial New & Replacement HVAC	140	3.0	1.5	5
Commercial Retrofit HVAC	119	2.4	1.9	4
Commercial Retrofit Lighting	117	3.4	1.3	4
Commercial Retrofit Equipment[6]	114	1.8	2.2	4
Commercial Retrofit Infrastructure[7]	105	2.2	1.8	4
Commercial New & Replacement Equipment	84	2.2	1.8	3
Commercial New & Replacement Shell	22	2.2	1.6	1
Commercial New & Replacement Infrastructure	11	1.4	2.4	0.4
Commercial Retrofit Shell	4	3.8	1.0	0.1
Industrial Non-Aluminum	350	1.7	2	13
Agriculture - Irrigation	80	1.6	3.2	3
New & Replacement AC/DC Power Converters[8]	155	1.5	2.7	6
Total	**2797**	**2.4**	**2.5**	**100**

Table D-1 also shows average real-levelized cost and the benefit-to-cost ratio of the region's remaining conservation potential by major end-use. The weighted average real-levelized cost of this

[3] This is the total amount of conservation estimated to be cost-effective and achievable, given sufficient economic and political resources, over a 20-year period under the medium forecast of loads, fuel prices, water conditions, and resource development.
[4] These levelized costs do not include the 10-percent credit given to conservation in the Northwest Power Act.
[5] These "benefit-to-cost" (B/C) ratios are derived by dividing the present value benefits of each measure's energy, capacity, transmission and distribution and non-energy cost savings by the incremental present value cost (including program administration) of installing the measure.
[6] Commercial equipment includes refrigeration equipment and controls, computer and office equipment controls and laboratory fume hoods.
[7] Commercial infrastructure includes sewage treatment, municipal water supply, LED traffic lights, and LED exit signs.
[8] Measure occurs in residential, commercial and industrial sectors.

conservation is 2.4 cents per kilowatt-hour (2000$).[9] In aggregate, these resources have a benefit-to-cost ratio of 2.5-to-1.0.[10] Note that some measures, such residential clothes washers, can have high-levelized cost while still providing high benefit-to-cost ratios. This seemingly counter-intuitive result can occur for several reasons. It may be that a measure, such as a high-efficiency air conditioner or heat pump, produces most of its savings at times when wholesale power market prices are high and therefore are more valuable to the region. Alternatively, this phenomenon can occur when a measure produces very large non-energy benefits such as the water savings from more energy-efficient residential clothes washers.

The amount of conservation that is cost-effective to develop depends upon, among other things, how fast the demand for electricity grows, future alternative resource costs and year-to-year variations in market prices.[11] It also depends upon whether the extent to which conservation in the region's resource portfolio can reduce the risk associated with future volatility in wholesale market prices, changes in technology, potential carbon controls and other risks. In order to assess whether 2,800 average megawatts (or some other amount) of conservation resource is more likely to provide the Northwest consumers with the lowest cost power system at an acceptable level of risk the Council tested a range of conservation deployment strategies in its portfolio analysis process and discussed in chapter 7.

REGIONAL CONSERVATION TARGET

Based on the portfolio analysis in chapter 7, the Council recommends that the regional target 700 average megawatts of conservation development over the next five years. This includes 600 average megawatts of cost-effective discretionary conservation and 100 average megawatts of lost-opportunity conservation. The Council believes that acquisition of these targets will produce a more affordable and reliable power system than alternative development strategies. The Council recognizes that the 700 average megawatts five-year conservation target it is recommending represents a significant increase over recent levels of development. However, the Council's analysis of the potential regional costs and risks associated developing lesser amounts of conservation demonstrates that failure to achieve this target exposes the region to substantially higher costs and risks.

Figure D-1 shows the Council's recommended targets by sector and resource type for the five-year action plan. These near-term targets call for constant levels of development of discretionary conservation and a steady acceleration of lost-opportunity conservation.

Figure D-2 shows the long-range mean build-out of lost-opportunity and discretionary conservation from the least risk plan. It is important to note that the Council recommends that acquisition rates of lost-opportunity resources continue to increase beyond the 30 average megawatts per year in 2009 shown in Figure D-1. The Council recommends that by no later than 2017, lost-opportunity resource acquisition should reach an 85 percent penetration rate. Under the medium forecast this would be about 70 average megawatts per year.

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[9] These levelized costs do not include the 10-percent credit given to conservation in the Northwest Power Act.
[10] These "benefit-to-cost" (B/C) ratios are derived by dividing the present value benefits of each measure's energy, capacity, transmission and distribution and non-energy cost savings by the incremental present value cost (including program administration) of installing the measure.
[11] For example, if economic growth follows the Council's medium-low forecast, the region will need to add approximately 100 average megawatts of new resources each year. However, if regional economic growth is at the Council's medium-high forecast, nearly 400 average megawatts of new resources will be needed each year.

The Council expects that total utility system investments in conservation needed to achieve its five-year target will be approximately in the range of $1.2 to $1.35 billion, or $200 to $260 million (2000$) per year.[12] This is slightly less than the $1.45 billion (2000$) in utility investments from 1992 through 1996 when the region captured similar amounts of conservation. It is about one-third more than average utility and Bonneville expenditures over the ten years from 1991 to 2002. The Council understands the difficulty of raising power rates to accomplish this level of investment. This means that acquiring conservation as cost-efficiently as possible must be a high priority.

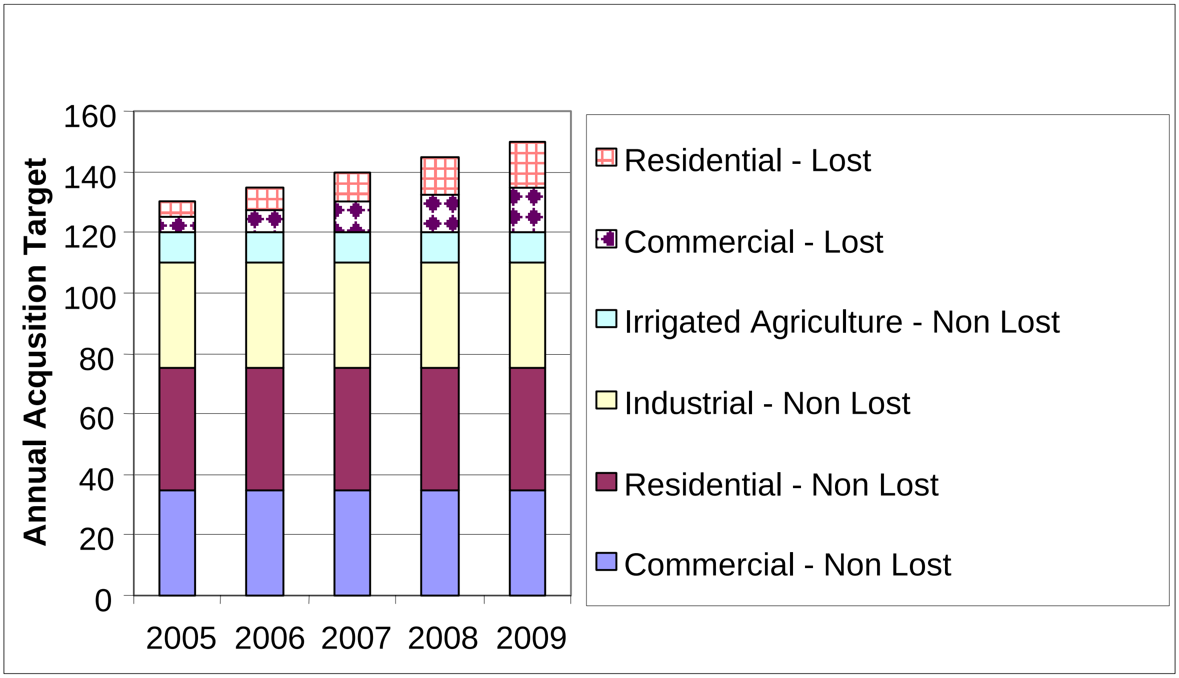

Figure D-1: Regional Conservation Targets 2005 - 2009

[12] The range of utility program costs estimated here is based on two methodologies. The high range of the estimate is based on $2.2 million per average megawatt saved, the 1991-2002 utility program cost average. This method yields a five-year average annual estimate of about $300 million, of which as much as $40 million could be for market transformation and regional acquisition activities. This method results in a high estimate of about $260 million per year over five years for local utility program expenditures. This is thought to be the high end of the range. Utility program costs per average megawatt have been lower since 1995, about $1.5 million per average megawatt. But historical performance may not be a good indicator of future costs. The future measures are different and there are new lost-opportunity programs to be developed. The low range of the utility program cost estimate is based on utility costs being a fraction of the total resource cost of the lost-opportunity measures in Council's conservation assessment. This method takes into account that there are different measures and programs going forward. For the second methodology the Council assumed utility costs are expected to be at or above 100 percent of the total resource cost of the lost-opportunity measures due to expected high initial start up costs for new programs. For discretionary measures, the Council assumed about 65 percent of the total resource cost of the measures would be needed in utility incentives and program costs. This second method yields a five-year annual average utility cost estimate of about $240 million. Again assume as mush as $40 million per year could be for market transformation and regional acquisition activities. That yields a low-end estimate of about $200 million per year for local utility program costs not including market transformation and regional acquisition activities. In 2002 Bonneville, the utilities and the SBC administrators spent about $200 million on local programs not including the Alliance.

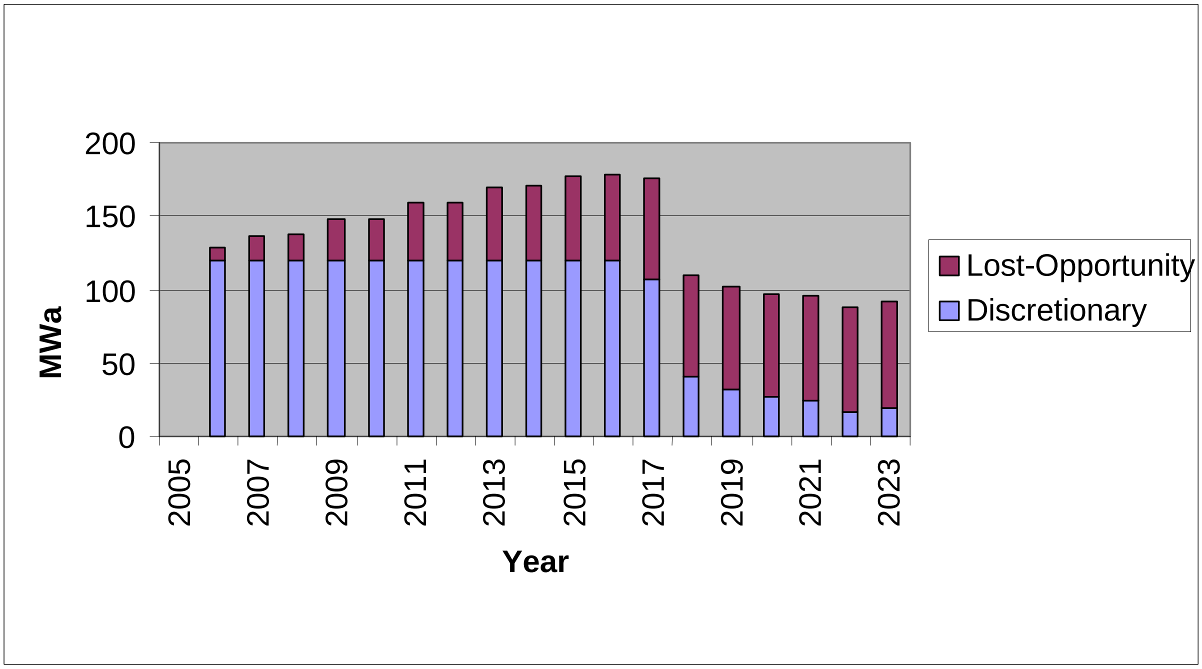

Figure D-2: Mean Annual Build-Out of Conservation in Plan

CONSERVATION IMPLEMENTATION STRATEGIES

Acquiring cost-effective conservation in a timely and cost-efficient manner requires thoughtful development of mechanisms and coordination among many local, regional and national players. This power plan cannot identify every action required to meet the conservation targets. However, the specific characteristics of the targeted conservation measures and practices, market dynamics, past experience and other factors suggest acquisition approaches that promise to be fruitful and effective. This section outlines major acquisition approaches and levels of effort that the Council recommends be pursued by entities in the region to secure the benefits from capturing the region's cost-effective conservation potential. It also sets forth some guidance on specific issues that the Council believes must be addressed in order to achieve its cumulative 2005 through 2009 target of 700 average megawatts.

Focus on "Lost Opportunity" Resources

The Council's portfolio analysis found that developing additional conservation serves as a "hedge" against future market price volatility. One of the principle factors behind the finding is that more "lost opportunity" resources are developed.[13] As described in the discussion of the results of the portfolio analysis, capturing these lost opportunity conservation resources reduces both net present value system cost and risk. If the region does not develop these resources when they are available, this value cannot be secured. These resources represent nearly half of the Council's 20-year

13 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. For example, some efficiency measures can only be implemented cost-effectively when a building is being constructed or undergoing major renovation. If they aren't done then, the opportunity to capture those savings at that cost is lost.

conservation potential if they could be developed for 85 percent of new buildings, appliances and equipment. But programs need to be initiated for many of the new lost-opportunity resources identified in this plan and the Council expects it may take as long as twelve years to reach an 85 percent penetration rates. Therefore, the region needs to focus on accelerating the acquisition of these resources. This will very likely require significant new initiatives, including local acquisition programs, market transformation ventures, improving existing and adopting new codes and standards, and regional coordination.

Additional Regional Coordination and Program Administration will be Required

The Council believes coordinated efforts will be an increasingly necessary ingredient to successful development of the remaining conservation potential. The boundaries between direct acquisition approaches, market transformation, infrastructure support, and codes and standards are blurry. In fact, for much of the conservation resource, efforts are needed on all these fronts to take emerging efficiency measures from idea to common practice or to minimum standard. Of increasing importance is improved coordination between local utilities, public benefits charge administrators, the Alliance, Bonneville, the states and others to assure efforts are targeted where they have the most impact on resource development and where synergies of approach and combined efforts can be taken advantage of.

In addition, a significant share of the savings identified by the Council require a regional scope to achieve economy of scale or market impacts or can be best acquired through regionally-administered programs. However, at present there is no regional organization chartered or funded to develop and administer such programs. In the past Bonneville has played this role.[14] However, it is not clear that Bonneville could or should continue to provide this function in the future. The Council intends to use the strategic planning process identified in its action plan to work with the Alliance, Bonneville, the region's utilities and system benefits charge administrators and regulators develop a solution to this problem.

Aggressive Action by the Power System is Necessary

As in most previous Council power plans, this plan does not attempt to quantify the portion of the achievable conservation that might be developed by consumers acting independent of utility or system benefits administrator programs. There are several reasons for this. First, to the extent feasible the Council has attempted to account for existing market penetration of consumer investments in energy efficiency and the effects of know future codes and standards. These have already been subtracted from estimates of future potential.

Second, the Council is charged with determining which mix of resources will provide the region with most economically efficient and reliable electric power system and services. Allocating the targets and the cost of meeting them between the region's consumers and its electric ratepayers does not change the total cost to the region of acquiring these savings. More importantly, since these two groups are comprised of the same individuals, from a regional perspective it makes no difference who pays -- the total bill is the same.

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14 For example, Bonneville administer the Manufactured Housing Acquisition Program (MAP) on behalf of all of the region's public and investor-owned utilities.

Third, this Plan's conservation target is achievable, yet aggressive. In order to achieve these targets, the region will need to make significant investments in conservation resources. While these conservation resources are less expensive than other resource options, their costs are front-loaded. This is especially true for "lost-opportunity" conservation resources because these resources have measure lives that typically exceed the 20-year planning period.[15] Only about 300 average megawatts of the 3,900 achievable average megawatts identified have real-levelized cost below 1.0 cent per kilowatt-hour. Even these conservation resources have "payback" periods exceeding those typically demanded by commercial and industrial customers. Given these facts, the Council is convinced that this Plan's conservation targets cannot be achieved without broad-based and aggressive programs. While these programs should be designed to target measures that would not otherwise be adopted and focus on consumers that would not likely adopt energy efficient technologies, those considerations should not drive program design.

Efficient Programs Are Not Necessarily Those With the Lowest (First Year) Cost

As noted in the previous discussion, conservation resource costs are "front-loaded." Therefore, measuring effectiveness of local or regional conservation acquisition programs based on their cost per first year savings is, at the very least, misleading and at worst, misguided. Lost-opportunity resources comprise fifty percent of the Council's assessment of 20-year conservation potential. These resources, as noted above, are by definition "long-lived." Moreover, because the region has been successful in improving energy codes, federal efficiency standards and building practices a significant share of the remaining lost-opportunity potential is more costly than "average." These two factors create a conflict between getting conservation "cheap" and achieving the Council's lost-opportunity targets.

To illustrate this conflict consider the following example. High-efficiency clothes washers represent 135 average megawatts of resource potential. Their real levelized cost is 5.2 cents per kilowatt-hour and they have a benefit-to-cost ratio of 2.6. The "first year cost" of savings from high efficiency clothes washers is $4.8 million per average megawatt. Compact fluorescent lamps (CFLs) represent 530 average megawatts of non-lost opportunity resource potential. They have a real levelized cost of just over 1.7 cents per kilowatt-hour and a benefit-to-cost ratio of 2.3. The "first year cost" of CFL savings is $1.4 million per average megawatt. If a conservation program operator "capped" its "willingness to pay" at $1.0 million per average megawatt it might forego securing one or both of these resources. Alternatively, to limit its costs, it might offer incentives to consumers that are so small that only those consumers who would have purchased the efficient clothes washer or CFLs end up participating in its program. As a result, the program produces no "incremental savings" beyond what the market would have done on its own.

This is not to say that the conservation should not be acquired at as low a cost to the power system as possible. While everyone benefits from cost-effective conservation, the end-user participants benefit most directly. Given that retail rates have risen significantly in recent years, end users have a greater incentive to share in the cost of the conservation. But the Council's goal is to achieve the 700 average megawatts 2005 through 2009. Whether the region's consumer's pay for more or less of the cost of doing so through their electric rates, while important, is a secondary goal.

[15] The "first year cost" of a measure with a real-levelized cost of just 1.0 cents per kilowatt-hour and a 20 year lifetime is over 17 cents per kilowatt-hour. At a retail electric rate of 5.0 cents per kilowatt-hour this measure would have a simple payback of over 3.5 years.

A Mix of Mechanisms Will Need to Be Employed

There are several acquisition approaches that have been used successfully in the region and around the country to develop cost-effective conservation not captured through market forces. Key among these are: direct acquisition programs run by local electric utilities, public benefit charge administrators, Bonneville or regional entities; market transformation ventures; infrastructure development; state building codes; national and state appliance and equipment standards; and state and federal tax credits. The Council believes a suite of mechanisms should continue to be the foundation used to tap the conservation resource.

It is the nature of the conservation resource, the kinds of measures and practices, and the inherent advantages of different acquisition approaches that suggest how much of the conservation potential should be pursued, by what entities and using which methods. Most of the successful conservation development over the past two decades has been through a combination of approaches deployed over time. Typically pilot projects demonstrate a new technology. Direct acquisition programs are used initially to influence leading decision makers to adopt the technology. Market transformation ventures are used to bring the technology to be part of standard practice. Then, in some cases, codes or standards can be upgraded to require the new measures, or capture a portion of the cost-effective savings.

Direct Acquisition Programs

Direct acquisition programs are typically programs run by local utilities, system benefits charge administrators, regional organizations, Bonneville and others that offer some kind of incentive to get decision makers to make energy-efficient choices. Incentives often take the form of rebates, loans, or purchased energy savings agreements. Direct acquisition programs are relatively expensive compared to other approaches because the incentive can be a significant fraction of the measure cost and substantial administrative costs are required. Historic program costs range from 1 to 5 million dollars per first-year average megawatt of savings. However, in many cases, direct acquisition programs are the only mechanism available or are a necessary first step to get new measures and practices into the market place. Acquisition programs can be local or regional. Many retrofit programs for residential and commercial building are best run as local efforts. On the other hand, for measures where there are just a few suppliers or vendors in the region, a regional approach to direct acquisition may be more cost-efficient.

Market Transformation Ventures

Market transformation ventures are regional and national efforts to get energy-efficient products and services adopted by the marketplace sooner and more thoroughly than they would be otherwise. The Northwest Energy Efficiency Alliance (Alliance) is the key entity in the region pursuing this approach. The Alliance has developed an impressive track record of improving the adoption of efficiency measures and practices in most of the markets it has ventured into racking up sizeable low-cost energy savings of about 100 average megawatts at a cost of $1 million per first-year average megawatt or less.[16] The Council envisions continued market transformation efforts will yield similarly impressive results at similarly low costs.

[16] Retrospective Assessment Of The Northwest Energy Efficiency Alliance, Final Report, by Daniel M. Violette, Michael Ozog, and Kevin Cooney, Available at http://www.nwalliance.org/resources/reports/120.pdf

Conservation Infrastructure Development

Often, the delivery of new energy-efficient products and services requires development of, or intervention in, the infrastructure that proposes to deliver those products or services. Conservation infrastructure includes education, training, development of common specifications for efficient practices or equipment, certification programs, market research, program evaluation and other activities that support quick, widespread adoption of energy efficiency that delivers savings. Infrastructure development is often best approached at a regional or national level if the product or service is one that crosses the boundaries of local utilities. The Alliance, Bonneville, the states, the federal government and some national organizations have fostered infrastructure development in the past. For example, the federal government's Energy-Star program identifies products that meet minimum efficiency levels for common household appliances. Both market transformation ventures and direct acquisition programs can use the federal designation to promote products in regional and local markets.

In the past, some infrastructure development has been supported through the Alliance. But limited Alliance budgets, combined with increasing need for regional infrastructure has orphaned some efforts. The Council believes more effort should be directed to regional infrastructure in the next five years to speed the development and lower the cost of capturing all cost-effective savings.

Building Codes

Residential and commercial energy codes are adopted at the state and local level to require minimum levels of efficiency in many of the energy-using aspects of new homes and commercial buildings. Energy codes are typically part of the building code and typically lag behind leading-edge efficiency practices. Once adopted as the minimum standard, codes generally lead to decreasing measure costs. However, not all cost-effective conservation can be captured by buildings codes. Code improvement is a continual process and regional efforts need to continue.

Appliances and Equipment Standards

The federal government, and some state governments adopt minimum efficiency standards for certain appliances and equipment. Federal laws dictate that certain appliances fall under federal jurisdiction and timelines for minimum efficiency standards. Other appliances and equipment are not under federal jurisdiction but might be subject to state or local standards. The region should continue to place significant efforts on improving federal appliance standards and to adopt new state standards for some appliances.

Tax Credits

State and national tax credits have been used effectively to promote efficient equipment and practices beyond what is required in federal standards and state codes. State laws differ and may limit the ability of a state to offer tax credits. However, in instances like Oregon's Business Energy Tax Credit, these mechanisms have been effective.

RECOMMENDED ACQUISITION STRATEGIES AND MECHANISMS

The Council considered the mechanisms above, the kinds of measures and practices that comprise the conservation assessment, and the state of development of each in order to get a general idea of what level of effort to apply to each of these approaches to capture the conservation potential identified in this plan. Suggested approaches are based on the characteristics of the potential conservation including whether it is lost-opportunity or retrofit, it's size, cost, and non-energy benefits, characteristics of the market and delivery channels used disseminate the measures, local, state, regional and national programs already in place, and if and when a measure or practice might be subject to codes or standards.

The following sections set forth near-term acquisition approaches, strategies and suggested mechanisms by sector for the key measures that make up the conservation targets. These are presented as starting points for a regional dialogue of how best to capture the targeted conservation. The specific mechanism or mix of mechanisms best suited to capture this resource will need to be addressed during the development of the region's strategic plan for conservation acquisition.

Residential-Sector Conservation Acquisition Strategies

Table D-2 shows the achievable savings, real levelized cost, benefit-to-cost ratio, total resource capital cost per average kilowatt and the share of sector savings for each of the major sources of residential sector potential. As can be seen from this table, the residential sector conservation potential is highly concentrated among just three measures. Nearly 70 percent of the realistically achievable residential sector conservation potential comes from three measures, compact florescent lighting, heat pump water heaters and high efficiency clothes washers. Moreover, of the remaining 30 percent, 10 percent comes from improving the efficiency of heat pumps and converting existing electric furnaces to high efficiency heat pumps and 6 percent comes from high efficiency water heater tanks. The remaining 14 percent of the sector's potential savings is spread among 12 other major measure types.

Table D-2: Sources and Total Resource Cost Economics of Residential Sector Realistically Achievable Conservation Potential

Measure	Realistically Achievable Potential (MWa)	Weighted Levelized Cost (Cents/kWh)	Benefit/ Cost Ratio	Weighted[17] Total Resource Capital Cost ($/KWa)	Share of Sector Realistically Achievable Potential
Energy Star Heat Pump Conversions	70	4.3	2.1	$ 4,520	5%
Energy Star Heat Pump Upgrades	60	2.9	2.1	$ 3,170	5%
PTCS Duct Sealing	10	3.1	2.3	$ 3,640	1%
PTCS Duct Sealing and System Commissioning	5	3.0	2.2	$ 3,520	0%
PTCS Duct Sealing, Commissioning and Controls	10	3.2	2.3	$ 3,860	1%
Energy Star - Manufactured Homes	20	2.3	2.1	$ 4,240	2%
Energy Star - Multifamily Homes	5	2.3	1.1	$ 4,620	0%
Energy Star - Single Family Homes	20	2.7	1.1	$ 5,490	2%
Weatherization - Manufactured Home	20	4.0	1.1	$ 5,490	2%
Weatherization - Multifamily	30	2.5	1.1	$ 4,480	2%
Weatherization - Single Family	40	1.9	2.4	$ 3,500	3%
Energy Star Lighting	530	1.7	2.3	$ 1,370	42%
Energy Star Refrigerators	5	2.0	2.3	$ 2,330	0%
CEE Tier 2 Clothes Washers	140	5.2	1.1	$ 4,820	11%
Energy Star Dishwashers	10	1.6	2.6	$ 1,480	1%
Efficient Water Heater Tanks	80	2.2	2.3	$ 1,810	6%
Heat Pump Water Heaters	200	4.3	1.1	$ 4,240	16%
Hot Water Heat Recovery	20	4.4	1.1	$ 7,620	2%
Total	**1,275**	**2.9**	**1.9**	**$ 2,960**	**100%**

Table D-3 shows approximate residential sector conservation target for 2005 through 2009 is 250 average megawatts. During the initial five years of this plan only twenty percent of this target is comprised of lost-opportunity resources to allow for the gradual ramp up of programs. Increasing the market penetration of high efficiency clothes washers and water heater efficiency improvements represent the principle areas where programs need to be focused. A single measure, Energy Star Lighting (compact fluorescent lamps) represents two-thirds of total five-year target for the residential sector. The fact that the bulk of the residential sector savings potential is concentrated in just a few measures reduces the number of mechanisms that may be required to capture this potential at any particular point in time. However, The Council believes that over the course of the next 20 years, nearly the full array of mechanisms and approaches will still be required to accomplish this sector's savings.

17 This is the entire incremental capital cost of the measure plus program administrative cost. Since utilities and system benefit charge administrators rarely pay 100 percent of a measure's cost, their cost will be below this value.

Table D-3: Residential Sector Lost Opportunity and Dispatchable Conservation Resource Targets 2005 through 2009

Measure	Five Year Dispatchable Target (Average Megawatts)	Five Year Lost Opportunity Target (Average Megawatts)
Energy Star Heat Pump Conversions	-	5.6
Energy Star Heat Pump Upgrades	-	4.8
PTCS Duct Sealing	3.1	-
PTCS Duct Sealing and System Commissioning	1.6	-
PTCS Duct Sealing, Commissioning and Controls	3.1	-
Energy Star - Manufactured Homes	-	1.8
Energy Star - Multifamily Homes	-	0.1
Energy Star - Single Family Homes	-	1.2
Weatherization - Manufactured Home	6.2	-
Weatherization - Multifamily	9.3	-
Weatherization - Single Family	12.4	-
Energy Star Lighting	164.3	-
Energy Star Refrigerators	-	0.4
CEE Tier 2 Clothes Washers	-	11.2
Energy Star Dishwashers	-	0.8
Efficient Water Heater Tanks	-	6.4
Heat Pump Water Heaters	-	16.0
Hot Water Heat Recovery	-	1.6
Total	**200**	**50**

Residential-Sector Lost Opportunity Resources

While most of the lost-opportunity resources are probably best targeted by regional or national market transformation ventures, several can benefit from complimentary local acquisition program in the near-to intermediate term. For example, the two largest lost-opportunity resources are high efficiency clothes washers and heat pump water heaters.

Residential Clothes Washers

The minimum permissible efficiency of clothes washers is set by federally preemptive appliance standards. These standards were last updated in 2001. The first "phase" of the 2001 standards took effect in January of 2004 and the second "phase" of those standards will take effect in January of 2007. By law, the US Department of Energy cannot revise the standard more than once every five years. This means that the first year a new clothes washer standard could take effect is 2012. Therefore, between now and then, a regional market transformation venture complimented by local acquisition programs and state tax credits that focus on the most efficient washers is needed to capture this resource. In addition, the region should continue to actively participate in the federal appliance standards rulemaking process to ensure that the higher efficiency standards are adopted in a timely manner.

Residential Heat-Pump Water Heaters

In contrast, securing the lost opportunity savings available from heat pump water heaters will require a quite different mix of mechanisms. The principle barriers to widespread application of this technology are that prior generations of heat pump water heaters were unreliable, too expensive or both and they lacked a national distribution network. As a result of federal research and demonstration efforts, the current generation of heat pump water heaters are now much more reliable. However, they still have an incremental cost (over a standard electric water heater) of about $800-900 and are not available through existing plumbing supply distribution networks. In order to overcome these barriers, a regional scale demonstration program coupled with either a regional or national market transformation venture are required.

The regional demonstration program is needed to convince contractors and consumers that this technology is as reliable as a standard electric water heater. This program needs to be of sufficient scale and duration to create a national (or regional) market for heat pump water heaters that is large enough to gain both economies of scale for manufacturers as well as to develop the regional distribution network. The Council believes that the Northwest Energy Efficiency Alliance (Alliance), working with both its regional partners and other national and regional organizations,[18] is the logical entity to lead the development of this resource.

During the initial stages of this venture it is highly probable that either significant local acquisition program incentives or manufacturer incentives will be required to defray a portion of the incremental cost of heat pump water heaters. The Council does not believe that the Alliance could realistically mount a successful market transformation venture for heat pump water heaters within its current budget constrains. For example, if the Alliance were to negotiate an agreement with manufacturers to cover 50 percent of the incremental capital cost of acquiring the savings from heat pump water heaters the annual cost of a successful program could be in the range of $10 to $15 million. This represents 50 to 75 percent of the Alliance's current annual budget for all of its activities. While these "acquisition payments" could be provided by local utilities, the Council believes that providing the Alliance with the ability to negotiate a single region wide payment to heat pump water heater manufacturers for all units installed in the region (as was done in the Manufactured Housing Acquisition Program) represents a more efficient mechanism for acquiring these savings. The specific mechanism or mix of mechanisms best suited to capture this resource will need to be addressed during the development of the region's strategic plan for conservation acquisition

Residential Water Heaters and Residential Heat Pump Space Heaters

The next two largest lost opportunity resources are high efficiency hot water tanks and the installation of high efficiency heat pumps in both new homes and the conversion of existing homes with other forms of electric heat to high efficiency heat pumps when the existing heating system is replaced. As is the case with clothes washers, the federal standards for both of these standards were recently revised. New standards for electric hot water heaters took effect in January of 2001 and new standards for air source heat pumps for space heating and cooling will go into effect in January of 2006. Local acquisition programs have successfully targeted high efficiency water heaters. The Council recommends that these programs be enhanced and expanded to ensure that a greater

[18] Ideally, a national market transformation venture should be implemented involving the Consortium for Energy Efficiency, the New England Energy Efficiency Partnerships, the Mid-West Energy Efficiency Alliance and other organizations so as to maximize the scale of the market demand for this product.

proportion of electric water heater tanks installed in both new and existing homes are high efficiency tanks.[19]

Capturing the savings from the installation of more efficient air source heat pumps involves more than selecting a higher efficiency unit. The Council's savings estimate also assumes that the heat pump and the ductwork through which it distributes warm or cool air have been installed properly. In fact, the bulk of the savings from this measure are actually derived from better installation practices and sealing the "leaks" in ductwork. Local acquisition programs designed to capture this resource must therefore focus on improving the installation practices of contractors and their technicians. This will require support of training and quality control/quality assurance programs in addition to direct program incentives.

Residential New HVAC systems

In new construction, the Alliance, working with its regional partners, recently embarked on an Energy Star new homes program that requires the proper installation of more efficient heat pumps and verification that the ductwork is indeed "tight." Local utility and system benefit charge administrator acquisition programs should compliment this venture. Local programs should also target heat pump installations in non-Energy Star new homes as well as be designed secure savings from the proper installation of high efficiency heat pumps and "duct sealing" in existing homes that are replacing their heating systems. The savings from "duct sealing" in both new and existing homes could be secured at a later date. However, failure to seal the duct system when the heat pump is installed dramatically reduces the heat pump's efficiency and also increases the cost of this measure since the home would have to be revisited.

Residential Appliances

The remaining lost opportunity conservation potential can be achieved by increasing the market share of high efficiency refrigerators, freezers and dishwashers and by increasing the efficiency of new electrically heated site built and manufactured homes. Current Alliance, utility and system benefits administrator programs aimed at increasing the market share of Energy Star refrigerators, freezers and dishwashers should be continued. In addition, the region should support revisions to the federal minimum standards for these appliances.

New Homes

Under the Council's medium load growth forecast, approximately two average megawatts of savings are achievable each year through improvements in the thermal efficiency of new single family, multifamily and manufactured homes. As mentioned above, the Alliance recently commenced an Energy Star new site built homes market transformation venture that attempts to capture the portion of these savings. In its initial stages this venture does not focus on multifamily construction. The Council believes that since a high percentage of multifamily buildings are electrically heated, the Alliance should develop and implement a market transformation strategy that targets these dwellings. The Council also recommends that local utility and system benefit administrator programs be designed to compliment the Alliance initiatives. To the extent possible these programs

[19]The minimum "Energy Factor" (EF) for a high efficiency tank varies with tank capacity. The larger the tank the lower the minimum EF. For a tank with a rated capacity of 50 gallons the Council recommends a minimum EF of 0.93.

should encourage the installation of high efficiency appliances, lighting and building thermal shell measures as part of an overall package.

Since the early 1990's the region's manufactured home suppliers in cooperation with the state's energy agencies, Bonneville and the region's utilities have supported the sales of high efficiency manufactured homes under the Super Good Cents® brand name. The industry has voluntarily underwritten the entire cost of the independent third-party inspection and certification program operated by the region's state energy agencies for the past 10 years. Under an agreement with the US Environmental Protection Agency, these homes are now being co-branded as meeting the Energy Star® certification requirements. Super Good Cents®/Energy Star® homes now represent just under two-thirds of all new manufactured homes sited in the region.

While by any metric this program continues to be a national model for what can be achieved through market transformation, its current specifications do not require homes to include all measures that are regionally cost-effective nor has it penetrated 85 percent of the market. It must accomplish both of these tasks in order to capture the lost opportunity savings identified in Table D-3. Therefore, the Council recommends that the state agencies and region's manufacturers adopt a revised set of specifications. The Council also recommends that utilities and system benefit administrators expand their support of this program so that it can achieve a greater market share. Enhance support for the program should be guided by an analysis of the market and other barriers that must be overcome to increase the market penetration rate of Super Good Cents®/Energy Star® manufactured homes.

Residential Hot Water Heat Exchanger

The remaining residential lost opportunity resource identified by the Council is a recently developed technology to recapture the waste heat contained in shower water as it drains out of the shower. This technology works by a principle called "gravity film adhesion". Warm water exiting through a vertical drain line does not "free fall" through the center of the pipe, but rather "adheres" to the side of the pipe, warming the pipe as it flows downward. The heat given off by this exiting shower water can be recaptured by wrapping copper tubing around the shower drain line and running the incoming cold water supply to the shower through the tubing. This pre-heats the cold water supply and reduces the amount of hot water needed to provide a comfortable shower.

A limited number of "gravity film heat exchange" (GFX) devices have been installed in the region. In order to work effectively these devices need to be installed where the shower drain line has at least a four-foot vertical drop. This limits their practical application to multifamily structures and two-story or basement homes. The Council has assumed that only one quarter of the new multifamily and single family residences built over the next twenty years could realistically install these devices. However, if state energy codes were to require that GFX devices be installed in all new homes and multifamily buildings (where physically feasible) then the regional savings from this measure could be four times larger or roughly 80 average megawatts.

In order to capture this potential savings from GFX devices will require a regional demonstration of the technology to familiarize builders, plumbers and code officials with its installation and operation. The Council believes that the Alliance is best positioned to identify the barriers to widespread market acceptance of this technology. Once the Alliance has completed the necessary market research it should design and implement a strategy to expand the market share GFX devices with the end goal of incorporating them into state energy or plumbing codes. In addition, the Council believes that local utility and system benefits charge administrator acquisition programs will need to target this device as part of their the Energy Star® new homes programs.

Residential-Sector Dispatchable Resources

About half of energy savings potential identified in the residential sector can be scheduled for development nearly anytime during the next twenty years, primarily through retrofits of existing residential lighting.

Residential Compact Fluorescent Lighting (CFL)

Research conducted by the Alliance indicates that the average household has about 30 "sockets" that use a standard "Edison" base. Based on estimated historical sales of CFLs in this region the Council believes that about 10 percent of these "sockets" now contain CFLs. With recent (and continuing) improvements in CFL technology, virtually all of the remaining sockets with incandescent bulbs could be retrofitted with CFLs over the next twenty years.

Although the cost of CFLs has dropped dramatically over the past five years, they still cost at least three to four times as much as standard incandescent bulbs. Specialty bulbs, such as multi-wattage/output and those with dimming capability are significantly more expensive than their incandescent equivalents. Consequently, the Council believes that current Alliance market transformation ventures as well as complimentary utility and system benefits administrator acquisition programs are still needed to accomplish regionwide re-lamping.

The Council recognizes that the region may wish to schedule the dispatch of this resource during periods when market prices are high or drought conditions limit resource availability. While delaying the deployment of this resource until "the time is right" may seem at first appealing, the Council does not recommend this approach during the next five years. First, the savings from CFLs could account for just over 25 percent of the Council's annual 120 average megawatt target for dispatchable conservation measures. Any reduction in the savings from this measure will have to be compensated for by increased savings from other measures. Since the Council has not identified any alternative "dispatchable resources" of comparable size and cost (1.7 cents per kilowatt-hour) any such substitution would likely come at a higher cost. Second, the Council believes that sustained and aggressive programs will be needed just to achieve the Council's total CFL savings target. Recent evaluation found that about 80 percent of the lamps sold are immediately installed.[20] Therefore, achieving the Council's five-year target will likely necessitate the deployment of roughly 11 million CFLs annually. That is about 2 million more than were distributed across the region in 2001 during the West Coast Energy Crisis. While this may sound overly aggressive it should be noted that the region was able to ramp up the distribution of CFLs from less than 500,000 to over 9 million in less than a year. Moreover, the typical cost of the most popular CFL is now half of what it was in 2001.

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[15]Findings and Report - Retrospective Assessment of the Northwest Energy Efficiency Alliance, Final Report. Prepared for the Northwest Energy Efficiency Alliance Ad Hoc Retrospective Committee by Summit Blue Consulting and Status Consulting. Portland, Oregon. December 8, 2003.

Residential Weatherization and HVAC

The remaining residential sector dispatchable conservation resources are available through the weatherization of existing single family, multifamily and manufactured (mobile) homes. The bulk of these savings comes from installing higher levels of insulation and replacing existing windows with new Energy Star® products. In addition, cost-effective savings in existing homes with forced air furnaces and heat pumps can be captured by sealing the leaks in their air ducts and by making sure the heat pump as the proper refrigerant charge and system air flow.[21] The Council believes that utility and public benefits charge administrator conservation acquisition programs should be the primary mechanism employed to capture these resources. These weatherization programs have a demonstrated track record. However, such programs need to be revised to incorporate duct sealing and heat pump maintenance in the package of efficiency improvements considered for installation in each home.

Table D-4 provides a summary of the Council's recommendations regarding the mix of resource development mechanisms needed to achieve the residential sector's conservation targets. A primary (P) and secondary (S) resource development mechanism is shown for each of the major sources of residential sector conservation. Specific major mechanisms, such as market transformation, regional programs and local acquisition programs are also divided into several subcategories. Within these subcategories Table 7-5 also indicates the type of action (e.g., acquisition payment, product specification or research and development) the Council believes may be needed to develop this sector's conservation potential.

Although the specific mix of mechanisms needed to accomplish the residential sector targets will be determined through the strategic planning process, the Council estimates that Bonneville, the region's utilities and system benefits charge administrators will need to be prepared to invest between $75 and $100 million annually to acquire the 45 - 55 average megawatts of residential sector conservation called for in this Plan. Of this amount approximately 75 to 85 percent will be needed for local acquisition programs, 15 to 25 percent for regional programs, market transformation initiatives, research and development and specifications. The actual split between regional and local budgets should be determined during the strategic planning process based on whether regional or local acquisition payments offer a more efficient and effective method of securing savings from heat pump water heaters and Energy Star appliances.

[21] These measures were not included in the Fourth Power Plan's estimate of conservation opportunities.

Table D-4 Summary of Council Recommended Residential Sector Conservation Resource Development Mechanisms

Measure	Acquisition Mechanism									
	Market Transformation					Regional Program			Local Program	
	Codes & Standards	MT Venture	National Product Specification	Regional Product Specification	Regional RD&D	Administration	Infrastructure	Acquisition Payments	Administration	Acquisition Payments
Heat Pump Conversions	S	S		Y	S				P	P
Heat Pump Upgrades	S	S		Y	S				P	P
PTCS Duct Sealing	S			Y		S	P		P	P
PTCS Duct Sealing and System Commissioning				Y		S	P		P	P
PTCS Duct Sealing, Commissioning and Controls				Y	S	S	P		P	P
Energy Star - Manufactured Homes	S	P		Y		P		M		S
Energy Star - Multifamily Homes	P	P		Y		P			S	S
Energy Star - Single Family Homes	P	P		Y		P			S	S
Weatherization - Manufactured Home				Y					P	S
Weatherization - Multifamily				Y					P	S
Weatherization - Single Family				Y					P	S
CFLs		S	Y			P				S
Refrigerators	S	S	Y							S
Clothes Washers	S	S	Y							S
Dishwashers	P	S	Y							S
Efficient Water Heater Tanks	S			Y						P
Heat Pump Water Heaters	S	P	Y	Y	P	S		Y		M
Hot Water Heat Recovery	S	P	M	Y	P					S
P-Primary Agent and/or Near Term Action Needed			**S - Secondary Agent and/or Medium to Long Term Action Needed**			**Y= Action or Product Needed**		**M= Action or Product May Be Needed**		

Commercial-Sector Acquisition Strategies

Several characteristics of the commercial conservation potential are notable. First, about 60 percent of the 20-year conservation potential identified is in lost-opportunity resources that must be captured when buildings are constructed or remodeled and when new or replacement equipment is purchased. These factors point to a relatively larger role for market transformation activities and regionally coordinated acquisition approaches compared to the residential sector.

The conservation potential identified in the commercial sector has several characteristics that suggest a relatively large role for regionally coordinated approaches. First, a large fraction of the savings potential, about 60 percent, is in lost-opportunity measures. Second, a large fraction of the savings potential requires changing practices or services as opposed to simply installing new technology. This practice-oriented characteristic will require significant amounts of education, training and marketing. Third, codes and standards can play an important role in some of the measures where savings result primarily from more efficient equipment such as better AC to DC power converters and commercial refrigeration appliances. Because many of those products are used throughout the country, and the world, the cost of improving efficiency can be shared with others from outside the region, reducing the cost of acquisition. Fourth, only part of the savings potential in new buildings is suitable for adoption in building energy codes. Consequently, the region will need to maintain long-term efforts to improve building design, construction and commissioning practices. In addition, commercial markets for energy efficient products and practices typically span across utility boundaries and state lines. This is true for the vendors, designers, installers, and distributors that need to be influenced as well as commercial-sector business and building owners that operate chains, franchises or multiple establishments.

Over the next five years, the Council recommends, about 40 to 50 average megawatts per year of commercial sector conservation be targeted for development. Region-wide commercial-sector lost-opportunity conservation targets should accelerate from 5 to 15 average megawatts per year between 2005 and 2009. Discretionary targets should be in the range of 35 average megawatts per year. While there is a relatively important role for regionally-administered efforts, in the commercial sector, incentive payments and direct-acquisition approaches through local utilities and public benefits charge administrators will continue to play a key role and will require the largest share of financial requirements. Based on a the kinds of measures and programs identified and estimated programs costs, the Council estimates that majority of annual utility system expenditures would be earmarked for direct acquisition approaches. But, a significant fraction of annual expenditures on commercial conservation should be directed toward regionally coordinated and administered efforts including the market transformation efforts of the Alliance. Coordinated approaches are needed among the utilities, administrators, Bonneville, local, state and federal governments, trade allies, retailers, distributors, manufacturers and entrepreneurs. The need for coordinated and strategic efforts adds to administrative costs, but will provide leverage across markets, minimize duplication of efforts and improve the effectiveness of conservation programs.

Although the specific mix of mechanisms needed to accomplish the commercial sector targets will be determined through the strategic planning process, the Council estimates that Bonneville, the region's utilities and public system benefits charge administrators will need to be prepared to invest budget between $70 and $100 million annually for five years to acquire the 225 average megawatt five-year commercial sector target called for in this Plan. Of this amount approximately two-thirds will be needed for local acquisition programs. Approximately one-third will be needed for regional programs, market transformation initiatives, codes and standards, research and development, specification development, training, education and other infrastructure needed to facilitate acquisition. The actual split between regional and local budgets should be determined during the strategic planning process.

Commercial-Sector Lost-Opportunity Resources

About 60 percent of the commercial-sector conservation potential is in lost opportunity resources under the medium forecast. The Council forecasts that under medium growth, typically 50 to 60 million square feet per year of new floor space are added annually in the region and another 20 million square feet undergo renovations significant enough to require compliance with more stringent energy codes. This is something on the order of 3000 new commercial buildings per year and significant renovations on another 2500 existing buildings. The Council recommends that the region gear up to be capturing 85 percent of the available lost-opportunities available by 2017. Under the medium forecast, 85 percent lost-opportunity penetration would amount to about 30 to 35 average megawatts per year of commercial sector lost-opportunity conservation.

These opportunities would benefit from strategic intervention in markets and efficiency efforts focused upstream of the consumer. Many of the lost-opportunity resources will require market transformation activities and regional infrastructure development. Furthermore, significant near-term effort is needed to ramp up conservation activities for commercial sector lost-opportunity resources to levels where penetration reaches 85 percent. Of the lost-opportunity conservation potential identified, about one-third is in new appliances and equipment that can be tapped eventually through efficiency standards. But near-term investments are needed to support development and adoption of the standards and to get efficient products in place absent standards.

The other two-thirds of lost-opportunity potential is in new building design, new and replacement lighting systems and new and replacement HVAC systems and controls. These opportunities require a multi-faceted approach to acquisition including market transformation, education, training, design assistance and pursuit of better building codes and standards. Eventually lighting codes can be upgraded to capture some of this potential. But the majority of savings potential will require near-term market transformation, development of regional infrastructure including training, education, marketing, and market research plus incentives and rebates for consumers, manufacturers or vendors. Table D-5 shows the size and cost characteristics of commercial lost-opportunity measures.

Table D-5: Commercial Sector Lost-Opportunity Measures

Measure	Realistically Achievable Potential in 2025 (MWa)	Weighted Levelized Cost (Cents/kWh)	Benefit Cost Ratio	Weighted Total Resource Capital Cost ($/kWa)	Share of Sector Realistically Achievable Potential
Efficient AC/DC Power Converters	156	1.5	2.7	$651	14%
Integrated Building Design	152	2.3	4.8	$2,968	14%
Lighting Equipment	101	0.3	12.1	$197	9%
Packaged Refrigeration Equipment	68	1.9	1.9	$1,299	6%
Low-Pressure Distribution	47	2.7	1.6	$4,641	4%
Skylight Day Lighting	34	3.4	1.6	$3,420	3%
Premium Fume Hood	16	3.7	1.0	$4,137	2%
Municipal Sewage Treatment	11	1.4	2.4	$687	1%
Roof Insulation	12	1.5	2.1	$2,458	1%
Premium HVAC Equipment	9	4.3	1.2	$4,060	1%
Electrically Commutated Fan Motors	9	2.4	1.8	$2,925	1%
Controls Commissioning	9	3.7	1.1	$3,248	1%
Variable Speed Chillers	4	3.1	1.6	$5,029	0.3%
High-Performance Glass	6	3.0	1.4	$5,572	0.5%
Perimeter Day Lighting	1	6.3	0.9	$7,441	0.1%
Evaporative Assist Cooling	0				0.0%
Total	**634**	**1.9**	**4.3**	**$1,970**	**58%**

Six lost-opportunity measures above account for nearly 90 percent of the savings from lost-opportunity measures identified. Table D-6 shows characteristics of these and other commercial sector lost-opportunity measures and estimates for energy savings targets over the 2005-2009 period. These include estimates of the level of activity required for locally and regionally administered aspects of programs. Table D-6 identifies that most of these measures require direct acquisition investments by utilities and public benefits charge administrators as well as regional approaches. Regional approaches include market transformation, development and implementation of codes and standards, establishing regional specifications for measures or practices, developing regional infrastructure, research and development, and in two cases potential regional acquisition payments.

Table D-6 also identifies in what areas new efforts need to be initiated, and where existing efforts need to be continued or expanded. The Council estimates that the amount of funding needed annually for regionally administered programs is significant increase over current expenditure levels. The Council intends to work through the conservation strategic planning process it recommends to put in place mechanisms and funding to acquire this conservation. Suggested acquisition approaches for the remaining lost-opportunity measures are discussed briefly following Table D-6.

Table D-6 Near-Term Actions for Commercial-Sector Lost-Opportunity Measures

Commercial-Sector Lost-Opportunity Measures									
			Regionally-Administered Activities Needed						
Measure	**Five-Year Target 2005-2009 (MWa)**	**Utility & SBC Acquisition Payments**	**Codes & Standards**	**Market Transformation Ventures**	**Regional or National Product Specs.**	**Regional RD&D**	**Regional Infra-structure Development**	**Regional Acquisition Payments**
Efficient AC/DC Power Converters	12	Potential	New	New	New			Potential
Integrated Building Design	12	Yes		Expand	Expand	Expand	Expand	
Lighting Equipment	7.8	Yes	Continue	New	New	New	Expand	
Packaged Refrigeration Equipment	5.2	Potential	New	New	New	New	New	Potential
Low-Pressure Distribution	3.6	Yes	Continue	Expand	New	Expand	Expand	
Skylight Day Lighting	2.6	Yes	Continue	Continue	Continue	Continue	Continue	
Premium Fume Hood	1.3	Yes	Continue	New		New		
Municipal Sewage Treatment	0.8	Yes		Expand		Continue	Continue	
Roof Insulation	0.9	Yes						
Premium HVAC Equipment	0.7	Yes			Continue	Continue		
Electrically Commutated Fan Motors	0.7		Continue				New	
Controls Commissioning	0.7	Yes	Continue	Expand	Expand		Expand	
Variable Speed Chillers	0.3	Yes					New	
High-Performance Glass	0.4	Yes		Continue		Continue		
Perimeter Day Lighting	0.1	Yes	Continue			Continue		
Evaporative Assist Cooling	0.0	Potential	Continue	New	New	New	New	
Total	**49**							

Efficient Power Supplies

This efficiency opportunity could reduce regional loads in the commercial and residential sectors by about 150 average megawatts in 2025 under medium load growth. The levelized cost of he savings is expected to be less than 1.5 cents per kilowatt-hour when fully deployed. The benefit-cost ratio is about three to one. Initially, program costs will be higher as production volumes are presently low and program costs could equal the capital costs of better power supplies. Eventually, appliance standards could capture the bulk of the savings at very low cost to the utility system or to society. These are lost-opportunity measures. There are many distinct markets for power supplies depending on how they are incorporated into devices, how products are specified and marketed and the structure and location of the manufacturers.

The large potential savings at low cost of efficient AC to DC power converters has recently spurred some national and international efforts aimed at capturing the resource. Initial efforts include standardized test procedures to measure performance of power supplies, design guideline specifications for power supplies in personal computers advanced by Intel, a design competition for efficient power supplies taking place in 2004 with winners to be announced in March 2005. Energy Star specifications are targeted for later in 2004 and efficiency labeling being considered for Energy-Star computers in 2005 which may include power supply specifications or overall computer performance specifications which encourage the use of efficient power supplies in computers. Finally, the state of California is considering mandatory efficiency standards for external power supplies in January of 2006, and more stringent standards in 2008. But additional efforts are needed in the Northwest to realize the full potential of the more efficient technology.

This efficiency opportunity suffers from classic barriers. The markets for both internal and external power supplies are highly competitive based primarily on first cost. The buyers of these devices are predominantly product manufacturers whereas the costs of operation fall on end users and are individually small, providing for little customer-driven demand for efficiency. But, because there are so many of these devices embedded in appliances and buildings, the savings to the power system are large and low cost. To overcome the barriers programs should aim at manufacturers, bulk purchasers and ultimately state level efficiency standards. What is needed is:

- Utility, system benefit charge administrators and Alliance participation in an emerging national buy-down program for desktop computers that contain highly efficient power supplies
- Development and adoption of buy down programs or manufacturer incentives for other high-volume products using power supplies like televisions, VCRs, and computer monitors
- States should adopt mandatory standards for external power supplies consistent with standards that are under consideration in California
- Participation of utilities and efficiency advocates in government labeling and standards discussions and continual improvement in qualifying specifications
- Utility or market transformation programs for high volume purchasers, like government procurement offices, to purchase winning products from the 2004 efficient power supply design competition
- Research and field measurements to better understand the total energy use of plug loads in homes and businesses

Regional and national market transformation efforts are needed in the near term as first steps toward acquisition. Simultaneous efforts will be needed to develop and adopt efficiency standards where applicable. A multi-year effort will be needed and should identify and focus on sub markets that offer significant savings and promising opportunities for effective intervention. The Council expects efforts to improve internal power supplies, which are integral to specific appliances like televisions and video cassette recorders, to require focused efforts for each product class and that these efforts will require cooperative funding of utilities and market-transformation entities from across the country.

Commercial New Building Integrated Design:

The Council estimates that approximately one-third of new commercial floor space could benefit form integrated building design. Estimated achievable conservation potential under the medium forecast is about 150 average megawatts in 2025 at a levelized cost of about 2.3 cents per kilowatt-hour and benefits that are about 5 times costs. Five-year conservation targets are about 12 average megawatts under medium growth.

Integrated building design expands the building design team to include owners, developers, architects, major sub-contractors, occupants and commissioning agents and involves them at the very start of a project. The early collaboration of interested parties lays the foundation for creating a high-performance building. Successful programs require training and education of design practitioners, early identification of projects, marketing, and professional services for coordination, facilitation, design and review. It is a change in the design process, as much as the application of efficiency technologies. As a result, the opportunities cannot readily be captured by codes and standards.

The cost of acquiring savings in new buildings through integrated building design programs is approximately equally split between the improving the design process and the incremental costs of more efficient technology. Although it is often the case that the net capital costs of measures is zero due to synergies that result from of the integrated design process like system downsizing.

There are many energy efficiency activities going on today in support of integrated building design. These include the Alliance-supported Better Bricks project and advisor services, support of the day lighting labs, commissioning and building operator certification, training programs and research assistance. The Alliance is also pursuing a target market strategy that includes integrated design, and is currently focusing on new schools, health care, and grocery stores. These efforts should be continued, and modified. The target market strategy should be expanded to other segments of the new building industry going forward. Several regional utilities have new building programs or green building programs that promote integrated building design concepts and fund or offset costs of a design process that optimizes for energy efficiency. But the penetration of integrated building design practices is low, on the order of 5 percent of new floor space.

At the national level, participation in the U.S. Green Building Council's Leadership in Energy and Environmental Design (LEED) rating system is growing rapidly with over 1000 projects in the registration process. LEED projects can earn points toward a rating in categories of energy efficiency, sustainable sites, water efficiency, materials and resources, indoor environmental quality and design process. While LEED projects do not necessarily employ integrated design processes for energy efficiency, the wide recognition of the rating is appealing to many design teams and owners alike. It is one of the most successful programs at developing interest in better-designed buildings within the new building community. As such it offers an opportunity to engage designers and owners of new buildings and to focus on and improve energy efficiency aspects of new buildings through integrated design. Efforts are underway to improve the energy-efficiency aspects of the LEED rating system. These should be continued. Several utilities in the region and around the country are using LEED as a framework for new building programs and enhancing the energy efficiency aspects of LEED projects.

Also at the national level are the advanced building guidelines for high-performance buildings being developed by the New Buildings Institute. These guidelines and strategies, dubbed E-Benchmark, focus on improving the design process for commercial buildings as well as on specific technologies and practices that improve energy performance. They are designed to be compatible with LEED, and could be a framework for local efficiency programs to foster higher energy performance in buildings.

Changing design practice will take time and continual efforts. Needed activities include:

- Continued training and education of design practitioners
- Developing and deploying strategies to identify and capture integrated design opportunities as they arise so opportunities are not lost
- Building the demand for high-performance buildings among owners and occupants
- Design team collaboration incentives, funding for energy modeling and design charettes and offsetting LEED registration costs
- Incentive payments for adoption of some technologies
- Adopting appropriate integrated design efficiency strategies into building codes
- Integration of operation and maintenance and commissioning practices
- Obtaining and analyzing performance data for high-performance buildings
- Continued research and development of high-performance design practices and technologies

Commercial New and Replacement Lighting Equipment

Advances in commercial lighting technology continue to improve system efficacy, which is the light output of lamps and fixtures per unit of energy input. About 100 average megawatts of savings are available by 2025 in new and replacement lighting systems in addition to lighting savings accounted for under integrated building design above.

About one dozen specific technologies and applications are included in this bundle. These measures tend to have low incremental cost in new and replacement lighting situations because higher system efficacy allows for fewer lamps, ballasts and fixtures and because of low incremental labor costs. The total resource cost is further reduced because of lower re-lamping and maintenance costs. The low cost characteristics combined with high customer benefits of lower maintenance costs and better quality and color, mean customers will eventually pick up a large share of the costs of these measures. But first, practitioners must get familiar with the technologies and their application to assure high-quality and long-lasting efficient lighting solutions. Because these are low cost lost-opportunity resources they are high priority. The ultimate goal is to apply these measures to all new buildings and all replace-on-burnout opportunities.

Northwest utilities, public benefits charge administrators have operated lighting programs for new commercial buildings for about a decade. These have included a range of rebates and design assistance focused at owners, vendors, specifiers and customers. Such efforts should continue and be expanded in the future to target all lost-opportunities. In addition, the region now sponsors lighting design labs in Seattle and Portland. These facilities offer expertise, training, workshops and opportunities for designers and owners to mock-up lighting system configurations to see the results.

As the region moves to the newer technologies and applications, education and training of practitioners will be needed. The region would benefit from common specifications for typical systems to simplify applications. This includes continued support for the lighting design labs and maintaining a cadre of well-informed lighting design specialists. Market research and target marketing is needed to identify and capture new and replacement lighting opportunities as they arise and to identify niche markets such as retail task lighting, warehouses and schools. In addition, increasing customer demand for the maintenance savings, and non-energy benefits of these systems will promote rapid deployment of the new measures. There are significant benefits to be gained from regional cooperation. The Council estimates that over the next five years, significant increases will be needed for regionally administered expenditures in addition to local utility and public benefits charge acquisition expenditures. The regionally-administered efforts should be focused on capturing these lighting measures in new and replacement markets including market transformation ventures, regional infrastructure support, market research and marketing, development of regional and national production specifications, and modifications of building codes and equipment standards.

Day Lighting in New Commercial Buildings

The Council estimates about 77 average megawatts of conservation potential from day lighting applications through skylights and perimeter day lighting in new buildings beyond what is required in code. About half is part of the integrated building design measures and the other half is in new buildings that won't be constructed under integrated design processes. Over the 2005-2009 period, targets for both approaches are about 5 average megawatts and should eventually ramp up to 3 to 4 average megawatts per year. Levelized costs for day lighting are estimated to be about 3.5 cents per kilowatt-hour.

The region has recently established four labs that specialize in day lighting in Seattle, Portland, Eugene and Boise. These work to raise awareness and understanding of the benefits of day lighting designs in commercial buildings. The Alliance contributes to funding the labs and their experts so that Northwest architects and other building professionals can use consulting and modeling services to decide how to best incorporate day lighting into a building design and investigate the use of window glazing, electric lighting and controls.

The Council recommends a combination of regionally administered efforts and local utility and public benefits charge administrator incentives to capture the savings from day lighting in new buildings. Significant utility and public benefits charge administrator support of day lighting is needed in the form of direct incentives. In addition, the Council recommends expanding day lighting efforts over the next five years for regionally based efforts including:

- A market transformation venture focused around the owners and developers in building types where day lighting is most appropriate such as large one-story retail, warehouses, schools and certain office applications
- Research on integration issues including HVAC interaction specific to Northwest climates and daylight patterns
- Continued and expanded support for advisor services, labs, and training that is incremental to amounts in Integrated Design
- Development of Northwest-specific day lighting specifications and design protocols
- Integration of day lighting into building codes

Packaged Refrigeration Units

By 2025, loads could be reduced by about 68 average megawatts through more efficient packaged refrigeration devices such as icemakers, reach-in refrigerators and freezers, vending machines, and glass-door beverage merchandisers. Acquisition targets for the 2005-2009 period are about 5 average megawatts as these programs ramp up. Costs are expected to fall as the technologies are embedded in the products, just as cost fell for efficient residential refrigerators. The Council estimates the levelized cost of these savings is about 1.9 cents per kilowatt-hour.

Ongoing efforts include Energy Star rated products, voluntary purchasing guidelines developed by the Federal Energy Management Program (FEMP) and two levels of voluntary standards developed by the Consortium of Energy Efficiency and used in some utility programs. In addition, the state of California has adopted minimum efficiency standards for icemakers, reach-in refrigerators, freezers and beverage merchandisers. California is considering more stringent standards for these appliances and expanding the standards to include walk-in refrigerators and water coolers. Market transformation efforts for efficient vending machines, undertaken with Coke and Pepsi at the national level, are on the verge of being fruitful. These two companies control the lion's share of the market and are considering specifications that would produce most of the savings from vending machines.

Efforts should focus on market transformation projects at the state, regional and national levels due to the scope of markets for these products. Ultimately standards can be adopted by the Northwest states to assure minimum efficiency levels in most products. The Council recommends that the states adopt the same testing procedures and minimum performance standards as California. This would allow standards to come into play sooner and at lower cost than developing state standards whole cloth. Following California would make for a large west-coast market for these products.

However, the efficiency levels under consideration in California, and proposed by the Council for the Northwest states, are not the most-efficient products on the market. Efforts are also needed to develop a broader range of products that exceed the minimum efficiencies of state standards and to build demand for those products. To promote that goal, acquisition incentives are needed for products that surpass the California standards to stimulate demand and build the case for improving standards over time. These efforts could include rebates and incentives to manufacturers, vendors or perhaps end users for Energy Star products and products that meet the more stringent Tier-2 performance levels suggested by the Consortium for Energy Efficiency (CEE). In addition, regionally based market transformation efforts are needed to work with trade associations & food service consultants, to develop market channels, tailor marketing and incentives to chains and multi-unit purchasers, and to pursue continuous improvements in voluntary standards and national and regional efficient-product specifications.

Costs are expected to decrease sharply as manufacturers incorporate efficiency measures in more of the stock produced. In the near-term, the lion's share of costs are for direct acquisition. The Council recommends that these efforts be regionally based and be focused upstream of consumers for better leverage.

Low-Pressure Distribution Systems

Total savings potential is about 100 average megawatts by 2025, half through integrated building design and half as stand-alone applications. Levelized costs are estimated at 2.7 cents per kilowatt-hour and the benefit-cost ratio is estimated at 1.6. The measure applies primarily to offices but there are some applications in education, health and “other” sub sectors. Two measures are modeled, under floor air distribution systems and dedicated outside air systems. Both are relatively new techniques in the US but are gaining in acceptance. Both show large savings potential of 1.0 to 1.5 kilowatt-hour per square foot where applicable, lower in schools.

These measures are best approached as design practice changes through market transformation efforts. Regionally administered program costs should be expanded over the next five years. Initial efforts should focus on:

- Demonstration projects including engineering, and evaluation and case studies
- Develop ASHRAE aspects for standards & design protocols
- Research and development to refine designs, collect and review performance data, and tailor to Northwest climates.
- Training and marketing
- Regional specification setting
- Incorporation of efficient design and construction practices into codes

Electrically Commutated Fan Motors

The measure has been adopted in the Seattle building codes but should be adopted in statewide codes in Washington, Oregon, Idaho and Montana.

Light Emitting Diode (LED) Exit Signs

This technology should also be adopted in state codes where they are not currently required.

Evaporative Assist Cooling

The Council has not included savings target for this measure in the draft plan. But the savings potential is significant because of the dry summer climate in much of the region and because the relatively poor performance of stock economizers available in new roof top cooling equipment. In the near term the Council recommends a significant research and pilot project for evaporative-assist cooling.

Premium Fume Hoods, Premium HVAC Equipment, New Building System Commissioning Measures, Variable Speed Chillers, High-Performance Glazing

These measures will require regional market transformation or regional infrastructure development with significant utility incentives in the early stages to buy down equipment costs, subsidize design costs.

High-Performance New and Replacement Glazing in Commercial Buildings

Improving the thermal efficiency of glass and window frames used in new buildings, over levels required by building codes, can provide economic electric savings potential in some cases. But identifying optimal “better-than-code” glazing for commercial-sector buildings is site- and application-specific. In some cases going beyond code will not produce significant savings. The Council recommends continued efforts to train and educate building designers and specifiers of commercial glazing products on the selection of optimal glazing system for the new building and replacement window markets. Optimizing the energy and day lighting aspects of glazing should be incorporated as part of the integrated building design process.

Commercial-Sector Dispatchable Resources

About 40 percent of the 2025 commercial-sector achievable conservation potential is in retrofit measures. The Council recommends that the region gear up to be capture 35 average megawatts per year of commercial sector dispatchable conservation, or 175 average megawatts over the 2005-2009 period. Like lost-opportunity measures, retrofit measures require a combination of acquisition approaches. About one quarter of the savings potential is from lighting measures, and it is relatively low-cost. The remainder are from a wide variety of measures and practices on various building types and end uses. Measure levelized costs are generally higher, and benefit-cost ratios generally lower than for commercial-sector lost-opportunity measures. But total capital and program costs per kilowatt-hour are similar. Table D-7 lists the characteristics of retrofit measures in order of total savings potential.

Table D-7: Characteristics of Commercial Sector Retrofit Measures

Measure	Realistically Achievable Potential in 2025 (MWa)	Weighted Levelized Cost (Cents/kWh)	Benefit Cost Ratio	Weighted Total Resource Capital Cost ($/kWa)	Share of Sector Realistically Achievable Potential
Lighting Equipment	114	1.8	2.2	$2,678	10%
Small HVAC Optimization & Repair	75	3.2	1.4	$1,773	6.9%
Network Computer Power Management	61	2.8	1.3	$1,008	5.6%
Municipal Sewage Treatment	37	1.4	2.4	$687	3.3%
LED Exit Signs	36	2.3	1.6	$445	3.3%
Large HVAC Optimization & Repair	38	3.7	1.2	$2,995	3.5%
Grocery Refrigeration Upgrade	34	1.9	1.9	$1,660	3.1%
Municipal Water Supply	25	3.3	1.2	$690	2.3%
Office Plug Load Sensor	13	3.1	1.2	$2,664	1.2%
Pre-Rinse Spray Wash	10	0.6	6.6	$222	0.9%
LED Traffic Lights	8	1.9	1.8	$3,234	0.7%
High-Performance Glass	4	3.8	1.0	$5,545	0.4%
Adjustable Speed Drives	3	4.3	1.1	$7,545	0.3%
Total	**459**	**2.5**	**1.8**	**$1,831**	**42%**

Regionally administered programs are important for retrofit measures, but play a relatively smaller role than utility and public benefits charge administrator direct acquisition approaches. Table D-8 shows the commercial sector retrofit measures and estimated savings targets over the next five years, and where regionally administered efforts need to be initiated, continued or expanded.

Table D-8 Near-Term Actions for Commercial-Sector Retrofit Measures

Commercial-Sector Retrofit Measures									
			Regionally-Administered Activities Needed						
Measure	**Five-Year Target 2005-2009 (MWa)**	**Utility & SBC Acquisition Payments**	**Codes & Standards**	**Market Transformation Ventures**	**Regional or National Product Specs.**	**Regional RD&D**	**Regional Infra-structure Development**	**Regional Acquisition Payments**
Lighting Equipment	44	Yes		New	New	Expand	Expand	
Small HVAC Optimization & Repair	29	Yes		Potential	New	Expand	Expand	
Network Computer Power Management	24	Yes		Expand			Expand	
Municipal Sewage Treatment	14	Yes		Expand		Expand	Expand	
LED Exit Signs	14	Yes						
Large HVAC Optimization & Repair	15	Yes		Expand	Expand	Expand	Expand	
Grocery Refrigeration Upgrade	13	Yes			New		New	Potential
Municipal Water Supply	9.5	Yes		Potential		New	Expand	
Office Plug Load Sensor	5.1	Yes		New		New	New	
Pre-Rinse Spray Wash	3.8	Yes	New					
LED Traffic Lights	3.0	Yes						
High-Performance Glass	1.5	Yes			Continue			
Adjustable Speed Drives	1.3	Yes		Continue				
Total	**176**							

Lighting Equipment

The lighting measures in this bundle are similar to their lost-opportunity counter parts. The main differences being the cost of retrofit applications higher due to labor costs and the savings are somewhat higher due to less efficient baseline systems. About 115 average megawatts is available by 2025. Approximately 44 average megawatts should be acquired over the 2005-2009 period. The benefit -cost ratio of retrofit lighting measures is over 2. Levelized costs are relatively low, about 1.8 cents per kilowatt-hour. The adoption of these measures suffers from the same barriers, primarily lack of awareness, training, equipment availability. Retrofit lighting measures would benefit from the regionally administered programs recommended for lost-opportunity lighting measures. This includes education and training of practitioners, common specifications for typical retrofits, continued support for the lighting design labs and maintaining a cadre of well-informed lighting design specialists. The Council estimates that over the next five years, increasaed funding needed for regionally administered expenditures in addition to local utility and public benefits charge acquisition payments. Regional utilities and public benefits charge administrators have operated commercial retrofit lighting programs for more than a decade with good results. These programs should continue and should focus on delivering the new technologies and applications.

Small HVAC Optimization & Repair

Small roof top HVAC systems provide the lion’s share of cooling and heating loads in the Northwest. The Council estimates about 75 average megawatts of savings potential is available by 2025, most of it in reduced cooling energy. Levelized costs are about 3.2 cents per kilowatt-hour and the benefit-cost ratio about 1.4. But this is a difficult market. There are many small customers, many vendors of repair service, and several different approaches to improve efficiency. Several pilot scale projects have been tried in recent years, at the Alliance and at several regional utilities, with mixed success on performance and cost. The Council believes the cost-effective savings potential is large and continued efforts are warranted to capture about 30 average megawatts over the 2005-2009 period. Currently three approaches are being tested in the region and in California. One addresses maintenance and repair protocols at the site. A second approach aims at replacing old economizers and controllers with a premium economizer package tailored to Northwest climates. A third approach addresses new equipment by promoting advanced system performance specifications for manufactures of new equipment.

In light of the uncertainty about what approach will perform best, the Council believes that first research is needed on the best approach to take and on field performance of fixes. Then pending results of that research, the region should embark on a strategy to capture the savings as effectively as possible. Near-term regionally administered actions include, research, development of a strategy, and building regional infrastructure to support that strategy. A possible market transformation venture would be to encourage a manufacturer to develop and market an economizer product that is designed to perform well in the Pacific Northwest and California.

Network Computer Power Management

Approximately 62 average megawatts of electricity could be saved at a levelized cost of 2.6 cents per kilowatt-hour through automated control on network personal computers (PC). The five-year target for acquisition is 24 average megawatts. An Alliance project aimed at this target has been largely successful in getting a viable product to market. Capturing the remaining potential may require some amount of utility and public benefits charge administrator incentives, particularly if penetration rates are to be increased. In addition, there may be opportunities to develop a market transformation venture aimed at corporate information technology managers, or expanding the concept to other network-addressable devices commonly used in commerce.

Municipal Sewage Treatment

Between existing and forecast new sewage treatment plant capacity, the Council estimates approximately 37 average megawatts could be saved by optimizing plant operations through relatively simple controls at a levelized cost of 1.4 cents per kilowatt-hour and a benefit-cost ratio of 2.4. The five-year acquisition target is 14 average megawatts. An Alliance project aimed at this target has been largely successful in getting a viable optimization service and some new technology to market. Capturing the remaining potential may require some amount of utility and public benefits charge administrator incentives, particularly if penetration rates are to be increased.

In addition, there may be further opportunities for improving the energy efficiency of treatment regimes through new technological developments that would aid in controlling the biological process of treatment. Such an effort would require about $1 million per year over the next five year in research and market transformation venture capital.

Municipal Water Supply

The estimated 25 average megawatts of electric savings in municipal water supply systems need to be confirmed through research and developed if it proves to be cost-effective and practicable. Near-term efforts should include a research and confirmation agenda with pilot projects. Depending on the outcome of the research and verification, utility and public benefits charge administrator programs would most likely be the vehicle for capturing the savings. Such a project may benefit from some regionally administered marketing, training, and infrastructure development.

LED Exit Signs

This is a proven technology with good product availability, significant labor savings, but small per unit savings. However, the Council estimates there are many exit signs in existing buildings that do not yet use efficient technologies. By 2025 about 36 average megawatts are available at levelized costs of 2.3 cents per kilowatt-hour and a benefit-cost ratio of about 1.6. Acquisition of this measure is most suitable through utility and public benefits charge administrator programs to buy down the replacement cost of the more efficient signage. The acquisition rate of this measure should target 14 average megawatts over the 2005-2009 period.

Large HVAC Optimization & Repair

Optimizing the performance of existing buildings, with complex HVAC systems, through commissioning HVAC and lighting controls could save the region nearly 40 average megawatts at a levelized cost of 3.7 cents per kilowatt-hour and a benefit-cost ratio of about 1.2. Capturing these savings requires a cadre of trained experts armed with analytical tools to optimize these complex energy systems. The Alliance has embarked on a market transformation pilot project dubbed Building Performance Systems that aims at developing a market structure that promotes and supports enhanced building operating performance. In partnership with the region's utilities, public benefits administrators, building owners/managers and service providers, key activities for this project include infrastructure development, a building performance services test, and a large-scale pilot. In addition, the Alliance supports building operator certification, the Building Commissioning Association and other regional training and educational infrastructure that support acquiring these savings. These efforts should be continued along with utility and public benefits charge administrator program incentives. The Council estimates that significant regionally administered program expenditures are needed to tap this measure in addition to locally administered incentives and programs.

Grocery Refrigeration Upgrade

Retrofitting the refrigeration systems of existing grocery stores to improve efficiency could save the region about 34 average megawatts by 2025 at a levelized cost of 1.9 cents per kilowatt-hour and a benefit-cost ratio of 1.9. These savings come from over one dozen individual measures that include simple and fairly complex retrofits such as high-efficiency case doors, anti-sweat heater controls, efficient motors in cases, floating head pressure control, and strip curtains and automatic door closers for walk-in coolers. This retrofit market overlaps many utility and Public Benefits Charge service territories and would benefit from common specifications for energy efficiency measures. Some training and education of service providers is needed as well as some regional marketing. The Council estimates that locally administered efforts would be modest. But the brunt of expenditures and incentives should be locally administered through utility and public benefits charge administrators.

High-Performance Glass

There remain a significant number of electrically heated buildings with single-glazed windows. Some of these are viable to retrofit with new high-performance glazing that will reduce both heating and cooling loads. The Council estimates about 4 average megawatts could be saved by 2025 by retrofitting the windows in these buildings and selecting new glazing to minimize heating and cooling energy use. Window retrofits on gas-heated buildings with electric cooling do not appear to be cost-effective. This measure is primarily a locally administered program that will require some design assistance in selecting appropriate glazing as well as providing incentives to do the retrofits.

Office Plug Load Sensor, LED Traffic Lights, Pre-Rinse Spray Valves and Adjustable Speed Drives

These measures together could reduce 2025 energy loads by nearly 30 average megawatts. The measures are best captured through locally administered programs. State codes can be adopted for pre-rinse spray valves.

Irrigated Agriculture Sector

Agricultural-Sector Lost Opportunity Resources

The Council did not identify any potential lost opportunity conservation resources in the Irrigated Agriculture Sector. However, this does not mean that all new irrigation systems are being designed to capture all cost-effective energy efficiency opportunities. While competitive economic and environmental pressures certainly encourage the use of more energy and water efficient irrigation systems, farmers, due to capital or other constraints, do not always install the most efficient systems. Utility, public benefits charge administrators and federal and state agricultural extension service education and technical assistance programs are still needed to help farmers and irrigation system hardware vendors design energy efficient systems.

Agricultural-Sector Dispatchable Resources

The Council believes that utility and public benefits charge administrator acquisition programs are best suited to capture the five average megawatts of savings targeted per year in existing irrigation systems. Over the course of the past two decades Bonneville, along with many of its utility customers with significant irrigation loads have operated irrigation system efficiency improvement programs. These programs will need to be significantly expanded to attain the Council's regional target.

Industrial Sector Acquisition Strategies

The Council believes that the 35 average megawatts of energy savings per year target for the industries in the region is best accomplished through closing coordinated utility and public benefits charge administrator acquisition programs and regional market transformation programs.

Several industrial market transformation projects have been operated by the Alliance. These include projects that impact compressed air and motor management systems commonly used across many industries. The Alliance has also targeted specific technologies used in Northwest industries including pneumatic conveyors common in the wood products industry, refrigeration systems for cold storage warehouses, sewage treatment and others. Utilities and SBC administrators have developed programs that support these market transformation efforts. Bonneville and the region's utilities have developed programs that purchase energy savings from industrial customers, that rebate specific technologies, or that develop customer-specific programs tailored to meet the needs of both parties. These approaches should continue.

Industrial conservation measures generally have relatively short lifetimes because of the rapid rate of change in production facilities. So few conservation measures qualify as lost-opportunity measures because they exceed the life of the planning period. But in practice, many of the opportunities to improve efficiency in the industrial sector are associated with changes in production techniques, products produced, plant modernization, or changes required for improving product quality, quality control and even safety or environmental compliance. Taking advantage of these opportunities to improve energy efficiency is important. The Council believes these windows of potential influence should be considered as lost-opportunities because in a practical sense, the associated savings are not available if not captured during the natural process of industrial change and modernization.

Successful development of industrial-sector energy efficiency depends on developing the infrastructure and relationships between program and plant staff. A network of consultants with appropriate technical expertise is needed. This expertise is available for motor management and compressed air programs. But for other measures, such as motor system optimization and industrial lighting design, where access to experienced engineers and designers is more critical, the identification and/or development of the support network will require time and effort. A mix of market transformation ventures, regional infrastructure development, and local program offerings from rebates to purchased savings will be needed to realize this source of low-cost energy efficiency potential. Stable funding of utility acquisition investments is needed so that industrial customers can coordinate their capital budgeting process with utility financial support. Regional market transformation initiatives that focus on changing industrial energy management practices are also needed to ensure that efficiency investment opportunities are integrated into corporate productivity goals.

The Council, Bonneville, the Alliance, utilities, and SBC administrators should work with the regions industries, industrial trade associations and industrial service providers to develop and implement a strategy to tap industrial conservation over the next decade.

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Conservation Cost-Effectiveness Determination Methodology

CONSERVATION COST-EFFECTIVENESS

As with all other resources, the Council uses its portfolio model to determine how much conservation is cost-effective to develop.[1] The portfolio model is designed to compare resources, including conservation on a "generic" level. That is, it does not model a specific combined cycle gas or coal plant 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. In order to capture the impact of variations in wholesale market prices during the day and through the year have on conservation's value, the savings in these two supply curves are allocated to "on-peak" and "off-peak" periods for each quarter of the year. This allocation is done based on the collective savings-weighted load shape of the individual measures in each of these supply curves.

However, it is not possible to determine individual measure or program cost-effective using the Council's portfolio model. Run time constraints limit the number of conservation programs the portfolio model can consider. The portfolio model 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. In addition, conservation provides other benefits that are not accurately captured by the portfolio model.

First, unlike generating resources, conservation savings can defer the need to expand distribution and transmission networks. While the Council attempts to capture these benefits by adjusting the levelized cost of the aggregate supply curves, the portfolio model does not evaluate each measure's specific load shape and therefore does not accurately reflect that measure's impact on the need to expand transmission and distribution systems. Second, some conservation measures, for example high efficiency clothes washers that save both water and electricity, provide "non-energy system" benefits to consumers. Because of programming constraints, the levelized costs of conservation used in the portfolio model are not adjusted for non-energy benefits that accrue to the customers. Therefore, to determine whether a specific conservation measure or package of measures is regionally cost-effective requires the Council to compare the present value of each measure's benefits to the present value of its life cycle costs based on its specific benefits and costs. Benefits

[1] 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.

include energy and capacity cost savings, local distribution cost savings and the 10 percent credit given conservation in the Northwest Power Act and any quantifiable non-energy benefits.[2]

Benefit-to-Cost Ratio

The costs included in the Council's analyses are the sum of the total installed cost of the measure, program administrative costs and any operation and maintenance costs (or savings) associated with ensuring the measure's proper functioning over its expected life. The benefit-to-cost ratio of a measure is the sum of the present value benefits divided by the sum of the present value costs. Any measure that has a benefit-to-cost ratio of 1.0 or greater is deemed to be regionally cost effective. Those measures that pass this screening step are then grouped into "programs. The cost of this package of measures is then increased to account for program administrative expenses to estimate whether the overall package is regionally cost-effective.[3] If the "program" package has a benefit-to-cost ratio of less than 1.0 then the most expensive measures are removed from the package until the program's benefits equal or exceed its costs.

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. Each measure's annual savings are evaluated for their effects on the power system over the 8,760 hours in a year and over the twenty years in the planning period.

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.

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

[2] To ensure that conservation and generating resources are compared fairly, the costs and savings of both types of resources must be evaluated at the same point of distribution in the electrical grid. Conservation savings and costs are evaluated at the point of use, such as in the house. In contrast, the costs and generation from a power plant are evaluated at the generator itself (busbar). Thus, to make conservation and the traditional forms of generation comparable, the costs of the generation plant must be adjusted to include transmission system losses and transmission costs.

[3] In addition to the direct capital and replacement costs of the conservation measures, administrative costs to run the program must be included in the overall cost. Administrative costs can vary significantly among programs and are usually ongoing annual costs. In prior power plans, the Council used 20 percent of the capital costs of a conservation program to represent administrative costs. The Council's estimate of 20 percent falls within the range of costs experienced in the region to date. Therefore, the average cost of all conservation programs is increased 20 percent before being compared to generating resources.

Southwest. Consequently, wholesale power prices are significantly higher during the peak air conditioning season in July and August than they are during the remainder of the year. As a result, 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.

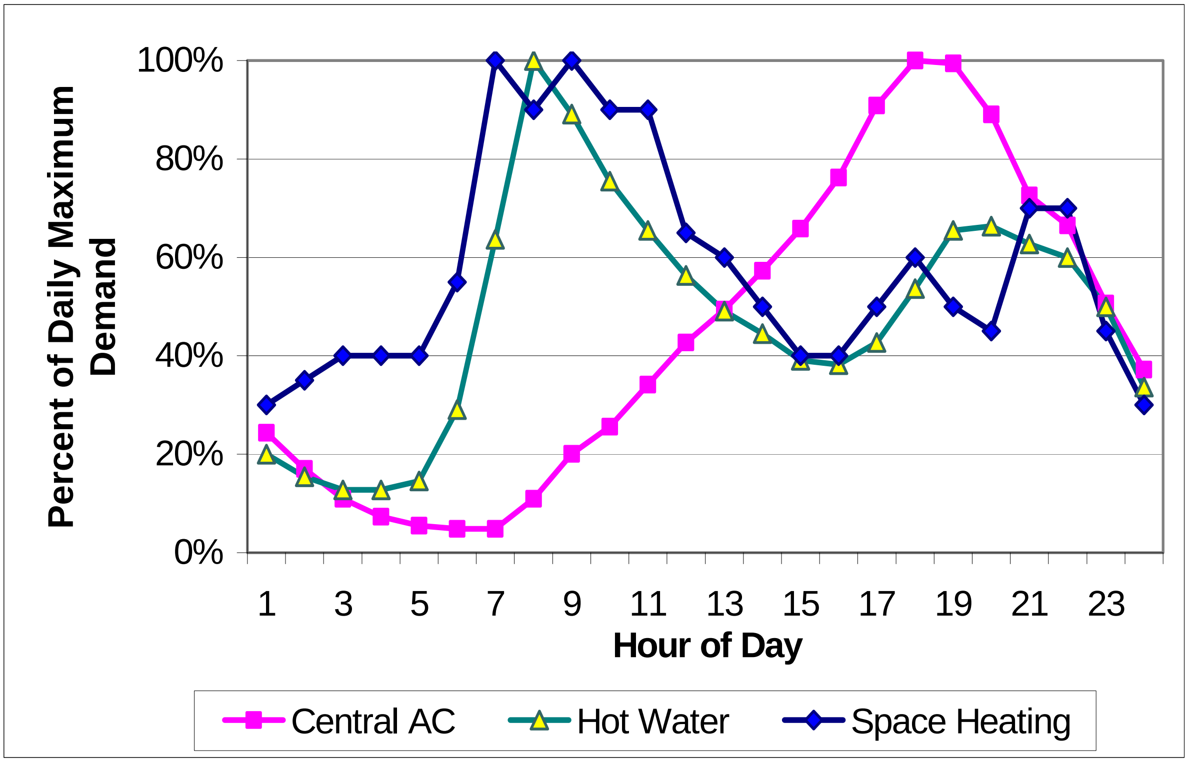

Figure E-1: Hour Load Profile for Residential Central Air Conditioning Water Heating and Space Heating Conservation Savings

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 over the course of a typical day. The horizontal axis shows the hour of the day, with hour "0" representing midnight.

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 significantly over the course of a typical summer day and less significantly over the course of a winter day. Figure E-2 shows the average levelized "on peak" and "off peak" wholesale market prices at the Mid-Columbia trading hub for January and August. As can be seen from Figure E-2, summer “on-peak” savings are far more valuable than those that occur either “off-peak” during the summer or either “on” or “off-peak” during the winter.

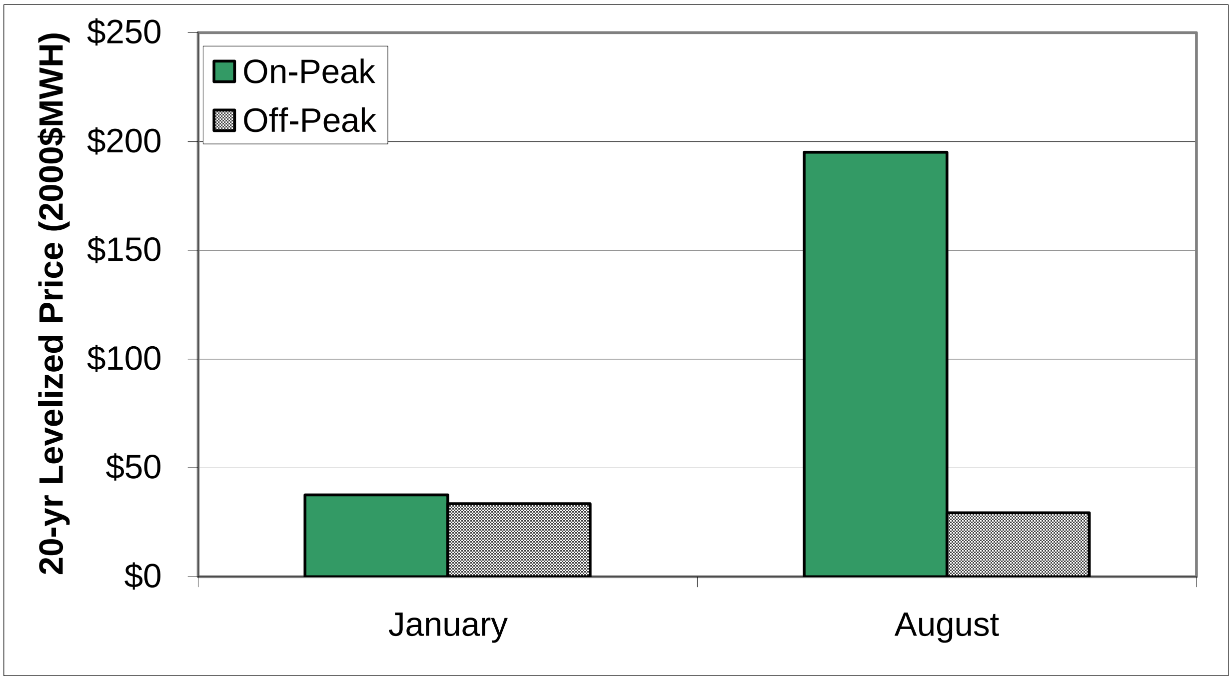

Figure E-2: Forecast Levelized “On” and “Off-Peak” Wholesale Power Market Prices for January and August at Mid Columbia Trading HUB

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. Figure E- 3 shows an illustrative example of the levelized avoided cost by month compared to the monthly distribution of central air conditioning and space heating savings. 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 all time periods’ avoided costs establishes the value of the kilowatt-hour portion of the energy savings.

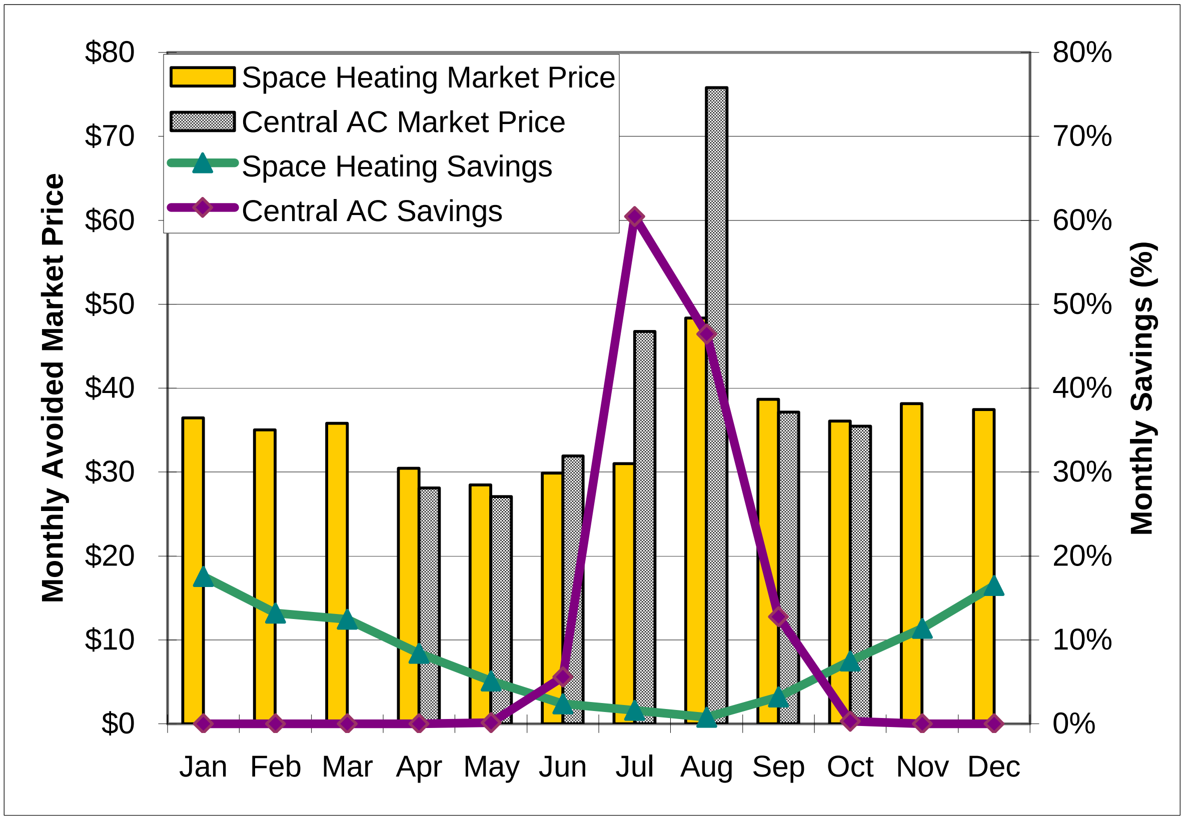

Figure E-3: Illustrative Levelized Wholesale Market Price by Month Compared to Monthly Energy Savings for Space Heating and Central Air Conditioning

An inspection of Figure E-3 reveals that the cost-effectiveness limit for air conditioning will be higher than for space heating because wholesale market prices for electricity are higher at the times when air conditioning energy is saved. In this example, the "cost-effectiveness limit" for a conservation measure that produced savings shaped like those for residential central air condition would be 8.8 cents per kilowatt-hour compared to just 3.7 cents per kilowatt-hour if its savings were shaped like residential space heating.

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. Although the Council currently uses its "base case" AURORA® model forecast of future wholesale market prices to determine conservation cost-effectiveness, the Council is reviewing its analytical system to determine whether it is feasible to use the portfolio model's distribution of future market prices rather than a single market price forecast. In the interim, the value of conservation savings determined using the "base case" AURORA® market price forecast should be viewed as conservative since this value does not incorporate any hedge against future market price volatility.

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) from the Oregon Public Utilities Commission to develop a "default" estimate of avoided transmission and distribution costs. Table 6 presents data collected from PacifiCorp and Portland General Electric (PGE) based on their filings in Oregon. Information from Snohomish County Public Utility District (Snohomish PUD) on distribution system costs only is also included in this table.

Table E-1: Utility Specific Avoided Costs for Transmission and Distribution

COMPANY	TRANSMISSION	DISTRIBUTION	TOTAL
PacifiCorp	$21.40/kW-yr	$57.59/kW-yr	$78.99/kW-yr
PGE	$7.18/kW-yr	$15.40/kW-yr	$22.58/kW-yr
Snohomish PUD	(N/A)	$9.50/kW-yr	(N/A)

From the information collected, the RTF chose as its "default" assumption a value of $20 per kilowatt year as the avoided cost of local utility transmission and distribution avoided cost. The RTF also chose a “default” value of $3 per kilowatt year for avoided transmission system expansion cost. The present value of avoiding these investments is included as part of the wholesale transmission and local distribution system benefits of conservation and distributed renewable resources.

As discussed above, due to the interconnected nature of the West coast wholesale power market, conservation measures that reduce consumption during the summer air conditioning season are the most valuable. 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. 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 is also used to determine the “on-peak” savings for each conservation measure. This varied from zero value for central air conditioning to 1.8 cents per kilowatt-hour for residential space heating.

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 when estimating benefit-to-cost ratios.[4]

Comparative Examples of Cost-Effectiveness Limits

Table E-2 shows the levelized cost for a sample of conservation measures that would produce a Total Resource Cost benefit-to-cost ratio of 1.0 based on avoided wholesale market purchases and deferred capital investments for transmission and distribution. As can be seen from a review of Table E-2 the "cost-effectiveness" limit ranges from 3.7 cents per kilowatt-hour for more efficient street and area lighting to 8.8 cents per kilowatt-hour for savings from efficiency improvements in window air conditioners when transmission and distribution benefits are considered. When these benefits are not considered the range extends from 3.3 cents per kilowatt-hour up to 7.0 cents per kilowatt-hour. These ranges are completely attributable to the load shape of each measures savings. In Table E-2 measure life is assumed to be 20 years for all measures for purposes of comparison. Actual measure lives used by the Council differ.

While the Act's 10 percent credit for conservation is included in the values shown in Table E-2 all measures shown in the table are assumed to have no non-energy benefits. As mentioned previously, some measures such as residential clothes washers provide the region with substantial non-energy benefits. One of the reasons high efficiency clothes washers save electricity is that they use less hot water. Consequently, they also use less detergent as well as reduce the amount of wastewater that needs to be treated. The Council includes these additional non-energy benefits in its calculation of the Total Resource Cost effectiveness. In the case of residential clothes washers, this increases the "cost-effectiveness limit" from 5.3 cents per kilowatt-hour to 12.1 cents per kilowatt-hour.

Cost-Effectiveness Limits and Power System Acquisition Costs

The Council uses Total Resource Cost as its measure of regional cost-effectiveness. It selected this metric because it attempts to account for all of a measure's costs and benefits, regardless of who pays or receives them. Ignoring a consumer's share of the cost of installing a conservation measure would understate its true cost to the region. Alternatively, ignoring a consumer's savings in operation and maintenance cost or reduced water consumption would understate a conservation measures actual benefits. Unfortunately, the distribution of conservation's costs and benefits among the region's consumers is rarely perfectly aligned. For example, the non-energy benefits accrue to the consumer purchasing the clothes washer and not to the region's power system. Therefore, while electricity savings from high efficiency clothes washers (and other similar measures) should be

[4] The Council's Portfolio analysis model uses levelized cost, rather than benefit-to-cost ratio to as its measure of cost-effectiveness when testing conservation development strategies. In its portfolio analysis process the Council eliminates from consideration any resource plans that do not develop at least the level of conservation that is consistent with the Act's requirement to provide conservation with a 10 percent premium over other resources.

viewed as regionally cost-effective, the power system's maximum contribution to the acquisition of these savings should be limited by the benefits provided by electricity savings.

Table E-2: Cost-Effectiveness Limits for Illustrative Conservation Resources[5]

Conservation Resource Category	Cost-Effectiveness Limit w/ Transmission and Distribution Benefits (Cents/kWh)	Cost-Effectiveness Limit w/o Transmission and Distribution Benefits (Cents/kWh)
Street & Area Lighting	3.7	3.3
Commercial - Existing Small Office and Retail Building Envelope Measures	4.1	3.5
Flat Load Profile	4.2	3.9
Commercial Lighting - New Small Office, Gas Heating	4.3	3.8
Agricultural - Dairy Milking Barn, Electric Hot Water	4.3	3.8
Residential Refrigerators	4.4	4.0
Agricultural - Dairy Milking Barn, Milking Machine Pumps (VFD)	4.4	4.0
Industrial - Primary Aluminum Smelting	4.4	3.9
Industrial - Pulp & Paper (SIC 26)	4.5	4.0
Industrial - Lumber & Wood Products (SIC 24)	4.5	4.1
Residential Lighting	4.5	3.9
Commercial Lighting - New Small Office, Air Source Heat Pump Heating and Cooling	4.6	4.0
Residential Freezers	4.6	4.1
PNW System Load Shape	4.6	4.1
Industrial - Food Processing (SIC 20)	4.6	4.1
Commercial Lighting - New Warehouse - Top Daylight, Unspecified Heating Fuel	4.6	4.0
Residential Space Heating - New Homes	4.8	3.3
Residential Domestic Water Heating	4.9	4.0
Commercial Lighting - New Large Retail, Electric Resistance Heating	4.9	4.4
Industrial - Generic Plant with One Shift	5.2	4.6
Commercial Lighting - New Large Office, Air Source Heat Pump Heating and Cooling	5.3	4.7
Residential Clothes Dryers	5.3	4.2
Residential Clothes Washers	5.3	4.2
Agricultural - Irrigation	5.5	4.7
Commercial Lighting - New Hotel, Electric Resistance Heating	5.5	5.1
Commercial Lighting - Existing School, Electric Resistance Heating	5.9	5.5
Commercial Lighting - New School - Top daylight, Unspecified Fuel	6.0	5.4

[5] The values in this table assume a 20 year measure life, the Council's medium market price forecast and that the measures are financed at 4% real interest over 15 years using a 4% real discount rate. Dollars are year 2000. In computing the regional benefit-to-cost ratios the Act's 10% conservation credit has been included. However none of these measures are assumed to produce any non-energy benefits.

Solar Domestic Water Heating - Summer Peaking Solar Zone 3	6.1	6.0
Commercial Lighting - New Large Office, Electric Resistance Heating	6.2	5.7
Residential Cooking	6.2	4.1
Customer Side Photovoltaic - Summer Peaking Solar Zone 1	6.3	5.5
Commercial Lighting - Existing Health Care Facility, Electric Resistance Heating	6.9	6.5
Commercial - Existing Small Office and Retail Building Central Air Conditioning Efficiency Improvements	7.3	5.9
Commercial Lighting - New Health Care Facility, Electric Resistance Heating	7.4	7.0
Residential Central Air Conditioning Regional Average	7.7	6.3
Residential Window Air Conditioning - Cooling Zone 2	8.8	7.4

MODEL CONSERVATION STANDARD

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 ELECTRICALLY 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 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 at least 85 percent of the 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.

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1 This chapter supersedes the Council's previous model conservation standards and surcharge methodology.

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.]

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:

The Model Conservation Standard for 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 F-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 F-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.

The Model Conservation Standard for 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] 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: 6,000-7,500 heating degree days; and Zone 3: over 8,000 heating degree days.

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 the Model Conservation Standard for New Site Built Electrically Heated Residential Buildings			
	Climate Zone		
Component	**Zone 1**	**Zone 2**	**Zone 3**
Ceilings			
• Attic	R-38 (U-0.031)[a]	R-38 (U-0.031)[a]	R-49 (U-0.020)[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-19	R-19	R-19
Floors			
• Crawlspaces and Unheated Basements	R-30 (U-0.029)	R-30 (U-0.029)	R-38 (U-0.022)
• Slab-on-grade - Unheated[e]	R-10 to 4 ft or frost line whichever is greater	R-10 to 4 ft or frost line whichever is greater	R-10 to 4 ft or frost line whichever is greater
• Slab-on-grade - Heated	R-10 Full Under Slab	R-10 Full Under Slab	R-10 Full Under Slab
Glazing[f]	R-2.9 (U-0.35)	R-2.9 (U-0.35)	R-2.9 (U-0.35)
Maximum Glazed Area (% floor area)[g]	15	15	15
Exterior Doors	R-5 (U-0.19)	R-5 (U-0.19)	R-5 (U-0.19)
Assumed Thermal Infiltration Rate[h]	0.35 ach	0.35 ach	0.35 ach
Mechanical Ventilation[i]	See footnote h, below		
Service Water Heater[j]	Energy Factor = 0.93		

[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 Zone 3 shall be framed using techniques to ensure full insulation depth to the exterior of the wall. Attics in multifamily buildings in Zone 3 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] Reference case glazing area limitation for use in thermal envelope component tradeoff calculations. Glazing area is not limited if all building shell components meet reference case maximum U-factors and minimum R-values.

[h] Assumed air changes per hour (ach) used for determination of thermal losses due to air leakage.

[i] Indoor air quality should be comparable to levels found in non-model conservation standards dwellings built in 1983. To ensure that indoor air quality comparable to 1983 practice is achieved, Bonneville’s programs must include pollutant source control (including, but not limited to, combustion by-products, radon and formaldehyde), pollutant monitoring, and mechanical ventilation, that may, but need not, include heat recovery. An example of source control is a requirement that wood stoves and fireplaces be provided with an outside source of combustion air. At a minimum, mechanical ventilation shall have the capability of providing the outdoor air quantities specified in the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 62-89, *Ventilation for Acceptable Indoor Air Quality*. Natural ventilation through operable exterior openings and infiltration shall not be considered acceptable substitutes for achieving the requirements specified in ASHRAE Standard 62-89.

[j] Energy Factor varies by tank capacity. Energy Factor = 0.996 - 0.00132 x rated volume

Table F-2: Illustrative Paths for the Model Conservation Standard for New Electrically Heated Manufactured Homes[a]			
	Climate Zone		
Component	**Zone 1**	**Zone 2**	**Zone 3**
Ceilings			
• Attic	R-38 (U-0.027)	R-38 (U-0.027)	R-49 (U-0.023)
• Vaults	R-30 (U-0.033)	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]	R-3.3 (U-0.30)	R-3.3 (U-0.30)	R-3.3 (U-0.30)
Maximum Glazed Area (% floor area)[c]	15	15	15
Exterior Doors	R-5 (U-0.19)	R-5 (U-0.19)	R-5 (U-0.19)
Assumed Thermal Infiltration Rate[d]	0.35 ach	0.35 ach	0.35 ach
Overall Conductive Heat Loss Rate (Uo)	0.049	0.048	0.047
Mechanical Ventilation[e]	See footnote e, below		
Service Water Heater[f]	Energy Factor = 0.93		

[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] Reference case glazing area limitation for use in thermal envelope component tradeoff calculations. Glazing area is not limited if all building shell components meet reference case maximum U-factors and minimum R-values.

[d] Assumed air changes per hour (ach) used for determination of thermal losses due to air leakage.

[e] Indoor air quality should be comparable to levels found in non-model conservation standards dwellings built in 1983. To ensure that indoor air quality comparable to 1983 practice is achieved, Bonneville's programs must include pollutant source control (including, but not limited to, combustion by-products, radon and formaldehyde), pollutant monitoring, and mechanical ventilation, that may, but need not, include heat recovery. An example of source control is a requirement that wood stoves and fireplaces be provided with an outside source of combustion air. At a minimum, mechanical ventilation shall have the capability of providing the outdoor air quantities specified in the American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE) Standard 62-89, *Ventilation for Acceptable Indoor Air Quality*. Natural ventilation through operable exterior openings and infiltration shall not be considered acceptable substitutes for achieving the requirements specified in ASHRAE Standard 62-89.

[j] Energy Factor varies by tank capacity. Energy Factor = 0.996 - 0.00132 x rated volume

The Model Conservation Standard for 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 90.1-2001 with addenda a through am, 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 90.1-2001 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 90.1-2001 (I-P Version) -- Energy Standard for Buildings Except Low-Rise Residential Buildings (IESNA cosponsored; ANSI approved; Continuous Maintenance Standard), I-P Edition and addenda a through am 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.

The Model Conservation Standard for 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.

The Model Conservation Standard for 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.

The Model Conservation Standard for Conservation Programs not Covered by Other Model Conservation 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, as a consequence of the West Coast Energy Crisis, many utilities have recently increased their rates significantly. Investments in conservation, like any other resource acquisition, will increase utility cost and place additional upward pressure on rates. Furthermore, it is uncertain when and to what extent Bonneville will implement the Council's recommended role in power supply and whether Bonneville will establish rates that result in all of its customers having at least some portion of their loads exposed to cost of new resources. Therefore, in the near term, Bonneville should structure its conservation programs to address the barriers faced by utilities.

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.

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[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.

Model Conservation Standards

COST-EFFECTIVENESS AND ECONOMIC FEASIBILITY OF THE MODEL CONSERVATION STANDARDS FOR NEW RESIDENTIAL BUILDINGS

This appendix provides an overview of the method and data used to evaluate the regional cost-effectiveness and consumer economic feasibility of the Council's Model Conservation Standards for New 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	R25	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)	R11	Not Applicable
Slab-below-Grade (F-Value/lin.ft. perimeter)	R10	Not Applicable
Window	Class 40 (U<0.40)	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.[2] These costs were converted to year 2000 dollars using the GDP Deflator from mid-1994 to mid-2000. Costs were obtained from builders, subcontractors and materials suppliers from across the region and include a 36 percent markup for overhead and profit. Table G-1 provides a summary of the incremental costs used in the staff analysis for site built homes.

Cost for new manufactured home energy efficiency improvements were obtained from regional manufacturers, insulation and window.[3] Table G-2 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.

[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.

[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-2: Incremental Cost of New Site Built Residential Space Heating Conservation Measures

Conservation Measure	Incremental Installed Cost (2000$/sq.ft.)
Wall R19 Standard Framing	Base
Wall R19 Intermediate Framing	$(0.04)
Wall R21 Intermediate Framing	$0.15
Wall R21 Advanced Framing	$0.15
Wall R21 Standard Framing + R5 Foam	$0.84
Wall R30 Stressed Skin Panel	$1.15
Wall R38 Double Wall	$0.59
Attic R38 Standard Framing	Base
Attic R49 Advanced Framing	$0.69
Attic R60 Advanced Framing	$0.40
Vault R30 (Joisted)	Base
Vault R38 (Joisted w/High Density Insulation)	$0.61
Vault R50 Stressed Skin Panel	$2.11
Vault R30 (Scissor Truss)	Base
Vault R38 (Scissor Truss)	$0.61
Underfloor R25	Base
Underfloor R30	$0.24
Underfloor R38 (Truss joist)	$0.40
Window Class 40 (U<0.40)	Base
Window Class 35 (U<0.35)	$0.66
Window Class 30 (U<0.30)	$3.46
Window Class 25 (U<0.25)	$3.69
Exterior Door R5	Base
Slab-on-Grade R10 Perimeter, down 2 ft.	Base
Slab-on-Grade R10 Perimeter, down 4 ft.	$2.48
Slab-on-Grade R10 Perimeter & Full Under Slab	$4.98
Below-Grade Wall R11 Interior	Base
Below-Grade Wall R19 Interior	$0.30
Below-Grade Wall R21 Interior	$0.15

Table G-3: Incremental Cost of New Manufactured Home Residential Space Heating Conservation Measures

Conservation Measure	Incremental Installed Cost (2000$/sq.ft.)
Wall R11 Standard Framing	Base
Wall R19 Standard Framing	$0.54
Wall R21 Standard Framing	$0.15
Attic R19	Base
Attic R25	$0.11
Attic R30	$0.09
Attic R38	$0.13
Attic R49	$0.19
Vault R19	Base
Vault R25	$0.11
Vault R30	$0.09
Vault R38	$0.13
Underfloor R22	Base
Underfloor R33	$0.15
Underfloor R44	$0.15
Window Class 50 (U<0.50)	Base
Window Class 40 (U<0.40)	$1.91
Window Class 35 (U<0.35)	$1.00
Window Class 30 (U<0.30)	$1.00
Exterior Door R2.5	Base
Exterior Door R5	$4.54

Energy Use Assumptions

The Council used an engineering simulation model, SUNDAY©, which has been calibrated to end-use metered space heating for electrically heated homes built across the region.[4] 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 SUNDAY© simulation model was then used to estimate the space heating 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	1,344 sq.ft.	2,200 sq.ft.	2,283 sq.ft.	924 sq.ft.	1,568 sq.ft.	2,352 sq.ft.
Attic	960	802	719	400	908	1,092
Door	38	55	89	38	38	58
Floor	1,344	1,721	104	924	1,568	2,352
Volume	10,752	17,600	18,264	7,577	12,858	19,286
Joisted Vault			479			479
Slab-on-Grade (F-Value/lin.ft.perimeter)			140			140
Trussed Vault	405	684		524	660	1,558
Wall	1,231	2,122	1,817	1,048	1,026	1,059
Wall below Grade (Int.)			560			560
Slab-below-Grade (F-Value/lin.ft.perimeter)			140			140
Window	176	366	210	116	196	353
Envelop Area	4,154	5,750	4,258	3,050	4,396	7,791

Five locations, Seattle, Portland, Boise, Spokane and Missoula were selected to represent the range of climates found across the region. 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	Missoula
Heating Zone 1	25%	53%	22%	0%	0%
Heating Zone 2	0%	0%	15%	85%	0%
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 F-6 through F-8 show the results of the cost-effectiveness analysis for each heating climate zone for site built homes and Tables F-9 through F-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.**				**2283 sq.ft**			
Measure	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**
Wall R21 ADV	$182	**565**	**2.77**	Wall R21 ADV	$313	**975**	**2.80**	Wall R21 ADV	$268	**894**	**3.05**
Window CL35	$117	**344**	**2.61**	Window CL35	$243	**710**	**2.61**	Window CL35	$133	**422**	**2.90**
Floor R30 STD	$318	**662**	**1.83**	Floor R30 STD	$407	**839**	**1.85**	Floor R30 STD	$25	**56**	**2.07**
Floor R38 STD w/12” Truss	$536	**382**	**0.62**	Floor R38 STD w/12” Truss	$686	**484**	**0.63**	BG Wall R19	$165	**294**	**1.62**
Attic R49 ADVrh	$666	**426**	**0.56**	Attic R49 ADVrh	$557	**352**	**0.57**	Slab R10-4 ft.	$347	**375**	**0.99**
Window CL30	$608	**335**	**0.48**	Window CL30	$1,265	**689**	**0.48**	Slab R10-Full	$697	**747**	**0.98**
Window CL25	$650	**332**	**0.44**	Window CL25	$1,351	**688**	**0.45**	Floor R38 STD w/12” Truss	$41	**32**	**0.71**
Vault R38 HD	$245	**111**	**0.39**	Vault R38 HD	$414	**187**	**0.40**	Attic R49 ADVrh	$832	**582**	**0.64**
Wall R21 STD+R5	$1,036	**381**	**0.32**	Wall R21 STD+R5	$1,786	**658**	**0.33**	Window CL30	$691	**418**	**0.55**
Wall 8” SS Panel	$1,418	**421**	**0.26**	Wall 8” SS Panel	$2,444	**725**	**0.26**	Window CL25	$738	**420**	**0.52**
Attic R60 ADVrh	$383	**107**	**0.24**	Attic R60 ADVrh	$320	**90**	**0.25**	Wall R21 STD+R5	$1,529	**635**	**0.38**
Wall R33 DBL	$727	**46**	**0.05**	Wall R33 DBL	$1,253	**79**	**0.06**	BG Wall R21	$83	**31**	**0.34**
Vault 10” SS Panel	$855	**15**	**0.01**	Vault 10” SS Panel	$1,444	**26**	**0.02**	Wall 8” SS Panel	$2,093	**711**	**0.31**

Table G-7: Regional Cost-Effectiveness Results for Site Built Homes in Heating Zone 2

1344 sq. ft				2200 sq. ft				2283 sq. ft			
Measure	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**
Wall R21 ADV	$182	**550**	**3.66**	Wall R21 ADV	$313	**948**	**3.66**	Wall R21 ADV	$268	**872**	**3.93**
Window CL35	$117	**335**	**3.46**	Window CL35	$243	**690**	**3.43**	Window CL35	$133	**411**	**3.74**
Floor R30 STD	$318	**644**	**2.45**	Floor R30 STD	$407	**816**	**2.42**	Floor R30 STD	$25	**54**	**2.68**
Floor R38 STD w/12" Truss	$536	**371**	**0.84**	Floor R38 STD w/12" Truss	$686	**471**	**0.83**	BG Wall R19	$165	**287**	**2.10**
Attic R49 ADVrh	$666	**414**	**0.75**	Attic R49 ADVrh	$557	**342**	**0.74**	Slab R10-4 ft.	$347	**366**	**1.27**
Window CL30	$608	**325**	**0.65**	Window CL30	$1,265	**669**	**0.64**	Slab R10-Full	$697	**729**	**1.26**
Window CL25	$650	**322**	**0.60**	Window CL25	$1,351	**668**	**0.60**	Floor R38 STD w/12" Truss	$41	**31**	**0.92**
Vault R38 HD	$245	**108**	**0.53**	Vault R38 HD	$414	**182**	**0.53**	Attic R49 ADVrh	$832	**569**	**0.83**
Wall R21 STD+R5	$1,036	**370**	**0.43**	Wall R21 STD+R5	$1,786	**639**	**0.43**	Window CL30	$691	**409**	**0.71**
Wall 8" SS Panel	$1,418	**409**	**0.35**	Wall 8" SS Panel	$2,444	**704**	**0.35**	Window CL25	$738	**410**	**0.67**
Attic R60 ADVrh	$383	**104**	**0.33**	Attic R60 ADVrh	$320	**87**	**0.33**	Wall R21 STD+R5	$1,529	**621**	**0.49**
Wall R33 DBL	$727	**44**	**0.07**	Wall R33 DBL	$1,253	**77**	**0.07**	BG Wall R21	$83	**30**	**0.44**
Vault 10" SS Panel	$855	**15**	**0.02**	Vault 10" SS Panel	$1,444	**25**	**0.02**	Wall 8" SS Panel	$2,093	**694**	**0.40**

Table G-8: Regional Cost-Effectiveness Results for Site Built Homes in Heating Zone 3

1344 sq. ft				2200 sq. ft				2283 sq. ft			
Measure	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**
Wall R21 ADV	$182	**655**	**4.35**	Wall R21 ADV	$237	**583**	**3.10**	Wall R21 ADV	$356	**910**	**3.23**
Window CL35	$117	**399**	**4.13**	Window CL35	$98	**223**	**2.86**	Window CL35	$118	**279**	**2.98**
Floor R30 STD	$318	**766**	**2.92**	Floor R30 STD	$71	**159**	**2.82**	Floor R30 STD	$168	**394**	**2.95**
Floor R38 STD w/12" Truss	$536	**443**	**1.00**	Floor R38 STD w/12" Truss	$78	**137**	**2.20**	BG Wall R19	$94	**171**	**2.28**
Attic R49 ADVrh	$666	**493**	**0.89**	Attic R49 ADVrh	$57	**100**	**2.20**	Slab R10-4 ft.	$135	**244**	**2.28**
Window CL30	$608	**386**	**0.77**	Window CL30	$374	**533**	**1.79**	Slab R10-Full	$674	**1,004**	**1.88**
Window CL25	$650	**384**	**0.71**	Window CL25	$196	**273**	**1.76**	Floor R38 STD w/12" Truss	$353	**517**	**1.85**
Vault R38 HD	$245	**129**	**0.63**	Vault R38 HD	$196	**265**	**1.70**	Attic R49 ADVrh	$353	**501**	**1.79**
Wall R21 STD+R5	$1,036	**444**	**0.52**	Wall R21 STD+R5	$152	**176**	**1.46**	Window CL30	$157	**190**	**1.52**
Wall 8" SS Panel	$1,418	**493**	**0.42**	Wall 8" SS Panel	$118	**129**	**1.38**	Window CL25	$142	**163**	**1.46**
Attic R60 ADVrh	$383	**126**	**0.40**	Attic R60 ADVrh	$86	**56**	**0.82**	Wall R21 STD+R5	$202	**138**	**0.86**
Wall R33 DBL	$727	**54**	**0.09**	Wall R33 DBL	$177	**102**	**0.73**	BG Wall R21	$212	**129**	**0.77**
Vault 10" SS Panel	$855	**18**	**0.02**	Vault 10" SS Panel	$237	**88**	**0.47**	Wall 8" SS Panel	$356	**139**	**0.49**

Table G-9: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 1

924 sq. ft				1568 sq. ft				2352 sq. ft			
Measure	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**
Floor R33	$140	**328**	**2.96**	Floor R33	$237	**583**	**3.10**	Floor R33	$356	**910**	**3.23**
Attic R25	$43	**94**	**2.75**	Attic R25	$98	**223**	**2.86**	Attic R25	$118	**279**	**2.98**
Vault R25	$57	**122**	**2.72**	Vault R25	$71	**159**	**2.82**	Vault R25	$168	**394**	**2.95**
Attic R30	$35	**57**	**2.08**	Attic R30	$78	**137**	**2.20**	Attic R30	$94	**171**	**2.28**
Vault R30	$45	**75**	**2.08**	Vault R30	$57	**100**	**2.20**	Vault R30	$135	**244**	**2.28**
Window CL40	$222	**304**	**1.73**	Window CL40	$374	**533**	**1.79**	Window CL40	$674	**1,004**	**1.88**
Window CL35	$116	**155**	**1.68**	Window CL35	$196	**273**	**1.76**	Window CL35	$353	**517**	**1.85**
Window CL30	$116	**152**	**1.65**	Window CL30	$196	**265**	**1.70**	Window CL30	$353	**501**	**1.79**
Wall R21 ADV	$156	**172**	**1.39**	Wall R21 ADV	$152	**176**	**1.46**	Wall R21 ADV	$157	**190**	**1.52**
Attic R38	$52	**54**	**1.31**	Attic R38	$118	**129**	**1.38**	Attic R38	$142	**163**	**1.46**
Vault R38	$68	**42**	**0.79**	Vault R38	$86	**56**	**0.82**	Vault R38	$202	**138**	**0.86**
Attic R49	$78	**43**	**0.70**	Attic R49	$177	**102**	**0.73**	Attic R49	$212	**129**	**0.77**
Floor R44	$140	**50**	**0.45**	Floor R44	$237	**88**	**0.47**	Floor R44	$356	**139**	**0.49**

Table G-10: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 2

924 sq. ft				1568 sq. ft				2352 sq. ft			
Measure	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**
Floor R33	$140	**441**	**3.98**	Floor R33	$237	**764**	**4.06**	Floor R33	$356	**1,175**	**4.16**
Attic R25	$43	**127**	**3.70**	Attic R25	$98	**293**	**3.76**	Attic R25	$118	**360**	**3.85**
Vault R25	$57	**165**	**3.68**	Vault R25	$71	**211**	**3.73**	Vault R25	$168	**512**	**3.84**
Attic R30	$35	**78**	**2.84**	Attic R30	$78	**181**	**2.91**	Attic R30	$94	**224**	**2.99**
Vault R30	$45	**102**	**2.84**	Vault R30	$57	**132**	**2.91**	Vault R30	$135	**319**	**2.98**
Window CL40	$222	**414**	**2.35**	Window CL40	$374	**711**	**2.39**	Window CL40	$674	**1,320**	**2.47**
Window CL35	$116	**212**	**2.30**	Window CL35	$196	**367**	**2.36**	Window CL35	$353	**683**	**2.44**
Window CL30	$116	**208**	**2.26**	Window CL30	$196	**356**	**2.29**	Window CL30	$353	**664**	**2.37**
Wall R21 ADV	$156	**234**	**1.90**	Wall R21 ADV	$152	**237**	**1.96**	Wall R21 ADV	$157	**253**	**2.03**
Attic R38	$52	**74**	**1.79**	Attic R38	$118	**174**	**1.86**	Attic R38	$142	**217**	**1.93**
Vault R38	$68	**58**	**1.07**	Vault R38	$86	**75**	**1.10**	Vault R38	$202	**185**	**1.15**
Attic R49	$78	**59**	**0.95**	Attic R49	$177	**137**	**0.98**	Attic R49	$212	**173**	**1.03**
Floor R44	$140	**68**	**0.61**	Floor R44	$237	**118**	**0.63**	Floor R44	$356	**186**	**0.66**

Table G-11: Regional Cost-Effectiveness Results for Manufactured Homes in Heating Zone 3

924 sq. ft				1568 sq. ft				2352 sq. ft			
Measure	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**	**Measure**	**Installed Cost**	**Savings (kWh/yr)**	**B/C Ratio**
Floor R33	$140	**527**	**4.75**	Floor R33	$237	**914**	**4.86**	Floor R33	$356	**1,392**	**4.93**
Attic R25	$43	**152**	**4.42**	Attic R25	$98	**351**	**4.51**	Attic R25	$118	**428**	**4.57**
Vault R25	$57	**197**	**4.39**	Vault R25	$71	**254**	**4.48**	Vault R25	$168	**609**	**4.56**
Attic R30	$35	**93**	**3.39**	Attic R30	$78	**218**	**3.50**	Attic R30	$94	**265**	**3.54**
Vault R30	$45	**122**	**3.39**	Vault R30	$57	**159**	**3.50**	Vault R30	$135	**378**	**3.54**
Window CL40	$222	**495**	**2.82**	Window CL40	$374	**858**	**2.89**	Window CL40	$674	**1,566**	**2.93**
Window CL35	$116	**254**	**2.76**	Window CL35	$196	**441**	**2.84**	Window CL35	$353	**806**	**2.88**
Window CL30	$116	**249**	**2.70**	Window CL30	$196	**428**	**2.75**	Window CL30	$353	**783**	**2.80**
Wall R21 ADV	$156	**283**	**2.29**	Wall R21 ADV	$152	**284**	**2.35**	Wall R21 ADV	$157	**298**	**2.39**
Attic R38	$52	**89**	**2.16**	Attic R38	$118	**209**	**2.24**	Attic R38	$142	**256**	**2.28**
Vault R38	$68	**70**	**1.30**	Vault R38	$86	**90**	**1.33**	Vault R38	$202	**218**	**1.36**
Attic R49	$78	**71**	**1.15**	Attic R49	$177	**166**	**1.18**	Attic R49	$212	**204**	**1.21**
Floor R44	$140	**82**	**0.74**	Floor R44	$237	**143**	**0.76**	Floor R44	$356	**219**	**0.78**

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 heating 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-12 shows the maximum annual space heating use permitted under the draft fifth 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 F-6 through F-11 that have a benefit-to-cost ratio of 1.0 or higher on a total resource cost basis.

Table G-12: Draft Fifth Plan Model Conservation Standards Annual Space Heating Budgets[5]

	Site Built Homes (kWh/sq.ft./yr)	Manufactured Homes (kWh/sq.ft/yr)
Heating Zone 1	3.3	2.6
Heating Zone 2	4.8	3.9
Heating Zone 3	5.8	4.8

The Council compared the annual space heating performance requirements in Table G-12 for site built homes with the requirements of state energy codes in the region. It also compared the annual space heating performance requirements in Table G-12 for manufactured homes with the requirements of regional Super Good Cents® manufactured home program specifications and current construction practices for non-Super Good Cents® manufactured homes. This comparison, shown in Table G-13, revealed that none of the region's energy codes or the Super Good Cents® program specifications for manufactured homes 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.

Table G-13: Estimated Annual Space Heating Use for New Site Built Homes Complying with State Energy Codes and Manufactured Homes Built to Current Practice and Super Good Cents®

	Site Built Space Heating Use (kWh/sq.ft./yr				Manufactured Home Space Heating Use (kWh/sq.ft./yr.	
	Idaho	Montana	Oregon	Washington	Current Practice	Super Good Cents®
Heating Zone 1	5.3	NA	3.5	3.6	4.3	3.0
Heating Zone 2	7.6	NA	5.3	4.7	6.2	4.6
Heating Zone 3	NA	6.8	NA	NA	7.7	5.8

[5] Annual space heating use for a typical 2100 sq.ft. site built home and 1730 sq.ft. manufactured home. Both homes are assumed to have a zonal electric resistance heating system.

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-12 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 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, down payment 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 percent 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 down payment 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 1,000 different combinations of major variables that determine a specific consumer's life cycle cost of home ownership for each heating climate zone. Table G-14 lists these variables and the data sources used to derive the actual distribution of values used.

Table G-14: 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
Down payment	Federal Housing Finance Board
Private Mortgage Insurance Rates	Mortgage Bankers Association
Retail Electric Rates	Energy Information Administration
Retail Gas Rates	ID, MT, OR & WA Utility Regulatory Commissions
Retail Electric and Gas Price Escalation Rates	Council 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 Microsoft 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 F-1 through F-10 show the distributions used for each of the major input assumptions to the life cycle cost analysis.

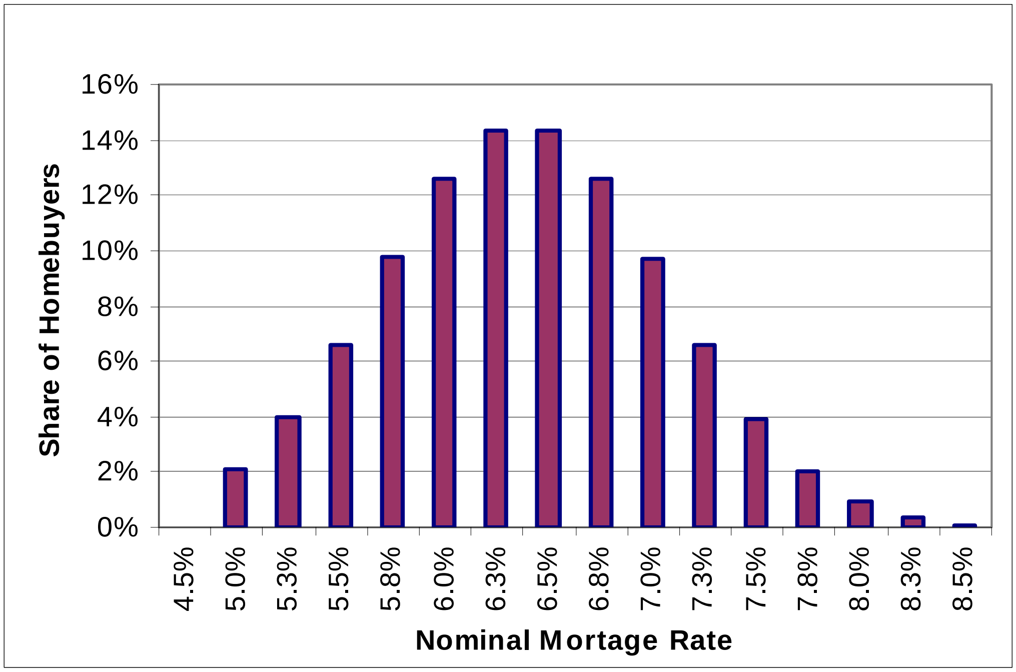

Figure G-1: Nominal Mortgage Rates - All Climate Zones for Single Family Homes

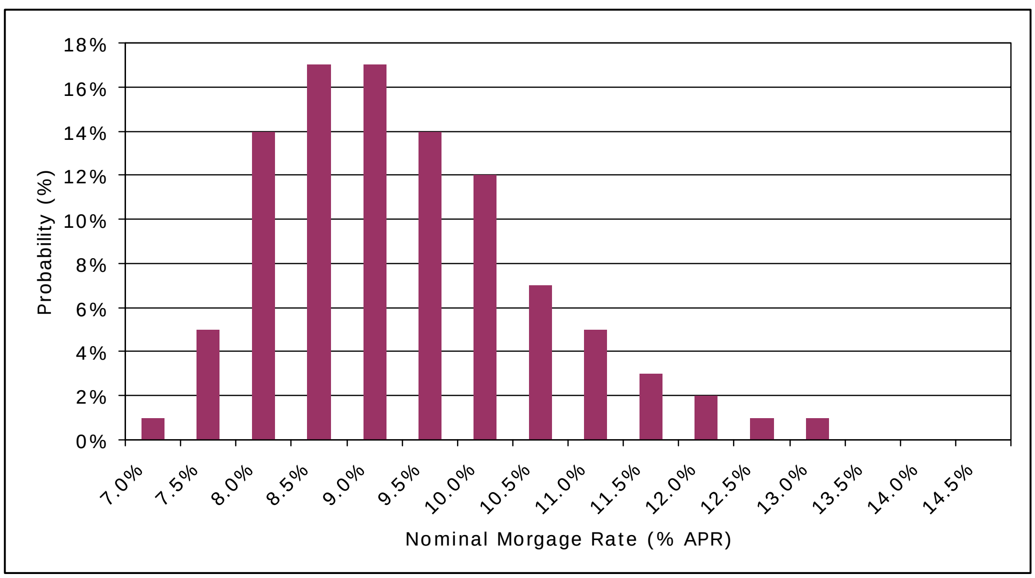

Figure G-2: Nominal Mortgage Rates - All Climate Zones for Manufactured Homes

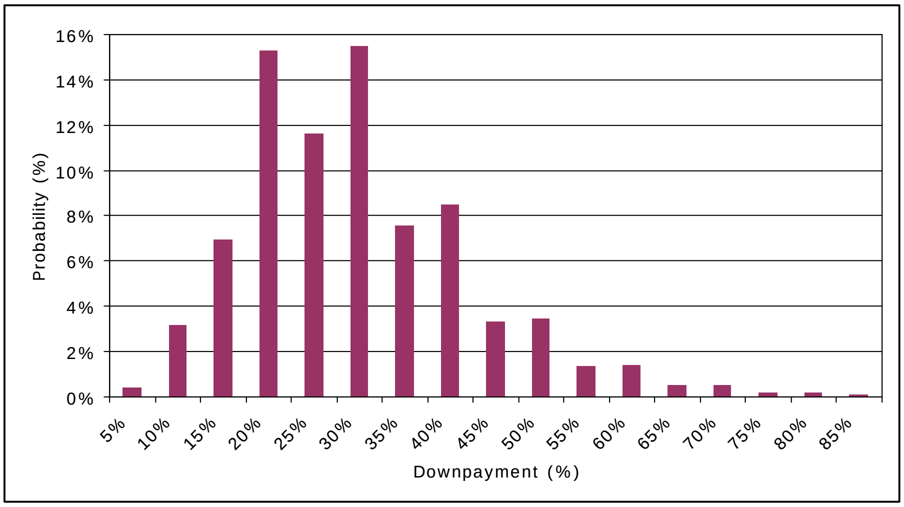

Figure G-3: Down payment Fraction for Single Family and Manufactured Homes- All Climate Zones

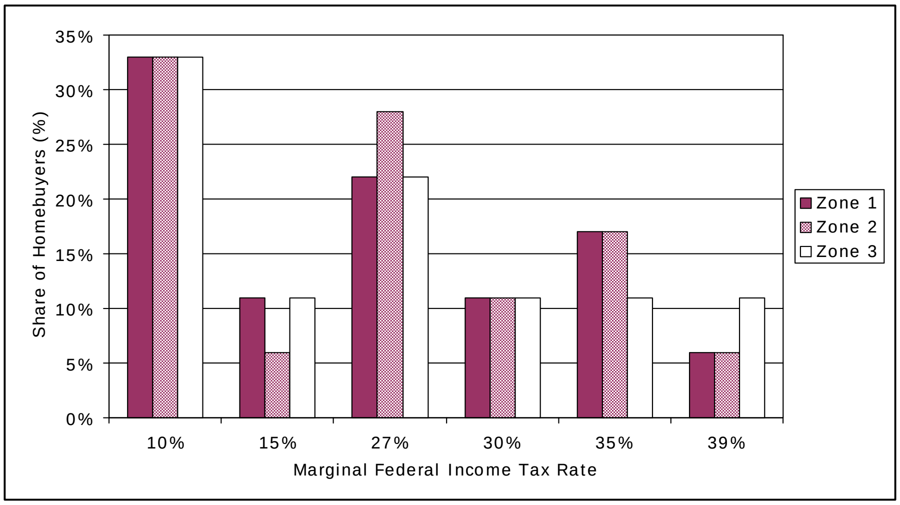

Figure G-4: Marginal Federal Income Tax Rates for Single Family and Manufactured Homes by Climate Zone

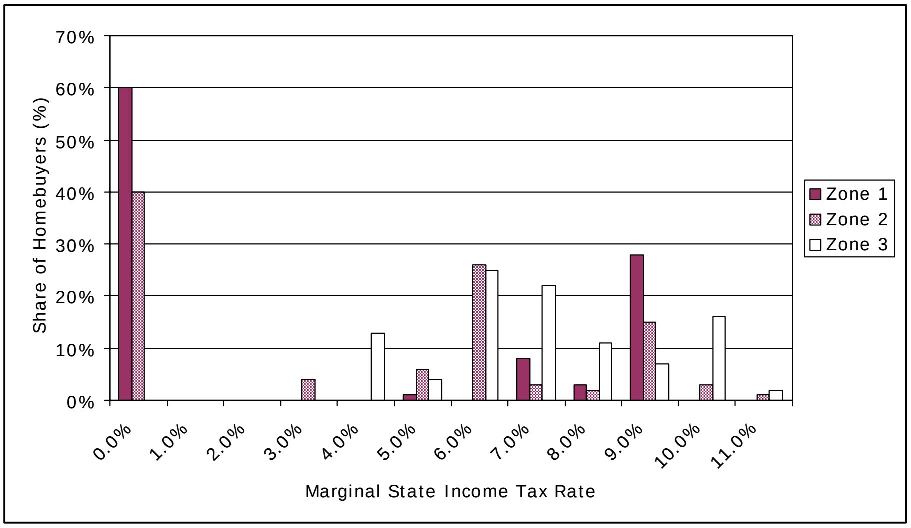

Figure G-5: Marginal State Income Tax Rates for Single Family and Manufactured Homes by Climate Zone

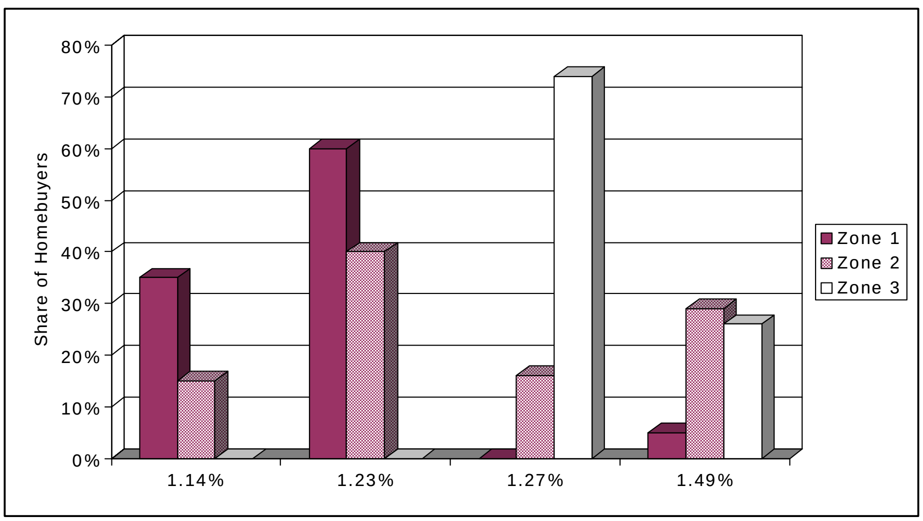

Figure G-6: Property Tax Rates by Climate Zone

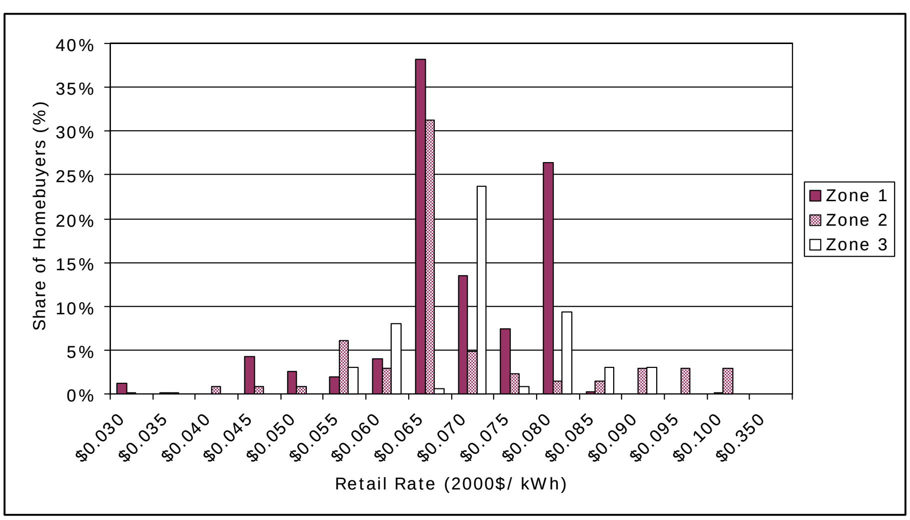

Figure G-7: Base Year Retail Electric Rates by Climate Zone

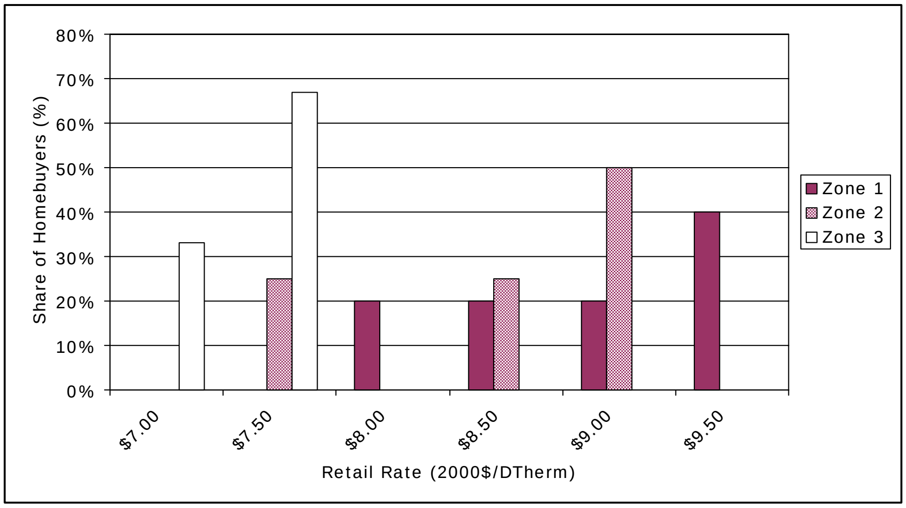

Figure G-8: Base Year Retail Natural Gas Rates by Climate Zone

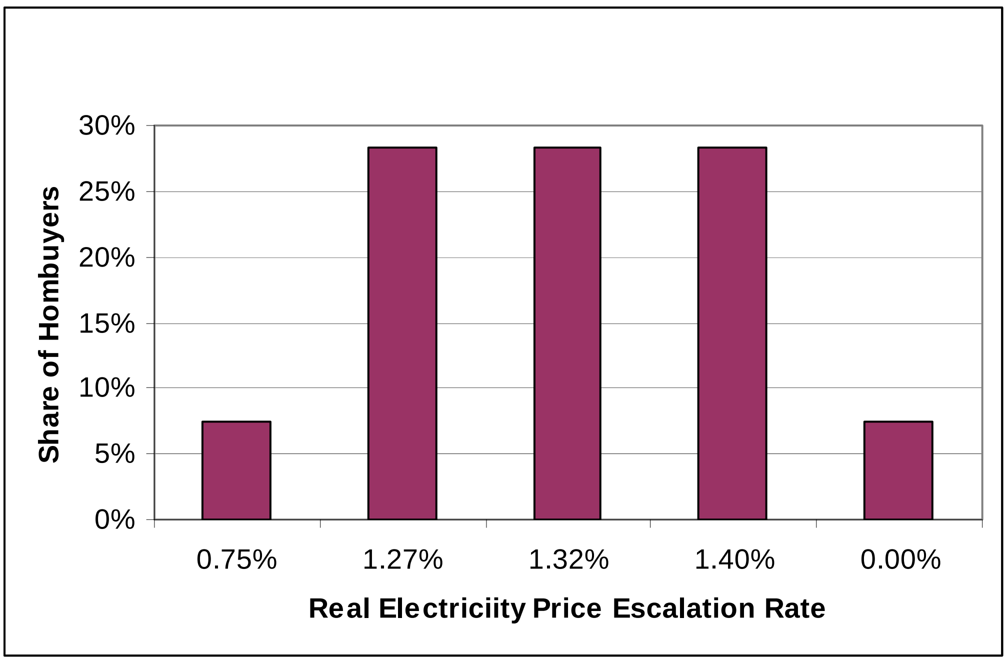

Figure G-9: Real Escalation Rates for Electricity Prices - All Climate Zones

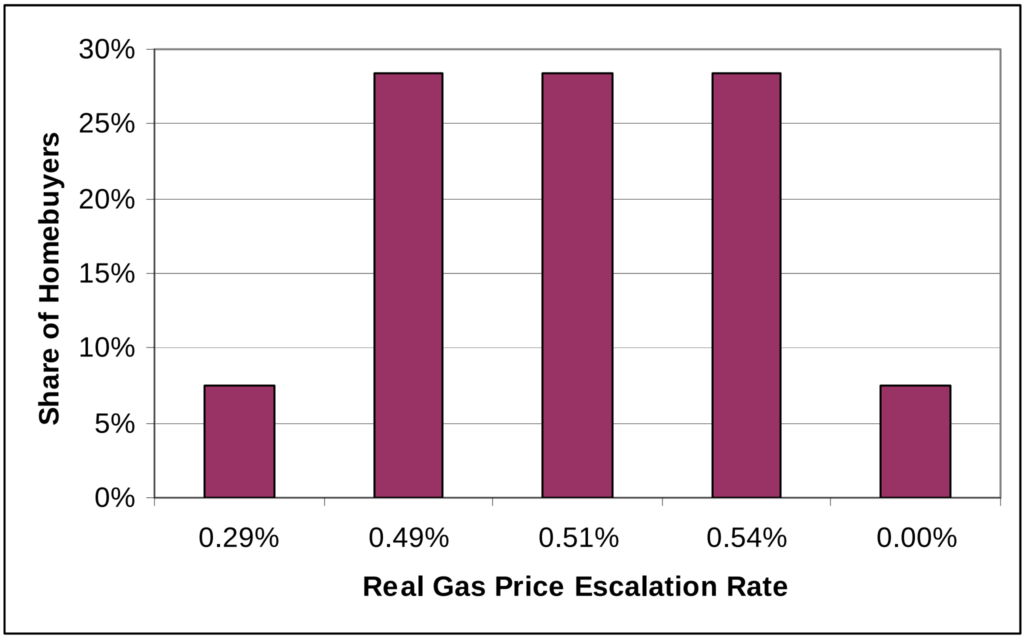

Figure G-10: Real Escalation Rates for Natural Gas Prices - All Climate Zones

The incremental costs of conservation measures described in the prior section on regional cost-effectiveness were used in these calculations. Annual space heating energy use was computed for four heating system types using the system efficiency assumptions shown in Table G-14. The system efficiency assumptions for electric and gas forced-air furnaces and heat pumps assume that the home has all or most of its ductwork outside the heated space.

Table G-15: Overall Heating System Efficiency Assumptions by System Type and Climate Zone[6]

Climate Zone	Zonal Electric	Electric Forced-Air Furnace	Air Source Heat Pump	Gas Forced-Air Furnace
Zone 1	100%	78%	155%	61%
Zone 2	100%	77%	124%	60%
Zone 3	100%	77%	114%	60%

The simulation model used the same 1,000 combinations of input assumptions for each level of energy efficiency tested. As a result, the Council could compare the distribution of 1,000 different net present value 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-11 illustrates a typical distribution of net present value results for one measure. In the upper left corner of the graph indicates the number ("2000 Trials") of different combinations of inputs tested in the analysis. The graph plots the net present value of a measures costs and savings over the term of the mortgage on the horizontal (x) axis. The "probability" of obtaining a given net present values is plotted on the vertical (y) axis. The percent of the cases tested that result in a particular net present value is shown on the left vertical axis and the number of cases

[6] Overall system efficiency includes the impact of duct system losses, combustion and cycling losses and for heat pumps losses due to defrost and the use of controls that energize back up electric resistance heating during "warm-up."

out of the total number tested is shown on the right vertical axis. The mean (average) and median net present values of all input combinations tested are shown as vertical lines near the center of the distribution.

Although the mean values can be considered the “expected” net present value it is also important to consider the entire distribution of results to determine the share of consumers who would be harmed or benefited. This is particularly important of the results are skewed by a specific combination of input assumptions (e.g., low initial electric rates combined with low real escalating rates and high mortgage rates). Figure G-12 displays the cumulative distribution of net present value across the range of possible combinations of inputs. The primary value of displaying the outcomes in this fashion is that it shows the both the fraction of consumers who may be benefited or harmed if required to invest in incremental improvements in efficiency and it also shows the magnitude of the benefit or harm. For example, Figure G-12 shows that approximately 90 percent of the combinations tested resulted in net present values. Moreover 75 percent of the combination of input assumptions produced net present values above $500 while less than 5 percent of the produced negative net present values, none of which were below $1,000.

Tables F-16 through F-18 show the average or “expected” net present value for each measure and heating system type by climate zone for site built homes. Tables F-19 through -21 show this information for manufactured homes.

The Council reviewed the net present value results for each measure. Measures were analyzed incrementally and in order of their cost-effectiveness. The package of measures that produced the highest average net present value (lowest life cycle cost) was considered by the Council to be “economically feasible” for consumers. The Council believes this is a conservation interpretation of the Act’s requirements, since any package of measures that results in a higher net present value than current codes or standards leaves the consumer “better off” than they are today. However, the package of measures that produces the highest net present value leaves results in the “best” economic choice for the consumer.

Based on its review of these results shown in Tables F-15 through F-20 the Council concluded that the level of energy efficiency that is regionally cost-effective shown in Table G-12 are also economically feasible for consumers. Table G-21 compares the annual space heating performance of typical site-built home and manufactured homes built to three different levels of energy efficiency. One is built to current codes/practice, the second with all regionally cost effective measures (i.e., “the MCS”) and the third with those measures that maximize the net present value of energy efficiency to the homeowner (i.e., “Economically Feasible”).

It is important to note that Table G-21 shows that the level of energy efficiency that is economically feasible for consumers is equal to or higher than that which would be cost-effective for the regional power system. Since this is the first time the Council has observed this result, some explanation is in order. There are two primary reasons that consumers in the Northwest would find it more economical to invest in the energy efficiency of their new site built or manufactured home than the regional power system. The first is that as a result of recent increases in power rates retail rates for electricity are generally above wholesale market prices.

Second, new homebuyers can frequently finance their homes at lower interest rates than utilities can borrow money to fund conservation programs.

The complete distribution of net present value results for each measure by heating system type for site built homes are shown in Figures F-13 through F-58 for climate zone 1, Figures F-63 through F-108 for climate zone 2 and Figures F-113 through F-158 for climate zone 3. The "expected value" average net present value results for each measure and heating system type are shown in figures F-59 through F-62 for climate zone 1, Figures F-109 through F-112 for climate zone 2 and Figures F-159 through F-162 for climate zone 3. The complete net present value results for each measure for manufactured homes are shown in Figures F-163 through F-175 for climate zone 1, Figures F-177 through F-189 for climate zone 2 and Figures F-191 through F-203 for climate zone 3. The "expected value" average net present value results for each measure are shown in Figure G-176 for climate zone 1, Figure G-190 for climate zone 2 and Figure G-204 for climate zone 3. Tables F-19 through -20 average "expected value" net present value for each measure by climate zone for manufactured homes.

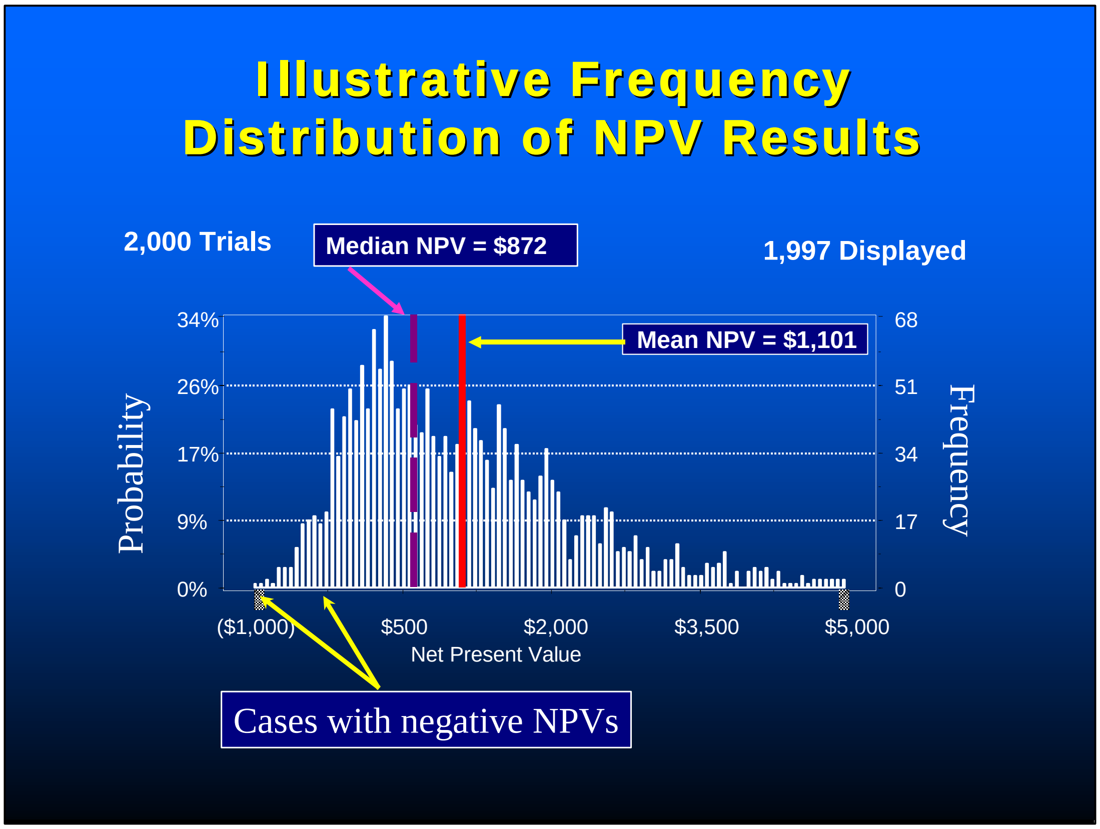

Figure G-11: Illustrative Distribution of Net Present Value Results

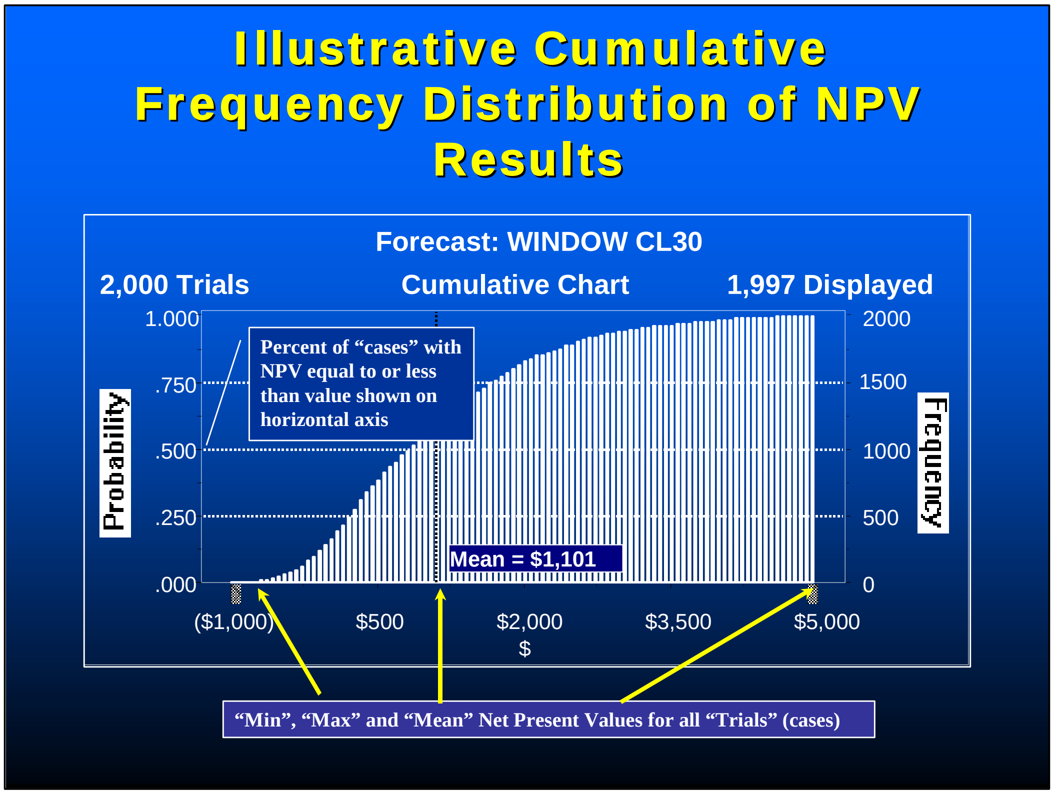

Figure G-12: Illustrative Cumulative Distribution of Net Present Value Results

Mean Net Present Value for Zone 1 (1000 Cases)

Measure	HP	Electric FAF	Gas FAF	Zonal
R21 Walls	$652	$1,581	$873	$1176
Class 35 Windows	$1113	$2,717	$1494	$2018
R30 Under Crawlspace Floors	$1546	$3,948	$2117	$2092
R38 Under Crawlspace Floor	$1374	$4,238	$2054	$2980
R49 Advanced Framed Attic	$1196	$4,395	$1955	$3001
Class 30 Windows	$683	$4,537	$1598	$2858
Class 25 Windows	$88	$4,598	$1158	$2634
R26 Walls	-$117	$4,571	$995	$2529
R30 Walls	-$1146	$4,168	$114	$1854
R60 Advanced Framed Attic	-$2725	$3,280	-$1302	$664

Maximum NPV = Lowest LCC

Table G-16: Climate Zone 1 Expected Value NPV by Measure and System Type

Mean Net Present Value for Zone 2
(1000 Cases)

Measure	HP	Electric FAF	GAS FAF	Zonal
R21 Walls	$942	$1,681	$832	$1237
Class 35 Windows	$1612	$2,890	$1422	$2122
R30 Under Crawlspace Floors	$2294	$4,208	$2010	$3057
R38 Under Crawlspace Floor	$2266	$4,547	$1927	$3176
R49 Advanced Framed Attic	$2192	$4,740	$1814	$3208
Class 30 Windows	$1882	$4,952	$1427	$3107
Class 25 Windows	$1490	$5,080	$957	$2992
R26 Walls	$1340	$5,072	$786	$2829
R30 Walls	$504	$4,734	-$123	$2191
R60 Advanced Framed Attic	-$862	$3,917	-$1570	$1044

Maximum NPV = Lowest LCC

Table G-17: Climate Zone 2 Expected Value NPV by Measure and System Type

Mean Net Present Value for Zone 3
(1000 Cases)

Measure	HP	Electric FAF	Gas FAF	Zonal
R21 Walls	$1342	$2,140	$872	$1569
Class 35 Windows	$2315	$3,699	$1500	$2708
R30 Under Crawlspace Floors	$3352	$5,430	$2127	$3942
R38 Under Crawlspace Floor	$3505	$5,986	$2042	$4209
R49 Advanced Framed Attic	$3560	$6,335	$1925	$4348
Class 30 Windows	$3491	$6,839	$1518	$4441
Class 25 Windows	$3326	$7,243	$1018	$4438
R26 Walls	$3234	$7,305	$835	$4389
R30 Walls	$2592	$7,195	-$137	$3891
R60 Advanced Framed Attic	$1391	$6,602	-$1680	$2870

Maximum NPV = Lowest LCC

Table G-18: Climate Zone 3 Minimum Expected Value NPV by Measure and System Type

Mean Net Present Value for Zone 1
(2000 Cases)

Measure	Net Present Value
Floor R33	$366
Attic R25	$489
Vault R25	$602
Attic R30	$662
Vault R30	$718
Class 40 Windows	$915
Class 35 Windows	$1012
Class 30 Windows	$1101
Walls R21 Advanced Framed	$1130
Attic R38	$1147
Vault R38	$1117
Attic R49	$1056
Floor R44	$915

Maximum NPV = Lowest LCC

Table 19 - Climate Zone 1 Expected Value Mean Net Present Value Results for Manufactured Homes

Mean Net Present Value for Zone 2
(2000 Cases)

Measure	Net Present Value
Floor R33	$638
Attic R25	$858
Vault R25	$1063
Attic R30	$1184
Vault R30	$1297
Class 40 Windows	$1774
Class 35 Windows	$2018
Class 30 Windows	$2249
Walls R21 Advanced Framed	$2359
Attic R38	$2437
Vault R38	$2441
Attic R49	$2427
Floor R44	$2333

Maximum NPV = Lowest LCC

Table G-20: Climate Zone 2 Expected Value Mean Net Present Value Results for Manufactured Homes

Mean Net Present Value for Zone 3
(2000 Cases)

Measure	Net Present Value
Floor R33	$792
Attic R25	$1068
Vault R25	$1325
Attic R30	$1479
Vault R30	$1624
Class 40 Windows	$2249
Class 35 Windows	$2567
Class 30 Windows	$2869
Walls R21 Advanced Framed	$3017
Attic R38	$3124
Vault R38	$3141
Attic R49	$3146
Floor R44	$3062

Maximum NPV = Lowest LCC

Table G-21: Climate Zone 3 Expected Value Mean Net Present Value Results for Manufactured Homes

Table G-22: Economic Feasibility of Regionally Cost-Effective Thermal Envelop Measures for New Electrically Heated Site Built and Manufactured Homes

	Site Built			Manufactured		
	Code Avg (kWh/sq.ft.yr)	MCS **(kWh/sq.ft.yr)**	Min LCC **(kWh/sq.ft.yr)**	Current Practice **(kWh/sq.ft.yr)**	MCS **(kWh/sq.ft.yr)**	Min LCC **(kWh/sq.ft.yr)**
Heating Zone 1	3.3	2.6	2.3	4.3	2.6	2.6
Heating Zone 2	5.3	4.3	3.9	6.2	3.9	3.9
Heating Zone 3	6.8	5.4	4.8	7.7	4.8	4.8

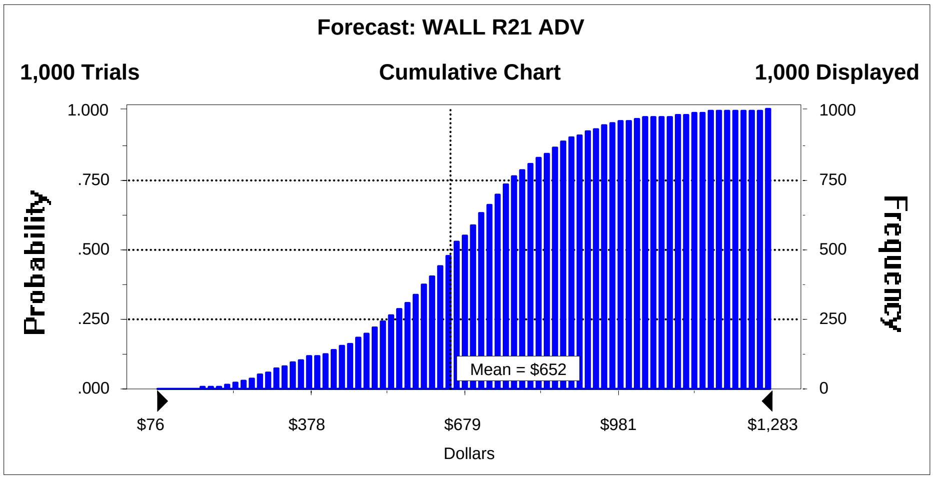

Figure G-13: Climate Zone 1 R21 Above Grade Wall NPV Results for Heat Pumps

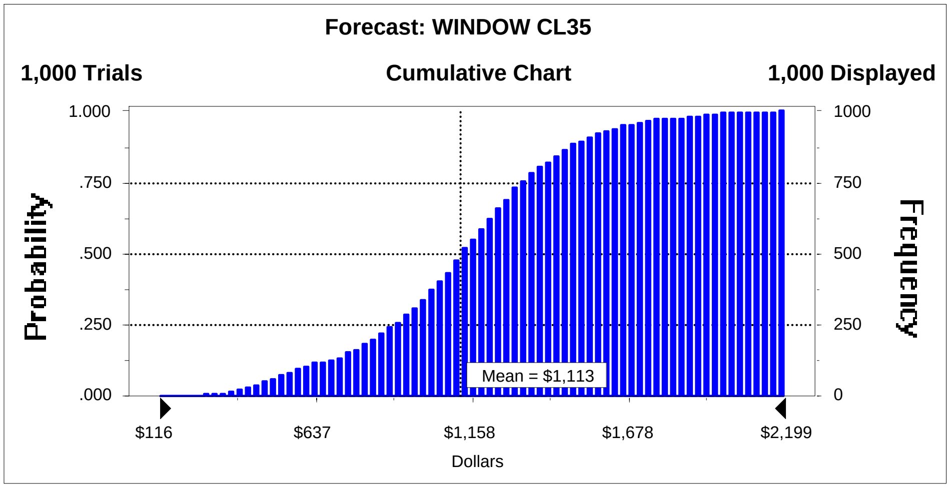

Figure G-14: Climate Zone 1 Class 35 Window NPV Results for Heat Pumps

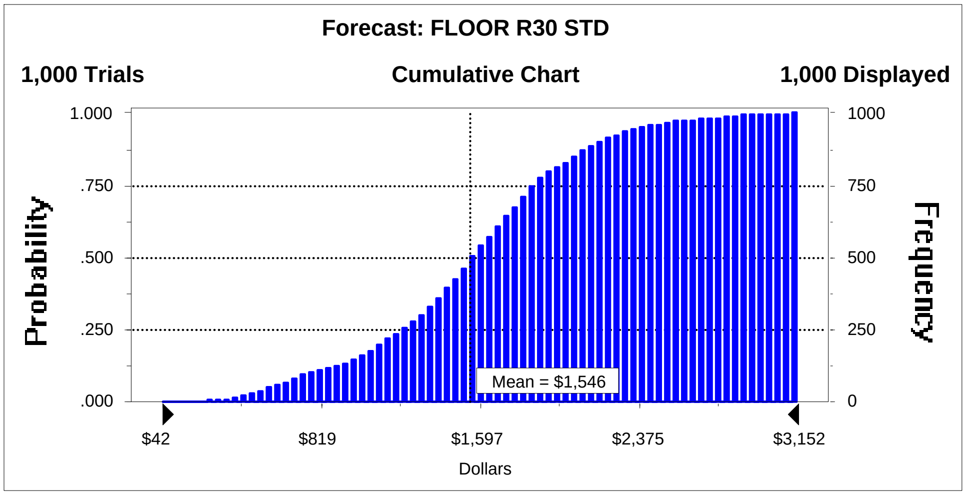

Figure G-15: Climate Zone 1 R30 Under floor NPV Results for Heat Pumps

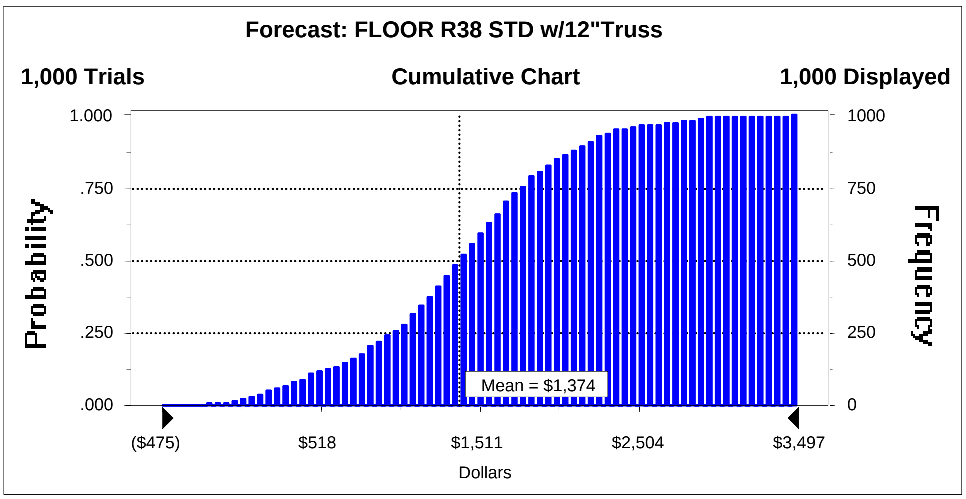

Figure G-16: Climate Zone 1 R38 Under floor NPV Results for Heat Pump

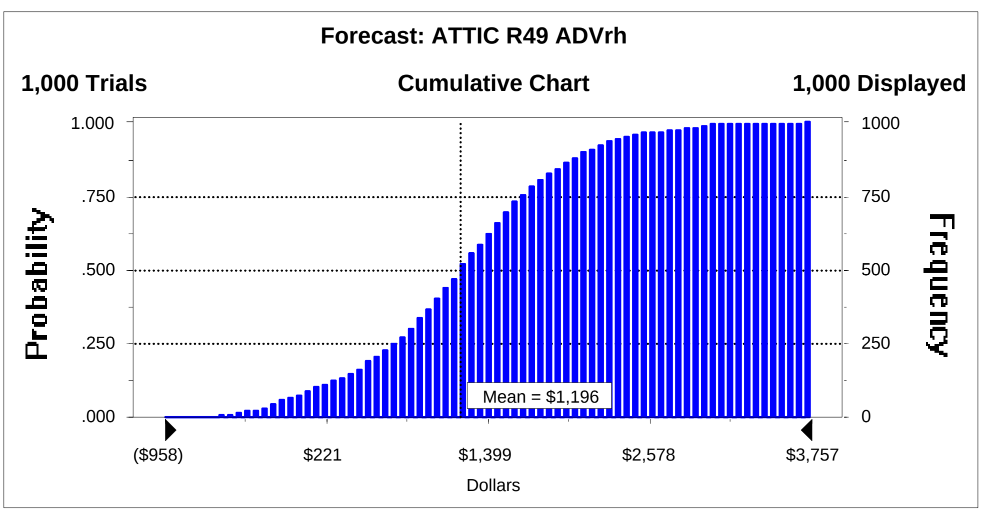

Figure G-17: Climate Zone 1 R49 Advance Framed Attic NPV Results for Heat Pumps

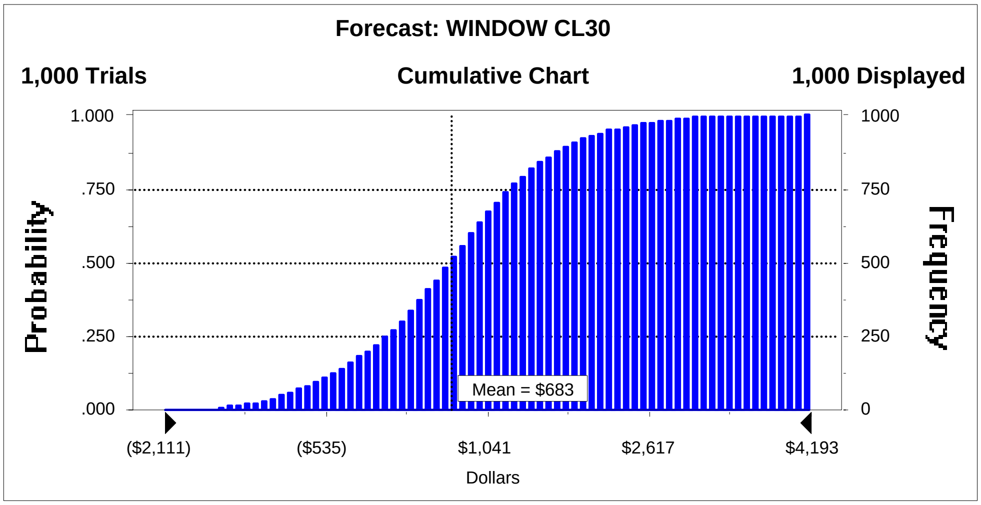

Figure G-18: Climate Zone 1 Class 30 Window NPV Results for Heat Pumps

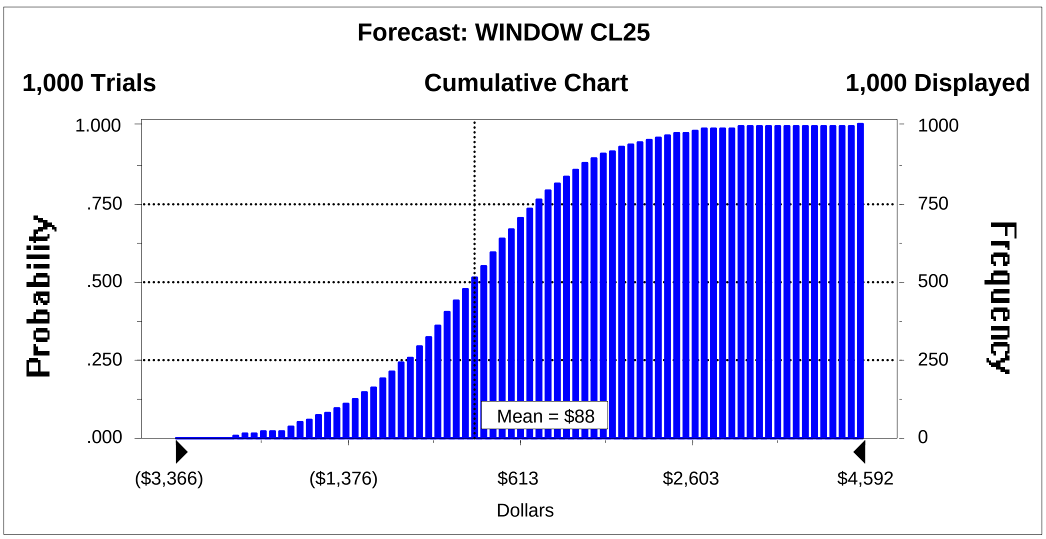

Figure G-19: Climate Zone 1 Class 25 Window NPV Results for Heat Pumps

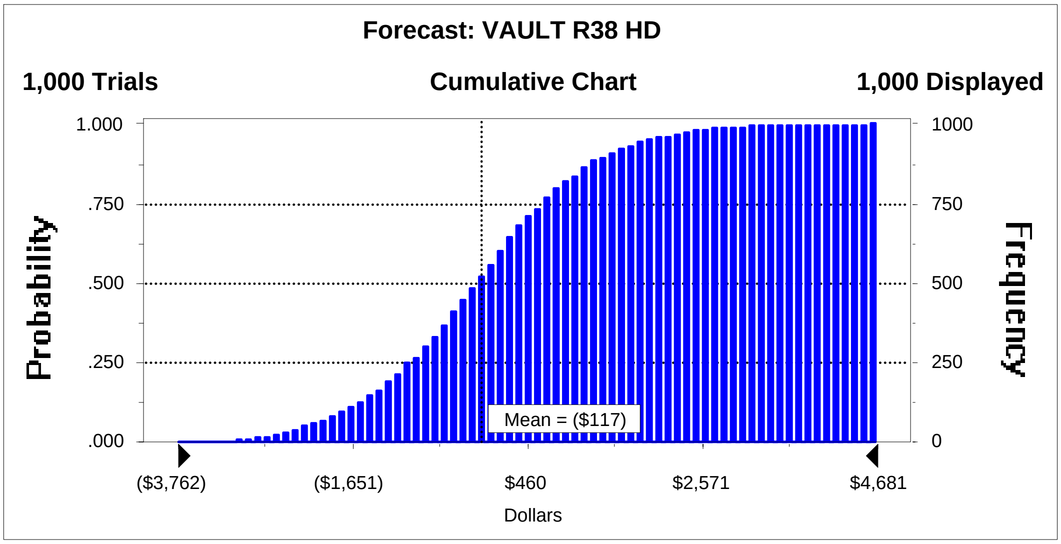

Figure G-20: Climate Zone 1 R38 Vaulted Ceiling NPV Results for Heat Pumps

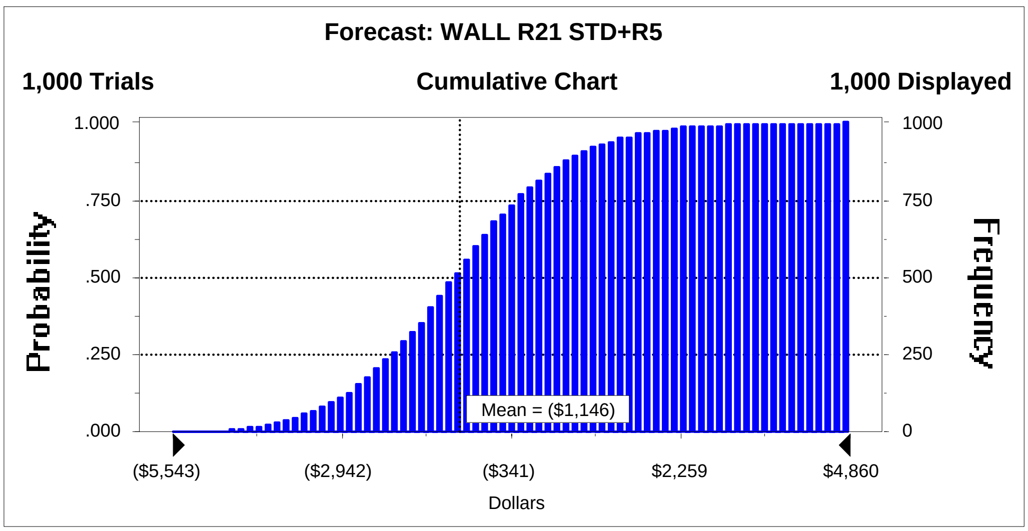

Figure G-21: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Heat Pumps

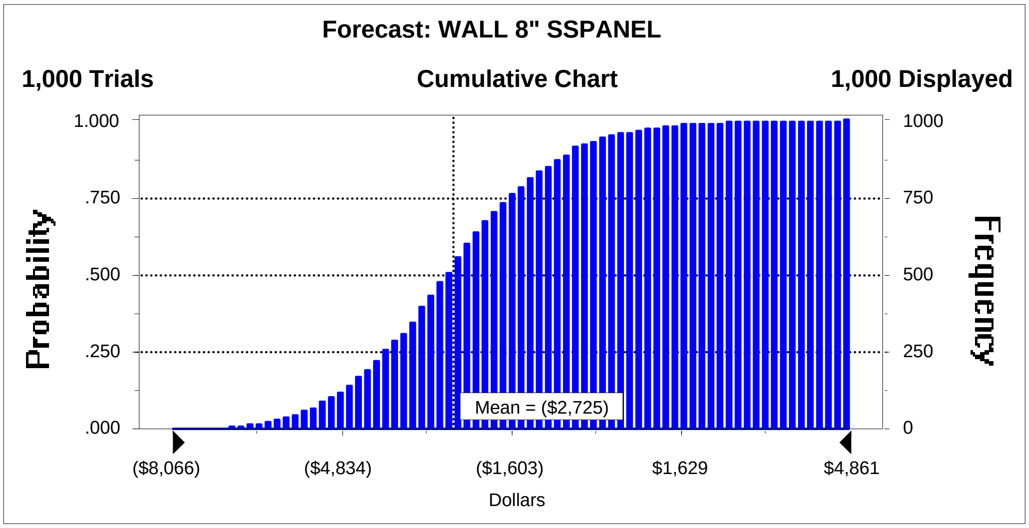

Figure G-22: Climate Zone 1 R33 Wall NPV Results for Heat Pumps

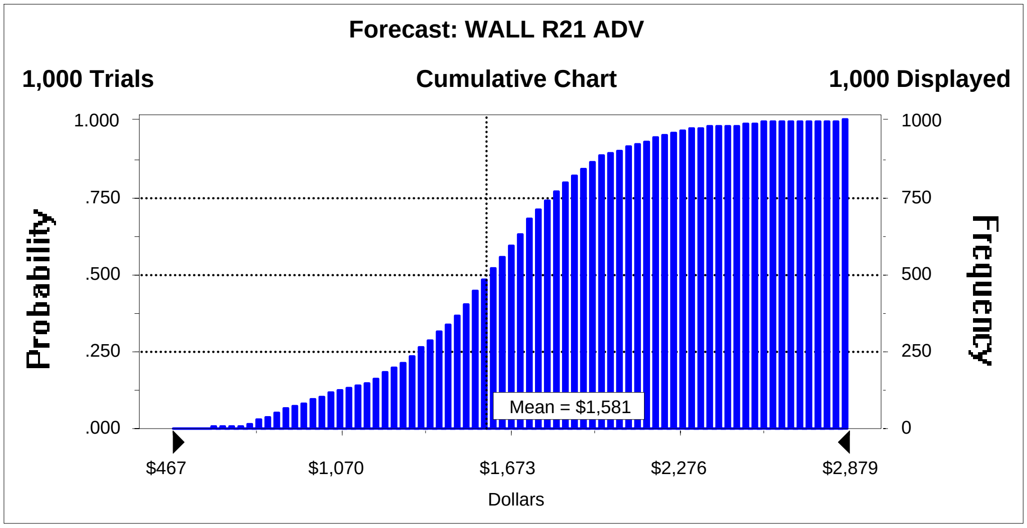

Figure G-23: Climate Zone 1 R21 Above Grade Wall NPV Results for Electric FAF

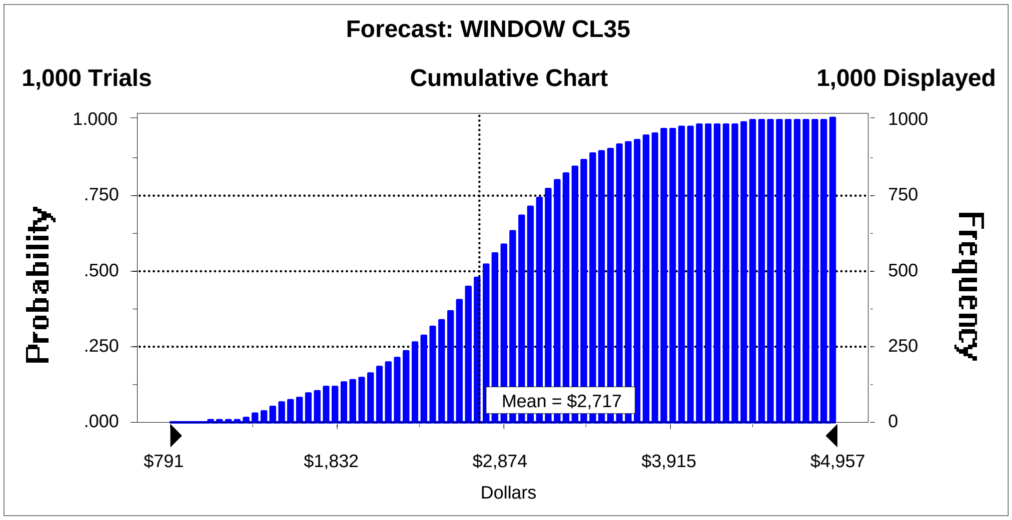

Figure G-24: Climate Zone 1 Class 35 Window NPV Results for Electric FAF

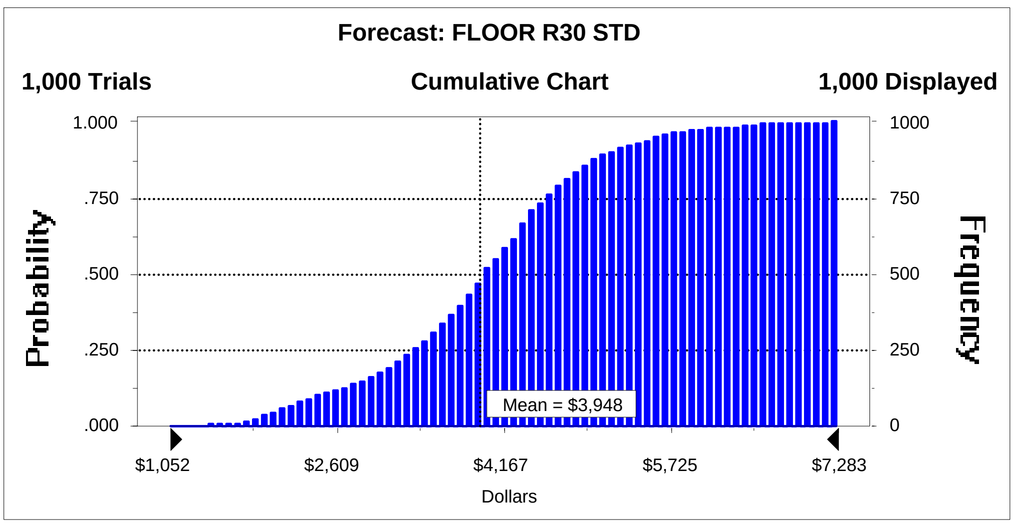

Figure G-25: Climate Zone 1 R30 Under floor NPV Results for Electric FAF

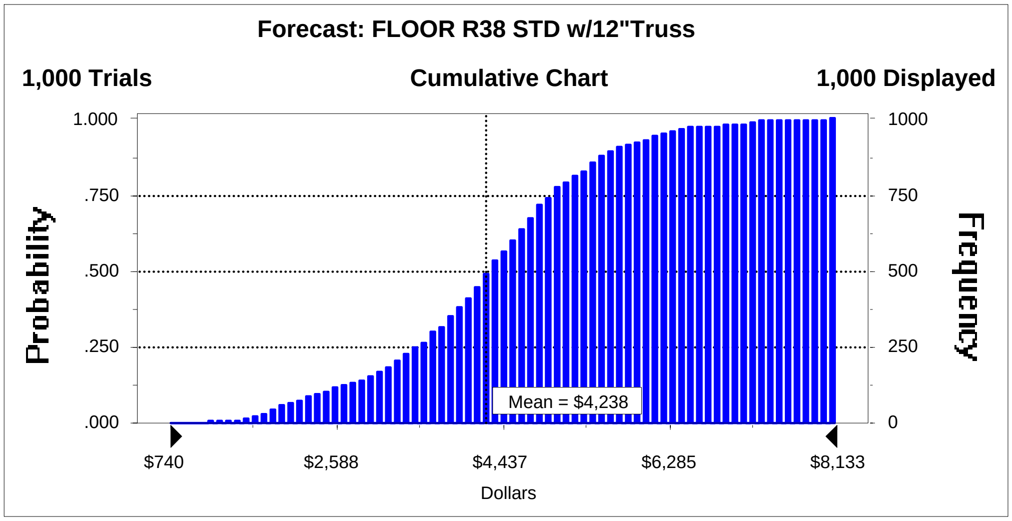

Figure G-26: Climate Zone 1 R38 Under floor NPV Results for Electric FAF

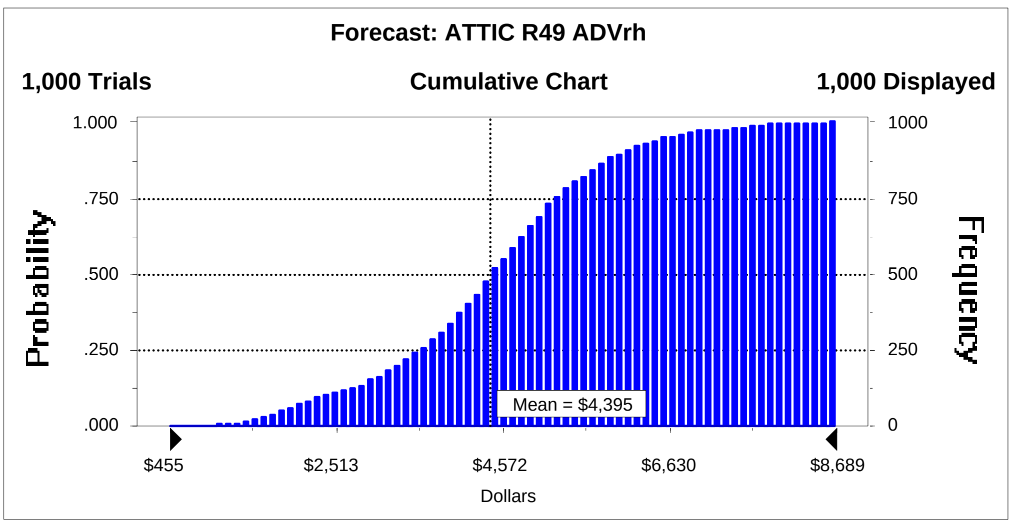

Figure G-27: Climate Zone 1 R49 Advanced Framed Attic NPV Results for Electric FAF

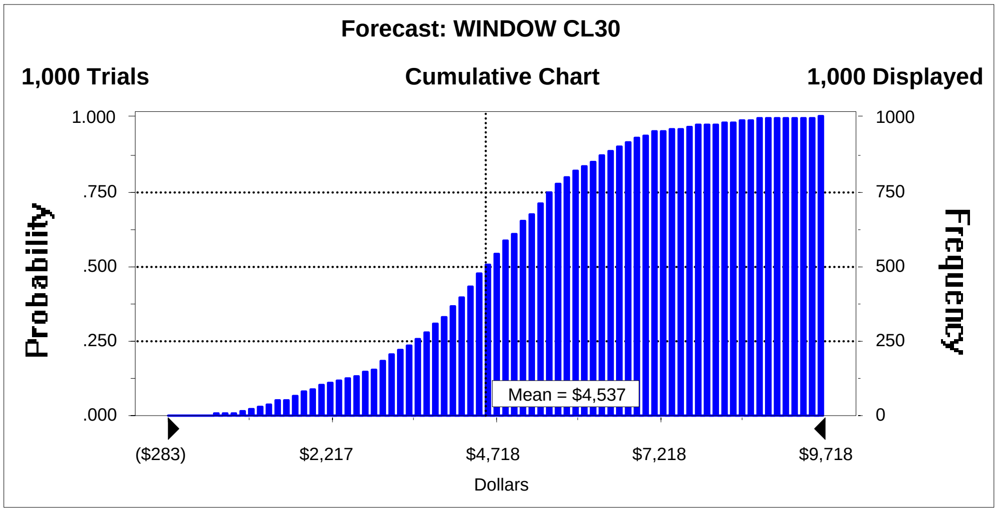

Figure G-28: Climate Zone 1 Class 30 Window NPV Results for Electric FAF

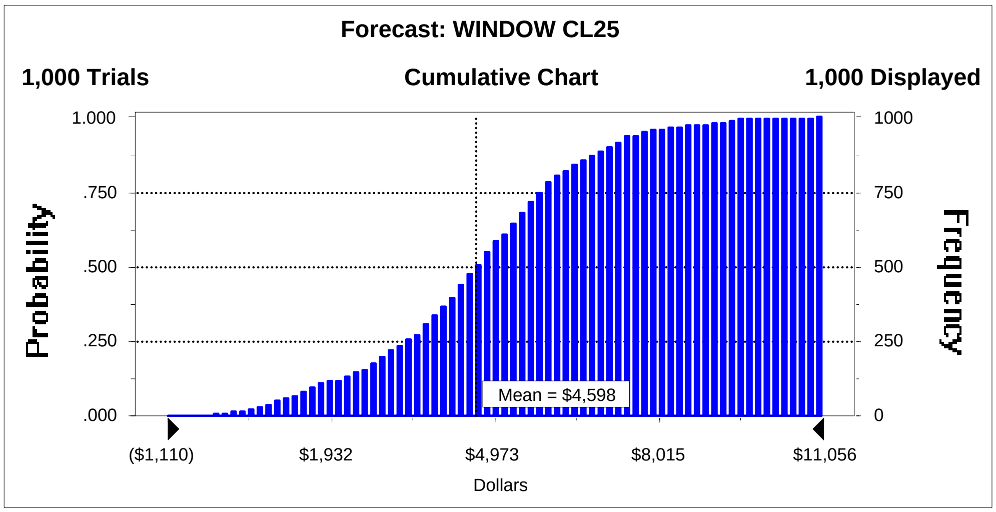

Figure G-29: Climate Zone 1 Class 25 Window NPV Results for Electric FAF

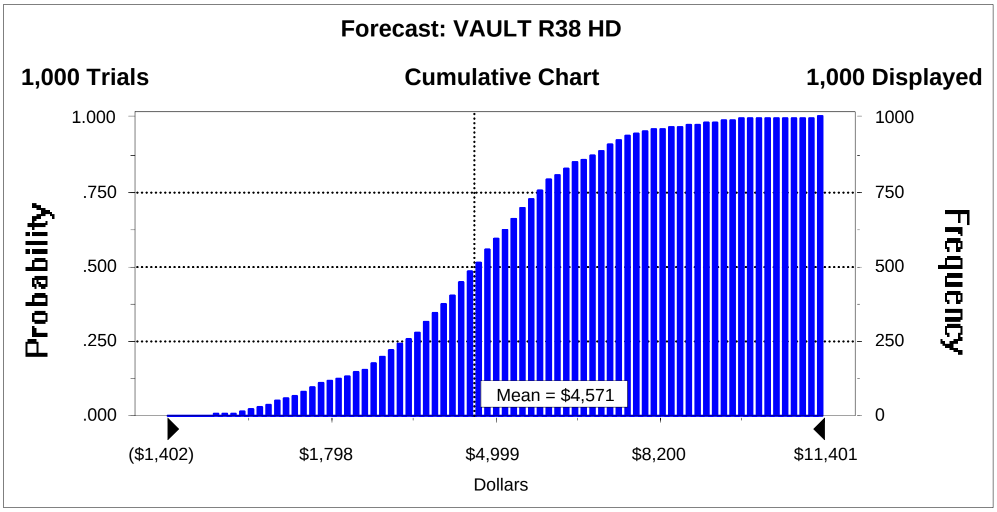

Figure G-30: Climate Zone 1 R38 Vaulted Ceiling NPV Results for Electric FAF

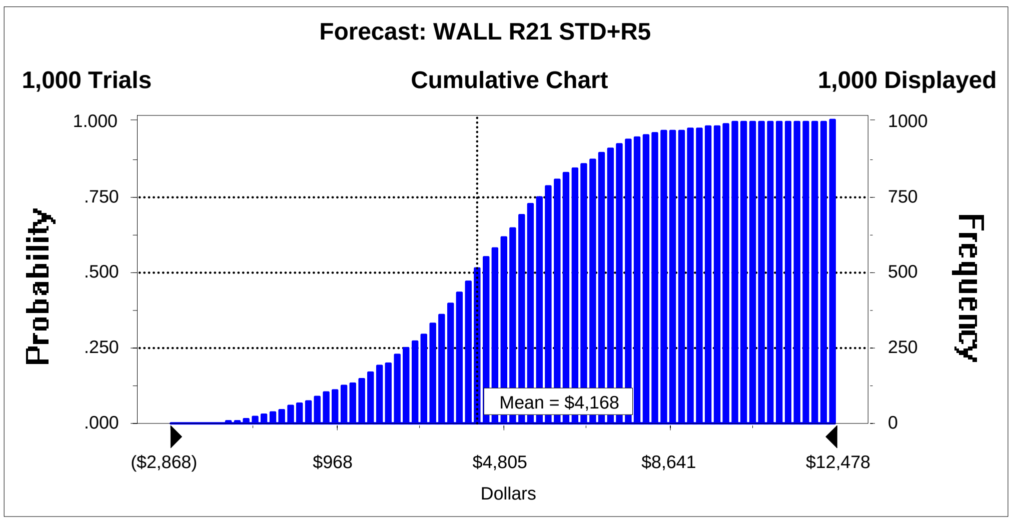

Figure G-31: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Electric FAF

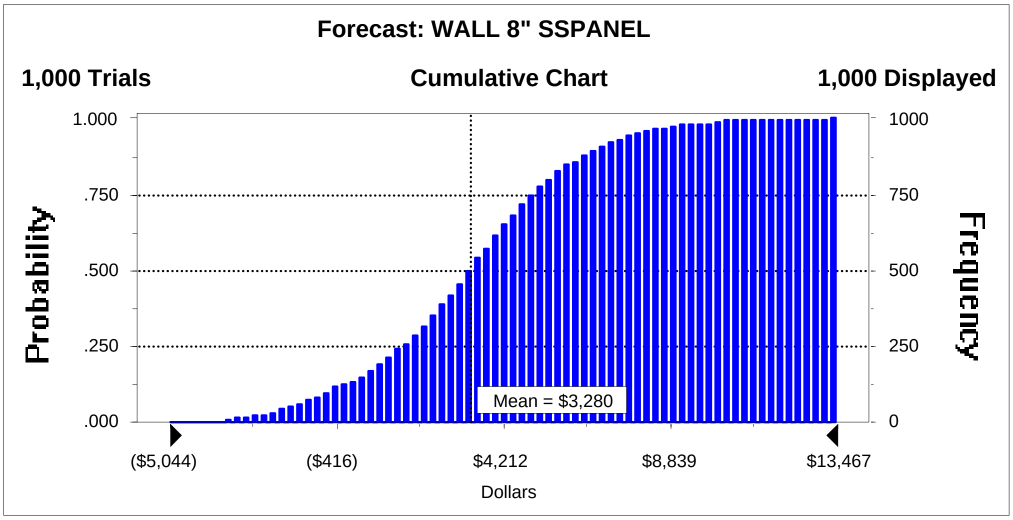

Figure G-32: Climate Zone 1 R33 Wall NPV Results for Electric FAF

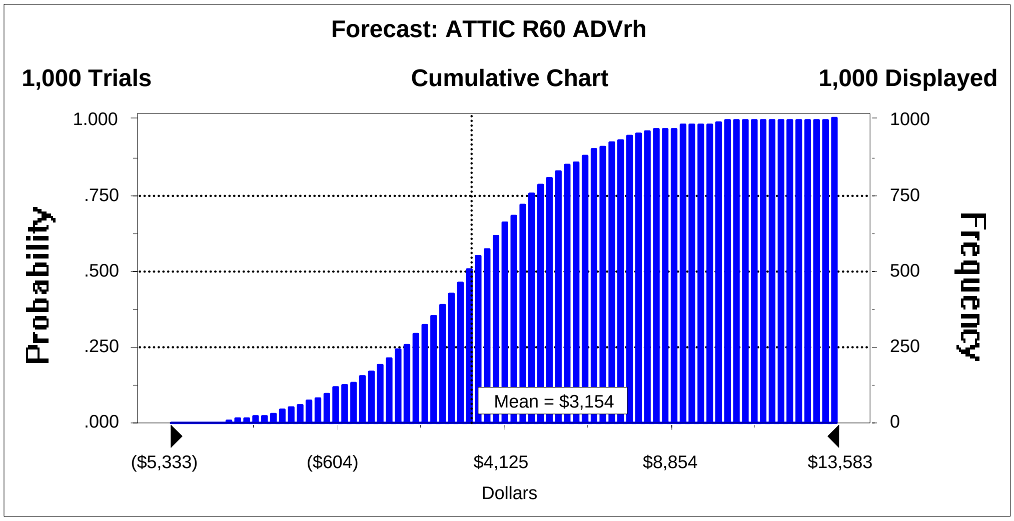

Figure G-33: Climate Zone 1 R60 Attic NPV Results for Electric FAF

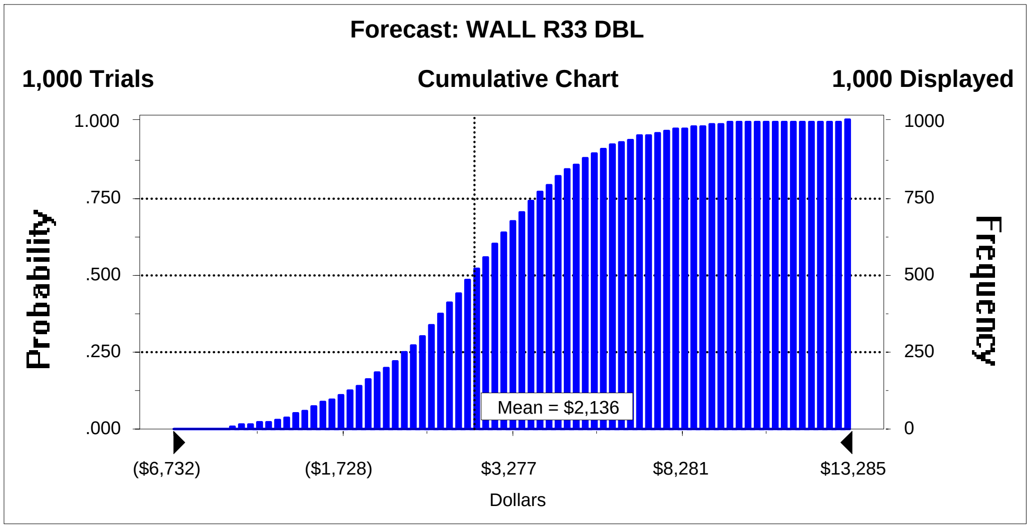

Figure G-34: Climate Zone 1 NPV Results for Electric FAF

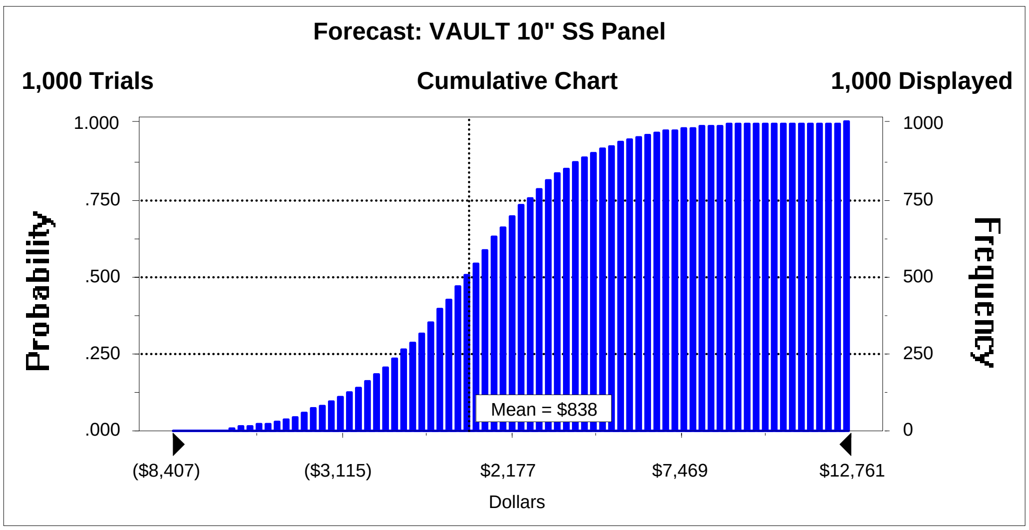

Figure G-35: Climate Zone 1 R38 Wall NPV Results for Electric FAF

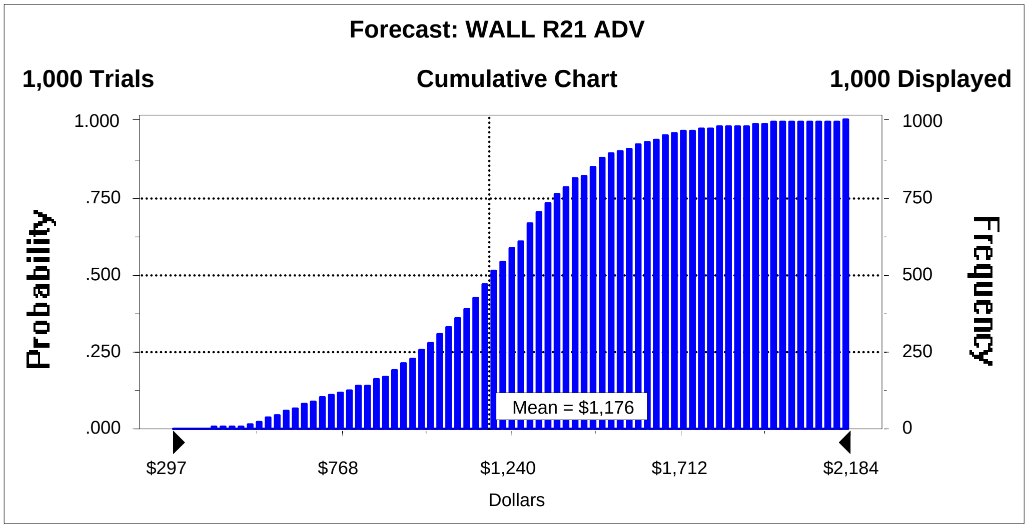

Figure G-36: Climate Zone 1 R21 Wall NPV for Electric Zonal

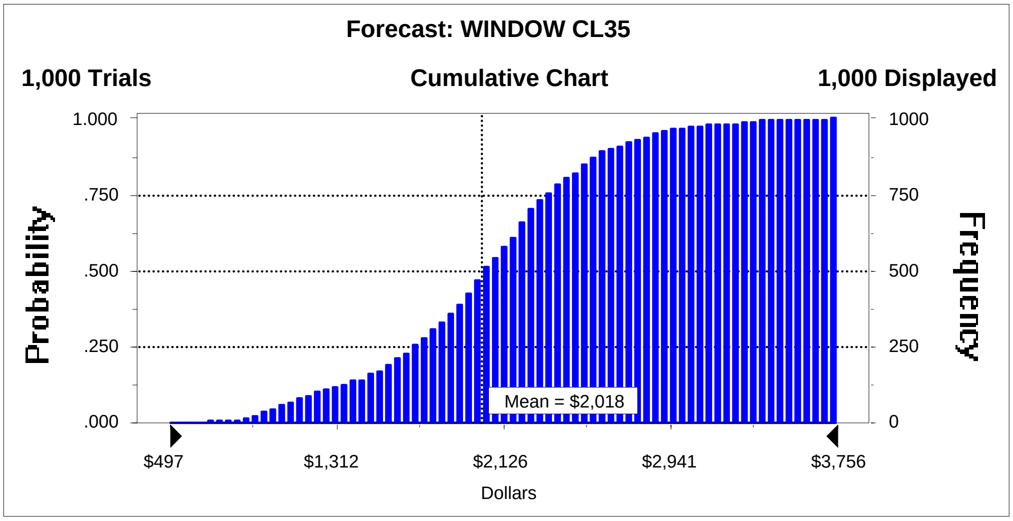

Figure G-37: Climate Zone 1 Class 35 Windows NPV Results for Electric Zonal

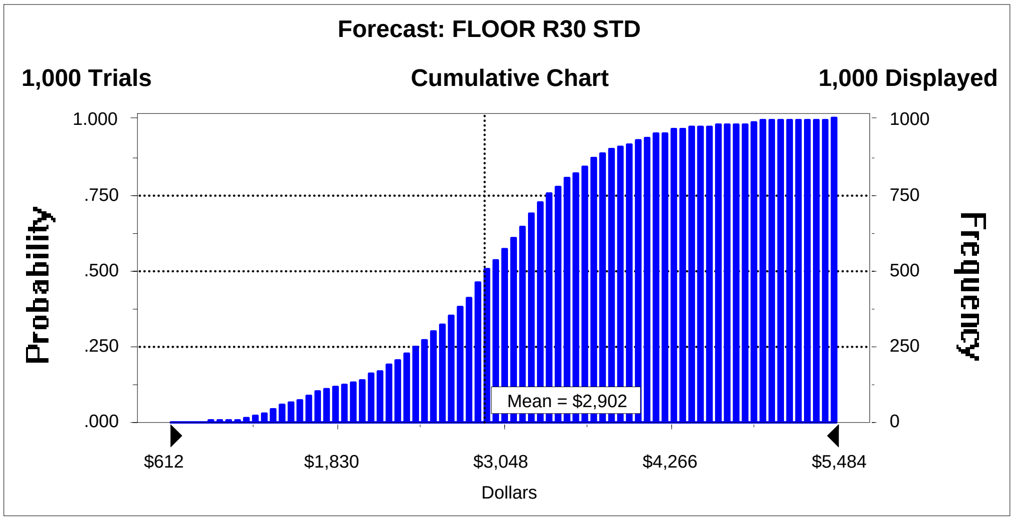

Figure G-38: Climate Zone 1 R30 Under floor NPV Results for Electric Zonal

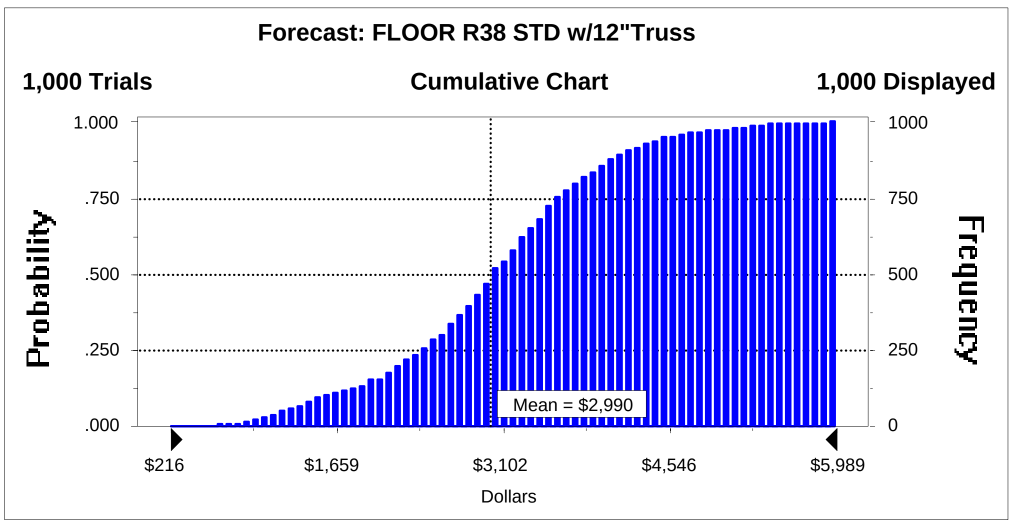

Figure G-39: Climate Zone 1 R38 Under floor NPV Results for Electric Zonal

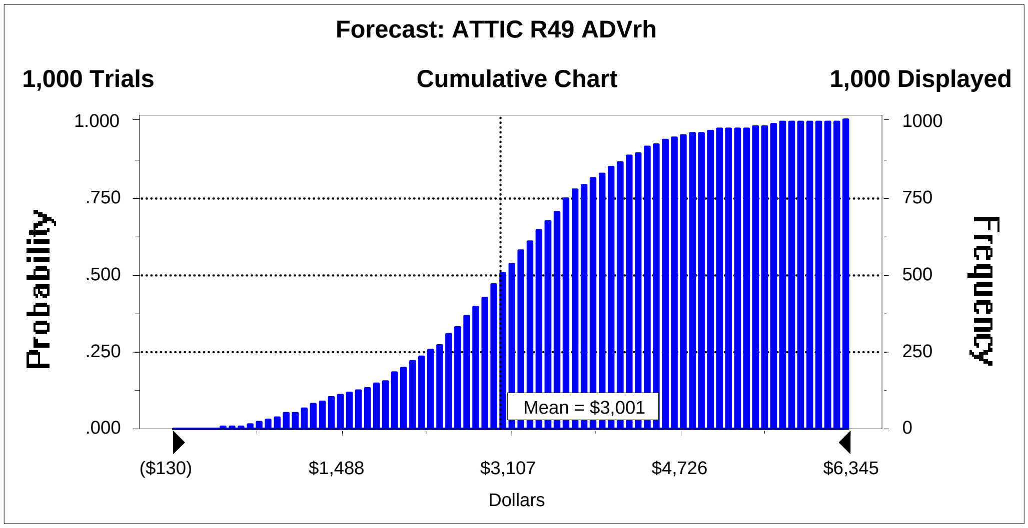

Figure G-40: Climate Zone 1 R49 Advanced Framed Attic NPV Results for Electric Zonal

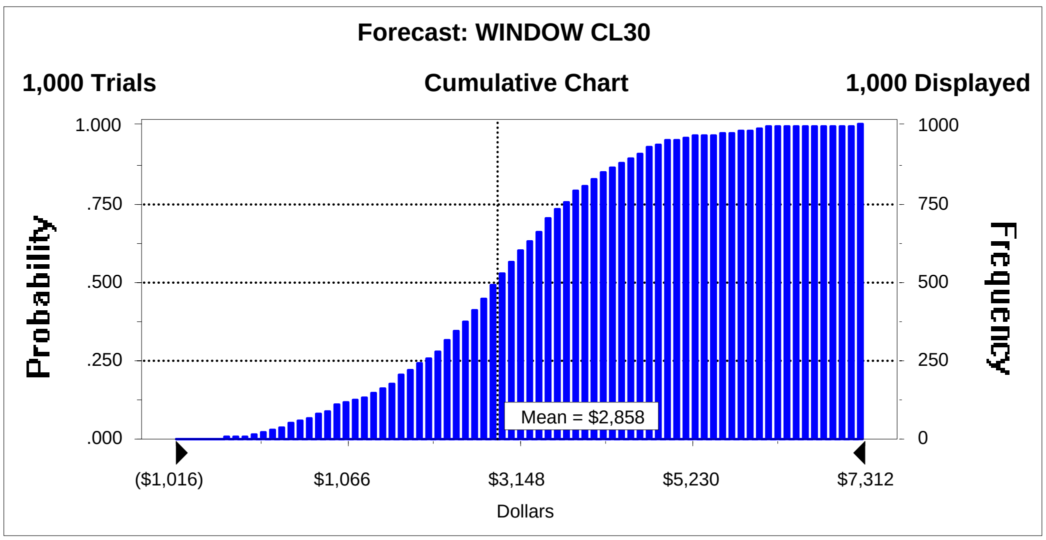

Figure G-41: Climate Zone 1 Class 30 Window NPV Results for Electric Zonal

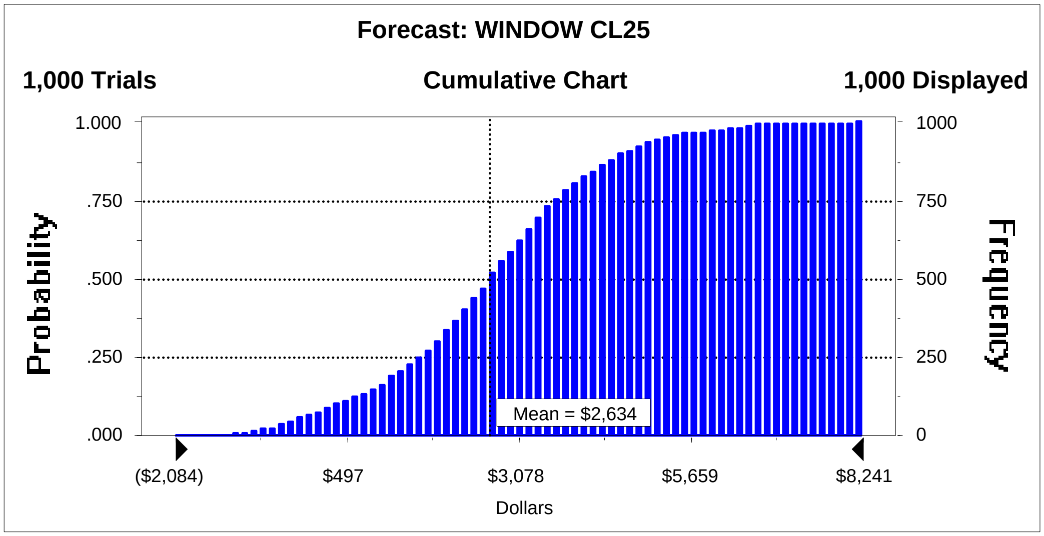

Figure G-42: Climate Zone 1 Class 25 Window NPV Results for Electric Zonal

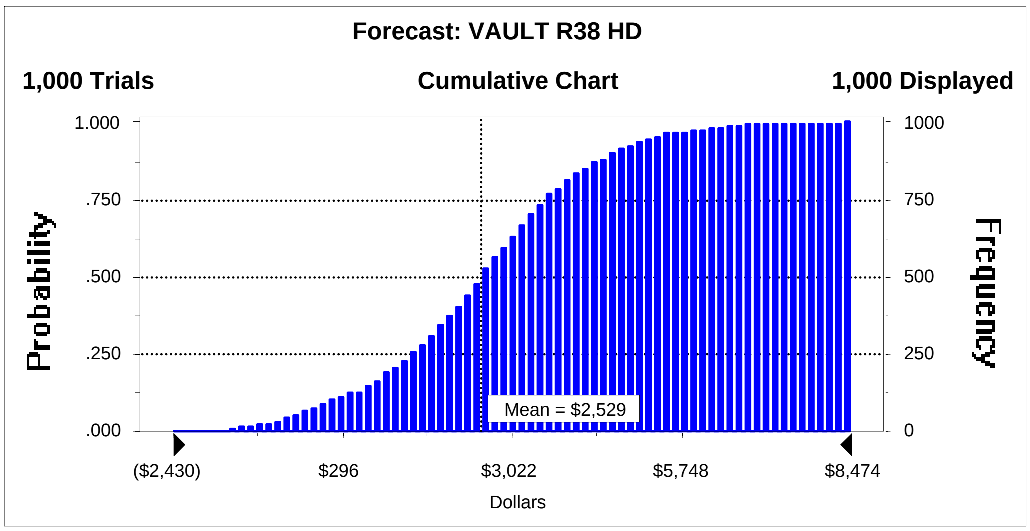

Figure G-43: Climate Zone 1 R38 Vaulted Ceiling NPV Results for Electric Zonal

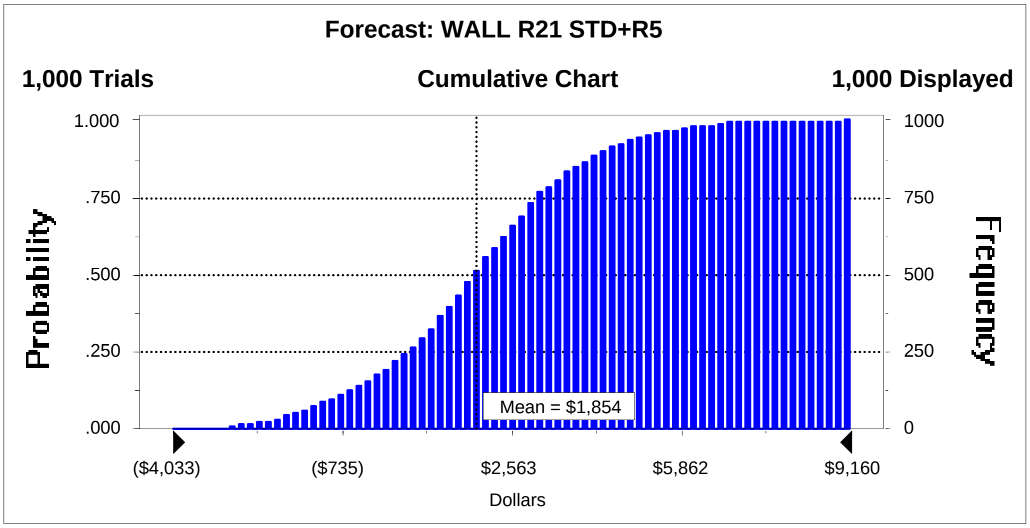

Figure G-44: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Electric Zonal

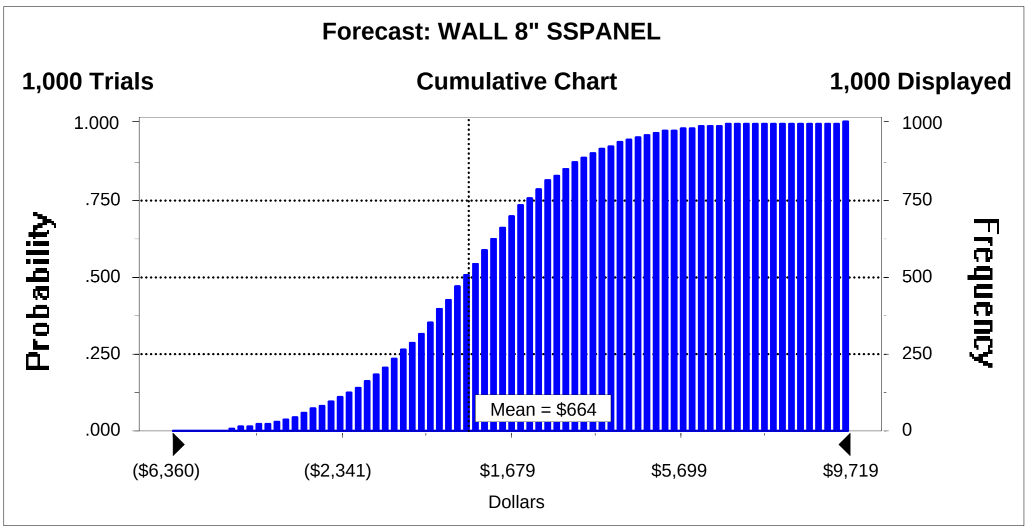

Figure G-45: Climate Zone 1 R33 Wall NPV Results for Electric Zonal

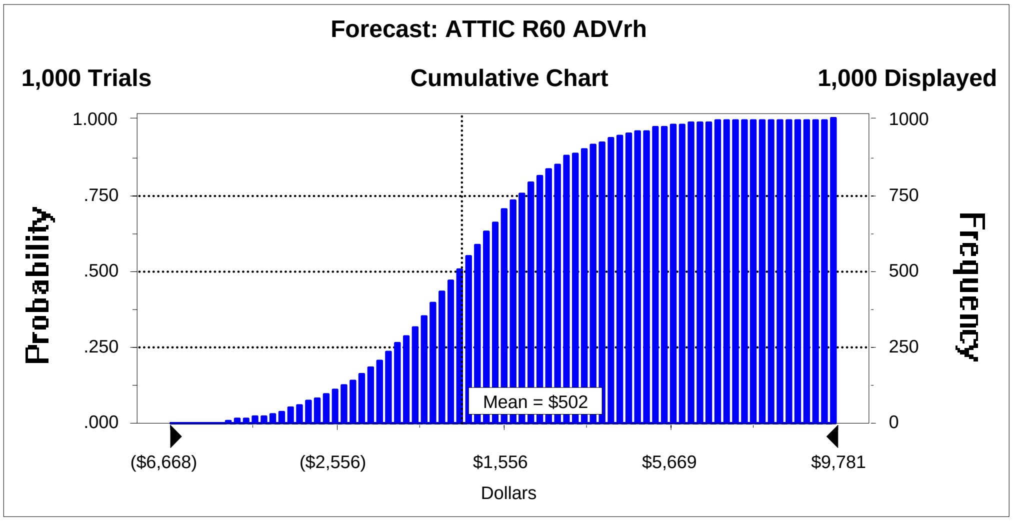

Figure G-46: Climate Zone 1 R60 Advanced Framed Attic NPV Results for Electric Zonal

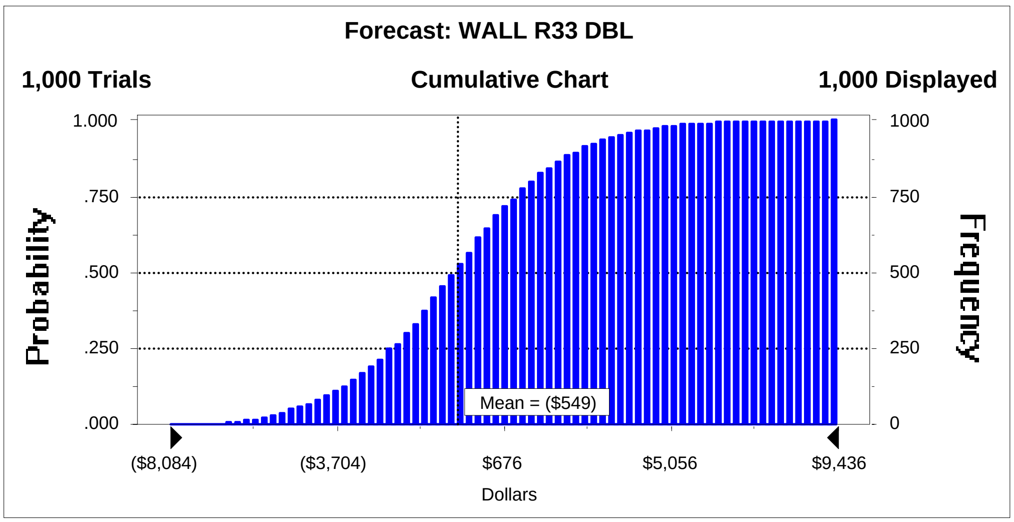

Figure G-47: Climate Zone 1 R38 Wall NPV Results for Electric Zonal

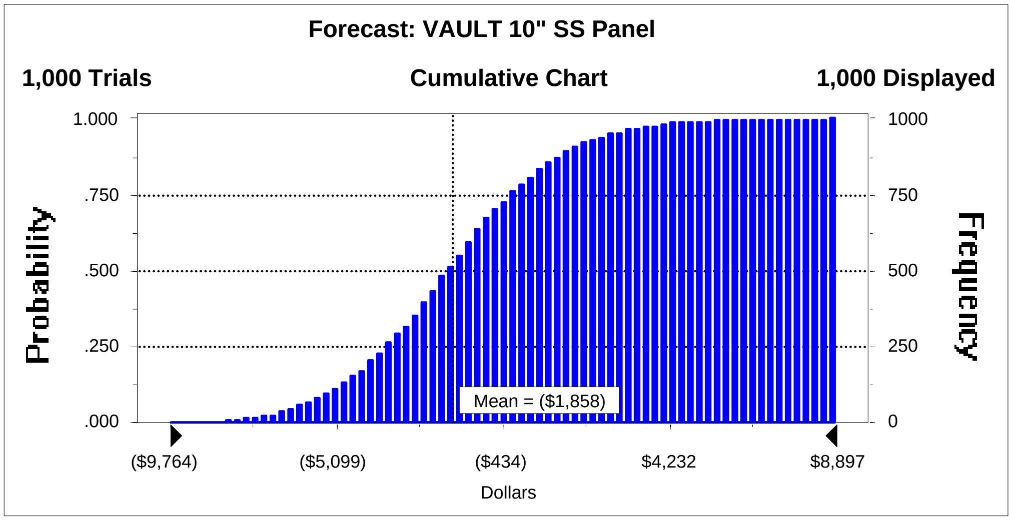

Figure G-48: Climate Zone 1 R49 Vault NPV Results for Electric Zonal

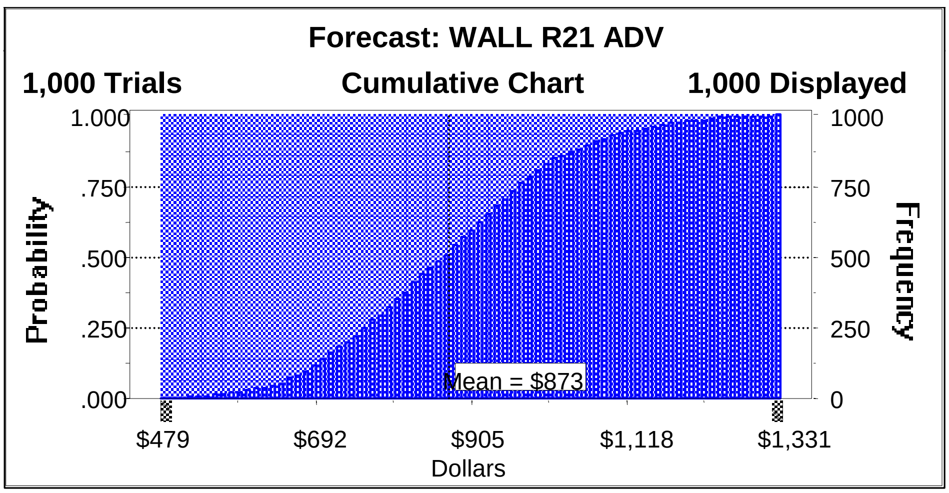

Figure G-49: Climate Zone 1 R21 Advanced Framed Wall NPV Results for Gas FAF

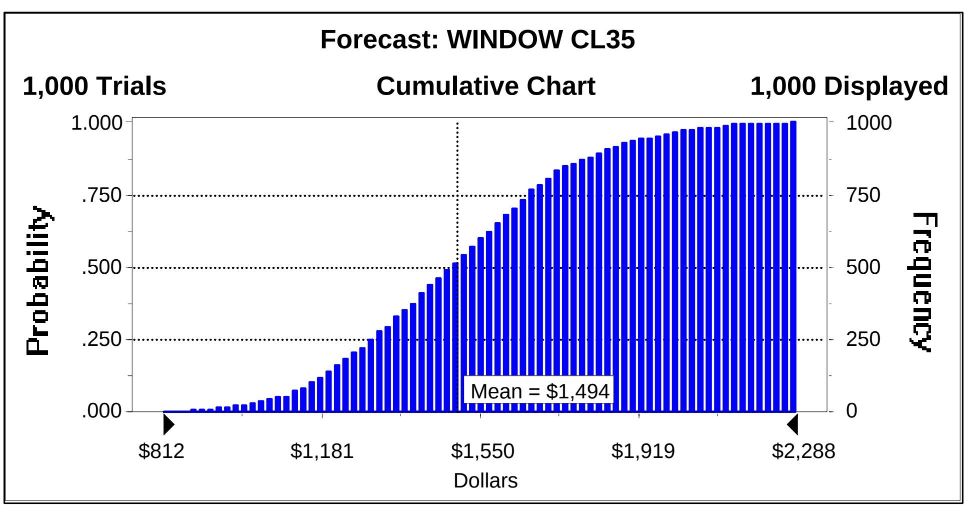

Figure G-50: Climate Zone 1 Class 35 Window NPV Results for Gas FAF

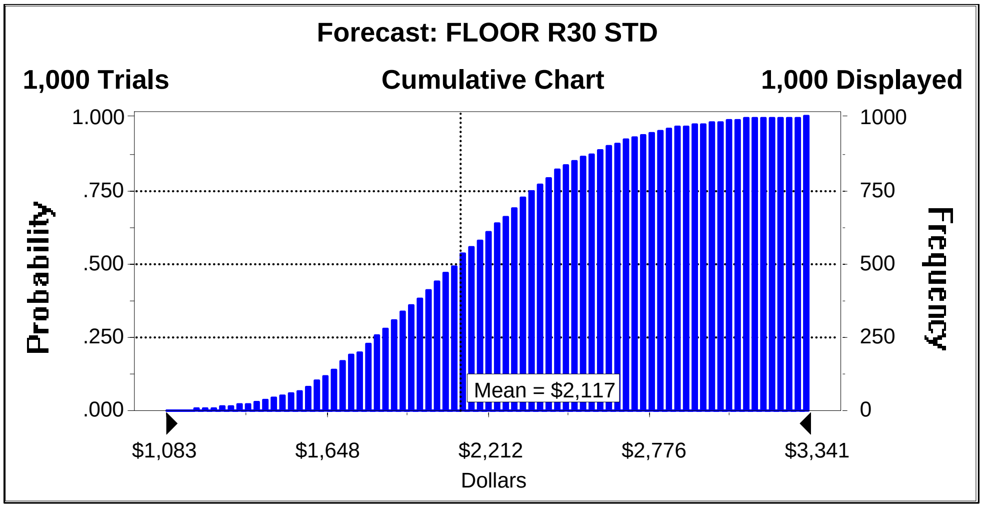

Figure G-51: Climate Zone 1 R30 Under floor NPV Results for Gas FAF

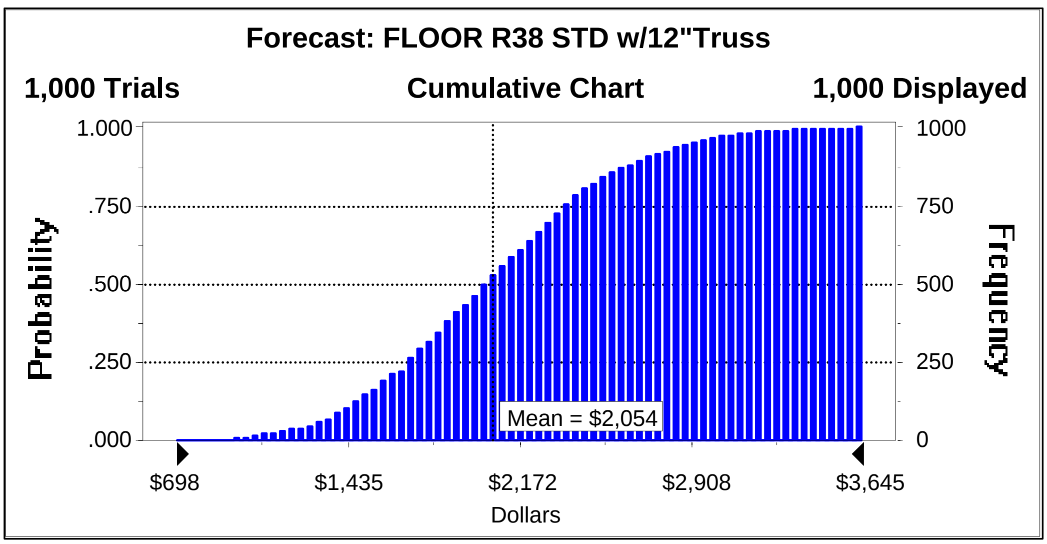

Figure G-52: Climate Zone 1 R38 Under floor NPV Results for Gas FAF

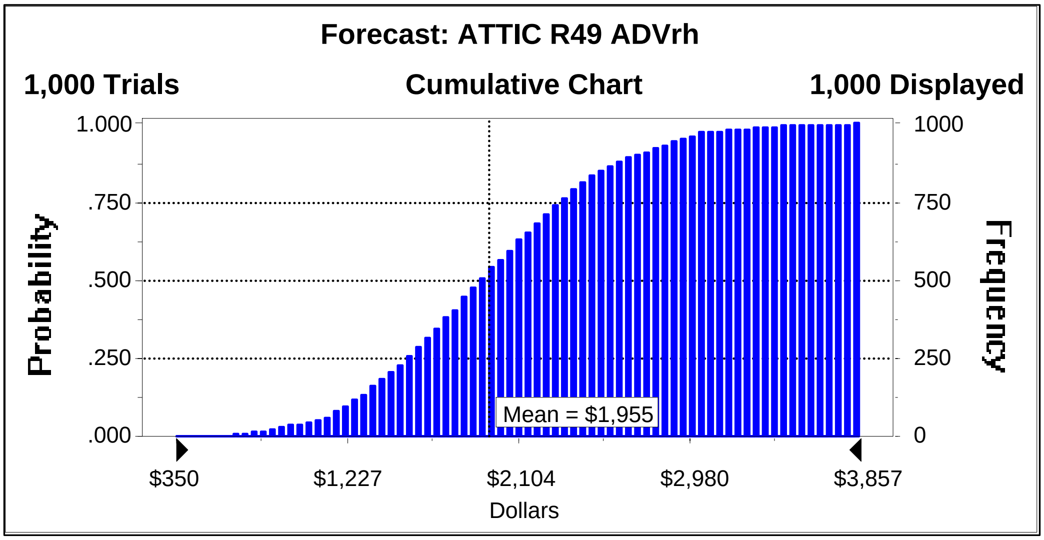

Figure G-53: Climate Zone 1 R49 Advanced Framed Attic NPV Results for Gas FAF

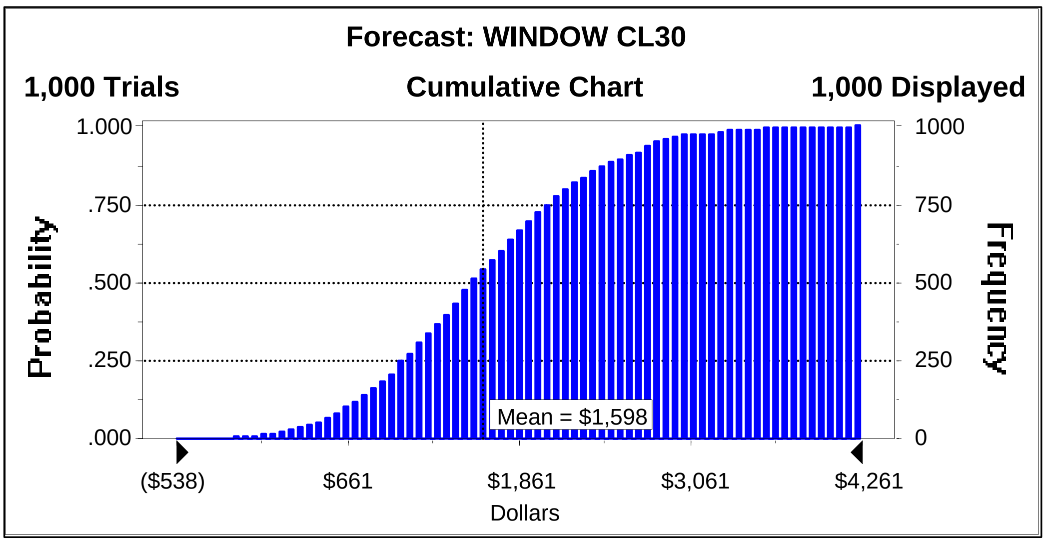

Figure G-54: Climate Zone 1 Class 30 Window NPV Results for Gas FAF

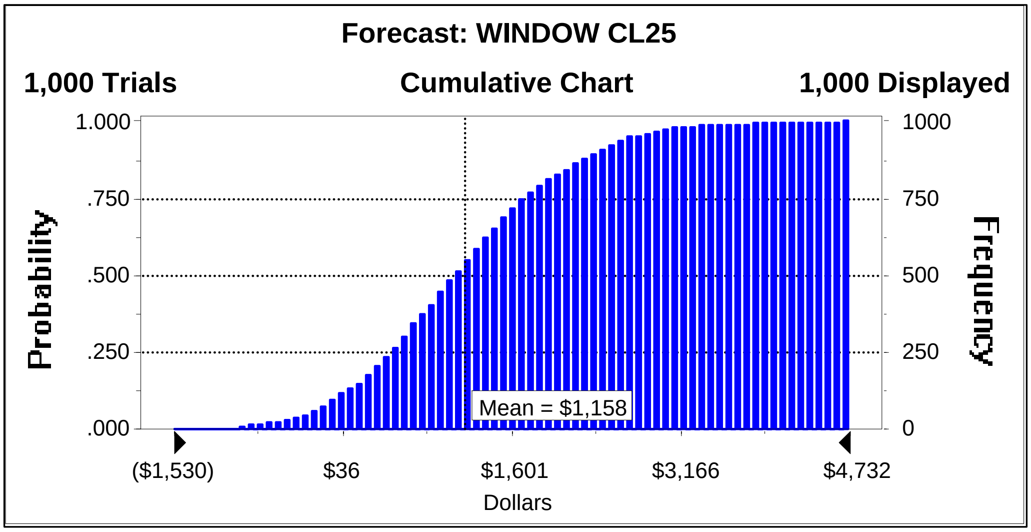

Figure G-55: Climate Zone 1 Class 25 Window NPV Results for Gas FAF

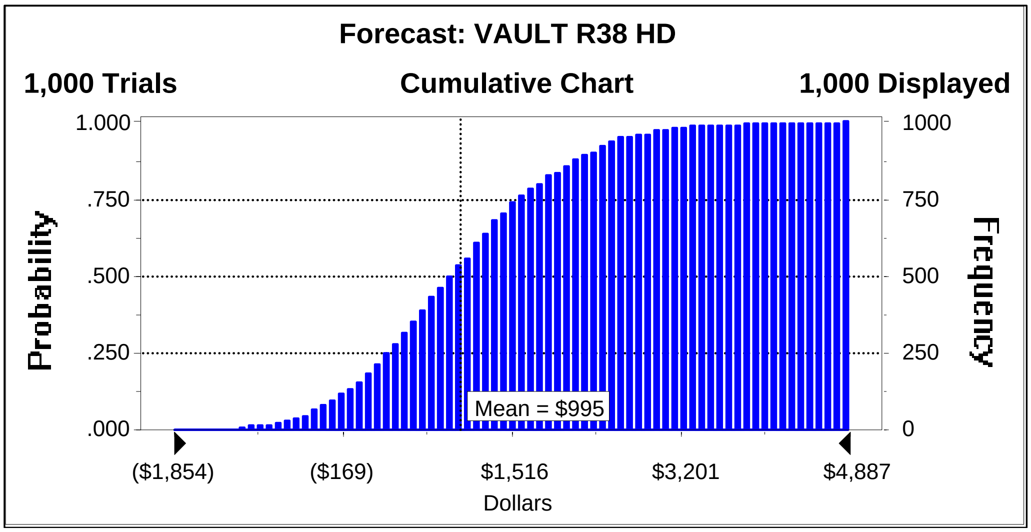

Figure G-56: Climate Zone 1 R38 Vault NPV Results for Gas FAF

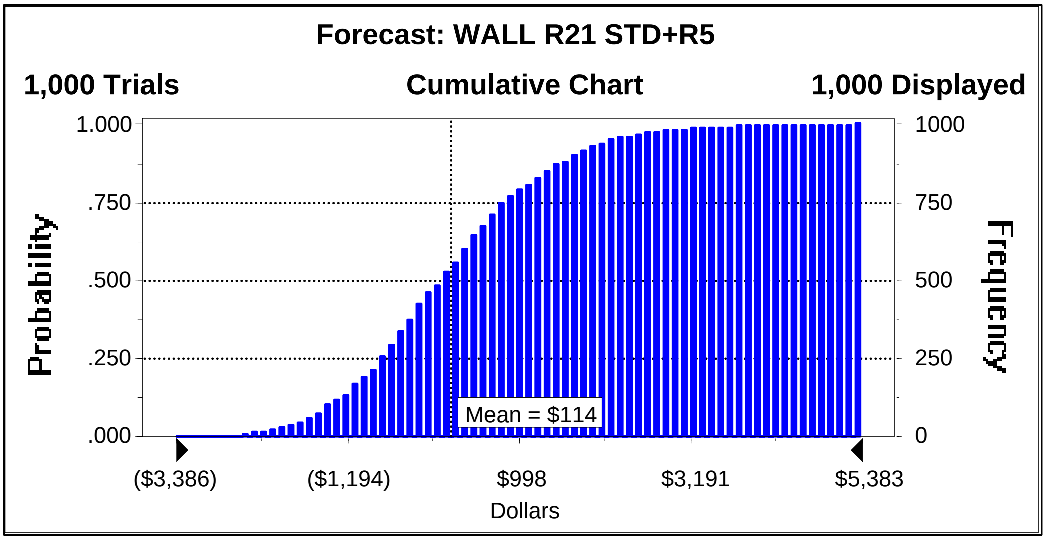

Figure G-57: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Gas FAF

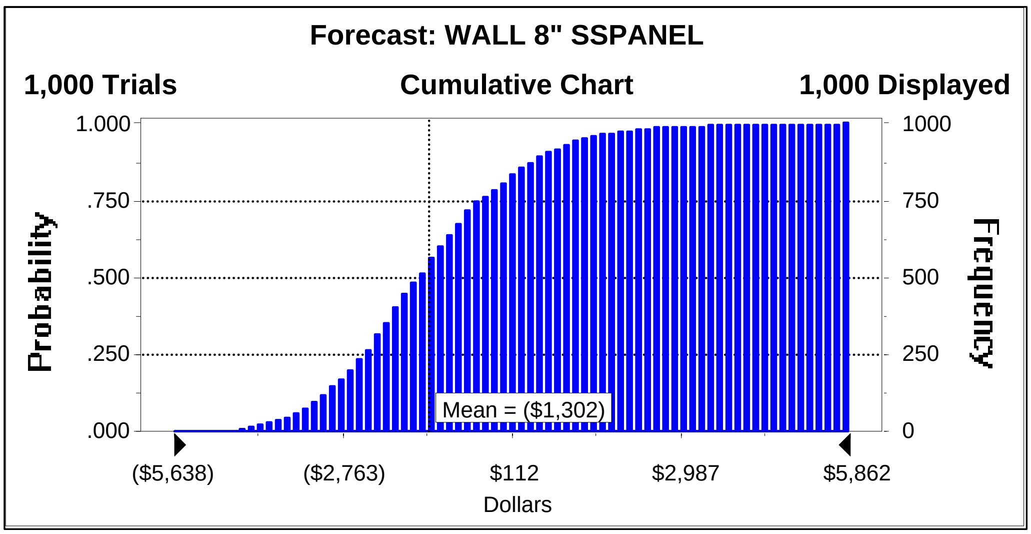

Figure G-58: Climate Zone 1 R33 Wall NPV Results for Gas FAF

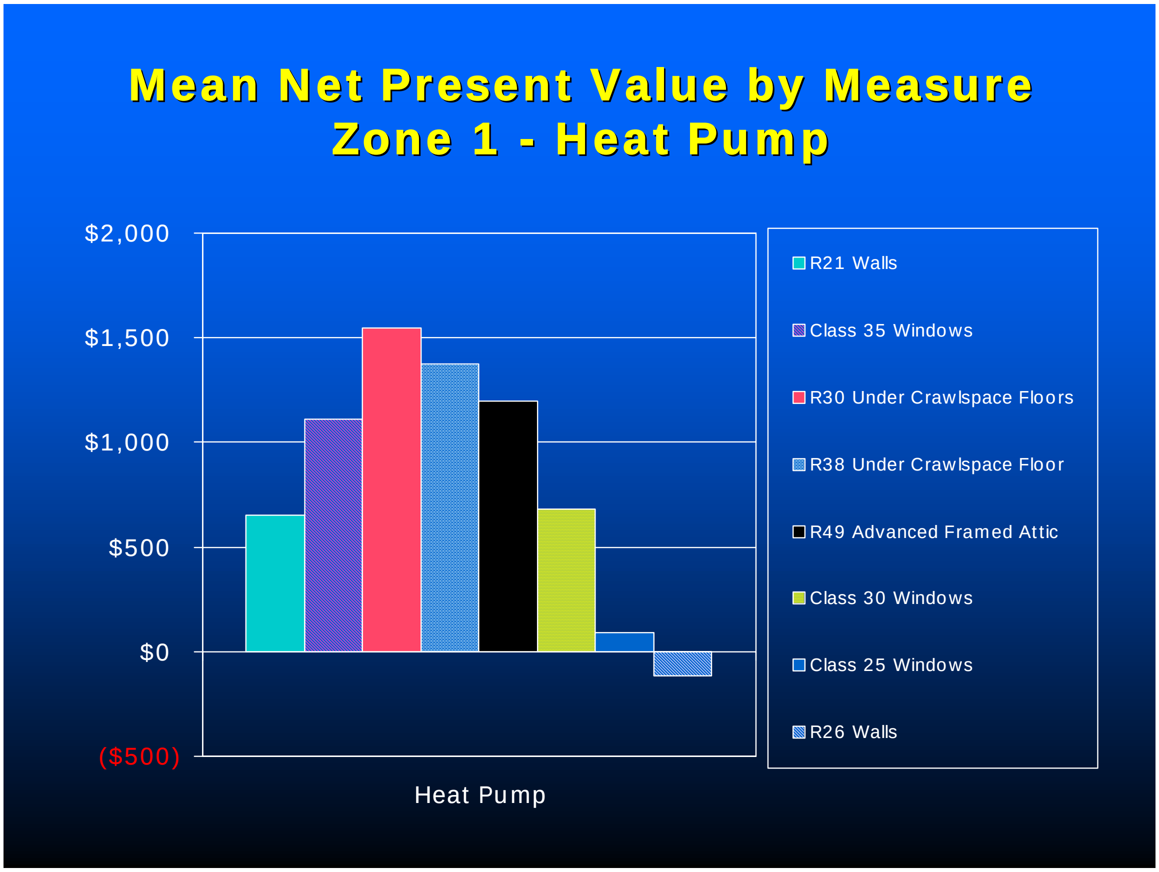

Figure G-59: Climate Zone 1 Mean NPV by Measure for Heat Pumps

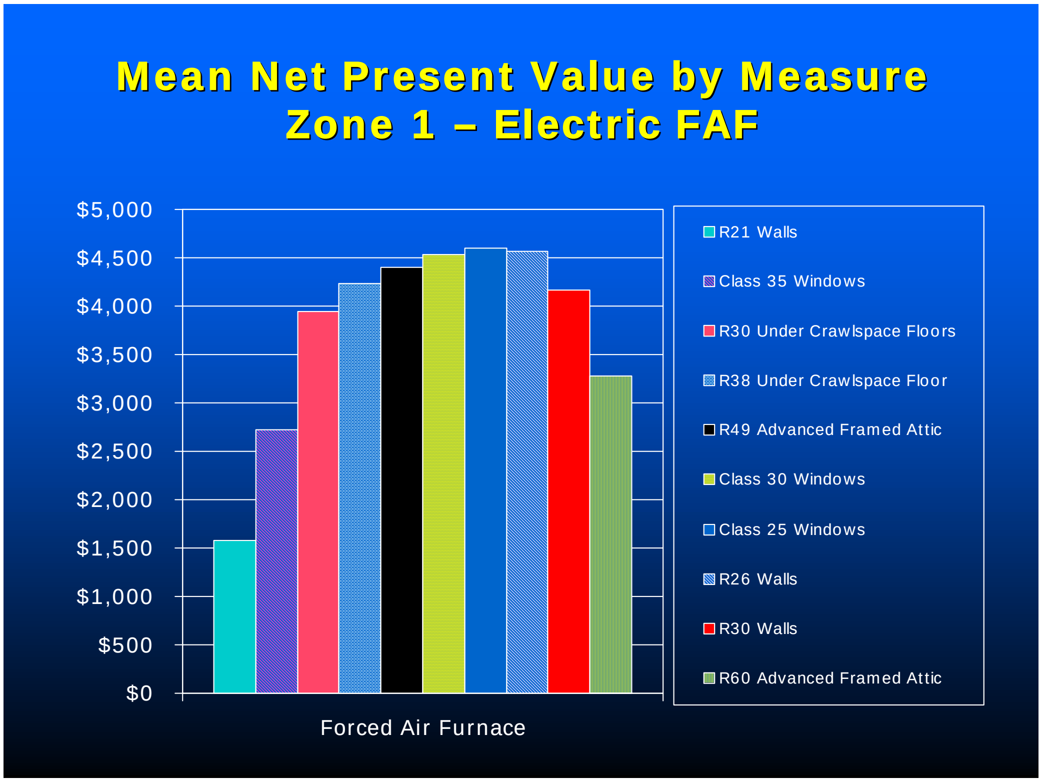

Figure G-60: Climate Zone 1 Mean NPV by Measure for Electric FAF

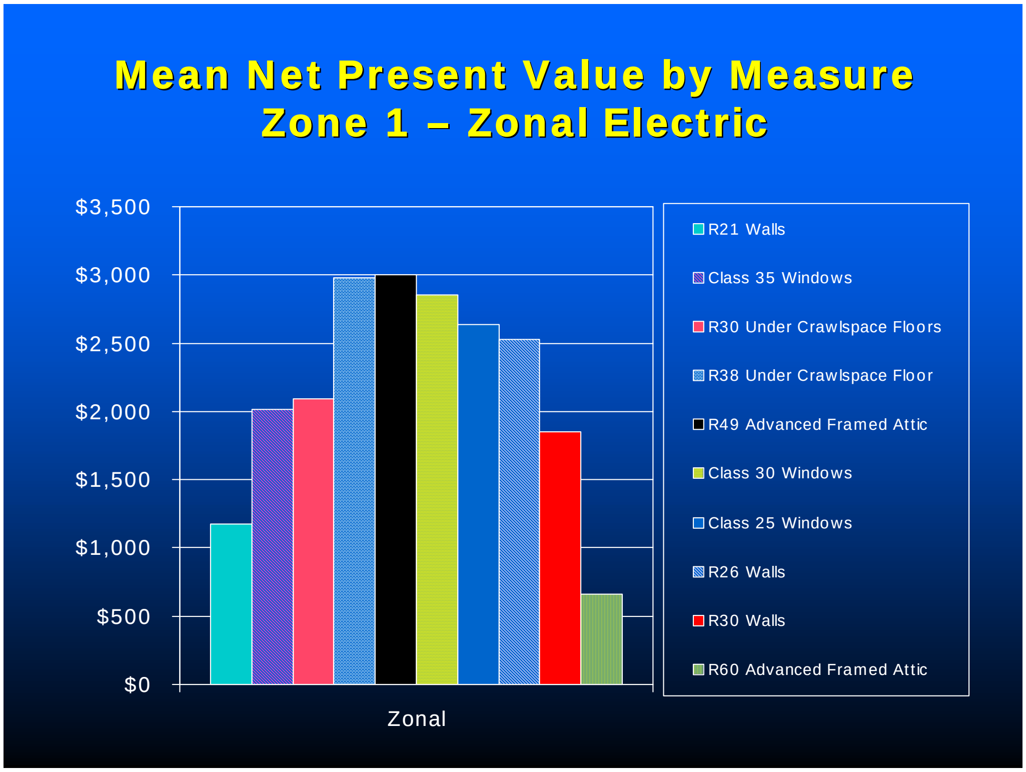

Figure G-61: Climate Zone 1 - Mean NPV by Measure for Electric Zonal

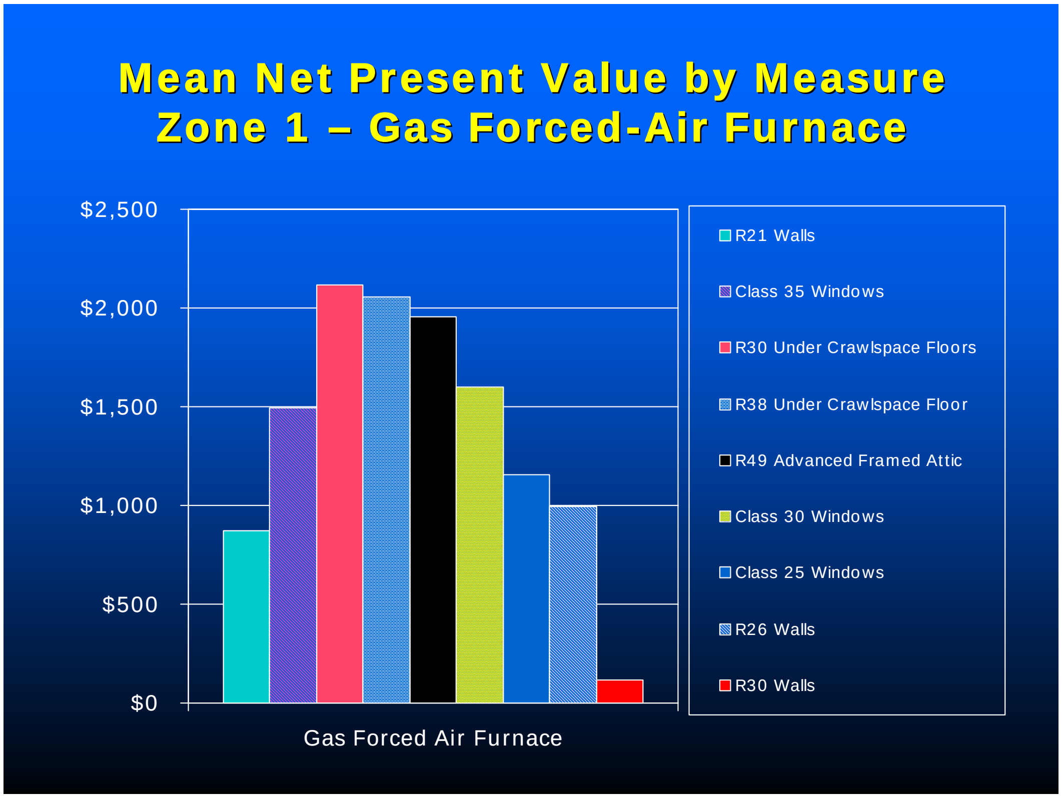

Figure G-62: Climate Zone 1 - Mean NPV by Measure for Gas FAF

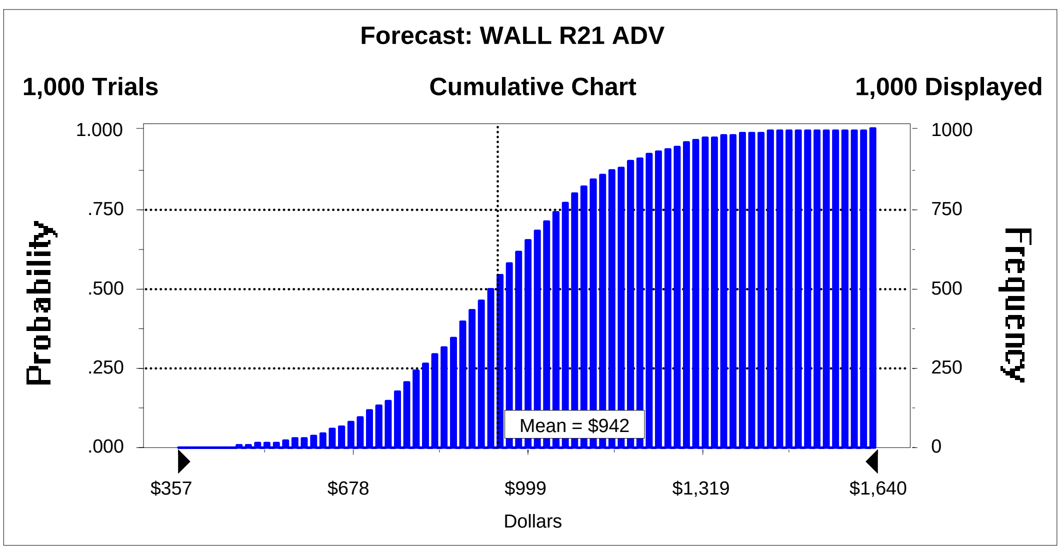

Figure G-63: Climate Zone 2 R21 Advanced Framed Wall NPV Results for Heat Pump

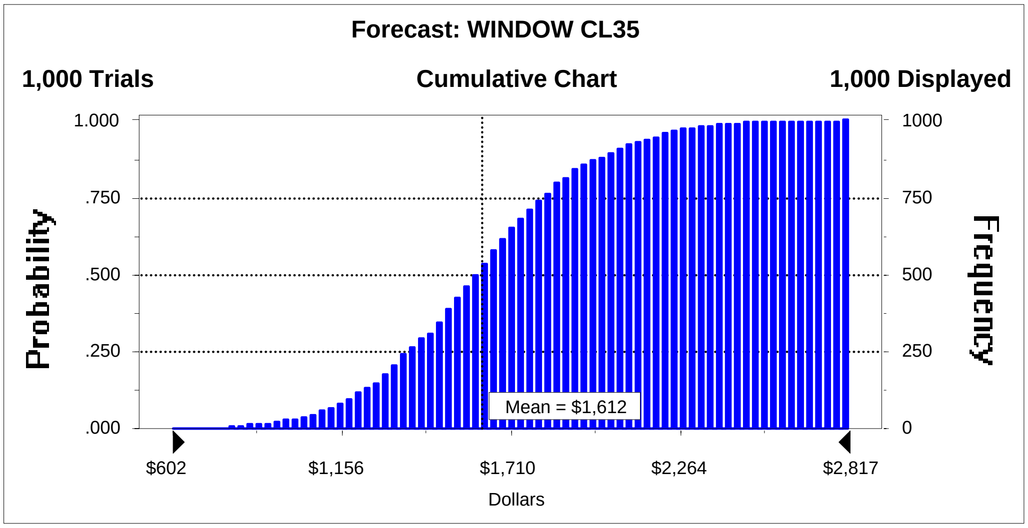

Figure G-64: Climate Zone 2 Class 35 Window NPV Results for Heat Pumps

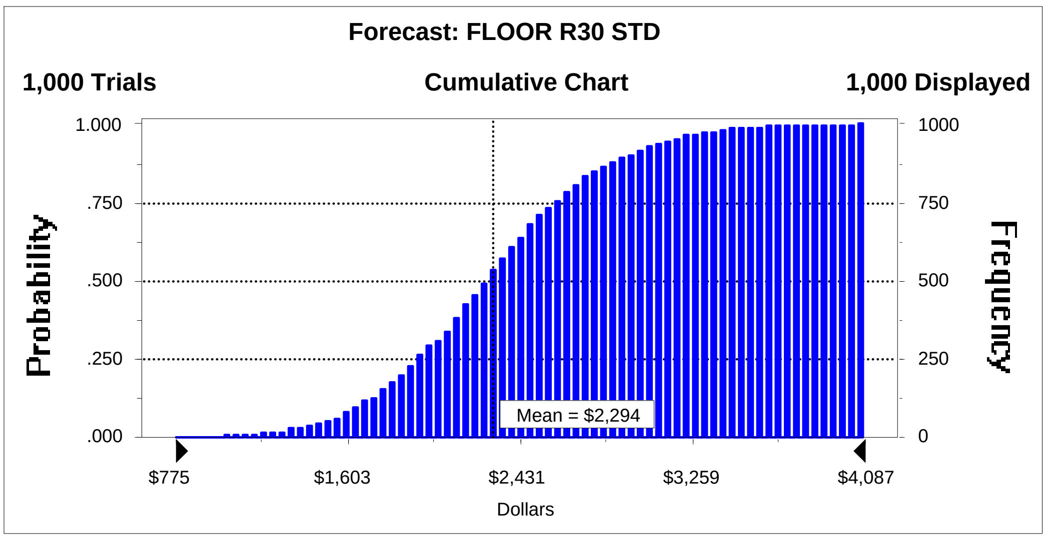

Figure G-65: Climate Zone 2 R30 Under floor NPV Results for Heat Pumps

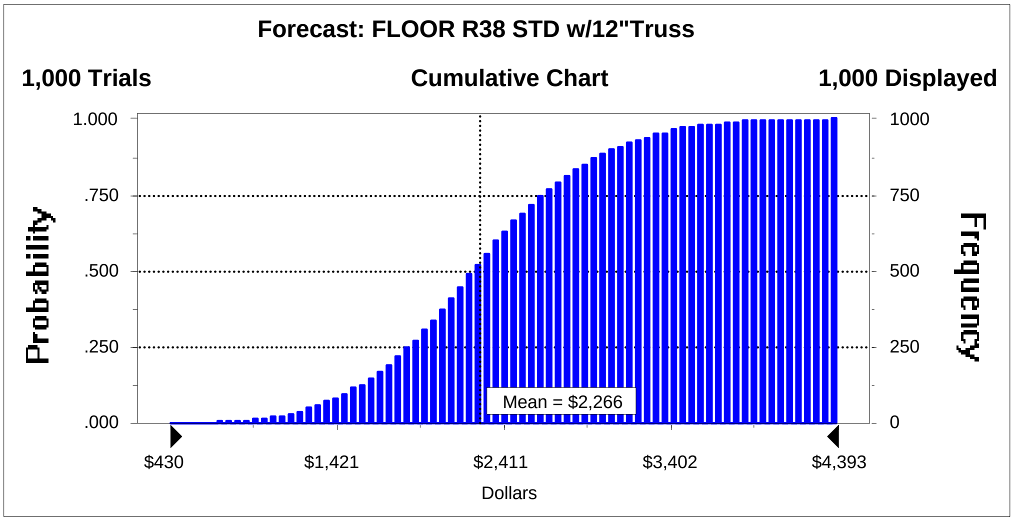

Figure G-66: Climate Zone 2 R38 Under floor NPC Results for Heat Pumps

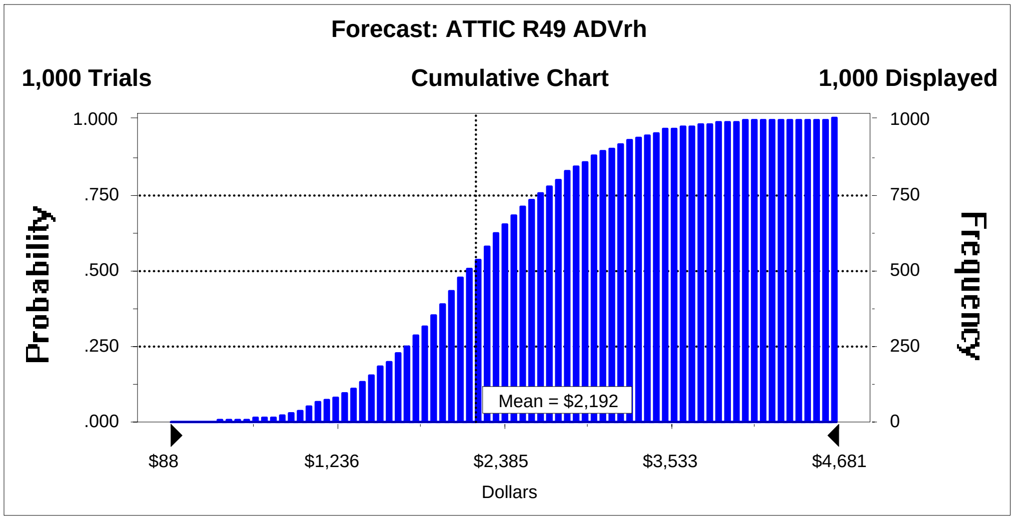

Figure G-67: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Heat Pumps

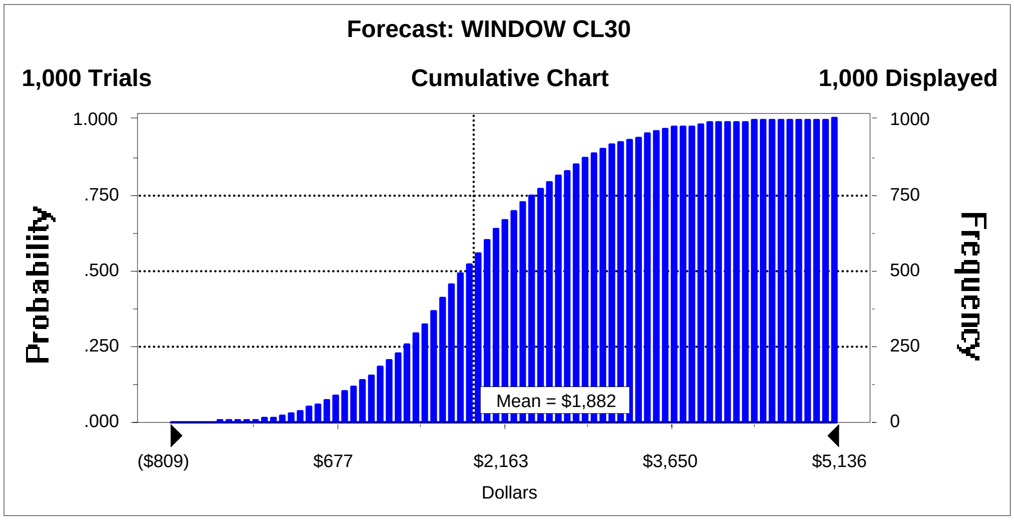

Figure G-68: Climate Zone 2 Class 30 Window NPV Results for Heat Pumps

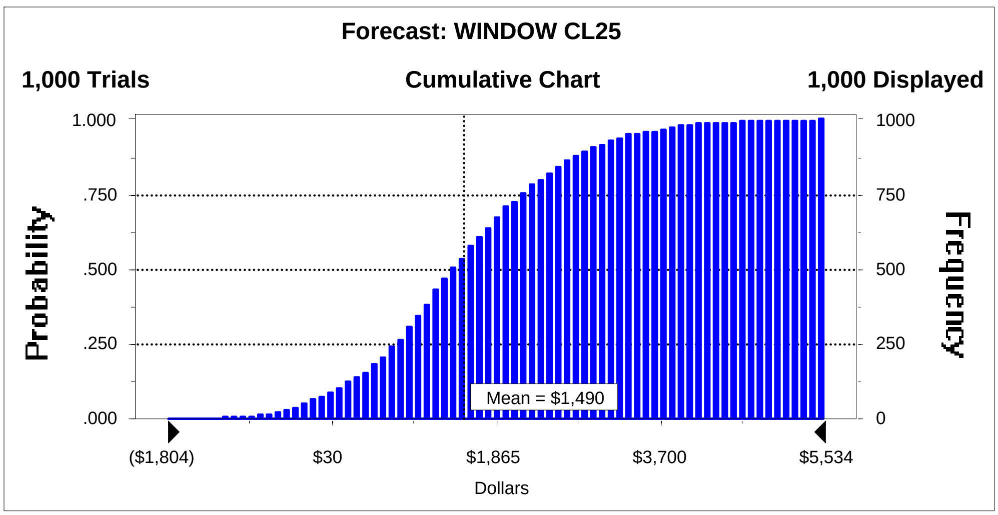

Figure G-69: Climate Zone 2 Class 25 Window NPV Results for Heat Pumps

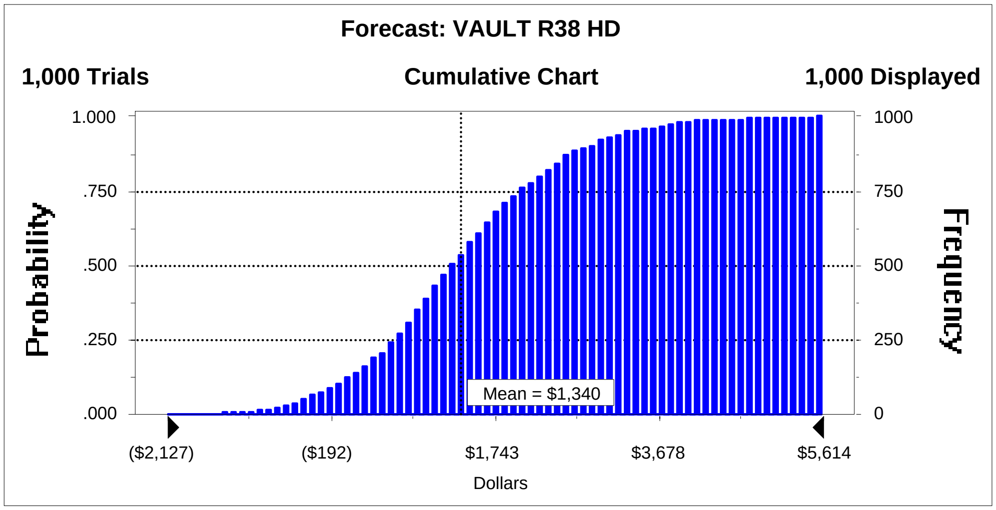

Figure G-70: Climate Zone 2 R38 Vault NPV Results for Heat Pumps

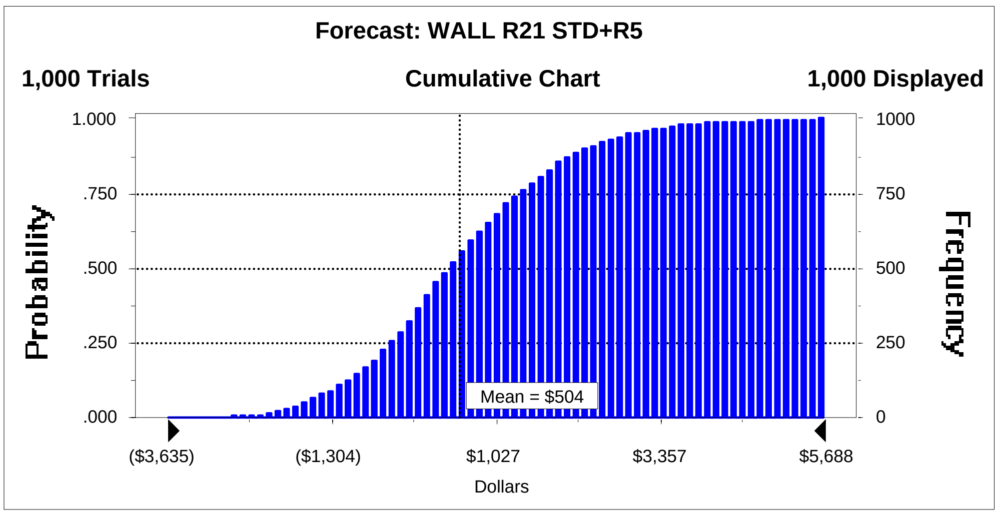

Figure G-71: Climate Zone 2 R26 Advanced Framed Walls NPV Results for Heat Pumps

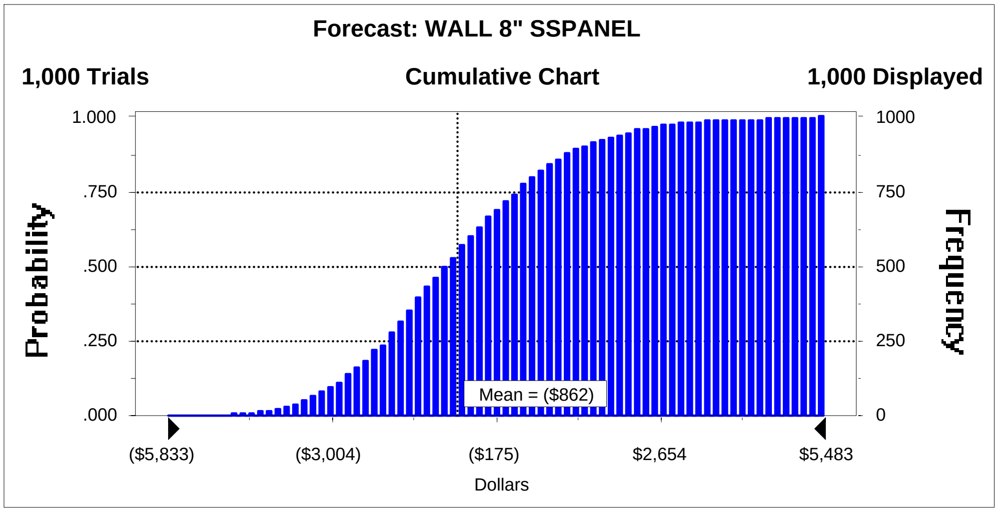

Figure G-72: Climate Zone 2 R33 Wall NPV Results for Heat Pumps

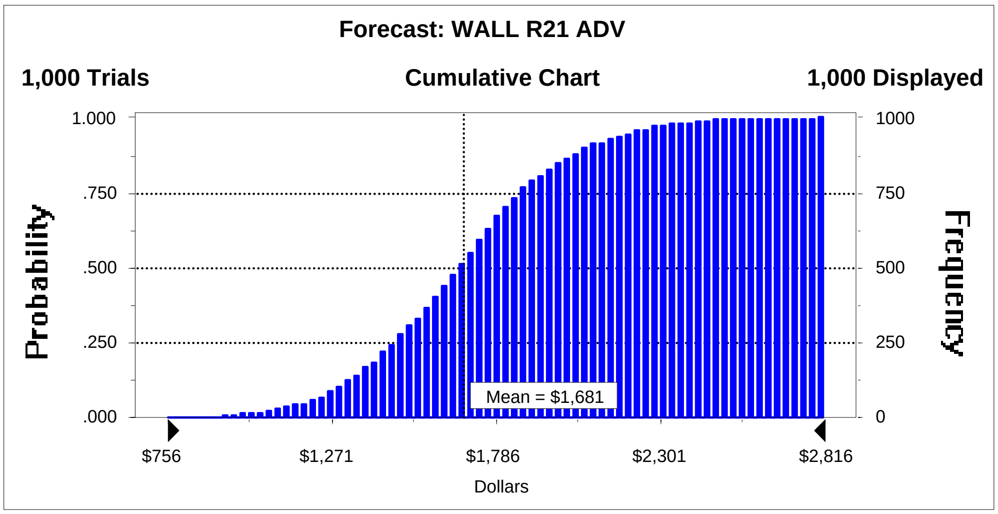

Figure G-73: Climate Zone 2 R21 Advanced Framed Walls NPV Results for Electric FAF

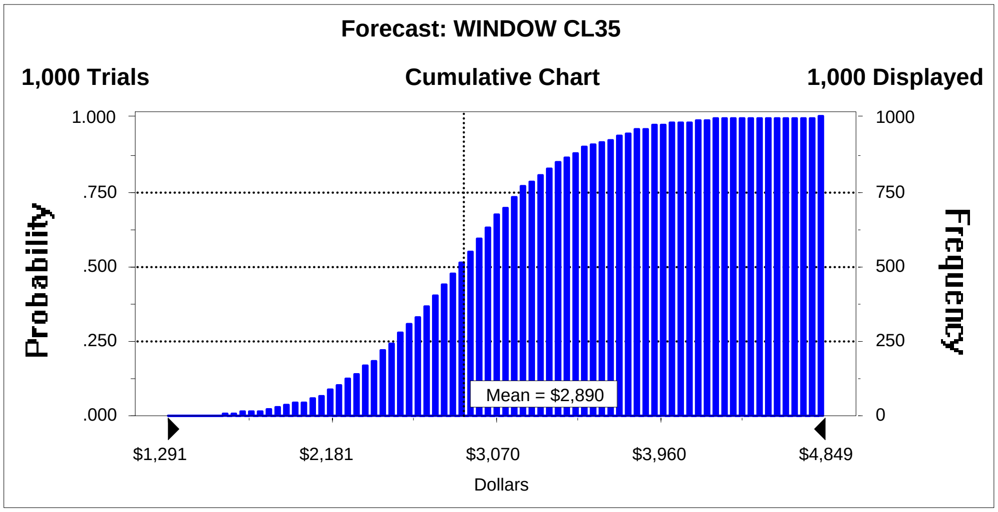

Figure G-74: Climate Zone 2 Class 35 Windows NPV Results for Electric FAF

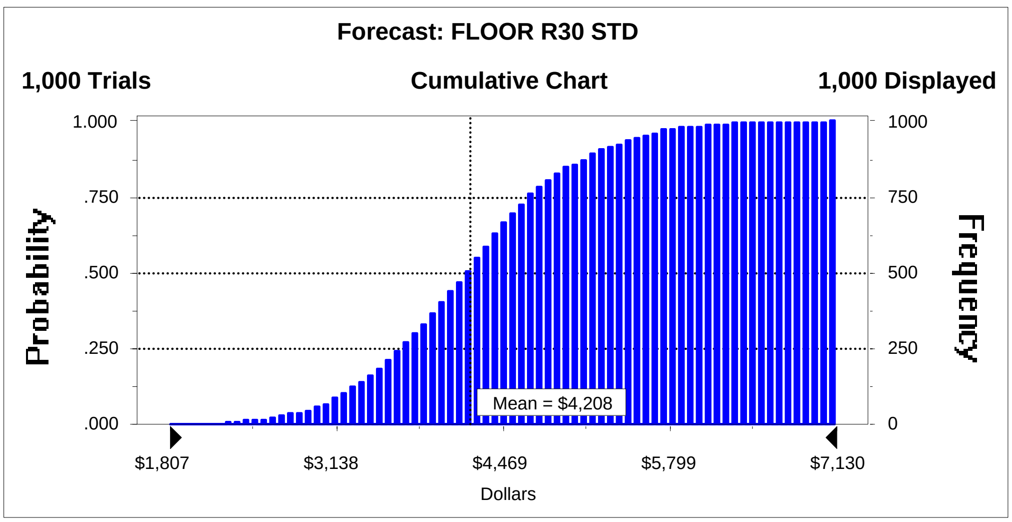

Figure G-75: Climate Zone 2 R30 Under floor NPV Results for Electric FAF

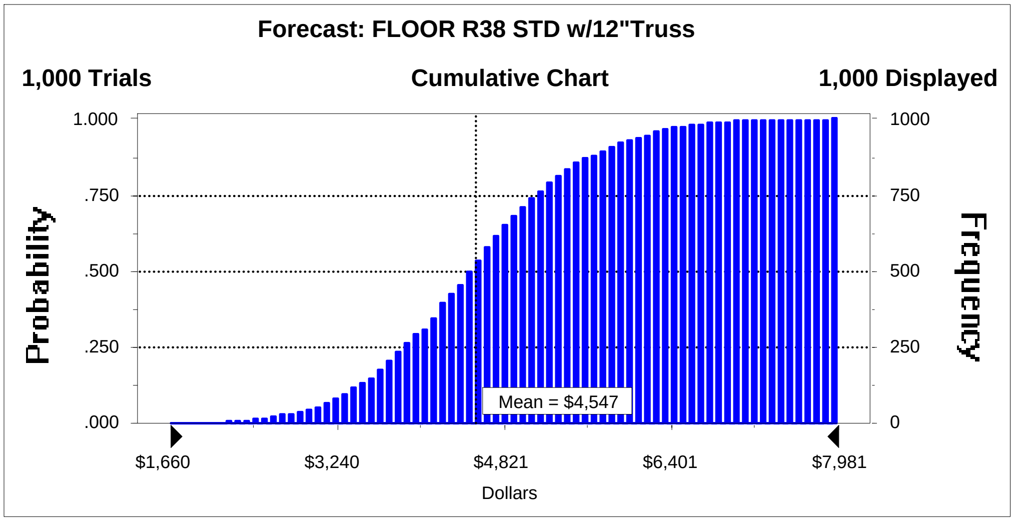

Figure G-76: Climate Zone 2 R38 Under floor NPV Results for Electric FAF

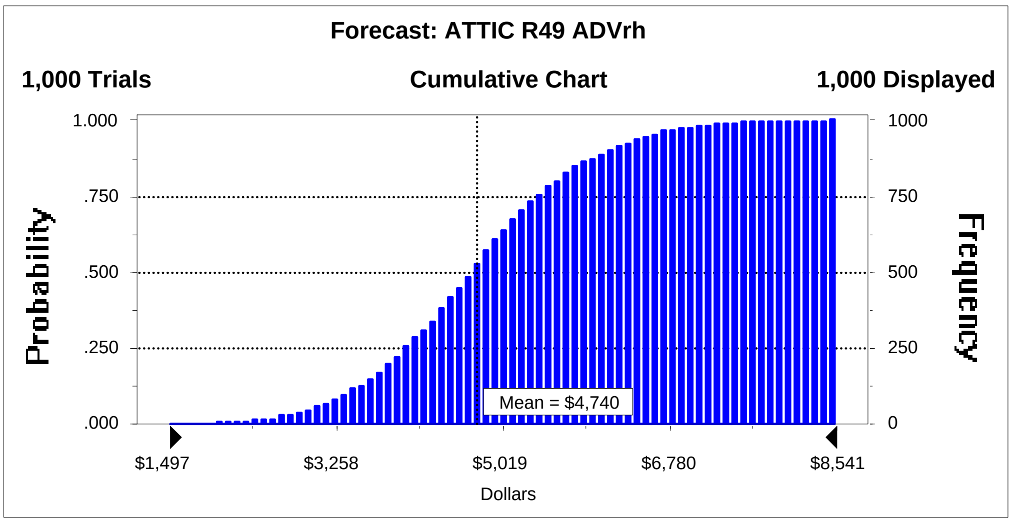

Figure G-77: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Electric FAF

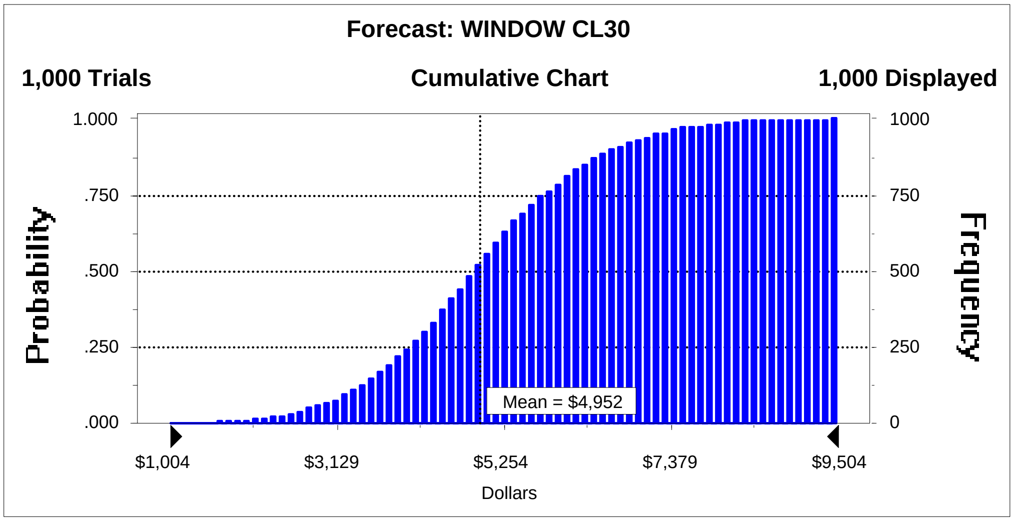

Figure G-78: Climate Zone 2 Class 30 Window NPV Results for Electric FAF

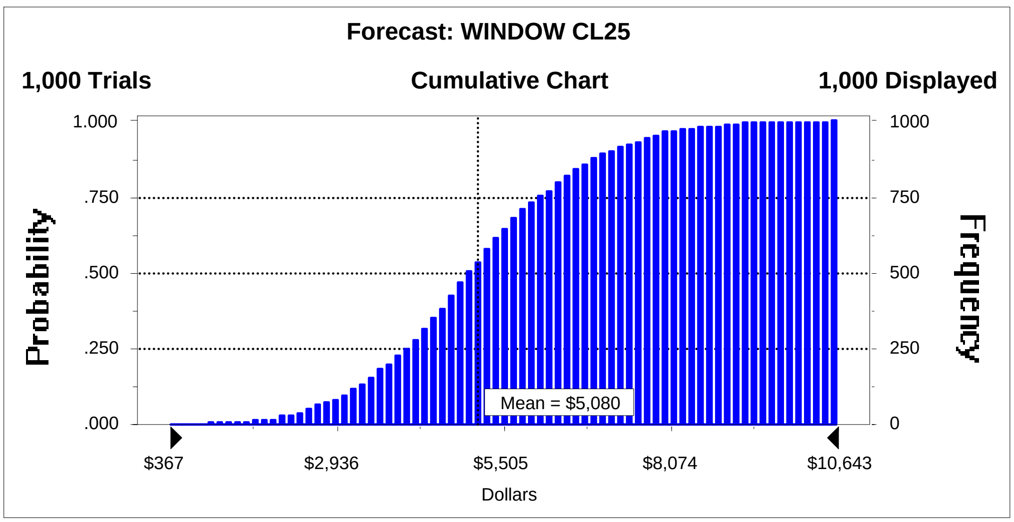

Figure G-79: Climate Zone 2 Class 25 Window NPV Results for Electric FAF

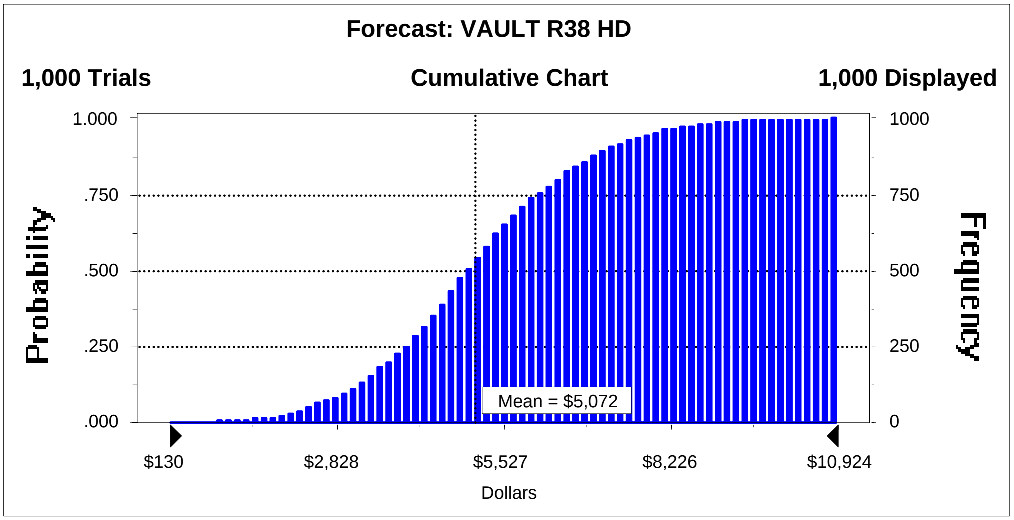

Figure G-80: Climate Zone 2 R38 Vault NPV Results for Electric FAF

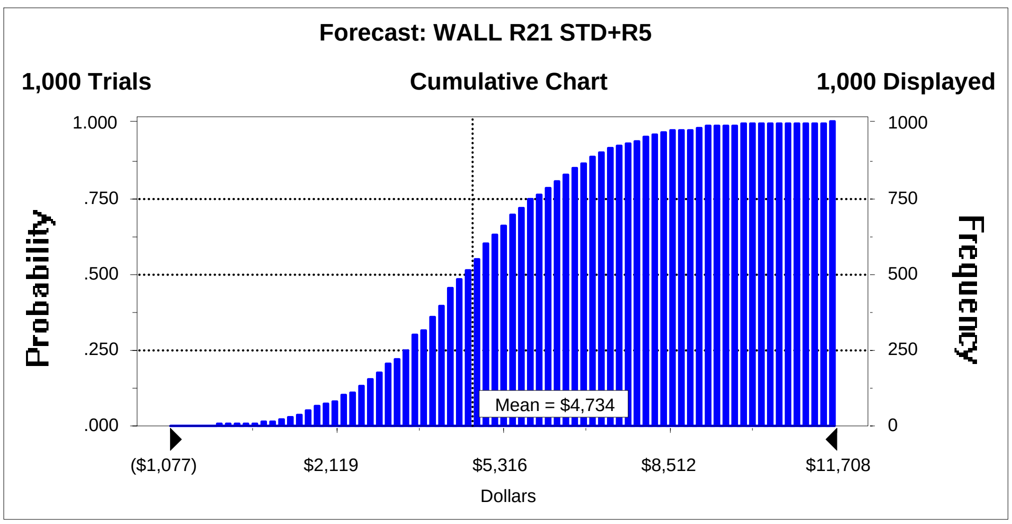

Figure G-81: Climate Zone 2 R26 Advanced Framed Wall NPV Results for Electric FAF

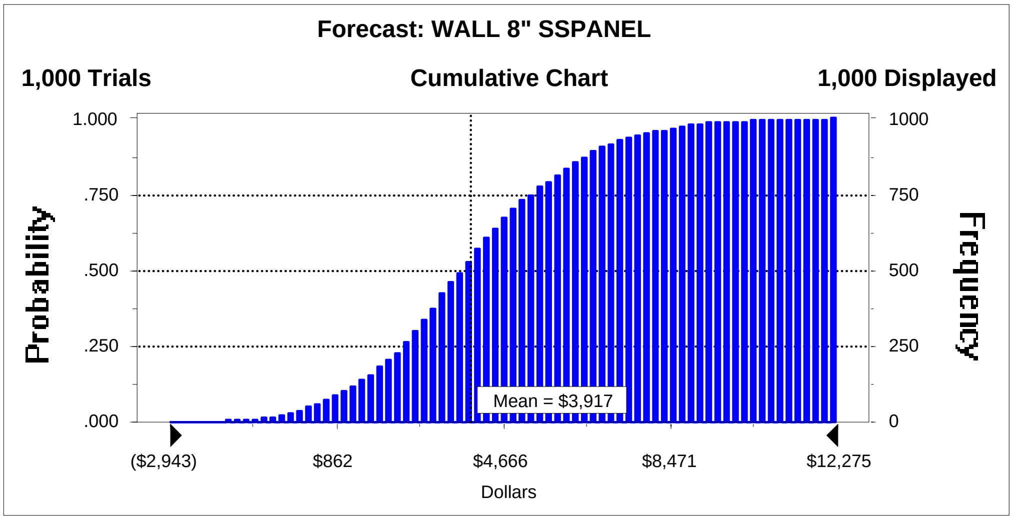

Figure G-82: Climate Zone 2 R33 Wall NPV Results for Electric FAF

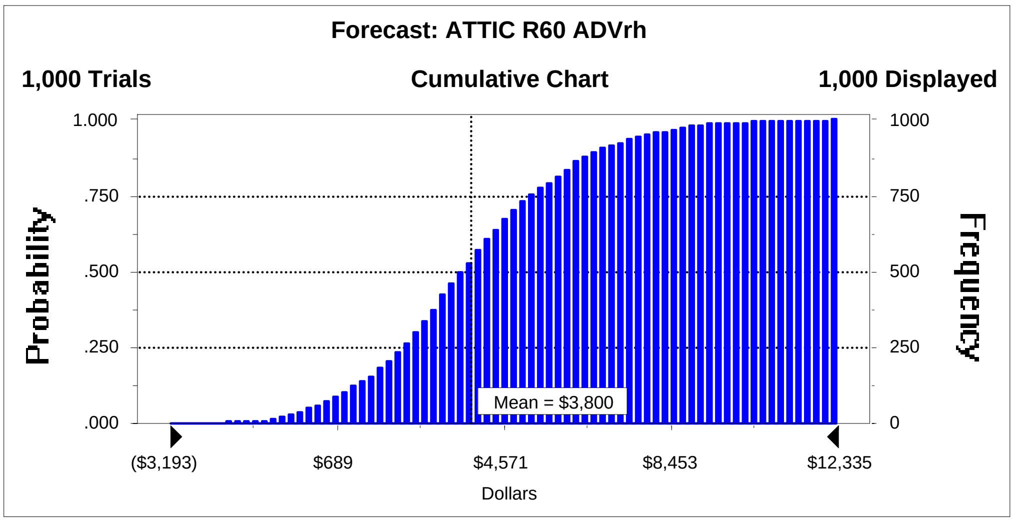

Figure G-83: Climate Zone 2 R60 Advanced Framed Attic NPV Results for Electric FAF

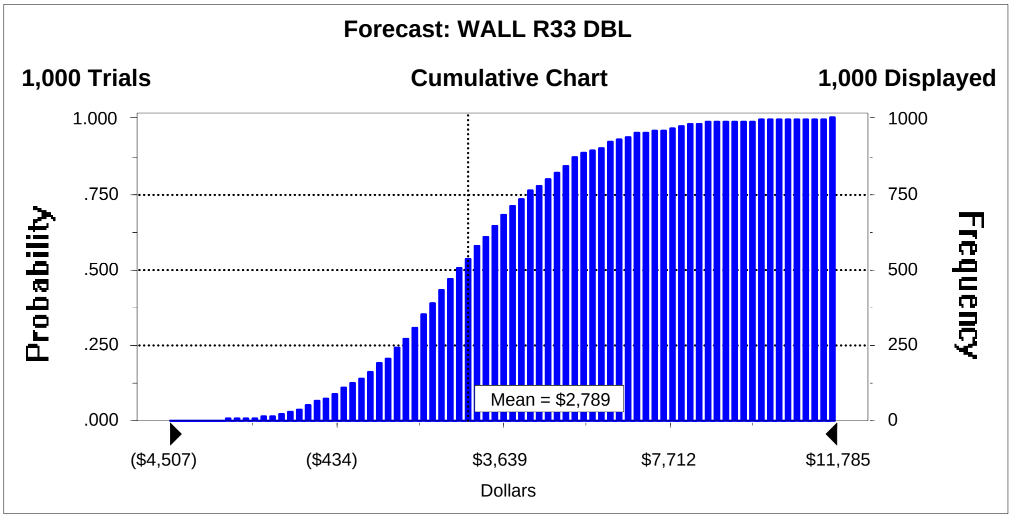

Figure G-84: Climate Zone 2 R38 Wall NPV Results for Electric FAF

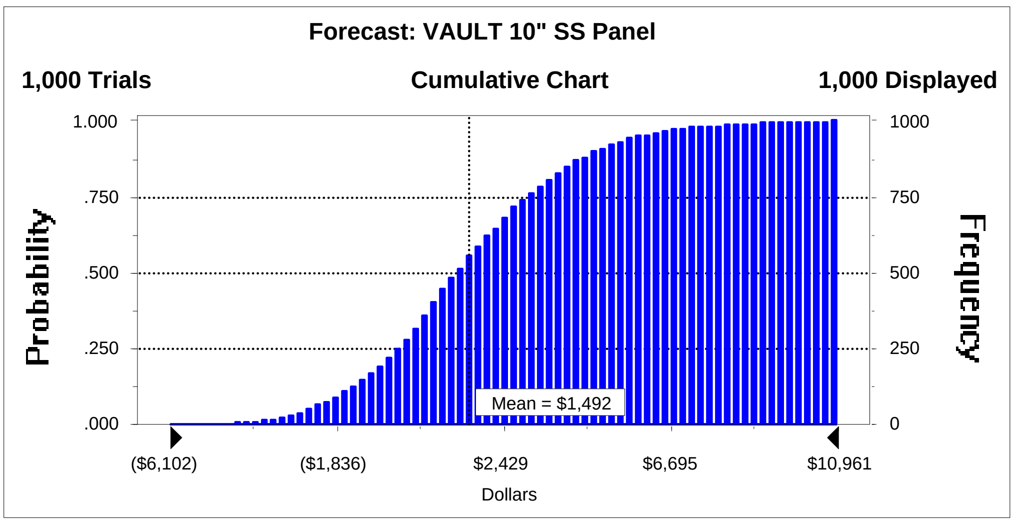

Figure G-85: Climate Zone 2 R49 Vault NPV Results for Electric FAF

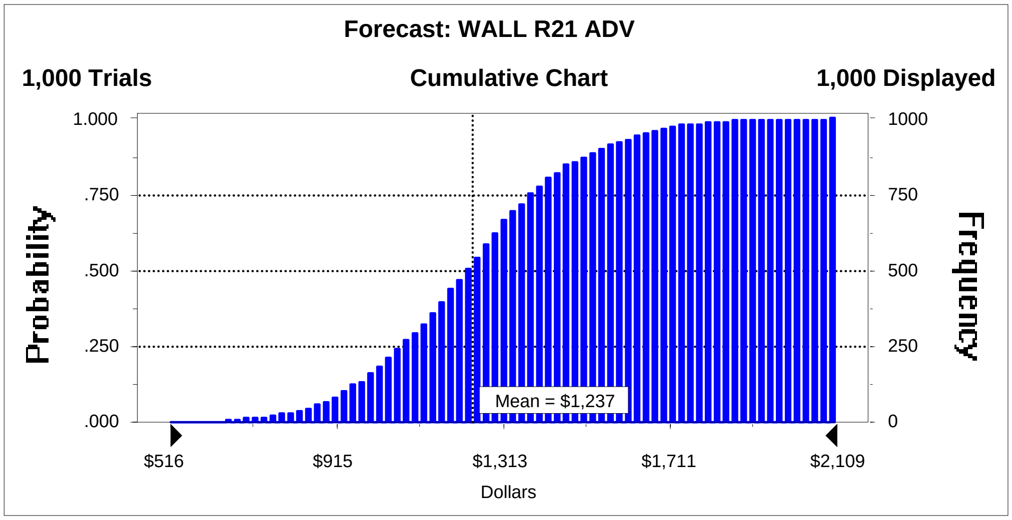

Figure G-86: Climate Zone 2 R21 Advanced Framed Walls NPV Results for Electric Zonal

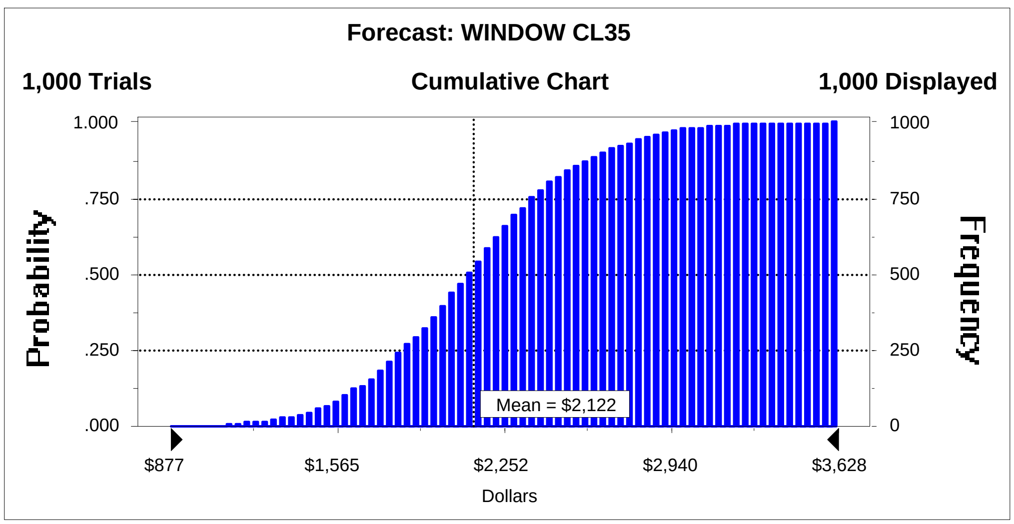

Figure G-87: Climate Zone 2 Class 35 Window NPV Results for Electric Zonal

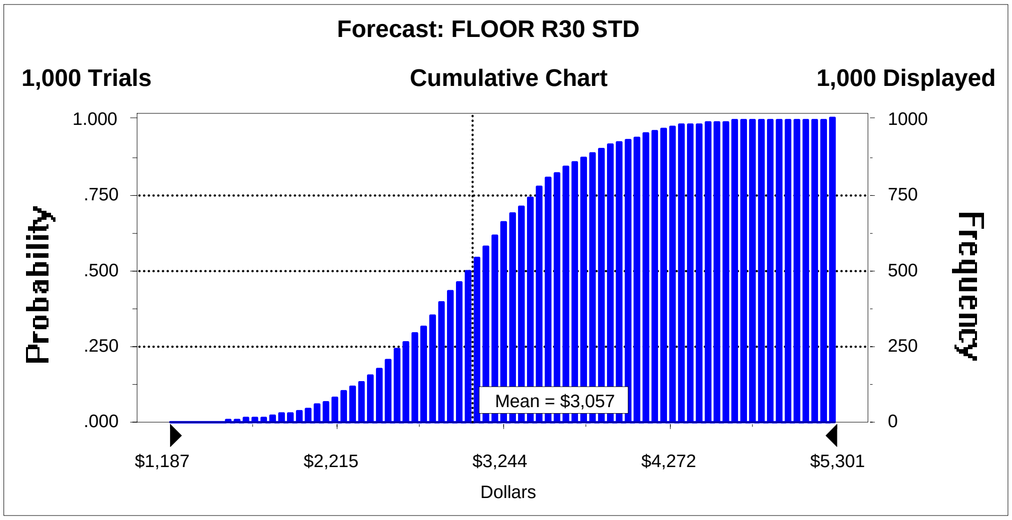

Figure G-88: Climate Zone 2 R30 Under floor NPV Results for Electric Zonal

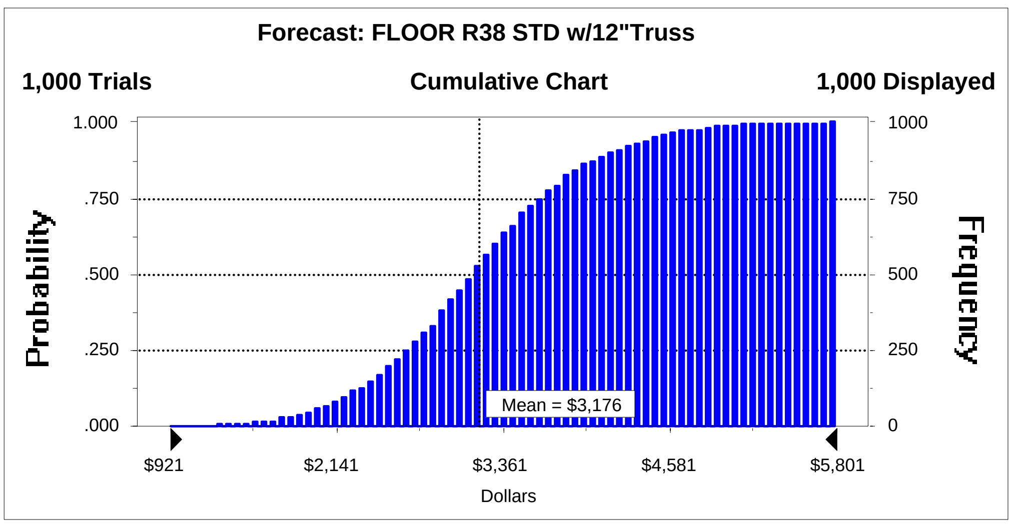

Figure G-89: Climate Zone 2 R38 Under floor NPV Results for Electric Zonal

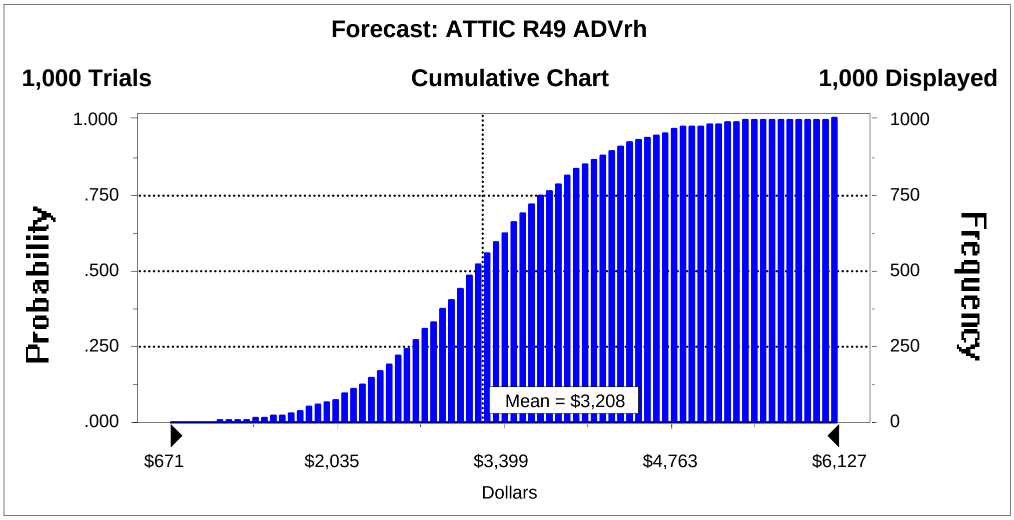

Figure G-90: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Electric Zonal

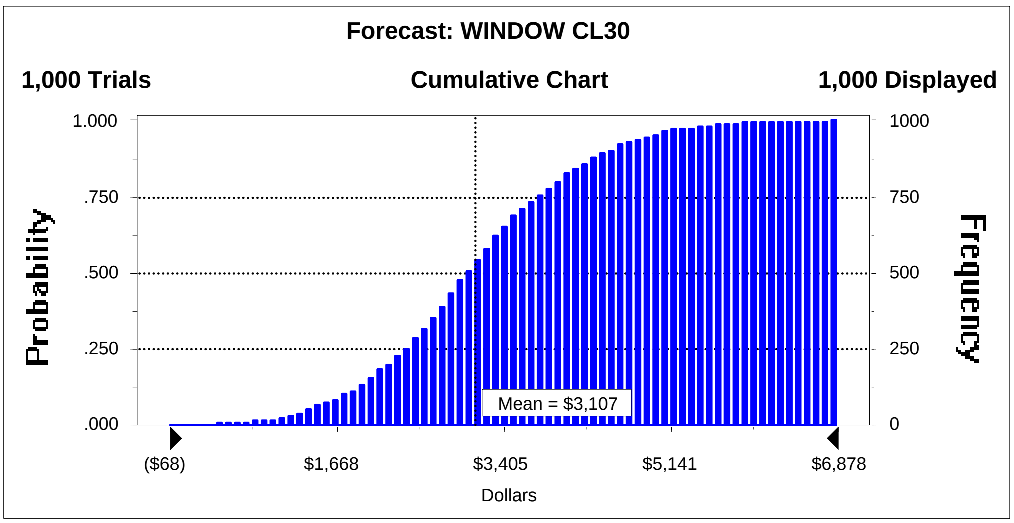

Figure G-91: Climate Zone 2 Class 30 Window NPV Results for Electric Zonal

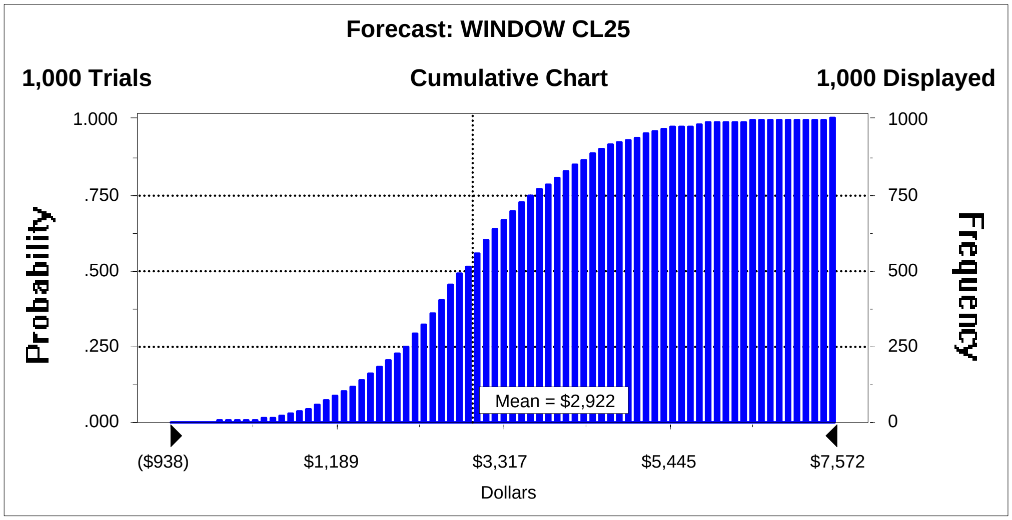

Figure G-92: Climate Zone 2 Class 25 Window NPV Results for Electric Zonal

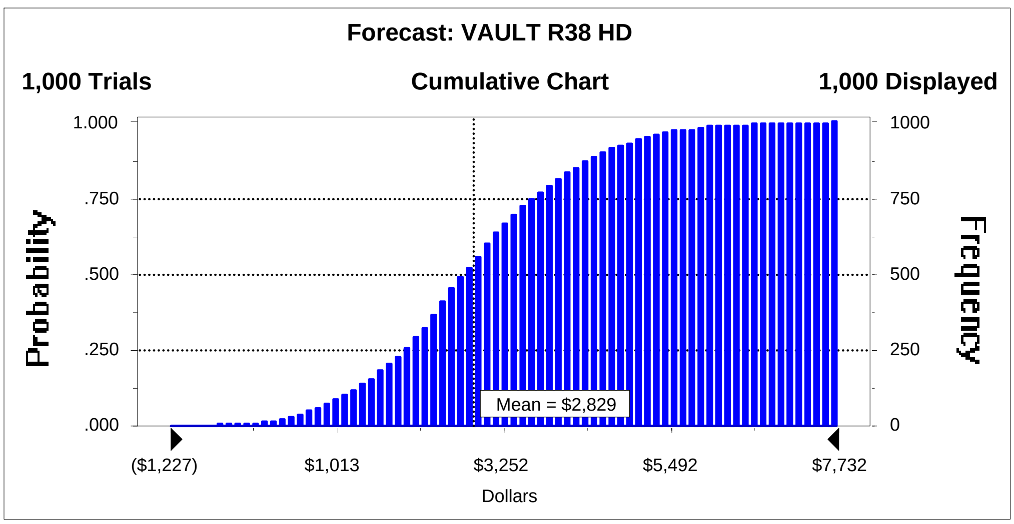

Figure G-93: Climate Zone 2 R38 Vault NPV Results for Electric Zonal

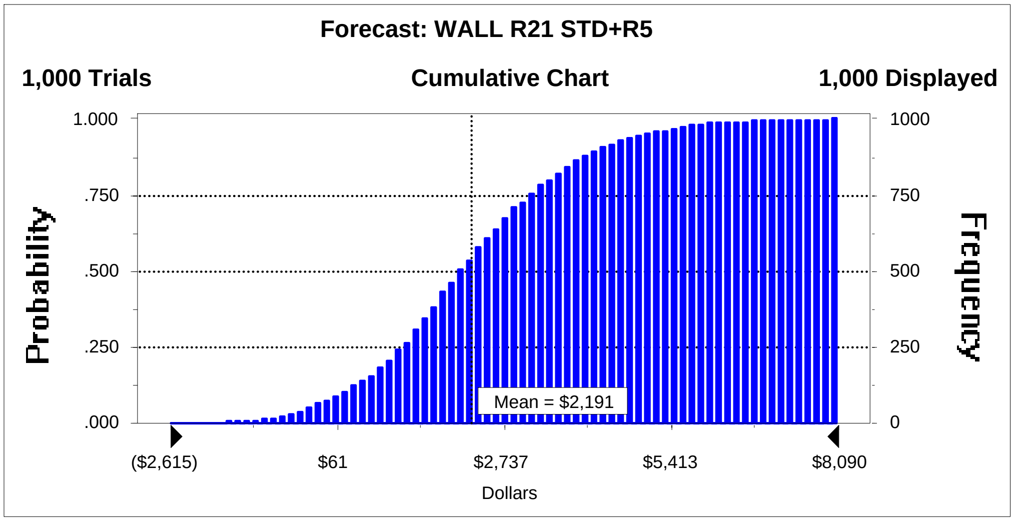

Figure G-94: Climate Zone 2 R26 Advanced Framed Wall NPV Results for Electric Zonal

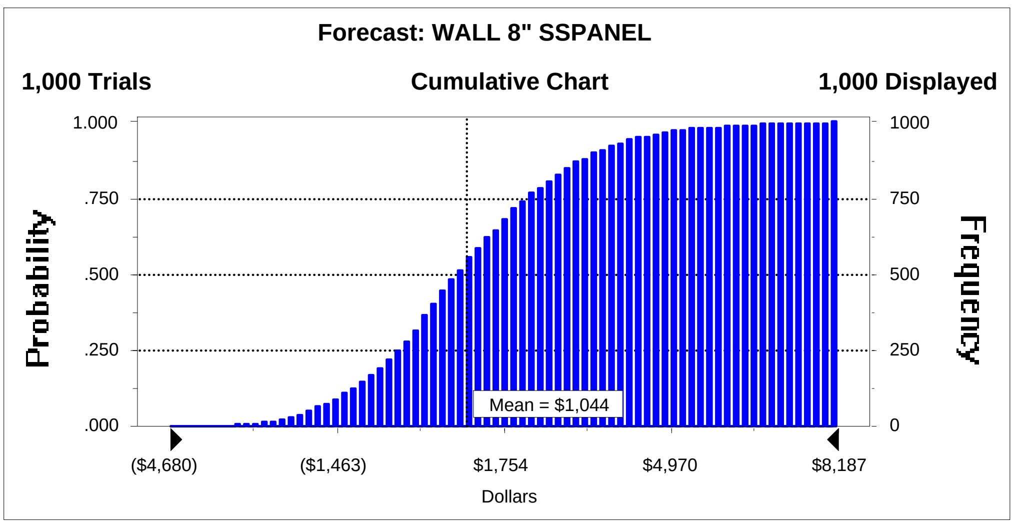

Figure G-95: Climate Zone 2 R33 Wall NPV Results for Electric Zonal

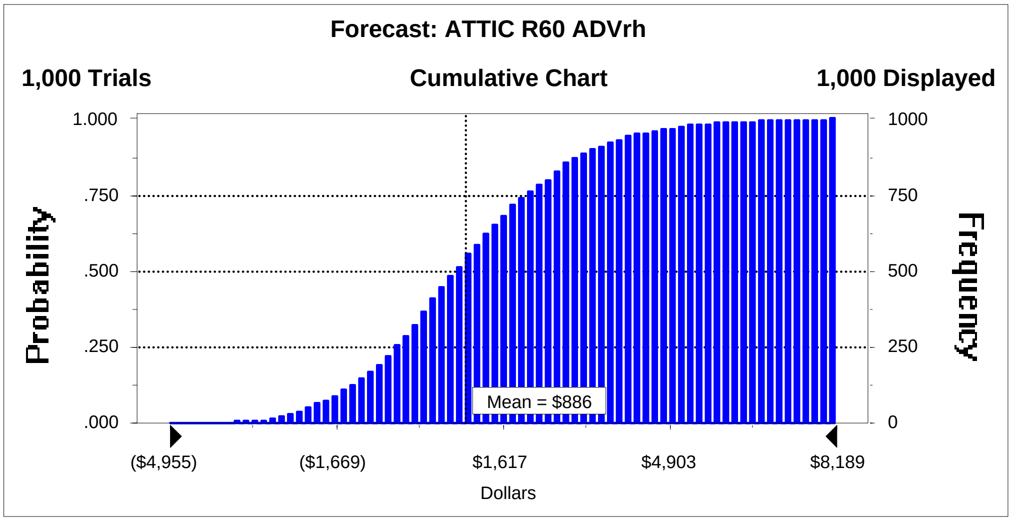

Figure G-96: Climate Zone 2 R60 Advanced Framed Attic NPV Results for Electric Zonal

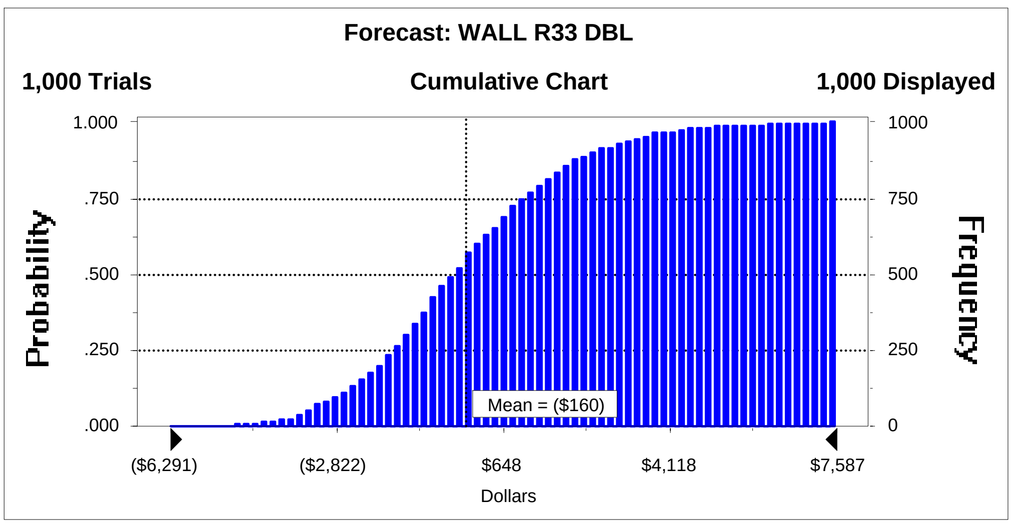

Figure G-97: Climate Zone 2 R33 Wall NPV Results for Electric Zonal

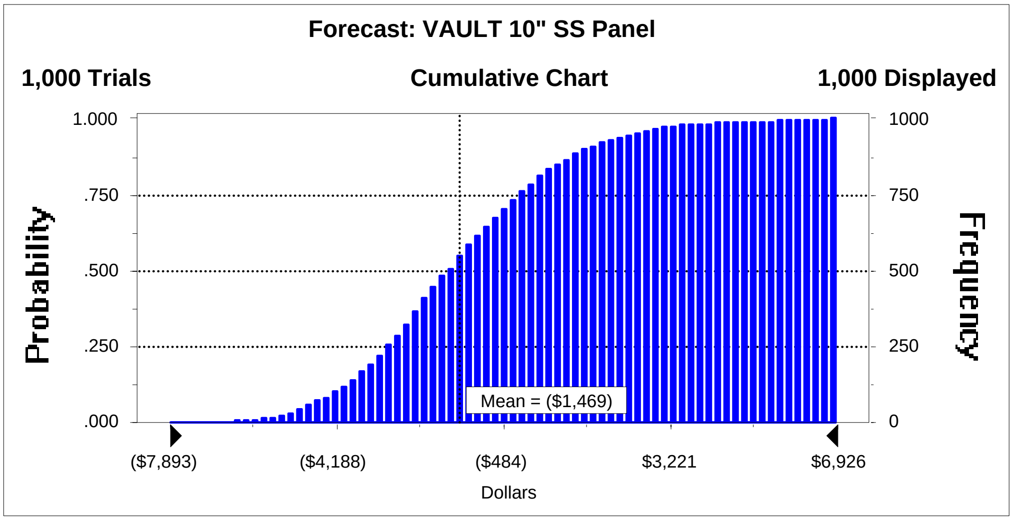

Figure G-98: Climate Zone 2 R49 Vault NPV Results for Electric Zonal

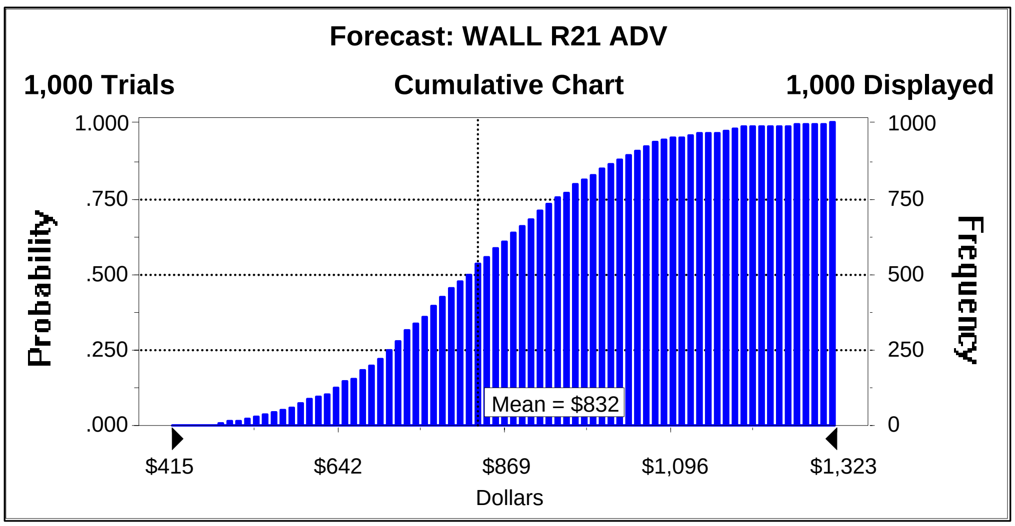

Figure G-99: Climate Zone 2 R21 Advanced Framed Wall NPV Results for Gas FAF

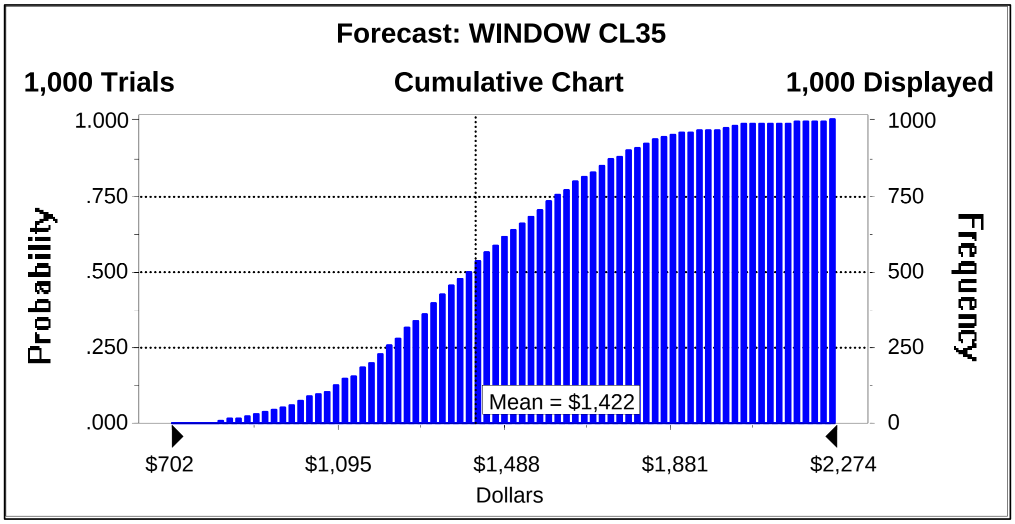

Figure G-100: Climate Zone 2 Class 35 Windows NPV Results for Gas FAF

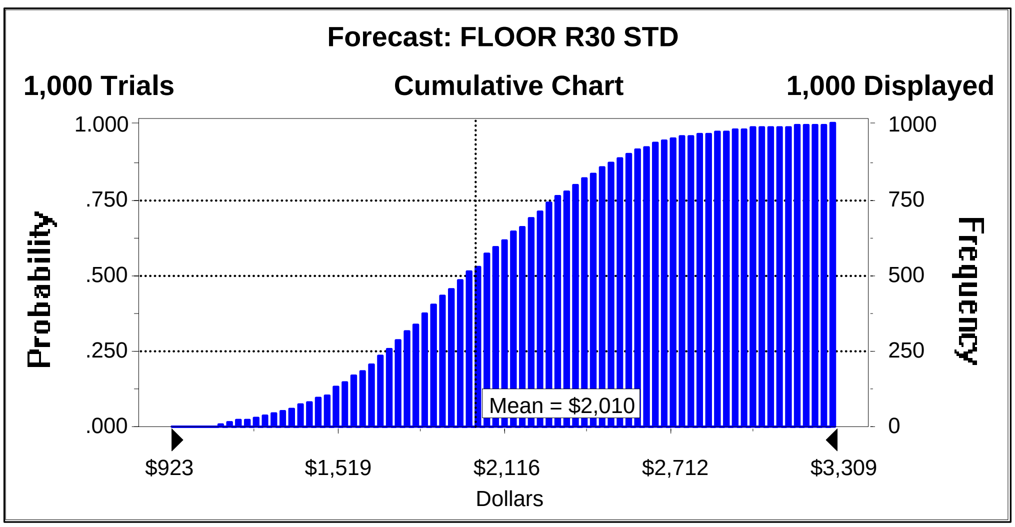

Figure G-101: Climate Zone 2 R30 Under floor NPV Results for Gas FAF

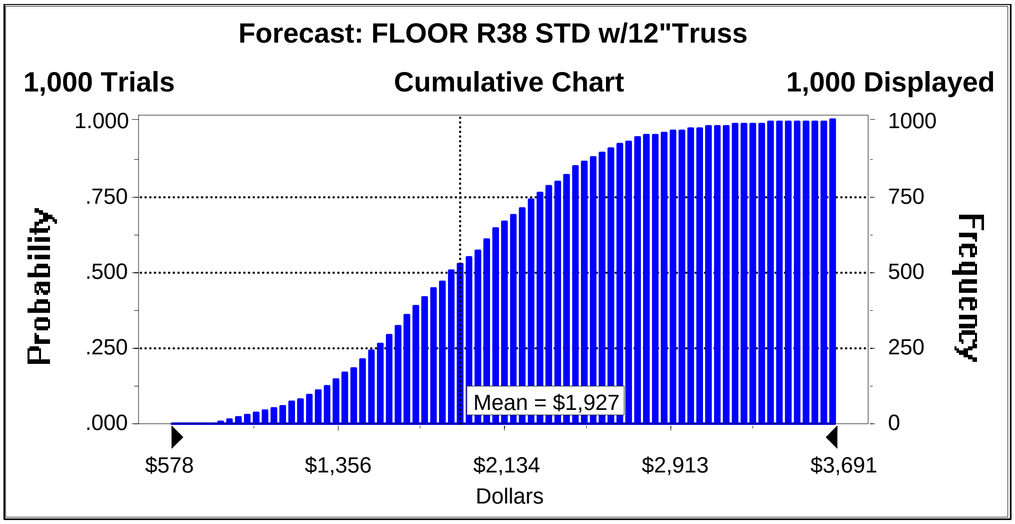

Figure G-102: Climate Zone 2 R38 Under floor NPV Results for Gas FAF

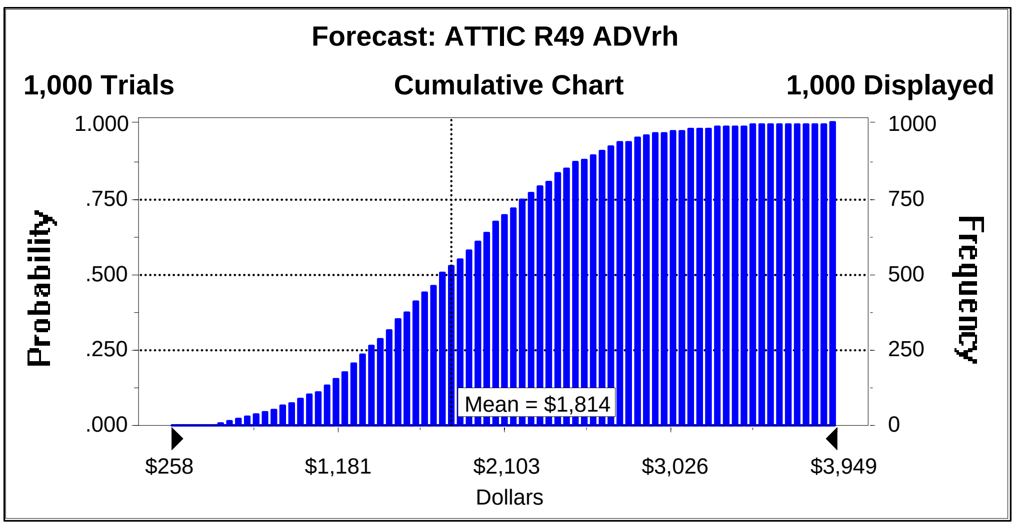

Figure G-103: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Gas FAF

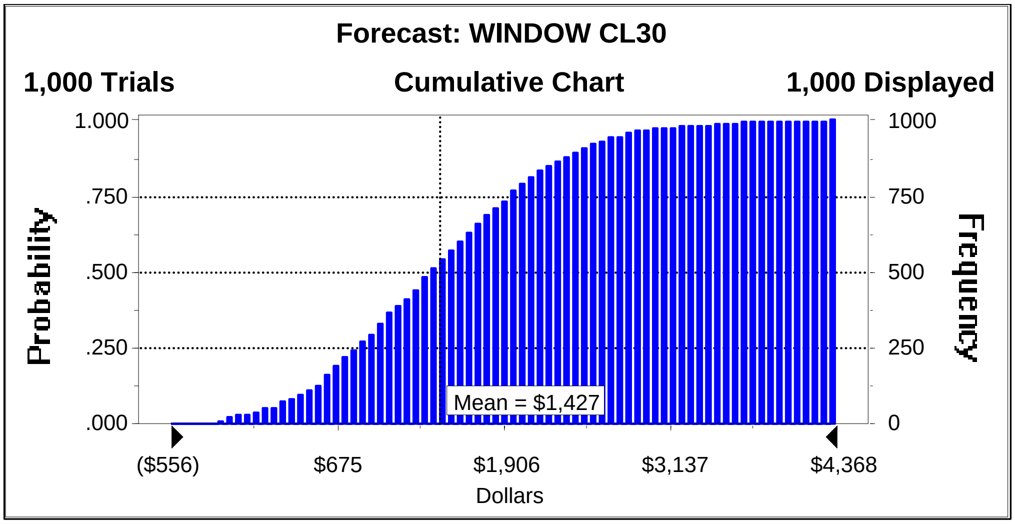

Figure G-104: Climate Zone 2 Class 30 Window NPV Results for Gas FAF

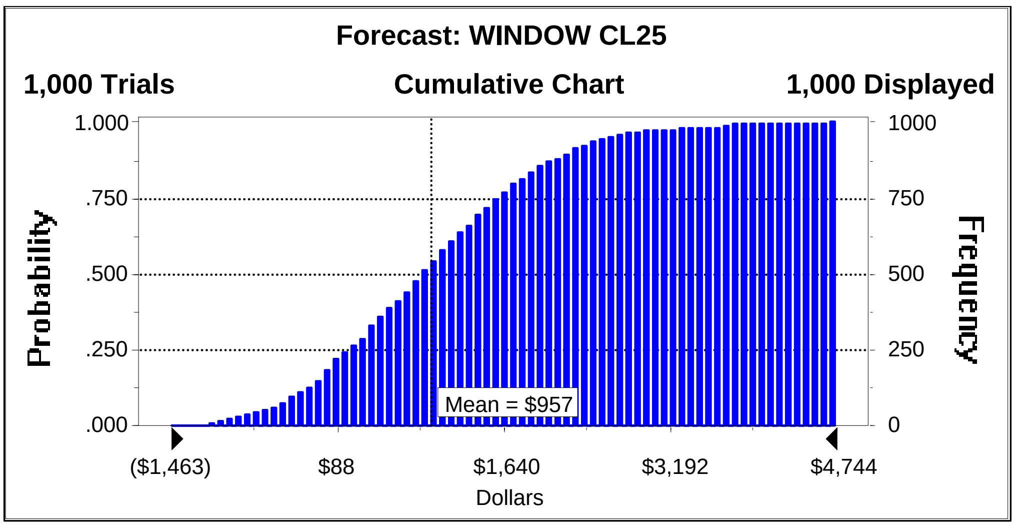

Figure G-105: Climate Zone 2 Class 25 Window NPV Results for Gas FAF

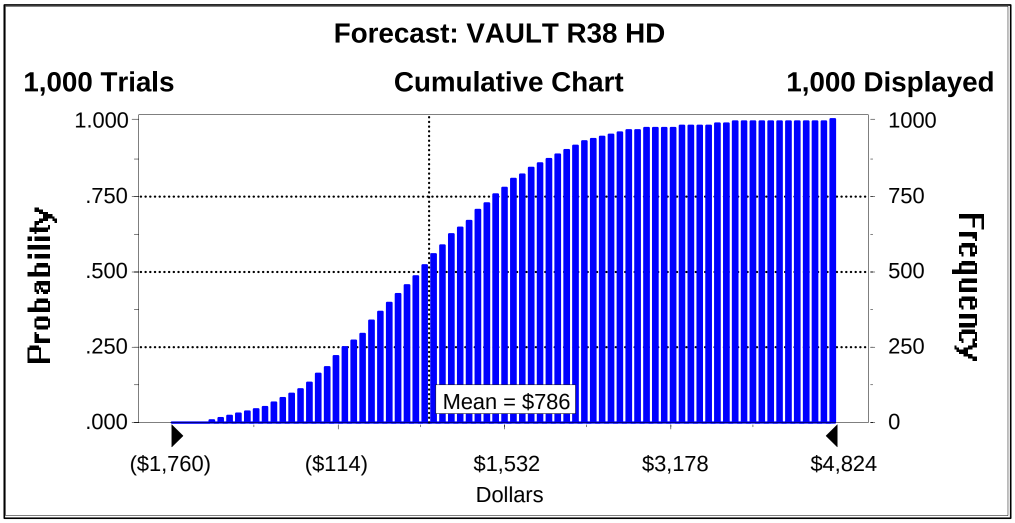

Figure G-106: Climate Zone 2 R38 Vault NPV Results for Gas FAF

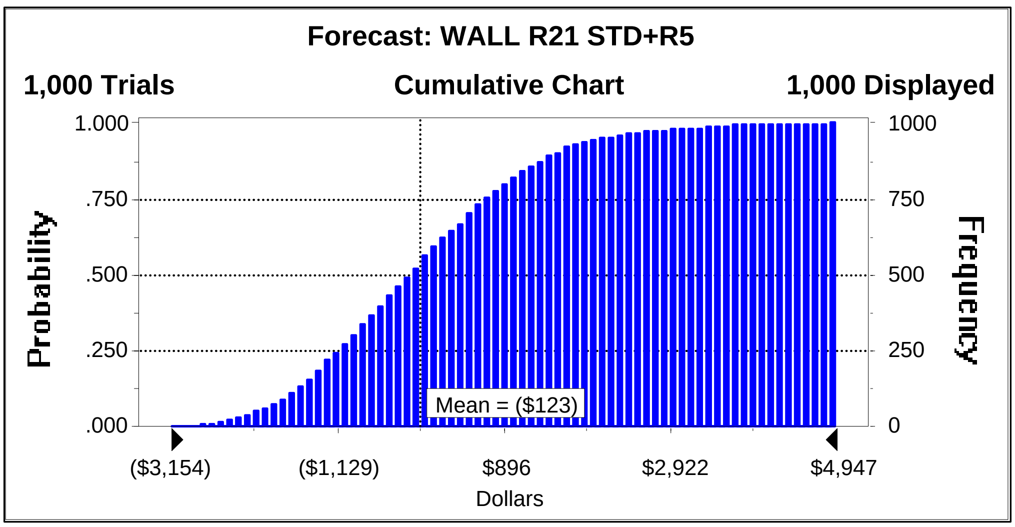

Figure G-107: Climate Zone 2 R26 Advanced Framed Wall NPV Results for Gas FAF

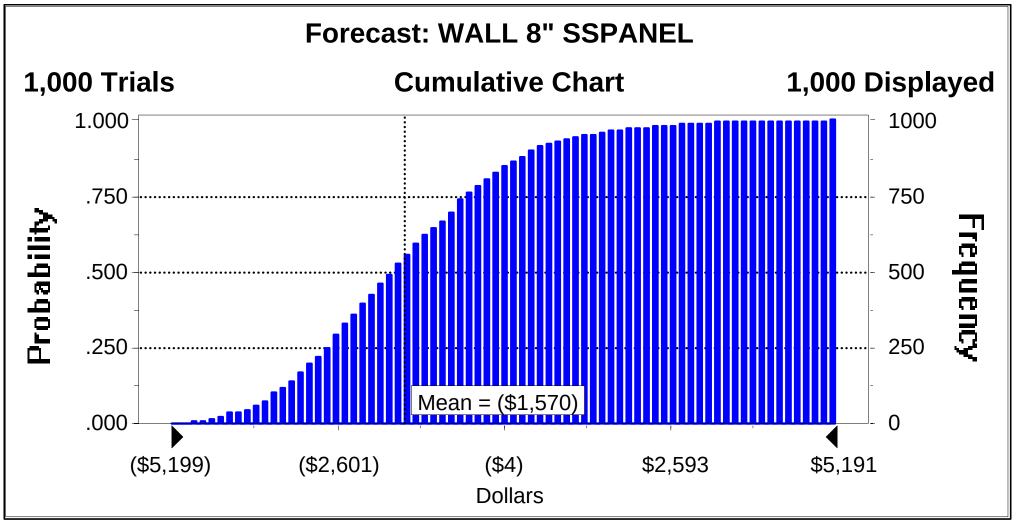

Figure G-108: Climate Zone 2 R33 Wall NPV Results for Gas FAF

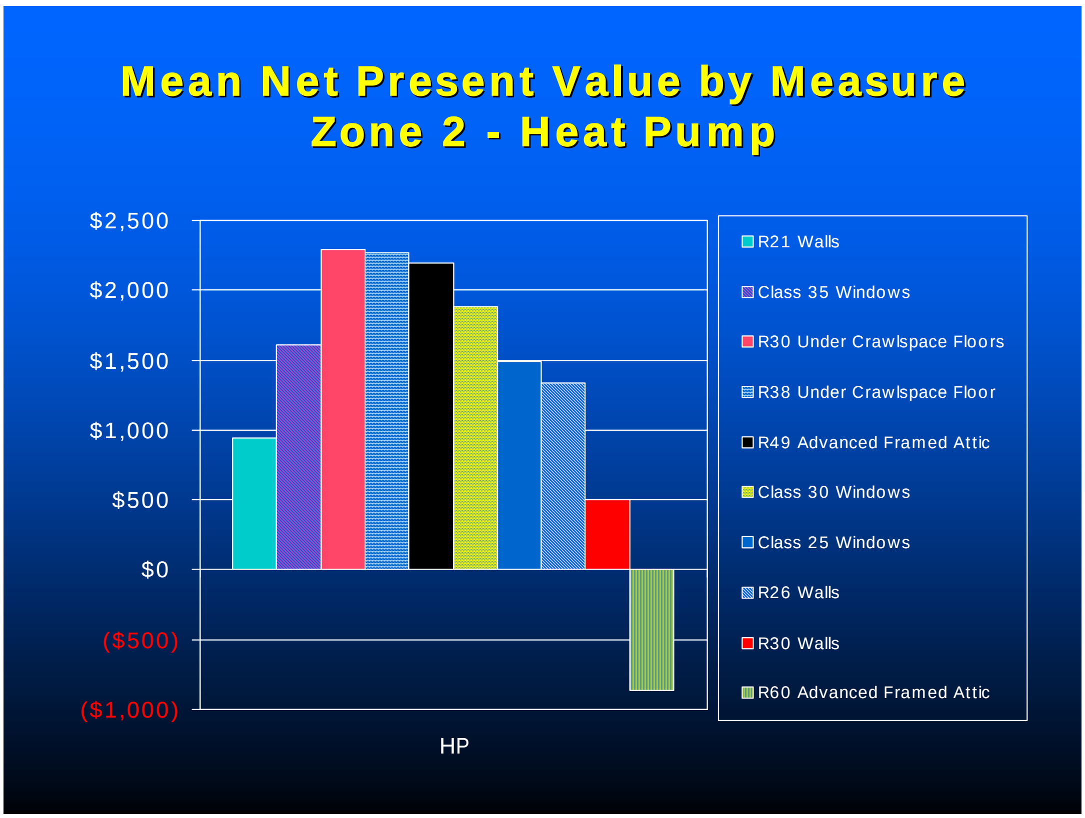

Figure G-109: Climate Zone 2 Summary of Mean NPV by Measure for Heat Pumps

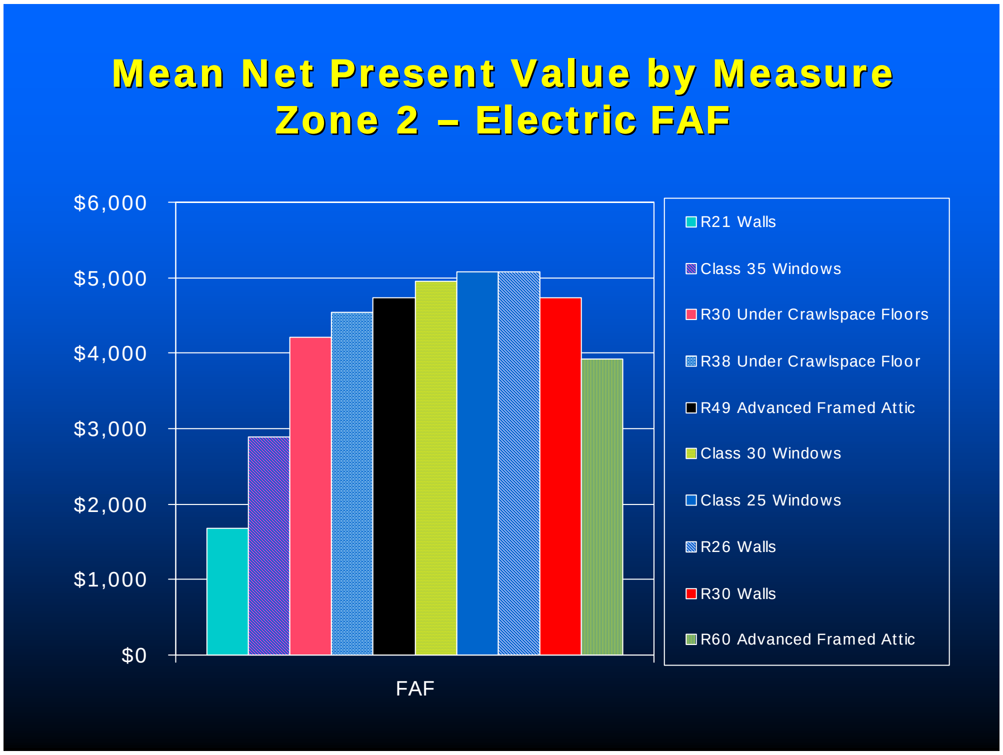

Figure G-110: Climate Zone 2 Mean NPV by Measure for Electric FAF

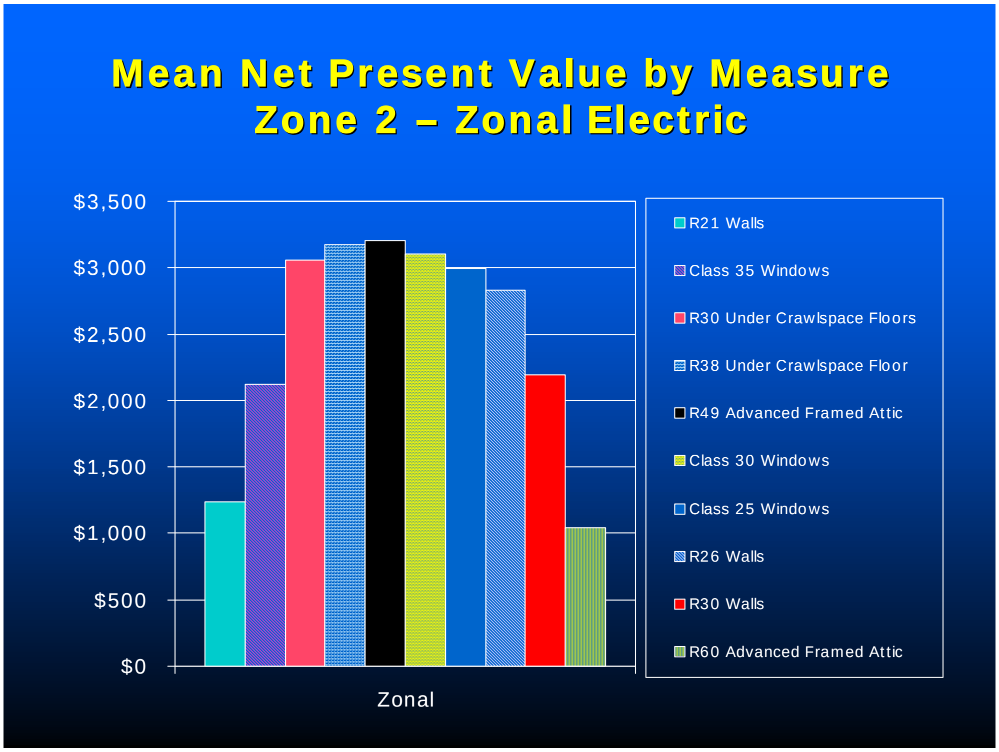

Figure G-111: Climate Zone 2 Mean NPV by Measure for Electric Zonal

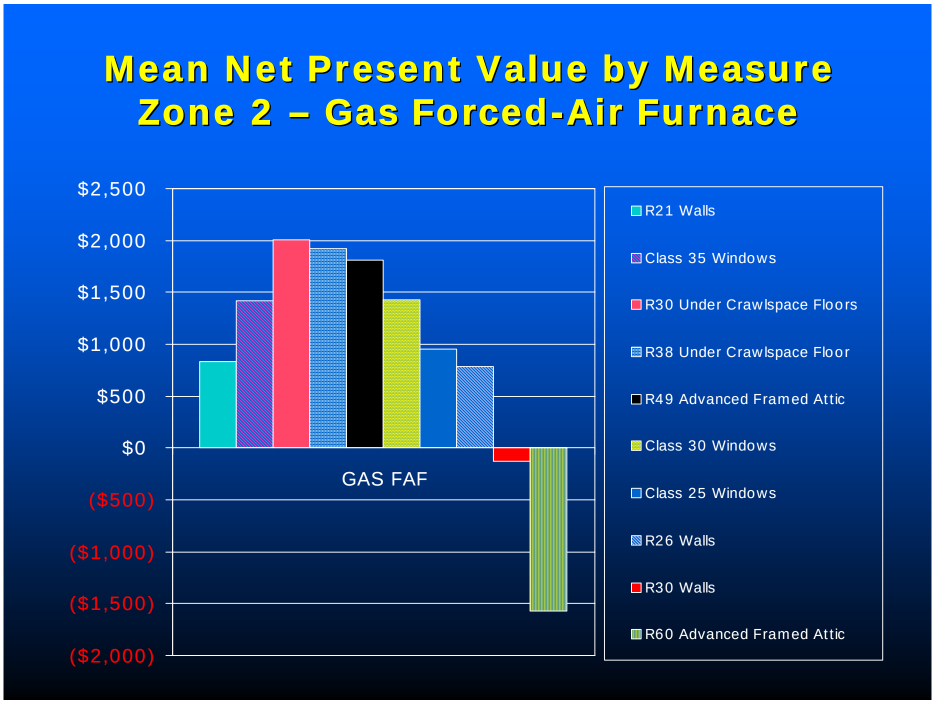

Figure G-112: Climate Zone 2 Mean NPV by Measure for Gas FAF

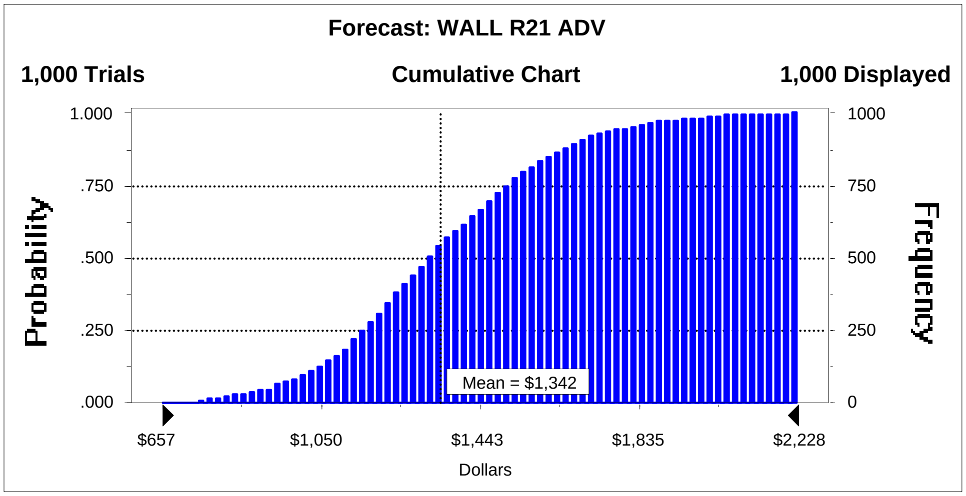

Figure G-113: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Heat Pumps

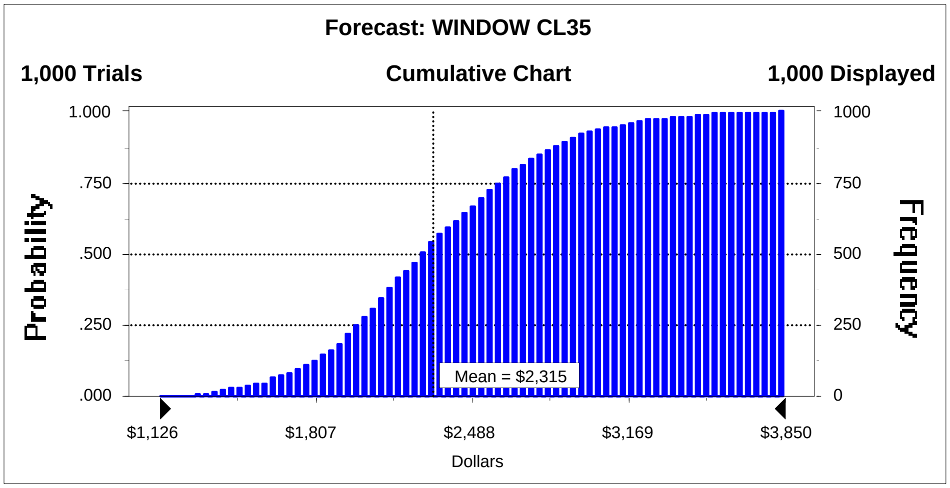

Figure G-114: Climate Zone 3 Class 35 Window NPV Results for Heat Pumps

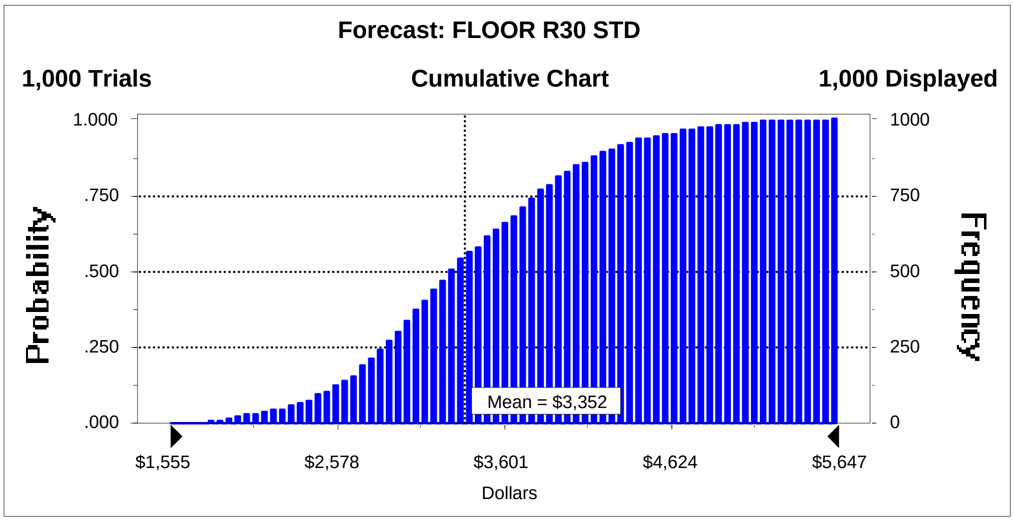

Figure G-115: Climate Zone 3 R30 Under floor NPV Results for Heat Pumps

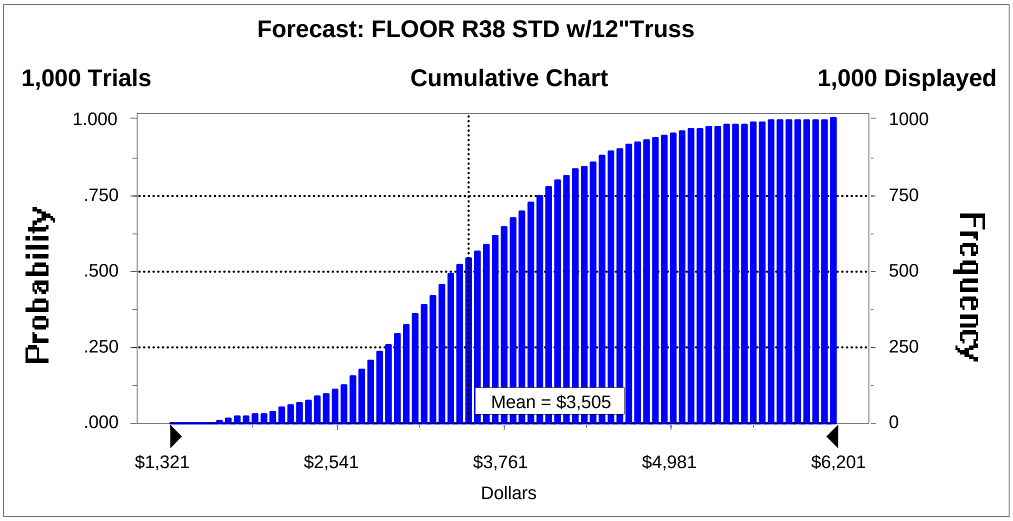

Figure G-116: Climate Zone 3 R38 Under floor NPV Results for Heat Pumps

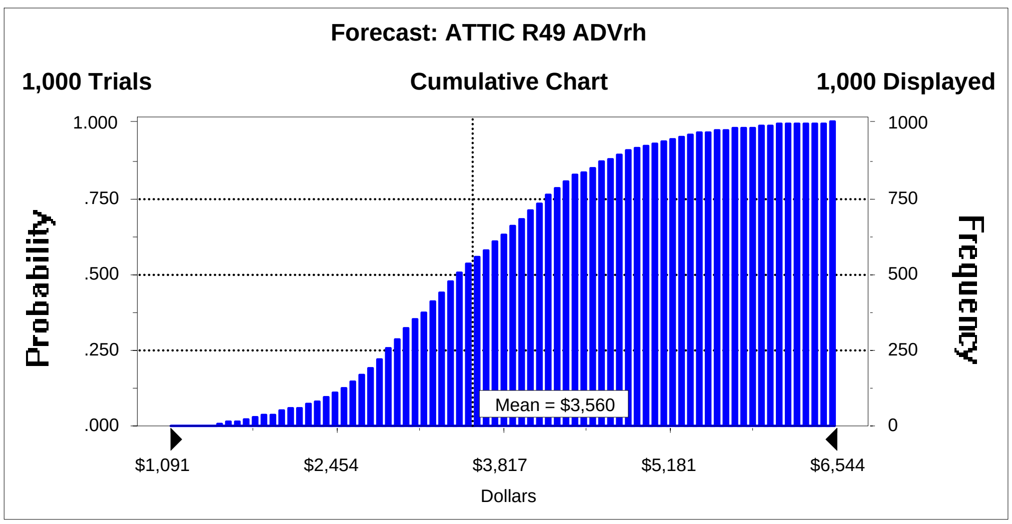

Figure G-117: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Heat Pumps

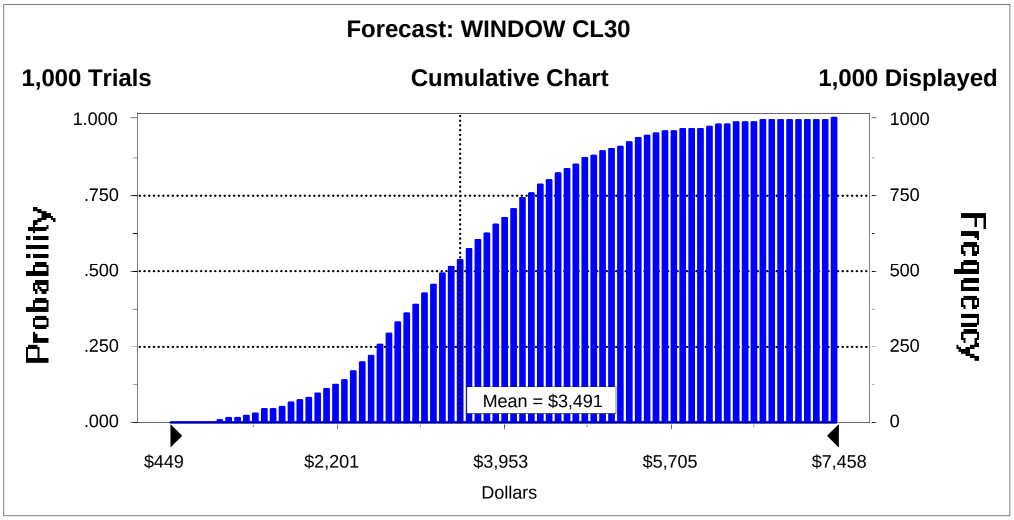

Figure G-118: Climate Zone 3 Class 30 Window NPV Results for Heat Pumps

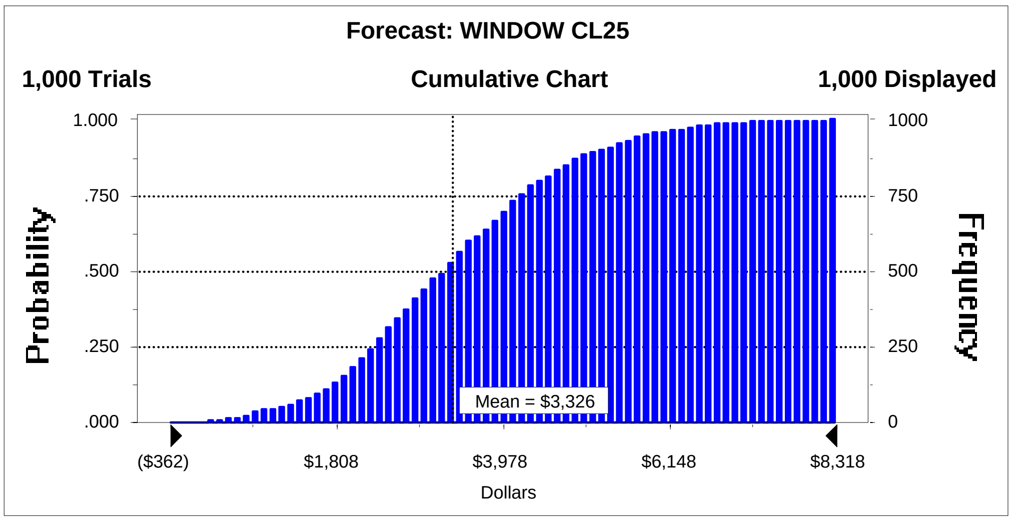

Figure G-119: Climate Zone 3 Class 25 Window NPV Results for Heat Pumps

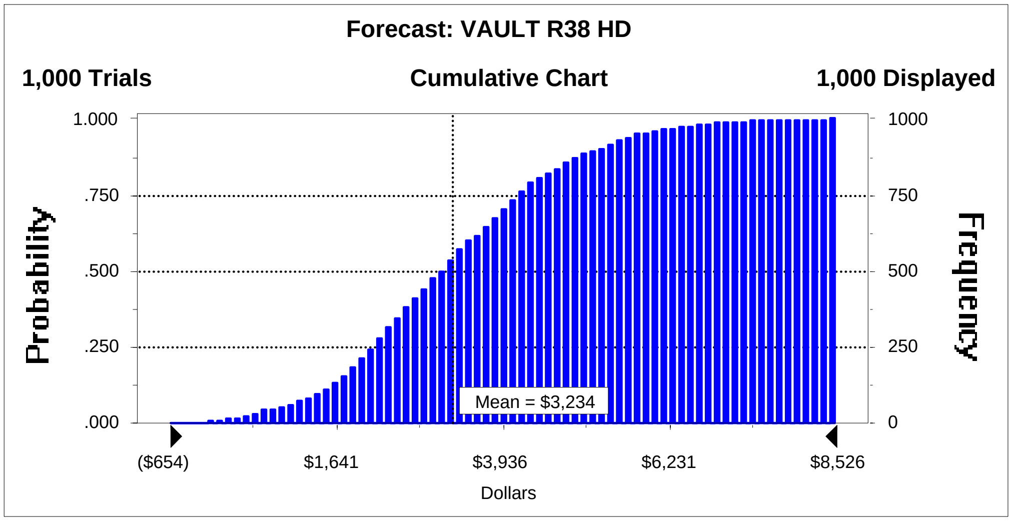

Figure G-120: Climate Zone 3 R38 Vault NPV Results for Heat Pumps

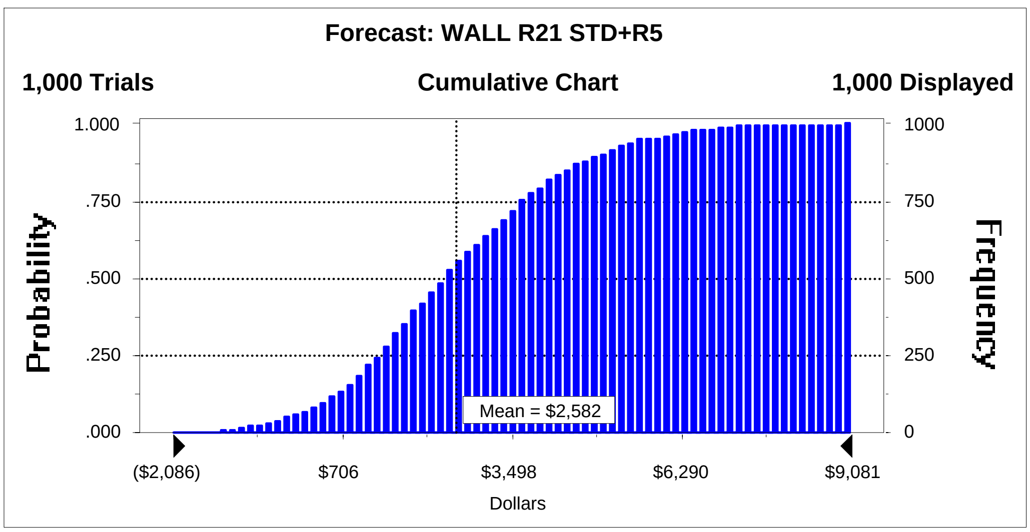

Figure G-121: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Heat Pumps

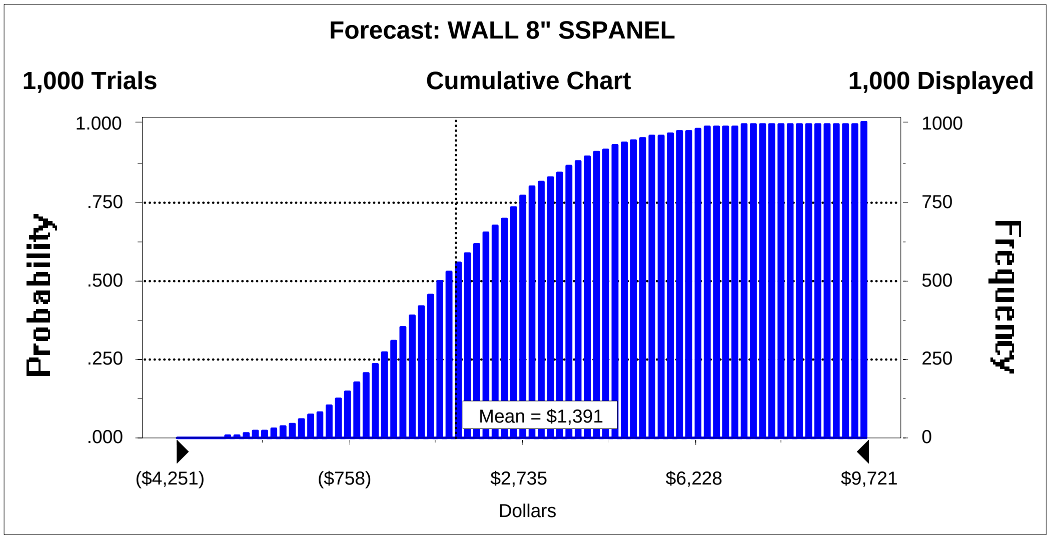

Figure G-122: Climate Zone 3 R33 Wall NPV Results for Heat Pumps

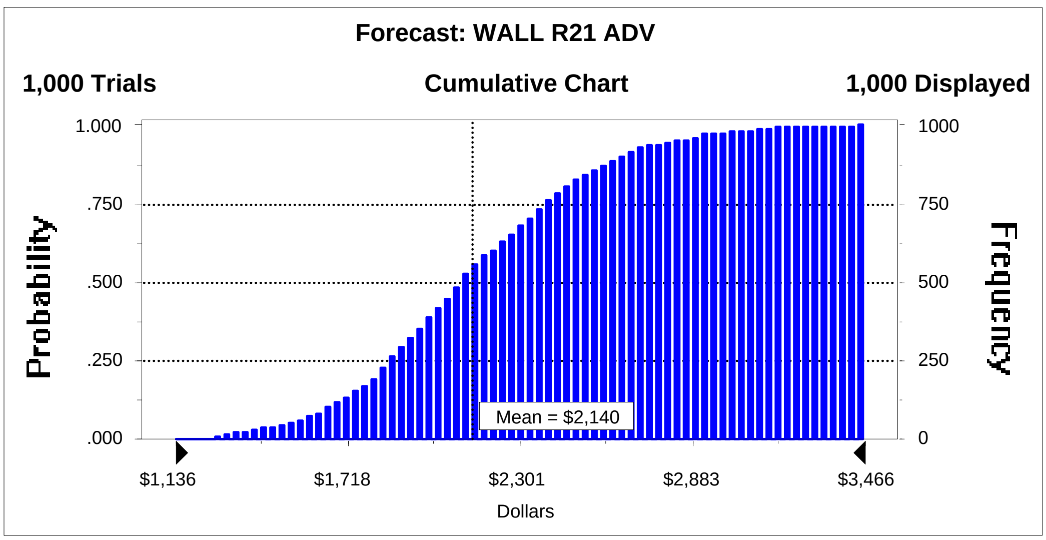

Figure G-123: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Electric FAF

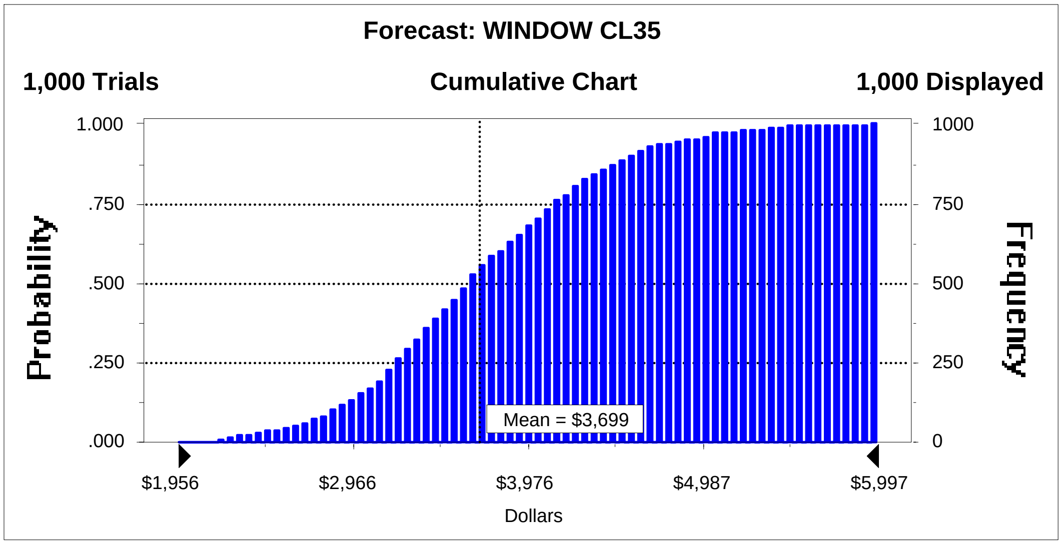

Figure G-124: Climate Zone 3 Class 35 Window NPV Results for Electric FAF

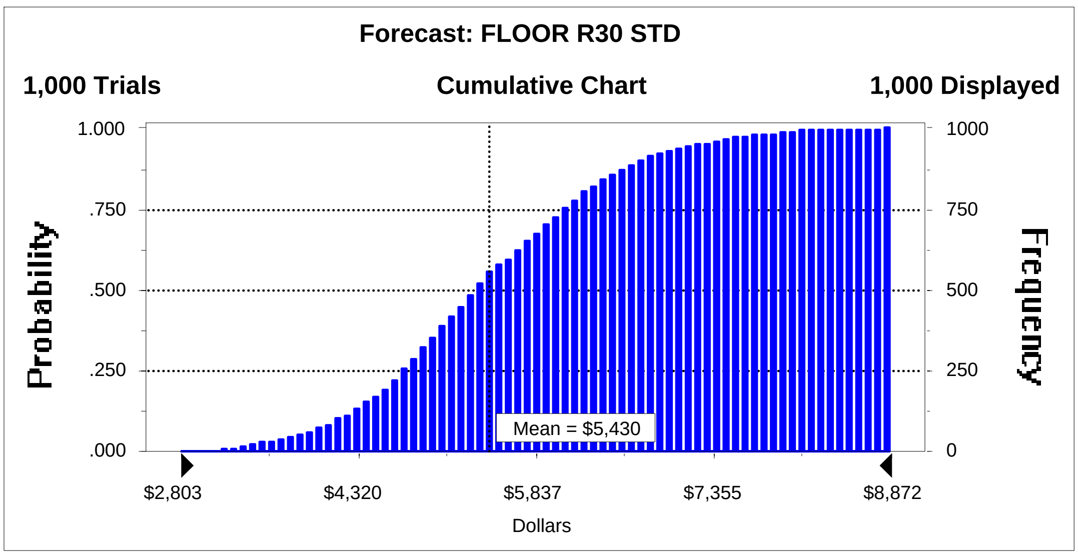

Figure G-125: Climate Zone 3 R30 Under floor NPV Results for Electric FAF

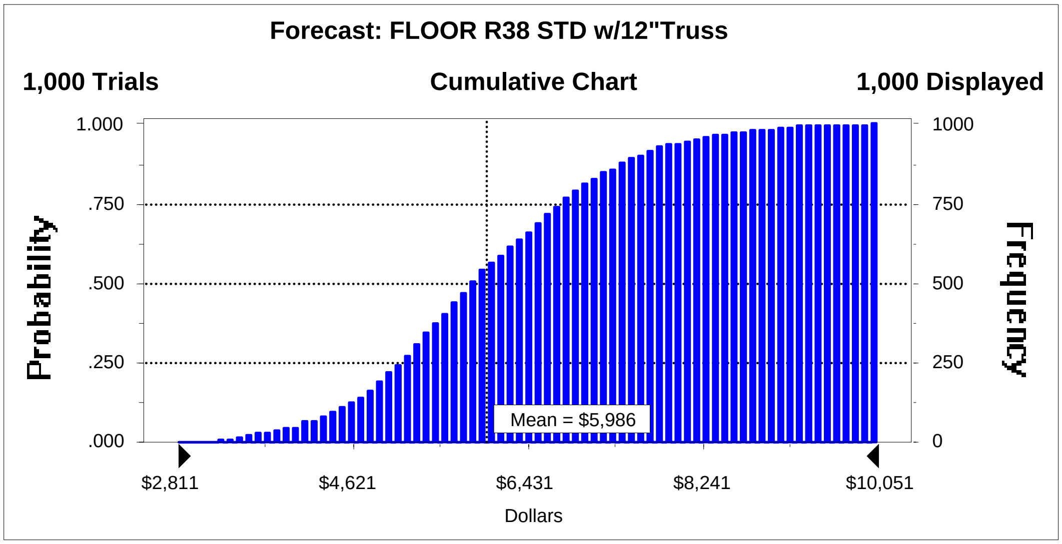

Figure G-126: Climate Zone 3 R38 Under floor NPV Results for Electric FAF

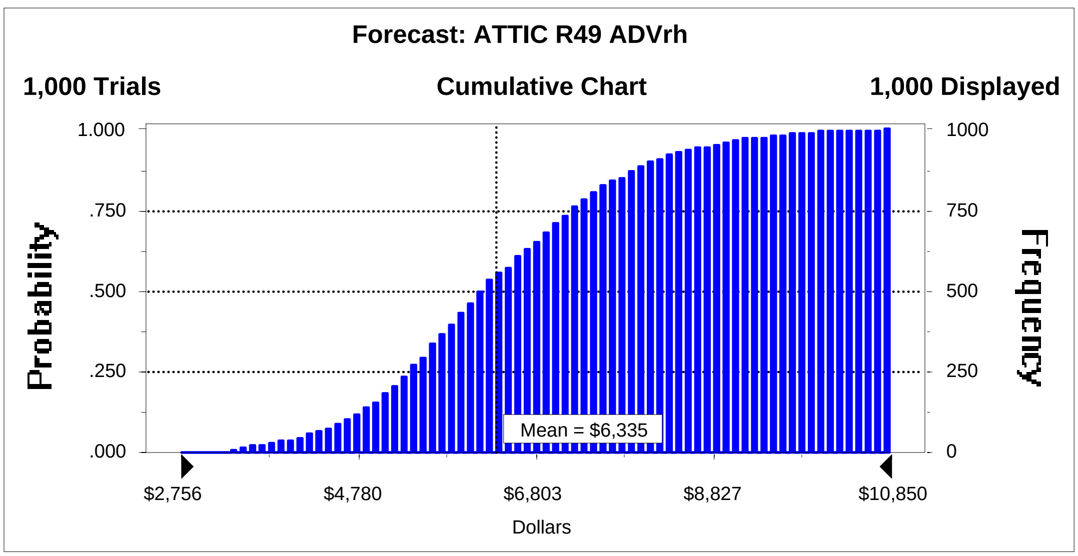

Figure G-127: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Electric FAF

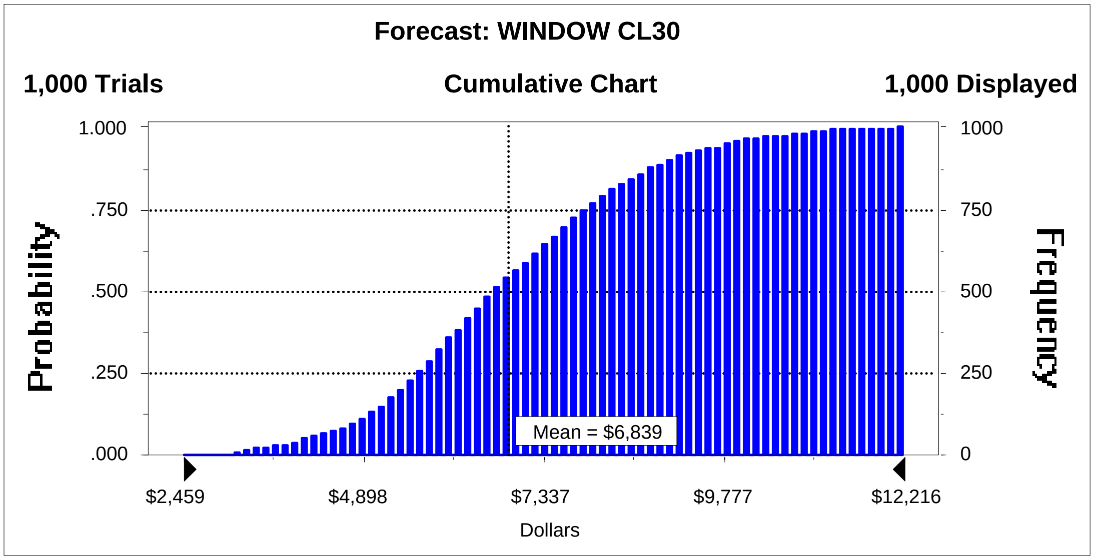

Figure G-128: Climate Zone 3 Class 30 Window NPV Results for Electric FAF

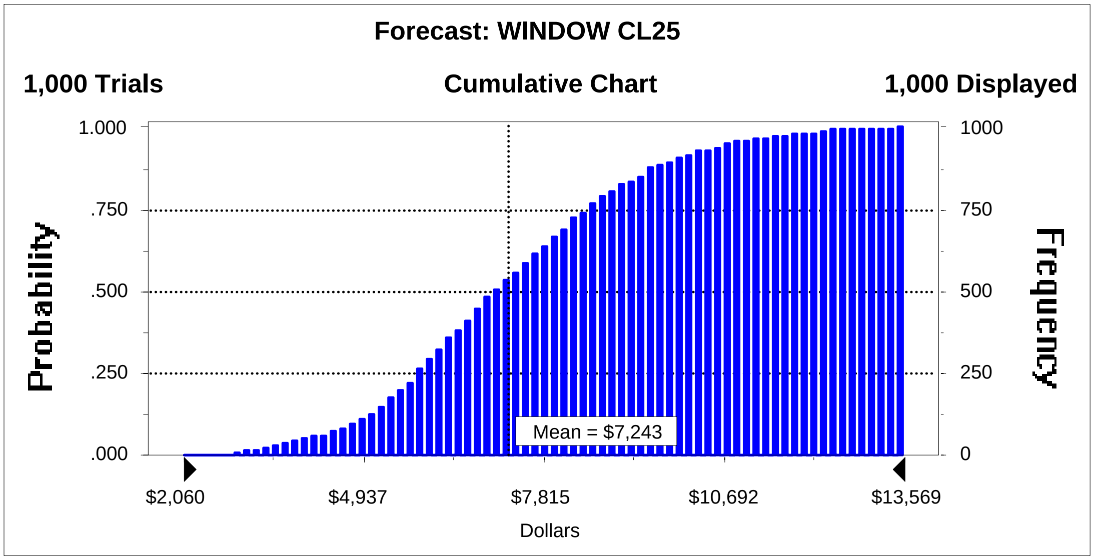

Figure G-129: Climate Zone 3 Class 25 Window NPV Results for Electric FAF

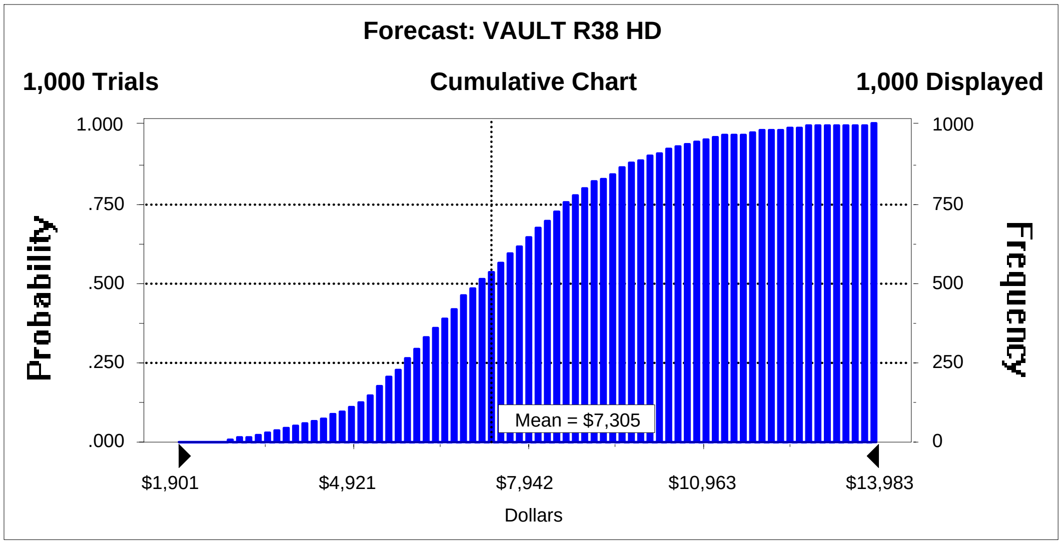

Figure G-130: Climate Zone 3 R38 Vault NPV Results for Electric FAF

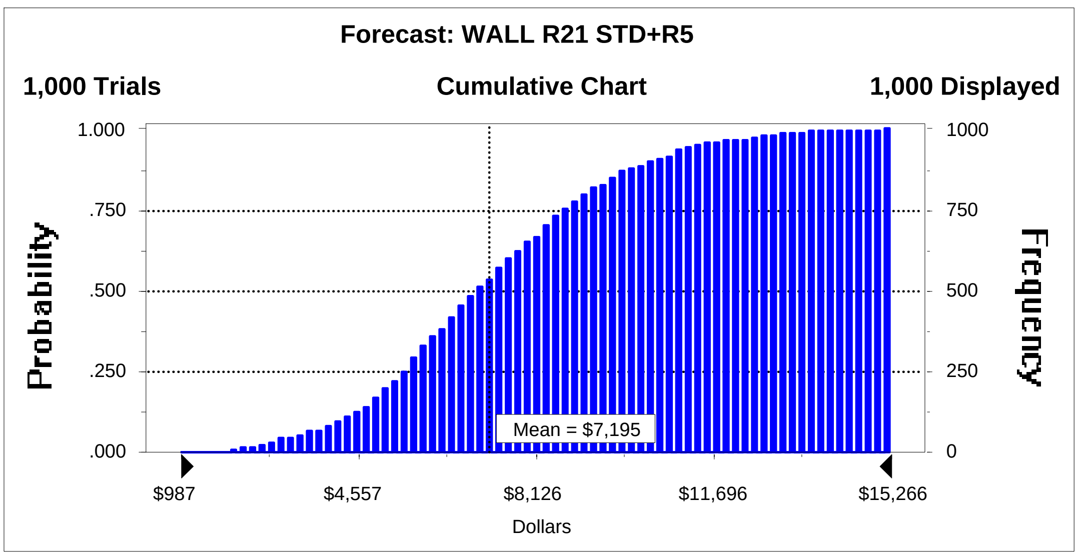

Figure G-131: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Electric FAF

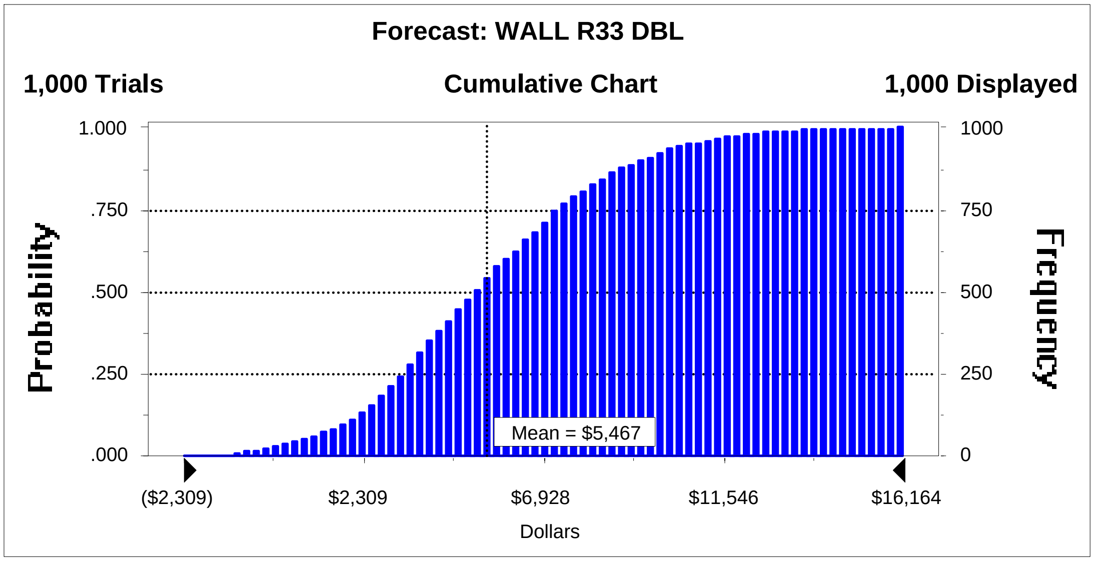

Figure G-132: Climate Zone 3 R33 Wall NPV Results for Electric FAF

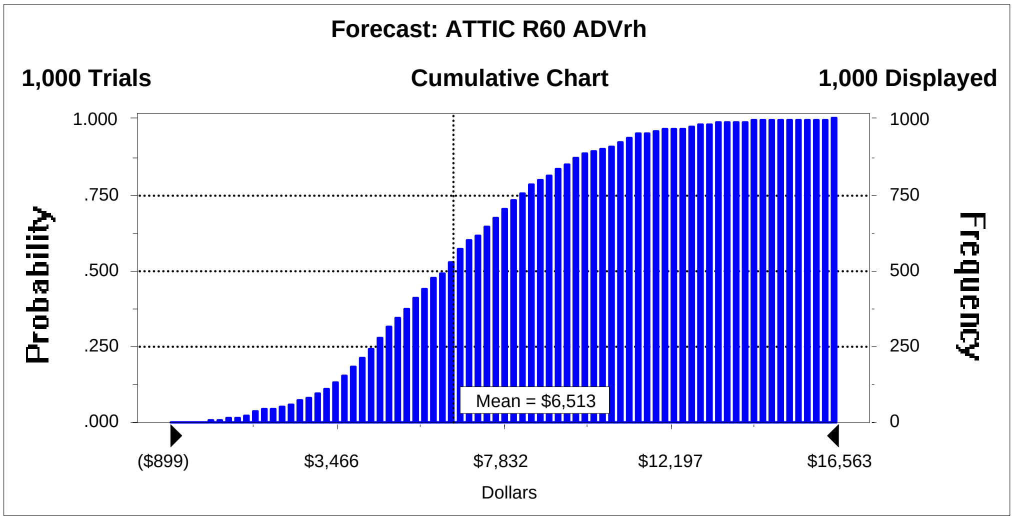

Figure G-133: Climate Zone 3 R60 Advanced Framed Attic NPV Results for Electric FAF

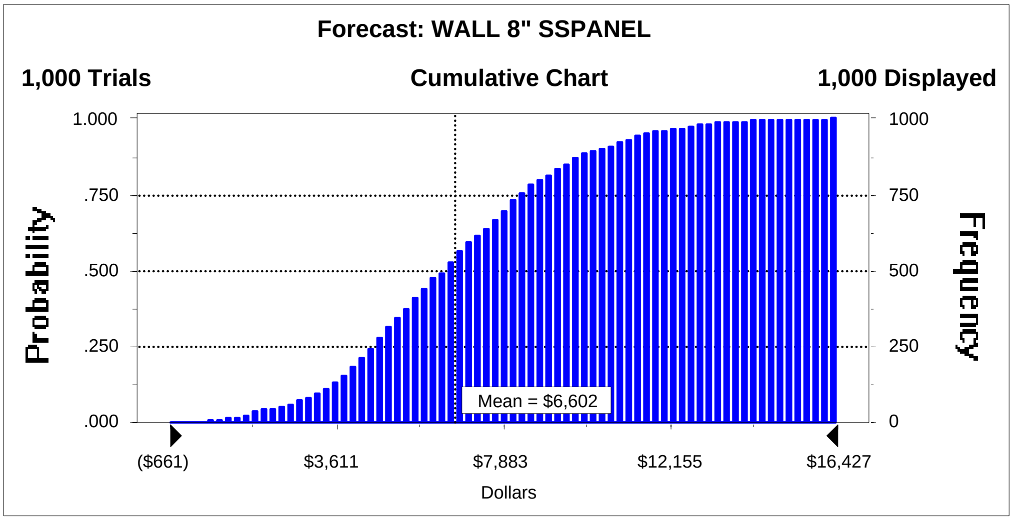

Figure G-134: Climate Zone 3 R38 Wall NPV Results for Electric FAF

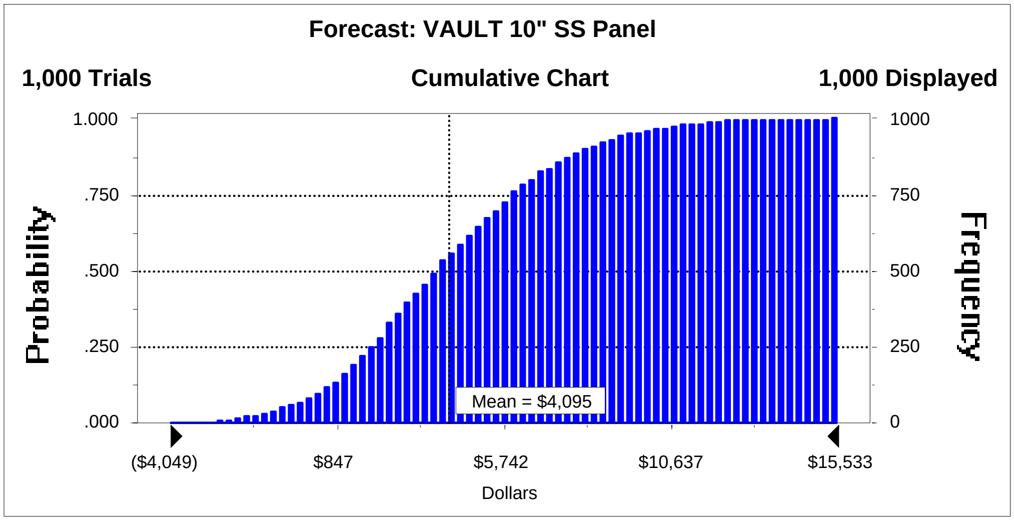

Figure G-135: Climate Zone 3 R49 Vault NPV Results for Electric FAF

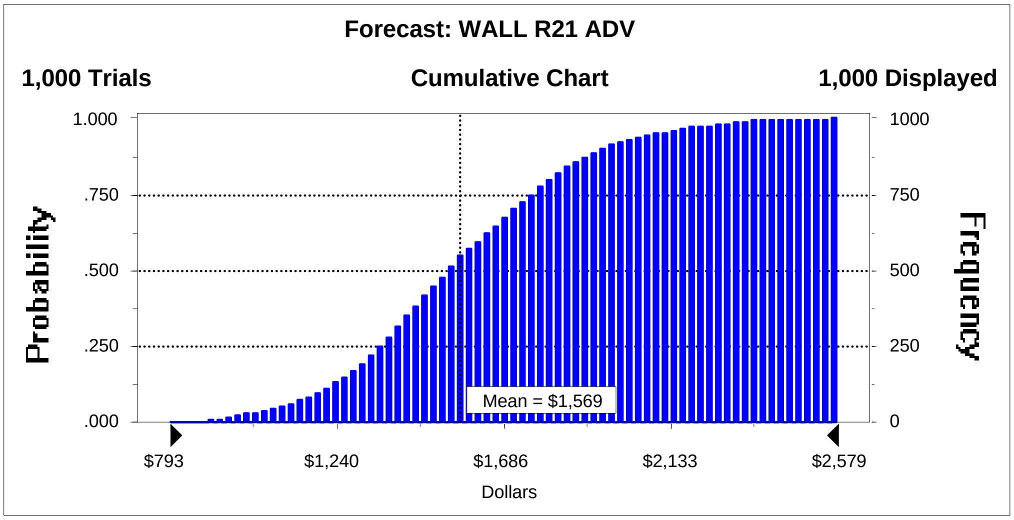

Figure G-136: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Electric Zonal

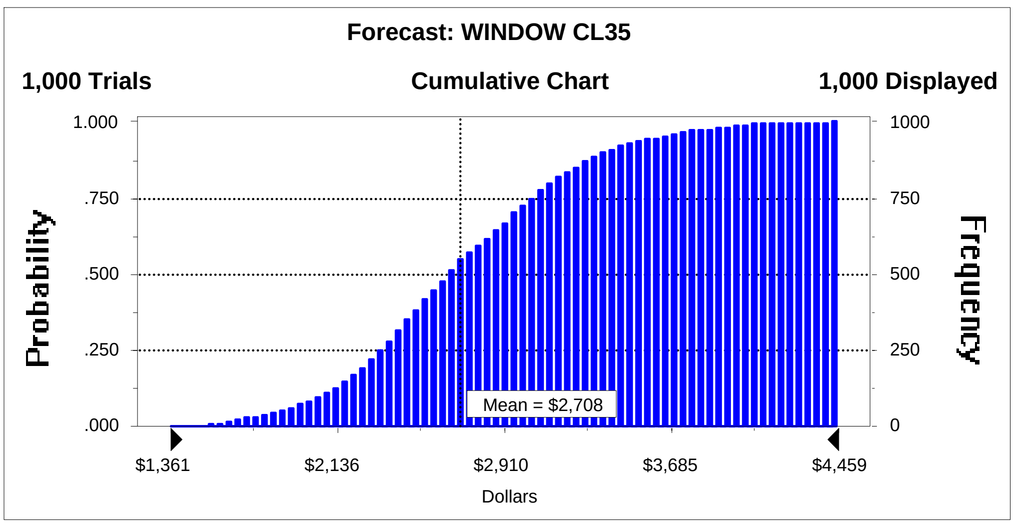

Figure G-137: Climate Zone 3 Class 35 Window NPV Results for Electric Zonal

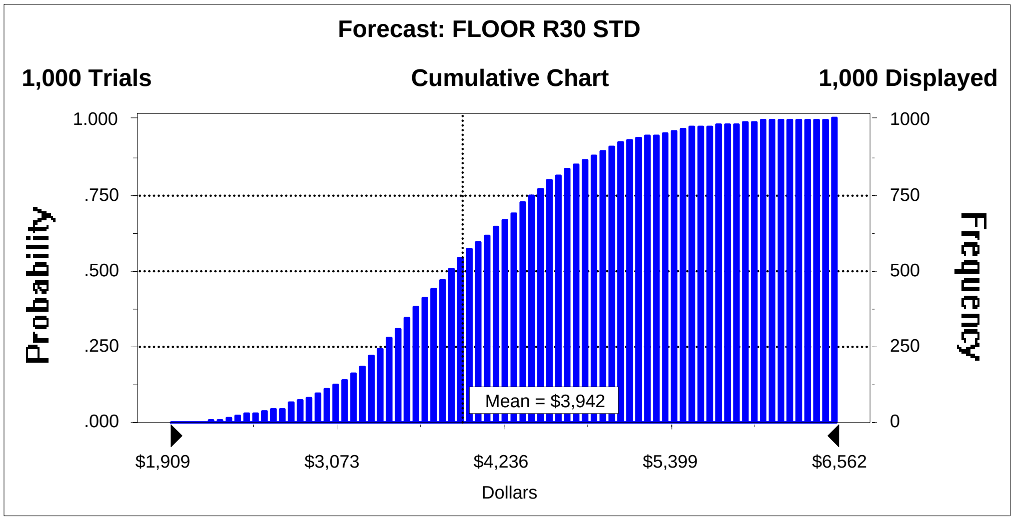

Figure G-138: Climate Zone 3 R30 Under floor NPV Results for Electric Zonal

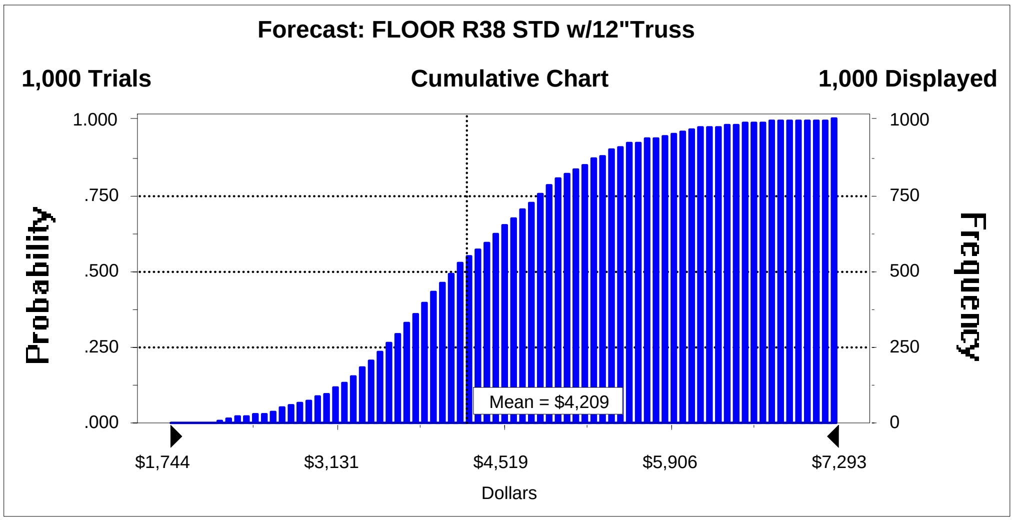

Figure G-139: Climate Zone 3 R38 Under floor NPV Results for Electric Zonal

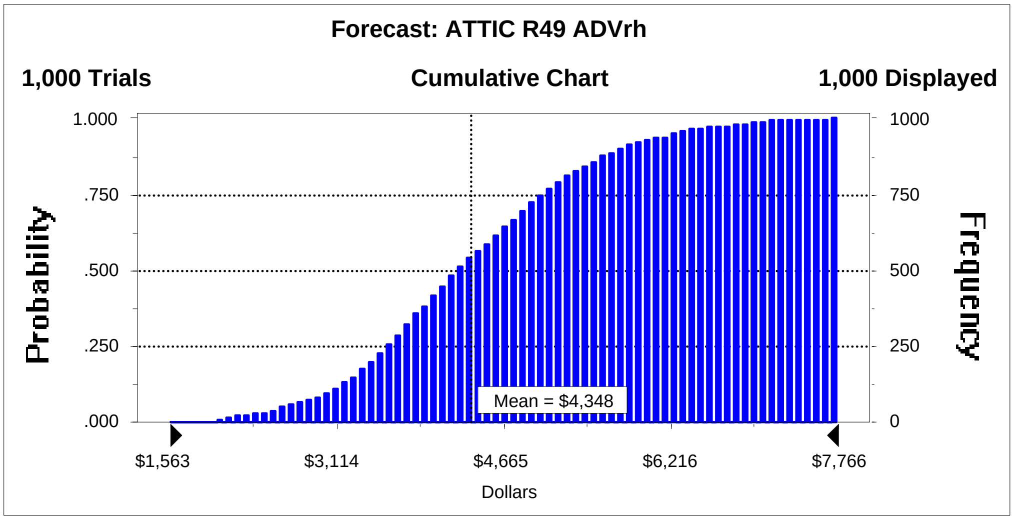

Figure G-140: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Electric Zonal

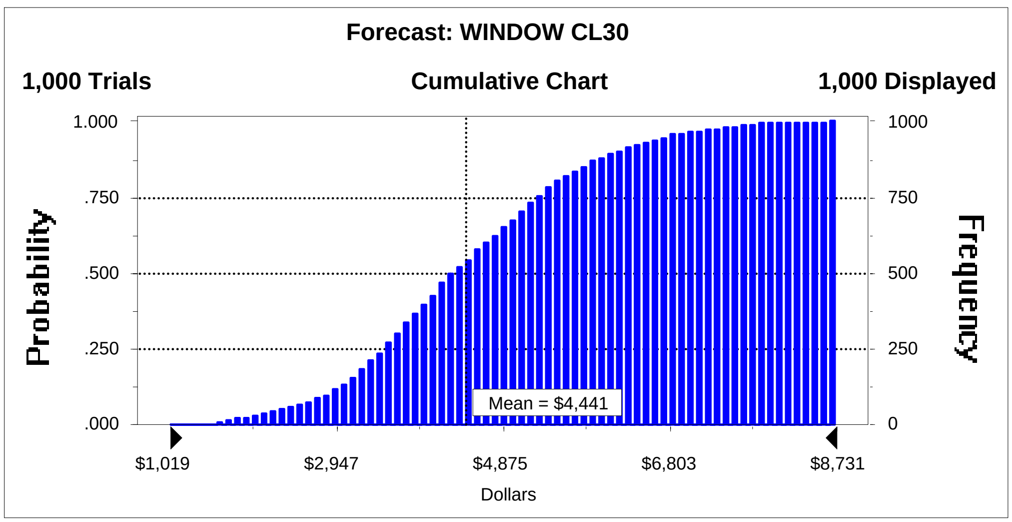

Figure G-141: Climate Zone 3 Class 30 Window NPV Results for Electric Zonal

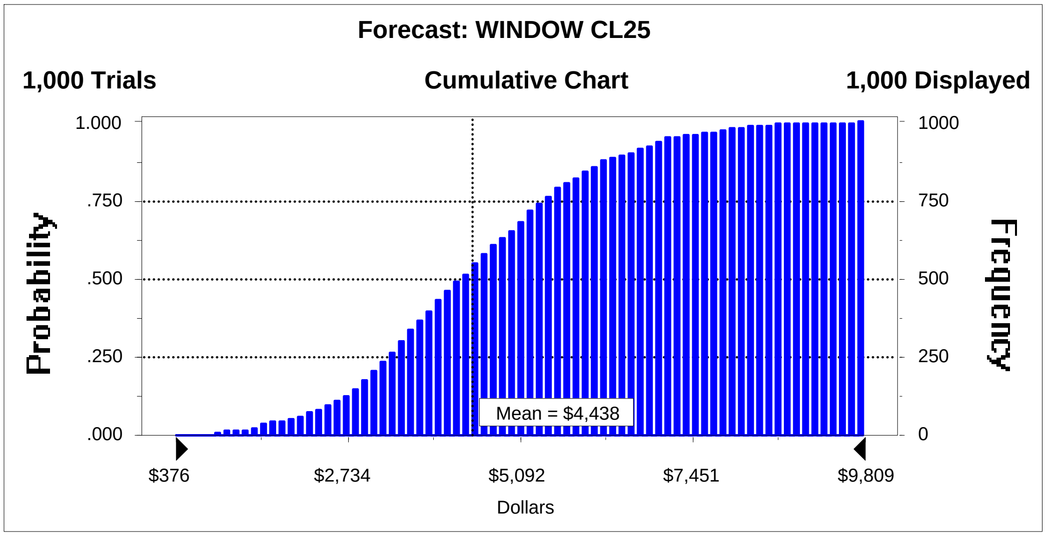

Figure G-142: Climate Zone 3 Class 25 Window NPV Results for Electric Zonal

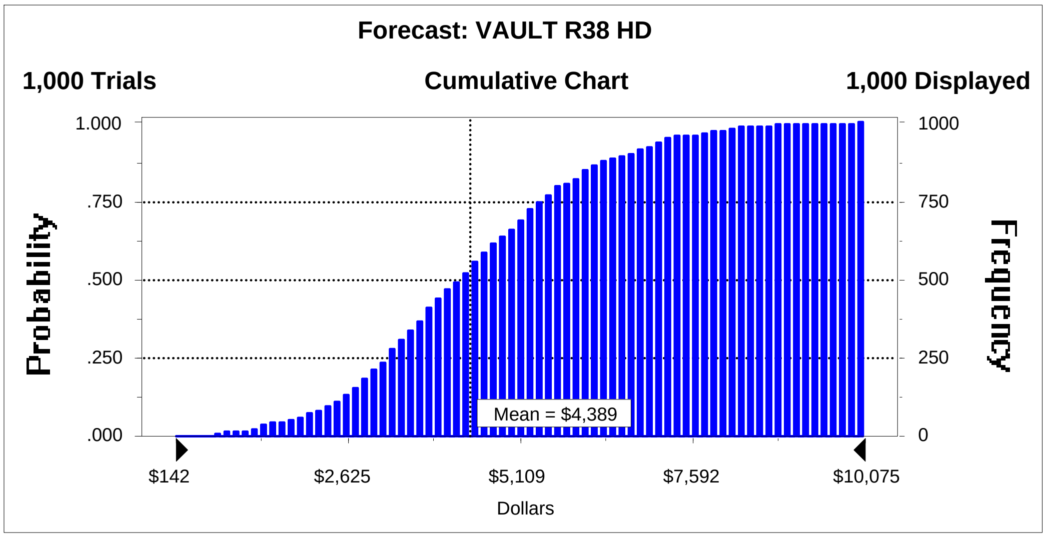

Figure G-143: Climate Zone 3 R38 Vault NPV Results for Electric Zonal

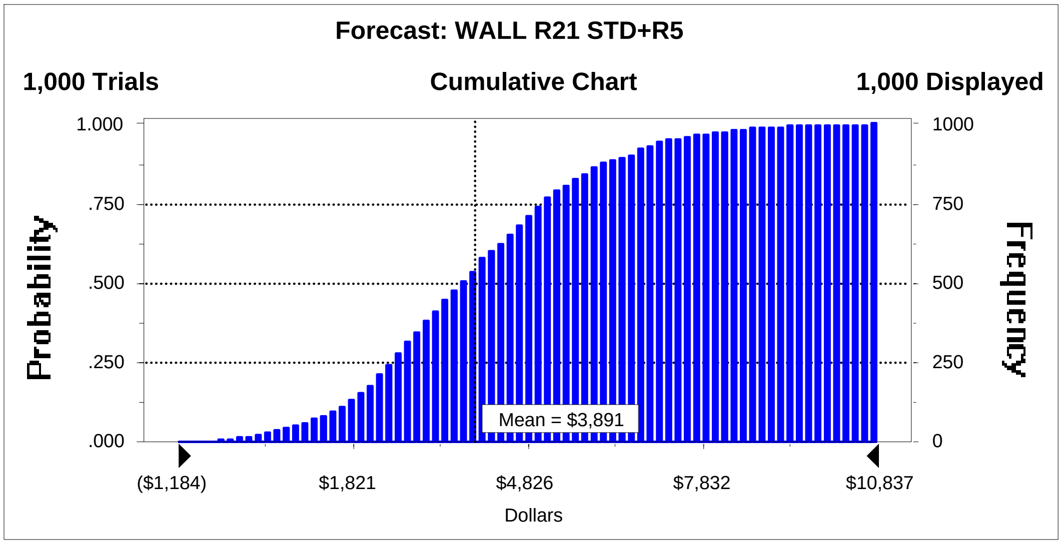

Figure G-144: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Electric Zonal

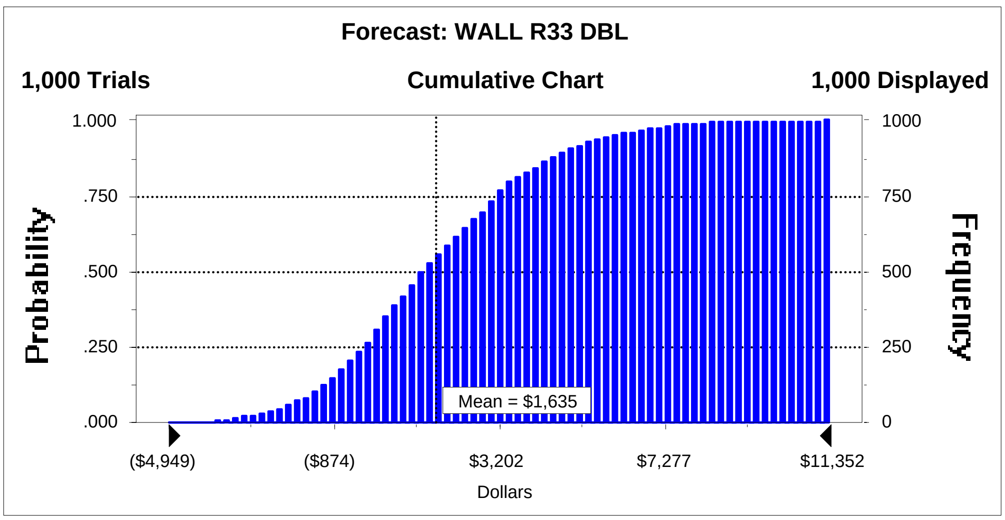

Figure G-145: Climate Zone 3 R33 Wall NPV Results for Electric Zonal

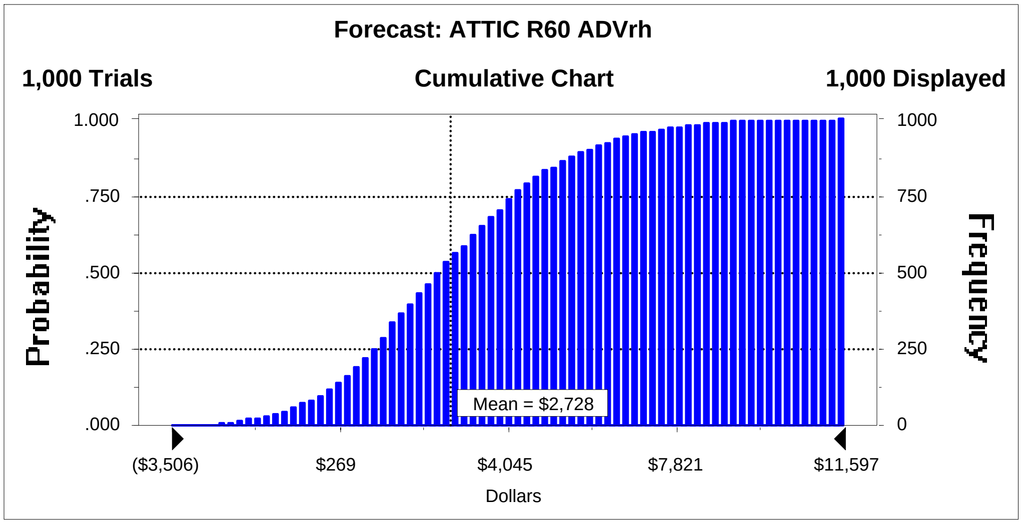

Figure G-146: Climate Zone 3 R60 Advanced Framed Attic NPV Results for Electric Zonal

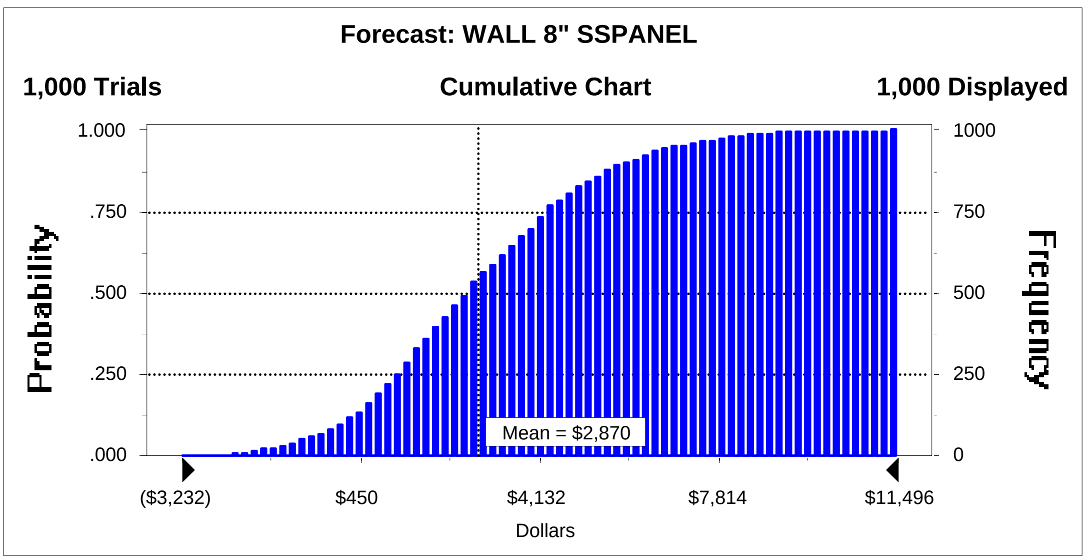

Figure G-147: Climate Zone 3 R38 Wall NPV Results for Electric Zonal

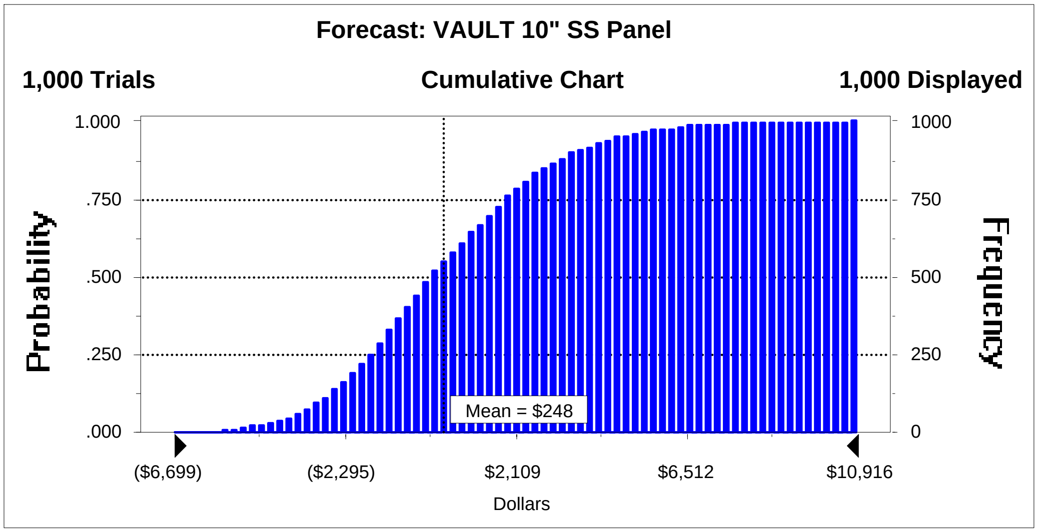

Figure G-148: Climate Zone 3 R49 Vault NPV Results for Electric Zonal

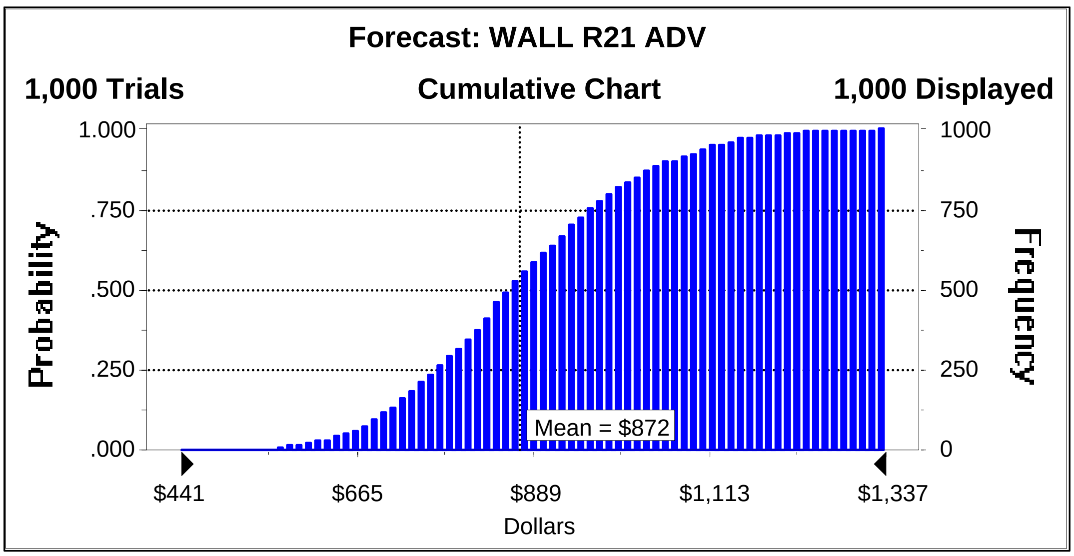

Figure G-149: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Gas FAF

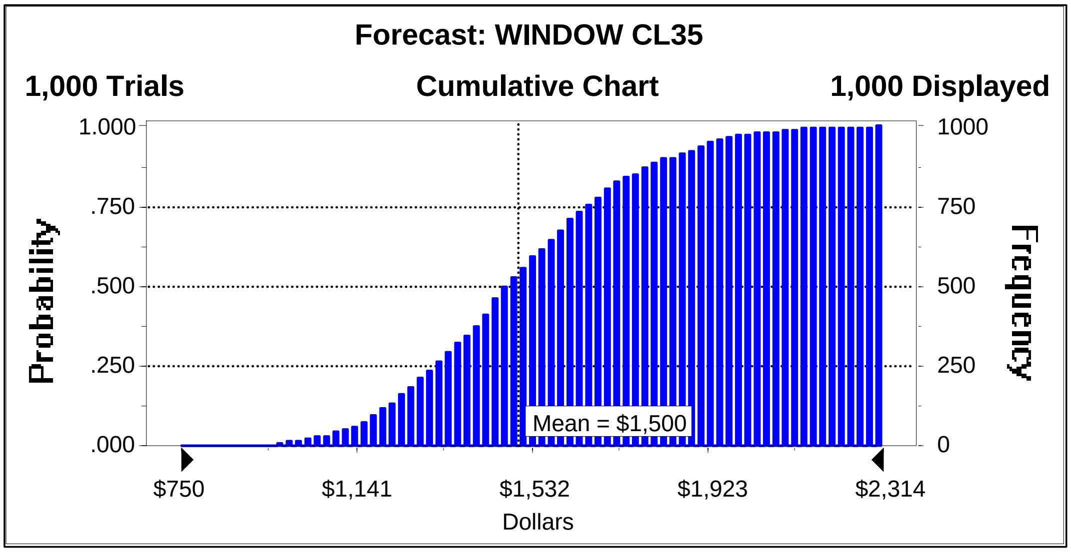

Figure G-150: Climate Zone 3 Class 35 Window NPV Results for Gas FAF

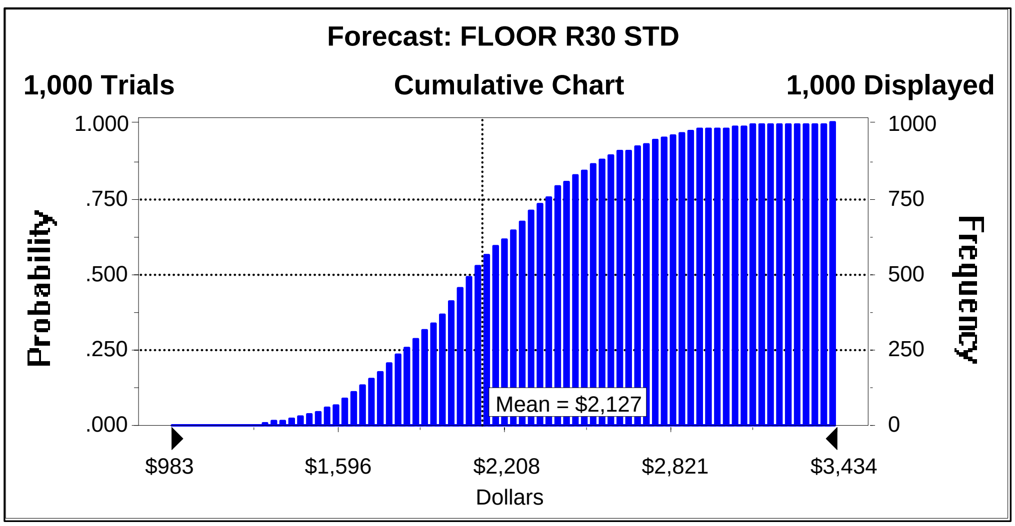

Figure G-151: Climate Zone 3 R30 Under floor NPV Results for Gas FAF

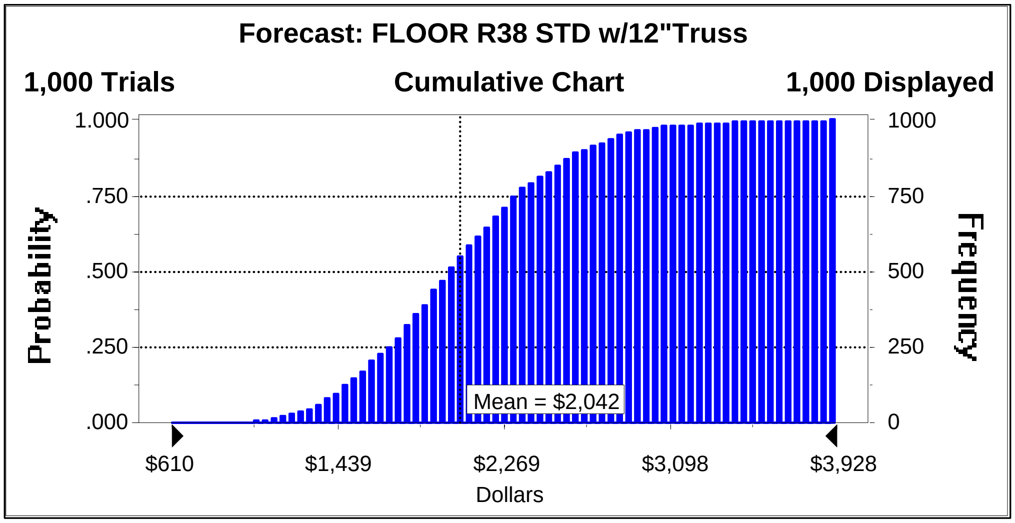

Figure G-152: Climate Zone 3 R38 Under floor NPV Results for Gas FAF

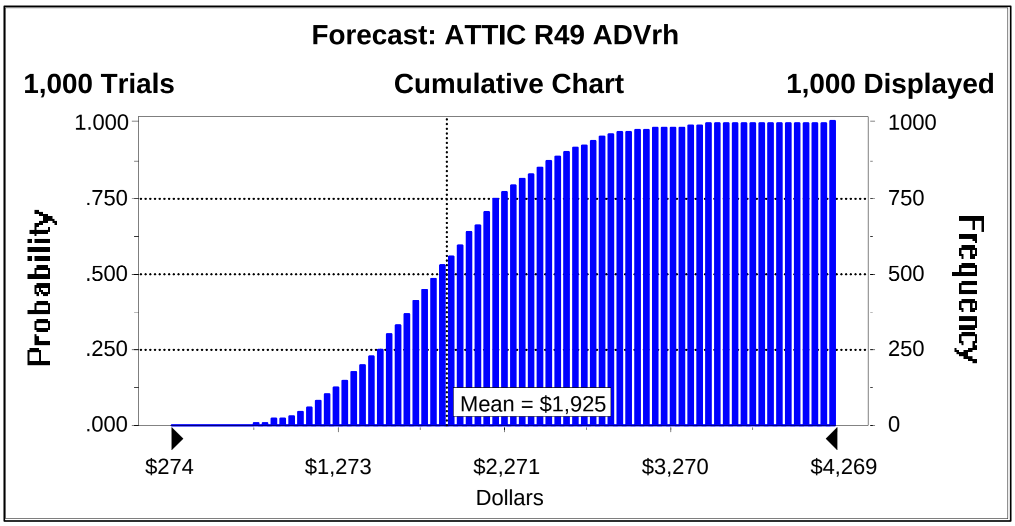

Figure G-153: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Gas FAF

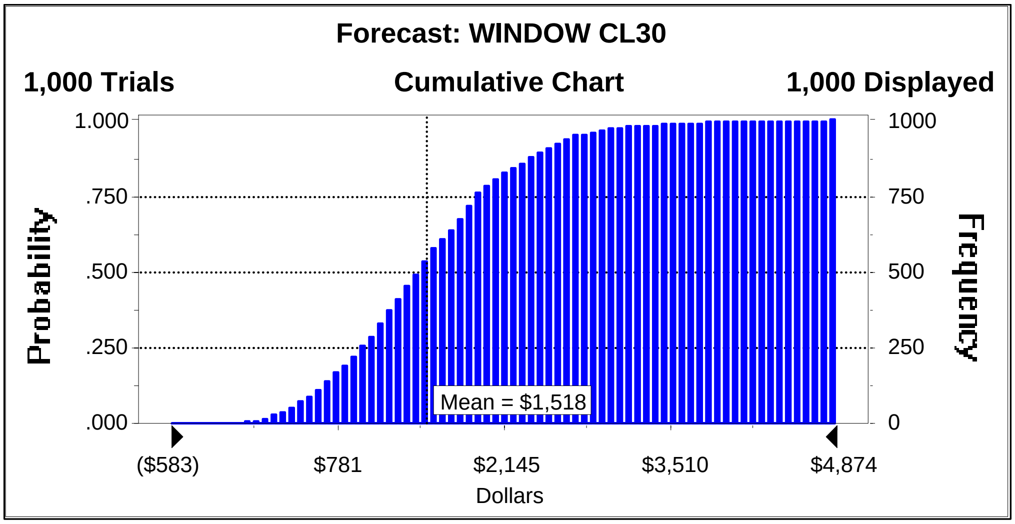

Figure G-154: Climate Zone 3 Class 30 Window NPV Results for Gas FAF

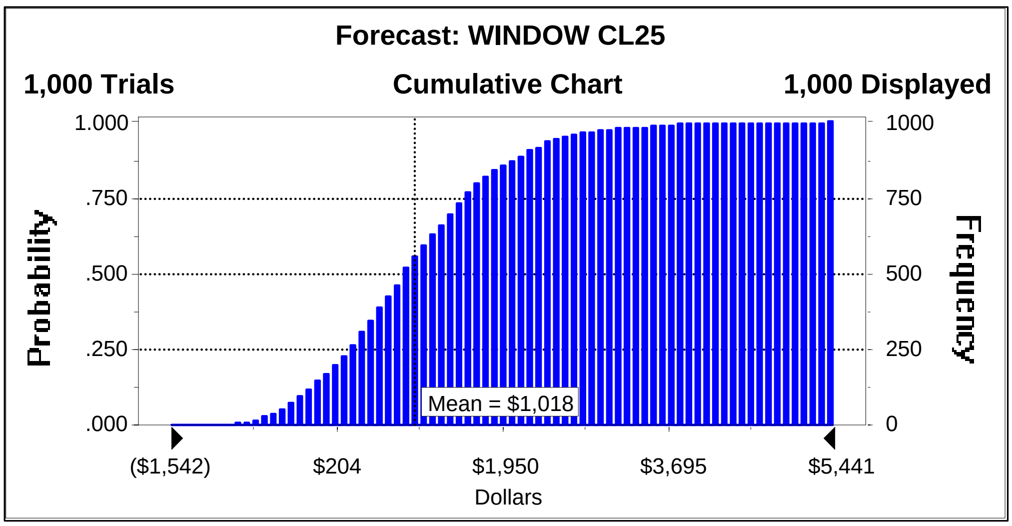

Figure G-155: Climate Zone 3 Class 25 Window NPV Results for Gas FAF

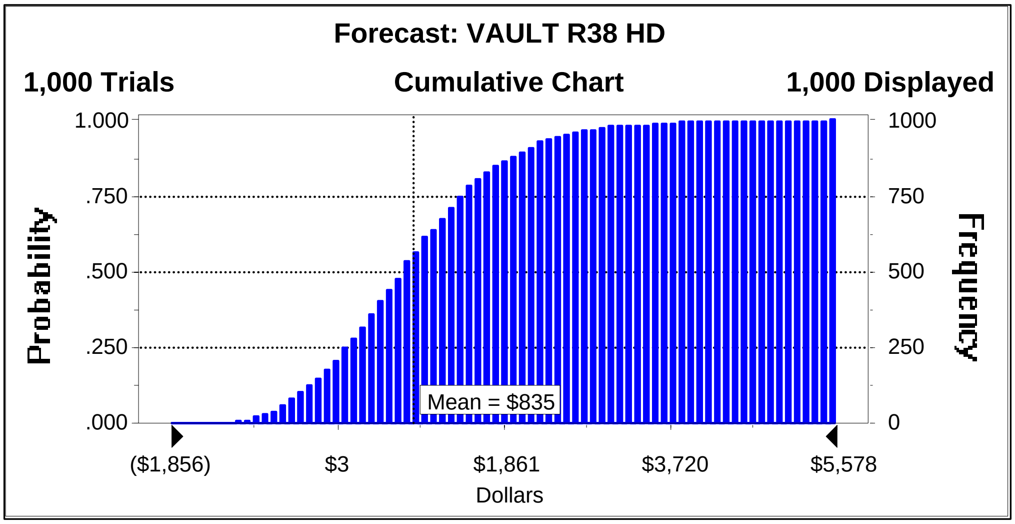

Figure G-156: Climate Zone 3 R38 Vault NPV Results for Gas FAF

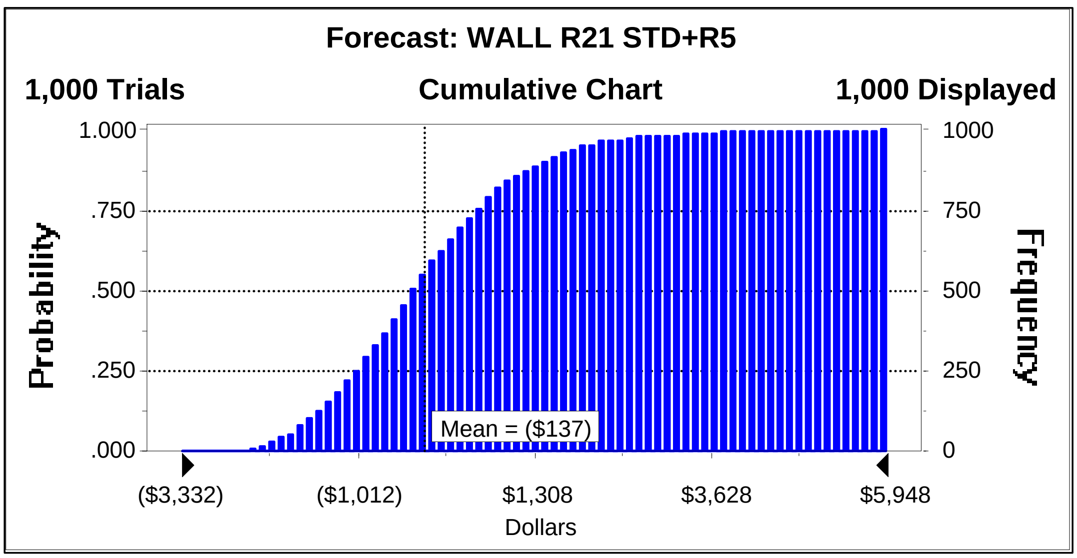

Figure G-157: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Gas FAF

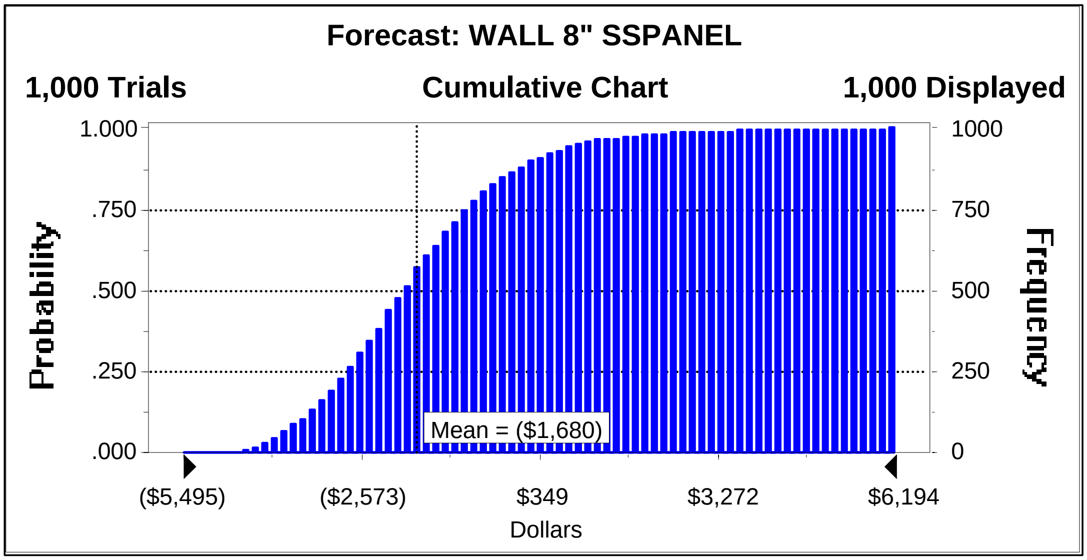

Figure G-158: Climate Zone 3 R33 Wall NPV Results for Gas FAF

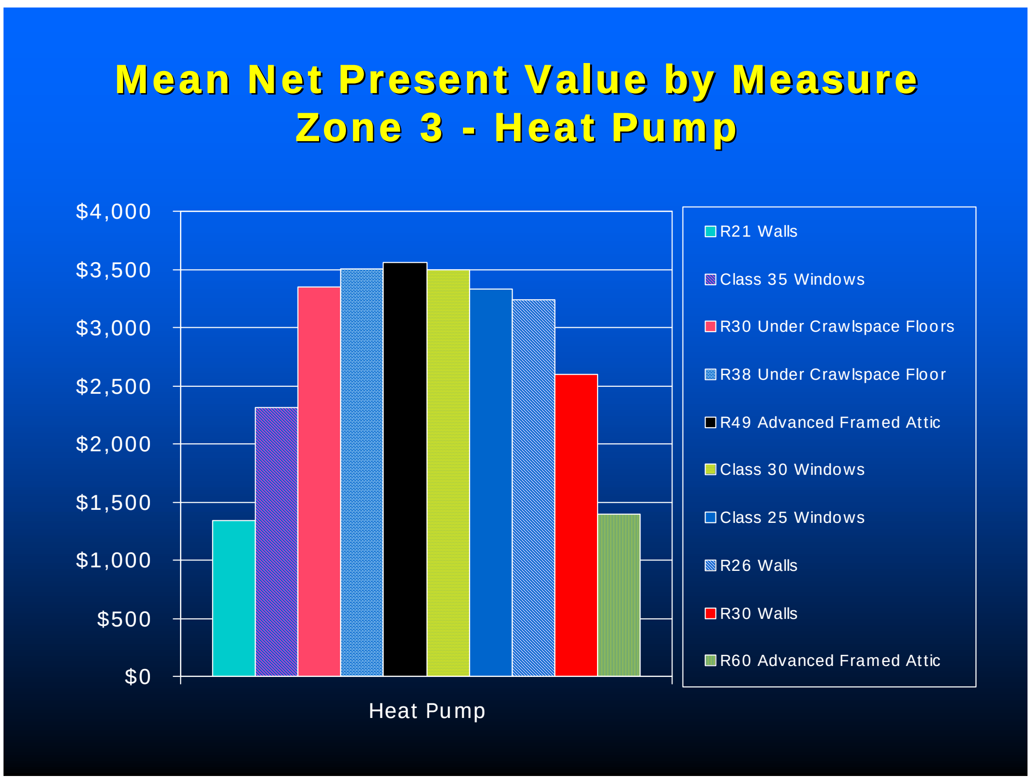

Figure G-159: Climate Zone 3 Mean Net Present Value by Measure for Heat Pumps

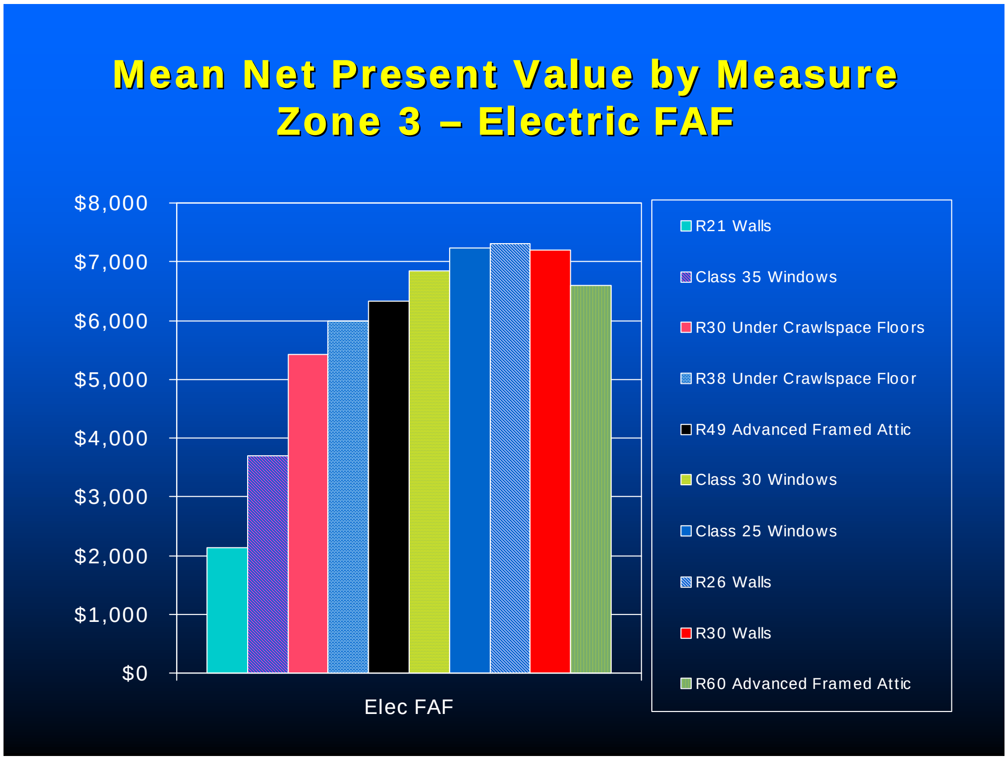

Figure G-160: Climate Zone 3 Mean Net Present Value by Measure for Electric FAF

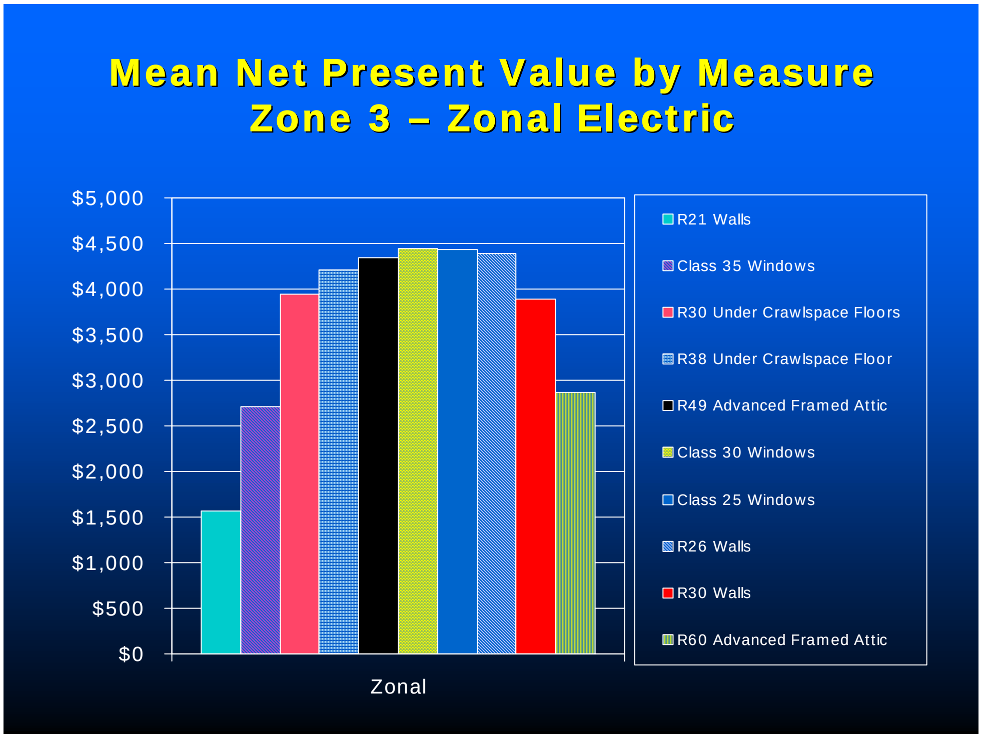

Figure G-161: Climate Zone 3 Mean Net Present Value by Measure for Electric Zonal

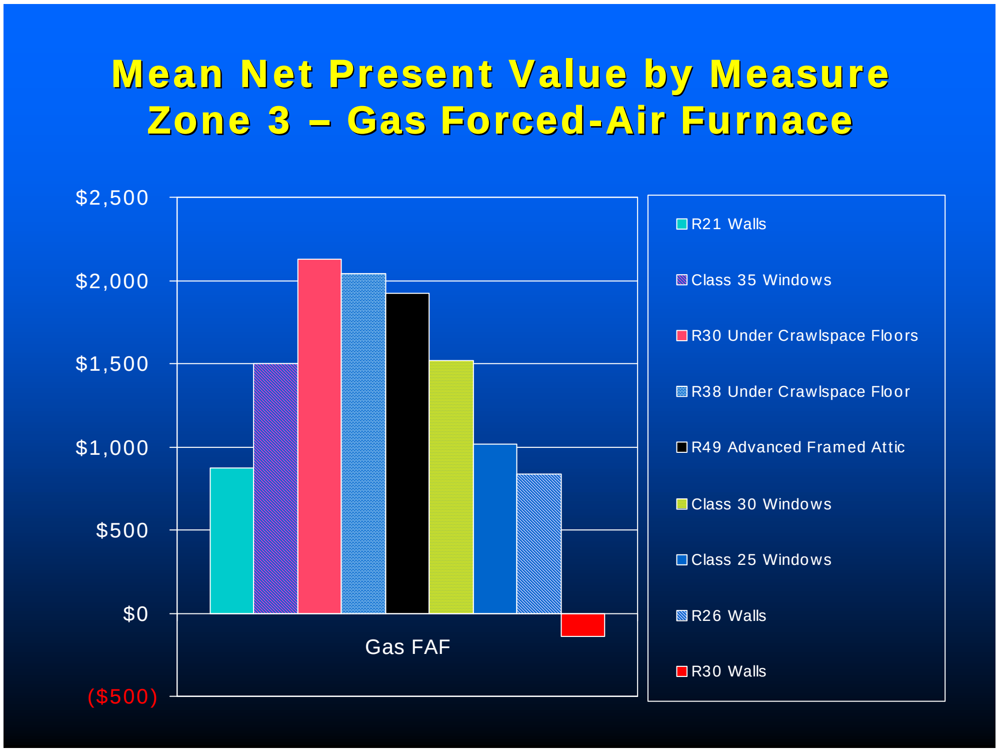

Figure G-162: Climate Zone 3 Mean Net Present Value by Measure for Gas FAF

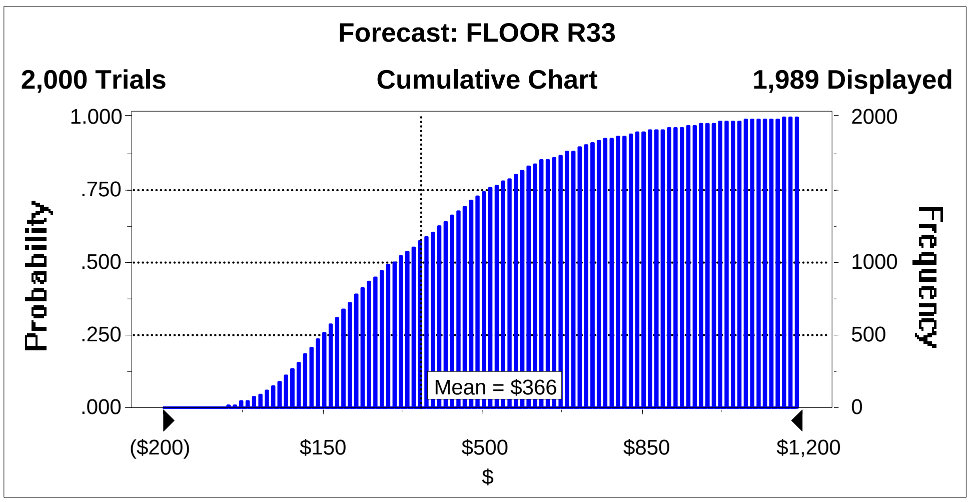

Figure G-163: Climate Zone 1 Net Present Value Results for Manufactured Homes for R33 Floors

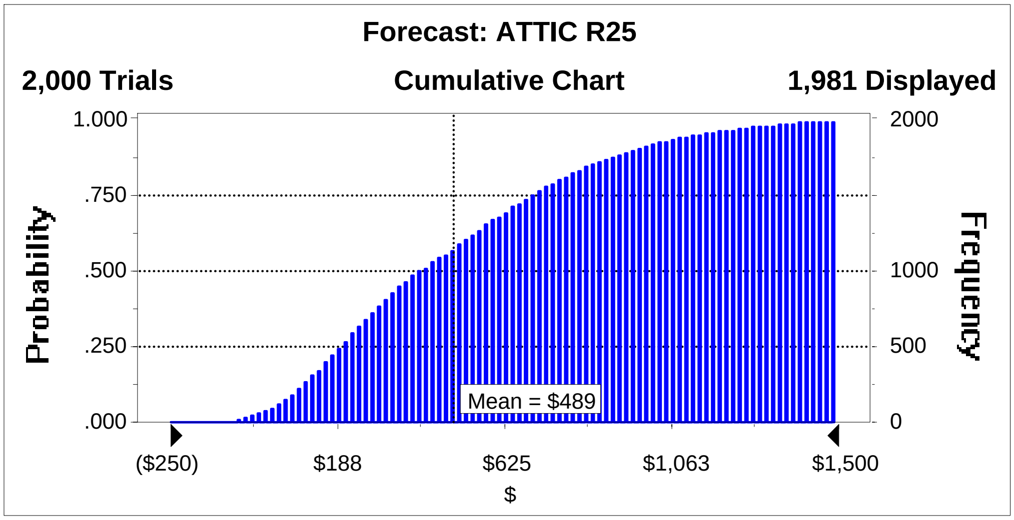

Figure G-164: Climate Zone 1 Net Present Value Results for Manufactured Homes for R25 Attic

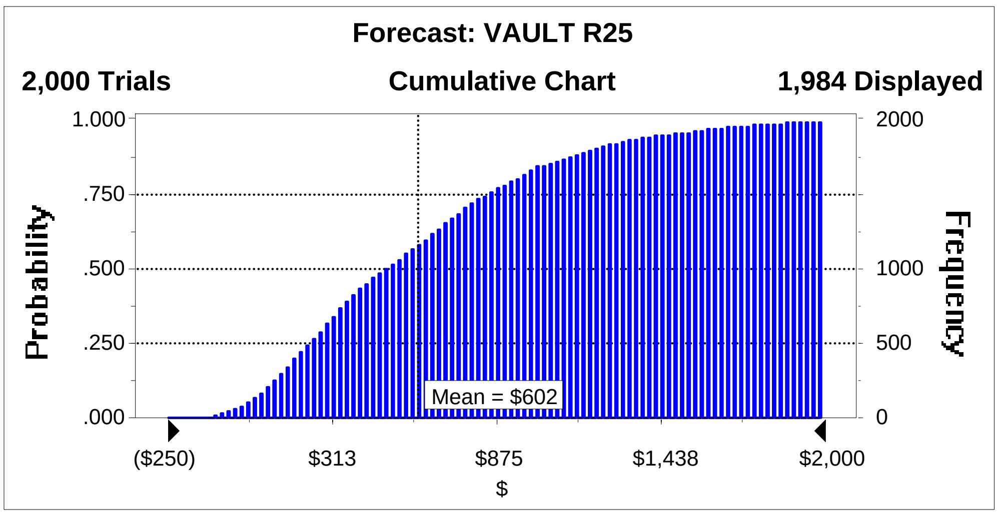

Figure G-165: Climate Zone 1 Net Present Value Results for Manufactured Homes for R25 Vault

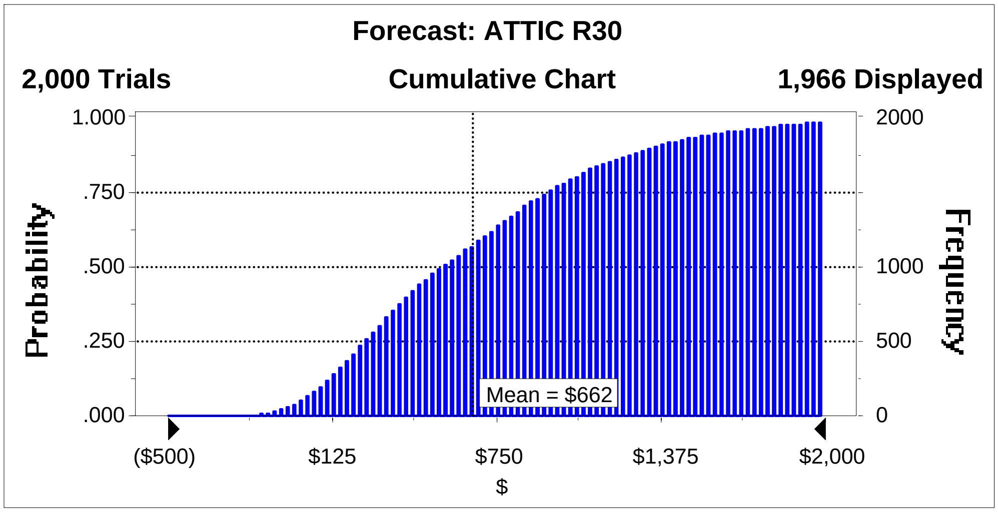

Figure G-166: Climate Zone 1 Net Present Value Results for Manufactured Homes for R30 Attic

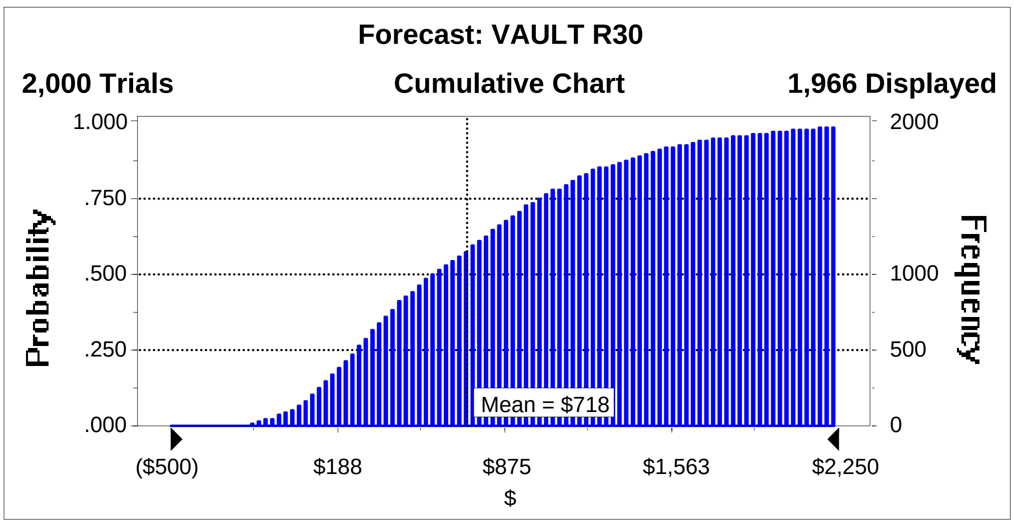

Figure G-167: Climate Zone 1 Net Present Value Results for Manufactured Homes for R30 Vaults

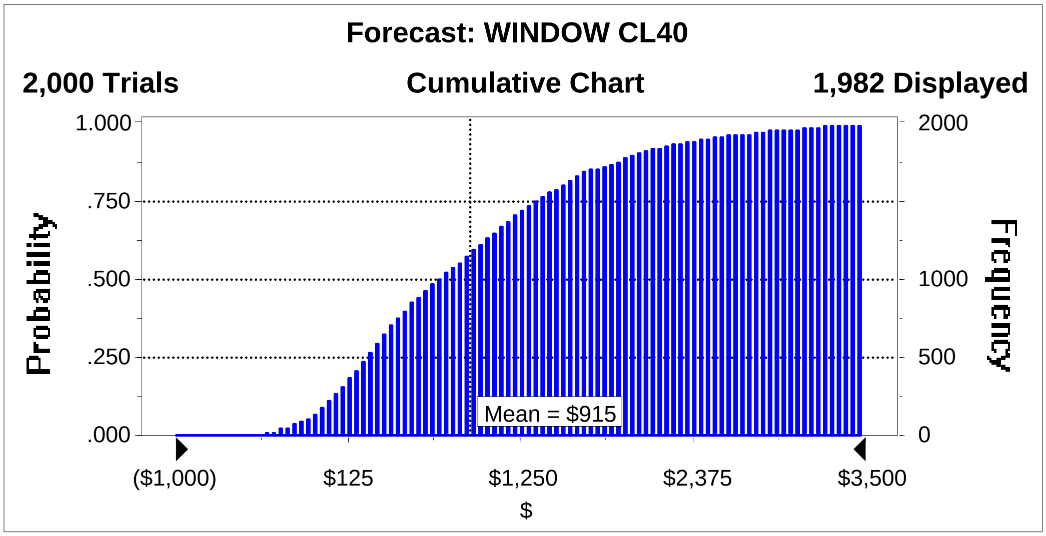

Figure G-168: Climate Zone 1 Net Present Value Results for Manufactured Homes for Class 40 Windows

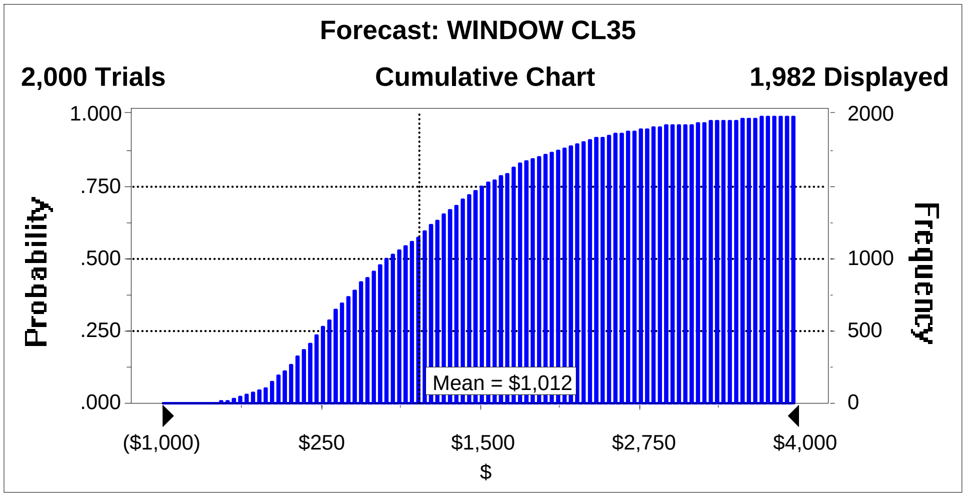

Figure G-169: Climate Zone 1 Net Present Value Results for Manufactured Homes for Class 35 Windows

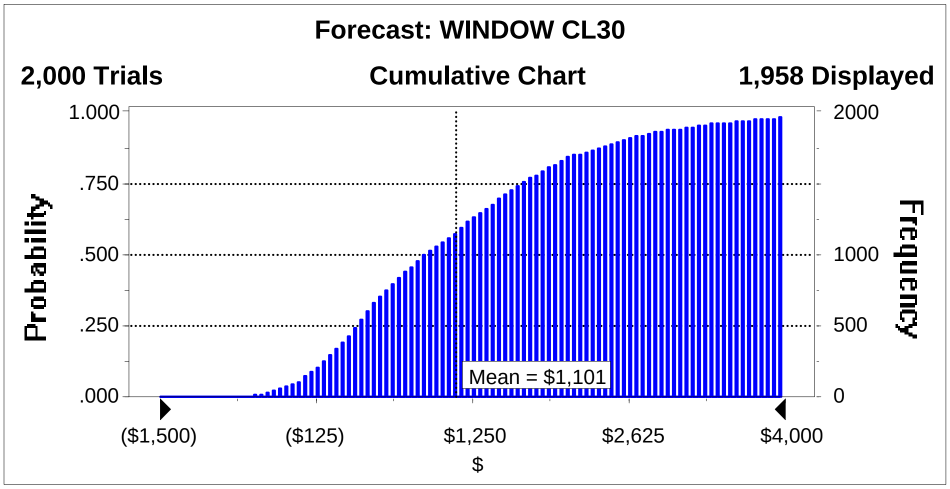

Figure G-170: Climate Zone 1 Net Present Value Results for Manufactured Homes for Class 30 Windows

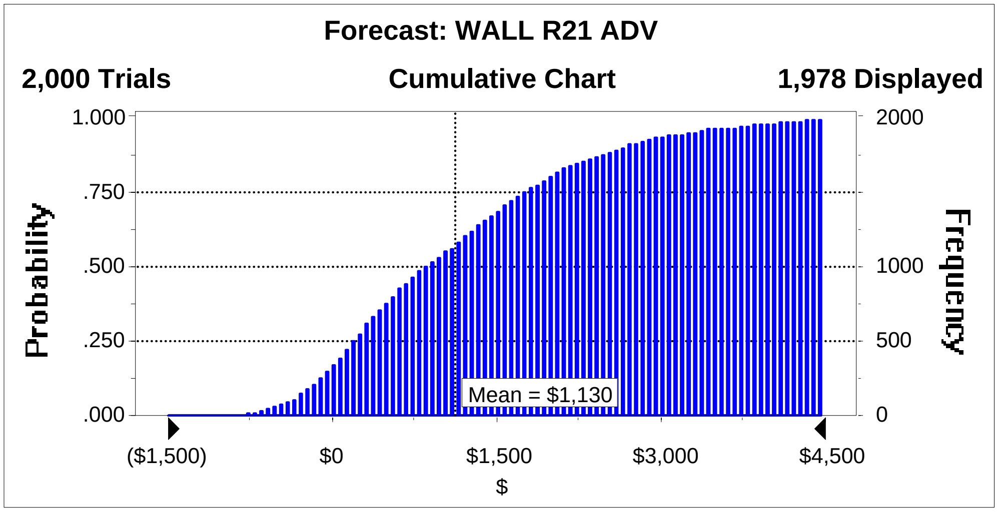

Figure G-171: Climate Zone 1 Net Present Value Results for Manufactured Homes for R21 Advanced Framed Walls

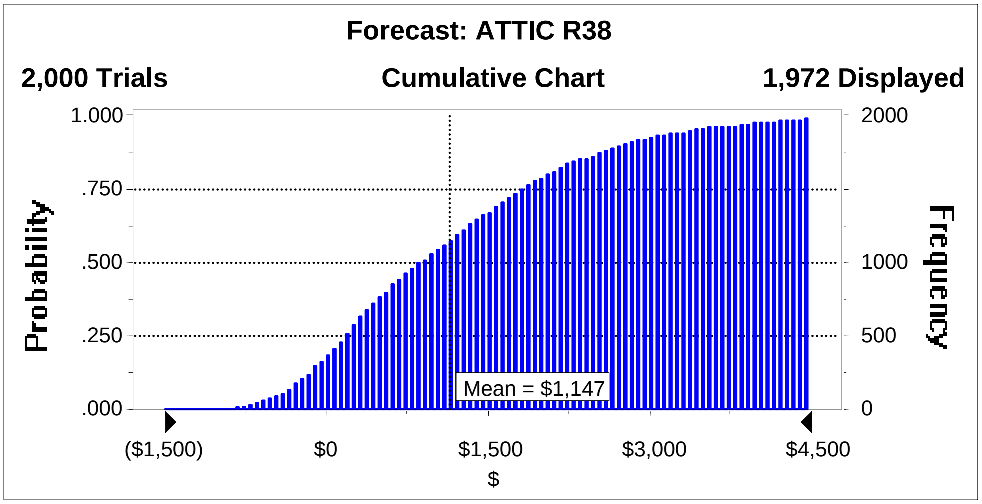

Figure G-172: Climate Zone 1 Net Preset Value Results for Manufactured Homes for R38 Attics

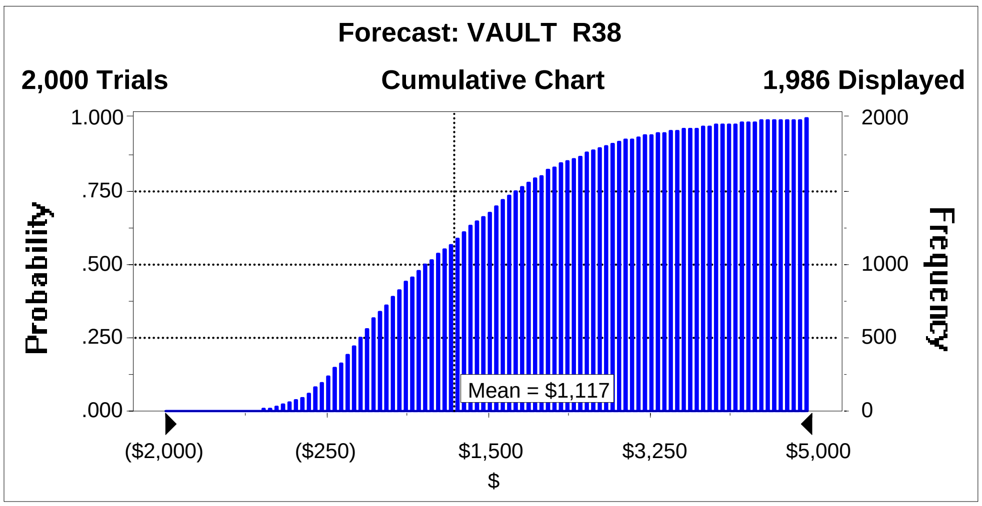

Figure G-173: Climate Zone 1 Net Present Value Results for Manufactured Homes for R38 Vaults

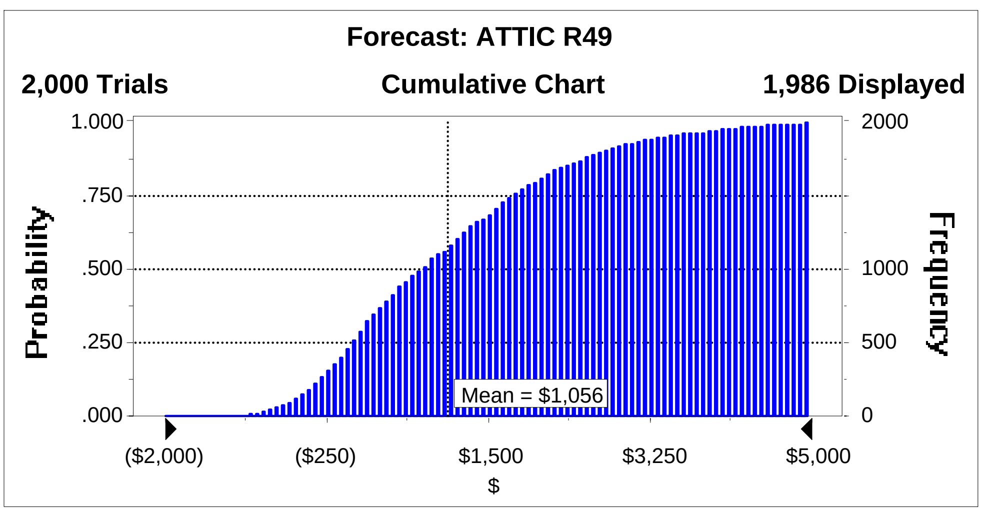

Figure G-174: Climate Zone 1 Net Present Value Results for Manufactured Homes for R49 Attics

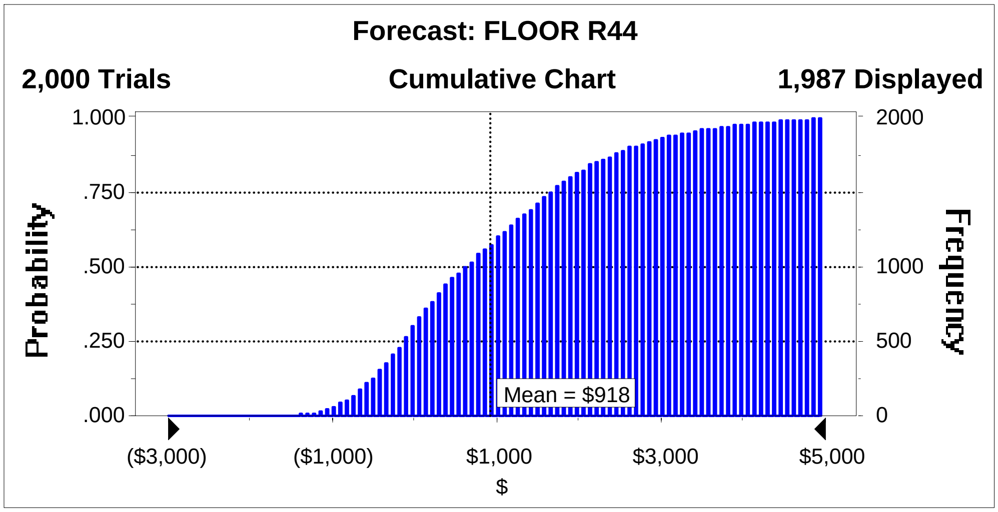

Figure G-175: Climate Zone 1 Net Present Value Results for Manufactured Homes for R44 Floors

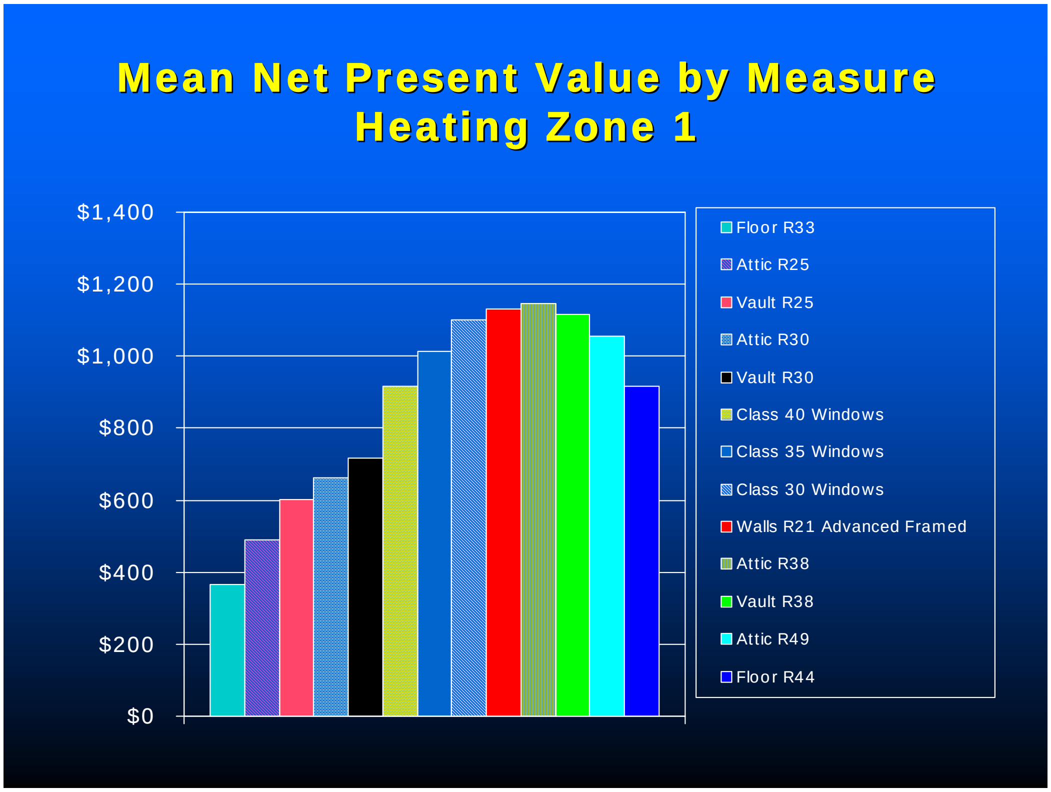

Figure G-176: Climate Zone 1 Expected Value Mean Net Present Value Results for Manufactured Homes

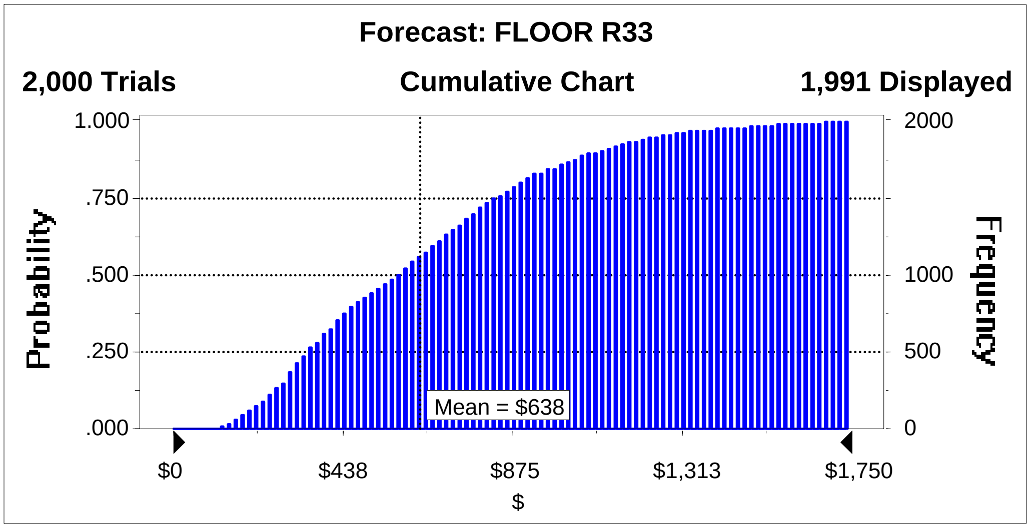

Figure G-177: Climate Zone 2 Net Present Value Results for Manufactured Homes for R33 Floors

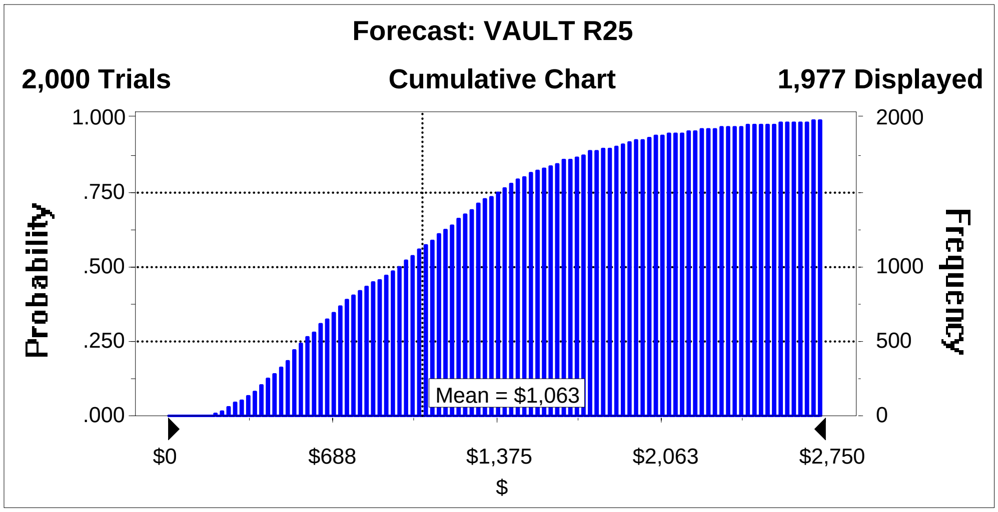

Figure G-178: Climate Zone 2 Net Present Value Results for Manufactured Homes for R25 Attics

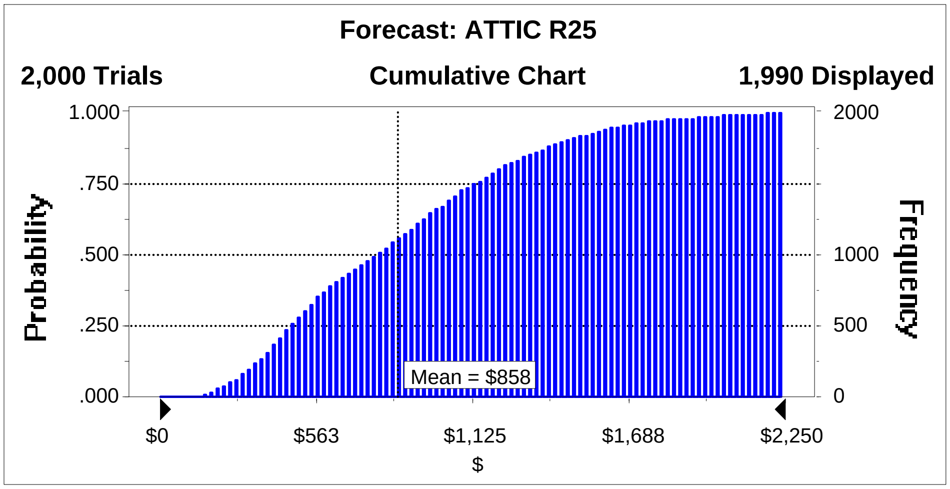

Figure G-179: Climate Zone 2 Net Present Value Results for Manufactured Homes for R25 Vaults

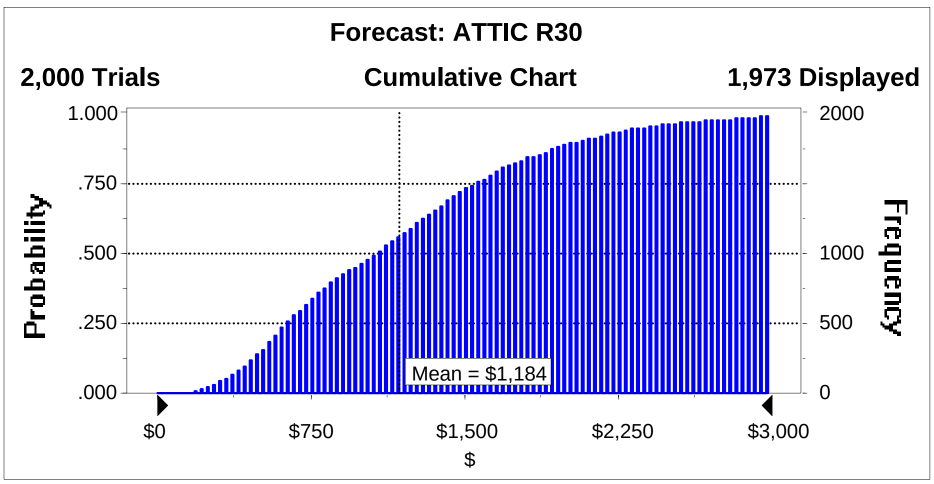

Figure G-180: Climate Zone 2 Net Present Value Results for Manufactured Homes for R30 Attics

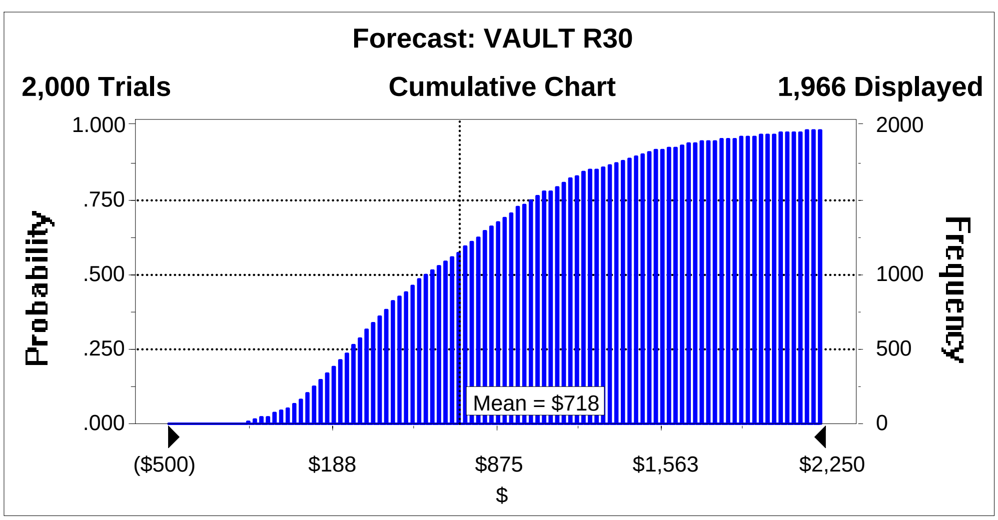

Figure G-181: Climate Zone 2 Net Present Value Results for Manufactured Homes for R30 Vaults

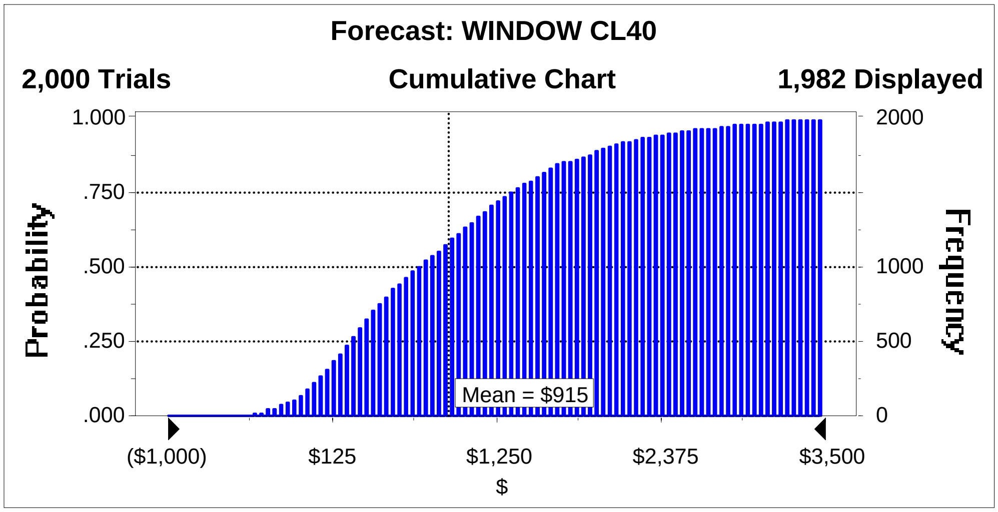

Figure G-182: Climate Zone 2 Net Present Value Results for Manufactured Homes for Class 40 Windows

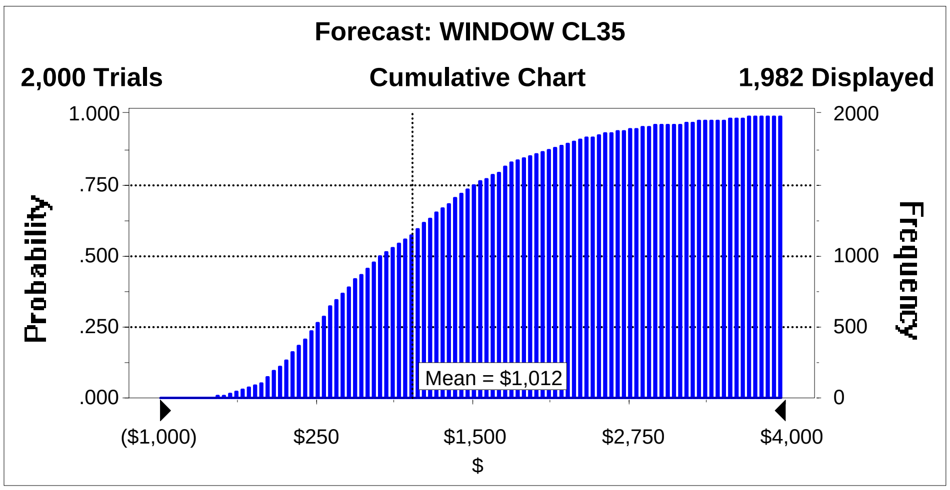

Figure G-183: Climate Zone 2 Net Present Value Results for Manufactured Homes for Class 35 Windows

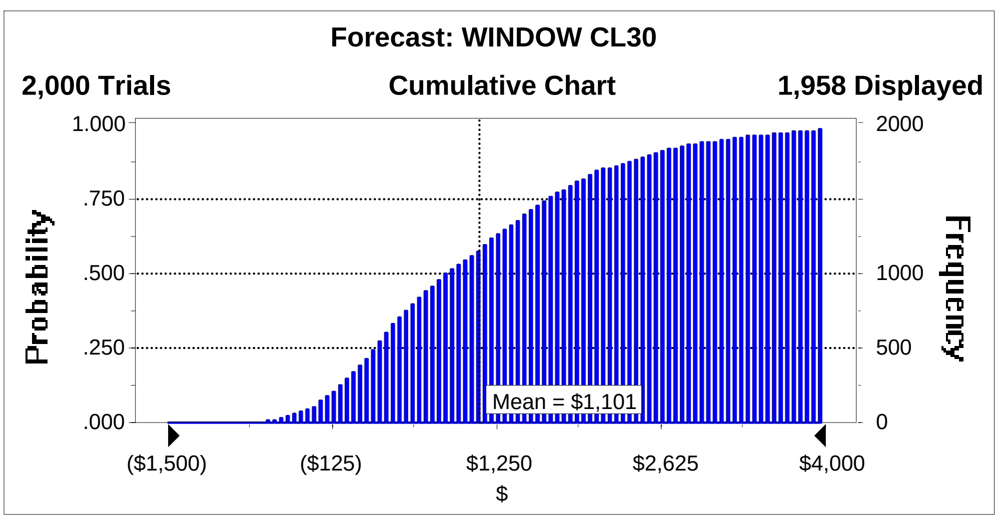

Figure G-184: Climate Zone 2 Net Present Value Results for Manufactured Homes for Class 30 Windows

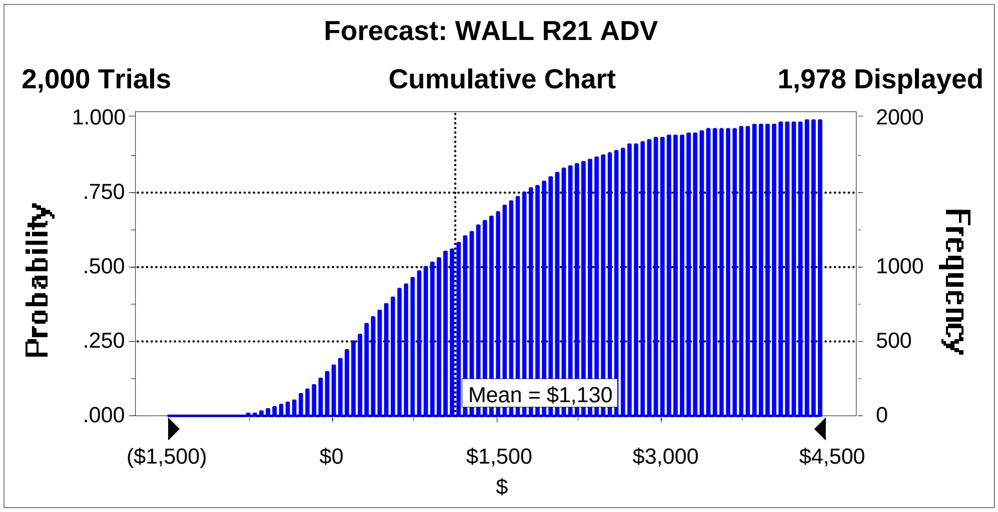

Figure G-185: Climate Zone 2 Net Present Value Results for Manufactured Homes for R21 Advanced Framed Walls

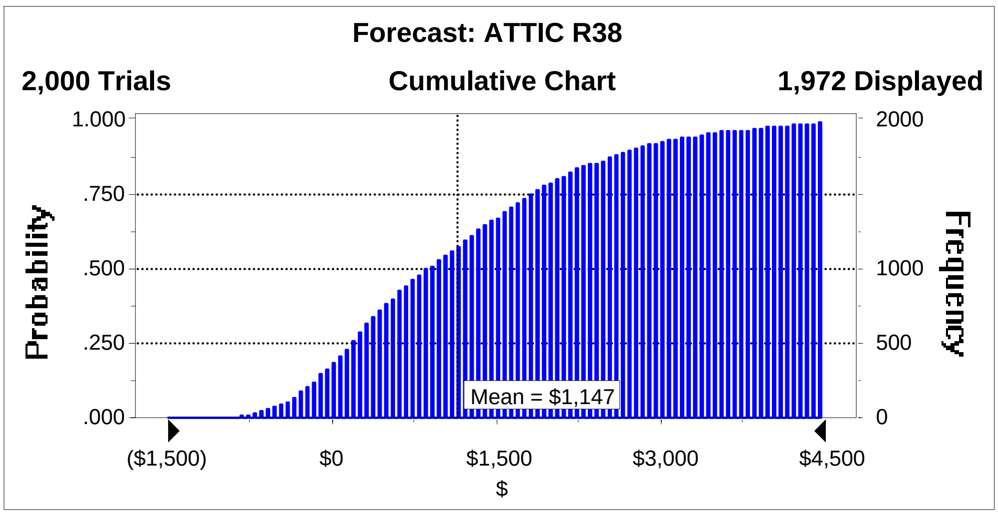

Figure G-186: Climate Zone 2 Net Present Value Results for Manufactured Homes for R38 Attics

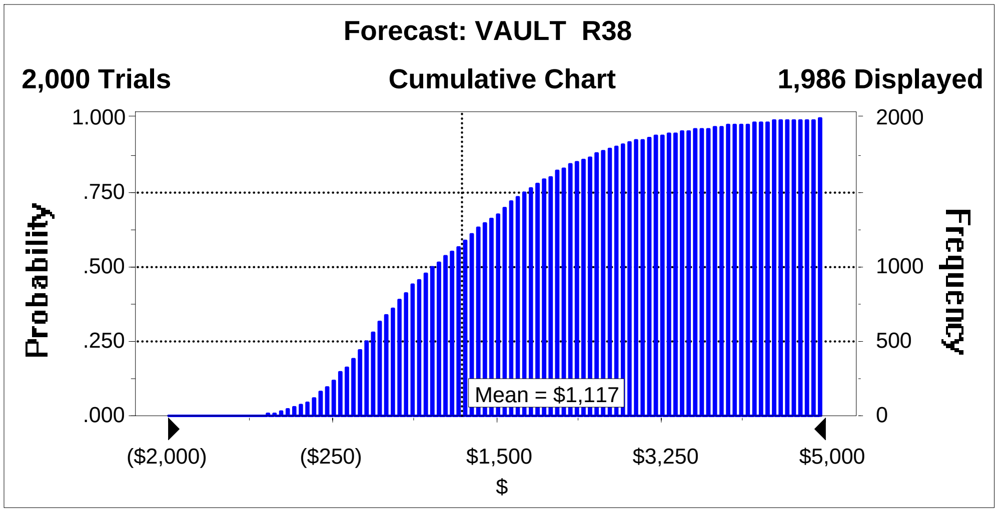

Figure G-187: Climate Zone 2 Net Present Value Results for Manufactured Homes for R38 Vaults

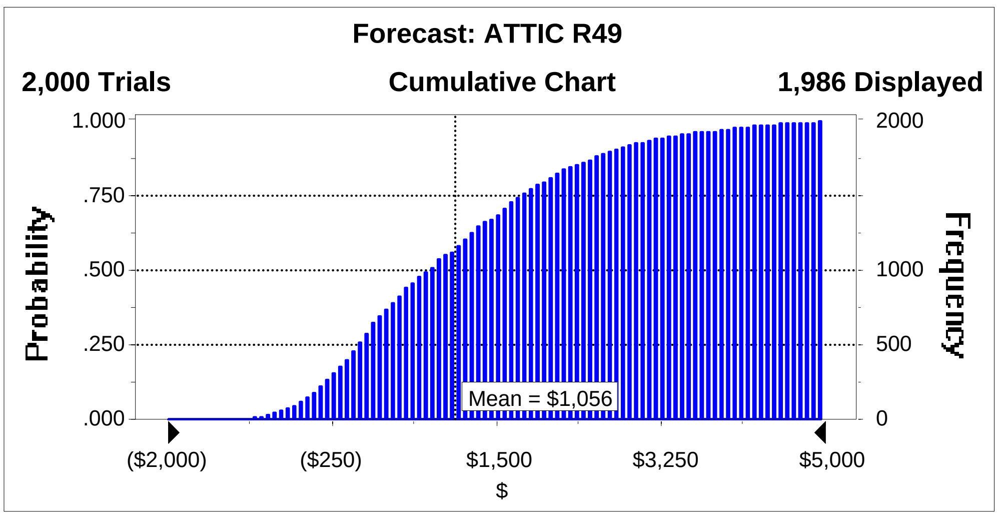

Figure G-188: Climate Zone 2 Net Present Value Results for Manufactured Homes for R49 Attics

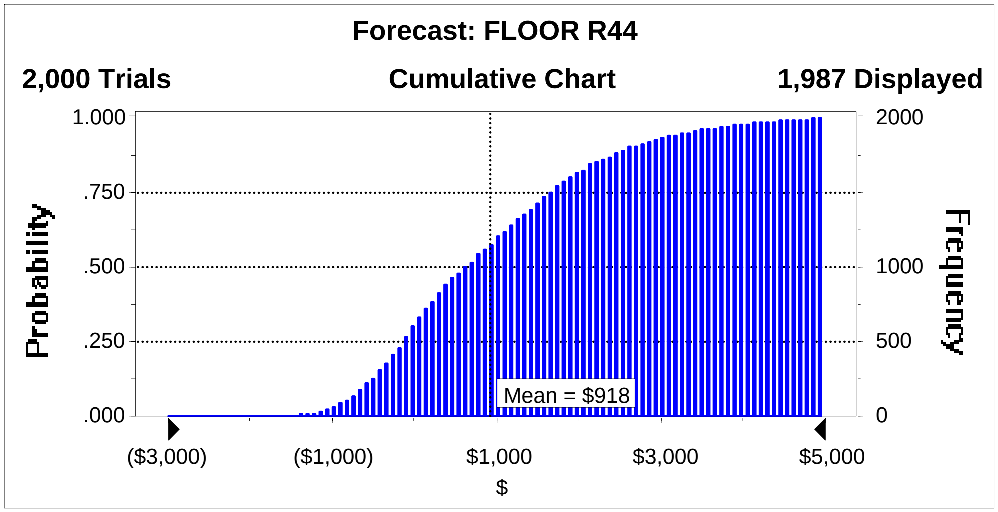

Figure G-189: Climate Zone 2 Net Present Value Results for Manufactured Homes for R44 Floors

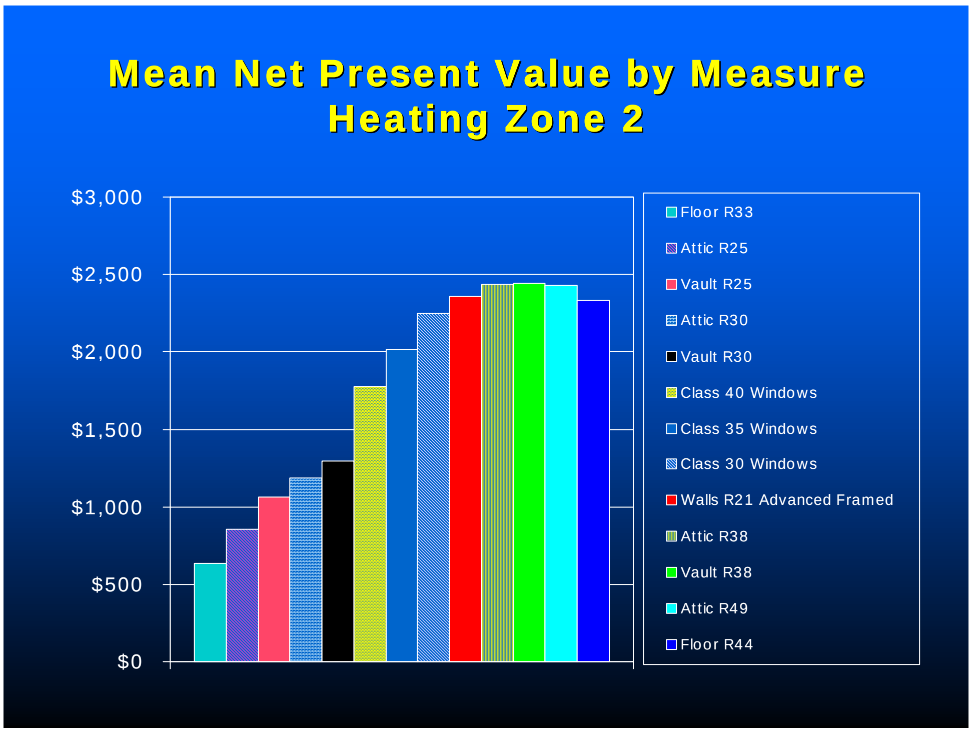

Figure G-190: Climate Zone 2 Expected Value Mean Net Present Value Results for Manufactured Homes

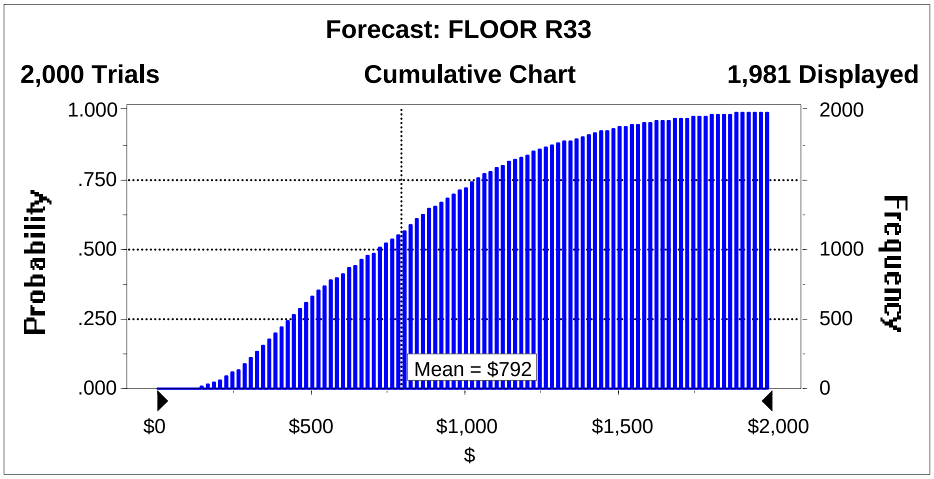

Figure G-191: Climate Zone 3 Net Present Value Results for Manufactured Homes for R33 Floors

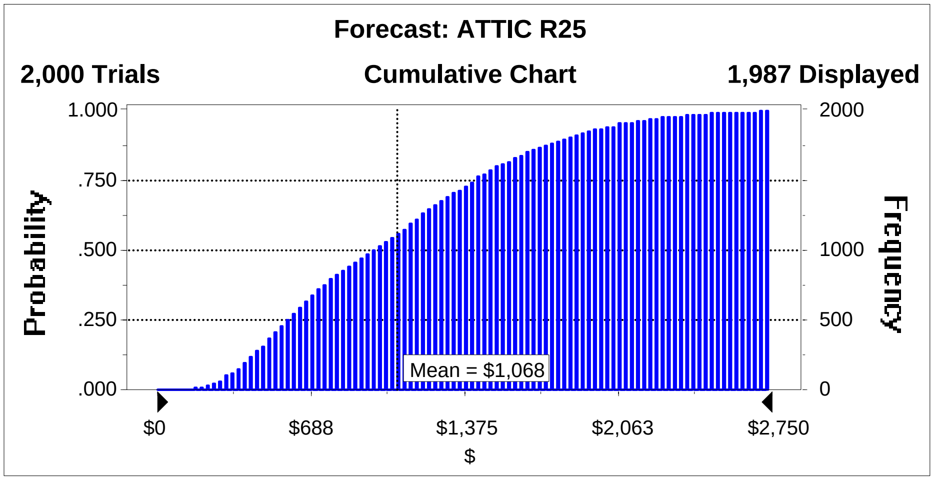

Figure G-192: Climate Zone 3 Net Present Value Results for Manufactured Homes for R25 Attics

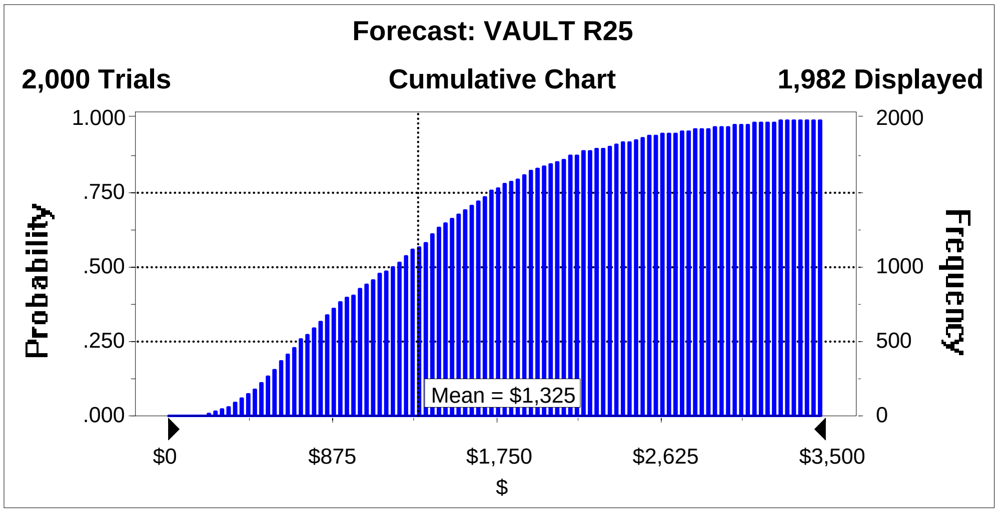

Figure G-193: Climate Zone 3 Net Present Value Results for Manufactured Homes for R25 Vaults

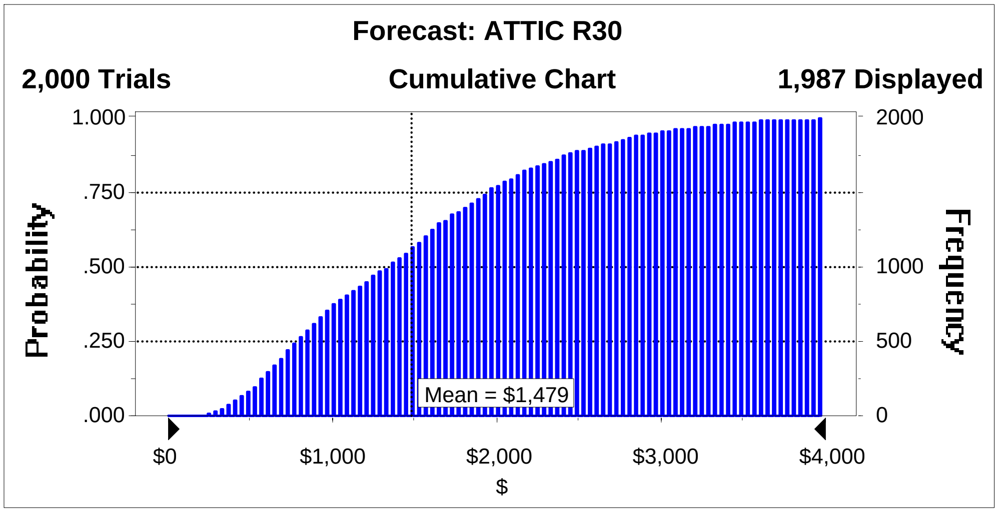

Figure G-194: Climate Zone 3 Net Present Value Results for Manufactured Homes for R30 Attics

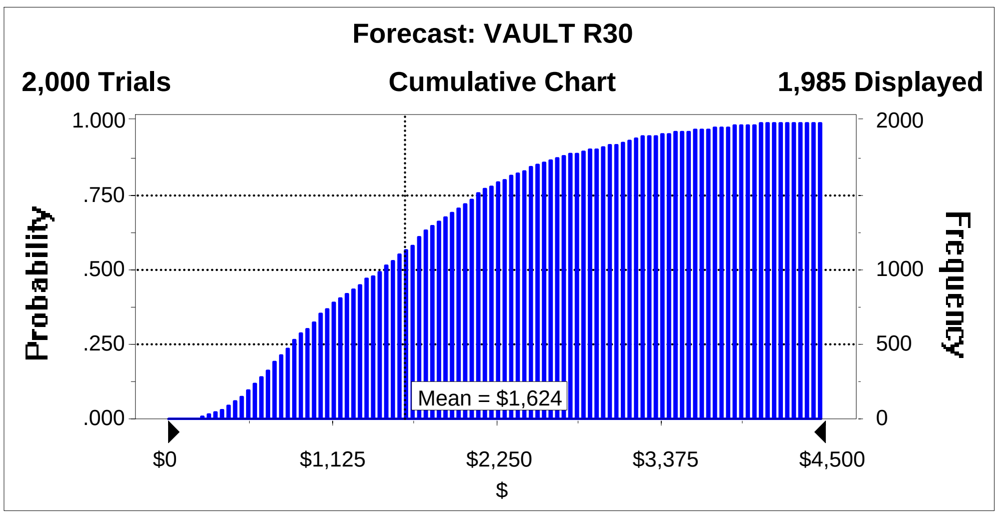

Figure G-195: Climate Zone 3 Net Present Value Results for Manufactured Homes for R30 Vaults

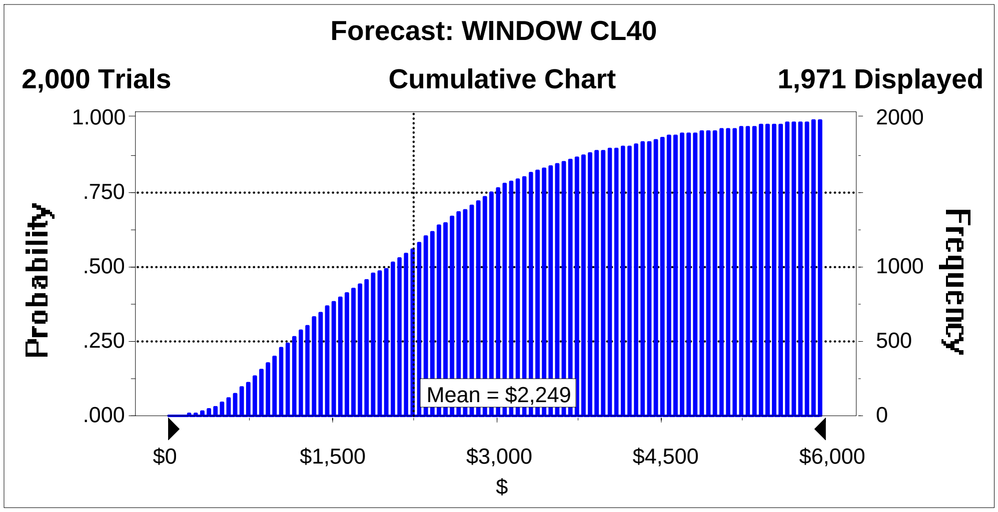

Figure G-196: Climate Zone 3 Net Present Value Results for Manufactured Homes for Class 40 Windows

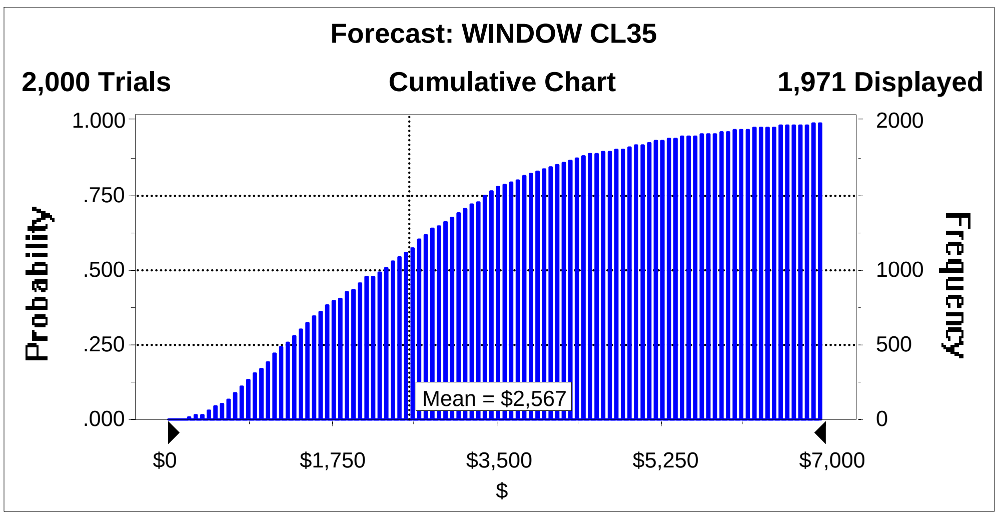

Figure G-197: Climate Zone 3 Net Present Value Results for Manufactured Homes for Class 35 Windows

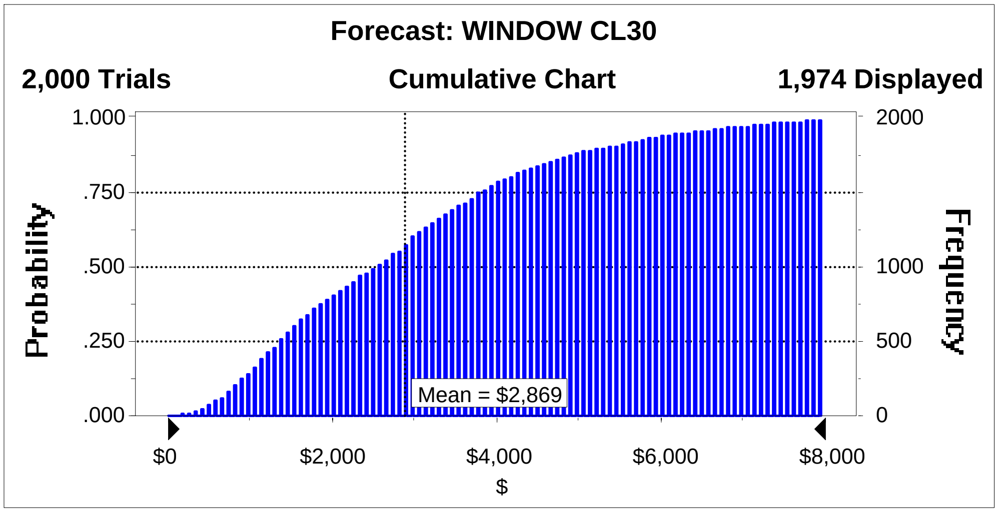

Figure G-198: Climate Zone 3 Net Present Value Results for Manufactured Homes for Class 30 Windows

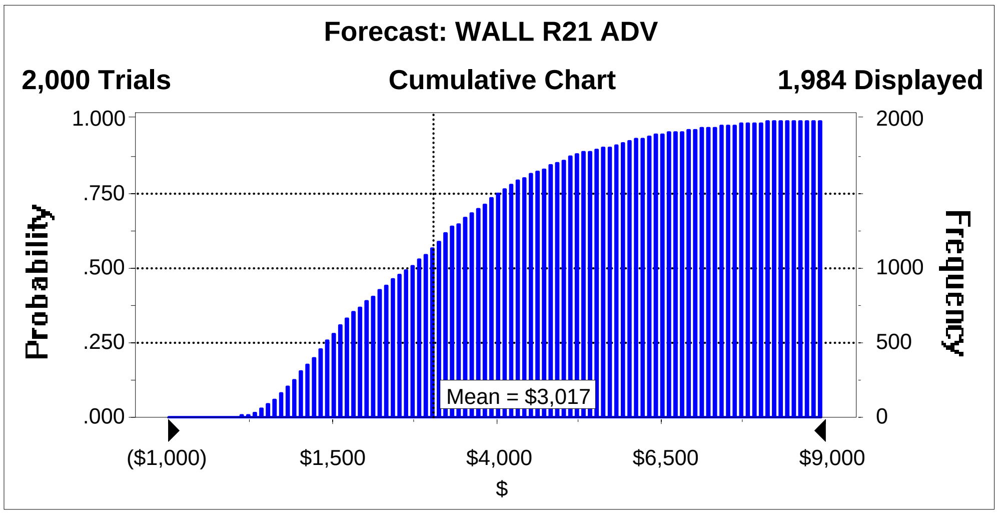

Figure G-199: Climate Zone 3 Net Present Value Results for Manufactured Homes for R21 Advanced Framed Walls

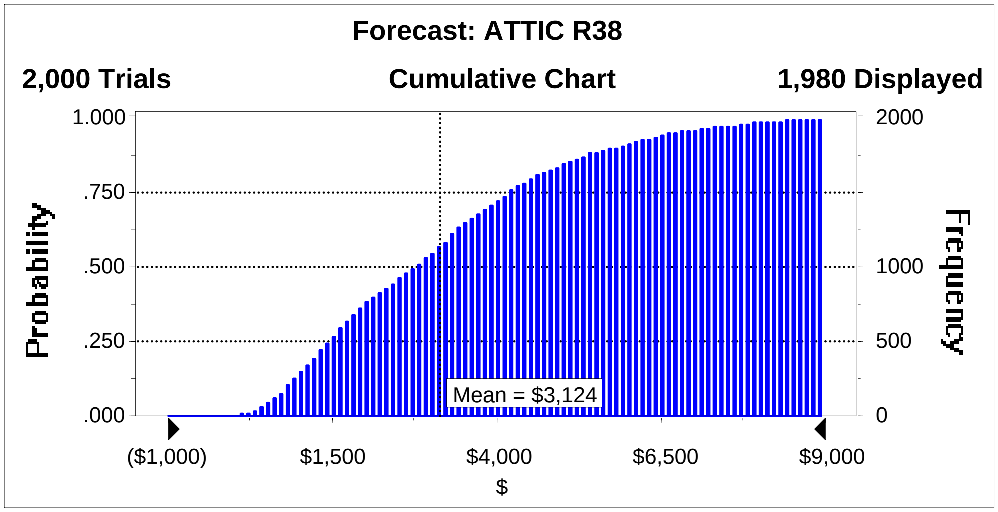

Figure G-200: Climate Zone 3 Net Present Value Results for Manufactured Homes for R38 Attics

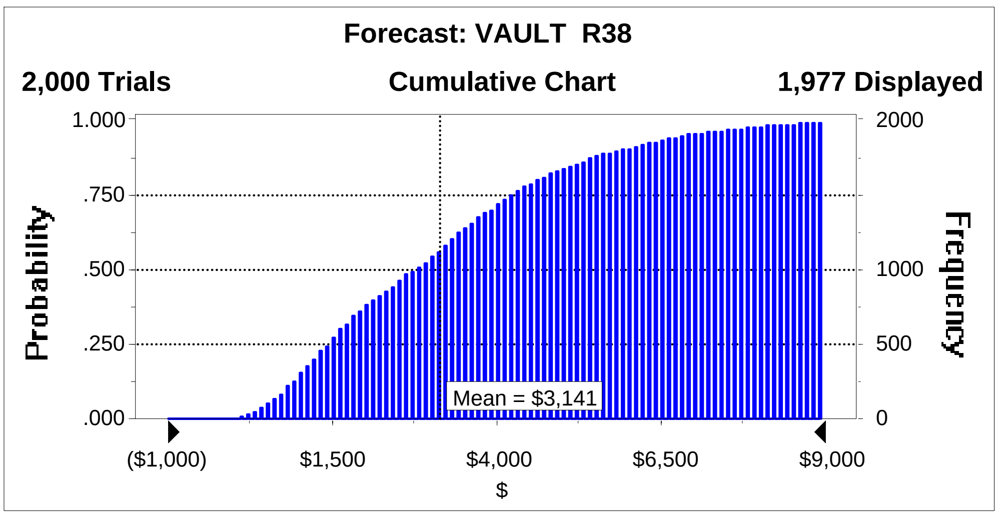

Figure G-201: Climate Zone 3 Net Present Value Results for Manufactured Homes for R38 Vaults

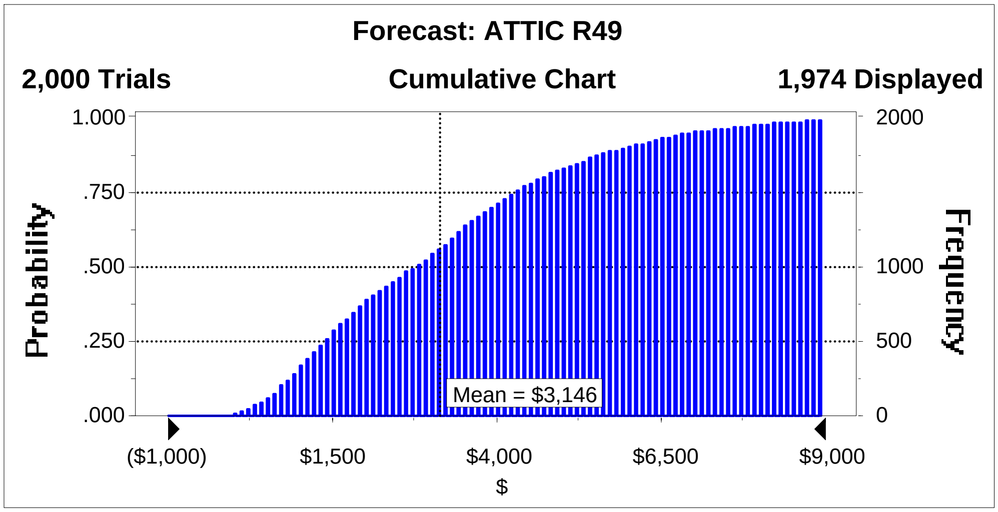

Figure G-202: Climate Zone 3 Net Present Value Results for Manufactured Homes for R49 Attics

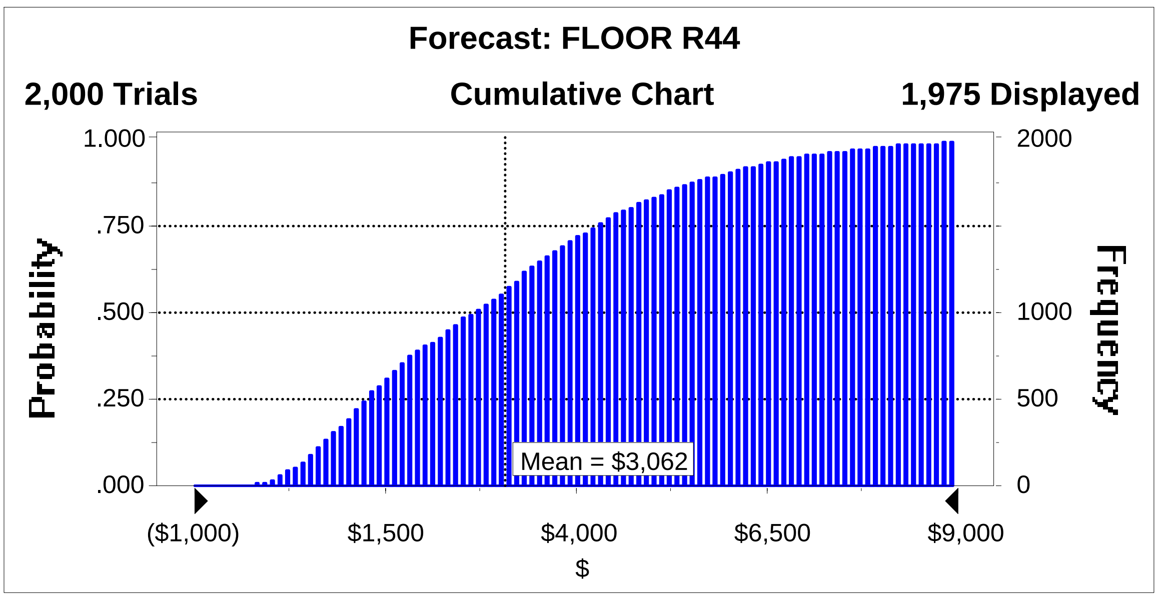

Figure G-203: Climate Zone 3 Net Present Value Results for Manufactured Homes for R44 Floors

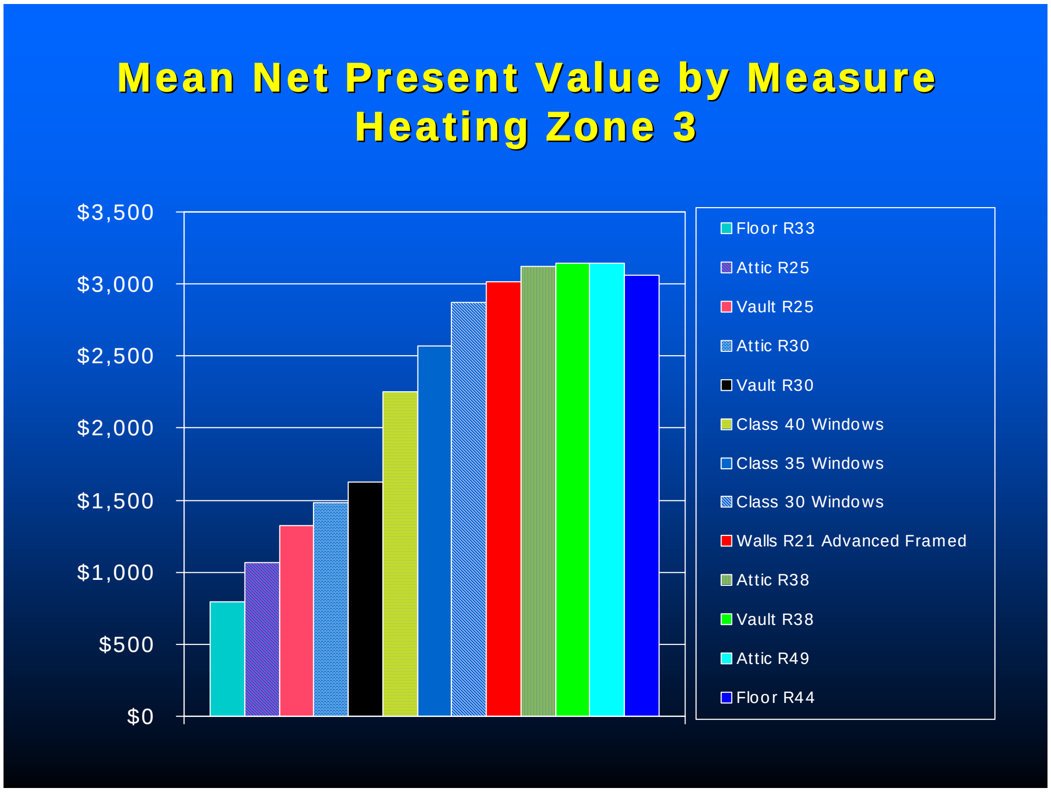

Figure G-204: Climate Zone 3 Expected Value Mean Net Present Value Results for Manufactured Homes

Demand Response Assessment

INTRODUCTION

This appendix provides more detail on some of the topics raised in Chapter 4, "Demand Response" of the body of the Plan. These topics include

1. The features, advantages and disadvantages of the main options for stimulating demand response (price mechanisms and payments for reductions)
2. Experience with demand response, in our region and elsewhere
3. Estimates of the potential benefits of demand response to the power system

PRICE MECHANISMS

Real-time prices

The goal of price mechanisms is the reflection of actual marginal costs of electricity production and delivery in retail customers' *marginal* consumption decisions. One variation of such mechanisms is "real-time prices" -- prices based on the marginal cost of providing electricity for each hour. This does not mean that every kilowatt-hour customers consume needs to be priced at marginal cost. But it does mean that consumers need to face the same costs as the power system for their *marginal* use.

Real-time prices, if we can devise variations that are acceptable to regulators and customers, have the potential to reach many customers. Real-time prices can give these customers incentives that follow wholesale market costs very precisely every hour. Once established, real-time prices avoid the transaction costs of alternative mechanisms. For all of these reasons, the potential size of the demand response from real-time prices is probably larger than other mechanisms.

However, real-time prices have not been widely adopted for a number of reasons:

1. Most customers would need new metering and communication equipment in order to participate in real-time pricing. Currently, most customers' meters are only capable of measuring total use over the whole billing period (typically a month). Real-time prices would require meters that can measure usage in each hour. Also, some means of communicating prices that change each hour would be required. It's worth noting that more capable meters are also necessary for alternatives such time-of-use metering, and for such programs as short term buybacks and demand side reserves.
2. Currently, there is no source of credible and transparent real-time wholesale prices for our region. Any application of real-time retail prices will need all parties' trust that the prices are fair representations of the wholesale market. The hourly prices from the California PX were used as the basis for some deals in our region until the PX was closed in early 2001, but prices from a market outside our region were regarded as less-than-ideal even while they were still available. Now the Cal PX is closed, and a credible

regional source is needed. This is a problem that affects many of the other mechanisms for demand response[1] as well.

3. Some customers and regulators are concerned that real-time prices would result in big increases in electricity bills. While the argument can be made that such increases would be useful signals to consumers[2], the result could also be big decreases in bills. In either case, however, many customers and regulators are concerned with questions of unfair profits or unfair allocation of costs if real-time prices are adopted. The Council shares this concern.
4. Even if price increases and decreases balance over time, the greater volatility of real-time prices is a concern. Customers are concerned that more volatile prices will make it hard for them to plan their personal or business budgets. Regulators are concerned that more volatile prices will make it a nightmare to regulate utilities' profits at just and reasonable levels. The volatility is moderated if the real-time pricing applies only to marginal consumption, but it is still greater than consumers are used to.
5. Some states' utility regulation legislation constrains the definition of rates (e.g. rates must be numerically fixed in advance, not variable based on an index or formula).

With time, some of these issues can probably be solved, making real-time prices more practical and more acceptable to customers and regulators. For example:

Metering and communication technology has improved greatly. New meters not only offer hourly metering and two-way communication but also other features, such as automatic meter reading and the potential for the delivery of new services, that may make their adoption cost-effective.

Customers and regulators' concerns with fairness and volatility may be relieved by such variations of real-time prices as the Georgia Power program. That program applies real-time prices to <u>increases</u> or <u>decreases</u> from the customer's base level of use, but applies a much lower regulated rate to the base level of use itself. Compared to application of real-time prices to the total use of the customer, this variation reduces the volatility of the total bill very significantly.

Concerns with fairness may also moderate, as it is better understood that "conventional" rates have their own problems with fair allocation of costs among customers.

Time-of-use prices

We could think of "time-of-use prices" -- prices that vary with time of day, day of the week or seasonally -- as an approximation of real-time prices. Time-of-use prices are generally based on the expected average costs of the pricing interval (e.g. 8 a.m. to 6 p.m. January weekdays).

While time-of-use prices, like real-time prices, require meters that measure usage over subintervals of the billing period, they have some advantages over real-time prices. A significant advantage of time-of-use rates is that customers know the prices in advance (usually for a year or

[1] For example, participation in short term buyback programs is enhanced when customers have confidence that their payments are based on a price impartially determined by the wholesale market rather than simply a payment the utility has decided to offer.

[2] For example, bills might rise for those customers whose use is concentrated in hours when power costs are high. While those customers would be unhappy about the change, their increased bills could be seen as an appropriate correction of a traditional misallocation of the costs of supplying them -- traditional rates shifted some of the cost of their service to other customers. Real-time prices would also increase the bills of all customers in years like 2000-2001, when wholesale costs for all hours went up dramatically. While customers are never happy to see bills rise, the advantage of such a <u>prompt</u> rise in prices would be a similarly prompt demand response, reducing overall purchases at high wholesale prices. This is a better result than the alternative of raising rates <u>later</u> to recover the utilities' wholesale purchase costs, after the costs have already been incurred.

more). This avoids the necessity of communication equipment to notify customers of price changes. It also makes bills more predictable, which is desirable to many customers and regulators.

A significant disadvantage, compared to real-time prices, is that prices set months or years in advance cannot do a very good job of reflecting the real-time events (e.g. heat waves, droughts and generator outages) that determine that actual cost of providing electricity. As a result, time-of-use pricing as it has usually been applied cannot provide efficient price signals at the times of greatest stress to the power system, when customers' response to efficient prices would be most useful.

"Critical peak pricing" is a variant of time-of-use pricing that could be characterized as a hybrid of time-of-use and real-time pricing. This variant leaves prices at preset levels, but allows utilities to match the timing of highest-price periods to the timing of shortages as they develop; these variations provide improved incentives for demand response.

Time-of-use prices will affect customers differently, depending on the customers' initial patterns of use and how much they respond to the prices by changing their patterns of use. While customers whose rates go up will be inclined to regard the change as unfair, regulators can mitigate such perceptions with careful rate design and making a clear connection between cost of service and rates.

PAYMENTS FOR REDUCTIONS

Given the obstacles to widespread adoption of pricing mechanisms, utilities have set up alternative ways to encourage load reductions when supplies are tight. These alternatives offer customers payments for reducing their demand for electricity. In contrast with price mechanisms, which vary the cost of electricity to customers, these offers present the customers with varying prices they can receive as "sellers". Utilities have offered to pay customers for reducing their loads for specified periods of time, varying from hours to months or years.

Short-term buybacks

Short-term programs can be thought of as mostly load shifting (e.g. from a hot August afternoon to later the same day). Such shifting can make investment in a "peaking" generator[3] unnecessary. The total amount of electricity used may not decrease, and may even increase in some cases, but the overall cost of service is reduced mostly because of reduced investment in generators and the moderating effect on market prices. Short-term programs can be expected to be exercised and have value in most years, even when overall supplies of energy are plentiful.

Generally, utilities establish some standard conditions (e.g. minimum size of reduction, required metering and communication equipment, and demonstrated ability to reduce load on schedule) and sign up participants before exercising the program. Then, one or two days before the event:

1. The utility communicates (e.g. internet, fax, phone) to participating customers the amount of reduction it wants and the level of payment it is offering.
2. The participants respond with the amount of reduction they are willing to contribute for this event.

[3] A generator that only runs at peak demands and is idle at other times.

3. The utility decides which bids to accept and notifies the respondents of their reduction obligation.
4. The utility and respondents monitor their performance during the event, and compensation is based on that performance.

Generally participants are not penalized for not responding to an offer. However, once a participant has committed to make a reduction there is usually a penalty if the obligation is not met.

Both BPA and PGE regarded their Demand Exchange programs as successful. Between the two programs, participating customers represented nearly 1,000 megawatts of potential reductions. Actual reductions sometimes exceeded 200 megawatts.

As the seriousness of the supply shortage of the 2000-2001 period became clearer, the participation in both utilities' Demand Exchange programs declined, but largely because customers who had been participating negotiated longer-term buybacks instead.

These programs require that customers have meters that can measure the usage during buyback periods. The programs also require that the utility and customer agree on a base level of electricity use from which reductions will be credited. The base level is relatively easy to set for industrial customers whose use is usually quite constant. It's more complicated to agree on base levels for other customers, whose "normal" use is more variable because of weather or other unpredictable influences.

Longer-term buybacks

Longer-term programs, in contrast to short-term buybacks, generally result in an overall reduction of electricity use. They are appropriate when there is an overall shortage of electricity, rather than a shortage in peak generating capacity.

Most utility systems, comprised mostly of thermal generating plants, hardly ever face this situation. If they have enough generating capacity to meet their peak loads, they can usually get the fuel to run the capacity as much as necessary. The Pacific Northwest, however, relies on hydroelectric generating plants for about two-thirds of its electricity. In a bad water year we can find ourselves with generating capacity adequate for our peak loads, but without enough water (fuel) to provide the total electricity needed.

This was the situation in 2000-2001, and the longer-term buybacks that utilities negotiated with their customers were reasonable responses to the situation. We faced an unusually bad supply situation in those years, however. We shouldn't expect to see these longer term buybacks used often even here in the Pacific Northwest, and hardly ever in other regions with primarily thermal generating systems.

Generally, buybacks avoid some of the problems of price mechanisms, and they have been successful in achieving significant demand response. Utilities have been able to identify and reach contract agreements with many candidates who have the necessary metering and communication capability. . The notification, bidding and confirmation processes have worked. Utilities in our region have achieved short-term load reductions of over 200 megawatts. Longer-term reductions of up to 1,500 megawatts were achieved in 2001 when the focus changed because of the energy shortages of the 2000-2001 water year.

In principle, the marginal incentives for customers to reduce load should be equivalent, but buybacks have some limitations relative to price mechanisms. Buybacks generally impose transaction costs by requiring agreement on base levels of use, contracts, notification, and explicit compensation. The transaction costs mean that they tend to be offered to larger customers or easily organized groups; significant numbers of customers are left out. Transaction costs also mean that some marginally economic opportunities will be passed--there may be times when market prices are high enough to justify some reduction in load, but not high enough to justify incurring the transaction cost necessary to obtain the reduction through a buyback.

Demand side reserves

Another mechanism for achieving demand response is "demand side reserves," which can be characterized as options for buybacks.

The power system needs reserve resources to respond to unexpected problems (e.g. a generator outage or surge in demand) on short notice. Historically these resources were generating resources owned by the utility and their costs were simply included in the total costs to be recovered by the utility's regulated prices. Increasingly however, other parties provide reserves through contracts or an "ancillary services" market. In such cases, the reserves are compensated for standing ready to run and usually receive additional compensation for the energy produced if they are actually called to run.

The capacity to reduce load can provide much the same reserve service as the capacity to generate. The price at which the customer is willing to reduce load, and other conditions of his participation (e.g. how much notice he requires, maximum and/or minimum periods of reduction) will vary from customer to customer. In principle, customers could offer a differing amount of reserve each day depending on his business situation.

The California Independent System Operator administers an ancillary services market that has used demand side reserves in some cases. Their early experience has been that most load cannot be treated the same as generating reserve in every detail, but that demand side reserve can be useful. Analysis of their experience is continuing.

The metering and communication equipment requirements, and the need for an agreed-upon base level of use, are essentially the same for demand side reserve participants as for short-term buyback participants. Demand side reserve programs may have a potential advantage to the extent that they can be added to an existing ancillary services market, compared to setting up stand-alone buyback programs.

Payments for reductions -- interruptible contracts

Utilities have negotiated interruptible contracts with some customers for many years. An important example of these contracts was Bonneville Power Administration's arrangement with the Direct Service Industries (DSI), which allowed BPA to interrupt portions of the DSI load under various conditions. In the past, these contracts have usually been used to improve reliability by allowing the utility to cut some loads rather than suffer the collapse of the whole system. Those contracts were used very seldom. Now these contracts can be seen as an available response to price conditions as well as to reliability threats. We can expect that participants and utilities will pay close attention to the frequency and conditions of interruption in future contracts, and we can imagine a utility having a range of contract terms to meet the needs of different customers.

Payments for reductions -- direct control

A particularly useful form of interruptible contract gives direct control of load to the utility. Part of BPA's historical interruption rights for DSI loads was under BPA direct control. Not all customers can afford to grant such control to the utility. Of those who can, some may only be willing to grant control over part of their loads. Direct control is more valuable to the utility, however, since it can have more confidence that loads will be reduced when needed, and on shorter notice. Advances in technology could mean expansion of direct control approaches. The ability to embed digital controls in residential and commercial appliances and equipment make it possible to, for example, set back thermostats somewhat during high cost periods. While the individual reductions are small, the aggregate effect can be large. Consumers typically have the ability to override the setbacks. Puget Sound Energy carried out a limited test of controlling thermostat setback. Most consumers were unaware that any setback had occurred. The adoption of advanced metering technologies for other reasons will facilitate the use of direct control.

SUMMARY OF ALTERNATIVE MECHANISMS

Table H-1 summarizes the alternative mechanisms and some of their attributes. Staff has offered subjective evaluations of each mechanism to stimulate comment and discussion.

Table H-1: Types of Demand Response Programs and Attributes

Type of Program	Primary Objective: Capacity or Energy?	Time span	Size of Potential Resource	Flexible for Customer?	Flexible for Utility?	Predictable, Reliable Resource for Utility?
Real-time Prices	Both	One hour to several hours	+++ (depending on extent applied)	++	++	-
Time-of-use Prices	Capacity	Several hours	++	++	--	-
Short Term Buybacks	Capacity	Several hours (possibly more)	++	++	+	+ (once customer committed)
Long Term Buybacks	Energy	Several months	+	--	--	+++
Standing Offer (e.g. 20/20)	Energy	Several months	+	++	--	-
Demand side reserves	Capacity	Hours or longer	+	++	++	+
Interruptible Contracts	Capacity	Hours or longer	+	--	++	++
Direct Control	Capacity	Minutes, Hours or longer	+	---	+++	+++

For example, staff's evaluation suggests that time-of-use prices:

- have significant potential for load reduction, but somewhat less than real-time prices;
- have the primary objective of reducing capacity requirements;
- are flexible for the customer -- the customer can decide how to respond depending on his real time situation;
- are relatively inflexible for the utility -- it is committed to the price structure in advance for an extended period;
- is not a very predictable resource for the utility – customers' response may vary from one day to the next (although more experience may help the utility predict that response more accurately).

Or, long term buybacks:

- have significant potential for load reduction, but less than time-of-use prices;
- have the primary objective of reducing energy requirements;
- are relatively inflexible for both customer and utility (because they are both committed to the terms of the buyback over a long term)
- are a predictable resource for the utility (once the contract is signed).

EXPERIENCE

Experience with demand response is growing constantly, so that any attempt to describe it comprehensively is likely to be incomplete and is certain to go out of date quickly. Rather than attempt a comprehensive account, this section presents a number of significant illustrations of experience around the U.S.

RTP Experience

Georgia Power

Georgia Power has 1,700 customers on real-time prices. These customers, who make up about 80 percent of Georgia Power's commercial and industrial load (ordinarily, about 5,000 megawatts), have cut their load by more than 750 megawatts in some instances. The program uses a two-part tariff, which applies real-time prices to <u>increases</u> or <u>decreases</u> from the customer's base level of use, but applies a much lower regulated rate to the base level of use itself. As a result, the total power bills don't vary in proportion to the variation of the real-time prices, but customers do have a "full strength" signal of the cost of an extra kilowatt-hour of use (and symmetrically, the value of a kilowatt-hour reduction in use).

Duke Power

Duke Power has a similar two-part tariff that charges real-time prices to about 100 customers with about 1,000 megawatts of load. Duke has observed reductions of 200 megawatts in these customers' load in response to hourly prices above 25 cents per kilowatt-hour.

Niagara Mohawk

Niagara Mohawk has a one-part real-time price tariff that charges real-time prices for all use of its largest industrial customers. More than half of the utility's original customers in this class have moved to non-utility suppliers, and many of those remaining have arranged hedges to reduce their vulnerability to volatility of real-time prices.

Critical Peak Pricing Experience

Gulf Power

Gulf Power offers a voluntary program for residential customers that includes prices that vary by time of day along with a programmable control for major electricity uses (space heating and cooling, water heating and pool pump, if present). While this program mostly falls in the "time-of-use pricing" category to be described next, it has an interesting component that is similar to real-time pricing--"Critical" price periods:

The Critical price (29 cents per kilowatt-hour) is set ahead of time, like the Low (3.5 cents), Medium (4.6 cents) and High (9.3 cents) prices, but unlike the other prices, the hours in which the Critical price applies are not predetermined. The customer knows that Critical price periods will total no more than 1 percent of the hours in the year, but not when those periods will be, until 24 hours ahead of time. Gulf Power helps customers program their responses to Critical periods ahead of time, although they can always change their response in the event.

Customers appear very satisfied by this Gulf Power program. Customers in the program reduced their load 44 percent during Critical periods, compared to a control group of nonparticipants.

TOU Experience

The Pacific Northwest

Puget Sound Energy offered a time-of-use pricing option for residential and commercial customers. There are about 300,000 participants in the program. PSE's analysis indicates that this program reduced customers' loads during high costs periods by 5-6 percent. However, analysis showed that most customers paid slightly more under time-of-use pricing than they would have under conventional rates. PSE has ended the program, though a restructured program might be proposed later if careful analysis suggests it would be effective.

In Oregon, time-of-use pricing options have been offered to residential customers of Portland General Electric and PacifiCorp since March 1, 2002. So far about 2,800 customers have signed up, and early measures of satisfaction are encouraging, but data are not yet available on any changes in their energy use patterns.

California

Time of use rates are now required for customers larger than 200 kilowatts, and critical peak pricing is available for those customers. The effect of the critical peak prices on customers who have selected that option is estimated to provide a load reduction potential of about 16 megawatts in 2004.

A pilot program testing the effectiveness of critical peak pricing for residential customer is completing its second year. Analysis of the first year's experience estimated own price elasticities of peak demand in the –0.1 to –0.4 range, similar to the results of the Electric Power Research Institute study described below.

There have been many other time-of-use pricing programs elsewhere in the U.S. Rather than describe a number of examples, it should suffice to say that a study funded by the Electric Power Research Institute concluded that 25 years of studies indicated that "peak-period own-price elasticities range from -0.05 to -0.25 for residential customers, and -0.02 to -0.10 for commercial and industrial customers." Stripped of the jargon, this means that a time-of-use rate schedule that increases peak period rates by an assumed 10 percent would lead to a 0.5 to 2.5 percent reduction in residential peak use, and a 0.2 to 1.0 percent reduction in commercial and industrial peak use. While the assumed 10 percent rate increase is only illustrative, it is not exaggerated; PSE's peak time rates are about 10 percent higher than its average rates, and PGE's peak time rates are 67 percent higher than its average rates.

Short-term Buyback Experience

The historical experience with demand response is limited, and most of it is from short-term situations of tight supply and/or high prices (i.e. episodes of a few hours in length). Therefore we'll examine the potential for short-term demand response first, and turn to longer-term demand response later.

Pacific Northwest

B.C. Hydro offered a form of short-term buyback as a pilot program quite early -- in the winter of 1998-1999. The utility offered payment to a small group of their largest customers for reductions in load. The offer was for a period of hours when export opportunities existed and B.C. Hydro had no other energy to export. Compensation was based on a "share the benefits" principle, sharing the difference between the customers' rates and the export price equally between B.C. Hydro and the customer.

The program was exercised once during the pilot phase, realizing about 200 megawatts of reduction. The overall evaluation of the program was positive and it has been adopted as a continuing program by B.C. Hydro.

Bonneville Power Administration, Portland General Electric and some other regional utilities offered another form of short-term buyback beginning in the summer of 2000. This program was called the Demand Exchange. The Demand Exchange was mostly limited to large industrial customers who had the necessary metering and communication equipment and who had demonstrated their ability to reduce load on call. Participating customers represented over 1,000 megawatts of potential reductions, and over 200 megawatts of reductions were realized in some events.

An exception to the focus on large customers was the participation of Milton-Freewater Light and Power, a small municipal utility with about 4,000 customers. Milton-Freewater participated by controlling the use cycles of a number of their customers' residential water heaters.

California

Investor-owned utilities in California have over 1,600 megawatts of demand response available in June 2004. Over 1,000 megawatts of that total are in interruptible contracts, with about 300 megawatts in air conditioning cycling and smart thermostat programs, about 150 megawatts in demand bidding programs and the remainder in critical peak pricing and backup generation programs.

The California Independent System Operator (CAISO) has reduced its demand response programs in recognition of the programs offered by California utilities and the California Power Authority. The CAISO continues its "Participating Load Program (Supplemental and Ancillary Services)," which includes demand reductions as a source of supplemental energy and ancillary services (non-spinning reserves and replacement reserves). In this program demand reductions are bid into the ancillary services market similarly to generators' capacity and output.

The California Power Authority offers a variant of interruptible contract, with capacity payments every month based on the customer's commitment to reduce load, and energy payments based on actual reductions when the customer is called upon to do so. In June of 2004 this program was estimated to have a demand reduction capability of over 200 megawatts.

New York Independent System Operator

The New York Independent System Operator (NYISO) has three demand response programs, the Emergency Demand Response Program (EDRP), the Day-Ahead Demand Response Program (DADRP) and Installed Capacity Special Case Resources (ICAP SCR).[4]

The EDRP is, as the name suggests, an emergency program that is exercised "when electric service in New York State could be jeopardized." Participants are normally alerted the day before they may be called upon to reduce load; they are usually notified that reductions are actually needed at least 2 hours in advance. Participants are expected, but not required, to reduce their loads for a minimum of four hours, and are compensated at the local hourly wholesale price, or $500 per megawatt hour, whichever is higher. Reductions are calculated as the difference between metered usage in those hours and the participants' calculated base loads (CBLs), which are based on historical usage patterns.

The DADRP allows electricity users to offer reductions to the NYISO in the day-ahead market, in competition with generators. If the reduction bid is accepted, the users are compensated for reductions based on the area's marginal price. The users are obligated to deliver the reductions and are charged the higher of day-ahead or spot market prices for any shortfall in performance.

The ICAP SCR program pays qualified electricity users for their <u>commitment</u> to reduce loads if called upon during a specified period, "during times when the electric grid could be jeopardized." Users receive additional payments when they are actually called and deliver reductions, at rates up to $500 per megawatt hour. Qualified electricity users cannot participate in both the EDRP and the ICAP SCR at the same time, and ICAP SCR resources are called first.

During the summer of 2003, these NYISO programs resulted in the payment of more than $7.2 million to over 1,400 customers, who reduced their peak electricity loads by 700 megawatts.

PJM Interconnection

PJM Interconnection is the regional transmission operator of a system that covers 8 Mid Atlantic and Midwestern states and the District of Columbia. It serves a population of about 35 million, with a peak load of about 85,000 megawatts. PJM has operated demand response programs for several years.

PJM's demand response programs are categorized as "Emergency" and "Economic" options. PJM takes bids from end-use customers specifying reduction amounts and compensation

[4] For more details, see http://www.nyiso.com/services/documents/groups/bic_price_responsive_wg/demand_response_prog.html

requirements for the next day. These bids are considered alongside bids from generators, and demand reduction bids can set the market clearing "locational marginal price" (LMP, the marginal cost of service for each zone in the system) in the same way as a generator's bid. Load reductions in their "Emergency" category are paid at each hour's LMP, or $500 per megawatt-hour, whichever is greater. Load reductions in their "Economic" category are paid the LMP less the retail rate if the LMP is less than $75 per megawatt-hour, or the whole LMP if it is higher than $75 per megawatt-hour.

PJM also has an "Active Load Management" (ALM) program that compensates customers for: allowing PJM to have direct control of some loads; committing to reduce loads to a specified level; or committing to reduce loads by a specified amount.

In total PJM demand response programs had over 2,000 megawatts of potential load reductions participating in 2003, and over 3,500 megawatts of potential load reductions in 2004.

ISO New England

The Independent System Operator (ISO) of the New England Power Pool operates the electrical transmission system covering the 6 New England states, with a population of 14 million people and a peak load of over 25,000 megawatts. Its demand response programs had 400 megawatts of capacity in 2004, about double the capacity in 2002.

ISO New England demand response programs share some features with those of the NYISO and PJM, in that they fall into "economic" and "reliability" categories. The "economic" category is voluntary -- qualified customers[5] are notified when the next day's wholesale price is expected to be above $.10 per kilowatt-hour for some period. They can voluntarily reduce their load during that period and be compensated at the greater of the real time wholesale price, or $.10 per kilowatt-hour. Their reduction is computed based on their recent load history, adjusted for weather conditions. There is no penalty for choosing not to reduce load for these customers.

In the "reliability" category customers can commit to reducing load at the call of the ISO, and be compensated based on the capacity they have committed and the energy reduction they actually deliver when called upon. The compensation for capacity (ICAP) is based on a monthly auction. The compensation for energy is the greater of the real time price or a minimum of $.35 or $.50 per kilowatt-hour, depending on whether the customer is committed to responding in 2 hours or 30 minutes, respectively. If a customer does not deliver the committed reduction it is compensated for energy reduction based on the actual performance, but the ICAP payment is reduced to the level of delivered reduction. The ICAP payment remains at that reduced level until another load reduction event; the customer's performance in that event resets the ICAP level higher or lower.

ISO New England recently issued a request for proposals to remedy a localized shortage of generation and transmission in Southwest Connecticut. It selected a combination of resources that included demand response amounting to 126 megawatts in 2004 and rising to 354 megawatts in 2007. These resources were called on in August of 2004 and delivered over 120 megawatts within 30 minutes. In that event, roughly another 30 megawatts of load reduction were realized elsewhere in ISO New England's territory.

[5] Customers with the ability to reduce loads by 100 kilowatts, with appropriate metering and communication equipment.

Longer-term Buyback Experience

As high wholesale prices and the drought in the Pacific Northwest continued, utilities began to negotiate longer-term reductions in load with their customers. BPA found the largest reductions, mostly in aluminum smelters but also in irrigated agriculture. Idaho Power, PGE, the Springfield Utility Board (SUB) and the Chelan Public Utility District negotiated longer-term reductions with large industrial customers. Idaho Power, Grant County Public Utility District and Avista Utilities negotiated longer-term reductions with irrigators. The total of these buybacks varied month to month but reached a peak of around 1,500 megawatts in the summer of 2001.

There were also "standing offer" buybacks offered by several utilities in 2001. Most of these offers were to pay varying amounts for reductions compared to the equivalent billing period in 2000. The general structure of these offers was a further savings on the bill if the reduction in use was more than some threshold. For example, a "20/20" offer gave an additional 20 percent off the bill if the customers' use was less than 80 percent of the corresponding billing period in 2000. Since the customer's bill was reduced more or less proportionally to his usage already, this amounted to roughly doubling his marginal incentive to save electricity. Utilities usually reported that many customers qualified for the discounts. However, attributing causation to the standing offers vs. quick-response conservation programs many utilities were running at the same time vs. governors' appeals for reductions, etc. is very difficult.

The Eugene Water and Electric Board had a standing offer that based its incentives more directly on current market prices. From April through September of 2001, 29 of EWEB's larger customers were paid for daily savings (compared to the corresponding day in 2000) based on the daily Mid-Columbia trading hub's quotes for on-peak and off-peak energy. Customers reduced their use of electricity by an average of 14 percent, and divided a total savings of $6.5 million with the utility.

ESTIMATES OF POTENTIAL BENEFITS OF DEMAND RESPONSE

Potential size of resource

One way to arrive at a rough estimate of short-term demand response is to use price elasticities[6] that have been estimated based on response to real-time prices elsewhere. Though we're unlikely to rely on real-time prices, at least in the near future, the other instruments we've described can provide similar incentives[7], resulting in similar demand reductions.

Price elasticities have been estimated based on data from a number of American and other utilities. The elasticities vary from one customer group and program to another, from near zero to greater than -0.3. For example, we can assume, conservatively:

1. a -0.05 elasticity as the lower bound of overall consumer responsiveness,
2. a $60 per megawatt hour average cost of electricity divided equally between energy cost and the cost of transmission and distribution
3. a $150 per megawatt hour cost of incremental energy at the hour of summer peak demand, and

[6] Price elasticity is a measure of the response of demand to price changes -- the ratio of percentage change in demand to the percentage change in price. A price elasticity of –0.1 means that a 10 percent increase in price will cause a 1 percent decrease in demand.

[7] For example, a customer with conventional electricity rate of $0.06 per kilowatt-hour might get a buyback offer of $0.15 per kilowatt-hour in a given hour. A real-time price of $0.21 per kilowatt hour would offer a similar incentive to reduce use in that hour -- in either case he is better off by $0.21 for each kilowatt hour reduction.

4. a 30,000 megawatts regional load at that hour.

For these conditions, the amount of load reduction resulting from real-time prices would be 1,603 megawatts[8]. Actual elasticities could well be larger and actual prices seem quite likely to be higher on some occasions. In either of these cases, the load reduction would be increased.

This very rough estimate could be refined, although the basic conclusion to be drawn seems clear – even if this estimate is wrong by a factor of 2 or 3, the potential is significant, and demand response should be pursued further.

The Value of Load Reduction (avoided cost)

The primary focus of analysis was the estimation of costs avoided by demand response. These avoided costs establish the value of demand response, and provide guidance for incentive levels in demand response programs.

We used three different approaches to the estimation of avoided cost. Each of these approaches has shortcomings, but together they suggest very strongly that development of demand response will reduce total system cost and reduce risk.

The first two of these estimates focus on the costs of meeting peak loads of a few hours' duration ("capacity problems"). These are not the only situations in which demand response can be useful, but they are the most common. These estimates address the net power system costs of serving incremental load, in a world of certainty.

If our region faced a fully competitive power market, the cost avoided by demand response would be the hourly price of power in that market. Over the long run, hourly prices at peak hours should tend to approach the fully allocated net cost of peaking generators built to serve those peak hours' loads. Even if prices are capped and the construction of peaking generators is encouraged by incentives such as capacity payment, the system costs avoided by load reductions should tend toward the net cost of a new generator. Approaches 1 and 2 estimate these net costs using contrasting methodologies.

Approach 1: Single utility, thermal generation

Approach 1 assumes that the power system is a single utility with an hourly distribution of demands similar to the Pacific Northwest. Further it assumes that the generating system is made up of thermal generators, with marginal peaking generators that are new single cycle combustion turbines or "duct firing" additions to new combined cycle combustion turbines. The assumed costs and other characteristics of these generators are taken from The NW Power Planning Council's standard assumptions for new generating resources.[9]

[8] Using the convention that the percentage changes in demand and price are $\ln(D_2/D_1)$ and $\ln(P_2/P_1)$, respectively, we can calculate the new demand $D_2 = \exp(-0.05*\ln(180/60) + \ln(30,000)) = 28,397$ megawatts. The reduction from the initial peak demand of 30,000 megawatts is 1,603megawatts.

[9] These assumptions are documented in the *Northwest Power Planning Council New Resource Characterization for the 5th Power Plan.* The duct firing and simple cycle combustion turbine generators cited in this paper are covered in sections on "Natural Gas Combined Cycle Gas Turbine Power Plants" and "Natural Gas Simple Cycle Gas Turbine Power Plants." These documents are available on request from the Council--contact the author.

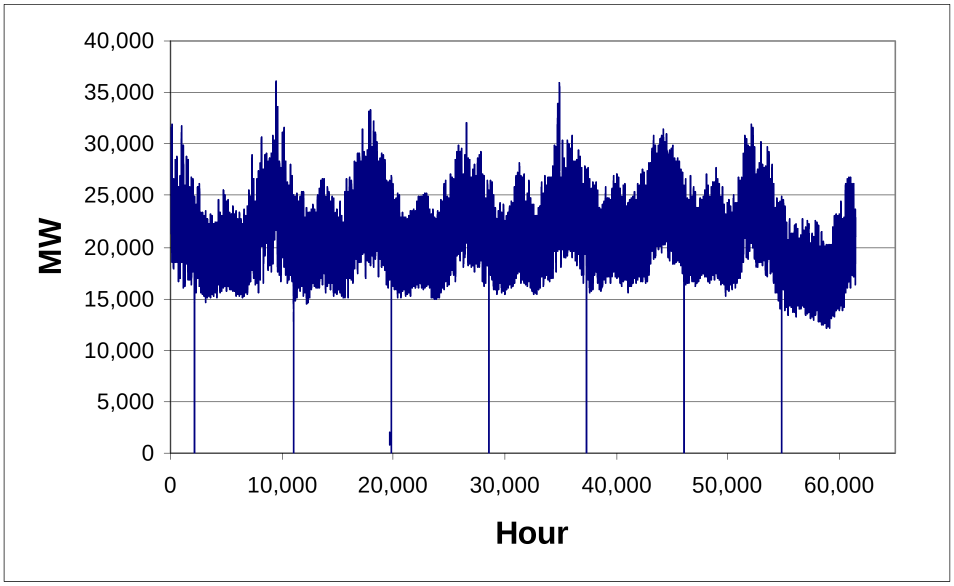

Figure H-1: Pacific Northwest Hourly Loads 1995-2001

In our assumed utility the cost of serving each increment of load depends on how many hours per year that load occurs. We must therefore examine the hourly distribution of loads. The Pacific Northwest hourly loads shown in Figure H-1 are loads from January 1, 1995 through December 31, 2001. The loads demonstrate that the Pacific Northwest is a winter-peaking system. The highest hourly load in the 7-year period shown is 36,118 megawatts in hour 8 of February 2, 1996 (hour 9536), and loads reach nearly 36,000 NW in several hours in December of 1998 (between hours 34,808 and 34,834). There is considerable year-to-year variation in peak loads; peak loads were below 32,000 megawatts in 1995, 1999 and 2000.

When we rearrange the same data, by ordering hourly loads from highest to lowest, we form a "load duration curve" shown in Figure H-2. Figure H-3 shows the first 700 hours in Figure 2, that is, the highest 700 hourly loads. These data let us focus on the amount of generating capacity that is used just a few hours each year to serve the highest loads.

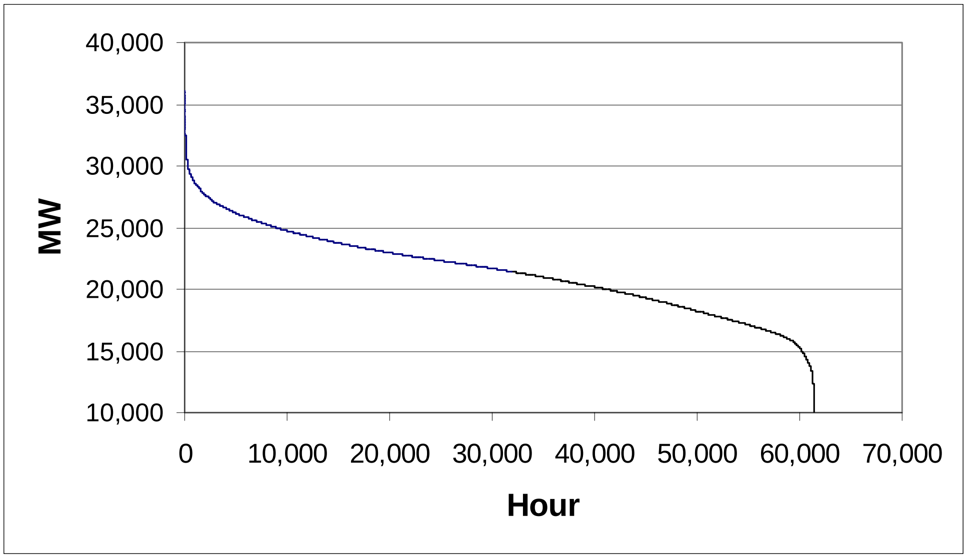

Figure H-2: Pacific Northwest Load Duration Curve 1995-2001

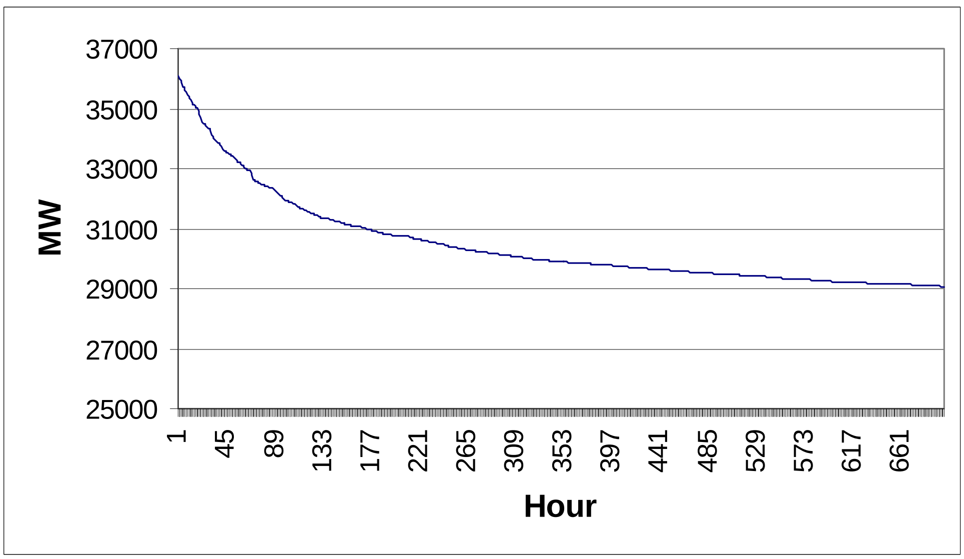

Figure H-3: Loads of Highest 700 hours 1995-2001

Referring to the data underlying Figure H-3, the highest load in the 7-year period is 36,118 megawatts. Of that peak load, 500 megawatts of load needs to be served only 7 hours (1 hour per year on average), 1,563 megawatts of load is served only 21 hours (3 hours per year on average), 3,500 megawatts is served 70 hours (10 hours per year on average), and so forth.

What does it cost to serve this load? Since incremental generators necessary to serve the load operate for different numbers of hours per year, each one has its own cost per megawatt-hour, declining as hours of operation per year increase. Let's look at two levels of use, 10 hours per year and 100 hours per year.

Based on the Council's generating cost data base, the cost of new[10] peaking generators used 10 hours per year is $6,489 per megawatt hour ($6.49 per kilowatt hour) for duct burner attachments on combined cycle combustion turbines, and $11,442 per megawatt hour ($11.44 per kilowatt hour) for simple cycle combustion turbines. The generators operating less than 10 hours will of course have even higher costs per megawatt-hour than these estimates.

The 700th highest hour's load in Figure 3 is 29,076 megawatts. This means that there are 3,542 megawatts of load that need to be served more than 10 hours but less than 101 hours per year. The same Council cost data cited above indicate that new peaking generators that are used 100 hours per year cost $677 per megawatt hour ($0.68 per kilowatt hour) for duct firing and $1,179 ($1.18 per kilowatt hour) for simple cycle combustion turbines. That means that serving peak loads between 29,076 megawatts and 32,618 megawatts by building and operating new peaking generators costs between $0.68 per kilowatt hour and $11.44 per kilowatt hour, depending on which type of generator is used and whether its hours of use are closer to 10 hours per year or 100 hours per year. All of these costs are much higher than retail electricity prices, which run in the $0.05-0.10 per kWh range in our region.

To summarize, the assumption of a single utility, Pacific Northwest hourly loads and new thermal resources leads to the conclusions:

1. The highest 70 hourly loads in the 1995-2001 period require about 3,500 megawatts of peaking generation to serve. Load reductions that made it unnecessary to serve these loads would save at least $6.49 per kilowatt-hour.
2. The next highest 630 hourly loads in the 1995-2001 period require about 3,542 megawatts of peaking generation to serve. Load reductions that made it unnecessary to serve these loads would save between $0.68 and $6.49 per kilowatt-hour.

Limitations of this analysis

This analysis used simplifying assumptions that let us focus on the concepts involved, but excluded some features of the real world, possibly influencing the results. What assumptions deserve consideration for a more refined analysis?

Hydroelectric resources

The initial analysis assumed that the generating system was made up entirely of thermal resources. In fact, hydroelectric generators provide more than half of the electrical energy of the Pacific Northwest power system. Hydroelectric resources look like baseload generators in some respects--their cost structure is high capital cost/low variable cost, like nuclear plants.

But in other respects, hydro resources lend themselves to use as peaking resources. Their output can vary quickly to follow loads' short-term variation. Our hydro system was built with a lot of generating capacity to take advantage of years when more-than-normal precipitation makes more energy production possible. By using their reservoirs, hydro resources can even store energy generated by baseload thermal units and release it to meet peak loads, within limits.

Finally, the total energy available from the hydro system varies, depending on variation in seasonal and annual precipitation. In our power system a thermal peaking generator may operate

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[10] Operating an existing peaking plant, once the fixed costs are incurred, is much cheaper. The greatest savings offered by demand response is as an alternative to building a new generating plant, avoiding the generator's fixed cost.

more like a baseload plant in bad water years, because of a shortage in energy from the hydro system.

These considerations make it desirable to reflect hydro resources' effects in our analysis.

Trade between systems with diverse seasonal loads

The initial analysis assumed that generation served a single utility with an hourly distribution of loads like the Pacific Northwest. Actually, our transmission system links us to other systems (most notably California) that have different load distributions. In the real world peaking generators may very well run to meet winter peak loads in our region, and also to help meet summer peak loads in California. This would tend to increase the use of each peaking generator, spreading its fixed cost over more hours and reducing the average cost of meeting peak loads.

Operational savings of new units

The marginal effect of a new peaking generator added to an existing system to meet peak loads is more complex than we assumed in the initial analysis. The new unit, if it is more efficient than older units, will be operated ahead of them. The result could be that the new unit is operated not just to cover growth in peak loads, but also to reduce operating costs by replacing older units' production. In this case the net cost of meeting incremental peak load is not the fixed and operating costs of the new unit, as we assumed in the initial analysis, but rather the fixed cost of the new unit minus the net operational savings that it makes possible for the system as a whole.

Approach 2: AURORA® simulation of Western power system

The Council uses a proprietary computer model, AURORA®,[11] to project electricity prices and to simulate other effects of changes in the development and operation of the power system. AURORA® simulates the development and operation of the power system of the Western United States and Canada. It takes account of interaction between hydro and thermal generators, trade among the various regions, and the operational interaction among plants of different generating efficiencies; that is, it allows a more realistic set of assumptions than we adopted in Approach 1. We used AURORA® to refine our initial estimate of the net cost of serving incremental peak load.

Our analytical approach was to begin with the Council's baseline projection, noting the amount of electricity service that is projected by AURORA® and the generating costs of the power system. Then we varied the amount of generating capacity, and simulated the operation of the power system again, noting the changes in electricity service and generating costs. We focused on the year 2010 because we appear to have a surplus of generating capacity at the present, and by 2010 AURORA® has arrived at something like equilibrium between supply and demand.

In order to vary the amount of generating capacity, we varied the operating reserve requirements simulated by AURORA® across three levels--6.5 percent, 15 percent and 25 percent. We performed the experiment twice with the same three generating portfolios: once assuming energy output from the Pacific Northwest hydro system based on average precipitation, and again with Pacific Northwest hydro energy based on "critical" precipitation.[12]

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[11] The AURORA® Energy Market Model is licensed from EPIS, Inc.

[12] "Critical" water is used in the Pacific Northwest as the basis of the energy that can be counted as "firm" from the hydro system. Critical water is based a series of bad water years in the 1930s.

The result was three levels of costs and levels of service for average water and three levels of costs and levels of service for critical water, shown in Table H-2.

Table H-2: West-wide Change in Costs and Service from AURORA® Simulations - 2010

Case	Change in System Costs ($thousands)	Change in Electricity Service - megawatt hour	Cost of Change in Service $ per megawatt hour ($ per kilowatt hour)
6.5% -15% Reserve (Average Water)	1,190,262	1,157,188	1029 (1.03)
15% - 25% Reserve (Average Water)	2,467,836	168,793	14,621 (14.62)
6.5% - 15% Reserve (Critical Water)	1,113,170	2,144,813	519 (0.52)
15% - 25% Reserve (Critical Water)	2,420,030	580,653	4,168 (4.17)

Given that Approach 2 is much different in structure and assumptions than Approach 1, it's not surprising that the estimated costs of incremental service are different. However, both approaches show that at high levels of service the cost of serving incremental load can be well over $1,000 per megawatt hour ($1.00 per kilowatt hour). Put another way, both approaches suggest that the power system could save well over $1.00 per kilowatt-hour if it could avoid serving the highest peak loads. In both approaches the cost of serving incremental load rises as we serve the last few hours of the highest peak loads (the highest 10 hours in Approach 1, the highest operational reserves in Approach 2).

Approach 2 lets us examine the effects of variation in output from the hydroelectric system on the results. Other factors equal, overall system costs are higher when we assume critical water than when we assume average water. However, with critical water, less energy is available from the Pacific Northwest hydroelectric system and generators run more hours, spreading their fixed cost and reducing the cost of incremental service per megawatt-hour. Table H-2 doesn't show this, but the absolute levels of service are lower with critical water. The general pattern noted above, of incremental costs rising at higher operational reserves, persists with critical water.

The Council's AURORA® analysis treats the power system of the western U.S. and Canada as made up of 16 regions, with four of these regions corresponding to the Pacific Northwest. Table H-2 shows the total results of all 16 regions, but we also examined the results for the Pacific Northwest, shown in Table H-3.

Table H-3: Pacific Northwest Change in Cost and Service from AURORA Simulations - 2010

Case	Change in System Costs ($thousands)	Change in Electricity Service MWh	Cost of Change in Service $ per megawatt hour ($ per kilowatt hour)
6.5% -15% Reserve (Average Water)	-2,112	328,705	-6 (-0.01)
15% - 25% Reserve (Average Water)	7,346	50,386	146 (0.15)
6.5% - 15% Reserve (Critical Water)	29,756	596,896	50 (0.05)
15% - 25% Reserve (Critical Water)	131,323	112,299	1,169 (1.17)

These results are markedly different than the results for the whole West. The costs of incremental service shown in the last column are much lower than in Table H-2, and even include a negative cost. This seemed unreasonable at first, but after more examination of the detailed results it became clear that the Pacific Northwest added relatively less generating capacity in response to the increased reserve requirements than did the West as a whole.

This is because the heavily hydroelectric power system of the Pacific Northwest already had relatively high reserves. Our hydro system was built with such reserves to cover the variation in river flows as well as concern about serving peak load. The result is that the Pacific Northwest had to invest relatively little fixed cost to meet the 15 percent and 25 percent operational reserve. At the same time, the extra generating reserves throughout the West drove market prices of wholesale electricity down. The Pacific Northwest could reduce operational costs by taking advantage of increased opportunities to buy energy from neighboring regions. These operational cost savings partially offset (and in the "6.5% -15% Reserve (Average Water)" case, more than offset) the increased fixed costs due to new generator investments in the Pacific Northwest.

This example illustrates a more general issue, which is: any region (or utility) will benefit if it can depend on its neighbors' reserves while avoiding some of the fixed costs of those reserves. The temptation for each party to lean on others' reserves will tend to discourage everyone from making such investments, and tend to leave the whole system with less-than-optimal reserves.

What's the implication of this issue for demand response? Avoidance of fixed costs is the main incentive for leaning on neighbors' reserves. To the extent we can identify lower-fixed-cost alternatives to provide reserves, we reduce this incentive. To the extent that demand response comes to be seen as a proven alternative to building peaking generators, the very low fixed cost of demand response would make it less risky for each party to cover its own reserve needs, and more likely that total system reserves are adequate.

Approach 3: Portfolio Analysis of Risk and Expected Cost

Approaches 1 and 2 estimated the avoided cost of serving known loads with known resources. In fact, loads are uncertain because we don't know future weather and economic growth, and the capability of our generating resources is uncertain because of unplanned outages, variation in rain and snowfall, among other factors. In addition, the region's utilities buy and sell into an electricity market that includes the western U.S. and Canada, making market prices a further source of uncertainty. For these and other reasons, the Council adopted a long-term portfolio analysis in formulating the Fifth Power Plan. Approach 3 used the Council's portfolio analysis model to make a third estimate of the value of demand response to the system.

The Council's portfolio methodology is described in Chapters 6 and 7 of the Plan, and in more detail in Appendix L. To evaluate the effect of demand response on risk and expected cost, the Council's portfolio model was run with and without demand response, and the resulting shift in the efficient frontier of portfolios was analyzed. This analysis was described briefly in Chapter 7.

For the "with" demand response portfolio analysis, Council staff assumed a block of 2,000 megawatts of load reduction is available by 2020, with an initial fixed cost of $5,000 per megawatt, a maintenance cost of $1,000 per megawatt per year and a variable cost of $150 per megawatt-hour when the load reduction is actually called upon.[13] The "without" demand response assumed that no demand response is available.

The portfolio model simulated 750 20-year futures with demand response available 16 years in each future. Demand response was used in 83 percent of years in which it is available, but the amount of demand response used is usually quite small. In 85 percent of the years in which demand response is used, it is used less than 0.1 percent of its capability (i.e. less than 9 hours per year). According to the portfolio model's simulations, demand response is used more than 10 percent of its capability (equivalent to about 870 hours per year) in about 5 percent of all years.

The effect of removing demand response on the efficient frontier is demonstrated in Figure H-4. The efficient frontier is shifted from the "Base Case" up and to the right to "No Demand Response," reflecting increases in both expected cost and risk. The amount of the shift varies along the frontier, but in general the loss of demand response increases expected cost by more than $300 to more than $500 million for constant levels of risk. Expressed another way, the loss of demand response increases risk in the range of $350 to $650 million at given levels of expected cost. These increases in expected cost and risk are largely due to increased purchases from the market at times of high prices and to the cost of building and operating more gas-fired generation.

[13] This assumption is simpler than reality, since the variety of load reduction opportunities mean that there is really a supply curve for demand response, with more response available at higher costs.

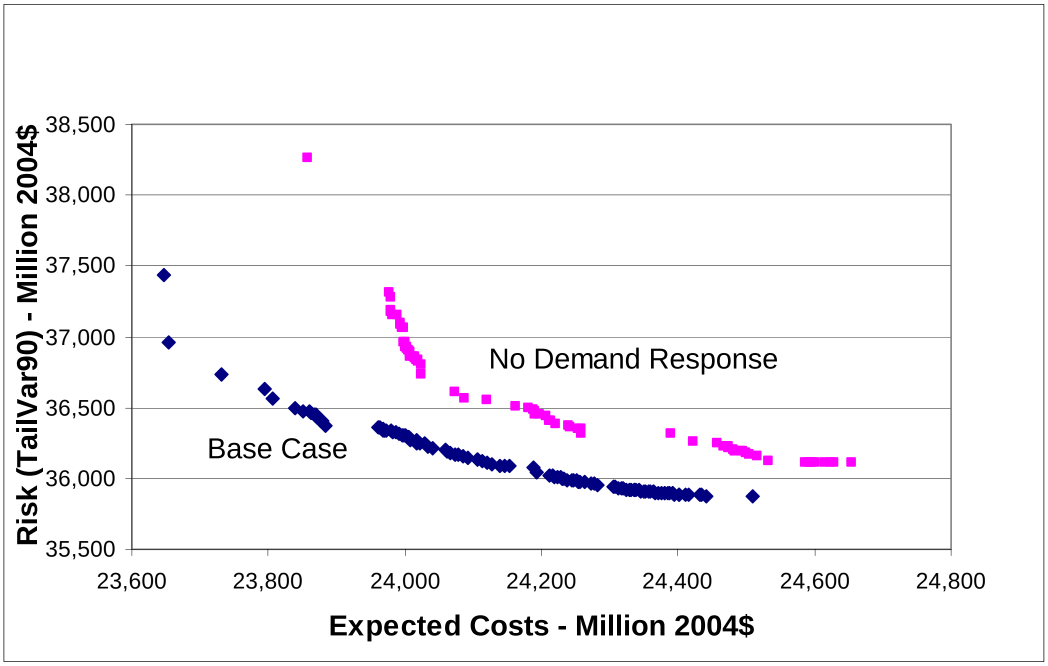

Figure H -4: Effect of Demand Response on Efficient Frontier

Summary of Analysis on Value of Load Reduction

Each of the approaches to estimating the value of load reduction has its own strengths and limitations, but the general conclusions are quite robust: Demand response offers very significant potential value to the region. As laid out in Chapter 4 and in the Action Plan, there are a number of areas that need further experience and analysis in order for the region to realize that potential value, but the analysis presented here is evidence that the effort to acquire that experience and perform that analysis is very worthwhile.

Bulk Electricity Generating Technologies

This appendix describes the technical characteristics and cost and performance assumptions used by the Northwest Conservation and Power Council for resources and technologies expected to be available to meet bulk power generation needs during the period of the power plan. These resources and technologies are explicitly modeled in the Council's risk and reliability models and are characterized in the considerable detail required by these models. Other generating resources and technologies are described in Appendix J - Cogeneration and Distributed Generation. The intent of this appendix is to characterize typical facilities, recognizing that actual projects will differ from these assumptions in the particulars. These assumptions are used in for the Council's price forecasting, system reliability and risk assessment models, for the Council's periodic assessments of system reliability and for the assessment of other issues where generic information concerning power plants is needed.

PROJECT FINANCING

Project financing assumptions are shown in Table I-1 for three types of possible project owners. Because the Council's plan is regional in scope, assumptions must be made regarding the expected mix of ownership for each resource. For the purpose of electricity price forecasting, the Council uses the weighted average of the expected mix of project owners for each resource type. For example, trends suggest that most wind projects will continue to be developed by independent power producers. Thus the "expected mix" for future wind capacity is 15 percent consumer-owned utility, 15 percent investor-owned utility and 70 percent independent power producer. For comparative evaluation of resources, including the portfolio analysis and the benchmark prices appearing in the plan, the Council uses a "standard" ownership mix. This consists of 20 percent consumer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer ownership. The expected mix of project owners is provided in the tables of resource modeling characteristics appearing in this appendix.

Table I-1: Project financing assumptions

Developer:	Consumer-owned Utility	Investor-owned Utility	Independent Developer
General			
General inflation	2.5%		
Debt financing fee	2.0%		
Project financing terms			
Debt repayment period	30 years	30 years	15 years
Capital amortization period		20 years	20 years
Debt/Equity ratio	100%	50%/50%	Development: 0%/100% Construction: 60%/40% Long-term: 60%/40%

Developer:	Consumer-owned Utility	Investor-owned Utility	Independent Developer
Interest on debt (real/nominal)	2.3%/4.9%	4.7%/7.3%	Development: n/a Construction: 3.9%/6.5% Long-term financing: 5.2%/7.8%
Return on equity (real/nominal)		8.3/11%	12.2/15%
After-tax cost-of-capital (real/nominal)	2.3 %/4.9%	5.0%/7.7%	6.1%/8.9%
Discount Rate (real/nominal)	2.3 %/4.9%	5.0%/7.7%	6.1%/8.9%
Taxes & insurance			
Federal income tax rate	n/a	35%	35%
Federal investment tax credit	n/a	0%	0%
Tax recovery period	n/a	20 years	20 years
State income tax rate	n/a	5.9%	5.9%
Property tax	0%	1.4%	1.4%
Insurance	0.25%	0.25%	0.25%

FUEL PRICES

The price forecasts for coal, fuel oil and natural gas are described in Appendix B.

COAL-FIRED STEAM-ELECTRIC PLANTS

Coal-fired steam-electric power plants are a mature technology, in use for over a century. Coal is the largest source of electric power in the United States as a whole, and the second largest supply component of the western grid. Over 36,000 megawatts of coal steam-electric power plants are in service in the WECC region[1], comprising about 23 percent of generating capacity. Beginning in the late 1980s, the economic and environmental advantages of combined-cycle gas turbines resulted in that technology eclipsing coal-fired steam-electric technology for new resource development in North America. Less than 500 megawatts of new coal-fired steam electric plant has entered service on the western grid since 1990.

The prospect for coal-generated electricity is changing. The economic and environmental characteristics of coal-fired steam-electric power plants have improved in recent years and show evidence for continuing evolutionary improvement. This, plus stable or declining coal prices and high natural gas prices are reinvigorating the competition between coal and natural gas. Over 960 megawatts of new coal steam capacity are currently under construction in the WECC region.

[1] WECC is the reliability council for the western interconnected grid, extending from British Columbia and Alberta on the north to Baja California, Arizona, New Mexico and the El Paso area in the south.

Technology

The pulverized coal-fired power plant is the established technology for producing electricity from coal. The basic components of a steam-electric pulverized coal-fired power plant include a coal storage, handling and preparation section, a furnace and steam generator and a steam turbine-generator. Coal is ground to dust-like consistency, blown into the furnace and burned in suspension. The energy from the burning coal generates steam that is used to drive the steam turbine-generator. Ancillary equipment and systems include flue gas treatment equipment and stack, an ash handling system, a condenser cooling system, and a switchyard and transmission interconnection. Environmental control has become increasingly important and newer units are typically equipped with low-NOx burners, sulfur dioxide removal equipment, filters for particulate removal and closed-cycle cooling systems. Selective catalytic reduction of NOx and CO emission is becoming increasingly common and post-combustion mercury control is expected to be required in the future. Often, several units of similar design will be co-located to take advantage of economies of design, infrastructure, construction and operation. In the west, coal-fired plants have generally been sited near the mine-mouth, though some plants are supplied with coal by rail at intermediate locations between mine-mouth and load centers.

Most North American coal steam-electric plants operate at sub-critical steam conditions. Supercritical steam cycles operate at higher temperature and pressure conditions at which the liquid and gas phases of water are indistinguishable. This results in higher thermal efficiency with corresponding reductions in fuel cost, carbon dioxide production, air emissions and water consumption. Supercritical units are widely used in Europe and Japan. Some were installed in North America in the 1960s and 70s but the technology was not widely adopted because of low coal costs and the poor reliability of some early units. Recent European and Japanese experience has been satisfactory[2] and many believe that supercritical technology will penetrate the North American market over the next couple of decades. We assume that future pulverized coal steam electric power plants will move toward the greater use of supercritical steam cycles. For purposes of forecasting the cost and performance of advanced technology, we assume full penetration of supercritical technology within 20 years at a cost penalty of 2 percent and a heat rate improvement of 5 percent[3] (World Bank, 1998).

Economics

The cost of power from a coal gasification power plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. Coal-fired power plants are a capital-intensive generating technology. A relatively large capital investment is made for the purpose of using relatively low-cost fuel. Though they can be engineered to provide load following, capital-intensive technologies are normally used for baseload operation.

The capital cost of new coal-fired steam-electric plants has declined about 25 percent in constant dollars since the early 1990s. This is attributable to plant performance improvements, automation and reliability improvements, equipment cost reduction,

[2] World Bank. Supercritical Coal-fired Power Plants. *Energy Issues* No 19. April 1999
[3] World Bank. Technologies for Reducing Emissions in Coal-fired Power Plants. Energy Issues No 14. August 1998.

shortened construction schedule, and increased market competition[4]. Meanwhile, coal prices have also declined in response to stagnant demand and productivity improvements in mining and transportation[5]. By way of comparison, in the Council's 1991 power plan, the overnight capital cost of a new coal-fired steam-electric plant was estimated to be $1,775 per kilowatt and the cost of Montana coal $0.68 per million Btu (escalated to year 2000 dollars). The comparable capital and fuel costs of this plan are $1,230 per kilowatt and $0.52 per million Btu, respectively.

Development Issues

Though the economics have improved, important issues associated with development of coal-fired power plants remain. Transmission, mercury emissions and carbon dioxide production appear to be the most significant.

Transmission issues will affect the siting and development of future coal-fired power plants in the Northwest. Coal supplies, though abundant, tend to lie at considerable distance from Northwest load centers. Environmental concerns will likely preclude siting of new coal plants close to load centers. However, new plants could be sited at intermediate locations having good rail and transmission access. Delivered coal cost will be greater that the mine mouth cost of coal because of the need to haul the coal by rail. Also, fuel cost component of the rail haul costs is sensitive to fuel oil price volatility and uncertainty. Alternatively, new plants could be sited at or near the mine mouth. Coal will be less expensive and free of fuel oil price uncertainties. Though the eastern transmission interties are largely committed, several hundred megawatts of additional transmission capacity may be available at low cost through better use of existing capacity and low-cost upgrades to existing circuits. This potential is currently under evaluation. Export of additional power from eastern Montana coalfields would require the construction of new long-distance transmission circuits. Preliminary estimates of the cost of an additional 500kV circuit out of eastern Montana indicate that the resulting cost of power delivered to the Mid-Columbia area would not be competitive with the cost of power from coal plants sited in the Mid-Columbia area using rail haul coal. Additional obstacles to construction of new eastern intertie circuits include long lead time (six to eight years from conception to energization), limited corridor options for crossing the Rocky Mountains and the current lack of an entity capable of large-scale transmission planning, financing and construction.

Coal combustion releases elemental mercury, some of which passes into the atmosphere and accumulates in the food chain where it poses a health hazard. On average, about 36 percent of the mercury contained in the coal is retained in ash or removed by existing controls.[6] Additional control of power plant mercury emissions is not currently required, however the EPA is under court order to issue rules governing control of mercury by March 2005. A promising approach to controlling mercury emissions from coal steam-electric plants is to augment mercury capture in existing particulate filters using activated carbon injection. Short-term tests of activated carbon injection on power plants using sub-bituminous coal increased capture rates to 65 percent of potential emissions. The estimated

[4] U.S. Department of Energy. *Market-based Advanced Coal Power Systems*. March 1999.
[5] The recent runup in coal prices is attributed to short-term supply-demand imbalances.
[6] U.S. Environmental protection Agency. Control of Mercury Emissions from Coal-fired Electric Utility Boilers. January 2004.

costs of the representative pulverized coal-fired power plant described below include an allowance for activated charcoal injection for mercury control.

Among the fossil fuels, coal has the highest proportion of carbon to hydrogen. This places coal-fired generation at greater risk than other resources regarding possible future limits on the production of carbon dioxide. The most promising approach to dealing with the carbon dioxide production of coal combustion is through improved generating plant efficiency and carbon dioxide separation and sequestration. Introduction of supercritical steam cycles will improve the thermal efficiency of pulverized coal-fired power plants and reduce the per-kilowatt production of carbon dioxide. However, generating technologies based on coal gasification appears to be a more effective approach for achieving both higher efficiencies and economical carbon dioxide separation capability.

Northwest potential

New pulverized coal-fired power plants could be constructed in the Northwest for the principal purpose of providing base load power. Because of the abundance of coal in western North America, supplies are adequate to meet any plausible Northwest needs over the period of this plan. While environmental concerns would likely make siting west of the Cascades near the Puget Sound and Portland load centers difficult, existing and potential plant sites elsewhere are sufficient to meet anticipated needs for the period of the plan. New plants could be constructed at or near mine-mouth in eastern Montana, in the inter-montane region of eastern Washington, Oregon and southern Idaho and in areas adjacent to the region including northern Nevada, Alberta and British Columbia.

Plants developed in the inter-montane portion of the region might require incremental rail upgrades for coal supply and local grid reinforcement and to deliver power to westside load centers. Plants located in eastern Montana could supply local loads and export up to several hundred megawatts of power to the Mid-Columbia area using existing non-firm transmission capacity and relatively low-cost upgrades to the existing transmission system. Further development of plants in eastern Montana to serve western loads would require construction of additional transmission circuits to the Mid-Columbia area. As a general rule-of-thumb, one 500 kV AC circuit could transmit the output of 1,000 megawatts of generating capacity.

Reference plant

The reference plant is a 400-megawatt sub-critical pulverized coal-fired unit, co-located with similar units. The plant would be equipped with low-NOx burners and selective catalytic reduction for control of nitrogen oxides. The plant would also be equipped with flue gas de-sulfurization, fabric filter particulate control and activated charcoal injection for additional reduction of mercury emissions. The capital costs include a shared local switchyard and transmission interconnection, but do not include dedicated long-distance transmission facilities.

The base case plant uses evaporative (wet) condenser cooling. Dry cooling uses less water, and might be more suitable for arid areas of the West. But dry cooling reduces the thermal efficiency of a steam-electric plant by about 10 percent, and proportionally increases per-kilowatt air emissions and carbon dioxide production. The effect is about three times greater for steam-electric plants than for gas turbine combined-cycle power plants, where recent proposals have trended toward dry condenser cooling. For this reason, we assume that the majority of new coal-fired power plants would be located in areas where water availability is not critical and would use evaporative cooling.

The assumptions of this plan regarding new coal-fired steam-electric plants are described in Table I-3. Specific proposals for new coal-fired power plants might differ substantially from this case. Important variables include the steam cycle (sub-critical vs. supercritical), method of condenser cooling, transmission interconnection, the level of equipment redundancy and reliability, number of units constructed at the same site and how scheduled, level of air emission control, the type of coal used and method of delivery.

The Northwest Transmission Assessment Committee of the Northwest Power Pool is developing cost estimates for additional transmission from eastern Montana to the Mid-Columbia area. As of this writing, only very preliminary estimates of the cost of a new 500 kV AC circuit were available. These, together with other modeling assumptions regarding additional eastern Montana - Mid-Columbia transmission are shown in Table I-4.

The benchmark[7] levelized electricity production costs for the reference coal-fired power plant, power delivered as shown, are as follows:

Eastern Montana, local service	\$32/MWh
Eastern Montana, via existing transmission to Mid-Columbia area	\$38/MWh
Eastern Montana, via new transmission to Mid-Columbia area	\$62/MWh
Mid-Columbia, rail haul coal from eastern Montana	\$38/MWh

[7] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; medium case fuel price forecast; 80 percent capacity factor, year 2000 dollars. No CO2 penalty.

Table I-3: Resource characterization: Coal-fired steam-electric plant (Year 2000 dollars)

Description and technical performance		
Facility	400 MW (nominal) pulverized coal-fired subcritical steam-electric plant, 2400 psig/1000°F/1000°F reheat. "Reduced redundancy" low-cost design. Evaporative cooling. Low-NOx burners; flue gas desulfurization; fabric particulate filter and activated charcoal filters. Co-sited with one or more additional units.	Reference plant from U.S. Department of Energy, *Market-based Advanced Coal Power Systems*, March 1999 (USDOE, 1999), modified to suit western coal and site conditions and anticipated mercury control requirements.
Status	Commercially mature	
Application	Baseload power generation	
Fuel	Western low-sulfur subbituminous coal. Rail-haul or mine-mouth delivery.	
Service life	30 years	
Power (net)	400 MW.	
Operating limits	Minimum load: 50 %. Cold startup: 12 hours Ramp rate: 0.5%/min	Values consistent with reduced-redundancy, low-cost design. Improved performance is available at additional cost.
Availability	Scheduled outage: 35 days/yr Equivalent forced outage rate: 7% Mean time to repair: 40 hours Equivalent annual availability: 84%	Scheduled outage is average of 1995 - 99 NERC *Generating Availability Data System* (GADS) scheduled outage factor for 200 - 399 MW coal-fired units, rounded to nearest day. Forced outage rate is average of GADS equivalent forced outage factor for 200 - 399 MW coal-fired units. Forced outage rate is intended as a lifecycle average. Generally higher for startup year, lower by second year, then slowly increasing over remainder plant life.
Heat rate (HHV, net, ISO conditions)	9550 Btu/kWh (annual average, 2002 base technology).	Midpoint from Kitto, J. B. *Developments in Pulverized Coal-fired Boiler Technology*. Babcock & Wilcox, April 1996, increased 0.8% for SCR.
Vintage heat rate improvement	0.26 %/yr (2002-25)	Assumes full penetration of supercritical steam cycle by 2021 with 5% reduction in heat rate. World Bank. *Technologies for Reducing Emissions in Coal-fired Power Plants* (World Bank 1998). Energy Issues No 14. August 1998.
Seasonal power output (ambient air temperature sensitivity)	Not significant	
Elevation adjustment for power output	Not significant	

Costs		
Capital cost (Overnight, development and construction)	$1243/kW	Assumes two units at a site completed within two years of one another. Single unit costs assumed to be 10% greater. Assumes development costs are capitalized. Overnight cost excludes financing fees and interest during construction.
Development & construction cash flow (%/yr)	Cash flow for "straight-through" 78-month development & construction schedule: 0.5%/0.5%/2%/10%/37%/37%/13%.	See Table I-4 for phased development assumptions used in portfolio risk studies.
Fixed operating costs	$40/kW/yr	From DOE (1999), excluding property taxes and insurance plus $15/yr capital replacement.
Variable operating costs	$1.75/MWh	Includes consumables & SCR catalyst replacement, makeup water, wastewater and ash disposal costs. From DOE (1999) plus $0.25 allowance for SCR catalyst replacement and $0.75/MWh for additional reagent and disposal costs for Hg control.
Incentives/Byproduct credits/CO2 penalties	Separately included in the Council's models.	
Interconnection and regional transmission costs	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Bonneville 2004 transmission tariff.
Transmission loss to market hub	1.9%	Bonneville contractual line losses.
Technology vintage cost change (constant dollar escalation)	0.1 %/yr (2002-25)	Assumes full penetration of supercritical steam cycle by 2021 with 2 % increase in capital and fixed operating costs. World Bank (1998).

Air emissions		
Particulates (PM-10)	0.072T/GWh	Roundup Power Project, MT, as permitted
SO2	0.575 T/GWh	Ibid
NOx	0.336 T/GWh	Ibid
CO	0.719 T/GWh	Ibid
VOC	0.014 T/GWh	Ibid
CO_2	1012 T/GWh	Based on average carbon content of U.S. subbituminous coals (212 lb/MMBtu) and lifecycle average heat rate.

Development		
Assumed mix of developers	For electricity price forecasting: Consumer-owned utility: 25% Investor-owned utility: 25% Independent power producer: 50% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is a GRAC recommendation. Resource comparison mix is a standard mix for comparison of resources. See Appendix B for project financing assumptions.
Development & construction schedule	Development - 36 Months Construction - 42 months	"Straight-through" development. See Table I-4 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	Permitted sites (MT only) - 2008 New sites - 2011	
Site availability and development limits through 2025.	MT in-state - no limit MT to Mid-Columbia - 400 MW w/o transmission expansion No development in western OR or WA	Primary coal resource sufficient to meet

Table I-4: Preliminary modeling characteristics - new 500kV transmission circuit from Colstrip area to Mid-Columbia (year 2000 dollars)

Capacity	1000 MW	Delivered
Losses	6.6%	
Capital cost (Overnight, development and construction)	$1590/kW	Based on delivered capacity
Operating costs	$8.00/kW/yr	Based on delivered capacity
Development & construction schedule	Development - 48 months Construction - 36 months	

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-5. The cumulative schedule of the three project phases shown in Table I-5 is longer than the "straight-through" development and construction schedule shown in Table I-3.

Table I-5: Coal-fired steam-electric plant project phased development assumptions for risk analysis (year 2000 dollars)[8]

	Development	Optional Construction	Committed Construction
Defining milestones	Feasibility study through completion of permitting	Notice to proceed to major equipment foundations complete	Start of boiler steel erection to commercial operation
Time to complete (single unit, nearest quarter)	36 months	18 months	27 months
Cash expended (% of overnight capital)	3%	27%	70%
Cost to suspend at end of phase ($/kW)	Negligible	$234	--
Cost to hold at end of phase ($/kW/yr)	$1	$10	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	$26	--
Cost of immediate termination ($/kW)	Negligible	$158	--

COAL-FIRED GASIFICATION COMBINED-CYCLE PLANTS

The production of synthetic gas fuel from coal and other solid or liquid fuels offers the opportunity for improving the environmental and economic aspects of generating electricity from coal, an abundant and low-cost energy resource. Coal gasification permits the use of efficient gas turbine combined cycle power generation, allows excellent control of air pollutants and facilitates the separation of carbon dioxide for sequestration (See Appendix K for discussion of carbon dioxide sequestration). Gasification plants can be equipped for co-production of liquid fuels, petrochemicals chemicals or hydrogen, creating the opportunity for more flexible and economical plant utilization. Gasification technology can also be used to produce synthetic fuels from petroleum coke, bitumen and biomass, providing a means of using the energy of these otherwise difficult fuels. Coal gasification power plants are in the demonstration stage of development. Issues needing resolution before widespread deployment include capital cost reduction, provision of overall plant performance warranties and demonstration of consistent plant reliability.

Coal gasification is an old technology, having been introduced in the early nineteenth century to produce “town gas” for heating and illumination. Development of the North American natural gas transportation network in the mid-20th century brought cleaner and less-expensive natural gas to urban markets and the old town gas plants, numbering over 1,000 at one time, were retired. Currently, gasification is widely employed in the

[8] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

petrochemical industry for processing of coal and petroleum residues into higher value products. Other than several demonstration projects[9], coal gasification has not penetrated the North American power generation industry. This is attributable to the availability of low-cost natural gas until recently, efficient, reliable and low-cost gas-fired combined-cycle gas turbine power plants and the high initial cost and reliability issues with gasification power plants. Rising natural gas prices, the prospect of more stringent control of particulates and mercury, and increasing acknowledgement that the production of carbon dioxide must be reduced is increasing interest in coal-fired gasification power plants.

Technology

The leading plant configuration for electric power generation using gasified coal is the integrated gasifier combined-cycle (IGCC) power plant. Integration refers to the extraction of pressurized air from the gas turbine compressor for use as feedstock to the air separation plant, and use of the energy released in the gasification process for power generation to improve net plant efficiency. These plants use the combined-cycle gas turbine power generating technology widely used for natural gas electricity generation. A variety of gasification technologies have been developed for use with different feedstocks and for producing different products. Pressurized oxygen-blown designs are favored for power generation. Pressurization and the use of oxygen for the gasification reaction reduce the volume of the resulting raw synthetic gas. This reduces the cost of gas cleanup, eliminates the need for syngas compression and reduces the cost of CO_2 separation if that is desired.

The principal components of an integrated gasifier combined-cycle generating plant are as follows:

- *Coal preparation*: The coal preparation section includes the on-site fuel inventory and equipment to prepare the coal for introduction to the gasifier. The coal is crushed or ground to size and (depending upon the gasification process) either suspended in slurry or dried for feeding to the gasifier.

- *Air separation*: The air separation plant produces oxygen for the gasification reaction. Use of oxygen, rather than air as the gasification oxidant increases the energy content and reduces the volume of the synthesis gas. This reduces the cost of gas cleanup and also reduces formation of nitrogen oxides in the gas turbine. Air separation plants currently use energy-intensive cryogenic processes in which incoming air is chilled to a liquid and distilled to separate the nitrogen, oxygen and other constituents. For example, about 20 percent of the power output of the Tampa Electric IGCC demonstration plant is consumed by air separation. Large-scale membrane separation technology under development is expected to require less energy, yield improvement in net plant efficiency.

[9] Currently operating coal gasification power plants in the U.S. are the Tampa Electric Integrated Gasification Combined-cycle Project (Polk Power Station) using theChevron-Texaco gasification process, and the Wabash River Coal Gasification Repowering Project, using the ConocoPhilips E-Gas process. Additional information regarding these projects can be obtained from the U.S. Department of Energy coal and natural gas power systems website (www.fe.doe.gov/programs/powersystems/index.html.)

- *Gasification*: Processed coal and oxygen are fed to the gasifier, a large pressure vessel. The coal is partially combusted, yielding heat and raw synthetic gas consisting largely of hydrogen, carbon monoxide and carbon dioxide. Coarse particulate material is removed and recycled to the gasifier. Non-combustible coal constituents form slag and are drained, solidified, then crushed for disposal or for marketable aggregate. The leading gasification processes suitable for power generation are the Chevron-Texaco, E-Gas and Shell processes. The Texaco process is used in the Tampa Electric Polk gasification power plant and the E-Gas process is used in the Wabash River coal gasification plant. The Shell process is used at the DEMKOLEC plant at Buggenum, The Netherlands. These plants have operated successfully for several years.

- *Gas processing:* The raw synthetic gas is scrubbed, cooled, and filtered to remove particulate material to prevent damage to downstream equipment and to control air emissions. Sulfur compounds are removed using regenerative sorbants then converted to marketable elemental sulfur. If CO_2 is to be separated or hydrogen-based co-products to be produced, the synthetic gas is passed through a series of water gas shift reactors. Here, the CO fraction reacts with water to form CO_2 and hydrogen. Though about 40 to 50 percent of the mercury in the feedstock coal remains in the slag, additional mercury capture can be achieved at this point by passing the synthetic gas through activated carbon beds.

- *CO_2 separation:* The relatively low volume of pressurized synthetic gas fuel provides a more economic means of separating carbon dioxide compared to removing the carbon dioxide from the larger volume of post-combustion flue gasses in a conventional steam-electric plant. Separation of up to 90 percent of the carbon dioxide content of the synthesis gas appears to be feasible using available technologies. Carbon dioxide can be separated from the synthesis gas using the same selective regenerative sorbent process used to remove sulfur compounds. The carbon dioxide could than be compressed to its high-density supercritical phase for transport to sequestration sites. An existing non-generating gasification plant, Dakota Gasification, uses a sorbent process to capture a portion of its carbon dioxide production. The carbon dioxide is piped 205 miles to Weyburn, Saskatchewan where it is injected for enhanced oil recovery. Though commercial, sorbent CO_2 removal is energy-intensive. Research is underway, mostly at the theoretical or laboratory stage, development of selective separation membrane technology capable of withstanding the operating conditions of a gasification power plant.

- *Power generation*: The finished synthetic gas is fired in a gas turbine of the same basic design as those used for natural gas combined-cycle power plants. Nitrogen from the air separation plant can be injected to augment the mass flow. The turbine exhaust gas is passed through a heat recovery steam generator to produce steam. This steam, plus steam produced by the synthetic gas coolers is used to drive a steam turbine generator. Reliable operation of F-class gas turbines on coal-based medium-Btu synthesis gas has been demonstrated and a plant constructed today would likely use this technology. More efficient H-class machines, currently being demonstrated on natural gas fuel would likely be used in future gasification power plants.

A pure, or nearly so hydrogen feedstock results from subjecting the synthesis gas to a water gas shift reaction followed CO_2 separation. F-class gas turbines have operated successfully on fuel hydrogen concentrations as high as 38 percent. Similar turbines have operated at hydrogen concentrations of 60 percent. Limited short-term testing has confirmed that F-class machines can operate on 100 percent hydrogen fuel. However, long-term reliable operation of gas turbines on pure hydrogen will require resolution of significant technical issues including hydrogen embrittlement, flashback, hot section material degradation and NOx control.

Fuel cells use pure hydrogen as fuel, so are natural candidates for use in a coal gasification facility with CO_2 separation. One concept consists of a combined-cycle plant using high temperature fuel cells with heat recovery and a steam turbine bottoming cycle. Cost and lifetime are key obstacles to employing fuel cells in this application. Current fuel cell costs of $2,000 - 4,000 per kilowatt must be significantly reduced for economical application to a gasification plant.

Economics

The cost of power from a coal gasification power plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. The capital cost of a coal gasification combined-cycle power plant (without CO_2 separation) is estimated to be about 15 to 20 percent higher than the cost of conventional pulverized coal-fired units. However, because coal gasification power plants are a new technology, it is likely that cost will decline as the technology is deployed, whereas it is expected that the costs of conventional technology may increase, particularly as additional emission control requirements are enacted.

Even more so than conventional coal plants, a relatively large capital investment in a gasification plant is made for the purpose of using a low-cost fuel. Because high reliability is essential to amortizing the capital investment, multiple air separation, gasification and synthetic gas processing trains would likely be provided to ensure high plant availability. Though a basic coal gasification power plant would normally be used for baseload power production, synthetic liquid fuel or chemical manufacturing capability could be provided for additional operating flexibility. Depending upon the economics of power production, the synthetic gas output could be shifted between the combined-cycle power plant and synthetic liquid fuel or chemical production.

Development Issues

Two gasification combined-cycle power plants are currently operating in North America and additional plants could be ordered and built today. However, high and uncertain capital costs, the extended (though ultimately successful) shakedown periods required for the existing demonstration projects and lack of overall plant performance warranties precluding commercial financing have kept coal gasification power plants from full commercialization.

Had natural gas combined-cycle plants not been the bulk power generating technology of choice for the past 15 years, these concerns undoubtedly would have been resolved. However, high natural gas prices, diminishing North American natural gas supplies and increasing acceptance of the need to curtail carbon dioxide production have prompted renewed interest in coal gasification power plants. Recent developments accelerating commercialization of gasification power plants include the May 2004 announcement by Conoco-Philips and Fluor Corporation of an alliance to develop, design, construct and operate projects utilizing Conoco-Philips E-Gas coal gasification technology; the June 2004 announcement by General Electric that it would acquire the Chevron-Texaco gasification technology business, the August 2004 announcement by American Electric Power that it plans to construct 1,000 megawatts of coal gasification power generation capacity by 2010, the October 2004 announcement of a partnership between General Electric and Bechtel to offer a standard coal gasification combined-cycle power plant, the October 2004 announcement by Cinergy that it had signed an agreement with GE/Bechtal to construct a 600 megawatt coal gasification power plant in Indiana, and the October 2004 announcement that Excelsior Energy had been selected for a US DOE grant to assist in the financing of 532 MW coal gasification power plant to be located in Minnesota.

Probable siting difficulties would likely preclude siting of new coal-fired plants near Westside Northwest load centers. New plants could be located in eastern Washington or Oregon, or Southern Idaho, with fuel supplied by rail. Rail haul costs would prompt the operators of plants located in this part of the region to use medium-Btu bituminous coal from Wyoming or Utah. Reinforcement of cross-Cascades transmission capacity might eventually be required for plants located in this area. Alternatively, plants could be located near mine-mouth in Wyoming, Eastern Montana, or Utah. New high voltage transmission circuits would be required for new mine-mouth coal plant development exceeding several hundred megawatts. As discussed in the section on conventional coal-fired power plants, only preliminary estimates of the cost of new transmission are available, however, more refined estimates are in development.

Sequestration of carbon dioxide may mandate the location of gasification power plants in the eastern portion of the region. Though ocean sequestration may eventually be proven feasible, opening opportunities for plants employing carbon dioxide separation in the western portion of the region, only certain geologic formations present in eastern Montana currently appear to be suitable for carbon dioxide sequestration (Appendix K). Thus, gasification power plants would have to be located in eastern Montana and would require new transmission interconnection to take advantage of carbon dioxide separation capability.

Northwest Applications

Because of the abundance of coal in western North America, supplies are adequate to meet any plausible Northwest needs over the period of this plan. Coal-fired power plants constructed in the Northwest within the next several years would likely employ conventional pulverized coal technology. However, the increasing interest in coal-fired power generation and the prospect of more stringent particulate control and control requirements for mercury and CO_2 is accelerating the commercialization of coal gasification technology. It appears that a basic gasification power plant without CO_2 separation could be operating in the Northwest as early as 2011.

Locational constraints differ somewhat from those of conventional coal-fired plants. The Superior environmental performance of gasification power plants may make siting west of the Cascades near the Puget Sound and Portland load centers less challenging. However, if carbon dioxide is to be separated and sequestered, plant sites may be limited to the vicinity of deep saline aquifers and bedded salt formations of eastern Montana.

Plants developed in the inter-montane portion of the region might require incremental rail upgrades for coal supply and local grid reinforcement and to deliver power to westside load centers. Plants located in eastern Montana could supply local loads and export up to several hundred megawatts of power to the Mid-Columbia area using existing non-firm transmission capacity and relatively low-cost upgrades to the existing transmission system, if not preempted by earlier generating plant development. Further development of plants in eastern Montana to serve western loads would require construction of additional transmission circuits to the Mid-Columbia area. As a general rule-of-thumb, one 500 kV AC circuit could transmit the output of 1,000 megawatts of generating capacity.

Reference Plants

The cost and performance characteristics of two IGCC plant designs are described in Table I-6. The 425 megawatt plant would not be equipped with carbon dioxide separation equipment. This type of plant could be located anywhere in the Northwest that coal and transmission are available. The extremely low air emissions could facilitate siting near load centers. The issues that have constrained commercial development of these plants are rapidly being resolved. This could lead to full commercial projects as early as 2011. This schedule is generally consistent with the proposed AEP coal gasification power plants.

The second plant is of the same general design, but includes equipment for the separation of 90 percent of the carbon dioxide produced by plant operation. It appears likely that this type of plant would have to be located in the eastern portion of the region to access geologic formations suitable for carbon dioxide sequestration. Net power output is reduced to 401 megawatt because of the additional energy required for the carbon dioxide separation and compression to pipeline transportation pressure. Though the technologies for carbon dioxide capture, transport and injection are commercially available, extended gas turbine operation on high hydrogen fuel will require further development and testing. Moreover, carbon dioxide sequestration in potentially suitable eastern Montana formations has not been demonstrated. The cost estimates of Table I-6 do not include the costs of carbon dioxide transportation or sequestration. Carbon dioxide transportation and sequestration cost estimates are provided in Appendix K to permit estimation of the total cost of power production from this plant.

Not included in the plants described in Table I-6 are liquid or hydrogen fuel co-production facilities. Inclusion of product co-production capability would increase the operational flexibility of the plant, including the ability to firm the output of wind power plants.

The benchmark[10] levelized electricity production costs for the reference coal-gasification power plant without carbon dioxide separation, power delivered as shown, are as follows:

Eastern Montana, local service	$33/MWh
Eastern Montana, via existing transmission to Mid-Columbia area	$38/MWh
Eastern Montana, via new transmission to Mid-Columbia area	$58/MWh
Mid-Columbia, rail haul coal from eastern Montana	$38/MWh

Table I-6: Resource characterization: Coal-fired gasification combined-cycle plants (Year 2000 dollars) Source EPRI 2000 unless noted

Description and technical performance			
Facility	Case A: 425 MW coal-fired integrated gasification combined-cycle power plant. Cryogenic air separation, pressurized oxygen-blown entrained-flow gasifier, solvent-based absorption sulfur stripping unit, carbon bed adsorption mercury removal and H-class gas turbine combined-cycle generating plant. (EPRI 2000 Case 3B)	Case B: 401 MW coal-fired integrated gasification combined-cycle power plant with 90% CO2 capture. Cryogenic air separation, pressurized oxygen-blown entrained-flow gasifier, water gas shift reactors, solvent-based selective absorption sulfur and CO2 separation, carbon bed adsorption mercury removal, CO2 compression to 2200psig and F-class gas turbine combined-cycle generating plant. (EPRI 2000 Case 3A w/2200psig CO2 product)	
Current Status	w/F-Class GT - Demonstration w/H-class GT - Conceptual	Conceptual	
Application	Baseload power generation	Baseload power generation	
Fuel	Western low-sulfur subbituminous coal	Same as Case A	
Service life	30 years	Same as Case A	
Power	474 MW (gross) 425 MW (net)	490 MW (gross) 401 MW (net)	
Operating limits	Minimum load: 75 % Cold restart: 24 hrs Ramp rate: 3 %/min	Same as Case A	Minimum is Negishi experience (JGC 2003). Lower rates may be possible with 2x1 combined-cycle configuration . Cold restart is Tampa Electric experience. Ramp rate is maximum w/o flare Negishi experience.

[10] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; Montana coal, medium case price forecast; 80 percent capacity factor, year 2000 dollars. No CO2 penalty.

Description and technical performance			
Availability	Scheduled outage: 28 days/yr Equivalent forced outage rate: 10% Equivalent annual availability: 83%.	Same as Case A	Design objectives for proposed WePower plant (GTW 2004). Multiple gasifier designs could increase availability to 90% or greater.
Heat rate (HHV, net, ISO conditions)	7915 Btu/kWh w/H-class gas turbine. F-class turbine would yield heat rates of 8500 - 9000 Btu/kWh.	9290 Btu/kWh w/H-class gas turbine. F-class turbine would yield heat rates of 10,000 - 10,600 Btu/kWh.	
Heat rate improvement (surrogate for cumulative effect of non-cost technical improvements)	-0.5 %/yr average from 2002 base through 2025	Same as Case A	Value used for combined-cycle gas turbines.
Seasonal power output (ambient air temperature sensitivity)	Assumed to be similar to those used for gas-fired combined-cycle power plants (Figure I-1).	Same as Case A	
Elevation adjustment for power output	Assumed to be similar to those used for gas-fired combined-cycle power plants (Table I-10).	Same as Case A	

Costs			
Capital cost (Overnight, development and construction)	$1400/kW Range $1300 - $1600/kW	$1805/kW Range $1650 - $1950/kW	Costs from EPRI, 2000 adjusted for additional mercury removal, project development and owner's costs. Escalated to year 2000 dollars.
Construction period cash flow (%/yr)	15%/35%/35%/15%	Same as Case A	
Fixed operating costs	$45.00/kW/yr	$53.00/kW/yr	
Variable operating costs	$1.50/MWh	$1.60/MWh	Consumables from EPRI, 2000 plus mercury removal O&M from Parsons, 2002. EPRI 2000 provides turbine maintenance costs as fixed O&M though most gas turbine costs are variable.
CO_2 transportation and sequestration	n/a	See Appendix K	
Byproduct credits	None assumed	None assumed	Potential sulfur and CO_2 byproduct credit (CO_2 for enhanced gas or oil recovery).

Costs			
Interconnection and regional transmission costs	$15.00/kW/yr	Same as Case A	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Bonneville 2004 transmission tariff.
Transmission loss to market hub	1.9%	Same as Case A	Bonneville contractual line losses.
Technology vintage cost change (constant dollar escalation)	-0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs)	Same as Case A	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.

Air Emissions & Water consumption			
Particulates (PM-10)	Negligible	Negligible	
SO2	Negligible	Negligible	Low sulfur coal and 99.8% removal of residual sulfur
NOx	< 0.11T/GWh	< 0.11T/GWh	
CO	0.015 T/GWh	0.017 T/GWh	O'Keefe, 2003, scaled to heat rate
VOC	0.005 T/GWh	0.005 T/GWh	O'Keefe, 2003, scaled to heat rate
CO_2	791 T/GWh	81 T/GWh (90% removal)	
Hg	6.3×10^{-6} T/GWh	7.4×10^{-6} T/GWh	90% removal
Water Consumption	412 T/GWh	820 T/GWh	

Development			
Developer	For electricity price forecasting: Consumer-owned utility: 25% Investor-owned utility: 25% Independent power producer: 50% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	For electricity price forecasting: Consumer-owned utility: 25% Investor-owned utility: 25% Independent power producer: 50% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is the GRAC recommendation for conventional coal-fired power plants. Resource comparison mix is used for the portfolio analysis and other benchmark comparisons of resources.

Development			
Development and construction schedule	Development - 36mo Construction - 48 mo	Same as Case A.	Development schedule is consistent with O'Keefe. Construction currently would require 54 months (O'Keefe, 2003). Expected to shorten to 38 months with experience. "Straight-through" development. See Table I-6 for phased development assumptions used in portfolio studies.
Earliest commercial service	2011	2011 for enhanced oil or gas recovery CO2 sequestration. 2015 - 2020 for novel CO2 repositories.	
PNW Site Availability	Site availability sufficient to meet regional load growth requirements through 2025.	Site availability sufficient to meet regional load growth requirements through 2025. Suitable geologic CO2 sequestration sites may be limited to eastern Montana. Montana development would require additional transmission development to serve western load centers.	

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-7. The cumulative schedule of the three project phases shown in Table I-7 is longer than the "straight-through" development and construction schedule shown in Table I-6.

Table I-7: Coal-fired gasification combined-cycle project phased development assumptions for the portfolio analysis (year 2000 dollars)[11]

	Development	Optional Construction	Committed Construction
Defining milestones	Feasibility study through completion of permitting	Notice to proceed to major equipment foundations complete	Accept major equipment to commercial operation
Time to complete (single unit, nearest quarter)	36 months	24 months	24 months
Cash expended (% of overnight capital)	2%	28%	70%
Cost to suspend at end of phase ($/kW)	Negligible	$218	--
Cost to hold at end of phase ($/kW/yr)	$1	$13	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	$41	--
Cost of immediate termination ($/kW)	Negligible	$180	--

NATURAL GAS-FIRED SIMPLE-CYCLE GAS TURBINE POWER PLANTS

A simple-cycle gas turbine power plant (also called a combustion turbine or gas turbine generator) is an electric power generator driven by a gas turbine. Attributes of simple-cycle gas turbines include modularity, low capital cost, short development and construction period, compact size, siting flexibility and operational flexibility. The principal disadvantage is low thermal efficiency. Because of their low thermal efficiency compared to combined-cycle plants, simple-cycle gas turbines are typically used for low duty factor applications such as peak load and emergency backup service. Energy can be recovered from the turbine exhaust for steam generation, hot water production or direct use for industrial or commercial process heating. This greatly improves thermal efficiency and such plants are normally operated as base load units.

Because of the ability of the Northwest hydropower system to supply short-term peaking capacity, simple-cycle gas turbines have been a minor element of the regional power system. As of January 2004, about 1,560 megawatts of simple-cycle gas turbine capacity were installed in the Northwest, comprising about 3 percent of system capacity. One thousand three hundred thirty megawatts of this capacity is pure simple-cycle and 230 megawatts is cogeneration. The power price excursions, threats of shortages and poor hydro conditions of 2000 and 2001 sparked interest in simple-cycle turbines as a hedge against high power

[11] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

prices, shortages and poor water. About 360 megawatts of simple-cycle gas turbine capacity has been installed in the region since 2000, primarily by large industrial consumers exposed to wholesale power prices, utilities exposed to hydropower uncertainty or growing peak loads.

Technology

A simple-cycle gas turbine generator consists of a one or two-stage air compressor, fuel combustors, one or two power turbines and an electric generator, all mounted on one or two rotating shafts. The entire assembly is typically skid-mounted as a modular unit. Some designs use two gas turbines to power a single generator. Pressurized air from the air compressor is heated by burning liquid or gas fuel in the fuel combustors. The hot pressurized air is expanded through the power turbine. The power turbine drives the compressor and the electric power generator. Lube oil, starting, fuel forwarding, and control systems complete the basic package. 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 and "aeroderivative" machines - 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. 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.

A simple-cycle gas turbine power plant consists of one to several gas turbine generator units. The generator sets are typically equipped with inlet air filters and exhaust silencers and are installed in acoustic enclosures. Water or steam injection, intercooling[12] or inlet air cooling can be used to increase power output. Nitrogen oxides (NOx) from fuel combustion are the principal emission of concern. Basic NOx 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. Fuel oil storage and supply system may be provided for alternate fuel purposes. Simple-cycle gas turbine generators are often co-located with gas-fired combined-cycle plants to take advantage of shared site infrastructure and operating and maintenance personnel.

Gas turbines can operate on either gas or liquid fuels. Pipeline natural gas is the fuel of choice in the Northwest because of historically low and relatively stable prices, widespread

[12] Chilling the compressed air between air compression stages.

availability and low air emissions. Distillate fuel oil, once widely used as backup fuel, has become less common because of environmental concerns regarding air emissions and on-site fuel storage and increased maintenance and testing. It is common to ensure fuel availability by securing firm gas transportation. Propane or liquified petroleum gas (LPG) are occasionally used as backup fuel.

Economics

The cost of power from a gas turbine plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. Capital costs of a gas turbine generator plants vary greatly because of the wide range of ancillary equipment that may be required for the particular application. Features such as fuel gas compressors, selective catalytic controls for nitrogen oxides and carbon monoxide and water or steam injection add to the cost of the basic package. Transmission interconnection, gas pipeline laterals and other site infrastructure requirements can add greatly to the cost of a plant. A further factor affecting plant costs is equipment demand. During the price runups of 2000 and 2001, equipment prices ran 25 to 30 percent higher than current levels. The reported construction cost of aeroderivative units built in WECC since 2000 range from about $420 to $1,390 per kilowatt with an average of $740. The range for plants using industrial machines is $300 to $1,000 per kilowatt with an average of $580. The reference overnight capital cost of simple-cycle gas turbine power plants used for this plan is $600 per kilowatt. This is based on an aeroderivative unit. Reasons for this cost being somewhat lower than average are that it is an overnight cost, excluding interest during construction; it is in year 2000 dollars, whereas most of the WECC examples were constructed later; most of the WECC examples were built in response to the energy crisis of 2000 and 2001 during a sellers market; and finally, most of the examples are California projects with more constrained siting and design requirements that are required in the Northwest.

Fuel prices and the relatively low efficiency of simple-cycle gas turbines low are not a key issue for plants used for peaking and emergency use. Fuel cost is of greater concern for base-loaded cogeneration plants, however, the incremental fuel consumption attributable to electric power generation ("fuel charged to power") for cogeneration units is low compared to a pure simple-cycle machine. For example, the full-load heat rates of the reference gas turbine plants of this plan are as follows: aeroderivative, no cogeneration - 9,955 Btu per kilowatt-hour; industrial, combined-cycle - 7,340 Btu per kilowatt-hour; aeroderivative, cogeneration - 5,280 Btu per kilowatt-hour. Simple-cycle gas turbines have been constructed in the Northwest for the purpose of backing up the non-firm output of hydropower plants. The cost of fuel for this application can be significant since the turbine may need to operate at a high capacity factor over many months of a poor water year.

Development Issues

Simple-cycle gas turbines are generally easy to site and develop compared to most other power generating facilities. Sites having a natural gas supply and grid interconnection facilities are common, the projects are unobtrusive, water requirements minimal and air emissions can be controlled to low levels. Simple-cycle gas turbine generators are often sited in conjunction with natural-gas-fired combined-cycle and steam plants to take advantage of the existing infrastructure.

Air emissions can be of concern, particularly in locations near load centers where ambient nitrogen oxide and carbon monoxide levels approach or exceed criteria levels. Post-combustion controls and operational limits are used to meet air emission requirements in these areas. The commercial introduction of high temperature selective catalytic controls for NOx and CO has enabled the control of NOx and CO emissions from simple-cycle gas turbines to levels comparable to combined-cycle power plants. Sulfur dioxide form fuel oil operation is controlled by use of low-sulfur fuel oil and by operational limits. Noise and vibration has been a concern at sites near residential and commercial areas and extra inlet air and exhaust silencing and noise buffering may be required at sensitive sites. Water is required for units employing water or steam injection but is not usually an issue for simple-cycle machines because of relatively low consumption. Gas-fired simple-cycle plants produce moderate levels of carbon dioxide per unit energy output.

Northwest Potential

Applications for simple-cycle gas turbines in the Northwest include backup for non-firm hydropower in poor water years ("hydropower firming"), peak load service, emergency system support, cogeneration (discussed in Appendix J), and as an alternative source of power during period of high power prices. Though simple-cycle turbines could be used to shape the output of windpower plants, the hydropower system is expected to be a more economic alternative for the levels of windpower development anticipated in this plan. Suitable sites are abundant and the most likely applications use little fuel. If natural gas use continues to grow, additional regional gas transportation or storage capacity may be needed to supply peak period gas needed to maintain the operating capability of simple-cycle gas turbines held for reserve or peaking purposes. Local gas transportation constraints may currently exist. Electric transmission is unlikely to be constraining because of the ability to site gas turbine generators close to loads.

Reference plant

The reference plant is based on an aeroderivative gas turbine generator such as the General Electric LM6000. The capacity of this class of machine ranges from 40 to 50 megawatts. The cost and performance characteristics of this plant are provided in Table I-8. Recently constructed simple-cycle projects in the Northwest have used both smaller machines as well as larger industrial gas turbines. Key characteristics of a plant using a typical industrial machine are also provided in Table I-8. The smaller gas turbines used for distributed generation are described in Appendix J.

Fuel is assumed to be pipeline natural gas. A firm gas transportation contract with capacity release provisions is assumed in lieu of backup fuel. Air emission controls include water injection and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC reduction. Costs are representative of a two-unit installation co-located at an existing gas-fired power plant.

Benchmark[13] levelized electricity production costs for reference simple-cycle turbines are as follows:

Aeroderivative, 10 percent capacity factor (peaking or hydro firming service)	$152/MWh.
Industrial, 10 percent capacity factor (peaking or hydro firming service)	$127/MWh
Aeroderivative, 80 percent capacity factor (baseload service)	$57/MWh.
Industrial, 80 percent capacity factor (baseload service)	$53/MWh

The capacity cost (fixed costs, generally a better comparative measure of the cost of peaking or emergency duty projects) of the reference aeroderivative unit under the benchmark financing assumptions is $89 per kilowatt per year. The benchmark capacity cost of a typical plant using industrial gas turbine technology is $50 per kilowatt per year.

Table I-8: Resource characterization: Natural gas fuelled simple-cycle gas turbine power plant (Year 2000 dollars)

Description and technical performance		
Facility	Natural gas-fired twin-unit aeroderivative simple-cycle gas turbine plant. Reference plant consists of (2) 47 MW gas turbine generators and typical ancillary equipment. Low-NOx combustors, water injection and SCR for NOx control and CO oxidizing catalyst for CO and VOC control.	Selected cost and performance assumptions for a basic plant (low-NOx burners emission control) using typical (80 - 170 MW) industrial-grade gas turbines are noted. Additional emission controls and other ancillary equipment will increase costs. Industrial turbine performance will differ for some characteristics not noted.
Status	Commercially mature	
Applications	Peaking duty, hydropower or windpower firming, emergency service	
Fuel	Pipeline natural gas. Firm transportation contract with capacity release provisions.	
Service life	30 years	
Power (net)	New & clean: 47 MW/unit Lifecycle average: 46 MW/unit	New & Clean: GE LM6000PC Sprint ISO rating less 2% inlet & exhaust losses. Lifecycle average is based on capacity degradation of 4% at hot gas path maintenance time, 75% restoration at hot gas path maintenance and 100% restoration at major overhauls.
Operating limits	Minimum load: 25% of single turbine baseload rating. Cold startup: 8 minutes Ramp rate: 12.5 %/min	Heat rate begins to increase rapidly at about 70% load. Startup time & ramp rate are for Pratt & Whitney FT8.

[13] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; firm natural gas, Westside delivery, medium case price forecast; no wheeling charges or losses, year 2000 dollars. No CO2 penalty.

Description and technical performance		
Availability	Scheduled outage: 10 days/yr Equivalent forced outage rate: 3.6% Mean time to repair: 80 hours Equivalent annual availability: 94%	The scheduled outage rate is based on a planned maintenance schedule comprised of 7-day annual inspections, 10-day hot gas path inspection & overhauls every sixth year and a 28-day major overhaul every twelfth year (inspection sequence is per General Electric recommendations. Actual intervals are a function of startups and hours of operation.). The assumed rate also includes two additional 28-day scheduled outages during the 30-year plant life. Based on the LM6000 fleet engine reliability of 98.8% (Fig 2 General Electric Power Systems. *GE Aeroderivative Gas Turbines - Design and Operating Features*, GER 3695e) and the assumption that engine-related outages represent about a third of all forced outages for a simple-cycle plant. Mean time to repair is NERC Generating Availability Data System (GADS) average for full outages.
Heat rate (HHV, net, ISO conditions)	New & clean: 9900 Btu/kWh Lifetime average: 9960 Btu/kWh Industrial machine: 10,500 Btu/kWh (lifetime average).	New & Clean is GRAC recommendation based on operator experience and typical vendor warranties. Lifecycle average based on capacity degradation of 1% during the hot gas path maintenance interval; 50% restoration at hot gas path maintenance and 100% restoration at major overhauls.
Heat rate improvement (surrogate for cumulative effect of non-cost technical improvements)	-0.5 %/yr average from 2002 base through 2025	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.
Seasonal power output (ambient air temperature sensitivity)	Assumed to be similar to those used for gas-fired combined-cycle power plants (Figure I-1).	
Elevation adjustment for power output	Assumed to be similar to those used for gas-fired combined-cycle power plants (Table I-10).	

Costs		
Capital cost	$600/kW (overnight cost) Industrial machine: $375/kW.	Includes development and construction. Overnight cost excludes financing fees and interest during construction. Based on new and clean rating. Derived from reported plant costs (2002-03), adjusted to approximate equilibrium market conditions. Single unit cost about 10% greater.
Construction period cash flow (%/yr)	100% (one year construction)	See Table I-8 for phased development assumptions used in portfolio risk studies.
Fixed operating costs	$8.00/kW/yr. Industrial machine: $6.00/kW/yr.	Includes labor, fixed service costs, management fees and general and administrative costs and allowance for equipment replacement costs (some normally capitalized). Excludes property taxes and insurance (separately calculated in the Council's models as 1.4%/yr and 0.25%/yr of assessed value). Fixed O&M costs for a single unit plant estimated to be 167% of example plant costs. Based on new and clean rating.
Variable operating costs	$8/MWh Industrial machine: $4.00/MWh	Routine O&M, consumables, utilities and miscellaneous variable costs plus major maintenance expressed as a variable cost. Excludes greenhouse gas offset fee (separately calculated in the Council's models).
Incentives/Byproduct credits/CO2 penalties	Separately included in the Council's models.	
Interconnection and regional transmission costs	Simple-cycle units are assumed to be located within a utility's service territory.	
Regional transmission losses	Simple-cycle units are assumed to be located within a utility's service territory.	
Technology vintage cost change (constant dollar escalation)	-0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs)	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.

Typical air emissions (Plant site, excluding gas production & delivery)		
Particulates (PM-10)	0.09 T/GWh	Typical emissions at normal operation over range of loads (50 to 100%). From West Cascades Energy Facility Prevention of Significant Deterioration Application November 2003. http://www.lrapa.org/permitting/applications_submitted/
SO2	0.09 T/GWh	Ibid
NOx	0.009 - 0.01 T/GWh	Ibid
CO	0.09 - 0.11 T/GWh	Ibid
Hydrocarbons/VOC	0.08 T/GWh	Ibid
CO_2	582T/GWh	Based on EPA standard natural gas carbon content assumption (117 lb/MMBtu) and lifecycle average heat rate.

Development		
Assumed mix of developers	Expected mix: Consumer-owned utility: 40% Investor-owned utility: 40% Independent power producer: 20% Benchmark mix: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is the GRAC recommendation for conventional coal-fired power plants. Resource comparison mix is used for the portfolio analysis and other benchmark comparisons of resources.
Development & construction schedule	Development - 18 months Construction - 12 months	"Straight-through" development. See Table I-8 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	New sites - 2006	
Site availability and development limits through 2025	Adequate to meet forecast Northwest needs.	

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-9. The cumulative schedule of the three project phases shown in Table I-9 is longer than the "straight-through" development and construction schedule shown in Table I-8.

Table I-9: Natural gas-fired simple-cycle project phased development assumptions for risk analysis (year 2000 dollars)[14]

	Project Development	Optional Construction	Committed Construction
Defining milestones	Feasibility study through completion of permitting	Notice to proceed to major equipment foundations complete	Accept major equipment to commercial operation
Time to complete (single unit, nearest quarter)	18 months	12 months	3 months
Cash expended (% of overnight capital)	2%	94%	5%
Cost to suspend at end of phase ($/kW)	Negligible	$25	--
Cost to hold at end of phase ($/kW/yr)	$1	$17	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	-$158	--
Cost of immediate termination ($/kW)	Negligible	-$125	--

NATURAL GAS FUELED COMBINED-CYCLE GAS TURBINE POWER PLANTS

For over a decade, high thermal efficiency, low initial cost, high reliability, low air emissions, and until recently, low natural gas prices have led to the choice of combined-cycle gas turbines for new bulk power generation. Other attractive features include operational flexibility, inexpensive optional power augmentation for peak period operation and relatively low carbon dioxide production. Combined-cycle power plants have become an important element of the Northwest power system, comprising 68 percent of generating capacity additions from 2000 through 2004. Natural gas-fired combined-cycle capacity has increased to 14 percent of regional generating capacity.

Technology

A combined-cycle gas turbine power plant consists of one or more gas turbine generators equipped with heat recovery steam generators to capture heat from the turbine exhaust. Steam produced in the heat recovery steam generators powers a steam turbine generator to produce additional electric power. Use of the otherwise wasted heat of the turbine exhaust gas yields high thermal efficiency compared to other combustion technologies. Combined-

[14] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

cycle plants currently entering service can convert about 50 percent of the chemical energy of natural gas into electricity (HHV basis[15]). Cogeneration provides additional efficiency. In these, steam is bled from the steam generator, steam turbine or turbine exhaust to serve thermal loads[16].

A single-train combined-cycle plant consists of one gas turbine, a heat recovery steam generator (HSRG) and a steam turbine generator ("1 x 1" or "single train" configuration), often all mounted on a single shaft. F-class gas turbines - the most common technology in use for large plants - in this configuration can produce about 270 megawatts. Uncommon in the Northwest, but common in high load growth are plants using two or even three gas turbine generators and heat recovery steam generators feeding a single, proportionally larger steam turbine generator. Larger plant sizes result in construction and operational economies and slightly improved efficiency. A 2 x 1 configuration using F-class technology will produce about 540 megawatts of capacity. Other plant components include a switchyard for electrical interconnection, cooling towers for cooling the steam turbine condenser, a water treatment facility and control and maintenance facilities.

Additional peaking capacity can be obtained by use of inlet air chilling and duct firing (direct combustion of natural gas in the heat recovery steam generator to produce additional steam). 20 to 50 megawatts can be gained from a single-train F-class plant with duct firing. Though the incremental thermal efficiency of duct firing is lower than that of the base combined-cycle plant, the incremental capital cost is low and the additional electrical output can be valuable during peak load periods.

Gas turbines can operate on either gas or liquid fuels. Pipeline natural gas is the fuel of choice because of historically low and relatively stable prices, extensive delivery network and low air emissions. Distillate fuel oil can be used as a backup fuel, however, its use for this purpose has become less common in recent years because of additional emissions of sulfur oxides, deleterious effects on catalysts for the control of nitrogen oxides and carbon monoxide and increased testing and maintenance. It is common to ensure fuel availability by subscribing to firm gas transportation.

Combined-cycle plant development benefits from improved gas turbine technology, in turn driven by military and aerospace applications. The tradeoff to improving gas turbine efficiency is to increase power turbine inlet temperatures while maintaining reliability and maintaining or reducing NOx formation. Most recently completed combined-cycle plants use "F-class" gas turbine technology. F-class machines are distinguished by firing temperatures of 1,300^{o}C (2370^{o} F) and basic [17]HHV heat rates of 6,640 - 6,680 Btu per kilowatt-hour in combined-cycle configuration. More advanced "G-class" machines, now in early commercial service, operate at firing temperatures of about 1,400^{o} C (2550^{o} F) and basic HHV heat rates of 6,490 - 6,510 Btu per kilowatt-hour in combined-cycle configuration. H-class machines, entering commercial demonstration, feature steam cooling

[15] The energy content of natural gas can be expressed on a higher heating value or lower heating value basis. Higher heating value includes the heat of vaporization of water formed as a product of combustion, whereas lower heating value does not. While it is customary for manufacturers to rate equipment on a lower heating value basis, fuel is generally purchased on the basis of higher heating value. Higher heating value is used as a convention in Council documents unless otherwise stated.

[16] Though increasing overall thermal efficiency, steam bleed for CHP applications will reduce the electrical output of the plant.

[17] Higher heat value, new and clean, excluding air intake, exhaust and auxiliary equipment losses.

of hot section parts, firing temperatures in the 1,430^o C range (2,610^o F), and an expected HHV heat rate of 6,320 Btu per kilowatt-hour.

Economics

The cost of power from a combined-cycle plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. Typically the largest component of these costs will be variable fuel cost. Combined-cycle gas turbines deliver high efficiency at low capital cost. The overnight capital cost of the reference combined-cycle plant, $525 per kilowatt, is the lowest of any of the generating technologies in this plan except for industrial simple-cycle gas turbines. As long as natural gas prices remained low, the result was a power plant capable of economical baseload operation at low capital investment - an unbeatable combination leading to the predominance of combined-cycle plant for capacity additions on the western grid over the past decade. Higher gas prices combined with depressed power prices have eroded this competitive advantage and many combined-cycle plants are currently operating at low capacity factors. The future economic position of combined-cycle plants is uncertain. If natural gas prices decline from current highs, these plans may again become economically competitive baseload generating plants. Their economic position could be further improved by more aggressive efforts to reduce carbon dioxide production. The low carbon-to-hydrogen ratio of natural gas and the high thermal efficiency of combined-cycle units could position the technology to displace conventional coal-fired plants if universal carbon dioxide caps or penalties were established.

Development Issues

Though natural gas production activities can incur significant environmental impacts, the environmental effects of combined cycle power plants are relatively minor. The principal environmental concerns associated with the operation of combined-cycle gas turbine plants are emissions of nitrogen oxides and carbon monoxide. Fuel oil operation may produce in addition, sulfur dioxide. Nitrogen oxide abatement is accomplished by use of “dry low-NOx” combustors and selective catalytic reduction within the heat recovery steam generator. Limited quantities of ammonia are released by operation of the nitrogen oxide selective catalytic reduction system. Carbon monoxide emissions are typically controlled by use of an oxidation catalyst within the heat recovery steam generator. If operating on natural gas, no special controls are used for particulates or sulfur oxides as these are produced only in trace amounts. Low sulfur fuel oil and limitation on hours of operation are used to control sulfur oxides when using fuel oil.

Though proportionally about two thirds less than for steam-electric technologies, the cooling water consumption of combined-cycle plants is significant if evaporative cooling is used. Water consumption for power plant condenser cooling appears to be an issue of increasing importance in the arid west. Water consumption can be reduced by use of dry (closed-cycle) cooling, though at added cost and reduced efficiency. Over time it appears likely that an increasing number of new projects will use dry cooling.

Carbon dioxide, a greenhouse gas, is an unavoidable product of combustion of fossil fuels. However, because of the relatively low carbon content of natural gas and the high efficiency of combined-cycle technology, the carbon dioxide production of a gas-fired combined-cycle plant on a unit output basis is much lower than that of other fossil fuel technologies. The reference plant, described below, would produce about 0.8 pounds CO_2 per kilowatt-hour output, whereas a new coal-fired power plant would produce about 2 pounds CO_2 per kilowatt-hour.

Northwest Potential

New combined-cycle power plants would be constructed in the Northwest for the purpose of providing base and intermediate load service. While the economics of combined-cycle plants are currently less favorable than in the recent past, a decline in natural gas prices or more aggressive carbon dioxide control efforts could lead to additional development of combined-cycle plants. Suitable sites are abundant, including many close to Westside load centers. Proximity to natural gas mainlines and access to loads via existing high voltage transmission are the key site requirements. Secondary factors include water availability, ambient air quality and elevation. Permits are currently in place for several thousand megawatts of new combined-cycle capacity and are being sought for several thousand more.

More constraining may be future natural gas supplies. While there is currently no physical shortage of domestic natural gas, consensus is emerging that ability to tap the abundant off-shore sources of natural gas via LNG import capability will be necessary to control long-term natural gas prices.

Reference plant

The reference plant is based on an F-class gas turbine generator in 2 x 1 combined-cycle configuration. The baseload capacity is 540 megawatts and the plant includes an additional 70 megawatts of power augmentation using duct burners. The plant is fuelled with pipeline natural gas using an incrementally-priced firm gas transportation contract with capacity release provision. 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. Specific characteristics of the reference plant are shown in Table I-10. Key cost and performance characteristics for a single-train (1x1) plant are also noted.

Benchmark[18] levelized electricity production costs for reference combined-cycle turbines are as follows:

540/610 MW combined-cycle, baseload increment, 80 percent capacity factor	$41/MWh
540/610 MW combined-cycle, peaking increment, 10 percent capacity factor	$117/MWh
270/305 MW combined-cycle, baseload increment, 80 percent capacity factor	$43/MWh
270/305 MW combined-cycle, peaking increment, 10 percent capacity factor	$126/MWh

[18] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; firm natural gas, Westside delivery, medium case price forecast; no wheeling charges or losses, year 2000 dollars. No CO2 penalty.

The capacity cost (fixed costs, generally a better comparative measure of the cost of peaking or emergency duty projects) for the peaking increment of the reference 540/610 megawatt unit under the benchmark financing assumptions is $71 per kilowatt per year. The capacity cost for the peaking increment of the reference 270/305 megawatt unit under the benchmark financing assumptions is $79 per kilowatt per year.

Table I-10: Resource characterization: Natural gas combined-cycle plant (Year 2000 dollars)

Description and technical performance		
Facility	Natural gas-fired combined-cycle gas turbine power plant. 2 GT x 1 ST configuration. F Class gas turbine technology. 540 MW new & clean baseload output @ ISO conditions, plus 70 MW of capacity augmentation (duct-firing). No cogeneration load. Dry SCR for NOx control, CO catalyst for CO control. Wet mechanical draft cooling.	Key cost and performance assumptions for single train (1x1) plants are noted.
Status	Commercially mature	
Application	Baseload and peaking generation, cogeneration	
Fuel	Pipeline natural gas. Firm transportation contract with capacity release provisions.	
Service life	30 years	
Power (net)	New & clean: 540 MW (baseload), 610 MW (peak) Lifetime average: 528 MW (baseload), 597 MW (peak)	Lifetime average is based on 1 % degradation per year and 98.75% recovery at hot gas path inspection or major overhaul (General Electric).
Operating limits	Minimum load: 40% of baseload rating. Cold startup: 3 hours Ramp rate: 7 %/min	Minimum load for single-train plant is 80% of baseload rating. Minimum load is assumed to be one gas turbine in service at point of minimum constant firing temperature operation.
Availability	Scheduled outage: 18 days/yr Equivalent forced outage rate: 5% Mean time to repair: 24 hours Equivalent annual availability: 90% (Reduce 2.2% if using new & clean capacity)	The scheduled outage rate is based on a planned maintenance schedule comprised of 7-day annual inspections, 10-day hot gas path inspection & overhauls every third year and a 28-day major overhaul every sixth year (General Electric recommendations for baseload service). The assumed rate also includes two additional 28-day scheduled outages and one six-month plant rebuild during the 30-year plant life. The forced outage rate is from NERC Generating Availability Data System (GADS) weighted average equivalent forced outage rate for combined-cycle plants. Mean time to repair is GADS average for full outages.

Description and technical performance		
Heat rate (HHV, net, ISO conditions)	New & clean (Btu/kWh): 6880 (baseload); 9290 (incremental duct firing); 7180 (full power) Lifetime average (Btu/kWh): 7030 (baseload); 9500 (incremental duct firing); 7340 (full power). 2002 base technology.	Baseload is new & clean rating for GE 207FA. Lifetime average is new & clean value derated by 2.2%. Degradation estimates are from General Electric. Duct firing heat rate is Generating Resource Advisory Committee (GRAC) recommendation.
Technology vintage heat rate improvement (Surrogate for cumulative non-cost technical improvements)	-0.5 %/yr average from 2002 base through 2025	Approximate 95% technical progress ratio (5% learning rate). Mid-range between EIA Assumptions to the Annual Energy Outlook 2004 (Table 39) (pessimistic) & Chalmers University of Technology, Feb 2001 (Sweden) (optimistic). Forecast WECC penetration is used as surrogate for global production.
Seasonal power output (ambient air temperature sensitivity)	Figure I-1	Figure I-1 is based on power output ambient temperature curve for a General Electric STAG combined-cycle plant, from Figure 34 of GE Combined-cycle Product Line and performance (GER 3574H) and 30-year monthly average temperatures for the sites shown.
Elevation adjustment for power output	Table I-11	Based on the altitude correction curve of Figure 9 of General Electric Power Systems GE Gas Turbine Performance characteristics (GER 3567H).

Costs & development schedule		
Capital cost (Overnight, development and construction)	Baseload configuration: $565/kW Power augmentation configuration: $525/kW Incremental cost of power augmentation (duct burners) $225/kW.	Assumes development costs are capitalized. Overnight cost excludes financing fees and interest during construction. 1x1 plant estimated to cost 110% of example plant. Based on new and clean rating. Derived from reported plant costs (2002), adjusted to approximate equilibrium market conditions.
Development & construction cash flow (%/yr)	Cash flow for “straight-through” 48-month development & construction schedule: 2%/2%/24%/72%	See Table I-11 for phased development assumptions used in portfolio risk studies.
Fixed operating costs	Baseload configuration: $8.85/kW/yr. Power augmentation configuration: $8.10/kW/yr.	Includes operating labor, routine maintenance, general & overhead, fees, contingency, and allowances for (normally) capitalized equipment replacement costs and startup costs. Excludes property taxes and insurance (separately calculated in the Council’s models as 1.4%/yr and 0.25%/yr of assessed value). Fixed O&M costs for a 1x1 plant estimated to be 167% of example plant costs. Values are based on new and clean rating.

Costs & development schedule		
Variable operating costs	$2.80/MWh	Includes consumables, SCR catalyst replacement, makeup water and wastewater disposal costs, long-term major equipment service agreement, contingency and an allowance for sales tax. Excludes any CO2 offset fees or penalties.
Incentives/Byproduct credits/CO2 penalties	Separately included in the Council's models.	
Interconnection and regional transmission costs	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded. Bonneville 2004 transmission tariff.
Regional transmission losses	1.9%	Bonneville contractual line losses.
Technology vintage cost change (constant dollar escalation)	-0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs)	See technology vintage heat rate improvement, above.

Typical air emissions (Plant site, excluding gas production & delivery)		
Particulates (PM-10)	0.02 T/GWh	River Road project permit limit
SO2	0.002 T/GWh	River Road project actual
NOx	0.039 T/GWh	Ibid
CO	0.005 T/GWh	Ibid
Hydrocarbon/VOC	0.0003 T/GWh	Ibid
Ammonia	0.0000006 T/GWh	Ibid. Slip from catalyst.
CO_2	411 T/GWh (baseload operation) 429 T/GWh (full power operation)	Based on EPA standard natural gas carbon content assumption (117 lb/MMBtu) and lifecycle average heat rates.

Development		
Assumed mix of developers	For electricity price forecasting: Consumer-owned utility: 20% Investor-owned utility: 20% Independent power producer: 60% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is a GRAC recommendation. Resource comparison mix is a standard mix for comparison of resources.
Development & construction schedule	Development - 24 Months Construction - 24 months	"Straight-through" development. See Table I-11 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	Suspended projects - 2006 Permitted sites - 2007	
Site availability and development limits through 2025	Adequate to meet forecast Northwest needs.	

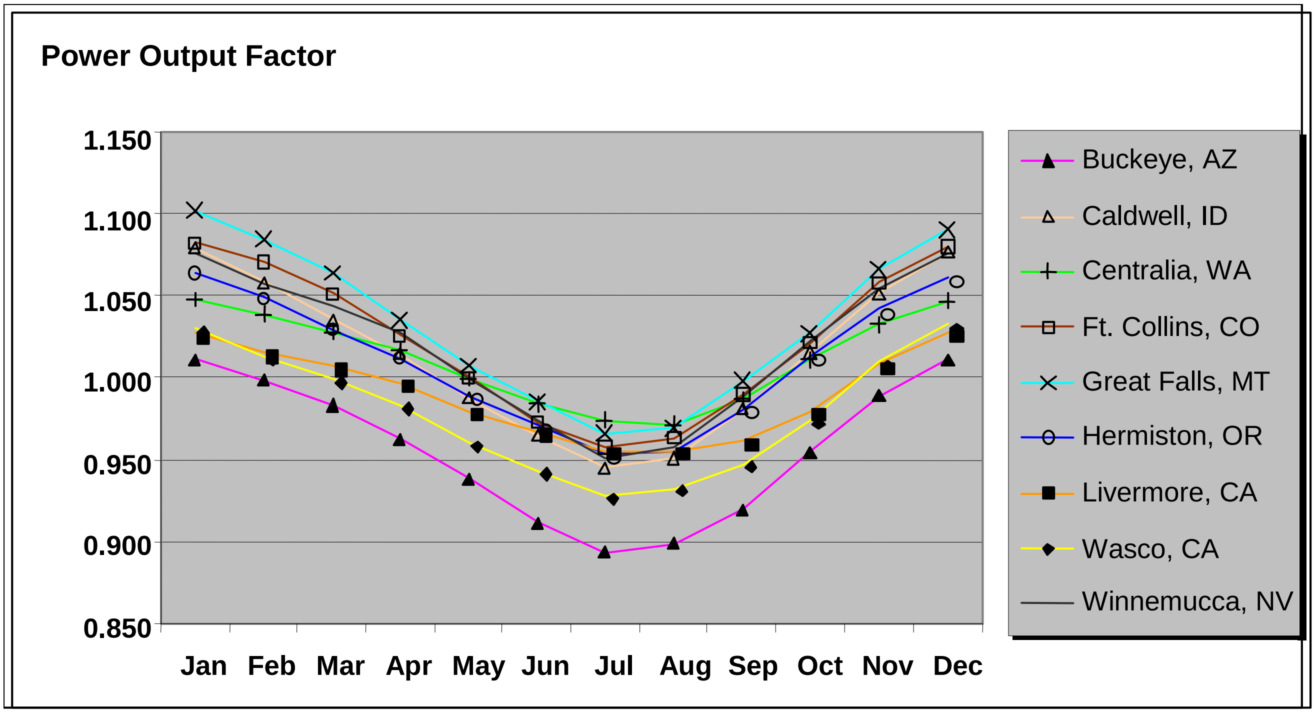

Figure I-1: Gas turbine combined-cycle average monthly power output temperature correction factors for selected locations (relative to ISO conditions)

Table I-11: Gas turbine power output elevation correction factors for selected locations

Location	Elevation (ft)	Power Output Factor
Buckeye, AZ (near Palo Verde)	890	0.972
Caldwell, ID	2370	0.923
Centralia, WA	185	0.995
Ft. Collins, CO	5004	0.836
Great Falls, MT	3663	0.880
Hermiston, OR	640	0.980
Livermore, CA	480	0.985
Wasco, CA (nr. Kern County plants)	345	0.990
Winnemucca, NV	4298	0.859

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-12. The cumulative schedule of the three project phases shown in Table I-12 is longer than the "straight-through" development and construction schedule shown in Table I-10.

Table I-12: Natural gas combined-cycle project phased development assumptions for risk analysis (year 2000 dollars)[19]

	Development	Optional Construction	Committed Construction
Defining milestones	Feasibility study through completion of permitting	Notice to proceed to major equipment foundations complete	Accept major equipment to commercial operation
Time to complete (single unit, nearest quarter)	24 months	15 months	12 months
Cash expended (% of overnight capital)	4%	24%	72%
Cost to suspend at end of phase ($/kW)	Negligible	$169	--
Cost to hold at end of phase ($/kW/yr)	$1	$4	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	$25	--
Cost of immediate termination ($/kW)	Negligible	$100	--

WINDPOWER

The first commercial-scale wind plant in the Northwest was the 25 megawatt Vansycle project in Umatilla County, Oregon, placed in service in 1998. Development of windpower proceeded rapidly following the energy crisis of 2000 and six commercial-scale projects totaling 541 megawatts of capacity are now in-service in the region. Regional utilities also own or contract for the output of Wyoming projects developed during this same period. Together, these projects currently comprise 651 megawatts of installed capacity, about 1.3 percent of the total capacity available to the region. This capacity produces about 220 average megawatts of energy. Declining power prices and expiration of federal production tax credits at the end of 2003 brought an end to this period of rapid wind power development. However, Northwest utilities continue to be interested in securing additional windpower and

[19] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

development is expected to resume following the recent extension of the production tax credit through 2005.

Technology

Wind energy is converted to electricity by wind turbine generators - tower-mounted electric generators driven by rotating airfoils. Because of the low energy density of wind, utility-scale wind turbine generators are physically large, and a wind power plant comprised of tens to hundreds of units. In addition to the wind turbine generators, a wind power plant (often called a “wind farm”) includes meteorological towers, service roads, a control system (often remote), a voltage transformation and transmission system connecting the individual turbines to a central substation, a substation to step up voltage for long-distance transmission and an electrical interconnection to the main transmission grid.

The typical utility-scale wind turbine generator is a horizontal axis machine of 600 to 1,500 kilowatts capacity with a three-bladed rotor 150 to 250 feet in diameter. The machines are mounted on tubular towers ranging to over 250 feet in height. Trends in machine design include improved airfoils; larger machines; taller towers and improved controls. Improved airfoils increase energy capture. Larger machines provide economies of manufacturing, installation and operation. Because wind speed generally increases with elevation above the surface, taller towers and larger machines intercept more energy. Machines for terrestrial applications are fully commercial and as reliable as other forms of power generation. Turbine size has increased rapidly in recent years and multi-megawatt (2 - 4.5 megawatts) machines are being introduced. These are expected to see initial service in European offshore applications.

Economics

The cost of power from a wind plant is comprised of capital service costs, fixed and variable operating and maintenance costs, system integration costs and transmission costs. Capital costs represent the largest component of overall costs and machine costs the largest component of capital costs. Though capital costs of wind power plants have remained relatively constant near $1,000 per kilowatt for several years, production costs have declined because of improvements in turbine performance and reliability, site selection and turbine layout. Busbar (unshaped) energy production costs at better sites are now in the range of $40-50 per megawatt-hour, excluding incentives.

Shaping costs are reported to be in the range of $3 to 7 per megawatt-hour, much lower than earlier estimates. While this range may be representative of the cost of shaping the output of the next several hundred megawatts of wind power developed in the region, shaping costs for additional levels of windpower development are uncertain. In the Northwest, shaping of additional increments of windpower capacity may draw water from higher value uses, increasing shaping cost. Offsetting this is the possible effect of geographic diversity in reducing the variability of windpower output. We assume a $4.55 per megawatt-hour shaping cost for the first 2,500 megawatts of wind capacity. The cost of shaping the second 2,500 megawatts of wind capacity, and any Montana capacity is assumed to be $9.75 per megawatt-hour.

The competitive position of wind power remains heavily dependent upon the federal production tax credit and to a lesser extent the value of green tags. Project construction ceased with expiration of the production tax credit at the end of 2003. The recent one-year reinstatement of the production tax credit will likely bring the cost of windpower below wholesale power value and result in a cycle of new development. But unless natural gas prices remain high, and mandatory carbon dioxide penalties enacted, it will be several years before wind power can compete with other resource options without incentives. The most important incentive is the federal production tax credit, currently about $18 per megawatt-hour, available for the first ten years of project operation. Complementing the production tax credit have been energy premiums resulting from the market for "green" power that has developed in recent years. This market is driven by retail green power offerings, utility efforts to diversify and "green up" resource portfolios, green power acquisition mandates imposed by public utility commissions as a condition of utility acquisitions, renewable portfolio standards and system benefits funds established in conjunction with industry restructuring. Because of the great uncertainty regarding future production tax credit and green tag values, these are modeled as uncertainties in the portfolio risk analysis (Chapter 6).

Development Issues

Many of the issues that formerly impeded the development of wind power have been largely resolved in recent years, clearing the way for the significant development that has occurred in the Northwest. Avian mortality, aesthetic and cultural impacts have been alleviated in the Northwest by the use of sites in dryland agriculture. The impact of wind machines on birds, which has been significant at some California wind plants has been also reduced by better understanding of the interrelationship of birds, habitat and wind turbines. Siting on arid habitat of low ecological productivity, elimination of perching sites on wind machines, slower turbine rotation speeds, and siting of individual turbines with a better understanding of avian behavior have greatly reduced avian mortality at recently developed projects. Bat mortality, however, is of concern at some sites.

It appears likely that several hundred to a thousand or more megawatts of wind power can be shaped at relatively low cost. The cost of firming and shaping the full amount of wind energy included in this plan are uncertain, pending further operating experience and analysis. Northwest wind development to date has not required expansion of transmission capacity, which can be expensive for wind developers because of the low capacity factor of wind plants. The wind potential included in this plan is expected to be accessible without significant expansion of transmission capacity.

Development of the high quality and extensive wind resources of eastern Montana is confronted by the same transmission issues faced by development of mine mouth coal-fired power plants in eastern Montana, except that the comparatively low capacity factor of a wind project renders transmission even more expensive. Though the eastern transmission interties are largely committed, several hundred megawatts of additional transmission capacity may be available at low cost through better use of existing capacity and low-cost upgrades to existing circuits. This potential is currently under evaluation. Export of additional power from eastern Montana would require the construction of new long-distance transmission circuits. Preliminary estimates of the cost of an additional 500kV circuit out of eastern

Montana indicate that the resulting cost of power delivered to the Mid-Columbia area would not be competitive with the cost of power from wind plants sited in resource areas of lesser quality west of the Continental Divide. Additional obstacles to construction of new eastern intertie circuits include long lead time (six to eight years from conception to energization), limited corridor options for crossing the Rocky Mountains and the current lack of an entity capable of large-scale transmission planning, financing and construction.

Northwest Potential

Winds blow everywhere and a few very windy days annually may earn a site a windy reputation, but only areas with sustained strong winds averaging roughly 15 mph, or more are suitable for electric power generation. A good wind resource area will have smooth topography and low vegetation to minimize turbulence, sufficient developable area to achieve economies of scale, daily and seasonal wind characteristics coincident to electrical loads, nearby transmission, complementary land use and absence of sensitive species and habitat. Because of the low capacity factors typical of wind generation, transmission of unshaped wind energy is expensive. Interconnection distance and distance to shaping resources are very important.

Because of complex topography and land use limitations, only localized areas of the Northwest are potentially suitable for windpower development. However, excellent sites are found within the region. Wind resource areas in the Northwest include coastal sites with strong but irregular storm driven winds and summertime northwesterly winds. Areas lying east of gaps in the Cascade and Rocky mountain ranges receive concentrated prevailing westerly winds plus wintertime northerly winds and winds generated by east-west pressure differentials. The Stateline area east of the Columbia River Gorge, Kittitas County in Washington and the Blackfoot area of north central Montana are of this type. A third type of regional wind resource area is found on the north-south ridges of the Basin and Range geologic region of southeastern Oregon and southern Idaho.

Intensive prospecting and monitoring are required to confirm the potential of a wind resource area. Though much wind resource information is proprietary, the results of early resource assessment efforts of the Bonneville Power Administration, the U.S. Department of Energy and the State of Montana, recently compiled resource maps based on computer modeling plus a the locations of announced wind projects give a sense of the general location and characteristics of prime Northwest wind resource areas. Educated guesses by members of the Council's Generating Resource Advisory Committee suggest that several thousand megawatts of developable potential occur within feasible interconnection distance of existing transmission. This estimate is supported by the 3,600 megawatts aggregate capacity of announced but undeveloped wind projects. For the base case portfolio analyses and power price forecasting we assume 5,000 megawatts of developable potential west of the Continental Divide.

Reference plants

The reference plant is a 100-megawatt wind plant located in a prime wind resource area within 10 to 20 miles of an existing substation. The plant would consist of 50 to 100 utility-scale wind machines. Sites west of the Rocky Mountains are classified into two blocks of 2,500 megawatts each. The first block represents the best, undeveloped sites, with an average capacity factor of 30 percent. These sites are assumed to be the first developed and thereby secure relatively low shaping costs of $4.55 per megawatt-hour. The second block is of lesser quality, yielding a capacity factor of 28 percent[20]. Because these lesser quality sites are likely to be developed later than the first block, they are assumed to incur higher shaping costs of $9.75 per megawatt-hour. Sites east of the Rocky Mountains are assumed to yield a capacity factor of 36 percent and incur a shaping cost of $9.75 per megawatt-hour. These sites are electrically isolated from the regional load centers and would require construction of long-distance transmission to access outside markets. Planning assumptions for the three resource blocks are provided in Table I-13.

The Northwest Transmission Assessment Committee of the Northwest Power Pool is developing cost estimates for additional transmission from eastern Montana to the Mid-Columbia area. As of this writing, only very preliminary estimates of the cost of a new 500 kV AC circuit were available. These, together with other modeling assumptions regarding additional eastern Montana - Mid-Columbia transmission are shown in Table I-4.

The benchmark[21] levelized electricity production costs for reference wind power plants, power shaped and delivered as shown, are as follows:

Eastern Montana, local service	$41/MWh
Eastern Montana, via existing transmission to Mid-Columbia area	$40/MWh
Eastern Montana, via new transmission to Mid-Columbia area, shaped @Mid-C	$82/MWh
Mid-Columbia, Block I	$43/MWh
Mid-Columbia, Block II	$50/MWh

[20] Because of portfolio model limitations, this block was assumed to operate at a 30 percent capacity factor.
[21] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; Montana coal, year 2000 dollars. No production tax credit or green tag credit.

Table I-13: Resource characterization: Wind power plants (Year 2000 dollars)

Facility description and technical performance		
Facility	100 MW central-station wind power project.	Utility-scale projects may range from 25 to 300 MW.
Status	Commercial	.
Application	Intermittent baseload power generation	
Fuel	n/a	
Service life	30 years	Typical design life for Danish wind turbine generators is estimated to be 20 years (Danish Wind Industry Association). 30 years, with allowance for capital replacement is used for consistency with other resources.
Power	100 MW	Net of in-farm and local interconnection losses.
Operating limits	n/a	
Availability	Scheduled outage: Included in capacity factor estimate. Equivalent forced outage rate: Included in capacity factor estimate. Mean time to repair: Zero hours	
Capacity factor	West of Continental Divide Block 1: 30% West of Continental Divide Block 2: 28% East of Continental Divide Block 3: 36%	Net of in-farm and local interconnection losses and outages and elevation (atmospheric density) effects.
Technology development	2000-04 annual average: -3.1 % 2005-09 annual average: -2.3 % 2010-14 annual average: -2.1 % 2015-19 annual average: -1.9 %	Applied to capital and fixed O&M cost. Represents effective reduction in production cost from cost & performance improvements. Based on 90% technical progress ratio (10% learning rate), derived from historical trends.
Seasonal power output	Table I-14	
Diurnal power output	None assumed	Insufficient evidence of diurnal pattern for Northwest resource areas.
Elevation adjustment for power output	Implicit in capacity factor.	

Costs		
Development & construction	$1010/kW (overnight). Range $1120/kW (25 MW project) to $930/kW (300 MW project).	Includes project development, turbines, site improvements, erection, substation, startup costs & working capital. "Overnight" cost excludes interest during construction.
Development and construction annual cash flow	1% - 13% - 86%	"Straight-through" development. See Table I-4 for phased development assumptions used in portfolio risk studies.
Capital replacement	$2.50/kW/yr	Levelized cost of major capital replacements over life of facility (e.g. blade or gearbox replacement) (EPRI, 1997)

Costs		
Fixed operating cost	$17.50/kW/yr. plus property tax & insurance. Property tax: 1.4%/yr of capital investment Insurance: 0.25%/yr of capital investment	Includes operating labor, routine maintenance, general & overhead costs
Variable operating cost	$1.00/MWh	Land lease
Interconnection and in-region firm-point-to-point transmission and required ancillary services.	$15.00/kW/yr	Bonneville point-to-point transmission rate (PTP-02) plus Scheduling, System Control and Dispatch, and Reactive Supply and Voltage Control ancillary services, rounded
Transmission energy loss adjustment.	1.9%	Represents transmission losses within modeled load-resource area. Losses between load-resource areas are separately modeled. (BPA contractual line losses.) Omit for busbar calculations.
Vintage cost escalation (technology development)	2000-04 annual average: -3.1 % 2005-09 annual average: -2.3 % 2010-14 annual average: -2.1 % 2015-19 annual average: -1.9 %	Net reduction in capital and fixed O&M cost of cost & performance improvements. Based on 10% learning rate (90% progress ratio) for each doubling in global capacity.
Shaping cost	West of Continental Divide Block 1: $4.55/MWh West of Continental Divide Block 2: $9.75MWh East of Continental Divide Block 3: $9.75/MWh	Applied to simulate flat product comparable to dispatchable resources.
Production tax credit	Modeled as described in Chapter 6	
Value of “green” attributes	Modeled as described in Chapter 6	

Development		
Assumed mix of developers	For electricity price forecasting: Consumer-owned utility: 15% Investor-owned utility: 15% Independent power producer: 70% For resource comparisons & portfolio analysis: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Price forecasting (expected) mix is a GRAC recommendation. Resource comparison mix is a standard mix for comparison of resources.
Development & construction schedule	Development - 18 months Construction - 12 months	“Straight-through” development. See Table I-4 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	Permitted sites - 2005 New sites - 2008	
Resource availability and development limits 2005 - 2024	West of Cascades: 500 MW ID, OR, WA east of Cascades: 4500 MW MT in-state - no limit MT to Mid-Columbia - 400 MW w/existing transmission	

Table I-14: Normalized monthly wind energy distribution

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Basin & Range	1.19	1.39	1.07	1.05	0.94	0.71	0.56	0.61	0.72	0.74	1.59	1.43
Cascades & Inland	1.03	0.90	1.07	1.07	1.21	1.07	1.11	1.07	0.94	0.73	0.85	0.96
Northwest Coast	1.19	1.57	1.07	0.86	0.84	0.84	1.01	0.54	0.66	0.80	1.40	1.21
Rockies & Plains	1.61	1.57	1.02	0.84	0.77	0.73	0.35	0.42	0.52	1.00	1.30	1.88

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are modeled: project development, optional construction and committed construction. The project development phase consists of siting, permitting and other pre-construction activities. Optional construction extends from the notice to proceed to irrevocable commitment of the major portion of construction cost (typically, completion of major equipment foundations in preparation for receipt of major plant equipment). The balance of construction through commercial operation is considered to be committed. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-15. The cumulative schedule of the three project phases shown in Table I-15 is longer than the "straight-through" development and construction schedule shown in Table I-13.

Table I-15: Wind project phased development assumptions for risk analysis (year 2000 dollars)[22]

	Development	Optional Construction	Committed Construction
Defining milestones	Feasibility study through completion of permitting	Turbine order through ready to ship	Turbine acceptance to commercial operation
Time to complete (nearest quarter)	18 months	9 months	6 months
Cash expended (% of overnight capital)	2%	12%	86%
Cost to suspend at end of phase ($/kW)	Negligible	$263	--
Cost to hold at end of phase ($/kW/yr)	$1	$4	--

[22] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

	Development	Optional Construction	Committed Construction
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	63	--
Cost of immediate termination ($/kW)	Negligible	$308	--

ALBERTA OIL SANDS COGENERATION

The oil sands[23] of northern Alberta contain an estimated 1.6 trillion barrels initial volume in place, the largest petroleum deposits outside the Middle East. Three major resource areas are present - Athabasca, Peace River and Cold Lake. Oil sands are comprised of unconsolidated grains of sand surrounded by a film of water and embedded in matrix of bitumen[24], water and gas (air and some methane). The mean bitumen content of Alberta oil sands ranges from 10 to 12 percent by weight. Extracted bitumen can be upgraded to a synthetic crude oil that can be processed by conventional refineries. Rising oil prices have made bitumen extraction and processing economic and production is expected to expand rapidly in coming years. Oil sands production currently comprise about one third of total Canadian oil production.

Bitumen is recovered from near-surface deposits using open pit mining followed by separation of the bitumen from the extracted oil sands. The extraction process uses hot water to separate the bitumen from the sand. About 75 percent of the bitumen is recovered and the residue is returned to the pit. Yield is about one barrel of oil for every two tons of extracted oil sands.

Bitumen from deep deposits is recovered using in-situ methods. The predominant method is steam assisted gravity drainage (SAGD). Steam is injected via injection wells to raise the temperature of the formation to the point where the bitumen will flow. The liquid bitumen is recovered using conventional production wells. It is estimated that about 80 percent of recoverable reserves will use in-situ methods.

The steam for in-situ injection can be produced using coke or natural gas-fired boilers. A more efficient approach is to cogenerate steam using gas turbine generators. Natural gas or synthetic gas derived from residuals of bitumen upgrading is used to fuel the gas turbines. Approximately 2,000 megawatts of oil sands cogeneration is in service. Additional development of electric generating capacity is constrained by limited transmission access to electricity markets. A 2,000-megawatt DC intertie from the oil sands region to the Celilo converter station near The Dalles, with intermediate converter stations near Calgary and possibly Spokane has been proposed as a means of opening markets for electricity from oil sands cogeneration. The transmission could be energized as early as 2011.

[23] Formerly known as "tar sands".
[24] Bitumen is a heavy, solid or semi-solid black or brown hydrocarbon comprised of asphaltenes, resins and oils, soluble in organic solvents. Alberta oil sands bitumen is the consistency of cold molasses at room temperature.

Economics

The cost of power from a gas turbine power plant is comprised of capital service costs, fixed and variable non-fuel operating and maintenance costs, fixed and variable fuel costs and transmission costs. In a cogeneration facility the fuel cost components are generally allocated between the cogeneration thermal load and electricity generation using a "fuel charged to power" heat rate. For a gas turbine cogeneration plant this heat rate is considerably lower than the stand-alone heat rate of the gas turbine unit. For example, the expected fuel charged to power heat rate of the proposed F-class gas turbine cogeneration units for oil sands application is 5,800 Btu per kilowatt-hour (HHV). This compares to a stand-alone HHV heat rate for an F-class machine of 10,390 Btu per kilowatt-hour. Because of the low effective heat rate and need for a constant steam supply, a gas turbine cogeneration unit will run at a high capacity factor, typically higher than a stand-alone baseload power plant. Though an 80 percent capacity factor is assumed for the benchmark costs given below, oil sands cogeneration units could operate at capacity factors of 90 to 95 percent.

The transmission costs given in Table I-16 are preliminary estimates provided by the proponents of the DC intertie. For very long distance interties, DC transmission costs are typically lower than for AC circuits. Nonetheless, the preliminary estimates appear to be low compared to the preliminary estimates for new transmission from eastern Montana. The Northwest Transmission Assessment Committee of the Northwest Power Pool will be refining these transmission estimates over the next several months.

Development Issues

Preliminary estimates suggest that power from oil sands cogeneration could be delivered to the Northwest at a levelized cost of $43 per megawatt-hour. While slightly higher than the comparable cost of electricity from a new gas fired combined cycle plant in the Mid-Columbia area, the higher thermal efficiency of oil sands cogeneration may offer better protection from natural gas price volatility. Moreover, a gasification process for deriving fuel gas from oil sands processing residuals is available. This alternative fuel could further isolate oil sands cogeneration from natural gas price risk. Also, because of the lower heat rate, the incremental carbon dioxide production of cogeneration is less than for stand-alone gas-fired generation, reducing the risk associated with possible future carbon dioxide control measures.

Development of the proposed intertie, however, would present a major challenge. Transmission siting and permitting efforts in the U.S., especially for new corridors, has proven difficult. Subscription financing is proposed. While effective for financing incremental natural gas pipeline expansions, subscription for financing large-scale transmission expansions is untested. Finally, the 2,000-megawatt capacity increment is likely too large for the Northwest to accept at one time. Some means of shortening commitment lead-time, phasing project output, or selling a portion to California Utilities would improve the feasibility for development.

Northwest Potential

The proposed DC intertie would deliver 2,000 megawatts of power to the Celilo area or to points south on the existing AC or DC interties. Whether larger increments of power are potentially available would depend upon future levels of oil sands production. Smaller, more easily integrated increments of power could be provided, but at additional cost because of transmission economies of scale. For example, a 500 kV AC transmission circuit could deliver approximately 1,000 megawatts of power. Refinement of transmission cost estimates, currently underway, will provide better estimates of the cost of various levels of development.

Reference plant

The estimated cost and technical performance a proposed 2,000 MW DC intertie from the Alberta oil sands region to Celilo and the associated gas turbine cogeneration units have been provided to the Council by Northern Lights. Northern Lights is a subsidiary of TransCanada formed to investigate and promote the concept. The project would consist of a single-circuit +/- 500kV DC transmission line from the Ft McMurray area of Alberta to the Celilo converter station in Oregon. The line would deliver 2,000 megawatts of capacity at Celilo with an input of about 2,160 megawatts. Intermediate converter taps could be provided near Calgary and near Spokane.

Electricity would be provided by 12 F-class gas turbine generators equipped with heat recovery steam generators. Each turbine would produce about 180 megawatts of electrical capacity plus steam for in-situ recovery of oil sands bitumen. The cost and performance assumptions of Table I-16 assume use of firm pipeline natural gas as fuel. A demonstration gasification project using bitumen processing byproducts is under development. If successful, the cogeneration units could be fired using synthetic gas.

Where necessary to support the Council's modeling, the Council's generic power plant assumptions have been used to augment the information supplied by TransCanada. Because of uncertainties regarding the cost and routing of the transmission intertie, the estimates of Table I-16 are considered to be very preliminary at his point

The benchmark[25] levelized electricity production costs for the reference plant, power delivered to Celilo, are $43 per megawatt-hour.

[25] Average financing cost for 20 percent customer-owned utility, 40 percent investor-owned utility and 40 percent independent power producer developer mix; 2010 service; Alberta natural gas, medium case price forecast; 90 percent capacity factor, year 2000 dollars. Based on fuel charged to power. No CO2 penalty.

Table I-16: Resource characterization: Alberta oil sands cogeneration and transmission intertie (Year 2000 dollars)

Description and technical performance		
Facility	180 MW natural gas-fired 7F-class simple-cycle gas turbine plant with heat recovery steam generator. 2000 MW DC circuit - Ft McMurray area to Celilo.	
Status	Commercially mature	
Applications	Baseload power generation with cogenerated steam for bitumen recovery	
Fuel	Pipeline natural gas. Firm transportation contract with capacity release provisions.	Council's forecast Alberta firm natural gas.
Service life	30 years	
Power (net)	180 MW/unit	
Operating limits	Minimum load: n/avail Cold startup: n/avail Ramp rate: n/avail	
Availability	Equivalent annual availability: 95%	
Heat rate (HHV)	5800 Btu/kWh (fuel charged to power)	
Heat rate improvement (surrogate for cumulative effect of non-cost technical improvements)	-0.5 %/yr average from 2002 base through 2025	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.
Seasonal power output (ambient air temperature sensitivity)	Assumed to be similar to those used for gas-fired combined-cycle power plants (Figure I-1).	
Elevation adjustment for power output	Included in gas turbine rating	

Costs		
Capital cost	Gas turbine cogeneration units: $506/kW Transmission: $621/kW	Overnight costs at 0.76 $US:$Cdn exchange rate.
Construction period cash flow (%/yr)	Gas turbine cogeneration units: 100% (one year construction) Transmission: 18%/27%/56% (3 year construction)	See Table I-8 for phased development assumptions used in portfolio risk studies.
Fixed operating costs	Gas turbine cogeneration units: Inc. in variable O&M. Transmission: $9.32	
Variable operating costs	Gas turbine cogeneration units: $2.78/MWh Transmission: $0.00	TransCanada value net of property tax & insurance
Incentives/Byproduct credits/CO2 penalties	Separately included in the Council's models.	
Interconnection and regional transmission costs	See above.	
Transmission losses	7.7% (to Celilo)	

Costs		
Technology vintage cost change (constant dollar escalation)	Gas turbine cogeneration units: -0.5 %/yr average from 2002 base through 2025 (capital and fixed O&M costs) Transmission: None	Approximate 95% technical progress ratio (5% learning rate). See combined-cycle description for derivation.

Typical air emissions (Plant site, excluding gas production & delivery)		
Particulates (PM-10)	Not available	
SO2	Not available	
NOx	Not available	
CO	Not available	
Hydrocarbons/VOC	Not available	
CO_2	365T/GWh	Based on EPA standard natural gas carbon content assumption (117 lb/MMBtu) and fuel charged to power heat rate. Corrected for transmission losses.

Development		
Assumed mix of developers	Benchmark mix: Consumer-owned utility: 20% Investor-owned utility: 40% Independent power producer: 40%	Resource comparison mix is used for the portfolio analysis and other benchmark comparisons of resources.
Development & construction schedule	Gas turbine cogeneration units: Development - 18 months Construction - 12 months Transmission Development - 48 months Construction - 36 months	"Straight-through" development. See Table I-8 for phased development assumptions used in portfolio risk studies.
Earliest commercial service	2011	
Resource availability through 2025	2000 MW	

Project Phasing Assumptions for the Portfolio Analysis

As described in Chapter 6, the portfolio risk model uses resource development flexibility as one means of coping with future uncertainties. Three phases of resource development are defined in the portfolio risk model: project development, optional construction and committed construction. Development of Alberta oil sands cogeneration for the Northwest market would have to be structured around the long lead time and large capacity increment of the proposed 2,000 megawatt DC transmission intertie. Because phased development of the proposed DC intertie is unlikely to be practical, the generation would have to be developed within a relatively brief period in order to fully use the transmission investment. The Council assumed that development of the generating capacity would occur in two 1,000 megawatt blocks. The first would be timed for completion coincidentally with the transmission intertie. The second block would be brought into service a year later. In the portfolio model, plant construction can be continued, suspended or terminated at the conclusion of project development or optional construction phases. Projects can also be terminated while suspended. The cost and schedule assumptions associated with these decisions are shown in Table I-17.

Table I-17: Alberta oil sands cogeneration and transmission intertie phased development assumptions for risk analysis (year 2000 dollars)[26]

	Project Development	Optional Construction	Committed Construction
Defining milestones	Initiate transmission system planning	Order major transmission equipment and materials.	Delivery of major transmission equipment and materials to commercial operation of second 1000 MW block of generation.
Time to complete (single unit, nearest quarter)	48 months	12 months	36 months
Cash expended (% of overnight capital)	5%	9%	86%
Cost to suspend at end of phase ($/kW)	Negligible	$340	--
Cost to hold at end of phase ($/kW/yr)	$1	$13	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/kW)	Negligible	-$74	--
Cost of immediate termination ($/kW)	Negligible	-$259	--

[26] The portfolio risk model was calibrated in year 2004 dollars for draft plan analysis. Assumptions are presented here in year 2000 dollars for consistency with other assumptions and forecasts appearing in the plan. Year 2004 dollars are obtained by multiplying year 2000 dollars by an inflation factor of 1.10.

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Carbon Dioxide Sequestration

Industrial-scale processes are available for separating carbon dioxide from the post-combustion flue gas of a steam-electric power plant or from the synthesis gas fuel of a coal gasification power plant. The separated carbon dioxide can be compressed and transported by pipeline for injection into suitable geologic formations for permanent storage ("sequestration").

Commercialization of coal-fired gasification power plants (Appendix I) is expected to boost the prospects for carbon dioxide separation and sequestration because the lower cost of carbon dioxide separation from the relatively low volume of pressurized synthesis gas fuel of a gasification plant compared to the cost of partitioning carbon dioxide from the much greater volume of steam-electric plant flue gas. Carbon dioxide can be separated using the sorbent processes currently used to remove sulfur compounds from the synthesis gas of existing gasification plants used for chemical production. Selective regenerative sorbent technology is capable of separating up to 90 percent of the carbon dioxide content of raw synthesis gas. The carbon dioxide would than be compressed to its high-density supercritical phase for pipeline transport to sequestration sites.

This process is in commercial operation at the Great Plains Synfuels Plant in central North Dakota. Here, carbon dioxide is separated, compressed and transported 205 miles by pipeline to Weyburn, Saskachewan where it is injected for enhanced oil recovery. Solvent-based regenerative processes are energy-intensive and would lower the thermal efficiency of coal gasification power plants. Selective separation membrane technology would reduce the energy requirements of carbon dioxide separation. Research, mostly at the theoretical or laboratory stage is underway for the development of selective separation membrane technology suitable for withstanding the operating conditions of a coal gasification power plant.

Among the sequestration alternatives being considered are depleted or depleting oil and gas reservoirs, unmineable coal seams, salt domes, deep saline aquifers and deep ocean disposal. Proven technology is available for injection of carbon dioxide into oil or gas-bearing formations. An advantage of sequestration involving enhanced recovery of gas, oil or coalbed methane is the byproduct value of the recovered oil or gas. Moreover, coal is often found in the general vicinity of oil or gas-bearing formations, which could reduce carbon dioxide transportation cost. Saline formations suitable for sequestration are widespread, and could also use existing injection technology, though there would be no byproduct value. Because the primary objective of existing carbon dioxide injection operations has been enhanced oil or gas recovery rather than carbon dioxide storage, additional development of monitoring capability and processes for verifying the integrity of geologic carbon dioxide disposal sites is needed.

Preliminary assessment of the costs of carbon dioxide transportation and storage range from $1.00 to over $16/tonCO2 for a power plant located near suitable depleted oil or gas reservoirs or saline aquifers (Table K-1)[1]. These estimates do not include the possible byproduct value of

[1] Heddle, Gemma, et al. The Economics of Carbon Dioxide Storage (MIT LFEE 2003-003 RP). MIT Laboratory for Energy and the Environment. August 2003.

enhanced oil or gas recovery. The report from which the values of Table K-1 were obtained also examined the cost of ocean disposal of carbon dioxide. These estimates were omitted from Table K-1 because the feasibility of ocean disposal appears to be speculative at this time.

Deep saline aquifers and bedded salt formations potentially suited for carbon dioxide sequestration are present in eastern Montana. The US DOE has provided matching funds to establish several Regional Carbon Sequestration Partnerships. These include the Northern Rockies and Great Plains partnership, led by Montana State University. This group will identify carbon dioxide sources and promising geologic and terrestrial storage sites in Montana, Idaho and South Dakota. The West Coast Regional partnership, led by the California Energy Commission will pursue similar objectives in the West Coast states, Arizona and Nevada.

Table K-1: Estimated costs for transporting & storing 7389 tonnes (8146 Tons) carbon dioxide per day ($/TonCO2, year 2000$)[2]

Depleted gas reservoir		
Base	Compression to 152 bar (2204 psi) at IGCC plant; 100km (62 mi) 12" (nominal) pipeline to injection site; 5000 ft injection wells. No recompression.	$4.10
Low cost	Compression to 152 bar (2204 psi) at IGCC plant adjacent to injection site; 2000 ft injection wells. No recompression.	$1.00
High cost	Compression to 152 bar (2204 psi) at IGCC plant; 300km (186 mi) 13.8" (min.) pipeline to injection site; 10,000 ft injection wells. No recompression.	$16.30
Depleted oil reservoir		
Base	Compression to 152 bar (2204 psi) at IGCC plant; 100km (62 mi) 12" (nominal) pipeline to injection site; 5100 ft injection wells. No recompression.	$3.20
Low cost	Compression to 152 bar (2204 psi) at IGCC plant adjacent to injection site; 5000 ft injection wells. No recompression.	$1.00
High cost	Compression to 152 bar (2204 psi) at IGCC plant; 300km (186 mi) 13.8" (min.) pipeline to injection site; 7000 ft injection wells. No recompression.	$9.40
Saline aquifer		
Base	Compression to 152 bar (2204 psi) at IGCC plant; 100km (62 mi) 12" (nominal) pipeline to injection site; 4100 ft injection wells. No recompression.	$2.50
Low cost	Compression to 152 bar (2204 psi) at IGCC plant adjacent to injection site; 2300 ft injection wells. No recompression.	$1.00
High cost	Compression to 152 bar (2204 psi) at IGCC plant; 300km (186 mi) 13.8" (min.) pipeline to injection site; 5600 ft injection wells. No recompression.	$9.80

2 Estimates exclude separation costs and possible byproduct credit from enhanced gas or oil recovery.

The Portfolio Model

Introduction

The portfolio model is a simple Excel worksheet that calculates energy and costs associated with meeting regional requirements for electricity. The energy and costs are for a single plan under a specific future.[1] As described in Chapter 6, estimating costs for a plan under many futures is necessary in order to obtain a likelihood distribution for cost. Preparing the feasibility space and efficient frontier, in turn, require the evaluation of many plans. Part of the objective of this appendix is to explain how the portfolio model works within other applications to achieve the goal of creating the feasibility space.

This appendix begins with a description of portfolio model principles. A flow diagram of the overall modeling process orients the reader to where the portfolio model fits into the process. The flow diagram shows that *period-specific* calculations are the lowest-level and simplest calculations in the workbook, providing a starting place for the detailed description of the model. (See “Single Period,” beginning on page L-11.) The *period-specific* section also outlines the model’s approach to calculating costs. Certain aspects of uncertainty and portfolio element behavior require a consideration of what is happening over time and how events in one period affect those in subsequent periods. In the section “Multiple Periods” on page L-58, the appendix discusses the inter-period nature of correlations and behaviors. This section also addresses the operation of smelters, the construction of new resources, and other activities that rely on events over multiple periods.

It is important to note that a portion of the description of the portfolio model is in Appendix P, instead of here in Appendix L. The treatment of uncertainties, like load and hydro generation, are to some extent separable from the rest of the model. (This appendix identifies a particular range of the model worksheet that creates the futures later in this introduction, on page L-10.) Because the description of uncertainties appears in Appendix P, it makes sense to describe the regional model’s treatment of those uncertainties in the same place. This appendix provides additional explanation wherever the uncertainties bear on the aspects of the model discussed here.

The section “Resource Implementation and Data,” beginning on page L-92, presents the rationale and references for most of the model’s data. The section identifies key parameters for existing and candidate generation resources, system benefit charge (SBC) wind additions, and contract imports and exports. It also discusses the characteristics and treatment of independent power producers (IPPs).

[1] Chapter 6 defines the terms “plan,” “future,” and “scenario” and provides examples. The glossary of this appendix includes brief definitions.

The appendix next describes the Council's modeling efforts. It illustrates how the Crystal Ball® Monte Carlo games are prepared and how the OptQuest™ stochastic optimization application is configured. The appendix lists some special utilities that extract data, prepare reports, and assist users to verify calculations. It summarizes the insights the Council has obtained through application of these tools and provides, in particular, an explanation of the value of conservation under uncertainty, which deterministic models fail to capture.

The appendix concludes with an introduction to ***Olivia***, the meta-model that created the regional portfolio model. ***Olivia*** creates Crystal Ball-aware Excel workbooks ready for use under Crystal Ball and OptQuest or for stand-alone use. ***Olivia*** is available free to any individual or agency that wants to create a portfolio or risk model describing their unique situation.

The reader may want to consult the following Table of Contents for orientation to the remaining appendix.

Table of Contents

Principles

The portfolio model is a simple calculation engine. For a given plan, it estimates costs of generation, of wholesale power purchases and sales, and of capacity expansion over the 20-year study under a particular future. An Excel add-in, Decisioneering Inc.'s Crystal Ball, runs a Monte Carlo simulation, with each game corresponding to a future, compelling the portfolio model to recalculate for each future. The portfolio model takes each future and determines the energies and costs associated with that future. A second Excel add-in finds least-cost, risk constrained plans using stochastic, non-linear optimization techniques.

Figure L-1 illustrates the kind of calculation that the portfolio model makes in a specific scenario. It shows energy use resulting from a plan over a two-year period for the fixed future. A future defines the hydro generation, loads, gas prices, and so forth in each hour. Existing and future resources in the plan generate power, largely in response to wholesale electricity prices. Because generation rarely exactly matches load, a load serving entity must buy power from the wholesale market or sell into the wholesale market. The costs and revenues in each hour add to any future fixed costs for existing and new generation or capital costs for new generation and conservation. The model discounts these cash flows to the beginning of the study. Of course, the portfolio model does this for 20 years, not for two years, but the process is identical.

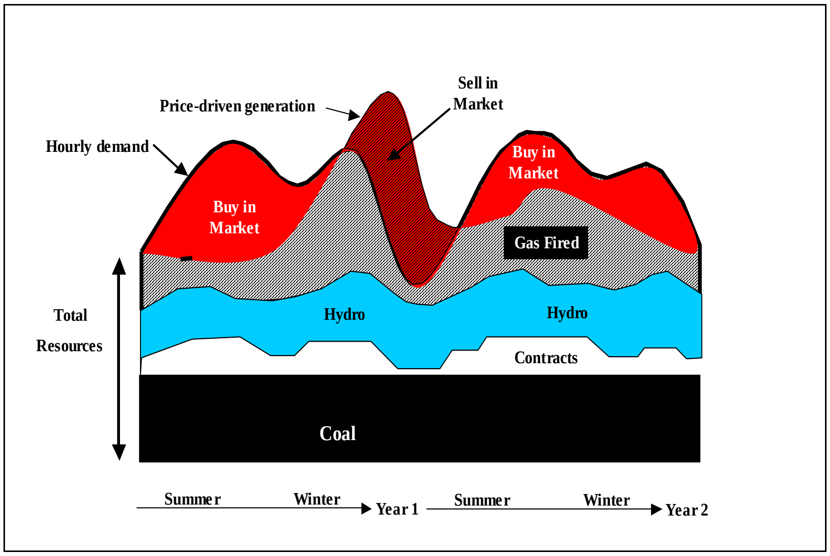

Figure L-1: Portfolio Model Calculation

The model evaluates 750 futures for each plan and about 1,400 plans per study, for a total of around a million scenarios. An hourly calculation for each of these 20-year scenarios would be prohibitive.[2] For this reason, the model uses special algorithms to estimate plant capacity factors, generation, and costs for periods of three months. The 20-year study period is represented by 80 hydro-year quarters on peak and another 80 off peak. The model does not break the Northwest into sub-regions. Consequently, there is no explicit treatment of cross-Cascade and other intra-regional transmission constraints. The model, however, does constrain imports and exports to 6,000 megawatt-quarters, before any contracts.[3] Transmission constraints within the region are considered outside the model. Existing regional thermal resources

[2] One estimate using AURORA® run times put the study at a little over 85 years.
[3] Contracts may be fully counter-scheduled.

are aggregated down to about 30 plants with similar characteristics. A 50-year streamflow record and 2000 Biological Opinion (BiOp) constraints on operations determine possible hydro generation. Operation of the region's seven remaining smelters depends the relative price of aluminum and wholesale electricity.

One of the things that make the portfolio models particularly simple is its construction in an Excel worksheet. Most analysts know how to read and modify an Excel worksheet. Columns in the worksheet denote periods, and rows contain information about loads and resources. Although simple to interpret, however, there are many calculations in the regional portfolio worksheet. In addition, special purpose Excel functions perform much of work, and the model carefully controls calculation order within worksheets. These issues require explanation.

To help the reader understand how the model works, therefore, its description will proceed in two steps. The first step will describe calculations that pertained to a single period. These include, for example, estimating thermal generation and costs for a given period. They will also cover some simple resources, such as contracts and hydrogeneration defined by streamflow. Balancing load requirements and generation with electricity price adjustments is another process that takes place within a single period. The second step will describe calculations involving several periods. This includes price processes, and the description of underlying trends for natural gas price and loads. This also includes more complex load and resource behaviors, such as decisions to shut down or restart a smelter and the rules for adding new resources to the system, such as those that govern whether or not to proceed with the construction of power generation resources.

ICON KEY
🗁 Key idea
◆ Definition

This appendix provides several tools to help the reader track this discussion. The first tool is the use of icons to flag key definitions and concepts. A table of these icons appears that the left. The second tool is a workbook, L24DW02-f06-P.xls, containing a pre-draft plan version the regional portfolio model. The reader can request a copy of the workbook from the Council or download a copy of this workbook from the Council's web site (http://www.nwcouncil.org/dropbox/Olivia_and_Portfolio_Model/L24X-DW02-P.zip). References to the workbook L24DW02-f06-P.xls appear in curly brackets ("{}"). Understanding the description does not require reference to the workbook, however. References to Council data sources appear in square brackets ("[]"). The References section at the end of the appendix lists these sources. Publicly available sources appear in footnotes.

To motivate the description of the portfolio model that appears here, discussion next turns to the logic structure of the portfolio model. The model calculation follows a specific order, with columns within certain ranges calculated in order. The strict order of calculation reflects the passage of time and the cause and effect of prior periods on subsequent periods. It also suggests why some calculations are best understood in terms of behaviors within a single period and others require understanding processes that span multiple periods.

Logic Structure

When a user opens the portfolio model workbook, the values they see are values for a particular future and for a particular plan. It is within this future (or game) that the energy and cost calculations take place. How, then, are the futures changed to create a cost distribution for a plan and the plans changed to create the feasibility space?

Figure L-2 illustrates the overall logic structure for the modeling process. The optimization application, the OptQuest Excel add-in, controls the outer-most loop. The goal of the outer-most loop is to determine the least-cost plan for each level of risk. It does so by starting with an arbitrary plan, determining its cost and risk, and refining the plan until refinements no longer yield improvements. The program first seeks a plan that satisfies a risk constraint level. Once it has found such a plan, the program then switches mode and seeks plans with equal (or lower) risk but lower cost. The process ends when we have found a least-cost plan for each level of risk. This process is a form of non-linear stochastic optimization. The interested reader can find a more complete, mathematical description of the optimization logic in reference [**1**].

In terms of the worksheet model, the optimizer OptQuest controls the Crystal Ball Excel add-in. OptQuest hands a plan to Crystal Ball, which manifests the plan by setting the values of "decision cells[4]" in the worksheet. These are the yellow cells in {range R3:CE9}. Crystal Ball then performs the function of the second-outer-most loop, labeled "Monte Carlo Simulation," in Figure L-2. It exposes the selected plan to 750 futures and returns the cost and risk measures associated with each future to OptQuest. For each future, Crystal Ball assigns random values[5] to 1045 "assumption cells." These assumption cells appear as dark green cells throughout the worksheet. (See for example, {R24}.) Crystal Ball then recalculates the workbook. In the portfolio model, however, automatic recalculation is undesirable, as described on page L-9. The portfolio model therefore substitutes its own calculation scheme. It uses a special Crystal Ball feature that permits users to insert their own macros into the simulation cycle, as shown in Figure L-3. Before Crystal Ball gets results from the worksheet, a macro recalculates energy and cost, period by period, in the strict order illustrated in Figure L-4 and described on page L-9. The values in the Crystal Ball "forecast cells" then contain final net present value (NPV) costs that Crystal Ball saves until the end of the simulation. Forecast cells are those that have the simulation results and have a bright blue color. The NPV cost, for example, is in {CV1045}.

[4] "Decision cell," "assumption cell," and "forecast cell" are Crystal Ball terms. The glossary at the end of this appendix defines each. This appendix details the function and application of decision cells in the section "Parameters Describing the Plan," page L-72. Appendix P describes "assumption cells."
[5] For a number of good reasons, these values are not truly random in the everyday sense of the word. For example, the random number generator uses a seed value, so that an analyst can reproduce each future exactly for subsequent study. The generator also selects the values to provide a more representative sampling of the underlying distribution, a technique known as Latin Hyper Square or Latin Hyper Cube.

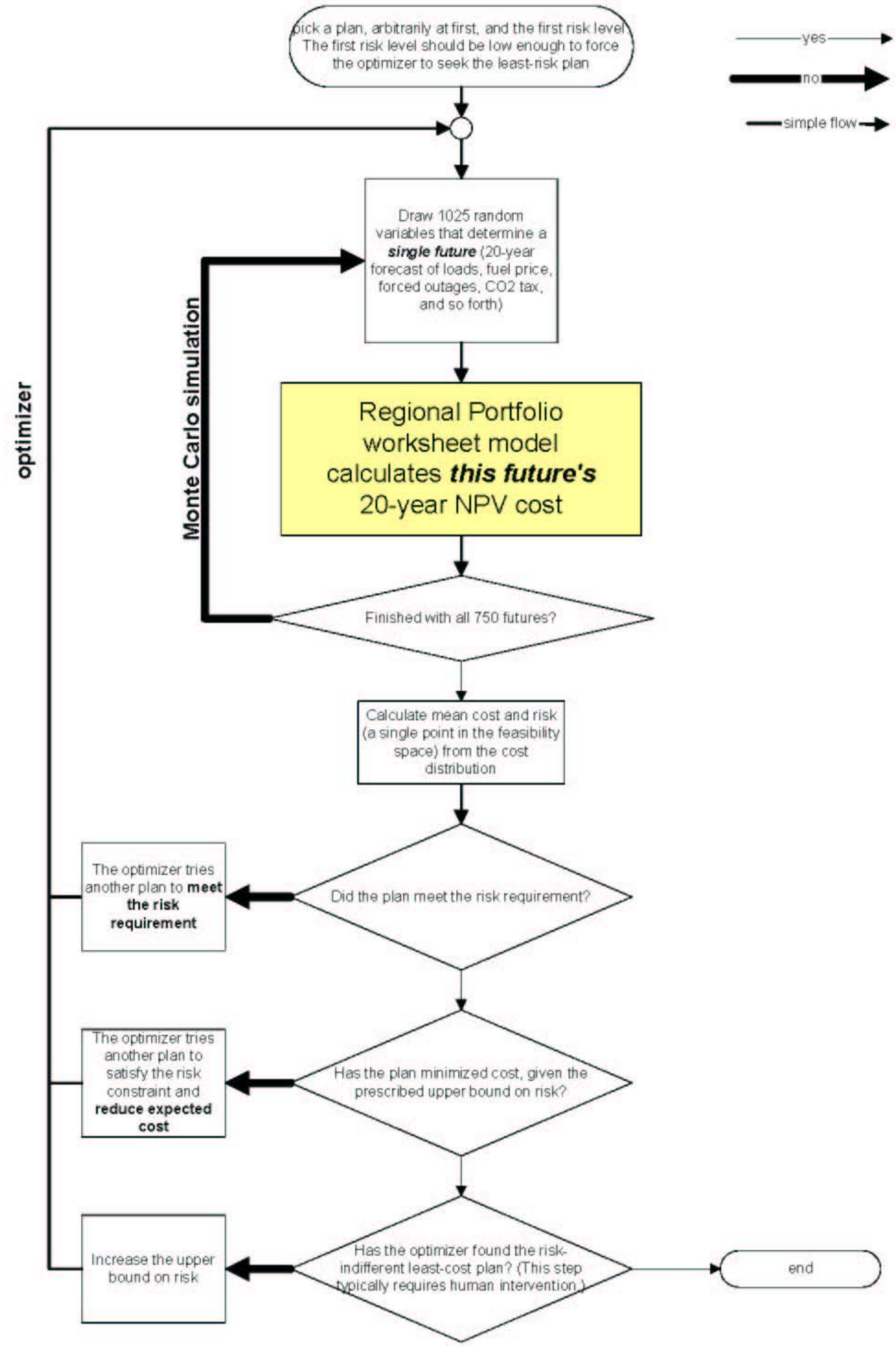

Figure L-2: Logic Flow for Overall Risk Modeling

After the simulation for a given plan is complete and Crystal Ball has captured the results for all the games, the last macro in Figure L-3 fires. This macro calculates the custom risk measures and updates their forecast cells. The custom risk measures include, for example, $TailVaR_{90}$, $CVaR_{20000}$, VaR_{90}, and the 90^{th} Quintile.

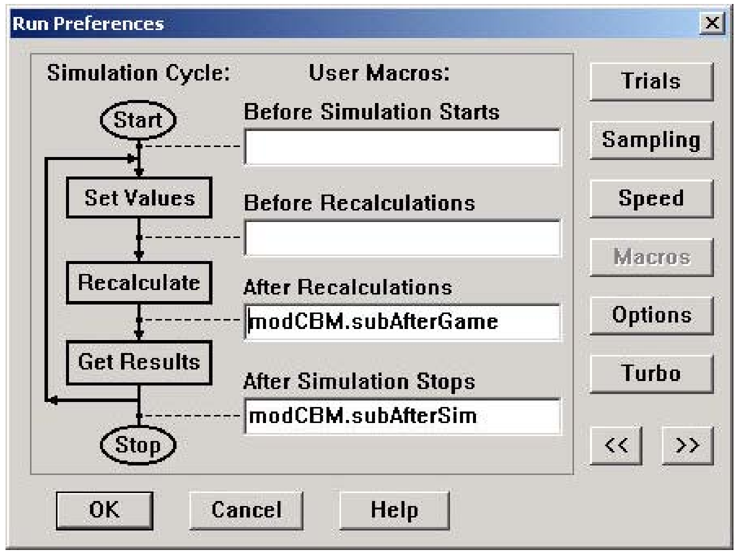

Figure L-3: Crystal Balls Macro Loop

One of the capabilities of Crystal Ball is distributed computation. Under its "Turbo Mode," Crystal Ball on a "master" machine packages bundles of several games and sends a bundle to each "worker" machine in a network, as illustrated in Figure L-5. After the bundle of games is complete, the worker sends back the results and requests another bundle. When all the games are finished, Crystal Ball evaluates the simulation results and returns required data to OptQuest. The Council uses nine 3-GHz Pentium 3 "worker" machines in a dedicated network, together with a 3-GHz Pentium 3 "master" and a server that coordinates the flow of bundles.

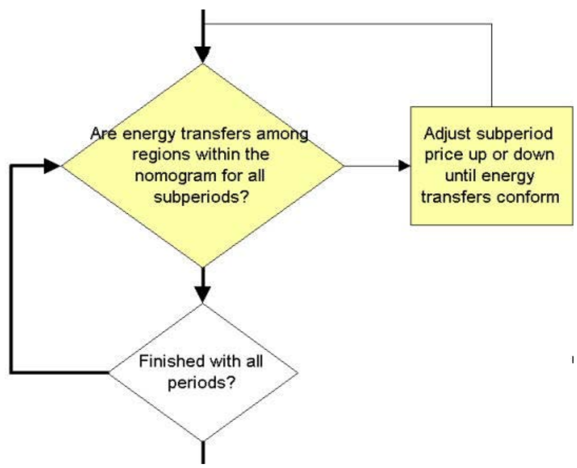

Figure L-4: Logic in the Regional Portfolio Worksheet Model

The portfolio model performs the duties of the innermost task, identified by the shaded box in Figure L-2. Given the values of random variables in assumption cells, the portfolio model constructs the futures, such as paths and jumps for load and gas price, forced outages for power plants, and aluminum prices over the 20-year study period. It does this only once per game. It then balances energy for each period, on- and off-peak and among areas, by adjusting the electricity price. The regional portfolio model uses only two areas, however, the region and the "rest of the interconnected system." Only after it iterates to a feasible solution for electricity price in one period does the calculation moves on to the next period. After calculating price, energy, and cost for each period, the model then determines the NPV cost of each portfolio element and sums those to obtain the system NPV. This sum is in a forecast cell.

There is a special step in the above process to recalculate the cells that control the long-term interaction of futures, prices, and resources, referred to here as the "Twilight Zone." This portion of the worksheet contains, for example, formulas for price elasticity of load and decision criteria. The workbook recalculates this portion of the worksheet multiple times for each subperiod.

Excel workbooks use an internal "recalculation tree" to determine which cells need recalculation when the user modifies any Excel worksheet.[6] If the workbook containing this worksheet is in automatic recalculation mode, the change will trigger a search of the tree, and Excel recalculates only the affected cells. This usually saves a great deal of time. It also explains why an Excel workbook initially may require 30 seconds to calculate when loaded but only an instant when a user makes certain changes.

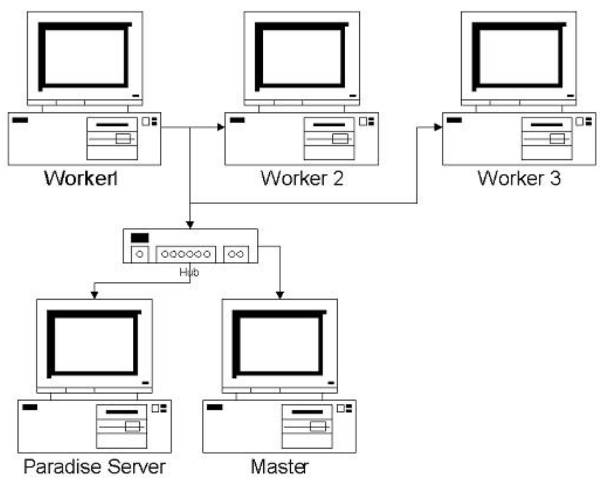

Figure L-5: Distributed Processing

The portfolio model worksheet, however, must solve several energy balancing problems by iteration, illustrated in Figure L-4. (The details of this process are in the section "RRP algorithm," which begins on page L-51.) This process proceeds from the earliest period (far left column {column R}) to the last period (far right column {column CS}). Under automatic calculation, the cells involved in iterative recalculation would not only influence a large number of "down stream" calculations but would cause dependent user-defined functions to fire, as well. These down stream recalculations could take significant amounts of time. Moreover, the energy rebalancing calculation finally discards the values of the down-stream cells, because the workbook must eventually recalculate those values anew. For this reason, the model turns off automatic calculation. The model instead controls the recalculation of all cells with a VBA range recalculation.

Figure L-6 illustrates the calculation order described above. The number in the parentheses is the order. The plus sign (+) is a reminder that iterative calculations take place in the area. Calculations made only once per game are near the top of the worksheet {rows 26-201}. The illustration denotes those recalculations that must be made multiple times per subperiod by TLZ {rows 202-321}. NP stands for on-peak

[6] The reader can find a description of the Excel recalculation method at http://msdn.microsoft.com/library/default.asp?url=/library/en-us/dnexcl2k2/html/odc_xlrecalc.asp

{rows 318-682}; FP stands for off-peak {rows 684-1058}. The area at the far right refers to the NPV summary calculations {range CU318:CV1045}.

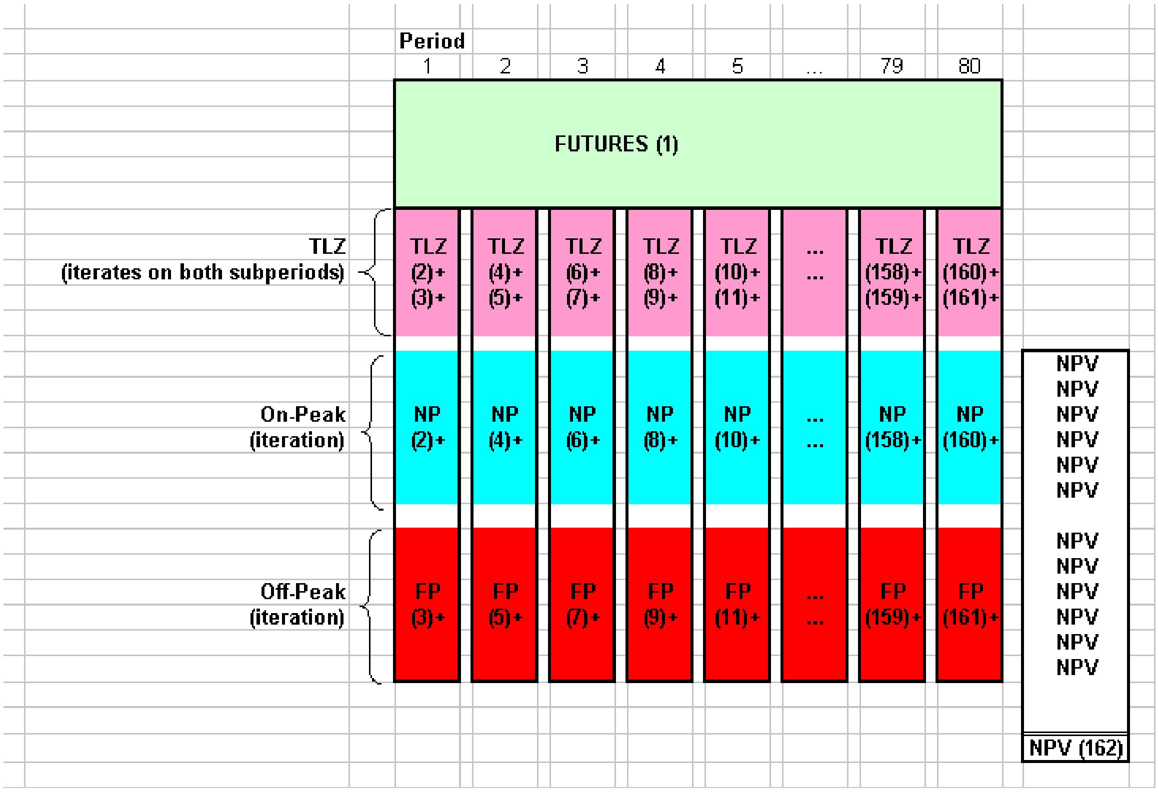

Figure L-6: Portfolio Model Calculation Order

Appendix P documents the uncertainties in the regional portfolio model. This includes the worksheet formulas for describing the uncertainties. Because it would be redundant to cover the same material in this appendix, the scope of this appendix is everything *except* the uncertainties.

Figure L-6 permits us to state the scope of this appendix with respect to ranges within of the portfolio model. Appendix P describes the calculations in the area of the worksheet denoted by “FUTURES (1)”. This Appendix L discusses all remaining areas.

With this overview, this appendix starts the detailed description of the regional model with perhaps the simplest area of calculation in the workbook, the single period. The calculations within a single period are to a certain extent independent of each other. They are the building blocks for more involved behaviors that span multiple periods. They also are the province of rich behavior and some of the most novel algorithms.

Single Period

This section considers only a single period in the study timeframe, December 1, 2009, through February 28, 2010 {column AQ}. There is nothing special about this period; any other period would do. Logic is identical across periods.

The portfolio model aggregates time into periods. The primary purpose for this is to achieve efficiencies in calculating energy generation and costs. Annual periods do not capture interesting seasonal behavior, and using monthly calculations do not provide any benefit over quarterly calculations. Because hydrogeneration determines much of the resource behavior in the Pacific Northwest, the model uses hydro quarters. For the purposes of the portfolio model, the hydro-year begins September 1, so the quarters are September through November, December through February, March through May, and June through August. This appendix will occasionally refer to these as the autumn, winter, spring, and summer quarters.

One of the distinctive features of the portfolio model is how it defines periods in terms of hours. A **standard month** is exactly four weeks. Similarly, a **standard quarter** is three standard months, and a **standard year** is four standard quarters. A standard month has exactly four weeks. By adopting this convention the number of hours on peak[7] and off peak in each month, quarter[8], and year are fixed and uniform. Consequently, conversion calculations to MWh from average megawatts are the same across all periods. In addition, shifting patterns of holidays and Sundays from month to month and year to year do not create misleading results due only to that kind of variation.

Because the periods in the portfolio are rather long, the ratio of on and off-peak hours using standard quarters are close to those the model would have obtained had the model not used standard quarters. Consequently, the regional portfolio model keeps costs in standard time units and simply scales up the results in the net present value calculation. For example, see {row 323, column CV}, where the model ratios up the costs by the ratio of hours in a non-leap year to the hours in a standard year, 8760/8064, or about 8.63 percent.

This convention does introduce one source of additional complexity, however. It requires that the model handle fixed costs carefully. Resource economics, and economic resource selection in particular, depends on the relationship between fixed and variable costs. Fixed costs are often denominated in units such as dollars per kilowatt-year ($/kWyr). The regional portfolio model uses dollars per kilowatt-standard year ($/kWstdyr), which is smaller by about 7.95 percent (1-8064/8760). If an analyst wished to scale fixed costs by the number of hour in a particular month and year, however, any fixed costs would scale appropriately. The detailed explanation of fixed costs under this convention appears on page L-69, where this appendix deals with "New Resources, Capital Costs."

[7] The portfolio model assumes a 6x16 convention for on-peak hours. That is, on peak is defined as hours 7 through 22 (6 AM to 10 PM) each weekday and Saturday. The remaining hours are off-peak.
[8] There are 1152 on-peak hours (6x16x4x3) each quarter and 864 off-peak hours.

Table L-1: Plan DW02

Conservation: $10/MWh higher on the supply curve in all periods, for both non-lost opportunity and discretionary conservation.[9]
Earliest construction start dates for the following increments of resource:
CCCT: 610 MW in 12/2009
SCCT: 100 MW in 12/2019,
Wind Power Plants: 1200MW in 12/2009, 1300MW in 12/2015, 2000MW in 12/2017, 400MW in 12/2019
Coal-Fired Power Plants: 400 MW in 12/2009
Demand Response: 500MW in 12/2007, 250MW in 12/2009, 250MW in 12/2011, 250MW in 12/2013, 250MW in 12/2015, 250MW in 12/2017, and 250MW in 12/2019
Critical Water threshold for resource additions: 3000 MWa

If an analyst needed to know the energy and costs associated with a particular calendar month and year, using standard months, quarters, and years makes recovering this information easy. The model effectively determines costs by normalizing energy and cost to rates of energy per hour (power in MW) and costs per hour ($/MWh and $/kWh), and then multiplying by the fixed number of hours in each standard subperiod.

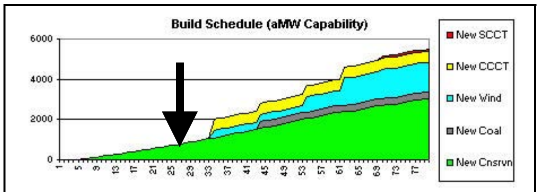

Figure L-7: Build 0ut of Future 6

Recovering a month and year's actual energy and cost amounts to rescaling by the month and year's actual hours per each subperiod. If the user wished to, the portfolio model could rescale before discounting of costs in the total system cost calculation.

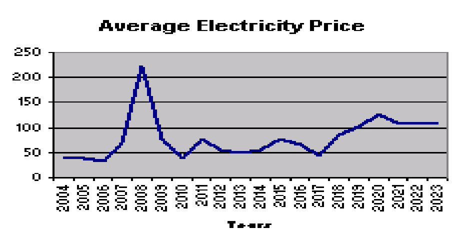

Figure L-8: Electricity Price Future

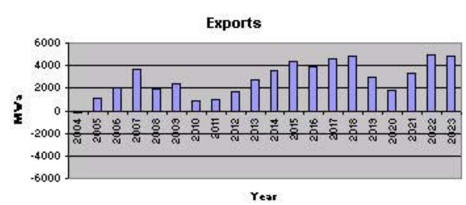

Figure L-9: Exports

[9] The description of this element in the decision criterion for conservation appears in Chapter 6 and under the section "Decision Criteria" that appears later in this appendix.

In addition to specifying the period that serves as our example, this description will assume a specific plan under a specific future.[10] Working with specific choices should make the calculations more concrete and easy to follow. The plan appears in Table L-1. The behavior of this plan under the 750 futures is illustrated in the workbook L24X-DW02-P.xls. The behavior of this plan under future number six appears in Figure L-7 and the details are in L24DW02-f06-P.xls. The figure contains an arrow that identifies the period under consideration. This plan is not the Council’s recommended plan but illustrates some interesting behavior for the reader. Figure L-8 through Figure L-12 show other aspects of future six and the behavior of this plan under future six.

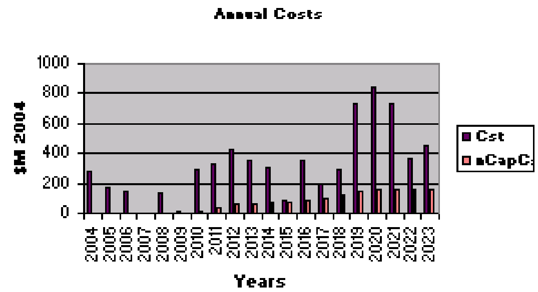

Figure L-10: Total Annual Costs and Capital Costs Only

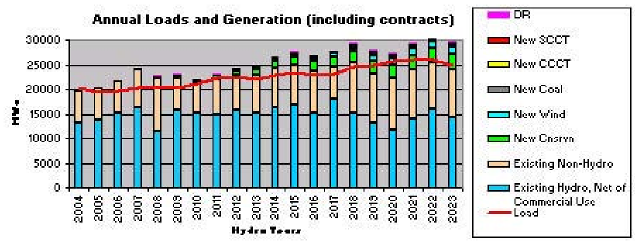

Figure L-12: Annual Energy Generation and Load

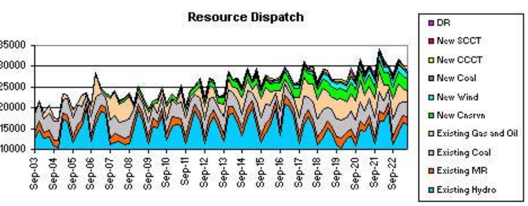

Figure L-11: Quarterly Energy Generation

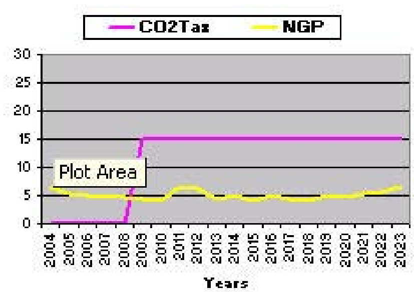

Figure L-13: Natural Gas Price and CO_2 penalty

The portfolio model NPV cost includes both variable and fixed components of system cost. The variable component includes total fuel, variable O&M, spot market purchases and sales, and the value of purchase contracts in the electricity market. (See the section “Contracts” for a more detailed discussion of contract costing.) The fixed component includes conservation costs and new plant incremental fixed O&M and construction cost.[11] The portfolio model uses special treatments of fixed and variable costs. The following section addresses the treatment of variable costs in the model; the subsequent section discusses fixed costs.

Valuation Costing

The portfolio model estimates period variable costs, such as hourly market purchases of electricity for a month, from average values over the period. Period costs can be tricky to estimate, however, because of the intra-period correlations that exist between relevant variables, such as market price for electricity and hourly requirements. For example, consider two simplified systems, System A and System B, which face the same market price over some period, say a week. (See Figure L-14.) The

[10] Chapter 6 provides definitions for the terms "future," "plan," and "scenario."

[11] Because the regional version of the portfolio model does not perform economic retirement, the model considers the incremental fixed O&M of existing plants sunk and does not include it.

task is to calculate the cost of market purchases. Even if both systems have average zero net position (resources-loads), they can have a non-zero cost. Not only this, but depending on the hourly correlation of their position with market price, the cost may be negative or positive. Clearly then, a calculation using average prices and positions is misleading. A simple illustration will demonstrate how this arises.

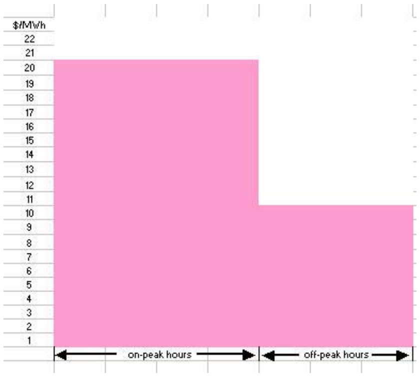

Figure L-14: Prices over on- and off-peak hours

The market price consists of a constant on-peak price of $20/MWh and a constant off-peak price of $10/MWh, as illustrated in Figure L-14. Although the on- and off-peak periods would alternate daily, the illustration aggregates the corresponding hours to simplify the calculation. The on-peak hours are 4/7 of the total number of hours. System A has loads -- constant over the subperiods -- shown as the heavy line in Figure L-15. The load is 2000 MW on peak and 1300 MW off peak, averaging 1700 MW over the week. System A has a constant, flat existing resource of 1700 MW, which results in a deficit on peak and a surplus off peak. The level of the source is shown by the cross-hatched area in Figure L-15. A simple calculation shows the net cost of market purchases over the week is $119,000.

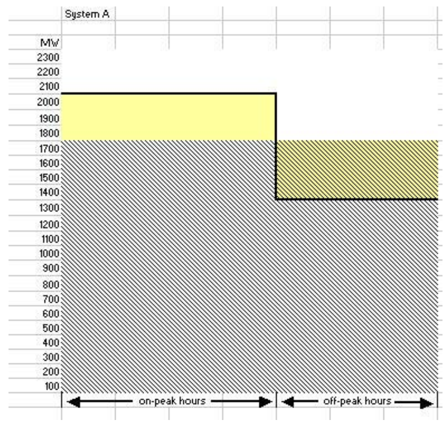

Figure L-15: System A

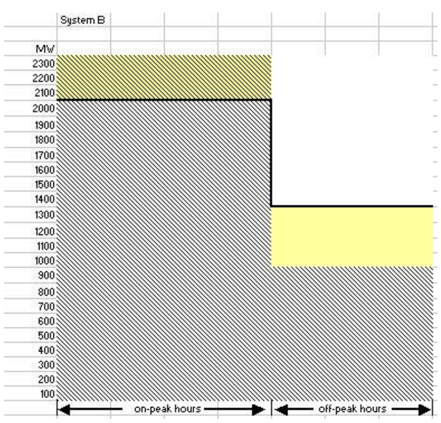

Figure L-16: System B

The System B has hydro generation (the cross-hatch area in Figure L-16) that is equal to loads on average, but surplus to its needs on peak. Again, using averages across the week, the cost of market purchases would be zero. System B, however, has 2300 MW on peak hydro generation and 900 MW off peak. Now the position has the opposite correlation to market price. The net cost of market purchases over the week is now negative, that is, there is a net $119,000 net benefit selling power into the market over the week.

To make these results more general, the expected revenue given average price, average position, and their correlation is

$$E(pq) = E(p)E(q) + \sigma_p \sigma_q \rho_{pq} \qquad (1)$$

where $\boldsymbol{p}$ denotes hourly price, $\boldsymbol{q}$ represents hourly position, $\boldsymbol{E(pq)}$ is expected revenue, $\boldsymbol{E(q)}$ is average position, $\boldsymbol{E(p)}$ is average price, $\boldsymbol{\sigma_p}$ is the standard deviation of price, $\boldsymbol{\sigma_q}$ is the standard deviation of position, and $\boldsymbol{\rho_{pq}}$ is the correlation between price and position. This is an estimate of revenue that the portfolio model uses is several calculations.

The more general situation, of course, is more challenging. Costs and revenues for power plants potentially include a complicated and time-varying set of correlations. For example, a gas-fired power plant revenue involves not only correlation of production to electricity prices, but of production to gas prices, and of gas prices to electricity. This situation would exist for each resource. Fortunately, there is a computational short cut available.

Instead of calculating costs using all the various cross-correlations, there is an easier calculation that involves only comparisons to the electricity market. To see this, we start with a "rate base" cost calculation:

$$c = \sum_i q_i p_i + p_m (Q - \sum_i q_i) \qquad (2)$$

c is total cost ($)

q_i is quantity (MWh) provided by resource i

p_i is the price ($/MWh) of resource i

p_m is the price ($/MWh) for wholesale energy

Q is total requirement

In this calculation, the variables represent hourly values. This calculation sums up the operating costs for each of the generating units and adds to that sum the cost of meeting the remaining load in the market. The problem is that $\boldsymbol{p_m}$ and $\boldsymbol{(Q-\Sigma q_i)}$ are correlated within a period, but the correlation is complex. Estimating $\boldsymbol{\Sigma q_i}$ alone involves knowledge of how the production among resources are correlated. Moreover, the relationship between the load Q and Σq_i must be calculated. By rearranging terms, however, another calculation for costs emerges.

$$
\begin{aligned}
c &= \sum_i q_i p_i + p_m (Q - \sum_i q_i) \\
&= p_m Q - p_m \sum_i q_i + \sum_i q_i * p_i \\
&= p_m Q - \sum_i q_i (p_m - p_i)
\end{aligned}
$$

This is the "valuation" cost estimate. The name stems from the fact that the load and each resource are valued in the electricity market. The first term in the last equation is the cost of meeting total load in the market. The second term is the sum of the resource values in the market.

The valuation formula simplifies the cost calculation, because we only have to consider how each resource's cost and dispatch relate to market price, rather than to other resources. For example, wind generation, conservation, and many other resources do not dispatch to market price. This mean their correlations to electric market price are zero, and multiplying average period energy by average electricity price yields expected revenues. Thermal generation, however, is a more complex situation. Thermal plants only have value when market prices exceed the variable generation price for the plant. Both market prices and fuel prices are variable within a period such as a month, and fuel prices may correlate with market prices. Fortunately, a well-understood equation provides an estimate of value in the market. This equation is precisely the topic of the section "Thermal Generation." Because such tricks exist for valuing the individual resources in the market, the valuation approach therefore significantly simplifies estimating system costs.

This concludes the description of variable cost estimation. The next section is on fixed cost treatment.

Real Levelized Costs

The model uses the real levelized (RL) representation of fixed costs, including fixed O&M, fixed fuel, fixed transmission, and construction costs. This section describes the rationale for that choice of representation.

Discounted Cash Flow Inadequate for Comparison[12]

Traditional engineering economics calls for life-cycle cost evaluation, taking into account risk, inflation, and the cost of money. This approach uses nominal cash flows associated with cost and benefit in each period of the analysis, and it discounts the period net cash flows to some fixed point in time. An equivalent approach uses cash flow stated in "real" or constant-year dollars and discounts by a rate that has inflation removed. This

[12] This section borrows heavily from the especially well-written description of real levelized costs that appears in PacifiCorp's 1992 Integrated Resource Plan, Appendix K.

approach is often referred to as the discounted cash flow (DCF) approach, irrespective of whether current or constant dollars are involved.

The DCF approach is limited in its ability to adequately compare one type of resource asset against another or to compare resources that employ distinct financing mechanisms. The latter is a problem perhaps unique to a regional analysis, which must address the economics of resources using rate-base cost recovery, non-utility equity investment, and the pure debt financing done by BPA, PUDs, and Co-ops.

Consider the problem comparing resources with lives of different lengths, or if the resources are placed in service in different years. For example, the design life of a new pulverized coal generating plant is 40 years, while a simple cycle combustion turbine is 25 years. Ratebase costing results in resource cost that is largest at the beginning of the asset life and declines over time as ratebase is depreciated. Capital resource cost includes depreciation expense, return on ratebase, income taxes and property taxes. Figure L-17depicts the nominal capital resource costs for a $100,000 asset with a 40-year depreciation life and for a $100,000 asset with a 25-year depreciation life.

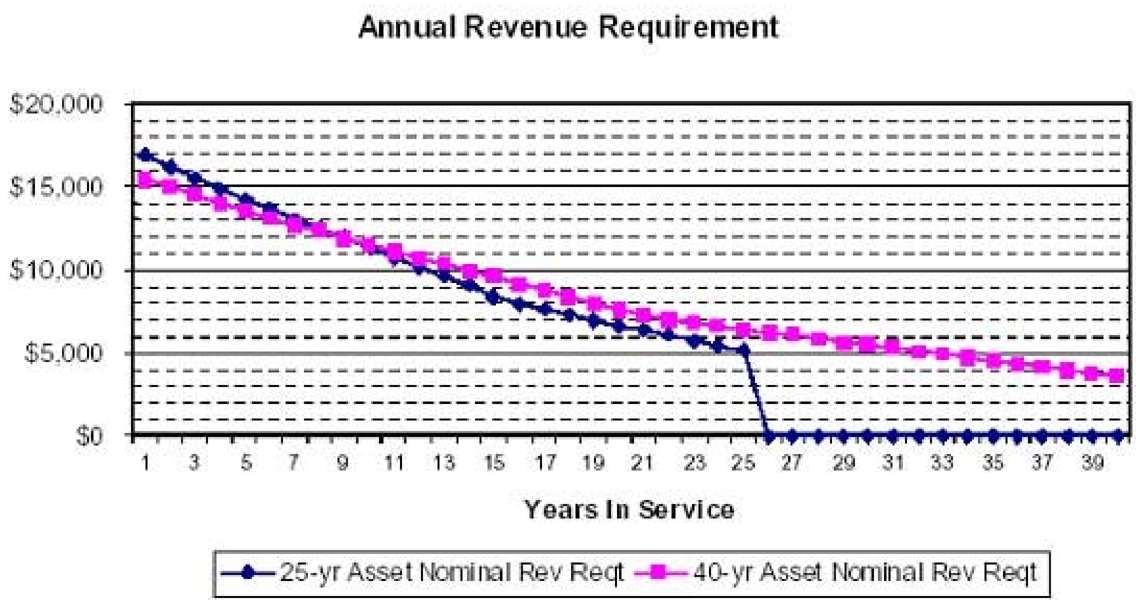

Figure L-17: IOU Revenue Requirements

An analysis mismatch occurs unless the analysis incorporates an adjustment for end-life effects. The “end effect” adjustment recognizes that the 25-year plant must be replaced earlier than the 40-year plant. The adjustment is a continuation of costs with those of the replacement unit. Of course, there must be a similar end-effect adjustment after 40 years, when the second 25-year plant would provide service beyond that of the 40-year asset. And so forth.

An alternative is to extend the analysis period to a length of time that results in the "least common denominator" analysis period. One could illustrate this point with an extreme example. It would take a 200-year analysis to make an equivalent comparison between the 25-year asset and a 40-year asset. The "least common denominator" analysis period would result in eight 25-year assets and five 40-year assets so that the analysis ended with the end-life of both assets. Figure L-18 shows a full 200 years of nominal resource costs for a series of 40-year and 25-year assets using rate-base cost recovery and assuming no real, but 2.5 percent nominal inflation. In this example, the Present Value of Resource costs (PVRR) of both assets is exactly the same. Therefore, if all else were equal in this example, one would be indifferent over this 200-year analysis period between owning a series of 25-year resources or owning a series of 40-year resources.

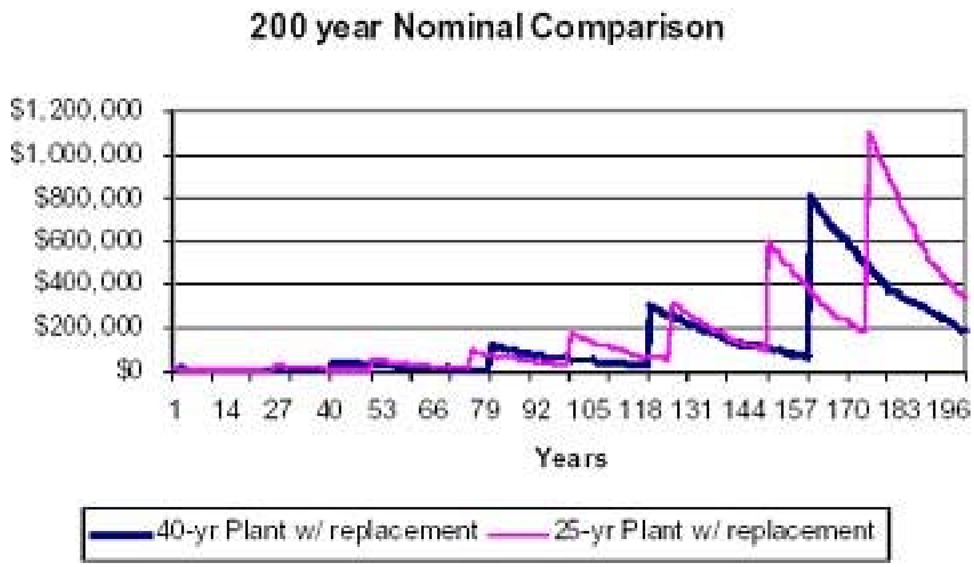

Figure L-18: 200 Year Comparison

Compiling a 200-year analysis is not practical. Even if it were, another common situation, new plants with *equal lives* staggered over the planning period, does not admit the "least common denominator" approach. There is no "least common denominator" of lifetimes in that case. The cash flows illustrated in Figure L-18 do illustrate a point, however. If one is indifferent between assets when considering an "equivalent" analysis period, then what are the results one gets when looking at a more practical analysis period, say 20 years.

Figure L-19 shows the cumulative PVRR of the above resource costs used in Figure L-18. (Cumulative PVRR is derived by taking the present value of each year's resource cost and adding it to the sum of the previous years' present value of resource cost; all discounted at 7.5% in this private utility example to a common time.) Figure L-19 shows only the results of the first 45 years in order to highlight the earlier years. Over an extended analysis period (200 years), the PVRR of both assets is the same.

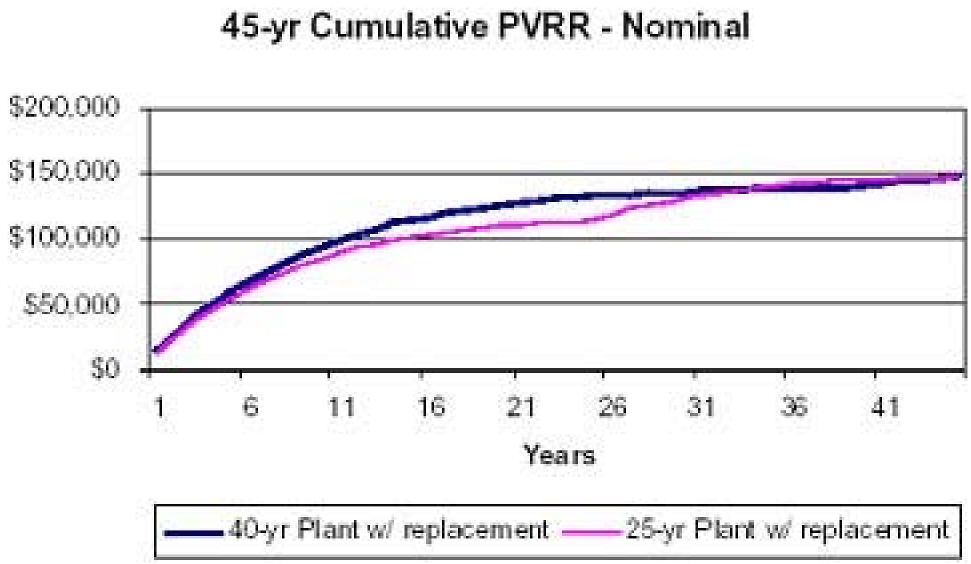

Figure L-19: 45-Year Cumulative PVRR

Figure L-19 clearly illustrates the problem with using DCF costs for comparing resources with different lifetimes. By definition, these assets were valued such that one should be indifferent. However, as can be seen, depending on the length of the analysis period, the nominal resource cost has created a valuation gap between the 40-year asset and the 25-year asset's resource cost. This could lead to misleading conclusions regarding the comparative cost of one resource versus another. DCF costs, without some kind of end-effects adjustment, could result in incorrect analysis findings.

End-effect adjustment calculations can be challenging as well. For example, within a 20-year analysis period, what is the proper adjustment to a 40-year asset and a 25-year asset's cost that will place the analysis on equal footing? There are mathematical formulas for the PVRR of capital projects over an infinite time horizon -- as would be necessary when no "least common denominator" of lives exist. Computing revenue requirements for capital, however, is the least of the problem. It is more difficult to estimate operating costs and benefits of generation, because no simple, regular pattern exists. In particular, there is at least some seasonal variation in such costs and benefits, but what about price spikes, excursions from equilibrium prices, in the last year? What about the effect of annual variation in stream flows and hydrogeneration? These questions apply to all resources, including market purchases and contracts. The answers are as varied as are methodologies to calculate the end-effect adjustment. However, an easier approach allows for comparative analysis between resource options. It provides more representative study results using a practical study period. It consists of using real levelized resource cost.

Real Levelized Resource Cost

Real levelized resource cost is a methodology for converting the year-by-year cash flows into a sequence of fixed constant dollar payments, much like certain kinds of annuities, that has the same present value as the year-by-year cash flows. This approach also easily accommodates both real and nominal cost inflation.

For DCF, the replacement unit causes resource cost to take a huge jump. For real levelized costs, the unit replacement cost continues at the same rate (assuming no real inflation in construction cost). An explanation of how real levelized resource costs are calculated appears in a later section. Figure L-20shows the real levelized resource cost for the same two assets that were shown in Figure L-18, which have no real inflation in construction costs but do have nominal inflation.

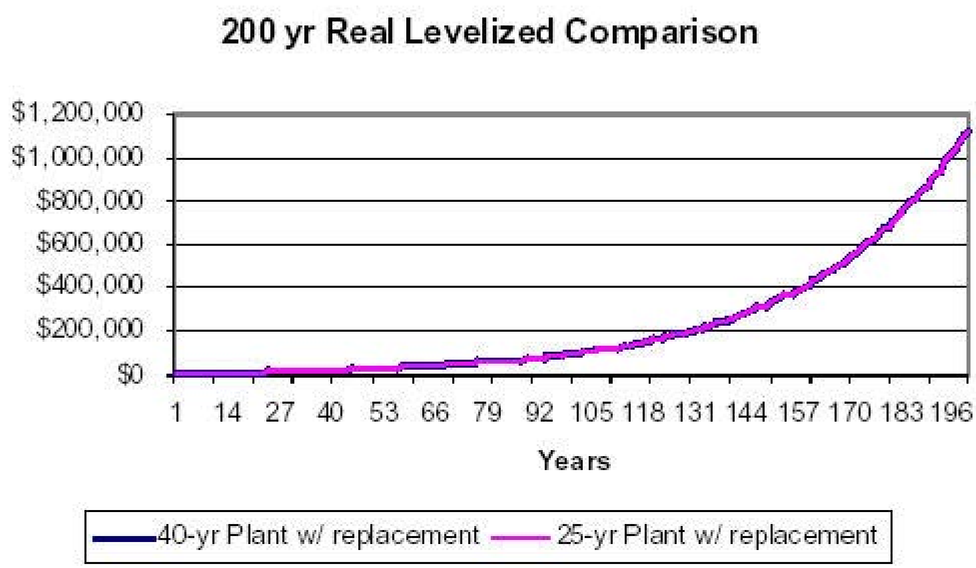

Figure L-20: Comparison (J.6)

Because Figure L-20 uses the same assets as Figure L-18, the PVRR of the resource costs are the same for both assets; hence the real levelized resource cost values for each resource are the same each year. As mentioned earlier, the replacement of the resources throughout time does not create huge jumps in resource costs. Figure L-21 is the same representation as Figure L-19, except that here again, the results are presented using real levelized resource costs. One can see that it does not matter how long the analysis period is, the comparative resource cost valuation is the same at any point in time.

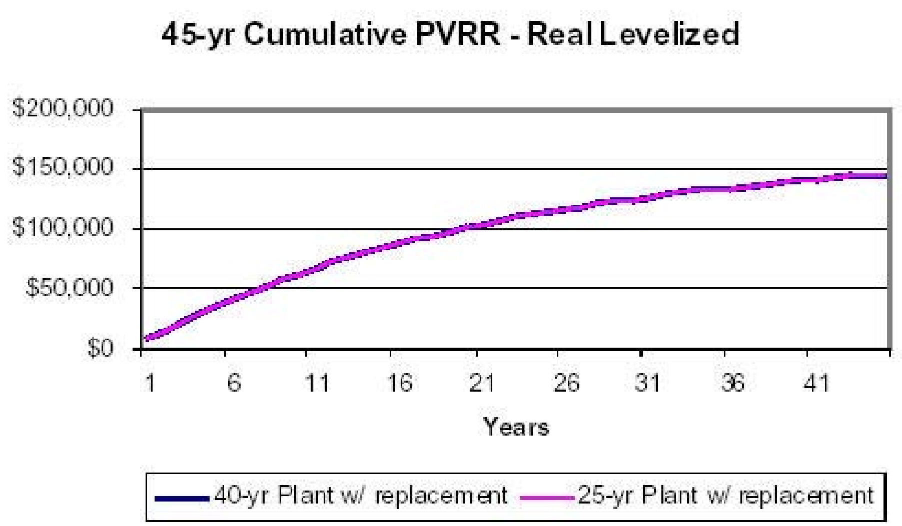

Figure L-21: J-7

So far, the two resources shown have been placed in service on the same date and have been priced to come to the same PVRR over an "equivalent" extended analysis period. This has been solely for the purpose of creating a case that shows that assets of equivalent cost should reflect that equivalent cost, regardless of how long the analysis period is. Real levelized resource costs provide such a case. The advantage of using real levelized resource costs is also extended to an analysis that compares various resources with various lives and various in-service dates. Real levelized resource costs will capture the comparative economic costs with respect to one set of resources being compared against another, without the need for end-effects adjustments.

Economic Decision-Making with Real Levelized Costs

Using real levelized costs for capital investments is more than a practical solution to this resource comparison problem. In accounting, there is a fundamental concept, the "matching principle," that stipulates that the costs for an asset should match the benefits the asset provides. The matching principle underlies a host of commonly accepted accounting practices that have their basis in economics, such as depreciation and rate-base recovery. If costs were not allocated over the useful life of an asset, it could be argued that economic efficiency would not be served. For example, if ratepayers had to pay for electricity in one year enough to recover the entire expense of a power plant, the resulting high price would significantly and inappropriately discourage electricity use. Moreover, costs for the plant would shift to a small group of ratepayers who could not afford to curtail use. In subsequent years, ratepayers would tend to over-use electricity, because they would not see the cost of that plant, despite the fact that they benefit from the plant's availability. Rates that do not match costs to benefits therefore send improper price signals to consumers. Using real levelized costs better reflects how costs apply in this economic, "matching" sense.

A conspicuous example of where some utilities engage in mismatched pricing is conservation. In particular, these utilities expense their investment cost of conservation programs, much like paying the full cost of a power plant in a single year. The reason often given for this practice is the difficulty of providing collateral for financing, which would levelize the conservation cost. That is, if the utility defaulted on its loans, it would be impractical and pointless for investors to remove conservation from utility customers' homes and businesses for resale. This is not the case with a power plant, which investors can sell to recover from default. Without this financing, however, either the ratepayer pays all conservation costs up front or the utility effectively makes an unsecured loan to the ratepayer. The first alternative creates uneconomic price signals. The second alternative requires the utility to burden its own balance sheet and hope for fair regulatory treatment in the future. Neither of these alternatives is attractive. The Council's solution to this situation is the Plan's Action Item **CNSV-11**, which calls for state-guaranteed utility (or non-utility) financing, assured through the state's taxing authority.

To prepare the RL costs for the portfolio model, life-cycle fixed plant costs, including construction and interest during construction, are discounted using the rate appropriate for the financing and accounting. For example, the Generation Resource Advisory Committee (GRAC) made determinations about which types of agencies would most likely build wind plants, coal plants, and so forth. Often, the GRAC arrived at a participation-weighted balance of financing, using a blend of private IOU, federal, and public investment. The present value calculation uses the blended discount rate. To levelize the present value the Council should have used its four percent discount rate. However, due to an oversight, the costs in the regional model runs were levelized at the blended after-tax cost of capital (4.9%) [**2**]. Finally, the portfolio model uses four percent to discount the real levelized quantities, adjusted for real cost escalation, over the study period. The section "Present Value Calculation," below, describes the formulas in the portfolio model that perform this task.

Comparison to Market Purchases

As explained in the previous section, the portfolio model uses valuation in the market for estimating variable system costs and benefits. The year-by-year capital resource cost in Figure L-17 shows the front-end loaded resource cost for capital investment typical of a private utility. How does this cost compare with the alternative of market purchases? Any analysis period short of a full asset life-cycle analysis will overstate the capital resource costs in the early years, while leaving the lower cost later years out of the analysis. With a 20-year analysis period, using cash flows for resource capital will overstate the comparative cost of long-lived resources. Restating the issue a different way, consider two groups of customers in a rising market price environment. Customer Group A will get to use and pay for a 40-year resource during the analysis period, say, the first 15 years, and Customer Group B will get to use and pay for the resource during the remaining plant life, or 25 years. Without some kind of adjustment, simple DCF resource costs would cause Group A to pay all the higher cost years, when market price is lower, while Group B would get to pay for all the lower cost years when market price is higher. This is hardly a fair allocation of resource costs among Customer Groups A and B when comparing the resource cost to market purchases.

Shortcomings and Disadvantages

Absent 20/20 foresight, any analysis methodology will have its challenges, and real levelized costs are no exception. Implicit in the use of this technique is the assumption that the future, beyond the horizon of the study, either does not make much difference to today's economic decision or will be economically similar to the study period. The former is true when the discount rate is large and the impact of cash flows beyond study period is negligible. The four percent discount rate used by the Council is probably toward the lower end of rates for which that argument might apply.

The latter assumption may hold in many circumstances, but there are situations where we expect it would not. For example, a carbon penalty imposed late in the study period would probably extent well beyond the study horizon. Such a carbon tax would have a disproportionate impact on coal plants. A coal plant built several years before the carbon tax arises may see economically productive years before the tax and harder times after the tax. Because the carbon tax is a variable cost of operation, and not included in the real levelized capital cost, the study would only see the balance of these, weighed by their relative term within the study and not the less attractive economics after the study.

There are several possible accommodations for this shortcoming. One is the consideration of some end effects, perhaps using the last year of analysis. This section has already discussed the associated difficulties with this approach. Nevertheless, in subsequent studies such adjustments might make reasonable sensitivities. Another accommodation, which the Council uses instead, is simply to ask whether the recommended plan would have changed if a carbon tax had more severely penalized coal-fired and, to a lesser extent, gas-fired generation. The Council concluded it would not. The plan prepares the region for significant amounts of conservation and wind generation. The amount of early coal is small, a single 400 MW unit. The timing and amount of this early coal permits re-evaluation before licensing and siting begins. By then, additional information about the likelihood of carbon penalties will be available. Gas-fired generation does not appear until late in the study period. The arguments regarding licensing and siting pertain to an even greater degree. For the Action Plan period, the plan merely calls for securing siting and licensing options for these fossil fuel-fired plants.

In summary, the portfolio model covers a 20-year forecast period. During this forecast period, the model is comparing the alternative resources available to determine the risk-constrained, least-cost plan. Because many of the potential resources have economic lives which extend beyond the analysis period and have lives of various lengths, appropriate methods are necessary to capture the comparative costs of such capital-intensive investments. Alternative financing and accounting methods can also distort the economic evaluation of such resources. An end-effects adjustment is feasible, but the value of those end-effects can be difficult to determine. An alternative approach, which the portfolio model uses, is real levelized capital resource cost. Real levelized cost eliminates the need for an end-effects adjustment, and provides a reasonable approach for comparing the cost of capital resources against each other and also against market purchase resources. Real levelized resource costs may not fit all analysis situations. Care must be taken when events near the end of the study, such as the emergence of a carbon penalty, create situations that extend beyond the study period and may render study results non-representative. Nevertheless, when used with care, real levelized capital costs can do a better job of reflecting the true economic costs of capital resources than simple DCF methods.

This concludes the preamble to single-period calculations. As explained in the previous section, Appendix P provides extensive discussions of how the model computes values for loads, natural gas, and other aspects of a future. Prior periods' electricity prices or other factors can then modify these in the Twilight Zone illustrated in Figure L-6. If there are any such modifications, the discussion is in the section "Multiple Periods," which follows below. The remaining portion of this section on single-period calculation picks up the calculation after any modification in the Twilight Zone.

Loads

Appendix P describes the construction of quarterly energy requirements before any adjustments due to the choice of plan. The plan *does* affect loads, however, as the amount of capacity available affects the price for wholesale electricity, and wholesale electricity prices have a long-term effect on loads because of price elasticity. See page L-59 in the section "Multiple Periods" for this treatment.

The **energy calculation** in {AQ322} is simply the product of the elasticity effect {AQ321}, the on-peak portion of load in MWa {AQ183}, and the number of hours on-peak in a standard quarter.

One of the conventions the model design tries to adhere to is to avoiding putting data into code or formulas. Admittedly, this version of the regional portfolio model is not always successful in achieving that objective. Nevertheless, some kinds of numbers arguably could appear in formulas. For example, the number of days in a week and the number of months in a year will not change, so burying them in code presents little risk to some future user who might want to make changes to the model. Because the design of the regional portfolio model permits only one particular definition of the period, namely the standard quarter, the number of on-peak hours in a standard quarter is a fixed constant and therefore would be an exception to this rule.

Calculating the **cost of meeting that load** in {AQ323} uses the valuation approach. Specifically, the cost is the average energy {AQ322} times the average on-peak period market price {AQ204} times a special factor that incorporates the correlation of loads and market prices. The cost is divided by 10^6 to restate the dollars in millions of 2004 dollars.

The special factor is (1+$S$14*$O$322), where $S$14 is the correlation between non-DSI loads and power prices and $O$322 is a fixed constant. The fixed constant is calculated in cell $O$322 from the formula

```
SQRT(EXP($R$184^2+$R$201^2)-EXP(R184^2)-EXP(R201^2)+1)
```

The value in $R$184 is the on-peak intra-period load variation; the value $R$201 is the on-peak intra-period electricity price variation. The complexity of this equation stems from the fact that the definitions of the load and price variations are slightly different from a simple standard deviation of load or price.

Appendix P lays out the justification for use of lognormal distributions for load and price. The variations that appear in $R$184 and $R$201 are the standard deviations of the log-transformed loads and prices. There is, however, a well-known relationship between the mean and standard deviation of the transformed and non-transformed variables.[13] If $\boldsymbol{E(p)}$ and $\boldsymbol{\sigma_p}$ denote the expected price and standard deviation after log transformation and $\boldsymbol{E(P)}$ and $\boldsymbol{\sigma_P}$ before transformation, and similarly and $\boldsymbol{E(q)}$, $\boldsymbol{\sigma_q}$, $\boldsymbol{E(Q)}$ and $\boldsymbol{\sigma_Q}$ for quantity, the relationship for standard deviations is

$$\sigma_Q = E(Q)(e^{\sigma_q{}^2} - 1)^{1/2}$$

$$\sigma_P = E(P)(e^{\sigma_p{}^2} - 1)^{1/2}$$

The correlation used in this calculation is a ranked correlation, so the correlation is unaffected by transformation. From equation (1) above, the expected revenue is

$$\begin{aligned} E(PQ) &= E(P)E(Q) + \sigma_P \sigma_Q \rho_{PQ} \\ &= E(P)E(Q) + E(P)(e^{\sigma_p{}^2} - 1)^{1/2} \sigma_Q E(Q)(e^{\sigma_q{}^2} - 1)^{1/2} \rho_{pq} \\ &= E(P)E(Q)\left\{1 + (e^{\sigma_p{}^2} - 1)^{1/2} (e^{\sigma_q{}^2} - 1)^{1/2} \rho_{pq}\right\} \\ &= E(P)E(Q)\left\{1 + (e^{\sigma_p{}^2 + \sigma_q{}^2} - e^{\sigma_p{}^2} - e^{\sigma_q{}^2} + 1)^{1/2} \rho_{pq}\right\} \end{aligned}$$

This is the formula in cell {AQ323}.

The on-peak non-DSI costs present-valued in {CV323}. The formula is described on page L-79, in the section, “Present Value Calculation.”

DSI interruptions can be of a short-term nature, such as hourly or daily curtailments, or they can be long-term. Long-term interruptions involve smelter shutdowns and startups. The portfolio model assumes that demand response, discussed below, captures short-term interruptions. Energy and cost calculations for long-term price induced interruptions of DSI on-peak load are in the range {AQ327:AQ329}. Indeed, the name of this behavior is Long Term Price Responsive Demand or LTPRD, and the acronym appears several places in the worksheet. The capacity in {AQ327} depends on smelters shutting down and restarting, behavior that requires understanding of choices made over several periods. Description of modeling DSI capacity therefore is in its own section on page L-60.

The **energy calculation** for DSIs is in {AQ328}. The formula is the product of the DSI total capacity and the number of on-peak hours in a standard quarter.

[13] See Hull, John C., ***Options, Futures, and Other Derivatives***, 3rd Ed., copyright 1997, Prentice-Hall, Upper Saddle River, NJ., ISBN 0-13-186479-3, page 230

Calculating the **cost of meeting that load** in {AQ329} uses the valuation approach. The long-term capacity is uncorrelated with short-term electricity price variation, so the cost is simply the product of the energy and the average on-peak price. It is divided by 10^6 to restate the dollars in millions of 2004 dollars. The costs are present valued in {CV329}.

Off-peak calculations begin in the second half of the worksheet {row 684}. The calculations for off-peak non-DSI loads and costs are in {AQ687:AQ688} and the DSI loads and costs are in {AQ692:AQ693}. These calculations are identical to those for on peak, except in obvious ways. The formulas use the number of off-peak hours in a standard quarter (864) and off-peak electricity prices. The off-peak long-term demand for DSI loads is the same as on-peak demand.

Thermal Generation

The model estimates hourly generation dispatch and value. Moving down from the load calculations, the first of these appears in range {AQ339:AQ340}, associated with PNW West NG 5_006. (A description of this gas-fired resource and of the modeling values that this resource uses appears in the section "Existing Resources" on page L-92, below.) The value in AQ339 is the energy in MWh and AQ340 is the cost in millions of 2004 dollars. A single call to a user-defined Excel function (UDF) returns these values as a vector of two single precision real numbers.

This section begins with an explanation of how the regional portfolio model estimates thermal dispatch and value, assuming fixed fuel price. It then generalizes this approach to the case where both electricity price and fuel price are possibly correlated stochastic variables. Finally, it documents the Excel user-defined function that implements the logic. It also points out the analogies between these calculations and financial, European call options and exchange-of-assets options.

Thermal resources dispatch whenever the market price of electricity exceeds their short-run marginal cost. The short-run marginal cost includes cost for fuel and variable operations and maintenance (O&M). For example, assume a gas turbine with a capacity of 1.0 MW has a short-run marginal cost of $30/MWh. For the sake of this illustration, the O&M cost is zero and all the short-run cost is fuel cost. The turbine faces a market price that varies regularly over some period, say a month with 672 hours. When the market price is greater than the fuel price, the turbine dispatches, as illustrated by the red area in Figure L-22.

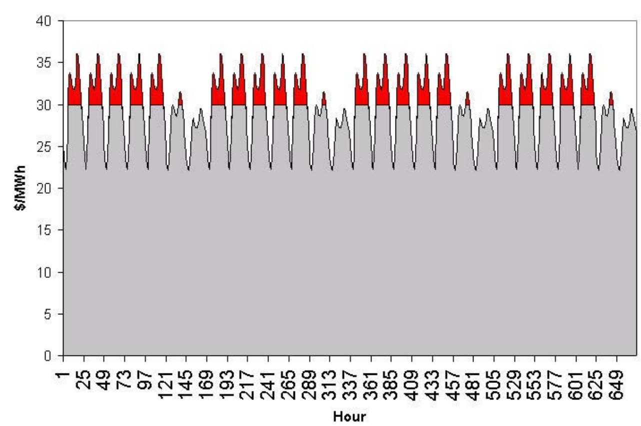

Figure L-22: Thermal Dispatch

In each hour, the value of this generation is the difference between what the generation earns in the market, the market price, and what it costs to generate the power, the short-run marginal cost. The value of the turbine over the month is the sum of the hourly values.

To make the valuation more quantitative, first note that the hourly value is $\boldsymbol{C\ max(0, p_e(h)-p_g(h))}$, where $\boldsymbol{C}$ is the capacity of the turbine, $\boldsymbol{p_e(h)}$ is the price of electricity and $\boldsymbol{p_g(h)}$ is the price of gas denominated in \$/MWh, i.e., the short-run marginal cost of the turbine. This is just the height of the red area in Figure L-22 in each hour. Note that it is never negative, because the turbine does not dispatch unless it can add value. Summing up the value across hours is just

$$V = \sum_{h \in H} C \cdot \max(0, (p_e(h) - p_g(h)))$$

where

H is the set of hours (672 in this case)

$p_e(h)$ is the price of electricity in this hour (\$/MWh)

$p_g(h)$ is the price of gas in this hour,

assuming a fixed heat rate (\$/MWh)

C is the capacity of the turbine (1 MW in our case)

Restating the total value in terms of the mean or average value over the period, and interpreting this as the expected mean of a sample drawn from the population of values, the total value is

$$\begin{aligned} V &= C \sum_{h \in H} \max\left(0, p_e(h) - p_g(h)\right) \\ &= CN_H \frac{\sum_{h \in H} \max\left(0, p_e(h) - p_g(h)\right)}{N_H} \end{aligned}$$

or

$$V = CN_H E\left[\max\left(0, p_e(h) - p_g(h)\right)\right] \qquad (3)$$

where $\boldsymbol{E}$ is the expectation operator and $\boldsymbol{N_H}$ is the number of hours in the period (672 in this case).

The expectation in this formula is (See reference [**3**]):

$$c = \overline{p}_e N(d_1) - p_g N(d_2) \qquad (4)$$

where

N is the CDF for a $N(0,1)$ random variable

$\overline{p}_e$ is the average electricity price

p_g is the gas price

σ_e is standard deviation of $\ln(p_e(h))$

$$d_1 = \frac{\ln(\overline{p}_e / p_g)}{\sigma_e} + \sigma_e / 2$$

$$d_2 = d_1 - \sigma_e$$

The turbine is therefore $\boldsymbol{V = CN_H c}$. Those familiar with financial derivatives theory will recognize the similarity of this equation to that of a European call option[14].

If we sort the hours illustrated in Figure L-22 by the market price, we obtain the market price duration curve in Figure L-23. This aggregation creates a simple area under the market price curve that corresponds to the value of the turbine. Flipping this duration curve over as in Figure L-24 creates a cumulative distribution function (CDF). The value of the CDF is the likelihood that electricity prices will exceed the values on the horizontal axis, if one drew an hour at random from the month. The red area to the left of the short-run marginal cost of $30/MWh is the expected value of turbine dispatch.[15]

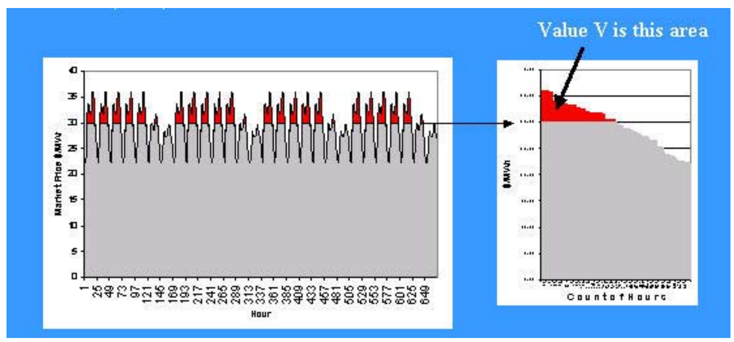

Figure L-23: Sorting by Market Price

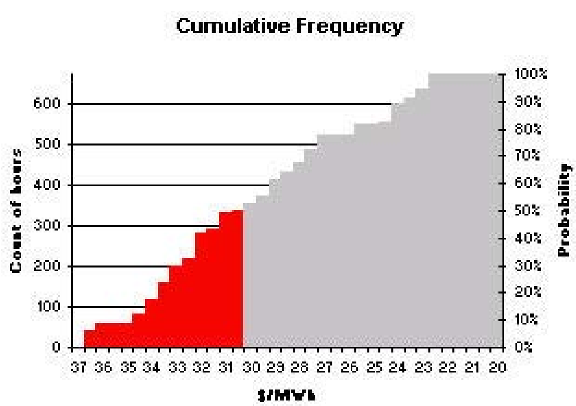

Figure L-24: Cumulative Probability Function

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[14] See for example, Hull, op. cit., page 241. Set r = 0, T = 1, X = p_g, $\sigma_s = \sigma_e$, and S equal to the average of the hourly electricity prices $p_e(h)$. This is the version of the equation for a stock that pays no dividends.

[15] This is completely analogous, however, with the valuation of an option. For an option, the value derives from the expected stock price above the strike price, given the likelihood distribution of prices at expiration. Whereas the volatility (standard deviation) of stock prices describes the width of the corresponding probability density function, here it describes the width of the probability density function for electricity prices during the month.

Although estimating the value of the turbine in the electricity market is essential for calculating system costs, **estimating the energy generation** of the turbine is equally important. At a minimum, we need to know its energy generation to determine whether the total system is in balance with respect to energy. That is, we need to know whether the electricity prices the model is using are generating more energy than system requirement plus exports. If so, prices are too high. Similarly, if the prices are inducing the generation of too little energy to meet requirements, given imports, the prices are too low.

To estimate generation, note that the CDF for generation already specifies the capacity factor for the turbine, as illustrated in Figure L-25. The energy will correspond closely to the hours of generation because for those hours when prices make generation economic, the optimal loading is loading to the lowest average heat rate, which is the plant's assumed maximal loading. The generation would therefore be the capacity of the turbine times the number of hours in the period, times the capacity factor. The function that computes the value of the power plant unfortunately cannot make use of this graphical representation for capacity factor and must resort to more algebraic devices. There is, however, an algebraic relationship between the value of an option (or turbine) and the dispatch factor.

The CDF is a function of $\boldsymbol{p_e}$, and the expectation $\boldsymbol{E(0,p_e(h)-p_g(h))}$ is the integral of the CDF($\boldsymbol{p_e}$) for $\boldsymbol{p_e}$ from infinity down to $\boldsymbol{p_g}$. Moreover, the capacity factor is just CDF($\boldsymbol{p_g}$). These relationships are evident from Figure L-25. Algebraically, the capacity factor ***cf*** is derived as follows:

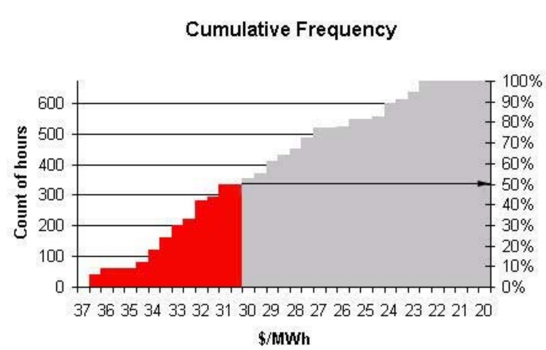


Figure L-25: Capacity Factor

$$V = C \cdot N_H \int_{\infty}^{P_g} \mathrm{CDF}(p_e)\, dp_e$$

$\Rightarrow$ (Fund Thm of Calculus)

$$\left.\frac{\partial V}{\partial p_g}\right|_{p_g = p_g^*} = -C \cdot N_H \cdot \mathrm{CDF}(p_g^*)$$

$\Rightarrow$

$$\mathrm{cf} = \mathrm{CDF}(p_g^*) = -\frac{1}{C \cdot N_H} \left.\frac{\partial V}{\partial p_g}\right|_{p_g = p_g^*}$$

To find the value of the partial derivative in the last equation, use the fact that $\boldsymbol{V=CN_Hc}$ and take the derivative of equation (4) with respect to the strike price [**4**].

$$\frac{\partial c}{\partial p_g} = -N(d_2)$$

where

$$d_2 = \frac{\ln(\bar{p}_e / p_g)}{\sigma_e} - \sigma_e / 2$$

This gives us an explicit formula for the capacity factor, and hence energy, as a function of the gas and electricity price.

$$\mathrm{cf}(p_g, \bar{p}_e) = N(d_2)$$
$$d_2 = \frac{\ln(\bar{p}_e / p_g)}{\sigma_e} - \frac{\sigma_e}{2}$$

Those who are familiar with option theory recognize that $\boldsymbol{N(d_2)}$ is the probability that the strike price is paid for an option, that is, the probability that the option is "in the money" upon expiration. This is consistent with the earlier observation (footnote 15) that capacity factor is the likelihood that electricity prices will exceed the short-run marginal cost of $30/MWh, if one drew an hour at random from the month.

Up to now, we have assumed that the gas price is fixed. The problem with that assumption, of course, is that gas prices do change and may correlate with electricity prices. The value of generation is still given by equation (3), but now both $\boldsymbol{p_e(h)}$ and $\boldsymbol{p_g(h)}$ are stochastic variables. Doing this directly introduces some computational problems[16], but by taking a slight rearrangement of equation (3), we obtain

$$V = E\left[S_2 \max\left(0, \frac{S_1}{S_2} - 1 \right) \right]$$
$$S_2 = CN_H \, p_g(h)$$
$$S_2 = CN_H \, p_e(h)$$

If we assume lognormal distribution for both electricity and gas prices, the preceding equation may be evaluated explicitly:

[16] One approach to solving this issue is to use a "spread option." The value of a spread option derives from the difference in price between two commodities, in our case electricity and natural gas (assuming some conversion efficiency). The problem with a general spread option, however, is that when the strike price is near the expected commodity price, the equations above do not work, so a more sophisticated approach is necessary, which involves solving some integral equations. Finding the solutions to the integral equations, unfortunately, is slow and somewhat unstable. Moreover, the spread option is unnecessarily general because, for the turbine, value derives from differences in only one "direction," that is, when electricity prices are strictly higher than gas prices.

$$
\begin{aligned}
&V = \varepsilon = S_1 N(d_1) - S_2 N(d_2) \\
&cf(\bar{p}_g, \bar{p}_e) = N(d_2) \\
&d_1 = \frac{\ln(S_1 / S_2)}{\sigma} + \sigma / 2 \\
&d_2 = d_1 - \sigma \\
&\sigma = \sqrt{\sigma_{S_1}{}^2 + \sigma_{S_2}{}^2 - 2\rho\sigma_{S_1}\sigma_{S_2}} \\
&\text{where} \\
&S_1 = \mathrm{CN_H}(\bar{p}_e - p_{VOM})(1 - FOR) \\
&S_2 = \mathrm{CN_H}(\bar{p}_g + p_{CO_2})(1 - FOR) \\
&p_{VOM} \text{ is the variable O \& M rate (\$/MWh)} \\
&p_{CO_2} \text{ is the carbon tax penalty (\$/MWh)} \\
&\sigma_{S_1} \text{ is standard deviation for } \ln(\mathrm{S}_{1,t} / S_{1,t-1}) \approx \ln(p_{e,t} / p_{e,t-1}) \\
&\sigma_{S_2} \text{ is standard deviation for } \ln(\mathrm{S}_{2,t} / S_{2,t-1}) \approx \ln(p_{g,t} / p_{g,t-1}) \\
&\rho \quad \text{ is the correlation in values between } S_1 \text{ and } S_2 \\
&FOR \text{ is the unit's forced outage rate } (0 \le FOR \le 1.0)
\end{aligned}
$$

where, as before, we have adjusted the price of gas ($/MMBTU) and the price of the CO_2 tax ($/MMBTU) to $/MWh using the assumed heat rate (BTU/kWh) of the unit. Also, this formula introduces the forced outage rate (FOR) for the unit, which limits the amount of energy that the unit can produce.[17] Note that the variables S1 and S2 here are total values, not prices. This means that, whereas in the case of deterministic $\boldsymbol{p_g(h)}$, the value V = CNHc used the quantity CNH times the unit value c, we now have V = ε.

The portfolio model performs this calculation through an Excel UDF. The range {AQ339:AQ340}, associated with PNW West NG 5_006, contains a vector-valued function. This function returns two single-precision real numbers, one for the energy and one for the value in millions of 2004 dollars. The call in {AQ339:AQ340} is

```
=SpreadOption( $P339, AQ$46,AQ$204-$R$337,AQ$68+0.059*AQ$74,(1-AQ336)*1152*$S$335,(1-AQ336)*1152*$S$335*9.2,1,0,0,0,$R$201,$R$55,$T$14)
```

The function's declaration[18] for the parameters is

[17] Those familiar with financial derivative theory will recognize the similarity to the value for an exchange option that pays no dividends (See, for example, Hull, op. cit., page 468, and note that S1 and S2 are reversed here from the notation Hull uses.) Using the convention T = 1, S1 for the average of the hourly values for electricity generation, and S2 for the average of the hourly values of gas that we must hold to produce the generation.

[18] Although the function's name is "SpreadOption," examination of the code will reveal that it is really the exchange option described above.

```
Function SpreadOption(ByVal lPlant As Long, ByVal lPeriod As Long, _
   ByVal dblSp1 As Double, ByVal dblSp2 As Double, _
   ByVal dblQuan1 As Double, ByVal dblQuan2 As Double, _
   ByVal dblTime As Double, ByVal dblIntRate As Double, _
   ByVal dblYeild1 As Double, ByVal dblYeild2 As Double, _
   ByVal dblVol1 As Double, ByVal dblVol2 As Double, ByVal dblCorr As Double) _
      As Variant
```

The parameters are as follows

lPlant As Long	a zero-based index of plant, on- and off-peak plants modeled separately
lPeriod As Long	a one-based index of period
dblSp1 As Double	price ($/MWh) for electricity, less VOM
dblSp2 As Double	price ($/MMBTU) for fuel, including CO2 tax
dblQuan1 As Double	MWh of electricity
dblQuan2 As Double	MMBTU of fuel
dblTime As Double	time to expiration (years) = 1 for plant dispatch purposes
dblIntRate As Double	annual interest rate for yields (not used)
dblYeild1 As Double	yield on commodity 1 (electricity, not used)
dblYeild2 As Double	yield on commodity 2 (natural gas, not used)
dblVol1 As Double	variation in electricity price within the period
dblVol2 As Double	variation in fuel price within the period
dblCorr As Double	correlation between electricity price and fuel price

The only parameter inputs that should require description beyond what the section already has provided are the following. The parameter dblSp2 uses converted cost of a tax in $/U.S. short ton of CO_2. The conversion to $/MMBTU is

$$\$/MMBTU = \frac{\$}{ton}\frac{ton}{lb}\frac{lb}{MMBTU}$$

where tons per lb is 1/2000, methane combustion produces 117 pounds of CO_2 per MMBTU, and carbon produces 212 pounds of CO_2 per MMBTU. For a gas-fired turbine, the conversion to dollars per million BTU from dollars per ton is 0.059, which appears in the example of the function call, above. The quantities dblQuan1 and dblQuan2 in the function call, above, also use 1152, the on-peak hours per standard hydro quarter. Finally, the value for the dblQuan2 parameter uses 9.2 kBTU/kWh, which is the assumed heat rate for this particular unit.

Contracts

For the purposes of the portfolio model, contracts are risk-management agreements that make future price and delivery of energy more certain. The regional model does not address contracts between parties within the region, because the region as a whole is indifferent to such arrangements. Consequently, only contracts between the region and counterparties outside of the region are material.

The regional model assumes most existing contracts are fixed-price, forward contacts for specific quantities of energy. Such contracts are agreements to pay a fixed sum for energy upon delivery. New contracts were not included among new resource candidates for reasons explained later in this section.

There are two aspects of contracts that impact regional risk: power flows and economic flows. Power flows potentially influence market price and dispatch; money flows impact economic predictability. The next two sections discuss these distinct aspects of contracts.

Power Flow

To understand how existing, firm contracts for energy sales out of the region affect power flow, market price, and dispatch, we consider a simplified example. In this example, only contracts with California exist. There are three cases to consider: uncongested transmission between the region and California, congested transmission with power flows headed north from outside the region into the region, and congested transmission with power flows headed south.

If transmission is not congested, market price in the region are substantially the same as that outside the region and it makes little difference whether or not the firm contracts exist. Wholesale market prices in the region would be the same with and without these firm contracts. The single market price would determine dispatch of plants both in and outside the region.

If transmission flow is congested in the northern direction, this means that market prices in the region are higher than market prices south of the region. In this case, and generators would be better off selling power into the higher-priced regional market and meeting their commitment to the southern counterparty with market purchases from the southern market. The counterparty, of course, would be indifferent to this arrangement, because the parties would have previously agreed upon price.

If transmission is congested southbound, market prices in the region are lower than market prices south of the region. Assume a regional generator is dispatching out of economic order, given regional load plus export limit, to meet contract requirements. First, consider the situation where the generator is dispatching when its cost is above regional market price. This makes no sense because the generator could buy in the regional market, shut down his plant, and make a profit by making the contract obligation with the market purchase. Second, consider the situation where the generator is not dispatching when its cost is below regional market price. The generator must meet its obligation to the contract, which leaves it two options. It could buy from the regional market, but that is more costly than dispatching. Alternatively, it could buy out of the southern market to meet the obligation, but that is even more costly. In this situation, the plant again dispatches at the regional market price. Certainly, the distribution of profits in this case depends on which generators have transmission rights, but the dispatch order of plants and consequently the market prices are unaffected by the contract.

What this discussion shows is that contracts do not affect power plant dispatch decisions or market prices, either within or outside the region. The dispatch and regional market price are unaffected by contracts, irrespective of who owns the generation projects or whether the regional load or an independent power producer (IPP) gets the value of the generation. Although the example is for an export contract, some thought will convince the reader that it applies to an import contract, as well. The ability to counter schedule contracts assures that the fundamental economics of power plants will determine their dispatch and the resulting market prices.

Modeling counter scheduling opportunities is important to the regional model and shows up explicitly in calculations. To illustrate the calculation, consider the region as a tank with a single pipe for importing and exporting energy as illustrated in Figure L-26. We can think of the transmission capability of the this simple system as the symmetric flow capability of the pipe, 5000 MW in both directions in this example.

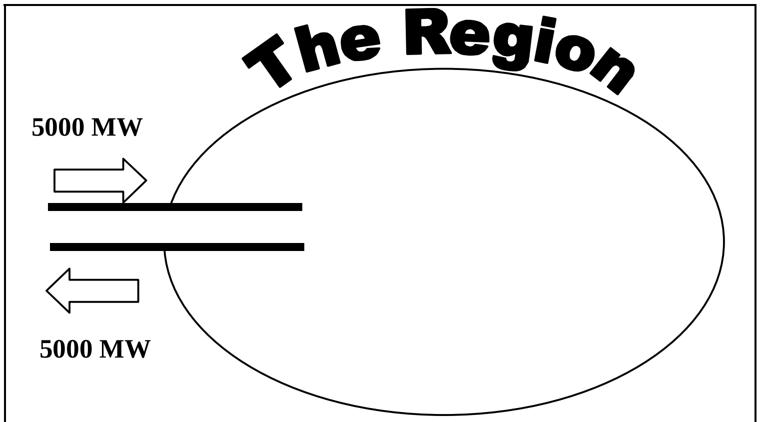


Figure L-26: Transmission Before Contracts

Now, we consider the situation where the model represents an energy import contract as a resource in the region. If we have 3000 MW of additional energy available to region by virtue of the import, there is an implied flow of energy over the transmission system into the region of 3000 MW. This, in turn, means we have only 2000 MW of net transmission capability left for remaining contracts or spot purchases from outside the region. By the same token, the import can be counter scheduled, which adds 3000 MW for remaining export contracts or spot sales to outside the region. Consequently, the net import and export capability of the region must be adjusted to reflect any firm contracts into or out of the region, as shown in Figure L-27.

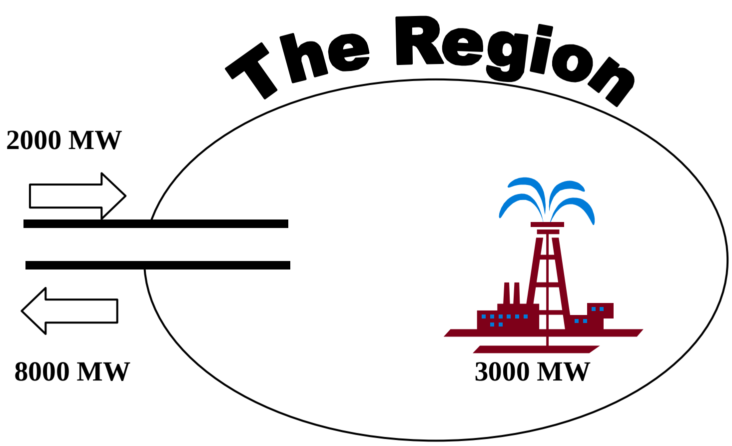


Figure L-27: Transmission After Contracts

In the workbook, the on- and off-peak average energies (MWa) appear initially in {rows 84 and 88} respectively. The data values are presented and documented below, in the subsection "Contracts" of the section "Resource Implementation and Data." These MWa values are used by the calculation of annual energy for the decision criteria in {row 290} (see e.g., {AT290}), for a estimate of Non-Hydro Capacity ({row 670}) used by certain reports (see the section "Portfolio Model Reports And Utilities"), and in the contribution to regional energy balance. For the regional energy balance calculation, the worksheet first converts MWa to MWh using the number of standard hours in the subperiod ({rows 367 and 731}). The value calculation {AQ368} uses MWh equivalent and the relevant market price to determine cost or value of the contract. For reasons described in the next section, the worksheet computes only the gross value, assuming the costs for these fixed contracts effectively are sunk. The energy requirements calculation { AQ676 and AQ1032} uses the MWh equivalent to determine the necessary purchases on the market. The adjustment to import and export capability, illustrated in Figure L-27 is reflected in calculations at { AQ677 and AQ1033}.

Money Flows

Contracts reduce risk to the parties by assuring financial certainty. Irrespective of factors that may influence the dispatch of resources, some party is responsible for delivering power to a particular substation at an agreed-upon price.

The portfolio model captures economic consequences of resource decisions to an unprecedented extent, but there are still limitations to what we have modeled. One of the practical constraints is our limited knowledge of the financial terms of existing and new contracts. The portfolio model incorporates energy flow associated with existing long-term contracts, but unfortunately the Council has no basis for estimating contract costs. It is assumed that existing contracts have fixed-price and fixed-energy terms, and the costs of the contracts are therefore sunk. The gross value of these contracts, however, is valued in the market. Thus, we capture the cost of meeting future requirements and value contract deliveries to the region. Because the energy is constant over each subperiod, the correlation with market price is zero and the calculation of the gross value is simply the product of average market price and energy, as shown in {AQ368}. All dollar amounts are in millions, so the formula divides the product by 1,000,000.

Although a single utility's risk model would do so, the regional model does not examine ***future*** contracts the region might enter into either with IPPs or with entities outside of the region. Although such contracts would certainly affect the economic risk situation for the region and for parties within the region, the regional model avoids modeling these contracts for several reasons.

- The terms of future contracts are hard to predict. Perhaps the best guess would be to set future contract prices at the prevailing market price. Unless the model assumed detailed rules for entering into fixed-term contracts -- the begin date and duration of the contracts, the amount of transmission left to accommodate the contract, and so forth -- the terms would have to float with the market price. In this case, however, the value of the contract would then be zero. That is, there is no point to explicitly modeling the contract.

- Contracts for regional load-serving entities and regional IPP capacity with parties outside the region would remove sources of contracts for regional parties, but arguable displace other sources outside of the region. Given the load diversity in the WECC, it stands to reason that contracts for power will continue to be more abundant in the winter, when the region needs the capacity.

Thus, while future contracts for energy out of the region could affect economic risk by hedging price risk and removing or adding contracting counterparties for the region, the model does not capture this. The practical limits on knowledge of existing and future terms and the small likelihood that such contracts would significantly diminish the pool counterparties for regional participants are significant hurdles to such modeling.

Before leaving this section, note that the value or cost associated with contracts accrues to the region in the base case model. As the reader will note in the discussion of the regional IPP sensitivity (Appendix P), this is not always the case. That is, the energy of contracts may affect the energy balance of the region before any counter-scheduling, but the associated costs may be excluded from the region's cost estimate. This occurs, for example, if the regional IPPs have firm contracts to export energy out of the region. This obligation is on the IPPs -- not the region -- and should not affect regional costs. The energy export will offset the generation of the IPPs in the region, however.

Supply Curves

The model uses supply curves to represent conservation and price-responsive hydro. For the purposes of the regional model, conservation is either discretionary or of a lost-opportunity nature. Price-responsiveness of hydrogeneration refers to a limited capability to shift hydrogeneration from month to month in response to wholesale electricity market prices. Do not confuse price-responsive hydrogeneration with what is often called "hydro flexibility," which refers to the ability of the hydrogeneration system to draw below Energy Content Curve (ECC) under adverse conditions for reliability purposes. The hydro flexibility capability of the region is over 7,200 GWh or about 10,000 MW-mo. The region uses this flexibility for severe situations, like extreme winter load conditions, and it comes usually at the cost of some non-hydrogeneration use of the system, such as fish survival enhancement. On the other hand, the magnitude of price-responsive hydrogeneration response is relatively small, about 1500MW-mo. Price-responsive hydrogeneration reflects adjustments that operators would make in anticipation of market conditions, and they perform these adjustments with energy above the ECC.

Background

To begin the description of the supply curve logic, consider the physical and economic situations to be modeled. The first example is lost-opportunity conservation, including a more detailed discussion of the model determines cost from the supply curve. The section then describes the examples of discretionary conservation and price-responsive hydrogeneration.

Lost opportunity conservation consists of energy saving opportunities that are available for only a limited time. Examples of these include insulating and the installation of high-efficiency heating and cooling systems in new buildings. After their construction, going back and changing the conservation measures in these buildings would be cost prohibitive. Special attributes of this kind of resource are the following:

- Assuming the same measures are available to all new buildings, there is effectively a new supply curve in each period. The supply curve consists of the aggregation of a host of measures, such as lighting, new insulation, and other energy efficiency programs, each of which has its own costs and potential. Each new generation of building in principle presents the opportunity to pursue the entire range of measures. Thus, the supply curve represents perennial increments of new opportunity available in the period, unaffected by prior conservation activity.
- The *decision* about how much energy conservation to pursue is independent of prior decisions about other lost opportunities. That is, cost effectiveness depends only on prevailing prices for electricity, not on prior conservation actions.
- Any period costs and energy savings are *accrued*. Costs and energy savings associated with period activity add to those already obtained to arrive at the total current cost burden and energy for the period. The total cost and energy from lost-opportunity conservation in a period is therefore the ***cumulative*** period activity cost and energy up to and including that period. Clearly, we would not assume that the aggregate of these would be non-decreasing as we go forward. Note that accumulating cost relies on the choice to use levelized costs; if the model had used cash flow instead, this would not be the case.
- It is reasonable to assume that the supply curve from which these energy saving measures remains unchanged from period to period. The only exception to this last observation is for changes in the overall potential for lost opportunity conservation. During a period of economic downturn, for example, loads may become depressed and the number of buildings -- and consequently the amount of lost opportunity conservation -- would diminish.

The model obtains the costs for lost-opportunity conservation from the supply curve in particular fashion. Now, clearly a contractor does not pay the same for energy savings from all sources. A contractor does not pay the same for the energy savings from compact fluorescent lights as he or she would for high-efficiency heating. Instead, the amount paid for energy savings from compact fluorescent lights is their market price. This rather obvious observation has implications for how supply curves will yield costs, as we will see in the following example.

Suppose that the prevailing market price for energy is \$60/MWh. At this price, given the supply curve in Figure L-28, the annual cost-effective level of conservation would be 70

MWa. If this were the supply curve of some commodity in a market, the cost of the purchase of this commodity would be $36,792,000, i.e., the 613,200 MWh in a year times the market-clearing price of $60/MWh.

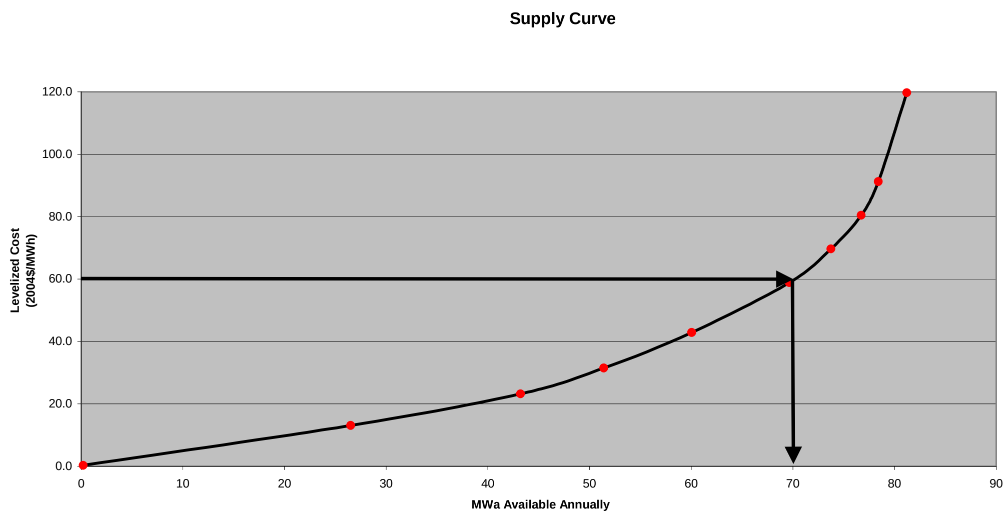


Figure L-28: Supply Curve

For the cost of conservation from a supply curve representing a host of distinct measures, however, the total cost associated with the conservation is the accumulated cost of each measure along the supply curve below the cost-effectiveness price, as illustrated in Figure L-29. This cost is much smaller, $13,467,624, although the value of the energy would still be $36,792,000, as estimated before. We will borrow the economist's term for this

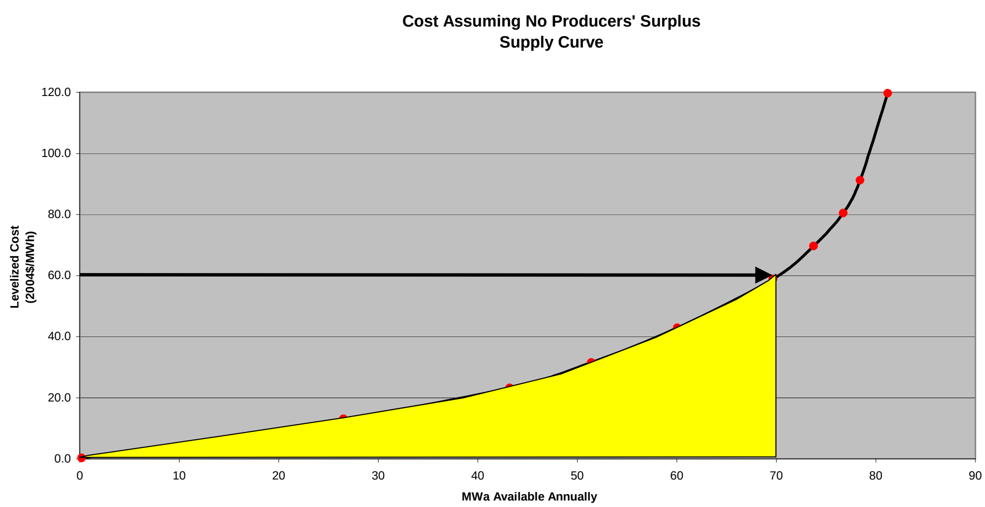


Figure L-29: Costs Associated with Supply Curve

cost, the "cost, assuming no producers surplus." This is how the model computes the costs of conservation.

Contrast lost-opportunity conservation with discretionary conservation measures. Discretionary conservation measures are the second example of the application of supply curves in the portfolio model. Discretionary conservation measures are those that can be performed cost effectively at any time. Examples of discretionary conservation include changing out low efficiency lighting for high-efficiency lighting in existing buildings. The Council's definition of discretionary conservation does not include new discretionary conservation that will arise from improvements in technology or opportunities for cost effective retrofitting in new construction. Instead, assessment of discretionary conservation is a snapshot in time representing conservation that exists at that point in time. It is therefore a very conservative estimate of discretionary conservation available in the future.

As with lost opportunity conservation, we would not assume that accumulated costs and energy savings could diminish as we go forward. The energy and costs reported in a period are the ***cumulative*** amounts due to decisions in all prior periods. Also, the costs associated with discretionary conservation are derived from the supply curve in the same way as were those for lost opportunity conservation. That is, they are costs assuming no producers' surplus. In several other regards, however, discretionary conservation differs from lost opportunity conservation.

- The conservation that is available in each period is directly dependent on prior conservation activity. A measure can be implemented only once, and once implemented is no longer available as a future development option.
- A single, unchanging supply curve represents total conservation available throughout the study period. Only as market prices rise above prior “high water marks” does additional conservation become cost effective.
- The highest prior cost-effectiveness level therefore determines both the energy and cost of total conservation available in that period. In the case of discretionary conservation, the costs and energy in Figure L-29 would represent the cumulative cost and energy due to all the prior conservation action taken up to the present, not the period’s addition of cost and energy as in the case with lost-opportunity conservation.

The third and final example is that of price responsive hydrogeneration. When system operators are making decisions about how much water to send through the dams, they must consider several factors. The amount of water that they have at their disposal is limited. Moreover, while they may allow temporary excursions from target forebay levels, they are responsible for assuring that the ending levels are on target. Given these constraints, they may use that water now -- possibly drawing down forebay levels -- to generate electric power, which they will sell on the market at the prevailing market price, or they may withhold the water until market prices are higher. Operators do not have perfect foresight about future prices. Experience with daily and weekly variation in prices and with the effect that other events have on electricity prices, however, help shape their expectations.

Even assuming perfect foresight, optimizing the economic value of this storage is challenging. There are, for example, minimum and maximum constraints on generation and stream flow. The portfolio model does not attempt any such optimization. Instead, the portfolio model logic borrows from that of earlier Council models, Genesys and the SAM model. In these models, the decision to draw down or withhold hydrogeneration is based on the comparison of prevailing market prices to prices associated with various blocks out of regional, thermal generation. The assumption is that if storage is drawn down below an equilibrium level, then some form of thermal generation will be needed to restore the hydrogeneration system to its equilibrium state. The further down the hydro system is drawn, the more expensive the replacement energy. Similarly, if current storage is in surplus, the associated energy is inexpensive.[19]

The supply curve associated with price responsive hydrogeneration, therefore, is a reversible supply curve. At the beginning of the study, the supply curve will start out with an equilibrium state, that is, a starting market price and energy level. If market prices rise above the starting price, the market prices is compared to the starting price and energy is made available up to the higher market price. Figure L-30 illustrates the situation where the starting price was \$35/MWh and current market price is \$58/MWh. This causes the hydro supply curve to yield 10 MW-mo of energy. The cost of this energy is the increment of cost, assuming no producers' surplus, incurred since the prior period, illustrated by the white area in the figure.

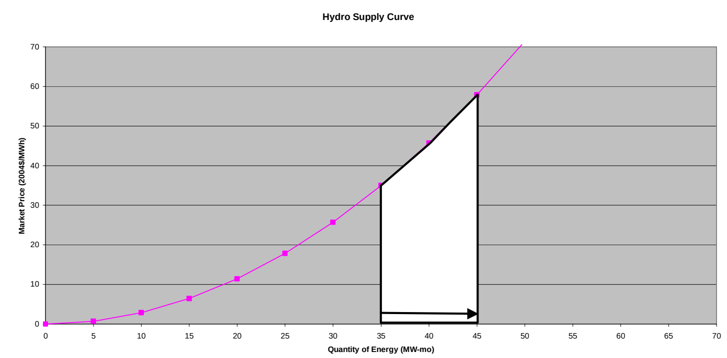


Figure L-30: Price-Responsive Hydro

[19] The cost typically is not assumed negative, because some surplus capability always has value as insurance against contingencies such as plant outages. The exception is if the surplus storage would interfere with the flood control responsibilities of the hydrogeneration project.

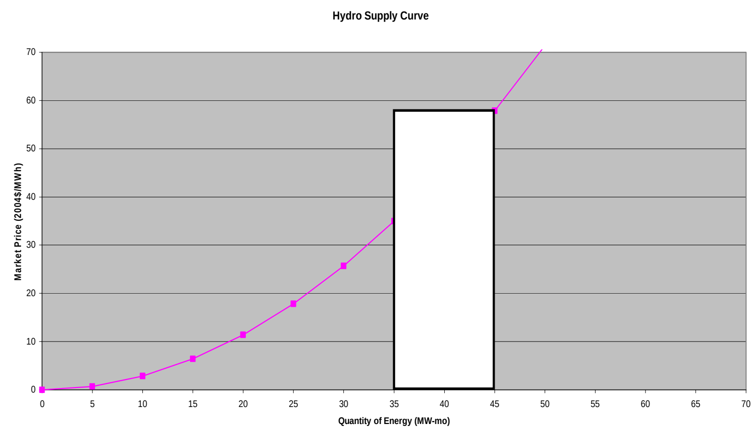


Figure L-31: Gross Value of Energy

The gross value of this energy is just the market price times the energy provided, illustrated (with suitable scaling for hours) by the rectangle in Figure L-31. The net value of this energy, therefore is the difference between gross value and cost, illustrated by the remaining triangle in Figure L-32.

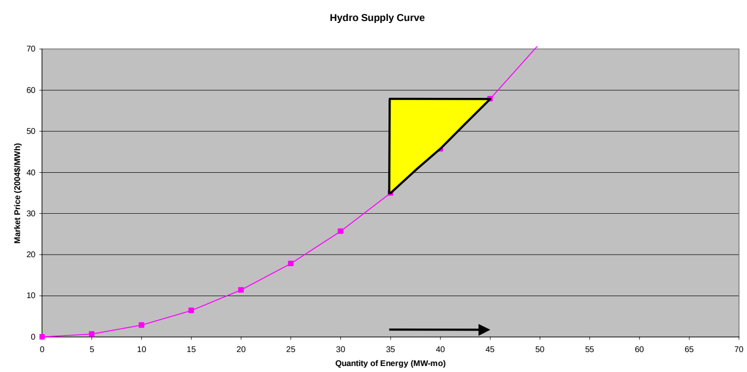


Figure L-32: Net Value of Energy, Increasing Price

In the next period, if the market price is higher than the prior period, an increment of energy corresponding to the difference of two prices will be made available. If the market price is lower than the prior period, the operators will effectively "refill" hydroelectric storage. If the system is refilling, the role of market price and supply curve cost reverse. The market price determines cost, not benefit, and the supply curve determines benefit, not cost. This results in the net value illustrated by the triangle in Figure L-33. When refilling, the hydro system puts load on the energy balance. The load will be equivalent to the energy corresponding to the difference of those two prices.

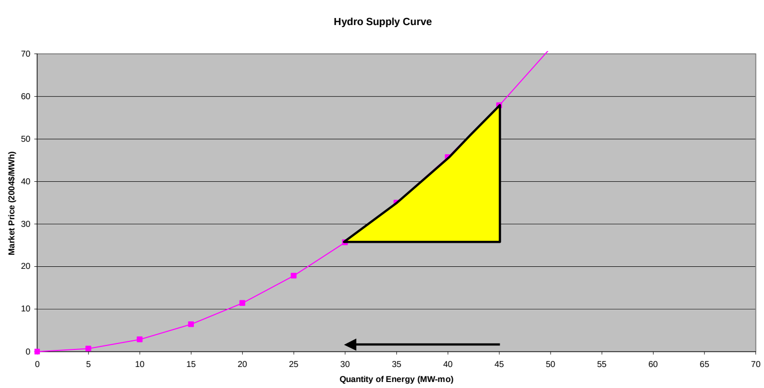


Figure L-33: Net Value of Energy, Decreasing Price

The supply curve for price-responsive hydro resembles that of discretionary conservation in that the cost and energy available does depend on decisions made in prior periods. It differs from discretionary conservation, however, in that the supply curve is reversible, and the cost and energy in each period is incremental rather than cumulative. Whereas discretionary conservation energy is all energy along the supply curve up to the cost-effectiveness price, price-responsive hydrogeneration energy is due to electricity market price differences between this period and the prior period. Costs for price-responsive hydrogeneration also depend on these price differences.

Note the following oddity about price responsive hydrogeneration value. The value of the energy is of course determined by market price, but it changes are gradual the market price is very close to the shadow price for that energy reflected in the supply curve. Consequently, as changes are more gradual and smaller the net value of the energy approaches zero. If, on the other hand, changes are abrupt, there is a positive value associated with the hydrogeneration because the gross value is determined by the market price all the cost is determined by the supply curve assuming no producers surplus. If there is an abrupt decrease in market price, however, the cost of the load is smaller than the value associated with restoring the energy to the hydro system. Thus there is a net positive gain or value to the storage, but the size of the gain depends on the size and frequency of adjustments.

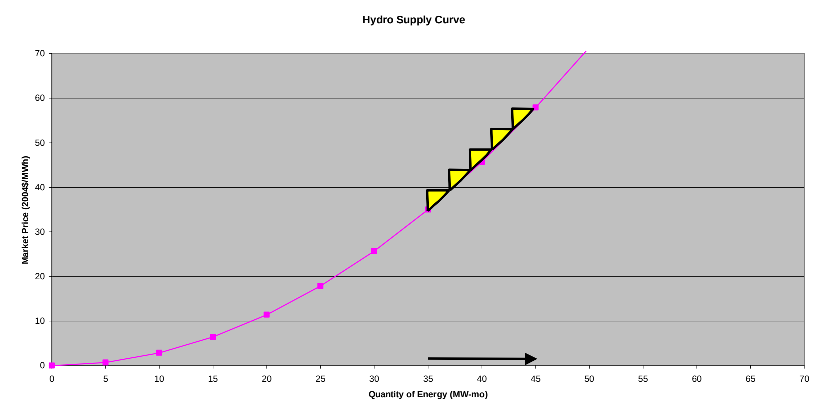


Figure L-34: Value as a Function of Adjustment Frequency

Because the value of the price-responsive hydro depends in such a sensitive fashion on the frequency and step-size of adjusts to market price, and because it seemed reasonable the operators made adjustments relatively frequently, the decision was made to ignore the value of the price responsive hydrogeneration effectively assuming that changes are made continuously and are small. This does not mean, however, that the hydro energy does not have value to the system. The primary source of value instead is due to price moderation. As explained in the section “The Market and Export/Import Constraints,” on page L-50, the ability of price-responsive hydro to rebalance system energy when the region is close to import and export limits prevents market price excursions. Preventing these excursions has significant value to the system.

Before examining the supply curve logic, consider the similarities and differences among the three applications of supply curves provided above. First, the supply curve may represent period potential, or they may represent the total amount of energy available over the study. An example of the former is lost-opportunity conservation; examples of the latter are discretionary conservation and hydro generation. While period curves may change from period to period, the fixed supply curves obviously can not. Second, supply curves may be reversible, as in the case of hydro generation, or non-reversible, as in the case of both types of conservation. To facilitate discussion, Figure L-35 presents these options as a grid. Lost opportunity conservation would fall in the upper left-hand corner, discretionary (non-lost opportunity) conservation would fall into the lower left-hand corner, and price-responsive hydro would fall into the lower right-hand corner.

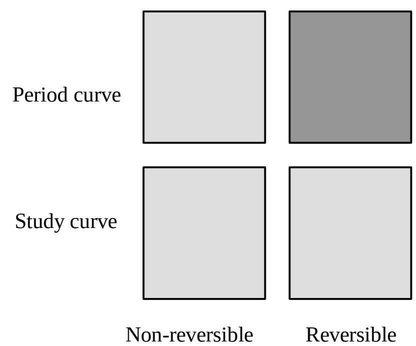


Figure L-35: Supply Curve Options

One question that arises is, "Does it makes sense to speak of a reversible, period supply curve?" This case would lie in the upper right-hand corner, which is slightly darker in Figure L-35. For this to be feasible, circumstances must arise where the supply curves for adjacent periods have at least one point in common, the access point. Because period curve can potentially change from period to period, however, this common point would typically change each time the curves are used. Because of the complexity of this situation, and because no physical systems come to mind which might require this representation, it is excluded from further consideration.

There is one more aspect of supply curves that Figure L-35 does not address. The energy and cost returned in a given period may either be the cumulative amount due to all changes in prior cost and energy, or may be the increment of cost and energy only due to changes in that period. In the former case, the incremental change adds to the cost and energy incurred up to the current period. Figure L-36 illustrates this additional dimension. The combination representing a reversible, varying supply curve is missing from this illustration, consistent with the exclusion described in the preceding paragraph. The three kinds of supply curves used in the regional model now correspond to the lighter-colored boxes in this figure. Price-responsive hydro now falls in the row of boxes associated with incremental costs and energy, behind the row of boxes associated with cumulative cost and energy.

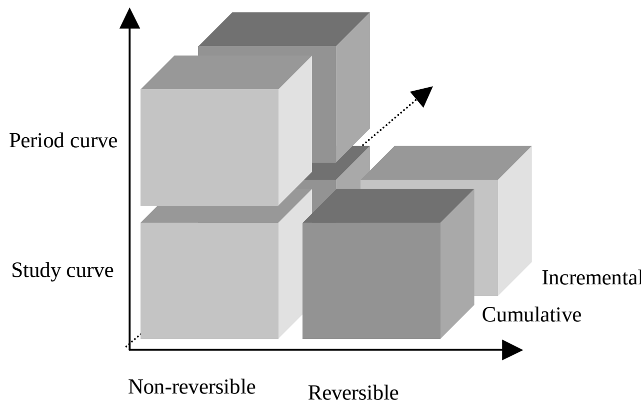


Figure L-36: Aspects of the Supply Curve

This concludes the discussion of supply curve concepts requisite to understanding the computer model. The subsequent material describes the use of functions that perform the tasks of computing the energy and cost.

Conservation

Before each game, the worksheet model must initialize several arrays of data that the supply curve worksheet function accesses. These arrays contain a description of the supply curve in each period and look-up values for cost. The description of the supply curve appears in {row 376}. The supply curve changes only if there is a new entry in the column corresponding to the period of interest. For lost opportunity conservation, the supply curve changes several times, including during this period. (See {AQ377}.) The supply curve syntax is

0,0@+5.075,15.5@+10.55,58.5@+11.475,78.9@+11.85,102,

which represents a piece-wise linear supply curve defined by five points. The points are separated by the special characters "@+". The second point, for example, is (5.075,15.5), where the first coordinate is the energy in MW (Q is 5.075 MW), and the second coordinate is the price in $/MWh (P is $15.5/MWh in 2004$). Because this supply curve represents quarterly increments, each Q value is one-fourth the annual capability. The description of the data development for these supply curves appears below, in the subsection "Resource Implementation and Data," of the section "Resource Implementation and Data," on page L-92.

Other information loaded at the beginning of each game appears in the range {F376: P377}. Column F contains the "curve type." The curve type is an integer -- 0, 1, or 2 -- representing to which category in Figure L-35 the curve belongs. (See Figure L-37.) Column G contains the integer 0 or 1, denoting the incremental or cumulative treatment of energy and cost, respectively.

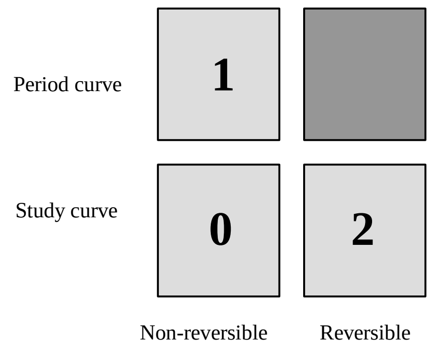


Figure L-37: Curve Type

All supply curves extrapolate indefinitely in both directions unless terminated by endpoints. Upper and lower prices define the endpoints. Column H contains the upper price; column I contains the lower price. Arbitrarily small and large numbers define unbounded curves.

Changes in energy from period to period may be constrained to a maximum rate. The maximum rate of change, or "ramp rate", is specified in column J. If no constraint is intended, use an arbitrarily large value.

Columns K through O specify initial conditions for cumulative and incremental cost and energy. These initial conditions play an important role in specifying the starting place for price-responsive Hydro. For both kinds of conservation, the initial values are zero.

The last parameter is an index that specifies to which supply curve this data pertains. This index appears in column P. The supply curve workbook function use this index to determine which portion of data arrays to access and modify.

The first row in the period containing an example of the worksheet supply curve function is {row 377}, where the on-peak energy for lost opportunity conservation is estimated. The formula in cell {AQ377} is

=1152*1.402*sfSupplyCurve(AP$233+$R$375,$P377,AP$46,AP377,AP240)

The first constant is the number of hours on peak. The second, 1.402, is the on-peak weight for lost opportunity conservation. Conservation typically does not have equal effect on peak and off peak or from month to month. As explained in the subsection “Supply Curves” of the section “Resource Implementation and Data,” below, the seasonal variation has been flattened, although the on- and off-peak effect has not. The calculation of this weighting factor appears in that section.

To understand the last factor, it is necessary to follow the parameters in the call to the function, defined as follows

Function sfSupplyCurve(ByVal sPrice As Single, ByVal lCurve As Long, ByVal lPeriod As Long, ByVal dummy As Single, Optional ByVal sProportion As Single = 1) As Single

```
==============================
Takes:
sPrice -   Price in $/MWh
lCurve -   index to unique supply curve
lPeriod -  0-based index into period
dummy  -   Forces the order of calculation
sProportion - multiplier for Lost-Opportunity supply curves only
==============================
Returns:
A single with the amount supplied, MW
```

The first parameter in the function call in cell {AQ377} is AP$233+$R$375, the price used to access the supply curve. This sum points to a decision criterion in the previous period (AP$233) and a constant over which the optimizer has control ($R$375). The optimizer can adjust this latter constant, which is a premium over decision criterion price, if doing so reduces cost or risk. A brief description of this appears in Chapter 6.

This is the first time we have encountered a situation where a function or formula accesses a price or decision criterion in a prior period to determine response. The complete discussion of this practice is in the section "Concept Of Causality," below, and description of the decision criterion is in the appropriate subsection of the section "Decision Criteria." Briefly, however, the decision criterion for lost opportunity conservation is a non-decreasing, average market price over five years. This is intended to reflect the fact that decisions to modify such programs, such as building code changes, usually take awhile, but much of the measure gets institutionalized into standards and building codes. It is much less typical to make such decisions based on *current* market prices.

The second and third parameters in the function call in cell {AQ377}, $P377 and AP$46, point to the curve 0-based index and the prior period's 0-based index, respectively. That is, the first supply curve has index 0, the second curve has index 1, and so forth, and these curves may appear in any order in the worksheet. Similarly, the first period (Sept-Nov 2003) has index 0, the second period (Dec 2003-Feb 2004) has index 1, and so forth. These are simply used to organize data in an array that holds data for all supply curves and all periods.

The fourth parameter in the function call in cell {AQ377}, AP377, points to the supply curve formula in the preceding period. This is a dummy reference that forces Excel to calculate the prior period's supply curve value *beforehand*. An internal, cell-dependency tree specifies the order of formula evaluation in a worksheet. This tree assures that when calculation takes place, only those cells that have changed -- and any cells that depend on those cells -- recalculate. This saves recalculation time, but renders the order of cell recalculation and function call unpredictable. Because conservation in one period depends directly on conservation in prior periods, calculations and supply curve function calls must occur in strict chronological order. The dummy reference assures chronological firing of function calls.

The fifth parameter in the function call in cell {AQ377}, AP240, scales the quantity of the lost-opportunity supply curve. As mentioned earlier, such things as downturns in building construction affect lost-opportunity conservation. To capture this, the model uses percentage change in load as a surrogate for these effects. If loads increase one percent relative to the benchmark load, lost-opportunity supply potential increases one percent at all price levels. Clearly, the *recently past* change in load affects the potential for lost-opportunity conservation.

The period cost of lost opportunity conservation lies in cell {AQ378}. The supply curve function sfSupplyCurve computes all costs when it computes energy. A simple function in {AQ378} simply retrieves that information from data arrays. The content of {AQ378} is

```
=(sfCostCurve(AQ377,$P377,AP$46)*1152*1.402-AQ$207*AQ377)/1000000
```

This formula is valuing the on-peak conservation energy in the market and converting the value to millions of dollars. As elsewhere, cost is positive and value is negative, so this formula computes cost less gross value, rather than gross value less cost. There are two terms in the numerator. The first term is

```
sfCostCurve(AQ377,$P377,AP$46)*1152*1.402
```

which represents the cost of the conservation in real levelized dollars for the period. (See page L-16, ff. for a discussion of the use of real levelized dollars.) The supply curve function has already multiplied the $/MWh value by the MW obtained from the supply curve, yielding real levelized $/hr which sfCostCurve(AQ377,$P377,AP$46) reports. Again, the real levelized $/hr is multiplied by the number of hours in the standard on-peak period and by the weighting factor.

The function sfCostCurve has the following syntax:

```
Function: sfCostCurve(ByVal dummy As Single, ByVal lCurve As Long, ByVal lPeriod As
        Long) As Single

Purpose:  Retrieve costs that were calculated by sfSupplyCurve

==============================
Takes:
dummy  -   Used only to re-trigger the fetch of cost information; Excel
          will call this function after the sfSupplyCurve function
          has been updated
lCurve -   Unique integer identifying curve
lPeriod-   Unique integer identifying period
==============================
Returns:
   A single with cost (value) in $/hour real.  The value already reflects
   the rate of energy supplied
```

The first parameter references the supply curve function, to assume that function has been updated before attempting to access the associated costs. The second and third parameters merely access the 0-based period and supply curve indices to permit the function to locate the data in the memory arrays.

The second term in the numerator is AQ$207*AQ377. This is the gross value of the energy. The cell {AQ$207} contains the relevant on-peak market price for electricity in the period; the cell {AQ377} is the on-peak conservation energy, which has already been adjusted by on-peak hours and weighting.

Similar calculations exist for off-peak energy and cost. The energy calculation in cell {AQ741} is

=AQ377*864*0.465/1152/1.402

which determines the off-peak energy contribution. The MWh off-peak is the product of off-peak hours (864) and weighting (0.465) applied to the MW rate. The MW rate, in turn, is the MWh on peak after removing the on-peak hours (1152) and weighting (1.402) factors. The calculation of costs off peak is the same as on-peak, with appropriate substitutions for off-peak hours and weighting:

=(sfCostCurve(AQ741,$P741,AP$46)*864*0.465-AQ$219*AQ741)/1000000

The allocation of gross conservation costs on and off peak is a bit of a fiction, but reader should be able to convince himself the distribution does not matter as long as the total gross cost is correct. The benefit, due to allocation of energy on- and off-peak, however, is critical.

Discretionary conservation energy and cost calculation is similar to lost-opportunity calculation. Before the game, the workbook reads a single supply curve from cell {R385}. It reads other information from the range {F385:P386}. Most of the parameters in this range are identical to those for lost-opportunity conservation. The two exceptions are the choice of "curve type," cell {F386}, and the ramp rate, cell {J386}. The curve type conforms to the type of conservation, as illustrated in Figure L-37. The ramp rate, expressed in MW per quarter, is a constraint that limits the amount of conservation that can be added in each quarter. This constraint is essential, because of the low cost of discretionary conservation programs. If the supply of energy were not constrained, almost half of the energy available in the curve, roughly 1500 MW, would be implemented in a single quarter. Clearly this is not realistic. For several reasons, including cash flow constraints, rate impact constraints, and limits of available resources for pursuing such programs, the model employs this ramp rate.

Price-Responsive Hydro

As for conservation, the worksheet model initializes the supply curve-worksheet function for price-responsive hydro before any games. The description of the supply curve for hydro is fixed throughout the study and appears in cell {R528}:

-250,5@+0,30@+250,60

The supply curve syntax is just as for conservation. As with lost-opportunity conservation, this supply curve represents quarterly increments. In this case, the supply curve has a zero quantity at $30/MWh, but this is somewhat arbitrary, because only differences in quantities on the supply curve get used. The supply curve, in fact, stops at $5/MWh and $60/MWh, as explained below. This means the total amount of energy available from the curve, obtained by a swing in market price from $5/MWh to $60/MWh, is 500MW, or 1,008 GWh (500MW * 2014 hours per standard quarter). Compared to the hydroflexibility limit for the PNW hydro system, about 7200 GWh, this is a small value, as it should be.

The other data loaded before simulation, in range {F528:P529}, differs significantly from what the model has for conservation. As explained earlier in this section, the curve type and treatment both differ from what we use for conservation. This combination of values assures the model uses a reversible supply curve and the user-defined function (UDF) returns only the incremental energy and associated increment cost between the current and the immediately prior year.

Upper and lower price limits (cells {H259} and {I259}, respectively) reflect the assumption that the amount of energy available for shifting is constrained. The values here match the endpoint values of the supply curve, although that is not a constraint of the model.

The initial price (cell {O259}) is set to $30/MWh, the midpoint of the supply curve. Recall that the energy provided by the supply curve is determined by comparing the period electricity price against a baseline, the price in the prior period. In the first period, however, there is no prior period, so an "initial price" must be specified. That is the purpose of this parameter. Its value is somewhat arbitrary, but it has been set to the rough, average cost of electricity at the beginning of the study. After several periods, this value of this initial price probably becomes immaterial to energy calculations.

Note that in cell {AQ529}, the price for accessing the supply curve ({AQ$224}) is the *current* price, not the price or criterion function value in a prior period:

```
=sfSupplyCurve(AQ$224,$P529,AP$46,AP529)*1152
```

This is a departure from the case for conservation. This is consistent with how we expect that price-responsive hydro would behave. Any generation or refill would be to avoid or take advantage of *current* market prices.

Conventional Hydro

Hydrogeneration is a key uncertainty, due to its reliance on variable stream flows and weather. For this reason, the discussion of the user-defined function (UDF) that provides these energy values appears in Appendix P, instead of here. Appropriate for discussion here, however, is how the MWa provided by the hydro UDF influences the costs and energies in the portfolio model.

As described in Appendix P, the UDF returns east-side and west-side generation separately. The west side, on-peak hydrogeneration formula in cell {AQ437} is

```
=$R$136*$AQ$36
```

The first term in this product points to the constant 1.0. This is a vestige of logic in Olivia that provides the user the capability to scale hydrogeneration. The second term points to a cell, {$AQ$36}, containing simple conversion from the MWa returned by the UDF, {AQ33}, to MWh:

=AQ33*1152

Finally, the cost is the inverse of the value of the hydrogeneration in millions of dollars. Because the model assumes no variable cost, the value is just the MWh times the market price in $/MWh from cell {$AQ$204}:

= -$AQ$36*$AQ$204/1000000

Identical calculations exist for east-side hydrogeneration, rows {594} and {595}, and for off-peak generation on the west side, rows {798} and {799}, and on the east side, rows {951} and {952}.

The Market and Export/Import Constraints

The portfolio model assumes that dispatchable resources respond to market prices for electricity.[20] When a power system is unconstrained by transmission or other import/export limitations, one typically does not have to worry about whether a given market price is somehow infeasible. This situation may exist for individual utilities that consider themselves price takers in a relatively deep market for electricity. Higher prices simply mean more generators will run.

The region as a whole, however, is different. If a lot of generation is added to the region and exports are constraining, prices must fall to balance demand. Price is no longer an independent variable.

A regional model that incorporates market price uncertainty lies somewhere between these extremes. Electricity prices are neither completely independent nor completely dependent of other variables. As the reader will see, at least one other variable must typically play the role of a "slack variable," so that the pair is dependent. In the Council's portfolio model, the slack variable is net exports.

When Monte Carlo simulation selects an electricity price for the regional model, it may not be feasible. If the price is high, the resulting generation, after exports, may be surplus to requirements. Energy must be conserved, however: energy consumed must equal energy produced. In this example, the price must be adjusted downward until the situation becomes feasible. The situation will be feasible when generation equals loads plus exports. Similarly, if the price is high, the resulting generation, after imports, may be inadequate for our requirements. The price must be adjusted upward.

[20] Strictly speaking, the assumption is that dispatchable resources respond to some explicit, widely visible signal of generation value. In the world before price deregulation, the measure of merit was "system lambda," which indicated the variable cost of generation on the system. Regulators among others sometimes refer to this concept as the "avoided cost." Economists refer to this kind of value as a "shadow price." It simply represents a means for assigning value to alternative means to meeting system requirements or the requirements of others. In describing the portfolio model, all of the arguments work if one substitutes these identical concepts for that of deregulated market price for electricity.

RRP algorithm

The Resource-Responsive Price (RRP) algorithm in the model finds a price that balances the system's energy. It does this by iteratively adjusting the price. Figure L-38 illustrates this process in the case where prices start out too low and upward adjustment is necessary.

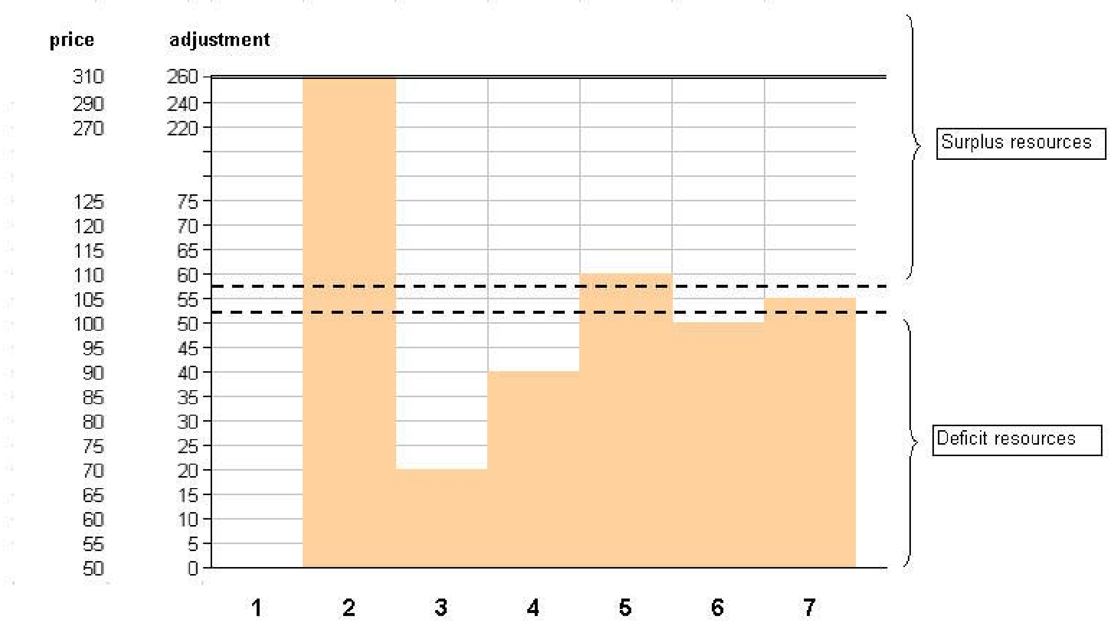


Figure L-38: RRP Algorithm Finds Price Iteratively

In this example, a random draw of electricity price yields $50/MWh. At this price, however, the system does not have enough generation to meet its load, even after all possible imports. The vertical axis is the price adjustment, from zero to $260/MWh. Next to the vertical axis are values representing the electricity price. Before any adjustment, the electricity price is $50 a megawatt hour. The difference between the two columns is the initial starting place of $50 a megawatt hour. Along the horizontal axis are the steps in the iteration process. At step number one, there is no adjustment. There are three horizontal lines on this graph. The first line, level with an adjustment of $260 per megawatt hour, represents the maximum possible adjustment. This corresponds to electricity market price of $310. As we will see shortly, this maximum price is the user-selected value. The second line, level with an adjustment of about $57 per megawatt hour, represents the lower limit of price adjustments that would produce resource generation surplus to our requirement. Above this price, resources would generate an amount of electricity that would exceed our ability to export energy surplus to our requirements. The third line, level with an adjustment of about $52 per megawatt hour, represents the upper limit of price adjustments that would result in generation inadequate for our system. Below this price, resources would not generate sufficient electricity to meet our requirements, even after importing the maximum possible energy. The distance between these latter to lines is quite small, atypical of situations that arise. The situation, however, will help us illustrate how the RRP algorithm works.

In step one, the worksheet determines that generation is deficit to our requirements. (The value that determines whether the system is surplus or deficit during the on-peak subperiod lies in a row {678}. A complete description of the functioning of the workbook and the formulas appears later in this section.) In step two, the algorithm tries the largest possible price adjustment. If the system is still deficit resources, the algorithm stops and uses this largest price. If the system is no longer deficit, the algorithm proceeds to step three. In steps three through five, the adjustment is moved upward by equal increments until the system is no longer deficit. If the system were in balance at this point, the algorithm would stop and use that adjustment. In step five, however, the adjustment was large enough that the system is now energy surplus. The algorithm now changes search strategy. Instead of using even steps, the algorithm uses a binary search strategy. In step six, the algorithm takes the value halfway between those in steps four and five. In step six, however, the resulting adjustment again overshoots the region where the system would be balanced. The algorithm then tries an adjustment halfway between those in steps five and six. The resulting price adjustment now balances the system (step seven), and the algorithm stops. This final adjustment is used.

The increment size used in steps three through five is a pseudo random value. It is chosen to be relatively small compared to the price. The algorithm uses the approach of equal size to increments at the beginning of the search process in order to arrive at a final adjustment that is only slightly above the largest adjustment that would result in deficit resources. Experience has shown us that using a binary search throughout this process produces a price adjustment close to the middle of the vertical scale in a very large number of instances. This in turn produces unnatural price probability distributions. Using even increments early in the search process brings us closer to the minimum adjustment that would balance the system, and that turns out to be a much more variable value.

If the system had started out to surplus instead of deficit, an identical search process would be used except that the algorithm would use negative adjustments to price. Instead of the maximum adjustment, the algorithm would use the starting price as the maximum negative adjustment.

To relate these observations back to the workbook, first consider Figure L-6. Recall that there are three regions in the workbook where distinct kinds of calculations are made. At the top of the workbook are the cells associated with futures. These are calculated only once, at the beginning of each game. Below this lie the twilight zone (TLZ) rows, in which each column will be updated iteratively whenever a subperiod's calculations update. (The TLZ is in fact defined by the Parameter section at the bottom of the worksheet.[21]) At the bottom are the rows in which the RRP algorithm iterates to a

[21] In range {Q1328:R1370} (range name, "Parameters"), there appear a list of variables that control the operation of the workbook. The top of the Twilight Zone is determined by the row number, 203, associated

feasible price. There is one set of rows for on-peak calculations and another for off-peak calculations. We are concerned with those rows in which the RRP iterates.

Consider the operation of the algorithm on on-peak prices. The relevant range of cells in the workbook is {AQ215:AQ678}. The algorithm starts with a zero adjustment in cell {AQ215}. The algorithm, which resides in a VBA module, modifies the value of this cell. This adjustment is then added to the on-peak price for the Eastern region in cell {AQ216}. The on-peak price for the Western region, in cell AQ219, is a simple percentage increase over the Eastern region price. This percentage increase represents transmission losses and wheeling costs. The electricity price in cell AQ216 will be then used by all resources in the Eastern region.

The net on-peak requirement for the system is calculated in cell AQ676. This is the on-peak load, including DSI load, less all generation.

> =AQ322+AQ328-AQ339-AQ349-AQ359-AQ367-AQ377-AQ386-AQ397-AQ407-AQ417-AQ428-AQ437-AQ460-AQ474-AQ488-AQ499-AQ511-AQ521-AQ529-AQ538-AQ545-AQ555-AQ565-AQ575-AQ586-AQ594-AQ604-AQ614-AQ625-AQ635-AQ645-AQ655-AQ665

The net on-peak requirement met through imports is calculated in cell AQ677. This is where we see the adjustment for contracts, through {AQ367}. That is, if there is imported, contract energy in this period, an adjustment to the export capability is made for counter-scheduling potential.

> =MIN(1152*6000-AQ367,MAX(-1152*6000-AQ367,AQ676))

The portion MAX(-1152*6000-AQ367,AQ676) limits exports to 6000 MW, before adjustment for contracts; the rest limits imports similarly.**5** The difference between the net on-peak requirement and the requirement met through imports is calculated in cell AQ678. This amount is the deficit the used by the RRP algorithm.

> =AQ676 - AQ677

If system generation were surplus to load requirements, the value in cell AQ676 would be negative. Again the amount of surplus met by exports would appear as a negative value in cell AQ677. The difference between these values would be the net remaining surplus. It would appear as a negative value in cell AQ679, which would signal the RRP algorithm to find a downward price adjustment.

In range {Q1328:R1370} (named "Parameters"), there appear a list of variables that control the operation of the workbook. The variable "dMaxPriceAdj"' a misnomer, has a value of 250. This is actually the maximum price, in $/MWh. The maximum adjustment will be the difference between this value and the original price. Also, when using an iterative technique for solving the problem such as this one, it is useful to know whether a solution is "close enough." The algorithm is searching for a feasible price, so searching

---

with the variable "lTopHeaderRow." The bottom of the Twilight Zone is specified by the row number, 320, associated with the variable “lBottomHeaderRow."

to the penny is neither necessary nor desirable. The variable "dEnergyTol", here set to 100 MWh, is the threshold. That is, if the surplus or deficit is less than 100 MWh, the RRP algorithm will stop refining its adjustment. (The variable "dEnergyTest" in the Parameters list is no longer used.)

The duality between price and import-export capability is now evident in Figure L-38. If there were no import-export capability, only one price would balance the system. Electricity price would be a dependent variable. Conversely if import/export capabilities is unlimited, the price is completely independent. Any price, in principle, is feasible. The RRP algorithm is not necessary.

The relationship between price and import/export capability has additional significance. The import/export capability determines how much random variability is feasible for market price. If there is no import/export capability, there can be no stochastic variation in market price for electricity.

Another issue related to RRP is capacity expansion and portfolio choice. Consider the situation of a single load-serving entity, a price taker in the wholesale electricity market. Assume this entity wants to make resource addition based on economics, as the regional market does. Any resource that makes money on average will of course appear attractive and the optimizer will add it. If resource addition does not depress prices, however, there is no reason to stop there. If one is good, two is better. This process would continue without end. That is, there could be no solution to the capacity expansion problem. If market prices are, on average, lower than the cost of a resource, the optimizer may add that resource if the resource reduces risk, even though it raises cost. It should be evident, however, that without RRP, the issue of portfolio choice depends in a more delicate fashion on the relationship between market price and resource candidate cost. RRP guarantees a reasonable balance because resource addition is limited irrespective of the initial relationship between resource cost and electricity price.

Finally, it may be useful to understand what the effect the RRP has on price for some simple cases. When they were first introduced to this algorithm, the Council staff expected the responsiveness of price to load-resource balance to be constant over the range of balance, perhaps like the resource supply curve in Figure L-39. What they found, instead, was the rather flat response over a significant variation in load-resource balance, as in Figure L-40. Moreover, for difference levels of price, the response was much the same, as shown in Figure L-41. To understand what is going on here, recall from the previous discussion

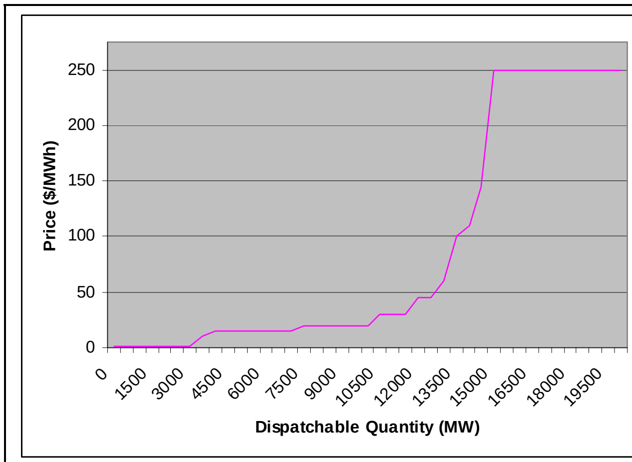


Figure L-39: Dispatchable Resource Supply Curve

that the algorithm does not adjust the price unless it is necessary to do so. This permits whatever stochastic relationship may exist between price and other variables, like load, to express itself without modification in most cases. Under what circumstances and how much the algorithm modifies price is a function of the import/export constraints, the supply curve, and of course, the price and load that are drawn.

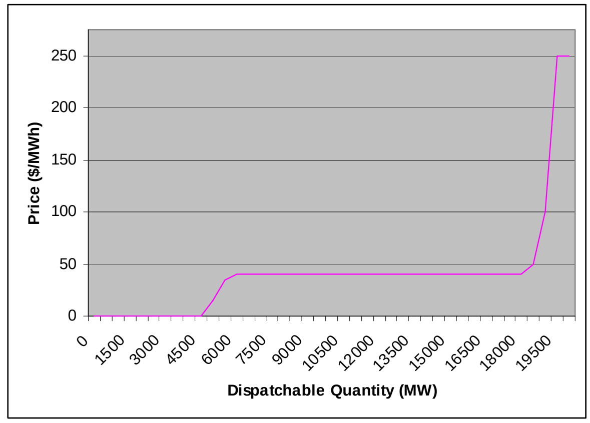


Figure L-40: RRP Response

Before proceeding with the description of price sensitivity to load-resource balance, we make the following simplifying assumptions. In practice, both loads and resources are constantly changing and both contribute to the load-resource balance. In these examples, however, we modify only load. Because only the load-resource balance concerns us, this simplification is not a hindrance to our understanding of the algorithm. The simplification makes these illustrations much easier to follow.

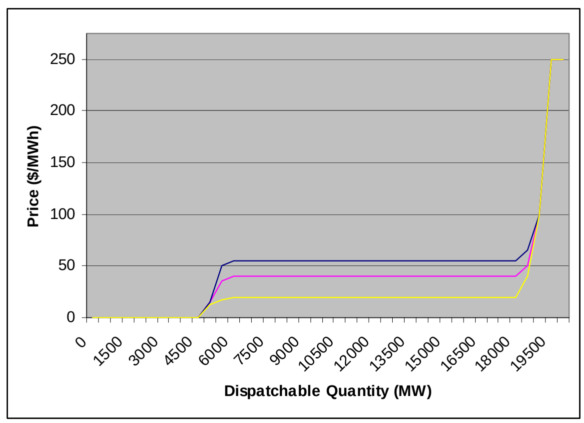


Figure L-41: RRP Response at Various Price Levels

The Monte Carlo simulation initially draws the electricity price and load level independently, although they may be correlated values. For whatever price is drawn, there exists a corresponding load, L_p in Figure L-42, determines by the resource supply curve. Absent imports and exports, this is the only feasible load. The supply curve makes load and price dependent variables. If import-export capability exists, however, there is actually a range of feasible loads that could correspond to this price. Below the load L_p, for example, native load combined with exports could sum to L_p. This is illustrated in Figure L-43. If exports are constrained, however, there is a lower limit on native loads consistent with our price. This lower limit is denoted L^e_p in Figure L-43. Similarly, if imports are constrained there is an upper limit on native loads consistent with our market price. Above this upper limit, it is impossible to import enough energy to bring our net load down to L_p. This upper limit is denoted L^i_p in Figure L-43.

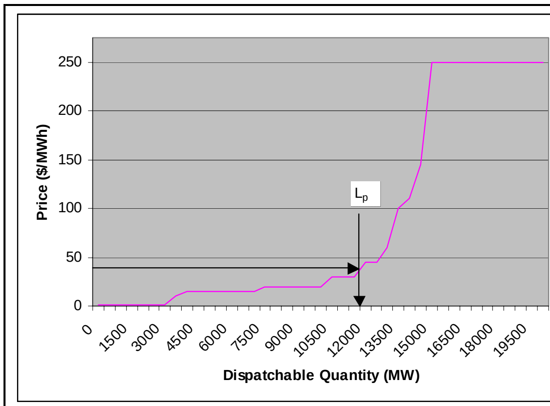


Figure L-42: Load Corresponding to Price

For all native loads between L^e_p and L^i_p, price adjustments are unnecessary. Imports and exports can explain the difference in net load that results in our initial price.

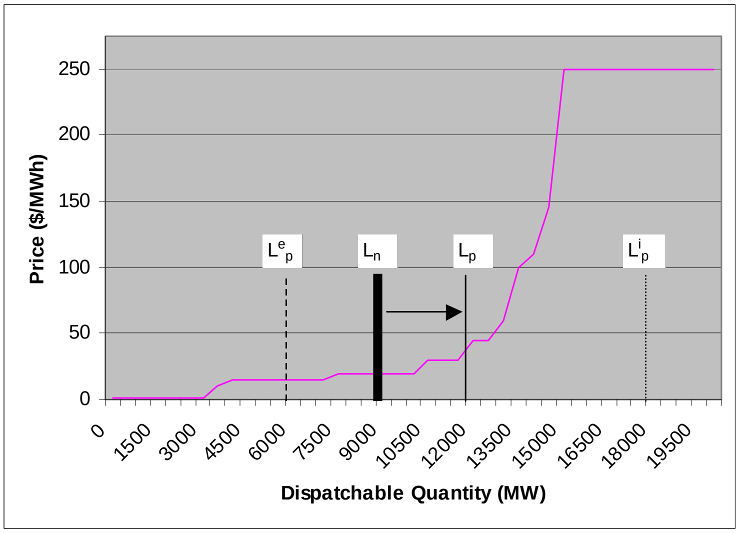


Figure L-43: Native Load

What happens if native load is below L^e_p, however? Clearly, our initial price and the native load are inconsistent, because the necessary amount of energy could not be exported. (See Figure L-44.) The algorithm adjusts the initial price so that the relationship between price and native load is once again consistent. In Figure L-45, the export limit L^e_p is reduced by 4000 MW to L^{*e}_p. This, of course, requires that the load L_p associated with our initial price be reduced by an equivalent amount. The adjusted "price load" L^*_p, together with the supply curve, now defines an adjusted price, illustrated in Figure L-46. In fact, any price between this adjusted price and the price associated with the native load is consistent with the native load.

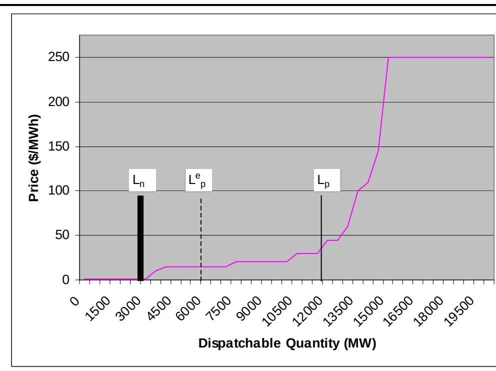


Figure L-44: Native Load below Export Limit

We can now see that over a range of loads corresponding to the sum of import and export constraints, no price adjustment is necessary or made by the algorithm. Outside of this range, however, the algorithm applies an adjustment that resembles the supply curve around the price load. Indeed, if there were no imports or exports the response provided by the RRP algorithm would look identical to the supply curve.

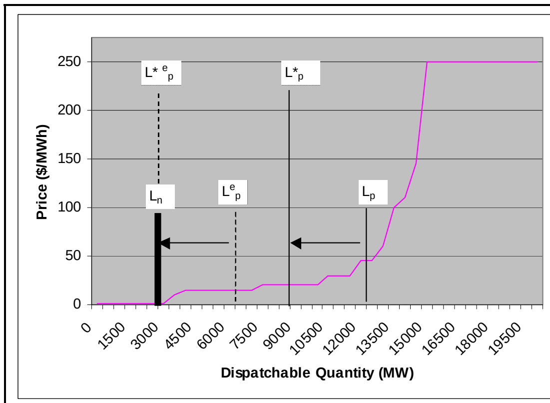


Figure L-45: Adjusting the Price-Load

There is a sense in which the RRP algorithm's response to load-resource balance is sensitive over a larger range of balance values, however. In Figure L-48, the average price as a function of the average load exhibits a more gradual response. The reason for this response is that for any average load level, there is some probability that sample loads will impact the load limits described in Figure L-43. There is greater probability of hitting a limit as the average load approaches the limit, and the effect on the average price increases correspondingly. Thus the relationship between average price average load is more gradual. The relationship for alternative price levels is illustrated in Figure L-47.

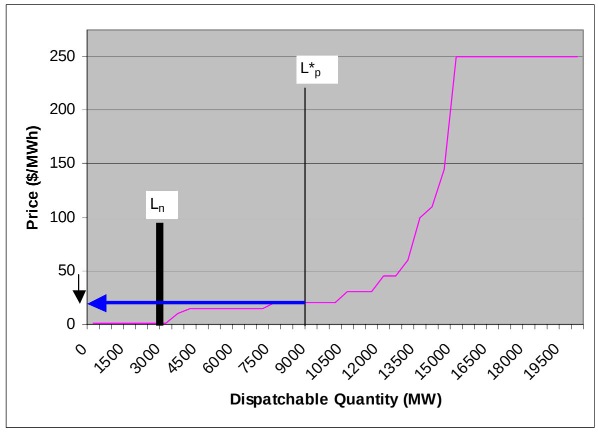


Figure L-46: New Price, After Adjustment

In this section, we have described how the algorithm works to acquire a price that is consistent with native loads, resources, and import and export constraints. This section described the duality between the stochastic behavior of electric market price and levels of imports and exports. Although it is possible to forego with the RRP algorithm when there are no constraints on imports and exports, the users must take special care if they want to add resources to the portfolio. In particular, if market prices are higher than the fully allocated cost of capacity expansion candidates, the optimal solution would be to add increments of the candidate without bound. Finally, we have examined how load-resource balance typically affects the final market price. Market price adjustment is generally insensitive to load-resource balance over a range that corresponds to the import-export limit of the system.

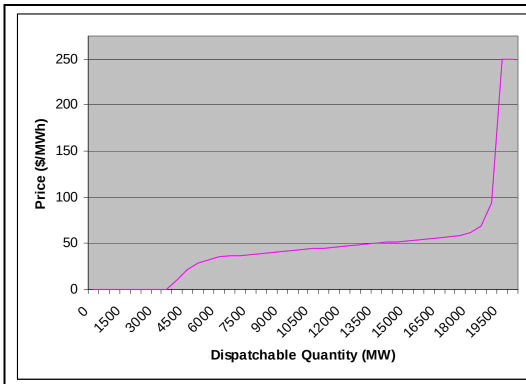


Figure L-48: Average Price vs Average Load

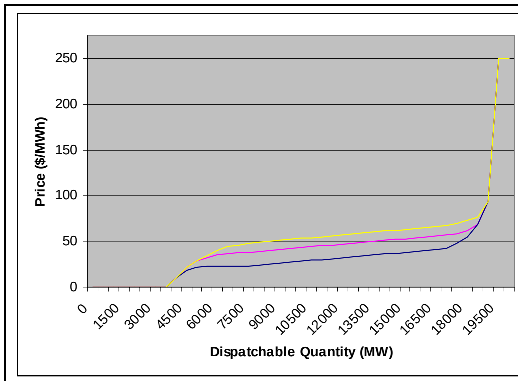


Figure L-47: Alternative Average Prices

This concludes the discussion of variables in quantities that depend only on the current period. Possible exceptions are supply curves for conservation. The amount of energy delivered in a given period can be, and typically is, a function of prices and activity in prior periods. The discussion of supply curves was included in this section nevertheless because the supply curves do not depend the history of a process. Processes such as the startup shutdown of aluminum smelters, on the other hand, depend in a direct fashion on how recently this smelter was shut down and whether it has been down for a significant amount of time. The functions and formulas that rely strongly on the nature of events over time are the subject of the next section.

Multiple Periods

This section addresses processes that rely on memory of past circumstances. They respond not so much according to what is happening now as what has happened in the past. Load elasticity is one example. While the short-term correlation between load and electricity price is typically positive, over the long-term load will decrease if electricity prices remain high for a substantial amount of time. Other examples are the start-up and shutdown of aluminum smelters and the construction of power plants. In the latter case, it may be advantageous to postpone or cancel the construction of a power plant if it appears the plant will be unprofitable or unneeded. This section begins with a discussion of a concept that guides much of the modeling of these behaviors. It then describes how the portfolio model addresses the processes mentioned above.

Concept Of Causality

In the description of the RRP algorithm (page L-51, above), there is a tacit assumption that generation is a continuous function of price. For example, what would the outcome have been if, in step five of Figure L-38, the increase in price had suddenly caused a smelter to shut down? Figure L-49 illustrates one possible outcome. With reduced load, the deficit after imports is reduced, which should make it possible to meet requirements with a lower market price for electricity. The illustration assumes that this affects both the lower price limit for surplus resources and upper price limit for deficit resources to roughly the same degree.

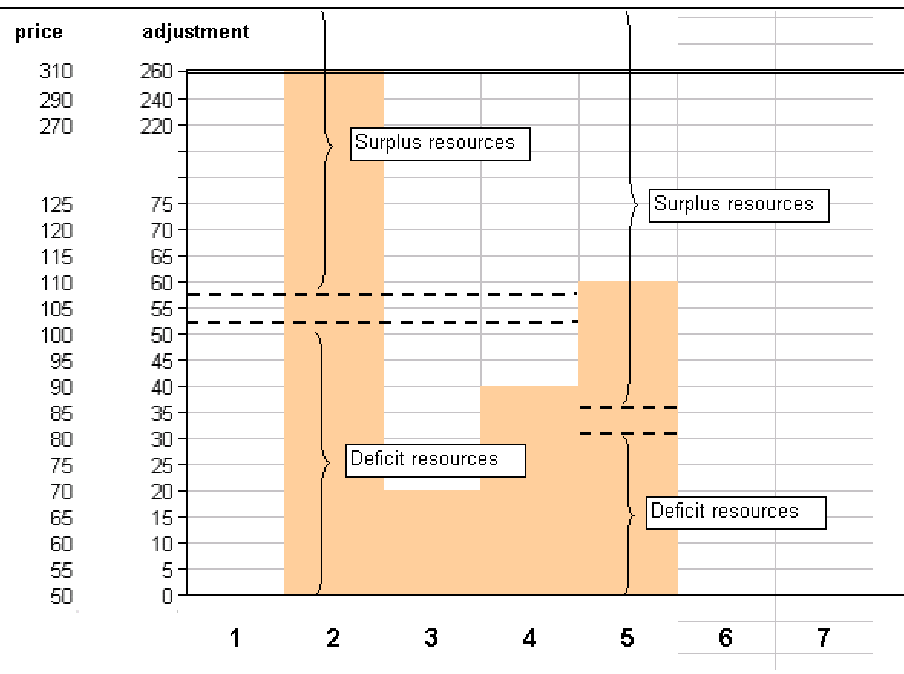


Figure L-49: Discontinuous Load Response to Price

Notice that the reduction in requirement is large enough that the price in step 4 is now too high to satisfy the balance constraints. The algorithm would not work, because there is no obvious way to determine what price would solve the problem, at least not by looking at price and deficit or surplus. In fact, the problem may be more serious than devising a smarter algorithm: there may *be no solution!* It can arise that no price would balance such a system.

To arrange for the iterative algorithm to solve the problem efficiently and avoid situations like this one, response of resources and loads to price must be stable and continuous. One way to assure this behavior is to remove such response from the current period, instead tying the response to past periods where prices have already been determined and fixed.

Thinking about how the primary sources of discontinuous response behave, this makes sense in terms of the accuracy of the model representation. For example, a smelter will not make start-up or shutdown commitments based strictly on current market prices. Instead, they will probably make some forecast about future conditions based on a trend that started at some point in the distant or recent past. It therefore is reasonable to assume that decision makers make such commitments at the beginning of a period and these remain fixed over the period.

This treatment of load or resource response in the portfolio model is an application of the "concept of causality." Actions in the past affect current circumstances, instead of having actions and circumstances occurring simultaneously. Wherever this approach is reasonable to use, it simplifies and speeds the iterative solution of the balance by removing a source of change and, as emphasized above, discontinuous change.

Conservation is an example of where the portfolio model employs a concept of causality, not because its response is discontinuous -- it is not -- but because it makes sense to do so and reduces computational burden. Pointing the supply curve's price to a decision criterion that depends only a on past period fixes the value of conservation in that period. The rather time-consuming computation of conservation takes place only once. Moreover, it makes sense that utilities would deploy conservation in this fashion, paying little or no attention to today's market prices but instead following budgets that may have been adopted the year before.

Load

There are several components to load representation. There is an underlying trend, possible jumps associated with economic cycles, and a seasonal variance. Appendix P describes these. There is also a long-term sensitivity of loads to electricity price, which this section describes. The final calculation of energy and cost appear under the previous section, "Single Period."

Load elasticity changes once each year, because customers base their consumption habits more on annual average prices than seasonal costs. Additionally, retail customers are unlikely to see seasonal variation because of the ratemaking process. The load adjustment for electric price in {AQ321} points to the calculation in {AP321}, where the annual revision takes place. That calculation is

=(1+MAX(-0.002, MIN(0.002,-0.002*(AO225-$Q$224)/$Q$224)))

This formula limits load variation due to price elasticity to 0.2 percent. Some bounding of the elasticity provided better stability. That is, without bounding, the situation can arise where high prices depress loads, which in turn reduce prices, which increases load, and so forth.

The cell {$Q$224} contains the study's starting price for annual average electricity price. This is a cumulative change in load, up to the current period, due to changes in electricity since the beginning of the study.

Council Staff [**6**] chose the value of -0.002 as follows. They estimated an upper limit by starting with a five-year elasticity factor of -0.1 as appropriate for non-DSI loads, where electricity price is a retail rate. Because wholesale prices contribute about half to retail rate variation, an upper limit using wholesale electricity price is about -0.05. Using a single year's change warrants a value of perhaps -0.01. Finally, the stochastic treatment of load uncertainty captures much and perhaps most of the impact of independent influences on load, including some economic effects related to electricity price. A figure of -0.002 seemed an appropriate choice and provided realistic behavior.

DSIs

Aluminum smelters have a cost structure heavily dependent on the price of electricity. With the increases in electricity price during the 2000-2001 energy crisis, the region saw 2000 MW of smelter load disappear. This constitutes 40% of the 5000 MW shift in the resource-load position the region has witnessed since 2001. Capturing the load uncertainty associated with direct service industries (DSIs) such as aluminum smelters is clearly important to the Council's treatment of risk.

Smelter load curtailment is distinct from dispatchable resources and demand response. Whereas dispatchable resources and demand response can curtail within hours, it requires months for a smelter to arrange for startup and shutdown. Although there is a portion of smelter load that can change with short notice, there are typically severe limitations on the amount and use of this load as a curtailment mechanism. Aluminum pot lines have significant thermal inertia, and several hours of interruption will not significantly affect production. However, extended shutdowns or repeated interruptions, without adequate preparation, can be disastrous.

In 1992, Council staff performed analysis of the profitability of each of the seven smelters in the region. Figure L-50 illustrates a typical calculation.

Aluminum Price	1550
Premium Rate	0.03
BPA Rate	23
BPA Allocation	100
Mwh/Tonne	13.199
	Plant A (modern prebake)
Potential Demand	457
Cost Components	
Alumina	403
Carbon	90
Labor/Other	400
Sustaining Capital	80
Electricity Cost Max	623.5
Electricity Price Max	47.24
Electricity Price	$30
Demand @ Price	457

Figure L-50: Cost structure of Aluminum Smelter

Given the cost structure of the smelter, including the smelter's requirement for electricity, alumina, carbon, labor, and other fixed costs, and with the knowledge of aluminum price and the allocation and the price for any BPA power, a breakeven price for electricity can be determined. For each price of electricity, we can restate the total demand for all seven smelters as a function of aluminum prices. Figure L-51 illustrates supply curves for regional smelter load, given assumptions about the price of power available to the smelters.

In the portfolio model, we capture this response of smelter load to electricity price and aluminum price with a single UDF. This function tracks the response of each of the seven smelters separately, based on its unique cost structure. There are initial conditions provided for each smelter, representing the number of months that the smelter has been shutdown. If any smelter is shutdown for more than five years, it will be permanently retired. More details about these operations appear below.

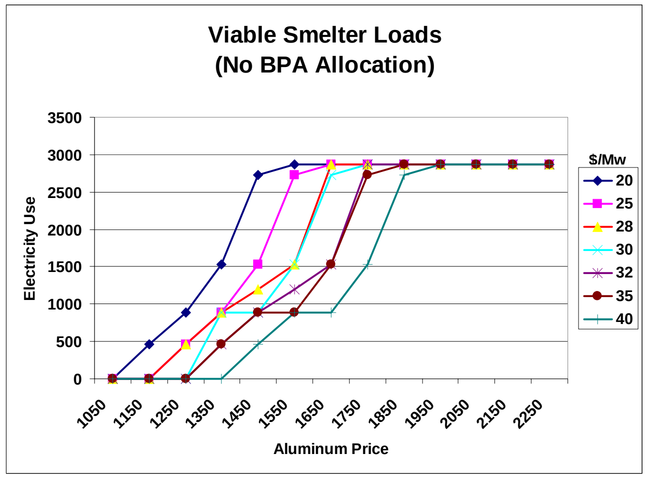


Figure L-51: Supply Curves for Regional Smelters

The model needs a criterion for determining whether a given plant should shutdown or restart. Figure L-52 illustrates a typical decision criterion for a smelter. Along the horizontal axis is time; along the vertical axis, the value of the decision criterion, denominated in arbitrary units. There is a horizontal line that determines whether the outlook for the smelter is favorable. We may think of the criterion as roughly the spread between aluminum electricity prices, although the reader will see shortly that the smelter-specific criterion is more detailed than this. The criterion starts out above zero, in positive territory, but soon becomes negative. The smelter enters an evaluation phase. During the evaluation phase, a decision maker would consider whether to shutdown the plant. If the decision criterion remains negative throughout the evaluation phase, the plant will be shutdown and remain down for a minimum amount of time. Later, when the criterion turns positives, the smelter enters

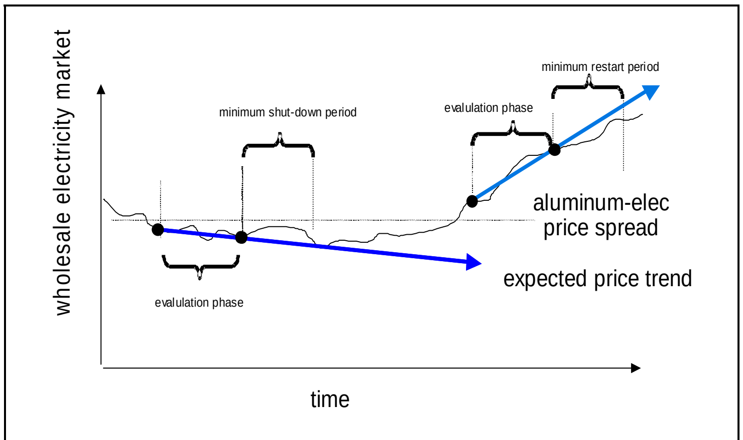


Figure L-52: Decision Criterion for Smelter

another evaluation phase. If the outlook for the smelter remains favorable throughout the evaluation phase, the smelter restarts. Once restarted, however, it must remain in service for a minimum amount of time. These minimum startup and shutdown times represent the time to adjust work schedules and contracts and to prepare equipment. Evaluation is ongoing during the minimum times.

The smelter-specific decision criterion *d* follows the profitability calculation in Figure L-50:

$$d = r - c \quad (\$/\text{mT}), \text{ where}$$
$$r = p_A(1+\rho) \quad (\text{revenue in } \$/\text{mT})$$
$$c = 0.26\,p_A + c_f + p_e\alpha \quad (\text{cost in } \$/\text{mT})$$

and

p_A is price of aluminum (\$/mT)

ρ is premium rate

c_f is fixed cost of carbon, labor, capital (\$/mT)

p_e is price of electricity (\$/MWh)

α is electricity intensity (MWh/mT)

The cost of alumina is $0.26p_A$. The decision criterion reflects any evaluation, so the plant operation will respond immediately to its value. Rearranging these terms, we have

$$d = p_A(1+\rho-0.26) - c_f - p_e\alpha$$

Whenever the criterion *d* turns from negative to positive, smelter operation continues or, if the smelter has been shutdown, restarts if minimum shutdown time is satisfied. When the criterion *d* turns from positive to negative, the smelter remains off-line or, if the smelter has been operating, shuts down if minimum in-service time is satisfied.

Turning to the workbook, we point out that, as opposed to all of the other UDF functions, some data hides in the UDF that calculates smelter capacity[22]. The portfolio model adopts this alternative to initializing the UDF from the worksheet because Council staff believes smelter parameters will not change significantly. If users wished to change some of these values, however, they are available in the VBA module containing the UDF code. Parameters that the user may specify are the following:

```
Const lNumberOfDSIPlants As Long = 7
Const dSmelterPricePremium As Double = 0.03
Const dAluminaCostFraction As Double = 0.26
Cosnt lNumPeriods as Long = 80

lDmd(0 To lNumberOfDSIPlants - 1)
```

[22] In range {F326:O327}, the reader will find values that appear to be parameters for the smelter UDF. This is a vestige of an older UDF. They should have been cleaned out. The model does not use these values.

```
dMWhPerTonne(0 To lNumberOfDSIPlants - 1)
dNonPowerCostPerTonne(0 To lNumberOfDSIPlants - 1)
dDiscountPowerPrice(0 To lNumberOfDSIPlants - 1)
dDiscountPowerAmt(0 To lNumberOfDSIPlants - 1)
lNumPersDown(0 To lNumberOfDSIPlants - 1)
lNumPersUp(0 To lNumberOfDSIPlants - 1)
lMinNumUpTimePers(0 To lNumberOfDSIPlants - 1)
lMinNumDownTimePers(0 To lNumberOfDSIPlants - 1)
dUpThreshold(0 To lNumberOfDSIPlants - 1)
dDownThreshold(0 To lNumberOfDSIPlants - 1)
lInitialPeriodsDown(0 To lNumberOfDSIPlants - 1)
lPeriodsDownBeforeShutdown(0 To lNumberOfDSIPlants - 1)
```

Because of the proprietary nature of some of this information, we do not provide smelter-specific values in this documentation. Most of the parameters in the list above should be self-explanatory. The parameters dUpThreshold and dDownThreshold permit users to specify thresholds above or below zero for the decision criteria on a plant specific basis. The parameter lPeriodsDownBeforeShutdown specifies how many periods of negative decision criteria values to permit before permanently shutting down the smelter.

The electricity price that the decision criterion uses may be a melded price, reflecting not only market price but also some subsidized power. The Wenachee smelter, for example, gets 40% of its power from Chelan PUD at a discount from market, and the portfolio model reflects that fact. The UDF that computes smelter load assumes that the smelter either operates at full capacity or does not operate at all. For this reason, decisions are made based on the melded price of electricity, not on the prices of each source of electricity. With this assumption, the user stipulates any discounts through the values of dDiscountPowerAmt and dDiscountPowerPrice. The definition of dDiscountPowerPrice, however, is idiosyncratic. We can express electricity price generally as:

$$p_e = \frac{p_{s_1} \times MWh_{s_1} + \cdots + p_{s_n} \times MWh_{s_n} + p_m \times MWh_m}{MWh_{s_1} + \cdots + MWh_{s_n} + MWh_m}$$

where

p_{s_i} is the price of discounted power from source $i, i = 1...n$

MWh_{s_1} is the amount of discounted power from source $i, i = 1...n$

p_m is the market price

MWh_m is the market amount

Let S denote the total amount of discounted power and D denote the total demand.

$$S = MWh_{s_1} + \cdots + MWh_{s_n}$$
$$D = S + MWh_m$$

Because the denominator is just the total amount of demand D for the smelter, we have

$$p_e = \frac{p_{s_1} \times MWh_{s_1} + \cdots + p_{s_n} \times MWh_{s_n}}{D} \; + \; p_m \times \frac{(D-S)}{D}$$

Now, the first term is entirely fixed. One can think of it as the weighted price of power,

if the price of market power were zero. This is the definition of dDiscountPowerPrice. The convenience of this definition is that if dDiscountPowerPrice and dDiscountPowerAmt (S) are zero, then p_e = p_m. Moreover, if discounted power comes in various amounts from various sources, these two variables alone still capture the total effect.

In the workbook, we find in cell AQ 327 the following formula

```
=lfDSICol(AP$227, AP$270, AP$46,2, AP327)
```

The UDF lfDSICol returns the value for the total smelter load in the region. The definition of this function is as follows

```
Function lfDSICol(ByVal sPowerPrice As Single, ByVal sAluminumPrice As Single, _
   ByVal lPeriod As Long, ByVal lSide As Long, ByVal dummy As Long) As Long

Takes:
sPowerPrice        - Electricity Price ($/MWh)
sAlumPrice          - Aluminum Price ($/metric tonne)
lPeriod  - period for which the calculation applies.  Note that to stabilize calculation, we are
           pointing to the period _preceding_ the period in which the function is called, consistent
           with the principle of causality
lSide      = 0 for east, 1 for west, 2 for both

Returns:
           Total smelter load (MW) as Long
```

The first two parameters point to the 18-month averages for electricity aluminum price in rows 227 and 270, respectively. Taking the average over an extended period in the recent past provides both inertia to the decision and a reasonable evaluation period. As discussed later in the section "Decision Criteria," these prices are proxies for forward prices. The UDF uses the flat price for electricity, the average of on and off peak electricity.

The third parameter merely tells the UDF for which period it is computing a value. The fourth parameter, which has the fixed value 2, specifies that the UDF return the sum of the loads for Eastern and Western smelters. If the user chose to employ this UDF in a different application, he or she could select loads for just those smelters in one subregion. The final parameter is merely a dummy that forces calculation of the previous period's UDF before execution of this period's UDF.

The formula in cell AQ328 computes the energy requirement in megawatt hours.

=1152*$AQ$327

This is merely the energy in average megawatts times the number of hours on peak. The cost in millions of dollars is computed in AQ329.

=AQ328*$AQ$204/1000000

Because we assume no correlation between energy prices and this load, the cost of this load is merely the product of the load and the price divided by one million. The off-peak calculation is identical.

One option that a user should consider if he or she wants to implement this UDF in their own application is that this is a specific application with potential generalization to other industries. That is, the modeling of any other industry that relies heavily on electricity, such as petrochemicals or paper refining, can make use of this UDF. Instead of the spread between aluminum prices and electricity prices, one would consider the spread between paper prices and electricity prices, for example. Indeed, the spread between the costs of any two commodities or any predictor of loads could provide a general decision criterion, although the user would obviously have to modify the UDF somewhat.

Finally, there is a utility available that permits users to view the status of each smelter for a particular future. This utility, a separate UDF, is not available in the portfolio model but is upon request.

In summary, the DSI UDF permits the portfolio model to quickly calculate total smelter load in the region based on each smelter's profitability, as determined by the prices for aluminum and electricity. It provides an idea of the long-term load response of these industries, as opposed to the short-term response captured through, for example, demand response. The UDF accommodates user-specified assumptions through VBA constants in the code, including those regarding discounted power. Although tailored to the aluminum production industry, the concepts and much of the code in this UDF are applicable to other industries as well.

New Resources, Capital Costs, and Planning Flexibility

Certain aspects of resources permit a decision maker to respond to changing circumstances quickly or inexpensively. Collectively, we refer to this as planning flexibility. Sources of planning flexibility include:

- Modularity (small size) permits a more exact match to requirements and reduces fixed-cost risk.
- Short lead-time facilitates rapid response to opportunities or unexpected requirements.
- Cost-effective deferral or cancellation is usually available only for a limited time during the construction cycle. The decision maker values the ability to change his or her mind without incurring excessive cost.

The value of flexibility played a key role in the 2000-2001 energy crisis. The region saw load management and conservation respond to changing circumstances much faster and more effectively than conventional thermal supply-side resources.

Valuing this source of flexibility is nothing new to the Council. Planning flexibility was explicitly valued in 1991 plan with the ISAAC model. However, ISAAC used load projections to decide when to add resources, instead of using market value like the portfolio model.

The discussion in this section focuses on the third source of planning flexibility listed above, cost-effective deferral or cancellation. The portfolio model captures the value of the other sources of planning flexibility, but valuing cost-effective deferral or cancellation requires special spreadsheet logic. This section describes how the portfolio model achieves this objective with a special UDF.

Although capturing planning flexibility has been a primary objective in the design of this special UDF, the UDF also performs the important function of computing capital and fixed costs for new resources. The discussion of valuation costing that begins on page L-13 addresses variable costs. The fixed costs of existing resources do not bear on any decisions in the regional model, but total system costs still require computing fixed and capital costs for additions. That latter task belongs to this special UDF.

Cost-effective deferral or cancellation of power plants depends on the construction cycle. Cash flow, in turn, provides an important perspective on the construction cycle. A typical cash flow pattern appears in Figure L-53. Cash flow determines natural decision points. For the first 18 months in the example illustrated in Figure L-53, only siting and permitting take place. Siting and permitting are inexpensive activities. The decision maker incurs relatively little expense if he or she interrupts or cancels the power plant during this phase. After completion of siting and permitting, however, construction begins, which typically requires a substantial initial investment. The project breaks ground on administrative buildings and substations. The owner may need to make deposits on some of the most expensive equipment, such as turbines or boilers. After some period of construction, nine months in our example, the project reaches a final decision point. If the project is to proceed, the owner must take delivery of and pay for the most expensive pieces of equipment. Beyond this point, the owner will complete construction, because most of the costs are effectively sunk. The owner presumably completes the plant and brings it online.

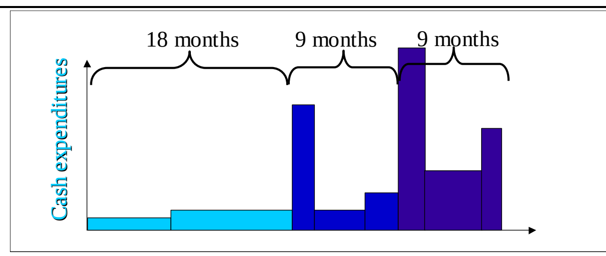


Figure L-53: Partitioning the Construction Cycle

As in the case of aluminum smelters, the portfolio model uses a decision criterion to determine whether to proceed through each phase of construction. The regional portfolio model assumes, however, that the first phase of siting and licensing is completed.[23] The details of the decision criterion are below, but it functions in a manner identical to that for DSIs. Given that siting and permitting is complete for a specific resource in a given plant, the decision criteria will immediately determine whether to proceed with the optional phase of construction. At any point during the optional phase of construction, the model may defer or cancel construction if the criterion turns negative. If the model defers construction ("mothballs" the plant) and construction does not resume within a number of periods specified by the user, construction terminates and the project incurs cancellation costs. During deferral, the plant accrues mothball costs instead of construction costs. Once the requisite time and cost for optional construction finishes, committed construction begins and continues until the plant goes online. Figure L-54 illustrates the decision criterion in a manner similar to Figure L-52, and Figure L-55 illustrates the effect that an adverse decision criterion value in periods five through nine would have on three plants started on a staggered schedule. The negative criterion value affects only the last plant, initiating the third period, because the criterion acquires a negative value after the planning period and before the committed construction period.

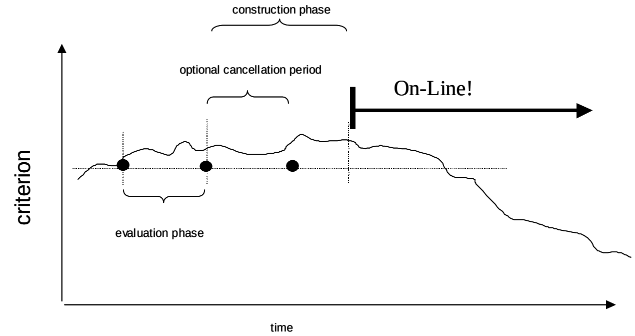


Figure L-54: Decision Criterion and Phases

As Figure L-55 implies, there are cohorts of plants available for planning or construction commencement in each period of the study. Each cohort has identical cost and operational characteristics. The UDF returns the cumulative capacity and total cost across all cohorts. Although the UDF makes cohorts available in each period, the user controls their size and availability by specifying a particular plan, so size and availability typically vary from period to period. The description of how to control the size and

[23] Here the fiction of a 20-year resource plan asserts itself. Although required by statute, the Council understands that a fixed blueprint for resource additions 15 years in the future, even the inexpensive siting and licensing process, is unrealistic. The purpose of the 20-year plan instead is to assure that the necessary commitments made in the Action plan do not preclude future opportunities or burden future generations in the region with imprudent, long-term obligations. Without specific future commitments, however, how does the region obtain a clear idea of the relationship of current decisions, made in the Action Plan, and future actions that might be precluded or required? For example, if the Action Plan tacitly relies on wind in the next decade, although it may not call for it in the next five years, how would the region know when to build long-lead time transmission now? Clearly, this requires a specific long-term resource plan. A fixed plan of construction, however, does not permit valuation of flexibility. The approach of the regional portfolio model is to commit to specific construction preliminaries, to the siting and licensing for specific amounts of specific technologies at specific points in the future. The Council believes this approach balances the need for specificity with the valuation of flexibility.

presence of each cohort through "decision cells" appears in the section "Parameters Describing the Plan" on page L-72.

If the user stipulates, the UDF that performs the function of tracking construction for cohorts of power plants is capable of adding plants *whenever* the decision criterion is positive. The intended application for this feature is modeling the market-driven addition of power plants. Using this feature, the user can specify that construction costs are different depending on whether power plants are planned for or are added when market conditions are favorable. Recent history shows that when market conditions are attractive, the demand for power plants and their components increases, as does the associated cost. The regional portfolio model, however, does not implement this feature. Instead, the optimizer controls all additions. The optimizer selects the timing, sizing, and choice of technology to find an optimal plan given risk constraints.

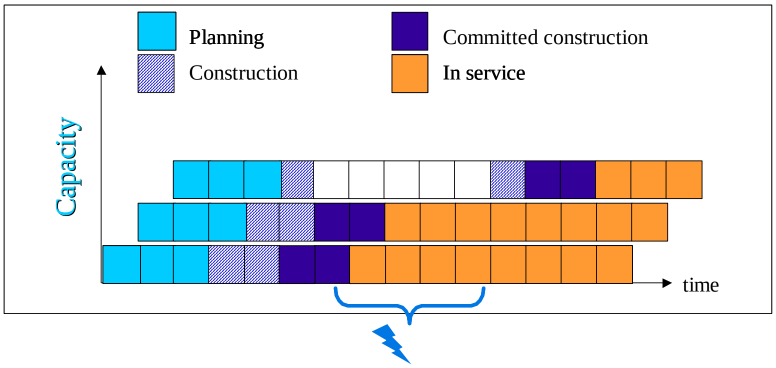


Figure L-55: Effect of Decision Criterion on Cohorts

The UDF can also provide for special cash flow features that the regional model *does* incorporate. First, it can capture sunk costs associated with a plan, specifically the sunk costs for planning, siting, and licensing. This takes place despite there being no planning periods per se with which to associate those sunk costs. Instead, the sunk costs merely add to subsequent levelized costs. Second, the UDF can represent the situation where the first period of optional construction incurs the total cash flow associated with that phase of construction. This type of cash flow pattern is a "pulse." Ordinarily, levelized cash flow rates increase in steps of constant size over periods when there is construction activity. The regional model uses pulse cash flow instead to better reflect the jump in cash flow at the beginning of the optional phase of construction, as illustrated in Figure L-53. Council staff felt the difference in cash flow patterns might affect valuation decisions.

The UDF also easily accommodates capacity expansion *without* planning flexibility, if the user wishes to either "hard-wire" new capacity or have an optimizer do so. The user assigns the cells containing the decision criterion a constant positive value. The Crystal Ball "decision" cells, described below, then control all additions directly.[24]

The scenarios in Chapter 7 of the plan illustrate the response of a plan to changing circumstances. These scenarios demonstrate, among other things, how this UDF controls

[24] There must be at least one planning or construction period, however.

the construction and completion of power plants. To the extent these changes are responsive and inexpensive, they add to the value of a plan.

In the workbook, three worksheet ranges control the performance of capacity additions and costing. The first are the parameters describing each technology. These values represent such things as capital cost, and they do not change unless the user changes the description of a plant. The second are the Crystal Ball decision cells, which the optimizer controls. These specify the timing, size, and type of technology, and their values specify the plan. The third are the period calculations, the values of which typically change under each future. This section will discuss each of these in turn.

Parameters Describing Each Technology

The worksheet cells that control the characteristics of any new capacity appear in the range {B454: P519}. The cells that control the characteristics for the generic combined-cycle combustion turbine (CCCT) units appear in Figure L-56. Identical sets of parameters, obviously with different values, exist for single cycle combustion turbines (SCCT), coal plants, wind plants, and optionally demand response and coal tar processing CCCTs in Alberta.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
453																
454		Criterion_S	Planning_P	Optional_C	Committed	Planning_C	Mothball_C	Cancellatio	Constructic	CancelThre	Const Cost	ResourceLi	OptionLife (	PermitMark	PlannedPla	Index
455		CCCT Crite	0	4	4	0	0.000292	0.0116796	0.0029199	-99999	-0.086%	80	20	FALSE	0.001491	0
456																

Figure L-56: New Capacity Parameters

Before we proceed with the description of each of the parameters appearing in this range, it may be useful to explain several conventions. First, the units of time are periods, as defined for the portfolio model. The regional model uses the hydro-year quarter. The escalation rates for capital costs are also expressed in rate of change per period. Second, all cost rates are denominated in real levelized millions of dollars per megawatt per period squared. The determination of this value is according to the following equation:

$$\frac{\text{RL \$M}}{MW \bullet per^2} = \frac{RL\$}{kWyr} \bullet \frac{yr}{per} \bullet \frac{1}{\# \, per} \bullet \frac{kW}{MW} \bullet \frac{\$M}{\$} \qquad (5)$$

This appendix has already discussed the reasons for using real levelized dollars. The reason for expressing cost rates in terms of dollars per period per period (or equivalently, dollars per period squared) is that construction can halt during the earlier construction phase. It is therefore necessary to stipulate the *rate* at which period construction costs accumulate. Another subtlety here is that this model uses standard months and standard years for variable cost calculations. (See discussion on page L-11.) To make sure that variable and fixed costs are consistent, the model uses fixed costs in dollars per kilowatt-***standard*** year, rather than the more conventional dollars per kilowatt-year. Thus, the second term on the right-hand side of equation (5) has a value of about 0.23, which derives from the following equation:

yr/per = (std mo per std qtr)(wks per std mo)(days per wk)(hours per day)/(hours per year)
= (3)(4)(7)(24)/(8760)

The third term on the right-hand side of equation (5) is simply the reciprocal of the number of periods in the phase of construction. In the example that appears in Figure L-56, this term would have a value 1/4 for the phase associated with committed construction.

So, for example, assume a CCCT with total fixed cost, including fixed fuel and transportation but excluding planning costs, of $101.50/kWyr. This real levelized cost is in 2004 dollars, ignoring escalation. If construction requires eight hydro quarters (two years), the equivalent cost rate from equation (5) would be

$$0.0029181 = (101.50)(0.23)(1/8)(1000)(1/1000000)$$

which corresponds to the construction cost rate in column I of Figure L-56.

The only exception to this characterization of costs is for the treatment of sunk costs, described above. If the numbers of periods for the planning phase in column C is zero, and non-zero “planned planning” costs appear in column O, the UDF assumes sunk costs. In this special case, the cost rate in column O applies.

With this background, consider the entries in the columns of Figure L-56:

- Column B has a name that specifies which planning flexibility record Olivia used to create this description. (The description of Olivia appears in the section “Olivia” starting on page L-136.) The value in this column has no meaning otherwise in the portfolio model.

- Columns C through E indicate the number of periods in the planning, optional construction, and committed construction periods, respectively. For example, optional construction lasts four periods, which correspond to one year because the periods in the regional model consists of hydro quarters. The number of planning periods in all of these capacity expansion options are zero, because the model assumes planning is complete and planning costs are sunk, as described above.

- Columns F through I contain the cost rates associated with the various phases of planning and construction. During each period of these phases, the plant cost accumulates R x C x $(1+E)^P$ millions of dollars, where R is the relevant cost rate, C is the plant capacity in megawatts, E is the escalation factor in column K, and P is the number of periods since the beginning of the study. Cancellation, if it occurs, happens in one period. Like all other costs, however, cancellation costs contribute to subsequent periods for the duration of the life of the plant, stipulated in column L.

The cost rate in column F is always the cost associated with unplanned construction, driven by market conditions. The model implements the use of unplanned construction in response to market conditions only when the user sets the value in column N is TRUE *and* there is no cohort planned for the period. Otherwise, the model uses the planning cost rate in column O. (See the discussion of choices for columns N and O, below.) The regional model does not use unplanned construction in response to market conditions, and the value in this column is zero for all new capacity candidates.

- Column J has the value of the cancellation threshold. If the decision criterion falls below this value, the plant cohort will cancel immediately and will incur the cancellation penalty. None of the plants in the regional model use this option; the value of the cancellation threshold is instead set arbitrarily low.

- Column K identifies the escalation rate for capital costs, including the capitalized planning and construction costs. The rate is per portfolio model period. For example, if the annual rate of increase is negative 0.3423 percent per year and the period is a hydro quarter, as in the case of the regional portfolio model, then the period escalation rate is $-0.00085682 = (1- 0.003423)^{1/4}-1.0$. Note that conversion from conventional years to standard years is neither necessary nor appropriate. Although the numbers of hours in each are different, standard years represent conventional years. That is, costs four standard quarters later will be five percent higher, too.

- Column L specifies the resource life in periods. In the regional model, 80 periods is 20 years. The model distributes all real levelized costs according to the resource life. The associated real levelized cost contributes to the total real levelized cost when the event (planning, construction, cancellation) occurs, disappears from the total after the resource life's number of periods, and applies to all intervening periods. Note that this implies the cost contribution typically begins and ends in periods other than the on-line date or retirement period of the plant.

- Column M has the maximum number of periods that the model will hold the plant in its mothballed state before canceling the plant. Its value is arbitrary, and setting the value higher than the number of study periods effectively turns off this option.

- If the user wishes the model to start a plant cohort in any period where the decision criterion is positive, they indicate so by setting to TRUE the value in column N. In this case, the model would interpret values that otherwise would determine the plan as capacity ramp rates. Each cohort, if completed, would contribute the capacity specified by the ramp rate. (Instructions on controlling the plan through "decision cells" appears in the next section, "Parameters Describing the Plan.") The calculation of planning costs also depends on the value in this column, as explained in the next bullet.

- How the model interprets the value in column O depends on the value of column C, the number of planning periods. If the number of planning periods is zero, the cost rate in column O is that for the sunk cost associated with planning incurred before construction begins. As for all cost rates, these are denominated in real levelized millions of dollars per megawatt per period squared, although the UDF assumes only one period for sunk costs. In the example appearing in Figure L-56, the value is .001491. The costs incurred quarterly due to sunk planning and siting is the product of the unit capacity, 610 MW, times this value, times the escalation factor, or about $910,000 per quarter. All new plants in the regional model use the convention of sunk planning and siting cost.

  If on the other hand the value in column C, the number of planning periods, is greater than zero, then the determination of the planning cost rate hangs on the value of the market addition flag in column N. If the market addition flag is FALSE, the cost rate in column O applies to each planning period, as in the description of costs in columns F through I, above. If the market addition flag is TRUE, then the cost rate in column O applies to each planning period only if there is a non-zero entry in the decision cell for the cohort. (Instructions on controlling the plan through "decision cells" appears in the next section, "Parameters Describing the Plan.") Otherwise, the cost rate in column F applies to each planning period. Presumably, the cost rate in column F would be higher than that in column O, reflecting higher costs of not planning for capacity additions. Although the higher costs are associated with planning in the portfolio model, they certainly may represent the total of higher costs due to both planning and construction.

One additional controlling parameter unfortunately does not appear here. The switch that determines whether costs in the optional phase of construction are "pulsed," as in the regional model, or applied as construction proceeds is at the top of the VBA code module "mod_PlanningFlex"

```
Private Const bTrigger As Boolean = True 'determines whether all construction costs _
    for optional construction are incurred at the beginning of construction
```

Council staff added this parameter and capability late in the modeling process, and they never completed the proper establishment in the worksheet interface.

These parameters and values may be initially confusing. Once set, however, the user typically would have little need to modify them, except perhaps to update construction costs. A numerical example of how the model interprets these parameters to arrive at final costs appears below in the section "Period Calculations" beginning on page L-74.

Parameters Describing the Plan

A plan is defined by the timing, size, and choice of technology for new resources. As explained in the previous section, the timing of new resources in the regional model is, more precisely, the earliest date of new construction. The resource's production of electricity may occur as early as the planners' scheduled completion of construction or much later or not at all, depending on circumstances.

In the worksheet, the range {R3:CS9} determines the plan. A simplified view of this range appears in Figure L-57. This range of cells contains special cells that are under the direct control of Decisioneering's Crystal Ball and OptQuest. Decisioneering Inc. refers to these as "decision cells." OptQuest is the Excel add-in performs stochastic, nonlinear optimization. During the process of seeking a Least-Cost, Risk-Constrained plan, OptQuest modifies the values of these decision cells. The decision cells in Figure L-57 are yellow, the default color for decision cells under Crystal Ball.

In the regional model, potential capacity additions occur according to an irregular schedule. The first opportunity for construction is in September 2003 (column R).[25] The next opportunity is December of calendar year 2007. After this, opportunities fall every two years through December of calendar year 2019.

PlnCap_0 = 0

	N	R	S	AH	AI	AJ	AP	AQ	AR	AX	AY	AZ	BF	BG	BH
1		Sep-04	Dec-0	Sep-08	Dec-08	Mar-0	Sep-10	Dec-10	Mar-10	Sep-12	Dec-12	Mar-1	Sep-14	Dec-14	Mar-
2	Capacity Data ID														
4	CCCT Capacity	0.00			0.00			610.00			610.00			610.00	
5	SCCT Capacity	0.00			0.00			0.00			0.00			0.00	
6	Coal Capacity	0.00			0.00			400.00			400.00			400.00	
7	PRD	0.00			500.00			750.00			1,000.00			1,250.00	
8	Wind 1	0.00			0.00			1,200.00			1,200.00			1,200.00	
9	Wind 2	0.00			0.00			0.00			0.00			0.00	
10															

Figure L-57: New Capacity Decision Cells

These dates are a bit arbitrary. Construction typically begins in December, because December is the closest to the beginning of a calendar year, a convenient milestone for describing a plan. Occasionally, utilities will attempt to complete construction before the end of a year for tax purposes, as well. It is crucial that the portfolio model use as few construction dates as possible. Increasing the number of choices for start dates and for increments of capacity additions can dramatically increase the number of possible plans. Indeed, with the rather conservative choice present in the regional model, the number of possible plans still exceeds 10^{24}. This is the key reason optimization is useful in identifying least-cost plans. Early in the study process, it became apparent that the model constructs few resources in the first 10 years, largely due to a surplus of existing resources in that period. It made sense therefore to sample the second decade of the study period more carefully than the first decade. These considerations led to the pattern of earliest construction dates that appear in the final regional model.

The previous section described how there are cohorts of a given plant technology available in each period of the study. The user, however, must make a given cohort available by assigning a nonzero capacity to the period in which the cohort originates.

[25] The header label in Figure L-57 and in the model says "September 04" because the regional model uses hydro years. The regional model deems September through August of the following year a hydro year or streamflow year. The calendar year in which it ends, in this case 2004, designates the hydro year.

There is an Excel range name in column R of each row corresponding to a new resource. (See for example the range name **PlnCap_0** in cell {R 4} of Figure L-57.) At the beginning of a Monte Carlo run for a given plan, the workbook finds this range and reads the associated row of values to determine which cells are blank and to obtain the values from nonblank cells.

How the model interprets the values in each row depends on whether the user has specified that additions are market-driven. (See discussion of columns N and O in the previous section.) In the regional model, additions are *not* market driven. If additions are not market driven, nonblank entries represent cumulative megawatts of the resource from that period forward until the next nonblank entry. The model permits only cohorts that start in the nonblank period *and* only if the value in the period increases from the previous nonblank value. This means that if the decision criterion is negative in that period, then cohort never begins construction.[26] Consider the situation for CCCT in Figure L-57. The cumulative capacity in December hydro year 2010 and December of hydro year 2012 are both 610 MW. This means that the model can add 610 MW in hydro year 2010, but it cannot add more capacity in hydro year 2012. It is the change in cumulative capacity that enables potential new construction.

If, instead, the user specifies that additions *are* market-driven, nonblank entries represent incremental megawatts possible in that period. The same ramp rate applies to all futures periods, unless there is a nonblank entry that changes this ramp rate. When additions are market driven, the cohort of the given technology will become active in any period where there is a positive value for the decision criterion. The prevailing ramp rate in a given period determines the amount of capacity that the model will add. Whether a non-blank entry specifies the ramp rate or the ramp rate is inherited from an earlier period *does* affect planning costs. If there is a nonblank incremental capacity entry, lower planning costs are available in the portfolio model, as described in the previous section. Otherwise, the model will use higher cost for planning.

Period Calculations

The third and final area of the worksheet that controls the capacity addition and costing are the period's cells. These cells contain the functions that return the capacity and cost. Cell {AQ455} contains the following formula, which returns the total capacity across all cohorts for the generic CCCT unit:

```
=lfPFCap(AQ$302,AQ$46,$P455)
```

The definition for this UDF is as follows

[26] Of course if they were nonblank entries in the subsequent period, the technology would "get another chance." This is not the case in the regional model, however, where options for the beginning of construction occur only once every two years.

```
Function: lfPFCap(ByVal dCriterion As Double, ByVal lPeriod As Long, _
          ByVal lPlant As Long) As Long
Takes:
          dCriterion - Prices or criteria values that would indicate success moving forward
          lPeriod    - 0-based index to period for which the calculation pertains
          lPlant     - 0-based index to plant for which computation pertains

Returns:  A long with the number of MW
```

All of the necessary information regarding the technology and the plan are available in memory arrays to the special UDF lfPFCap. Based on this information and the value of the decision criterion, the UDF determines the appropriate amount of capacity to add, according to the rules described earlier. The UDF updates the real levelized costs at the same time. There are identical formulas for generic coal plants, wind plants, and the other new resources in other periods. Each generic technology, of course, points to its own decision criterion and plant index.

The second special UDF, sfPFCost, then retrieves the period real levelized costs totaled across all cohorts for this technology.

=sfPFCost(AQ455,AQ$46,$P455)

The definition of the special UDF is as follows

```
Function sfPFCost(ByVal lDummy As Long, ByVal lPeriod As Long,
          ByVal lPlant As Long) As Single
Purpose:
          This function is a companion to lfPFCap.  It reads the cost matrices and
          returns the appropriate period's information

Takes:
  lDummy    - Forces calculation of lPFCap
  lPeriod   - 0-based index to period for which the calculation pertains
  lPlant    - 0-based index to plant to which computation pertains

Returns:
  The real dollar amount ($M) for the period, after escalation, but before discounting
```

Up to this point, this section has discussed the use of the capacity expansion and planning flexibility logic in detail but has not provided an example of how all these pieces fit together. To see how the model interprets the parameters and values presented above, consider Figure L-58. This illustration features two special UDFs that facilitate viewing the model's internal workings. The UDF "lfPFCohortStatus" returns the status of a given cohort for each period in the study; the UDF "sfPFCohortCost" returns the period cost for that cohort. Because the results returned by the "lfPFCap" and "sfPFCost" are aggregate capacity and period cost across all cohorts of a given technology, it is useful for diagnostic and training purposes to have UDFs that permit an analyst to study the workings of one cohort in isolation.

These UDFs are available in the portfolio model, but the only range in the regional model that refers to them is {R463:CS464}. In the model, placing an "m" before the equal sign in their formulas has deactivated them. The “m” forces Excel to interpret the formulas as strings. In Figure L-58, removing the “m” reactivated them, and pointing the parameters to updated cells eliminated some bad initial references. The VBA code module “mod_PlanningFlex” defines and recommends how to use the status UDFs, so this appendix will provide no further explanation.

The cursor in Figure L-58 is on cell {AQ464}, and the formula in that cell appears in the equation window at the top of the figure. Formula auditing is on, revealing that the parameters of the UDF point to the cohort index, to the period, to the plant index, and to the previous cell. The reference to the previous cell, as elsewhere, forces the calculation order by guaranteeing the worksheet updates the previous formula before the subject cell. Other instances of this formula in row {464} have identical parameter formulas but of course point to different period columns and different previous cells.

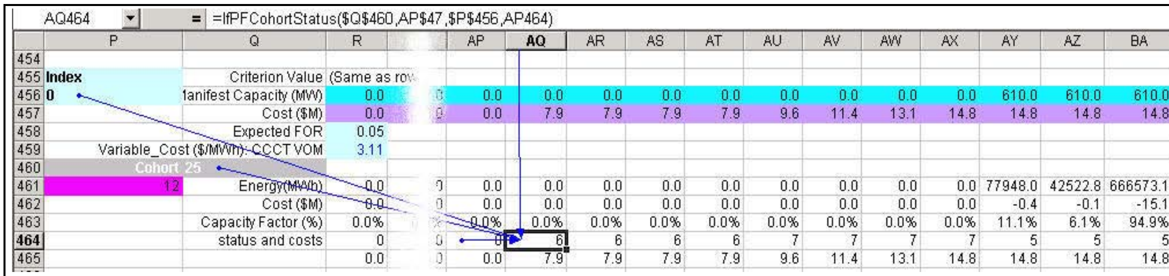


Figure L-58: Status Functions

In Figure L-58, the UDF lfPFCohortStatus returns the value 0 in row {464} up to column {AQ}. In columns {AQ:AT}, the value is 6; in columns {AU:AX}, the value is 7; and in columns to the right of {AX}, the value is 5. These values represent the status of cohort 25, plant 0 (the CCCT) in each period. Cohort 25 is the cohort that begins in period 25, the period in column {AQ}. The following table defines the meaning of the status codes:

lUnderConsideration As Long = 0
lNeverStarted As Long = 1
lPlanned As Long = 2
lMothballed As Long = 3
lCancelled As Long = 4
lCompleted As Long = 5
lOptionProceed As Long = 6
lConstrProceed As Long = 7
lRetired As Long = 8

The next row contains instances of the UDF sfPFCohortCost, which return costs for cohort 25 only. *With this information and the value of the decision criterion in each period, the user has the means to verify the calculations determining capacity addition and costs in each period*.

Start with the description of the construction cycle of the CCCT, including the percentage of costs and amount of time spent in each of the construction phases:

name		Siting and Permitting	Optional Construction	Commited Construction	Totals
CCCT	Periods to complete phase (quarters)	8	4	4	16
CCCT	Periods to complete phase (months)	24	12	12	48
CCCT	Cost to complete phase (Overnight, MM 2000$)	20	66	234	320
CCCT	Cost to complete phase (Overnight, 2000$/kW)	33	108	384	525
CCCT	Cost to complete phase (% Overnight)	6%	21%	73%	100%

Figure L-59: CCCT Construction Cycle

In Figure L-56, the specification of periods for optional and committed construction is evidently consistent with Figure L-59. The next step is to determine the cost and cost escalation rates for planning and construction. Figure L-60 identifies the real levelized costs for generic CCCT plant started in each year listed in column A. The capital cost in column T includes planning costs. The calculation adds fixed O&M and fixed fuel costs to arrive at a total fixed real levelized cost for each generation of generic CCCTs. From this calculation, we take away two numbers, the 2004 levelized cost in cell Z38 and the quarterly cost escalation rate in cell Z62. This quarterly escalation rate calculation is on page L-71; it matches the escalation rate in Figure L-56.

Z40 = =W40+U40+T40

	A	T	U	V	W	X	Y	Z
32	Levelized costs by service year (2004$):							
33								
34		Capital (2004$)	Operation (2004$)					
35								
36								
37	Service Year	($/kW/yr)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Fixed Fuel ($/kW/yr)	Variable Fuel ($/MWh)		Total fixed for portfolio
38	2004	$53.77	$29	$3.11	$25	$25		$108
39	2005	$53.56	$29	$3.11	$26	$24		$108
40	2006	$53.34	$29	$3.11	$26	$24		$108
41	2007	$53.13	$29	$3.11	$26	$24		$107
42	2008	$52.92	$28	$3.11	$26	$24		$107
43	2009	$52.71	$28	$3.11	$26	$24		$107
44	2010	$52.50	$28	$3.11	$25	$24		$106
45	2011	$52.29	$28	$3.11	$25	$24		$106
46	2012	$52.08	$28	$3.11	$25	$24		$106
47	2013	$51.87	$28	$3.11	$25	$24		$105
48	2014	$51.67	$28	$3.11	$25	$24		$105
49	2015	$51.46	$28	$3.11	$25	$24		$104
50	2016	$51.25	$28	$3.11	$25	$24		$104
51	2017	$51.05	$28	$3.11	$25	$24		$104
52	2018	$50.85	$28	$3.11	$25	$24		$103
53	2019	$50.64	$28	$3.11	$24	$24		$103
54	2020	$50.44	$28	$3.11	$24	$23		$102
55	2021	$50.24	$28	$3.11	$24	$23		$102
56	2022	$50.04	$28	$3.11	$24	$23		$102
57	2023	$49.84	$27	$3.11	$24	$23		$101
58	2024	$49.64	$27	$3.11	$24	$23		$101
59	2025	$49.44	$27	$3.11	$24	$23		$100
60	Escalation, 2004-25	-0.399%	-0.23%	0.00%	-0.32%	-0.34%		-0.342%
61								
62							Quarterly	-0.00085682

Figure L-60: Year-by-Year Real Levelized Costs

Not all of the $108/kWyr is construction cost. Figure L-59 specifies the portion of this that is planning cost, and the difference is the basis from the construction cost rate estimate illustrated in Figure L-61. The detailed construction cost rate calculation for this CCCT already appears as the example on page L-70. Applying the planning fraction of construction costs to the total construction cost in $M/MW gives the planning cost rate in Figure L-62. Recall that, despite the number of periods for planning that appears in Figure L-59, the number of periods is taken as one (1) when the user models planning costs as sunk, as does the regional model. This planning cost rate matches that in Figure L-56.

CCCT		
	RL$/kWyr	$101.50
	1/#per	0.125
	RL $M/MW/per/per	0.0029199

Figure L-61: Construction Cost Rate

D72 = =D9/(1-D9)*(E5+F5)*D40

	A	B	C	D
69				
70		**Planning Costs**		
71				
72		CCCT		0.001491007
73				

Figure L-62: Planning Cost Calculation

Having reproduced the values in Figure L-56, the final step is to verify the costs in Figure L-58. From the status codes, it is evident that construction proceeds without interruption. The optional phase of construction takes four periods and the committed phase takes four periods. Figure L-63 reproduces the costs in each period of Figure L-58. Column D identifies the 0-based period, and the costs begin in period 25 for cohort 25. Column E is just the period escalation factor, i.e., one plus the escalation rate, all raised to the number of periods. Column F has the one-time sunk cost for planning, just the escalation factor times the capacity times the planning rate. (This and the other formulas here are as in the description of columns F through I on page L-70.) In column G, rows 15 through 18, the formula is identical except that the formula uses the construction cost rate instead of the planning rate. The formula appears in the equation window at the top of the page. In column G, row 11, the formula is the same as that in rows 15 through 18, except multiplied by four because all the optional construction costs are "pulsed" into the first period. The reader may now compare the cumulative costs in column H with the costs in row 465 of Figure L-58. Because there is only one active cohort, these costs match those in row 457.

This concludes the description of the new resource capital costing and planning flexibility representation in the portfolio model. This section described the portfolio model's concept of planning and construction flexibility, including features such as market addition of plants, sunk costs for planning, and pulsed construction costs. It presented the three ranges in the workbook that implement new resource additions and planning flexibility. In illustrating the range that specifies the resource plan, it provided some background on the reasons why the Council chose planning commitments to describe the plan and how they selected the planning intervals. Finally, the section reproduced the costs associated with a cohort, using special UDFs that identify the construction status and costs of any specific cohort.

Two areas of modeling are conspicuously absent: summarizing the costs and development of the decision criteria that drive both the DSI and the planning flexibility UDFs results. The present value calculations are in the following subsection. The important issue of decision criteria has its own section following this one.

G16 = =E16*$C$3*$C$5

	B	C	D	E	F	G	H
2	escalation	-0.0008568	per quarter				
3	cap	610	MW				
4	planning rat	0.00149	$M/MW/per^2				
5	constr rate	0.00292	$M/MW/per^2				
6							
7		Column	Period	escl	incr plng	incr cnstr	cum
8					(M$)	(M$)	(M$)
9		AO	23				0.000
10		AP	24				0.000
11		AQ	25	0.9788	0.890	6.973	7.864
12		AR	26	0.9780			7.864
13		AS	27	0.9771			7.864
14		AT	28	0.9763			7.864
15		AU	29	0.9754		1.737	9.601
16		AV	30	0.9746		1.736	11.367
17		AW	31	0.9738		1.734	13.101
18		AX	32	0.9729		1.733	14.834
19		AY	33	0.9721			14.834
20		AZ	34	0.9713			14.834
21		BA	35	0.9704			14.834

Figure L-63: Costs in Each Period

Present Value Calculation

Previous sections have presented the concepts, equations, and formulas for computing the cost of each source of load and energy. Loads, including smelter loads, and resources such as thermal generation, hydrogeneration, conservation, contracts, and renewables -- all of these produce period costs. As seen in the last section, the portfolio model treats the fixed costs associated with capital investment, fuel, and O&M as real levelized period costs, as well. The final step in the portfolio model is to compute the total net present value from these period costs.

The net present value calculation appears in column {CV}. For example, the net present value cost for the on-peak non-DSI loads is in row {323}:

```
=8760/8064*NPV(0.00985340654896882,$R323:$CS323)*(1+0.00985340654896882)
```

This equation has three multiplicative terms. The first term is the ratio of the number of hours in a calendar year to the number of hours in a standard year. As described in section "Single Period," all period calculations assume standard months, quarters, and years. This first term performs the cosmetic task of converting dollars per standard year to dollars per year. The portfolio model does not concern itself with the exact number of on- and off-peak hours in each quarter.[27]

The second and third terms discount the period costs to the first period. The Excel net present value function NPV discounts cash flows to the period immediately *before* the first cash flow. The third term merely moves it up to the first cash flow. The discount rate is the discount per quarter, given the four percent discount per year.

This formula represents an unfortunate instance where data appears in code. The ratio of hours in a calendar year to a standard year is a constant and might be appropriate for a formula like this one. The discount rate, however, should never appear in a formula like this. This formula is a vestige of an earlier version of the portfolio model.

The formulas in {CV1063} and {CV1065} total the net present value cost contributions for energy use and production and for the fixed costs of new resources. The only resource that does not contribute to the total net present value cost is the supply curve associated with commercial use of hydrogeneration. The section "Price-Responsive Hydro" explains this convention.

Cell {CV1065} is a Crystal Ball "forecast" cell. It has the default sky-blue color of such cells. Crystal Ball tracks the values in forecast cells and makes them available to the OptQuest add-in. One may think of these cells as the primary "output" of the worksheet.

Below the formulas in cell {CV 1065}, the reader will recognize several cells as risk measures. In fact, it is not possible to determine the risk associated with the distribution of net present value costs from a single future. Instead, after all 750 futures have been simulated and their total system costs calculated by this workbook, and an Excel subroutine uses Crystal Ball functions to recover the 750 values for {CV 1065}, stored in memory. The subroutine then calculates risk measures such as TailVaR_{90} and places the resulting values in Crystal Ball "forecast" cells for use by that application. The section "Using the Regional Model" explains this process.

Decision Criteria

The previous section introduced the concept of decision criteria. Both the DSI smelter startup/shutdown decision and the construction decision for new electric power resources rely on decision criteria. Conservation also uses a decision rule to determine whether to buy more conservation than short-term cost effectiveness would suggest, and if so how much.

This section begins with background on what decision criteria are, how the regional model uses them, and some of the discoveries and considerations that went into selecting the decision criteria. The specific criteria for new resources, conservation, and DSIs then

[27] As explained at the beginning of the section "Single Period," if it became important to do so, a user could recover the exact calendar year costs by applying to each standard quarter the weighting of on- and off-peak hours in that quarter relative to the other quarters in the year.

each have their own sections. The sections describe the particular aspects of each criterion and trace the formulas that implement them though the sample workbook.

Background

The defining characteristic of planning under uncertainty is imperfect foresight. With perfect foresight, there would be no risk. A risk model must therefore incorporate at least two special features. First, a risk model must have the ability to add resource capacity or other course of action without the benefit of perfect foresight. Most production cost or system simulation models capable of capacity expansion use techniques that assume perfect foresight. For example, these models may remove resources that do have sufficient value in the market to cover forward going fixed costs or add resources that would make a risk-adjusted profit in the market. An iterative process removes or adds resources until all new resources would just cover their risk-adjusted costs. Alternatively, a capacity expansion model may choose a capacity expansion schedule that minimizes cost. Both of these approaches must determine future hourly costs and prices to feed back to the capacity expansion algorithm. This feedback determines whether some adjustment to the construction schedule is necessary. If the model modifies the schedule, of course, the model must re-estimate future costs and price changes. The process repeats until the model finds a solution. These estimates of future costs and prices represent perfect foresight regarding how resources, costs, and prices affect one another. Perfect foresight, however, is contrary to the principles of risk analysis.[28]

Second, a risk model that incorporates capacity expansion must have a decision rule that determines whether to build or continue building. Because a risk model cannot use perfect foresight, the value of this criterion must use information about the current situation or about the past. Of course, different resources may use different criteria. A good test of a decision criterion, as it turns out, is whether it reduces cost and risk.

A decision criterion need not be perfect. The assessment of the value of planning flexibility relies on how well a resource plan performs when circumstances *do not* materialize as planned. As long as the decision criterion adds resources and makes wrong forecasts (from the standpoint of perfect foresight) in a realistic manner, it could be deemed adequate.

All decision criteria implement the concept of causality. Decisions to build, shut down or start up smelters, and so forth rely on the strict past (prior periods). That is, the logic that controls construction progress or smelter operation references the criterion value in the *prior* period. The reasons appear above in the section "Concept Of Causality," beginning on page L-58.

All decision criteria formulas are in the Twilight Zone, rows {223} through {316}. The model updates these before beginning any period calculations and with any iterations of

[28] A peculiar side effect of perfect foresight models is they often lead decision makers to rely on the market. Capacity expansion models with perfect foresight add power plants precisely when they have greatest value. Following this approach, however, leads to market prices that match the fully allocated cost of the capacity expansion alternative or to long-term marginal expansion costs that match market prices. Given that the decision maker is no better building a plant than she would be if she purchased firm power in the market, there is little incentive to incur the considerable risks and challenges of building.

the RRP algorithm. The reason this is necessary is that some intermediate values that contribute to decision criteria will change with each iteration, such as power plant value when electricity price changes.

New Resource Selection

The section "New Resources, Capital Costs, and Planning Flexibility" describes how the model uses a decision criterion to halt or continue activity during the earlier phase of construction. The model incorporates such behavior to permit the valuation of planning flexibility.

Given how important the decision criterion is to assessing planning flexibility, it is natural to ask what alternatives exist and why the Council chose this particular decision rule. The first rule implemented in early versions of the portfolio model was valuation using forward prices. One concern that arose when consideration turned to valuing conservation is that plans with more conservation often received substantial value by virtue of "being there" when high market price excursions occurred.[29] Resources that used only valuation in the market could only react to these excursions; often completing construction after the excursion subsided. Although this may help describe behavior during the 2000-2001 energy crisis, a more experienced market will probably pay careful attention to physical resource adequacy in the future. Moreover, when a resource-load balance criterion replaced the market valuation criterion in the portfolio model, the feasibility space and its efficient frontier displayed reduced risk at no increase in cost. Resource-load balance does a better job of predicting the need for resources.

Resource-load balance alone, however, presents some problems as a decision criterion. An examination of particular futures revealed unrealistic behavior. Resource-load balance ignores economics completely. Given a future with high gas prices, for example, the portfolio model would be as likely to develop a gas-fired turbine as a coal plant if it has a choice between the two. Consequently, the criterion in the final version of the portfolio model gives consideration first to resource-load balance and then uses plant valuation to make the resource choice.

For conventional thermal resources and wind generation, the approach that performed best incorporates information about resource-load balance and forward prices for fuel and electricity prices. Specifically, the model uses a three-year average of load growth and any change in resource capability to determine when in the future resource-load balance would cross below a given threshold. The selection of the threshold is itself part of the choice the model makes to minimize cost or risk. That is, the threshold is in a Crystal Ball decision cell, under the control of the optimizer. In each simulation period and for each resource candidate, the model determines whether the crossover point is less than the construction time required for that resource.

[29] This value comes not only from the advantageous resource-load position, but also from price moderation due to the additional resources. This raised the question of whether other resources, built to maintain some reserve margin, would not also benefit plans. This turns out to be the case, although – as the section "Conservation Value Under Uncertainty" describes – conservation often can serve this role a lower net cost.

If the model needs a resource to meet anticipated future load, the criterion consults pertinent forward prices for each resource. For example, for a gas-fired power plant, the model would estimate the plant's value from forward prices for electricity and natural gas and compare those to capital and other fixed costs to determine whether the plant would pay for itself. If the plant would pay for itself, construction proceeds; if not, the model compares the value of the plant to that of alternatives. If the plant cannot pay for itself but is still the least expensive alternative, construction continues.

The model uses forward prices for electricity, natural gas, and other commodities, but it cannot use perfect foresight. Consequently, the model estimates forward prices using the assumption that futures and forward prices closely track current prices. This relationship is apparent in data for many commodities for which storage of the commodity is limited, including natural gas and electricity. For example, for gas-fired new resources, average commodity price for natural gas and electricity over the last 18 months is the forecast of those forward prices. This reflects the fact that it often takes awhile for perceptions about long-term prices to change.

Model Representation

In the workbook, we will trace the decision criterion for the CCCT backward from the final value. This section will also point out any differences with the decision criteria for the coal plant, SCCT, demand response, and wind. Demand response and wind, in particular, merit a paragraph each at the end of this discussion.

The CCCT new capacity UDF in cell {AQ455} points to the decision criterion in cell {AP302}. The formula in cell {AP302} is as follows

```
=IF(AP$297<$O303,IF(OR(AP253>=0,AP253>(AP$282-$R$283)),1,-1),-1)
```

This formula first checks to determine whether the forecasted crossover point for resource-load balance is less than the lead time for construction of the CCCT. If that is false, then the decision criterion is set to -1 (no-go). Otherwise, the formula sets the value to +1 (go) if the CCCT either is expected to make money in the market or is the least cost resource among the available alternatives and to –1 otherwise. It may be useful to parse the formula to better understand it. The outside "if statement"

```
=IF(AP$297<$O303,...,-1)
```

checks the forecasted crossover point in cell {AP297} against the number of periods for construction in cell {O303}. If the lead time for construction is greater than the forecasted crossover time, the formula returns to –1 indicating that construction is unnecessary and undesirable. Otherwise the inner if statement is executed

```
IF(OR(AP253>=0,AP253>(AP$282-$R$283)),1,-1)
```

the first condition in the OR test

```
AP253>=0
```

checks whether the CCCT makes money in the market. The second condition in the OR test

```
AP253>(AP$282-$R$283)
```

checks to see whether the cost of the CCCT is within some small interval, specified in {R283}, of the minimum cost among all resources, calculated in cell {AP253}. There are four key variables in this formula:

- Construction lead time
- Neighborhood of the minimum cost
- Forecasted Energy Margin Crossover Point
- Market Viability

The first two variables are easy to describe. The construction lead-time is the sum of the periods for optional and committed construction:

```
=C455+D455+E455
```

The first term in the sum points to the number of periods for planning and siting, but that value is zero for all new resources in the regional model.

The test with the minimum uses a neighborhood for technical reasons. The model does not test whether the cost of the CCCT is *exactly* the minimum cost among all resources, because of the problem associated with comparing any two real numbers in computer code. That is, some manipulation, e.g., finding the minimum of a set of numbers, may corrupt the minimum by an infinitesimal amount. This corruption could render the comparison invalid. To avoid this situation, the formula instead checks whether the resource is within some very small neighborhood of the minimum.

The remaining two variables, Forecasted Energy Margin Crossover Point and Market Viability, are more complex and merit their own sections. These are the next two sections.

Forecasted Energy Margin Crossover Point

The forecasted crossover point ({AP297}) is an estimate of when requirements will surpass resources. The calculation of load requirements for this estimate, however, includes the addition of a user-specified, energy reserve margin target. This user-specified target is under the control of the optimization software through its assignment to a Crystal Ball decision cell.

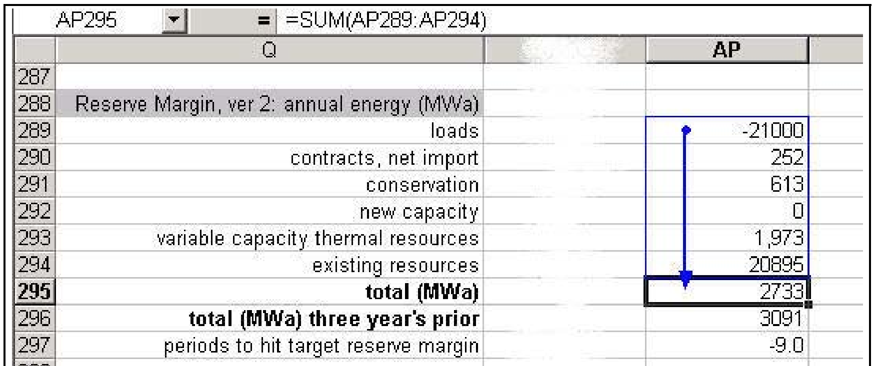
The formula in cell {AP297} is the following

```
=IF(AP295<AP296,(AP295-$T$3)*12/(AP296-AP295),IF(AP295<$T$3,-1,100))
```

This formula checks to see if resource net of total load ({AP295}) has declined over the last three years. If so, it uses the rate of decline to determine how many periods will pass before resources decline below the load plus energy reserve margin. If not, it checks whether resource net of total loads is below the energy reserve margin target ({$T$3}). If so it returns the value -1. Otherwise it returns the value 100. These values are the number of periods before crossover is anticipated to take place. Negative one (-1), of course, will be less than the construction time for any resource and will therefore result in a positive value for the decision criterion, other factors permitting. The value 100 exceeds the construction time of any resource and would typically result in a negative decision criterion value.

It can of course happen that the balance ({AP295}) has declined over the last three years but is already below the target energy-reserve margin. In this case, the formula will return a negative number. This number is a back-cast of the number of periods in the past that the balance slipped below the target. Any negative value signals that construction is necessary.

The cell {AP295} computes resources net of loads by adding the various terms immediately above that cell in the worksheet, as shown in Figure L-64. The model updates these for the new values under this future. (The Figure L-64 also demonstrates the situation described above where the balance has declined but is already below the 3000MW target energy reserve margin, and the value returned is negative.)


AP295 = =SUM(AP289:AP294)

	Q	AP
287		
288	Reserve Margin, ver 2: annual energy (MWa)	
289	loads	-21000
290	contracts, net import	252
291	conservation	613
292	new capacity	0
293	variable capacity thermal resources	1,973
294	existing resources	20895
295	**total (MWa)**	2733
296	**total (MWa) three year's prior**	3091
297	periods to hit target reserve margin	-9.0

Figure L-64: Resources Net of Loads

The load estimate in cell {AP289} is the hydro year's average, weather-corrected non-DSI load (the range {AL126: AO126}), plus the DSI load in the final period. The model's weather corrected load is simply the load, less the stochastic part that represents weather variation in the winter and summer. The reader will find a complete discussion of load representation in Appendix P.

Net import contract energy in MWa (cell {AP290}) is given by

=4/7*AVERAGE(AL84:AO84)+3/7*AVERAGE(AL88:AO88)

This is merely the average of contracts (MWa) over the previous four quarters on peak (row {84}) and off peak (row {88}), weighted by the respective number of on- and off-peak hours in the standard quarters.

Conservation in MWa (cell {AP291}) is

=(SUM(AL377:AO377)+SUM(AL386:AO386)+SUM(AL741:AO741)+SUM(AL749:AO749))/(4*(1152+864))

This formula references the lost opportunity (rows 377 and 741) and discretionary (rows 377 and 741) conservation energy in MWh on- and off-peak over the last four quarters. The average MW are then this sum, divided by the hours in a standard year, 4*(1152+864).

New capacity in MWa (cell {AP292}) is

=AO455+AO469+AO483+0.3*(AO509+AO519)

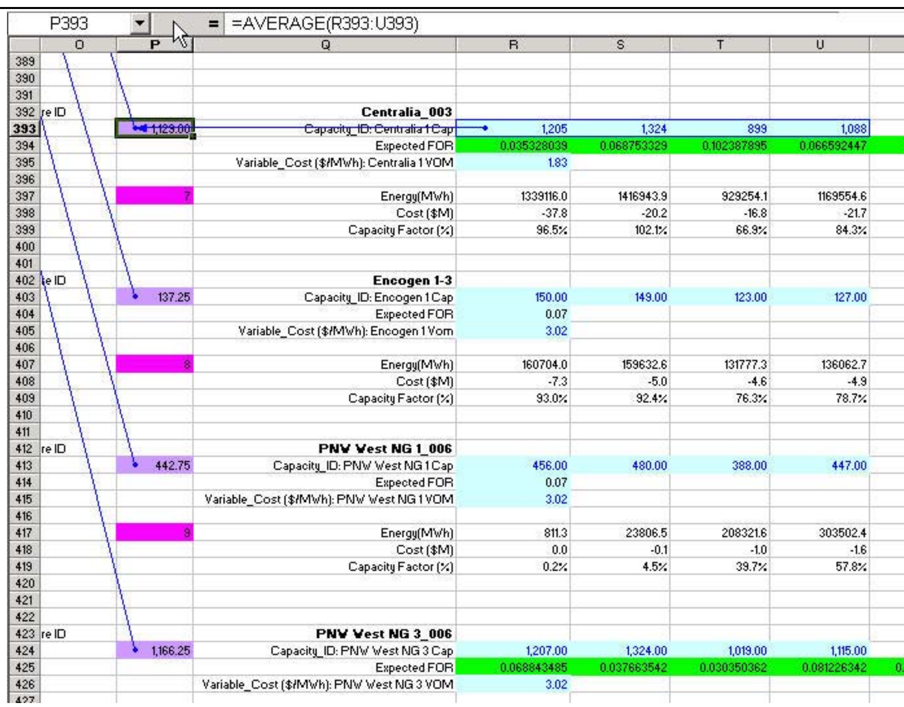
The CCCT, SCCT, and coal-fired capacity in the last period is added to 30 percent of the two wind unit capacities. Energy from the wind units must be discounted, because of the low availability of wind. Missing here is any capacity from demand response (DR). DR is considered an emergency resource in these studies and its expected energy contribution is nil.

"Variable capacity thermal resources" (cell {AP292}) is a misnomer. In fact, there is a substantial amount of renewable (wind) energy in this sum. This capacity changes from year to year. It requires summing the annual average capacity of those resources.

```
=SUM(AVERAGE(AL345:AO345),AVERAGE(AL355:AO355),1497+0.3*(AVERAGE(AL536:AO536)-
1497),AVERAGE(AL610:AO610))
```

In this workbook, developed before the draft plan, three generic thermal resources are retired over 10 years. The average capacity for each appears as the first, second, and forth terms in this sum. Must run resources, the third term, include thermal resources that stay at the same capacity (1497 MW) over this period and wind resources that increase in capacity. There is an error in this formula. The energy of the wind is discounted twice, once in the values reported in the range {AL536:AO536} and again by the formula. In the version of the model used to create the final plan, there are no thermal unit retirements, and the double-discounting does not take place. The cell is also labeled more accurately, "variable must-run firm energy."

The "existing resources" (cell {AP293}) are those resources that have annual energy production that is constant over the study. Hydro generation energy is included at the critical water amount. The formula in cell {AP293} merely adds the critical-water hydro


P393 = =AVERAGE(R393:U393)

	O	P	Q	R	S	T	U
389							
390							
391							
392	re ID		**Centralia_003**				
393		1,129.00	Capacity_ID: Centralia 1 Cap	1,205	1,324	899	1,088
394			Expected FOR	0.035328039	0.068753329	0.102387895	0.066592447
395			Variable_Cost ($/MWh): Centralia 1 VOM	1.83			
396							
397		7	Energy(MWh)	1339116.0	1416943.9	929254.1	1169554.6
398			Cost ($M)	-37.8	-20.2	-16.8	-21.7
399			Capacity Factor (%)	96.5%	102.1%	66.9%	84.3%
400							
401							
402	re ID		**Encogen 1-3**				
403		137.25	Capacity_ID: Encogen 1 Cap	150.00	149.00	123.00	127.00
404			Expected FOR	0.07			
405			Variable_Cost ($/MWh): Encogen 1 Vom	3.02			
406							
407		8	Energy(MWh)	160704.0	159632.6	131777.3	136062.7
408			Cost ($M)	-7.3	-5.0	-4.6	-4.9
409			Capacity Factor (%)	93.0%	92.4%	76.3%	78.7%
410							
411							
412	re ID		**PNW West NG 1_006**				
413		442.75	Capacity_ID: PNW West NG 1 Cap	456.00	480.00	388.00	447.00
414			Expected FOR	0.07			
415			Variable_Cost ($/MWh): PNW West NG 1 VOM	3.02			
416							
417		9	Energy(MWh)	811.3	23806.5	208321.6	303502.4
418			Cost ($M)	0.0	-0.1	-1.0	-1.6
419			Capacity Factor (%)	0.2%	4.5%	39.7%	57.8%
420							
421							
422							
423	re ID		**PNW West NG 3_006**				
424		1,166.25	Capacity_ID: PNW West NG 3 Cap	1,207.00	1,324.00	1,019.00	1,115.00
425			Expected FOR	0.068843485	0.037663542	0.030350362	0.081226342
426			Variable_Cost ($/MWh): PNW West NG 3 VOM	3.02			

Figure L-65: Resources with Constant Annual Energy Availability

energy, a user-specified constant, and the total capacity for the fixed-capacity resources. The total fixed capacity in cell {I289} merely points to averages of energies across the hydro year for each relevant plant, as illustrated in Figure L-65.

Market Viability

Returning to the beginning of this section, “Model Representation” on page L-83, the last variable in the decision criterion for new resources is market viability (cell {AP253}). The market viability test is made in a set of rows just above those where the worksheet determines resource-load balance. As explained above, the intent is to simulate forward curves values and calculate whether or not the value of the resource in the market would cover its fixed costs. Figure L-66 shows the formula for this cell.

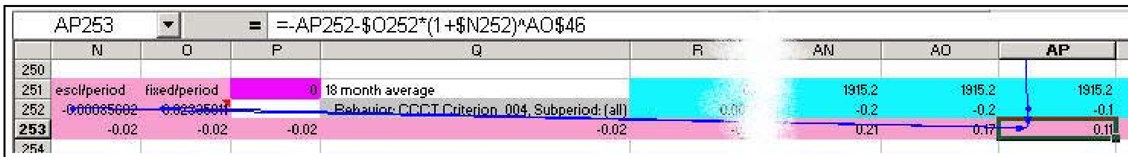


Figure L-66: The Net Market Value Test

The first term in the formula {AP252} is the value of the CCCT in the market. It contains a call to the spread option UDF described in the section “Thermal Generation,” above, which returns the value (2004 $M) in the market. (See Figure L-67.) This call is identical to the one for the generic CCCT itself with three exceptions: the size of the plant is 1MW, the electricity price is an 18-month average of flat electricity prices, and the natural gas price is also an 18-month average. The market viability valuation uses equal 1MW capacities for all new resource candidate to normalize the value to dollars per MW. The 18-month averages of past prices, as explained above, is used as a surrogate for forward prices and to reflect the time necessary for owners to develop confidence in the forward prices. The development of these stochastic prices appears in Appendix P.

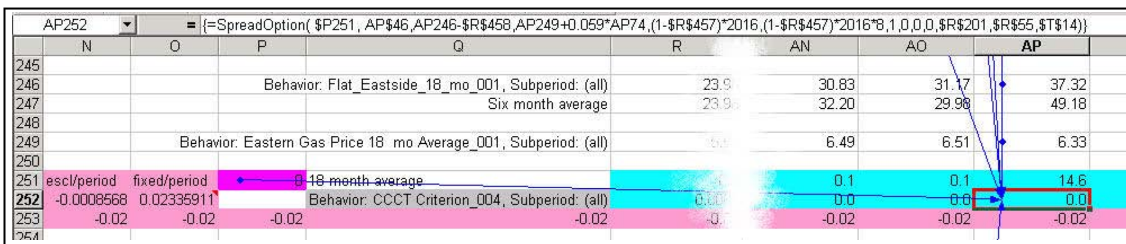


Figure L-67: Value of Plant in Market

The second additive term in formula {AP252}, $O252*(1+$N252)^AO$46, is the fixed cost per MW. (See Figure L-66.) The cell {$N252} references the escalation rate per period for CCCT fixed costs, and the cell {AO$46} is the zero-based period index. The formula for 2004$ fixed cost per MW in cell {$O252} is

=SUM(D455:E455)*I455

which sums the number of optional and committed construction periods and multiplies it by the real levelized millions of dollars per period squared. The cost for planning periods, which are zero anyway, should not be included as they are sunk cost for the plan.

For demand response, the treatment is identical to the CCCT decision criterion with the following exceptions. Demand response (DR) is modeled as a thermal unit with a dispatch cost of $150/MWh (2004$). Because DR programs require little time to implement, they can respond more quickly to changing circumstances. Their relatively small set-up cost minimizes the risk of having the opportunity disappear. For this reason, the DR decision criterion does not use an 18-month average electricity price, but uses the period price instead. Note also that in both the draft and final plans, the plans hard-wire the plan for DR development (row {7}) rather than placing it under the control of the optimizer. The model still uses the decision criterion logic.

For wind generation, the treatment is identical to the CCCT decision criterion with the following exceptions. The value of wind in the market (cell {AP$277}) is

```
=2016*0.3*(AO$506-AP$247)/1000000
```

As before, the implied capacity is 1MW. The value in 2004 $M is then just the energy times the market price adjusted for any costs. The energy is 1MW times the number of hours in the period, times the capacity factor. The adjusted market price is the six-month average of flat electricity prices (cell {AP$247}), less the net of integration cost, production tax credit, green tag credit, and variable O&M (cell {AO$506}). The model uses a six-month average for electricity price instead of the 18-month average because the Council believed that, with the shorter construction cycle for wind, owners would want to respond more quickly and would not take as much time to build confidence in their lower dollar commitment to the more modular wind units. This represents an approach to averaging past prices that fall between that of DR and the thermal resources.

This concludes the discussion of decision criteria for new resources. One shortfall of these criteria is that they include the full fixed cost of construction irrespective of where plants are in their construction cycle. That is, forward-going construction decisions should treat costs associated with past construction as sunk cost. Modeling this economics would probably require a significant revision to the new capacity-planning flexibility UDF, as such detail must be tracked by cohort. It might make for even more realistic behavior, however.

Conservation

Conservation uses a decision criterion somewhat different from that for new resources. Conservation can introduce thorny problems, like cost shifting for ratepayers and revenue recovery for load-serving entities. Consequently, special regulatory or administrative intervention is typically necessary. Cost effectiveness has been the standard that administrators use to deem the type and amount of conservation to pursue.

Because conservation uses a cost-effectiveness standard, a criterion that resembles such a standard seems appropriate. However, the challenges in constructing a cost-effectiveness criterion are several.

- Cost effectiveness levels change over time as market prices for electricity change, although administrators tend to base them on long-term equilibrium prices for electricity. Models that estimate equilibrium prices for electricity are sensitive to commodities that have been less volatile than electricity prices, such as natural gas price. Regardless, cost-effectiveness standards are subject to uncertainty and change depending on the particular future.

- Because they are often determined administratively, they change more slowly than commodity prices. Moreover, the time between changes in efficiency standards and when the conservation measure starts to contribute can be a year or more, while load-serving entities develop their budgets and ramp up programs. Thus, there is considerable lag time between changes in commodity prices and changes in conservation energy rate of addition.

- Some types of conservation become institutionalized, such as that associated with new codes and standards for building construction. Once the codes pass into law, the corresponding measures are no longer directly subject to the cost-effectiveness standard. Thus, the decision criterion for this kind of conservation is "sticky downward." It does not decrease, and it increases only when the cost-effectiveness standard passes the previous "high-water mark."

- The NW Power Act requires that the power plan assign a ten percent cost advantage to the acquisition of conservation. By using a criterion that accessed the supply curve as a level at least 10 percent higher than a market-based cost-effectiveness standard, the portfolio would accommodate this requirement.

- A long-standing Council objective has been to understand what value there may be in sustained, orderly development of conservation. Is there any advantage to this policy over the sustained, orderly development of any other resource? Is there any cost or risk advantage to developing more conservation than a conventional cost-effectiveness standard would suggest?

These considerations drove the design of the decision criteria for conservation. The decision criterion takes the form of a price. This price and a supply curve determine how much conservation to develop in a given period. Both lost-opportunity and discretionary conservation[30] criteria are the sum of two terms. The first term approximates the cost-effectiveness standard. This is a "myopic" estimate of cost effectiveness, which depends on the specific future and changes over time in that future. The second term determines how much additional conservation to deploy compared to the cost-effectiveness level. This second term, a price adjustment, is under the control of the logic that helps the portfolio model find the least-cost plan, given a fixed level of risk.

[30] The description of these classes of conservation appears in Chapter 3

Lost Opportunity Conservation

Lost opportunity conservation modeling uses the supply curve UDF described in the section “Conservation,” beginning on page L-44. In the column {AQ}, the model accesses the lost-opportunity conservation supply curve using the price {AP$233+$R$375}. (See Figure L-68.) The first term represents the cost-effectiveness standard. The second term, {$R$375}, merely points to a cell which, in turn, references a Crystal Ball decision cell. The optimizer can change the value in the decision cell to specify the plan. Our focus here will be the cost-effectiveness measure in cell {AP$233}.

Note that the formula in cell {AQ377} also accesses the response to load factor in cell {AP240}. This is not part of the decision criterion. This appendix addresses the response to load factor in section “New Resources,” beginning on page L-99.

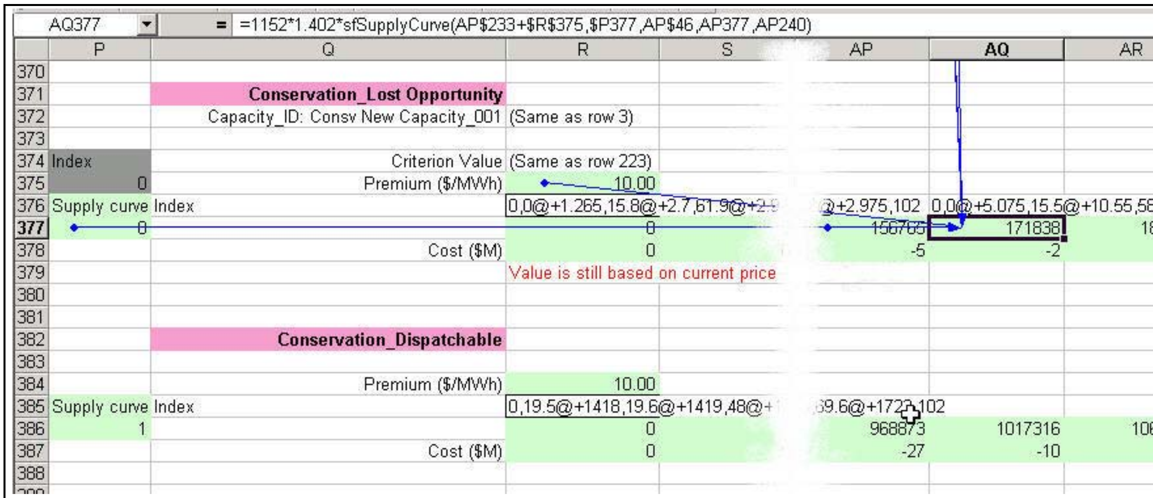


Figure L-68: Criterion References for Conservation

The formula in cell {AP$233} clearly does nothing more than find the highest value in the preceding row since the beginning of the study:

=MAX($Q$232:AO232)

This facilitates the “sticky downward” behavior. The value of the decision criterion will always be the highest value the preceding row achieves. As explained above, this represents such things as market transformation and the implementation of codes and standards.

Columns in the preceding row uses a fairly complicated formula. For example in column {AO}, the formula is

=MAX(0,20-AN46)*$Q$232/20+MIN(20,AN46)*
AVERAGE(OFFSET($Q$230,0,MAX(0,AN46-19),1,MIN(AN46+1,20)))/20

(Column {AO} is the last column referenced by cell {AP$233}.) This formula computes a five-year (20 period) average of the electricity price values in row {230}. The electricity price values in row {230} are weighted by the amount of conservation on- and off-peak. We will return to them shortly.

The reason for the complexity of the formula is that a single cell is providing an estimate of electricity prices in the past. For many prices and other stochastic variables, the worksheet contains explicit values for the time before the beginning of the study wherever necessary. For such a long reach into the past, however, a different approach was necessary. This formula uses the average of electricity prices over the past 20 periods, unless the beginning of the averaging interval is less than 20 periods in the past. In the latter case, it uses the value in cell {$Q$232} to form a weighted average, giving the value in {$Q$232} to as many periods as precede the beginning of the study.

The electricity price values in row {230} are of the form

=AP$207*1.402*4/7 + AP$219*0.465*3/7

This weighs the on-peak electricity price west of the Cascades by the expected on-peak conservation savings (1.402) and the fraction (4/7) of hours on peak during a standard quarter. The second term is the off-peak contribution, calculated in an identical fashion. Much of the load and conservation potential lies west of the Cascades.

Conservation typically does not have equal effect on peak and off peak or from month to month. As explained in the subsection "Supply Curves" of the section "Resource Implementation and Data," below, the seasonal variation has been flattened, although the on- and off-peak effect has not. The calculation of the weighting factor 1.402 appears in that section.

Discretionary Conservation

Returning to Figure L-68 and the worksheet, the user finds a near-identical supply curve formula for discretionary conservation in cell {AQ386}. As in the lost-opportunity case, the supply curve access price is the sum of two values, the cost-effectiveness standard and value that references a Crystal Ball decision cell, which is under the control of the optimizer.

The cost-effectiveness calculation is different from that for lost opportunity. In cell {AP235}, which cell {AQ386} references, we find

=AVERAGE(AH230:AK230)

Because discretionary conservation is available for implementation at any time, codes and standards are not necessary to capture it. Utilities can wait until prices and the cost-effective standards increase before taking action. This formula averages the conservation-weighted electricity price from not the immediate past year, but the *preceding* year, to obtain the cost-effectiveness level. The reason for looking back two years is to reflect budgeting delays. That is, utilities usually set a budget earlier in the year for the following year and follow that schedule the following year. When they prepare that budget, however, they would be looking back over the preceding year.

DSIs and Smelters

As with thermal plants, the model uses prices for aluminum and electricity over the preceding 18 months as a surrogate for forward prices. These inform the decision to shutdown or start up each of the seven smelters in the region. (See section "DSIs" for a description of the algorithm for smelter operation.)

The UDF for smelter capacity in cell {AQ327} references the 18-month average of flat electricity prices in row {227} and the 18 month average of aluminum prices in row {270}. These averages are straight forward. The model of electricity prices and aluminum prices appears in Appendix P.

This section addressed decision criteria. It reviewed some of the experiences that led to the final selection of decision criteria for new resources, and it explained the calculation of resource-load balance and market viability of resources. It also explained the thinking behind, and formulas that implement, decision criteria for conservation and smelters.

With an understanding in principle of how various ranges in the worksheet function, this appendix now turns to the detailed representation of plants and conservation, including the model's data.

Resource Implementation and Data

This section begins with the procedure by which existing regional resources are aggregated into the thirty plants in the regional model. It dedicates extra sections to the treatment of the region's independent power producers and system benefit charge (SBC) wind. It then addresses the candidate new resources, such as the generic CCCT, coal, and wind plants used for capacity expansion. Because forced outages are really an aspect of the future, detailed description of their modeling appears in Appendix P, although the key descriptive statistic, the effective forced outage rate (EFOR), appears in this appendix. Conservation is a candidate for meeting new requirements, and there is a section on data for the conservation supply curves and on conservation energy weighting assumptions. The section concludes with documentation for the contract data used in the model.

Existing Resources

The portfolio model consolidates regional resources into surrogates with identical technology and similar operating characteristics. Besides simplifying the worksheet, this reduces the computation time.[31] Each surrogate has regional plants of identical fuel type

[31] Each UDF call requires approximately 300 microseconds. This execution cost appears to be largely independent of the amount of VBA code behind the UDF. The execution cost is associated primarily with Excel's handling of the function call. Each plant in the regional model occupies 80 periods and two subperiods. This results in 48 milliseconds per plant or about 21 plants per second. This computational burden does not include the calls to other UDF's, such as those for planning flexibility or smelter operation. If a worksheet requires one second to compute, a thousand plans under 750 futures -- a typical requirement for the construction of a feasibility space -- would require approximately 8.7 days of computation time. Although the regional model wound up with about 30 surrogate plants, distributed processing across 10 machines reduced computation time to one day. Although modeling each of the 115 plants individually is feasible in principle, it would have increased these runtimes fourfold with questionable benefit.

and technology (CCCT, SCCT, etc.). Surrogates also represent plants of similar variable operating cost, which plant heat rate largely determines. Surrogates have a heat rate equivalent to the capacity-weighted heat rate of their constituents.

Monthly availabilities for the surrogate are the sum of the regional plants' monthly availabilities. The monthly availability of existing regional power plants appears in Figure L-69 and Figure L-70 [**7**]. Genesys simulations generate the monthly availabilities [**8**]. The simulations rely on the database that the Council uses to populate its Aurora model. These availabilities reflect maintenance outages but not forced outages. The reference for forced outage data is [**9**]. The model captures forced outages through a stochastic variable or explicit capacity de-ration. (See Appendix P and below.)

The characteristics of the surrogate plants appear in Figure L-71[**10**]. The quarterly availabilities are averages of the corresponding monthly availabilities. Forced outage rates reflect forced outage rates of the constituent plants. For some of these plants, the model uses capacity duration to reflect forced outages. The policy for determining whether to use stochastic forced outages or capacity de-ration is that larger existing plants use stochastic forced outages. Smaller existing plants contributed little risk. Modeling stochastic forced outages for new plants represented a challenge not attended to by the regional model. In particular, the reliability of an ensemble of plants is better than that of a single plant. As the model added capacity, either the forced outage rate characteristics of the ensemble would have to improve, or the model would have to provide each cohort with its own stochastic forced outage schedule. Both of these approaches presented a considerable programming challenge for questionable benefit. This version of the regional model, therefore, takes the more simplistic approach.

In the workbook, the first on-peak resource listed is a surrogate resource, "PNW West NG 5_006." (The meta-model Olivia generated these names, and the "006" has no particular significance. See section "Olivia" below for information about this model.) In Figure L-72, auditing reveals the references for cell {AQ 339}. This cell contains the UDF for computing energy for a thermal resource. (See section "Thermal Generation.") Above, this appendix has described most of the references. The following, however, are noteworthy. First, the UDF is referencing the stochastic forced outage rate in cell {AQ 336}. The model uses this forced outage rate to modify the assumed availability of the plant. Second, the seasonal availabilities for this surrogate plant are evident in row 335, columns R through U. The formula cycles among these four availabilities. The cycling assures proper representation of seasonal variation and differences due to maintenance.

The regional model represents other thermal surrogate resources similarly. Must-run resources are an exception. The energy and value for the must-run units are simple to calculate because energy is uncorrelated with market price. The value is simply the market price of electricity times the energy. In addition, because must-run resources include system benefit charge (SBC) wind generation, and the wind capacity increases over time, the capability references do not cycle as with thermal resources. Instead, the UDF references typically point to the capability in the same period. SBC wind is the subject of the next section.

Unit Name	Alternative name/description	Aggr_Unit	Sep (MW)	Oct (MW)	Nov (MW)	Dec (MW)	Jan (MW)	Feb (MW)	Mar (MW)	Apr (MW)	May (MW)	Jun (MW)	Jul (MW)	Aug (MW)
Bailey (Clatskanie GT)	Alden Bailey	PNW West NG 7	10	11	11	11	11	11	10	9	9	9	10	10
Beaver 1-7	Beaver	PNW West NG 5	475	487	498	504	505	500	435	370	364	359	469	468
Beaver 8	Beaver 8	PNW West NG 6	23	23	24	24	24	24	22	20	19	19	22	22
Big Hanaford	Big Hanaford	PNW West NG 3	233	239	245	248	248	246	214	182	179	176	230	230
Biomass-One 1	Biomass One	Must Run	23	23	23	23	23	23	23	23	23	23	23	23
Boardman 1	Boardman	Boardman 1	556	556	556	556	556	556	467	379	379	379	556	556
Boise Cascade Medfor	Boise Cascade Medfor	PNW West NG 1	8	8	8	8	8	8	8	8	8	8	8	8
Boulder Park	Boulder Park	PNW East NG 6	24	24	24	24	24	24	24	24	24	24	24	24
Boundary GT	(emergency)	PNW Oil												
BP (Cherry Point) GTs	BP Cherry Point GTs	PNW West NG 7	69	70	72	73	73	72	66	59	59	58	68	68
Centralia 1	Centralia 1	Centralia	670	670	670	670	670	670	563	456	456	456	670	670
Centralia 2	Centralia 2	Centralia	670	670	670	670	670	670	563	456	456	456	670	670
Chehalis Generation Facility	Chehalis Generating	PNW West NG 3	489	501	513	519	520	515	448	381	375	369	483	482
Coffin Butte 1	Coffin Butte	Waste Burner	2	2	2	2	2	2	2	2	2	2	2	2
Colstrip 1	Colstrip 1	Colstrip 1&2	307	307	307	307	307	307	258	209	209	209	307	307
Colstrip 2	Colstrip 2	Colstrip 1&2	307	307	307	307	307	307	258	209	209	209	307	307
Colstrip 3	Colstrip 3	Colstrip 3&4	740	740	740	740	740	740	622	504	504	504	740	740
Colstrip 4	Colstrip 4	Colstrip 3&4	740	740	740	740	740	740	622	504	504	504	740	740
Columbia Generating Station	Columbia Generating	Must Run	1170	1170	1170	1170	1170	1170	944	720	720	720	1170	1170
Combine Hills I	Combine Hills I	Must Run	12	11	17	22	24	32	7	10	8	7	7	11
Condon Wind Project Phase I	Condon 2001	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
Condon Wind Project Phase II	Condon 2002	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
Corrette	J.E. Corrette	Corrette	160	160	160	160	160	160	134	109	109	109	160	160
Coyote Springs 1	Coyote Springs 1	PNW East NG 3	208	215	221	226	226	223	192	163	159	156	202	203
Coyote Springs 2	Coyote Springs 2	PNW East NG 3	258	267	274	280	280	276	238	202	197	193	251	252
Crystal Mountain 1 &	Crystal Mountain 1 &	PNW West NG 6	3	3	3	3	3	3	3	3	3	3	3	3
D R Johnson Lumber (Riddle, Coge	Cogen II	Must Run	7	7	7	7	7	7	7	7	7	7	7	7
Danskin	Danskin (Evander And	PNW So ID NG 2	83	86	88	90	90	89	77	65	63	62	81	81
Eastsound 4 & 5	Eastsound 4 & 5	PNW West NG 6	1	1	1	1	1	1	1	1	1	1	1	1
Encogen 1	Encogen 1-3	Encogen 1	151	154	158	160	160	159	138	117	115	114	149	148
Equilon GTs	Equilon GTs	PNW West NG 7	37	38	38	39	39	39	35	32	31	31	36	36
Everett Cogen 1	Everett Cogen	Must Run	24	24	24	24	24	24	24	24	24	24	24	24
Finley	Finley	PNW East NG 6	25	26	26	27	27	27	24	22	21	21	24	24
Foote Creek	Foote Creek	Must Run	17	15	25	31	34	45	11	14	12	10	10	15
Frederickson 1	Frederickson (PSE)	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
Frederickson 2	Frederickson (PSE)	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
Frederickson Power 1	Frederickson Power (	PNW West NG 1	259	265	271	275	275	273	237	202	198	195	255	255
Fredonia 1	Fredonia 1	PNW West NG 6	117	120	122	124	124	123	107	91	89	88	115	115
Fredonia 2	Fredonia 2	PNW West NG 6	117	120	122	124	124	123	107	91	89	88	115	115
Fredonia 3	Fredonia 3	PNW West NG 6	57	59	60	61	61	60	55	50	49	48	57	57
Fredonia 4	Fredonia 4	PNW West NG 6	57	59	60	61	61	60	55	50	49	48	57	57
Frontier Energy	(no match)	Waste Burner												
Georgia Pacific (Camas)	Georgia-Pacific (Cam	Must Run	47	47	47	47	47	47	47	47	47	47	47	47
Georgia Pacific (Wauna)	Georgia-Pacific (Wau	Must Run	24	24	24	24	24	24	24	24	24	24	24	24
Georgia-Pacific (Bellingham) GTs	Georgia-Pacific (Bel	PNW West NG 7	9	10	10	10	10	10	9	8	8	8	9	9
Glenns Ferry Cogeneration	Glenns Ferry Cogener	PNW East NG 3	8	9	9	9	9	9	8	7	7	7	8	8
Goldendale Energy Ce	Goldendale Energy Ce	PNW East NG 2	229	236	243	248	248	245	211	179	174	171	222	223
Grays Harbor ICs	Hoquiam 1 - 5	PNW Oil	10	10	10	10	10	10	10	10	10	10	10	10
Hermiston Generating 1	Hermiston Gen 1	PNW East NG 2	218	225	231	236	236	233	201	170	166	163	211	212
Hermiston Generating 2	Hermiston Gen 2	PNW East NG 2	218	225	231	236	236	233	201	170	166	163	211	212
Hermiston Power Project	Hermiston Power	PNW East NG 1	581	600	617	629	630	621	536	454	443	435	564	566
ICT PP&L/Utah&Wyo to	ICT PP&L/Utah&Wyo to	Valmy	184	160	168	154	187	187	178	171	189	265	296	253
Jim Bridger 1	Jim Bridger 1	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
Jim Bridger 2	Jim Bridger 2	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
Jim Bridger 3	Jim Bridger 3	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
Jim Bridger 4	Jim Bridger 4	Bridger	173	173	173	173	173	173	145	118	118	118	173	173
Kettle Falls GT	Kettle Falls GT	PNW East NG 3	6	7	7	7	7	7	6	6	5	5	6	6
Kettle Falls ST	Kettle Falls	Must Run	45	45	45	45	45	45	45	45	45	45	45	45
Klamath Cogen Project	Klamath Cogeneration	PNW East NG 1	443	457	470	480	480	473	408	346	337	331	430	432
Klamath Expansion (GTs)	(no match)	PNW East NG 3												
Klondike	Klondike	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
Libby 1 Champion	(retired)	Must Run												
Libby 2 Champion	(retired)	Must Run												
March Point 1&2	March Point	PNW West NG 3	132	135	138	140	140	139	121	103	101	99	130	130
Mariah	Mariah	Must Run	0	0	0	0	0	0	0	0	0	0	0	0
Marion Solid Waste 1	Covanta Marion	Waste Burner	9	9	9	9	9	9	9	9	9	9	9	9
MEAD	MEAD	PNW West NG 6	1	1	1	1	1	1	1	1	1	1	1	1
Morrow Power	Morrow Power	PNW East NG 6	23	24	25	25	25	25	21	18	18	17	22	22
Mountain View	Mountain View	PNW East NG 6	148	152	157	160	160	158	136	115	112	110	143	144
Nine Canyon	Nine Canyon	Must Run	14	12	20	25	27	36	9	11	10	8	8	12
Nine Canyon	Nine Canyon Expansio	Must Run	4	4	6	8	9	12	3	4	3	3	3	4
North Side	North Side	PNW East NG 6	1	1	1	1	1	1	1	1	1	1	1	1
Northeast	Northeast 1 & 2	PNW East NG 6	62	64	66	67	67	66	57	48	47	46	60	60
Okanogan Co PUD ICs Ph 2	Okanogan Co. PUD ICs	PNW Oil	25	25	25	25	25	25	25	25	25	25	25	25
OR RPS/SBC Wind 03	OR RPS/SBC Wind 03	Must Run												
Pasco	Pasco	PNW So ID NG 2	40	41	42	43	43	42	38	34	34	33	39	39
Pine Products	(out of the mix)	Must Run												
Pocatello Waste 1	(lost)	Waste Burner												
Point Whitehorn 2	Point Whitehorn 2	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
Point Whitehorn 3	Point Whitehorn 3	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
Potlatch Corp 1-4	Potlatch Corp. 1-4	Must Run	53	53	53	53	53	53	53	53	53	53	53	53
Prairie Wood Products (Cogen 1)	Prairie Wood Product	Must Run	7	7	7	7	7	7	7	7	7	7	7	7
Randolph Road 1- 20	Randolph Road 1- 20	PNW East NG 6	31	31	31	31	31	31	31	31	31	31	31	31
Rathdrum 1 & 2	Rathdrum 1 & 2	PNW East NG 6	162	168	172	176	176	174	150	127	124	121	158	158
Rathdrum Power Project	Rathdrum Pwr Proj	PNW East NG 2	223	231	237	242	242	239	206	174	170	167	217	218
River Road 1	River Road	PNW West NG 1	233	239	245	248	248	246	214	182	179	176	230	230
Rock River	Rock River	Must Run	17	15	25	31	34	45	11	14	12	10	10	15
Roosevelt Landfill	Hill	Must Run	9	9	9	9	9	9	9	9	9	9	9	9
Rupert Cogeneration	Rupert Cogeneration	PNW So ID NG 2	8	9	9	9	9	9	8	7	7	7	8	8
Salmon 1 & 2	Salmon 1 & 2	PNW East NG 6	6	6	6	6	6	6	6	6	6	6	6	6
SDS Lumber ST	(unavailable)	Must Run												
Short Mountain	Short Mountain	Waste Burner	3	3	3	3	3	3	3	3	3	3	3	3
Simplot Cogen 1	Simplot Pocatello	PNW East NG 3	8	8	8	8	8	8	8	8	8	8	8	8
Skagit Co Waste 1	(retired)	Waste Burner												
SP Newsprint (Newberg)	SP Newsprint GT	PNW West NG 3	86	88	90	91	91	90	82	74	73	72	85	84
Spokane MSW 1	Spokane MSW	Waste Burner	21	21	21	21	21	21	21	21	21	21	21	21
Springfield ICs Phase II	Springfield Ph II	PNW West NG 6	10	10	10	10	10	10	10	10	10	10	10	10
Stateline	Stateline	Must Run	156	141	227	286	310	415	98	129	111	93	91	141
Steam Plant No 2 1	(retired)	Waste Burner												
Steam Plant No 2 2	(retired)	Must Run												
Sumas Energy 1	Sumas Energy	PNW West NG 3	116	119	121	123	123	122	106	90	89	87	114	114
Tacoma Landfill	Tacoma Landfill	PNW West NG 6	2	2	2	2	2	2	2	2	2	2	2	2
Tenaska 1	Tenaska Washington I	PNW West NG 3	231	236	242	245	245	243	211	180	177	174	228	227
Vaagen Bros 1	Vaagen Bros Lumber	Must Run	4	4	4	4	4	4	4	4	4	4	4	4
Valmy 1	Valmy 1	Valmy	127	127	127	127	127	127	107	86	86	86	127	127
Valmy 2	Valmy 2	Valmy	134	134	134	134	134	134	113	91	91	91	134	134
Vansycle Ridge	Vansycle	Must Run	6	5	9	11	12	16	4	5	4	4	3	5
Wah Chang	(unavailable)	PNW West NG 1												
Warm Spgs Forest Products	Warm Springs Forest	Must Run	5	5	5	5	5	5	5	5	5	5	5	5
West Boise Waste 1	(lost)	Must Run												
West Point Treatment Plant 3	West Point	Must Run	1	1	1	1	1	1	1	1	1	1	1	1
Weyco Energy CTR 1	Weyerhaeuser Springf	Waste Burner	18	18	18	18	18	18	18	18	18	18	18	18
Whatcom MSW	Whatcom MSW	Waste Burner	2	2	2	2	2	2	2	2	2	2	2	2
Willamette Industries (Albany) GT (	(unavailable)	PNW West NG 3												
Wood Plants 2	Evergreen Forest Pro	Must Run	5	5	5	5	5	5	5	5	5	5	5	5

Figure L-69: Existing Resources, Sorted by Name

Fuel	Heat Rate BTU/kWh	VOM 2004$/MWh	Unit Name	Alternative name/description	Aggr_Unit	Sep (MW)	Oct (MW)	Nov (MW)	Dec (MW)	Jan (MW)	Feb (MW)	Mar (MW)	Apr (MW)	May (MW)	Jun (MW)	Jul (MW)	Aug (MW)
##55	10836	1.83	Boardman 1	Boardman	Boardman 1	556	556	556	556	556	556	467	379	379	379	556	556
	9990	1.40	Jim Bridger 1	Jim Bridger 1	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
	9990	1.40	Jim Bridger 2	Jim Bridger 2	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
	9990	1.40	Jim Bridger 3	Jim Bridger 3	Bridger	177	177	177	177	177	177	149	121	121	121	177	177
	9990	1.40	Jim Bridger 4	Jim Bridger 4	Bridger	173	173	173	173	173	173	145	118	118	118	173	173
##53	10240	1.83	Centralia 1	Centralia 1	Centralia	670	670	670	670	670	670	563	456	456	456	670	670
##53	10240	1.83	Centralia 2	Centralia 2	Centralia	670	670	670	670	670	670	563	456	456	456	670	670
	11170	1.30	Colstrip 1	Colstrip 1	Colstrip 1&2	307	307	307	307	307	307	258	209	209	209	307	307
	11170	1.30	Colstrip 2	Colstrip 2	Colstrip 1&2	307	307	307	307	307	307	258	209	209	209	307	307
	10650	1.83	Colstrip 3	Colstrip 3	Colstrip 3&4	740	740	740	740	740	740	622	504	504	504	740	740
	10650	1.83	Colstrip 4	Colstrip 4	Colstrip 3&4	740	740	740	740	740	740	622	504	504	504	740	740
	11010	1.83	Corrette	J.E. Corrette	Corrette	160	160	160	160	160	160	134	109	109	109	160	160
#112	5000	3.02	Encogen 1	Encogen 1-3	Encogen 1	151	154	158	160	160	159	138	117	115	114	149	148
###7	8000	2.15	Biomass-One 1	Biomass One	Must Run	23	23	23	23	23	23	23	23	23	23	23	23
###5	10064	2.15	Columbia Generating Station	Columbia Generating	Must Run	1170	1170	1170	1170	1170	1170	944	720	720	720	1170	1170
			Combine Hills I	Combine Hills I	Must Run	12	11	17	22	24	32	7	10	8	7	7	11
##30	0	1.40	Condon Wind Project Phase I	Condon 2001	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
##30	0	1.40	Condon Wind Project Phase II	Condon 2002	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
###7	8000	2.15	D R Johnson Lumber (Riddle, Coge	Cogen II	Must Run	7	7	7	7	7	7	7	7	7	7	7	7
###7	5000	2.15	Everett Cogen 1	Everett Cogen	Must Run	24	24	24	24	24	24	24	24	24	24	24	24
			Foote Creek	Foote Creek	Must Run	17	15	25	31	34	45	11	14	12	10	10	15
###7	5000	2.15	Georgia Pacific (Camas)	Georgia-Pacific (Cam	Must Run	47	47	47	47	47	47	47	47	47	47	47	47
###7	5000	2.15	Georgia Pacific (Wauna)	Georgia-Pacific (Wau	Must Run	24	24	24	24	24	24	24	24	24	24	24	24
###7	14380	2.15	Kettle Falls ST	Kettle Falls	Must Run	45	45	45	45	45	45	45	45	45	45	45	45
##30	0	1.40	Klondike	Klondike	Must Run	7	6	10	12	14	18	4	6	5	4	4	6
###7	12380	2.15	Libby 1 Champion	(retired)	Must Run												
###7	15476	2.15	Libby 2 Champion	(retired)	Must Run												
			Mariah	Mariah	Must Run	0	0	0	0	0	0	0	0	0	0	0	0
##30	0	1.40	Nine Canyon	Nine Canyon	Must Run	14	12	20	25	27	36	9	11	10	8	8	12
##30	0	1.40	Nine Canyon	Nine Canyon Expansio	Must Run	4	4	6	8	9	12	3	4	3	3	3	4
##30	0	1.40	OR RPS/SBC Wind 03	OR RPS/SBC Wind 03	Must Run												
###7	17000	2.15	Pine Products	(out of the mix)	Must Run												
###7	8000	2.15	Potlatch Corp 1-4	Potlatch Corp. 1-4	Must Run	53	53	53	53	53	53	53	53	53	53	53	53
###7	5000	2.15	Prairie Wood Products (Cogen 1)	Prairie Wood Product	Must Run	7	7	7	7	7	7	7	7	7	7	7	7
			Rock River	Rock River	Must Run	17	15	25	31	34	45	11	14	12	10	10	15
###7	10000	2.15	Roosevelt Landfill	Hill	Must Run	9	9	9	9	9	9	9	9	9	9	9	9
###7	6000	2.15	SDS Lumber ST	(unavailable)	Must Run												
##30	0	1.40	Stateline	Stateline	Must Run	156	141	227	286	310	415	98	129	111	93	91	141
###7	14000	2.15	Steam Plant No 2 2	(retired)	Must Run												
###7	8000	2.15	Vaagen Bros 1	Vaagen Bros Lumber	Must Run	4	4	4	4	4	4	4	4	4	4	4	4
##30	0	1.40	Vansycle Ridge	Vansycle	Must Run	6	5	9	11	12	16	4	5	4	4	3	5
			Warm Spgs Forest Products	Warm Springs Forest	Must Run	5	5	5	5	5	5	5	5	5	5	5	5
###7	8000	2.15	West Boise Waste 1	(lost)	Must Run												
###7	8000	2.15	West Point Treatment Plant 3	West Point	Must Run	1	1	1	1	1	1	1	1	1	1	1	1
###7	8000	2.15	Wood Plants 2	Evergreen Forest Pro	Must Run	5	5	5	5	5	5	5	5	5	5	5	5
#114	6700	3.02	Hermiston Power Project	Hermiston Power	PNW East NG 1	581	600	617	629	630	621	536	454	443	435	564	566
#114	6800	3.02	Klamath Cogen Project	Klamath Cogeneration	PNW East NG 1	443	457	470	480	480	473	408	346	337	331	430	432
			Goldendale Energy Ce	Goldendale Energy Ce	PNW East NG 2	229	236	243	248	248	245	211	179	174	171	222	223
#114	7050	3.02	Hermiston Generating 1	Hermiston Gen 1	PNW East NG 2	218	225	231	236	236	233	201	170	166	163	211	212
#114	7050	3.02	Hermiston Generating 2	Hermiston Gen 2	PNW East NG 2	218	225	231	236	236	233	201	170	166	163	211	212
#114	7000	3.02	Rathdrum Power Project	Rathdrum Pwr Proj	PNW East NG 2	223	231	237	242	242	239	206	174	170	167	217	218
#114	7050	3.02	Coyote Springs 1	Coyote Springs 1	PNW East NG 3	208	215	221	226	226	223	192	163	159	156	202	203
#114	6950	3.02	Coyote Springs 2	Coyote Springs 2	PNW East NG 3	258	267	274	280	280	276	238	202	197	193	251	252
#120	8000	3.02	Glenns Ferry Cogeneration	Glenns Ferry Cogener	PNW East NG 3	8	9	9	9	9	9	8	7	7	7	8	8
#114	9500	8.62	Kettle Falls GT	Kettle Falls GT	PNW East NG 3	6	7	7	7	7	7	6	6	5	5	6	6
#114	8700	8.62	Klamath Expansion (GTs)	(no match)	PNW East NG 3												
#120	5000	3.45	Simplot Cogen 1	Simplot Pocatello	PNW East NG 3	8	8	8	8	8	8	8	8	8	8	8	8
#114	11600		Boulder Park	Boulder Park	PNW East NG 6	24	24	24	24	24	24	24	24	24	24	24	24
#114	10700		Finley	Finley	PNW East NG 6	25	26	26	27	27	27	24	22	21	21	24	24
#114	11500		Morrow Power	Morrow Power	PNW East NG 6	23	24	25	25	25	25	21	18	18	17	22	22
			Mountain View	Mountain View	PNW East NG 6	148	152	157	160	160	158	136	115	112	110	143	144
			North Side	North Side	PNW East NG 6	1	1	1	1	1	1	1	1	1	1	1	1
#114	10750		Northeast	Northeast 1 & 2	PNW East NG 6	62	64	66	67	67	66	57	48	47	46	60	60
			Randolph Road 1- 20	Randolph Road 1- 20	PNW East NG 6	31	31	31	31	31	31	31	31	31	31	31	31
			Rathdrum 1 & 2	Rathdrum 1 & 2	PNW East NG 6	162	168	172	176	176	174	150	127	124	121	158	158
			Salmon 1 & 2	Salmon 1 & 2	PNW East NG 6	6	6	6	6	6	6	6	6	6	6	6	6
##84	13000		Boundary GT	(emergency)	PNW Oil												
##84	11600		Grays Harbor ICs	Hoquiam 1 - 5	PNW Oil	10	10	10	10	10	10	10	10	10	10	10	10
##84	11600		Okanogan Co PUD ICs Ph 2	Okanogan Co. PUD ICs	PNW Oil	25	25	25	25	25	25	25	25	25	25	25	25
#120	12100		Danskin	Danskin (Evander And	PNW So ID NG 2	83	86	88	90	90	89	77	65	63	62	81	81
#114	11500		Pasco	Pasco	PNW So ID NG 2	40	41	42	43	43	42	38	34	34	33	39	39
#120	8000	3.02	Rupert Cogeneration	Rupert Cogeneration	PNW So ID NG 2	8	9	9	9	9	9	8	7	7	7	8	8
			Boise Cascade Medfor	Boise Cascade Medfor	PNW West NG 1	8	8	8	8	8	8	8	8	8	8	8	8
#112	7000	3.02	Frederickson Power 1	Frederickson Power (	PNW West NG 1	259	265	271	275	275	273	237	202	198	195	255	255
#112	7000	3.02	River Road 1	River Road	PNW West NG 1	233	239	245	248	248	246	214	182	179	176	230	230
#112	5800	3.45	Wah Chang	(unavailable)	PNW West NG 1												
#112	7200	3.02	Big Hanaford	Big Hanaford	PNW West NG 3	233	239	245	248	248	246	214	182	179	176	230	230
#112	7000	3.02	Chehalis Generation Facility	Chehalis Generating	PNW West NG 3	489	501	513	519	520	515	448	381	375	369	483	482
			March Point 1&2	March Point	PNW West NG 3	132	135	138	140	140	139	121	103	101	99	130	130
#112	5500	8.62	SP Newsprint (Newberg)	SP Newsprint GT	PNW West NG 3	86	88	90	91	91	90	82	74	73	72	85	84
#112	8000	3.02	Sumas Energy 1	Sumas Energy	PNW West NG 3	116	119	121	123	123	122	106	90	89	87	114	114
#112	7700	3.02	Tenaska 1	Tenaska Washington I	PNW West NG 3	231	236	242	245	245	243	211	180	177	174	228	227
#112	5500	8.62	Willamette Industries (Albany) GT (	(unavailable)	PNW West NG 3												
#112	9200	3.02	Beaver 1-7	Beaver	PNW West NG 5	475	487	498	504	505	500	435	370	364	359	469	468
#112	11500		Beaver 8	Beaver 8	PNW West NG 6	23	23	24	24	24	24	22	20	19	19	22	22
			Crystal Mountain 1 &	Crystal Mountain 1 &	PNW West NG 6	3	3	3	3	3	3	3	3	3	3	3	3
			Eastsound 4 & 5	Eastsound 4 & 5	PNW West NG 6	1	1	1	1	1	1	1	1	1	1	1	1
#112	10600		Frederickson 1	Frederickson (PSE)	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
#112	10600		Frederickson 2	Frederickson (PSE)	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
#112	10711		Fredonia 1	Fredonia 1	PNW West NG 6	117	120	122	124	124	123	107	91	89	88	115	115
#112	10711		Fredonia 2	Fredonia 2	PNW West NG 6	117	120	122	124	124	123	107	91	89	88	115	115
#112	10300		Fredonia 3	Fredonia 3	PNW West NG 6	57	59	60	61	61	60	55	50	49	48	57	57
#112	10300		Fredonia 4	Fredonia 4	PNW West NG 6	57	59	60	61	61	60	55	50	49	48	57	57
			MEAD	MEAD	PNW West NG 6	1	1	1	1	1	1	1	1	1	1	1	1
#112	10600		Point Whitehorn 2	Point Whitehorn 2	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
#112	10600		Point Whitehorn 3	Point Whitehorn 3	PNW West NG 6	84	86	88	89	89	88	77	65	64	63	83	83
#112	11600		Springfield ICs Phase II	Springfield Ph II	PNW West NG 6	10	10	10	10	10	10	10	10	10	10	10	10
			Tacoma Landfill	Tacoma Landfill	PNW West NG 6	2	2	2	2	2	2	2	2	2	2	2	2
#112	11500		Bailey (Clatskanie GT)	Alden Bailey	PNW West NG 7	10	11	11	11	11	11	10	9	9	9	10	10
#112	13000		BP (Cherry Point) GTs	BP Cherry Point GTs	PNW West NG 7	69	70	72	73	73	72	66	59	59	58	68	68
#112	13000		Equilon GTs	Equilon GTs	PNW West NG 7	37	38	38	39	39	39	35	32	31	31	36	36
#112	13000		Georgia-Pacific (Bellingham) GTs	Georgia-Pacific (Bel	PNW West NG 7	9	10	10	10	10	10	9	8	8	8	9	9
			ICT PP&L/Utah&Wyo to	ICT PP&L/Utah&Wyo to	Valmy	184	160	168	154	187	187	178	171	189	265	296	253
	10030	1.83	Valmy 1	Valmy 1	Valmy	127	127	127	127	127	127	107	86	86	86	127	127
	10030	1.83	Valmy 2	Valmy 2	Valmy	134	134	134	134	134	134	113	91	91	91	134	134
###6	8000	2.15	Coffin Butte 1	Coffin Butte	Waste Burner	2	2	2	2	2	2	2	2	2	2	2	2
###7	17000	2.15	Frontier Energy	(no match)	Waste Burner												
###6	8000	2.15	Marion Solid Waste 1	Covanta Marion	Waste Burner	9	9	9	9	9	9	9	9	9	9	9	9
###7	8000	2.15	Pocatello Waste 1	(lost)	Waste Burner												
			Short Mountain	Short Mountain	Waste Burner	3	3	3	3	3	3	3	3	3	3	3	3
###6	8000	2.15	Skagit Co Waste 1	(retired)	Waste Burner												
###6	8000	2.15	Spokane MSW 1	Spokane MSW	Waste Burner	21	21	21	21	21	21	21	21	21	21	21	21
###7	14000	2.15	Steam Plant No 2 1	(retired)	Waste Burner												
###6	12500	2.15	Weyco Energy CTR 1	Weyerhaeuser Springf	Waste Burner	18	18	18	18	18	18	18	18	18	18	18	18
			Whatcom MSW	Whatcom MSW	Waste Burner	2	2	2	2	2	2	2	2	2	2	2	2

Figure L-70: Existing Resources, Sorted by Aggregate Unit

Name	Heatrate	Fuel	FOR	FOR Stochastic	VOM	Sep-Nov	Dec-Feb	Mar-May	Jun-Aug
	kBTU/kWh	2004$/MWh			2004$/MWh	(MW)	(MW)	(MW)	(MW)
Boardman 1	10.836	$1.20/MMBTU	0.07	TRUE	1.83	556.0	556.0	408.3	497.0
Bridger	9.990	$0.89/MMBTU	0.07	TRUE	1.40	704.0	704.0	518.0	629.7
CCCT	7.270	PNW East NG_006	0.05	FALSE	3.11	610.0	610.0	610.0	610.0
Centralia	10.240	$1.82/MMBTU	0.07	TRUE	1.83	1340.0	1340.0	983.3	1197.3
Coal	9.550	$1.00/MMBTU	0.07	FALSE	1.94	400.0	400.0	400.0	400.0
Colstrip 1&2	11.170	$0.78/MMBTU	0.07	TRUE	1.30	614.0	614.0	450.7	548.7
Colstrip 3&4	10.650	$1.00/MMBTU	0.07	TRUE	1.83	1480.0	1480.0	1086.7	1322.7
Consv_LO	0.000	(none)	0.00	FALSE					
Consv_NLO	0.000	(none)	0.00	FALSE					
Contracts	0.000	(none)	0.00	FALSE					
Corrette	11.010	$1.00/MMBTU	0.07	FALSE	1.83	160.0	160.0	117.3	143.0
Encogen 1	5.005	Waste	0.07	FALSE	3.02	154.3	159.7	123.3	137.0
Hydro	0.000	(none)	0.00	FALSE					
Hydro Commercial	0.000	(none)	0.00	FALSE					
Must run	0.000	(none)	0.05	FALSE	0.00	1699.7	1956.3	1227.0	1444.7
PNW East NG 1	6.743	PNW East NG_006	0.05	TRUE	3.02	1056.0	1104.3	841.3	919.3
PNW East NG 2	7.032	PNW East NG_006	0.05	TRUE	3.02	915.7	958.0	729.3	796.7
PNW East NG 3	7.050	PNW East NG_006	0.07	FALSE	3.02	504.3	527.7	404.7	440.3
PNW East NG 6	10.603	PNW East NG_006	0.07	FALSE	3.02	495.3	515.3	408.7	438.7
PNW So ID NG 2	11.741	PNW So ID NG_004	0.00	FALSE	3.02	135.3	141.3	111.0	119.3
PNW West NG 1	6.968	PNW West NG A_006	0.07	FALSE	3.02	512.0	529.7	412.0	455.0
PNW West NG 3	7.337	PNW West NG A_006	0.05	TRUE	3.02	1318.0	1362.7	1062.0	1171.3
PNW West NG 5	9.200	PNW West NG A_006	0.05	TRUE	3.02	486.7	503.0	389.7	432.0
PNW West NG 6	10.637	PNW West NG A_006	0.05	TRUE	3.02	741.0	764.3	606.0	663.3
PNW West NG 7	12.879	PNW West NG A_006	0.07	FALSE	8.62	128.3	132.7	111.7	117.3
SCCT	9.810	PNW East NG_006	0.07	FALSE	8.65	100.0	100.0	100.0	100.0
Valmy	10.030	$1.00/MMBTU	0.07	FALSE	1.83	431.7	437.0	370.7	504.3
Waste Burner	4.000	Waste	0.10	TRUE		55.0	55.0	55.0	55.0
Wind	0.000	(none)	0.70	FALSE	1.06	100.0	100.0	100.0	100.0
Wind - MT	0.000	(none)	0.64	FALSE	1.06	100.0	100.0	100.0	100.0

Figure L-71: Surrogate Plant Characteristics

Figure L-72: Thermal Resource UDF References

System Benefit Charge Wind

Senate bill 1149, the state of Oregon's 1999 electric power restructuring legislation, established a "system benefit charge" which funds conservation and renewable development. Other states have looked at establishing similar reserves. Those responsible for renewables development have identified a preliminary system benefit charge (SBC) wind development schedule for the next 10 years. The regional model does not find that wind technology will be cost effective until the next decade, but SBC wind is included in the regional models baseline set of resources in the "must run" surrogate. SBC wind is one of very few future resources included in the baseline. It is included in part because it appears certain the region is proceeding with the development of this wind. It is included in part because the Council recognizes the importance of developing experience with this resource before it becomes a major resource for the region. The recommended plan relies heavily on commercially competitive wind generation after 2010.

The amount of SBC wind in the regional model's baseline appears in Figure L-73 [**11**]. Although the table extends only through 2014, these availabilities extend indefinitely in the regional model. Apart from the capacity duration forced outage rate assigned to the must run surrogate plant in the regional model, the model does not reflect the potentially complex forced outage nature of this resource.

Wind MWa	1st Mo			
Hydro Year	sep	dec	mar	jun
2004		17.5	20.3	19.7
2005	15.3	31.9	45.2	43.9
2006	34.0	53.9	71.0	68.9
2007	53.4	76.9	98.1	95.2
2008	73.8	101.8	128.0	124.1
2009	96.3	130.8	163.4	158.5
2010	122.9	167.6	209.7	203.4
2011	157.7	216.3	271.2	263.1
2012	204.0	284.7	359.3	348.5
2013	270.2	309.9	359.3	348.5
2014	270.2	309.9	359.3	348.5

Figure L-73: SBC Capability, by Hydro Year

Independent Power Producers

The PNUCC Northwest Regional Forecast identifies approximately 3200 average megawatts of IPP generation (3500 MW capacity) that is not under contract to Northwest load. Most of the generation is in the form of gas-fired combined cycle combustion turbines located in Washington and Oregon, much of that west of the Cascades. The 1300 MW Centralia coal-fired power plant located in western Washington is also part of that sum. The Council also surveyed the independent power producers of the region through the Northwest Independent Power Producers Coalition (NIPPC). NIPPC identify 3600 MW (capacity) in Oregon and Washington. Of that, approximately 1400 MW (capacity) is under contract through 2005, 950 MW is under contract through 2008, and 4300 MW is under contract beyond 2008. NIPPC noted, "... Virtually all IPP capacity is, as a result of transmission constraints and by design, committed exclusively to the Northwest."

The Council regards the IPP contribution to the wholesale electricity market significant, both in terms of power and of price stability. The Council chose to model the availability of this IPP generation in the market explicitly. Indeed, the Council considered the alternative of modeling ownership purchase or long-term contracts with IPP generators. They discarded this approach, however, because the region has no way of knowing what contract terms parties might eventually enter into through bilateral purchase or contract negotiation.

Although the energy from IPP generation contributes to the region's energy balance, and therefore affects price through the RRP algorithm, the value of these resources does not offset market purchases. Specifically, the energy is included in the system energy requirement calculation in cell {AQ676} of the sample workbook. When the surrogate plant is valued in the market, however, that portion of the surrogate's value associated with IPP generation does not contribute. A more concrete example of this follows.

Figure L-74 identifies regional IPP ownership [**12**]. The first column identifies the percentage of each plant under contract to meet regional load. The second column identifies to which surrogate plant each IPP unit is aggregated. To determine what fraction of the surrogate plant's capacity and value contribute to the region's portfolio, the seasonal availabilities are multiplied by the contract percentages and summed by surrogate plant. The original surrogate availabilities appear in Figure L-75. These availabilities contribute to the resource-load energy balance of the region. The seasonal availabilities meeting regional load appear in Figure L-76. These determine the amount of economic value the region gets. The fraction of each surrogate unit that contributes value to the region appears in the column on the right hand side of Figure L-76.

Contracted	Aggr_Unit	Unit Name	FoundinFazio	Location	Fall	Winter	Spring	Summer
0%	Centralia 2	Centralia 2	Centralia 2	PNW West	670	670	492	599
0%	Centralia 1	Centralia 1	Centralia 1	PNW West	670	670	492	599
0%	PNW East NG 1	Hermiston Power Project	Hermiston Pow	PNW East	599	627	478	522
21%	PNW East NG 1	Klamath Cogen Project	Klamath Coger		457	478	364	398
100%	PNW West NG 1	Frederickson Power 1	Frederickson F		265	274	212	235
0%	PNW East NG 2	Goldendale Energy Ce	Goldendale Energy Ce		236	247	188	205
100%	PNW East NG 2	Hermiston Generating 1	Hermiston Ger	PNW East	225	235	179	195
100%	PNW East NG 2	Hermiston Generating 2	Hermiston Ger	PNW East	225	235	179	195
0%	PNW East NG 2	Rathdrum Power Project	Rathdrum Pwr	PNW East	230	241	183	201
0%	PNW West NG 3	Chehalis Generation Faci	Chehalis Gene		501	518	401	445
0%	PNW West NG 3	Big Hanaford	Big Hanaford	PNW West	239	247	192	212
100%	PNW West NG 3	March Point 1	March Point	PNW West	135	140	108	120
100%	PNW West NG 3	Sumas Energy 1	Sumas Energy	PNW West	119	123	95	105
100%	PNW West NG 3	Tenaska 1	Tenaska Wash	PNW West	236	244	189	210
100%	PNW East NG 3	Coyote Springs 2	Coyote Springs	PNW East	266	279	212	232
0%	PNW East NG 3	Klamath Expansion (GTs	(no match)		0	0	0	0
0%	PNW East NG 6	Morrow Power	Morrow Power	PNW East	24	25	19	20

Figure L-74: IPP Capabilities

Orginal

	Fall	Winter	Spring	Summer	Average
Centralia	1340.0	1340.0	983.3	1197.3	1215
PNW East NG 1	1056.0	1104.3	841.3	919.3	980
PNW West NG 1	512.0	529.7	412.0	455.0	477
PNW East NG 2	915.7	958.0	729.3	796.7	850
PNW West NG 3	1318.0	1362.7	1062.0	1171.3	1229
PNW East NG 6	741.0	764.3	606.0	663.3	694
	5883	6059	4634	5203	5445

Figure L-75: Surrogate Capabilities, including IPPs

Final

	Fall	Winter	Spring	Summer	Average	Amt of Value to use
Centralia	0.0	0.0	0.0	0.0	0	0%
PNW East NG 1	96	100	76	84	89	9%
PNW West NG 1	512.0	529.7	412.0	455.0	477	100%
PNW East NG 2	449	470	358	391	417	49%
PNW West NG 3	578.0	597.3	469.0	514.7	540	44%
PNW East NG 6	717	739	587	643	672	97%
	2352	2437	1902	2087	2195	

Figure L-76: Surrogate Capabilities, without IPPs

To see a specific example of how these fractions are applied, consider the on-peak values for the surrogate plant "PNW West NG 3 006" which appear in row {429}. Recall from the discussion of valuation costing and of the thermal dispatch UDF that value is the negative cost appearing in this row. The formula in cell {CV429} discounts these values to the first period:

=0.434512325830654*8760/8064*NPV(0.00985340654896882,$R429:$CS429)*
(1+0.00985340654896882)

Comparing this formula to those described in section "Present Value Calculation," page L-79, we note that this formula has an additional leading coefficient of about 43.45%. This corresponds to the fraction identified on the far right hand side of Figure L-76.

Several of the Council members expressed interest in the impact that contracts for the export of firm energy outside the region might have on model results. A detailed discussion of the impacts appears in Appendix P[32] and in reference [**13**]. To summarize, the impact of such firm contracts would be nil. Of course, firm contract might reduce the pool of counterparties with whom regional utilities could deal. There would be no effect, however, on the market prices, upon which these LSEs are dependent for any unmet requirements.

New Resources

The new resources in the regional model

- CCCT
- SCCT
- coal plant
- IGCC
- demand response
- wind

are based on corresponding resources in the Council's Aurora model [**14**]. Figure L-77 and Figure L-78 summarize these. (The values in these figures are from the model runs for the final plan. Values in the example workbook and in examples appearing elsewhere in this appendix may differ.)

	Expected FOR	Stochastic FOR	Variable_Cost ($/MWh): VOM	Fuel Set (ID)	Heatrate (kBTU/kWh)
CCCT	0.05	FALSE	3.11	PNW East NG	7.270
SCCT	0.07	FALSE	8.65	PNW East NG	9.810
Coal Plant	0.07	FALSE	1.94	Coal_003	9.550
IGCC	0.10	FALSE	1.66	Coal_003	7.790
Demand Response	0.00	FALSE	0.00	(none)	(none)
Wind 1	0.00	FALSE	1.06+PTC+GT+Integration(Cap)	(none)	(none)
Wind 2	0.00	FALSE	1.06+PTC+GT+Integration(Cap)	(none)	(none)

Figure L-77: New Resource Parameters (1/2)

The section "New Resources, Capital Costs, and Planning Flexibility," beginning on page L-65, describes the parameters in Figure L-78. Reference [**15**] documents the calculation of these values. In addition to the parameters discussed in that section, a column calculating the real levelized $2004 per kilowatt year has been added to the far right hand side of Figure L-78 for reference.

[32] See “Independent Power Producers,” in the Appendix P chapter, “Sensitivity Studies.”

	Criterion	Index	Planning_Periods	Optional_Construction_Periods	Committed_Construction_Periods	Planning_Costs (RL $M/MWPeriod^2)	Mothball_Costs (RL $M/MWPeriod^2)	Cancellation_Costs (RL $M/MWPeriod^2)	Construction_Costs (RL $M/MWPeriod^2)	CancelThreshold	Const Cost Escl (.01=1%/period)	Annual Escl	ResourceLife (periods	OptionLife (periods	PermitMarketAdds (T/F)	PlannedPlanning_Costs	RLL 2004$/kWyr
CCCT	R-L, then cost	0	0	4	4	0	0.00029	0.01168	0.00292	-99999	-0.086%	-0.34%	80	20	FALSE	0.00149	108.0
SCCT	R-L, then cost	1	0	0	4	0	0.00055	0.02185	0.00546	-99999	-0.100%	-0.40%	80	20	FALSE	0.00044	96.8
Coal Plant	R-L, then cost	2	0	5	9	0	0.00034	0.01355	0.00339	-99999	0.018%	0.07%	80	20	FALSE	0.00048	208.1
IGCC	R-L, then cost	2	0	8	8	0	0.00033	0.01310	0.00328	-99999	-0.116%	-0.46%	80	20	FALSE	0.00107	232.3
Demand Response	fixed	3	0	0	1	0	0.00005	0.00200	0.00050	-99999	0.000%	0.00%	80	80	FALSE	0.00002	2.3
Wind 1	R-L, then cost	4	0	2	2	0	0.00074	0.02970	0.00743	-99999	-0.430%	-1.71%	80	80	FALSE	0.00061	131.7
Wind 2	R-L, then cost	5	0	2	2	0	0.00166	0.06623	0.01656	-99999	-0.179%	-0.71%	80	80	FALSE	0.00135	293.7

Figure L-78: New Resource Parameters (2/2)

The CCCT, SCCT, Coal, IGCC, and demand response plants use the calculations described in sections "Thermal Generation" and "New Resources, Capital Costs, and Planning Flexibility" to determine costs[33]. While wind plants use the techniques described in the latter section for capital costs calculations, the variable cost calculation is different from that of the other new resources.

The variable cost for wind consists of four parts: variable operations and maintenance (VOM), green tag credit (GTC), production tax credit (PTC), and integration cost (IC). The VOM and IC increase cost; GTC and PTC decrease cost. The history of the PTC and GTC appear in Chapter 6 of the plan. The GTC and PTC are essentially aspects of the future, and Appendix P therefore covers their derivation. VOM is deterministic and IC is a function of wind deployment. This section therefore limits itself to how IC works and how the cost of wind incorporates these various cost components.

Windpower shaping costs range from $3 to $8 per megawatt hour, lower than expected several years ago. The model uses deterministic shaping costs: $5.02 per megawatt hour for the first 2,500 megawatts of wind capacity and $10.76 per megawatt hour thereafter (2004$).

In the example worksheet, the cells {AQ509} and {AQ510}, which compute the wind capacity and cost of capacity, use the same new capacity UDFs as the other resources, as just mentioned:

=lfPFCap(AP$314,AP$46,$P509)

[33] The model represents demand response as a combustion turbine with a fixed $150/MWh dispatch cost. When better information is available for describing the supply curve of regional demand response, the Council will enhance this representation. Also, while implementation uses the planning flexibility logic, the plan is fixed. Given the uncertainty surrounding the cost and availability of this resource, the Council elected to hold the plan for DR constant in all simulations.

=sfPFCost(AQ509,AP$46,$P509)

The energy (cell {AQ511}) is the capacity (MW) times the capacity factor times the number of on-peak hours in a standard quarter:

=AQ509*1152*0.3

The cost of wind (cell {AQ512}) in millions of 2004 dollars is

=AQ$511*(AQ$506-AQ$204)/1000000

Here the reader will recognize the now familiar valuation formula for costs, the energy times the value of the energy in the market. The on-peak price of electricity is in cell {AQ$204} and cell {AQ$506} contains the variable costs.

During the preparation of the final plan, the calculation of the variable costs change from what is in the sample workbook. This description will first explain the old logic in the sample worksheet. It will then explain how the new logic in the final plan works.

The sample workbook, the GTC and PTC went away completely with the advent of any carbon penalty. Moreover, the IC was $4.00/MWh for 2500 MW or less of wind and $8.00/MWh otherwise. The variable cost in cell {AQ$506} contains the formula

=IF(AQ74=0,AQ79+AQ505+AQ80+AQ81*(1+$R$78*AQ$46/80),AQ505+AQ80)

This formula is testing whether there is a tax for carbon. If so, the variable costs are the sum of the integration charge (cell {AQ505}) and the variable O&M in cell {AQ80}. The integration cost, in turn is given in cell

=IF(AP509+AP519>2500,2*$R$77,$R$77)

As we might expect, the integration cost formula merely doubles the $4.00/MWh in cell {$R$77} if the sum of the capacities for the wind plants exceeds 2500 MW.

If there is no carbon tax, then to these two terms the model adds the PTC (cell {AQ79}) and the GTC. The GTC has the formula

AQ81*(1+$R$78*AQ$46/80)

This simply changes the GTC linearly over time. Depending on the future, the GTC in the draft plan always started out at $6.66 (2004$) and increased or decreased linearly over time.

In the revised logic that the final plan employs, the situation is a bit more complicated. The GTC and PTC are relatively large, and several parties commented that it seemed unreasonable that these would disappear if even the smallest carbon tax occurred. The Council agreed. To make the behavior more realistic, the Council decided that PTC subsequent to the introduction of a carbon penalty depends on the magnitude of the carbon penalty. If the carbon penalty is below half the initial value ($9.90 per megawatt hour in 2004$) of the PTC, the full value of the PTC remains [34]. If the carbon penalty exceeds the value of the PTC by one-half, the PTC disappears. Between 50 percent and 150 percent of the PTC value, the remaining PTC falls dollar for dollar with the increase in carbon penalty, so that the sum of the competitive assistance from PTC and the carbon penalty is constant at 150 percent of the initial PTC value over that range. A complete description of the regional model's treatment of GTC and PTC appear in the Appendix P chapter, "Uncertainties."

[34] The conversion of carbon penalty ($/US short ton of CO_2) to $/MWh is achieved with a conversion ratio 1.28 #CO_2/kWh. This conversion ratio corresponds to a gas turbine with a heat rate of 9000 BTU/kWh.

In the workbook, the variable cost formula is now

=AQ505+AQ82-AQ81-AQ83

The VOM in cell AQ82 of the new workbook is still fixed, and the integration cost in cell AQ505 is similar to the test described as above. The other two components, however, are more interactive with the carbon tax and the model treats them strictly as elements of the model future. Appendix P therefore describes those worksheet formulas.

Supply Curves

The portfolio model employs supply curves to represent conservation and price response hydro. This section describes data that the model uses, and it explains some of the choices and considerations behind these representations. During the Council's early modeling efforts, an unexpected relationship emerged between the shape of the supply curve and the value of conservation under uncertain market prices. This appendix describes those discoveries in section "Conservation Value Under Uncertainty," beginning on page L-129.

This section begins with a description of energy allocation for conservation across the on- and off-peak periods. The allocation pertains to both lost opportunity and discretionary conservation.

Energy Allocation

Figure L-79 illustrates the assumed conservation energy allocation by month [**16**]. Because these are percentages of annual energy, instead of power rates (MW), both the rate of usage and the number of hours in each subperiod influence the values. The regional model, which uses standard periods and power rates, requires the restatement of these percentages.

	High Load	Low Load
Jan	7.7%	1.9%
Feb	7.1%	1.7%
Mar	7.5%	1.5%
Apr	7.0%	1.6%
May	6.2%	1.3%
Jun	5.5%	2.0%
Jul	5.8%	1.5%
Aug	6.0%	1.2%
Sep	5.6%	1.3%
Oct	7.0%	2.0%
Nov	6.9%	1.8%
Dec	7.6%	2.1%
Jan	7.7%	1.9%
Feb	7.1%	1.7%

Figure L-79: Energy by Month

2005	High Load	Low Load	Total
Jan	416	328	744
Feb	384	288	672
Mar	432	312	744
Apr	416	304	720
May	416	328	744
Jun	416	304	720
Jul	416	328	744
Aug	432	312	744
Sep	416	304	720
Oct	416	328	744
Nov	416	304	720
Dec	432	312	744
			8760

	on-peak	off-peak	
Sp	1232	928	2160
Sum	1248	936	2184
Fall	1264	944	2208
Win	1264	944	2208
			8760

Figure L-80: Typical Hours Per Year and Hydro Quarter

Using the assumptions in Figure L-80, which represent a typical year, we obtain the average power by hydro quarter by subperiod in Figure L-81:

MW=MWh/hrs

There is significant difference in the weightings for on-and off peak power, but the seasonal variations in these factors is relatively small. To simplify calculations, the model uses the average of the seasonal values, which appear in Figure L-81. These averages are the constants to which the section "Conservation" (page L-44) and other sections refer.

	on-peak	off-peak
Sp	1.48	0.42
Sum	1.22	0.44
Fall	1.35	0.46
Win	1.55	0.53
average	1.402	0.465

Figure L-81: Relative Power Rates

Lost Opportunity Conservation

As explained in Chapter 3, lost opportunity conservation arises from new building construction and similar situations. While current codes and standards capture a significant amount of lost opportunity conservation, these effects are already captured in the "frozen efficiency" load forecast. That is, the frozen efficiency load forecast incorporates the effects of existing codes and standards on *future* growth in requirements. The lost opportunity conservation in the regional model's supply curves is therefore *new, incremental* conservation. Much of the potential for lost opportunity conservation comes from the advent of new technology.

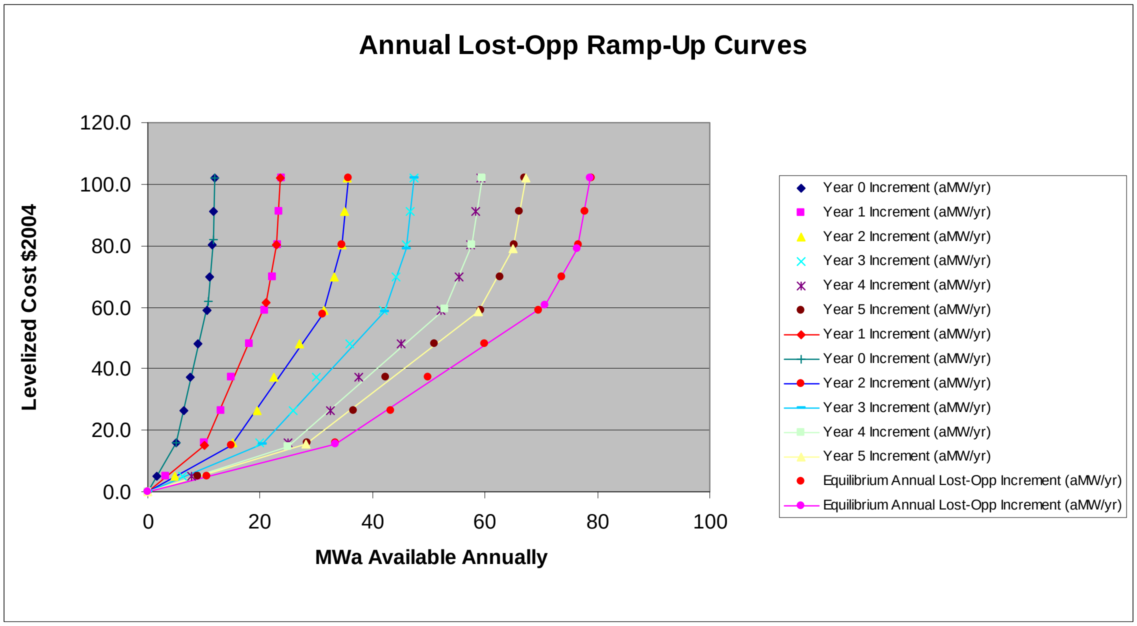


Figure L-82: Lost Opportunity Supply Curves

The regional model captures the development of new lost opportunity conservation technology through a sequence of supply curves that reflect increasing potential over time at each price point. This set of supply curves appears in Figure L-82, and the corresponding data appear in Figure L-83 [**17**]. At the bottom of Figure L-83, the reader will find the corresponding representation that the regional portfolio model uses. All supply curves reflect 5.5 mills per kilowatt-hour T&D credit and credit for any benefits unrelated to electric energy efficiency improvement.

In Figure L-83, six years pass before conservation achieves a mature level of potential. This mature level of potential is 85 percent of the theoretical potential. The Council recognizes that the even under the most optimistic conditions, the region will not be able to develop all conservation. Moreover, the rate of development is even more gradual in the regional model than this figure suggests. Instead of one year between supply curves, the regional model assumes two years, and no conservation commences before December of calendar year 2004. For lost opportunity, therefore, the first supply curve applies to the one year period after December 2004, the next supply curve applies to December 2005 up to December 2007, and the remaining supply curves apply every second year through December 2015, when potential reaches maturity.

Annual Energy (Q)	Year 0 Increment (aMW/yr)	Year 1 Increment (aMW/yr)	Year 2 Increment (aMW/yr)	Year 3 Increment (aMW/yr)	Year 4 Increment (aMW/yr)	Year 5 Increment (aMW/yr)	Equilibrium (aMW/yr)
Point 1	0	0	0	0	0	0	0
Point 2	5.06	10	14.9	20.3	25	28.1	33.5
Point 3	10.8	21.1	31.2	42.2	52.8	58.8	70.6
Point 4	11.6	22.9	34.6	45.9	57.7	65	76.5
Point 5	11.9	23.6	35.6	47.4	59.4	67.2	78.8

Quarterly Energy (Q)	Year 0 Increment (aMW/yr)	Year 1 Increment (aMW/yr)	Year 2 Increment (aMW/yr)	Year 3 Increment (aMW/yr)	Year 4 Increment (aMW/yr)	Year 5 Increment (aMW/yr)	Equilibrium (aMW/yr)
Point 1	0	0	0	0	0	0	0
Point 2	1.265	2.5	3.725	5.075	6.25	7.025	8.375
Point 3	2.7	5.275	7.8	10.55	13.2	14.7	17.65
Point 4	2.9	5.725	8.65	11.475	14.425	16.25	19.125
Point 5	2.975	5.9	8.9	11.85	14.85	16.8	19.7

Price (P)	Year 0 Increment (aMW/yr)	Year 1 Increment (aMW/yr)	Year 2 Increment (aMW/yr)	Year 3 Increment (aMW/yr)	Year 4 Increment (aMW/yr)	Year 5 Increment (aMW/yr)	Equilibrium (aMW/yr)
Point 1	0	0	0	0	0	0	0
Point 2	15.8	15	15	15.5	14.5	15.5	15.5
Point 3	61.9	61.5	57.6	58.5	59.5	58.5	60.5
Point 4	81.8	80.3	80.3	78.9	80.3	78.9	78.9
Point 5	102	102	102	102	102	102	102

0,0@+1.265,15.8@+2.7,61.9@+2.9,81.8@+2.975,102
0,0@+2.5,15@+5.275,61.5@+5.725,80.3@+5.9,102
0,0@+3.725,15@+7.8,57.6@+8.65,80.3@+8.9,102
0,0@+5.075,15.5@+10.55,58.5@+11.475,78.9@+11.85,102
0,0@+6.25,14.5@+13.2,59.5@+14.425,80.3@+14.85,102
0,0@+7.025,15.5@+14.7,58.5@+16.25,78.9@+16.8,102
0,0@+8.375,15.5@+17.65,60.5@+19.125,78.9@+19.7,102

Figure L-83: Lost Opportunity Supply Curve Values

As described in section "Supply Curves," page L-44, lost opportunity conservation depends on the rate at which construction is taking place, which is related to overall load growth. The supply curve logic for lost opportunity conservation accommodates this behavior. In the sample workbook, the cell {AQ377} contains the following formula

```
=1152*1.402*sfSupplyCurve(AP$233+$R$375,$P377,AP$46,AP377,AP240)
```

The last parameter in the UDF refers to cell {AP240}. Row 240 contains the ratio of on-peak load in column {AP} to an on-peak load benchmark level:

```
=AP183/AP195
```

If the period's on-peak load exceeds the period's benchmark on-peak load by 1%, the applicable supply curves quantity will increase 1% at each price level.

The section "Supply Curves" describes the remaining parameters in these formulas. The section “Decision Criteria,” page L-90, explains the price criterion (AP$233+$R$375) in this formula.

Discretionary Conservation

Discretionary conservation, also referred to as dispatchable or schedulable conservation, is energy efficiency that the region can pursue at any time. Some of these opportunities will disappear over time, so the supply curve represents a forecast of the balance of measures available in 2025. Figure L-84 illustrates a supply curve that the regional models uses for representing discretionary conservation. The values are in Figure L-85 [17]. This source of conservation also has a T&D credit of 5.5 mills per kilowatt-hour.

Discretionary conservation does not increase over time for a couple of reasons. First, the Council does not attempt to forecast technology improvements. The technology and standards are static. Second, the Council assumes that any structure built today with all cost-effective efficiencies will have no potential for additional improvement in 10 years. If conservation for the new facility becomes a lost opportunity, it remains a lost opportunity. It cannot become discretionary after some time has passed.

Several aspects of discretionary conservation economics became evident early in studies with the regional model. First, because there is so much discretionary conservation that is cost-effective at today's market prices that, without constraining the rate of development, the model would select unrealistic rates of conservation acquisition. In practice, program infrastructure, rate impacts, and budgets constrain development. To reflect this, the supply curve logic was modified to incorporate a rate limit. The Council considered several levels of ramp rate, and settled on a rate (30 MW) that appeared to significantly improve cost and risk but be realistic in light of some of the known

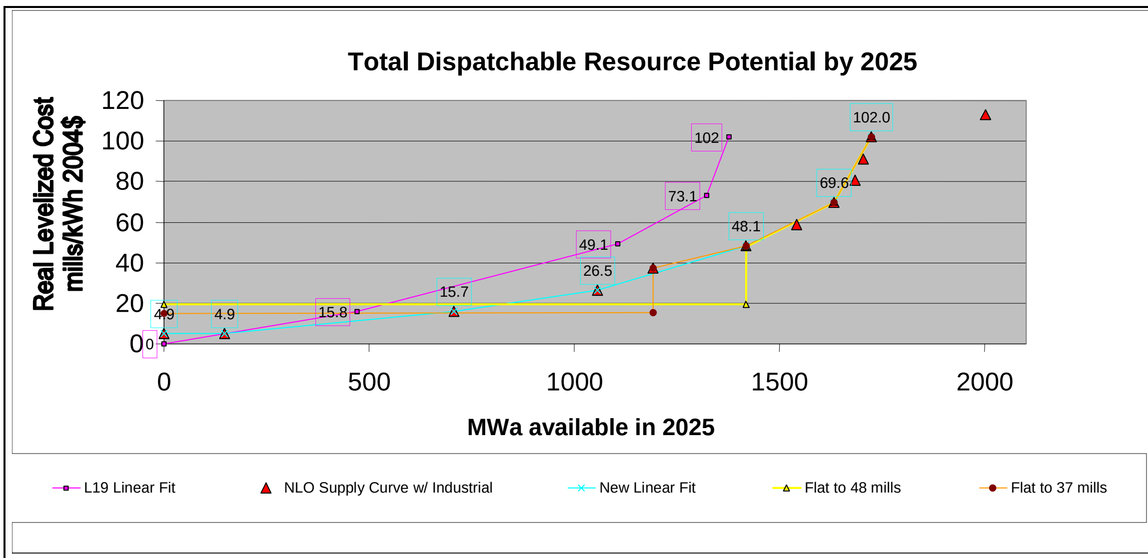


Figure L-84: Discretionary Conservation Supply Curve constraints. The selection of this discretionary conservation ramp rate is the subject of a sensitivity analysis in Appendix P.

The second aspect of discretionary conservation economics that became evident was that bundling of conservation programs prohibited strict implementation of the supply curve. When a utility decides to pursue discretionary conservation, they commit resources and crews to a commercial or industrial location. While at these locations, it makes economic sense to implement a host of programs, not just the ones below a given point on the supply curve. It is not realistic to expect that utilities will be able to "cherry pick" only those measures that are cost-effective and do so with 100 percent effectiveness.

Flat to 48 mills	
Energy (Q)	**Year 2025 Total Available**
Point 1	0
Point 6	1418
Point 6	1419
Point 8	1633
Point 11	1723
Price (P)	
Point 1	19.5
Point 6	19.6
Point 6	48.0
Point 8	69.6
Point 11	102.0
0,19.5@+ 1418,19.6@+ 1419,48@+ 1633,69.6@+ 1723,102	
0,19.5@+1418,19.6@+1419,48@+1633,69.6@+1723,102	

Figure L-85: Data for Discretionary Conservation Supply Curve

To model the situation, the model uses a modified discretionary conservation supply curve. Council staff decided to change the shape of the supply curve to increase the average cost of discretionary conservation available at the low end of the supply curve. Where to make these modifications is to an extent arbitrary. Council staff considered several factors including the regional portfolio model's apparent appetite for discretionary conservation costing less than 40 mills per kilowatt-hour, the historic performance of utility programs, and the mix of discretionary conservation measures available. The staff chose to represent discretionary conservation with a first block representing all the conservation under the curve up to 48 mils per kilowatt-hour. This is about 1490 average megawatts and average cost of 19.6 mils per kilowatt-hour in 2004 constant dollars. It includes 200 average megawatts of conservation above 40 mils per kilowatt-hour. [17]

The supply curve logic for discretionary conservation in cell {AQ377} contains the following formula

=sfSupplyCurve(AP235+$R$384,$P386,AP46,AP386)*1152*1.402

The section "Supply Curves" describes the parameters in this formulas. The section "Decision Criteria," page L-91, explains the price criterion (AP235+$R$384) in this formula.

Price Responsive Hydro

The model uses a reversible supply curve to represent price responsive hydro. Section "Supply Curves," page L-48, describes the considerations that went into selecting values to represent this resource.

Contracts

Contract data represents firm energy imports and exports to the region. The source of this data is the BPA 2004 White Book [18]. Energy values appear in Figure L-86 as extracted from the source. Note that this figure uses calendar years, not hydro years.

Using a calendar of NERC holidays, the energy values in Figure L-86 become power levels over each hydro quarter. This permits restatement in standard periods. Figure L-87 illustrates the resulting values, which the model then incorporates. Because the values provided by BPA extend only through 2014 and because of the regular pattern exhibited in the last several years, the model extends the pattern of energy values through the end of the study.

As explained in section "Contracts," page L-32, the model can counter-schedule these firm contracts for economic reasons. Consequently, the contracts have little effect on market prices. Counter-scheduling affects the amount of power available to the market, which stabilizes prices. The contracts, however, do affect portfolio economics and risk. Regional load still benefits from the protection that these contracts afford against economic exposure to the market.

This concludes the appendix description of resources that the regional model uses. The model represents existing regional resources in aggregate plants, but SBC wind and IPP modeling requires special attention. Contract data reflects the most recent BPA White Book, extended through the end of the study. Most new resources use the UDF described in the section "New Resources, Capital Costs, and Planning Flexibility" for capital costs; all new resources except wind use the UDF described in "Thermal Generation" for variable costs. Wind must account for integration cost and special renewables credits. New conservation energy has its own, special supply curve logic.

One aspect of the resources that this section did not discuss is how the model constructs plans. Plans must conform to certain constraints: A plant, once constructed, may not disappear the next year, for example, and there are constraints on the addition of wind generation. The next section describes how the Crystal Ball and OptQuest Excel add-ins use the regional model to prepare the feasibility space, including constructing plans subject to constraints and finding least-cost plans subject to risk constraints. It also describes some utilities that help the analyst make sense of the simulation results.

MWhs			Month											
On/Off Peak	Cal Yea	I/E	1	2	3	4	5	6	7	8	9	10	11	12
On-Peak	2004	Export								1009725	982675	877696	824291	874006
		Import								163798	127562	170293	313234	424215
	2005	Export	801258	733297	790424	773177	784213	876105	909973	910011	873102	742359	705020	736716
		Import	392401	318405	287876	234573	130284	172270	190170	187681	155162	179321	329674	412567
	2006	Export	727018	665963	737764	712355	739955	795224	811648	804054	772577	617872	585371	606787
		Import	382401	307691	269559	219490	102443	171521	181210	149319	132522	153725	301904	373910
	2007	Export	611999	552671	611035	592672	615517	672647	710778	728831	693228	609790	572397	594008
		Import	345772	262714	226411	178287	87527	143906	134992	140868	92166	139149	279464	363590
	2008	Export	554273	517882	548613	540204	548669	577665	591676	566925	552765	544691	505046	534237
		Import	265610	259835	231893	194563	106788	149176	156358	68746	56616	80397	157859	208871
	2009	Export	533241	481879	527510	522319	530517	566911	576003	615994	600009	593652	556458	587668
		Import	207370	179846	171864	133744	49577	84542	82144	68746	56616	80397	157859	208871
	2010	Export	582702	530029	584596	573560	583288	613019	623807	604813	589060	578493	551365	578666
		Import	201310	179846	176774	133744	49577	65323	63549	50151	56616	77930	123928	168103
	2011	Export	573659	521787	575314	564448	572062	607287	613611	602545	582472	571772	545234	572658
		Import	162110	142214	134438	92976	49577	65323	61792	51574	56616	77930	123928	168103
	2012	Export	567608	533510	569018	553813	567586	594468	600522	588566	564402	559651	530453	554066
		Import	162110	147835	134438	90327	50794	65323	61792	51574	54726	80397	117520	156565
	2013	Export	556503	502423	549805	543019	551864	574990	589465	573374	550241	553050	524466	548234
		Import	159981	136234	131096	92976	50794	63816	63549	51574	54726	80397	117520	156565
	2014	Export	550624	497030	543662	536926	545266	547101	560816					
		Import	159981	136234	131096	92976	50794	63816	63549					
Off-Peak	2004	Export								294739	277615	204704	200887	212999
		Import								151512	129214	157907	254667	322426
	2005	Export	206106	173346	185717	187526	187707	220818	278787	228051	227494	177214	175611	184580
		Import	315020	223304	199821	172771	114193	127641	180810	158877	151294	165046	267819	313242
	2006	Export	192800	162197	173580	184952	166932	190604	233049	225936	225078	113840	114234	127931
		Import	306420	215268	186592	175200	84375	127094	173105	131171	133182	144848	245665	306460
	2007	Export	121181	106807	113301	123682	103719	131737	176143	174600	181766	100408	106934	120228
		Import	254097	181529	155384	142399	72655	106883	133502	125022	107164	125005	227713	297585
	2008	Export	81735	71666	78202	78940	63894	81183	85311	83285	79150	69034	77862	80842
		Import	195503	176759	171776	138310	74153	103328	125513	60159	56590	68730	130767	142349
	2009	Export	80178	69203	76357	77201	64188	74782	83524	81268	77238	67130	78969	82189
		Import	133657	104994	108520	86326	31222	47578	66998	60159	56590	68730	130767	142349
	2010	Export	85423	70346	73597	78239	65095	75714	84594	82248	78101	72013	76203	83601
		Import	139718	104994	103609	86326	31222	28637	47277	40438	51694	61810	96586	112734
	2011	Export	86806	71546	74821	79328	66045	76693	90101	78848	78988	72996	77395	85051
		Import	108535	79055	75563	61165	26162	28637	49034	39016	51694	61810	96586	112734
	2012	Export	88228	73662	76080	84855	64784	77699	91245	79895	84318	63831	72235	83606
		Import	108535	81337	75563	63815	24945	28637	49034	39016	53583	59343	96586	117651
	2013	Export	79220	68301	74755	75553	59241	76751	81468	74743	78558	64894	73523	85174
		Import	104042	79055	78905	61165	24945	30144	47277	39016	53583	59343	96586	117651
	2014	Export	80757	69633	76115	76764	60299	77839	82705					
		Import	104042	79055	78905	61165	24945	30144	47277					

Figure L-86: Regional Contract Energy (MWh)

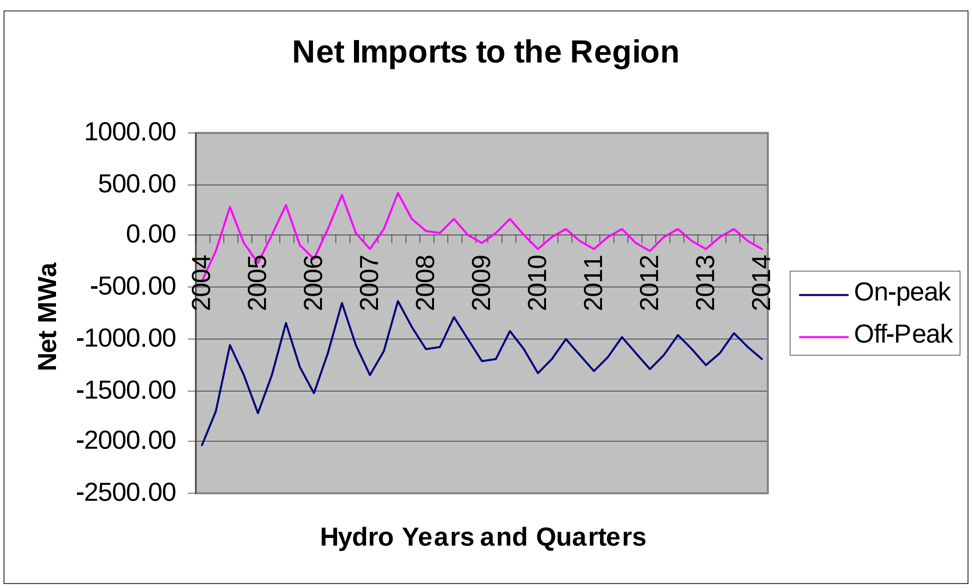


Figure L-87: Net Contract Imports MW

Using the Regional Model

This section describes how a user can run the regional model alone, or can use Excel add-ins to perform Monte Carlo simulation and plan optimization. The last portion of this section describes utilities the Council used to verify modeling and extract additional insights from the simulations.

Stand-Alone Calculation

When the workbook opens, the Excel calculation mode is set to Manual and special macros recalculate the worksheet in the order described in section "Logic Structure," at page L-9, and in section "RRP algorithm," page L-51. Because the workbook does not recalculate automatically, making changes to data in the workbook appears to have no effect.

To recalculate the worksheet, the user must execute the workbooks "Auto_Open" macro. By default, this macro is assigned the hotkey combination <CTRL>-I.

When the user presses <CTRL>-I, she can watch the calculations proceed from left to right across the worksheet. Recalculation requires about a second and a half. During recalculation, most of the values in the worksheet, and in particular the total system cost, are invalid. Their values may appear nonsensical. For example, prices may be negative.

Crystal Ball Simulations

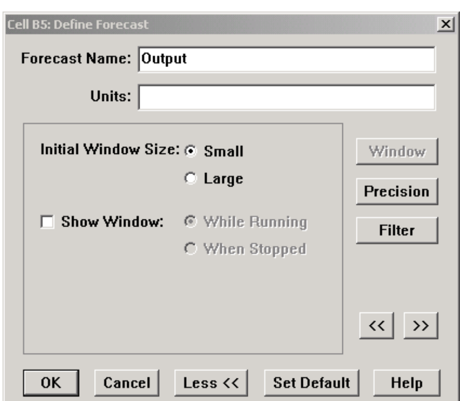


Figure L-88: Defining Forecasts

To perform Monte Carlo simulation or to prepare for creating a feasibility space, the user must specify Monte Carlo run preferences. The user should configure forecast cells to suppress forecast windows during the run, as in Figure L-88. Clicking on the Run Preferences button, illustrated in Figure L-89, the user has a sequence of choices to make.

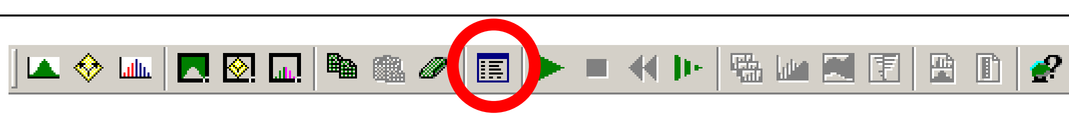


Figure L-89: Run Preferences

The first of these choices, illustrated in Figure L-90, determines the number of games or futures and how the application should handle calculation in each of those. Regional model studies used 750 games. This assured that there are 75 samples of the 10% worse outcomes. This number of samples yields a standard error that is about 12% of the tail's standard deviation. The 750 games provide a standard error of the mean that is about 4% of the distribution's standard deviation, or about $250 million net present value. Because of the size of the standard error of the mean, the Council always studied those plans that were nearly efficient. The Council examined all plans that were within $250 million cost and risk of the efficient frontier for evidence that a different resource strategy might be efficient.

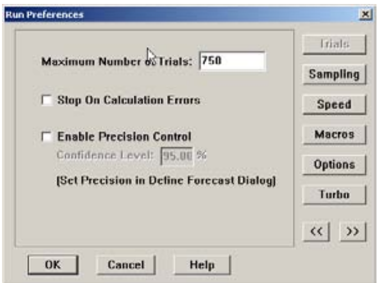


Figure L-90: Run Prefs, Trials

The second run preference is Sampling (Figure L-91). All studies used the same sequence of random numbers and the same initial seed value. Specifying the random number seed value is essential to reproducing and verifying simulations. Latin Hypercube is a statistical method that forces the sampling of less likely portions of a statistical distribution. All regional model simulations used the Latin Hypercube option.

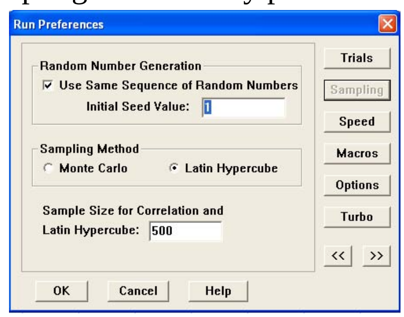


Figure L-91: Run Prefs, Sampling

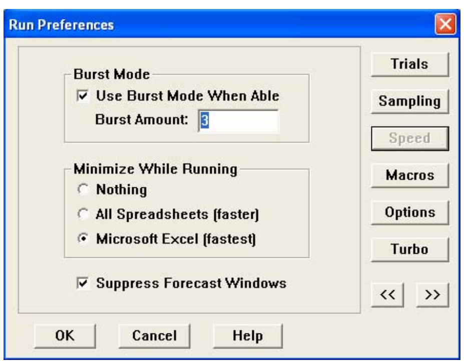


Figure L-92: Run Prefs, Speed

The third run preference, Speed, features an option called Burst Mode (Figure L-92). Burst Mode does different things depending on whether the user is running under Normal or Turbo simulation mode. Under Normal mode, this option suppresses screen updating for the number of games that the user specifies. Under Turbo mode, this controls the number of games each Worker receives in a packet. For the regional model, small packets containing only three futures appear to optimize performance.

The fourth run preference permits the user to specify macros that Crystal Ball will run during its simulation. The regional model employs two such macros, illustrated in Figure L-93. The macro names must be here whenever the user runs a Monte Carlo simulation or executes the regional model under Crystal Ball's single-step feature.[35] The regional model has a special macro that loads the names of the two subroutines into the correct fields in this dialog box. The user invokes this macro by pressing <CTRL>-M. Using the macro not only saves time but also reduces the likelihood of inadvertent errors. The

[35] Warning: The single-step feature does not reproduce the same games as when Monte Carlo simulation employs a user-specified seed value, even if the user specifies a seed value. The next section describes a utility to extract the values for assumption cells corresponding to a particular future.

subroutine names specified in this run preference dialog box must include the name of the regional portfolio model workbook. This name to typically changes from run to run.

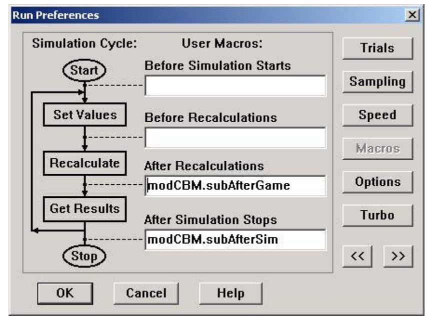


Figure L-93: Run Prefs, Macros

Executing the <CTRL>-M macro serves another purpose. For the macros in the regional model to perform correctly, there must not be any other Excel workbook present. Depending on the computer environment, Excel may load personal or hidden workbooks that are not evident to the user. This macro will locate any such workbooks and warn the user to close them.[36]

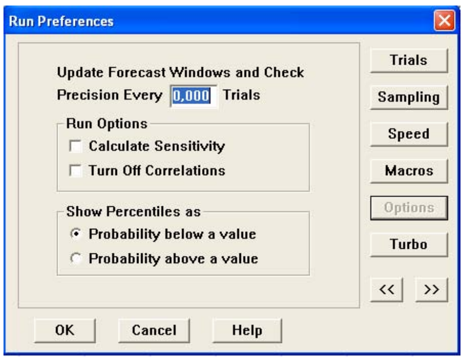


Figure L-94: Run Prefs, Options

Figure L-94 illustrates a fifth option, which should be set up as shown and thereafter disregarded. For reasons described in the next section, the regional model does not use precision or confidence testing.

The final option controls whether the Monte Carlo simulation will run in Normal (Figure L-96) or Turbo mode (Figure L-95). The user can run the regional model in either mode. For the Council's work, Turbo mode produced a tenfold decrease in run time for the creation of feasibility spaces. An important verification test, described below, is comparing the results of a plan run under Normal mode on a single machine and under Turbo model on multiple machines. The results for each game must be identical.

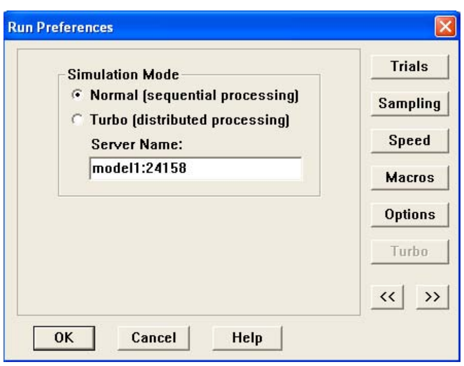


Figure L-96: Run Prefs, Turbo (Normal)

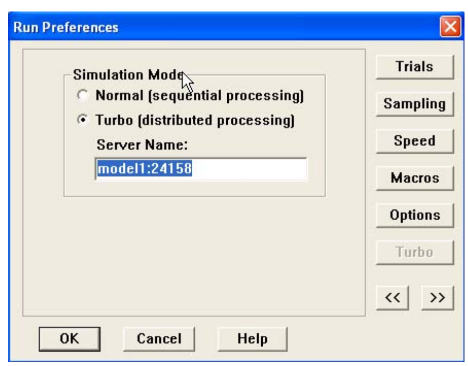


Figure L-95: Run Prefs, Turbo (Turbo)

[36] Closing the workbook may require entering the Visual Basic editing environment and issuing the Workbooks("***name***.xls").close command in the Immediate Window, where ***name*** is the offending workbook.

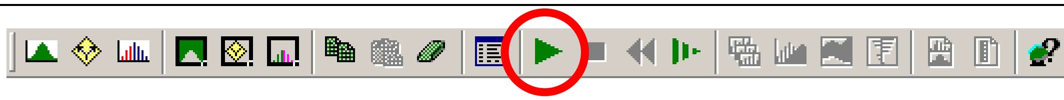


Figure L-97: Begin Simulation

With these preparations, the user is prepared to begin the Monte Carlo simulation using the start button in Figure L-97 or to prepare a stochastic optimization run as illustrated in Figure L-98. The next section describes considerations when preparing the optimization.

OptQuest Stochastic Optimization

When a user endeavors to create feasibility space using OptQuest, he can either open an existing configuration file or create one from scratch. If he chooses to create one from scratch, OptQuest will read the workbook and find all assumption, decision, and forecast cells. The user would then proceed through the following steps.

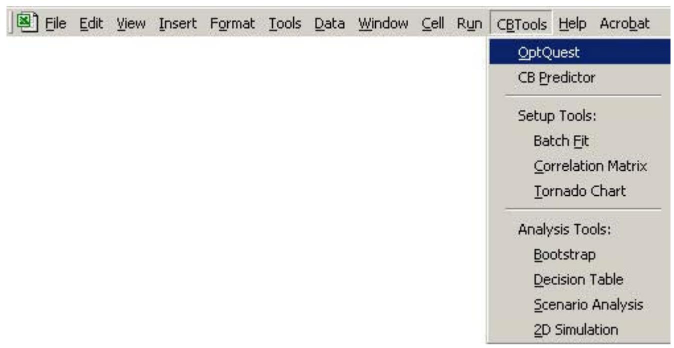
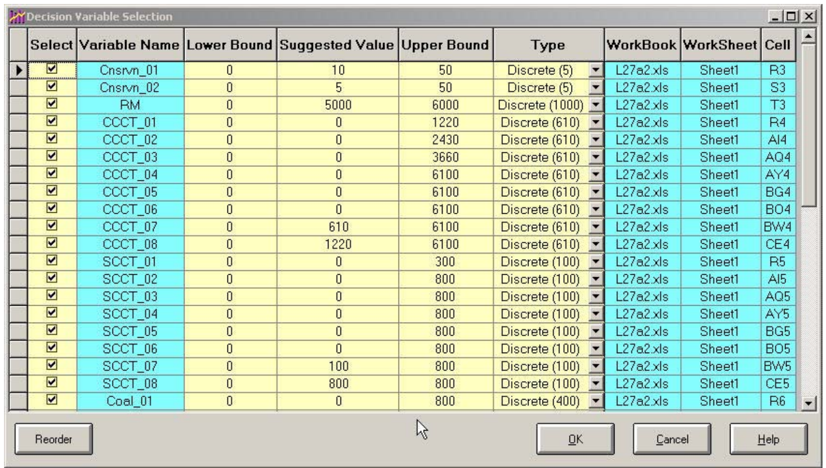


Figure L-98: Menu Bar

The OptQuest menu bar has four buttons that, proceeding from left to right in Figure L-99, open "Variable Selection," "Constraints," "Forecast Selection," and "Run Options" dialog boxes, respectively.

Figure L-99: OptQuest Menu Bar

Variable Selection, Figure L-100, is where the user specifies the value for decision cells. The optimizer will endeavor to perform its task by modifying the values of these cells. The column labeled "Type" specifies how the optimizer can vary the associated cell value. In this example, the optimizer can choose capacities for CCCT_01 in the fourth row between zero and 1220 MW in discrete steps of 610 MW. CCCT_01 is the decision cell that determines how much cumulative construction might be started by September of calendar year 2003. (See section "New Resources, Capital Costs, and Planning Flexibility," beginning on page L-65.). CCCT_02 is the corresponding number of megawatts for December, 2007, and so forth. The user must determine step size, upper limit, and lower limit through trial and error. If an upper or lower limit is constraining the plans along the efficient frontier, this would be an indication that the values for the constraints should be adjusted. The user endeavors to keep the number of choices as small as possible, however, because the size of the search space grows explosively with the number of steps and decision cells available. [**19**]



Decision Variable Selection

Select	Variable Name	Lower Bound	Suggested Value	Upper Bound	Type	WorkBook	WorkSheet	Cell
☑	Cnsrvn_01	0	10	50	Discrete (5)	L27a2.xls	Sheet1	R3
☑	Cnsrvn_02	0	5	50	Discrete (5)	L27a2.xls	Sheet1	S3
☑	RM	0	5000	6000	Discrete (1000)	L27a2.xls	Sheet1	T3
☑	CCCT_01	0	0	1220	Discrete (610)	L27a2.xls	Sheet1	R4
☑	CCCT_02	0	0	2430	Discrete (610)	L27a2.xls	Sheet1	AI4
☑	CCCT_03	0	0	3660	Discrete (610)	L27a2.xls	Sheet1	AQ4
☑	CCCT_04	0	0	6100	Discrete (610)	L27a2.xls	Sheet1	AY4
☑	CCCT_05	0	0	6100	Discrete (610)	L27a2.xls	Sheet1	BG4
☑	CCCT_06	0	0	6100	Discrete (610)	L27a2.xls	Sheet1	BO4
☑	CCCT_07	0	610	6100	Discrete (610)	L27a2.xls	Sheet1	BW4
☑	CCCT_08	0	1220	6100	Discrete (610)	L27a2.xls	Sheet1	CE4
☑	SCCT_01	0	0	300	Discrete (100)	L27a2.xls	Sheet1	R5
☑	SCCT_02	0	0	800	Discrete (100)	L27a2.xls	Sheet1	AI5
☑	SCCT_03	0	0	800	Discrete (100)	L27a2.xls	Sheet1	AQ5
☑	SCCT_04	0	0	800	Discrete (100)	L27a2.xls	Sheet1	AY5
☑	SCCT_05	0	0	800	Discrete (100)	L27a2.xls	Sheet1	BG5
☑	SCCT_06	0	0	800	Discrete (100)	L27a2.xls	Sheet1	BO5
☑	SCCT_07	0	100	800	Discrete (100)	L27a2.xls	Sheet1	BW5
☑	SCCT_08	0	800	800	Discrete (100)	L27a2.xls	Sheet1	CE5
☑	Coal_01	0	0	800	Discrete (400)	L27a2.xls	Sheet1	R6

Reorder OK Cancel Help

Figure L-100: Variable Selection

The values for decision cells illustrated in Figure L-100 are completely independent. The optimizer uses the equations in the Constraints dialog box, Figure L-101, to enforce any relationship among those values. The first seven equations in Figure L-101, for example, constrain the amount of CCCT capacity to be non-decreasing. The last seven equations in Figure L-101 specify that the model construct no more than 2000 MW of wind between decision cells. Two years separate each technology's decision cells after 2007 in the regional model.

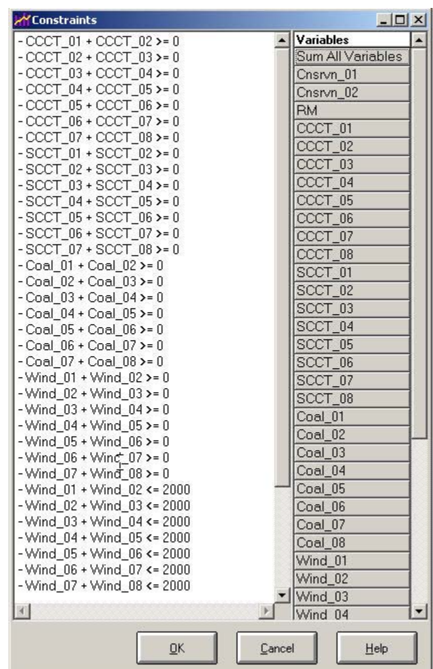
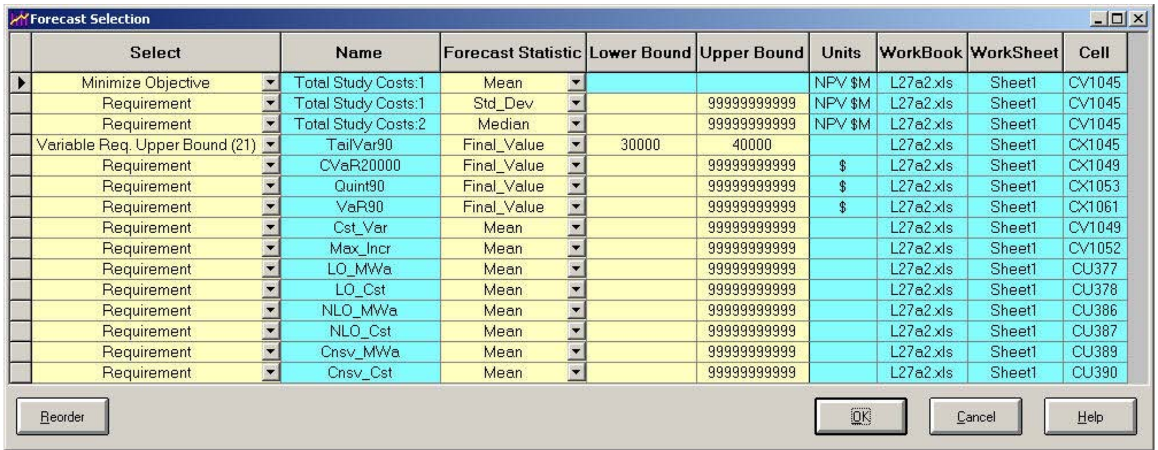


Figure L-101: Constrains

The "Forecast Selection" dialog window, illustrated in Figure L-102, is where the user specifies the objective function and risk constraint. The first row in this example specifies that our objective is to minimize total study cost. The fourth row specifies that a plan will be deemed feasible if it satisfies the upper bound on TailVaR_{90}. The optimization does not use the other rows. By specifying that other variables are requirements and placing an upper bound on these requirements guaranteed to be non-binding, the user fools the optimizer into keeping track of their values and reporting their values in the final optimization log.

Specifying that the TailVaR_{90} risk measure is a variable-requirement upper bound permits the user to create the efficient frontier. Initially, this upper bound will start out at its lowest value, $30 B in this example. (Bounds for TailVaR_{90} in Figure L-102 are in millions of 2004 NPV dollars.) The optimizer will first attempt to find a plan that satisfies this upper bound. By choosing a sufficiently low upper bound, the user guarantees that the optimizer will seek the least-risk plan. After giving the optimizer sufficient opportunity to identify the least-risk plan, the user lifts the upper bound. In our example, the upper bound will have 21 even steps between $30 B and $40 B inclusive. (See the value in parenthesis under the first column.) After the upper bound has been



Forecast Selection

Select	Name	Forecast Statistic	Lower Bound	Upper Bound	Units	WorkBook	WorkSheet	Cell
Minimize Objective	Total Study Costs:1	Mean			NPV $M	L27a2.xls	Sheet1	CV1045
Requirement	Total Study Costs:1	Std_Dev		99999999999	NPV $M	L27a2.xls	Sheet1	CV1045
Requirement	Total Study Costs:2	Median		99999999999	NPV $M	L27a2.xls	Sheet1	CV1045
Variable Req. Upper Bound (21)	TailVar90	Final_Value	30000	40000		L27a2.xls	Sheet1	CX1045
Requirement	CVaR20000	Final_Value		99999999999	$	L27a2.xls	Sheet1	CX1049
Requirement	Quint90	Final_Value		99999999999	$	L27a2.xls	Sheet1	CX1053
Requirement	VaR90	Final_Value		99999999999	$	L27a2.xls	Sheet1	CX1061
Requirement	Cst_Var	Mean		99999999999		L27a2.xls	Sheet1	CV1049
Requirement	Max_Incr	Mean		99999999999		L27a2.xls	Sheet1	CV1052
Requirement	LO_MWa	Mean		99999999999		L27a2.xls	Sheet1	CU377
Requirement	LO_Cst	Mean		99999999999		L27a2.xls	Sheet1	CU378
Requirement	NLO_MWa	Mean		99999999999		L27a2.xls	Sheet1	CU386
Requirement	NLO_Cst	Mean		99999999999		L27a2.xls	Sheet1	CU387
Requirement	Cnsv_MWa	Mean		99999999999		L27a2.xls	Sheet1	CU389
Requirement	Cnsv_Cst	Mean		99999999999		L27a2.xls	Sheet1	CU390

Reorder OK Cancel Help

Figure L-102: Forecast Selection and Requirements Specification

lifted a sufficient number of times, the optimizer will find at least one plan that satisfies the upper bound. At this point, the optimizer will endeavor to minimize the cost objective function. The optimizer will attempt to find the least cost plan subject to this risk constraint. After giving the optimizer sufficient opportunity to identify the least cost plan, the user then again lifts the upper bound on $TailVaR_{90}$. The optimizer will then endeavor to minimize cost subject to the new upper bound on $TailVaR_{90}$. The process continues until the optimizer has swept out the entire efficient frontier.

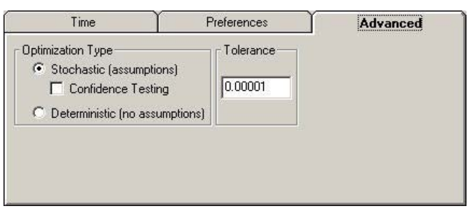


Figure L-103: Run Options (1/3)

Finally, the user specifies options for the run by clicking on the clock icon on the OptQuest menu bar (Figure L-99) to open the Options tab sheet. The first tab, labeled Advanced in Figure L-103, permits the user to specify whether optimization should be deterministic or stochastic. To create the feasibility space, the user selects Stochastic. It is imperative that the user leave the Confidence Testing option box unchecked. An undocumented problem running Crystal Ball Turbo under OptQuest produces random, meaningless results. The second to Options tab, Preferences, permits users to specify a descriptive string for output reports and the location of the optimization log file. An example of the log file appears below. The third Options tab, Time, permits the user to specify the amount of time for the optimization run. Using the Turbo mode, a feasibility space requires between 24 and 30 hours. Permitting two days for the optimization run should be ample therefore.

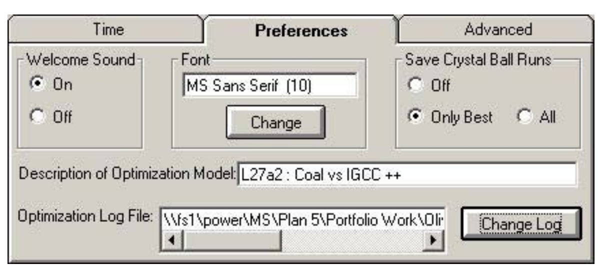


Figure L-104: Run Options (2/3)

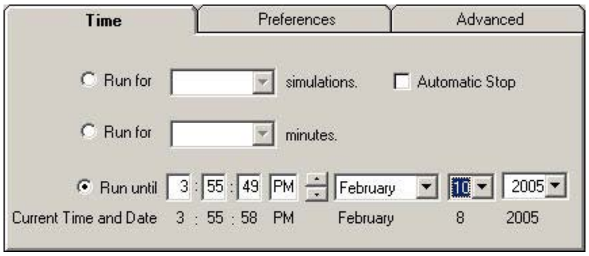


Figure L-105: Run Options (3/3)

The optimization is ready to run. The user may click on the run button in Figure L-106 to launch the optimization.

Figure L-106: LAUNCH!

Portfolio Model Reports And Utilities

In section "New Resources, Capital Costs, and Planning Flexibility," page L-74, the appendix describes a utility for extracting the planning status and cost for each cohort of a new resource. The Council has developed many other applications for extracting and evaluating regional model data. This section describes some of these utilities, including those that help the user perform the important tasks of verifying the computer simulations and "drilling down" through simulation results to the calculations performed by each cell for each plan, under each future.

This section describes utilities which

- create feasibility spaces and efficient frontiers
- extract data for each future and animate the "spinner" graphs, illustrating the behavior and performance of a plan under each future
- extract the assumption values for a particular future and populate a copy of the portfolio model with them for detailed examination
- run arbitrary sets of plans automatically and collect data
- paint prescribed cells with assumptions or forecasts
- compare two feasibility spaces to determine which, if any, plans are identical
- permit the user to compute the "stochastic adjustment" that results in distributions with a target mean, by period
- install menu bars to perform standard portfolio model or Olivia tasks, such as those listed above

Many of these utilities are included as special macros in the regional model. Some of them are macros in stand-alone workbooks. All of them are available to users from the Council upon request. They appear in this appendix because they demonstrate the ease with which and Excel-based model facilitates analysis. They also provide some insight into how the Council performed some of the tasks described elsewhere in this appendix.

Creating Feasibility Spaces and Efficient Frontiers

The previous section describes the means to constructing a feasibility space. A routine analysis is the comparison of two feasibility spaces. For example, one feasibility space may reflect a slightly modified set of assumptions, such as alternative probabilities for a CO_2 tax; the other may employ basecase assumptions. The comparison takes the form of an Excel graph such as the example in Figure L-107. The steps that the user would go through manually to create such a graph are:

- Convert the OptQuest output (see Figure L-108) to an Excel worksheet for analysis
- Sort the plans to reveal those that are 1) on the efficient frontier, 2) near the efficient frontier, and 3) do not belong to either of these categories (see Figure L-109)
- Re-label columns for easier comprehension. For example, the column of representing values for CCCT_02 might be relabeled to CCCT_1207 to reflect the fact that this decision cell controls construction beginning December 2007.

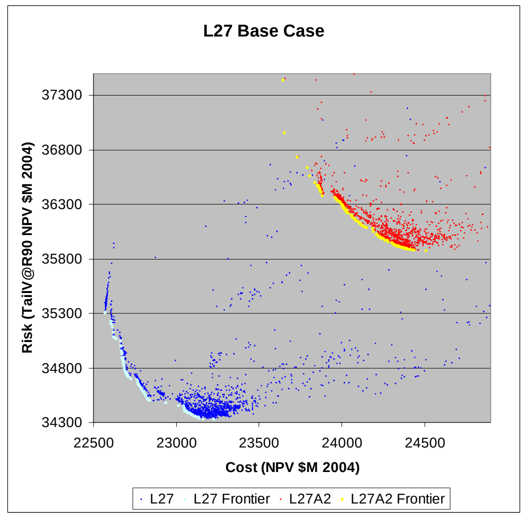


Figure L-107: Comparison of Feasibility Spaces

- Add the data points from the worksheet to a graph that already has the data points for the basecase. This includes identifying which points are on the efficient frontier and formatting those points with a distinct shape and color so that they are clearly distinguished.

The workbook "Analysis of Optimization Run.xls"[37] contains the macro sub_PROCESS, which performs these tasks automatically. To use the macro, the user merely identifies the file containing the OptQuest output and a string for labeling the analysis or sensitivity case.

It may be helpful to understand the typical structure of the worksheet containing sorted plans, illustrated in Figure L-109. An example of this report appears in worksheet "Base Case" of the workbook "Analysis of Optimization Run.xls." Figure L-109 is an abbreviated version, with certain columns and rows removed for clarity.

- Column A identifies the plan number, which is assigned sequentially as the simulations are performed
- Columns B through AR specify the value of decision cells. As described in previous sections, these specify the plan.

[37] This workbook is available from the Council's website or from the Council upon request.

- Columns AS through BG specify the values for forecast cells. These are the results of the simulation. Particularly significant are the mean net present value study cost in column AS and the $TailVaR_{90}$ risk in column AV.
- Column BH specifies plans on the efficient frontier. This report sorts the plans so that all of the plans on the efficient frontier appear together at the top of the report.
- Column BI specifies plans that are near the efficient frontier. These are plans within $250 million cost and risk of the efficient frontier.

```
Simulation: 1

Values of Variables:
Cnsrvn_01: 20
Cnsrvn_02: 10
RM: 5000
CCCT_01: 0
CCCT_02: 0
CCCT_03: 0
CCCT_04: 0
CCCT_05: 0
CCCT_06: 0
CCCT_07: 610
CCCT_08: 1220
SCCT_01: 0
SCCT_02: 0
SCCT_03: 0
SCCT_04: 0
SCCT_05: 0
SCCT_06: 0
SCCT_07: 200
SCCT_08: 200
Coal_01: 0
Coal_02: 0
Coal_03: 0
Coal_04: 0
Coal_05: 0
Coal_06: 0
Coal_07: 0
Coal_08: 0
Wind_01: 0
Wind_02: 0
Wind_03: 100
Wind_04: 600
Wind_05: 2500
Wind_06: 4500
Wind_07: 5000
Wind_08: 5000
IGCC_01: 0
IGCC_02: 0
IGCC_03: 0
IGCC_04: 425
IGCC_05: 425
IGCC_06: 425
IGCC_07: 425
IGCC_08: 425

Objective: Total Study Costs:1: Mean: 24421.4227133067
Feasible Requirement: Total Study Costs:1: Std_Dev: 5614.3871222492
Feasible Requirement: Total Study Costs:2: Median: 23223.7005012319
Feasible Requirement: TailVar90: Final_Value: 35924.8641878857
Feasible Requirement: CVaR20000: Final_Value: 26183.2357784132
Feasible Requirement: Quint90: Final_Value: 32370.2595941873
Feasible Requirement: VaR90: Final_Value: 7948.83688088056
Feasible Requirement: Cst_Var: Mean: 5.01001288051045
Feasible Requirement: Max_Incr: Mean: 13.503317703262
Feasible Requirement: LO_MWa: Mean: 1016.67790085181
Feasible Requirement: LO_Cst: Mean: 25.4497985131799
Feasible Requirement: NLO_MWa: Mean: 1561.91236255434
Feasible Requirement: NLO_Cst: Mean: 23.278176520789
Feasible Requirement: Cnsv_MWa: Mean: 2578.59026340615
Feasible Requirement: Cnsv_Cst: Mean: 24.1821505178384


Simulation: 2

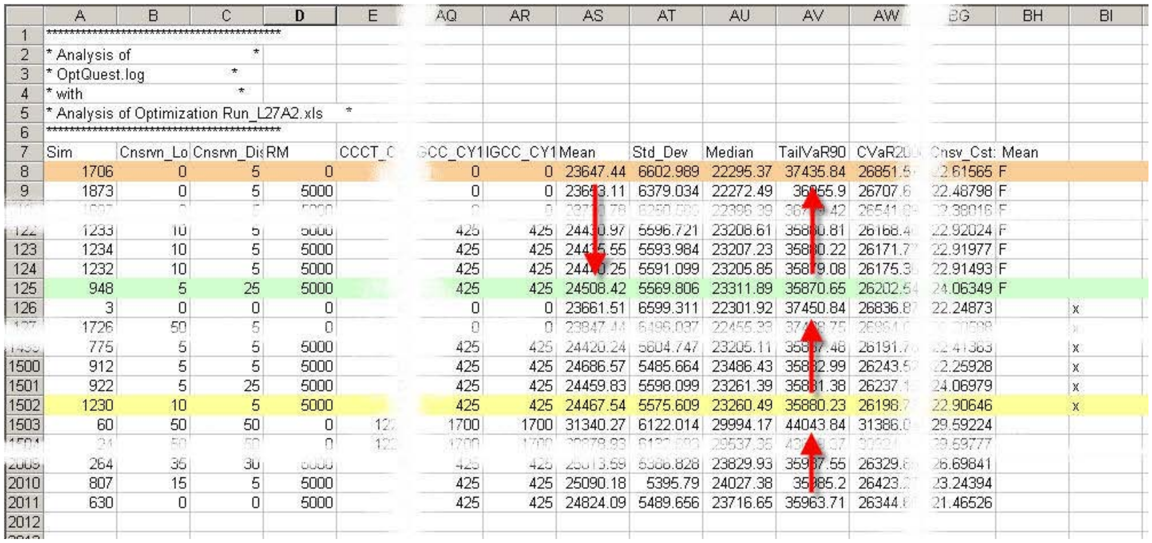
Values of Variables:
Cnsrvn_01: 25
Cnsrvn_02: 25
RM: 3000
CCCT_01: 610
CCCT_02: 1220
CCCT_03: 1830
CCCT_04: 3050
CCCT_05: 3050
CCCT_06: 3050
CCCT_07: 3050
…. Etc….
```

Figure L-108: OptQuest Log

Plan A dominates Plan B if Plan A has lower cost *and* lower risk then Plan B. The plans on the efficient frontier of those plans that are not dominated by any other plan. Along the efficient frontier, sorting by risk automatically sorts by cost. We illustrated this sorting by the arrows in columns AS and AV of Figure L-109. For the remaining plans, there generally is no way to simultaneously sort cost and risk. The report sorts the near-efficient plans and the remaining plans, therefore, merely by risk.

Data Extraction And Spinner Graphs

A developer does not validate a strategic planning model that incorporates uncertainty the same way that he would most models. When a developer wants to validate the typical simulation model, he performs calibration of the model on a portion of historical data but withholds a portion of historical data for testing. Validation consists of checking the performance of the model against this test data. The situation is different for a long-term planning model. The future will differ from the past in ways that are predictable. For example, structural changes in the supply and demand of natural gas will affect future prices. New resources will similarly affect demand for natural gas, supply of electricity, and transmission power flows. Using data from the past would not be valid. Similarly, while some types of variation, like stream flows, may indicate future variation, they probably don't have any bearing on strategic uncertainty or risk. Strategic uncertainty deals with changes about which we have little current information, such as diminished stream flow due to climatic change, new regulation, or unforeseen changes in irrigation requirements.



	A	B	C	D	E	AQ	AR	AS	AT	AU	AV	AW	BG	BH	BI
1	**														
2	* Analysis of *														
3	* OptQuest.log *														
4	* with *														
5	* Analysis of Optimization Run_L27A2.xls *														
6	**														
7	Sim	Cnsrvn_Lo	Cnsrvn_Di	RM	CCCT_C	CC_CY1	IGCC_CY1	Mean	Std_Dev	Median	TailVaR90	CVaR2[illegible]	Cnsv_Cst:	Mean	
8	1706	0	5	0		0	0	23647.44	6602.989	22295.37	37435.84	26851.5[illegible]	[illegible]2.61565	F	
9	1873	0	5	5000		0	0	236[illegible]3.11	6379.034	22272.49	36[illegible]55.9	26707.6	22.48798	F	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	[illegible]	237[illegible]78	[illegible]	22396.39	36[illegible]42	26541.[illegible]	[illegible]2.38016	F	
122	1233	10	5	5000		425	425	244[illegible]0.97	5596.721	23208.61	358[illegible]0.81	26168.4[illegible]	22.92024	F	
123	1234	10	5	5000		425	425	244[illegible]5.55	5593.984	23207.23	358[illegible]0.22	26171.7[illegible]	22.91977	F	
124	1232	10	5	5000		425	425	244[illegible]0.25	5591.099	23205.85	358[illegible]9.08	26175.3[illegible]	22.91493	F	
125	948	5	25	5000		425	425	24508.42	5569.806	23311.89	35870.65	26202.5[illegible]	24.06349	F	
126	3	0	0	0		0	0	23661.51	6599.311	22301.92	37450.84	26836.8[illegible]	22.24873		x
127	1726	50	5	0		0	0	23847.44	6496.037	22455.33	37[illegible]8.75	[illegible]	[illegible]		x
[illegible]	775	5	5	5000		425	425	24420.24	5604.747	23205.11	358[illegible]7.48	26191.7[illegible]	[illegible]2.41363		x
1500	912	5	5	5000		425	425	24686.57	5485.664	23486.43	358[illegible]2.99	26243.5[illegible]	[illegible]2.25928		x
1501	922	5	25	5000		425	425	24459.83	5598.099	23261.39	358[illegible]1.38	26237.1[illegible]	24.06979		x
1502	1230	10	5	5000		425	425	24467.54	5575.609	23260.49	35880.23	26198.7[illegible]	22.90646		x
1503	60	50	50	0	12[illegible]	1700	1700	31340.27	6122.014	29994.17	44043.84	31386.0[illegible]	29.59224		
1504	24	50	50	0	12[illegible]	1700	1700	[illegible]878.93	612[illegible]	29537.35	43[illegible]7.37	[illegible]	29.59777		
2009	264	35	30	5000		425	425	25[illegible]13.59	5386.828	23829.93	359[illegible]7.55	26329.6[illegible]	26.69841		
2010	807	15	5	5000		425	425	25090.18	5395.79	24027.38	35[illegible]85.2	26423.[illegible]	23.24394		
2011	630	0	0	5000		425	425	24824.09	5489.656	23716.65	35963.71	26344.[illegible]	21.46526		
2012															

Figure L-109: Plans, Arranged By Cost and Risk

In lieu of traditional validation, therefore, the Council relies on decision makers' direct evaluation of futures. That is, witnessing individual futures, including all sources of uncertainty taken as a joint event, convinces decision makers and builds credibility. If decision makers find that the futures are realistic and the plans respond to the futures appropriately, they are apt to have confidence in the results.

The workbook L24DW02-f06-P.xls[37] contains the macro subRunPlans for running a simulation on a given plan and placing selected data from each of the 750 futures into specific worksheets. A collection of Excel graphs displays the data, including values for all sources of uncertainty in each period. A sample of these graphs appears as Figure L-7 through Figure L-11, starting on page L-12.

The graphs also present to the user information about the plan and its performance under each of the futures, including generation and cost by technology and fuel type. They illustrate the resulting imports and exports. The graphs also show capital and total costs by period for the study. Decision makers can study these to decide whether the model is performing according to their expectations. The decision maker or analyst can also press a button that permits her to quickly move through the futures and witness the corresponding data in the graphs. Because these graphs update so quickly, the Council refers to them as "spinner graphs."

The same workbook that creates the spinner graphs can also extract data for any cell in the portfolio model and for any set of plans, not just a single plan. The user can specify the plans to be subjected to the futures by pasting copies of the decision cells into the worksheet "Plans," as illustrated in Figure L-110. The macros in this workbook will

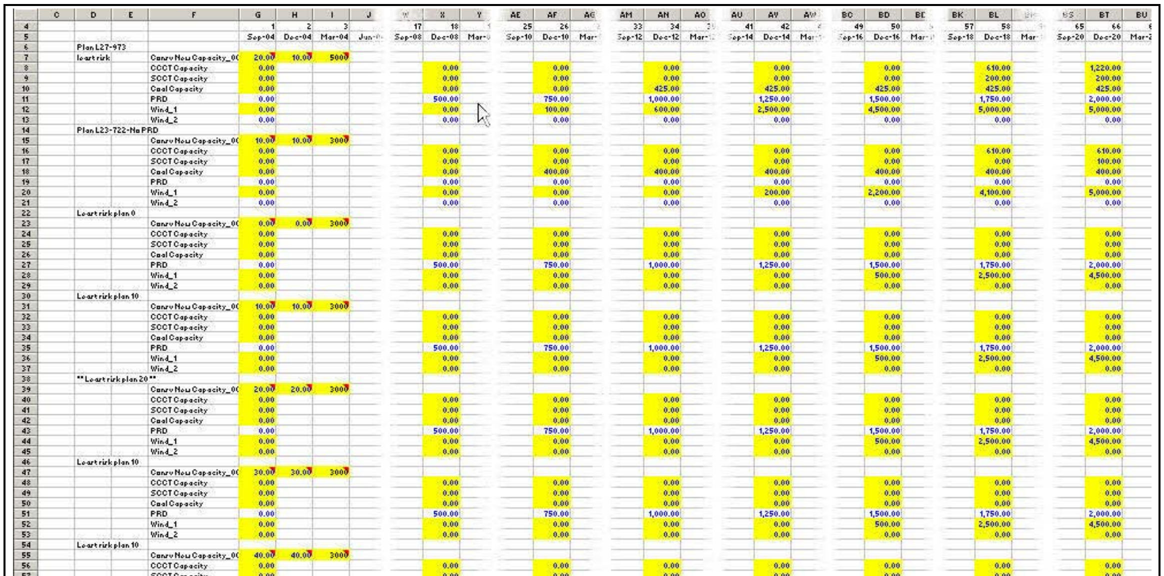
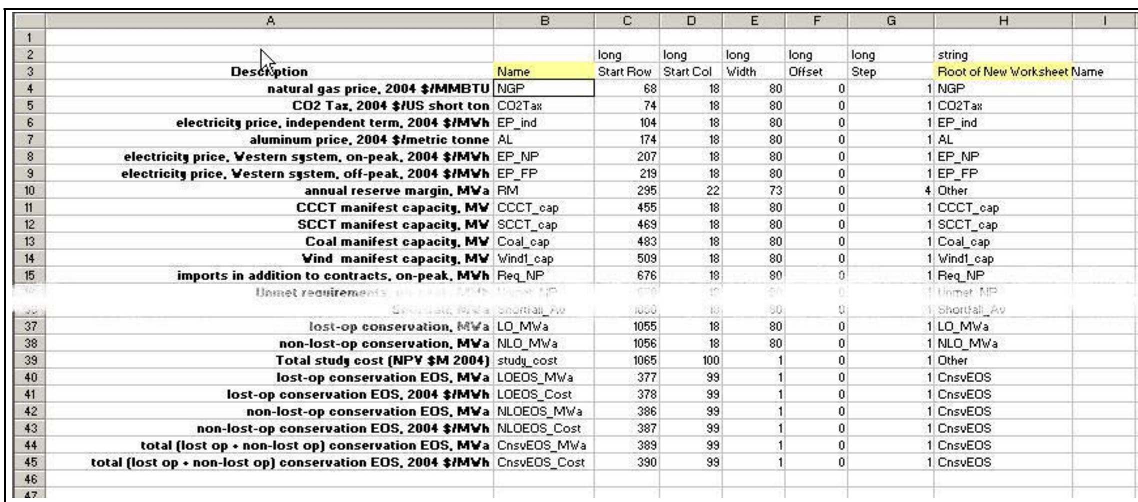


Figure L-110: Specified Plans Simulation Utility

perform a Monte Carlo simulation on each of these plans in turn and place the results in specified worksheets.

The data that the macro places into the selected worksheets comes from Crystal Ball forecast cells. To prepare a spinner graph, the user must prepare about 3200 forecast cells in the regional portfolio model worksheet. Converting a cell into a Crystal Ball forecast cell at a minimum requires the user to assign a unique name to the cell. The macro subAutoPaintForecasts in the workbook L24DW02-f06-P.xls does this work automatically. The macro reads instructions from the worksheet "Forecast Addresses", illustrated in Figure L-111. This worksheet identifies the rows and columns to be "painted with" forecast cells. The text in column B forms the names that the macro assigns to the forecast cells, together with the number of the column, and the address of the cell. Column H determines the names of the worksheets into which the macro places the resulting data. With a minor modification, this macro can also paint cells as Crystal Ball *assumption* cells.



	A	B	C	D	E	F	G	H
1								
2			long	long	long	long	long	string
3	Description	Name	Start Row	Start Col	Width	Offset	Step	Root of New Worksheet Name
4	natural gas price, 2004 $/MMBTU	NGP	68	18	80	0	1	NGP
5	CO2 Tax, 2004 $/US short ton	CO2Tax	74	18	80	0	1	CO2Tax
6	electricity price, independent term, 2004 $/MWh	EP_ind	104	18	80	0	1	EP_ind
7	aluminum price, 2004 $/metric tonne	AL	174	18	80	0	1	AL
8	electricity price, Western system, on-peak, 2004 $/MWh	EP_NP	207	18	80	0	1	EP_NP
9	electricity price, Western system, off-peak, 2004 $/MWh	EP_FP	219	18	80	0	1	EP_FP
10	annual reserve margin, MWa	RM	295	22	73	0	4	Other
11	CCCT manifest capacity, MW	CCCT_cap	455	18	80	0	1	CCCT_cap
12	SCCT manifest capacity, MW	SCCT_cap	469	18	80	0	1	SCCT_cap
13	Coal manifest capacity, MW	Coal_cap	483	18	80	0	1	Coal_cap
14	Wind manifest capacity, MW	Wind1_cap	509	18	80	0	1	Wind1_cap
15	imports in addition to contracts, on-peak, MWh	Req_NP	676	18	80	0	1	Req_NP
16	Unmet requirements ...	Unmet_NP	[illegible]	[illegible]	[illegible]	[illegible]	1	Unmet_NP
36	[illegible]	Shortfall_Av	1050	[illegible]	[illegible]	[illegible]	1	Shortfall_Av
37	lost-op conservation, MWa	LO_MWa	1055	18	80	0	1	LO_MWa
38	non-lost-op conservation, MWa	NLO_MWa	1056	18	80	0	1	NLO_MWa
39	Total study cost (NPV $M 2004)	study_cost	1065	100	1	0	1	Other
40	lost-op conservation EOS, MWa	LOEOS_MWa	377	99	1	0	1	CnsvEOS
41	lost-op conservation EOS, 2004 $/MWh	LOEOS_Cost	378	99	1	0	1	CnsvEOS
42	non-lost-op conservation EOS, MWa	NLOEOS_MWa	386	99	1	0	1	CnsvEOS
43	non-lost-op conservation EOS, 2004 $/MWh	NLOEOS_Cost	387	99	1	0	1	CnsvEOS
44	total (lost op + non-lost op) conservation EOS, MWa	CnsvEOS_MWa	389	99	1	0	1	CnsvEOS
45	total (lost op + non-lost op) conservation EOS, 2004 $/MWh	CnsvEOS_Cost	390	99	1	0	1	CnsvEOS
46								
47								

Figure L-111: Specified Cells To Make Assumptions or Forecasts

Calculations for a Particular Future

To verify the calculations in the regional model, the user must be able to drill down into the results to check calculations at the lowest level. Typically, when the user sees something that he or she does not understand, they will attempt to identify a plan in which that behavior is extreme. Using this plan, they look for a future in which the same behavior is evident. Depending on the issue, they may then need to trace the problem to a particular resource or period under that future. This final step requires that the user have access to the calculations taking place in every cell of the portfolio model worksheet for that plan and for that future.

As mentioned in the previous section (page L-110), single stepping with Crystal Ball does not reproduce the same sequence of futures that obtains from a simulation starting with a specific seed value for the random number generator. For this reason, it is necessary to run the simulation up to the future of interest. In simulation mode, however, the macros that the regional model uses to recalculate are not available to the user for experimentation and debugging. Therefore, the user must capture of the values of the assumption cells and put them in a copy of the regional model that the user can run independently, as described in section "Stand-Alone Calculation."

The user can run the Monte Carlo simulation up to the future of interest, and copy and paste the values of the regional model worksheet into a new worksheet. The workbook "L24DW02-f06-P.xls"[37] contains a macro, subCBAssumptionCopy, that transfers values from the cells in one worksheet to the corresponding assumption cells in a target worksheet. A dialog box interface prompts the user for the source and target worksheet names.

Finding the Intersection of Two Feasibility Spaces

Occasionally, an analyst may see something surprising and counterintuitive when he compares two feasibility spaces. For example, suppose the user were comparing two feasibility spaces, the first with a base case set of assumptions regarding resource availability, and the second with resources that were constrained relative to the base case. Perhaps the CCCT capacity expansion resource is constrained from developeding to the same quantity (megawatts) in later years as under the base case. We would expect that the efficient frontier for the base case would dominate that of the constrained case. That is, we would not expect a plan from the constrained case would outperform the plans from the base case. A natural question to ask would be, "has the model changed?"

This question may not be so easy to answer. Perhaps the computers or software versions are different. It may be difficult to reproduce a specific plan from the base case. Even if the results for a particular plan matched, we have little reassurance that results would have matched if we chose another plan.

The macro sub_Compare in the module mod_ComparisionOfPlans.bas[37] permits the user to locate and compare identical plans from two feasibility spaces. It compares two feasibility space plan listings, such as that illustrated in Figure L-109. Specifically, for any matching plan the macro reports the difference in mean distribution cost and $TailVaR_{90}$. If these are identical for all of the matching plans, the user has greater confidence that the difference he is seeing is real and not merely the result of the change in logic or platform.

This macro has served a particularly important role for the Council. Recall that the modeling process uses optimization to find least cost plans given risk constraints. The primary reason for using optimization is to avoid simulating and comparing a very large number of plans[38]. Optimizing nonlinear, stochastic processes is a thorny technical problem, and initial conditions and early results can lead the optimizer to suboptimal search strategies. By comparing two feasibility spaces, the user gets a better idea of when and why the optimizer began a particular search strategy. A plan like the one just described in our example may be the result of such alternative strategy. The efficient frontier produced for the base case may simply not be optimal.

This situation is a reminder that the Council's model is no substitute for judgment. The analyst must study the feasibility space to determine whether alternative strategies near the efficient frontier exist and are beneficial. She must also question whether she can improve the strategies on the efficient frontier.

It has been the experience of the Council that, where the base case efficient frontier has proven to be suboptimal, intervention made at best marginal improvement. Occasionally, one resource of a given fuel type can substitute for another of the same fuel type, and the optimizer may tend to report only one of these along the efficient frontier. This has had little impact on the overarching strategy along the efficient frontier, however. These observations have provided the Council with overall confidence in the optimizer's efficient frontier.

Stochastic Adjustment

Prices in the model derive from the Council's assumptions for long-term equilibrium prices[39]. For reasons discussed in Chapter 6, these equilibrium prices can be associated with the median price because there is equal probability of being above and below the median price. Some users may prefer, however, for the long-term equilibrium prices to match the price distribution's ***mean***. Because prices in the regional model use a lognormal distribution, however, the mean price is *higher* than the median price. (See Appendix P.)

To accommodate this situation, the model can apply a "stochastic adjustment" to the benchmark price. This adjustment, a number between zero and one, is chosen so that the distributions mean price matches the benchmark price. An example of a stochastic

[38] For the base case used in the final version (L28) of the plan, there are about to 5.1 x 10^{24} possibilities.
[39] Because the median and the mean both described the final distribution of prices after any adjustment, we refer to the starting place as the "benchmark price." The benchmark price is typically the long-term equilibrium price.

adjustment for on peak wholesale electricity market prices appears in the second row of Figure L-112.

	Series: Market Prices Independent Term_005				
Expected_Value_Set: Market Exp Price On-Peak 4x2	32.29	33.04	32.99	32.33	32.66
Stochastic_Adjust_Set: Stoch Adj On-Peak 4x2	0.87	0.73	0.78	0.76	0.85
Principal_Factor_Set: Reg Mkt Prc	-0.02037443	1.00			
Data_Series: Mkt Prin Fac Level	0.50				
	0.007267999	1.00			
Data_Series: Mkt Prin Fac Lin Growth	0.00	0.07			
Combined factors	-0.010187215	-0.009678455	-0.009678455	-0.009678455	-0.009678455
Jump_Set: Elec Mkt_002	8.770426174	0.072691876	8.899814829		
	16.07130502	0.100080134	11.46780741		
Combined Jumps	8.770426174	173.850772	0.072691876	173.850772	220.5905142
	0	0	0	0	0

Figure L-112: Stochastic Adjustment

Each period typically requires a separate stochastic adjustment. The regional model workbook macro subTarget automates this process. The user may specify several different prices, say wholesale electricity price, natural gas price, and oil price, and simultaneously find stochastic adjustments for each of these in every period.

Menu Bars

Menu bars are available for the portfolio model. These menu bars provide a simplified interface to many of the macros and utilities that this section describes. (See Figure L-113.) The menu bars are not in the regional model, because they interfere with distributed computation (see section ".")

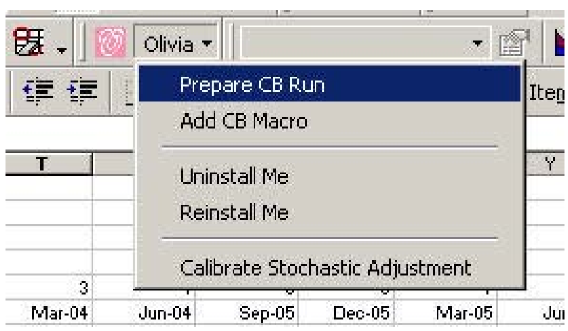


Figure L-113: Olivia Toolbar

Insights

This section summarizes some of the insights and discoveries the Council has made using the regional portfolio model. Many of these insights arose out of paradoxes, behaviors that contradicted our intuition about how the model should behave. For this reason, the section presents these insights as the answers to a series of questions.

General Paradoxes

"The model suggests that we should build the resources we don't expect to use. It calls for conservation that is not cost effective and power plants that are not 'used and useful.' How can we justify this?"

Building resources surplus to our requirements is analogous to buying insurance. We hope we never have to use it, but it would be foolish not to have the protection.

There are several differences between planning under uncertainty and planning with perfect foresight. Most strategic resource planning done today makes implicit use of the perfect foresight assumption. Whenever a plan assumes power plants recover their fully allocated costs or market price average around some long-term equilibrium level, planners are invoking perfect foresight.

Much of the planning today limits its treatment of uncertainty to what the Council would refer to as variation or variability. These are sources of uncertainty about which we have a great deal of information, such as hydro generation variability from year to year or the variation in loads due to weather. This kind of planning, however, does not embrace strategic uncertainty, the possibility that the underlying systems and markets themselves will change, perhaps dramatically and irreversibly. Embracing uncertainty means abandoning faith in averages and equilibrium. It means finding strategies that permit us to respond effectively and inexpensively to changing circumstances and protect us from the direst outcomes.

When we recognize that we need to protect our constituents from an uncertain future, insurance becomes useful. We hope that we will never have to use our insurance. We *hope* to lose money on the insurance, that we will forever pay a premium for our insurance and never have an opportunity to use it, *because if we ever do have to use our insurance, we will be worse off than we would have been otherwise*. The insurance merely reduces the magnitude of the damage; it does not eliminate it and it certainly should not reward us. (We would probably call such an expectation *speculation*, rather than risk mitigation.) Thus, some conservation and power plant capacity surplus to our anticipated need may not be used and useful, but it may be important protection.

Planning that does not embrace uncertainty not only fails to capture the insurance value of resources, but it in fact contributes to a riskier industry environment. Before the energy crisis, many utilities relied on the wholesale market instead of building their own resources. There are several reasons for this. The industry had surplus generating capacity and wholesale prices for electricity were low. Planners in the industry knew, however, that this situation would eventually correct itself. They relied on models, however, that computed long-term equilibrium prices for electricity. These planners elected to use a single price forecast for their analysis. Probably the single most meaningful price forecast is the long-term equilibrium price forecast, because it is the best estimate of where prices should return after any excursions, given a fixed set of assumptions. If one had to choose a single price forecast, this one would be the one to use. The problem with using a single price forecast, of course, is that it doesn't permit the planner to estimate the insurance value of resources. It does not tell the planner what kinds of risks he is incurring.

An insidious trap, however, lay in the fully allocated costs of some new resource setting the equilibrium price[40]. A CCCT is a typical candidate for new resource in the Pacific Northwest. If the planner is evaluating the utility-build decision using such a price forecast, it is unlikely that the utility build option will be cost effective. The new resource that sets the market price is the most cost effective in the region and is unlikely to be the unit that the utility is building. Even if the utility happens to be building the most cost-effective resource, however, there is no incentive to incur the risks associated with building a new resource if the planner believes the utility can purchase electricity from the market for a similar cost. Consequently, the utility does not build. Consequently, there is no gradual return of market prices to equilibrium. This produces a "boom and bust" cycle in electricity prices.

Cost-effectiveness levels change over time. Planning that ignores this will fail to capture the insurance value of resources, and in particular conservation. In the next section, this appendix documents how the shape of the supply curve for conservation and the changing cost-effectiveness level can make a policy of acquiring conservation in addition to that which appears cost effective today beneficial not only because of it reduces risk, but because the policy reduces *expected* cost.

"The regional model tells us that we need resource surplus to our needs for insurance purposes. Why don't the combustion turbines and coal plants my utility wants to build support this objective?"

The Regional Model tells us that having a little surplus is better than having a little deficit, but the principal strategic blunder would be to overbuild. Plans farther from the efficient frontier have higher levels of capacity.

Many utilities got themselves into difficulty during the energy crisis because of their exposure to the market. Twenty years ago, however, a crisis of equal if not greater proportion was visited on the region and much of the rest of the country when loads fell and ratepayers were exposed to fixed-cost risk. This is a source of risk that the regional model warns us may be a problem for the next decade. During the four years following the energy crisis, the region lost 2000 MWa of load and added 3000 MW of new power plants. Much of the load loss was from smelters that shut down. It is unlikely that most of these smelters will return to service. This 5000 MW is a significant portion of the 20,000 MW of regional load. The Council estimates that 3000 MW would probably have been sufficient to keep the region in balance during the energy crisis. Load growth in the region is approximately 300 MW per year, and new resources, such as the 500 MW Port Westward Project and portfolio standard wind, will continue to contribute to this surplus.

When it comes time to build for an energy reserve margin, the region has to be careful about the resources that it selects. A reserve margin criterion that only specifies how

[40] This is classical macroeconomics: equilibrium price equals long-term marginal cost.

much capacity to build surplus to requirements ignores economics and many important sources of risk. Confronted with a capacity reserve margin requirement, a utility will probably build a single-cycle combustion turbine (SCCT). On a dollar per kilowatt basis, this is the cheapest way to meet that requirement. A coal plant might be the cheapest way to meet an energy reserve margin requirement. Both of these fuels expose the utility to greater carbon emission penalty risk and fuel price risk, however.

"Why are IPPs included in the region? My utility has a resource deficit, but there isn't sufficient transmission capacity to wheel IPP power to our load center."

The focus of the regional model is economic efficiency and risk. Market prices across the western states do not deviate materially among themselves. Most of the time, they track each other closely. This means that a utility need not wheel power from a plant in order to reduce economic risk, because it can buy power in the market to meet its load center requirement and offset the cost of that wholesale spot power with the value of power used in a remote market. The economic effect is virtually identical to having a local power plant, selling into the market of the load center.

This is idea is not new; utilities have used this principle for many years. For example, Portland General Electric owns a portion of Colstrip Units 3 and 4 in Wyoming. While there are contracts to wheel this power to Portland, those contracts are counter-scheduled. When the Kaiser Mead and Columbia Falls aluminum smelter in eastern Washington shut down in response to federal buy-back offers in 2001, a remedial action scheme (RAS) shut down the Colstrip units to prevent instability on the Avista system. Power bottled up on the east side of the West-of-Hatway (WoH) transmission cut-plane. If the fiction of contract path transmission were true, and transmission lines were "electron pipes," there would be no reason for the Colstrip units to be taken down. The load situation in Portland certainly had not changed. The fact is, the Colstrip power is actually serving power loads and supporting the integrated power system east of the WoH cut-plane. Nevertheless, the Colstrip units remain a valuable economic hedge for PGE's customers against the more volatile market power purchased from the Mid-Columbia, and PGE accounts for the units as though the power meets Portland demand. Most utilities have similar arrangements.

"Surplus conservation appears to have a significant benefit to the region. The benefit, however, far exceeds the product of market price and surplus conservation capacity. Where is this extra value coming from?"

Modeling has revealed that early development of conservation can play an important role in moderating price volatility. Reducing price volatility reduces system cost. Conservation is uniquely suited to this task.

Early in regional model studies, the portfolio model used market value as the decision criterion for adding new resources. That is, when the model estimated that a resource would make money in the market based on the model's estimate of forward curves, it would proceed with construction of that resource. The exception to this situation, however, was conservation. Conservation has a slightly different decision criterion that caused continuous and early additions.

This situation effectively created a resource reserve margin. If a situation arose that created a price spike, this surplus of capacity mitigated the spikes. In fact, the value of conservation estimated by looking only at market price and the cost of the conservation would actually go down when the model added surplus conservation. Market prices lowered and conservation costs increased. Nevertheless, these plans performed better because the cost of serving load, a major cost component in the valuation equation, went down with lower market prices.

Conservation has certain advantages with respect to other resources as a source of energy reserve margin. One of these stems from the fact that, if conservation is to be developed into a significant resource, it needs to be developed continuously anyway. Whereas utilities can add power plant capacity on relatively short notice, conservation capacity must be added slowly over time, largely because the opportunities for securing conservation are constrained.

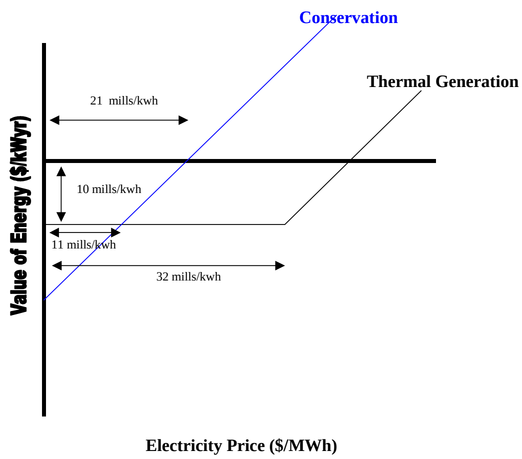


Figure L-114: Supply for Conservation vs Dispatchable

Another advantage of conservation is that it always contributes some value irrespective of market price. In Figure L-114, we assume a combined-cycle combustion turbine (CCCT) has a capital cost of 10 mills per kWh and a dispatch cost of 32 mills. It does not provide a positive net benefit until market prices exceed 42 mills. Assume that this CCCT is setting the market price, which would therefore be 42 mills. If this is the cost-effectiveness level of a supply curve for conservation that is linear between zero and 42 mills, the average cost of conservation would be 21 mills. Between 11 and 21 mills, both the turbine and the conservation would lose money, but the turbine would lose more money. Between 21 mills and 42 mills, the conservation is paying for itself, but the combustion turbine is not. Above 11 mills, conservation provides greater value than the CCCT. While some policymakers may be concerned that pursuing an aggressive program of conservation acquisition is risky when depressed market prices are likely in the future, this example suggests the opposite. Conservation would be the best solution unless market prices are extremely low, below 11 mills per kilowatt-hour. (And under that circumstance, lower purchase power costs for loads not met by conservation provide the utility a hedge against the extra cost.) This example, moreover, ignores the high-price risk mitigation value of conservation described in a previous paragraph.

In the past, system planners have regarded reserve margin primarily as a means to enhance system reliability. The economic and price effects of reserve margin have been largely ignored. The regional portfolio model identifies significant value in the price moderation effect of conservation. Others have seen this effect for renewables, as well. [**20**]

"The regional model appears to find larger energy reserve margins attractive the further out in time we plan. Reserve margins have traditionally been expressed as some percentage of loads or a fixed level of energy surplus to requirements. Why does the regional model's surplus requirements grow so much faster than load growth?"

One of the attributes of uncertainty is that it grows over time. As uncertainty grows, there must be a greater diversity of options and a greater availability (megawatts) of each option to cover contingencies. For example, assume we provide the regional model with only two candidates for new capacity: a coal plant and combustion turbine. There is greater uncertainty about loads and possible carbon penalty 20 years from today. It may also be likely that there will be high natural gas prices. Consequently, the best choice for the model is to plan for and site enough coal plant capacity and combustion turbine capacity to cover the entire load requirement. This may double the apparent amount of construction that the model is calling for. In fact, depending on the future, the owner would construct either one resource or the other, but probably not both.

A couple of related issue are the dependence of the regional model's plans – which specify options for construction – on uncertainty and the need to revise plans as that uncertainty resolves itself. The regional model specifies the risk-constrained, least-cost plans given today's view of uncertainty. Implicit in the plans is the assumption that decision makers must commit to siting and licensing today. For the most part, this is unrealistic. Before committing to plant siting and licensing for construction commencement ten years in the future, for example, there will be opportunities to review the plans to determine whether the siting and licensing costs are still warranted. Decision makers must use these opportunities to update information about assumptions and review plans before committing funds.

"The efficient frontier sweeps out a fairly small range of cost and risk. Given the magnitude of costs going forward, why is this trade-off curve so small?"

The primary reason the trade-off curve is small relative to the scale of costs in this study is that the regional model has no control over the choice of existing resources. While the model can choose resources going forward that reduce exposure to natural gas prices, for example, about 25% of the energy requirement will be met with natural gas in the future irrespective of what the regional model chooses.

We see in many of the sensitivity studies presented in Appendix P that the impact of uncertainties dwarfs the effect of resource choice. The efficient frontier, which may represent a trade-off of $500 million to $1 billion, moves between $6 and $10 billion if expected gas prices double. CO_2 emission penalties can have even larger impacts. Both of these affect the existing system, over which the model has no control. Perhaps it is useful to remember the relative scale of that which is controllable, compared to that which is out of our hands.

"Market prices in the regional model do not behave as we would expect. For example, you are not building any resources in the future and loads are increasing. Nevertheless, electricity prices stay low. Moreover, if you increase import-export capability, market price volatility increases instead of decreasing. Access to greater imports increases reliability, doesn't it? How do you explain this?"

A model that explicitly incorporates uncertainty behaves in ways that are counterintuitive to those who have used in deterministic models. This behavior is due to two terms: locality and modeling degrees of freedom.

Locality means the model is capturing behavior of local resources and loads, based to a large part on local prices for natural gas and other local parameters. This representation, however, ignores much of the world and many, perhaps most, sources of uncertainty. While local electricity prices depend on local loads, local hydro generation, and local natural gas prices, these factors describe perhaps half of the variation in electricity prices. As we saw during the energy crisis, factors completely outside of the region can determine our local electricity prices. Looking forward, it is easy to see that a California policy encouraging the building of surplus resources probably will affect local prices for electricity. Technology enhancements that may reduce loads and electricity prices are not represented explicitly anywhere in the regional model. For these reasons, a significant contribution to the price of electricity is an independent stochastic variable, intended to represent these factors in aggregate. This large source of uncertainty is unrelated to explicitly modeled, local factors. How can market prices remain low when loads are increasing in no resources are being built? Through non-local factors, such as purchases of inexpensive electricity, supplied by breakthrough solar photovoltaic technology or from conventional resources that are now surplus to depressed copper mine electricity requirements outside the region, for example.

Because of the first law of thermodynamics, energy supply and load must balance. Electricity price, which has the special independent term described in the previous paragraph, determines generation and must have an additive inverse among other parameters in the model. This is a mathematical degrees-of-freedom requirement. (See discussion of the section “RRP algorithm” beginning on page L-51.) In the case of the regional model, import-export capability is the dual to electricity market price. That is, given a market price that includes the independent term, import-export energy together with regional generation must match regional load requirements exactly. If electricity market price uncertainty is large, import-export capability must be large to accommodate the balance; small import-export capability accommodates only a small amount of electric price uncertainty. Having no import-export capability implies that there is only one price that balances system load requirements, that is, there can be no uncertainty about electricity prices. This explains the behavior to which the opening question refers.

To understand intuitively what is taking place in the regional model, think of the regional market as extending to the out-of-region market, via the transmission system. Much of the uncertainty comes from the out-of-region market. If the import-export capability is small, the exposure to this larger market is small. The converse is also true.

The duality between wholesale market prices and import-export levels is in a sense arbitrary. A modeler could choose variables other than import-export capability to maintain energy balance. For example, adjusting regional loads would establish balance. Alternatively, regional resources could have been manipulated through forced outage rates to achieve the same end. Using these mechanisms would have introduced the same questions about cause-and-effect, however.

Whenever we attempt to model closed systems, like transmission constrained power systems, there are conservation laws that constrain the degrees of freedom. Prices, for example, are a direct function of supply and demand in modeling. Similarly, variation of one parameter, say price, correlates perfectly with load or the sum of generation. This representation permits no freedom of any parameter from any other; all variables are dependent variables. Constraining parameters transfer variation on to other variables. If all but one variable is constrained, they all are. In our case, market price variation is dual to imports and exports.

From these observations, we conclude uncertainty models should aspire to feasible scenarios, not complete explanations. In engineering models, such as circuit diagrams, the initial conditions and the system characteristics determine the future state of the system. An analyst can explain all behavior in terms of the model and inputs. Within an uncertainty analysis, where much of the input is, by definition, unknown, the analyst does not have an explicit, detailed story that explains why stochastic variables assume the values that they do. He nevertheless must assure the behavior does not violate the laws of physics. The behavior of the stochastic variables should not conflict with what the decision maker believes is possible, although the decision maker may find the behavior highly unlikely. The decision maker must recognize the scope of possible influences.

Conservation Value Under Uncertainty

As the previous section explains, conservation cost and risk mitigation originates from several sources, including conservation's contribution at low prices and the effect that early conservation development has on reserve margin and price volatility suppression. One of the discoveries that the Council made during studies under uncertainty was that the shape of the conservation energy supply curve could justify policies that would seem foolish if decision makers were to ignore uncertainty.

The following argument is somewhat long, but the basic idea is simple. Under certain circumstances, if the supply curve is nonlinear, the policy of acquiring more conservation than a cost-effectiveness standard would deem prudent can lower cost. Consider a simple world where there are only two market prices, $\boldsymbol{p_1}$ and $\boldsymbol{p_2}$, and these occur with equal frequency. (See Figure L-115) In this case, of course, the average price is between the two. Assume that these two prices fall on different segments of the supply curve for lost opportunity conservation, as shown.

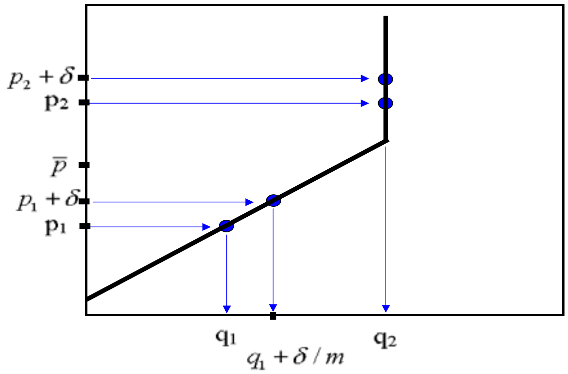


Figure L-116: Supply Curve with Premiums

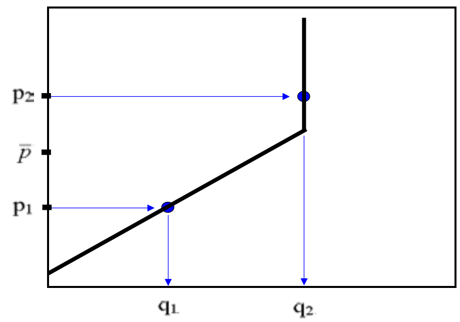


Figure L-115: Nonlinear Curve, Market Prices

Consider now the policy where we acquire conservation up to higher prices, $p_1+\delta$ and $p_2+\delta$. We obviously acquire more conservation than we would have without the premium when the market is at the lower price, p_1. Because the supply curve is vertical at p_2, however, the policy does not result in any additional acquisition at the price p_2. The policy results in acquiring more conservation at cost that is below average. Figure L-117 shows the value of the policy as the shaded area. This figure uses the same cost and value assumptions, such as "no producers' surplus," that the appendix detailed in section "Supply Curves."

Several aspects of this example are unsatisfying. For example, conservation acquisitions must be borne over the life of the measure. This example does not address that. The remaining portion of this section, therefore, provides a more detailed example.

Before proceeding, note that this example is intended to illustrate how the policy we have just described *can* result in lower cost. This is not to suggest that it *must* result in lower cost. Whether this policy reduces cost depends in a sensitive fashion on assumptions about the shape of the supply curve, the time value of money, and other things that this example intentionally glosses over for the purpose of keeping the example a simple as possible.

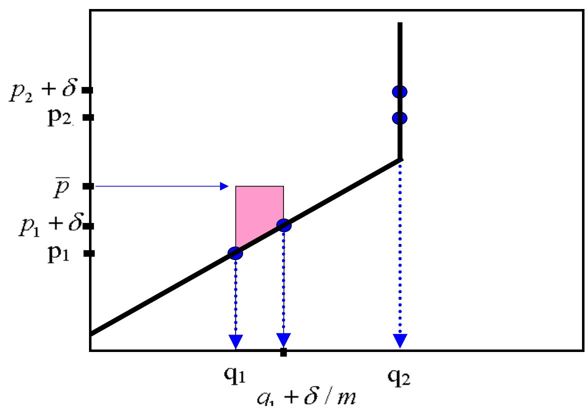


Figure L-117: Value of the Policy

In this example, we repeatedly referred to market price as a cost-effectiveness standard. This is a shorthand way of talking about whatever kind of cost-effectiveness standard would make sense to a decision maker. The Council has traditionally used a long-term equilibrium electricity price forecast produced by a spreadsheet model or by the Aurora model. That price effectively turns out to be the fully allocated cost of the least-expensive resource over the long term, typically taken to be a CCCT. This cost-effectiveness standard changes slowly, but its variation can still be quite large. In the late 1990s, this value would have been about $20 per megawatt hour. During the energy crisis, it could have been hundreds of dollars per megawatt hour in the short term, but probably would have remained about $20 per megawatt hour in the long-term. Today, with expectations for natural gas prices running about twice as high as they have historically, this value would be $35-$40 per megawatt hour. Irrespective of the nature of the cost-effectiveness standard, it is critical to recognize that there is variation and uncertainty in the cost-effectiveness standard over time. If that is recognized, the following example pertains.

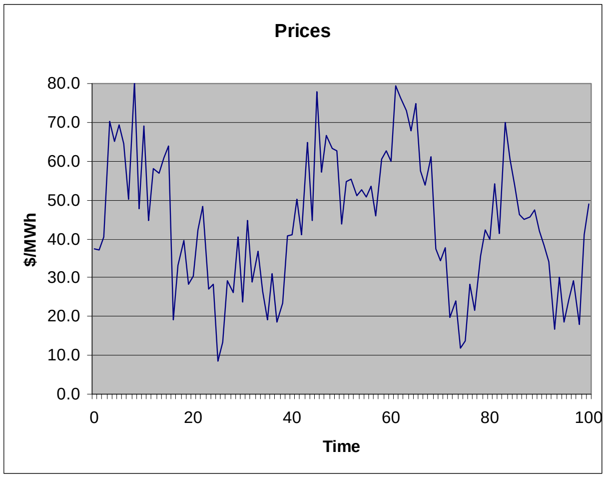


Figure L-118: Prices

Start by choosing a period with a representative distribution of prices (cost-effectiveness levels). This example assumes that prices are stationary over the long-term but have some variation around the average. Figure L-118 illustrates prices that this example will use, and Figure L-119 shows the frequency distribution of these prices. The period chosen, by definition, has prices representative of future periods, as Figure L-120 suggests. In Figure L-120, we take the effective life of the conservation measure to be some multiple, N, of this period. Over periods 2 through N, this example assumes that the distribution of prices, if not identical to that in the first period, has the same average as that in the first period.

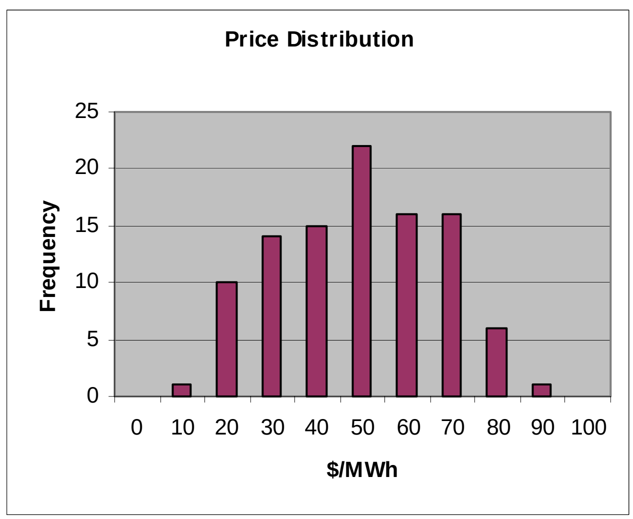


Figure L-119: Distribution of Prices

The conservation is a lost opportunity measure. In each period, potential conservation acquisition is represented by the supply curve in Figure L-121. This

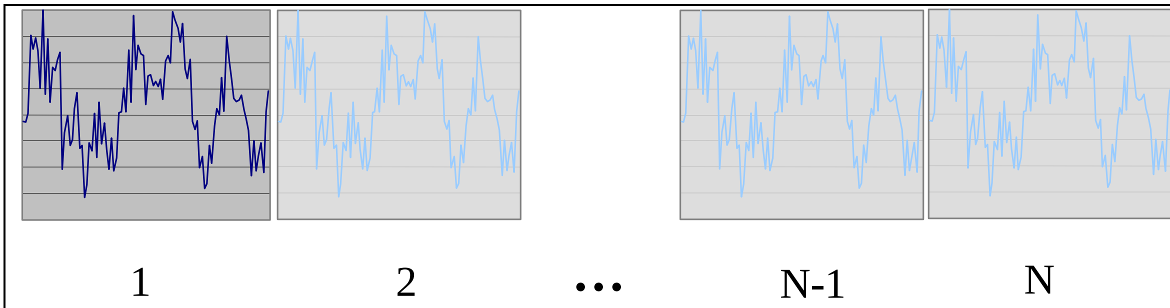


Figure L-120: Prices over Time

appendix's section "Supply Curves" details the technique for computing the amount of energy and the real levelized cost for the conservation from this supply curve.

During the period we have chosen, the example gatherers energy and cost according to the supply curve. In Figure L-122, the rate of acquisition of cost in the upper graph and of energy in the lower graph varies directly with the price. We note that the cost acquisition rate seems to be more sensitive to price variation than the energy acquisition rate, especially during periods of low prices, such as that identified as subperiod B in the figure. The energy and real levelized cost are present through the effective life of the conservation, which in this example we assume is identical to the economic life.

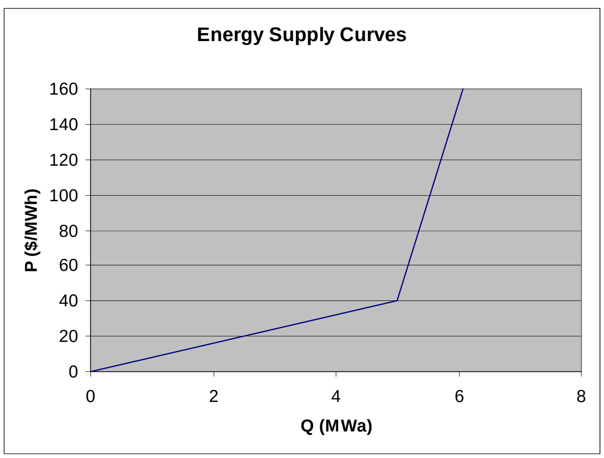


Figure L-121: Supply Curve for Conservation

The gross conservation value associated with the selected period is the sum of the acquisition rates over the selected period (just the cumulative height of the stacked acquisitions), times the average market price, times N-1. To see this, recall that the average market price over each of the N periods is identical, as Figure L-123 suggests. If the prices in period N are identical to those in period 1, the value the remaining life for each cohort *in* period N is unchanged *if moved to period **1***, as illustrated in Figure L-124. Note also that the *order* of the prices in period 1 does not affect the value, only the *distribution*. It is immaterial whether the process begins with a high or a low price.

A similar argument shows that the total cost of conservation acquired over the selected period is the sum of the acquisition rates for cost over the selected period, times N-1. The net benefit of conservation acquisitions over the selected period would then be the gross value minus this cost.

One of the assumptions this example makes to simplify calculations is that money has no time value. This example does not discount any of the cash flows.

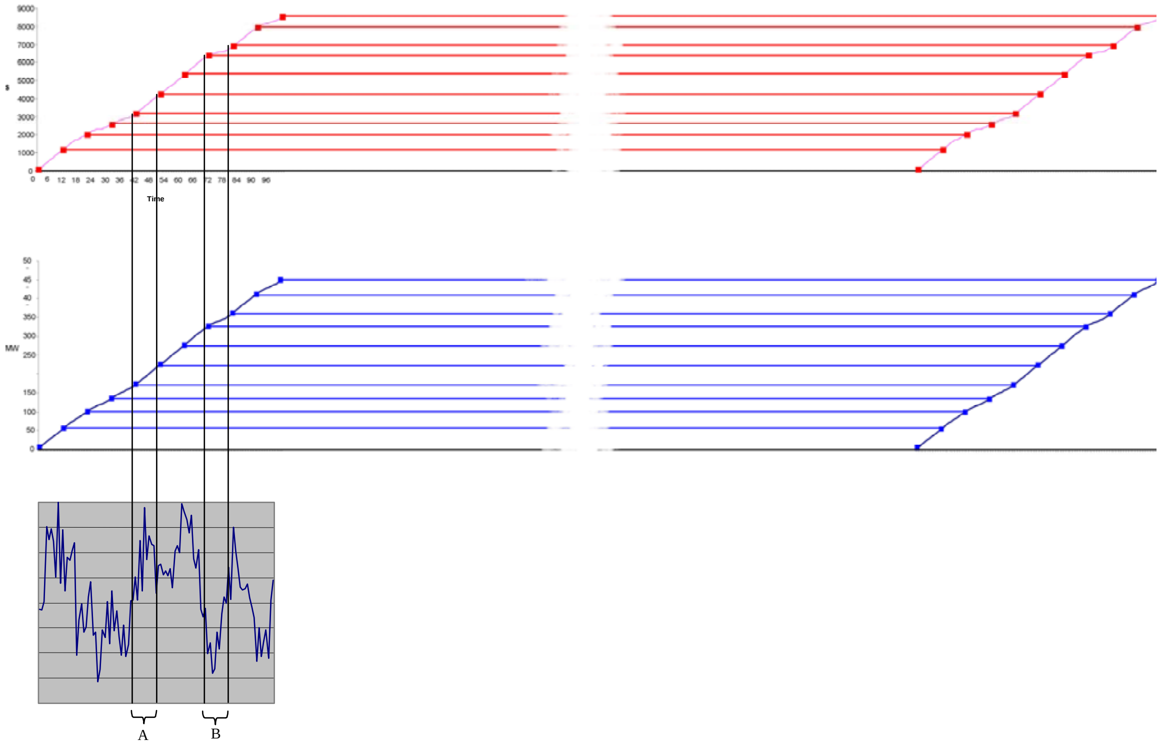


Figure L-122: Conservation Additions

We can summarize the above calculation of the net benefit of conservation acquisitions as follows:

$$V = \overline{p}\Delta q - \Delta c$$

where

$\overline{p}$ is the average market price

Δq is the cumulative increase in quantity

Δc is the cumulative increase in cost

These considerations demonstrate that gross value and cost of conservation acquired over the selected period are both proportional to the sum of the acquisition rates over the

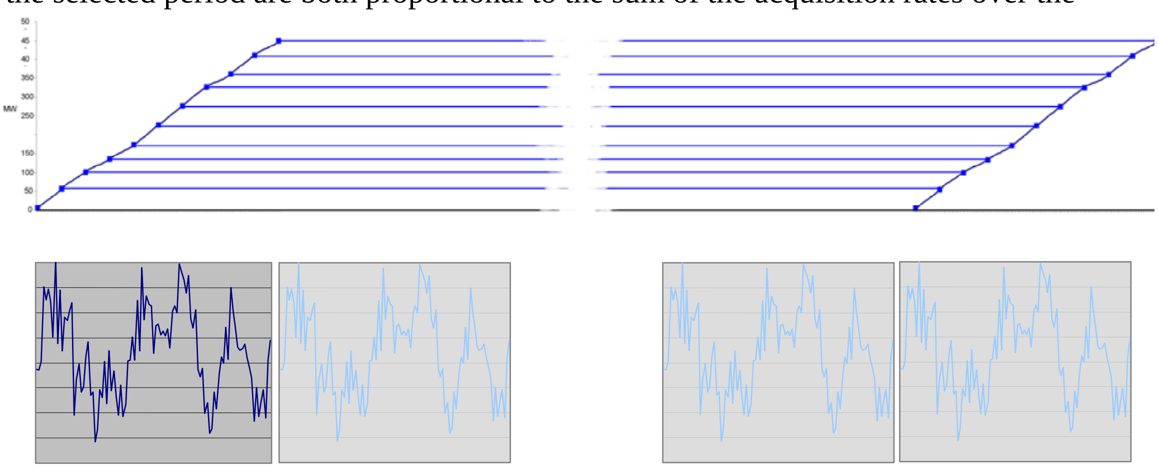


Figure L-123: Value of Conservation

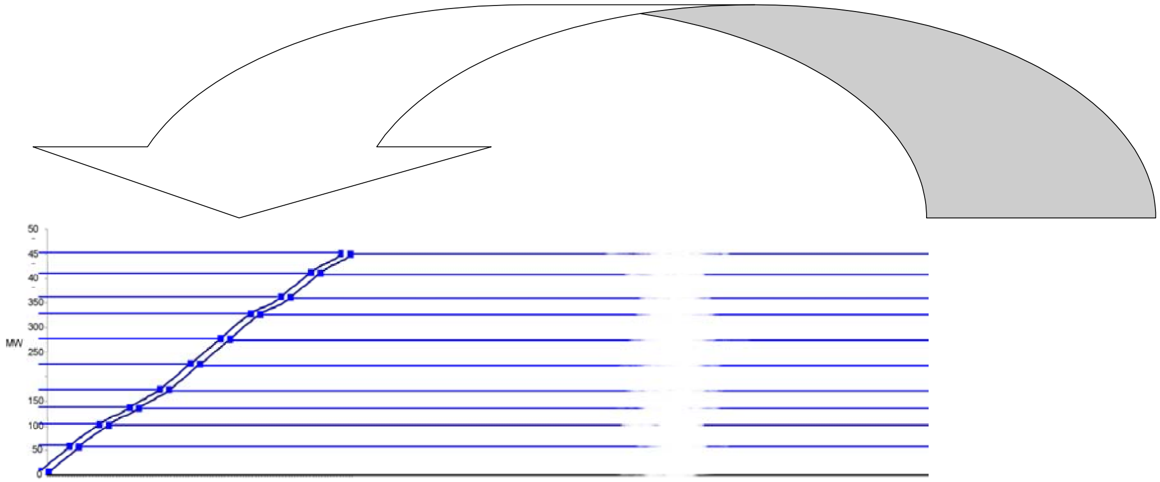
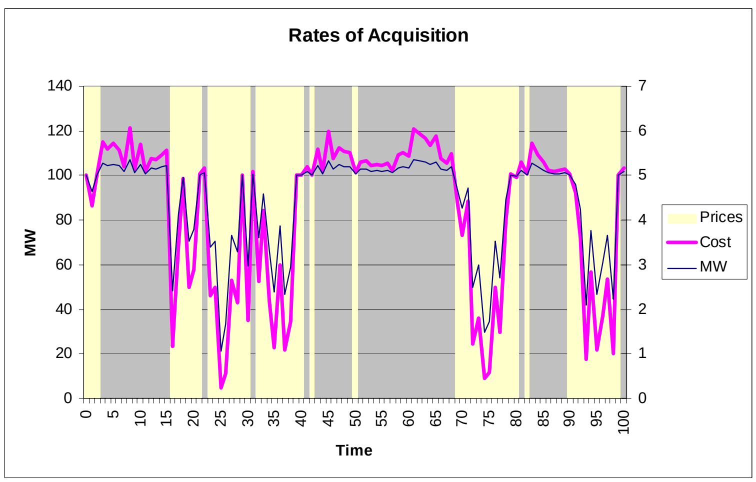


Figure L-124: Rearranging the MW

selected period. (The net benefit, of course, involves the average market price and is not so easily characterized.) Figure L-125 illustrates the rates of acquisition for cost and megawatts over the selected period. In this figure, the subperiods with prices that are below average are highlighted. As we would expect, cost and acquisition rates are much lower during these periods. We also note that the variation in the rate is much greater during subperiods of lower than average price.



Now consider the effect of the policy to acquire conservation up to 10 mills per kilowatt hour over market prices. The corresponding acquisition rates for costs and energy appear in Figure L-126. The policy of paying over market applies to all prices, including higher prices. What is striking, however, is that the acquisition of costs and energy during periods of high prices changes very little, while acquisition rates increase dramatically

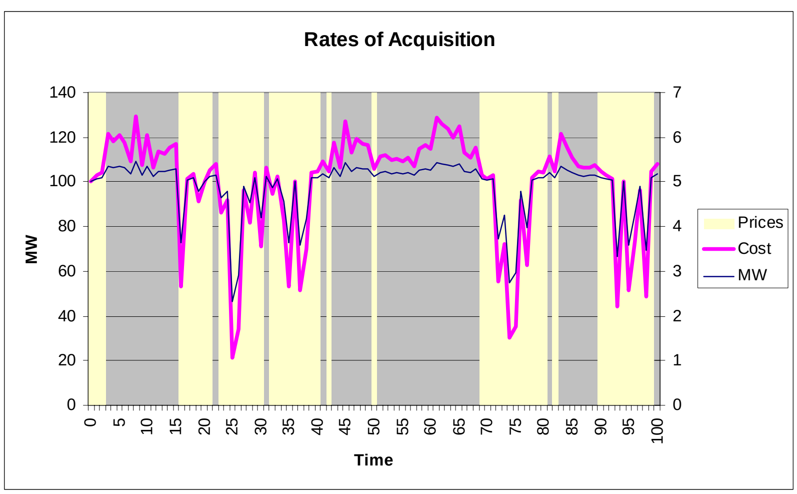


Figure L-126: Acquisition with 10 mill/kWh Adder

in times of lower prices. The differences in acquisition rates for energy and cost under the policy are highlighted in Figure L-127and Figure L-128, respectively. This behavior corresponds roughly to that in the example in Figure L-116, which opened this section.

Summing up rates of acquisition corresponds to finding the area under the curves in Figure L-125 and Figure L-126. Without the premium, cumulative energy acquisition is 449 MW, and cumulative cost acquisition is $8,553 per period. The average cost is 19.05 mills per kilowatt hour, about half of the average price for electricity, 44.36 mills per kilowatt hour. With the 10-mill premium, the cumulative energy and cost of course go up. The cumulative energy acquisition is 494 MW and the cumulative cost acquisition is $10,047 per period. The average cost increases to 20.33 mills per kilowatt-hour. Because we have acquired so many more megawatts at prices well under the average market price, however, the net value of conservation under the policy is greater. The net value of the policy is $520 per period, of 4.6% gain.

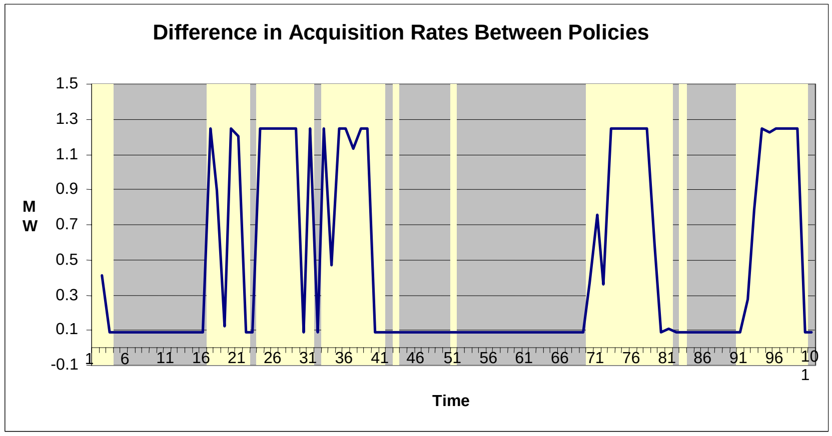


Figure L-127: MW Difference with 10 mill/kWh

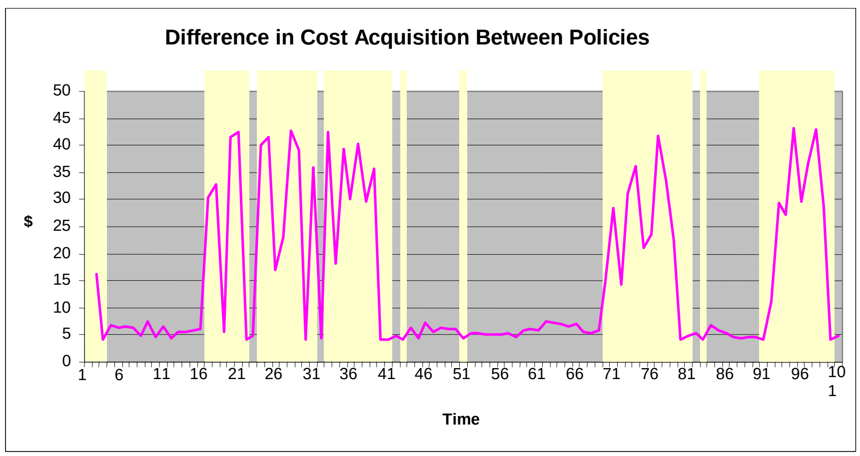


Figure L-128: Cost Difference with 10 mill/kWh

It is important to emphasize that the assumptions in this example are simple and not necessarily representative of existing circumstances. The purpose of this example is only to demonstrate how the shape of the supply curve could produce savings with a policy like the one this example uses. If the supply curve in this example were linear, there would be no net benefit. (Those readers who are becoming conversant in the supply curve cost computations will find the argument in Figure L-129.) Both supply curve non-linearity and uncertainty in cost-effectiveness levels are necessary for this effect.

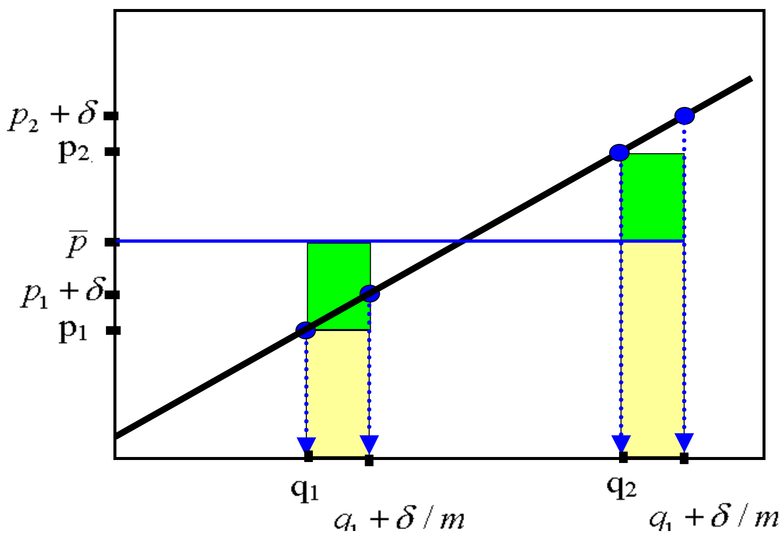


Figure L-129: Comparing Cost Areas

Olivia

On February 6, 2002, the Council released Document 2002-01, "Issues for the Fifth Power Plan." This document solicited comments from the industry on issues that the Council was considering for inclusion in the plan. The first among these issues was, Incentives for Development of Generation:

> "The current market structure appears to have failed to provide adequate and timely incentives for adding new capacity to ensure power supply adequacy and to moderate price volatility. The Council proposes to assess existing incentives and disincentives for development of new generation and examine options available to encourage development that will moderate potential supply demand imbalances and price volatility. Options will be analyzed to determine their effect on prices, system costs, adequacy and reliability. If appropriate, the plan may recommend measures to address systematic problems or improve signals for market development."[41]

The Council considered possible incentives for new capacity and the issues each approach raised. Apart from the questionable efficacy of the various approaches, key

[41] Page 2 of NPPC Document 2002-01.

questions plagued all of the approaches, specifically who should be responsible and how can that responsibility be enforced? The Council was particularly cognizant of the limited formal authority granted to the Council by statute.

One approach that emerged during discussions of the regional portfolio model was to empower individual utilities to make resource selection decisions that reduce their risk and cost. This approach recognized the diverse and independent decisions that utilities make. It assumed that the real leadership the Council exercises stems not from the formal authority of the Council, but from the quality and objectivity of its ideas, data, information, and methods. Utilities have built and acquired resources to meet their own needs, subject to the approval of their commissions and boards. Their requirement for new capacity, not markets for capacity or administrative requirements, drove the demand for new power plants, including those constructed by IPP's. Arguably, utilities have always attempted to incorporate risk assessment into their resource acquisition decisions. Each utility approached risk somewhat differently, however, and consequently few standards have been forthcoming. This made communication with boards and commissions difficult. By providing these parties with concepts, methods, and tools for assessing risk and for assessing the risk mitigation value of resources, the Council would achieve the goal of improving regional reliability by empowering individual utilities to acquire resources that reduce their own risk. These concepts, methods, and tools might eventually lead to standards that would facilitate communication around risk management issues.

Ideally, the Council could hand its portfolio model to utilities and other interested parties. The regional model, however, is an Excel workbook. The selection of this platform makes it possible for those who wish to understand and reproduce the Council's results to do so easily. The associated transparency is consistent with the statutory objectives of the Council. The disadvantages of an Excel workbook, however, are several. If not carefully designed, a workbook will recalculate very slowly. A more serious problem is the structural inflexibility of calculations in a worksheet. For example, changing resources, redefining periods, modifying subperiods, and changing the attributes of resources can require significant restructuring. A utility that wanted to use the logic of the regional model to represent its system would probably need to rewrite the workbook. Because dozens of the workbook macros interact with the worksheets, a non-expert would likely introduce errors into the operation of the model.

To address these concerns, the Council designed Olivia. Olivia is a computer application, illustrated in Figure L-130, that writes workbook portfolio models. The user can characterize his utility's loads and resources, markets for electricity, imports and exports, and other relevant features with simple and high-level parameters. For example, he can type the monthly average energy by subperiod into a column of an Excel worksheet, and paste this into Olivia's database. He can define subperiods within a period and stipulate the number of hours in each. He can characterize a generation resource in terms of its capacity, heat rate, variable operation and maintenance, and most of the other parameters with which individuals who use production cost models are already familiar. He can specify correlations among sources of uncertainty and the kind of stochastic processes he wishes to use to represent the sources of uncertainty. Finally he can specify aspects of the portfolio model such as the layout, the cost and risk criteria he wishes to use, the utilities he would like included in the workbook (described in the previous section, "Portfolio Model Reports And Utilities"), and whether they should be accessible through a new menu bar in the workbook model.

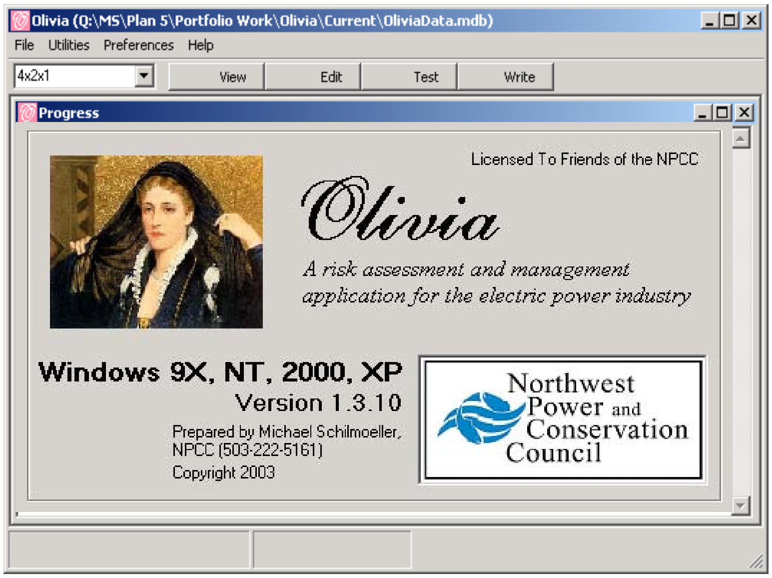


Figure L-130: Olivia

After pasting these data into Olivia's database, the user presses a button and Olivia writes the workbook. The workbook contains not only the data and formulas that the user specifies, but also any macros that the portfolio model needs to perform the simulation. Significantly, this workbook contains only those calculations and macros that this user requires, and no more, despite the richness of options and representations that Olivia can provide to users who need them. This keeps the workbook small and calculation as fast as possible.

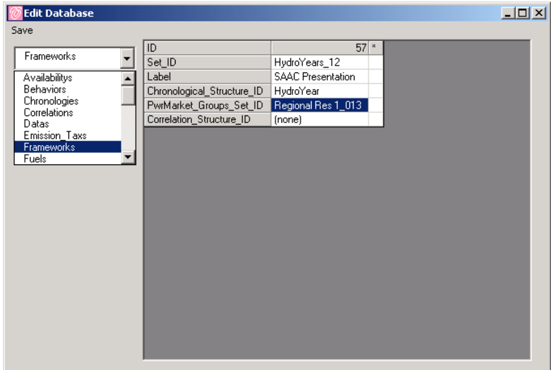


Figure L-131: Editing Olivia's Database

Olivia has editing features that make it easy to modify a portfolio model. The user can make these edits permanent or make edits to a "clone" of the model. Unless the user specifies otherwise, any updates to a model will automatically update all clones. This eliminates the potential for "revision sprawl" and models becoming de-synchronized. (See Figure L-131.) The editing interface features referential integrity, which guarantees that fields link to valid fields in other tables. (See Figure L-132.) There is also a utility that permits the user to test any changes he has made to a model to assure that they are legal and Olivia will interpret them properly.

This section is not a complete description of Olivia. As of this writing, Olivia is not in full production, although a version of Olivia extant in December 2003 produced the regional model used for this plan's analysis. The Council intends to release a production version of Olivia in Spring of 2005 and hold classes on its use shortly thereafter.

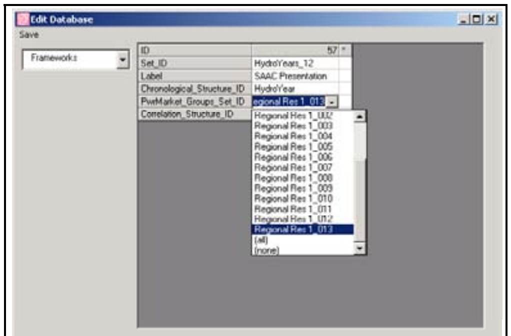


Figure L-132: Referential Integrity

Glossary

American option – an option that may be exercised up to expiration. (See European option, put option, call option.)

assumption cells – A Crystal Ball designation for a worksheet cell in a spreadsheet model that contains a value defined by a probability distribution's random variable.

availability – maximum power plant production, derated for planned outages (maintenance), but not forced outages (MW-period). Availability is synonymous with capability. Because the regional model expresses plant availability in average MW, maximum production is average capacity (MW).

call option – the right to buy the underlying asset by a certain date for a certain price.

capability – see availability.

CCCT – combined-cycle combustion turbine. A natural-gas fired combustion turbine that extracts additional efficiency from the turbine by capturing waste heat to create steam that assists generation. (See SCCT.)

CDF – Cumulative Distribution Function or Distribution Function. A function that specifies the probability that a variable's value falls at or below a given value.

cohort – a group has some descriptive factor, such as age, in common. In the regional model, all plants of a given type, e.g., SCCT, that are ready for construction in the same period are cohorts. They will respond to changing circumstances the same way and will remain in the same stage of development, production, or retirement throughout their lives.

Concept of Causality – relying on conditions that are strictly in the past (prior periods) to determine behavior in the current period.

DCF – discounted cash flow. A standard technique for the economic evaluation of projects, given the projects' associated cash flows. DCF analysis uses future free cash flow projections and discounts them to arrive at a present value, which is used to evaluate the potential for investment. Most often, DCF discounts cash flow at a weighted average cost of capital.

decision cells – A Crystal Ball designation for a worksheet cell in a spreadsheet model that the user controls. The reader may think of the value of these cells as representing the plan. The optimization program adjusts the decision cells in the regional portfolio model to minimize cost, subject to risk constraints.

distributed computation – partitioning computation into subtasks that are parceled out to several machines for processing and then reassembling the results in a manner that makes the final computation indistinguishable from that obtained from a single computer. Also referred to as "parallel processing."

dollars per kilowatt-standard year ($/kWstdyr) – the standard unit of fixed costs in the portfolio model. A standard year consists of standard months of exactly four weeks. (See "standard periods," below.) If a calendar year has 365 days, the $/kWstdyr is 336/365 or about 92 percent of the value of a project's $/kWyr. (See sections "Single Period" and "New Resources, Capital Costs, and Planning Flexibility" for discussions of standard periods and their use.)

DR – demand response. The voluntary curtailment of load, typically in response to prices. See chapter four and appendix H of the plan.

DSI – direct service industry, the community of industries that historically have been direct service customers of the Bonneville Power Administration. Aluminum smelters are a conspicuous DSI in the Pacific Northwest.

effective forced outage rate (EFOR) – percent of time that a power plant or other productive service is expected to be unavailable, due to unforeseen problems.

elasticity – The percent change in demand for a commodity divided by the percent change in the commodity's price

Energy Content Curve (ECC) – An operating guide to the use of storage water from reservoirs operated by parties to the Pacific Northwest Coordination Agreement. Gives 95 percent confidence of reservoir refill, given (projected) water conditions. The variable energy content curve (VECC) is the January-through-July portion of the energy content curve, based on the forecasted amount of spring runoff.

energy reserve margin – resource energy surplus to requirements. Unless otherwise qualified, this refers to the hydro year surplus in MWa (MW-years), assuming critical water hydrogeneration levels.

European option – an option that may be exercised only on the expiration date.
exchange option – an option to exchange a quantity of one asset, such as an mcf of natural gas, for another, such as a kWh of electricity.
feasibility space – a metric-free set of ordered pairs, where each pair represents a plan and the values of the two entries reflect the cost and risk of the plan. There is no metric because cost and risk typically are measured differently and are not comparable. Nevertheless, there is an efficient frontier of plans that are not dominated by other plans. (A plan is dominated by any plan with *both* lower risk and lower cost.)
forecast cells – A Crystal Ball designation for a worksheet cell in a spreadsheet model that contains statistical output of the model. The default color for these cells is turquoise. In the regional model, the primary forecast cell is the NPV cost for a plan under a 20-year future. Other forecast cells in the regional model, such as those that regional model macros assign risk values, serve to communicate data back to the OptQuest optimizer.
future – In the context of the regional model, a future is a set of circumstances over which the decision maker does not have control, such as requirements for electricity, prices for fuel, and stream flows that determine hydroelectric generation. (Appendix P addresses the complete list of uncertainties that give rise to a future in the regional portfolio model.) A set of samples for each of these, specified hourly over the 20-year planning horizon, comprises a single future.
GRAC – The Council's Generation Resource Advisory Committee
GTC – green tag credit. See Chapter 6 for a description and history of green tag credits.
IGC, IGCC – Integrated Gasification of Coal or Integrated Gasification Combined Cycle. A process for converting coal to gases suitable for combustion in power plants
IC – integration cost. Refers to costs necessary to integrate electricity from a power plant into an electric power system. Typical sources of cost are back-up or firming, shaping, and storage.
IPP – independent power producer. Synonymous with non-utility generation (NUG).
load-resource balance – see resource-load balance.
macro – a computer subroutine.
Monte Carlo simulation – Any method which solves a problem by generating suitable random numbers and observing that fraction of the numbers obeying some property or properties. The method is useful for obtaining numerical solutions to problems which are too complicated to solve analytically. It was named by S. Ulam, who in 1946 became the first mathematician to dignify this approach with a name, in honor of a relative having a propensity to gamble (Hoffman 1998, p. 239). Ulam was involved with the Manhattan project to build the first atomic bomb, where physicists used the technique for evaluating complex integrals.
MWa – An average megawatt, typically the energy equivalent to one megawatt-year, although occasionally used rather loosely to refer to the average power rate (MW) over whichever period (day, month, quarter) is under discussion. Where it is important to avoid ambiguity, the appendix refers to the energy as a MW-year (MWyr), MW-month (MWmo), MW-quarter (MWqtr), and so forth.
NIPPC – Northwest Independent Power Production Coalition

O&M – operation and maintenance. When referring to the associated cost, may be either fixed (FOM) or variable (VOM).

On-peak, off-peak – refers to subperiods of loads and prices that are typically higher and lower, respectively. The regional model subscribes to the convention that on-peak hours are hours 7 through 22 (6AM to 10PM), Monday through Saturday, excepts for NERC holidays. Any hours that are not on-peak are off-peak. Because the regional model uses standard periods (see below), however, the model does not need to address variation due to days per month, Sundays per month, and holidays per month in cost and energy computation.

plan – The meaning of the term "plan" must be determined from context: 1) In the context of the regional model, a plan is that over which the decision maker has control, such as the siting and licensing schedule, earliest construction dates, and size and type of generation. In the regional portfolio spreadsheet model, the values of the worksheet's decision cells determine the plan. See the section "Parameters Describing the Plan" for a detailed description and explanation. 2) In the larger context, it may refer to the Council's Fifth Power Plan, either the Action Plan or the plan for resources beyond the five-year Action Plan.

put option – the right to sell the underlying asset by a certain date for a certain price.

PNUCC – Pacific Northwest Utility Conference Committee

production tax credit (PTC) – See Chapter 6 for a description and history of production tax credits.

resource-load balance – No standard definition of this term exists in the industry. In the context of this appendix, resource-load balance refers specifically to energy surplus to requirements on a hydro-year basis, assuming critical hydro water generation and weather-adjusted average load.

risk – No standard definition of this term exists in the industry. In the context of this appendix, risk always refers to the expected severity of *bad outcomes*. TailVaR_{90} (see below) is the principal screen for risk in the regional portfolio model, although Council analysis considers other source of risk such as annual variation in power costs and exposure to market prices. This definition means predictability or uncertainty of costs, as measured by standard deviation, would not be a risk measure. (See the discussion of risk measures in Appendix P.)

RL costs – real levelized cost. See section "Real Levelized Costs," beginning on page L-16, for a detailed discussion.

SAAC – The Council's System Analysis Advisory Committee.

SCCT – Single- or simple-cycle combustion turbine. (See CCCT.)

scenario – a particular plan under a particular future. See the definitions of "plan" and "future."

spinner graph – A collection of Excel graphs display the data for a scenario, including values for all sources of uncertainty in each period. The graphs also present to the user information about the plan and its performance under each of the futures, including generation and cost by technology and fuel type. They illustrate the resulting imports and exports. The graphs also show capital and total costs by period and for the study. Decision makers can study these to decide whether the model is performing according to their expectations. The decision maker or analyst can also press a button that permits her to quickly move through the futures and witness the corresponding data in the graphs. Because these graphs update so quickly, the Council refers to them as "spinner graphs." See section "Data Extraction And Spinner Graphs," beginning on page L-117, for details.

standard period, standard month, standard quarter, standard year – any period based on the standard month, which has exactly four weeks (1152 on-peak hours, 864 off-peak hours). There are three standard months per standard quarter and four standard quarter (12 standard months) per standard year. See section "Single Period," beginning on page L-11, for details.

$TailVaR_{90}$ – The average of the ten percent worst outcomes. In the regional model, the outcomes are NPV 20-year system costs for operation and forward-going fixed cost, including that for new construction. See Appendix P for details.

Twilight Zone, TLZ – a region in the regional portfolio model where computations typically are iterated several times for each subperiod or region. See section "Logic Structure," beginning on page L-6, for a more specific description.

UDF – A Microsoft Visual Basic for Applications (VBA) user-defined function. These inhabit worksheet code modules, workbook code modules, and VBA standard modules (in contrast with VBA class modules). All regional portfolio model UDFs occupy standard modules.

valuation cost estimate – A technique for computing variable costs by referencing the gross value of each resource and the gross cost of meeting requirements to the price for marginal purchases and sales. The standard price used in the regional portfolio model is the wholesale market price for electricity. See section "Valuation Costing," beginning on page L-13.

Index

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M. Laguna. "Optimization of Complex Systems with OptQuest." Graduate School of Business, University of Colorado, 1997. Available at http://www.decisioneering.com/optquest/complexsystems.html

2 Jeff King, NPCC, Tuesday, 4/4/2005 11:12 AM, email Subject: "RE: Appendix L," attachment AppL_050311JKcmts 040405.doc. "Perhaps unfortunately, the levelized cash flows that I supplied were based on a constant mix of developer (20% COU, 40% IOU and 40% IPP), and levelized using the blended after-tax cost of capital of these (4.9%). The resulting levelized fixed costs for a conventional coal and wind plants are about 9% and 4% greater, respectively, using these assumptions (the per MWh difference would be less because of the lower capacity factor of wind). – JK"

3 Direct Calculation of Expected Value.doc

4 Deriving_option_greeks.TIF and Derivative of call wrt strike.TIF

5 The value of 6000MW was established by Council Staff analysis of intertie loadings. See, e.g., Dick Watson, intertieloading.xls, August 13, 2004.

6 Terry Morlan, Ph.D., NPCC, Wednesday, June 23, 2004, Notes_L14.doc.

7 Worksheet qry_041101_AppM_02 of Appendix M_04.xls

8 Original Geneys model output is in System.out. The same subdirectory holds all the Genesys input and output files. See also Notes on comp_040626.doc for fundamental information about the database and queries and Notes.doc and Notes_Update_041103.doc for revisions. The database Appendix M.mdb and it successors are spawned from the comparison database, Comparison_040626.mdb. This latter database was originally in the subdirectory ..\Portfolio Work\Olivia\Calibration and Verification\Loads & Resources (LR) Studies\Portfolio vs LR balance 031030.

9 Jeff King, NPCC, Tuesday, April 27, 2004 5:15 PM, *email* Subject: "GEBESYS genres list," [SIC] attachment FOR_040502.xls

10 Worksheet "tbl_041110_Resources_in_L25" of Appendix M_04.xls

11 Worksheet "Calc RPS" of Appendix M_04.xls

12 Worksheet "IPP calculations" of Appendix M_04.xls

13 MJS_Comments_041116.doc

14 Worksheet "New Resources" of Appendix M_04.xls

15 Worksheet "Construction Costs" of ConvertingOvernightToPeriodCosts_v06.xls

16 The original energy allocation are from the workbook AllSectorSupply.xls worksheet "All Sector Supply," from Tom Eckman, Fri 1/16/2004 5:17 PM, email "Conservation Supply Curve Data." These calculations are from L8.xls (see Notes on L7.doc). See also Conservation Energy Allocation Reconstructed.xls for the simplified calculation that appears in this appendix.

17 Workbook AllSectorSupplywithSysTDValue_L21.XLS

18 Contracts data originally from Tim Misley, BPA, *email* Friday, August 27, 2004 3:22 PM, subject: "RE: Conversation with Tim Misley." Figure data from MSchilmoellerRegionalContracts_MJS.xls. The computation of the MWa for the regional portfolio model is in the worksheet "Contracts for Portfolio Model". Most of the data that went into preparing the workbook derives from the database Contract Data_03.mdb. See the database table "## Comments and Instructions ##" for an embedded MS Word document describing the more technical data transformations.

19 Workbook States.xls permits a user to calculate the number of states for the choices available. It accounts for the reduction in the number of states for the constraint that no plants may be "un-built" after construction.

20 See, for example, Paul Komor, Platts Research and Consulting, “Hedging Energy Price Risk with Renewables and Energy Efficiency,” ER-04-12 Strat, September 2004.

c:\backups\appendix model\appl_060120.doc (Michael Schilmoeller)

Global Climate Change Policy

A significant proportion of scientific opinion, based on both empirical data and large-scale climate modeling holds that the Earth is warming due to atmospheric accumulation of carbon dioxide (CO_2), methane, nitrous oxide and other greenhouse gasses. The increasing atmospheric concentration of these gasses appears to be largely from anthropogenic causes, in particular, the burning of fossil fuels. The effects of warming may include changes in atmospheric temperatures, storm frequency and intensity, ocean temperature and circulation, and the seasonal pattern and amount of precipitation. Possible beneficial aspects to warming, such as improved agricultural productivity in cold climates, on balance appear to be outweighed by adverse effects such as increased frequency of extreme weather events, flooding of low-lying coastal areas, ecosystem stress and displacement, increased frequency and severity of forest fires and northward migration of warm climate disease vectors. While the occurrence of warming and the general nature of its global effects are generally agreed upon, significant uncertainties remain regarding the rates and ultimate magnitude of warming and its effects.

The regional effects of climate change are more uncertain. Global models seem to agree that Northwest temperatures will be higher, but they disagree regarding levels of precipitation. Current thinking by Northwest scientists leans towards a warmer and wetter climate. The proportion of winter precipitation currently falling as high elevation snow is expected to decline and peak runoff expected to shift from springtime to winter. Summer stream flows would decline as a result of loss of snowpack. Warming would lead to a relative reduction in winter peak electricity demand and an increase in the frequency and intensity of summer peaks. The possible effects of climate change on the hydropower system are discussed in Appendix N.

Nationwide, the electric power system is a prime contributor to the production of CO_2, producing about 39 percent of U.S. anthropogenic CO_2 production in 2002[1]. Any meaningful effort to control greenhouse gas production will require substantial reduction in net power system CO_2 production. The most economically efficient means of achieving this likely to be through a combination of improved end use and generating plant efficiencies, addition of generating resources having low or no production of $CO_{2,}$ and CO_2 sequestration. Because it is unlikely that significant reduction in CO_2 production can be achieved without some net cost, future climate control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing.

Analytical consideration of the effects of climate change requires plausible estimates of the timing and magnitude of possible climate change actions. The approach used in this plan to capture the uncertainties of climate change policy was to separate the highly uncertain political factors (the probability and extent of actions being undertaken to control greenhouse gasses) from factors more subject to analysis (the cost of offsetting a ton of carbon dioxide).

The current state of climate change policy was summarized for the Council in April 2004 by Dr. Mark Trexler of Trexler Climate + Energy Services. Dr. Trexler noted that while the United States has not ratified the Kyoto Climate Protocol which establishes targets for reduction of

[1] U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks1990 - 2002. April 2004.

greenhouse gas emissions, there is a good deal of climate policy action both in the US and internationally. Canada, for example, has ratified the Kyoto protocol, and compliance is a significant factor in Canadian energy policy. Elsewhere, a pilot cap-and-trade system for carbon dioxide is to be implemented in Europe in 2005 with a mandatory system in place by 2008[2].

Here in the United States, many states have or are developing climate change mitigation strategies. Oregon, Massachusetts, New Hampshire and Washington require partial offsets of CO_2 produced as a result of power generation.[3] The governors of the West Coast states, through the West Coast Governors' Global Warming Initiative have initiated an effort to develop common regional policy. California has recently adopted regulations that will require automakers to begin reducing the CO_2 production of vehicles sold in California by about 30 percent, beginning in model year 2009. Nationally, the United States Senate in late 2003 came within a few votes of passing the McCain-Lieberman Climate Stewardship Act that would have established a cap and trade system for the United States.[4] CO_2 reduction appears to be one of the primary drivers of efforts to reauthorize the federal renewable energy production credits and to expand state renewable portfolio standards and other renewable energy incentives. Finally, corporations increasingly are recognizing the likelihood of global climate change and the need to control greenhouse gas production[5].

Dr. Trexler presented three scenarios for the evolution of climate change policy in the United States. One scenario portrayed collapse of efforts to implement climate change policy. He viewed the probability of this to be low. A second scenario looked at the likelihood that a combination of factors would generate the political will to seriously tackle climate change. He viewed the probability of this as "modest" although perhaps somewhat greater than the probability of total collapse of climate change mitigation efforts. The third scenario was one that postulates that the issue will not go away and that there will be continue to be efforts to enact mitigation policy. He viewed the likelihood of this scenario to be high.

The Council's estimates of the cost of CO_2 offsets were guided by current state CO_2 offset experience, the conclusions of a Council-sponsored workshop held in May 2003, a June 2003 MIT study of the cost of implementing the McCain-Lieberman proposal[6] and an August 2003 MIT study of the costs of CO_2 sequestration[7]. A cap and trade allowance system, as called for in the McCain-Lieberman proposal and as used for a number of years for control of sulfur emissions, appears to be the most cost-effective approach to CO_2 control. However, to simplify modeling, a fuel carbon content tax was used as a proxy for the effects of climate change policy, whatever the means of implementation. The results are believed to be representative of any approach to control CO_2 production using carbon-proportional constraints on both existing and new generating resources.

[2] Define Cap and Trade
[3] Reference these actions.
[4] S139
[5] "Global Warming: Why Business is Taking it so Seriously" Business Week August 16, 2004.
[6] Massachusetts Institute of Technology Joint Program on the Science and Policy of Global change. Emissions Trading to Reduce Greenhouse Gas Emissions in the United states: The McCain-Lieberman Proposal. June 2003.
[7] Massachusetts Institute of Technology Laboratory for Energy and the Environment. The Economics of CO2 Storage. August 2003.

The estimates of CO_2 control costs from these sources are very wide. The Oregon and Washington offset requirements for new generating resources include a provision whereby a developer can pay a deemed fee for each ton of CO_2 required to be offset. These payments currently amount to about $0.87 per ton CO_2 for Oregon and $2.10 per ton CO_2 for Washington. It is generally acknowledged that actual offset costs are double to triple the Oregon rate. The MIT report on the costs of compliance the Climate Stewardship Act provide a series of time-dependent estimates based on various assumptions regarding implementation. These range from $0 to $39 per ton CO_2 in 2010, $10 to $70 per ton CO_2 in 2015 and $13 to $86 per ton CO_2 in 2020. The Council workgroup estimated offset credits on the international market to range from $5 to 10 per ton CO_2 in the 2005 - 2013 timeframe and $20 to 40 per ton CO_2 from 2010 - 2025. Finally, the MIT study on the costs of CO_2 sequestration estimated costs ranging from $2 to $23 per ton CO_2 for various forms of geologic sequestration. Not included in this latter estimate was the cost of CO_2 separation at the power plant or possible offsetting revenues from enhanced petroleum or natural gas recovery.

Effects of Climate Change on the Hydroelectric System

SUMMARY

The Council is not tasked, nor does it have the resources to resolve existing uncertainties associated with global warming. Currently, there is still much debate surrounding the data, although a preponderance of scientific opinion asserts that the Earth is warming. The science has gotten stronger over the last 15 years and many uncertainties have been resolved. And although it appears that this trend is likely to continue, some uncertainties remain.

While the Council cannot resolve these issues, it does have the obligation to investigate potential impacts of climate change to the power system and to recommend mitigating actions whenever possible. While global warming 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.

Many nations and government agencies are already taking actions. Canada, for example, has signed on to the Kyoto agreement. Also, a pilot cap-and-trade system for carbon dioxide is to be implemented in Europe in 2005 with a mandatory system in place by 2008. Oregon, Massachusetts and New Hampshire require offsets for new fossil power plants and Washington legislators have recently enacted a carbon dioxide offset requirement for new power plants, similar to Oregon's.

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.

There also are potential impacts away from the river system, particularly for the electricity industry. Current scientific knowledge holds that global warming largely results from increased production of carbon dioxide and other greenhouse gasses due to human activities. Because of the widespread use of fossil fuels to produce electricity, the electricity industry worldwide is a principal contributor to the growing atmospheric concentration of carbon dioxide and would be affected by any initiatives to reduce carbon emissions.

The Council has used its resource portfolio model to look at the potential effects of control polices aimed at reducing greenhouse gas emissions on the relative cost-effectiveness of resources available to the Northwest. This involved posing different scenarios about the probability, timing and magnitude of carbon control measures and assessing their effect on different portfolios in terms of cost and risk. This analysis may also shed light on the value of various strategies to address climate change impacts.

The Council's electricity price forecasting model, AURORA©, is being used to assess the possible impact of carbon dioxide control measures on electricity prices and what changes in the composition of the generating resource mix it might induce.

The effects of the uncertainty surrounding a potential carbon tax 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 the main section of the power plan and in appendix M.

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.

BACKGROUND

Over the last century or so, the Earth's surface temperature has risen by about 1 degree Fahrenheit, with accelerated warming during the past two decades. The ten warmest years have all occurred in the last 15 years. Of these, 1998 was the warmest year on record. Warming has occurred in both the northern and southern hemispheres, and over the oceans. Melting glaciers and decreased snow cover further substantiate the assertion of global warming and appears to be more pronounced at higher latitudes. Figure N-1 below illustrates the warming trend, showing global temperatures from 1880 to 2000.

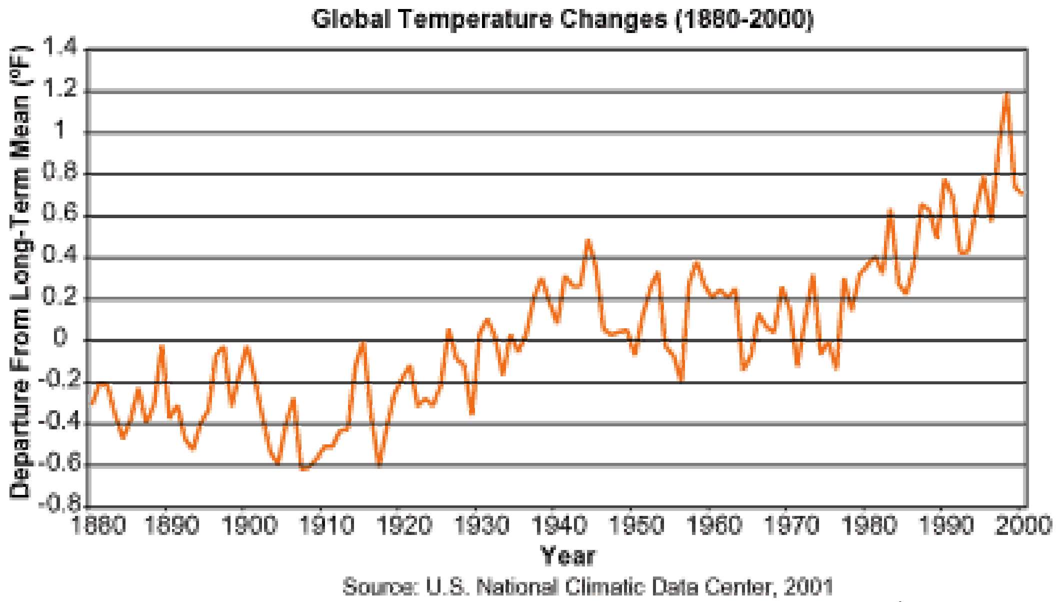

Figure N-1: Global Temperature Changes (1880-2000)[1]

Two rather obvious questions arise related to the data in Figure N-1. First, is this rise in temperature statistically significant (i.e. is the warming trend real?) and, if it is, what are its causes? Secondly, what potential impacts might global warming have and are there mitigating actions that we can take? While the first question is scientifically very interesting and is of great importance to Northwest inhabitants, the Council is not tasked to explore or debate this issue. Rather, the Council's efforts are directed toward the second question. More specifically, it must assess potential Northwest impacts of global warming and determine what mitigating actions are required to continue to protect, mitigate and enhance fish and wildlife populations, while maintaining an adequate, efficient, economic and reliable power supply for the Northwest. However, before moving on to a discussion of potential Northwest impacts and mitigating actions, the debate surrounding global warming will be briefly examined.

Is Global Warming Real?

There is much anecdotal evidence of increasing temperature. Over the last 20 years, we have observed retreating glaciers, thinning arctic ice, rising sea levels, lengthening of growing seasons (for some), and earlier arrival of migratory birds. The northern hemisphere snow cover and Arctic Ocean floating ice have decreased. Sea levels have risen 8 to 10 centimeters over the past century, as illustrated in Figure N-2. Worldwide precipitation over land has increased by about one percent and the frequency of extreme rainfall events has increased throughout much of the United States. Figure N-3 shows that in 1910 about 9 percent of the U.S. experienced extreme rainfall compared to about 11 or 12 percent by 1990.

[1]Source: U.S. National Climatic Data Center, 2001

A cursory look at the temperature data in Figure N-1 indicates that there has been a warming trend and that it appears to be accelerating. However, the average change in temperature over the last century has been about one degree Fahrenheit, which may arguably be smaller than the accuracy of early measuring devices. It is also not clear how many geographical data points were available in the early years. (Recall that the data reflects average surface temperature over the entire Earth). Other things to consider are rare natural events, such as large volcanic eruptions or serious weather events that may have increased the greenhouse effect sporadically over the years. Such events may explain (at least in part) some of the year-to-year variation in the curve in Figure N-1. But, before further discussing the uncertainties surrounding global warming, it would be beneficial to understand what scientists believe is the cause.

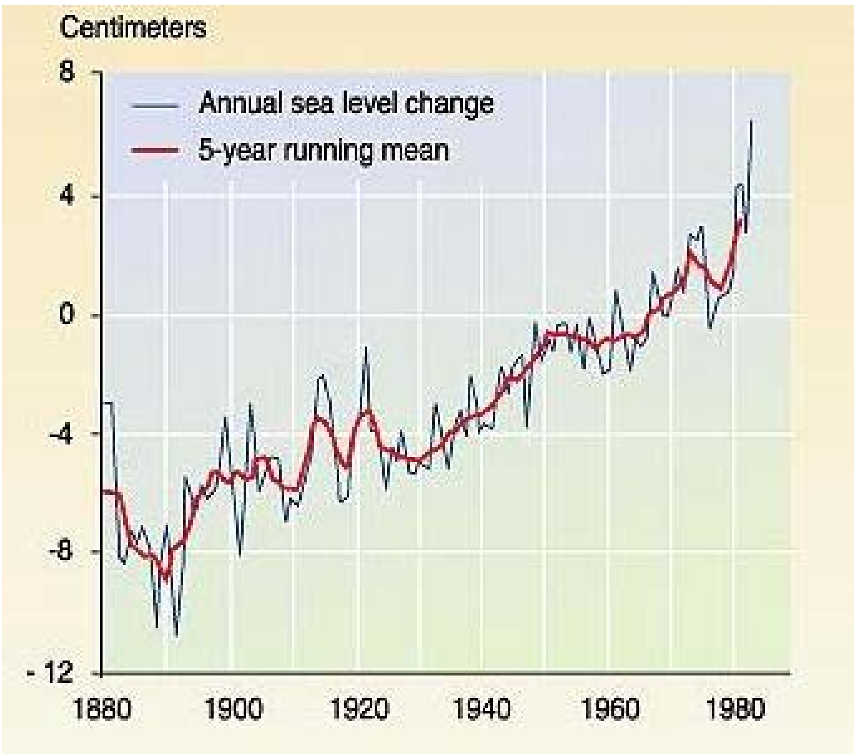

Figure N-2: Historical Rise in Sea Level

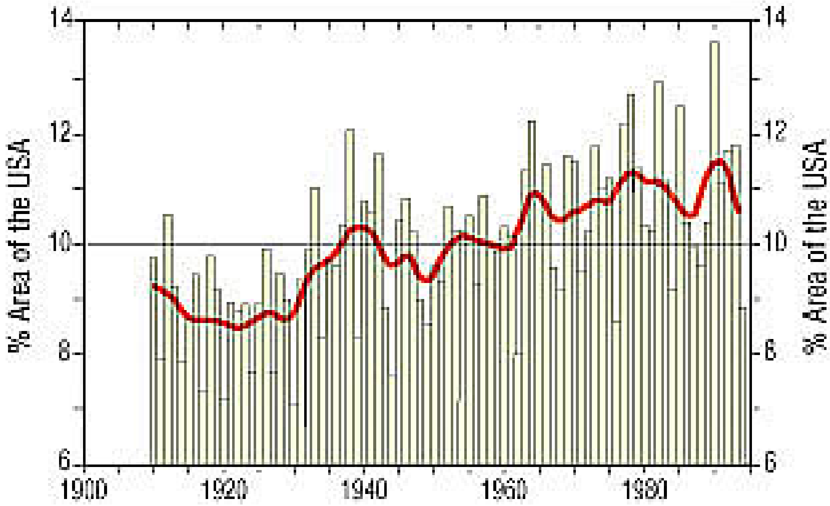

Figure N-3: Percentage of US Area Experiencing more Extreme Rainfall[2]

Causes of Global Warming

It has been scientifically proven that greenhouse gases (water vapor, carbon dioxide, methane, nitrous oxide and the man-made CFC refrigerants) trap heat in the Earth's atmosphere and tend to warm the planet. A schematic illustrating this effect is shown in Figure N-4. The Inter-governmental Panel on Climate Change (IPCC) concluded that the apparent global warming in the last 50 years is likely the result of increases in greenhouse gases, which accurately reflects the current thinking of the scientific community. Scientists know for certain that human activities are changing the composition of Earth's atmosphere. Increasing levels of greenhouse gases, like carbon dioxide, in the atmosphere since pre-industrial times have been well documented. Figure N-5 illustrates both temperature and carbon dioxide concentration increases over the past thousand years. While the uncertainty in data prior to the development of sophisticated temperature measuring devices in the 19th century may be rather large, it is apparent from this graph that both temperature and carbon dioxide concentration have increased more rapidly over the past 100 years.

Though ninety-eight percent of total greenhouse gas emissions are *naturally* produced (mostly water vapor) and only 2 percent are from man-made sources, over the last few hundred years, the concentration of man-made greenhouse gases in the atmosphere has increased dramatically. Since the beginning of the industrial revolution, atmospheric concentrations of carbon dioxide have increased nearly 30 percent, methane concentrations have more than doubled, and nitrous oxide concentrations have risen by about 15 percent. These increases have enhanced the heat-trapping capability of the earth's atmosphere and tend to remain in the atmosphere for periods ranging from decades to centuries. Figure N-6 shows the approximate makeup of greenhouse gases in our atmosphere today (excluding water vapor).

[2] Source: Center for Climate Change and Environmental Forecasting (www.climate.volpe.dot.gov/precip.html)

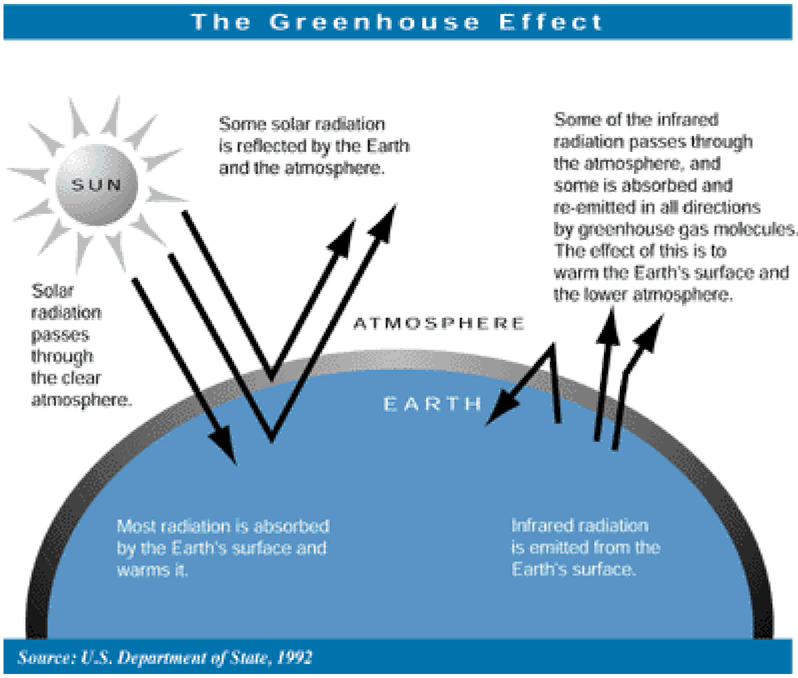

Figure N-4: The Greenhouse Effect[3]

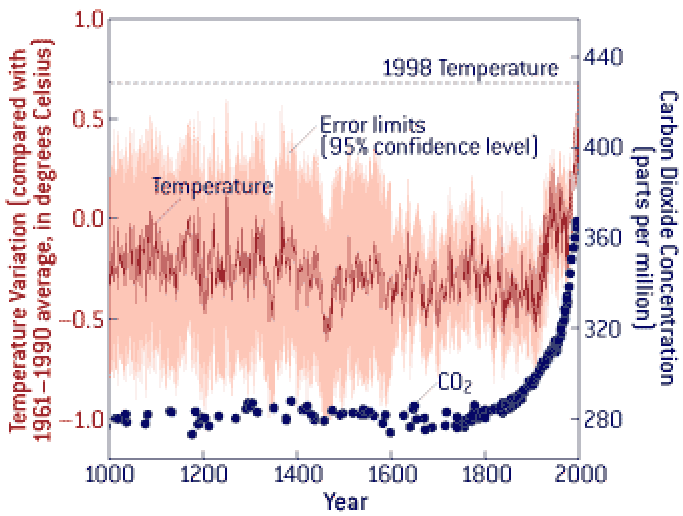

Figure N-5: Temperature and Carbon Dioxide Concentration over the last Century[4]

[3] Source: U.S. Department of State, 1992
[4] Source: Intergovernmental Panel on Climate Change

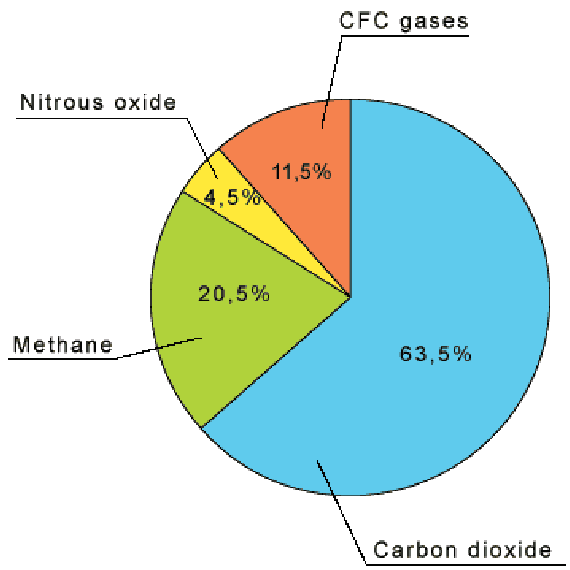

Figure N-6: Greenhouse Gases Worldwide[5]

Fossil fuels burned to run cars and trucks, heat homes and businesses, and power factories are responsible for about 98 percent of U.S. carbon dioxide emissions, 24 percent of methane emissions, and 18 percent of nitrous oxide emissions. Increased agriculture, deforestation, landfills, industrial production, and mining also contribute a significant share of emissions. In 1997, the United States emitted about one-fifth of total global greenhouse gases. Figure N-7 below provides a breakdown of the known sources of greenhouse gases. The largest contributors are electricity production and transportation, which both produce carbon dioxide. Together, they represent approximately one-third of the total man-made production of carbon dioxide. Industrial and commercial uses and residential heating make up about a quarter of the total. Figure N-8 illustrates the production of carbon dioxide by sector since 1970.

[5]Source: Institut Français du Pétrole (IFP) (http://www.ifp.fr/IFP/en/images/fb/gaz-effet-serre-fb04.gif)

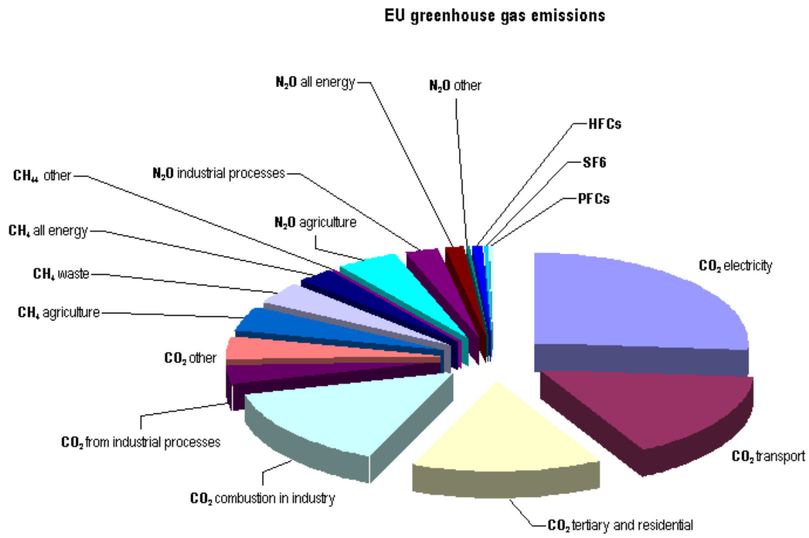

Figure N-7: Sources of Greenhouse Gases[6]

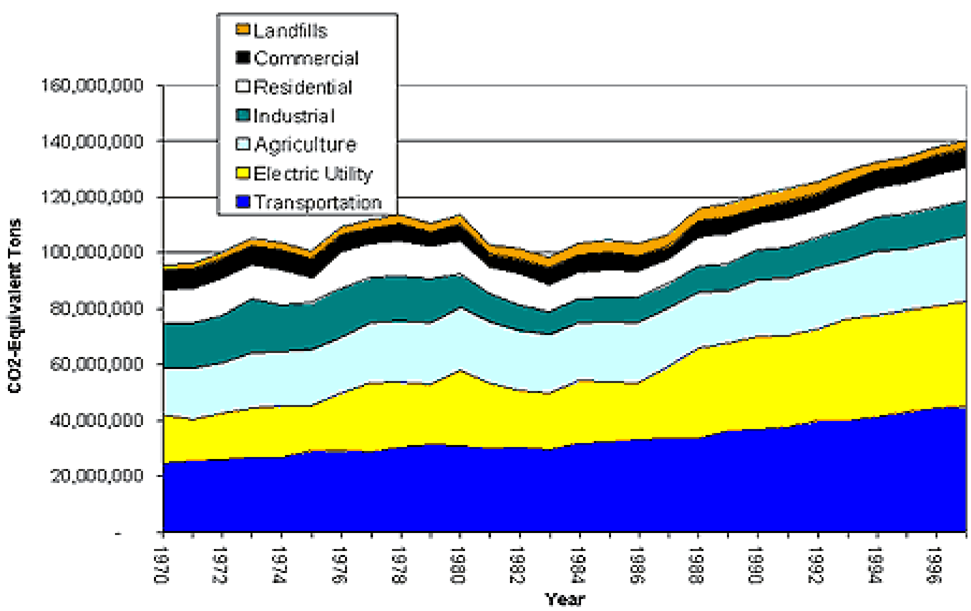

Figure N-8: Sources of Carbon Dioxide Production[7]

[6] Source: Climate Action Network Europe (www.climnet.org)
[7] Source: Minnesota Pollution Control Agency (www.pca.state.mn.us)

Figuring out to what extent the human-induced accumulation of greenhouse gases since pre-industrial times is responsible for the global warming trend is still under debate. This is because other factors, both natural and human, affect our planet's temperature. Scientific understanding of these other factors – most notably natural climatic variations, changes in the sun's energy, and the cooling effects of pollutant aerosols – remains incomplete.

As atmospheric levels of greenhouse gases continue to rise, scientists estimate average global temperatures will continue to rise as a result. By how much and how fast remain uncertain. Based on assumptions that concentrations of greenhouse gases will continue to grow the IPCC projects further global warming of 2.2 to 10°F (1.4 to 5.8°C) by the year 2100. This range results from uncertainties in greenhouse gas emissions, the possible cooling effects of atmospheric particles such as sulfates, and the climate's response to changes in the atmosphere. The IPCC goes on to say that even the low end of this warming projection "would probably be greater than any seen in the last 10,000 years, but the actual annual-to-decadal changes would include considerable natural variability."

Uncertainty Surrounding Climate Change

Scientists are more confident about their projections of climate change for large-scale areas (e.g., global temperature and precipitation change, average sea level rise) and less confident about the ones for small-scale areas (e.g., local temperature and precipitation changes, altered weather patterns, soil moisture changes). This is largely because computer models used to forecast global climate change are still ill equipped to simulate how things may change at smaller scales.

There are at least 19 different global models that simulate changes in temperature over time. Every one of these models, to some degree (no pun intended), projects a warming trend for the Earth. Each is a sophisticated computer model using 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 the 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.

Potential Impacts of Global Warming

One of the consequences of global warming is a more rapid melting of ice caps, which would increase the likelihood of flooding at coastal cities. Given the forecasted range of global temperature increase, mean sea level is projected to rise by 0.09 to 0.88 meters by 2100, due to melting ice caps and thermal expansion of the oceans (due to higher water temperatures). Warmer oceans could also lead to shifts in upwelling and currents and could have detrimental impacts to ecosystems.

Evaporation should increase as the climate warms, which will increase average global precipitation. There is also the possibility that a warmer world could lead to more frequent and intense storms, including hurricanes. Preliminary evidence suggests that, once hurricanes do form, they will be stronger if the oceans are warmer due to global warming. However, it is unclear whether hurricanes and other storms will become more frequent. Figure N-9 shows the frequency of hurricanes since 1949. In spite of the decline in hurricanes in 1994 and 1995, it appears that a trend exists toward more frequent occurrences, but the data is not conclusive.

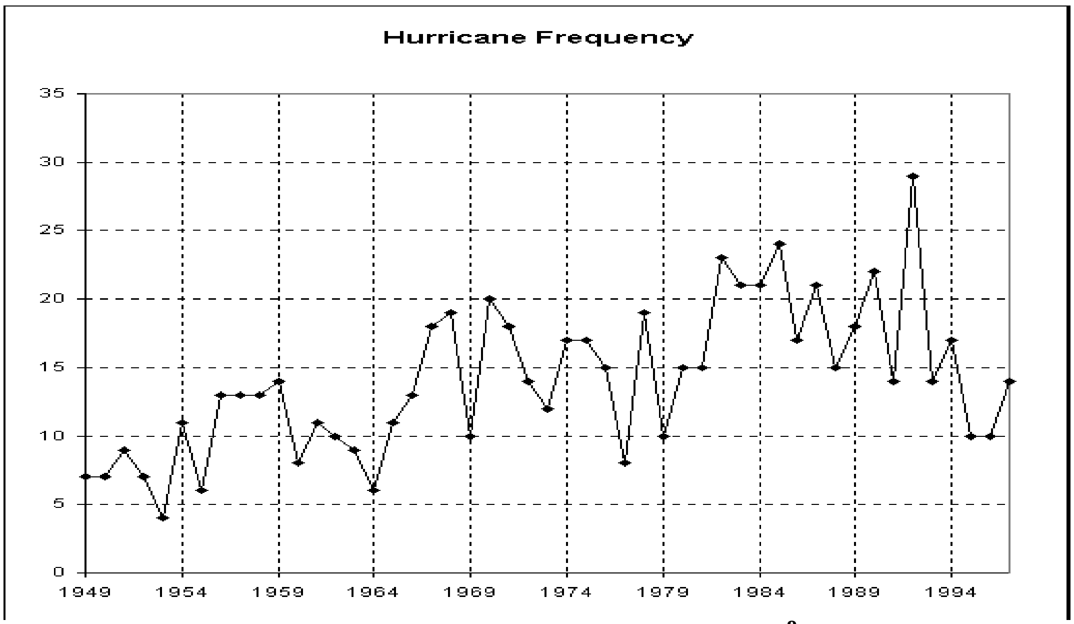

Figure N-9: Frequency of Hurricanes[8]

More and more attention is being aimed at the possible link between El Niño events – the periodic warming of the equatorial Pacific Ocean – and global warming. Scientists are concerned that the accumulation of greenhouse gases could inject enough heat into Pacific waters such that El Niño events would become more frequent and fierce. Here too, research has not advanced far enough to provide conclusive statements about how global warming will affect El Niño.

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 should 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.

Actions to Address Climate Change

Global warming poses real risks. The exact nature of these risks remains uncertain. Ultimately, this is why we have to use our best judgment – guided by the current state of science – to determine what the most appropriate response to global warming should be.

[8] Source: TV Weather (www.tvweather.com)

In 1992 the United States and nations from around the world met at the United Nations' Earth Summit in Rio de Janeiro and agreed to voluntarily reduce greenhouse gas emissions to 1990 levels by the year 2000. The Rio Treaty was not legally binding and, because reducing emissions would likely cause unwanted economic impacts, many nations were expected not to meet that goal.

Representatives from around the world met again in December of 1997 in Kyoto to sign a revised agreement. Because of concerns regarding the possible economic effects, the treaty excluded developing nations. However, the US Senate voted 95-0 against supporting a treaty that doesn't include developing nations. At the time, the Clinton Administration negotiators agreed to legally binding, internationally enforceable limits on the emission of greenhouse gases as a key tenet of the treaty. The president's position presupposed that the potential damage caused by global warming would greatly outweigh the damage caused to the economy by severely restricting energy use.

The Clinton Administration also supported a system of tradable permits to be used by companies that emit carbon dioxide. These permits could be bought and sold internationally, giving companies an incentive to lower emissions and thus sell their permits. But this system would require massive international oversight on the order of a worldwide Environmental Protection Agency (EPA) to track carbon dioxide emissions, and the costs to consumers would be high.

The U.S. did agree to a 7 percent reduction of carbon dioxide emissions from what they were in 1990 -- a target to be met by 2008-12. This agreement would place further restrictions on energy generation from fossil-fuel burning resources. There appears to be as much controversy regarding the economic impacts of control policies for greenhouse gases as there is regarding the effects of climate change. In addition, suggestions were made to establish a vigorous program of basic research to reduce uncertainties in future climate projections and to develop a system that monitors long-term climate predictions.

ASSESSING IMPACTS TO THE NORTHWEST

Northwest Climate Models

Dozens of groups around the world are actively investigating global climate change and its potential impacts.[9] Most of these organizations have developed complex computer models used to forecast long-term changes in the Earth's climate. These models are used to estimate the effect of greenhouse gases on the Earth's climate. The most sophisticated of these models are known as "general circulation models" or GCMs. These models take into account the interaction of the atmosphere, oceans and land surfaces.[10] 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.

The one problem that global models share, however, is that their minimum geographical scale is generally too large to make predictions for small regions such as the Northwest. GCMs tend to do a very reasonable job of forecasting on a global basis, but unfortunately, that information is of no use to planners in the Northwest. Thus, a method of "downscaling" the output from these

[9] http://stommel.tamu.edu/~baum/climate_modeling.html
[10] http://gcrio.org/CONSEQUENCES/fall95/mod.html

models has been developed.[11] This downscaled data matches better with hydrological data used to simulate the operation of the Columbia River Hydroelectric Power System. Thus, using temperature and precipitation changes forecast by global climate models, 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 in the Northwest. Temperature changes lead to adjustments in electricity demand forecasts and river flow adjustments translate into both changes and temporal shifts in hydroelectric generation.

Projected Changes in Northwest Climate and Hydrology

Downscaled hydrologic and temperature data for the Northwest was obtained from the Joint Institute for the Study of Atmosphere and Ocean (JISAO)[12] Climate Impacts Group[13] at the University of Washington. This data was derived primarily from two GCMs, the Hadley Centre model (HC)[14] and the Max Planck Institute model (MPI)[15] although the Climate Impacts Group also uses other models.

The JISAO Climate Impacts Group at the University of Washington has compiled a set of projected future temperature and precipitation changes based on four global climate models.[16] Figure N-10 below illustrates those projections for the four models and also shows the mean (dark line). Two conclusions can be drawn from the figure below; 1) that each model shows a net temperature and precipitation increase, and 2) that there is great variation in both the temperature and precipitation forecasts.

For the Council's analysis, mean monthly temperature changes were used for both 2020 and 2040. Figure N-11 illustrates the temperature change forecast used for 2020 and 2040. Please note that in Figure N-11, the vertical temperature scale is in degrees Fahrenheit instead of Celsius and the horizontal time scale reflects an operating year (September through August) as opposed to a calendar year. Because the correlation between temperature change and water condition was not yet available, the analysis assumed that mean monthly temperature changes would apply to each water condition examined.

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[11] 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."
[12] http://tao.atmos.washington.edu/main.html
[13] http://tao.atmos.washington.edu/PNWimpacts/index.html
[14] http://www.met-office.gov.uk/research/hadleycentre/models/modeltypes.html
[15] http://www.mpimet.mpg.de/en/web/
[16] The global climate models used for these scenarios were the HadCM2, HadCM3, ECHAM4, and PCM3. Mote, P., 2001: "Scientific Assessment of Climate Change: Global and Regional Scales," White Paper, JISAO Climate Impacts Group, University of Washington.

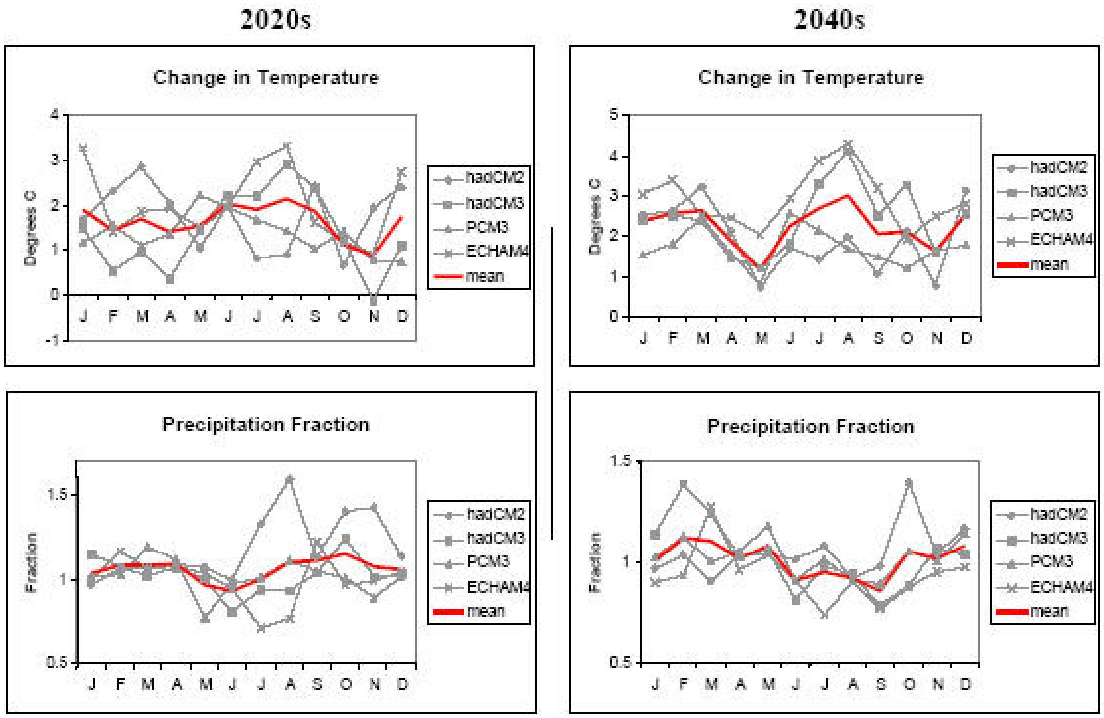

Figure N-10: Temperature and Precipitation Change Forecasts[17]

[17] 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.

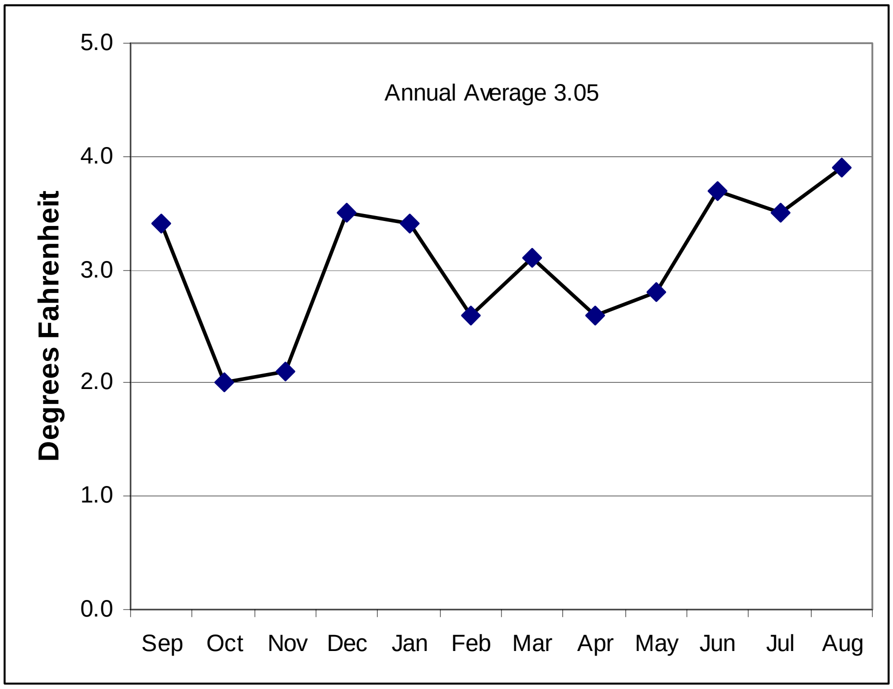

Figure N-11: Forecast Change in NW Monthly Temperatures by 2020

Table N-1: Forecast Temperature Increases for the Northwest (Degrees Fahrenheit)

	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug
2020	3.4	2.0	2.1	3.5	3.4	2.6	3.1	2.6	2.8	3.7	3.5	3.9
2040	3.7	3.8	2.9	4.6	4.3	4.7	4.8	3.4	2.2	4.1	4.9	5.4

The Hadley Centre (HC) model generally shows an overall increase in precipitation across the year. The Max Planck Institute (MPI) model tends to forecast a drier future. Figures N-12a and N-12b compare the mean annual runoff volumes (in millions of acre-feet as measured at The Dalles Dam) for each scenario for 2020 and 2040. The historical mean is about 133 million acre-feet (maf). For this analysis, the historic water conditions from 1930-78 were used.

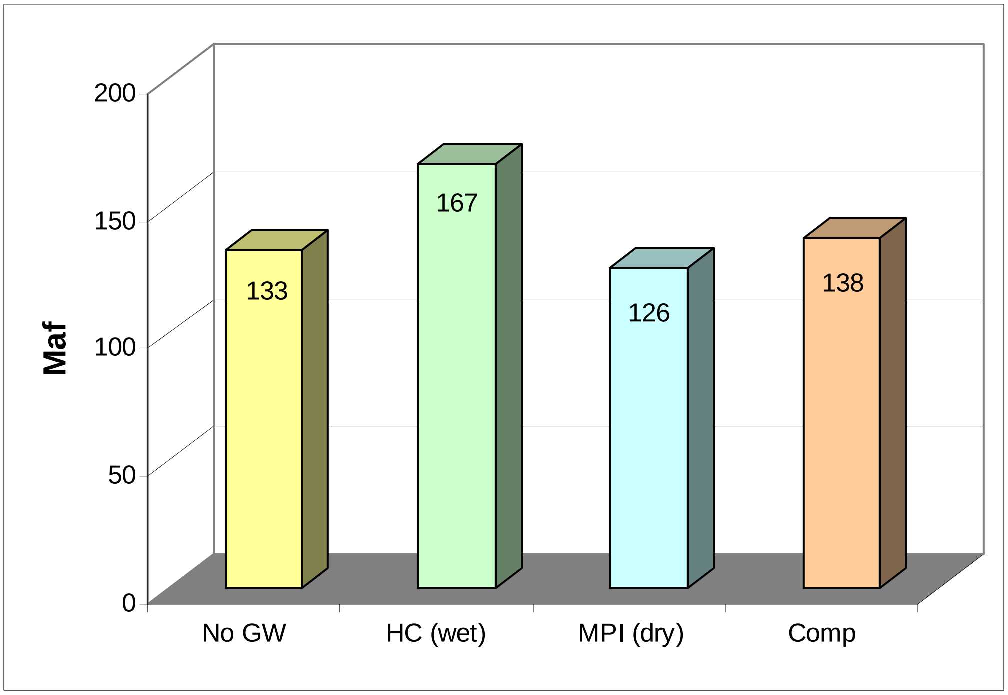

Figure N-12a: Annual Average Runoff Volume at The Dalles (2020)

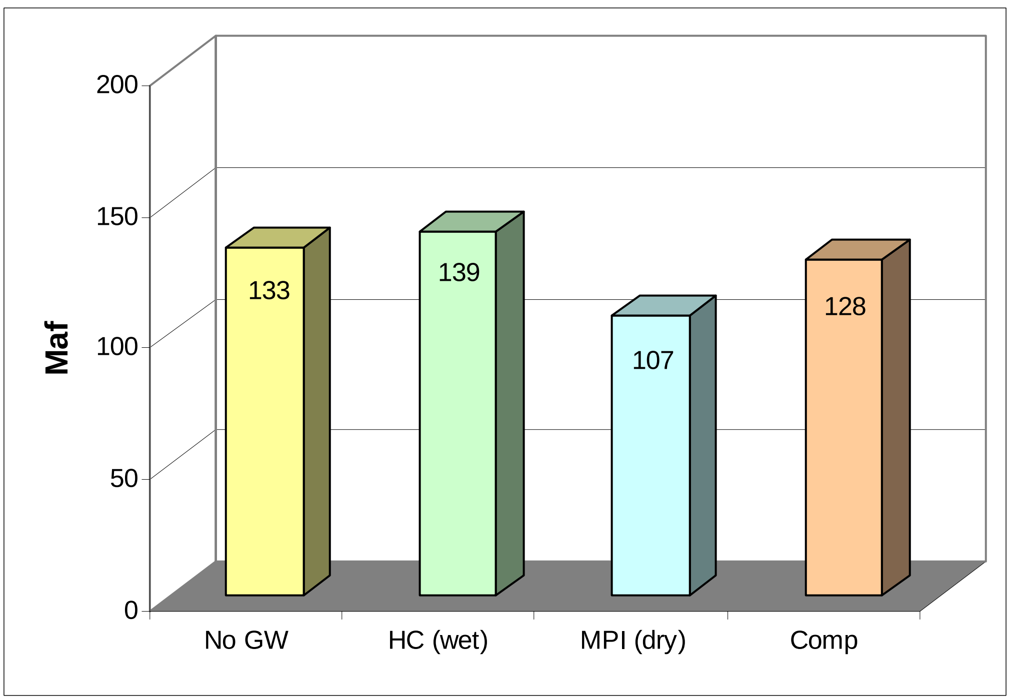

Figure N-12b: Annual Average Runoff Volume at The Dalles (2040)

For 2020, the HC model shows a greater annual runoff volume (167 Maf compared to the historical average of 133 Maf). Total useable storage in the Columbia River Basin is about 42 maf, with about half of that available in U.S. reservoirs. Under the HC scenario, the hydroelectric system should see about 34 Maf more water on an average annual basis. That is almost as much water as can be stored in all of the reservoirs on the Columbia River. This means that the region can displace more non-hydroelectric resources and sell more surplus hydroelectric energy in the wholesale market. Overall, it means that the region should see a decrease in the average cost of energy production.

The MPI model shows a slight annual decrease in river volume (126 Maf relative to the historical average of 133 Maf). While this reduction in average annual volume is not as large as the projected increase in volume under the HC model, it is still a significant amount of water. The 7 Maf reduction amounts to about a 5 percent drop in river volume, which translates into higher costs for the region because more expensive non-hydro resources must be run to make up the difference (or less revenue will be gained from the sale of surplus hydroelectric generation). More on the estimated cost under each of theses scenarios is discussed later.

For 2040, the HC model forecasts a much smaller increase in annual runoff volume (139 Maf as opposed to 167 Maf for 2020). Although smaller, the projected average annual river volume for 2040 is still 6 Maf larger than the historical average and should still result in lower overall average operating costs for the northwest power system. The MPI model for 2040 shows a much greater decrease in annual volume (107 Maf). This decrease of 26 Maf, relative to the historical annual average of 133 Maf, is more water than can be stored in U.S. reservoirs (21 Maf) and would increase the cost of operation.

Despite the inconsistencies between the HC and MPI models in terms of projected annual river volume, they both show greater winter period runoff (and consequently flows) and lower summer runoff. More information on this will be discussed in the next section.

Assessment of Impacts to the Power System

Three sets of hydrological data were produced for operating years[18] 2020 and 2040. Each is a downscaled and bias-adjusted set of water conditions generated using output from a particular global model. The first two sets of water conditions are derived from the HC and MPI models and the third set is derived from a combination of model runs (COMP). Other caveats regarding this study are specified below:

- Adjusted streamflows are only available for 1930-78 water conditions (out of the 1929-78 historical record generally used for Northwest power-system analysis)
- Only one monthly temperature adjustment is associated with each water condition (this implies no correlation between water conditions and temperature change)
- Operating guidelines (rule curves) for the hydro system have not been adjusted (i.e. flood control has not been adjusted for the change in spring runoff forecast nor have firm drafting limits been re-optimized)
- Summer demand sensitivity to temperature is likely too low (it must be increased to take into account the higher level of air-conditioning penetration)

[18] Power planners in the Northwest generally define an operating year to be from September through August.

- This analysis is a deterministic study, in the sense that each adjusted water condition was given an equal likelihood of occurring.
- The analysis modeled the current generating-resource/demand mix (no attempts were made to use projected resources or loads in 2020 or 2040)

Impacts to 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. Also, more rain in winter months (as opposed to snow) means higher streamflows at a time when electricity demand is highest. This, plus 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 begin 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.

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 river 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 (there are none currently), which would also decrease the peaking capability. The projected increase in Northwest summer demand along with potential reductions in both hydroelectric and thermal generation may force the Northwest to compete with the Southwest for resources. Currently, the Northwest has surplus capacity during summer months when the Southwest sees its peak demand and the Southwest is surplus in the winter months when the Northwest has its peak.

This unfortunately, is not the only summer problem inherent with a climate change. Because river flows are likely to decrease, 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. In a later section, some actions will be explored that may ease this situation, although in the worst case the region will have insufficient means to adjust to the forecasted changes.

Figures N-13a, N-13b and N-13c illustrate monthly average river flows at The Dalles for the historic water record and the climate-change adjusted water record (all based on historic natural flows from 1930 to 1978). Figure N-13a shows the HC model adjustments for both 2020 and 2040. The HC data reflects a warm-and-wet scenario, which translates into higher flows, especially in winter and early spring. Flows are lower in summer through early fall. As with all the climate model runs, flows in 2040 are projected to be lower than in 2020. In addition to the overall increase in river flow volume, the peak flow occurs a little earlier than the historic average. Peak flows in the HC adjusted data occur in mid-May as opposed to early June for the historic data. This same pattern exists for each of the three climate change scenarios examined.

Figure N-13b illustrates projected changes in average river flows for the MPI scenario (warm and dry). In this case, winter flows are higher but not nearly as much as in the HC case. Late spring and summer flows are greatly reduced. Again we see the slightly earlier peak in about mid-May. Figure N-13c shows average river flows for the COMP scenario, which is essentially an average of several climate change studies.

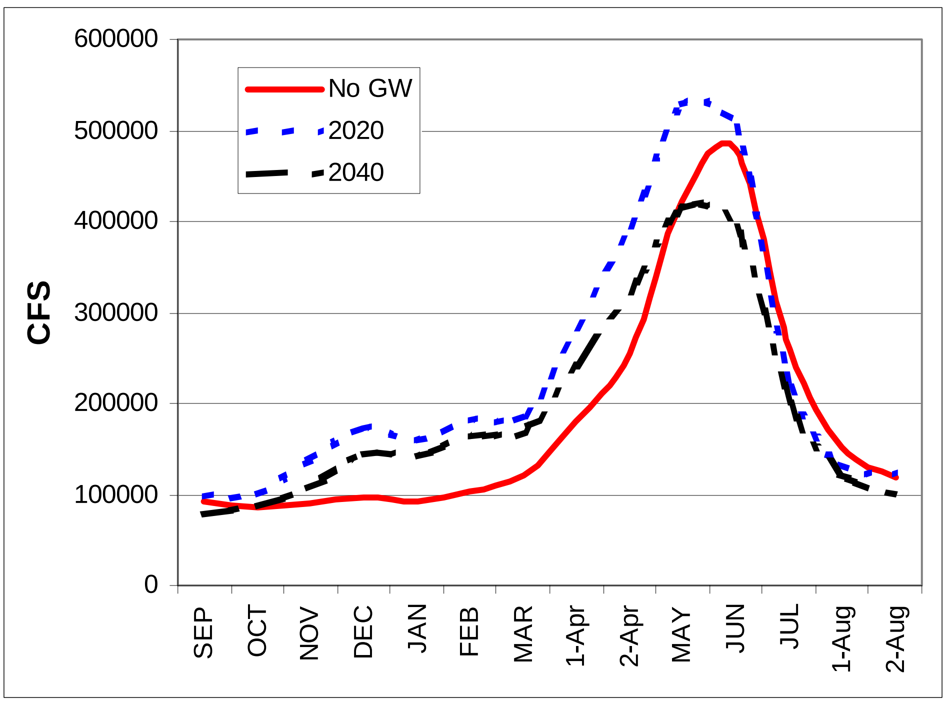

Figure N-13a: Average Unregulated Flow at The Dalles - HC (wet)

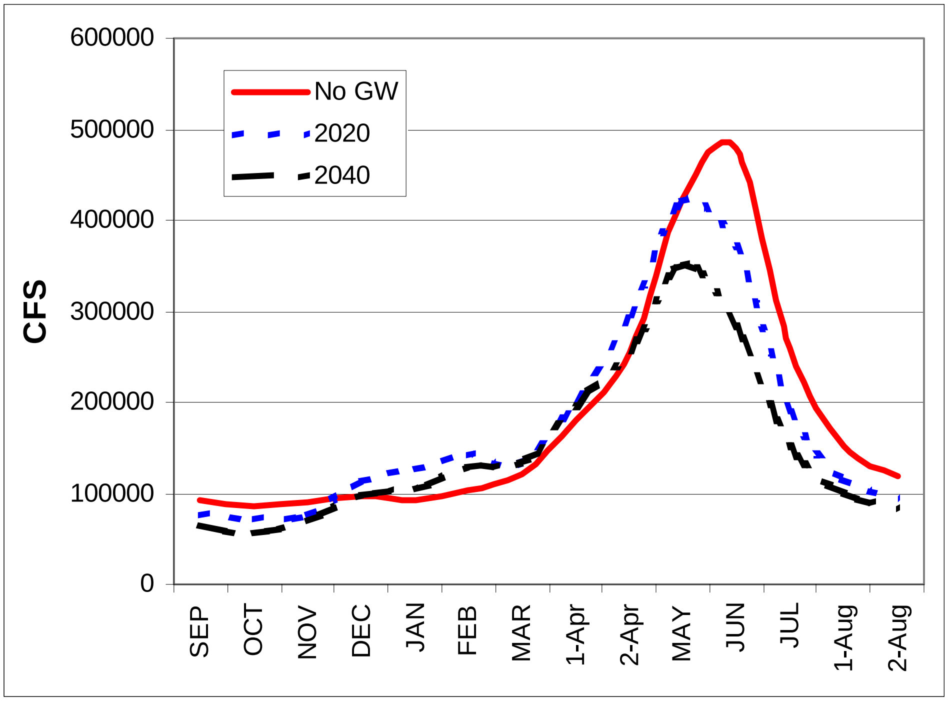

Figure N-13b: Average Unregulated Flow at The Dalles - MPI (dry)

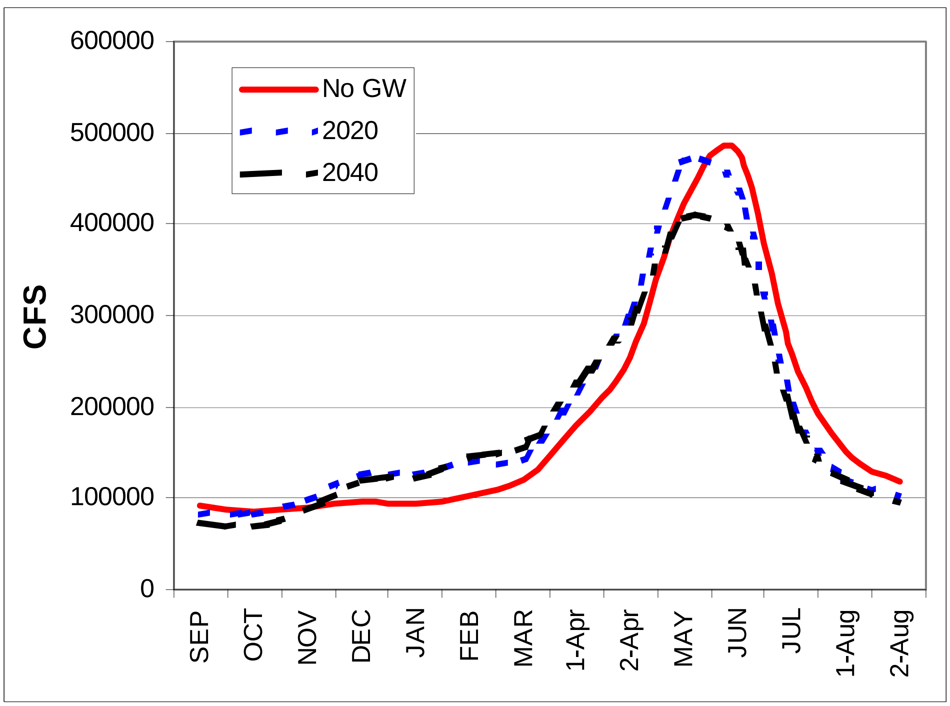

Figure N-13c: Average Unregulated Flow at The Dalles - COMP

Effects on 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 five-degree increase in average temperature over winter months translates into about a 1500-megawatt decrease in electricity demand.

However, the Council does not rely on the Power Pool to estimate fluctuation in demand caused by temperature changes. Simulation models used by the Council use the HELM algorithm to assess demand variations as a function of temperature. Results of that relationship are presented in Figure N-14, which plots the average monthly temperature increase for 2040 and the corresponding change in electricity demand. For December, the average increase in temperature is about 5 degrees and the corresponding decrease in demand is nearly 2,000 megawatts. This is a little more than the Power Pool's anecdotal relationship would predict but the Power Pool's relationship is based more on hourly demand than monthly average demand.

In the summer, higher temperatures mean greater electricity demand because of greater air conditioning use. While the HELM model forecasts for winter demand decreases seem reasonable, at least on the surface, forecasts for summer demand increases are likely too low. Since the data for HELM was developed, air-conditioning penetration rates have increase significantly. In other words, a greater percentage of new homes are being built with air conditioning and more room-sized air conditioners are being used. Thus, forecasted increases in demand (per degree increase in temperature) for summer months (Figure N-14) are too low and must be revised.

However, 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. The existing power system is sufficient to "pick up" the additional demand that is projected for future summer months. However, with continued demand growth, increasing operating constraints on generating resources and perhaps little incentive to build, it is possible that at some future date the Northwest will be forced to plan for both a winter and summer peak. According to the Northwest Power Pool, the difference between winter peak load maximums and summer peak loads is getting smaller each year.

However, even if our analysis included higher summer demands, the operation of the hydroelectric system over those months would not likely change because of the rather rigid constraints for fish and wildlife protection. Without modifications to those constraints the decrease in forecasted natural summer flows (shown in Figure N-13) are not likely to be augmented by release of stored water in reservoirs. Under this assumption, higher summer demands would result in an increased cost to the region, either from reduced sales of surplus hydroelectric energy or from purchases from an expensive wholesale market.

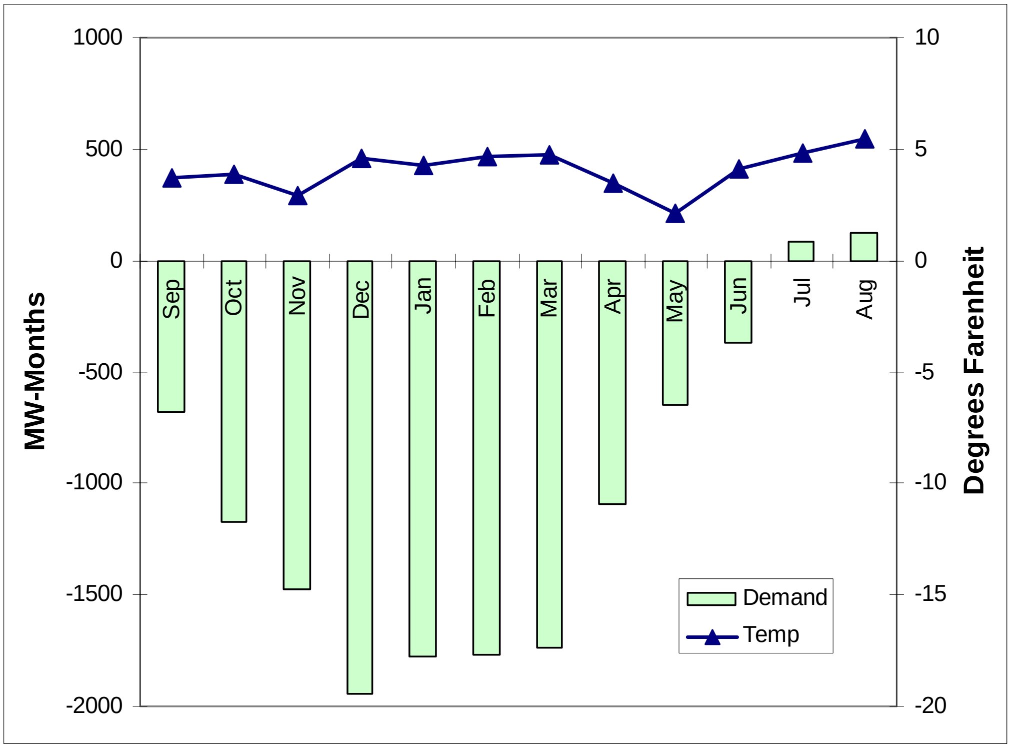

Figure N-14: Average GW Impacts to Temperature and Demand (2040)

Methodology Used to Assess Impacts to the Power System

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[19] 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.

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,

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[19] See www.nwcouncil.org/GENESYS

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.

Changes to Hydroelectric Generation

Table N-2 summarizes the economic results of the Council's study. The average annual change in hydroelectric generation is provided for each climate change scenario for both 2020 and 2040. What is clear from this table is that runoff volume (fuel for the hydroelectric system) makes a big difference in total annual generation. Under the MPI scenario (warm and dry), the hydroelectric system is estimated to lose about 700 average megawatts of energy in 2020 and 2,000 average megawatts by 2040. Current annual hydroelectric generation for the Columbia River system is about 16,000 average megawatts under average conditions and about 11,600 average megawatts for the driest year.[20] These energy losses are not cheap. The estimated regional annual cost of the MPI scenario is $231 million in 2020 and $730 million by 2040.

For a warm-and-wet scenario, the economic outlook is much better. With more fuel for the hydroelectric system, the region is forecast to see about 2,000 average megawatts more energy by 2020 and about 300 average megawatts more by 2040. The corresponding economic benefits are presented in Table 2 below. Under the combination scenario, the region will see a slight increase in generation by 2020 and a net loss of generation by 2040. This scenario shows a net increase in generation (and revenue) by 2020 but a net loss of generation and revenue by 2040.

[20] For another perspective, hydroelectric energy losses due to measures provided for fish and wildlife concerns amount to about 1,100 average megawatts.

Table N-2: Summary of Energy and Cost Impacts

	Change in Annual Energy (average megawatts)		Annual Benefits (Millions)	
	2020	**2040**	**2020**	**2040**
HC (wet)	1982	333	777	169
COMP	164	-477	74	-155
MPI (dry)	-664	-2033	-231	-730

Figure N-15 below illustrates the average monthly change in hydroelectric generation for each of the climate change scenarios. In each case, generation increases over the winter and early spring months and decreases in the late spring and summer months. The magnitude of the change depends on the specific scenario but for all climate-change scenarios examined, the direction of the change is the same.

Figures N-16 and N-17 illustrate the change in regulated outflows and cost. As expected, the same pattern of change observed in Figure N-15 for generation (higher values in winter and lower values in summer) exists for river flows and cost. Figure N-18 provides the average monthly electricity prices used to calculate economic costs/benefits.

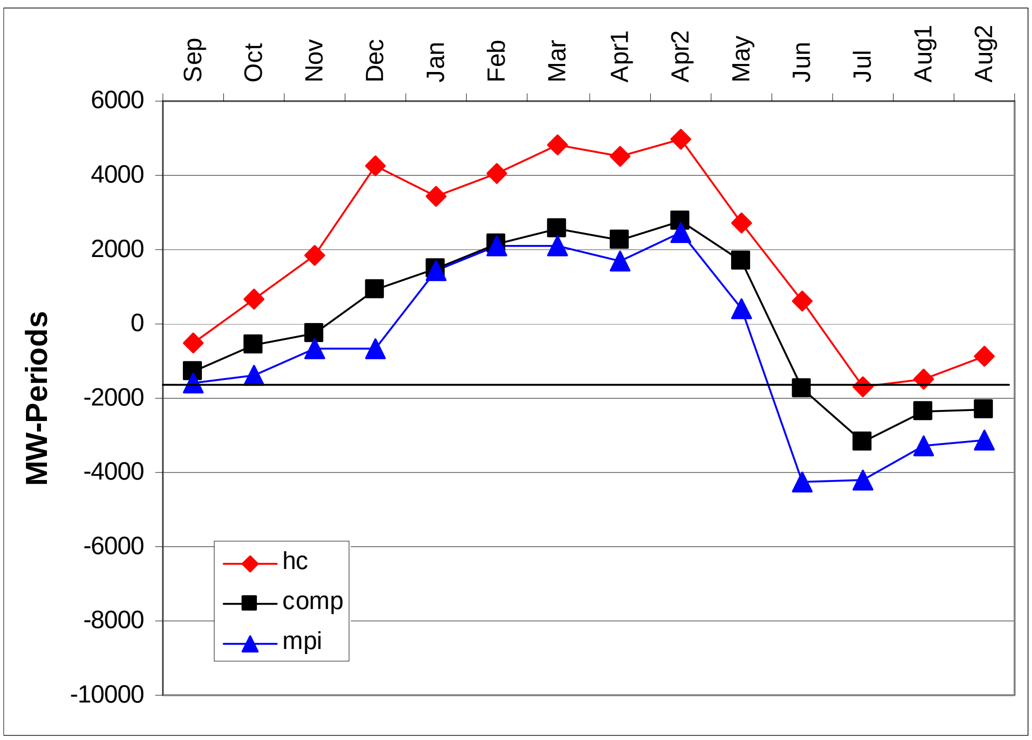

Figure N-15: Average Difference in Hydro Generation (2020)

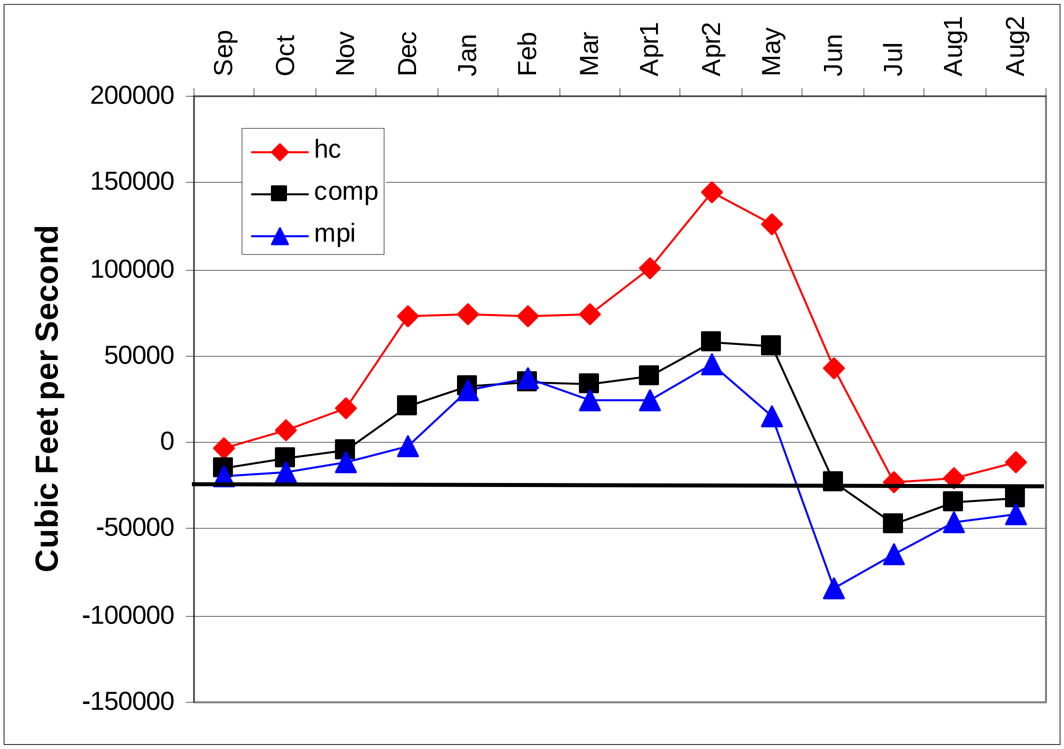

Figure N-16: Average Difference in Regulated Flows at The Dalles (2020)

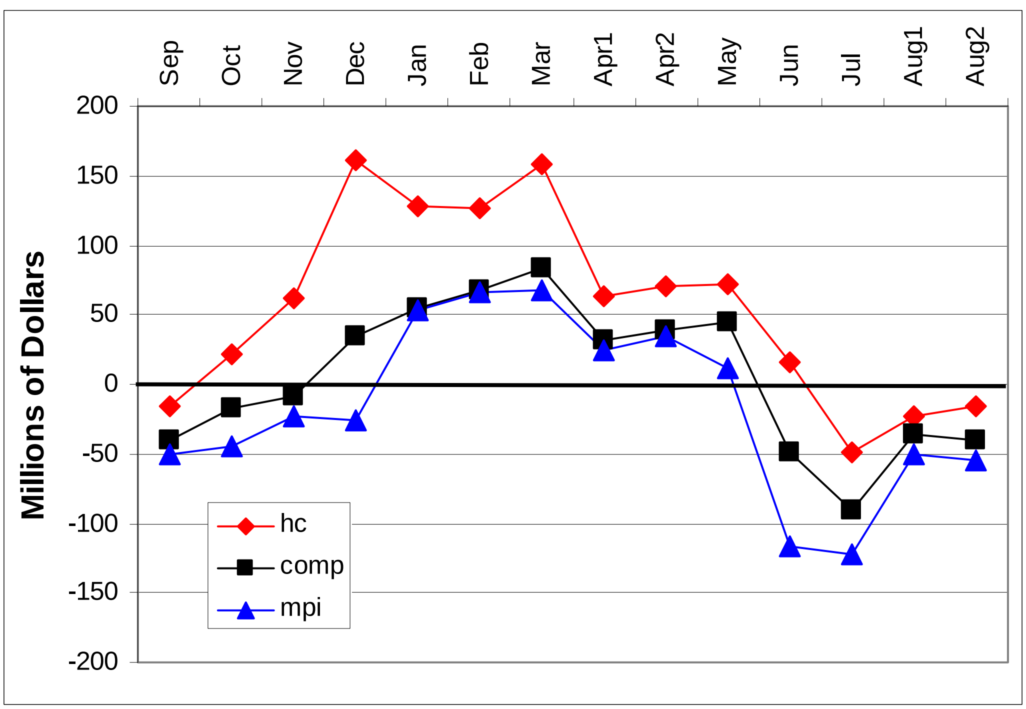

Figure N-17: Average Regional Benefits (2020)

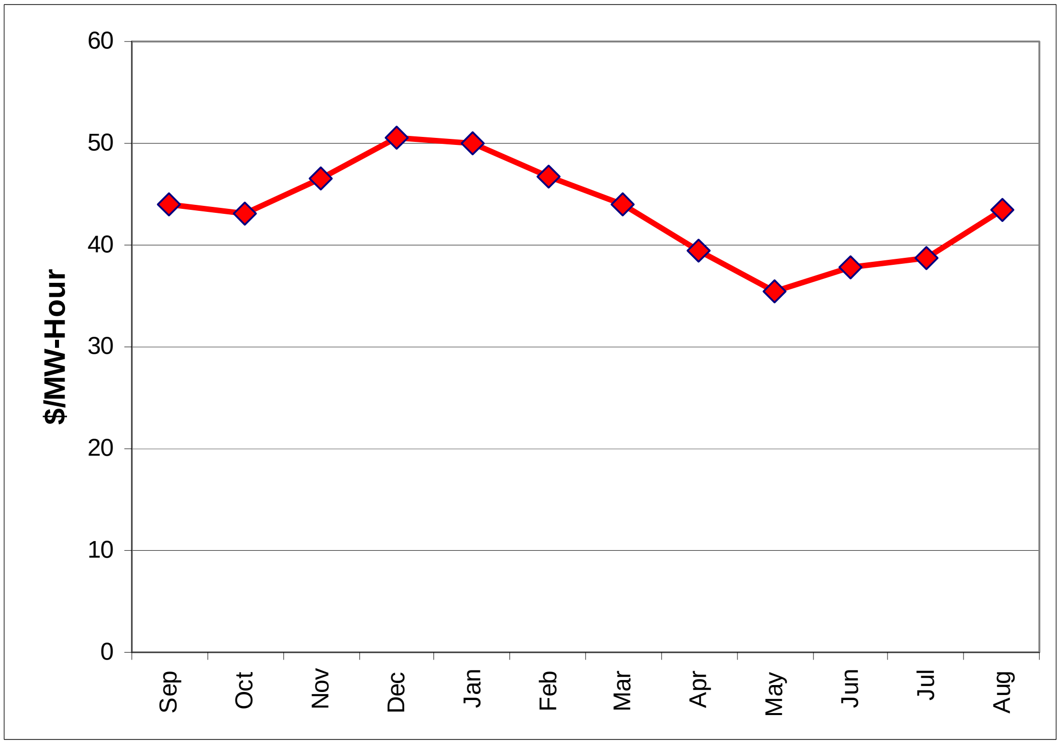

Figure N-18: Forecast Bulk Electricity Prices
(at Mid-Columbia, 2006 operating year, 2004 dollars)

Figures N-19 and N-20 illustrate the data in Table N-2 in graphic form. Conclusions drawn from this study are that; 1) the expected annual change in hydroelectric generation due to climate change depends heavily on forecasted changes to future precipitation (a very uncertain factor) and 2) power-system benefits or costs of climate change correspond directly with the change in runoff volume.

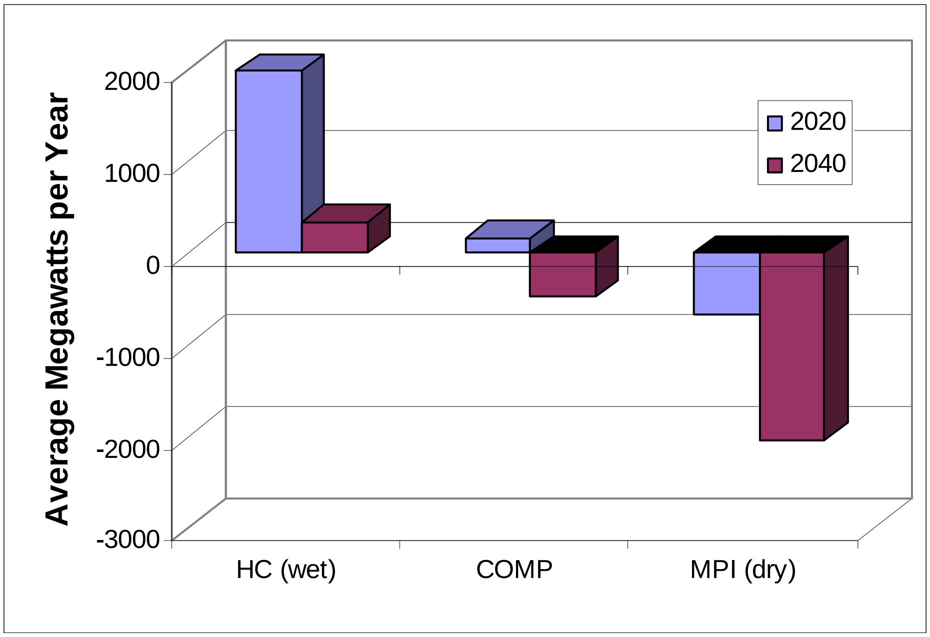

Figure N-19: Average Annual Change in Hydro Generation

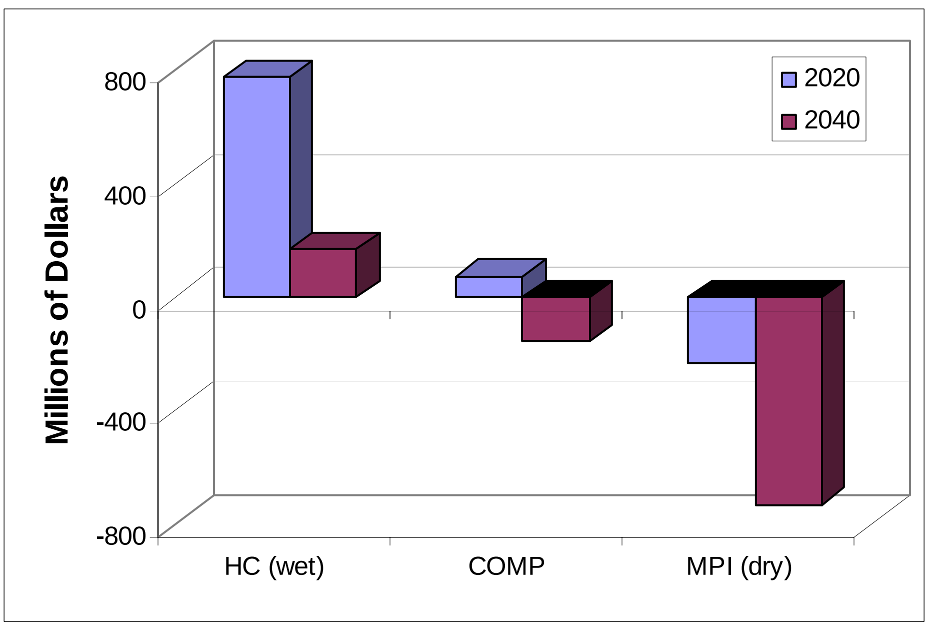

Figure N-20: Average Annual Regional Benefits

Other Impacts

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 (such as the MPI case) 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.

Improving the Analysis

There are several areas where we can improve this analysis. First of all, a larger set of water conditions (1929-1999) should be used. Secondly, a correlated set of monthly temperatures and electricity prices will be used for each water condition. Summer demand response to temperature changes will be revised to incorporate the latest data on air-conditioning penetration rates. In addition, the anti-bias river-flow adjustments are being refined, as are some other data from the Climate Impacts Group.

However, while the final results will change somewhat in magnitude when the revisions mentioned above are incorporated, the general conclusions should not. We can expect, for example, that summer flows will decrease regardless of the climate-change scenario. Only the magnitude of the decrease is still in question. Also, there is no doubt that hydroelectric generation will be shifted across the months of the year. Whether this benefits the region economically or not depends on the overall increase or decrease in river volume.

POTENTIAL MITIGATING ACTIONS FOR THE NORTHWEST

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. Though the effects of climate change remain imperfectly understood, it would be unwise for the Council to ignore its potential impacts to the region. Strategies should be developed to 1) help suppress warming trends and, 2) to mitigate any potential impacts.

In terms of suppressing warming trends, the region should place additional emphasis on reducing the net carbon dioxide production of the power system. Any incentive to reduce greenhouse gases should be examined and electricity customers should be encouraged to use their energy more efficiently. Other actions that would help include;

- Developing low carbon energy sources,
- Substituting more efficient lower-carbon producing energy technologies for older, less efficient technologies, and
- Offsetting unavoidable carbon dioxide production with sequestration technologies.

Reservoir Operations

While no immediate actions regarding reservoir operations are indicated by the analysis, the scoping process should begin to identify potentially mitigating operations to offset climate change impacts. Some of those actions may include:

- Adjust reservoir operating rule curves to assure that reservoirs are full by the end of June
- Allow reservoirs to draft below the biological opinion limits in summer months
- Negotiate to use more Canadian water in summer
- Use increased winter streamflows to refill reservoirs (US and Canadian)
- Explore the development of non-hydro resources to replace winter hydro generation and to satisfy higher summer needs.

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The Interaction between Power Planning and Fish and Wildlife Program Development

BACKGROUND

The Columbia River Basin hydroelectric system is a limited resource that is unable to completely satisfy the demands of all users under all circumstances. Conflicts often arise that require policy makers to decide how to equitably allocate this resource. In particular, measures developed to aid fish and wildlife survival often diminish the generating capability of the hydroelectric system. Conversely, "optimizing[1]" the operation of the system to enhance power production has detrimental effects on fish survival.

As the years of 2000 and 2001 unfolded, analyses by the Council and others indicated that fully implementing the NOAA Fisheries' 2000 Biological Opinion (BiOp) mainstem hydroelectric operations in 2001 was very likely to compromise power system reliability. This was due to very dry conditions in that year and the basic state of power supply in the Northwest and the rest of the Western Interconnection. Allowances in the BiOp, however, permit the curtailment of fish and wildlife operations during emergencies. The Bonneville Power Administration (Bonneville) declared a power emergency in that year based on the water supply and the lack of available generation on the market. Decisions were made to severely reduce fish bypass spill during the spring and summer months in order to ensure adequate supplies of power and to manage the economic impact of the high market prices.[2]

The events of 2001 are just one example that there will always be significant financial incentives to deviate from prescribed fish and wildlife operations when power supplies become tight and prices soar. The solution is to develop a power plan that assures the region an adequate power supply and also minimizes the risk of emergency interruptions to fish and wildlife operations.

THE COUNCIL'S ROLE

The Council has dual responsibilities: to "protect, mitigate and enhance" fish and wildlife populations while assuring the region "an adequate, efficient, economical and reliable" power supply.[3] The interpretation of this mandate has led to great debate within the region. Some argue that fish and wildlife needs must be balanced or integrated with power planning activities. This implies that some sort of cost-effectiveness analysis be done, examining the tradeoff between biological benefits and power system costs. Others argue, however, that fish and wildlife operations should be viewed as firm environmental constraints similar to air and water quality standards. This implies that the power system would build adequate supplies to ensure that fish operations would never be compromised, regardless of cost. These two positions bracket the range of opinions regarding these often conflicting operations.

[1] "Optimizing" here means that energy production is maximized limited by other than fish and wildlife constraints, such as flood control, irrigation, navigation, etc.
[2] See the Council's account of the events of 2000-01 in the main power plan document.
[3] See the Council's publication "Analysis of Adequacy, Efficiency, Economy and Reliability of the Power System"

Although developed at different times and under different processes, the Council has attempted to use an integrated approach in developing both its fish and wildlife program (program) and the power plan (plan). During the development of the program, physical and economic impacts of each fish and wildlife measure affecting the operation of the hydroelectric system were assessed and considered before final adoption of the program. The Council, in its program, has recommended that fish measures be examined for their cost-effectiveness. The program dictates that if the same biological objectives can be met at less cost, those less costly means should be pursued.

The analysis for this power plan assumes that all fish and wildlife operations pertaining to the hydroelectric system, as outlined in the NOAA Fisheries' biological opinion and in the Council's program, will be followed. However, the Council realizes that emergencies may occur in which fish and wildlife operations would be interrupted. Assuring the adequacy of resources for the power system minimizes not only the risk of electrical shortages and high prices but also minimizes the risk of emergency interruptions to fish and wildlife operations.

RECOMMENDATIONS

Federal agencies have formed several committees through the biological opinion process to deal with in-season operational issues affecting fish and power. The Technical Management Team (TMT) consists of technical staff from both federal and non-federal agencies that usually meet on a weekly basis 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 Implementation Team (IT), which consists of higher policy-level staff. Impasses not resolved by this group are forwarded to the Executive Committee (EC), made up of executive staff from the various participating organizations. The process of resolving conflicts in proposed hydroelectric operations can sometimes be lengthy and cumbersome.

While the existing committee structure is intended to solve in-season problems, no currently active process exists to address long-term planning issues. The Council recommended in its 2003 program that both in-season and annual decision-making forums be improved.[4] The program states "at present, this decision structure is insufficient to integrate fish and power considerations in a timely, objective and effective way." It goes on to recommend that the forums should broaden their focus by including "expertise in both biological and power system issues" and by directly addressing longer-term planning concerns, not just weekly and in-season issues.

It is in such a forum where the long-term physical, economic and biological impacts of a fish and wildlife operation can be openly discussed and debated. Actions identified in the program to benefit fish and wildlife "should also consider and minimize impacts to the Columbia basin hydropower system if at all possible." The program further says that the goal should be "to try to optimize both values to the greatest degree possible."

To this end, the Council reiterates its recommendation in the 2003 program to improve and broaden the focus of the forums created to address issues surrounding fish and wildlife operations, especially those related to long-term planning.

[4] "Fish and Wildlife Program," Northwest Power Planning Council, Council Document 2000-19, pp.28, and "Mainstem Amendments to the Columbia River Basin Fish and Wildlife Program," Northwest Power Planning Council, Council Document 2003-11, pp.28-29.

ACTION ITEM

In this power plan, the Council recommends (Action F&W-1 in the Action Plan) that it "will work with federal agencies, the states, tribes, and others to broaden the focus of the forums created to address issues surrounding fish and wildlife operations, especially those related to long-term planning." This action is intended to improve the interaction between power planning efforts and fish and wildlife program development. More specifically this may include the following:

NOAA Fisheries and other Federal Agencies

- Improve and broaden the focus of forums created to address issues surrounding fish and wildlife operations, especially those related to long-term planning.
- Allow region-wide participation in these forums.

Council, Bonneville Power Administration and Hydroelectric Facility Operators

- Analyze the physical impacts (river flows and reservoir elevations) and economic impacts (changes in energy production and cost) of alternative mainstem operations for fish and wildlife.
- Whenever appropriate, analyze physical and economic analysis of individual components or sets of components of a fish and wildlife operation.

Council

- Work with the Independent Economic Advisory Board (IEAB) to continue to develop and demonstrate methods to improve the cost effectiveness of the fish and wildlife operations.
- Work with fish and wildlife managers to develop a methodology to assess whether protective mainstem measures are being treated equitably. This may involve establishing some sort of a metric similar to those developed to assess power system reliability.

Fish Managers

- Work with power planners and agencies to develop a minimum impact curtailment plan for fish and wildlife operations in the event of a power emergency.
- Work with power planners to assure the region that the most cost-effective measures are taken to achieve biological objectives.

BENEFITS OF INTEGRATION

Power system planners can provide valuable information to fish and wildlife managers to aid their development of measures to improve survival. Similarly, fish and wildlife managers can provide data to power planners so that they can plan for resource mixes that minimize impacts to fish and wildlife, whenever possible.

Biologists developing a fish and wildlife program must be able to assess relationships between various physical parameters and survival. For example, river flows, water temperature, passage routes (turbines, bypass or barges), predation, ocean conditions and a host of other factors all affect survival and long-term population forecasts for salmon. Based on these relationships, biologists can make recommendations regarding those elements that can be controlled, such as the operation of the hydroelectric system. Any changes to the operation of that system will result in differences in reservoir elevations, river flows, energy production and cost.

Using sophisticated computer models that simulate the operation of the northwest power system, power planners can assess the impacts of any given set of fish and wildlife measures that change the operation of the hydroelectric system. For a fish and wildlife program and, in particular, for individual elements of that program, physical impacts (effects on reservoir elevations and on river flows) and economic impacts (changes in generation production and related cost) can be analyzed and provided to fish and wildlife managers.

Changes in reservoir elevations, river flows and spill are used, along with other data, by biologists to estimate fish passage survival through the system. Passage survival estimates are an important part of life-cycle models, which are used to forecast long-term fish populations. Long-term population estimates, along with their corresponding uncertainties, will determine whether certain species are well off, stable or declining. In this sense, physical analysis by power planners plays a very important role in the development of the fish and wildlife program.

In addition, 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 a policy in place prior to an emergency, in order to minimize the risk to fish and wildlife. The following section provides a description of the mainstem measures under the fish and wildlife program and an analysis of their cost.

COMPONENTS OF A FISH AND WILDLIFE OPERATION

The mainstem portion of the fish and wildlife program consists of two major types of actions to promote survival that will also affect the power supply; 1) flow augmentation and 2) bypass spill.[5]

Flow Augmentation

Monthly flow objectives are provided for both the Snake and Columbia rivers during the migration season (April through August). These flow objectives, however, cannot be achieved 100 percent of the time because our reservoir system simply cannot store enough water to make up the difference in dry years. The BiOp makes considerations for extremely dry years and for the large uncertainty in forecasting runoff volumes. Language in the BiOp directs spring refill curves at Grand Coulee to be developed using an 85 percent level of confidence (assuming that sufficient non-hydro resources are available for winter power needs). Refill curves at Libby, Hungry Horse and Dworshak are developed using a 75 percent level of confidence. Realistically, because of other higher priority constraints, these refill probabilities are not always achieved. In simulated operations, Grand Coulee refills 84 percent of the time and Libby, Horse and Dworshak refill 40 percent, 58 percent and 66 percent, respectively.

When analyses are done using the existing non-hydro resources in a probabilistic manner (i.e. simulating forced outages), reservoirs must sometimes be drafted below their operating rule curves during winter months to sustain electricity service. This use of hydro is often referred to as "hydro flexibility." Hydro flexibility is used to make up energy needs during cold snaps or periods when imports from out-of-region utilities are not available or during the outage of a major power system component. The additional water drafted to produce the extra energy is replaced as soon as possible,

[5] See the Council's 2003 Fish and Wildlife program and NOAA Fisheries' 2000 Biological Opinion.

even if energy must be imported. Most often reservoirs can recover and get back to the projected refill elevations by spring. In the event that hydro flexibility cannot be replaced by spring, then less water is available for flow augmentation through spring and summer.

Bypass Spill

During the summer, flow augmentation measures in the BiOp actually provide more generation from the hydroelectric system because they increase river flow. However, bypass spill, which diverts water around turbines, reduces generation and reactive support for the transmission system.[6] Bypass spill can be curtailed for two reasons; 1) due to summer power emergencies (which should be more rare than winter emergencies) or 2) to refill reservoirs to minimum end-of-summer elevations as specified in the BiOp or the Council's fish and wildlife program. Bypass spill could also be curtailed in order to store additional water in Canadian reservoirs as a safeguard for anticipated winter problems in an upcoming winter, as was the case in 2001.

Measuring the Success Rate of Providing Fish and Wildlife Operations

The BiOp allows for curtailment of fish and wildlife operations during power emergencies but it does not specify an upper bound for such actions. For a number of reasons (i.e. what occurred during the 1990s) it could happen that the region under builds its generation supply, which increases the likelihood of having to curtail fish and wildlife operations. Using curtailment of fish and wildlife operations as a "safety valve" for an inadequate power supply is not acceptable. Curtailment of fish and wildlife operations cannot be used in lieu of planning for and acquiring an adequate regional power supply.

As a possible method of quantitatively measuring the likelihood of curtailment to fish and wildlife operations, a probabilistic metric (similar to the loss of load probability) can be developed. The simulation models used to calculate the reliability of the power system can also readily provide an assessment of how often fish and wildlife operations would be curtailed. The model can count how often reservoirs do not reach the desired pre-migration elevations and also how often bypass spill would be curtailed to avoid power shortfalls.

Council staff has developed a prototype metric and has solicited comments from a wide range of agencies and organizations in the region. While there was significant interest and support for developing such a metric, it became clear that more regional analysis and debate would be required before such a metric could be implemented into the planning process. Problems yet to be resolved related to this metric are defining what a "significant" curtailment is and how often curtailments would be allowed (that is, setting a standard). Future discussion of this approach should be discussed in the long-term planning committee that the Council is recommending to be established.

COST OF INDIVIDUAL FISH AND WILDLIFE MEASURES

The analysis presented here estimates the cost of individual measures in the fish and wildlife program. This effort is not designed to be a cost-effectiveness analysis. Rather, it is to be used to help the Council identify the most costly elements of the fish and wildlife program, which should be re-examined for biological effectiveness. The Council specified, in its fish and wildlife program, that such measures, especially bypass spill, should be revisited in terms of assessing their biological

[6] See the February 24, 1998 memorandum from John Fazio to the Council members regarding the transmission impacts of drawing down John Day Dam (Council document 98-3).

benefits. During that process benefits to fish and wildlife from alternative main stem operations and their effects on the power system should also be examined.

Methodology

This analysis begins with a simulation of current river operations (BiOp). The simulation is performed with the GENESYS model.[7] Each subsequent study repeats the simulation but with one fish and wildlife measure removed. For each case study, the energy produced is compared to that in the base case and power system cost is calculated. This effectively determines the cost of each fish and wildlife measure analyzed. The measures are then ranked by cost.

It should be noted that fish and wildlife measures are not totally independent of each other. In other words, the cost of removing two measures will be different than the sum of the costs of removing each individually. Some measures, such as winter storage and flow augmentation are more dependent than others, such as bypass spill. However, performing the analysis as if each measure were independent provides a good first pass approximation. Once the data has been examined, the most expensive measures can be analyzed in more detail.

The key output parameter is annual-average regional power-system cost. That value is calculated by multiplying the difference in monthly hydroelectric energy production between the base case and a study case with the forecasted monthly market electricity price.[8] When the study case produces less energy, the difference is assumed to be purchased on the market and represents a cost. When the study case produces a surplus, the difference is sold on the market and represents revenue that offsets purchase costs. This calculation is performed for each month of the year, simulated over the 50-year historical water record.

The power system cost calculated for this analysis does not include costs of implementing fish and wildlife measures. It also does not include costs associated with loss of capacity or loss of transmission capability. Future analysis with the GENESYS model can shed some light on potential capacity problems associated with fish and wildlife measures. Those costs are not insignificant but it is believed, in most cases, that they are small compared to energy costs.

Results

Simulation results compare hydroelectric generation from the base case with that from the various scenarios analyzed. The monthly change in generation is multiplied by the wholesale electricity price (shown in Figure 1[9]) to compute the net gain or loss of revenue. Decreases in generation are assumed to be made up with purchases from the market and increases in generation are assumed to be sold into the market. By adding up the monthly purchases or sales over all water conditions, the average annual net cost or benefit of a particular scenario can be calculated for the region. Figure 2 below illustrates the range of annual costs for the entire BiOp. The average annual cost is $410 million. To put this in perspective, Bonneville’s annual net revenue requirement is in the range of $3.5 billion. Thus, the BiOp cost is a little more than 10 percent of Bonneville’s net revenue

[7] See http://www.nwcouncil.org/genesys.
[8] Electricity prices are forecast using the Aurora model, created and leased by EPIS.
[9] It should be noted that the long-term forecast electricity price drops from the 2006 average of about $43/megawatt-hour to about $30/megawatt-hour by the year 2010. The forecast price then rises gradually to a little over $35/megawatt-hour by 2025. This means that in real terms, the costs for fish and wildlife measures will be lower in future years relative to their cost for 2006.

requirement. Energy-wise, the BiOp has decreased average hydroelectric generation by about 1,100 average megawatts or about 10 percent of the firm hydro energy capability.

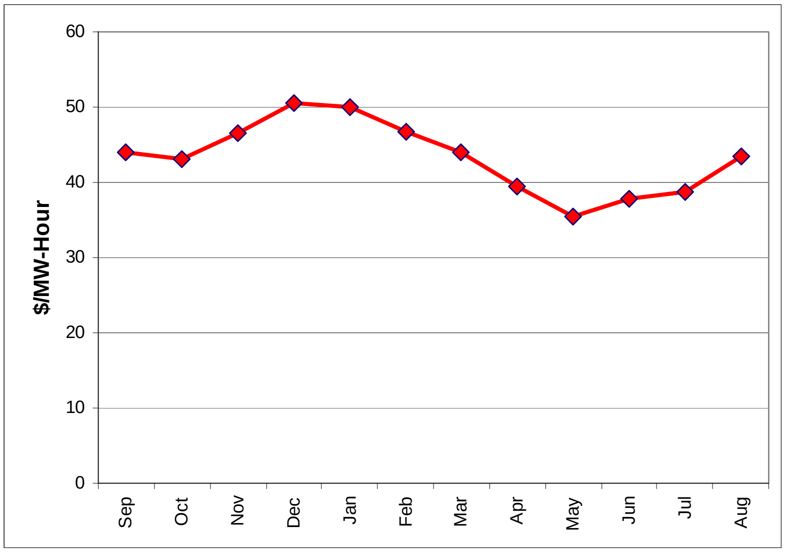

Figure O-1: Forecast Bulk Electricity Prices
(at Mid-Columbia, 2006 operating year, 2004 dollars)

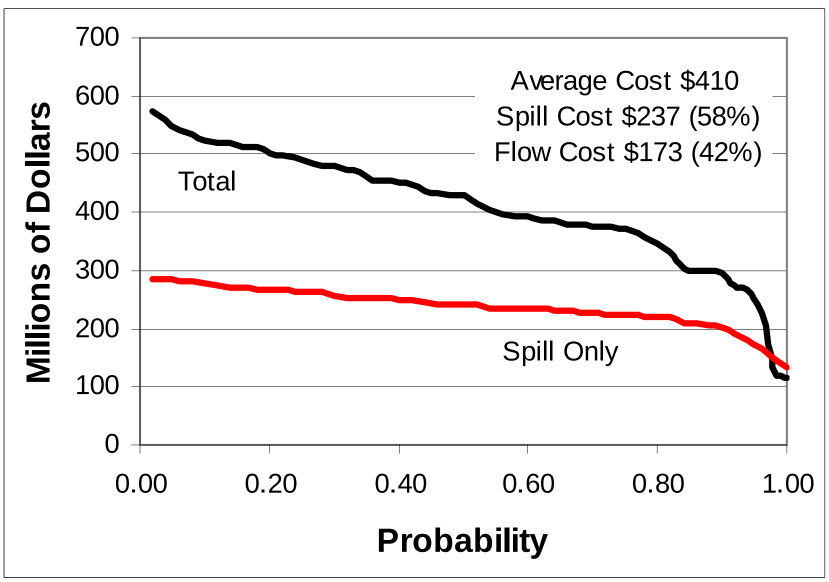

Figure O-2: Range of Annual Cost for Fish and Wildlife Operations
(2006 operating year, 2004 dollars)

Annual BiOp costs range from a high of about $600 million to a low of about $100 million. In order to explain why some years have low costs, we must describe in more detail the two major components of fish and wildlife operations -- flow augmentation and bypass spill. Holding water back during winter months for release in spring and summer months effectively moves hydroelectric generation from months when the average price is about $50/MW-hour into spring months when the price can be as low as $35/MW-hour and into the summer months when the price can still be lower than the winter price. (There are also energy efficiencies to take into account but their impact is small relative to the shift in prices). Depending on how much water (energy) is moved into spring vs. summer, the range of economic impacts for flow augmentation is very large (Figure 2). There may be some situations when summer prices are higher than winter prices, in which case, flow augmentation actions could improve revenues. Unfortunately, the effects of bypass spill overwhelm any economic benefits derived from such situations.

Bypass spill is water that is routed around the turbines to enhance survival of migrating smolts. It always represents a loss of revenues for the region. At some projects, bypass spill is defined to be a fraction of outflow and at other projects it is defined as a flat amount. Both are subject to maximum spill levels that limit gas supersaturation to no more than 120 percent. The cost of spill varies with water conditions and prices. Figure 3 illustrates the annual breakdown of flow augmentation and bypass spill costs for the region. Overall, bypass spill costs represent about 58 percent of the total average cost of the BiOp. That percentage varies quite a bit as demonstrated in Figure 3.

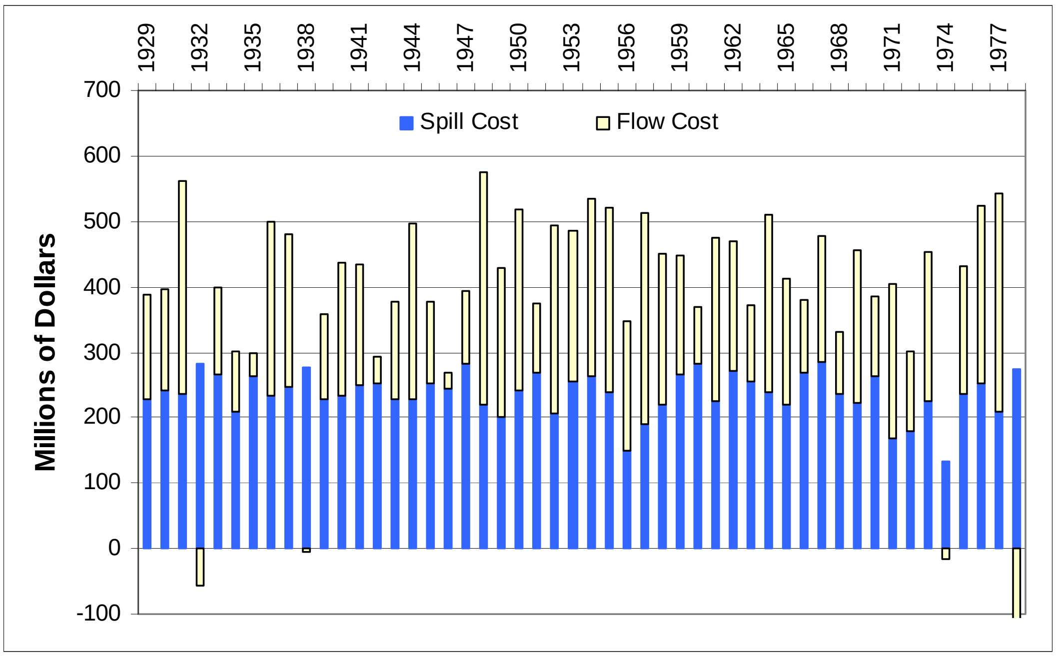

Figure O-3: Flow and Bypass Spill Cost by Water Condition (2006 operating year, 2004 dollars)

It is of interest to understand how fish and wildlife operation costs vary with water conditions. Figure 4 below plots the cost of both flow augmentation and bypass spill as a function of the January-to-July runoff volume as measured at The Dalles. The flow augmentation costs are represented by the square points in that figure and do not show any particular pattern, except that they may perhaps decrease slightly as runoff volume increases. This makes some intuitive sense since less water must be shifted from winter months into spring and summer months in wet years to attempt to achieve BiOp flow objectives.

Bypass spill costs however, behave in a very different manner. Figure 5 illustrates only the spill costs as a function of runoff volume. As runoff conditions increase, so do bypass spill costs but only up to a point. For more-or-less average water conditions spill costs seem to level off. For wet years, bypass spill costs actually decrease. This apparently unusual relationship between spill and costs can be explained fairly easily. At some projects, bypass spill is a percentage of outflow -- meaning that as the outflow increases (or as runoff volume increases) the absolute volume of spill also increases. However, this trend is limited by the gas supersaturation constraint. That is, once the absolute volume of spill reaches the gas limit, no more volume is spilled. In this case, the cost of bypass spill remains constant until the runoff volume increases to a point where the hydraulic capacity of the project is exceeded. In that case, the amount of bypass spill is reduced so that the total spill (bypass and forced) equals the desired amount. Because forced spill (flow exceeding hydraulic capacity) would occur anyway, there is no cost associated with it and the cost of the declining bypass spill decreases. This phenomenon is illustrated in Figure 6.

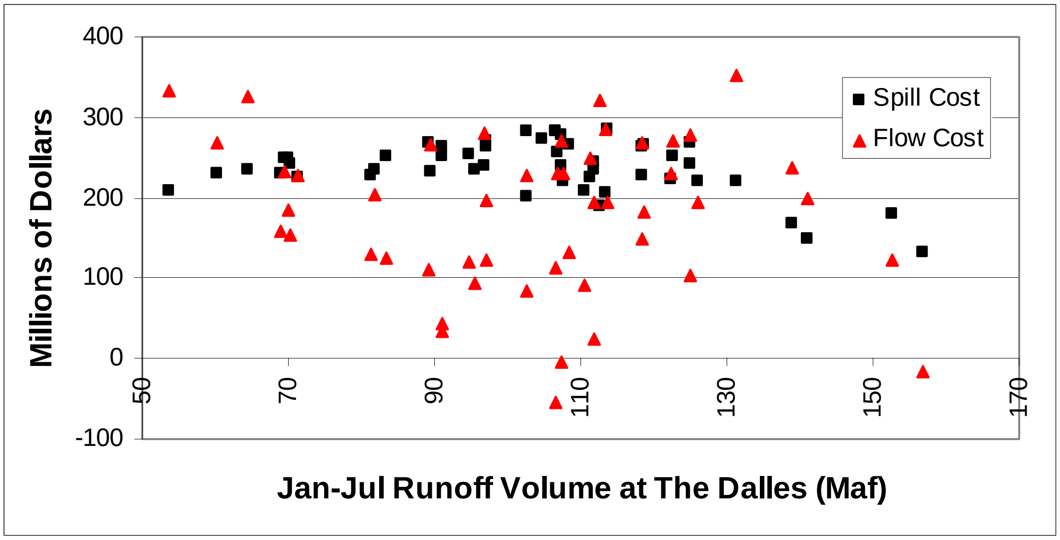

Figure O-4: Flow and Spill Cost as a function of Runoff Volume (2006 operating year, 2004 dollars)

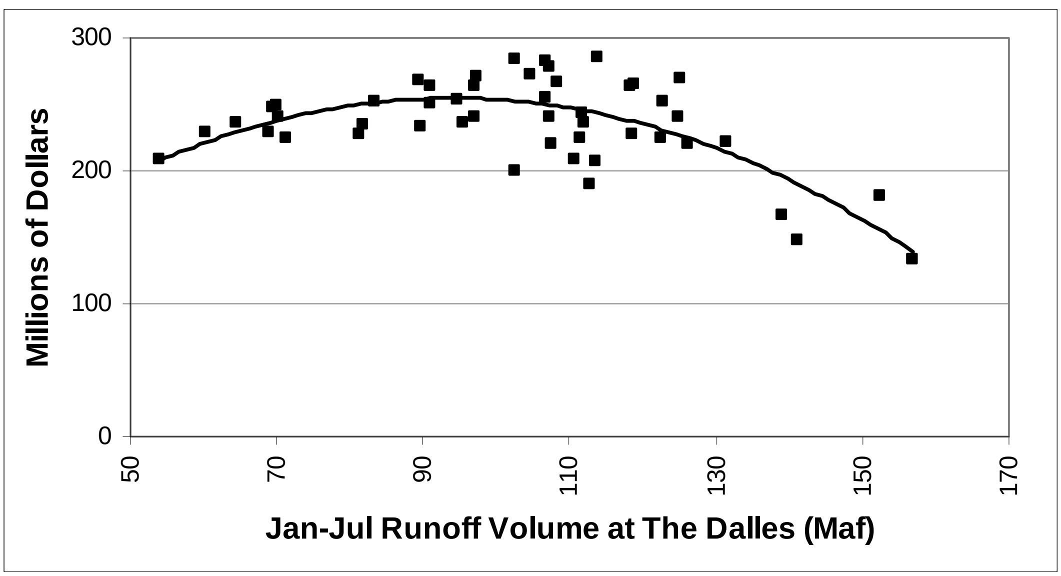

Figure O-5: Bypass Spill Cost as a function of Runoff Volume (2006 operating year, 2004 dollars)

It is of no great surprise that bypass spill shows the greatest cost to the power system in most years. Not only does the region lose energy when providing spill but it also limits the peaking capability of the project and in some cases may reduce reactive support for the transmission system. The later impact effectively reduces the transfer capability of nearby transmission lines.[10]

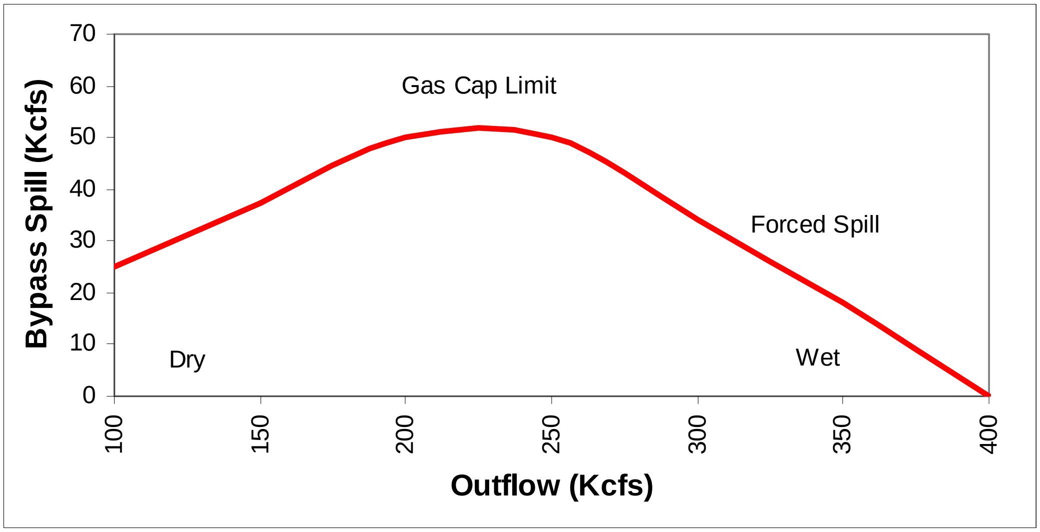

Figure O-6: Illustration of Bypass Spill Flow as a function of Outflow

Because of the Council's commitment to re-examine bypass spill, the remaining analysis focuses on that operation. Table 1 below identifies the energy loss and associated costs of providing bypass spill at the eight lower river dams for both spring and summer periods. From Table O-1, it is clear that bypass spill at The Dalles and John Day is the most costly. In fact, bypass spill costs at those two projects make up almost half of the total spill cost. If any research money is to be spent, it should focus on these two projects and perhaps Ice Harbor.

Figures 7 and 8 illustrate the cost of bypass spill in graphic form. Figure 7 shows the average cost for bypass spill at each of the eight lower river dams. Figure 8 breaks those costs down into spring and summer periods, just like the data in Table 1. Using this information helps direct money and research efforts to the right projects.

[10] See Council document number 98-3.

Table O-1: Annual Average Cost and Energy Loss of Bypass Spill (2006 operating year, 2004 dollars)

Project/Season	**Cost** (Millions $)	**Energy Loss** (MW-Hours)
John Day/Summer	31.1	766,810
John Day/Spring	29.6	791,895
Ice Harbor/Spring	28.6	742,361
The Dalles/Spring	27.5	735,028
The Dalles/Summer	25.6	625,399
Bonneville/Summer	23.3	560,671
Bonneville/Spring	20.7	542,524
McNary/Summer	12.2	306,571
Ice Harbor/Summer	11.8	292,441
McNary/Spring	10.6	276,784
Lower Monumental/Spring	8.8	233,917
Little Goose/Spring	4.1	109,644
Lower Granite/Spring	3.3	87,504
Total (energy loss in average megawatts)	**237**	**693**

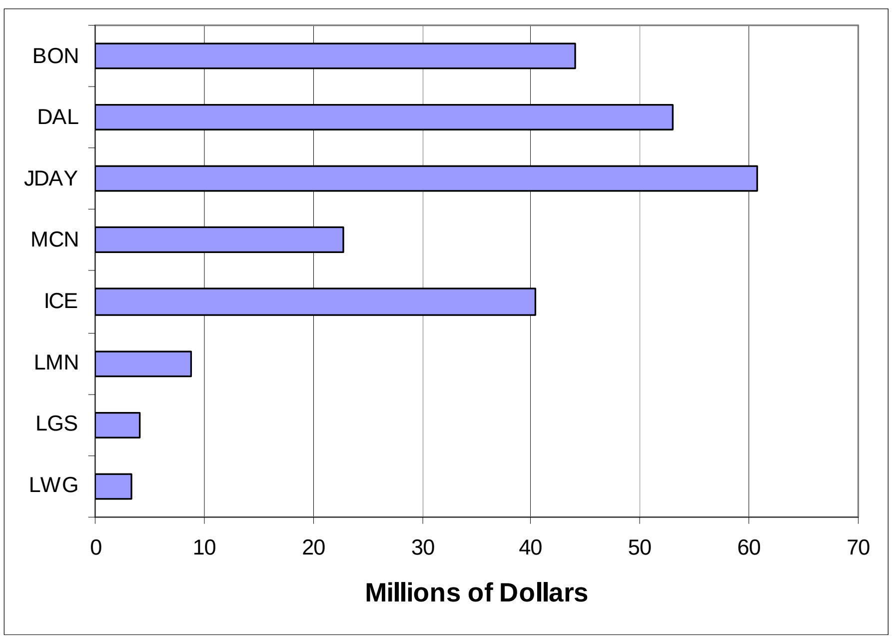

Figure O-7: Bypass Spill Cost by Project (2006 operating year, 2004 dollars)

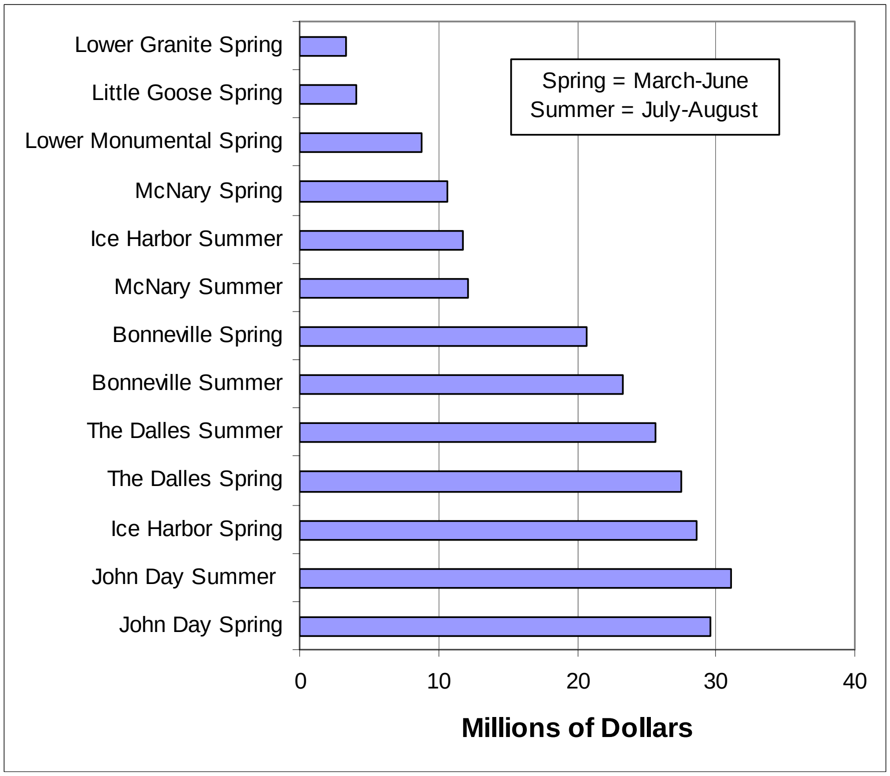

Figure O-8: Bypass Spill Cost by Project and by Season (2006 operating year, 2004 dollars)

Risk and Uncertainty

This appendix deals with the representation of uncertainties and risks in the plan's regional model.[1] It also describes the various studies the Council has performed to understand how the Council's perception of risk and uncertainty bear on its recommendations. A glossary, index, and list of references appear at the end.

This appendix addresses the regional model itself to a limited extent. This appendix identifies a particular range of the model worksheet cells that creates a model "future," the single draw of each source of uncertainty over the study horizon. In the section on "Uncertainties," beginning on page P-19, it describes in detail how the regional portfolio model manifests these modeling futures with Excel® formulas and user-defined functions. The description of the rest of the model, however, appears in Appendix L.

ICON KEY
Key idea
Definition

This appendix provides several tools to help the reader track this discussion. The first tool is the use of icons to flag key definitions and concepts. A table of these icons appears that the left.

The second tool is a set of workbooks containing versions of the regional model, utilities, and a document that describes particular worksheets. The reader can request a copy of these workbooks from the Council or download them from the Council's web site.[2] The first of these files is a compressed file containing the workbooks that Appendix L uses, L24X-DW02-P.zip. In particular, L24DW02-f06-P.xls is a workbook containing a pre-draft plan version the regional portfolio model. The compressed file also contains examples of utilities and documentation. References to the workbook L24DW02-f06-P.xls appear in curly brackets ("{}"). The second file is L28_P.zip, which contains the workbook L28_P.xls, the regional model that the final plan's preparation used. Note that the treatment of several key sources of uncertainty changed significantly between the draft and final plan. A document in L28_P.zip describes the changes. References to L28_P.xls appear in double curly brackets ("{{}}"). Access to the workbooks should not be necessary for following the discussion in this appendix, however.

References to Council work papers and data sources appear in square brackets ("[]"). The "References" section at the end of the appendix lists these sources. Other publicly available sources appear in footnotes. The reader may want to refer to the following Table of Contents for orientation to the remaining appendix.

[1] The reader will find definitions for terms such as "uncertainty," "risk," and "futures" in the glossary. Chapter 6 of the plan also defines and illustrates these terms with examples.
[2] As of this writing, http://www.nwcouncil.org/dropbox/Olivia_and_Portfolio_Model/

Table of Contents

Introduction

This appendix begins with a discussion of the Council's approach to decision making under uncertainty. This shapes the means of and choice of tools for addressing uncertainty. It also influences the validation of analyses and models. The issue of validation arises not only in the formal validation of the model futures but extents to basic judgments about assumptions, as well. The Appendix will return many times to the issue of whether the judgments about assumption values are reasonable in the section on "Uncertainties."

Between its discussion of the Council's approach to decision making under uncertainty and the validation of data and models, the appendix introduces the regional model. This serves several purposes. First, the next main section is about the Council's treatment of uncertainties. As mentioned earlier, this appendix identifies a particular range of the model worksheet cells that creates a model "future," the single draw of each source of uncertainty over the study horizon. This introduction identifies that range. The introduction also gives the reader an overview of the philosophy and methods for modeling uncertainty. It describes, for example, the use of Monte Carlo simulation and how the application this technique facilitates the Council's approach to decision making. Second, it identifies how the model produces its principal results, the distribution of present value total system costs and associated risk and central tendency measures. This is the topic of the next main section of this appendix, "Risk Measures." Third, the introduction provides a concrete framework for the discussion of the last section, "Sensitivity Studies." This last section examines not only the purpose and conclusions of the studies, but how Council staff modified the regional model to obtain the results. Finally, the introduction mentions utilities that access regional model output to assist interested parties to perform their own validation of the model's assumptions and results.

Decision Making Under Uncertainty

Strategic decision-making models ***use and manage uncertainty*** differently from many simulation models that incorporate uncertainty. The key difference between the two is the scale of risk and how a decision maker responds to uncertain events.

An example of a simulation that addresses uncertainty, but is not what we would call strategic decision analysis, is how many utilities model hydrogeneration. To simulate generation due to hydro streamflow variability, an analyst would create a model using some sample of historical data, say 1939 through 1978 streamflows. The analyst has a great deal of information about the distribution of streamflows. He may be willing to assume that the underlying processes that give rise to the streamflows – and the relationship between generation and stream flows – are stable. Because the variation in hydrogeneration averages out over a sufficient number of years with high probability, the average generation and average system cost are useful statistics, and may be the key outputs of interest.

The decision maker may need to make a choice among different plans to deal with this variation in hydrogeneration, but the tool she uses is essentially sensitivity analysis, albeit sophisticated sensitivity analysis. This kind of analysis is appropriate where the scale of the uncertainty and risk is small enough that the decision maker feels she can live with the outcomes, given the selected plan. In particular, the emphasis is on choosing a plan to which the decision maker feels comfortable committing.

This approach is common to many kinds of analysis. For example, it would be the way an industrial engineer would represent a manufacturing process, if he wanted to maximize throughput. It is the way a civil engineer would model traffic flow, if he were trying to minimize congestion or travel time.

Against these examples, contrast strategic decision analysis. If the scale of change is large, extreme outcomes may be catastrophic. If the outcome would be catastrophic, the decision maker may need to consider individual scenarios. The way each scenario turns out would typically determine how the decision maker would respond to circumstances. Scenario analysis will focus on developing options, deciding what circumstances would trigger the implementation of each option, and evaluating the benefits of using each option. Scenario analysis usually has decision rules or "flags" that tell the decision maker when to change plans or implement options.

An example of strategic decision analysis is planning for a military operation. In the fog of war, leaders must make life or death decisions about tactic and strategy. In addition to the main plan, strategists will develop Plan B, Plan C, and so forth, alternatives to implement if circumstances are not as expected. They create options by deploying resources and small numbers of troops to monitor enemy activity and serve as support if it becomes necessary to adapt to new scenarios.

Note that a general would never consider implementing a fixed strategy, one without options or alternatives, based on average survival. If an option will spare a life, it merits consideration. Whereas the average hydro generation over five or six years is a useful number for certain calculations, such as average power cost, failing to adapt military plans because the expected distribution was acceptable would be ludicrous and tragic. In decision analysis, the tails of the distribution, especially the "bad" tail, assumes greater significance than they do in ordinary simulations. Adaptations that improve the outcomes in the worst of circumstances receive emphasis. Decision making under uncertainty has more to do with making decisions that, while they may not have been optimal in retrospect, did not lead to a catastrophic outcome. This appendix returns to the discussion of managing bad outcomes in the section "Risk Measures."

One of the issues that a decision maker who is making decisions under strategic uncertainty must grapple with is the relative likelihood of each scenario. This issue is central to the question of how much to spend on a given option. If the decision maker believes that scenario A is much more likely than scenario B, which has the same cost, the decision maker might be inclined to spend more to mitigate scenario A. Another difficulty that sometimes arises in scenario analysis is that a decision maker can only evaluate a small number of scenarios. The question arises, "How were these scenarios selected, and how representative are they?"

The next section introduces to a technique, Monte Carlo simulation, which helps address concerns about the likelihood and range of scenarios. The regional model employs Monte Carlo simulation. The regional model, however, also implements planning flexibility. Planning flexibility, described in Appendix L, enables the regional model to evaluate contingency plans and implement those plans as circumstances change during each scenario's study period. Therefore, the regional model performs true strategic decision analysis on a large number of scenarios, effectively "scenario analysis on steroids."

Another distinction of decision analysis models is how one validates the models. The section that follows the next section discusses those differences.

Monte Carlo Simulation

"Monte Carlo simulation" refers to any method that solves a problem by generating suitable random numbers and observing that fraction of the numbers obeying some property or properties. The method is useful for obtaining numerical solutions to problems that are too complicated to solve analytically.[3] In 1946, S. Ulam became the first mathematician to dignify this approach with a name, in honor of a relative having a propensity to gamble (Hoffman 1998, p. 239). Ulam was involved with the Manhattan project to build the first atomic bomb. Physicists used the technique for evaluating complex integrals.

The Council applies the Monte Carlo technique to regional resource planning to generate futures based on the likelihood of particular values of each source of uncertainty in each modeling period of the regional model:

- Load requirements
- Gas price
- Hydrogeneration
- Electricity price
- Forced outage rates
- Aluminum price
- CO_2 tax
- Production tax credits
- Green tag value

The regional model performs true strategic decision analysis on a large number of scenarios, effectively "scenario analysis on steroids."

The technique produces values for each source that have the correct correlation with previous values and with values of the other sources.

[3] The interested reader can consult any of a host of books and Internet resources describing Monte Carlo simulation in general.

The principal reason for using Monte Carlo simulation for decision analysis, however, is that it avoids what the Richard Bellman referred to as the “curse of dimensionality.”[4] To evaluate the outcomes associated with values of uncertainties, an analyst can construct a “decision tree” that associates with each combination of values for the various sources a probability and outcome. The problem, however, is that the “branches” of the decision tree proliferate exponentially with the number of uncertainties addressed. For example, a decision tree with three values of electricity price forecasts (“high,” “medium,” and “low”) would require only three studies. A decision tree large enough to examine three forecasts for each of the nine uncertainties listed above, however, requires $19{,}683 = 3^9$ studies. The regional model uses 750 values for each of 1045 random variables to represent values in each of the model’s 80 periods, which would produce 750^{1045} branches. This number of branches far exceeds the storage capability of any machine imaginable. The regional model, moreover, must perform this calculation roughly a million times to produce a single feasibility space, described below.

Of course, not all of the branches of a decision tree have sufficiently high probability and extreme value that they would contribute much to the solution. It is this observation that leads to Monte Carlo simulation. Monte Carlo simulation chooses random values for each source of uncertainty according to their likelihood.[5] The distribution that results therefore automatically reflects both the likelihood and value of the outcome. Because Monte Carlo simulation is a statistical sampling technique, the criterion for the number of samples is the confidence necessary for statistics of interest, such as the error of the mean or of the mean of a tail. This sample size is typically only weakly sensitive to the number of sources of uncertainty.

The regional model uses Decisioneering Inc.’s Crystal Ball® Excel add-in to perform Monte Carlo simulation. Crystal Ball uses particular terms to refer to the Excel worksheet cells that perform the principal tasks.

Assumption Cells are worksheet cells in a spreadsheet model that contain a value defined by a probability distribution’s random variable. These cells are distinguished in the sample workbooks by their distinctive green color. (See, for example, {{R24}}.) This appendix regularly refers to assumption cells in the section “Uncertainties.” Crystal Ball reassigns values to each assumption cell at the beginning of each “game” or modeling future.

A **Decision Cell** is a worksheet cell in a spreadsheet model that the user controls. The user controls these indirectly – for example, via an optimizer – or directly. The reader may think of the value of these cells as representing the plan. The optimization program adjusts the decision cells in the regional portfolio model to minimize cost, subject to risk

[4] Bellman, R. (1961), Adaptive Control Processes: A Guided Tour, Princeton University Press.
[5] For a number of good reasons, these values are not truly random in the everyday sense of the word. For example, the random number generator uses a seed value, so that an analyst can reproduce each future exactly for subsequent study. The generator also selects the values to provide a more representative sampling of the underlying distribution, a technique known as Latin Hyper Square or Latin Hyper Cube.

constraints. Appendix L details the function and application of decision cells in the section "Parameters Describing the Plan," page L-72. These cells are yellow in the regional model. (See, for example, {{R2}}.)

Forecast Cells contain statistical output of the model. The default color for these cells is turquoise. In the regional model, the primary forecast cell is the NPV cost for a plan under a 20-year future, {{CV1045}}. Other forecast cells in the regional model, such as those that regional model macros assign risk values, serve to communicate data back to the OptQuest optimizer.

The assumption and decision cells are, in a sense, the exogenous inputs to the model; the forecast cells report the output. The topic of the next section is the calculation engine that processes the input and produces the output.

Logic Structure of the Portfolio Model

To understand how the regional portfolio model represents uncertainty and generates the system cost values that give rise to risk, it is useful to understand the model itself. The treatment of uncertainties, like load and hydro generation, are to some extent separable from the rest of the model. This section identifies a particular range of the model worksheet cells that creates futures. (See page P-15.) Likewise, the forecast cells that report the final costs and risks inhabit a small range of adjacent cells. The description of the rest of the model appears in Appendix L. The following provides a brief introduction that should be sufficient for understanding that portion of the model that simulates sources of uncertainty.

The Council calls its approach to resource planning "risk-constrained least-cost planning." Given any level of risk tolerance, there should be a least-cost way to achieve that level of risk protection. The purpose of the Council's analysis is to define those plans that do just that.

Given a particular future, the primary measure of a plan is its net-present value total system costs. These costs include all variable costs, such as those for fuel, variable operation and maintenance (O&M), certain short-term purchases, and fixed costs associated with future capital investment and O&M. The present value calculation discounts future costs to constant 2004 dollars using a real discount rate of four percent.[6]

If the future were certain, net present value system cost would be the only measure of a plan's performance. Because the future is uncertain, however, it is necessary to evaluate a plan over a large number of possible futures. Complete characterization of the plan under uncertainty would require capturing the distribution of outcomes over all futures, as illustrated in Figure P-1 below. Each box in Figure P-1 represents the net present value cost for a scenario sorted into "bins." Each bin is a narrow range of net present value total system costs. A scenario is a plan under one particular future.

[6] See Appendix L.

Because a simulation typically uses 750 futures, the resulting distributions can be complicated. Representative statistics make manageable the task of capturing the nature of a complex distribution. The *expected* net present value total system cost captures the central tendency of the distribution. The expected net present value is the average of net present value total system costs, where the average is frequency weighted over futures. This plan will often use the shorthand expression, "average cost of the plan." The average cost is identified in Figure P-1.

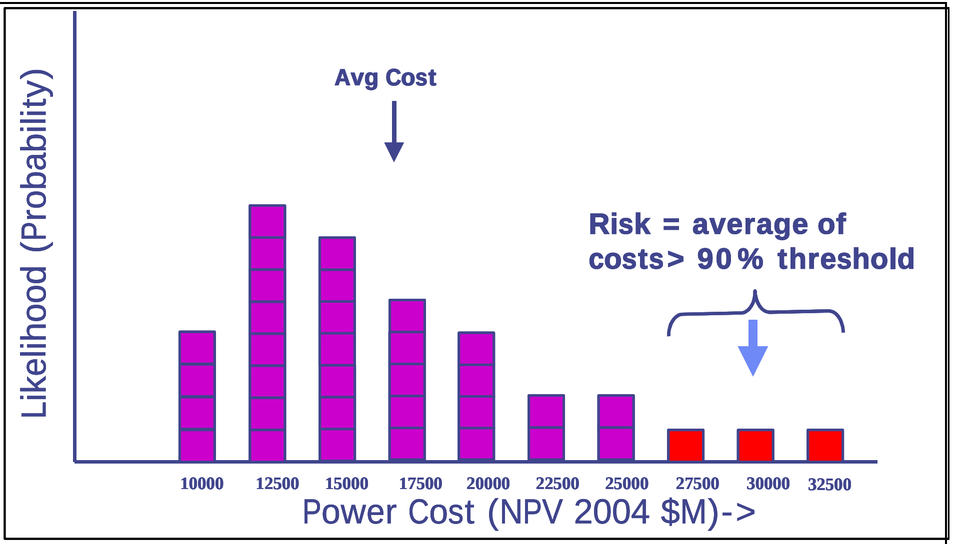

Figure P-1: Plan Cost Distribution, Average Cost and Risk (TailVaR90)

Expected net present value cost, however, does not give a picture of the risk associated with the plan. There are a number of possible risk measures that could be used. A summary measure of risk called "TailVaR$_{90}$" was chosen. A discussion of this choice of risk measure and its comparison with other risk measures appears in section "Risk Measures," below. Very briefly, TailVaR$_{90}$ is the average value for the worst 10 percent of outcomes. It belongs to the class of "coherent" risk measures that possess mathematical properties superior to alternative risk measures. Since 1998, when papers on coherent measures first appeared, the actuarial and insurance industries have moved to adopt these, abandoning non-coherent measures such as standard deviation and Value at Risk (VaR).

Figure P-1 represents the cost distribution associated ***with a single plan***. If the outcomes for different plans are plotted as points, with coordinates given by the expected cost and risk of each plan, one obtains the new distribution illustrated in Figure P-2. Each point on the figure represents the average cost and TailVar$_{90}$ value for a particular plan over all futures. The least-cost outcome for each level of risk falls on the left edge of the distribution in the figure. The combination of all such least-cost outcomes is called the "efficient frontier." Each outcome on the efficient frontier is preferable to the outcomes to the right of it, since it has the same risk as those outcomes, but lowest cost. Choosing from among the outcomes on the efficient frontier, however, requires accepting more risk in exchange for lower cost, or vice versa. The "best" outcome on the efficient frontier depends on the risk that can be accepted.

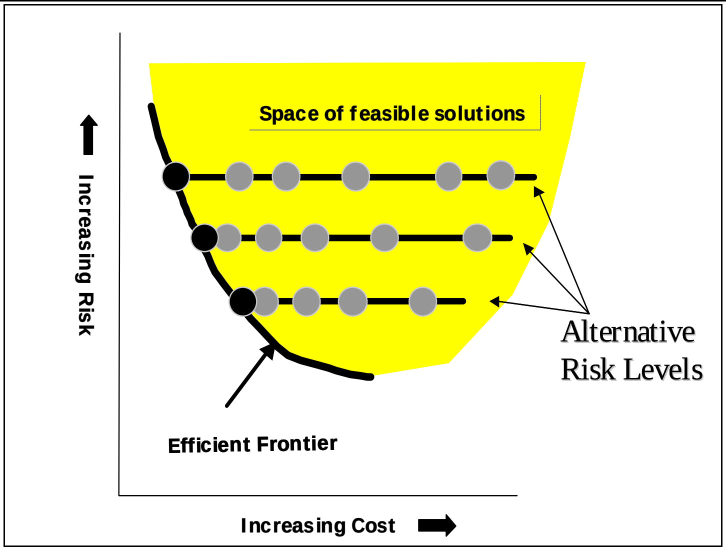

Figure P-2: Feasibility Space

When a user opens the portfolio model workbook, the values they see are values for a particular future and for a particular plan. It is within this future or "game" that the energy and cost calculations take place. How, then, are the futures changed to create a cost distribution for a plan and the plans changed to create the feasibility space?

Figure P-3 illustrates the overall logic structure for the modeling process. The optimization application, the Decisioneering, Inc. OptQuest™ Excel® add-in, controls the outer-most loop. The goal of the outer-most loop is to determine the least-cost plan for each level of risk. It does so by starting with an arbitrary plan, determining its cost and risk, and refining the plan until refinements no longer yield improvements. The program first seeks a plan that satisfies a risk constraint level. Once it has found such a plan, the program then switches mode and seeks plans with equal (or lower) risk but lower cost. The process ends when we have found a least-cost plan for each level of risk. This process is a form of non-linear stochastic optimization.[7]

[7] The interested reader can find a more complete, mathematical description of the optimization logic in reference the following references:
Glover, F., J. P. Kelly, and M. Laguna. "The OptQuest Approach to Crystal Ball Simulation Optimization." Graduate School of Business, University of Colorado (1998). Available at http://www.decisioneering.com/optquest/methodology.html ;
M. Laguna. "Metaheuristic Optimization with Evolver, Genocop, and OptQuest." Graduate School of Business, University of Colorado, 1997. Available at http://www.decisioneering.com/optquest/comparisons.html; and
M. Laguna. "Optimization of Complex Systems with OptQuest." Graduate School of Business, University of Colorado, 1997. Available at http://www.decisioneering.com/optquest/complexsystems.html

The optimizer OptQuest controls the Crystal Ball® Excel add-in. OptQuest hands a plan to Crystal Ball, which manifests the plan by setting the values of decision cells in the worksheet. These are the yellow cells in {range R3:CE9}. Crystal Ball then performs the function of the second-outer-most loop, labeled "Monte Carlo Simulation," in Figure P-3. It exposes the selected plan to 750 futures and returns the cost and risk measures associated with each future to OptQuest. For each future, Crystal Ball assigns random values to 1045 assumption cells, the dark green cells throughout the worksheet. (See for example, {R24}.) Crystal Ball then recalculates the workbook. In the portfolio model, however, automatic recalculation is undesirable, as described in Appendix L. The portfolio model therefore substitutes its own calculation scheme. It uses a special Crystal Ball feature that permits users to insert their own macros into the simulation cycle, as shown in Figure P-4. Before Crystal Ball gets results from the worksheet, a macro recalculates energy and cost, period by period, in the strict order illustrated in Figure P-5 and Figure P-6 and as described on page P-15. The reason for performing its own calculations is to assure calculations take place in a strict chronological order, as required by several mechanisms in the model, including the planning flexibility. The values in the Crystal Ball forecast cells then contain final net present value (NPV) costs that Crystal Ball saves until the end of the simulation. Forecast cells are those that have the simulation results and have a bright blue color. The NPV cost, for example, is in {CV1045}.

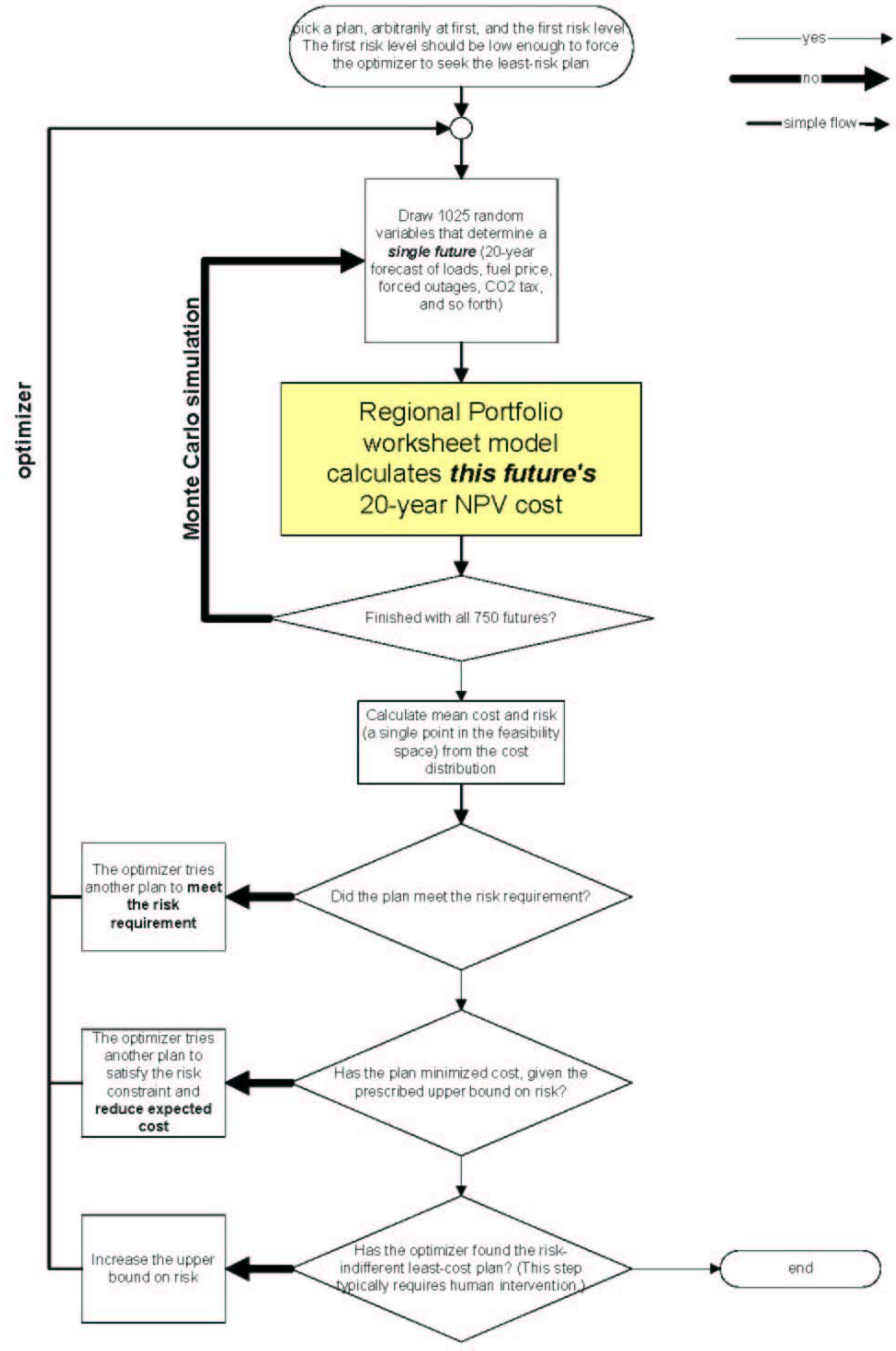

Figure P-3: Logic Flow for Overall Risk Modeling

After the simulation for a given plan is complete and Crystal Ball has captured the results for all the games, the last macro in Figure P-4 fires. This macro calculates the custom risk measures and updates their forecast cells. The custom risk measures include, for example, $TailVaR_{90}$, $CVaR_{20000}$, VaR_{90}, and the 90th Quintile.

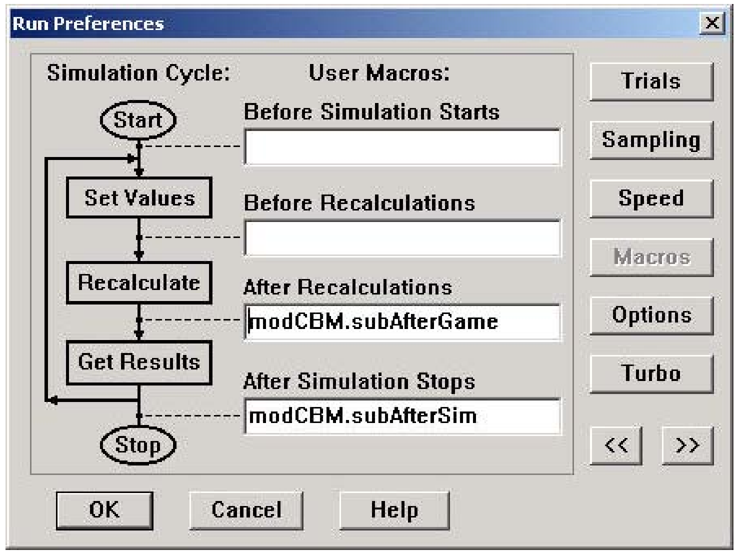

Figure P-4: Crystal Balls Macro Loop

The portfolio model performs the duties of the innermost task, identified by the shaded box in Figure P-3.

Given the values of random variables in assumption cells, the portfolio model constructs the futures, such as paths and jumps for load and gas price, forced outages for power plants, and aluminum prices over the 20-year study period. It does this only once per game. It then balances energy for each period, on- and off-peak and among areas, by adjusting the electricity price, as illustrated in Figure P-5. The regional portfolio model uses only two transmission zones, however, the region and the "rest of the interconnected system," although some it does model some geographic diversity of fuel and electricity price. Only after it iterates to a feasible solution for electricity price in one period does the calculation moves on to the next period. After calculating price, energy, and cost for each period, the model then determines the NPV cost of each portfolio element and sums those to obtain the system NPV. This sum is in a forecast cell.

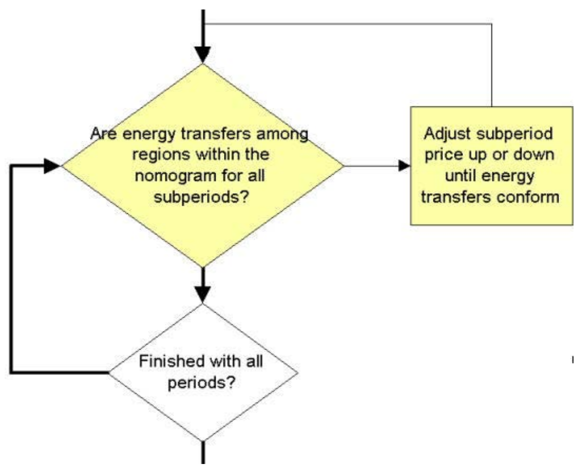

Figure P-5: Logic in the Regional Portfolio Worksheet Model

Some worksheet cells are involved in the energy rebalancing calculation. These cells, many of which contain formulas for electricity prices, must recalculate multiple times for each subperiod. These and other cells that rely on them, such as those that control the long-term interaction of futures, prices, and resources, are the "Twilight Zone" (TLZ) of the regional model. This portion of the worksheet also contains formulas for price elasticity of load and decision criteria.

Figure P-6 illustrates the calculation order described above. The number in the parentheses is the order. The plus sign (+) is a reminder that iterative calculations take place in the area. The workbook calculates the primary uncertainties only once per game, and their cells are near the top of the worksheet {rows 26-201}. (Plant forced outages are the exception. These cells are located elsewhere, as explained below and detailed on page P-84.) The cells associated with the uncertainties are denoted “Futures (1)” in Figure P-6.

The illustration denotes those recalculations that must be made multiple times per subperiod by TLZ {rows 202-321}. NP stands for on-peak {rows 318-682}; FP stands for off-peak {rows 684-1058}. The area at the far right refers to the NPV summary calculations {range CU318:CV1045}.

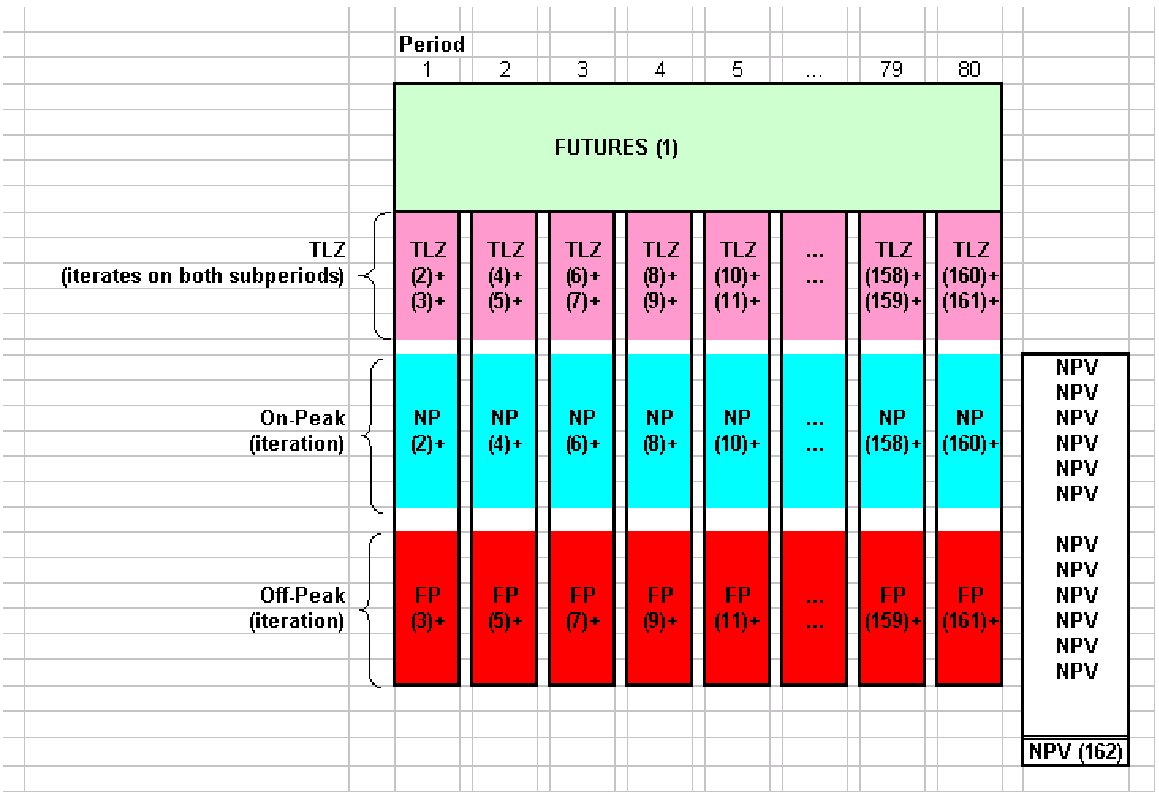

Figure P-6: Portfolio Model Calculation Order

Appendix P documents the uncertainties in the regional portfolio model. This includes the worksheet formulas for describing the uncertainties. Because it would be redundant to cover the same material in Appendix L, Appendix L describes everything *except* the uncertainties.

Figure P-6 permits us to state the scope of this appendix with respect to ranges within of the portfolio model. This **Appendix P**, and particular this section "Uncertainties," describes the calculations in the area of the worksheet denoted by "FUTURES (1)" and with the dark green assumption cells for plant forced outage associated with each power plant. For ease of reference, the worksheet calculates a future's forced outages in rows associated with the power plants themselves. Consequently, the user will find them not in the range marked "Futures (1)" in Figure P-6, but down in the rows associated with "NP" and "FP" calculations. **Appendix L** discusses all ranges of the regional model except that denoted by "FUTURES (1)".

Model Validation

Given the differences between decision-making models and other simulation models that incorporate uncertainty, it should not be too surprising that how one validates the two differs. This section discusses some of those differences, with attention to the treatment of validation in the regional model.

The example of a simulation model that began this section was a hydrogeneration estimator. To validate the hydrogeneration model, an analyst would make some prediction about how the model would perform with a new set of streamflows. They would be concerned about how well the model reproduced certain patterns of generation. To validate their model they would then apply the model to a new set of historical streamflows, say 1979 through 1990, and compare the model generation with the actual generation over those years. An analyst would apply a similar process in constructing and validating simulation models for other systems where stochastic processes are important, such as for vehicle traffic flow or industrial manufacturing processes.

With strategic decision-making models, this approach does not work. The past is not a good standard for the future, because we have assumed our modeling futures differ dramatically from one another. It may be appropriate to look at a single future that resembles some past event to see how reasonable the model responds. This is effectively a one-point sample of possible futures, however. By design, there are many possible futures, and the model should prepare the decision maker for futures that unanticipated and unfamiliar.

This is not to say that there is no role for more traditional validation. There is a distinction, however, between short-term variation and strategic uncertainty. If we think of an example like electrical load requirements, we recognize there is some short-term variation due to weather and seasonality. We may tend to believe we understand this variation rather well and expect future variation to resemble that which we have seen in the past. This kind of variation lends itself well to statistical analysis of past behavior and patterns.

Once we attempt to forecast load requirements beyond a couple of years, however, we enter the realm of strategic uncertainty. We recognize there are many things that can affect system load requirements. Economic disruptions within and outside the region and technological innovations, for example, can greatly influence energy requirements. We may expect that there is strong chronological correlation in load requirements, i.e., load in a given month will not differ significantly from load in the previous month beyond what we expect from seasonal variation. The underlying tendency or path of system load requirements, however, can move in a host of different directions, so that after just a few years, system load requirements are significantly different from the expected forecast.

While previous statistical patterns may be helpful in validating the short-term variation behavior of the model, they do not help with strategic uncertainty. Fundamental models, which relate strategic behavior to underlying processes, can be helpful in understanding and reducing strategic uncertainty. Even fundamental models, however, rely on assumptions that are plagued by uncertainty once forecasts extend beyond a few years. Moreover, because of their associated computational burden, it is difficult to incorporate a fundamental model directly into a model for decision making under uncertainty.

Ultimately, the representation and validation of strategic uncertainty is highly subjective. Expert opinion, often formed through careful consideration of many sources of information, including the results of fundamental models, is the arbiter of credibility. When they are available, ranges of expert forecasts can help validate possible futures. The Council attempts to achieve regional model consistency with its forecasts for electricity load requirements and natural gas prices, for example.

This approach is certainly not without its shortcomings. Those who have examined case histories of decision making under uncertainty have noted that experts often overestimate their ability to forecast the future.[8] That is, experts tend to underestimate uncertainty. We do not have to look any further than the load forecasts made by utility experts in the 1970s and 1980s to find examples where each year, the load forecasts fell below the lower jaw of the previous years set of load forecasts. The Council's own oil price forecasts since the 1980s provide another example where actual prices repeatedly fell outside the range of bounding (high and low) forecasts [**1**]. (See Figure P-7.)

While recognizing these shortcomings, the Council has elected to validate the regional portfolio model using expert's review of the futures used in the model. In Appendix L, the reader will find a description of the utility for data extraction and Spinner graphs. This utility, and in particular the set of graphs embedded in the principal worksheet, permit anyone to quickly scan through all 750 futures. For each future, the user can simultaneously view the 20-year projection of electricity prices, loads, natural gas prices, and so forth, for that future. In addition, the user can also witnessed how power plants are built out under that future and how much energy generation there is by technology for each period under that future. They can view the period costs and net present value cost, and most of the other variables that an analyst would want to see to verify that the model

[8] See, for example, John T. Christian, Consulting Engineer, Waban, Massachusetts Geotechnical Engineering Reliability: *How well do we know what we are doing?* The 39th Terzaghi Lecture, Spring 2005 GeoEngineering Seminar Series, Annual GeoEngineering Society Year-End Distinguished Lecture Program and Banquet, University of California at Berkeley

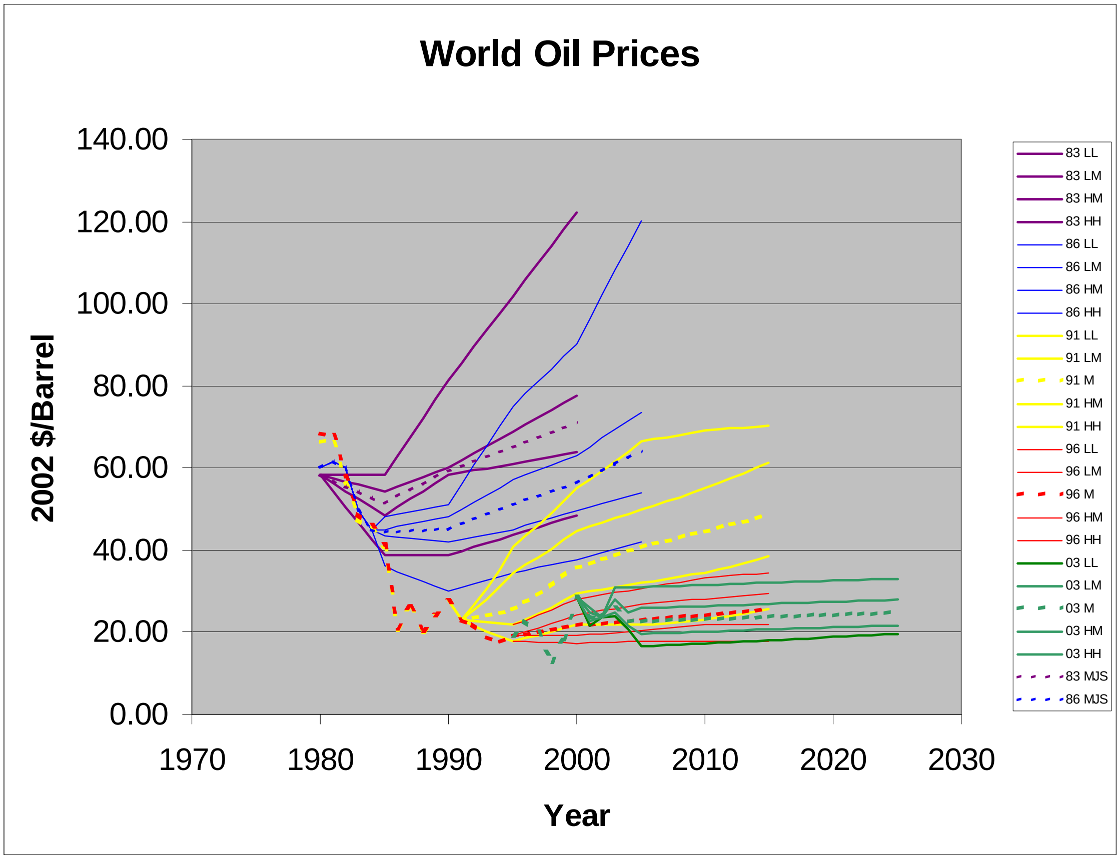

Figure P-7: Council's World Oil Price Predictions

is behaving correctly and to understand how the system and the plan to perform under that future.

This utility provides the principal means of validation. Rather than attempting to understand statistical distributions for each source of uncertainty in the relationship to other sources of uncertainty, an analyst can witness the final behaviors and see how they stand in relationship to each other. The Council's System Analysis Advisory Committee (SAAC) and the Council have reviewed these futures and found them to be reasonably representative of possible future behaviors.

With this overview of the decision making under uncertainty, this appendix starts the first section, the detailed description of the model's treatment of uncertainties.

Uncertainties

This section consists of two main parts. The first part is an introduction to Stochastic Process Theory implemented in the regional model. There are six main discussions:

- Log normal distributions
- Geometric Brownian motion (GBM)
- GBM with mean reversion
- Simulating Values for Correlated Random Variables
- Principal factor decomposition
- Stochastic Adjustment
- Jumps

The regional model uses each of these techniques to represent the future behavior of sources of uncertainty. The discussion will identify how each technique captures both short-term variation and strategic uncertainty.

The second part of this section steps through each source of uncertainty and describes why that source of uncertainty is model the way that it is. The uncertainties include:

- Load requirements
- Gas price
- Hydrogeneration
- Electricity price
- Forced outage rates
- Aluminum price
- CO_2 tax
- Production tax credits
- Green tag value

It explains how each source of uncertainty uses the chosen stochastic process to achieve the desired behavior. It also documents data sources and provides a reference to the sample worksheet to provide a detailed description of how the formulas in the worksheet implement the desired stochastic behavior.

Stochastic Process Theory

Lognormal distributions are a key characteristic of geometric Brownian motion (GBM) and GBM with mean reversion. The regional model uses lognormal distribution in the electricity price, fuel price, load requirements, and aluminum price processes. This discussion therefore starts with a review of the lognormal distribution and then describes the GBM and the GBM with mean reversion processes. Principal factor analysis technique does not rely per se on any of these, and the section will review this technique last.

Lognormal Distribution

It might be useful to understand why the lognormal distribution finds such intensive use in the regional portfolio model and in other simulation and valuation models. There are three reasons the regional model uses lognormal distributions:

1. It solves problems we encounter with simpler distributions,
2. It has an nice intuitive rationale, and
3. It describes much data better than simpler (and sometimes more complex) distributions.

To understand these advantages, we start by examining the problems that a naïve application of simpler distributions might encounter.

If an inexperienced analyst with some background in statistics were to approach the challenge of modeling stochastic prices, he might try to use a simple distribution, such and the normal distribution. However, any unbounded, symmetric distribution, like the normal distribution, must produce negative numbers, as illustrated in Figure P-8. Negative prices, however, are bothersome and may cause some programs to fail in mysterious and unpredictable ways. One fix to this problem is to use an asymmetric, bounded distribution, such as the triangular distribution, to keep prices positive. Of course, the drawback to this approach is that because the distribution has both a lower and upper bound, the analyst must now provide some rationale for choosing the value of the upper price limit.

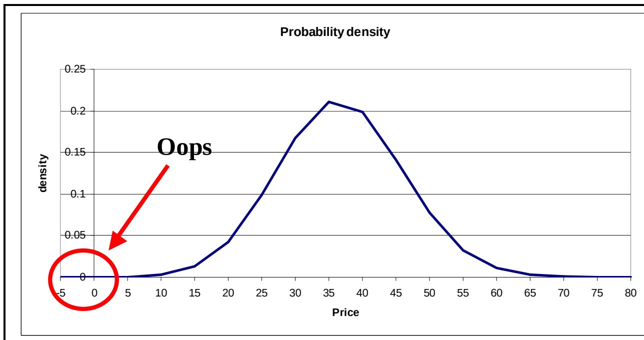

Figure P-8: Symmetric Distribution

The second problem the analyst might encounter would be difficulty in performing meaningful statistics on prices. There are several issues here.

First, prices for commodities typically are not symmetric. Because they are bounded below by zero, but are unbounded above in principle, they can be strongly skewed. This means that simple distributions, like the normal distribution, and statistical tests based on these distributions, do not work. For example, one can not say that 95 percent of the observations lie within of two standard deviations of the mean.

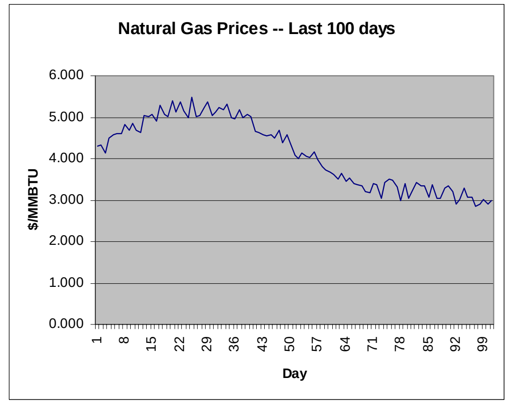

Figure P-9: Price Variation

Second, prices can drift in ways that mask the information in which an analyst might be interested. To illustrate this, suppose an analyst were interested in estimating the daily variation for natural gas price. Perhaps she is interested in estimating the likely change in natural gas price between today and tomorrow. Because she is interested in the change in daily price, it makes sense to use daily prices for the statistical sample, as opposed to hourly prices or weekly prices. To get a representative sample, she uses the last 100 days of natural gas price history, illustrated in Figure P-9. If she made the mistake of calculating the variation in prices, as measured by their standard deviation, without studying the data beforehand, she would compute the standard deviation to be about $0.83. The one standard deviation bound around the average price appears in Figure P-11. Clearly, this overestimates the daily price variation. The actual daily price variation is closer to the $0.14 that Figure P-10 illustrates. If she did discovered that price drift was distorting the estimate of price variation, she would need to develop a model of the underlying drift or seasonality to remove that influence.

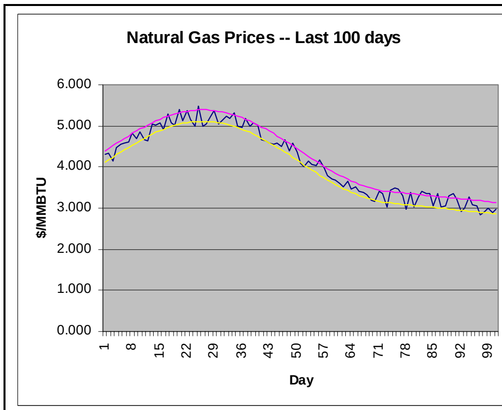

Figure P-10: Daily Price Uncertainty

Third, prices are often the wrong variable to study. Natural gas, for example, is a commodity traded by both hedgers and speculators. Both of these groups, but perhaps especially speculators, buy and sell natural gas to maximize profit. Now, initially it may appear that a $1.50 price increase of natural gas is equally attractive (or costly) irrespective of whether the underlying price of the gas is $3.00 or $4.50. The gross profit would be $1.50 times the quantity of gas. This ignores the fact, however, that an investor can buy more $3.00 gas than they can buy $4.50 gas. That is, what investors are interested in is the return on dollar invested: p_t/p_{t-1}, where p_t is the price today and p_{t-1} was the price yesterday.

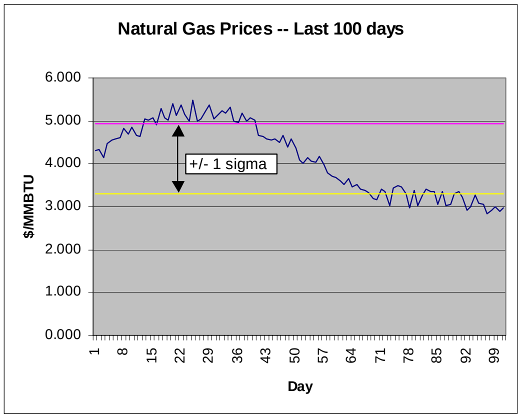

Figure P-11: Standard Deviation of Price Data

The same is true for other commodities and for financial investments. The return on the investment that matters, not the price. In fact, an analysis of prices for stocks and commodities show that returns, not prices, bump up and down symmetrically in the very short term (hourly or daily) as new information is forthcoming and they are traded. *Symmetry of returns* often explains a large portion of the *asymmetry of prices* described in the first paragraph.

Another advantage of using price returns instead of prices is that the second problem mentioned above disappears. That is, if the analyst uses daily price returns, she will obtain an estimate of daily price variation that more closely resembles that illustrated in Figure P-10.

Using returns, however, seems to give rise to yet another problem: calculating meaningful statistics on price return is tricky. Let us say that our analyst discovers that return on prices has about a normal distribution. It may be easy to calculate the mean and standard deviation of this distribution, but what do these numbers represent? To see the problem with interpreting these statistics, consider the following example. Suppose we have a simple sample of two observations, 50 percent price return and -50 percent price return. That is, on day two, the price increases 50 percent from that on day one; on day three, the price decreases 50 percent from that on day two. The naïve average of these two would be zero price return. In fact, however, we would have

$$1.5 \times 0.5 = .75$$

That is, our final price return would be -25 percent. It is unclear what the average of this distribution means and it is even less clear how to extract meaningful information out of the standard statistics of this distribution.

Consider now taking the log transformation of price return:

$$y_t = \ln(p_t / p_{t-1}), \text{sometimes also denoted } p_t / p_{t-1} \overset{\ln}{\mapsto} y_t \qquad (1)$$

This has the inverse transformation:

$$p_t / p_{t-1} = e^{y_t}, \text{sometimes also denoted } y_t \overset{\mathrm{e}}{\mapsto} p_t / p_{t-1} \qquad (2)$$

The transformed variable y_t has properties that solve the problems this section has raised and has some additional nice properties, as well. First, for small returns the logarithm of returns has a value close to that for the regular return:

$$\text{As } p_t \to p_{t-1}, \text{then } y_t \to p_t / p_{t-1} - 1$$

The sum and the average of the transformed returns have straightforward and useful interpretations. The sum of the transformed return is the total return over the period:

$$
\begin{aligned}
&\ln(p_2/p_1)+\ln(p_3/p_2)+\cdots+\ln(p_n/p_{n-1})\\
&=\ln(p_2)-\ln(p_1)+\ln(p_3)-\ln(p_2)+\cdots+\ln(p_n)-\ln(p_{n-1})\\
&=\ln(p_n)-\ln(p_1)\\
&=\ln(p_n/p_1)\overset{e}{\mapsto} p_n/p_1,\text{ the return over the period}
\end{aligned}
$$

The average of the transformed return is the periodic growth rate, also called the geometric mean:

$$
\begin{aligned}
&\frac{1}{n}\left(\ln(p_2/p_1)+\ln(p_3/p_2)+\cdots+\ln(p_n/p_{n-1})\right)\\
&=\frac{1}{n}\ln(p_n/p_1)\\
&=\ln((p_n/p_1)^{\frac{1}{n}})\overset{e}{\mapsto}\sqrt[n]{p_n/p_1},\text{ the periodic growth rate}
\end{aligned}
$$

The reader will recognize this as the constant rate of growth that, if applied in each period, would increase or decrease the value in the first period to the value in the last period.

If the returns have normal distribution, the prices are said to have lognormal distribution. The lognormal distribution is bounded below by zero and unbounded above, as Figure P-12 illustrates. The population standard deviation of the transformed returns

$$
\sigma_y=\sqrt{\sum_{t=1}^{n}(y_t-\bar{y}_t)^2}=\sqrt{\frac{\sum_{t=1}^{n}y_t^{\,2}}{n}-\bar{y}_t^{\,2}} \qquad (3)
$$

and its inverse transformed value give uncertainty bounds consistent with those illustrated in Figure P-10. Standard quantitative finance texts typically refer the value of σ in Equation (3) (or the corresponding *sample* standard deviation) as the “volatility” of the price sequence. For small values, this volatility approaches the standard deviation of returns.

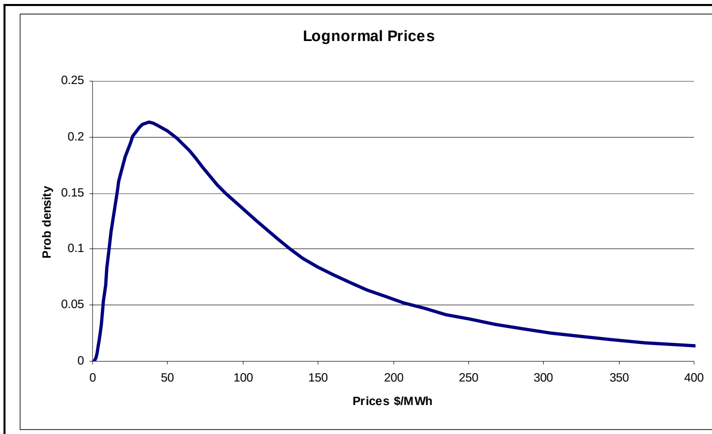

Figure P-12: Lognormal Distribution

Standard statistics for the transformed variables are relatively easy to compute and are readily available. For example if μ and σ are the mean and standard deviation of a normally distributed variable, such as the transformed returns y_t,

$$\text{pdf } f(x) = \frac{1}{x\sigma\sqrt{2\pi}} e^{-(\ln x-\mu)^2/2\sigma^2}$$

$$E(x) = e^{\mu+\sigma^2/2}$$

$$\text{var}(x) = (e^{\sigma^2} - 1)E^2(x) = (e^{\sigma^2} - 1)e^{2\mu+\sigma^2}$$

where as usual, *E(x)* is the expectation of the lognormally distributed *x* and var*(x)* is the variance of *x*.

Geometric Brownian Motion

The previous section made passing reference to the behavior of prices, bumped around by short-term purchases and sales of the commodity in the market. A standard quantitative representation of this process is Brownian motion. Brownian motion assumes that changes in location (or price) take place in discrete steps. At each step, displacement is determined by a sample from a normal distribution with constant means zero and constant standard deviation sigma.

The standard deviation of the distribution for the sum of these steps is a well-known formula. If there are T steps, the standard deviation is

$$\sqrt{{\sigma_1}^2 + {\sigma_2}^2 + \cdots + {\sigma_T}^2}$$
$$= \sqrt{T\sigma^2} = \sigma\sqrt{T}$$

The standard deviation grows as the square root of the number of steps, as illustrated in Figure P-13.

The previous section explained that the distribution of transformed returns, y_t, is normal for many investments and commodity prices. If the transformed returns follow the kind of process described above, the corresponding prices are said to follow geometric Brownian motion (GBM). At each step, prices have lognormal distribution.

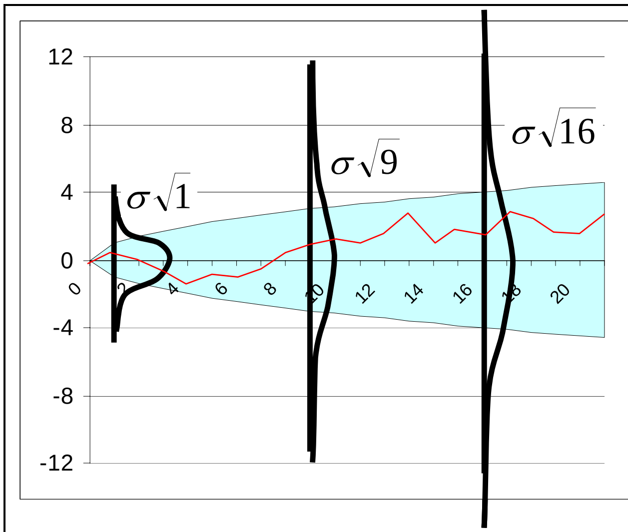

Figure P-13: Uncertainty Growth of GBM Process

GBM with Mean Reversion

Some commodity prices, instead of drifting away from their starting point, instead tend to return to some equilibrium level. This appendix and **Appendix L** describe how fundamental models will produce long-term equilibrium prices that equal long-run marginal costs for new capacity. The long-term equilibrium price represents the level to which prices trend whenever substantial excursions occur. Away from the equilibrium price, long-term supply and demand do not balance, and fundamental economic forces contrive to rebalance them.

There are several price models for a geometric Brownian motion with mean reversion. The regional model uses the following to represent aluminum prices.[9]

$$dp_t = a(b - p_t)dt + \sigma p_t dz$$

where

p_t is stochastic variable in question

dp_t is the change in p_t from the previous step

dz is a drawn from a N(0,1) process

dt is the step size, which has value 1 for discrete processes

a is constant which controls the rate of reversion

b is the equilibrium level

σ is the standard deviation of the log transformed process

The process is identical to an Ito process for a lognormally distributed random variable, but with a drift term that incorporates mean reversion. As prices depart from the equilibrium price b, the term $(b - p_t)$ becomes larger and forces the price back to equilibrium. The strength of the reversion is determined by the constant a. The first-order autocorrelation of price provides an estimate of the value of the constant a. If the

[9] See, for example, Hull, John C., ***Options, Futures, and Other Derivatives***, 3rd Ed., copyright 1997, Prentice-Hall, Upper Saddle River, NJ., ISBN 0-13-186479-3, page 422

constant *a* has value zero, there is no mean reversion and the price process resembles that of standard GBM. Price will drift in away from the starting point with increasing probability. This corresponds to zero autocorrelation. If the constant *a* is 1.0, the price fluctuates around the equilibrium price and does not drift.

The section "Aluminum Price," beginning on page P-86, describes how this price process represents future aluminum prices. That section includes an explanation of how Excel formulas implement the price process.

There are many other price process models. Some of the more popular models employ jump diffusion and jump diffusion coupled with mean reversion. For the purposes of the regional model, however, these models are excessive. Studies of natural gas and electricity prices suggest that simple geometric Brownian motion does a good job of describing those prices.

Simulating Values for Correlated Random Variables

For each future, the model must generate a large number of correlated values for the stochastic variables. This section describes one standard technique for doing so. The next section uses a simplification of this technique to obtain a more economical representation of strongly correlated values.

Suppose that we have a vector $\boldsymbol{\varepsilon}$ of m values ε_j which have some covariance structure Σ. Recall that the covariance matrix is constructed by taking the expectation of the outer product[10] of the vector of deviations from the mean vector **u**:

$$\sum = E((\varepsilon - \mathbf{u})(\varepsilon - \mathbf{u})') \quad (5)$$

Because the covariance matrix is a positive definite, symmetric matrix of real numbers, it has representation as the product of its Cholesky factors $\Sigma = TT'$, where T is a lower triangular matrix with zeros in the upper right corner.[11]

Now, take another m-vector η composed of independent variables with zero mean and unit variance. The covariance matrix of the vector η will just be the m x m identity matrix. If we construct the vector $T\eta$, we discover its covariance matrix is

$$\begin{aligned} E(T\eta\eta' T') &= TE(\eta\eta')T' \\ &= TIT' = TT' = \Sigma \qquad (6) \end{aligned}$$

Thus, the vector $T\eta$ has the requisite covariance structure. If we were working with the correlation structure instead of the covariance structure, the conversion is easy. The

[10] For our purposes, an outer product is the matrix product of a (column) vector right-multiplied by its transpose. This multiplication creates a matrix instead of a scalar, which inner products produce.
[11] See, for example, Burden and Faires, ***Numerical Analysis***, 4th ed., ISBN 0-53491-585-X, Corollary 6.26 and Algorithm 6.6, page 370.

covariance matrix transforms into the correlation matrix by a simple operation using the diagonal matrix of standard deviations, *D*:

$$\Sigma = DRD \qquad (7)$$

For an example of how to generate correlated values, consider the two-vector $\boldsymbol{\varepsilon}$, where the variables both have zero mean and unit variance. The covariance matrix is the same as the correlation matrix:

$$\begin{bmatrix} 1 & \rho \\ \rho & 1 \end{bmatrix}$$

By the existence of the Cholesky decomposition, there are variables t_{11}, t_{12}, and t_{21}, such that

$$\begin{bmatrix} 1 & \rho \\ \rho & 1 \end{bmatrix} = \begin{bmatrix} t_{11} & 0 \\ t_{12} & t_{22} \end{bmatrix} \begin{bmatrix} t_{11} & t_{12} \\ 0 & t_{22} \end{bmatrix} = \begin{bmatrix} t_{11}{}^2 & t_{11}t_{12} \\ t_{11}t_{12} & t_{12}{}^2 + t_{22}{}^2 \end{bmatrix}$$

Because the Cholesky matrix is triangular, we can find the values for the entries in the Cholesky matrices by successive substitution:

$$\begin{aligned} t_{11}{}^2 &= 1 \\ t_{11}t_{12} &= \rho \\ t_{12}{}^2 + t_{22}{}^2 &= 1 \end{aligned}$$

so

$$\begin{bmatrix} 1 & \rho \\ \rho & 1 \end{bmatrix} = \begin{bmatrix} 1 & 0 \\ \rho & (1-\rho^2)^{1/2} \end{bmatrix} \begin{bmatrix} 1 & \rho \\ 0 & (1-\rho^2)^{1/2} \end{bmatrix}$$

which means

$$\varepsilon = \begin{bmatrix} 1 & 0 \\ \rho & (1-\rho^2)^{1/2} \end{bmatrix} \eta \qquad (8)$$

Of course, this technique applies to vectors of arbitrary dimension. Note, however, the number of non-zero entries in *T* increases as $(m^2+m)/2$, as do the number of multiplications and additions, roughly, to create a sample vector. When m is large, the computation burden can increase dramatically. For this reason, practitioners have developed various numerical efficiencies to reduce the computation burden. One of these efficiencies is the topic of the next section.

Principal Factor Decomposition

Principal factor analysis is a general statistical technique for capturing complex statistical behavior with a small number of random variables. In the regional model, principal factor analysis simplifies the representation of strategic uncertainties that have strong chronological correlation, i.e. follow some underlying path over time.

Natural gas price has such a strategic uncertainty, as well as short-term variation due to weather effects and regional economics. For example, consider the price path illustrated by the dotted line in Figure P-14.[12] One way to model the path is by adding up several simpler paths, each of which is a draw from a separate statistical population of similar, simple paths. The advantage of this approach is the resulting sum will look like a path, i.e., the entries will be strongly correlated, and it gives rise to a great number of possible such paths. This section explains how to perform the construction.

Before the reader attempts to work their way through this section, which is among the more mathematically challenging, they should be aware of its purpose. The regional model implements an adaptation of the concepts presented here. While these concepts have rigorous application to statistical problems with abundant and representative data, the application in the regional model is more art than science. While this is consistent with the spirit of validation articulated on page P-17, it means that understanding the mathematics is not essential to grasping the basic technique of adding up constituents "sub-paths" point-wise. This section merely provides the basis for the technique, to assure the reader that it is neither arbitrary nor original.

Before tackling the construction of paths for future prices under strategic uncertainty, we begin with a simpler construction, one for which data exists and that may be more familiar to some readers. Suppose that, instead of representing strategic natural gas price uncertainty, Figure P-14 represented represent possible *forward or futures* prices for natural gas. Suppose further, that our objective were to estimate *tomorrow's* forward curve for natural gas, that is, tomorrow's prices for future delivery of natural gas in each year through 2024. There is data about the variation in the forward curves for natural gas price, in principle, because each day traders buy and sell gas forward. Every day, for example, traders buy and sell 2006 gas, and it is possible to get statistics about how that price varies. Others statistics of interest that we can obtain is how the price of 2006 gas price correlates with that of 2005, 2007, and all other years.

[12] Figure P-14 illustrates the ranges of natural gas prices that the Council adopted for the plan. The middle, solid line is the median price forecast; there is equal probability that annual prices will lie above and below this line.

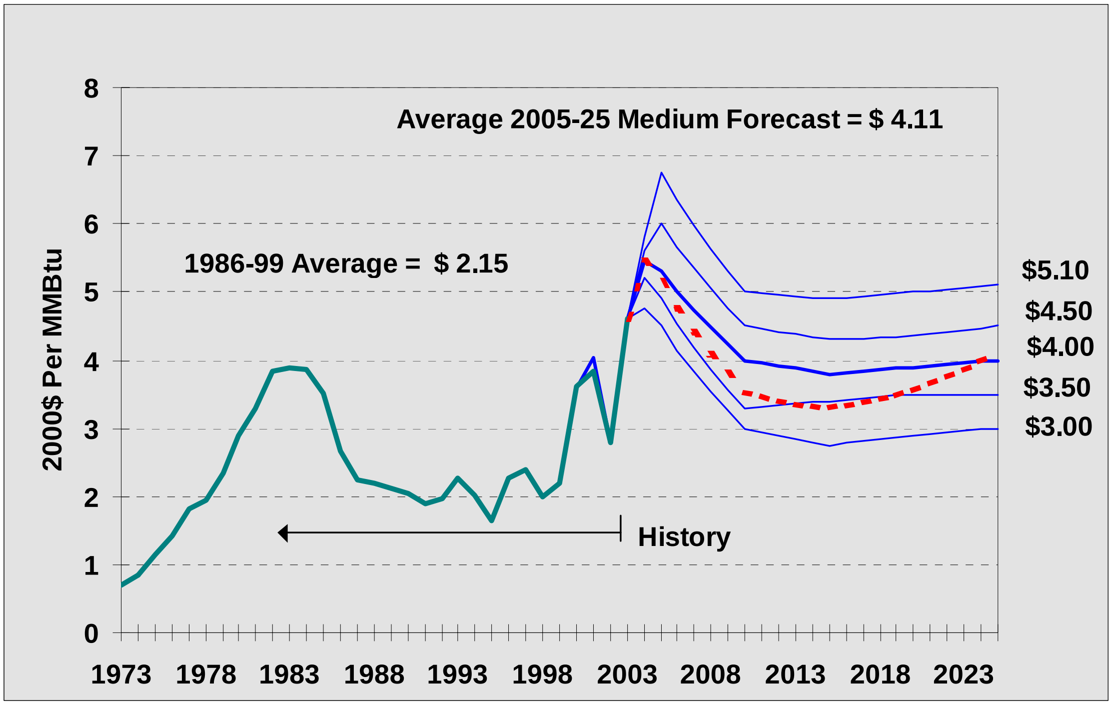

Figure P-14: Possible Natural Gas Prices

For this purpose, the medium forecast of natural gas prices in Figure P-14 will play the role of today's forward curve. The higher and lower price forecasts will represent the typical daily variation in the forward curve. (We will not use the higher and lower price forecasts directly in this example, so we do not need to be precise in how we think about them or their magnitude.)

The dotted line in Figure P-14 will play the role of one possible forward curve that may materialize tomorrow. We want to be able to generate many such forward curves, say, because we are valuing a portfolio of natural gas forward positions and want to understand how much variation and risk there may be in holding that portfolio overnight.

Recall from the discussion of "Lognormal Distribution," beginning on page P-20, that it is convenient, for all the reasons discussed in that section, to use transformed price returns. We will do that, but the approach will look different from the discussion in that section. Specifically, in that section, the price returns represented prices from successive periods. The section "Geometric Brownian Motion" described paths that result when these transformed returns stem from independent, uniform "innovations."[13] In fact, we are not going to make any such assumptions about how prices in 2006 relate to those in 2005 or 2007. We may have information that a large supply of natural gas is coming on-line in 2006, for example, so in a sense the 2006 product is distinct from those in 2005

[13] By innovation, we mean small, random shocks. These are generated by drawing a value from a random variable.

and 2007. Instead, for each year's price, we represent its covariance with any other year using principal factor analysis, and the only innovation we are interested in is the one-step change between today and tomorrow. (Remember, we are simulating tomorrow's forward curve.) If we do this for each forward year, we get a new curve.

We start by taking the logarithm of the price for each year *j*, *j*=1 to m, of today's forward curve. The prices and transformed prices appear in equations (1). Denote this transformed price by ln($p_{j,0}$). Denote the corresponding transformed price for *tomorrow* by ln($p_{j,1}$). The innovations ε_j are drawn from a the distribution of the transformed returns ln($p_{j,t+1}/p_{j,t}$) obtained from historical data for that forward year. A given draw then gives us the means of estimating a possible prices for tomorrow's forward curve:

$$\ln(p_{j,1}) = \ln(p_{j,0}) + \varepsilon_j \text{, where} \qquad (9)$$
$$\varepsilon_j \approx \ln(p_{j,t+1} / p_{j,t})$$

The second line merely says that the innovations are distributed like the transformed daily price returns for year *j*.

The previous section provides a technique for simulating this vector of innovations. We can construct the covariance matrix from historical data, find the Cholesky decomposition, and use a higher-dimensional version of equation (8) to produce the samples. If natural gas prices behave as many commodity prices do, the innovations will be roughly normally distributed, so the vector η in equation (8) will be drawn from a normal distribution.

When practitioners applied these techniques to very large vectors, however, they discovered that these calculations could become burdensome. The computations increase roughly as the number of non-zero elements, $(m^2+m)/2$, in the Cholesky factor. They discovered that, by using principal factor analysis, they could substantially reduce that computational burden, especially when the entries in the vector of prices were strongly correlated.

Principle factor analysis is based on the fact that any symmetric matrix, such as any covariance matrix, has a "spectral decomposition"

$$\mathbf{A} = \lambda_1 \mathbf{e}_1 \mathbf{e}'_1 + \lambda_2 \mathbf{e}_2 \mathbf{e}'_2 + \cdots + \lambda_m \mathbf{e}_m \mathbf{e}'_m \qquad (10)$$

where

$\mathbf{A}$ is a $(m \times m)$ symmetric matrix

λ_i is the ith eigenvalue

$\mathbf{e}_i$ is the ith normalized eigenvector $(m \times 1)$

$\mathbf{e}'_i$ is the transpose of $\mathbf{e}_i$

If there are strong correlations among entries of the random vector, several of the eigenvalues tend to be much larger than the rest. The eigenvectors are principal patterns of correlated variation in entries and these give rise to the paths to which this section has referred. If the terms in equation (10) are sorted with respect to magnitude of their eigenvalues (they will all be positive), we can represent the covariance matrix as the sum of two matrices, one associated with the first *k* dominant eigenvalues and the second associated with the remaining eigenvalues. Because these two terms are also symmetric matrices, they both have Cholesky terms:

$$\begin{aligned}&\Sigma = \mathrm{LL'} + \mathrm{SS'}\\&\text{where}\\&\mathrm{L}\text{ is }m\times k\\&\mathrm{S}\text{ is }m\times(m-k)\end{aligned}$$

The S matrix should be nearly diagonal and if we replace it by a diagonal matrix, we obtain an equation for creating the innovations that corresponds to equation (8):

$$\mathbf{X}-\boldsymbol{\mu}=\mathbf{L}\mathrm{f}+\boldsymbol{\varepsilon} \qquad (11)$$

where

$\mathbf{X}$ is the k - vector of random variables

$\boldsymbol{\mu}$ is their k - vector of means

$\mathbf{L}$ is the $(k\times m)$ matrix of k - eigenvectors

f is an m - vector of independent random variables

$\boldsymbol{\varepsilon}$ is a k - vector of independent random "specific factors"

The entries in the m-vector f may be taken to be distributed N(0,1); the specific factors may also be taken as independent, normally distributed with mean zero, but the variance of each is determined by the residual variance necessary to match that of **X-μ**. Efficiencies arise when *m* is much less than *k*.

In Figure P-14, the possible forward curve is the weighted sum of the following three eigenvectors:

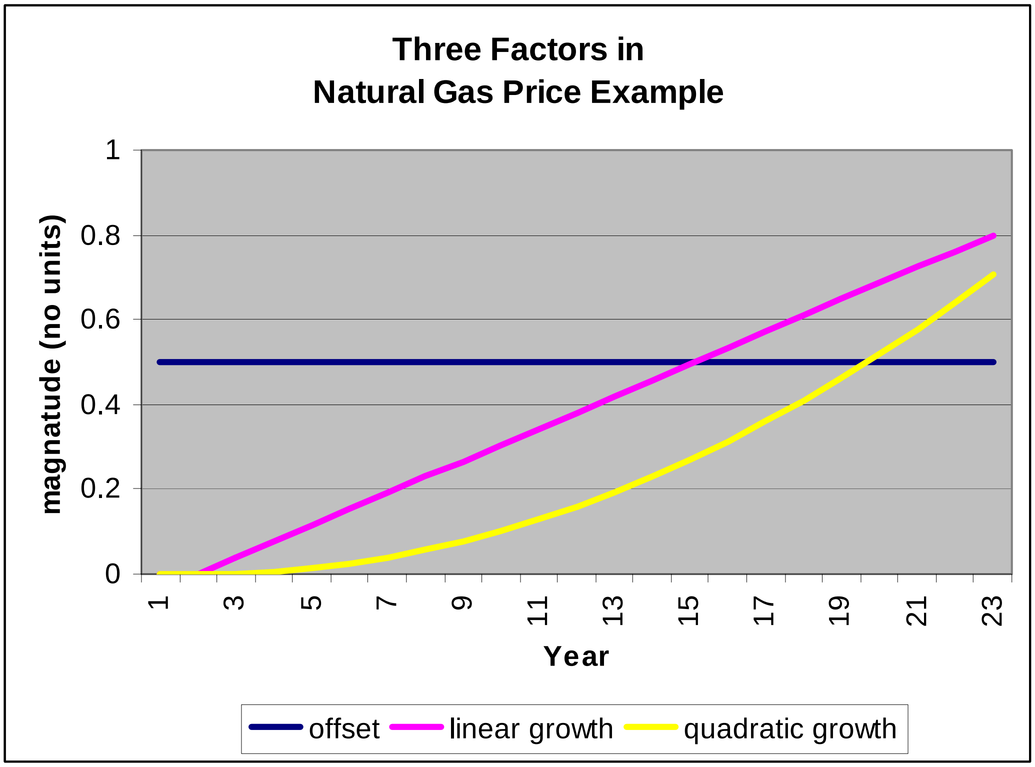

Figure P-15: Constituent Eigenvectors

For the possible (dotted line) forward curve in Figure P-14, the offset, linear growth, and quadratic growth eigenvectors, of "sub-paths," are weighted by 0.00, -0.75, and 0.90, respectively. These sub-paths are then added to the transformed returns, as in equation (9), and transformed back to prices using the standard exponential transformation described on page P-22. Figure P-16 illustrates the steps.

Slightly different weightings provide dramatically different paths. For example, the weighting (0,1.25, -1.2) gives rise to the path illustrated in Figure P-17. The weighting (-1.4, 1.25, -1.2) generates the curve in Figure P-18.

P0	ln(P0)	offset	linear	quadratic	sum (e)	ln(P0)+e	P1= exp(ln(P0)+e)
4.62	1.53	0.00	0.00	0.00	0.00	1.53	4.62
5.45	1.70	0.00	0.00	0.00	0.00	1.70	5.47
5.30	1.67	0.00	-0.03	0.00	-0.03	1.64	5.16
5.01	1.61	0.00	-0.06	0.01	-0.05	1.56	4.76
4.74	1.56	0.00	-0.09	0.01	-0.08	1.48	4.39
4.48	1.50	0.00	-0.11	0.02	-0.09	1.41	4.10
4.23	1.44	0.00	-0.14	0.04	-0.10	1.34	3.82
4.00	1.39	0.00	-0.17	0.05	-0.12	1.27	3.56
3.96	1.38	0.00	-0.20	0.07	-0.13	1.25	3.49
3.92	1.37	0.00	-0.23	0.09	-0.14	1.23	3.42
3.88	1.36	0.00	-0.26	0.12	-0.14	1.22	3.39
3.84	1.35	0.00	-0.29	0.14	-0.15	1.20	3.32
3.80	1.34	0.00	-0.31	0.17	-0.14	1.20	3.32
3.82	1.34	0.00	-0.34	0.21	-0.13	1.21	3.35
3.84	1.35	0.00	-0.37	0.24	-0.13	1.22	3.39
3.86	1.35	0.00	-0.40	0.28	-0.12	1.23	3.42
3.88	1.36	0.00	-0.43	0.32	-0.11	1.25	3.49
3.90	1.36	0.00	-0.46	0.37	-0.09	1.27	3.56
3.92	1.37	0.00	-0.49	0.42	-0.07	1.30	3.67
3.94	1.37	0.00	-0.51	0.47	-0.04	1.33	3.78
3.96	1.38	0.00	-0.54	0.52	-0.02	1.36	3.90
3.98	1.38	0.00	-0.57	0.58	0.01	1.39	4.01
4.00	1.39	0.00	-0.60	0.64	0.04	1.43	4.18

Figure P-16: Steps in the Calculation

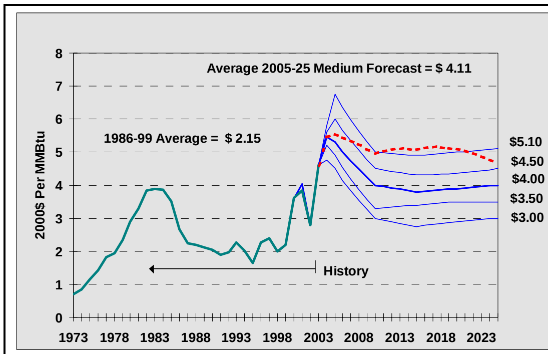

Figure P-17: Path with (0,1.25, -1.2) Weighting

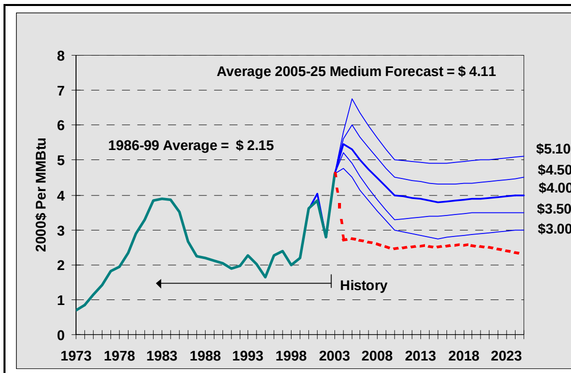

Figure P-18: Path with (-1.4, 1.25, -1.2) Weighting

Returning to the original challenge of creating new paths for future prices and loads, it would be natural to attempt construction of future paths based on historical data. It turns out, though, that those kinds of patterns generally did not garner credibility with experts. They usually failed to capture the experts' scale of uncertainty. Effectively the curve weighting and parameters were calibrated to the experts' expectations. This is in keeping with the spirit of strategic decision analysis articulated on page P-17, however, which recognizes the subjective nature of characterizing complex and unpredictable behaviors.

Three factors, like those illustrated in Figure P-15, appear to be sufficient to capture the kind of underlying path behaviors that experts wished to see. Of course, these paths do not suffice to produce all of the kinds of necessary behavior. There is short-term (period) variation, as we might expect to see with weather differences. Prices and requirements possess short-term correlations, within the modeling period, and these require attention. There are also jumps that reflect excursions from long-term supply and demand equilibrium or other economic disruption. The construction of the jumps is the subject of the next section.

The example of natural gas price simulation in the workbook L24DW02-f06-P.xls provide a good example of how the regional model treats the factors. This takes place in rows {56 to 62}. As shown in Figure P-19, the value for the period 7 in {X62} is a sum of three products. The first product is the weighting for the linear growth {$S$56}, times the random number in {$R$56}, times the value of the factor in {$W$57}. The random

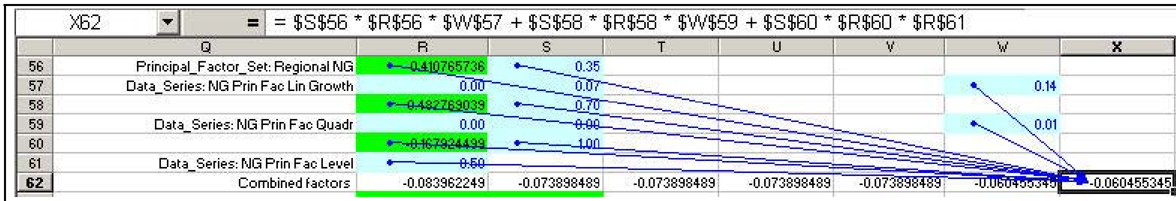

Figure P-19: Adding the Principal Factors

number plays the role of an entry of η in equation (8) or of **f** in equation (11). The distribution of the random number will depend on the simulated uncertainty. The value of the linear factor does *not* increase smoothly over the 80 periods, from 0.0 to 1.33. Instead, because the Olivia model[14] that created this workbook used annual values, the values only change once each four columns, and the logic points back to the last data value for the factor.

The remaining two terms in the sum {X62} add the quadratic and offset factors. Because the offset factor does not change across periods, the formulas in row {62} all point to the offset factor value in cell {R61}.

This is not the last step in creating the behavior for natural gas price. Other influences, such as jumps, add to the combined factor, and the worksheet applies the necessary inverse transformation to the sum. The next two sections discuss specific factors and jumps. The subsequent section describes the stochastic adjustment, and the section following that one shows the final inverse transformation.

Specific Factors

Specific Factors arise in equation (11) as a means to capturing variance not accounted for by the principal factors. They are “specific” in the sense that they describe only the remaining variance for a stochastic vector’s entries.

[14] Olivia is a Council application that creates Excel worksheet portfolio models. Appendix L describes Olivia.

In the regional model, specific factors are typically describing seasonal variation, which can be greater at certain times of the year. For example, loads tend to have greater uncertainty during the winter and summer, so the model adds independent variance to those seasons. Figure P-20 shows the crystal ball dialog box that specifies the distribution of the random variable in cell {AQ 124}. This is a normal distribution with mean zero and a standard deviation of five percent. As described in the section "lognormal distribution," this small standard deviation will correspond to roughly five percent standard deviation change in the final quarterly loads

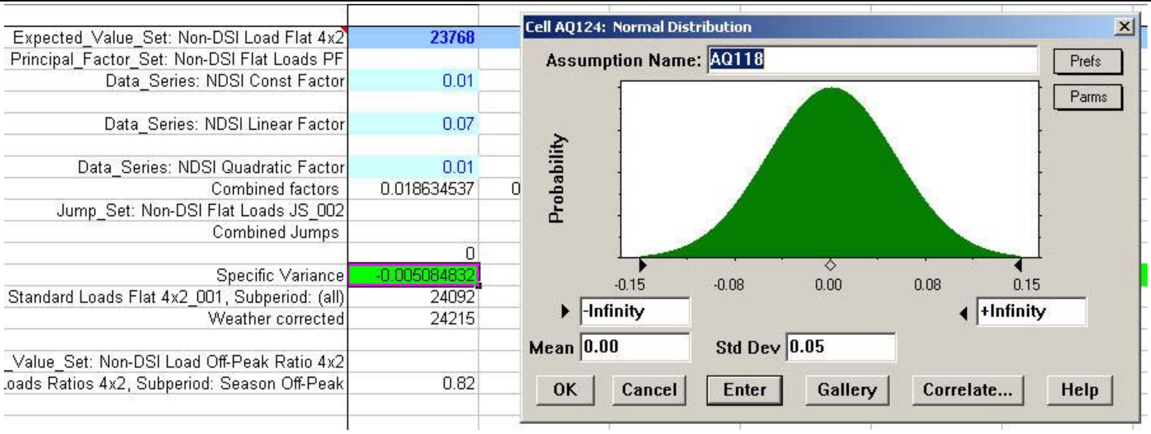

Figure P-20: Assumption Cell

Jumps

Excursions occur in prices and loads for several reasons, in particular because of disequilibrium in long-term supply and demand. Gas and electricity prices, as we have seen in the last few years, can depart significantly from their equilibrium values when capacity shortages occur. It typically takes a year or two for new capacity to come on-line. Load excursions will occur due to business cycles or large economic displacements. It is important to have this kind of behavior in the regional model because large and sudden changes, which can last a significant time, are key sources of uncertainty and risk. These changes, moreover, may stem from activities and prices outside the region and may therefore be uncorrelated with local events.

One of the shortcomings of the principal factor approach to simulating price paths is that it does not easily or naturally accommodate excursions that begin at random times and last for a random number of periods. Rather that forcing the principle factor metaphor, the regional model represents these excursions with a different, simpler technique.

In the regional model, jumps can begin at random times and have random magnitude and duration. There is logic to model the "recovery" from excursions and to constrain when jumps can take place.

Figure P-21, which shows the wholesale electricity price[15] in row {102} of our sample workbook L24DW02-f06.xls, illustrates a typical jump with recovery. The first jump, illustrated by the heavy line, and the subsequent recovery have an obvious impact on the electricity price, illustrated by the light line. In addition, a second jump begins in the 79th period and lasts the remaining two periods of the study.

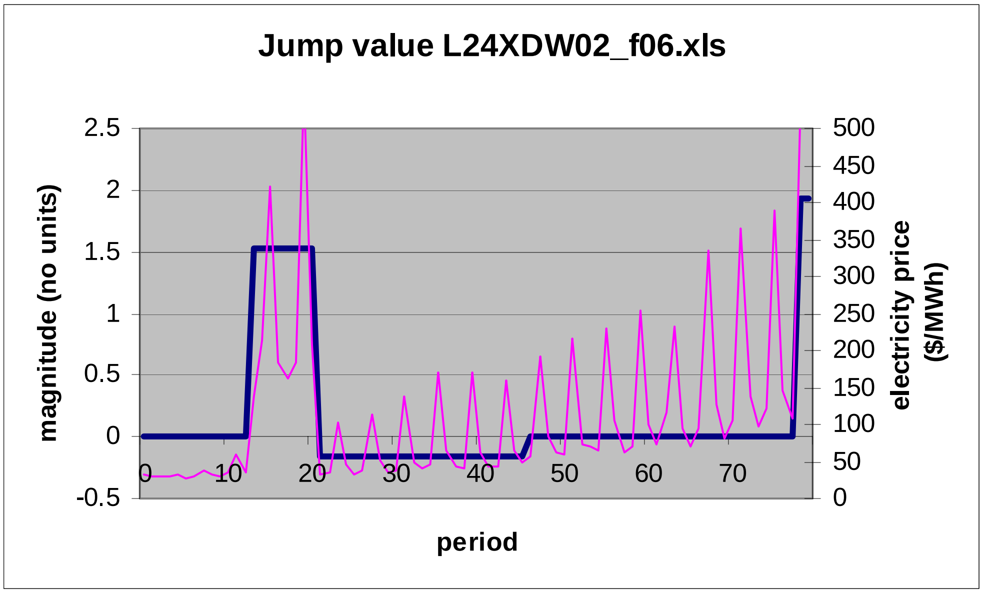

Figure P-21: Typical Jump with Recovery

The worksheet logic that produces the jump pattern appears in rows {99} through {102}. In principle, there can be as many jumps as the user desires. For this two-jump system, we first have the following Crystal Ball assumption cell values:

	R	S	T
99	13.74923	1.534261	10.59427
100	32.05555	1.935131	8.386783

where R, S, and T are the wait, size, and duration of the jump, respectively. The values for the wait and duration of a jump specify the number periods that must pass before a jump can begin and end, respectively. For proportional jumps, the model ignores the last parameter, because the size of the jump determines its duration. This particular example uses proportional jumps.

Then the formulas in the row {101} calculate intermediate values, which specify the periods in which events occur.

[15] This is the flat market price before any resource response. Resource responsive price modeling is the subject of Appendix L. "Flat" market prices are average prices, where the average is with respect to on- and off-peak hours in whatever period is under discussion.

R101	=$R$99	wait_1	start time of jump 1
S101	=R101+ IF($S$99= 0,0,12/$S$99)	wait_1+ 12/size_1	end time of jump 1
T101	=$S$99	size_1	size_log xfr jump 1
U101	=S101	end time of jump 1	start time of recovery 1
V101	=U101+ S101*EXP(T101)	end time of jump 1 + duration recovery 1	end time of recovery 1
W101	=-T101/10	-size_1/10	size_log xfr recovery 1
X101	=V101+ $R$100	end time of recovery 1+ wait_2	start time of jump 2
Y101	=X101+ IF($S$100= 0,0,12/$S$100)	wait_2 + 12/size_2	end time of jump 2
Z101	=$S$100	size_2	size_log xfr jump 2
AA101	=Y101	end time of jump 2	start time of recovery 2
AB101	=AA101+ Y101*EXP(Z101)	end time of jump 2 + duration recovery 2	end time of recovery 2
AC101	=-Z101/10	-size_2/10	size_log xfr recovery 2

Figure P-22: Intermediate Jump Calculations

The first six columns, {R101 through W101}, calculate parameters for the first jump; those the next six columns pertain to the second jump. Note that the formulas for the first jump are almost identical to those for the second. If the user specified additional jumps, there would be six additional columns in that row for each additional jump.

The size and duration of the jump recovery are proportional to the inverse of the size of the jump. The scaling factors of 10 and 12 in columns {S, W, Y, and AC} control the sizes. The size of these factors produce "realistic" behavior, i.e., behavior that conformed to expectations about the future. Originally, the size of the duration and jump assured that the price or load adjustment, after appropriate inverse transformation

$$\overset{e}{y_t \mapsto p_t / p_{t-1}}$$

would average to 1.0. The intent was to create prices that averaged out to the long-term equilibrium value over time. This approach, however, produced recoveries that were much too large and lasted too long. The Council therefore abandoned it. Part of the rationale in moving away from an adjustment that averaged to 1.0 was some disbelief that there was justification for prices returning to a fixed long-term price. Equilibrium prices, after all, can change as underlying economics change.

Row {102} interprets the values in row {101} based on the period number in row {46} and produces the final jumps:

```
R102 = IF(AND(R$46>$R101,R$46<=$S101),$T101,0)+           jump_1
       IF(AND(R$46>$U101,R$46<=$V101),$W101,0)+           recovery_1
       IF(AND(R$46>$X101,R$46<=$Y101),$Z101,0)+           jump_2
       IF(AND(R$46>$AA101,R$46<=$AB101),$AC101,0)         recovery_2

S102 identical, except S$46 instead of R$46
T102 identical, except T$46 instead of R$46
```

Row {102} contains the values that must then undergo inverse transformation. This final transformation is the subject of the next section.

CO_2 and emission taxes exhibit a special kind of jump behavior not shared by loads and prices. There is only one jump, but its value can change on in particular periods. When the Council queried experts about the likelihood of carbon tax legislation, the experts agreed that any changes would probably occur with a change in the federal administration. Therefore, emission taxes can arise only in the year of a presidential campaign (2008, 2012, etc.). These are step functions of uncertain size and timing, otherwise. Any jump remains in place through the end of the study. The section on CO_2 tax uncertainty further describes this behavior.

Stochastic Adjustment

Prices in the model derive from the Council's assumptions for long-term equilibrium prices[16]. For reasons discussed in Chapter 6, these equilibrium prices can be associated with the median price because there is equal probability of being above and below the median price. Some users may prefer, however, for the long-term equilibrium prices to match the price distribution's ***mean***. Because prices in the regional model use a lognormal distribution, however, the mean price is *higher* than the median price.

To accommodate this situation, the model can apply a "stochastic adjustment" to the benchmark price. This adjustment, a number between zero and one, is chosen so that the distributions mean price matches the benchmark price. An example of a stochastic adjustment for on peak wholesale electricity market prices appears in the second row of Figure P-23.

	Series: Market Prices Independent Term_005				
Expected_Value_Set: Market Exp Price On-Peak 4x2	32.29	33.04	32.99	32.33	32.66
Stochastic_Adjust_Set: Stoch Adj On-Peak 4x2	0.87	0.73	0.78	0.76	0.85
Principal_Factor_Set: Reg Mkt Prc	-0.02037443	1.00			
Data_Series: Mkt Prin Fac Level	0.50				
	0.007267999	1.00			
Data_Series: Mkt Prin Fac Lin Growth	0.00	0.07			
Combined factors	-0.010187215	-0.009678455	-0.009678455	-0.009678455	-0.009678455
Jump_Set: Elec Mkt_002	8.770426174	0.072691876	8.899814829		
	16.07130502	0.100080134	11.46780741		
Combined Jumps	8.770426174	173.850772	0.072691876	173.850772	220.5905142
	0	0	0	0	0

Figure P-23: Stochastic Adjustment

Each period typically requires a separate stochastic adjustment. Appendix L describes a utility, the macro subTarget, which automates the process for finding values for the stochastic adjustment.

Combinations of Principal Factors, Specific Factors, and Jumps

The preceding sections describe how the model represents stochastic behavior using combinations of principal factors, specific factors, and jumps. It is easiest, however, to model these elements with simple symmetric or unbounded distributions. The inverse lognormal transformation then guarantees physical values that have positive value and behavior that is more realistic.

[16] Because the median and the mean both described the final distribution of prices after any adjustment, we refer to the starting place as the "benchmark price." The benchmark price is typically the long-term equilibrium price.

In the example of natural gas price from the sample workbook, the model combines these influences in row {68}. For example, the formula in column {R} is

= R53*R54*EXP(R66+R62+R67)

The first two terms are the baseline price and the stochastic adjustment factor, respectively. The remaining three terms R66, R62, and R67, are the jump, principal factor, and specific factor contributions, which must be inverse transformed according to equation (2). Because the inverse transformation produces the ratio of the new value to today's value or, in the case of strategic uncertainty, the value of the benchmark, the worksheet must multiply it the benchmark price (modified by any stochastic adjustment) to obtain the new price.

This concludes the discussion of the regional model's representation of stochastic processes. The appendix now turns to how the model applies these principles to the specific sources of uncertainty that are of interest.

Load

Electricity requirement, or load, in the regional model has characteristics that depend on the timescale. On an hourly basis, loads have distinct on- and off-peak variation. Hourly electricity prices typically move with this load. However, the period duration in the regional model is three months. When we consider load requirements averaged over three months there are

- strong chronological correlation,
- seasonal shapes,
- excursions due to changing economic circumstances, and
- long-term elasticity to electricity prices.

The long-term correlation with electricity prices differs in magnitude and direction from the short-term correlation. That is, loads generally correlate positively to electricity prices in the short term but negatively in the long-term.

This appendix has described the techniques the regional model uses for capturing this broad spectrum of behaviors. This section details the specific formulas and data that implement those techniques.

Electric load serves a number of purposes in the regional model. Its main role is its contribution to energy balance and costs in the regional model. Two other roles that it serves, however, are as a term in the reserve margin calculation and as an influence on medium-term electricity prices.

Appendix L describes how the regional model uses energy requirements to determine energy balance, costs, and reserve margin. This Appendix P will trace back the logic and data from the point where Appendix L begins the discussion. This will be a "bottoms-up" description. The description proceeds from the final values used in Appendix L to the constituent components from which they are constructed. Because the influence of load on medium-term electricity prices is an issue of modeling uncertainty, either that of load or of electricity price, that entire discussion appears in this appendix, in the section "Electricity Price."

Energy Balance and Cost

The discussion of energy load in Appendix L begins with the average megawatts for the period, on peak and off-peak. The specific worksheet cells in the sample worksheet that provide on peak and off-peak load in column {AQ} are {AQ 183} and {AQ 236}, respectively. The formulas in these two cells are similar. The on peak calculation in {AQ 183} is

=AQ$125*AQ$133

Tracing back from these cells, the reader will find that AQ$125 is the period estimate for the flat load in that period. (By flat load, we mean the average load across all -- on peak and off-peak -- hours.) The value in cell {AQ 133} is a constant factor for converting monthly flat average megawatts to average megawatts over the on peak hours.

The source of these conversion constants is reference [**2**]. The process used to arrive at them is as follows

1. From Northwest Power Pool energy and peak loads for 2000 through 2002, calculate a monthly load factor,

2. Estimate the on peak and off-peak energy using the number of corresponding hours in each month and the simple load duration curve model illustrated in Figure P-24,

3. Estimate the monthly and quarterly multiplication factors, and

4. Recognize that the quarterly factors, illustrated in Figure P-25, change little and are effectively constants.

The preceding section, Stochastic Process Theory, describes how the model represents uncertainties with principal factors, jumps, and specific factors. As shown in Figure P-26, the period estimate for flat load that appears in cell AQ 125 is the product of the benchmark level load requirement {AQ$113} times the inverse transformation (equation 2) for specific variance {AQ$124}, jump {AQ$123}, and combined factor terms {AQ$120}:

=AQ$113*EXP(AQ$123+AQ$120+AQ$124)   (12)

The specific factor contribution ({AQ124}) is nonzero, roughly five percent, only for winter and summer seasons. Council staff [3] concluded that this was an appropriate amount of seasonal variation of loads due to weather uncertainty.

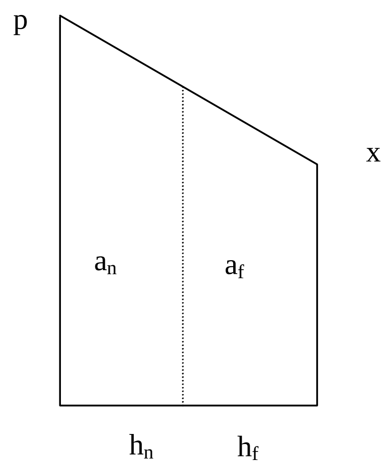

Figure P-24: Load Duration Curve to Estimate On- and Off-Peak Energies

$$\text{area or energy } a = a_n + a_f$$
$$\text{hours } h = h_n + h_f$$
$$\text{min load } x = 2(a/h) - p$$
$$\text{average on-peak energy } a_n / h_n = p + (h_n / h) * (x - p)/2$$
$$\text{average off-peak energy } a_f / h_f = (a - a_n)/h_f$$

The jump contribution in cell {AQ 123} represents longer-term excursions in load requirements due to a host of influences, including general economic activity. Because business cycles tend to last several years, the regional model uses only a single jump. The logic for the jump is a variation of the example that the previous section illustrated. In particular, the duration of the jump is specified rather than being a function of the size of the jump, and the recovery is specialized.

Spring	1.14	0.82
Summer	1.10	0.87
Fall	1.14	0.82
Winter	1.18	0.78
average	1.14	0.82

Figure P-25: Quarterly Multiplication Factors (Unitless)

The wait, size, and duration for jumps are all random variables. The specification for the wait, size, and duration appear in Figure P-27.

AQ125 = =AQ$113*EXP(AQ$123+AQ$120+AQ$124)

	Q	AQ	AR
112			
113	Expected_Value_Set: Non-DSI Load Flat 4x2	23768	20287
114	Principal_Factor_Set: Non-DSI Flat Loads PF		
115	Data_Series: NDSI Const Factor	0.01	
116			
117	Data_Series: NDSI Linear Factor	0.07	
118			
119	Data_Series: NDSI Quadratic Factor	0.01	
120	Combined factors	0.018634537	0.018634537
121	Jump_Set: Non-DSI Flat Loads JS_002		
122	Combined Jumps		
123		0	0
124	Specific Variance	0.005084832	0
125	Standard Loads Flat 4x2_001, Subperiod: (all)	24092	20669
126	Weather corrected	24215	20669

Figure P-26: Average Megawatt Requirements Calculation

The jump recovery is such that, after transformation, the jump area equals the recovery area. The size of the jump before transformation equals the size of the recovery before transformation. This is an arbitrary choice, to make the calculation simple. To make of the areas after transformation the same, the duration of the recovery is a function of the jump duration and size. To make the areas the areas the same, we have D_1(exp(J)-1)=D_2(1-exp(-J)), where D_1 is the duration of the original jump and D_2 is the duration of the "recovery" jump. This gives us D_2=D_1*exp(J). Having equal areas means the load excursions average out over a sufficiently long (D_1+D_2) period.

Random Variables

	Type	Cell	Distribution	Parameters	
Jump 1	wait	{{R121}}	**uniform**	min 0	max 85
	size	{{S121}}	**uniform**	min -0.10	max 0.80
	duration	{{T121}}	**uniform**	min 8	max 20
Principal Factors	offset	{{R114}}	**normal**	mean 0	stdev 1
	linear	{{R116}}	**normal**	mean 0	stdev 1
	quadratic	{{R118}}	**normal**	mean 0	stdev 1
Specific Variance		{{row 124}}	**normal**	mean 0	stdev 0.05

Figure P-27: Assumption Cell Values for Load

The combined principal factors have the weightings, distributions, and eigenvalues illustrated in Figure P-29. The Council selected these to provide realistic behavior [**3**]. The validation for this behavior is the topic of this section's "Comparison with the Council's Load Forecast", below.

Finally, the baseline load forecast {row 113} corresponds to the Council's weather-adjusted, non-DSI load forecast [**4**] and reflects the following assumptions.

- Nine percent losses for distribution and transmission
- Existing conservation through hydro-year 2003

	R	S	T
121	48.54747	-0.03909	16.17535

		interpretation
R122 =$R$121	wait_1	start time of jump 1
S122 =R122+ $T$121	wait_1+ duration_1	end time of jump 1
T122 =$S$121	size_1	size_log xfr jump 1
U122 =S122	end time of jump 1	start time of recovery 1
V122 =U122+ S122*EXP(T122)	end time of jump 1 + duration recovery 1	end time of recovery 1
W122 =-T122	-size_1	size_log xfr recovery 1

R123 = IF(AND(R$46>$R122,R$46<=$S122),$T122,0)+ jump_1
IF(AND(R$46>$U122,R$46<=$V122),$W122,0) recovery_1

S123 identical, except S$46 instead of R$46
T123 identical, except T$46 instead of R$46

Figure P-28: Jump Data and Formulas for Load

- Frozen efficiency for hydro year 2004 and beyond [17]
- Monthly distribution of annual energies, and the aggregation of those monthly energies into quarterly energies.

This baseline forecast serves as the median of the distribution of energy requirements. The model has all future conservation in the conservation supply curves described in Appendix L. The only exceptions are conservation implemented before 2003 and conservation due to building codes and appliance standards implemented before 2003.

Pricipal Factors

Dec of Cal Year	offset	linear	quadratic
Weight			
	0.000	0.300	0.051
Value			
2003	0.01	0.01	0.00
2004	0.01	0.02	0.00
2005	0.01	0.03	0.00
2006	0.01	0.04	0.00
2007	0.01	0.05	0.01
2008	0.01	0.06	0.01
2009	0.01	0.07	0.01
2010	0.01	0.08	0.02
2011	0.01	0.09	0.02
2012	0.01	0.10	0.03
2013	0.01	0.11	0.04
2014	0.01	0.12	0.04
2015	0.01	0.13	0.05
2016	0.01	0.14	0.06
2017	0.01	0.15	0.07
2018	0.01	0.16	0.08
2019	0.01	0.17	0.09
2020	0.01	0.18	0.10
2021	0.01	0.19	0.11

Figure P-29: Principal Factors for Load

Energy Reserve Margin

Appendix L describes how the model uses weather-adjusted energy load requirement in each period to determine the energy reserve margin. The energy reserve margin plays a prominent role in the decision criterion to proceed with construction of new power plants.

The load estimate in cell {AP289} is the hydro year's average, weather-corrected non-DSI load (the range {AL126: AO126}), plus the DSI load in the final period.

=-AVERAGE(AL126:AO126)-AO327

The model's weather corrected load is simply the load, less the stochastic part that

[17] The frozen efficiency load forecasts assume no new conservation of any kind, although it does incorporate any *prior* conservation and the effect of *existing* codes and standards on future requirements. Instead, conservation supply curves represent future conservation measures and new codes and standards.

represents weather variation in the winter and summer. Specifically, if the user examines cell {AO 126}, the last cell in the average computed in the previous equation, they will find formula

=AO$113*EXP(AO$123+AO$120)

This of course matches to equation (12), less the term that corresponds to specific variance for weather.

Hourly Behavior

The regional model captures hourly price and requirements information through descriptive statistics. In particular, the transformed hourly variation in load given by equation (3) and its correlation with hourly electricity price determine revenues to meet load. Appendix L describes the calculation in its discussion of Single-Period load behavior. The intra-period hourly load variation is 25 percent, as specified in cell {R 185}. The hourly correlation with other variables appears in this section's, "Hourly Correlation" discussion, below.

Comparison with the Council's Load Forecast

Statute requires that the Council's Northwest Regional Conservation and Electric Power Plan have a 20-year forecast of electricity demand.[18] This forecast of electricity demand serves as the basis for other, alternative forecasts that are necessary for specific purposes, such as a source of input data for the Aurora™ model. The alternative forecasts use assumptions that differ from those for the primary forecast. For example, an alternative forecast may use different assumptions about energy losses or about the representation of conservation. To compare the regional model's load forecast to the primary forecast, this section determines what adjustments to the primary forecast would make the two forecasts comparable. The section then compares the modified primary forecast and the loads from regional model futures.

The regional model uses a non-DSI forecast. The model simulates the behavior of DSI load separately, using electricity and aluminum prices in the model. (See Appendix L for a description of DSI modeling in that appendix's "Multiple Period" section of Principles.) The non-DSI load forecast appearing in the Plan (Appendix A) is of sales (MWa) by calendar year, including conservation expected to arise from a forecast of retail electricity rates but excluding conservation due to codes and standards implemented since the Council's 4th Plan. The basis of electricity rate forecast is an earlier calculation of long-term equilibrium wholesale prices. The annual loads appear in Table P-1, which details the values in Appendix A, Table A-2.

[18] Public Law 96-501, Sec. 4(e)(3)(D)

	Non-DSI Sales (Price Effects)				
YEAR	Low	Medlo	Medium	Medhi	High
2004			18072		
2005	17191	17824	18433	19020	20221
2006	17200	17955	18663	19360	20727
2007	17214	18098	18906	19721	21257
2008	17228	18239	19145	20093	21814
2009	17257	18398	19405	20479	22397
2010	17297	18570	19688	20879	23007
2011	17320	18729	19959	21275	23598
2012	17353	18906	20251	21696	24214
2013	17366	19067	20521	22106	24843
2014	17430	19274	20830	22547	25501
2015	17489	19482	21147	23000	26187
2016	17522	19672	21456	23449	26906
2017	17554	19864	21770	23907	27645
2018	17586	20058	22089	24375	28407
2019	17619	20254	22413	24853	29190
2020	17652	20453	22742	25341	29997
2021	17686	20653	23076	25839	30827
2022	17719	20855	23415	26347	31681
2023	17753	21059	23760	26866	32560
2024	17787	21265	24109	27396	33466
2025	17822	21474	24464	27937	34397

Table P-1: Council's Non-DSI Calendar-Year Sales Forecast

Some background about the Council’s load-forecasting methods will be helpful to following the development of forecast adjustments. Electricity prices, building codes, and appliance standards determine the level of pursuit of conservation and consequently, energy requirements. Because Council policy can affect codes and standards directly and electricity prices indirectly, it is useful to separate these influences.

One way approach this decomposition is to start with a "frozen efficiency" load forecast. The frozen efficiency load forecast reflects the amount of energy requirement that would arise only from current appliance standards and codes. Next, one would attempt to estimate how much conservation would arise in the future from the price effect of retail electricity rates. That is, ratepayers should pursue some conservation because it costs less than the electricity it displaces. The Council refers to load forecast net of this reduction as the “price-effects” forecast.

The Council has demonstrated, however, that additional benefit accrues to ratepayers from conservation beyond that which ratepayers would pursue to offset anticipated electricity purchases. Specifically, additional conservation can reduce fuel cost and defer the utility's capacity expansion. Electric power rates may go up or down because of this conservation, but this additional conservation would minimize ratepayers’ total power costs. To induce this additional conservation, however, the region typically must pursue additional codes and standards or other conservation measures. The Council refers to the forecast that arises by virtue of this additional conservation as a "sales" forecast, that is, the actual sale of electricity to consumers after the effects of codes and standards, energy conservation, utility program savings, and consumers’ own response to prices.

The regional model, on the other hand, represents conservation using supply curves, which include new utility programs, appliance codes and standards, and price effects. Consequently, the regional model needs the frozen efficiency load forecast. If price effects or program saving were subtracted from the load, the model would be double counting their effect.

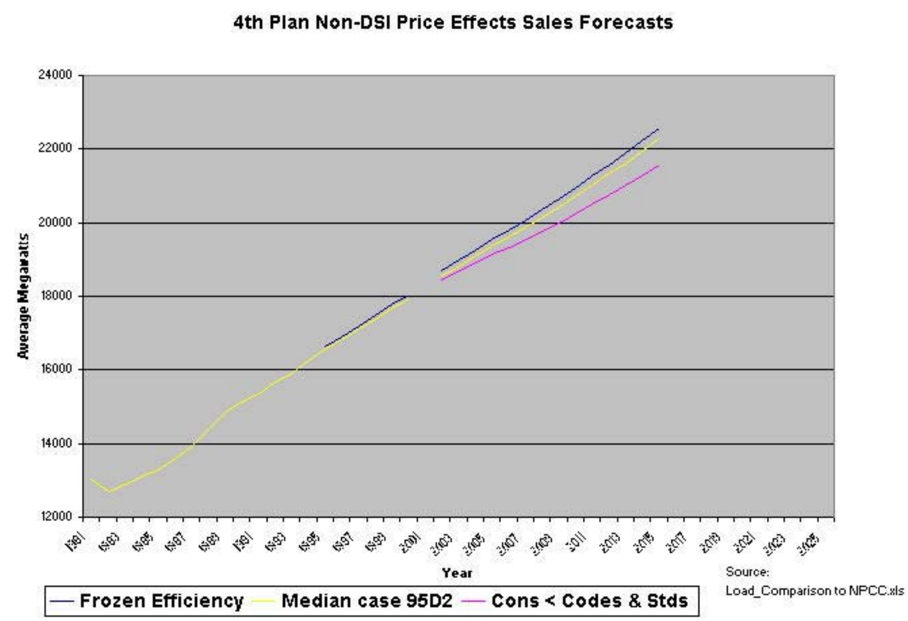

Figure P-30: Comparison of 4th Plan Load Forecasts

As mentioned in Appendix A, the load forecast of the Fifth Plan builds directly on work of the Fourth Plan. Figure P-30 illustrates the relationship in the Fourth Plan between the

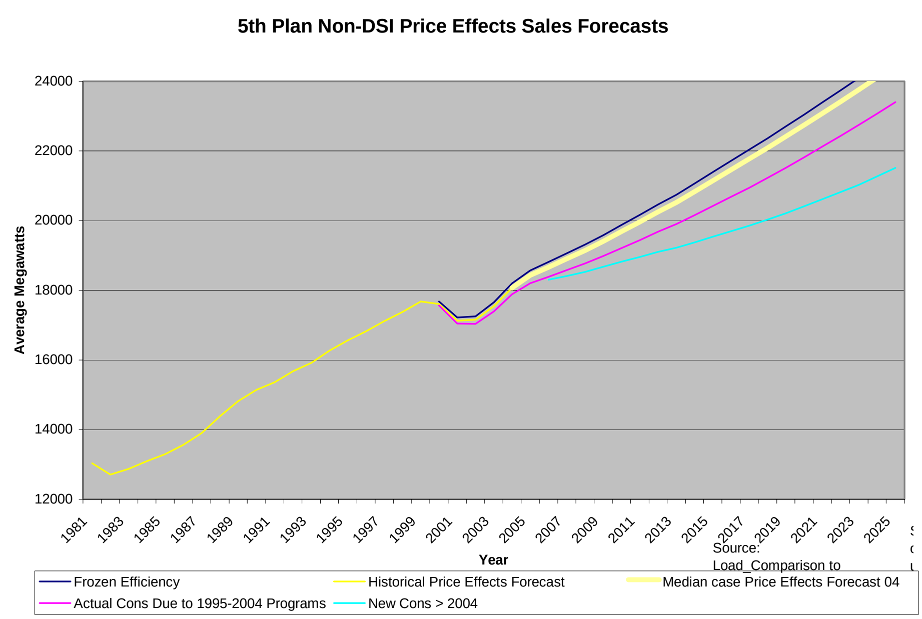

Figure P-31: Comparison of 5th Plan Load Forecasts

frozen-efficiency, price-effects, and sales load forecasts. To prepare the load forecast for the Fifth Power Plan, the Council uses a revised price-effects forecast (Table A-2). The revised price-effects forecast builds on the price-effects forecast in the Fourth Plan, incorporating history over the last five years. In particular, the revised price-effects forecast does not reflect the conservation arising from codes and standards enacted since the Fourth Plan. Figure P-31, which has five loads, illustrates the resulting situation. Before 2004, it shows an estimate of the price-effects forecast due to actual history. This price-effects forecast is continued after 2004 as the "median case price-effects forecast 04". We know, however, that codes and standards since 1995 have in fact reduced loads, and ***this reduced forecast is our best estimate of where a price-effects forecast might wind up if the Council had updated the analysis for the fifth Plan***. (The effect on loads of any new conservation, subsequent to the ***fifth*** plan is captured by the line "new conservation > 2004.") Similarly, our best estimate of where the "frozen efficiency" load forecast would lie relative to the price-effects forecast comes from using the increment between the “price-effects” forecast and the "frozen efficiency" forecast in the last plan. In summary, therefore, the "frozen efficiency" load forecast used in the regional model starts with a revised price-effects forecast anchored in 1995 but reflecting economic history since then, reduces this forecast by the effect of conservation due to codes and standards implemented since the fourth plan, and adds the increment for frozen efficiency increment developed the fourth plan. The frozen efficiency adders appear in Table P-2, and the estimated Code and Standards Savings since the Fourth Plan are in Table P-3.

	Frozen Efficiency Adders (From 95D4)				
YEAR	Low	Medlo	Medium	Medhi	High
2004	66	70	78	87	105
2005	60	64	74	86	109
2006	53	57	68	83	111
2007	48	53	66	83	116
2008	46	51	67	86	125
2009	46	51	69	91	137
2010	45	51	71	97	149
2011	46	52	74	103	163
2012	49	56	80	114	184
2013	57	67	92	131	210
2014	65	76	105	151	238
2015	72	85	116	167	265
2016	72	85	116	167	265
2017	72	85	116	167	265
2018	72	85	116	167	265
2019	72	85	116	167	265
2020	72	85	116	167	265
2021	72	85	116	167	265
2022	72	85	116	167	265
2023	72	85	116	167	265
2024	72	85	116	167	265
2025	72	85	116	167	265

Table P-2: Frozen Efficiency Adders

Finally, the revised forecast must capture losses due to distribution and transmission. An energy loss, which amounts to nine percent, will increase the end use forecast measured at the customers’ electric power meters. The power plants in the regional model, of course, must meet both end use and losses of energy.

	Conservation Captured Since the 4th Plan		
YEAR	Residential	Commercial	Total
2004	174	14	187
2005	212	18	231
2006	254	23	276
2007	298	27	325
2008	343	31	373
2009	387	35	422
2010	433	39	472
2011	478	43	521
2012	524	47	571
2013	571	50	621
2014	618	54	672
2015	664	58	722
2016	711	62	773
2017	758	66	824
2018	794	70	863
2019	830	74	903
2020	852	78	929
2021	875	82	956
2022	898	86	984
2023	922	90	1012
2024	946	94	1040
2025	966	98	1064

Source: Load_Comparison to NPCC.xls

Table P-3: Conservation Since the 4th Plan

The data presented in tables and graphs to this point reflect calendar year averages. Because the regional model uses hydro quarters, we must make the conversion to hydro year averages. The final formula for combining these effects is in Figure P-32. The table of the resulting values, by hydro year, appears in Table P-4.[19] The load forecast in this table serves as the basis for comparison between the Council's primary forecast and the regional model loads.

One subtlety of the formula in Figure P-32 is that we have implicitly assumed transmission and distribution losses are included in the frozen efficiency adders and the codes and standards savings. In any case, the adjustment for losses due to these effects is very small.

$$L_{HY,T} = \frac{8}{12}\left\{(1+\lambda)\cdot L_{CY,T} + PE_{CY,T} - C_{CY,T}\right\} + \frac{4}{12}\left\{(1+\lambda)\cdot L_{CY,T-1} + PE_{CY,T-1} - C_{CY,T-1}\right\}$$

where

$L_{HY,T}$ is load (MWa) for hydro year T

λ is loss factor (0.09)

$L_{CY,T}$ is load (MWa) for calendar year T

$PE_{CY,T}$ is price effect for calendar year T

$C_{CY,T}$ is conservation in calendar year T arising from programs implemented since the 4th Plan

Figure P-32: Calculation of Adjusted Primary Forecast

The regional model uses futures containing chronological loads that can vary quite dramatically. Jumps and excursions due to business cycles and weather are evident in

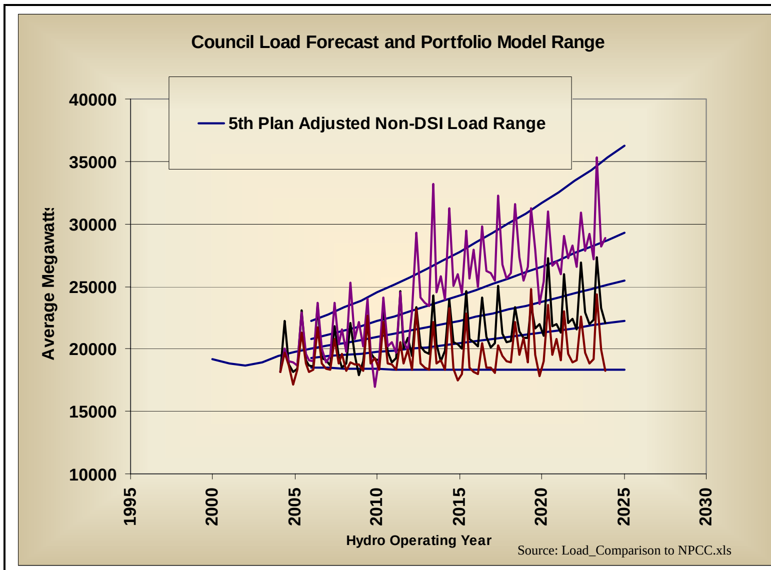

Figure P-33: Regional Model Loads from Futures

[19] The hydro year September 2006 through August 2007 is defined to be hydro year 2007.

individual futures, as illustrated in Figure P-33. This figure compares three randomly chosen futures from the 750 futures to the five load forecasts presented in Table P-4. Figure P-33 also has the disadvantage of comparing quarterly energy load values against annual averages. Even with only three futures, the figure is rather difficult to sort out. Two refinements to this graph that help make the data from the regional model more accessible are the presentation of the load data across all futures statistically and the averaging the quarterly data into annual values.

HYDRO	Olivia Input Loads				
YEAR	Low	Medlo	Medium	Medhi	High
2004			19398		
2005			19800		
2006	18516	19298	20045	20778	22234
2007	18472	19393	20249	21112	22755
2008	18431	19492	20458	21462	23308
2009	18403	19604	20682	21828	23892
2010	18388	19733	20931	22211	24505
2011	18366	19858	21179	22597	25116
2012	18346	19994	21441	23002	25742
2013	18320	20129	21699	23414	26393
2014	18324	20293	21980	23847	27072
2015	18343	20473	22279	24298	27782
2016	18335	20634	22567	24739	28507
2017	18314	20787	22852	25180	29250
2018	18302	20951	23151	25639	30025
2019	18295	21121	23459	26113	30828
2020	18297	21303	23782	26608	31665
2021	18304	21491	24115	27118	32532
2022	18311	21681	24453	27638	33425
2023	18318	21872	24796	28170	34344
2024	18324	22065	25144	28713	35290
2025	18334	22264	25502	29271	36269

Source: Load_Comparison to NPCC.xls

Table P-4: Hydro-Year Forecast for Regional Model

Figure P-35 compares the 0, 10^{th}, 50^{th}, 90^{th}, and 100^{th} percentiles against the forecast from Table P-4. The data falls somewhat outside of the jaws of the revised, primary forecast, as we would expect. The quarterly values have greater variation largely due to seasonal variation, and the Council believes there is some very small probability that annual average load will fall outside of the jaws.

Figure P-34 addresses the second problem, replacing quarterly values with annual averages. Now it is evident, for example, that the median forecast (50^{th} percentile) lies directly on top of the adjusted Council "Medium" forecast.

In Figure P-34, there appears to be greater uncertainty associated with the futures in the early part of the study than near the end of the study. Indeed, if these forecasts are truly comparable we would expect the 0 percent and 100^{th} percentiles to lie outside of the jaws.

One of the things going on here is the difference in assumption about electricity prices between the Council's primary forecast and the regional model. The Council's primary forecast, again, stems from a 1995 load forecast, which assumes much smaller variation in electricity price. The regional model sees electricity prices that are orders of magnitude larger, in particular. The regional portfolio model incorporates electricity price elasticity of loads. This elasticity will cause the variation in load excursions to diminish on average, especially in outlying years where greater electricity price variation occurs.

Another influence is the limited samples of futures. The regional model data presented in Figure P-34 are directly from the model's Monte Carlo simulations. As the sample size increases beyond the 750 samples reflected here, the zero percent and 100 percent deciles

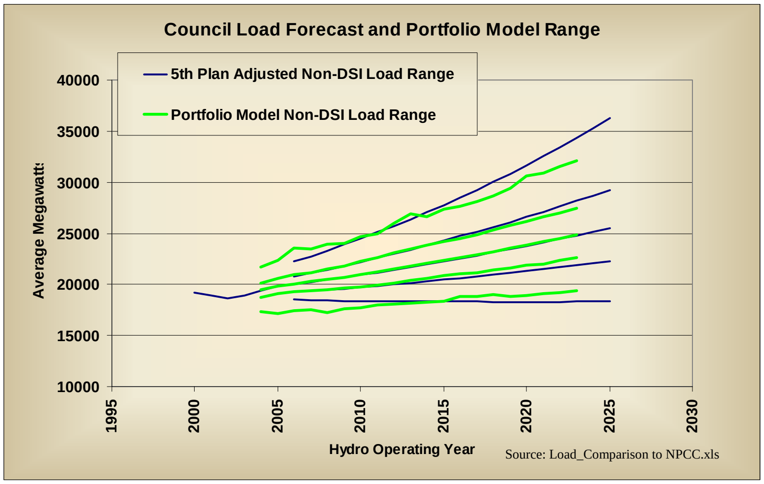

Figure P-34: Annual Averages of Deciles for Regional Model Loads

would grow apart. The maximum range of excursion in the Monte Carlo simulation is sensitive to the number of samples in the simulation.

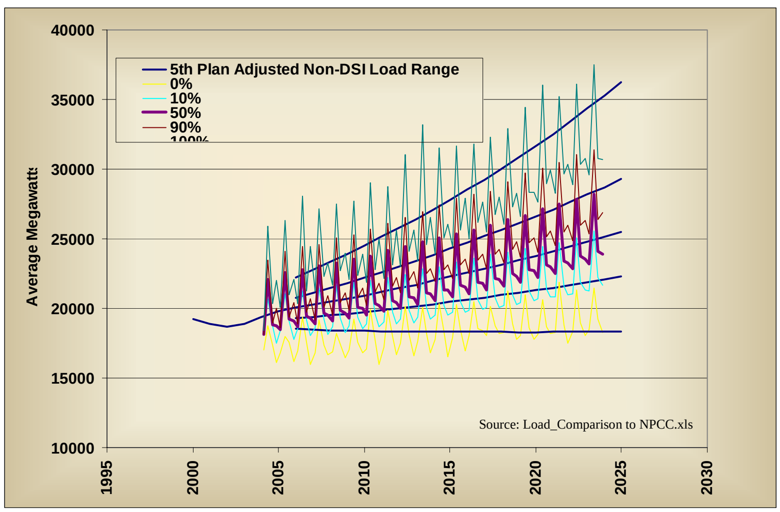

Figure P-35: Deciles for Quarterly Load

Because the regional model simulates hydro quarters, conversion of energy to that period is necessary. The basis of conversion (Ref [**5**]) is averages of monthly load allocation factors from Ref [**6**], which is integral to the study for the Council's primary load forecast.

Gas Price

Like electricity requirement load, natural gas price has characteristics that to depend on the time scale. Although natural gas price does not vary a great deal across the day, there can be substantial variation within the month. The kinds of behavior that natural gas price demonstrates include:

- Chronological correlation, stronger than that for electricity prices perhaps due to the storage capability of natural gas,
- Seasonal shapes,
- Excursions due to disequilibrium of long-term supply and demand,
- Daily variation within the month and hydro quarter,
- Basis differential, in particular between regions separated by the Cascade mountain range, and
- Relatively small hourly price variation, because of storage capability within natural gas transmission lines. This eliminates the requirement for modeling on- and off-peak price differences.

Natural gas prices also exhibit correlation with other variables. Natural gas prices correlate with loads and with electricity prices because weather affects all of these. Moreover, natural gas-fired generation is a marginal resource for power generation and consequently affects electricity price. Finally, higher electricity load generally places higher demand on natural gas markets. The model must capture both the long-term and short-term correlation among these variables.

Natural gas prices serve several functions or roles within the regional model. Short-term prices determine economic dispatch of gas-fired thermal generation. Forward gas prices feed decision criteria for the construction of new capacity. This section discusses the simulation of each of these uses.

As noted above, gas prices also influences longer-term electricity price. This influence of natural gas price on electricity prices appears in the discussion of electricity price uncertainty (See the section "Electricity Price," below). Short-term correlation is outlined at the end of this chapter.

Worksheet Function and Formulas

Appendix L identifies how the regional model uses natural gas prices for the dispatch of gas-fired thermal generation and for the decision criteria for construction of new power plants. Appendix L traces natural gas price back to specific workbook cells. The description of natural gas prices in this Appendix P begins with those cells and continues the description back to the "building blocks" of these prices.

East of Cascade's gas prices {AQ180} are derived from those for west of Cascade's {AQ 68}. The worksheet range {A176: U176} provides the seasonal basis differential. The source of these basis differential values is [**7**]. The formulas in {Row 178} limit the lowest price in the East to $.20 per million BTU. This constraint assures Eastside prices remain positive irrespective of what Westside prices may do.

The formulas in {Row 180} add the values in {Row 179} to those in {Row 178}, but the values in {Row 179} are zero. This is a vestige of earlier logic, which attempted to add a contribution for fixed costs differentially to the Eastern natural gas prices. Council staff later decided that a fixed-cost adder would be inappropriate.

A lognormal process creates West of Cascade's natural gas prices, using combined factors, specific variation, and two jumps. Figure P-36 identifies the random variables for the natural gas price representation. The character of the jumps differs from that for the load's representation. The Council deemed the original size and duration of the jumps too large to be realistic. The Council substituted the representation in Figure P-37.

	R	S
63	14.7678	0.0886
64	12.1453	0.1863

Cell	Formula		interpretation
R65	=$R$63	wait_1	start time of jump 1
S65	=R65+ IF($S$63= 0,0,3/$S$63)	wait_1+ 3/size_1	end time of jump 1
T65	=$S$63	size_1	size_log xfr jump 1
U65	=S65	end time of jump 1	start time of recovery 1
V65	=U65+ S65*EXP(T65)	end time of jump 1 + duration recovery 1	end time of recovery 1
W65	=-T65/10	-size_1/10	size_log xfr recovery 1
X65	=V65+ $R$64	end time of recovery 1+ wait_2	start time of jump 2
Y65	=X65+ IF($S$64= 0,0,3/$S$64)	wait_2 + 3/size_2	end time of jump 2
Z65	=$S$64	size_2	size_log xfr jump 2
AA65	=Y65	end time of jump 2	start time of recovery 2
AB65	=AA65+ Y65*EXP(Z65)	end time of jump 2 + duration recovery 2	end time of recovery 2
AC65	=-Z65/10	-size_2/10	size_log xfr recovery 2

R66	= IF(AND(R$46>$R65,R$46<=$S65),$T65,0)+	jump_1	source: L28_P.xls
	IF(AND(R$46>$U65,R$46<=$V65),$W65,0)+	recovery_1	
	IF(AND(R$46>$X65,R$46<=$Y65),$Z65,0)+	jump_2	
	IF(AND(R$46>$AA65,R$46<=$AB65),$AC65,0)	recovery_2	

Figure P-36: Jump Data and Formulas for Natural Gas Price

The specific variance contributes to shoulder months, the spring in the fall. In contrast with several other stochastic variables, there seems to be much greater uncertainty in the price of natural gas during these off-peak seasons (see Reference [**8**]). This is perhaps due, in part, to the storage capability for natural gas and the buying that takes place in anticipation of the heating season and occasional surpluses resulting from warm winters. The values for the specific variances appear in Figure P-37.

Random Variables

	Type	Cell	Distribution	Parameters		
Jump 1	wait	{{R63}}	**uniform**	min 0	max 30	
	size	{{S63}}	**uniform**	min 0	max 0.70	
Jump 2	wait	{{R64}}	**uniform**	min 4	max 20	
	size	{{S64}}	**uniform**	min 0	max 0.70	
Principal Factors	offset	{{R56}}	**triangle**	min -1	mode 0	max 1
	linear	{{R58}}	**triangle**	min -1	mode 0.1	max 1
	quadratic	{{R60}}	**triangle**	min -1	mode 0	max 1
Specific Variance		{{row 67}}	**normal**	mean 0	stdev 0.30	

source: L28_P.xls

Figure P-37: Assumption Cells for Natural Gas Price

The principal factors appear Figure P-38. These were chosen largely to create realistic behavior. Some comparative statistics appear in the section "Comparison with the Council's Gas Price Forecast," below.

Pricipal Factors

Dec of Cal Year	offset	linear	quadratic
	Weight		
	0.350	0.700	1.000
	Value		
2003	0.50	0.07	0.00
2004	0.50	0.14	0.01
2005	0.50	0.21	0.02
2006	0.50	0.28	0.03
2007	0.50	0.35	0.05
2008	0.50	0.42	0.07
2009	0.50	0.49	0.10
2010	0.50	0.56	0.13
2011	0.50	0.63	0.16
2012	0.50	0.70	0.20
2013	0.50	0.77	0.24
2014	0.50	0.84	0.29
2015	0.50	0.91	0.34
2016	0.50	0.98	0.39
2017	0.50	1.05	0.45
2018	0.50	1.12	0.51
2019	0.50	1.19	0.58
2020	0.50	1.26	0.65
2021	0.50	1.33	0.72

source: L28_P.xls

Figure P-38: Principal Factors for Natural Gas Prices

The influence of principal factors, specific variance, and jumps combine just as they did for the construction of load futures. The cell {AQ68} contains the formula that combines these:

= AQ53*AQ54*EXP(AQ66+AQ62+AQ67)

where {AQ53} contains the benchmark (Council "medium" forecast, Reference [7]) value for natural gas in this period, {AQ54} is a special "stochastic adjustment," {AQ66} contains the sum of the jumps, {AQ62} is the sum of the factors, and {AQ67} is the contribution from the specific variance (seasonal uncertainty). The stochastic adjustments in row {66} are multipliers that would guarantee that the average, rather than the median, of the prices in that period match the benchmark. Early in the Council's studies, the Council identified their "medium" forecast with the average of the futures prices. Subsequently, the Council decided that the Council's medium forecast is a median forecast and the stochastic adjustment became 1.0 (no effect). That is, the Council constructs its forecast so that there is equal likelihood of the long-term equilibrium price being on either side of the forecast.

Forward Prices for Decision Criteria

Forward prices for natural gas play a key role in decisions about whether to construct new gas-fired power plants. The price of its fuel largely determines the value of the gas-fired power plant, and if future natural gas prices are low, the power plant will have greater value.

Some decision makers believe forward prices for natural gas are the best predictor of future spot price. The relationship between forward prices and current and future spot prices has been the subject of financial research for over 70 years. Arbitrage between forward and *current* spot price is possible for financial instruments and for commodities that can be stored. There is therefore a strict relationship between current spot prices and forward prices for these products. Natural gas, however, can only be stored in significant volumes up to about six months. Beyond that period, arbitrage opportunities are rare or nonexistent. For electricity, of course, the opportunities are even scarcer.

The relationship between forward prices and future spot prices is even weaker. The argument is often that the forward price incorporates all information about future spot price. This ignores, however, the question of whether the forward price in fact does a good job of predicting spot price. A substantial body of research has demonstrated that long-term forward prices are a poor predictor of future spot prices for commodities that cannot be stored.[20] (In this context, "long-term" would be any period significantly longer than that which the commodity is stored.) Moreover, such an assessment ignores the influence of scarcity or abundance on the attitudes of hedgers or speculators, and these can bias the price up or down when there is uncertainty, even when all market participants share the same view of *expected* future spot price.[21]

Even if long-term forward prices are no better than throwing darts for predicting future prices, however, this does not mean that forward prices are irrelevant to the value of a power plant. On the contrary, an appropriate use of forward contracts is for hedging. If decision makers purchase the natural gas forward and sell the output of the power plant forward before proceeding with construction, changes in the values for forward contracts for natural gas and electricity will offset any change in the value of the plant due to fuel and output price variation. This provides a means for managing such risk associated with the "merchant" (un-hedged) portion of the plant. That is, an owner can make the merchant portion as small as desirable by hedging the rest of the plant. For various reasons, this hedging is likely to "lock in" as loss for the owners. However, decision makers view this loss as the cost of reducing risk, much like an insurance premium.

Forward prices continuously change, and this is an important source of uncertainty. One challenge for the portfolio model is to continuously forecast changing forward prices for natural gas and electricity. The question is, what is a reasonable basis for making such a forecast? Experience shows that forward prices tend to track current spot prices. Figure P-39 (Reference [**9**]) illustrates the relationship over time between current spot prices and a contract for delivery of natural gas in July 2003. The same kind of relationship exists for electricity. FERC analysis of electricity prices[22] in fact explicitly supports the position that spot prices move forward prices. (See discussion of the role of electricity spot prices in forecasting electricity forward prices on page P-75.)

[20] See, for example, Frank K. Reilly, ***Investment Analysis and Portfolio Management***, 2nd ed., The Dryden Press, Chicago 1979. See especially Chapter 24, "Commodity Futures," which discusses research for shell eggs, cattle, and other perishable commodities. For a more recent examination of electricity prices, see Longstaff and Wang, "Electricity Forward Prices: A High-Frequency Empirical Analysis," Anderson Graduate School of Management, UCLA, 2002.

[21] John C. Hull, ***Options, Futures, and Other Derivatives***, 4th ed., Prentice Hall 2000. See section 3.12, "Futures Prices and the Expected Future Spot Price."

[22] U.S. Dept. of Energy, Federal Energy Regulatory Commission, ***Final Report On Price Manipulation In Western Markets, Fact-Finding Investigation Of Potential Manipulation Of Electric And Natural Gas Prices***, Docket No. PA02-2-000, March 2003. PDF version.

This observation led the Council to adopt averages of current spot prices for natural gas over the prior 18 months as a simulated forecast of natural gas forward prices. In the cell {{AQ 249}}, the model averages the prior six periods (18 months) to estimate the

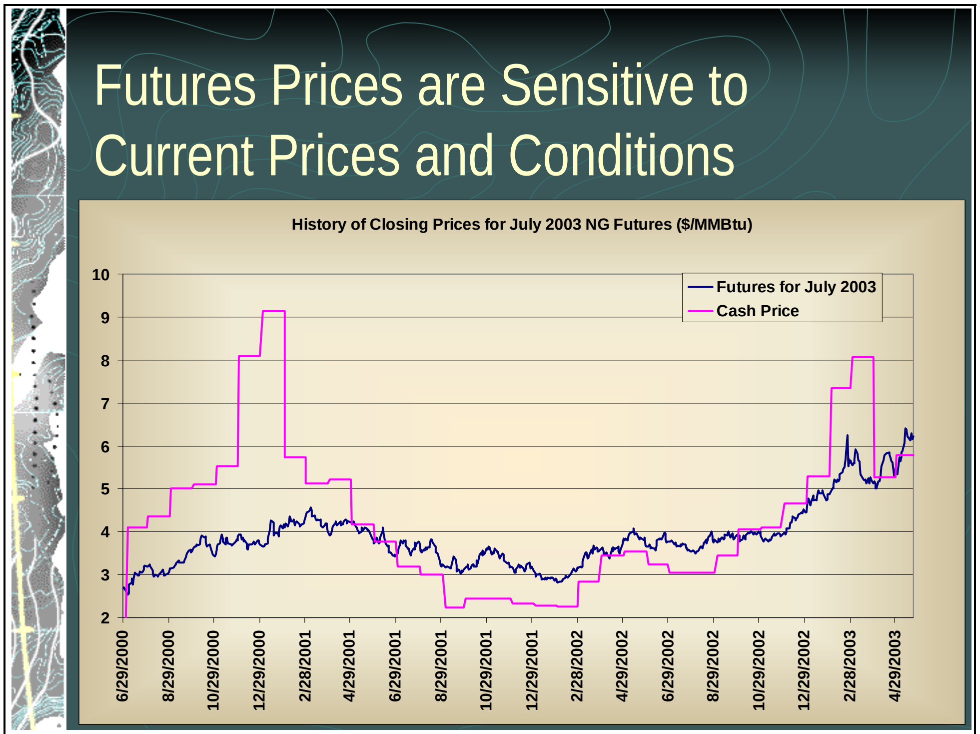

Figure P-39: Relationship Between Futures and Spot Prices

corresponding forward priced for the decision criteria.

Hourly Behavior

Hourly volatility of natural gas prices within the period is taken as 10 percent, as indicated in the cell {{R55}}. Hourly price data for gas is not available to the Council, but casual exchanges with traders suggest this figure is representative. This appendix discusses correlation of natural gas prices to other variables at the end of this chapter.

Comparison with the Council’s Gas Price Forecast

In addition to preparing a long-term load forecast for the Region, the Council prepares and updates long-term natural gas price forecasts. A comparison of the regional model’s gas prices to the Council’s forecast is more direct than the comparison to loads provided in the previous section.

Figure P-40 illustrates the quarterly natural gas price averages for four randomly chosen futures. Also shown, with the shaded area, is the range (high, median, and low) associated with the Council's natural gas price forecast. The quarterly averages fall well outside the range. In most of the futures, for example, there is at least one quarter when the natural gas price exceeds $10/MMBTU, well above the Council's "high" forecast. Some of the same caveats used in the comparison of the regional portfolio model's futures to the Council's load forecast apply here. The Council's forecast is a long-term equilibrium price forecast and does not capture excursions due to, for example, two- or three-year disruptions in supply and demand balance. Also, the Council's forecast is of annual averages, and quarterly averages will be more volatile.

By looking at statistical averages of the quarterly values for the regional portfolio model's natural gas price futures (Figure P-41), a more representative picture emerges. Quarterly averages for gas price can run from as low as $0.90 per MMBTU (2004 $) to as high as $28.24 per MMBTU, although those extremes are unlikely. The seasonal variation in price is not as extreme as that for load, so calculating annual averages for comparison with the Council's forecast is not essential. By carefully examining the deciles for quarterly gas price averages, it appears (Figure P-42) that there is about a 20

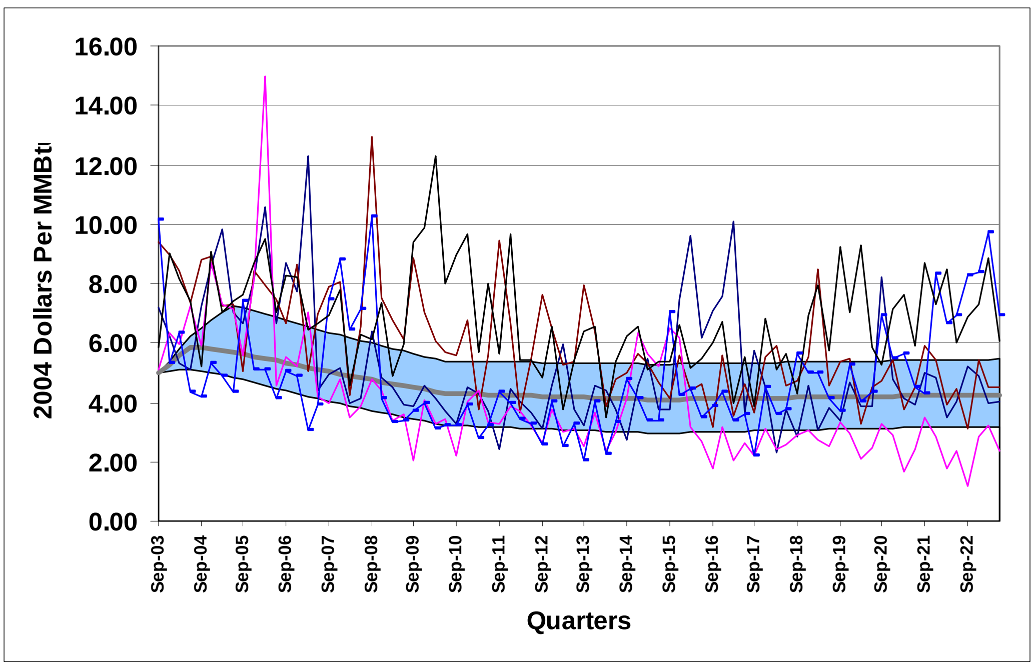

Figure P-40: Quarterly Natural Gas Prices for Selected Futures

percent chance of finding quarterly averages above the Council's high natural gas price forecast and a 20 percent chance of finding quarterly averages below the Council's low price forecast. The median of the price futures falls on top of the Council's median price forecast. This is all desirable behavior for these forecasts.

The results of the comparison of the regional model's natural gas price futures with the Council's forecasts are favorable. The only improvement on the regional model's representation that is evident after the fact is that, as has been the case in the past, the Council's price forecasts may underestimate uncertainty. (See Figure P-7) This may be a difficult situation to improve. The intuition of experts determines the range of uncertainty; without behavior that is consistent with experts' intuition, the results of the model do not have credibility. Perhaps the best outcome will be one where *low probability ranges* are as wide as feasible.

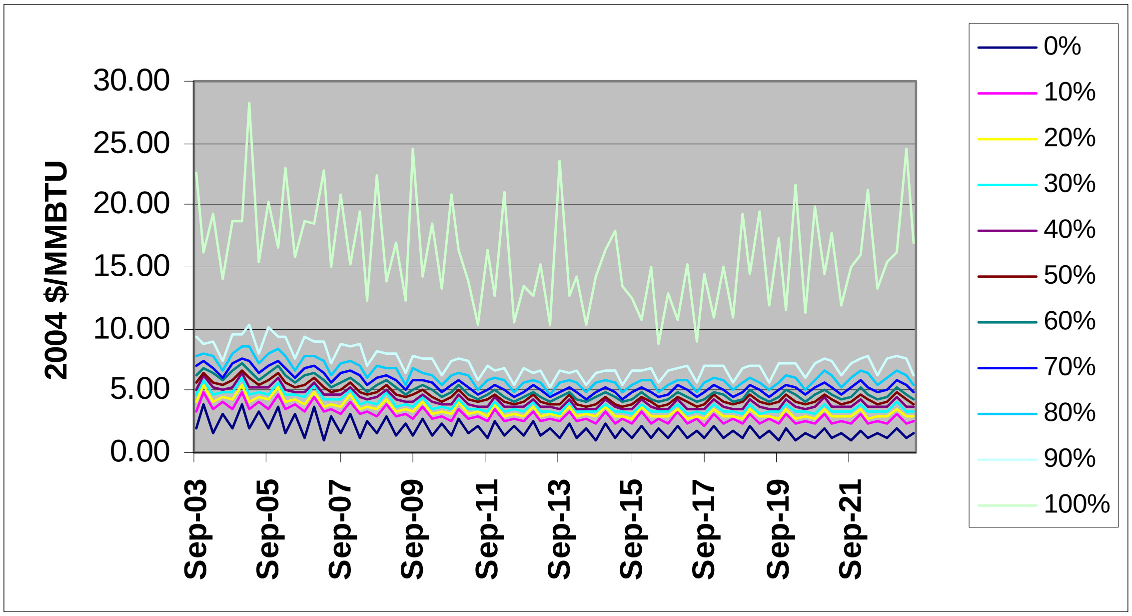

Figure P-41: Deciles for Quarterly Natural Gas Price Futures

Hydro

A 50-year history of streamflows and generation provide the basis for hydro generation in the model. The hydro-generation reflects constraints associated with the NOAA Fisheries 2000 biological opinion. The modeling assumes a decline of 300 average megawatts over the 20-year study period to capture relicensing losses, additional water withdrawals, the retirement of inefficient hydro generation units, and other factors that might lead to capability reduction. Hydro generation modeling did not reflect generation changes due to any climate change, because study results are too preliminary. Appendix N addresses work to understand any climate change impact on the hydroelectric system.

The regional model assumes that most hydrogeneration is insensitive to price. Hydrogeneration already occurs primarily on peak for both economic and reliability purposes, as much as non-economic constraints permit. The regional model captures differences in on- and off-peak generation, as described below. Nevertheless, there often remains a relatively small amount of energy that operators can shift among months for commercial reasons, without adversely affecting the refill probabilities of the system. Appendix L describes how the regional model captures that behavior using reversible supply curves. (See the Appendix L section "Price-Responsive Hydro.") The scope of hydrogeneration modeling that this Appendix P discusses is the energy that is not responsive to price.

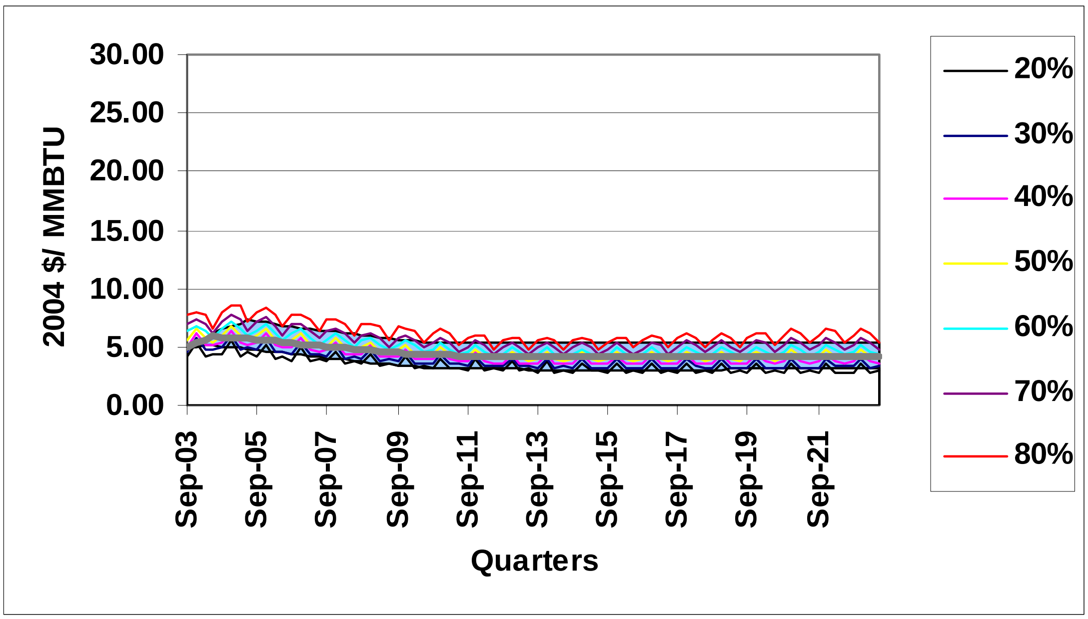

Figure P-42: Correspondence of Council's Natural Gas Price Range to Futures' Deciles

Data Sources and Representation

The source of all data for the price-invariant hydrogeneration is a BPAREGU.OUT file [**10**]. The Council's GENESYS model, specifically the HYDREG subroutine, produces this file.[23] HYDREG is the monthly hydro regulator for Genesys, the same hydro regulator that BPA, the Northwest Power Pool, and Canada use for determining rights under the Pacific Northwest Coordination Agreement (PNCA). HYDREG produces monthly generation for each hydro generation project in the region for each of 50 years (hydro years 1929-1978) of stream flow conditions. Figure P-43 illustrates the output of HYDREG for a single month in 2001 under a single (1929) stream flow condition. As

[23] Genesys is available for download from the Council's website. Contact John Fazio or Michael Schilmoeller, Council staff (503-222-5161), for directions on acquiring, installing, and using the model.

explained below, HYDREG models more facilities than appear in Figure P-43, and a complete list of such facilities appears in Figure P-44 and Figure P-46.

The regional energy value reported at the top of Figure P-43, under the heading "FINAL," primarily determines the energy used in the regional portfolio model. However, not all facilities in Figure P-43 contribute to the "FINAL" value. There are three reasons why energy is not included. First, the facility may have no generation. An example is Columbia Falls *gage* ("COLFLS") in Montana, which is a constraint on the hydro regulator. Gages always have zero energy under the column "AVMW" in Figure P-43. In Figure P-44 and Figure P-46, these have the word "gage" included in their names.

The second reason a facility may not contribute to the "FINAL" energy is that the facility may be located in Canada. Their operation is critical to the regulator, but the unit obviously does not directly contribute to regional energy. Any dams located in Canada have an asterisk in Figure P-43. In Figure P-44 and Figure P-46, these have the expression "(CAN)" included in their names, and their location is CAN. The capacity, ownership, and regulation status of Canadian facilities does not appear in the latter figures.

The third reason a facility would not contribute to the "FINAL" energy is that the PNCA does not incorporate its generation. Three Idaho facilities, Brown Lee, Oxbow, and Hell's Canyon, are part of the region and are regulated, but are not under the PNCA. The names of these three facilities have an asterisk in Figure P-43, as well.

Another class of regional plants that *contribute* to the region's energy supply but *do not* contribute to the "FINAL" energy is unregulated or "independent" plants. These are run-of-river plants and dams with capacity that is so small that HYDREG ignores their regulation. The names of these plants do not appear in Figure P-43 but are in Figure P-44 and Figure P-46, along with ownership and location information. They appear with regulation status "unreg." The total generation for the independents, however, does appear under the heading INDP at the top of Figure P-43.

HYDREG knows whether the hydro generator is east or west of the Cascades, and it produces a separate subtotal for each area. A special Council application [**11**] parses the BPAREGU.OUT file and creates a simple table of regional hydro generation (average MW) for both the East side and the Westside of the Cascades, by month and by hydro condition. Because the regional portfolio model needs all regional generation, the parsing application uses the "FINAL" energy from the BPAREGU.OUT file, adds in the unregulated generation from the "INDP" field, and adds the generation of Brown Lee, Oxbow, and Hell's Canyon.

One subtlety to preparing the hydro generation data lies in extracting on- and off-peak power from the monthly average energies that HYDREG produces. For the regional model, the on-peak period is 6 a.m. to 10 p.m. Monday through Saturday. The remaining hours are off peak. (Western power operations professionals refer to this subperiod definition of 16 on-peak hours on the six days of the week as the 6x16 or "six by sixteen" standard.) Although HYDREG does not provide subperiod values for systems hydrogeneration, extensive studies of sustained peeking capability for the system provide some guidance.

For their fourth power plan, the Council commissioned Dr. Mike McCoy to make estimates of two-, four-, and 10-hour sustained peeking capability for the hydroelectric system.[24] An analysis of the conclusions from this study suggests that the peeking capability in average megawatts decreases roughly linearly with the number of hours of sustained capability [**12**]. With this assumption, the following equation relates on- and off-peak generation capability, using the 6x16 on-peak standard, to the average energy and 10-hour sustained peaking capability.

Let
E_p denote the on-peak (6days x 16hours) power (MW)
$\hat{E}_p$ denote the sustained 10-hour on-peak (5 weekdays) power (MW)
$\overline{E}$ denote the flat or average power over the entire week (MW)
X denote the average power (MW) over hours that do not contribute to 10-hour sustained peak
then

$$\overline{E} = \frac{5\times 10\times \hat{E}_p + (7\times 24 - 5\times 10)X}{7\times 24}$$

$$E_p = \frac{\text{(saturday peak)} + \text{(weekday sus peak)} + \text{(weekday non-sus peak)}}{\text{total peak hours}}$$

$$= \frac{16\times X + 5\times 10\times \hat{E}_p + 5\times 6\times X}{(16 + 5\times 10 + 5\times 6)}$$

So solving for X gives us

$$X = \frac{7\times 24\times \overline{E} - 5\times 10\times \hat{E}_p}{(7\times 24 - 5\times 10)} \text{ so}$$

$$E_p = \frac{5\times 10\times \hat{E}_p + (16 + 5\times 6)\times X}{(16 + 5\times 10 + 5\times 6)}$$

which gives us on-peak power in terms of average power and 10-hour, sustained peak power.

[24] Northwest Power Planning Council, "A Trapezoidal Approximation to the Pacific Northwest Hydropower System's Extended Hourly Peeking Capability Using Linear Programming," Appendix H 2, *Fourth Northwest Power Plan*.]

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                    BPA REGULATOR OUTPUT FOR SEPTEMBER (PERIOD  1)     WATER YEAR 1929 STUDY YR 2001 GAME   1
                2000 BIOLOGICAL OPINION - FSH027C Updated Spi

         DESIRED   FINAL     URC     ECC     PDP    XTRA1   XTRA2     INDP    PUMP        Draft Mode        ENER
EAST               7582.   6327.   7482.   7582.   7582.  14079.     267.                User Draft Point  9.00
WEST               1189.   1126.   1184.   1189.   1189.   1385.     400.
TOTAL    11615.    8771.   7453.   8665.   8771.   8771.  15464.     667.     137.

 PLANT   NO.  NAT Q  Q OUT   QMIN  FORCE  BYPAS  OTHER  OVERG I HKSM  AVMW   DRAFT ENDSTO  ELEV    URC    ECC    AER   CON VIOL
 -----  ---- ------  -----  -----  -----  -----  -----  ----- ------ -----  ------ ------ ------ ------ ------ ------  --- -- --
CUSH 1  2208    113   1390    100      0      0      0      0  49.08    26    38.3  149.1  718.5  171.3  161.5  149.1  FC
CUSH 2  2206    114   1391      0      0      0    100      0  30.59    43
ALDER   2190    450    683    300      0      0      0      0  20.25    14     7.0   74.4 1202.3   81.4   79.7   74.4  FC
LAGRND  2188    450    683      0    683      0      0      0   0.00    21
WHITE   2160    606    237    100      0      0    130      0  32.00     3   -11.1   20.9  540.9   23.5   21.4   20.9  FC
ROSS    2070   1047   2288    788      0      0      0      0  84.31    70    37.2  474.0 1592.5  530.5  482.3  473.9  QH  FC
DIABLO  2067   1613   2854      0      0      0      0      0  53.56    74
GORGE   2065   1759   3000   1500      0      0      0      0  27.06    87
U BAKR  2028   1030   1265      0      0      0      0      0  39.41    26     7.0   72.7  707.3  111.2   74.2   72.7  FC
L BAKR  2025   1220   1495     80      0      0      0      0  19.16    29     1.2   70.6  437.5   71.8   71.8   70.6  FC
MICA  * 1890  19310  19310  10000      0      0      0      0  84.62   834     0.0 5825.1 2470.1 5825.1 5825.0 5825.1  FC
REVELS* 1870  25280  25280      0      0      0      0      0  84.62   806     0.0  557.0 1875.6  557.0  557.0  557.0  FC
ARROW * 1831  36329  40642   5000      0      0      0      0  84.62     0   129.4 3450.2 1442.0 3579.6 3233.6 3450.2  FC
LIBBY   1760   5072   9656   4000      0      0    200      0 107.95   221   137.5 1923.8 2432.5 2510.5 1731.6 1923.8  PD  FG
BONFER  1740   6694  11279      0  11279      0      0      0  84.62     0
DUNCAN* 1681   2140   2973    100      0      0      0      0  84.62     0    25.0  680.8 1889.2  705.8  678.8  680.8  FC
CORA L* 1665  12270  13971   5000      0      0      0      0  84.62    21  -111.5  396.9 1745.3  396.9  396.9  396.9  FC
CANAL * 1664  12270   8971      0      0      0      0      0  84.62   177
UP BON* 1663  12270   5000      0      0      0      0      0  84.62    21
LO BON* 1660  12270   5000      0      0      0      0      0  84.62    23
S SLOC* 1658  12270   5000      0      0      0      0      0  84.62    25
BRILL * 1652  12197  13898      0      0      0      0      0  84.62    96
H HORS  1530    646   1419   1419      0      0      0      0 180.93    49    23.2 1290.0 3538.0 1549.0 1259.7 1290.0  QP  QL SL
COLFLS  1520   2727   3500   3500   3500      0      0      0 146.48     0
KERR    1510   3847   5083   3200      0      0      0      0 146.48    72    13.9  600.8 2892.8  614.7  575.4  600.8  FC
THOM F  1490   8840  10076   6000      0      0      0      0 132.37    45
NOXON   1480   6862   8098   3727      0      0      0      0 128.93    94     0.0  108.5 2329.0  116.3  108.5  108.5  FC
CAB G   1475   8136   9371   5000      0      0      0      0 117.27    65
PRST L* 1470    118      1      0      0      0      0      0 110.37     0    -3.5   25.0    2.1   35.5   26.0   25.0  FC
ALBENI  1465   9656  14665   4000      0      0     50      0 110.37    30   116.7  465.7 2060.0  582.4  465.7  465.7  FC
BOX C   1460   9806  14815      0      0      0      0      0 108.30    41
BOUND   1450   9939  14948      0      0      0      0      0 105.62   308
7-MILE* 1442  10206  15215      0      0      0      0      0  84.62   242
WANETA* 1440  10206  15215      0      0      0      0      0  84.62   244
CDA LK* 1341    704   1634    300      0      0      0      0 122.77     0    27.9   84.6 2126.6  112.5   86.9   84.6  FC
POST F  1340    704   1634    300      0      0      0      0 122.77     6
UP FLS  1332   1350   2280      0      0      0      0      0 118.92    10
MON ST  1330   1350   2280      0      0      0      0      0 115.92    13
NINE M  1315   1753   2683      0      0      0      0      0 105.45    11
LONG L  1305   2156   3092      0      0      0      0      0 101.70    36     0.2   50.1 1535.0   52.5   50.2   50.1  FC
L FALL  1302   2156   3092      0      0      0      0      0  89.97    16
COULEE  1280  56077  64261  50000      0      0      0      0  84.62  1574  -113.3 2329.7 1283.0 2614.3 2368.4 2329.7  PD
CH JOE  1270  56117  64301      0      0      0    500      0  60.12   822     0.0    0.0  953.8    0.0    0.0    0.0
WELLS   1220  58698  66882      0      0      0   1200      0  47.23   337
CHELAN  1210    647   1637     50      0      0      0      0  68.79    43    29.7  308.5 1098.0  341.5  308.3  308.5  FC
R RECH  1200  59404  68578      0      0      0      0      0  42.75   457
ROCK I  1170  61975  71149      0      0      0      0      0  36.08   209
WANAP   1165  62061  71235      0      0      0   2200      0  33.25   410
PRIEST  1160  62340  71514  36000      0      0   2200      0  27.60   413
BRNLEE*  767  14452  14452   5000      0      0      0      0  50.27   252     0.0  293.8 2045.0  491.7  411.2  293.8  PD
OXBOW *  765  14452  14452      0      0      0    100      0  50.27   112
HELL C*  762  14497  14497      0      0      0      0      0  50.27   215
DWRSHK   535   1060   1300   1300      0      0    100      0  93.13    51     7.2  388.6 1518.9  902.6  378.1  388.6  QL  SA
LR.GRN   520  22361  22600  11500      0      0    670      0  50.27   154     0.0  225.0  733.0  245.8   78.1  225.0  FC
L GOOS   518  22361  21783  11500      0      0    630      0  43.27   147   -24.5  285.0  638.0  285.0  128.6  285.0  UR  FC
LR MON   504  21657  20758  11500      0      0    750      0  36.30   142    -9.6  190.1  540.0  190.1   83.2  190.1  FC
ICE H    502  21647  20367   7500      0      0    740      0  29.20   137   -11.4  204.8  440.0  204.8   90.8  204.8  FC
MCNARY   488  79759  87654  50000      0      0   4000      0  22.23   458     0.0    0.0  338.7    0.0    0.0    0.0
J DAY    440  80738  88631  50000      0      0    800      0  16.76   664    -0.1  127.8  262.5  269.7  127.8  127.8  PD  FC
RND B    390   3154   3302   2800      0      0    200      0  47.09    81     4.4  131.9 1941.7  138.3  135.5  131.9  FC
PELTON   388   3354   3502   3000      0      0      0      0  21.10    33
REREG    387   3354   3502      0      0      0      0      0  11.74     8
DALLES   365  84499  92540  50000      0      0   4300      0   9.20   540
BONN     320  87725  95766      0      0      0   8400      0   4.86   424     0.0    0.0   74.1   -1.0    0.0    0.0  PL  UR
TMTHY    117     87    177     10      0      0      0      0  86.88     0     2.7   28.4 3186.1   31.1   29.2   28.4  FC
OK GRV   115    344    434      0      0      0      0      0  86.88    27
NFORK    111    822    912      0      0      0      0      0  23.89     9
FRDAY    110    822    912      0      0      0      0      0  13.99     8
R MILL   108    822    912      0      0      0      0      0   5.10     5
SWFT 1    82    715    555      1      0      0      0      0  69.69    16    -4.8  219.4  997.2  225.4  225.4  219.4  FC
SWFT 2    80    715    555      0      0      0      0      0  40.59     5     0.0    0.0  603.0    0.0    0.0    0.0  FC
YALE      78    837    561      0      0      0      0      0  32.34    10    -3.5   93.1  488.7   95.6   95.6   93.1  FC
MERWIN    76    933   1475    800      0      0      0      0  13.77    20    24.6   62.4  224.4   92.1   63.2   62.4  FC
PCKW L*   63     56     56     10      0      0      0      0  40.54     0     0.0    0.0 2850.5    1.4    0.0    0.0  FC
MOSSYR    48   1194   3957   2858      0      0      0      0  40.54   103    82.9  566.3  763.0  654.3  654.3  566.3  FC
MAYFLD    42   1336   4099   3000      0      0      0      0  14.63    57
------------------------------------------------------------------------------------------------------------------------------
                       RESULTS FOR SEPTEMBER  (PERIOD  1)     WATER YEAR 1929          INTERLACE PERIOD    3

PHASE                DESIRED  ACTUAL = (REGUL  + INDEP   - PUMP)     SPILL   MICA+RVL  DRAFT PT    DRAFT
------------------      MW       MW       MW       MW       MW        MW       MW                 MW-MO
PROPORTIONAL DRAFT  12145.0   9300.8   8770.8    667.0    137.0        0.             6.000000
MICA NON-TRTY (BC)   1046.1      0.0      0.0                          0.        0.  MAX STORE    0  MAX RETURN    0
MICA NON-TRTY (US)   1020.8      0.0      0.0                          0.        0.  MAX STORE    0  MAX RETURN    0
ALLOCATE SPILL                   0.0      0.0                          0.
FINAL OPERATION     12145.0   9300.8   8770.8    667.0    137.0        0.                         7419.
ENERGY CONTENT (MW-MO) RELATIVE TO TARGET  54683. 33 PLANTS ABOVE BY  54683.     0 BELOW BY       0.
ENERGY CONTENT (MW-MO) RELATIVE TO ECC   1807.  TO PDP(AER)      0.
THE DALLES FLOW AT URC=      0.  ECC=      0.  TREATY=  92540.  FINAL=  92540.
```

Figure P-43: Sample from a BPA HYDSIM Regulator BPARegu.out file

Name	Cap (MW)	ownership	regulated	location
Albeni Falls	43	Fed	Reg	OR/WA
Alder	50	Non-Fed	Reg	OR/WA
American Falls	92	Non-Fed	Unreg	ID
Anderson Ranch	40	Fed	Unreg	ID
Arrow (CAN)				CAN
Big Cliff	18	Fed	Unreg	OR/WA
Big Creek (Flathead Irr Prj, MT)	1	Non-Fed	Unreg	MT
Black Canyon	10	Fed	Unreg	ID
Bliss	75	Non-Fed	Unreg	ID
Boise Diversion (USBR)	2	Fed	Unreg	ID
Bonners Ferry gage				ID
Bonneville	1093	Fed	Reg	OR/WA
Boundary	951	Non-Fed	Reg	OR/WA
Box Canyon (PEND)	60	Non-Fed	Reg	ID
Brill (CAN)				CAN
Brownlee	585	Non-Fed	Reg	ID
Bull Run (PGE)	21	Non-Fed	Unreg	OR/WA
C.J. Strike	83	Non-Fed	Unreg	ID
Cabinet Gorge	222	Non-Fed	Reg	ID
Calispel Creek	1	Non-Fed	Unreg	ID
Canal (CAN)				CAN
Carmen Smith	90	Non-Fed	Unreg	OR/WA
Cascade (IDPC)	12	Non-Fed	Unreg	ID
Cedar Falls (SCL)	20	Non-Fed	Unreg	OR/WA
Chandler	12	Fed	Unreg	OR/WA
Chelan	48	Non-Fed	Reg	OR/WA
Chief Joseph	2457	Fed	Reg	OR/WA
City of Idaho Falls	42	Fed	Unreg	ID
Clear Lake (IDPC)	3	Non-Fed	Unreg	ID
Clearwater 1,Clearwater 2	41	Non-Fed	Unreg	OR/WA
Coeur D'Alene Lake gage				ID
Columbia Falls gage				MT
Condit	10	Non-Fed	Unreg	OR/WA
Copco 1	20	Non-Fed	Unreg	OR/WA
Copco 2	27	Non-Fed	Unreg	OR/WA
Corra Linn (CAN)				CAN
Cougar	25	Fed	Unreg	OR/WA
Cowlitz Falls (Lewis Co PUD)	70	Non-Fed	Unreg	ID
Cushman 1	43	Non-Fed	Reg	OR/WA
Cushman 2	81	Non-Fed	Reg	OR/WA
Dalles	1807	Fed	Reg	OR/WA
Detroit	100	Fed	Unreg	OR/WA
Dexter	15	Fed	Unreg	OR/WA
Diablo	123	Non-Fed	Reg	OR/WA
Duncan (CAN)				CAN
Dworshak	400	Fed	Reg	ID
Electron	26	Non-Fed	Unreg	OR/WA
Faraday	35	Non-Fed	Reg	OR/WA
Fish Creek	11	Non-Fed	Unreg	OR/WA
Foster	20	Fed	Unreg	OR/WA
Gorge (SCL)	207	Non-Fed	Reg	OR/WA
Grand Coulee	6494	Fed	Reg	OR/WA
Green Peter	80	Fed	Unreg	OR/WA
Green Springs	16	Non-Fed	Unreg	OR/WA
Hells Canyon	392	Non-Fed	Reg	ID
Henry M Jackson (Snohomish PUD)	112	Non-Fed	Unreg	OR/WA
Hills Creek	30	Fed	Unreg	OR/WA
Hungry Horse	428	Fed	Reg	MT
Ice Harbor	603	Fed	Reg	OR/WA
Iron Gate	18	Non-Fed	Unreg	OR/WA
Island Park Hydroelectric Proj	5	Fed	Unreg	ID
John C Boyle	80	Non-Fed	Unreg	OR/WA
John Day	2160	Fed	Reg	OR/WA
Kerr	168	Non-Fed	Reg	MT
La Grande	64	Non-Fed	Reg	OR/WA
Leaburg	14	Non-Fed	Unreg	OR/WA
Lemolo units 1& 2	62	Non-Fed	Unreg	OR/WA
Libby - USCEPD	525	Fed	Reg	MT

Figure P-44: Facilities Contributing to Hydrogeneration (1/2)

Off-peak (168-6x16) hours are a subset of the hours to which *X* pertains. Therefore, the off-peak power is exactly *X*. The sustained peaking information is from reference [**13**], which provides relationships between 2-, 4-, and 10-hour sustained peak capacity as a function of system energy for each month.

The special Council application [**14**] that parses the BPAREGU.OUT file uses the appropriate number of on- and off-peak hours for each month to estimate average on- and off-peak power (MW). For the regional model, another Council application reduces these data to hydro year quarters [**15**].

Worksheet Function and Formulas

Turning to the worksheet function that provides this data to the regional model, we note that several versions of the function exist and are available to the public. One of these, for example, is an Excel add-in that provides monthly energies in both megawatt-hours and average energy, on peak and off peak, as well as sustained, 10-hour peak generation for the region, for each stream flow condition, and separately for or combined east and west of the Cascades. The version used in the regional portfolio model, however, is not an Excel add-in, but instead a VBA function that reads a worksheet ("For AddIn ver 7") of data.[25] This section returns shortly to the description of this function.

The regional model uses hydrogeneration for three purposes, meeting energy requirements, influencing electricity price, and for planning long-term resource requirements. The influence on electricity price is discussed in the following section, "Electricity Price." For planning long-term resource requirements, the model uses critical hydrogeneration levels, which the model assumes remain constant. Consequently, this section outlines only the use of hydrogeneration for meeting energy requirements.

The discussion of hydrogeneration in Appendix L refers to the on-peak average MWh hydrogeneration in a specific, but representative cell, {AQ 36} in the example workbook L24DW02-f06-P.xls. (This is identical to cell {{AQ 36}} in L28_P.xls.) The on-peak calculation in {{AQ 36}} is

```
=(AQ33-300*AP$21/79)*1152
```

This differs from the formula in {AQ 36}, "=AQ33*1152," in the draft plan workbook. Between the draft and final plan, the Council added a loss of hydroelectric availability over the twenty years of the study. The beginning of this section describes the reasons for this loss. The loss is deterministic and increases linearly with time to 300MWa by the end of the study. Incorporating that loss is what the additional term -300*AP$21/79 achieves.

[25] The use of Excel add-ins complicates the use of distributed computing with Decisioneering, Inc.'s CB Turbo®, described in Appendix L. Each machine would have to be equipped with a copy of the add-in, so changing any logic in the add-in becomes burdensome.

The cell {{AQ 33}} references the VBA function that provides average MW for the period:

=vfuncHydro4x2W($R$24:$CS$24,1)

VBA function vfuncHydro4x2W takes as its first argument a range containing cells that assume random, real values – one for each hydro year – between 0.0 and 50.0. In the preceding example of {{AQ 33}}, the range is $R$24:$CS$24. These real numbers determine the stream flow condition for the hydro year (September through August of the following year). We return to this determination in a moment.

After the range, the function takes integer that specifies the subregion for which hydrogeneration is requested. A zero designates hydrogeneration for east of the Cascades; the one in {{AQ 33}} designates hydrogeneration west of the Cascades.

The function returns a range two rows high and 80 columns wide, in the case of the regional model. The range contains cells with the hydrogeneration (MWa) for that subregion, for each period (column). The first row contains on-peak hydrogeneration; the second row contains off-peak hydrogeneration.

It may be helpful to examine the VBA function vfuncHydro4x2W from a couple of perspectives. The definition of the vfuncHydro4x2 function is as follows

```
Function vfuncHydro4x2(ByRef rYears As Range, ByVal lLoc As Long, Optional
        ByVal, lStartPeriod As Long = 0) As Variant

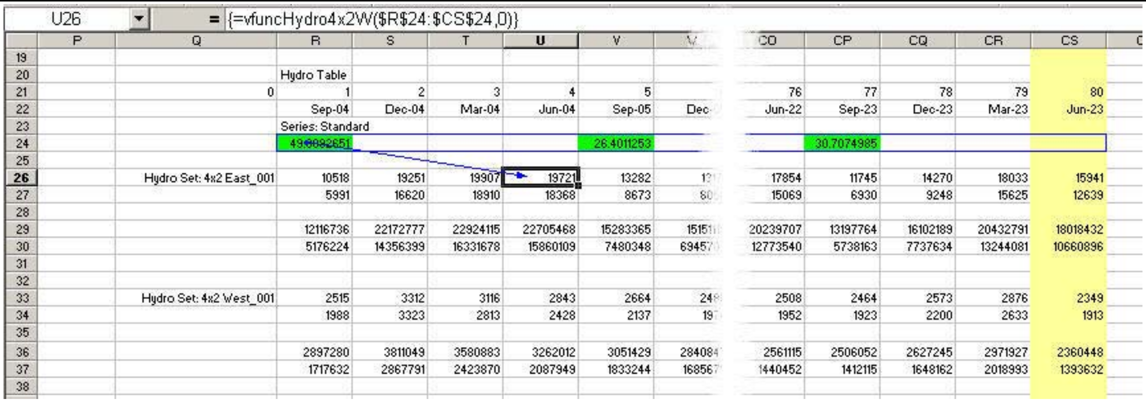
Takes:
rYears - Range, pointing to a vector of single [0.00-50.00] representing the years 1929-
        1978, sorted ascending by annual energy. For example, the user can have Excel
        pass 50 * rand() as sYear to this function to get draws of hydro condition.
        Ascending order permits user to correlate annual energy with other variable.  To
        access a particular year, use the sfuncYear() function, below.

lLoc - 0, East only
      1, West only
      2, East+West Generation

lStartPeriod - Optional'
      0, (default), Range of returned energies starts with Sep - Nov
      1, Dec - Feb
      2, Mar - May
      3, Jun - Aug
==============================================================
Returns:
      A variant containing an array of period Hydrogeneration (MWa) for east-side or
      west-side generation, or both.  The value of each element of the array corresponds
      to the value of the hydro year choice, for the appropriate region and subperiod
```

For a different perspective on what this function is doing, consider the auditing references in Figure P-45. The average MW of generation in cell {{U26}} is one entry of a range, {{R26:CS27}}, which the function is returning. The value of {{U26}} is the on-peak hydrogeneration East of the Cascades for a particular hydro year. For which hydro year does the function return generation? The function is returning the fourth quarter for the first hydro year, so it uses the random number a the beginning of the hydro year, cell {{R24}} from the input range {{$R$24:$CS$24}}.

To what historical hydro year do the values correspond? In Figure P-45, the random number in cell {{R24}} has the value 49.38926508. There are 50 years of hydrogeneration data. The generation returned is for the year, according to the rank by



U26 = {=vfuncHydro4x2W($R$24:$CS$24,0)}

	P	Q	R	S	T	U	V	W	CO	CP	CQ	CR	CS
19													
20			Hydro Table										
21		0	1	2	3	4	5		76	77	78	79	80
22			Sep-04	Dec-04	Mar-04	Jun-04	Sep-05	Dec	Jun-22	Sep-23	Dec-23	Mar-23	Jun-23
23			Series: Standard										
24			49.0092651				26.4011253			30.7074985			
25													
26		Hydro Set: 4x2 East_001	10518	19251	19907	19721	13282	13	17854	11745	14270	18033	15941
27			5991	16620	18910	18368	8673	80	15069	6930	9248	15625	12639
28													
29			12116736	22172777	22924115	22705468	15283365	15151	20239707	13197764	16102189	20432791	18018432
30			5176224	14356399	16331678	15860109	7480348	69457	12773540	5738163	7737634	13244081	10660896
31													
32													
33		Hydro Set: 4x2 West_001	2515	3312	3116	2843	2664	24	2508	2464	2573	2876	2349
34			1988	3323	2813	2428	2137	19	1952	1923	2200	2633	1913
35													
36			2897280	3811049	3580883	3262012	3051429	284084	2561115	2506052	2627245	2971927	2360448
37			1717632	2867791	2423870	2087949	1833244	168567	1440452	1412115	1648162	2018993	1393632
38													

Figure P-45: Hydro Function References

annual hydrogeneration energy, for lowest to highest. For example, the random number 49.38926508 lies in the last bin, (49,50], so the year with the highest annual hydrogeneration would be returned, in this case hydro year 1973-1974. If the random number had been 0.5 on the other hand (or any number less than 1.0), the function would return the driest year on record, 1931, as determined by total annual generation.

A separate function simplifies the process of getting data for a particular hydro year. The regional model does not use the function sfuncYear, but the Council would make it available to any party on request. It returns a real number corresponding to each hydro year that the vfuncHydro4x2 function returns. Its definition follows.

Function sfuncYear(ByVal lYear As Long, ByVal lType As Long) As Single
Takes a calendar year, e.g., 1937, and returns a real single with a value in the middle of the correct "bin" for that year, for use as input to vfuncHydroGen. For example, 1937 is the second lowest year for Eastside Hydro, in terms of annual energy and is therefore the second entry in vfuncHydroGen(*,0). Then sfuncYear(1937,0) = 1.5 (The first bin is [0,1), the second is [1,2), etc.

lYear - calendar year, as long
lType - 0, East Generation only
1, West Generation only
2, East+West Generation

This concludes the description of the model worksheet VBA function. This section next considers the assumed hourly behavior of hydrogeneration.

Name	Cap (MW)	ownership	regulated	location
Little Falls (WWPC)	32	Non-Fed	Reg	OR/WA
Little Goose	810	Fed	Reg	OR/WA
Long Lake	70	Non-Fed	Reg	OR/WA
Lookout Point	120	Fed	Unreg	OR/WA
Lost Creek	49	Fed	Unreg	OR/WA
Lower Baker	64	Non-Fed	Reg	OR/WA
Lower Bonnington (CAN)				CAN
Lower Granite	810	Fed	Reg	OR/WA
Lower Malad	14	Non-Fed	Unreg	ID
Lower Monumental	810	Fed	Reg	OR/WA
Lower Salmon	60	Non-Fed	Unreg	ID
Mayfield	162	Non-Fed	Reg	OR/WA
McNary	980	Fed	Reg	OR/WA
Merwin	136	Non-Fed	Reg	OR/WA
Mica (CAN)				CAN
Mill Creek	1	Fed	Unreg	OR/WA
Milner (IDPC)	59	Non-Fed	Unreg	ID
Minidoka	8	Fed	Unreg	ID
Monroe Street	15	Non-Fed	Reg	OR/WA
Mossyrock	300	Non-Fed	Reg	OR/WA
Nine Mile	26	Non-Fed	Reg	OR/WA
North Fork	38	Non-Fed	Reg	OR/WA
Noxon Rapids	467	Non-Fed	Reg	MT
Oak Grove	51	Non-Fed	Reg	OR/WA
Oxbow (IDPC)	190	Non-Fed	Reg	ID
Packwood	30	Non-Fed	Unreg	OR/WA
Packwood Lake gage				OR/WA
Palisades (USBRCO)	177	Fed	Unreg	ID
Pelton	97	Non-Fed	Reg	OR/WA
Pelton Re-Regulation	18	Non-Fed	Reg	OR/WA
Post Falls	15	Non-Fed	Reg	OR/WA
Priest Lake gage				OR/WA
Priest Rapids	923	Non-Fed	Reg	OR/WA
Prospect units 1-4	44	Non-Fed	Unreg	OR/WA
Revelstoke (CAN)				CAN
River Mill	19	Non-Fed	Reg	OR/WA
Rock Island Powerhouse	624	Non-Fed	Reg	OR/WA
Rocky Reach	1280	Non-Fed	Reg	OR/WA
Ross Dam	360	Non-Fed	Reg	OR/WA
Round Butte	247	Non-Fed	Reg	OR/WA
Roza	13	Fed	Unreg	ID
Seven Mile (CAN)				CAN
Shoshone Falls	13	Non-Fed	Unreg	ID
Slide Creek	18	Non-Fed	Unreg	OR/WA
Smith Creek (EWEB)	38	Non-Fed	Unreg	OR/WA
Snoqualmie	42	Non-Fed	Unreg	OR/WA
Soda Springs	11	Non-Fed	Unreg	OR/WA
South Slocan (CAN)				CAN
Stone Creek (EWEB)	12	Non-Fed	Unreg	OR/WA
Strawberry Creek (Lower Valley P&L)	2	Non-Fed	Unreg	ID
Swan Falls	25	Non-Fed	Unreg	ID
Swift 1	204	Non-Fed	Reg	OR/WA
Swift 2	70	Non-Fed	Reg	OR/WA
T.W. Sullivan	15	Non-Fed	Unreg	OR/WA
Thompson Falls (MPC)	93	Non-Fed	Reg	MT
Thousand Springs	9	Non-Fed	Unreg	ID
Timothy Lake gage				OR/WA
Toketee Falls	43	Non-Fed	Unreg	OR/WA
Trail Bridge (EWEB)	10	Non-Fed	Unreg	OR/WA
Twin Falls (IDPC)	44	Non-Fed	Unreg	ID
Upper Baker	105	Non-Fed	Reg	OR/WA
Upper Bonnington (CAN)				CAN
Upper Falls (WWP)	10	Non-Fed	Reg	OR/WA
Upper Malad	8	Non-Fed	Unreg	ID
Upper Salmon Falls	35	Non-Fed	Unreg	ID
Wanapum	1038	Non-Fed	Reg	OR/WA
Waneta (CAN)				CAN
Wells (DOPD)	774	Non-Fed	Reg	OR/WA
White River (PSPL)	70	Non-Fed	Reg	OR/WA
Yale	108	Non-Fed	Reg	OR/WA
Yelm (Centralia)	10	Non-Fed	Unreg	OR/WA

Figure P-46: Facilities Contributing to Hydrogeneration (2/2)

Hourly Behavior

Recall that there are two types of hydrogeneration in the regional model, the type that this section discusses, which does not respond to electricity market prices, and the market-price responsive type. Appendix L has a description of how the regional model captures the latter at the time step of a hydro year quarter. (See pages L-48 and L-106.)

At the hourly time step, there is certainly a difference for non-price responsive hydrogeneration on- and off-peak. Because the function vfuncHydro4x2W already accounts for these differences through separate returned values, however, the question of any remaining variation means variation *within* the respective subperiods. If there is any such residual variation in hydrogeneration, the model assumes it is small and uncorrelated with electricity price. The hydrogeneration valuation calculations in the model therefore implicitly assume a zero correlation between hourly hydrogeneration and hourly electricity market price. (See page L-50.)

Electricity Price

Many forecasters use long-term equilibrium price models to estimate future electric power prices. These models result in annual average electricity prices that equal the fully allocated cost of the plant used for expanding system capacity, which in the West is typically a combined-cycle combustion turbine (CCCT). While useful to understanding price trends, these models ignore the disequilibrium between supply and demand that is commonplace for electricity. Disequilibrium results from less than perfect foresight about supply and demand, inactivity due to prior surplus, overreaction to prior shortages, and other factors. Periods of disequilibrium can last as long as it takes for new capacity to be constructed or released, or surplus capacity to be retired or “grown into.” Resulting excursions from equilibrium prices can be large and are a significant source of uncertainty to electric power market participants. Because it is very difficult for an individual utility to exactly match loads and its own resources at all times, virtually all utilities participate in the wholesale market, directly or indirectly, as buyers and as sellers. This is particularly so when the region’s primary source of generation, hydroelectricity, is highly variable from month to month and year to year.

To capture these effects, the regional model must incorporate correlation of electricity prices with hydropower availability, loads, and natural gas prices. Correlation between electricity prices and load on the time scale of the hydro quarter should have the opposite sign of the correlation on the time scale of years. That is, demand elasticity of loads needs attention.

In addition, market prices must reflect changes in available generation relative to load. For a given load, additional generation tends to drive down electric power prices. In particular, if generation would initially exceed requirements, plus the region’s ability to export, prices will be reduced until generation equals loads plus export capability. Similarly, if generation is inadequate to meet requirements, given the region’s import capability, prices will increase until the situation is resolved, e.g., loads are reduced or the price induces sufficient generation.

Finally, electricity prices also exhibit substantial random variations due to conditions in other parts of the interconnected West and other factors that are not explicitly considered. These other factors include, for example, regulatory and legislative innovations and the introduction of new generation technologies.

This section begins with an overview of the construction of electricity prices in the regional model. It describes how the model accommodates the requirements just mentioned. The treatment addresses price averages at the time scale of the hydro quarter-year. The model uses electricity prices for energy requirement valuation, as input to various decision criteria, and for producing load elasticity, and the section explores those in turn. The section then traces the formulas in the sample Excel workbook portfolio model from the point where the discussion of Appendix L, "The Portfolio Model" leaves off. Finally, it elaborates on some of the hourly price behavior, which typically is different from that at the time scale of the hydro quarter.

Background

At its December 19, 2002, meeting, the Council's System Analysis Advisory Committee (SAAC) discussed the influence that various sources of uncertainty have on each other. Figure P-47 resembles the Influence Diagram that the SAAC used. Most of the influences are predictable. As hydro generation increases, for example, electricity prices should decrease. In the short term, increases in load, natural gas prices, and forced outages should push up the price of electricity.

There are hosts of factors besides regional hydro generation, load requirements, natural gas prices, and forced outage rates, however that influence regional electricity prices. (For brevity, we will refer to regional hydro generation, load requirements, natural gas prices, and forced outage rates as the "local variables" in the following.) First, the values of local variables do not capture the corresponding influences from outside the region. For example, economic recession and load reduction in California or the Pacific Southwest would probably have the effect of depressing electricity prices in the Pacific Northwest. Second, there are certainly factors that influence electricity price besides the four just identified. Over the long-term, technology innovation could easily trump the influence of these four. Unanticipated changes in legislation or the regulation of electricity could influence the availability of supply both within the region and outside the region. Changes in supply availability from outside what we traditionally think of as the region is another factor. Examples of these influences are regional Independent Power Producers (IPP) and California's initiative to implement a strong reserve margin. While it might be possible to model these individual factors explicitly, a surrogate for these effects is an unanticipated excursion in electricity price that is independent of the local variables. That is, such excursions are the primary means by which supply outside the traditional region's system influences regional costs.

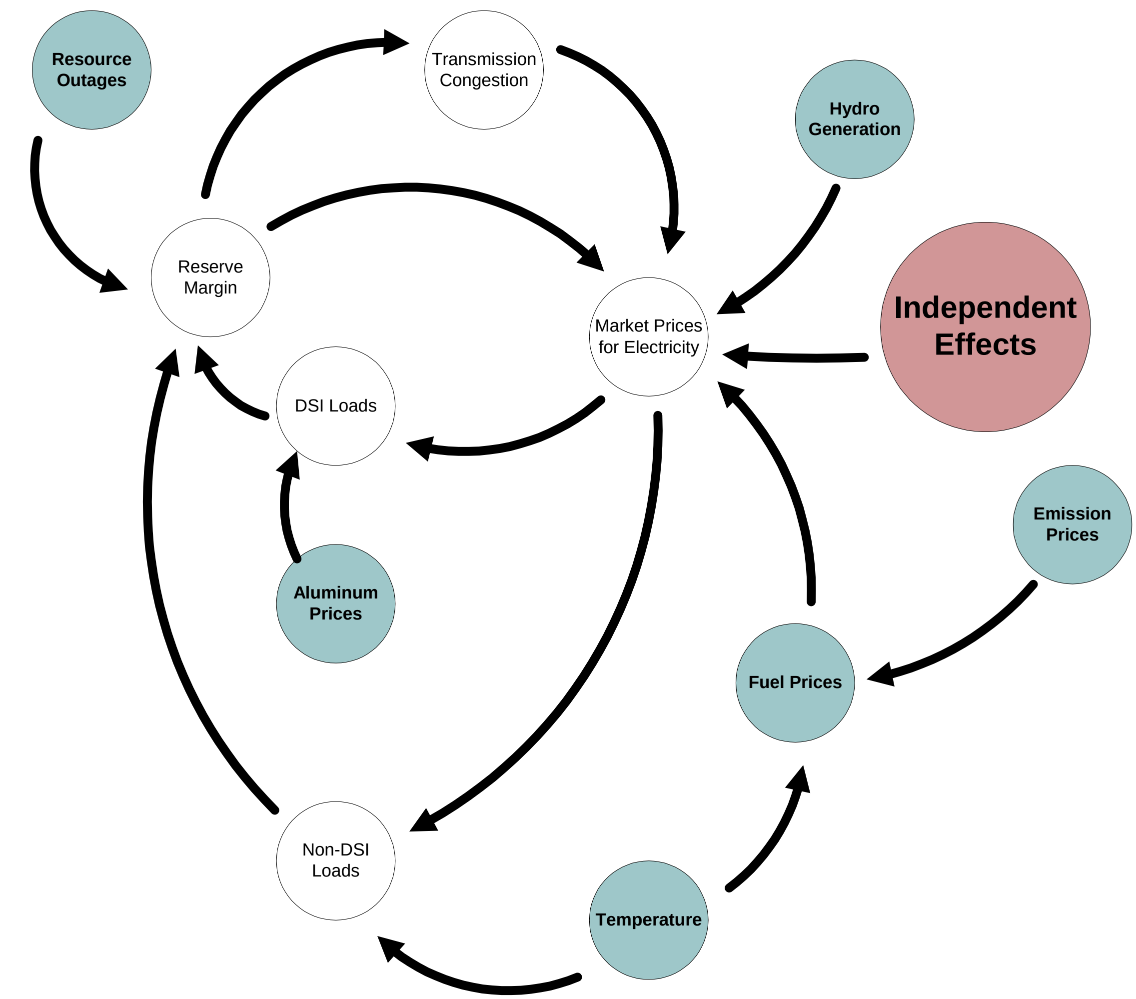


Figure P-47: Independent Term

The Council used Bench Mark Heuristics (BMH) to study the statistical behavior of electricity prices, transmission, load requirements, natural gas prices, hydro generation, and a host of other related data [**16**]. BMH studied each of the factors individually, and created a detailed regression model for each, using an ARMA process to simulate the error term. BMH then modeled the relationship between local electricity prices and local loads, natural gas prices, and hydro generation, seasonal, and weekday factors. Based on the best explanatory model BMH produced, local variables explain only about 43 percent of the change in daily electricity prices [**17**]. When markets are in transition, the influence of these local variables is even smaller. There is a significant amount of variation in electricity price behavior that local variables do not explain. Figure P-47 illustrates the influence of such Independent Effects with a conspicuous bubble.

Both local and independent effects, of course, work together to produce the final electricity prices. For modeling purposes, however, we conceive of these influences as follows. If in every period, loads and other local variables had “normal” values, what remained would be a path of electricity prices that must be the result of the independent effects. (The influence of independent effects, of course, could differ from "normal" conditions for all the reasons articulated in the previous paragraph.) To construct an electricity price series, therefore, it is valid to reverse this process. That is, it should be reasonable to apply the influence of loads, hydro generation, and a natural gas price to values representing the Independent Effect to obtain the resulting electricity price.

Unfortunately, we are not quite finished, because we may still need to adjustment for any energy imbalance. The section "The Influence of Resource-Load Imbalances" below, beginning on page P-74, discusses this adjustment issue.

The process just described is the one that the regional model uses to produce electricity price series. The next discussion focuses on the construction of the prices associated with Independent Effects. The subsequent discussion outlines the incorporation of influences for local hydro, load requirements, and natural gas prices. Forced outages influence prices to the extent that they affect energy imbalance.

The Independent Term for Electricity Price

The model constructs the Independent Effect for electricity price in a manner very similar to the way it constructs natural gas prices and loads. See the section, "Stochastic Process Theory," above for details. Underlying strategic paths for average price[26] are the sum of principal factors, jumps, and optionally a stochastic adjustment. (The final regional model does not make use of the stochastic adjustment.) The model applies this path separately to on- and off-peak prices from the Council's long-term, electricity equilibrium price forecast to obtain corresponding prices for the regional model.

The principal factors appear in Figure P-48. The model permits up to two jumps, and the values and formulas for those jumps appear in Figure P-49. Both principal factors and jumps, in turn, rely on stochastic variables in assumption cells, the data for which appear in Figure P-50. The values for all of these objects ultimately originate from SAAC and Council staff judgments about what seem to be realistic and feasible futures. (See the section "Model Validation," above.)

Pricipal Factors

	offset	linear
	Weight	
	1.000	1.000
Dec of Cal		
Year	Value	
2003	0.50	0.07
2004	0.50	0.14
2005	0.50	0.21
2006	0.50	0.28
2007	0.50	0.35
2008	0.50	0.42
2009	0.50	0.49
2010	0.50	0.56
2011	0.50	0.63
2012	0.50	0.70
2013	0.50	0.77
2014	0.50	0.84
2015	0.50	0.91
2016	0.50	0.98
2017	0.50	1.05
2018	0.50	1.12
2019	0.50	1.19
2020	0.50	1.26
2021	0.50	1.33

source: L28_P.xls

Figure P-48: Principal Factors for the Independent Component of Electricity Price

[26] Here average price refers to period (hydro quarter) average, across on- and off-peak hours. This is synonymous with "flat" market prices, where the average is with respect to on- and off-peak hours in whatever period is under discussion.

	R	S	T
99	29.35806	0.409331	11.08000719
100	22.56537	0.26246	10.60643151

Cell	Formula		interpretation
R101	=$R$99	wait_1	start time of jump 1
S101	=R101+ IF($S$99= 0,0,12/$S$99)	wait_1+ 12/size_1	end time of jump 1
T101	=$S$99	size_1	size_log xfr jump 1
U101	=S101	end time of jump 1	start time of recovery 1
V101	=U101+ S101*EXP(T101)	end time of jump 1 + duration recovery 1	end time of recovery 1
W101	=-T101/10	-size_1/10	size_log xfr recovery 1
X101	=V101+ $R$100	end time of recovery 1+ wait_2	start time of jump 2
Y101	=X101+ IF($S$100= 0,0,12/$S$100)	wait_2 + 12/size_2	end time of jump 2
Z101	=$S$100	size_2	size_log xfr jump 2
AA101	=Y101	end time of jump 2	start time of recovery 2
AB101	=AA101+ Y101*EXP(Z101)	end time of jump 2 + duration recovery 2	end time of recovery 2
AC101	=-Z101/10	-size_2/10	size_log xfr recovery 2

R102	= IF(AND(R$46>$R101,R$46<=$S101),$T101,0)+	jump_1	source: L28_P.xls
	IF(AND(R$46>$U101,R$46<=$V101),$W101,0)+	recovery_1	
	IF(AND(R$46>$X101,R$46<=$Y101),$Z101,0)+	jump_2	
	IF(AND(R$46>$AA101,R$46<=$AB101),$AC101,0)	recovery_2	

S102 identical, except S$46 instead of R$46
T102 identical, except T$46 instead of R$46

Figure P-49: Jump for Independent Component of Electricity Price

Random Variables

	Type	Cell	Distribution	Parameters		
Jump 1	wait	{{R99}}	**uniform**	min 0	max 80	
	size	{{S99}}	**uniform**	min 0	max 2.5	
	duration	**<------------------- not used ------------------->**				
Jump 2	wait	{{R100}}	**uniform**	min 16	max 36	
	size	{{S100}}	**uniform**	min 0	max 2.5	
	duration	**<------------------- not used ------------------->**				
Principal Factors	offset	{{R94}}	**triangle**	min -1	mode 0	max 1
	linear	{{R96}}	**triangle**	min -0.83	mode -0.33	max 1.17

source: L28_P.xls

Figure P-50: Assumption Cells for Independent Component of Electricity Price

The Influence of Loads, Natural Gas Price, and Hydro Generation

The BMH study [16] provides the foundation for estimating the influence of loads, hydro generation, and natural gas price, on Mid-C electricity price. This study identified a regression equation for electricity price against these other influences. The equation, of course, is only accurate for the specific series of electricity prices and values of local variables assumed in the study. One difficulty with this approach, however, is that we assume electricity prices to some extent independent from these other factors. The sensitivity to each of the influences, however, is implicit in the regression equation. By taking the difference between regression equations corresponding to two Independent sets of Independent variables we obtain a difference between two electricity price series. If we interpret this has the difference in electricity price due to changes in assumptions about the independent variables, we obtain the result we need.

The BMH model is of the form

$$\ln(P_e(t)) = \alpha_0 + \alpha_1 \ln(P_g(t)) + \alpha_2 L(t) + \alpha_3 H(t) + \varepsilon(t)$$

where

$P_e(t)$ is electric price ($/MWh) over interval t

$P_g(t)$ is gas price ($/MMBTU) over interval t

$L(t)$ is peak load (MW) over interval t

$H(t)$ is hydrogeneration (MWa) over interval t

$\varepsilon(t)$ is an error term with a specified ARMA structure, having zero mean

α_i are constants determined by a statistical estimation technique, such the effect of weekday

Coefficient		Value
α_1	ln(Sumas price $/MMBTU)	4.40E-01
α_2	Max Load (MW)	4.38E-05
α_3	Hydro (MWa)	-1.34E-05

Figure P-51: Electricity Price Sensitivity Coefficients

Given three specific series $P^*_g(t)$, $L^*(t)$, and $H^*(t)$, this model predicts a specific $P^*_e(t)$. Given a distinct, arbitrary series $P_g(t)$, $L(t)$, and $H(t)$ and the associated, predicted $P_e(t)$, we have the following description of differences in electric price, given differences in the independent variables.

$$\begin{aligned} \ln(P_e(t)) - \ln(P^*_e(t)) &= \alpha_0 + \alpha_1 \ln(P_g(t)) + \alpha_2 L(t) + \alpha_3 H(t) + \varepsilon(t) - \alpha_0 + \alpha_1 \ln(P^*_g(t)) + \\ &\qquad \alpha_2 L^*(t) + \alpha_3 H^*(t) + \varepsilon^*(t) \\ &= \alpha_1\left[\ln(P_g(t)) - \ln(P^*_g(t))\right] + \alpha_2\left[L(t) - L^*(t)\right] + \alpha_3\left[H(t) - H^*(t)\right] + \varepsilon'(t) \end{aligned}$$

where

ε' is a error term with the same properties as ε and ε^*

We note several things. First, we have lost the constant coefficient, alpha zero. Second, the price of electricity does not appear on the right-hand side of this equation. The sensitivity of electric price to our independent variables does not depend on the absolute electric price.

Now, handed another series $Q_e(t)$ that shares the same sensitivity as $P_e(t)$ to our independent variables, we would predict $\ln(Q_e(t))$-$\ln(Q^*_e(t))$ would be described by the right-hand side of the preceding equation, where $Q^*_e(t)$ represents the value of $Q_e(t)$ when the perturbations of the independent variables are all zero.

The last step, then, is to take $Q^*_e(t)$, $P^*_g(t)$, $L^*(t)$, and $H^*(t)$ as the expected values of the electricity price, gas price, loads, and hydrogeneration values the regional model begins with, before accounting for the effect of the last three variables on the first. This gives us a means of forecasting electricity price $Q_e(t)$ given our assumed expected values for the four variables and excursions in the three independent variables. By taking the exponent of both sides,

$$\ln(P_e(t)) - \ln(P^*{}_e(t)) = \alpha_0 + \alpha_1 \ln(P_g(t)) + \alpha_2 L(t) + \alpha_3 H(t) + \varepsilon(t) - \alpha_0 + \alpha_1 \ln(P^*{}_g(t)) + \alpha_2 L^*(t) + \alpha_3 H^*(t)$$

implies

$$P_e(t) = P^*{}_e(t) \cdot \frac{1}{c} \cdot P_g(t)^{\alpha_1} \exp\{\alpha_3 H(t) + \alpha_2 L(t)\} \qquad (13)$$

where

$$c = P^*{}_g(t)^{\alpha_1} \exp\{\alpha_3 H^*(t) + \alpha_2 L^*(t)\}$$

Note in particular that equation (13) consists of the product of three terms, the unadjusted electricity price, a term of the form

$$P_g(t)^{\alpha_1} \exp\{\alpha_3 H(t) + \alpha_2 L(t)\}$$

and a term that corresponds to the reciprocal of this expression, albeit with different values for certain variables. The section returns to the use of this expression later, at the discussion of "Worksheet Function and Formulas," below.

The Influence of Resource-Load Imbalances

After taking into the account of local influences, such as natural gas price, the resulting electricity price may prove to be infeasible, in a sense. The portfolio model assumes that dispatchable resources respond to market prices for electricity.[27] When a power system is unconstrained by transmission or other import/export limitations, one typically does not

[27] Strictly speaking, the assumption is that dispatchable resources respond to some explicit, widely visible signal of generation value. In the world before price deregulation, the measure of merit was "system lambda," which indicated the variable cost of generation on the system. Regulators among others sometimes refer to this concept as the "avoided cost." Economists refer to this kind of value as a "shadow price." It simply represents a means for assigning value to alternative means to meeting system requirements or the requirements of others. In describing the portfolio model, all of the arguments work if one substitutes these identical concepts for that of deregulated market price for electricity.

have to worry about whether a given market price is somehow infeasible. Higher prices simply mean more generators will run.

If a lot of new generation capacity arrives in the region, the region produces more MWh of energy at the same wholesale electricity market price level. Now if loads are unchanged and exports are constraining, prices must fall to balance demand. Electricity prices are neither completely independent nor completely dependent of other variables. If the price is high, the resulting generation, after exports, may be surplus to requirements. Energy must be conserved, however: energy consumed must equal energy produced. In this example, the price must fall until the situation becomes feasible. The situation will be feasible when generation equals loads plus exports. Similarly, if the price is high, the resulting generation, after imports, may be inadequate for our requirements. The price must rise.

The Resource-Responsive Price (RRP) algorithm in the regional model finds a price that balances the system's energy. It does this by iteratively adjusting the price. Appendix L, in the section "RRP Algorithm," beginning on page L-51, describes this process in detail. Although this adjustment is made infrequently, keep in mind that it may be necessary and is part of the model logic. The RRP adjustment is also the principal means by which the model captures the influence of surplus and deficit resources and of forced outages.

<u>The Application to Decision Criteria</u>

The regional model makes extensive use of spot electricity prices for estimating forward electricity prices and future spot prices. The philosophical basis for this choice is the observation that forward prices and estimates of future spot prices generally track existing spot prices, as discussed in the section "Gas Price" and illustrated in Figure P-39 above. For forward electricity prices, the argument received fortification in March 2003, when FERC staff released their final analysis of "Price Manipulation in Western Markets," which features a section on "The Influence of Electricity Spot Prices on Electricity Forward Prices"[22]. After examining prior analyses and studying the relationship between the prices, the report concludes "the forward power contracts negotiated during the period 2000-2001 in western United States were influenced by then-current spot prices, presumably because spot power prices influenced buyers' and sellers' expectations of spot prices in the future."

Because the horizon that a planner must consider depends in a sensitive fashion on the particular decision, technology, or power plant type she is considering, the role of electricity prices in each decision criterion differs. For this reason, Appendix L addresses their role in each specific criterion. (See section "Decision Criteria," beginning on page L-80 of Appendix L.)

In all cases, an average of current electricity prices over some brief history determines the influence on the decision criterion. When this section turns to "Worksheet Function and Formulas," it will identify the specific average and describe its formula.

The Application to Load Elasticity

Load elasticity played an important role in the history of the Council. Arguably, it was a failure to recognize load elasticity that was responsible for some of the region's planning failures in the 1970s and was therefore the impetus for creating the Power Planning Council.

Despite the prominence of the issue of load elasticity, the first versions of the regional model did not attempt to address it. The primary reason for this is that the effect of load elasticity is small relative to the load uncertainty that the model already incorporated. That is, because the regional model must already address futures where loads are much lower than could be accounting for price elasticity alone, it would seem unnecessary to include this smaller influence.

At the SAAC meetings where the Council Staff presented the representation of load behavior, however, several of the participants felt uncomfortable that there was no separate accounting for this effect. Ultimately, the Council Staff agreed that if for no other reason than to simplify the communication around treatment of load, it would be easier to include price elasticity explicitly.

Dr. Terry Morlan, who has prepared prior Council load forecasts, provided the basic characterization of price elasticity [**18**]. As we use the expression here, price elasticity of load is the change in load induced by a change in price over some specified time period.

$$\varepsilon_{l,p} = \frac{\Delta L}{L} \bigg/ \frac{\Delta P}{P} = \frac{\Delta L}{L}\frac{P}{\Delta P}$$

where *L* and *P* are the load and price, respectively, at the beginning of the period. His sources indicate that the price elasticity over five years, which has a value of about -0.1, is less than that over 20 years, which he estimated at closer to -0.4. He said these factors would correspond to non-DSI retail rates, not wholesale price, which typically contribute about half to rate change. For a single year, and using wholesale prices, -0.02 max would probably be better figure for non-DSI loads. To understand the impact of this selection of values, examples may be helpful. A doubling in prices, say from \$30/MWh to \$60/MWh, well in line with changes the region has seen in the last couple of year, predict almost a 20 percent reduction in loads over 10 years, about 3600 MW. A one-year shock like the 2000-2001 energy crisis, where annual prices approached \$300/MWh would result in a similar change.

While at first glance, these seem comparable to changes the region has witnessed, in fact most of the change in loads corresponding to the 2000-2001 energy crisis is attributable to DSI load changes. (The regional model captures DSI loads separately. See the section on the principles of DSI modeling under the section "Multiple Periods" of Appendix L.) This level of elasticity therefore created unrealistic behavior – over-response of non-DSI load – in the regional model.

Another difficulty with modeling this level of elasticity in the regional model was that it seemed to create model instability. Feedback from load to price can create an undampened oscillation. High price can lower requirements load via elasticity, and low loads can depress electricity prices via the model's resource-responsive price (RRP) algorithm. One way to avoid this behavior is to use small elasticities, but without extensive study, it is not clear what the upper limit on the magnitude of the elasticities needs to be.

In the end, the model did incorporate load price elasticity, but the model caps their influence, and their magnitude is one-tenth of the original values. This section will return to formulas that implement the elasticity in the next discussion. The issue of how best to represent price elasticity, however, remains for now unresolved and potentially an area of research for the next plan.

Worksheet Function and Formulas

With these preliminaries, tracing the formulas in the sample workbook should be straightforward. As is the custom, the discussion begins with column {{AQ}}, December 2009 through February 2010.

This section deals with the East and West, on- and off-peak quarterly average prices. Energy, cost, and dispatch calculations use these, as well as the decision criteria and elasticity calculations. This section does not address the decision criteria, however, because each decision criterion uses electricity prices differently. Therefore, Appendix L addresses each specific criterion separately. (See section "Decision Criteria," beginning on page L-80 of Appendix L.) This section also does not describe the worksheet formulas for load price elasticity, because Appendix L addresses those as well. (See the discussion "Loads" under the section "Multiple Periods," beginning on page L-59 of Appendix L.)

We begin with the calculation of flat[28] prices. A number of decision criteria, e.g., the decision criterion for price-responsive hydro, use flat electricity prices. The calculation of the electricity prices in {{AQ 224}} is

```
=AQ$207*4/7 + AQ$219*3/7
```

which is the average of on- and off-peak prices for electricity west of the Cascades, weighted by the number of hours on and off peak.[29]

Tracing backward, the on-peak price in {{AQ 207}} has the formula

```
=AQ$204*(1.01)
```

[28] "Flat" market prices are average prices, where the average is with respect to on- and off-peak hours in whatever period is under discussion.

[29] There are 1152 hours on peak in a standard hydro quarter and 864 hours off peak. See Appendix L for more background about standard months and quarters. Then, for example, 4/7=1152/(1152+864).

This is the on-peak price for electricity East of the Cascades, with a one percent adder for losses and wheeling costs. The off peak price, AQ 219, has an identical formula that points to the off peak price for electricity East of the Cascades.

If we continue to trace the on-peak price, {{AQ 204}} has the formula

=AQ203+AQ200

This is the price adjustment in {{row 203}}, plus the unadjusted price in {{AQ200}}. The price adjustment in {{row 203}} does not contain any formulas. The RRP algorithm writes the values in this row. Appendix L, in the discussion of "RRP" from the section on "Multiple Periods" describes how this algorithm works to produce a price adjustment that balances energy requirements with energy sources.

The unadjusted on peak East of Cascades price in {{AQ 200}} uses the formula

=MIN(250, AQ$104*AQ$191*AQ$197)

This formula caps the East of Cascades prices at $250 a megawatt hour. The council chose this ceiling on electricity prices because it reflects the current limit imposed by the Department of Energy on west-wide prices in 2002.

The expression AQ$104*AQ$191*AQ$197 in the previous equation captures the influence of local hydro generation, loads, and natural gas prices on electricity prices. Referring to equation (13), the adjusted electricity price is the product of the unadjusted electricity price, times two factors of the form

$$P_g(t)^{\alpha_1} \exp\left\{\alpha_3 H(t) + \alpha_2 L(t)\right\} \qquad (14)$$

One of the factors is the reciprocal of this expression and includes parameters that describe "normal" values for hydro generation, loads, and natural gas prices. The other factor has these values for the particular future. In the workbook model, the value in {{AQ104}} is the unadjusted electricity price. The term {{AQ 191}} has the form in equation 14 with the values for hydro generation, loads, and natural gas prices from the current future. The term {{AQ 197}} has the reciprocal of the form in equation 14, with the values for expected hydro generation, base case loads, and base case natural gas prices. In the following, the section first traces the construction of the value in {{AQ 197}}. It then traces the value in {{AQ 191}}, and finally it proceeds with the construction of the unadjusted electricity price in {{AQ 104}}.

The formula in {{AQ 197}} is

=1/AQ$194^0.44/EXP(0.000045*AQ$195-0.000014*AQ$196)

which the reader will recognize as the constant 1/c in equation 13, page P-74. That is, {{AQ 194}} just points to the median forecast of natural gas prices in {{row 53}}. The cell {{AQ 195}} reconstructs the on peak west-of-Cascades load by multiplying the median load forecast by the on peak multiplier 1.14. (See discussion of this multiplier on page P-40, leading up to Figure P-25.) The value in cell {{AQ 196}} is the average on peak hydro generation for that period. The values in {{row 196}} are from reference [**19**].

The formula in cell {{AQ 191}} is

=AQ$178^0.44*EXP(0.000045*AQ$183-0.000014*AQ$188)

which is essentially identical except that it references the values for hydro generation, loads, and natural gas prices that manifested this particular modeling future.

Hourly Behavior

The regional model assumes a lognormal standard deviation of hourly electricity prices that are 10 percent of the respective on- and off-peak quarterly averages. This means, for example, that if the average on-peak electricity price over the hydro quarter is $35/MWh,

- 99.7 percent of the hourly on-peak prices would fall below $47.25,
- 95.4 percent of the hourly on-peak prices would fall below $42.75,
- 68.3 percent of the hourly on-peak prices would fall below $38.68,
- 31.7 percent of the hourly on-peak prices would fall below $31.67,
- 4.6 percent of the hourly on-peak prices would fall below $28.66, and
- 0.3 percent of the hourly on-peak prices would fall below $25.93

The distribution of prices is not symmetric because of the nature of the lognormal distribution. That is, there is greater up-side variation than downside variation. It is also true that, while there is substantial variation in monthly and quarterly prices, daily prices correlate with monthly prices, and hourly prices correlated to daily prices. There is more information available, and therefore more price variation seen, on the longer time scales.

The last section of this chapter will address the correlations of hourly electricity price with those of other variables, such as natural gas price and loads.

Comparison with the Council's Electricity Price Forecast

The Council electricity prices used in the final Plan and regional model L28 are from work that Council staff completed on October 21, 2004. (See Reference [**20**].) This section begins with a comparison of the Council's forecast with the independent term of the electricity price. Because this independent term represents the electricity price generated by the model before adjustments necessary to restore supply-demand balance, it is, in a sense, more directly comparable to the Council's price forecast. The final prices that resources see, however, can differ dramatically due to such adjustments. Therefore, the section also presents a statistical characterization across futures of the final, adjusted on- and off-peak prices for the Council's recommended resource plan.

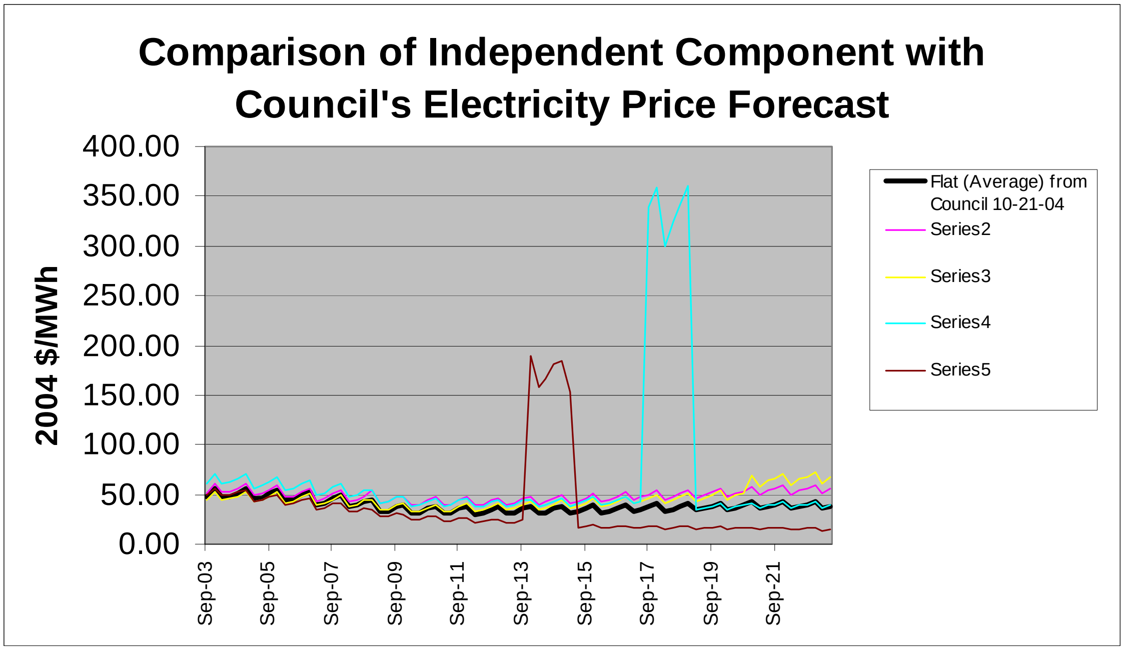


Figure P-52: Comparison of Independent Term Futures with Council's Electricity Price Forecast

The methods of principal factors, jumps, and specific variance described earlier produce the independent term of the electricity price. These use the Council's forecast as a median forecast. In Figure P-52, four random price futures appear along with the Council's forecast (the heavier line). This figure presents the average of the Council's forecast over each quarter, on- and off-peak.

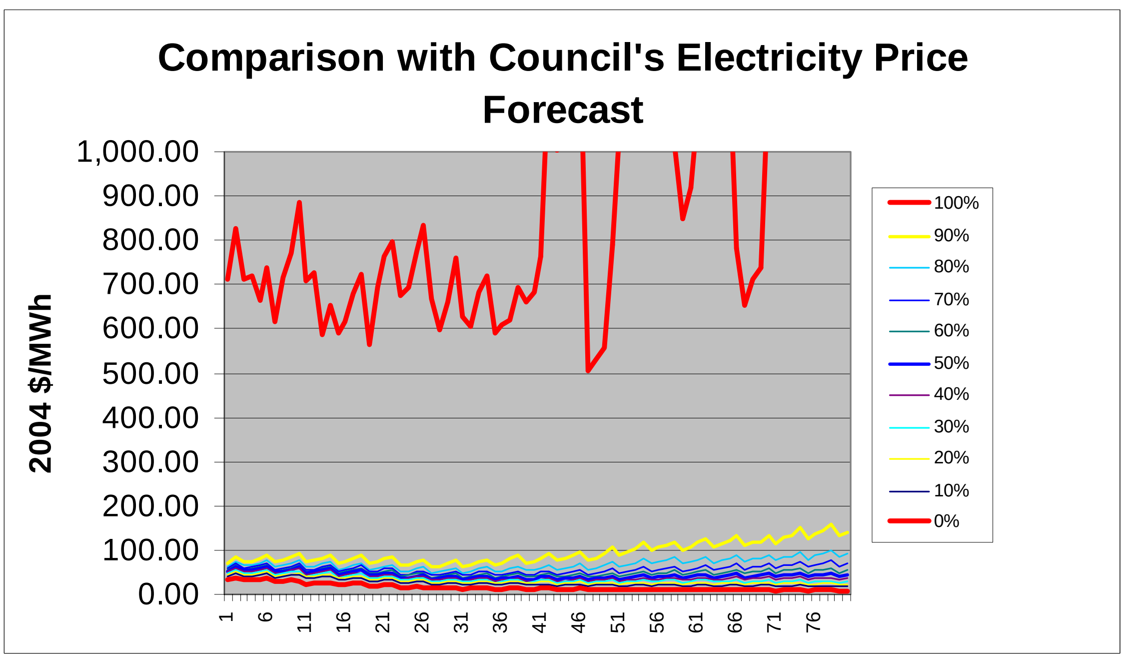


Figure P-53: Statistical Characterization of Independent Term Futures

There are price series both above and below the Council's forecast, but two of the forecasts have jumps that last a couple of years. To get a more representative idea of the likelihood of these excursions, a statistical representation is helpful. Figure P-53 shows the price deciles for the 750 futures. It is clear that prices above $150/MWh (2004$) are rare, occurring less than 10 percent of the time in each quarter, but their magnitudes can be quite significant. These low-probability events are largely due to the kinds of jumps illustrated in Figure P-52. Because the top decile dominates Figure P-53, the same information with that decile removed appears in Figure P-54.

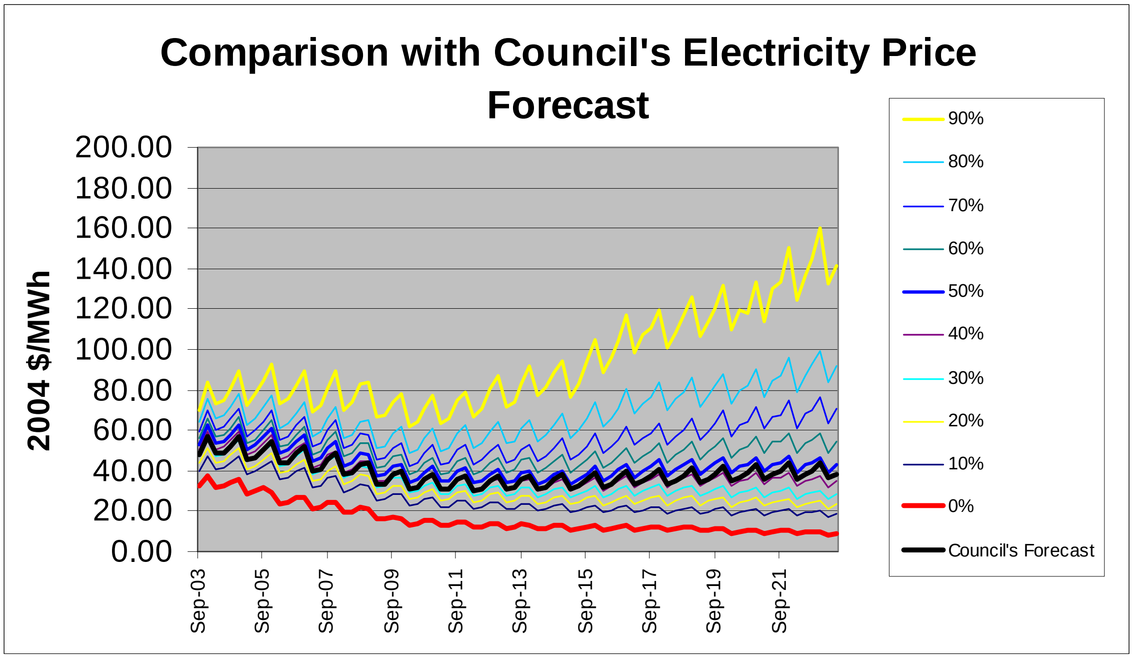


Figure P-54: Statistical Characterization of Independent Term Futures (Lower 90 Percent)

One observation about the distribution of the regional model's electricity prices at this point is that the regional model's price median (50 percent decile) is slightly above the Council's forecast. The difference is small, less than $6.29/MWh and averaging $4.26/MWh. The reason for this difference is the influence of jumps. In early studies with electricity price, jumps had a recovery period that would cause their influence over time to average out. The recovery time was so long, however, that it precluded multiple jumps in a study. (One jump's recovery needed to finish before another jump could take place.) For this reason, the model uses a somewhat shorter jump recovery period, which produces a net lifting of median prices. This slight lifting effect, however, is not considered material to the analysis. One reason the effect is immaterial is that other influences on the independent term, described next, dwarf the lifting.

As described earlier, the influences of loads, natural gas price, and resource generation, including hydro generation, are significant in the regional model's electricity price. The effect is evident in Figure P-55 for the four futures appearing in Figure P-52. In Figure P-55, the prices are depressed in general from those in Figure P-52. This should not be

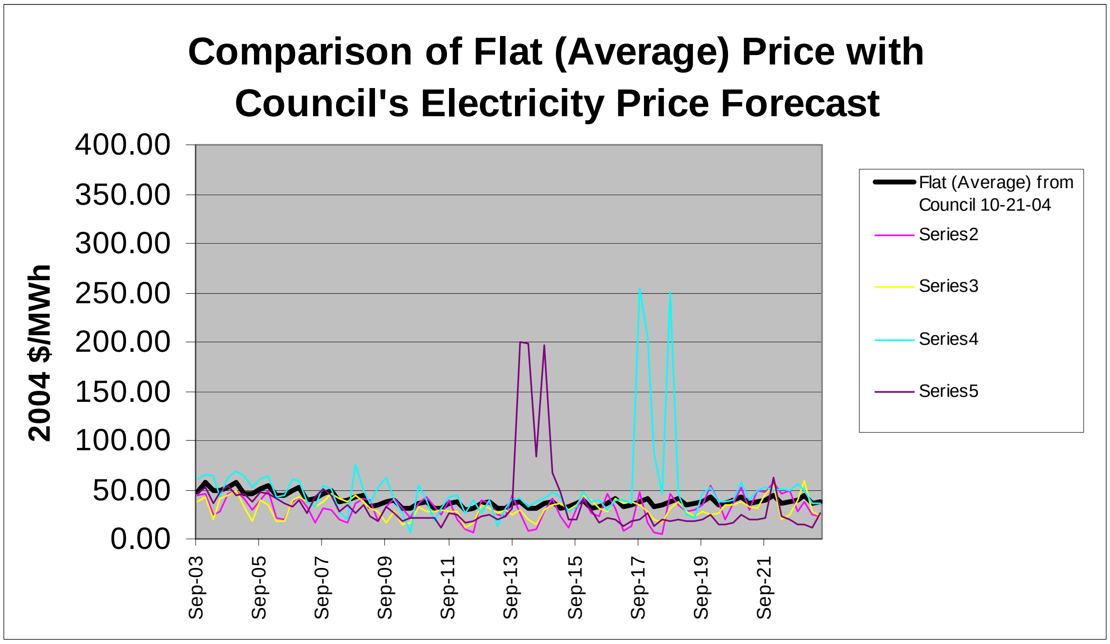


Figure P-55: Comparison of Futures after Adjustment with Council's Electricity Price Forecast

too surprising. The recommended resource plan, to which these price futures pertain, has significant resources in most futures. The downward pressure on electricity due to surplus resources alone will produce this effect.

A statistical comparison of the final on- and off-peak prices for the regional model to the Council's price forecast shows a similar pattern. While the median of independent term for electricity price is slightly above the Council's forecast, that for the regional model's

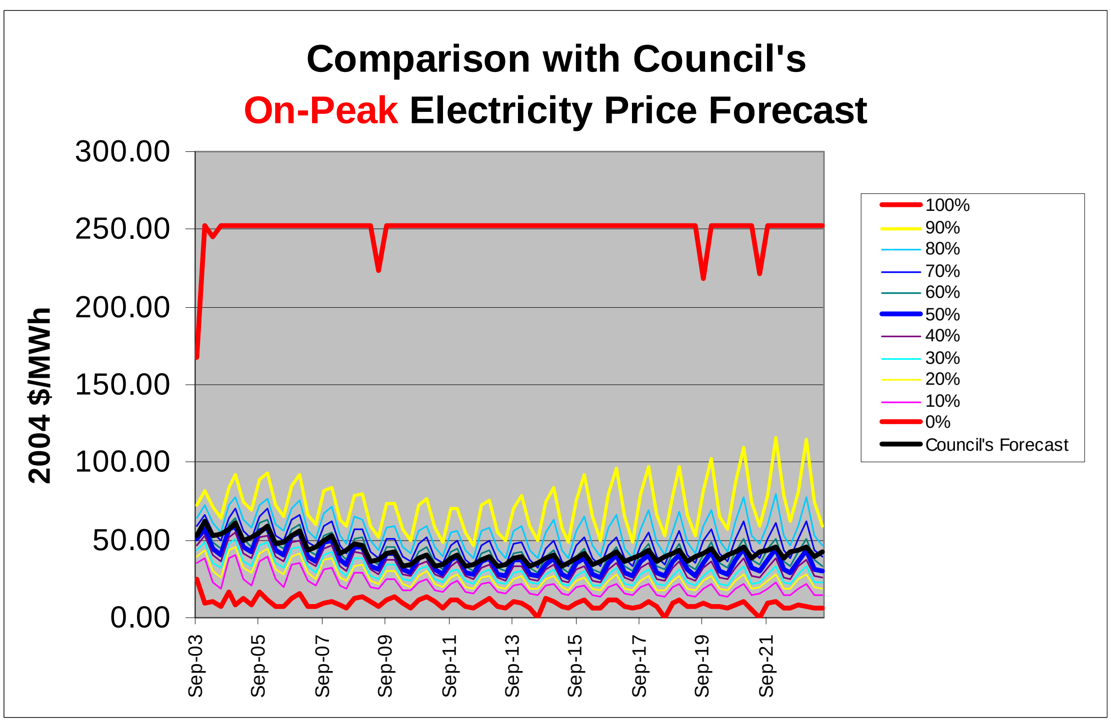


Figure P-56: Statistical Characterization of Futures' On-Peak Prices

on-peak price is slightly below that for the Council, as seen in Figure P-56. Another feature of the on-peak price distribution is that all prices are at or below $250/MWh. Actually, the ceiling price is slightly higher than $250/MWh, because the model assumes the cap applies to East-of-Cascades prices, and transmission costs cause the delivered price to West-of-Cascade loads to be higher. The reason for the ceiling is a cap imposed by the U.S. Department of Energy in June 2001.[30] The view of Staff and advisors is that this cap, or something like it, is likely to remain in place for the foreseeable future.

In Figure P-57, the off-peak price deciles from the regional model appear next to the Council's off-peak power price. As expected, the deciles general lie slightly below the corresponding on-peak price deciles.

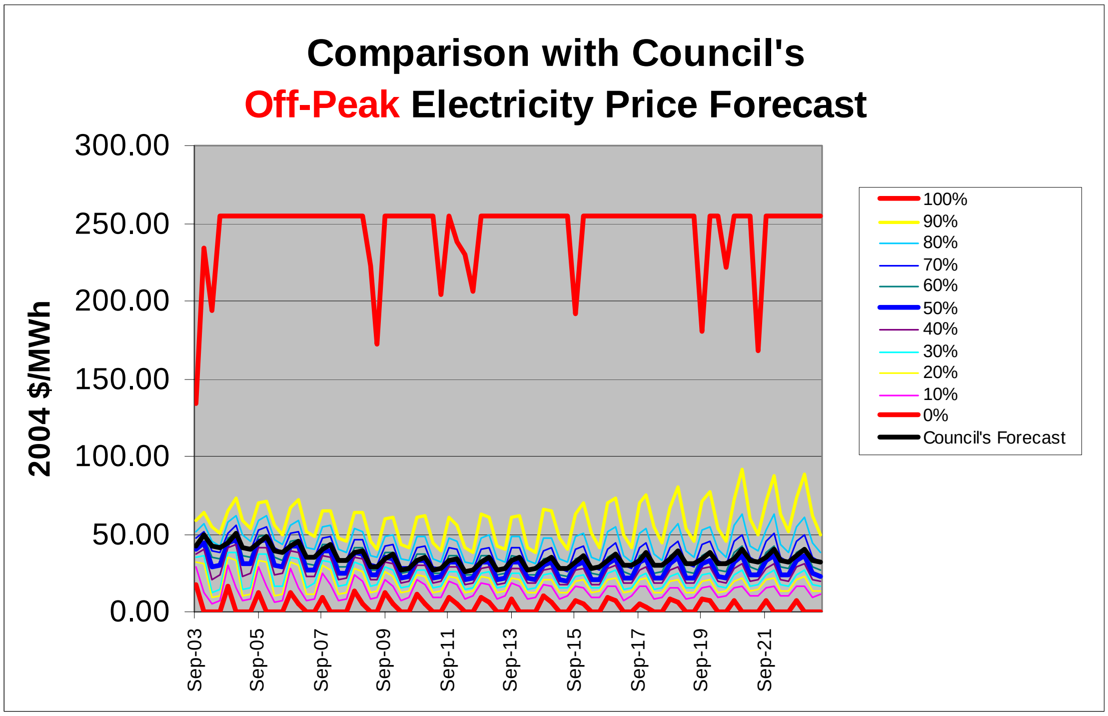


Figure P-57: Statistical Characterization of Futures' Off-Peak Prices

This concludes the discussion of electricity price and its associated uncertainty. A comparison of the regional model's prices with those of the Council's forecast shows some predictable differences. For the most part, however, there is general agreement, and the behaviors of the regional model's price futures appear reasonable.

[30] See, for example, Federal Energy Regulatory Commission, "Commission Extends California Price Mitigation Plan for Spot Markets to All Hours, All States In Entire Western Region," news release, June 18, 2001, EL00-95-031, EL00-98-030 and - 033, RT01-85-001 and -033, EL01-68-000 and –001.

Forced outage rates

Unplanned outages affect the availability of power plants. Although, by definition, planners cannot forecast when these outages may occur for a specific plant, an ensemble of power plants have predictable behavior over sufficiently long time period. This behavior has permitted the power generation industry to acquire estimates of forced outage rates (***FOR***s) for various kinds of generation technology.

If *H* is the number of hours in a sufficiently large period, and *h* is the number of hours we expect a plant to be unavailable due to forced outages, the ***FOR*** is defined to be *h/H*. The period must only be large enough for the ***FOR*** to have predictive significance. Unfortunately, this tells us very little about the frequency or duration of forced outages. That is, even if a planner where using the same period as that on which the statistic is based, he cannot tell how long or how frequently a plant should be out of service. Of course, the period a planner would use would typically be smaller than that of the statistical sample, further muddying the water. Typically, the planner simply derates each period's energy by the ***FOR***. Unfortunately, this eliminates the risk of extended outages that would nevertheless be consistent with the statistical value.

The traditional approach to modeling forced outages statistically is to use a binomial distribution. The binomial distribution represents events that are independent of each other and of all other parameters when these events have fixed likelihood. For existing power plants, creating a stochastic variable with this distribution is relatively easy. For new power plants, however, the situation is more challenging in the regional portfolio model. As the number of identical power plants increases, the availability of the ensemble of power plants becomes more predictable. Because each new plant actually represents an ensemble of plants in the regional model, and because the number of plants, or cohorts, changes not only from plan to plan but from future to future, creating exactly the right distribution of energy duration is not easy.

Because of these considerations, the regional portfolio model uses a simpler approach than incorporating a binomial distribution. Energy deration due to forced outages is random variable with a symmetric triangular distribution, with an average (and most likely) value equal to the ***FOR*** (see Figure P-58). The generation technology determines the expected availability of each plant in the regional portfolio model. A Fall 2003 reassessment of regional power plant outage rates [**21**] form the basis for the technology values. A summary of the regional model's final values of FOR appear in Figure P-59.

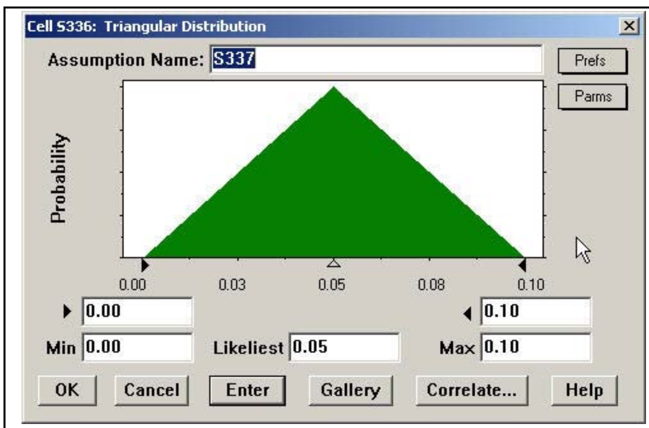


Figure P-58: Typical FOR Distribution (FOR=0.05)

SourcePType	Fuel Type	FOR
Hyd	Water	0.000
Wind	Wind	0.000
CCCT	MT gas	0.050
CCCT	PNW E. gas	0.050
CCCT	PNW W. gas	0.050
Biomass ST	Mill Residue	0.070
Coal	MT coal	0.070
Coal	N. NV coal	0.070
Coal	PNW E. coal	0.070
Coal	PNW W. coal	0.070
GT	PNW E. gas	0.070
GT	PNW W. gas	0.070
GTAero	PNW E. gas	0.070
GTAero	PNW W. gas	0.070
STCG	No. 2 FO	0.070
STCG	PNW E. gas	0.070
STCG	PNW W. gas	0.070
IC	No. 2 FO	0.080
IC	PNW E. gas	0.080
IC	PNW W. gas	0.080
Nuclear	WNP-2 nuclear fuel	0.090

Figure P-59: FOR Rates

In each future, the model makes a separate draw from the triangular distribution for each plant (or surrogate plant) for each hydro quarter. The energy of the plant over the period diminishes by a corresponding amount. For example, for the energy calculation for the plant "PNW West NG 5_006" in cell {{S339}}, one finds the references illustrated in Figure P-60. The reference to cell S336 in Figure P-60 is to this plant's FOR in this period. (The values in the assumption cell S336 happen to appear in Figure P-58.) As explained in Appendix L, the FOR must derate both the electric energy and the gas used.

For some plants, the model does not use this stochastic representation. For certain classes of resources, the model uses a simple capacity deration instead. These plants are those that are small, and would make trivial contribution to forced outages, and new units. For new units, the issue is the potential complexity, described above, associated with the changing number of units in the ensemble. Rather than introduce another source of complexity into the model that could influence the choice of new resources, by insisting on the use of a representation with known shortcomings, the model takes the simplest approach.

S339 = {=SpreadOption($P339, S$46,S$207-$R337,S$68+0.059*S$74,(1-S336)*1152*$S335,(1-S336)*1152*$S335*$I335,1,0,0,0,$R$201,$R$55,$T$14)}

	Q	R	S	T	U	V	W	X
333		Resources						
334	PNW West NG 5_006							
335	Capacity_ID: PNW West NG 5 Cap	487	503	390	432			
336	Expected FOR	0.04746901	0.040443308	0.053736452	0.038572008	0.070589275	0.028776688	0.066424
337	ariable_Cost ($/MWh): PNW West NG 5 VOM	3.02						
338								
339	Energy(MWh)	169103.1	1223.0	0.0	0.0	94317.0	180308.7	27320
340	Cost ($M)	-0.8	0.0	0.0	0.0	-0.3	-0.9	-
341	Capacity Factor (%)	30.2%	0.2%	0.0%	0.0%	16.8%	31.1%	48.
342								

Figure P-60: Calculations in Cell {{S339}}

Where the model uses the stochastic representation, the same availability is used both on- and off-peak. This makes sense, as an outage would not discriminate between these subperiods.

Finally, we point out that FOR is the only aspect of a future that is ***not*** computed in the range of the worksheet reserved for such calculations[31], although it could be and arguably should be. Keeping it with the resource facilitates review and verification of resource performance.

[31] The discussion "Logic Structure of the Portfolio Model" on pages P-15 ff identifies the specific range.

Aluminum Price

Aluminum smelters in the Pacific Northwest have represented a substantial portion of regional loads in the past. This introduces a source of uncertainty directly related to the relative price of aluminum and the price of wholesale power. When electric power is costly relative to aluminum prices, smelters will shut down. The portfolio model captures the relationship among varying aluminum prices, electricity prices, and aluminum plant operation. In addition, the analysis considers the likelihood of permanent aluminum plant closure if a plant is out of operation for an extended period. Given the future electricity and aluminum price trends and variations and absent some policy intervention, the portfolio model results show an 80 percent likelihood of all aluminum plants closing during the forecast period.

To represent aluminum price futures, the Council evaluated several approaches, and the approach that most closely matched historical price patterns is a geometric Brownian motion (GBM) process with mean reversion. Aluminum prices do not exhibit the seasonal shape that natural gas and electricity prices possess. Instead, they tend to wander away from a trend with quasi-cyclical excursions of varying regularity, as illustrated in Figure P-61. (See Reference [**22**].)

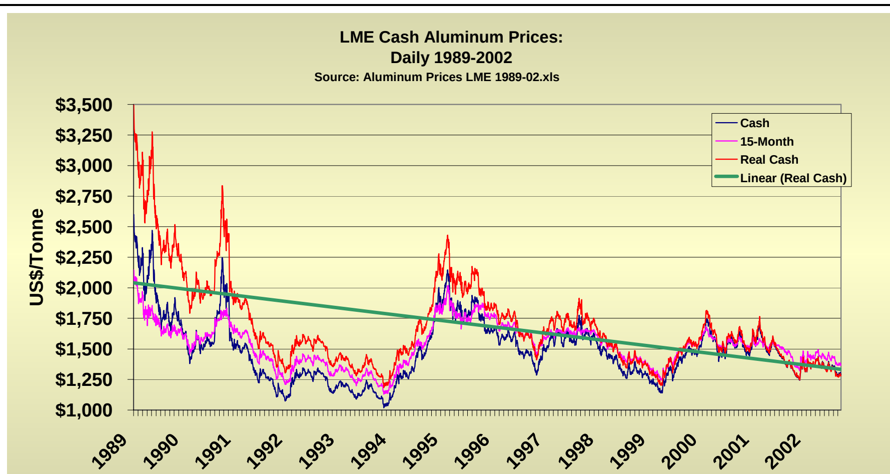


Figure P-61: Historical Aluminum Prices (2002 $/metric Tonne)

In Figure P-61, a linear regression line emphasizes the downward trend in aluminum prices that has been evident over the last 20 years or so.

The section "GBM with Mean Reversion," beginning on page P-25 describes the mathematical principles of the stochastic process. The regional model workbook implements the equations as follows:

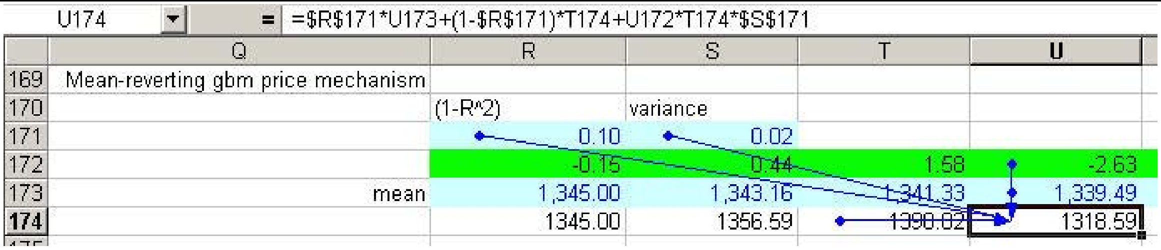


Figure P-62: Workbook Formula for GBM with MR

The formula

=$R$171*U173+(1-$R$171)*T174+U172*T174*$S$171

replicates the equation from the section "GBM with Mean Reversion,"

$$p_t + dp_t = p_t + a(b - p_t)dt + \sigma p_t dz = abdt + (1-a)\,p_t dt + dz \cdot p_t \sigma$$

where

p_t is stochastic variable in question

dp_t is the change in p_t from the previous step

dz is a drawn from a N(0,1) process

dt is the step size, which has value 1 for discrete processes

a is constant which controls the rate of reversion

b is the equilibrium level

σ is the standard deviation of p_t

(Note that the label "variance" in cell {{S 172}} of Figure P-62 is incorrect. This value is the standard deviation of the log-transformed aluminum prices. See Reference [**23**].) A Crystal Ball assumption cell provides an underlying Weiner process *dz* with the appropriate distribution (Figure P-63).

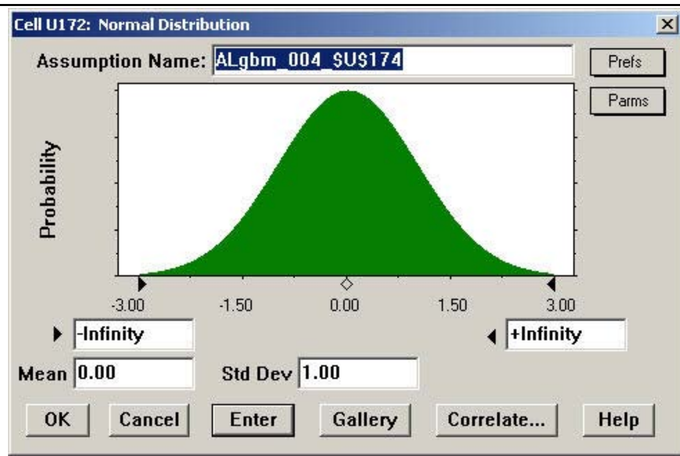


Figure P-63: Assumption Cell {{U 172}}

Figure P-64 illustrates the behavior of this process representation. The individual futures exhibit the same kind of irregular walk around the mean that does the historical data. The values are smoother, however, as expected from quarterly averages.

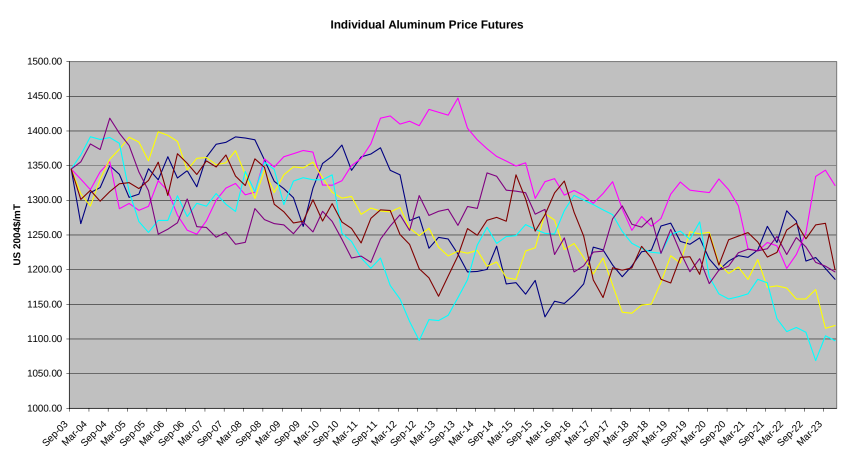


Figure P-64: Selected Aluminum Price Futures

Figure P-65 provides additional, statistical description of the aluminum price futures. It shows the quarterly deciles, plotted against the periods in the study. It is evident that the mean to which prices are reverting is trending down, consistent with the historical price behavior. The mean price descends from the May 2004 price of $1345/mT to $1200/mT (2004 $) by the end of the study (see Reference [**24**]).

CO2 tax

A significant proportion of scientific opinion holds that the earth is warming due to atmospheric accumulation of greenhouse gasses. The increasing atmospheric concentration of these gasses appears to result largely from combustion of fossil fuels. Significant uncertainties remain, however, regarding the rate and ultimate magnitude of warming and its effects. The possible beneficial aspects to warming appear outweighed by adverse effects. 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 United States could eventually enact federal climate change policy involving carbon dioxide control. Further discussion of climate change policy appears in Appendix M.

Because it is unlikely that reduction in carbon dioxide production will occur without cost, future climate-control policy is a cost risk to the power system of uncertain magnitude and timing. A cap and trade allowance system appears to be the most cost-effective approach to CO2 control. The model, however, uses a fuel carbon content tax as a proxy for the cost of carbon dioxide control, whatever the means of implementation. The effect on existing power plant generation and the economic value of new generation would be

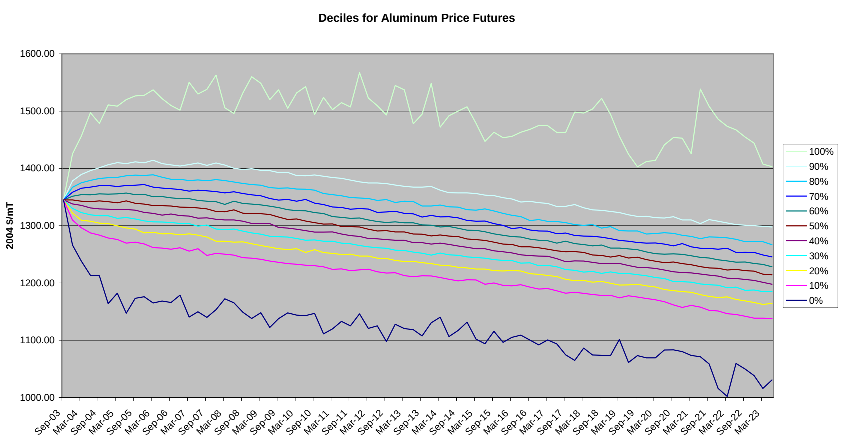


Figure P-65: Deciles for Quarterly Aluminum Prices

representative of any type of effort to control CO2 production using carbon-proportional constraints.

In the model, a carbon tax can arise in any election year.[32] (See Reference [**25**]) The probability of any such tax during the forecast period is sixty-seven percent. If enacted, the value for the carbon tax has a uniform distribution between zero and $15 per ton if it is enacted between 2008 and 2016; and between zero and $30 per ton if enacted thereafter (2004$). These draws are independent of other parameters, although other stochastic variables, like production tax credit, depend on CO2 tax. The two sections following this one describe the relationship.

[32] At a May 20, 2003 meeting held in the Council's main Portland office, experts on carbon tax were reluctant to speculate on the likelihood or magnitude on any carbon tax. There did appear to be agreement, however, that if the United States enacted a carbon tax, it would require the support of the Executive Branch of the U.S. Government. The change would likely arrive, therefore, with a change in administration.

The probability distribution of this stochastic variable was the subject of intensive debate during the development of the Plan. While authoritative studies[33] supported carbon tax as high as \$100/ton$_{CO2}$, the final values had as much to do with the principle of "thresholding" as with perspectives of what likely values might be. Specifically, increasing the CO_2 tax had little effect on the plans lying on the efficient frontier. Using higher values would therefore have only token value and would render the model results questionable among those who do not believe higher taxes are likely. Few participants, on the other hand, could argue for smaller probability and magnitude of tax. One third of the futures had no tax at all. The expected value tax rate in the regional model until 2020 is less than the expected value forecast that appeared in PacifiCorp's 2004 IRP [**26**].[34] PacifiCorp is heavily reliant on coal-fired power, the cost of which would be especially sensitive to carbon tax, and high future CO_2 tax-rate assumptions probably do not elevate PacifiCorp stockholder wealth. That is, PacifiCorp has little motivation to argue for high likely CO_2 tax rate.

Given what some might consider such a low expected CO_2 tax rate assumption, did the tax matter? It did, but for reasons that may require explanation. First, in a risk model, the extreme values are as important as the expected value, and the high end of the range exceeded what some would consider likely, as it should. Second, what drives much of the resource selection in the regional model is not a single source of risk, such as CO_2, but combinations of risks. Each independent source of risk adds to the expected net cost of the resource. For coal-fired power plants, for example, lack of planning flexibility, capital cost exposure, and load uncertainty were equally issues affecting economic feasibility.

Figure P-66 has six of the first CO_2 tax futures, although in two of those futures no tax arrives. In each future, there is at most only one arrival of taxes, and it occurs as a step. This is, in fact, the way the regional model represents CO_2 tax in all futures. However, the *maximum* size of the step depends on the year it happens, as mentioned earlier.

[33] See, for example, ***MIT Joint Program on the Science and Policy of Global Change***, *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States, The McCain-Lieberman Proposal*, Report 97, June 2003, available at http://mit.edu/globalchange/www/reports.html#r100

[34] PacifiCorp used \$8.00/ton$_{CO2}$ (2008 \$) beginning in 2010 or about \$7.38 in 2004 dollars using PacifiCorp's inflation assumption of 2.02 percent. Their study discounted this value in the first two years only to \$3.69 (2004 \$) in 2010 and to \$5.54 (2004 \$) in 2011. (See Table C.7, and supporting discussion in Appendix C, page 37 of the PacifiCorp 2004 IRP, Technical Appendix.) The regional model's expected tax rate grows and surpasses PacifiCorp's by less than \$0.46 only in the last three years of the study.

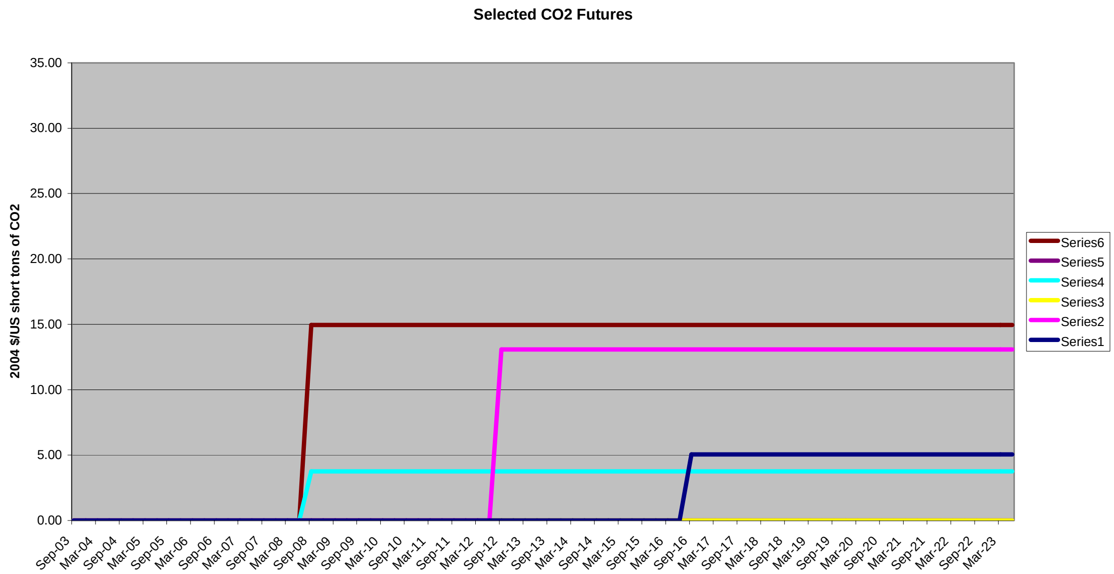


Figure P-66: Selected CO2 Futures

Figure P-67 provides some descriptive statistics across periods. In addition to the deciles the reader has seen in prior illustrations, the graph includes the average CO_2 tax across all futures. (A dotted line identifies the average.) One of the striking features of this graph is the non-appearance of the deciles below 40 percent. Those deciles all lie on the zero-tax line. On reflection, however, this is consistent with the earlier observation that approximately a third of the futures contain no tax.

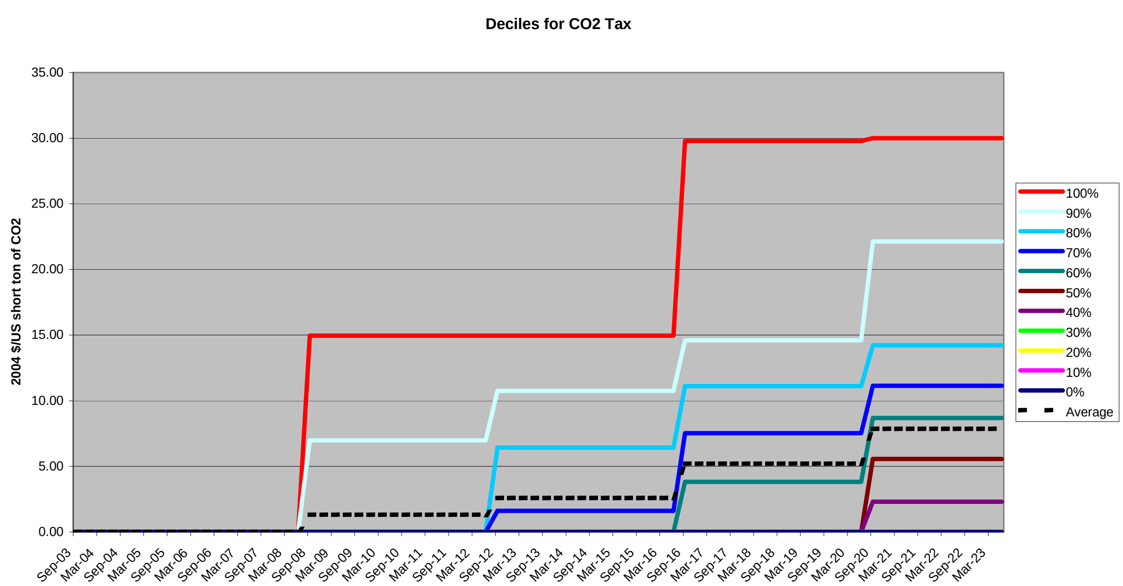


Figure P-67: CO2 Statistics

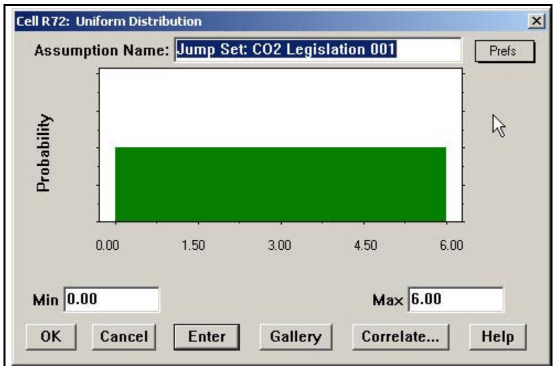


Figure P-68: Timing

To capture this behavior in the workbook, only two Crystal Ball assumption cells are necessary. The first one, {{R72}}, illustrated in Figure P-68, controls the timing of step. It is a uniform distribution from 0.0 to 6.0. The explanation for the range of this random variable becomes evident in a moment. The second assumption cell, {{S72}}, illustrated in Figure P-69, determines the size of the step.

The model first determines in which column any step takes place, as shown in Figure P-70. The formula in cell {{T72}}, for example, is

=IF(T$46>4+INT($R72)*16, $S72,0)

This formula compares the period ({{T46}}) to one of the values 4, 20, 36, 52, 68, or 84, which {{R72}} determines and which each occurs equal likelihood. (The value 100, corresponding to {{R72}} having value 6.0, has probability zero.) These period values correspond to the period September through December of each election year. If the column's period number exceeds this value, it assumes the value in cell {{S72}}, which will determine the size of the step.

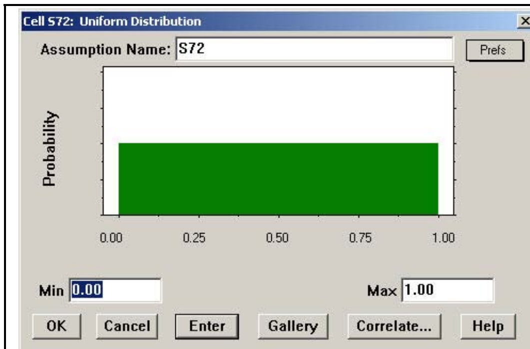


Figure P-69: Size

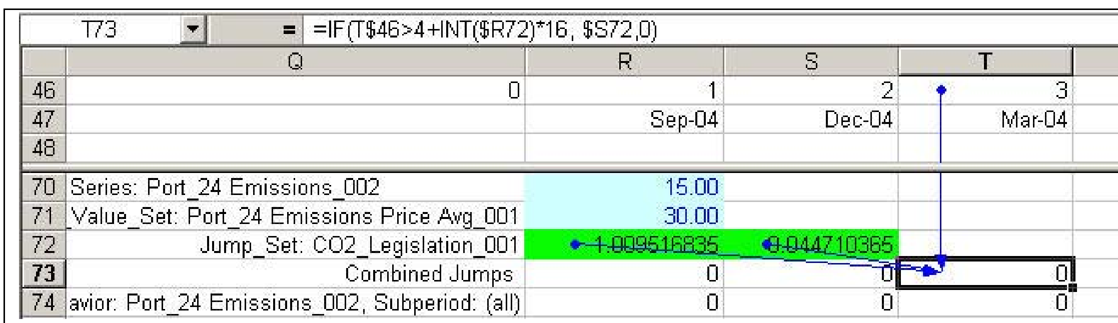


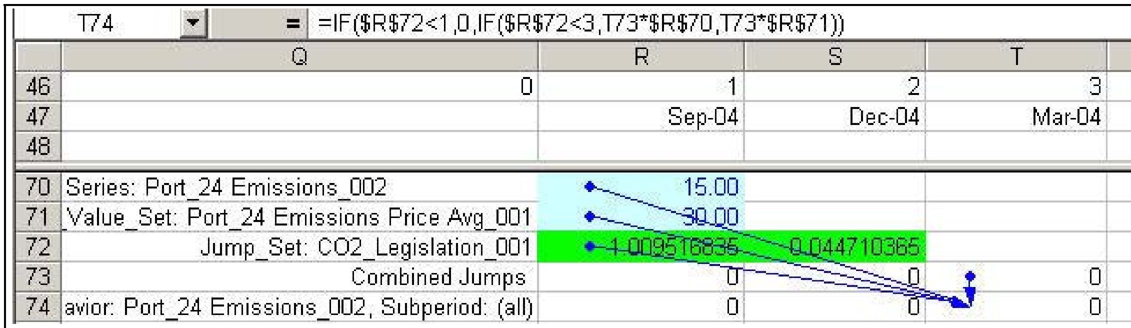
Figure P-70: Normalized Step

At this point in the calculation, the values in {{row 73}} have the value in cell {{S72}} if they belong to periods after the first occurrence of any step. Otherwise, they have the value 0.0.

The task remaining for formulas in {{row 74}} is to properly scale these values to the real tax rate. The formulas are of the form

=IF($R$72<1,0,IF($R$72<3,T73*$R$70,T73*$R$71))

and Figure P-71 illustrates the references. The first "if" test prohibits any tax from appearing during the George W. Bush administration. This was a modification made later in the development of the model. It effectively decreases the probability of a tax in the study period. The second "if" test scales the range of the tax to $15/ton before 2016 and to $30/ton subsequently.



T74 = =IF($R$72<1,0,IF($R$72<3,T73*$R$70,T73*$R$71))

	Q	R	S	T
46	0	1	2	3
47		Sep-04	Dec-04	Mar-04
48				
70	Series: Port_24 Emissions_002	15.00		
71	Value_Set: Port_24 Emissions Price Avg_001	30.00		
72	Jump_Set: CO2_Legislation_001	1.009516835	0.044710365	
73	Combined Jumps	0	0	0
74	avior: Port_24 Emissions_002, Subperiod: (all)	0	0	0

Figure P-71: Nominalized Step

Production Tax Credits

Originally enacted as part of the 1992 Energy Policy Act to commercialize wind and certain biomass technologies, the production tax credit and its companion Renewable Energy Production Incentive have been repeatedly renewed and extended. These production tax credits (PTCs) have amounted to approximately $13 per megawatt hour on a levelized basis (2004$). The incentive expired in at the end of 2003 but, in September 2004, Congress extended it to the end of 2005, retroactive to the beginning of 2004. In addition, in October, they extended the scope of qualifying facilities to include all forms of "open loop" biomass (bioresidues), geothermal, solar and certain other renewable resources that did not previously qualify. Though the amount and duration of the credit for wind remained as earlier, the credit for open loop biomass and other newly qualifying resources is half the amount available for wind and limited to the first five years of project operation. The longer-term fate of these incentives is uncertain. The original legislation contains a provision for phasing out the credit as the cost of qualifying resources becomes competitive with electricity market prices. Moreover, federal budget constraints may eventually force reduction or termination of the incentives. In the model, two events influence PTC value over the study period.

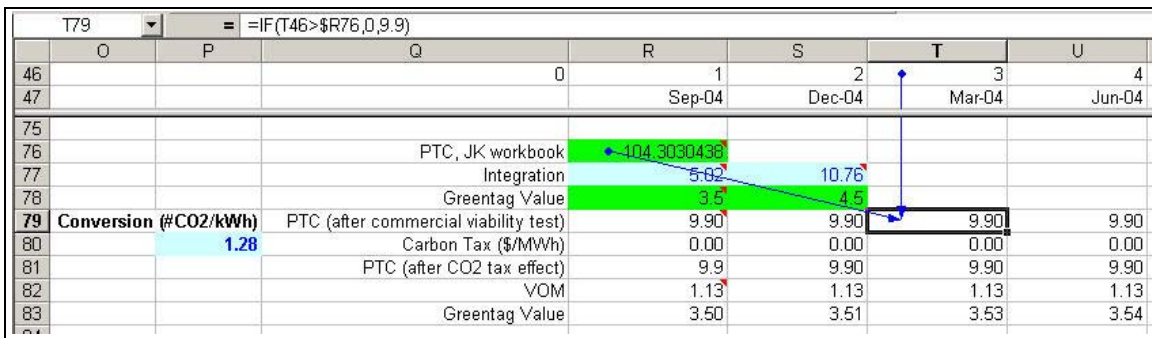
The first event is termination due to cost-competitiveness. There is a small probability the PTC could disappear immediately, if congress decided renewable energy technology is sufficiently competitive and funds are needed elsewhere. The likelihood of termination peaks in the model when the fully allocated cost of wind approaches that of a combined cycle power plant around 2016. Termination always takes place before the wind energy-cost forecast declines to 30 mills/kWh in 2034 (2004$). That is, there is never a modeling future where a PTC extends beyond 2034.

The second event that modifies the PTC in the Council's model is the advent of a carbon penalty. This event is related to the first, in that a carbon penalty would make renewables that do not emit carbon more competitive relative to those generation technologies that do. A CO2 tax of less than about $15 per short ton of CO2, however, would not completely offset the support of the PTC. For this reason, the value of the PTC subsequent to the introduction of a carbon penalty depends on the magnitude of the carbon penalty. If the carbon penalty is below half the initial value ($9.90 per megawatt hour in 2004$) of the PTC, the full value of the PTC remains[35]. If the carbon penalty exceeds the value of the PTC by one-half, the PTC disappears. Between 50 percent and 150 percent of the PTC value, the remaining PTC falls dollar for dollar with the increase in carbon penalty, so that the sum of the competitive assistance from PTC and the carbon penalty is constant at 150 percent of the initial PTC value over that range.

A three-step process determines the PTC value the regional model will use in a given future and period. In the first step, a formula like

=IF(T46>$R76,0,9.9)

in cell {{T79}} determines whether the wind plant should be commercially viable. Figure P-72 illustrates the references. The label in {{Q79}}, "PTC (after commercial



T79 = =IF(T46>$R76,0,9.9)

	O	P	Q	R	S	T	U
46			0	1	2	3	4
47				Sep-04	Dec-04	Mar-04	Jun-04
75							
76			PTC, JK workbook	104.3030436			
77			Integration	5.82	10.76		
78			Greentag Value	3.5	4.5		
79	Conversion (#CO2/kWh)		PTC (after commercial viability test)	9.90	9.90	9.90	9.90
80		1.28	Carbon Tax ($/MWh)	0.00	0.00	0.00	0.00
81			PTC (after CO2 tax effect)	9.9	9.90	9.90	9.90
82			VOM	1.13	1.13	1.13	1.13
83			Greentag Value	3.50	3.51	3.53	3.54

Figure P-72: PTC Calculation, Step 1

viability test)," is misleading. Federal politics would determine viability, and commercial competitiveness is one of several issues. As mentioned above, the PTC could go away almost immediately, if it became unpopular for any reason. The PTC may also outlive its original purpose if political or economic forces support retention. The distribution of a random variable describing this lifetime must therefore have some small, positive value in the near term and in years after renewables would become competitive.

[35] The conversion of carbon penalty ($/US short ton of CO_2) to $/MWh is achieved with a conversion ratio 1.28 #CO_2/kWh. This conversion ratio corresponds to a gas turbine with a heat rate of 9000 BTU/kWh.

This model compares Council forecasts of wind generation fixed costs to its electric market prices to estimate when renewables would become competitive. In an outboard calculation (Reference [**27**]), Staff estimated wind would achieve economic competitiveness in 2016. This assumes an electric price of $40/MWh in that year and wind generation costs that decline at about 1.7 percent per year (Reference [**28**]). Moreover, Staff assumed the chance of the PTC surviving when wind generation cost fell to $30/MWh in 2034 would be nil, so the model uses a triangular distribution for the lifetime of the PTC. The year 2016 corresponds to the 52nd period, so the distribution has

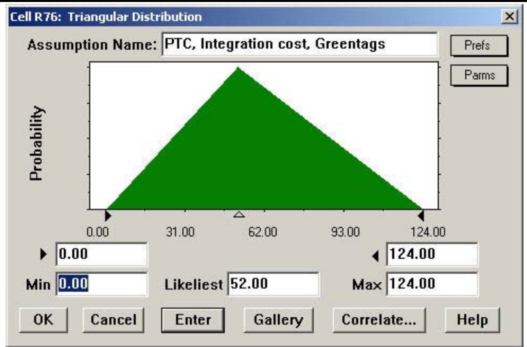


Figure P-73: Political Viability Distribution

52 as its mode; the year 2035 corresponds to the 124th period, so that value determines the maximum value. Because the study only extends 80 periods, there is a substantial probability that the PTC does not disappear due to political non-viability during the study.

The formula in cell {{T79}} stipulates that if the period exceeds the value of the random variable, the PTC is zero; otherwise it has a real levelized value $9.90/MWh in 2004 dollars (Reference [**29**]). This value corresponds to the current credit of roughly 1.7 cents/kWh in year 2000 dollars, using Council assumptions for wind capacity factor and inflation. Staff elected not to make the PTC value a random variable and saw no compelling reason to assume this would either increase or decline over time.

The second step of the process to determine the PTC value the regional model is an examination of any CO_2 tax in the period. The cell {{T80}} is typical and contains

=T74*$P$80/2

(Cell references appear in Figure P-74.) This formula converts the tax in $/US short ton (2004 $) to $/MWh using the value in {{P80}}[35]. The conversion factor is in pounds of CO_2 per kWh, so the conversion is

$$\$/\text{MWh} = \$/\text{ton} \bullet \text{tons/pound} \bullet \text{pounds/kWh} \bullet \text{kWh/MWh or}$$
$$\$/\text{MWh} = \$/\text{ton} \bullet \text{pounds/kWh} \bullet 1000/2000$$

This gives rise to the factor of two in the denominator of the formula in cell {{T80}}.

T80 = =T74*$P$80/2

	O	P	Q	R	S	T	U
74		Behavior: Port_24 Emissions_002, Subperiod: (all)		0	0	0	0
75							
76			PTC, JK workbook	104.3030438			
77			Integration	5.02	10.76		
78			Greentag Value	3.5	4.5		
79	Conversion (#CO2/kWh)		PTC (after commercial viability test)	9.90	9.90	9.90	9.90
80		1.20	Carbon Tax ($/MWh)	0.00	0.00	0.00	0.00
81			PTC (after CO2 tax effect)	9.9	9.90	9.90	9.90
82			VOM	1.13	1.13	1.13	1.13
83			Greentag Value	3.50	3.51	3.53	3.54

Figure P-74: Carbon Tax Effect (Step 2)

The third and final step of the process to determine the PTC value the regional model implements the "PTC offset" due to any CO_2 tax. In the draft Plan, the PTC went away in any future where any positive CO2 tax occurred. The issue that arose between the draft and final plan was, "Would the PTC go away entirely even if the CO_2 tax were very small?" The problem was that the combined support for renewables could undergo a discontinuity, a net drop, if the CO_2 tax were very small. This struck the Council as unrealistic.

To address this matter, new logic provided for the remaining PTC to be a function of the magnitude of the CO_2 tax. Figure P-75 illustrates the PTC remaining. In terms of support for wind generation, the PTC corresponds to a $15.47/ton CO_2 tax, given Council assumptions. With the new logic, if the CO_2 tax that arises is less than half of this, the PTC remains in place; if the tax is fifty percent higher than this, it disappears entirely. Between those values, it declines dollar for dollar with the tax rate. Figure P-76 shows the combined advantage relative to gas-fired generation provided by the CO_2 tax and the PTC. Note that no discontinuity exists for the combined support.

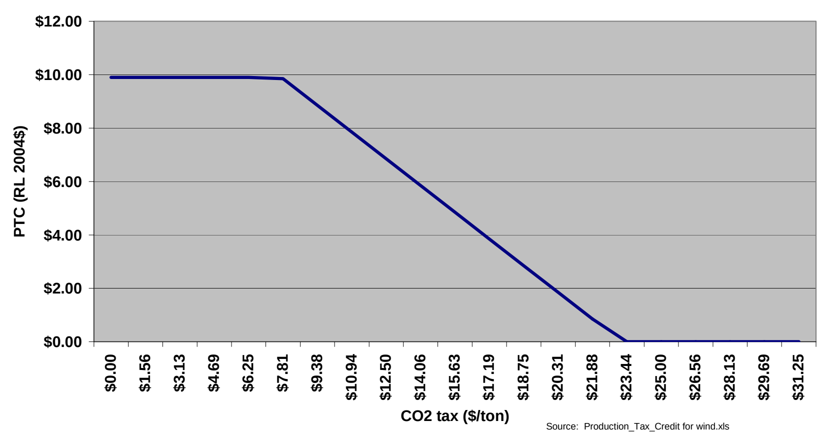


Figure P-75: PTC as a Function of CO2 Tax

Figure P-77 shows how the workbook implements the PTC with formulas, such as that in cell {{T81}}. Again, if the tax has become politically non-viable, the PTC from cell {{T79}} in this example is zero.

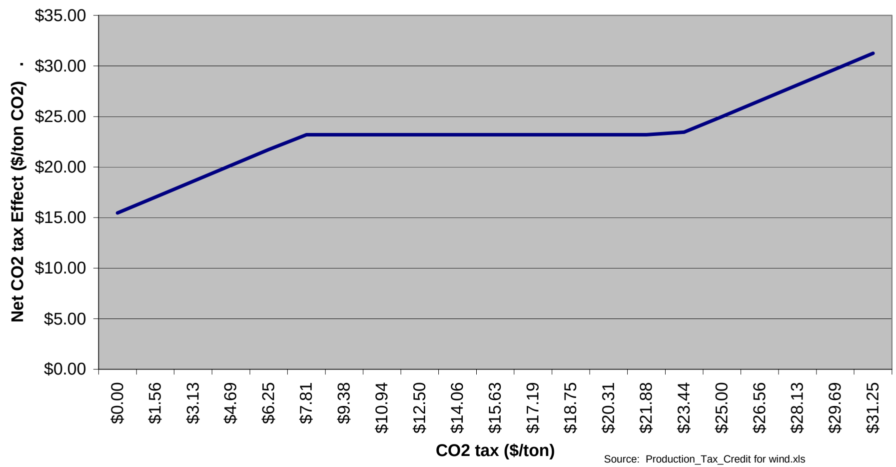


Figure P-76: Combined PTC and CO2 Tax Effects

T81 = =IF(T80<0.5*T79,T79,IF(T80>1.5*T79,0,1.5*T79-T80))

	O	P	Q	R	S	T	U
74		Behavior: Port_24 Emissions_002, Subperiod: (all)		0	0	0	0
75							
76			PTC, JK workbook	104.3030438			
77			Integration	5.02	10.76		
78			Greentag Value	3.5	4.5		
79	Conversion (#CO2/kWh)		PTC (after commercial viability test)	9.90	9.90	9.90	9.90
80		1.28	Carbon Tax ($/MWh)	0.00	0.00	0.00	0.00
81			PTC (after CO2 tax effect)	9.9	9.90	9.90	9.90
82			VOM	1.13	1.13	1.13	1.13
83			Greentag Value	3.50	3.51	3.53	3.54

Figure P-77: Transition Logic (Step 3)

Figure P-78 characterizes the deciles for the PTC before adjustment for CO_2 tax. As

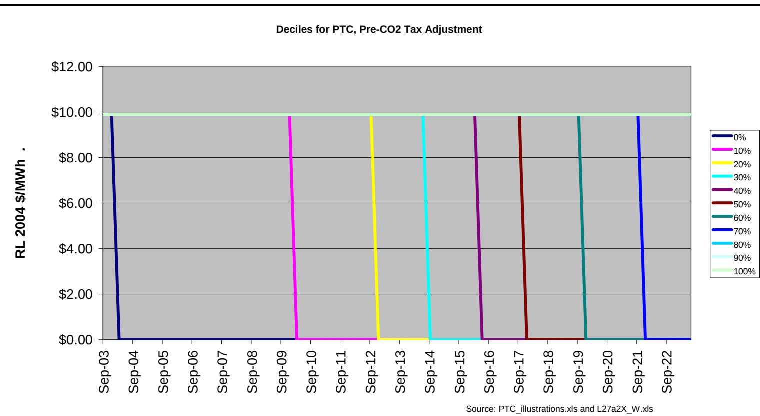


Figure P-78: Deciles for PTC before the CO2 Tax adjustment

expected, the median value is around 2016, although the median is not the mode for the distribution in Figure P-73.

Figure P-79 has deciles for the final PTC, after the CO2 tax adjustment. The effect of the tax is evident in each of the decile curves, with greater effect visible in out-lying years. The average of the final, quarterly values is a dotted line in this Figure. It also behaves as expected. Appendix L documents the final use for PTC value.

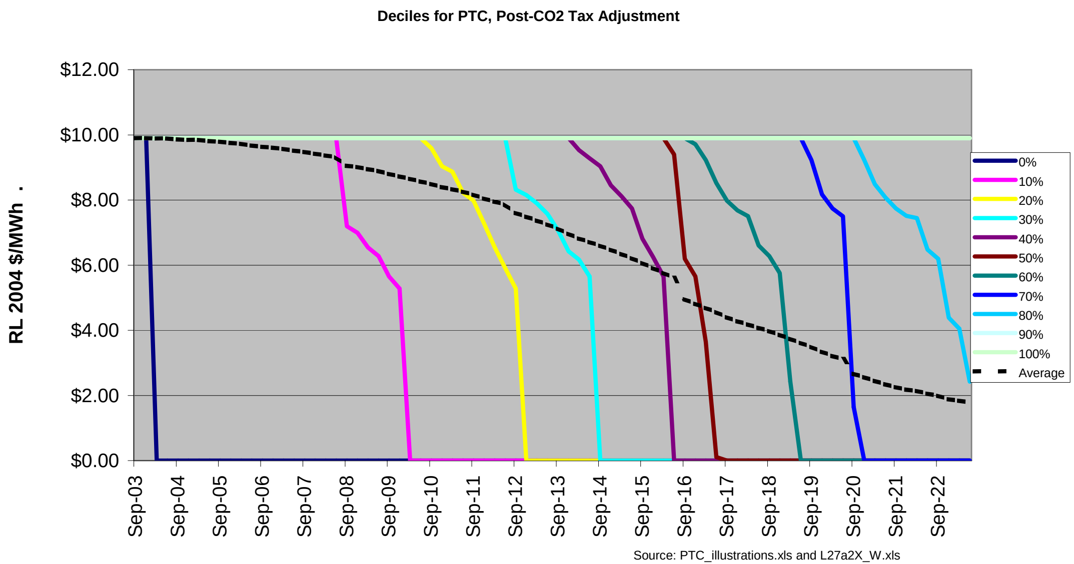


Figure P-79: Deciles for PTC After the CO2 Tax Adjustment

Green Tag Value

Power from renewable energy projects currently commands a market premium - a reflection of the perceived environmental, sustainability, and risk mitigation value of renewable energy resources. Driving the premium are above-market prices paid by utility customers for “green” power products, above-market prices paid for renewable energy components of utility supply portfolios and above-market prices for renewable acquisitions to meet requirements of renewable portfolio standards and system benefit charges. Tag value varies by resource and was between $3 to $4 per megawatt-hour for wind power when the Council approved the final Plan.

In the model, green tag value can start the study period any where between $3 and $4 per megawatt-hour with equal likelihood (2004$). By the end of the study, the value can be anywhere between $1 and $8 per megawatt-hour (2004$). (See Reference [**30**].) A straight line between the beginning and ending values determines the value for intervening periods. Consequently, green tag value averages 3.50 at the beginning of the study and averages $4.50 at the end of the study. Uncertainty in the value increases over time. This value is unaffected by events such as the emergence of a carbon penalty or the termination of the production tax credit.

In the workbook, the green tag value is a simple linear function of time. First, the model draws of random variables for the starting value and the ending values. Figure P-80 illustrates the Crystal Ball assumption cells, {{R78}} and {{S78}}, respectively, responsible for providing those values.

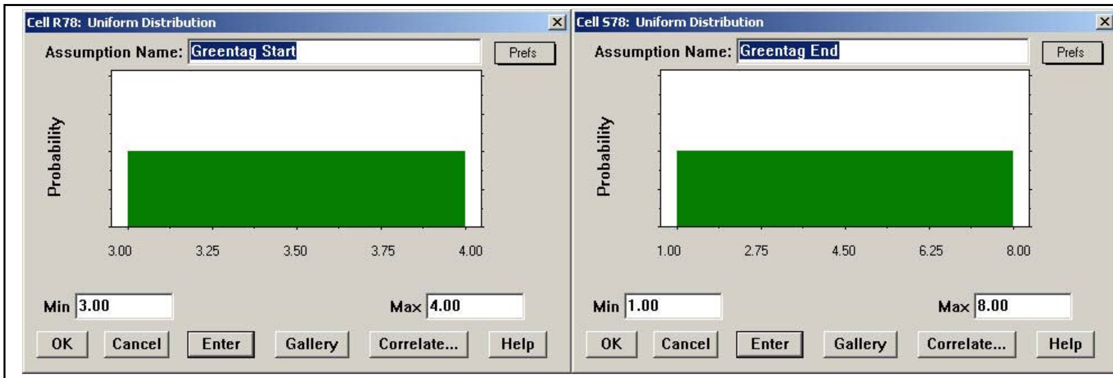


Figure P-80: Green Tag Starting and Ending Values

The model then creates a straight-line function over periods, as illustrated by the formula in Figure P-81.

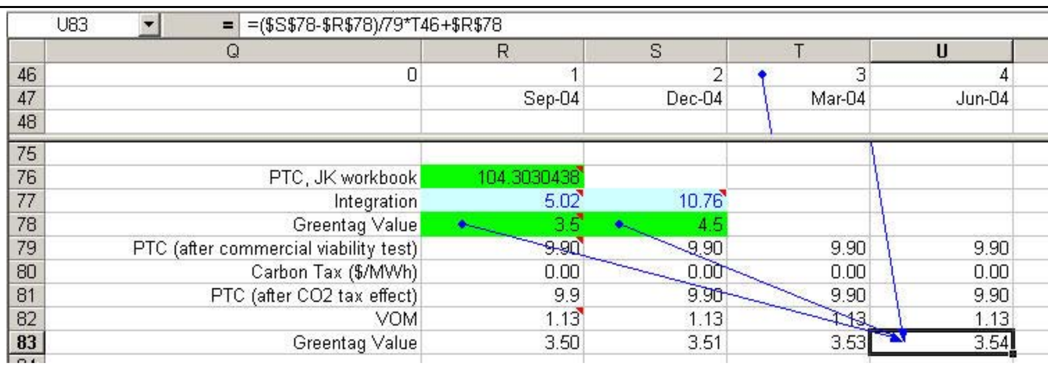


Figure P-81: Formula for Green Tag Value Over Periods

The decile summary for this stochastic variable is particularly uncomplicated and appears in Figure P-82:

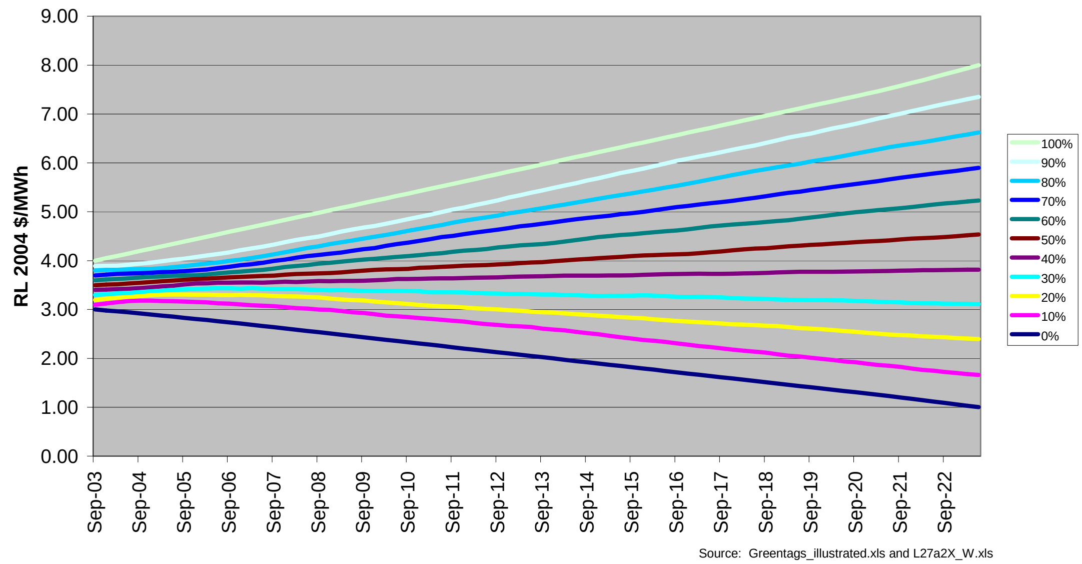


Figure P-82: Deciles and Average for Green Tag Value

Appendix L documents the final use for green tag value and how it is incorporated, along with PTC and variable operations and maintenance, into the cost of wind generation.

Correlations

Correlations among variables are typically different at different time scales. For example, load may have positive correlation with electricity prices on an hourly time scale, but on an annual average scale have negative correlation. This negative correlation stems from demand elasticity. Consequently, this section deals with correlation among key variables at different time scales.

The regional model explicitly addresses three time scales. The first is hourly correlation, within a quarterly period, referred to here as intra-period correlation. The second is correlation of quarterly averages. The third is correlation that exists on the scale of multiple periods. The first situation has its own section below, while the second and third situations are combined. If it is essential to discriminate between the second and third types of correlation, the section distinguishes them in context.

There are also explicitly modeled correlations and those correlations that arise from assumptions, choices, and constraints in the model. The latter includes the relationship between electricity price and the amount of resource that is available due to the selection of a particular specific plan. (See the discussion of "RRP Algorithm" in Appendix L, page L-51.) It also extends to the relationship between electricity price and resource parameters, like the CO_2 tax. Because these relationships depend on variables that may or may not be representative for particular situations, however, this section does not attempt to characterize such correlations.

Short-term Correlations

The correlation of values assumed within each period appears in Figure P-83. More accurately, these are correlations of values within each subperiod. The distinction is important. Note, for example, that there is no correlation assumed between hydrogeneration energy and load or between hydrogeneration and market price. In fact, as much hydrogeneration as possible is produced on peak, when market prices are high, which would result in high correlation. The solution to this apparent paradox is that the model already captures such correlation by distinct treatment of these variables in subperiods. The correlation table in Figure P-83, properly speaking, is any correlation net of subperiod modeling.

	Market Price	Non-DSI Load Flat Energy	PNW West - NG Price	Hydrogeneration Energy
Market Price	1.00	0.95	0.60	0.00
Non-DSI Load Flat Energy	0.95	1.00	0.00	0.00
PNW West - NG Price	0.60	0.00	1.00	0.00
Hydrogeneration Energy	0.00	0.00	0.00	1.00

Figure P-83: Correlation of Hourly Values

Because of how the regional model captures energy and cost, any temporal correlation of a variable with itself (autocorrelation) at the hourly scale is not relevant. The value of thermal dispatch over a subperiod, for example, is the sum of hourly values.

Correlation of natural gas price with electricity prices is significant to estimating the cost and value of thermal dispatch, as well as a forecasting capacity factor. An hourly correlation of 60 percent is taken as representative. Because of the many sources of interaction between load and electricity market price this correlation is 0.95. All other correlations are zero. These values appear in the regional model at range {{R14:T16}}, shown below (Figure P-84). Because hydrogeneration has no correlation with the other variables, its presence is not necessary. Because the correlation matrix is symmetric, this table includes only the values above the diagonal.

	Market Vol Price	Non-DSI Load Flat Vol	PNW West - NG variable cost vo
Market Vol Price	1	0.95	0.60
Non-DSI Load Flat Vol		1	0.00
PNW West - NG variable cost vol			1

Figure P-84: The Regional Model's Correlation Table

Long-term and Period Correlations

There are essentially three, explicit long-term correlations: the effect of natural gas price, loads, and hydrogeneration on electricity price; the effect of electricity price on loads; and the autocorrelation (chronological correlation) of variables with themselves. The regional model handles correlations of period averages for distinct variables through sensitivities, that is, a linear adjustment of one variable's average by another variable's average. It captures autocorrelations either through principal factors (Page P-28) or, in the case of aluminum price, through GBM coefficients (Page P-25).

Modeling correlation between averages of distinct variables as sensitivities is consistent with the correlation simulation described in the section "Simulating Values for Correlated Random Variables" on page P-26. Recall that for electricity, there remains a significant random term, the "independent" term, which provides uncorrelated behavior.

This appendix describes the effect of natural gas price, loads, and hydrogeneration on electricity price in section "The Influence of Loads, Natural Gas Price, and Hydro Generation," beginning on page P-72. It outlines the effect of electricity price on loads in the treatment of electricity price uncertainty, under the subsection "The Application to Load Elasticity," starting on page P-76.

Risk Measures

This chapter describes risk measures and the treatment of risks. It begins with a discussion of risk measures generally and considerations that led the council to select the risk measure used in the regional model, $TailVaR_{90}$. It examines alternative risk measures and explains how each one relates to the $TailVaR_{90}$ risk measure.

This examination leads us to the following observations. Mean costs and $TailVaR_{90}$ do a reasonable job of screening plans. For modeling the regional portfolio, there is a strong consistency between the chosen measures and the alternatives in most cases. This correspondence is not accidental. It probably does not hold for individual utilities. The correspondence stems from the impact that adding substantial amounts of regional resources can have on regional prices. Individual utilities, on the other hand, are typically price takers whose supply actions do not affect market prices.

Background

It may be useful to define what the Council means by risk.

Risk is a measure of the expected severity of bad outcomes.

A specific example of a measure of risk, therefore, is the average of outcomes in the "bad" tail of a distribution of costs, as illustrated in Figure P-85. In this case, bad outcomes are outcomes that are more expensive. This definition distinguishes the Council's risk measure from several in common use. For example, some use the standard deviation of the distribution of outcomes as a risk measure. The standard deviation, however, does not measure bad outcomes per se. The Council considers the standard

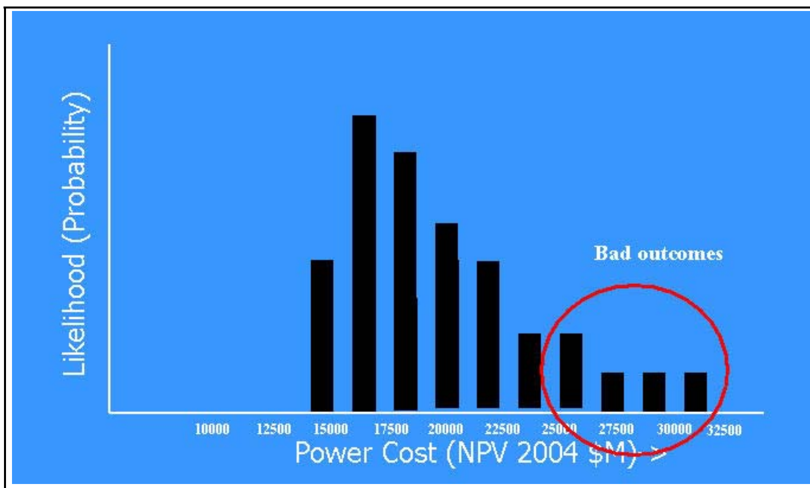


Figure P-85: Bad Outcomes

deviation a measure of predictability, not risk.

There are several reasons for the selection of this definition of risk. First, the Council believes a measure should not penalize a plan because the plan produces less predictable, but strictly better outcome. Consider, for example, Plan A and Plan B, which have cost outcomes distributed as illustrated in Figure P-86. Plan B has more predictable outcome but every outcome is worse (more expensive) than any outcome for Plan A. The Council would not consider Plan A riskier than Plan B. Even if the distributions overlapped, but for each future (game) Plan B did worse than Plan A, the Council would not consider Plan A riskier than Plan B.

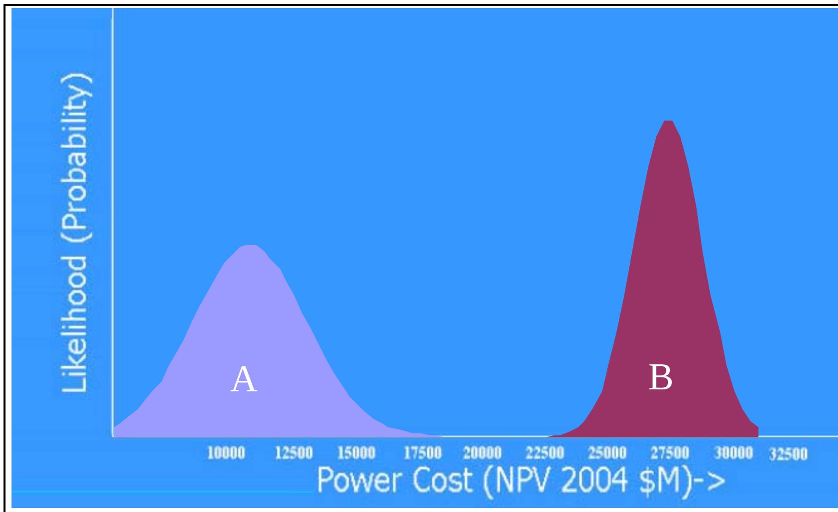


Figure P-86: Plans A and B

When confronted with situations like that which Figure P-86 illustrates, it is tempting to dismiss the problem because the average costs for Plan B are obviously worse than those for Plan A. No decision maker, it is argued, would fall into the trap of choosing the "less risky" Plan B over Plan A. That may be true in this situation, but consider the following example.

One plan produces the distribution of costs shown in Figure P-85; another plan creates the distribution in Figure P-87. (The section discussing cost distributions for the regional study, below, describes the characterization of these distributions as "price taker, with surplus plan and deficit plan.") The distributions are mirror images of one another, reflected around the mean. Because they are mirror images of each other, they obviously have the same average cost and standard deviation. A decision maker using average cost and standard deviation would therefore not be able to discriminate between them. Comparing the distributions directly, however, reveals that the first distribution has much greater likelihood of bad outcomes than the second. (See Figure P-88). The Council would consider the first plan riskier than the second.

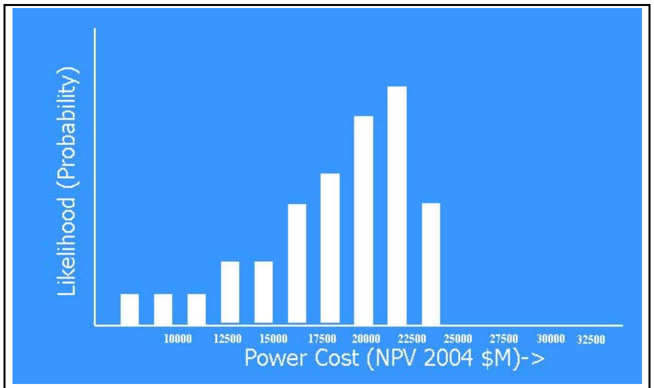


Figure P-87: Cost Distribution for Price Taker with Surplus Resources

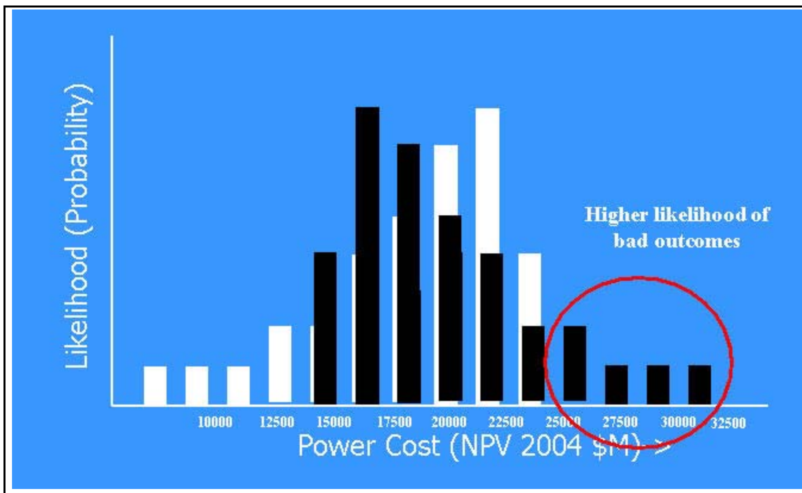


Figure P-88: Cost Distributions for a Price Taker, a Resource-Surplus Plan (white) and Resource-Deficit Plan (black)

Another reason to choose the definition of risk that the Council has is because it can be less expensive to reduce only expected severity of bad outcomes. Homeowner's fire insurance, for example, limits the economic damage that would otherwise take place in an accident. The insurance premiums, however, are typically much less expensive than the alternative of fire-proofing the home and its contents.

Finally, improving predictability, reducing the standard deviation, may come at the cost of eliminating good outcomes as well as bad. In the example of fire insurance, for example, neither the fire insurance nor the alternative of fireproofing the home improve the outcome in fortunate circumstances. Either there is a premium to pay or the cost of fire-proofing. The cost of fireproofing, however, impacts good outcomes much more.

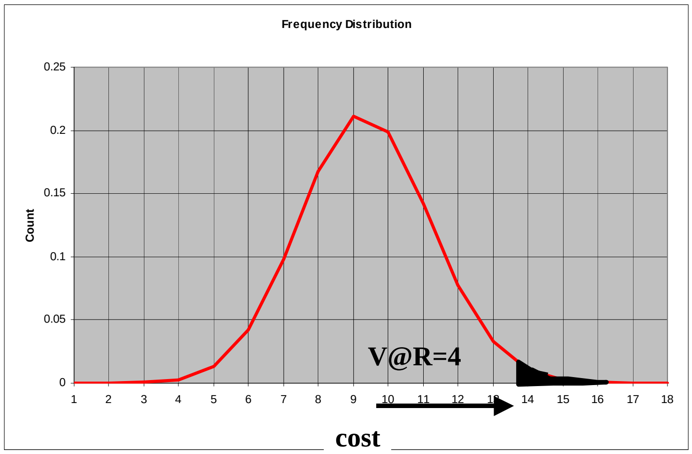


Figure P-89: Value at Risk

Some measures of risk recognize the logic of reducing bad outcomes but fall short in other regards. Value-at-Risk or VaR (sometimes V@R) is an example. Value-at-risk is a risk measure popular with investment and trading companies. VaR estimates the loss on a portfolio possible over a given period. Specifically, VaR_{95} is the loss exceeded with less than five percent likelihood. The loss is usually relative to some benchmark, such as the mean of the distribution. In Figure P-89, the probability distribution represents the possible costs[36] associated with a project over the next month, denominated in millions of dollars. The black tail of the probability distribution represents five percent of the area, and the 95th quantile is \$13.5M. If the expected cost is \$9.5M, the VaR is \$4M.

The problem with VaR is that is does not capture the value of portfolio diversification. To illustrate this, consider a simple situation where the good outcome has zero cost and the bad outcome has a cost of \$1. Consider two instruments ($\boldsymbol{X_1}$ and $\boldsymbol{X_2}$) with independent but identically distributed costs, sampled across ten futures (games) as shown in Figure P-90. Each instrument has a one-in-ten chance of producing a bad outcome. Each instrument has a VaR_{85} of zero, because more than 85 percent of the outcomes are zero (or less). The portfolio comprised of combining these two independent instruments, however, has a VaR_{85} of 1.0, which is a riskier VaR level. That is, the portfolio is riskier, as measured by VaR_{85}, than the individual instruments! This is contrary to the concept of diversification.

[36] Note that we could have used the example of losses on a portfolio of investments, operating expenses incurred by a company, or a host of other cases. The principle of measuring bad outcomes is the same.

Future	X_1	X_2	X_1+X_2
1	0.00	0.00	0.00
2	0.00	0.00	0.00
3	0.00	0.00	0.00
4	0.00	0.00	0.00
5	0.00	0.00	0.00
6	0.00	0.00	0.00
7	0.00	0.00	0.00
8	0.00	0.00	0.00
9	0.00	1.00	1.00
10	1.00	0.00	1.00
VaR@85%	0.00	0.00	1.00

$$0 = VaR(X_1) + VaR(X_2) < VaR(X_1 + X_2) = 1$$

Figure P-90: Outcomes for Two Instruments in a Portfolio

The problem with VaR is it gives no indication of *how bad* the outcomes are within the bad tail. In fact, any risk measure that reports only statistical quantiles suffers this problem.

Coherent Measures of Risk

Experts in investment and risk management recognized the problems just described, and in the 1990s produced a class of risk measures that addressed them.[37] A ***coherent*** measure $\boldsymbol{\rho}$ of risk is a function from outcome distributions to the real numbers. It has the four mathematical properties below. These properties make the measure useful for properly ranking choices. They also address the issues raised above. The property of Monotonicity, for example, guarantees that if all of the outcomes for a given plan are better, then that plan will not have greater risk. The property of Subadditivity guarantees that portfolio diversity reduces risk. In the following, $\boldsymbol{\lambda}$ and $\boldsymbol{\alpha}$ are real number-valued constants.

[37] In 1999, Philippe Artzner, Universite Louis Pasteur, Strasbourg; Freddy Delbaen, Eidgenƒossische Technische Hochschule, Zurich; Jean-Marc Eber, Societe Generale, Paris; and David Heath, Carnegie Mellon University, Pittsburgh, Pennsylvania, published "Coherent Measures of Risk" (***Math. Finance*** 9 (1999), no. 3, 203-228) or http://www.math.ethz.ch/~delbaen/ftp/preprints/CoherentMF.pdf

- Subadditivity – For all random outcomes (losses) X and Y,

$$\rho(X+Y) \leq \rho(X)+\rho(Y)$$

- Monotonicity – If $X \leq Y$ for each future, then

$$\rho(X) \leq \rho(Y)$$

- Positive Homogeneity – For all $\lambda \geq 0$ and random outcome X

$$\rho(\lambda X) = \lambda\rho(X)$$

- Translation Invariance – For all random outcomes X and constants α

$$\rho(X+\alpha) = \rho(X) + \alpha$$

The Council's measure of risk, TailVaR_{90}, is coherent [**31**]. It is defined to be the average of the ten percent worst outcomes, as illustrated in Figure P-91.

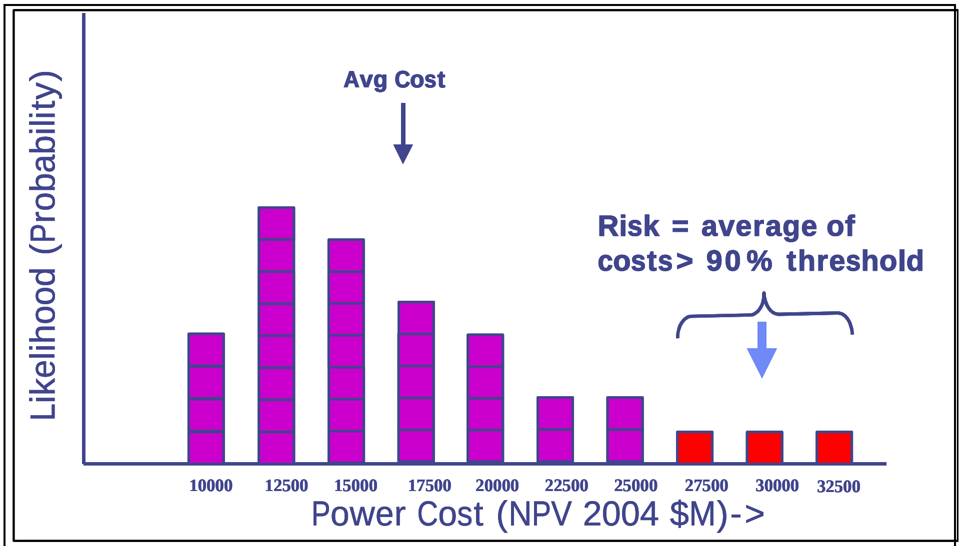


Figure P-91: Plan Cost Distribution, Average Cost and Risk (TailVaR90)

TailVaR_{90} is a measure of risk associated with *economic efficiency*. The Northwest Power and Conservation Council is required to develop a 20-year power plan under the Pacific Northwest Electric Power Planning and Conservation Act to assure the region of an adequate, efficient, and reliable power system. Previous and current Council studies use net present value (NPV) as a measure of economic efficiency. NPV is demonstrably better for this purpose than alternatives, such as B/C ratios and internal rate of return (IRR). Because the primary measure is one that relies on NPV, it stands to reason that bad outcomes are those with unfavorable NPV. Consequently, TailVaR_{90} is fashioned to measure the expected severity of unfavorable NPV.

TailVaR_{90} distinguishes between the two distributions illustrated in Figure P-88. It reasonable to expect, therefore, that the results obtained using this measure would not compare well with those obtained using a non-coherent measure of risk, like standard deviation. Surprisingly, non-coherent and coherent measures give comparable results in regional studies. The next section explains why this is so.

Distributions of Cost for Regional Study

Distributions of cost for typical load-serving entities or generators in the region differ significantly from that of the region as a whole, because individual participants are usually price takers. That is, their individual loads and the operation of their resources typically will not move prices in the region. If they have surplus resources, in particular, their potential for making money is large. This potential depends only on how high the market price for electricity goes. As the following explains, however, this is not the case for the region as a whole.

An example of the cost distribution situation for price takers with surplus resources appears in Figure P-85, reproduced here as Figure P-87. The source of risk for utilities with surplus resources is low market prices for electricity. With low market prices, the utility and its customers are better off if the utility buys its electricity from the market. This leaves the utility with the cost of “stranded resources,” that is, plants that customers are still paying for but are not using. The size of this risk may be large, but it is limited.

Market price for electricity may go down significantly, but it obviously cannot go below zero. This means costs beyond meeting requirements out of market purchases will not be greater than the fixed costs of unused resources. Therefore, total costs have an upper bound, as illustrated in simple example shown in Figure P-92.

Figure P-92 shows the total costs of a simple system over a period, say a year, if electricity prices remained fixed at the value on the horizontal axis. This system has a load, and there is a cost of meeting that load in the electricity market. The dark purple, dotted line illustrates that cost. The system has a single generator that costs $50M/year in fixed costs and a dispatch price[38] of $30/MWh. Significantly, the size of the generator is twice the size of the load. The generator costs are the solid, dark blue line. When electricity price exceeds the generator’s dispatch price, the generator creates value that offsets its fixed costs. The value of the generator in the electricity market increases dollar for dollar, with each dollar that the electricity price exceeds the dispatch price. The total costs, shown by the solid yellow line, are maximum at the dispatch price of the turbine. For prices higher than that, the turbine value offsets the cost of serving the load; for lower prices, lower purchase costs reduce total cost.

[38] The dispatch price is the electricity price that would cause the generator to just cover the cost of fuel and any other cost of operation that depends only on the amount of energy generated.

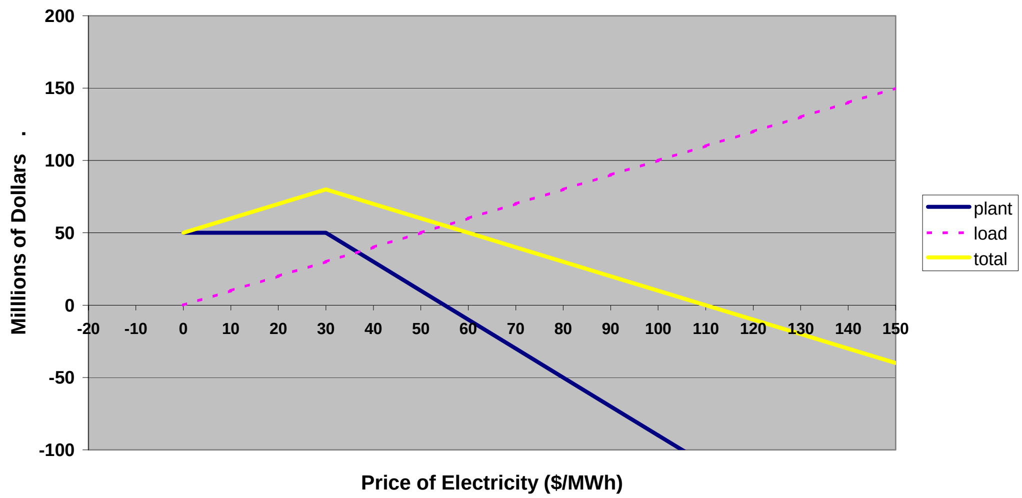


Figure P-92: Example of Total Costs for a Simple Surplus System

If electricity prices were fixed, the total cost could be read off the vertical axis of Figure P-92. For electricity prices that have a distribution instead of being fixed, however, there is a corresponding total cost distribution. The cost distribution has a tail extending to the left (*lower* costs) in Figure P-87, corresponding to *higher* electricity prices, because of the relationship shown in Figure P-92. Net costs can even become negative if prices are high enough, as Figure P-92 suggests.

The cost distribution situation for price takers with *deficit* resources is similar, except costs are now bounded below and *unbounded above*. For the simple example illustrated in Figure P-93, the load is larger than the plant. Now, however, *higher* costs correspond to *higher* electricity prices. If electricity prices have lognormal distribution, the distribution will have an unbounded tail extending to higher prices. This situation leads to a total cost distribution resembling that in Figure P-94. That cost distribution now has a tail pointing in the direction opposite that of Figure P-87.

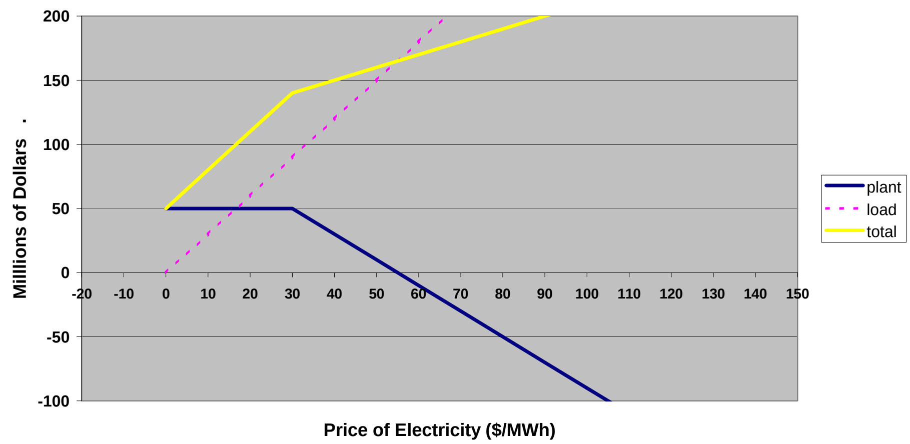


Figure P-93: Example of Total Costs for a Simple Deficit System

The region's cost distribution, it turns out, never resembles that for the surplus system. The preceding examples assume that utilities are price-takers, that is, the utility's surplus does not dampen electricity market prices. The aggregate regional resource situation, however, can affect market prices. Resources surplus to the regions requirements, after

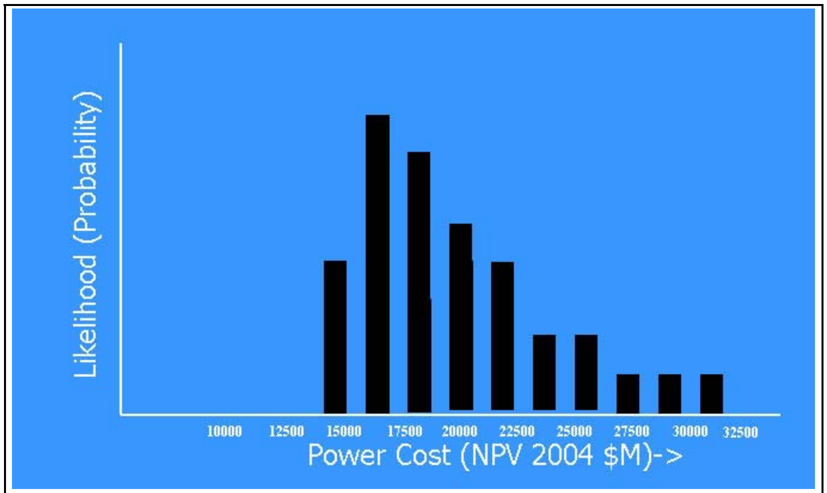


Figure P-94: Cost Distribution for Price Taker with Deficit Resources

exports, depress price. Effectively, the price range in Figure P-92 is capped on the high side, trapping the costs in positive territory. The final distribution for costs will tend to be more symmetric in this case than it would be for a deficit region. The width of the distribution may become quite small, but the mean will go up due to fixed costs. The "good" tail that is present in Figure P-87, however, does not materialize.

Because distributions like that in Figure P-87 never arise in the regional study, the mean cost is higher than the median cost. This has relevance to the question of the metric chosen for central tendency. Some would argue that the median is a better measure of central tendency than the mean for risk analysis. The next section is a brief digression from the topic of risk measures to address that issue.

Median and Mean Costs

Is the median is a better measure of central tendency than the mean for risk analysis? The median future is a future above and below which lie an equal number of better and worse futures. In contrast, a weighing scheme defines the mean: the mean is the average of outcomes, weighed by their probabilities. What future will the region face? For that matter, what determines the outcome of rolling dice? It is a matter of the likelihood of landing on each face, not the value of the faces. The mean cost, in fact, may not correspond to any particular future, just as there is no face on a die with the value 3.5, the average outcome. For an odd number of futures, however, there is always a median value future[39]. This all tends to argue for the use of the median.

On the other hand, the mean is a statistic with which most decision makers seem to have greater comfort. Some decision makers may feel that they want extreme outcomes to influence their measure of the central tendency. The Council chose the mean to a certain extent because it is simpler to communicate than the median.

Fortunately, it does not make much difference which of the two measures of central tendency we choose. Distributions for outcomes of plans exhibit a strong relationship between the two measures. Figure P-95 shows that the mean and median values track very closely.

The mean value is consistently above the median, reflecting the observation above that distributions have long tails extending in the high-cost direction, pulling up the mean. As costs go down, the skewing becomes more pronounced. This has implications to the discussion of risk measures. Moreover, what typically occurs is that the least-cost, highest-risk plan consists of relying on the market to meet requirements. In this case, of course, the distribution for regional costs becomes highly skewed. This explains why skewing becomes more pronounced in Figure P-95 at the lowest average cost.

In conclusion, while the median might be a better measure of the central tendency than the mean for decision making under uncertainty, using the mean will give the same results in terms of the construction of the feasibility space and selection of plans. For studies of regional costs, distributions are skewed in the same direction as resource-deficit plans and the mean and median have a strong relationship.

[39] The median of an even number of observations is the arithmetic average of the two middle observations.

This section suggests that, because distributions for regional cost are always skewed in one direction, non-coherent measures like standard deviation might give comparable results to those obtained by $TailVaR_{90}$. Returning to the topic of risk measures, next section addresses the question of, how representative is $TailVaR_{90}$?

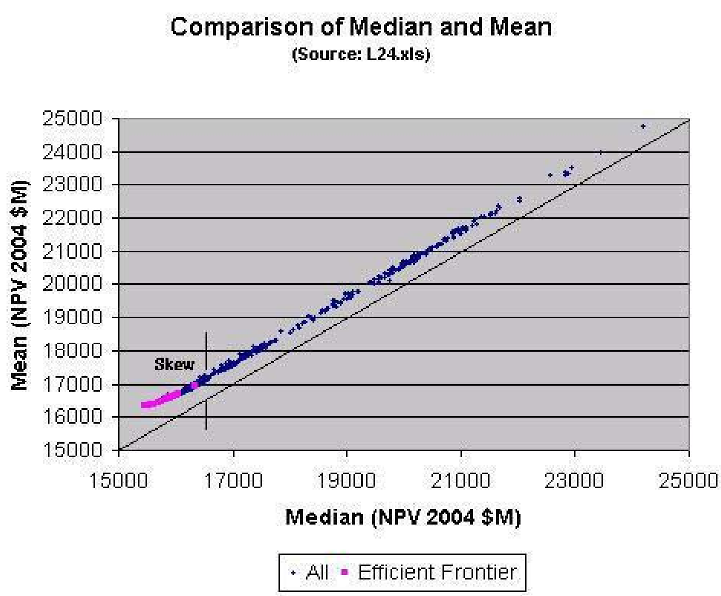


Figure P-95: Mean versus Median

Perspectives on Risk

Many alternatives exist for measuring the risk. Each study performed with the regional model recorded a host of alternative risk measures, as well as both the mean and median cost. Figure P-96 illustrates the standard report, which Appendix L describes in detail. Risk measures for each plan appear on the right-hand side of this report and include:

- $TailVaR_{90}$
- Standard deviation
- $CVaR_{20000}$
- VaR_{90}
- 90^{th} Decile
- Mean (over futures) of maximum (over 20 years) of annual cost increases
- Mean (over futures) of standard deviation (over 20 years) of annual costs

(The figure simplifies the report, leaving out some columns and rows, to provide a more comprehensive view of the report.) Subsequent, out-board studies examined alternative sources of risk, such as relative exposure to bad market conditions and variation in average power cost.

This section reviews this information, extracted from the final Plan. This section asks

- How representative of alternatives is TailVaR$_{90}$? Would the Council have made a different choice of plans if it had used some other measure of economic risk?
- Given that the Council chooses a plan from among those on the efficient frontier, do other measures help the selection?
    - o How do conventional measures of reliability, like loss-of-load probability (LOLP), vary along the frontier?
    - o Do other perspectives on risk, such as cost volatility, give us a way to further refine the selection?

	A	B	C	D	E	AQ	AR	AS	AT	AU	AV	AW	BG	BH	BI
1	**														
2	* Analysis of *														
3	* OptQuest.log *														
4	* with *														
5	* Analysis of Optimization Run_L27A2.xls *														
6	**														
7	Sim	Cnsrvn_Lo	Cnsrvn_Dis	RM	CCCT_C	GCC_CY1	IGCC_CY1	Mean	Std_Dev	Median	TailVaR90	CVaR20	Cnsv_Cst:	Mean	
8	1706	0	5	0		0	0	23647.44	6602.989	22295.37	37435.84	26851.5	22.61565	F	
9	1873	0	5	5000		0	0	23653.11	6379.034	22272.49	36955.9	26707.6	22.48798	F	
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]		[illegible]	0	23730.78	[illegible]	22396.39	36729.42	26541.[illegible]	22.38016	F	
122	1233	10	5	5000		425	425	24430.97	5596.721	23208.61	35880.81	26168.4	22.92024	F	
123	1234	10	5	5000		425	425	24435.55	5593.984	23207.23	35880.22	26171.7	22.91977	F	
124	1232	10	5	5000		425	425	24440.25	5591.099	23205.85	35879.08	26175.3	22.91493	F	
125	948	5	25	5000		425	425	24508.42	5569.806	23311.89	35870.65	26202.5	24.06349	F	
126	3	0	0	0		0	0	23661.51	6599.311	22301.92	37450.84	26836.8	22.24873		x
127	1726	50	5	0		0	0	23847.44	6496.037	22455.33	37438.75	[illegible]	[illegible]		x
1499	775	5	5	5000		425	425	24420.24	5604.747	23205.11	35887.48	26191.7	22.41363		x
1500	912	5	5	5000		425	425	24686.57	5485.664	23486.43	35882.99	26243.5	22.25928		x
1501	922	5	25	5000		425	425	24459.83	5598.099	23261.39	35881.38	26237.1	24.06979		x
1502	1230	10	5	5000		425	425	24467.54	5575.609	23260.49	35880.23	26198.7	22.90646		x
1503	60	50	50	0	12	1700	1700	31340.27	6122.014	29994.17	44043.84	31386.0	29.59224		
1504	24	50	50	0	12	1700	1700	[illegible]	[illegible]	29537.35	43619.37	[illegible]	29.59777		
2009	264	35	30	5000		425	425	25513.59	5386.828	23829.93	35987.55	26329.6	26.69841		
2010	807	15	5	5000		425	425	25090.18	5395.79	24027.38	35985.2	26423.2	23.24394		
2011	630	0	0	5000		425	425	24824.09	5489.656	23716.65	35963.71	26344.6	21.46526		
2012															

Figure P-96: Alternative Risk Measures (Right Hand Side) from Appendix L

The section first examines economic risk measures. These derive from distributions of net present value study costs and include coherent and non-coherent measures of risk. It then reviews measures of cost volatility. Cost volatility here refers to year-to-year variation in both going-forward costs and total costs, including embedded costs. It also refers to the consistency of factors that would affect rates, such as imports of expensive energy. Finally, the section addresses two conventional measures of engineering reliability, LOLP and resource-load balance.

Alternatives to TailVaR$_{90}$

As explained earlier in this chapter, measures of NPV distribution are the most appropriate risk measures, given the task of the Council's Plan. Measures of NPV distribution are a kind of as "economic efficiency" risk. Among alternatives to $TailVaR_{90}$ for measuring such risk are 90th quantile, standard deviation, VaR_{90}. These examples happen to be non-coherent measures of risk. Even among coherent measures of economic risk, however, there are unlimited choices for such measures.

$CVaR_{20000}$, for example, is a coherent measure of economic risk, and earlier Council studies used it as the primary risk measure. $CVaR_{20000}$ is the average of costs exceeding $20,000 million. The concept is that if decision makers can deem an economic threshold as undesirable, the average of costs above that threshold makes a reasonable measure of risk.

$CVaR_{20000}$, however, has several shortcomings. Most important, the Council does not have an a priori vision of what that threshold should be. The $CVaR_{20000}$ measure even complicates the process of studying cost distributions to arrive at such a threshold. A distribution may shift dramatically with the introduction of new assumptions. If plan distributions for the base case and change case fall on one side or the other of the threshold, $CVaR_{20000}$ cannot discriminate between them. Finally, because the threshold is a subjective assessment by the decision maker, selecting a threshold introduces another assumption to defend and debate.

$TailVaR_{90}$ addresses these issues and affords additional benefits. Because the value of $TailVaR_{90}$ is never less than the 90th quantile, for example, the Council can make statements about the likelihood of "bad" outcomes. That is, futures with $TailVaR_{90}$ costs or greater are expected with less than 10 percent probability.

One measure of how well $CVaR_{20000}$ compares with $TailVaR_{90}$ is their correlation. If they produce the same rank of outcomes, they provide effectively the same information. If the two measures are plotted against one another, as in Figure P-97 [**32**], the points would fall on a strictly monotonic curve. (See, for example, Figure P-95.) The dispersion of points around the monotonic curve is an indication of their correspondence. Correlation is a measure of that dispersion. Figure P-97 suggests that the correspondence between $CVaR_{20000}$ and TailVaR 90 is rather weak, in general. The white points in the bottom left-hand corner of the distribution, however, correspond to the efficient frontier,

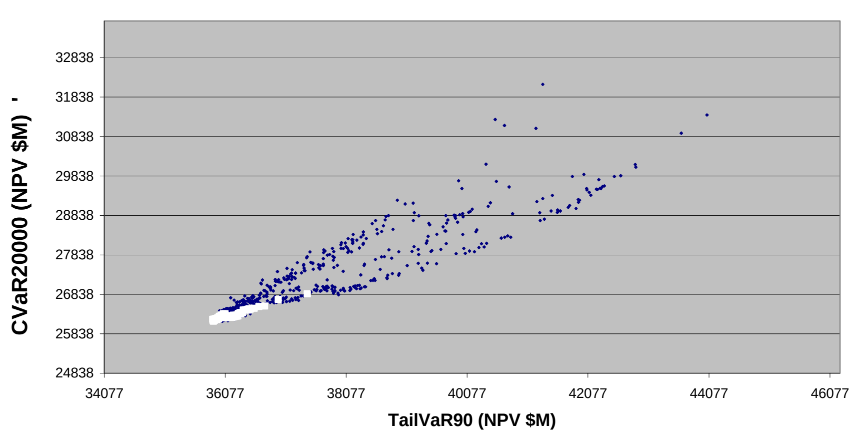


Figure P-97: Relationship, CVaR20000 to TailVaR90

using $TailVaR_{90}$. On that efficient frontier, the correspondence is quite good.

Figure P-98 reconstructs the feasibility space using $CVaR_{20000}$. Again, the white points are the efficient frontier constructed by using $TailVaR_{90}$. Evidently, it does not make any difference whether we construct the efficient frontier using $TailVaR_{90}$ or $CVaR_{20000}$.

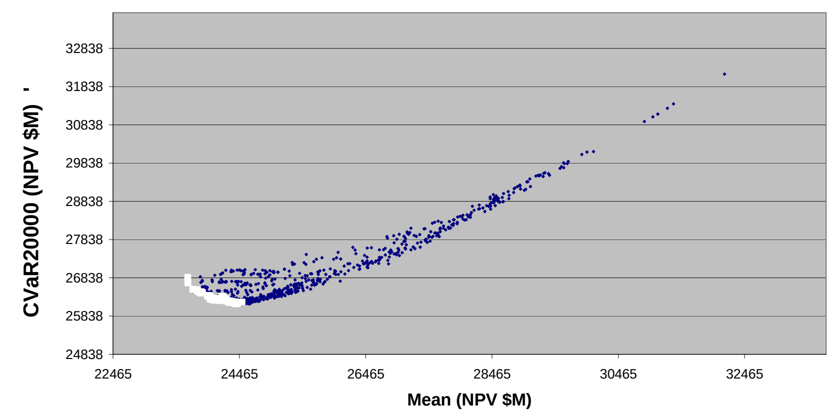


Figure P-98: Feasibility Space, using CVaR20000

<u>90th Quantile</u>

Non-coherent measures do not correspond well, in general, to $TailVaR_{90}$. Figure P-99 plots the 90th quantile against $TailVaR_{90}$. The relationship is clearly much weaker than for $CVaR_{20000}$. Figure P-100 makes it clear that the efficient frontier using the 90th quantile does not correspond to that using $TailVaR_{90}$. The efficient frontier using

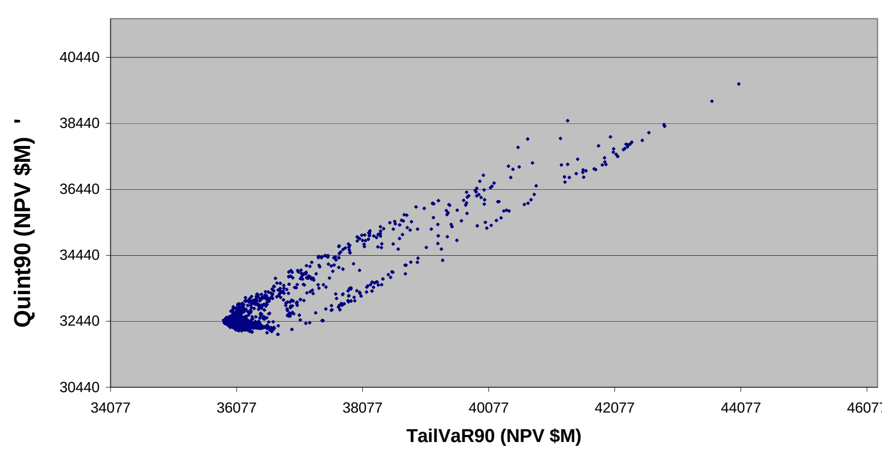


Figure P-99: Relationship, 90th Quantile to TailVaR90

$TailVaR_{90}$ is clearly well within the set of dominated points. It is reassuring, however, that the efficient frontier using $TailVaR_{90}$ is contained in the set of nearly efficient points using the 90th quantile. It appears that plans that are efficient with respect to $TailVaR_{90}$ are efficient, or nearly efficient, with respect to the 90th quantile.

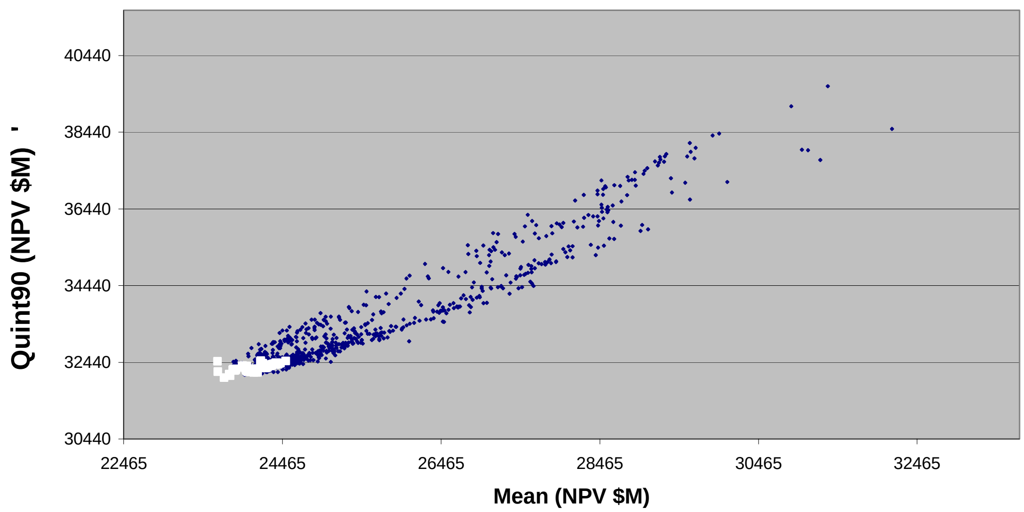


Figure P-100: Feasibility Space, using 90th Quantile

Standard Deviation

Standard deviation bears virtually no relationship to $TailVaR_{90}$, as illustrated in Figure P-101. Fortunately, because the cost distribution for the region is always skewed in the same direction, plans that are efficient using $TailVaR_{90}$ have least standard deviation for each level of cost. Consequently, those plans that are efficient using $TailVaR_{90}$ are also efficient using standard deviation, as Figure P-102 illustrates. In fact, the sequence of

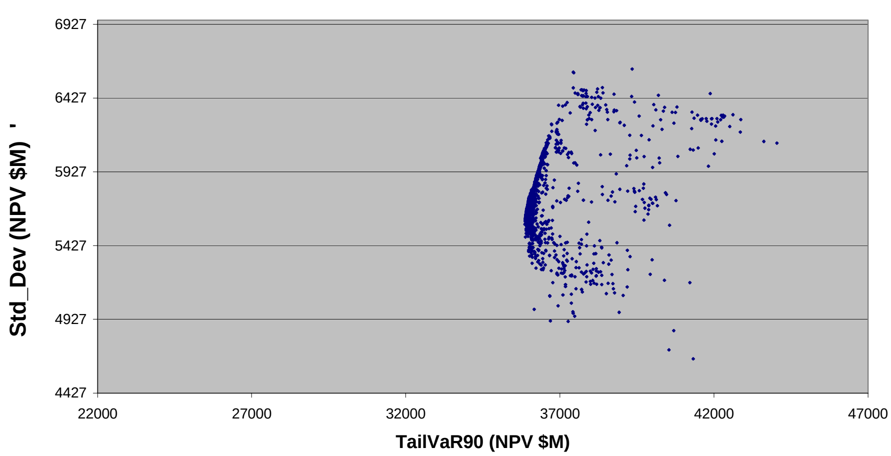


Figure P-101: Relationship, Standard Deviation to TailVaR90

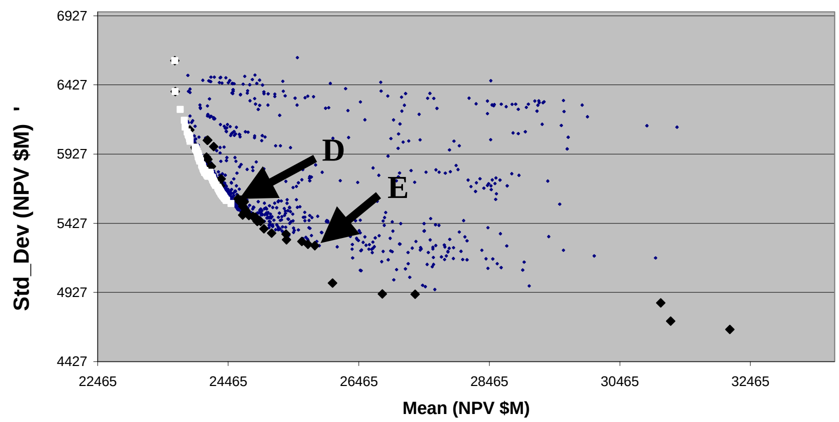


Figure P-102: Feasibility Space, using Standard Deviation

plans along the efficient frontier closely follows that for the efficient frontier using $TailVaR_{90}$. For example, the least risk plan, Plan D, is also least risk – among the white points – using standard deviation. (See Figure P-103.)

There are a good number of plans, identified by the black diamonds in Figure P-102, that are efficient with respect to standard deviation, but not efficient with respect to $TailVaR_{90}$. This raises the obvious question, "Would the council have selected another plan if they used standard deviation?"

It is unlikely that the council would have chosen any of the Black Diamond plans. The reason, simply stated, is that these plans to perform worse under a preponderance of futures than the plans corresponding to the white points.

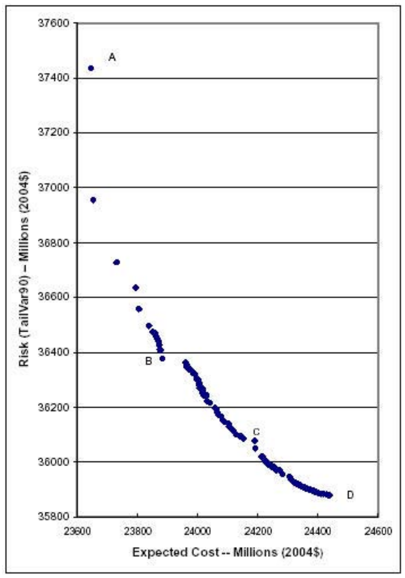


Figure 7-2: Plans Along the Efficient Frontier

Figure P-103: Chapter Seven's Figure 7-2

For example, Plan E in Figure P-102 has substantially better standard deviation than Plan D ($380 million smaller). If we compare the total system cost of plan E in each future against the cost of the corresponding future for Plan D, we can construct the illustration of the sorted differences appearing in Figure P-104. While Plan E is more predictable as measured by standard deviation, it produces a better outcome in less than two percent of the futures. The number of futures with significant difference is half of that. In over 80 percent of the futures, the outcome for plan E is over $1 billion worse than that for Plan D. The ability of $TailVaR_{90}$ to discern plans that perform better in the vast majority of futures is directly related to the property of monotonicity shared by all coherent risk metrics.

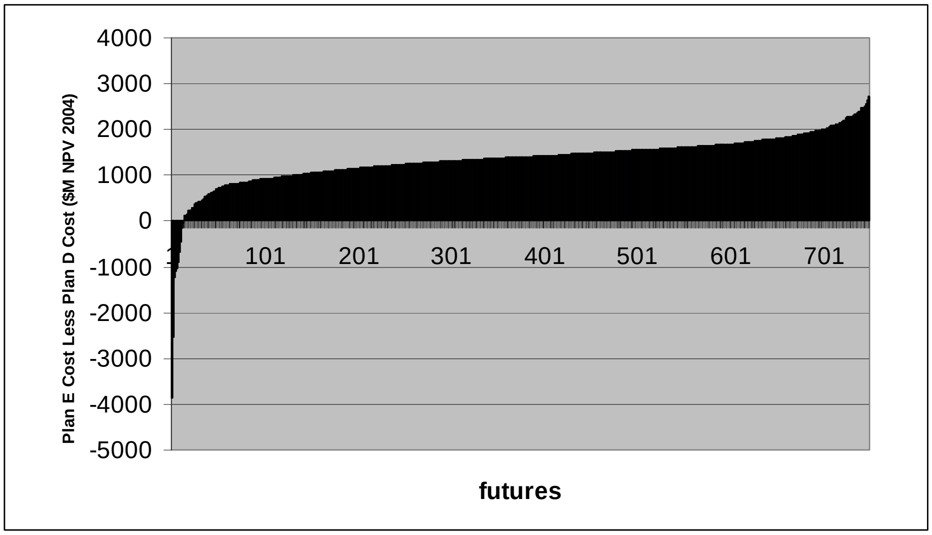


Figure P-104: Cost Differences Between Plans D and E, by Future

VaR$_{90}$

The definition of Value-at-risk (VaR) appears earlier in this chapter. It is a risk metric that, like standard deviation, primarily measures the width of the distribution. It should not be too surprising, therefore, that its correspondence to TailVaR$_{90}$ resembles that of standard deviation. (See Figure P-105.) The correspondence of the efficient frontier to that defined using TailVaR90 (white points) is not as clean as it is for standard deviation. Nevertheless, plans that are efficient with respect to TailVaR$_{90}$ are efficient or nearly efficient with respect to VaR$_{90}$. The efficient frontier in Figure P-105 below the white dots has the same explanation as the corresponding area for standard deviation. Once again, the conclusion is that it is unlikely the Council would have chosen plans from the efficient frontier of Figure P-105 below the plans illustrated with white points.

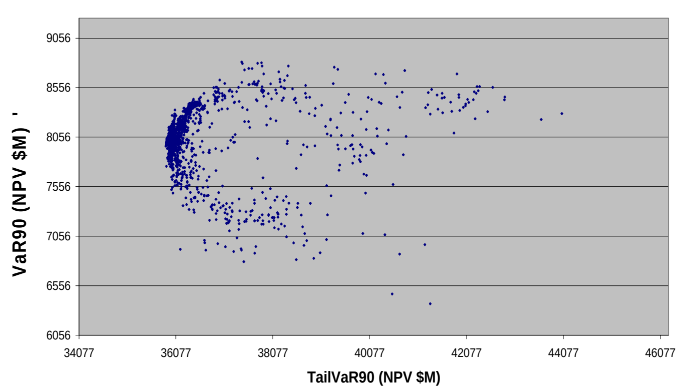


Figure P-105: Relationship, VaR90 to TailVaR90

Cost Volatility

Economic efficiency can hide a multitude of sins. Costs over the study period can produce low net present value while still exhibiting large volatility. Cost volatility is undesirable because it can produce sudden and unexpected retail rate increases.

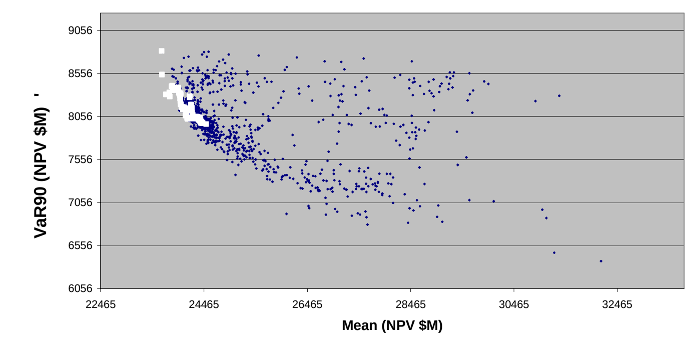


Figure P-106: Feasibility Space, using VaR90

There are several questions one can ask about cost volatility. First, how to the plans along the efficient frontier perform with respect to cost volatility relative to those plans that are not on the efficient frontier? Second, what kind of variation in cost volatility exists among plans on the efficient frontier? Third, what are some of the key drivers of cost volatility?

There are many ways to define cost variability. The next section considers several types of cost volatility and explains the purpose of each.

Average Incremental Annual Cost Variation

In Figure P-107, it is evident that the relationship between the mean cost variation and $TailVaR_{90}$ is quite weak. Mean cost variation is the average, across futures, of the standard deviations for changes in annual costs across the study. This tends to be a weak indicator of volatility for a couple of reasons. This standard deviation uses the first half of the study, when there are virtually no differences among plans. Averaging over futures tends to water down this metric as well.

There are a few things that we can discern, however, from Figure P-107. Plans on the TailVaR90 efficient frontier[40] (white points) all tend to lie in a narrow range of mean cost variation. That is, by this measure it does not really matter which plan from the efficient frontier we choose. It is also notable that there are many plans with less mean cost variation. These are associated with more expensive plans and surplus resources. Resource shortage and electricity market price volatility increase cost variability; surplus resources will lower cost volatility because they tend to dampen wholesale electric market prices.

[40] In this chapter, the $TailVaR_{90}$ efficient frontier refers to those plans that are on the efficient frontier if they were in a plot of plan mean cost against plan $TailVaR_{90}$.

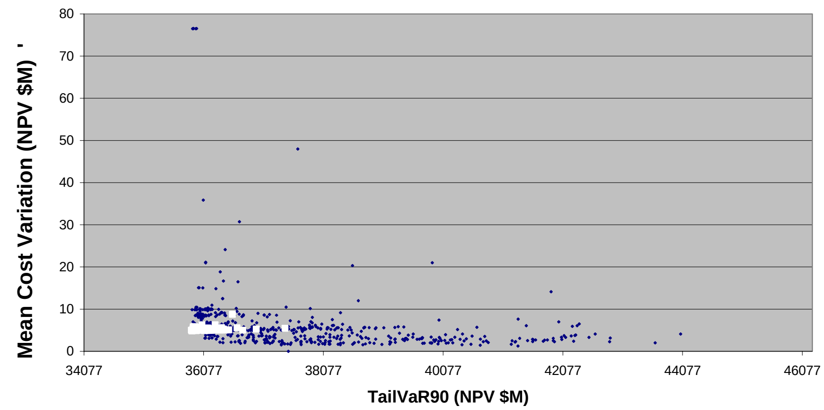


Figure P-107: Relationship, Average Incremental Annual Cost Variation to TailVaR90

Maximum Incremental Annual Cost Increase

A slightly more sensitive measure of cost volatility is the maximum increase in costs over the study. Figure P-108 compares the average maximum cost increase, across futures, to TailVaR$_{90}$. We still see roughly the same pattern that was evident for average incremental annual cost variation. If we expand the region around the TailVaR$_{90}$ efficient frontier, we can see that there is a very weak relationship between the two measures. Figure P-109 includes a regression line that emphasizes this weak relationship.

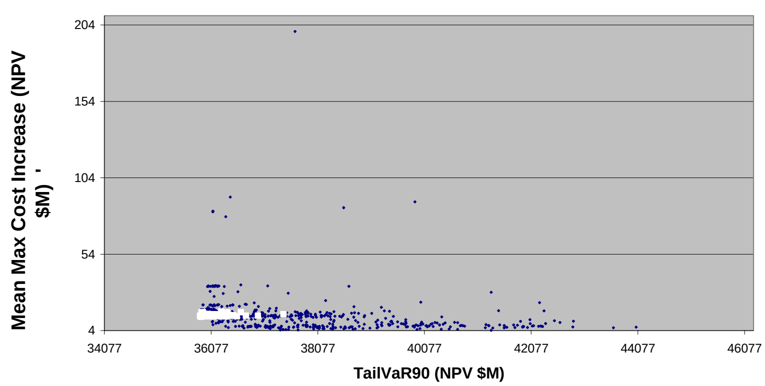


Figure P-108: Relationship, Maximum Incremental Annual Cost Increase to TailVaR90

Council Staff investigated several alternative measures for cost volatility. The next section describes several of the more successful results.

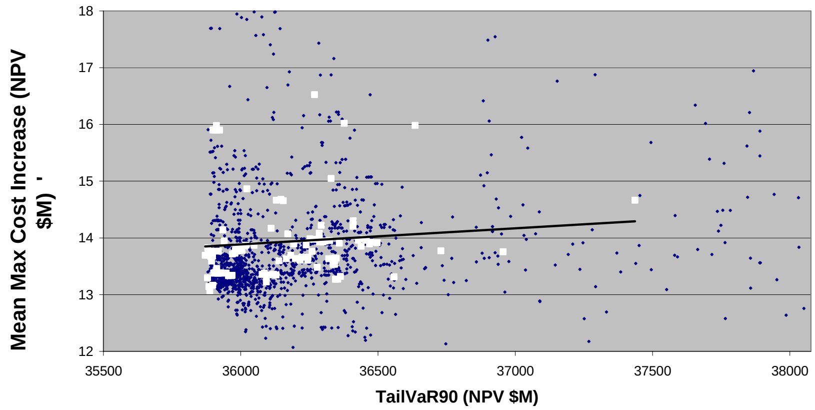


Figure P-109: Magnification of Previous Figure

Average Power Cost Variation (Rate Impact)

By parsing out the number of futures with increases that exceed in a given level, a more refined measure of cost volatility is possible. This section describes how the four scenarios identified in Figure P-103 perform under this measure.

Figure P-110 [**33**] shows the percent of futures where cost increases exceed the levels on the horizontal axis. While the preceding discussions of annual cost volatility used only variable costs and forward-going fix costs, Figure P-110 includes system embedded costs of about $7 billion per year[41]. Including this embedded cost reduces the cost volatility, compared to the statistics in the previous section, but it provides values that more closely correspond to total power costs and retail rates.

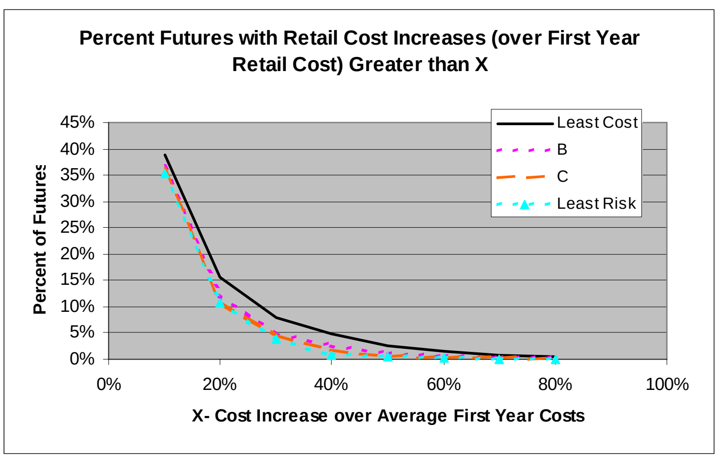


Figure P-110: Exceedance Probability: Increase Over First Year's Cost

[41] Staff attempted to adjust the embedded costs from year-to-year for depreciation. In real terms, these costs decreased by 3 percent per year.

In Figure P-110, the horizontal axis are cost increases calculated by dividing each year's costs by the costs in the first year the study:

$$\frac{C_i}{C_1}$$

This provides some insight into how the costs vary with respect to current circumstances. The graph suggests that there is significant improvement in moving from the least-cost plan A to Plan B. In particular, the likelihood of cost increases exceeding 30 percent is half of that for the least-cost plan. Plans B, C, and D (the least risk plan) all have comparable cost volatility.

An alternative way of measuring cost variation is to look at the difference in costs from year-to-year and compare that change to costs in the first year the study:

$$\frac{C_i - C_{i-1}}{C_1}$$

This provides an idea of rate shock, while "normalizing" the denominator. Without normalizing the denominator, cost increases expressed as percentage change would appear to be different when the change in annual cost expressed in dollars is the same. The results for this analysis appear in Figure P-111. They suggest the same conclusions as the previous figure, although the reduction in likelihood is now for percentage cost increases over 40 percent, instead of 30 percent.

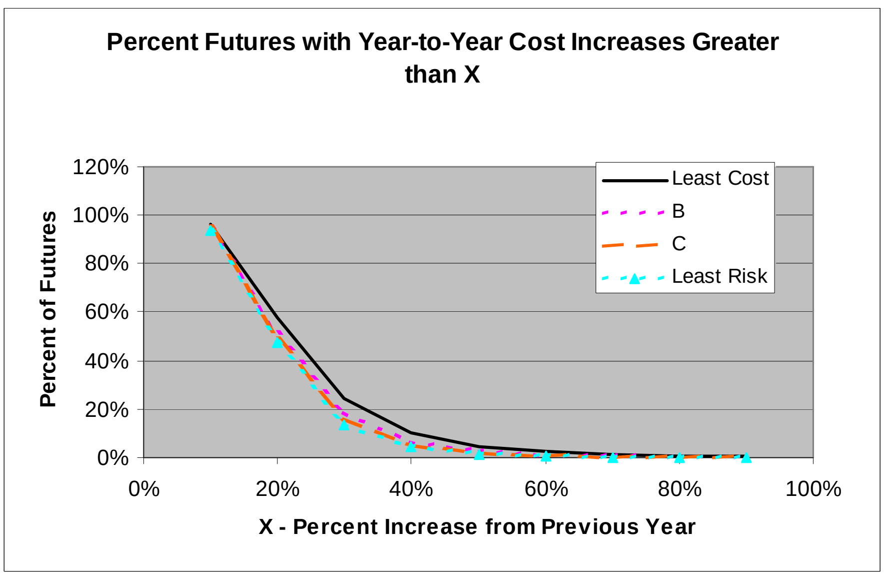


Figure P-111: Exceedance Probability: Changes Over First Year's Cost

Finally, Figure P-112 uses simple cost change from year-to-year:

$$\frac{C_i - C_{i-1}}{C_{i-1}}$$

The conclusions from this figure would be the same as the previous one.

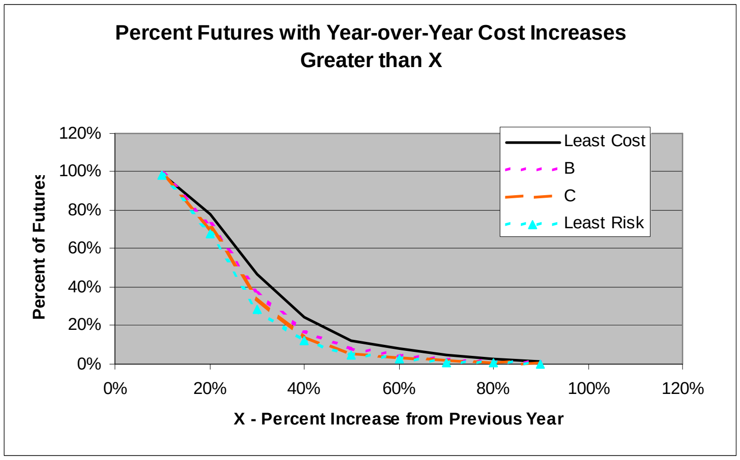


Figure P-112: Exceedance Probability: Changes Over Previous Year's Cost

By these measures, we see substantial reduction in cost volatility in going from the least-cost plan to any of the other three plans. Cost volatility among the three lower risk plans clearly decreases as TailVaR$_{90}$ risk decreases, but those three provide roughly similar results.

It is reasonable to ask what is driving the cost volatility. Figure P-107 and Figure P-108 suggests that the fix costs associated with new power plants are not the source of cost variation. In fact, plans with more resources seem to have less cost variation. This points to a source of risk that is prominent among the Council's concerns: electricity market price risk. While market price uncertainty can contribute to risk, it is not in itself a source of bad outcomes. The region needs to be a deficit situation and importing energy for high market prices to produce sudden increases in costs.

<u>Imports and Exports</u>

Figure P-113 [**34**] shows the difference in substantial imports between the least risk plan at least cost planned. For the purpose of this illustration, substantial imports are those exceeding 1500 MW-quarters. Imports are identical until about the year 2013, when power plants begin to appear in the least risk plan. As expected, there is more import in the least cost plan, exposing the region to high electricity market prices.

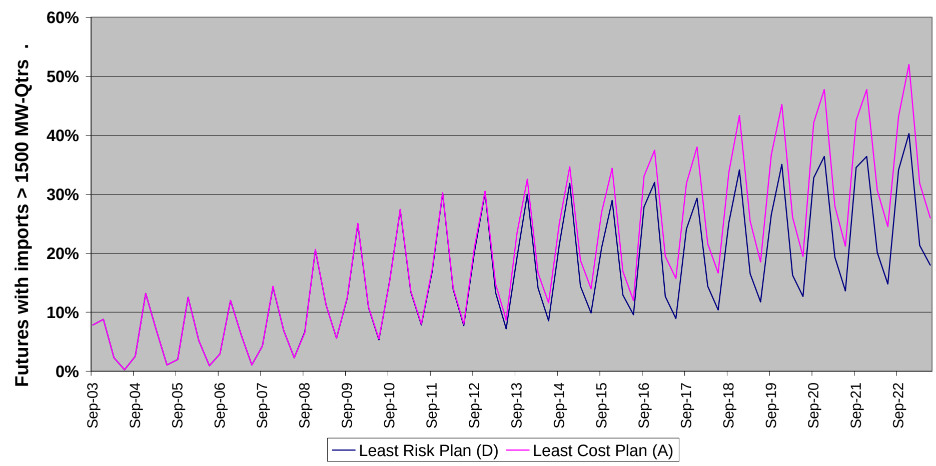


Figure P-113: Frequency of Futures with Large Imports

Exposure to Wholesale Market Prices

Figure P-114 [**34**] examines specifically those events where there are both substantial imports and high market prices for electricity (over $100 per MWh). This figure suggests several conclusions. The least-cost plan introduces substantially greater likelihood of incurring costs associated with high market prices than the least-risk plan. This is due to both the higher likelihood of high market prices with the least-cost plan and the higher likelihood of substantial imports. It is also notable that, with the least-risk plan the likelihood of regional exposure to wholesale market prices remains roughly the same throughout the study. Plan B reduces this likelihood by half, but not to the extent of the least-risk Plan D.

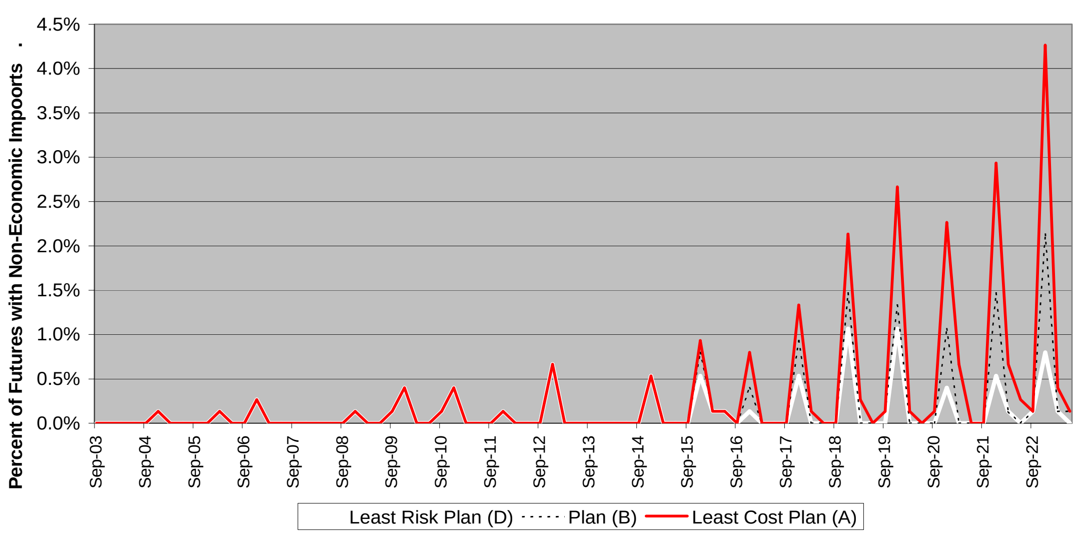


Figure P-114: Likelihood of Exposure to Non-Economic Imports

This concludes the analysis of cost volatility among plans in the feasibility space, and among plans on the efficient frontier, in particular. This analysis suggests that plans on the efficient frontier do not have the least cost volatility, but they do possess moderate cost volatility. Economically inefficient, resource-surplus plans have lower cost volatility. Among the plans on the efficient frontier, cost volatility decreases with plan risk, as measured by TailVaR_{90}. Most of the volatility, however, diminishes passing from the least-cost plan (Plan A) to Plan B (Figure P-103). Plan B has substantially more wind development than Plan A, and it lacks the IGCC plant and late CCCT development of Plans C and D.

Engineering Reliability

Many of the concepts introduced with the regional model are new to decision makers in the regional power planning community. Economic risk metrics, in particular, may be unfamiliar. As we will see, economic risk metrics appear to be more sensitive than engineering risk metrics. Nevertheless, there is no guarantee that a plan that has good economic characteristics must have high reliability from an engineering perspective. It stands to reason that decision makers will want to confirm that plans along the efficient frontier meet traditional measures of engineering reliability.

<u>Energy Load-Resource Balance</u>

It is challenging to relate the results from the regional portfolio model to other system planning models. Other models cannot capture certain events and behaviors, such as the regional model's dynamic reaction to unforeseeable futures. To better communicate the results of the regional model, Council Staff nevertheless examined questions typically put to system planning models like, "What is the loss of load probability associated with this plan?" or "What kind of a energy resource-load balance does that plan produce?"

The last question is the genesis of this section. At first glance, answering the question should be easy. There is, after all, a plan of construction and an expected load forecast. The difference between these, expressed in energy, should characterize the resource-load balance, shouldn't it? Actually, no, because the plan is a schedule of earliest construction. Which and how many plants eventually come on-line and the energy requirement both depend on the future.

Moreover, because the plan is essentially a schedule of options to build resources, the number and size of resources grows relative to the expected load. That is, the energy resource-load balance – what we occasionally refer to as the "energy reserve" – is growing relative to the load. The reason for the growth in reserve is that, further out there is greater uncertainty. With growing uncertainty about fuels, loads, taxes, and so forth, it is becomes cost effective to have more options to respond to that uncertainty. That is, the plan may have both a coal-fired and a gas-fired power plant as options in outlying years because the model will develop one or the other, depending on circumstances, but presumably not both.

One way to make the regional model results to a certain extent comparable is to examine the energy reserve on a future-by-future basis. For the recommend Plan, a sample on annual energy reserve from the 750 futures appears in Figure P-115.

What the figure shows are 12 futures with wildly varying reserve margins, which can rapidly change from relatively high, positive values to negative values. These sudden excursions are typically associated with business cycles, the return or departure of smelters, changing contract levels, and power plants coming into service. A major sources of load and production variability, weather and hydrogeneration stream flows, do not influence this picture, however. This figure reflects a planning energy reserve margin. Planning studies typically disregard those sources of variation. Instead, this figure shows energy reserve margin using weather-adjusted loads and critical water assumptions. (Critical water is the lowest hydrogeneration energy due to historical stream flow variation.)

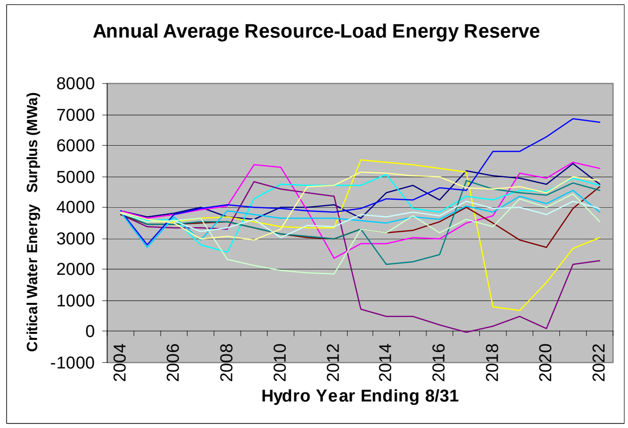


Figure P-115: Resource-Load Balance for the Plan

Figure P-115, however, does not provide a sense of what kind of patterns may exist over all the 750 futures. To see those patterns, statistical summaries are necessary. We emphasize again here that these statistical summaries may be misleading and require interpretation. (See the subsection “Comparison with the Council’s Load Forecast” of the section of the Uncertainties chapter dealing with Load.)

Figure P-116 shows the recommended Plan’s quarterly deciles for critical water energy reserve [**35**]. Chapter 7 of the Plan discusses four plans selected from along the efficient frontier. These plans are illustrated in Figure 7-2, which is reproduced below (Figure P-103) for easy reference. Figure 7-2 refers to the recommended Plan as Scenario D.

What is evident is from Figure P-116 is the median energy reserve stays about where it is today, perhaps a few hundreds of MWa higher. This is consistent with the observation that the region is currently surplus of resources, on an expected value basis. Also, the upper and lower bounds, the “jaws” so to speak, become wider farther along in time. This illustrates one of the facts highlighted earlier in this section: greater uncertainty merits greater contingency planning.

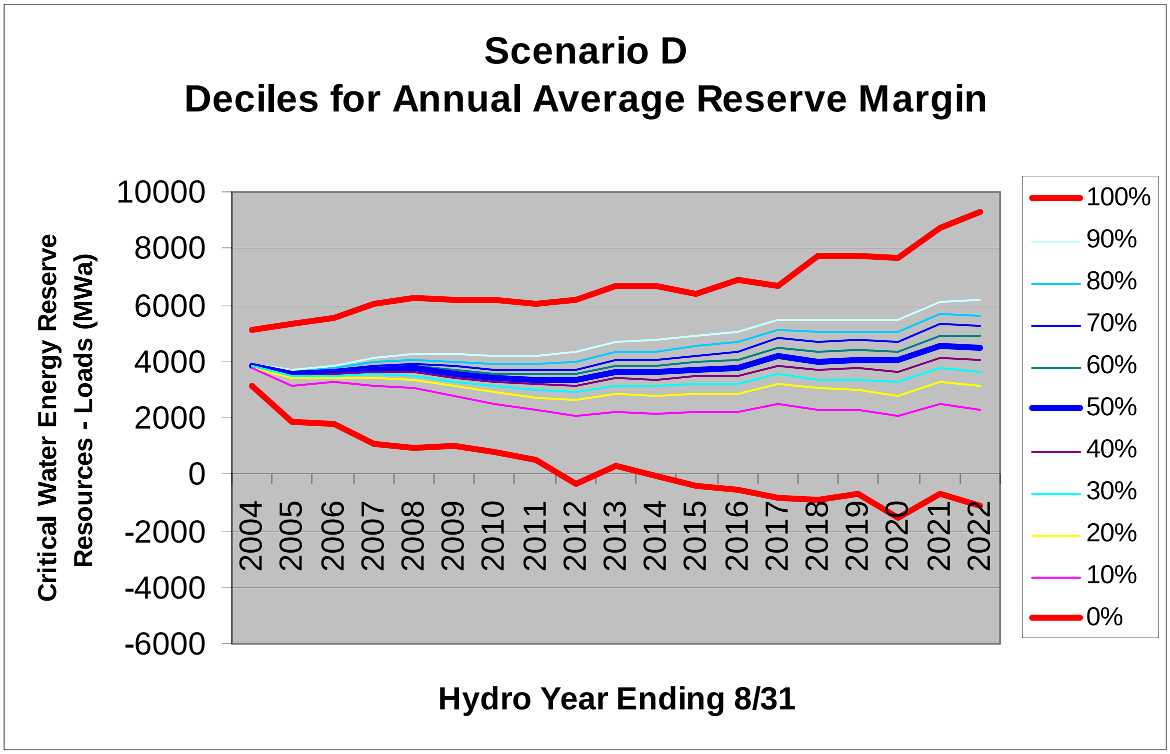


Figure P-116: Statistical Summary of Reserve Margin, Least-Risk Plan (D)

Finally, the lower jaw moves into negative energy reserve only in outlying years. From studies that the Council has performed on regional reliability, a deficit of 1000 MWa would still produce a reasonably reliable system as measured by loss of load probability. This graph suggests that economic reliability is more conservative, requiring more total resource, than engineering reliability measures. This stands to reason, because engineering reliability ignores the costs of the plants providing such reliability. In fact, inefficient or costly resources may be supporting the system for significant periods.

Several technical assumptions are material to interpreting these figures. First, IPP energy, totally about 3250 MWa, is included in the reserve margin calculation. Several regional planning organizations, such as the Pacific Northwest Utility Coordinating Council (PNUCC), do not include regional energy not under contract. Second, the energy associated with generation resources is discounted by maintenance but not by forced or unplanned outages. This is consistent with industry practice. Finally, the reserve calculation includes firm regional contracts and sales, according to the BPA White Book, and assumes 11650 MWa for critical water hydrogeneration.

Intuition suggests that lower cost, higher risk plans on the efficient frontier would have lower energy reserves. Working along the efficient frontier through Scenarios C and D (Figure P-118) to Scenario A (Figure P-117), this pattern is evident. All of the plans start out in a similar situation, which existing resource and load dictate. Only after about the year 2010 do the energy reserves differ significantly. The region is in a surplus situation

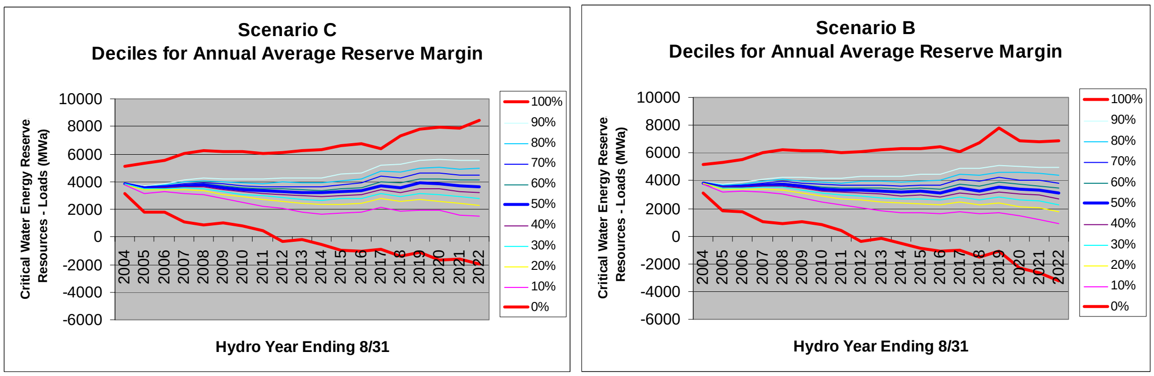


Figure P-118: Energy Reserve Statistics for Scenarios C and B

until then, and no resources or other actions – except for small differences in conservation – differentiate the scenarios.

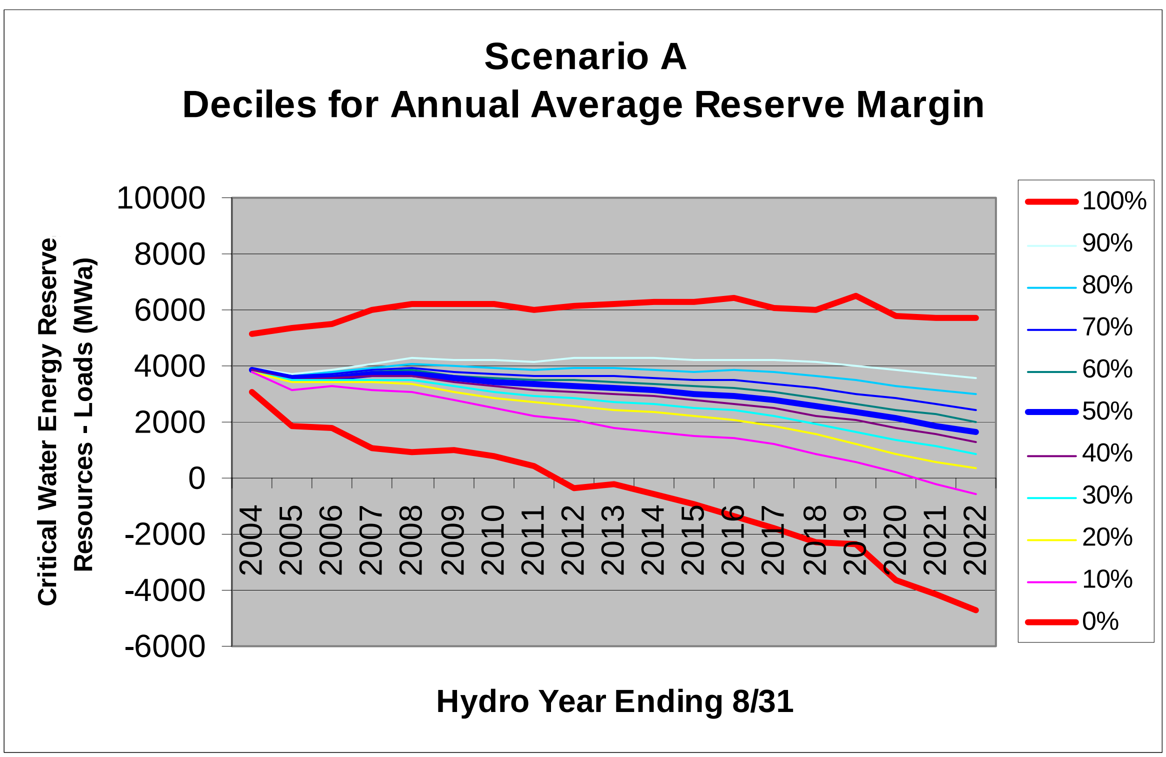


Figure P-117: Statistical Summary of Reserve Margin, Least-Cost Plan (A)

The least-cost plan, Scenario A, has a reserve margin that falls roughly 2200MWa between 2010 and the end of the study. In the least-cost plan, only inexpensive conservation enters the plan. It is not evident that Scenario A's energy reserve margin stabilizes during the study.

Loss of Load Probability (LOLP)

For the reasons described in the previous section, it's difficult to make a direct comparison of loss of load probability using the regional model to that from the traditional model. Nevertheless, Council Staff used the GENESYS model to analyze Plans A, B, C, and D using a single, representative future [**36**]. For this future, fuel prices and loads are identical to the benchmark values used in the regional model. Conservation and smelter loads are the average values across futures in the regional model. Power plant construction proceeds without interruption, and all power plants are in service on the earliest feasible date.

The three lower risk plans all produced zero loss of load probability across the years in the study. Only the least cost plan produced nonzero values.

Figure P-119 [**37**] shows the loss of load for the least cost plan in average megawatt-seasons on the vertical axis and the exceedance probability of the horizontal axis. There are five exceedance curves in this figure, corresponding to the study years 2008, 2010, 2013, 2018, and 2023. The horizontal, heavy black line is the Councils threshold for a significant event. The Council considers events smaller than 10 megawatt-seasons too small to be of concern. System operators can probably take some extraordinary measure to deal with such events, short of curtailing loads. The vertical, dashed red line is the Councils threshold for event likelihood. In principle, it is impossible to build a completely reliable system. Therefore, it becomes necessary to define a likelihood below which loss of load events are acceptable.

The Council considers a plan reliable if events do not simultaneously exceed the two thresholds. Referring to Figure P-119, the reliability of the system in a year corresponding to the curves is adequate if the curve does not enter the upper right hand quadrant defined by the two thresholds.

Clearly, the least-cost plan (Plan A in Figure P-103) is adequate by this definition in every year. The maximum loss of load probability associated with least-cost plan occurs in those two years just before an early combined cycle and wind power plant come online and again near the end of the study. Loss of load probability, by the Councils definition, reaches four percent in those two years.

This section on engineering reliability opened with a comment that economic risk assessment appears to be more sensitive than engineering reliability assessment. In this section, studies show that plans – even least-cost plans – that are on the efficient frontier pass engineering reliability planning criteria. This stands to reason because engineering reliability criteria, such as those presented in this section, ignore cost. Engineering criteria use prices to assure that the system operates in a realistic manner, using merit dispatch, but if load is not lost, there is no penalty. Economic risk metrics, on the other hand, will warn planners in advance that the last remaining, most expensive resources in the supply stack are maintaining reliability. Sufficiently high prices and penalties, moreover, will signal any event relevant to engineering reliability. In this sense, then, we conclude that economic risk assessment tend to be more sensitive than engineering reliability assessment.

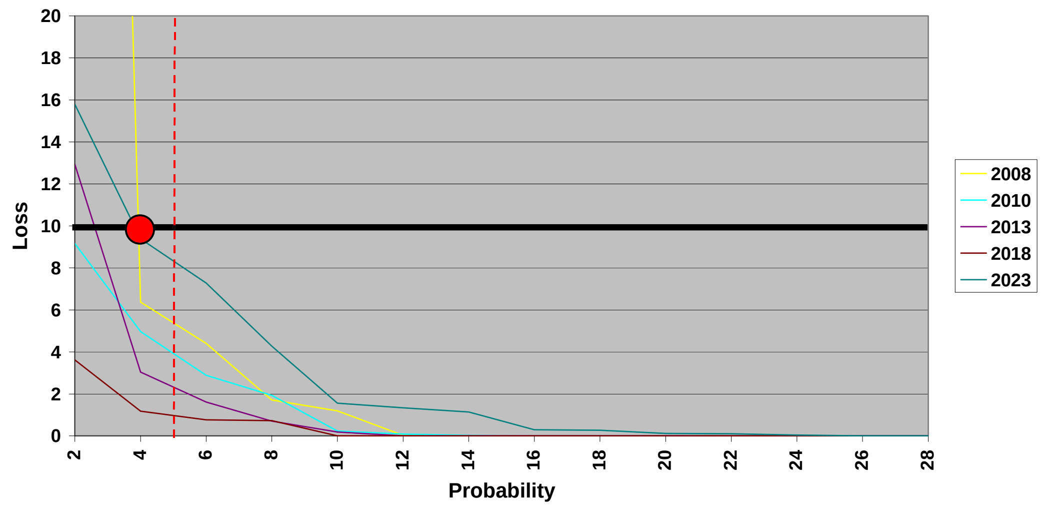


Figure P-119: LOLP for Least-Cost Plan

A Final Risk Consideration

Reviewing the results presented in this chapter, it would be reasonable to choose Plans B, C, or D. Plan A clearly has more risk and cost volatility. While Plan D has lowest risk, Plans B, C and D have comparable performance. All three plans call for substantial amounts of wind, which is absent in Plan A. Plan C adds more CCCT capacity later in the study; Plan D begins the construction of an IGCC coal plant in 2012.

One source of risk not discussed above, however, is the risk of premature commitment. Most planners understand that it would be a blunder to commit to a decision any earlier than necessary. More time brings more information and perhaps additional options. This is the reason why plans typically comprise an *action plan*, focusing on the immediate commitments, and the rest of the plan, which addresses activities later in the study.

The selection of Plan D costs nothing now and reduces premature commitment risk. Specifically, it implicitly calls for reevaluation of alternatives earlier than would Plan B or Plan C. The coal plant and CCCT units have longer lead-time than do the wind units, and the wind units in Plan D arrive earlier and in larger number. By selecting Plan D, the Council has signaled a reevaluation of the Plan no later than 2009, three years before the earliest construction date 2012. Three years are necessary for the siting and licensing process of a IGCC plant. If the IGCC were to be located in a transmission constrained region like Idaho or Montana, which is a strong possibility, transmission studies need to begin immediately. Transmission has an even longer lead-time. If the Council were to choose Plans B or C, instead, no reevaluation probably would be necessary until 2012, and transmission may not be as much of an issue. If the region waited until 2012 and then discovered it needed an IGCC plant, however, the delay could be costly.

Summary and Conclusions

This section addresses $TailVaR_{90}$ as a risk measure for the region. The section introduced coherence measures of risk and explained their advantages. ($TailVaR_{90}$ as a coherent risk measure.) It explored alternative measures of economic risk and evaluated how representative $TailVaR_{90}$ is with respect to each. It concludes that $TailVaR_{90}$ is representative, in the sense that the other risk measures examined would have produced the same or substantially the same choice of plans for the efficient frontier.

This section also examined the plans on the efficient frontier using cost volatility and engineering reliability planning criteria. Plans on the efficient frontier do not have the least cost volatility, but they do possess moderate cost volatility. Economically inefficient, resource-surplus plans have lower cost volatility. Among the plans on the efficient frontier, cost volatility decreases with plan risk, as measured by $TailVaR_{90}$. Most of the volatility, however, diminishes passing from the least-cost plan (Plan A) to Plan B (Figure P-103). All of the plans on the efficient frontier appear to be reliable with respect to loss-of-load probability (LOLP) and resource-load balance.

Finally, while Plans B, C, and D have similar performance with respect to cost volatility and engineering reliability planning criteria, Plan D permits the Council to minimize premature commitment risk at no cost. For this reason, the Council selected Plan D as its preferred resource plan for the Council's Fifth Power Plan.

Sensitivity Studies

This chapter presents the results of detailed sensitivity analyses. The Council performed over 160 studies to understand how the conclusions of the model depended on assumptions, such as model structure, natural gas price, carbon penalty, the rate of conservation implementation, the feasibility of wind generation, and alternative decision criteria. Valuation studies are a specific kind of sensitivity analysis. The Council performed studies to value conservation, demand response, wind, and the gross value of independent power producers' power plants. Each study requires producing a feasibility space: about 1400 twenty-year plans, each evaluated using 750 futures. In all, this work represents approximately 160 million twenty-year studies of hourly Northwest power-system operation.

The sensitivity studies appearing in this section do not all use the same basecase or model. Because preparing feasibility spaces is time-consuming, typically requiring a day of computer simulation and a comparable amount of time for analysis, this section presents only the last completed studies. This should not be a limitation, however, to understanding the influence or effect in question. The Council performed these sensitivities with several models and varying sets of assumptions. After studying the results from multiple studies, typically a strong and intuitive pattern emerges. This chapter will present those patterns.

The reader should pay *little* attention to the absolute cost and risk values associated with the feasibility spaces, therefore. The base case values will depend on the model logic and assumptions, which may change dramatically from summary to summary. Instead, the reader should pay attention to the *change in location and shape* of the efficient frontier, between the sensitivity case and *its* corresponding base case. Each section below will present these side by side, with the base case illustrated with blue points and the change case illustrated in red points.

In the following, the format of each section will be

- A brief description of the issue
- Description of the workbook modeling
- Results from the efficient frontier
- General observations and conclusions

High Natural Gas Price

In this sensitivity [**38**], the average natural gas price was $1.50/MMBTU higher than in the base case. The purpose is to understand the implications if the median of the natural gas price distribution were higher than used in the base case.

There is no adjustment to electricity price, including through sensitivity parameters, described in the section beginning on page P-72. The benchmark prices in {{row 53}} are $1.50/MMBTU higher.

Figure P-120 shows the displacement of the efficient frontier due to increased price of natural gas. The base case is in blue (light blue frontier) and the sensitivity case is in red (yellow frontier). Much of this displacement, of course, is due to existing gas-fired resource. The new resources in the plans along the frontier have little influence on total system cost.

What is of interest is the makeup of plans on the efficient frontier. Perhaps not surprising is that wind generation and conservation develop more across the entire efficient frontier, while CCCTs are less popular. More surprising is that coal is not on the efficient frontier in either case, and there remains a substantial amount of CCCT siting and licensing. Despite low coal price and there being no uncertainty associated with coal price, this change in the distribution of probabilities for gas price futures seems to have little effect on the attractiveness of coal-fired generation. That CCCTs remain attractive can be understood from two factors. First, wind generation development is capped, and additional capacity of some sort is required. Second, new gas-fired generation is more efficient than existing gas-fired generation. Consequently, the newer units can economically displace older gas-fired units.

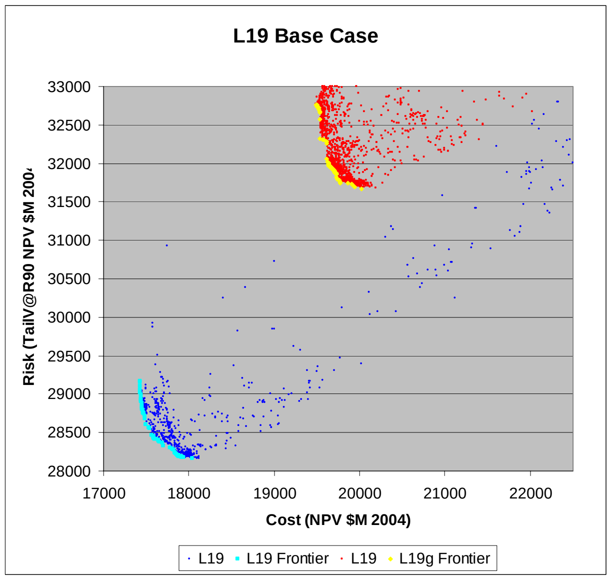


Figure P-120: High Natural Gas Price

Reduced Electricity Price Volatility

Electricity price volatility does not affect the value of all plants or plans equally. Non-dispatchable plants like wind and conservation, for example, are unaffected by such volatility. Only the average price of electricity determines their hourly value. On the other hand, volatility is a major determinant of the value of high-heat rate combustion turbines, such as SCCTs, and of demand response. Volatility also will increase the value of reserve margin strategies. Volatility can affect decision criteria differently. Thus, it is important to understand the influence of volatility assumptions.

In one study [**39**], Council Staff cut in half the four parameters that control the jump size and principal factors for the independent term of electricity price:

Principle Factor constant offset (R94): (-0.5, 0.0, 0.5) ← (-1.0, 0.0, 1.0) triangular distribution
Principle Factor growth (R96): (-0.58, -0.33, 0.42) ← (-0.83, -0.33, 1.17) triangular distribution
Jump 1 Size (S99): (0.1.25) ← (0,2.50) uniform
Jump 2 Size (S100): (0.1.25) ← (0,2.50) uniform

As one might suspect, the average cost and risk declined with reduced electricity price volatility (Figure P-121). With this change, the premium for conservation disappeared, except at the most risk-averse end of the efficient frontier. The CCCTs are not developed. Contrary to the situation described at the opening of this section, there is *more* development of SCCTs. The lower probability of futures with high electricity prices would tend to make the fully allocated cost of such power less expensive. Wind develops somewhat less extensively across the efficient frontier, perhaps for the same reason as for other capital-intensive resources.

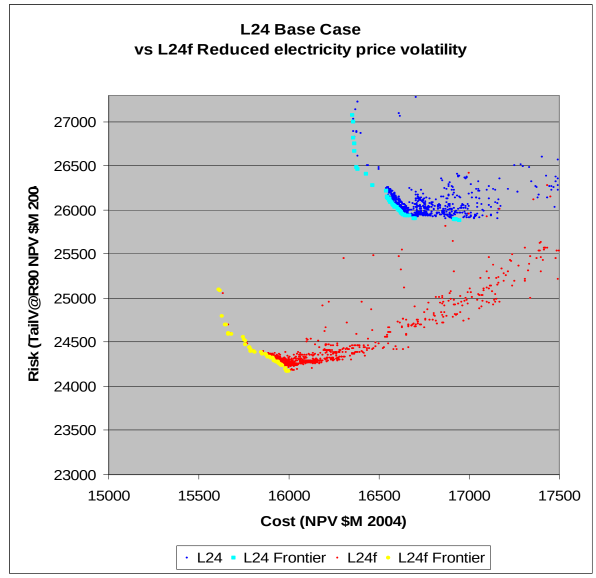


Figure P-121: Reduced Electricity Price Volatility

CO_2 Policy

Because of the prominence of debate over climate change, its possible causes, and its possible effects, the Council performed numerous analyses with alternative assumptions regarding the magnitude and likelihood of a CO_2 tax. (See also the discussion of CO_2 uncertainty, above.) Some decision makers may do not share the view of CO_2 tax uncertainty adopted by the Council. These studies can perhaps help inform those decision makers about the credibility of regional model results.

No CO_2 Tax or Incentives for Wind

One view of the future might be that, scientists will determines climate change is unrelated to manmade activities. Moreover, clean fossil fuels will become cheap and abundant. There is no chance of any CO_2 tax in this world and renewable energy has no value. Consequently, there is no chance for continuing the PTC, and green tag value falls to zero.

Note that base case modeling for CO_2 tax, PTC, and green tags already allows for *futures* such as this. This sensitivity study, however, posits that there is ***no possibility*** of positive values for these uncertainties.

Four separate studies examined the consequences of this set of assumptions. The latest [**40**] found new wind generation constructed in less quantity and much later, if at all, along the efficient frontier. Instead, a modest amount (400MW) of coal-fired capacity can begin construction around 2013 in about half the plans, those nearer the least-risk plan. The plans also have greater incentive for and more extensive deployment of lost-opportunity conservation. There is slightly less CCCT development at the least-cost end of the efficient frontier and slightly more development at the other end.

Many assume that the possibility of a CO2 tax is coal generation's biggest risk. This study shows that eliminating CO2 tax alone does not make coal a leading candidate for new capacity, even assuming low and stable fuel cost. The section "Conventional Coal," below, elaborates on the regional model's study results for that technology.

Higher CO2 Tax

For a study that incorporates higher levels of CO_2 tax [**41**], the Council chose one of the tax scenarios that appear in an MIT analysis of the proposed 2003 McCain-Lieberman Act.[42] The study implements the McCain-Lieberman schedule for CO2 tax (MIT Study, Table 4, page 17, Scenario 5), which is \$25/ton (2010), \$32/ton CO2 (2015), \$40/ton CO2 (2020), all in 1997\$. These levels are converted to 2004\$ by annual inflation of 2.5 percent and are converted to piecewise linear function of time. The resulting schedule appears in Figure P-122. This high level of tax is deterministic and is present in all futures with the same fixed schedule. (The regional model workbook implements the tax by pasting the values in this figure into row {{74}}, the final value for the CO2 tax future.)

The feasibility space, illustrated in Figure P-123, shifts significantly up and to the right. The additional expected system cost associated with this sensitivity is about \$9 billion (NPV 2004\$). Discretionary conservation takes a big step forward in this sensitivity, increasing both the recommended premium for development and the amount delivered. CCCTs and wind develop extensively, even in the least-cost plans. The incentive for new CCCT capacity is the displacement of older, less efficient units. Not too surprising, coal-fired generation is nowhere near the efficient frontier.

Inflation annual rate		Conversion to 2004$	
2.5%			1.188686
Calendar Year	Period	1997$	2004$
2004	2	1.00	1.19
2004	3	2.00	2.38
2004	4	3.00	3.57
2004	5	4.00	4.75
2005	6	5.00	5.94
2005	7	6.00	7.13
2005	8	7.00	8.32
2005	9	8.00	9.51
2006	10	9.00	10.70
2006	11	10.00	11.89
2006	12	11.00	13.08
2006	13	12.00	14.26
2007	14	13.00	15.45
2007	15	14.00	16.64
2007	16	15.00	17.83
2007	17	16.00	19.02
2008	18	17.00	20.21
2008	19	18.00	21.40
2008	20	19.00	22.59
2008	21	20.00	23.77
2009	22	21.00	24.96
2009	23	22.00	26.15
2009	24	23.00	27.34
2009	25	24.00	28.53
2010	26	25.00	29.72
2010	27	25.35	30.13
2010	28	25.70	30.55
2010	29	26.05	30.97
2011	30	26.40	31.38
2011	31	26.75	31.80
2011	32	27.10	32.21
2011	33	27.45	32.63
2012	34	27.80	33.05
2012	35	28.15	33.46
2012	36	28.50	33.88
2012	37	28.85	34.29
2013	38	29.20	34.71
2013	39	29.55	35.13
2013	40	29.90	35.54
2013	41	30.25	35.96
2014	42	30.60	36.37
2014	43	30.95	36.79
2014	44	31.30	37.21
2014	45	31.65	37.62
2015	46	32.00	38.04
2015	47	32.40	38.51
2015	48	32.80	38.99
2015	49	33.20	39.46
2016	50	33.60	39.94
2016	51	34.00	40.42
2016	52	34.40	40.89
2016	53	34.80	41.37
2017	54	35.20	41.84
2017	55	35.60	42.32
2017	56	36.00	42.79
2017	57	36.40	43.27
2018	58	36.80	43.74
2018	59	37.20	44.22
2018	60	37.60	44.69
2018	61	38.00	45.17
2019	62	38.40	45.65
2019	63	38.80	46.12
2019	64	39.20	46.60
2019	65	39.60	47.07
2020	66	40.00	47.55
2020	67	40.40	48.02
2020	68	40.80	48.50
2020	69	41.20	48.97

Figure P-122: Adapted CO2 Schedule

[42] Paltsev, S., J.M. Reilly, H.D. Jacoby, A.D. Ellerman & K.H. Tay, ***Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal***, MIT Joint Program on the Science and Policy of Global Change, Massachusetts Institute of Technology, June 2003 http://web.mit.edu/globalchange/www/ (Link to file server)

This study is the latest of three performed using different base case assumptions. All studies resulted in roughly the same outcomes.

CO2 Tax of Varying Levels of Probability

As mentioned in the Uncertainty chapter, some carbon tax is present in about two-thirds of futures. With no CO2 tax and few incentives for wind, coal-fired generation begins to make an appearance on the efficient frontier. (See the discussion on page P-135.") In early studies [**42**], CO2 tax was not tiered as it is in the Draft and Final Plans, and the probability of a CO2 tax was higher. In an attempt to threshold the conditions that favor alternative plans, various modeling studies [**43**] examined the effect of reduced probability of CO_2 tax and increased natural gas price. These studies shaped the representation for CO2 tax used in the final Plan.

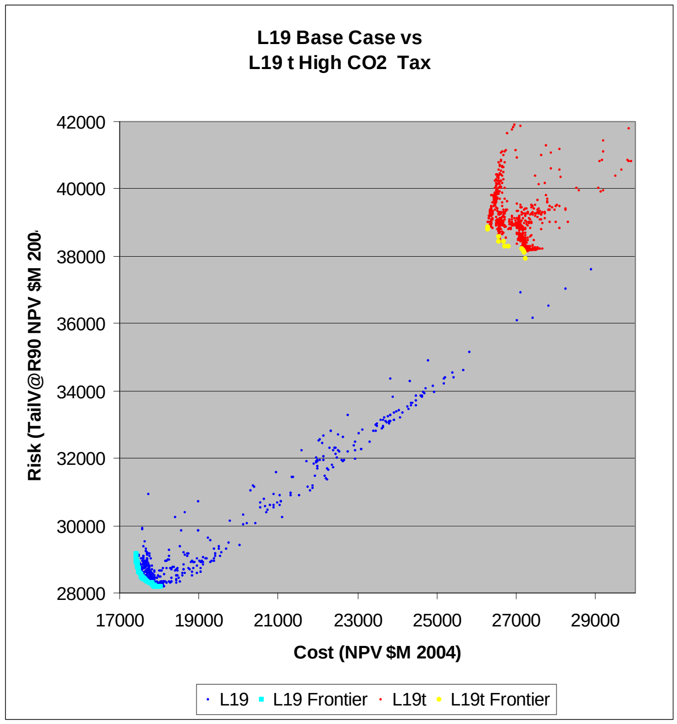


Figure P-123: Feasibility Space for High CO2 Tax

Examining the plans on the efficient frontier of the study least favorable to wind generation and most favorable to coal-fired generation, wind still demonstrated a relative advantage. Even with only 25 percent probability of a CO2 tax by the end of the study and an increase of $1.50/MMBTU in natural gas prices, no coal plants appeared.

These studies convinced the Council that in the kind of risk analysis the regional model performs the "tail events" can and often are more important than expected value events. The models does not choose Coal in plans at the least-cost end of the risk-cost trade-off curve, because relying on the market and not building resources is least cost. The models does not choose Coal in plans at the least-risk end of the curve, often because the futures where CO_2 tax does appear and planning flexibility is important hurt the performance of such plans.

To model these studies, the uniform distribution in the assumption cell {{R72}}, which controls in which period a CO2 tax of any size occurs, has larger range. Extending the upper value of the uniform distribution to 20 from six effectively reduces the chance any tax will start before the end of the study. (See page P-88 ff for a description of how the model uses this parameter.)

Independent Power Producers

In studies performed before release of the Draft Plan, the regional model considered Independent Power Producer (IPP) generation part of the region. During the vetting process, however, the Council realized that this was not consistent with how previous Council plans have defined the region. Specifically, the Council has taken the "region" to be the *ratepayers* in the area specified by the Act. It is also not consistent with how other regional utility planning organization, such as the Pacific Northwest Utility Coordinating Council (PNUCC) account of IPP plants.

Equating the region to its ratepayers is key to how the regional model performs its economic evaluation. The fully allocated costs of power plans belonging to regional utilities eventually pass to regional ratepayers. With public utilities and co-ops, the flow of plant expenses and profits back to ratepayers is relatively direct and evident. For privately held utilities, the flow may be less obvious to some observers. Assuming perfect regulation, the shareholders of private utilities receive only the return of and the return on capital investment in plants, called the "ratebase." These returns occur over time, through the utility rates. This means that revenues *unrelated* to ratebase, the profits and losses from power plant operation, flow back to *ratepayers*, not to shareholders. Thus, the economic situation is just as it would be for a municipal utility.[43]

With IPP generators, however, the situation is different. Profits and losses from power generation of merchant plants flow to shareholders, who are *not* generally ratepayers of the region. The ratepayers effectively pay prevailing market prices for IPP power. (Perhaps forward contracts markets or ancillary services markets are more appropriate than wholesale firm energy markets in a given situation, but the principle is the same.)

With that clarification, the Council changed how the regional model captures the role of IPP plants. In the Draft and Final Plan, IPP plants contribute only to the energy balance in the region. The model ignores IPP costs and profits.

This does not mean, however, that the IPP units have no influence in the results. Because the model constrains regional imports and exports, the model changes electricity prices as necessary to balance supply and demand. (See "The Market and Import/Export Constraints" and, in particular, the subsection "RRP Algorithm" in Appendix L for an explanation of this process.) To the extent that there are additional sources in the region to balance requirements, therefore, the likelihood of higher electric market prices diminishes. The lower expected market prices, in turn, flow through to the region. Regional utilities will buy and sell into the market to balance their respective load, and the additional IPP generation will extend the depth of supply in that market. The Council believes this approach more accurately models the role IPPs serve in the region.

[43] There are, of course, financing, governance, and other differences, but the model tries to deal with those through the calculation of real levelized costs (see Appendix L). The discussion here is only about whether the construction and operating revenues pass to the ratepayer.

This situation comports with information provided by the IPP industry and with publicly available data on IPP plant dispatch. Much of the information about the role of IPPs in the region appears in Chapter 2 of the Plan, as well as in the Overview of the Plan. In summary, about 3000 MW of IPP capacity remained uncommitted as of December 2004, when the Council adopted the Final Plan. Spot sales into the market remained vigorous, nevertheless, with plants averaging about 50 percent capacity factor over the previous year.

How does the workbook model represent IPP operations? Appendix L has several pages of description, under the chapter "Resource Implementation and Data." The reader will find there both the model's data and formulas.

This section describes two studies the Council performed to better understand the role of the IPPs in the region. The first looks at the value of IPPs to the region. The second examines the effect if out-of-region purchasers contracted for all of the IPP capacity.

IPP Value

A study [**44**] attempted to estimate how much the IPP generation would be worth to the region, assuming all of the costs and benefits flowed through to regional ratepayers. This might arise, for example, if regional utilities contracted for all the output of the IPP plants.

The study, however, suffers from a serious difficulty. The approach is simply to include the operating costs and benefits of IPP plants, much as in early study work. This is acceptable for existing regional plants, because the construction costs are embedded and do not change from plan to plan or from future to future. For the region, however, the cost of acquiring the IPP plants is not "sunk;" it is not embedded. In fact, depending on the price that utilities would pay to acquire the output of the IPP plants, any benefit will shift between regional ratepayers and IPP shareholders. If the price were high enough, the region might not see any benefit, and it might even see a net disadvantage.

The problem does not go away if the study simply chooses an arbitrary allocation of benefit. The modeling issue is more delicate than that. At some price, which we have no easy way to determine beforehand, plans including IPP purchases or contracts will not appear on the efficient frontier of the feasibility space. Substitutes for risk mitigation will become competitive. Moreover, because the IPP plants are not homogeneous – Centralia coal plant is among them, for example – plants will not appear on the efficient frontier in aggregate. The problem would then become one of determining a threshold acquisition price for each resource. That threshold price, in turn, depends on which other IPP resources appear on the efficient frontier. Of course, nothing assures us that the price the region might be willing to pay for a plant's output would be acceptable to the current owner.

There are, of course, many other difficulties. Acquiring IPP output can adversely affect utility financing, for example. Chapter 2 of the Plan mentions some of the more prominent reasons why utilities might not choose to contract for IPP output.

With these caveats, this sensitivity study implicitly assumes IPP owners give the plants to the region for free. There is no acquisition cost. This sets a (rather unrealistic) cap on the potential value of acquiring the plants for the region. Figure P-124 illustrates the reduction in cost (about $4 billion) and risk.

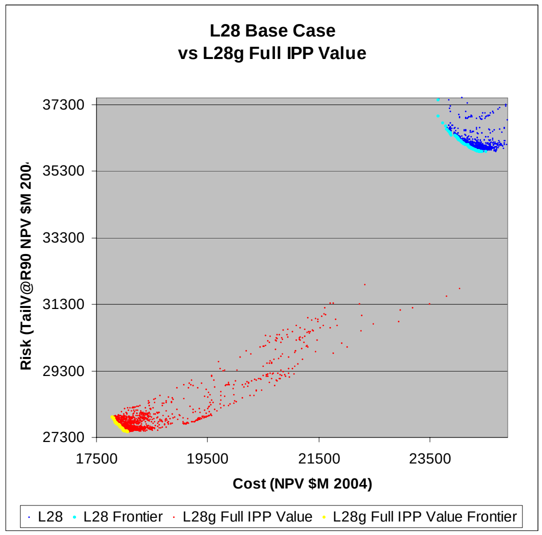


Figure P-124: Acquiring the Full Value of IPP Plants

Purchasing the output of the IPP plants pushes off most of the schedules for new resources, in including conservation and wind. Because of their reliance on fossil fuels and natural gas in particular, however, IPP units cut the schedule of wind by half, but some wind remains on the frontier. In the least-risk case, 2500MW of wind appears before the end of the study.

In the workbook, capturing the cost and benefit of the IPPs amounts to reversing the NPV cost adjustments described in Appendix L. Appendix L uses the example of the on-peak values for the surrogate plant "PNW West NG 3 006" which appear in row {429}. From the Appendix L discussion of valuation costing and of the thermal dispatch UDF, the value is the negative cost appearing in this row. The formula in cell {CV429} discounts these values to the first period:

=0.434512325830654*8760/8064*NPV(0.00985340654896882,$R429:$CS429)*
(1+0.00985340654896882)

The factor of roughly 0.4345 discounts the value of the plant, because about 43.45 percent of the plant belongs to a utility in the region and the rest of the plant (56.55 percent) is IPP. For the sensitivity study, this leading coefficient becomes 1.0, as do those for any plant that is partially or completely IPP.

Contracts for Sale of IPP Energy Outside of the Region

Participants in the public process of reviewing the regional resource plan asked, “What would happen if the output of the IPP plants were contracted outside the region?” The concern is that the region might suddenly find itself substantially short of resources. If that situation were possible, the region might need to acquire additional resources as protection against that contingency.

The initial approach to modeling this situation was simply adding contract exports, along with corresponding counter-scheduling adjustments to import/export constraints (see "Contracts" in Appendix L). This creates a heavier load for region, which the IPPs should incur. There must be an addition adjustment, however, to the economics. Increasing the load alone increases the *economic* obligation of the *region*. That is, the region sees an increase in the load it must serve. This is incorrect, however, as the IPPs are incurring the economic obligation, not the region. Thus to correctly model the situation, the energy out of the region must be increased, but the load used for economic value (or cost) of existing contracts to the region should remain *as in the base case*. With this representation, any effect for the region is due to electricity market price increases due to IPPs no longer contributing to the market.

Figure P-125 shows the results of this study [**45**]. Effectively, the sensitivity case and base case feasibility spaces are lying on top of one another. Within the repeatability of this tool, there is no discernable difference. The plans along the efficient frontier are essentially the same, as well.

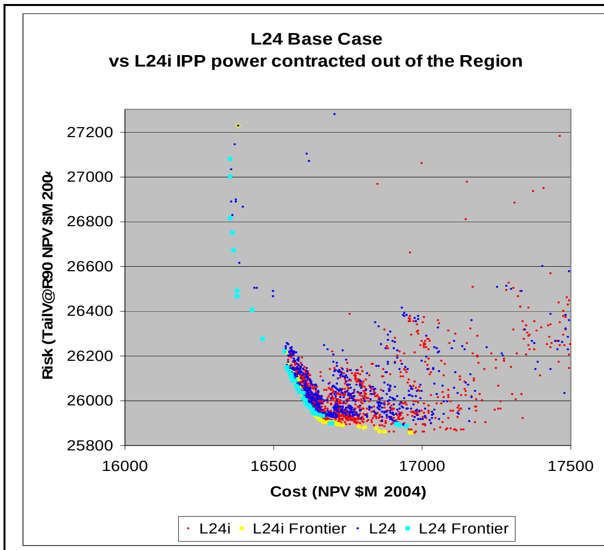


Figure P-125: IPP Energy Contracted Out-of-Region

Why would there be so little change? At least market prices should rise, as mentioned above, increasing the cost to the region. In fact, what happens is that the model counter schedules contracts. The final dispatch of IPP units does not depend on the contract terms or initial contract obligations, but only on the IPP plant economics relative to the other plants in the region, i.e., a plant's place in the system merit order. The market price for electricity, in turn, depends primarily on the dispatch of the plants in the region. (See Appendix L for a discussion of economic contract counter-scheduling.) Therefore, market prices are unaffected by contracts. Indeed, this is the reason why many simulation models, such as Aurora, can and do ignore contracts.[44]

[44] A handful of models, such as the Henwood's PROSYM® model, do model contracts because they need to capture pre-dispatch commitment costs due to reliability provisions in transmission and capacity contracts, or because their results will be used for production costing, where financial arrangements are important.

Contracts do make a large difference to the parties of the contract, of course. The difference is financial, however, and Appendix L shows it is in the economic self-interest of the supplier to re-dispatch units whenever physical constraints are binding or plant economics are out of merit order.

The workbook modeling for this sensitivity study is involved. First, contract sales, both on- and off-peak, increase by the combined seasonal output of the IPP plants. The original level of sales, however, remains in the workbook for the economic costing calculation. The net cost of contracts will be the net position times the prevailing market price. (The study assumes contract cost of energy is fixed and embedded. This would be the case for a forward contract. The *net* value of contracts is the difference between this fixed cost and the value of the energy.) The seasonal IPP capacity is in Figure P-126.

	Fall	Winter	Spring	Summer
IPP cap	3259	3469	2547	2939
source: IPPs Removed.xls				

Figure P-126: Seasonal Distribution of IPP Capacity

Second, the seasonal capacities reduce the import values for contracts. The original values remain, however, to permit the cost calculations described above. Figure P-127 illustrates the original and adjusted values for contracts (MWa) on- and off-peak. The on-peak values appear in rows {{83 and 84}} and the off-peak are in rows {{87 and 88}}. The differences between the original and adjusted values are the numbers in Figure P-126. (The difference cycles among the seasonal values throughout the study.) The on-peak energy values are negative, representing net sales out of the region. The original off-peak values are positive, representing net imports, and the adjusted off-peak values are negative, representing net sales.

Figure P-127 also shows the on-peak energy (MWh) and cost ($M 2004) calculations in rows {{367 and 368}}, respectively. The energy calculation uses the adjusted values; the costs use the original. In the formula for cell {{U368}},

= -1152*U83*U204/1000000

the reference to {{U204}} is the on-peak price for energy, and 1152 is the number of on-peak hours in the hydro season. (Appendix L provides a more complete description of this formula and conventions.)

U368 = = -1152*U83*U204/1000000

	Q	R	S	T	U
82					
83	Original On-Peak Contracts	-996.63	-205.46	-657.54	-1147.22
84	Adjusted On-Peak Contracts	-4,255.74	-3,674.89	-3,204.04	-4,086.42
85					
86					
87	Original Off-Peak Contracts	247.50	759.93	372.54	309.84
88	Adjusted Off-Peak Contracts	-3,011.61	-2,709.50	-2,173.96	-2,629.36
366					
367	Fixed Energy ID: Reg Contracts 8 SubPer_003	-4902614.1	-4233478.4	-3691053.4	-4707557.2
368	Cost ($M)	54.3	8.4	32.0	42.8

Figure P-127: Contract Energy and Value

The formulas for energy balance and for total study cost point to rows {{367 and 368}}, just as before.

Reduced Discretionary Conservation

Many questions about the representation and assumptions regarding conservation arose during the studies that led up to the Final Plan. These questions included

- How are decisions about conservation programs made?
- How can the model capture program diversity with a simple supply curve? It is not economic to develop only the least expensive conservation programs, as the supply curve approach assumes. Typically, a utility or customer implements a variety of programs when an opportunity arises to do so. Instead, these programs have a mix of different cost-effectiveness profiles.
- How should the model represent the fact that not all of the energy efficiency programs are mature and that they will mature at different times?
- How does the efficient frontier change as a function of the premium paid for conservation over the “myopic” cost-effectiveness standard?
- Is there value in sustained orderly development, and if so, what is that value?
- To what extend does the rate of deployment affect the cost of a measure?
- What is a reasonable rate of deployment for discretionary conservation, where large amounts of discretionary conservation are cost-effective?

Circumstances forbid sharing all of these studies. The last study, however, is especially prominent. The Council incorporated the results of this study into the base case.

By definition, the region can pursue discretionary conservation at any time. The Council has estimated the amount of such conservation exists in the region, and much of it is cost effective today. In early studies, the regional model controlled the rate of deployment, and the model would choose thousands of MWa of this conservation in the first periods of the study. This is unrealistic behavior for several reasons; not least among them being the limited resources utilities have to pursue conservation.

Chapters 3 and 7 of the Final Plan describe the issues that the Council faced in deciding how rapidly the model could pursue discretionary conservation. Ultimately, this is an educated guess. This section presents some of the quantitative information the Council used to arrive at its conclusions.

The associated studies [**46**] examined three rates of discretionary conservation development: 10 MWa, 20 MWa, and 30MWa per quarter. The Council began examining the effect of these levels over six months before issuing the Draft Plan and checked the results again with the model used to prepare the Final Plan. The results here are from the Final Plan studies. By the time the Council had released the Draft Plan, however, the base case adopted the 30MWa per quarter rate.

Figure P-128 shows how the feasibility space changes as the rate of acquisition moved to 20 MWa per quarter (L28b “Mildly Restricted Conservation”) and to 10 MWa per quarter (L28c "Least Conservation"), from 30MWa per quarter. The policy of pursuing 30MWa per quarter appears to facilitate plans that are both less risky *and* less costly.

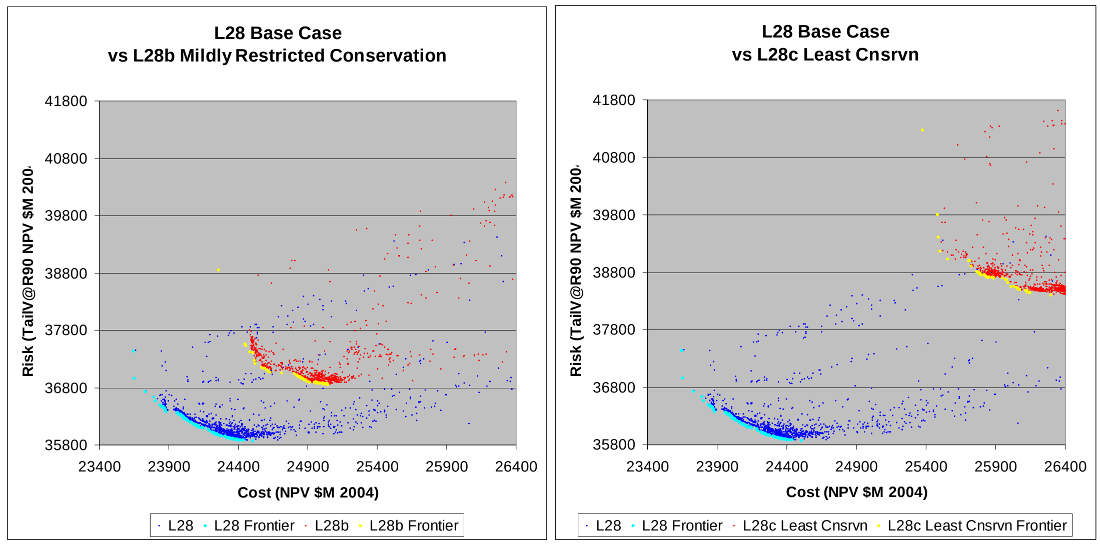
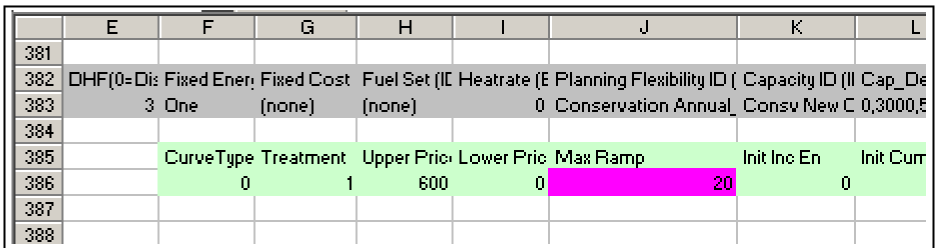


Figure P-128: Discretionary Conservation Ramp Rate Sensitivity Cases

To implement this sensitivity in the workbook, the study modified a supply curve modeling parameter. The cell {{J386}} controls the quarterly ramp rate. Figure P-129 shows the set up for the 20MWa per quarter case. A description of how the model represents discretionary conservation with a supply curve is in Appendix L.



	E	F	G	H	I	J	K	L
381								
382	DHF(0=Dis	Fixed Ener	Fixed Cost	Fuel Set (ID	Heatrate (E	Planning Flexibility ID (	Capacity ID (II	Cap_De
383	3	One	(none)	(none)	0	Conservation Annual_	Consv New C	0,3000,5
384								
385		CurveType	Treatment	Upper Pric	Lower Pric	Max Ramp	Init Inc En	Init Curr
386		0	1	600	0	20	0	
387								
388								

Figure P-129: Supply Curve Ramp Rate Specification

Value of Demand Response

Like the situation for discretionary conservation, early studies suggested that the regional model would take unrealistically large amounts of demand response immediately, given the assumptions in the model. The Council therefore chose to constraint demand response to levels of development it deemed reasonable. Because constraining demand response to these levels essentially fixed deployment of demand response at these levels, the Council eventually decided to fix the demand response-deployment pattern. Using a fixed pattern saves time by relieving the regional model's plan optimizer from examining plans known to be subordinate.

One issue that interested Council Staff, however, was the value of demand response. In the discussion of IPP valuation, above, simply adding the IPP energy value and variable costs to the region's budget did not permit the Council from accurately capturing the value of the IPPs to the region. The reason is that that approach ignores IPP acquisition cost to the region. With demand response, however, the model includes an acquisition cost. Because the Council fixes the demand response-deployment pattern, the study finesses the question of whether a given acquisition cost would affect the deployment decision.

Demand response appears in regional studies as a simple, dispatchable resource. It has low capital cost, and a fuel/dispatch cost corresponding to the payment for which the Council assumed loads might voluntarily remove themselves. The model represents demand response as a combustion turbine with a fixed $150/MWh dispatch cost. The capital costs, however, are low: about $2.26 per kw-year real levelized [**47**]. (See Appendix L.) The Council has an Action Item in the Final Plan to study and refine its cost and availability information about demand response potential in the region. Eventually, modeling will mature into a supply curve approach that reflects the short- and long-term diversity of costs among options.

One study [**48**] of demand response evaluated the impact of removing demand response entirely from the study. The change in feasibility space suggests that, in contrast with many other resources, demand response retains its value at the least-cost end of the efficient frontier. (See Figure P-130.)

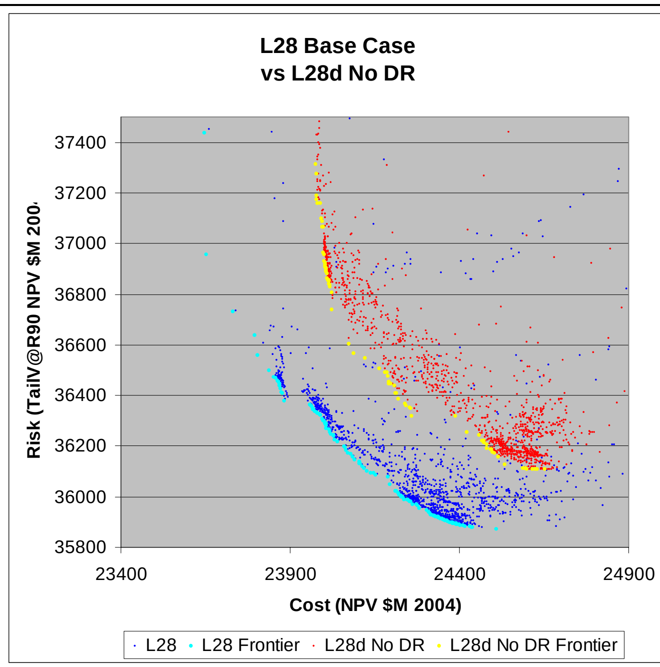


Figure P-130: Removing Demand Response from the Base Case

Most resources provide little value at the least-cost end of the efficient frontier because building new plant is no better than relying on the market. (Recall from the discussion for electricity price uncertainty that electricity market price is the same as the fully allocated cost of power plants in equilibrium. Appendix L, in the chapter on "General Paradoxes," and Chapter 6 elaborate on this principle.) If the region plans to build fewer resources, however, electricity prices become more volatile. This is precisely when demand response becomes more valuable.

We can refine the evaluation of the DR value by comparing this sensitivity case against one where the study holds constant the level of demand response across all years. For the purposes of valuing demand response, the base case model is poor because the amount of demand response is increasing over time. In a study [**49**] where demand response is fixed at 500MW, the reader will find a similar pattern as before. Figure P-131 plots the horizontal shift in the efficient frontier as a function of the risk level [**50**]. Again, at the least-cost end (right end of graph) the value of demand response increases. Over most levels of risk, the benefit is between $150M NPV and $200M NPV (2004$). This corresponds to $300 to $400 per kilowatt of benefit, net of program costs. The data is rather noisy at this level of resolution, so a fit polynomial in Figure P-131 reinforces the pattern.

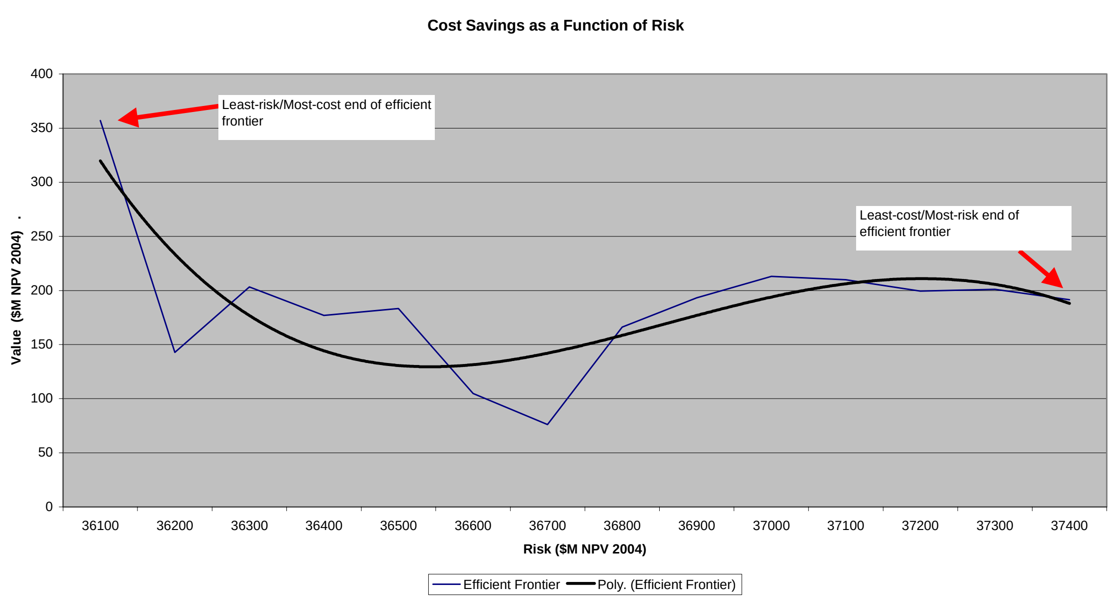


Figure P-131: Cost Savings as a Function of Risk Level (500MW DR Case)

Creating the workbook models to perform these studies was simple. As described in Appendix L, Crystal Ball decision cells determine the capacity for new resource candidates. The model considers demand response is a new resource, and the decision cells appear on row {{7}}, labeled "PRD" for *price responsive demand*. Figure P-132 shows the situation for the base case. In the base case, demand response increases over time, and the values in the decision cells indicate the cumulative number of MW of capacity for the new resource option.

In the base case and in the sensitivity cases, the model removes control of the decision cells for demand response from Crystal Ball. For this reason, the cells do not have the yellow background that other decision cells have.

PlnCap_0 = 0

	N	R	S	AH	AI	AJ	AP	AQ	AR	AX	AY	AZ	BF	BG	BH
1		Sep-04	Dec-0	Sep-08	Dec-08	Mar-0	Sep-10	Dec-10	Mar-1	Sep-12	Dec-12	Mar-1	Sep-14	Dec-14	Mar-
2	Capacity Data ID														
4	CCCT Capacity	0.00			0.00			610.00			610.00			610.00	
5	SCCT Capacity	0.00			0.00			0.00			0.00			0.00	
6	Coal Capacity	0.00			0.00			400.00			400.00			400.00	
7	PRD	0.00			500.00			750.00			1,000.00			1,250.00	
8	Wind 1	0.00			0.00			1,200.00			1,200.00			1,200.00	
9	Wind 2	0.00			0.00			0.00			0.00			0.00	
10															

Figure P-132: Decision Cells for Base Case

To simulate the situation without demand response, it is necessary only to set the cumulative capacity of demand response to zero in all periods. This is illustrated in Figure P-133.

PlnCap_0 = 0

	N	R	S	AH	AI	AJ	AP	AQ	AR	AX	AY	AZ	BF	BG	BH
1		Sep-04	Dec-0	Sep-08	Dec-08	Mar-0	Sep-10	Dec-10	Mar-1	Sep-12	Dec-12	Mar-1	Sep-14	Dec-14	Mar-
2	Capacity Data ID														
4	CCCT Capacity	0.00			0.00			610.00			610.00			610.00	
5	SCCT Capacity	0.00			0.00			0.00			0.00			0.00	
6	Coal Capacity	0.00			0.00			400.00			400.00			400.00	
7	PRD	0.00			0.00			0.00			0.00			0.00	
8	Wind 1	0.00			0.00			1,200.00			1,200.00			1,200.00	
9	Wind 2	0.00			0.00			0.00			0.00			0.00	
10															

Figure P-133: Decision Cells for Case Without DR

Finally, the case where demand response is fixed at 500MW in all years requires only that the cumulative capacity be set to that value and held across the study. See Figure P-134, below.

PlnCap_0 = 0

	N	R	S	AH	AI	AJ	AP	AQ	AR	AX	AY	AZ	BF	BG	BH
1		Sep-04	Dec-0	Sep-08	Dec-08	Mar-0	Sep-10	Dec-10	Mar-1	Sep-12	Dec-12	Mar-1	Sep-14	Dec-14	Mar-
2	Capacity Data ID														
4	CCCT Capacity	0.00			0.00			610.00			610.00			610.00	
5	SCCT Capacity	0.00			0.00			0.00			0.00			0.00	
6	Coal Capacity	0.00			0.00			400.00			400.00			400.00	
7	PRD	0.00			500.00			500.00			500.00			500.00	
8	Wind 1	0.00			0.00			1,200.00			1,200.00			1,200.00	
9	Wind 2	0.00			0.00			0.00			0.00			0.00	
10															

Figure P-134: Decision Cells for Case With 500MW DR

With these modifications, the model creates the three feasibility spaces described above.

Wind

Two prominent themes for wind generation studies dealt with the assumption of declining capital cost and with the opportunity cost for not pursuing wind.

Non-Decreasing Wind Cost

Chapter 5 of the Final Plan and Appendix I describe key generation cost assumptions. The Plan assumes wind construction costs decline at 1.6 percent per year. To understand the extent to which this declining-cost assumption might be driving the results of the model, a study [**51**] assumed that the wind costs did not decline from today's levels.

As expected, the overall system costs increased dramatically (see Figure P-135), and there was some reduction of wind along the efficient frontier, but wind still appeared in 2013 and develops to its full potential (5000 MW) by the end of the study. Coal developed in somewhat more plans near the least-risk end of the efficient frontier, but never by more than 400MW. Conservation commanded more of a premium closer to the least-risk end of the efficient frontier.

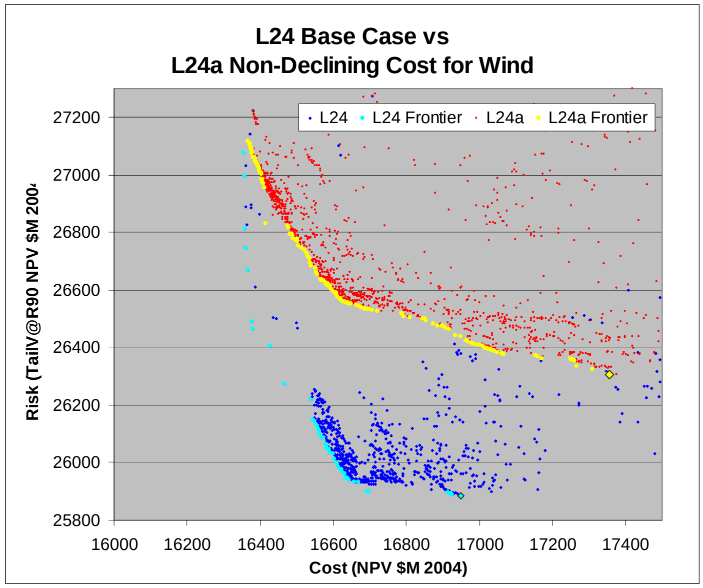
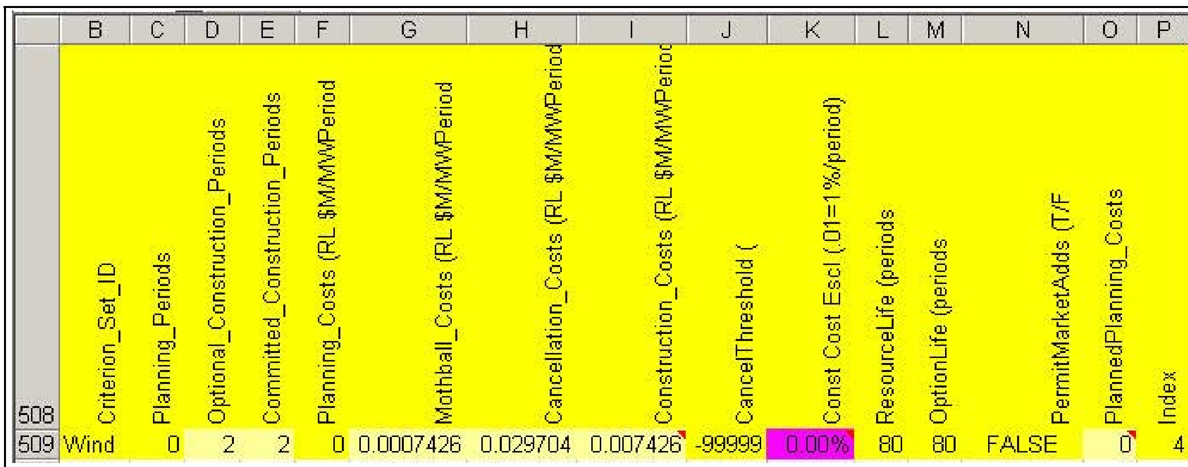


Figure P-135: Feasibility Spaces for Non-Declining Wind Cost Study

The rate of construction cost escalation is a parameter specified in the workbook. The cell {{K509}} of the base case stipulates that the quarterly escalation rate is -0.408 percent. The Council performed this sensitivity study merely by setting this value to zero, as illustrated in Figure P-136. Note that the row containing data labels has a modified format to make reading it easier.



	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
508	Criterion_Set_ID	Planning_Periods	Optional_Construction_Periods	Committed_Construction_Periods	Planning_Costs (RL $M/MW/Period	Mothball_Costs (RL $M/MW/Period	Cancellation_Costs (RL $M/MW/Period	Construction_Costs (RL $M/MW/Perio	CancelThreshold (	Const Cost Escl (.01=1%/period)	ResourceLife (periods	OptionLife (periods	PermitMarketAdds (T/F	PlannedPlanning_Costs	Index
509	Wind	0	2	2	0	0.0007426	0.029704	0.007426	-99999	0.00%	80	80	FALSE	0	4

Figure P-136: Modified Cost Escalation for Wind

The Value of Wind

One study [**52**] examined the opportunity cost of ignoring wind as a capacity expansion option. This study removed wind generation as a candidate for system expansion from the base case.

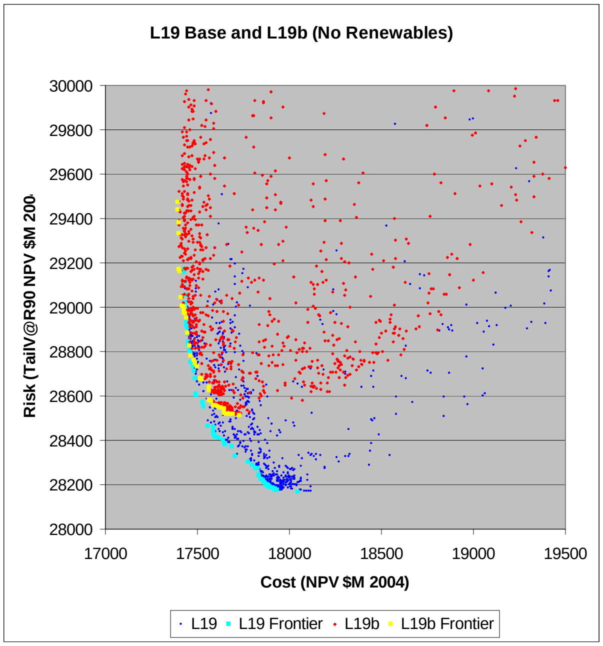


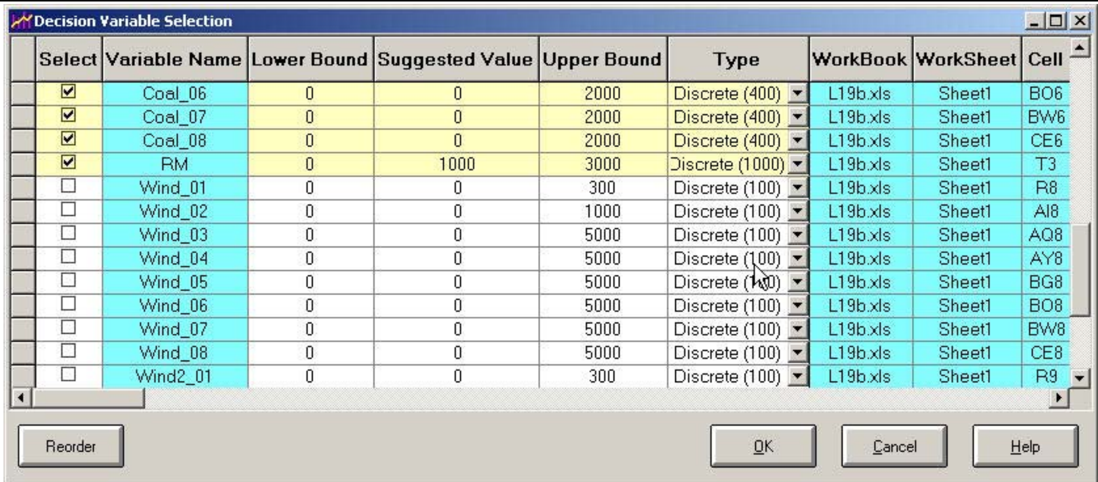
Figure P-137: The Feasibility Space, Removing Wind As An Option

As the section on the value of demand response suggests, *value* – in terms of cost reduction – typically *depends on the level of risk the region is willing to assume*. To understand value, therefore, we must consider the efficient frontier. At each level of risk the efficient frontier may shift different amounts to the left, or not at all. Figure P-137 illustrates this principle, with negligible cost shift near the least-cost end of the efficient frontier and significant variation in the least-risk plans.

We should not be surprised to see little or no value at the least-cost end. After all, wind generation is expensive today relative to expected, long-term equilibrium market prices. If the region were content to "ride the market," the right answer would be to build little or no wind – or any thermal resource for that matter. After all, the equilibrium price for wholesale electricity is the same as that for a CCCT. Why build when you can buy? This is the argument that the "Gas Price" and "Electricity Price" sections of this Appendix explore, and some would claim it is the fundamental assumption that led to the 2000-2001 energy crisis.

As risk mitigation becomes a consideration, however, the value grows. Moving to lower-risk plans, the difference in least-costs plans grows to about $200 million. Beyond the level of risk mitigation that maximizes the difference, however, the value is impossible to determine. Why is the value impossible to determine? Beyond that point, there are no plans *without wind* at any cost that provide the level of risk mitigation that plans *with wind* generation provide!

To create the feasibility space without wind generation, this study eliminated the optimizer's decision cells and constraints pertaining to wind. In the workbook, the values in the decision cells associated with wind are zero across the study. Because the optimizer cannot modify the decision cells, those zero values never change. The situation for the decision variables appears in Figure P-138; the absence of wind capacity constraints is evident in Figure P-139. For more detail about decision cells and how the optimizer modifies them to define a plan, see Appendix L, in particular the section "OptQuest Stochastic Optimization."



Decision Variable Selection

Select	Variable Name	Lower Bound	Suggested Value	Upper Bound	Type	WorkBook	WorkSheet	Cell
☑	Coal_06	0	0	2000	Discrete (400)	L19b.xls	Sheet1	BO6
☑	Coal_07	0	0	2000	Discrete (400)	L19b.xls	Sheet1	BW6
☑	Coal_08	0	0	2000	Discrete (400)	L19b.xls	Sheet1	CE6
☑	RM	0	1000	3000	Discrete (1000)	L19b.xls	Sheet1	T3
☐	Wind_01	0	0	300	Discrete (100)	L19b.xls	Sheet1	R8
☐	Wind_02	0	0	1000	Discrete (100)	L19b.xls	Sheet1	AI8
☐	Wind_03	0	0	5000	Discrete (100)	L19b.xls	Sheet1	AQ8
☐	Wind_04	0	0	5000	Discrete (100)	L19b.xls	Sheet1	AY8
☐	Wind_05	0	0	5000	Discrete (100)	L19b.xls	Sheet1	BG8
☐	Wind_06	0	0	5000	Discrete (100)	L19b.xls	Sheet1	BO8
☐	Wind_07	0	0	5000	Discrete (100)	L19b.xls	Sheet1	BW8
☐	Wind_08	0	0	5000	Discrete (100)	L19b.xls	Sheet1	CE8
☐	Wind2_01	0	0	300	Discrete (100)	L19b.xls	Sheet1	R9

Reorder OK Cancel Help

Figure P-138: Optimizer Decision Variable for No Wind Generation

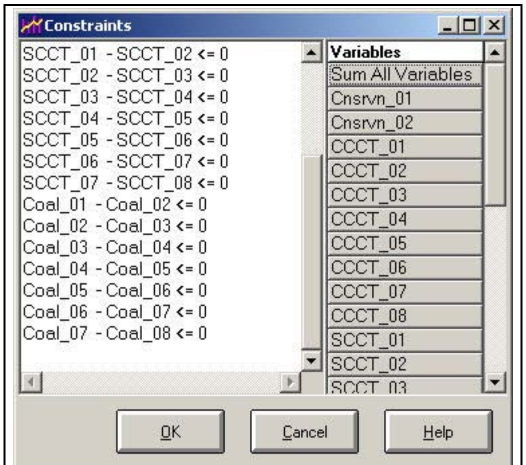


Figure P-139: Optimizer Constraints for No Wind Generation

Two other studies presented in this Appendix bear on the question of wind generation value. The section on CO_2 taxes, above, looks at the issues of how CO_2 tax, green tags, and production tax credits affect the value of wind. As expected, new wind generation constructed in less quantity and much later along the efficient frontier. Nevertheless, wind did appear in the least-risk plans. Despite its cost, low availability factor, and disadvantage with respect to dispatchable generation, it still provides a hedge against fuel cost excursions and has planning flexibility advantages, like short lead-time and modularity.

The second sensitivity study that bears on the value of wind generation is one that examines the role of planning flexibility for conventional coal-fired generation. In that study, the CO_2 tax, green tags, and production tax credits again are zero, but coal is given a shorter construction cycle. Coal then becomes competitive with wind. This study is the topic of the next section.

Conventional Coal

Conventional coal faired poorly in most studies, entering as a construction option only in the most risk-averse plans and then only in fairly small amounts, typically 400 MW or less. Various studies indicated that the problems with coal were associated with CO_2 taxes, long construction lead times, and to some extent, PTC and green tag programs that make wind more competitive. If this is true, removing these factors should cause coal to appear on the efficient frontier. All regional model studies assumed, after all, that coal had several benefits, primarily stable and low fuel price.

One study [**53**] assumed no carbon tax, no green tag credit or PTC for wind, and a construction cycle for coal that matches that for a CCCT. The construction cycle, after siting and licensing, is two years. Total overnight cost of coal, however, are the same as in the basecase, only compressed into the shorter construction interval.

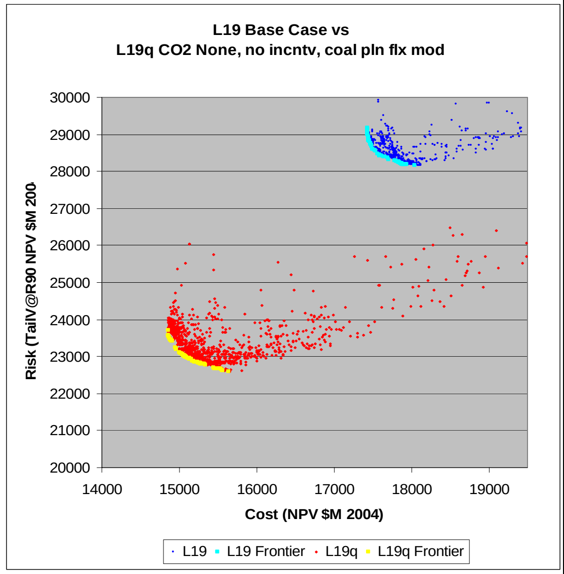


Figure P-140: Removing the Barriers to Coal Development

The study appears to corroborate the view that the perceived disadvantages drive the results. The feasibility space (Figure P-140) is generally less risky and less costly due to the elimination of the CO_2 tax and reduction of the coal plants' construction cycle. Moreover, coal plants appear in almost all of the efficient frontier's plans, being absent in only the risk-indifferent, least-cost plans (upper left hand extreme of the trade-off curve). This stands to reason, as few resources except some inexpensive conservation appear among these plans. At the other extreme of the curve, least-risk plans have substantial amounts of coal, adding up to 400MW of coal-fired generation by 2012 and up to 2000MW by 2015. (In this particular study, coal was constrained at 2000MW from 2015 until the end of the study, so it is not possible to determine whether or how much additional coal the model might have added otherwise.) CCCT capacity and conservation develop, too. Coal displaces primarily wind capacity development.

To perform this study, {{rows 74 (CO_2 tax), 81 (PTC), and 83 (green-tag value)}} are hard-wired to zero. The study accelerates the rate at which cost accumulates during construction achieve the same overnight cost in the shorter construction cycle [**54**]. The resulting values modify the construction cost information in {{row 483}}, as shown in Figure P-141. (Appendix L, section "Parameters Describing Each Technology," provides an interpretation of these parameters.)

	A	B	C	D	E	F	G	H	I
482		Criterion_Set_ID	Planning_Periods	Optional_Construction_Periods	Committed_Construction_Periods	Planning_Costs (RL $M/MWPeriod^2)	Mothball_Costs (RL $M/MWPeriod^2)	Cancellation_Costs (RL $M/MWPeriod^2)	Construction_Costs (RL $M/MWPeriod^2)
483		Coal Criter	0	4	4	0	0.000593	0.023708	0.005927
484									
485	Original	Coal Criter	0	5	9	0	0.000339	0.013547	0.003387

Figure P-141: Cost Data Cells in the Workbook

A separate study shows that while eliminating CO_2 tax, PTC, and green tags alone does result in some coal construction, the construction levels are relatively low. (See the sensitivity study "No CO_2 Tax or Incentives for Wind," above.) Those results, combined with the subject study, suggest that the relative lack of ***planning and construction flexibility*** associated with coal plants is a major source of risk and cost.

Larger Sample of Futures

As explained in the first chapter of this Appendix, Monte Carlo simulation provides many advantages for modeling uncertainty. One of the disadvantages, however, is that one must estimate the number of games necessary to guarantee a given level of estimate accuracy. Both the statistics that the regional model uses, mean cost and $TailVaR_{90}$, are averages and therefore have well-understood statistical properties. Because the regional model used 750 futures, the estimate of the mean cost was relatively precise: where the standard deviation of costs associated with a given plan is on the order of $6 Billion, the standard deviation of the mean estimate is about $220 Million. While the tail is smaller, however, the sample of the tail has only 75 games, so the precision in the $TailVaR_{90}$ statistic is not much better.

Given the uncertainty associated with these statistical samples, the Council took several steps to assure that the results are representative. For example, Staff examined plans that lie off the efficient frontier. The section "Portfolio Model Reports And Utilities" of Appendix L, for example, explains how reports are marked to reveal not only the plans lying on the efficient frontier, but also those lying within $250Million NPV cost and risk from the efficient frontier. In particular, Staff studied these plans, searching for patterns or strategies that differed from those on the efficient frontier.

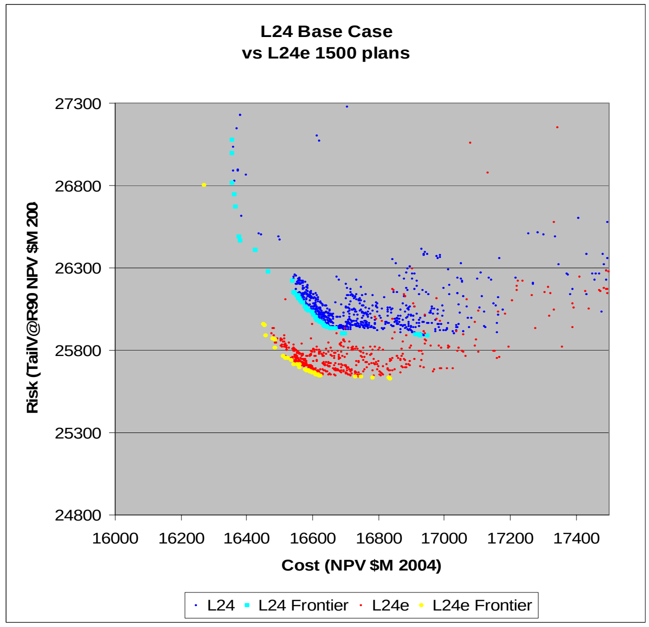


Figure P-142: Increased Number of Futures

Staff also reproduced the final study using 1500 futures [**55**]. To our surprise, there did appear to be some differences between the two approaches. First, both cost and risk appeared to improve. (See Figure P-142.) The magnitude of the improvement, however, is consistent with sample variation. For example, Figure P-143 shows the average of N random values drawn from a normal distribution with mean 100 and standard deviation of 100 [**56**]. The value on the horizontal axis is N. At around 750, the estimate of the average is off about two percent. If the standard deviation of the costs associated with plans is about $6 B, two percent corresponds to about $120 M. Figure P-144 demonstrates that this is about the effect on the 192 plans that both the base case and the sensitivity case evaluated [**57**]. More important, perhaps, is that the position of plans relative to the efficient frontier are, by and large, unchanged. In particular, of the 50 plans on or within $250M of the efficient frontier, the range of costs differences for 49 plans is $99M to $108M ($9M wide) and the range of risk differences is $206M to $280M ($74M wide). Thus, the shifts are very regular. (The one plan in 50 that fell outside these ranges was associated with a high-risk plan.) Figure P-144 identifies the 50 plans lying near the efficient frontier with larger, pink points.

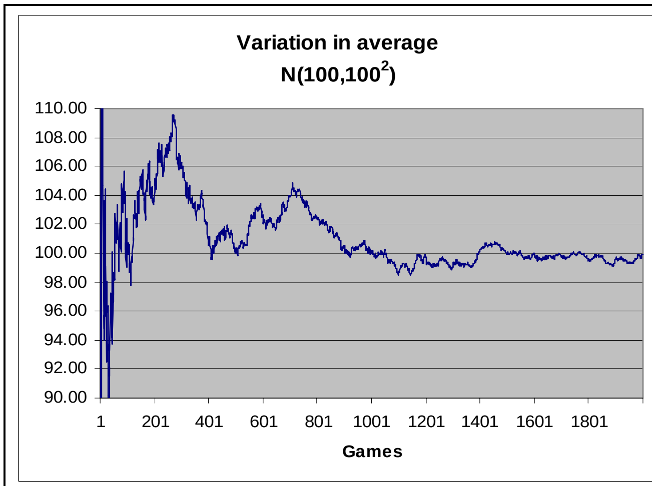


Figure P-143: Variation in Mean

A second difference observed in the sensitivity study was minor difference in the make-up of plans on the efficient frontier. While coal-fired power plants still appeared in plans near the efficient frontier, none of the plans on the efficient frontier had this resource.

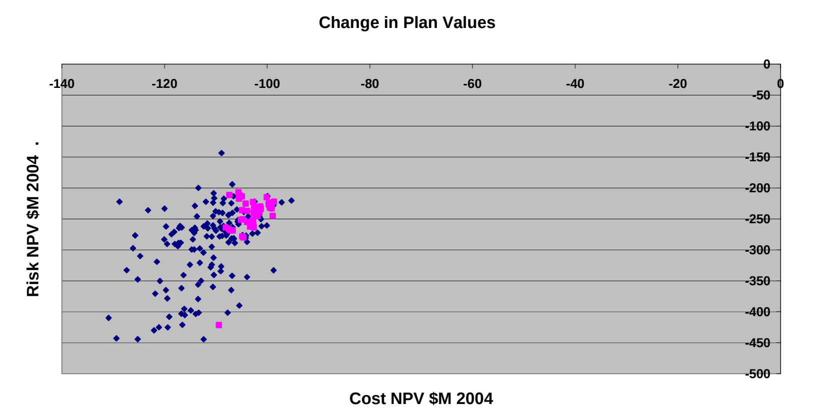


Figure P-144: Consistent Effect on Cost and Risk of Plans

More lost-opportunity conservation also appears in the plans on the efficient frontier, and it merits an additional 10-mill/kWh premium. The reason for these differences in plans on the efficient frontier may simply have been that the sensitivity study had fewer plans than did the final base case (827 vs 1010) and the optimizer had not yet found the best strategies. Because doubling the number of futures increased the study time proportionally, however, the sensitivity case had to be ended prematurely.

While the results somewhat different than expected, the study did not contradict the results suggested by the base case. The plan recommended by the Council would appear very close to, if not on, the efficient frontier near the least-risk end of the efficient frontier.

Glossary

uncertainty
innovation
GBM
Monte Carlo simulation
Spinner graphs

[WORK IN PROGRESS]

Figures

Index

[WORK IN PROGRESS]

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17 See Dependence on local variables.xls. The change in electricity price is taken as the first-order change in electricity price due to a one-standard deviation change in the electricity price ARMA error term relative to the first-order change in electricity price due the sum of one-standard deviation changes in the local terms.
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34 Import-Export Analysis.xls
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36 Q:\MS\Plan 5\Portfolio Work\Olivia\Calibration and Verification\Genesys Validations\L13\LOLP_L13_LC\LOLP_L13_LC.zip\Durat.vbi
37 Chart 2 in Comparison of Risk Measures.xls
38 L19g High Gas Price
39 L24f Lower Electricity Price Volatility
40 L19i CO2 None and no incentives
41 L19t CO2 McCain-Lieberman
42 See, for example, the Base Case for L19
43 L19e CO2 50% & tiered, L19f CO2 50% & tiered + NG inc $1.50, L19n CO2 25% & tiered, and L19p CO2 25% & tiered + NG inc $1.50. The tiered approach was adopted in the Final Plan.
44 L28g Value of IPPs and notes.
45 L24i Contracting the IPP out of the region and notes.
46 L28 basecase, L28b Mildly Restricted Conservation and notes, and L28c Severely Restricted Conservation and notes.
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48 L28d No DR and notes.
49 L28j 500MW DR and notes.
50 Graph is developed in DR Study.xls
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52 L19b Renewables=0 and notes
53 L19q No CO2 Tax or Incentives for Wind, Shorter Construction Cycle for Coal
54 ConvertingOvernightToPeriodCosts_v03A.xls
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Biennial Assessment of the Fifth Power Plan

Assessment of Other Generating Technologies

November 7, 2006

The purpose of this paper is to assess recent developments regarding new electric power generating resources for use by the Pacific Northwest and the possible significance of these developments to the Fifth Northwest Electric Power and Conservation Plan. The focus is on developments occurring since adoption of the Fifth Plan. For completeness, this paper summarizes the findings of the assessments of coal, natural gas and wind power, covered in more detail in specific papers.

The paper begins with an overview of generating resource development since adoption of the Fifth Plan. This is followed by an assessment of changes to the commercial status, cost or performance of the litany of new generating resource options. The paper concludes with a summary table of key developments, their significance and possible Council responses.

Resource Development Activity

A new cycle of resource development has occurred since adoption of the Fifth Plan (Figure 1). The Plan foresaw little need for new capacity prior to 2010, and recommended no major resource acquisitions other than 500 megawatts of wind to help confirm the resource potential. However, nearly 1900 megawatts of new capacity primarily wind and natural gas has entered service or is are under construction since adoption of the Plan. Wind plant construction is driven by extension of the federal production tax credit, the California renewable portfolio standard and high natural gas prices. Current thinking is that the wind production tax credit is likely to be extended, possibly for several years, but at a declining rate. In combination with the aggressive 2010 target of the California, this will likely lead to a continued rapid rate of wind power development in the Northwest. A preliminary estimate prepared for the Northwest Wind Integration Action Plan project is for 1200 to 2200 megawatts of wind power development from 2007 through 2009.

The natural gas capacity additions shown in Figure 1 were under construction at the time of Plan adoption. An additional 170 megawatts of natural gas capacity for serving growing peaking capacity is planned for 2008. The coal resource appearing in 2006 is the 116-megawatt Hardin plant, located in eastern Montana.

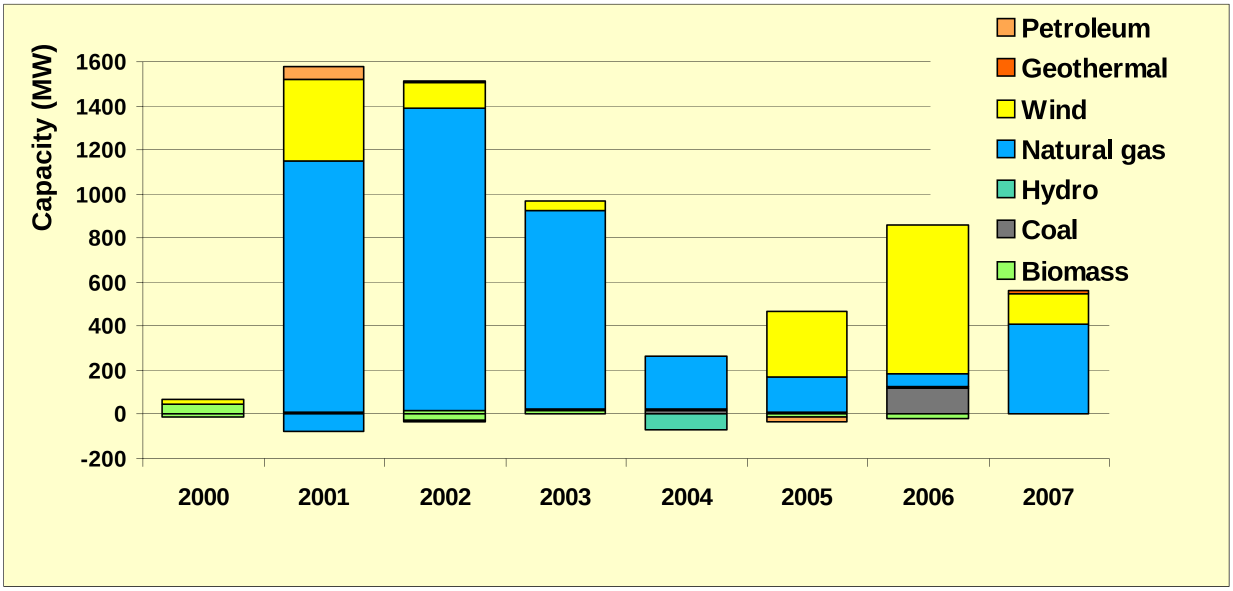

Figure 1: Pacific Northwest electrical generating capacity additions

Resource Status and Recent Developments

Biomass

Biomass generation currently represents about two percent (900 megawatts) of Northwest generating capacity. Though opportunities for expansion are diverse, the relatively high cost of new biomass capacity has resulted in only about 15 megawatts of new biomass generation since adoption of the Fifth Plan. The most feasible near-term uses of biofuels for electric power generation in the Northwest are expected to be landfill gas energy recovery, wastewater treatment plant and animal manure energy recovery and chemical recovery boiler upgrades. Other possible sources of biofuels include forest thinnings, agricultural field residues, municipal solid waste and energy crops. While available in large quantities in the Northwest, the high cost of generation using forest thinning residues may continue to constrain further development of this resource. It is possible that the development of processes for economically producing ethanol form cellulosic waste may divert forest residues to this application. Likewise, ethanol production may ultimately be the most economic use of agricultural field residues. Public opposition, high cost, and established municipal solid waste (MSW) disposal systems are likely to retard development of energy recovery from raw MSW. Much of the energy value of MSW, however, can be recovered by separating the clean combustible fraction for use as fuel. Though technically feasible, the estimated cost of producing electricity from dedicated hybrid cottonwood exceeds $100/MWh. The wood is more valuable as a fiber crop.

The most significant development regarding biofuels since adoption of the Fifth Plan has been acceleration of efforts to derive synthetic liquid fuels from energy crops and biomass residues.

Development of economic processes for converting cellulosic waste to ethanol could divert the fairly large bio-residue potential to liquid fuel production.

Coal

Coal-fired power plants represent about 14 percent (7560 megawatts) of Northwest generating capacity. Most of this capacity consists of large central station units completed between 1968 and 1986. Low coal prices, mature technology, limited availability of natural gas and nearly complete development of low-cost hydropower made coal a "resource of choice" during this period. Rising natural gas prices has renewed interest in coal-fired generation throughout North America. However, the choice of coal technology, fuel and site has become more complex. An array of technologies, carbon dioxide (CO_2) control policy, availability of petroleum coke, co-production options[1], mercury control, federal incentives, water and transmission availability and public perception all meld in the choice of coal technology, fuel and site. It is becoming evident that no single correct choice of technology or configuration exists for all situations.

The current status of coal-based generation is assessed in the paper *Assessment of Coal-fired Power Plant Planning Assumptions*. That assessment found: (1) advanced (super-critical) steam-electric coal technologies are entering the market more rapidly than anticipated; (2) the Fifth Plan capital cost assumptions for steam-electric technologies remain reasonable; (3) cost assumptions for integrated gasification combined-cycle (IGCC) power plants should be increased to account for the spare gasifier needed to achieve the availability expected of base load power plants; (4) availability assumptions for new coal technologies should be increased; (5) petroleum coke is becoming increasingly available as a fuel option for gasification plants; and (6) the efficiency of IGCC plants will be lower and the efficiency of supercritical steam-electric plants will be higher than previously thought.

Geothermal

The heat of the earth is naturally concentrated as hot water at certain near-surface locations, from which it can be economically captured and converted into electricity. Potential geothermal resource areas in the Northwest include deep vertical faults in the Basin and Range geological province in southeastern Oregon and Southern Idaho and shallow magmatic intrusions associated with Cascades vulcanism. Basin and Range geothermal resources have been developed for both power generation and for direct application in Nevada, Utah and California. The 13-megawatt phase I of the Raft River project in southern Idaho, when completed in 2007 will be the first commercial geothermal power plant in the Northwest.

Newberry Volcano, Oregon and Glass Mountain, California are the only Cascades structures offering geothermal potential not largely precluded by land use. Geothermal potential has been confirmed at Glass Mountain. Though projects have been proposed for these sites over the years, none have yet come to fruition. Overall Northwest geothermal potential is poorly understood. The estimate of the Fourth Power Plan, 340 to 3300 average megawatts with a most likely potential of 940 average megawatts, remains reasonable.

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[1] Co-production is the manufacture of electricity, hydrogen, and substitute natural gas, synthetic liquid fuels and other products from a common plant.

Only dated and uncertain geothermal cost information was available for the Fifth Plan. Because of this, and the uncertainty regarding Northwest potential, geothermal was not specifically included in the portfolio analysis. The developers of the Raft River project have recently published generic cost information that could be used to update the Council's estimates of geothermal cost and provide a sounder basis for considering geothermal in future portfolio analyses.

Hydropower

Though hydropower represents about 64 percent (33,560 megawatts) of Northwest generating capacity, most feasible sites have been developed. The remaining opportunities are for the most part small-scale and relatively expensive. In its Fourth Plan, the Council estimated that new sites might yield about 480 megawatts of additional hydropower capacity at $90 per megawatt-hour, or less. This capacity could produce about 200 average megawatts of energy. Some additional energy is available from upgrades to existing projects. The Council retained this estimate for the Fifth Plan, and concluded that few projects are expected to be constructed because of the high cost of developing most of the remaining feasible sites and the complex and lengthy licensing process. Overall, it appears unlikely that new hydroelectric development will be able to offset the loss of capacity and energy from expected removal of several older environmentally damaging projects.

The conclusion has largely been borne out. Three projects, totaling 25 megawatts of capacity have been brought into service since adoption of the Fifth Plan and no additional projects are currently under construction. While new hydropower is unlikely to become a major contributor to new resource needs, newer information is available regarding undeveloped hydropower potential. The Idaho National Laboratory (INL) as part of a nationwide assessment has identified 1315 sites in the four-state region with an undeveloped potential exceeding 8000 megawatts. Though it is not clear that this survey fully considered all constraints to development faced by new hydropower in the Northwest, the INL survey employed methods and information not available when the surveys upon which the Council's estimates are based were undertaken in the 1980s. A revised estimate of new Northwest hydropower potential could be prepared for the next power plan using the INL survey and other, more recent information.

Natural Gas

Natural gas combined-cycle power plants represent about 11 percent (5914 megawatts) of Northwest generating capacity. Simple-cycle units, valued for system reliability, regulation, load following and hydro firming, comprise about 3 percent (1654 megawatts) of Northwest generating capacity. Most of the combined-cycle capacity was completed between 1995 and 2004 when low natural gas prices and reliable, low-emission and efficient gas turbine technology made these plants the resource of choice. Higher natural gas prices have reduced the attractiveness of bulk power generation using natural gas and construction of only one large combined-cycle project has been initiated since 2001. That plant is the 399-megawatt Port Westward project, scheduled for completion in 2007.

The current status of natural gas power generation technologies are assessed in the paper *Assessment of Gas-fired Power Plant Planning Assumptions*. That assessment found: (1) the Fifth Plan assumptions regarding cost and performance of natural gas power plants remain representative of real-world experience; (2) possible needed capacity to maintain system reliability, and regulation and load following capability for the integration of wind power may result in the need for additional natural gas capacity prior to that identified in the Fifth Plan; (3) completion of currently suspended combined-cycle capacity may become attractive in the face of the cost increases being experienced for other new generating resources; and, (4) in view of the strongly cyclical market observed for natural gas and other new generating resources, future portfolio analyses might consider possible correlations between electricity market activity and resource capital costs.

Nuclear

At the time the Fifth Plan was prepared, future U.S. nuclear plants were expected to use advanced “Generation III+” designs such as the Westinghouse AP-1000. These are completely new designs employing passively-operated safety systems and factory-assembled standardized modular components. These features are expected to result in improved safety, reduced cost and greater reliability. In the Fifth Plan, the first North American Generation III+ plants were assumed to be operating by 2015, probably at southeastern sites, following which a decision might plausibly be made to proceed with construction with a new plant in the Northwest. That plant would see service by 2020 at the earliest. Because of the distant decision dates, a new nuclear option was not considered in the portfolio analysis and actions bearing on new nuclear plants were not included in the plan.

The Energy Policy Act of 2005 includes incentives for new commercial nuclear plants including a production tax credit, loan guarantees and insurance against construction delays. These incentives, plus high natural gas prices and greenhouse gas risk have motivated developers, mostly operators of existing nuclear facilities in southeastern United States to seriously consider construction of new nuclear capacity. As of August 2006, the Nuclear Regulatory Commission has received notices of interest for 27 potential new commercial nuclear projects. One, Constellation Energy has proceeded to order heavy components, but not for a Generation III+ plant. The components are for an enlarged (1600 megawatt) Generation III “evolutionary” design, an example of which is under construction in Finland. Another developer, NRG, has announced its intention to apply for a two-unit operating license for another evolutionary design, the General Electric Advanced Boiling Water Reactor, similar to units operating in Japan since 1996 and currently under construction in Taiwan. Generation III plants are refined versions of the current generation of nuclear plants. These developments suggest that the next U.S. plants will likely be evolutionary designs, rather than the full passively safe modular designs formerly thought to represent the next generation of U.S. plants.

The assumption that the earliest decision to proceed with construction of a new nuclear power plant in the Northwest would come no sooner than 2015 remains reasonable. Cost and performance assumptions for Generation III and III+ units and the proposed hydrogen co-production demonstration reactor at INL should be included in the next plan.

Ocean and Tidal Currents

The kinetic energy of flowing water can be used to generate electricity by turbines operating on similar principals to wind turbines, but more compact because of the greater density of water. Turbine energy yield is very sensitive to current velocity and little potential is available from the weak and ill-defined currents off the Northwest coast and in the Strait of Juan de Fuca. However, tidal currents of 3 to 8 knots occur locally in Puget Sound and estuaries along the Oregon and Washington coast could provide an economic source of energy as Tidal In-Stream Energy Conversion (TISEC) devices are perfected. A prototype machine was deployed at Race Rocks in British Columbia in September and the deployment of the first two turbines of a six turbine pilot plant in New York City's East River is planned for November. Twenty-nine requests for preliminary permits have been filed with the Federal Energy Regulatory Commission, including sites in the Tacoma Narrows, Deception Pass and the San Juan Islands. A feasibility study of the Tacoma Narrows site concluded that a commercial project could yield about 16 average megawatts at $72 to $90/MWh (2005 dollars, including federal production tax credit). Commercialization of this resource will require development and production of TISEC machines suitable for extended reliable and efficient operation under fully-submerged conditions. Other issues needing resolution include system integration, environmental impacts, installation and maintenance procedures, cost uncertainties and public acceptance. Though the potential Northwest resource would be of limited size (tens to low hundreds of average megawatts), TISEC plants would have predictable though intermittent output, low aesthetic profile and could provide local distribution system support. The resource should be more fully assessed in the next power plan. The current plan contains an action (GEN-17) supporting the development and commercialization of new renewable technologies such as wave power and TISEC.

Ocean Thermal Gradient

An ocean thermal energy conversion (OTEC) power plant extracts energy from the temperature difference that may exist between surface waters and waters at depth. Megawatt-scale OTEC technology has been demonstrated in Japan and Hawaii, but practical application of the technology requires a temperature differential of about 20^{o} C (36^{o}F), or greater. Temperature differentials of this magnitude are limited to tropical regions extending to 25 to 30 degrees of latitude. Ocean thermal temperature differentials in the Northwest range from 0 to 12^{o}C (0 - 20^{o}F) precluding operation of OTEC technology.

Petroleum

Petroleum-derived fuels such as propane, distillate and residual fuel oils are too costly for bulk electric power generation in the Northwest. Distillate fuel oil and propane are used as backup fuel, plant startup, for peaking or emergency service power plants and for power generation in remote areas. About 90 megawatts of capacity primarily fuelled by petroleum fuels are in service in the region.

Petroleum coke ("pet coke") is a solid carbonaceous residual product produced by thermal decomposition (cracking) of heavy residual oils during refining. This product consists mostly of carbon and small amounts of hydrocarbons, sulfur and ash and trace quantities of metals. Increasing use of heavier crudes and more efficient processing of refinery residuals has resulted in rapid growth in US and worldwide production of petroleum coke. Additional supplies are becoming available from Alberta oil sands synthetic crude production. Green coke[2] can be used directly as fuel, or further processed for use as a raw material for the manufacture of electrodes

[2] Coke directly from refinery coking units.

for the smelting of metals. A 65-megawatt cogeneration project at the Exxon Billings refinery uses petroleum coke as fuel.

Petroleum coke has a superior heating value compared to lower-rank coals and a very low ash content. However, most of the sulfur, inert materials and heavy metals present in the crude feedstock are concentrated in the coke, making it an environmentally unattractive fuel for conventional boilers. For this reason, petroleum coke has historically been priced at a discount to coal. An attractive approach for recovering the energy value of coke is to convert it to a synthetic fuel gas in a gasification plant. The sulfur can be removed from the raw synthesis gas using standard processes. Metals are embedded in the gasifier slag or removed in the syngas coarse particulate removal and scrubbing process. Some refineries now employ gasification plants to process coke into higher value products. Since release of the Plan, Energy Northwest has proposed constructing a 600-megawatt gasification combined-cycle power plant at Kalama on the lower Columbia River. The plant would use petroleum coke from Puget Sound refineries possibly in combination with other coke and coal supplies as feedstock.

Because of the increasing availability of petroleum coke and the availability of gasification technology to use this fuel, a forecast of the future price and availability of petroleum coke should be added to the next power plan.

Salinity Gradient Energy

Energy is released when fresh and saline water area mixed. Conceptually, the energy potential created by fresh water streams discharging to salt water bodies could be captured and converted to electricity. The technologies to do so are in their infancy, and it is not clear that current concepts would be able to operate off the natural salinity gradient between fresh water and seawater as present at the mouth of the Columbia and other rivers. Although the theoretical resource potential in the Northwest is substantial, many years of research, development and demonstration would be required to bring these technologies to commercial availability.

Solar

The best solar resource areas of the Northwest - the inter-mountain basins of south-central and southeastern Oregon and the Snake River plain of southern Idaho - receive about 75 percent of the solar energy received at the best Southwestern sites. However, because of latitude and climate, the Northwest solar resource exhibits strong summer seasonality. While desirable for serving local summer-peaking loads, the Northwest resource is not coincident with general regional loads. There has been no regional assessment resource potential, though it is likely there is sufficient developable resource to support any feasible demand[3].

The use of small photovoltaic arrays to generate electricity is widespread and has been encouraged in the Northwest by state incentive programs. While economic for small isolated loads, bulk photovoltaic power is currently much more expensive than power from competing sources. The present-day cost of bulk power from photovoltaics was estimated in the Fifth Plan to be $250 per megawatt-hour, compared to $33 - 46 per megawatt-hour for other bulk power

[3] An assessment developed by the Western Governor's Association Clean and Diversified Energy Initiative was limited to the deployment of central station solar thermal plants in the Southwest.

sources. Photovoltaic costs have historically declined at about 8 percent per year on average and capacity addition studies using the AURORA model suggested that bulk photovoltaic generation might become economically competitive in the Northwest about 2025 (and sooner in the Southwest) if this rate of cost reduction was sustained. Strong demand and increasing material costs have recently reversed the declining trend in photovoltaic prices. Module prices rose three percent in real terms between 2004 and 2005, though this is a modest increase compared with cost increases incurred by many other generating resources. Over the long-term, increasing demand should lead to increasing economies of production. Also, technology developments promise more efficient use of materials. These factors should lead to continued decline of photovoltaic costs over the long-term.

Solar thermal technologies employ concentrating devices to create temperatures suitable for driving thermal engines. Concentrating thermal technologies are currently less costly than photovoltaics for bulk power generation. They can also be provided with energy storage or auxiliary boilers to allow operation during periods when the sun is not shining. Concentrating solar thermal technologies require high levels of direct normal solar radiation for most efficient operation and are best suited for Southwest conditions. Over 350 megawatts of concentrating solar thermal capacity was constructed under favorable contracts in California during the 1980s. Following a 15-year hiatus, a one-megawatt plant was recently completed by Arizona Public Service Company. A much larger (65-megawatt) plant is under construction in southern Nevada.

Fifth Plan assumptions regarding solar generation remain consistent with long-term expectations.

Tidal Energy

Tidal energy can be captured and converted to electricity by means of hydroelectric “barrages” constructed across natural estuaries. These admit water on the rising tide and discharge water through hydro turbines on the ebb. The key requirement is a large mean tidal range, preferably 20 feet or more. Suitable sites with tides of this magnitude occur only in a few places worldwide where landforms amplify the tidal range. Economic development of tidal hydroelectric plants in the Northwest is precluded by insufficient tidal range.

Wave Energy

Three wave energy projects have been proposed in the Northwest. Each would initially consist of a small demonstration array of wave energy converters. These could be expanded to commercial-scale if the technology and site proves feasible. Though the technology is still in the pre-commercial stage, wave energy could be a major player in the Northwest. The theoretical wave power potential of the Washington and Oregon ocean coast is estimated to 3,400 - 5,100 megawatts for near-shore sites and 21,000 megawatts for offshore sites. Wave power converters are expected to have an efficiency of at least 12 percent, suggesting a technical potential of up to 2,500 megawatts, though only a portion of this potential is likely to be available because of navigational, aesthetic or ecological concerns. Wave power in the Northwest is winter peaking with a seasonal factor of 20. While the Council concluded that it is unlikely that commercial wave power projects will become widespread during the period of the Fifth Plan, development of the technology is accelerating and a full review of wave power cost and technical potential should be prepared for the next plan.

Wind Power

With completion of projects under construction, wind power will have grown to about 3 percent of regional capacity (1730 megawatts) for zero ten years ago. Factors contributing to the recent acceleration in the growth rate of wind include sustained high natural gas prices, climate change concerns, the federal production tax credit (PTC), and state renewable portfolio standards (RPS). Adoption of proposed RPS for Washington and Oregon would sustain current rates of development. For the Fifth Plan, the Council assumed 6000 additional megawatts of wind potential consisting of 1000 megawatts of committed resource and 5000 megawatts of discretionary resource. All 5000 megawatts of discretionary wind capacity were included in the recommended resource portfolio. The action plan recommended near-term development of 500 megawatts of wind power to resolve uncertainties associated with large-scale development of the resource. Actual development has greatly exceeded this recommendation.

Earlier this year, in response to Bonneville and utility concerns regarding significant cost increases, the Council released the paper *Assessment of Near-term Wind Power Plant Planning Assumptions*. That assessment found a 50 to 60 percent increase in wind project capital cost over the past four years principally from increased commodity and energy costs, a weak dollar and escalating demand for wind power equipment and services. These factors have been offset to some extent by higher capacity factors and somewhat more favorable financing. The focus of the paper was on short-term costs and the long-term persistence of higher costs was not addressed. Long-term effects are uncertain. Commodity and energy costs are historically cyclical and are likely to decline over the next several years as global production capacity is increased, substitutes introduced or currently strong demand weakens. A significant unknown is continuation of strong economic growth in East Asia.

A prolonged weak dollar should increase investment in domestic wind turbine production capacity, as would long-term extension of the PTC and broader adoption of state renewable portfolio standards. Continued strong demand should also increase the availability of specialized transportation and erection equipment and skilled construction and operating personnel. While political support for the PTC appears to be strong, extension at current levels will increasingly conflict with the federal budget deficit. Immediate termination of the PTC would suppress demand for a period, reducing costs. On net, wind capacity costs may remain high for the next several years, and then resume their historic downward trend. Offsetting this trend may be declining site quality. As better sites are developed, interconnection and integration will become increasingly expensive and wind quality may diminish.

Bonneville, the Council and the region's utilities recently launched the Northwest Wind Integration Action Plan project. The initial phase of this project seeks to improve the understanding of the ability and cost of integrating the wind capacity expected to be developed within the next several years using existing system capabilities. A subsequent phase will identify the most cost-effective means of expanding transmission, load following and regulation capability to integrate the much larger amounts of wind capacity envisioned in the longer-term. The results of the project are expected to become available beginning in early 2007.

Transmission and Remote Resources

The Fifth Plan assessment of Alberta oil sands cogeneration was the first Council assessment of resource potential external to the Region. Though not included in the recommended portfolio, oil sands cogeneration was sufficiently attractive for the Council to recommend that additional study be undertaken of the transmission costs of importing power from remote locations. Since adoption of the Fifth Plan, the Northwest Transmission Assessment Committee (NTAC) of the Northwest Power Pool has undertaken several scoping studies of major transmission expansion options. Completed studies include Eastern Montana to Northwest load center corridors and Western Canada - Northwest - Southwest corridors. These studies have yielded better information regarding the cost, capacity and possible location of transmission to access remote resources. Assessments undertaken for the Western Governor's Association Clean and Diversified Energy Advisory Initiative have yielded new information regarding the cost and potential of new coal, wind, hydropower, biomass, combined heat and power, geothermal and solar resource potential in the West. The new transmission and resource information will provide the basis for expanding the scope of future Council resource assessments.

Summary of Recent Developments

Table 1 summarizes recent developments and new information regarding new generating resources. For completeness, the findings of the separate papers on coal, natural gas generation and wind power are included here. Items are listed in general order of priority with respect to possible near-term impacts on Plan recommendations.

Table 1: Summary of recent developments regarding new generating resources.

Development	Significance	Possible Council Response	Timing
Better information regarding coal-fired plant availability, efficiency and cost	Timing of coal in resource portfolio; technology recommendations.	Update coal-fired technology availability, efficiency and cost assumptions. Test effects on portfolio	Near-term
Wind development greatly exceeding levels called for in Plan	Sufficiency of integration capability Timing of non-wind resources	(1) Keep Wind Integration Action Plan project on fast track (2) Add assessment of system flexibility[4] augmentation options to plan	(1) Near-term (2) Following completion of Wind Integration Action Plan
Better information regarding wind cost and resource potential, transmission & integration	Role of wind in longer-term; need to secure transmission & integration capability.	Update wind power planning assumptions. Test effects on portfolio.	Following completion of Wind Integration Action Plan
Growing summer peak loads	Possible need for suitable supply or demand-side capacity in addition to energy-driven needs identified in Plan	Broaden assessment of system capacity needs and options	Next power plan
INL assessment of undeveloped hydropower	Possible expansion of estimated potential	Update estimate of new hydro potential	Next power plan
Increasing availability of petroleum coke	Inexpensive feedstock for IGCC plants	Forecast pet coke cost and availability Assess pet coke/IGCC plant cost and performance	Next power plan
Better information regarding remote resources and transmission	Expanded inventory of new resource options	Expand assessment of remote resource options	Next power plan
Notices of intent to license, equipment orders for new nuclear units; proposed co-production reactor at INL	Role of nuclear in longer-term	Update nuclear planning assumptions	Next power plan
Better information regarding cost of "CO2-ready" IGCC plants	Role of coal-fired plants in longer-term	Prepare estimates of the cost and performance of "CO2 ready" IGCC	Next power plan
Wave power demonstration projects	Role of wave power in longer-term	Update wave power planning assumptions	Next power plan
Tidal current power demonstration projects	Future role of tidal current power	Update tidal current planning assumptions	Next power plan

[4] "System flexibility" includes regulation (sub-hourly) and load following (hourly and longer) capability, provided by generating capacity and possibly by demand response measures.

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NORTHWEST 6th POWER PLAN

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Sixth Power Plan Overview

SUMMARY

The Pacific Northwest power system is faced with huge uncertainties about the direction and form of climate change policy, future fuel prices, salmon recovery actions, economic growth, and integration of rapidly growing amounts of variable wind generation. And yet the focus of the Council's Power Plan is clear, especially with regard to the important near-term actions.

The Council's Power Plan addresses the risks that these uncertainties and others pose for the region's electricity future and seeks an electrical resource strategy that minimizes the expected cost of the regional power system over the next 20 years. Across hundreds of possible futures considered in the development of the Sixth Power Plan, one conclusion was constant; the most cost-effective and least risky resource for the region is improved efficiency of electricity use.

In each of its power plans, the Council has found substantial amounts of conservation to be cheaper and more sustainable than many forms of additional electric-generating capability. In this Sixth Power Plan, because of higher costs of alternative generation sources, rapidly developing technology, and heightened concerns about global climate change, conservation holds an even larger potential for the region.

The Plan finds enough conservation to be available and cost-effective to meet the load growth of the region for the next 20 years. If developed aggressively, this conservation, combined with the region's past successful development of energy efficiency could constitute the future equivalent of the regional hydroelectric system; a river of energy efficiency that will complement and protect the regional heritage of a clean and affordable power supply.

Aggressive pursuit of this conservation in the near-term is the primary focus of actions for the next five years. Combined with investments in renewable generation as required by state renewable portfolio standards, this holds the potential for delaying investments in more expensive and uncertain forms of electricity supply until the direction and form of future environmental legislation becomes clearer, and availability of alternative low-carbon technologies has matured in both technology and cost.

At the same time, the region cannot stand still in maintaining and improving the reliability of its power system. Investments in additional transmission capability and improved operational agreements are important for the region, both to access growing site-based renewable energy and to better integrate it into the power system. The Council expects that there are small-scale resources available at the local level in the form of cogeneration or renewable energy opportunities. The Plan encourages investment in these resources when cost effective.

The Power Plan also recognizes that meeting capacity needs and providing the flexibility reserves necessary to successfully integrate growing variable generation sources may require shorter-term investments in generation resources to provide reliable electricity supplies in specific utility balancing areas. In addition, individual utilities have varying degrees of access to electricity markets and varying resource needs. The Plan is not a plan for every individual utility in the region, but rather is intended to provide guidance on the types of resources that should be considered and their priority of development.

The near-term actions recommended in the Council's Sixth Power Plan are important, but the region cannot neglect the consideration of longer-term needs. The Plan encourages research on, and exploration of, advanced technologies for the long-term development of the power system. Advancing technologies that facilitate consumers' participation in their own efficiency improvements and their provision of capacity and flexibility services to the power system offer great potential for a transformed power system that is more diverse in its supplies and more efficient in its operation. Such "smart grid" development may facilitate the deployment of plug-in electric hybrid vehicles that work in concert with the power system to improve the use of available generating capacity and help reduce carbon emissions in the transportation sector. This is a long-term process that will require many years to reach its full potential, but the region can facilitate progress through research, development, and demonstration of the technologies.

Along with a smarter grid, other technologies may be able to provide power when it is needed with low cost, low risk, and low emissions. In the future we may find greater value in power generated by geothermal resources, ocean waves, tides, gasified coal with carbon sequestration, or currently unknown technologies. New methods to store electric power, such as pumped storage or advanced battery technologies may enhance the value of existing generators like wind. Given the uncertainties of the future, the region should not concentrate on any one potential future solution to its power supply, and should diversify its exploration of potential sources of future energy generation and conservation.

FUTURE REGIONAL ELECTRICITY NEEDS

The Pacific Northwest is expected to develop and expand over the next 20 years. Regional population is likely to increase from 12.7 million in 2007 to 16.3 million by 2030. This 3.6 million increase compares to a 3.8 million increase between 1985 and 2007. The population growth will be focused on older age categories as the baby boom generation reaches retirement age. While the total regional population is projected to increase by 28 percent, the population over age 65 is expected to nearly double. Such a large shift in the age distribution of the population will change consumption patterns and electricity uses. Some possible effects could include increased health care, more retirement and elder care facilities, more leisure activities and travel, and smaller size homes.

The cost of energy (natural gas, oil, electricity) is expected to be significantly higher than during the 1980s and 1990s. Although these prices have decreased significantly since the summer of 2008, current price levels, especially natural gas, are depressed by the effects of the recession. The production of nonconventional natural gas supplies has increased dramatically in the last few years, encouraged by higher prices. The technology to retrieve these supplies cost-effectively has only developed recently and this has made expectations for adequate future supplies more certain. Nevertheless, the cost of finding and producing these supplies is higher than for conventional supplies, which increases the estimated future price trend for natural gas.

Carbon emissions taxes or cap-and-trade policies are likely to further raise these energy costs. Some of the planning scenarios used to develop this Plan include a wide range of possible carbon mitigation costs from $0 to $100 per ton. The expected average prices in this range start at zero and increase over time to $47 per ton of CO_2 emissions by 2030. Carbon costs can have a significant impact on electricity costs and prices to consumers. While higher prices reduce demand, they also bring forward new sources of supply and efficiency, and make more efficiency measures cost-effective.

Electricity use before accounting for new conservation is expected to grow by about 5,500 average megawatts by 2030, growing at about 273 average megawatts, or 1.3 percent, per year. Residential and commercial sector electricity use account for much of the growth in demand. Contributing to the growth in the residential sector is an anticipated increase in air conditioning and consumer electronics. Also, summer peak electricity use is expected to grow more rapidly than annual energy. All of this growth in energy demand must be met by a combination of existing resources, more efficient use of electricity, and new generation. An important change for the Sixth Power Plan is that electricity needs in the future can no longer be adequately addressed by evaluating only average annual energy requirements. In the future resource needs must also consider capacity to meet peak loads and the flexibility to provide within-hour load following and regulation. The requirements for within-hour flexibility reserves have been increased by the growing amount of variable wind generation located in the region.

CONSERVATION POTENTIAL

The Council's Power Plan includes a detailed analysis of efficiency potential in hundreds of applications. The achievable technical potential of efficiency improvements increased from the Fifth Power Plan levels due to advancing technology, reduced cost, development of estimates in new areas such as efficiency in electricity distribution systems, consumer electronics, and street, parking and exterior building lighting. The estimated achievable potential conservation is nearly 6,000 average megawatts for measures costing under $100 per megawatt-hour. Over 4,000 average megawatts is available at a cost of less than $40 per megawatt-hour. These increased opportunities excluded savings from efficiencies that have already been secured through building codes, appliance efficiency standards, and utility programs. However, the amount of achievable technical conservation that is found to be cost-effective still has increased significantly because avoided costs have doubled and carbon cost risk is several times higher than in the Fifth Power Plan.

The Plan shows that a substantial amount of the growth in demand for electricity could be met by conservation. Portfolio model analysis shows that over 5,800 average megawatts of conservation are cost-effective in the draft plan, double the amount in the Council's Fifth Power Plan. The amount that can be achieved is constrained by the commercial availability of technologies, limits on the annual development rate considered possible, and an ultimate penetration rate limit of 85 percent. However, the amount of conservation that was found to be cost-effective changed very little in response to changing assumptions about carbon costs and policies. In general, failure to achieve the conservation included in the plan will increase both the cost and risk of the power system.

GENERATION ALTERNATIVES

The Council analyzed a large number of alternative generating technologies. Each of these technologies is compared in terms of risk characteristics and cost with other generating technologies, efficiency improvements, and demand response. In addition, resource contributions need to be considered in terms of their energy, capacity, and flexibility characteristics.

Generating technologies that are technologically mature, meet restrictions on new plant emissions, and are cost-effective are limited in the short to intermediate term. Wind remains the primary large scale cost-effective renewable generation source in the near term, and natural gas-fired generation is also feasible and cost-effective. New coal-fired generation is difficult to site and permit, and prohibited in many states by new plant emissions standards. There are likely some small-scale dispersed renewable generation alternatives that are local and site specific. Cost-effective development of these is encouraged even though the Council currently lacks enough information to include them explicitly in the Plan. Longer-term alternatives that may develop include carbon separation and sequestration, maturing renewable technologies, advanced nuclear generation, demand response, smart grid, and storage technologies to help provide flexibility reserves. When CO2 costs are added to the direct cost of generating alternatives, the cost of most generating resource alternatives range between $75 and $105 (levelized 2006$) per megawatt-hour.

RESOURCE STRATEGY

In addition to efficiency improvements, new renewable generation (primarily wind) is required to meet renewable portfolio standards in Washington, Oregon, and Montana. Analysis shows that meeting RPS requirements uses most of the readily accessible wind potential (5,300 MW) in the region. In addition to the wind, some geothermal resources enter the plan. However, the amount of geothermal potential is considered quite limited. Given risk of some form of carbon pricing strategy in the future, additional renewable generation is cost effective. Natural gas-fired generation is optioned toward the middle of the planning period. It is attractive for energy and capacity needs and provides an ability to displace coal plants in futures with high carbon costs, or assumed coal plant closures. Both combined-cycle turbines and simple-cycle turbines are included in most scenarios. Although these natural gas plants are optioned in the plan, they are not optioned until after the 5-year action plan period, and although the options protect against the risk of uncertain future conditions, they are not actually constructed in many of the simulated futures during the entire 20 year period.

Due to slower growth of electricity demand, the large conservation potential, and required RPS resources, there is no apparent need for these other generating resources in the Plan's first five years from a regional planning perspective. The Council recognizes that individual utilities' needs and access to market resources will vary. Some utilities will need additional resources in the next few years even if they acquire all conservation available to their service territory and meet their renewable portfolio standards.

During the last 10 years of the Power Plan the non-conservation resource priorities become less clear. Given current climate change policies and concerns, new coal without carbon sequestration is unlikely, and any significant reduction in carbon will require reduced operations of existing coal plants. Alternatives beyond more reliance on natural gas are typically unproven commercial technologies or alternatives that require significant new transmission investments. Long-term generating resources considered include wind developed outside the region and imported on new transmission lines, advanced nuclear, use of gasified coal with carbon sequestration, and development of relatively unproven renewable resources, or ones that are currently too expensive. Natural gas is used in the Plan to meet long-term needs, but the Council recognizes that other alternatives are likely to become available over time.

CLIMATE CHANGE POLICY

The focus of climate policy especially for the power generation sector will be on carbon dioxide emissions. Nationwide, carbon dioxide accounts for 85 percent of greenhouse gas emissions. Nationally, about 38 percent of carbon dioxide emissions are emitted from electricity generation, but for the Pacific Northwest the power generation share is only 23 percent because of the hydroelectric system. Analysis by others has shown that substantial and inexpensive reductions in carbon emissions can come from more efficient buildings and vehicles. More expensive reductions can come from substituting non- or reduced-carbon electricity generation such as renewable resources and nuclear, or from sequestering carbon.

Reductions in carbon emissions can be encouraged through various policy approaches including, regulatory mandates (e.g. RPS or emission standards), emissions cap-and-trade systems, emissions taxation, and efficiency improvement programs. State policy responses within the region to climate change concerns have focused on renewable energy standards and new generation emission limits. National and regional proposals have focused on cap-and-trade systems, although none have been adopted successfully nationally or in the region. Although carbon taxes are easier to implement than cap-and-trade systems, none have been proposed. The Council's Sixth Power Plan reflects the likely, but uncertain, costs of potential carbon pricing policies by assuming a possible range of carbon costs between $0 and $100 per ton. The average of these uncertain future costs increases over time and reaches about $47 per ton by 2030. These potential costs play an important role in the proposed resource portfolio, with the exception of the conservation resource, which remains a key component regardless of climate change policy assumptions.

The key findings from the Council's analysis of climate change policies include the following:

- Without any carbon control policies, including existing ones, carbon emissions from the Northwest Power System would continue to grow to 5 percent over 2005 levels by 2030.

- Without additional carbon pricing policies, current policies would stabilize carbon emissions from the Northwest power system.

- Assuming higher carbon prices, the Sixth Plan resource strategy has the potential to reduce regional power system carbon emissions to below 1990 levels, or 30 percent below 2005 levels adjusted for normal hydro conditions.

- Significant reductions of carbon emissions from the Northwest's power system require reduced reliance on coal, which currently emits over 85 percent of the carbon dioxide from the regional power system. A carefully coordinated retirement and replacement of coal-fired generation with conservation, renewable generation, and lower-carbon-emission resources could reduce carbon emissions to 35 percent of 1990 levels.

- To the extent that public policy raises the cost of carbon, we can expect an increase in a typical consumer's electric bill and a decrease in carbon emissions, especially when the carbon price begins to exceed $40 per ton. A variety of different scenarios are considered in Chapter 9.

- Protecting the capability of the existing regional hydroelectric generation through conservation and preservation of its generating capability keeps costs and carbon emissions down. In scenarios where the capability of existing resources are reduced, whether hydroelectric or coal, the energy and capacity are largely replaced with gas-fired generation.

CAPACITY, FLEXIBILITY, AND WIND INTEGRATION

Reliable operation of a power system requires minute to minute matching of electricity generation to varying electricity demands. In the Pacific Northwest, resource planners have been able to focus mostly on annual average energy requirements, leaving the minute to minute balancing problem to system operators. This was because the hydroelectric system historically had sufficient peaking capacity and flexibility to provide the needed operations as long as there was sufficient energy capability. This is changing for several reasons; growing regional electricity needs are reducing the share of hydroelectricity in total demand, peak loads have grown faster than annual energy, the capacity and flexibility of the hydro system has been reduced over time for fish operations, and growing amounts of variable wind generation have added to the balancing requirements of the system.

As a result, planners must now consider potential resources in terms of their energy, capacity, and flexibility contributions. The rapid growth of wind generation, which has little capacity value and increases the need for flexibility reserves, means that meeting growing peak loads and flexibility reserves will require adding these capabilities to the power system. Changes can be made to the operation of the power and transmission system that will reduce flexibility reserve needs. These operational changes are expected to be lower cost than adding peaking generation, demand response, or flexibility storage, and can be implemented more quickly.

FISH AND WILDLIFE PROGRAM AND THE POWER PLAN

The Fish and Wildlife Program is part of the Council's Power Plan. It is intended to guide Bonneville's efforts to mitigate for the adverse effect on fish and wildlife that resulted from construction and operation of the Columbia River hydroelectric system. One of the roles of power plan is to help assure reliable implementation of fish and wildlife operations. The power system, guided by the power plan, has done this in the past and will continue to do this in the future. It has done so by acquiring conservation and generating resources to make up for 1,170 average megawatts of lost hydroelectric generation stemming from actions to aid fish migration, by developing resource adequacy standards, and by implementing strategies to minimize power system emergencies and events that might compromise fish operations. Power system adaptations have taken place in such a way not only to accommodate fish operations but also to leave the power system adequate and reliable.

In addition to operational changes, the direct cost and capital costs of fish and wildlife programs have been recovered through Bonneville revenues, resulting in higher electricity prices. Bonneville estimates that replacing lost hydropower capability and funding direct fish and wildlife program expenditures has increased its costs from $750 to $900 million per year. This amount represents approximately 20 percent of Bonneville's annual net revenue requirement. The power system is less economical as a result of fish and wildlife program costs, but still economical in a broad affordability sense.

The future presents a host of uncertain changes that are sure to pose challenges for the successful integration of power system and fish and wildlife needs. These include possible new fish and wildlife requirements, increasing wind generation and other variable renewable integration needs that could require more flexibility in power system operations, conflicts between climate change policies and fish and wildlife operations, possible changes to the water supply from climate change that might make it more difficult to deliver flows for fish and meet power needs, and possible revisions to Columbia River Treaty operations to match 21st century power, flood control, and fish needs.

To address current operations and prepare for these additional challenges, the Council has adopted a Regional Adequacy Standard to help ensure that events like the 2000-01 energy crisis, in which fish operations were affected, do not happen again. In addition, the Wind Integration Forum is addressing issues with integration of wind into the power system. Large swings in wind output have sometimes adversely affected hydropower and fish operations. Addressing adequacy and flexibility issues in the Sixth Power Plan will both improve electricity reliability and help insure reliable fish operations.

Sixth Power Plan Action Plan

CONSERVATION

Energy efficiency is the first priority resource in the Northwest Power Act. The Council's analysis for the Sixth Power Plan strongly affirmed that energy efficiency improvements provide the most cost-effective and least risky response to the region's growing electricity needs. Further, accelerated acquisition of cost-effective efficiency reduces the contribution of the power system to green house gas emissions. With green house gas reduction policies in flux, and many new sources of carbon-free electricity expensive or lacking capacity contributions to go with their energy, accelerated acquisition of cost-effective efficiency can buy time to develop policies and identify alternative sources of carbon-free generation.

The region is increasing its efforts to accomplish conservation through integrated resource planning requirements, state and utility programs, and the Northwest Energy Efficiency Taskforce. Nevertheless, achieving the level of conservation identified in the Sixth Power Plan is a task that will require aggressive actions by the region. The Action Plan of the Sixth Power Plan contains a list of recommendations that will help the region to meet the efficiency challenge.

Key areas for enhanced implementation activity include, (1) enhancing the region's ability to acquire efficiency potential that has been identified (2) increasing efforts to identify and verify new cost-effective and feasible technologies, and (3) developing regional mechanisms to keep efficiency policies up to date with changing information, to track and verify achievements, and adaptively manage regional efficiency acquisition strategies.

The Council target for regional acquisition of conservation over the first 5 years of the Plan is 1200 MWa. However, the conservation target relies on forecasts of underlying load and economic conditions, such as the rate of economic recovery and the construction rate of new *buildings, that may turn out to be different in the next five years than forecast. The uncertainties of the underlying assumptions thus create uncertainty about the total amount of the targeted conservation that will be available to acquire in the first five years. For this reason, the Council also developed a range of likely conservation savings over the first 5 years of 1100 to 1400 MWa. The Council will monitor the actual conservation savings acquired by the region by conducting reviews of the region's progress each year during the initial five-year planning horizon of the 6th Power Plan. The Council may choose to adjust the conservation target following a mid-term review to reflect actual achievements or conditions different than forecast that have effected the total amount of conservation available. These periodic evaluations will help the Council to monitor actual conservation savings and help prepare for the next major power plan in 5 years.*

Conservation: Deployment

CONS-1. **Achieve the level of conservation resource acquisition identified in the Sixth Plan's conservation target and accomplish the other actions necessary to accelerate conservation deployment.** [Utilities, Energy Trust of Oregon, Utility Regulators, Bonneville Power Administration, Northwest Energy Efficiency Alliance (NEEA), and States][1] The Council believes that the region should be able to achieve at least 1,200 average megawatts of cost-effective conservation savings under the majority of future conditions. Consequently, activities, resources and budgets should be geared to acquire 1,200 average megawatts of savings from 2010-2014 from utility program implementation, market transformation efforts, and codes and standards not included in the regional load forecast. However, the Council recognizes that there is a level of uncertainty inherent in its assessment of regional conservation potential, the pace of anticipated economic recovery, power market conditions, carbon control requirements, technology evolution, the success or failure of acquisition mechanisms and strategies, progress on research and development and the adoption of codes and standards. Therefore, the Sixth Plan's likely range of conservation savings is from a low of 1100 average megawatts of savings to a high of 1,400 average megawatts over the next five years. Since the future is uncertain, Action Item CONS-16, calls for a mid-term review of regional progress towards the regional conservation target and to consider any adjustment to that target during the remainder of the period covered by the Action Plan. In addition the mid-term review will assess the potential impacts on other resource actions if there is significant difference, either up or down, in conservation acquisitions from the targets.

CONS-2. **Develop and implement an action plan for measures that are commercially viable but relatively new to programs or markets.** [Bonneville, Utilities, Energy Trust of Oregon, and NEEA] The Sixth Power Plan identifies new or technologically-improved efficiency measures that are cost-effective to pursue. The Sixth Plan identified nearly 6,000 average megawatts of cost-effective conservation realistically achievable over twenty years. Of that, approximately 2,500 average megawatts will require new initiatives, programs, market transformation efforts or progress towards adoption in codes and standards. While in the near-term these measures make up about one-quarter of the conservation targets, activities to develop these measures need to start now, so that the

[1] Format note: The text in brackets following the bolded actions identifies the implementing entities.

region is positioned to place increased reliance on them in the future. The Council believes that regional collaboration on initiatives to develop and deploy these measures would greatly enhance their chance of success. This activity will require concurrent market research to determine the most effective ways to develop and deploy these new measures. Each of these measures is at different stage of development and requires a different implementation strategy. All require efforts beyond what is now being done. An initial list of these measures includes distribution system efficiency, commercial outdoor lighting, residential heat pump water heaters, residential ductless heat pumps, TV, set-top boxes, desktop PCs, PC monitors and industrial system optimization.

CONS-3. **Provide continued funding, in adequate amounts, for the Northwest Energy Efficiency Alliance's (NEEA) to support its market transformation efforts.** [Bonneville, Utilities, and Energy Trust of Oregon] NEEA's regional market transformation activities have proved to be a great value. Market transformation has been a key part of the development of many existing efficiency initiatives, and will need to be so for many of the new initiatives that the region must take up.

NEEA's newly adopted strategic plan should be funded by regional utilities. In addition, the region should institute an ongoing process to identify needed market transformation efforts that are not in the current NEEA business plan but which may be necessary to reach regional conservation targets. The process should include a mechanism, such as subscription-based initiatives, to adjust funding allocations between regional and local program as market dynamics change and new opportunities arise.

CONS-4. **Develop long-term partnerships with energy efficiency businesses, trade allies and other parties in product and service supply chains.** [Bonneville, Utilities, Energy Trust of Oregon, NEEA, Governors, and States] Decisions to adopt efficiency measures and practices are made by consumers. Consumer's decisions are influenced by many factors, including relationships with the energy efficiency industry and trade allies such as building designers, equipment vendors, contractors, engineering firms, lighting designers, and the product and service options available to them. Accelerating consumer adoption of energy efficient technologies and practices can be facilitated by creating cooperative working relationships between NEEA and utility programs, product manufacturers, distributors, retailers and the energy efficiency industry and trade allies to leverage their market relationships.

CONS-5. **Support the adoption of cost-effective codes and standards and work to help ensure compliance.** [Council, Utilities, Energy Trust of Oregon, NEEA, Bonneville, Governors and States] The Council will encourage the adoption of new codes in the region by working closely with the Governors' Offices and with the responsible energy code adoption and enforcement agencies and other regional entities. This includes, but is not limited to the following activities:

- Advocating for the development and adoption of cost-effective energy codes and equipment and appliance standards at the state and national level in a manner that is consistent with the entities' roles in the acquisition of efficiency resources and legal limitations on political activities.

- Providing technical and political leadership in both legislative and rulemaking processes.

- Enhancing code compliance by working with local government officials to create a supportive environment and adequate funding for comprehensive energy code implementation.

- Providing technical and educational support to code-enforcement staff.

- Developing and implementing a coordinated, high-level, adequately funded Pacific Northwest presence in federal efficiency standard rulemaking processes, to ensure that efficiency standards for federally regulated appliances and equipment achieve cost-effective energy savings.

CONS-6. **Implement the Sixth Plan's Model Conservation Standards (MCS).** [Utilities, Energy Trust of Oregon, NEEA, Bonneville, Governors and States] This includes supporting the adoption of the MCS in state codes and standards and working with local jurisdictions to increase compliance rates. It also includes implementing programs to achieve savings from measures in the MCS not adopted into code and operating programs consistent with the MCS for Conservation Program Not Covered by Other MCS.

CONS-7. **Adopt policies that encourage utilities to actively participate in the processes to establish and improve the implementation of state efficiency codes and federal efficiency standards in a manner that is consistent with their responsibility to acquire cost-effective efficiency resources.** [Utility Regulatory Commissions] For example, state regulators could clarify conditions under which utilities could qualify for cost recovery for efforts to establish new codes and standards.

CONS-8. **Support the ongoing operation of the Regional Technical Forum (RTF) and assure that the RTF has sufficient resources to review the new efficiency measures identified in the Power Plan.** [Bonneville, Utilities, Energy Trust of Oregon, and States] The financial resources provided to the RTF's to support its review of energy savings estimates, development of measurement and verification protocols, and establishment of measure specifications needs to be enhanced to cover the expanding suite of conservation activities. In order to avoid delaying the acceleration of regional conservation acquisition efforts the RTF will require increased funding to carry out its reviews in a timely and thorough manner. The region should provisionally increase its support of the RTF in 2010 at a level commensurate with estimated cost of identified research, analysis, tracking and evaluation while the Northwest Energy Efficiency Taskforce (NEET) conducts a review of the RTF's function, role, funding, and governance. Upon completion of the independent review, NEET should submit its recommendations regarding these issues to the Council for consideration.

CONS-9. **Develop energy savings verification protocols for conservation measures, practices, and programs when current verification methods appear problematic or expensive or verification methods do not exist.** [Regional Technical Forum] Streamlined measurement and verification protocols will allow the region to monitor the reality and persistence of savings as well as help Bonneville, the utilities, and regulators identify savings against targets and goals. The RTF should work with utilities for consistent guidance on tracking and verification of savings. Pursuant to CONS-17, the RTF should develop measurement and verification protocols and/or recommend mechanisms for savings evaluation and verification that recognize the limited capabilities, customer and service territory characteristics and experience of the region's small and/or rural utilities. The RTF should prioritize its work to allow the region to move forward quickly to capture and verify savings. The RTF should also recommend improvements to the regional conservation measurement and evaluation procedures based on recommendations from the NEET workgroup as a starting point.

CONS-10. **Develop a comprehensive library of estimates of savings from conservation measures and savings evaluation and measurement protocols.** [Regional Technical Forum] Review and compare utility and Energy Trust of Oregon savings estimates for measures not addressed by current RTF recommendations. Expand and update the library of energy savings estimates, over time resolve any inconsistencies, and make the library available for use across the region. Pursuant to CONS-17, in consultation with Bonneville and the region's small and/or rural utilities identify conservation measures that recognize the limited capabilities, customer and service territory characteristics and experience of the region's small and/or rural utilities.

CONS-11. **In recognition of the higher goal for industry-sector conservation, develop and implement a comprehensive strategy to improve the energy efficiency and economic competitiveness of industries in the region.** [Industry and trade allies, Bonneville, Utilities, Energy Trust of Oregon, NEEA, and States]

CONS-12. **Consistent with standard practices for integrated resource plans, establish polices for incorporating a risk-mitigation premium for conservation in the determination of the avoided cost used to establish the cost-effectiveness of conservation measures.** [State Utility Regulatory Commissions and Utilities] The Council's resource portfolio modeling identified valuable risk-mitigation benefits for the region from developing conservation. A risk-mitigation value should be incorporated into conservation cost-effectiveness methodologies used by utilities and their regulators and system benefits administrators. The Council recognizes that each utility and system benefits administrator is in a different position with regard to the risks it faces. Regulators and utilities should establish policies on how to incorporate the estimated cost of addressing greenhouse gas emissions from thermal resources in conservation avoided-cost methodologies and integrated resource plans.

CONS-13. **Identify regulatory barriers and disincentives to the deployment of conservation, and consider policies to address these barriers.** [To State Utility Regulatory Commissions, Investor-Owned and Publicly Owned Utilities, States, BPA and Others]

Conservation: Adaptive Management

The Council is well positioned to conduct periodic reviews of the remaining conservation potential, and of existing and planned conservation initiatives as well as conservation research and evaluation efforts. However, Bonneville, the utilities, the Energy Trust of Oregon, and NEEA along with the States are best positioned to develop and adaptively manage the actual acquisition of conservation resources. These entities have a long and successful history of developing strategies and funding programs to acquire conservation, transform markets, and upgrade codes and standards.

CONS-14. **Prepare a strategic and tactical plan to achieve the Sixth Plan's regional conservation target and accomplish the other actions set forth in the Sixth Plan that are necessary to build the capability to accelerate conservation deployment for the remainder of the planning period in a cost-efficient manner.** [Bonneville, Utilities, Energy Trust of Oregon, and NEEA] A regional conservation implementation plan is needed to assure resources are being effectively deployed to reach the Sixth Plan's conservation target. The Council recognizes that Bonneville, Utilities, Energy Trust of Oregon, and NEEA are best positioned to prepare and adaptively manage the implementation of such a plan. However, the development and implementation of this plan will require the active collaboration of these entities with other market actors, including energy efficiency business and their trade allies, state and local governments, as well as associations and organizations that represent key customer groups. The Council believes that the plan should include specific actions focused on developing energy efficiency technologies and practices. The plan should describe how these technologies and practices will be brought to market from conception to full deployment using local utility programs, coordinated regional programs, market transformation, codes and standards adoption and enforcement and any other mechanism deemed appropriate and all parties should collaborate on the disaggregation of these savings into these delivery categories. In particular, the plan should address the need to transition from reliance on compact fluorescent light bulbs (CFLs) to a more diversified portfolio of measures. Savings achieved through all of these mechanisms, including savings for utility-acquired CFLs until federal standards take effect in 2012, will count toward achievement of the Council's conservation target. The plan should also set forth the level of funding for staffing and infrastructure needed for its successful implementation. Finally, the plan should develop quantifiable milestones to measure progress toward these targets and actions that can be evaluated at strategic points over the five-year action plan. Progress toward these milestones should be reviewed in the mid-term report on progress towards meeting plan objectives (CONS-16).

CONS-15. **Develop an ongoing mechanism to identify high-priority actions that will enhance the deployment of cost-effective energy efficiency across the region.** [Bonneville, Utilities, Energy Trust of Oregon, NEEA, State Regulatory Commissions, along with the States and the Council] Adaptive management of the implementation of the regional conservation action plan called for in CONS-14 will require timely decisions regarding the allocation of resources between local, regional programs and market transformation initiatives; the continuation and expansion of successful existing programs and efforts; the modification or termination of poorly performing programs, and the development of new initiatives for new efficiency measures and practices identified in the Sixth Plan. In order to accomplish this, the Council believes that a high-level forum for ongoing policy-level guidance on these issues should be formed. The Council views this as a continuance of the NEET efforts to address the dynamic nature of conservation acquisition and, like NEET, this forum must include senior-level management and decision makers to assure common understanding, commitments, and follow through. While pursuant to the NEET recommendations NEEA has agreed to host and facilitate regional efforts to better coordinate programs that do not adequately address this need.

CONS-16. **Report on progress towards meeting plan objectives.** [Bonneville, Utilities, Energy Trust of Oregon, and NEEA] As part of the Council's biennial review of the

Sixth Power Plan, Bonneville, Utilities, Energy Trust of Oregon, and NEEA should report on progress towards meeting plan's conservation targets and objectives. The report should include an assessment of progress toward mid-term milestones established in the strategic plan developed in CONS-14. The Council recognizes that the plan's conservation targets are based on an "expected value" across a wide range of potential futures. The actual future the region experiences will differ in some regard from the plan's assumptions. Therefore, this report should identify whether the regional conservation acquisition plan (CONS-14), the implementation of that plan (CONS-15) and/or the Council's target (CONS-1), need to be modified to account for conditions or circumstances different than expected. These include slower- or faster-than-anticipated economic recovery, substantially different power market conditions, carbon control requirements, technology evolution, the success or failure of acquisition mechanisms and strategies, progress on research and development and the adoption of codes and standards.

CONS-17. **Take into account the unique circumstances and special barriers faced by small and/or rural utilities in achieving conservation and the development and implementation of conservation programs.** [Bonneville] Work with and give assistance to these customers to ensure that their capabilities, customer and service territory characteristics, and experiences are addressed in the identification of conservation measures applicable in their service territories and in the implementation of these conservation measures. Work with the RTF to see that these measures are expeditiously evaluated so that they are available to meet the conservation goals of small and/or rural utilities. Assist these utilities as needed in their efforts to implement these conservation measures and help Bonneville meet its share of the regional conservation target, working with these utilities either individually or pooled, as appropriate in each circumstance. Finally, a panel consisting of Bonneville and small and/or rural utilities should report its findings back to the Council during the mid-term check-in of the Sixth Power Plan.

CONS-18. **In consultation with Bonneville, Utilities, Energy Trust of Oregon, and NEEA develop recommendations on measure bundling, the use of cost-effectiveness tests, research and development investments and others issues.** [Council] Guidance is needed to ensure that the Sixth Plan's conservation resource assessment is translated into acquisition programs and research and development activities. The NEET process identified the Council as the lead for the development of a cost-effectiveness reference document and the need for an ongoing process to assist utilities and others in their efforts to design and implement effective and administratively-efficient conservation program using the data from the Council's plan.

CONS-19. **Develop and implement improvements to the regional conservation Planning, Tracking and Reporting (PTR) systems so that energy efficiency savings and expenditures are more consistently and comprehensively reported.** [Regional Technical Forum, Utilities, Energy Trust of Oregon, Bonneville, NEEA, and States] Also identify a governance structure to guide improvement of the systems and funding agreements to share the responsibility for its ongoing operation and maintenance equitably. The tracking system should evolve over time so that conservation from all mechanisms and funding sources, including utility, state and local conservation programs, codes and standards, state and federal tax credits, market transformation, and non-programmatic changes in markets can be reported. Savings from market changes outside of programs may need to be tracked outside of the PTR system.

Conservation: Development and Confirmation

The Sixth Plan's assessment of technically achievable energy efficiency resources relies on research and demonstration program results initiated as long ago as the early 1980's. In order to expand the conservation options available in the future, and to confirm the resource cost, savings, and consumer acceptance of some measures identified in the Sixth Plan, the region should fund conservation research and demonstration activities. The responsibility for carrying out these activities varies with their purpose and scope. However, given the "community property" nature of the results of these projects, Bonneville, the utilities, NEEA and the Energy Trust of Oregon should, to the extent practicable, collaborate on funding and coordinate on implementation. At the same time, regulatory commissions should establish guidelines to allow cost recovery for such research and demonstration activities.

CONS-20. **In order to ensure the long-term supply of conservation resources, develop and fund a regional research plan that directs development, demonstration, and pilot program activity.** [Utilities, Bonneville, Energy Trust of Oregon, NEEA and other program operators] The plan should focus on both the new measures and practices identified in the Sixth Power Plan conservation assessment and promising measures that emerge over the next five years that require additional technical, market, or other research. An initial list of measures that should be incorporated into the research plan is in an attachment to Appendix E. Assess feasibility, collect and evaluate data on costs and savings (including load shape impacts), and identify programmatic approaches, delivery mechanisms, implementation strategies, and infrastructure needs. The research plan should :

a. Prioritize research needs based on the magnitude of potential savings and level of uncertainty of measure performance.
b. Identify research objectives that define specific milestones or the knowledge sought in order to increase certainty and solidify resource components of the long-term conservation supply.
c. Identify funding requirements and commitments to accomplish research objectives.
d. Assign the roles and responsibilities of the various regional entities, including but not limited to the Regional Technical Forum, Bonneville, NEEA, utilities, Energy Trust of Oregon, and the states.
e. Identify milestones for reviewing research progress, determining additional research needs, and determining how regional conservation potential and associated targets should be adjusted based on the findings. Periodic review of the research plan and findings could be done as part of a biennium review of the power plan, or as needed.

CONS-21. **Develop a regional approach to support data needs for energy efficiency.** [Bonneville, NEEA, Utilities, Council and Regional Technical Forum] The region should develop multi-year data collection and research plan that prioritizes the initiatives needed to facilitate the implementation of conservation resources and determine their impact on the power system. The plan should set forth a process to improve data coordination, distillation and dissemination and outline the most appropriate and cost-efficient way to acquire needed data. The development of this plan should be carried out in a manner consistent with the NEET recommendations. Elements of this data collection work can assigned to the Regional Technical Forum, NEEA, Bonneville, and the utilities. High priority data needs include:

a. Residential and commercial building characteristics
b. Customer end-use surveys
c. Measured end use & savings load shapes
d. Efficiency measure saturations
e. Capacity impact of efficiency measures
f. Appliance and equipment saturations
g. Market/Supply Chain structure
h. Tracking of non-programmatic conservation savings

CONS-22. **Establish guidelines to consider, balancing utility and consumer interests, cost recovery for conservation research, demonstration, confirmation, and coordination activities.** [State Utility Regulatory Commissions, Public Utility Boards and Commissions, and Utilities]

GENERATING RESOURCES

From a regional energy perspective, new generating capacity in excess of that needed to meet state renewable portfolio standards is unlikely to be needed in the near-term[2] for the purpose of maintaining energy adequacy. Additional energy acquisitions for the purpose of risk or cost reduction also appear not to be cost-effective. Although the region as a whole does not appear to be short of energy, this may not be true for individual utilities, some of which may be surplus while others may need to acquire additional energy generation capacity because of transmission or other limitations that constrain access to energy markets and surplus generation. This action plan includes guidelines for energy acquisitions in these circumstances.

Though the summertime surplus of firm capacity is declining, additional firm capacity is not needed on a region-wide basis in the near-term for the purpose of maintaining adequate winter or summer peaking reserves. However, continued development of wind power to meet regional renewable portfolio standards and for export[3] will continue to increase the demand for balancing capacity[4]. This action plan includes actions to reduce the demand for system flexibility, to more fully access the latent flexibility of the existing system and to better understand the interactions between provision of balancing, capacity and energy services. These actions are consistent with the current recommendations of the Northwest Wind Integration Action Plan.

Even with implementation of measures to more effectively use existing system flexibility, continued development of variable-output resources may eventually lead to the need to augment capacity and flexibility. Though the timing of this need on a regional basis is poorly understood,

[2] First five years of the 20-year period of the plan.
[3] Balancing authorities are obligated to provide interconnection and integration services for generators irrespective of local need.
[4] Balancing capability (often referred to as system flexibility or regulation and load-following) refers to the ability to balance generation and loads on seconds to minutes (regulation) and within-hour (load-following) bases.

Bonneville has asserted that it may confront this need in the near-term because of the geographic concentration of wind development within the Bonneville balancing area. This action plan includes guidelines for capacity acquisitions in these circumstances. As the region considers the cost effectiveness of new low or non-carbon emitting resource options, it will need to explicitly consider the costs that may be associated with the potential need to develop complementary carbon fueled resources to firm and shape variable-output non-carbon fueled generation, as well as the costs to the environment and region to develop necessary transmission facilities to integrate such resources. The region should also consider the carbon reduction attributes associated with using other technologies to integrate wind, such as smart grid and storage.

Over the longer-term it is expected that additional sources of low-carbon energy will be needed to reduce carbon dioxide production to sustainable levels. Cost-effective near-term low-carbon options include wind, limited quantities of geothermal, biogas and biomass residues, new hydropower and hydropower upgrades, and high-efficiency natural gas generation and cogeneration. Expanding the suite of available cost-effective low-carbon resource choices would be beneficial. Prospects include enhanced geothermal, wave energy, offshore wind, advanced and modular nuclear plants, solar photovoltaics, imported wind, concentrating solar power, tidal current energy and technologies for the capture, storage or recycling of carbon from existing and new fossil-fueled power plants. This action plan includes actions to promote the cost-effectiveness and availability of additional low-carbon generating resources with a focus on options of special relevance to the Northwest.

Sound power system planning and decisions require capable analysis tools and reliable supporting data. In particular, techniques and data for assessing the most cost-effective approaches for long-term development and integration of variable-output resources are inadequate or lacking. This action plan contains actions to support improved planning and decision-making.

Generating Resource Acquisition

GEN-1. **Acquisitions to meet capacity, energy and ancillary service needs.** Bonneville, other balancing authorities and utilities needing to acquire resources to serve capacity, energy and ancillary service needs should seek to acquire the most cost-effective, suitably reliable resources available to provide the needed service. All potentially cost-effective alternatives capable of providing the needed services should be considered including, but not limited to, conservation, demand management, storage, transmission, generating resources, operational and institutional solutions and other emerging technologies (for example smart grid). Resource cost-effectiveness evaluations should recognize the net value of services provided (e.g., energy, capacity, ancillary services, avoided transmission and distribution costs, cogeneration load) and services needed to support (e.g., transmission, balancing services, supplemental firm capacity) the available alternatives. Resource-related risks including investment, performance and environmental risks should be quantified where feasible.

GEN-2. **Facilitate development of smaller-scale cost-effective low-carbon resources.** Generating resource development in recent years has been dominated by wind power and natural gas combined-cycle plants. However, it is evident that certain smaller-scale renewable and high-efficiency projects can be equally, if not more cost-effective than these more prevalent resources. Smaller-scale resource development opportunities include waste heat energy recovery, bioresidue energy recovery, cogeneration, geothermal, hydropower upgrades and new hydropower projects. These opportunities are available in limited quantity and tend to be challenging to develop because of the complexity of business arrangements, engineering, fuel supply and interconnection, proportionally high transaction costs and long lead times, coupled with relatively small size. Design and engineering is often highly site-specific, as are costs and business arrangements. If successful, however, these projects can provide baseload energy, avoided transmission and distribution costs, residue disposal solutions, local economic development, low-carbon energy production and revenues to host facilities.

The Council encourages Bonneville and the utilities to facilitate development of these resources where cost-effective by undertaking activities such as the following:

- Surveys of resource development potential
- Requests for proposals structured to accommodate small and diverse projects
- "Open window" application and evaluation process for unsolicited proposals
- Standard power purchase offers for qualifying projects
- Standard interconnection provisions
- Consideration of all project attributes in proposal evaluations
- Provision of financial, engineering and other development assistance
- Support for demonstration and pilot projects for developing, testing and demonstrating technology and business practices

Adequacy of System Integration Services

GEN-3. **Reduce demand for system flexibility.** The demand for balancing reserves for integrating variable-output resources can be reduced by improved wind forecasting, sub-hourly scheduling, liquid intra-hour wholesale power markets, curtailment of wind plant output during severe ramp-up events, curtailment of wind export schedules during severe ramp-down events, and ACE[5] diversity sharing among balancing areas. The Northwest Wind Integration Forum, working with Bonneville, regional utilities and grid entities should assess the feasibility, cost and benefits of these and other possible measures that would reduce the demand for balancing reserves and implement promising measures. ***This action is of high priority.***

GEN-4. **Expand access to existing system flexibility.** Some of the latent balancing capability of the existing power system cannot be used because of operating protocols, transmission and communication limitations, absence of equipment allowing plants to be operated for balancing purposes and environmental constraints. The latent balancing capability can be more fully tapped by expanded dynamic scheduling capability within the region and between interconnected regions, and by retrofit of existing plants where feasible and necessary to provide balancing capability. The Northwest Wind Integration Forum, working with regional balancing authorities and grid entities should assess the feasibility, cost and benefits of expanded dynamic scheduling within region and across the Northern and Southern interties. Attractive opportunities for expansion should be

[5] Area Control Error - A measure of the instantaneous difference in scheduled and actual system frequency and a balancing authority's scheduled and actual interchanges with other balancing areas.

developed. This working group should also work with plant owners to establish balancing capability for generating units theoretically, but not currently practically capable of providing balancing services. ***This action is of high priority.***

GEN-5. **Assess adequacy of system flexibility.** Periodic assessments of the adequacy of available balancing capability for following load and for variable-output generating resource integration are needed to complement to existing assessments of energy and capacity adequacy. The Wind Integration Forum, working with the Resource Adequacy Forum should develop and implement a methodology for evaluating the adequacy of fast-response balancing capability.

GEN-6. **Evaluate flexibility augmentation options.** This plan recommends development of wind and other renewable resources to offset carbon control cost and natural gas price risks. Addition of wind and other variable-output resources will continue to expand the need for balancing capability. In response to this need, the highest priority should be given to measures to reduce the demand for balancing reserves and measures to expand access to the latent flexibility of the existing system, as called for in GEN-3 and GEN-4. However, Bonneville and other balancing authorities may eventually need to augment the supply of balancing capability to meet the needs of an expanding inventory of variable-output resources. The Council, working with the Wind Integration Forum will undertake an effort to assess the availability, reliability and cost-effectiveness of resources for augmenting the existing balancing capability of the power system. Priority in this effort will be given to resources or combinations of resources that can jointly satisfy peak load and system flexibility requirements. This effort will include, but not be limited to, consideration of combined-cycle plants, gas turbine generators and reciprocating engines, compressed air energy storage, pumped storage hydro, battery storage, smart grid and demand-side options. Metrics should be developed to measure and compare the various options. The completed assessment should include a plan of development, consisting of research, development and demonstration activities, needed to ensure that the most promising options are available for operation when required. ***Because of the early commercial status or long development lead time of several of these options, this action is of high priority.***

Expanding the Menu of Cost-effective Low Carbon Resources

GEN-7. **Commercialize and confirm promising low-carbon resources.** Wave energy, deep-water wind power and enhanced geothermal have promise for future development in the Northwest as potentially abundant, low-carbon resources. Yet, these resources, together with tidal current generation are technically immature and the benefits, costs and consequences of commercial-scale development insufficiently understood. Bonneville, regional utilities, industry groups and the states, working with the federal government should initiate and support efforts to develop and demonstrate the relevant technologies and to establish the body of knowledge and legal framework to support commercial development of the resources when available and needed. These efforts would include: 1) energy resource measurements of sufficient geographic scope, frequency and duration to support assessment of resource economics, identification of promising resource areas and assessment of resource integration needs; 2) technology assessment; 3) identification and resolution of potential environmental, economic and other development conflicts; 4) demonstration projects to test and evaluate technology; 5) assessment of system integration needs; and, 6) pilot projects to serve as the basis for commercial development. The initiatives of the Oregon Wave Energy Trust provides a model of a comprehensive resource confirmation agenda.

GEN-8. **Resource development mandates and incentives.** A diverse collection of federal and state resource development mandates and incentives has developed over time. The underlying public interest goals of mandates and incentives include commercialization of immature but promising technologies, developing the power system and social "infrastructure" for accommodating commercial-scale development of promising resources and promoting the development of low-carbon resources. While these mandates and incentives are effectively promoting development of specific resources, their focus on resource types rather than ends (e.g., GHG reduction, cost and risk minimization) may constrain development of equally attractive resources and impact efficient system operation. The Council will undertake a review of the impacts and effectiveness of mandates and incentives including consideration of the following:

a. **Impact of production tax credits on optimal dispatch.** The federal production tax credit lowers the effective variable cost of generation, in some cases to negative levels. Concerns have been voiced that this can result in inefficient resource dispatch and in some cases increased environmental impact.

b. **Effects of an unbundled REC market.** A renewable energy credit (REC) generally represents the environmental and renewable attributes of renewable energy production as a separate commodity from the associated energy. RECs can be transacted as "bundled" (i.e., with the associated energy) or "unbundled" (separate from the associated energy. Some states credit unbundled RECs (also called "tradable RECs") to meeting a portion of renewable portfolio standards. Unbundled sale of RECs allows utilities to acquire the attributes of renewable power without securing transmission from the renewable energy plant to the utility's service territory. To the extent that the renewable energy benefits are not location-specific (e.g., avoided carbon dioxide production), tradable RECs can reduce the cost to utilities of securing these attributes by allowing a utility to avoid transmission wheeling charges and to purchase from a higher quality, lower cost renewable resource than might otherwise be available. Tradable RECs can also provide a revenue stream to utilities choosing to develop renewable resources in advance of need without having to establish transmission to the customer utility, and can foster the non-power economic benefits of renewable energy resource development. Stimulating additional development of variable-output resources in the Pacific Northwest without corresponding inter-regional transmission connections may, however, create challenges for the region. The residual ("null") power will be marketed locally and may depress the value of competing, non-RPS-qualifying energy. Integrating the additional variable-output resources that may be developed to export unbundled RECs will increase the demand for integration services, thus possibly increasing the costs of such services. This could have the effect of driving up costs of integrating variable-output resources needed to comply with RPS requirements within the region, even for variable-output resources where RECs will not be unbundled, but consumed in the region. The purpose of this review will be to identify and articulate the costs and benefits of the unbundled REC market and to suggest modifications, if any, needed to remedy significant inequities or perverse incentives.

c. **Geothermal development risk reduction.** Geothermal is a very attractive, competitive low-carbon resource. Geothermal development, however, is hampered by a financially risky resource exploration and confirmation phase. Current federal incentives that reward successful production may be insufficient to offset the investment risk of resource development. Earlier federal incentives, directed to offsetting resource exploration and development risk, resulted in substantial geothermal power development and production. The cost and effectiveness of a range of incentives should be assessed to determine what set of incentives appear to be the most cost-effective in stimulating productive geothermal development.

d. **Promote CO2 reduction parity of resource mandates and incentives.** The principal underlying public purpose of many resource mandates and incentives is reduction in greenhouse gasses, yet CO2 reduction potential is not always reflected in the structure and level of mandates and incentives. An example is the prevalent failure to equate the carbon dioxide reduction potential of energy efficiency with that of renewable generating resources in state renewable portfolio standards. This may result in overly costly carbon dioxide reduction and greater environmental impact by diverting expenditures from conservation to renewable resource development. States should attempt to establish a reasonable parity in the treatment of resources, including conservation in the design of renewable portfolio standards and other low-carbon resource incentives.

GEN-9. **Carbon separation and sequestration technologies.** Though not yet fully commercial, carbon separation, sequestration, and recycling may prove to be an economic approach to reducing carbon dioxide releases in the longer-term. The Council encourages states and utilities to support efforts to develop commercial technologies for separation, sequestration and recycling of carbon dioxide with emphasis on technologies unique to Northwest situations such as flood basalt sequestration. The Council also encourages the states to establish the legal framework for permitting and operating carbon dioxide transportation and sequestration facilities.

GEN-10. **Monitoring development of other promising resources and technologies.** Certain emerging resources and technologies have potential though not exclusive application in the Northwest. These include technologies for post-combustion carbon dioxide capture from conventional fossil-fuel power plants, carbon dioxide “recycling” technologies such as algae-derived biofuel production, integrated coal gasification combined-cycle technology, advanced nuclear technology, carbon dioxide sequestration in saline reservoirs and depleted gas and oil fields, and concentrating solar thermal and photovoltaic technologies. The commercial development of these technologies will be promoted by policies, incentives and other technological development drivers enacted at the global or federal level, or within regions where the technology might play a particularly vital role. While active participation of Northwest entities in the development of these technologies is not necessary, development of these technologies should be closely monitored. Moreover consideration might be given to joint participate in demonstration projects and other resource development efforts.

Information to Support Sound Planning and Decision Making

GEN-11. **Resource Assessment.** Bonneville, working with the Council should reestablish a program of periodically assessing the availability, cost and performance of generating resources and associated technologies to support the Council's power plan and Bonneville's resource program. These assessments should focus on resources identified in this plan with near or longer-term promise to the Northwest, including waste heat energy recovery, bioresidue energy recovery, cogeneration, conventional and enhanced geothermal, hydropower upgrades, new hydropower projects, natural gas technologies for energy, firm capacity and flexibility, wave and offshore wind power. This work should be coordinated with the inventories of "small-scale" renewable energy and cogeneration resources called for in GEN-2.

GEN-12. **Planning for optimal development of the power system.** The Council, working with the Wind Integration Forum, should undertake an effort to identify the optimal development of a future power system containing a high penetration of wind and other new low carbon resources. This effort should assess the cost and environmental tradeoffs associated with various combinations of transmission facilities, balancing capacity and storage capacity needed to secure remote or local low-carbon resources. The work will consider the diversity value and possible greater productivity of wind developed on a broader geographic basis and the tradeoff between conditional firm transmission service and the value of delivered wind energy. Solar, wave, tidal current and offshore wind sources of low-carbon power should also be evaluated. This work will draw upon the results of the flexibility augmentation assessment for estimates of the availability, cost and performance of new sources of system flexibility including various generating, demand-side and storage options.

GEN-13. **Long-term synthetic hourly wind data series.** The Resource Adequacy Forum should complete development of a long-term synthetic hourly wind data series. This work is needed to further refine estimates of the sustained peaking value of wind, and to implement analytic capability to evaluate tradeoffs between hydrosystem operational constraints and the availability of flexibility.

FUTURE ROLE OF BONNEVILLE

The Bonneville section of the Action Plan encourages Bonneville and its customers to successfully complete and implement the regional dialogue policy and contracts. It recognizes that there remains litigation on some of the elements of the policy, and encourages Bonneville and its customers to resolve the issues, or if necessary to seek a legislative solution to the contested areas. The Action Plan says the Bonneville should follow the Council's regional resource strategy in its own acquisitions, and meet its share of the conservation targets as it has agreed to do. Bonneville should actively fund and support regional conservation activities and provide incentives and support for utility conservation acquisitions. It specifies that Bonneville continue to meet its fish and wildlife mitigation responsibilities.

BPA-1. **Implement the Council's Plan.** Pursuant to the overall directives of the Act, Bonneville's resource acquisition activities should be consistent with the Council's power plan, including the resource strategies relevant to Bonneville identified in other sections of the Action Plan and further described in Chapter 12.

BPA-2. **Conservation goals.** Bonneville should meet its conservation goals. The Council believes Bonneville should observe certain principles in designing its post-2011 energy efficiency efforts. These principles include:

a. **Conservation targets.** Bonneville should continue to commit that it will work with its public utility customers and meet Bonneville's share of the Council's conservation targets. Bonneville should ensure that public utilities have the incentives, support, and flexibility to pursue sustained conservation acquisitions appropriate to their service areas in a cooperative manner, as set forth in detail in the Conservation Action Plan items, especially in the Introduction and in CONS-1, CONS-14 and CONS-17. The Council supports Bonneville's regional dialogue policy to fund conservation primarily as a Tier 1 obligation of the Federal Base System (FBS).

b. **Utility reporting.** Bonneville should enforce provisions in its power sales contracts that require utility reporting and verification of conservation savings so that Bonneville and the Council can track whether conservation targets are being achieved.

c. I**mplementation mechanism.** Bonneville should offer flexible and workable programs to assist utilities in meeting the conservation goals, including a backstop role for Bonneville, should utility programs fail to achieve these goals.

d. **Regional conservation support.** Bonneville should continue to be active in funding and implementing conservation programs and activities that are inherently regional in scope, such as the Northwest Energy Efficiency Alliance, the Regional Technical Forum, and other regional efforts proposed as a result of the Northwest Energy Efficiency Taskforce process.

BPA-3. **Additional resources, including capacity and flexibility priorities.** Bonneville may have a need for additional resources for a number of reasons, including possible resource acquisitions to address capacity and flexibility needs, after taking account of its conservation acquisition. Bonneville should make these resource acquisition decisions consistent with the following:

a. **Institutional changes to meet flexibility needs.** Bonneville should aggressively pursue the various institutional and business practice changes that are currently being discussed to reduce the demand for flexibility, and more fully to use existing resources (federal and non-federal) for its balancing needs, before acquiring additional generating resources for this purpose. These institutional measures, including better forecasting, short-term wind curtailment, sub-hourly scheduling, markets for the exchange of balancing services among balancing authorities, generation owners and operators, and demand response providers, have the potential to be more cost-effective and faster to develop than new generation to provide these services.

b. **Generation for capacity and flexibility.** Institutional changes described above may require complex multilateral agreements and similarly complex changes in operating systems. And even if accomplished, these changes may not completely solve Bonneville's flexibility needs. Given these factors, BPA may need to acquire flexibility or capacity resources, which could include investments in a smart grid and storage. Bonneville should take a broad look at the cost-effectiveness and reliability of the possible sources of additional capacity and flexibility, if it turns out that they are needed to meet its obligations. The possible synergies in simultaneously meeting both capacity and flexibility requirements need to be taken into account, and the possibility of newly developed technologies should also be considered.

c. Possible additional resources to meet other needs. Besides the flexibilty and capacity needs described above, Bonneville may need additional resources for a number of reasons. These include Bonneville's proposal to acquire resources to augment the existing system to serve the "high water mark" load of its preference customers at Tier 1 rates; additional energy resources if needed because one or more customers call on Bonneville to meet their load growth, at Tier 2 rates reflecting the costs of the additional resources; additional resources to serve DSI loads, if Bonneville decides to offer such service; additional resources as may be necessary for system reserves, system reliability, and transmission support; and additional resources if necessary to assist the Administrator in meeting Bonneville's fish and wildlife obligations under Section 4(h) of the Northwest Power Act. Conservation resources will help reduce the need for additional resources, but may not address all of these needs. The Council is not undertaking at this time a detailed, quantitative assessment of Bonneville's need for additional resources for any of these reasons, but will work with Bonneville to identify if these needs exist and whether and when additional resources should be acquired. In making decisions about additional resources for these reasons, Bonneville should act consistent with the principles set forth in Chapter 12 and the with the details in the relevant resource chapters of the plan.

BPA-4. **Proper financial incentives for customers.** Bonneville should meet the loads placed on the agency by its customers and ensure system reliability with the existing Federal Base System, acquired conservation resources and, if necessary, additional generating resources that Bonneville acquires consistent with the power plan and with Bonneville's Regional Dialogue Policy and Tiered Rates Methodology. Bonneville resource acquisitions to meet customers' loads above their "high water marks" should be structured so that these customers bear the financial risk associated with such acquisitions.

BPA-5. **Focus on preserving the FBS.** Bonneville should conduct its business in a way that will preserve the benefits of the FBS for the region.

BPA-6. **Fish and Wildlife.** Bonneville should meet its fish and wildlife obligations.

BPA-7. **Implement the Regional Dialogue policy.** Bonneville should implement the policy choices it has made in adopting Tiered Rates, signing long-term contracts, and revising its Residential Exchange Program in ways that will allow the agency to achieve the goals identified in the various regional processes that established Bonneville's future role.

BPA-8. **Solve legal challenges to Regional Dialogue implementation.** Bonneville should be prepared to take all necessary steps to revise those policy choices, as necessary, if the Ninth Circuit rules that the choices or some aspects of the choices must be overturned. Bonneville should be prepared to engage the region in any such revisions. If Bonneville's policies for Tiered Rates, the Residential Exchange Program (including the Average System Cost Methodology), long-term contracts and related matters are struck down by the Ninth Circuit, Bonneville should initiate regional efforts to bring those policies into line with the court's decision(s) or, if necessary, seek a legislative solution to enable the agency to achieve the goals those policies were intended to reach.

BPA-9. **Conditions if considering service to the DSIs**. If the Administrator decides to consider service to the DSIs, such service should:

- have the lowest impact possible on other customers' rates;
- provide, so far as possible, ancillary services;
- provide the reserves required under the Northwest Power Act; and
- be offered at rates that will allow the DSIs a reasonable opportunity for operations in the region.

ENSURING ADEQUACY

Development and adoption of regional adequacy standards was an important accomplishment of one of the key action items in the Council's Fifth Power Plan. It not only protects against future energy or capacity shortages by providing an early warning system, it also helps ensure that Fish and Wildlife operations are reliably implemented. The action plan is intended to ensure that the Council, working with others in the region, complete an annual assessment using the standards, but also that the Resource Adequacy Forum continues to refine and update the standards to reflect new information and adjust to changing conditions. In addition, an action item is included to enhance the region's ability to assess the adequacy of flexibility resources for within hour wind integration and system balancing.

ADQ-1. **Adequacy Assessment.** The Council, in collaboration with the Northwest Resource Adequacy Forum and others will annually assess the adequacy of the regional power supply.

ADQ-2. **Data Review.** The Council, in collaboration with the Forum and others will annually review demand and resource data used for the adequacy assessment, compare its results with other regional reports and work to standardize data reporting.

ADQ-3. **Methodology Review.** The Council, in collaboration with the Forum and others will periodically review the Pacific Northwest's adequacy standard and the methodology used to define the standard. If warranted, the Council will amend the standard.

ADQ-4. **Working with other regions.** The Council will monitor adequacy assessment methodologies in other regions and work with the Western Electricity Coordinating Council to incorporate Pacific Northwest adequacy metrics and assessments into west-wide adequacy reports.

DEMAND RESPONSE

Power systems are required to maintain resources to meet extreme peak loads events. Some of these resources are seldom used and therefore are very expensive on a per kilowatt-hour basis if significant capital costs are involved in building the capability. An alternative growing in potential is demand response, which allows voluntary reductions in load during extreme loads events or interruptions of generation or transmission. The action plan for demand response includes increasing our understanding of demand response potential and cost effectiveness. This involves monitoring implementation of demand response in the Pacific Northwest and other areas where more demand response programs have been tested, supporting pilot programs to test demand response approaches, and further exploring the potential of demand response as a source of system flexibility for within hour balancing reserves.

DR-1. **Inventory demand response programs.** The Council should compile and maintain an inventory of demand response acquisition programs and pilot programs that are active or in the planning stages in the region. The objective is to encourage communication among planners and administrators of these efforts at early stages in the work, so that experience is shared and unnecessary duplication is avoided as much as possible,

DR-2. **Evaluate and demonstrate demand response programs.** Utilities and regulators should consider not only pilots that test implementation strategies and demonstrate effectiveness of programs that have been successful elsewhere (e.g. direct load control of space heating or air conditioning), but also pilots that explore innovative programs have little or no history but that have promise (e.g. use of demand response for load following).

DR-3. **Evaluate potential for providing ancillary services.** The Council, the region's utilities and regulators should examine demand response as a source of ancillary services, including estimation of potential megawatts available, its cost and its cost effectiveness.

DR-4. **Monitor new programs.** The Council, the region's utilities and regulators should monitor new programs to obtain demand response, including Bonneville's pilot programs and the aggregator contracts of PacifiCorp, Portland General Electric and Idaho Power.

DR-5. **Monitor experience in other regions.** The Council, the region's utilities and regulators should monitor progress outside the Pacific Northwest on demand response.

DR-6. **Evaluate direct service industry as a source of demand response.** If Bonneville serves Direct Service Industry load, it should analyze all possibilities for using these loads to provide reserves as required in the Power Act. In particular the potential for these loads to provide ancillary services should be examined for its cost effectiveness.

DR-7. **Complete the work of the PNDRP.** Council staff should continue the coordination, with the Regulatory Assistance Project, of the Pacific Northwest Demand Response Project (PNDRP). In particular, PNDRP should complete the examination of pricing strategies to stimulate demand response.

DR-8. **Include appliance response controls in standards.** The region should advocate appliance standards that include Smart Grid controls to interrupt load (at least for under frequency events and utility calls). This action item could be included in consideration of energy efficiency action items Appliances could include:

a. Water heaters (mixing valve as well as smart thermostat switch)
b. Clothes dryers
c. Refrigerators
d. Freezers
e. Air conditioners

DR-9. **Implement demand response recommendations of NEET.** The final recommendations of the Northwest Energy Efficiency Taskforce are likely to provide suggestions as to how to develop demand response in the region. These recommendations should be pursued by the region.

DR-10. **Improve Council modeling of demand response.** The Council should examine the treatment of demand response in its regional portfolio model to ensure that the model properly captures the benefits and costs of demand response. To the extent that demand response has benefits that are difficult or impossible to simulate with the portfolio model, such as the benefits of demand response providing ancillary services, the Council should work with other parties to identify alternative analytical approaches to estimate these benefits.

SMART GRID

The development of smart-grid technologies has the potential to transform the operation of the power system in ways that are difficult to predict, but that hold great potential for improved operations and reliability, and for making electricity consumers partners in maintaining the efficiency and reliability of the power system. These technologies are in their infancy and will take time to develop to full potential. To understand better smart-grid potential the action plan supports regional pilot programs to gain experience with smart-grid technologies and the role they might play in the power system.

SG-1. **Monitoring smart grid technology.** Monitor development and adoption of smart grid technology

SG-2. **Smart grid demonstration.** Develop smart grid demonstration projects.

SG-3. **Develop evaluation methods.** Develop methodology for evaluating demand response used for ancillary services.

TRANSMISSION

When the Council developed the Fifth Power Plan, there was reason to be concerned about the transmission system. There had been no progress on improving the operation of the transmission system and little activity in planning for transmission system expansion. To a large extent, this is no longer the case either in the region or in the broader western interconnection. The Council will continue to participate in WECC activities relating to wind integration, transmission planning, and adequacy assessment. Bonneville is moving ahead with critical transmission expansions within its balancing area, and there are several large transmission projects in various stages of planning by other utilities or merchant transmission providers that would affect the Northwest. The Action Plan encourages continued regional efforts to improve wind integration capability through improved operational procedures such as reserve sharing, dynamic scheduling, improved wind forecasting, and the ability to curtail wind ramps under extreme conditions.

TX-1. **Participate in / track WECC activities.** Many of the actions that the Council is interested in, e.g., integration of large amounts of intermittent renewable generation, expansion of the transmission system to accommodate this generation, and development of resource adequacy assessments and guidelines are affected by, and can be assisted by, actions at WECC.

a. **Wind: Variable Generation Subcommittee (VGS).** The VGS was formed in early 2009 to coordinate WECC actions and information sharing (both internally and with the actions of WECC members) regarding intermittent generation, especially wind and solar. Many of the actions that need to take place to integrate large amounts of intermittent generation into the system need to take place, or are more effective if they take place, on a wider scale than just the Northwest. Examples are changes in business practices like scheduling (e.g., to greater frequency than every hour), standardizing protocols for dynamic scheduling and developing detailed operating dynamics models of wind generation.

b. **Resource Adequacy: Loads and Resources Subcommittee (LRS).** LRS develops WECC resource adequacy guidelines and assessments and acts as the interface with NERC on these areas and on NERC's development of standards in the resource adequacy area. The WECC and NERC activities provide the background within which the Council analyzes adequacy issues and approaches and develops assessments.

c. **Transmission: Transmission Expansion Planning Policy Committee (TEPPC).** Coordinated transmission planning for larger scale projects needed to move distant, typically renewable, generation to load centers takes place primarily in two forums: first, sub regional planning groups (SPGs) like Northern Tier Transmission Group and ColumbiaGrid and second, interconnection-wide, through TEPPC. TEPPC acts as a data provider and provider of overall scoping studies for the SPGs and other entities like the Committee on Regional Electric

Power Cooperation (CREPC) and the Western Governors' Association (WGA). TEPPC is expected to receive substantial funding from DOE under the American Recovery and Reinvestment Act of 2009 (ARRA) to develop an interconnection-wide transmission plan, which will substantially expand the scope of its current activities.

TX-2. **Track transmission expansion proposals and evaluate impact on the region.** This effort focuses on monitoring the status of transmission proposals that would have significant effects on the ability of regional utilities to develop resources, particularly to import renewables, and to access regional and other markets.

TX-3. **Continue to assess needs and costs of transmission for wind development.**

FISH AND POWER

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." In other words, the mutual impacts of fish and power measures are intended to be examined together. By statute, hydroelectric operations to improve fish survival that are specified in the fish and wildlife program become a part of the power plan and the plan must be designed to accommodate these operations and their cost. Guided by the Council's power plan, Bonneville is to acquire resources to assist in meeting the requirements of the fish and wildlife program.

The action items listed below are designed to improve the way in which we plan for the long-term needs of both power and fish and wildlife. The key action is to create a public forum which brings together power planners and fish and wildlife managers to explore ways to better identify and analyze long-term uncertainties that affect all elements of fish and power operations. These uncertainties include climate change, demand, fuel prices, policies involving resource operation, and treaties affecting the hydroelectric system. Forum members will assist in developing ways to integrate these uncertainties into the Council's planning models.

The forum will also provide an opportunity to identify synergies that may exist between power and fish operations and to explore ways of taking advantage of those situations. For example, the acquisition of fish and wildlife habitat may also an opportunity to mitigate the effects of carbon emissions. The forum will also be expected to examine the impacts of fish and wildlife operations on the flexibility and capacity of the hydroelectric system and explore ways to minimize those impacts. These and other issues that may come up in the future need to be discussed in an open forum with both fish and power planners involved.

F&W-1. **Long-term planning forum.** The Council will work with federal, state, tribal and other entities in a public forum to improve the integration of long-term fish and wildlife operations and power planning.

F&W-2. **Contingency plans.** The Council will work with fish and wildlife managers and regional power planners to; 1) develop a curtailment plan for fish and wildlife operations in the event of a power emergency, 2) prepare a contingency power operation in the event of a fish and wildlife emergency, and 3) develop a plan for continued improvement in our ability to forecast and operate the system to reduce the likelihood of emergencies.

F&W-3. **Analytical capability.** The Council will work with Bonneville and other federal action agencies, federal and state fish-and-wildlife agencies and tribes, and other regional entities (in particular the Independent Economic Analysis Board, the Independent Scientific Advisory Board and the Independent Scientific Review Panel) to analyze the physical, economic and biological impacts of alternative operations for fish and wildlife and to develop ways of improving the cost effectiveness of fish and wildlife programs.

F&W-4. **Columbia River Treaty.** The Council will work with Bonneville and others to examine the impacts of possible changes to the Columbia River Treaty between the United States and Canada. The treaty expires during this plan's study horizon and modifications to the treaty are very likely to affect both power and fish and wildlife. The Council should be proactive in addressing this issue.

F&W-5. **Climate change.** The Council will work with Bonneville, the University of Washington's Climate Impacts Group and others to examine the physical impacts of climate change to electricity demand, river flows, reservoir elevations, power production and cost. The Council will examine ways to mitigate for these impacts and encourage others to improve runoff volume forecasting methods, especially for the fall.

MONITORING PLAN IMPLEMENTATION

The Council will monitor conditions in the region for significant changes that would affect the Power Plan. The region's progress in implementing the resource strategy in the plan will be assessed and a biennial monitoring report will be prepared describing any significant changes in the assumptions underlying the plan. The monitoring report also will assess resource development in the region including efficiency acquisition compared to the Power Plan's recommendations.

MON-1 **Biennial monitoring report.** Council will monitor implementation of the recommendations in the Sixth Plan and report on progress biennially.

MON-1 **Assess changing conditions affecting the plan.** Council will monitor how developing electricity loads, fuel price, electricity prices, conservation technologies, resource costs, and other planning forecasts and assumptions compare to assumptions included in the Sixth Plan.

MON-1 **Analyze changes for significance.** The Council will conduct analysis of specific changes or issues to determine their effects on the regional power system and the Power Plan.

MON-1 **Monitor climate change policies and analysis.** Continue to monitor progress in climate change models and their assessments of impacts on temperature, precipitation and stream flows. As the need arises, analyze specific climate change scenarios and assess potential effects on the plan's resource strategy.

MAINTAINING AND ENHANCING COUNCIL'S ANALYTICAL CAPABILITY

The development of the Council's Power Plan is extremely data and model intensive. Maintaining data on electricity demand, resource development, energy prices, and generating and efficiency resources is a significant effort. It is one that the Council's staff cannot do alone. As recognized in the NEET recommendations collection of data relating to the regional power system and alternative resources available to meet demand is something best accomplished through regional cooperation. The Action Plan contains recommendations to maintain and improve planning data for the region.

ANLYS-1. **Review analytical methods**. As is customary between power plans, the Council will undertake a comprehensive review of the analytic methods and models that are used to support the Council's decisions in the Power Plan. The goal of this review is to improve on the Council's ability to analyze major changes in regional and Bonneville Power systems and make recommendations on how best for the BPA Administrator to meet BPA's obligations and for the region as a whole to achieve as low cost and low risk in future power plans as possible. This review will focus on changing regional power system conditions such as capacity constraints, integration of intermittent resources and transmission limitations because these currently pressing issues will need to be more formally addressed in future Power Plans. The Council will work with Bonneville and other utilities to evaluate available data and models that can be used to support the Council's planning. This action item will require the Council to clearly define the planning problems facing BPA and the region and identify or develop new analytic tools that can help the Council to identify the best possible approaches to meeting the region's and BPA's future power needs.

ANLYS-2. **Improve hourly load data.** Work with utilities and NWPP to standardize collection of regional hourly loads data. Currently there is a substantial lag in getting regional hourly loads from NWPP. In fact, the last year of hourly data from NWPP is for 2002. This situation creates problems for updating short-term forecasting model which is used for resource adequacy work.

ANLYS-3. **Improve irrigation sales reporting.** Work with utilities to receive Irrigation sales data annually. Currently there is substantial problem with getting accurate data on irrigation sales in the region. This problem is more pronounced when it comes to public utilities. This problem has been solved in the past by putting substantial amount of work by staff to contact individual utilities and obtain the data.

ANLYS-4. **Improve industrial sales data.** Work with utilities to improve industrial sector sales data: Currently industrial sales are reported by utilities to FERC and EIA in an aggregate fashion. Reporting sales data at more disaggregated industrial level would improve the ability to forecast loads. Confidentiality concerns should be addressed and solved.

ANLYS-5. **Follow up on NEET data recommendations.** There are other "data holes" where updating information would substantially benefit the region. Some of these data needs were identified in the NEET recommendation from workgroup 1. An action item would be to track and implement NEET recommendations. Example of data holes are:

a. End-use hourly load shapes
b. Energy use for end-uses (ICE)
c. Establishing Panel Data for residential and small commercial, especially elder care facilities.
d. Improve the baseline consumption and conservation potential for Data Centers

ANLYS-6. **Improve electricity end-use data.** Work with NEEA, RTF and utilities to:

a. Develop a common survey and data gathering instrument
b. Develop the requirements for a data clearinghouse
c. Develop the data gathering cycles for each sector/measure
d. Coordinate the data gathering implementation plan for 2010-2015

ANLYS-7. **Improve peak load forecasting.** Facilitate a discussion among regional forecasters and others on peak load forecasting methodologies in use in the region.

ANLYS-8. **Improve natural gas demand forecasting.** Work with regional gas utility demand forecasters to fine-tune gas forecasting capabilities of the load forecasting model

ANLYS-9. **Develop the supply side of the demand forecasting system.** Work with BPA to integrate the electric supply module of long-term forecasting model with the current demand forecasting model. This integration should enhance Council's ability to see impact of various policies in a more cohesive manner.

ANLYS-10. **Improve transportation electricity use forecasting.** Enhance the electric transportation segment of the long-term model for better representation of potential demand and impact on electric supply from the Plug-in hybrid electric vehicles.

ANLYS-11. **Demand response modeling methods.** Work with BPA and others to incorporate the framework for modeling DR in the long-term forecasting model.

ANLYS-12. **Evaluation of sustained peaking capability of the hydroelectric system.** Work with others in the region, in particular the Resource Adequacy Forum, to develop a better methodology to assess the sustained peaking capability of the regional hydroelectric system.

ANLYS-13. **Improved demand response modeling.** The Council should examine the regional portfolio model's treatment of demand response in case there are opportunities for improvement (see Action Item DR-9).

ANLYS-14. **Planning coordination and information outreach.** The Council will continue to participate in the development of Bonneville's Resource Program and in utility integrated resource planning efforts. In addition, the Council will periodically convene its planning advisory committees including the Natural Gas Advisory Committee, Conservation Resources Advisory Committee and Generating Resources Advisory

Committee for purposes of sharing information, tools and approaches to resource planning.

Chapter 1: Introduction

PURPOSE OF THE POWER PLAN

The Northwest Power and Conservation Council (Council) was formed by the Northwest states in 1981 in accordance with the Northwest Electric Power Planning and Conservation Act (Act). Each state's governor appoints two members to the Council making eight members in total representing Washington, Oregon, Idaho, and Montana. The Council was formed to give the Pacific Northwest states and the region's citizens a say in how growing electricity needs of the region would be provided. The Act charges the Council with creating a power plan for the region. The purpose of the Council's Power Plan is to ensure an adequate, efficient, economical, and reliable power system for the Pacific Northwest[1].

The Act also recognized that development of the region's hydropower dams had detrimental effects on migratory fish and wildlife and required the Council to develop a program to mitigate those effects. The fish and wildlife program is an integral part of the Council's power plans.

The Council's power plan and the fish and wildlife program are developed through an open, public process to involve the region's citizens and businesses in decisions about the future of these two interdependent aspects of the Pacific Northwest environment and economy. The Act grants different approaches for these two Council responsibilities. The fish and wildlife program is based on, and defers to, recommendations from fish and wildlife agencies and tribes. However, the power plan is developed through Council analysis, helped by scientific and statistical advisory committees.

The power plan develops a strategy for the region to meet its future electricity needs. The Act recognizes that the demand for electricity is derived from the need for services electricity can provide, such as heat for homes, lights for commercial buildings, or motors for industrial processes. These services are the focus of the power plan. Technologies that allow production of these services more efficiently are the equivalent of generating additional electricity. In fact, the Act designates efficiency improvements as the highest priority resource for meeting electricity demands and gives it a 10 percent cost advantage. Second priority is renewable

[1] Public Law 96-501, Sec. 2(2).

resources followed by high efficiency generating technologies and then other generating technologies.[2] Except for efficiency improvements, the priorities of the Act are only tie breakers when alternative resources have equal cost.

The power plan includes a resource strategy to ensure demand for electricity is met by a combination of improved efficiency and generating resources that minimizes the cost of the energy system, including quantifiable environmental costs. Because there are many unknowns in the future, the power plan considers how costs might vary with changing conditions and identifies strategies to reduce the risk of high-cost futures. The action plan identifies specific actions needed in the next five years for the region to achieve the long-term strategy. These actions are the heart of the power plan because they set an agenda for the next several years.

The Act requires that the Council's power plan be reviewed at least every five years. This power plan is the Sixth produced by the Council since the Act was passed in December of 1980. In each plan, costs and technologies have changed resulting in subtle changes in the plans. Alternative generating technology cost-effectiveness has shifted away from large coal and nuclear facilities toward shorter-lead-time, more flexible, gas-fired generation. Recently, climate concerns and related state regulations have made renewable generation technologies more attractive.

However, consistently in all of the Council's power plans, efficiency improvement has been the lowest cost resource. As the Council's ability to assess risk has grown more sophisticated, efficiency has also proven to be the least risky resource alternative. As a result, in each of the Council's plans energy efficiency has been identified as an important resource for the region. In the Council's first plan, conservation was expected to meet half of the region's 20- year, medium-high load growth to 2002. In successive plans, the amount and share of conservation varied as utility programs or codes and standards captured some of the potential, new technologies became available, and cost-effectiveness levels changed, but the share of expected new energy resources to be provided by efficiency improvements never fell below 25 percent, and has typically been between 30 and 40 percent.

Over the years since the Council was formed, conservation has met nearly half of the region's growth in energy service demand. If the region's energy savings were added back to the regional energy loads, load would have increased by 7,831 average megawatts between 1980 and 2007. During that time the region acquired 3,645 average megawatts of conservation, so that actual loads to be met by electricity generation only increased by 4,186 average megawatts.

In addition to the resource strategy, the Council's Power Plan addresses significant issues facing the Northwest power system and provides guidance to the region on addressing those issues. The focusing issues have changed with each Power Plan. The region's power system has gone through many changes over the 28 years of the Council's existence, including changes to the operation of the power system to aid fish and wildlife, electricity industry restructuring, a changing role for Bonneville, and evolving environmental concerns. The Council's power plans have reflected those changing conditions.

A constant focus through all of the Council's power plans has been the significant uncertainty facing the regional power system. In early plans, long resource lead times for coal and nuclear

[2] Public Law 96-501, Sec. 4(e)(1).

plants created risk in the face of highly uncertain load growth. Over time, other risks became a larger part of the problem including fuel prices and availability, industry restructuring, and environmental risks. Although the regional power system has changed in many ways from what was envisioned in the Act, the basic planning guidelines have proven resilient, and continue to provide guidance to the region.

MAJOR ISSUES

The regional power system is facing significant changes. The Sixth Power Plan addresses these changes through its resource recommendations and action plan. Some of the most important changes include:

- Growing concern about, and evolving policies to address, climate change
- Increased importance of assessing the capacity of the power system to meet periods of sustained peak electricity needs and provide ancillary services to meet system operation and wind integration requirements
- The changing role of the Bonneville Power Administration in providing resources to meet the growing needs of public utilities
- Emerging technologies and incentives with the potential to change significantly the relationships among electricity producers, utilities, and consumers
- Significant increases in the price of natural gas, oil, and coal supplies

Climate Change

Concerns about climate change have changed the power planning landscape dramatically. Regardless of one’s beliefs about the causes of climate change there is a wide consensus among scientists and policy makers that human-caused greenhouse gas emissions are contributors. These concerns have resulted in a wide variety of polices throughout the world, the nation, and the Pacific Northwest and western states. These policies are affecting the resource choices available for electricity generation both directly through restrictions on certain types of resources, and indirectly through incentive programs to encourage certain types of resources.

An example of these policies is restrictions on new coal-fired power plants. In some cases these restrictions are direct prohibitions against new power plants emitting more than a determined amount of carbon. In others, it is regulatory or public resistance. But in any case, new conventional coal-fired power plants appear unlikely to be an alternative in the Northwest’s future.

Renewable portfolio standards in Montana, Oregon, and Washington will require that a substantial portion of utilities’ added electricity generation will be from renewable resources. By 2030, the shares of loads that must be met from renewable technologies are: 15 percent in Montana, 25 percent in Oregon, and 20 percent in Washington. The timing to reach these levels varies by state. Many other states in the West have similar renewable requirements.

Some policies are in already in place. However, that does not mean they will remain unchanged. Policies can be reassessed and refined. Further, the Western Climate Initiative (WCI), an effort of 11 U.S. states and Canadian provinces to address climate issues, has set greenhouse gas emissions goals and designed a market oriented cap and trade process to facilitate meeting their goals. Participants in the WCI may have individual goals to reduce greenhouse gas emissions. Such initiatives are often accompanied by a host of state policies to help reach the goals. The U.S. has yet to act at the national level on greenhouse gas policies although legislation is being actively considered. The result of all these factors is simply that many future policies that could profoundly affect resource choices remain unknown, creating risks for resource decisions that have to be made now.

Uncertainty about climate policies raise several questions for the Sixth Power Plan. These include:

- What are likely costs of carbon control policies, and will those costs be known (carbon tax) or unknown (cap and trade system)?
- What is the lowest cost approach to meeting carbon emissions reduction targets, and what are those targets most likely to be?
- What are the costs of renewable resources, and what will be the costs to consumers of meeting renewable portfolio standards?
- How will development of renewable generation affect the operation of the power system and the need for new transmission investments?
- Are there carbon control policies in other sectors, such as transportation or building construction and maintenance, that will affect the need for electricity?
- Will uncertainty about future carbon policies and their effects on energy costs lead to inadequate investment in electricity supplies?

Providing Capacity and Ancillary Services

Until recently, the Pacific Northwest was able to plan its power system based on average annual energy needs and supplies. The hydroelectric system provided a large share of the regional electricity supply and had the flexibility to provide most of the peaking and shaping (ancillary services) required to match reliably electricity generation to consumption on an annual, seasonal, hourly and sub-hourly time scale.

The hydroelectric system, however, can no longer be assumed to provide all of these services. There are several reasons for this change:

First, the seasonal patterns of electricity demand in the region are changing as air conditioning use has grown.

Second, flexibility of the hydroelectric system has been constrained by actions taken to help mitigate for its impacts on fish and wildlife.

Third, the share of non-hydroelectric generating resources has been growing over the last 40 years and those resources typically do not have the same degree of flexibility as the hydroelectric system.

Finally, the region has added significant amounts of wind generation, which is a variable resource and adds to the shaping and flexibility requirements of the power system.

Assuring an adequate and reliable power system increasingly requires addressing the peaking and shaping capability of the power system. This power plan, for the first time, addresses these issues.

- What is the capacity of the hydroelectric system to meet peak loads and provide flexibility resources?
- Are there actions that can reduce the need for additional capacity and flexibility?
- What other resources can provide such services and what are their costs?
- What mix of generating resources, energy storage, and demand side response is most cost-effective for providing needed flexibility?

Bonneville's Role

More than 10 years ago, the Comprehensive Review of the Northwest Energy System recommended that Bonneville should focus on marketing the existing federal base resources to protect its low cost and ensure regional commitment to repaying debt to the U.S. Treasury.[3] One of the Review's basic tenets was that utilities would pay the cost of new electricity supplies for growth in their customers' demand beyond that provided through the existing federal base system.

Bonneville and its customers have been working toward new long-term contracts that would protect the cost-based federal system while providing better incentives for utility resource decisions. Bonneville adopted its Regional Dialogue Policy in July 2007. Since then, Bonneville and its customer utilities have been developing the policies and contracts needed to implement the policy.

This change will empower many customer-owned utilities to make their own resource decisions. In addition, many of these utilities are now subject to planning requirements and renewable portfolio standards imposed by states in the region.

As a result of these changes, the implementation of the Council's plan will become even more diverse. Bonneville's role in developing future power resources for the region will likely be reduced.

- How will the region implement the Council's power plan?

[3] Comprehensive Review of the Northwest Energy System: Final Report. December 12, 1996.

- Who will be responsible for meeting efficiency goals, and how will achievements be tracked?
- How will small customer-owned utilities develop resources to meet their load growth?

Changing Technologies

The digital revolution has created technologies that could substantially change the way the power system is planned and operated. These technologies offer the possibility for improved control, reliability, and efficiency of power system operations, an enhanced market for energy and ancillary services, and a greater opportunity for consumers and distributed generation to participate in the operation of the power system.

This general area of technology is frequently referred to as the “smart grid.” Components of this technology include electric meters at homes and businesses that can be remotely monitored, saving utilities meter reading costs, but also other sensor technology that can communicate back to the power system on the status of electricity use, the exact location of outages, and the status of the distribution system at all points in a utility’s system. This technology provides a foundation for automated demand response when coupled with appropriate price signals, consumer agreements, and end-use equipment controls.

The advancement and deployment of these technologies is likely to significantly change the way in which improved efficiency is acquired. With data on each customer's use at intervals of one hour or less, we can have much more confidence in our estimates of savings, and in our evaluations of conservation acquisition alternatives. As better information about the value of electricity savings in particular locations and at particular times is made available to consumers, efficiency improvements will increasingly be pursued as a business strategy. Energy service and management companies will be able to offer a business case to consumers that improves the quality and reduces the cost of electricity. This continues a trend of increasing roles for non-utility entities in the acquisition of energy efficiency. This trend has included the creation of the Northwest Energy Efficiency Alliance, the Energy Trust of Oregon, and numerous energy service companies. Pursuit of efficiency as a profitable business case may be the next stage of energy efficiency acquisition strategies.

- How will advancement of smart grid technologies change the role of utilities and customers?
- What actions are needed to facilitate development of these technologies?
- Are there barriers to expansion of these technologies?
- Will smart grid technologies and practices improve the reliability and efficiency of the electrical grid, or will diffusion of control create problems for management of the system?
- How will smart grid technologies facilitate other objectives of energy or climate policy? For example, is it needed to integrate plug-in electric vehicles into the power system?

Growing Cost of Energy

Since the Council was formed in 1981 there have been two major incidents of electricity price increases. The first was just about completed as the Council was created and it was due to large overinvestment in electricity generation in nuclear facilities that turned out to be unneeded. The second large increase occurred in 2000-2001 and was due to underinvestment in electricity generation.

Current expectations predict we are facing a third increase in electricity costs, although perhaps it may occur over a more extended time period. In this case, the increase will be due to increased cost of basic energy supplies, such as oil, natural gas, and coal, increased carbon emissions controls, and requirements to develop more expensive renewable sources of electricity.

Each historical increase in electricity prices changed the Northwest economy and electricity use. The 1979-1981 increase pushed electricity intensive industries of the region to marginal producers in world markets. The 2000-2001 increase resulted in the permanent closure of many of these regional industries. From the 10 aluminum plants that were operating in the region when the Act was passed, only three remain in partial operation. In addition, many other energy intensive industries have closed permanently in the last 10 years.

- What additional effects will increasing electricity prices have on the economic structure of the region?
- Are there strategies to reduce the effects of higher prices on the region's consumers of electricity?
- Are there approaches to carbon emissions reduction that moderate the price increases?

BACKGROUND

The Council's Power Plan looks 20 years into the region's electricity future. Decisions regarding this future are long-lasting and have important effects on the adequacy, efficiency, reliability, cost, and environmental footprint of the power system. To plan for a future that ensures the region a resilient supply of electricity consistent with long-term growth and environmental sustainability, it is important to understand how the regional electricity market has evolved. Anticipating changes that could take place during a period of 20 years requires investing in a power system that is as adaptable as possible.

This section provides background on trends in electricity demand and supply since the time the Council was created. It looks at changes that have occurred during the past 25 years to provide important insights into the region's energy future. This section seeks to answer questions: How has the use of electricity grown and changed? What role has improved efficiency played in these trends? How have the sources of electricity generation changed over the years, and how have the institutions and regulations changed?

Electricity Demand

The year 1980, the year the Northwest Power Act was passed, was a watershed for the region. In preceding decades, the region had experienced rapid growth in electricity demand. There was an expectation that this rate of demand growth would continue. During this time, there was little hydroelectric expansion and many planned investments in large-scale coal and nuclear generating plants. The cost of these new generating sources was much higher than existing hydroelectricity. Their development created a huge increase in electricity costs.

Instead of the ever-growing electricity demand experienced before 1980, the region found that demand was indeed responsive to price changes. The region's aluminum plants, which accounted for nearly 20 percent of all regional electricity use, became far less competitive in world markets. But other users of electricity also responded by altering their consumption. Between 1960 and 1980 regional electricity loads grew at 5 percent per year, but in the subsequent 20 years from 1980 to 2000, load growth was only slightly over 1 percent per year. Slowed growth in demand and escalated costs of new power plants combined and forced many of the regional investments in new nuclear facilities to be abandoned. Unfortunately, many of their costs were already incurred and still affect electricity prices today.

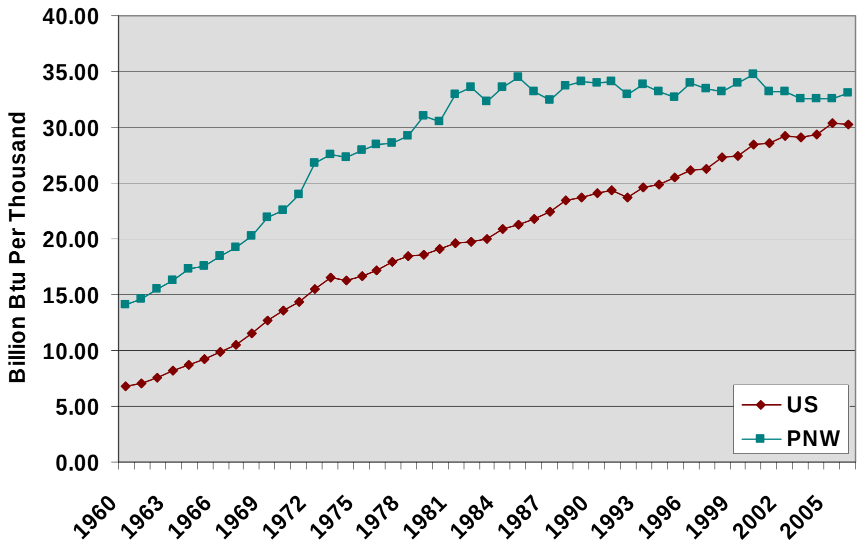
In 2000 and 2001, the region experienced a second large electricity price increase. Unlike the 1980 price increase, this one was a result of too little investment in electricity generation, combined with a poor water year, and a flawed power market design in California. This price increase confirmed the demise of most of the region's aluminum smelters, and resulted in closure or cutbacks in other energy intensive industries as well. Regional loads dropped by 16 percent between 1999 and 2001, falling back to levels of the mid-1980s.

Electricity prices and consumption are often compared to national statistics. Such comparisons help us understand regional long-term trends. The Pacific Northwest economy historically has been both more energy intensive than the rest of the nation, and more electricity intensive. However, the regional trends in total energy use per capita, and per dollar of economic production (Gross Domestic Product (GDP) or Gross State Product (GSP)), have been different from the national trends in recent decades. National total energy use per capita flattened following the early 1970s whereas the regional use of energy per capita declined. By 2006, the region's energy use per capita and the nation's were the same. National total energy use per real dollar of GDP has declined since 1977 when the data were first available. However, the Pacific Northwest's energy use per real dollar of GSP declined faster, and has equaled the nation's since 2001.

The Pacific Northwest remains more electricity intensive than the nation. That is, the share of electricity used to meet all energy needs, is higher here in the Northwest than it is in the rest of the nation. But that gap has narrowed significantly since 1980. Until 1980 the regional share of end-use energy needs met by electricity, compared to other sources such as oil or natural gas, was nearly double the national share. Both the national and regional shares grew between 1960 and 1980. However after 1980, the national electricity share continued to grow, but the regional share remained stable. By 2006, the regional electricity share in total energy consumption by households and business was 20 percent compared to a national share of 17 percent.

The greater electricity intensity of the Pacific Northwest historically was due in large part to the region's electricity intensive industries drawn here because of low-cost electricity supplies. The loss of some of these industries has significantly reduced the region's electricity demand. Not only has the region's industrial use been electricity intensive, the region's residential and commercial energy use has also historically been more electricity intensive than the rest of the nation. The national electrical intensity of these sectors has grown over the last 45 years, but the region's intensity has remained flat since 1980. Figure 1-1 shows that the region's per capita residential and commercial electricity demand has been higher but its rate stable, whereas the nation's demand has been lower but is growing at a steady rate.

Figure 1-1: Residential and Commercial Electricity Use Per Capita: U.S. versus Region

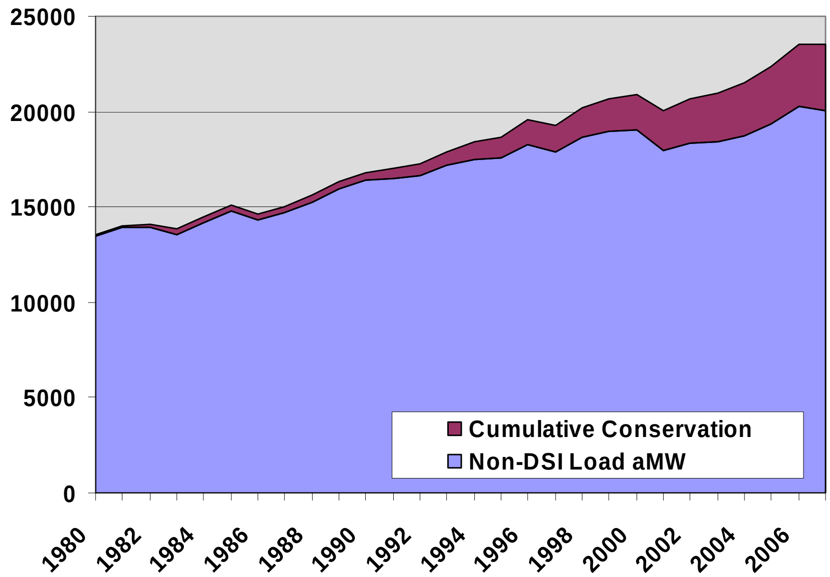


Both regional and national electricity prices have increased over the last 35 years. National prices increased following the oil embargo in 1973, but the region's prices, which were less influenced by changes in oil and natural gas prices, did not escalate rapidly until 1980. During the 1980s and 1990s regional electricity prices remained roughly half of national prices. With the price increases following the western electricity crisis in 2000-2001, the gap closed some, but as shown in Figure 1-6, the region continues to have significantly lower prices than the nation as a whole.

Although the nation and the region had similar electricity price growth, regional demand per capita stopped growing after 1980 while the nation's continued to grow. What accounts for this difference in response? Part of the explanation is the loss of electricity intensive industrial sectors. However, the pattern is also evident in the residential and commercial sectors. Part of the pattern can be traced to conversions of space and water heat from electricity to natural gas. Other parts of the country already used natural gas for these services.

Another important factor limiting the region's growth of electricity demand has been its efforts to improve the efficiency of electricity use. Since the Northwest Power Act in 1980, the Pacific Northwest has pursued programs to improve the efficiency of electricity use. In 2007, the region saved 3,700 average megawatts of electricity as a result of the accumulated effects of Bonneville and utility conservation programs, improved energy codes and appliance efficiency standards, and market transformation initiatives. Figure 1-2 shows the effects of these savings over time. These efficiency improvements have met 46 percent of the region's load growth since 1980, and the savings now amount to more than the total electricity use of Idaho and Western Montana combined. Without improved efficiency, the growth of regional electricity use would have been 1.4 percent per year from 1980 to 2007 instead of the 0.8 percent the region experienced during that time.

Figure 1-2: Effects of Conservation on Growth of Demand



The region's historical electricity use has implications for electricity demand forecasts. Because fuel conversions and decreased electricity intensive industries played an important role in the past stabilization of the electricity intensity of the Pacific Northwest, it may be more difficult to offset growth in the future. Without aggressive conservation efforts, electricity demand may return to growing at the same rate as population and economic activity.

Electricity Generation

A long-term view of electricity generation in the Pacific Northwest reveals a trend of growing diversity of energy sources. In 1960, nearly all electricity was supplied from hydroelectric dams. As Figure 1-3 shows, growth in electric generation needs has been met by other sources, such as coal, nuclear, natural gas, biofuels, and most recently wind power.[4] These resources weren't developed with diversity in mind; they were developed in phases based what was apparently most attractive at the time. Early diversification from hydroelectricity focused on coal and nuclear generation. In the late 1990s and early 2000s natural gas was favored, and most recently wind has been encouraged by economic incentives and state renewable portfolio standards.

But not all growth in electricity consumption has been met by increased generation capability. Figure 1-3 shows conservation as part of the current mix of electricity generating resources.

[4] Figure X-3 shows average annual energy capability. The hydro numbers are critical water, and wind assumes a 30 percent capacity factor.

Conservation is the fourth largest resource meeting the Northwest's electric energy needs, exceeded only by hydro, coal, and natural gas.

Figure 1-3: Growing Electricity Resource Diversification in the Pacific Northwest

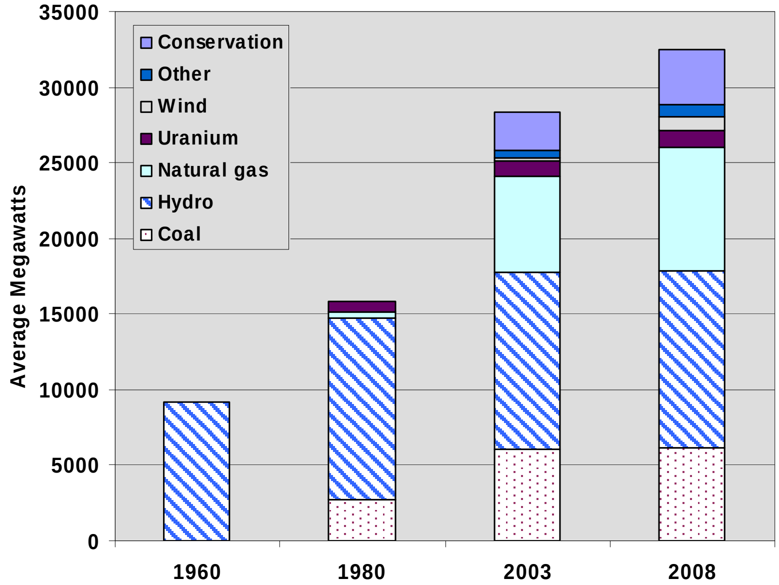
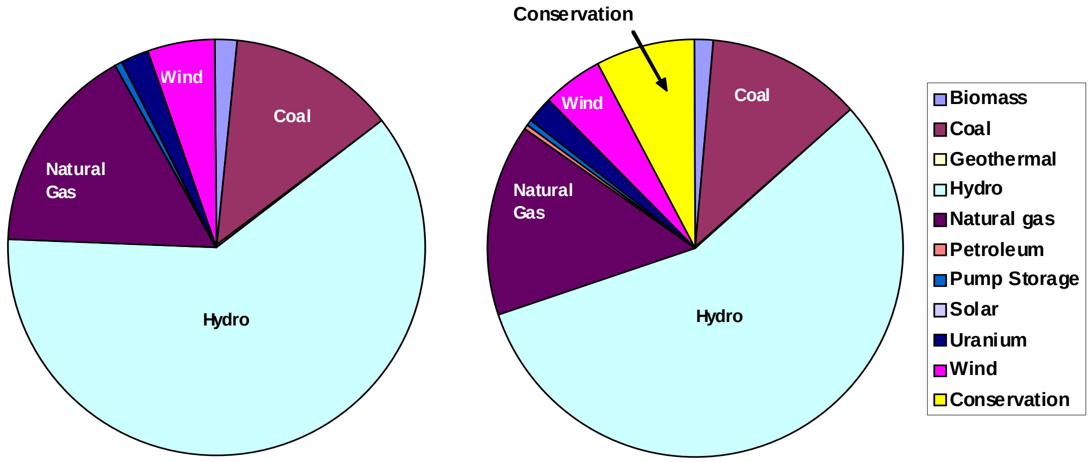


Figure 1-4 shows the mix of electricity capacity in the region.[5] Capacity refers to the ability to produce energy during peak demand hours. Figure 1-3 showed contributions to "energy," which refers to the sources of electricity used to meet average annual demand over a year typically. Compared to the energy mix, installed capacity shows much higher hydro and wind shares. The left side of Figure 1-4 shows generation only; the right side includes the effect of conservation on peak loads.

However, hourly capacity as shown in Figure 1-4 can be misleading for the assessment of adequacy of electricity supplies. For example wind is a variable resource and has very little dependable capacity value because its generation cannot be counted on reliably over short periods of time.   Likewise, the hydroelectric system's capacity value must be reduced because of its limited ability to sustain energy production over several days of high loads. In both cases, the generation that can be counted on is limited by the fuel supply, that is, by the wind or, in the case of hydroelectric generation, by available water. In April of 2008, the Council adopted a resource adequacy standard, which acts as an early warning system to alert the region when the power supply can no longer reliably supply annual energy or peak capacity needs.

[5] Figure 1-4 shows installed generating capacity of resources. Installed capacity is the maximum amount of energy that could be generated during a peak hour. Dependable capacity is the amount of energy that can be counted on in a peak load hour. In the case of wind generation, dependable capacity is only about 5 percent of the installed capacity shown in Figure 1-4. Conservation has been increased by the system load factor, that is peak energy consumption relative to average annual consumption.

Figure 1-4: Electrical Capacity Resource in the Pacific Northwest

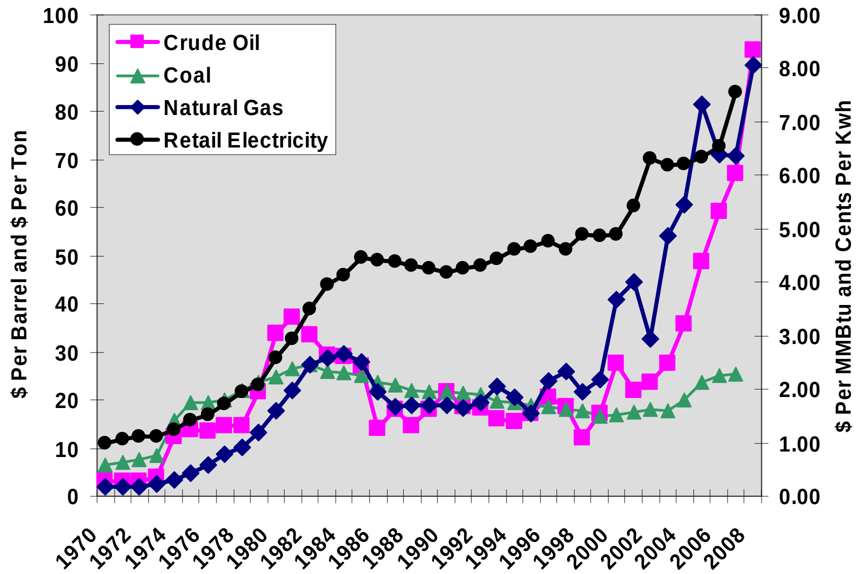


Energy Cost Trends

Energy, like many other commodities, tends to experience price cycles. At the time the Council was developing its first power plan in the early 1980s, energy prices were at a high point. Oil prices were high due to OPEC policies and war in the Middle East. Natural gas prices were high as a result of regulatory policies that impeded development of new supplies. Electricity costs in the Pacific Northwest had just experienced a huge increase due to overbuilding new nuclear generation capacity exacerbated by the high inflation and interest rates of the late 1970s.

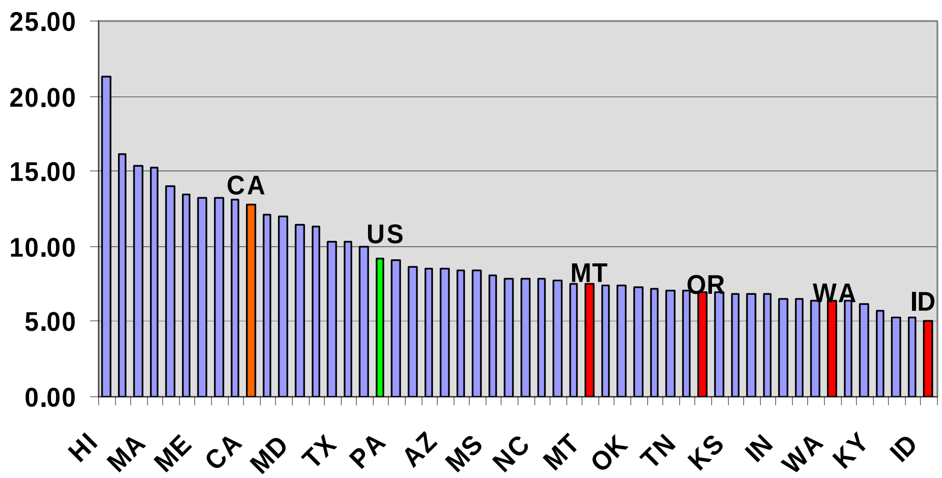
In the mid-1980s fuel prices fell, but electricity prices in the region remained high. The new millennium brought another commodity price cycle for oil, natural gas, and coal, which is now collapsing due to the economic recession and the price response of supply and demand to high prices. Electricity prices are more likely to follow this downward cycle in fuel prices because more generation is based on natural gas and coal now, and the stranded capital cost of over-investment is not as big a factor as it was in 1980. Figure 1-5 illustrates these historical trends in fuel and electricity prices.

Figure 1-5: Energy Price Trends



In spite of price increases over the past 30 years, the cost of electricity to Pacific Northwest consumers remains lower than costs to consumers in other parts of the country. In 2007, Idaho was the lowest price state in the nation, Washington rated seventh lowest, Oregon was 15th, and Montana 22nd. Taken together, retail electricity prices in the four Northwest states in 2007 were a little more than two-thirds of the national average, and only half of electricity prices in California. Although prices have increased substantially since 1980, the Northwest still enjoys relatively low electricity prices.

Figure 1-6: Average Retail Electricity Prices by State, 2007



An important factor in California's higher electricity prices is the cost of resources for peak demand. California electricity demand is more variable than the Pacific Northwest. Peak electricity loads in California are about 70 percent higher than average annual electricity use. In comparison, peak loads in the Pacific Northwest, are typically 25 percent higher than average annual electricity use. But more importantly, California uses fuel-based peaking resources to meet their requirements to a much larger extent than in the Pacific Northwest. The capital and fuel costs of these peaking resources must be recovered over very few operating hours a year when they are used to meet these periods of high demand. In the Pacific Northwest, the hydroelectric system provides much of the peaking capacity and ancillary services for the region at very low cost.

The hydro system's use as a base resource and its inexpensive flexibility together keep Northwest electricity prices low. As the region outgrows the hydro system's capability to provide peaking and flexibility, other resources will be necessary and the cost of electricity will likely grow. Preservation of the hydro system's flexibility and capacity is key to keeping Northwest prices low, and also to maintaining a low carbon footprint. Developing cost-effective demand response can also contribute to meeting peak loads and providing flexibility.

A Vision for the Sixth Power Plan

For nearly 30 years, the Council's mission – to assure the region of an adequate, efficient, economical, and reliable power supply, while also protecting, mitigating and enhancing fish and wildlife affected by the Columbia River Basin hydroelectric system – has not changed.

The Northwest's energy environment is complex, and this is a time of profound change. From concerns about the increasing cost of electricity to the effects of greenhouse gases on climate and the operation of the region's hydroelectric and transmission systems to meet peak demand, integrate wind generation, and recover endangered salmon and steelhead, the challenges are many, and they are interrelated.

The Council's Sixth Power Plan recognizes and responds to this new environment. It lays out a strategy for moving toward the power system of the future while maintaining a reliable and affordable system.

How will these challenges be addressed, and what will the energy system of the future look like? The Council's Sixth Power Plan envisions a cleaner and more efficient system for the region.

- Nearly 6,000 average megawatts of achievable energy efficiency will greatly reduce the Northwest's electricity demand and carbon-dioxide production over the next 20 years.

- Improved operation of the regional power system will help accommodate diverse and variable-output renewable generation and promote the efficient use and expansion of the regional transmission system.

- Conventional coal plants will operate with effective carbon-reducing technologies or be displaced by resources that emit less or no carbon.

- Smart grid and other technologies will make the energy system more efficient and decentralized, maintaining its reliability and safety, and potentially transforming power system operations. It could facilitate instant notification and location of outages, control the timing of water heater use to help meet peak loads, provide flexibility and energy storage, and help integrate variable-output wind power and plug-in hybrid cars into the regional power system.

- The region will preserve and improve the capability of the hydroelectric system to provide low-cost power for the region, providing both flexibility to help integrate wind and other variable-output resources and improved conditions for salmon and steelhead.

- Citizens of the Pacific Northwest will have access to better information about their electricity supply and participate in the formation and implementation of important regional policies.

Today, the road to this vision means addressing many new questions. The Sixth Power Plan is a map to that future.

Chapter 2: Key Drivers of Demand

SUMMARY OF KEY FINDINGS

The Pacific Northwest is expected to develop and expand over the next 20 years. Regional population is likely to increase from 12.7 million in 2007 to 16.3 million by 2030. This 3.6 million increase compares to a 3.8 million increase between 1985 and 2007. The population growth will be focused on older-age categories as the baby boom generation reaches retirement age. While the total regional population is projected to increase by 28 percent, the population over age 65 is expected to nearly double. Such a large shift in the age distribution of the population will change consumption patterns and electricity use. Some possible effects could include increased health care, more retirement and elder-care facilities, more leisure activities and travel, and smaller-sized homes.

The cost of energy (natural gas, oil, electricity) is expected to be significantly higher than during the 1980s and 1990s. Although prices have decreased significantly since the summer of 2008, current levels, especially for natural gas, are depressed by the effects of the recession. Nonconventional natural gas production has increased in the last few years, encouraged by higher prices. The technology to retrieve these supplies cost-effectively has only developed recently, making expectations for adequate future supplies more certain. Nevertheless, the cost of finding and producing it is higher than for conventional supplies, which increases the estimated future price trend for natural gas.

Carbon emission taxes or cap-and-trade policies are likely to further raise energy costs. Wholesale electricity prices are expected to increase from about $45 per megawatt-hour in 2010 to $85 by 2030 (2006$). These electricity prices reflect preliminary carbon costs that start at zero and increase to $47 per ton of CO_2 emissions by 2030. Residential consumer retail electricity prices are also expected to increase, growing 1.8 percent faster per year than general inflation for residential consumers, for example. Higher prices reduce demand, advance new sources of supply and efficiency, and make more efficiency measures cost-effective.

INTRODUCTION

The Northwest Power Act requires the Council's Power Plan to include a forecast of electricity demand for the next 20 years. Demand, to a large extent, is driven by economic growth, but it is also influenced by the price of electricity and other fuel.

The Power Plan treats energy efficiency as a resource for meeting future demand. In order to understand and properly assess its potential, demand forecasts must be done in great detail considering specific uses of electricity in various sectors. Such assessments require significant detail in their underlying economic assumptions; the number and types of buildings, their electrical equipment, and their current efficiency levels are all critical to accurately assessing potential efficiency improvements.

Most of the assumptions and forecasts for the demand forecast are also important for other parts of the Power Plan. For example, fuel prices affect not only electricity demand, but also the cost of electricity generation from natural gas, oil, and coal-fired power plants. Because of this, fuel price forecasts help determine the wholesale electricity price and the avoided cost of alternative resources when considering the cost-effectiveness of improved efficiency. In addition, sector-specific economic forecasts of building and appliance stocks, their expected growth over time, and their pattern of energy use over different seasons and times of the day are factors in determining efficiency potential and cost-effectiveness. Basic financial assumptions such as rates of inflation, the cost of capital for investments by various entities, equity to debt ratios, and discount rates are used throughout the planning analysis.

For many of these assumptions, there is significant uncertainty about the future. That uncertainty creates risk that is addressed in the Council’s Power Plan. These risks and uncertainty include long-term trends, commodity and business cycles, seasonal variations, and short-term volatility.

ECONOMIC GROWTH

Demand for energy is driven by demand for services needed in homes and places of work. In the long-term, the region’s economic growth is a key driver of demand. One general measure of the size of the regional economy is its population. As the regional population increases, the number of households increases, the number of jobs increases, and goods and services produced in the economy increase, all driving the need for energy. This is not to say there is a one-to-one relationship between growth in the economy and growth in demand. Other factors, such as energy prices, technology changes, and increased efficiency can all change the relationship between economic growth and energy use.

The residential demand forecast is driven by the number of homes and the amount and types of appliances they contain. Commercial sector demand is determined by square feet of buildings of various types, and industrial demand depends on projections of industrial output in several manufacturing sectors. The expected electricity use in aluminum smelters is forecast independently. A brief overview of the forecast assumptions for each of the key economic drivers of demand follows:

Population. Population in the Northwest states grew from about 8.9 million in 1985 to about 13 million in 2007, increasing at about 1.6 percent per year. The growth in population is projected to slow to about 1.3 percent annually, resulting in a total regional population of 16 million by 2030.

Homes. The number of homes is a key driver of demand in the residential sector. Residential units (single family, multifamily, and manufactured homes) are 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.

Appliances. In the residential sector, lifestyle choices affect demand. As more homes are linked to the Internet, and as the saturation rate for air conditioning and electronics increases, residential sector demand increases. Over 80 percent of all new homes in the region now have central air conditioning, and the growth rate in home electronics has been phenomenal--over 6 percent per year since 2000, and it is expected to continue growing at about 5 percent per year.

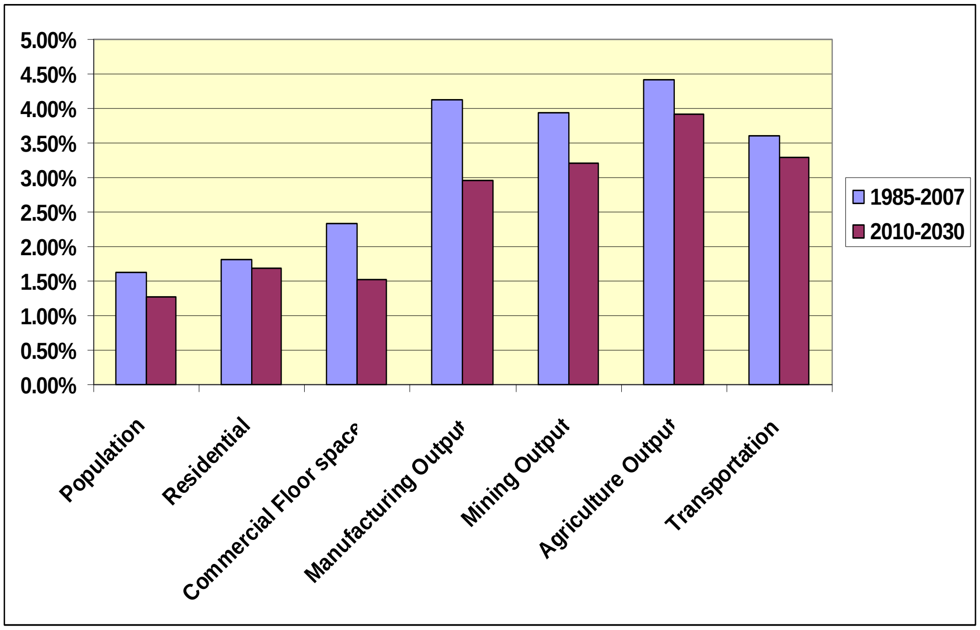
Commercial Square Footage. Demand for electricity in the commercial sector is driven by demand for commercial floor space that requires lighting, air conditioning, and services to make occupants comfortable and productive. The square footage of commercial buildings is forecast to grow at 1.5 percent annually from 2010-2030. The current 2007 commercial building stock of 2.9 billion square feet is expected to grow to 3.9 billion square feet by 2030, or at a rate of 40 million square feet per year. A growing portion of this commercial floor space is for elder-care facilities.

Industrial Output. The key driver of demand for the industrial and agricultural sectors is dollars of value added (a measure of output) in each industry. Industrial output is projected to grow at 3 percent per year, growing from $95 billion (2006 constant dollars) in 2007 to $193 billion by 2030. Agricultural output, which drives irrigation electricity use, is projected to grow at 3.2 percent per year, from $14 billion (2006 constant dollars) in 2007 to $29 billion by 2030.

Direct Service Industries. Demand for Bonneville's direct service industries (mainly aluminum smelting operations) is projected to be nearly constant, rising from 764 average megawatts in 2007 to 818 average megawatts in 2012, and then remaining constant from 2012 through 2030.

The main source of data for the economic drivers is HIS Global Insight's quarterly forecast of the national and regional economy and Global Insight's U.S. business demographic forecast. Second quarter 2008 data was used in developing the Council's draft Sixth Power Plan. The Council's financial assumptions, such as the inflation rate, are also drawn from the same economic forecast. Figure 2-1 shows both the historic and medium case growth rate assumed for the development of the draft Sixth Power Plan. In general, the medium forecast reflects a slowdown in key economic drivers compared to the last 20 years. The impact of the current recession was incorporated into the draft plan using Global Insight's short-term March 2009 forecast.

Figure 2-1: Comparison of Key Economic Drivers



Alternative Economic Scenarios

Three alternative scenarios are considered in the demand forecast. In the medium case scenario, the key economic drivers project a long-term, healthy regional economy (albeit with a slower growth path than in the recent past). In addition to the medium 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 case scenario reflects a future with slow economic growth, weak demand for fossil fuel, declining fuel prices, a slowdown in labor productivity growth, and a low inflation rate. On the other hand, the high case scenario assumes faster economic growth, stronger demand for energy, higher fossil fuel prices, sustained growth in labor productivity, and a higher inflation rate.

It is assumed in the medium, low, and high scenarios that climate change concerns and demand for cleaner fuel lead to a carbon tax, which pushes fuel prices to a higher trajectory. Table 2-1 summarizes the average growth rate for key inputs in each of the alternative scenarios.

Table 2-1: Historic, Medium Case and Alternative Scenarios Growth Rates

Key Economic Drivers	1985-2007 (Actual)	2010-2030 (Low)	2010-2030 (Medium)	2010-2030 (High)
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%
Inflation Rate	2.2%	3.5%	1.9%	1.7%
Average Annual Growth Rate in Price (2008-2030)*				
Oil Prices	1.7%	-1.0%	1.0%	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

PRICE FORECASTS

Fuel Prices

The future prices of natural gas, coal, and oil have an important effect on the Council's Power Plan. As the Pacific Northwest's electricity system has diversified beyond hydropower, it has become more connected to national and global energy markets. Fuel price assumptions affect demand, choice of fuel, and the cost of electricity generation. The effect on demand is primarily through retail natural gas prices to consumers, but natural gas prices may also affect electricity consumption because of its effect on cost. Oil and coal are not used extensively by end users in the Pacific Northwest. Coal is, however, an important source of electricity generation; it affects the wholesale market price of electricity in some hours, and the overall cost of electricity for utilities that rely on coal-fired generation.

The connection between fuel costs and electricity planning has been strengthened by changes in energy regulation and the development of active trading markets for energy commodities. Less regulation and mature commodity markets have also made the price of energy more volatile. The volatility of natural gas price, in particular, is an important factor when considering the use of natural gas for electricity generation. Price volatility creates risks that the Council evaluates in developing a resource plan.

Because natural gas is the primary energy source affecting both the demand and supply of electricity, forecasts of natural gas prices receive far more detailed attention than oil or coal prices. Fuel price forecasts start with global, national, or regional energy commodity prices, depending on the fuel. Oil is a global commodity, natural gas is still primarily a North American commodity (although this could change as liquefied natural gas imports grow), and coal prices tend to be regional in nature. All of these commodities have experienced periods of high and volatile prices since the Fifth Power Plan was developed in 2004. In most scenarios, fuel prices are assumed to decline from recent very high levels. This reduction in price is partly due to natural supply and demand responses to a period of high prices, but also is greatly increased by the current recession and financial crisis.[1]

Long-term fuel price trends are uncertain, as reflected in a wide range of assumptions. The plan reflects three distinct types of uncertainty in natural gas prices: (1) uncertainty about long-term trends; (2) price excursions due to supply and demand imbalances that may occur for a number of years; and (3) short-term and seasonal volatility due to such factors as temperatures, storms, or storage levels. This section discusses only the first uncertainty. Shorter-term variations are addressed in the Council's portfolio model analysis.

The high and low forecasts are intended to be extreme views of possible future prices from today's context. The high case wellhead natural gas price increases to $10 by 2025 and increases to nearly $12 by 2030. The Council's forecasts assume that rapid world economic growth will lead to higher energy prices, even though the short-term effects of a rapid price increase can adversely affect the economy. For the long-term trend analysis, the need to expand energy supplies, and its effect on prices, is considered the dominant factor. 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 liquefied natural gas (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 reduced demand are very limited.

The low case assumes slow world economic growth which reduces the pressure on energy supplies. Wellhead natural gas prices in the low case fall to levels between $4 and $5 per million Btu; still double prices during the 1990s. It is a future where world supplies of natural gas are made available through the aggressive development of LNG capacity, favorable nonconventional supplies and the technologies to develop them, and low world oil prices that provide an alternative to natural gas use. The low case would also be consistent with a scenario of rapid progress in renewable generating technologies, reducing 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.

Many of the assumptions that lead to high or low fuel prices are independent of one another or have offsetting effects. Those conditions lead to the medium fuel price cases being considered more likely. Figures 2-2 through 2-4 illustrate the forecast ranges for natural gas, oil, and powder basin coal prices compared to historical prices. Tables 2-2 through 2-4 show the forecast values for selected years. Appendix A provides a detailed description of the fuel price forecasts.

Most of the cases show fuel prices declining from their most recent high levels in the early years of the forecast. This decline does not completely reflect very recent price changes and the likely

[1] The fuel price forecast used for the draft plan does not completely reflect the current recession and the recent collapse in commodity prices. Therefore, the near-term prices through 2012 are likely higher than the most likely range. These short-term differences are not expected to affect the Council's resource portfolio or planning results significantly, but will be modified for the final Power Plan.

effects of what is becoming a severe recession. Longer-term trends in most of the cases show real fuel prices increasing gradually. All prices, even in the lowest cases, remain well above prices experienced during the 1990s.

The fuel price forecast ranges are both higher and broader than the Council's Fifth Power Plan, reflecting greater uncertainty about long-term trends. The smooth lines for the price forecasts should not be taken as an indication that future fuel prices will be stable. Price cycles and volatility will continue. These variations, and the risks they impose, are introduced into the Council's planning by the portfolio analysis tools.

Figure 2-2: U.S. Wellhead Natural Gas Prices: History and Forecast Range

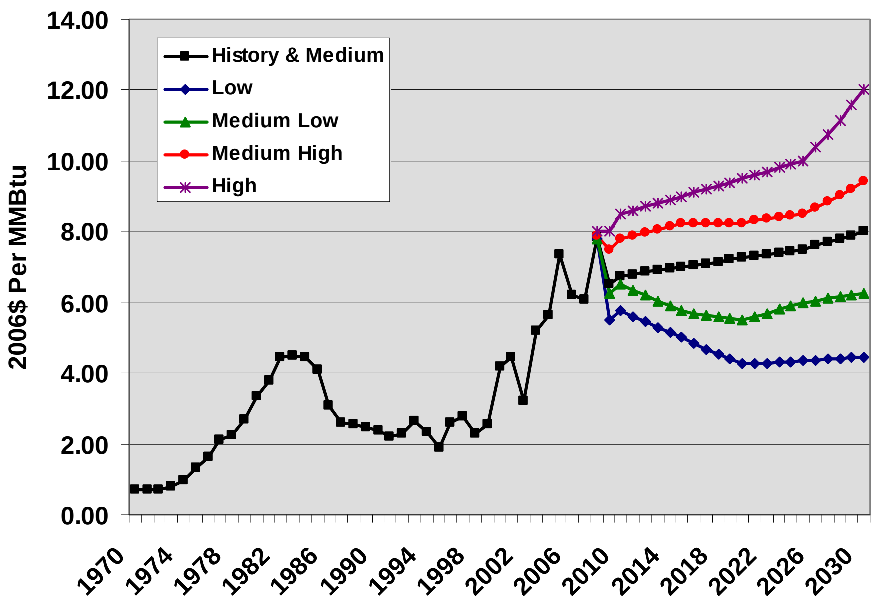


Table 2-2: U.S. Wellhead Natural Gas Price Forecast Range (2006$ per MMBtu)

	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					
2007-2015	-2.36%	-0.64%	1.83%	3.94%	5.08%
2007-2030	-1.33%	0.14%	1.22%	1.93%	2.89%

Figure 2-3: World Oil Prices: History and Forecast Range

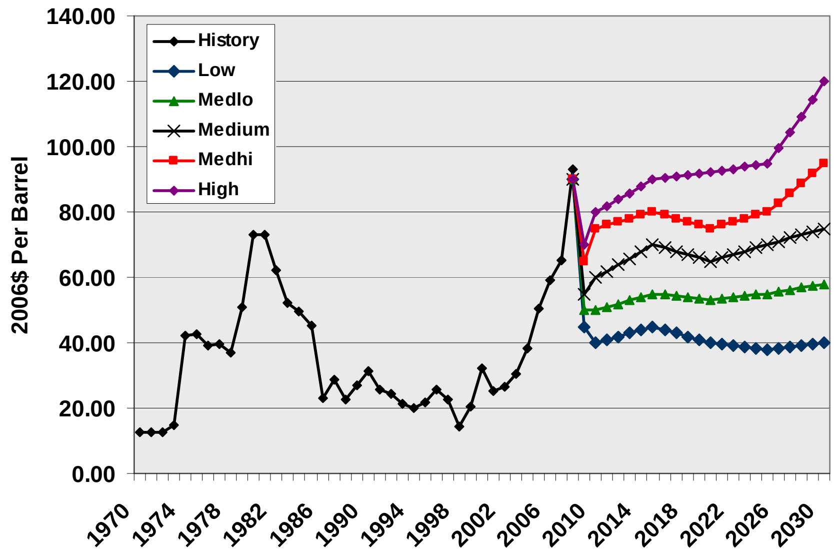


Table 2-3: World Oil Price Forecast Range (2006$ per Barrel)

	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					
2007-2015	-4.54%	-2.12%	0.88%	2.57%	4.09%
2007-2030	-2.11%	-0.51%	0.60%	1.64%	2.68%

Figure 2-4: Powder River Basin Minemouth Coal Prices: History and Forecast

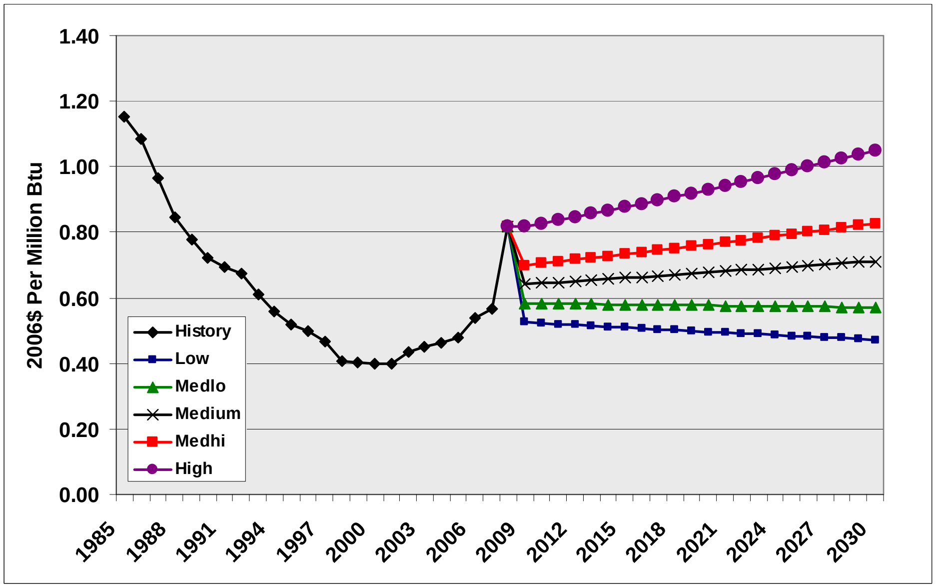


Table 2-4: Powder River Basin Minemouth Coal Price Forecasts (2006$ per MMBtu)

	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					
2007-2015	-1.29%	0.32%	1.98%	3.33%	5.65%
2007-2030	-0.78%	0.05%	1.01%	1.67%	2.73%

Wholesale Electricity Prices

Load-serving entities in the Pacific Northwest depend on the wholesale marketplace to match their customers' 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 resources with the lowest operating cost are serving 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 generating resources and demand in the region and connected areas. Uncertainty regarding future demand in the region is discussed in Chapter 3. On the supply side, there are three primary factors that are likely to influence the wholesale power market during the current planning period: (1) the future price of natural gas; (2) the future cost of carbon dioxide (CO_2) emissions associated with climate control regulation; and (3) the future path of renewable resource development associated with the region's renewable portfolio standards (RPS).

The Council uses the AURORA$^{xmp®}$ Electric Market Model to forecast wholesale power prices for the Pacific Northwest. With AURORA$^{xmp®}$, the Council has the ability to build assumptions regarding future climate control regulation and RPS resource development into its forecasts of future wholesale power prices.

For the purpose of forecasting the long-term trend of future wholesale power prices, the Council developed a preliminary medium CO_2 emissions price forecast. The forecast begins in 2012 at a price of $8 per short ton of CO_2, increases to $27 per ton in 2020, and to $47 per ton in 2030.[2] Uncertainties regarding future climate control regulation and its impact on future resource development in the region are discussed more fully in Chapter 10.

There has been a rapid pace of renewable resource development in the Pacific Northwest in recent years, and the region's utilities appear to be well positioned to meet their future RPS targets. The Council has developed an expected build-out of renewable resources associated with state RPS in the western U.S. By 2030, the cumulative capacity of the RPS build-out includes: 17,000 megawatts from wind plants; 4,000 megawatts from concentrating solar plants; 3,000 megawatts from solar photovoltaic plants; and roughly 1,000 megawatts each from

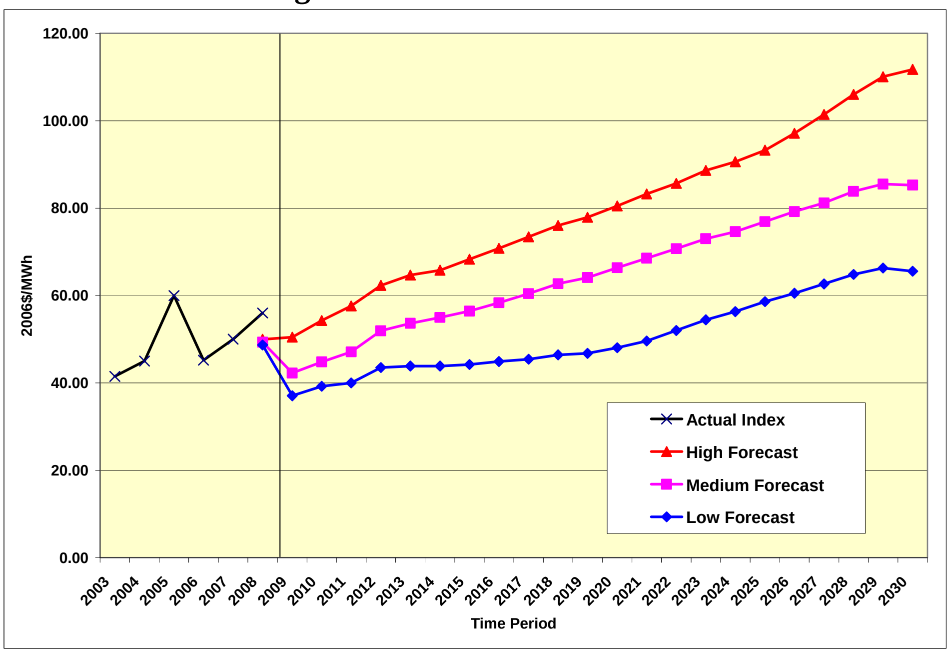
[2] These prices are not exactly the same as assumptions adopted later for the Regional Portfolio Model analysis. They will be revised when the Council's wholesale electricity prices, demand forecast, and other projections are revised in the process moving from the Draft Power Plan to the Final Plan.

geothermal, biomass, and small hydro plants. This mandated RPS resource development is reflected in the Council's wholesale power price forecasts.

The price of natural gas is an important factor in determining the future wholesale price of electricity. Natural gas-fired generating units are often the marginal generating unit, and therefore determine the wholesale price of electricity during most hours of the year. To establish a wide 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 the previous section, and more fully in Appendix A.

Under medium fuel price and CO_2 emission price assumptions, wholesale power prices at the Mid-Columbia trading hub are projected to increase from $45 per megawatt-hour in 2010 to $85 per megawatt-hour in 2030. For comparison, Mid-Columbia wholesale power prices averaged $56 per megawatt-hour in 2008 (in real 2006 dollars). Figure 2-5 compares the forecast range of Mid-Columbia wholesale power prices to actual prices during the 2003 through 2008 period.

Figure 2-5: 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 (RPM) 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 2-6 shows the medium forecast of Mid-Columbia monthly on-peak and off-peak power prices. The forecast shows a narrowing of the difference between on-peak and off-peak power prices during the planning period. Table 2-5 shows the forecast values for selected years. Appendix D provides a detailed description of the wholesale power price forecasts.

Figure 2-6: Medium Forecast of Mid-Columbia Wholesale Power Prices

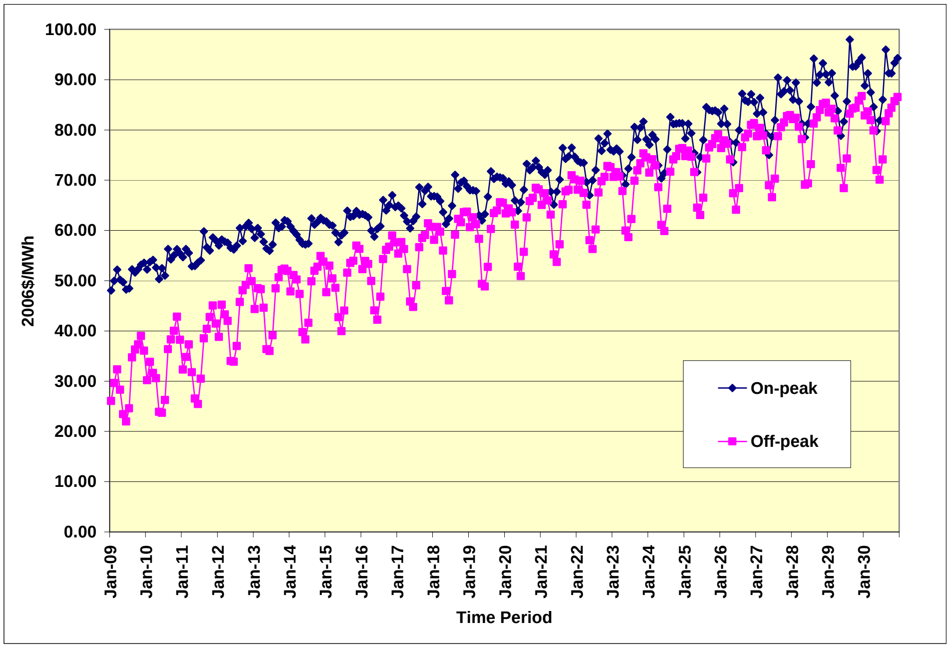


Table 2-5: Forecast of Mid-Columbia Wholesale Power Prices (2006$/MWh)

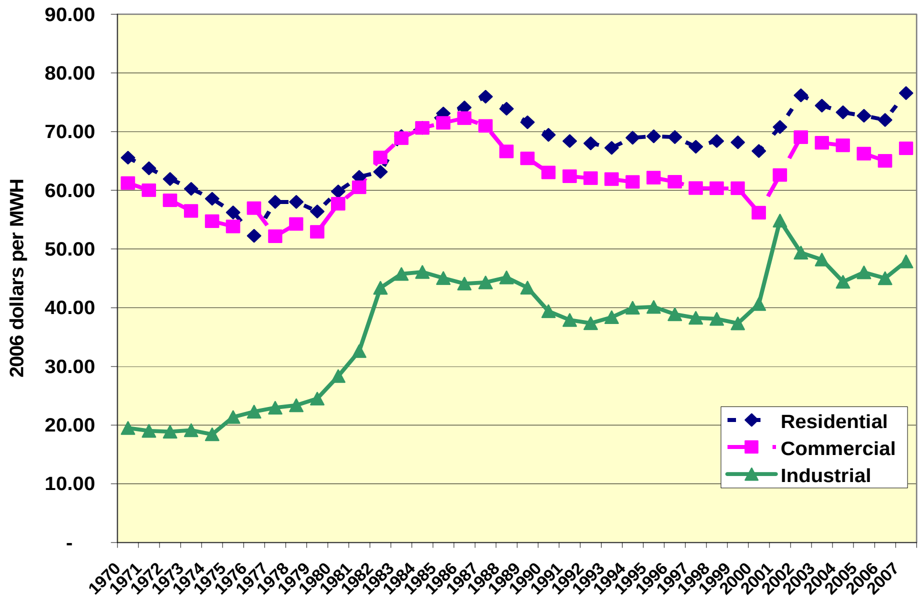
	On-Peak	Off-Peak	Average
Actual 2008	62.00	49.00	56.00
2010	54.00	33.00	45.00
2015	61.00	50.00	56.00
2020	70.00	62.00	66.00
2025	80.00	73.00	77.00
2030	89.00	81.00	85.00
Growth Rates			
2010-2020	2.61%	6.30%	3.93%
2020-2030	2.43%	2.62%	2.51%

Retail Electricity Prices

History

In the first half of the 1970s, consumers in the Northwest experienced declining electricity prices. However, by mid-1970 and into the 1980s, the region experienced dramatic increases in the price of electricity, followed by an economic recession that hit the region particularly hard. In the latter half of the 1980s, electricity prices began a decade-long decline, in real terms. But in late 2000, the region again experienced large increases in the price of energy, accompanied by a moderate recession. Since the sharp increase in 2000, electricity prices have stabilized, and even declined in inflation-adjusted prices. However, since 2006, another round of more moderate price increases has begun to be reflected in increases in fuel prices and other commodities. Figure 2-7 illustrates this price history.[3]

Figure 2-7: Average Retail Electricity Price by Sector (2006$/MWh)



Forecast of Retail Electricity Prices

Typically, the price of electricity for investor-owned utilities is determined through a regulatory approval process, with utilities bringing a rate case to their regulatory body and seeking approval of future rates. Future rates depend on the cost of serving electricity to customers and the level of sales. The approved rates should cover the variable *and* fixed-cost components of serving customers, plus a rate of return on invested capital. For customer-owned utilities, rates are set by elected boards to recover the costs of serving the electricity needs of their customers.

The methodology used for forecasting future electricity prices in the Sixth Power Plan is a simplified approach, 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 Mid-Columbia, transmission and delivery charges, along with other incremental fixed costs like conservation investments or meeting regional portfolio standards, are added in.

Sector Retail Prices

The estimated price of electricity by sector and state is presented in Tables 2-6 through 2-8. For the residential sector, the annual real growth rate of electricity prices is expected to be in the 1.5-1.9 percent per year range for the 2010-2030 period. It should be noted that these forecasts are at the state level, and within each state, individual electric utility rates may be higher or lower than

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[3] Prices in Figure 2-7 are expressed in constant year 2006 dollars, as are many other tables and graphs throughout the plan.

the figures presented here. Also, individual utilities may have significantly higher or lower rate increases than these average state-wide figures would indicate.

Table 2-6: Price of Electricity for Residential Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	74	60	68	74
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 2-7: Price of Electricity for Commercial Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	81	57	65	67
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 2-8: Price of Electricity for Industrial Customers (2006$/MWh)

	Oregon	Washington	Idaho	Montana
1985	56	34	42	40
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%

Chapter 3: Electricity Demand Forecast

SUMMARY OF KEY FINDINGS

The Pacific Northwest consumed 19,000 average megawatts or 166 million megawatt-hours of electricity in 2007. That demand is expected to grow to 25,000 average megawatts by 2030 in the Council's medium forecast. Between 2007 and 2030, demand is expected to increase by a total of 6,500 average megawatts, growing on average by 270 average megawatts, or 1.2 percent, per year. This forecast has been influenced by expected higher electricity prices that reflect a rapid rise in fuel prices and emerging carbon emission penalties. At the same time, the impact of cost-effective efficiency improvements identified in the Sixth Power Plan should help to meet that demand growth.

This increase is driven primarily by significant growth in two areas: home electronics and elder-care facilities. Demand for home electronics--a new component to the Council's residential sector--is expected to double in the next 20 years. In the commercial sector, the elder-care segment is increasing as the population ages, resulting in their surge. While the industrial sector is growing at a relatively slow pace, custom data centers (Google, etc.) are a relatively new end-use that has been seeing significant growth as well.

The Northwest has always been a winter-peaking power system. However, due to growing summer load, mostly because of the increased use of air conditioning, the difference between winter- and summer- peak load is expected to shrink over time. Assuming normal weather conditions, winter-peak demand in the Sixth Power Plan is projected to grow from about 34,000 megawatts in 2010 to around 42,000 megawatts by 2030, an average annual growth rate of 1 percent. Summer-peak demand is forecast to grow from 28,000 megawatts in 2010 to 39,000 megawatts by 2030, an annual growth rate of 1.4 percent. By the end of the planning period, the gap between summer-peak load and winter-peak load has narrowed.

The projected growth of demand is comparable to the actual growth rate experienced during the 1990s. When new cost-effective conservation is subtracted, the need for additional generation will be quite small compared to past experience. However, summer supply needs will likely increase as summer-peak demand continues to grow. In addition, the growing share of variable wind generation may change the types of generation needed to meet demand. There is likely to be an increased need for resources that can provide reliable capacity to meet high load conditions and that can operate flexibly to accommodate variable, but non-CO_2 emitting, wind energy.

INTRODUCTION

The 2001 energy crisis in the West refocused the region on long-term demand forecasting. There has been a renewed interest and concern about generating capacity and flexibility as well. To deal with these issues, the Council replaced its end-use forecasting models with a new end-use forecasting and policy analysis tool and, working with Bonneville, adapted it to the regional power system and the Council's planning requirements. The new demand forecasting system is based on the Energy 2020 model and generates forecasts for electricity, natural gas, and other fuel.

The Energy 2020 model is an integrated end-use forecasting model.   The Council will use the demand module of Energy 2020 to forecast annual energy and peak loads for electricity as well as other fuels. The model has been used extensively by several utilities, and within the region the Bonneville Power Administration uses a version of it.

Three electricity demand forecasts were developed in the Sixth Power Plan. Each scenario corresponds to an underlying set of economic drivers, discussed in Chapter 2 and Appendix B. The high and low range of the load forecasts are not explicitly used in the development of the Power Plan, but rather are used as loose guidelines for the regional portfolio model when creating the 750 alternative load forecasts. These demand scenarios reflect an estimate of the impact of the current recession.

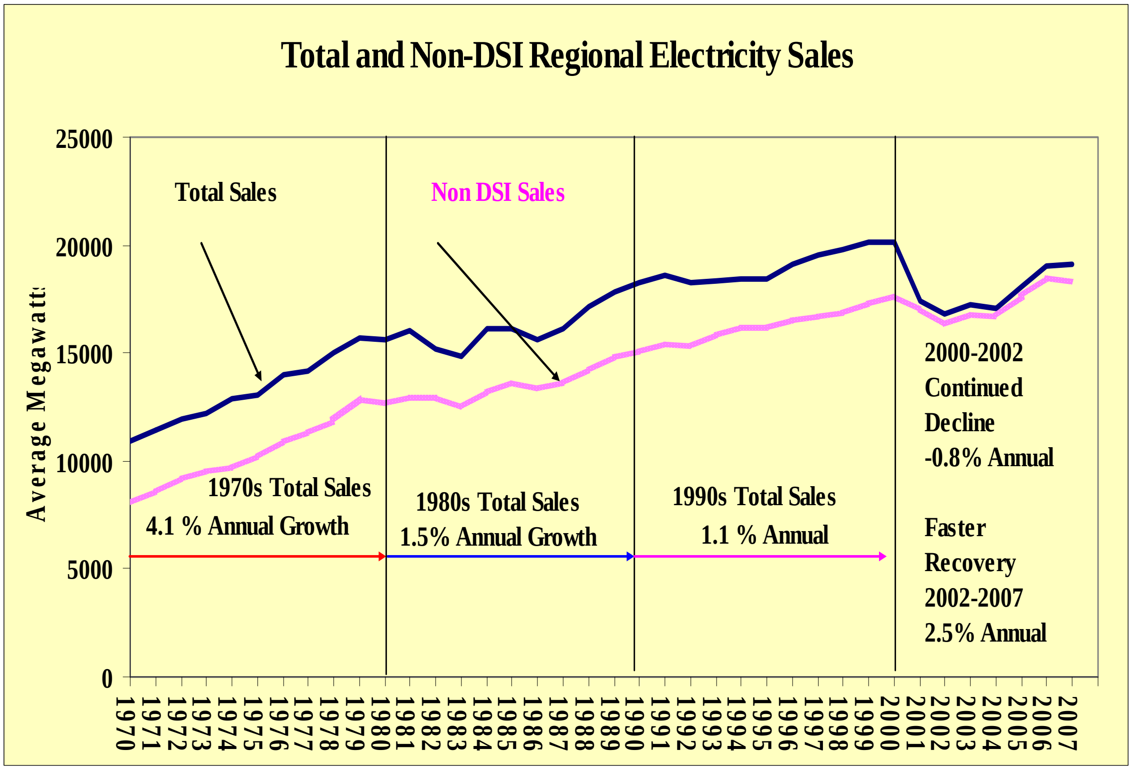
Historic Demand Growth

It has been 26 years since the Council's first Power Plan in 1983. In the decade prior to the Northwest Power Act, regional demand was growing at 4.1 percent per year and the non-direct service industry (DSI) load was growing at an annual rate of 5.2 percent. Back in 1970, regional demand was about 11,000 average megawatts. In the decade between 1970 and 1980, it grew by about 4,700 average megawatts.   During the 1980s, demand growth slowed significantly, falling to about 1.5 percent per year and load increased by about 2,300 average megawatts. In the 1990s, another 2,000 average megawatts were added to regional demand, making growth in the last decade of the 20th century only about 1.1 percent per year. The energy crisis of 2000-2001 increased electricity prices dramatically. As a result, regional demand decreased by 3,700 average megawatts between 2000 and 2001, eliminating much of the growth since 1980. The bulk of this decline was in the region's aluminum industry and other energy-intensive industries. Since 2002, however, regional demand has begun to recover, growing at an annual rate of 2.5 percent. This growth has been driven by increases in commercial and residential sector demand. Nevertheless, demand remains well below levels of the late 1990s. Table 3-1 and Figure 3-1 illustrate regional electricity demand from 1970-2007.

Table 3-1: Historical Growth Rate of 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%

Figure 3-1: Total and Non-DSI Regional Electricity Sales (MWa)



The dramatic decrease in demand after the Power Act 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 was the result of a shift in the regional economy as the number of energy-intensive industries declined, largely because of the dramatic increase in electricity prices that followed the region's over-investment in nuclear generation in the 1970s and increased investment in conservation. As shown in Table 3-2, electricity intensity in terms of use per capita increased between 1980 and 1990, but has been declining since 1990.

Table 3-2: Changing Electricity 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

The upswing in demand since 2002 has been mainly due to growth in residential and commercial sector sales. By the end of 2007, the residential sector had added about 888 average megawatts and the commercial sector had added 285 average megawatts, whereas the industrial sector saw a reduction of 337 average megawatts.

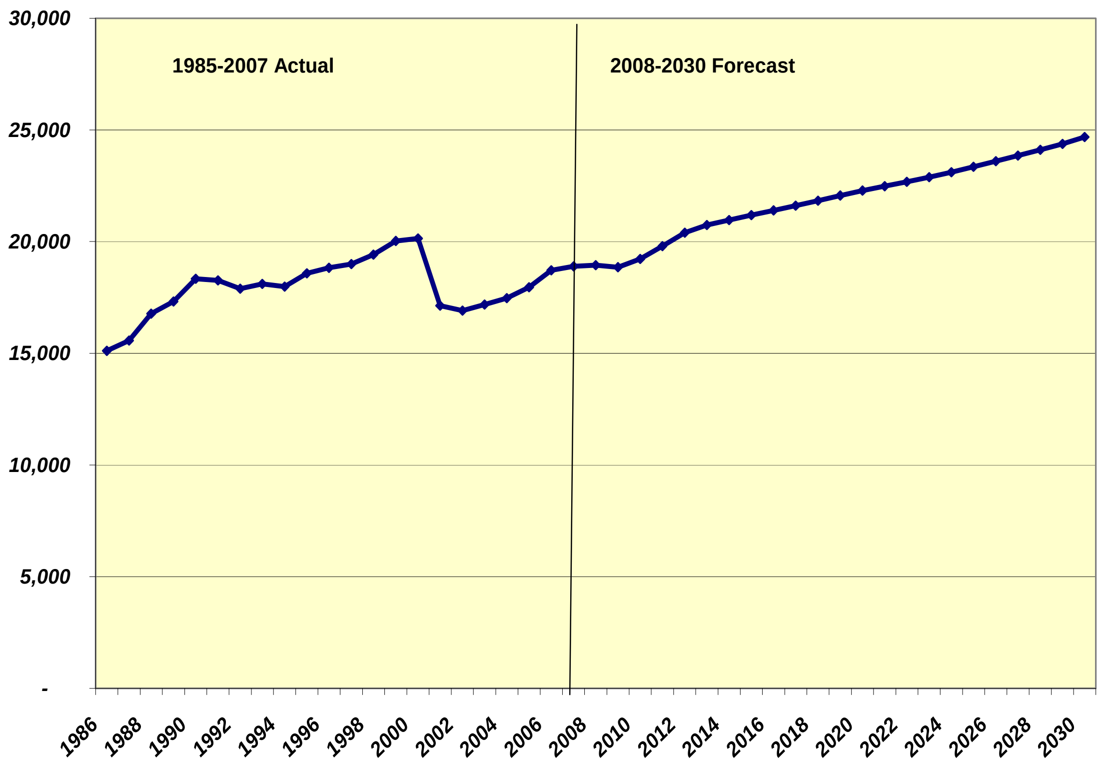
Sixth Power Plan Demand Forecast

Demand is forecast to grow from about 19,000 average megawatts in 2007 to 25,000 average megawatts by 2030 in the medium case forecast. The average annual rate of growth in this forecast is about 1.2 percent. This level of growth does not take into account reductions in energy from new conservation resources. To the extent conservation is used to meet demand growth, the forecast will decrease. This growth rate is similar to the Council's Fifth Power Plan forecast, which projected growth of 1.4 percent per year from 2000 to 2025.

Assuming normal weather conditions, the winter-peak demand for power is projected to grow from about 34,000 megawatts in 2010 to around 42,000 megawatts by 2030 at an average annual growth rate of 1 percent. Summer-peak demand is projected to grow from 28,000 megawatts in 2010 to 39,000 megawatts by 2030, an annual growth rate of 1.4 percent.

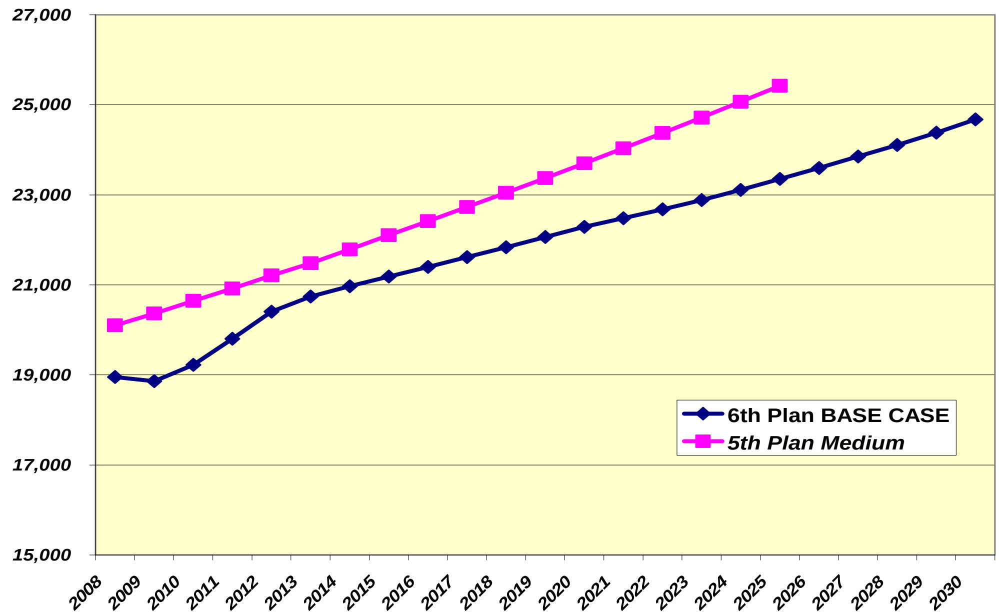
The medium demand forecast means that the region's electricity needs would grow by about 6,000 average megawatts by 2030, absent any conservation, an average annual increase of 260 average megawatts. Most of the growth is from increased electricity use by the residential and commercial sectors, with slower growth in the industrial sector, especially for energy-intensive industries. Higher electricity and natural gas prices have fundamentally shifted the energy intensity of industries in the region. As a result of the 2000-01 energy crisis and mild recession of 2002, the region lost about 3,500 average 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 2008-9 recession may prolong this recovery. Figure 3-2 illustrates the demand forecast for the medium case. Table 3-3 shows the sectoral demand forecast for selected years.

Figure 3-2: Sixth Plan Medium Demand Forecast (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 as illustrated in Figure 3-3. By 2025, the two forecasts differ by about 2,000 average megawatts.

Figure 3-3: Sixth Plan Demand Forecast Comparison to Fifth Plan (MWa)



Sectoral Demand

The draft Sixth Power Plan forecasts demand to grow at an average annual rate of 1.3 percent in the 2010 through 2030 period. The residential sector is expected to grow at 1.3 percent per year which, on average, translates to about 100 megawatts each year. Increased growth in the residential sector is from a substantial increase in demand for home electronics, categorized as information, communication, and entertainment (ICE,) and the increased use of air conditioning.

Table 3-3 shows the actual 2007 demand for electricity and the forecast for selected years, as well as the corresponding annual growth rates. These demand forecasts do not include any new conservation initiatives.

Table 3-3: Medium Case Sector Forecast of Annual Energy Demand (MWa)

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Residential	7,432	7,554	8,452	9,765	1.1%	1.5%	1.3%
Commercial	6,106	6,537	8,201	8,767	2.3%	0.7%	1.5%
Industrial Non-DSI	3,725	3,648	3,952	4,277	0.8%	0.8%	0.8%
DSI	764	693	818	818	1.7%	0.0%	0.8%
Irrigation	802	728	781	958	0.7%	2.1%	1.4%
Transportation	64	65	83	94	2.5%	1.3%	1.9%
Total	18,893	19,224	22,288	24,678	1.5%	1.0%	1.3%

Commercial sector electricity consumption is forecast to grow by 1.5 percent per year between 2010 and 2030. During this period, commercial sector demand is expected to increase from

6,500 average megawatts to 8,800 average megawatts. This increase is higher than the 1.2 percent per year that was forecast in the Fifth Power Plan. Compared to the Fifth Power Plan's forecast of commercial electricity use, the Sixth Power Plan cases have been adjusted upward to reflect the fact that there has been a tendency to under-forecast 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 adds about 120 average megawatts per year.

Industrial electricity demand is difficult to forecast with much confidence. Unlike the residential and commercial sectors, where energy use is predominately for buildings, and therefore reasonably uniform and easily related to household growth and employment, industrial electricity use is extremely varied. Also, industrial electricity use tends to be concentrated in relatively few, very large users instead of spread among many relatively uniform users.

In the last plan, Bonneville's direct service industries were treated separately because this assortment of plants (mainly aluminum smelters) accounted for nearly 40 percent of industrial electricity use. In addition, the future of these plants was highly uncertain. Large users in a few industrial sectors such as pulp and paper, food processing, chemicals, primary metals other than aluminum, and lumber and wood products dominate the remainder of the industrial sector's electricity use. Many of these sectors have declined or are experiencing slow growth. These traditional, resource-based industries are becoming less important to regional electricity demand, while new industries, such as semiconductor manufacturing, are growing faster.

Industrial (non-direct service industries) 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. One segment of the industrial sector that has experienced significant growth is that of custom data centers. Although these businesses do not manufacture a tangible product, they are typically classified as industrial customers because of the amount of electricity they use. The Council's estimates show that there are currently about 300 average megawatts of connected load for these businesses. Demand from this sector is forecast to increase by about 7 percent per year. However, considering existing opportunities to improve the energy efficiency of custom data centers, it was assumed that demand from these centers will grow about 3 percent per year.

Demand Forecast Range

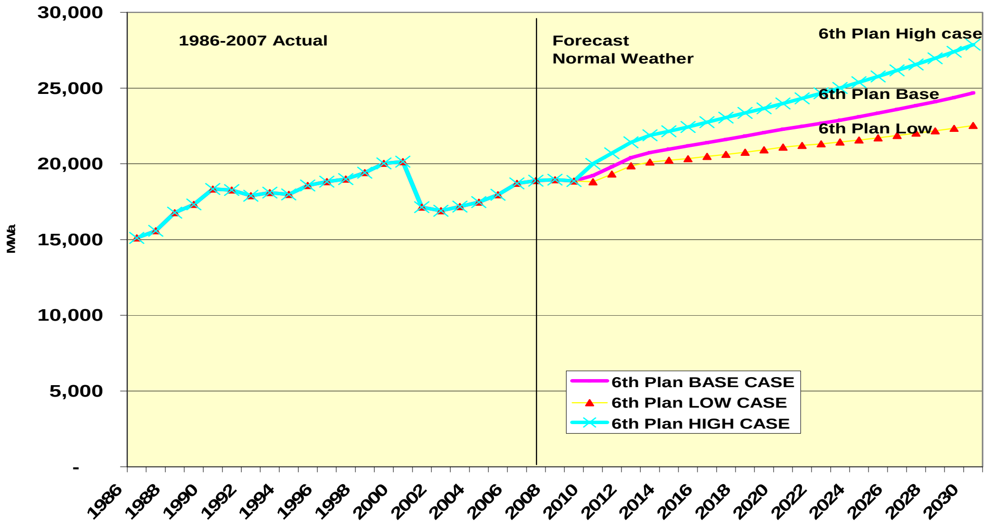
Uncertainty about economic and demographic variables, along with uncertainty about fuel prices, adds to uncertainty about demand. To evaluate the impact of these economic and fuel price uncertainties in the Sixth Power Plan, two alternative demand forecasts were produced. To forecast demand under each scenario, the appropriate economic and fuel projections were used. Table 2-1, presented in Chapter 2, shows a range of values for key economic assumptions used for each scenario. The resulting range in the demand forecast is shown in Table 3-4 and Figure 3-4, and is compared to the Fifth Power Plan in Figure 3-5.

Two alternative scenarios were developed for the Sixth Power Plan. The most likely range of demand growth (between the low and high forecasts) is between 0.9 and 1.7 percent per year. Figure 3-4 summarizes the forecast range.   In all three scenarios demand growth in the first 10 years of the forecast is faster than the second 10 years, reflecting a recovery from the current recession in the 2010-2020 period followed by a return to the long term growth trend from 2020-2030.

Table 3-4: Sixth Plan Electricity Demand Forecast Range (MWa)[1]

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Low	18,893	18,815	21,103	22,538	1.2%	0.7%	0.9%
Medium	18,893	19,224	22,288	24,678	1.5%	1.0%	1.3%
High	18,893	20,006	23,982	27,876	1.8%	1.5%	1.7%

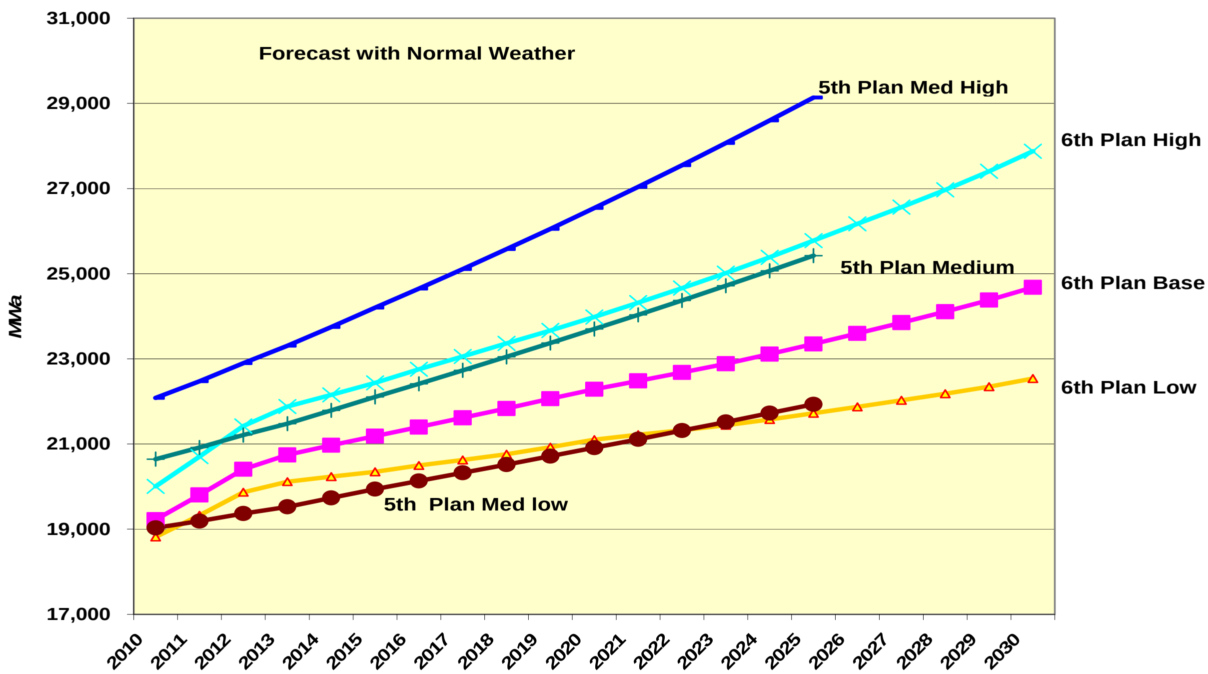
Figure 3-4: Historical Sixth Plan Sales Forecast



A comparison of the range of forecasts in the Fifth and Sixth Power Plans shows that the range is narrower in the Sixth Power Plan. As indicated in Figure 3-5, the medium cases for the two plans are very close. The low case in the Sixth Power Plan is comparable to the medium-low case of the Fifth Power Plan. The Sixth Power Plan medium case is about 2,000 average megawatts lower than the medium case in the Fifth Power Plan. The high case in the Sixth Power Plan is also lower than the medium-high case in the Fifth Power Plan. The main reason for this smaller difference between the high and low case in the Sixth Plan is the narrower range in the economic drivers. The low to high range in the Fifth Plan was intended to cover 95 percent of future demand growth possibilities. The Sixth Power Plan's low to high range is based on Global Insight's range of forecasts, which stays closer to its most likely forecast. The Sixth Plan's low to high range is more comparable to the medium-low to medium-high range in previous Council plans, and both are considered reasonably likely to occur. However, additional uncertainty is addressed in the Regional Portfolio Model (RPM).

[1] Sales figures are electricity use by consumers and exclude transmission and distribution losses.

Figure 3-5: Comparison of Fifth and Sixth Plan Demand Forecasts (MWa)



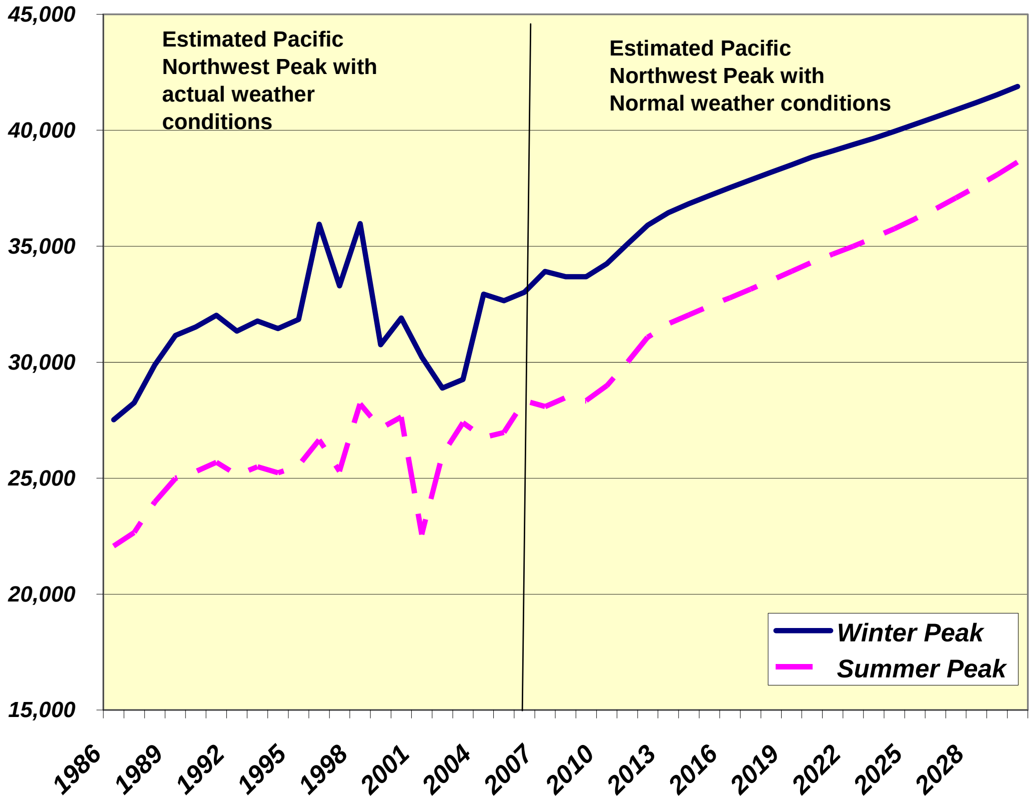
LOAD FORECAST AND PEAK LOAD

Peak Load

The Council's new long-term demand forecasting system forecasts annual sales, as well as monthly energy and peak load. The Council often refers to electricity sales to consumers as demand, following the Northwest Power Act's definition. The difference between sales and load is transmission and distribution losses on power lines. Regional peak load is determined from the end-use level for each sector. The regional peak load for power, which has typically occurred in winter, 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. Assuming normal historical temperatures, the region is expected to remain a winter-peaking system, although summer peaks are expected to grow faster than winter peaks, significantly narrowing the gap between summer-peak load and winter-peak load.

The forecast for regional peak load assumes normal weather conditions. There are no assumptions regarding temperature changes incorporated in the Sixth Power Plan's load forecast at this time. Sensitivities will be conducted to help assess the potential effects of climate change on electricity use (See Appendix L). Figure 3-6 shows estimated actual peak load for 1985-2007, as well as the forecasts for 2008-2030. Note that load growth looks very steep due to the graph's smaller scale.

Figure 3-6: Historical and Forecast Regional Peak Load (MW)



Load Forecast Range

Figure 3-7 shows forecast winter and summer month peak load under the three alternative cases. Assuming the high-growth scenario, regional summer-peak load is expected to grow from about 28,000 megawatts in 2007 to about 43,000 megawatts by 2030. Between 2010 and 2030, the growth rate in summer-peak load is 1.8 percent per year, about 0.1 percent higher than the growth rate in the high case average annual demand. The growth rate of winter-peak load in the high case is lower than the growth in average annual energy demand. Assuming normal weather, the region is forecast to remain a winter peaking system. However, the difference between winter and summer peak loads shrinks overtime.

Figure 3-7: Total Summer and Winter Peak Load Forecast Range (MW)

	Actual 2007	2010	2020	2030	Growth Rate 2010-2020	Growth Rate 2020-2030	Growth Rate 2010-2030
Low - Winter	33,908	33,795	37,109	39,060	0.9%	0.5%	0.7%
Low - Summer	28,084	28,229	32,462	35,357	1.4%	0.9%	1.1%
Medium - Winter	33,908	34,243	38,842	41,885	1.3%	0.8%	1.0%
Medium - Summer	28,084	28,976	34,313	38,630	1.7%	1.2%	1.4%
High - Winter	33,908	35,416	41,481	46,552	1.6%	1.2%	1.4%
High - Summer	28,084	30,232	36,876	43,413	2.0%	1.7%	1.8%

In the low case, summer-peak load is expected to grow from 28,000 megawatts in 2007 to 35,000 megawatts in 2030. Winter-peak load grows from 34,000 in 2007 to 39,000 in 2030. Other patterns between summer and winter peaks are similar to the other cases. Winter peaks grow more slowly than average energy load, and summer peaks grow faster.

Plug-in Hybrid Electric Vehicles

A study of the potential impacts of plug-in hybrid electric vehicles (PHEVs) assumed a range of penetration of these cars into the market, with the result that regional electricity use increases by 100 to 550 average megawatts. The power system's emissions of greenhouse gasses increases slightly as a result of PHEVs, but that effect is more than offset by the decrease in emissions by vehicles. The estimated effects on electricity bills and rates were small; these estimates "conservative" since they did not include an estimate of the reduction in cost of gasoline purchases due to PHEVs.

Chapter 4: Conservation Supply Assumptions

SUMMARY OF KEY FINDINGS

The Council defines conservation as improved energy efficiency. This means that less electricity is used to provide the same level of services. Conservation resources are measures that ensure that new and existing residential buildings, household appliances, new and existing commercial buildings, commercial-sector appliances, commercial infrastructure such as street lighting and sewage treatment, and industrial and irrigation processes are energy-efficient. These efficiencies reduce operating costs and ultimately decrease the need to build new power plants. Conservation also includes measures to reduce electrical losses in the region's generation, transmission, and distribution system.

The Council identified just under 7,000 average megawatts of technically achievable conservation potential in the medium demand forecast by the end of the forecast period, at a levelized (net) life-cycle cost of up to $200 per megawatt-hour (2006 dollars). Sources of potential savings are about 50 percent higher than in the Fifth Power Plan. The assessment is higher for two principle reasons. First, the Council identified new sources of savings in areas not addressed in the Fifth Power Plan: consumer electronics, outdoor lighting, and the utility distribution system. Second, savings potential has increased significantly in the residential sector as a result of technology improvements and in the industrial sector as a result of a more detailed conservation assessment. Not all of the 7,000 average megawatts identified will prove to be cost-effective to develop. The Council uses its portfolio model to identify the amount of conservation that can be economically developed.

The savings break down as follows:

- About 3,300 average megawatts of conservation are technically achievable in the residential buildings and appliances. Most of the savings come from improvements in water-heating efficiency and heating, ventilating, and air conditioning efficiency.

- Nearly 1,000 average megawatts of potential savings are estimated in the fast-growing consumer electronics sector. These savings come from more efficient televisions, set top boxes, desktop computers, and monitors primarily in homes but also in businesses.

- Approximately 100 average megawatts of conservation is available in the agriculture sector through irrigation system efficiency improvements, improved water management practices, and dairy milk processing.

- The commercial sector offers about the same amount of savings as the Fifth Power Plan, about 1,400 average megawatts. Nearly two-thirds of commercial savings are in lighting systems. New technologies like light-emitting diodes and improved lighting fixtures and controls offer added potential savings in both outdoor and indoor lighting.

- Potential savings in the industrial sector are estimated to be about 800 average megawatts by the end of the forecast period. The industrial assessment found that effective business management practices could significantly increase savings from equipment and system optimization measures.

- Finally, potential savings from improved efficiency in utility distribution systems are estimated to be over 400 average megawatts by the end of the forecast period.

While there are a number of barriers to achieving these savings, the Council believes these challenges can be met.

RECENT CHANGES SINCE THE FIFTH POWER PLAN

The Fifth Power Plan recommended that the region develop at least 700 average megawatts of conservation savings from 2005 through the end of 2009. Based on surveys conducted by the Council's Regional Technical Forum, regional conservation programs are likely to achieve a total savings of at least 875 average megawatts by 2009.

Federal Standards

Since the Fifth Power Plan was adopted, Congress enacted the 2007 Energy Independence and Security Act (EISA) and the Department of Energy has promulgated several new standards. The EISA legislation revised several existing federal efficiency standards and established new standards as well. The most significant EISA standard requires "general service lighting" (40 - 100 watt lamps) to be at least 30 percent more efficient beginning in 2012, and 60 percent more efficient beginning in 2020. The Fifth Power Plan estimated that converting standard incandescent bulbs to compact fluorescent light bulbs (CFL) could save the region 625 average megawatts by 2025. While the EISA standard does not cover all incandescent bulbs (bulbs over 100 watts and 3-way light bulbs are exempt), it does cover 70-80 percent of residential sector applications. Consequently, roughly 75 percent of savings from CFL contributes to a lower load forecast, leaving approximately 150 average megawatts of residential lighting potential.

EISA also sets minimum standards for certain commercial lighting products that were incorporated into the conservation assessment and load forecast. In addition, new efficiency standards were developed and adopted since 2004 for a suite of residential and commercial appliances regulated by federal law or state standards. Baseline assumptions for energy use of new appliances and equipment have been updated in the new conservation assessment to reflect these improved standards. Table 4-1 shows a summary of all the federal standards that have changed since the adoption of the Fifth Power Plan and the effective dates of these new and/or revised standards.

Table 4-1: New or Revised Federal Standards Incorporated in Sixth Power Plan Conservation Assessment Baseline Assumptions

Product Regulated	Effective Date
Battery Chargers and External Power Supplies	July 1, 2008
Clothes Washers (Residential)	January 1, 2007
Clothes Washers (Commercial)	January 1, 2011
Consumer dehumidifier products	October 1, 2012
Dishwashers (Residential)	January 1, 2010
Ice Makers (Commercial)	January 1, 2010
Motors	December 17, 2010
Distribution Transformers (Low Voltage)	January 1, 2007
Distribution Transformers (Medium-voltage, dry-type and Liquid-immersed distribution transformers)	January 1, 2010
Packaged Air Conditioners and Heat Pumps (Commercial - ≥65,000 Btu/h)	January 1, 2010
Refrigerators and Freezers (Commercial)	January 1, 2010
Single-Package Vertical Air Conditioners and Heat Pumps	January 1, 2010
Walk-In Coolers and Walk-In Freezers (Commercial)	January 1, 2009
Ceiling Fan Light Kits	January 1, 2007
Compact Fluorescent Lamps (Efficacy and Rated Life)	January 1, 2006
Exit Signs	January 1, 2006
Fluorescent Lamp Ballasts	Beginning October 1, 2009 and phasing in through July 2010
Incandescent General-Service Lamps	Beginning January 1, 2012 and phasing in through 2014
Incandescent Reflector Lamps	June 1, 2008
Metal Halide Lamp Fixtures	January 1, 2009
Torchieres	January 1, 2006

New Sources of Potential Savings

Additional savings were identified from utility distribution systems. Distribution system savings, including voltage management and system optimization, add over 400 average megawatts of conservation potential not included in the Fifth Power Plan assessment.

A more in-depth analysis of the industrial sector more than doubled the conservation potential identified in the Fifth Power Plan.

Along with these major adjustments, the conservation assessment incorporates new conservation opportunities brought about by technological advances. For example, recent advances in solid-state lighting--light-emitting diodes (LED) and organic light-emitting diodes (OLED)--appear to offer significant opportunities for savings in televisions and some lighting applications. The arrival in the U.S. market of ductless heat pumps for space heating also provides new savings opportunities.

ESTIMATING THE COST OF CONSERVATION

The Council determines the total resource cost of energy savings from all measures that are technically feasible. This process requires comparing all the costs of a measure with all of its benefits, regardless of who pays those costs or who receives the benefits. In the case of efficient clothes washers, the cost includes the difference (if any) in retail price between the more efficient Energy Star model and a standard efficiency model, plus any utility program administrative and marketing costs. On the other side of the equation, benefits include the energy (kilowatt-hour) and capacity (kilowatt) savings, water and wastewater treatment savings, and savings on detergent costs.[1] While not all of these costs and benefits are paid by or accrue to the region's power system, they are included in the evaluation because ultimately, it is the region's consumers who pay the costs and receive the benefits.

Once the *net cost* (levelized over the life of the conservation resource) of each of the conservation technologies or practices is determined, the technologies are ranked by cost in two supply curves that depict the amount of conservation resource available in the region. These net levelized costs of conservation are calculated the same way that levelized costs of new generating resources are calculated so they can be compared.

One supply curve represents all of the retrofit or non-lost opportunity resources. The other represents all the lost-opportunity conservation resources.[2] The Council divides conservation resources into these two categories because their patterns of deployment are different. Non-lost opportunity conservation resources can be deployed at any time. Lost-opportunity resources are only available during specific periods; for example, when new buildings are built with improved insulation. Savings from most appliances are available only as appliance stock turns over. If the savings from these lost-opportunity resources are not acquired within this limited window of opportunity, they are treated as lost and no longer available at that time or cost.

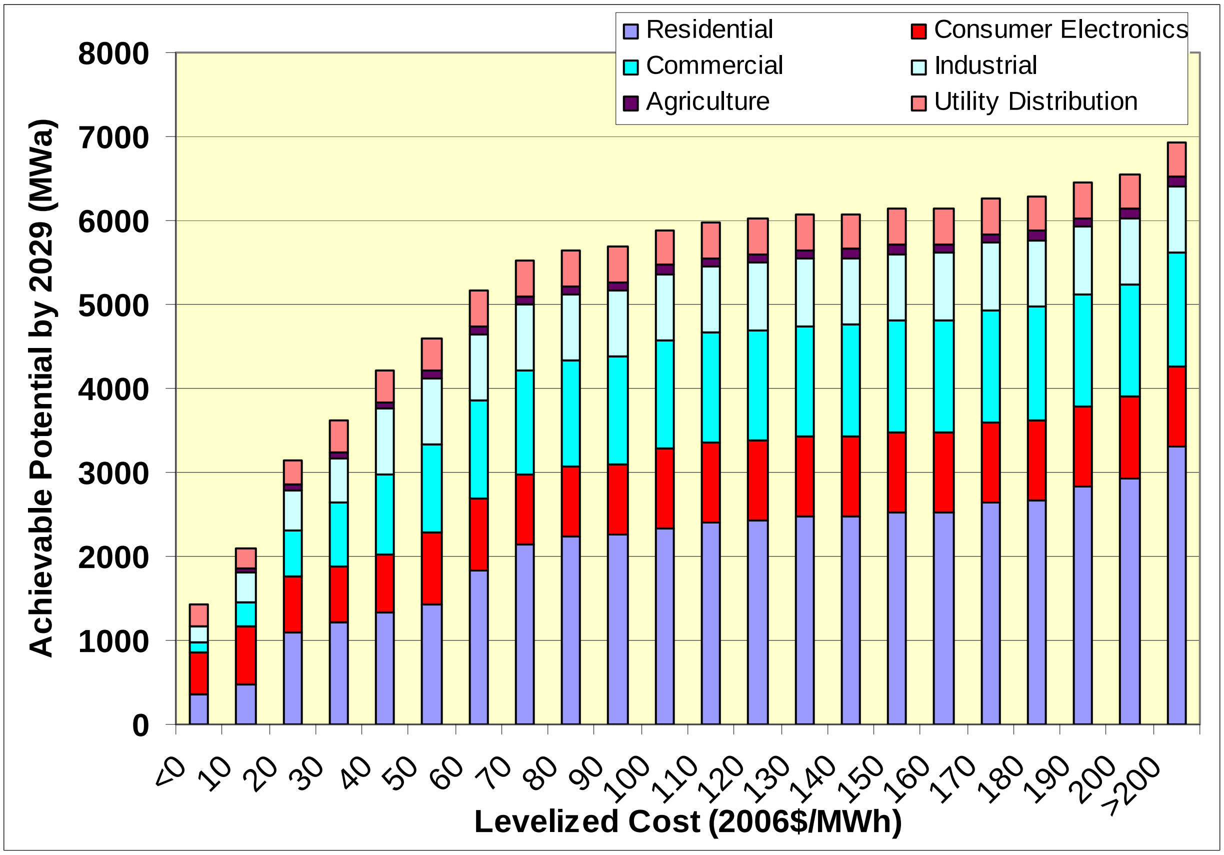
Figure 4-1 shows the Sixth Power Plan's estimate of the amount of conservation available by sector and levelized life-cycle cost. The Council identified just under 7,000 average megawatts of technically achievable conservation potential in the medium demand forecast by the end of the forecast period at a levelized life-cycle cost of up to $200 per megawatt-hour (2006 dollars). New sources of potential savings result in about 50 percent more technical potential compared to the Fifth Power Plan.[3] Slightly less than half of the potential is from lost-opportunity measures.

[1] Energy-efficient clothes washers use less water and require less detergent.

[2] Lost-opportunity resources can only be technically or economically captured during a limited window of opportunity, such as when a building is built or an industrial process is upgraded.

[3] For purposes of comparison, the Council's Fifth Power Plan estimated that the technically achievable conservation was approximately 4,600 average megawatts at $120 per megawatt-hour. This plan's estimate is just over 5,100 average megawatts at an equivalent levelized life-cycle cost.

Figure 4-1: Achievable Conservation by 2029 by Sector and Levelized Cost



RESOURCE POTENTIAL ESTIMATES BY SECTOR

Residential Sector

In the Fifth Power Plan, the Council estimated that approximately 1,600 average megawatts of conservation potential was technically available in the residential sector from improvements in lighting, appliances, and water-heating technologies at a levelized cost of less than $120 per megawatt-hour (2006 dollars). The Sixth Power Plan's estimate for these same end-uses places the remaining technically achievable conservation at nearly 2,400 average megawatts at an equivalent cost.

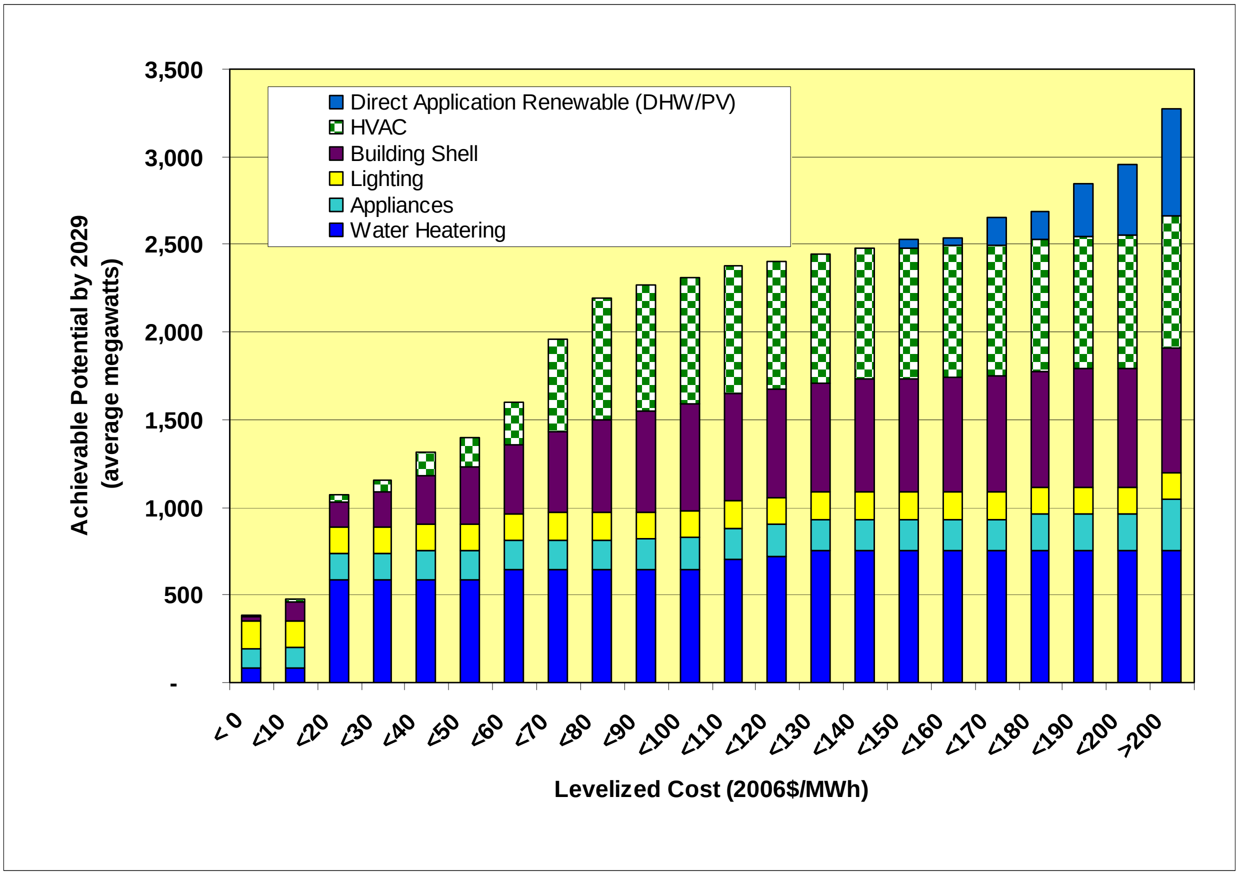
The largest decrease (475 average megawatts) in residential-sector potential came from the new federal efficiency standards for lighting. Figure 4-2 shows the residential resource potential by major category and cost. The figure shows that the largest remaining savings come from improvements in water-heating efficiency and heating, ventilating, and air conditioning (HVAC) efficiency. These increases in residential sector potential stem from greater availability of heat pump water heaters, the introduction of ductless heat pumps to the U.S. market, and cost reductions for high-efficiency heat pumps.

Since the adoption of the Council's Fifth Power Plan, the Northwest Energy Efficiency Alliance (NEEA), with the support of the Bonneville Power Administration and other regional utilities, and in cooperation with the Energy Trust of Oregon, launched a regionwide market transformation program to encourage the installation of split-system heat pumps. These systems, referred to as "ductless heat pumps," do not use forced-air ducts to perform their heating and cooling function. Instead, they distribute the hot or cold refrigerant created by an outside unit to inside units through refrigerant lines. The advantage of these systems is that they can be more easily installed in homes with electric resistance zonal heating systems (baseboard, ceiling radiant, or wall fan units). While these systems are used throughout Northern Europe and all across Asia, Australia, and New Zealand, they have only recently been promoted in the U.S. If the savings and cost estimates adopted by the Regional Technical Forum are confirmed through NEEA's market transformation venture, this technology has the potential to reduce regional space-heating use by approximately 200 average megawatts at a cost of less than $60 per megawatt-hour.

The Council's Fifth Power Plan estimated that regional electric water-heating use could be reduced by approximately 250 average megawatts through the installation of heat pump water heaters commercially available at the time of the plan's adoption.[4] However, since there were no major water heater manufacturers producing heat pump water heaters, the Council's estimate of potential savings from these heaters fell short.

[4] A heat pump water heater uses a compressor that circulates hot refrigerant through a heat exchanger in a water tank to heat water rather than electric resistance elements.

Figure 4-2: Residential-Sector Achievable Conservation by Sector and Levelized Cost



In the past year, three major U.S. water heater manufacturers have announced that they will begin producing heat pump water heaters by the end of 2009. Consequently, the Council raised its estimate of the maximum penetration of these systems from 25 percent of single family and manufactured homes with electric water heat to 50 percent. Nevertheless, since these are new products, it is likely that their initial market penetration rates will be modest. The Council assumes that by the end of 2014 the market share of these heaters will be just over 1 percent. However, by 2030 heat pump water heaters could reduce regional electric water heating use by over 600 average megawatts at a cost less than $30 per megawatt-hour.

The third largest increase in residential sector potential came from the lower costs of high-efficiency heat pumps. When the Fifth Power Plan was adopted, the minimum federal standards for heat pumps and air conditioners had just gone into effect. As a result, there was little price competition among products that exceeded these new standards. Based on program data obtained from the Energy Trust of Oregon, high performance heat pump costs have come down. Moreover, it now appears that heat pumps with a minimum performance level of 17 percent above the federal standards are more cost competitive than those that only exceed the federal standards by 10 percent. At a levelized life-cycle cost of less than $60 per megawatt-hour, there are almost 120 average megawatts of savings available from converting existing single family and manufactured homes with electric forced-air furnaces to high-performance heat pumps. At less than $70 per megawatt-hour, the potential savings increase to over 340 average megawatts.

Agriculture Sector

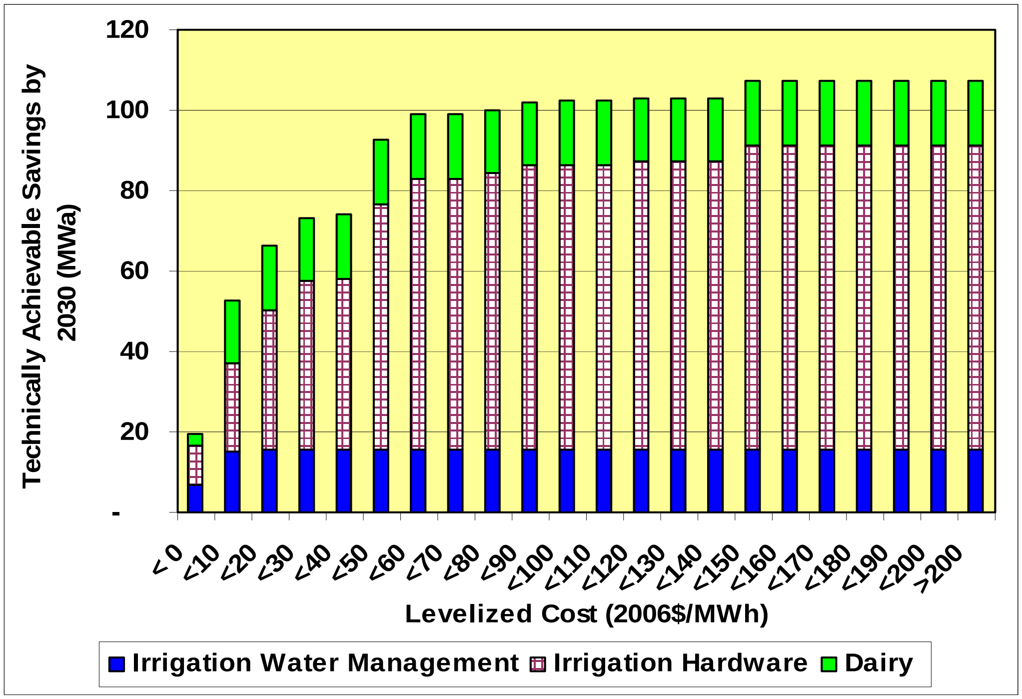
The Fifth Power Plan identified approximately 100 average megawatts of conservation potential available in the region through efficiency improvements in irrigation system hardware. Since the Fifth Power Plan, almost 685,000 acres have been added as land irrigated by pressurized sprinkler systems. However, due to improvements in system efficiency, such as the conversion to low-pressure delivery systems and improved water management, total estimated regional electricity use for irrigation decreased from 655 average megawatts to 645 average megawatts.

After accounting for these changes, the Council estimates that approximately 75 average megawatts of conservation remains available through hardware efficiency improvements such as pump efficiency, leak reduction, conversion to lower pressure applications, and better sprinkler/nozzle management practices at costs significantly below $100 per megawatt-hour.

Along with improving irrigation system hardware, better water management practices could also reduce the energy consumed in irrigation. Despite some of the measure’s limitations due to state-specific water laws, over 15 average megawatts of conservation potential are available in the region through scientific irrigation water scheduling. More potential exists if mechanisms can be found to ensure that irrigation water savings on one farm are not consumed by additional irrigation on farms with junior water rights.

Non-irrigation “on farm” electricity use in the remainder of the agriculture sector is dominated by dairy milk production. According to the Department of Agriculture, the region produced approximately 20 billion pounds of milk in 2007. Idaho and Washington rank among the top 10 states in milk production and Oregon ranks 18. The Council estimates that 2007 electricity use for dairy milk production was approximately 55 average megawatts. Many of the dairies in the region, and particularly in Idaho, were established and/or enlarged within the last decade. Consequently, many already have energy-efficient lighting, pumps, and milk cooling equipment. Nevertheless, the Council estimates that approximately 15 average megawatts of conservation potential is available through improvements such as variable-speed drives on milking machine vacuum pumps, the use of flat-plate heat exchangers for pre-cooling milk prior to refrigeration, and improved lighting. A summary of the technically achievable conservation in the agriculture sector is shown in Figure 4-3

Figure 4-3: Agriculture Sector Achievable Conservation by 2030 (MWa) by Sector and Levelized Cost



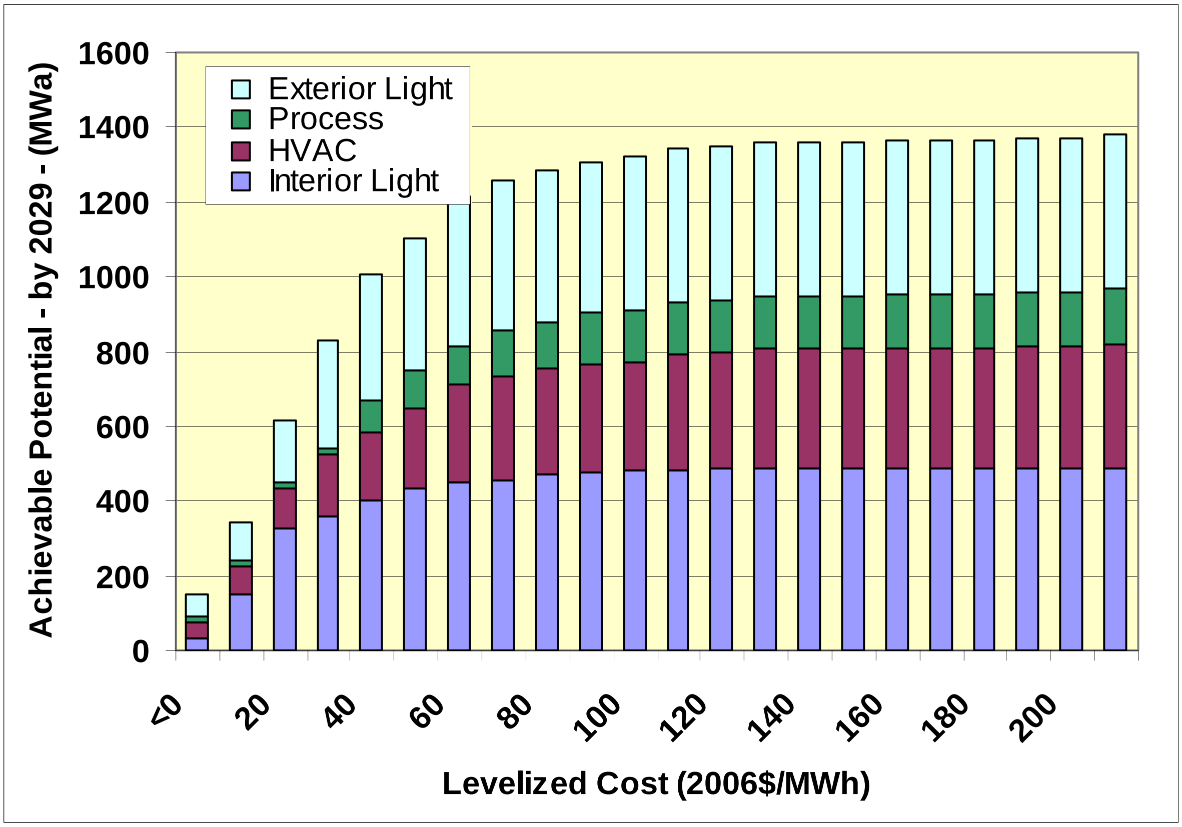
Commercial Sector

Over 250 commercial-sector conservation measures were analyzed to develop the conservation potential for the Sixth Power Plan. The assessment includes lighting, heating, ventilation, and air conditioning (HVAC), and envelope measures in 19 separate building types such as offices, retail stores, warehouses, and schools. The assessment covers several classes of electricity-intensive process equipment used in buildings such as refrigerators, computers, and ventilation hoods. The assessment also covers infrastructure activities such as street and highway lighting, municipal sewage treatment, and municipal water supply.

The aggregate Sixth Power Plan conservation potential is similar to what was identified in the Fifth Power Plan, about 1,400 average megawatts. However, the allocations are different. For the Sixth Power Plan, there is more conservation potential in lighting and less in HVAC. Updated analysis has reduced conservation potential for several key HVAC measures that appeared in the Fifth Power Plan. However, new technology and design practices in lighting offer more potential than identified five years ago. In addition, the Sixth Power Plan identifies savings in areas not addressed in the Fifth Power Plan, including interior lighting controls, outdoor lighting, street and highway lighting, and computer server rooms. A summary of the supply curves by major end-use category is shown in Figure 4-4.

Lighting efficiency measures top the list of commercial conservation potential. Improvements in fluorescent lights, fixture efficiency, lighting controls, and improved lighting design contribute to the large and low-cost potential available for indoor lighting. The availability of new lights such as light-emitting diodes (LED) and improved emerging technologies such as ceramic metal halide lighting also contribute to the large lighting conservation potential. For example, streetlight, parking lot, and outdoor-area lighting can now take advantage of emerging LED technology in certain applications and reduce consumption 25 to 50 percent.

Figure 4-4: Achievable Commercial Sector Savings Potential by 2029 (MWa) by End Use and Levelized Cost



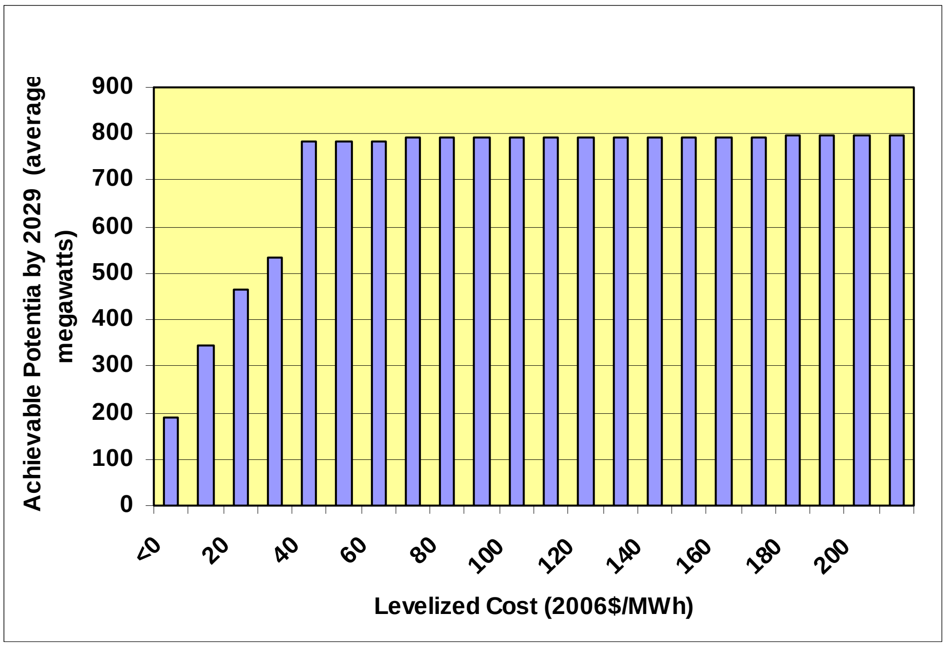
Nearly two-thirds of commercial-sector conservation potential identified in the Sixth Power Plan is lost-opportunity conservation. The increase in lost-opportunity conservation compared to the Fifth Power Plan is primarily due to a revised approach to modeling natural lighting stock turnover as a lost-opportunity conservation measure. Retrofit conservation is more expensive than lost-opportunity conservation, so overall costs of commercial conservation are somewhat lower than in the Fifth Power Plan. Two-thirds of the conservation potential costs less than $40 per megawatt-hour.

Much of the remaining conservation potential in the commercial sector requires a high degree of human intervention to achieve it. For example, careful choice of lamp, ballast, fixture, control, and layout are needed to install highly-efficient lighting systems with excellent visual characteristics. In order to increase a building's efficiency beyond energy code requirements, improved building design practices are also needed. Relatively sophisticated HVAC engineering, smart control systems, and careful system operations are needed to harvest much of the low-cost HVAC energy savings. In addition, the commercial sector is complex, with a variety of decisionmakers and market channels that can deliver high-efficiency equipment and well-trained designers and system operators. Implementation strategies will need to take these factors into consideration in the design of efficiency programs and market interventions.

Industrial Sector

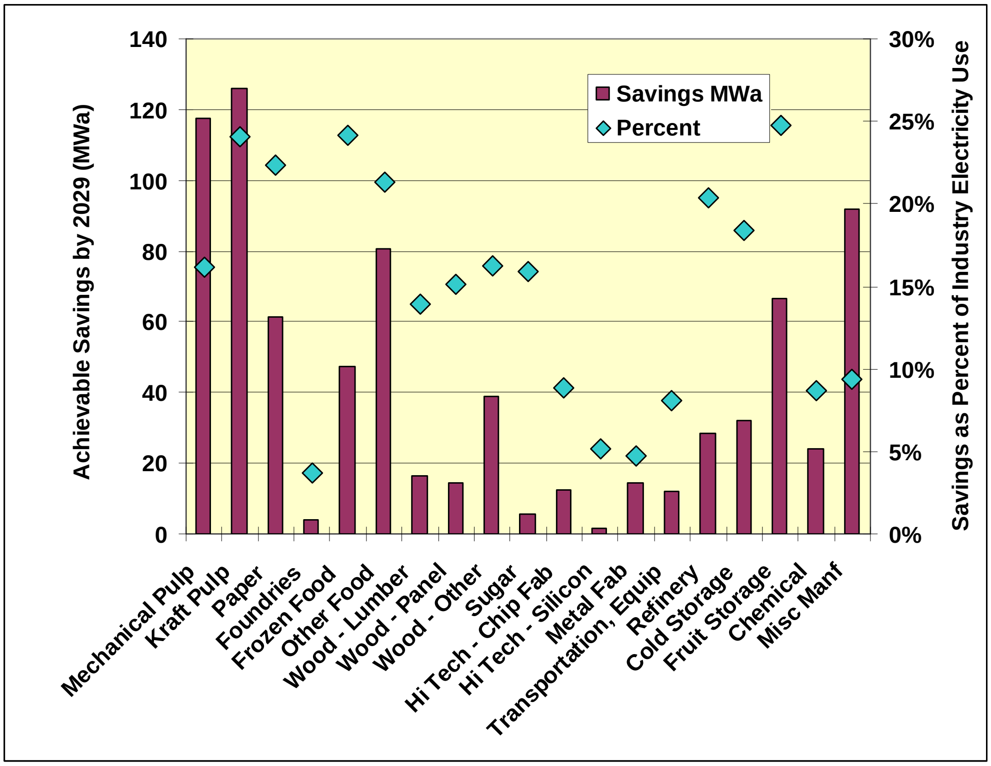
In the Fifth Power Plan, the industrial sector's potential was estimated to be 5 percent of 2025 sales, or 350 average megawatts. For the Sixth Power Plan, the Council, with financial support from the Bonneville Power Administration, contracted an in-depth study of industrial-sector potential. The industrial-sector conservation assessment evaluates 60 conservation measures and practices as they apply to 19 Northwest industries. This research indicates potential savings of about 800 average megawatts by 2029. Industrial savings are low cost. Nearly all of the savings have levelized costs of less than $50 per megawatt-hour. Almost half the savings costs $20 per megawatt-hour or less. Figure 4-5 shows the savings achievable by 2029 in the industrial sector.

Figure 4-5: Achievable Industrial Sector Savings Potential by 2029 (MWa) by Levelized Cost



Savings vary by industry both in average megawatts and as a fraction of industry electric use. The pulp and paper industry has the largest overall potential for electric savings, over 300 average megawatts. The food processing and food storage industries are the second largest with over 230 average megawatts of potential. Savings as a fraction of electricity use range from 4 percent in foundries to nearly 25 percent. Savings fractions are relatively high in the food processing and storage industries. These facilities use large amounts of electricity for refrigeration, freezing, and controlled-atmosphere storage. Significant efficiency improvements are available for those end-uses. Sectorwide, potential savings are about 15 percent of industry electric use. Figure 4-6 shows savings for the industry subsectors.

Figure 4-6: Achievable Industrial Sector Savings Potential by Industry Subsector



The 60 measures include an array of efficient equipment, improved operations and maintenance, demand reduction, system-sizing, system optimization, and improved business management practices. About one-quarter of the savings are specific to industry subsectors such as refiner plate improvements in mechanical pulping, or refrigeration improvements in frozen food processing. About three-quarters of the savings are applicable in pump, fan, compressed air, lighting, and material handling systems that occur across most industry subsectors. For these measures, the savings come primarily from more efficient equipment and system optimization. The assessment also found that effective business management practices can significantly increase equipment and operational savings.

Most industrial conservation measures are complex and require considerable design and careful implementation. Many measures and practices need continuing management and operational attention to ensure continued savings. The human factor to achieve these savings is also critical. Implementation strategies will need to take these factors into consideration in the design of efficiency programs and market interventions.

Utility Distribution Systems

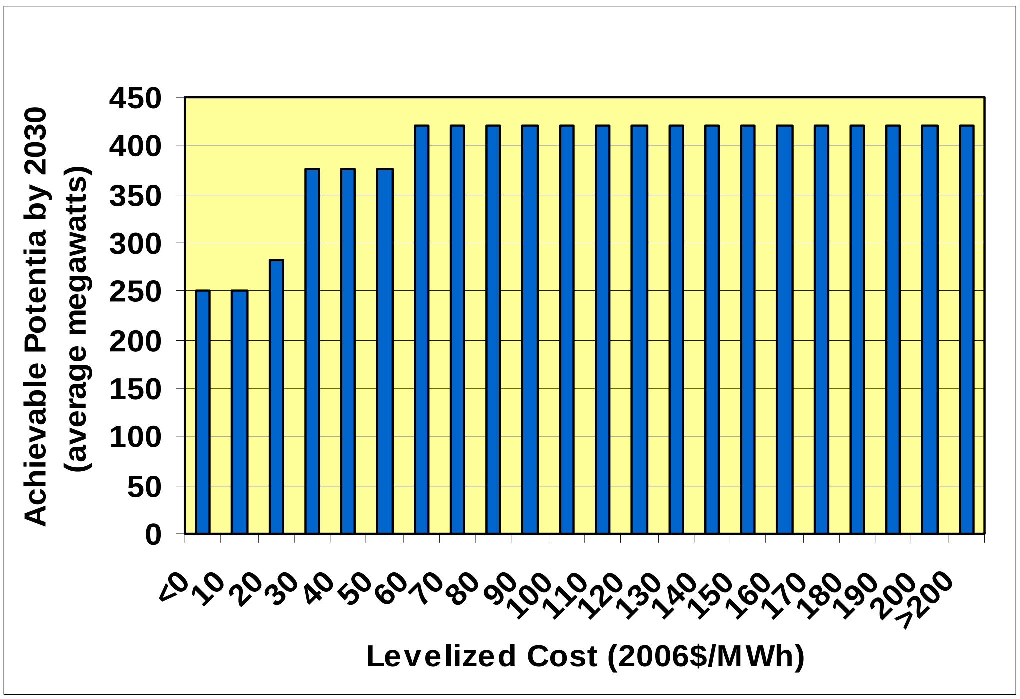
Potential savings from utility distribution systems come from a NEEA project to improve the efficiency of utility distribution systems. Based on the results of a pilot program in six utilities across the region, the study demonstrated that operating a utility distribution system in the lower portion of the acceptable voltage range (120-114 volts) saves energy, reduces demand, and reduces reactive power requirements without hurting the customer. As a package, these measures are referred to as conservation voltage reduction.

Reducing excess voltage saves energy for both the customer and the utility. Savings could amount to over 400 average megawatts by 2029. Levelized costs for distribution savings are low. Figure 4-7 shows that two-thirds of potential savings cost less than $30 per megawatt-hour.

These savings stem from several types of changes to distribution equipment and operations. They include system improvements that reduce primary and secondary line losses, optimize reactive power management on substation feeders and transformers, and balance feeder voltage and current. These improvements help limit the total voltage drop on the feeder from the substation to the customer's meter while staying within industry standards. The NEEA study results indicate energy savings of 1 to 3 percent, a kilowatt peak-demand reduction of 2 to 5 percent, and a reactive power reduction of 5 to 10 percent. Approximately 10 to 40 percent of the savings are on the utility side of the meter.

There are a number of barriers, however, to implementing voltage regulation. These include regulatory disincentives, the need for outside assistance, lack of verification protocols to prove savings, and organizational challenges within utilities. The Council believes most of these barriers can be addressed and that near-term savings are achievable.

Figure 4-7: Achievable Utility Distribution System Efficiency Savings Potential (MWa) by Levelized Cost



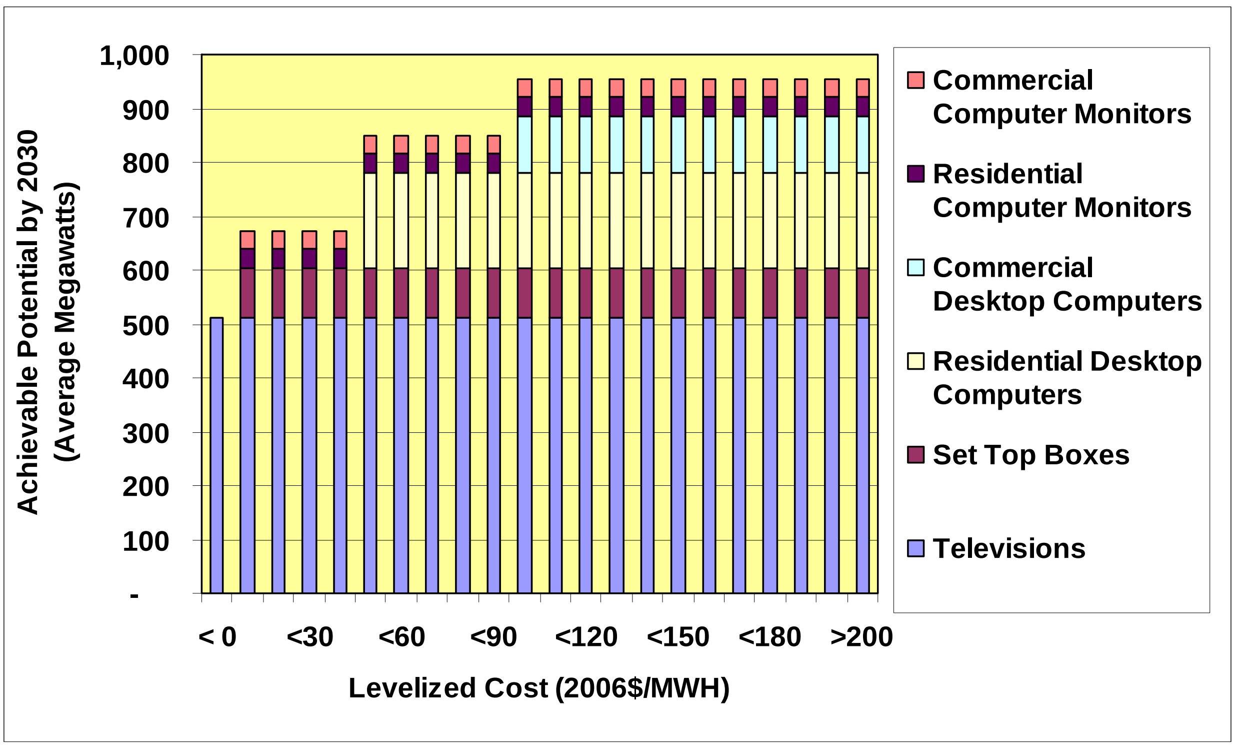
Consumer Electronics

Consumer electronics, such as televisions, set top boxes (digital video recorders, satellite and cable television tuners, digital television converters), computers and monitors, is one of the fastest growing segments of electricity use in the region. This increase is driven by both the growth of these devices and the additional features that increase energy use. For example, in 2007, the number of televisions in the average home exceeded (2.73) the average number of occupants (2.6) for the very first time. If current trends continue, it is anticipated that by 2015 over 90 percent of the televisions sold will have screen sizes exceeding 32 inches. Energy consumption increases with screen size.

There are a significant number of options available to increase the efficiency of these devices. Some of these options simply involve better power management of this equipment when it is not in use. Other options, especially for televisions and computer monitors, will involve the transition from plasma and liquid crystal display (LCD) screens to LED and OLED screens. LED televisions already on the market consume 40 percent less than comparably sized models using LCD technology, while also producing a higher quality picture.

Figure 4-8 shows the achievable potential from improvements in consumer electronics totaling nearly 1,000 average megawatts by the year 2029. Most of the savings potential, over 800 average megawatts, is available at a levelized life-cycle cost of less than $60 per megawatt-hour. Moreover, as can be seen in this figure, over half of these savings are from improving the efficiency of televisions.

Figure 4-8: Consumer Electronics Savings Potential by Levelized Cost



ESTIMATING THE AVAILABILITY OF CONSERVATION OVER TIME

The Council establishes constraints on the availability of the conservation in these supply curves, which are used in the Council's portfolio modeling process. The portfolio model selects the quantity and timing of both generating and conservation resource development. Because significant quantities of conservation are available at costs below most forecasts of future market prices, the portfolio model would deploy all of the low-cost conservation immediately, unless the pace of conservation deployment is constrained to achievable rates.

Therefore, the Council establishes two types of constraints on the amount of conservation available for development. The first constraint is the maximum achievable potential over the 20-year period covered by the Council's Power Plan. The Sixth Power Plan assumes that no more than 85 percent of the technically feasible and cost-effective savings can be achieved.[5]

The second constraint is the rate of annual deployment, which represents the upper limit of annual conservation resource development based on implementation capacity. Such constraints include the relative ease or difficulty of market penetration, regional experience with the measures, likely implementation strategies and market delivery channels, availability of qualified installers and equipment, the number of units that must be addressed, the potential for adoption by building code or appliance standards, and other factors.

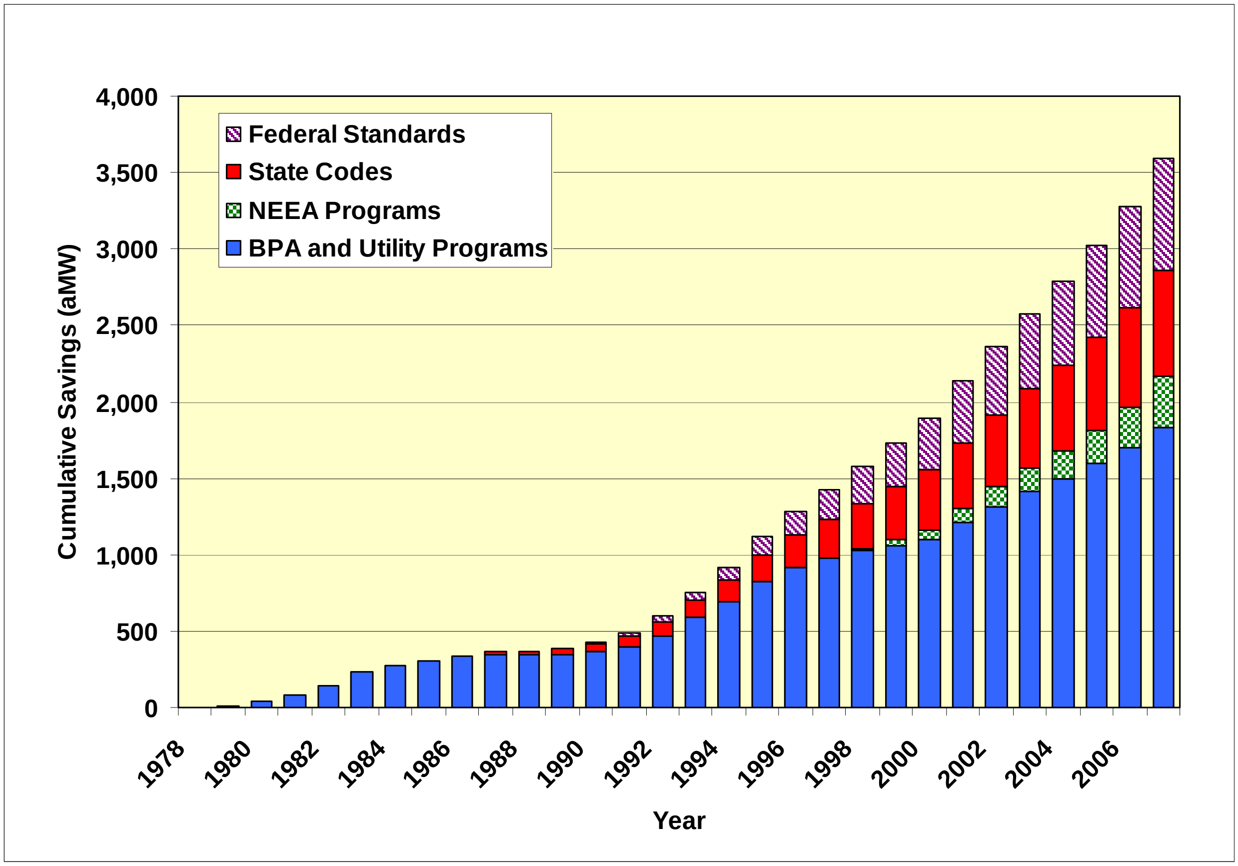
The upper limit of annual conservation resource development reflects the Council's estimate of the maximum that is realistically achievable. Since there is no perfect way to know this limit, the Council used several approaches to develop estimates of annual achievable conservation limits. First, the Council reviewed historic regional conservation achievements and considered total achievements, as well as year-to-year changes. The Council also considered future annual pace constraints for the mix of conservation measures and practices on a measure-by-measure basis. As in the Fifth Power Plan, annual deployment limits were developed separately for lost-opportunity and non-lost opportunity conservation.

The Pace of Historic Conservation Achievements

Over the last 30 years, the region acquired more than 3,500 average megawatts in energy savings. Annual rates of conservation acquisition vary considerably. Figure 4-9 shows the Council's estimate of cumulative regional conservation achievements since 1978. Figure 4-10 shows annual program conservation acquisitions since 1991, excluding savings from codes or standards.

[5] In 2007, Council staff compared the region's historical achievements against this 85 percent planning assumption. The results of this review supported continued use of the estimate, or perhaps even the adoption a higher one in the Sixth Power Plan. The paper is on the Council website at http://www.nwcouncil.org/library/2007/2007-13.htm.

Figure 4-9: Cumulative Regional Conservation Achievement 1978-2007 (MWa)

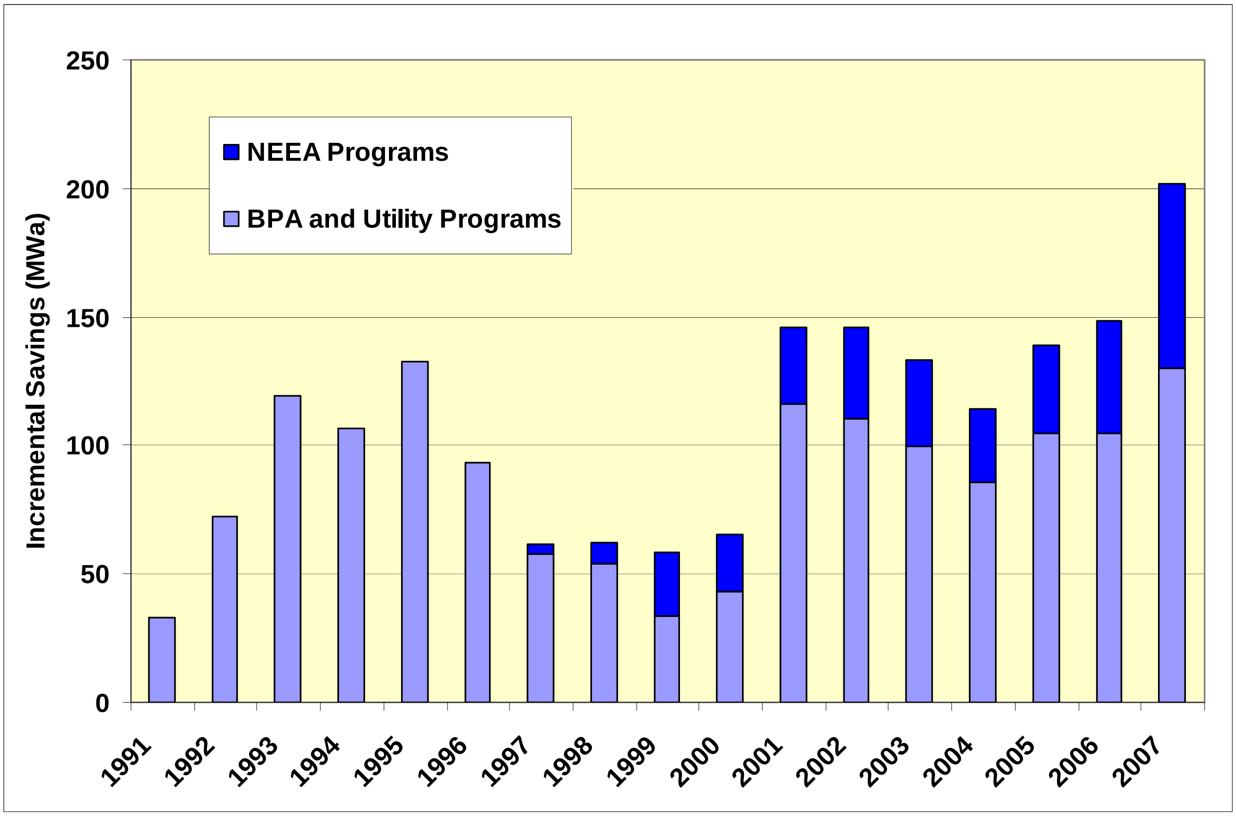


Over this 30-year period, the mix of measures has changed significantly. Early years were dominated by residential programs. In the 1990s commercial and industrial programs were added. Starting in the mid-1980s, state building codes began to capture significant savings. About five years later, federal appliance standards also added savings. Fluctuations in annual achievements, shown in figure 4.10, were caused by many factors. For example, response to the energy crisis of 2000-2001 brought on a surge in conservation achievement, more than doubling the annual conservation acquisition rate between 2000 and 2001. And the threat of retail competition in the late-1990s was a key factor in the drop in utility-sponsored conservation activity in that period.

Over the last 20 years, state building codes and federal and state appliance standards have accounted for over one-third of all savings. Savings from codes and standards accumulate slowly over time. They do not result in large annual jumps in acquisition because they apply only to new buildings or replacement equipment. Furthermore, code and standard savings would not have been possible without utility programs that demonstrated the savings could be achieved.

Bonneville, utility, and Energy Trust of Oregon conservation programs, Oregon tax credits, NEEA market transformation, and other programs have delivered the bulk of the savings over time. Annually, these program savings ranged from lows of about 60 average megawatts per year to 200 average megawatts per year in 2007, the most recent year reported. Since 2001, regional programs, without codes and standards, delivered about 150 average megawatts per year on average. Annual rates of program acquisition since 2001 have been between 115 to 200 average megawatts per year, which is consistently higher than long-term annual rates for program delivery.

Figure 4-10: Annual Conservation Achievements from Programs 1991-2007 (MWa)



There were three historic periods when program savings showed fast acceleration. The 1991-1993 period, the 2000-2001 period, and more recently the 2005-2007 period. During these periods, regional program activities increased by over 40 average megawatts year-to-year, not counting codes and standards.

While complete data are not available for 2008, preliminary surveys indicate that regional program savings alone will be in the range of 220 average megawatts. Consequently, recent savings exceed the targets established in the Fifth Power Plan by a wide margin. The Fifth Power Plan's called for a cumulative 700 average megawatts between 2005 and 2009. Early indications are the region will capture about 1000 average megawatts, exceeding the targets by about 40 percent. A large part of that success is due to higher penetration of compact fluorescent lamps, than anticipated in the 5th Power Plan.

Regional savings in 2007 and 2008 include about 75 average megawatts from the sale of compact fluorescent light bulbs (CFL), a substantial portion of which are not in the conservation assessment going forward since they are covered by the federal standards. The 2007 suite of programs (without CFLs) has achieved about 140 average megawatts per year in 2007 and 2008. The Council believes that non-CFL program accomplishments have been on the increase since 2007 based on preliminary reports from large utilities and system benefits administrators. Furthermore, non-CFL acquisitions would likely have been higher if the region had not been so successful at deploying residential CFLs to exceed near-term conservation targets. Summing up, it appears that at a minimum the region can achieve about 150 average megawatts per year of non-CFL savings based on the current pace of activity and the suite of existing programs and measures.

New measures identified in the Sixth Power Plan and increased penetration rates for existing programs could add significantly to future annual acquisition rates. For example, the Council estimates that 150 average megawatts of potential residential retrofit lighting savings are available by replacing incandescent lamps not covered by recently enacted federal standards with compact fluorescent lamps or lamps of similar efficacy. An additional 85 average megawatts of potential savings are available from the replacement of residential showerheads with more efficient fixtures. Since utility programs and infrastructure already are in place, these savings could be captured over a five to seven year period. Thus, by ramping in these two measures alone, utilities could immediately add 50 to 65 average megawatts of savings to the 150 average megawatts savings they are currently acquiring from measures other than CFLs covered by federal standards.

Estimating the Annual Achievable Pace of Future Conservation Development

To gauge the pace for future conservation development, the Council estimated how fast the region could develop the remaining conservation measures identified in the Sixth Power Plan. To do this, the Council estimated year-by-year acquisition rates for each of the measure bundles identified in the conservation assessment.

The results of this year-by-year and measure-by-measure analysis are only one indication of how fast the region could deploy conservation. Clearly, deployment efforts could shift from the assumptions made in this analysis. Acquisitions of specific measure bundles could accelerate or slow down. Nevertheless, the annual limits give some idea of how fast conservation could be brought on line with multi-year acquisition strategies, ramp-up rates for new programs, and a more or less steady pace in the long run.

There are about 200 measure bundles that were considered in this analysis. Details of these assumptions are in the conservation appendices.

In estimating the level of conservation that could be achieved in the future, the Council considered several factors. For all measure bundles, the Council assumed multi-year acquisition plans. Depending on the measure, getting to full penetration could take as little as five years or as long as 20 years. The Council also considered retrofit and lost-opportunity measures differently. Table 4.2 shows the results of the year-by-year, measure-by-measure approach used to estimate the pace of conservation development.

Table 4-2: Achievable Pace of Future Conservation Development Approximate Savings by Time Period (MWa)

	Lost Opp	Non-Lost Opp	Total
20-Yr Cumulative	3,200	2,600	5,800
5-Yr Cumulative (2010-2014)	370	900	1,270
5-Yr Annual Average	70	180	250
5-Yr Ramp Up	30 to 110	160 to 200	190 to 310
10-Yr Cumulative (2010-2019)	1,200	1,700	2,900
10-Yr Annual Average	120	170	290
10-Yr Ramp Up	30 to 200	160 to 160	190 to 370

Most retrofit measures were paced at annual acquisition rates that require 15 to 20 years to accomplish. However, it was assumed that some retrofit measure bundles with simple, proven delivery mechanisms, like low-flow showerheads, could be accomplished in as little as five years. Annual acquisition rates for new retrofit initiatives or measures that have not been targeted previously, such as distribution-efficiency, were estimated to start slowly and accelerate to a steady annual pace. As a result, these new retrofit measures account for only about 20 percent of this five-year total because low penetration rates were assumed in the early years. Measures that are already targeted by current programs were assumed to accelerate from a higher starting point. Across all retrofit opportunities the overall ramp-up increases from about 160 average megawatts in 2010 to 200 average megawatts per year by 2014, averaging about 160 average megawatts per year over the five-year period. In aggregate, this results in nearly 900 average megawatts of retrofit conservation viewed as achievable. This is only about one-third of the over 2,400 average megawatts of retrofit conservation available at an average cost of $30 per megawatt-hour in the Council's supply curve. At an average pace of 160 average megawatts per year, it would take about 15 years to acquire all 2,400 average megawatts of this potential.

It was assumed that the maximum achievable pace of acquisition for lost-opportunity resources never exceeds 85 percent of the annual units available. The bulk of lost-opportunity measures were assumed to take five to 15 years to reach this 85 percent annual penetration rate. Lower (0.5 to 15 percent) first-year penetration rates were assumed for new lost-opportunity resources because acquiring these measures is slower given the relative difficulty of deploying them. For lost-opportunity measures where the region has experience and ongoing programs, such as residential appliances, first-year penetration rates were set relatively higher and with a faster ramp-up rate over time.

The annual acquisition for all lost-opportunity conservation measures start at a penetration rate of about 15 percent, increases to around 80 percent in 12 years, and reaches the assumed maximum 85 percent in 15 years. In aggregate, this results in about 370 average megawatts of savings from lost-opportunity conservation resources over the first five-years covered by the Sixth Power Plan. About one-third of these savings are from new measures in the plan. The maximum annual pace for lost-opportunity conservation accelerates from 30 average megawatts per year in 2010 to 110 average megawatts per year five years out, and to 200 average megawatts per year 10 years out.

In combination, this analysis indicates that nearly 1300 average megawatts of lost-opportunity and retrofit conservation are achievable over the 2010-2014 action plan period. Maximum annual average acquisitions increase from nearly 200 average megawatts per year in 2010 to about 350 average megawatts per year within 10 years. The estimates of acquisition rates produced by this analysis are used to estimate annual pacing constraints in the portfolio model. Along with information on historic performance, and utility and NEEA plans, these estimates also help inform the Council's near-term conservation targets for the region.

Testing Annual Pace Constraints for the Portfolio Model

Because the maximum annual pace of conservation achievement is to a major extent a function of the level of resources dedicated to acquiring conservation, the Council performed sensitivity tests to estimate the impact of achieving conservation faster and slower than assumed in the base case. For a high-case sensitivity, the Council assumed a 10-year period to develop the first 2,400 average megawatts of retrofit conservation, instead of the 15 years assumed in the base case. This means an average pace of 220 average megawatts per year for retrofit conservation and no increase in the ramp-up for lost-opportunity conservation. For the low-case sensitivity, the Council assumed that no more than 100 average megawatts per year of retrofit conservation could be developed, and the lost-opportunity ramp-up would take 20 years to reach 85 percent annual penetration, instead of 15 years in the base case. At the high-case sensitivity, 1,500 average megawatts could be developed over the first five years of the action plan. For the low-case only about 800 average megawatts would be developed in the five years of the action plan. The results of these sensitivity tests are discussed in Chapter 9.

Figures 4-11 and 4-12 show the maximum annual conservation rates used as the base case assumptions and the high- and low-conservation sensitivity cases.

Figure 4-11: Maximum Conservation Acquisition Rates Tested for Non-Lost-Opportunity Conservation

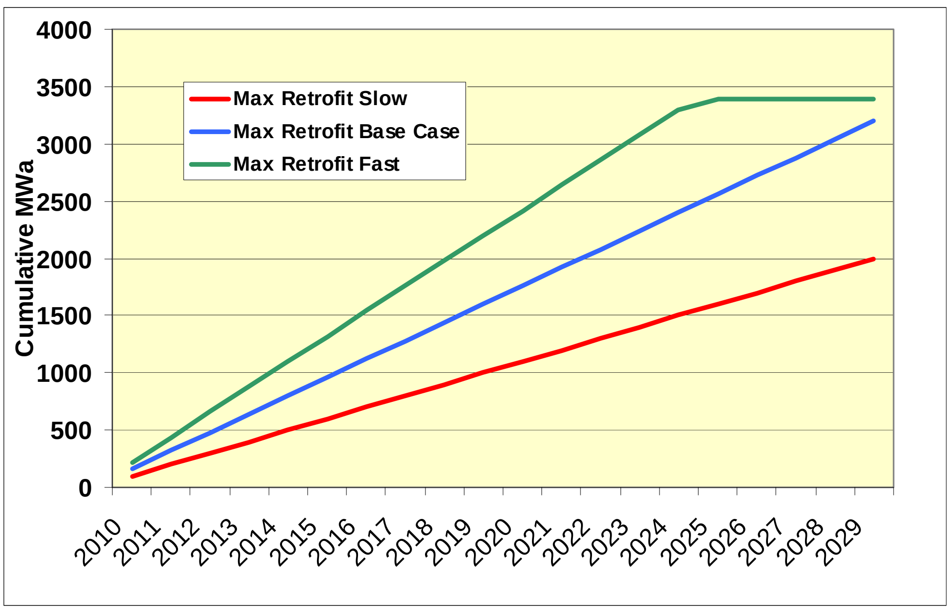
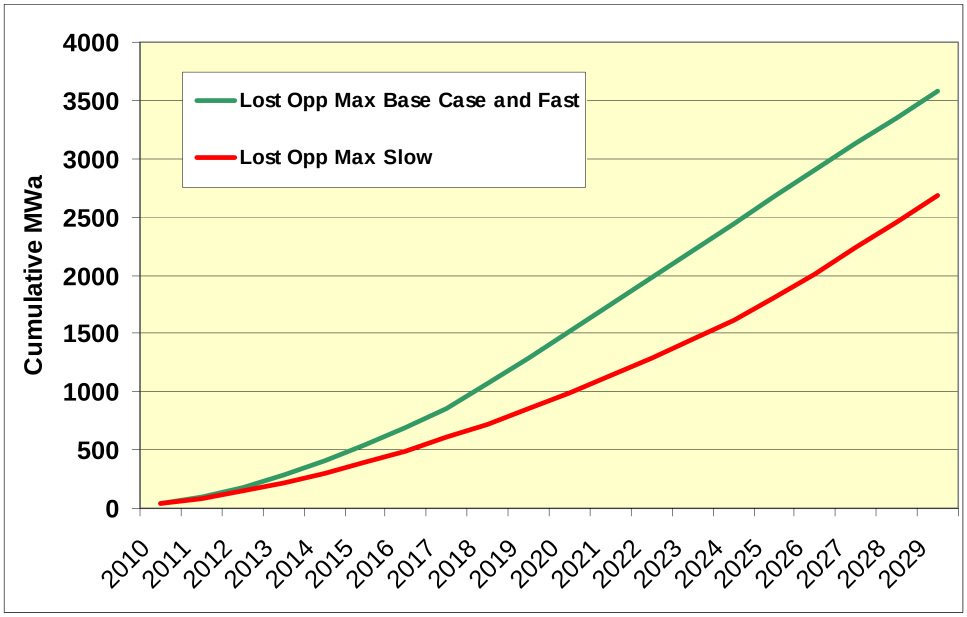


Figure 4-12: Maximum Conservation Acquisition Rates Tested for Lost-Opportunity Conservation



COUNCIL METHODOLOGY

The Northwest Power Act establishes three criteria for resources included in the Council's power plans: resources must be 1) reliable, 2) available within the time they are needed, and 3) available at an estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative.[6] Beginning with its first Power Plan in 1983, the Council interpreted these requirements to mean that conservation resources included in the plans must be:

- Technically feasible (reliable)
- Economically feasible (lower cost)
- Achievable (available)

Development of the conservation potential assessment takes into account an assessment of what has been accomplished and what remains to be done. The first step in the Council's methodology is to identify all of the technically feasible potential conservation savings in the region. This involves reviewing a wide array of commercially available technologies and practices for which there is documented evidence of electricity savings. Over 300 specific conservation measures were evaluated in developing the conservation potential for the Sixth Power Plan. This step also involves determining the number of potential applications in the region for each of these technologies or practices. For example, electricity savings from high-efficiency water heaters are only "technically feasible" in homes that have, or are forecast to have, electric water heaters. Similarly, increasing attic insulation in homes can only produce

[6] See Section 839a(4)(A)(i) and (ii) of the Northwest Power Planning and Conservation Act. (http://www.nwcouncil.org/library/poweract/3_definitions.htm or http://www.nwcouncil.org/LIBRARY/poweract/poweract.pdf)

electricity savings in electrically heated homes that do not already have fully insulated attics. At the conclusion of this step, the Council's load forecast and conservation assessment are adjusted and calibrated to reflect changes in baseline conditions since the adoption of the Fifth Power Plan.

The Sixth Power Plan's assessment reflects program accomplishments, changes in codes and standards, technological evolution, and the overall adoption of more energy-efficient equipment and practices since the Fifth Power Plan was adopted in 2004. There are five significant changes:

1. Accounting for utility conservation program savings since 2004.

2. Adjusting both the load forecast and the conservation assessment to reflect improvements in federal and state standards for lighting and appliances.

3. Adding potential savings from utility distribution efficiency improvements and consumer electronics.

4. Increasing potential industrial savings from a more in-depth analysis.

5. Adding potential savings from new technologies and practices that have matured to commercial readiness since the Fifth Power Plan's estimates were developed.

Implications for the State of Washington's I-937 Requirements

Initiative 937 (I-937) in the State of Washington, approved by the voters in 2006, obligates seventeen utilities that serve 88% of the retail load in that state to "pursue all available conservation that is cost-effective, reliable, and feasible." By January 2010, each utility to which the law applies must develop a conservation plan that identifies its "achievable cost-effective potential" for the next ten years, "using methodologies consistent with those used by the Pacific Northwest electric power and conservation planning council in its most recently published regional power plan." Every succeeding two years, the utility must review and update its assessment of conservation potential for the subsequent ten-year period.

I-937 is a matter of state law, and does not alter or obligate the Council in its conservation and power planning under the Northwest Power Act. Similarly, the Council has no authority to interpret or apply or implement I-937 for the utilities and regulators in the State of Washington. But because of the intersection between the two mandates -- the state's utilities are to engage in conservation planning "using methodologies consistent with" the conservation planning methodology used by the Council – it is helpful to understand some of the issues raised by the two planning processes.

There is some misunderstanding that I-937 requires Washington utilities to meet some pro-rata share of the conservation targets in the Power Plan. In fact, I-937 does not require the state's utilities to adopt or meet conservation targets set forth in the Council's plan nor does the plan identify any particular utility's "share" of regional conservation targets. However, I-937 does require utilities to develop their own plan using methods "consistent with" the methodology used in the Council's plan, leaving the utilities discretion to adapt the planning methods to their particular circumstances. To assist Washington consumer-owned utilities in this effort, the Washington Department of Commerce (Commerce),[7] with the assistance of Council staff and others, adopted rules in 2008 that outline the methodology that the Council uses in its conservation planning. Although one sub-section of these rules allows utilities to adopt a share of the Council's regional targets, this is an option, not a requirement. The Washington Utilities and Transportation Commission (UTC) also adopted rules to guide the investor-owned utilities. These rules are not as prescriptive and, per the law, integrate I-937 requirements into ongoing regulatory practice.

Concern has also been expressed about the fact that utilities will need to produce their first I-937 conservation plans at the precise moment the Council is making the transition from the Fifth to the Sixth regional power plan. On this issue we should point out that the Council's methodology is essentially the same in the Sixth and Fifth power plans and is clearly described in Chapter 4 of this draft. The conservation targets are higher in the Sixth Plan because of changes in prices, technology, and other factors, not because of a change in methodology.

The Council's plan describes the analytical methods used to identify cost-effective achievable conservation and provides a menu of possible cost-effective measures for the utilities to consider. Neither I-937 nor the Council's plan requires utilities to choose any of the plan's particular measures in particular amounts. The utilities may make that judgment based on their own loads (composition, amounts, growth rates) and their own determination of avoided cost and the measures available to them.

There are two issues—"ramping" and "penetration rates"—that may present potential inconsistencies between I-937 and the Council's conservation methodology. An important element in the Council's methodology is the principle that it takes time to develop certain conservation measures to their full potential, while other measures are available right away. Consequently, conservation potential ramps up and on occasion ramps down. The Council uses its ramp rate assumptions along with other information and the results of its regional portfolio model to establish five-year cumulative conservation targets for the region. The end result is that achievable conservation potential under the Council's planning assumptions will not be evenly available across each year in the period. I-937 separately instructs the utilities to identify not just cost-effective potential over the ten-year life of the utility's conservation plan for I-937, but also to identity and meet biennial conservation acquisition targets that must be "no lower than the qualifying utility's pro rata share for that two-year period of its cost-effective potential for the subsequent ten-year period." Having to acquire 20 percent of any ten-year target in any two-year period under I-937 may produce different two-year targets than would result using ramp rates consistent with the Council's methodology. Commerce rules do not address what is meant by "pro-rata share," but the UTC rules state that "'pro rata' means the calculation used to establish a minimum level for a conservation target based on a utility's projected ten year conservation potential." Because the provisions of I-937 are a matter of state law, this issue is not one that the Council can resolve in its plan.

A related but distinct issue concerns conservation measure "penetration" rates. Part of the Council's methodology is to estimate the extent of total penetration of a conservation measure in the area of study over the total period analyzed. The Commerce rules address this issue, calling

[7] Formerly the Washington Department of Community Trade and Economic Development (CTED)

on utility conservation plans to "[i]nclude estimates of the achievable customer conservation penetration rates for retrofit measures and for lost-opportunity (long-lived) measures." Because, as with "ramp rates," I-937 requires a ten-year plan while the Council produces a twenty-year plan, the rules needed to harmonize the potential difference between penetration rates over ten years versus penetration rates over twenty years. As a result, the Commerce rules then go on to describe the Council's 20-year and 10-year penetration rates (from the Fifth Plan, although they do not differ in the Sixth Plan), "for use when a utility assesses its" conservation potential. The UTC rules are silent on penetration rates.

One final point to consider is the treatment of savings achieved through building codes and other standards. The Council's conservation methodology calculates the conservation potential for measures that might, at some point, be covered by building codes or energy codes, and then assumes that the savings will be accomplished over time by either utility programs or codes. If codes are adopted that ensure the capture of the potential savings, then those savings are "counted" against the regional target. The rules adopted by Commerce for I-937 do not appear to be inconsistent with this approach while the UTC rules do not address this issue specifically.

Chapter 5: Demand Response

SUMMARY OF KEY FINDINGS

The Council's definition of demand response (DR) is a voluntary and temporary change in consumers' use of electricity when the power system is stressed. The change in use is usually a reduction, although there are situations in which an increase in use would relieve stress on the power system and would qualify as DR.

Demand response could provide value to our power system in four forms. It can provide a form of peaking capacity by reducing load a few hours a year at peak load. It can provide contingency reserves, standing ready to interrupt load if unscheduled generation outages occur. Some demand response could provide flexibility reserves (e.g. load following) by decreasing or increasing load as needed to accommodate small errors in scheduling in virtually all hours of the year. Finally, some demand response could absorb and store energy when its cost is low and return the energy to the system a few hours later when its value is higher.

This plan assumes, based on experience in the region and elsewhere, that the achievable technical potential for demand response in the region is around 5 percent of peak load over the 20-year plan horizon. The plan assumes 1,500 to 1,700 megawatts of load reductions in the winter and summer, respectively, and 2,500 to 2,700 of load reductions together with dispatchable standby generation. This achievable technical potential was included in analysis by the Council's regional portfolio model[1] to determine how much demand response is included in the preferred resource portfolios identified by the model.

The region still lacks the experience with demand response to construct a detailed and comprehensive estimate of its potential. To make that estimate possible, the region will need to conduct a range of pilot programs involving demand response. These pilots should pursue two general objectives, research and development/demonstration.

[1] See Chapter 9 for a description of this analysis.

"Research pilot programs" should explore areas that have not been tried before. These pilot programs should be regarded as programs to buy essential information. They should not be designed or evaluated based on how cost effective each pilot is on a stand-alone basis, but rather based on how much the information gained from each pilot will contribute to a long run demand response strategy that is cost effective overall. Ideally regional utilities and regulators will coordinate these research pilots to avoid duplication of effort. Regulators should allow cost recovery of pilots that contribute to such a strategy.

The region should also pursue "development and demonstration pilot programs" that are designed to test acquisition strategies and customers' reactions to demand response programs that have been proven elsewhere. These pilots will allow the region to move to full-scale acquisition of some elements of demand response while the research pilots expand the potential by adding new elements. The development and demonstration pilots should be designed and evaluated with cost effectiveness in mind, but with the recognition that the product of these pilots includes experience that can make the acquisition program more cost effective.

Both the research pilots and the development and demonstration pilots should include projects to test the practicality of demand response as a source of ancillary services.

DEMAND RESPONSE IN THE FIFTH POWER PLAN

The Council first took up demand response as a potential resource[2] in its Fifth Power Plan.[3] The Fifth Plan explained that concern with demand response rises from the mismatch between power system costs and consumers' prices. While power system costs vary widely from hour to hour as demand and supply circumstances change, consumers generally see prices that change very little in the short term. The result of this mismatch is higher consumption at high cost times, and lower consumption at low cost times, than is optimal. The ultimate result of the mismatch of costs and prices is that the power system needs to build more peaking capacity than is optimal, and uses base load generation less than is optimal. Programs and policies to encourage demand response are efforts to correct these distortions.

The Fifth Plan described pricing and program options to encourage demand response, made a very rough estimate of 2,000 MW of demand response that might be available in the Pacific Northwest over the 2005-2025 period, and described some estimates of the cost effectiveness of demand response. The Plan concluded with an Action Plan to advance the state of knowledge of demand response.

The Fifth Power Plan's treatment of demand response is laid out in more detail in Appendix H of this plan, with references to relevant parts of the Fifth Plan.

[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 response as a resource in the sense of the general definition of the word - "a source of supply or support."

[3] 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

Progress Since the Fifth Power Plan

Since the release of the Fifth Plan, the region has made progress on several fronts. Idaho Power, PacifiCorp and Portland General Electric have expanded existing demand response programs. Portland General Electric and Idaho Power have begun to install advanced metering for all their customers, which facilitates demand response programs and enables time-sensitive pricing. Many utilities in the region are now treating demand response as an alternative to peaking generation in their integrated resource plans.

The Council and the Regulatory Assistance Project (RAP) have worked together to coordinate the Pacific Northwest Demand Response Project (PNDRP), composed of parties interested in the stimulation of demand response in the region. The initial focus of PNDRP has been on three primary issues; defining cost effectiveness of demand response, discussing a role for pricing, and considering the transmission and distribution system costs that can be avoided by demand response.

PNDRP adopted guidelines for cost effectiveness evaluation that are included in Appendices H-1 and H-2. Agreement on these guidelines is a major accomplishment by the region. These cost effectiveness guidelines provide an initial valuation framework for demand response resources and should be considered as a screening tool by state commissions and utilities in the Pacific Northwest. PNDRP has begun the consideration of price structures encouraging demand response.

The Council has extended its analysis of demand response, examining the effect of the cost structure of demand response (i.e. high fixed cost/low variable cost as compared to low fixed cost/high variable cost) on its attractiveness in resource portfolios. This analysis takes into account the benefits of demand response in reducing risk, which other analyses tend to overlook.

The region's system operators have also become increasingly concerned with the system's ability to achieve minute-to-minute balancing of increasingly peaky demands for electricity against generating resources that include increasing amounts of variable generation such as wind. Demand response is recognized as a potential source of some of the "ancillary services" necessary for this balancing.

These areas of progress are covered in more detail in Appendix H.

DEMAND RESPONSE IN THE SIXTH POWER PLAN

Estimation of Available Demand Response

The region has gained much experience in the estimation of conservation potential over the last 30 years but demand response analysis is still in its infancy. For conservation the general approach has been to compile a comprehensive list of conservation measures, analyze their costs and effects, and arrange them in order of increasing cost per kilowatt-hour. Given the resulting supply curve, planners can identify all conservation measures that cost less than the marginal generating resource.[4]

Estimating demand response potential using a similar approach makes perfect sense, and it is the Council's strategy. However, demand response presents some unique problems to this approach. Some of the features that make estimating a supply curve for demand response more complex than estimating one for conservation are listed below and treated in more detail in Appendix H.

- 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.

- Demand response can provide a variety of services to the power system (e.g. peak load service, contingency reserves, regulation, load following) as described in Appendix H. 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 load, 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.

- 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.

- 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.

- Estimates of conservation potential have usually depended on understanding the performance of "hardware" such as insulation and machinery, predictable through an 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.

- The economics of demand response will be powerfully influenced by technological change, particularly the development of "Smart Grid" technologies,[5] 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

[4] The methodology for estimating conservation potential is described in more detail in Appendix E.
[5] See Appendix K

change over the next 20 years, and that the change will make demand response more attractive.

Demand Response Assumptions

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, and 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 the Northwest, studies of potential have been contracted by the Bonneville Power Administration, PacifiCorp, Portland General Electric, and Puget Sound Energy.

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 commercial customers, an "Emergency Demand Response"[6] program for medium and large commercial and industrial customers, capacity market options,[7] customers' participation in a market for ancillary services, and two pricing options. The study estimated potential demand response for each of these 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.

[6] Customers are offered payment for load reductions during system events, but are not penalized if their usage does not change.
[7] 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 percent 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 released, 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. Table 5-1 shows some of this experience. It also shows some scheduled increases in demand response over the next few years; these schedules are based on expansion of existing programs or signed contracts that make the utilities quite confident that the scheduled demand response will be realized.

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.”[8] 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 percent of peak load in firm demand response, and another 1-2 percent 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 committed to achieving a total of 307 megawatts by 2013, pending the expected approval of this plan by the Idaho Public Utility Commission. This level of demand response would be accomplished by converting much of their irrigation demand response to dispatchable[9] and adding demand response from the commercial and industrial sectors. This level would be 8.1 percent 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 percent of its 2021 forecasted peak demand of about 4,400 megawatts.

Portland General Electric had 53 MW of dispatchable standby generation in place in 2009 and expects to have 125 megawatts in place by 2012. PGE is using it to provide contingency reserve, which only operates when another resource is unexpectedly unavailable. This means that while this generation is licensed to operate 400 hours per year, it actually operates a much smaller

[8] 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.

[9] 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.

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. Finally, PGE has 10 megawatts of interruptible contracts with industrial customers. The sum of these three components, 185 megawatts, is equal to 4.1 percent of the company's projected peak load of 4500 megawatts in 2012.

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 percent, according to NYISO staff. The 2,000 megawatts of firm demand response amounts to about 5.9 percent of the NYISO's expected 2009 peak load of 34,059 megawatts. Adding the expected 70 percent of the 300 megawatts of non firm demand response would raise the expected total demand response to 2,210 megawatts, or 6.5 percent 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 percent of the ISO's average weather summer peak load of 27,400 megawatts, (winter 22,775 megawatts).[10]

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 4460 megawatts of demand response in its control area in 2008 compared to a forecasted peak load of 137,950 megawatts[11] or about 3.2 percent of peak load. There may be some demand response in the utilities of states that have been recently added to PJM (Illinois, Ohio, Michigan, and 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.[12] The 2,400 megawatts of total demand response used and available amounted to 4.8 percent 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 percent of the California Energy Commission's forecast of the three utilities' peak loads total for 2011 (53,665 megawatts).[13]

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[10] 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

[11] http://www.pjm.com/documents/~/media/documents/presentations/pjm-summer-2008-reliability-assessment.ashx

[12] "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

[13] 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.

Table 5-1: Demand Response Achieved by System Operator

System Operator	Year Achieved/ Scheduled	Demand Response as % of Peak Load (Achieved/Scheduled)
PacifiCorp	2009	5.1
Idaho Power	2008/2013	1.9/8.1
Portland General Electric	2009/2012	1.4/4.1
New York ISO	2009	5.9 firm, 6.5 expected
New England ISO	2007	8.3
PJM	2008	3.2
California ISO	2006/2011	4.8/6.5

Council Assumptions

Based on these study results and experience elsewhere, 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.[14]

The Council based its assumptions in part on the evidence that demand response of at least 5 percent 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 percent level, depending on whether the dispatchable standby generation is included or not. Without dispatchable standby generation, the assumed potential is 1,500 megawatts in the winter and 1,700 megawatts in the summer (about 3.8 percent and 4.3 percent of the forecast 40,000 megawatt peak load forecast for 2030, respectively). With dispatchable standby generation the totals are 2,500 megawatts in the winter and 2,700 megawatts in the summer, or 6.3 percent and 6.8 percent of forecast peak load, respectively.

The assumptions are summarized in Table 5-2. Three further 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. Finally, these assumptions are used as long run assumptions for the portfolio model, and are not targets for short run utility implementation planning. Targets for implementation result from the portfolio analysis and a strategy to accumulate experience with demand response, described in the Action Items of this chapter, the Implementation Plan and in Chapter 9.

[14] For more information about the working of the portfolio model, see Chapter 8.

Table 5-2: Demand Response Assumptions

Program	MW	Fixed Cost	Variable Cost (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 are described below.

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. 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.

Irrigation. PacifiCorp and Idaho Power are currently reducing irrigation load by nearly 100 megawatts 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 megawatts 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. Experience this summer should support the revision of this assumption before the release of the final version of the Sixth Plan.

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.

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 regional transmission organization in the Mid-Atlantic states (PJM). 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. 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.

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 it became a de facto discount 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 a year. The costs of existing interruptible contracts are considered proprietary, so the Council's cost assumption is based on conversations with aggregators.

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 demand buyback program and 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.[15] 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

[15] These longer-term buybacks were predominantly from Direct Service Industries (DSIs).

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 is expected to be used for contingency reserves, which cannot be represented in the regional portfolio model. The other programs were simulated in the portfolio model, with schedules based[16] on those in Table 5-3. 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 aggregator's component, and the interruptible contracts component were modeled similarly.

Table 5-3: Schedule of Demand Response Programs in the Regional Portfolio Model (MW)

	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

Caveats for Demand Response Assumptions

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 and the programs most cost effective 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.[17] 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. As the region gains more experience the Council will revise these assumptions.

Ongoing Analysis with the Regional Portfolio Model

The portfolio model analysis described in Chapter 9 did not include demand response options in the "efficient frontier," although some demand response options were included in portfolios that were quite close. The Council continues to regard demand response as a resource with

[16] Because of computer run time considerations, the schedules were treated as ten-year blocks. The portfolio model tried various combinations of these blocks to determine which combinations appeared in portfolios on the efficient frontier (see Appendix H). 200 MW of AC and irrigation were assumed adopted in all portfolios to reflect the level of program already adopted by PacifiCorp and Idaho Power, and the 400 MW demand buyback resource was assumed adopted in all portfolios based on its very low fixed costs. The remaining resources were modeled as "optional" i.e. the portfolio model could include them or not in trial portfolios.

[17] See Appendix H for details on the range of demand response potential from this possibility.

significant potential to reduce the cost and risk of a reliable power system. The Action Plan includes further work with the portfolio model to better reflect and estimate the value of demand response. The Action Plan also includes work to understand the potential of demand response to provide ancillary services; this latter work will need to use other approaches, since the portfolio model does not simulate the within-the-hour operation of the power system.

Pricing Structure

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 structure initiatives.

The Pacific Northwest Demand Response Project, co-sponsored by the Council and the Regulatory Assistance Project (see Appendix H) 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). 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.[18]

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.[19] 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

[18] 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.

[19] 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[20] this exchange.[21]

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.[22] 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 4,500 watts, the total connected load is about 15,300 megawatt. 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 5,300 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 5,300 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 6,198 megawatt hours of energy, store it (at the cost

[20] 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, PHEVs have the ability to charge their own batteries, so they are not stranded.
[21] A more detailed description of how PHEVs could contribute to the power system is at Appendix K-1
[22] More details of the potential for water heating as a source of ancillary services is in Appendix K.

of 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.[23]

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.

[23] 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.

Chapter 6: Generating Resources and Energy Storage Technologies

SUMMARY OF KEY FINDINGS

- *Generating resource development will be driven by the need for reliable, economic and low-carbon energy supplies, supplemented as needed with firm capacity to maintain system reliability and balancing reserves to complement variable-output energy resources.*

- *Economic and reliable low carbon energy resources available in abundance in the near-term (2010 - 2015) include "local"[1] wind and natural gas combined-cycle plants. These technologies are commercially mature, economically competitive and relatively easy and quick to develop. Energy from these alternatives ranges from about $80 to $100/MWh.*

- *Other low-to-moderate carbon resources available in the near-term, but in limited quantities include bioresidue energy recovery projects, natural gas and bioresidue cogeneration, conventional geothermal and new and upgraded hydropower projects. These resources are commercially mature and in many cases economically competitive. They are, however, typically small and often challenging to develop. Solar photovoltaics, while commercially mature, low carbon, easy to develop and available in large quantity, is very expensive.*

- *Conventional coal plants are unlikely to be developed in the near-term because of climate policy uncertainty.*

- *In the medium-term (2015 - 2020), remote resources could be accessed via expansions to the transmission system. These include wind from Montana, Alberta or Wyoming and concentrating solar power from Nevada and other southwest areas. These resources are typically 40 to 100% more expensive than comparable local resources because of the transmission investment and low transmission load factor. The "lumpiness", capital cost and lead time of the transmission adds investment risk to these options.*

- *Resources available in the long-term (2020 - 2030) include advanced nuclear and coal gasification combined-cycle plants. Emerging technologies such as wave power, tidal current power, enhanced geothermal, deep water wind turbines, compact nuclear plants, commercial-scale CO_2 sequestration and technologies for the capture of CO_2 from steam-electric coal-fired plants may become commercial during this decade.*

- *Construction costs increased 60 to 100 percent between 2004 and mid-2008, driven by increased commodity cost, declining value of the dollar against overseas currencies and market incentives for wind and other technologies. The weakening global economy and difficulty in securing credit has reversed this trend and costs are declining for most technologies. The timing and level of cost stabilization are highly uncertain.*

- *Significant risk factors include natural gas price volatility and uncertainty (combined-cycle plants), greenhouse gas control policies (coal-fired plants), plant size and lead time (geothermal, nuclear, coal gasification plants, and transmission for importing wind or solar) and technology performance (coal gasification, advanced nuclear plants).*

- *Climate policies will increase the cost of fossil-fuel power generation in proportion to fuel carbon content and plant efficiency. Estimated increases under the mean allowance prices assumed for this plan range from 18% ($14/MWh) for gas combined-cycle plants to 48% ($33/MWh) for coal steam-electric plants. While carbon dioxide separation and sequestration could reduce the cost of compliance, current estimates of the cost and*

[1] "Local" wind refers to wind power not relying on the development of high-capacity, long-distance dedicated transmission.

performance of plants so equipped suggest that these features would not be economic under the mean value of carbon dioxide allowance costs assumed for this plan.

- *Wind power in the Northwest has relied on existing firm capacity and balancing reserves. Continued development of wind and other variable-output energy resources (wave power, tidal current power and solar photovoltaics) will eventually require firm capacity and balancing reserve additions to sustain reliable system operation. Simple- and combined cycle gas turbines, reciprocating engine-generators, compressed air energy storage, flow batteries, pumped storage hydropower and sodium-sulfide batteries can provide firm capacity and balancing reserves. Further analysis is needed to identify the alternatives best suited for the Northwest.*

INTRODUCTION

Electricity is a high value form of energy produced from naturally occurring primary energy sources. These include the fossil fuels (coal, petroleum, and natural gas), geothermal energy, nuclear energy, solar radiation, energy from processes driven by solar radiation (wind, hydropower, biomass production, ocean waves, ocean thermal gradients, ocean currents, and salinity gradients), and tidal energy.

The energy of these primary resources is captured, converted to electricity, and delivered to the end-user by means of energy conversion systems. An energy conversion system may include fuel extraction, fuel transportation and fuel processing, power generation, and transmission and distribution stages. Most power generation technologies are mechanical devices that capture the energy contained in heated, pressurized or moving fluids, and use this energy to drive an electric power generator. Exceptions include fuel cells (solid-state devices that convert the chemical energy of hydrogen into electric power) and photovoltaics (solid-state devices that convert solar irradiation to electric power).

Many primary forms of energy are found in the Northwest, including various biofuels, coal, geothermal, hydropower, marine energy resources, solar, and wind. Others, including natural gas, uranium and petroleum are readily transported into the region. The few resources not available in the Northwest include ocean thermal differentials and ocean currents (both insufficient in the Northwest for practical application) and adequate direct normal solar radiation for concentrating solar thermal plants[2].

Energy storage technologies decouple electricity production from consumption and can be used to can shift energy from lower value to higher value periods and provide firm capacity, balancing reserves and other capacity-related services. Storage technologies appearing to have the greatest value for Northwest application are those with the ability to provide extended energy storage, firm capacity and balancing reserves. These include compressed air energy storage, flow batteries, pumped storage hydro and sodium-sulfur batteries.

Characteristics of potential Northwest generating resources and energy storage technologies are summarized in Table 6-1.

[2] Satellite data suggests that local areas in southwestern Idaho and southeastern Oregon may be suitable for concentrating solar power. Further ground data is needed to confirm this.

Table 6-1: Summary of Generating Resources and Energy Storage Technologies

Resource	Applications	Estimated Undeveloped Potential	Reference Capacity Cost ($/kW-yr)	Reference Energy Cost ($/MWh)	Key Issues
Renewable generating resources					
Hydropower - New	Firm capacity Energy	Low hundreds of MWa?	--	$87	Siting constraints Development cost
Hydropower - Upgrades	Firm capacity Energy Balancing	Low hundreds of MWa?	Highly variable	Variable	
Biogas - Wastewater energy recovery	Capacity Energy	7 - 14 MWa	--	$104	Cost
Biogas - Landfill gas	Firm capacity Energy	80 MWa	--	$77	Competing uses of biogas
Biogas - Animal manure	Firm capacity Energy	57 MWa	--	$101	Cost Competing uses of biogas
Biomass - Woody residues	Firm capacity Energy Cogeneration	665 MWa	--	$96 (CHP) - $123 (No CHP)	Cost CHP revenue Reliable fuel supply
Geothermal - Hydrothermal	Firm capacity Energy	370 MWa	--	$80	Investment risk (Exploration & well field confirmation)
Geothermal - Enhanced	Firm capacity Energy	Thousands of MWa?	--	Not available	Immature technology Cost of commercial technology
Marine - Tidal current	Energy	Low hundreds of MWa?	--	Not available	Immature technology Environmental impacts Competing uses of sites
Marine - Wave	Energy	Low thousands of MWa?	--	Not available	Immature technology Competing uses of seaspace
Marine - Wind	Energy	Thousands of MWa?	--	Not available	Immature technology Competing uses of seaspace
Solar - Photovoltaics	Energy	Abundant	--	$300	Cost Poor load/resource coincidence Availability and cost of balancing services
Solar - Parabolic trough CSP (Nevada)	Firm capacity Energy	600 MWa/500kV circuit	--	OR/WA $222 ID $183	Cost Lack of suitable PNW resource Availability and cost of transmission
Wind - "Local"	Energy	OR/WA - 1410 MWa ID - 215 MWa MT - 80 MWa	--	OR/WA $102 ID $108 MT $88	Availability and cost of balancing services
Wind - Alberta	Energy	760 MWa/+/-500kV DC Ckt	--	OR/WA $135	Availability and cost of balancing services Availability and cost of transmission
Wind - Montana	Energy	570 MWa/500kV Ckt	--	ID $116 OR/WA $143	Availability and cost of balancing services Availability and cost of transmission
Wind - Wyoming	Energy	570 MWa/500kV Ckt	--	ID $120 OR/WA $150	Availability and cost of balancing services Availability and cost of transmission
Waste Heat Recovery					
Bottoming Rankine cycle	Energy	Tens to low hundreds of MW?	--	$55	Suitable host facilities Host facility viability

Resource	Applications	Estimated Undeveloped Potential	Reference Capacity Cost ($/kW-yr)	Reference Energy Cost ($/MWh)	Key Issues
Fossil Generating Resources					
Coal - Steam-electric	Firm capacity Energy	Abundant	--	No CSS ID - $103 (2020) CSS MT>WA via CTS $142 (2025)	GHG policy Immature CO_2 separation technology Lack of commercial CO_2 sequestration facility
Coal - Gasification	Firm capacity Energy Balancing Polygeneration	Abundant	--	No CSS ID - $113 (2020) CSS MT>WA via CTS $141 (2025)	Investment risk Reliability GHG policy Lack of commercial CO_2 sequestration facility
Natural gas - Combined-cycle	Firm capacity Energy Balancing Cogeneration	Abundant	$92[3]	Baseload $90 Probable dispatch $95 - 120	Gas price volatility & uncertainty
Natural Gas - Simple-cycle (Aeroderivative)	Firm capacity Balancing Cogeneration	Abundant	$166	--	Gas price volatility & uncertainty
Natural gas - Simple-cycle (Frame)	Firm capacity Balancing Cogeneration	Abundant	$127	--	Gas price volatility & uncertainty
Natural gas - Reciprocating engine	Firm capacity Energy Balancing Cogeneration	Abundant	$234	$110	Gas price volatility & uncertainty
Petroleum coke - Gasification	Firm capacity Energy Balancing Polygeneration	Abundant	--	Possible reduction in fuel cost offset by increased CO2 allowance or sequestration cost	Investment risk Reliability GHG policy Lack of commercial CO_2 sequestration facility
Nuclear Generating Resources					
Nuclear fission	Firm capacity Energy	Thousands of MW (late in planning period)	--	$109 (2025)	Public acceptance Cost escalation Construction delays Regulatory risk “Single shaft” reliability risk
Energy Storage Systems					
Compressed air energy storage	Firm capacity Balancing Diurnal shaping	Uncertain	Uncertain & site-specific	--	Confirming suitable geology Monetizing system benefits
Flow batteries	Firm capacity Balancing Diurnal shaping	No inherent limits	Uncertain	--	Immature technology Monetizing system benefits
Pumped storage hydro	Firm capacity Balancing Diurnal shaping	Numerous sites (thousands of MW)	$352	--	Project development Monetizing system benefits
Sodium-sulfur batteries	Firm capacity Balancing Diurnal shaping	No inherent limits	Uncertain	--	Early commercial technology Monetizing system benefits

[3] Incremental cost of duct-firing capacity.

Proven Technology

The Power Act requires priority be given to resources that are cost-effective, defined as a resource that is available at estimated incremental system cost no greater than that of the least-cost similarly reliable and available alternative[4]. Because the supply of resources using commercially-proven technology is sufficient to meet forecast needs over the twenty year period of the power plan, unproven resources, not being "similarly reliable and available" as those using commercially proven technologies are not included in the recommended portfolio. Unproven resources include those for which the available quantity is poorly-understood and resources requiring unproven technology. For this plan, unproven resources include salinity gradient energy generation, deep water wind power, wave energy, tidal currents, and enhanced geothermal. Because it is probable that proven technologies for use of deep water offshore wind power, wave energy, tidal currents, and enhanced geothermal will become available over the next two decades, actions to monitor and to support development of these technologies are included in this plan.

Cost Estimates

The electricity production costs cited in this chapter are forecast costs in constant 2006 year dollars, levelized over the anticipated economic life of the plant. The costs include:

- plant costs (plant development and construction, operation, maintenance, fuel and byproduct credits)
- integration costs (regulation and load following)
- transmission costs and cost of transmission losses
- carbon dioxide allowance (emission) costs

The following assumptions are used for calculating these costs: reference plant configuration and location as described, investor-owned utility financing, medium fuel price forecast and delivery to a load serving entity point of delivery. The derivation of forecast plant and transmission cost components and method of calculating levelized costs are described in Appendix I. Fuel cost forecasts are described in Appendix A. The carbon dioxide allowance costs are based on the forecast medium case developed for the wholesale power price forecast as described in Appendix D[5]. Federal production and investment tax credits and renewable energy credits are excluded in an effort to yield a more accurate comparison of societal costs. Accelerated depreciation is included. Actual project costs may differ, to a greater or lesser degree from the costs appearing here because of factors including site-specific conditions, incentives, financing and timing.

Levelized electricity costs for a given resource and technology will vary by initial year of service because of forecast escalation of fuel prices, carbon dioxide allowance costs and escalation of integration costs. Forecast technological improvements and production economies will also affect costs through time. A significant effect in the near-term is the current decline in

[4] Regional Act 3.(4)(A)

[5] The medium carbon dioxide allowance cost estimates used for the power price forecast are slightly lower in the near- and mid-term than the mean value of the distribution used for the Regional Portfolio Model (RPM) because of subsequent adjustments to the RPM distribution. The difference will have a very minor effect of the carbon dioxide allowance component of the costs appearing in this chapter and will be reconciled prior to release of the final plan.

construction costs for many resources because of the tight credit market and weak economic conditions. To facilitate more accurate comparisons among resources the costs shown in Figures 6-1 A-C are based on a common initial service year for each figure: These are 2015 for Figure 6-1A (near-term) , 2020 for Figure 6-1B (mid-term) and 2025 for Figure 6-1C (longer-term). Elsewhere in the chapter, with a few exceptions cited electricity costs are based on an initial service year of 2015. The exceptions are resources such as nuclear or coal with carbon sequestration for which a 2015 service date is clearly infeasible. The reference service dates are noted for these resources.

Finally, the cost of transmission for remote resource options requiring new long-distance transmission assumes no network credit for the transmission improvements. Network credit could reduce transmission costs for these alternatives.

GENERATING RESOURCE APPLICATIONS & SERVICES

Energy generation has been the focus of previous power plans because the Northwest hydropower system is capacity-rich and energy-limited. Increasing demand for balancing reserves[6] for integrating wind power and a prospective firm capacity shortfall in coming years has broadened to scope of this plan to the capacity as well as the energy characteristics of resources. Power generation technologies differ in their ability to deliver these services and in the cost of providing these services. Capacity issues are further discussed in Chapter 11 of this plan.

The principal power system services of interest for purposes of long-term planning are energy, balancing reserves and firm capacity (the ability to contribute to meeting peak loads)[7]. Though an electric power system could consist of a single resource such as hydropower or gas combined cycle plants capable of providing all generating services needed for reliable system operation, a power system normally consists of a mix of resource types; some specialized for the production of certain services.

Another service provided by some power plants is cogeneration (also referred to as combined heat and power or CHP). Cogeneration is the simultaneous production of electricity and useful thermal energy for industrial or commercial processes or space conditioning. In addition to providing a revenue stream to help offset the cost of electricity production, cogeneration increases the thermal efficiency of fuel use and can reduce net carbon dioxide production and other environmental impacts.

Energy

All power plants produce electric energy, but power plants used extensively for the production of electric energy (baseload plants) are those with low variable production costs. Little can be saved by curtailing operation of these plants so they are typically dispatched to the extent that

[6] Balancing reserves provide regulation and load-following for the integration of variable-output renewable energy resources. Also referred to as system flexibility.

[7] In addition to energy, seven capacity-related ancillary services are needed for reliable operation of a power system and are therefore commercially significant. These include: regulation, load-following, spinning reserves, non-spinning reserves, supplemental or replacement reserves, voltage support and black start. See Kirby, B. *Ancillary Services Technical and Commercial Insights*, July 2007 for additional discussion.

they are available. Because non-fuel variable costs are generally a minor element of production costs, baseload units tend to be those with low (or no) fuel costs such as coal, hydropower, geothermal, biogas, wind, solar and nuclear plants. Natural gas combined-cycle plants, while using a relatively expensive fuel, are very efficient, so typically operate as intermediate load units - producing energy at times of higher demand and prices but curtailed during periods of low energy prices. Cogeneration plants though often using expensive fuel (natural gas or residue biomass) are efficient and normally have a steady thermal load, so also operate as baseload energy generators. Production-related financial incentives such as the federal production tax credit (PTC) and renewable energy credits (RECs) affect dispatch decisions and promote energy production by lowering the effective variable production cost.

The reference levelized cost of electric energy from new generating resources is shown in Figures 6-1A-C. Figure 6-1A includes resources that could plausibly be brought into service in the near-term period of the plan (2010-14). These include resources with short development and construction lead times such as wind and combined-cycle plants, and resources such as geothermal and new hydropower. While the latter typically have long lead times, specific projects are sufficiently-advanced in the development process[8] to be brought into service in the near-term period. Costs are for projects entering service in 2015.

Figure 6-1B includes additional resources (in color) that could be brought into service in the mid-term period (2015-19). These include remote wind and solar resources requiring construction of long-lead time transmission lines, and long-lead time coal-fired steam-electric and gasification plants. Because of Montana, Oregon and Washington carbon dioxide performance standards that effectively prohibit utilities from owning or contracting for the output of coal plants not provided with carbon capture and sequestration, these coal-fired options would be limited to Idaho. Costs are for projects entering service in 2020. The effect of assumed rates of technological improvement and other factors affecting cost through time become evident in this and the following figure, especially for solar photovoltaics.

Figure 6-1C shows resources that could be brought into service in the long-term period (2020-29). New options (in color) include long lead time advanced nuclear plants and ultra-supercritical steam-electric coal technology. The latter would be limited to Idaho unless equipped with carbon separation and sequestration. Commercial-scale carbon dioxide sequestration facilities based on depleted oil and gas fields are assumed to be available by this period. These could be located in Montana, Wyoming or Saskatchewan and accessible to coal-fired plants located in eastern Montana, opening the possibility of repowering the Colstrip Transmission System (CTS) using coal gasification plants with carbon dioxide separation (Colstrip 1 and 2 will have been in service for 50 years by 2025). The estimated cost of repowering the CTS using wind power is also shown. Costs are for projects entering service in 2025.

Though the total costs shown in the figures reflect the approximate cost-effectiveness order based on energy production, these are expected values and do not incorporate the effects of risk and uncertainty evaluated in the Resource Portfolio Model.

[8] "Development" is used in this chapter in the customary sense to refer to the process of preparing to construct a power plant, including site selection; feasibility assessment, environmental, geotechnical and resource assessment; permitting and preliminary engineering. Project development is generally akin to the resource optioning process referred to elsewhere in the plan.

Figure 6-1A: Levelized Electricity Cost of Energy Generating Options Available in the Near-term (2010-14) [9]

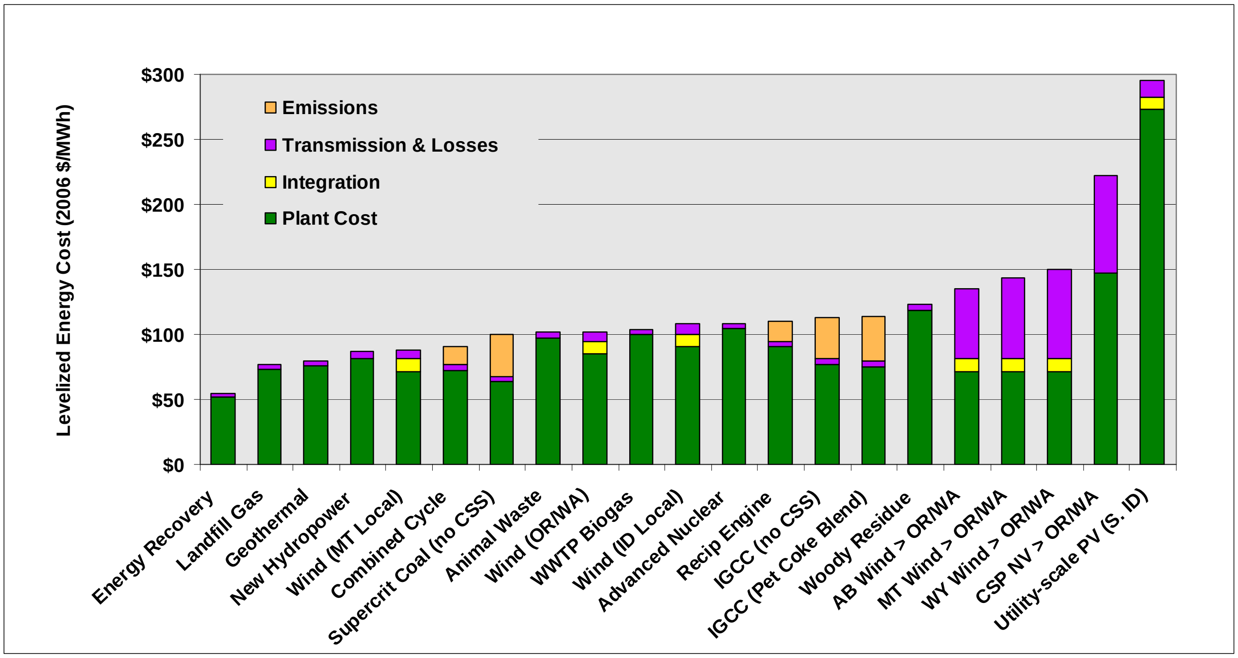
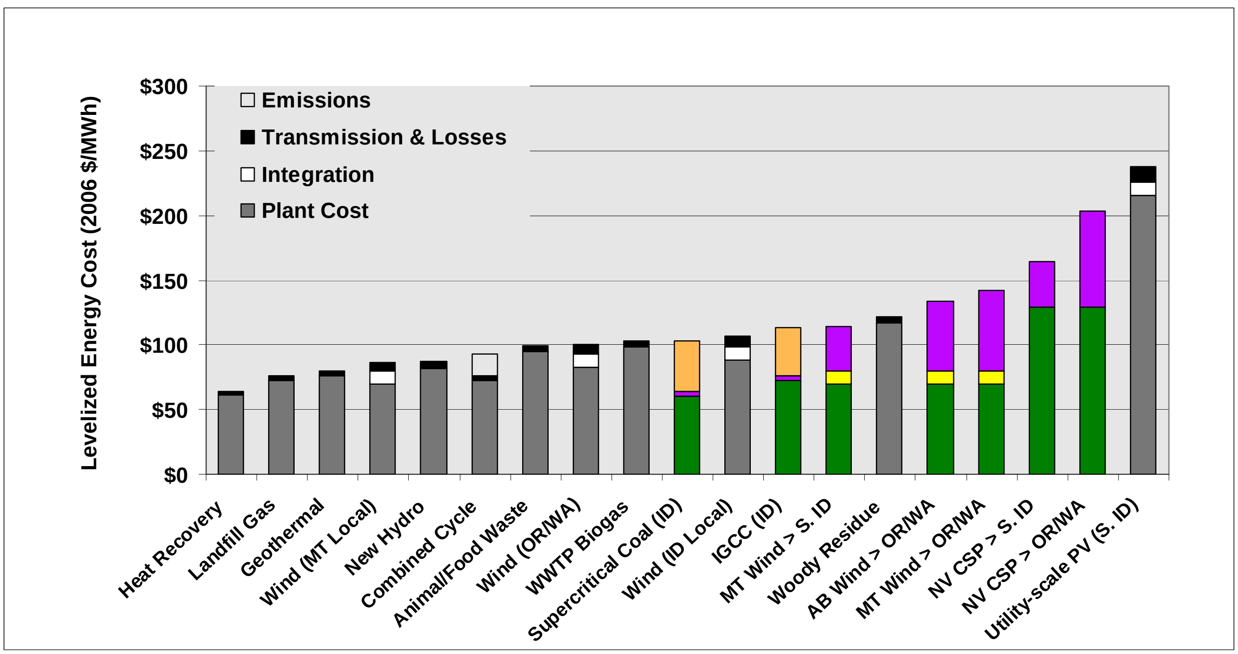
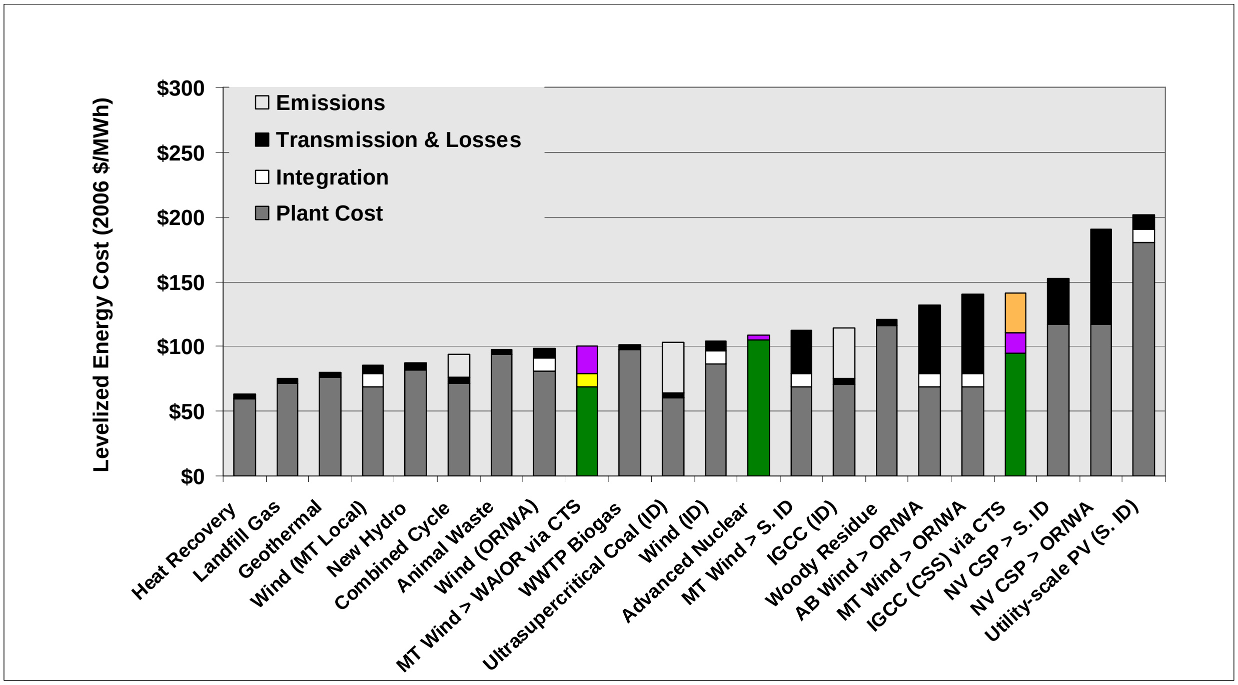


Figure 6-1B: Levelized Electricity Cost of Energy Generating Options Available in the Mid-term (2015-19)[10]



[9] Assumptions: 2015 service, investor-owned utility financing, medium fuel price forecast, wholesale delivery point. CO_2 allowance costs at the mean values of the portfolio analysis. Incentives excluded, except accelerated depreciation. Actual project costs may differ because of site-specific conditions and different financing and timing.
[10] Assumptions as in Figure 6.1A except 2020 service.

Figure 6-1C: Levelized Electricity Cost of Energy Generating Options Available in the Longer-term (2020-25)[11]



Firm Capacity

With the exception of wind and other variable-output energy resources, most power plants provide firm capacity to meet peak loads and to provide contingency reserves[12]. In general, these plants can provide capacity up to net installed capacity less an allowance for forced (unscheduled) outages. In some cases, contractual, fuel, permitting and ambient environmental conditions may limit the peak contribution of otherwise firm capacity. Some resources are developed primarily to provide firm capacity. Because these resources are operated infrequently, variable cost is less important than fixed costs. Also, units intended for peaking service may need rapid start and load-following ability to avoid displacing generation having lower variable cost.

A comparison of the fixed costs of several resources typically developed for capacity value is provided in Figure 6-2. In the case of the combined-cycle option, the cost shown is the incremental cost of duct firing. Duct firing is an inexpensive option for increasing plant output (though at some sacrifice of efficiency) and is nearly always provided on combined-cycle units. But duct firing capability is limited and other capacity resources are sometimes needed. Levelized capacity costs of Figure 6-2 would not be the sole criterion for choosing among these options. The technologies have different attributes, leading to different choices depending on needs. Aeroderivative gas turbines and reciprocating engines, for example, have very rapid start times (less than 10 minutes), allowing them to provide "spinning" reserve, even when shut down. Duct firing requires additional condenser cooling water, whereas simple-cycle gas turbine and reciprocating units require no condenser cooling, a factor of importance in arid regions.

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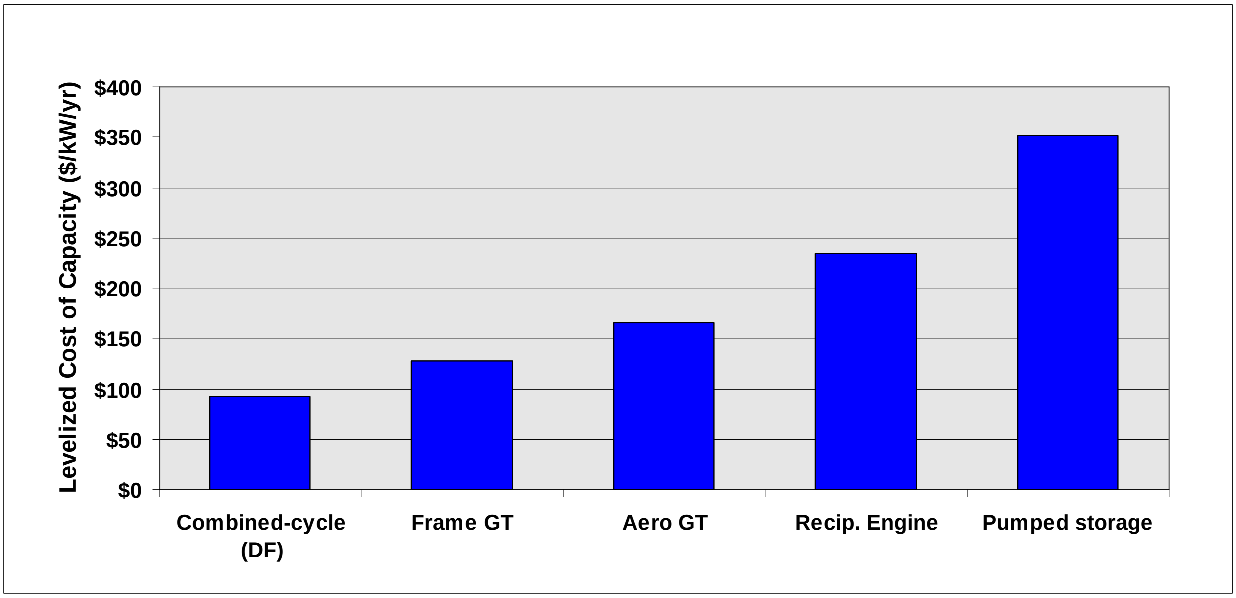
[11] Assumptions as in Figure 6.1A except 2025 service.
[12] Capacity held for use in case of a contingency event such as unplanned loss of generation.

Moreover, anticipated operating conditions can affect fixed costs. Gas turbines, if located in a non-attainment area may need expensive air emission controls. Several prospective capacity options are omitted from the figure because they are uncertain at present.

Figure 6-2: Fixed Cost of Commercially-available Firm Capacity Options



Regulation and Load-following

The addition of large amounts of wind power to the Northwest power system has increased the demand for regulation and load-following services. Regulation is the continuous balancing of generation to load on a second-to-second basis, and is typically supplied by fast-response generating units equipped with automatic generation control. Hydropower units are normally used to provide regulation in the Northwest. Though windpower at low penetration does not significantly increase the net second-to-second variability of load and generation; incremental variation is introduced as wind penetration increases. However, the incremental demand for regulation introduced by wind, even at high penetration levels is relatively small compared to the incremental increase in load-following requirements.

Load-following services make up the difference between scheduled generation and actual load. Load-following is currently provided by operating capacity reserves set to provide either upward (incremental) regulation (“inc”) or downward (decremental) regulation (“dec”). The need to prepare for unpredictable rapid upward and downward ramps in wind output is increasing demand for load-following capability.

A related service is shaping. Shaping involves the shifting of energy from low-value off-peak hours to higher-value on-peak hours on a diurnal or multi-day basis. Shaping can also be used to level load on transmission lines serving remote renewable resource areas, thereby reducing incremental transmission costs.

Resources suitable for providing regulation and load-following services have rapid and flexible response capability, low capital cost and near-market operating costs. Other desirable attributes include siting flexibility and low standby emissions. Among generating resource options, combined-cycle gas turbines, simple-cycle gas turbines and reciprocating engines offer the greatest potential for supplying regulation and load-following services. Long-duration storage technologies including pumped-storage hydro, compressed air energy storage, flow batteries and sodium-sulfur batteries offer similar capability.

Further assessment of the relative cost and value of these options in the context of the Northwest power system is needed. Action GEN-6 calls for an assessment of flexibility augmentation options with priority given to resources or combinations of resources that can jointly satisfy peak load and system flexibility requirements. This effort should consider combined-cycle plants, gas turbine generators, reciprocating engines, pumped storage hydro, compressed air energy storage, flow batteries, sodium-sulfur batteries and demand-side options.

Combined Heat and Power

Combined heat and power (CHP or cogeneration) is the joint production of electricity and useful thermal or mechanical energy for industrial process, space conditioning or hot water loads. The fundamental attribute of cogeneration is higher thermodynamic efficiency compared to separate production of electricity and the thermal or mechanical services. Improved efficiency is achieved through higher initial temperatures and pressures and by use of otherwise wasted thermal energy. Benefits of cogeneration include net reduction in cost, carbon dioxide and other environmental impacts, improved economic viability of the host facility, improved system reliability and reduced transmission and distribution system costs.

Cogeneration includes diverse combinations of fuels, technologies and applications, making it difficult to characterize a definitive cogeneration project. Fuels used for cogeneration include waste heat from industrial equipment and processes, natural gas, wood residues, biogas and spent pulping liquor. Technologies include gas turbine generators, combined-cycle power plants, steam-electric plants and reciprocating engine generator sets. Several examples of the expected cost of resources and technologies configured for cogeneration are provided in Table 6-1.

About 3970 megawatts of cogeneration is installed in the Northwest. About 1790 megawatts of this capacity is industrial cogeneration, closely integrated with the host facility and sized to the thermal load. The remaining 2180 megawatts are utility-scale combined-cycle plants at which steam is extracted to serve a nearby thermal load. Operation of industrial cogeneration is generally determined by thermal demand (i.e., the operation of the thermal host), whereas operation of utility-scale combined-cycle cogeneration is largely determined by fuel and electricity prices. Fifteen cogeneration plants totaling 143 megawatts of cogeneration capacity has been constructed in the Northwest since release of the Fifth Power Plan. All of these new plants are industrial cogeneration and most are fuelled by bio-residues.

The greatest near-term cogeneration potential in the Northwest is at energy-intensive industrial facilities and commercial facilities having large space conditioning and hot water loads. While technical potential exists in the smaller commercial and residential sectors, these tend not to be cost-effective given current technology. A growing cogeneration application is energy recovery from agricultural and other bioresidues where the reject heat of the generating unit is used to maintain the waster digester operating temperatures.

A 2004 assessment[13] identified 14,425 megawatts of technical cogeneration potential for Idaho, Oregon and Washington[14]. Under "business-as-usual" assumptions (little improvement in technology, no incentives and continuation of standby charges) the economic potential through 2025 was estimated to be about 1030 average megawatts of energy. No applications using woody biomass residues were considered, nor were any applications involving capture of waste energy such as from gas pipeline compressor stations, cement kilns or metal remelt furnaces. These are promising applications and this estimate of economic potential may be low because of these omissions.

Unfortunately, the full benefits of cogeneration are rarely seen by the individual parties (utility, host facility, developer) involved in the decision to develop cogeneration. Many of the barriers to cogeneration stem from these differing perspectives and include:

- The required return on investment of the host facility is often higher than that of a utility.
- Unless participating as an equity partner, the utility sees no return plus possible loss of load.
- Limited capital and competing investment opportunities often constrain the host facility's ability to develop cogeneration.
- Energy savings benefits to the host facility may not be worth the hassle of installing and operating a cogeneration plant.
- Difficulty in establishing a guaranteed fuel supply for wood residue plants.
- Uncertainties regarding the long-term economic viability of the host facility.
- The locational value of cogeneration is often not reflected in electricity buy-back prices.
- Relative complexity of permitting and environmental compliance for small plants.

Actions to help resolve these issues were identified in the Fifth Power Plan. These remain valid and include:

- Routine surveys to identify cogeneration and small-scale renewable energy resource development opportunities.
- Resource evaluation criteria that fully reflect costs and benefits including energy, capacity and ancillary services values, avoided transmission and distribution costs and losses and environmental effects.
- Elimination of disincentives to utility acquisition of power from customer-side projects such as inability of investor-owned utilities to receive a return on investment in generation owned or operated by others.

[13] Energy and Environmental Analysis, Inc... *Combined Heat and Power in the Pacific Northwest: Market Assessment*, B-REP-04-5427-004. July 2004.
[14] CHP opportunities in Montana were not assessed in the Energy and Environmental Analysis study.

- Uniform interconnection agreements and technical standards.
- Equitable standby tariffs.
- Provision for the sale of excess customer-generated power through the utility's transmission and distribution system.

Distributed Generation

Distributed generation is the production of power at or near electrical loads. Distributed generation can provide standby power for critical loads, regulation of voltage or frequency beyond grid standards, cogeneration, use of an on-site byproduct as fuel, local voltage support, an alternative to the expansion of transmission or distribution capacity, service to remote loads, peak shaving to reduce demand charges and an alternative source of supply for times of high power prices or system islanding. Distributed energy storage technologies can provide many of the same services and emerging "smart grid" controls can synchronize the operation of individual units to create a virtual large-scale storage facility. The modularity and small-scale of distributed technologies can lead to rapid technological development and cost reduction.

Distributed generation installations are smaller than central-station plants, ranging from tens of kilowatts to about 50 megawatts in capacity. The benefits of distributed generation can best be secured with technologies that are flexible in location and sizing such as small gas turbine generators, reciprocating engine-generators, boiler-steam turbines, and solar photovoltaics, microturbines and fuel cells. However, distributed generation applications are often uneconomic sources of bulk power compared to central-station generation because of the higher cost of equipment, operation, maintenance and fuel and the lower thermodynamic efficiency. It is the additional value imparted by the factors listed above that may make distributed generation attractive. Distributed long-duration storage options include flow batteries and sodium-sulfur batteries.

HYDROELECTRIC POWER

The mountains of the Pacific Northwest and British Columbia and heavy precipitation, much of which falls as snow, produce large volumes of annual runoff that create the great hydroelectric power resource for this region. The theoretical potential has been estimated to be about 68,000 megawatts of capacity and 40,000 average megawatts of energy. Nearly 33,000 megawatts of this potential capacity has been developed at about 360 projects. Though the remaining theoretical hydroelectric power potential is large, most economically and environmentally feasible sites have been developed. The remaining opportunities are, for the most part, small-scale and somewhat expensive.

Hydroelectric power is by far the most important generating resource in the Pacific Northwest, providing about two-thirds of the generating capacity and about three quarters of electric energy on average. The annual average runoff volume, as measured at The Dalles Dam, is 134 million acre feet but it can range from a low of 78 million acre-feet to a high of 193 million acre-feet. Unfortunately, the combined useable storage in U.S. and Canadian reservoirs is only 42 million acre-feet. This means that the system has limited capability to reshape river flows (meaning power) to better match the monthly shape of electricity demand. The Pacific Northwest is a winter peaking region yet river flows are highest in spring (during the snow melt) when electricity demand is generally the lowest. Because of this, the region has historically planned its resource acquisitions based on critical hydro conditions, that is, the historical water year[15] with the lowest runoff volume over the winter peak demand period. Under those conditions, the hydroelectric system produces about 11,800 average megawatts of energy. On average, it produces nearly 16,000 average megawatts of energy and in the wettest years, it can produce over 19,000 average megawatts. For perspective, the annual average regional demand is about 22,000 average megawatts. In order to reflect the important variability of hydroelectric production as water conditions change, the Council's analysis uses a 70-year water record in its analysis.

Existing Hydropower System

The current hydroelectric system has a capacity of about 33,000 megawatts but operates at about a 50 percent annual capacity factor because of water supply and limited storage. For hourly needs, the Northwest's power supply must be sufficient to accommodate increased demands during a sustained cold snap, heat wave or the temporary loss of a generating resource. The hydroelectric system provides up to 24,000 megawatts of sustainable peaking capacity, which is designed to provide for the six highest load hours of a day over a three consecutive day period.

These assumptions for the annual and hourly capability of the hydroelectric system are sensitive to fish and wildlife operations, which have changed in the past and could change in the future. There remain a number of uncertainties surrounding these operations, which could 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. 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.

For the Sixth Power Plan, hydroelectric system capability over the study horizon is based on fish and wildlife operations specified in the 2008 biological opinion. The possible impacts to the resource strategy due to climate change effects on hydroelectric generation will be examined via scenario analysis. However, it should be noted that the range of potential changes to hydroelectric generation is relatively small compared to the range of other planning uncertainties.

Integrating Fish & Wildlife and Power Planning

The Power Act requires that the Council's power plan and Bonneville's resource acquisition program assure that the region has sufficient generating resources on hand to serve energy demand and to accommodate system operations to benefit fish and wildlife.[16] The Act requires the Council to update its fish and wildlife program before revising the power plan, and the amended fish and wildlife program is to become part of the power plan. The plan is then to set forth "a general scheme for implementing conservation measures and developing resources" with "due consideration" for, among other things, "protection, mitigation, and enhancement of fish

[15] The water year or hydrologic year is normally defined by the USGS from the beginning of October through the end of September and denoted by the calendar year of the final nine months. The water year of the Columbia River system, however, is modeled from the beginning of September (beginning of operation for reservoir refill) through the end of August.
[16] For more information please see Appendix M: Fish and Wildlife Interactions.

and wildlife and related spawning grounds and habitat, including sufficient quantities and qualities of flows for successful migration, survival and propagation of anadromous fish."[17]

On average, fish and wildlife operations reduce hydroelectric generation by about 1,170 average megawatts (relative to an operation without any constraints for fish and wildlife).[18] For perspective, this energy loss represents about 10 percent of the hydroelectric system's firm generating capability[19]. Bonneville estimates that replacing that lost hydropower capability and funding direct fish and wildlife program expenditures have increased Bonneville's costs by over $800 million per year. That amount represents about 20 percent of Bonneville's annual net revenue requirement.[20]

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 1980, 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. The Council's current assessment[21] 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.

The Council recognizes the need to better identify and analyze long-term uncertainties that affect all elements of fish and power operations. In its action items, the Council addresses this need by proposing the creation of a public forum, which would bring together power planners and fish and wildlife managers to explore ways to address these uncertainties. Long-term planning issues include climate change, alternative fish and wildlife operations, modifications to treaties affecting the hydroelectric system and the integration of variable-output resources, in particular how they affect system flexibility and capacity. The forum would provide an opportunity to identify synergies that may exist between power and fish operations and to explore ways of taking advantage of those situations.

New Hydropower Development

New Hydropower Projects

Though the remaining theoretical hydroelectric power potential is large, most economically and environmentally feasible capacity appears to have been developed. The remaining opportunities for new projects are, for the most part, small-scale. Among these are addition of generating

[17] Northwest Power Act, Sections 4(e)(2), (3)(F), 4(h)(2)

[18] The comparison study, which includes no actions for fish and wildlife, is represented by hydroelectric operations prior to 1980.

[19] 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.

[20] Bonneville's annual net revenue requirement is on the order of $3.5 billion (Bonneville's 2007 Annual Report).

[21] See http://www.nwcouncil.org/energy/resource/Adequacy%20Assessment%20Final.doc.

equipment to irrigation, flood control and other non-power water projects, incremental additions of generation to existing hydropower power projects with surplus stream flow, and a few projects at undeveloped sites. A comprehensive assessment of new hydropower potential has not been attempted by the Council since the Fourth Power Plan. In that plan, the Council estimated that about 480 megawatts of additional hydropower capacity was available for development at costs of 9.0 cents per kilowatt-hour, or less. This capacity could produce about 200 megawatts of energy on average. Few projects have been developed in the intervening years and it is likely that the Fourth Plan estimate is representative of the current situation. Hydropower development costs are sensitive to configuration, size, and site characteristics. A review of recent projects shows costs ranging from $65 to over $200 per megawatt-hour and a weighted average cost for committed and completed projects of $96 per megawatt-hour. Demand for low carbon resources and resources qualifying for state renewable portfolio standards has increased interest in hydropower development and the Council recommends that a comprehensive assessment of new hydropower potential be undertaken to gain a clear understanding of the cost and potential of this resource.

Upgrades to Existing Hydropower Projects

Renovations to restore the original capacity and energy production of existing hydropower projects, and upgrades to yield additional capacity and energy are often much less costly than the development of new projects. Most existing projects date from a time when the value of electricity was lower and equipment efficiency less than now and it is often feasible to undertake upgrades such as advanced turbines, generator rewinds, and spillway gate calibration and seal improvement. Even a slight improvement in equipment efficiency at a large project can yield significant energy. The last comprehensive assessment of regional hydropower upgrade potential was completed more than twenty years ago and many renovations and upgrades have been completed in the intervening years. Much like end use efficiency, improved technology and higher electricity values are likely to have increased the undeveloped potential even as renovations and upgrades have been completed. Informal surveys suggest that several hundred average megawatts, or more are potentially available from renovations and upgrades. The Council recommends that a comprehensive assessment of hydropower upgrade potential be undertaken to gain a clear understanding of the cost and potential of this resource.

NON-HYDRO RENEWABLE ENERGY RESOURCES

Biofuels

Biofuels include combustible organic residues of the production and consumption of food, fiber and materials, and fuels obtained from dedicated energy crops. Bio-residues available for electric power generation in the Northwest include woody residues (forest residues, logging residues, mill residues, and the biogenic components of municipal solid waste), spent pulping liquor, agricultural field residues, animal manure, food processing residues and landfill and wastewater treatment plant digester gas. Hybrid poplar plantations represent the greatest potential for dedicated bio-energy production for the electrical sector in the Northwest, but typically have greater fiber than fuel value.

Landfills

Anaerobic decomposition of the organic matter in landfills produces a low-grade (~450 Btu/scf) combustible gas consisting largely of methane and carbon dioxide. Gas production usually begins one or two years following waste emplacement and may last for several decades. The gas is collected and flared for safety reasons and to reduce its greenhouse gas potential[22]. Increasingly, the gas is used for productive purposes including direct use as low-grade fuel, upgrading to pipeline-quality gas and on-site power generation. A typical power generation facility consists of gas cleanup equipment and one or more reciprocating engine-generator sets. The principal business model is third-party development of the gas cleanup and power generation facilities with purchase of the raw gas from the landfill operator.

Six projects totaling 28 megawatts are currently in operation in the Northwest. The estimated feasible undeveloped power generation potential in the Northwest is about 80 average megawatts, represent about 94 megawatts of installed capacity. Because the gas from some landfills is being upgraded for injection into the natural gas system, a portion of this potential is unlikely to be available for power generation. The reference three megawatt project would produce electricity at an estimated cost of $79 per megawatt-hour, though the costs of specific projects will vary due to economies of scale, gas quality and gas production rates. Barriers to further development of landfill gas for power generation include competing uses, low financial incentives and cost, especially for smaller landfills.

Agricultural and Food Wastes

A combustible gas largely consisting of methane and carbon dioxide usable as a power generation fuel can be derived from anaerobic digestion of animal manure, food wastes and similar biogenic organic material. A typical animal manure or food waste energy recovery plant uses enclosed slurry-fed anaerobic digesters for gas production and reciprocating engine generators for power generation. Heat recovered from the reciprocating engine-generator is used to maintain digester temperature and to dry the residual fiber for use as animal bedding or soil amendment. These projects provide baseload, carbon-neutral electricity from an otherwise wasted resource. Unfortunately, the most feasible candidate facilities for installation of energy recovery facilities are limited to large-scale confined animal feeding operations including dairies, swine and poultry facilities using slurry manure handling. European dry fermentation technology, currently being introduced to North America could broaden application to feedlots and other operations using dry manure handling.

At least eight large-scale (0.5 megawatts and larger) animal manure energy recovery projects and one food processing residue project totaling about 13 megawatts are known to be in operation or under construction in the Northwest. The undeveloped Northwest potential, primarily at large-scale dairy operations is estimated to be 50 to 60 average megawatts. Additional potential might be secured through development of cooperative facilities jointly serving smaller dairy or food processing operations. Power generation costs are widely variable and sensitive to project size and type of digester. Costs might range from $90 per megawatt-hour for a large 2.5 megawatt project (~16000 head of cattle) to about $145 per megawatt-hour for a 450 kilowatt project (~ 2900 head). The principal impediments to greater use of the available resource include cost and collection of a sufficient supply of manure or other agricultural waste to support economically feasible projects. The principal barriers to further development of this resource are aggregation

[22] Methane has about 21 times the greenhouse warming potential than the carbon dioxide product of its combustion.

of sufficient biomass for an economically-sized plant, and cost in general, particularly for smaller facilities.

Wastewater Treatment Plants

In many wastewater treatment facilities, sludge is processed in anaerobic digesters that produce a moderate quality (600 - 650 Btu/kWh) combustible biogas consisting largely of methane and carbon dioxide. Anaerobic digesters require addition of heat for optimal operation and the common method of disposing of the biogas is to use it as a fuel for controlling digester temperature. Surplus is flared. A more productive alternative is to clean the biogas for use as fuel for a cogeneration plant where the heat rejected from the generating unit is used to maintain digester temperature. Reciprocating engines are typically used for this application.

Nineteen wastewater treatment energy recovery projects totaling 22 megawatts are in operation or under construction in the Northwest. Though an estimate of remaining regional potential was not located, a 2005 assessment prepared for the Oregon Energy Trust estimated 2 to 4 megawatts of undeveloped near-term potential for Oregon. Extrapolating this estimate to the region based on population suggests a remaining undeveloped near-term potential of 7 to 14 megawatts.

The reference plant is an 850-kilowatt reciprocating engine generator fuelled by gas from the anaerobic digesters of a wastewater treatment plant. Reject engine heat is captured and used to maintain optimal digester temperatures. The reference cost of electricity would be $127/MWh with the plant operating in baseload mode (seasonal fluctuations may occur due to wastewater treatment plant loading). Capacity, site conditions, financing and incentives can lead to wide variation in cost. Electricity production costs might range from about $108 per megawatt-hour for larger (1 - 2 megawatts installations) to twice that for smaller installations. Though these costs appear high, the electricity is typically used to offset treatment plant loads so electricity production costs compete with retail rates. Cost, especially for smaller installations is the primary barrier to full development of the remaining potential.

Woody Residue

The largest source of woody residues in the Northwest has been the forest products industry. Currently 26 projects, comprising 290 megawatts of capacity using woody residues as a primary fuel operate in the Northwest, a slight increase since the Fifth Plan. Surveys indicate that nearly all woody residues currently produced in the forest products sector are beneficially used, for fuel or otherwise. Some undeveloped potential is available from further separation of biogenic material from municipal solid waste otherwise land-filled, but the major potential is forest thinning residues from expanded ecosystem recovery and wildfire hazard reduction efforts and from more intensive management of commercial timberlands. Additional woody residue from these sources could provide about 90 TBtu annually on a reliable, sustained basis. The price of this residue will vary depending upon the source, alternative uses and prevailing economic conditions, but is expected to average about $3.00 per million Btu in the near-term. Introduction of specialized collection and transportation equipment for bulk low-density fuels is expected to result in an annual average real price reduction, estimated to be 1 percent over the period of the plan.

Conventional steam-electric plants with or without cogeneration will be the chief technology for electricity generation using wood residues in the near-term. Modular biogasification plants are under development and may be introduced within the next several years. A sustained annual fuel supply of 90 Tbtu is sufficient to generate about 665 average megawatts using conventional technology.

The reference plant is a 25 megawatt stand-alone unit using conventional steam-electric technology, operating entirely on forest thinning residues. This plant would produce electricity at $123 per megawatt-hour. Capital ($51/MWh) and fuel ($40/MWh) are the two major components of the energy cost of the reference plant. The reference configuration was selected because of the limited supply of low-cost mill residues and limited opportunities for cogeneration in areas where abundant supplies of forest thinning residues are expected to be available. Lower-cost opportunities are available, however. Factors that could significantly reduce the cost of specific projects include use of refurbished equipment, availability of mill or urban wood residues, cogeneration revenue, established infrastructure, low-cost financing and financial incentives. For example, cost-reducing elements of a feasibility study by the Port of Port Angeles for a wood residue cogeneration plant in Forks, WA, included use of a travelling grate rather than a more costly fluidized bed boiler, an adjacent cogeneration load, refurbished turbine-generator and electrical equipment and a close-by supply of mill residue. Applying the reference financing assumptions used elsewhere in this chapter yields $78 per megawatt-hour energy for this plant, placing it well within the competitive range for new generating resources.

The principal barriers to development of woody biomass plants are capital costs, availability of cogeneration load and ensuring an adequate, stable, and economical fuel supply.

Pulping Chemical Recovery

Chemical recovery boilers are employed to recover the chemicals from spent pulping liquor produced by chemical pulping of wood. Lignins and other combustible materials in the spent liquor create the fuel value. Recovery boilers, usually augmented by power boilers fired by wood residue, natural gas or other fuels, supply steam to the pulping process. More efficient use of the fuel is possible by producing the steam at high pressure and extracting process steam at the desired pressures from a steam turbine-generator. When the Fourth Power Plan was prepared, 8 of the 19 mills then operating in the Northwest were not equipped for cogeneration. Estimates prepared for that plan indicated that an additional 280 average megawatts of electric power could be produced from installation of cogeneration equipment at recovery boilers not having such equipment. Mills have closed since then and upgrades have been undertaken at several of the remaining plants, including addition of a 55 megawatt generating plant at the Simpson Tacoma Kraft mill, scheduled for service this summer. The remaining Northwest potential has not been recently assessed. Limited capital availability, short pay-back periods and the uncertain economic conditions in the industry typically constrain development of this resource.

Geothermal Power Generation

The crustal heat of the earth, produced primarily by the decay of naturally-occurring radioactive isotopes may be used as a source of energy for power generation. Conventional hydrothermal electricity generation requires the coincidental presence of fractured or highly porous rock at temperatures of about 300^{o} Fahrenheit or higher and water at depths of about 10,000 feet, or less. The most promising Northwest geologic structure for hydrothermal generation is the basin and range province of southeastern Oregon and southern Idaho. Here, natural circulation within vertical faults brings hot fluid towards the surface. Basin and Range geothermal resources have been developed for electric power generation in Nevada, Utah and California, and recently in

Idaho. The 13 megawatt Raft River project in Idaho is the first commercial geothermal power plant in the Northwest. Earlier models of the geology of the Cascades Mountains suggested the presence of large geothermal potential. More recent research suggests that while local hydrothermal systems may exist in the Cascades, geothermal potential suitable for electric power generation outside of these areas is limited or absent. Moreover, development of much of the Cascades potential would be precluded by land use constraints. Newberry Volcano (Oregon) and Glass Mountain (California) are the only Cascades structures offering geothermal potential not largely precluded by existing land use. These structures may be capable of supporting several hundred megawatts of geothermal generation.

Conventional Geothermal Power Generation

Depending on resource temperature, flashed-steam or binary-cycle geothermal technologies could be used with the liquid-dominated hydrothermal resources of the Pacific Northwest. A preference for binary-cycle or heat pump technology is emerging because of modularity, applicability to lower temperature geothermal resources and the environmental advantages of a closed geothermal fluid cycle. In binary plants, the geothermal fluid is brought to the surface using wells, and passed through a heat exchanger where the energy is transferred to a low boiling point fluid. The vaporized low boiling point fluid is used to drive a turbine-generator, then condensed and returned to the heat exchanger. The cooled geothermal fluid is re-injected to the geothermal reservoir. This technology operates as baseload resource. Flashed steam plants typically release a small amount of naturally-occurring carbon dioxide from the geothermal fluid, whereas the closed-cycle binary plants release no carbon dioxide. The reference geothermal plant for this plan is a binary-cycle plant consisting of three 13-megawatt units. The reference cost of electricity production is $84 per megawatt-hour - among the lowest-cost generating resources identified in this plan.

A recent U.S. Geological Survey assessment[23] yielded a mean total Northwest hydrothermal electricity generating potential of 1369 average megawatts. However, geothermal development has historically been constrained by high-risk, low-success exploration and wellfield confirmation. Using historical Nevada development rates as guidance, the Council has adopted a provisional estimate of 416 megawatts of developable hydrothermal resource for the period of the plan. This would yield about 375 average megawatts of energy. These assumptions should be revisited at the biennial assessment of the 6th Plan.

Enhanced Geothermal Power Generation

The natural presence of high-temperature permeable rock and fluid at feasible drilling depth is uncommon. Much more common are high-temperature, but insufficiently permeable formations. Enhanced geothermal systems (EGS)[24] involve creation of the necessary permeability by fracturing or other means. EGS technology is one of several emerging geothermal technologies[25] that could vastly increase the potentially developable geothermal resource. Three areas of special EGS interest identified in a 2004 MIT assessment of geothermal potential[26] occur in the

[23] United States Geological Survey. *Assessment of Moderate- and High-Temperature Geothermal Resources of the United States*. 2008.
[24] Also known as engineered geothermal systems.
[25] Others include "Hidden" hydrothermal resources, supercritical volcanic geothermal, oil and gas co-production and geopressured reservoirs.
[26] Massachusetts Institute of Technology. *The Future of Geothermal Energy*, 2004.

Northwest and two of these (Oregon Cascades and Snake River Plain) are unique to the Northwest. The USGS study cited above identified 104,000 average megawatts of EGS potential at 95% confidence level in the four Northwest states. Because EGS technology has not been commercially proven, it is not included among the resources evaluated for the portfolio of this plan. Because of its potential, the Council encourages Northwest utilities to support efforts to develop and demonstrate EGS technology.

Marine Energy

Ocean Currents

The kinetic energy of flowing water can be used to generate electricity by water-current turbines operating on a principal similar to wind turbines. Conceptual designs and prototype machines have been developed and an array of current turbines is being installed in New York City's East River. Turbine energy yield is very sensitive to current velocity and little electrical potential is available from the weak and ill-defined currents off the Northwest coast.

Thermal Gradients

An ocean thermal energy conversion (OTEC) power plant extracts energy from the temperature difference that may exist between surface waters and waters at depths of several thousand feet. OTEC technology requires a temperature differential of about 20 degrees Celsius (36 degrees Fahrenheit). Temperature differentials of this magnitude are limited to tropical regions extending to 25 to 30 degrees of latitude. Ocean thermal temperature differentials in the Northwest range from 0 to 12 degrees Celsius (0 - 20 degrees Fahrenheit,) precluding operation of OTEC technology.

Salinity Gradients

Energy is released when fresh and saline water are mixed. Conceptually, the energy potential created by fresh water streams discharging to salt water bodies could be captured and converted to electricity. Concepts that have been advanced for the generation of electric power from salinity gradients include osmotic hydro turbines, dilytic batteries, vapor pressure turbines, and polymeric salinity gradient engines. These technologies are in their infancy, and it is not clear that current concepts would be able to operate off the natural salinity gradient between fresh water and seawater. Although the theoretical resource potential in the Northwest is substantial, many years of research, development, and demonstration will be required to bring these technologies to commercial availability.

Tidal Energy

Tidal energy originates from the loss of the earth's rotational momentum due to drag induced by gravitational attraction of the moon and other extraterrestrial objects. The conventional approach to capturing tidal energy is by means of hydroelectric "barrages" constructed across natural estuaries. These admit water on the rising tide and discharge water through hydro turbines on the ebb. The extreme tidal range, preferably 20 feet or more, required by this technology precludes their application to only a few places worldwide where the landform greatly amplifies the tidal range. Environmental considerations aside, the development of economic tidal hydroelectric plants in the Northwest appear to be precluded by insufficient tidal range. Mean tidal ranges in the Pacific Northwest are between 4.5 and 10.5 feet, with the greatest mean tides found in bays and inlets of southern Puget Sound. A more promising approach to capturing tidal energy is to use kinetic energy of tide-induced currents to generate electricity by water-current turbines. Intermittent tidal currents of three to eight knots occurring locally in Puget Sound and channels within the San Juan Islands my be sufficient to support tidal current generation. Several Northwest utilities have secured preliminary permits to further explore this potential.

Wave Energy

The Northwest coast is among the better wave energy resource areas, world-wide. The theoretical wave energy potential of the Washington, Oregon and Northern California coast is estimated to be about 50,000 average megawatts. The practical potential will be much smaller because of competing uses of sea space, environmental constraints and conversion losses. Nonetheless, the developable potential is likely to be substantial, and could provide the Northwest with an attractive source of low-carbon renewable energy. While highly seasonal and subject to storm-driven peaks (winter energy flux may exceed summer rates by a factor of 20), wave energy is continuous and is more predictable than wind, characteristics that may reduce integration cost. Though it would be impractical to capture the full winter energy flux, the seasonal output of a wave energy plant would be generally coincident with winter-peaking regional loads. A further attribute of wave energy is its geographic location close to Westside load centers.

Numerous and diverse wave energy conversion concepts have been proposed, and are in various stages of development ranging from conceptualization to pre-commercial demonstration. It is too early to say which technologies will eventually prove best for particular conditions. Wave energy conversion devices will need to perform reliably in a high-energy, corrosive environment and demonstration projects will be needed to perfect reliable and economic designs. Successful technology demonstration will be followed by commercial pilot projects that could be expanded to full-scale commercial arrays. Because of potential environmental issues and competition for sea space from commercial and sport fisheries, wildlife refuges and wilderness areas, shipping, undersea cables and military exclusion zones, site suitability should be assessed and siting protocols established in advance of large-scale commercial development. An important role of demonstration projects will be to gain understanding of site suitability, potential conflicts and impacts and remediation measures. Assessment of interconnection and integration requirements in advance of development is also essential. Northwest utilities are encouraged to support these efforts.

The cost of electricity from wave energy power plants will be site-specific. Conversion technology, depth, ambient wave energy, ocean floor conditions and distance from shore will all affect cost. A 2004 estimate of the capital and operating costs and productivity of a 90-megawatt commercial-scale plant using an array of 500 kilowatt Pelamis wave energy conversion devices optimized to Northwest conditions suggests a cost range of $140 to $270 per megawatt-hour[27] for the initial plant. Learning and economies of production will reduce costs as installed capacity increases. Given installation of 1600 megawatts of wave energy plant globally, an amount appearing feasible by the 2020s, learning curves derived from experience in the wind, solar and other industries yield expected costs to $105 per megawatt-hour and range of $80 to $150 per megawatt-hour. These costs would make wave energy potentially competitive with other generating resources.

[27] Using the reference cost assumptions used elsewhere in this chapter.

Solar

The amount of solar radiation reaching the ground and available for conversion into electricity is a function of latitude, atmospheric conditions, and local shading. The best solar resource areas of the Northwest are the inter-mountain basins of south-central and southeastern Oregon and t he Snake River plateau of southern Idaho. On an annual average, these areas receive about 75 percent of the irradiation received in Barstow, California, one of the best U.S. sites.

Because of its strong summer seasonality, the Northwest solar resource has potential for serving local summer-peaking loads, such as irrigation and air conditioning, but is less suitable for serving general regional loads which are forecast to continue to be winter-peaking for many years. There have been no comprehensive studies of site suitability for development, though in theory, there is sufficient solar resource to support all regional electrical requirements.

Solar energy can be converted to electricity using photovoltaic or solar-thermal technologies.

Photovoltaics

Photovoltaic plants convert sunlight to electricity using solid-state cells. Because no combustion or other chemical reactions are involved, power production is emission-free. No water is consumed other than for periodic cleaning. Power output is variable and battery storage or auxiliary power is required for remote loads demanding a constant supply. Grid-connected installations require firm capacity and balancing reserves, though balancing reserve requirements may be mitigated by distributing many small plants over a wide geographic area, thus dampening cloud-driven ramp rates.

Photovoltaic technology is commercially established and is widely employed to serve small remote loads for which it is too costly to extend grid service. Strong public and political support has lead to attractive financial incentives, so despite the high cost and low productivity, grid-connected installations of several hundred kilowatts, or more are becoming common.

A low-cost photovoltaic plant would employ thin film photovoltaic cells mounted on fixed racks. The energy conversion efficiency and overall productivity of such a design is low and thin film cells suffer from more rapid degradation than more expensive cell technology. Crystalline silicon cells operate at higher efficiency, and are more durable but are more costly. At greater cost, plant productivity can be further improved by mounting cell arrays on tracking devices to improve daily and seasonal orientation. Maximum productivity is achieved by use of concentrating lenses focusing on high-efficiency multi-junction photovoltaic cells with wide spectral response, mounted on fully automatic dual-axis trackers. Concentrating photovoltaic plants operate on only direct (focusable) solar radiation, so are best suited for clear southwestern desert conditions.

The reference plant is a 20-megawatt (AC net) central-station plant employing flat-plate (non-concentrating) crystalline photovoltaic cells and single-axis trackers. The direct-current output of the modules is converted to alternating current for grid interconnection. The relatively small size would permit interconnection at distribution system and sub-transmission voltages and thereby facilitate a high degree of modularity and distribution across a wide geographic area. This would help reduce ramping events driven by cloud movement. The reference plant could yield capacity factors up to 26 percent at the very best Northwest locations. If constructed in the near-term, this plant would deliver energy at about $300 per megawatt-hour. Costs are expected to continue to decline, on average, at the historical rate of about 8 percent per year.

Solar Thermal Power Plants

Solar thermal power generation technologies (also referred to as concentrating solar power or CSP) use lenses or mirrors to concentrate solar radiation on a heat exchanger to heat a working fluid. The working fluid is used directly or indirectly to power a turbine or other mechanical engine to drive an electric generator. CSP technologies are broadly categorized by the design of the concentrator and the type of thermal engine. The three basic types are parabolic trough, central receiver and Sterling dish. Parabolic trough plants, the most mature, have been in commercial operation in California since the 1980s. Plants have been recently completed in Nevada and Spain[28]. These plants employ arrays of mirrored parabolic cross-section troughs that focus solar radiation on a linear heat-exchange pipe filled with circulating heat transfer fluid. The hot fluid is circulated through heat exchangers to generate steam to supply a conventional steam-electric power plant. Many parabolic trough plants are equipped with auxiliary natural gas boilers to stabilize output during cloudy periods and to extend daily operating hours. Plants can also be equipped with thermal storage for the same purpose.

Central-receiver plants employ a field of tracking reflectors (heliostats) that direct solar radiation on an elevated central receiver where energy is transferred to a working fluid, usually a molten salt. The hot molten salt is circulated through heat exchangers to generate steam to supply a conventional steam-electric power plant. Molten salt storage tanks are provided to stabilize output during cloudy periods and to extend daily operating hours. Several demonstration plants have been constructed. The first commercial central receiver plant, a 17 megawatt unit, is scheduled for 2011 service in Spain.

A Stirling dish consists of a tracking parabolic mirror that concentrates solar radiation on the heat exchanger of a small Stirling reciprocating engine at the focal point of the mirror. Individual dishes are small, and utility-scale plants would consist of large arrays of individual dish units. Because of the small size of the individual units, Stirling dish technology may benefit from economies of standardization and production. However, Stirling dish technology is not suitable for thermal storage. The technology is in the demonstration stage.

Concentrating solar plants use direct solar radiation so are best suited for dry, clear sky locations. Though potentially suitable areas might be found in southern Idaho and southeastern Oregon, the most suitable locations are in the Southwest. The reference plant is a 200-megawatt parabolic trough concentrating solar thermal plant, with thermal storage, 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. One 500 kV transmission circuit could deliver about 1500 megawatts of capacity and about 530 average megawatts of energy. Because of the time needed to construct the necessary transmission, it is unlikely that a solar-thermal plant would be available for serving Northwest loads prior to 2015. A plant coming into service in 2015 could deliver energy to southern Idaho for about $180 per megawatt-hour. Delivery to the Mid-Columbia trading hub would be about $220 per megawatt-

[28] An in-depth source of information regarding parabolic trough solar-thermal plants is at http://www.nrel.gov/csp/troughnet/.

hour. Technological improvements and economies of production are expected to result in continued cost reduction.

Solar-thermal technology can provide an abundant alternative source of low-carbon energy. Because they can be fitted with thermal storage and supplementary boilers, parabolic trough and central receiver technologies have the further advantage of providing reliable output through the peak load hours of the day. These technologies are particularly attractive in the southwest where they can be sited near loads at a cost approaching that of competing low-carbon resources. The added cost and investment risk of long distance transmission needed for these plants makes them less attractive for the Northwest.

Wind

Northwest wind resource areas include coastal sites with strong but irregular storm-driven winter winds and summertime northwesterly winds. Areas lying east of gaps in the Cascade and Rocky mountain ranges such as the Columbia River Gorge, Snoqualmie Pass and Marias Pass receive concentrated prevailing westerly winds, occasional wintertime northerly winds, and winds generated by east-west pressure differentials. Favorable winds are also found on the north-south ridges of southeastern Oregon and southern Idaho, lying athwart prevailing southwesterlies.

Beginning in 1998 with the 25 megawatt Vansycle Ridge project, commercial wind power has grown to about 4000 megawatts of nameplate capacity, the fourth largest component of the Northwest power system. Though some geographic diversification has occurred, capacity remains concentrated in the area of the Columbia Basin east of the Columbia River Gorge. Nearly 80% of the total regional wind capacity is located in a 160 mile corridor from The Dalles, Oregon northeast to Pomeroy, Washington.

The rapid rate of development reflects the fundamental attributes of wind power as an abundant, mature, relatively low-cost source of low-carbon energy with local economic benefits. While the recent development rate has slightly subsided due to the tight credit market, an array of market and financial incentives and strong political support are expected to sustain robust development.

Wind power in the Northwest has variable output and little dependable capacity and therefore requires complementary firm capacity and balancing reserves. An existing surplus of balancing reserves and dependable capacity within the Northwest power system has enabled the growth of wind power without the need or cost, to date, of additional complementary capacity. Concentration of installed wind capacity east of the Columbia River Gorge, and within in single balancing area (Bonneville) has led to significant ramping events, placing demands on the ability of Bonneville, in particular to integrate additional wind development.

The least cost, and quickest solutions to accommodating the integration needs of additional wind development appear not to be construction of new flexible capacity, but rather reducing the demand for system flexibility and fully accessing the flexibility of the existing system. Measures such as improved load forecasting, up-ramp curtailment and sub-hourly scheduling can reduce the amount of flexibility required to integrate a given amount of wind capacity. Over the longer-term, a further means of reducing the demand for flexibility may be to increase the geographic diversity of wind development by construction of transmission to import wind from remote wind resource areas. Existing system flexibility, scattered across numerous Northwest balancing areas, can be more fully accessed by the development of mechanisms to facilitate trade of balancing services concurrent with development of expanded dynamic scheduling capability and generation control. Issues of cost allocation will need resolution, especially now that substantial amounts (close to 50% of 2008 development) of Northwest wind power is marketed to California customers. Following these steps, new balancing reserves and dependable capacity from generation, storage or demand side sources may be required.

The abundance of compatible wheat and grazing land with good wind resources and available transmission has minimized environmental conflicts. As these prime sites are developed and pressure to geographically diversify wind development increases, environmental conflicts may become more common. Advance identification of sensitive areas and establishment of transparent and comprehensive permitting criteria and procedures will help preclude potential conflicts.

The Council assessed the cost and potential for continued wind development to meet local needs in the Columbia Basin, Southern Idaho and Montana. The Council also examined the cost of importing wind energy to Northwest load centers from Alberta, Montana and Wyoming wind resource areas. Whereas the development wind for local use is ongoing, , it is unlikely that wind power from Alberta, Montana or Wyoming would be available to serve Oregon or Washington loads prior to 2015 because of the time needed to construct the necessary transmission. These options are summarized in Table 6-2.

Table 6-2: Cost and Availability of New Wind Power[29]

Resource	Limiting Factor	Capacity (MW)	Energy (MWa)	Cost ($/MW)
Columbia Basin > PNW Westside	Transmission at embedded cost	4060	1300	$102
Other local OR/WA	20% peak load penetration	340	110	$102
Local Southern Idaho	20% peak load penetration	725	215	$108
Local Montana	20% peak load penetration	215	80	$88
Alberta > OR/WA	+/-500kV DC transmission	2000/circuit	760	$122
Montana > ID	500kV AC transmission	1500/circuit	570	$116
Montana > OR/WA	500kV AC transmission via S. ID	1500/circuit	570	$143
Wyoming > ID	500kV AC transmission	1500/circuit	570	$120
Wyoming > OR/WA	500kV AC transmission	1500/circuit	570	$150

Because of modeling limitations the four local wind resource blocks were consolidated into a single block for purpose of the Resource Portfolio Model. For similar reasons, the Montana to OR/WA case was selected as representative of imported wind[30].

WASTE HEAT ENERGY RECOVERY

Certain industrial processes and engines reject energy at sufficient temperature and volume to justify capturing the energy for electric power production. “Waste heat” is considered a priority

[29] Estimates of capacity and energy are of delivered potential, incremental to installed capacity operating or under construction as of end of 2008.
[30] A review of the cost estimates following this initial portfolio runs suggested that Alberta wind has potential as the least-cost imported wind option for Oregon and Washington loads. Because of the larger incremental size of imported Alberta wind (2000 MW vs. 1500 MW), further analysis would be required to confirm the least-risk/least cost imported wind option.

category 3 resource by the Regional Act[31]. Candidate sources of high and medium-temperature waste heat potentially suitable for electric power generation include cement kilns, glass furnaces, aluminum smelters, metals refining furnaces, open hearth steel furnaces, steel heating furnaces, hydrogen plants, waste incinerators, steam boiler exhaust, gas turbines and reciprocating engine exhaust, heat treating and annealing furnaces, drying and baking ovens and catalytic crackers. While many of these facilities are customarily equipped with recuperators, regenerators, waste heat recovery boilers and other devices to capture a portion of the reject heat for beneficial use, opportunities exist for installing bottoming cycle cogeneration on some of these facilities. Recovered energy cogeneration is attractive because of the increased efficiency of fuel use, baseload operation, and few, if any incremental air emissions or carbon dioxide production. Heat recovery boilers supplying steam turbine-generators have been the conventional approach to using waste heat for electric power generation. However, the introduction of small-scale, modular organic Rankine cycle power plants using lower-temperature energy sources have expanded potential applications for recovered energy cogeneration.

The reference plant is a 5-megawatt organic Rankine cycle generating unit supplied by the exhaust gas from the mechanical drive gas turbines of a trunkline natural gas compressor station. This unit would be operated in baseload mode with some seasonal fluctuation in coincidence with electrical load. At $66 per megawatt-hour, electricity from the reference plant would be among the lowest-cost generating resources.

An inventory of potential Northwest opportunities for the development of recovered energy cogeneration was not located for this plan, however, such opportunities are known to exist. For example, more than 50 natural gas pipeline compressor stations are located in the Northwest, many of which are powered by mechanical drive gas turbines potentially suitable for heat recovery generation. Recovered energy cogeneration facilities for trunkline compressor station applications are typically about five megawatts in capacity suggesting a significant potential. Cement kilns, steel processing facilities and glass furnaces offer additional possibilities. The potential is sufficiently attractive to warrant an effort on the part of Bonneville and regional utilities to identify and to develop these opportunities.

FOSSIL FUELS

Coal

Coal resources available to the Northwest include the Powder River basin fields of eastern Montana and Wyoming, the East Kootenay fields of southeastern British Columbia, the Green River basin of southwestern Wyoming, the Uinta basin of northeastern Utah and northwestern Colorado, and extensive deposits in Alberta. Coal could also be obtained by barge from the Quinsam mines of Vancouver Island or the Chuitna mines of Alaska. Mines at Centralia, Washington, have recently closed and the Centralia power plant is now supplied by rail.

Sufficient coal is available to the region to support all electric power needs for the 20-year planning horizon of this plan. Improvements in mining and rail haul productivity have resulted in generally declining constant dollar production costs. Climate change policy and overseas demand are the important factors affecting future coal prices. Carbon dioxide penalties would

[31] Northwest Power Act, Section 4(e)(1).

depress future demand and prices absent economical carbon dioxide separation and sequestration technologies. However, if technologies for separating and sequestering carbon dioxide for sequestration become commercial, domestic and overseas demand and prices are likely to remain stable or increase. This plan uses Powder River Basin coal as the reference coal. The minemouth price of Powder River Basin coal is forecast $0.64/MMBtu in 2010, increasing to $0.71 in 2029 (medium case). Transportation adders based on rail costs are used to adjust prices to other locations. Further discussion of fuel prices is provided in Chapter 2 and Appendix A.

Coal is the major source of electric power in the United States as a whole, but comprises only 13 percent (7300 megawatts) of capacity in the Northwest. Pulverized coal-fired steam-electric plants, though a mature technology, continue to improve through use of higher temperature and more efficient steam cycles. The preferred technology for new North American plants is shifting from subcritical steam cycles with thermal efficiency of about 37 percent to supercritical cycles with thermal efficiency of 37 to 40 percent. Ultra-supercritical units with thermal efficiencies of 41 - 43 percent are being constructed in Europe and Asia, and have been proposed in the United States.

The continued use of coal for power generation will hinge on efforts to reduce carbon dioxide production. While abundant in the United States, coal has the highest carbon content of the major fossil fuels[32]. Moreover, conventional coal-fired plants operate at lower efficiency than gas-fired plants. Despite the relatively small penetration of coal capacity in the Northwest, coal combustion is responsible for 85 to 90 percent of the carbon dioxide from the Northwest electricity sector. The approaches to reducing per megawatt-hour carbon dioxide production from coal-fired plants are increased thermal efficiency; fuel switching and carbon dioxide capture and sequestration. For new construction, increasing the efficiency of combustion is the least cost and logical first step to reducing carbon dioxide production. Ultra-supercritical plants, for example produce about 80 percent of the carbon dioxide of conventional coal-fired units. Fuel switching can reduce the carbon-dioxide production from existing as well as new plants. Switching from sub-bituminous to certain bituminous coals can reduce carbon dioxide production several percent, but the economics and net impact on carbon dioxide production are case-specific because of coal production and transportation considerations. Co-firing biomass can reduce carbon dioxide production but the biomass quantities and co-firing percentages are limited. Carbon capture and sequestration will be required to control carbon dioxide releases to the levels needed to achieve proposed greenhouse gas reduction targets. While carbon capture technology for coal gasification plants is commercially available, capture technology for steam-electric plants remains under development. Though legal issues remain to be resolved, sequestration in depleted oil or gas fields is commercially proven. Suitable oil and gas reservoirs are limited in extent in the Northwest and though other geologic alternatives are potentially available, including deep saline aquifers and possibly flood basalt sequestration, these remain to be proven and commercialized.

Coal-fired Steam-electric Plants

New steam-electric coal-fired power plants increasingly employ supercritical or ultra-supercritical technology. The overriding issue is development of economical technology for separation of carbon dioxide, coupled with development of commercial-scale carbon sequestration facilities. This would pave the way to continued use of coal for new power

[32] The carbon content of petroleum coke is somewhat greater than that of coal.

generation and continued operation of existing coal-fired power plants. One approach to carbon dioxide separation for steam-electric plants is oxy-firing, in which the furnace is supplied with pure oxygen, rather than air for combustion. This would produce a flue gas consisting largely of carbon-dioxide and water vapor from which the carbon dioxide could be readily separated. An alternative is chemical separation of carbon dioxide from the flue gas of a conventionally air-fired furnace. Neither of these carbon removal technologies nor sequestration facilities are expected to be commercially available before the 2020s.

Because of the lead time required to develop and construct a coal-fired steam-electric power plant, it is unlikely that a new plant could be placed in service until the mid-term. The reference plant for this period is a 400-megawatt supercritical unit. The plant would be equipped with a full suite of criteria air emission[33] control equipment and activated charcoal injection for additional reduction of mercury emissions. Because the technology is unlikely to be commercial by this time, the reference plant is not provided with carbon dioxide separation equipment. The plant could provide firm capacity and energy services and limited balancing reserves. This plant, however, would not comply with Washington, Montana or Oregon carbon dioxide performance standards. Plausibly, this plant could be constructed in Idaho. The estimated levelized lifecycle electricity cost for a southern Idaho location is $103 per megawatt-hour, including forecast levelized carbon dioxide allowance costs of $39 per megawatt-hour (2020 service).

By the mid-2020s carbon separation technology for steam-electric plants may be commercially available. Likewise, commercial-scale carbon sequestration facilities may be available, particularly those using depleted oil and gas fields. Also, by this time, new steam-electric plants are likely to employ higher-efficiency ultra-supercritical steam conditions. The reference plant for this period is a 400-megawatt ultra-supercritical unit, equipped for removal of 90 percent of flue gas carbon dioxide. This plant could comply with state carbon dioxide performance standards and supplement or replace existing coal-fired units. The example of Figure 6-1C is a repower of the existing Colstrip transmission system. The estimated levelized lifecycle electricity cost is $142 per megawatt-hour, including transmission costs of $16 per megawatt-hour and carbon dioxide sequestration and residual allowance costs of $30 per megawatt-hour (2025 service).

Coal-fired Gasification Combined-cycle Plants

Pressurized fluidized bed combustion and coal gasification technologies allow application of efficient combined-cycle technology to coal-fired generation. This reduces fuel consumption, improves operating flexibility, and lowers carbon dioxide production. Of the two technologies, coal gasification is further along in commercial development and offers the additional benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration and optional co-production of hydrogen, liquid fuels, or other petrochemicals. Several coal gasification project proposals were announced in North America during the early 2000s, however, escalating costs and refined engineering indicating that non-carbon emissions and plant efficiency would not be significantly better than supercritical steam electric plants has dampened enthusiasm. Uncertainties regarding the timing and magnitude of greenhouse gas regulation and the availability of carbon sequestration facilities have further clouded the future of these plants and only a handful of proposals remain active.

[33] Emission controlled under the Clean Air act of 1990. These include sulfur dioxide, nitrogen oxides, particulates, hydrocarbons and carbon monoxide.

Because of the lead time required to develop and construct a coal gasification combined-cycle power plant, it is unlikely that a new plant could be placed in service until the mid-term. The reference plant is a 620 megawatt integrated coal-fired gasification combined-cycle plant using an oxygen-blown Conoco-Philips gasifier, sulfur recovery, particulate filters and carbon bed mercury control. The Conoco-Philips technology is thought to be suitable for sub-bituminous Powder River Basin coal, and could also be fired with bituminous coal or petroleum coke. The clean synthesis gas supplies a combined-cycle power generation plant that would provide firm capacity, energy and balancing reserves. This plant, however, would not comply with Washington, Montana or Oregon carbon dioxide performance standards. Plausibly, this plant could be constructed in Idaho. The estimated levelized lifecycle electricity cost for a southern Idaho location is $113 per megawatt-hour, including forecast levelized carbon dioxide allowance costs of $37 per megawatt-hour (2020 service).

By the mid-2020s, commercial-scale carbon sequestration facilities may be available, particularly those using depleted oil and gas fields. The reference plant for this period is equipped for removal of 88 percent of flue gas carbon dioxide. This plant could comply with state carbon dioxide performance standards and supplement or replace existing coal-fired units. The example of Figure 6-1C is a repower of the existing Colstrip transmission system. The estimated levelized lifecycle electricity cost is $141 per megawatt-hour, including transmission costs of $16 per megawatt-hour and carbon dioxide sequestration and residual allowance costs of $30 per megawatt-hour (2025 service).

Natural Gas

Natural gas is a mixture of naturally occurring combustible gases, including methane, ethane, propane, butane, isobutene and pentanes found in porous geologic structures, often in association with petroleum or coal deposits. Raw natural gas is recovered by means of wells and processed to remove condensable fraction (propane, butane, isobutene and pentanes), carbon dioxide, water, and impurities. The resulting product, consisting of methane (~90 percent) and ethane is odorized and compressed for transportation by pipeline to markets. The “natural” natural gas supply can be slightly augmented with methane recovered from landfills and from anaerobic digestion of organic wastes. Methane can also be synthesized from coal.

Natural gas is a valuable energy resource because of its clean-burning properties, ease of transportation, low carbon dioxide production and diversity of applications. Gas is directly used for numerous residential, commercial and industrial end uses and is widely used for electric power production using steam, gas turbine and reciprocating engine technologies. Natural gas is also the principal feedstock in the manufacture of ammonia and ammonia-based fertilizers.

Low natural gas prices and the development of efficient, low-cost, environmentally attractive gas-fired combined-cycle power plants led to a surge of construction early in the 1990s and again following the 2000/2001 energy crisis. Natural gas power plants represent about 16 percent (9100 megawatts) of Northwest generating capacity. Of this, 6960 megawatts are combined-cycle units, 1830 megawatts are peaking units and 350 megawatts are industrial cogeneration units.

Natural Gas Supply and Price

Though natural gas has been produced in Montana and to a limited extent in local areas west of the Cascades, the Pacific Northwest does not have significant indigenous gas resources. Rather, gas is imported by pipeline from the Western Canada Sedimentary Basin of Alberta and British Columbia, the Rocky Mountain basin of Wyoming and Colorado and the San Juan basin of New Mexico. Rising natural gas prices following the energy crisis prompted interest in constructing liquefied natural gas (LNG) terminals to secure access to lower-cost overseas supplies. Interest in LNG facilities has waned following recently declining gas prices due to falling demand, expansion of unconventional sources such as coal bed methane and tight formations, and new conventional discoveries in British Columbia.

Worldwide, the reserves-to-production ratio of natural gas at the end of 2007 was estimated to be 63 years[34]. The North American ratio is much lower, about 10 years. However a significant amount of natural gas remains undiscovered and reserves have trended upward for many years, more than offsetting increasing consumption[35]. New sources of supply including "Frontier Gas" from the Alaskan North Slope and the McKenzie Delta, unconventional sources such as coal bed methane and tight sands, U.S. and Canadian offshore fields and LNG are expected to make up shortfalls and to set North American marginal prices in the long-term. Natural gas delivered on a firm basis to a power plant east of the Cascades is forecast to increase from $7.02/MMBtu in 2010 to $8.32/MMBtu in 2029 in the medium case (about 0.9%/year in constant 2006 dollars). Westside prices are expected to run about 80 cents per MMBtu higher. Unpredictable periods of price volatility are likely to occur during this period. The natural gas price forecast is further discussed in Chapter 2 and Appendix A.

Natural Gas Generating Technologies

Natural gas and liquid petroleum products are the most flexible of the energy resources in terms of technologies and applications. Generating technologies that can be fueled by natural gas include steam-electric plants, gas turbine generators, gas turbine combined-cycle plants, reciprocating engine generators, and fuel cells. Applications run the gamut - base-load energy production, regulation and load following, peaking, cogeneration, and distributed generation. Gas turbine generators, combined-cycle plants and reciprocating engines are expected to continue play a major role in electric power production and are further discussed below. Fuel cells and microturbines may see some specialized applications, but appear unlikely to be major players in the near- to mid-term because of cost and reliability issues.

Simple-cycle Gas Turbine Power Plants

Simple-cycle gas turbine power plants (also called gas turbine generators or combustion turbines) consist of one or two combustion gas turbines driving an electric generator. These are compact, modular generating plants with rapid-response startup and load-following capability, extensively used for meeting short-duration peak loads. A wide range of unit sizes is available, from submegawatt to 270 megawatts. Low to moderate capital costs and superb operating flexibility make simple-cycle gas turbines attractive for peaking and grid support applications. Because of their relatively low efficiency and the cost of natural gas, simple-cycle gas turbines are rarely used purely for energy production unless equipped with exhaust heat recovery

[34] BP *Statistical Review of World Energy 2008*, June 2008. p22
[35] Energy Information Administration. *International Energy Outlook 2008 (DOE/EIA-0484(2008)).* June 2008. Fig. 43.

cogeneration. Gas turbine generators feature highly modular construction, short construction time, compact size, low air emissions, and low water consumption[36].

Because of the ability of the hydropower system to supply peaking and flexible capacity, simple-cycle gas turbines have historically been a minor element of the Northwest power system. However, increasing summer peak loads and demand for regulation and load-following services are driving addition of simple-cycle gas turbines to the power system.

Gas turbine generators are generally divided into two classes: heavy-duty industrial machines specifically designed for stationary applications (often called “frame” machines), and “aeroderivative” machines using aircraft gas turbine engines adapted to stationary applications. A hybrid, intercooled design with high part-load efficiency (the GE LMS100) intended for load-following applications has recently been introduced to the market. Though a mature technology, further increases in gas turbine performance is expected to continue in the coming decades. Gas turbines for power generation benefit from research driven by military and commercial aircraft applications.

The reference aeroderivative plant consists of two 45 megawatt (nominal) aeroderivative gas turbine generators located at an existing gas-fired power plant site. Natural gas supplied on a firm gas transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include water injection and selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC reduction. The total plant cost for 2008 construction is $1050 per kilowatt. This unit would normally be used for sustained energy production only if provided with heat recovery for serving cogeneration loads.

The reference frame plant consists of a single 85 megawatts (nominal) capacity unit located at an existing gas-fired power plant site. Siting, fuel and air emission control assumptions are as described for the reference aeroderivative unit. The total plant cost for 2008 construction is $610 per kilowatt. Like an aeroderivative unit, a frame unit would normally be used for sustained energy production only if provided with heat recovery for serving cogeneration loads.

Reciprocating Engine-generators

Reciprocating engine-generators (also known as internal combustion, IC or gen-sets) consist of a compression or spark-ignition reciprocating engine driving a generator typically mounted on a frame and supplied as a modular unit. Unit sizes for power system applications range from about one to 15 megawatts. Conventionally, reciprocating generators are used for small isolated power systems, emergency capacity at loads susceptible to transmission outages and to provide emergency power and black start capacity at larger power plants. Other power system applications include units modified to operate on biogas from landfills or anaerobic digestion of waste biomass, and “recip farms” installed as a hedge to high power prices during the 2000-2001 energy crisis. On the load side, reciprocating units are provided for emergency service for hospitals, high-rise office buildings and other loads needing ultra-reliable electric service. Except for biogas units, these applications typically use light fuel oil stored on site.

The introduction of more efficient, cleaner and reliable reciprocating generators configured in standard modules in recent years coupled with increasing demand from wind capacity for load-

[36] Larger amounts of water are required for intercooled or cogeneration units and units using air inlet evaporative cooling or water injection for power augmentation or nitrogen oxide control.

following services has increased interest in the use of arrays of gas-fired reciprocating generators to provide peaking and load-following services. A typical installation consists of five to 20 units of 3 to 16 megawatts capacity each. Multiple units, each with a low minimum load and flat, high efficiency curve, and rapid response yields a highly reliable plant with high and very flat efficiency across a very wide load range - ideal for providing load-following services. These plants can also be fitted with exhaust, turbocharger and lube oil heat recovery for low-temperature cogeneration loads. The reference plant consists of twelve 8 megawatt units operating on natural gas supplied on a firm gas transportation contract with capacity release capability. No backup fuel is provided. Air emission controls include selective catalytic reduction for NOx control and an oxidation catalyst for CO and VOC reduction. Baseload operation would yield energy at $110 per megawatt-hour. Cogeneration revenues would reduce this cost.

Combined-cycle Gas Turbine Power Plants

Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam turbine generator, greatly increases the overall thermal efficiency of the plant. Cogeneration steam loads can be served (at some loss of electricity production) by extracting steam at the needed pressure from heat recovery steam generator or steam turbine. Additional generating capacity (power augmentation) can be obtained at low cost by oversizing the steam turbine generator and providing the heat recovery steam generator with natural gas burners (duct firing). Because the resulting capacity increment operates at lower electrical efficiency than the base plant it is usually reserved for peaking operation. Because of their reliability and efficiency, low capital costs, short lead-time, operating flexibility and low air emissions, gas-fired combined-cycle plants have been the bulk power generation resource of choice since the early 1990s.

The reference plant is comprised of 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.[37] Condenser cooling is wet mechanical draft. Baseload operation (80% of full load capacity) would yield reference energy costs of $90 per megawatt-hour including forecast carbon dioxide allowance costs of $14 per megawatt-hour. Though fully capable of baseload operation, combined-cycle units, because of high fuel cost, normally operate as swing units, during heavy load hour. Capacity factors ranging from 35 to 65 percent are not uncommon. This range would result in reference electricity production costs from $95 to $125 per megawatt-hour. Cogeneration revenues could slightly reduce electricity production costs[38].

Petroleum

Petroleum fuels, including propane, distillate, and residual fuel oils are universally available at prices largely determined by the global market. In general, other than for special uses such as for

[37] Volatile Organic Compounds
[38] Combined-cycle cogeneration plants normally support a relatively small steam load.

backup fuel, peaking or emergency service power plants and for power generation in remote areas where its transportability and storability are essential, petroleum-derived fuels cannot compete with natural gas for electric power generation. Forecast prices for petroleum fuels are discussed in Chapter 2 and Appendix A.

Petroleum Coke

Petroleum coke is a carbonaceous solid byproduct of cracking residual fuel oil in a delayed coker to extract higher value products. Petroleum coke supply is increasing as refineries increasingly crack residual fuel and draw upon lower quality crudes. EIA reports that the refinery yield of petroleum coke has increased from 4.3 percent in 1995 to 5.3 percent in 2008. Higher purity petroleum coke is used for aluminum smelting anodes whereas fuel-grade petroleum coke is primarily used for firing cement kilns and power plants. About two-thirds of the merchantable petroleum coke originating in U.S. refineries is exported, primarily to Latin America, Japan, Europe and Canada. The remainder is gasified in refinery trigeneration plants or marketed to electric power generators, calciners, cement kilns and other industries. Because of its low ash content and very high heating value, petroleum coke transportation costs are lower than for coal on a Btu basis. However, petroleum coke is usually priced at a discount to coal because of its typically higher sulfur and metals content. Because refineries can economically dispose of petroleum coke at a loss because of the added value of the lighter products obtained from cracking residual, there is a great deal of pricing flexibility and the discount to coal is highly variable. Further discounting may occur in the future because of the higher carbon content of petroleum coke compared to coal (225 vs. 212 pounds per million Btu). Based on very limited publically-available pricing information, the discount to subbituminous coal is about 80%. For this plan we assume petroleum coke prices are 80% of delivered coal prices. Gasification combined-cycle plants would be the preferred technology for power generation using petroleum coke because of the superior ability to control sulfur and heavy metals, and in the longer term, to capture and sequester carbon dioxide. Because of possible supply limitations and fluctuating prices relative to coal, it is unlikely that a plant would be fuelled purely on petroleum coke.

The net effect of petroleum coke on the cost of electricity from a gasification plant is uncertain, as it is a function the tradeoff of reduction, if any, in fuel cost achieved by use of petroleum coke and the possible additional cost of carbon dioxide allowances or sequestration costs resulting from the higher carbon content of petroleum coke.

NUCLEAR

Nuclear power plants produce electricity from energy released by the controlled fission of certain isotopes of heavy elements such as uranium, thorium, and plutonium. Commercial nuclear fuel is comprised of a mixture of two isotopes of natural uranium - about three percent fissionable U-235 and 97 percent non-fissionable, but fertile U-238. The U-238 is transmuted to fissionable Pu-239 within the reactor by absorption of a neutron. Though reactors using thorium and “bred” plutonium have been developed in anticipation of eventual shortages of natural uranium, it appears that the industry can rely on abundant supplies of natural uranium for the foreseeable future. The price of fabricated nuclear fuel is forecast to be relatively stable, averaging $0.73/MMBtu through the planning period.

Commercial nuclear plants in the United States are based on light water reactor technology developed in the 1950s. One, the 1200 megawatts Columbia Generating Station operates in the Northwest. Motivated by improved plant designs, need for new low-carbon baseload resources and financial incentives of the Energy Policy Act of 2005, nuclear development activity has resumed in the United States following a three-decade hiatus. As of spring 2009, developers have submitted applications to the Nuclear Regulatory Commission for combined construction and operating licenses for 27 new units at 17 sites, mostly in central and southeastern states. Most proposals are planned for service in the 2015-20 period, and construction of the initial units is expected to be contingent on federal incentives. The proposed plants employ evolutionary designs with increasing use of passively operated safety systems and factory-assembled standardized modular components. These features are expected to result in improved safety, reduced cost, and greater reliability. Work is also underway on a highly modular light water design using standard 40-megawatt modules that could be built out into plants of the desired capacity.

Nuclear plants could be attractive source of dependable capacity and baseload low-carbon energy largely immune to high natural gas prices and climate policy. The reference plant is a single-unit 1100 megawatt advanced light water reactor design. The reference cost of power from this unit would be $112 per megawatt-hour (2025 initial service). Construction of a new unit in the Northwest would likely require successful completion and operation of at least one of the proposed new units elsewhere in the United States, an operating spent nuclear fuel disposal system and full development of equally cost-effective conservation and renewable resources. If these conditions were satisfied, the remaining development risks would include construction delays, regulatory uncertainties, cost escalation and the reliability risk associated with a large “single-shaft” machine.

ENERGY STORAGE TECHNOLOGIES

A major challenge to increasing the penetration of variable-output renewable energy resources including wind, solar, wave and tidal current generation is shaping the variable and not fully predictable output of these resources to meet the power quality standards and loads of the power system. One approach is the use of complementary dispatchable firm generation such as the hydropower currently used to integrate wind power in the Northwest. An alternative is energy storage technologies. Energy storage technologies enable decoupling of the production and consumption of electricity, and can provide regulation, sub-hourly load following, hour-to-hour storage and shaping, firm capacity and other services. Storage projects located within a renewable resource zone could flatten the output of variable-output generation, thereby increasing transmission load factors and improving the economics of long-distance transmission.

A variety of storage technologies are commercially available or under development, including pumped storage hydropower, compressed air energy storage, numerous types of electrically rechargeable batteries, metal-air batteries, several types of flow batteries, flywheels, electromagnets and capacitors. For the foreseeable future, only a subset of these have the “bulk” or “massive” energy storage potential needed to integrate utility-scale renewable energy resources[39]. This requires megawatt-scale power ratings, run times of hours and extended charge/discharge capability. The most promising systems for this purpose currently include compressed air energy storage, flow batteries, pumped-storage hydropower and sodium-sulfur batteries.

A common constraint to the deployment of energy storage systems is a business model that permits the project developer to capture the full value of the services that these systems can provide. Value may accrue separately to the generation, transmission and distribution sectors and to the extent that these sectors are structured to impede sharing of benefits, capturing the full value of a storage project may be difficult for a project developer. No formal market exists in the Northwest for the services provided by energy storage systems and with one small exception[40], no successful example of non-utility development of a pumped-storage project is found in the West.

A second constraint is the need for frequent cycling. Amortization of the capital cost of these technologies, which tends to be relatively high, requires that they be employed frequently and for as many services as they are capable of delivering. One reason very little pumped storage capacity has been developed in the Northwest despite favorable sites is that most of the Northwest does not experience the daily summer afternoon peak loads and resulting opportunity for daily off-peak/on-peak arbitrage common to other areas of the country.

Compressed Air Energy Storage

A compressed air energy storage (CAES) plant is an early-commercial technology that can provide load-following and energy shaping over periods up to several days. “Conventional” compressed air energy storage plants consist of motor-driven air compressors that use low-cost off-peak electricity to compress air into an underground cavern. During high-demand periods, the stored energy is recovered by releasing the compressed air through a natural-gas-fired combustion turbine to generate electricity. The compressed air reduces or eliminates the normal gas turbine compression load, greatly reducing its heat rate and fuel consumption. A CAES combustion turbine might have a heat rate of 4000 Btu/kWh compared to the 9,300 - 12,000 Btu/kWh heat rate of a stand-alone simple-cycle gas turbine. The efficiency of the process is further improved by recuperation - heating the compressed air with the combustion turbine exhaust prior to introducing it to the turbine combustors. The economics of a conventional CAES plant requires sufficient spread between on and off-peak prices to cover compression and storage losses (about 25%) plus the cost of the natural gas used to fire the gas turbine. Economic amortization of the capital cost requires frequent cycling such as that needed to serve a daily summer peak load in a warm climate.

Two compressed air energy storage plants are currently in operation. The original 290 megawatt plant was placed into operation in Germany in 1978. A 110 megawatt plant using an improved design including recuperators was constructed in 1991 in Alabama. These plants were intended to shift energy from off-peak hours to on-peak hours in power systems with low-cost coal-fired baseload energy. However, the inherently high degree of flexibility of CAES plants would make

[39] Individual units need not be at a megawatt/hour scale. Megawatt/hour scale could be achieved by deployment of a large number of responsive grid-connected small-scale units, as for example provided by the aggregate storage capability of a fleet of plug-in hybrid vehicles.
[40] The 40 megawatt Olevenhain - Hodges project near San Diego.

them capable of load-following and for shaping the output of wind generation. The Arkansas project has storage capacity for 26 hours of full-load operation, and can ramp from standby to full load in about five minutes. CAES plants located at remote wind resource areas could shape wind project output to improve the transmission load factor. The fast start and rapid ramp rate capability could provide decremental load following capability. High part-load efficiency could provide economic load-following capability compared to conventional simple-cycle gas turbines.

A variety of second generation CAES concepts have been advanced to address the integration of variable-output renewable resources. Unlike earlier designs, these plants would use standard industrial components and would use multiple motor-driven compressors and separate multiple air expansion turbine-generators to improve efficiency, provide additional operating flexibility and to reduce cost. Concepts include a no-fuel adiabatic CAES in which the thermal energy of compression would be stored as a substitute for fuel in the expansion-generation process.

Potentially suitable locations are available in the Northwest. Solution-mined salt caverns, excavated hard rock chambers, depleted oil or natural gas fields or other porous geologic media could be used for the compressed air storage reservoir. Recent proposals for small-scale (~ 15 megawatt) CAES would employ above-ground pressure vessels or buried high-pressure piping, further increasing siting flexibility, though at greater cost.

CAES technology has potential application in the Northwest for improving the load factor of transmission used to deliver power from remotely-located wind and solar generation and for within-hour and hour-to-hour load following and shaping services. An advantage compared to pumped storage hydropower is greater siting flexibility. A disadvantage (except for adiabatic concepts) is the need for natural gas to fire the output generator and the resulting air emissions. The available cost information is not adequate to support a meaningful comparison of CAES with alternatives. Though cost estimates have been published for the various second generation CAES concepts, these are preliminary and suitable only for comparison among CAES alternatives. Moreover, CAES costs are sensitive to geology and storage volume. Second generation demonstration project results and a Northwest feasibility study would be required to accurately fix the relative cost of CAES and other sources of system flexibility.

Flow Batteries

First used in 1884 to power the airship *La France*, flow batteries are a rechargeable battery with external electrolyte storage. Charging or discharging is accomplished by pumping the electrolyte is pumped through a stack of electrolytic cells. External electrolyte storage permits independent scale-up of energy storage capability (governed by storage tank capacity) and power output (governed by cell area and electrolyte transfer rate). Flow batteries are characterized by rapid response, ability to hold charge and longevity in terms of charge/discharge cycles. Three technologies are under development: vanadium redox, zinc bromine and polysulfide bromine. Flow batteries offer the attributes of modularity, sizing flexibility, siting flexibility and zero emission operation. A potential disadvantage is relatively low energy density. Large electrolyte storage facilities may be required to achieve needed energy storage capability.

Flow battery technology is in the demonstration stage. Several installations up to 500 kilowatt capacity and five megawatt-hour storage capacity are reported in Japan and a two megawatt capacity demonstration project is under construction in Ireland. Current cycle efficiency is 70 to

75 percent with potential for improvement. Capital costs are relatively high - one U.S. demonstration plant of 250 kilowatts capacity and two megawatt-hours of storage is reported to have cost $4000/kW. However, current cost and performance are likely not representative of production units.

Pumped-storage Hydropower

Pumped-storage hydropower is an established commercially-mature technology. A typical project consists of an upper reservoir and a lower reservoir interconnected by a water transfer system with reversible pump-generators. Energy is stored by pumping water from the lower to the upper reservoir using the pump-generators in motor-pumping mode. Energy is recovered by discharging the stored water through the pump-generators operating as turbine-generator mode. Cycle efficiency ranges from 75 to 82 percent. Seventeen pumped-storage projects comprising more than 4,700 megawatts of capacity are installed in WECC. One project is located in the Northwest - the six-unit, 314 megawatt Grand Coulee pumped-generator at Banks Lake. This plant is primarily used for pumping water up to Banks Lake, the headworks of the Columbia Basin Irrigation system.

Most existing pumped storage projects were designed for the daily shifting of energy from low variable cost thermal units from nighttime off-peak periods to afternoon peak load periods. However, pumped storage can also provide capacity, frequency regulation, voltage and reactive support, load-following and longer-term shaping of energy from variable-output resources without the fuel consumption, carbon dioxide production and other environmental impacts associated with thermal generation. Importantly for the Northwest, pumped storage could provide within-hour incremental and decremental response to extreme wind ramping events.

Pumped storage projects require suitable topography and geologic conditions for the construction of nearby upper and lower reservoirs at significantly different elevations. Designs using subsurface lower reservoirs are technically feasible, though much more expensive. A water supply is required for initial reservoir charge and makeup. Currently, 13 pumped storage projects ranging in size from 180 to 2000 megawatts and totaling nearly 14,000 megawatts have been announced in Idaho, Oregon and Washington, suggesting no shortage of suitable sites. Construction costs are highly project-specific. Important factors influencing costs include the presence of an existing water body that can be used for one of the reservoirs (usually the lower), storage capacity and transmission interconnection distance. Though $1000 per kilowatt of installed capacity is often quoted as a representative cost of pumped storage hydro, a review of available cost estimates suggests that $1750 to $2500 per kilowatt[41] is more representative. The principal constraints to development of pumped storage are development complexity and lead time, capital cost and the recovery of revenues for services provided.

Sodium-sulfur Batteries

A sodium sulfur battery is a high energy-density high-temperature rechargeable battery consisting of molten sodium and molten sulfur electrodes separated by a ceramic electrolyte. The technology is in the early commercial stage with about 190 installations in Japan, totaling about 270 megawatts capacity. About nine megawatts of sodium-sulfur battery capacity is

[41] Overnight costs.

installed in the United States. The largest unit in operation is Rokkasho in Northern Japan, a 34 megawatt unit with 245 megawatt-hours storage capability used for integrating wind power. Advantages of sodium-sulfur batteries include high energy density, high cycle efficiency (89 percent), modularity, siting flexibility, and the ability to deploy in either centralized or distributed configurations. Current units are fairly expensive with capital costs in the $2500 - 3000 per megawatt range but increasing production rates are expected to lead to cost reductions.

SUMMARY OF REFERENCE PLANT CHARACTERISTICS

Key planning characteristics of the reference power plants are compiled in Table 6-3. Derivation of these values is described in Appendix I.

Plant size: The unit size (installed capacity) used in the Council's planning models.
Heat rate: The fuel conversion efficiency of fuel-burning technologies in Btu/kWh. Higher heating value (HHV) for consistency with fuel pricing.
Availability/Capacity factor: Availability ((1 - forced outage rate)*(1 - scheduled outage rate)) for firm capacity technologies. Expected capacity factor (adjusted for availability) for energy-limited technologies.
Total plant cost: The overnight (instantaneous) project development and construction cost in constant 2006 year dollar values as of mid-2008. Includes direct and indirect construction costs, engineering, owner's development and administration costs and contingencies. Excludes financing fees and allowance for funds used during construction. Construction and fixed O&M costs are declining, so must be adjusted as described in Appendix I to arrive at the expected cost for a given service year. Capital and fixed operating costs are assumed to be fixed at start of construction.
Fixed O&M: Fixed operating and maintenance cost in constant 2006 year dollars as of mid-2008. Includes operating labor, maintenance costs and overhead. Interim capital replacement costs included if significant. Excludes property tax and insurance.
Variable O&M: Variable operating and maintenance costs in constant 2006 year dollars as of mid-2008. Includes consumables such as water, chemicals and lubricants.
Integration cost: The cost of providing regulation and sub-hourly load-following services for operational integration. These vary over the planning period. Assumed values are provided in Appendix I. Excludes the cost, if any of shaping to load on the hours to days time frame.
Transmission cost: The cost of dedicated long-distance transmission, if any plus within-region wheeling cost.
Project development and Construction periods: Months to develop a project from conception to first major expenditure; months to complete construction of one unit from the first major expenditure (typically the down payment for major equipment order).
Earliest service year: Earliest service for plants constrained by factors other than plant development and construction time (e.g., construction of long-distance transmission).
Developable potential: The estimated total developable potential of energy-limited resources over the 2010 - 2029 period.

Assumptions that are constant across all resources:

Property tax and Insurance: Annual property tax is assumed to be 1.4% of depreciated capital cost. Insurance is assumed to be 0.25% of depreciated capital cost.
Transmission losses: Within-region transmission losses are assumed to be 1.9%.

Table 6-3: Key Planning Assumptions for Reference Power Plants

Reference Plant	Plant Size (MW)	Heat Rate (HHV Btu/kWh)[42]	Capacity Factor	Total Plant Cost [43] ($/kW)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Integration Cost[44]	Trans Cost ($/kW/yr)	Trans Losses	Proj Dev / Construction (mos)	Earliest Service	Developable Potential (MWa)
Biogas (animal manure)	.85	10,250	75%	$5000	$45	$15	--	$17.15	1.9%	12/12	--	50 - 60
Biogas (landfill)	2.4	10,060	85%	$2350	$26	$19	--	$17.15	1.9%	18/15	--	80
Biogas (WWTP)	.85	10,250	85%	$4000	$32	$24	--	$17.15	1.9%	18/15	--	7 - 14
Biomass (woody residue)	25	15,500	80%	$4000	$180	$3.70	--	$17.15	1.9%	24/24	--	665
Geothermal (binary)	14	28,500	90%	$4800	$175	$4.50	--	$17.15	1.9%	48/36	2010	375[45]
Hydropower (new)	0.5 - 50	--	50%	$3000	$90	Incl in fixed	--	$17.15	1.9%	48/24	--	Uncertain
Solar (CSP) (NV > ID)	750	200[46]	36%	$4700	$60	$1.00	--	$96	4.0%	24/24[47]	--	530/500kV ckt
Solar (CSP) (NV > OR/WA)	750	200[46]	36%	$4700	$60	$1.00	--	$180	6.5%	24/24	2015	530/500kV ckt
Solar (Tracking PV)	20	--	S. ID - 26% MT - 25% OR - 25% E. WA - 24%	$9000	$36	Incl in fixed	Yes	$17.15	1.9%	24/24	--	Ltd by integration capability
Solar (Tracking PV) - NV	20	--	30%	$9000	$36	Incl in fixed	Yes	$96	4.0%	24/24[47]	2015	435/500kV ckt
Wind - ID	100	--	30%	$2100	$40	$2.00	Yes	$17.15	1.9%	18/15	2010	215
Wind - MT	100	--	38%	$2100	$40	$2.00	Yes	$17.15	1.9%	18/15	2010	80
Wind - OR/WA	100	--	32%	$2100	$40	$2.00	Yes	$17.15	1.9%	18/15	2010	1410
Wind (AB > OR/WA)	750	--	38%	$2100	$40	$2.00	Yes	$120	3.9%	18/15[47]	2015	570/500kV ckt
Wind (MT > ID)	750	--	38%	$2100	$40	$2.00	Yes	$83	4.2%	18/15[47]	2015	570/500kV ckt
Wind (MT > OR/WA)	750	--	38%	$2100	$40	$2.00	Yes	$188	6.5%	18/15[47]	2015	570/500kV ckt
Wind (WY > ID)	750	--	38%	$2100	$40	$2.00	Yes	$120	4.5%	18/15[47]	2015	570/500kV ckt
Wind (WY > OR/WA)	750	--	38%	$2100	$40	$2.00	Yes	$208	7.0%	18/15[47]	2015	570/500kV ckt
Waste heat recovery	5	38,000	80%	$4000	Incl in var.	$8.00	--	$17.15	1.9%	24/24	--	Uncertain
Combined-cycle	Baseload - 390 Peak incr - 25 Full load - 415	Baseload - 7110 Pk incr - 9500 Full load - 7250	90%[48]	$1160	$14	$1.70	--	$17.15	1.9%	24/30	2012	--
Gas turbine (aero)	90	9370	86%[48]	$1050	$14	$4.00	--	$17.15	1.9%	18/15	--	--
Gas turbine (frame)	85	11960	88%[48]	$610	$4	$1.00	--	$17.15	1.9%	18/15	--	--
Reciprocating engine	96 (12 units)	7940	96%[48]	$1275	$67	$4.80	--	$17.15	1.9%	18/15	--	--
Supercritical (coal)	400	9000	90%[48]	$3500	$60	$2.75	--	$17.15	1.9%	36/48	--	--
IGCC	620	8900	85%[48]	$3600	$45	$6.30	--	$17.15	1.9%	36/48	--	--
Nuclear	1100	10,400	90%[48]	$5500	$90	$1.00	--	$17.15	1.9%	48/72	2023	--

[42] Lifecycle average.
[43] Expected cost values are shown, see Appendix I for range estimates.
[44] Integration cost is a function of time; see Appendix I.
[45] Limited to 14 MW/yr through 2014; 28 MW/yr thereafter.
[46] Equivalent heat rate for natural gas used to stabilize output.
[47] Development and lead time for power plant. Long-distance transmission will require additional lead time.
[48] Equivalent annual availability (maximum dispatch).

Chapter 6a: Transmission

SUMMARY OF KEY FINDINGS

For a number of years leading up to the Fifth Power Plan, there was concern that there had been little progress on addressing the developing transmission issues in the region, both in operating the existing system and in planning for new major transmission lines. Since then, there has been significant progress in both areas. The Western Electricity Coordinating Council (WECC) has created two new reliability coordination centers in the West, with new operating tools, which they share with the interconnection's balancing authorities, to address operational reliability issues. Other operating challenges posed by the large increase in wind generation in the region and in the West, are being addressed as well. That issue is explored in more depth in Chapter 11.

On the planning side, there have been major changes and significant progress in the last five years. Both regional and WECC-wide organizations have been created and are producing or developing plans or system assessments, partly in response to the needs of their members and partly in response to increased Federal interest in transmission planning and development. A number of new projects are in the development and study stage, sponsored by utility members of the two regional planning groups, ColumbiaGrid and Northern Tier Transmission Group (NTTG), and by merchant developers.

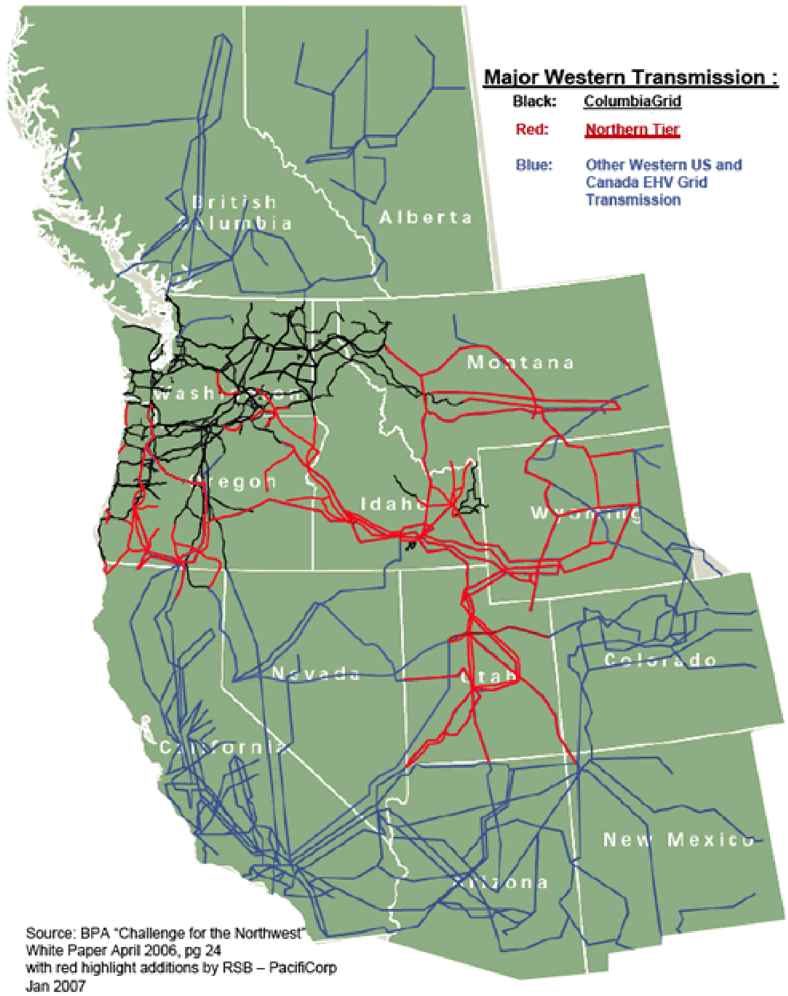
The Federal Energy Regulatory Commission (FERC) is, on a case-by-case basis, reviewing and modifying its financing and study process requirements and Bonneville has taken advantage of this to propose a useful new approach to financing transmission for access to wind resources. Currently proposed legislation in Congress would increase the Federal backstop siting authority that already exists in the Energy Policy Act of 2005 for projects that are supported by regional and interconnection-wide planning efforts.

Nonetheless, the region's utilities are, for the most part, just getting to the stage when they have to address siting and construction of the projects that have been planned. Siting can present significant difficulties, and for individual utilities that may be depending on getting projects sited and built on time, can present challenges if there are delays. The utilities may be forced to rely on backstop plans in order to assure themselves of meeting their loads reliably. The Council supports and encourages regional transmission planning efforts, recognizing that new transmission investment can be key both to maintaining reliable load service and to bringing new renewable resources in to meet regional loads.

BACKGROUND

The regional transmission system is an integral part of the regional power system. It functions roughly like the highway system, allowing power to flow from generators all across the region (and outside the region in the rest of the Western Interconnection) to loads. Figure 6a-1 below shows a schematic of the entire Western high-voltage transmission system, which is operated in a coordinated fashion in order to maintain system reliability, though it is constructed and built by individual utilities to meet their own needs. As can be seen from the map, the Northwest transmission system is closely integrated into the overall Western system. The colors highlight the systems of the two Northwest subregional planning groups described further below, ColumbiaGrid and Northern Tier Transmission Group.

Figure 6a-1: Major Western Transmission



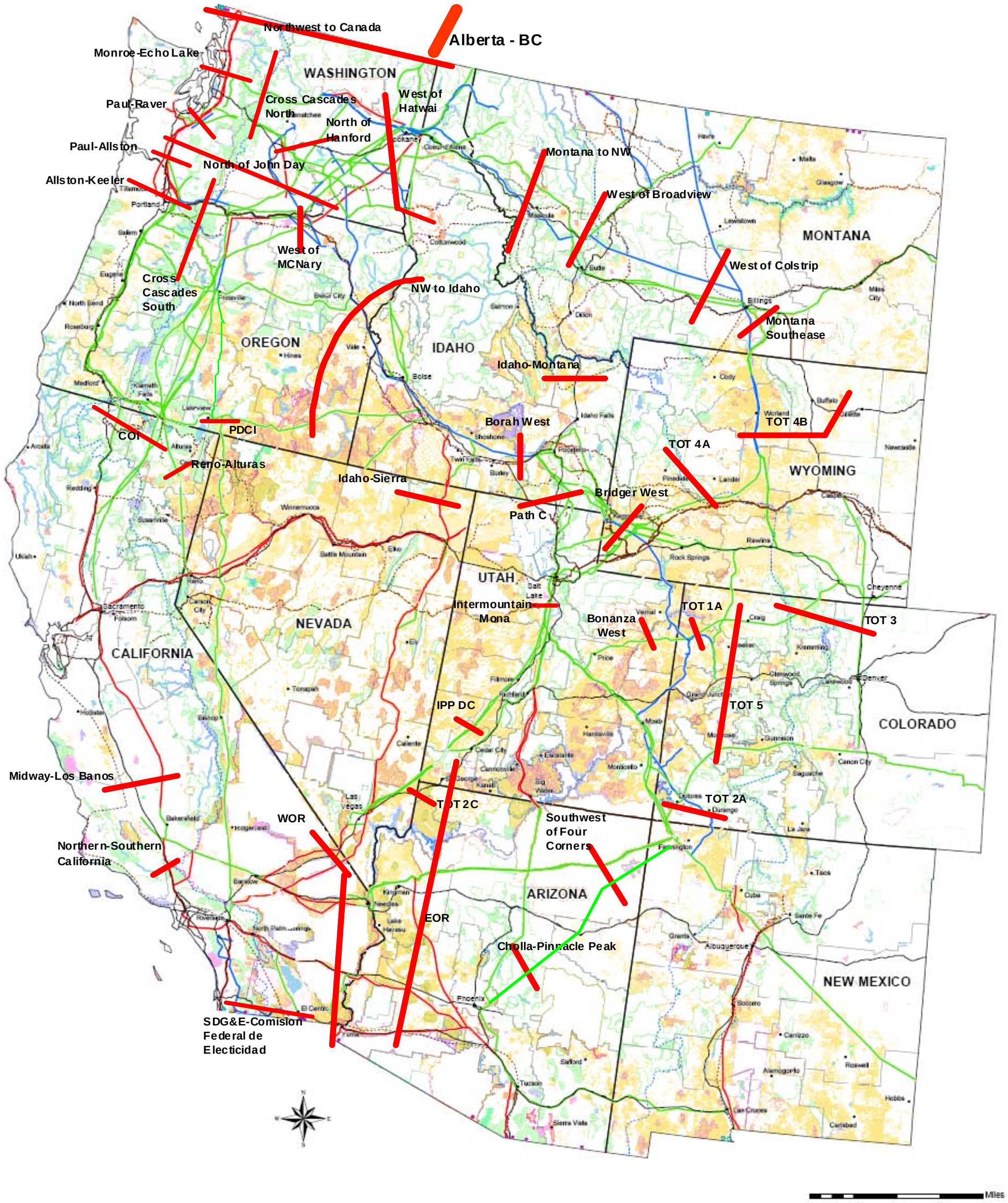
Despite the similarities, the transmission system differs from a highway system in key ways. When the highway system gets overloaded, traffic slows down or stops at one point or another. These conditions can persist for hours until the traffic volume drops down, as for instance, when an extended rush hour is over.

In the electric transmission system, however, the system is not actually allowed to get overloaded in normal circumstances, and in the case of an outage, either of a generator or of part of the transmission system, overloads are allowed to persist for only very short periods of time. Moreover, the amount of the allowed overload is limited by constraints on the amount of power that can be allowed to be generated and flow over the transmission lines ("scheduled"), in normal, non-outage, conditions.

This is done for reliability reasons, because serious overloads will often lead to automatic load or generation disconnections that can in turn lead to wider, uncontrolled cascading loss of load, like the 2003 Northeastern blackout. Overloads can be created almost instantaneously by sudden generation or transmission outages. The operating limits that require these operator or automatic actions are set by NERC and WECC and are based on extensive computer simulations by system planners of the behavior of the transmission system under many different operating conditions. Margins for reliable operation are built into operating procedures, so that the system does not collapse when there is a sudden outage on the system. The operating procedures may require that transmission schedules be cut in the event of a system outage in order to bring power flows and other system parameters within the acceptable limits of the reduced system.

Operating limits are set for and managed by system operators at a number of points or paths on the system. Figure 6a-2 below shows the locations of the major constrained paths in the Western transmission system. A path can often consist of several lines or sets of lines in parallel to each other (several examples of this occur in the Northwest, e.g. North of John Day). Most of the paths in the Northwest are constrained, in the sense that there is little to no capacity available to sell and under certain operating conditions they need to be monitored by system operators to ensure that they do not exceed system operating limits. West of Hatwai, however, in the Spokane area is an example of a path that was upgraded by additional line construction several years ago so that it is no longer seriously constrained.

Figure 6a-2: Western Constrained Paths



When the loading on an individual path, controlled by individual balancing authorities in coordination with their neighbors (see Chapter 11 for more details on what balancing authorities do) reaches these predefined limits, operators do not allow additional transactions to be scheduled. The system can be said to be congested at that point, though it is not overloaded, but is operating normally.

Congestion can occur in a longer-term time frame as well. The amount of transmission service that can be sold in advance is limited so that the total amount sold can actually be scheduled within the reliability limits. This case, when there is no more available transmission capacity

(ATC), is also a form of congestion, even though it does not necessarily lead to a congested operating condition if all of the transmission service that has been sold is not used fully at the same time.

The transmission system is built and upgraded incrementally to meet projected service requirements, so that new service, for new loads or from new generation, can be accommodated within reliable operating limits. Relieving congestion can be costly. Because of the high cost of transmission system upgrades (500 kV transmission lines can cost $2-$3 million per mile to construct, depending on the terrain and land use), transmission is not constructed speculatively. It is constructed to meet forecast native load service requirements and to meet specific service requests from third parties[1], like independent generators or parties wishing to wheel power across a utility's transmission system to a load outside it.

The high cost of expanding the transmission system, particularly with long, high voltage lines and intermediate substations means that some congestion on the system, either on an operating basis or as shown by the absence of ATC for sale, may be an economically appropriate result. This is generally not the case for congestion that could impact reliable load service, but could be for the case of projects designed to access cheaper energy supplies in order to reduce operating costs.

Transmission system improvements range from lower voltage upgrades which may be part of an ongoing system upgrade process at a utility to major high voltage projects which can cost hundreds of millions of dollars and take five or more years to plan and construct. Typically the former do not get as much attention, as they cost less, are done on a more routine basis, and depend more on local conditions and requirements, though some higher-voltage local projects or those in sensitive areas can be expensive and difficult to site and can be subject to uncertainty. The latter, however, because of their cost and land-use impacts can get considerable attention.

For a number of years leading up to the Fifth Power Plan, there was little major transmission project development, although there continued to be upgrades to meet local reliability needs. Partly this was a result of the ability to site natural gas generation closer to load centers and with a smaller requirement for transmission. However, when the Council developed the Fifth Power Plan, there was reason to be concerned about the transmission system. There had been no progress on improving the operation of the transmission system to allow better use of limited existing capacity on the system and there had been little activity in planning for major transmission system expansion.

These problems are now being addressed. There have been important changes in operations though WECC's creation of two new reliability coordination centers in the West and funding of new software that gives the reliability coordinators and the West's balancing authorities clearer and more current information on the instantaneous state of the system. Other operational changes are being considered and implemented in large part because of the pressure to integrate large amounts of variable generation, primarily wind. The operational changes related to wind integration are discussed in Chapter 11.

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[1] These third-party service requests are governed by the FERC Open Access Transmission Tariff (OATT). The OATT specifies the study procedures and financial circumstances under which the transmission owner must respond to third-party service requests.

On the transmission planning side, two subregional planning groups, ColumbiaGrid, centered on Bonneville and the Washington IOUs, and Northern Tier Transmission Group, focused primarily on the east side of the region, have been formed and are conducting planning studies and coordinating transmission development efforts across the Northwest. They are also leading efforts to address the operational changes mentioned above and described further in Chapter 11.

In addition, the Transmission Expansion Planning Policy Committee (TEPPC) has been formed by WECC to develop West-wide commercial transmission expansion planning studies and coordinate and provide information to subregional planning efforts. Finally, a number of projects are being proposed by both utilities and merchant developers, largely in response to the state RPS requirements and increasing emphasis on reducing carbon emissions across the West.

There has also been a significant increase in interest in transmission planning and siting at the federal level. In the Energy Policy Act of 2005, DOE was required to conduct triennial transmission congestion studies and allowed to designate National Interest Electric Transmission Corridors and FERC was given a backstop siting role for transmission proposals in those corridors for which state siting authorities did not act promptly. In the currently developing 2009 national energy legislation, the Waxman-Markey bill that passed in the House contains provisions for regional transmission planning entities to submit plans to FERC, and gives FERC additional backstop siting authority in the Western Interconnection for projects vetted through and supported by a regional transmission plan.

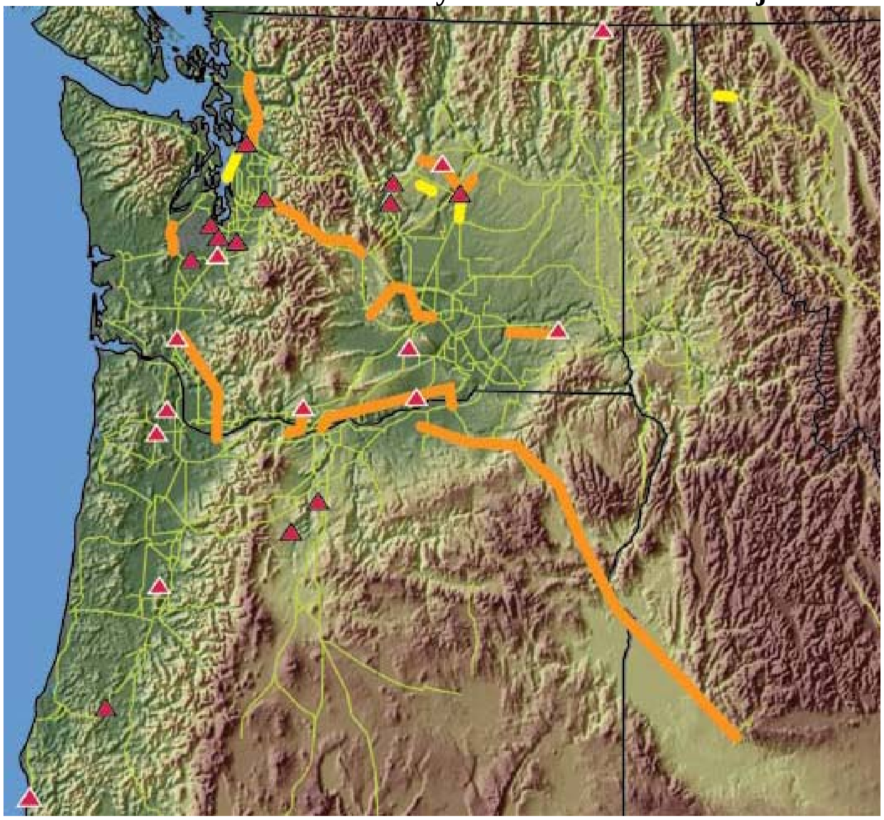
The American Recovery and Reinvestment Act of 2009 (ARRA) has provided DOE with funding for technical support of interconnection-based transmission plans, including support for state and relevant non-governmental organizations to participate, as well as support for state resource planning efforts. WECC, through TEPPC, is working with the Western Governors' Association (WGA) to develop an application for funding, which is expected to be successful. Some of the WGA funding will be used to support completion of the Western Renewable Energy Zone (WREZ) project, which will help coordinate state and utility efforts to target specific areas for renewable development, along with the necessary transmission corridors. This is intended to provide basic input information into the TEPPC transmission planning effort.

NORTHWEST TRANSMISSION PLANNING

ColumbiaGrid, formed in 2006, develops a system assessment and biennial transmission plan for its members. It finished its first biennial plan in 2008, which was approved by its Board and published in February 2009. It has recently published a draft 2009 System Assessment, highlighting the areas in its members' systems that need to be addressed, either by the individual owners, or in the case of issues involving several owners, by a ColumbiaGrid study team. Joint study teams are also formed to address issues and projects that overlap between ColumbiaGrid and adjacent planning groups like NTTG.

This current draft system assessment identified a number of potential reliability issues over the next five and ten years that would need to be addressed by the transmission owners, ranging from relatively local issues such as service in the Olympic Peninsula over the 115 kV system up to wider-scale issues such as service over the 500 kV West of Cascades paths to loads in the I-5 corridor. The transmission owners have identified potential mitigation projects for a number of these issues, which will be studied further in the ColumbiaGrid biennial plan. The main projects studied are shown on Figure 6a-3 below. The underlying transmission system shown on the map is the facilities of ColumbiaGrid members. The Hemmingway - Boardman project is also in the study set, although its sponsor, Idaho Power, is not a ColumbiaGrid member.

Figure 6a-3: ColumbiaGrid 2009 System Assessment - Projects Studied



Source: ColumbiaGrid

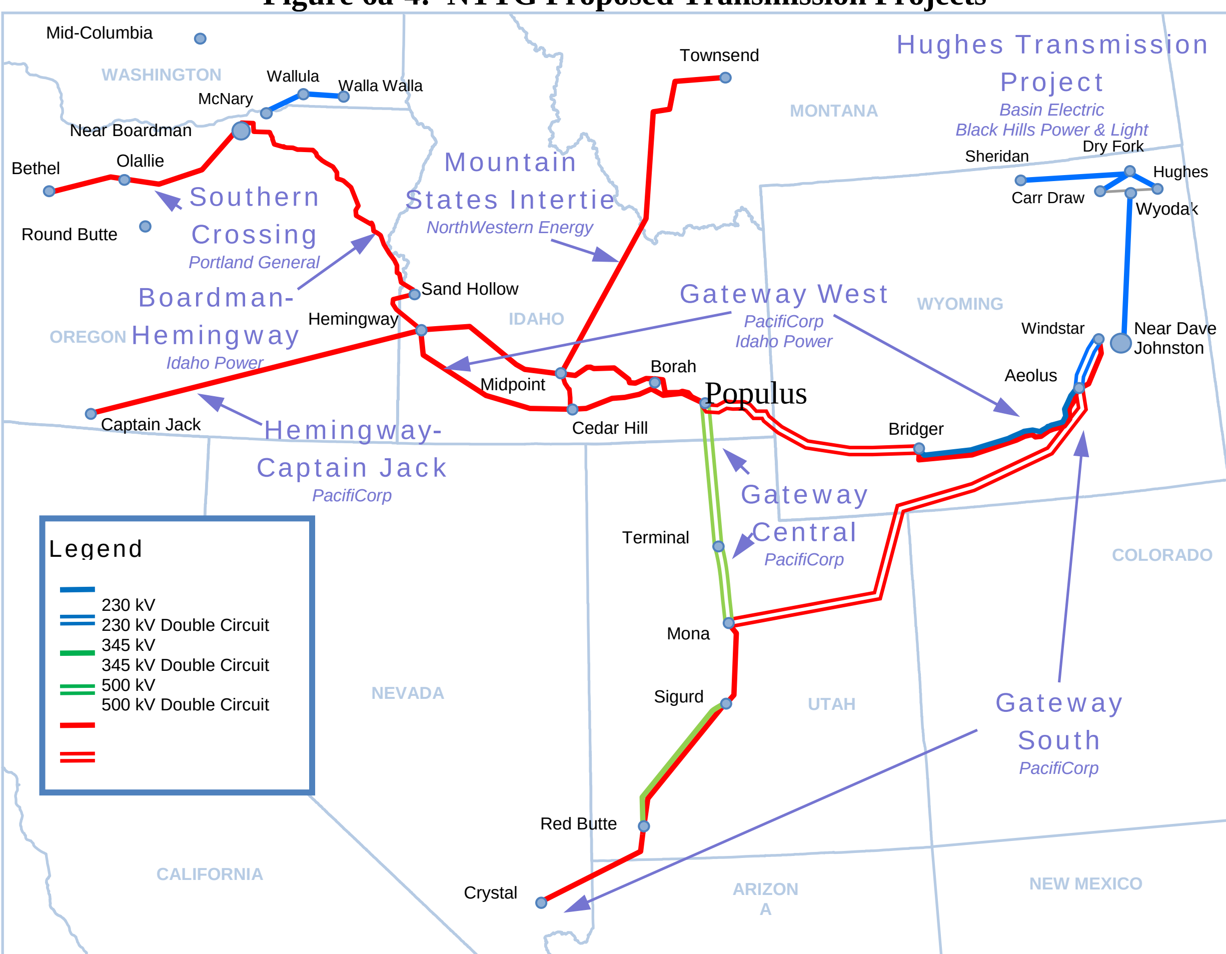
Bonneville, which is a member of ColumbiaGrid, has developed an innovative approach to financing transmission development for dispersed generation projects like wind farms. The first use of this network open season approach was in 2008 and a second open season is being conducted in 2009. The Bonneville approach, approved by FERC, provides for cluster studies of the best approach to serving a number of projects in the transmission service request queue, an offer of service at embedded cost rates with Bonneville providing the financing (to be repaid through wheeling rates when service commences) and reordering of the queue positions for those generation projects not willing to commit to take service with the proposed transmission project. This approach was very successful in 2008 and led to Bonneville's determination to move forward with several major transmission projects, including the West of McNary project and the I-5 corridor reinforcement project. Bonneville was also aided in the ability to finance these projects by the availability of stimulus funding.

This approach improves the default process, required by the FERC OATT, which both requires that service requests be studied in the order in which they were received and puts the financing burden primarily on the entity requesting transmission service. Both of these conditions served as significant impediments to development of large transmission projects to serve a number of smaller wind developments.

Bonneville's approach is one of several modifications to the OATT approach to financing new transmission for renewables that FERC has recently approved. In a 2007 order on the California ISO, FERC allowed modifications to OATT financing requirements for a renewable collector project in the Tehachapi area of Southern California. In October 2008, FERC allowed an incentive rate of return on PacifiCorp's Energy Gateway projects (described below), taking into account their ability to move large amounts of renewable energy to load centers. Recently, FERC held a technical conference on integrating renewable resources into the transmission grid, which may result in modifications to the OATT itself, building on the case-by-case approach employed so far. The Council supports actions such as these to enhance the ability of the transmission system to support renewables and robust markets.

NTTG, formed in 2007, focuses its efforts on larger transmission projects that move power across its footprint, and connect with adjacent sub-regional groups' footprints (ColumbiaGrid and WestConnect). Lower voltage, more local projects are addressed by the individual NTTG transmission owning members. NTTG member have proposed a set of primarily 345 kV and 500 kV projects to meet native load service and transmission service requests under the OATT from potential exporters from the NTTG footprint. These projects are shown on Figure 6a-4 below.

Figure 6a-4: NTTG Proposed Transmission Projects

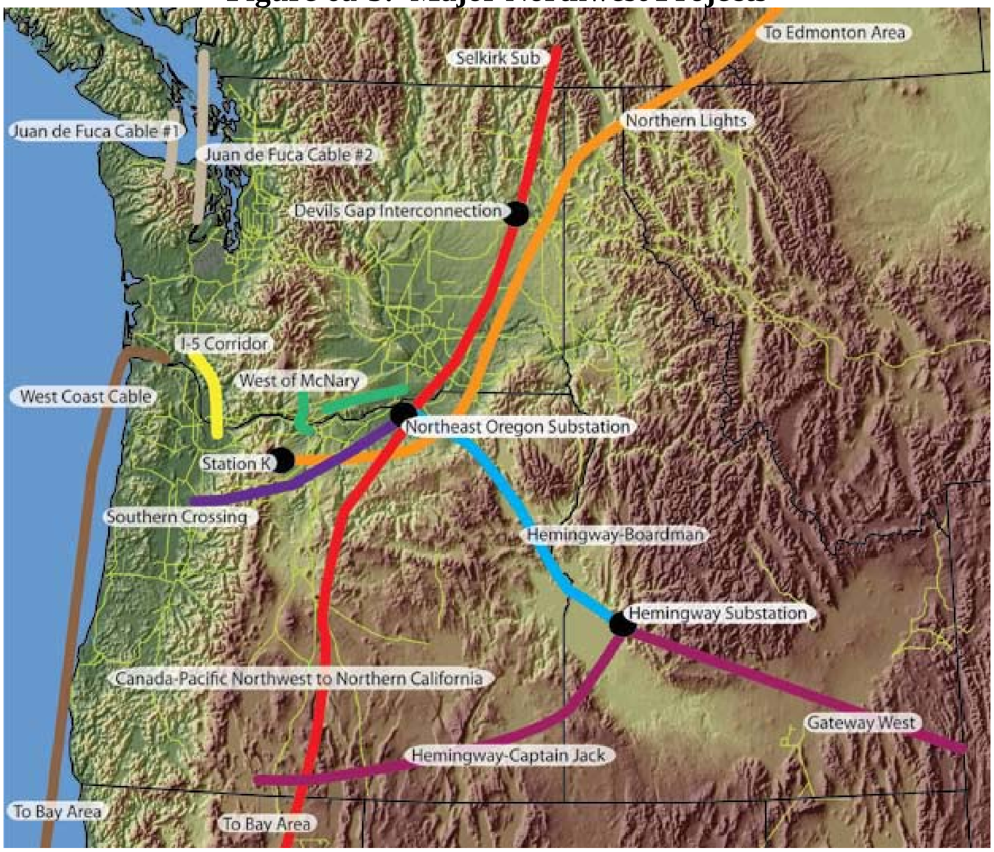


Source: NTTG

ColumbiaGrid, NTTG and the Northwest Power Pool are also jointly sponsoring a project review process to examine potential interactions among various major project proposals that connect with or pass though the McNary area of Northeastern Oregon. The examination of project interactions is a fundamental part of the process of getting an approved rating for a project under WECC procedures. The rating is a foundational part of the determination of reliable operating limits for transmission lines and paths.

The map in Figure 5 below shows projects sponsored by Columbia Grid members, like Bonneville's West of McNary and I-5 Corridor projects, those sponsored by NTTG members, like the Gateway, Hemmingway - Boardman, Hemmingway - Captain Jack and Southern Crossing projects, and those sponsored by others, like TransCanada's Northern Lights, PG&E's Canada - California project, and the Sea Breeze cable projects. There is some overlap between what is shown on Figure 6a-4 and Figure 6a-5.

Figure 6a-5: Major Northwest Projects



Source: ColumbiaGrid

Although there has been a substantial improvement in coordinated regional transmission planning and development over the period since the Fifth Power Plan, some utilities are still facing difficulties in getting transmission access to market hubs and to resources they are planning on to meet future loads or to meet their transmission service obligations to generators under their OATTs. Even the projects that are furthest along in development, like Bonneville's West of McNary project, have not yet surmounted all the possible problems that may face them on the path to completion.

Whether this situation comes from difficulties in siting large transmission lines or from the planning process itself taking longer than anticipated, it can leave utilities in the position of having to acquire back-stop resources to make up for those that they were not able to access reliably due to transmission limitations. The Council recognizes that this can also lead to differences in resource timing and acquisition strategy from those described for the overall region in the power plan. The inability to site needed transmission can also force utilities to make less-desirable resource choices than might otherwise be made, such as precluding access to distant renewables and to regional and other markets. The Council supports and encourages regional transmission planning efforts, recognizing that new transmission investment can be key both to maintaining reliable load service and to bringing new renewable resources in to meet regional loads.

Chapter 7: Direct Use of Natural Gas

THE POLICY QUESTION

The appropriate role for the Council in promoting the direct use of natural gas for space and water heating has long been an issue in the region. The Council has analyzed the technical and the policy issues in a number of studies dating back to its very first plan. While the specific issues have changed somewhat over time, three central questions have remained:

1. Is the conversion from electricity to natural gas for residential space and water heating a lower cost and lower risk alternative for meeting the region's load growth when compared to other options?

2. If so, how much cost-effective "fuel-switching" potential is there in the region?

3. Are fuel choice markets working adequately?

During development of the Sixth Plan, a fourth question has been raised: How does the conversion from electricity to natural gas for space and water heating impact the region's carbon emissions?

Current Council Policy on the Direct Use of Gas Analysis

The Council's current policy on the direct use of natural gas is stated in the text box below. This policy was adopted with the Council's Fourth Power Plan following a detailed analysis of fuel conversion potential and cost in 1994.[1] The policy was reaffirmed in the Council's Fifth Power Plan.[2]

[1] Northwest Power Planning Council. Fourth Northwest Conservation and Electric Power Plan. March 1996 (96-5). Pages 4-10,11.
[2] Pacific Northwest Power and Conservation Council. Fifth Northwest Electric Power and Conservation Plan. May 2005 (2005-7). Page 3-45.

Council Policy Statement

The Council recognizes that there are applications in which it is more energy efficient to use natural gas directly than to generate electricity from natural gas and then use the electricity in the end-use application. The Council also recognizes that in many cases the direct use of natural gas can be more economically efficient. These potentially cost-effective reductions in electricity use, while not defined as conservation in the sense the Council uses the term, are nevertheless alternatives to be considered in planning for future electricity requirements.

The changing nature of energy markets, the substantial benefits that can accrue from healthy competition among natural gas, electricity and other fuels, and the desire to preserve individual energy source choices all support the Council taking a market-oriented approach to encouraging efficient fuel decisions in the region.

The Council has not included programs in its power plans to encourage the direct use of natural gas, or to promote conversion of electric space and water heat to natural gas. This policy is consistent with the Council's view of its legal mandate. In addition, the Council's analysis has indicated that fuel choice markets are working well. Since the large electricity price increases around 1980, the electric space heating share has stopped growing in the region while the natural gas space heat share in existing homes increased from 26 to 37 percent. A survey of new residential buildings conducted in 2004 for the Northwest Energy Efficiency Alliance found that nearly all new single-family homes constructed where natural gas was available had gas-fired forced air heating systems.[3] The survey also found an increased penetration of natural gas heating in the traditionally electric heat dominated multi-family market, especially in larger units and in Washington.[4] Fuel conversion of existing houses to natural gas has been an active market as well, often promoted by dual fuel utilities.

The Council policy on fuel choice has consistently been that fuel conversions, while they do reduce electricity use, are not conservation under the Northwest Power Act because they do not constitute a more efficient use of electricity. However, the Council's analysis has also recognized that in some cases it is more economically efficient, and beneficial to the region and individual customers, to use natural gas directly for space and water heating than to use electricity generated by a gas-fired generator. However, this is very case specific and depends on a number of factors including the proximity of natural gas distribution lines, the size and structure of the house, the climate and heating requirements in the area, and the desire for air conditioning and suitability for heat pump applications. In general, although direct use of natural gas is more thermodynamically efficient (except for the case of heat pumps), it is more costly to purchase and install. Therefore, its economic advantage depends on the ability to save enough in energy costs to pay for the higher initial cost.

[3] Northwest Energy Efficiency Alliance, Single-Family Residential New Construction Characteristics and Practices Study. Portland, OR March 27, 2007. Prepared by RLW Analytics.

[4] Northwest Energy Efficiency Alliance, MultiFamily Residential New Construction Characteristics and Practices Study. Portland, OR June 14, 2007. Prepared by RLW Analytics.

Analysis of the Direct Use of Natural Gas for the Sixth Plan

In 1994, the Council analyzed the economic efficiency of converting existing residential electric space and water heating systems to gas systems.[5] The results of that study showed there were many cost-effective fuel-switching opportunities within the Region, representing a potential savings of over 730 aMW. As stated above, the market, with its high rate of conversions from electric to gas systems, was performing many of the conversions on its own. Consequently, the Council has not included fuel switching or fuel choice measures in its subsequent power plans.

With the financial support and cooperation of the Northwest Gas Association and Puget Sound Energy, the Council, working through its Regional Technical Forum, is conducting an updated economic analyses of fuel conversion for residential space and water heating equipment in existing homes and fuel choice for residential space and water heating equipment in new homes in the Pacific Northwest. While the study's results are not yet available, it is possible to forecast potential implications for the Council's final plan. Should the direct use of natural gas prove to be a lower cost and lower risk alternative for meeting the region's load growth, including potential cost and risk from carbon emissions, the Council will need to assess whether the fuel choice markets are working adequately. If the markets appear to be working adequately, i.e, consumers are selecting natural gas for space and water heating where it makes economic sense, then the Council will retain its current policy which leaves the choice of heating fuels to individual consumers. If however, the market is not working adequately, then the Council may decide to include specific recommendations in the final plan to address this market failure, including but not limited to providing information and promoting efficient pricing of electricity.

The Council's objective for this analysis is to recreate its 1994 study with up-to-date information. The scope of the analysis has been expanded to include new construction for single family applications and both new construction and existing buildings for multi-family applications. The updated analysis is also testing the cost, risk and carbon emissions impact of converting from natural gas to electricity as well as conversions from electricity to natural gas. A major difference between the Council's 1994 study and the current analysis is that all direct use of natural gas alternatives will be modeled as "resources" directly in the Council's portfolio model. This will allow the Council to directly compare the cost and risk associated with meeting regional eletricity loads with conservation and traditional generating resources (including those fired by natural gas) with meeting those same needs by using natural gas directly in the home.

Multiple space and water heating technologies are being considered in the analysis. Individual residential customers have different combinations of these technologies. In addition, each customer has a number of technology options from which to choose when their existing equipment fails and needs to be replaced. This analysis assumes that customers install new equipment only when their existing equipment needs to be replaced because it has come to the end of its useful life. At that time, customers can install the same type of equipment they already have or install a different technology. In new construction, the consumer has the choice of all technologies and energy sources, but once that choice is made, they must live with it for the life of the equipment.

[5] Northwest Power Planning Council. "Direct Use of Natural Gas: Analysis and Policy Options". Issue Paper 94-41. Portland, OR. August 11, 1994.

For example, in one identified market segment, the home has electric forced air furnace (FAF) for space heating and an electric resistance water heater. This study assumes that when the electric FAF fails, it could be replaced with a gas FAF, a gas/heat pump hybrid, or a gas hydronic system. Likewise, when the electric resistance water heater fails it could be replaced with the same type of water heater, a gas tank water heater, or an instantaneous gas water heater.

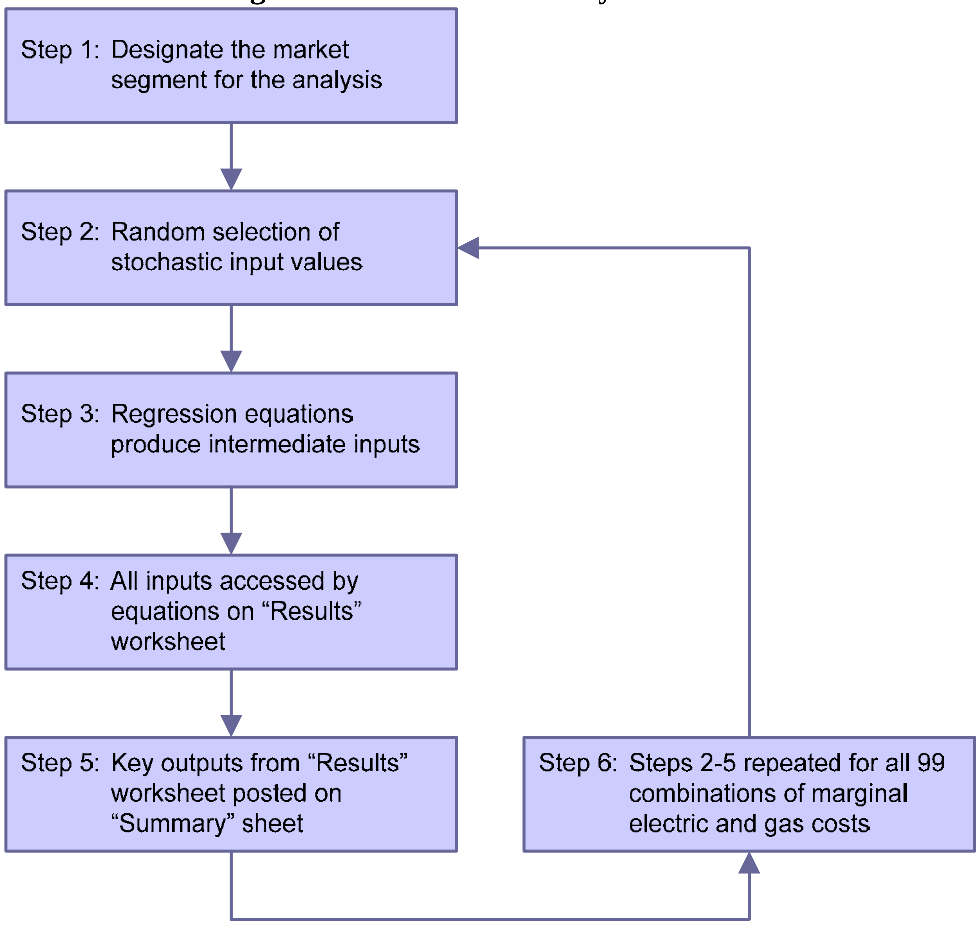
In this study each market segment consists of just one type of equipment for replacement of the failed existing equipment. Therefore, one market segment would include a gas FAF and a gas tank water heater as the retrofit equipment options for the electric FAF system and the electric resistance water heater, while another market segment would specify another combination of technologies.

Each of these technology choices comes at a cost to not only the individual customer, but more importantly, the entire Region. Consistent with the Council's other analysis, this analysis accounts for both the money spent by customers to install a different type of new equipment and the resultant impact on natural gas or electricity consumption, changes in operations and maintenance costs and changes in greenhouse gas emissions.

The economics of these technology choices are highly dependent on the relative costs of natural gas and electricity and the capital cost of conversion. To address the wide range of conversion cost faced by consumers, a "Monte Carlo" model was developed similar to that used in the 1994 Council analysis. The flowchart in Figure 7-1 illustrates the "Monte Carlo" process being used in this economic analysis. It begins by designating one of the 84 market segments for the analysis. The model uses the 84 inputs, 51 of which are stochastic, meaning they are randomly selected. In the second step, the values for the 51 stochastic inputs are selected. Four of the inputs are established by regression equations in Step 3. The inputs for the regression equations are among the stochastic inputs. In Step 4, the 51 stochastic inputs, the four regression inputs, 24 deterministic (fixed) inputs, and two decision inputs (marginal cost of electricity and marginal cost of gas) are accessed by the model's equations. After the completion of the calculations, the values for key outputs are displayed for summary viewing in Step 5. Steps 2 through 5 are repeated at this point, because the model performs all the necessary calculations 1,000 times for each of the 88 market segments and for each of the 99 combinations of marginal electric and marginal gas costs.

A complete description of the direct use of natural gas economic model and the input assumptions used in the model appear in Appendix O.

Figure 7-1: Economic Analysis Process



Once the Monte Carlo model has identified the most economical market choices for fixed combinations of natural gas and electricity prices this information will be feed into the Regional Portfolio Model (RPM). The RPM will then be used to test the economics of each technology choice over wide range of future natural gas and electricity price combinations. This analysis will seek to determine whether across the entire range of electric and gas cost combinations there are conversions to natural gas that are economically efficient and which result in lower risk to the region's power system.

Results of the analysis will be added in the final Sixth Power Plan as well as any policy changes and action items related to the findings.

Chapter 8: Developing a Resource Strategy

INTRODUCTION

This chapter describes the Council's treatment of risk in its planning analysis. In particular it describes studies that use the Council's regional portfolio model. This computer model simulates the development and operation of the region's power system in an uncertain world.

The Council's plans always recognized uncertainty. Its Fifth Power Plan, however, was the first of its plans that used the portfolio model to analyze strategies over hundreds of futures.

The chapter describes the model's approach to evaluating and selecting portfolios. It discusses the interpretation of the results of testing thousands of portfolios against 750 futures. The chapter then describes each of the sources of uncertainty that are included in the portfolio model for the Sixth Plan. The basic financial assumptions that are used throughout the planning analysis are described. These include rates of inflation, the cost of capital for various entities, equity to debt ratios, and discount rates. This chapter also includes a description of the way transmission is accounted for in the plan's analysis.

The chapter concludes with a discussion about effects that are not captured in the model.

DEVELOPING A RESOURCE STRATEGY

Risk assessment has been central to Council planning since the first Plan. The Council's resource portfolio and forecasts must, by statute, address regional requirements over the next 20 years. However, reliably forecasting factors on which the plan relies is difficult, if not impossible. Therefore, the Council must assess cost and risk, both to power rates and to the environment, under significant uncertainty.

Earlier plans looked at an array of uncertainties and sources of risk. Load uncertainty, fuel price uncertainty, and hydro generation variability figured prominently in the conclusions of the plan. Those portfolios incorporated gas and coal price excursions in forecasts and sensitivity analyses. They also considered capability to export and import various amounts of power to and from outside the region. Since the first power plan, the Council has analyzed the value of shorter lead times and rapid implementation of conservation and renewables. The Council has also valued "optioning" generating resources. Optioning refers to carrying out pre-construction activities and then, if necessary, delaying construction until conditions favor going ahead.

In the Fifth Power Plan, the Council extended its risk assessment and management capabilities. It developed a computer model that enabled the Council to look at decisions made without the perfect foresight that most models assume. Studies captured the costs associated with portfolios that adapted to changing circumstances and alternative scenarios. Moreover, the model permitted the Council to examine thousands of portfolios at a time. The studies broadened the scope of uncertainty. New uncertainties included those associated with electricity market price, aluminum smelter loads, carbon emission penalties, tax credits, and renewable energy credits.

This Sixth Plan builds on the lessons and techniques of the Fifth Plan. Council studies now incorporate uncertainty about power plant construction costs and availability. Studies track carbon production using several new techniques, and the impact of carbon penalties move to center stage. The representation of conservation and demand response continues to evolve.

The treatment of uncertainty and management of risk require suitable study concepts and techniques. The next section describes how uncertainty, cost, and risk bear on the selection of a resource portfolio.

Resource Strategy is Tied to the Act

The Council's Power Plan identifies resource strategies that minimize the expected cost of the region's electricity future. The Act calls for a plan that assures an "adequate, efficient, economic, and reliable" power supply. Efficient and economical are interpreted to mean economically efficient, and net present value (NPV) system cost is arguably the best indicator of such efficiency.

The expected costs of any given portfolio, however, hide a wide distribution of potential outcomes. Changes in markets and legislative policy will cause the cost of a portfolio to vary significantly depending on the circumstances encountered.

The Council's Resource Portfolio Model (RPM) evaluates possible portfolios over 750 different possible future sets of conditions to assess how each portfolio is affected by changing conditions.

The average of the outcomes, that is, the average of NPV system costs, gives us an idea of the most likely cost outcome. Most futures will cluster around this value. Comparing average NPV system costs gives us an indication of which portfolio is most likely to achieve the Act's goal of an economically efficient system.

If the "best" portfolio is one that is economically efficient and has low NPV, what would a "bad" portfolio be? A portfolio would certainly be bad if it failed to meet the other requirements of the Act, adequacy and reliability. Consequently, the Council screens out such portfolios. That leaves, however, very many portfolios, including ones that are overbuilt and quite expensive.

It stands to reason that a portfolio that met the other requirements would be considered "bad" if it had a high NPV. This is the principal reason for the Council's risk measure.

The risk measure is the average of the highest 10 percent NPV cost outcomes across the 750 futures. We cannot know in advance what the future will bring. We cannot know whether we may find ourselves in a future that would result in a high NPV. Consequently, we endeavor to find portfolios that minimize exposure to the worst futures and outcomes envisioned.

Using these definitions of cost and risk, therefore, maximizes the chance of identifying portfolios that achieve the Act's original objectives. Such a resource portfolio is likely to be lowest-cost. It recognizes, however, that our ability to forecast is extremely poor. Consequently, it must not perform too badly even if our assumptions are wrong or the region finds itself in the worst circumstances.

Portfolio Selection

To understand the Council's approach requires a little background. Some familiarity with the meaning of several terms, as the Council uses them, is helpful.

A ***future*** is a specific combination of values for uncertain variables, specified hourly over the study period. For the Council's work, a future will be a specific sequence of hourly values for each uncertainty. A future is hourly electricity requirements for twenty years, combined with hourly electricity prices for twenty years, combined with hourly (or daily) natural gas prices for twenty years, and so forth. The number of sources of uncertainty considered in Council studies would render the enumeration here unwieldy, but the next section describes them generally.

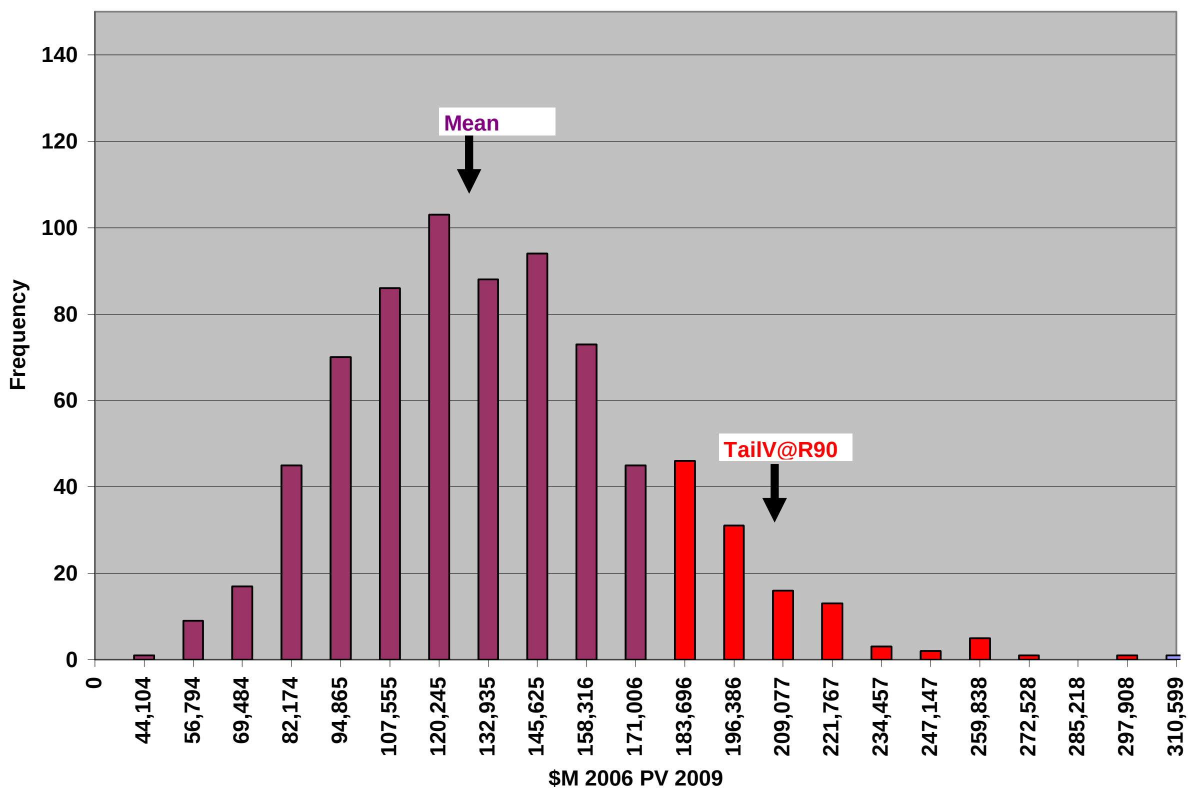
Given a particular future, the primary measure of a portfolio is its net present value total system cost. These costs include all variable costs, such as those for fuel, variable operation and maintenance (O&M), long- and short-term purchases. These costs also include the fixed costs associated with new plants and investment and with operations and maintenance. The present value calculation discounts future costs to constant 2006 dollars. Discounting and other financial assumptions are discussed in Appendix N: Financial Assumptions and Discount Rate.

The futures differ significantly one from the other. While some planners would base future uncertainty on historical patterns, the Council recognizes that future markets and other sources of uncertainty rarely resemble the past. Some would refer to a Council future as a scenario. They typically include some historically unprecedented paths for prices, loads, and other variables. A small number may have unlikely but not impossible future behavior.

The Council's treatment of uncertainty reflects the potential for a larger pool of contributing factors than history provides. The model uses larger variation and weaker relationship among sources of uncertainty to achieve this effect. In this manner, studies provide for the possibility of technological innovation, legislative and regulatory initiatives, transformation of markets, and other "unforeseeable" events. Combining futures in unlikely ways, moreover, reveals how different sources of uncertainty can combine to bring extraordinary risk. The next section describes the nature of specific sources of uncertainty.

The effect of different futures on the cost of a portfolio produces a distribution of portfolio costs. This distribution is the source of expected cost and risk attributed to that portfolio. Figure 8-1 represents the number of times the net present value cost for a single portfolio under all futures fell into specific ranges or "bins." That is, each bin is a narrow range of net present value total system costs.

Figure 8-1: Example of a Portfolio Cost Distribution



Source: "Costs Illustrated.xls", worksheet "distribution"

Because a simulation typically uses 750 futures, the resulting distributions can be complicated. Representative statistics make manageable the task of capturing the nature of a complex distribution.

The *expected* net present value total system cost captures the central tendency of the distribution. As mentioned earlier, this gives us an idea of the most likely cost outcome. Comparing average NPV system costs gives us an indication of which portfolio is most likely to be least cost.

The ***measure of risk*** that the Council adopted is TailVaR_{90}. Briefly, TailVaR_{90} is the average value for the worst 10 percent of outcomes.[1] It belongs to the class of "coherent" risk measures that possess special properties. These properties assure the measure reflects diversification benefits of resources in a portfolio. They capture the magnitude and likelihood of bad outcomes, rather than the predictability of or range of distribution for an outcome. As mentioned above, use of TailVaR_{90} is also consistent with the spirit of the Act.

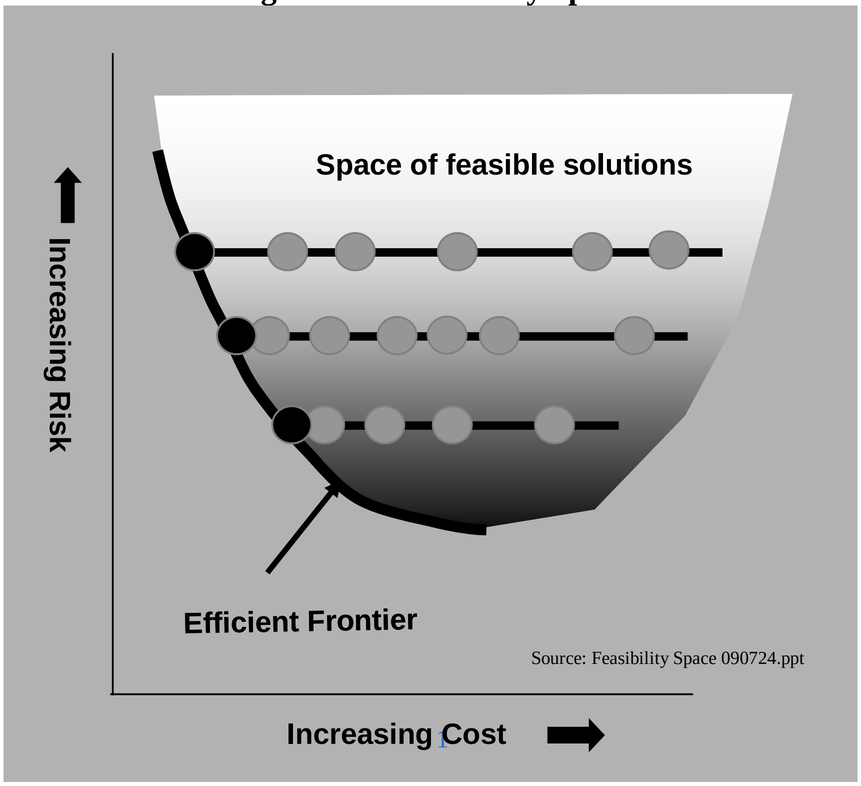
Using these two statistics, Council studies associate the cost and risk of a portfolio with a point on a graph. The horizontal axis measures the portfolio's cost and the vertical axis measures the portfolio's risk. This way, a large number of portfolios, or resource strategies, can be compared on these two measures. A typical study evaluates 2,000 to 5,000 possible portfolios. The set of all portfolios is a ***feasibility space***, an example of which appears in Figure 8-2.

For each level of risk, there is a level, horizontal line passing through the feasibility space. The left-most portfolio in the feasibility space on that line is the least-cost portfolio for that level of risk. The ***efficient frontier*** of the feasibility space will contain only least-cost portfolios. A portfolio that does *not* lie on the efficient frontier is "inefficient" in the following sense. For any "inefficient" portfolio, there is another portfolio that is "better", because it has both lower risk ***and*** cost. This construct enables the Council to identify preferred portfolios and policies to meet its risk requirements.

Because the Council typically evaluates thousands of portfolios, the efficient frontier permits the Council to narrow its search, typically to a fraction of one percent of these portfolios. It does so without invoking weighting factors or other, more problematic schemes that have been used to assess decisions with multiple objectives.

[1] See Appendix P of the Fifth Power Plan for a more detailed discussion of this risk measure and a comparison with other risk measures.

Figure 8-2: Feasibility Space



The Council's approach to resource planning could be called "risk-constrained least-cost planning." Given any level of risk tolerance, the efficient frontier finds portfolios that achieve that level at least cost. In this sense, it is comparable with traditional utility integrated resource plans (IRPs), also referred to as "least-cost" plans. If risk is ignored, the "least-cost" plan is the upper-left most portfolio on the efficient frontier.

Risk, however, often expresses itself over short periods of time. Viewed from the perspective of lifetime income, the loss of a home to fire or the cost of a serious accident may not appear so significant. This is especially so when that loss is compared to the cost of a lifetime of insurance premiums. Insurance, however, often makes it possible to weather brief but severe events. Bankruptcy is another example. It is often due to short term cash flow disruption, not lifetime wealth or even the availability of assets.

By the same token, the NPV study cost is a rather coarse sieve for evaluating portfolios that reduce risk. As we move to examine portfolios along the efficient frontier, therefore, it is appropriate to refine our study.

Before discussing the risk mitigation value of portfolios, however, we need to introduce the Council's notion of a ***portfolio***. We will see this definition is tied directly to concerns about and aspects of risk.

Model Portfolios

The Council's resource portfolio does not look like a traditional firm resource plan to meet firm electricity demand. For example, it does not contain completion dates for new resources that will just meet load growth when needed.

The Council's definition of a resource portfolio consists of two elements. For most conventional resources, the portfolio specifies the option dates for specific types and amounts of generating resources. A resource is optioned when the design, siting, and licensing have been completed and it is ready for construction to start.

The second element of the portfolio consists of policies for conservation and demand response (DR). Policies include premiums that should be paid over market price for conservation acquisitions. Instead of the detailed optioning described above, the model specifies levels of demand response deployed in a portfolio through a limited number of prescribed schedules.

The option schedules, conservation premiums, and DR deployment for portfolios that lie on the efficient frontier are determined through a computerized search process. The model tries random portfolios but is capable of learning from the results for prior portfolios. By trying modifications of more successful portfolios, it attempts to minimize the cost of the power system at different levels of risk.

The reason for including such a resource portfolio construction rule lies with the nature of risk associated with constructing generating resources. A significant source of risk to the region arises from inaccurate forecasts of the need for or the value of a generating resource. Both building a resource that is not needed, and having insufficient resources, can cost the region. The Council's model reflects the reality that decision makers can never be sure of how the future will work out.

The opportunity to construct a resource is prescribed by a given portfolio. Given such an opportunity, the model makes a decision whether to proceed with construction. This decision is based on what the model thinks about the future value of and need for that resource. This decision is based on what prices and requirements have been in the future up to that point. In particular, it makes its decision without knowledge of what will happen subsequent to that decision.

The conservation acquired and the generating resources constructed in a given portfolio will be different in each of the 750 futures. The actual construction of generating resources and the acquisition of conservation in a study future will therefore depend on how the particular future unfolds. Candidate portfolios are tested against 750 possible futures.

Moreover, constructing the plant does not guarantee it will perform well economically. Just as in life, circumstances change without notice. The model, however, keeps track of the consequences of the portfolios it tests, and the outcomes inform the selection of better portfolios.

The resulting resource portfolio is one that addresses the risks inherent in the future, not one that is minimum cost for one specific future.   Portfolio resources will not cover their costs exactly in model simulations. Some will do very well in certain futures and poorly in others. Resources do not even cover their costs in an "average" sense across futures. For example, what determines whether they fall on the efficient frontier at the least-risk end is how they perform in the worst futures.

A traditional resource plan cannot address such scenario risks. Alternative scenarios can be tested in a traditional sense. This gives the planner an idea of how the ideal plan might change if the future turns out different. It will not, however, tell the planner how to prepare when he doesn't know which future will occur.

Because the Council's power plan directly addresses risk, some aspects of its portfolio may look contrary to a traditional approach to resource plans. In traditional planning, new resources were stacked up against growing loads so that new resources were scheduled at a particular date to meet requirements. Uncertainty about requirements was considered by looking at different levels of load growth. Uncertainty about hydro conditions was addressed by planning for only critical water conditions. These plans did not consider uncertainty about the cost of resources, the price of market power, or changing policies that could dramatically affect the cost of different strategies.

The Council's plan recognizes, however, that it may be advantageous to develop a portfolio for simultaneous construction of different types of resources. In any given future, only one of these might be constructed. From a traditional load-resource balance perspective, the option schedule might suggest the region would be overbuilt.

Interpreting Portfolio Costs

Future costs of the power system in the Council's RPM are expressed in traditional planning terms. They are the net present value of future power system costs that can vary with resource choices made in each future for the portfolio. They include the operating cost of existing resources and the capital and operating costs of future resources. The capital costs of existing resources are sunk cost and are not affected by future resource choices.

An important distinction exists between the NPV system costs shown in illustrations of the feasibility space and the ***optioning cost*** of a particular portfolio. The NPV system costs include costs that are largely outside the control of decision makers. They include, for example, carbon penalties and natural gas costs. Option costs are the costs for siting, planning, and licensing new generation. They may also include some above-market cost for conservation, depending on one's view. These are decisions within the scope of what decision makers control.

It is a common misinterpretation of the efficient frontier that the region is paying the change in portfolio cost to achieve the change in portfolio benefit represented by the frontier. The costs, however, represent distinct attributes of ***outcomes***. The decision maker cannot pay the difference in cost, because he or she does not get to choose the final cost. They can pay the optioning costs of the resources, but these typically are a fraction of a percent of the average costs illustrated on the efficient frontier. The benefits of optioning resources can, on the other hand, be much larger than the scale of the efficient frontier. Again, the efficient frontier is only a screen for portfolios.

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.

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. Because of this, certain “end effects” are neutralized. It is typical to assume that the economics of the plant beyond the study horizon are represented by the economics of operation within the study.

This all works just fine unless we have good reason to believe that the economics during the study cannot represent operation beyond the study horizon. 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. 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.

Even though the costs beyond the planning horizon are discounted and carry decreasing weight over time, they still increase the measure of cost significantly. For example, one study showed that the perpetuity factor increased NPV study costs from $38.5 B to $105.5 B, a difference of 175 percent.[2]

The Council does translate the portfolio cost into rate effects in order to make the results more meaningful to consumers and others. There are several steps necessary to convert the annual operating costs and construction costs for new generation into rates. First, the fixed costs of the existing power system (generating resources, transmission, and distribution) need to be added because these are still being recovered in rates. Second, portions of cost included in the planning power system costs that aren’t recovered through consumer rates need to be subtracted. This is primarily the portion of conservation cost that is not paid by utilities. Third, the Act’s credit for conservation, which is not present in the model’s costs, is added back. These adjusted costs are divided by electricity sales, net of conservation, to get an estimate of electricity rates.

It should be noted that the model uses real levelized costs to represent costs for new generation and conservation. To the extent that utilities expense conservation, however, these costs will differ from actual costs. Moreover, if utilities depreciate assets or pass along plant construction expense non-uniformly over the life of the plant, these costs will differ. This is often the case for tax expense, for example. If costs are recovered from ratepayers non-uniformly for any reason, these costs will differ. Nevertheless, the rates presented here should be indicative.

[2] L811n future 742 versus L811 future 1987.

Interpreting Carbon Emissions and Costs

A new measure of power system performance is the emissions of carbon dioxide. It is important because of various greenhouse gas reduction targets and proposed policies to price carbon emissions through a tax or a cap and trade system.

Measurement of regional carbon emissions is more difficult than one might think because of electricity trade among regions. Estimating the emissions from an individual power plant is relatively straightforward. But electricity trading creates a variety of options for counting emissions. One option is to count only the emissions of power plants actually located in the Pacific Northwest. Another is to count, in addition, the emissions of power plants that are located outside the Pacific Northwest, but whose output is contractually committed to serve Northwest loads. A third is to count the carbon content of all electricity used to serve Northwest loads. This requires adding an estimated carbon content of imported power and subtracting the estimated carbon content of exported power from Northwest emissions.

The rules for such accounting have not been established, and proposed rules often vary by state and region. Such calculations are further complicated by the fact that electricity that is traded in wholesale markets is not typically identified as coming from a particular plant or technology. For example, is power exported from the Northwest hydroelectricity with no carbon emissions, or is it coal-fired generation with large carbon emissions?

Because the accounting treatment is not settled, the RPM reports carbon emissions in two different ways. One is based on generation located within, or contracted to, the Pacific Northwest (generation based). The other is based on the consumption of electricity within the region (load based).

For the purpose of calculating load-based carbon, the model assumes imported and exported power has the same carbon loading, 1,053 pounds of CO_2 per megawatt hour. This corresponds to a natural gas-fired combustion turbine with a heat rate of 9,000 BTU per kilowatt hour. Regional generation averages a somewhat lower loading factor; surrounding areas average a somewhat higher loading factor during periods when the Pacific Northwest in importing. This loading factor does not reflect the fact that alternative carbon control regimes may shift the effective carbon loading. This assumption does have the advantage, however, of being simple and easy to understand. Moreover, it closely resembles the assumed carbon loading adopted by Washington State Department of Commerce[3] and the California Energy Commission.

Low Risk Portfolios

The feasibility space and efficient frontier are really a means to filter down the number of portfolios to a handful for more careful study. The Council looks beyond expected NPV cost and risk to distinguish portfolios. Often, risk originates from short-term events within a future. For example spikes in market electricity prices such as occurred in 2000-2001 can create huge cost increases if the region is overly exposed to the market. The imposition of a high carbon penalty can lead to high cost futures if the region has become over reliant on coal. The Regional

[3] See final opinion on California Energy Commission Rulemaking 06-04-009, issued September 12, 2008, which calls for a default value of 1100 pounds per MWh; and Tony Usibelli
Assistant Director, Washington Department Of Community, Trade And Economic Development, to the CEC regarding this rulemaking, dated July 10, 2007, which uses 1,014 pounds per MWh.

Portfolio Model is designed to assess such risks and help the Council build resource strategies that will help avoid the impacts of such events.

The portfolios along the efficient frontier are distinguished by cost and risk. At the low-risk end of the efficient frontier, a portfolio's behavior in the worst 10 percent of outcomes determines its selection. It follows therefore that the benefits of a low-risk portfolio are revealed in those futures. The model evaluates each portfolio against about 750 future conditions; combinations of uncertain carbon costs, demand growth, electricity and fuel prices, hydroelectric conditions, and other variables. It is informative, however, to see which futures result in bad outcomes for the least-cost and least-risk portfolios. This isolates principal sources of uncertainty and may suggest alternative risk mitigation mechanisms.

Risk mitigation does not affect all futures equally. Low cost futures become more expensive; high cost futures become less expensive. The average cost of the low-risk portfolio will be slightly higher, but it provides protection, similar to an insurance policy, against the most costly future events. Understanding why particular resources in the low-risk portfolio provide this protection yields insight into their value.

Other evidence of reduced risk is reduced rate volatility and reduced exposure to the wholesale power market during high price excursions. These characteristics of portfolios along the efficient frontier were explored in more detail in the Council's Fifth Power Plan.[4]

In general, portfolios near the lower risk end of the frontier contain more resources and rely less on the wholesale power market. By reducing price volatility and building more resources these low-risk portfolios are more consistent with regulatory preferences and utility planning criteria than the lower cost but higher risk portfolios.

SOURCES OF UNCERTAINTY

Wholesale Power Prices

It would be difficult and expensive for an individual utility to exactly match electricity requirements and generation at all times. Therefore virtually all utilities participate in the wholesale market, directly or indirectly, as buyers and as sellers. This is particularly so for regional utilities because the region's primary source of generation, hydroelectricity, is highly variable from month to month and year to year.

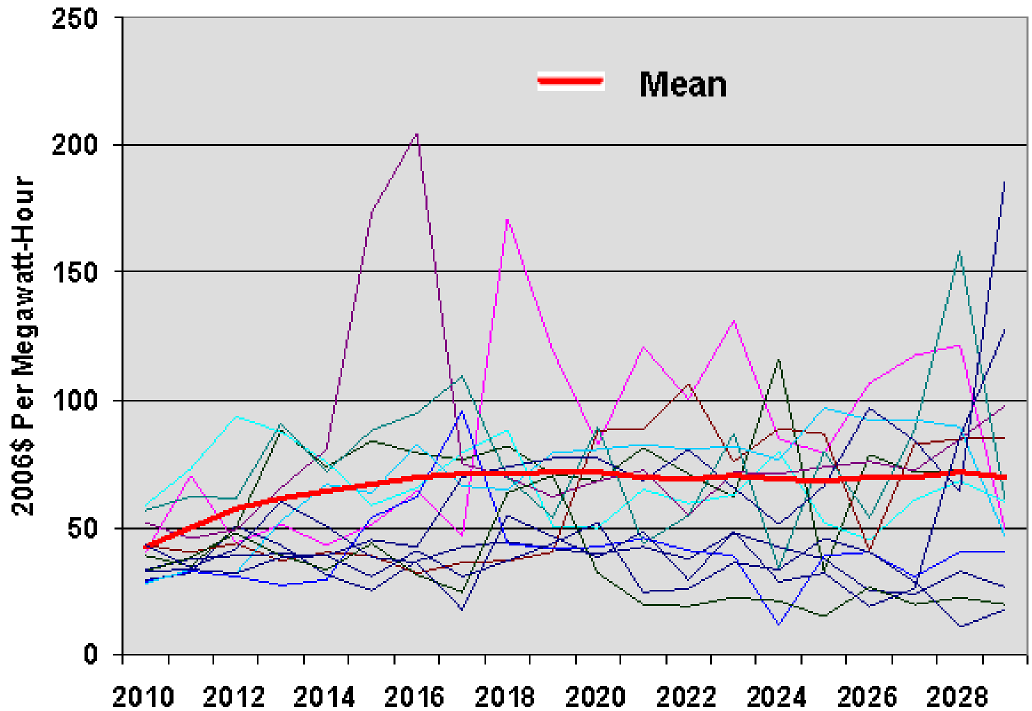
Whether a utility has surplus generation or needs to purchase power affects the magnitude and direction of change in costs to electricity consumers when wholesale power prices rise. That is, if electricity market prices go up, consumers' costs can go up if the utility needs power. If the utility has surplus power to sell into the market, however, and electricity market prices go up, electricity costs will come down. This illustrates that uncertainty in wholesale power prices, like other uncertainties, does not necessarily lead to risk. Risk resides with a utility's overall portfolio of requirements and resources, rather than with one resource, one requirement, or one kind of fuel.

[4] Northwest Power and Conservation Council. The Fifth Northwest Electric Power and Conservation Plan. Volume 2, Chapter 7.

Disequilibrium between supply and demand is commonplace for electricity markets. Disequilibrium results from less than perfect foresight about supply and demand, inactivity due to prior surplus, overreaction to prior shortages, and other factors. Periods of disequilibrium can last years. The resulting excursions from equilibrium prices can be large relative to the routine variation due to temperatures, fuel prices, plant outages, and hydro generation. These excursions are a significant source of uncertainty to electric power market participants, and they are therefore an important part of Council studies.

Figure 8-3 shows a sample of electricity price futures from among those that the Council's model uses. Description of the Council's electricity price forecast is in Chapter 2 and Appendix D.

Figure 8-3: Electricity Price Future



Load Uncertainty

The Council's model assumes a larger range of variation in loads than present in the Council's official load forecast for the Sixth Plan. The additional variation stems in part from seasonal and hourly patterns of load and from weather variation. A much larger source of variation, however, is uncertainty about changing markets for electricity, possible technology innovations, and excursions due to business cycles. In a section below, this chapter elaborates on the uncertainty associated with new technologies.

Figure 8-4: Load Futures

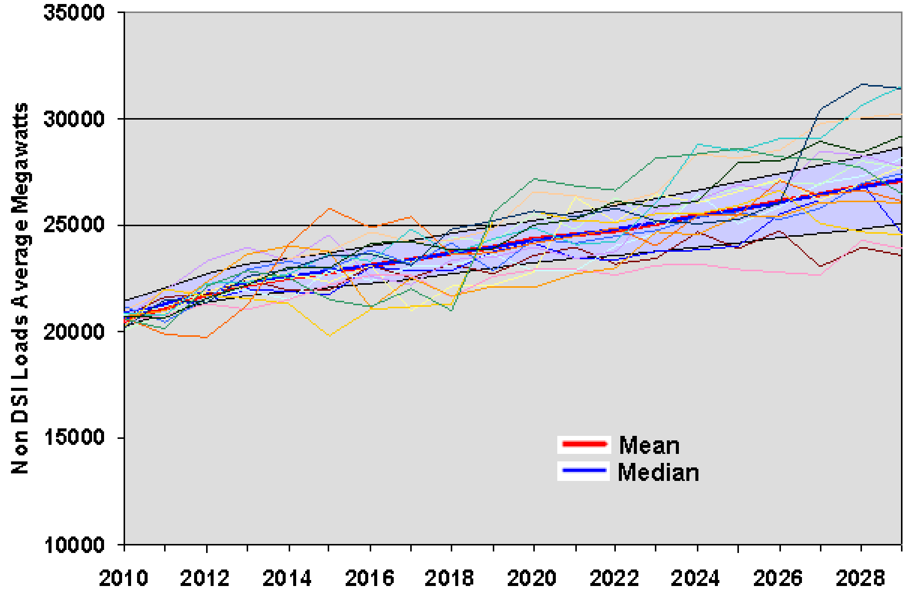
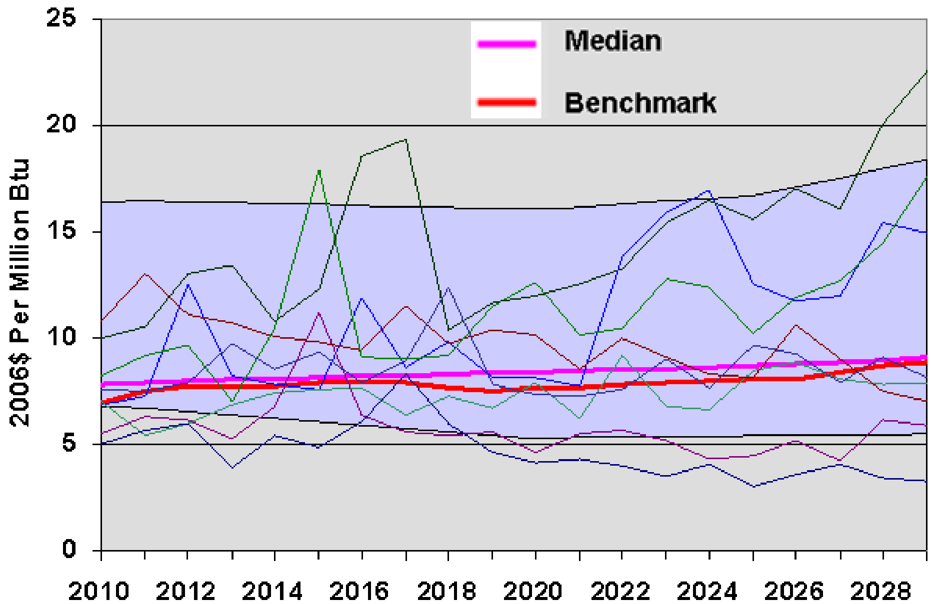


Figure 8-4 displays a sample of load futures from the Council's model simulations compared to the shaded trend forecast range. Detailed description of the Council's official load forecast appears in Chapter 3.

Fuel Prices

The basis for uncertain natural gas price trends is the Council's fuel price forecast range as described in Chapter 2 and Appendix A. In addition to uncertainty in long-term trends in fuel prices, the modeling representation uses seasonal patterns and brief excursions from these trends. These excursions may last from six months to four years and then recover back toward the trend path. The duration of the excursion and the duration of the price recovery are both functions of the size of the excursion. Figure 8-5 illustrates some natural gas price futures from the portfolio model simulations (2006$).

Figure 8-5: Gas Price Futures



Hydro Generation

A 70-year history of streamflows and generation provide the basis for hydro generation in the model. The hydro generation reflects constraints associated with the NOAA Fisheries 2008 biological opinion. Moreover, studies evaluate resource choices assuming no emergency reliance on the hydro system, even though such reliance might not violate 2008 biological opinion constraints.

In addition to meeting fish and wildlife requirements, hydro operation must satisfy other objectives. These objectives include standard flood control, river navigation, irrigation, recreational, and refill requirements. All studies incorporate these constraints.

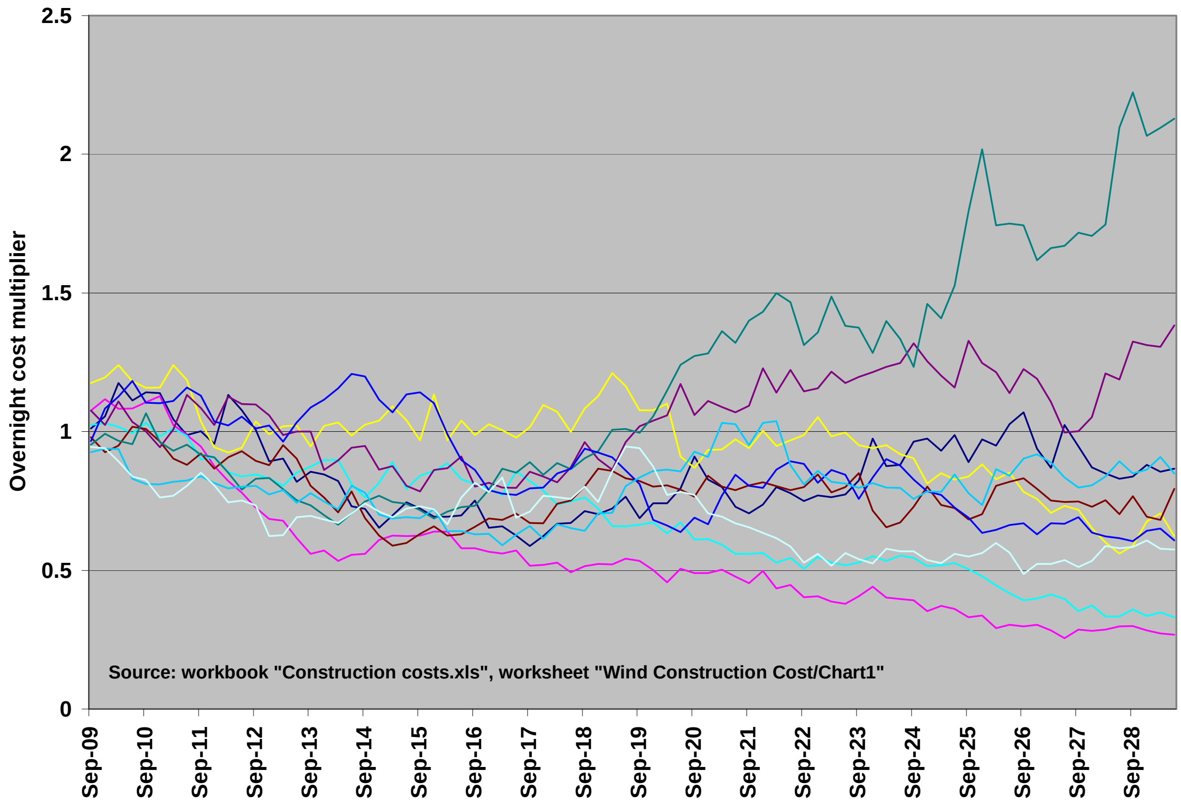
The modeling assumes no decline of output over the 20-year study period due to relicensing losses or other factors that might lead to capability reduction. Nor does it assume any increases due to deployment of removable spillway weirs or turbine upgrades. Chapter 9 does feature, however, a study of the potential effects of possibly removing the four Lower Snake River dams.

Resource Construction Costs

Recent resource development has revealed costs that are significantly higher than anticipated in earlier planning. The details of expected costs for resource technologies over time appear in Chapter 6 of this plan. These expected costs, which typically trend downward over time, serve as the benchmark for resource construction cost futures the model uses to capture construction cost uncertainty. The Council's Generating Resource Advisory Committee assisted the Council in characterizing the types and likelihood of futures for construction costs.

The Council's model uses these futures to assess the likely future economic value of resources, among other things. Economic value is one aspect of the decision the model makes within a future whether or not to construct a resource.

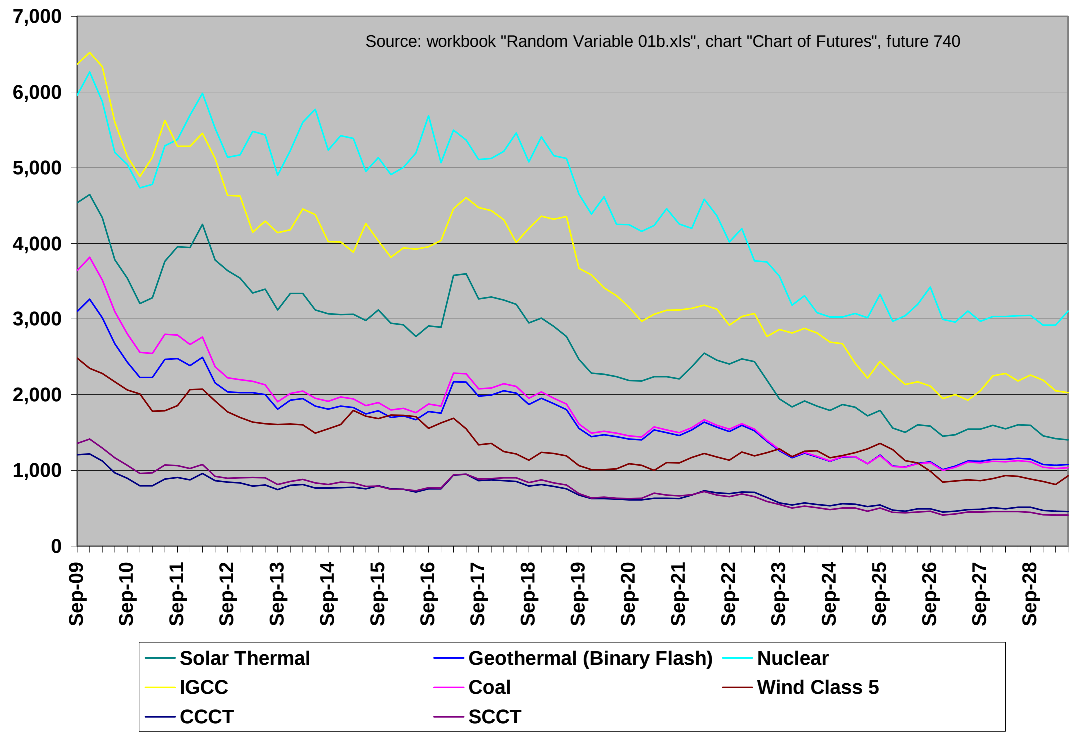
Figure 8-6: Construction Cost Futures for Wind Generation



Several cost futures for wind generation resources appear in Figure 8-6. Each future is a sequence of cost multipliers for overnight construction. They are applied to a figure of dollars per kilowatt of capacity for a wind plant to determine the effective "overnight" construction cost for that plant. The overnight construction is the total dollars spent over the plant's construction cycle, but it does not include any costs for financing or for delays in construction. Figure 8-6 therefore represents how the overnight cost for constructing a power plant will change over time. The model takes the cost available at the time of plant construction. The model then effectively places that cost in ratebase and customers continue to pay off the construction cost over the life of the plant. Subsequent changes in the multiplier have no effect.

An example of a ***single*** construction cost future for several generation technologies appears in Figure 8-7. This figure illustrates how construction costs generally move together through time, reflecting their shared cost components, such as steel, concrete, and labor. Appendix J provides a more complete description of probability ranges of costs over time for each resource Figure 8-7.

Figure 8-7: Construction Cost Multipliers



Climate Change and Carbon Emission Goals

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.

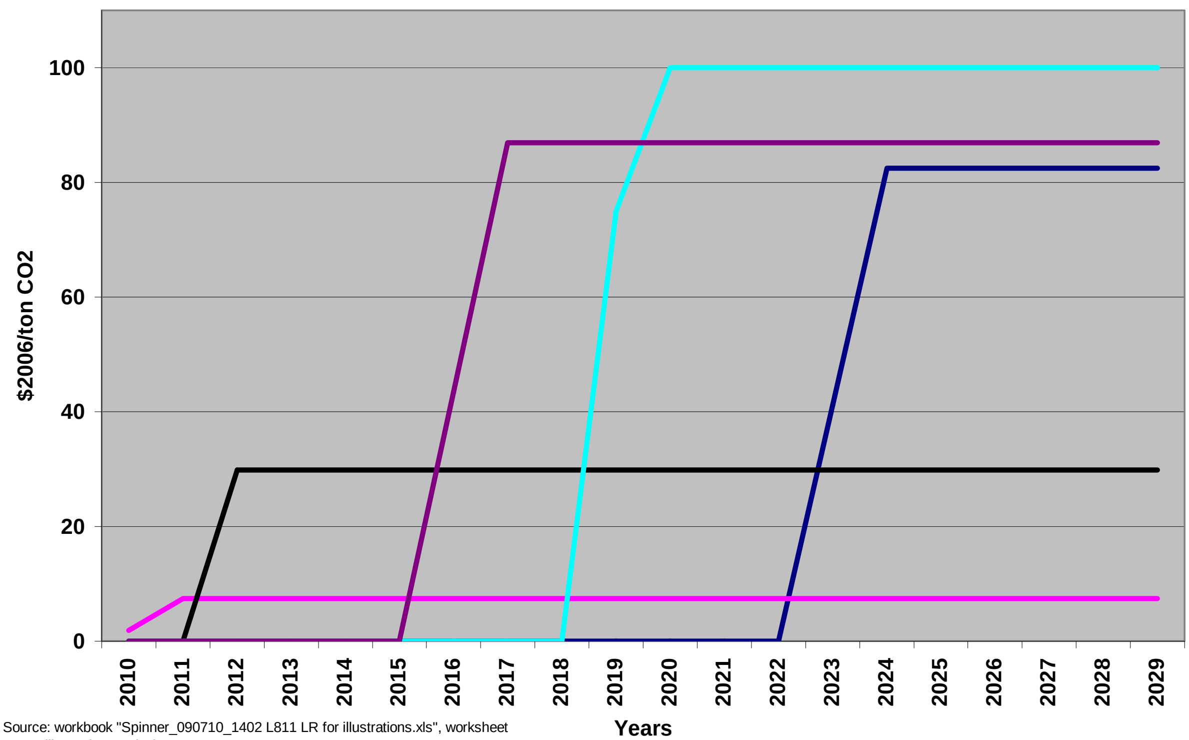
It is unlikely that reduction in carbon dioxide production can be achieved without cost. Consequently, future climate control policy can be viewed as a cost risk to the power system of uncertain magnitude and timing. A cap and trade allowance system appears to have been a successful approach to SO2 control 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 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 model keeps track separately of the two costs that arise from a carbon tax. There is a cost associated with any revenues generated by the tax. There is also a cost associated with alternative dispatch of resources. Separate accounting facilitates evaluation of the effects of a tax independent of assumptions regarding the use of the tax revenues.

Each carbon penalty future is a step up to a random value, selected by the model, where it remains until the end of the study (See Figure 8-8.) The progression of carbon penalty over time is unlikely to resemble any of these futures. Nevertheless, we believe using a large number of futures should give us a fair idea of the risk associated with most paths.

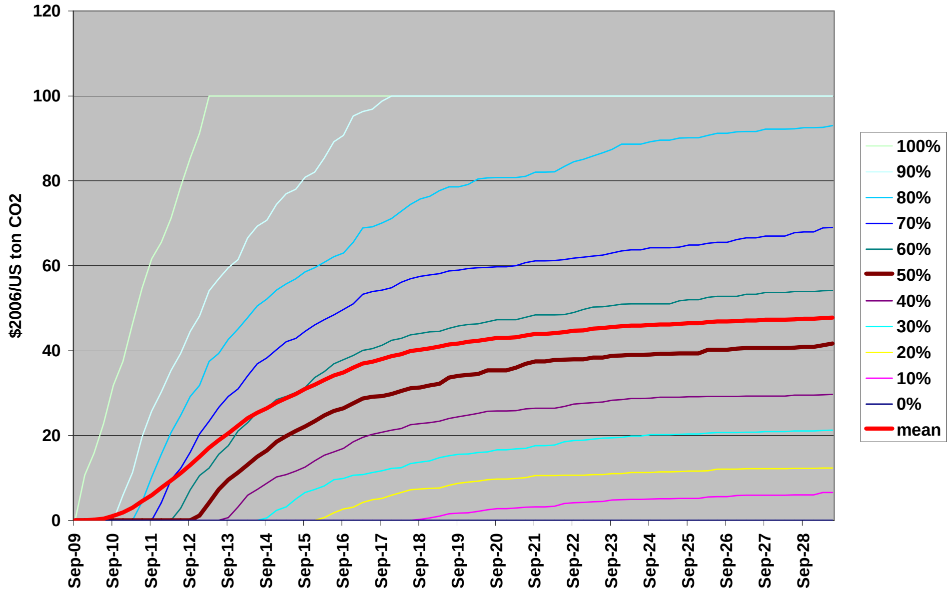
Figure 8-8: CO_2 Penalty Futures



Source: workbook "Spinner_090710_1402 L811 LR for illustrations.xls", worksheet "CO2_illustration" and Chart1

In the Council's studies, a carbon penalty can arise at any time. The probability of such a penalty being enacted at some time during the forecast period is ninety-five percent. If a penalty is enacted, its value is selected from a uniform distribution between zero and $100 per ton (2006$). The resulting probability of finding a carbon penalty at or below various levels in each period appears in Figure 8-9. The distribution indicates an even likelihood of seeing some positive carbon penalty around 2012. This assumption, recommended by the Council's Generation Resource Advisory Committee and adopted by the Council's Power Committee, is responsible for the shape of the distribution. The mean of the distribution over all futures rises gradually to about $47.50/ton CO_2 by the quarter June – August 2029. As discussed in Chapter 10, the distribution corresponds to the range of outcomes that EcoSecurities, Ltd., provided the Council.

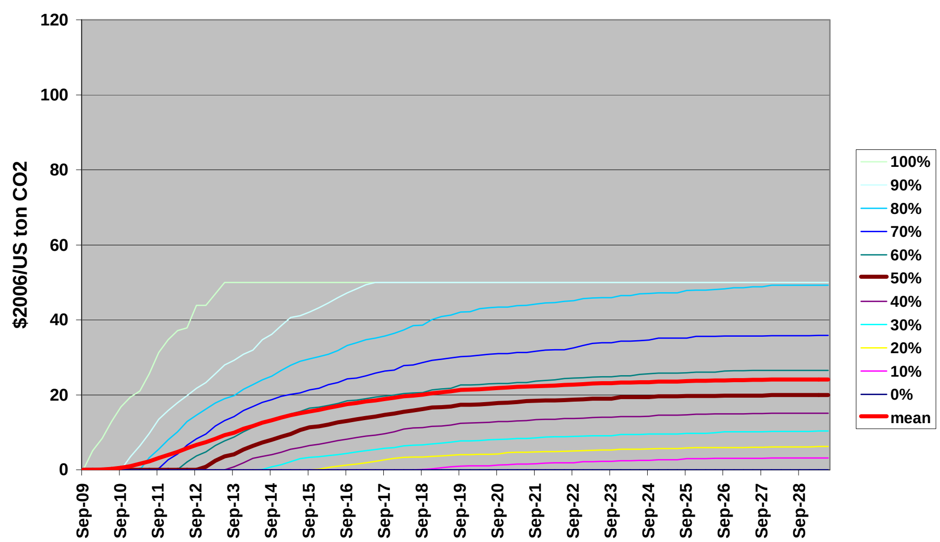
Figure 8-9: Deciles for Carbon Penalty



Source: workbook "New CO2 Distribution 090425.xls", chart "Carbon Distribution"

An alternative carbon penalty distribution, with a cap of $50 per ton instead of $100 per ton, appears in Figure 8-10. The average of this distribution rises to about half that of the first distribution, $24.12 per ton. Chapter 9 will show that the alternative carbon penalty distribution results in substantially the same plan for the first decade of the study as does the first distribution.

Figure 8-10: Study of a $50/ton Cap on Carbon Penalty



Source: "CO2_Penalty.xls", and module mod_Deciles of "L811q auditor.mdb"

There are mechanisms in addition to carbon penalties and trading programs to meet carbon emission objectives. Studies considered displacement of existing resources with new renewables or more efficient gas-fired plants. The Council also evaluated direct curtailment and retirement of existing units. Results of these analyses appear in the last section of Chapter 9.

Plant Availability

Power plants are not perfectly reliable, and forced outages are an important source of uncertainty. The analysis includes simulation of forced outages based on typical forced outage rates for the generating technologies considered.

Aluminum Smelter Load Uncertainty

Aluminum smelters in the Pacific Northwest have represented a substantial portion of regional loads in the past. Today, there are only three smelters in partial operation and the associated uncertainty in energy requirements is smaller. The Council has nevertheless retained smelter load uncertainty in its studies.

The difference between the price of aluminum and the price of a key ingredient, electric power, drive smelter activity. Council studies examine 750 futures for aluminum price and electricity price. It also considers the likelihood of permanent aluminum plant closure if a plant is out of operation for an extended period.

Renewable Energy Production Incentives

The production tax credit and its companion Renewable Energy Production Incentive were originally enacted as part of the 1992 Energy Policy Act. The intent was to commercialize wind and certain biomass technologies. Congress has repeatedly renewed and extended them.

The longer-term fate of these incentives is uncertain. The original legislation contains a provision for phasing out the credit as the cost of qualifying resources become competitive. Moreover, federal budget constraints may eventually force reduction or termination of the incentives.

In the model, two events influence PTC value over the study period. The first event is termination due to cost-competitiveness. The likelihood of termination peaks in about five years in the Council's model. The model provides, however, for the possibility of the PTC remaining indefinitely or expiring immediately. The second event that modifies the PTC in the Council's model is the advent of a carbon penalty. The value of the PTC subsequent to the introduction of a carbon penalty depends on the magnitude of the carbon penalty[5].

The Council did not want any reduction in PTC value to exceed the advantage afforded renewables by a CO_2 penalty. Such an outcome would be contrary to the likely intent of a CO_2

[5] If the carbon penalty is below half the initial value of the PTC, the full value of the PTC remains. If the carbon penalty exceeds the value of the PTC by one-half, the PTC disappears. Between 50 percent and 150 percent of the PTC value, the remaining PTC falls dollar for dollar with the increase in carbon penalty. The sum of the competitive assistance from PTC and the carbon penalty is constant at 150 percent of the initial PTC value over that range. The conversion of carbon penalty ($/US short ton of CO_2) to $/MWh is achieved with a conversion ratio 1.28 #CO_2/kWh. This conversion ratio corresponds to a gas turbine with a heat rate of 9000 BTU/kWh. The Fifth Power Plan, which uses the same approach, has additional explanation and details.

control policy. This concern determines the model's PTC value due to the magnitude of any carbon penalty that arises in a given future.

Production tax credits (PTCs) amounted to $15 per megawatt hour when first adopted and have escalated with inflation. Its current value for wind, closed loop biomass and geothermal is $21 per megawatt hour. Investors receive credits only for the first ten years of project operation. Council studies use real levelized values, however. The levelized value over a 20-year economic life would be about $9.10 in 2006 dollars.

Renewable Energy Credits

Power from renewable energy projects currently commands a market premium, which can be unbundled from the energy and traded separately as renewable energy credits (RECs). REC value varies by resource and over time, like most commodities. This value reduces the cost of the power source if sold. In the Council's model, REC value varies in a manner similar to other commodities and differs by future.

In the Sixth Plan, the Council models the Montana, Oregon, and Washington Renewable Portfolio Standards (RPS). The RPS requirements of these states require an obligated utility to retain the REC unbundled from the power produced to meet the standard. That is, the REC may not be sold and the REC value may not be realized. While obligated utilities may sell RECs associated with resource surplus to their requirements, they may also bank the energy to meet future RPS needs. If this makes economic sense, the utility would also not sell the REC. The value of RECs therefore plays a much smaller role in the selection of resources than it did in the Fifth Plan.

OTHER ASSUMPTIONS

Discount Rate and Other Financial Assumptions

Investment analysis, such as that for the Council's resource portfolio, 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 embodies the rate of time preference being applied to the analysis; that is, how much relative importance is given 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 zero discount rate, for example, would treat costs in all years the same. Regardless of whether the costs happened next year or 30 years from now, their impact on an investment decision taken now would be the same.

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, a dollar to be paid next year is less of a burden than a dollar to be paid 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. Investing the dollar can turn it into more than a dollar next year. 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. The actions of the Federal Reserve in setting the federal funds rate also affects interest rates by influencing inflation expectations. 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.

The approach builds on two sets of assumptions. The first is a set of forecast data developed by HIS Global Insight, a national economic consulting firm. Their forecasts are used for various purposes by the Council and data from utility IRPs. HIS Global Insight provides forecasts of various kinds of interest rates, inflation, and economic and demographic growth that are used throughout the Council's planning. The second is the relative shares of future investment decisions made by different actors (BPA, publicly owned utilities, IOUs and residential and business customers).

Plausible changes from the reference assumptions on shares of future decisions by various actors would affect the ultimate discount rate somewhat. Because of that, both the reference assumptions and a range of assumption values on these shares have been examined. Moreover, the final calculated value has been rounded rather than an attempt being made to capture unrealistic precision. Summary financial assumption information and the range of assumptions for the discount rate calculation are shown in Table 8-1. The discount rate is the weighted after-tax costs of capital in the IOU case. Details are given in Appendix N.

Table 8-1: Summary of Financial Assumptions

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%

Taking account of the range of assumptions above, the plan rounds to a real discount rate of 5 percent. The Council expects that individual entities may well have different values based on their own financing costs, rather than using a regional average, at the point at which they actually make investment decisions.

While proper treatment of discount rate is critical, studies have revealed the least-risk portfolio is largely insensitive to discount rate variation of 1 percent. Using a discount rate that is 1 percent higher results in a least-risk plan with 50 average megawatts less conservation by the end of the study. The resource plan is substantially the same.

Treatment of Transmission

The Council has traditionally not engaged in transmission planning, for several reasons. First, transmission expansion, beyond that required for local reliability, necessarily follows the choice and location of new resources, for which the Council does offer guidance in its power plan. Second, such planning is a highly technical effort in which the Council does not have expertise.

However, the Council incorporates information about the costs of transmission expansion into its analysis of resource choices for the Plan. All resources are treated on a comparable basis with respect to transmission costs. The primary driver for most transmission expansion, new resource type and location, therefore incorporates the relevant transmission information.

The Council also tracks and participates in the various transmission planning efforts. The Council encourages both transmission planning, aimed at getting new wires up, and improvements in transmission system operations. Improved operations assure the system can deliver and integrate economically the portfolio resources the Plan recommends.

Transmission constraints do not appear explicitly in the model. It is assumed that resources that do not have additional transmission cost can be located such that additional transmission is unnecessary.

Conservation from New Programs, Codes, and Standards

Conservation due to existing codes and standards is incorporated in the Council's load forecast. An example of such a code is the effectively mandated conversion to compact florescent lighting throughout the nation beginning 2012. Such conservation is excluded from programs that the model may select going forward.

New conservation is subject to severe constraints on development in the model early in the study period. Full penetration of lost opportunity conservation is assumed to develop slowly over the next decade.

A large amount of discretionary conservation, however, exists at prices far below the current wholesale power price. Left unconstrained, the model would add as much as 2,000 average megawatts of this conservation immediately. While difficult to quantify, utilities have budget constraints that, given no other consideration, would significantly limit how quickly the region can acquire this conservation. The Council, with the guidance of the Conservation Resource Advisory Committee and the Regional Technical Forum, have therefore chosen a rate of acquisition which it considers aggressive, but achievable.

The Council adopts a 160-average-megawatts-per-year constraint assumption on the development of discretionary conservation. Would a lower or higher rate of conservation development be less costly or reduce risk? This question is discussed in Chapter 4 and Chapter 9.

Existing Renewable Portfolio Standard Resources

Table 8-2 lists the 843 average megawatts of existing renewables. The table includes about 2,500 megawatts of wind that the region has completed or will soon complete. After the release of the Fifth Power Plan, the Council discovered that there was considerable confusion about the amount of renewable generation that the Plan had assumed. In particular, while studies included them, the Fifth Plan often neglected to mention existing and nearly constructed renewables. Those renewables that were completed or would soon be completed were not relevant to construction decisions going forward. They are therefore pointed out here.

Table 8-2: Base of RPS Resources

Project	Capacity (MW)	Service Year	Type	Load	Allocation by State (%) CA	MT	OR	WA
Biglow Canyon Ph I	125.4	2007	Wind	PGE			100%	
Broadwater	10.0	1989	Hydro	NWE		100%		
Clearwater Hatchery (Dworshak)	2.9	2000	Hydro	BPA			22%	78%
Coffin Butte 1 - 5	5.2	1995	Biomass	Consumers			100%	
Combine Hills I	41.0	2003	Wind	PAC	4%		74%	22%
Condon	49.8	2002	Wind	BPA			22%	78%
DeRuyter Dairy	1.2	2007	Biomass	PAC	4%		74%	22%
Douglas County Forest Products	3.2	2006	Biomass	PAC	4%		74%	22%
Dry Creek Landfill	3.2	2007	Biomass	PAC	4%		74%	22%
Foote Creek (BPA)	16.8	2000	Wind	BPA			22%	78%
Foote Creek (EWEB)	8.3	1999	Wind	EWEB			100%	
Foote Creek (PAC)	33.1	1999	Wind	PAC	4%		74%	22%
Freres Lumber	10.0	2007	Biomass	PAC	4%		74%	22%
Georgia-Pacific (Camas)	52.0	1995	Biomass	PAC	5%		95%	0%
Georgia-Pacific (Wauna)	27.0	1996	Biomass	BPA			100%	0%
Goodnoe Hills	94.0	2008	Wind	PAC	4%		74%	22%
H.W. Hill (Roosevelt Biogas) 1 - 5	10.5	1999	Biomass	Klickitat				100%
Hampton Lumber	7.2	2007	Biomass	Snohomish				49%
Hopkins Ridge	150.0	2005	Wind	PSE				100%
Judith Gap	135.0	2006	Wind	NWE		100%		
Klondike I	24.0	2001	Wind	BPA			22%	78%
Klondike II	75.0	2005	Wind	PGE			100%	
Klondike III (BPA)	50.0	2007	Wind	BPA			22%	78%
Klondike III (EWEB)	25.0	2007	Wind	EWEB			100%	
Klondike III (PSE)	50.0	2007	Wind	PSE				100%
Leaning Juniper	100.5	2006	Wind	PAC	4%		74%	22%
Marengo I	140.4	2007	Wind	PAC	4%		74%	22%
Marengo II	70.2	2008	Wind	PAC	4%		74%	22%
Martinsdale (Two Dot)	2.8	2004	Wind	NWE		100%		
McNary Dam Fish Attraction	7.0	1997	Hydro	N. Wasco			50%	
Nine Canyon	63.7	2002	Wind	COU				100%
Portland Habilitation	0.9	2008	PV	PGE			100%	
ProLogis	1.1	2008	PV	PGE			100%	
Puyallup Energy Recovery Company (PERC) 1 - 3	2.8	1999	Biomass	PSE				100%
Rock River I	50.0	2001	Wind	PAC	4%		74%	22%
Rough & Ready Lumber	1.2	2007	Biomass	PAC	4%		74%	22%
Round Butte	339.0	1964	Hydro	PGE			15%	
Short Mountain 1 - 4	2.5	1993	Biomass	Emerald			100%	
Sierra Pacific (Aberdeen)	10.0	2003	Biomass	Grays Harbor				56%
Sierra Pacific (Fredonia)	28.0	2007	Biomass	SMUD, SCL	82%			11%
South Dry Creek	1.8	1985	Hydro	NWE		100%		
Stateline (AVA)	35.0	2001	Wind	AVA				100%
Stateline (BPA)	90.0	2001	Wind	BPA			22%	78%
Stateline (SCL)	175.0	2001	Wind	SCL				100%
Tiber-Montana	6.0	2004	Hydro			100%		
Tieton	13.6	2006	Hydro	EWEB			100%	
Two Dot	0.9	2004	Wind	NWE		100%		
Vansycle Wind Energy Project	24.9	1998	Wind	PGE			100%	
Weyerhaeuser (Springfield) 4 (WEYCO)	25.0	1975	Biomass	EWEB			100%	
Wheat Field	96.6	2009	Wind	Snohomish				100%
White Creek (Benton PUD)	3.0	2007	Wind	Benton PUD				100%
White Creek (Cowlitz)	94.0	2007	Wind	Cowlitz				100%
White Creek (Emerald)	15.0	2007	Wind	Emerald			100%	
White Creek (Franklin)	10.0	2007	Wind	Franklin				100%
White Creek (Klickitat)	53.0	2007	Wind	Klickitat				100%
White Creek (Lakeview)	2.0	2007	Wind	Lakeview				100%
White Creek (Snohomish)	20.0	2007	Wind	Snohomish				100%
White Creek (Tanner)	4.0	2007	Wind	Tanner				100%
Wild Horse Wind	228.6	2006	Wind	PSE				100%
Wolverine Creek	64.5	2005	Wind	PAC	4%		74%	22%

Source: workbook "RPS Estimates 021909b for table.xls", worksheet "Commitments", created 7/19/2009

Forced-in RPS Requirements

As have many other states in the west, Montana, Oregon, and Washington have adopted Renewable Portfolio Standards. These legislated goals obligate utilities to meet a prescribed portion of their energy loads with renewable generation according to schedules that extend to 2025, in the case of Oregon. When modeled as an uncertainty related to regional load growth, the Council assumes utilities meet their nominal RPS goals. This representation, however, does not capture the possibility that utilities will fail to meet their nominal targets. One mechanism, for example, that might give rise to not meeting targets is the “opt out” provision. This provision in legislation excuses utilities from meeting their targets when meeting the requirements would cause significant rate increases. Council studies, however, do capture diminished RPS requirement due to load reduction from conservation.

Adoption of RPS legislation by other states, in particular California, is expected to impact the region primarily through the expected price of wholesale power. The anticipated change in wholesale electricity prices due to this effect is incorporated in Council modeling, as is the uncertainty around such change.

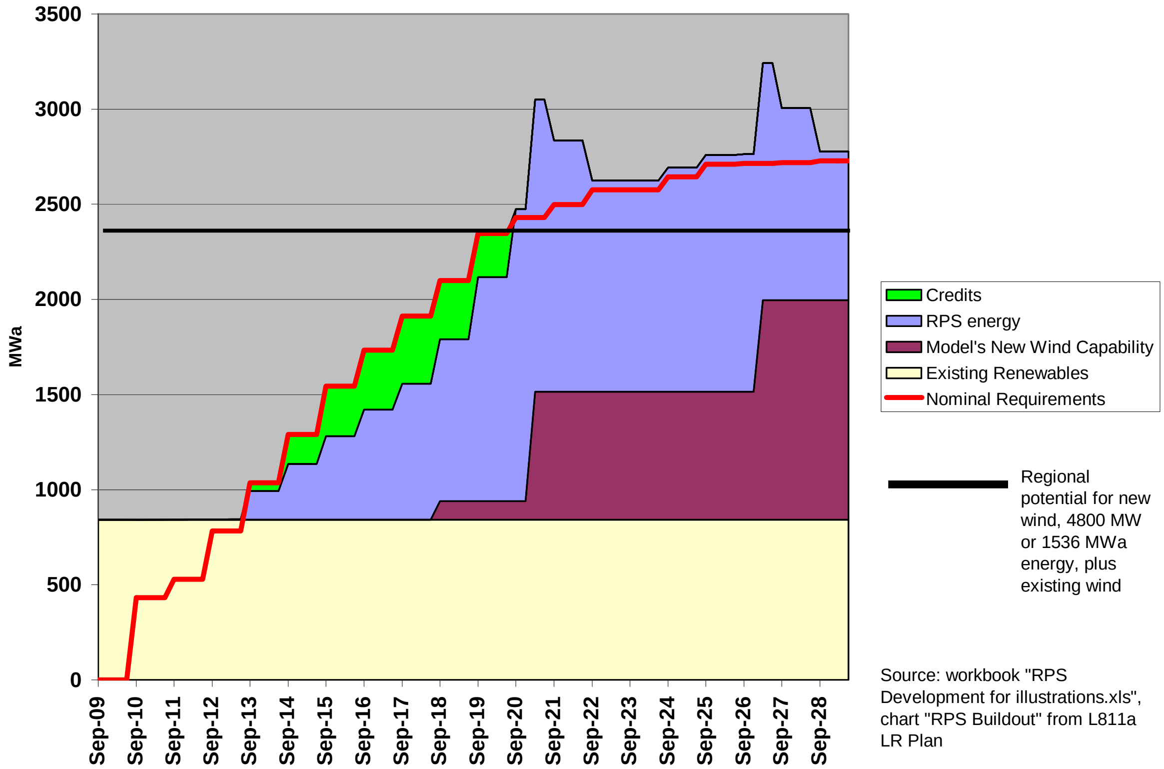
Renewable resources constructed to meet RPS requirements do not receive a cost reduction due to the sale of Renewable Trading Credits (RECs). When regional utilities acquire renewables to meet their state’s requirements, they must retain any RECs associated with the resource. This has the effect of increasing the cost of the resource relative to what renewable costs would have been had the utility been able to sell the RECs. Utilities, however, may bank RECs that are not used toward meeting RPS requirements. These credits may be applied toward future obligations. States differ in the policy regarding how long RECs may be banked and under what conditions.

Acquisition of renewables for compliance with RPS requirements also removes from the model’s discretionary selection the region’s total potential of new renewable development. By the end of the study, we estimate that all of the wind generation available without special transmission additions would be necessary to meet RPS requirements. Council studies do, however, consider portfolios in which the renewables are constructed ahead schedule and RECs are sold, at least prior to RPS schedules. The model, however, can never exceed the renewable development potential in the region.

Figure 8-11 provides an example of how existing RPS resources, banked RECs, wind selected and built by the model, and new RPS resources play out in a particular future. The heavy red line shows total RPS requirements. The green area shows the use of banked RECs. The blue area is RPS credit that the model must purchase in addition to the wind generation that has been added in this future. The model uses the cost of new wind generation, about $90 per megawatt hour in 2006 dollars, for this purpose.

There are spikes in the amount of RPS energy acquired to meet requirements in Figure 8-11. These spikes occur when new wind is added to the system and cause the total RPS energy to exceed the RPS requirement. This is a consequence of annual RPS accounting in the model. This anomaly will be absent in the model used for the final Plan.

Figure 8-11: RPS Source Development



Independent Power Producers' Resources

IPPs provide depth to wholesale markets but do not mitigate regional ratepayer costs or risks. IPP plants not currently under contract provide energy for the regional wholesale energy market. The IPP owners, however, receive the benefits of any energy sold, not the region. There are about 3,342 megawatts currently not under contract to regional utilities. This generation does not have firm transmission access to markets outside the region. The amount that is under contract declines over the next few years. A list of the IPPs modeled in Council studies appears in Table 8-3.

Table 8-3: Independent Power Producers

Plant name	Uncommitted share	Project Owner	January Capacity (MW)
Big Hanaford CC1A-1E	100%	TransAlta	235.6
Centralia 1	85%	TransAlta	623.1
Centralia 2	100%	TransAlta	623.1
Grays Harbor Energy Facility (Satsop)	100%	Invenergy (dba Grays Harbor Energy)	617.5
Hermiston Power Project	100%	Calpine, dba Hermiston Power Partners	503.5
Klamath Cogeneration Project	100%	Iberdrola Renewables	456.0
Klamath Generation Peakers 1 & 2	100%	Iberdrola Renewables	45.0
Klamath Generation Peakers 3 & 4	100%	Iberdrola Renewables	45.0
Lancaster (Rathdrum CC)	100%	Cogentrix	264.1
Morrow Power	100%	Morrow Power (Subsidiary of Montsano Enviro Chem Systems)	22.5
		Discounted total	3341.9

Source: workbook "Table of IPPs.xls", worksheet Sheet2

New Generating Resource Options

Resources explicitly considered include natural gas combined-cycle gas turbines, natural gas simple-cycle gas turbines, wind power plants, and gasified coal combined-cycle combustion turbines. A complete list appears in Table 8-4, below.

Table 8-4: New Resource Candidates

- Conservation
    - Discretionary conservation limited to 160 average megawatts per year
    - phased in up to 85% penetration maximum
- CCCT (415 MW) available 2011-2012
- SCCT (85 MW Frame GT) available 2012
- Wind generation (100 MW blocks), 4800 MW available by end of study
    - no REC credit if RPS are assumed in force
    - costs includes any production tax credit (PTC), transmission, and firming and integration cost
- Geothermal (14 MW blocks) available 2011, 424 MW (382 MWa) by end of study
- Woody Biomass (25 MW), available 2014, 830 MW by end of study
- Advanced Nuclear (1100 MW), available 2023, 4400 MW by end of study
- Supercritical pulverized coal-fired power plants (400 MW), available 2016
- IGCC (518 MW) available 2023, with carbon capture and sequestration
- Wind imported from Montana, with new transmission, available 2011, 1500 MW by end of study
- Five classes of demand response, 2000MW available by end of study, 1300 MW of this limited to 100 or fewer hours per year of operation

As mentioned in the discussion of existing Renewable Portfolio Standard resources, resources that have very good chance of completion are included in the base level of resources. This includes certain other thermal resources having high probability of completion. They are not modeled explicitly as new resources. Table 8-5 shows relatively new resources that are not listed in Table 8-2.

Table 8-5: Recent Construction

Project	Capactiy (MW)	Fuel Type	In-service Month
Mint Farm	319	Natural Gas	Jan 2008
Raft River I	15.8	Geothermal	Jan 2008
Hay Canyon	100.8	Wind	Dec 2008
Grays Harbor Energy Facility	650	Natural Gas	Jul 2008
Bettencourt Dry Creek Dairy	2.25	Biomass	Sep 2008
City of Albany (Vine Street WTP)	0.5	Hydro	Feb 2009
Danskin (Evander Andrews) CT1	170	Natural Gas	Jun 2008

In order to keep the analysis manageable, only new resources that are found to be competitive and of significant potential6, or required by law, are considered in the model. The RPM, because it evaluates large numbers of possible portfolios under many scenarios requires several computers and significant time to develop a portfolio. The number of generation resources in the model affects the time required for a study. Consequently, small amounts of new micro-hydrogeneration, solar thermal, and other smaller sources are assumed to be captured under States' RPS programs.

System Flexibility and Capacity Requirements

Energy balance is central to economic risk and has been the focus of Council risk assessment. Regional power crises of the past were associated with energy shortages and surpluses. The hydro generation insufficiency of the early 1970s and the 2000-2001 energy crisis of the west coast come to mind. Overbuilding in the late 1970s and the unprecedented rate increases and financial failures that ensued illustrate the dangers of overbuilding.

The power system has other requirements, however. Power system balance on the sub-hourly level is critical to integration of wind and other renewable resource. Without providing for system peaking and flexibility requirements, the region risks forgoing resources that can reduce energy risk. Chronic shortages in the special-purpose markets for resources that meet these requirements may result, or the power system may otherwise become inefficient.

In modeling wind, an additional integration and firming cost is added to that of direct wind turbine costs. The model does not include, however, any additional resources that may be required to provide these services. The model, moreover, does not have the capability to evaluate any incremental need for within-hour load following or regulation. The Action Plan supports work underway by the Regional Wind Integration Forum to evaluate those requirements.

The RPM uses an economic valuation approach to evaluating peaking contribution. The RPM does not have the information it needs to determine energy 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 resource portfolios that meet peaking requirements. The model can discern economic value that arises from hourly

[6] The cutoff for consideration is around 300 MW of cost-effective potential by the end of the study.

events, such as forced outages. Economic value 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. 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.

There is no guarantee that the model will always build portfolios that meet energy peaking requirements. Consequently, staff evaluates recommended portfolios using the **GENESYS** model. So far, however, we have not seen a situation where economic adequacy has failed to produce energy adequacy and to meet peaking requirements. The Plan addresses flexibility extensively in Chapter 11.

Electricity Price Cap

Prices for wholesale electricity price are capped at $325 per megawatt hour on average for a quarter. This value corresponds to the $400 per megawatt hour price caps imposed in the Western power system. That is, the latter is the maximum hourly price the model would impute based on the former. Electricity prices rarely hit this level in the portfolio model.

BEYOND ECONOMIC COST AND RISK

The studies that the Council performs attempt to address sources of uncertainty that the preceding overview ignores. They are significant to the selection of the portfolio. The following is a brief description of more prominent issues.

The Protection of Fish and Wildlife

Concurrent with the development of its resource portfolio, the Council has updated its fish and wildlife program. This program to "protect, mitigate, and enhance fish and wildlife" informs resource decisions and hydro operation, in particular. Of particular significance to fish and wildlife is a resource portfolio that does not place extraordinary burden on the hydroelectric system. This consideration is especially important when addressing reliability, adequacy, and system flexibility. It is under reliability events that fish are at the greatest risk, because inadequate resources would increase the likelihood that the region would need hydrogeneration to maintain system reliability.

To minimize impact on fish and wildlife, the Council's portfolio model assumes the hydroelectric system is ***never*** used to meet extraordinary requirements. This places the burden for minimizing cost and risk on new resource candidates. It also reflects the value that such resources have in providing protection to fish and wildlife.

Other Effects on the Region

The Council recognizes the economic opportunities and costs associated with the selection of power resources. The preceding section referred to risk-constrained, least-cost planning. The referenced costs and risks are taken to mean strictly those that regional electricity consumers bear, both in their utility bills and in the consumers' share of conservation investments. The Council also recognizes, however, that resource and policy choices impact regional communities and industries. The economic welfare of the region extends beyond its electric power rates. Consequently, the Council endeavors to understand and recognize those impacts.

The next chapter presents the Council's preferred resource portfolio. Chapter 9 then returns to address the non-economic issues raised in the preceding section.

Chapter 9: Recommended Resource Strategy

SUMMARY OF KEY FINDINGS

The resource strategy of the Sixth Power Plan was developed by examining a number of different planning scenarios. The Resource Portfolio Model (RPM) identifies resource plans that minimize the cost and risk of future power system costs as described in Chapter 8. As in previous plans, improved efficiency of electricity use is the most cost-effective and least risky resource available to the region. The value of conservation was recognized in all planning scenarios and all scenarios call for developing significant amounts of conservation. The amount of conservation that is cost-effective changes very little regardless of assumptions about carbon costs and policies. Due to advancing technologies, new applications, much higher energy costs, and the risk of carbon emission penalties, much more conservation is available and cost-effective in the Sixth Plan. Therefore, the Sixth Power Plan calls for aggressive development of conservation. There is enough cost-effective conservation in the resource portfolio to provide a substantial portion of the region's load growth.

In addition to efficiency improvements, new renewable generation (primarily wind) is required to meet renewable portfolio standards in Washington, Oregon, and Montana. Analysis shows that meeting RPS requirements uses most of the readily accessible wind potential (5,300 MW) in the region. In addition to the wind, some geothermal resources enter the plan. However, the amount of geothermal potential is considered quite limited. In planning scenarios without the RPS requirements, about one third less renewable development would be optimal given the carbon price risk considered. Instead more conservation would be developed and some additional gas-fired generation would be optioned.

Reducing carbon emissions from the power system will increase the future cost of electricity and increase consumers' electric bills. The risk of carbon prices between $0 and $100 is estimated to increase average electricity rates by about 2.4 to 9.3 compared to current policies that only include renewable portfolio standards, renewable energy credits and limits on new power plants carbon emissions. The effect on average residential consumers' monthly bills is estimated as an increase 1.4 to 7.1 percent.

The effects of carbon pricing risk are reduced in the Pacific Northwest by the existing hydroelectric system and the relatively minor role of coal-fired generation. The resource strategy focus on conservation and renewable generation also help avoid future cost impacts.

ROLE OF ANALYSIS IN THE RESOURCE STRATEGY

The Council uses several computer models in the process of developing its Power Plan. These include demand forecasting models, market price forecasting models, hydroelectric simulation models, resource financial costing models, and the Regional Portfolio Model (RPM) discussed in Chapter 8. All of these models help the Council combine the best information available to identify a resource strategy that minimizes the future cost of the power system as required by the Northwest Power Act, and also includes strategies to mitigate the risks of unknown future conditions.

The Council's models and analyses help inform the resource strategy, but models are limited in their ability to address all of the considerations that need to go into the Power Plan. The Council's plan recognizes that available models do not capture the local limitations of the transmission system, for example, or the unique situations faced by all individual utilities. As a result, the resource strategies that result from particular model analyses are supplemented by additional information to come up with the Council's recommended resource strategy.

In addition, the resource strategy is supplemented by additional information about potential future resources, explanations of special challenges facing the power system, and an action plan containing steps the region should take to implement the plan. The action plan addresses important issues like wind integration, conservation acquisition, resource development and confirmation, and research and demonstration projects.

THE RESOURCE STRATEGY

Planning Scenarios

The Resource Portfolio Model analyzes the Power Plan's forecasts of demand, conservation supply, and generating resource alternatives. The RPM is unique because it is acknowledges that forecasts are well-informed but uncertain. The RPM considers risk in its analysis, including the risk that the Council's forecasts are incorrect. It adds a range of climate policy and other unknown future conditions to identify least-cost and least-risk plans along an efficient frontier of least-cost resource plans. This process is described in Chapter 8. The RPM searches through thousands of potential portfolios to estimate how each one would perform in 750 futures. This analysis allows the program to find the lowest cost resource portfolios for different levels of risk. In more typical planning these futures would generally be called "scenarios." In the RPM the

Council refers to these as "futures," and the term "scenario" is reserved for different RPM runs as described below.

In developing its resource strategy, the Council evaluated several scenarios focused primarily on different climate policy approaches to see if the resource strategy is sensitive to such differences. Below is a list of scenarios considered. Each scenario analyzed produced a least-cost and least-risk mix of resources. The scenarios are described here in terms of their least-risk portfolio of resources. Resource plans at the lowest cost end of the frontier tend to rely on electricity markets instead of optioning and building resources. Plans at the low-risk end of the efficient frontier produce more adequate and reliable power systems, reduce electric price volatility, and provide more information about the types and amounts of resources needed. For these reasons the Council has focused on least-risk plans.

- *Current Policy* is a scenario that includes renewable portfolio standards that exist in three of the four Northwest states, renewable energy credits, and new carbon emissions performance standards that preclude the construction of new coal plants. The current policy scenario does not, however, include the stated emissions reduction goals that some states have adopted as policy.

- *No Policy* is a scenario that assumes no renewable portfolio standards or other policies aimed at reducing carbon emissions exist. However, it does not allow new coal-fired generation.

- *$0 to $100 Carbon* is a scenario that adds to the Current Policy scenario uncertain carbon pricing policy that can vary from zero to $100 per ton of carbon emission. The carbon cost range for this scenario was based on staff analysis and a study that reviewed various cost estimates that would successfully achieve carbon reduction.

- *No RPS* takes renewable portfolio standards out of the $0 to $100 Carbon scenario to test whether a strategy to mitigate risk of future carbon pricing would develop as much renewable generation as the RPS requirements.

- *$0 to $50 Carbon* tests the effects of a smaller range of potential carbon price risks on the resource plan.

- *$100 Carbon* puts a firm price on carbon emissions of $100 per ton. The price is not a risk in this scenario, it is a known cost.

- *$20 Carbon* puts a price on carbon emissions of $20 per ton. As in the $100 scenario, it is a known cost.

- *Retire Coal w/ CO2* phases out existing coal plants between 2015 and 2020 but retains uncertain carbon pricing policy that can be between $0 and $100.

- *Retire Coal w/0 CO2* phases out existing coal plants between 2015 and 2020 but considers that action a substitute for carbon pricing policy and does not include carbon price risk.

- *Dam Removal* assumes that the four Lower Snake River dams are removed in 2020 in order to test the value of the hydroelectric capability of the power system.

- *Low Conservation* assumes a reduced acquisition rate for discretionary conservation and lower penetration of lost-opportunity conservation.

- *High Conservation* assumes a higher acquisition rate for discretionary conservation.

The Resource Strategy

The Council developed a resource strategy based on analysis of the results of all of these scenarios as well as other considerations to supplement the model results. What emerges is a clearly focused strategy for near-term actions and flexible guidance on future resources and actions.

The resource strategy is summarized below in six elements. The first three are high-priority actions that should be pursued immediately and aggressively. The longer-term actions must be more responsive to changing conditions to provide an array of solutions to meet the long-term needs of the regional power system. The last element recognizes the adaptive nature of the power plan and commits the Council to regular monitoring of the regional power system to identify and adjust to changing conditions.

- **Conservation:** The region should aggressively develop conservation with a goal of acquiring 1,200 average megawatts by 2014, and 5,800 average megawatts by 2030. Conservation is by far the least-expensive resource available to the region and it avoids risks of volatile fuel prices, financial risks associated with large-scale resources, and it mitigates the risk of potential carbon pricing policies that would address climate change concerns.

- **Renewables:** The region should meet existing renewable portfolio standards. Most of the recent renewable development has been wind and that is assumed to be the primary source of renewable energy in the immediate future. Wind’s variable energy production creates little dependable peak capacity and increases the need for within-hour balancing reserves. The Council encourages the development of other renewable alternatives that may be available at the local, small-scale level and cost-effective now. The Council also supports research and demonstration into different sources of renewable energy for the future. On average, the renewable resources developed to fulfill state RPS mandates should contribute 1,800 average megawatts of energy, or 5,600 megawatts of installed capacity.

- **Wind Integration:** The Plan encourages the region to improve wind scheduling and system operating procedures as a more cost-effective and more quickly achievable alternative to new gas-fired generation for the purpose of wind integration.

- **Natural Gas:** The region may need to develop new natural gas resources, depending on load growth and the possible need to displace coal use to meet high carbon reduction goals. Even if the region has adequate resources, individual utilities or areas may need additional supply for capacity or wind integration. In these cases, the strategy relies on natural gas-fired generation to provide energy, capacity, and ancillary services.

- **Future Resources:** In the long term, the Council encourages the region to expand the alternative resources available to the region. Among these are additional sources of renewable energy, improved regional transmission capability, new conservation technologies, new energy storage techniques, carbon capture and sequestration, smart grid and demand response resources, and new or advanced generating technologies, including advanced nuclear energy. Research, development, and demonstration funding should be prioritized in areas where the Northwest has a comparative advantage or unique opportunities.

- **Adapting to Change:** The Council will regularly assess the adequacy of the regional power system to guard against power shortages, identify departures from planning assumptions that could require adjustments to the Plan, and help ensure the successful implementation of the Council's Fish and Wildlife Program.

The following sections describe the basis for the resource focus on conservation, renewable generation and natural gas.

Conservation

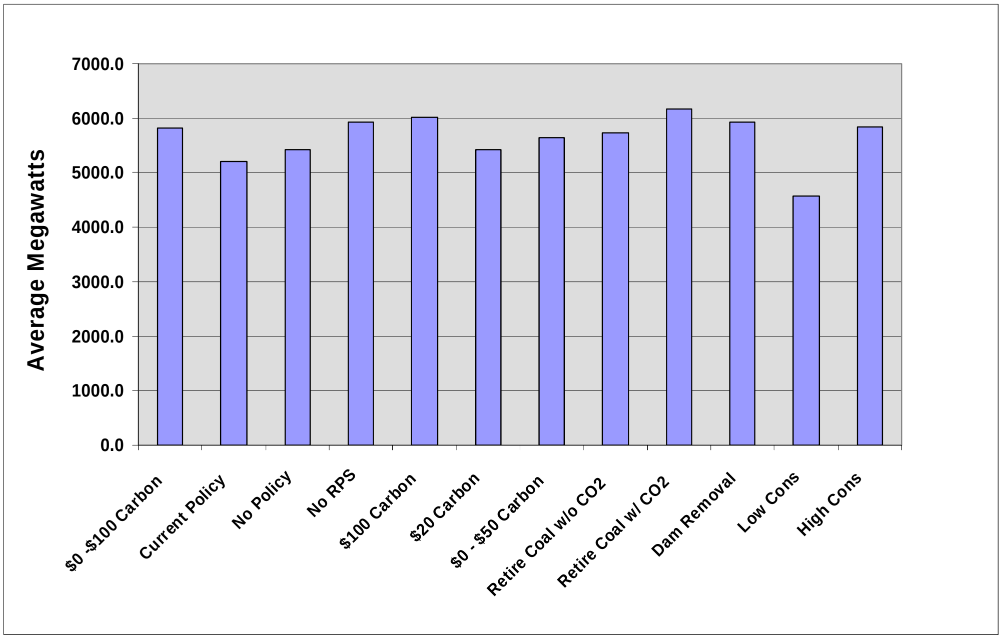
The Council's research on conservation potential demonstrated a large potential for improved efficiency of electricity use. Increased costs of electricity generation, new areas of application and changing technologies mean this potential is much larger than the potential identified in the Council's Fifth Power Plan.

Conservation is the clear priority resource as evaluated by the RPM. It is by far the lowest cost resource and provides protection against the risks of volatile natural gas prices, high electricity prices and the possibility of carbon pricing policies. Conservation also has the risk advantages associated with small scale resources that require less time to develop.

Each portfolio, regardless of the scenario analyzed, contained conservation in the range of 5,200 and 6,200 average megawatts. The one exception is the Low Conservation scenario in which the rate of development for conservation was further limited. Figure 9-1 illustrates the level of conservation included in the least-risk plan for each scenario.

Similar amounts of conservation are cost effective regardless of the assumption about climate policies. Even in the Current Policy and No Carbon Policy scenarios, conservation was demonstrated to have clear advantages. It is interesting to note that Current Policy reduces the amount of conservation compared to No Carbon Policy. Renewable portfolio standards force the addition of renewable generation and both reduce resource needs and mitigate some of the risk from fuel prices. The fact that varying levels of conservation are driven partly by resource needs is also evident in the other scenarios. Scenarios with high-carbon prices result in reduced operations of existing coal plants, making replacement energy more valuable. This effect is most clear in the scenarios that retire currently generating coal plants.

Figure 9-1: Cost-Effective Conservation Resources



Renewable Generation

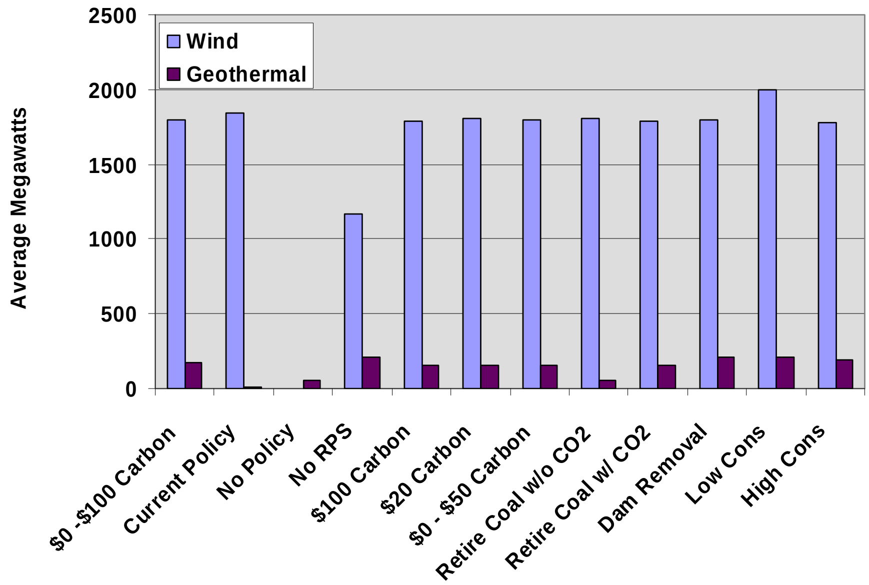
Renewable resources are mostly modeled as wind in the RPM. A limited amount of geothermal is included in the resource alternatives and is generally an attractive resource choice. The Council has recognized that additional small-scale renewable resources are likely available and cost-effective and the Plan encourages development of them. In addition, there are many potential renewable resources that are currently either too expensive or unproven technologies that may, with additional research and demonstration, prove to be valuable resources.

Wind development in the various scenarios is driven primarily by state renewable portfolio standards. The amount of wind energy acquired depends on the future demand for electricity because state requirements specify percentages of demand that have to be met with qualifying renewable sources of energy. Across the 750 futures of demand growth the amount of wind developed on average is 1,800 average megawatts. In terms of available capacity, that is 5,600 megawatts of installed wind capacity, but only about 300 megawatts of firm peaking capacity.

Figure 9-2 shows the amounts of wind and geothermal energy acquired on average in the various scenarios studied. 860 average megawatts of wind (2,700 megawatts of available capacity) exists in all scenarios because that level of development already exists or is committed to be developed. In all cases with renewable portfolio standards in place, the development of wind is limited to 1,800 average megawatts as required by the standards when the state's goals are combined. The only exception to this is when low rates of conservation are assumed. In that case, an additional 200 megawatts of wind is developed.

In the two scenarios without renewable portfolio standards, No Carbon Policy and No RPS, the results are different. In the No Carbon Policy scenario no additional wind is developed. In the No RPS scenario, which includes the risk of carbon prices between $0 and $100 per ton, additional wind is developed, but only about 1,200 average megawatts instead of the 1,800 average megawatts in the scenarios that include renewable portfolio standards.

Figure 9-2: Renewable Resource Development



Geothermal energy is considered cost-effective in many of the scenarios although the amount available is quite small. The Council expects that the geothermal resource may be representative of other small-scale, locally available renewable generation that offers dependable energy capability and peaking contribution.

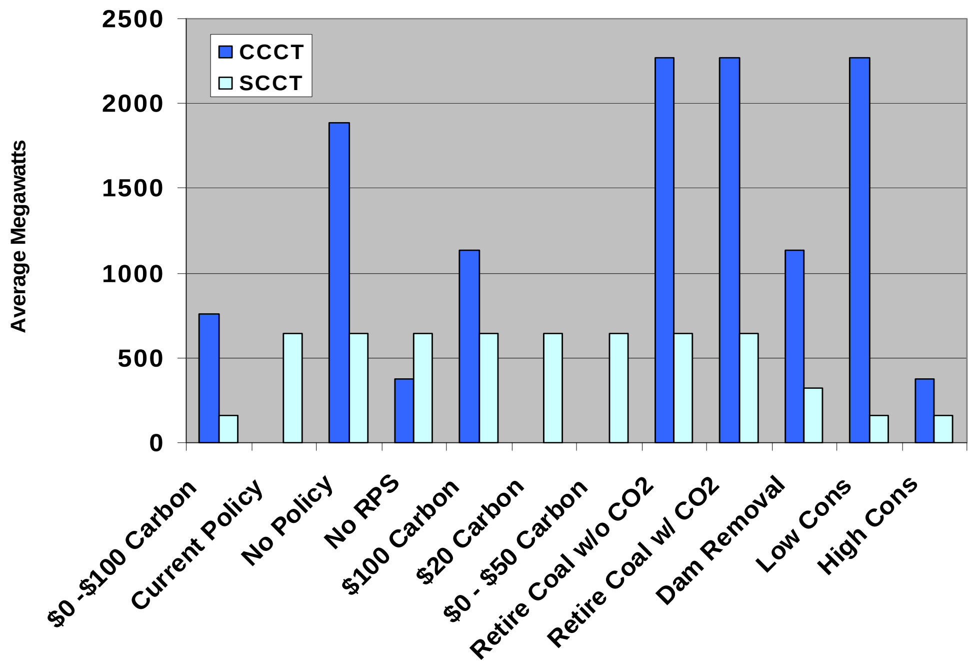
Natural Gas

There are two types of natural gas-fired generation considered in the RPM: simple-cycle turbines (SCCT) that are most suitable for providing peaking capacity, and combined-cycle turbines (CCCT) that are more suitable to providing base-load energy as well as peaking capacity.

While the amount of conservation and wind was fairly consistent across all scenarios examined, the future role of natural gas-fired generation is variable and specific to the scenarios studied. Figure 9-3 shows the average amounts of SCCT and CCCT optioned among the 750 futures considered in each scenario. The gas-fired plants are optioned (sited and licensed) so that they are available to develop if needed in each future. The actual amount of natural-gas fired generation constructed will vary in each future. For example, on average in the $0 - $100 Carbon scenario 162 average megawatts of CCCTs are optioned by the end of the planning period, but are constructed only in about 30 percent of the futures.

The optioning of CCCTs is largest when there is a need for energy. This occurs, for example, in scenarios that feature energy lost from other resources like the retirement of existing coal plants or reduced conservation achievements. Among these scenarios not only does the amount of gas-fired resources optioned vary, but the likelihood of completing the plants also varies.

Figure 9-3: Natural Gas-Fired Resource Options



The particular type of natural gas-fired generation optioned and added depends significantly on anticipated future conditions. Specific utility needs drive resource choices. For example, individual utilities may find their circumstances include need for within-hour balancing reserves, a system with differing capacity requirements, or limited access to market resources. All of these factors limit the ability of the regional resource strategy to be specific about optioning and construction dates for natural gas fired resources, or for the types of natural gas-fired generation.

Nevertheless, it is clear that after conservation and renewables, natural gas-fired generation is the most cost-effective resource option for the region in the near-term. Other resource alternatives may become available over time, and the Sixth Power Plan recommends actions to encourage expansion of the diversity of resources available.

CHARACTERISTICS OF SCENARIOS

The most important considerations for selecting a resource strategy are the cost, risk, and carbon emissions of the various scenarios considered. The measurement of these attributes was discussed in Chapter 8. Although the Council's resource strategy is based on the analysis of several different scenarios, a comparison of the characteristics of the scenarios provides important information about the value of conservation achievement and the cost and effectiveness of various carbon policy approaches.

This section summarizes the analysis results of the various scenarios the Council considered in developing its resource strategy. The tables provide information on average values over 750 futures for costs, carbon emissions, conservation acquisition, and wind development. The resource planning costs have been converted into estimated retail rates. These are presented as levelized rates over the planning period. It also provides the amounts of other generation that are optioned by the end of the planning period.

In many of the tables and discussions the different scenarios are compared to the $0 to $100 Carbon scenario. This scenario is chosen as a matter of convenience to illustrate the varying effects of the scenarios. The results of this scenario are also representative of the Council's resource strategy in terms of the amount of conservation and wind development recommended.

Conservation Scenarios

The Council's draft Sixth Power Plan includes significantly more conservation than previous Council plans. The conditions that led to this increase in cost-effective conservation are discussed in Chapter 4. In essence, conservation provides a low-cost resource to the power system that is without risk of increased fuel prices and carbon prices.

Two scenarios were developed to test the value of conservation to the power plan. Both scenarios were based on the $0 to $100 Carbon scenario assumptions with variations in the conservation assumptions. In the Low Conservation scenario, the amount of conservation was reduced from the $0 to $100 Carbon scenario by assuming that no more than 100 average megawatts per year of retrofit conservation could be developed, instead of 160 in the $0 to $100 Carbon scenario, and that lost-opportunity conservation ramp-up would take 20 years to reach 85 percent annual penetration, instead of 15 years used in the $0 to $100 Carbon scenario. The Low Conservation scenario only develops 800 average megawatts in the 5-year action plan period, compared to 1,200 average megawatts in the $0 to $100 Carbon scenario.

The second conservation scenario explores the effects of raising the assumption about conservation development. For this High Conservation scenario, the Council assumed it would take 10 years to develop the first 2,400 average megawatts of retrofit conservation, instead of the 15 years assumed in the $0 to $100 Carbon scenario. This equates to an average pace of 220 average megawatts per year for retrofit conservation, but no increase in the ramp-up for lost-opportunity conservation. In the High Conservation scenario, 1,500 average megawatts of conservation is developed over the first five years of the action plan.

Table 9-4 shows a summary of the results of the Low and High Conservation scenarios compared to the $0 to $100 Carbon scenario. The amount of conservation achieved in the Low Conservation scenario is reduced significantly. It is lower than the amount found cost effective in any of the carbon scenarios, including the No Policy scenario. However, the High Conservation scenario changes only slightly the amount of conservation achieved over the planning period. This is because the High Conservation scenario accelerates discretionary conservation. The total amount of conservation available does not change. In addition, the lost opportunity conservation was not changed for the High Conservation scenario.

The Low Conservation scenario results in a 4.4 million ton increase in average annual carbon emissions, but the High Conservation shows approximately the same level of carbon emissions as found in the $0 to $100 Carbon scenario.

Reduced conservation achievements in the Low Conservation scenario are made up for by increased gas-fired combined-cycle generation and more renewables. Three times as many combined-cycle combustion turbines are optioned in the Low Conservation scenario as in the $0 to $100 Carbon scenario. New renewable generation capability increases by 196 average megawatts.

Under the Low Conservation scenario, power system costs are increased by $5 billion in added resource acquisition costs and carbon penalties if conservation is developed at this limited level. If this scenario excludes any anticipated carbon penalties, limiting conservation achievement increases power system costs by $3.7 billion over the 20 years of the power plan. These changes are reflected in the first line of Table 9-4.

Not only is the power system more expensive if 1,000 megawatts of conservation is replaced with primarily gas-fired generation, risk is also increased. Although the average cost of the power system, including carbon penalties, increases by 8 percent in the Low Conservation scenario, the risk of the power system increases by 12 percent, from $155.5 to $173.9 billion. Risk is a measure of the average cost of the 75 highest cost futures. The increase in risk demonstrates the value of conservation in reducing the risk of futures that feature high carbon costs.

Table 9-1: Low and High Conservation Scenarios versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	Low Conservation	High Conservation
Cost (billion 2006$ NPV)			
With Carbon Penalty	$105.60	$114.30	$103.80
Without Carbon Penalty	$85.10	$88.70	$84.80
Retail Rates - Change (%) from $0 to $100 Carbon Scenario			
With Carbon Penalty		- 1.4%	+ 0.6%
Without Carbon Penalty		- 2.4%	+ 0.9%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	41.0	36.6
Resources 2030			
Conservation (MWa)	5,827	4,566	5,849
Wind (MWa)	1,800	1,996	1,778
Geothermal Options (MWa)	169	208	195
CCCT Options (MWa)	756	2268	378
SCCT Options (MWa)	162	162	162

The cost-effective level of conservation is consistent across each climate change scenario examined. The amount of conservation selected in the several climate change scenarios described in the previous section falls consistently between 5,000 and 6,000 average megawatts. Figure 9-1 illustrates this fact. Thus the importance of conservation in the Sixth Power Plan is not dependent on any particular view about climate change or specific climate change policies; it is a simple reflection of cost and risk. Risk associated with demand growth, water conditions, natural gas prices, and other uncertainties provide justification for conservation development even in the absence of carbon price risks.

Carbon Policy Scenarios

The discussion of the carbon policy scenarios first compares the No Policy and Current Policy scenarios to the $0 to $100 Carbon price risk scenario. Then other approaches to carbon pricing or other control policies are compared to the $0 to $100 Carbon scenario.

Current Policy Scenario

The Current Policy scenario tests the effect of only known, instituted carbon policies on the plan's resource strategy. As the name implies it includes current RPS requirements, new plant carbon dioxide performance standards, and renewable energy credits, but ignores the potential risk of carbon pricing policies in the future, as are being discussed by individual states, the WCI, and in proposed federal legislation.

This scenario shows that carbon emission levels of the regional power system could be stabilized with existing policies, but carbon emission reduction goals would not be achieved. Compared to the least-risk portfolio, as shown in table 9-2, future power system costs would be reduced by 17 percent compared to the $0 to $100 Carbon scenario if utilities are provided free emission allowances for most of the planning period. In this scenario, the effects on electricity retail rates would be very small. The cost reduction would be nearly one third larger if the carbon emissions allowances are assumed to be entirely auctioned in the $0 to $100 Carbon scenario, that is, if utilities had to pay the full cost of allowances. National policy proposals would provide free allowances to utilities for most of the planning period and therefore are much closer to the free allowance end of the range. Tables in this section show power system costs both with free allowances and with allowance costs paid entirely by the power system in scenarios that include carbon pricing policy.

Compared to the $0 to $100 Carbon portfolio the Current Policy scenario would develop less conservation and natural gas-fired combined-cycle generation would shift to simple-cycle turbines to provide capacity for integrating wind power into the regional power system. Because the Current Policy scenario does not include carbon pricing policy risk, the region's existing coal plants continue to provide base load energy for the power system, whereas in the $0 to $100 Carbon scenario coal plants are dispatched less to mitigate carbon costs. Table 9-5 compares the Current Policy scenario to the $0 to $100 Carbon scenario.

Table 9-2: The Current Policy versus the $0 to $100 Carbon Scenario

	Current Policy	$0 to $100 Carbon
Cost (billion 2006$ NPV)		
With Carbon Penalty	$70.50	$105.60
Without Carbon Penalty	$70.50	$85.10
Retail Rates - Change (%) from Current Policy		
With Carbon Penalty		+ 9.3%
Without Carbon Penalty		+ 2.4%
Carbon Emissions (Gen) (Million Tons/Year)	52.1	37.1
Resources 2030		
Conservation (MWa)	5,197	5,827
Wind (MWa)	1,845	1,800
Geothermal Options (MWa)	13	169
CCCT Options (MWa)	0	756
SCCT Options (MWa)	648	162

The figures for carbon emissions, conservation, and wind development are averages across all futures at the end of the study. The cost and rates without carbon penalty do not include the penalty applied to CO2 production. There is still an economic effect on the dispatch order of resources included in these costs.

No Policy Scenario

One question the Council has been asked to address is: what will be the cost of reducing carbon emissions from the power system? To address that question a scenario was developed that excluded not only the risk of potential future carbon pricing penalties, but also excluded the RPS requirements, new plant carbon dioxide performance standards, and RECs. However, this No Policy scenario did not assume that new pulverized coal plants would be available for development.

Table 9-3 compares the result of the No Policy scenario to both the Current Policy and $0 to $100 Carbon scenarios. Costs of the power system would be increased from $56.5 billion in the No Policy scenario to $70.5 billion with Current Policy, and to $85.1 billion in the $0 to $100 Carbon scenario. The $0 to $100 Carbon scenario increases the cost of the regional power system by 50 percent compared to a scenario that ignores current climate policy and potential future climate policy risks. If carbon penalties were borne by the power system, the cost increases associated with addressing climate policy would be greater. In that case, the power system costs in the $0 to $100 Carbon scenario would be nearly double to cost of the No Policy scenario. The effect on retail rates is an increase of between 5 and 12 percent on average over the planning period depending on whether or not carbon penalties are included in utility costs.

In the absence of any climate policy, carbon emissions would continue to grow. By 2030 carbon emissions from the power system would increase by 5 percent over 2005 levels. Interestingly, under the No Policy scenario, the amount of conservation that is developed is smaller than the $0 to $100 Carbon scenario but more than that developed under the Current Policy scenario. However, no new renewable resources are developed in the No Policy scenario except for a small amount of geothermal; and a large amount of natural gas-fired resources are added. Table 9-3 summarizes the comparison.

Table 9-3: The No Policy Scenario Versus the Current Policy and $0 to $100 Carbon Scenarios

	No Policy	Current Policy	$0 to $100 Carbon
Cost (billion 2006$ NPV)			
With Carbon Penalty	$56.50	$70.50	$105.6
Without Carbon Penalty	$56.50	$70.50	$85.10
Retail Rates - Change (%) from No Policy Scenario			
With Carbon Penalty		+ 2.8%	+ 12.3%
Without Carbon Penalty		+ 2.8%	+ 5.3%
Carbon Emissions (Gen) (Million Tons/Year)	60.0	52.1	37.1
Resources 2030			
Conservation (MWa)	5,432	5,197	5,827
Wind (MWa)	0	1,845	1,800
Geothermal Options (MWa)	52	13	169
CCCT Options (MWa)	1,890	0	756
SCCT Options (MWa)	648	648	162

No Renewable Portfolio Standards

Three of the four states in the region have some form of renewable portfolio standard that requires a certain share of electricity consumption to be supplied from qualifying renewable generation. This policy favors one particular solution to carbon emissions, but encourages development of new forms of electricity generation. Questions the Council considered were whether an RPS would be necessary if there is a perceived risk that a substantial carbon penalty could be imposed in the future, and whether other policies might be as effective in reducing carbon emissions. To explore this question, a scenario was run that removed RPS requirements from the $0 to $100 Carbon scenario.

Table 9-4 compares the results of the $0 to $100 Carbon scenario and the No RPS scenario. The results show only a small effect from the additional effect of RPS on the cost of the least-cost, low-risk resource portfolio. Cost is slightly lower without the RPS, and carbon emissions are higher. Significantly less renewable generation is developed, more conservation is acquired and more natural gas-fired generation is optioned in the No RPS scenario.

Table 9-4: The No RPS Scenario versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	No RPS
Cost (billion 2006$ NPV)		
With Carbon Penalty	$105.60	$101.40
Without Carbon Penalty	$85.10	$79.30
Retail Rates - Change (%) from $0 to $100 Carbon Scenario		
With Carbon Penalty		- 1.2%
Without Carbon Penalty		- 1.7%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	40.3
Resources 2030		
Conservation (MWa)	5,827	5,935
Wind (MWa)	1,800	1,171
Geothermal Options (MWa)	169	208
CCCT Options (MWa)	756	378
SCCT Options (MWa)	162	648

This scenario indicates that RPS requirements make an additional contribution to meeting carbon targets at a modest cost. RPS is a policy that can be, and has been, put in place to move the region toward a lower carbon future while other policy solutions are being developed at the national, regional, and state level. These potential future policies can have an effect on resource decisions even though they are not yet enacted because of the risk they pose for future carbon penalties. Unfortunately one of those effects may be to delay needed resource decisions because of the uncertainty. A similar situation occurred in the mid-1990s. Fear that federal policy would restructure the electric industry caused utilities to delay resource development decisions, which eventually led to an inadequate power system and the 2000-01 electricity crisis.

Retiring Existing Coal Plants

Existing coal plants account for over 85 percent of power system carbon emissions in the Pacific Northwest. Therefore any significant reduction in carbon emissions from the power system must include reduced operation of these power plants. In the $0 to $100 Carbon scenario, the ability to reduce carbon emissions to below 1990 levels results partly from coal plants being displaced in favor of renewable generation and conservation. In futures with high-carbon costs, natural gas plants become lower in cost than coal and as a result coal is dispatched less often.

If coal plants are dispatched less but remain available to run under some future conditions, carbon emissions become more variable. When low-carbon prices are assumed for a future, the coal plants will operate and they may operate more when water conditions are low or demand is high. As a result, reduced carbon emissions are not assured even though they are lower on an expected or average basis. There are also questions about the viability of continued operation of these plants if they are used infrequently or at minimum capacity. It may be unrealistic to expect coal plants to run as natural gas plants currently do. Coal plants are less flexible and have higher fixed operating and maintenance costs.

An alternative approach was considered in two coal retirement scenarios. It was assumed that the regional coal plants are phased out between 2012 and 2020. They could be retired or mothballed, but they are not considered available to meet loads and their output must be replaced with other resources. The two Retire Coal scenarios are distinguished by two different assumptions regarding the existence of carbon pricing policies, with carbon penalties and without carbon penalties. Table 9-5 shows the results of these scenarios compared to the $0 to $100 Carbon scenario.

Table 9-5: The Retire Coal Scenarios versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	Retire Coal w/ CO2	Retire Coal w/o CO2
Cost (billion 2006$ NPV)			
With Carbon Penalty	$105.60	$122.20	$94.70
Without Carbon Penalty	$85.10	$109.70	$94.70
Retail Rates - Change (%) from $0 to $100 Carbon Scenario			
With Carbon Penalty		+ 4.7%	- 0.4%
Without Carbon Penalty		+ 8.0%	+ 6.2%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	14.7	14.0
Resources 2030			
Conservation (MWa)	5,827	6164	5,739
Wind (MWa)	1,800	1,787	1,809
Geothermal Options (MWa)	169	156	52
CCCT Options (MWa)	756	2268	2268
SCCT Options (MWa)	162	648	648

The retirement of the coal plants results in a dramatic reduction of carbon emissions. In 2030 the average emissions are reduced by 70 percent from 2005 levels. These reductions are approaching some of the targets proposed by the Intergovernmental Panel on Climate Change for 2050.

In the scenario where coal plants retirement is treated as a substitute for carbon pricing policy (Retire Coal without CO2), costs are decreased compared to the $0 to $100 Carbon scenario without free allowances. However, if coal is retired in combination with carbon pricing policy (Retire Coal with CO2) and free allowances are not granted, the power system costs increase by 16 percent. In rough terms, these cost increases would translate into real (without general economic inflation) average retail electricity price increases of 6 and 8 percent with free allowances.

The amounts of conservation acquired change moderately under each of these scenarios. The bulk of the coal capability is replaced by additional options on combined-cycle gas-fired generation, which has about 38 percent of the carbon emissions of an existing coal plant.

Like the RPS, a policy of retiring coal plants is an alternative carbon control policy. It also focuses on one particular solution without creating wide-spread incentive to find creative and low-cost solutions to reducing carbon emissions in every sector that produces carbon. Nevertheless, the results are more predictable and the policy could be implemented through regulations at the state level. It could be a viable alternative in a region like the Pacific Northwest where coal is not the dominant power supply, but is the dominant carbon emissions source. Replacement by natural gas is the alternative assumed here, but in the longer term other options may become available such as carbon capture and sequestration, advanced nuclear, or additional renewable generation technologies.

Fixed Carbon Price Scenarios

The $0 to $100 Carbon scenario assumes risk associated with an uncertain carbon pricing policy in the future. One question posed is: would the plan resource strategy change if a fixed carbon price were assumed? Two scenarios were tested: one with a $100 per ton carbon price and one with a $20 a ton carbon price. These scenarios generally cover the range of prices used in utility and other analyses. Table 9-6 shows the results of these two scenarios compared to the $0 to $100 Carbon scenario.

Table 9-6: The Fixed Carbon Price Scenarios versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	$100 Carbon	$20 Carbon
Cost (billion 2006$ NPV)			
With Carbon Penalty	$105.60	$143.70	$89.70
Without Carbon Penalty	$85.10	$97.40	$72.30
Retail Rates - Change (%) from $0 to $100 Carbon Scenario			
With Carbon Penalty		+ 14.3%	- 2.1%
Without Carbon Penalty		+ 7.1%	- 1.0%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	26.1	43.5
Resources 2030			
Conservation (MWa)	5,827	6,025	5,427
Wind (MWa)	1,800	1,790	1,808
Geothermal Options (MWa)	169	156	156
CCCT Options (MWa)	756	1134	0
SCCT Options (MWa)	162	648	648

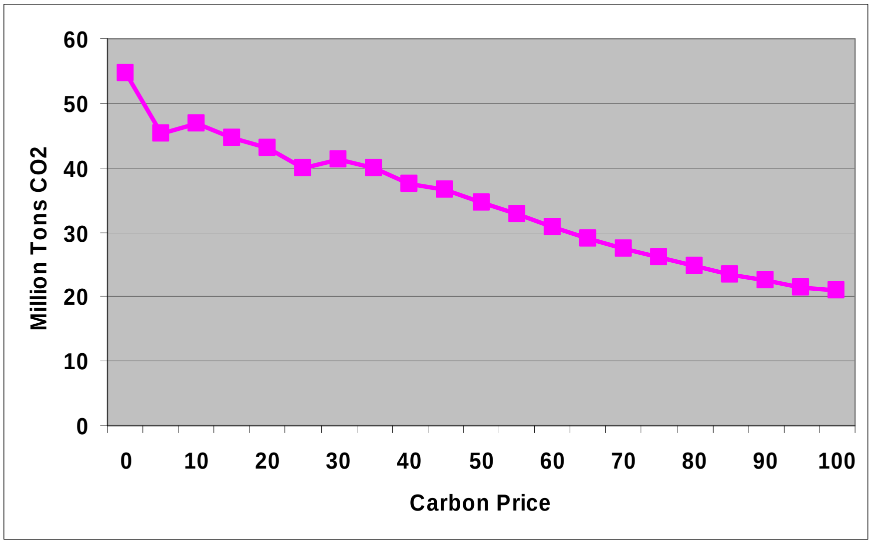
As would be expected, the $100 Carbon scenario reduces average carbon emissions far more than does the $0 to $100 Carbon scenario, which has an average carbon price that only reaches $47 per ton by 2030. The $20 carbon cost does not achieve these substantial reductions. Conservation does not increase substantially with $100 carbon costs because most of the available conservation was developed in the $0 to $100 Carbon scenario. There is a 400 average megawatt (7 percent) reduction of conservation in the $20 scenario. The development of renewable generation changes little among these scenarios and is largely determined by RPS requirements.

An interesting result is apparent in the changes of natural gas-fired generation options. With fixed carbon prices of $100 there is a large increase in the optioning of natural gas combined-cycle turbines, whereas with fixed $20 carbon costs more simple-cycle turbines are optioned. In the $100 Carbon scenario significant reductions in carbon emissions are achieved by displacing existing coal plants. The combined-cycle plants are being optioned to provide base-load energy and capacity to displace the coal plants. In the $20 Carbon Cost scenario the coal plants remain viable base-load plants and additional capacity is provided by simple-cycle turbines to provide capacity. In the $100 Carbon scenario, the question again arises of whether coal plants would remain viable at low-capacity operations.

These results are consistent with preliminary estimates done by the Council of carbon emissions using the AURORA$^{xmp®}$ Electric Market Model. The results of those studies showed that carbon prices of between $40 and $70 per ton are required to change the dispatch order of coal and natural gas-fired generation. The exact point of change will depend on the price of natural gas relative to the carbon price and will vary for individual plants. The future price of natural gas and carbon costs cannot be known. The $0 to $100 Carbon scenario, therefore, models the risks of alternative futures for both carbon cost and natural gas price to find a resource strategy that reduces the risk associated with these uncertainties.

Another approach to the question of how carbon prices are related to emission levels was done using the Regional Portfolio Model in a deterministic mode (i.e. using expected values of variables instead of stochastic analysis). The $0 to $100 Carbon scenario resource strategy was tested with costs for carbon emissions varying in $5 increments from $0 to $100. Figure 9-4 shows the results. Increasing carbon costs lead to reduced emissions. Again prices of carbon above $40 per ton begin to push carbon emissions below 40 million tons by 2030, and emissions could be cut in half from that level with institution of a carbon cost of $100 per ton. These results should not be expected to match closely the results for the $0 to $100 Carbon scenario in the tables in this section because of the effects of varying levels of demand, natural gas prices, hydro conditions, and other varying future conditions modeled in the $0 to $100 Carbon scenario.

Figure 9-4: An Estimated Relationship between Carbon Price and Emissions



Random Carbon Penalty up to $50

If a cap and trade system is implemented, the price of carbon emission permits will be determined in a market with multiple buyers and sellers. The price in that market will depend on the demand for allowances and the cost of reducing carbon emissions. Although there are estimates of the future cost of carbon emission allowances under the proposed Waxman Markey Bill, the actual costs experienced will depend on supply of and demand for allowances and on the role and geographic scope of any offsets that may be allowed to meet carbon reduction requirements.

To test this, the Council looked at a scenario where carbon prices could vary from $0 to $50 instead of the range of $0 to $100 assumed in the $0 to $100 Carbon scenario. The expected value of this smaller range of prices by 2030 is about $20 compared to the $47 average in the $0 to $100 Carbon scenario. Table 9-7 compares the results of the two carbon price risk scenarios.

Table 9-7: The $0 to $50 Carbon Scenario versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	$50 CO2 Price Maximum
Cost (billion 2006$ NPV)		
With Carbon Penalty	$105.60	$91.60
Without Carbon Penalty	$85.10	$78.30
Retail Rates - Change (%) from $0 to $100 Carbon Scenario		
With Carbon Penalty		- 3.6%
Without Carbon Penalty		- 1.0%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	41.7
Resources 2030		
Conservation (MWa)	5,827	5,638
Wind (MWa)	1,800	1,798
Geothermal Options (MWa)	169	156
CCCT Options (MWa)	756	0
SCCT Options (MWa)	162	648

With a lower carbon price range, the cost of the power system is less, especially when carbon emission allowance costs are included in the costs. However, the costs that result from different resource choices and operations are only reduced by 8 percent. Carbon emissions are increased about 12 percent.

Most importantly, the Power Plan's basic resource strategy is not significantly changed by the lower carbon price range. Conservation remains the dominant resource choice, renewable development is driven by RPS requirements and does not change significantly, and natural gas remains the fuel-based resource for other needs.

Value of the Hydroelectric System

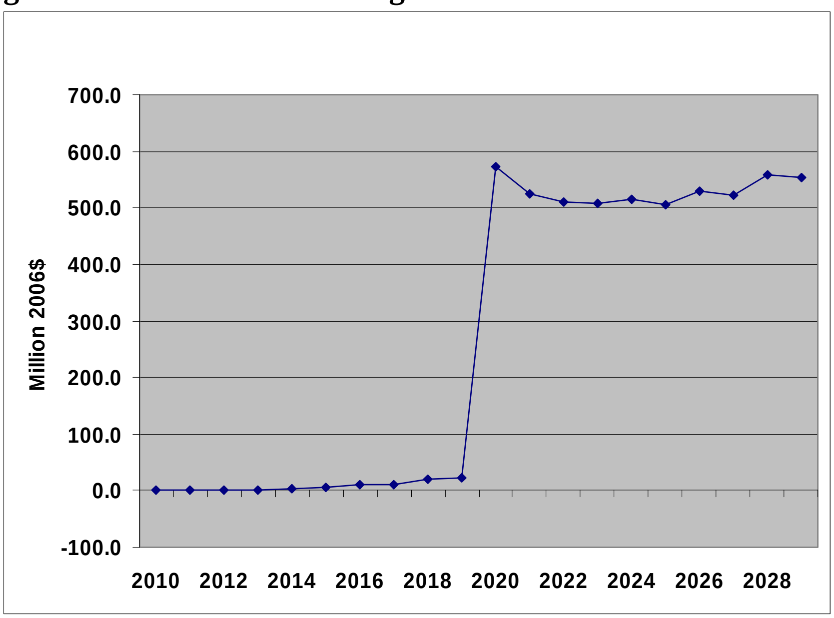
The Pacific Northwest power system emits about half the carbon dioxide per kilowatt-hour of the nation or the rest of the western states. This is due to the large role played by the hydroelectric system of the region. The value of this system is sometimes overlooked. To illustrate this tradeoff a scenario was run to examine the effects of removing the lower Snake River dams on costs, carbon emissions, and replacement resources that would be required for the power system. The capability of the dams was removed from the $0 to $100 Carbon scenario. The results of the scenario, however, could apply to other changes that reduce the capability of the hydroelectric system for any reason. For this scenario, it was assumed that the dams are removed in 2020 and the energy and capacity are replaced by the Regional Portfolio Model. The results are compared to the $0 to $100 Carbon scenario in Table 9-8.

Table 9-8: The Dam Removal Scenario versus the $0 to $100 Carbon Scenario

	$0 to $100 Carbon	Dam Removal
Cost (billion 2006$ NPV)		
With Carbon Penalty	$105.60	$112.50
Without Carbon Penalty	$85.10	$88.80
Retail Rates - Change (%) from $0 to $100 Carbon Scenario		
With Carbon Penalty		+ 1.7%
Without Carbon Penalty		+ 1.0%
Carbon Emissions (Gen) (Million Tons/Year)	37.1	40.2
Resources 2030		
Conservation (MWa)	5,827	5,923
Wind (MWa)	1,800	1,801
Geothermal Options (MWa)	169	208
CCCT Options (MWa)	756	1134
SCCT Options (MWa)	162	324

Dam removal increases both the carbon emissions and cost of the power system. Small increases in conservation and renewable resources occur in this scenario, but the primary replacement of the dams is provided by natural gas-fired combined-cycle combustion turbines. Figure 9-5 shows the annual pattern of cost changes for the Dam Removal scenario. Annual cost of the power system increases in 2020 by about $550 million dollars and remains higher.

Figure 9-5: Annual Cost Changes for the Dam Removal Scenario



Summary

Figure 9-6 summarizes the results of the various scenarios described above. Significantly reducing carbon emissions from the regional power system will increase costs of electricity. The costs shown in this summary assume that carbon penalties are excluded from utility revenue requirements through free emission allowances or other mitigation. The Current Policies scenario demonstrates the region can stabilize emissions near 2005 levels by 2030, but not reduce them without additional actions aimed at reducing carbon emissions. Without the current policies in place now, however, carbon emissions from the power system would continue to grow. Because over 85 percent of these carbon emissions are from existing coal plants serving regional loads, any significant reduction requires reduced reliance on these coal plants. Carbon prices above $40 per ton can reduce coal plant use, but an alternative policy would be to retire coal plants. In either scenario, the future cost of electricity would be increased.

Another way of looking at these results is to compare scenarios in terms of changes relative to the $0 to $100 Carbon scenario. Figure 9-7 shows changes in net present value system costs as bars and changes in carbon emissions as diamonds measured from the left hand scale. There is only one scenario in which costs and carbon emissions move in the same direction. That is the Dam Removal scenario where the policy choice is not intended to reduce carbon emissions, but rather to improve salmon and steelhead survival.

Figure 9-6: Summary of Costs and CO2 Emissions in Climate Policy Scenarios

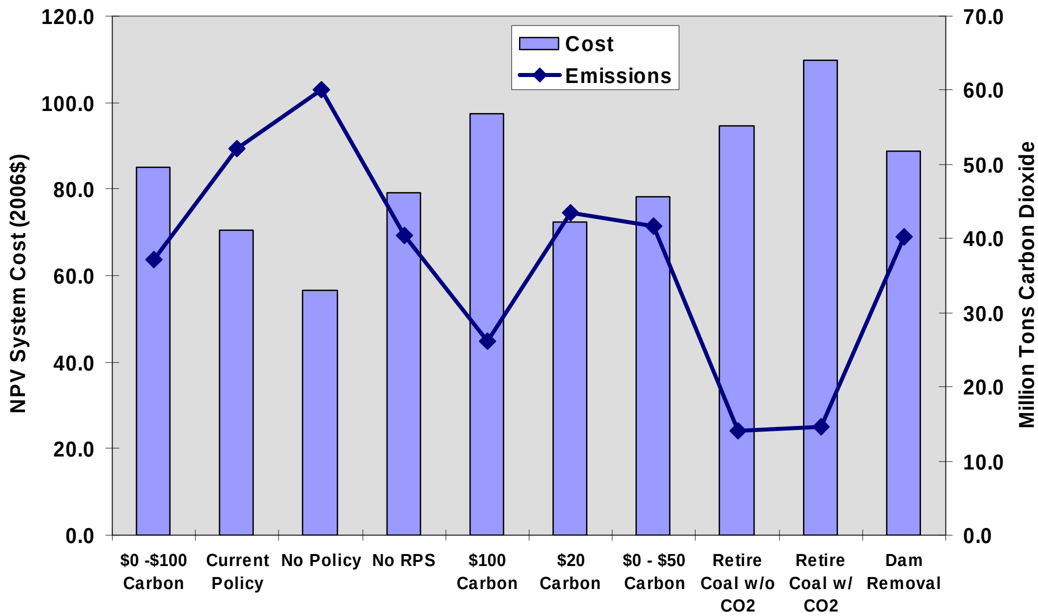
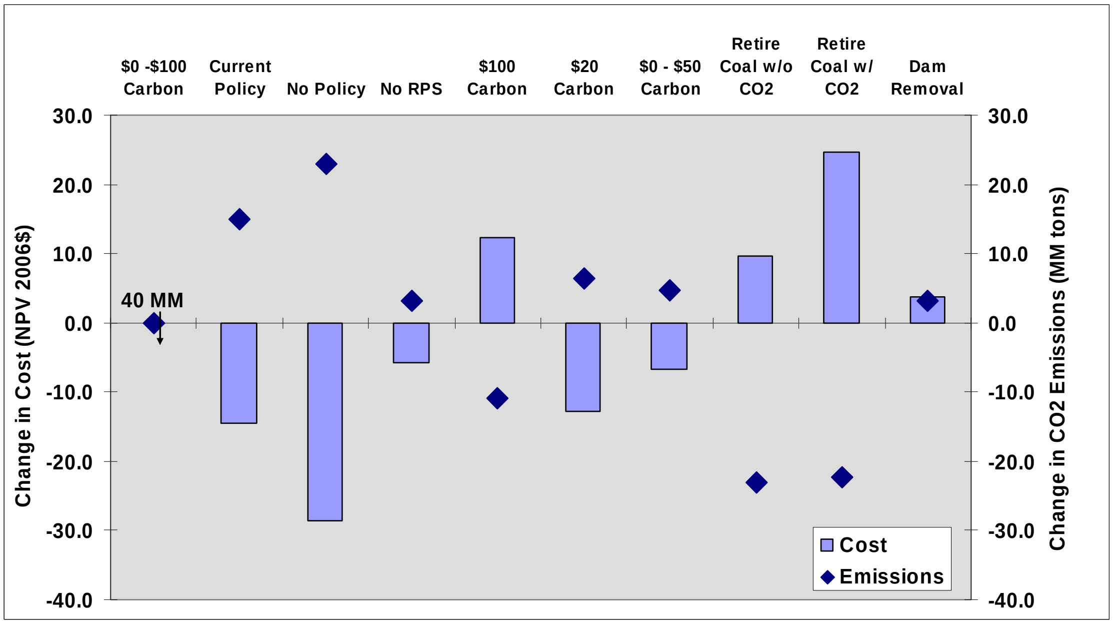


Figure 9-7: Summary of Costs and CO2 Emissions: Changes from $0 to $100 Carbon Scenario



Consumer Electric Rates and Monthly Bills

The net present value system costs that are the basis for resource planning do not mean a great deal to the region's citizens. They are more likely to be interested in their monthly electricity bills or the electricity rates that they pay. In this section, the effects of the various scenarios used to develop the Council's resource strategy for the Sixth Power Plan on consumers bills and rates are discussed.

By law, the Council's Power Plan is to minimize the cost of energy services, such as heat or light. The Council is not charged with minimizing electricity rates. The objective of the Plan is to minimize consumers' electric bills. There are a number of steps involved in estimating rates or bills from the going forward system costs that are the planning criteria for the Council's Plan. Most notably, the fixed cost of the existing power system must be recovered through rates (paid for in bills) but is not included in the system costs of the Council models. In addition, some of the costs of conservation are not paid through electricity bills, but are paid directly by consumers. For example, an energy efficiency standard will improve the efficiency of appliances and to the extent it results in higher cost appliances, consumers will pay for the increased efficiency directly, rather than through electricity bills. There are other adjustments as well. For example, as described in Chapter 8, it is not clear what amount of any carbon tax or carbon emissions allowance cost will have to be recovered through electricity rates.

The Council has calculated costs, rates and bills including both all and none of these carbon penalty costs to provide a range of effects. From a societal perspective someone will pay these costs to reduce carbon emissions, but it isn't clear how much of the reduction will be accomplished in the electricity sector, nor how much will show up in bills and rates.

In the rates and bills calculations in this section, the fixed cost of the existing power system is assumed to remain constant in real terms. Depreciation of existing assets is assumed to be offset by equipment upgrades and replacements. To the extent that major transmission upgrades are needed in the future, these costs are not included in these estimates. Those costs are likely to occur regardless of the resources chosen for the Council's resource strategy, although aggressive conservation will reduce the need for additional transmission along with reducing the need for new electricity generation capability. One exception is the cost of upgrading transmission to access remote wind resources; these costs are recognized in the Council's planning.

Figure 9-8 shows a comparison of electricity rates among the scenarios considered in the Plan. The rates are shown both with and without the carbon penalties. The variation in rates is not as large as the variation shown earlier in power system planning costs. That is because a large portion of the revenue requirement that has to be recovered in rates and bills is fixed and does not change among the scenarios. It is important to remember that these rates are averages over 750 futures. There will be very significant variations among these futures depending on natural gas prices, hydroelectric conditions, the need to build new generation, and electricity market prices.

Another reason for relatively little variation in rates is the fact that conservation accounts for the majority of new resources. The low and high conservation scenarios show that the effect on electricity rates is not large. Conservation does tend to raise the rates for electricity, but as can be seen in Figure 9-9 it reduces electricity bills because less electricity is used.

The $0 to $100 Carbon scenario is one that is estimated to attain on average the carbon reduction goals in Oregon and Washington and in proposed federal legislation. It is therefore interesting to examine the estimated rate and bill effects of that scenario compared to the Current Policy scenario. The implicit assumption in these comparisons is that the electricity sector would be required to meet a similar percent reduction in emissions as the economy at large. The rates in the $0 to $100 Carbon scenario are between 2.4 percent and 9.3 percent higher than the Current Policy scenario. The range depends on how much of the carbon penalty has to be recovered through electricity sale revenues. The effect on electricity bills is to increase average monthly bills for a residential consumer by between $.94 and $5.58.

The largest effect on bills and rates is in the fixed $100 Carbon scenario. The second largest effect is in the coal retirement scenarios. Unless replacement of existing coal-fired generation is subsidized in such a policy scenario, the cost would be expected to be recovered through electricity revenues.

Figure 9-8: Levelized Retail Rates in Alternative Scenarios

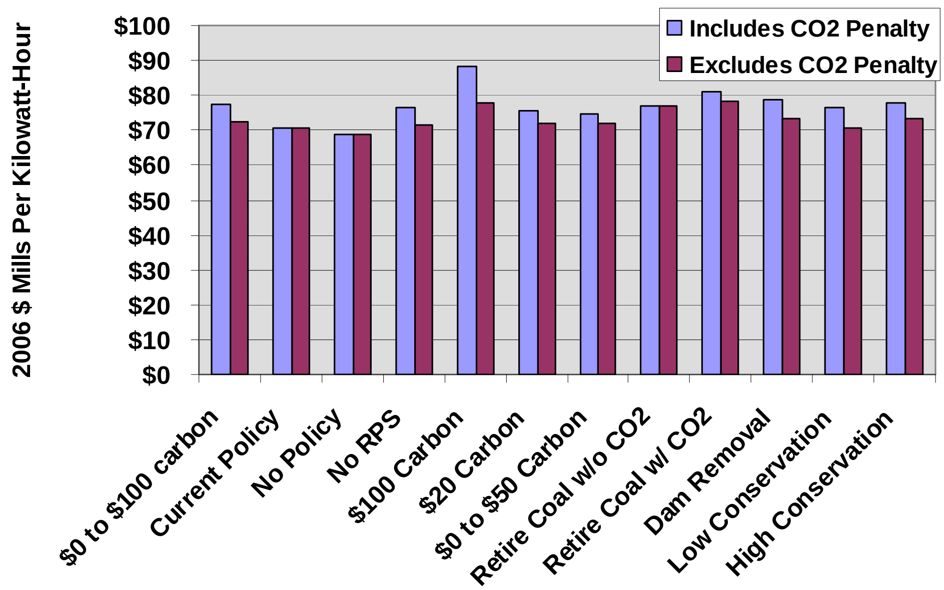


Figure 9-9: Levelized Residential Monthly Electricity Bills in Alternative Scenarios

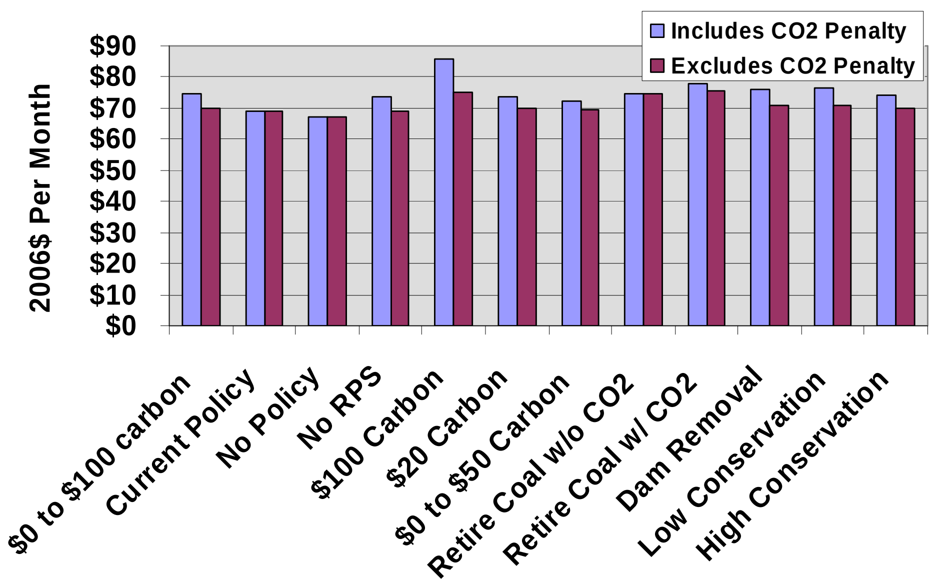


Figure 9-10 shows forecasts of monthly residential electricity bills over time for three scenarios; No Policy, Current Policy, and the $0 to $100 Carbon price risk assessment scenario. The $0 to $100 Carbon scenario bills are shown both with and without carbon costs included in the rates. This graph illustrates that attaining significant carbon reductions will increase electricity rates and bills. Without carbon price risk in the Current Policy scenario average bills would remain about the same over time. In the $0 to $100 Carbon scenario bills would be expected to increase by about 0.8 percent per year during the planning period if cost penalties are included. In the same scenario electricity rates would increase by 1.2 percent per year.

The increases seem small relative to some of the changes in planning costs. The effects of carbon pricing are minimized by the large role of conservation and renewables in the plan and the fact discussed above that a large share of electricity bills goes to cover existing infrastructure costs that are assumed not to change. In addition, a carbon penalty impacts the Pacific Northwest less than other regions because of the large role of our hydroelectric system and limited reliance on coal-fired generation.

Figure 9-10: Monthly Residential Electric Bills in Three Scenarios

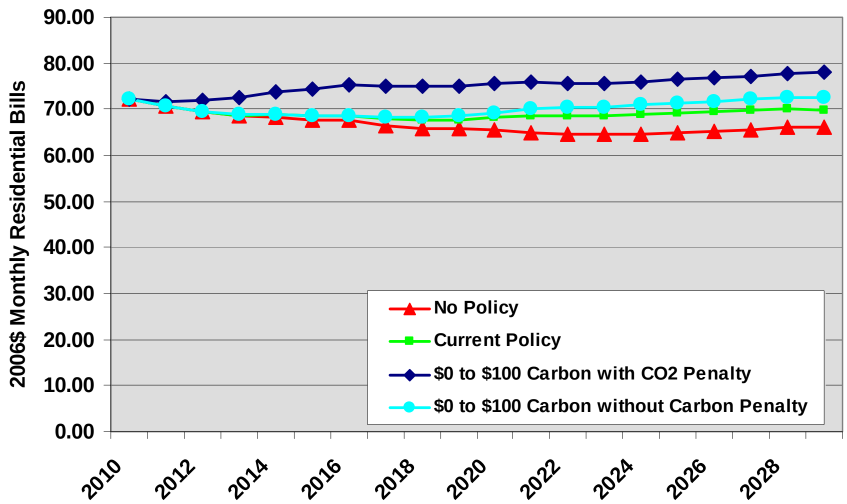
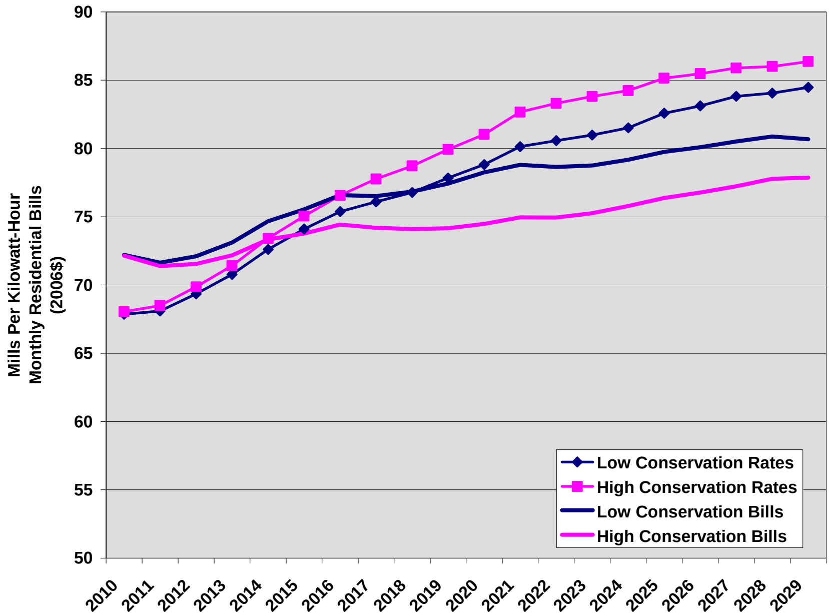


Figure 9-11 illustrates the effect of conservation costs on rates and bills. Conservation imposes cost on the power system, but reduces electricity sales. To recover the costs, therefore, utilities are required to raise electricity rates per kilowatt-hour. At the same time, however, consumers' use of electricity decreases. The net effect is that on average, consumers' monthly electricity bills are reduced. This is illustrated in Figure 9-11 by comparing rates and bills between the Low Conservation scenario and the High Conservation scenario. With low conservation, rates are reduced but bills are increased.

Figure 9-11: Electric Rate and Bill Effects of Low and High Conservation Scenarios



Detailed Scenario Results

The table below summarizes the most important results from the scenario analyses. It includes information of the costs, retail rates, carbon emissions, and resource choices. The differences between the Current Policy (Zero Carbon Risk) and other scenarios are calculated. In addition, for rates alternative scenarios are compared to both the Current Policy scenario and the $0 to $100 Carbon scenarios.

Scenario Comparison	No Policy	Zero Carbon Risk Current Policy	$0 to $50 Carbon risk	$0 to $100 Carbon risk	No RPS	Retire Coal with CO2	Retire Coal w/o CO2	$100 Carbon	$20 Carbon	Dam Removal	High Conservation	Low Conservation
Cost (billion 2006$ NPV) **with** Carbon Penalty	$56.5	$70.5	$91.6	$105.6	$101.4	$122.2	$94.7	$143.7	$89.7	$112.5	$103.8	$114.3
NPV Change from Current Policy	-$14.0	$0.0	$21.1	$35.1	$30.9	$51.7	$24.2	$73.2	$19.2	$42.0	$33.3	$43.8
% Change from Current Policy	-20%	0%	30%	50%	44%	73%	34%	104%	27%	60%	47%	62%
Cost (billion 2006$ NPV) **without** Carbon Penalty	$56.5	$70.5	$78.3	$85.1	$79.3	$109.7	$94.7	$97.4	$72.3	$88.8	$84.8	$88.7
NPV Change from Current Policy	-$14.0	$0.0	$7.8	$14.6	$8.8	$39.2	$24.2	$26.9	$1.8	$18.3	$14.3	$18.2
% Change from Current Policy	-20%	0%	11%	21%	12%	56%	34%	38%	3%	26%	20%	26%
Retail Rates - **with** Carbon Penalty	68.87	70.80	74.60	77.37	76.48	80.97	77.03	88.44	75.78	78.70	77.83	76.28
% Change from $0 to $100 Carbon Risk	-11.0%	-8.5%	-3.6%	0.0%	-1.2%	4.7%	-0.4%	14.3%	-2.1%	1.7%	0.6%	-1.4%
% Change from Zero Carbon Risk	-2.7%	0.0%	5.4%	9.3%	8.0%	14.4%	8.8%	24.9%	7.0%	11.2%	9.9%	7.7%
Retail Rates - **without** Carbon Penalty	68.87	70.80	71.78	72.51	71.30	78.28	77.03	77.68	71.79	73.21	73.17	70.75
% Change from $0 to $100 Carbon Risk	-5.0%	-2.4%	-1.0%	0.0%	-1.7%	8.0%	6.2%	7.1%	-1.0%	1.0%	0.9%	-2.4%
% Change from Zero Carbon Risk	-2.7%	0.0%	1.4%	2.4%	0.7%	10.6%	8.8%	9.7%	1.4%	3.4%	3.3%	-0.1%
Carbon Emissions Comparison												
Carbon Emissions (Gen) (Millions Tons/year)	60	52.1	41.7	37.1	40.3	14.7	14	26.1	43.5	40.2	36.6	41
Millions of tons Saved Compared to Current Case over 20 yrs.	-158	0	208	300	236	748	762	520	172	238	310	222
Resources 2030												
Conservation (MWa)	5,432	5,197	5,638	5,827	5,935	6164	5,739	6,025	5,427	5,923	5,849	4,566
Wind (MWa)	0	1,845	1,798	1,800	1,171	1,787	1,809	1,790	1,808	1,801	1,778	1,996
Geothermal Options (MW)	52	13	156	169	208	156	52	156	156	208	195	208
CCCT Options (MW)	1890	0	0	756	378	2268	2268	1134	0	1134	378	2268
SCCT Options (MW)	648	648	648	162	648	648	648	648	648	324	162	162

Chapter 10: Climate Change Issues

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. This chapter describes the second of these issues, namely how current policies affect the plan's resource strategy and what future policies may help achieve green house gas emission reduction goals. The first issue, relating to physical changes resulting from climate change is discussed in Appendix L.

The focus of climate policy especially for the power generation sector will be on carbon dioxide emissions. Nationally, carbon dioxide accounts for 85 percent of greenhouse gas emissions, with about 38 percent originating from electricity generation. For the Pacific Northwest the power generation share is only 23 percent because of the hydroelectric system. Analysis by others has shown that substantial and inexpensive reductions in carbon emissions can come from more efficient buildings and vehicles. More expensive reductions can come from substituting non- or reduced-carbon electricity generation such as renewable resources and nuclear, or from sequestering carbon.

Reductions in carbon emissions can be encouraged through various policy approaches including, regulatory mandates (e.g. renewable portfolio standard or emission standards), emissions cap-and-trade systems, emissions taxation, and efficiency improvement programs. Policy responses to climate change concerns for the Northwest states have focused on renewable energy and new generation emission limits. National and west-wide proposals have focused on cap-and-trade systems, although none have been implemented successfully. Although carbon taxes are easier to implement than cap-and-trade systems, none have been proposed.

The Council's "$0 to $100 per ton carbon penalty" scenario assumes current climate policies that include renewable portfolio standards (RPS), new generation emissions standards and renewable energy credits. The scenario also assumes various future carbon penalty cost trajectories that vary between zero and $100 per ton and average $47 per ton by 2030. The least risk resource portfolio in this scenario includes a combination of conservation, renewable resources and gas-fired resources and results in a reduction of power system carbon emissions from 57 million tons per year in 2005 to an average of 37 million tons in 2030. This expected reduction, which is below the 1990 emission level of 44 million tons, is generally consistent with targets adopted by Northwest states. This expected reduction is the average of 750 futures, which means that about half of all futures have greater reductions and about half have less reductions.

If no future carbon pricing policies are assumed, a least-cost resource strategy would only stabilize carbon emissions at about current levels. Therefore, relying only on existing policies will not achieve the WCI carbon emission goals or those of individual states in the region. To significantly lower carbon emissions, existing coal-fired generation must be reduced. In the $0 to $100 per ton carbon penalty scenario, these plants are simply used much less frequently because of cost. However, there are potential future conditions where coal generation would be needed. In order to ensure a reduction in emissions, coal plants must be retired. Analysis of a scenario in which all regional coal plants are phased out between 2012 and 2020 showed that carbon emissions could be reduced to about 15 million tons by 2030. A number of alternative scenarios were analyzed to investigate the relationship between future carbon cost levels and emissions.

The Columbia River hydroelectric system provides most of the region's energy, capacity, and flexibility supply. As a carbon free resource, it is extremely valuable to the region. Primarily because of the hydroelectric system the region's carbon emissions are half of those for the nation as a whole. Meeting the region's responsibilities for mitigating the fish and wildlife losses caused by the dams has depleted the capabilities of the hydroelectric system over time. The region should carefully consider future fish and wildlife operations because loss of hydroelectric capability will increase carbon emissions. For example, removing the lower Snake River dams would undo 40 percent of the carbon reductions expected to be accomplished through the Council's plan.

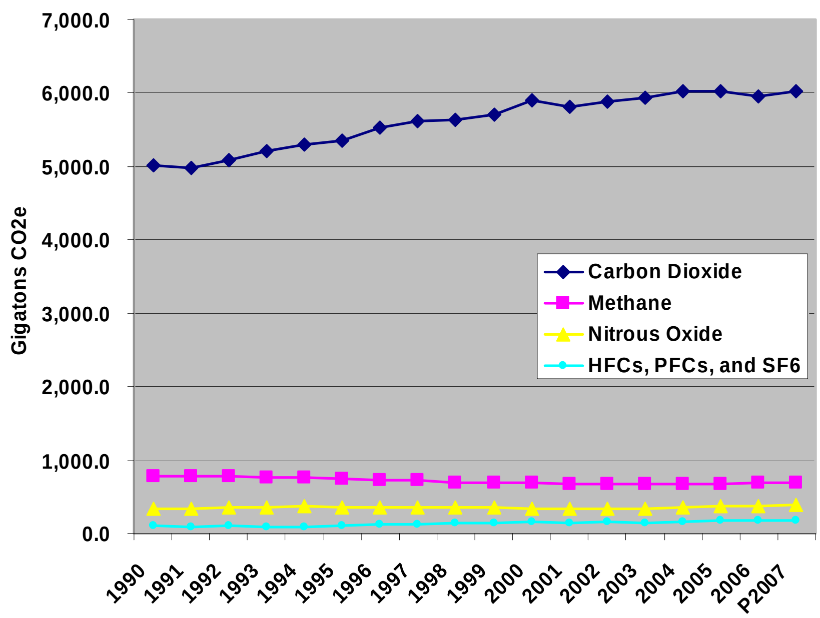
BACKGROUND

A large uncertainty facing future plans for electricity generation and use is climate change and associated policies aimed at controlling greenhouse gas (GHG) emissions. This chapter focuses on sources of GHGs related to the production and consumption of energy, especially the burning of fossil fuels, which are the focus of these policies. It does not address the phenomenon of climate change or its likely effects, but rather on how concerns and policies about those affect the region's energy system planning. Appendix L examines the physical implications of some specific climate change scenarios on the region's power system.

Greenhouse gases include a family of gases that affect the ability of the earth's atmosphere to absorb or reflect heat.[1] These include carbon dioxide, methane, nitrous oxide, and man-made CFC refrigerants. Different gases have different degrees of effect on warming and these are measured as global warming potential (GWP). Carbon dioxide, which has become almost synonymous with GHG, has the least global warming potential of the GHGs. Many of the other GHGs have global warming potentials thousands of times greater than that of carbon dioxide. Nevertheless carbon dioxide has become the primary focus of climate policy and discussion. The reason is that carbon dioxide accounts for more than three quarters of global GHG emissions. In the U.S. carbon accounts for 85 percent of GHG emissions and it is a growing source. Figure 10-1 shows that growth in carbon dioxide emissions are the primary reason for total U.S. GHG emissions growing since 1990. Levels of emissions from most other GHGs have been stable or declining. Even carbon dioxide emissions, although growing in total, have declined relative to population and gross domestic product growth in the United States.

Declining carbon dioxide emissions per dollar of gross domestic product have been due to a changing mix of economic activity and improved efficiency of energy use. The combustion of fossil fuels accounts for 94 percent of U.S. carbon dioxide emissions. Therefore declining carbon dioxide emissions reflect a corresponding decline in energy use per dollar of gross domestic product.

Figure 10-1: Sources of U.S. Greenhouse Gas Emissions, 1990 to 2007



Source: U.S. Energy Information Administration

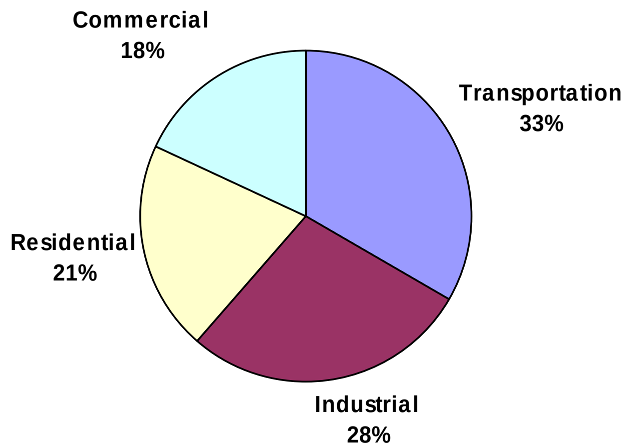
[1] The source of information for much of the following discussion is from the Environmental Protection Administration. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006. April, 2008. USEPA #430-R-08-005. http://www.epa.gov/climatechange/emissions/usinventoryreport.html

The National View

For the United States as a whole, electricity generation is the largest source of carbon dioxide emissions. Electricity generation accounted for 34 percent of carbon dioxide emissions in 2006. The next largest emissions sector was transportation at 28 percent, followed by the industrial sector at 20 percent. Other significant sectors include agriculture, residential and commercial. However, electricity is generated to be used in other sectors. When the carbon dioxide emissions from electricity generation are allocated to the sectors using the electricity, and added to those sectors' direct combustion of fossil fuels, a different mix of emissions sources results. In that accounting framework, which relates carbon emissions to the underlying human activities, transportation becomes the largest carbon dioxide emitting sector. Figure 10-2 shows the sources of carbon dioxide emission by end use sector in the U.S.

For electricity planning, the implication of this information is that, to reduce carbon dioxide emissions from the electricity sector, policies should address both the generation of electricity and the efficiency of electricity use. Carbon emissions from electricity generation can be addressed through improved efficiency of generation and transmission technologies, changing the mix of generation from coal to natural gas, substituting renewable non-carbon-emitting sources of generation, or various strategies to sequester the carbon dioxide emissions. On the electricity use side, improved efficiency of use reduces the need to generate electricity. Policies should target both sides of the electricity equation with priority given to the lowest cost mitigation approaches. Further, policies should also address emissions from the direct use of fossil fuels in other sectors, including transportation.

Figure 10-2: Carbon Dioxide Emissions by Sector, 2006

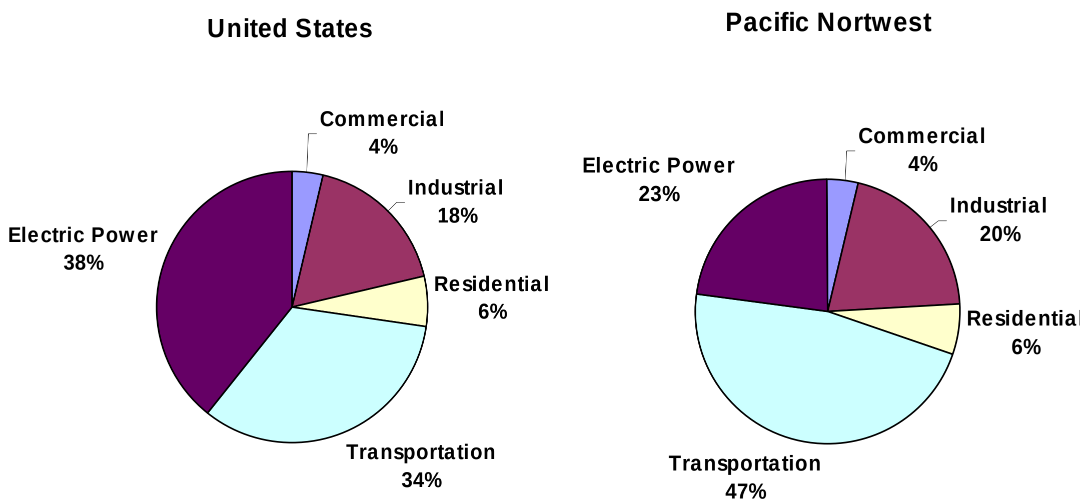


Note: Electricity generation emissions allocated to end use sectors
Source: U.S. Environmental Protection Agency

The Pacific Northwest Regional View

The sources of carbon emissions in the Pacific Northwest are not typical of the U.S. as a whole. Figure 10-3 compares the shares of carbon dioxide emissions from economic sectors for the U.S. and the 4 states in the Northwest. Unlike Figure 10-2, emissions from electricity generation are included in the electric power sector in Figure 10-3. In the Pacific Northwest, the share of energy related carbon dioxide emissions from electric power generation is much smaller than for the U.S. For the U.S. electric power is the largest source of carbon dioxide, but in the Pacific Northwest transportation is the largest. The reason, of course, is the dominance of the hydroelectric system in Northwest electricity supply.

Figure 10-3: Energy Carbon Emissions by Sector, 2005

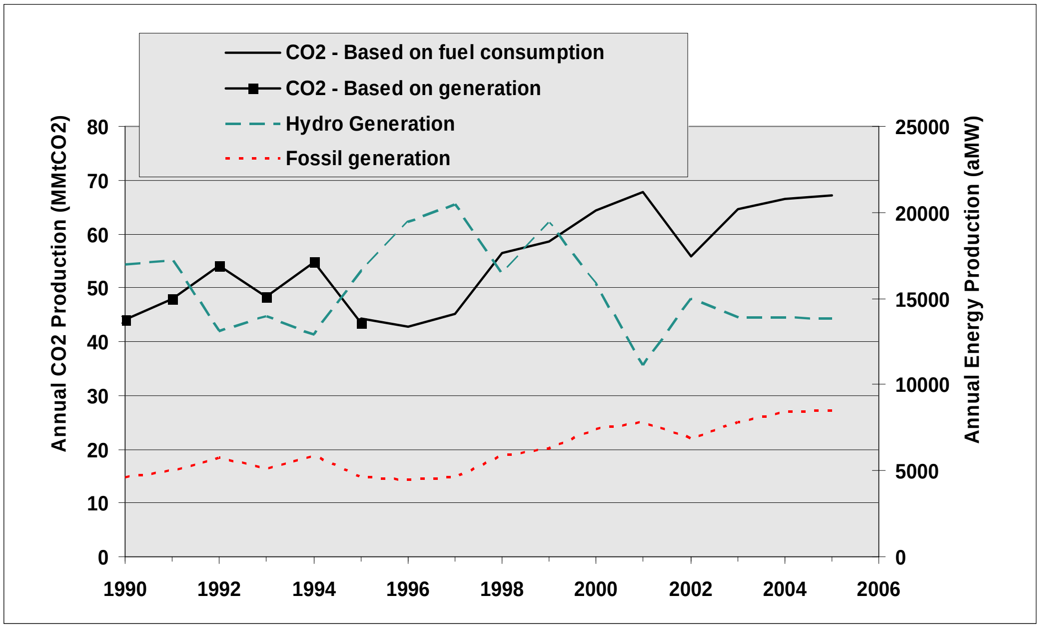


The years 1990 and 2005 are frequently used as benchmarks in policies for the control of greenhouse gasses.[2] The 1990 production of carbon dioxide from the Pacific Northwest power system is estimated to have been about 44 million tons, based on electricity production records of that year. Load growth, the addition of fossil-fuel generating units, the loss of hydropower production capability, and the retirement of the Trojan nuclear plant resulted in growing CO_2 production over the next 15 years. By 2005, the most recent year for which electricity production or fuel consumption data are available, CO_2 production increased 52 percent to 67 million tons (Figure 10-4). This is approximately the CO_2 output of 23 400-megawatt conventional coal-fired power plants, 56 400-megawatt gas-fired combined-cycle plants or about 11.7 million average U.S. passenger vehicles.

[2] For example, California Assembly Bill (AB) 32, passed by the legislature and signed by the governor in 2006, calls for enforceable emission limits to achieve a reduction in CO_2 emissions to the 1990 rate by 2020. Washington Governor Gregoire's climate-change executive order includes the same target for CO_2 reductions. Oregon House Bill 3543, passed by the legislature and signed by Governor Kulongoski in August, declares that it is state policy to stabilize CO_2 emissions by 2010, reduce them 10 percent below 1990 levels by 2020, and 75 percent below 1990 levels by 2050. The goal of the Western Climate Initiative is to reduce GHG emissions to 15 percent below 2005 levels by 2020.

The regional CO_2 production estimates from 1995 through 2005 shown in Figure 10-4 are based on the fuel consumption of Northwest power plants as reported to the Energy Information Administration (EIA). Because fuel consumption data were not available before 1995, estimates for 1990 through 1995 are based on plant electrical output as reported to EIA and staff assumptions regarding plant heat rate and fuel type. Estimates based on plant electrical production are likely somewhat less accurate than estimates based on fuel consumption because of multi-fuel plants and uncertainties regarding plant heat rates. However, the two series of estimates are within 2 percent in the "overlap" year of 1995.

Figure 10-4: Growth of CO_2 Emissions from Electricity Generation in the Pacific Northwest



Annual hydropower conditions can greatly affect power system CO_2 production. Average hydropower production in the Northwest is about 16,400 average megawatts. As shown by the plot of Northwest hydropower production in Figure 10-4, the 1990 water year was nearly 17,000 average megawatts, slightly better than average. Other factors being equal, this would have slightly reduced CO_2 production that year by curtailing thermal plant operation. Conversely, hydro production in 2005 was about 13,800 average megawatts, a poor water year. Other factors being equal, this would have increased thermal plant dispatch, raising CO_2 production. The effect of hydropower generation on thermal plant generation and CO_2 production is apparent in Figure 10-4.[3]

If normalized to average hydropower conditions, actual generating capacity, and the medium case loads and fuel prices of the Fifth Power Plan, the estimated CO_2 production in 2005 would have been 57 million tons, a 29 percent increase over the 1990 rate. This is the value used for comparison in this paper.

[3] In Figure 10-4, it is evident that Northwest thermal generation does not decline as much as Northwest hydro generation increases in above average water years, e.g. 1994 - 1997. This is likely due to the fact that the abundant hydropower of good water years creates a regional energy surplus that can be sold out of the region where it displaces thermal generation, which often consists of older, less efficient gas-fired units.

ACTIONS TO REDUCE GREENHOUSE GAS EMISSIONS

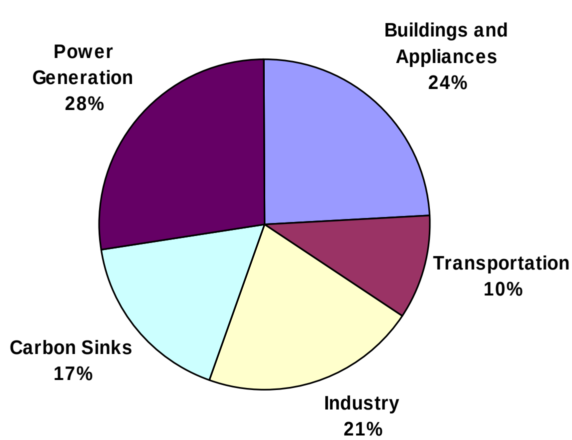
Because GHG emissions are dominated by carbon dioxide emissions from burning fossil fuels, and that is the primarily source of emission from electricity generation, the focus in this section is on carbon dioxide emissions. From a broad perspective, there are three general kinds of actions that can be taken to reduce carbon dioxide emissions; electricity could be generated from lower or zero carbon emitting fuels, the use of electricity could be reduced, or carbon that is released could be sequestered or offset. Similar possibilities exist for other uses of energy from fossil fuels besides electricity generation.

In 2007, McKinsey and Company undertook a study of how much GHG reduction was possible in the U.S. and what it might cost.[4] The McKinsey report looked at alternative actions to reduce GHG emissions. They assumed that without actions GHG emissions would grow from 7.2 billion metric tons to 9.7 billion metric tons by 2030. They then analyzed ways to reduce 2030 emissions by 3.0 billion metric tons, which was characterized as the mid-range of reductions sought in proposed legislation.

They estimated that about 40 percent of the reduction could be done at negative cost. Nearly all of this came from improved efficiency of energy use in buildings or vehicles. The remaining 60 percent of GHG reduction came from an array of actions that increased in cost as reductions grew. The most expensive option used to achieve the 3.0 billion metric ton reduction of 2030 emissions was estimated to cost $60 per ton.

All of the actions included in the McKinsey analysis were placed into five categories; buildings and appliances, transportation, industry, carbon sinks (or sequestration), and power generation. In the case where carbon emissions were reduced by 3.0 billion tons, the sources of reductions are shown in Figure 10-5. As was the case for Figure 10-2 emissions reductions from more efficient use of electricity are counted in the sector where electricity is consumed.

Figure 10-5: Estimated Sources for a 3 Billion Ton Reduction of GHG Emissions by 2030



[4] McKinsey & Company. Reducing U.S. Greenhouse Gas Emissions: How Much at What Cost? U.S. Greenhouse Gas Abatement Mapping Initiative, Executive Report. December 2007.

There are some interesting observations to make about the McKinsey results. Although a great deal of the policy discussion on GHG reduction centers on the electricity generation sector, only a quarter of the actions identified in the McKinsey report are electricity generation changes. Further, the electricity generation changes are among the more expensive actions, and they include actions such as renewable generation and carbon capture and sequestration, which cannot be implemented easily in the near term.

Another focus of policy speculation and potential is hybrid vehicles. In the McKinsey analysis, it is the most expensive alternative shown (around $90/ton) and it has relatively small potential for GHG reduction. The plug-in hybrid option was not needed to reach the 3.0 billion ton reduction case described above. Improved efficiency of conventional vehicles has far greater and cheaper potential.

If the goal is to stabilize GHG concentrations in the atmosphere, and if the climate change science is correct, policy decisions would not be a question of which mitigation strategies to pursue, but rather how to pursue all possible actions. The reductions in emissions that the McKinsey report addressed were for recent GHG policy proposals, but they do not reach the reduction levels needed to stabilize warming trends identified by climate scientists. For example, the Intergovernmental Panel on Climate Change estimated that emissions of GHG would need to be reduced to about one quarter of today's emissions by 2100 to stabilize atmospheric concentrations of GHG.

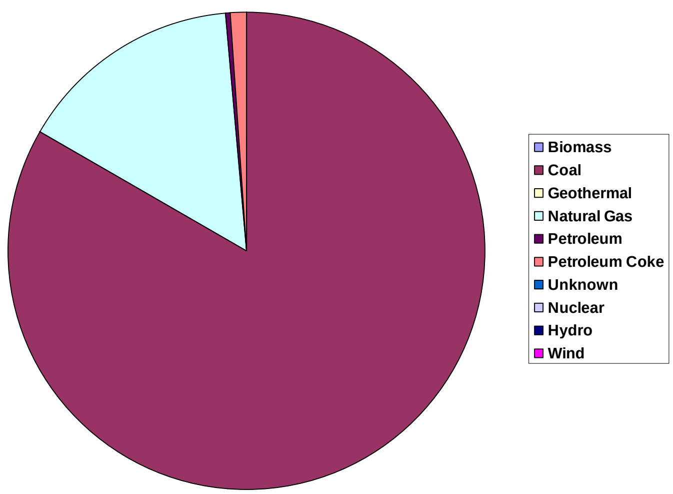
There have been many studies of the costs of particular policies or goals for GHG reduction. The usual purpose has been to try to estimate the price of carbon that is likely to be associated with a policy. The Council had a study done by EcoSecurities Consulting Limited to provide a range of likely carbon costs during the period of the Council's power plan. EcoSecurities reviewed many studies and provided a set of alternative estimates of carbon prices based on their models of supply curves for carbon mitigation actions. Point Carbon reviewed the results of 7 studies of the Lieberman-Warner bill for Bonneville, and used the studies to estimate a reasonable range of expected carbon prices under the proposed cap-and-trade policy.

Carbon price estimates under cap-and-trade programs are very sensitive to different assumptions about such things as the level of the carbon emissions cap, the use of offsets, banking and borrowing provisions, and the geographic scope of trading assumed. Price forecasts for the 2025 to 2030 time period varied from near zero to well over $100 per ton of carbon emissions. However, the more plausible range of prices was from roughly $10 to $80. The EcoSecurties report estimated that carbon prices might need to reach about $50 a ton by 2030 to progress toward the Intergovernmental Panel of Climate Change goal of stabilizing GHG concentrations by 2100. Point Carbon's assessment suggested that prices would escalate rapidly in years beyond 2030 although they regard their forecasts that far into the future as highly speculative and unlikely to consider technological developments that may occur.

For the Sixth Power Plan the Council considered a range of possible carbon costs between zero and about $100 per ton, with an average cost of about $47 per ton by the end of the study horizon. This possible but uncertain cost of carbon emissions has a significant influence on the plan's resource strategy. Conservation, renewable generation, natural gas-fired generation, coal (with or without carbon sequestration), and advanced nuclear power all compete to provide the lowest cost and least risky resource portfolio. Even before accounting for the effects of uncertainty and risk on resource expected costs, it is clear that improved efficiency is available in significant amounts and at low cost without adding to carbon or fuel price risks for the region. Natural gas, wind (that can be developed without significant transmission expansion) and possibly some small quantities of other currently available renewable technologies are next most expensive. Many other renewable resources, coal with carbon separation and sequestration, and advanced nuclear may become available within the Council's planning horizon, but are not currently available or are very expensive.

To achieve very significant reductions in the regional power system's carbon emissions, simply reducing or stopping the growth of carbon emissions will not be enough. As shown in Figure 10-6, existing coal-fired power plants account for about 88 percent of the region's emissions. Therefore, for example, the region could not reduce its power system emissions below 1990 levels, as some targets suggest, if the region's coal plants continue to operate as they do now. Thus part of the solution to aggressive carbon emission reductions would have to include changing the role of existing coal-fired generation. This would occur as a matter of economics if carbon penalties are high enough and natural gas prices low enough. Natural gas-fired generation would begin to displace coal-fired generation in the dispatch order. In addition, some older coal-fired plants that face additional investment to extend their lives or meet more stringent environmental requirements may choose to close rather than face the uncertainty of unknown future carbon costs.

Figure 10-6: Sources of CO_2 Emissions from the Northwest Power System, 2005



POLICIES TO REDUCE GREENHOUSE GASES

There are many possible policy approaches to reduce carbon emissions. They include GHG cap-and-trade programs, direct taxation of GHG emissions, regulatory programs that limit emissions or require non-emitting resources to be developed, and efforts to improve the efficiency of energy use. Choices among these approaches have varied. Most recently proposed national legislation has focused on cap-and-trade programs, but none has been passed to date. At the regional and state level, renewable portfolio standards and limits on emissions of new power plants have been the focus of much policy. The Council has primarily focused on efficiency of electricity use, and states, utilities, and the Federal Government have initiatives in efficiency improvement as well. Most of these efficiency programs existed well before the climate change issue was prominent, simply because improved efficiency was cheaper than building new electric generating plants and it contributed to reduced oil imports. Each of these approaches has advantages and disadvantages.

Mandates

A number of mandates direct companies and individuals to acquire or produce energy-using equipment that meets an approved standard of energy efficiency, or uses approved types of energy. One example of such mandates is the Corporate Average Fuel Efficiency standard for cars and light trucks. It has been in place since 1975 and imposes fines on car manufacturers whose products don't meet the standard. Other examples are appliance efficiency standards and the region's building codes, which have had an energy-efficiency component for more than 20 years.

More recently Washington, Oregon, and Montana in the Pacific Northwest region and a number of states elsewhere in the country have passed laws (Renewable Portfolio Standards) that require utilities to increase the level of electricity generated by renewable resources. These or related laws have in some cases also required generators that use non-renewable fuels to meet maximum emissions per kilowatt-hour standards (e.g. Washington and California).

Mandates have the advantage of relative simplicity and are fairly simple to enforce. They have the disadvantage that they are inflexible in the face of changed technology or other conditions. For example, future reductions in emissions from a state renewable portfolio standard might well cost more per ton than subsidizing modernization of generation in China, or expanded forests in South America. But unless the mandate has been made sufficiently flexible, it would not recognize these new alternatives as satisfying the mandate.

Tax Incentives

Tax incentives may reduce the cost of investment in preferred equipment such as hybrid cars or energy-efficient equipment or equipment that captures renewable energy, by allowing accelerated depreciation, tax credits or various forms of tax exemptions. Tax incentives of these types have been extended to hybrid cars, electricity generators powered by wind, and energy-efficient equipment and structures, renewable energy equipment purchases and renewable energy equipment manufacturing facilities.

Tax incentives can also increase the value of output from preferred equipment such as wind-driven generators by granting tax credits (e.g. the production tax credit) based on the amount of electricity produced by the generators. Compared to investment tax credits, production credits have the advantage of rewarding the final product desired, so that producers are encouraged not only to invest in preferred equipment, but also to produce as much electricity as possible with it.

Cap-and-trade Programs

A cap-and-trade policy sets a cap on the total amount of emissions allowed in the covered territory. The cap is enforced by issuing allowances in the amount of the cap and then requiring emitters to surrender allowances in the amount of their emissions. The strategy is to reduce the amount of the cap and the equivalent allowances over time to reduce emissions. Emitters are allowed to trade allowances to encourage those who can reduce emissions easily and cheaply to do so and profit by selling their surplus allowances to other emitters. Emitters may be allowed to "bank" or "borrow" allowances from year to year if they have a surplus or deficit of allowances in a given year. Cap-and-trade programs may include provisions for offset allowance credits resulting from taking certain emission reduction actions outside the scope of the regulated system.

A cap-and-trade policy to control emissions of SO_2 and NO_X was established as part of the Clean Air Act Amendments of 1990. This policy is generally regarded as a success, resulting in faster reductions in SO_2 emissions at lower costs than anticipated. Cap-and-trade programs have been included in proposed federal legislation to control greenhouse gas emissions and are also included in Western Climate Initiative discussions. The European Union Emission Trading System has been in place since 2005, capping a substantial fraction of Europe's total greenhouse gas emissions, and providing experience with this policy approach.

Compared to mandates and tax incentives, a cap-and-trade policy has the advantage of flexibility. Emitters can pursue a variety of strategies to reduce their own emissions or they can pay other emitters to reduce. They can be expected to choose the strategy that will minimize their cost (and the societal cost) of compliance. Another advantage of cap-and-trade policy compared to mandates and tax policies is that the cost of emission allowances is incorporated into retail prices of energy, providing appropriate price signals to final consumers of energy or of products produced using energy.

As a policy with the goal of reducing emissions of greenhouse gasses, cap-and-trade programs make the physical target for emissions explicit. As a result, the policy should meet the target reliably, but emission prices and total costs of emission reductions could be volatile and hard to predict. In contrast, the carbon tax policy, described next, has a more predictable total cost, but a less predictable total reduction in emissions.

Finally, cap-and-trade programs require the development of a market to trade emission allowances. The market mechanism offers the potential for emission reductions at low costs, but the development of a market trading newly-created assets like emission allowances requires careful consideration to have confidence that the market will function as expected.

Carbon Taxes

A carbon tax would likely apply not only to carbon, but also to all greenhouse gasses in proportion to their climate-changing effects. The climate impacts of the non-CO_2 gases are generally expressed as "CO_2 equivalents," so for this discussion all such taxes will be referred to as a carbon tax. It would tax emissions of greenhouse gasses at a level that would be expected to reduce emissions to the level chosen to control and mitigate climate change.

At the margin, the effect on overall emissions of a carbon tax of a certain cost per ton of carbon equivalent emitted should be the same as a cap-and-trade policy that results in an allowance price of the same cost per ton of carbon equivalent emitted. But as was pointed out above, the tax makes the total cost of emissions reduction reasonably predictable while leaving total reductions unpredictable, while a cap-and-trade program makes reductions more predictable and leaves the total cost less predictable.

As a practical matter this distinction between a carbon tax and cap-and-trade program may be less than it seems. Given the current state of knowledge about the effects of climate change and the technological choices available for reducing emissions, it seems inevitable that whatever initial cap is chosen for the cap-and-trade program, or whatever initial level is chosen for a carbon tax, new information that becomes available over the next several decades will require adjustments in the national and global strategy to control greenhouse gasses.

CURRENT POLICIES AND GOALS AFFECTING THE PACIFIC NORTHWEST

At present, CO_2 reduction policies regionally, nationally and globally are still very much in a state of flux. CO_2 reduction goals range from stabilizing emissions at current levels to reducing emissions to 1990 levels or below. Many different policy initiatives and actions have been proposed (see above) to achieve these reduction goals. This section describes policies and actions that are currently being implemented on an international, federal and regional basis.

International Initiatives

Significant international initiatives targeted at climate change can probably be dated from 1992, when the U.N. Framework on Climate Change was negotiated. Since then there have been several significant milestones in international action, including the Berlin Mandate in 1995, calling for emission targets for developed countries and the Kyoto Protocol in 1997, which set targets for developed countries reductions by 2008-2012. The Kyoto Protocol, in spite of the withdrawal of the U.S. in 2001, has been ratified by 182 countries including 37 industrialized countries who account for over 60 percent of developed countries' emissions. It is hoped that a conference in Copenhagen in late 2009 will result in agreement on international action after 2012.

The European Union's Emissions Trading System has been functioning since 2005. It is a cap-and-trade system currently covering sources that are responsible for about half of the European Union's total carbon dioxide emissions. The system's first three years of operation (2005-2007) were intended to test the functioning of the market mechanism itself rather than to achieve significant carbon dioxide emission reductions. The system has experienced episodes of price volatility, which has been attributed to imperfect data and limited provision for banking emission allowances. Some electric power generators appear to have received windfall profits, which has focused attention on the regulatory treatment of those generators. The system will gradually expand to include emissions from more sources constituting a bigger share of total emissions over time.

The Intergovernmental Panel on Climate Change[5] has identified a goal of limiting global warming to 2 degree Celsius (3.6 degrees Fahrenheit) and has translated that goal into emission reduction targets for developed countries. Those targets call for an 80 to 95 percent reduction in emissions relative to 1990 levels by 2050.

[5] Information on the Intergovernmental Panel on Climate Change (IPCC) can be found at http://www.ipcc.ch/.

Federal Policies

The Waxman-Markey draft legislation, entitled "The American Clean Energy and Security Act of 2009," proposes a comprehensive strategy for energy planning and use. This legislation has four parts (or titles in legislative terms), which 1) promote clean energy production, 2) encourage energy efficiency, 3) reduce emission of greenhouse gases and 4) protect U.S. consumers and industry during the transition to a clean energy economy.[6]

Title I requires electricity suppliers to meet 6 percent of their load in 2012 and 25 percent of their load in 2025 with a combination of renewable resources and energy efficiency. It includes a carbon capture and sequestration (CCS) demonstration program, incentives for adoption of CCS, and performance standards for new coal-fired power plants. The title contains provisions to encourage the modernization and expansion of the electrical transmission system. Finally, it offers federal assistance to state clean energy and energy efficiency projects, and allows federal agencies to sign long-term contracts to buy electricity generated from renewable sources.

Title II includes a range of federal assistance measures to improve the energy efficiency of new and existing buildings. It strengthens efficiency standards for lighting and appliances, and improves the U.S. Department of Energy process for setting these standards in the future. It sets standards for electricity and natural gas distribution companies to help their customers accomplish energy efficiency. Finally, it calls for the establishment of standards for industrial energy efficiency, and extends eligibility for grants and loads for energy efficiency to nonprofit and public health hospitals.

Title III establishes a program that covers emitters responsible for about 85 percent of total U.S. greenhouse gas emissions. The program creates tradable allowances that must be surrendered for each ton of GHG emitted. The total amount of allowances is reduced over time so that aggregate emissions by the covered entities is reduced in stages to a level that is 83 percent lower than their 2005 levels by 2050. The title includes measures for the establishment and regulation of the market for trading allowances, and gives responsibility to the Federal Energy Regulatory Commission for regulating the cash market for allowances.

Title III directs the Environmental Protection Agency (EPA) to enter into agreements to reduce GHG concentrations by preventing international deforestation. The bill allows both domestic and international offsets not to exceed 2 billion tons yearly. The bill allows banking allowances to be used in later years, allows borrowing allowances that must be repaid the next year, and creates a strategic reserve of allowances to be used to limit market price volatility. Finally, the bill directs the EPA to set emission standards for sources not covered by the cap-and-trade program, and the bill creates special programs to reduce emissions of two pollutants that contribute to global warming: hydro fluorocarbons (HFCs) and black carbon.

Title IV is focused on the process of adjusting to a clean energy economy. It authorizes the Secretary of Education to award grants to colleges and universities to develop training programs to prepare students for careers in renewable energy, energy efficiency, and other climate change mitigation work. This section also establishes an interagency council to integrate federal

[6] Citation on internet for language of bill

response to the effects of global warming, and establishes an adaptation fund to provide support for state, local and tribal adaptation projects.

Regional Policies

The Western Climate Initiative (WCI) is a broad regional effort to implement policies to reduce greenhouse gas (GHG) emissions. The governors of Oregon, Washington, and Montana have joined governors from five other western states and the premiers of four Canadian provinces to collaborate on implementation of policies to address climate change. The overall goal of the WCI is to reduce the region's GHG emissions to 15 percent below 2005 levels by 2020. The primary policy objective of the WCI is implementation of an economy-wide regional cap-and-trade program.

The WCI Partners have promulgated specific design recommendations for the regional cap-and-trade program. In its first phase, beginning in 2012, the program would cover emissions from electricity production and from large industrial processes. The program would cover emissions of carbon dioxide and five other major greenhouse gases. In its second phase, beginning in 2015, the program would be expanded to cover emissions from the combustion of transportation fuels and from fuels burned at industrial, commercial, and residential buildings.

The process of developing the WCI has made it clear that a regional cap-and-trade program faces problems that are reduced if the program is made national or international. For example, individual states and provinces have significant flexibility to affect their jurisdiction's GHG reduction targets. The shares of the total reduction target that result are a source of potential conflict. Another example is the potential for "leakage," which can result from shifting emissions from inside the WCI to outside it. Such a shift would allow WCI emission targets to be met, but no net reduction in overall (global) emissions. Leakage becomes less likely as geographic scope of the cap-and-trade program increases to national or international.

State Policies

Policy initiatives at the state level to address climate change are numerous. This section narrows the focus to three types of state policy: GHG reductions goals; renewable portfolio standards; and emission performance standards. This selective summary misses a great deal of policy work aimed at establishing renewable energy tax credits, renewable energy feed-in tariffs, renewable energy enterprise zones, funding mechanisms for energy efficiency projects, improved commercial and residential building codes, and others that either directly or indirectly influence GHG production. The intent is to focus on policies that have the greatest relevance to the Sixth Power Plan.

Greenhouse Gas Emission Reduction Goals

The 2007 Oregon State Legislature set GHG emissions reduction goals for the state. The mid-term goal is to reduce emissions to 10 percent below 1990 levels by 2020. The long-term goal is a 75 percent reduction from 1990 levels by 2050. The 2009 Legislature is considering Senate Bill 80 which would authorize the state's participation in the WCI cap-and-trade program as a key means of reaching the future emission goals.

The 2009 Washington State Legislature is also considering WCI cap-and-trade legislation. House Bill 1819 and Senate Bill 5735 would codify the states goal of reducing greenhouse gas emissions to 1990 levels by 2020, achieving a 25 percent reduction by 2035, and a 50 percent reduction by 2050.

The Oregon and Washington emission reduction goals for 2020 have a direct bearing on the Sixth Power Plan. The Council's current modeling framework does not model each state separately, so its results can be interpreted as averages across the region as a whole. Analysis described later in this chapter examines the feasibility, cost, and best method of reducing Northwest power sector carbon dioxide emissions to 1990 levels by 2020.

Renewable Portfolio Standards

Renewable resource portfolio standards targeting the development of certain types and amounts of resources have been adopted by three of the four states in the region (Oregon, Montana, and Washington) since adoption of the Fifth Power Plan. Similar standards have also been adopted by Arizona, British Columbia, California, Colorado, New Mexico, and Nevada. The key characteristics of the Pacific Northwest state renewable targets are summarized in Table 10-1. The targets are subject to adjustments if costs increase above certain limits.

Table 10-1: Renewable portfolio standard targets

	Basic Standard
Montana	15% of IOU sales by 2015
Oregon	25% of sales by 2025 (large utilities) 10% of sales by 2025 (medium utilities) 5% of sales by 2025 (small utilities)
Washington	15% of sales 2020 + cost-effective conservation (utilities w/25,000 or more customers)

Carbon Dioxide Emission Performance Standards

Carbon dioxide emission performance standards have been adopted by California, Montana, Oregon and Washington. The Northwest state standards in effect at the time of draft plan release are as follows:

Montana: In May 2007, Governor Schweitzer of Montana signed into law HB 25, an electric power reregulation bill. Among various provisions, this bill prohibits the Public Service Commission from approving electric generating units constructed after January 1, 2007 and primarily fuelled by coal unless a minimum of 50% of the carbon dioxide produced by the facility is captured and sequestered. The requirement remains in effect until such time that uniform state or federal standards are adopted for the capture and sequestration of carbon dioxide. The bill further provides that an entity acquiring an equity interest or lease in a facility fueled primarily by natural or synthetic gas is required to secure cost-effective carbon offsets where cost-effective is defined as actions to offset carbon dioxide that do not increase the cost of electricity produced by more than 2.5%.

Oregon: Since 1997, the developers of new power plants in Oregon have had to offset their carbon dioxide emissions to a level 17% below best commercial generating technology of equivalent type. In July 2009, Governor Kulongoski signed into law SB 101 to establish a new greenhouse gas emission performance standard for all long-term procurements of electricity by electricity providers. The standard will be established by the State Department of Energy and will apply to all baseload electrical generating facilities. Baseload generating facilities are defined as facilities designed to produce electricity on a continuous basis at a 60% capacity factor or greater. The standard established by the State Department of Energy is to require that the greenhouse gas emissions of new baseload facilities be no greater than the rate of greenhouse gas emissions of a combined-cycle power plant fuelled by natural gas.

Washington: Since 2004, Washington has required fossil fuelled power plants subject to state site certification (generally plants of 350 MW, or greater) to offset or otherwise mitigate carbon dioxide emissions by 20%. Substitute Senate Bill 6001, signed into law by Governor Gregoire in May 2007 establishes a greenhouse gas performance standard for all "long-term financial commitments" for baseload generation used to serve load in Washington, entered into in July 2008, or later. The requirement applies whether the source is located within or without the state. Modeled on California Senate Bill 1368, the law defines baseload electrical generating facilities as facilities designed to produce electricity at a 60% capacity factor or greater. The law adopts the initial California limit of 1,100 lbs/CO_2 per MWh, and requires that the limit be reviewed and adjusted every five years by the Department of Community Trade and Economic Development to match the average rate of emissions of new natural gas combined-cycle power generation turbines. The limit is likely to be reduced on review since current natural gas combined cycle plants produce about 830 lb/CO_2 per MWh (the California limit appears to have been based on the carbon dioxide output of an aeroderivative simple-cycle gas turbine operating on natural gas, not a combined-cycle turbine). The law allows up to five years to provide carbon dioxide separation and sequestration as long as average lifetime emissions comply.

EVALUATION OF CARBON STRATEGIES

Existing climate change policies and proposed future policies have had a very significant effect on the development of the Sixth Power Plan resource strategy. In this section the effects of alternative policy assumptions are described. The intent is not to recommend any particular approach, but to provide information to policy makers about the likely effects of different approaches on the cost of the power system and its future carbon emissions.

The recommended actions in the Sixth Power Plan reflect existing carbon emissions policies that are assumed to continue. That is, the renewable portfolio standards (RPS) that have been adopted in three states, the new generation emissions standards adopted by three states, and renewable energy credits are included in the analysis. In addition, the plan recognizes that there are adopted goals for greenhouse gas emissions reductions for Oregon and Washington as well as proposed federal legislation. Most proposed policies to attain these goals rely on some system for putting a cost on carbon emissions. Whether these costs are the price of emission allowances under a cap-and-trade system, or some form of carbon tax, the costs imposed on the power system are a risk that the plan addresses. The plan includes resource actions that mitigate carbon risk along with other costs and risks faced by the regional power system.

The Council's assumptions on carbon price risk were based on consultations with a range of utility and other analysts and comparisons with a report by Ecosecurities Consulting Ltd. The assumptions are included in the Regional Portfolio Model as a distribution of 750 carbon price trajectories that range from zero to $100/ton, with an expected value of about $47/ton in 2030. A partial survey of regional utilities indicated that the range of prices the Council has included in its analysis is generally consistent with assumptions used in utility IRP analysis.

Accounting for regional power system carbon emissions requires a decision regarding the treatment of emissions associated with electricity that is imported and exported. The approach used for the Council's modeling is to count emissions by several generators that are located outside the region but whose output is committed to serving regional loads. These generators include parts of the Colstrip generation complex in eastern Montana, all of the Jim Bridger complex in Wyoming, and part of the Valmy generation complex in Nevada. Other imports and exports of energy are treated in two alternative accounting frameworks. One is referred to as "generation based" and counts emission from plants located within the region or contracted to regional utilities. The other approach is referred to as "load based" and counts emissions associated with imports and excludes emissions associated with the electricity exported from the region. For ease of exposition and comparability, most of the discussion in the plan refers to generation based carbon counting. In addition, the generation based carbon emissions are adjusted to be consistent with the accounting reflected in the Council's 2007 Carbon Footprint paper.7

There are also some complications in how to account for the estimated cost to the regional power system of carbon pricing policies. The default accounting of power system costs includes carbon penalties as though they were paid as a tax on every ton of carbon emitted. This approach is valid for modeling the penalties' effect on the development and operating decisions of the power system. However, the default accounting can significantly overestimate the total costs that the power system would recover from ratepayers, depending on the specific form of carbon penalty that the system faces. In particular, the current language of the U.S. House of Representatives proposal on climate policy includes a cap-and-trade system that grants free allowances to utilities that roughly offset their emissions until 2026. This approach would greatly reduce the cost impact on the power system, compared to a carbon tax on all emissions. To allow the reflection of different forms of carbon penalties, the portfolio model has an alternative accounting that excludes the amount of tax revenues. This alternative accounting provides a better estimate of the cost of a cap-and-trade free allowances mechanism to the power system.

The Council's plan provides a resource strategy that minimizes the cost of the future power system given the policy risks described above. A combination of aggressive conservation development, renewable resources, and in the longer-term, new gas-fired resources results in a reduction of power system carbon emissions from 57 million tons per year in 2005 to 37 million tons in 2030, which is below the 1990 emission level of 44 million tons. These reductions are generally consistent with the targets adopted by Northwest states.

The carbon cost risk assumptions play an important role in these results. If only current policies are assumed in the future, that is if no carbon pricing policies are implemented or expected, a least cost resource strategy would only stabilize carbon emissions from the power system at about current levels. Existing policies will not achieve the carbon emissions goals that exist in the WCI or some individual states in the region.

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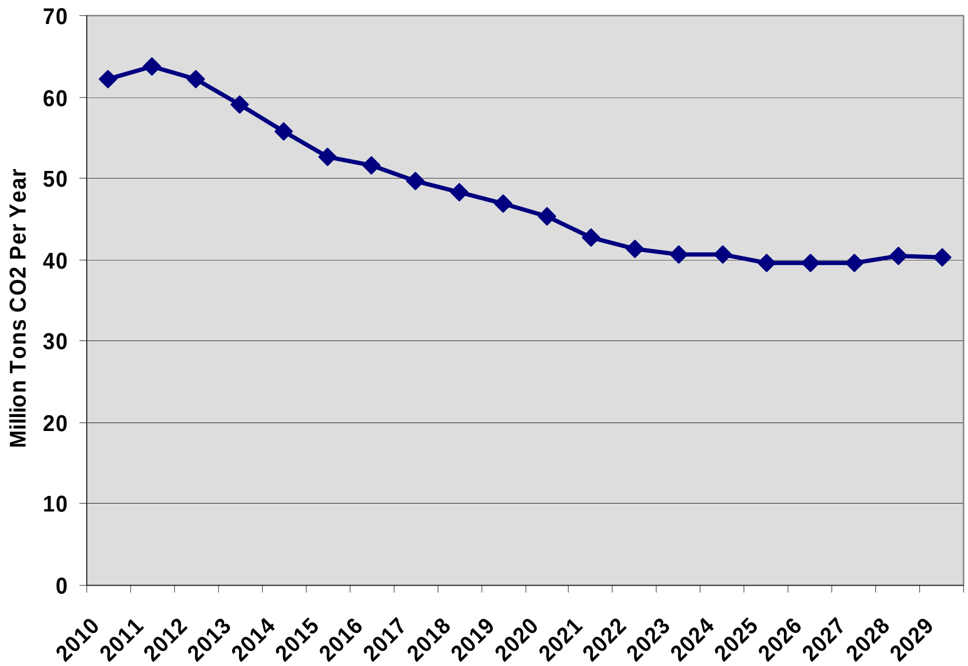
[7] Northwest Power and Conservation Council. Carbon Dioxide Footprint of the Northwest Power System. November 2007. (Council Document 2007-15)

The cost of moving from current policies to the $0 to $100 per ton carbon penalty scenario is significant. Response to the assumed carbon penalties increase power system costs by between 20 and 50 percent. The range in cost estimates depends on how policy is structured as described above. Current proposed federal policy provides free emission allowances under a cap-and-trade system for many years, which would put the cost impacts at near the lower end of the range. If power system costs increase by 20 percent, average retail rates would increase by about 3 percent compared to current policies.

To significantly lower carbon emissions from the power system, reliance on existing coal-fired generation would have to be reduced. This is not a surprising result because existing coal plants account for about 88 percent of the carbon emissions from the regional power system. In the $0 to $100 per ton carbon penalty scenario, these plants are simply used much less frequently. If they are used in that way, maintaining the plants may not be feasible for utilities. An alternative policy would be to phase out the existing coal plants or some portion of them. An analysis of phasing out all of the regional coal plants between 2012 and 2020 showed that power system 2030 carbon emissions could be reduced from 40 million tons in the $0 to $100 per ton carbon penalty scenario to about 15 million tons. Replacing the energy and capacity from the coal plants would increase average power system costs by about 30 percent. While this is an alternative policy approach to consider, it would not have the broad effects on other sectors and resource decisions that a cap-and-trade or tax system would have.

A number of scenarios addressed the issue of what level of carbon penalty would be required to meet alternative carbon emission reduction levels in 2030. The $0 to $100 per ton carbon penalty scenario, with average carbon prices growing to $47 per ton and possible futures between zero and $100, reduces average carbon emissions in 2030 to about 15 percent below 1990 levels. That is the WCI target for total greenhouse gas reduction by 2020. As shown in Figure 10-7, the $0 to $100 per ton carbon penalty scenario attains these reductions by 2020. However, these average reductions are not assured. In some futures, depending on demand, natural gas prices, hydroelectric conditions and carbon prices, emissions may not be reduced at all. These are cases where existing coal plants are utilized more intensively. The scenario where coal plants are retired results in more assured carbon reductions.

Figure 10-7: Average Sixth Power Plan Annual Carbon Emissions



Sensitivity analysis with the Regional Portfolio model and the AURORA$^{xmp®}$ Electric Market Model indicate that carbon costs of between \$40 and \$70 per ton would likely be required to reduce carbon emissions from the regional power system to below 1990 levels.

Just as coal-fired generation is the source of most of the power system's carbon emissions, the regional hydroelectric system is the source of most of the region's energy, capacity, and flexibility supply. As a carbon free resource, it is extremely valuable to the region. Because of the hydroelectric system, combined with the region's past accomplishments in conservation, the region's carbon emissions are half of that of the nation in terms of carbon emission per kilowatt-hour of energy consumption. Meeting the region's responsibilities for mitigating the fish and wildlife losses caused by the dams has depleted the capabilities of the hydroelectric system over time. The region should further reduce hydropower generation for salmon migration with careful analysis of the costs, risks and benefits of any proposed salmon mitigation action. The region needs to be sensitive to the fact that further reduction in hydroelectric generation will increase carbon emissions which will also harm fish and wildlife in the long term through accelerated climate change. For example, an analysis showed that removing the lower Snake River dams would undo 40 percent of the carbon reductions expected to be accomplished through the existing carbon policies in the region while also increasing the cost of the power system.

Chapter 11: Capacity and Flexibility Resources

SUMMARY OF KEY FINDINGS

Historically, Northwest power system planners have focused on providing sufficient energy to meet the annual energy load of the region. Largely because of the way the hydroelectric system developed, capacity, the ability to meet peak-hour load, and flexibility, the ability to rapidly increase or decrease generation output, were not significant problems.

Today, however, focusing regional power system planning solely on annual energy requirements is no longer adequate. Changes in the seasonal shape of Northwest load, increasing constraints on the operation of the hydrosystem to meet fish requirements, and rapidly increasing amounts of variable generation, especially wind, are making increased system capacity and flexibility a new priority.

Wind generation needs back-up, flexible resources to handle unexpected changes in its output. While the problems appear daunting, particularly in integrating new wind generation with a more constrained hydrosystem, there are solutions. The first step is to change system operating procedures and business practices to more fully utilize the inherent flexibility of the existing system. The Council believes these changes will be significantly cheaper to achieve, and can be implemented sooner than adding additional generating capacity solely to provide flexibility. It will also set the stage for determining how much flexibility will ultimately be needed from new generation.

Actions for these operating and business practice changes include: establishing metrics for measuring system flexibility; developing methods to quantify the flexibility of the region's existing resources; improving forecasting of the region's future demand for flexible capacity; improving wind forecasting and scheduling; transitioning from the current whole-hour scheduling framework to an intra-hour scheduling framework; and increasing the availability and use of dynamic scheduling. Fully implementing these improvements may also require physical upgrades to transmission, communication, and control facilities, though the cost of these upgrades is expected to be relatively small compared to the cost of adding new flexible capacity.

Because the reliable operation of the power system depends on agreement on these operating procedures, they cannot be changed overnight. However, significant studies and discussions are underway to achieve these changes.

The next step is to ensure that resources added to meet peak-hour load are also flexible enough to respond to unexpected changes in wind plant output. These solutions should be sought in a sequence that makes economic sense. Actions include: considering rapid-response natural gas-fired generators, pumped-storage hydro plants and other storage resources, utility demand response programs, and geographic diversification of wind generation as options to meet the region's future demand for flexibility. Some balancing authorities, Bonneville especially, may need additional flexibility resources, either from better use of existing resources or from new resources, solely for integration of wind generation that meets load in other balancing authorities.

BACKGROUND

The fundamental objective of power system operations is to continuously match the supply of power from electric generators to the customers' load. Historically, for resource planners, the balancing problem was addressed in two ways. First, build enough generating capacity to meet peak-hour demand, plus a reasonable cushion to account for unexpected generator outages. Second, ensure an adequate fuel supply to operate electrical generators month-after-month and year-after-year to meet customers' energy demand. This was sufficient because traditional resources provided system operators with the means to deal with the fundamental requirements of power system operation. For historical reasons, over most of the past 40 years the Northwest's resource planning problem has been simpler, to meet the annual energy need of the system. The Northwest was able to focus on annual energy needs because the hydrosystem provided ample capacity and flexibility to balance generation and load at all times.

Today, power system operators and planners must again focus on ensuring that the installed generating capacity is flexible enough to rapidly increase or decrease output to maintain system balance second-to-second and minute-to-minute.

The shift in the region's focus to flexibility at the minute-to-minute time scale is a result of the dramatic increase in the region's use of wind generation, which creates unique challenges for system operators. Over the course of minutes and hours, the output of a wind generator can be extremely variable, ranging from zero to its maximum output. While power system operators try to predict changes in wind generation, they also need other capacity, sufficiently flexible, to offset unexpected changes in its output.

POWER SYSTEM REQUIREMENTS: CAPACITY, ENERGY, AND FLEXIBILITY

Capacity: Meeting Peak Demand

In previous plans, the Council focused primarily, like other regional resource planners, on the energy output of generators. Energy is the total output of a plant, typically measured over a year in megawatt hours or average megawatts. The touchstone for judging whether the region had adequate resources has long been whether the power system could generate sufficient energy during adverse water conditions. This focus was largely due to the Northwest's hydrosystem, which had an excess of installed capacity. Because most traditional generating resources, like natural gas, coal, and nuclear plants, provide additional capacity at the same time they provide the ability to generate energy, most resource planning was carried out in an environment in which capacity could be taken for granted, as long as enough additional energy capability was provided to meet the total energy needs of the region.

Capacity is the maximum net output of a generator, measured in megawatts. For most generation, this is relatively straightforward: the plants can operate at their maximum output level (within certain predictable environmental, emission, and technical constraints) if called upon by the system operators, unless they have an unplanned, or forced, outage. Utilities account for the probability of forced outages by carrying contingency reserves, which are required by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC) reliability standards. The required contingency reserves equal about 6 to 8 percent of demand for most utilities.

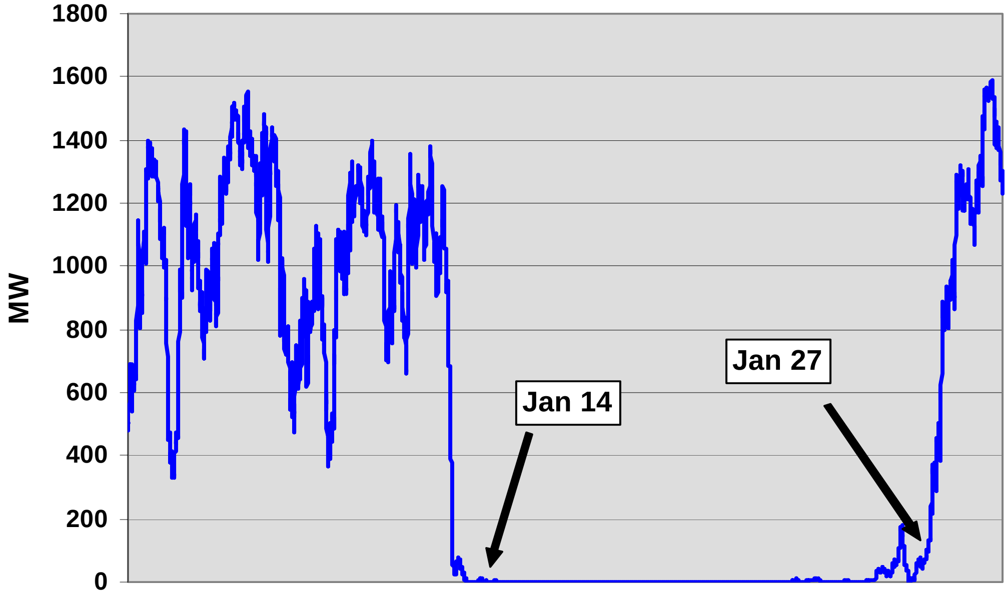
For hydroelectric generation, measuring capacity can be problematic. The total output of the hydrosystem is limited by its fuel supply, water, which is extremely variable from year-to-year. It is also limited by the fact that the reservoir system can only store about 30 percent of the annual runoff volume of water. Under some circumstances, there may not be enough stored water to run the generators at their maximum level to meet hourly load during peak conditions, like multi-day cold snaps in the winter or multi-day heat waves in the summer. While the machinery may be capable of reaching maximum output for short periods, it cannot sustain that level of output for longer periods. In fact, the maximum output a hydroelectric facility can provide depends on the duration of the output period -- the longer the period, the lower the maximum sustainable output. This type of capacity is referred to as "sustainable capacity" and is a characteristic peculiar to hydroelectric systems.

The Northwest Resource Adequacy Forum, jointly chaired by the Council and Bonneville, with participation by other regional utilities and interest groups, has devoted considerable effort over the past several years to reaching an understanding of the hydrosystem's sustainable capacity value. The work of the Adequacy Forum is described more fully in Chapter 13.

Wind generation capacity is also difficult to define. Wind generation is variable; operators can reduce generation when the wind is blowing, but they cannot make it produce more, even if the rated wind capacity is much higher. Furthermore, the output level is relatively unpredictable and, in the Northwest, is unlikely to be available at times of extreme peak load--for example when load is high because of a winter cold spell or a summer hot spell.

The amount of installed capacity expected to be available during peak-load hours is often called a generator's "peak contribution" or "reliable capacity." Analysis done by Bonneville and the Resource Adequacy Forum suggests that, for the wind area at the east end of the Columbia River Gorge, where much of the region's current wind generation is located, there may be an inverse relationship between wind generation and extreme temperatures, both in winter and summer. This is likely due to widespread high pressure zones covering the region's load centers (the biggest ones being west of the Cascades) and the area of wind generation east of the Cascades during periods of extreme low and extreme high temperatures. Figure 11-1 illustrates the loss of wind generation during a recent winter period. While efforts to better define the reliable capacity of wind generators are ongoing, the Resource Adequacy Forum has adopted a provisional peak contribution for wind of 5 percent of installed capacity. This work will need to address the impact of future wind development in other areas, such as Montana and Wyoming, that may have different weather patterns and could improve the overall capacity contribution of wind.

Figure 11-1: Bonneville Wind Generation
January 5 - 28, 2009



The current adequacy assessment (Chapter 13) indicates that the Northwest will probably encounter a summer-capacity problem before a winter-capacity problem, largely because of hydrosystem constraints and different expectations about the availability of power from plants owned by the region's independent power producers and from wider Western markets. Providing capacity to meet peak demand is only one part of balancing generation and load. Resources added to provide energy and flexibility will also help the region meet its developing summer-capacity deficit.

Before system planners and operators began to emphasize flexibility as part of the solution to the balancing problem, it was possible to talk about pure peaking resources. Peaking units were resources added to the system primarily to meet peak-hour demand, without having to generate large amounts of energy over the course of the year. Peaking units have been characterized as low-fixed cost and high-operating cost resources. These cost characteristics correspond to their intended infrequent use as peaking plants. To a certain extent, this characterization originated with the historical practice of demoting aging, less-efficient baseload units to infrequent peaking duty. In recent decades, however, specialized units capable of delivering a broad array of ancillary services as well as peak capacity at reasonable efficiency--such as aeroderivative and intercooled gas turbines and gas-driven high-efficiency reciprocating engines--have appeared on the market. These units may have greater per-kilowatt capital costs than combined-cycle plants.

Resources in this category include simple-cycle gas turbine generators (both frame and aeroderivative), reciprocating engines, capacity augmentation features for combined-cycle gas turbines (including water or steam injection and fired heat-recovery steam generators), and utility demand response programs. Today, aeroderivative combustion turbines, reciprocating engines, and even some types of demand response, are often considered first for their flexibility and second for their ability to help meet peak demand. Demand response programs are described more fully in Chapter 5. These generating technologies are discussed later in this chapter and in Chapter 6

Energy: Meeting Average Demand

Energy is the total output of a plant, typically over a year. For most plants, the maximum energy is simply the capacity times the number of hours per year that the plant runs, excluding forced or planned (maintenance) outages. For most types of generation, the energy output of the plant is not limited; the plant can run at its maximum level as long as desired, subject to forced or planned outages, and occasionally fuel supply and environmental constraints.

A fuller discussion of the resource portfolio results of the Council's analysis, as well as their implications for meeting capacity and energy requirements of the system, is in Chapter 9 of the plan.

Flexibility: Providing Within-hour Balance

The basic measures of a plant's flexibility are: its ramp rate, measured in megawatts-per-minute or some other short period; its minimum generation level; and its capacity. Minimum generation is most often defined by a combination of physical limits and economic limits, as when a plant's efficiency drops off dramatically below a certain point. Power system operators need to set aside a certain amount of flexible generation just to follow load, which varies. More flexibility is required if there is a significant amount of wind or other variable generation on the system.

The Northwest's hydroelectric generators are tremendously flexible resources. Physically, they have a wide operating range and very fast ramp rates. The inherent flexibility of the Northwest hydrosystem helps explain why flexibility has been taken for granted in previous Power Plans. This inherent flexibility is now partly limited by the challenges of salmon protection in Columbia and Snake Rivers and the increasing amount of flexibility that is needed.

POWER SYSTEM OPERATIONS

The electric power system is organized into balancing authorities[1] for the purpose of operating the system reliably. Each generator (or fraction of a generator in specific circumstances) and load is in one, and only one, balancing authority. There are 17 balancing authorities in the Northwest Power Pool Area and 36 in the Western Interconnection.

Each balancing authority is responsible for a number of things, including continuously balancing load and resources, contributing to maintaining the frequency of the interconnection at its required level, monitoring and managing transmission power flow on the lines in its own area so they stay below system reliability limits, maintaining system voltages within required limits, and

[1] Balancing authority is NERC terminology for the entity that is responsible for the actions. Balancing area is sometimes used for the portion of the electrical system for which the balancing authority is responsible.

dealing with generation or transmission outages as they occur. It does these things using what are called ancillary services, most of which are services provided by generation or, less commonly, demand response under the control of the balancing authority. The potential to expand demand response for ancillary services is addressed further in Chapter 5.

Ancillary Services

The NERC and WECC reliability standards, and prudent utility practice, require balancing authorities to hold operating reserves, first to maintain load and resource balance in case of an outage of a generator or transmission line, second to meet instantaneous variations in load, and in the case of wind generation, fluctuations in resource output.

The portion of operating reserve held ready in case of an outage is called contingency reserve, specified by NERC and WECC standards. The portion of operating reserve meeting the second requirement is called regulating reserve in the reliability standards. Additional reserves that are not explicitly required by NERC and WECC, but are prudent practice and assist in meeting the regulation requirement, are often called balancing reserves.

Regulating and Balancing Reserves

Operators must balance load and resources and keep track of imports and exports, all while load is continuously changing.

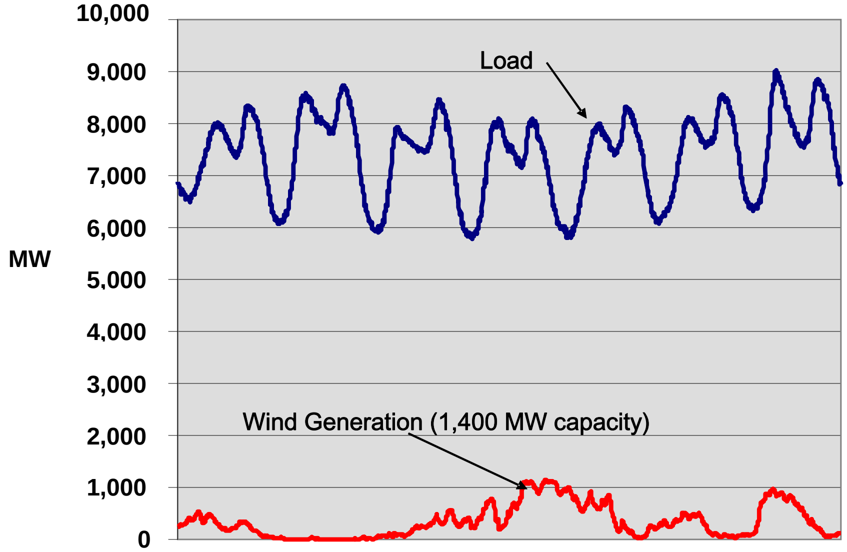
Balancing authorities do this by operating in a basic time frame of one hour, every hour of the day. The basic test of success in this balancing is called Area Control Error (ACE). ACE is a measurement, calculated every four seconds, of the imbalance between load and generation within a balancing area, taking into account its previously planned imports and exports and the frequency of the interconnection. The NERC and WECC reliability standards govern the amount of allowable deviation of the balancing authority's ACE over various intervals, although the basic notion is that ACE should be approximately zero. The ACE is maintained through a combination of automatic and operator actions. The automatic part is done through a computer-controlled system called Automatic Generation Control (AGC).

The basic regulation and balancing control challenge for the balancing authority is driven by load changes, both random, short-term fluctuations, and trends within the hour. It is exacerbated by the presence of large amounts of wind generation physically located in the balancing area, whether or not that wind is generating for the customers of the balancing area.

This is illustrated in several graphs, based on five-minute interval data from the Bonneville balancing area in the first week of January 2008. The problems in this period are representative of the problems in other periods, although for Bonneville, the problems are now magnified by the increase in installed wind capacity on its system (Bonneville now has approximately 2,100 megawatts of installed wind capacity). Figure 11-2 illustrates a typical weekly load pattern at five-minute intervals, with a sharp daily ramp in the morning as people rise, turn on electric heat, turn on lights, take showers, and as businesses begin the day.

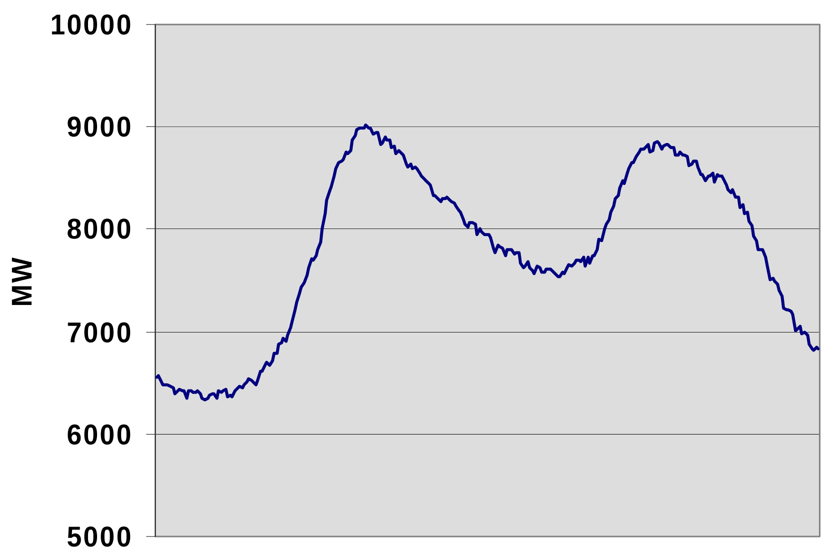
It also shows the Bonneville balancing area wind generation from the same period, illustrating the irregular pattern typical of wind generation. The data from this week will be used in several subsequent graphs, focusing on shorter time intervals and illustrating particular issues.

Figure 11-2: Example Load and Wind Pattern
BPA January 1-7, 2008, Midnight to Midnight



Focusing on a single day, January 7, 2008, Figure 11-3 highlights a single operating hour, from 6:00 a.m. to 7:00 a.m.

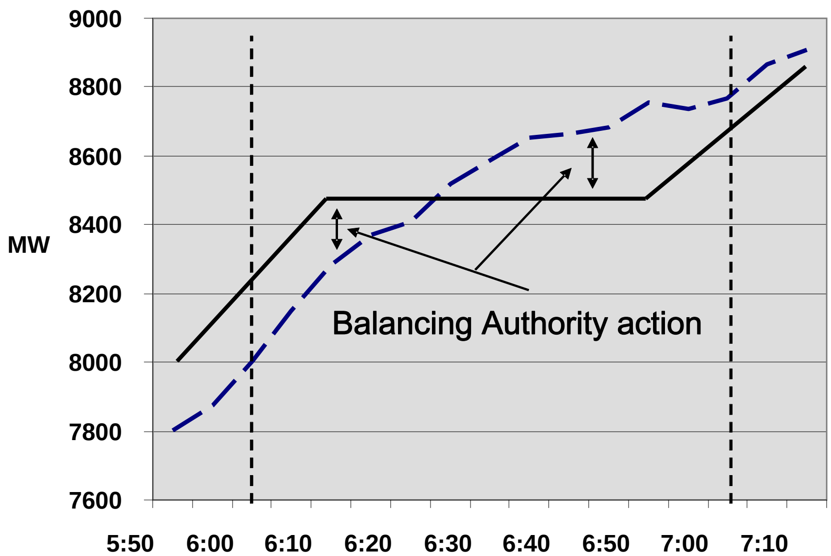
Figure 11-3: Daily Load Curve - BPA January 7, 2008
Midnight to Midnight



A balancing authority has to deal with a load ramp like this one, 762 megawatts over the course of an hour, using the generation under its control in its own balancing area. At the same time, it must deal with any imports or exports that have their own time pattern for adjustment. Scheduling between balancing authorities in WECC is generally done in one-hour increments, with the schedules ramping in across the hour, from 10 minutes before the hour to 10 minutes after the hour.

Figure 11-4 focuses on the 6:00 a.m. to 7:00 a.m. load from the previous graph, while adding a hypothetical net schedule (including exports from and imports into the balancing area), and the generation scheduled to meet the average hourly load by any of its providers, including the transmission provider's merchant arm. The balancing authority must address the differences (both positive and negative) between the total scheduled generation and the net load in the balancing area by operating the generation in its control either up or down to match the load instantaneously, and to manage its ACE to acceptable levels. The graph points to the differences between scheduled generation and actual load that requires balancing authority action.

Figure 11-4: Example Hourly Scheduling



There are NERC and WECC reliability standards that govern how that action must be taken. In addition to contingency reserves, which must be available in case of a sudden forced outage, the standards require regulation reserves, which is generation connected to the balancing authority's AGC system. The standards do not require any specific megawatt or percentage level of regulation reserves. Rather, they require that the balancing authority hold a sufficient amount so that its ACE can be controlled within the required limits. How the balancing authority meets the requirements highlighted in Figure 8-3 involves some discretion on its part.

Most balancing authorities prefer to break the requirement into two parts: one meeting the pure regulation requirement, allowing AGC generation to respond every four seconds; the other adjusting generation output over a longer period, typically 10 minutes. The pure regulation requirement is illustrated by Figure 11-5, which shows a hypothetical, random pattern at four-second intervals (which is the kind of pattern the load actually exhibits) on top of a five-minute trend. This is the load that the generation on AGC actually follows.

Figure 11-5: Example Load at Four-Second Intervals Over Five Minutes

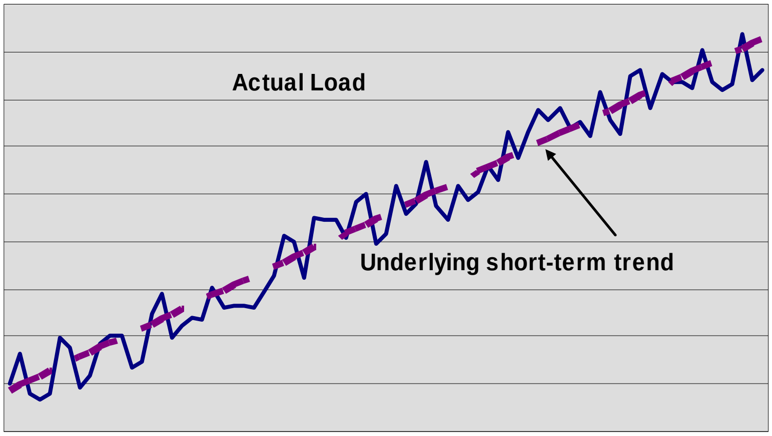
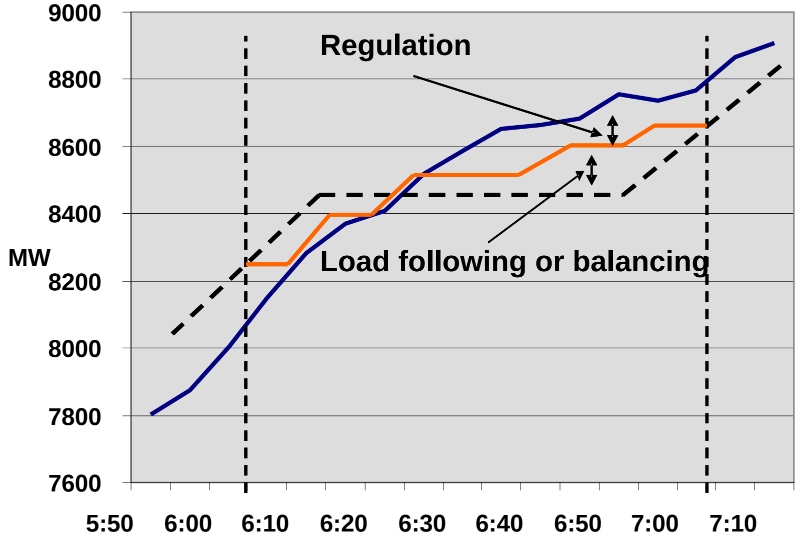


Figure 11-6 illustrates one pattern of breaking that requirement up, separating the regulation requirement for generation on AGC from the remaining requirement, usually called load following or balancing.[2]

Figure 11-6: Illustration of Hourly Scheduling with Load Following



Balancing authorities plan for regulation and balancing services before the need for them arises. They ensure that enough scheduled generation is on AGC to provide moment-to-moment regulation services. They also plan to operate some generators at levels lower than they otherwise would in order to have the ability to increase generation and provide incremental load following. Conversely, they may also need to operate some generators at levels higher than they otherwise would in order to have the ability to decrease generation and provide decremental load following.

[2] When the only remaining requirement is the variation in load, load following is the most common term. When the requirement includes the effect of variable generation, like wind, the term balancing is often used instead.

By operating generators in this manner, a balancing authority can incur increased operation costs, increased maintenance costs, and foregone revenues. These are the opportunity costs of providing regulation and load following or balancing services. Balancing authorities typically decide which generators to use for regulation and load following based on the physical characteristics of their generators and the opportunity cost of operating specific generators in this manner. Much of the region's flexibility, and particularly for the large amount of wind generation in Bonneville's balancing area, has been provided by the hydrosystem.

Historically, the cost of operating the power system to provide regulation and load following services received little attention. The effect of wind and other variable generation on the balancing authority's control problem has raised awareness of the cost of providing these services. Improvements in operating procedures and business practices, described below, should help to hold down integration costs, but they will likely increase over time as more variable generation is added to the system.

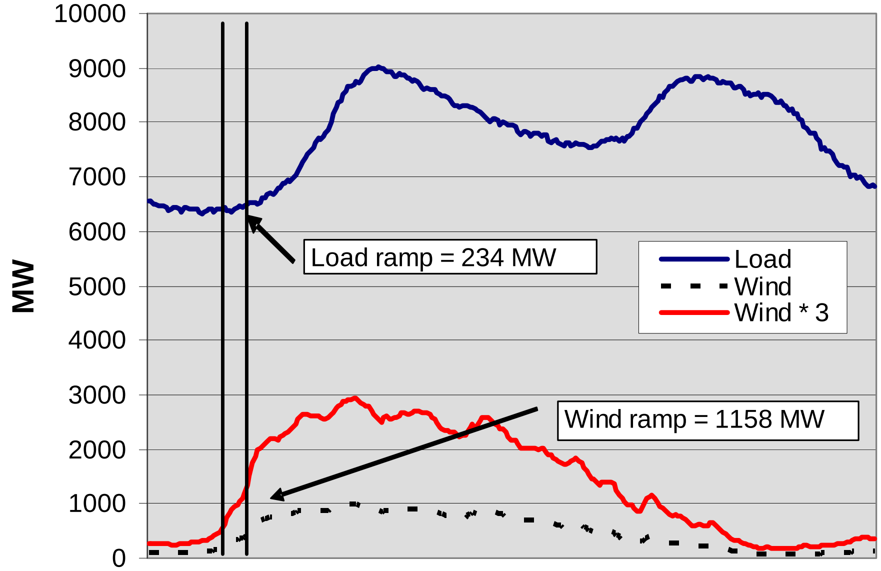
FLEXIBILITY ISSUES RAISED BY WIND GENERATION

Unpredictable and rapid swings in the output of wind generators have increased the need for power system flexibility. Load is typically much more predictable in the one-to-two hour time frame than wind generation. If load is relatively flat, and the wind unexpectedly drops off over the course of 10-20 minutes, then system operators must ramp up other generation at the same speed that the wind generation is ramping down in order to maintain load and resource balance and support the system frequency. Likewise, if the wind unexpectedly increases, then system operators must be able to ramp down other generators in order to maintain load and resource balance.

The possibilities become more complicated with changes in both wind generation and load over a given time period. But the result is still the need to be able to quickly adjust generation up or down.

Figure 11-7 highlights a situation where both load and wind generation increased at the same time. It shows the load and wind pattern from the last day of Figure 11-1, and the effect of wind generation if its capacity were three times greater than what was operating on January 7, 2008. Note that Bonneville already has about 2,100 megawatts of installed wind capacity, instead of the then 1,400 megawatts. Bonneville expects as much as 3,000 megawatts by 2010, and is concerned about the potential of over 6,000 megawatts by 2013.

Figure 11-7: January 7, 2008 Load and Hypothetical Wind Data Midnight to Midnight



Looking at the early morning hours only, between 3:00 a.m. and 4:00 a.m. indicated by the vertical bars on the graph, we see an increase in load of 234 megawatts in that period. We also see an increase in wind generation of 1,158 megawatts. System operators would need to ramp down other generators by 924 megawatts to maintain system balance. Because Bonneville can face significant minimum generation requirements in the low-load night time hours, this pattern is a particular problem for them.

For capacity and energy, it is possible to provide estimates of the timing and size of future deficits. At this time, we are unable to make a similar projection for flexibility. This is because the industry has not yet developed standard methodologies and metrics to make such an assessment. However, Bonneville has estimated that by 2012 it might need to set aside up to 1,700 megawatts of generation to respond to unexpected drops in wind generation, and 2,200 megawatts of generation to respond to unexpected increases in wind generation. The exact amount will depend in part on the result of the actions described below. For Bonneville's needs specifically, see also the discussion in Chapter 12.

Response to Growing Need for Flexibility

The response needs to be twofold. First, modify existing operating procedures and business practices to allow the maximum and most efficient use of the region's existing flexibility for those balancing authorities with large amounts of wind generation. Second, the new dispatchable generation needed for energy, or to meet the peak-hour capacity needs of the system (should that become the primary need in the future), should also be able to be adjusted up or down to deal with changes in wind output, and to allow the region's balancing authorities to maintain their ACE measures within acceptable bounds.

Institutional Changes

There are several changes in operating procedures and business practices that would either reduce the burden on the balancing areas or substantially increase the available flexibility of the existing system.

Increasing the accuracy of short-term wind forecasting, either by the wind generators in producing the schedules that they send to the balancing authorities or by the balancing authorities themselves, would reduce the amount of balancing reserve capacity needed to cover a forecast error. Bonneville has estimated, for example, that using the prior 30 minutes' generation level (rather than the current method) as the forecast for the next hour would substantially reduce the forecast error and the amount of balancing reserves needed to be set aside ahead of time. More sophisticated wind modeling is also being explored.

Standardizing within-hour schedule changes by going to, for example, a 10-minute scheduling window instead of the current whole-hour scheduling, would help maintain the host balancing authority's ACE by allowing it to bring in generation from other balancing authorities. This would require a more developed market (either bilateral or centralized) in these intra-hour, short-term generation deliveries to take advantage of the new framework. The Joint Initiative between ColumbiaGrid, Northern Tier Transmission Group, and WestConnect, is taking steps in this direction by examining the creation of a tool to facilitate within-hour transactions on a bilateral basis.

Increasing the availability and ease of use of dynamic scheduling is another important change. This mechanism enables generation in one balancing authority to be transferred into another balancing authority for the ACE calculations of the two areas. This is helpful for several reasons. It allows available generation in one balancing authority to be used in another to meet the latter's regulation and balancing needs.

It also allows wind generation that is physically located in one balancing authority, but meeting load in another balancing authority, to be effectively transferred out of its area and into the second authority's area and ACE. Normally, while the FERC Open Access Transmission Tariff (OATT) allows the first balancing authority to charge some other party (the wind generators meeting external load or the external load) for the ancillary services, including regulation and balancing, NERC standards require that the host balancing authority provide the physical response. Dynamic scheduling allows both the physical response and cost of the wind generation to be the responsibility of the recipient load.

Dynamic scheduling is a long-established practice, but is typically done now on a case-by-case basis, for relatively long periods, and it requires time-consuming, individual communication link set-ups between balancing authorities. Work is underway by the Joint Initiative to standardize the protocols and communication to make dynamic scheduling easily and quickly available--ideally so that dynamic schedules could be changed on an hour-to-hour or shorter basis.

There are some additional issues that need to be resolved regarding the limits on the amount of generation that can be dynamically scheduled over various transmission paths, particularly if the schedule involves long distances; for example, dynamic scheduling between Bonneville and the California ISO. Among these issues is control of voltage levels in the system. Voltage levels on transmission lines are in part a function of the line loading, and dynamic scheduling tends to change line loadings rapidly, increasing the burden of controlling voltage levels within reliability limits. The Northern Tier Transmission Group and ColumbiaGrid have formed a group called the Wind Integration Study Team to examine these limits within the two entities.

Adding Flexible Capacity

System planners and operators are looking at resources that can be used to meet peak-hour demand and to respond to variations in wind output. These flexible-duty resources do not necessarily need to generate large amounts of energy over the course of the year. Resources typically placed in this category include: rapid-response natural gas-fired generators; storage resources such as pumped-storage hydro plants; and utility demand response programs.

In the near-term, natural gas-fired turbines and reciprocating engines appear to be good options for meeting the increased demand for flexibility. To offset unexpected changes in wind output, these resources need rapid-start capability and efficient operation at output levels less than full capacity.

The LM6000 Sprint (50 megawatt) and LMS 100 (100 megawatt) aeroderivative turbines are two good candidates for flexibility augmentation. Starting cold, both turbines can be ramped to their maximum output within 10 minutes. These aeroderivative turbines are more efficient than comparable frame turbines, and therefore more cost-effective to operate at partial output levels. The LM6000 Sprint is a commercially mature technology with more than 200 units in operation. The first LMS100 unit went into commercial operation at the Groton Generating Station in South Dakota in 2006.

Gas-fired reciprocating engines are also a good flexibility option. The Plains End Generating Facility in Colorado is a 20-unit plant that has an output range of anywhere from 3 megawatts to 113 megawatts. The engines have a 10-minute quick start capability and can ramp up and down in response to an AGC signal. All of the above options can be constructed with short lead times, and therefore are good near-term flexibility options. A more complete description of these natural gas-fired generating technologies is provided in Chapter 6.

Pumped-storage hydro is a good mid-term option for meeting increased demand for flexibility since it can quickly change its operating level. These hydro plants operate in either a pumping mode or a generating mode. Traditional operation of pumped-storage hydro is based on the price of electric power. When the price of electric power is low, water is pumped from a source to a storage reservoir located at a higher elevation. When the price of electric power is high, the stored water is released and passed through a turbine to generate power.

As more wind power is added to the system, pumped-storage operation is likely to respond to the price of regulation and load following services. For example, operators of pumped-storage plants can commit in advance to increase pumping when there are unexpected increases in wind output. Plants with variable-speed pumps are likely to be more responsive in these circumstances. Likewise, operators can also commit to increase generation when wind power output unexpectedly drops. Furthermore, operating the plant in this manner is not likely to result in dramatic operating cost increases or reduced revenue. However, with a 13-year construction lead time, and high capital cost, risk is high. Other options may capture a large share of the ancillary services market before a new pumped-storage plant can be brought on-line.

The potential use of hot water heaters, plug-in hybrid vehicles, and other demand response options to provide regulation and load-following services is described in Chapter 5, Appendix H, and Appendix K.

Chapter 12: Bonneville's Obligations

SUMMARY OF KEY FINDINGS

Bonneville has engaged in an extensive, multi-year set of regional processes, culminating in the Regional Dialogue, to define its future power supply role. The Council strongly supported and participated in these processes and offered a number of recommendations as part of the Fifth Power Plan, which have been addressed in the Regional Dialogue.

Bonneville has adopted a Regional Dialogue Policy, which has defined its potential resource acquisition obligations for power sales after 2011, whether at Tier 1 or Tier 2 rates. The Administrator's potential future obligations also include additional firm energy, capacity and flexibility for integrating wind power into BPA's balancing area. Its obligations to provide flexibility for wind balancing are also driven by its obligations under NERC standards as the host balancing authority for wind resources that are meeting load elsewhere, primarily in California.

The Council's analysis, while it looks at regional capacity and energy requirements, does not break out utility-specific capacity and energy requirements and does not look at within-hour issues like flexibility. Thus there might be specific BPA obligations that are not addressed in detail in the Plan. The size of these obligations for Bonneville is, however, not well known at this time because it will be driven by choices of Bonneville's customers and the amount of wind power that is located in BPA's balancing area whether to serve BPA's customers, other regional utilities or for sales outside of the region. These will not be known until after the adoption of the Plan. Moreover, the supply of resources available to meet these obligations, particularly for additional flexibility to deal with wind integration, is uncertain at this time. There are, for instance, a number of regional and West-wide discussions underway about institutional and business practice changes to help balancing authorities deal with these issues.

Because of these uncertainties, the Council has several general principles to guide Bonneville should it need to acquire resources to meet any of these several kinds of obligations. They are, briefly:

- Aggressively pursue the Council's conservation goals first
- Aggressively pursue the various institutional and business practice changes to reduce the demand for flexibility and to use the existing system more fully,

- Look broadly at the cost-effectiveness and reliability of possible sources of new capacity and flexibility, such as gas or other generation types, and take into account synergies in meeting several types of needs with single resources.

STATUTORY BACKGROUND

The Northwest Power Act gave the Bonneville Power Administration (Bonneville) new authorities and new responsibilities. It authorized the Bonneville Administrator to acquire resources to meet the Administrator's obligations. At the same time, it obligated the agency to serve the loads placed on the agency by preference customers and the Investor Owned Utilities (IOUs). The Act also authorized sales to federal agency customers and to the direct service industries (DSIs). Sales to the DSIs must provide a portion of the reserves available for meeting the Administrator load obligations.

The Act also gave new authority to the member states of the Pacific Northwest Power Planning and Conservation Council (Council), the interstate compact created under the Act. Congress directed the members of the Council, appointed by the governors of the member states, to develop a 20-year regional power plan. One component of that plan is the Council's fish and wildlife program, intended to protect, mitigate, and enhance fish and wildlife resources in the region. The Council's power plan is meant to assure the Pacific Northwest of an adequate, efficient, economical, and reliable power supply. Bonneville, with certain narrow exceptions, must act consistently with the power plan in its resource acquisition activities. This consistency requirement is most prominent when Bonneville proposes to undertake a number of actions related to a major resource, that is, a resource that has a planned capability greater than 50 average megawatts and is acquired for a period of more than five years. Thus, Congress intended the four Northwest states to have some "say" in Bonneville's resource acquisition activity.

Bonneville occupies a unique, dual role in the region's utility system. On the one hand it functions as a utility business, supplying energy, load following, reserves, and transmission. Indeed, the agency markets the output of the federal base system (FBS), which consists of 31 federal hydro-electric projects in the Columbia River Basin, one non-federal nuclear plant, and several other small non-federal power plants. As noted, Bonneville also acquires resources to meet customer loads. In acquiring resources, the Act directs Bonneville to make cost-effective conservation the resource of first choice. To carry out that function, Bonneville also manages programs that help utilities acquire conservation. Bonneville accounts for the amount of conservation acquired and verifies savings. These functions are important in assuring the region that rate-payer funds are being expended in a business-like fashion. To enhance the range of conservation resources that will be available in the future, Bonneville also funds research and development. The resource of second choice under the Act is renewables. Bonneville both acquires renewables, as it has added about 245 megawatts of wind to its portfolio of resources, and provides integration services, both for its own renewable resources and for wind located in its control area, but owned by others. In acquiring renewable resources, Bonneville first adds to its power supply to meet its total contractual load obligation and secondarily assists its customers who are obligated to meet Renewable Portfolio Standards set by their respective states. Again, Bonneville also supports research and development in the realm of renewable resources, to expand the amounts and sorts of renewables that will be available in the future.

On the other hand, in addition to its utility business functions, Bonneville is also a federal agency, to which Congress entrusted defined public purposes. The Act gave Bonneville the responsibility of funding efforts to restore fish and wildlife affected by the hydroelectric dams on the mainstem Columbia River and its tributaries. Among other public purposes, the agency also funds low-income weatherization programs through local public utilities, at the Administrator's discretion.

BONNEVILLE'S EVOLVING ROLE

Bonneville's evolving role in the changing electricity utility industry has been the subject of a number of public processes that have garnered widespread regional participation. These processes were ultimately reflected in recommendations from the Council in its Fifth Power Plan and decisions by Bonneville in its Regional Dialogue Policy.

The Comprehensive Review of the Northwest Energy System in 1996, the 1997 Cost Review, the Joint Customer Proposal in 2004, and the Administrator's 2005 Power Supply Role for FYs 2007-2011 all examined the issue of Bonneville's role in the region's electricity system. Each step in this series of discussions contributed to or modified in some way the region's thinking about what role Bonneville should serve. Naturally, not every entity that took part in each process endorsed every recommendation. .

Impetus for these various processes derived from the restructuring and deregulation of the nation's electricity industry following passage of the National Energy Policy Act of 1992. Bonneville, the marketer of nearly half the electricity consumed in the region, faced an unusual and troubling situation. The agency's longstanding customers suddenly sought to diversify their wholesale power sources away from Bonneville by purchasing from competitive, lower-cost providers of electricity. In the mid-1990s, there were concerns that Bonneville's high fixed costs, including the debt on the Federal Columbia River Power System (FCRPS) and its past investments in nuclear power plants, would make it uncompetitive in the wholesale power market. Against this background, the region determined it was time to give serious thought to Bonneville's role in the region's electricity system.

The Council's Recommendations for Bonneville's Future Role in Power Supply

The Council recognized that recommendations from these various regional processes had a number of principles in common; most importantly, preserving the region's low cost hydroelectric resources through long-term contracts, improving preference customer utilities' and federal agencies' incentives to meet their load growth with responsible resource choices by charging an individual utility that chooses to have Bonneville meet its needs beyond the capability of the existing FCRPS the cost of incremental supplies, and providing benefits to the residential and small farm customers of the region's investor-owned utilities that are equitable and predictable.

Based on these considerations, the Council developed its own set of recommendations regarding Bonneville's future role in power supply for the Fifth Power Plan. As summarized here, these remain the Council's recommendations regarding Bonneville's role:

- Bonneville should market the output of the existing FCRPS to eligible customers at cost. Customers that request more power than Bonneville can provide from the existing federal system should pay the additional cost of providing that service. This change in role should be implemented through 20-year contracts that should be offered as soon as possible, and compatible rate structures.

- Bonneville should develop a clear and durable policy regarding the agency's future role in resource acquisition, to guide contract negotiations and future rate cases.

- To implement its new role, Bonneville should allocate the power from the existing FBS among eligible customers through a process that minimizes opportunities for gaming the process.

- Bonneville should move to implement tiered rates as soon as practicable; if they cannot be offered in new contracts by October 2007, the Council would consider recommending their implementation under the existing contracts.

- Bonneville should offer the full range of products currently available, such as requirements, block, and slice products. The costs of each product should be confined to the purchasers of that product, avoiding cross-subsidies.

- If Bonneville offers service to the DSIs, the amount of power and term should be limited, the cost impact on other customers should be minimized, and Bonneville should have the right to interrupt service to maintain system stability and cover any temporary power supply inadequacy.

- Bonneville should find a stable and equitable approach to offer benefits of low-cost federal power to the residential and small-farm customers of the IOUs for a significant period.

- Bonneville and the region's utilities should continue to acquire the cost-effective conservation and renewable resources identified in the Council's power plans. Bonneville's role could be reduced to the extent customers can meet these objectives. But, if necessary, Bonneville must use the full extent of its authorities to ensure that the cost-effective conservation and renewables identified in the Council's power plan are achieved on all its customers' loads. The Council committed to working with Bonneville, utilities, the states, regulatory commissions, and other regional and West-wide organizations to ensure that appropriate adequacy policies are in place and that the data and other tools to implement the policies are available.

- Bonneville should continue to carry out its fish and wildlife obligations, allocating its mitigation costs to the existing FCRPS.

The Regional Dialogue

The concepts that emerged from the Comprehensive Review and the Joint Customer Proposal, as well as the Fifth Power Plan, have been addressed in subsequent discussions among Bonneville, its customers, state agencies, regulatory bodies, the Council, and public interest groups in a process called the "Regional Dialogue." The Regional Dialogue concluded in 2007 with a set of policy decisions by Bonneville to guide development of tiered rates and new power sales contracts to replace the contracts that expire in 2011. The highlights of the Regional Dialogue Policy, as expressed when the policy was adopted, follow.

- Bonneville will offer contracts to all its customers, public utilities, IOUs, and DSIs; at the same time. For public utilities, Bonneville will develop new 20-year contracts accompanied by a long-term Tiered Rate Methodology (TRM). Through the contracts and TRM, each public utility will get a High Water Mark (HWM) that defines the amount of a customer's load that can be served with Federal power at BPA's lowest cost-based Tier 1 rate. To meet load above the HWM customers can choose to purchase power from either non-federal resources or from Bonneville at rates reflecting Bonneville's marginal cost of acquiring the additional power, or through a mix of Bonneville Tier 2 priced power and non-federal resources.

- Bonneville will acquire resources, if necessary, to supply up to 250 megawatts at the Tier 1 rate to new public utilities (including new and existing public body tribal utilities).

- Bonneville will acquire resources to augment the existing system by the lesser of 300 megawatts or the amount needed to meet utilities' HWMs based on their FY 2010 loads. At the 300 megawatt cap, this would be roughly a 4 percent increment to the existing system and is in addition to any acquisitions to serve new public utilities.

- Bonneville will offer three product choices: load-following, block and slice. The load-following product will include services to follow the actual loads a customer experiences. Slice and block products do not include load-following service.

- Bonneville will increase the amount of power sold under the slice product from the current 22.6 percent to as much as 25 percent of the power available from the FBS resources.

- Bonneville acknowledged that service to the DSIs had not been resolved and so that issue was not decided in this policy.

- Bonneville omitted a section on the residential exchange, due to then-recent decisions from the Ninth Circuit. Nonetheless, Bonneville's goal is to ensure that the residential and small-farm customers of the IOUs receive a fair and reasonably stable share of the benefits from the federal system over the long term, consistent with law, that will parallel the certainty obtained by public utilities.

- Bonneville will institute a regional cost review to give customers and other stakeholders opportunities to comment on Bonneville's costs.

- Bonneville established guidelines for dispute resolution, in response to customer requests, but noted that final decisions in this arena will likely be taken in conjunction with development of the TRM and power sales contracts.

- Bonneville will pursue the development of all cost-effective conservation in the service territories of public utilities served by Bonneville and of renewable resources based on its share of regional load growth. Bonneville expects these goals to be met to a significant extent through programs initiated and funded by its public utility customers. Bonneville will supplement and facilitate utility initiatives. Bonneville will provide the necessary integration services to customers that wish to acquire non-federal renewable resources to meet their load growth and enhanced incentives for conservation development.

- Bonneville will require its customers to provide their load and resource data and resource development plans necessary to track regional implementation of the voluntary resource adequacy standards adopted by the Council. Bonneville did not make compliance with the standards a contractual requirement.

- Bonneville will propose stable and predictable low density discount (LDD) and irrigation rate mitigation (IRM) programs in future rate proceedings. Bonneville will ensure that the LDD approach will not bias customers' choices between taking power at a Tier 2 rate from Bonneville or from non-federal resources.

These policy choices did not conclude the Regional Dialogue process. Negotiation and drafting of new contracts, their release for public comment, and eventual execution were to follow. Bonneville also committed to a review of its 5(b)/9(c) policy. The TRM was to be developed in a separate 7(i) process, as were rates to be effective for power sales under the Regional Dialogue contracts in FY 2012. The Regional Dialogue policy decisions were meant to inform those subsequent processes, but it did not decide them.

Bonneville's Posture Today; its Response to Regional Recommendations

Late last year Bonneville signed 20-year contracts with all its public utility customers. This was the culmination of a lengthy public process in which all parties had the opportunity to address the terms and conditions under which Bonneville would offer power to its customers. The fact that these contracts are long-term should help ensure the stability of the relationship between Bonneville and its customers. Knowing that Bonneville will have this long-term, stable financial relationship with its customers should also bolster confidence that Bonneville will be able to meet its annual payment to the U.S. Treasury. The contracts also support Bonneville's commitment to conservation and renewables, as well as to meeting its fish and wildlife costs.

Bonneville has also developed and is preparing to implement a Tiered Rate Methodology. Bonneville will sell electricity from the existing FCRPS to eligible customers at cost. To ensure that it has sufficient resources to meet the initial demand, Bonneville will augment the federal base by acquiring a limited amount of additional resources, the cost of which it will meld with the cost of the existing system. This initial demand will be sold at priority firm (PF) Tier 1 rates. Customers that place more demand on Bonneville, that is, load above their individual high water mark, will pay PF Tier 2 rates for that service, which will recover the costs of additional power needed to meet this demand[Also okay] Note that Bonneville has reached an accommodation with a number of small customers that do not view themselves as well-situated to acquire new resources on their own. Participants in this Shared Rate Plan will not face Tier 2 rates for individual growth, but if Bonneville has to acquire resources to meet the overall growth of the pool, costs will be shared among all participants in this subset of customers.

This tiered rate structure should meet several goals in the recommendations the region has offered. First, tiered rates will make clear who has responsibility for resource development. This structure should result in customers seeing the true cost of adding resources, which will provide better incentives for resource choices. It will also prevent the dilution of the value of the existing federal system that results from melding the costs of new and more expensive resources.

Bonneville has also responded to direction from the Ninth Circuit and reworked its Residential Exchange Program (REP). To accomplish this, the agency revised and implemented a new Average System Cost Methodology, the result of a lengthy and comprehensive consultation process with customers, interested parties, and the Council. Bonneville aimed at sharing with the residential and small farm customers of the IOUs the benefits of the generally lower cost FCRPS, both over the time when payments were made under settlements struck down by the Ninth Circuit, the look-back period, and going forward. The issues are again being litigated, and the customers are now discussing a negotiated settlement to try and resolve the uncertainty in the REP methodology under the Act.

These changes in Bonneville's future role do not change Bonneville's fundamental responsibility to serve the loads of qualifying customers that choose to place load on Bonneville; it does not change Bonneville's responsibility for ensuring the acquisition of Bonneville's share of all cost effective conservation and renewable resources identified in the Council's plan; and it does not change Bonneville's responsibility to fulfill its fish and wildlife obligations under the Act and the Council's fish and wildlife program. It does represent a change in the way Bonneville traditionally has carried out those responsibilities.

Some important policies Bonneville has adopted to implement the recommendations of these public processes and the Regional Dialogue Policy have recently been challenged in the Ninth Circuit. As of the date of the release of this draft plan, more than 40 petitions have been filed that could result in the invalidation of how Bonneville has responded to earlier judicial decisions directing the agency to implement the REP in line with the directives of the Northwest Power Act, its determination of how to make the preference customers whole, and its adoption and implementation of the Tiered Rates concept. Depending on the outcome of these challenges, the region may need to undertake a variety of efforts to enable Bonneville to serve the roles identified in the long series of public processes outlined above and in the Regional Dialogue Policy.

THE ADMINISTRATOR'S RESOURCE REQUIREMENTS

The Northwest Power Act requires that the Council's power plan "shall set forth a general scheme for implementing conservation measures and developing resources pursuant to section 6 of this Act to reduce or meet the Administrator's obligations." The Act requires the plan to give "priority to resources which the Council determines to be cost-effective," and also ranks types of resources by priority: "Priority shall be given: first, to conservation; second, to renewable resources; third, to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency; and fourth, to all other resources."

When Bonneville acquires resources, the Power Act then requires that, with certain narrow exceptions, all of Bonneville's resource actions be consistent with the Council's power plan. The Council engages in an extended planning process for developing and amending the power plan. It gathers experts in advisory committees on important subjects the plan treats: generating resources, conservation, and natural gas, for several examples. These committees both contribute technical information for use in the plan and evaluate analysis done by Council staff and others. It is the staff's analysis and synthesis, combined with public input and comment, that form the basis for the Council members' decisions when they adopt a plan or a plan amendment. Bonneville participates in the Council's process, sometimes as a member of an advisory committee, sometimes as a contributor to studies or analyses, and sometimes as a commenter on draft Council positions. Being fully apprised of the thinking that underlies a final Council plan should enable Bonneville to ensure that its own resource assessments and acquisitions build on the Council's planning process and are consistent with the plan.

The Council's power plan is first developed from a "regional perspective." Much of the technical analysis for the plan assumes that the electrical loads in the region are served by all of the electric generation and conservation resources available in the region, without respect to specific utility loads and resources. The result is a regional resource strategy that minimizes costs and risks as if the entire region was served by all the resources and transmission in the region. The Power Act also requires, however, that the Council's power plan specifically include a resource plan for Bonneville to act consistent with as it works to meet its current and future obligations. For this plan, the Council has examined Bonneville's particular power system needs as described in this chapter. The Council did not develop its own quantitative forecast of Bonneville's loads and resources, concluding that analyses by Bonneville of its projected loads and resources will be more than sufficient for the Council to rely on here for planning purposes, with an understanding of further work to come as described below. The Council then distilled the plan's regional resource strategies into a set of specific resource acquisition strategies that Bonneville is to act consistent with as it meets its needs into the future.

Conservation Resources

Section 6(a)(1) of the Northwest Power Act obligates Bonneville to "acquire such resources through conservation . . . as the Administrator determines are consistent with the [Council's power] plan." And as noted, the Act further requires the Council to give first priority in the plan to cost-effective conservation resources. The power plan's conservation measures thus have real legal meaning for Bonneville, and real effects on Bonneville's utility customers in terms of conservation's ability to reduce the need for Bonneville or the utilities to acquire lower priority or higher-cost resources and in terms of the costs of conservation acquired by BPA and its customers.

The acquisition of cost-effective conservation by Bonneville through an ongoing program is not conditioned in the Power Act on whether Bonneville is or soon will be out of load-resource balance and therefore in need of additional resources. Rather, the point of this provision and of the structure of the Power Act as a whole is that conservation is a resource used to serve firm power loads by reducing consumer demand for electricity. As such, conservation lessens the need for Bonneville to acquire power generated by conventional generating resources that are more expensive than the costs of the hydrosystem The Regional Dialogue's new power supply paradigm for Bonneville does not alter the legal or practical framework for Bonneville's ongoing conservation program. Bonneville's customers are still placing load on the agency and Bonneville is planning to acquire resources to serve its contractual load obligations, including potential loads above customer high water marks and possibly Direct Service Industrial loads. Bonneville will thus need to continue) to acquire cost-effective conservation to reduce loads and stretch the Federal Base System, consistent with the conservation provisions of this plan.

For this reason, the principal recommendation regarding Bonneville in the Sixth Plan, as in past plans, is that Bonneville aggressively pursue its share of the Council's regional conservation goals. This is to ensure that Bonneville meet whatever load it faces, whether served at Tier 1 or Tier 2 rates, in as efficient and cost effective way as possible.

Bonneville and its customers understand the basic principle and through their actions have sustained the conservation program for decades. However, they have expressed concerns about the particulars here, that is, about the greater number of conservation measures, about the expanded conservation goals, and about what mechanisms might ensure that Bonneville achieves its share of the regional conservation goals. Even as concerns over the near-term targets are being worked out in collaborative discussions, the utility customers have remained generally concerned about having goals, methods, measures, and costs imposed on them by Bonneville to satisfy the plan. Under Bonneville's new resource policy, utility customers are responsible for the marginal costs of new resources acquired to meet their load growth, whether acquired by themselves or from Bonneville at Tier 2 rates. For this reason, the utilities believe it is their interest to implement conservation programs tailored to their particular needs, programs that can serve to satisfy the plan's conservation goals, without mandates from Bonneville and with measures and costs the utilities themselves control.

In response, the Council believes Bonneville has the discretion to tailor its conservation program to match this new power supply paradigm and to assuage the utility customers concerns, in a way consistent with the principles the Council recently outlined:

1. Conservation targets. Bonneville should continue to commit that its public utility customers will meet Bonneville's share of the Council's conservation targets. Bonneville should ensure that public utilities have the incentives and the support to pursue sustained conservation development. Active utility commitment to conservation should continue to be a condition for access to Bonneville power at Tier 1 rates.

2. Utility reporting. Bonneville has included in its power sales contracts requirements for utility reporting and verification of conservation savings so that Bonneville and the Council can track whether conservation targets are being achieved.

3. Implementation mechanism. Bonneville should offer flexible and workable programs to assist utilities in meeting conservation goals, including a backstop plan, should Bonneville and utility programs be found insufficient.

4. Regional conservation programs. Bonneville should continue to be active in funding and implementing conservation programs and activities that are inherently regional in scope, such as NEEA.

It should be emphasized that the Council's conservation methodology calculates conservation potentials for certain measures that might, at some point, be covered by building or energy codes, and then assumes that the savings will be accomplished over time by *either* utility programs or codes. The utilities should include these cost-effective, available conservation measures in their own plans and programs. However, *if* codes are adopted that ensure the capture of the potential savings, then the utilities may count the resulting savings in their service territories against the regional target. The Council in return expects the utilities to join with the Council, the Governor's Offices, and other relevant state and local agencies in their support of the necessary state and national improvements in codes and standards.

Additional Resources

Along with the conservation program, the power plan is to set forth a general scheme for developing other resources if needed to meet the Administrator's obligations. Bonneville may need additional resources for a number of reasons. These include Bonneville's proposal to acquire resources to augment the existing system to serve the "high water mark" load of its preference customers at Tier 1 rates; additional energy resources if needed because one or more customers call on Bonneville to meet their load growth, at Tier 2 rates reflecting the costs of the additional resources; additional resources to serve DSI loads, if Bonneville decides to offer such service; additional resources that may be necessary for capacity and within-hour flexibility purposes, such as to support the integration of intermittent renewable resources like wind; additional resources as may be necessary for system reserves, system reliability, and transmission support; and additional resources if necessary to assist the Administrator in meeting Bonneville's fish and wildlife obligations under Section 4(h) of the Northwest Power Act. Conservation resources will help reduce the need for additional resources, but are unlikely to address all of these needs. The Council is not undertaking at this time a detailed, quantitative assessment of Bonneville's need for additional resources, given the extent to which the overarching decisions and information that will affect this assessment are uncertain or in development. Instead, the Council is setting forth further information and a set of principles in this section (and linked to other chapters in the plan) to help guide any decisions by Bonneville to acquire additional resources consistent with the plan and the provisions of the Power Act:

Bonneville anticipates acquiring resources on a long term basis to meet its obligations under the new Regional Dialogue power sales contracts. In the Long-Term Regional Dialogue Final Policy Bonneville said it would acquire up to 300 average megawatts of power to augment the existing system to meet the "high water mark" load of its preference customers at Tier 1 rates.

In addition to augmenting energy to meet preference customer high water mark demand, the Regional Dialogue Policy also provides that over the 20-year contract period, Bonneville may augment its energy supplies by up to 250 megawatts of power to be sold at the Tier 1 rate to serve any newly created public utilities. Additional high-water marks for new publics will be limited to 50 megawatts in each rate period, that is, in any two year period. Of the 250 megawatts, Bonneville has designated 40 megawatts for service, on a first-come, first-served basis, at Tier 1 rates for recently created or future tribal utilities that experience load growth beyond their high-water marks. Bonneville also committed to augmenting its energy supplies by up to 70 average megawatts to meet possible expansions of the Department of Energy's Richland facilities.

Beyond the Regional Dialogue provision to augment energy supplies by up to 620 average megawatts to be sold at Tier-1 rates, as described above, Bonneville may also be required to acquire resources to meet loads that are beyond a customer's high water mark if the customer calls on Bonneville to meet its load growth. The amount of power sold to supply a customer's above-high water mark load will be subject to a Tier 2 rate. The extent of this Tier-2 rate service is unknown at this time. This service is by definition flat, so if Bonneville acquires resources to meet these loads, it will offer power in flat blocks. Further, Bonneville's service to Direct Service Industrial customers has not been determined and could require additional resource acquisitions in the future. As of the time of this draft, Bonneville and the DSIs have not reached an agreement regarding service of those industries.

Historically, Bonneville has purchased resources to serve the average annual energy needs of its customers. Given the reductions in the ability of the hydro system to support the integration of intermittent resources like wind, it is more likely that Bonneville will focus on acquiring resources that offer both added capacity and flexibility that cannot be provided by conservation. Bonneville is designing such products in its Resource Support Services (RSS). For example, if a customer decides to meet its own load growth with new resources that have little or no firm capacity and operate intermittently, Bonneville will not require that utility to convert such resources into resources that can be used to meet firm loads by acquiring capacity, firming up the energy, and reshaping the output. Instead, Bonneville will do this for the customer and charge a Resource Shaping Charge, one of the RSS. Because many of Bonneville's customers are acquiring wind to meet state-imposed Renewable Portfolio Standards, this may prove to be an important Bonneville service.

Bonneville will also acquire resources to offer ancillary services to its utility and transmission service customers. These are flexibility services such as regulation, load-following and balancing services, spinning reserves, non-spinning reserves, supplemental reserves, and voltage control. Bonneville will need to provide some of these services to support resources, such as a good portion of the wind generation physically located in Bonneville's balancing authority area, that serve load outside the agency's balancing area. Resources needed for this service will be chiefly those that offer added capacity and flexibility. The resource strategy laid out in this plan acknowledges Bonneville's potential need to acquire capacity resources to meet heavy-load hour demand and provide the flexibility needed to integrate intermittent resources.

Bonneville is currently engaged in developing a Resource Program for meeting these various requirements. The first step in developing that program is a Needs Assessment. The Council will continue to work closely with Bonneville to ensure that the Sixth Power Plan takes account of Bonneville's estimates of its future resources needs.

However, a number of the key factors that will establish the levels of those obligations are not known at the time of the draft Plan, and some will not be known by the time the Sixth Plan is adopted. These include any additional energy and capacity needed for loads served at Tier 1 rates, the levels of the loads to be served at Tier 2 rates, both energy and capacity, that will be placed on the agency, the responsibility for Resource Support Services, and the other needs for balancing services for Bonneville's balancing authority.

Not only are the magnitudes of the requirements unknown at this time, but the availabilities of potential solutions, are, in some cases, not known either, because they will depend on ongoing regional and West-wide efforts. This is the case for solutions to the balancing problems Bonneville faces in integrating the large amounts of wind generation that appear likely to be developed in its balancing authority. Several institutional solutions that would relieve or mitigate the burden facing Bonneville's balancing authority are being discussed and developed by Bonneville's Wind Integration Team, which recently released a two-year work plan, and by the ColumbiaGrid/NTTG/WestConnect Joint Initiative, in which Bonneville, as a member of ColumbiaGrid, is participating.

These different kinds of needs can interact with each other. For instance, some kinds of resources that might be valuable for meeting capacity needs could also provide flexibility for managing wind fluctuations, or, alternatively, resources that might be required to meet flexibility needs, if institutional changes in business practices prove insufficient, could also provide resources to meet capacity requirements. However, the generating resources that might be best at providing flexibility, because they have wide operating ranges, might not be optimized to provide the cheapest energy.

The Council's analysis, while it looks at regional capacity and energy requirements, does not break out utility-specific capacity and energy requirements and does not look at within-hour issues like flexibility. Thus there might be specific Bonneville needs that are not explicitly addressed in detail in the Plan.

First, there are some kinds of resources that the Council considers in its analysis, both for the Plan specifically and for its annual adequacy assessments, that specific utilities may or may not want to purchase or acquire. Specifically these are out-of-region purchases and in-region uncontracted IPP generation. The Council considers these as available to meet regional loads, but they are not owned or contracted by any in-region load serving entity. (For more on this distinction, see Chapter 13.) For any in-region utility, they are potential resources, like others, that would need to be evaluated based on cost and risk.

Second, Chapter 11 of the Plan describes various ways of meeting flexibility needs (both business practice changes and types of new generation). It suggests that the institutional and business practice changes are likely to be the easiest and cheapest. It does not, however, describe the total amounts of flexibility that would be available through all the various business practice changes, or the time frame within which they would all be available, because those issues are still being examined by various regional and WECC entities.

Because of this, the Plan's recommendations for Bonneville's response to Bonneville's needs described above cannot be precise with regard to specific resources or strategies to meet those needs nor to their timing. Here are a set of general principles Bonneville should follow, with corresponding provisions in the Action Plan:

The first, and major principle, is that Bonneville aggressively pursue the Council's conservation goals. This will ensure that the customer load that remains, whether at Tier 1 or Tier 2 rates, is as efficient as is cost effective.

A second principle is that Bonneville should aggressively pursue the various institutional solutions to its balancing needs that are currently being discussed before acquiring power produced by new generation. These institutional changes, better forecasting, shorter scheduling windows, markets for the exchange of balancing services among balancing authorities, generation owners and operators, and demand response providers, as well as other actions have the potential to be significantly more efficient and faster to develop than new generation to provide these services.

A third principle is that Bonneville should take a broad look at possible resource acquisitions for additional capacity and flexibility, if it turns out that resources are needed to meet its obligations. While Chapter 11 gives an overview of the business practice changes and generating technologies that are available to meet these needs, the possible synergies in simultaneously meeting both capacity and flexibility requirements need to be taken into account, and the possibility of newly developed technologies, including a smart grid and storage, should also be considered. Bonneville should take similarly careful look at possible resource strategies and resources choices, if needed to meet its obligations in the other areas listed at the beginning of this section, including for reserve and reliability requirements and for transmission support.

Major Resources

If Bonneville proposes to undertake a suite of activities related to the acquisition of a *major* resource, Section 6(c) of the Act requires the Administrator to conduct a public review of the proposal and make findings, taking into account the public comment. A major resource under the Act is one that is greater than 50 average megawatts and is acquired by the Administrator for a period of more than five years. This review provision applies to any proposal: (1) to acquire a major generating resource, (2) to implement an equivalent conservation measure, (3) to pay or reimburse investigation and preconstruction expenses for a major resource, or (4) to grant billing credits or services involving a major resource.

One of the findings Bonneville must make is whether a proposed action is consistent with the Council's plan. After Bonneville has made its finding, the Council has an opportunity to undertake its own review of the proposal to determine consistency with the plan. If either agency finds the proposal inconsistent, Bonneville must get specific authorization from Congress to proceed.

Chapter 13: Regional Adequacy Standards

SUMMARY OF KEY FINDINGS

The 1990s saw little new resource development in the Northwest due, in part, to the emergence of an electricity market and the anticipation of deregulation. As load continued to grow, supply remained stagnant, and utility planners became concerned about the adequacy of the power system. In 2001, the second driest year on record in the Northwest coupled with a failed market in California meant the region faced a serious threat of blackouts. Actions were taken to avoid forced curtailments, but those actions were costly and resulted in soaring electricity prices.

It was becoming obvious that a new method of assessing resource adequacy was necessary. The power system was becoming more complex, with greater constraints placed on the operation of the hydroelectric system, increasing development of intermittent and dispersed resources, and the growth of a Westwide electricity market. The Council recognized this need, and in its Fifth Power Plan recommended developing a resource adequacy standard. Supporting this decision was federal legislation, passed in 2005, requiring an Electric Reliability Organization (the role now filled by the North American Electric Reliability Corporation, or NERC) to assess the adequacy of the North American bulk power supply.

In 2005, the Council and the Bonneville Power Administration created the Northwest Resource Adequacy Forum to aid the Council in developing a standard, and to periodically assess the adequacy of the power supply. The forum, which is open to the public, includes utility planners, state utility commission staff, and other interested parties. After nearly three years of coordinated effort, it reached consensus on a proposed resource adequacy standard, which the Council subsequently adopted in April 2008.

The standard helps to assess whether the electricity supply is sufficient to meet the region's needs now and in the future. It provides a minimum threshold that serves as an early warning should resource development fall dangerously short. It also suggests a higher threshold that encourages greater resource development to offset electricity price volatility. It does not mandate compliance or enforcement. It does not directly apply to individual utilities – because every utility's circumstances differ. Individual utilities must assess their own needs and risk factors and determine their own planning targets, which are screened by public utility commissions or by their boards of directors. It would be a misapplication of the adequacy standard to infer that utilities should slow their resource acquisition activity simply because the adequacy standard is being met. The Pacific Northwest Resource Adequacy Standard can be found at: http://www.nwcouncil.org/library/2008/2008-07.pdf.

Over the next five-year period, the region's resources, in aggregate, exceed the standard's minimum threshold. However, the minimum threshold should not be mistaken as a resource planning target or acquisition strategy. The Council's Power Plan, developed through an integrated resource planning process, provides a blueprint for the types and amounts of resources the Northwest should acquire to assure that the region has an "adequate, efficient, economical, and reliable power supply." In this sense, the Power Plan includes resources beyond minimum need.

BACKGROUND

Motivation for Developing a New Standard

Economic growth depends on an adequate electricity supply, and the resource adequacy standard was developed to ensure that the region's energy needs will be met well into the future. In the worst case scenario, an inadequate electricity supply can affect public health and safety, as in a blackout. Fortunately, such events are rare, and when they do happen, they are most often caused by a disruption in the delivery of electricity, not the supply. However, there have been times – during extreme cold spells or heat waves – when supply has been tenuous. The fact that most of the region's electricity comes from the hydroelectric system presents unique challenges to the energy supply, too, since periods of drought that limit hydroelectric power production are unpredictable.

While most disruptions in supply have been short term, the Western United States did experience an extended energy crisis in 2000-01. At its root, the crisis was precipitated by an imbalance of electricity supply and demand centered in California and the Pacific Northwest, where for years, development of new energy resources had lagged behind energy demand. Ripple effects from that crisis were felt throughout the West as electricity prices and consumer rates soared to historic highs.

Adding to the issue of power supply adequacy are changes in the energy environment that have made ensuring the region's power supply more challenging. Greater constraints on the operation of the hydroelectric system, increasing development of intermittent and dispersed resources, and the growth of a Westside electricity market have all contributed to creating a much more complex and interconnected power system. Changes in the Bonneville Power Administration's role as a power provider also mean that load-serving entities will bear more responsibility for their load growth, making regional coordination to ensure adequacy especially important.

Historical Approach

Historically, the Northwest has planned to a critical-water standard, which implies that Northwest resources, including hydroelectric generation produced under the driest water condition, should at least match the forecast load on an annual basis. This standard originated when the region was essentially isolated from the rest of the Western system by limited transmission links. Even after cross-regional interties were built, this policy continued because high oil and gas prices dominated generation markets in the rest of the West. However, since the collapse of oil and gas prices in the mid-1980s, the region has not had to balance in-region resources and demand under critical water conditions in order to maintain a physically adequate power supply. The reasons for this are twofold. In almost all years, hydroelectric generation will exceed production under critical water conditions; and the Southwest should always have surplus winter energy to export (the Southwest is a summer-peaking region and the Northwest is a winter-peaking region).

In practice, however, the region has strayed from strict critical period planning. Generally, reservoirs behind the dams were drafted in the fall and early winter under the assumption that the region would realize better than critical water conditions. Should a dry year ensue, the region could import surplus energy from the Southwest or interrupt a portion of the direct service industry load (DSI). These kinds of contractual agreements with the remaining DSIs no longer exist, but the Northwest is still connected to the Southwest. Both regions should be able to benefit from their different peak-demand seasons. A strict assessment of adequacy, therefore, should consider the ability to import power from outside the region. For resource acquisition purposes, however, reliance on market resources will depend on impacts to overall cost and customer rates.

Adequacy Assessment Efforts Outside of the Northwest

In order for a regional adequacy standard to be effective, it must be compatible with actions in the rest of the West. Therefore, working with the Western Electricity Coordinating Council (WECC) and other Westwide organizations is necessary. Most of the discussions in the region and the rest of the West have been directed toward developing some sort of adequacy standard that would apply to load-serving entities. The Federal Energy Regulatory Commission (FERC) proposed an adequacy standard as part of its standard market design. However, that standard was inappropriate for an energy-constrained, hydro-dominated system like the Northwest's. The FERC has subsequently deferred to the states, but in the absence of state or regional action, it might attempt to reassert authority in this area. In addition, the North American Electric Reliability Corporation (NERC) has begun developing a power supply adequacy assessment standard that would apply to the WECC.

The NERC Resource and Transmission Adequacy Task Force prepared a report with recommendations for both resource and transmission adequacy. The NERC adopted the report in 2004, and subsequently drafted a standard authorization request for a resource adequacy assessment incorporating the task force's recommendations. This proposed new standard requires regional reliability councils, such as the WECC, to establish resource adequacy assessment frameworks that the NERC will review to ensure compliance.

The WECC has since established a new framework that has been implemented in the annual Power Supply Assessments for the last two years. Northwest planners continue to refine the characterization of the Columbia River hydroelectric system, both for the regional assessment, and to improve the accuracy of its adequacy assessment for the Western Interconnection.

Some states, through their public utility commissions (PUC), have the ability to implement adequacy standards for the utilities they regulate. For example, the California PUC adopted an adequacy standard requiring investor-owned utilities to have a 15-17 percent reserve margin over their peak load. This planning reserve includes the approximately 7 percent operating reserves required by the WECC. The California PUC order also requires load-serving entities to forward contract to cover 90 percent of their summer (May through September) requirements, which would include their peak load, plus the 15 percent reserve one year in advance. Some believe this standard goes beyond what is required to assure adequacy in a purely physical sense, as it is intended to limit California's exposure to the risk of extreme prices.

THE PACIFIC NORTHWEST ADEQUACY STANDARD

In 2005, the Council and the Bonneville Power Administration initiated the Pacific Northwest Resource Adequacy Forum. The forum includes representatives from the region's electric utilities and utility organizations, public utility commissions and public interest groups, as well as from BPA and the Council. It is made up of a steering committee and a technical committee.

The forum's overarching goal is to *"establish a resource adequacy framework for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."*

To that end, the forum has forged a voluntary, consensus-based standard for the region to address both energy (annual) and capacity (hourly) needs. This standard has been designed to assess whether the region has sufficient resources to meet growing demand for electricity well into the future. This is important, because it takes time – usually years – to acquire or construct the necessary infrastructure for an adequate electricity supply.

While some interests may wish to see an enforceable adequacy standard, currently, there are no institutions in the Northwest that could enforce such a standard for all the region's load-serving entities.

Physical Adequacy, Economic Adequacy, or Both

Is the purpose of an adequacy standard to ensure that the "lights stay on" with an acceptably high probability (physical adequacy); or is it to protect against the economic and social costs of an energy shortage (economic adequacy)? The adequacy standard addresses the first level by providing a minimum threshold that serves as an early warning should resource development fall dangerously short. The standard also suggests a higher threshold that encourages greater resource development to offset electricity price volatility--or economic adequacy. The economic threshold is defined through the development of the Council's power plan.

Different adequacy standards could be applied at different levels. For instance, a physical standard might be most appropriately applied at the WECC level. At this level, it would provide a baseline for physical reliability and actions by load-serving entities and their regulators to address. Economic adequacy might be better addressed at the individual (or perhaps state policy) level, where different mechanisms for mitigating price risk could be put in place.

Unlike past adequacy assessments, this assessment considers the question of reliance on market supply. Physical adequacy is determined by forecast load, existing firm resources, and assessing available market supply, cost notwithstanding. Economic adequacy is determined in a similar manner, except that the region (or utility) uses an economic analysis or makes a policy decision to determine how much power to buy from the market. Utilities may want to limit their exposure to market resources for a number of reasons, price volatility being only one.

The Council's portfolio analysis results suggest maintaining a higher level of in-region resources than the adequacy standard's minimum threshold. These additional resources reduce the likelihood of having to purchase high-priced electricity. At the same time, however, the analysis also indicates that if the overall level of regional resources is sufficient, overbuilding is a riskier and more expensive alternative than some level of reliance on the market. This is true regardless of the ownership of the resources.[1] The challenge is to find the right balance.

Defining the Resource Adequacy Standard

The Northwest resource adequacy standard[2] is based on a sophisticated hourly assessment of load and resources and how they might be affected by temperature (load deviations), precipitation (water supply), forced outages to generating resources, and other factors.

Historically, the region's tolerance for a significant power supply shortage has been assumed to be 5 percent – that is, the region would tolerate a significant power shortage no more than once in 20 years. This type of metric is commonly referred to as a loss-of-load probability (LOLP) and requires a complicated computer model to assess. However, not all utilities or other planning entities are willing or able to use such a tool. Therefore, the LOLP threshold is translated into a simpler and more familiar load/resource balance measurement that regional planners can more easily use. These simpler measurements are provided both for annual energy needs and peak hourly capacity needs.

Annual Needs (Energy Standard)

Energy in this context refers to the annual electricity needs of the region. The measure for this is the annual average load/resource balance in units of average megawatts. The threshold for this measure is set so that the resulting LOLP assessment yields a 5 percent value. In determining resource generating capability, the standard includes hydroelectric generation available under

[1] Ownership refers to either utility ownership or ownership by independent power producers.
[2] The Northwest resource adequacy standard can be found at: http://www.nwcouncil.org/energy/resource/Default.asp.

critical water conditions, available annual output of regionally committed thermal generators and renewable resources, and a portion of the uncommitted independent power producer generation. The standard also includes a small amount of non-firm resources such as out-of-region market supplies and non-firm hydroelectric generation. The amount of non-firm resources the region should rely on is determined by the 5 percent LOLP analysis. In determining load, the standard uses the region's average annual firm load based on normal temperatures, and adjusted for firm out-of-region energy contract sales and purchases and savings from conservation programs.

Peak Hourly Needs (Capacity Standard)

Capacity in this context refers to the peak electricity needs of the region. The measure for this is the planning reserve margin, or the surplus sustained-peaking capacity, in units of percent. It represents the surplus generating capability above the sustained-peak period demand. In determining the planning reserve margin, the standard includes the same firm and non-firm resources used to assess the energy standard for the region. The planning reserve margin is assessed over the six highest load hours of the day for three consecutive days (sustained-peak period). This is intended to simulate a cold snap or heat wave – periods of the year when the Northwest requires the most capacity. The planning reserve margin is computed relative to normal weather sustained-peak load. The threshold for this measure is determined by the 5 percent LOLP analysis and should be sufficient to cover load deviations due to extreme temperatures and the loss of some generating capability.

Implementing the Standard

The forum wanted to ensure it did not overstep the jurisdiction of states or the prerogatives of individual utilities in planning and acquiring resources to meet load. Because each utility's circumstances differ, it is difficult to translate a regional standard into a utility-specific standard. The forum has provided some guidance for utilities, but ultimately, they and their regulators are the decision makers for resource acquisition. The implementation plan depends on regional sharing of information, transparency of assessment methodologies, and regional coordination. The forum believes that a voluntary approach will work because utilities and their governing bodies have a strong incentive to develop adequate resources to meet retail load.

Working with Other Entities

The Council, in conjunction with the forum, will assess the adequacy of the region's power supply on an annual basis. Demand forecast and resource assumptions will be compared to those in other regional reports, such as the Bonneville Power Administration's White Book and the Pacific Northwest Utilities Conference Committee's Northwest Regional Forecast. This sharing of information in a public forum should provide a favorable environment for addressing inconsistencies in data and reporting standards.

The Northwest is not alone in focusing on ensuring an adequate power supply. The NERC is expected to pick up its previously delayed work on the development of a resource adequacy assessment standard in 2009, which is expected to require the WECC to develop an adequacy assessment framework. The WECC has spent the past several years developing a framework for the West's power supply, which is currently in place. The WECC's framework is not intended to override any state or regional assessments, including regional adequacy measures or their thresholds. In fact, the WECC has solicited help from regional entities to aid in its assessment of Westwide resource adequacy. The Council and the forum will continue to participate in the WECC's efforts.

THE ADEQUACY OF THE NORTHWEST POWER SUPPLY

The adequacy standard calls for the average annual energy capability to at least equal the average annual demand. It also calls for the system's peaking capability to be able to meet expected peak-hour demand and to have sufficient surplus to cover operating reserves,[3] prolonged generator forced outages, and demand deviations due to extreme temperatures. Key findings of the current assessment are:

- Based only on existing resources (and those under construction), the region's power supply may fail to provide sufficient summer peaking capability by 2013.
- This puts the region in a "yellow alert" situation, which triggers specific actions that include a review of all load and resource data and a review of the methodology used to assess adequacy.
- The Council and regional utilities are actively developing resource acquisition strategies, which take economic risk, carbon emission policies and other factors into account.
- Adding the plan's expected resource additions keeps the power supply adequate until about 2029.

Assessment

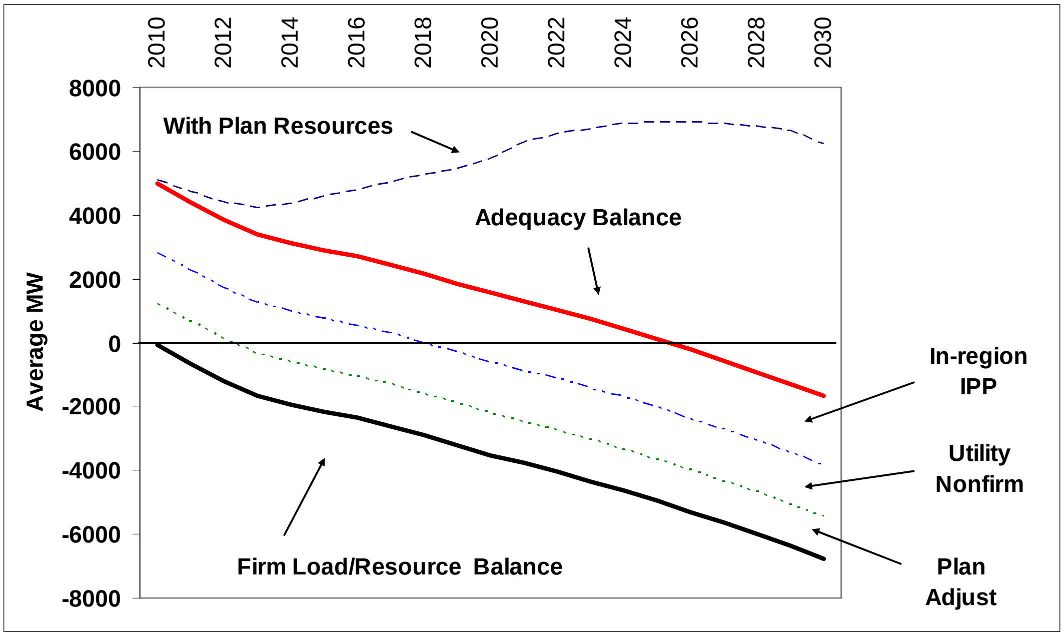
The Northwest Adequacy Standard, developed by the Resource Adequacy Forum and adopted by the Council in 2008, specifies minimum thresholds for annual energy load/resource balance and for winter and summer surplus capacity margins. Normally the adequacy assessment is targeted for 3 and 5 years out, but because this year the Council is releasing its 20-year power plan, it seems appropriate to make the assessment throughout the study period. Figures 13-1 through 13-3 show the assessed annual load/resource balance and capacity reserve margins through the year 2030.

As apparent in Figure 13-1, only counting existing firm resources, the region is in about load/resource balance today, which (without any new resources) grows to a large deficit by 2030 (black line). The standard, however, includes some non-firm resources in its definition of the load/resource balance for adequacy purposes. A planning adjustment of 1,300 average megawatts is included to account for out-of-region market supplies and some amount of non-firm hydroelectric generation. Regional utilities also own non-firm resources in that some of their resources are not fully declared as firm. These resources amount to about 1,600 average megawatts. Finally, there is a substantial amount of within-region but uncommitted generation, namely the independent power producer resources, which add about 2,150 average megawatts to

[3] Operating reserves currently do not include additional regulating or load-following reserves anticipated to be needed to integrate large amounts of new wind generation into the regional power grid, primarily because these reserves have not yet been quantified. In addition, this assessment only includes existing wind facilities and those currently under construction.

the balance. Adding the non-firm resources to the calculation yields the solid red line in Figure 13-1, which shows the region well above the adequacy threshold until about 2025 (red line). Adding new resources suggested by the power plan increases the surplus relative to a physical adequacy need (but are needed for economic and risk aversion needs).

Figure 13-1: Energy Adequacy Assessment



In a similar fashion, the winter and summer surplus sustained peaking reserve margins can be calculated and compared to their adequacy thresholds. Figures 13-2 and 13-3 show that assessment for January and July, respectively. The sustained peak reserve margin represents the amount of surplus generating capacity over the expected demand averaged over the sustained peak period, in terms of percent. The sustained peak period is defined to be the 6 highest load hours per day over 3 consecutive days (to reflect the duration of a typical cold snap or heat wave). As with the energy assessment, counting only existing firm resources, shows the region below the January minimum capacity threshold for the entire planning horizon (black line). Adding non-firm resources, as defined in the standard, raises the reserve margin above the threshold until about 2030. Again, adding the plan resources makes the reserve margin even higher.

The story is a little different for July. Looking at Figure 13-3, the reserve margin, including defined non-firm resources, only keeps the region above the minimum threshold through about 2013. According to the standard, this puts the region in a “yellow alert” situation, triggering specific regional actions, which are currently underway. First, regional planners are reviewing all load and resource data. Second, the methodology used to assess the minimum thresholds is in the process of being reviewed. Third, the Council and regional utilities are actively developing resource acquisition strategies to offset this projected need. Adding plan resources to the reserve margin in Figure 13-3 puts it above the minimum threshold through nearly the entire study horizon.

Figure 13-2: January Capacity Adequacy Assessment

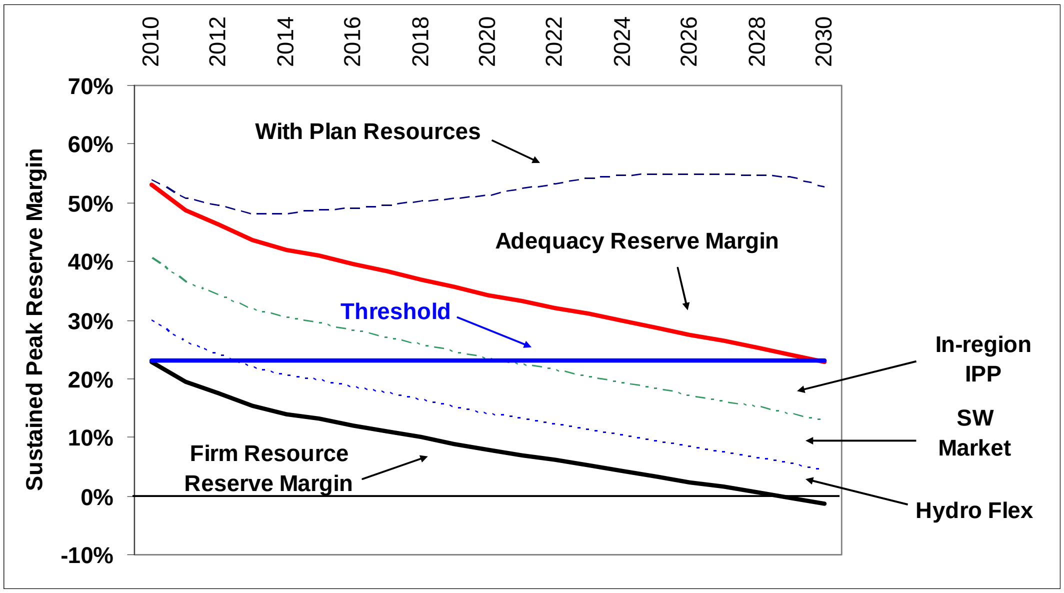
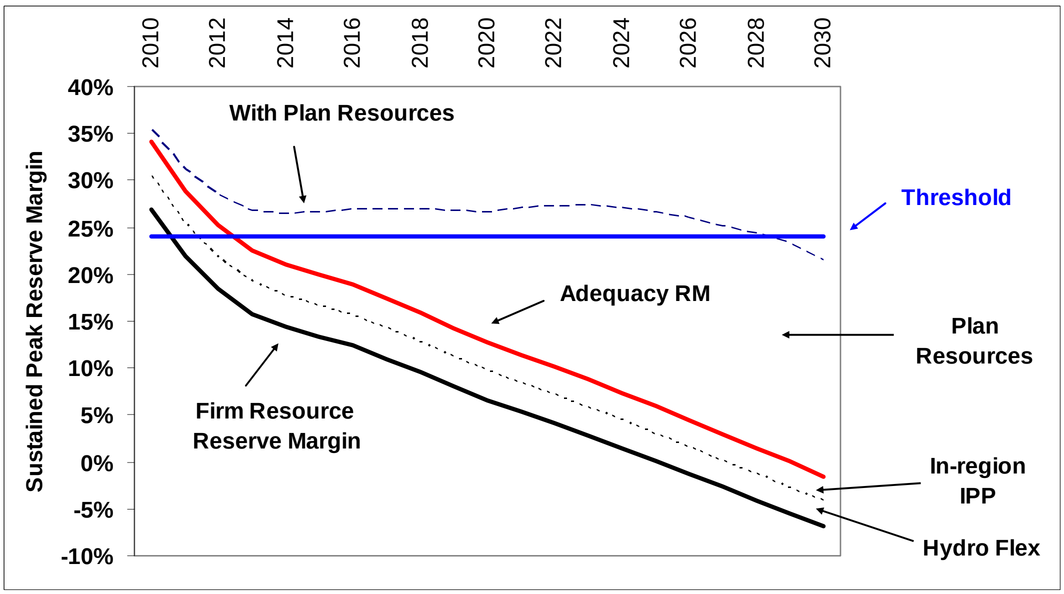


Figure 13-3: July Capacity Adequacy Assessment



Adequate vs. Optimal Power Supply

There has been considerable confusion about the relationship between the resource recommendations in the Council's power plan and the results of the Council's resource adequacy analysis using procedures developed by the Resource Adequacy Forum. The adequacy assessment implies that by acquiring the resources proposed in the power plan, the region will create a large energy surplus by the end of the study horizon (see Figure 13-1). Utility planners have questioned the need for such a surplus.

The adequacy assessment is meant to be an early warning system to alert the region if and when resource development falls dangerously short -- it is not intended to be a resource planning target. Unlike the adequacy assessment, the power plan is intended to provide guidance to regional utilities regarding the types and amounts of resources to acquire. The Council uses sophisticated analytical tools to develop its resource strategy, which is designed to keep costs low and to minimize economic risk. Plan analysis indicates that relying too much on market supplies is not in the best interest of the region. Thus, the plan suggests acquiring firm resources for economic reasons and also as a hedge against potential future carbon polices. Removing non-firm and market supplies from the load/resource balance shown in Figure 13-1 paints a different story, as described below.

Interpreting Load/Resource Balance in the Power Plan

Regional utilities have consistently used the annual average load/resource balance as a quick and simple metric to get an indication of their resource needs. For the region, the load/resource balance reported in PNUCC's NRF provides an aggregate look at utility resource needs. That calculation assumes firm loads and resources, which include critical hydro generation but no market resources. The general takeaway from this simple metric is that when the average annual load is greater than the firm supply, additional resources are likely needed. For a resource "needs" assessment this assumption makes sense. However, once a need is identified, the decision regarding how to fill that need requires a more sophisticated analysis.

While the power plan provides a general indication of the types and quantities of cost effective resources for the region, each utility's situation is unique and may require a different solution. For example, some may not have full access to market supplies (i.e. transmission limitations); others may want to limit their exposure to volatile market prices or may want more control over the resources they rely on. A full integrated resource plan assessment must be made to determine the operational reliability and cost of different resource combinations, to help lay out strategies to mitigate major risks that utilities face (such as dealing with carbon emissions) and to detail the types and quantities of required resources.

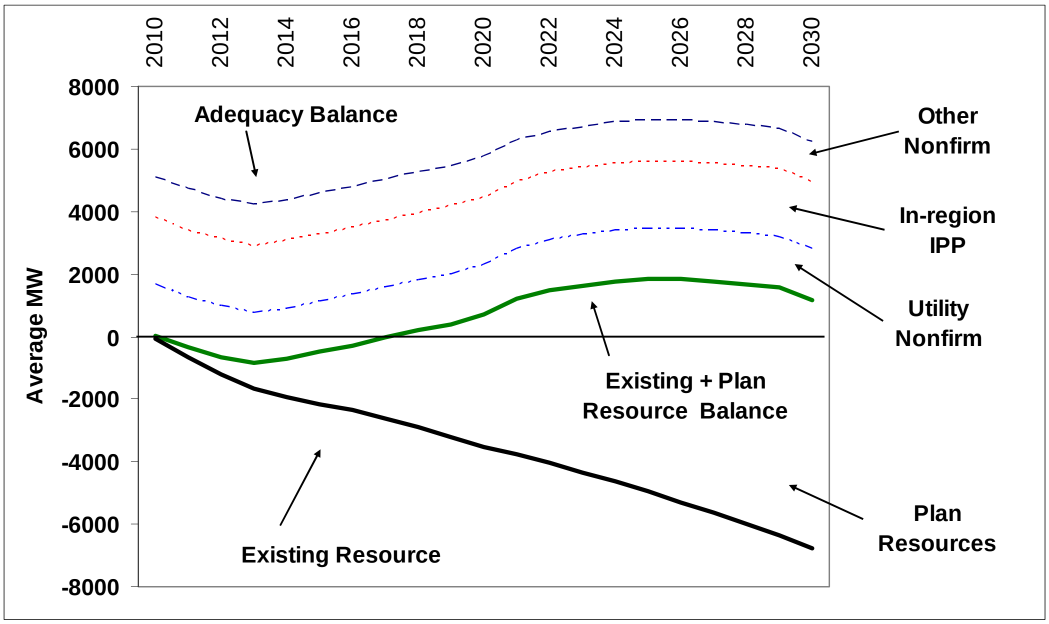
Nonetheless, the load/resource balance still provides a useful guide in assessing the status of the power supply. Figure 13-4 shows the same annual average load/resource balance as in Figure 13-1 but slightly rearranged. In this figure, we begin by counting only firm loads and existing firm resources. That assessment, illustrated in Figure 13-4 as the curve labeled "Firm Balance," indicates that the region currently is in approximate firm load/resource balance and becomes quite deficit by 2030 -- thus indicating a resource need. Adding new resources derived from the Council's plan raises the balance to positive values in later years but leaves the region somewhat deficit during the first 5 year period (solid green line). This small deficit in the near term is acceptable from an adequacy point of view because the amount of non-firm resources required to fill gap in the first 5 years is a fraction of the available market supply.

One source of non-firm generation comes from existing regional firm resources that are not expected to be fully dispatched. For example, a utility may have a simple cycle combustion turbine that it intends to use for peaking purposes only. The firm part of this resource may only be 5 percent of its availability but the other 95 percent should be available during periods of unexpectedly high demand. The area in Figure 13-4 labeled "Utility Nonfirm" represents the amount of this type of non-firm regional resource (dashed blue line). On average this value is about 1,600 average megawatts.

Another source of non-firm generation comes from uncommitted independent power producers in the region, which is labeled in Figure 13-4 as "In-region IPP" (red dashed line). All uncommitted IPP generation is assumed to be available for Northwest use during winter but only 1,000 average megawatts is assumed to be available in the summer (because of competition with the Southwest). On an annual average basis this amounts to 2,156 average megawatts.

Finally, there remains the out-of-region market supply and availability of non-firm hydroelectric generation. A loss-of-load probability analysis is used to assess how much the region should rely on these resources. That amount is reflected in the area labeled "Other Nonfirm" in Figure 13-4 and on average is 1,300 average megawatts. Putting all these pieces together yields the load/resource balance used for an adequacy assessment, which is labeled "Adequacy Balance" in Figure 13-4 (top line).

Figure 13-4: Energy Load/Resource Balance



The adequacy load/resource balance in Figure 13-4 is 5,180 average megawatts (MWa) in 2010. Subtracting the non-firm contributions results in a near zero load/resource balance for the needs assessment, which is consistent with the NRF value. Looking toward the future, the Council's power plan and utility plans (in aggregate) all indicate a need for new resources. The Council's planning approach, which is similar to methods used by many utilities, indicates that adding lost-opportunity and discretionary conservation is very effective in reducing both long-term cost and economic risk. In addition, the Council's plan includes renewable resources that would be acquired under the renewable resource portfolio standards that have been adopted in three of the four Northwest states.

The resource strategy outlined in the plan can be a useful starting point for utilities in terms of identifying the types and amount of new resources that may be cost effective for them. Of course, each utility's situation is different and may require more or different types of resource to address their own particular needs. For example, the Bonneville Power Administration, which is a balancing authority, must provide reserves to accommodate within-hour balancing operations. This may require that Bonneville acquire additional resources to provide this service.

Assessing Hourly Needs

Although not used as often in the past, capacity load/resource balances (usually computed as reserve margins) are becoming more important for assessing the need for new resources. The combination of rapidly growing summer loads and decreasing summer hydroelectric capability is pushing the region to consider more carefully its peaking needs in summer months. Figure 13-5 and Figure 13-6 show the same sustained peak reserve margin calculations for January and July as in Figures 13-2 and 13-3 but again slightly rearranged. Based on existing firm resources only, the 2010 reserve margins are 23 percent for January and 27 percent for July. Without counting any new or non-firm resources, these reserve margins decline rapidly over the 20-year study horizon. It has not yet been clearly defined what the minimum reserve requirement should be for a firm sustained peak reserve margin calculation. In other regions, a 15 to 17 percent reserve margin is typically used but that is based on a single hour peak requirement in mostly thermal systems.

For adequacy assessments, minimum sustained peak reserve margin thresholds have been estimated using a loss-of-load probability analysis. Those thresholds are 23 percent for January and 24 percent for July. However, these minimum thresholds cannot be compared to the firm reserve margin values because they include contributions from non-firm resources, which are illustrated in Figures 13-5 and 13-6. For winter months, in-region IPP generation is assumed to be fully available at 3,550 megawatts but for summer months that availability is reduced to 1,000 megawatts. Additional hydroelectric generation, in excess of critical period generation, is assumed to be 2,000 megawatts in winter and 1,000 megawatts in summer. Finally, a maximum of 3,000 megawatts of out-of-region supply is assumed for winter but none for summer. Adding the non-firm components and the plan's new resource additions to the firm reserve margin calculation yields 54 percent for January and 35 percent for July, both above the minimum thresholds required for system adequacy.

Figure 13-5: January Sustained Peaking Reserve Margin

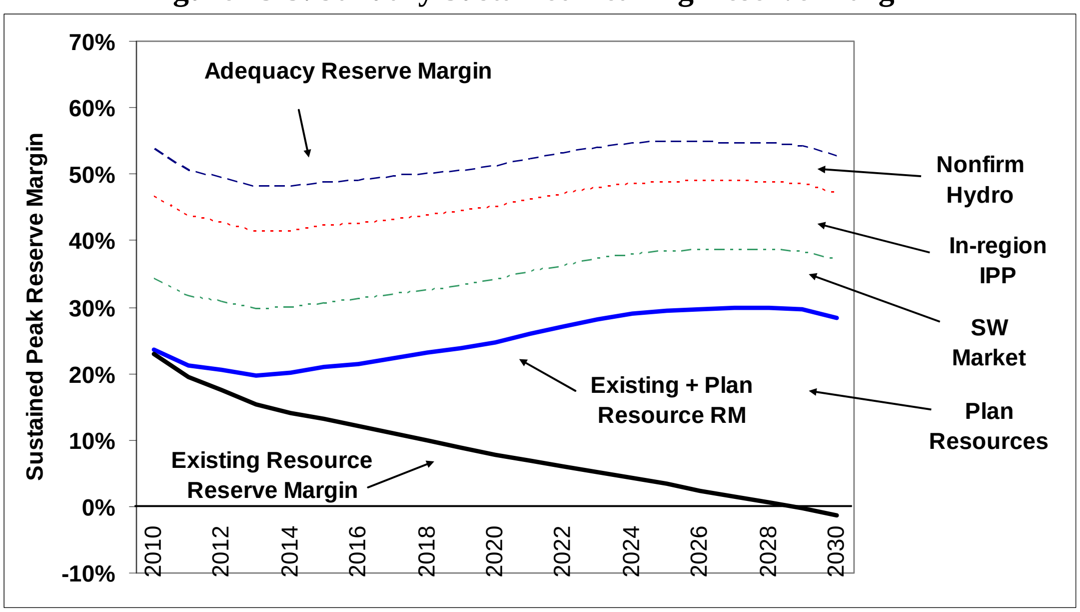
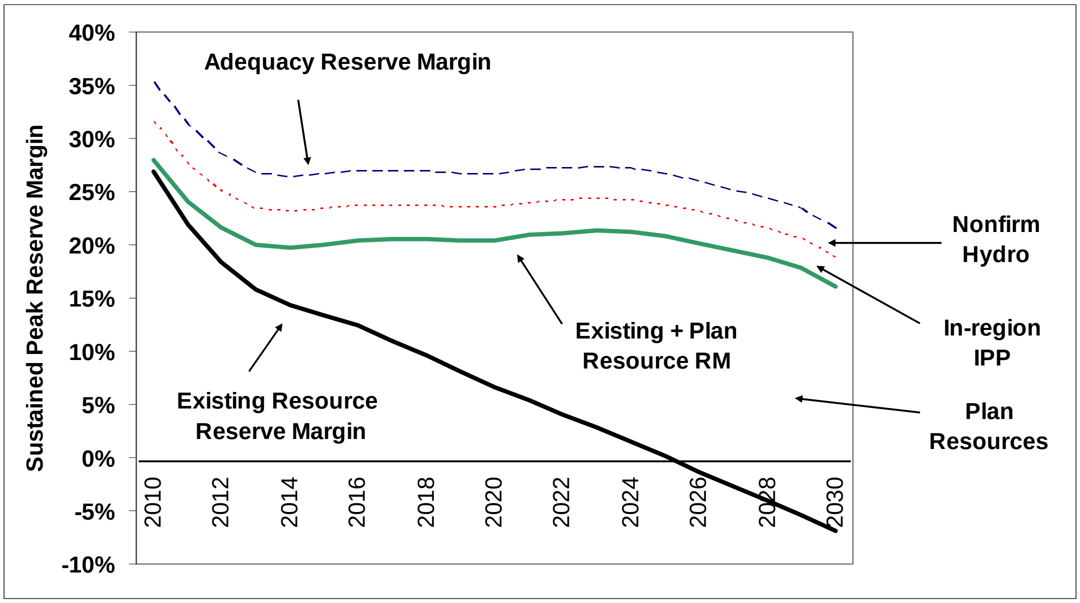


Figure 13-6: July Sustained Peaking Reserve Margin



METHODOLOGY

Analytical Tools

The Council used two complementary analyses to develop the adequacy standard. One addresses physical adequacy – the ability to meet load. The other addresses economic adequacy – avoiding extremely high costs that can result from tight supply conditions. The first analysis uses the GENESYS model, which performs a detailed simulation of the Northwest power system to assess the ability of the system to meet load with variations in future conditions.   The second analysis uses the portfolio model, described in Chapter 8, to explore the cost/risk tradeoff over a large number of possible futures.

The GENESYS model was developed in 1999 to assess the adequacy of the regional power supply.[4] One of its most important features is that it is a probabilistic model, that is, it incorporates future uncertainties into its analysis. Each GENESYS study involves hundreds of simulations of the operation of the power system. Each simulation is performed using different values for uncertain future variables, such as precipitation (which affects the amount of water for hydroelectric generation) and temperature (which affects the demand for electricity).

More precisely, the random (or uncertain) variables modeled in GENESYS are Pacific Northwest streamflows, Pacific Northwest demand, generating-unit forced outages, and variability in wind generation. The variation in streamflow is captured by incorporating the 70-year (1929–1998) Pacific Northwest streamflow record. Uncertainty in demand is captured by using the Council’s short-term (temperature-driven) demand model.

GENESYS does not model long-term demand uncertainty (unrelated to temperature variations in demand) nor does it incorporate any mechanism to add new resources should demand grow more

[4] *Northwest Power Supply Adequacy/Reliability Study Phase 1 Report,* Council Document 2000-4, March, 2000. http://www.nwcouncil.org/library/2000/2000-4.pdf

rapidly than expected. It performs its calculations for a known system configuration and a known long-term demand forecast, which can change over time. In order to assess the physical adequacy of the system over different long-term demand scenarios, the model must be rerun using the new demand and the corresponding new resource additions. The portfolio model deals with long-term demand uncertainty explicitly, as well as with other long-term uncertainties.

Another important feature of GENESYS is that it captures the effects of "hydro flexibility," that is, the ability to draft reservoirs below normal drafting limits during emergencies. Hydro flexibility can be particularly important in helping address potential supply problems during extended periods of high demand from extreme cold events (or heat waves). In order for GENESYS to properly assess the use of this emergency generation, a very detailed hydroelectric-operation simulation algorithm was incorporated into the model. This logic simulates the operation of the hydroelectric system on an hourly basis. The portfolio model has a much more simplistic representation of the hydroelectric system and simulates resource dispatch on a seasonal basis.

The probabilistic assessment of adequacy in GENESYS provides much more useful information to decision makers than a simple deterministic (static) comparison between resources and demand. Besides the expected values for hydroelectric generation and dispatched hours for thermal resources, the model also provides the distribution (or range) of operations for each resource. It also includes situations when the power supply is not able to meet all of its obligations. These situations are informative because they identify the conditions under which the power supply is inadequate. The frequency, duration, and magnitude of these curtailment events are recorded so that the overall probability of not being able to fully serve load is calculated. This probability, commonly referred to as the loss-of-load probability (LOLP), is the figure of merit provided by GENESYS.

It should be noted that in determining the LOLP, an assumption is made in GENESYS that all available resources will be dispatched in economic order to "keep the lights on," no matter what the cost. As such, the LOLP is a physical, rather than economic, metric.

For the Northwest, the Council has defined an adequate system to have an LOLP no greater than 5 percent. This means that of all the simulations run, with uncertain water conditions, temperatures, forced outages, and variable wind, no more than 5 percent had significant curtailments. Such a system faces a maximum 5 percent likelihood that some demand will not be served due to inadequacies in the generation system (not counting potential problems in the transmission network).

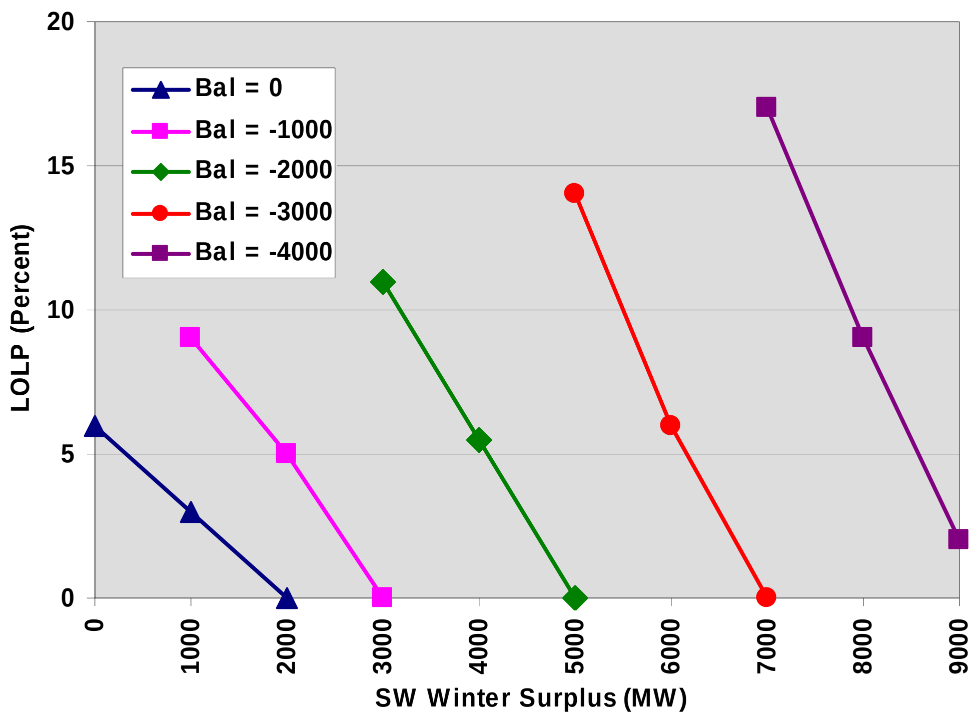
But what constitutes a significant curtailment event? Since the GENESYS model cannot possibly simulate all potentially varying parameters or know precisely every single resource that is available, a threshold is used to screen out inconsequential curtailment events. This threshold is commonly referred to as a "contingency" resource and depicts the amount and characteristics of additional generation available to utilities during emergencies.

Reliance on Market Resources

Assessing power supply adequacy is very sensitive to assumptions regarding market supplies, whether they come from within or outside the region. But how much of the market supply should the region rely on for adequacy? Assuming that no supply is available is probably too conservative, as it will result in greater resource acquisition and be more costly in the long run. And although relying more on market supplies could lower long-term costs, price volatility from year-to-year could be extreme. Therefore, some level in between, calculated with the tradeoff between risk and cost in mind, is more appropriate for planning purposes.

Figure 13-1 illustrates the relationship between the LOLP and available market supply (presented in units of capacity), for different levels of Northwest firm load/resource balance. Generally speaking, the more the market supply, the lower the LOLP will be. For example, consider the case where the region is 2,000 average megawatts deficit on a firm basis (the curve with the diamond-shaped points in Figure 13-1). Assuming that a 5 percent LOLP represents an adequate power supply, the Northwest would be adequate (even though the load/resource balance is negative) if at least 4,000 megawatts of market supply were available. If no market supply were available, the projected LOLP would be on the order of 25 percent -- well over the minimum threshold of 5 percent. Even if the Northwest were in load/resource balance (the far left curve with the circular points), the LOLP would be over 5 percent with no available market supply.

Figure 13-1: Illustrative Example: LOLP as a Function of Available SW Capacity for Different Load/Resource Balance Conditions

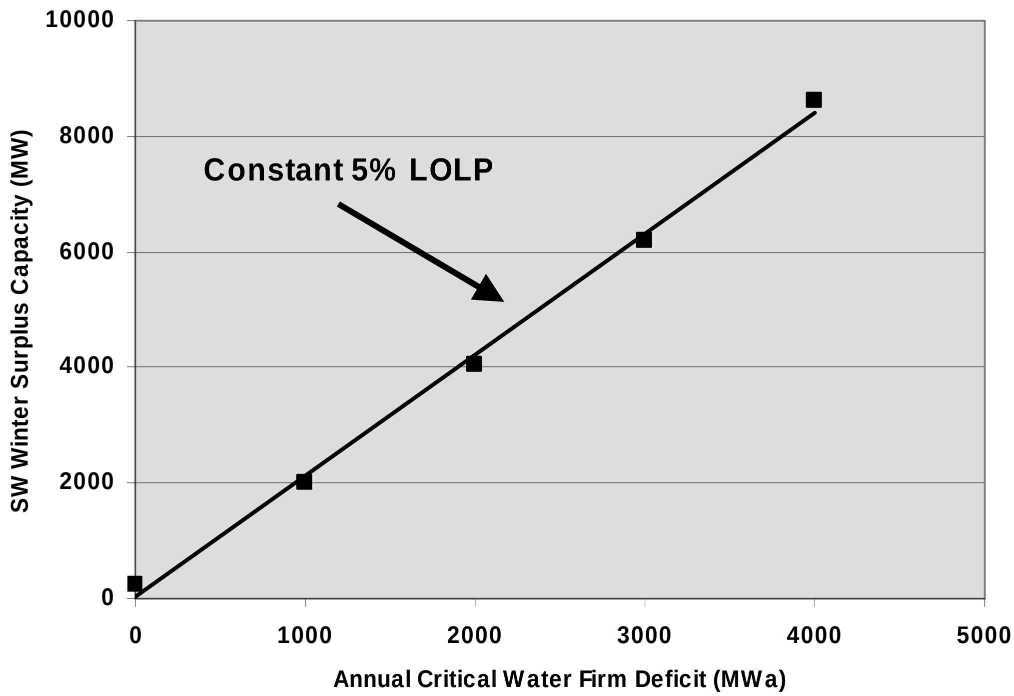


Translating the Adequacy Standard into a Simpler Measure

To make the relationship between the LOLP and market supply a little easier to see, the values in Figure 13-1 for all the points that cross the 5 percent LOLP level are plotted in Figure 13-2. In that figure, every point on the plotted curve represents the same adequacy, namely a 5 percent LOLP. Given a particular load/resource balance in the Northwest (horizontal axis), this graph shows how much market supply (vertical axis) is required to maintain an adequate system.

Again, using the same example, if the region was deficit by 2,000 average megawatts (on a firm basis), it would require about 4,000 megawatts of market supply from the SW surplus in order for the Northwest to maintain a 5 percent LOLP. This does not mean that the region would import 4,000 megawatts, but it does mean that in some hours the full 4,000 megawatts could be imported.

Figure 13-2: Illustrative Example Relationship between SW Surplus Capacity and Load/Resource Balance



The question of how much out-of-region surplus the Northwest should rely on for planning purposes, however, ends up being a policy question. If California goes forward with aggressive adequacy standards, it should mean that California will have ample winter surplus for years to come. However, current and potentially new air quality concerns may limit the operation of surplus resources in California. In addition, the potential of a future carbon tax may diminish their availability to the Northwest. Based on recent analysis, the current (arguably conservative) analysis assumes a 3,000 megawatt supply of out-of-region surplus capacity during winter months and no surplus capacity during summer months.

The in-region market supply is composed of independent power producer (IPP) resources, which sell their output to the highest bidder, whether inside or outside the region. Current estimates show about 3,550 megawatts of such resources in the Northwest. During winter months, assuming that the Southwest region is surplus, all of the IPP market supply should be available for Northwest use. However, during summer months, when Northwest utilities must compete with Southwest utilities for access to IPP generation, only a portion of their generation is assumed to be available for adequacy assessments. An estimate of available summer IPP generation for Northwest use is determined by their access to interregional transmission. IPP resources that have no direct access to interregional transmission are assumed to be available for

Northwest use. Current adequacy assessments assume that 1,000 megawatts of IPP generation is available for summer use. Thus, for capacity assessments, 3,550 megawatts of IPP generation is assumed for winter and 1,000 megawatts are assumed for summer. For energy assessments, 2,200 average megawatts of IPP annual average generation is assumed.

By using the relationship in Figure 13-2 and assuming that 3,000 megawatts of out-of-region surplus capacity is available, regional planners can assess the minimum balance between resources and loads that will yield an adequate supply (5 percent LOLP). Based on current analysis, that minimum for annual energy needs is a 1,300 average-megawatt deficit. In other words, counting only Northwest firm and IPP resources, the region's power supply can be no lower than 1,300 average megawatts less than firm loads in order to maintain an adequate supply. This means that, on average, the region can depend on 1,300 average megawatts from non-firm hydroelectric power and out-of-region supplies. A similar analysis and relationship is used to assess the minimum threshold for hourly needs.

Catfish Creek
National Natural Landmark

Photo of Catfish Creek

IN BRIEF

Catfish Creek is one of the few remaining undisturbed riparian habitats in the western Gulf Coastal Plain biophysiographic province. Located primarily within the Gus Engeling Wildlife Management Area, the site supports several wildlife species that are rare in the state.

Ownership: State, private.

Link to Catfish Creek

DESIGNATION DATE

1983

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Limestone 3 Expansion Project

POWERING TEXAS WITH NRG

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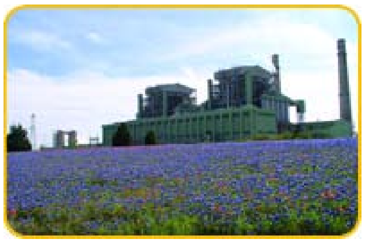
Overview



NRG is planning an expansion of the existing Limestone Electric Generating Station located in Limestone County near Jewett, Texas. An investment in the future of Texas, this expansion will increase generating capacity throughout the region, enhance the availability and reliability of low-cost electric power and reduce the state's dependence on fuel sources—such as natural gas—that are highly susceptible to price volatility. The new unit will be one of the cleanest pulverized coal-fueled electric generating units in North America and will use best available control technology to reduce air emissions and dry cooling to conserve our water resources.

The proposed expansion project would add a third generating unit to the facility and bring approximately 744 megawatts (MW) of low-cost, stable electric generating capacity to the region — enough to supply approximately 600,000 households.

The new unit, unit 3, will be constructed adjacent to existing generating units 1 and 2 so that it will be located on land already in use for electrical generation. Unit 3 will include a new pulverized coal boiler, steam turbine, generator and the necessary additional plant equipment required for power generation and emissions control. The unit construction phase is expected to last approximately four years, employ over 1,000 construction workers, represent an investment of more than $1 billion and will have a positive economic impact in Central Texas, specifically Limestone, Freestone and Leon Counties.

Facility Background

Currently, the Limestone Electric Generating Station is comprised of two lignite/coal-fueled steam units, which generate over 1,700 MW of baseload generating capacity. The facility, which went into operation between 1985 and 1986, operates throughout the year and employs 250 people full time. The Limestone Generating Station is 100 percent owned and operated by NRG Texas, a wholly owned subsidiary of NRG Energy, Inc.

Environmental Improvements

With upwards of $400 million in environmental controls, the new unit will help set the environmental standard for clean pulverized coal-fueled electric generation. Unit 3 will primarily use low sulfur coal as its fuel source and use best available control technology to minimize emissions.

Specifically, it will be equipped with low nitrogen oxides (NOx) burners/over-fire air and selective catalytic reduction for NOx control, flue gas desulfurization (scrubber) for sulfur dioxide (SO2) control, and a fabric filter baghouse for particulate control. Emissions of mercury will be reduced through a combination of controls that will exceed current regulatory requirements.

The project would also use much of the existing infrastructure at Limestone to minimize the amount of space required for the expansion.

To conserve scarce water resources in the area, Limestone 3 will use dry cooling to condense the steam back into water. Dry cooling uses a radiator-like system to allow air to cool the heated water instead of cold water. By using dry cooling, Limestone unit 3's water usage will be approximately one sixth of the water used by a traditional coal plant.

Since 1999, about $75 million has been spent on environmental controls and other equipment that has dramatically reduced emissions from the current units at Limestone. In addition, the

ABOUT THE PROJECTS
Powering California
Powering Connecticut
Powering Delaware
Powering Louisiana
Powering Massachusetts
Powering New York
Powering Texas

Limestone Station is participating in several Department of Energy sponsored programs aimed at developing technology that further reduces emissions from electric generating units.

NRG has donated land adjacent to the Limestone Station as a possible home for the Department of Energy-sponsored FutureGen project.

Economic Benefits

According to an economic impact study conducted by leading economist Dr. M. Ray Perryman, improving the capacity and reliability of the electricity supply will benefit the entire state of Texas, contributing an anticipated $3.1 billion in spending to the local economy. In addition, the expansion project will directly benefit Limestone, Freestone and Leon counties with the creation of approximately 90 permanent high-paying jobs at the plant.

The construction alone will create substantial economical benefits—both direct and indirect—leading to additional business activity within the state. Ongoing operations of the facility will also lead to sizable gains in business activity including approximately 1,400 jobs in the local area and approximately 1,800 jobs in the state.

The Lower Bois d'Arc Creek Reservoir

The Facts You Should Know

More water for our future.

Fannin County will undergo some great changes in the coming years as the population grows as projected. Fannin County's current population of 34,000 is expected to grow to 83,000 within 50 years. Along with new roads, homes and schools, there is a need for more water to sustain this growth. The North Texas Municipal Water District (NTMWD) in partnership with the City of Bonham is building a water treatment plant to serve Bonham.

Within 50 years, the region served by NTMWD, which includes Fannin County, will be home to about 3.5 million people, more than doubling the current population. NTMWD supplied 268 million gallons of water daily in 2006 to the region served. In anticipation of the impending growth, the NTMWD is pursuing several strategies to help water supplies keep pace with the region's population. Water conservation efforts and expansion of the water reuse programs are already underway, but additional sources are still needed to meet rising demand. The Lower Bois d'Arc Creek Reservoir (Reservoir) is one of these new sources.

Learn more about the Lower Bois d'Arc Creek Reservoir and Fannin County.

Fact Sheets

View LBDC Reservoir - Fact Sheet as required by TAC 295.155 (b)(3)
View LBDC Reservoir - Facts You Should Know (revised November 2009)
(Archive Copy) LBDC Reservoir - Facts You Should Know - January 2007
View LBDC Reservoir - Meeting Our Water Needs
View LBDC Reservoir - Positive Economic Growth
View LBDC Reservoir - Conservation and Reuse (revised November 2009)
(Archive Copy) LBDC Reservoir - Conservation and Reuse - January 2007
View LBDC Reservoir - Frequently Asked Questions (revised November 2009)
(Archive Copy) LBDC Reservoir - Frequently Asked Questions - January 2007
View LBDC Reservoir - Land For A New Reservoir

Maps

View NTMWD Service Area
View 2007 State Water Plan For NTMWD
View LBDC Reservoir - General Location Map
View LBDC Reservoir - General With Land Owner Parcels, Tax ID, ISD
View LBDC Reservoir - USGS Topographical Map With Land Owner Parcels
View LBDC Reservoir - USGS Topographical Map Without Land Owner Parcels
View LBDC Reservoir - Aerial With Land Owner Parcels and Tax ID
View LBDC Reservoir - Aerial With Land Owner Parcels
View LBDC Reservoir - Aerial Without Land Owner Parcels
View LBDC Reservoir - 100 Year Floodplain Outline
View LBDC Reservoir - Mitigation Requirements
View LBDC Reservoir - Vegetation and Land Use

505 E. Brown Street
P.O. Box 2408
Wylie TX 75098

View LBDC Reservoir - Wetland Delineation Transects

Graphics

View LBDC Reservoir - Economic Impact

View Water Surface Profile Along Lower Bois d'Arc Creek

Permitting Information

View Click the link to the left to launch the Permitting Information page.

Southern Company Breaks Ground on Biomass Plant

Texas Facility to be Among Nation's Largest

PRNewswire
ATLANTA
(NYSE:SO)

ATLANTA, Nov. 10 /PRNewswire-FirstCall/ -- Southern Power, the Southern Company subsidiary that acquires, builds, manages and owns wholesale generation assets, today took a major step in building one of the nation's largest biomass-fueled projects with a groundbreaking ceremony in Sacul, Texas.

"Southern Company continues to develop and deploy smarter and cleaner energy technologies, including increased energy efficiency, nuclear power, clean coal and renewables," said David Ratcliffe, Southern Company chairman, president and CEO. "This project represents another step in developing a diverse portfolio to meet the nation's growing energy demands."

"This is an exciting time for Southern Power as we expand our presence in the wholesale market and diversify our fuel mix with a renewable resource," said Southern Power President Ronnie Bates. "Southern Power has a reputation of helping its customers meet their energy needs in cost-effective, reliable and environmentally responsible manner and we're pleased to be a partner with Austin Energy on a project that supports their environmental goals."

Southern Power acquired the 100-megawatt project -- the Nacogdoches Generating Facility -- from American Renewables, LLC on Oct. 9, noting at the time that it would move ahead with construction and bring the plant on line in the summer of 2012. The plant's output is committed to Austin Energy in a 20-year agreement that will help the city of Austin, Texas, meet a 30-percent renewable energy goal.

As a Southern Company subsidiary, Southern Power supports the parent company's commitments to corporate responsibility, which include generating affordable and reliable electricity and reducing environmental impact. Southern Company has invested about $6.3 billion in environmental controls and plans to spend an additional $3.1 billion through 2011 to further reduce emissions of nitrogen oxide, sulfur dioxide and mercury.

The company is committed to finding solutions to environmental issues that make technological, environmental, and economic sense.

The Nacogdoches plant is one of two Southern Company biomass projects. The Georgia Public Service Commission in March approved Georgia Power's application to convert its 96 megawatt Plant Mitchell near Albany, Ga., to biomass. Georgia Power is the Atlanta-based Southern Company subsidiary serving 2.25 million customers in 155 of Georgia's 159 counties.

Southern Company is evaluating the feasibility of converting five additional coal plants to biomass as well.

Construction of the Nacogdoches facility will take about 32 months and will generate about 300 construction jobs. Approximately 40 permanent jobs will be created to operate the plant.

Total cost of the project will be between $475 million and $500 million. The plant, which will be built on 165 acres, will be fueled with biomass materials, including forest residue from the surrounding areas, wood processing residues and clean municipal wood waste. The project will require approximately 1 million tons of fuel annually, which is planned to be procured within a 75-mile radius of the project site.

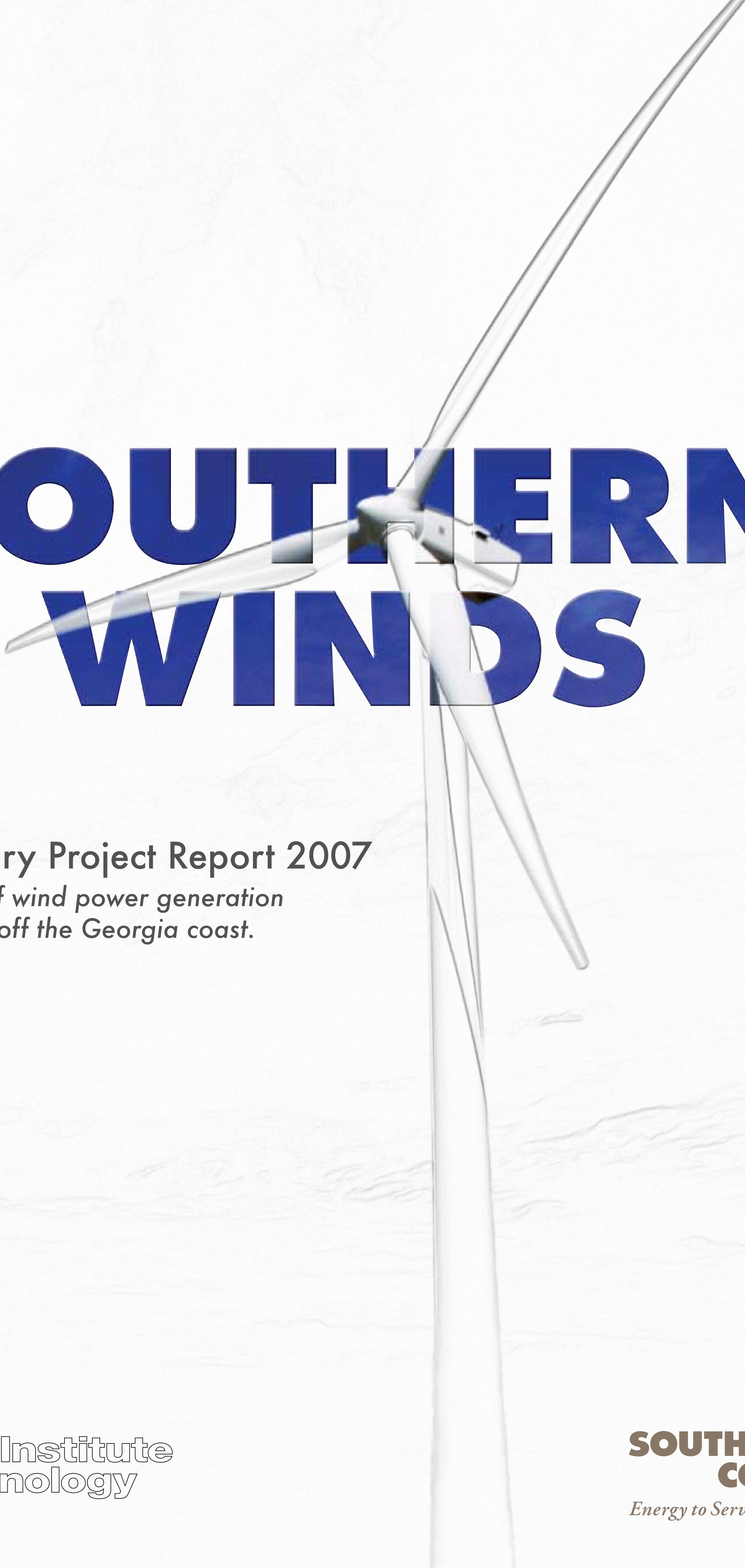
Southern Power is among the largest wholesale energy providers in the Southeast, meeting the electricity needs of municipalities, electric cooperatives and investor-owned utilities. The company owns and operates more than 7,500 megawatts with facilities in Alabama, Florida, Georgia and North Carolina and has an additional 820 megawatts committed to construction in North Carolina and Texas.

With 4.4 million customers and more than 42,000 megawatts of generating capacity, Atlanta-based Southern Company (NYSE: SO) is the premier energy company serving the Southeast. A leading U.S. producer of electricity, Southern Company owns electric utilities in four states and a growing competitive generation company, as well as fiber optics and wireless communications. Southern Company brands are known for excellent customer service, high reliability and retail electric prices that are below the national average. Southern Company is consistently listed among the top U.S. electric service providers in customer satisfaction by the American Customer Satisfaction Index (ACSI). Visit our Web site at www.southerncompany.com.

SOURCE: Southern Company

Web site: http://www.southerncompany.com/

SOUTHERN WINDS



Summary Project Report 2007

A study of wind power generation potential off the Georgia coast.

Georgia Institute of Technology

SOUTHERN COMPANY

Energy to Serve Your World®

The Forest Stewardship Council (FSC) is a series of applied standards for well-managed forestry overseen by an independent body. They set forth principles, criteria and standards for the wood fiber industry that span economic, social and environmental concern. FSC was created to change the dialogue about and the practice of well-managed forestry worldwide.

Printed on FSC-certified paper manufactured with electricity in the form of renewable energy (wind, hydro and biogas), and includes a minimum of 30% post-consumer recovered fiber. The FSC trademark identifies products which contain fiber from well-managed forests certified by SmartWood in accordance with the rules of the Forest Stewardship Council.

Green U Power

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Acknowledgements

Southern Company would like to thank the Georgia Tech Strategic Energy Institute, specifically Susan Stewart, Mary Hallisey Hunt, Sam Shelton, and Roger Webb, for their effort in conducting this work and preparing this document. Southern Company would also like to thank those Georgia Tech, Skidaway Institute of Oceanography and Southern Company employees who participated on the different project teams. In particular, Southern Company appreciates the efforts of the project team leaders, William S. Bulpitt of the Georgia Tech Strategic Energy Institute and Elizabeth F. Philpot of Southern Company, for their work bringing this collaborative endeavor together. The work that was conducted by the teams was critical in generating the project conclusions and recommendations, which will help Southern Company management determine how to proceed.

1 Executive Summary

Traditionally it has been assumed a fact that there is "no wind resource" in the southeastern U.S. except for small isolated areas, such as mountain ridges in Tennessee and North Carolina. Indeed, the only onshore wind farm built in the Southeast to date is located on one of these mountain ridge locations.

In 2004, a research team from the Georgia Institute of Technology's Strategic Energy Institute (SEI) began an examination of the wind data available from a Navy platform via the South Atlantic Bight Synoptic Offshore Observational Network (SABSOON) located off the Georgia coast and concluded that there is a "Class 4" wind regime in coastal Georgia waters which may provide enough energy to power an offshore wind farm. A "Class 4" wind has wind speeds that range from 15.7 – 16.8 mph or 7.0 – 7.5 m/s. In 2005, SEI and Southern Company decided to work together to determine the technical and economic feasibility of locating an offshore wind farm in this area.

The project included a more detailed review of wind data, siting options and issues, regulatory issues, and the technology. An economic analysis was also conducted as a part of this project. This report is a summary of the findings from this project.

In general, it was concluded at the end of this project that:

- Despite the large amount of historical wind resource data available, more data in the exact location of a proposed wind farm would be required. Wind turbine vendors prefer wind data collected within the footprint of the selected site and at heights comparable to the hub height of an offshore wind turbine prior to providing wind turbine costs.

- As authorized in the Energy Policy Act of 2005 (EPAct), the Department of Interior Minerals Management Service (MMS) has jurisdiction over alternative energy-related projects on the outer continental shelf, including wind power developments. MMS has been authorized to complete a rulemaking process outlining the permitting requirements for such projects. Until these regulations are finalized, only limited activities toward the development of an offshore wind farm in federal waters can be conducted. The permitting process is anticipated to be complete by fall of 2008.

- There are currently only three equipment vendors in the marketplace manufacturing offshore wind turbines. Much of the manufacturing is taking place in Europe and due to the high demand for such turbines most of the manufacturers are "sold out" until 2008.

- The current commercially available offshore wind turbines are not built to withstand major hurricanes above a Category 3 or a 1-minute sustained wind speed of 124 mph.

- Coastal Georgia waters include large areas with good wind resources in shallow water that have the potential for wind farm development. Also, much of the coastline includes undeveloped areas with close proximity to potential landfall sites for transmission grid access.

- The available wind data indicates that a wind farm located offshore in Georgia would likely have an adequate wind speed to support a project, although offshore project costs run approximately 50% – 100% higher than land based systems. Based on today's prices for wind turbines, a commercial size 50 MW to 160 MW offshore wind farm could produce electricity at 12.9 to 8.2 cents/kWh respectively, assuming a 20-year life and regulatory incentives such as a federal production tax credit (PTC) with accelerated depreciation similar to those currently available. A smaller or larger commercial wind farm would increase or decrease, respectively, the cost per kWh because of the economies of scale. Also, the development costs would need to be taken into consideration. The size of an offshore wind farm would not be a significant factor in the overall development costs, but because the permitting process is currently unknown, these costs cannot be fully realized until MMS has outlined the requirements for permitting.

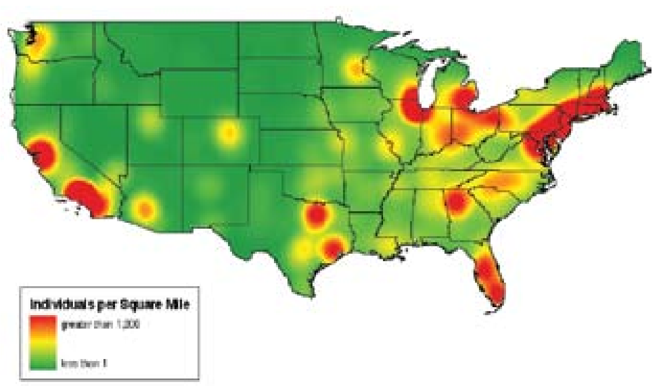
- The benefits to a wind project include the following:
  - Free fuel for the duration of the project with no impacts from increasing fuel prices.
  - Renewable energy credits and/or potential reduced costs from carbon credits/avoided taxes.
  - Significant benefit in public relations, showing Southern Company to have a "proactive" stance with regard to renewable energy.
  - Potential for the creation of a new industry and new job opportunities within Southern Company's service territory.

2 Project Background

Offshore wind power has seen significant maturation in Europe during the 15 years since the first development project was located off the coast of Vindeby, Denmark. The Kyoto Protocol, national initiatives by European Union (EU) countries, and lack of land space for further onshore farms have encouraged the development of the offshore wind industry in Europe. In contrast, the United States market for wind power has been focused solely on land-based facilities, because the U.S. drivers for offshore wind projects have not been as strong as in Europe.

One of the main reasons for exploring the potential for offshore wind development in the U.S. is that the major load centers, as shown in Figure 2.1, are located near the oceans and Great Lakes. Also, windy land is not often found near the load centers. Few people want to live where it is windy, so therefore, current onshore wind farms are usually located far from major load centers in the U.S., and in its present configuration, the grid is not set up for long interstate electric transmission. Some regions of the U.S. have had support from the federal and state governments in the establishment of wind farms, especially land-based, through the passage of Renewable Portfolio Standards (22 states) and the Federal Production Tax Credit (currently expiring 12/2008). Another significant driver of wind power development has been the high cost of electricity in some regions of the country such as the Northeast and in some western states.

Figure 2.1: Major Load Centers in the U.S.[1]



Traditionally, it has been assumed that there is “no wind” in the southeastern U.S. However, after analyzing the offshore data collected from equipment on U.S. Navy platforms located approximately 40 miles off the coast near Savannah, researchers at the Georgia Institute of Technology Strategic Energy Institute (SEI) have found a “Class 4” wind resource off the Georgia coast. A “Class 4” wind has winds speeds ranging from 15.7 – 16.8 mph or 7.0 – 7.5 m/s. Though this wind resource is not as strong in comparison to the winds available in certain offshore areas of Europe and the northeastern U.S., which are primarily “Class 6” or above or 17.9+ mph or 8.0+ m/s, the Georgia resource has been found to be similar to the resource available in the location of at least one European offshore wind farm.

The program under which these analyses were conducted, InfinitEnergy: A Coastal Georgia Partnership for Innovation, was developed and supported by the National Science Foundation’s (NSF) Partnerships for Innovation (PFI) Program (Grant No. 0332613).[2] A critical component of this PFI grant was performing strategic technology assessments on alternative energy options to determine the potential for implementation. Upon the preliminary analysis of wind data obtained for the region offshore of Georgia, it was determined that the wind resource merited further research on the feasibility of locating an offshore wind farm in the area.

SEI approached Southern Company to determine its interest in jointly pursuing a more in-depth study into the feasibility of building and operating a wind farm off the coast of Georgia. Georgia Tech and Southern Company signed a contract in June 2005 to conduct a joint feasibility study for one year. This project has been referred to as *Southern Winds*.

This document serves as a summary version of the final report produced as a result of the *Southern Winds* study to determine the overall feasibility of building a wind farm off the Georgia coast. The full final report contains additional information on the wind resource data, analyses conducted using the data, wind turbine technology, and possible regulatory issues.

[1] *Musial, W., National Renewable Energy Lab, presentation.*

[2] *Grant No. 0332613, any opinions, findings, and conclusions or recommendations expressed in this material are those of the author(s) and do not necessarily reflect the views of the National Science Foundation.*

3 Wind Resource

Skidaway Institute of Oceanography (SkIO), a research unit of the University System of Georgia located 16 miles southeast of Savannah, has been recording meteorological data off the coast of Georgia since June 1999. There are eight platforms spanning the Georgia coast, covering a 69 mile x 30 mile [111 km x 48 km] area or an area of roughly 2,100 square miles [5,400 km^2] on the outer continental shelf located directly off the Georgia coast. Originally, these platforms had been built by the Navy to monitor tactical aircrew training.

In 1999 Skidaway received funding from the National Oceanographic Partnership Program (NOPP) to implement the South Atlantic Bight Synoptic Offshore Observational Network (SABSOON) using the network of existing fixed platforms.[3] Three of these eight platforms, R2, M2R6, and R8, were equipped as a part of SABSOON to gather meteorological and oceanographic data at 6-minute intervals. The data from one of these towers (R2) was used by SEI in its data analysis. Data from the other two towers equipped (M2R6 and R8) was studied but not used in this feasibility study because these towers were located beyond 60 miles from shore. An example of these platforms has been shown in Figure 3.1.

Figure 3.1: SABSOON Tower[4]

Table 3.1: Summary of *Southern Winds* Wind Data Sources

Location	Anemometer Height ft [m]	Distance from Shore mi [km]	Water Depth ft [km]	Data Time Coverage	Coordinates
SABSOON – R2	164 [50]	37 [60]	85 [26]	6/99 - present	31.375 N, 80.567 W
SABSOON – R8	112 [34]	65 [105]	164 [50]	6/03 - present	31.6266 N, 79.9216 W
SABSOON – M2R6	164 [50]	55 [88]	98 [30]	8/04 - present	31.5334 N, 80.2334 W
Savannah Light Tower	108 [32.9]	10 [16]	<66 [20]	5/95 - 11/96	31.95 N, 80.68 W
Gray's Reef Buoy	16 [5]	17 [28]	59 [18]	1988-1990 1990-1992 1997 - present	30.6997 N, 81.100 W 30.7308 N, 81.080 W 31.4022 N, 80.871 W
St. Augustine Buoy	16 [5]	37 [60]	125 [38]	6/02 - present	30.0 N, 80.6 W

[2] *Grant No. 0332613, any opinions, findings, and conclusions or recommendations expressed in this material are those of the author(s) and do not necessarily reflect the views of the National Science Foundation.*

[3] *Skidaway Institute of Oceanography, SABSOON: http://www.skio.peachnet.edu/research/sabsoon/.*

[4] *Skidaway Institute of Oceanography, SABSOON, http://www.skio.peachnet.edu/research/sabsoon/images/M2_R8.jpg.*

Figure 3.2: Savannah Light Tower[5]

Another valuable resource for offshore wind data for this study was the former Savannah Light Tower (SLT), as shown in Figure 3.2. This tower had been equipped to take hourly wind data at 108 ft [32.9 m] above the ocean surface from 1985 until the tower was destroyed by a freighter in 1996. This site was approximately 10 miles [16 km] from shore and very close to Tybee Island, which is near one of the sites considered for placement of a potential wind farm.

Figure 3.3: Gray's Reef Buoy[6]

To illustrate the geographical variation of the wind resources along the coast of the southern part of Georgia, two additional sources of data were evaluated. Both sources were collected from five-meter high buoys. One buoy (GR), shown in Figure 3.3, was in the Gray's Reef Marine Sanctuary and located about 17 miles [24 km] off the middle of the Georgia coastline. This location provided hourly data for the time periods 1988-1992 and 1997-present. The second buoy (StA) was located due south of R2 near St. Augustine, Florida. This site provided hourly data for the years 2002-present

The wind data collected at all of the wind data sources had anomalies that were removed before the analysis was conducted. There were also time periods over which no data recordings occurred. Corrections were made to account for the missing data, and these corrections have been documented.

Figure 3.4 shows the locations of these wind data sources, and Table 3.1 lists the specifics for these data sources.

As shown in Table 3.1, the data from the available data sources was collected at varying heights, and thus, not directly comparable. Because the data from R2 was collected at 164 ft [50 m] above the ocean's surface, this data most closely resembled the wind speeds that would be found at the typical hub heights (approximately 230+ ft [70+ m]) of current commercially available offshore wind turbines. In order to determine the geographic variation in the wind resource, the wind speeds measured at SLT and the buoys were extrapolated using the power law model to wind speeds at a height of 164 ft [50 m] or the height of the R2 tower anemometer. The power law model has been generally used to estimate the wind speed at a specific height by taking into account the wind shear or the amount of turbulence caused by surface conditions such as ocean waves. An estimated power law exponent of 0.1 was used for extrapolation.

Even though the SLT data was extrapolated to represent data collected at a height of 164 ft [50 m] using a wind shear model, a direct chronological comparison was not possible because the time periods of data collection at SLT and R2 did not overlap.

3.A Wind Speeds and Directions

The wind speeds measured at each data location were averaged by month and by year to show seasonal and annual variation, respectively. Averages for the annual and monthly wind speeds were calculated by summing up all of the wind speed recordings and dividing by the total number of recordings for each year and month, respectively.

Figure 3.5 shows the average wind speeds by month for R2. As shown by the figure, the strongest wind velocities (8+ m/s) are associated with the winter months, December through March, and with the peak tropical storm season, September (8.30 m/s). The summer has the lowest wind speeds with the minimum average calculated for August (5.88 m/s). The overall annual average wind speed, 7.36 m/s, is noted by the dotted line in Figure 3.5. The annual averages are fairly consistent with a low in 1999 of 7.01 m/s and a peak in 2004 of 7.73 m/s. The standard deviation shown is +/- 0.268 m/s.

[5] *National Renewable Energy Laboratory, Publication # 40045, http://www.nrel.gov/wind/pdfs/40045.pdf.*

[6] *National Data Buoy Center, Station 41008, http://www.ndbc.noaa.gov/station_page.php?station=41008.*

Figure 3.4: Locations of Data Sources for the *Southern Winds* Data Collection and Analysis

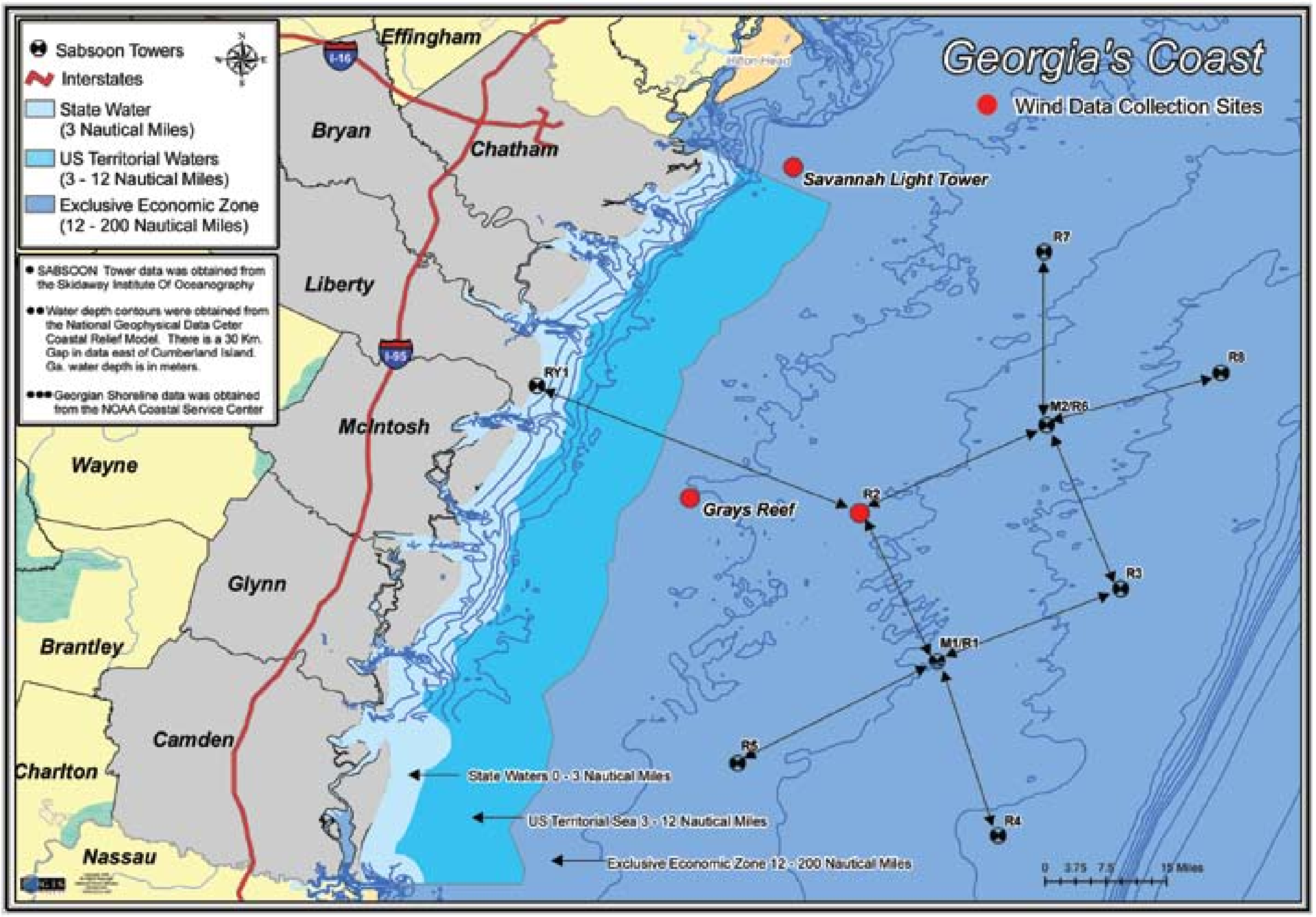


Figure 3.6 and Figure 3.7 show the monthly average and annual average wind speeds, respectively, calculated for the all of data sources extrapolated to a height of 164 ft (50 m). The bars on Figures 3.5 and 3.7 show a confidence level of ±1%. Table 3.2 shows the annual average wind speeds for all of the data sources at both their data collection heights and their extrapolated values for 50-m height. These show that both the monthly averages and the annual averages for each data location are fairly consistent with the R2 trends.

Figure 3.5: R2 Monthly Average Wind Speed at a Height of 164 ft [50 m]

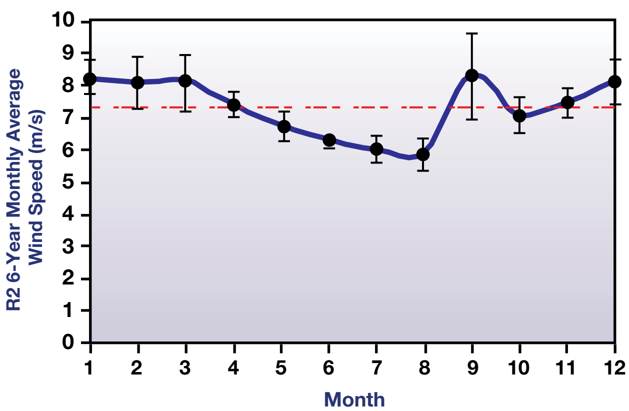


Figure 3.6: Monthly Average Wind Speeds by Data Source at a Height of 164 ft [50 m]

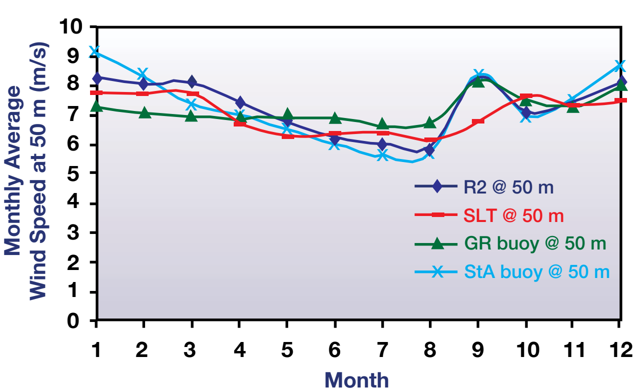
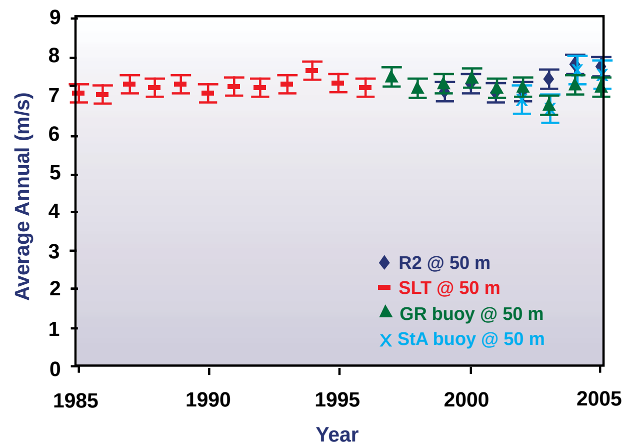


Table 3.2: Summary of the Overall Average Wind Speeds

Location	Height (m)	Wind Speed (m/s)	Extrapolated Wind Speed at 50m (m/s)
R2	50	7.36	7.36
SLT	32.9	6.73	7.02
GR	5	5.79	7.29
StA	5	5.66	7.12

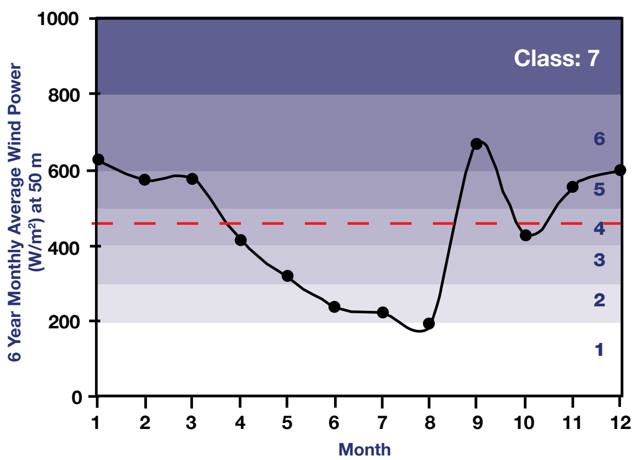
Figure 3.7: Annual Average Wind Speeds at a Height of 164 ft [50 m]



In determining a site's wind power resource, it is standard to calculate the average annual power density. The power density is then used to classify the resource into wind power classes. A filter had been used to remove wind speeds above a specified limit in calculating average power densities. The National Renewable Energy Laboratory (NREL) has recommended this limit should be 25 m/s, which is the typical cut-out speed for wind turbines. Using this limit in the filter, 0.063% of the R2 data had been excluded before the analysis. By restricting the wind power densities to occurrences below this limit, a more realistic value of the wind resource is obtained. Figure 3.8 shows the average monthly power density and its respective wind class determined from the R2 data. There is a significant seasonal variation in wind power density, with the strongest in the fall and winter months and the weakest in the summer months. The dotted line on the chart represents an average annual power density of 460 W/m^2. The area above the dotted line indicates a "good" Class 4 or better wind. This is based on the wind power density classes used by NREL.[8]

[8] *National Renewable Energy Laboratory, Wind, Dynamic Maps, GIS Data, and Analysis Tools, Classes of Wind Power Density at 10 m and 50 m, http://www.nrel.gov/gis/wind.html.*

Figure 3.8: R2 Monthly Average Wind Power Density



The direction from which the wind blew was recorded on R2, SLT, and GR over the same time period as the wind speeds. The dominant wind directions were from the northeast and south by southwest with secondary effects from the northwest and west. However, the wind power density was the strongest from the northeast and northwest with secondary effects from the south by southwest. The 13-year average wind direction frequencies and power densities by direction from GR buoy data showed that winds from the northeast provided the most power, even though the most prevalent wind direction was from the south. This agreed with the results found from the SLT data except that most of the winds came from both the northeast and the south.

Figure 3.9: R2 6-Year Average Wind Speeds by Hour of the Day (EST) at a Height of 164 ft [50 m]

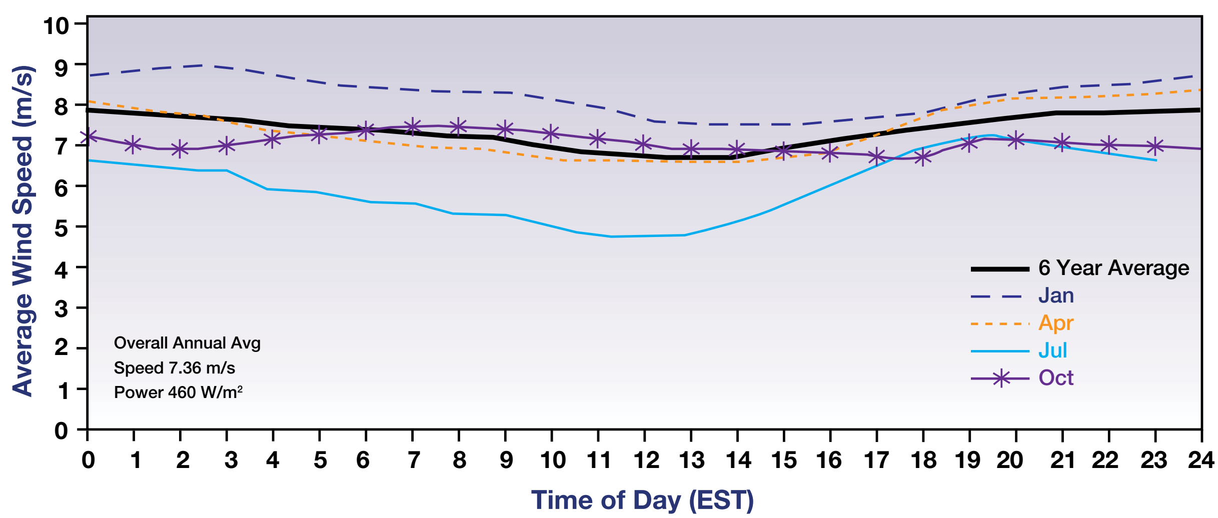
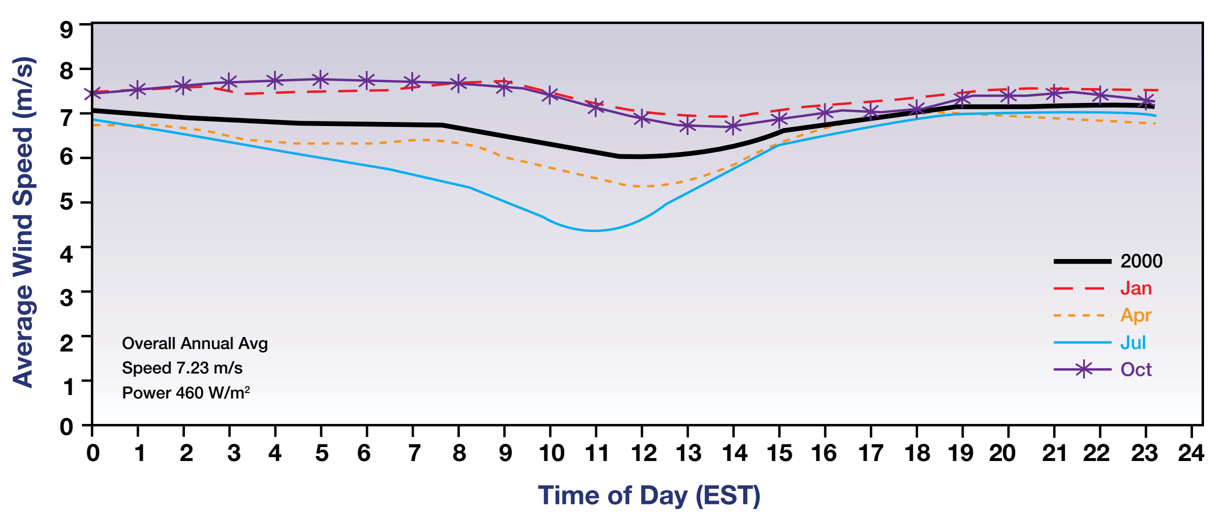


Figure 3.10: SLT 11-Year Average Wind Speeds by Hour of the Day (EST) at a Height of 108 ft [32.9 m]



The wind speed varied with the time of day as shown in Figure 3.9 and Figure 3.10 for R2 and SLT, respectively. For R2, the wind speeds decreased throughout the morning, with the minimum occurring between 12–2 p.m., and the wind speeds increased throughout the evening until approximately midnight. This trend was found to be fairly consistent during the different seasons. As found from earlier analyses, the summer months experienced lower wind speeds while the winter months had higher wind speeds. The spring and fall months experienced wind speeds generally closer to the annual average wind speeds.

For SLT, however, the minimum occurred slightly earlier than for R2. It occurred between approximately 11 a.m. and 1 p.m. Also, the averages from mid-afternoon through early morning were found to be less influenced by seasons. During the morning hours, the fall and winter months experienced higher than average wind speeds, while the spring and summer months had lower than average wind speeds.

3.B Wind Power

The average wind speed measured at a site is a poor indicator of the wind resource. Wind power is a more accurate measure. Wind power is generated when the wind turbine captures the wind and converts the wind's kinetic energy into electricity. Wind power can be calculated using the following equation.

$$P = \frac{1}{2}\rho V^3$$

where ρ is air density (approximately 1.2 kg/m^3), P is wind power, and V is wind speed. This equation shows that wind power is proportional to the cube of the wind speed.

Using the average wind speed in the wind power calculation above ignores how the wind speed varies throughout the year. For example, a calculation of the wind power produced for a year with a fixed average speed of 7 m/s gives a wind power of 205.8 W/m^2. This assumes that the wind blows constantly at that speed throughout the entire year. However, because of the cubic relationship of wind speed with power, it is necessary to incorporate the annual wind speed distribution or actual wind speed data to get a more realistic approximation of the wind power at a location. The wind blowing at speeds higher than the average speed over a time period will generate considerably more power than winds blowing at lower than average speeds over a time period. In fact, by adding up the wind power calculated for each data point throughout the year and taking the average, the resultant wind power is approximately twice (~400 W/m^2) the wind power calculated using just the average wind speed.[9]

Wind power is generated when the wind turbine captures the wind and converts the wind's kinetic energy into mechanical energy or shaft energy from which electricity is generated through a generator. Not all of the wind's kinetic energy is able to be used by the turbine. If all of the kinetic energy is extracted from the wind by the turbine, the air moving through the turbine will come to a standstill behind the turbine and the air would not flow away from the turbine. However, the air moves away from the turbine at a lower wind speed, so only a portion of the kinetic energy from the wind is captured and is converted to mechanical energy or shaft energy. Betz's Law estimates that the maximum amount of energy extracted from the wind and converted to shaft power is 59% of the energy flowing into the turbine.[10] Most modern turbines approach 40% – 45% conversion.

In order to calculate different wind turbine power outputs, wind data measured at the actual hub height of the wind turbine must be used with the turbine vendor's power curves. However, actual wind speed data at this height was not available; therefore, the power law model was used to extrapolate the wind speeds measured at the different heights up to 262 ft [80 m] to allow for estimations of power outputs from specific wind turbines.

In addition, the power curves from selected wind turbines were digitized from vendor brochures. The turbines selected were the GE 3.6sl MW machine, the Siemens 2.3 MW Mk II machine, and the Vestas V90 2.0 MW

[9] *Danish Wind Energy Association, Wind Energy Reference Manual, Part 1: Wind Energy Concepts, http://www.windpower.org/en/stat/unitsw.htm#anchor1345942, Accessed 10-4-06.*

[10] *Ackermann, T. ed. Wind Power in Power Systems, Wiley, West Sussex, England 2005. p. 527.*

Table 3.3: Wind Turbine Specifications

Vestas V90-2.0 MW	Siemens 2.3 MW MkII	GE 3.6sl MW
• Hub height: 80 m • Rotor Diameter: 90 m • Swept Area: 6362 m² • Operating wind velocities: 3.5-25 m/s • Nominal wind speed: 11.5 m/s	• Hub height: 80 m • Rotor Diameter: 93 m • Swept Area: 6793 m² • Operating wind velocities: 4-25 m/s • Nominal wind speed: 13-14 m/s	• Hub height: 80 m • Rotor Diameter: 104 m • Swept Area: 8495 m² • Operating wind velocities: 3.5-27 m/s • Nominal wind speed: 14 m/s

Figure 3.11: R2 Total Annual Electrical Energy Output Using Three Different Wind Turbine Power Curves

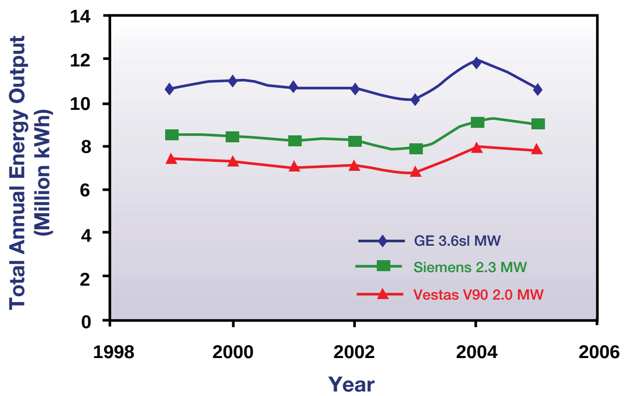
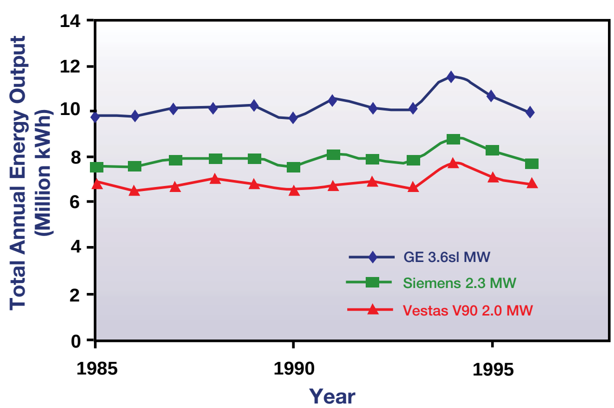


Figure 3.12: SLT Total Annual Electrical Energy Output Using Three Different Wind Turbine Power Curves



machine. Each of these machines has been marinized (weatherized to protect against the marine environment) to be able to withstand the offshore environment. The turbine specifications for these models have been shown in Table 3.3. This information was obtained from the specific turbine manufacturers.[11,12,13] This list does not include all machine options, but shows a range of sizes, technologies and vendors.

Only the wind data measured at R2 and SLT was used to calculate the energy outputs for the three selected machines. These stations were the closest to shore with the highest positioned anemometers, and thus, the results of the energy output analysis had less extrapolation error.

Figure 3.11 and Figure 3.12 show the calculated annual energy output for the selected turbines using R2 and SLT data, respectively.

The resulting overall annual averaged capacity factors (kWh_{actual} per year / kWh_{max} per year) using R2 data and SLT data for the three selected turbines are shown in Table 3.4.

These results alone do not provide enough information to select an optimum turbine with respect to the wind resource. Economic models are needed to maximize power output and minimize cost.

[11] *National Data Buoy Center, Station 41008, http://www.ndbc.noaa.gov/station_page.php?station=41008.*

[12] *Siemens Power Generation, http://www.powergeneration.siemens.com/en/windpower/index.cfm.*

[13] *GE Wind, www.gewind.com.*

Table 3.4: Average Ideal Annual Capacity Factors

Turbine	R2 Average Ideal Annual Capacity Factor	SLT Average Ideal Annual Capacity Factor
GE 3.6 MW	34%	33%
Vestas 2.0 MW	42%	39%
Siemens 2.3 MW	42%	40%

3.C Site-Specific Data

To obtain accurate, site-specific wind data, a meteorological tower should be installed at the selected site. Often for land-based applications the meteorological tower is installed in the exact location where a wind turbine will be placed. Once enough data has been collected, the meteorological tower is taken down, and a wind turbine is installed in the same location, possibly using the same foundation. This may not be the case for offshore applications. The cost for purchasing, installing, and maintaining an offshore wind meteorological tower will be high. Because of these high costs, an offshore meteorological tower may be installed at a site in the selected area where it will be used to determine if the wind resource is good enough for wind farm installation prior to project development. It also will remain there after project construction to monitor the performance of the wind farm.

In general, the installed meteorological tower needs to be as tall as the anticipated wind turbine hub height and must have anemometers located at three or more different heights so that the wind shear can be determined. The wind data needs to be collected for at least one year and preferably for three years. Only after this data has been obtained will the wind turbine manufacturers give “ballpark” capital and installation costs for constructing an offshore wind farm.

The Energy Policy Act of 2005 has given U.S. Department of Interior Minerals Management Service (MMS) authority over alternative energy activities on the outer continental shelf (OCS). This includes the placement of meteorological towers on the OCS to collect data needed for determining the potential for offshore wind power generation. During discussions, MMS has stated that placement of a meteorological tower in a selected site would resemble “staking a claim” and thus has put a moratorium on the placement of any energy-related structures in federal waters until the rulemaking has been completed. It is anticipated that the rulemaking will be completed by fall of 2008. However, MMS encourages discussions with agency representatives during the early stages of project planning.

4 Siting

Determining the location, size and footprint, or siting, of power plants has often been a controversial subject. Even back in the days of Thomas Edison, it did not take long for communities and property owners to voice concern about the placement of power plants near residential areas. The siting of wind farms has been no less controversial and has received a significant amount of media coverage, both pro and con, in recent years.

Coastal Georgia waters and the adjacent offshore regions are located in the South Atlantic Bight, as shown in Figure 4.1. A bight is defined as a long, gradual bend or recess in the coastline that forms a large, open bay. This loosely describes the coastal ocean between North Carolina and Florida. It has up to an 87-mile [140 km] wide continental shelf[14] and approximately 3,100 square miles [8,000 km^2] of open water less than 66 ft [20 m] deep (100 miles [160 km] coastline by 31 miles [50 km] out from shore). Beyond this area, there is an open area of water with a depth of up to 98 ft [30 m] that spans an additional 1,900 square miles [4,900 km^2].

In addition, as shown in Figure 4.1, the Georgia coast is dominated by a series of barrier islands, many of which contain salt water marshes. Many of these barrier islands are protected areas, and some are almost totally uninhabited. The areas of greatest population concentration include Wilmington and Tybee Islands in the north at the mouth of the Savannah River, and St. Simons and Jekyll Islands to the south, just north of Florida. The islands with more inhabitants tend to have sandy beaches and are more resort-like in nature. Some of the coastal islands are National Wildlife Refuges, including Wassaw Island, Blackbeard Island, and Wolf Island. Cumberland Island is maintained by the National Park Service and is designated the Cumberland Island National Seashore. The lack of coastal habitation could be a benefit from the perspective of development of a wind farm, since the potential for viewshed objections might be reduced.

The *Southern Winds* project was initially conceived as a "demonstration" project that would be a nominal 10 MW wind farm consisting of 3 – 5 wind turbines in the 2.0 MW – 3.6 MW size range. While this size project could still be developed as a stepping stone to a larger project, the project team, during the course of this study, decided to look at larger wind farms that would improve the economics by using the economies of scale.

In the United Kingdom there have been several projects constructed in the 60 MW range (Scroby Sands, Kentish Flats etc.) and in Denmark two projects have been constructed in the 160 MW range (Nysted and Horns Rev). These two size ranges have thus been considered as potential build out scenarios for a demonstration project.

4.A Potential Wind Farm Locations

The first step in determining potential locations for an offshore wind farm was to select the best landfall sites for the offshore wind farm transmission line. In August 2005, a team composed of both Georgia Tech and Southern Company personnel traveled along the Georgia coast evaluating the coastal Georgia Power substations. Each substation was examined according to its geographic characteristics, substation configuration, and landfall options. The initial consideration was a substation's proximity to the ocean. Any site located further than six miles from the coastline was eliminated from consideration because of additional transmission costs that would be incurred. The substations visited are shown in Figure 4.1.

After the results were compiled, all of the visited substations were ranked according to their potential with regard to supporting an offshore wind facility. It was determined that all of the visited substations would require some additional infrastructure. The Jekyll Island and Tybee Island Georgia Power substations were considered the best options.

In addition to the Georgia Power substation review, a review of the Georgia Transmission Corporation (GTC) coastal substations was conducted. However, all of these substations were located further than six miles from the coastline and thus, were not considered as economically viable options.

After the landfall review, a separate review was conducted of the obstacles such as natural reefs, shipwrecks, flight

[14] *Shepard, Andrew N. "South Atlantic Bight: Bitten by Worsening Problems." NOAA National Undersea Research Center. July 12, 2005: http://oceanexplorer.noaa.gov/explorations/islands01/background/bight/bight.html.*

Figure 4.1: Map of Georgia Coast

paths, and shipping lanes that would potentially impact wind farm placement on the outer continental shelf near each of the two landfall sites deemed the best options for transmission interconnection. Three potential wind farm footprints were identified in the waters adjacent to each of the two landfall sites (refer to Figure 4.2). These potential footprints were sized so that 80 turbines, each with a 295 ft (90 m) rotor diameter, could be positioned in the selected areas with a spacing of eight times the rotor diameter, or 2,363 ft (720 m). This wind farm size and spacing were selected based on the size and spacing used at Horns Rev, an offshore wind farm in Denmark.

4.B Geology

Data collection and analysis would be required to provide information on the location of buried channels which could impact tower footing installation, to provide existing geotechnical information to support footing installation and to identify areas where the seafloor sediments are significantly mobile. For the *Southern Winds* study, existing data was identified and interpreted to characterize seabed structure and stability in the selected areas. Some of this data existed in grey literature reports, whereas other portions of the data were in a raw data format and required interpretation. This was only a preliminary survey prior to the initiation of new data collection for the eventual site. In this survey, existing data was examined to identify what data gaps and geologic hazards existed.

In general, the Georgia coast consists mainly of marine sediments of variable sands, silts, and clays of varying ages and consistencies, overtopped at localized positions by more recent soft alluvial and/or deltaic soils from rivers that enter into the Atlantic Ocean. Information concerning seabed surface and subsurface structure are contained in original sidescan and subbottom surveys of the area. All the raw data from these surveys is archived at the Georgia Southern Applied Coastal Research Laboratory and at the Skidaway Institute of Oceanography (SkIO). There exist two sources of sidescan data that portray the surficial character of the seabed: paper records collected by Dr. Jim Henry over the past 30 years and digital data collected by Dr. Clark Alexander in the last decade.[15]

4.C Wave Conditions

SkIO completed a report on the wave and weather characteristics of the coastal Georgia region using available offshore data as a part of the *Southern Winds* project. In general, SkIO found that the ocean and atmospheric conditions in the study area are influenced by the Gulf Stream, tides, river discharge, wind stress, and air-sea fluxes of heat and moisture from the Gulf Stream. One example found was that river discharge to coastal waters during spring has an embedded weak flow to the south, which is significant in the central South Atlantic Bight (SAB) and can lead to a low salinity zone along the coast. This embedded southward flow easily reverses by prevailing winds from the southwest in spring and summer and is reinforced by northeast winds in autumn.

It is not uncommon to see anomalies in normal water temperatures in the SAB. Intrusions of Gulf Stream waters on the SAB outer continental shelf associated with the meandering of the Stream are common during all seasons. However, detection of these intrusions in the mid-shelf is rare.[16] In the spring of 2003, several of these intrusions were detected as far inshore as the mid-shelf at the SABSOON towers off Georgia and South Carolina (in depths less than 40 m). Although there is no data linking this cold water event to wind conditions in the region during this time period, the occurrence of these intrusions should be noted for possible future review.

Data on wave heights and currents was obtained from observations at two NOAA National Data Buoy Center (NDBC) stations (SLT and GR).[17] The NDBC stations had complete sets of meteorological data plus wave data and air and sea temperature data. To provide information on currents, the NDBC station data was supplemented with older observations from SLT and a current meter station near St. Simons. Information on the locations of these sites and the time periods covered by the data summaries have been tabulated in Table 4.1.

[15] *Raw data from these sources archived at the Georgia Southern Applied Coastal Reseasrch Laboratory and at the Skidaway Institute of Oceanography.*

[16] *Aretxabaleta, A., Edwards, C., Seim, H., Nelson, J., Characterizing Spring and Summer Gulf Stream Water Intrusions in the Mid-Shelf of the South Atlantic Bight, Gordon Research Conference, Coastal Ocean Circulation, New London, NH, 2005. http://seacoos.org/Research%20and%20Technology/Folder.Publications/WaterIntrusion.*

[17] *National Data Buoy Center, http://www.ndbc.noaa.gov.*

Figure 4.2: Proposed Wind Farm Sites

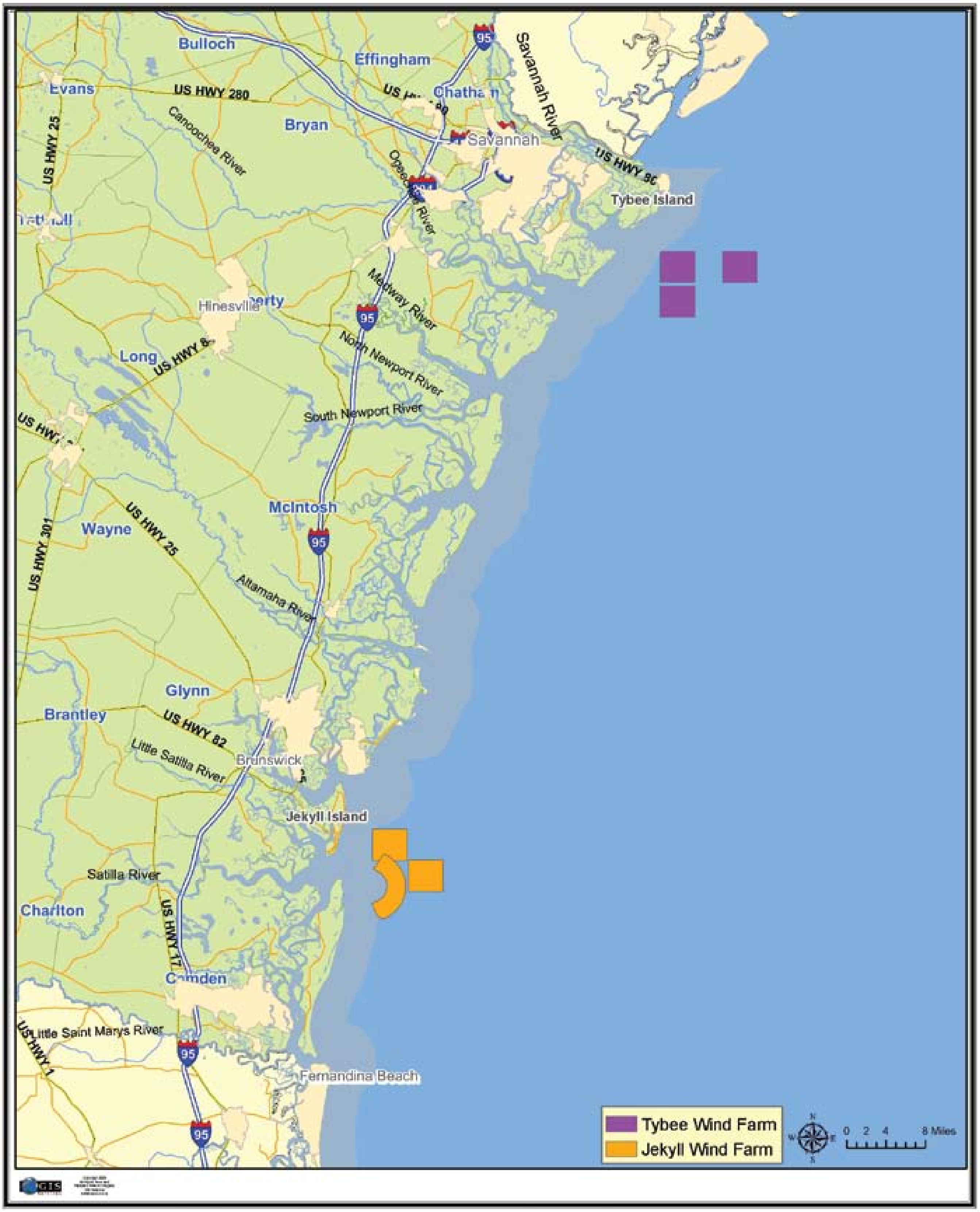


Table 4.1: Data Sources Used

Site	Station	Latitude (N)	Longitude (W)	Depth	Time Period
NORTH SITE					
Winds/waves	SLT	31°57.0'	80°40.8'	16 m	Nov 1985 - Oct 1996
Currents	SLT	31°57.0'	80°40.8'	16 m	Feb - May 1977
Water levels	Ft. Pulaski	32°02.0'	80°54.1'	N/A	Jul 1935 - Dec 2005
SOUTH SITE					
Winds/waves	GR	31°24.1'	80°52.2'	18 m	Jan 1988 - Dec 2005
Currents	FREEF	31°05.9'	81°12.5'	14 m	May - Dec 1985
Water levels	St. Simons	31°07.9'	81°23.8'	N/A	Jul 1999 - Dec 2005

Table 4.2: Summary of Water Levels (m) at the North and South Sites

Parameter	North Site Fort Pulaski, GA	South Site St. Simons Island, GA
Highest Observed Water Level	3.32 (15 Oct 1947)	2.92 (22 Jul 2001)
Mean Higher High Water (MHHW)	2.29	2.19
Mean High Water (MHW)	2.17	2.07
North American Vertical Datum (1988)	1.24	1.28
Mean Sea Level (MSL)	1.17	1.08
Mean Tide Level (MTL)	1.12	1.07
Mean Low Water (MLW)	0.07	0.06
Mean Lower Low Water (MLLW)	0.00	0.00
Lowest Observed Water Level	-1.40 (20 Mar 1936)	-0.86 (8 Mar 2005)
Mean Tide Range	2.11	2.01
Mean Spring Tide Range	2.45	2.35

Water levels and other auxiliary parameters are compared between the sites in Table 4.2. Tidal data is based on a 19-year series (Jan 1983 - Dec 2001) at Fort Pulaski and a 2-year series (Jul 1999 - Jun 2001) at St. Simons. Water levels are based on data from coastal tide gauges at Fort Pulaski and St. Simons.[18] It is assumed that the highest storm surge is included in the highest observed water level at the two sites. Elevations are referenced to Mean Lower Low Water (MLLW).

[18] *National Ocean Service, Fort Pulaski Tide Data, http://tidesandcurrents.noaa.gov/data_menu.shtml?stn=8670870%20Fort%20Pulaski,%20GA&type=Tide%20Data.*

5 Environmental and Regulatory

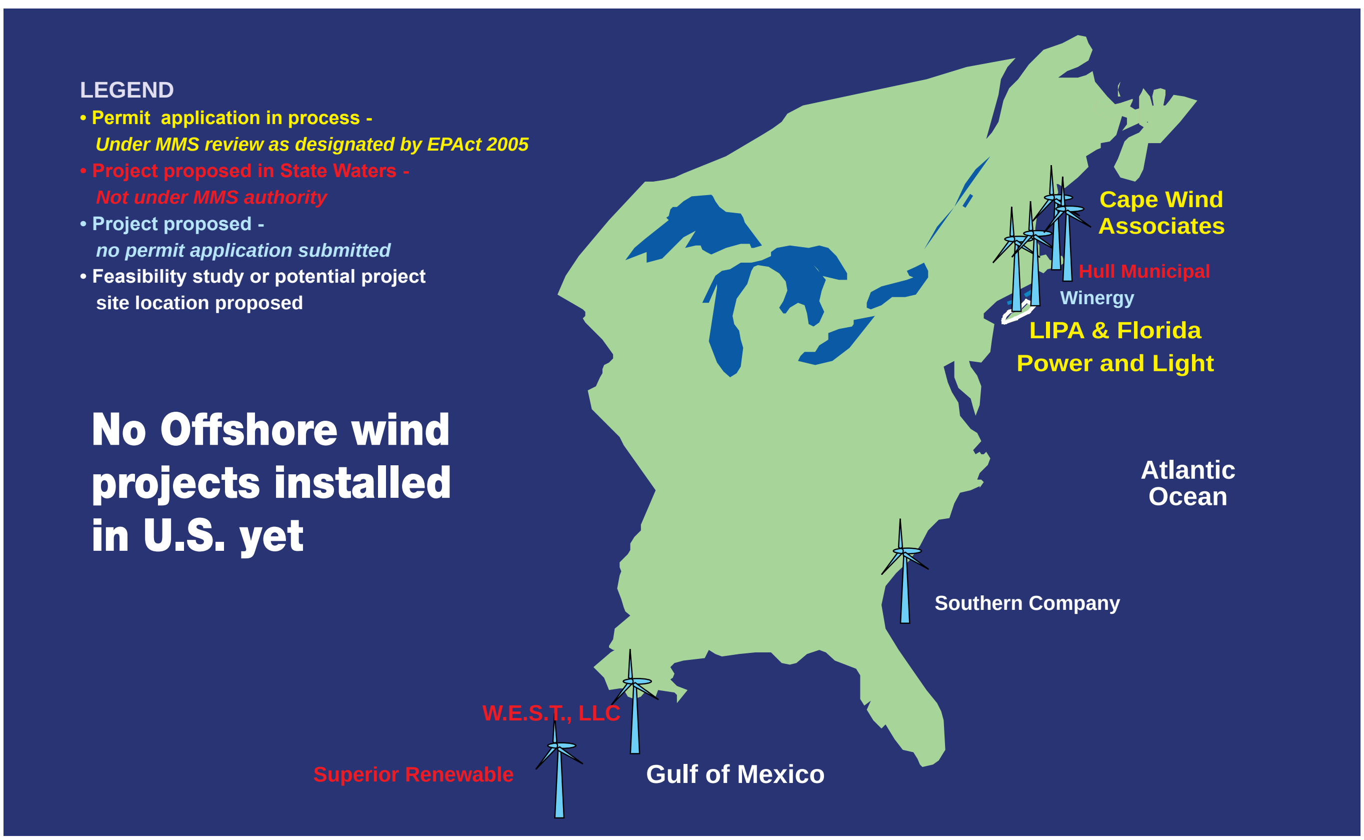
There are currently several offshore developments proposed in the U.S, as shown by Figure 5.1. However, as discussed previously, the Department of the Interior Minerals Management Service (MMS) has been given the authority to regulate alternative energy activities on the outer continental shelf by the Energy Policy Act of 2005 (EPAct). MMS is in the process of developing their rulemaking and does not anticipate its completion until fall of 2008. Until that time, no alternative energy-related activities can occur on the outer continental shelf.

Two proposed projects, Cape Wind and LIPA, were grandfathered under EPAct. These projects had started the permitting process with the U.S. Army Corps of Engineers (USACE) before EPAct was enacted. Also, two Texas offshore wind projects have been proposed. These projects would not fall under MMS authority because they would be located in state waters. State waters in Texas and the panhandle of Florida are unique in that they extend nine nautical miles from the coastline instead of three nautical miles as in all other coastal states.

The Cape Wind project proposed by Energy Management, Inc. (EMI) would consist of 130 large 3.6 MW wind turbine generators located at Horseshoe Shoal in Nantucket Sound in Massachusetts. These turbines would produce up to 450 MW of electricity. The overall size of the wind facility would be approximately 26 square miles [62 km^2]. Electricity would be brought ashore by a cable into Hyannis and interconnected to the utility grid.

EMI embarked on a permitting process with the USACE in the 2000 – 2001 timeframe. On January 30, 2002

Figure 5.1: U.S. Offshore Wind Projects Proposed[19]



[19] *Figure courtesy of Walt Musial, NREL.*

the USACE published a Notice of Intent in the Federal Register for the "Preparation of an Environmental Impact Statement (EIS)" for the proposed Cape Wind Project. The Cape Wind Draft Environmental Impact Statement (EIS) was extensive and represented approximately a $25 million investment.[20]

This project has gained significant attention in New England and polarized many citizens and stakeholder groups into camps for and against the project. Cape Wind has answered all questions and concerns that arose during the public hearing process. However, the entire permit process has been currently slowed by the transition in authority from USACE to MMS.

In 2003 the Long Island Power Authority (LIPA) selected Florida Power and Light (FPL) Energy to install a 140 MW wind facility off the south shore of Long Island, New York, near Jones Beach. The project is conceived to have a nominal capacity of 140 MW consisting of forty 3.6 MW turbines. The nearest turbines to shore would be approximately 3.6 miles [5.8 km] south of Jones Beach. Studies have shown that the average wind speed in this area is 18.5 – 19 mph [8.3 – 8.5 m/s][21] and that the water depth is 40 – 60 feet [12 – 18 m].

FPL Energy submitted an application for the wind farm to USACE on April 26, 2005. Several public meetings and a public comment period were held. Comments have been received, and LIPA/FPL provided USACE a response to the comments on December 5, 2005. As in the case of the Cape Wind project, the LIPA project has been required to restart the permitting process due to the transitions of authority to MMS. A draft EIS from MMS for the LIPA project was scheduled for release in the second quarter of 2007.

5.A Environmental

Georgia's coastal waters are home to a number of unique animals and plant species, some of which have been listed as endangered, threatened, rare, and, otherwise, species of interest. For the purposes of this project, the project team compiled a list of those species currently identified by the Georgia Department of Natural Resources under each category. This information provided a broad baseline summary of species that might be impacted by some aspect of an offshore wind facility. The summary included those species that may be found onshore where potential transmission access may affect habitat during construction and/or follow-up maintenance or those marine or avian species with habitats or migratory pathways that might intersect with potential wind farm site footprints or routes for construction and/or maintenance vehicles. Once a location has been formally identified for potential wind power development, many of the identified species would be removed from the list because of insignificant or no impact on habitat. The current list was designed to address all potentially impacted species along the entire Georgia coastal region in order to make the best case, environmentally sound decisions prior to siting an offshore wind facility.

One specific environmental consideration is that this coastline and its adjacent waters provide one of the primary corridors for many migratory birds.[22] Some potential impediments to migratory birds from an offshore wind farm include collision risk and the possibility of habitat loss. These factors must be incorporated into future environmental assessments.

Another migration of particular interest is that of the North Atlantic right whale. These whales travel along the entire Atlantic coastline. They travel to the waters adjacent to the Georgia-Florida coast for calving in the fall and winter and travel along the Atlantic seaboard to the north Atlantic region for the remainder of the year. Because Georgia's coastal waters are home to the North Atlantic right whale calving grounds, any potential wind farm located in these waters will need to adhere to a construction schedule that does not overlap the calving season between December and March.

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[20] *Conversation with Craig Olmsted, Cape Wind.*

[21] *Long Island's Offshore Wind Energy Development Potential: Phase 2 Siting Assessment.*

[22] *United States Geological Survey, Migration of Birds – Patterns of Migration, http://www.npwrc.usgs.gov/resource/birds/migratio/patterns.htm Accessed 9-15-06.*

In the fall of 2006, a multi-year study, *Danish Offshore Wind: Key Environmental Issues,* was published with a positive evaluation from the International Advisory Panel on Marine Ecology. The study examined the research findings of the Danish environmental monitoring program at two large scale offshore wind farms both pre- and post-construction.[23]

5.B Regulatory

Because the offshore wind industry is new to the U.S. and current regulatory issues are undefined, it is important to understand the basic jurisdictional boundaries and oversight issues that are defined for existing activities in coastal waters. The jurisdictional areas that will be affected by a potential offshore wind farm can be identified in two ways: "by whether they are navigable and by their distance from the shore (usually defined as the mean high tide line). The activities include permanent structures and various effects related to the operation of the projects.[24]" The bodies of water that define U.S. (and Georgia) coastal waters are

- State Waters – Waters extending from shoreline to three nautical miles seaward
- U.S. Territorial Sea – Waters extending from the shoreline seaward to twelve nautical miles (overlap with both state and federal waters)
- Federal Waters – Waters extending from three-mile to two hundred-mile economic exclusive zone boundary

While Europe has expanded its wind industry to offshore locations, the U.S. has proceeded cautiously by providing general guidelines in the form of an overview of federal regulations and a list of governing agencies that would be involved in permits and approvals. While MMS proceeds with the scoping process to provide a consensus on federal regulatory and jurisdictional authority, potential projects are navigating the offshore wind development process with the assistance of legal input and policy guidance based on other offshore industries. Each proposed project must work through significant multi-jurisdictional issues at federal, state, and local levels. The following lists identify governing authorities at the federal and state levels, but until such time that MMS has developed a comprehensive regulatory regime, this information and analysis should serve only as a guide.

FEDERAL GOVERNING AUTHORITIES

Rivers and Harbors Act, Section 10
National Environmental Policy Act (NEPA)
Coastal Zone Management Act
Navigation and Navigable Waters
Navigational Hazard to Air Traffic
Migratory Bird Treaty Act
National Historic Preservation Act
Magnuson-Stevens Fishery Conservation & Management Act
National Marine Sanctuary Act (Title III)
Endangered Species Act
Marine Mammal Protection Act
Submerged Lands Act
Outer Continental Shelf (OCS) Lands Act
Clean Water Act
Estuary Protection Act

Federal Agencies Involved in Offshore Wind Farm Permitting

Because of the overlapping jurisdictions both in geographical location and policy application, numerous federal, state, and local agencies will need to participate in a coordinated manner during the process of permitting an offshore wind facility. Below is a list of federal agencies that will be involved in some aspect of the process based on currently required mandates. It is important to note that this list may be subject to change as a result of the MMS rule-making process scheduled for completion by fall of 2008.

Minerals Management Service (lead agency)
U.S. Army Corps of Engineers
Council on Environmental Quality
National Ocean and Atmospheric Administration
U.S. Coast Guard
U.S. Federal Aviation Administration (Regional Administrator)
Fish and Wildlife Service
Migratory Bird Conservation Commission
Department of the Interior
National Marine Fisheries Service
U.S. Environmental Protection Agency

[23] *DONG Energy, Vattenfall, Danish Energy Authority, and Danish Forest and Nature Agency, Danish Offshore Wind Key Environmental Issues, http://www.ens.dk/graphics/Publikationer/Havvindmoeller/havvindmoellebog_nov_2006_skrm.pdf.*

[24] *Renewable Energy Policy Project, Coastal North Carolina Wind Resource Assessment Project, http://www.repp.org/articles/static/1/binaries/REPP_Offshore_Wind_Approval.pdf (accessed 8-8-06).*

GEORGIA GOVERNING AUTHORITIES

Georgia's coastal region has a unique ecosystem that is home to many rare, threatened and endangered species. It is imperative that any proposed energy generating facility meet a rigorously scrutinized review of impacts prior to development. The Georgia Coastal Management Program addresses issues related to balancing economic development with the natural resources of Georgia's coastal region. The program is administered by the Georgia Department of Natural Resources (DNR), Coastal Resources Division (CRD) and covers an 11 county region in southeast Georgia. Multiple agencies coordinate activities via the CRD under the authority of the Coastal Management Act. This network ensures that all appropriate state laws are addressed in parallel to issues of national concern under Federal Consistency regulations. As noted on the Georgia DNR Web site, there are 33 state laws that fall under the auspices of federal consistency regulations.[25] The acts that are most likely to be triggered with the development of an offshore wind farm include the following;

State of Georgia Primary Governing Authorities

Georgia Coastal Management Act
Coastal Marshlands Protection Act
Shore Protection Act
Georgia Environmental Policy Act
Endangered Wildlife Act of 1973
Game and Fish Code
Georgia Boat Safety Act
Georgia Oil & Gas Deep Drilling Act
Georgia Water Quality Control Act
Groundwater Use Act
Heritage Trust Act of 1975
Protection of Tidewaters Act

Additional legislation has been identified as a part of the Coastal Management Program framework and has been noted in the primary project report. Although it does not deal directly with ocean and coastal management, some aspect of the legislation may be pertinent to a potential offshore wind farm.[26]

State and Local Agencies Involved in Offshore Wind Farm Permitting

Georgia Department of Natural Resources (DNR)

- Coastal Resources Division
- Environmental Protection Division
- Historic Preservation Division
- Parks, Recreation, and Historic Sites Division
- Wildlife Resources Division

Other State and/or Local Agencies

- Department of Community Affairs
- Human Resources
- Georgia Department of Transportation
- Georgia Forestry Commission*
- Georgia Ports Authority
- Jekyll Island Authority*
- Office of the Secretary of State
- Public Service Commission
- Local City and/or County Commissions*

** may have oversight subject to project footprint and landfall site location*

[25] *http://www.gadnr.org/.*

[26] *Georgia Department of Natural Resources, Coastal Resources Division Website, "State Laws Under Federal Consistency." http://crd.dnr.state.ga.us/content/displaycontent.asp?txtDocument=100 (accessed 8-8-06).*

6 Technology

6.A Wind Turbine Technology

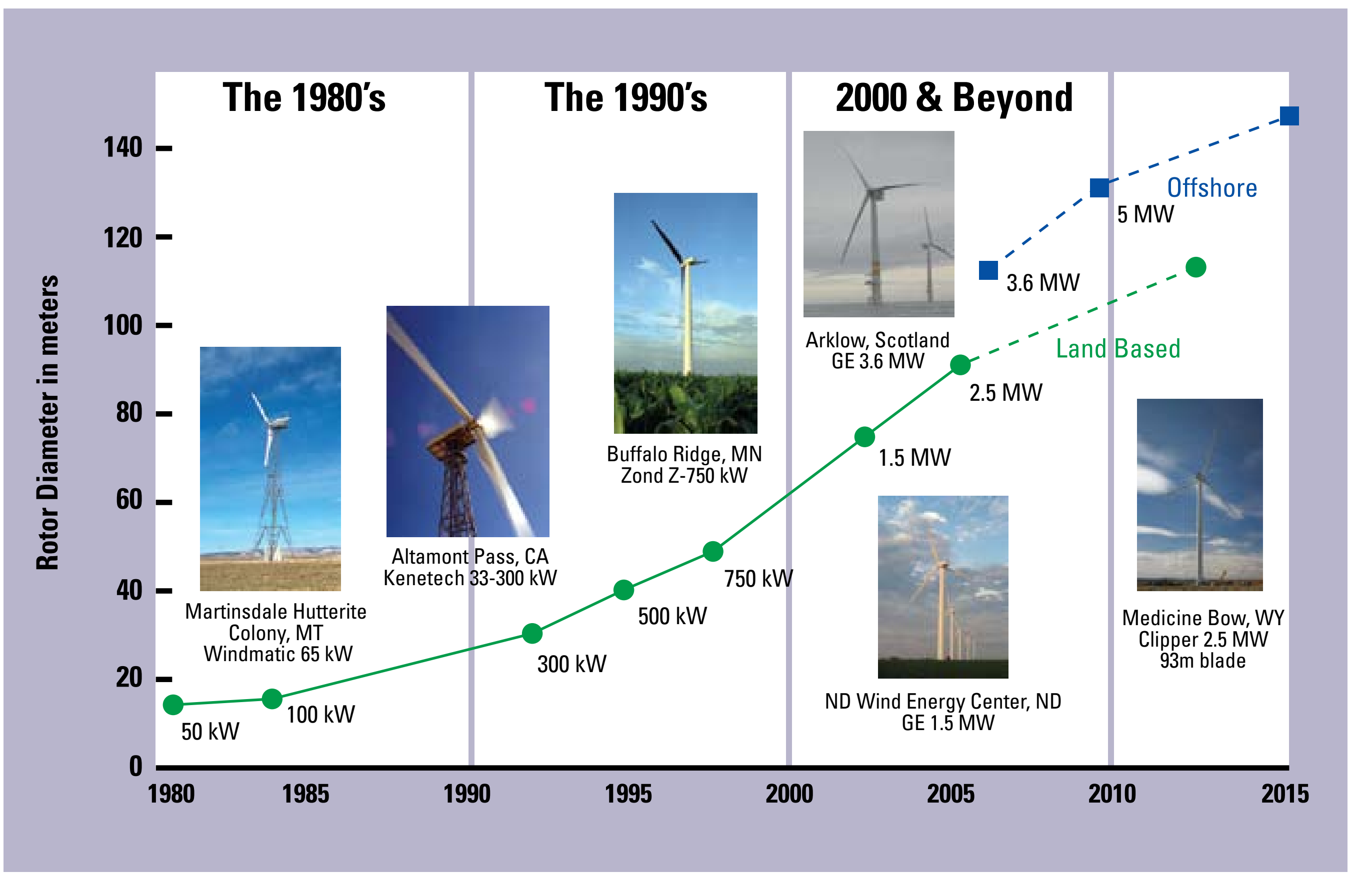
The first "modern" wind farm was located in California in 1981. This resulted because of the incentives put in place by the California Energy Commission. These "modern" wind farms consisted of wind machines that produced 50-100 kW. Over time these machines have evolved into much larger machines as shown in Figure 6.1.

A typical wind turbine machine layout is shown in Figure 6.2. The nacelle is the case of the turbine and contains all of the key components, including the gearbox and generator.

The rotor blades capture the energy from the wind and cause the rotor hub to rotate and deliver power to the generator. It operates in a similar manner as an airplane propeller. The lift experienced on the rotor blade increases with the pitch of the blade up to the point of stall. The blades twist with increasing radius to keep a constant angle of attack. The pitch of the rotor blades changes to extract the most power possible from the prevailing wind, or the blades can be "feathered" to actually stop the rotor rotation. The relatively low speed (12 – 20 rpm) rotor is "geared up" through the main gearbox to reach the high speed required for the generator. This speed will depend on the characteristics of the particular machine and the characteristics of the interconnected electrical grid (50 hertz or 60 hertz). It typically may be 1,800 rpm in U.S. applications.

Turbine generator sizes currently range from 1.5 – 5 MW. In theory, the rotor size can be optimized for a given generator size based on the wind resource. This allows the power output to be maximized and the cost to be minimized. Alternatively, the generator size could be

Figure 6.1: Evolution of Wind Technology[27]



[27] *National Renewable Energy Laboratory, Wind Energy Update, http://www.eere.energy.gov/windandhydro/windpoweringamerica/docs/wpa_update. ppt#442.*

optimized for a given rotor size. It should be noted that the rotor/generator configuration with the highest capacity factor may not be the most economical choice. Also, the type and number of commercially available turbines limits this optimization. A wind developer can only install what the turbine vendors can provide.

This section of the wind turbine historically has been the most troublesome. Gearbox failures have been frequent in many applications. From a maintenance standpoint, it is important to monitor the quality of lubricating oil to detect bearing and gear metal deposits early to be able to determine the presence of any potential gearbox problems.

Figure 6.3 is a more basic schematic drawing of a nacelle. It shows that the rotor hub of the nacelle connects the rotor blades to the low speed shaft.

The gearbox transfers torque from the low speed shaft coming from the rotor hub to the high speed shaft. An induction or asynchronous electrical generator is typically used because the power output can vary greatly in a short period of time.

The electronic controller continuously monitors the wind conditions and the turbine and controls the yaw and pitch mechanisms using the hydraulic system. The controller also stops the turbine in the case of a malfunction, sending an alarm message to the control station.
The anemometer measures the wind speed while the wind vane measures the direction from which the wind is blowing. This information is used to operate the yaw and pitch mechanisms and stops the turbine when the wind is lower or higher than the allowed operating wind speed range. The operating range varies from manufacturer to manufacturer and includes "cut in" and "cut out" speeds.

The yaw mechanism uses electric motors to rotate the nacelle around the tower axis to keep the blades facing into the wind. The yaw is controlled by the electronic controller which receives data from the wind vane.

The cooling unit contains an electrical fan which cools the generator and radiator for cooling the oil in the gearbox.

The actual size of the Megawatt Class wind turbines and their swept areas are large, especially compared to earlier machines. Earlier machines had very small swept areas but had high rpm which made them very noticeable to the public. This aspect is clearly shown in Figure 6.4 and Figure 6.5.

Figure 6.2: Wind Turbine Layout

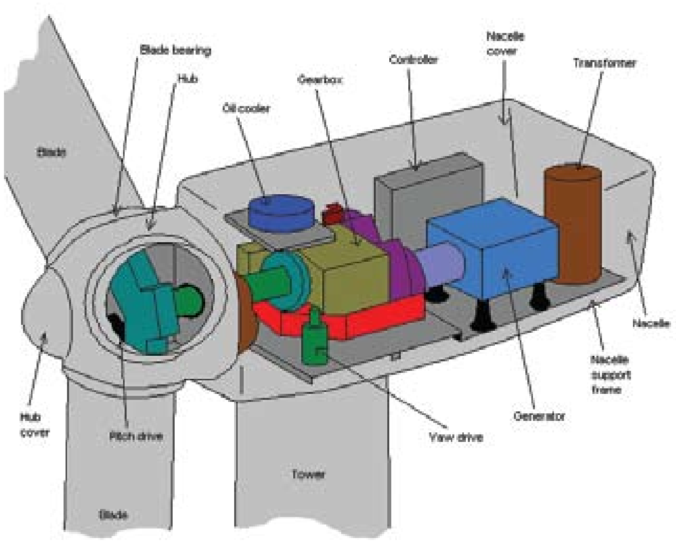


Figure 6.3: Wind Turbine Nacelle

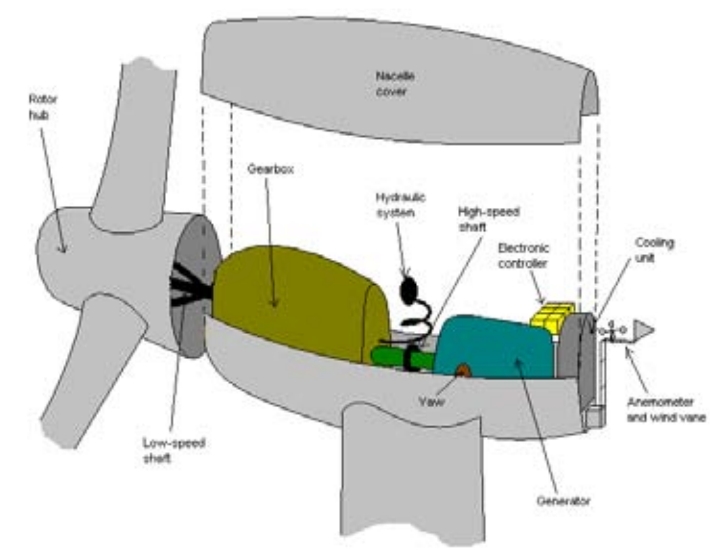
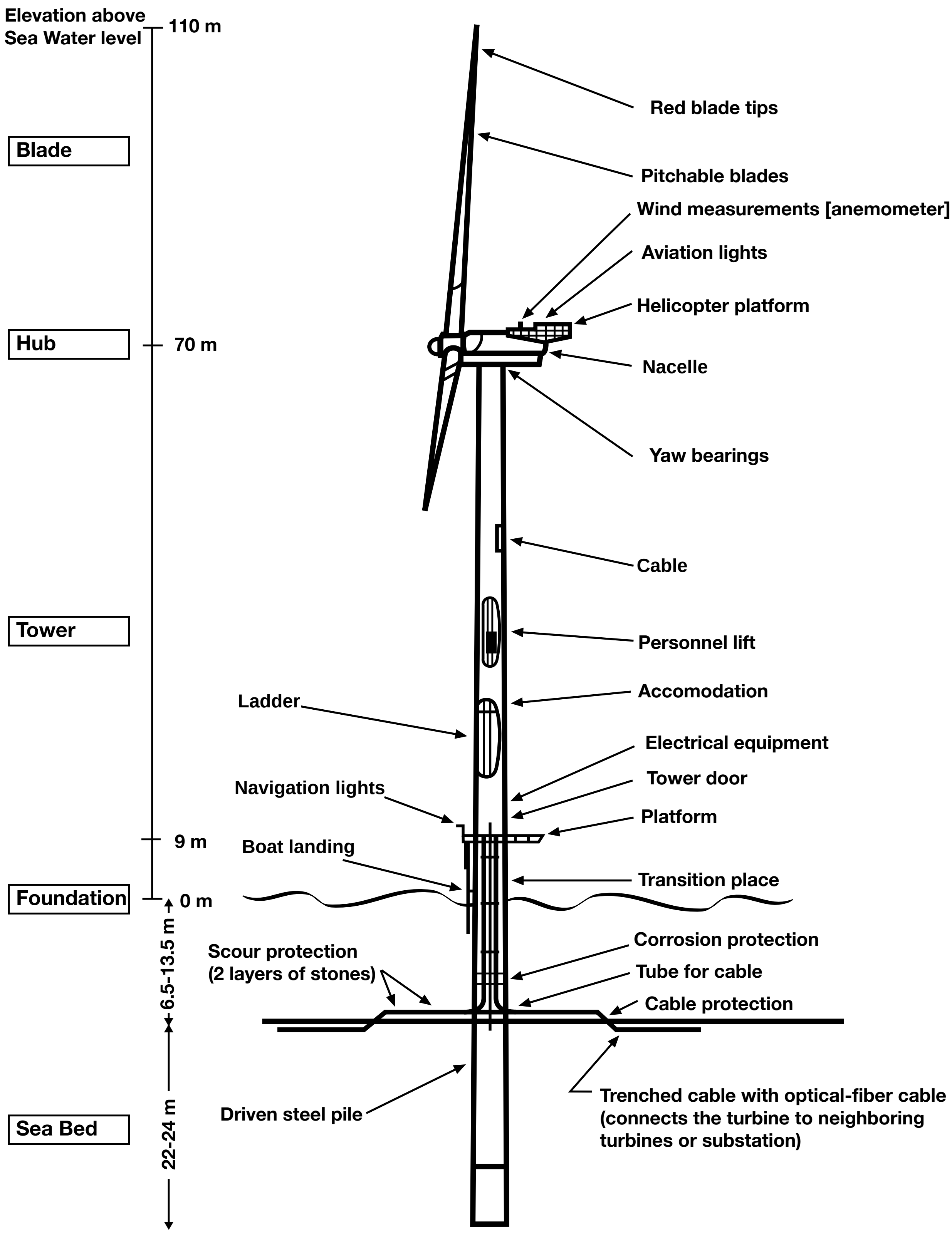


Figure 6.4: Horns Rev Offshore Wind Turbine Schematic



6.B Offshore Wind Vendors

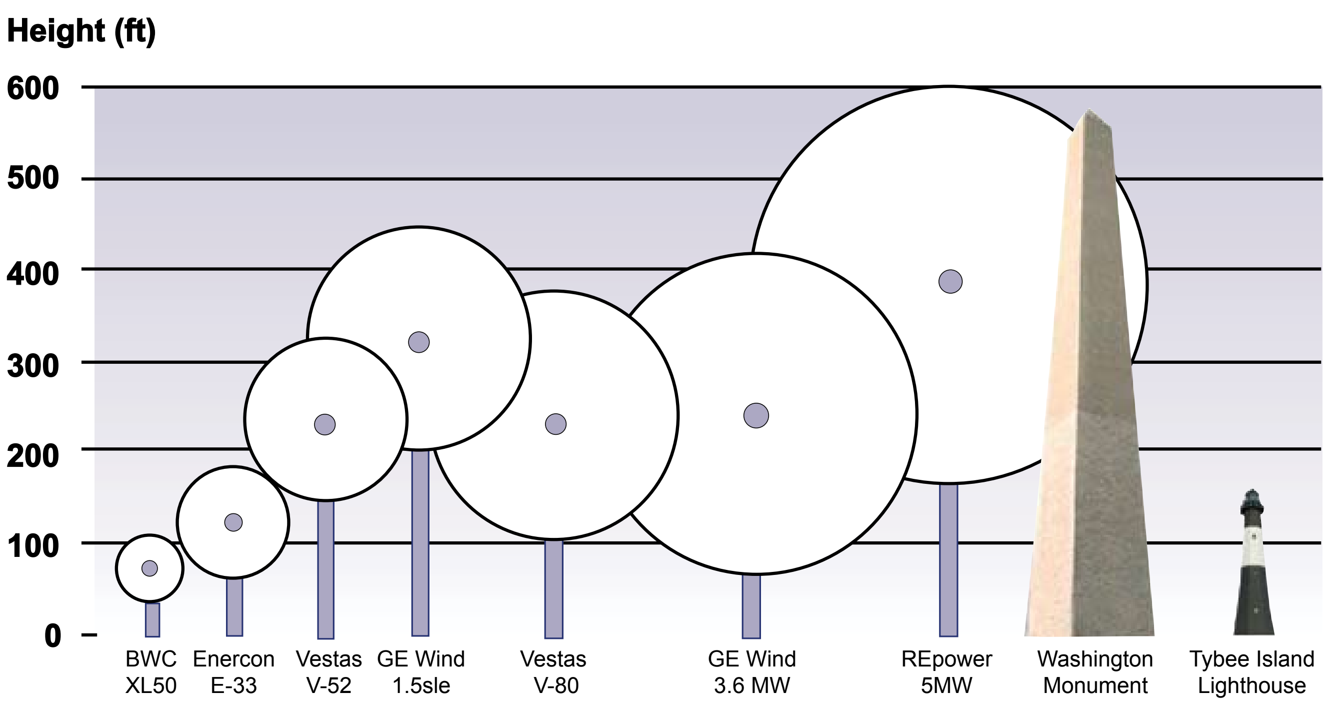
Information was collected from three equipment vendors: Siemens (Bonus), Vestas, and General Electric (GE). These vendors were asked to make presentations on their products. At the time of data collection, these were only three turbine vendors with products available for offshore applications. The other turbine vendors had not yet taken necessary steps to “weatherize” their products to protect them against salt spray and the other harsh aspects of offshore locations.

A review was conducted during the study of the various wind turbine designs with regard to appropriateness for the wind regime, projected capital cost, projected operating and maintenance cost, history of component failures, ease of construction, etc.

Costs for all wind turbine equipment have been going up recently because of the increase in demand and the increase in steel and copper prices. In fact, the price of steel for some of the critical components has doubled over the past two years. Figure 6.6 shows NREL’s guidelines on offshore component costs.

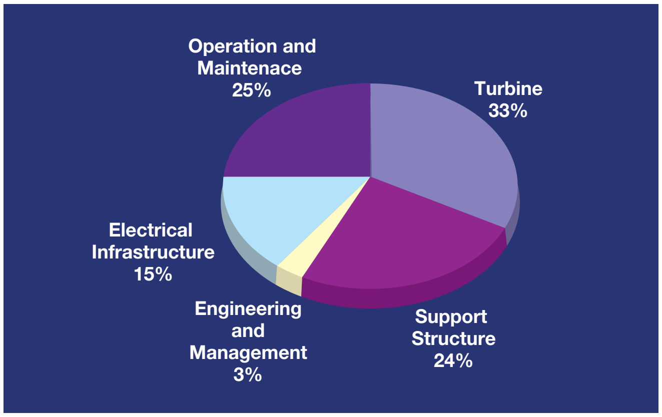
As discussed, the vendors with offshore products have in addition to taken special steps to “marinize” their offshore machines, have developed methods for access to these turbines for maintenance. Because of weather conditions, the turbines at existing wind farm locations can only be accessed by sea 60% - 70% of the time. The vendors have designed and built special boats that allow them to dock next to the turbines and reduce problems gaining access

Figure 6.5: Wind Turbine Size



Capacity	50 kW	330 kW	850 kW	1500 kW	2000 kW	3600 kW	5000 kW		
Rotor diameter	46 ft (14 m)	110 ft (33 m)	171 ft (52 m)	253 ft (77 m)	265 ft (80 m)	341 ft (104 m)	413 ft (126 m)		
Tower height	82 ft (25 m)	144 ft (44 m)	243 ft (74 m)	328 ft (100 m)	230 ft (80m)	243 ft (104m)	394 ft (120 m)	558 ft (170 m)	151 ft (47 m)

Figure 6.6: Offshore Wind Electricity Cost Components[28]



to the turbines from the ocean. However, these special boats cannot overcome access problems associated with "rough" seas. In this situation, wave conditions make personnel access too dangerous. Some turbines have platforms on top of the nacelle that allow helicopter drops for personnel and equipment.

The real time cost data was unobtainable from the vendors. Because of the constrained wind turbine market at this time and the recent rise in the costs of raw materials, especially copper and steel, the vendors contacted would not provide any cost information on their machines without a complete project specification being presented from a developer. This situation has made it difficult to put "real" cost data in the financial models being used to look at the feasibility for an offshore wind farm in Georgia. An estimated cost curve was developed using cost data from the recent European offshore wind farms (developed since 2003). The curve was adjusted to current pricing using a cost number provided by a vendor of $2,700/kW for a 100 MW wind facility. This was a substantial premium above the cost for an onshore project and a substantially higher cost that was reported more than three years ago.

6.C Foundation Systems

Based on studies completed by the Skidaway Institute of Oceanography and the Georgia Tech School of Civil and Environmental Engineering, it was determined that six different foundation systems can be considered as foundation options for the proposed offshore wind turbines. These have been listed below.

1. Large diameter driven open-ended steel pipe (most common used to date).
2. Drilled shaft foundations (used extensively along I-95 for bridge support).
3. Gravity platform, similar to those used for offshore oil platforms.
4. Multi-pod arrangement (e.g., tripod or quad-pod).
5. Suction anchors (new for deep water offshore oil production).
6. Floating foundations using anchored moorings to keep the wind turbines in place.

The most appropriate foundation system will depend upon the actual site-specific stratigraphy and the results from the data collection of geotechnical and geophysical parameters at a particular location. For general loading, consideration must be given to the following: (a) dead loads; (b) wave loading; and (c) wind loading. Components of loading include axial, lateral, moment, and torsion.[29] Depending on the specific situation, additional considerations must be made towards seismic earthquake loading, ship and/or barge impact, scour, snow and ice loading as well as transient loads due to shutdown.[30]

Based on the limited geotechnical information currently available for the proposed offshore wind farm sites, the use of large diameter driven steel open-ended pipe appears to be the best choice for foundation support of the wind turbine towers. The driving will require the mobilization of specialized installation equipment, because these size pilings are not normally utilized along the U.S. eastern coast. Large diesel hammers may be found in the Houston, Texas, area for the driving of the large pipe piles in offshore environments. Driven piles up to 6 ft (2 m) in diameter and to embedded depths of 100 - 150 ft (30 - 45 m) are not uncommon. For very large piles with 10 - 15 ft (3- 4.5 m) diameters, it may be necessary to mobilize special hammer systems from Europe.

[28] *Conversation with Walt Musial, NREL.*

[29] *Lesny, K. and Wieman, J. Design aspects of monopiles in German offshore wind farms. Frontiers in Offshore Geotechnics (Proc. ISFOG, Perth), Taylor & Francis Group, London: 2005. pp.383-390.*

[30] *Senders, M. (2005). Tripods with suction caissons in sand under rapid loading. Frontiers in Offshore Geotechnics (Proc. ISFOG, Perth), Taylor & Francis Group, London: pp. 397-404.*

6.D Wind Integration on the Utility Grid[31]

With most forms of electricity production, the primary fuel is "dispatchable." This means that the fuel can be converted to electrical energy at a rate which is controlled by the operator. Controlling electricity production is important because it allows the electric utility industry to adjust power output to meet demand as it fluctuates throughout the day. Wind power is not dispatchable. Wind is an intermittent resource. It does not blow consistently and it is hard to predict when it will blow. An operator cannot adjust the speed of the wind when more electricity is needed.

Traditional power plants generally fall into one of two categories: base load plants and "peaking" plants. Base load plants provide a steady supply of power that is at, or less than, the lowest demand on the system. Peaking plants fluctuate or adjust output to meet the load that is not met by the base load plants. Due to the non-dispatchable nature of the resource, wind farms do not fit well into either category. It is impossible for a wind farm to provide a steady supply of power, and it is impossible for them to provide extra power "on demand." One advantage of wind farms, however, is that the energy resource is free. Once a plant is built, its operating costs are very low and are more-or-less limited to maintenance. Because of this, the objective of a wind facility is to always capture as much energy as possible. Other power plants, particularly peaking plants, can adjust output to match demand.

Capacity factor is defined as energy produced during a given period (usually a year) divided by the amount that would have been produced if the equipment was driven at capacity the entire time. When purchasing electric generating equipment, it is often desirable to select devices that will operate at a high capacity factor. This is driven by economics. Equipment represents a significant investment, and there is considerable incentive not to purchase more machinery capacity than is absolutely necessary.

Utilities have traditionally avoided relying on intermittent resources such as wind power because of the risks such as large blackouts resulting from not having adequate capacity or generation to meet the demand on their systems. Therefore the question can be raised: "Can wind power replace part of the (conventional) capacity in a (power) system[32]?" Many wind power experts feel that it can despite these issues. In fact, some consider wind power to offer a capacity credit.[33,34,35] The capacity credit of wind power refers to the capability of a wind power plant to increase the reliability of a power system by increasing the availability of more capacity on the system.

To determine the ability of wind power to replace conventional generation, an examination of the wind power potential production during the system's peak load events and during each day should be made using at least several years of data.[36,37] If this examination shows that wind power is consistently available during the peak load times of the power system and/or shows a diurnal pattern of wind power production that matches the daily peak loads for a particular season, wind power can be used to replace part of the conventional capacity in a power system. For example, during the summer, the daily peak loads occur in the afternoon and early evening hours, and during the winter the daily peak loads occur in the early morning hours.

A limited review of the data was conducted looking at the Georgia offshore locations. As shown in Figure 3.9 and Figure 3.10 for the R2 and SLT locations respectively, there is a pronounced increase in average wind speeds in the afternoon hours during the summer months. Meanwhile in the winter months, the average wind speeds are generally constant through the morning hours. A more detailed data analysis would be required to determine the potential of wind power's capacity credit in the region off the Georgia coast.

Another advantage of including wind power in the generation mix of a power system is fuel source diversity. Wind

[31] *Martin, Kirk. Site Specific Optimization of Rotor/Generator Sizing of Wind Turbines. Georgia Institute of Technology MS Thesis, August 2006.*

[32] *Ackermann, T. ed. Wind Power in Power Systems, Wiley, West Sussex, England 2005. p.162.*

[33] *Ackermann, T. ed. Wind Power in Power Systems, Wiley, West Sussex, England 2005. Chapters 8.4.3, 9.2.2, 9.3.1.*

[34] *Munksgaard, J., Pedersen, M.R., Pederson, J.R. 1995. Economic Value of Wind Power, Report 1, Amternes of Kommunernes Forskningsinstitut (AKF) Copenhagen (in Danish).*

[35] *van Wijk, A. 1990. Wind Energy and Electricity Production, PhD Thesis, Utrecht University, Utrecht, The Netherlands.*

[36] *Giebel, G. 2001. On the Benefits of Distributed Generation of Wind Energy in Europe, VDI Verlag, Dusseldorf, available at http://www.drgiebel.de/.thesis.htm, Accessed 10-12-06.*

[37] *Milligan, M. 2000. Modeling Utility-scale Wind Power Plants. Part 2: Capacity Credit, Wind Energy, 2000, 3, 167-206.*

power provides a generation option for the power system that is independent of a fuel cost and transportation fees. It also provides an energy generation option that does not emit any greenhouse gases.

Wind's variability and uncertainty and the performance of the turbines themselves have caused concern among utilities with respect to wind's potential and effects on the electrical system's operation and reliability and the ability to forecast wind's impact on the system. Standards have and are being established so that wind integration does not affect electrical system's operation and reliability. The North American Electric Reliability Council (NERC) and its eight Regional Reliability Organizations, which includes the Southeastern Electric Reliability Council (SERC), have been given authority by U.S. Federal Energy Regulatory Commission (FERC) under the Energy Policy Act of 2005 (EPAct) to set up standards for adding new generation such as wind power generation and the construction or modifications of the transmission and distribution components of the grid necessary to accommodate the generation. Included in these standards are studies that have and are being conducted to examine the response of a wind turbine and a wind farm to recover from disruptions such as a gust of wind and its effects on the electrical system. Computer models are being developed to help complete these studies and to predict the system's behavior.[38]

Formal rules and regulations have begun to be set up in portions of the U.S. for wind generation. FERC has included in its "Standardization of Generator Interconnection Agreements and Procedures for Large Generators" (Order 2003 and subsequent revisions) provisions specifically addressing interconnection issues for wind generation with an aggregate total capacity greater than 20 MW. The order focuses on issues such as low-voltage ride through capability, reactive support capability, and communication.[38]

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[38] Smith, C. Demeo, E., and Smith, S., Integrating Wind Generation Into Utility Systems. North American Windpower, September 2006, Volume 3, Number 8. pp 12 -18.

7 Other Considerations

Wind resources, technological challenges, and geographical parameters are only some of the many aspects that must be considered in order to determine if a site is appropriate for an offshore wind facility. Multiple issues need to be examined prior to site selection to avoid potential roadblocks from local communities, other interested parties, and to ensure compliance with legislative authorities. The following sections represent some of the considerations that have been identified by the Europeans in their offshore wind siting experience and by the Cape Wind and Long Island Wind Park developers in their initial U.S. permitting process work.

7.A Viewsheds

The ability to see a wind farm from shore could be a significant constraint in the ability to permit and locate the facility. Perhaps the least controversial location from a viewshed standpoint would be the placement of the wind farm far enough offshore where it could not be seen from land. Thus, any landowners or other stakeholder concerns about views could be mitigated. This approach, however, might have significant negative financial impacts due to the high cost of running cable from the offshore wind farm to the coastline and to the additional costs associated with maintaining a wind farm so far off shore. A compromise would need to be made taking into account all of these important parameters when locating an offshore wind facility.

To better understand the visual impact of wind farms off the coast of Georgia, photo-simulation studies were conducted using the potential wind farm footprints identified in Section 4.A. Figure 7.1 to Figure 7.6 have been included to illustrate the results of these studies. These figures illustrated the results from the simulations of a "demonstration" wind farm which would consist of only five turbines. The photo-simulation studies consisted of two tasks: photography in the field and post-production assembly of images using Adobe PhotoShop®, and computer-design applications within the AutoDesk® family: AutoCAD® and 3D Studio VIZ. The results were felt to reasonably depict completed wind farms using Vestas V90 2.0 MW turbines with an 80 m hub height as observed from selected shore locations.

7.B Noise and Vibrations

The noise level generated during the construction of monopiles, which would be pile driven into the ocean bottom, would create a substantial and unavoidable short term impact. Though there would be some impact, studies have shown that noise levels would still be below 180 dBL at a distance of 500 meters, which is the threshold set by the National Marine Fisheries Service (NMFS) to prevent injury or harassment to marine mammals, sea turtles and fish. Based on simulated modeling, potential acoustical impacts on fish and marine mammal populations were deemed to be minimal.

In Europe, there have been some tactics used to scare marine animals away from sites before pile driving begins, such as the release of air jets and the creation of other objectionable low level noise before the pile driving is started.

In *Danish Offshore Wind: Key Environmental Issues,* observation data showed some effects on fish behavior related to the cable running between turbines and to shore. The primary change in behavior was an avoidance or attraction to the cable route, depending on species, but the observations noted that these behaviors did not correlate to the strength of the magnetic fields.[39]

7.C Air and Climate

Currently, the only existing offshore wind farms have been located in areas with cold water and predominantly cool weather climates. The South Atlantic Bight experiences a mild climate with both significantly higher water and air temperatures throughout the year. Lightning strikes are also very common in this region of U.S. coastal waters, especially during the summer months. The effect of lightning on a potential wind farm located in this region must be considered and mitigated.

Although the Georgia coast has not been hit by a major hurricane in over 100 years, as shown in Figure 7.7, the possibility of such an occurrence must be factored into the site selection process for an offshore project. At present, the highest wind speed turbine for which manufacturers have certified turbine survival is a 10-minute sustained wind speed of 111 mph. This equates to a 1-minute sustained wind speed of 124 mph, which is a "Category 3" hurricane on the Saffir-Simpson scale.

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[39] *DONG Energy, Vattenfall, Danish Energy Authority, and Danish Forest and Nature Agency, Danish Offshore Wind Key Environmental Issues, http://www.ens.dk/graphics/Publikationer/Havvindmoeller/havvindmoellebog_nov_2006_skrm.pdf, p.13.*

Figure 7.1: Photo-Simulation, Northern Wind Farm Location, 6.8 miles Southeast of Tybee Island

Figure 7.2: Photo-Simulation, Southeastern Wind Farm Location, 10.4 miles Southeast of Tybee Island

Figure 7.3: Photo-Simulation, Eastern Wind Farm Location, 10.2 miles South-Southeast of Tybee Island

Figure 7.4: Photo-Simulation, Eastern Wind Farm Location, 4.1 miles East of Jekyll Island

Figure 7.5: Photo-Simulation, Far Eastern Wind Farm Location, 8.4 miles East of Jekyll Island

Figure 7.6: Photo-Simulation, Arcing Wind Farm Location, 9.4 miles Southeast of Jekyll Island

New developments in hurricane survivability from the equipment vendors and research organizations are being made and need to be monitored continually. Insurability also needs to be established, and the risks of a total loss should be considered.

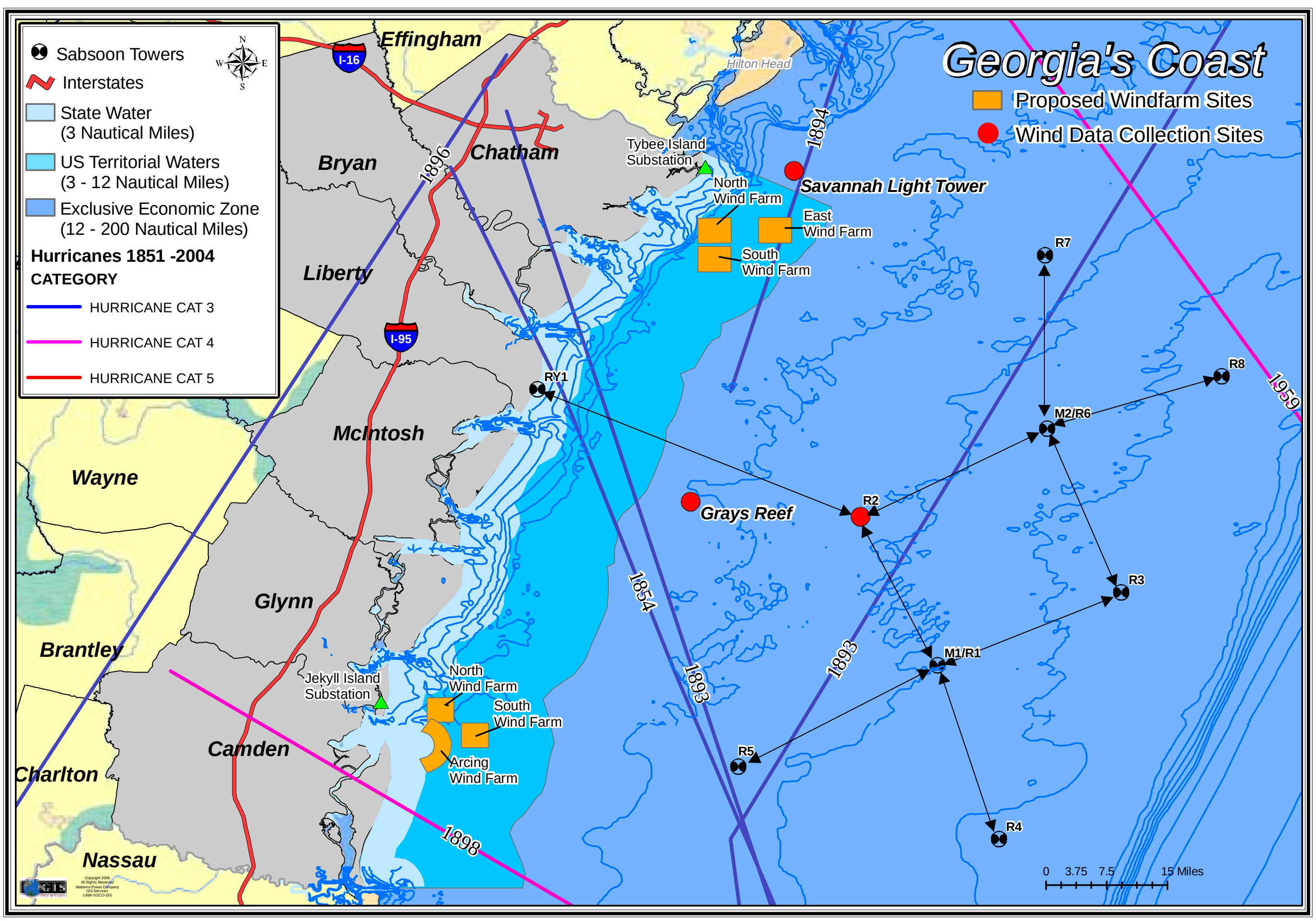
7.D Competing Uses

Georgia's coastal waters are home to significant commercial and recreational activity. Shrimp trawling, sport fishing, reef diving, sailing, and many other activities share this region and must be considered during both the construction, maintenance, and operating phases of an offshore wind development.

In Europe, each country individually handles public access to the area in the vicinity of the offshore wind farms differently. For example, in the UK and Ireland, the public is allowed access to the areas around some of the wind farms, while in Denmark the public is not permitted access.

During the course of this study, several meetings were held with sport fishers, saltwater fishing guides, and personnel with the Georgia Department of Natural Resources (DNR) who were concerned with commercial fishing activities off the Georgia coast. These groups and individuals have been generally in favor of the placement of the wind turbines offshore as they will act as fish attractants much like artificial reefs[40]. The commercial fishing interest was concerned about the offshore cabling because of shrimp trawling activities.

Figure 7.7: Major Hurricanes in Offshore Georgia Region Since 1854



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[40] Conversation with Kathy Knowlton of DNR – April 3, 2006.

8 Project Economics

Before the economics for an offshore wind farm were estimated, the electrical output from three different commercially available marinized wind turbines - GE 3.6sl MW machine, Siemens 2.3 MW MkII machine, and Vestas V90 2.0 MW machine - were calculated and compared. The electrical output estimates were made using digitized power curves and the Savannah Light Tower (SLT) data extrapolated to 80 m using the wind shear power law model. The results have been shown in Table 8.1.

Table 8.1: Estimated Annual Ideal Electrical Output by Machine using SLT Data

Turbine	Estimated Ideal Annual Electrical Output (kWh/yr/machine)
Vestas V90 2.0 MW	6,826,000
Siemens 2.3 MW MkII	7,996,000
GE 3.6sl MW	10,304,000

8.A Cost Model

Very little cost information for offshore wind farms was available from the vendors. One data point of $2,700/kW in-service cost for a 100 MW wind farm built today was given by a vendor during a conversation.[41] Therefore, in order to better represent the economies of scale, the recent European offshore wind experience was assessed.

The European offshore wind farms developed since 2003 with publicly available cost data have been tabulated in Table 8.2. The costs reported in euros or British pounds were converted to U.S. dollars using the currency conversion factors from the year of their contract.[42] These costs were then inflated by 3% per year to 2006 U.S. dollars. The resulting offshore wind farm costs per kW were shown versus farm size in Figure 8.1 with the additional data point, $2,700/kW, obtained from the vendor.[41] A power law curve fit has been shown to fit fairly well for this data set.

The European data points (in 2006 U.S. dollars) shown in Figure 8.1 were increased by 25% in order to incorporate the “$2,700/kW for 100 MW wind farm” number obtained from a vendor and to account for the recent increases in turbine price. Turbine prices have been recently increasing because of constraints on supplies of steel, copper, and carbon fiber and because of the extremely high demand for wind turbines which currently exceeds near-term manufacturing capacity. The results from this adjustment have been shown with the cost curve fit in Figure 8.2. The 25% multiplier used was determined by calculating that the “$2,700/kW for a 100 MW wind farm” represents an approximate 25% increase in offshore wind farm costs.

Even though the Arklow expansion project (520 MW) was listed in Table 8.2, it was not used in the curve fit. The size of this project was significantly larger than the other projects listed in Table 8.2, and large inaccuracies would probably result from extrapolating the calculated curve fit beyond the point of 166 MW. However, it should be noted that the cost curve begins to flatten between 165.6 MW ($2,179.1/kW) and 520 MW ($2,164.7/kW).

Also, no economy of scale on individual machine sizes has been included in this curve fit. Additional vendor cost information for a product line would be needed to determine a wind turbine economy of scale. Information would also be needed on the difference in cost for foundations. Since the larger capacity turbine is larger in physical size, it would require a larger foundation. However, a wind farm made up of larger capacity turbines would require fewer turbines, and thus, fewer foundations, for the same total farm size than a farm with smaller capacity turbines. This added information would improve the overall offshore wind farm economy of scale.

The resulting curve fit equation shown in Figure 8.2 is of a power law type:

$$\$Cost/kW = 14460 \times Size^{-0.3702}$$

This equation was used to analyze the levelized busbar cost or the cost to generate electricity before it enters the transmission grid for a 50 MW, 100 MW, and 160 MW wind farm as discussed in Section 8.C.

8.B Wind Turbine Comparisons

Using the ideal annual electricity production estimated from the SLT data and the three different turbines shown

[41] *Conversation with Vendor, September 2006.*

[42] *Currency Exchange Rates, http://www.x-rates.com.*

Table 8.2: Recent European Experience Offshore Wind Farm Economics

Name	Completed Year	Contract Year	Farm Size	Cost				2006 $	Machine Size	Depth	Distance	Avg Wind Speed
			MW	mill euro	mill British pound	mill $[43]	$/kW	$/kW	MW	m	km	m/s
Horns Rev[44]	2003	2002	160	270		256.5	1603.1	1804.3	2	6 – 12	14 – 20	9.2
North Hoyle[45]	2003	2002	60		80	120	2000.0	2251.0	2	10 – 20	6	
Scroby Sands[46]	2003	2003	60		66.8	123.58	2059.7	2318.2	2	4 – 8	2.3	7.5
Nysted/ Rodsand[44]	2003	2003	165.6	270		256.5	1548.9	1743.3	2.3	5 – 9.5	10	9.1
Barrow-in-Furness[44,47]	2004 - 2005	2004	90	145	100+	185	2055.6	2180.7	3	21 – 23	7	9
Kentish Flats[48]	2005	2004	90		105	194.3	2158.3	2223.1	3	5	8.5	8.7
Egmond[49]	2006	2005	108	200		250	2314.8	2314.8	3	16 – 22	10	
Beatrice (Moray Firth)[50]	under const.	2006	10	41		52.1	5210.2	5210.2	5	40	5.5 – 9.5	
Arklow, expansion[44]	2003 - 2007	2006	520	630		800.1	1538.7	1731.8	3.6	2 – 5	10	

Figure 8.1: European Experience Offshore Wind Farm Costs ($2006)

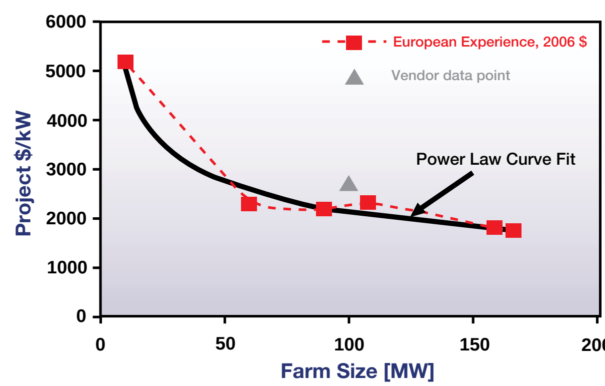
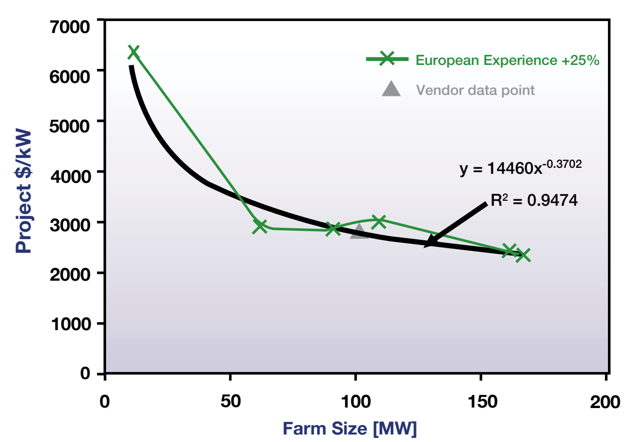


Figure 8.2: European Experience Offshore Wind Farm Costs + 25% Cost Increase ($2006)



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[43] *Currency Exchange Rates, http://www.x-rates.com.*

[44] *Offshore Wind Energy Europe, Windfarms, http://www.offshorewindenergy.org.*

[45] *NPower Renewables, North Hoyle, Site Statistics, http://www.natwindpower.co.uk/northhoyle/statistics.asp.*

[46] *Scroby Sands Annual Report, 2005.*

[47] *BO Wind, Press Releases, http://www.bowind.co.uk/press030506.htm.*

[48] *Vattenfall, Kentish Flats, http://www.kentishflats.co.uk/page.dsp?area=1414.*

[49] *Nordzee Wind, Egmond, aan Zee, Project, http://www.noordzeewind.nl/.*

[50] *Beatrice Wind Farm Demonstration Project, http://www.beatricewind.co.uk/home/default.asp.*

in Table 8.1, the ideal annual capacity factors can be calculated by dividing the expected ideal annual turbine energy output (kWh) by the total turbine capacity times the number of hours in a year. Table 8.3 summarizes these ideal capacity factors.

Table 8.3: Estimated Ideal Annual Capacity Factors

Machine	Estimated Ideal Annual Capacity Factor (%)
Vestas V90 2.0 MW	39
Siemens 2.3 MW MkII	40
GE 3.6sl MW	33

Adjustments to the ideal capacity factor based on several assumptions need to be made in order to make a more realistic cost estimate. These adjustments have been summarized in Table 8.4.

Table 8.4: Adjustments to Ideal Capacity Factor

Assumption	% Reduction in Ideal Energy Output
Wake effect	95.0
Electrical Efficiency	97.0
Availability	94.0
Icing & Blade Fouling	98.0
High Wind Hysteresis	99.7
Substation Maintenance	99.8

The net annual capacity factors were calculated by taking the ideal annual capacity factors and correcting them using the adjustments shown in Table 8.4. The results are shown in Table 8.5.

Table 8.5: Estimated Net Annual Capacity Factors

Machine	Estimated Ideal Annual Capacity Factor (%)
Vestas V90 2.0 MW	33
Siemens 2.3 MW MkII	34
GE 3.6sl MW	28

The best net capacity factor shown in Table 8.5 is 34%. This is the number used in the levelized busbar analysis as shown in Section 8.C.

8.C Levelized Busbar Modeling Assumptions

A Southern Company model incorporating publicly available data[53,54] was used to estimate the levelized busbar costs for an offshore wind farm. The term "levelized busbar cost" indicated the cost to generate electricity before it enters the transmission grid.

The following assumptions were made during modeling the levelized busbar costs:

- Financing structure assumptions
  - Generic regulated utility capital structure
  - 55% debt, 45% equity
  - ROE = 13.5%, cost of debt = 7.5%
  - Tax rate = 40%
  - Standard revenue requirement methodology for capital cost recovery over economic life of asset
  - 20 year economic life
  - 5-yr tax life (accelerated depreciation per MACRS 5-yr schedule)
  - 2.02 ¢/kWh Production Tax Credit (PTC) levelized over 30-yr life[55]
  - 33.5% capacity factor assumed
  - Costs calculated are considered in-service costs
- Capital and O&M costs constant for all technologies
- 50, 100, and 160 MW wind farm size
- 12-month construction schedule
- 2007 in-service date

The resulting levelized busbar costs using these assumptions along with the cost curve developed in Section 8.A for 50, 100, and 160 MW wind farms have been shown in Figure 8.3. As shown in this figure, there is an "economy of scale" which makes a larger wind farm more economical. This concept, previously discussed in Section 8.A, was the impetus for using the European experience to determine an appropriate curve to depict the wind farm size economic scaling. Also, the levelized busbar costs shown in Figure 8.3 include an approximate 25% increase in cost over the European data to account for recent increases in turbine costs.

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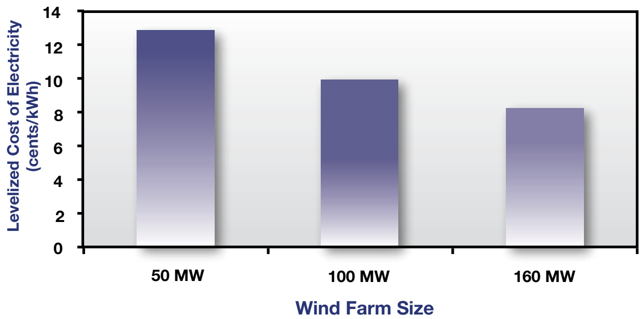
[53] *Assumptions for EIA Annual Energy Outlook 2006, Table 38 and p. 85-86.*

[54] *Recurring capital estimates based on rounded internal data (no data in EIA for recurring capital since it is such a small component of busbar cost).*

[55] *Assumed 1.9 cent/kWh PTC (2005$) grossed up to pre-tax value based on 40% assumed federal tax rate, PTC escalated at 1.9% annually over 10 years of PTC applicability.*

Figure 8.3: Levelized Busbar Costs for Various Wind Farm Sizes (with PTC)



In addition to the levelized busbar costs, one consideration needs to be made for the development costs incurred for an offshore wind project. The busbar costs represented in the above calculations do not include the costs required to develop the project. The Cape Wind project as previously described has incurred costs of $25M for the development of their project and their project has not been built to date. However, this project is the first one of its kind in the U.S. and, thus, the anticipated development costs would be expected to be higher than for the "nth plant". Based on a conversation with a developer, it is anticipated that the development costs for an "nth plant" of any size would be approximately $15M.[56] The actual cost will depend on the issues that might arise such as avian and "not in my backyard" issues as the project is being developed. If issues such as these become significant, the developmental costs may increase significantly.

[56] *Confidential source.*

9 Conclusions

After extensive study of the many technical, financial, environmental, and public issues related to the potential for development of an offshore wind farm in coastal Georgia waters, several conclusions can be drawn. This section outlines some of the conclusions based on the work performed during the *Southern Winds* project period from July 2005 to March 2007.

9.A The Wind Resource

Traditionally, it has been assumed a fact that there is "no wind resource" in the southeastern U.S. except for small isolated areas, such as mountain ridges in Tennessee and North Carolina. The only onshore wind farm built in the Southeast to date is located on one of these mountain ridge locations. In 2004, a research team from the Georgia Institute of Technology's Strategic Energy Institute (SEI) began an examination of the wind data available via SABSOON located on a Navy platform off the Georgia coast and based on this, concluded that there is a "Class 4" wind regime off the Georgia coast which may provide enough energy to power an offshore wind farm. In 2005, SEI and Southern Company decided to work together to determine the technical and economic feasibility of locating an offshore wind farm in this area.

While the strength of the wind regime off the coast of Georgia is not as high as in the other locations being considered for offshore wind development in the eastern U.S. (e.g. Cape Wind and Jones Beach, New York), the actual breadth of the Georgia data available was better than at these other locations. The Georgia data came from three different offshore locations collected over a 20-year span. An important point to note is that at least one of the wind farms built in Europe (Scroby Sands in England) has a wind resource just slightly higher in magnitude than that found off the Georgia coast. However, British utilities and developers in Europe have different motivations and or regulatory incentives due to participation in ratification of the Kyoto Protocol, which help improve wind farm economics. If similar incentives and regulatory requirements develop for U.S. energy markets, the Georgia offshore wind resource represents one of the best opportunities available for harnessing large scale wind energy in the Southeast.

9.B Ongoing Data Needs

Despite the historical wind resource data available, the wind turbine vendors prefer to have wind data collected within the footprint of the selected site and at heights comparable to the hub height of an offshore wind turbine. The project team, thus, recommends that if the project goes forward, the next step should be the placement of a meteorological data collection system offshore in the actual site selected for the wind farm. However, the team recognizes the inability to currently place structures offshore in federal waters until the regulatory rulemaking process has been completed by the Minerals Management Service (MMS).

9.C Project Permitting

The original intent of SEI was to have a permitting package essentially completed at the end of this project to present to the U.S. Army Corps of Engineers (USACE) for a "10 MW demonstration" wind farm. A "10 MW demonstration" wind farm was believed to have been small enough not to require a full Environmental Impact Study (EIS). However, during the course of this project, the Energy Policy Act of 2005 was passed which gave MMS the governing authority rather than USACE over offshore wind development. This change in authority ruled out the possibility of a submitting a permitting package for a "10 MW demonstration" wind farm at the conclusion of the *Southern Winds* project, because MMS has placed a moratorium on any activities offshore until their rulemaking has been completed, which they anticipate to be finalized by the fall of 2008.

The project team recommends that Southern Company should continue engagement in the MMS regulatory rulemaking process, with the continued assistance from Georgia Tech if appropriate. If the decision is made to go ahead with a "demonstration" wind farm or a "full scale" commercial wind farm, Southern Company should prepare for a comprehensive permitting process that is likely to be required by MMS. With regard to biological issues (avian, aquatic and sea bed), relevant studies can require a significant amount of time and expense and as such, should be undertaken as soon as feasible, if the project appears to have forward momentum.

9.D Equipment Availability

During the course of this project the project team learned that there are a number of equipment vendors in the marketplace manufacturing large (greater than 1 MW) wind turbines considered "state of the art." Much of the manufacturing is taking place in Europe, and most of the manufacturers are "sold out" until 2008. The equipment vendors have expressed a lack of confidence in the long-term viability of the wind production tax credit (PTC) program in the U.S. and in the uncertainty as to the timeframe for permitting of offshore wind farms under an as yet to be developed MMS permitting process and regulatory scheme. These issues have caused the equipment vendors to limit their manufacturing capabilities in the U.S.

General Electric, Siemens, and Vestas are currently the only equipment vendors who offer offshore wind turbines. Clipper Wind may be offering an offshore product in the future, and it is likely that this machine will be built in the U.S. Developments in wind turbine technologies need to be monitored.

Globally, equipment vendors are taking similar approaches to the current high market demand. Vendors are screening projects to gauge whether or not the projects are likely to succeed, by predetermining on their own if the site is a good fit for their equipment. This approach can be taken in a seller's market but is subject to change over time.

9.E Offshore Conditions and Foundations

Studies performed with the support of the Skidaway Institute of Oceanography and the Georgia Tech Civil Engineering School indicate that monopile foundations similar to those used in many of the offshore locations in Europe would be appropriate in an installation located off the coast of Georgia. However, none of these foundations have been constructed in U.S. waters. If foundations are constructed in the near future, specialized marine construction equipment and seagoing vessels provided by contractors in Europe or Asia might have to be used, although many of the construction firms used to build the offshore drilling platforms in the Gulf of Mexico may also be able to adapt their equipment for these projects.

9.F Georgia Weather Conditions

The increased frequency of major hurricanes in the southeastern U.S. is a major potential concern to the developers of offshore wind farms. At present, the highest wind speed turbine manufacturers have certified turbine survival for is a 10-minute sustained wind speed of 111 mph. This equates to a 1-minute sustained wind speed of 124 mph, which is a "Category 3" hurricane on the Saffir-Simpson scale. However, hurricane and severe storm activity needs to be planned for in any offshore project. Insurability needs to be established, and the risks of a total loss should be considered. New developments in hurricane survivability from the equipment vendors and research organizations need to be monitored continually.

Lightning, another weather phenomenon particularly severe in the Southeast, must be considered in wind turbine design. Any chosen vendor design must be examined closely to determine its success in handling lightning strikes.

9.G Project Location

The project team has identified two regions off the coast of Georgia which appear to offer feasible sites for wind farms – either for demonstration or for "full scale." These regions are southeast of Tybee Island and east of Jekyll Island. The Tybee Island location has been determined to be more suitable because of a slightly better wind resource and preferable substrate conditions on the ocean floor.

9.H Regulatory Issues

With interest in developing wind generation, long term extension of the federal wind production tax credit (PTC) should be supported, as well as the possibility of additional incentives that could be put in place for renewable energy in the State of Georgia. In addition, discussions should be started with the Georgia Public Service Commission about cost recovery in the rate base for wind generation feasibility evaluations, early site permitting, and development planning.

9.I Stakeholder Involvement

No widespread release of information on a potential offshore wind farm in the Georgia coastal area has been made to the general public or to other stakeholders. A careful roadmap for sharing of this information with the general public should be developed if Southern Company chooses to go ahead with an offshore wind project. The project team has learned much from the other projects being planned in the U.S. While the Cape Wind project may eventually be permitted and built, the progress might have come much easier if the public announcements had taken place in a phased approach and if a "demonstration" rather than a "full-scale" project was recommended. Several turbines could have been installed initially as a "proof of concept" project, rather than announcing an entire project consisting of 170 wind turbines. It was likely that consensus could have been built more quickly and more positively with that approach. The Long Island Power Authority/FPL project has taken a more collaborative approach with stakeholders and might be a better model for a Georgia project.

The project team has had a number of meetings and informal discussions with the Georgia Department of Natural Resources, commercial and private fishermen, and other interested parties, and the majority of their comments have been positive. It is recommended that discussions continue with state and local agencies and other stakeholders to ensure accurate dissemination of information if a project moves forward.

9.J Project Economics

There are very few locations in the Southeast where the average wind speed is adequate to support the construction of an onshore wind farm on an economic basis. Available wind data indicates that a wind farm located offshore in Georgia would likely have an adequate wind speed to support the project, but the high costs associated with offshore technology, construction, and maintenance would drive the costs up by 50% – 100%. Based on today's prices for wind turbines, a commercial size 50 MW to 160 MW offshore wind farm could produce electricity at 12.9 to 8.2 cents/kWh respectively, assuming a 20-year life and regulatory incentives such as a federal production tax credit (PTC) with accelerated depreciation similar to those currently available. A smaller or larger commercial wind farm would increase or decrease, respectively, the cost per kWh because of the economics of scale. Also, the development costs would need to be taken into consideration. The size of an offshore wind farm would not be a significant factor in the overall development costs of an offshore wind farm, but because of the unknown permitting process these costs cannot be fully understood until MMS has completed their rule-making process.

In the Southeast, the real opportunities for renewable projects are limited. The only other type of renewable projects equal to or less in cost than wind are biomass and landfill methane gas electric generation projects.

However, there are benefits to a wind project which include the following:

- Free fuel for the duration of the project with no impacts from increasing fuel prices.
- Renewable energy credits and/or potential reduced carbon tax costs.
- Tremendous benefit in public relations, showing Southern Company to have a "pro-active" stance with regard to renewables.
- Potential for the creation of a new industry and new job opportunities within Southern Company's service territory.

10 Recommendations

It is recommended that Southern Company continue to pursue the potential development of wind energy resources off the coast of Georgia. The next step should be to remain active in the offshore rule making process currently being developed by the MMS. Once the MMS completes the rulemaking process and begins to allow structures to be built on the continental shelf, the team recommends that Southern Company attempt to secure rights from the MMS for future wind energy development in the most promising area or areas of the study. If Southern Company is successful in acquiring these rights and wind energy technology is continuing its move toward economic viability, then the company should consider the erection of an offshore meteorological tower near Tybee Island to measure the wind speeds and directions and to collect other required data.

If analysis of the meteorological data shows the resource to be technically viable (i.e., at least Class 4) the project team recommends that Southern Company consider the construction of a small (10 MW) "demonstration" wind farm, possibly as a joint project with a vendor, the Department of Energy and other federal and state agencies. The erection of a small demonstration farm would allow ongoing data collection and would establish a better database for operation and maintenance issues.

If the concerns about the costs and insurability of offshore wind have been sufficiently resolved by the time the necessary wind resource data has been acquired and analyzed, then this demonstration project phase might be bypassed in favor of an effort to move forward with the development of a commercial-scale wind farm.

Both Georgia Tech and Southern Company found this study to have been productive. Georgia Tech personnel have learned more about the details and the technology issues involved in a wind project, and Southern Company personnel have become involved with a new generation option and have formed a good basis to look at renewable energy from a more informed standpoint in the future. The project team recommends that an ongoing relationship be promoted between Southern Company and Georgia Tech SEI.

GLOSSARY

A

ADIZ – Air Defense Intercept Zone: serves as a national defense boundary for air traffic and is administered by the U.S. and Canada.

B

C

CZMA – Coastal Zone Management Act.

Capacity factor – ratio of the energy produced over a given period of time to the energy that could have been generated at the equipment's full capacity over the same period of time.

Cooper marl – layer of stiff clay (North Carolina).

Cut in speed – wind speed at which the turbine begins to produce power.

Cut out speed – wind speed at which the turbine may be shut down to protect the rotor.

D

E

EIS – Environmental Impact Statement: document under NEPA stating environmental impacts of an action affecting the quality of human environment.

Estuarine – Formed in an estuary.

Estuarine area – (from Coastal Marshland Protection Act) All tidally influenced waters, marshes, and marshlands lying within a tide-elevation range from 5.6 feet above mean high-tide level and below.

F

FHWA – Federal Highway Administration.

FPL – Florida Power & Light Energy Company, selected to install a wind farm off the south coast of Long Island.

G

GDOT – Georgia Department of Transportation.

GTC – Georgia Transmission Corporation.

Green Tags – also known as Renewable Energy Credits or Tradable Renewable Certificates that represent environmental benefits associated with generating electricity from renewable energy sources.

Grey literature – literature (often of a scientific or technical nature) that is not available through the usual bibliographic sources such as databases or indexes. It can be both in print and, increasingly, electronic formats. Grey literature is produced by government agencies, universities, corporations, research centers, associations and societies, and professional organizations.

H

Hub height – height of wind turbine axis above water or land.

I

Isobath – an imaginary line or one drawn on a map connecting all points of equal depth below the surface of a body of water.

J

K

L

LIOWI – Long Island Offshore Wind Initiative: educational and public outreach forum for the wind power generation project off the coast of Long Island.

LIPA – Long Island Power Authority.

M

Marginal sea – a part of ocean partially enclosed by land such as islands, archipelagos, or peninsulas. Marginal seas are different from mediterranean seas because they have ocean currents caused by ocean winds. The waters between some of Georgia's barrier islands are considered marginal seas.

Marinize – Weatherized to protect against the offshore environment.

MMS – Minerals Management Service: Lead federal agency for offshore wind farm permitting.

MOA – military operations areas.

Miocene marl – unconsolidated limestone in soil-like consistency with partial to full cementation in localized areas (Georgia).

N

NEPA - National Environmental Policy Act.

NHPA – National Historic Preservation Act.

NIMBY – Not In My Back Yard: phenomenon in which residents say a development is inappropriate for their local area.

NMFS – National Marine Fisheries Service.

NMSA – National Marine Sanctuary Act.

NREL – National Renewable Energy Laboratory: Golden, Colorado.

NSF – National Science Foundation: U.S. agency supporting research and education in non-medical fields of science and engineering.

Nacelle – Enclosure for wind turbine mechanical components.

Nautical mile – 1.1 statute miles.

O

OCSLA – Outer Continental Shelf Lands Act.

OPEC – Organization of the Petroleum Exporting Countries: Algeria, Indonesia, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, the United Arab Emirates, and Venezuela; headquarters Vienna, Austria.

Outer Continental Shelf – submerged lands, subsoil, and seabed between the U.S. and Federal seaward jurisdiction.

P

PFI – Partnerships for Innovation: program developed by NSF involving technology assessments on alternative energy options to determine potential for implementation.

Pitch mechanism – turns rotor blades of a wind turbine into and out of the wind.

Power curve – graphical representation of the relationship between a wind turbine's power output and wind speed.

Q

R

RHA – Rivers and Harbors Act.

Rotor Diameter – diameter of swept circle of wind turbine rotor blades.

S

SABSOON – South Atlantic Bight Synoptic Offshore Observational Network.

SEI – Strategic Energy Institute.

SLT – Savannah Light Tower: entrance to Savannah River ship channel (destroyed 1996).

South Atlantic Bight – U.S. coastal ocean from North Carolina to the east coast of Florida.

Squirrel cage – a type of induction machine that uses copper bars in order to generate electrical power.

Stator – the stationary part of an electric motor.

T

U

USACE/USACOE – US Army Corps of Engineers: formerly lead agency for offshore permitting.

V

Viewshed – an area of land, water, and other environmental elements that is visible from a fixed point.

W

Weibull curve – a frequency diagram that is used to approximate the variation of wind speed over time.

Wind farm – a collection of wind turbines in the same location.

Wind rose – a map symbol showing, for a given locality or area, the frequency and strength of the wind from various directions.

Wind shear – the change in wind speed or direction with height.

Wound rotor – a type of induction machine that is comprised of a set of coils used to generate electrical power.

X

Y

Yaw mechanism – turns the wind turbine rotor against the wind.

Z

Baseload and Dispatchable Power

While energy consumers rarely think about it, the power grid upon which we depend for our energy is one of the world's largest machines and has a number of different parts. On the electrical energy generation side, grid managers make three main distinctions between types of generators according to the type of power they output: baseload, load-following, and peaker generators. In addition, power engineers value a generator more if it is dispatchable, meaning it can generate more or less power on-demand or on a human-defined schedule.

A baseload generator can generate power constantly day and night at an even level. Usually the per kilowatt-hour cost of baseload generators are low. Coal and nuclear plants are commonly used as baseload generators but also large natural gas and hydroelectric plants are used for baseload power.

A load-following generator gradually ramps up and down its power output to respond to scheduled changes in power demand over the course of a day. Gas, pulverized coal, and hydroelectric generators are commonly used to follow the load. Solar photovoltaic or CSP without storage can approximately follow the load on sunny days, when peak demand is around mid-day.

A peaker plant responds rapidly to changes in power demand that baseload and load-following plants do not; often within less than a minute. Natural gas turbine and hydroelectric plants are used as peakers. Peakers are the most expensive to operate but produce the least amount of power over the course of the year. Some newer types of energy storage, like batteries and flywheels, can also function as peakers, though they are still in the early stages of commercialization and are not yet cost competitive with fossil peaker plants.

To reduce and eventually eliminate the carbon footprint of the electric grid, we will have to develop renewable generators that can output power in ways that partially or completely occupy these roles. While hydroelectric facilities with storage (dams) can occupy all three roles, they are limited by geography, water availability, and competing natural and societal uses for water and river valleys. Geothermal wells work well as baseload power, though are currently limited to specific hot spots. In decades to come we will see more geothermal baseload power as what has been called Enhanced Geothermal Systems are developed.

Currently, to use the strongest renewable resource we have, the sun, to fulfill these roles, CSP with Storage is our most economical and scalable alternative. Paired with enough thermal storage and solar collectors, a CSP plant can operate as baseload power. Alternatively a CSP plant with storage can be built to scale up and down to follow the load, peaking its power output in mid-afternoon when power demand is highest on summer days. With storage and with a steam generator and turbine already warmed up, a CSP plant with storage can be dispatched to meet peak demand within a few minutes.

The usefulness of CSP with storage as a coal and natural gas power plant replacement is then clear in an era of carbon-constraint and concern about climate stability. Coal moratoria and other measures to curtail the use of coal and natural gas generators should to be paired, along with increased energy efficiency, with a promotion of sustainable replacements for these generators. Furthermore, the emergence of plug-in electric vehicles also will eventually increase the demand for clean nightime power, which CSP with storage as baseload can help provide.

Tags The Importance of Energy Storage

Princeton Environmental Institute

PRINCETON UNIVERSITY

Energy Systems Analysis Group

Compressed Air Energy Storage: Theory, Resources, And Applications For Wind Power

8 April 2008

Samir Succar and Robert H. Williams

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Preface

This report reviews the literature on compressed air energy storage (CAES) and synthesizes the information in the context of electricity production for a carbon constrained world.

CAES has historically been used for grid management applications such as load shifting and regulation control. Although this continues to be the dominant near-term market opportunity for CAES, future climate policies may present a new application: the production of baseload electricity from wind turbine arrays coupled to CAES.

Previous studies on the combination of wind and CAES have focused on economics and emissions [1-10]. This report highlights these aspects of baseload wind/CAES systems, but focuses on the technical and geologic requirements for widespread deployment of CAES, with special attention to relevant geologies in wind-rich regions of North America.

Large penetrations of wind/CAES could make substantial contributions in providing electricity with near-zero GHG emissions if several issues can be adequately addressed. Drawing on the results of previous field tests and feasibility studies as well as the existing literature on energy storage and CAES, this report outlines these issues and frames the need for further studies to provide the basis for estimating the true potential of wind/CAES.

Executive Summary

Compressed Air Energy Storage (CAES) is a commercial, utility-scale technology suitable for providing long-duration energy storage with fast ramp rates and good part-load operation. CAES works by using electricity to compress air, which is subsequently stored in a large reservoir (typically in an underground geologic formation). Electricity is regenerated by recovering compressed air from storage, burning in this air a small amount of fuel (typically natural gas), and expanding the combustion products through a turbine (see section 1.2, page 15).

This report is intended to analyze the potential of CAES for balancing large penetrations of wind energy. The economic analysis of wind coupled with CAES for providing baseload power indicates that it will likely be competitive in economic dispatch under the same range of greenhouse gas (GHG) emissions price needed to make carbon capture and storage (CCS) economic for new coal integrated gasification combined cycle (IGCC) systems (~\$30/tCO_2). However the potential for wind/CAES is contingent on the availability of geologies suitable for CAES in windy regions. Thus the central focus of the report is on the geologic and technical requirements for CAES as they relate to the potential for large-scale deployment of this technology.

The CAES storage reservoir can often be constructed in pre-existing formations (e.g. a salt cavern, aquifer or abandoned mine). As a result, the capital cost of adding an incremental amount of storage capacity can be much lower than for other comparable storage technologies. This makes CAES especially well suited for bulk storage applications.

The total capital cost of a CAES unit tends to be dominated by the cost of the turbomachinery. The low total capital cost can be understood by noting that the turbomachinery is essentially a gas turbine for which the compression and expansion functions are separated in time—and gas turbines are characterized by relatively low capital costs.

In the 1970s, CAES began to attract attention as a way to store inexpensive baseload power produced during off-peak periods for use later when demand is higher and electricity is more valuable.

Shifts in market conditions led to diminished interest in CAES. However, the sustained rapid growth of wind power has catalyzed a renewed interest in this technology as an option for making wind power dispatchable (see section 1.1, page 12). Additionally, because CAES consumes significantly less fuel than a conventional gas turbine per unit of energy delivered, the GHG emissions from wind/CAES systems can be quite low.

Although the global wind resource can theoretically satisfy the demand for electricity several times over, the variability of wind and the typical remoteness of high-quality wind resources from major electricity demand centers (e.g. in the U.S.) must be addressed for wind to serve a large percentage of electricity consumption (>20-30%). CAES offers the potential for overcoming these challenges by both smoothing the output from wind and enabling the cost-effective operation of high capacity, high-voltage transmission lines carrying this power at high capacity factors.

The ultimate potential of wind in satisfying electricity needs via wind/CAES depends on the availability of geologies suitable for CAES in regions with high-quality wind resources (for a description of geologic options for CAES reservoirs see section 1.3, page 17). In the continental US, high-quality wind resources overlap more closely with porous rock geology than any other storage geology (see Figure i). Thus, in this region at least, widespread deployment of CAES in connection with wind power implies a considerable role for aquifers.

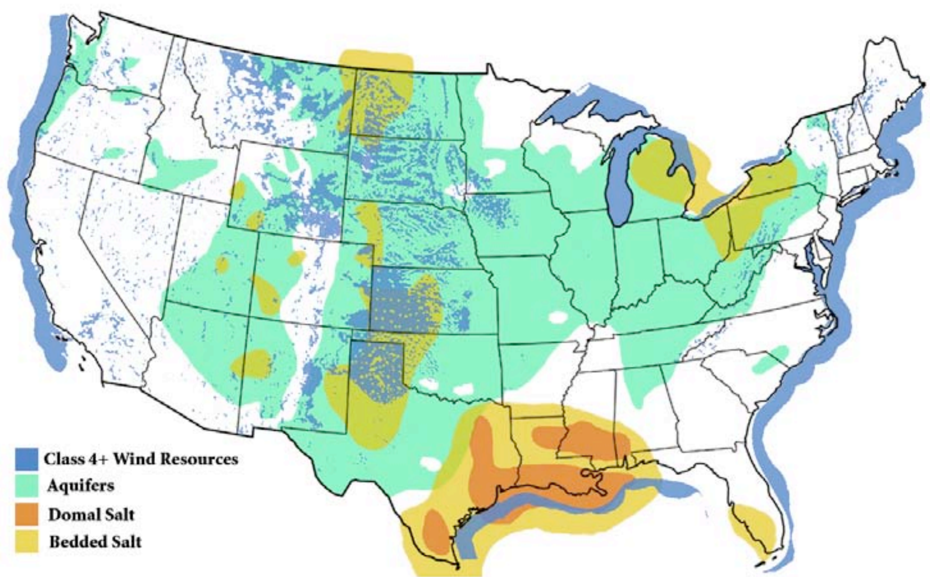

Figure i Areas with geologies favorable for CAES and class 4+ winds (see Section 3, "Aquifer CAES Geology and Operation" on page 42)

Although two commercial CAES plants have been built, neither uses aquifers as the storage reservoir (see section 1.4 "Existing and Proposed CAES Plants" on page 22). However, previous studies and field tests have confirmed that air can be successfully stored and withdrawn using a saline aquifer as a storage reservoir. Furthermore, a recently announced wind/CAES plant in Iowa will use an aquifer [a porous sandstone formation (see Figure ii)]. Once built, this project will provide important information about these systems in terms of both the utilization of aquifers for air storage and coupling of CAES to wind. The system is being designed to enable wind power to be dispatched in electric load-following transmission support applications, which is likely to be the most important near-term use of wind/CAES systems.

Although there has been no commercial experience with aquifer CAES, much can be gleaned from what is already known about natural gas storage in aquifers. The natural gas storage industry has vast experience with porous rock formations under conditions similar to those for CAES (see section 3.2.2, page 44). As such, the theory of natural gas storage provides a useful point of departure for understanding CAES, and many of the methodologies and data amassed for identifying natural gas storage opportunities may well prove useful for assessing CAES sites.

Relative to methane however, air has both different physical properties (e.g., air has a higher viscosity than methane) and different chemical properties (e.g., introducing oxygen underground can lead to various oxidation reactions, corrosion mechanisms, and the promotion of bacteria) that could pose challenges for air storage (see sections 3.4 and 3.5 on page 53). While it is expected to be often feasible to mitigate the effects of these factors, it will be essential to test the viability of aquifer CAES under a wide variety of geologic conditions and to carefully determine the impact of local geology on CAES system planning and design.

The use of CAES in an intermediate load application such as that envisioned for the Iowa wind/CAES plant will provide a valuable demonstration of wind/CAES integration. However, demonstration of much more closely coupled systems capable of serving baseload power markets is also needed to understand better the potential of wind/CAES, because although bulk storage may be valuable for serving a broad range of grid management applications, ultimately the role of wind as a tool for climate change mitigation will depend on the extent to which it will be able to supplant new baseload coal-fired capacity.

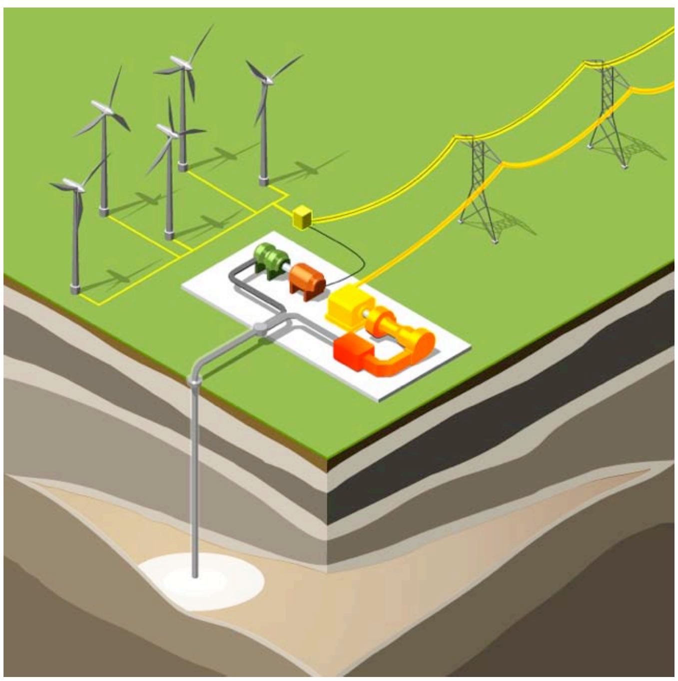

Figure ii The wind/CAES system scheduled to begin operation in 2011 near Des Moines, Iowa (IAMU, 2006)

A dispatch cost analysis suggests that a natural gas-fired wind/CAES system would often be able to compete against coal and other baseload power options, especially under a climate change mitigation policy sufficiently stringent to make CO_2 capture and storage cost-effective for coal power (see section 4, "Wind/CAES Systems in Baseload Power Markets" on page 58). Thus, the wind/CAES hybrid could give both wind and natural gas entry into baseload markets in which they would otherwise not be able to compete.

The storage capacity of CAES systems designed to deliver baseload power would typically be several times that for other grid management applications, but even so the "footprint" of a 10-m thick aquifer capable of providing baseload wind/CAES power would occupy a much smaller (~14%) land area than that of the corresponding wind farm under typical conditions (see section 2.3 on page 30).

A better understanding is needed of the performance of CAES over a wide range of conditions. In particular, use of CAES for wind balancing will require CAES to adjust output more frequently and to switch between compression and generation modes more quickly than has been required of CAES in applications such as storing off-peak power at night and generating peak electricity during the day (see section 2.1, page 27). Understanding well the impacts of these operational demands requires further study.

Determining the ultimate potential of baseload wind/CAES as a climate change mitigation option also requires knowledge of the prevalence of suitable geologies. Although porous rock formations seem to be prevalent in high wind areas, understanding the full potential of this technology will require in-depth assessments of the extent of formations with anticlines suitable for containment and, for promising structures, their geochemical and geophysical suitability for CAES. Data on local geology from US and state geological surveys including natural gas storage candidate site evaluations might aid in further characterizing these areas, but new data will also be needed, especially in regions where natural gas storage is not commonplace (see section 3.3 "Geologic Requirements" on page 47).

CAES appears to have many of the characteristics necessary to transform wind into a mainstay of global electricity generation. The storage of energy through air compression may enable wind to meet a large fraction of the world's electricity needs competitively in a carbon constrained world. If the needed steps are taken soon, it should quickly become evident just how large this fraction might be.

1. Background

Compressed Air Energy Storage (CAES) is a low cost technology for storing large quantities of electrical energy in the form of high-pressure air. It is one of the few energy storage technologies suitable for long duration (tens of hours), utility scale (100's to 1000's of MW) applications. Several other energy storage technologies such as flywheels and ultracapacitors have the capability to provide short duration services related to power quality and stabilization but are not cost effective options for load shifting and wind generation support [11, 12].

The only technologies capable of delivering several hours of output at a plant-level power output scale at attractive system costs are CAES and pumped hydroelectric storage (PHS) [13-17]. Although some emerging battery technologies may provide wind-balancing services as well, typical system capacities and storage sizes are an order of magnitude smaller than CAES and PHS systems (~10 MW, <10 hours) with significantly higher capital costs (see Table 1).

PHS does not require fuel combustion and has a greater degree of field experience relative to CAES, but it is only economically viable on sites where reservoirs at differential elevations are available or can be constructed. Furthermore, the environmental impact of large-scale PHS facilities is becoming more of an issue, especially where preexisting reservoirs are not available and sites with large, naturally occurring reservoirs at large differential elevations where environmentally benign, inexpensive PHS can be built are increasingly rare.

Table 1 Capital Costs for Energy Storage Options [11, 12, 18]

Technology	Capital Cost: Capacity ($/kW)	Capital Cost: Energy ($/kWh)	Hours of Storage	Total Capital Cost ($/kW)
CAES (300MW)	580	1.75	40	650
Pumped Hydroelectric (1,000MW)	600	37.5	10	975
Sodium Sulfur Battery (10MW)	1720-1860	180-210	6-9	3100-3400
Vanadium Redox Battery (10MW)	2410-2550	240-340	5-8	4300-4500

In contrast, CAES can use a broad range of reservoirs for air storage and has a more modest surface footprint giving it greater siting flexibility relative to PHS. High-pressure air can be stored in surface piping, but for large-scale applications, developing a storage reservoir in an underground geologic formation such as solution mined salt, saline aquifer, abandoned mine, or mined hard rock are typically more cost effective. The widespread availability of geologies suitable for CAES in the continental US suggests that this technology faces far fewer siting constraints than PHS, which is especially important for the prospect of deploying CAES for wind balancing.

One of the central applications for CAES is for the storage of wind energy during times of transmission curtailment and generation onto the grid during times of shortfalls in wind output. Such wind balancing applications require not only large-scale, long duration storage, but also fast output response times and siting availability in wind-rich regions. Prior studies indicate that suitable CAES geologies are widely available in the wind-rich US Great Plains. Furthermore, CAES is able to ramp output quickly and operate efficiently under partial load conditions making it well suited to balance the fluctuations in wind energy output. Finally, the low greenhouse gas (GHG) emissions rate of CAES makes it a good candidate for balancing wind in a carbon constrained world.

Among the geologic options for air storage, porous rock formations offer the most widespread availability and potentially the lowest cost. Moreover, geographical distributions of aquifers and good wind resources are strongly correlated in the US. Therefore the potential for CAES to play a major role in balancing wind output and producing low greenhouse gas (GHG) emitting power will depend to a large degree on the availability of aquifer structures suitable for CAES.

1.1. Evolving Motivations for Bulk Energy Storage

CAES emerged in the 1970s as a promising peak shaving option [19]. High oil prices together with an expanding nuclear power industry sparked an interest in energy storage technologies such as CAES to be used in load following applications. The high price of peak power and the perceived potential for inexpensive baseload nuclear power made attractive the option of storing inexpensive off-peak electricity and selling this electricity during peak demand periods [20, 21].

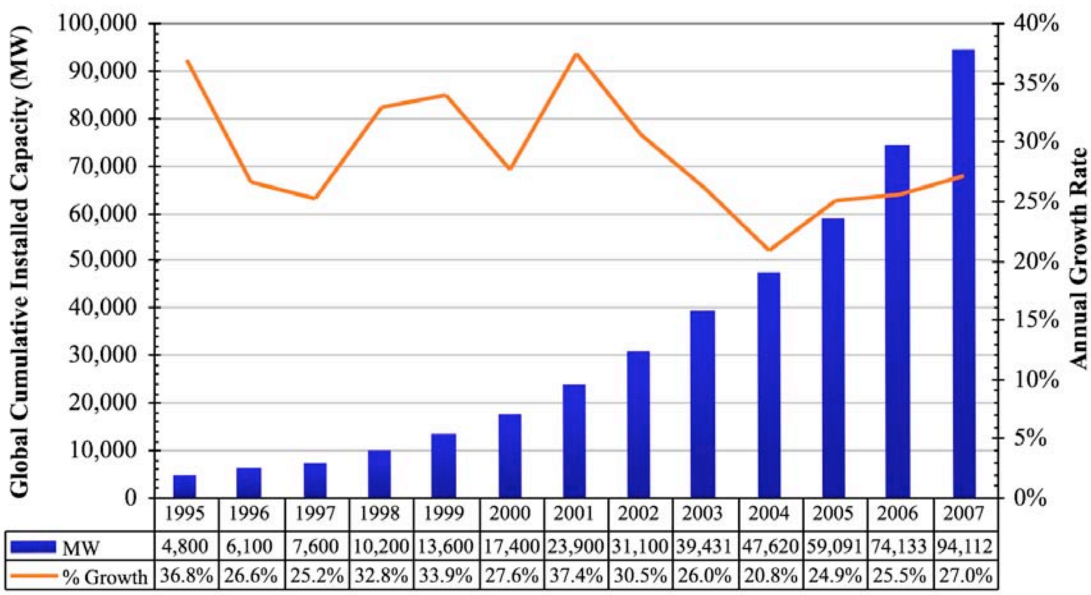

Figure 1 Global Wind Capacity 1995-2007 (GWEC, 2008)

These conditions initially fueled a strong interest in CAES among many utilities, but as the nuclear power industry lost momentum and oil prices retreated from their peaks, the market conditions for CAES began to change. During the 1980s the gas turbine and combined cycle generation emerged as the leading low cost options for peaking and load-following markets. This together with overbuilt generating capacity on the grid and the perception that domestic natural gas supplies were abundant led to erosion of market interest in energy storage.

Recent trends in gas price and wind power development have fostered new interest in energy storage, not as a way to convert baseload power into peak power, but as a way mitigate the variability of wind energy [8, 10]. Global wind power capacity has grown rapidly in recent years from 4.8 GW in 1995 to 94 GW by the end of 2007 (see Figure 1). The variability of wind output requires additional standby reserve capacity to ensure output during times of peak demand. Gas turbines can respond quickly to shortfalls in wind output and so gas fired spinning reserve units are good candidates for dispatch to meet the challenge of balancing this growing wind segment of the power mix.

Energy storage represents an alternative wind balancing strategy, and the low fuel consumption of CAES makes it especially relevant in the face of high gas prices. Although wind balancing has long been acknowledged as a potential application for bulk energy storage [22], it is only recently that wind penetrations have reached levels that require additional balancing measures for maintaining system stability [23]. However recent studies have shown that bulk storage can reduce the integration costs for wind energy even at relatively low penetration levels [24].[1] The use of storage for balancing wind and for serving other grid management applications will be especially valuable where the supply of flexible generating capacity (e.g. hydroelectric) is limited [10, 25]. The continued increase of wind penetration on the grid and the need to reduce greenhouse gas emissions may create an incentive to use storage systems directly coupled with wind to produce baseload power rather than as independent entities to provide grid support services (see below). Further, because the fuel consumption of CAES is less than half of that of a simple cycle gas turbine, using CAES would provide a hedge against natural gas price volatility [26].

A further reason for considering wind farms coupled to CAES storage (henceforth referred to as wind/CAES) stems from the fact that most high quality onshore wind resources are often remote from load centers. The exploitable onshore wind potential in classes 4 and above in North America is huge—equivalent to more than 12 times total electricity generation in 2004 [27, 28].[2,3] However the resources in the US are concentrated in the sparsely populated Great Plains and Midwest States (see Figure 2) which account for over half of the exploitable US wind generation potential in class 4+ [29]. Bringing electricity cost-effectively from the Great Plains to major urban electricity

[1] The cited report indicates that removal of bulk storage (pumped hydroelectric storage in this case) increases integration costs for wind by approximately 50% for a wind penetration level of 10%. Also, doubling of storage capacity lowered integration cost by ~$1.34/MWh in the 20% penetration case.

[2] The Greenblatt (2005) estimate is based on the assumption that various land use constraints limit the technical potential for wind to what can be produced on 50% of the land on which class 4+ wind resources are available.

[3] The technical wind power potential at the global level is also huge. Considering only class 4+ winds exploited on 50% of the land on which these resources are available, as in the North American case, Greenblatt (2007) estimated that the global technical wind energy potential is 185,000 TWh/y on land plus 49,400 TWh.year offshore. For comparision the global electricity generation rate in 2004 was 17,400 TWh/year.

demand centers requires that it be transmitted via GW-scale high-voltage transmission lines that are baseloaded. CAES systems coupled to multi-GW-scale wind farms could provide such baseload power.

As will be shown, wind/CAES systems have good prospects of being able to compete in a carbon constrained world directly with other low carbon *baseload* power options such as the coal integrated gasification combined cycle (IGCC) with carbon capture and storage (CCS) (see Section 4).

Because the incremental capital cost for increasing CAES storage volume capacity is relatively low, it is well suited for providing long-duration storage (>80 hours) needed to produce baseload power. Although seasonal storage of wind is also possible, it would require much larger storage volumes [30].

Wind/CAES also gives natural gas a role in baseload power markets that are often out of reach due to the relatively high dispatch costs of natural gas generation. Thus, wind/CAES gives both wind and natural gas an entry into large baseload power markets

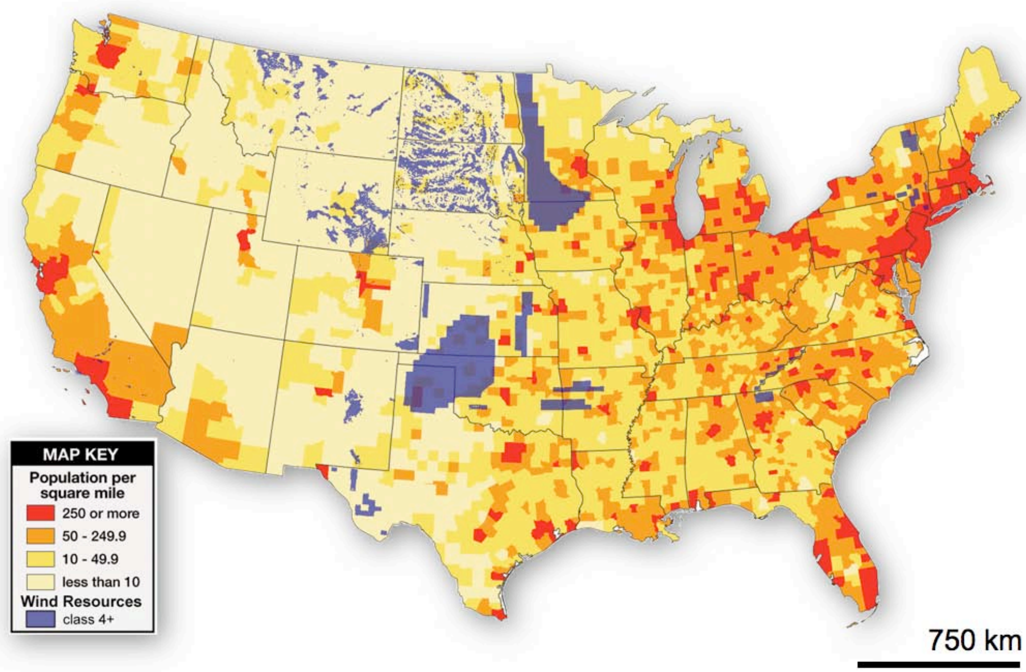

Figure 2 Onshore wind resources and population density in the continental US (US Census 2000; NREL, 2001, 2002, 2006)

to which they would not otherwise have access.

While typical capacity factors for wind farms are approximately 30-40% [31], wind/CAES systems can achieve capacity factors[4] of 80-90% typical of baseload plants.

[4] Capacity factor in this case is on the basis of a constant demand level. The rated capacity of the wind park will be "oversized" relative to this demand level and the CAES turboexpander capacity matched to it such

Therefore, the coupling of wind to energy storage enhances utilization of both existing transmission lines and dedicated new lines for wind. This can alleviate transmission bottlenecks or obviate transmission additions and upgrades.

In the case that transmission capacity is limited, it will be advantageous to site the storage reservoir and wind turbine array as closely as possible to exploit the benefits described above. If this is not the case however, there is no need to co-locate the storage system and wind array. Independently siting these components would allow added flexibility for simultaneously matching facilities to the ideal wind resource, storage reservoir geology and the required natural gas supplies.

1.2. CAES Operation

CAES systems operate much in the same way as a conventional gas turbine except that compression and expansion operations occur independently and at different times (see Figure 3). Because compression energy is supplied separately, the full output of the turbine can be used to generate electricity during expansion, whereas conventional gas turbines typically use two thirds of the output power from the expansion stage to run the compressor.

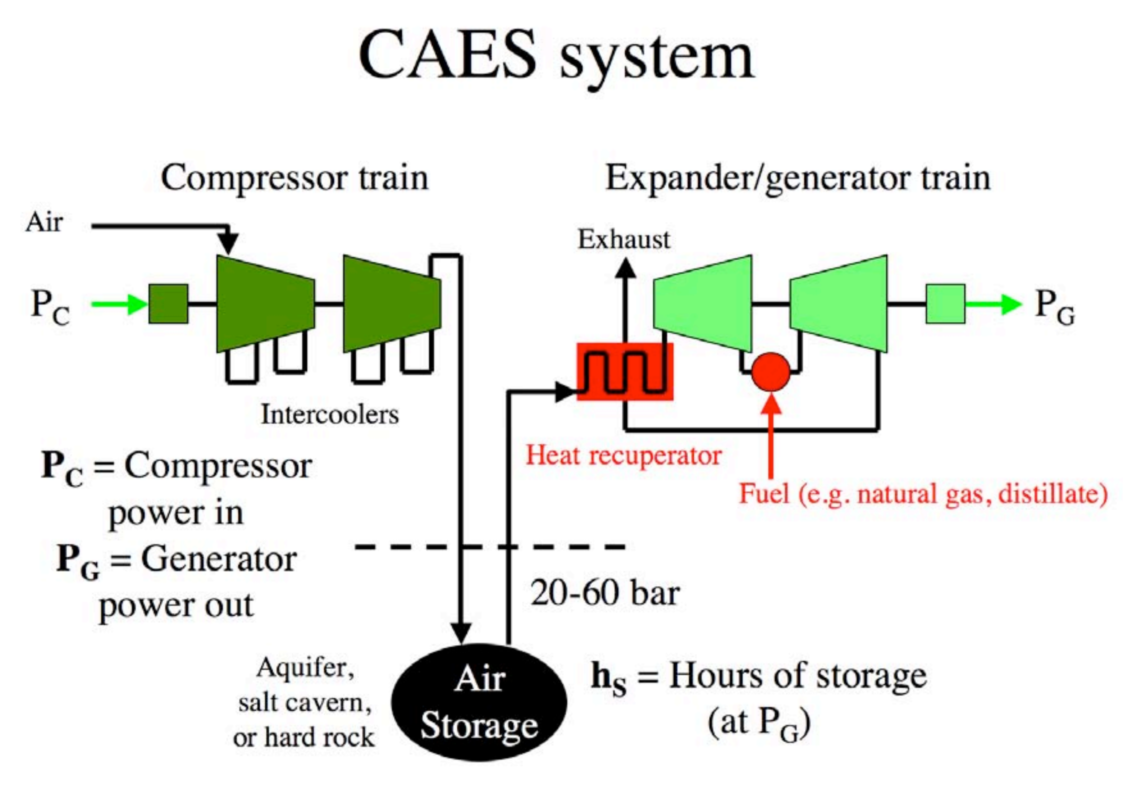

Figure 3 CAES System Configuration

that excess wind can be stored to balance subsequent shortfalls. While it is possible to produce constant output (i.e. 100% capacity factor) from a wind/CAES plant, it would require a significantly larger storage volume capacity.

During the compression (storage) mode operation, electricity is used to run a chain of compressors that inject air into an uninsulated storage reservoir, thus storing the air at high pressure and at the temperature of the surrounding formation. The compression chain makes use of intercoolers and an aftercooler to reduce the temperature of the injected air thereby enhancing the compression efficiency, reducing the storage volume requirement and minimizing thermal stress on the storage volume walls.

Despite the loss of heat via compression chain intercoolers, the theoretical efficiency for storage at formation temperatures in a system with a large number of compressor stages and intercooling can approach that for a system with adiabatic compression and air storage in an insulated cavern (see the discussion of compression efficiency in Appendix A).[5]

During the expansion (generation) operation mode, air is withdrawn from storage and fuel (typically natural gas) is combusted in the pressurized air. The combustion products are then expanded (typically in two stages), thus re-generating electricity

Fuel is combusted during generation for capacity, efficiency and operational considerations. Expanding air at the wall temperature of the reservoir would necessitate much higher air flow in order to achieve the same turbine output – thus increasing the compressor energy input requirements to the extent that the charging energy ratio would be reduced by roughly a factor of four [32]. Furthermore, in the absence of fuel combustion the low temperatures at the turbine outlet[6] would pose a significant icing risk for the blades because of the large airflow through the turbine, despite the small specific moisture content for air at high pressure. There is also the possibility that the turbine materials and seals might become brittle during low temperature operation.

[5] Adiabatic CAES designs capture the heat of compression in thermal energy storage units (see discussion of AA-CAES in section 5, Advanced Technology Options)

[6] For example assuming air recovered from storage at 20°C, adiabatic expansion, and a 45x compression ratio, T=-174°C at the turbine exhaust

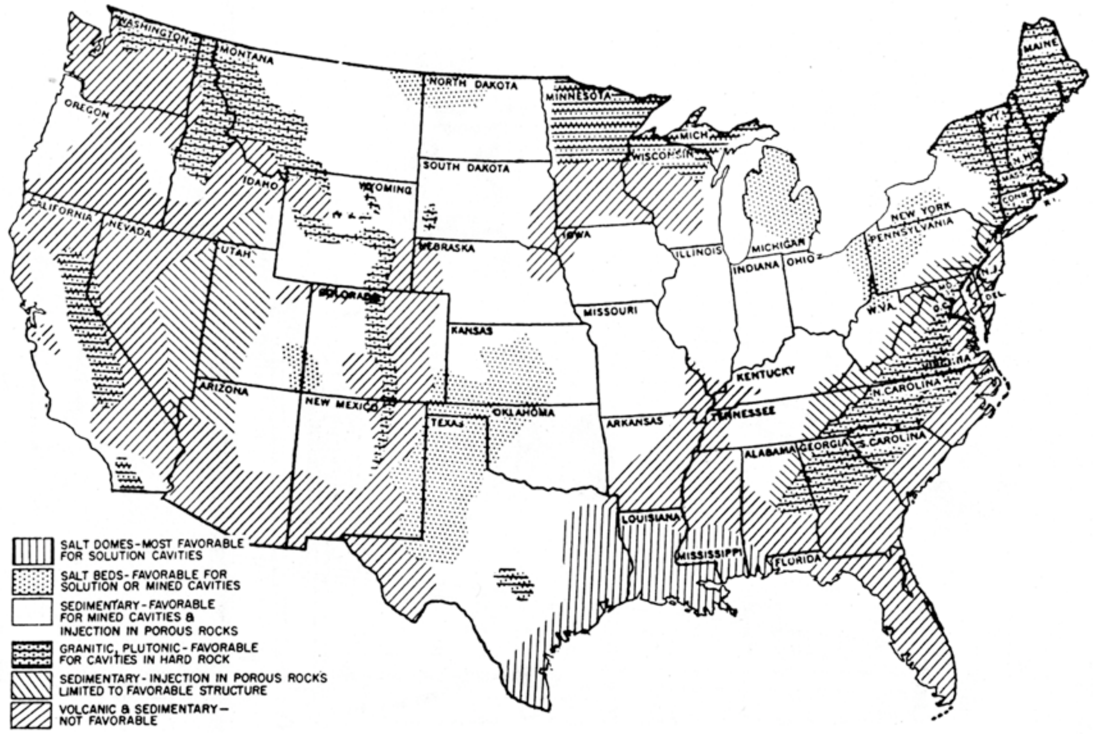

Figure 4 Areas classified for subsurface storage of fluids. From the National Petroleum Council Report of the Committee on Underground Storage for Petroleum, April 22, 1952; updated in Oct 1962 b C.T. Brandt, Underground Storage and Mining Consultant, Bartesville, OK; additional changes reflect comments in Katz and Lady, 1976.

1.3. Suitable Geologies for CAES

Geologies suitable for CAES storage reservoirs can be classified into three categories: salt, hard rock, and porous rock. Taken together, the areas that have these geologies account for a significant fraction of the continental United States (see Figure 4). Prior studies indicate that over 75% of the U.S. has geologic conditions that are potentially favorable for underground air storage [33, 34].

However, those studies carried out only macro scale analyses that did not evaluate areas according to the detailed characteristics necessary to fully estimate their suitability for CAES. While the large fractions of land possessing favorable geologies is encouraging, broad surveys such as the data presented in Figure 4 can only serve as a template for identifying candidate areas for further inquiry and detailed regional and site-specific data will be necessary to determine the true geologic resource base for CAES.

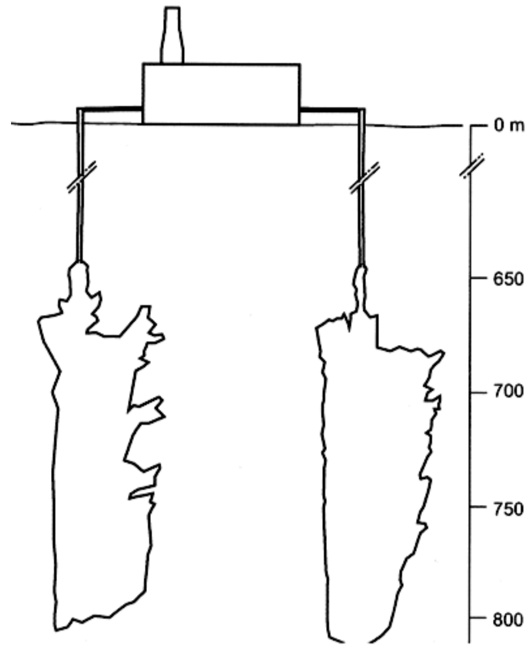

Figure 5 Structure of Huntorf CAES plant salt dome storage with caverns and plant on same scale [35]

1.3.1. Salt

The two CAES plants currently operating use solution-mined cavities in salt domes as their storage reservoirs (see Figure 5 and section 1.4 "Existing and Proposed CAES Plants"). In many ways, such formations are the most straightforward to develop and operate. Solution mining techniques can provide a reliable, low cost route for developing a storage volume of the needed size (typically at a storage capital cost of ~ $2.00 per kWh of output from storage) if an adequate supply of fresh water is available and if the resulting brine can be disposed of easily [11, 12]. Furthermore, due to the elasto-plastic properties of salt, storage reservoirs solution-mined from salt pose minimal risk of air leakage [33, 36].

Large bedded salt deposits are available in areas of the Central, North Central and North East United States while domal formations can be found in the Gulf Coast Basin [37].

Although both bedded and domal formations can be used for CAES, salt beds are often more challenging to develop if large storage volumes are required. Salt beds tend to be much thinner and often contain a comparatively higher concentration of impurities which present significant challenges with respect to structural stability [37]. Caverns mined from salt domes can be tall and narrow with minimal roof spans as is the case at both the Huntorf (see Figure 5) and McIntosh CAES facilities. The thinner salt beds cannot support long aspect ratio designs because the air pressure must support much larger roof spans. In addition, the presence of impurities might further compromise the structural integrity of the cavern and further complicate the development a large capacity storage system.

Although the locations of domal formations in the United States are not well correlated with high quality wind resources (see Figure 17), there are some indications the prospects may be more favorable in Europe (see Figure 6).

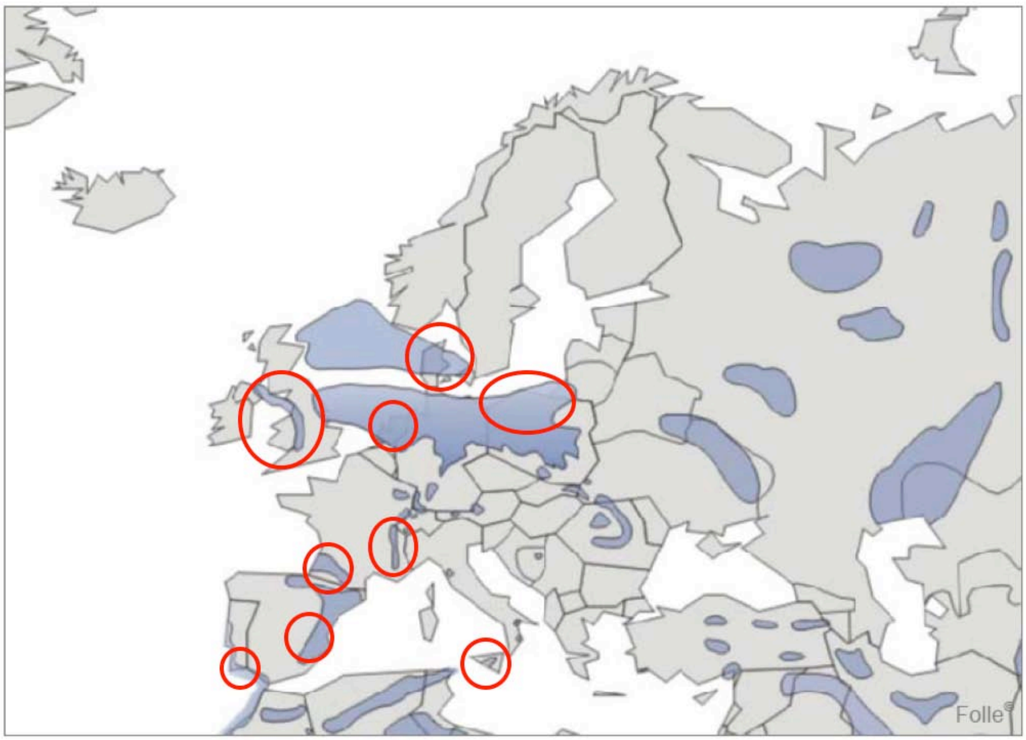

Figure 6 Coincidence of high wind potential and salt domes in Europe. Red circles indicate areas investigated for CAES development [38]

1.3.2. Hard Rock

Although hard rock is an option for CAES, the cost of mining a new reservoir is often relatively high (typically $30/kWh produced). However in some cases existing mines might be used in which case the cost will typically be about $10/kWh produced [11, 39, 40] as is the case for the proposed Norton CAES plant, which makes use of an idle limestone mine (see section 1.4).

Detailed methodologies have been developed for assessing rock stability, leakage and energy loss in rock-based CAES systems including concrete-lined tunnels [44-46]. Several such systems have been proposed [47] and known field tests include two recent programs in Japan: a 2 MW test system using a concrete-lined tunnel in the former Sunagaawa Coal Mine and a hydraulic confinement test performed in a tunnel in the former Kamioka mine [11].

In addition, a test facility was developed and tested by EPRI and the Luxembourg utility Societe Electrique de l'Our SA using an excavated hard-rock cavern with water compensation [48]. The site was used to determine the feasibility of such a system for CAES operation and to characterize and model water flow instabilities resulting from the release of dissolved air in the upper portion of the water shaft (i.e. the "champagne effect").

Hard rock geologies suitable for CAES are widely available in the continental US and overlap well with high-quality wind resources (see Figure 7). However, because the development costs are currently high relative to other geologies (especially given the limited availability of preexisting caverns and abandoned mines [36]), it is unlikely that this option will be the first option pursued for a large-scale deployment of CAES. Although future developments in mining technology may reduce the costs of utilizing such geologies, it appears that other geologies may currently offer the best near-term opportunities for CAES development.

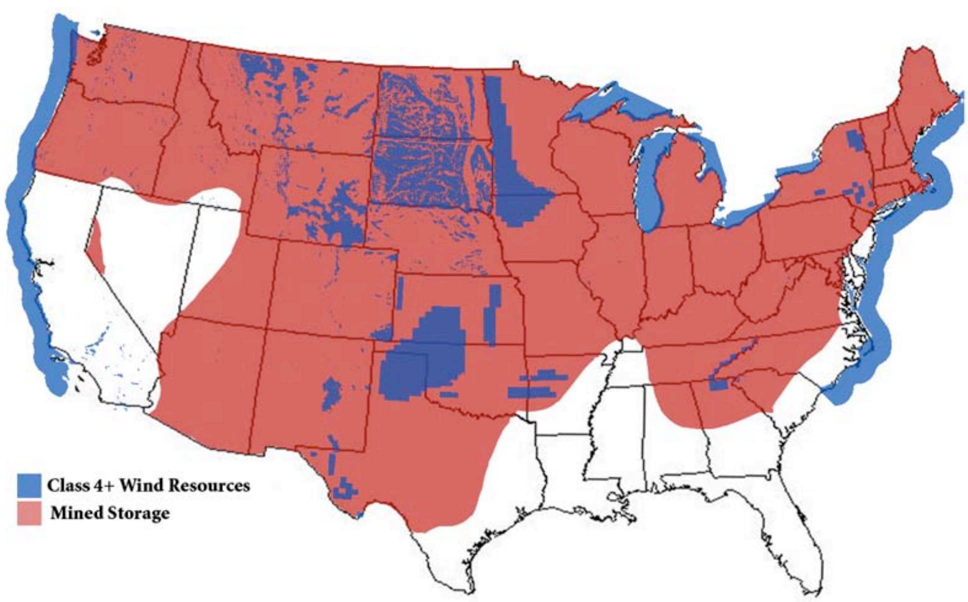

Figure 7 Areas with geologies suitable for mined storage (red) and high-quality wind resources (blue) [33, 41-43]

1.3.3. Porous Rock

Also suitable for CAES are porous rock formations such as saline aquifers. Porous reservoirs have the potential to be the least costly storage option for large-scale CAES with an estimated development cost of ~$0.11/kWh for incremental storage volume expansion [11]. In addition, large, homogeneous aquifers potentially suitable for CAES operation can be found throughout many areas of the central US. Because this area coincides with areas of high quality wind (see Figure 17) and because of the limited availability and/or cost-effectiveness of other options, aquifer CAES will be especially relevant to the discussion of energy storage for balancing wind. Despite its potential for low cost development, utilization of an aquifer for CAES requires extensive characterization of a candidate site to determine its suitability (see section 3, “Aquifer CAES”).

A 25 MW porous rock-based CAES test facility operated for several years in Sesta, Italy. Although the tests were successful, a geologic event disturbed the site which led to closure of the facility [11]. In addition, EPRI and the U.S. Department of Energy have conducted tests on porous sandstone formations in Pittsfield, Illinois to determine their feasibility for CAES (see section 3, “Aquifer CAES”). Construction of the first commercial CAES plant with a porous rock reservoir is scheduled to begin in Dallas Center, Iowa in 2009 (see section 1.4)

1.4. Existing and Proposed CAES Plants

1.4.1. Huntorf

The Huntorf CAES plant, the world's first CAES facility, was completed in 1978 near Bremen, Germany (see Figure 9 and Figure 8). The 290 MW plant was designed and built by ABB (formerly BBC) to provide black-start services[7] to nuclear units near the North Sea and to provide inexpensive peak power. It has operated successfully for almost three decades primarily as a peak shaving unit and to supplement other (hydroelectric) storage facilities on the system to fill the generation gap left by slow-responding medium-load coal plants. Availability and starting reliability for this unit are reported as 90% and 99% respectively.

Because the Huntorf plant was designed for peaking and black start applications, it was initially designed with a storage volume capable of two hours of rated output. The plant has since been operationally modified to provide up to three hours of storage and has been used increasingly to help balance the rapidly growing wind output from North Germany [35, 49].

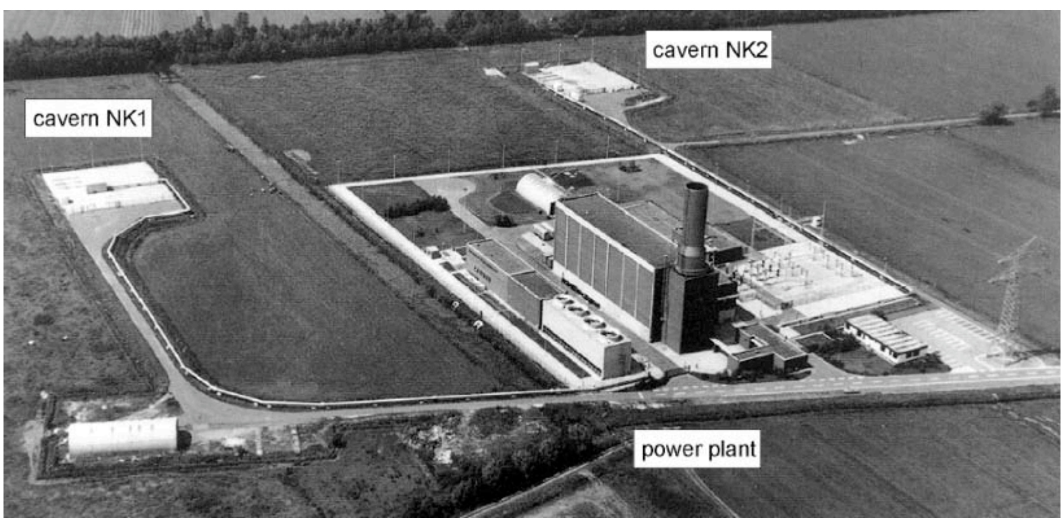

Figure 8 Aerial view of the Huntorf CAES plant [35]

The underground portion of the plant consists of two salt caverns (310,000 m^3 total) designed to operate between 48 and 66 bar. The air from the salt caverns was found to cause oxidation upstream of the gas turbine during the first year of operation, leading to the installation of fiberglass reinforced plastic (FRP) tubing. Because the turbine expanders are sensitive to salt in the combustion air, special measures were taken to ensure acceptable conditions were met at the turbine inlet as well [35].

[7] Black start refers to the ability of a plant to start up during a complete grid outage. Because nuclear power stations require some power to resume operation, the Huntorf CAES plant was built in part to provide this start up power.

The compression and expansion sections draw 108 and 417 kg/s of air respectively and are each comprised of two stages. The first turbine stage expands air from 46 to 11 bar.

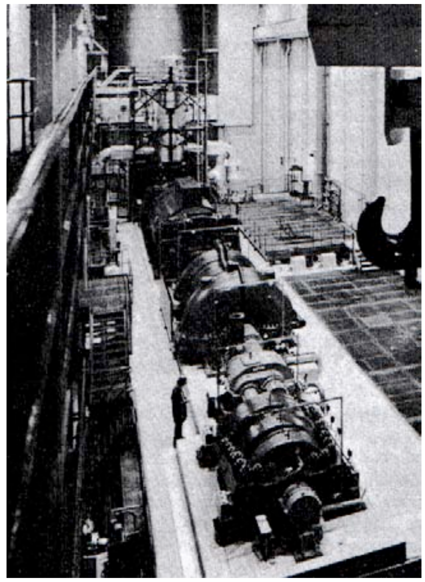

Figure 9 Huntorf Machine Hall [50]

Because gas turbine technology was not compatible with this pressure range, steam turbine technology was chosen for the high-pressure (hp) expansion stage. Due to the increase in heat transfer coefficient at elevated pressure and temperature and to ensure proper cooling (and to control NO_x emissions as well), the hp turbine inlet temperature was held to only 550° C compared to 825° C for the lp turbine (typical for a gas turbine without blade cooling). Moderate combustion inlet temperatures also facilitate the daily turbine starts needed for CAES operation [50].

Although the plant would be able to operate at a lower heat rate if equipped with heat recuperators (so as to recover exhaust heat from the lp turbine for preheating the gas entering the hp turbine), this addition was omitted in order to minimize system startup time [51, 52].

1.4.2. McIntosh

Although high oil and gas prices through the early 1980s continued to draw the attention of utilities to CAES as a source for inexpensive peak power [47] it was not until a decade later that a CAES facility began operating in the United States. The 110 MW McIntosh plant was built by the Alabama Electric Cooperative on the McIntosh salt dome in southwestern Alabama and has been in operation since 1991 (see Figure 10). It was designed for 26 hours of generation at full power and uses a single salt cavern (560,000 m^3) designed to operate between 45 and 74 bar.

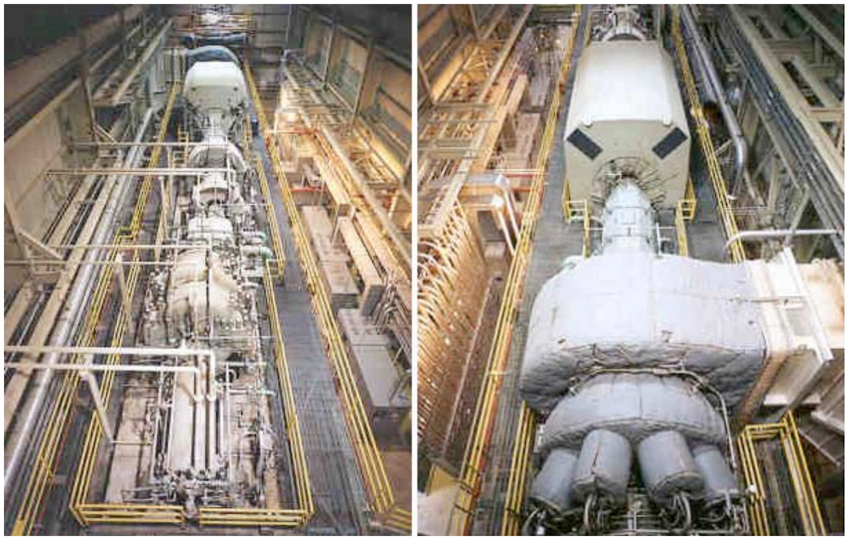

Figure 10 McIntosh CAES system compressor train (left) and combustion turbine (right)

The project was developed by Dresser-Rand, but many of the operational aspects of the plant (inlet temperatures, pressures, etc) are similar to those of the BBC design for the Huntorf plant. The facility does, however, include a heat recuperator that reduces fuel consumption by approximately 22% at full load output and features a dual-fuel combustor capable of burning No. 2 fuel oil in addition to natural gas [11].

Although the plant experienced significant outages in its early operation, the causes of these outages were addressed through modifications of the high pressure combustor mounting and a redesign of the low pressure combustor [53]. These changes enabled the McIntosh plant, over 10 years of operation, to achieve 91.2% and 92.1% average starting reliabilities as well as 96.8% and 99.5% average running reliability for the generation cycle and compression cycle respectively [54].

1.4.3. Norton

A proposal has been under development to convert an idle limestone mine in Norton, Ohio into the storage reservoir for an 800MW CAES facility (with provisional plans to expand to 2,700 MW [9 x 300 MW] see Figure 11). The mine, purchased in 1999, would provide 9.6 million cubic meters of storage and operate at pressures of between 55 and 110 bar. The project, initially approved by the Ohio Public Siting Board in 2001, was granted a five-year extension in 2006. Project negotiations are currently underway and it appears that the project will move forward [52, 55-57].

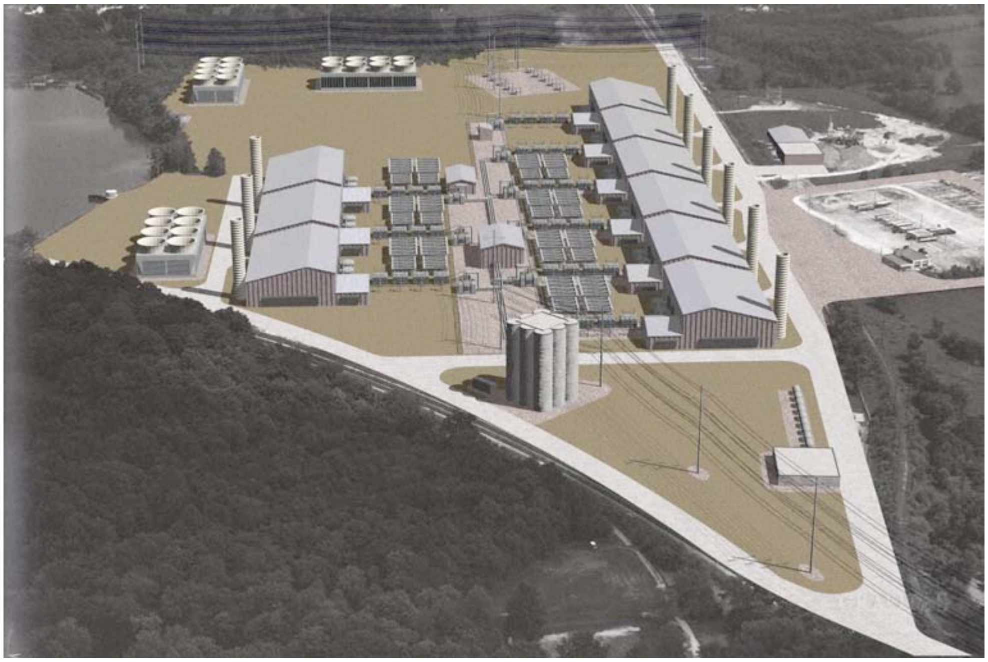

Figure 11 A rendering of the proposed 2700 MW CAES plant based on an abandoned limestone mine in Norton, OH [55]

1.4.4. Iowa Stored Energy Park

The Iowa Association of Municipal Utilities (IAMU) is developing an aquifer CAES project in Dallas Center, Iowa that will be directly coupled to a wind farm (see Figure 12). The Iowa Stored Energy Park (ISEP, a 268 MW CAES plant coupled to 75 to 100 MW of wind capacity, was formally announced in December 2006. This is the only publicly announced project to date directly linking CAES with wind energy and the only one using a porous rock storage reservoir. The CAES facility will occupy 40 acres located within 30 miles of Des Moines, Iowa and use a 3000 ft deep anticline in a porous sandstone formation to store wind energy generated as far away as 100 to 200 miles from the site. This was the third location studied for ISEP after an initial screening of more than

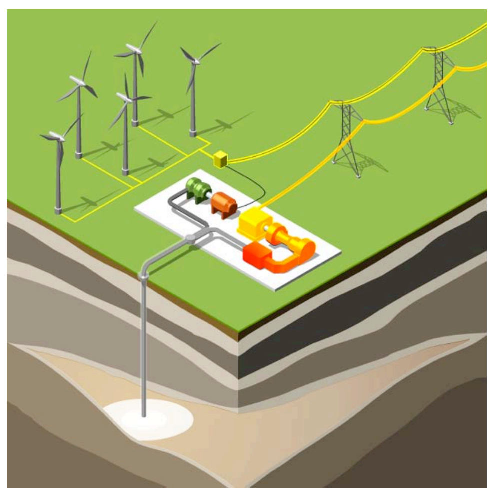

Figure 12 Diagram of the Iowa Stored Energy Park [58]

20 geologic structures in the state. Studies of the chosen formation have verified it has adequate size, depth and caprock structure to support CAES operation. Construction is due to begin in 2009, with completion and operation scheduled for 2011 [58].

1.4.5. Proposed Systems in Texas

Several factors make Texas and the surrounding region attractive for CAES development: First, the rapid growth of wind power in Texas (currently the largest and fastest growing wind market of any US state) is putting increasing burdens on existing load-following capacity in the region. Second, there are considerable transmission bottlenecks and few interconnection points with neighboring grids presenting a significant curtailment risk for wind developers as wind penetrations continue to increase. Lastly, domal salt formations such as those used at the existing Huntorf and McIntosh CAES sites exist in the state. This geology has been proven to work well under CAES operating conditions and thus poses limited risk.

Consequently, Ridge Energy Storage & Grid Services L.P. have announced plans to develop several CAES projects throughout Texas, including a 540 MW (4x135MW) system in Matagorda County, TX based on the McIntosh Dresser-Rand design and utilizing a previously developed brine cavern.[8]

Ridge also prepared two CAES studies focused on the Texas panhandle and surrounding region. The first, commissioned by the Texas State Energy Conservation Office (SECO) and led by the Colorado River Authority, analyzed the alleviation of transmission curtailment through the use of CAES [7]. The second addressed the broader economic impacts of CAES in Texas, Oklahoma and New Mexico (the study area comprised the control area of SPS, an operating company of Excel Energy) [8]. The studies found compelling reasons for pursuing CAES in this region—including improved delivery profile for renewable energy on the system, reduced ramping of other system capacity due to wind energy, and transmission cost offsets. Furthermore, the study estimated a net value of $10 million per year to SPS for developing a 270 MW CAES unit with 50 hours of storage. The report also claims that such a system could enable the development of an additional 500 MW of wind without any additional ramping burdens on the system.

More recently, Shell and TXU have announced they intend to explore the possibility of adding CAES to a proposed 3,000 MW wind farm in the Texas Panhandle [59].

[8] At the time of the release of this report, it appears that this project is not moving forward.

2. CAES Operation and Performance

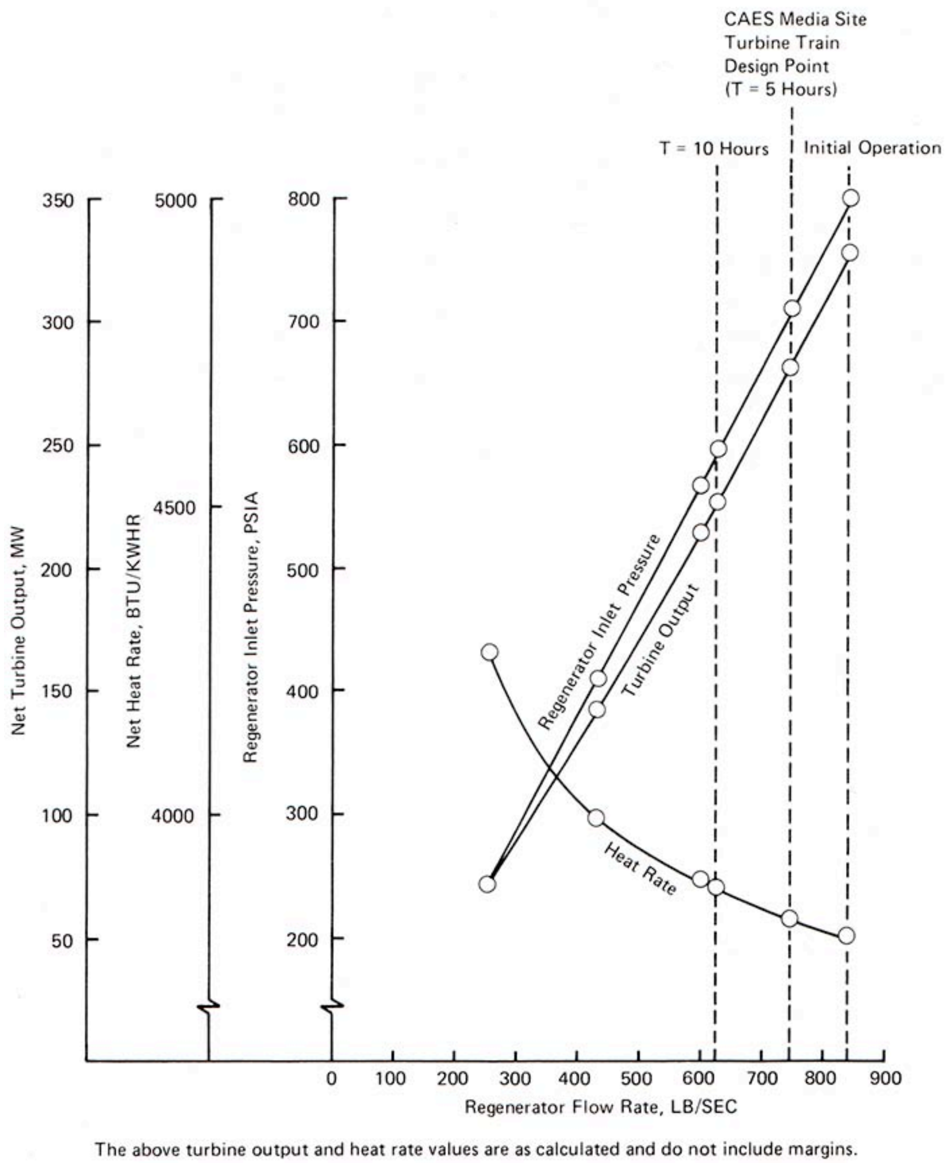

Figure 13 Turbine performance characteristics for Aquifer CAES based on EPRI design for Media, Illinois site [60]

2.1. Ramping, Switching and Part-Load Operation

The high part-load efficiency of CAES (see Figure 13) makes it well suited for balancing variable power sources such as wind. The heat rate increase at part-load is small relative to a conventional gas turbine because of the way the turboexpander output is controlled. Rather than changing the turbine inlet temperature as in a conventional turbine, the CAES output is controlled by adjusting the air flow rate with inlet temperatures kept constant at both expansion stages. This leads to better heat utilization and higher efficiency during part-load operation [51].

The McIntosh CAES plant delivers power at heat rates of 4330 kJ/kWh (LHV) at full load and 4750 kJ/kWh (LHV) at 20% load [53]. This excellent part-load behavior could be further enhanced in modular systems such as the proposed Norton plant where the full plant output would be delivered by multiple modules. In this case, the system could ramp down to 2.2% of the full load output and still be within 10% of the full load output heat rate.

The ramp rates for a CAES system is also better than for an equivalent gas turbine plant. The McIntosh plant can ramp at approximately 18 MW per minute, which is about 60% greater than for typical gas turbines. The Matagorda Plant proposed by Ridge Energy Storage is designed to be able to bring its four 135 MW power train modules to full power in 14 minutes (or 7 minutes for an emergency start)—which translates to 9.6 to 19 MW per minute per module. These fast ramp rates together with efficient part load operation make CAES an ideal technology for balancing the stochastic variations in wind power.

To initiate compression operation, the turbine typically brings the machinery train to speed. After synchronization, the turbine is decoupled and shut off and the compressors are left operating. This means that the turbines are called upon to initiate both compression and generation. In the case of the Huntorf CAES system the switch from one operating mode to another is completely automated and requires a minimum of 20 minutes during which time the system is neither generating power nor compressing air [50]. The switchover time could have a significant impact for balancing rapid fluctuations in wind output. It is possible alternative startup designs, such as use of an auxiliary startup motor could reduce this interval further [60].

Operation switchover time limitations could even be eliminated altogether with new system designs that decouple the compression and turboexpander trains. By separating these components rather than linking them through a common shaft via a clutch as in the McIntosh and Huntorf system, direct switching between compression and expansion operation is possible. This change also means compressor size can be optimized independently of the turboexpander design and permits standard production compressors to be used in the system configuration [52].

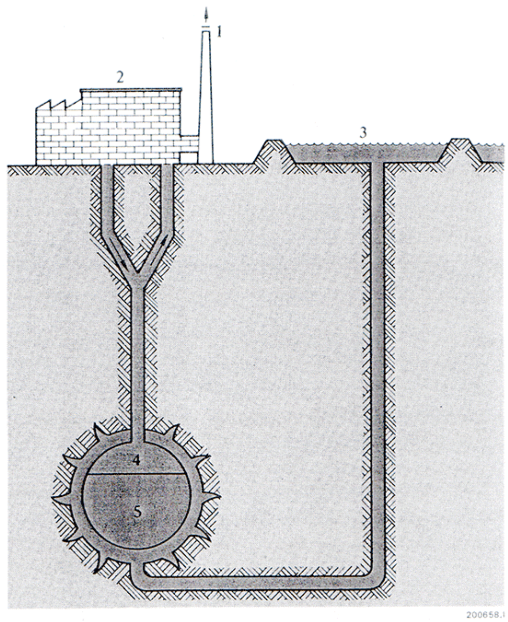

Figure 14 Constant pressure CAES reservoir with compensating water column. (1) Exhaust (2) CAES Plant (3) Surface Pond (4) Stored Air (5) Water Column [51]

2.2. Constant Volume and Constant Pressure

A CAES system can operate in a number of different ways depending on the type of geology being utilized for the storage reservoir. The most common mode is to operate the CAES system under constant volume conditions. This means that the storage volume is a fixed, rigid reservoir operating over an appropriate pressure range.[9] This mode of operation offers two design options: (1) it is possible to design such a system to allow the hp turbine inlet pressure to vary with the cavern pressure (reducing output) or (2) keep the inlet pressure of the hp turbine constant by throttling the upstream air to a fixed pressure. Although this latter option requires a larger storage volume (due to throttling losses), it has been pursued at both of the existing CAES facilities due to the increase in turbine efficiency attained for constant inlet pressure operation. The Huntorf CAES plant is designed to throttle the cavern air to 46 bar at the hp turbine inlet (with caverns operating between 48 to 66 bar) and the McIntosh system similarly throttles the incoming air to 45 bar (operating between 45 and 74 bar).

A third option is to keep the storage cavern at constant pressure throughout operation by using a head of water applied by an aboveground reservoir (see Figure 14). The use of

[9] Although aquifer bubbles are not rigid bodies, the time scale at which the air-water interfaces migrate is much longer than CAES storage cycles and therefore porous rock systems can be approximated as fixed-volume air reservoirs in this context (see section 3.6)

compensated storage volumes minimizes losses and improves system efficiency, but care must be taken to manage flow instabilities in the water shaft such as the so-called champagne effect [61].

This technique is incompatible with salt-based caverns since a continual flow of water would dissolve walls of the cavern. Brine cycling with a compensating column connected to a surface pond of saturated brine could be implemented, but biological concerns and ground water contamination issues would need to be addressed [51]. Since pressure compensated operation cannot be employed in aquifer systems (see Flow in Aquifers below), the use of constant-pressure CAES operation is primarily limited to systems with reservoirs mined from hard rock.

2.3. Storage Volume Requirement

Although several CAES systems have been successfully implemented and even though suitable geologies appear plentiful, the realistic potential for large scale worldwide deployment will not be known until there is much better understanding of the geologic resources available to support many plants deployed under a wide variety of conditions.

One of the keys to assessing the geologic requirements for CAES is to understand how much electrical energy can be generated per unit volume of storage cavern capacity (E_{GEN}/V_S). The electrical output of the turbine (E_{GEN}) is given by:

$$E_{GEN} = \eta_M \, \eta_G \int_0^t \dot{m}_T \, w_{CV,TOT} \, dt \tag{1}$$

where the integral is the mechanical work generated by the expansion of air and fuel in the turbine,

$w_{CV,TOT}$ = total mechanical work per unit mass generated in this process

$\dot{m}_T$ = air mass flow rate

t = time required to deplete a full storage reservoir at full output power

η_M = mechanical efficiency of the turbine (which reflects turbine bearing losses)

η_G = electric generator efficiency

Since all CAES systems to date are based on two expansion stages, the work output can be expressed as the sum of the output from the two stages. The first term reflects the work output from the hp turbine that expands the air from the hp turbine inlet pressure (p_1) to the lp turbine inlet pressure (p_2). Likewise, the second term reflects the expansion work derived from the expansion from p_2 to barometric pressure (p_b).

$$w_{CV,TOT} = w_{CV1} + w_{CV2} = -\int_{p_1}^{p_2} v \, dp - \int_{p_2}^{p_b} v \, dp \tag{2}$$

Consider first the work output from the first expansion stage. Assuming adiabatic compression and that the working fluid is an ideal gas with a constant specific heat (so that $P \cdot v^k = c$, a constant, where $k_1 \equiv C_{p1}/C_{v1}$) the work per unit mass is:

$$w_{CV1} = \int_{p_2}^{p_1} v \, dp = c^{1/k_1} \int_{p_2}^{p_1} \frac{dp}{p^{1/k_1}} \tag{3}$$

$$= \frac{k_1}{k_1 - 1}\left[p\left(\frac{c}{p}\right)^{1/k_1}\right]_{p_2}^{p_1} = \frac{k_1}{k_1 - 1}\left[p_1 v_1 - p_2 v_2\right] \tag{4}$$

$$= \frac{c_v}{c_p - c_v}\frac{c_p}{c_v} p_1 v_1 \left(1 - \frac{p_2 v_2}{p_1 v_1}\right) \tag{5}$$

$$= c_p T_1 \left[1 - \left(\frac{p_2}{p_1}\right)^{\frac{k_1 - 1}{k_1}}\right] \tag{6}$$

Combining with a similar expression for the second stage gives the total work per unit mass for the process ($w_{CV,TOT}$):

$$w_{CV,TOT} = c_{p2} T_2 \left(\frac{c_{p1} T_1}{c_{p2} T_2}\left[1 - \left(\frac{p_2}{p_1}\right)^{\frac{k_1 - 1}{k_1}}\right] + \left[1 - \left(\frac{p_b}{p_2}\right)^{\frac{k_2 - 1}{k_2}}\right]\right) \tag{7}$$

Furthermore, the total mass flow through the turbine can be expressed as separate air and fuel input terms:

$$\dot{m}_T = \dot{m}_A + \dot{m}_F = \dot{m}_A \left(1 + \frac{\dot{m}_F}{\dot{m}_A}\right) \tag{8}$$

Since

$$\frac{\dot{m}_F}{\dot{m}_A} \approx \text{constant} \tag{9}$$

The result is:

$$\frac{E_{GEN}}{V_S} = \frac{\alpha}{V_S}\int_0^t \dot{m}_A \left(\beta + 1 - \left(\frac{p_b}{p_2}\right)^{\frac{k_2 - 1}{k_2}}\right) dt \tag{10}$$

where

$$\alpha = \eta_M \, \eta_G \, c_{p2} T_2 \left(1 + \frac{\dot{m}_F}{\dot{m}_A}\right) \tag{11}$$

and

$$\beta = \frac{c_{p1} T_1}{c_{p2} T_2}\left[1 - \left(\frac{p_2}{p_1}\right)^{\frac{k_1 - 1}{k_1}}\right] \tag{12}$$

2.3.1. Case 1: Constant Cavern Pressure

First consider the case of a CAES system with constant cavern pressure such as a hard rock cavern with hydraulic compensation (see Figure 14). In this case, the mass flow of air is constant throughout the process and can be expressed as a simple ratio:

$$\dot{m}_A = \frac{m_A}{t} = \frac{p_S V_S M_W}{R T_S t} \tag{13}$$

Likewise, since the inlet pressures and temperatures are constant in time, equation (10) reduces to the following:

$$\frac{E_{GEN}}{V_S} = \frac{\alpha}{V_S}\dot{m}_A\left(\beta + 1 - \left(\frac{p_b}{p_2}\right)^{\frac{k_2-1}{k_2}}\right)\int_0^t dt \tag{14}$$

Combining these expressions,

$$\frac{E_{GEN}}{V_S} = \frac{\alpha\, M_W}{R T_S}\, p_S\left(\beta + 1 - \left(\frac{p_b}{p_2}\right)^{\frac{k_2-1}{k_2}}\right) \tag{15}$$

2.3.2. Case 2: Variable Cavern Pressure, Variable Turbine Inlet Pressure

In the case of a variable pressure CAES system, the pressure at the turbine inlet is allowed to vary over the operating range of the storage volume (from p_{S2} to p_{S1}). However, since the pressure ratio across the hp turbine (p_2/p_1) remains constant, the pressure ratio across the lp turbine is proportional to the cavern pressure p_S [32]:

$$\frac{p_b}{p_2} = \frac{p_1}{p_2}\frac{p_b}{\varphi p_S} = \frac{\text{constant}}{p_S} \tag{16}$$

where φ is a correction factor that accounts for the pressure loss from the storage reservoir to the turbine inlet (~0.90).

$$\dot{m}_A = \frac{d}{dt}\left(\frac{V_S p_S\, M_W}{R T_S}\right) = \frac{d}{dt}\left(\frac{V_S M_W p_S}{R T_{S2}}\left(\frac{p_{S2}}{p_S}\right)^{\frac{k_S-1}{k_S}}\right) \tag{17}$$

$$\dot{m}_A = \frac{1}{k_S}\left[\frac{V_S\, M_W}{R T_{S2}}\left(\frac{p_{S2}}{p_S}\right)^{\frac{k_S-1}{k_S}}\right]\frac{dp_S}{dt} \tag{18}$$

Substituting equations (16) and (18) into (10), the energy storage density is:

$$\frac{E_{GEN}}{V_S} = \frac{\alpha\, M_W}{R T_{S2}}\frac{p_{S2}^{\frac{k_S-1}{k_S}}}{k_S}\int_{p_{S1}}^{p_{S2}}\left(\frac{1}{p_S}\right)^{\frac{k_S-1}{k_S}}\left(\beta + 1 - \left(\frac{p_1}{p_2}\frac{p_b}{\varphi\, p_S}\right)^{\frac{k_2-1}{k_2}}\right)dp_S \tag{19}$$

$$= \frac{\alpha\, M_W}{R T_{S2}} \frac{p_{S2}^{\frac{k_S-1}{k_S}}}{k_S} \left\{ (\beta+1)\int_{p_{S1}}^{p_{S2}} \left(\frac{1}{p_S}\right)^{\frac{k_s-1}{k_S}} dp_S - \left(\frac{p_1}{p_2}\frac{p_b}{\varphi}\right)^{\frac{k_2-1}{k_2}} \int_{p_{S1}}^{p_{S2}} \left(\frac{1}{p_S}\right)^{\frac{k_s-1}{k_S}+\frac{k_2-1}{k_2}} dp_S \right\} \quad (20)$$

$$= \frac{\alpha\, M_W\, p_{S2}}{R T_{S2}\, k_S}\left\{(\beta+1)\frac{1}{p_{S2}^{1/k_S}}\int_{p_{S1}}^{p_{S2}} p_S^{\frac{1}{k_S}-1}\, dp_S - \left(\frac{p_1}{p_2}\frac{p_b}{\varphi}\right)^{\frac{k_2-1}{k_2}} \frac{p_{S2}^{-\frac{k_2-1}{k_2}}}{p_{S2}^{\frac{1}{k_S}+\frac{1}{k_2}-1}} \int_{p_{S1}}^{p_{S2}} p_S^{\frac{1}{k_S}+\frac{1}{k_2}-2}\, dp_S\right\} (21)$$

$$= \frac{\alpha\, M_W\, p_{S2}}{R T_{S2}}\left\{(\beta+1)\left(1-\left(\frac{p_{S1}}{p_{S2}}\right)^{1/k_S}\right) - \left(\frac{p_1}{p_2}\frac{p_b}{\varphi\, p_{S2}}\right)^{\frac{k_2-1}{k_2}} \frac{1}{k_S\left(\frac{1}{k_S}+\frac{1}{k_2}-1\right)}\left(1-\left(\frac{p_{S1}}{p_{S2}}\right)^{\frac{1}{k_S}+\frac{1}{k_2}-1}\right)\right\} (22)$$

2.3.3. Case 3: Variable Cavern Pressure, Constant Turbine Inlet Pressure

The third case we consider is one in which the air recovered from storage is throttled from the reservoir pressure p_s to the hp turbine inlet pressure p_1 such that the mass flow and expansion work output are constant in time. As in case 1, the integral representing the mechanical work in turbine expansion can be reduced to a simple time average, but in this case, the net air mass withdrawn from storage is a function of the storage pressure fluctuation over the range p_{S2} to p_{S1}:

$$\dot{m}_T = \frac{\Delta m_A}{t}\left(1+\frac{\dot{m}_F}{\dot{m}_A}\right) \quad (23)$$

$$\Delta m_A = \frac{V_S p_{S2}}{R T_{S2}} - \frac{V_S p_{S1}}{R T_{S1}} = \frac{V_S p_{S2}}{R T_{S2}}\left(1-\left[\frac{p_{S1}}{p_{S2}}\right]^{\frac{1}{k_S}}\right) \quad (24)$$

Substituting these into equation (10) yields

$$\frac{E_{GEN}}{V_S} = \frac{\alpha\, M_W\, p_{S2}}{R T_{S2}}\left(\beta+1-\left(\frac{p_b}{p_2}\right)^{\frac{k_2-1}{k_2}}\right)\left(1-\left[\frac{p_{S1}}{p_{S2}}\right]^{\frac{1}{k_S}}\right) \quad (25)$$

2.3.4. Cavern Size

Figure 15 shows the energy storage density for the above three cases as a function of the maximum reservoir pressure, and, for cases 2 and 3, as a function of the storage pressure ratio as well.

For all three cases, the electric energy storage density E_{GEN}/V_S increases approximately linearly with increasing reservoir pressure p_{S2} (or equivalently with mass per unit volume $p_{S2}*M_W/RT_{S2}$). In some cases however, this might result in large heat loss in the aftercooler depending on the thermal constraints of the cavern [62].

The use of a constant-pressure compensated cavern requires the smallest cavern by far. Zaugg estimates for a configuration similar to the Huntorf design (with a storage pressure of 60 bar), a constant pressure cavern could deliver the same output with only 23% of the storage volume required for a constant volume configuration with variable inlet pressure (p_{S2}/p_{S1}=1.4) [32]. If hard rock reservoirs are unavailable or too costly, pressure compensated systems will most likely not be an option, so that a case 2 or a case 3 design would be required.

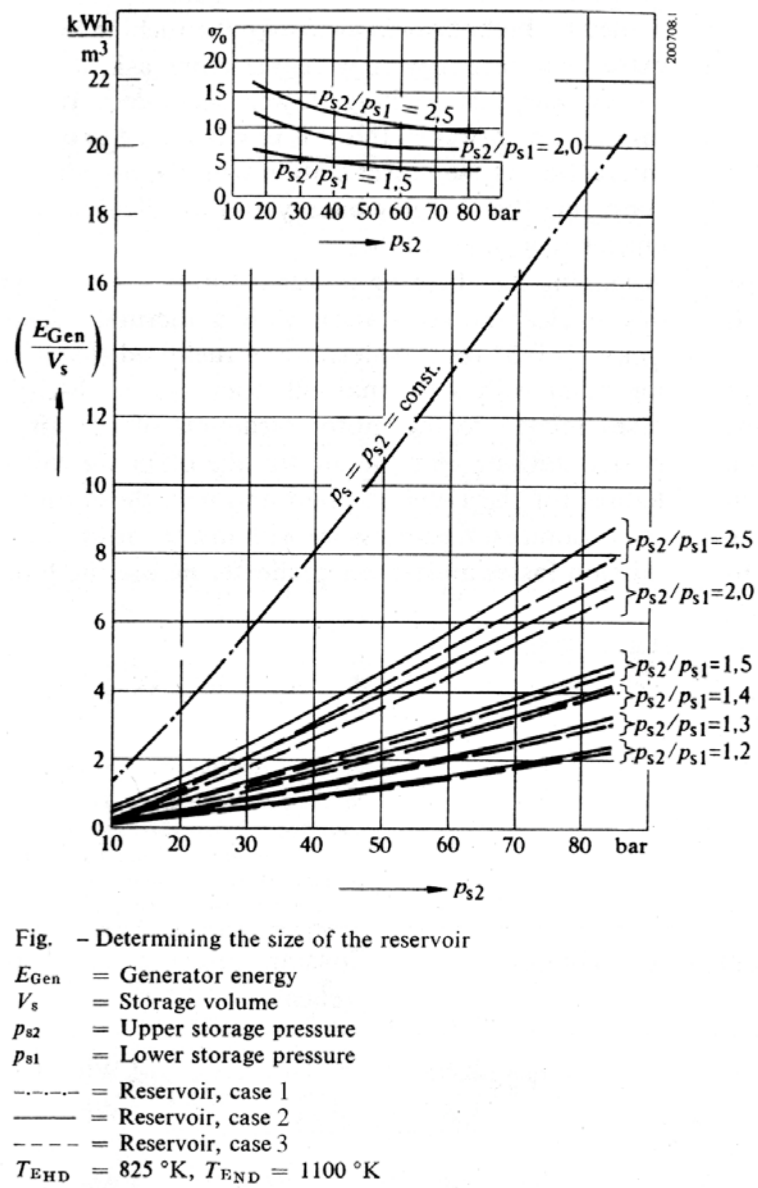

Figure 15 The energy produced per unit volume for CAES with constant pressure reservoir (case 1), variable pressure reservoir (case 2) and variable pressure reservoir with constant turbine inlet pressure (case 3). Inset shows throttling losses associated with case 3 relative to the variable inlet pressure scenario (case 2)- figure from [32].

Notably, although the throttling losses incurred in case 3 relative to the variable turbine inlet pressure system (case 2) implies a required larger storage volume, the penalty is not large (see Figure 15 inset). In particular the throttling losses are small with large initial pressures (p_{s2}>60 bar) that is consistent with all known existing and proposed CAES systems. Because this small penalty is offset by the benefits of higher turbine efficiency and simplified system operation, it is often optimal to operate a CAES system in this mode (as is the case at both the Huntorf and McIntosh plants).

However, in some cases it might be advantageous to allow the inlet pressure to vary depending on the geologic characteristics of the system. For aquifer systems for example, due to the large amount of cushion gas needed, the storage pressure ratio p_{s2}/p_{s1} is relatively small (<1.5) such that the hp turbine can operate over the full storage reservoir pressure range with relatively small penalties relative to the design point performance

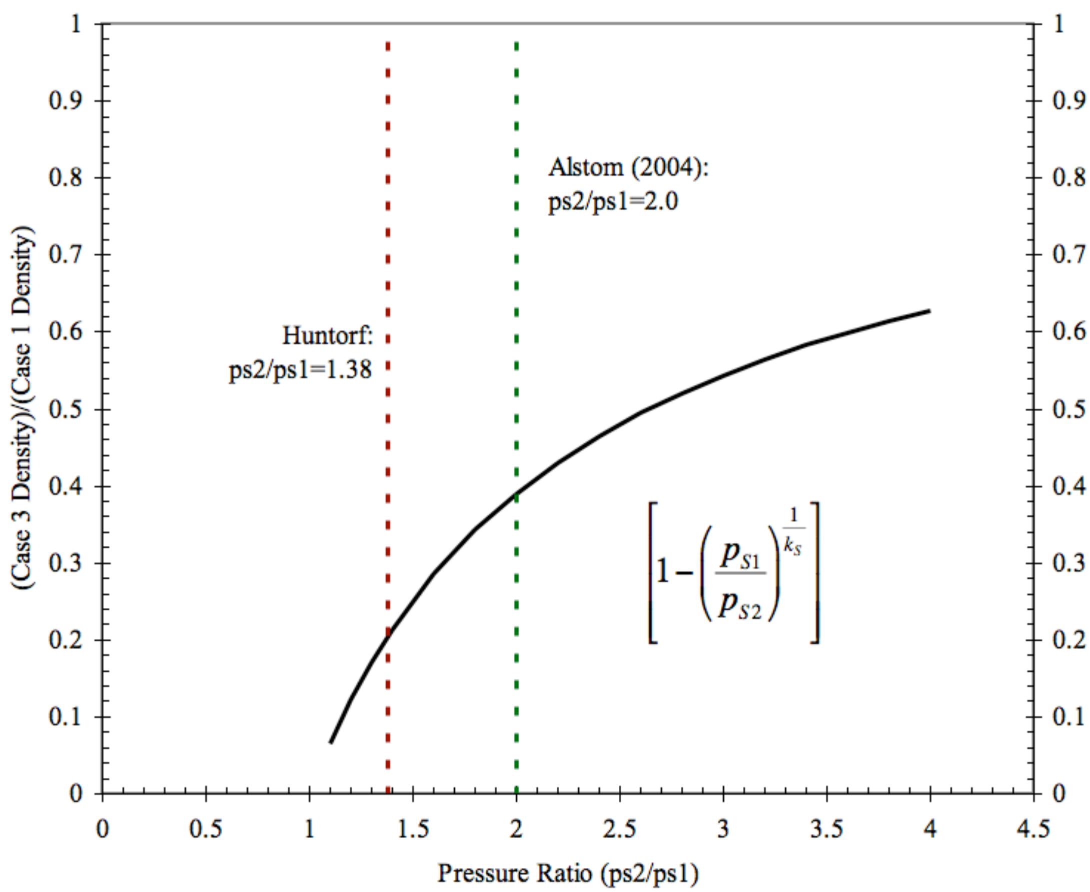

Figure 16 The ratio of storage energy density between a constant volume CAES system with constant turbine inlet pressure (case 3) and a pressure compensated CAES reservoir (case 1) as a function of the ratio between the operating pressures of the case 3 system (p_{S2}/p_{S1}). [10]

[10] Here we assume k_S=1.4 and $(p_{S2}/T_{S2})\,/\,(p_{S1}/T_{S1}) = 1$

(see Figure 13) [50, 60].

Although a variable pressure reservoir CAES system requires a larger storage volume than a compensated reservoir, volume requirements might be reduced substantially by an appropriate design of the storage volume pressure range, to the extent that so doing is consistent with the pressure limits of the reservoir and the turbomachinery. The ratio of the energy storage density for case 3 relative to case 1 is given by (compare equations (25) and (15)):

$$\left(1-\left[\frac{p_{S1}}{p_{S2}}\right]^{\frac{1}{k_S}}\right) \tag{26}$$

This term increases with p_{S2}/p_{S1} as shown in Figure 16. Thus selecting formations that can accommodate large pressures swings and high maximum reservoir pressures will reduce land area requirements for CAES through increased storage energy density.

Typical numbers for E_{GEN}/V_S are 2-4 kWh/m^3 for lower pressure ratios such as those at Huntorf (p_{S2}/p_{S1}=1.38, p_{S2}=66 bar, E_{GEN}/V_S=3.74) and 6-9 kWh/m^3 for the newer designs such one proposed by Alstom, which is designed with higher operating pressures and larger pressure ratios (p_{S2}/p_{S1}=2.0, p_{S2}=110 bar, E_{GEN}/V_S=8.44) [11, 63].

In section 4, "Wind/CAES Systems in Baseload Power Markets", a CAES system design is described which converts wind power into baseload electricity. The system configuration includes a storage reservoir capable of supporting 2 GW of baseload power for 88 hours (176 GWh of storage). The land area requirement for the wind turbine array is 860 km^2. For a system with an electricity storage density consistent with a formation depth similar to the Dallas Center, Iowa CAES plant (depth 880m, discovery pressure ~ 80 bar, E_{GEN}/V_S ~ 5 kWh/m^3) the total pore volume needed for the cycled air would be 35 million cubic meters.[11] Assuming the ratio of total air mass (cushion air plus cycled air) in the reservoir to the mass of cycled air is 5 [64], and assuming an average reservoir height of 10 meters and an effective porosity of 15%, the "footprint" of the reservoir would occupy an area of land equal to approximately 14% of the land area of the wind turbine array.

2.4. Performance Indices for CAES Systems

The energy performance of a conventional fossil fuel power plant is easily described by a single efficiency: the ratio of electrical energy generated to thermal energy in the fuel. The situation is more complicated for CAES due to the presence of two very different energy inputs. On the one hand, electricity is used to drive the compressors and on the other natural gas or oil is burned to heat the air prior to expansion. This situation makes it difficult to describe CAES performance via a single index in a way that is universally useful—the most helpful single index depends on the application for CAES that one has in mind. Before turning to a discussion of alternative options for a single CAES

[11] This volume corresponds to a gas volume that is of the same order as the working gas capacity of the largest porous rock natural gas storage sites in the US and Canada, but is considerably larger (by about an order of magnitude) than the mean capacity among these facilities (AGA, 2004).

performance index, it is worthwhile considering the two performance indices that apply to each energy input separately: the heat rate and the charging electricity ratio.

2.4.1. Heat Rate

The heat rate (HR) or fuel consumed per kWh of output for a CAES system is a function of many system design parameters, but the design choice that most critically affects the heat rate is the presence of a heat recovery system. The addition of a heat recuperator allows the system to capture the exhaust heat from the lp turbine to preheat the air withdrawn from the storage reservoir. Heat rates for CAES systems without a heat recovery system are typically 5500-6000 kJ/kWh LHV (e.g., 5870 kJ/kWh LHV for Huntorf). Heat rates with a recuperator are typically 4200-4500 kJ/kWh LHV (e.g., 4330 kJ/kWh for McIntosh). By comparison, a conventional gas turbine has at least twice this level of fuel consumption (~9500 kJ/kWh LHV) because two thirds of the electrical output is used to run the compressor. Because the CAES compression energy is supplied separately, the system can achieve a much lower heat rate [11, 51].

The addition of the heat recuperator reduced the fuel consumption at McIntosh by 22% relative to operation without this component [53], but a high pressure combustor was still required in this case. Newer CAES designs feature higher inlet temperatures at the lp turbine. The added heat generated at this stage facilitates the removal of the hp combustor from the design altogether (as for the CAES unit shown in Figure 3). In addition to further reducing fuel consumption, these systems also offer significant NO_x emissions benefits relative to prior designs [63].

2.4.2. Charging Electricity Ratio

The second performance index for CAES is the ratio of generator output to compressor motor input—the charging electricity ratio (CER). Because of the fuel input, the CER is greater than unity and will typically lie in the range of 1.2 to 1.8 (kWh_{output}/kWh_{input}) [11, 32, 65]. The CER also takes into account piping and throttling losses as well as compressor and expander efficiencies. Throttling loss is a function the reservoir pressure range (see Figure 15). Turbine efficiency is especially important in the low-pressure expansion stage, in which most of the enthalpy drop occurs and where approximately three quarters of the power is generated [66]. Increased turbine inlet temperatures (e.g., by using expander blade cooling technologies) would enhance the turbine and CAES electrical efficiencies as well [67].

2.4.3. Toward a Single CAES Performance Index

Several single-parameter performance indices have been proposed for CAES. The simplest possible index is an efficiency η defined as the ratio of energy generated by the turbine (E_T) to the sum of electrical energy delivered to the compressor motor (E_M) and the thermal energy in the fuel (E_F)

$$\eta = \frac{E_T}{E_M + E_F} \tag{27}$$

Typical HR and CER values of, respectively, 4220 kJ/kWh and 1.5 imply $\eta = 54\%$. However, because of the substantial difference between the energy qualities of the thermal energy in the fuel and the electrical energy supplied to the compressor, their sum is not a meaningful number. In order to estimate the total energy input to CAES, it is necessary to express both the fuel and compressor electricity on an equivalent energy basis. One approach is to express the electrical input as an equivalent quantity of thermal energy.

2.4.3.1. Primary Energy Efficiency

When CAES is used to convert baseload thermal power into peaking power (in place of gas turbines or other peaking units) one can introduce a primary energy efficiency η_{PE} defined in terms of the thermal efficiency of the baseload plant (η_T). Here compressor motor energy input E_M is replaced by an expression for the effective thermal energy input required to produce E_M. Thus, the overall efficiency value reflects the system (grid + CAES) efficiency of converting primary (thermal) energy into electrical energy:

$$\eta_{PE} = \frac{E_T}{E_M / \eta_T + E_F} \tag{28}$$

This methodology has been applied to CAES units charged by nuclear and fossil fuel power plants [32], CHP plants [62], as well as grid-averaged baseload power [68]. Assuming $\eta_T = 40\%$ (as might characterize a modern supercritical steam-electric plant) and the same other parameters as considered in the earlier calculation of η, implies η_{PE} = 35%.

In principle, this formulation of system efficiency can be applied to a wind/CAES system by using the atmospheric efficiency of the wind turbines η_{WT} in place of the thermal plant efficiency η_T. This formulation, proposed by Arsie et al, gives rise to a system efficiency of 39% [69]. However, the use of atmospheric efficiency in this case does not serve the same function as the thermal efficiency. In the case of fossil fuel or nuclear power as the source of compressor energy, use of the thermal efficiency provides a measure of the amount of primary fuel needed to deliver a quantity of electrical energy E_M. In contrast, the extraction of "fuel" in the case of wind energy does not affect the environmental impact or overall cost of the plant. Consequently, this measure of the amount of atmospheric kinetic energy captured in providing E_M is not very helpful and in the case of wind/CAES systems and therefore this is not the optimal formulation for CAES efficiency.

2.4.3.2. Round Trip Efficiency

A CAES unit powered by wind energy will be compared to other electrical storage options that might be considered for wind back up such as electrochemical or pumped hydroelectric storage. Such alternative storage systems are typically characterized by a roundtrip electrical storage efficiency η_{RT} defined as

η_{RT} = (electricity output)/(electricity input).

To facilitate comparisons of CAES to other electrical storage devices, a round trip efficiency can be introduced that employs an "effective" electricity input $\equiv E_M + \eta_{NG} {*} E_F$. The second term is the amount of electricity that could be have been made from the natural gas input E_F, had that fuel been used to make electricity in a stand-alone power plant at efficiency η_{NG} instead of to fire a CAES unit. The round-trip efficiency $\eta_{RT,1}$ so defined is:

$$\eta_{RT,1} = \frac{E_T}{E_M + \eta_{NG} E_F} \tag{29}$$

This methodology has the advantage of providing an electricity-for-electricity roundtrip storage efficiency that isolates the energy losses in the conversion of electricity to compressed air and back to electricity. Several values for η_{NG} have been proposed including the hypothetic Carnot cycle efficiency [65] as well as the efficiencies of commercial simple cycle and combined cycle power plants [2, 70]. For typical natural gas power systems, (heat rates in the range 6700-9400 kJ/kWh) CAES roundtrip efficiencies are in the range of 77-89% assuming a 1.5 ratio of output to input electricity and a heat rate of 4220 kJ LHV per kWh. An exergy analysis of conventional CAES systems indicates that 47.6% of the fuel energy input is converted into electrical work [71]. For this measure of the thermal efficiency, the roundtrip efficiency is 81.7%.

An alternative formulation $\eta_{RT,2}$ of an electrical roundtrip storage efficiency introduces an output correction term $E_F*\eta_{NG}$. Instead of expressing the fuel input as an effective electrical input, the electrical output is adjusted by subtracting the assumed contribution to the output attributable to the fuel. Correspondingly the output attributable to the electrical input is E_T - $E_F*\eta_{NG}$ [72].

$$\eta_{RT,2} = \frac{E_T - E_F \eta_{NG}}{E_M} \tag{30}$$

Using the same assumptions as for $\eta_{RT,1}$ with the Zaugg efficiency for fuel conversion, η_{NG} = 47.6%, the round trip efficiency is 66%.

Thus, depending on the index chosen for its measure, the roundtrip efficiency for CAES is typically in the range 66-82%. This is in the same range as the roundtrip efficiencies cited for other bulk energy storage technologies such as pumped hydroelectric storage (74%) and Vanadium flow batteries (75%) [70].

2.4.3.3. Additional Approaches

Still another measure of the efficiency of CAES proposed by Schainker et al might be useful for an economic evaluation of CAES in load leveling or arbitrage applications. This approach is similar to $\eta_{RT,1}$ in that it adjusts the fuel input by a correction factor:

$$\eta_{AD} = \frac{E_T}{E_F/CR + E_M} \tag{31}$$

In this case however, the fuel input is converted to equivalent electricity not by using the primary energy conversion efficiency for natural gas but rather the cost ratio CR ≡ (off-peak electricity price)/(fuel price) [73] . Although this index might be helpful in deciding how to operate a given CAES unit over time, the measure varies significantly both over time and with geographical region and so is not a useful general plant characterization.

A final description of CAES efficiency compares the CAES output to the electrical output of a thermodynamically ideal CAES plant operating between ambient temperature T_o and T_{max} [65]:

$$\eta_{II} = \frac{E_T}{E_{T,REV}} \tag{32}$$

$$E_{T,REV} = E_M + E_F - T_o \bullet \Delta S = E_M + E_F - T_o \bullet E_F / T_{MAX} \tag{33}$$

Analysis of a conventional CAES system yields a second law efficiency of η_{II}=68% with a recuperator and 59-61% without[12].

Ultimately, the choice of efficiency measure remains an open question because thermal energy and electrical energy quantities cannot be combined by algebraic manipulation. The formulations provided in this section help only to provide a basis for comparison with other storage technologies, but as indicated above, the relevant expression is determined in large part by the application one has in mind.

[12] The range of efficiencies for the system without recuperator reflects change in system performance due to varying storage pressures (p_S = 20 to 70 bar). The change in efficiency was < 1% for the system with recuperator.

Table 2 Selected CAES Efficiency Expressions and Values in The Literature

Parameter	**Definition**	**Reported Value**	
		No Recuperator	*With Heat Recuperator*
Heat Rate	$\eta_F = \frac{E_T}{E_F}$	6000-5500 kJ/kWh (~60-65%)	4500-4200 kJ/kWh (~80-85%)
Charging Energy Ratio	$\eta_{PE} = \frac{E_T}{E_M}$	1.2-1.4	1.4-1.6
Primary Energy Efficiency	$\eta_{PE} = \frac{E_T}{E_M/\eta_T + E_F}$	CAES Charged From Nuclear Power (η_T=33%) [32]	
		24.5%	29.7%
		Charged From Fossil Fuel Power Plant (η_T=42%) [32]	
		28.2%	34.4%
		Charged from Combined Heat and Power Plant (η_T=35%) [62]	
			35.1-41.8%
		Charged from grid-averaged Baseload Power (η_T=35%, CER=1.4) [68]	
			42-47%
Roundtrip Efficiency (1)	$\eta_{RT,1} = \frac{E_T}{E_M + \eta_{NG} E_F}$	4220 kJ LHV/kWh, CER=1.5, η_{NG}=47.6%, [2]	
			81.7
Roundtrip Efficiency (2)	$\eta_{RT,2} = \frac{E_T - E_F \eta_{NG}}{E_M}$	4220 kJ LHV/kWh, Eo/Ei=1.5, η_{NG}=47.6% [72]	
			66.3%
Second Law Efficiency	$\eta_{II} = \frac{E_T}{E_{T,REV}}$	T_O=15 C, T_{MAX}=900 C, p_S=20 bar [65]	
		58.7%	68.3%

3. Aquifer CAES Geology and Operation

3.1. Motivations

Interest in aquifer CAES technology stems from the widespread availability of this formation type and the expected relatively low development costs. Furthermore, Figure 17 shows that onshore wind resources in the US of class 4 and above correlate well with aquifers.

While solution-mined salt domes offer advantages in terms of reliability and flexibility of design, the supply of salt domes is limited in the U.S. to the Gulf Coast region (see Figure 17). However, most of this region has very poor wind resources (typically wind classes 2 and below) that are not economically exploitable. If the aim of storage is to provide backup for large quantities of wind power, salt domes will not play a large role in the United States. While bedded salt formations might be used, their development will likely be more challenging and costly than the salt dome CAES systems that have been deployed (see section 1.3.1).

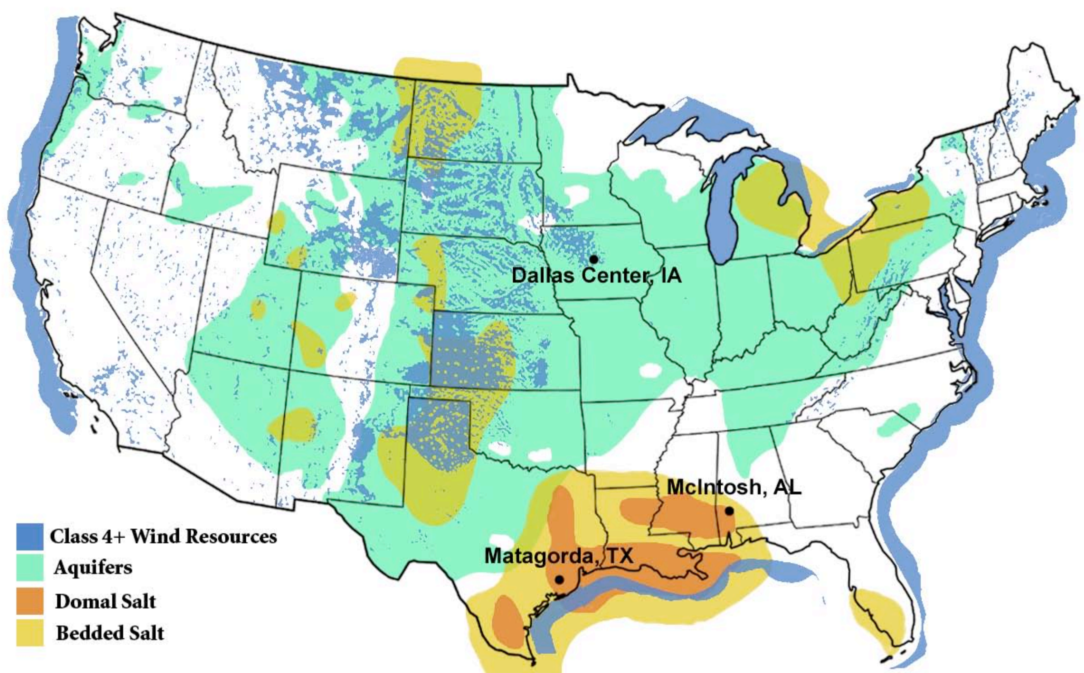

Figure 17 A comparison of areas of high quality wind resources and geology compatible with CAES (areas suitable for mined rock caverns omitted due to the high estimated cost of developing such formations for CAES) [33, 37, 41-43]. Locations of the existing McIntosh CAES plant, the recently announced Dallas Center wind/CAES system and the proposed Matagorda plant are indicated as well.

Figure 17 indicates areas favorable for air injection into porous rocks overlaid with areas with wind resources of class 4 and above (today, class 5 winds are economical, and class 4 resources are considered marginally viable). The overlap includes large areas in the southern tier states that extend from New Mexico to Arkansas, and includes large areas of Colorado, Wyoming, Montana, Kansas, Iowa, and Minnesota and Iowa, and most of the Dakotas. Although resource maps such as Figure 17 can be useful in helping to decide where to site a CAES storage unit, a detailed geologic site characterization is needed to ascertain whether a site is actually suitable for CAES development.

Although the total cost of developing a porous rock formation for CAES will depend on the characteristics of the storage stratum (e.g. thinner, less permeable structures will require more wells and therefore a higher development cost), it appears that this type of geology is often the least cost option. Prior CAES cost estimates (see Table 3) indicate that total development costs are in the range $2-$6 million per Bcf of total volume (working gas and base gas) which is similar to development cost estimates for natural gas storage in porous rock [74]. This implies a capital cost of $2.0-$7.0 per kWh of storage capacity depending on the site characteristics and assuming a five-to-one base gas to working gas volume ratio [64]. These costs are somewhat lower than those estimated for salt cavern storage ($6-$10 per kWh of storage capacity) which is the next cheapest option.

Table 3 Estimated Well and Reservoir Development Costs for Aquifer CAES[a]

	Site 1: Oneida	Site 2: Rockland County	Site 3: Buffalo
Depth	910	460	610
CAES Well, Each ($)	775,000	480,000	520,000
Well Lateral, Each ($)	100,000	100,000	100,000
Gathering System ($)	2,600,000	2,600,000	2,600,000
Number of Wells	18 - 38	80 – 107	40 - 71
Total Cost ($ per kWh of storage capacity)[b,c]	2.0 – 2.2	5.6 – 7.0	2.7 – 3.4

a. Costs based on a 1994 survey of CAES plant sites in New York State [64] inflation-adjusted to a $2006 basis

b. Wells, laterals and gathering system account for 90% of total cavern development costs. Remaining costs include reservoir characterization activities such as a seismic monitoring array for the candidate site.

c. Storage costs assume a five-to-one ratio of base gas volume to working gas volume. Actual base gas volume ratios will depend on the characteristics of individual sites.

Aquifer CAES has the further advantage that the cost of incremental additions to storage capacity is significantly lower than for alternative geologies. Assuming sufficient wells are in place to ensure adequate air flow to the surface turbomachinery, the cost of increasing the storage capacity of the aquifer is simply the compression energy required to increase the volume of the bubble [60]. This cost (~$0.11/kWh) is an order of magnitude lower than the equivalent marginal costs of solution mining salt and more than two orders smaller than excavating additional cavern volume from hard rock [11].

Because this combination of low cost and potential for widespread availability is unique among the options for storage reservoirs types, it will be essential to pursue development of aquifer-based systems if CAES is to serve more than a niche role in balancing U.S. wind capacity.

3.2. Applicability of Industrial Fluid Storage Experience

To gauge the potential for aquifer CAES, much can be gained from existing studies on other underground fluid storage applications. To date the storage of natural gas has been the principal commercial application for storage of fluids in porous rock strata, but storage of other materials such as liquid fuels, propane and butane have been pursued as well.

3.2.1. CO_2 Storage

More recently, storage of supercritical CO_2 in deep formations has garnered significant attention in the context of carbon capture and storage (CCS) technology development for climate mitigation.

Assessments of CO_2 storage are somewhat less relevant to CAES however. The minimum depth required for CO2 to become supercritical (~800m) is typically at the high end of acceptable limits for CAES (see Geologic Requirements below). In addition, because CO_2 is stored permanently rather than being cycled, the presence of an anticline is not necessary. Flatter caprock layers are in fact more desirable for storage of carbon dioxide, since they promote further migration and faster dissolution of the injected CO_2 in the brine. In addition, the higher viscosity of CO_2 under storage conditions and the lower average permeability of deep aquifers imply that flow behavior relevant to carbon storage will be different than for CAES.

3.2.2. Natural Gas Storage

In contrast, natural gas is stored under conditions much closer to those needed for CAES. Consequently, consideration of natural gas storage provides a valuable starting point for an analysis of air storage in porous rock formations.

The extensive industrial experience with natural gas storage provides a theoretical and practical framework for describing underground storage media and assessing candidate sites for seasonal storage of natural gas [75]. Field tests and prior studies discussed below indicate that this theory is applicable to CAES site analysis and operational planning.

Seasonal storage of natural gas began as an industry in 1915 when the Natural Fuel Gas Company used a partially depleted natural gas reservoir in Ontario, Canada to meet peak winter demand for gas. By 2004 the working gas capacity of the natural gas storage industry in the U.S. and Canada had grown to 4.1 trillion standard cubic feet in 428 facilities spread over 30 U.S. states and 5 Canadian provinces. This storage capacity corresponds to roughly 17% of the total annual demand for natural gas in the U.S. and Canada for 2002 [76, 77]. Over 95% of this capacity is held in porous rock formations (mostly in depleted gas fields) making this industrial experience base especially relevant to the understanding of aquifer CAES systems.

3.2.2.1. Site Characterization and Bubble Development

While there are important differences in the details of storing air versus natural gas in underground formations, the methodologies developed for evaluating natural gas storage sites are directly applicable to CAES.

High-resolution seismic surveys can help to define the shape of a geologic structure, the thickness of a zone of interest and presence of viable cap rock. Also, pump tests can be used to measure critical flow properties of the reservoir. Following successful site characterization, the reservoir is developed over the course of several months.

By injecting fluid above the discovery pressure (the hydrostatic pressure in the formation prior to well drilling), the brine can be displaced from the porous stratum with gas - initially fingering through the stratum and eventually resulting in formation of a coalesced bubble. The bubble is developed to the point that bubble volume and closure rating are deemed sufficient (for further discussion of closure rating see Geologic Requirements section and Figure 18 below). From this point forward, the reservoir can begin storage operations.

During operation the mean pressure in the reservoir is kept at the discovery pressure to ensure that the bubble volume remains constant and so that there is no long-term migration of the bubble walls (migration of water interface is more pertinent to seasonal natural gas storage than to high frequency reservoir cycling for CAES, see section 3.6, "Flow in Aquifers").

Formation flow (injectivity and deliverability) is critical for determining the suitability of a candidate storage site. The analytical description of reservoir flow begins with calculations of steady state flow, which is described by Darcy's Law:

$$\frac{q}{A} = -\frac{k}{\mu}\frac{dp}{dL} \qquad (34)$$

where

q = flow rate (cm^3/s)
A = cross-sectional area (cm^2)
k = permeability (darcy)
μ = viscosity (centipoises)
dp/dL = pressure gradient in the direction of flow (atm/cm).

Assuming radial laminar flow near a well (injection well or recovery well) through an aquifer [described as a homogeneous formation of thickness h (with $A = 2\pi rh$) and permeability k], the flow rate for a single well can be expressed as.

$$q = -\frac{2\pi r h k}{\mu}\frac{dp}{dr} \qquad (35)$$

From the real-gas equation-of-state, the number of gas moles n is given by:

$$n = \frac{pV}{ZRT} \qquad (36)$$

where:

Z = gas deviation factor

The flow rate q at temperature T and pressure p can be expressed in terms of the flow rate q_{SC} at standard conditions (p_{SC}, T_{SC}) by:

$$\frac{pV}{zT} = \frac{p_{SC}V_{SC}}{T_{SC}} \tag{37}$$

and so

$$q_{SC} = \frac{q}{z}\frac{T_{SC}}{T}\frac{p}{p_{SC}} \tag{38}$$

In English units, T_{sc} = 519.67 °R (60 °F) and P_{sc} = 14.7 psia, so that the flow Q_{sc} (in MMscfd) is:

$$Q_{SC} = -\frac{0.447x10^{-6}\pi\ k\ h\ p\ dp}{\mu\, T\, Z\, dr/r} \tag{39}$$

Because the total radial flow rate is independent of the radial distance from the well, Q_{sc} can be evaluated by integration from the wellbore radius to the formation radius. Assuming the temperature in the reservoir is constant, the deliverability equation is:

$$Q_{SC} = \frac{0.703\times10^{-6}\ k\ h\left[p_F^2 - p_S^2\right]}{\mu\, T\, Z \ln\left[{r_F}/{r_W}\right]} \tag{40}$$

where:

r_W = wellbore radius (ft)
r_F = formation radius (ft)
p_S = pressure at the wellbore (psia)
p_F = pressure at the formation edge (psia)
h = formation height (ft)
k = permeability (millidarcy)
T = temperature in the reservoir (°R)
μ = viscosity (centipoises)
Q_{sc} = gas flow rate (MMcfd)—which is positive for flow out of the reservoir

This equation is widely used to describe the flow capacity of natural gas fields [78]. Additional terms are needed to reflect effects of turbulence, but field studies indicate that the assumption of laminar flow is adequate to describe CAES operation [79].[13]

3.2.2.2. Applicability to CAES

The applicability of this methodology for describing airflow in aquifer-based CAES systems was verified during the Pittsfield Aquifer Field Test, which took place at the Pittsfield-Hadley Anticline in Pike County, Illinois from 1982-1983. Prior to conducting deliverability measurements of the site, data sources such as core sample analysis, pump tests, injection tests, and earlier geophysical tests were sampled. These provided estimates of formation thickness and permeability data that were used to calculate

[13] Steady state flow equations are useful for evaluating reservoir deliverability, but time-dependent unsteady-state and pseudosteady-state flow expressions are required to adequately describe the evolution of flow during bubble development (see section 3.6, “Flow in Aquifers”)

predicted deliverability rates. Ultimately, the deliverability measurements acquired during site operation corresponded closely with the predicted values based on the geophysical data:

> During the process of reviewing and analyzing the multitude of operating data for the Pittsfield experiment, most of the questions and apprehensions regarding the Pittsfield reservoir were answered satisfactorily. The flow behaviors of the Green and White St. Peter are now understood to the extent necessary to conduct an underground storage operation. Natural gas equations have been shown to be applicable to air flow. There is no question that the experiment proved that CAES in porous media is feasible in terms of storage and flow of air [79].

The applicability of natural gas storage formation analysis techniques extends beyond porous rock formations (aquifers). In the case of salt dome storage, the fact that both the Huntorf and McIntosh CAES facilities are located adjacent to natural gas storage facilities mined from the same formation[14] suggests that the conditions favorable for CAES development and natural gas development might often overlap. Since a large volume of test data is available from state geological surveys on potential natural gas storage facilities, it is likely that this body of knowledge will be useful in identifying potential sites for CAES.

3.2.2.3. Differences

While natural gas storage provides an important departure point for a discussion of CAES, several important differences must be considered. First, the differences in the physical properties of air relative to natural gas have important implications for the geologic requirements for aquifer CAES. Second, a CAES system used for arbitrage or backing wind power will likely switch between compression and generation at least once a day and perhaps several times a day. In contrast, most natural gas storage facilities are often only cycled once over the course of the year to meet the seasonal demand fluctuations for natural gas. Third, several oxidation processes might take place in the presence of oxygen from the air depending on the mineralogy of the formation. Also, introduction of air into the formation might promote propagation of aerobic bacteria that might pose a significant corrosion risk. Finally, additional corrosion mechanisms might be promoted due to the introduction of oxygen into the formation. These considerations and their impact on system design and operation are discussed in the following sections.

3.3. Geologic Requirements

The requirements for air storage in a porous rock reservoir encompass a broad range of geologic features. In general terms, CAES operation requires an anticline consisting of permeable, porous media such as sandstone capped by an impermeable caprock (see Figure 20). Other important considerations during site selection are the volume requirement of the storage application, the pressure requirements of the surface turbomachinery, the homogeneity of the formation and the detailed mineralogy.

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[14] The Huntorf CAES facility was built adjacent to a preexisting natural gas storage facility consisting of four caverns solution-mined from a Permian salt dome. The McIntosh Salt dome natural gas storage facility was completed three years after the CAES facility began operating.

One of the most complete studies on the feasibility of aquifer-based CAES systems, prepared by the Public Service Company of Indiana and Sargent and Lundy Engineers for the Electric Power Research Institute (EPRI) in 1982, explores the potential benefits of these systems [60]. Although no field tests were conducted as part of this EPRI study, a detailed methodology was presented for identifying formations with the necessary geologic requirements. A score-based system was developed to evaluate candidate sites on the basis of geologic, economic and environmental considerations (see Table 4). The parameters used to evaluate the geologic aspects of the formation include permeability, depth, porosity, closure, geology type, and caprock properties.

3.3.1. Porosity, Permeability and Thickness

Each parameter will impact different aspects of CAES operation including reservoir capacity, compressed air deliverability and compatibility with operating pressures for standard turbomachinery. The permeability and reservoir thickness will determine the deliverability of the reservoir (see section 3.2.2.1) and together with the porosity will determine the pore volume per unit land area and the number of wells needed to achieve the desired total flow.

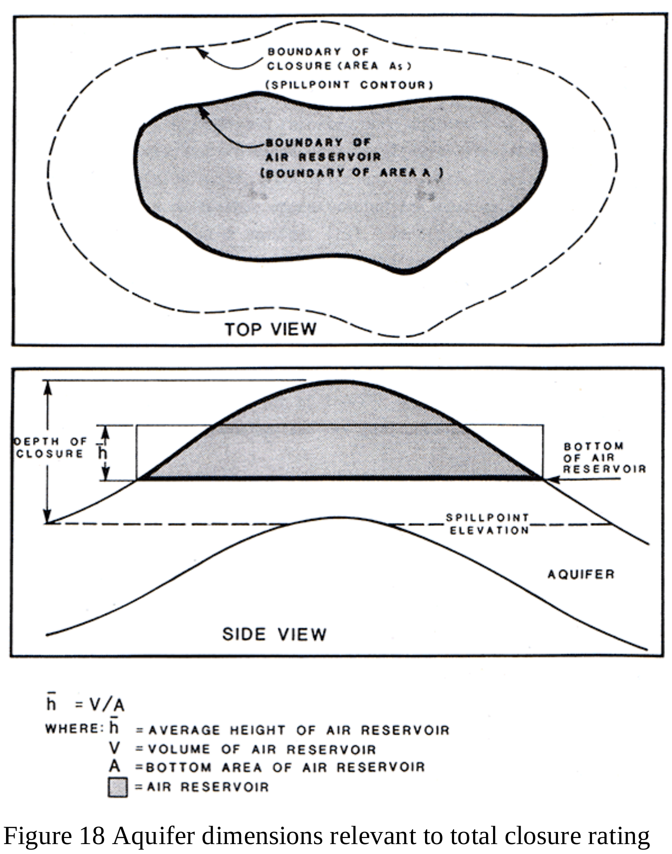

Figure 18 Aquifer dimensions relevant to total closure rating [60]

Air has a viscosity approximately twice that of natural gas over a wide range of pressures and temperatures as well as a higher gas deviation factor (see Figure 19). Therefore in order to achieve the same flow rate, a formation for storing air must have a higher flow capacity[15] than a natural gas storage facility operated under similar conditions (see equation 40).

This underscores the importance of careful site characterization, including seismic monitoring, core sample analysis, injection tests, pump tests, and careful well observation. A reliable permeability value for the formation is essential for predicting bubble development and deliverability characteristics of a reservoir for air storage.

Porosity indicates the percentage of the media that consists of voids and interstices. A lower porosity implies a larger areal expanse is needed to contain the necessary volume of air. In the context of the 1982 EPRI study, 13% was deemed the minimum porosity needed for CAES operation. All of the aquifers screened for this study met this criterion and 12 of 14 candidate sites exceeded 16% porosity.

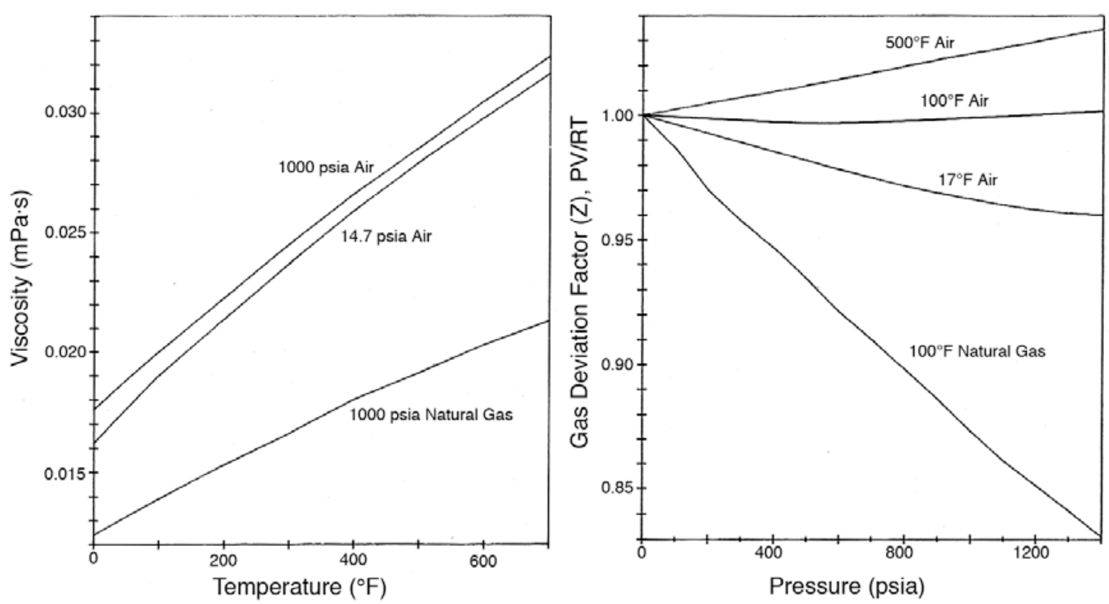

Figure 19 Viscosity and Gas Deviation Factor of Air versus Natural Gas [79]

3.3.2. Reservoir Dimensions

The total void volume of the aquifer above the spill point contour (V_R) must be at least as great as the volume needed for CAES operation (V_S). But if V_R is much bigger than is needed for CAES operation, excessive land rights acquisition costs might be incurred and hence values of V_R/V_S greater than 3 receive a reduced score.

[15] "Flow capacity, " the product of formation thickness and permeability (kh), is a parameter used to characterize the flow properties of geologic formations used for underground storage of fluids.

The total closure rating is defined as the ratio of the total thickness of the formation (H) to the thickness of the fully developed air bubble (h) (see Figure 18). This parameter is important with regards to water encroachment into the wellbore.

Water might be drawn up into the well during extended air withdrawal periods due to the radial pressure gradient created as air is withdrawn. To avoid this condition sufficient distance between the bottom of the well perforations and the air-water interface should be maintained at all times. Typically, the reservoir will be developed such that 10 to 15 feet of air is maintained below the well perforations, but the actual distance depends on the pressure relative to the discovery pressure of the formation as well as the permeability and porosity of the structure.

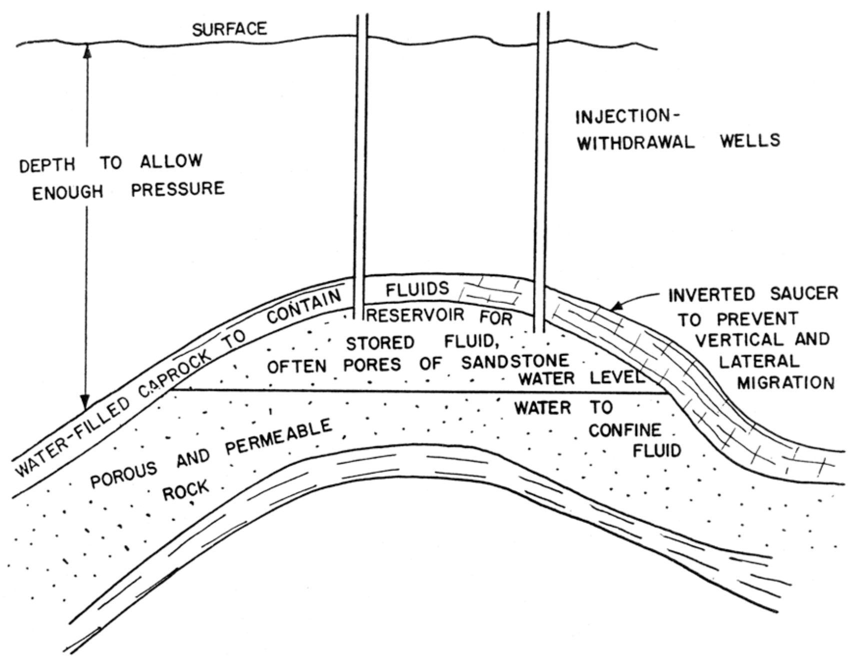

Figure 20 Porous Rock CAES Storage Volume [19]

It would be optimal to develop the air bubble to the extent that it spans the full formation thickness (h/H=1.0), in which case the possibility of water encroachment is eliminated. This is more easily accomplished in thinner anticlines with larger curvature so that a smaller volume of air is needed to displace the air/water interface sufficiently. In the case of flatter and thicker reservoirs, it might not be possible to develop the bubble to this extent.

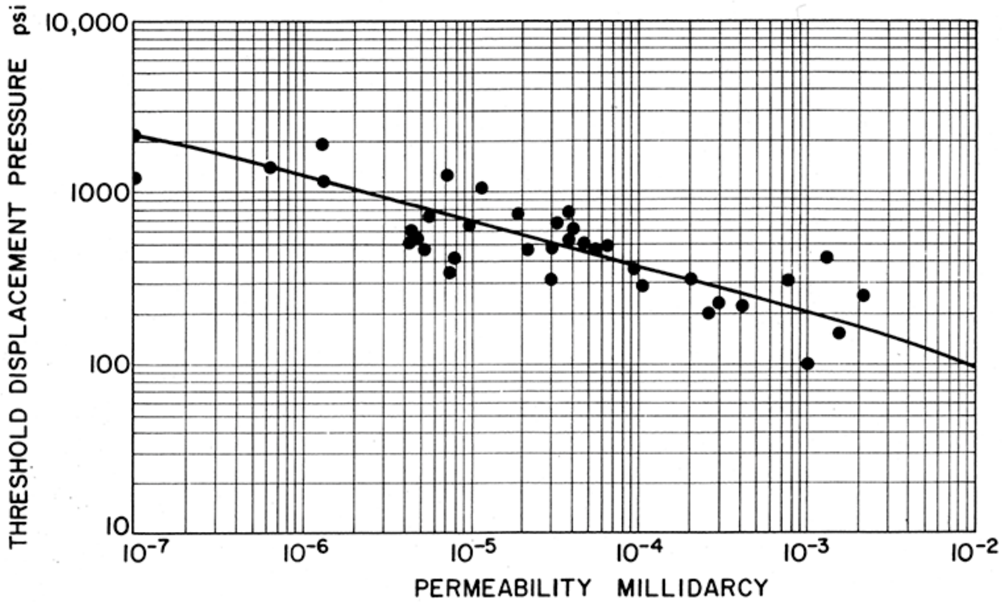

Figure 21 Measurements of threshold pressure as a function of permeability [19]

3.3.3. Pressure Limits and Caprock Characteristics

Pressure limits presented in the EPRI study were based on considerations related to caprock integrity and turbomachinery operational limits. For the 1982 EPRI study, the allowed pressure range was set at 14-69 bar.[16] However, to make best use of existing turbomachinery and to ensure optimal performance, the desired range was 39-50 bar. Both the McIntosh and Huntorf systems operate in this range (45 and 46 bar inlet pressures, respectively). The pressure limits or depth limits in a new CAES application might be substantially different from these values, depending on the caprock characteristics and the CAES turbomachinery design.

The caprock layer must be a relatively impermeable stratum immediately over the porous storage reservoir. The rock, usually shale, siltstone or dense carbonate, must be thick enough to prevent fracturing and have low permeability together with large capillary forces in order to prevent air from migrating through the media. As a rule of thumb, the pressure of injection is not allowed to exceed the discovery pressure of the formation by more than 0.16 bar per meter depth to avoid caprock fracture [19].

An important measure for determining the adequacy of the caprock layer is the threshold pressure, which is defined as the pressure at which air begins to displace water from a

[16] Based on the turbomachinery available at the time, the maximum allowable turbine inlet pressure and maximum compressor discharge pressure was 62 bar and 76 bar respectively. The minimum turbine inlet pressure was 10 bar and a 3.4 bar pressure drop from the storage reservoir to the surface turbomachinery was assumed.

porous rock. A sufficiently high threshold pressure is needed to ensure that air will not migrate through pore spaces in the caprock in response to pressure fluctuations during CAES operation. This threshold pressure reflects the wetability of the rock and is a function of the surface forces at the water-rock interface. These forces are ultimately responsible for the water-filled caprock layer's ability to act as an impermeable barrier to air migration [75]. Threshold pressure and its relationship to caprock permeability can be determined by measurements of water migration through core samples subject to differential pressures (see Figure 21).

3.3.4. Residual Hydrocarbons

In addition to using saline aquifers for CAES, it is also possible to use depleted oil and gas reservoirs, which are fundamentally aquifers. Since the bulk of natural gas storage experience is in depleted fields, many issues related to residual hydrocarbons have been extensively studied; however the injection of oxygen would present challenges not encountered when storing natural gas.

For example, residual hydrocarbons in the pore spaces of the formation might lead to the formation of permeability-reducing compounds and corrosive materials. Another possibility is that the presence of residual hydrocarbons may introduce the risk of flammability and insitu combustion upon the introduction of high-pressure air.

The flammability of the natural gas/air mixture may be a concern for CAES operation, but displacement of natural gas away from the active bubble area can mitigate this risk considerably. In some cases, nitrogen injection may be desirable to further minimize air/natural gas mixing. Previous studies indicate that these methods adequately address the challenge of using depleted natural gas fields for CAES and that these structures can provide a suitable air storage medium [79].

Table 4: Ranking Criteria for Candidate Sites for Aquifer CAES [60]

Score	1	2	3	4	5
Score Interpretation	Unusable	Marginal	OK	Good	Excellent
Permeability (md)	< 100	100- 200	200- 300	300-500	> 500
Porosity (%)	< 7	7-10	10-13	13-16	> 16
Total Reservoir Volume (V_R/V_S)	<0.5		0.5 – 0.8 or > 3.0	0.8 – 1.0 or 1.2 – 3.0	1.0 – 1.2
Total Closure Rating (h/H)	< 0.5		0.5-0.75	0.75-0.95	0.95-1.0
Depth to Top of Reservoir (m)[17]	< 137 or >760	140-170	170-260 or 670-760	260-430 or 550-670	430 -550
Reservoir Pressure (bar)	< 13 or > 69	13-15	15-23 or 61-69	23-39 or 50-61	39-50
Type of Reservoir	Highly Discontinuous	Moderately vulgar limestone & dolemite	Reefs, highly vulgar limestone & dolemite	Channel sandstones	Blanket sands
Residual Hydrocarbons (%)	> 5%		1-5%		< 1%
Caprock leakage	Leakage evident	No data available	Pumping test shows no leakage		
Caprock Permeability (md)			$> 10^{-5}$	$< 10^{-5}$	
Caprock Threshold Pressure (bar)			21-55	> 55	
Caprock Thickness (m)			< 6		> 6

3.4. Oxidation Considerations

The Pittsfield CAES experiment, conducted during the period 1981-85 in Pike County, IL under EPRI/DOE sponsorship, involved extensive field tests to determine the feasibility of using aquifers for air storage [79]. One of the important findings of the study was that introduction of air into the reservoir leads to the reaction of oxygen with native species that in turn leads to a reduction in the O_2 concentration in the stored air. These oxidation reactions proceed with a characteristic time scales of the order of months.[18] The observed oxygen depletion was largely attributed to the presence of sulfide minerals in the formation and subsequent reactions that were catalyzed by the injection of air into the formation. The presence of oxygen can lead to reactions among several mineral species with various outcomes.

The primary reactant in the Pittsfield case was pyrite, a sulfide of ferrous iron (FeS_2). The oxidation of pyrite ultimately leads to the formation of hematite (Fe_2O_3):

$$4\,FeS_2 + 11\,O_2 \rightarrow 2\,Fe_2O_3 + 8\,SO_2 \tag{41}$$

The products of this reaction do not present significant problems for reservoir operability. However, if this process does not proceed to completion the presence of intermediate species might lead to serious formation damage. Partial oxidation might lead to the

[17] Depth limits are based on a hydrostatic pressure of approximately 0.09 bar per meter.

[18] This oxygen depletion was not observed in short duration (several day) storage tests

presence of ferrous sulfate or $Fe(OH)SO_4$, which can result in the production of colloidal ferric hydroxide and melanterite[19] respectively.

$$2FeS_2 + 7O_2 + 2H_2O \rightarrow 2FeSO_4 + 2H_2SO_4 \tag{42}$$

$$4FeSO_4 + O_2 + 2H_2O \rightarrow 4Fe(OH)SO_4 \tag{43}$$

These species swell to as much as 500% of the original pyrite volume and result in considerable permeability decline in the reservoir. This expansion, together with the collection of these products on pore interiors could impact the permeability of the reservoir substantially. In addition, the volume increase due to oxidation of pyrite and carbonates might lead to deteriorating expansive stresses on caprock layers.

Another problematic oxidation product is gypsum ($CaSO_4 \bullet 2\ H_2O$), which might precipitate through dissolution of carbonate minerals. Gypsum forms scale deposit that might occlude porosity and impair CAES system performance [79].

The degradation of reservoir permeability is not the only challenge which oxidation poses for aquifer CAES systems. Because the withdrawn air is combusted with fuel, the depletion of oxygen might result in impaired combustion efficiency downstream. However, because current CAES systems do not utilize all the oxygen in the air stream, some depletion can be tolerated without any loss in combustion efficiency [79].

Oxidation might have significant impacts on CAES operation and as such it is essential to fully characterize the mineralogy of a candidate site. It might be possible in some cases to control the rate of reactions by dehumidification of incoming air. Such dehumidification might have additional benefits, as discussed below.

In addition, if the formation cement between sand grains consists predominantly of carbonates and/or sulfides, the dissolution of these materials through oxidation might release particulates. If this happens in the vicinity of the well bore, it is likely that these particles can find their way to the turbomachinery (the effect of particulates on surface turbomachinery will be covered below). For this reason and for reasons related to the effects mineralogical reactions described above, reservoirs having high sulfide content should be avoided [79].

3.5. Corrosion

The deterioration of wellbore tubulars and casing cement through corrosion is an important problem to consider for CAES applications. Prominent corrosion types include biological (esp. bacterial), uniform, galvanic, crevice, pitting, erosion, intergranular, stress corrosion cracking, fatigue, and fretting corrosion. The promotion of corrosion by air injection might be further exacerbated by high-pressure and high-temperature conditions, especially if significant moisture is present.

[19] Melanterite ($FeSO_4 \bullet 7\ H_2O$) is a hydrated form of ferrous sulfate often formed from oxidation in pyritic ore zones

While many corrosion types (e.g. erosion corrosion, corrosion fatigue, fretting corrosion) might be prevented by suitable choice of materials or might simply not be relevant to the conditions in a CAES reservoir (e.g. intergranular corrosion), some might present particular problems for air storage applications. Controlling electrochemical corrosion processes such as uniform corrosion and pitting corrosion might require internal coatings of piping and wellbore tubulars. Although such coatings and linings might mitigate some of the effects of corrosion, even the most corrosion-resistant materials might ultimately succumb to deterioration, and care must be taken to carefully monitor the condition of all piping and well materials (see Figure 22). Because water might form an electrolyte and enhance the corrosion rate, it might be desirable to dehydrate the injected air. In the oil and gas industry, use of dehydrated natural gas streams has been shown to control corrosion and stress corrosion cracking.

General aerobic bacteria (GAB) such as Thiobacillus thioxidans (sulfur oxidating) can flourish in a CAES environment. Such species might oxidize native sulfur to sulfuric acid, which might have detrimental effects on wellbore tubulars and casing cement. Presence of these bacteria can result in localized corrosion and pitting of steel surfaces. Free-floating planktonic species might be present as well, which could be detrimental to

Figure 22 This photograph, from the Huntorf CAES facility in Germany, shows where the protective fiberglass-reinforced plastic tubing fractured. [35]

formation permeability. Care must be taken to avoid contamination of the reservoir during drilling operations including careful choice of drilling fluids. To control populations of preexisting bacterial species, biocides might be injected into the air stream once relevant species have been identified. Comprehensive reviews of reservoir analysis techniques for the detection of corrosion causing bacteria are available in the literature [80].

3.6. Flow in Aquifers

The dynamics of air flow are important for determination of storage energy density and prediction of air –water interface evolution during initial bubble development and subsequent storage operation. The deliverability calculation outlined above (see section 3.2.2.1) is simply a static calculation of airflows, but in reality the flow conditions will evolve as the bubble size fluctuates. This in turn will impact the storage energy density and reservoir volume requirement for CAES. While detailed analysis of aquifer flow behavior is outside the scope of this report, it is useful to highlight some basic concepts and discuss the impact on aquifer dynamics on CAES design and operation.

Use of aquifers for air storage differs greatly from other storage options due to the limited mobility of fluids through porous media. Hard rock caverns and solution mined salt formations can be described as rigid, open-space containers where pressure changes quickly equilibrate throughout the volume. However, flow through porous reservoirs results in dynamic pressure gradients throughout the formation that evolve over hours, days or weeks. Steady-state deliverability estimates are useful, but operational planning must take into account the effects of unsteady-state and pseudosteady-state air flows within the reservoir. The dynamics of these flow modes and the deviations of airflow behavior from steady state conditions are determined by the propagation rates of pressure gradients through the reservoir.

The injection or withdrawal of air at the wellbore introduces pressure pulses within the formation that propagate according to the viscosity of the fluid, the size of the pressure gradient, as well as the permeability and porosity of the reservoir. As a pressure gradient propagates through the formation, the pressure within the formation varies as a function of both time and location. This condition, called unsteady-state flow, persists until a flow boundary is reached.

When airflow is impeded (e.g. by the air-water interface, a permeability pinch-off, the presence of an adjacent well or some other flow constraint) the pressure throughout the reservoir will vary uniformly with time. This flow condition is called pseudosteady-state flow and the edge of this advancing pressure gradient is called the radius of drainage (r_d). Under pseudosteady-state flow the rate of change of pressure is uniform within the formation (i.e. independent of radial distance from the wellbore).

Van Everdingen and Hurst developed expressions for the evolution of aquifer pressures under unsteady-state conditions subject to constant terminal pressure and pseudosteady-state in a finite reservoir [81]. The radius of drainage is described in terms of the stabilization time (hours) for the reservoir to transition to a pseudosteady-state flow condition [75] and the time for the radius of drainage to reach a radial distance r is expressed as:

$$t_{stabilization} \propto \frac{\mu\,\phi\,r^2}{k\;p} \qquad (44)$$

where

r = radial distance from the well bore
μ = viscosity (cp)

ϕ = porosity
k = permeability (md)
p = mean pressure between the wellbore and the radius of drainage (psia)

Typical values for t_{stab} over small distances are of the order of hours. Over significant fractions of a kilometer, t_{stab} will typically be of the order of days. The speed at which the pressure gradient evolves impacts the relevant flow regime at a given time. More importantly, it is clear that whether the reservoir is managed under "unsteady-state" or "pseudo-steady-state" flow conditions, true "steady-state" flow cannot occur in aquifers and hence aquifers cannot operate efficiently as compensated, constant-pressure systems (see section 2.2 above) [79].

The flow of water through the formation follows the same behavior described above, but due to the much larger viscosity of water and forces acting at the water interfaces, the stabilization time will be 20 to 100 times longer. Thus, the bubble movement will occur over time scales of days/weeks and the initial bubble development will typically take several months. Consequently, the impact of air-water interface migration will typically be most relevant during initial bubble development and for seasonal storage applications.

Such considerations imply that over the time scales necessary to balance wind, the bubble will not change appreciably in shape or extent [19]. Aquifer CAES systems can therefore be approximated as rigid, constant-volume systems when determining the storage volume necessary to provide a given storage capacity (see section 2.3, "Storage Volume Requirement").

3.7. Particulates

When particulates are generated around the wellbore, they can be carried in the air flow to the CAES turbomachinery where they might damage the turbine blades and other sensitive equipment. The ability of the air to transport particles depends on the air flow rate, the particle size distribution, and the distance of particle formation from the wellbore. Previous studies have shown that because of the high flow rates that would be typical for CAES, the air stream will be able to pick up particles of nearly any size that are generated within a few feet of the wellbore [60].

The generation of particulates in the reservoir can come about via a number of different mechanisms. As mentioned above, the dissolution of minerals that act as cement between sand grains can generate free particles that can be entrained into the air stream. In addition, injection of air, especially at elevated temperatures, can lead to dehydration and destabilization of clays that might lead to particulate formation.

Several approaches can be taken to mitigate particulate damage on turbomachinery. Particle filtration units are available for any size particle, but the capital cost and energy penalty increases steeply for small particle sizes. Alternatively, injecting a silica solution into the formation can cement the grains in the structure. This is commonly done in the natural gas storage industry to preclude the formation of particles in loosely held sandstones. The procedure gives rise to only a slight change in permeability and costs only about $25,000 ($1982) per well [60].

4. Wind/CAES Systems in Baseload Power Markets

This section addresses the emissions, and economics of baseload wind/CAES systems to illustrate the prospective importance of developing CAES, and especially aquifer CAES, for baseload power applications based on wind. These systems are compared to baseload power systems, giving emphasis to economics under a climate change mitigation policy.

Baseload power is typically provided by technologies such as conventional coal and nuclear generation. Although wind has a low, stable short run marginal cost, the variability of wind implies that it is unable to deliver firm power at similar capacity factors (~70-90%) without some form of backup generation. However a baseload power system made up of wind power plus dispatchable backup generation can be compared to other baseload generation options.

Two options for backing wind are utilizing dedicated stand-alone natural gas capacity and CAES. Natural gas capacity is chosen as the stand-alone backup generation technology due to its low capital costs and its fast ramping rates that are well suited to balancing rapid fluctuations in wind power output.

To illustrate the potential benefits of these baseload wind options, costs are compared with those of three other baseload power systems: coal integrated gasification combined cycle (IGCC) with CO_2 vented (IGCC-V), coal IGCC with CO_2 captured and stored (IGCC-C) and natural gas combined cycle (NGCC).

Although coal IGCC power is currently more costly than coal steam-electric power, the incremental cost of CO_2 capture and storage (CCS) is less for IGCC plants (via pre-combustion CO_2 capture) than for steam-electric plants (via post-combustion CO_2 capture). Furthermore, the total generation cost of coal IGCC power with CCS tends to be less than that of coal steam-electric power with CCS—at least for bituminous coals [82]. Thus coal IGCC-C is likely to be the major competitor that wind/CAES will face in a world with a climate policy in place.

Costs are presented for greenhouse gas (GHG) emissions prices of $0 and $31 per tonne of CO_2 equivalent —the first carbon price for the current situation where there is no climate change mitigation policy and the second carbon price representing a GHG emissions valuation that is likely to characterize a climate change mitigation policy. (A GHG emissions price ~ $31/t$CO_2$ is the minimum price on GHG emissions needed to make a coal IGCC-C plant with storage of CO_2 in deep saline aquifers competitive with a coal IGCC-V plant (see Table 8) [83, 84].

4.1. Methodology

Levelized generation costs for alternative baseload power systems are estimated using the financing model in the EPRI Technical Assessment Guide [85]. The assumed financing parameters are 50% debt (9%/y nominal return) and 45% equity (12%/y nominal return), a 30-year (20-year) plant (tax) life, a 38.2% corporate income tax rate, a 2%/y property tax/insurance rate, and a 2.35%/yr inflation rate. Under these conditions the discount rate (real weighted after-tax cost of capital) is 6.72%/year, and the levelized annual capital charge rate is 13.3%/year. It is assumed that plant construction requires four years (except wind capital which is built over one year), with the capital investment committed in equal annual payments, so that interest during construction factor (IDCF) is 1.0687 with Base Case financing.[20] All costs are expressed in 2006 inflation-adjusted U.S. dollars.

Table 5: **Coal IGCC System Parameters**[a]

	IGCC-V	**IGCC-C**
Fate of CO_2	Vented	Captured
Capacity Factor	80%	
Levelized Annual Capital Charge Rate (%)	13.3	
Coal Price ($/GJ HHV)	1.65	
Installed Capacity (MW_e)	640.3	555.7
CO_2 Capture Fraction (%)	0.00	90
Fixed Operation and Maintenance ($/kW-yr)	34.81	43.16
Variable Operation and Maintenance ($/MWh)	6.40	7.98
Efficiency (LHV/HHV, %)	(39.6/38.2)	(33.7/32.5)
CO_2 Transport/Storage ($/t$CO_2$)	0	5.0
Overnight Construction Cost ($/$kW_e$)	1789	2358

[a] All IGCC performance/cost estimates are for a water-slurry-fed single-stage GEE gasifier, which is currently the least cost IGCC option with CO_2 capture and storage. Data adapted from NETL 2007 [84] and expressed in 2006$.

[20] The levelized annual capital charge = LACCR*IDCF*OCC, where LACCR = 13.3%/year, IDCF = 1.0687, and OCC = overnight construction cost.

Table 6: Wind System Parameters

	Wind/CAES	Wind/Gas
Installed Baseload Capacity (MW_e)	2000	
Levelized Annual Capital Charge Rate (%)	13.3	
System Capacity Factor (%)	85	
Natural Gas Price ($/GJ HHV)	6.00	
Wind Farm Rated Power (MW_e)	3130	2000
CAES Expander Capacity (MW_e)	1270	0
CAES Compressor Capacity (MW_e)	1130	0
SC Capacity (MW_e)	0	234
CC Capacity (MW_e)	0	1700
Storage Capacity at CAES Expander Capacity (Hours)	88	0
Wind Turbine Specific Rating [86]	1.21	1.36
Transmission Loss Over 500 km (%) [b]	3.39	3.06
Transmission Line Capacity Factor After Losses for 85% System Capacity Factor (%)	85	42.2
Wind Energy Transmitted Directly for 85% System Capacity Factor (TWh/y)	10.3	7.40
Wind Energy Input to CAES at 85% System Capacity Factor (TWh/y)	2.97	0
CAES Output Power (TWh/y)	4.46	0
SC Power Output (TWh/y)	0	0.239
CC Power Output (TWh/y)	0	7.26
CAES Charging Energy Ratio (CER)	1.5	0
CAES Heat Rate (kJ/kWh)	4220	0
SC Heat Rate (kJ/kWh)	0	9020
CC Heat Rate (kJ/kWh)	0	6680
Wind Capital Cost at Nominal Rating $/kW$_e$ [a]	$1241/kW	$1241/kW
CAES Capital Cost [a]		
Cost of CAES surface turbomachinery and balance of plant capital ($/kW$_e$) [a]	610	0
Capital cost of incremental storage capacity ($/kWh)	1.95	0
SC Overnight Construction Cost ($/kW$_e$) [a]	0	410
CC Overnight Construction Cost ($/kW$_e$) [a]	0	611

[a] Wind turbine costs based on [31], CAES costs based on [11, 12], SC and CC costs based on [87]
Installed Capacity for systems with dedicated transmission lines reflects the discharge capacity at the end of the transmission line after losses.
[b] Transmission losses are expressed as a fraction of transmitted energy at the source of generation. Since transmission here reflects a differential in transmission distance, converter losses are not included. Such losses would add an additional 0.75% of loss at each terminal.

Energy quantities are expressed on a lower heating value (LHV) basis, except energy prices are on a higher heating value (HHV) basis—the norm for US energy pricing. Energy prices are assumed to be $1.65/GJ for coal and $6.00/GJ for natural gas [87]. The GHG fuel emissions include the CO_2-equivalent upstream GHG emissions (3.66 kg CO_2 per GJ of coal and 10.4 kg CO_2 per GJ of natural gas [88]), resulting in total CO_2-equivalent GHG emissions rates of 93.0 kg CO_2 and 66.0 kg CO_2 per GJ of coal and natural gas, respectively.

Coal IGCC plant performances, capital costs, and O&M costs are based on 2007 NETL data [84]. CO_2 transport and storage costs are estimated using the model developed by Ogden et al [89] (see Table 5). Cost modeling of wind energy systems and transmission as well as optimization methodology for variable scaling of wind turbine components (i.e. derating) are as described in previous studies unless otherwise noted (see Table 6) [2, 86, 90].

Although assumptions in this report relating to capital costs reflect the most recent numbers published in the open literature, the escalation of construction costs continues [91], so that estimated absolute costs may differ from actual realized cost levels for plants that might be built. However, construction cost escalation is a phenomenon affecting essentially all energy technologies, and it is reasonable to assume that continuing construction cost escalation will not appreciably affect the relative economics among the alternative baseload options considered or the conclusions of this analysis.

The cost of electricity (COE) or generation costs is estimated two ways. For the first set of COE estimates presented in Table 8, it is assumed that the power systems are operated at specified capacity factors. Subsequently, economic dispatch is discussed, which, in real markets, has the effect of reducing the capacity factors of systems with high dispatch costs.

4.2. Generation Costs for Alternative Baseload Power Systems Operated at Specified Capacity Factors

The COEs for alternate baseload power systems are presented in Table 8 disaggregated into components. The COEs are compared under three sets of conditions: The first set of costs are evaluated without a valuation on GHG emissions , the next set applies a CO_2-equivalent GHG emissions price of \$31/tCO_2 and the third includes the cost of transmitting remote wind supplies 500 km to demand centers.

Table 7 CO_2-equivalent GHG Emission Rates for Alternative Baseload Power Systems (kgCO_2/MWh)

IGCC-V	IGCC-C	Wind/CAES	Wind/Gas	NGCC
829	132	86.5	224	440

In the absence of a GHG emissions price, IGCC-V is the least costly baseload power option, while the cost for wind/CAES is a few percent higher than that of IGCC-C. When GHG emissions are valued at \$31/tCO_2, the wind and natural gas options become more competitive with the coal options. In this case, wind/gas and NGCC are the least costly baseload power options. At this GHG emissions price (the breakeven price for IGCC-C with respect to IGCC-V), wind/CAES is now has a nearly equivalent cost as both coal options. The addition of transmission line costs adds approximately 10% to the levelized cost of energy to both baseload wind options.

The generation cost estimates presented in Table 8 underscore the sensitivity of the results to the stringency of the climate change mitigation policy and the wind resource remoteness.

Table 8: Disaggregated Generation Costs for Coal IGCC, Baseload Wind and NGCC ($/MWh)

	IGCC-V	IGCC-C	Wind/CAES	Wind/Gas	NGCC
Fixed Costs					
Capital	36.37	47.94	65.15	39.66	13.49
Fixed Operations and Maintenance	4.95	6.15	3.90	3.95	1.75
Variable (Dispatch) Costs					
Variable Operations and Maintenance	6.38	7.99	8.98	5.42	1.94
Fuel	15.55	18.27	8.43	22.68	44.53
CO_2 Transport and Storage	0.00	4.21	0.00	0.00	0.00
Total Dispatch Cost	21.93	30.47	17.40	28.09	46.47
Total Generation Cost at Zero Carbon Price	**63.25**	**84.55**	**86.45**	**71.70**	**61.72**
GHG Emissions Costs @$31/tCO$_2$.	25.35	4.04	2.64	6.86	13.48
Total Dispatch Cost	47.28	34.51	20.04	34.96	59.95
Total Generation Cost @ $31/tCO$_2$	**88.60**	**88.60**	**89.09**	**78.56**	**75.19**
Cost of 500km Dedicated TL for Remote Wind [a]	0.00	0.00	7.23	7.25	0.00
Transmission Losses [b]	0.00	0.00	3.29	1.29	0.00
Total Generation Cost Including TL Cost for Remote Wind @ $31/tCO$_2$	**88.60**	**88.60**	**99.61**	**87.11**	**75.19**

[a] This is the TL cost per total MWh of electricity production. Allocated only to the electricity transmitted, the TL cost for the Wind/Gas option is 95% *greater* than the TL cost for wind/CAES because of the lower TL capacity factor.
[b] Transmission costs based on 500kV bipole technology [92]. Since transmission distance is regarded as differential rather than absolute only the cost of the 500km increment are included (i.e. no convertor costs).

4.3. Dispatch Competition in Baseload Power Markets

The ordering of the total generation costs presented in Table 8 does not represent the ordering that would occur in real-world power markets, in which capacity factors cannot be assumed to be fixed at a specified rate. Rather, capacity factors are determined by market forces to reflect the relative dispatch costs of the competing options on the electric power grid.

For a given set of power generating systems connected to the electric power grid, the grid operator determines the capacity factors of these systems by calling first on the system with the least dispatch cost. Under this condition, deployment in sufficient quantity of the technology with the least dispatch cost can lead to a reduction of the capacity factors and thus an increase in the COEs of the competing options on the grid.

The impact of dispatch competition on capacity factors is well known. For example, as a result of the recent increases in natural gas prices in the U.S. this phenomenon has resulted in reducing capacity factors for natural gas combined cycle plants originally designed for baseload operation to average utilization rates in the range 30-50% where coal plants are available to compete in dispatch [82].

In principle, this downward pressure on capacity factors for options with high dispatch costs could be avoided with “take-or-pay” contracts that require the generator to provide a specified fixed amount of electricity annually. However, uncertainties about future fuel prices, technological change, and future electricity demand make such contracts rare.

4.3.1. Dispatch Duration Curves

Table 8 presents average dispatch costs for the options considered. The table shows that in the presence of a GHG emissions price of \$31/tCO_2 the total average dispatch cost (i.e. the sum of all short-run marginal costs on average: fuel + variable operations and maintenance + GHG emissions cost) is the lowest by far for wind/CAES systems.

Since dispatch costs determine the relative suitability of alternative options for baseload operation, it is necessary to examine closely the *dynamics* of dispatch. Although to good approximation one can assume that the dispatch costs for coal IGCC plants are constant, the dispatch costs for wind-based power systems cannot be treated as simple averages.

Dispatch costs for wind-based systems vary from the minimum value (corresponding to times when all electricity is provided by wind—i.e., when fuel expenditures are zero) and increase significantly as backup generation comes on line to balance shortfalls in wind output. Thus, it is important to analyze the variations in dispatch costs for these options, not simply their average value as reported in Table 8.

Figure 23 shows the variation in dispatch costs in a manner similar to a “load-duration” curve or, more precisely, as an inverse cumulative probability curve counting from the top end of the distribution. The choice of horizontal axis (in reverse order from 1 to 0) can be useful since horizontal axis values at the intersection of the wind curves with each constant-cost IGCC line indicate the percent of time that it can deliver power at a lower dispatch cost. These dispatch cost curves are evaluated at both p_{GHG}=\$0/tCO_2 and \$31/tCO_2 (this is the break-even greenhouse gas emissions price for IGCC-C relative to IGCC-V as is evident from Table 8).

4.3.2. Results

Dispatch costs are the same lowest value for both the wind/gas and wind/CAES systems when all power comes directly from the wind array (right portion of each plot in Figure 23), but dispatch costs rise at very different rates as the fraction of power coming from the backup system increases (left portion of each plot). In addition, the wind/CAES system has an intermediate dispatch cost regime where CAES compressors are running to store wind energy that cannot be transmitted; this appears as a step in intermediate ranges on the wind/CAES dispatch cost curve.

Figure 23 shows that wind/gas has the highest dispatch cost of all the coal and wind options when natural gas generation is dispatched in significant quantities to balance wind output. For the portion of the dispatch duration curve corresponding to zero wind output, the dispatch cost matches the dispatch cost of NGCC as expected. These relationships hold true at both valuations of GHG emissions assumed in Figure 23. At

$0/tCO$_2$ wind/gas cannot compete in economic dispatch relative to the lowest cost coal technology for more than 35% of the time and even at $31/tCO$_2$ it will be competitive less than 40% of the time. Hence a baseload-level capacity factor cannot be sustained with wind/gas if either coal or wind/CAES capacity is available in significant quantity on the grid. Thus in light of current and prospective high natural gas prices, it is unlikely that

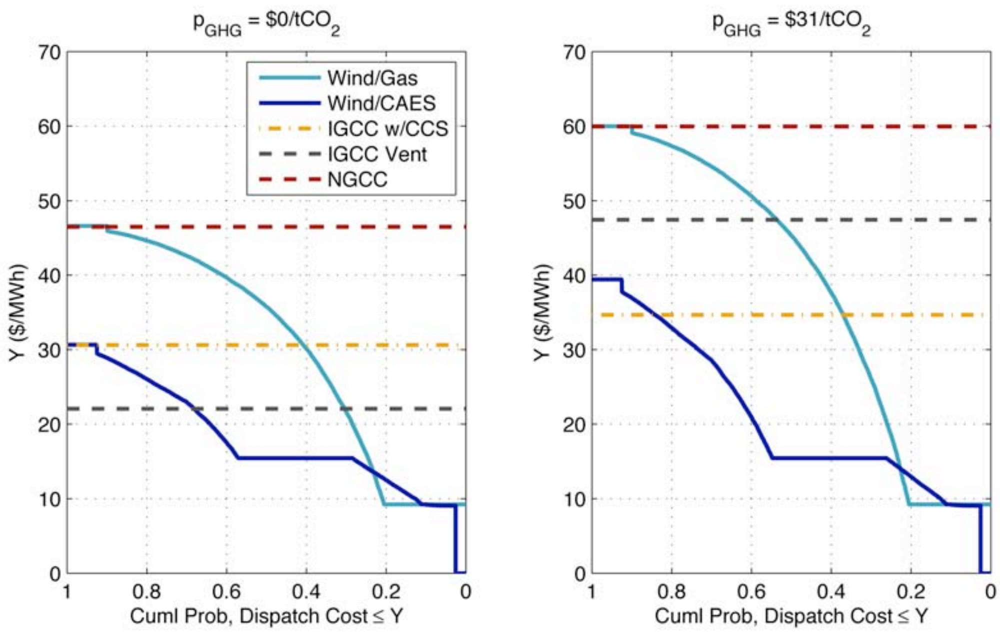

Figure 23 Dispatch costs for the four alternative power systems for two valuations of GHG emissions

wind/gas will be a viable baseload power option for the near future.[21]

In contrast, because wind/CAES systems have a lower heat rate (4220 kJ/kWh) and because direct energy from wind accounts for a larger fraction of the output (see Table 6), they are able to run at a lower dispatch cost than both coal options more than 70% of the time at \$0/tCO$_2$ and more than 85% of the time at \$31/tCO$_2$.

Thus, via dispatch competition, wind/CAES systems can be highly competitive with coal power systems—especially in the presence of a substantial valuation of GHG emissions. An economic model of the entire electric power system is needed to determine the capacity factors of coal power plants on the grid resulting from dispatch competition. Although such modeling is beyond the scope of this report, it is clear that the average capacity factor for coal systems would decline as more and more wind/CAES power is added to the grid. At a GHG emissions valuation of \$31/tCO$_2$, the COE for a wind/CAES system at 85% capacity factor would be lower than for an IGCC-C system

[21] Wind power backed by existing reserve capacity might still be cost-effective in serving intermediate load applications, especially where diurnal variations in wind speed are positively correlated with electricity demand. However, analysis of intermediate load markets is outside the scope of this report.

when the latter has a capacity factor less than 79% when both systems are equally distant from major electricity markets or less than 71% when the wind supply is more distant by 500 km.

The coupling of wind farms to large scale storage technologies such as CAES opens the door to participation in baseload markets for both wind and natural gas—especially in the presence of a strong climate change mitigation policy. The variability of wind makes it impossible for a "pure" wind system to provide baseload power. Moreover, current and prospective high natural gas prices exclude natural gas combined cycle power technology from providing baseload power if there is a substantial amount of coal power on the grid. But coupling wind to CAES makes it possible for wind to deliver firm power. And the use of wind to provide compressor energy results in fuel consumption that is sufficiently low for wind/CAES to be competitive with coal in economic dispatch. This represents an important opportunity for both wind and natural gas to compete in baseload power markets, and opens the door to an important option for realizing cost-effectively deep reductions in GHG emissions from the power sector.

5. Advanced Technology Options

Although commercial CAES plants have been operating for several decades, the technology is still in an early state of development. This is reflected in the fact that the two existing plants are based largely on conventional gas turbine and steam turbine technologies. Consequently, various technological improvements might be pursued to enhance performance and reduce costs over relatively few product cycles.

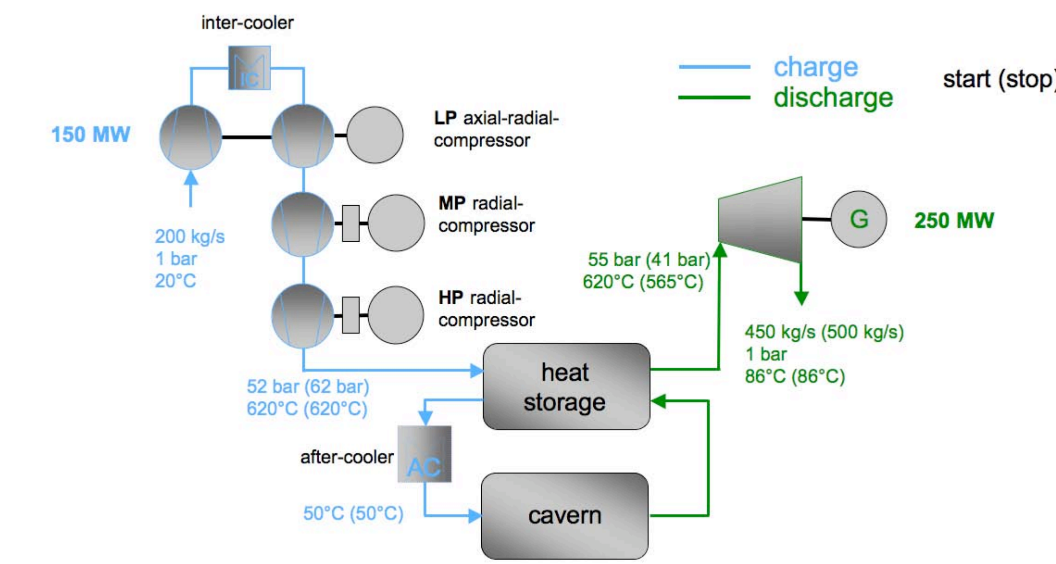

Figure 24 A possible technical concept for an AA-CAES system under development [38]

One option that has attracted interest is to reduce (and perhaps eliminate) the CAES fuel requirements and associated GHG emissions by recovery and storage of the high-quality heat of compression in thermal energy storage (TES) systems. Heat recovery could be implemented at some or all compression stages, which would then allow stored heat to be used in place of fuel to reheat air withdrawn from the CAES cavern thereby either partially or completely eliminating the need for natural gas [65]. In order to be economic, the fuel cost reductions must offset the additional capital cost associated with the TES system. Early studies found that very high fuel prices would be required to justify such systems making adiabatic CAES too costly for commercial use [93-97].

More recent studies however suggest that new TES technologies, together with improvements in the compressor and turbine systems might make so-called Advanced Adiabatic CAES (AA-CAES), economically viable [9, 98]. One such AA-CAES concept with a high efficiency turbine and a high-capacity TES, achieves a round trip efficiency of approximately 70% with no fuel consumption (see Figure 24) [38]. But it should be noted that the efficiency gain of adiabatic systems over multistage compression with intercooling is small (see Appendix A), and both the fuel use and GHG emissions for wind/CAES systems are already very modest (see Table 7).

Table 9 The main thermal energy storage (TES) concepts considered for AA-CAES [98] [a]

Concept	Solid TES					Liquid TES		
	Rock bed	Cowper-Derivative	Concrete Walls	Cast Iron Slabs	'Hybrid'-phase-change materials	Two Tank	1-Tank Thermo-cline	Air-Liquid
Contact	Direct	Direct	Direct	Direct	Direct	Indirect	Indirect	Indirect
Storage Materials	Natural Stone	Ceramics	Concrete	Cast Iron	Ceramics, Salt	Nitrate Salt, Mineral Oil	Nitrate Salt, Mineral Oil	Nitrate Salt, Mineral Oil

a. Storage technologies chosen on the basis of the capability to deliver 120-1200 MWh (thermal), maintain high consistency of outlet temperature, and cover the full temperature range (50 to 650°C)

Another proposal is to use biomass-derived fuels to reheat the air withdrawn from storage. This could reduce GHG emissions and decouple the plant economics from fuel price fluctuations [99]. This might also allow CAES to be run on fuel produced locally, thereby facilitating the utilization of energy crops in remote, wind-rich areas and eliminating the need to secure natural gas supplies. However, as in the adiabatic case, the emissions benefit would be small because the emissions level of wind/CAES is already quite low (~ 2/3 the rate for a coal IGCC plant with CCS, see Table 7). Moreover, a biofuels plant dedicated to a wind/CAES system would require fuel storage, because biofuels must be produced in large-scale plants that are run flat-out in order to be cost effective, while CAES expander capacity factors for backing wind will typically be modest (see Table 6)

A CAES variant proposed for wind applications is to replace the electrical generator in the wind turbine nacelle with a compact compressor. So doing would enable the wind turbine to generate compressed air directly, thereby eliminating two energy conversion processes.[22] However, the reduced losses and potential drop in turbine capital cost would have to offset the added capital cost of the compact compressors and the considerable cost of the high pressure piping network needed to transport the compressed air from each turbine to the storage reservoir.

In contrast to the option of coupling intermittent wind to CAES to enable the provision of baseload electricity, CAES might also be coupled to baseload power systems to facilitate the use of such systems to provide load-following and/or peaking power, the function originally envisioned for CAES—e.g., by coupling CAES to a coal IGCC plant [100, 101].

Improving CAES turbomachinery is a promising area for innovation. CAES turbine operating temperatures might be increased, thereby increasing their efficiency by introducing turbine blade cooling technologies routinely deployed in conventional gas turbines but not in commercial CAES units. Other advanced CAES concepts include various humidification and steam injection schemes which can be used to boost the power output of the system and reduce the storage requirement [102]. The CAES

[22] The company General Compression is currently developing this technology.

combined cycle is still another option that allows the system to generate electricity even when the compressed air storage reservoir is depleted [103, 104].

A recent hybrid CAES system design incorporates a standard combustion turbine in place of the turboexpander chain in a traditional CAES design. The air withdrawn from storage is heated by means of a recuperator at the turbine exhaust instead of by way of fuel combustors as in a conventional CAES plant. The heated air is then injected into the turbine to boost the output. The use of commercial technology and the elimination of fuel combustors could reduce the capital cost of the system substantially and provide a low risk option for early adoption of bulk storage. Such an Air-Injection CAES (AI-CAES) plant could also include a bottoming cycle and TES system to reduce fuel consumption further [52, 105].

Although it is possible that new CAES concepts will bring important changes to the way air storage operates or the way wind power is stored, performance/cost gains are most likely to arise in the near term as a result of marginal improvements in existing CAES designs as a result of learning by doing. Thus, after technology launch in the market, costs for new technologies such as CAES can be expected to decline at faster rates than for mature technologies and more quickly the faster the rate of deployment. This phenomenon bodes well for wind/CAES as a baseload power climate change mitigation option if there is a way forward that offers opportunity for substantial early market experience.

6. A Way Forward

Although the exploitable global wind potential is sufficient to meet total electricity demand several times over, the future role of wind will ultimately be determined by the extent to which the temporal variability and resource remoteness challenges can be addressed. Compressed air energy storage is a potential solution, but to evolve from the two commercial-scale CAES plants in the field today to wide-scale deployment of this technology requires clarification of several issues.

Widespread deployment of CAES will depend on the availability of suitable geologies that can be developed economically to provide the needed storage capacity. The two existing commercial CAES plants at Huntorf and McIntosh both use salt dome storage but, as Figure 17 shows, regions with domal salt formations do not have significant overlap with high quality wind resources. Bedded salt and hard rock geologies overlap well with windy areas (see Figure 7 and Figure 17), but there are challenges associated with each, namely structural issues in the case of salt beds and the high cost of mining new caverns in the case of hard rock (see section 1.3). Developments in mining technology may reduce the cost of using hard rock storage reservoirs making this geology a viable option for future CAES systems. However, porous rock formations can currently be developed at a much lower cost and appear to be available in many windy areas throughout the continental US and thus are the most likely candidate for coupling CAES with wind capacity in the near term.

Although the geographical distributions of good wind resources and potential aquifer storage opportunities seem to be well correlated (see Figure 17), this broad-brush judgment must be buttressed by detailed assessments of specific aquifers and local, facility-sized structures in the aquifers. In the necessary detailed resource assessments, clarification is needed of the extent of anticlines with suitable characteristics (permeability, caprock thickness, etc) among the porous rock formations of the regions where there are good wind resources and of the geochemical suitability of various formations for storing air. Data on local geology from US and state geological surveys including natural gas storage candidate site evaluations might aid in further characterizing these areas, but new data will also be needed especially in regions where natural gas storage is not commonplace.

The planned wind/CAES system in Iowa will help to establish the viability of aquifer CAES, but as indicated in section 3, the suitability of a porous rock formation for CAES depends on a host of geologic factors. As such, it will be important to demonstrate several commercial scale systems to ensure that CAES technology can be developed in a sufficiently broad set of geologic conditions as to have the potential for widespread deployment.

Finally, direct coupling of CAES with wind farms will present challenges not faced in today's CAES systems. The system at Huntorf is primarily used for peaking services and the McIntosh system charges storage at night and provides output during the day. This is in contrast to the higher frequency fluctuations imposed by wind power and the more rapid switching between compression and generation modes needed to back up wind power.

The use of CAES in an intermediate load application such as that envisioned for the Iowa wind/CAES plant will provide a valuable demonstration of wind/CAES integration. However, demonstration of a much more closely coupled system capable of serving baseload markets is also needed to understand better the potential of wind/CAES for displacing new coal capacity in a carbon constrained future. Ultimately the role of wind as a tool for climate mitigation will depend on the extent to which it will be able to supplant new baseload coal-fired capacity.

7. Conclusions

Traditionally, CAES technology has been used for grid operational support applications such as regulation control and load shifting. But a new major possibility that is especially relevant for a carbon constrained world is to enable exploitation at large intermittent wind resources that are often remote from major electricity demand centers. CAES appears to have many of the characteristics necessary to transform wind into a mainstay of global electricity generation.

Backing wind to produce baseload output requires short response times to accommodate fluctuations in compressor power and turbine load. The ability of a CAES system to ramp output quickly and provide efficient part-load operation make it particularly well suited for balancing such fluctuations—key performance characteristics that are not often called upon at existing CAES plants that simply store low-cost off-peak electricity for use when electricity is more valuable.

Air storage volume requirements translate into a geologic footprint ~15% of the wind farm land area, so that CAES will have relatively limited impact on land use and ecology.

The wide availability of potentially suitable geology in wind-rich areas points to CAES as a technology well-suited for making baseload power from wind—thereby making it feasible to provide wind power at electric grid penetrations far greater than 20%+ penetration rates that are feasible without storage. And, to the extent that wind-rich regions are remote from major electricity markets, such baseload power can often be delivered to distant markets via high voltage transmission lines at attractive costs.

Aquifer CAES seems to be the most suitable storage geology for wind/CAES in the US due to the potential for low development costs and because regions with porous rock geologies are strongly correlated with the onshore wind-rich regions of the US.

Aquifer CAES technology has been studied for nearly three decades, but the first commercial plant was only recently formally announced. Nevertheless, a great deal of commercial experience can be gleaned from the natural gas storage industry, which uses geologies similar to those needed for CAES to meet seasonal heating demand fluctuations. The methodologies for evaluating natural gas storage reservoirs have been shown to be directly applicable to aquifer CAES development, but several differences between use of methane and air as a storage fluid must be taken into account. Care must be taken to carefully characterize local mineralogy, existing bacterial populations and relevant corrosion mechanisms in order to anticipate any problems resulting from the introduction of air into porous underground media. Methods for mitigating the impact of these factors such as air dehydration, particulate filtration or biocide application could help to expand the number of suitable sites. Despite the various issues that must be taken into account, none obviously diminish CAES as a strong candidate option for wind balancing.

The planned wind/CAES plant in Iowa will provide valuable experience both with an aquifer as a storage medium and with operating a CAES system under conditions somewhat different from those at Huntorf and McIntosh due to the coupling of CAES with variable wind power.

However, understanding the large-scale deployment potential of CAES will require both a more detailed characterization of existing porous rock formations as well as operational experience from multiple plants over a wide variety of geologic conditions.

An economic analysis of wind/CAES systems shows that its costs would be very similar to costs for other baseload power options offering low GHG emissions. The dispatch cost of wind/CAES systems is low enough to defend a baseload (~85%) capacity factor against other low carbon generation technologies such as coal IGCC with CCS. Furthermore, the fact that few commercial CAES systems exist suggests that significant cost reductions are likely to be realizable over relatively few product cycles of experience via “learning by doing”

The storage of energy through air compression offers the potential to enable wind to meet a large fraction of the world’s electricity needs competitively in a carbon constrained world. If the needed resource assessments and system studies are completed soon, it should quickly become evident just how large this fraction might be.

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Appendix A Theoretical Efficiency of Compressed Air Energy Storage for Alternative Configurations

The storage efficiency of adiabatic compressors and storage in an insulated cavern is compared to that of intercooled compressors and storage at ambient temperature.

The theoretical maximum efficiency of compressed air energy storage η_S is ratio of the maximum work b (the exergy, in kJ) that can be extracted from 1 kmol of air stored at temperature T_S and pressure P_S to the work wc required to compress 1 kmol of air from ambient temperature T_o (= 300 K) and pressure P_o (= 1 atmosphere):

$$\eta_S = b/w_C \qquad (45)$$

$$b\,(P_S,T_S) = h\,(P_S,T_S) - h\,(P_o,T_o) - T_o*[s\,(P_S,T_S) - s\,(P_o, T_o)], \qquad (46)$$

where

h = air enthalpy, and
s = air entropy.

Suppose that air is compressed from P_o, T_o to P_C, T_C. Assuming air is an ideal diatomic gas with constant specific heats:

$$k = c_p/c_v = 7/5 = 1.4 \qquad (47)$$

where:

c_p = specific heat at constant pressure,
c_v = specific heat at constant volume,

the exergy per kmol of compressed air is:

$$b\,(P_S, T_S) = cp*(T_S - T_o) - c_p*T_o*\ln(T_S/T_o) + RT_o*\ln(P_S/P_o) \qquad (48)$$

$$= RT_o*[k/(k - 1)]*[[(T_S/T_o - 1) - \ln(T_S/T_o)] + [(k - 1)/k]*\ln(P_S/P_o)], \qquad (49)$$

where R is the universal gas constant (R = 8314 kJoules/kmole/K).

Moreover, assuming a compressor with an efficiency η_c, with N stages of adiabatic compression, with perfect intercooling between stages, and with the optimal compression ratio per stage = $(P_C/P_o)^{1/N}$, the work required to compress a kmol of air from pressure P_o to P_C is:

$$w_C = RT_o*[Nk/(k - 1)]*[(P_C/P_o)^{(k-1)/Nk} - 1]/\eta_c \qquad (50)$$

and T_C is given by:

$$T_C = T_o*(P_C/P_O)^{(k-1)/Nk} \qquad (51)$$

The theoretical maximum efficiency of storage is thus:

$$\eta_S = (\eta_C/N)*[(T_S/T_o-1)-\ln(T_S/T_o)+[(k - 1)/k]*\ln(P_S/P_o)]/[(P_C/P_o)^{(k-1)/Nk}-1] \qquad (52)$$

<u>Case I:</u> Consider first a system with one stage of adiabatic compression (N = 1) and perfect insulation of the air storage reservoir, so that $T_S = T_C$ and $P_S = P_C$. In this case, η_S

$= \eta_C$, and the highest possible storage efficiency is realized. However, this is not a good representation of the actual situation where the air in storage is typically cooled to the ambient temperature.

<u>Case II:</u> Consider next a system with N stages of compression, perfect intercooling between stages, and poor insulation of the storage reservoir so that $T_S \rightarrow T_o$ before energy recovery is attempted. In this case,

$$P_S \rightarrow P_C*(T_o/T_C) = P_C*(P_C/P_o)^{-(k-1)/Nk} = P_o*(P_C/P_o)^{1-(k-1)/Nk} \quad (53)$$

$$b(P_S, T_S) \rightarrow RT_o*[1 - 1/N + 1/(Nk)]*\ln(P_C/P_o) \quad (54)$$

and

$$\eta_S = (\eta_C/N)*[(k - 1)/k]*[1 - 1/N + 1/(Nk)]*\ln(P_C/P_o)/[(P_C/P_o)^{(k-1)/Nk} - 1] \quad (55)$$

For example, suppose air is compressed to $P_C = 100$ atmospheres and $N = 1$, so that $T_C = 1118$ K, and at the time of energy recovery, $P_S = (300/1118)*100 = 26.8$ atmospheres. In this case $\eta_S = 0.345*\eta_C$.

But if $P_C = 100$ atmospheres and $N = 5$, $T_C = 390$ K and $P_S = 77.0$ atmospheres at the time of energy recovery, so that $\eta_S = 0.824*\eta_C$.

In the limit of an infinite number of stages of compression with perfect intercooling, the compressor work is isothermal, and the compressor work required is:[23]

$$w_C \rightarrow (RT_o*/\eta_C)*\ln(P_C/P_o),\ P_S \rightarrow P_C, \text{ so that } \eta_S \rightarrow \eta_C \quad (56)$$

This is the same as for Case I. Thus, via the use of large number of intercoolers, the theoretical efficiency of a CAES unit with storage at ambient temperature can approach that of a CAES unit compressing air adiabatically and storing air in an insulated cavern.

[23] Note that $(X^a - 1)/a \rightarrow \ln X$ as $a \rightarrow 0$.

Fannin County Profile

Compiled by
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POPULATION (Census Bureau)	
County Population «History» «Group Quarters»	
Estimate 2008:	33,229
Estimate 2007:	32,930
Estimate 2006:	32,814
Estimate 2005:	32,647
Estimate 2004:	32,237
Estimate 2003:	32,053
Estimate 2002:	31,580
Estimate 2001:	31,301
Census 2000:	31,242
Census 1990:	24,804
Census 1950:	31,253
Population of the County Seat **(Bonham)**	
Census 2000:	9,990
Census 1990:	6,688
POPULATION ESTIMATES - 2007 (Census Bureau)	
Note: City and town populations include only those parts of each place found within this county. Use our «Town & City Search» to find the total population of each place.	
Fannin County:	32,930
Bailey:	221
Bonham:	10,536
Dodd City:	441
Ector:	625
Honey Grove:	1,820
Ladonia:	691
Leonard:	2,080
Pecan Gap:	8
Ravenna:	226
Savoy:	890
Trenton:	713
Whitewright:	15
Windom:	252
Balance of Fannin County:	14,412
GENERAL INFORMATION	
County Size in Square Miles (Census Bureau and EPA)	
Land Area:	892
Water Area:	8
Total Area:	900
Population Density Per Square Mile	
2000:	35.0
DEMOGRAPHICS	
Ethnicity - 2008 (Census Bureau)	
Percent Hispanic:	7.6%
Race - 2008 (Census Bureau)	
Percent White Alone:	89.3%
Percent African American Alone:	7.8%

Percent American Indian and Alaska Native Alone:	1.1%
Percent Asian Alone:	0.4%
Percent Native Hawaiian and Other Pacific Islander Alone:	0.0%
Percent Multi-Racial:	1.4%
Age - 2007 (Census Bureau)	
17 and Under:	21.8%
65 and Older:	16.9%
85 and Older:	2.8%
Median Age:	38.3
Income	
Per Capita Income - 2007 (BEA):	$25,258
Total Personal Income - 2007 (BEA):	$831,746,000
Median Household Income - 2007 (Census Bureau):	$40,840
Poverty - 2007 (Census Bureau)	
Percent of Population in Poverty:	16.5%
Percent of Population under 18 in Poverty:	22.5%
Wages (BEA)	
Average Wage Per Job - 2007:	$31,001
Average Wage Per Job - 2006:	$30,871
Average Wage Per Job - 2005:	$29,184
Average Wage Per Job - 2004:	$28,583
Average Wage Per Job - 2003:	$27,612
Average Wage Per Job - 2002:	$26,756
Average Wage Per Job - 2001:	$26,978
Average Wage Per Job - 2000:	$26,028
Average Wage Per Job - 1990:	$17,029
Annual Unemployment Rate, Not Adjusted (Texas Workforce Commission)	
Unemployment Rate - 2008:	5.9%
Unemployment Rate - 2007:	5.2%
Unemployment Rate - 2006:	6.0%
Unemployment Rate - 2005:	6.4%
Unemployment Rate - 2004:	7.0%
Unemployment Rate - 2003:	7.5%
Unemployment Rate - 2002:	7.8%
Unemployment Rate - 2001:	6.6%
Unemployment Rate - 2000:	4.9%
COUNTY FINANCES (Texas Comptroller of Public Accounts)	
Property Taxes - 2008	
Total County Tax Rate: «Historic Tax Rate» «Detailed Tax Rates»	$0.611000
Total Market Value: «Values and Levies»	$2,371,532,563
Total Appraised Value Available for County Taxation:	$1,382,825,613
Total Actual Levy:	$8,449,064
Sales Tax Allocation History	
CY 2008:	$944,226.77
CY 2007:	$719,443.09
CY 2006:	$710,162.43
CY 2005:	$599,276.35
CY 2004:	$593,232.08
CY 2003:	$580,338.18
CY 2002:	$589,073.72
CY 2001:	$579,263.92
INFRASTRUCTURE EXPENDITURES (Texas Comptroller of Public Accounts)	
Road and Bridge - 2007	
County Roads, Construction:	$0
County Roads, Maintenance:	$1,539,205
County Roads, Rehabilitation:	$0
County Bridges, Construction:	$0

County Bridges, Maintenance:	$89,941
County Bridges, Rehabilitation:	$0
Right of Way Acquisition:	$0
Utility Construction:	$0
Other Road Expenditures:	$444,692
Total Road and Bridge Expenditures:	**$2,073,838**
COUNTY ROAD MILES (TXDOT)	
Centerline Miles - 2004	
Unpaved (Earth and All-weather):	839
Paved (bituminous surface, treated, less than 1):	36
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	0
Total Centerline Miles:	**875**
Lane Miles - 2004	
Unpaved (Earth and All-weather):	1,678
Paved (bituminous surface, treated, less than 1):	70
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	0
Total Lane Miles:	**1,747**

Special Districts in Fannin County.
School Districts in Fannin County.
History of City Tax Rates in Fannin County.

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Grayson County Profile

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POPULATION (Census Bureau)	
County Population «History» «Group Quarters»	
Estimate 2008:	118,804
Estimate 2007:	118,066
Estimate 2006:	116,829
Estimate 2005:	115,577
Estimate 2004:	114,932
Estimate 2003:	114,384
Estimate 2002:	113,273
Estimate 2001:	112,381
Census 2000:	110,595
Census 1990:	95,021
Census 1950:	70,467
Population of the County Seat **(Sherman)**	
Census 2000:	35,082
Census 1990:	31,584
POPULATION ESTIMATES - 2007 (Census Bureau)	
Note: City and town populations include only those parts of each place found within this county. Use our «Town & City Search» to find the total population of each place.	
Grayson County:	118,066
Bells:	1,300
Collinsville:	1,478
Denison:	24,016
Dorchester:	109
Gunter:	1,316
Howe:	2,693
Knollwood:	404
Pottsboro:	2,090
Sadler:	437
Sherman:	37,455
Southmayd:	1,078
Tioga:	913
Tom Bean:	1,023
Van Alstyne:	2,921
Whitesboro:	4,009
Whitewright:	1,684
Balance of Grayson County:	35,140
GENERAL INFORMATION	
County Size in Square Miles (Census Bureau and EPA)	
Land Area:	934
Water Area:	46
Total Area:	980
Population Density Per Square Mile	
2000:	118.4
DEMOGRAPHICS	
Ethnicity - 2008 (Census Bureau)	
Percent Hispanic:	10.2%

Race - 2008 (Census Bureau)	
Percent White Alone:	89.8%
Percent African American Alone:	5.9%
Percent American Indian and Alaska Native Alone:	1.6%
Percent Asian Alone:	0.8%
Percent Native Hawaiian and Other Pacific Islander Alone:	0.1%
Percent Multi-Racial:	1.9%
Age - 2007 (Census Bureau)	
17 and Under:	24.3%
65 and Older:	14.9%
85 and Older:	2.4%
Median Age:	37.2
Income	
Per Capita Income - 2007 (BEA):	$28,901
Total Personal Income - 2007 (BEA):	$3,412,174,000
Median Household Income - 2007 (Census Bureau):	$44,392
Poverty - 2007 (Census Bureau)	
Percent of Population in Poverty:	12.6%
Percent of Population under 18 in Poverty:	18.3%
Wages (BEA)	
Average Wage Per Job - 2007:	$35,271
Average Wage Per Job - 2006:	$33,814
Average Wage Per Job - 2005:	$32,468
Average Wage Per Job - 2004:	$31,227
Average Wage Per Job - 2003:	$30,310
Average Wage Per Job - 2002:	$29,617
Average Wage Per Job - 2001:	$29,892
Average Wage Per Job - 2000:	$29,196
Average Wage Per Job - 1990:	$20,979
Annual Unemployment Rate, Not Adjusted (Texas Workforce Commission)	
Unemployment Rate - 2008:	5.3%
Unemployment Rate - 2007:	4.7%
Unemployment Rate - 2006:	4.9%
Unemployment Rate - 2005:	5.4%
Unemployment Rate - 2004:	6.2%
Unemployment Rate - 2003:	7.1%
Unemployment Rate - 2002:	6.7%
Unemployment Rate - 2001:	5.3%
Unemployment Rate - 2000:	4.1%
COUNTY FINANCES (Texas Comptroller of Public Accounts)	
Property Taxes - 2008	
Total County Tax Rate: «Historic Tax Rate» «Detailed Tax Rates»	$0.490900
Total Market Value: «Values and Levies»	$8,910,461,517
Total Appraised Value Available for County Taxation:	$6,014,298,073
Total Actual Levy:	$29,524,189
Sales Tax Allocation History	
CY 2008:	N/A
CY 2007:	N/A
CY 2006:	N/A
CY 2005:	N/A
CY 2004:	N/A
CY 2003:	N/A
CY 2002:	N/A
CY 2001:	N/A
INFRASTRUCTURE EXPENDITURES (Texas Comptroller of Public Accounts)	
Road and Bridge - 2007	
County Roads, Construction:	$2,696,543

County Roads, Maintenance:	$2,765,646
County Roads, Rehabilitation:	$0
County Bridges, Construction:	$0
County Bridges, Maintenance:	$11,283
County Bridges, Rehabilitation:	$0
Right of Way Acquisition:	$0
Utility Construction:	$0
Other Road Expenditures:	$3,104,748
Total Road and Bridge Expenditures:	**$8,578,221**
COUNTY ROAD MILES (TXDOT)	
Centerline Miles - 2004	
Unpaved (Earth and All-weather):	585
Paved (bituminous surface, treated, less than 1):	683
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	1
Total Centerline Miles:	**1,269**
Lane Miles - 2004	
Unpaved (Earth and All-weather):	1,170
Paved (bituminous surface, treated, less than 1):	1,366
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	1
Total Lane Miles:	**2,538**

Special Districts in Grayson County.
School Districts in Grayson County.
History of City Tax Rates in Grayson County.

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Austin County Profile

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POPULATION (Census Bureau)	
County Population «History» «Group Quarters»	
Estimate 2008:	26,851
Estimate 2007:	26,510
Estimate 2006:	26,062
Estimate 2005:	25,744
Estimate 2004:	25,501
Estimate 2003:	25,019
Estimate 2002:	24,571
Estimate 2001:	24,185
Census 2000:	23,590
Census 1990:	19,832
Census 1950:	14,663
Population of the County Seat **(Bellville)**	
Census 2000:	3,794
Census 1990:	3,378
POPULATION ESTIMATES - 2007 (Census Bureau)	
Note: City and town populations include only those parts of each place found within this county. Use our «Town & City Search» to find the total population of each place.	
Austin County:	26,510
Bellville:	4,345
Brazos Country:	291
Industry:	335
San Felipe:	964
Sealy:	6,190
Wallis:	1,287
Balance of Austin County:	13,098
GENERAL INFORMATION	
County Size in Square Miles (Census Bureau and EPA)	
Land Area:	653
Water Area:	4
Total Area:	657
Population Density Per Square Mile	
2000:	36.1
DEMOGRAPHICS	
Ethnicity - 2008 (Census Bureau)	
Percent Hispanic:	21.9%
Race - 2008 (Census Bureau)	
Percent White Alone:	88.6%
Percent African American Alone:	9.7%
Percent American Indian and Alaska Native Alone:	0.3%
Percent Asian Alone:	0.4%
Percent Native Hawaiian and Other Pacific Islander Alone:	0.0%
Percent Multi-Racial:	1.0%
Age - 2007 (Census Bureau)	
17 and Under:	24.8%
65 and Older:	14.5%

85 and Older:	2.4%
Median Age:	37.4
Income	
Per Capita Income - 2007 (BEA):	$35,580
Total Personal Income - 2007 (BEA):	$943,229,000
Median Household Income - 2007 (Census Bureau):	$50,277
Poverty - 2007 (Census Bureau)	
Percent of Population in Poverty:	10.9%
Percent of Population under 18 in Poverty:	15.0%
Wages (BEA)	
Average Wage Per Job - 2007:	$39,815
Average Wage Per Job - 2006:	$36,404
Average Wage Per Job - 2005:	$33,671
Average Wage Per Job - 2004:	$33,406
Average Wage Per Job - 2003:	$32,377
Average Wage Per Job - 2002:	$31,344
Average Wage Per Job - 2001:	$31,775
Average Wage Per Job - 2000:	$29,532
Average Wage Per Job - 1990:	$18,969
Annual Unemployment Rate, Not Adjusted (Texas Workforce Commission)	
Unemployment Rate - 2008:	4.3%
Unemployment Rate - 2007:	3.8%
Unemployment Rate - 2006:	4.4%
Unemployment Rate - 2005:	4.5%
Unemployment Rate - 2004:	5.3%
Unemployment Rate - 2003:	6.2%
Unemployment Rate - 2002:	5.3%
Unemployment Rate - 2001:	4.0%
Unemployment Rate - 2000:	4.0%
COUNTY FINANCES (Texas Comptroller of Public Accounts)	
Property Taxes - 2008	
Total County Tax Rate: «Historic Tax Rate» «Detailed Tax Rates»	$0.479600
Total Market Value: «Values and Levies»	$4,109,533,860
Total Appraised Value Available for County Taxation:	$2,219,085,140
Total Actual Levy:	$10,626,906
Sales Tax Allocation History	
CY 2008:	$1,157,186.33
CY 2007:	$1,095,112.22
CY 2006:	$1,032,904.61
CY 2005:	$1,032,415.25
CY 2004:	$1,075,919.18
CY 2003:	$882,486.05
CY 2002:	$829,761.11
CY 2001:	$793,456.80
INFRASTRUCTURE EXPENDITURES (Texas Comptroller of Public Accounts)	
Road and Bridge - 2007	
County Roads, Construction:	$1,364
County Roads, Maintenance:	$2,860
County Roads, Rehabilitation:	$4,121
County Bridges, Construction:	$0
County Bridges, Maintenance:	$263
County Bridges, Rehabilitation:	$424
Right of Way Acquisition:	$0
Utility Construction:	$0
Other Road Expenditures:	$3,238
Total Road and Bridge Expenditures:	**$12,271**
COUNTY ROAD MILES (TXDOT)	

Centerline Miles - 2004	
Unpaved (Earth and All-weather):	371
Paved (bituminous surface, treated, less than 1):	231
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	0
Total Centerline Miles:	**601**
Lane Miles - 2004	
Unpaved (Earth and All-weather):	741
Paved (bituminous surface, treated, less than 1):	461
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	0
Total Lane Miles:	**1,203**

Special Districts in Austin County.
School Districts in Austin County.
History of City Tax Rates in Austin County.

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Fort Bend County Profile

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POPULATION (Census Bureau)	
County Population «History» «Group Quarters»	
Estimate 2008:	532,141
Estimate 2007:	507,576
Estimate 2006:	484,160
Estimate 2005:	458,516
Estimate 2004:	437,884
Estimate 2003:	416,407
Estimate 2002:	396,697
Estimate 2001:	375,211
Census 2000:	354,452
Census 1990:	225,421
Census 1950:	31,056
Population of the County Seat **(Richmond)**	
Census 2000:	11,081
Census 1990:	10,042
POPULATION ESTIMATES - 2007 (Census Bureau)	
Note: City and town populations include only those parts of each place found within this county. Use our «Town & City Search» to find the total population of each place.	
Fort Bend County:	507,576
Arcola:	1,226
Beasley:	671
Fairchilds:	919
Fulshear:	952
Houston:	37,846
Katy:	1,382
Kendleton:	523
Meadows Place:	6,432
Missouri City:	67,569
Needville:	3,419
Orchard:	476
Pearland:	211
Pleak:	1,248
Richmond:	13,405
Rosenberg:	32,850
Simonton:	864
Stafford:	19,132
Sugar Land:	79,276
Thompsons:	377
Balance of Fort Bend County:	238,798
GENERAL INFORMATION	
County Size in Square Miles (Census Bureau and EPA)	
Land Area:	875
Water Area:	11
Total Area:	886
Population Density Per Square Mile	
2000:	405.1

DEMOGRAPHICS	
Ethnicity - 2008 (Census Bureau)	
Percent Hispanic:	23.9%
Race - 2008 (Census Bureau)	
Percent White Alone:	62.4%
Percent African American Alone:	20.9%
Percent American Indian and Alaska Native Alone:	0.4%
Percent Asian Alone:	14.7%
Percent Native Hawaiian and Other Pacific Islander Alone:	0.1%
Percent Multi-Racial:	1.5%
Age - 2007 (Census Bureau)	
17 and Under:	28.1%
65 and Older:	6.5%
85 and Older:	0.6%
Median Age:	32.9
Income	
Per Capita Income - 2007 (BEA):	$41,779
Total Personal Income - 2007 (BEA):	$21,205,823,000
Median Household Income - 2007 (Census Bureau):	$77,016
Poverty - 2007 (Census Bureau)	
Percent of Population in Poverty:	8.4%
Percent of Population under 18 in Poverty:	11.2%
Wages (BEA)	
Average Wage Per Job - 2007:	$46,207
Average Wage Per Job - 2006:	$43,725
Average Wage Per Job - 2005:	$42,044
Average Wage Per Job - 2004:	$38,311
Average Wage Per Job - 2003:	$37,000
Average Wage Per Job - 2002:	$36,443
Average Wage Per Job - 2001:	$36,106
Average Wage Per Job - 2000:	$34,833
Average Wage Per Job - 1990:	$23,228
Annual Unemployment Rate, Not Adjusted (Texas Workforce Commission)	
Unemployment Rate - 2008:	4.5%
Unemployment Rate - 2007:	4.1%
Unemployment Rate - 2006:	4.8%
Unemployment Rate - 2005:	5.2%
Unemployment Rate - 2004:	5.5%
Unemployment Rate - 2003:	6.1%
Unemployment Rate - 2002:	5.2%
Unemployment Rate - 2001:	3.9%
Unemployment Rate - 2000:	3.6%
COUNTY FINANCES (Texas Comptroller of Public Accounts)	
Property Taxes - 2008	
Total County Tax Rate: «Historic Tax Rate» «Detailed Tax Rates»	$0.499750
Total Market Value: «Values and Levies»	$47,727,143,111
Total Appraised Value Available for County Taxation:	$38,147,525,694
Total Actual Levy:	$190,736,711
Sales Tax Allocation History	
CY 2008:	N/A
CY 2007:	N/A
CY 2006:	N/A
CY 2005:	N/A
CY 2004:	N/A
CY 2003:	N/A
CY 2002:	N/A
CY 2001:	N/A

INFRASTRUCTURE EXPENDITURES (Texas Comptroller of Public Accounts)	
Road and Bridge - 2007	
County Roads, Construction:	$5,211,427
County Roads, Maintenance:	$5,149,693
County Roads, Rehabilitation:	$0
County Bridges, Construction:	$449,042
County Bridges, Maintenance:	$1,189,070
County Bridges, Rehabilitation:	$0
Right of Way Acquisition:	$73,936
Utility Construction:	$0
Other Road Expenditures:	$4,745,032
Total Road and Bridge Expenditures:	**$16,818,199**
COUNTY ROAD MILES (TXDOT)	
Centerline Miles - 2004	
Unpaved (Earth and All-weather):	180
Paved (bituminous surface, treated, less than 1):	579
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	451
Total Centerline Miles:	**1,210**
Lane Miles - 2004	
Unpaved (Earth and All-weather):	360
Paved (bituminous surface, treated, less than 1):	1,159
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	964
Total Lane Miles:	**2,483**

Special Districts in Fort Bend County.
School Districts in Fort Bend County.
History of City Tax Rates in Fort Bend County.

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Freestone County Profile

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The County Information Project

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POPULATION (Census Bureau)	
County Population «History» «Group Quarters»	
Estimate 2008:	18,923
Estimate 2007:	18,719
Estimate 2006:	18,750
Estimate 2005:	18,583
Estimate 2004:	18,489
Estimate 2003:	18,343
Estimate 2002:	18,328
Estimate 2001:	18,104
Census 2000:	17,867
Census 1990:	15,818
Census 1950:	15,696
Population of the County Seat **(Fairfield)**	
Census 2000:	3,094
Census 1990:	3,234
POPULATION ESTIMATES - 2008 (Census Bureau)	
Note: City and town populations include only those parts of each place found within this county. Use our «Town & City Search» to find the total population of each place.	
Freestone County:	18,923
Fairfield:	3,618
Kirvin:	128
Oakwood:	10
Streetman:	209
Teague:	4,749
Wortham:	1,089
Balance of Freestone County:	9,120
GENERAL INFORMATION	
County Size in Square Miles (Census Bureau and EPA)	
Land Area:	885
Water Area:	7
Total Area:	892
Population Density Per Square Mile	
2000:	20.2
DEMOGRAPHICS	
Ethnicity - 2008 (Census Bureau)	
Percent Hispanic:	11.5%
Race - 2008 (Census Bureau)	
Percent White Alone:	80.7%
Percent African American Alone:	17.7%

Percent American Indian and Alaska Native Alone:	0.4%
Percent Asian Alone:	0.3%
Percent Native Hawaiian and Other Pacific Islander Alone:	0.0%
Percent Multi-Racial:	0.9%
Age - 2007 (Census Bureau)	
17 and Under:	21.9%
65 and Older:	15.0%
85 and Older:	2.3%
Median Age:	36.8
Income	
Per Capita Income - 2007 (BEA):	$26,107
Total Personal Income - 2007 (BEA):	$488,701,000
Median Household Income - 2007 (Census Bureau):	$40,664
Poverty - 2007 (Census Bureau)	
Percent of Population in Poverty:	13.6%
Percent of Population under 18 in Poverty:	18.8%
Wages (BEA)	
Average Wage Per Job - 2007:	$36,666
Average Wage Per Job - 2006:	$33,797
Average Wage Per Job - 2005:	$30,611
Average Wage Per Job - 2004:	$29,076
Average Wage Per Job - 2003:	$27,763
Average Wage Per Job - 2002:	$25,859
Average Wage Per Job - 2001:	$26,871
Average Wage Per Job - 2000:	$26,490
Average Wage Per Job - 1990:	$21,198
Annual Unemployment Rate, Not Adjusted (Texas Workforce Commission)	
Unemployment Rate - 2008:	4.1%
Unemployment Rate - 2007:	3.7%
Unemployment Rate - 2006:	4.0%
Unemployment Rate - 2005:	4.2%
Unemployment Rate - 2004:	4.8%
Unemployment Rate - 2003:	6.0%
Unemployment Rate - 2002:	5.8%
Unemployment Rate - 2001:	4.5%
Unemployment Rate - 2000:	5.1%
COUNTY FINANCES (Texas Comptroller of Public Accounts)	
Property Taxes - 2008	
Total County Tax Rate: «Historic Tax Rate» «Detailed Tax Rates»	$0.210000
Total Market Value: «Values and Levies»	$6,168,222,970
Total Appraised Value Available for County Taxation:	$5,190,004,700
Total Actual Levy:	$10,899,010
Sales Tax Allocation History	
CY 2008:	N/A
CY 2007:	N/A
CY 2006:	N/A
CY 2005:	N/A
CY 2004:	N/A
CY 2003:	N/A
CY 2002:	N/A

CY 2001:	N/A
INFRASTRUCTURE EXPENDITURES (Texas Comptroller of Public Accounts)	
Road and Bridge - 2007	
County Roads, Construction:	$0
County Roads, Maintenance:	$2,326,831
County Roads, Rehabilitation:	$0
County Bridges, Construction:	$0
County Bridges, Maintenance:	$369,555
County Bridges, Rehabilitation:	$41,062
Right of Way Acquisition:	$0
Utility Construction:	$0
Other Road Expenditures:	$1,404,159
Total Road and Bridge Expenditures:	**$4,141,607**
COUNTY ROAD MILES (TXDOT)	
Centerline Miles - 2004	
Unpaved (Earth and All-weather):	605
Paved (bituminous surface, treated, less than 1):	39
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	0
Total Centerline Miles:	**645**
Lane Miles - 2004	
Unpaved (Earth and All-weather):	1,211
Paved (bituminous surface, treated, less than 1):	79
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	0
Total Lane Miles:	**1,290**

Special Districts in Freestone County.
School Districts in Freestone County.
History of City Tax Rates in Freestone County.

The County Information Project | County Profiles | Advanced Search | County Locator Map | Town & City Search

Anderson County Profile

Compiled by
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The County Information Project | County Profiles | Advanced Search | County Locator Map | Town & City Search

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POPULATION (Census Bureau)	
County Population «History» «Group Quarters»	
Estimate 2008:	56,838
Estimate 2007:	56,716
Estimate 2006:	56,354
Estimate 2005:	56,020
Estimate 2004:	55,562
Estimate 2003:	55,563
Estimate 2002:	54,357
Estimate 2001:	54,102
Census 2000:	55,109
Census 1990:	48,024
Census 1950:	31,875
Population of the County Seat **(Palestine)**	
Census 2000:	17,598
Census 1990:	18,042
POPULATION ESTIMATES - 2007 (Census Bureau)	
Note: City and town populations include only those parts of each place found within this county. Use our «Town & City Search» to find the total population of each place.	
Anderson County:	56,716
Elkhart:	1,279
Frankston:	1,241
Palestine:	18,129
Balance of Anderson County:	36,067
GENERAL INFORMATION	
County Size in Square Miles (Census Bureau and EPA)	
Land Area:	1,071
Water Area:	7
Total Area:	1,078
Population Density Per Square Mile	
2000:	51.5
DEMOGRAPHICS	
Ethnicity - 2008 (Census Bureau)	
Percent Hispanic:	14.3%
Race - 2008 (Census Bureau)	
Percent White Alone:	75.1%
Percent African American Alone:	22.6%
Percent American Indian and Alaska Native Alone:	0.7%
Percent Asian Alone:	0.7%
Percent Native Hawaiian and Other Pacific Islander Alone:	0.0%
Percent Multi-Racial:	0.9%
Age - 2007 (Census Bureau)	
17 and Under:	20.0%
65 and Older:	12.1%
85 and Older:	2.0%
Median Age:	35.5
Income	

Per Capita Income - 2007 (BEA):	$23,399
Total Personal Income - 2007 (BEA):	$1,327,089,000
Median Household Income - 2007 (Census Bureau):	$37,973
Poverty - 2007 (Census Bureau)	
Percent of Population in Poverty:	18.9%
Percent of Population under 18 in Poverty:	23.4%
Wages (BEA)	
Average Wage Per Job - 2007:	$36,968
Average Wage Per Job - 2006:	$33,293
Average Wage Per Job - 2005:	$30,917
Average Wage Per Job - 2004:	$29,933
Average Wage Per Job - 2003:	$29,350
Average Wage Per Job - 2002:	$29,205
Average Wage Per Job - 2001:	$28,697
Average Wage Per Job - 2000:	$27,382
Average Wage Per Job - 1990:	$19,227
Annual Unemployment Rate, Not Adjusted (Texas Workforce Commission)	
Unemployment Rate - 2008:	5.7%
Unemployment Rate - 2007:	5.2%
Unemployment Rate - 2006:	5.9%
Unemployment Rate - 2005:	6.3%
Unemployment Rate - 2004:	7.0%
Unemployment Rate - 2003:	8.0%
Unemployment Rate - 2002:	7.5%
Unemployment Rate - 2001:	6.0%
Unemployment Rate - 2000:	6.1%
COUNTY FINANCES (Texas Comptroller of Public Accounts)	
Property Taxes - 2008	
Total County Tax Rate: «Historic Tax Rate» «Detailed Tax Rates»	$0.511000
Total Market Value: «Values and Levies»	$3,586,418,372
Total Appraised Value Available for County Taxation:	$2,511,968,450
Total Actual Levy:	$12,833,719
Sales Tax Allocation History	
CY 2008:	$2,537,260.78
CY 2007:	$2,447,719.53
CY 2006:	$2,371,677.22
CY 2005:	$1,944,301.81
CY 2004:	$1,732,639.33
CY 2003:	$1,641,125.03
CY 2002:	$1,495,224.53
CY 2001:	$1,535,956.60
INFRASTRUCTURE EXPENDITURES (Texas Comptroller of Public Accounts)	
Road and Bridge - 2007	
County Roads, Construction:	$0
County Roads, Maintenance:	$3,373,632
County Roads, Rehabilitation:	$0
County Bridges, Construction:	$48,000
County Bridges, Maintenance:	$8,700
County Bridges, Rehabilitation:	$0
Right of Way Acquisition:	$0
Utility Construction:	$0
Other Road Expenditures:	$0
Total Road and Bridge Expenditures:	**$3,430,332**
COUNTY ROAD MILES (TXDOT)	
Centerline Miles - 2004	
Unpaved (Earth and All-weather):	531
Paved (bituminous surface, treated, less than 1):	345

Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	0
Total Centerline Miles:	**877**
Lane Miles - 2004	
Unpaved (Earth and All-weather):	1,067
Paved (bituminous surface, treated, less than 1):	691
Paved (mixed bituminous surface, base and surface depth 7):	0
Paved (mixed bituminous surface, base and surface depth 7 or more):	0
Asphalt:	0
Concrete:	0
Total Lane Miles:	**1,757**

Special Districts in Anderson County.
School Districts in Anderson County.
History of City Tax Rates in Anderson County.

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2008 Texas Water Quality Inventory
Water Bodies with Concerns for Use Attainment and Screening Levels (March 19, 2008)

Explanation of Column Headings

SegID and Name:	May be one of two types of numbers for SegID. The first type is a classified segment number (4 digits, e.g. 0218), as defined in the Texas Surface Water Quality Standards. The second type is an unclassified water body (0218A), not defined in the Standards, associated with a classified water body because it is in the same watershed.
Area:	AU_ID (*e.g.* 0101A_01) and description of the specific area in which one or more water quality standards are not met.
Parameter(s):	These are pollutants or water quality conditions that assessment procedures indicate are the reason the water quality standards are not met.
Level of Concern:	**CN** - Concern for near-nonattainment of the Water Quality Standards **CS** - Concern for water quality based on screening levels

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0101 Canadian River Below Lake Meredith

		Level of Concern
0101_03	*portion in Hutchinson County*	
	ammonia	**CS**

0101A Dixon Creek (unclassified water body)

		Level of Concern
0101A_01	*Dixon Creek downstream of Phillips*	
	bacteria	**CN**
	nitrate	**CS**
	orthophosphorus	**CS**
0101A_02	*Dixon Creek upstream of Phillips*	
	chlorophyll-a	**CS**

0101B Rock Creek (unclassified water body)

		Level of Concern
0101B_01	*Perennial stream from the confluence with the Canadian River up to SH 136 in the City of Borger*	
	nitrate	**CS**

0102 Lake Meredith

		Level of Concern
0102_01	*Downstream half of lake including Big Blue Creek arm*	
	mercury in fish tissue	**CS**
0102_02	*Upstream half of lake, above Big Blue Creek arm*	
	mercury in fish tissue	**CS**

0103A East Amarillo Creek (unclassified water body)

		Level of Concern
0103A_01	*Entire water body*	
	chlorophyll-a	**CS**
	nitrate	**CS**

0104 Wolf Creek

		Level of Concern
0104_03	*Lake Fryer to upstream end of segment*	
	chlorophyll-a	**CS**

0105 Rita Blanca Lake

		Level of Concern
0105_01	*Entire segment*	
	chlorophyll-a	**CS**
	orthophosphorus	**CS**
	ammonia	**CS**
	total phosphorus	**CS**

0199A Palo Duro Reservoir (unclassified water body)

		Level of Concern
0199A_01	*Entire reservoir*	
	ammonia	**CS**

0201 Lower Red River

		Level of Concern
0201_01	*Arkansas State Line to Walnut Bayou (Oklahoma)*	
	chlorophyll-a	**CS**

0201A Mud Creek (unclassified water body)

		Level of Concern
0201A_01	*Entire water body*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

0202 Red River Below Lake Texoma

		Level of Concern
0202_01	*End of segment to Pecan Bayou confluence*	
	chlorophyll-a	**CS**
0202_02	*Pecan Bayou to Pine Creek*	
	chlorophyll-a	**CS**
0202_03	*Pine Creek to Bois d'Arc Creek*	
	chlorophyll-a	**CS**
0202_04	*Bois d'Arc Creek to SH 78*	
	chlorophyll-a	**CS**

0202C Pecan Bayou (unclassified water body)

		Level of Concern
0202C_01	*Entire water body*	
	chlorophyll-a	**CS**

0202D Pine Creek (unclassified water body)

		Level of Concern
0202D_01	*Perennial and intermittent stream from the confluence with the Red River upstream to the dam forming Lake Crook*	
	orthophosphorus	**CS**
	chlorophyll-a	**CS**

0202E Post Oak Creek (unclassified water body)

		Level of Concern
0202E_01	*Entire segment*	
	orthophosphorus	**CS**
	chlorophyll-a	**CS**

0202F Choctaw Creek (unclassified water body)

		Level of Concern
0202F_01	*Entire water body*	
	nitrate	**CS**
	orthophosphorus	**CS**

0202G Smith Creek (unclassified water body)

		Level of Concern
0202G_01	*Entire segment*	
	depressed dissolved oxygen	**CN**
	ammonia	**CS**
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0203 Lake Texoma

		Level of Concern
0203_01	*Near dam*	
	chloride in finished drinking water	**CS**
	orthophosphorus	**CS**
	total dissolved solids in finished drinking water	**CS**
0203_02	*Little Mineral arm*	
	chloride in finished drinking water	**CS**
	total dissolved solids in finished drinking water	**CS**
0203_03	*Mid-lake near Big Mineral arm*	
	chlorophyll-a	**CS**
	total dissolved solids in finished drinking water	**CS**
	chloride in finished drinking water	**CS**
0203_04	*Upper end of lake*	
	chloride in finished drinking water	**CS**
	chlorophyll-a	**CS**
	total dissolved solids in finished drinking water	**CS**
0203_05	*Remainder of lake*	
	chloride in finished drinking water	**CS**
	total dissolved solids in finished drinking water	**CS**

0203A Big Mineral Creek (unclassified water body)

		Level of Concern
0203A_01	*From Lake Texoma upstream to the confl. with an unnamed 2nd order trib. on North Branch 2.4 km upstream of US 377 and upstream to the confl. with an unnamed 2nd order trib. on South Branch 1.1 km upstream of US 377 north of the City of Whitesboro*	
	ammonia	**CS**
	orthophosphorus	**CS**

0204 Red River Above Lake Texoma

		Level of Concern
0204_01	*Segment end to Fish Creek*	
	chlorophyll-a	**CS**
	bacteria	**CN**

0205 Red River Below Pease River

		Level of Concern
0205_01	*From lower end of segment to IH 44*	
	chlorophyll-a	**CS**
0205_02	*China Creek to upstream end of segment*	
	bacteria	**CN**
	chlorophyll-a	**CS**

0206B South Groesbeck Creek (unclassified water body)

		Level of Concern
0206B_01	*Entire segment*	
	bacteria	**CN**
	nitrate	**CS**

0207 Lower Prairie Dog Town Fork Red River

		Level of Concern
0207_04	*SH 70 to upstream end of segment*	
	chlorophyll-a	**CS**
	orthophosphorus	**CS**

0207A Buck Creek (unclassified water body)

		Level of Concern
0207A_01	*From Oklahoma state line to House Log Creek*	
	nitrate	**CS**

0209 Pat Mayse Lake

		Level of Concern
0209_01	*Lower half of lake*	
	manganese in sediment	**CS**
0209_02	*Upper half of lake*	
	manganese in sediment	**CS**

0211 Little Wichita River

		Level of Concern
0211_02	*East Fork confluence to dam*	
	chlorophyll-a	**CS**

0212 Lake Arrowhead

		Level of Concern
0212_01	*Entire lake*	
	total phosphorus	**CS**
	orthophosphorus	**CS**

0214 Wichita River Below Diversion Lake Dam

		Level of Concern
0214_01	*Lower end of segment to FM 2393*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
0214_02	*FM 2393 to River Road WWTP*	
	bacteria	**CN**
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
0214_03	*From River Road WWTP to confluence with Buffalo Creek*	
	chlorophyll-a	**CS**
0214_05	*From Beaver Creek to Diversion Dam*	
	chlorophyll-a	**CS**

0214A Beaver Creek (unclassified water body)

		Level of Concern
0214A_01	*From Wichita River to confluence with Bull Creek*	
	depressed dissolved oxygen	CN
0214A_02	*From Bull Creek to Santa Rosa Lake dam*	
	chlorophyll-a	CS
	depressed dissolved oxygen	CS

0219 Lake Wichita

		Level of Concern
0219_01	*Entire segment*	
	orthophosphorus	CS
	total phosphorus	CS
	chlorophyll-a	CS

0226 South Fork Wichita River

		Level of Concern
0226_02	*From SH 6 to confluence with Willow Creek*	
	ammonia	CS
0226_03	*From confluence with Willow Creek to confluence with Long Canyon Creek*	
	ammonia	CS

0229 Upper Prairie Dog Town Fork Red River

		Level of Concern
0229_01	*Lower end of segment to Palo Duro State Park northern boundary*	
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
0229_02	*Palo Duro Canyon State Park upstream boundary to upper end of segment at Tanglewood Dam*	
	total phosphorus	CS
	chlorophyll-a	CS
	nitrate	CS
	orthophosphorus	CS

0229A Lake Tanglewood (unclassified water body)

		Level of Concern
0229A_01	*Entire lake*	
	total phosphorus	CS
	orthophosphorus	CS
	chlorophyll-a	CS
	nitrate	CS

0230A Paradise Creek (unclassified water body)

		Level of Concern
0230A_03	*Lower 5 miles of water body*	
	chlorophyll-a	CS
	nitrate	CS
0230A_04	*Remainder of water body*	
	chlorophyll-a	CS
	nitrate	CS

0301 Sulphur River Below Wright Patman Lake

		Level of Concern
0301_01	*Lower 9 miles*	
	chlorophyll-a	CS
0301_02	*Upper 10 miles*	
	chlorophyll-a	CS

0302 Wright Patman Lake

		Level of Concern
0302_01	*800 acres near dam*	
	chlorophyll-a	**CS**
0302_02	*300 acres at International Paper intake*	
	ammonia	**CS**
	chlorophyll-a	**CS**
0302_04	*500 acres in the northeast corner of lake*	
	ammonia	**CS**
	chlorophyll-a	**CS**
0302_06	*Big Creek arm*	
	chlorophyll-a	**CS**
0302_09	*5000 acres mid-lake, below Hwy 8*	
	chlorophyll-a	**CS**
0302_10	*4000 acres in upper portion of lake*	
	chlorophyll-a	**CS**
	orthophosphorus	**CS**

0303 Sulphur/South Sulphur River

		Level of Concern
0303_01	*Lower 25 miles*	
	chlorophyll-a	**CS**
0303_02	*Middle 25 miles*	
	chlorophyll-a	**CS**

0303A Big Creek Lake (unclassified water body)

		Level of Concern
0303A_01	*Entire segment*	
	atrazine in finished drinking water	**CS**

0303B White Oak Creek (unclassified water body)

		Level of Concern
0303B_03	*Upper 25 miles of segment*	
	total phosphorus	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**

0304 Days Creek

		Level of Concern
0304_01	*Entire segment*	
	naphthalene in sediment	**CS**
	acenaphthene in sediment	**CS**
	pyrene in sediment	**CS**
	phenanthrene in sediment	**CS**
	nitrate	**CS**
	fluoranthene in sediment	**CS**
	chrysene in sediment	**CS**
	benz(a)antracene in sediment	**CS**
	benzo(a)pyrene in sediment	**CS**

0304C Wagner Creek (unclassified water body)

		Level of Concern
0304C_01	*Entire segment*	
	ammonia	**CS**
	depressed dissolved oxygen	**CS**

0305 North Sulphur River

		Level of Concern
0305_02	*Upper 23 miles*	
	impaired habitat	**CS**

0306 Upper South Sulphur River

		Level of Concern
0306_02	*25 miles above SH 11*	
	total phosphorus	CS
	orthophosphorus	CS
	nitrate	CS
	chlorophyll-a	CS

0401 Caddo Lake

		Level of Concern
0401_01	*Lower 5000 acres*	
	manganese in sediment	CS
	mercury in fish tissue	CS
	ammonia	CS
0401_02	*Harrison Bayou arm*	
	mercury in fish tissue	CS
0401_03	*Goose Prairie arm*	
	mercury in fish tissue	CS
0401_05	*Clinton Lake*	
	ammonia	CS
	mercury in fish tissue	CS
0401_07	*Mid-lake near Uncertain*	
	manganese in sediment	CS
	mercury in fish tissue	CS
0401_08	*Remainder of segment*	
	mercury in fish tissue	CS

0401B Kitchen Creek (unclassified water body)

		Level of Concern
0401B_01	*Entire water body*	
	depressed dissolved oxygen	CN

0402 Big Cypress Creek Below Lake O' the Pines

		Level of Concern
0402_01	*Lower 9 miles*	
	chlorophyll-a	**CS**
0402_02	*11 miles below Black Cypress Creek*	
	depressed dissolved oxygen	**CN**

0402A Black Cypress Bayou (unclassified water body)

		Level of Concern
0402A_01	*Lower 15 miles of water body*	
	copper in water	**CN**
	lead in water	**CN**
0402A_03	*Middle 1 mile, Pruitt Lake*	
	cadmium in water	**CN**
	copper in water	**CN**
	depressed dissolved oxygen	**CN**
	chlorophyll-a	**CS**
	mercury in fish tissue	**CS**
0402A_04	*Middle 13 miles near FM 250*	
	depressed dissolved oxygen	**CN**
	depressed dissolved oxygen	**CS**

0402B Hughes Creek (unclassified water body)

		Level of Concern
0402B_01	*Entire Segment*	
	impaired macrobenthos community	**CN**
	impaired habitat	**CS**

0402E Kelly Creek (unclassified water body)

		Level of Concern
0402E_01	*Entire segment*	
	impaired macrobenthos community	**CN**
	impaired habitat	**CS**

0404 Big Cypress Creek Below Lake Bob Sandlin

		Level of Concern
0404_01	*Lower 15 miles*	
	depressed dissolved oxygen	**CN**
	nitrate	**CS**
0404_02	*Upper 18 miles*	
	toxic sediment (LOE)	**CN**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0404A Ellison Creek Reservoir (unclassified water body)

		Level of Concern
0404A_01	*Entire reservoir*	
	PCBs in fish tissue	**CS**
	zinc in sediment	**CS**
	nickel in sediment	**CS**
	lead in sediment	**CS**
	iron in sediment	**CS**
	cadmium in sediment	**CS**
	manganese in sediment	**CS**

0404B Tankersley Creek (unclassified water body)

		Level of Concern
0404B_01	*Lower 3 miles*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
0404B_03	*3 miles below Tankersley Lake*	
	bacteria	**CN**
	impaired fish community	**CN**
	impaired macrobenthos community	**CN**

0404C Hart Creek (unclassified water body)

		Level of Concern
0404C_01	*Entire water body*	
	depressed dissolved oxygen	**CN**
	depressed dissolved oxygen	**CS**
	nitrate	**CS**

0404E Dry Creek (unclassified water body)

		Level of Concern
0404E_01	*Entire segment*	
	nitrate	**CS**

0404J Prairie Creek (unclassified water body)

		Level of Concern
0404J_01	*Entire segment*	
	depressed dissolved oxygen	**CN**

0404K Walkers Creek (unclassified water body)

		Level of Concern
0404K_01	*Entire water body*	
	depressed dissolved oxygen	**CN**

0404N Lake Daingerfield (unclassified water body)

		Level of Concern
0404N_01	*Entire lake*	
	mercury in fish tissue	**CS**

0405 Lake Cypress Springs

		Level of Concern
0405_02	*Upper 2600 acres*	
	depressed dissolved oxygen	**CN**
0405_03	*Panther Arm*	
	ammonia	**CS**
	depressed dissolved oxygen	**CS**

0406 Black Bayou

		Level of Concern
0406_01	*Lower 12 miles*	
	depressed dissolved oxygen	**CS**
0406_02	*Upper 12 miles*	
	depressed dissolved oxygen	**CS**

0407 James' Bayou

		Level of Concern
0407_01	*Lower 15 miles of segment*	
	ammonia	**CS**

0408 Lake Bob Sandlin

		Level of Concern
0408_01	*Lower 2000 acres near dam*	
	cadmium in water	**CN**

0408C Brushy Creek (unclassified water body)

		Level of Concern
0408C_01	*Entire segment*	
	impaired habitat	**CS**

0409 Little Cypress Bayou (Creek)

		Level of Concern
0409_03	*Middle 25 miles below Hwy 271*	
	bacteria	**CN**
	depressed dissolved oxygen	**CN**
	impaired macrobenthos community	**CN**
0409_04	*Upper 25 miles*	
	bacteria	**CN**

0409B South Lilly Creek (unclassified water body)

		Level of Concern
0409B_01	*Entire segment*	
	depressed dissolved oxygen	**CS**

0501 Sabine River Tidal

		Level of Concern
0501_01	*Lower 10 miles of segment*	
	bacteria	**CN**

0501B Little Cypress Bayou (unclassified water body)

		Level of Concern
0501B_01	*Lower 4.2 miles of bayou*	
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
0501B_02	*0.3 mile upstream to 0.5 mile downstream of Bear Path Road*	
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
0501B_03	*Upper 3.2 miles of bayou*	
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**

0502A Nichols Creek (unclassified water body)

		Level of Concern
0502A_01	*Lower 25 miles of creek*	
	bacteria	**CN**

0502B Caney Creek (unclassified water body)

		Level of Concern
0502B_02	*From Davison Street upstream to the confluence with Caney Branch and Little Caney Branch*	
	bacteria	**CN**

0504 Toledo Bend Reservoir

		Level of Concern
0504_06	*Tenaha Creek arm*	
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
0504_07	*Uppermost 5120 acres of reservoir*	
	depressed dissolved oxygen	**CS**
	chlorophyll-a	**CN**
0504_10	*San Patricia arm*	
	depressed dissolved oxygen	**CS**
0504_11	*Toledo Bend reservoir near Buzzard Bend*	
	chlorophyll-a	**CS**

0504D Tenaha Creek (unclassified water body)

		Level of Concern
0504D_01	*Entire segment*	
	orthophosphorus	**CS**

0505 Sabine River Above Toledo Bend Reservoir

		Level of Concern
0505_03	*22 mile reach near SH 149*	
	bacteria	**CN**

0505B Grace Creek (unclassified water body)

		Level of Concern
0505B_02	*Upper 12.3 miles*	
	bacteria	**CN**
	depressed dissolved oxygen	**CN**

0505D Rabbit Creek (unclassified water body)

		Level of Concern
0505D_01	*Perennial stream from the confluence with the Sabine River in Gregg County up to the confluence with Little Rabbit Creek in Rusk County*	
	bacteria	**CN**

0506A Harris Creek (unclassified water body)

		Level of Concern
0506A_01	*Entire segment*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**

0506C Wiggins Creek (unclassified water body)

		Level of Concern
0506C_01	*Appendix D - From the confluence with Harris Creek upstream to Smith County WWTP*	
	bacteria	**CN**
	ammonia	**CS**
	orthophosphorus	**CS**
0506C_02	*From Smith County WWTP upstream to dam impounding unnamed reservoir*	
	depressed dissolved oxygen	**CS**

0506G Little White Oak Creek (unclassified water body)

		Level of Concern
0506G_01	*Entire water body*	
	bacteria	CN
	depressed dissolved oxygen	CN

0507 Lake Tawakoni

		Level of Concern
0507_01	*Lowermost 5,120 acres of reservoir, adjacent to dam*	
	chlorophyll-a	CS
0507_02	*Kitsee Inlet*	
	chlorophyll-a	CS
	orthophosphorus	CS
0507_03	*South Fork of Sabine River cove*	
	bacteria	CN
	depressed dissolved oxygen	CS
0507_04	*Cowleech Fork of Sabine River arm*	
	chlorophyll-a	CS
0507_05	*5120 acres near SH 276*	
	chlorophyll-a	CS
0507_06	*5120 acres near Spring Point*	
	chlorophyll-a	CS

0507A Cowleech Fork Sabine River (unclassified water body)

		Level of Concern
0507A_01	*Lower 10 miles, downstream of Long Branch confluence*	
	orthophosphorus	CS
	depressed dissolved oxygen	CS
	nitrate	CS

0507B Long Branch (unclassified water body)

		Level of Concern
0507B_01	*Entire creek*	
	nitrate	CS

0507G South Fork of Sabine River (unclassified water body)

		Level of Concern
0507G_01	*Entire segment*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**

0507H Caddo Creek (unclassified water body)

		Level of Concern
0507H_01	*Entire creek*	
	depressed dissolved oxygen	**CS**

0508 Adams Bayou Tidal

		Level of Concern
0508_01	*Lower 3 miles of segment*	
	depressed dissolved oxygen	**CS**
0508_02	*2 mile reach near Western Avenue*	
	depressed dissolved oxygen	**CS**
0508_03	*1 mile reach near Green Avenue*	
	depressed dissolved oxygen	**CS**
0508_04	*Upper 2 miles of segment*	
	pH	**CN**
	depressed dissolved oxygen	**CS**

0508C Hudson Gully (unclassified water body)

		Level of Concern
0508C_01	*Entire creek*	
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**

0509 Murvaul Lake

		Level of Concern
0509_01	*Entire reservoir*	
	orthophosphorus	**CS**
	chlorophyll-a	**CS**

0510 Lake Cherokee

		Level of Concern
0510_01	*Lower 2352 acres of reservoir*	
	orthophosphorus	**CS**
0510_02	*Upper 1629 acres of reservoir*	
	orthophosphorus	**CS**
	depressed dissolved oxygen	**CS**

0511 Cow Bayou Tidal

		Level of Concern
0511_01	*Lower 5 miles*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**
0511_02	*6 mile reach near FM 105*	
	depressed dissolved oxygen	**CS**
0511_03	*5 mile reach near FM 1442 (north crossing)*	
	depressed dissolved oxygen	**CS**
0511_04	*Upper 4 miles*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**

0511A Cow Bayou Above Tidal (unclassified water body)

		Level of Concern
0511A_01	*Lower 5.3 miles of above-tidal reach*	
	bacteria	**CN**
0511A_02	*Upper 5.3 miles of above-tidal reach*	
	depressed dissolved oxygen	**CS**

0511B Coon Bayou (unclassified water body)

		Level of Concern
0511B_01	*Entire tidal reach*	
	depressed dissolved oxygen	**CS**

0511C Cole Creek (unclassified water body)

		Level of Concern
0511C_01	*Entire tidal reach*	
	depressed dissolved oxygen	**CS**

0511E Terry Gully (unclassified water body)

		Level of Concern
0511E_01	*Entire creek*	
	orthophosphorus	**CS**
	depressed dissolved oxygen	**CN**
	depressed dissolved oxygen	**CS**

0512 Lake Fork Reservoir

		Level of Concern
0512_03	*Running Creek cove, centering on FM 2966*	
	orthophosphorus	**CS**
0512_05	*Uppermost 5120 acres of Lake Fork Creek arm*	
	chlorophyll-a	**CS**

0512A Running Creek (unclassified water body)

		Level of Concern
0512A_01	*Entire creek*	
	ammonia	**CS**
	depressed dissolved oxygen	**CS**
	nitrate	**CS**

0512B Elm Creek (unclassified water body)

		Level of Concern
0512B_01	*Entire creek*	
	depressed dissolved oxygen	**CN**
	ammonia	**CS**
	depressed dissolved oxygen	**CS**

0514 Big Sandy Creek

		Level of Concern
0514_02	*From just upstream of FM 49 to upper end of segment*	
	depressed dissolved oxygen	**CS**

0601 Neches River Tidal

		Level of Concern
0601_01	*Lower boundary to top of first oxbow*	
	malathion in water	**CN**

0601A Star Lake Canal (unclassified water body)

		Level of Concern
0601A_01	*Entire water body*	
	depressed dissolved oxygen	**CN**

0602 Neches River Below B. A. Steinhagen Lake

		Level of Concern
0602_01	*Lower boundary to confluence with Village Creek (0608)*	
	mercury in fish tissue	**CS**
0602_02	*confluence with Village Creek (0608) to 18.4 miles upstream Evadale*	
	mercury in fish tissue	**CS**
0602_03	*18.4 miles upstream Evadale to 5.4 miles upstream FM 1013*	
	mercury in fish tissue	**CS**
0602_04	*5.4 miles upstream FM 1013 to Town Bluff Dam*	
	mercury in fish tissue	**CS**

0603A Sandy Creek (unclassified water body)

		Level of Concern
0603A_01	*Lower 11.5 miles*	
	bacteria	**CN**

0603B Wolf Creek (unclassified water body)

		Level of Concern
0603B_01	*Entire creek*	
	bacteria	**CN**

0604 Neches River Below Lake Palestine

		Level of Concern
0604_01	*Lower boundary to US 69*	
	ammonia	**CS**
0604_04	*From SH 21 to US 84*	
	chlorophyll-a	**CS**
0604_05	*From US 84 to Blackburn Crossing Dam in Anderson/Cherokee County*	
	chlorophyll-a	**CS**

0604A Cedar Creek (unclassified water body)

		Level of Concern
0604A_02	*Upper area upstream of FM 2497*	
	total phosphorus	**CS**
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**

0604C Jack Creek (unclassified water body)

		Level of Concern
0604C_01	*Entire water body*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	nitrate	**CS**
	ammonia	**CS**

0604D Piney Creek (unclassified water body)

		Level of Concern
0604D_01	*Lower 25 miles*	
	depressed dissolved oxygen	**CS**

0604M Biloxi Creek (unclassified water body)

		Level of Concern
0604M_02	*Lower portion below CR 228*	
	bacteria	**CN**
0604M_03	*Upper portion above CR 228*	
	total phosphorus	**CS**

0605 Lake Palestine

		Level of Concern
0605_01	*Lower portion of reservoir near dam*	
	depressed dissolved oxygen	**CS**
0605_03	*Mid-lake near Tyler PWS intake*	
	toxic sediment (LOE)	**CN**
	chlorophyll-a	**CS**
	manganese in sediment	**CS**
0605_04	*Upper lake (Neches arm)*	
	nitrate	**CS**
	orthophosphorus	**CS**
	depressed dissolved oxygen	**CS**
	ammonia	**CS**
	total phosphorus	**CS**
0605_07	*Headwaters (Kickapoo Creek arm)*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
0605_08	*Flat Creek Headwaters*	
	ammonia	**CS**
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
0605_09	*Flat Creek arm*	
	chlorophyll-a	**CS**
0605_10	*Upper Lake*	
	chlorophyll-a	**CS**

0605A Kickapoo Creek (unclassified water body)

		Level of Concern
0605A_01	*Downstream of FM 1803*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0606 Neches River Above Lake Palestine

		Level of Concern
0606_01	*Lower boundary to Prairie Creek*	
	nitrate	CS
	orthophosphorus	CS
0606_02	*Prairie Creek to river mile 7.0*	
	depressed dissolved oxygen	CS
0606_03	*River mile 7.0 to headwaters*	
	depressed dissolved oxygen	CN

0607 Pine Island Bayou

		Level of Concern
0607_01	*Mouth to river mile 5.7*	
	depressed dissolved oxygen	CS
0607_04	*River Mile 35.4 at confluence with Willow Creek (0607C) to mile 60.4*	
	depressed dissolved oxygen	CS

0607A Boggy Creek (unclassified water body)

		Level of Concern
0607A_01	*Entire creek*	
	impaired habitat	CS
	depressed dissolved oxygen	CN

0607B Little Pine Island Bayou (unclassified water body)

		Level of Concern
0607B_01	*Lower 25 miles*	
	depressed dissolved oxygen	CN
	depressed dissolved oxygen	CS

0607C Willow Creek (unclassified water body)

		Level of Concern
0607C_01	*Entire creek*	
	depressed dissolved oxygen	**CS**

0608 Village Creek

		Level of Concern
0608_01	*From confluence with Neches River to FM 418*	
	mercury in fish tissue	**CS**
0608_02	*From FM 418 to Lake Kimble dam*	
	mercury in fish tissue	**CS**

0608A Beech Creek (unclassified water body)

		Level of Concern
0608A_01	*Lower 20 miles of water body*	
	pH	**CN**
0608A_02	*Upper 19 miles of water body*	
	pH	**CN**
	impaired habitat	**CS**

0608B Big Sandy Creek (unclassified water body)

		Level of Concern
0608B_02	*Upper 16.9 miles of segment*	
	bacteria	**CN**

0608C Cypress Creek (unclassified water body)

		Level of Concern
0608C_01	*Entire water body*	
	impaired habitat	**CS**
	depressed dissolved oxygen	**CN**
	pH	**CN**
	depressed dissolved oxygen	**CS**

0608E Mill Creek (unclassified water body)

		Level of Concern
0608E_01	*Entire water body*	
	depressed dissolved oxygen	**CN**

0610 Sam Rayburn Reservoir

		Level of Concern
0610_01	*Main pool by the dam*	
	ammonia	**CS**
0610_02	*Lower Angelina River arm*	
	ammonia	**CS**
	mercury in fish tissue	**CS**
0610_03	*Mid-Angelina River arm (SH 147)*	
	ammonia	**CS**
	arsenic in sediment	**CS**
	iron in sediment	**CS**
	manganese in sediment	**CS**
0610_04	*Upper mid-Angelina River arm*	
	ammonia	**CS**
	nitrate	**CS**
0610_05	*Lower Attoyac Bayou arm*	
	ammonia	**CS**
	nitrate	**CS**
0610_08	*Bear Creek arm*	
	ammonia	**CS**
	nitrate	**CS**
0610_09	*Lower Ayish Bayou arm*	
	nitrate	**CS**
	ammonia	**CS**

0611 Angelina River Above Sam Rayburn Reservoir

		Level of Concern
0611_03	*FM 343 to US 84*	
	ammonia	**CS**

0611A East Fork Angelina River (unclassified water body)

		Level of Concern
0611A_04	*Wooten Creek to headwaters*	
	bacteria	**CN**

0611D West Mud Creek (unclassified water body)

		Level of Concern
0611D_01	*Entire Segment*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0611Q Lake Nacogdoches (unclassified water body)

		Level of Concern
0611Q_01	*Entire reservoir*	
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**

0611R Lake Striker (unclassified water body)

		Level of Concern
0611R_01	*Entire Lake*	
	nitrate	**CS**
	ammonia	**CS**

0612 Attoyac Bayou

		Level of Concern
0612_01	*Mouth to 8.2 miles downstream of SH 7*	
	bacteria	**CN**
0612_02	*8.2 miles below SH 7 to Bear Creek confluence*	
	ammonia	**CS**
0612_03	*Bear Creek to headwaters*	
	bacteria	**CN**
	ammonia	**CS**

0615 Angelina River/Sam Rayburn Reservoir

		Level of Concern
0615_01	*Upstream of Papermill Creek*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
0615_02	*Downstream of Papermill Creek*	
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0615A Papermill Creek (unclassified water body)

		Level of Concern
0615A_01	*Lower 9 miles*	
	ammonia	**CS**
	depressed dissolved oxygen	**CS**
	depressed dissolved oxygen	**CN**

0701 Taylor Bayou Above Tidal

		Level of Concern
0701_01	*From saltwater lock to 8 miles upstream*	
	chlorophyll-a	**CS**
0701_02	*from 8 miles upstream of saltwater lock to the confluence of N and S Forks Taylor Bayou*	
	chlorophyll-a	**CS**

0701D Shallow Prong Lake (unclassified water body)

		Level of Concern
0701D_01	*Entire water body*	
	arsenic in fish tissue	**CS**
	depressed dissolved oxygen	**CS**

0702A Alligator Bayou (unclassified water body)

		Level of Concern
0702A_02	*Lower portion from SH82 to its confluence with Taylor Bayou*	
	chlorophyll-a	**CS**
	chrysene in sediment	**CS**
	lead in sediment	**CS**
	phenanthrene in sediment	**CS**
	pyrene in sediment	**CS**

0704 Hillebrandt Bayou

		Level of Concern
0704_01	*From confluence with Taylor Bayou to confluence with Bayou Din*	
	chlorophyll-a	**CS**
0704_02	*From confluence with Bayou Din to upper end of segment*	
	chlorophyll-a	**CS**
	ammonia	**CS**

0801B Old River (unclassified water body)

		Level of Concern
0801B_01	*Entire Segment*	
	chlorophyll-a	**CS**

0802 Trinity River Below Lake Livingston

		Level of Concern
0802_01	*Lower 17 miles of segment*	
	chlorophyll-a	**CS**
0802_03	*11 miles upstream to approx. 9 miles downstream of FM 787*	
	chlorophyll-a	**CS**
0802_04	*5 miles upstream to 11 miles downstream of US 59*	
	chlorophyll-a	**CS**
0802_05	*Upper 6 miles of segment*	
	chlorophyll-a	**CS**

0803 Lake Livingston

		Level of Concern
0803_01	*Lowermost portion of reservoir, adjacent to dam*	
	nitrate	CS
	orthophosphorus	CS
0803_04	*Middle portion of reservoir, East Pointblank*	
	nitrate	CS
	orthophosphorus	CS
0803_05	*Middle portion of reservoir, downstream of Kickapoo Creek*	
	chlorophyll-a	CS
	orthophosphorus	CS
	total phosphorus	CS
0803_06	*Middle portion of reservoir, centering on US 190*	
	chlorophyll-a	CS
	total phosphorus	CS
	nitrate	CS
	orthophosphorus	CS
0803_07	*Upper portion of reservoir, west of Carlisle*	
	pH	CN
	chlorophyll-a	CS
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
0803_08	*Cove off upper portion of reservoir, East Trinity*	
	depressed dissolved oxygen	CS
	nitrate	CS
	orthophosphorus	CS
0803_09	*West Carolina Creek cove, off upper portion of reservoir*	
	depressed dissolved oxygen	CS
0803_10	*Upper portion of reservoir, centering on SH 19*	
	total phosphorus	CS
	depressed dissolved oxygen	CN
	nitrate	CS
	orthophosphorus	CS
0803_11	*Riverine portion of reservoir, centering on SH 21*	
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS

0804 Trinity River Above Lake Livingston

		Level of Concern
0804_01	*Lower 25 miles of segment*	
	bacteria	**CN**
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
0804_02	*12 miles upstream to 13 miles downstream US 79*	
	total phosphorus	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
0804_03	*9.5 miles upstream to 15.5 miles downstream of US 287*	
	nitrate	**CS**
	orthophosphorus	**CS**
0804_04	*Upper 22 miles of segment*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0804G Catfish Creek (unclassified water body)

		Level of Concern
0804G_01	*Entire Segment*	
	bacteria	**CN**

0805 Upper Trinity River

		Level of Concern
0805_01	*25 mile reach near FM 85*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
0805_02	*25 mile reach near SH 34*	
	bacteria	**CN**
	total phosphorus	**CS**
	orthophosphorus	**CS**
	nitrate	**CS**
	chlorophyll-a	**CS**
0805_03	*11 mile reach near S. Loop 12*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
0805_04	*Upper 8 miles*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
0805_06	*From 15.57 mi. upstream of SH 34 to 4.71 mi. downstream of S Loop 12*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
	nitrate	**CS**

0806 West Fork Trinity River Below Lake Worth

		Level of Concern
0806_01	*Lower 22 miles of the segment*	
	chlorophyll-a	**CS**
	bacteria	**CN**

0806D Marine Creek (unclassified water body)

		Level of Concern
0806D_01	*Marine Creek from the confluence with W. Fork Trinity River 2 miles upstream to Tenmile Bridge Rd. in Ft. Worth*	
	bacteria	**CN**

0807 Lake Worth

		Level of Concern
0807_01	*Entire reservoir*	
	chlorophyll-a	**CS**

0809 Eagle Mountain Reservoir

		Level of Concern
0809_01	*Lowermost portion of reservoir near east end of dam*	
	depressed dissolved oxygen	**CS**
0809_03	*Ash Creek cove*	
	ammonia	**CS**
0809_08	*Middle portion of reservoir near Cole subdivision*	
	chlorophyll-a	**CS**
0809_09	*Indian Creek cove*	
	chlorophyll-a	**CS**
0809_10	*Upper portion of reservoir near Indian Creek cove*	
	chlorophyll-a	**CS**
0809_12	*Upper portion of reservoir near Newark Beach*	
	chlorophyll-a	**CS**
0809_14	*Mid-Lake,from just above Walnut Cr. Cove to Oakwood Rd. peninsula*	
	chlorophyll-a	**CS**

0810D Salt Creek (unclassified water body)

		Level of Concern
0810D_01	*Eleven mile stretch of Salt Creek running upstream from confluence with Garrett Creek, Wise County.*	
	bacteria	**CN**

0814 Chambers Creek Above Richland-Chambers Reservoir

		Level of Concern
0814_03	*Lower 8.5 miles of segment*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0815 Bardwell Reservoir

		Level of Concern
0815_01	*Entire reservoir*	
	nitrate	**CS**

0815A Waxahachie Creek (unclassified water body)

		Level of Concern
0815A_01	*Entire creek*	
	nitrate	**CS**

0817 Navarro Mills Lake

		Level of Concern
0817_01	*Entire reservoir*	
	nitrate	**CS**

0818 Cedar Creek Reservoir

		Level of Concern
0818_01	*1674*	
	chlorophyll-a	**CS**
0818_02	*Caney Creek cove*	
	ammonia	**CS**
0818_04	*Lower portion of reservoir east of Key Ranch Estates*	
	chlorophyll-a	**CS**
0818_05	*Cove off lower portion of reservoir adjacent to Clearview Estates*	
	ammonia	**CS**
0818_06	*Middle portion of reservoir downstream of Twin Creeks cove*	
	chlorophyll-a	**CS**
0818_08	*Prairie Creek cove*	
	chlorophyll-a	**CS**
	ammonia	**CS**
0818_09	*Upper portion of reservoir adjacent to Lacy Fork cove*	
	chlorophyll-a	**CS**
0818_10	*Lacy Fork cove*	
	chlorophyll-a	**CS**
0818_11	*Upper portion of reservoir east of Tolosa*	
	chlorophyll-a	**CS**
0818_13	*Cedar Creek cove*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0819 East Fork Trinity River

		Level of Concern
0819_01	*Entire segment*	
	nitrate	**CS**
	orthophosphorus	**CS**
	ammonia	**CS**
	total phosphorus	**CS**
	chlorophyll-a	**CS**

0820 Lake Ray Hubbard

		Level of Concern
0820_01	*Lower portion of East Fork arm, centering on IH 30*	
	chlorophyll-a	**CS**
	nitrate	**CS**
0820_02	*Middle portion of East Fork arm, centering on SH 66*	
	chlorophyll-a	**CS**
0820_04	*Lower portion of main body of reservoir extending up from dam to Yankee Cr. Arm.*	
	nitrate	**CS**
0820_05	*Mid-reservoir, I30 crossing Rowlett Cr. Arm to Yankee Cr. Arm*	
	nitrate	**CS**

0820C Muddy Creek (unclassified water body)

		Level of Concern
0820C_01	*Entire creek*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**

0821 Lake Lavon

		Level of Concern
0821_01	*Lowermost portion of reservoir*	
	nitrate	**CS**

0822 Elm Fork Trinity River Below Lewisville Lake

		Level of Concern
0822_01	*Lower 11 miles of segment*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
0822_04	*Upper 1.5 miles of segment*	
	chlorophyll-a	**CS**

0822A Cottonwood Branch (unclassified water body)

		Level of Concern
0822A_01	*A 2.5 mile stretch of Cottonwood Branch running upstream from confluence with Hackberry Creek to approx. 0.5 miles downstream of N. Story Rd., Dallas Co.*	
	chlorophyll-a	**CS**

0822D Ski Lake (unclassified water body)

		Level of Concern
0822D_01	*Entire segment.*	
	chlorophyll-a	**CS**

0823 Lewisville Lake

		Level of Concern
0823_02	*Stewart Creek arm*	
	bacteria	**CN**
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
0823_04	*Little Elm Creek arm*	
	nitrate	**CS**

0823A Little Elm Creek (unclassified water body)

		Level of Concern
0823A_01	*From the confluence with Lake Lewisville in Denton Co., up to FM 455 in Collin Co. (Lower 12 miles of segment).*	
	depressed dissolved oxygen	**CS**

0823B Stewart Creek (unclassified water body)

		Level of Concern
0823B_01	*Entire segment.*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0824 Elm Fork Trinity River Above Ray Roberts Lake

		Level of Concern
0824_01	*Lower 7.5 miles of segment*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
0824_02	*2 mile reach near unmarked county road, 1.4 km downstream Gainesville WWTP*	
	nitrate	**CS**
	orthophosphorus	**CS**
0824_03	*3.5 mile reach near SH 51*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

0826 Grapevine Lake

		Level of Concern
0826_01	*Lowermost portion of reservoir*	
	nitrate	**CS**
0826_05	*Middle portion of reservoir east of Meadowmere Park*	
	nitrate	**CS**
0826_06	*Middle portion of reservoir southeast of Walnut Grove Park*	
	nitrate	**CS**
0826_07	*Upper portion of reservoir east of Marshall Creek Park*	
	nitrate	**CS**

0826A Denton Creek (unclassified water body)

		Level of Concern
0826A_01	*Lower 7.9 miles of creek*	
	nitrate	**CS**

0827A White Rock Creek (unclassified water body)

		Level of Concern
0827A_01	*Entire segment.*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

0828 Lake Arlington

		Level of Concern
0828_02	*Lowermost portion of lake along eastern half of dam*	
	chlorophyll-a	**CS**
0828_05	*Western half of upper portion of lake*	
	chlorophyll-a	**CS**
0828_06	*Eastern half of upper portion of lake*	
	chlorophyll-a	**CS**

0830 Benbrook Lake

		Level of Concern
0830_01	*Lower portion of reservoir*	
	ammonia	**CS**
	chlorophyll-a	**CS**
0830_02	*Middle portion of reservoir*	
	ammonia	**CS**
	chlorophyll-a	**CS**
0830_03	*Upper portion of reservoir*	
	chlorophyll-a	**CS**

0831 Clear Fork Trinity River Below Lake Weatherford

		Level of Concern
0831_01	*Lower 12.75 miles, downstream from South Fork Trinity River confluence*	
	orthophosphorus	**CS**
0831_04	*2 mi upstream of South Fork Trinity River confluence to Squaw Ck. Confluence*	
	depressed dissolved oxygen	**CN**
0831_05	*From the confluence of Squaw Ck. to Lake Weatherford Dam*	
	depressed dissolved oxygen	**CS**

0831A South Fork Trinity River (unclassified water body)

		Level of Concern
0831A_01	*Eleven mile stretch of S. Fork Trinity River running upstream from confluence with Clear Fork Trinity River to confluence with Willow Creek, Parker Co.*	
	orthophosphorus	**CS**
	total phosphorus	**CS**

0833 Clear Fork Trinity River Above Lake Weatherford

		Level of Concern
0833_02	*Upper 11 miles of segment*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
0833_03	*From the confluence of McKnight Branch to the confluence of Cottonwood Ck.*	
	depressed dissolved oxygen	**CS**
0833_04	*From the confluence with Dobbs Branch to confluence with McKnight Branch*	
	depressed dissolved oxygen	**CN**

0836 Richland-Chambers Reservoir

		Level of Concern
0836_04	*Upper portion of Chambers Creek arm*	
	chlorophyll-a	**CS**
	total phosphorus	**CS**
0836_05	*Lower portion of Richland Creek arm*	
	chlorophyll-a	**CS**
0836_06	*Upper portion of Richland Creek arm*	
	chlorophyll-a	**CS**

0838B Sugar Creek (unclassified water body)

		Level of Concern
0838B_01	*Entire segment.*	
	bacteria	**CN**

0840 Ray Roberts Lake

		Level of Concern
0840_01	*Lowermost portion of reservoir adjacent to dam*	
	nitrate	**CS**
0840_02	*Lower portion of Jordan Creek arm west of Pilot Point*	
	nitrate	**CS**
0840_03	*Upper portion of Jordan Creek arm*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	nitrate	**CS**
	bacteria	**CN**
	ammonia	**CS**
0840_04	*Buck Creek cove*	
	ammonia	**CS**
	nitrate	**CS**

0841 Lower West Fork Trinity River

		Level of Concern
0841_01	*Lower 14 miles of segment*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
0841_02	*Upper 13 miles of segment*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	nitrate	**CS**

0841D Big Bear Creek (unclassified water body)

		Level of Concern
0841D_01	*Entire segment.*	
	bacteria	**CN**

0841H Delaware Creek (unclassified water body)

		Level of Concern
0841H_01	*Entire segment.*	
	chlorophyll-a	**CS**

0841K Fish Creek (unclassified water body)

		Level of Concern
0841K_01	*Entire segment.*	
	bacteria	**CN**

0841L Johnson Creek (unclassified water body)

		Level of Concern
0841L_01	*Entire segment.*	
	depressed dissolved oxygen	**CS**

0841M Kee Branch (unclassified water body)

		Level of Concern
0841M_01	*Entire segment.*	
	depressed dissolved oxygen	**CS**

0841N Kirby Creek (unclassified water body)

		Level of Concern
0841N_01	*Entire segment*	
	bacteria	**CN**

1002 Lake Houston

		Level of Concern
1002_01	*Confluence with Red Gully to FM 1960 East Pass*	
	nitrate	**CS**
	orthophosphorus	**CS**
1002_02	*West Lake Houston Parkway to FM 1960 West Pass*	
	total phosphorus	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
1002_03	*FM 1960 to Missouri Pacific Railroad Tracks*	
	nitrate	**CS**
	orthophosphorus	**CS**
1002_04	*Missouri Pacific Railroad to Foley Road*	
	orthophosphorus	**CS**
1002_05	*From Foley Road to Dam*	
	bacteria	**CN**
	nitrate	**CS**
	orthophosphorus	**CS**
1002_06	*Confluence with Spring Creek to West Lake Houston Pkwy*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1002B Luce Bayou (unclassified water body)

		Level of Concern
1002B_02	*From confluence with Tarkington Bayou to upstream of Key Gully*	
	depressed dissolved oxygen	**CS**
1002B_03	*Upstream of Key Gully to confluence with Lake Houston*	
	depressed dissolved oxygen	**CS**

1004 West Fork San Jacinto River

		Level of Concern
1004_02	*IH 45 to the Spring Creek confluence*	
	orthophosphorus	**CS**
	nitrate	**CS**
	bacteria	**CN**

1004E Stewarts Creek (unclassified water body)

		Level of Concern
1004E_02	*From Airport Rd to confluence with West Fork San Jacinto River*	
	depressed dissolved oxygen	**CS**

1005 Houston Ship Channel/San Jacinto River Tidal

		Level of Concern
1005_01	*Downstream I-10 to Lynchburg Ferry Road*	
	nitrate	**CS**
1005_02	*Lynchburg Ferry Road to Goose Island*	
	bacteria	**CN**

1006 Houston Ship Channel Tidal

		Level of Concern
1006_01	*Houston Ship Channel Tidal-Greens Bayou confluence to Patrick Bayou confluence*	
	ammonia	**CS**
	nitrate	**CS**
1006_02	*Houston Ship Channel Tidal- Patrick Bayou confluence to lower segment boundary*	
	ammonia	**CS**
	nitrate	**CS**
1006_03	*Greens Bayou Tidal*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
	nitrate	**CS**
	bacteria	**CN**
1006_04	*Patrick Bayou Tidal*	
	acenaphthylene in sediment	**CS**
	ammonia	**CS**
	fluorene in sediment	**CS**
	mercury in sediment	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	phenanthrene in sediment	**CS**
	pyrene in sediment	**CS**
	total phosphorus	**CS**
	acenaphthene in sediment	**CS**
1006_05	*Goodyear Creek Tidal*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	nitrate	**CS**
	depressed dissolved oxygen	**CS**
	ammonia	**CS**

1006D Halls Bayou (unclassified water body)

		Level of Concern
1006D_01	*From the confluence with Greens Bayou to US 59*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
	ammonia	**CS**
1006D_02	*From Hirsch Road to Homestead Road*	
	ammonia	**CS**
	nitrate	**CS**
	total phosphorus	**CS**

1007 Houston Ship Channel/Buffalo Bayou Tidal

		Level of Concern
1007_01	*Houston Ship Channel/Buffalo Bayou Tidal*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
	nitrate	**CS**
	ammonia	**CS**
	depressed dissolved oxygen	**CN**
1007_02	*Sims Bayou Tidal (upstream of SH 35 to Houston Ship Channel confluence)*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
	ammonia	**CS**
1007_03	*Hunting Bayou Tidal (I-10 to confluence with Houston Ship Channel)*	
	bacteria	**CN**
	nitrate	**CS**
1007_04	*Brays Bayou Tidal (downstream of I 45 to confluence with the Houston Ship Channel)*	
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1007_05	*Vince Bayou Tidal (SH 225 to confluence with the Houston Ship Channel*	
	nitrate	**CS**
	orthophosphorus	**CS**
	ammonia	**CS**
	total phosphorus	**CS**
1007_06	*Berry Bayou Tidal (2.4 km upstream of the Sims Bayou confluence)*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1007_07	*Buffalo Bayou (US 59 to upstream of 69th Street WWTP)*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1007B Brays Bayou Above Tidal (unclassified water body)

		Level of Concern
1007B_01	*From 11.5km upstream of confluence with Brays Bayou Tidal to SH 6*	
	ammonia	CS
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
1007B_02	*SH 6 to Clodine Road*	
	ammonia	CS
	nitrate	CS
	total phosphorus	CS

1007C Keegans Bayou Above Tidal (unclassified water body)

		Level of Concern
1007C_01	*From Harris County line to confluence with Brays Bayou*	
	nitrate	CS
	total phosphorus	CS

1007D Sims Bayou Above Tidal (unclassified water body)

		Level of Concern
1007D_01	*From 0.4 miles north of Beltway 8 to Hiram Clark*	
	depressed dissolved oxygen	CS
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
1007D_02	*From Hirman Clark to 11 miles upstream of the confluence with the Houston Ship Channel*	
	ammonia	CS
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
1007D_03	*From 11 miles upstream of the Houston Ship Channel confluence to SH 35*	
	nitrate	CS
	total phosphorus	CS
	ammonia	CS

1007F Berry Bayou Above Tidal (unclassified water body)

		Level of Concern
1007F_01	*1.5 miles upstream from confluence with Sims Bayou to SH 3*	
	total phosphorus	**CS**
	nitrate	**CS**

1007G Kuhlman Gully Above Tidal (unclassified water body)

		Level of Concern
1007G_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

1007K Country Club Bayou Above Tidal (unclassified water body)

		Level of Concern
1007K_01	*From just downstream of South Lockwood Drive to the confluence with Brays Bayou*	
	depressed dissolved oxygen	**CS**

1007O Unnamed Non-Tidal Tributary of Buffalo Bayou (unclassified water body)

		Level of Concern
1007O_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

1007R Hunting Bayou Above Tidal (unclassified water body)

		Level of Concern
1007R_01	*From Bain Street to Sayers Street (South Fork)*	
	ammonia	**CS**
	depressed dissolved oxygen	**CS**
1007R_03	*From Falls Street to Loop 610 East*	
	nitrate	**CS**
1007R_04	*From Loop 610 East to IH 10*	
	nitrate	**CS**

1008 Spring Creek

		Level of Concern
1008_03	*SH 249 to IH 45*	
	impaired habitat	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
1008_04	*IH 45 to confluence with Lake Houston*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1008B Upper Panther Branch (unclassified water body)

		Level of Concern
1008B_01	*From Old Conroe Road to the confluence with Bear Branch*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1008B_02	*From the confluence with Bear Branch to confluence with Lake Woodlands*	
	total phosphorus	**CS**

1008C Lower Panther Branch (unclassified water body)

		Level of Concern
1008C_01	*From the Lake Woodlands Dam to Saw Dust Road*	
	bacteria	**CN**
	orthophosphorus	**CS**
1008C_02	*From Saw Dust Road to confluence with Spring Creek*	
	total phosphorus	**CS**
	bacteria	**CN**
	nitrate	**CS**
	orthophosphorus	**CS**

1008F Lake Woodlands (unclassified water body)

		Level of Concern
1008F_01	*Upper end of segment to Northshore Park/Woodlock Forest*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	nitrate	**CS**
	depressed dissolved oxygen	**CS**
1008F_02	*Northshore Park/Woodlock Forest to inflow from unnamed tributary*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
1008F_03	*From inflow of unnamed tributary to dam*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
1008F_04	*Arm near dam adjacent to West Isle Drive and Pleasure Cove Drive*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**

1008H Willow Creek (unclassified water body)

		Level of Concern
1008H_01	*Entire water body*	
	nitrate	**CS**
	total phosphorus	**CS**

1009 Cypress Creek

		Level of Concern
1009_01	*Upper portion of segment to downstream of US 290*	
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
	depressed dissolved oxygen	CS
1009_02	*US 290 to SH 249*	
	impaired habitat	CS
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
1009_03	*SH 249 to IH 45*	
	total phosphorus	CS
	nitrate	CS
	orthophosphorus	CS
1009_04	*IH 45 to confluence with Spring Creek*	
	total phosphorus	CS
	orthophosphorus	CS
	nitrate	CS

1009C Faulkey Gully (unclassified water body)

		Level of Concern
1009C_01	*From an unnamed lake 0.3 miles southeast of Telge Road to the confluence with Cypress Creek*	
	nitrate	CS
	total phosphorus	CS

1009D Spring Gully (unclassified water body)

		Level of Concern
1009D_01	*Entire water body*	
	nitrate	CS
	total phosphorus	CS

1009E Little Cypress Creek

		Level of Concern
1009E_01	*Entire water body*	
	ammonia	**CS**
	nitrate	**CS**
	total phosphorus	**CS**

1010 Caney Creek

		Level of Concern
1010_04	*FM 2090 to lower segment boundary*	
	bacteria	**CN**

1011 Peach Creek

		Level of Concern
1011_02	*US Hwy 59 to confluence with Caney Creek*	
	bacteria	**CN**

1012 Lake Conroe

		Level of Concern
1012_03	*Lewis Creek arm*	
	chlorophyll-a	**CS**
1012_04	*Caney Creek arm to Hunters Point*	
	chlorophyll-a	**CS**
1012_05	*Johnson Bluff to FM 1097*	
	chlorophyll-a	**CS**
1012_06	*Little Lake Creek arm to Walden Estates*	
	chlorophyll-a	**CS**
1012_07	*Lewis Creek arm to Bowsprit Point*	
	chlorophyll-a	**CS**
1012_11	*Walden Estates to dam*	
	chlorophyll-a	**CS**

1013 Buffalo Bayou Tidal

		Level of Concern
1013_01	*Entire segment*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1013A Little White Oak Bayou (unclassified water body)

		Level of Concern
1013A_01	*From the confluence of White Oak Bayou upstream to the RR Tracks north of IH 610*	
	ammonia in water	**CS**
	depressed dissolved oxygen	**CS**

1014 Buffalo Bayou Above Tidal

		Level of Concern
1014_01	*Entire segment*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1014A Bear Creek (unclassified water body)

		Level of Concern
1014A_01	*Confluence with South Mayde Creek to a point upstream of an unnamed tributary north of Langenbaugh Road*	
	nitrate	**CS**
	total phosphorus	**CS**

1014B Buffalo Bayou (unclassified water body)

		Level of Concern
1014B_01	*From SH6 to the confluence with Willow Fork Buffalo Bayou*	
	nitrate	**CS**

1014E Langham Creek (unclassified water body)

		Level of Concern
1014E_01	*Confluence with Bear Creek upstream to the confluence with Dinner Creek*	
	nitrate	**CS**
	total phosphorus	**CS**

1014H South Mayde Creek (unclassified water body)

		Level of Concern
1014H_01	*From the confluence with Buffalo Bayou upstream to the confluence with an unnamed tributary 0.62 km east of Barker-Cypress Road*	
	nitrate	**CS**
	total phosphorus	**CS**
1014H_02	*From the confluence with an unnamed tributary 0.62 km east of Barker-Cypress Road upstream to an unnamed tributary 1.05 km south of Clay Road*	
	bacteria	**CN**
	nitrate	**CS**
	total phosphorus	**CS**

1014L Mason Creek (unclassified water body)

		Level of Concern
1014L_01	*Confluence with Buffalo Bayou upstream to the channelization south of Franz Rd.*	
	nitrate	**CS**
	total phosphorus	**CS**

1014M Neimans Bayou (unclassified water body)

		Level of Concern
1014M_01	*Entire water body*	
	orthophosphorus	**CS**
	depressed dissolved oxygen	**CS**

1014N Rummel Creek (unclassified water body)

		Level of Concern
1014N_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

1016 Greens Bayou Above Tidal

		Level of Concern
1016_01	*Upper segment boundary (FM 1960) to IH 45*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
	nitrate	**CS**
1016_02	*IH 45 to US 59*	
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1016_03	*US 59 to lower segment boundary at the Halls Bayou confluence*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1016A Garners Bayou (unclassified water body)

		Level of Concern
1016A_02	*From the confluence with Williams Gully upstream to 1.5 km north of Atascosita Road*	
	total phosphorus	**CS**
	depressed dissolved oxygen	**CS**
1016A_03	*From the confluence with Greens Bayou upstream to the confluence with Williams Gully*	
	total phosphorus	**CS**
	nitrate	**CS**

1016C Unnamed Tributary of Greens Bayou (unclassified water body)

		Level of Concern
1016C_01	*Entire water body*	
	nitrate	CS
	total phosphorus	CS

1017 Whiteoak Bayou Above Tidal

		Level of Concern
1017_01	*Huffsmith Rd to the confluence with Vogel Creek*	
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
1017_02	*Vogel Creek to the Cole Creek confluence*	
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
1017_03	*Cole Creek confluence to the Brickhouse Gully confluence*	
	orthophosphorus	CS
	total phosphorus	CS
	nitrate	CS
1017_04	*Brickhouse Gully confluence to lower segment boundary*	
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS
	ammonia	CS

1017A Brickhouse Gully/Bayou (unclassified water body)

		Level of Concern
1017A_01	*Entire water body*	
	nitrate	CS

1017D Unnamed Tributary of Whiteoak Bayou (unclassified water body)

		Level of Concern
1017D_01	*Entire water body*	
	depressed dissolved oxygen	CS

1101 Clear Creek Tidal

		Level of Concern
1101_01	*Upper segment boundary to Chigger Creek confluence*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
1101_02	*Chigger Creek confluence to IH 45*	
	nitrate	**CS**
	total phosphorus	**CS**
1101_03	*IH45 to Cow Bayou confluence*	
	nitrate	**CS**
	orthophosphorus	**CS**
	bacteria	**CN**
	chlorophyll-a	**CS**
	total phosphorus	**CS**

1101B Chigger Creek (unclassified water body)

		Level of Concern
1101B_02	*FM 528 to the confluence with Clear Creek*	
	bacteria	**CN**

1101D Robinson Bayou (unclassified water body)

		Level of Concern
1101D_01	*From headwater to Abilene St.*	
	depressed dissolved oxygen	**CS**
1101D_02	*From Abilene St. to confluence with Clear Lake*	
	depressed dissolved oxygen	**CS**

1102 Clear Creek Above Tidal

		Level of Concern
1102_01	*Upper segment boundary (Rouen Road) to SH 288*	
	depressed dissolved oxygen	**CS**
1102_02	*SH 288 to Hickory Slough confluence*	
	depressed dissolved oxygen	**CS**
	impaired habitat	**CS**
	orthophosphorus	**CS**
1102_03	*Hickory Slough confluence to Turkey Creek confluence*	
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1102_04	*Turkey Creek confluence to Mary's Creek confluence*	
	depressed dissolved oxygen	**CS**
	total phosphorus	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
1102_05	*Mary's Creek confluence to lower segment boundary*	
	bacteria	**CN**
	ammonia	**CS**
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**

1102A Cowart Creek (unclassified water body)

		Level of Concern
1102A_01	*Sunset Drive to SH35*	
	bacteria	**CN**

1102B Mary's Creek/ North Fork Mary's Creek (unclassified water body)

		Level of Concern
1102B_01	*Entire segment*	
	orthophosphorus	**CS**
	total phosphorus	**CS**

1102C Hickory Slough (unclassified water body)

		Level of Concern
1102C_01	*From confluence with Clear Creek to (approx. 0.3 miles) upstream of CR 93*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**

1102D Turkey Creek (unclassified water body)

		Level of Concern
1102D_01	*Confluence with Clear Creek to IH 45*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
	depressed dissolved oxygen	**CS**

1102E Mud Gully (unclassified water body)

		Level of Concern
1102E_01	*Beamer Road to confluence with Clear Creek*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**

1103B Bordens Gully (unclassified water body)

		Level of Concern
1103B_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

1103C Geisler Bayou (unclassified water body)

		Level of Concern
1103C_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

1104 Dickinson Bayou Above Tidal

		Level of Concern
1104_02	*From FM 517 upstream to FM 528*	
	depressed dissolved oxygen	**CS**

1107 Chocolate Bayou Tidal

		Level of Concern
1107_01	*Entire segment*	
	chlorophyll-a	**CS**

1108 Chocolate Bayou Above Tidal

		Level of Concern
1108_01	*Entire segment*	
	depressed dissolved oxygen	**CS**
	impaired habitat	**CS**

1110 Oyster Creek Above Tidal

		Level of Concern
1110_02	*4 mi upstream South Texas Water Co. Canal to just above Ramsey Prison Unit*	
	ammonia	**CS**
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
1110_03	*From just upstream of Ramsey Prison Unit (Cow Cr) to CR 290/S Walker St.*	
	chlorophyll-a	**CS**

1111 Old Brazos River Channel Tidal

		Level of Concern
1111_01	*Entire segment*	
	nitrate	**CS**

1113 Armand Bayou Tidal

		Level of Concern
1113_01	*Upper segment boundary to confluence with Big Island Slough*	
	depressed dissolved oxygen	**CS**
1113_02	*Big Island Slough confluence to Horsepen Bayou confluence*	
	chlorophyll-a	**CS**
1113_03	*Horsepen Bayou confluence to lower segment boundary (Nasa Rd 1)*	
	chlorophyll-a	**CS**

1113A Armand Bayou Above Tidal (unclassified water body)

		Level of Concern
1113A_01	*0.5 miles downstream of Genoa Red Bluff to Preston Road*	
	depressed dissolved oxygen	**CS**

1113B Horsepen Bayou (unclassified water body)

		Level of Concern
1113B_01	*Confluence with Armand Bayou to SH 3*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1201 Brazos River Tidal

		Level of Concern
1201_01	*Entire segment*	
	nitrate	**CS**

1202H Allen's Creek (unclassified water body)

		Level of Concern
1202H_01	*Entire water body*	
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**

1202J Big Creek (unclassified water body)

		Level of Concern
1202J_01	*Upstream portion of water body to Whaley-Longpoint Road*	
	bacteria	**CN**
	chlorophyll-a	**CS**
	impaired habitat	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1202J_02	*Downstream portion of water body*	
	chlorophyll-a	**CS**

1202K Mill Creek (unclassified water body)

		Level of Concern
1202K_01	*Downstream portion of creek to confluence with Brazos River*	
	impaired fish community	**CN**

1203 Whitney Lake

		Level of Concern
1203_01	*Portion near dam*	
	depressed dissolved oxygen	**CN**
1203_05	*Nolan River Arm*	
	chlorophyll-a	**CS**
	nitrate	**CS**
1203_06	*Brazos River Arm*	
	chlorophyll-a	**CS**

1205 Lake Granbury

		Level of Concern
1205_01	*Upstream portion of lake*	
	chloride in finished drinking water	CS
	demineralization costs	CS
	total dissolved solids in finished drinking water	CS
1205_02	*Portion of lake adjacent to the City of Oak Trail Shores*	
	chloride in finished drinking water	CS
	demineralization costs	CS
	total dissolved solids in finished drinking water	CS
1205_03	*Portion of lake adjacent to the City of Granbury*	
	chloride in finished drinking water	CS
	demineralization costs	CS
	total dissolved solids in finished drinking water	CS
1205_04	*Portion of lake downstream of Granbury*	
	chloride in finished drinking water	CS
	demineralization costs	CS
	total dissolved solids in finished drinking water	CS
1205_05	*Downstream portion of lake*	
	total dissolved solids in finished drinking water	CS
	demineralization costs	CS
	chloride in finished drinking water	CS

1206 Brazos River Below Possum Kingdom Lake

		Level of Concern
1206_01	*Downstream portion of segment*	
	impaired habitat	CN
1206_02	*Middle Portion of Segment*	
	impaired habitat	CS

1207 Possum Kingdom Lake

		Level of Concern
1207_01	*Rock Creek arm of lake*	
	demineralization costs	**CS**
1207_02	*Deep Elm Creek arm*	
	demineralization costs	**CS**
1207_03	*Portion of segment west of SH 16*	
	demineralization costs	**CS**
1207_04	*Portion of lake containing Costello Island*	
	demineralization costs	**CS**
1207_07	*Portion of lake adjacent to northeast corner of state park*	
	demineralization costs	**CS**
1207_08	*Caddo Creek arm of lake*	
	demineralization costs	**CS**
1207_09	*Portion of lake south of FM 2951*	
	demineralization costs	**CS**
1207_10	*Bluff Creek arm of lake*	
	demineralization costs	**CS**
1207_11	*Jewell Creek arm of lake*	
	demineralization costs	**CS**
1207_12	*Downstream portion of lake*	
	demineralization costs	**CS**

1208 Brazos River Above Possum Kingdom Lake

		Level of Concern
1208_01	*From confluence with Possum Kingdom upstream to confluence with spring Branch*	
	chlorophyll-a	**CS**
	bacteria	**CN**
1208_05	*From confluence with Millers Creek upstream to confluence with Lake Creek*	
	chlorophyll-a	**CS**

1208A Millers Creek Reservoir (unclassified water body)

1208A_01 entire water body

	Level of Concern
bacteria	**CN**
depressed dissolved oxygen	**CS**

1209 Navasota River Below Lake Limestone

1209_01 From lower segment boundary to confluence with Rocky Creek

	Level of Concern
nitrate	**CS**
orthophosphorus	**CS**

1209A Country Club Lake (unclassified water body)

1209A_01 Entire reservoir

	Level of Concern
orthophosphorus	**CS**
total phosphorus	**CS**

1209B Fin Feather Lake (unclassified water body)

1209B_01 Entire reservoir

	Level of Concern
orthophosphorus	**CS**
copper in sediment	**CS**
arsenic in sediment	**CS**
ammonia	**CS**
chromium in sediment	**CS**

1209C Carters Creek (unclassified water body)

1209C_01 Entire water body

	Level of Concern
orthophosphorus	**CS**
nitrate	**CS**

1209G Cedar Creek (unclassified water body)

		Level of Concern
1209G_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

1209H Duck Creek (unclassified water body)

		Level of Concern
1209H_02	*From FM 2096 to Twin Oak Reservoir dam*	
	depressed dissolved oxygen	**CS**

1209J Shepherd Creek (unclassified water body)

		Level of Concern
1209J_01	*Entire water body*	
	depressed dissolved oxygen	**CN**
	depressed dissolved oxygen	**CS**

1209L Burton Creek (unclassified water body)

		Level of Concern
1209L_01	*entire water body*	
	nitrate	**CS**
	orthophosphorus	**CS**

1210 Lake Mexia

		Level of Concern
1210_01	*Eastern end of reservoir, from dam to RR 2681 east of Washington Park*	
	total phosphorus	**CS**
	chlorophyll-a	**CS**
	orthophosphorus	**CS**
1210_02	*Western end, from point where reservoir begins to widen, to upper end*	
	total phosphorus	**CS**
	chlorophyll-a	**CS**
	orthophosphorus	**CS**

1212 Somerville Lake

		Level of Concern
1212_01	*Eastern end of reservoir near dam*	
	chlorophyll-a	**CS**
1212_03	*Middle of reservoir near Birch Creek State Park*	
	chlorophyll-a	**CS**
1212_04	*Western end of reservoir near upper segment boundary*	
	chlorophyll-a	**CS**

1212B East Yegua Creek (unclassified water body)

		Level of Concern
1212B_01	*Lower 25 miles*	
	bacteria	**CN**

1213 Little River

		Level of Concern
1213_01	*From the confluence with Brazos River upstream to confluence with City of Cameron WWTP receiving water*	
	atrazine in finished drinking water	**CS**
	nitrate	**CS**
1213_02	*From the City of Cameron WWTP receiving water upstream to the confluence with the San Gabriel River*	
	atrazine in finished drinking water	**CS**
	nitrate	**CS**
1213_03	*From confluence with San Gabriel River upstream to confl. with Boggy Creek*	
	atrazine in finished drinking water	**CS**
	nitrate	**CS**
1213_04	*From confluence with Boggy Creek upstream to its confluence with Leon and Lampasas Rivers*	
	atrazine in finished drinking water	**CS**
	bacteria	**CN**

1214 San Gabriel River

		Level of Concern
1214_01	*From confluence with Little River upstream to confl. with Alligator Creek*	
	nitrate	**CS**

1218 Nolan Creek/ South Nolan Creek

		Level of Concern
1218_01	*Entire segment*	
	bacteria	**CN**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1219 Leon River Below Belton Lake

		Level of Concern
1219_01	*Entire segment*	
	nitrate	**CS**
	orthophosphorus	**CS**

1220 Belton Lake

		Level of Concern
1220_03	*Leon River Arm*	
	nitrate	**CS**

1221 Leon River Below Proctor Lake

		Level of Concern
1221_01	*Directly upstream of Lake Belton*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
1221_04	*From the confluence with Plum Creek, upstream to the confluence with Pecan Creek*	
	bacteria	**CN**
1221_05	*From confluence with Pecan Creek, upstream to confluence with South Leon Creek*	
	depressed dissolved oxygen	**CS**
	chlorophyll-a	**CS**
1221_06	*From confluence with South Leon Creek upstream to confluence with Walnut Creek*	
	chlorophyll-a	**CS**
1221_07	*From the confluence with Walnut Creek upstream to Lake Proctor*	
	depressed dissolved oxygen	**CS**
	chlorophyll-a	**CS**

1221A Resley Creek (unclassified water body)

		Level of Concern
1221A_01	*Downstream portion, from confluence with Leon River upstream to conf. with unnamed tributary, approx. 1.0 mile N. of Comanche County Line*	
	bacteria	**CN**
	chlorophyll-a	**CS**
1221A_02	*From confluence with unnamed tributary, upstream to end of water body, approx. 1.0 mile north west of Dublin*	
	nitrate	**CS**
	orthophosphorus	**CS**

1221B South Leon River (unclassified water body)

		Level of Concern
1221B_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

1221D Indian Creek (unclassified water body)

		Level of Concern
1221D_01	*From confluence with Leon River, upstream to confluence with Armstrong Creek*	
	depressed dissolved oxygen	**CN**
1221D_02	*From confluence with Armstrong Creek upstream to headwaters of water body*	
	nitrate	**CS**
	orthophosphorus	**CS**

1222 Proctor Lake

		Level of Concern
1222_01	*Sabana River arm of lake*	
	total phosphorus	**CS**
	chlorophyll-a	**CS**
1222_02	*Copperas / Duncan Creeks arm of lake.*	
	chlorophyll-a	**CS**
1222_03	*Portion of water body near dam*	
	chlorophyll-a	**CS**

1222A Duncan Creek (unclassified water body)

		Level of Concern
1222A_01	*Entire creek*	
	chlorophyll-a	**CS**

1223 Leon River Below Leon Reservoir

		Level of Concern
1223_01	*Entire Segment*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

1224 Leon Reservoir

		Level of Concern
1224_01	*Portion near dam*	
	manganese in sediment	**CS**
1224_02	*Headwater portion*	
	manganese in sediment	**CS**

1225 Waco Lake

		Level of Concern
1225_01	*North Bosque River arm of lake*	
	chlorophyll-a	**CS**
	nitrate	**CS**
1225_02	*Portion of lake near dam*	
	nitrate	**CS**
1225_03	*Middle/South Bosque River arm of lake*	
	chlorophyll-a	**CS**
	nitrate	**CS**

1226 North Bosque River

		Level of Concern
1226_02	*Portion of segment near Clifton*	
	depressed dissolved oxygen	**CN**
1226_03	*Portion of segment near Meridian*	
	chlorophyll-a	**CS**
1226_04	*Upstream portion of segment near Hico*	
	orthophosphorus	**CS**
	chlorophyll-a	**CS**

1226B Green Creek (unclassified water body)

		Level of Concern
1226B_01	*Entire water body*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

1226E Indian Creek (unclassified water body)

		Level of Concern
1226E_01	*Entire water body*	
	bacteria	**CN**
	nitrate	**CS**
	orthophosphorus	**CS**

1226K Little Duffau Creek (unclassified water body)

		Level of Concern
1226K_01	*entire water body*	
	orthophosphorus	**CS**
	total phosphorus	**CS**

1226M Little Green Creek (unclassified water body)

		Level of Concern
1226M_01	*entire water body*	
	bacteria	**CN**

1226N Indian Creek Reservoir (unclassified water body)

		Level of Concern
1226N_01	*entire water body*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
	ammonia	**CS**
	chlorophyll-a	**CS**

1226O Sims Creek Reservoir (unclassified water body)

		Level of Concern
1226O_01	*entire water body*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

1227 Nolan River

		Level of Concern
1227_01	*Downstream portion, including Mustang Creek confluence*	
	chlorophyll-a	CS
	nitrate	CS
1227_02	*Upstream portion, to Lake Pat Cleburne*	
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS

1229A Squaw Creek Reservoir (unclassified water body)

		Level of Concern
1229A_01	*Entire water body*	
	orthophosphorus	CS
	total phosphorus	CS

1231 Lake Graham

		Level of Concern
1231_01	*Entire segment*	
	total dissolved solids	CN

1232 Clear Fork Brazos River

		Level of Concern
1232_02	*From confluence with Hubbard Creek upstream to confluence with Deadman Creek*	
	chlorophyll-a	CS
	total phosphorus	CS
	nitrate	CS
	orthophosphorus	CS
1232_03	*From confluence with Deadman Creek upstream to conf. With Bitter Creek*	
	chlorophyll-a	CS
	depressed dissolved oxygen	CS

1232A California Creek (unclassified water body)

		Level of Concern
1232A_01	*Middle 25 miles near RR 142*	
	chlorophyll-a	**CS**
	nitrate	**CS**

1232B Deadman Creek (unclassified water body)

		Level of Concern
1232B_01	*From the confluence with Clear Fork Brazos, upstream to city of Abilene WWTP receiving water*	
	nitrate	**CS**
	orthophosphorus	**CS**

1233 Hubbard Creek Reservoir

		Level of Concern
1233_02	*Hubbard Creek Arm*	
	depressed dissolved oxygen	**CS**

1233A Big Sandy Creek (unclassified water body)

		Level of Concern
1233A_01	*entire water body*	
	bacteria	**CN**

1235 Lake Stamford

		Level of Concern
1235_01	*Entire segment*	
	chloride in finished drinking water	**CS**
	depressed dissolved oxygen	**CS**

1236 Fort Phantom Hill Reservoir

		Level of Concern
1236_01	*Entire segment* demineralization costs	**CS**

1238 Salt Fork Brazos River

		Level of Concern
1238_01	*25 miles near Hwy 83* depressed dissolved oxygen	**CS**
1238_02	*25 miles near Hwy 380 at Swenson* temperature	**CN**

1240 White River Lake

		Level of Concern
1240_01	*Entire segment* sulfate	**CN**

1241 Double Mountain Fork Brazos River

		Level of Concern
1241_01	*25 miles near Hwy 83* total dissolved solids	**CN**
1241_02	*Remainder of segment* total dissolved solids	**CN**

1241A North Fork Double Mountain Fork Brazos River (unclassified water body)

		Level of Concern
1241A_01	*From confluence with Dbl. Mtn. Frk. Of Brazos to Lake Ransom Canyon*	
	ammonia	**CS**
	chlorophyll-a	**CS**
1241A_02	*Upstream portion, from confluence with Yellow House Draw to Lake Buffalo Springs*	
	bacteria	**CN**
	chlorophyll-a	**CS**
	nitrate	**CS**

1241C Buffalo Springs Lake (unclassified water body)

		Level of Concern
1241C_01	*entire water body*	
	chlorophyll-a	**CS**

1242 Brazos River Above Navasota River

		Level of Concern
1242_01	*Downstream portion of segment*	
	demineralization costs	**CS**
1242_02	*Portion of segment upstream of Bryan*	
	demineralization costs	**CS**
1242_03	*Middle portion of segment*	
	demineralization costs	**CS**
1242_04	*Portion of segment downstream of Marlin*	
	demineralization costs	**CS**
1242_05	*Portion of Segment downstream of Waco*	
	demineralization costs	**CS**
1242_06	*Portion of Segment within Waco City Limits*	
	demineralization costs	**CS**

1242A Marlin City Lake System (unclassified water body)

		Level of Concern
1242A_01	*Old Marlin City Lake*	
	atrazine in finished drinking water	**CS**
	chlorophyll-a	**CS**
	total phosphorus	**CS**
1242A_02	*New Marlin City Lake*	
	atrazine in finished drinking water	**CS**
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

1242B Cottonwood Branch (unclassified water body)

		Level of Concern
1242B_01	*Downstream portion, downstream of Sanderson Farms receiving water*	
	nitrate	**CS**
	orthophosphorus	**CS**
1242B_02	*Upstream portion, upstream of Sanderson Farms receiving water*	
	bacteria	**CN**

1242C Still Creek (unclassified water body)

		Level of Concern
1242C_01	*Downstream of Bryan WWTP*	
	nitrate	**CS**
	orthophosphorus	**CS**

1242D Thompson Creek (unclassified water body)

		Level of Concern
1242D_01	*Portion downstream of the confluence with Still Creek*	
	nitrate	**CS**
	orthophosphorus	**CS**
1242D_02	*Portion of segment upstream of confluence with Still Creek*	
	ammonia	**CS**
	chlorophyll-a	**CS**

1242F Pond Creek (unclassified water body)

		Level of Concern
1242F_01	*From the Brazos confluence upstream to Live Oak Creek confluence*	
	bacteria	**CN**
	nitrate	**CS**

1242I Campbells Creek (unclassified water body)

		Level of Concern
1242I_01	*Entire water body*	
	bacteria	**CN**

1242J Deer Creek (unclassified water body)

		Level of Concern
1242J_01	*Entire water body*	
	nitrate	**CS**

1242M Spring Creek (unclassified water body)

		Level of Concern
1242M_01	*Entire water body*	
	bacteria	**CN**

1243 Salado Creek

		Level of Concern
1243_01	*Downstream portion of segment from confluence with Lampasas River, just upstream of Stagecoach outfall*	
	nitrate	**CS**
1243_02	*From confluence with unnamed tributary just upstream of Stagecoach discharge upstream to end of segment*	
	nitrate	**CS**

1244 Brushy Creek

		Level of Concern
1244_03	*From confluence with Cottonwood Branch upstream to City of Round Rock WWTP outfall*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1244A Brushy Creek Above South Brushy Creek (unclassified water body)

		Level of Concern
1244A_01	*Entire segment*	
	orthophosphorus	**CS**

1244D South Brushy Creek (unclassified water body)

		Level of Concern
1244D_01	*entire water body*	
	nitrate	**CS**

1245 Upper Oyster Creek

		Level of Concern
1245_01	*From the confluence with the Brazos River upstream to Dam #3*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1245_02	*From Dam #3 upstream to Harmon St. crossing in Sugar Land*	
	bacteria	**CN**
1245_03	*From Harmon St. crossing in Sugar Land upstream to the end of the segment*	
	depressed dissolved oxygen	**CN**
	chlorophyll-a	**CS**

1245B Brown's Bayou (unclassified water body)

		Level of Concern
1245B_01	*entire water body*	
	bacteria	**CN**

1246 Middle Bosque/South Bosque River

		Level of Concern
1246_01	*Middle Bosque River*	
	nitrate	**CS**
1246_02	*South Bosque River*	
	nitrate	**CS**

1246D Tonk Creek (unclassified water body)

		Level of Concern
1246D_01	*Entire water body*	
	nitrate	**CS**

1246E Wasp Creek (unclassified water body)

		Level of Concern
1246E_01	*Entire water body*	
	nitrate	**CS**

1247 Granger Lake

		Level of Concern
1247_01	*Eastern end of lake near the dam*	
	nitrate	**CS**
1247_02	*Willis Creek arm of lake*	
	nitrate	**CS**
1247_03	*Western end of lake on the San Gabriel River*	
	nitrate	**CS**

1247A Willis Creek (unclassified water body)

		Level of Concern
1247A_01	*Entire water body*	
	nitrate	**CS**

1248B Huddleston Branch (unclassified water body)

		Level of Concern
1248B_01	*Entire reach*	
	bacteria	**CN**
	nitrate	**CS**

1248C Mankins Branch (unclassified water body)

		Level of Concern
1248C_01	*Entire water body*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1250 South Fork San Gabriel River

		Level of Concern
1250_03	*From CR 279 crossing to upper end of segment*	
	depressed dissolved oxygen	**CS**

1252 Lake Limestone

		Level of Concern
1252_01	*South end of lake near dam*	
	depressed dissolved oxygen	**CS**
1252_05	*Navasota River Arm near headwaters*	
	chlorophyll-a	**CS**

1253 Navasota River Below Lake Mexia

		Level of Concern
1253_02	*From confluence with Plummer's Creek upstream to Springfield Lake*	
	depressed dissolved oxygen	**CS**
1253_03	*From headwaters of Springfield Lake upstream to confluence with Lake Mexia*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

1253A Springfield Lake (unclassified water body)

		Level of Concern
1253A_01	*Entire water body*	
	depressed dissolved oxygen	**CN**
	chlorophyll-a	**CS**

1254 Aquilla Reservoir

		Level of Concern
1254_01	*South end of reservoir near dam*	
	atrazine in finished drinking water	**CS**
	nitrate	**CS**
1254_02	*Aquilla Creek arm on the west*	
	atrazine in finished drinking water	**CS**
	nitrate	**CS**
1254_03	*Hackberry Creek arm on the east*	
	nitrate	**CS**
	nickel in sediment	**CS**
	atrazine in finished drinking water	**CS**
	arsenic in sediment	**CS**

1255 Upper North Bosque River

		Level of Concern
1255_01	*Lower portion of segment downstream of Stephenville*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
	bacteria	**CN**
1255_02	*Upper portion of segment, upstream of Stephenville*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**

1255A Goose Branch (unclassified water body)

		Level of Concern
1255A_01	*Entire water body*	
	ammonia	**CS**
	total phosphorus	**CS**
	nitrate	**CS**
	bacteria	**CN**
	orthophosphorus	**CS**

1255B North Fork Upper North Bosque River (unclassified water body)

		Level of Concern
1255B_01	*Entire water body*	
	chlorophyll-a	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1255C Scarborough Creek (unclassified water body)

	Level of Concern
1255C_01 Entire water body	
ammonia	CS
nitrate	CS
orthophosphorus	CS
total phosphorus	CS

1255D South Fork North Bosque River (unclassified water body)

	Level of Concern
1255D_01 Entire water body	
chlorophyll-a	CS

1255H South Fork Upper North Bosque River Reservoir (unclassified water body)

	Level of Concern
1255H_01 entire water body	
depressed dissolved oxygen	CS

1255J Goose Branch Reservoir (unclassified water body)

	Level of Concern
1255J_01 entire water body	
orthophosphorus	CS
chlorophyll-a	CS
ammonia	CS
total phosphorus	CS

1255K Scarborough Creek Reservoir (unclassified water body)

	Level of Concern
1255K_01 entire water body	
chlorophyll-a	CS
orthophosphorus	CS
total phosphorus	CS

1256 Brazos River/Lake Brazos

		Level of Concern
1256_02	*Lake Brazos portion of segment*	
	chlorophyll-a	**CS**

1301 San Bernard River Tidal

		Level of Concern
1301_01	*Entire Segment*	
	chlorophyll-a	**CS**

1302 San Bernard River Above Tidal

		Level of Concern
1302_02	*25 miles from just upstream of FM 442 to downstream of US 90A*	
	depressed dissolved oxygen	**CS**
1302_03	*25 miles from downstream of US 90A to upstream of FM 3013*	
	depressed dissolved oxygen	**CS**

1302A Gum Tree Branch (unclassified water body)

		Level of Concern
1302A_01	*The entire 15 miles of the segment*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**

1302B West Bernard Creek (unclassified water body)

		Level of Concern
1302B_01	*Lower 15 miles of segment*	
	depressed dissolved oxygen	**CS**
1302B_02	*Upper 25 miles of segment*	
	depressed dissolved oxygen	**CS**

1304 Caney Creek Tidal

		Level of Concern
1304_01	*Lower 25 miles of segment*	
	depressed dissolved oxygen	**CS**
	depressed dissolved oxygen	**CN**
	chlorophyll-a	**CS**
1304_02	*Upper 7 miles of segment*	
	bacteria	**CN**

1304A Linnville Bayou (unclassified water body)

		Level of Concern
1304A_01	*Entire water body*	
	nitrate	**CS**

1305 Caney Creek Above Tidal

		Level of Concern
1305_02	*25 miles surrounding SH 35*	
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
1305_03	*Upper 55 miles of segment*	
	depressed dissolved oxygen	**CN**

1401 Colorado River Tidal

		Level of Concern
1401_01	*Entire segment*	
	nitrate	**CS**

1402 Colorado River Below La Grange

		Level of Concern
1402_01	*Lower end to Wharton County line*	
	chlorophyll-a	**CS**
1402_02	*Wharton County line to US 59*	
	chlorophyll-a	**CS**
1402_06	*Cummins Creek to 5 mi above Fayette County line*	
	nitrate	**CS**
1402_07	*Upper 17 miles of segment*	
	orthophosphorus	**CS**
	nitrate	**CS**

1402A Cummins Creek (unclassified water body)

		Level of Concern
1402A_01	*From the confluence with the Colorado River upstream to the confluence of Boggy Creek at FM 1291 in Colorado County*	
	impaired habitat	**CS**

1402C Buckners Creek (unclassified water body)

		Level of Concern
1402C_01	*Entire water body*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

1402G Fayette Reservoir (unclassified water body)

		Level of Concern
1402G_02	*Near intake canal*	
	chlorophyll-a	**CS**
1402G_03	*Mid-lake near dam*	
	chlorophyll-a	**CS**

1402H Skull Creek (unclassified water body)

		Level of Concern
1402H_01	*Entire water body*	
	depressed dissolved oxygen	**CN**

1403 Lake Austin

		Level of Concern
1403_01	*From Tom Miller dam to Loop 360 bridge*	
	manganese in sediment	**CS**

1403D Barrow Preserve Tributary (unclassified water body)

		Level of Concern
1403D_01	*Entire water body*	
	nitrate	**CS**

1403E Stillhouse Hollow (unclassified water body)

		Level of Concern
1403E_01	*Entire water body*	
	nitrate	**CS**

1403K Taylor Slough South (unclassified water body)

		Level of Concern
1403K_01	*Entire water body*	
	nitrate	**CS**

1404 Lake Travis

		Level of Concern
1404_05	*From the confluence with Cow Creek upstream to the confluence of the Pedernales River*	
	depressed dissolved oxygen	**CS**
1404_06	*From the confluence with the Pedernales River upstream to Muleshoe Bend*	
	depressed dissolved oxygen	**CS**

1406 Lake Lyndon B. Johnson

		Level of Concern
1406_01	*From Alvin Wirtz Dam upstream to Granite Shoals*	
	depressed dissolved oxygen	**CS**
1406_06	*From a point near Pair Lane in Kingsland upstream to Roy Inks Dam*	
	depressed dissolved oxygen	**CS**

1407 Inks Lake

		Level of Concern
1407_01	*From Roy Inks Dam upstream to the Clear Creek Arm*	
	manganese in sediment	**CS**
1407_02	*From Clear Creel Arm upstream to Buchanan Dam*	
	depressed dissolved oxygen	**CS**

1407A Clear Creek

		Level of Concern
1407A_01	*From the confluence with Inks Lake upstream to FM 2341*	
	pH	**CN**
	sulfate	**CN**
	total dissolved solids	**CN**

1408 Lake Buchanan

		Level of Concern
1408_05	*From the Willow Slough area upstream to the Headwaters near the Yancey Creek confluence*	
	chlorophyll-a	**CS**

1410 Colorado River Below O. H. Ivie Reservoir

		Level of Concern
1410_01	*From the confluence of the San Saba River upstream to the confluence of Indian Creek*	
	chlorophyll-a	**CS**

1411 E. V. Spence Reservoir

		Level of Concern
1411_01	*Main pool from the dam upstream to the Rough Creek confluence area*	
	harmful algal bloom/golden alga	**CN**
	chlorophyll-a	**CS**
1411_02	*From the Rough Creek confluence area upstream to the confluence of Little Silver Creek*	
	harmful algal bloom/golden alga	**CN**

1412 Colorado River Below Lake J. B. Thomas

		Level of Concern
1412_01	*From the confluence of Little Silver Creek upstream to the confluence of Beals Creek*	
	chlorophyll-a	**CS**
1412_02	*From the confluence of Beals Creek upstream to the dam below Barber Reservoir pump station*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
1412_03	*From the dam below Barber Reservoir pump station upstream to the confluence of Deep Creek*	
	chlorophyll-a	**CS**

1412A Lake Colorado City (unclassified water body)

		Level of Concern
1412A_01	*Entire water body*	
	harmful algal bloom/golden alga	**CN**
	chlorophyll-a	**CS**

1412B Beals Creek (unclassified water body)

		Level of Concern
1412B_03	*From the confluence of Gutherie Draw upstream to the confluence of Mustang Draw and Sulphur Springs Draw*	
	bacteria	**CN**
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1416A Brady Creek (unclassified water body)

		Level of Concern
1416A_02	*From the confluence of an unnamed tributary approximately 5 km east of FM 2309 east of Brady upstream to FM 714*	
	total phosphorus	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
1416A_03	*From FM 714 upstream to Brady Lake dam*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

1417 Lower Pecan Bayou

		Level of Concern
1417_01	*Entire water body*	
	bacteria	**CN**
	chlorophyll-a	**CS**
	nitrate	**CS**

1418 Lake Brownwood

		Level of Concern
1418_01	*Mid-lake near dam*	
	manganese in sediment	**CS**

1420 Pecan Bayou Above Lake Brownwood

		Level of Concern
1420_01	*Lower 25 miles*	
	chlorophyll-a	**CS**

1421 Concho River

		Level of Concern
1421_01	*Downstream end to Chandler Lake confluence*	
	chlorophyll-a	**CS**
1421_02	*From Chandler Lake confluence upstream to confluence of Puddle Ck.*	
	nitrate	**CS**
	orthophosphorus	**CS**
1421_03	*From the confluence of Puddle Creek upstream to the confluence of Willow Creek*	
	orthophosphorus	**CS**
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
1421_04	*From the confluence of Willow Creek upstream to the confluence of an unnamed tributary near Chandler Road*	
	nitrate	**CS**
	chlorophyll-a	**CS**
1421_05	*From the confluence of an unnamed tributary near Chandler Rd. upstream to the confluence of Red Ck.*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
1421_06	*From the confluence of Red Creek upstream to the dam near Vines Rd.*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
1421_07	*From the dam near Vines Road upstream to the confluence of the North Concho River and the South Concho River*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
1421_08	*North Concho River, from the confluence with the South Concho River upstream to O.C. Fisher dam*	
	chlorophyll-a	**CS**
1421_09	*South Concho River, from the confluence with the North Concho upstream to Nasworthy Dam*	
	depressed dissolved oxygen	**CS**

1421A Dry Hollow Creek (unclassified water body)

		Level of Concern
1421A_01	*Entire water body*	
	nitrate	**CS**

1423 Twin Buttes Reservoir

		Level of Concern
1423_01	*North pool*	
	nitrate	**CS**
	orthophosphorus	**CS**
1423_02	*South pool*	
	orthophosphorus	**CS**

1423B Dove Creek (unclassified water body)

		Level of Concern
1423B_01	*From the confluence of Spring Creek upstream to RR 915*	
	depressed dissolved oxygen	**CS**

1425 O. C. Fisher Lake

		Level of Concern
1425_01	*Entire reservoir*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1425A North Concho River (unclassified water body)

		Level of Concern
1425A_02	*Sterling County line to SH 163*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**

1426 Colorado River Below E. V. Spence Reservoir

		Level of Concern
1426_01	*Lower end of segment to Country Club Lake*	
	chlorophyll-a	**CS**
1426_02	*Country Club Lake to Coke County line*	
	chlorophyll-a	**CS**
1426_03	*Coke County line to SH 208*	
	chlorophyll-a	**CS**
1426_04	*SH 208 to dam*	
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**

1426A Oak Creek Reservoir (unclassified water body)

		Level of Concern
1426A_01	*Entire water body*	
	sulfate in finished drinking water	**CS**

1426C Bluff Creek (unclassified water body)

		Level of Concern
1426C_01	*From the confluence with Elm Creek upstream to the confluence of Mill Creek*	
	nitrate	**CS**

1426D Coyote Creek (unclassified water body)

		Level of Concern
1426D_01	*Entire water body*	
	nitrate	**CS**

1427A Slaughter Creek (unclassified water body)

		Level of Concern
1427A_01	*Entire water body*	
	depressed dissolved oxygen	**CN**

1427G Granada Hills Tributary to Slaughter Creek (unclassified water body)

		Level of Concern
1427G_01	*Entire water body*	
	nitrate	**CS**

1428 Colorado River Below Town Lake

		Level of Concern
1428_01	*Lower end of segment to Gilleland Creek confluence*	
	impaired fish community	**CN**
	impaired macrobenthos community	**CN**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1428B Walnut Creek (unclassified water body)

		Level of Concern
1428B_01	*From the Colorado River upstream to FM 969*	
	bacteria	**CN**
1428B_04	*From Dessau Rd. upstream to MoPac/Loop 1*	
	impaired macrobenthos community	**CN**
1428B_05	*From MoPac/Loop 1 upstream to railroad tracks west of Loop 1*	
	bacteria	**CN**

1428C Gilleland Creek (unclassified water body)

		Level of Concern
1428C_01	*From the Colorado River upstream to Taylor Lane*	
	orthophosphorus	**CS**
	nitrate	**CS**
1428C_02	*From Taylor Lane upstream to Old Highway 20*	
	bacteria	**CN**
	nitrate	**CS**
1428C_03	*From Old Highway 20 to Cameron Road*	
	bacteria	**CN**
1428C_04	*From Cameron Road to the spring source*	
	bacteria	**CN**

1429 Town Lake

		Level of Concern
1429_01	*Longhorn Dam upstream to Lamar Street bridge*	
	nitrate	**CS**

1429C Waller Creek (unclassified water body)

		Level of Concern
1429C_01	*From the confluence with Town Lake to East MLK Blvd.*	
	bacteria	**CN**
1429C_02	*From East MLK Blvd. to East 41st Street*	
	fluoranthene in sediment	**CS**
	pyrene in sediment	**CS**
	phenanthrene in sediment	**CS**
	bacteria	**CN**
	lead in sediment	**CS**
	chrysene in sediment	**CS**
	benz(a)antracene in sediment	**CS**
	benzo(a)pyrene in sediment	**CS**
	dibenz(a,h)anthracene in sediment	**CS**

1429D East Bouldin Creek (unclassified water body)

		Level of Concern
1429D_01	*Entire water body*	
	pyrene in sediment	CS
	benz(a)antracene in sediment	CS
	cadmium in sediment	CS
	chrysene in sediment	CS
	dibenz(a,h)anthracene in sediment	CS
	fluoranthene in sediment	CS
	lead in sediment	CS
	phenanthrene in sediment	CS

1430 Barton Creek

		Level of Concern
1430_02	*From Barton Springs Pool upstream dam to a point 2 miles upstream of Loop 1*	
	toxic sediment (LOE)	CN
1430_04	*SH 71 upstream to Hays County Line*	
	depressed dissolved oxygen	CS

1430A Barton Springs (unclassified water body)

		Level of Concern
1430A_01	*Barton Springs Pool - entire water body*	
	toxic sediment (LOE)	CN

1430B Tributaries to Barton Creek (unclassified water bodies)

		Level of Concern
1430B_01	*Tributaries entering Barton Cr from a point 2 mi upstream of Loop 1 upstream to Barton Creek Blvd.*	
	nitrate	CS

1431 Mid Pecan Bayou

		Level of Concern
1431_01	*Entire water body*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1434 Colorado River above La Grange

		Level of Concern
1434_02	*Southern-Pacific RR upstream to the confluence of Reeds Creek west of Smithville*	
	nitrate	**CS**
	orthophosphorus	**CS**
1434_03	*From the confluence of Reeds Creek west of Smithville upstream to the end of segment*	
	nitrate	**CS**
	orthophosphorus	**CS**

1434B Cedar Creek (unclassified water body)

		Level of Concern
1434B_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

1501 Tres Palacios Creek Tidal

		Level of Concern
1501_01	*Entire segment*	
	chlorophyll-a	**CS**

1602 Lavaca River Above Tidal

		Level of Concern
1602_01	*Upper 29 miles of segment*	
	chlorophyll-a	**CS**

1604 Lake Texana

		Level of Concern
1604_01	*Navidad River arm of Lake Texana*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
1604_02	*East Mustang Creek arm of Lake Texana*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1604_03	*Upstream middle portion of Lake Texana*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1604_04	*Downstream middle portion of Lake Texana*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1604_05	*Downstream portion of Lake Texana*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1701 Victoria Barge Canal

		Level of Concern
1701_01	*Entire segment*	
	chlorophyll-a	**CS**
	nitrate	**CS**

1801 Guadalupe River Tidal

		Level of Concern
1801_01	*Entire segment*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**

1802 Guadalupe River Below San Antonio River

		Level of Concern
1802_01	*Entire segment*	
	nitrate	**CS**

1803C Peach Creek (unclassified water body)

		Level of Concern
1803C_01	*Lower 25 miles of water body*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**
1803C_03	*From approx. 1.2 mi. downstream of FM 1680 in Gonzales Co. to confluence with Elm Cr. In Fayette Co.*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**

1804A Geronimo Creek (unclassified water body)

		Level of Concern
1804A_01	*Entire water body*	
	nitrate	**CS**

1805 Canyon Lake

		Level of Concern
1805_02	*North end of Crane's Mill Park peninsula to south end of Canyon Park*	
	orthophosphorus	**CS**
1805_03	*Upper end of segment*	
	orthophosphorus	**CS**
1805_04	*Lower end of reservoir from dam upstream to Canyon Park*	
	orthophosphorus	**CS**

1810 Plum Creek

		Level of Concern
1810_01	*Confluence with San Marcos River to approx. 2.5 mi. upstream of the confluence with Clear Fork Plum Creek*	
	nitrate	**CS**
1810_02	*From approx. 2.5 mi. upstream of confluence with Clear Fork Plum Ck to approx. 0.5 mi upstream of SH21*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1810_03	*From approx. 0.5 mi. upstream of SH 21 to upper end of segment*	
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	total phosphorus	**CS**

1813 Upper Blanco River

		Level of Concern
1813_05	*From Hays CR 1492 to Blanco CR 406*	
	depressed dissolved oxygen	**CS**

1817 North Fork Guadalupe River

		Level of Concern
1817_01	*Entire segment*	
	depressed dissolved oxygen	**CS**

1901 Lower San Antonio River

		Level of Concern
1901_01	*25 miles downstream of the confluence with Manahuilla Creek*	
	total phosphorus	**CS**
	nitrate	**CS**
1901_02	*25 miles upstream of Manahuilla Creek*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	bacteria	**CN**
	nitrate	**CS**
1901_03	*From 25 miles upstream of Manahuilla Cr to 9 mi downstream of Escondido Cr*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1901_04	*9 miles downstream of Escondido Creek*	
	bacteria	**CN**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1901_05	*From upstream end of segment to Escondido Creek*	
	nitrate	**CS**
	orthophosphorus	**CS**
	impaired fish community	**CN**
	total phosphorus	**CS**
1901_06	*Lower 31 miles of segment*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1902 Lower Cibolo Creek

		Level of Concern
1902_01	*Lower 5 miles of segment*	
	bacteria	**CN**
	nitrate	**CS**
1902_03	*From FM 541 to confluence with Clifton Branch*	
	impaired fish community	**CN**
1902_04	*From confluence with Clifton Branch to the confluence with Elm Creek*	
	nitrate	**CS**
	orthophosphorus	**CS**
1902_05	*Upper end of segment*	
	total phosphorus	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**

1903 Medina River Below Medina Diversion Lake

		Level of Concern
1903_01	*Lower 5 miles of segment*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	ammonia	**CS**
	nitrate	**CS**
1903_02	*From 5 mi upstream of San Antonio River to 1.5 mi upstream of Leon Creek*	
	nitrate	**CS**
	total phosphorus	**CS**
1903_03	*From 1.5 miles upstream of Leon Cr to confluence with Live Oak Slough*	
	impaired fish community	**CN**
	nitrate	**CS**
1903_04	*From confluence with Live Oak Slough to upstream 25 miles*	
	nitrate	**CS**
1903_05	*Upper 32 miles of segment*	
	impaired fish community	**CN**

1905 Medina River Above Medina Lake

		Level of Concern
1905_01	*From lower end of segment to RR 470, upstream of Bandera*	
	impaired habitat	**CS**
1905_02	*Remainder of segment*	
	impaired fish community	**CN**

1906 Lower Leon Creek

		Level of Concern
1906_01	*Lower 3 miles of segment*	
	nitrate	**CS**
	silver in sediment	**CS**
1906_02	*From 3 miles upstream lower end of segment to confluence with Indian Creek*	
	silver in sediment	**CS**
1906_03	*From confluence with Indian Creek to Hwy 353*	
	silver in sediment	**CS**
1906_04	*From Hwy 353 to two miles upstream*	
	bacteria	**CN**
	silver in sediment	**CS**
1906_05	*From 2 miles upstream of Hwy 353 to Hwy 90*	
		CS
	silver in sediment	**CS**
1906_06	*Remainder of segment*	
	impaired fish community	**CN**
	ammonia	**CS**
	impaired habitat	**CS**
	silver in sediment	**CS**

1908 Upper Cibolo Creek

		Level of Concern
1908_01	*From confl. with Balcones Ck. to approx. 2 mi. upstream of Hwy 87 in Boerne*	
	impaired habitat	**CS**
	orthophosphorus	**CS**
1908_02	*From approx. 2 mi. upstream of Hwy 87 in Boerne to upper end of segment*	
	ammonia	**CS**

1910 Salado Creek

		Level of Concern
1910_02	*From confluence with Rosillo Creek to Roland Road*	
	impaired fish community	**CN**
1910_03	*From Roland Road to Rice Road*	
	depressed dissolved oxygen	**CS**
1910_05	*From IH 10 to approx 1.5 miles upstream of IH 35*	
	impaired fish community	**CN**
1910_06	*From approx. 1.5 miles upstream of IH 35 to Hwy 368*	
	bacteria	**CN**
	impaired fish community	**CN**
1910_07	*From Hwy 368 to approx 1.5 miles upstream of Loop 410*	
	depressed dissolved oxygen	**CS**
	impaired habitat	**CS**

1910A Walzem Creek (unclassified water body)

		Level of Concern
1910A_01	*Lower 0.25 miles*	
	bacteria	**CN**

1911 Upper San Antonio River

		Level of Concern
1911_01	*Lower 6 miles of segment*	
	nitrate	**CS**
	total phosphorus	**CS**
1911_02	*From 6 miles upstream of lower end of segment to confluence with Picosa Cr*	
	nitrate	**CS**
	total phosphorus	**CS**
1911_03	*From confluence with Picosa Creek to approx. 2.5 miles upstream of FM 536*	
	nitrate	**CS**
1911_04	*From approx. 2.5 miles upstream of FM 528 to Bexar CR 125*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	nitrate	**CS**
1911_05	*From Bexar CR 125 to approx. 2 miles downstream confluence with Medina R.*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1911_06	*From 2 miles downstream of confluence with Medina River to confluence*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1911_07	*From the confluence with the Medina River to 3 miles upstream*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1911_10	*From confluence with Sixmile Creek to confluence with San Pedro Creek*	
	nitrate	**CS**
	bacteria	**CN**
1911_11	*Upper 8 miles of segment*	
	impaired fish community	**CN**
	nitrate	**CS**

1912 Medio Creek

		Level of Concern
1912_01	*Entire segment*	
	impaired fish community	**CN**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

1912A Upper Medio Creek (unclassified water body)

		Level of Concern
1912A_01	*Entire water body*	
	total phosphorus	**CS**
	bacteria	**CN**
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**

1913 Mid Cibolo Creek

		Level of Concern
1913_01	*Lower 7 miles of segment from IH 10 to Bexar CR 320*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	nitrate	**CS**
	ammonia	**CS**
1913_02	*From Bexar CR 320 to approx. 0.50 miles upstream of Buffalo Lane in Cibolo*	
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
1913_03	*From approx. 0.50 mi. upstream of Buffalo Lane in Cibolo to upper end of segment*	
	ammonia	**CS**
	nitrate	**CS**

2003 Aranssa River Tidal

		Level of Concern
2003_01	*Entire segment*	
	orthophosphorus	**CS**

2004 Aransas River Above Tidal

		Level of Concern
2004_02	*Upper 18 miles of segment*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
	nitrate	**CS**
	depressed dissolved oxygen	**CS**

2004A Aransas Creek (unclassified water body)

		Level of Concern
2004A_01	*Entire 20 miles of segment*	
	depressed dissolved oxygen	**CS**
	depressed dissolved oxygen	**CN**

2101 Nueces River Tidal

		Level of Concern
2101_01	*Entire segment*	
	chlorophyll-a	**CS**

2102 Nueces River Below Lake Corpus Christi

		Level of Concern
2102_01	*Lower 25 miles of segment*	
	chlorophyll-a	**CS**

2103 Lake Corpus Christi

		Level of Concern
2103_01	*Mid-lake near dam*	
	orthophosphorus	**CS**
	total phosphorus	**CS**
2103_02	*Area approx. 4 mi. SE of FM 3162 and FM 534 intersection near western shore*	
	chlorophyll-a	**CS**
2103_06	*Remainder of lake*	
	chlorophyll-a	**CS**
	orthophosphorus	**CS**

2104 Nueces River Above Frio River

		Level of Concern
2104_01	*Lower 20 miles of segment*	
	impaired habitat	**CS**
	impaired fish community	**CN**
	impaired macrobenthos community	**CN**
2104_02	*25 miles surrounding State Highway 16*	
	impaired fish community	**CN**
2104_03	*Upper 46 miles of segment*	
	impaired fish community	**CN**

2105 Nueces River Above Holland Dam

		Level of Concern
2105_01	*Lower 25 miles of segment*	
	depressed dissolved oxygen	**CS**

2107 Atascosa River

		Level of Concern
2107_01	*Lower 25 miles of segment*	
	chlorophyll-a	**CS**
2107_02	*25 miles surrounding FM 541*	
	bacteria	**CN**
	orthophosphorus	**CS**
2107_03	*25 miles surrounding State Highway 97*	
	chlorophyll-a	**CS**
	impaired habitat	**CS**

2108 San Miguel Creek

		Level of Concern
2108_01	*Lower 25 miles of segment*	
	chlorophyll-a	**CS**

2109 Leona River

		Level of Concern
2109_01	*Lower 25 miles of segment*	
	nitrate	**CS**
2109_02	*25 miles surrounding US Highway 57*	
	nitrate	**CS**
2109_03	*Upper 28 miles of segment*	
	bacteria	**CN**
	nitrate	**CS**

2113 Upper Frio River

		Level of Concern
2113_01	*Lower 25 miles of segment*	
	impaired habitat	**CS**
2113_02	*Upper 22 miles of segment*	
	impaired habitat	**CS**

2116 Choke Canyon Reservoir

		Level of Concern
2116_05	*Southern arm near mid lake and Rec. Road 7 west of Calliham*	
	depressed dissolved oxygen	**CS**
2116_06	*Western end of lake up to RR 99 bridge*	
	depressed dissolved oxygen	**CN**
	depressed dissolved oxygen	**CS**

2117 Frio River Above Choke Canyon Reservoir

		Level of Concern
2117_01	*Lower 25 miles of segment*	
	nitrate	**CS**
2117_02	*From 1.5 mi. downstream of SH 97 to 23.5 mi. upstream of SH 97 crossing*	
	nitrate	**CS**
2117_03	*33 mi. surrounding State Highway 85*	
	nitrate	**CS**
2117_04	*40 miles surrounding US Highway 57*	
	nitrate	**CS**

2201 Arroyo Colorado Tidal

		Level of Concern
2201_01	*Lower 9.0 miles of segment*	
	chlorophyll-a	**CS**
	nitrate	**CS**
2201_02	*Approx. 2 miles upstream to approx. 2 miles downstream of Marker 22*	
	chlorophyll-a	**CS**
	nitrate	**CS**
2201_03	*Approx. 3 miles upstream to 2 miles downstream of Marker 27*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
2201_04	*Approx. 1 mile upstream to 3 miles downstream of Camp Perry*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
2201_05	*Upper 4 miles of segment*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
	ammonia	**CS**
	bacteria	**CN**
	chlorophyll-a	**CS**

2202 Arroyo Colorado Above Tidal

		Level of Concern
2202_01	*Lower 4 miles of segment*	
	orthophosphorus	CS
	total phosphorus	CS
	nitrate	CS
	chlorophyll-a	CS
	ammonia	CS
2202_02	*Approx. 11 miles upstream to approx. 4 miles downstream of US 77*	
	total phosphorus	CS
	chlorophyll-a	CS
	nitrate	CS
	orthophosphorus	CS
	ammonia	CS
2202_03	*Approx 14 miles upstream to approx. 11 miles downstream of FM 1015*	
	total phosphorus	CS
	orthophosphorus	CS
	ammonia	CS
	chlorophyll-a	CS
	nitrate	CS
2202_04	*Upper 19 miles of segment*	
	ammonia	CS
	chlorophyll-a	CS
	nitrate	CS
	orthophosphorus	CS
	total phosphorus	CS

2202B Unnamed Drainage Ditch Tributary (B) to S. Arroyo Colorado (unclassified water body)

		Level of Concern
2202B_01	*Entire 0.8 miles of segment*	
	bacteria	CN
	ammonia	CS
	chlorophyll-a	CS

2202C Unnamed Drainage Ditch Tributary (C) to S. Arroyo Colorado (unclassified water body)

		Level of Concern
2202C_01	*Entire 1.1 miles of segment*	
	bacteria	**CN**
	ammonia	**CS**

2203 Petronila Creek Tidal

		Level of Concern
2203_01	*Entire segment*	
	chlorophyll-a	**CS**

2204 Petronila Creek Above Tidal

		Level of Concern
2204_01	*Lower 25 miles of segment*	
	chlorophyll-a	**CS**

2301 Rio Grande Tidal

		Level of Concern
2301_01	*Upper segment boundary to 25 miles upstream of lower segment boundary (mouth of Rio Grande)*	
	bacteria	**CN**
	chlorophyll-a	**CS**
2301_02	*25 miles upstream of lower segment boundary (mouth of Rio Grande)*	
	chlorophyll-a	**CS**

2302 Rio Grande Below Falcon Reservoir

		Level of Concern
2302_01	*Falcon Dam to Arroyo Los Olmos confluence*	
	mercury in fish tissue	**CS**
2302_02	*Arroyo Los Olmos confluence to Los Ebanos Ferry Crossing*	
	mercury in fish tissue	**CS**
2302_03	*Los Ebanos Ferry Crossing to Anzalduas Dam*	
	mercury in fish tissue	**CS**
2302_04	*Anzalduas Dam to McAllen Int'l Bridge (US 281)*	
	mercury in fish tissue	**CS**
2302_05	*McAllen Int'l Bridge(US 281) to Progresso Int'l Bridge (FM 1015)*	
	mercury in fish tissue	**CS**
2302_06	*Progresso Int'l Bridge (FM 1015) to the Rancho Viejo Floodway area*	
	mercury in fish tissue	**CS**
2302_07	*Rancho Viejo Floodway area to El Jardin Pump Station*	
	mercury in fish tissue	**CS**
	depressed dissolved oxygen	**CS**

2303 International Falcon Reservoir

		Level of Concern
2303_02	*Area around Zapata WTP intake*	
	toxicity in ambient water	**CN**

2304 Rio Grande Below Amistad Reservoir

		Level of Concern
2304_01	*Amistad Dam to San Felipe Creek confluence*	
	depressed dissolved oxygen	**CS**
2304_04	*Hwy 277 (Eagle Pass) to El Indio*	
	bacteria	**CN**
2304_07	*World Trade Center Bridge to Laredo water treatment plant intake*	
	toxicity in ambient water	**CN**
2304_08	*Laredo water treatment plant intake to International Bridge #2*	
	toxicity in ambient water	**CN**

2305 International Amistad Reservoir

		Level of Concern
2305_02	*Devils River arm*	
	nitrate	**CS**

2306 Rio Grande Above Amistad Reservoir

		Level of Concern
2306_01	*Confluence with Rio Conchos to Alamito Creek*	
	chlorophyll-a	**CS**
2306_03	*Mouth of Santa Elena Canyon to Johnson Ranch*	
	chlorophyll-a	**CS**
2306_05	*Mariscal Canyon to Boquillas Canyon*	
	chlorophyll-a	**CS**
2306_06	*Boquillas Canyon to FM 2627*	
	chlorophyll-a	**CS**
2306_08	*Dryden Crossing to lower segment boundary downstream of Ramsey Canyon*	
	total phosphorus	**CS**

2307 Rio Grande Below Riverside Diversion Dam

		Level of Concern
2307_01	*Downstream of Riverside Dam to Guadalupe Bridge*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
	ammonia	**CS**
2307_02	*Guadalupe Bridge to the Alamo Grade Structure*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	depressed dissolved oxygen	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
2307_03	*Alamo Grade Structure to Little Box Canyon*	
	chlorophyll-a	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
	ammonia	**CS**
2307_05	*25 miles upstream of the Rio Conchos confluence (lower segment boundary)*	
	chlorophyll-a	**CS**

2308 Rio Grande Below International Dam

		Level of Concern
2308_01	*Entire segment*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	total phosphorus	**CS**

2310 Lower Pecos River

		Level of Concern
2310_01	*Upper segment boundary to Big Hackberry Canyon*	
	harmful algal bloom/golden alga	**CN**
2310_02	*From FM 2083 near Pan Dale Rd to the lower segment boundary*	
	harmful algal bloom/golden alga	**CN**

2311 Upper Pecos River

		Level of Concern
2311_01	*Red Bluff Dam to FM 652*	
	harmful algal bloom/golden alga	**CN**
	chlorophyll-a	**CS**
2311_02	*FM 652 to SH 302*	
	harmful algal bloom/golden alga	**CN**
2311_03	*SH 302 to Barstow Dam*	
	harmful algal bloom/golden alga	**CN**
2311_04	*Barstow Dam to US 80 (Bus 20)*	
	bacteria	**CN**
	harmful algal bloom/golden alga	**CN**
2311_05	*US 80 (Bus 20) to FM 1776*	
	chlorophyll-a	**CS**
	harmful algal bloom/golden alga	**CN**
2311_06	*FM 1776 to US 67*	
	harmful algal bloom/golden alga	**CN**
	depressed dissolved oxygen	**CS**
2311_07	*US 67 to US 290*	
	harmful algal bloom/golden alga	**CN**
	chlorophyll-a	**CS**
2311_08	*US 290 to lower segment boundary*	
	harmful algal bloom/golden alga	**CN**

2312 Red Bluff Reservoir

		Level of Concern
2312_01	*Texas/New Mexico State Line to Mid-lake*	
	harmful algal bloom/golden alga	**CN**
	chlorophyll-a	**CS**
	nitrate	**CS**
2312_02	*Mid-lake to dam*	
	depressed dissolved oxygen	**CS**
	orthophosphorus	**CS**
	ammonia	**CS**
	harmful algal bloom/golden alga	**CN**
	chlorophyll-a	**CS**

2314 Rio Grande Above International Dam

		Level of Concern
2314_02	*Upstream of Anthony Drain to International Dam*	
	chlorophyll-a	**CS**

2421 Upper Galveston Bay

		Level of Concern
2421_01	*Red Bluff to Five Mile Cut to Houston Point to Morgans Point*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
	total phosphorus	**CS**
2421_02	*Western portion of the bay*	
	chlorophyll-a	**CS**
	nitrate	**CS**
2421_03	*Eastern portion of the bay*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	total phosphorus	**CS**

2422 Trinity Bay

		Level of Concern
2422_01	*Upper half of bay*	
	nitrate	**CS**
2422_02	*Lower half of bay*	
	chlorophyll-a	**CS**

2422B Double Bayou West Fork (unclassified water body)

		Level of Concern
2422B_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

2423 East Bay

		Level of Concern
2423_02	*Remainder of segment*	
	chlorophyll-a	**CS**

2424A Highland Bayou (unclassified water body)

		Level of Concern
2424A_01	*From the headwaters to FM 2004*	
	depressed dissolved oxygen	**CS**
2424A_04	*From Fairwood Road to Bayou Lane*	
	bacteria	**CN**

2424C Marchand Bayou (unclassified water body)

		Level of Concern
2424C_01	*Entire water body*	
	bacteria	**CN**
	depressed dissolved oxygen	**CS**

2425 Clear Lake

		Level of Concern
2425_01	*Entire segment*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**
	total phosphorus	**CS**

2425B Jarbo Bayou (unclassified water body)

		Level of Concern
2425B_01	*From headwaters to Lawrence Road*	
	bacteria	**CN**

2426 Tabbs Bay

		Level of Concern
2426_01	*Entire segment*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	ammonia	**CS**
	nitrate	**CS**

2427 San Jacinto Bay

		Level of Concern
2427_01	*Entire segment*	
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

2428 Black Duck Bay

		Level of Concern
2428_01	*Entire segment*	
	chlorophyll-a	**CS**
	total phosphorus	**CS**

2429 Scott Bay

		Level of Concern
2429_01	*Entire segment*	
	total phosphorus	**CS**
	ammonia	**CS**
	chlorophyll-a	**CS**
	orthophosphorus	**CS**

2430 Burnett Bay

		Level of Concern
2430_01	*Entire segment*	
	total phosphorus	**CS**
	orthophosphorus	**CS**
	nitrate	**CS**
	ammonia	**CS**
	chlorophyll-a	**CS**

2432B Willow Bayou

		Level of Concern
2432B_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

2432C Halls Bayou Tidal

		Level of Concern
2432C_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

2436 Barbours Cut

		Level of Concern
2436_01	*Entire segment*	
	ammonia	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

2437 Texas City Ship Channel

		Level of Concern
2437_01	*Entire segment*	
	chlorophyll-a	**CS**
	total phosphorus	**CS**
	ammonia	**CS**

2438 Bayport Channel

		Level of Concern
2438_01	*Entire segment*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**

2439 Lower Galveston Bay

		Level of Concern
2439_01	*Area adjacent to the Texas City Ship Channel and Moses Lake*	
	nitrate	**CS**
2439_02	*Main portion of the bay*	
	chlorophyll-a	**CS**

2441 East Matagorda Bay

		Level of Concern
2441_01	*Caney Creek am and western shoreline area*	
	nitrate	**CS**
	orthophosphorus	**CS**
2441_02	*Remainder of segment*	
	nitrate	**CS**
	orthophosphorus	**CS**

2451 Matagorda Bay/Powderhorn Lake

		Level of Concern
2451_01	*Northern end of Matagorda Bay*	
	orthophosphorus	**CS**
	nitrate	**CS**
2451_02	*Remainder of segment*	
	nitrate	**CS**
	orthophosphorus	**CS**

2452 Tres Palacios Bay/Turtle Bay

		Level of Concern
2452_03	*Tres Palacios Creek Arm*	
	chlorophyll-a	**CS**
	total phosphorus	**CS**

2452A Tres Palacios Harbor (unclassified water body)

		Level of Concern
2452A_01	*Entire water body*	
	ammonia	**CS**

2453 Lavaca Bay/Chocolate Bay

		Level of Concern
2453_02	*North-northeastern portion of the bay near Point Comfort*	
	chlorophyll-a	**CS**

2454 Cox Bay

		Level of Concern
2454_01	*North end of bay near Cox Creek*	
	nitrate	**CS**
2454_02	*Remainder of Cox Bay*	
	nitrate	**CS**

2454A Cox Lake (unclassified water body)

		Level of Concern
2454A_01	*Entire water body*	
	chlorophyll-a	**CS**
	nitrate	**CS**
	total phosphorus	**CS**

2456 Carancahua Bay

		Level of Concern
2456_02	*Upper half of bay*	
	nitrate	**CS**
	orthophosphorus	**CS**
	total phosphorus	**CS**
	chlorophyll-a	**CS**

2456A West Carancahua Creek Tidal (unclassified water body)

		Level of Concern
2456A_01	*Entire water body*	
	depressed dissolved oxygen	**CS**

2461 Espiritu Santo Bay

		Level of Concern
2461_01	*Entire segment*	
	nitrate	**CS**

2462 San Antonio Bay/Hynes Bay/Guadalupe Bay

		Level of Concern
2462_01	*San Antonio and Hynes Bays*	
	nitrate	**CS**

2473 St. Charles Bay

		Level of Concern
2473_01	*Entire bay*	
	depressed dissolved oxygen	**CS**

2484 Corpus Christi Inner Harbor

		Level of Concern
2484_01	*Entire segment*	
	ammonia	**CS**
	chlorophyll-a	**CS**
	nitrate	**CS**

2485 Oso Bay

		Level of Concern
2485_01	*Upper bay (Holly Road to County Hwy 24)*	
	chlorophyll-a	**CS**
2485_02	*Middle bay (State Park Road 22 to Holly Road)*	
	chlorophyll-a	**CS**
2485_03	*Lower portion of bay (Ocean Drive to State Park Road 22)*	
	chlorophyll-a	**CS**
	total phosphorus	**CS**
	ammonia	**CS**

2485A Oso Creek (unclassified water body)

		Level of Concern
2485A_01	*Entire water body*	
	nitrate	**CS**
	total phosphorus	**CS**
	chlorophyll-a	**CS**

2491 Laguna Madre

		Level of Concern
2491_01	*Upper portion of bay north of the Arroyo Colorado confluence*	
	chlorophyll-a	**CS**
2491_02	*Area adjacent to the Arroyo Colorado confluence*	
	bacteria	**CN**
	chlorophyll-a	**CS**
	nitrate	**CS**

2492 Baffin Bay/Alazan Bay/Cayo del Grullo/Laguna Salada

		Level of Concern
2492_01	*Entire segment*	
	chlorophyll-a	**CS**

2492A San Fernando Creek (unclassified water body)

		Level of Concern
2492A_01	*Entire water body*	
	nitrate	**CS**
	total phosphorus	**CS**

2494 Brownsville Ship Channel

		Level of Concern
2494_01	*Brownsville Ship Channel*	
	depressed dissolved oxygen	**CS**

2494A Port Isabel Fishing Harbor (unclassified water body)

		Level of Concern
2494A_01	*Entire water body*	
	nitrate	**CS**
	bacteria	**CN**