Appendix A. 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

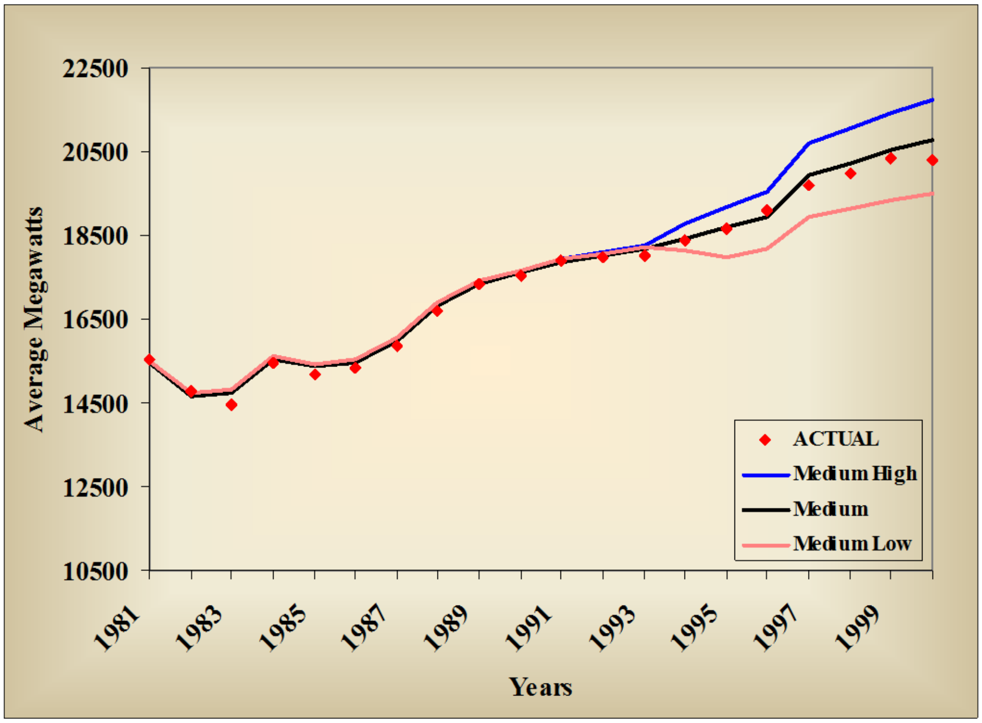


Figure A-1: Demand Forecast Versus Actual Consumption of Electricity

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

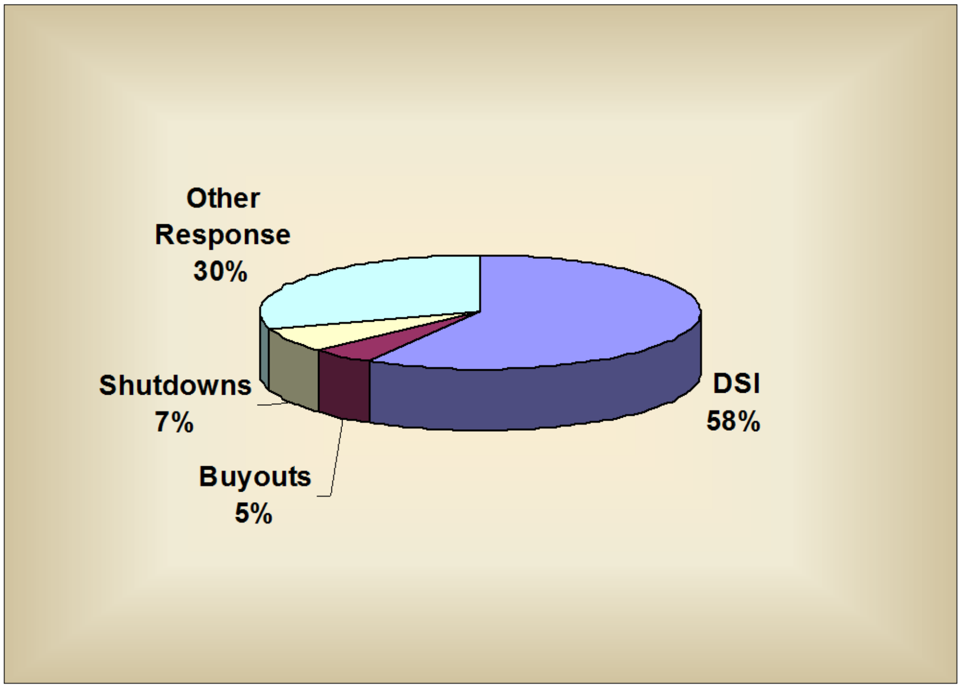


Figure A-2: Components of a 20 Percent Load Reduction from July 2000 to July 2001

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.

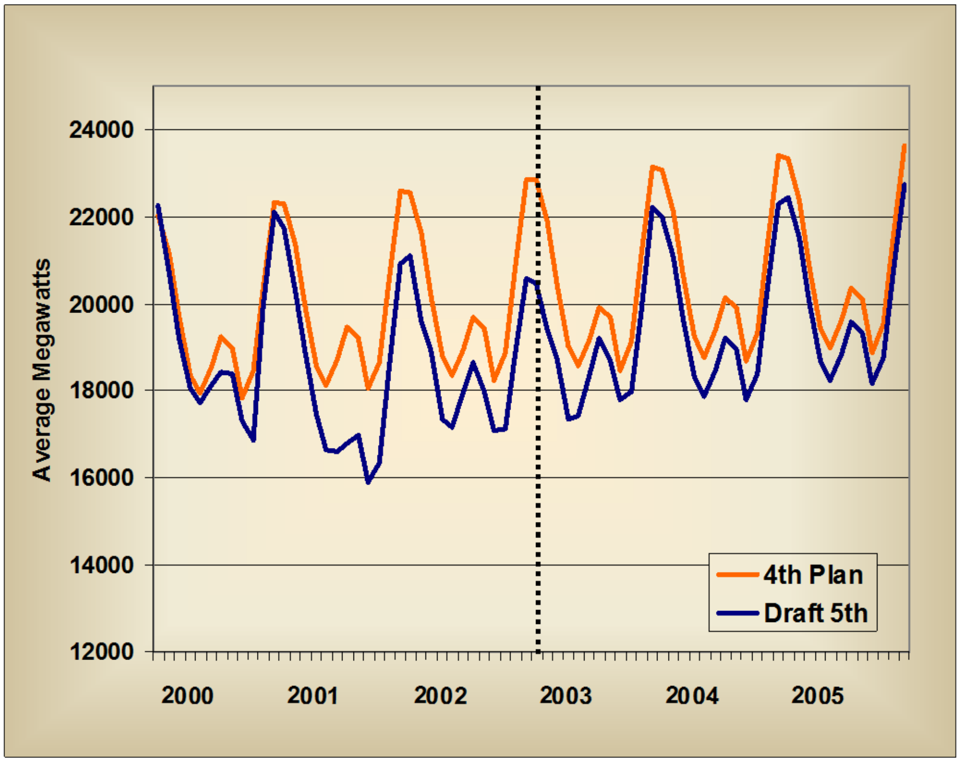


Figure A-3a: Comparison of Monthly Near-Term Forecast to the Fourth Power Plan

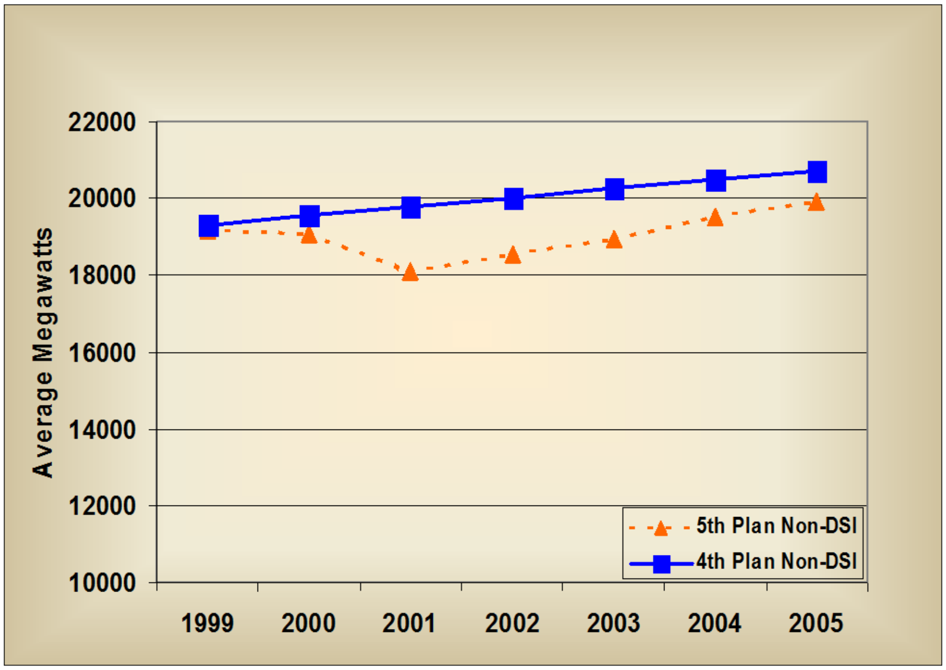


Figure A-3b: Comparison of Annual Near-Term Forecast to the Fourth Power Plan

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 draft 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.

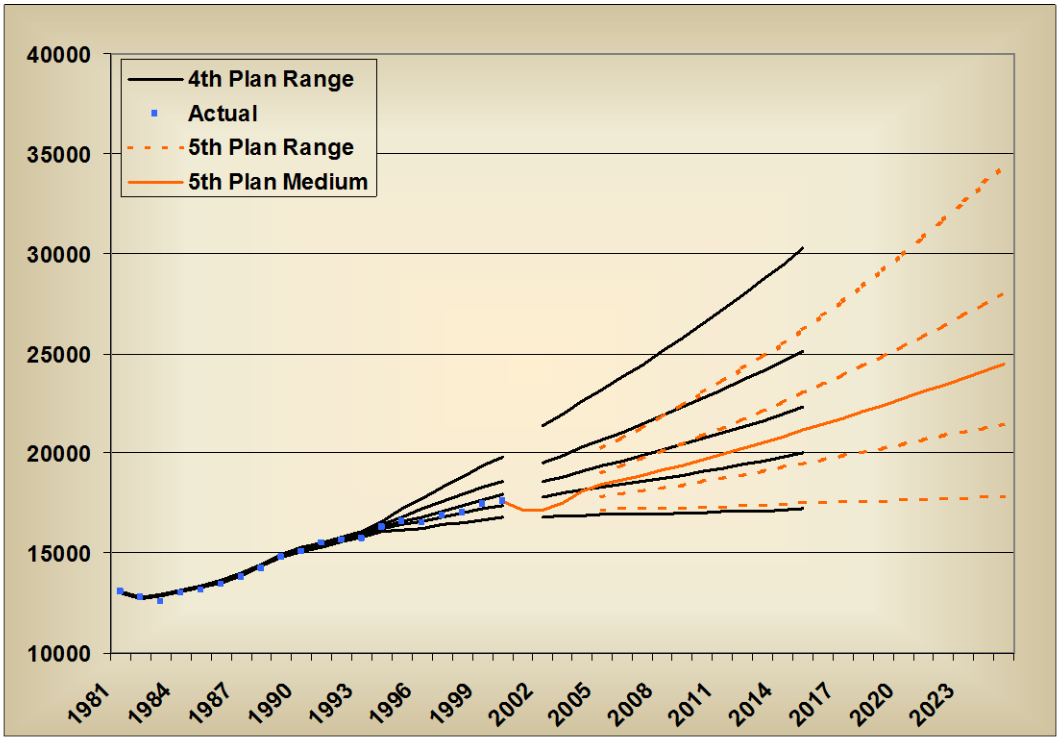


Figure A-4: Forecast Total Non-DSI Electricity Sales Compared to Fourth Plan Forecasts

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

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

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.

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 Draft 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.

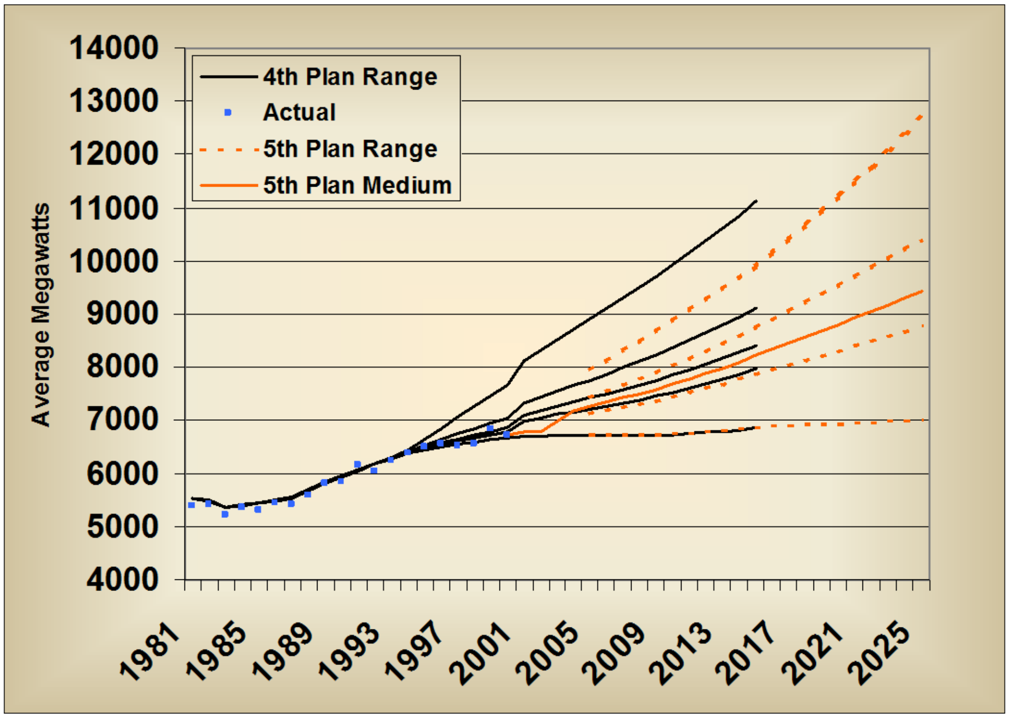


Figure A-5: Forecast Residential Electricity Sales Compared to Fourth Plan Forecasts

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 draft 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 draft forecast for 2005 is 325 average megawatts higher than the 2005 medium forecast in the Council's Fourth Power Plan.

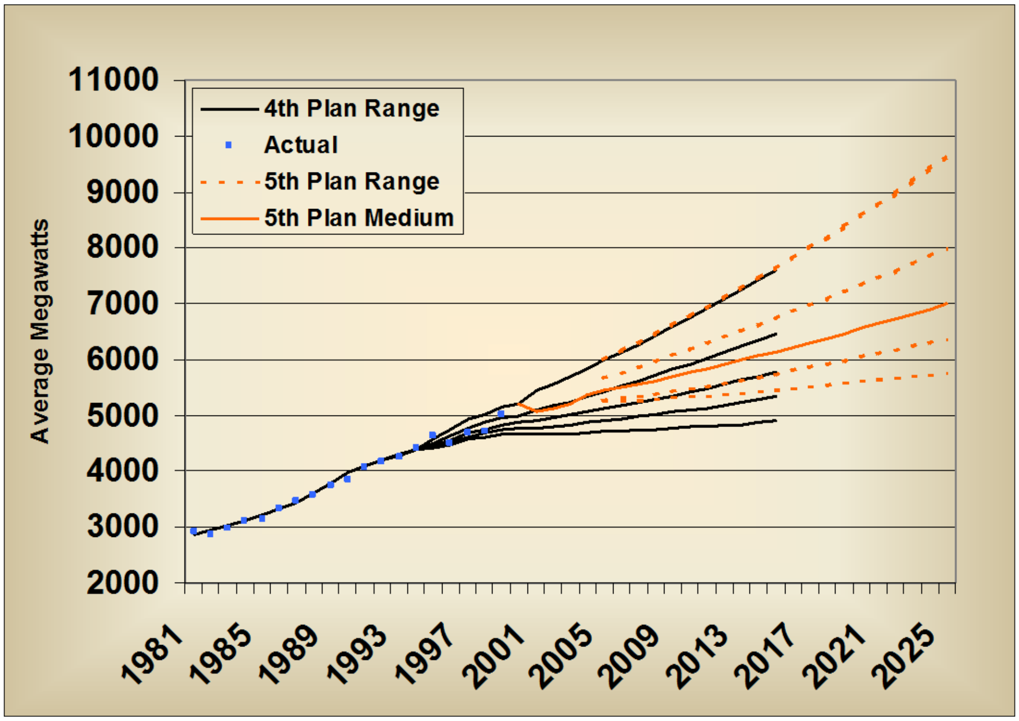


Figure A-6: Forecast Commercial Electricity Sales Compared to 4th Plan Forecasts

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.

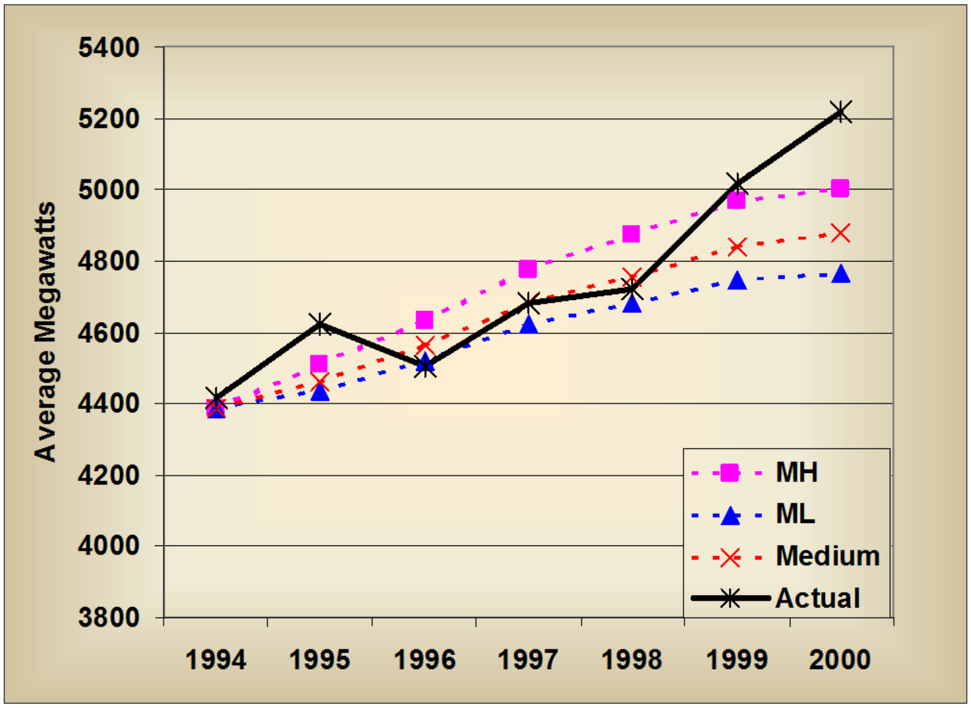


Figure A-7: Fourth Plan Commercial Forecast Performance

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.

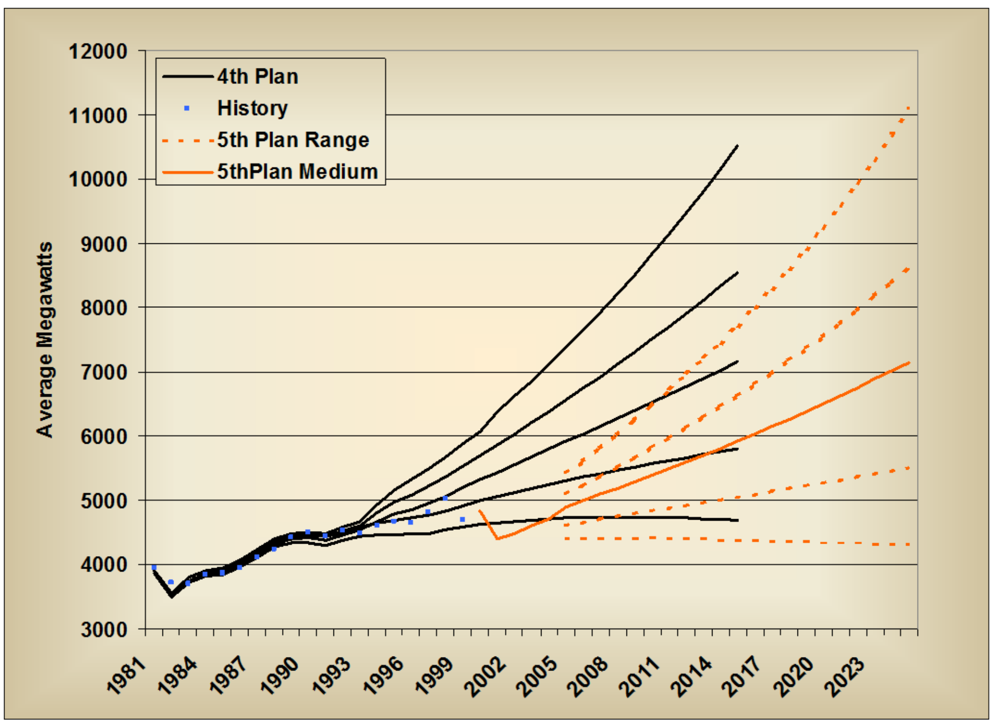


Figure A-8: Forecast Non-DSI Industrial Electricity Sales Compared to Fourth Plan Forecasts

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 draft 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 in the draft forecast, 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.

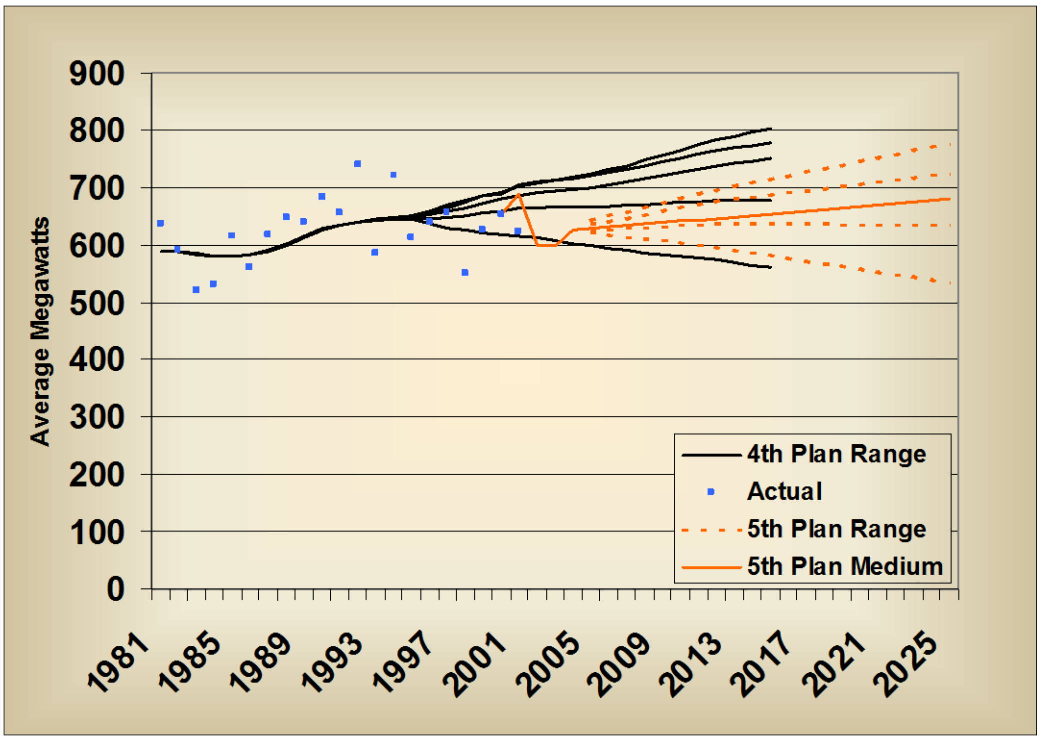


Figure A-9: Forecast Irrigation Electricity Sales Compared to Fourth Plan Forecasts

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.

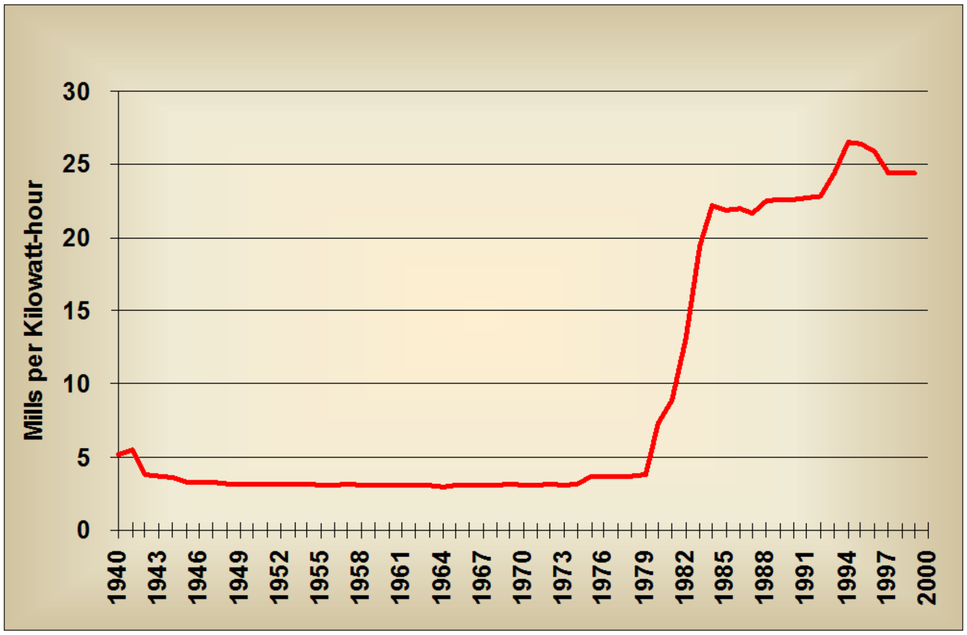
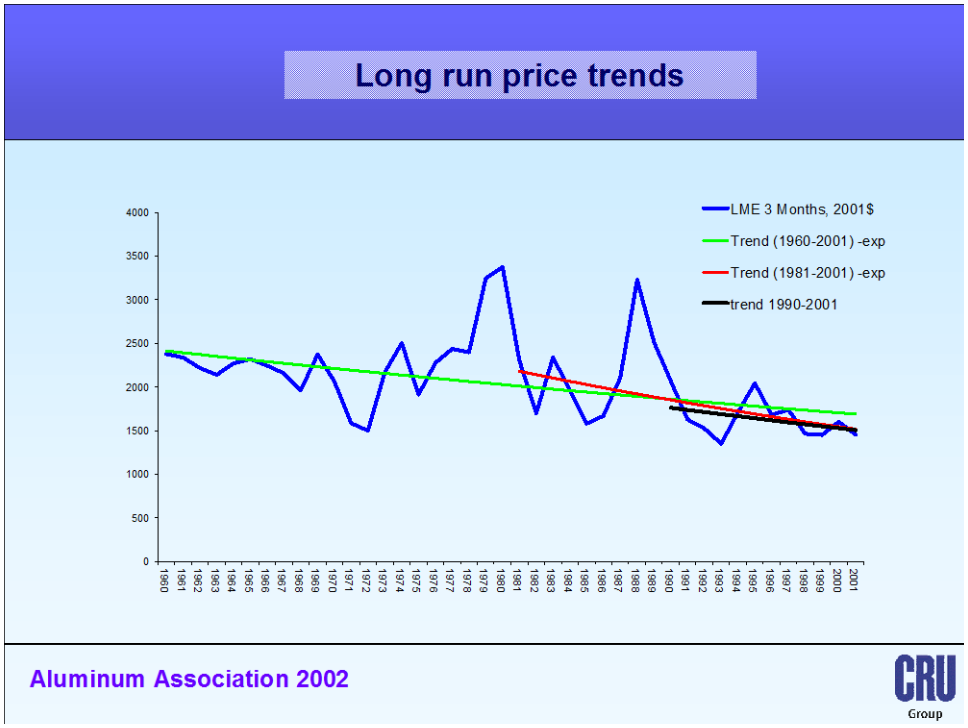


Figure A-10: Bonneville Power Administration Preference Rates

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 $35 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.

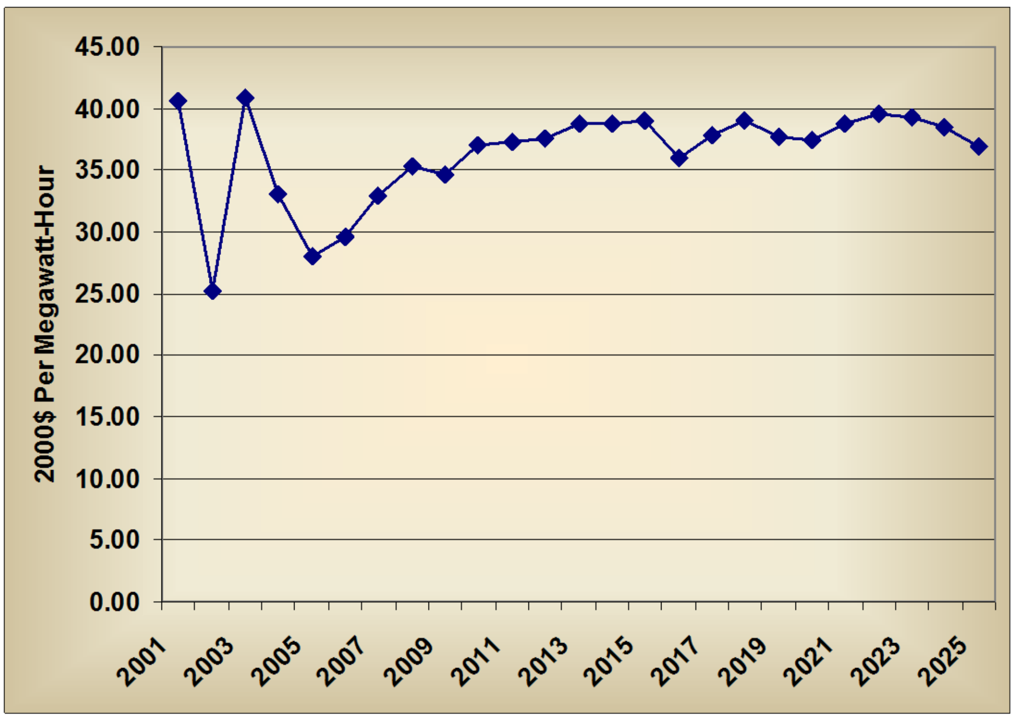


Figure A-12: Draft Medium Case Wholesale Price Forecasts for Mid-Columbia Electricity

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]

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.

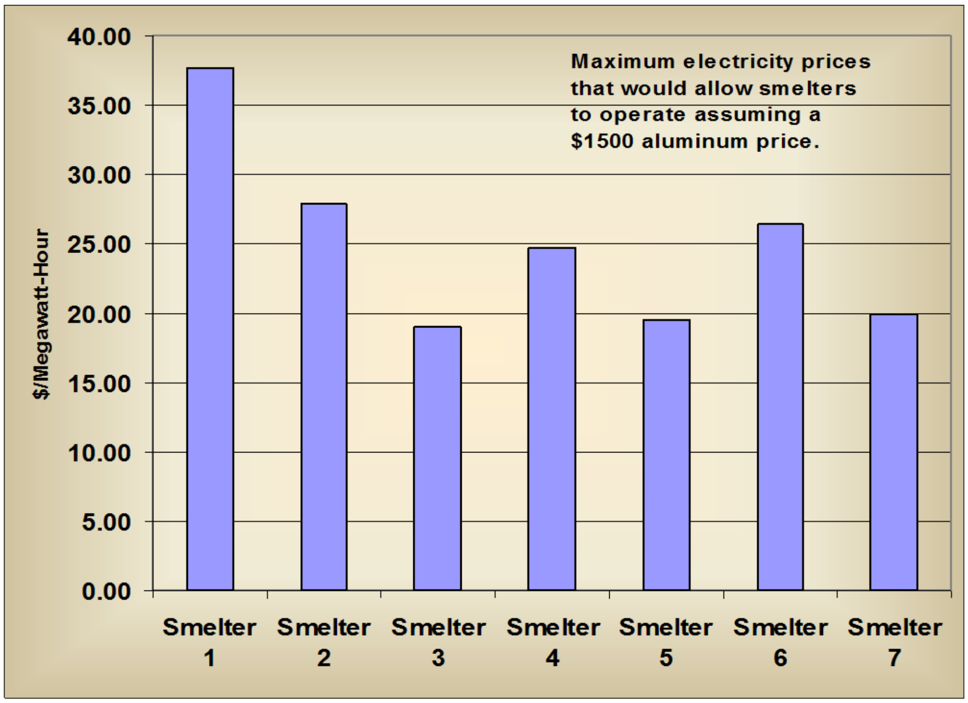


Figure A-13: Affordable Electricity Price Limits of PNW Aluminum Smelters At $1,500 Per Ton Aluminum Prices

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

[5] "Forecasting Electricity Demand of the Region's Aluminum Plants." Northwest Power Planning Council document 2002-20. December, 2002.
[6] "Tonne" refers to a metric ton, which contains 2,240 pounds.

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 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.

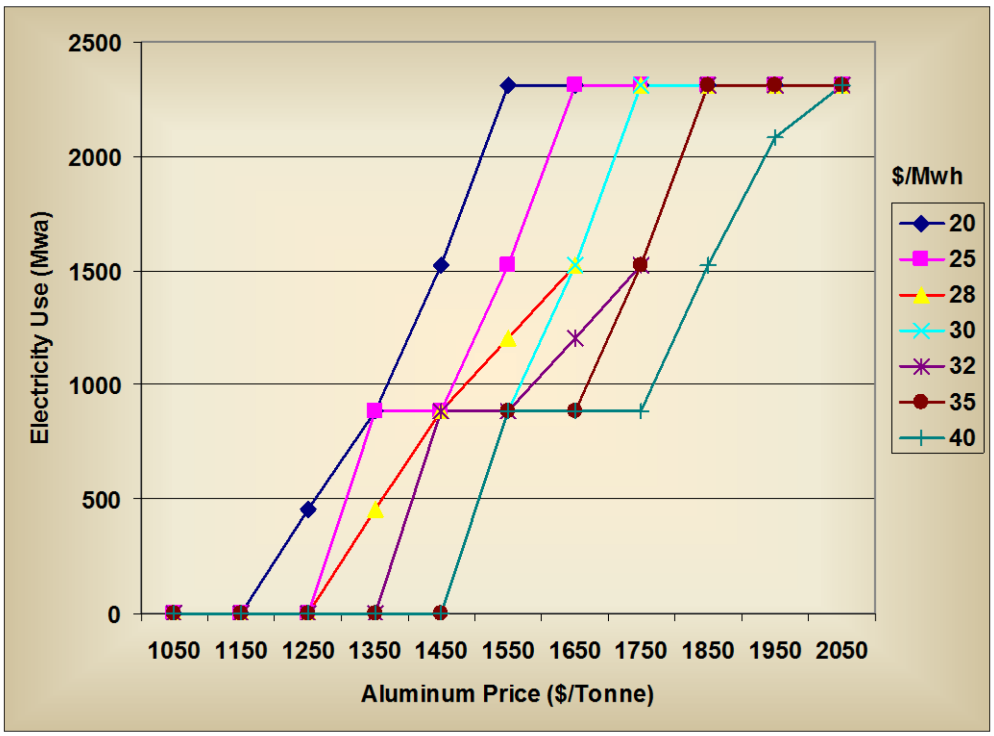


Figure A-14: Spectrum of Potential Aluminum Smelter Electricity Demands

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.

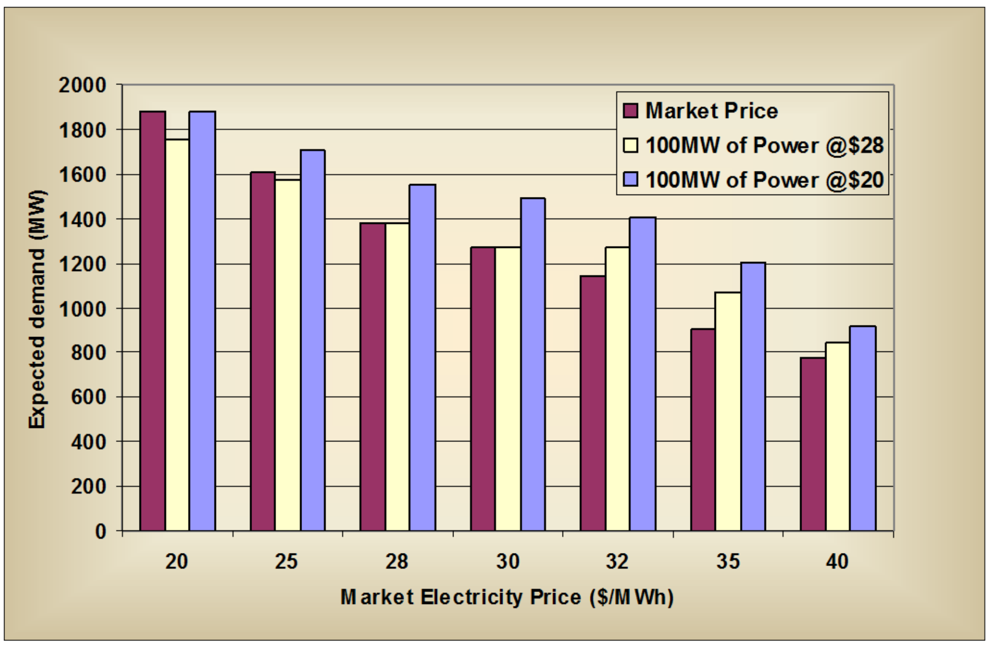


Figure A-15: Expected Aluminum Plant Electricity Demand (Effect of Special Electricity Supplies)

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.

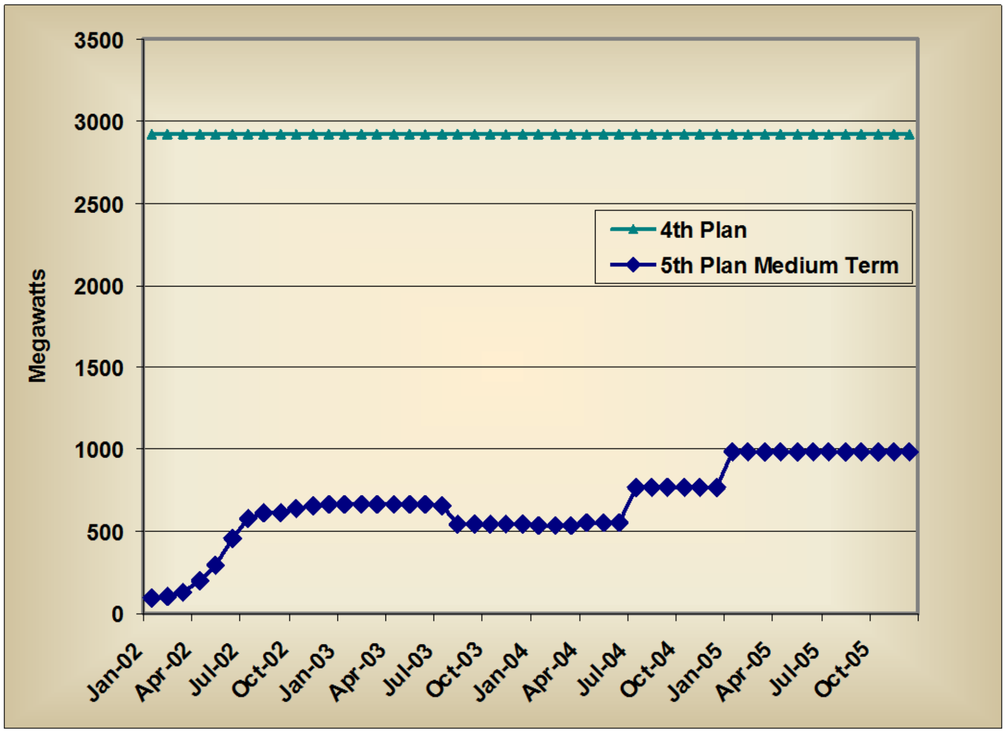


Figure A-16: Medium Case Assumptions for Aluminum Demand Recovery to 2005 (Comparison to 4th Plan Assumptions)

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.

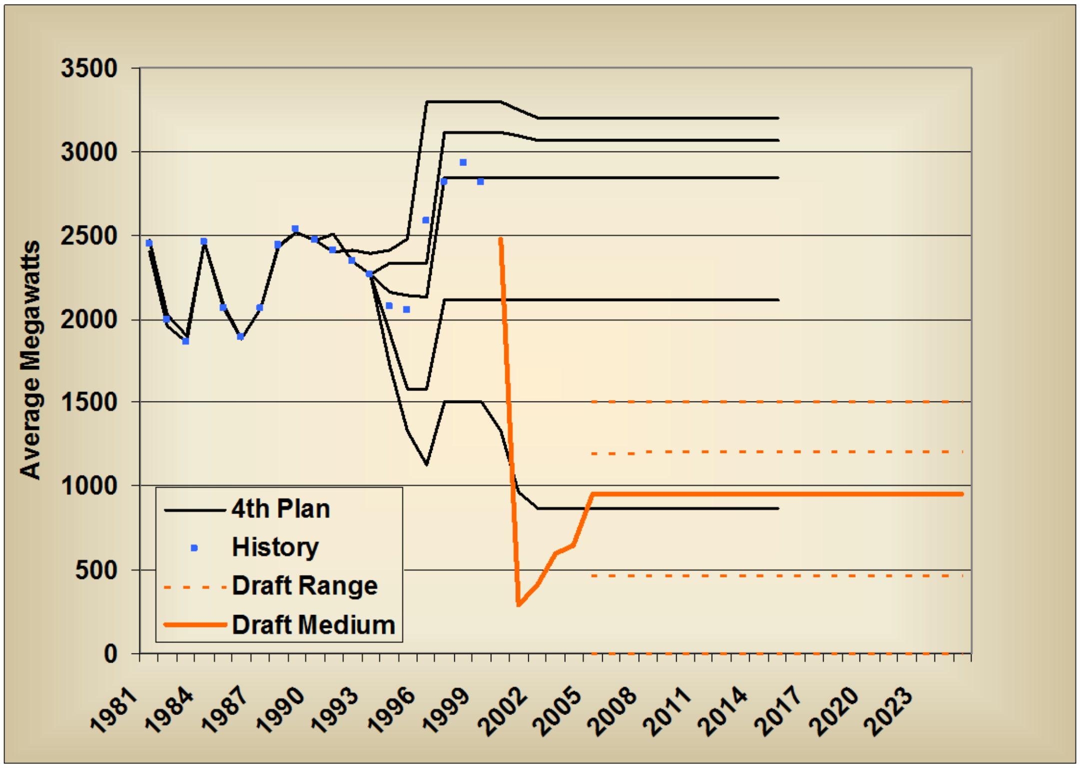


Figure A-17: Demand Assumptions for DSI Industries Compared to Fourth Plan Assumptions

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.

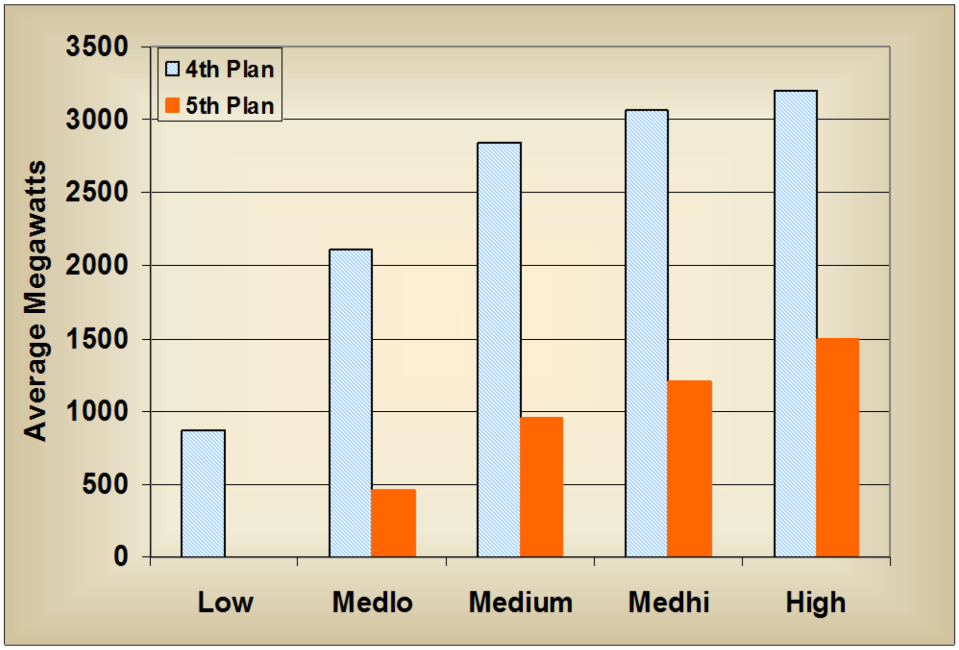


Figure A-18: Aluminum Electricity Demand Assumptions for 2005-2025 Compared to the Council's Fourth Power Plan

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 70 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 25 average megawatts in the later years. This compares to the medium discrete assumption of 958 average megawatts.

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

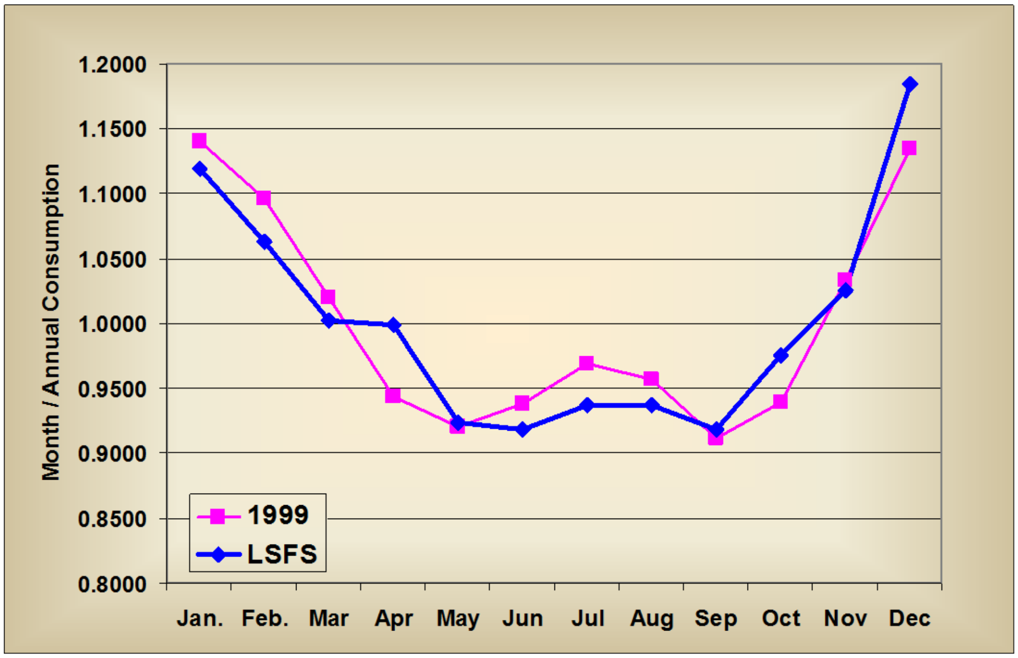


Figure A-19: Monthly Patterns of Non-DSI Electricity Use

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.

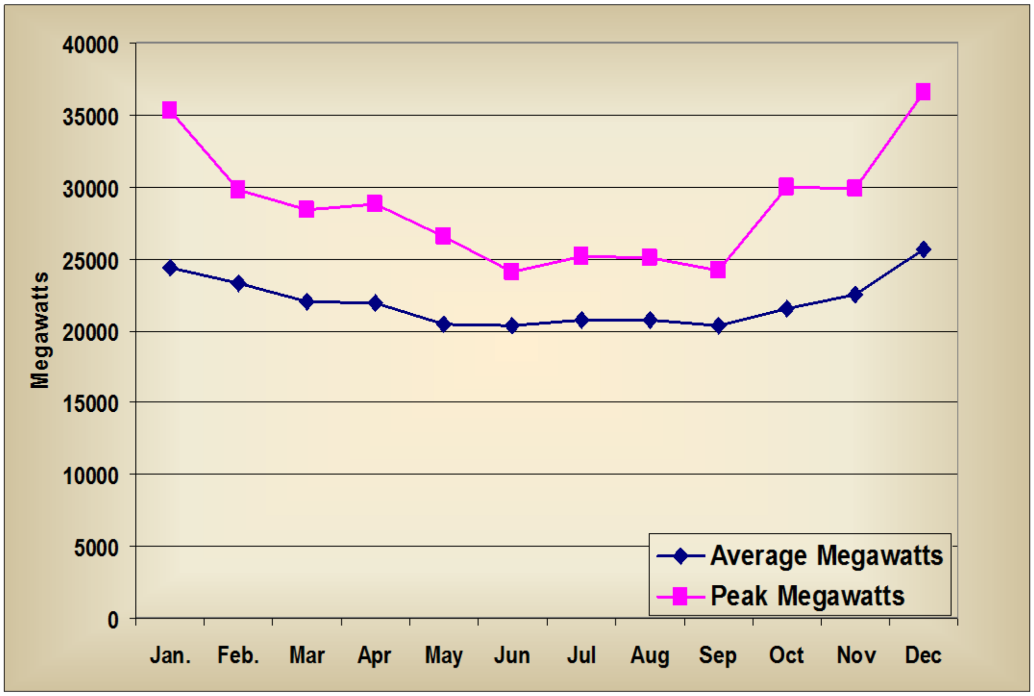


Figure A-20: Hourly Peak Demand Compared to Average Monthly Demand

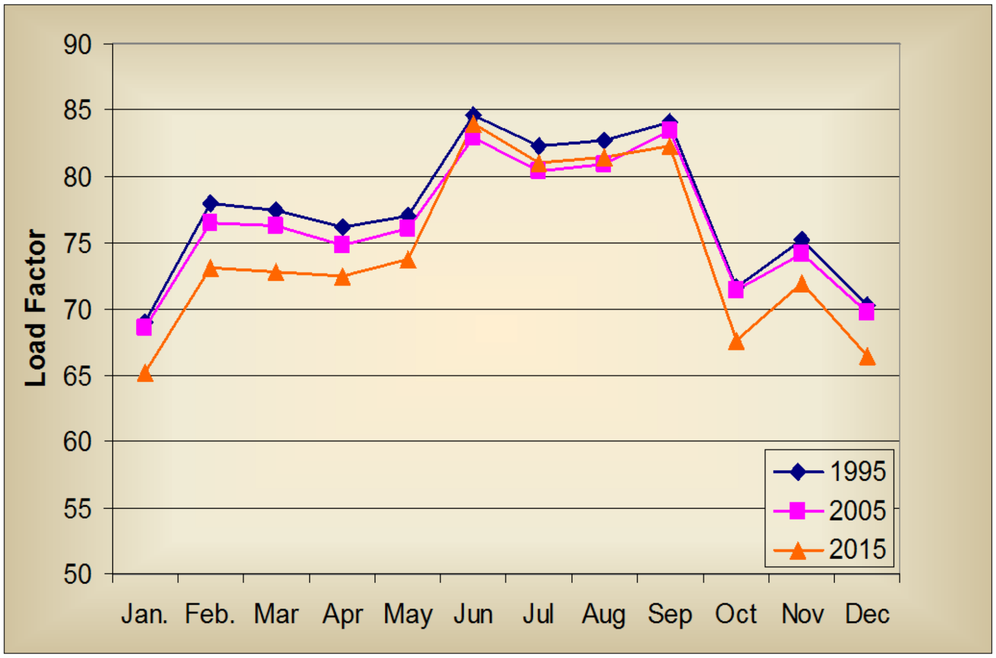


Figure A-21: Forecast of Electricity Demand Load Factors

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.

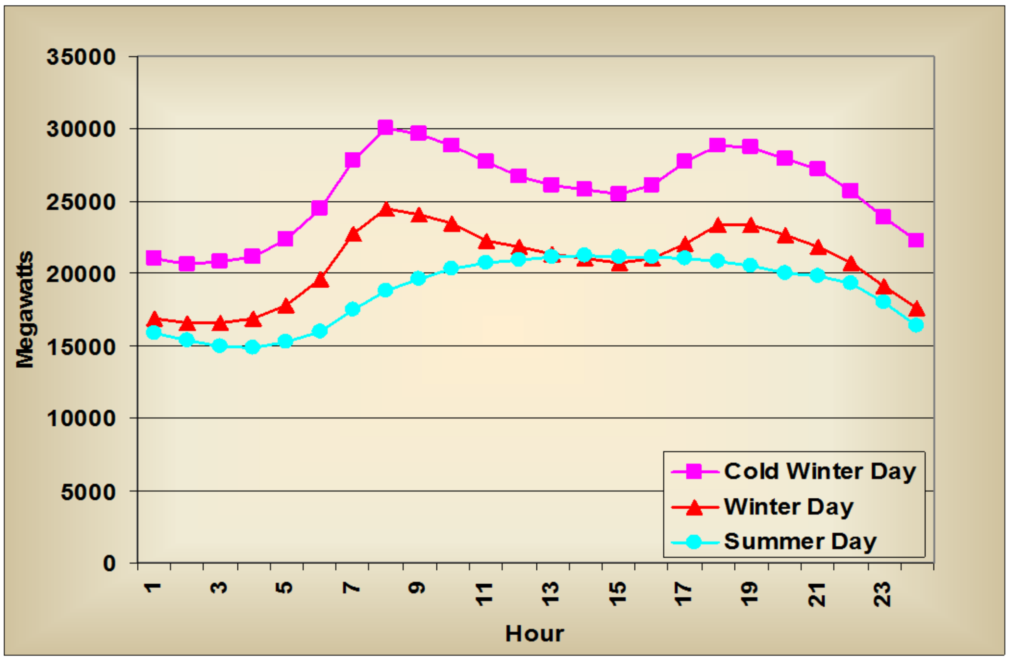


Figure A-22: Illustrative Hourly Demand Patterns in a Day

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.

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.

For this draft forecast, 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

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

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-23 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.

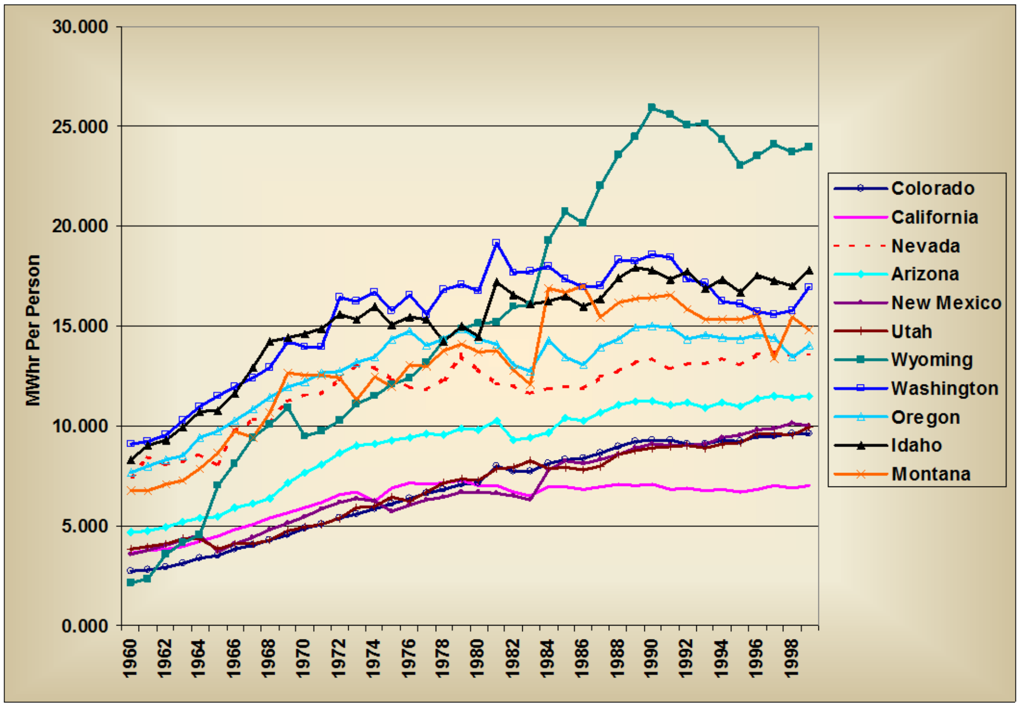


Figure A-23: State Electricity Use Per Capita: 1960 to 1999

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

[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

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 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

	Revised Forecast				
Year	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	Low	Medlo	Medium	Medhi	High
	Revised Forecast				
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%

Appendix B. 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.

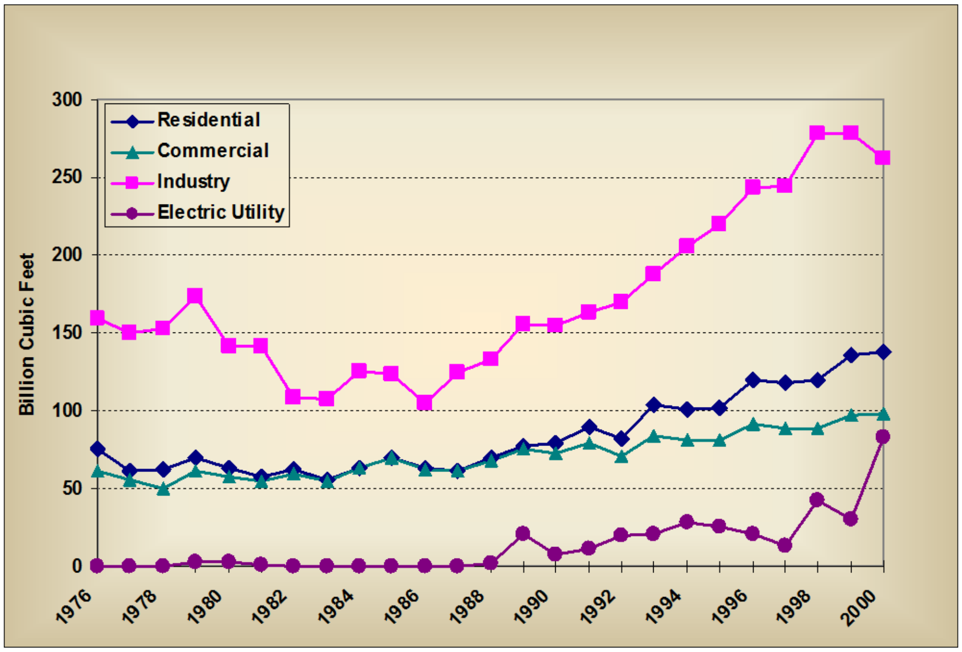
The forecast describes fuel price assumptions for three major sources of fossil fuels: natural gas, oil, and coal.

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 is in the residential sector and about 17 percent is 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 NPPC 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 recently 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 the 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.

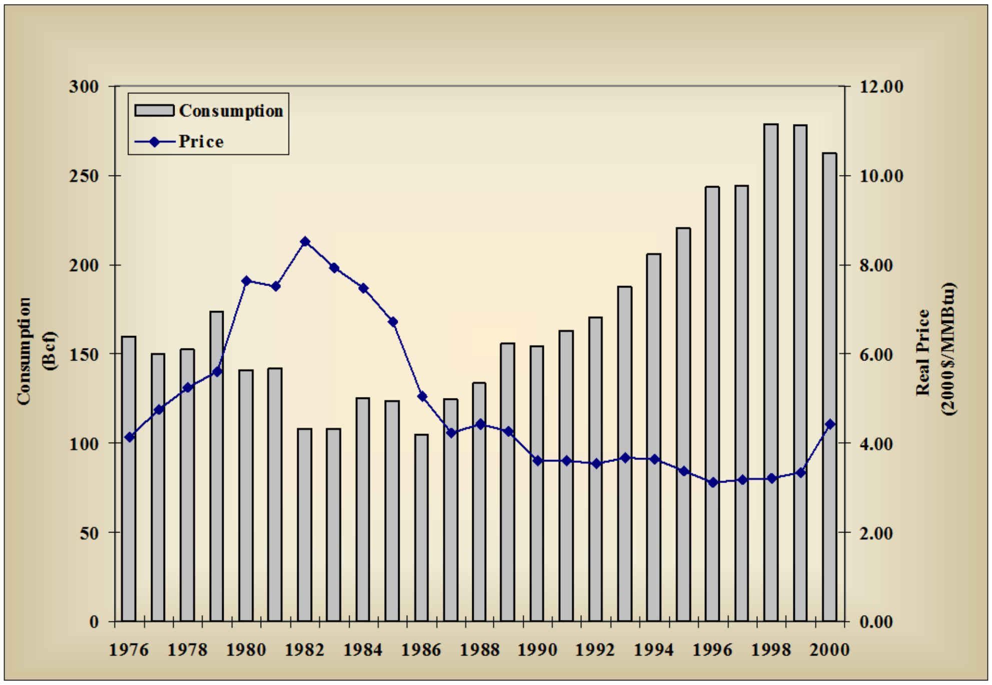


Figure B-2a: Pacific Northwest Industrial Natural Gas Consumption and Price

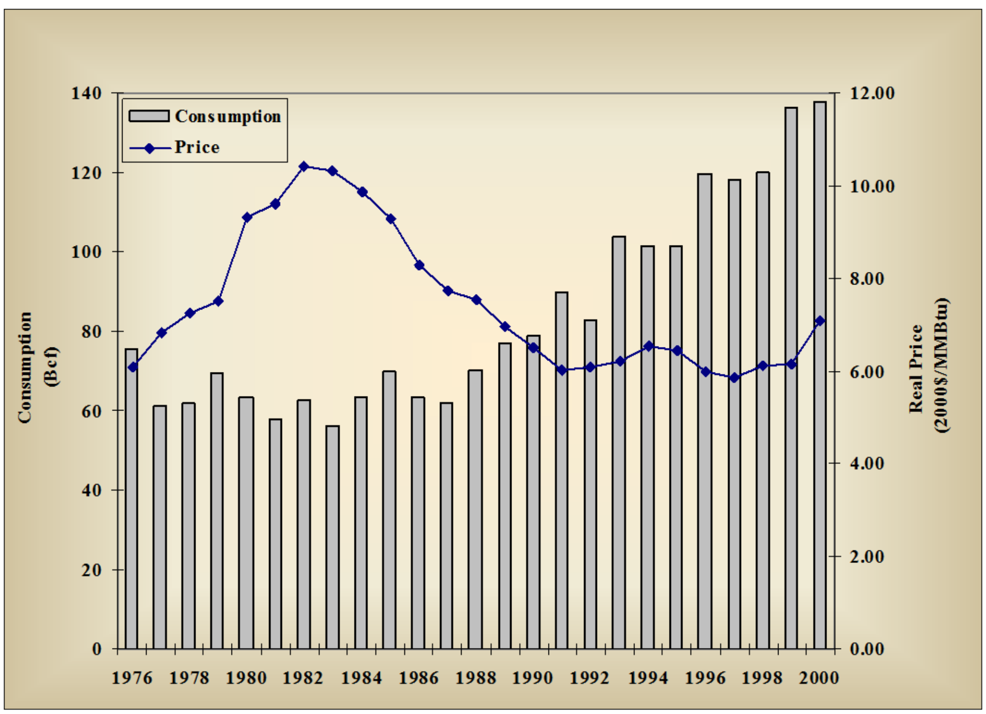


Figure B-2b: Pacific Northwest Residential Natural Gas Consumption and Price

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

[1] 2004 Regional Resource Planning Study, Terasen Gas., July 2004.

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

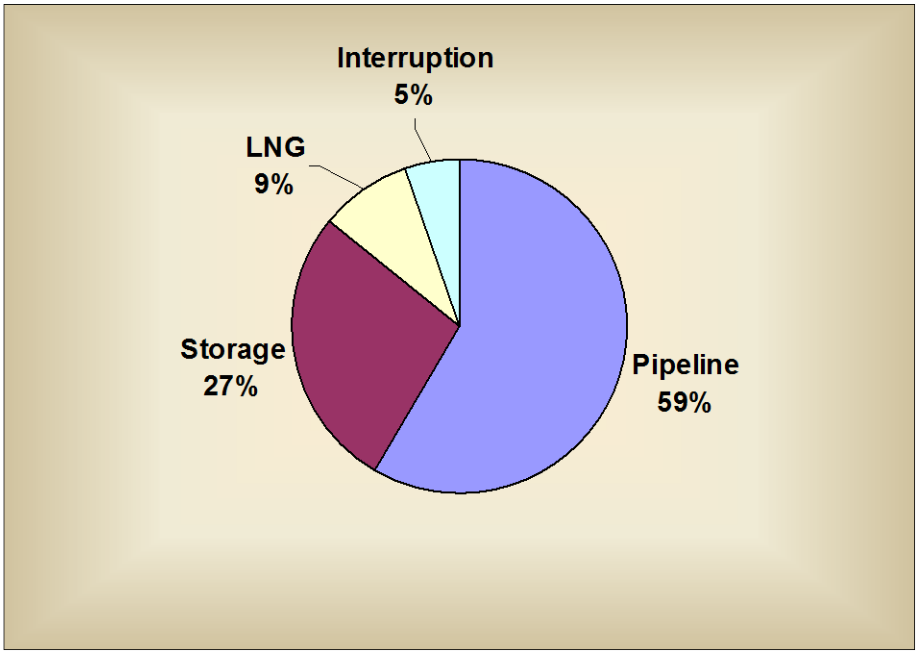


Figure B-3: Contributions to Peak Day Natural Gas Supplies

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 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

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

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 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 the 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 557 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

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[3] Natural Gas Week, Vol. 17, No. 18 (April 30,2001).
[4] U.S. Energy Information Administration, Annual Energy Outlook 2004.

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. How much costs increase depends a great deal on technological developments in the exploration and recovery field.

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 a change in 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

[5] U.S. Geological Survey. "Coal-Bed Methane: Potential and Concerns." USGS Fact Sheet FS-123-00 (October 2000).

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 may expect that the ability to produce 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.

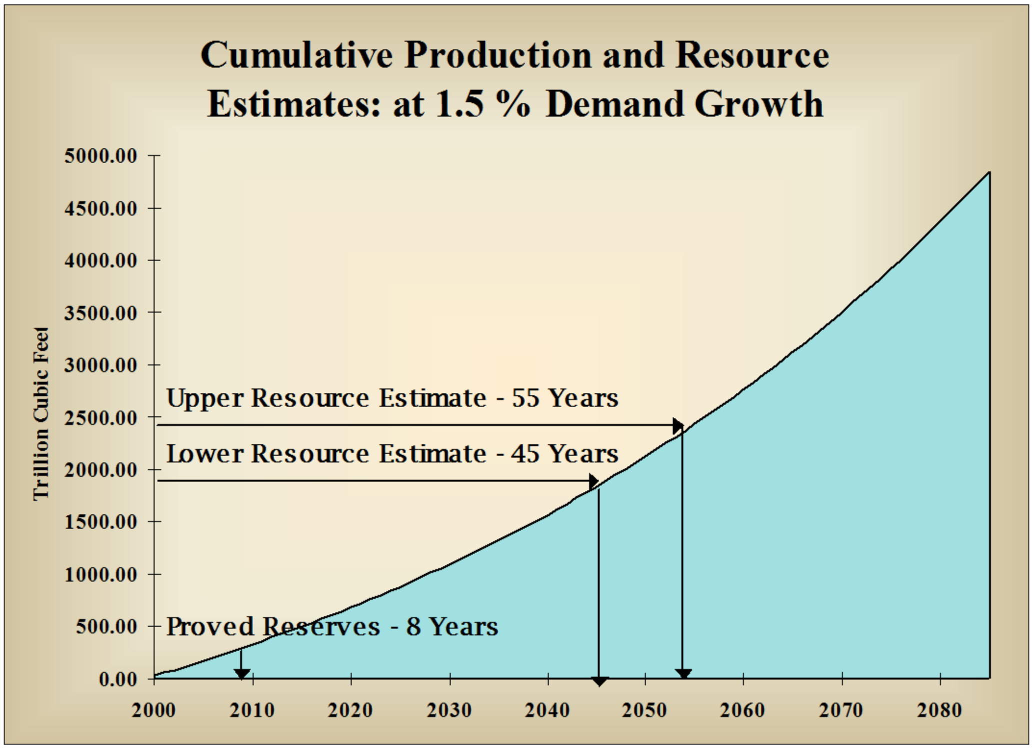


Figure B-4: Cumulative Natural Gas Production and Resources

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 world wide 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.

[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)

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 were imported through Huntington and Kingsgate on the region's border with Canada, with a substantial amount of that gas destined for California markets.

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

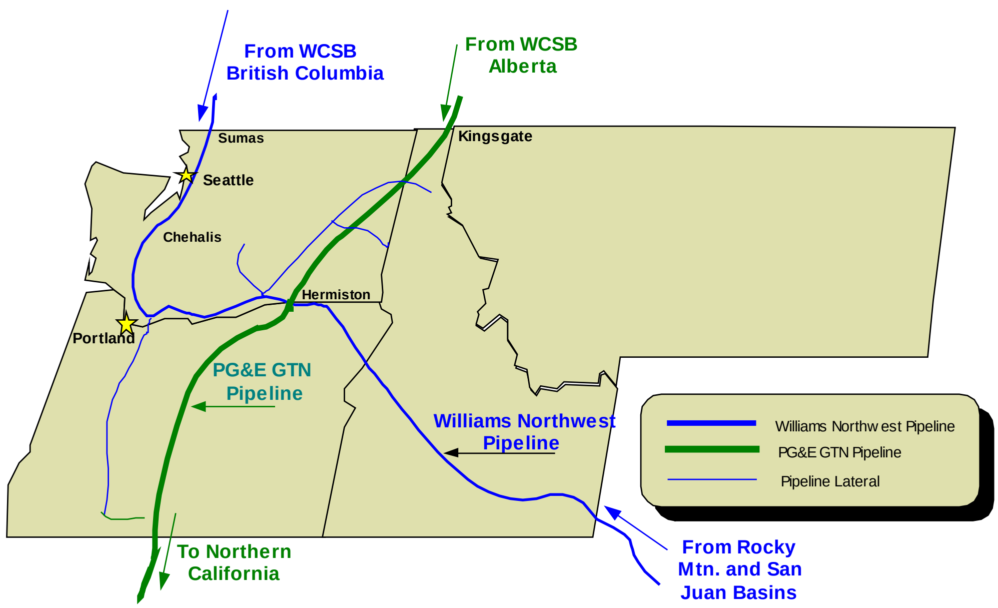


Figure B-5: Natural Gas Pipelines Serving the Pacific Northwest

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 draft 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

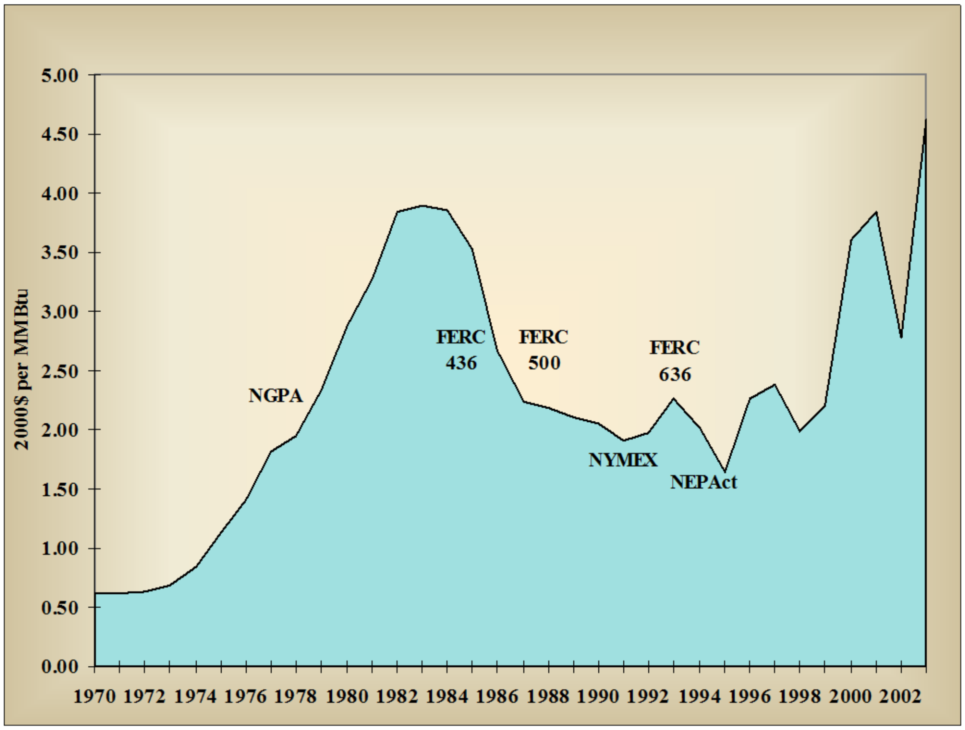


Figure B-6: History U.S. Wellhead Natural Gas Prices

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.

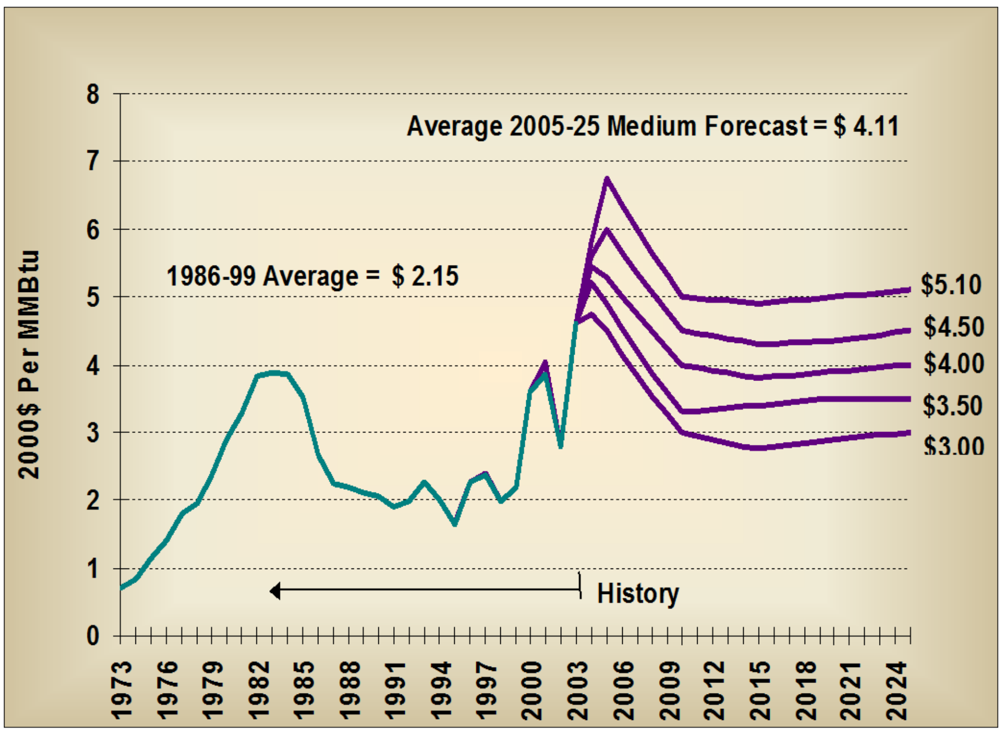
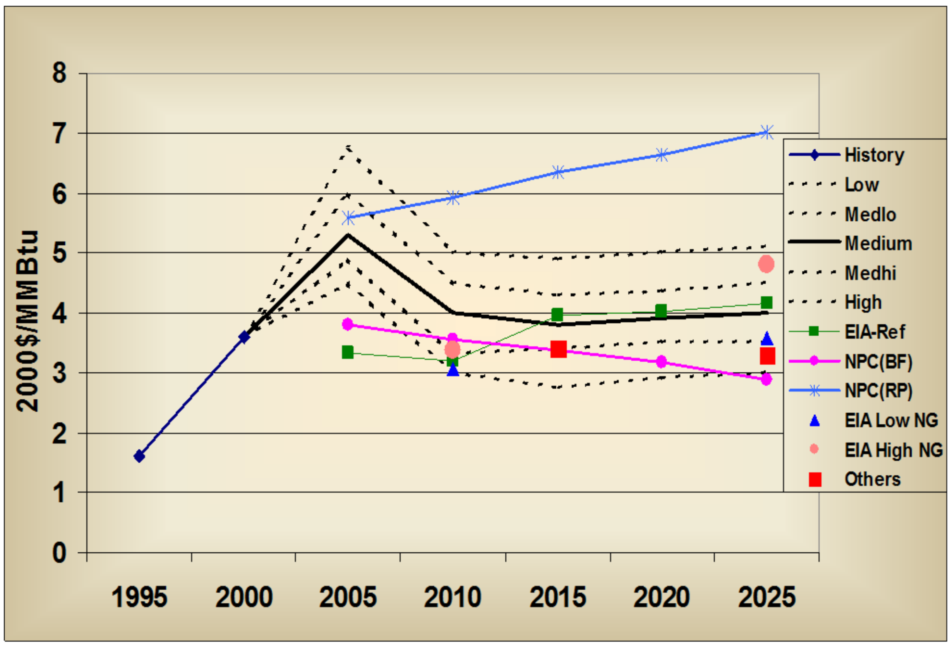


Figure B-7: U.S. Wellhead Prices: History and Forecast

Figure B-8 compares the draft 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

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

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 forecast 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 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 to late 2001. Excluding the most extreme values, the difference averaged $0.12 per million Btu. 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 this revision for the draft 5th 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. During the 1990s Canadian natural gas prices delivered to the Washington border at Sumas averaged $.52 per million Btu less than the national market index at Henry Hub, Louisiana. Prices at the Canadian border at Kingsgate have averaged about $.10 lower than the Washington 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 during the 1990s. 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.

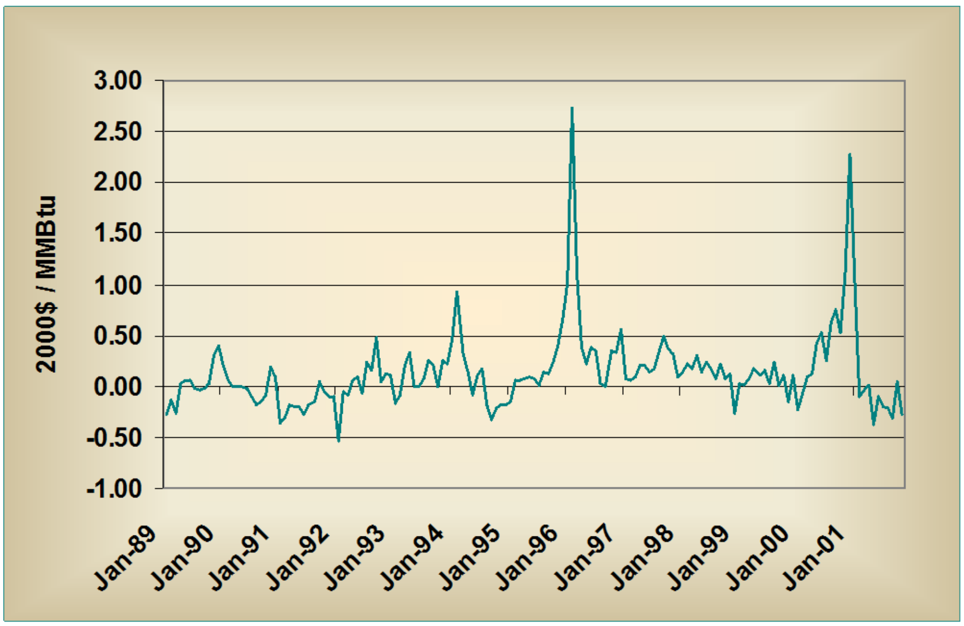


Figure B-9: Difference Between Henry Hub and U.S. Wellhead Natural Gas Prices

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 $.72 per million Btu (2000$) less than Henry Hub prices in recent years. 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

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

British Columbia. However, there was insufficient historical data on Station 2 prices to estimate a relationship.

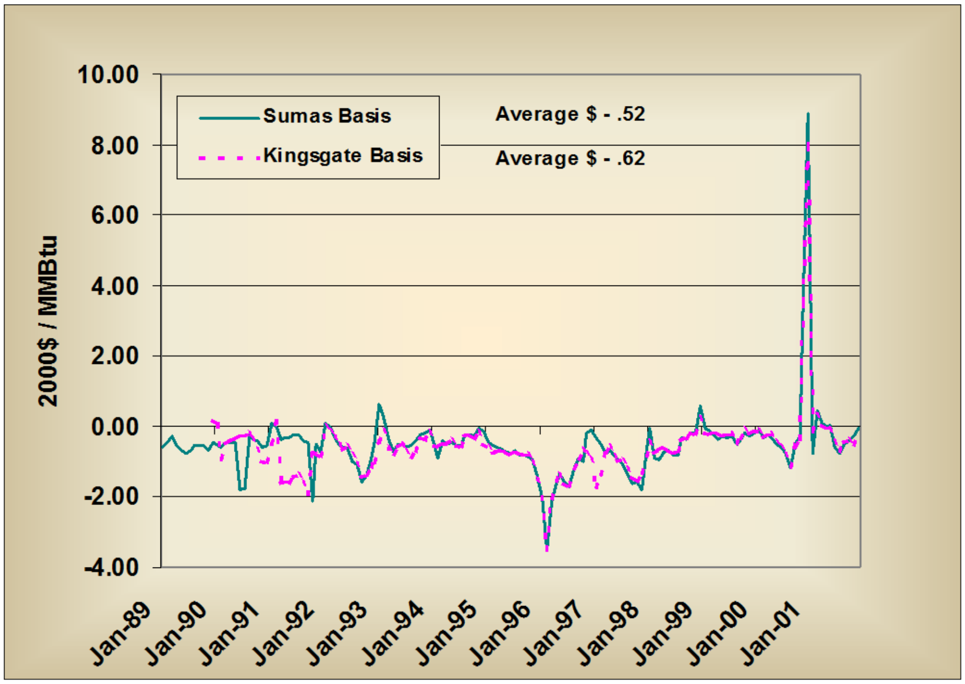


Figure B-10: Canadian Gas Price Differences from Henry Hub

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.

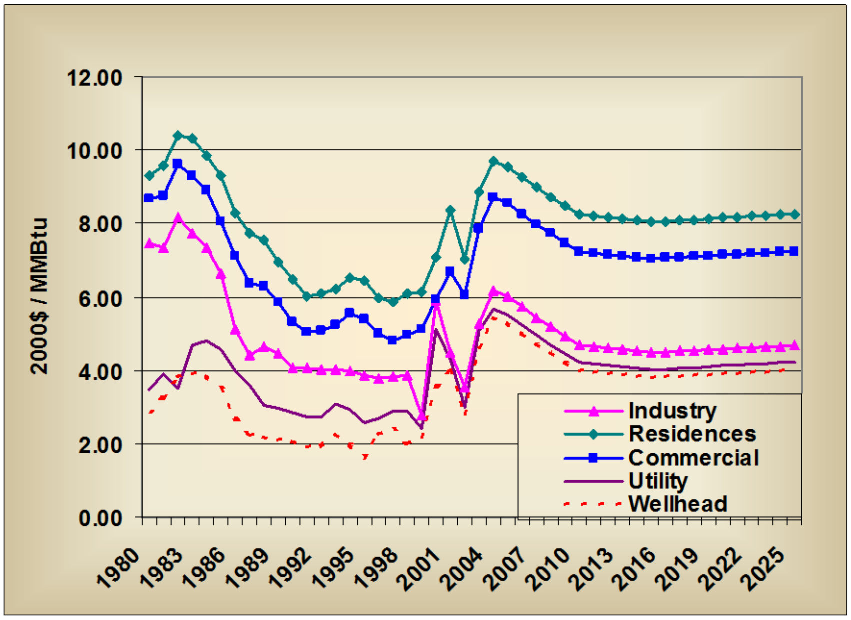


Figure B-11: Retail and Wellhead Prices History and Medium Forecast

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.

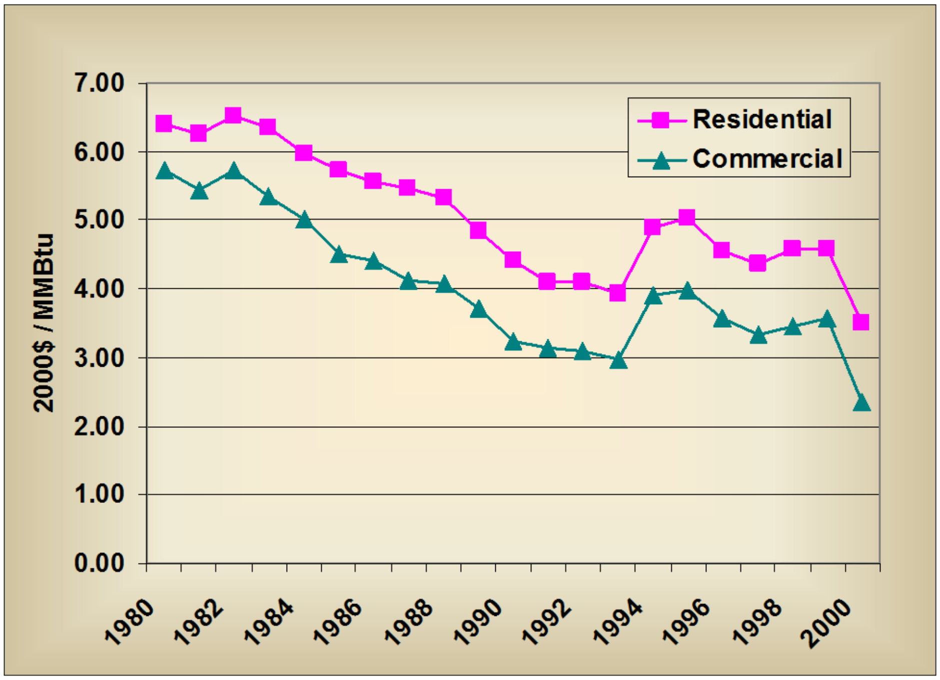


Figure B-12: Historical Difference Between Regional Residential and Commercial Retail Natural Gas Prices and U.S. Wellhead Prices

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 will not be directly affected. Electricity generation costs assume a direct connect to interstate pipelines.

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 adjustments 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 the draft 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.

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-13 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-13.

In general, the price of oil products is determined by the world price of crude oil. Figure B-14 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.

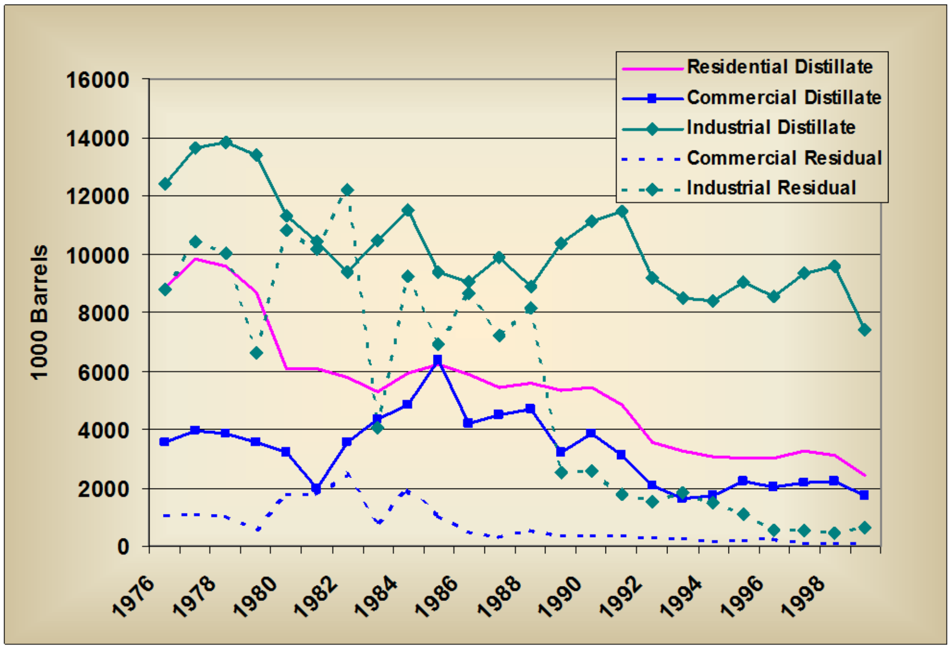


Figure B-13: Historical Oil Consumption in the Pacific Northwest

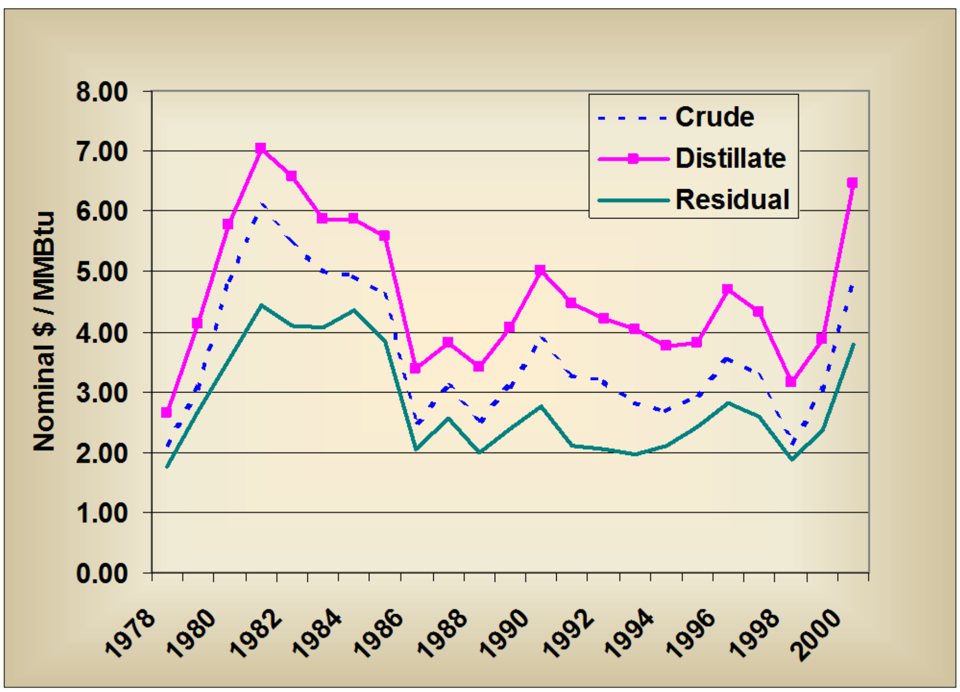


Figure B-14: Comparison of Crude Oil and Refiner Product Prices

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 15a and 15b 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 the 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.

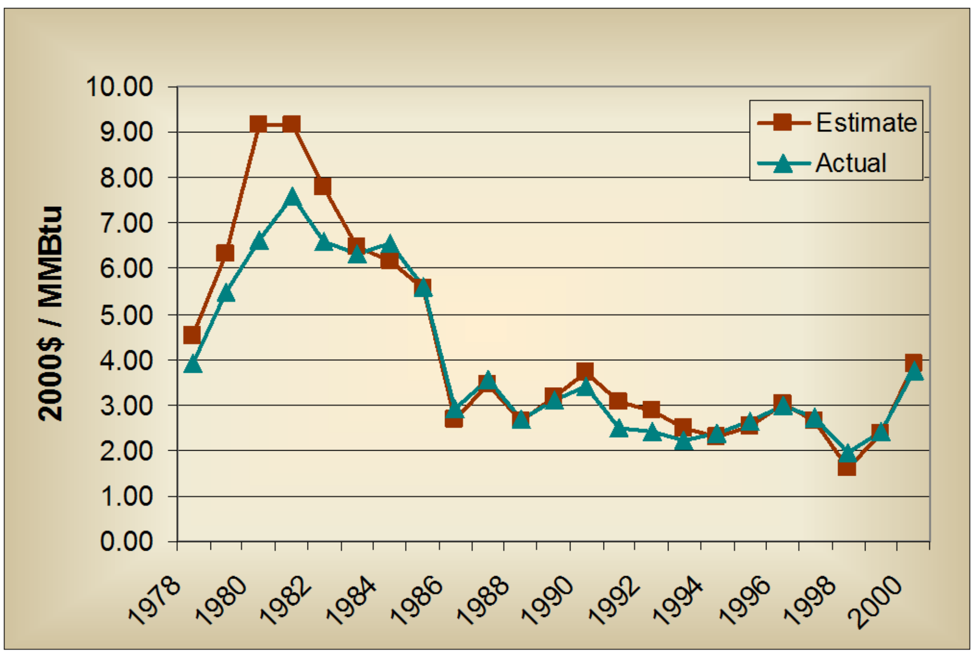


Figure B-15a: Comparison of Forecast and Actual Residual Oil Prices

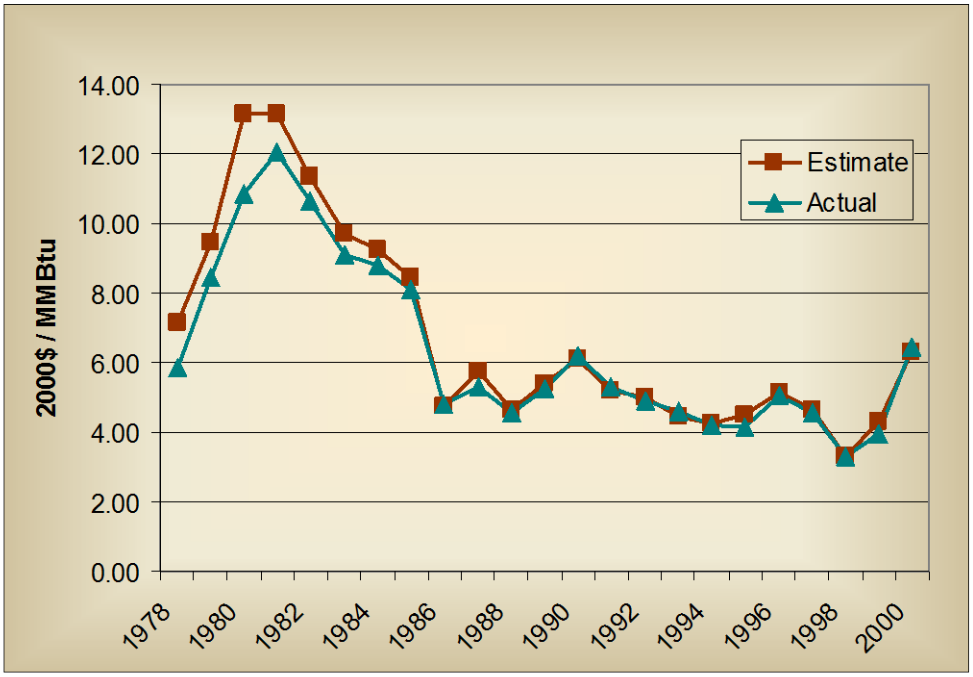


Figure B-15b: Comparison of Forecast and Actual Distillate Oil Prices

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-16 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.

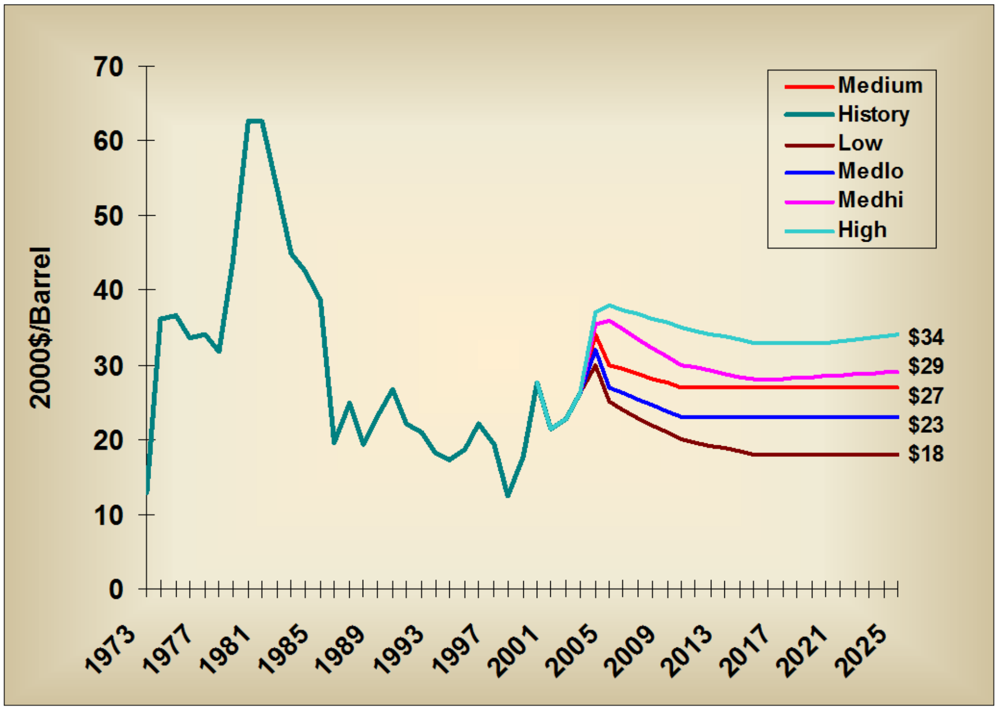


Figure B-16: World Oil Price: History and Forecasts

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-17 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-17 shows EIA's forecast range and the average of 8 other forecasts that EIA compared to their own

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

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.

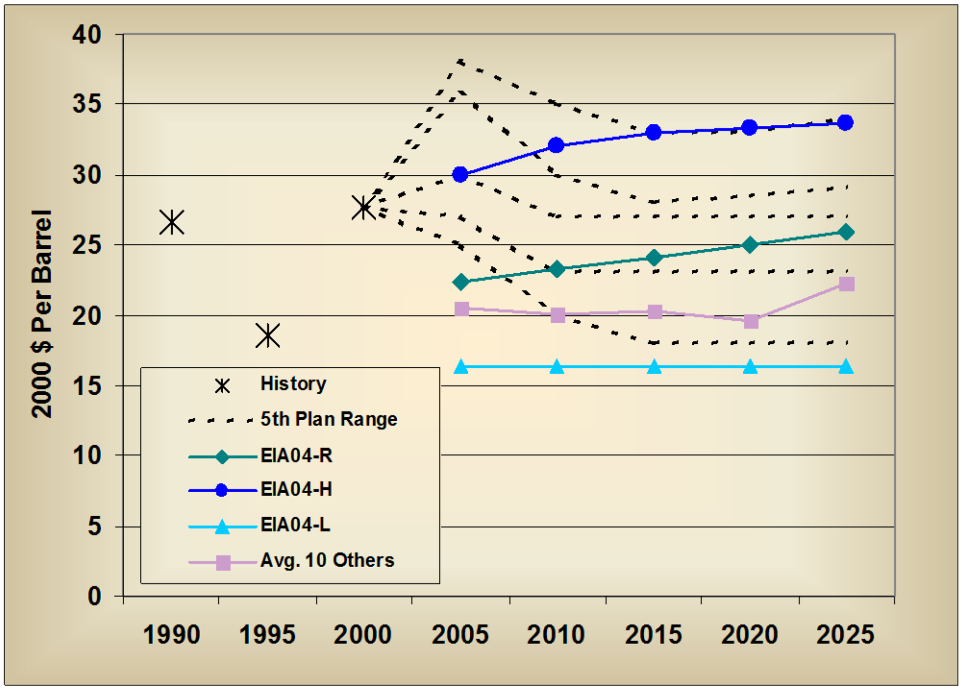


Figure B-17: Comparison to Other World Oil Price Forecasts

Consumer Prices

Using the methods described earlier, world oil price forecasts are converted to refiner prices of residual oil and distillate oil. Figure B-18 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.

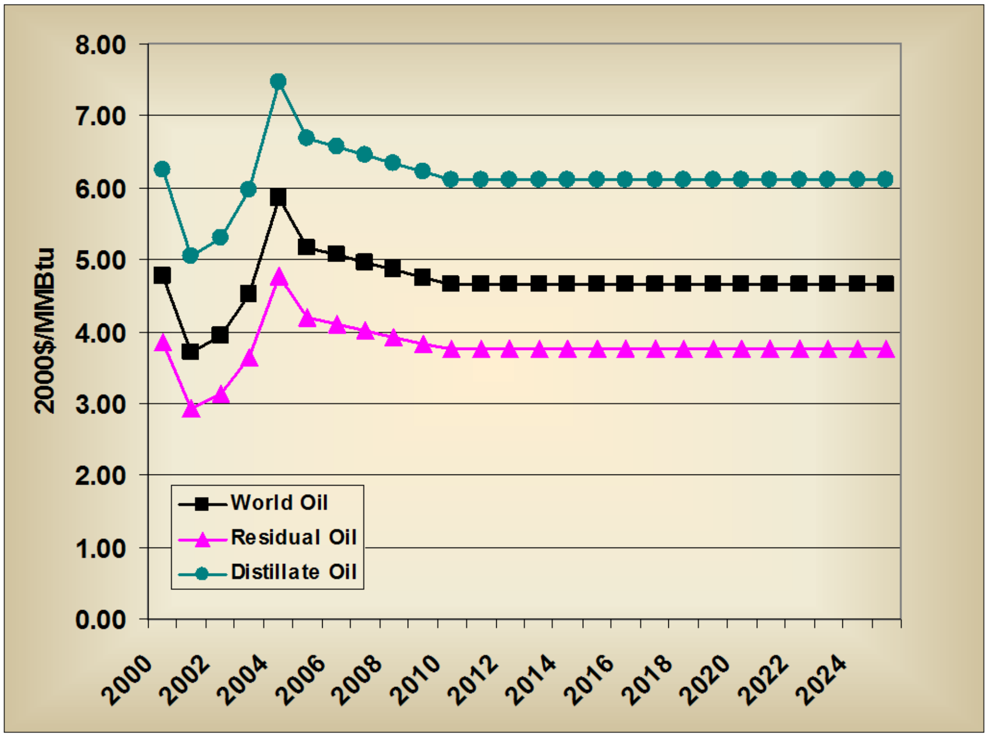


Figure B-18: Refiner Prices of Residual and Distillate Oil Compared to World Crude Oil Price (Medium Case)

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

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 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 coal mines. 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-19 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.

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

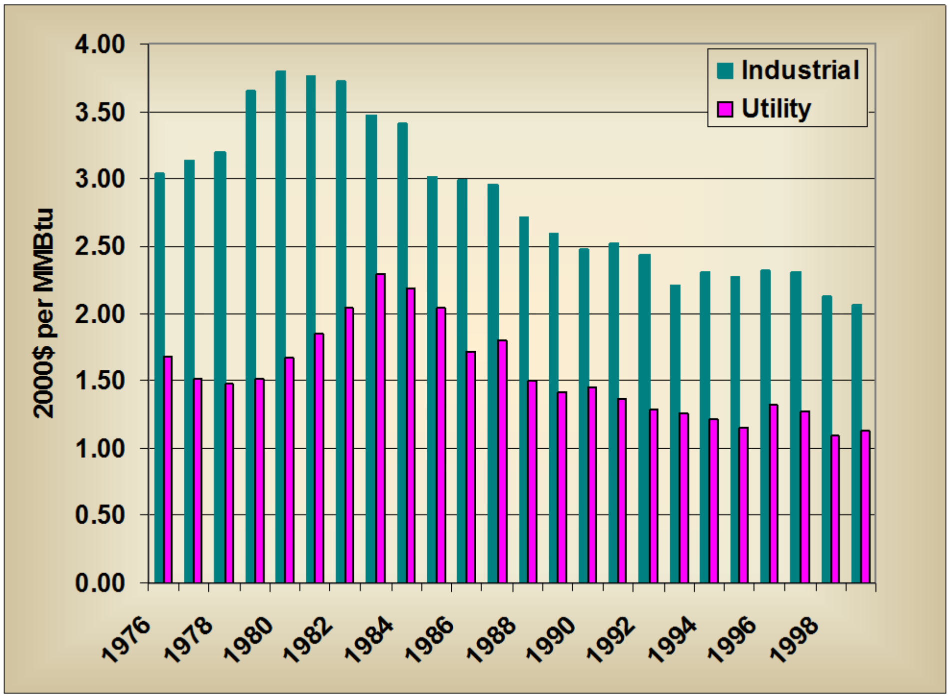


Figure B-19: Pacific Northwest Industrial and Utility Historical Coal Price Trends

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. 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.

<u>Complex refinery</u>

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

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

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

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

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

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

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

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

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

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

The simple refinery model thus gives the estimates of residual oil (heavy) and distillate oil (light) prices based on the assumed crude oil prices. Distillate wholesale prices equals 112 percent of the crude oil price plus $5.38 (2000$) 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										
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	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										
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	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										
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	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		Regional Industrial Price	Selected State Electricity Generation Coal Prices					
Year	Western Minemouth 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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Appendix C. Wholesale Electricity Price Forecast

This paper describes the wholesale electricity price forecast for use in the draft Fifth Northwest Power Plan. The price 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 over the planning period 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. An ancillary product of the price forecast is a forecast of the future generating resource mix. The forecast resource mix is used in GENESYS, the Council's system reliability assessment model, for forecasting the fuel consumption and environmental effects of future power system configurations and as the base resource portfolio for the Council's portfolio risk analyses.

The next section describes the base case forecast results and summarizes the underlying assumptions. The subsequent section describes the modeling approach. The third section describes underlying assumptions in greater detail and the results of sensitivity tests conducted on certain assumptions. The fourth section describes the results of two alternative scenarios. The final section summarizes the definitions and results of the base case, alternative scenarios and sensitivity cases.

BASE CASE FORECAST

The "Current Trends" (base case) forecast is based on medium load and fuel price forecasts, average hydropower conditions, and extrapolation of current trends with respect to technological developments, energy-related policies and other factors affecting the market price of electricity (Table C-1). These assumptions and the resulting forecast resource mix are not necessarily "the right things to do," nor will necessarily reflect the Council's portfolio recommendations in the Fifth Power Plan. On completion of the portfolio risk studies and the development of recommendations for the plan, one or more additional price forecasts will be developed to illustrate the effect of the Council's recommendations on future power prices.

Table C-1: Summary of assumptions underlying the Current Trends forecast

Hydropower	Average hydropower conditions
Fuel prices	5th Plan revised draft forecast, Medium case (April 2003)
Loads	5th Plan revised draft sales forecast, Medium case (April 2003)
Existing and planned resources	Resources in service Q1 2003 Additions under construction Q1 2003 Retirements scheduled Q1 2003 75 percent of state renewable portfolio standard and & system benefit charge target acquisitions 50 percent of forecast Demand Response potential by 2025.
New resource options (market-driven development)	Gas-fired combined-cycle Wind Coal steam-electric Gas-fired simple-cycle Central-station solar photovoltaics Suspended projects > 25 percent complete
Inter-regional transmission	2003 WECC path ratings Scheduled upgrades Q1 2003
Climate change policy	Oregon CO_2 standard phased in Westwide, escalating in cost
Renewable resource incentives	Continued federal production tax credit Green tag revenue, escalating in value
Intermittent resource penetration limit	20 - 25 percent of installed capacity by load-resource area

The forecast levelized cost of power at the Mid-Columbia trading hub for the period 2005 through 2025 is $36.10 per megawatt-hour (2000$). In Figure C-1, the current forecast is compared to two earlier forecasts - the preliminary draft forecast released in September 2002 (levelized value of $37.50 per megawatt-hour) and the forecast prepared in conjunction with the Council's Adequacy and Reliability Study of February 2000 (levelized value of $29.80 per megawatt-hour).

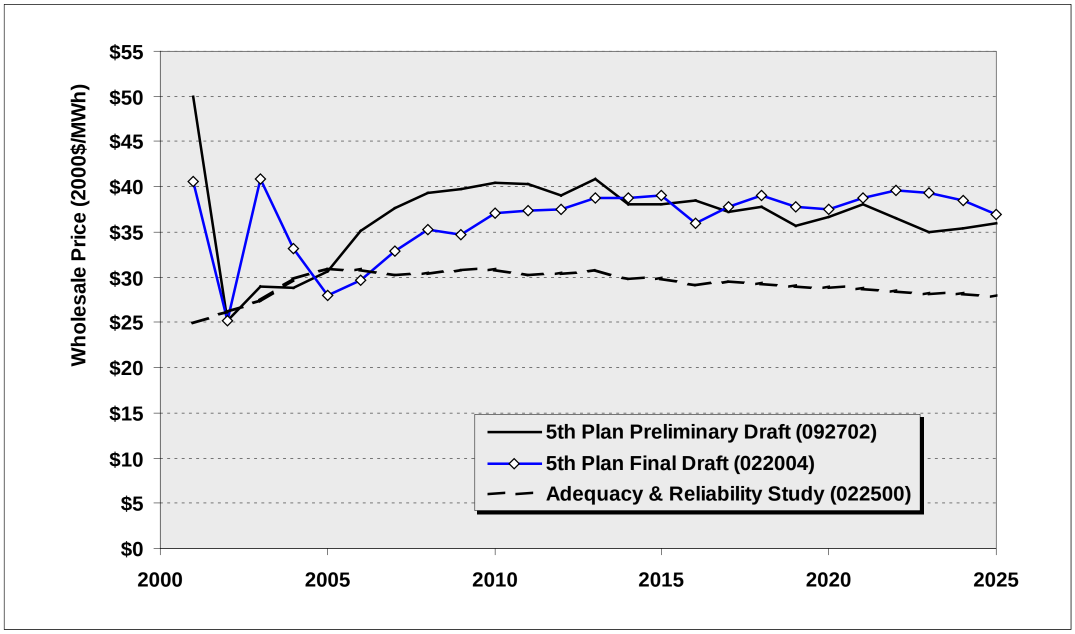

Figure C-1: Current and Earlier Base Case Forecasts of Average Annual Wholesale Power Prices at the Mid-Columbia Trading Hub

The initial years of the forecast conform to historical price behavior. Prices are shown declining from 2000-2001 highs, then rising in 2002 as a result of gas prices increases. Forecast prices decline from 2003 highs as gas prices ease, and rise through 2010 as loads recover and the current capacity surplus is exhausted. Average prices are forecast to be stable through the remainder of the planning period as slowly increasing natural gas prices are offset by improved combined-cycle efficiency and increasingly more cost-effective windpower. Not forecast beyond 2003 are likely episodes of price excursions resulting from volatility in the gas market or poor hydro conditions.

The annual average prices of Figure C-1 conceal significant seasonal price variation that develops as the current capacity surplus declines. This seasonal variation appears in the plot of monthly average prices in Figure C-2. A strong August price peak, driven by summer afternoon air conditioning loads in the Southwest, is fully developed by 2010. As the capacity surplus further declines, the price peak broadens to include July. Note the coincidence of Northwestern seasonal peak prices and Southwestern summer load peaks. Spot market prices in the Northwest will follow those in the Southwest as long as capacity to transmit electricity south is available on the interties. The strong seasonal price peak adds value to summer-peaking resources such as irrigation efficiency improvements.

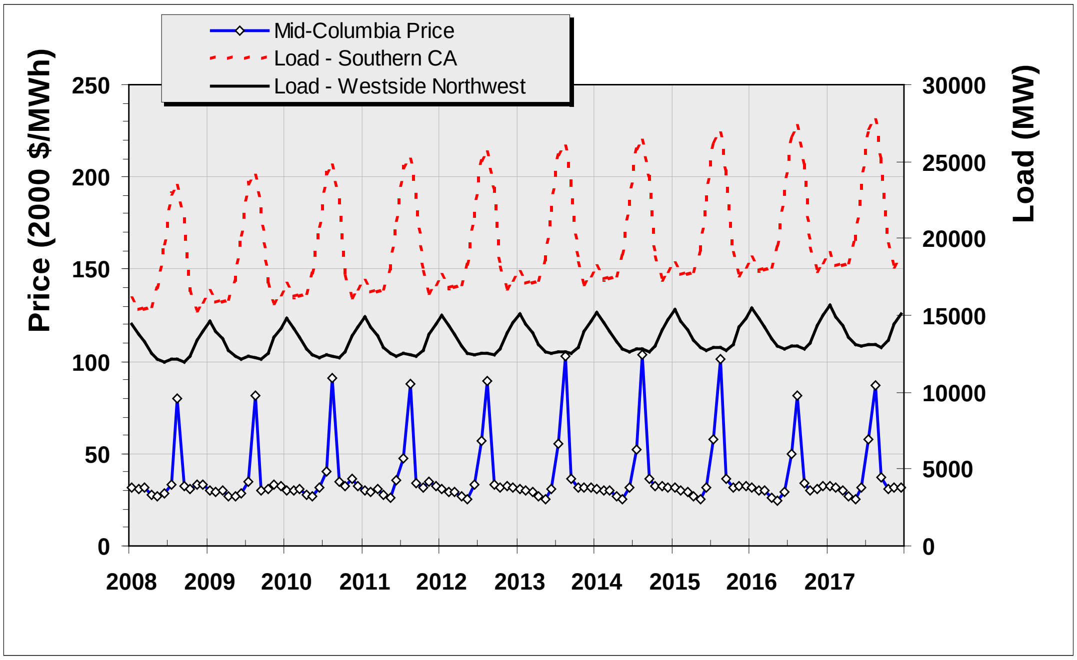

Figure C-2: Forecast Monthly Wholesale Mid-Columbia Electricity Prices Compared to Northwest and Southwest Loads

Forecast daily variation in price 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 forecast for the first week of August 2004.

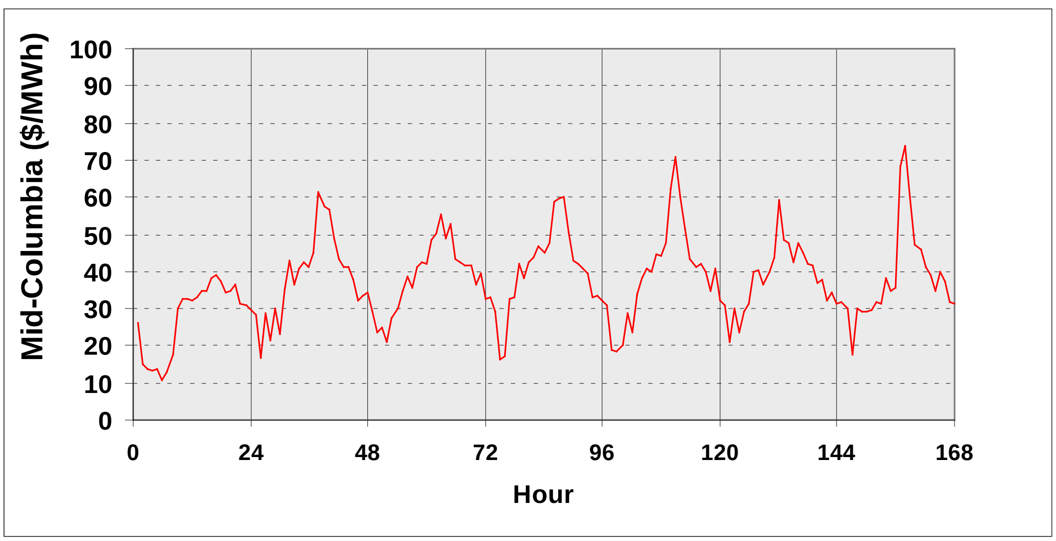

Figure C-3: Illustrative Hourly Prices (August 1-7, 2004)

A table of forecast annual average prices for the Mid-Columbia trading hub and other Northwest pricing points is provided in Appendix C1. Monthly and hourly price series are available from the Council on request.

The forecast Western Electricity Coordinating Council (WECC) resource mix associated with the Current Trends forecast is shown in Figure C-4. Factors at work in the 2005-2025 period include load growth, slowly increasing natural gas prices, technology improvements resulting in reduction of new resource costs, continued renewable resource incentives and increasing cost of offsetting a portion of carbon dioxide (CO_2) production. Resource changes over time include the retirement of most existing gas-fired steam-electric capacity and addition of approximately 6,000 megawatts of renewable resources as the result of state renewable portfolio standards and system benefit charges. Market-driven resource additions include 37,000 megawatts of combined-cycle plant, 13,000 megawatts of coal capacity, 33,000 megawatts of wind capacity and 3,500 megawatts of gas peaking capacity. About 14,000 megawatts of solar photovoltaics capacity are added near the end of the planning period. The 2025 capacity mix includes 30 percent natural gas, 23 percent hydropower, 18 percent coal and 20 percent wind and solar. The 2025 energy mix is 30 percent natural gas, 20 percent hydropower, 29 percent coal and 12 percent 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.

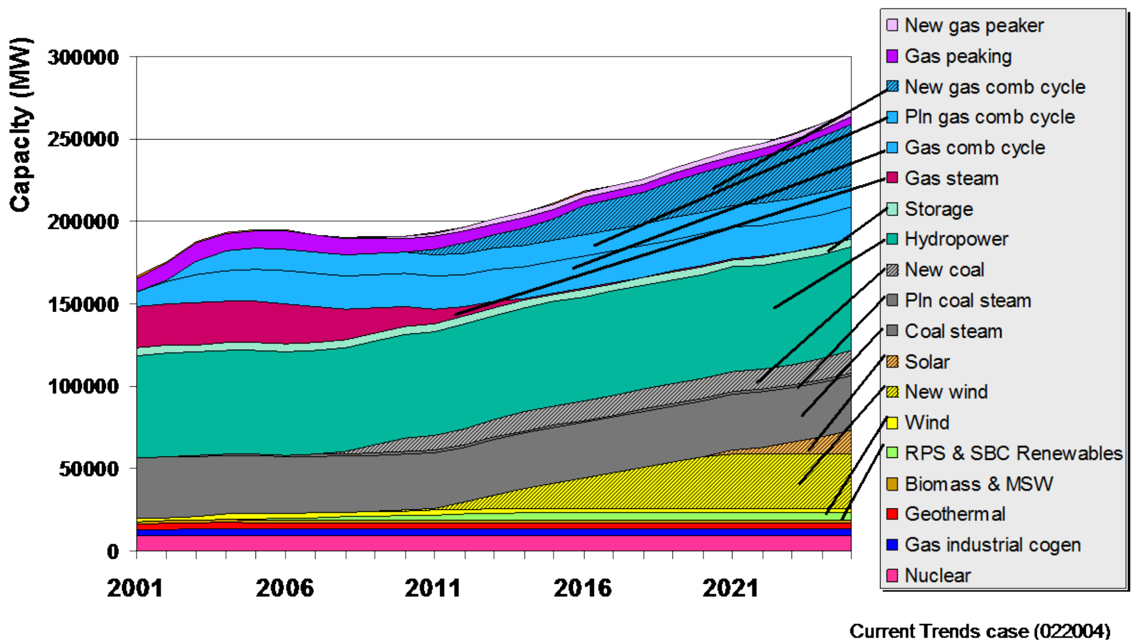

Figure C-4: Base Case Forecast WECC Resource Mix

The Northwest resource mix is shown in Figure C-5. The hydropower component (which does not change) has been omitted from Figure C-5 to emphasize changes among other resource types. About 1,600 megawatts of coal, 7,000 megawatts of wind, 1,200 megawatts of renewables funded by state system benefit charges (modeled as wind) and 1,800 megawatts of new combined-cycle capacity is added through the forecast period. Much of the existing gas peaking capacity is retired. The regional capacity mix in 2025 includes 61 percent hydropower, 15 percent wind, 10 percent coal and 10 percent natural gas. On an average energy basis the mix includes 56 percent hydropower, 17 percent coal, 13 percent natural gas and 9 percent wind.

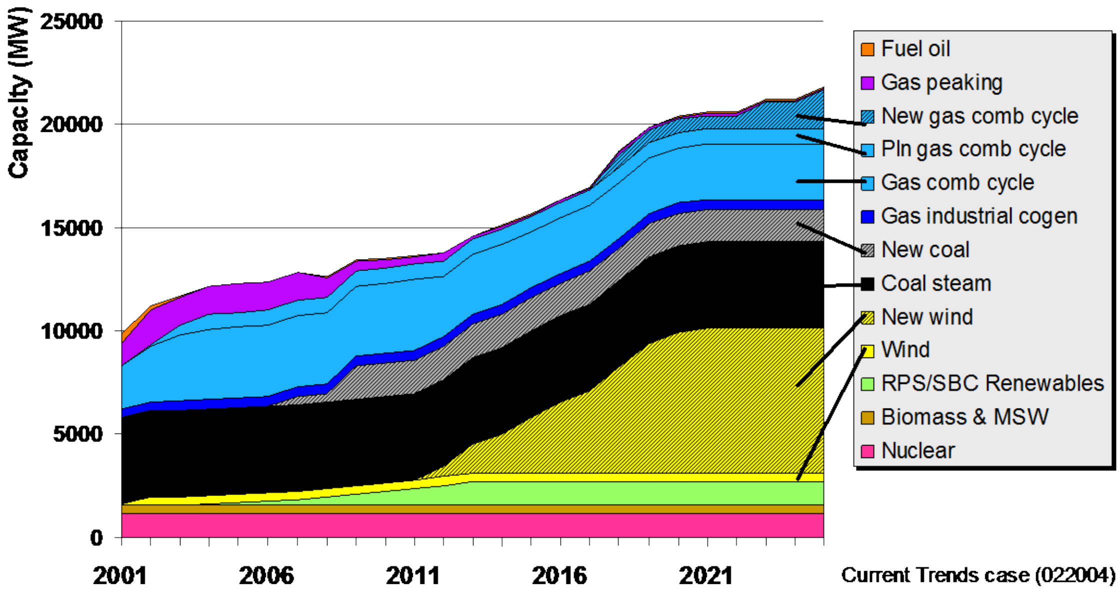

Figure C-5: Base Case Forecast of Pacific Northwest Resource Mix (Hydro Omitted)

Not shown in the figure is about 1,900 megawatts of demand response capability assumed to be secured between 2007 and 2025.

APPROACH

The Council forecasts wholesale electricity prices using the AURORA® electricity market model. Using AURORA®, 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. Preparing a forecast is a two-step process (Figure C-6). First, a forecast of capacity additions and retirements beyond those currently scheduled is developed using the AURORA® long-term resource optimization logic. This is an iterative process, in which the present values of possible resource additions and retirements are calculated for each year of the study period. Existing resources are retired if market prices are insufficient to meet future maintenance and operation costs. New resources are added if forecast market prices are sufficient to cover the fully allocated costs of resource development, maintenance and operation, including a return on the developer's investment. This step results in a future resource mix such as depicted in Figure C-4. Once the mix of resources for the forecast period has been developed, power prices are forecast by dispatching the resulting mix of resources to serve forecast loads.

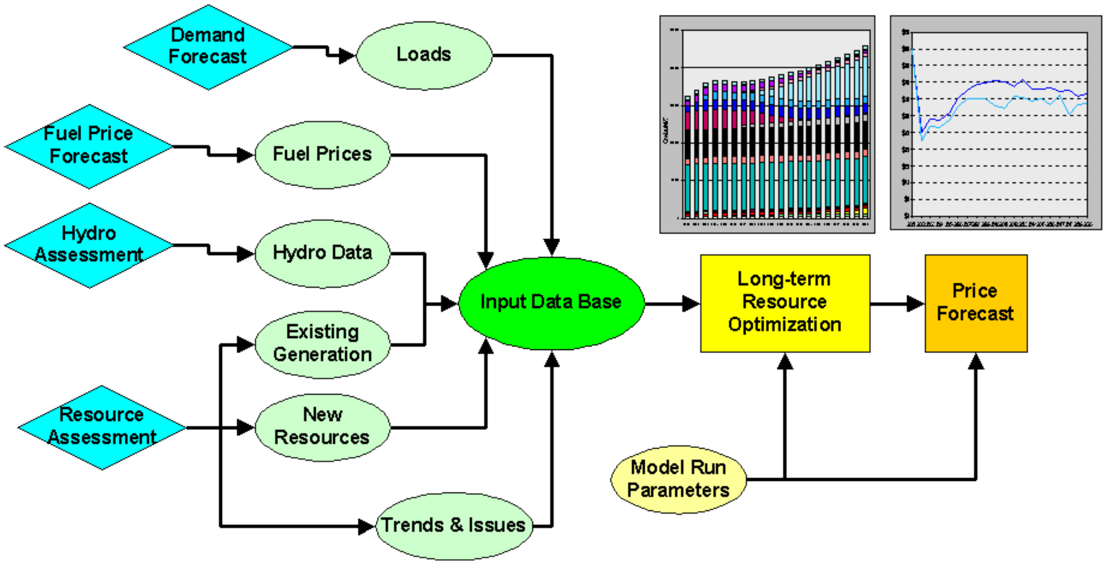

Figure C-6: Price Forecasting Process

As configured by the Council, AURORA® 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 major 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 areas if economic, and if transmission transfer capability is available.

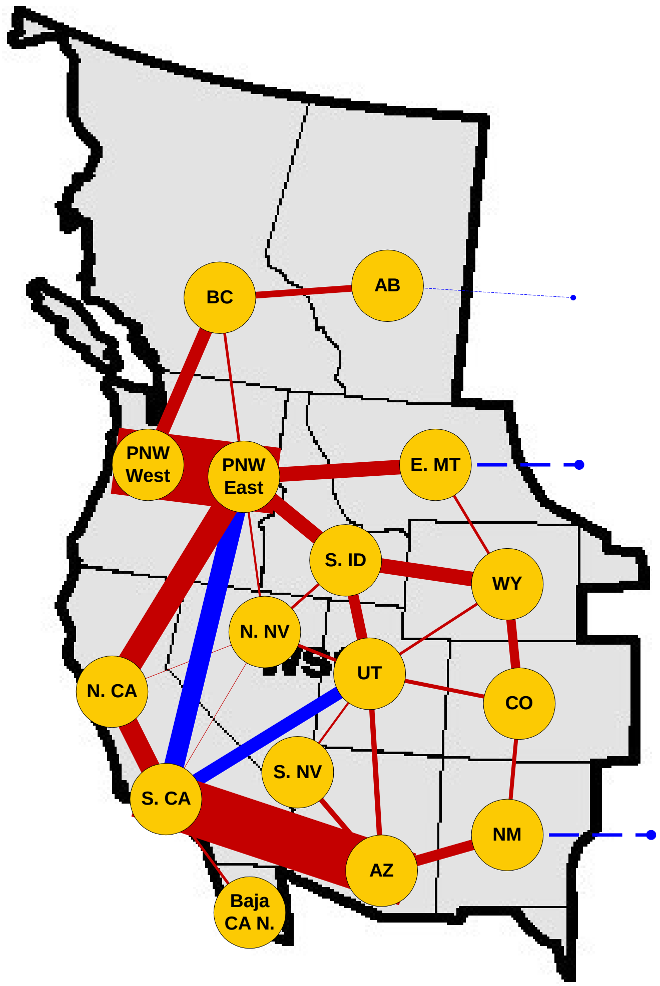

Figure C-7: Load-Resource Zones

DATA, ASSUMPTIONS AND SENSITIVITIES

Forecasts and assumptions underlying the price forecast, including future loads, fuel prices, hydropower characteristics, new resource characteristics, and energy and environmental policies are developed by the Council with the assistance of its advisory committees. The Council's Generating Resources Advisory Committee has been particularly helpful in the development of information and assumptions for the electricity price forecast. Members of the Generating Resources Advisory Committee are listed in Appendix C2.

The Current Trends forecast assumes continuation of current economic, technical and energy-related policy trends. This case used the medium load forecast, fuel price forecast and average water conditions. Water conditions and fuel prices are adjusted to compensate for the biasing effect of fuel price volatility and water conditions on long-term average electricity prices. However, with the exception of near-term natural gas prices, specific episodes of gas price and hydro volatility are not modeled.

ELECTRICITY DEMAND

The Council's revised draft medium case 20-year sales forecast is the load basis for the Current Trends price forecast. The load forecast includes in-region transmission and distribution losses and the effects of price-induced and programmatic conservation. In the medium case, loads are forecast to grow at an average annual rate of approximately 1 percent per year from 20,080 average megawatts in 2000 to 25,420 average megawatts by 2025. Because of the decline in loads during the first portion of this period, the annual growth rate from 2003 to 2025 is higher than the average (1.5 percent per year), with annual increases of 330 average megawatts.

The general approach used to forecast loads for WECC areas outside the Northwest is 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 electricity demand forecasts are available from the National Energy Board.

WECC loads are forecast to grow from 91,200 average megawatts in 2000 to 133,900 average megawatts in 2025. Load-resource areas outside of the Northwest did not experience the extent of load loss in 2000 and 2001 as did the Northwest and also are forecast to see more rapid average long-term load growth. The average annual load growth rate for the WECC as a whole for 2000 through 2025 is expected to be 1.6 percent. Annual average medium load growth rates for each load-resource area are provided in Appendix C3.

The Council develops a range of demand forecasts for the Northwest to assess the implications of load growth uncertainty on power prices and resource development recommendations. The most likely range of demand growth is believed to be between the medium-low (0.4 percent per year) and medium high (1.5 percent per year) cases. These cases were used to test the sensitivity of electricity prices to loads. Medium-low and medium-high load growth rates for the areas other than the Northwest were estimated by adjusting the medium-case long-term growth rates for each area by the load growth rate case differences developed for the Northwest.

Faster load growth in the medium-high load case leads to more rapid price recovery, and somewhat higher near-term power prices (Figure C-8). Prices drop below the base case in the mid-term, and then rise to a level somewhat higher than the base case in the long-term. Because of the lower mid-term prices, the levelized Mid-Columbia price for the medium-high load growth case is slightly lower than the base case ($36.00 per megawatt-hour). This apparent anomaly appears to be due to the more rapid development of fossil fuel resources in the near-term, prior to the time (for many of the load-resource areas) that CO_2 offsets are assumed to be required for new fossil resources. Other results of the medium-high load growth case (and other sensitivity and scenario analyses) are summarized in Table C-3 (p. C-23).

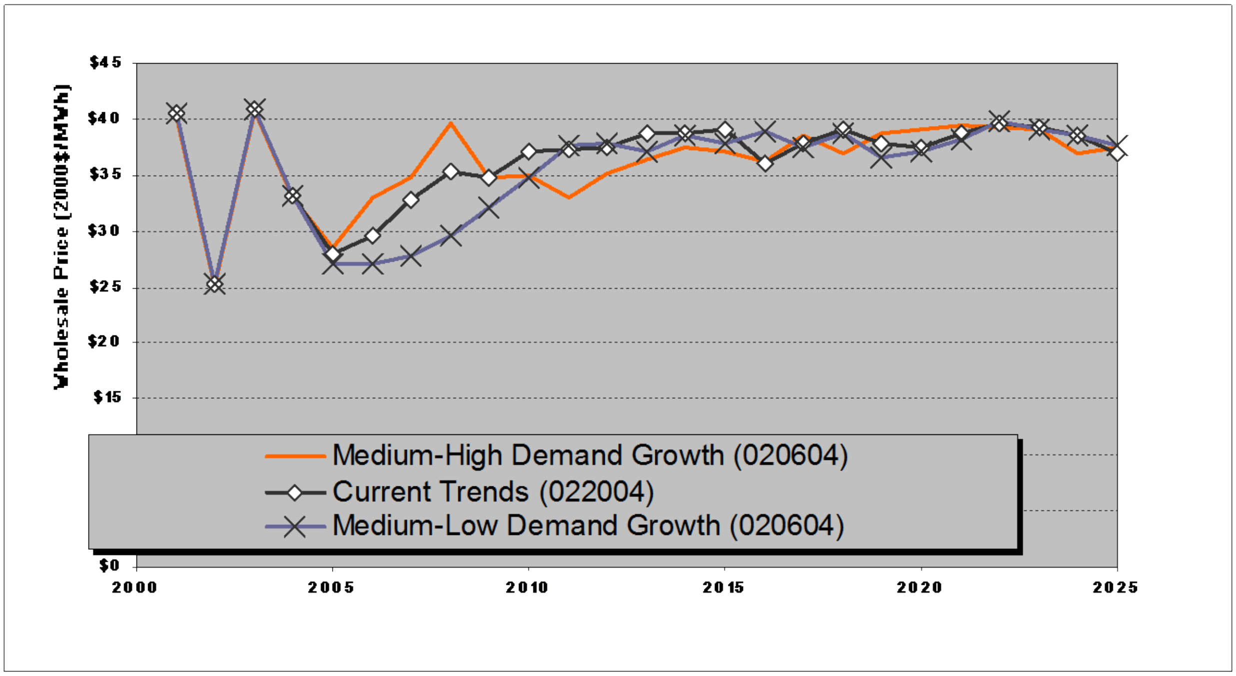

Figure C-8: Price Sensitivity to Load Growth Uncertainty

Slower load growth in the medium-low case leads to a more extended price recovery. Prices rise to about the same level as the base case in the long-term, since the marginal resources in the long-term are similar. The levelized forecast Mid-Columbia price is lower in this case, $34.80 per megawatt-hour.

Additional information regarding the load forecasts is provided in Council Document 2003-6 Revised Draft Forecast of Electricity Demand for the Fifth Power Plan (http://www.nwcouncil.org/library/2003/2003-6.htm).

FUEL PRICES

The Council's revised draft medium-case 20-year 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 differential prices are added to the base prices to arrive at delivered fuel prices for each load-resource area. Some fuel 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 base fuel price forecasts and derivation of load-resource area prices are fully described in Council Document 2003-7 Revised Draft Fuel Price Forecasts for the Fifth Power Plan, http://www.nwcouncil.org/library/2003/2003-7.htm.

In the medium-case, Western mine-mouth coal is forecast to decline from $0.51 per million Btu in 2000 to $0.42 per million Btu in 2025 (constant 2000$). Following a decline from the 2000 high of $6.71 per million Btu to $5.61 per million Btu in 2005, distillate fuel oil prices are expected to escalate slowly to $6.00 in 2025 at a rate of 0.3 percent per year. The U.S. average wellhead natural gas price is forecast to decline from current highs to $3.25 per million Btu in 2005, then rise on average at 0.5 percent per year to $3.60 per million Btu in 2025 (2000$). The 2025 wellhead price is based on the expected cost of imported 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. Fuel prices in AURORA® are allocated into fixed (dollars per kilowatt per year) and variable (dollars per million Btu) components to differentiate costs, such as pipeline reservation costs that are fixed in the short-term.

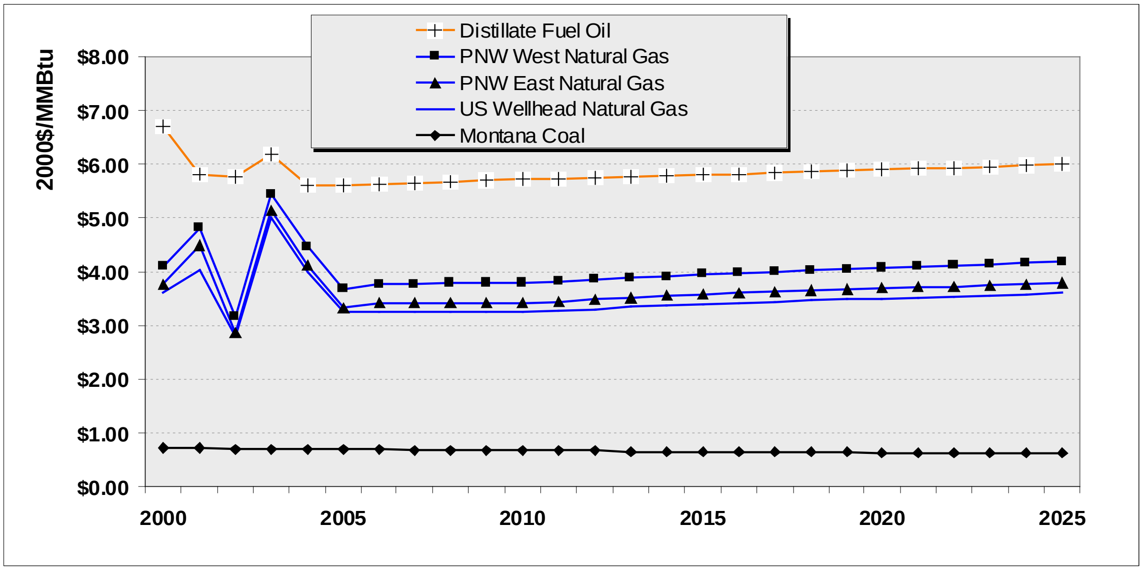

Figure C-9: Price Forecasts for Selected Fuels - Medium Case

Because future natural gas prices may have important effects on the future resource mix and electricity prices, sensitivity analyses were run using the Council's high and low fuel price forecasts and a special "extended high gas price" forecast. The extended-high case was developed in response to concerns that natural gas prices may have to remain at current levels for an extended period in order to stimulate the development of new reserves or liquefied natural gas (LNG) import capability needed to stabilize gas prices in the long-term. The extended-high price forecast for Pacific Northwest "westside" delivered gas is compared to the medium, medium-high and high forecast cases in Figure C-10. Coal and fuel oil prices in the extended-high sensitivity case were unchanged from the medium case forecast.

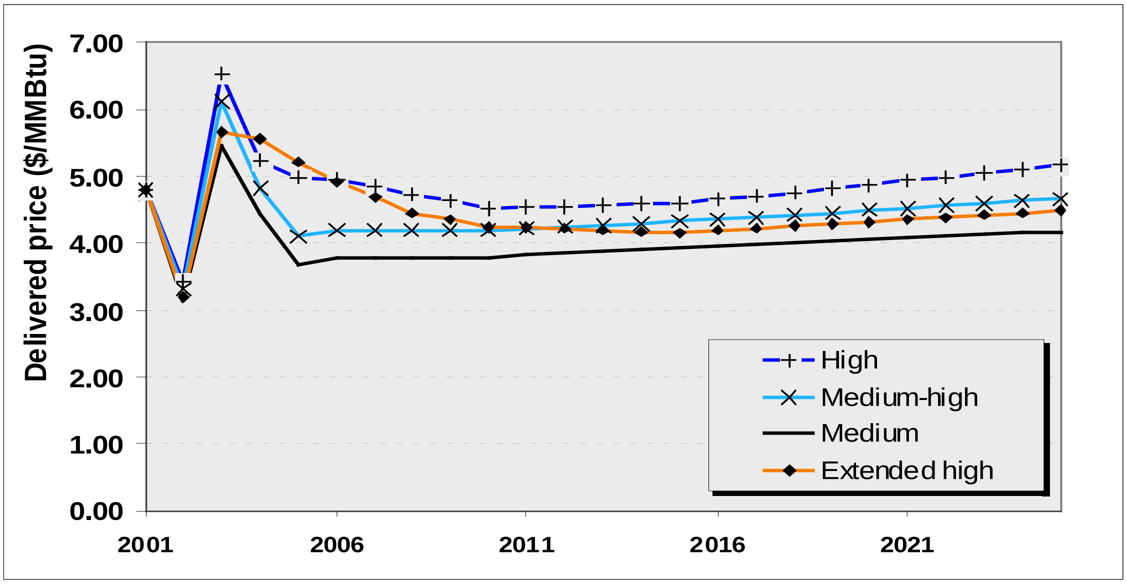

Figure C-10: "Extended High" natural gas price forecast

Forecast electricity prices are very sensitive to future fuel prices. The low fuel price forecast reduces levelized forecast Mid-Columbia electricity prices by 17 percent to $30.10 per megawatt-hour. Price reductions are evident in the near-term and in the longer-term, less so in the midterm (Figure C-11). Resource development (not shown) shifts away from new coal, wind and solar to new gas peaking units and existing gas-fired capacity that is retired in the base case.

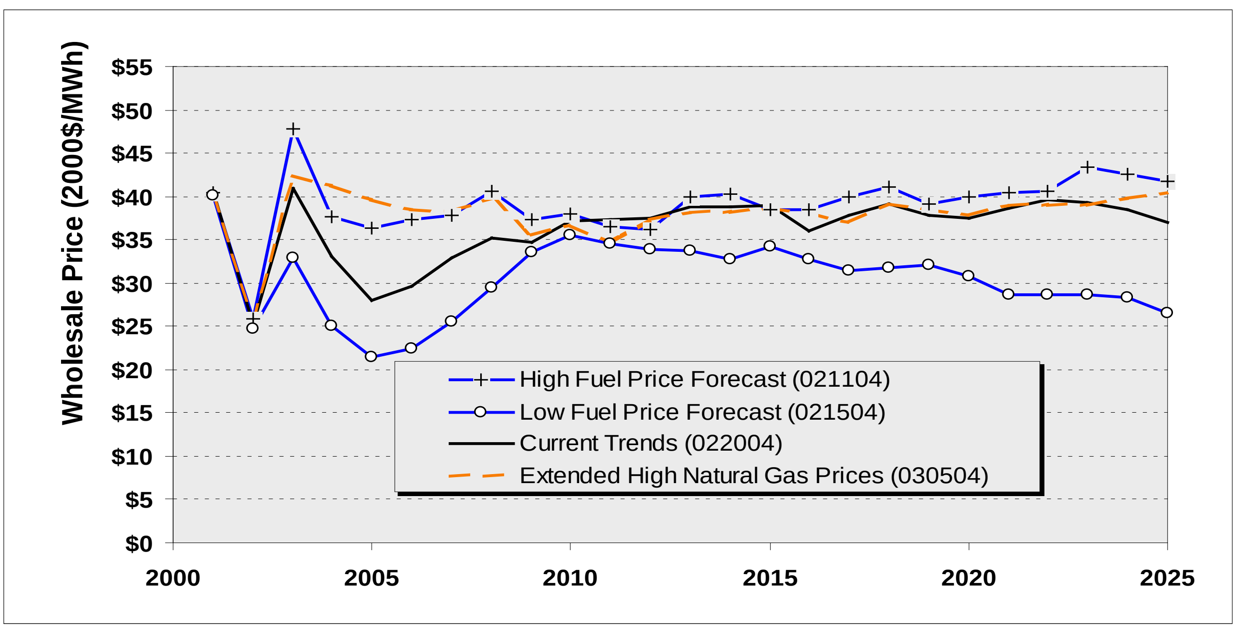

Figure C-11: Sensitivity of power prices to fuel price forecasts

The high fuel price forecast increases Mid-Columbia electricity prices by 8 percent to $39.00 per megawatt-hour. As shown in Figure C-11, though the higher fuel price cases have a significant impact on power prices in the near-term, the effect in the longer-term is less significant, probably due to the availability of new coal resources at costs not significantly above the cost of new natural gas resources in the base case. Over the long-term, higher fuel prices shift resource development from natural gas to wind and coal, tempering the impact of fuel price increases.

The extended high fuel price forecast increases forecast Mid-Columbia electricity prices by 6 percent to $38.10 per megawatt-hour. Most of the increase is in the near-term (Figure C-11). The development of additional coal resources moderates the effect of higher natural gas prices in the longer-term.

DEMAND RESPONSE

The Council believes that demand response is a potentially attractive alternative to construction of seldom-used peak generating resources. 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.

Bonneville formerly maintained an infrequently used demand response capability through its direct service industry contracts. Ad-hoc efforts at implementing demand response capability were undertaken during the power crisis of 2000 and 2001. 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 by 2025, beginning in 2007 and ramping up through the forecast period. Similar penetration is assumed throughout WECC.

Though demand response has been successfully developed in other regions, efforts to assess and implement demand response in the Northwest (other than the former Bonneville DSI contracts) have been limited and inconclusive. Because efforts to develop demand response capability may less successful than assumed in the base case, a sensitivity analysis omitting the demand response resource was run.

As expected, forecasted electricity prices rise in the mid- and longer-term as more expensive new resources are developed to substitute for the foregone demand response. Levelized Mid-Columbia electricity prices increase from $36.50 in the base case to $37.10 in the sensitivity case, indicting that demand response, at least under the assumptions used here, is a more cost-effective approach to meeting peak period demand than construction of generating resources. The resources developed in lieu of demand response are shown in Figure C-12 on a cumulative annual basis for WECC as a whole. By the end of the forecast period roughly equal amounts of coal and gas peaking capacity have been substituted for the absent demand response. (The forgone demand response is not shown in the figure.)

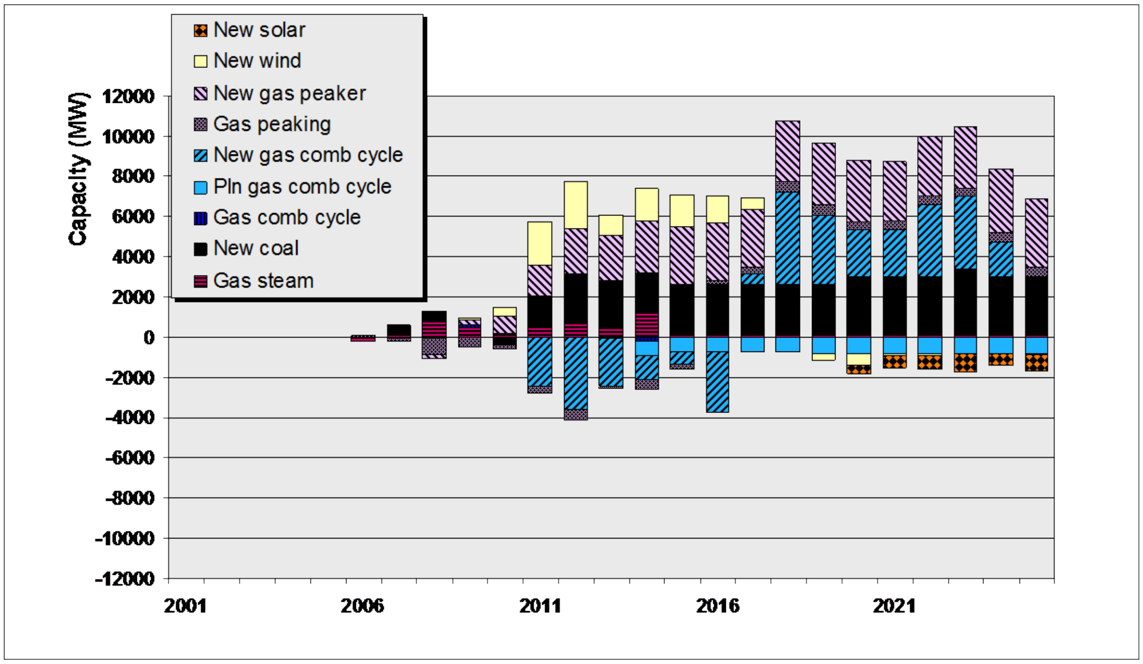

Figure C-12: WECC Resources Developed in Lieu of Demand Response

Additional discussion of demand response is provided in Council Document 2002-18: Demand Response (http://www.nwcouncil.org/library/2002/2002-18.htm).

NEW GENERATING RESOURCE ALTERNATIVES

When running a capacity expansion study, AURORA® 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 study run time is sensitive to the number of available new resource alternatives, a compromise must be drawn between portrayal of a diversity of future resource alternatives and study run time. 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 biomass, are unlikely to be available in sufficient quantity to significantly influence future power prices. Some, such as solar photovoltaics are not significant at present, but may become so as costs decline. Finally, some resources, such as gas-fired reciprocating generator sets are not markedly different from simple-cycle gas turbines with respect to their effect on future power prices. With these considerations in mind, the new resources modeled for this forecast included natural gas combined-cycle power plants, two cost levels of wind power, coal-fired steam-electric power plants, natural gas simple-cycle gas turbine generating sets and central-station solar photovoltaic plants.

Gas Combined Cycle

Gas-fired combined-cycle plants have been the "resource of choice" since the early 1990s. Reasons include high thermal efficiency, low environmental impact, excellent operating flexibility and low natural gas prices for much of this time. Technology improvements are expected to continue, helping offset expected real increases in natural gas prices. Though over 7,000 Megawatts of additional gas combined-cycle capacity currently are permitted in the Northwest, the future role of this resource is sensitive to the cost of natural gas and global climate change policy. Higher gas prices could shift development to coal. Conversely, more extensive 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. Combined-cycle and other new resource assumptions are summarized in Table C-2.

Wind

Wind power has progressed from niche to mainstream over the past decade. Factors include 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. 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, technological improvement, availability of transmission and shaping services and financial incentives. Higher gas prices increase the attractiveness of wind, particularly if there is expectation that coal may be subject to future carbon offset requirements. 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 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

No coal-fired power plants have entered service in the Northwest since the mid-1980s. However, continuing decline in coal 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. Because no practical means of capturing and sequestering the carbon dioxide production of fossil-fuel power plants currently exists, the most feasible approach to the reduction of carbon dioxide from coal plants may be introduction of coal gasification technology. The higher thermal efficiency of this technology would reduce per kilowatt-hour carbon dioxide production, and the gasification process could facilitate removal of CO_2 for sequestration. 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.

Gas Simple Cycle

As described earlier, the Council 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. 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) aero derivative simple-cycle gas turbine generator set.

Solar

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

Other power supply resources are available for future development, but in more limited quantity than those described above. One attractive alternative is cogeneration, where exhaust heat from gas turbine or reciprocating engines is used for process, space or water heating. This improves the overall efficiency of fuel use and often reduces net air emissions and other environmental impacts. Also attractive is the use of various bio-residues for power generation. Though typically small scale, these plants can produce useful energy from otherwise wasted material and simultaneously resolve waste disposal problems. A few small-scale environmentally acceptable hydropower projects remain available for development in the Northwest, and some additional potential is available through upgrade of older equipment at existing projects. Geothermal potential, once thought extensive, appears to be limited in quantity in the Northwest and has proven difficult and relatively expensive to develop. Nuclear power remains available for development, but is relatively expensive and controversial. Additional commercial development of nuclear power in the United States appears unlikely until a spent fuel disposal system is established and operation of new-generation, modular, “passively safe” power plants is successfully demonstrated. None of these resource alternatives were modeled in this forecast.

Also included as new generating resource alternatives are four Northwest gas combined-cycle power plants for which construction has been suspended. These are Grays Harbor, Mint Farm, Goldendale and Montana First Megawatts.

Table C-2: Summary of new generating resource assumptions

	Unit Size (MW)	Capital Cost ($/kW)	Non-fuel Fixed O&M ($/kW/yr)	Non-fuel Variable O&M ($/MWh)	Trans Cost ($/kW/yr) & losses (%)	Shaping Cost ($/MWh)	Heat Rate (Btu/kWh)	Operating Availability	Northwest Potential (Units)
Natural gas combined-cycle gas turbine	540 MW baseload 610 MW peak.	$525	$8.10	$2.80	$15.00 1.9 %	n/a	7030 (Baseload) 9500 (Peak increment)	90 percent	19
Natural gas single-cycle gas turbine	90 MW (2 x 45 MW units)	$600	$8.00	$8.00	None	n/a	9960	92 percent	16
Wind plant (Block 1)	100 MW	$1010	$20.00	$1.00	$15.00/ 1.9 %	$4.00	n/a	28 - 36 percent[1]	40
Wind plant (Block 2)	100 MW	$1010	$20.00	$1.00	$15.00 1.9 %	$8.00	n/a	26 - 34 percent	30
Coal steam-electric plant	400 MW	$1230	$40.00	$1.75	$15.00 1.9 %	n/a	9550	84 percent	15
Central-station solar photovoltaic plant	100 MW	$6000	$15.00	$0	$15.00 1.9 %	$8.00	n/a	22 percent	15

[1] Varies by load-resource area.

TRANSMISSION

Transfer capability between load-resource areas is modeled on the existing transmission system and scheduled additions. Additions include scheduled upgrades to Path 15 between northern and southern California, and a scheduled upgrade between the Baja California and southern California load-resource areas.

Because wind (other than that in California for which hourly output profiles are available) is modeled as having a constant output over the course of any given month, available transmission capacity is likely to be used more efficiently by AURORA® than is possible in reality where the output of a wind farm may vary significantly over the day. As a result, AURORA® may be developing more wind capacity in load-resource areas remote from load centers than may be possible with current transmission capability. The Council staff will be refining the treatment of wind to better simulate the ability of the current transmission system to accommodate additional remote wind resource development. Staff will also explore the cost-effectiveness of expanding transmission capacity to accommodate additional remote coal and wind resource development.

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. Tax incentives are persistent, and the resource costs used in this forecast assume continuation of federal incentives. Because of practical data development considerations, state and local financial incentives, such as sales and property tax exemptions, have not been modeled.

One 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. Though these incentives expired in 2003, because of the apparent widespread support for their extension and expansion we assume in the base case forecast that they are indefinitely continued at previous levels. The base case also assumes that they are equally applied to solar as well as wind generation.

Because of controversy regarding other aspects of proposed federal energy legislation, extension of the PTC and REPI has not been as timely as originally foreseen. Moreover, the increasing magnitude of the projected federal budget deficit suggests that continued renewal of these incentives over the long-term may not be as certain as believed when the base case assumptions were developed. The significance of the PTC and REPI was tested by a sensitivity case that assumed no extension of these incentives following 2003.

The absence of the production tax credit significantly retards the development of wind and solar resources (Figure C-13). The ultimate level of wind development is, however, unchanged because the supply is eventually exhausted in both cases. Gas combined-cycle development is also reduced. New coal and gas peaking capacity and retained existing gas-steam capacity substitute for the deferred wind and solar capacity. The effect on power prices is negligible. Without the credit, forecast Mid-Columbia prices decline less than 1 percent to $36.00 per megawatt-hour. Total WECC CO_2 production over the forecast period increases 4 percent (Table C-2).

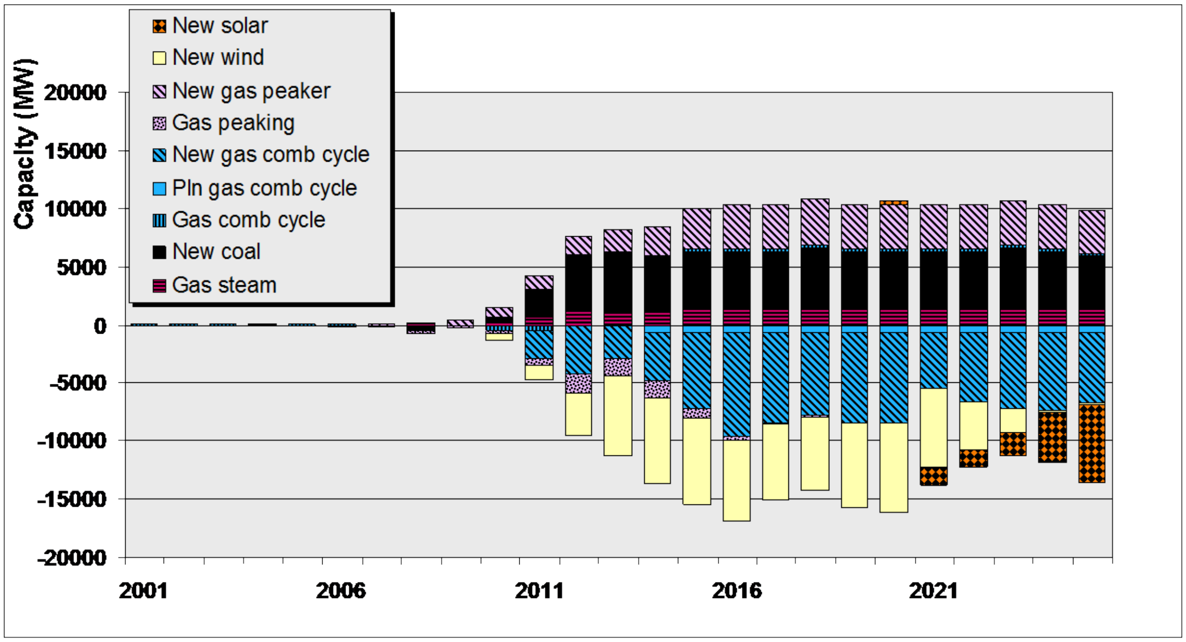

Figure C-13: Changes in WECC Resource Development in the Absence of the Production

GREEN TAG VALUE

Another financial assumption affecting renewable energy development is the future value of green tags. The current market value of green tags is reported to be in the $5 to $7 per megawatt-hour range, though somewhat weak. This value presumably represents the market value of the environmental externalities offset by a megawatt-hour of generation from "green" resources. A portion of this value is the value of offset CO_2 production. The Current Trends base case includes the assumption that green tag values will rise as additional restrictions are placed on CO_2 production and the cost of CO_2 offsets rise. The base case forecast of CO_2 offset cost and associated forecast of green tag value is shown in Figure C-14.

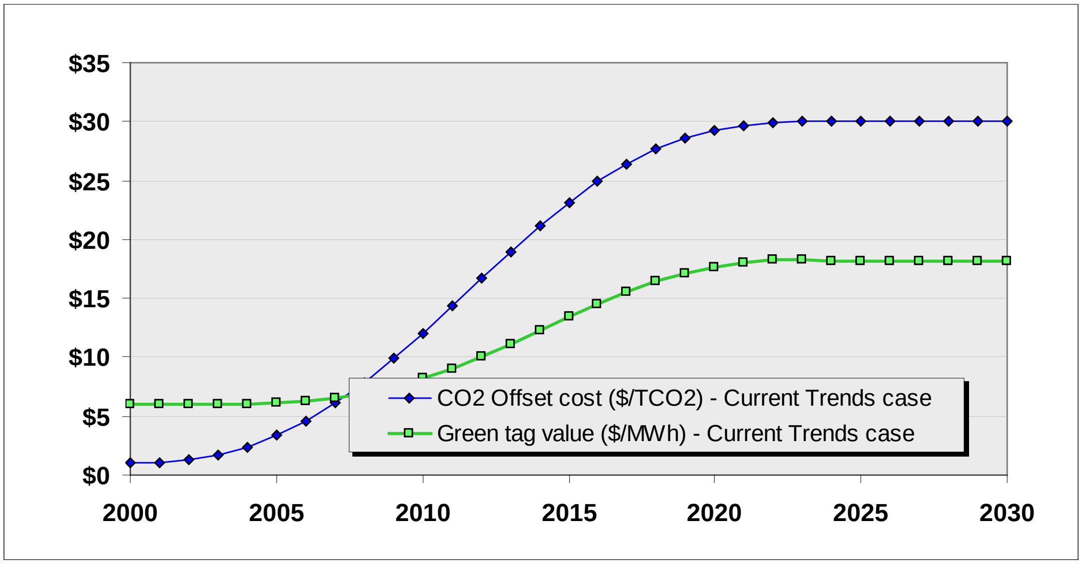

Figure C-14: Forecast CO_2 Offset Costs and Green Tag Values in the Base Case

A case was run with the green tag value fixed at a constant $6 per megawatt-hour to explore the sensitivity of wind and solar development to green tag revenues. Lower green tag revenue, as expected, retards the development of wind and solar resources (Figure C-15). New coal and gas peaking capacity replace the deferred wind and solar. The ultimate level of wind development is unchanged from the base case because the supply is eventually exhausted in both cases. Unlike the case described above where the production tax incentive was removed, gas combined-cycle development is not greatly affected, perhaps because tag revenue directly affects variable cost whereas the production tax credit, as modeled, affects fixed costs via income tax obligations. With fixed tag revenues, forecast Mid-Columbia prices decline less than 1 percent to $36.00 per megawatt-hour. Total WECC CO_2 production over the forecast period increases 2 percent (Table C-3).

Table C-3: Summary of base case, scenario and sensitivity case results

Case	Changes from Base	Electricity Price Forecast ($/MWh)	Ave of top 10% of Monthly Prices ($/MWh)	2025 WECC Resource Mix[a] (percent)	WECC Coal Use (2005-25) (TBtu)	WECC Gas Use (2005/25) (TBtu)	WECC CO_2 Production (2005-25) ($MMTCO_2$)	WECC Long-term Reserve Margin (percent)	PNW Long-term L/R Balance (aMW)
Scenarios									
Current Trends (Base) (022004)	--	$36.10	$81.52	H 23 C 18 G 30 I 20	67632	41475	9641	7 percent	-186
Planning reserve margin	Resource additions and retirements to maintain ~ 15 percent reserve margin	$39.80 (incl inc fxd cst) (+10 percent)	$44.54 (incl inc fxd cst) (-45 percent)	H 22 C 19 G 33 I 18	72.360 (+7 percent)	38,520 (-7 percent)	9966 (+3 percent)	15 percent	386
Business-as-Usual	PTC phased out by 2013 CO2 offset limited to WA, CA, BC & AB $6/MWh (real) green tag value Demand Response 2 percent of load Extended high gas prices $250/MWh price cap RPS renewables 50 percent of targets	$35.70 (-1 percent)	$59.32 (-31 percent)	H 25 C 26 G 28 I 12	77,835 (+15 percent)	33,563 (-19 percent)	10,260 (+6 percent)	5 percent	209
• ***Sensitivity cases (off Current Trends scenario)***									
Medium-low demand forecast	NPCC Medium-low demand forecast case	$34.80 (-4 percent)	$78.31 (-4 percent)	H 26 C 18 G 25 I 22	62,343 (-8 percent)	32,563 (-21 percent)	8551 (-11 percent)	n/avail	N/avail

[a] H - Hydropower
C - Coal
G - Natural gas
I - Wind and solar

Case	Changes from Base	Electricity Price Forecast ($/MWh)	Ave of top 10% of Monthly Prices ($/MWh)	2025 WECC Resource Mix[a] (percent)	WECC Coal Use (2005-25) (TBtu)	WECC Gas Use (2005/25) (TBtu)	WECC CO_2 Production (2005-25) ($MMTCO_2$)	WECC Long-term Reserve Margin (percent)	PNW Long-term L/R Balance (aMW)
Scenarios									
Medium-high demand forecast	NPCC Medium-high demand forecast case	$36.00 (0 percent)	$77.79 (-5 percent)	H 21 C 18 G 35 I 19	73,361 (+8 percent)	48,038 (+16 percent)	10,632 (+10 percent)	n/avail	N/avail
Low fuel price forecast	NPCC Low fuel price forecast case	$30.10 (-17 percent)	$74.32 (-9 percent)	H 23 C 14 G 36 I 20	56,667 (-16 percent)	51,631 (+24 percent)	9055 (-6 percent)	5 percent	-515
High fuel price forecast	NPCC High fuel price forecast case	$39.00 (+8 percent)	$78.93 (-3 percent)	H 23 C 23 G 25 I 31	75,341 (+11 percent)	34,885 (-16 percent)	10,082 (+5 percent)	7 percent	369
Extended high natural gas price	Current gas prices decline slowly to 2010, approximately medium-high thereafter	$38.10 (+6 percent)	$75.81 (-7 percent)	H 23 C 21 G 27 I 20	78,665 (-16 percent)	33,075 (-20 percent)	10,089 (+5 percent)	7 percent	225
Production tax credit not extended	No production tax credit	$36.00 (0 percent)	$78.35 (-4 percent)	H 24 C 20 G 30 I 18	72,239 (+7 percent)	40,043 (-3 percent)	10,049 (+4 percent)	8 percent	229
Reduced green tag revenue	Green tag value fixed at $6/MWh	$36.00 (0 percent)	$79.25 (-3 percent)	H 24 C 19 G 32 I 17	69,315 (+3 percent)	41,904 (+1 percent)	9845 (+2 percent)	8 percent	596
Non-aggressive CO2 control	$0.87/T CO2 mitigation, WA & OR only Lower green tag value	$33.70 (-7 percent)	$67.65 (-17 percent)	H 24 C 22 G 30 I 16	74,532 (+10 percent)	38,226 (-9 percent)	10,180 (+6 percent)	9 percent	153
McCain-Lieberman CO2 control	Immediate $0.87/T CO2 offset in WA & OR Climate Stewardship Act enacted 2006, Ph I in 2012	$49.40 (+37 percent)	$90.71 (11 percent)	H 23 C 6 G 44 I 18	29,524 (-56 percent)	62,100 (+50 percent)	6840 (-29 percent)	7 percent	-262

Case	Changes from Base	Electricity Price Forecast ($/MWh)	Ave of top 10% of Monthly Prices ($/MWh)	2025 WECC Resource Mix[a] (percent)	WECC Coal Use (2005-25) (TBtu)	WECC Gas Use (2005/25) (TBtu)	WECC CO_2 Production (2005-25) ($MMTCO_2$)	WECC Long-term Reserve Margin (percent)	PNW Long-term L/R Balance (aMW)
Scenarios									
No demand response	No demand response capability	$36.50 (+1 percent)	$80.21 (-2 percent)	H 23 C 19 G 31 I 20	69,749 (+3 percent)	40,026 (-4 percent)	9781 (+2 percent)	7 percent	-866
$250 price cap	$250/MWh FERC price cap extended indefinitely	$35.30 (-2 percent)	$66.13 (-19 percent)	H 24 C 19 G 29 I 20	70,900 (+5 percent)	39,014 (-6 percent)	9848 (2 percent)	4 percent	1382

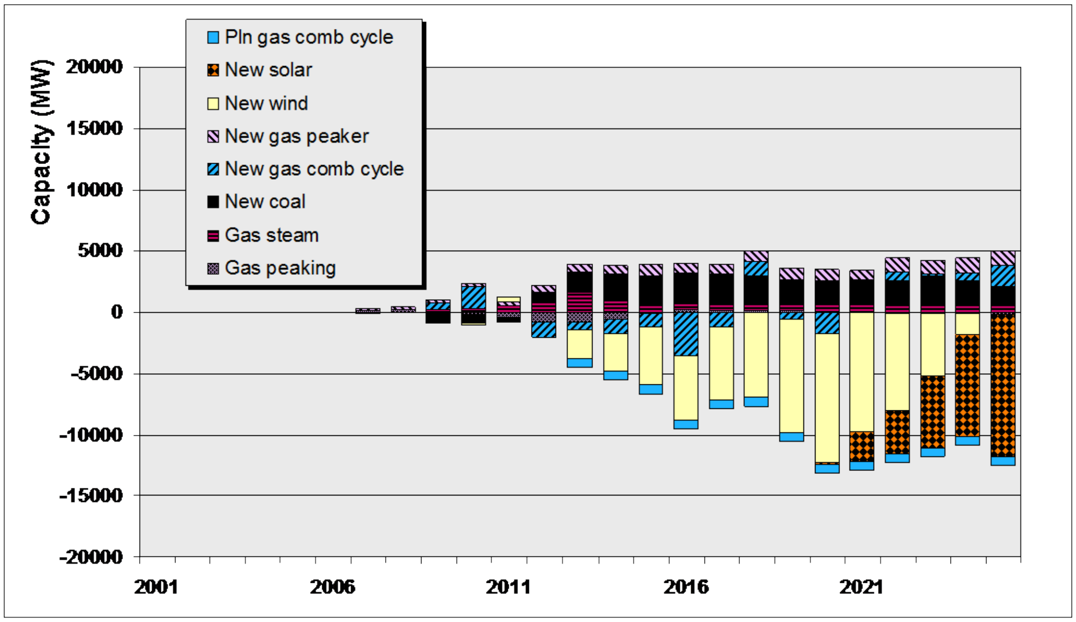

Figure C-15: Changes in WECC Resource Development with Green Tag Revenues Fixed at $6/MwH

GLOBAL CLIMATE CHANGE POLICY

In the absence of federal requirements for greenhouse gas reductions in the face of growing scientific evidence supporting the existence of anthropogenic global climate change, individual states are moving to establish controls on the production of carbon dioxide and other greenhouse gasses. Beginning in 1997, Oregon required mitigation of 17 percent of the carbon dioxide production of new power plants. Washington has required CO_2 mitigation for recently permitted projects on an ad-hoc basis and this year adopted mandatory CO_2 mitigation requirements for new fossil power plants exceeding 25 megawatts capacity. Recently, California has joined with Washington and Oregon to develop joint policy initiatives leading to a reduction of greenhouse gas production.

Carbon dioxide control requirements could significantly affect the future mix of generating resources and resulting power prices. The base case forecast assumes that the CO_2 mitigation similar to the Oregon standard will be gradually adopted by other states and provinces, and that a uniform mitigation requirement at the Oregon level will be in place throughout the WECC region by 2012. The resulting increasing demand for CO_2 offsets is assumed to increase the cost of offsets from current levels of about $1 per ton CO_2 to $30 per ton CO_2 in 2025. (Figure C-14)

Because of the great uncertainty regarding future CO_2 control, two alternatives regarding CO_2 control were examined. A “Non-aggressive” case assumes that throughout the forecast period, CO_2 mitigation is required only in Oregon and Washington and that the cost of mitigation remains constant at $0.87 per ton CO_2, similar to the current Oregon fixed payment option.

The assumptions of the non-aggressive case shift resource development from wind, natural gas and solar to coal (Figure C-16). (Figures C-16 and C-17 are at the same scale to facilitate comparison of these two cases.) Wind resource development returns to base case levels by the end of the forecast period because of overall limits on the availability of the resource. Overall solar development is significantly reduced. Forecast Mid-Columbia prices decline by 7 percent to \$33.70 per megawatt-hour. As expected, CO_2 production increases by 6 percent for the WECC area as a whole through the forecast period.

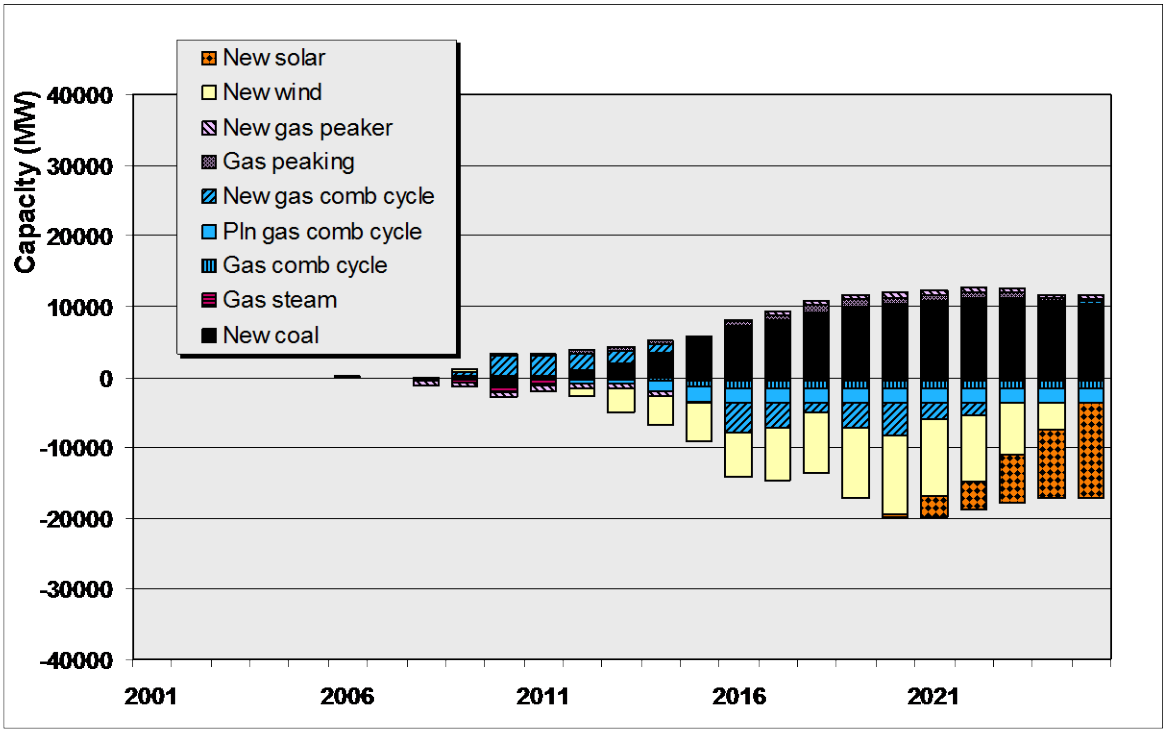

Figure C-16: Changes in WECC Resource Development with CO_2 Mitigation Limited to New Fossil Capacity in Oregon & Washington

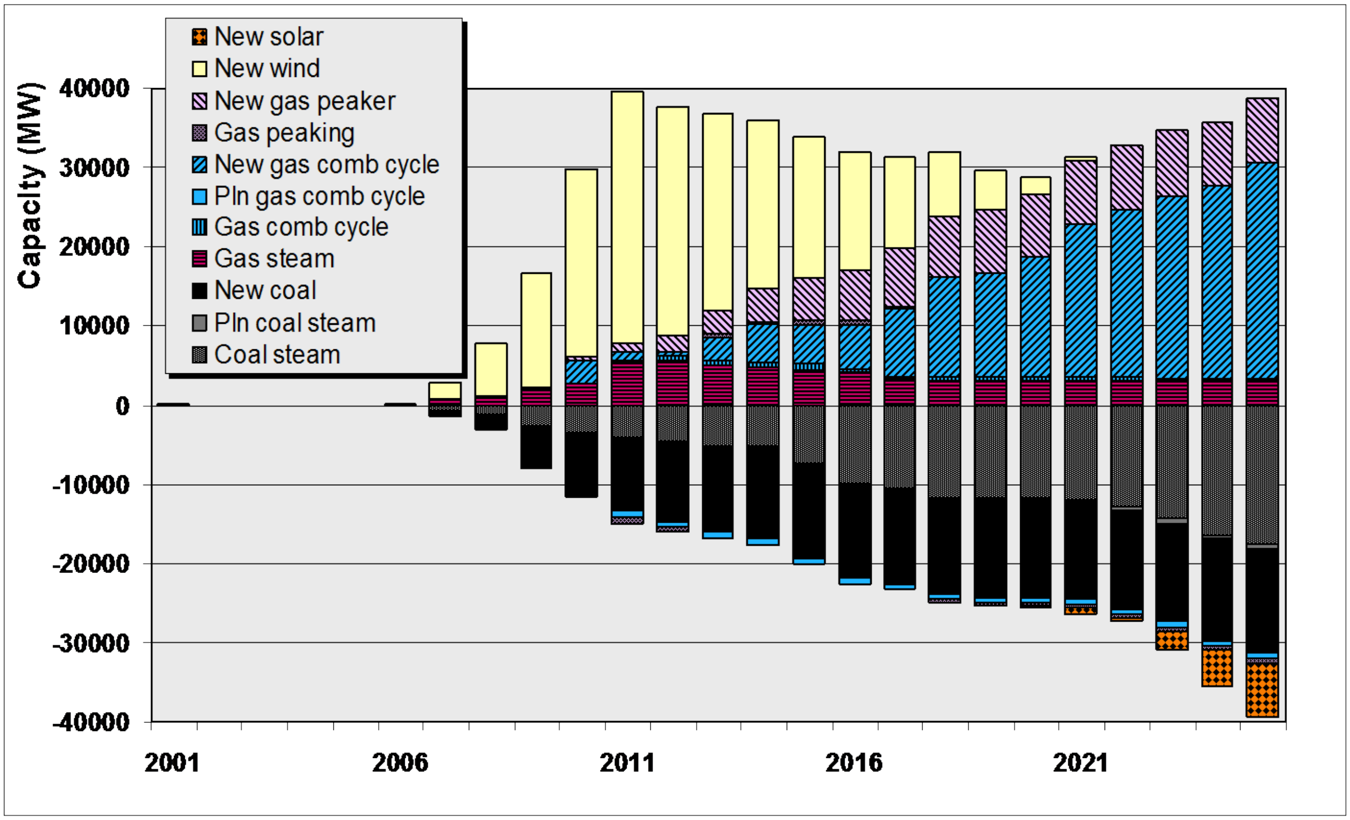

Figure C-17: Changes in WECC Resource Development with an Aggressive CO_2 Cap & Trade System

A more 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 reduced them to 1990 levels in 2016.

For this sensitivity case we assume that the program is enacted in 2006, and the year 2000 cap goes into effect in 2012. Model limitations require the system is to be modeled as a carbon tax on fuel use rather than as a true cap and trade system. Fuel carbon for existing and new projects is taxed at the equivalent of a forecast allowance costs required to achieve the proposed McCain-Lieberman caps. Allowance costs are based on the Case 5 forecast of the Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman proposal (Massachusetts Institute of Technology, June 2003), shifted back two years to coincide with the assumed 2012 Phase I implementation date. Because of the Act's banking provisions, we assume that a liquid market in allowances develops in 2006 and that any subsequent fuel carbon consumption sees an opportunity cost equivalent to the discounted forecast allowance value of 2012. Oregon and Washington are assumed to continue their current mitigation standards at $0.87 per ton through 2006. The federal production tax credit for renewable resources is assumed to continue until 2012. Green tag values drop slightly to a level estimated as representative of the bundle of "green" resource attributes other than carbon-free electricity production.

The assumptions of the McCain-Lieberman case result in a massive shift of resources from coal, both existing and new, to wind and natural gas (Figure C-17). Wind resource development is accelerated, and the wind resources available to the model are fully developed by 2020. Over 65 percent of existing coal capacity is retired over the forecast period. New gas-fired capacity and retention of existing gas-fired capacity fills the remaining resource needs. Solar development is somewhat less than in the base case perhaps because of the assumed reduction in green tag revenue. Forecast levelized Mid-Columbia prices increase 37 percent to $49.40 per megawatt-hour as a result of increased CO_2 mitigation cost and reduced federal subsidies via the production tax credit. CO_2 production drops 29 percent for WECC as a whole through the forecast period.

Not included in this sensitivity case are factors that on the whole might moderate the forecast electricity price increase. Natural gas prices could be expected to increase as a result of increased demand. This would raise forecast prices, other factors being equal. On the other hand, demand could be expected to moderate 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 power prices, the FERC implemented a floating WECC wholesale trading power 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 load. This mitigation system was revised in July 2002 to a fixed cap of $250 per megawatt-hour, effective October 2002.

The base case forecast does not include a wholesale price cap. Instead, peak period prices are determined by a load curtailment price curve ranging from $500 to $1,600 per megawatt-hour (2000$). In practice, forecast prices rarely exceed $550 per megawatt-hour.

A $250 fixed price cap will undercut the load curtailment blocks and most of the demand response blocks used in this forecast. The effect will be to lower peak period prices and reduce the development of generation to meet peak period loads. Reduction in long-term reserves likely will result. These effects were explored by a sensitivity case for which a $250 per megawatt-hour price cap remained in effect through the forecast period.

As expected, the price cap tends suppress resource development (Figure C-18). Somewhat unexpectedly, the effect is limited to new combined-cycle plants in the long-term. Approximately 18,000 fewer megawatts of new combined-cycle capacity are in place at the end of the forecast period compared to the base case. New coal development is initially deferred, but by the end of the forecast period a net increase of 2,000 megawatts is observed. The development of wind is advanced in time and a net increase of nearly 6,000 megawatts of new and existing gas peaking capacity is in service in 2025.

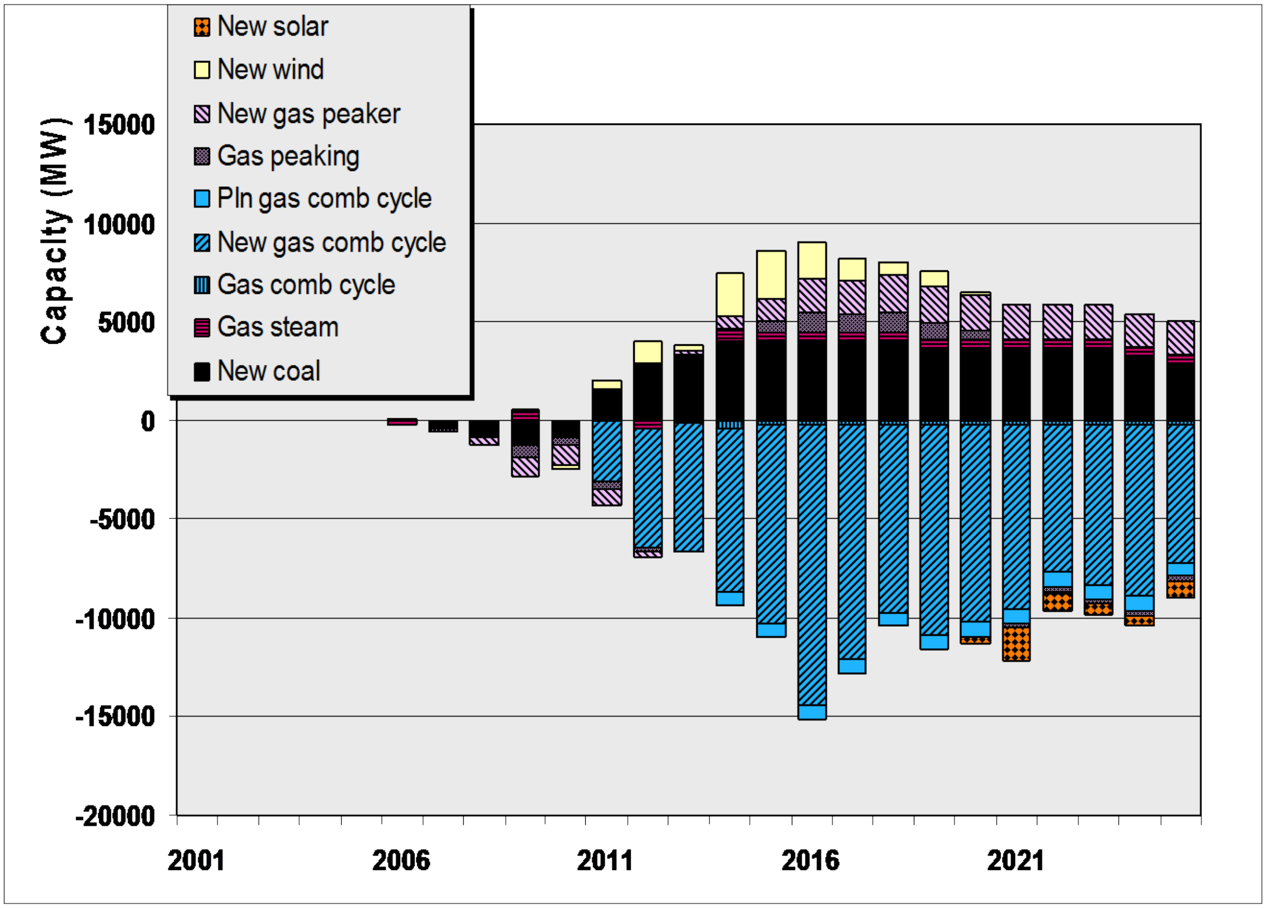

Figure C-18: Changes in WECC Resource Development with $250 per megawatt-hour Price Cap

As expected, the price cap lowers monthly average prices during peak months. Figure C-19 is a duration curve of average monthly prices for the forecast period. Suppression of peak period monthly prices is clearly evident in the price cap case. The average of the top 10 percent of monthly prices declines 19 percent to $66.13 from $81.52 per megawatt-hour. Average annual prices are less affected. Annual average prices decline 2 percent to $35.30 per megawatt-hour. WECC reserves decline to 4 percent in this case, compared to 7 percent in the base case (Table C-3). This implies that the level of unserved load increases in the price cap case.

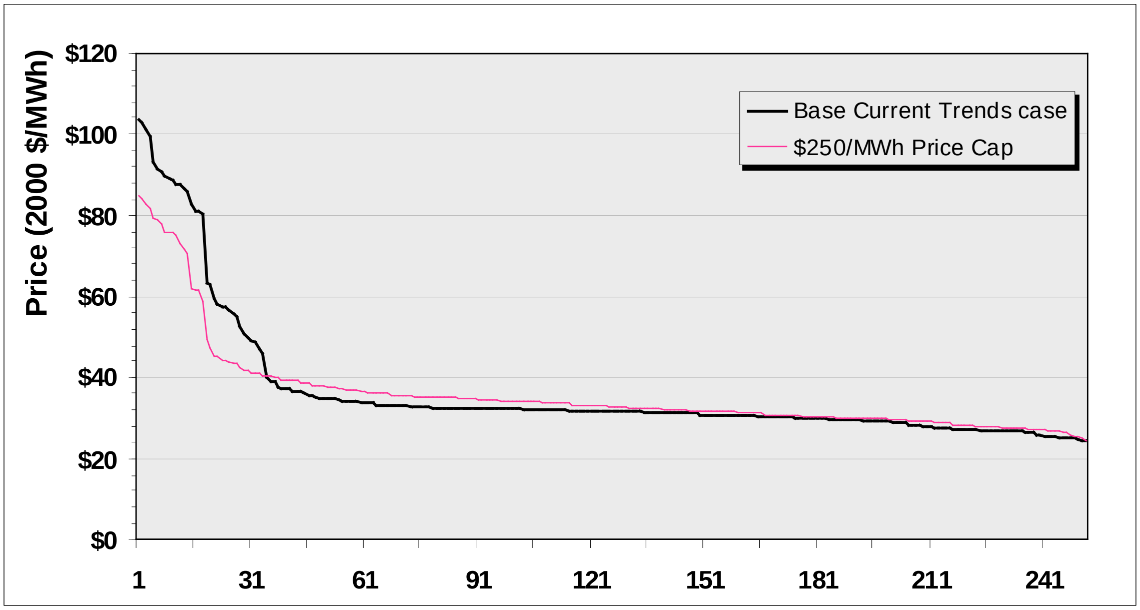

Figure C-19: Duration Curve of Average Monthly Mid-Columbia Prices: Base vs. $250 per megawatt-hour Price Cap

OTHER SCENARIOS

Planning Reserves

Long-term capacity-expansion studies using AURORA® typically result in relatively low reserve margins in the longer-term. For example, coincident peak hour reserve margins for WECC as a whole in the base case Current Trends forecast decline to about 7 percent in the longer-term (Figure C-20). While adequate for operating reserve needs, this reserve margin would not allow for planning contingencies. Conventional system planning would typically include 5 to 8 percent additional "planning margin" as protection against events such as low water years, unexpected rates of load growth and failure to complete projects as scheduled. Shown in Figure C-20, for example, is the minimum 12 percent reserve margin recommended by FERC in its Standard Market Design NOPR of July 2002.

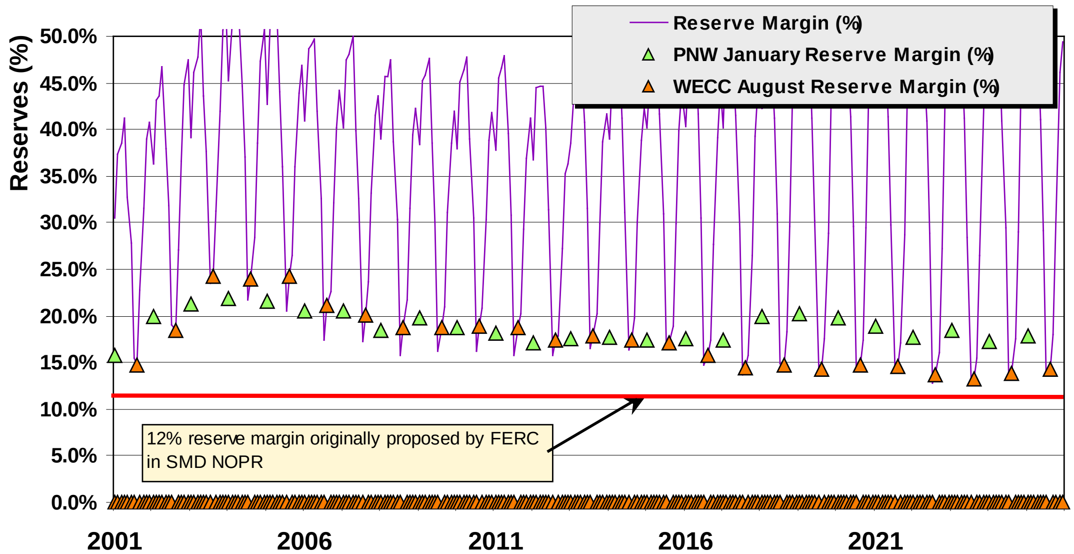

Figure C-20: Reserve Margins of the Base Case Current Trends Forecast

AURORA® currently allows specification of operating reserves, but not planning reserves. While the costs of planning reserves (the costs of maintaining little-used capacity) are seen by AURORA®, the benefits (protection against the longer-term uncertainties not modeled) are not. AURORA®, therefore, tends to minimize capacity in excess of that required for specified operating reserve levels. What would be the resource composition of a system including planning reserves and what would be the incremental cost of creating and maintaining these reserves?

Selecting the optimal mix and margin of resources for a planning reserve requires modeling the uncertainties for which a planning reserve is maintained, a task unsuited to the AURORA® resource optimization process. Furthermore, the reserve resources, if allowed to freely dispatch into the market, depress market prices, in turn suppressing market-driven resource development and confounding the very attempt to develop an additional capacity margin. Finally, while a capacity margin, such as recommended by FERC is generally appropriate for a thermal-based, capacity-limited system as found in much of North America, an energy margin is more appropriate for hydro-based energy -limited systems such as the Northwest.

A variation of the Current Trends base case was run to force AURORA® to create a resource portfolio incorporating a planning margin. Curtailment costs were increased to induce development of additional peaking capacity and the operating reserve levels were increased to induce additional baseload capacity. A WECC resource portfolio averaging 15 percent reserves in the long-term was produced following several iterations. The changes in that portfolio compared to the base case portfolio are illustrated in Figure C-21. Higher reserve levels have been achieved by adding new coal and new gas peaking capacity, and retaining existing gas peaking capacity otherwise retired. While the resulting resource mix may not be optimal, the incremental additions are intuitively reasonable.

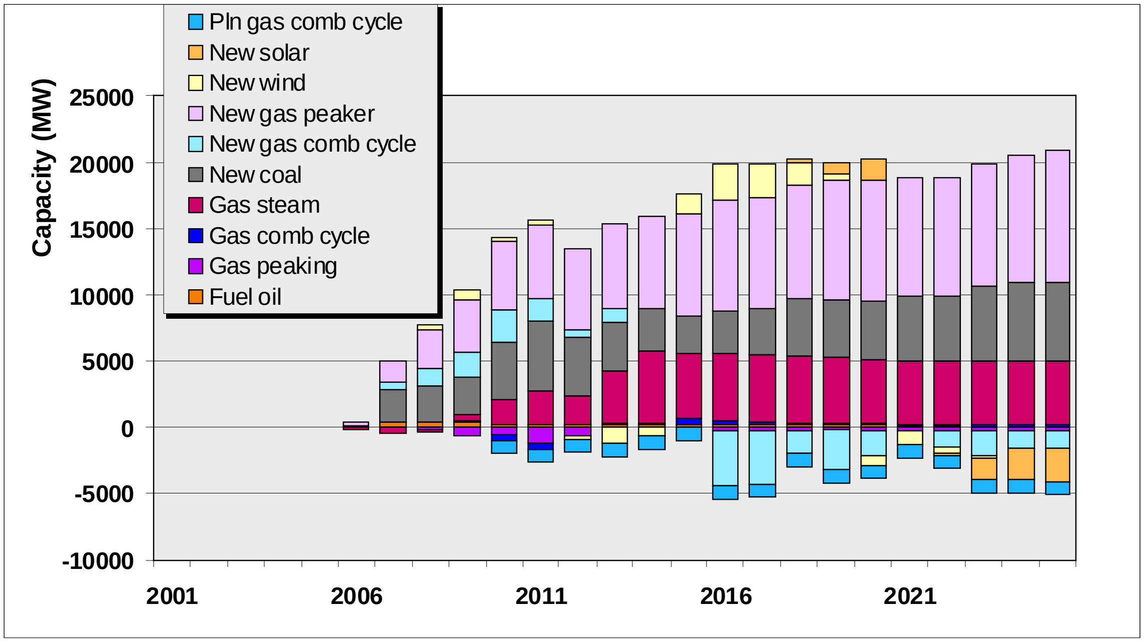

Figure C-21: Changes in WECC Resource Mix Resulting in a 15 percent Reserve Margin

The resulting resource mix, dispatched using the base case Current Trends assumptions (including curtailment costs and operating reserves) significantly lowers market prices as shown by the lower curve of Figure C-22. However, inclusion of the additional fixed costs of the added increment of capacity ($5.30 per kilowatt per year, levelized across all installed capacity) raises prices about 10 percent over the base case to $39.80 per megawatt-hour (Upper curve of Figure C-22). The additional cost represents the cost of insuring against long-term planning risks.

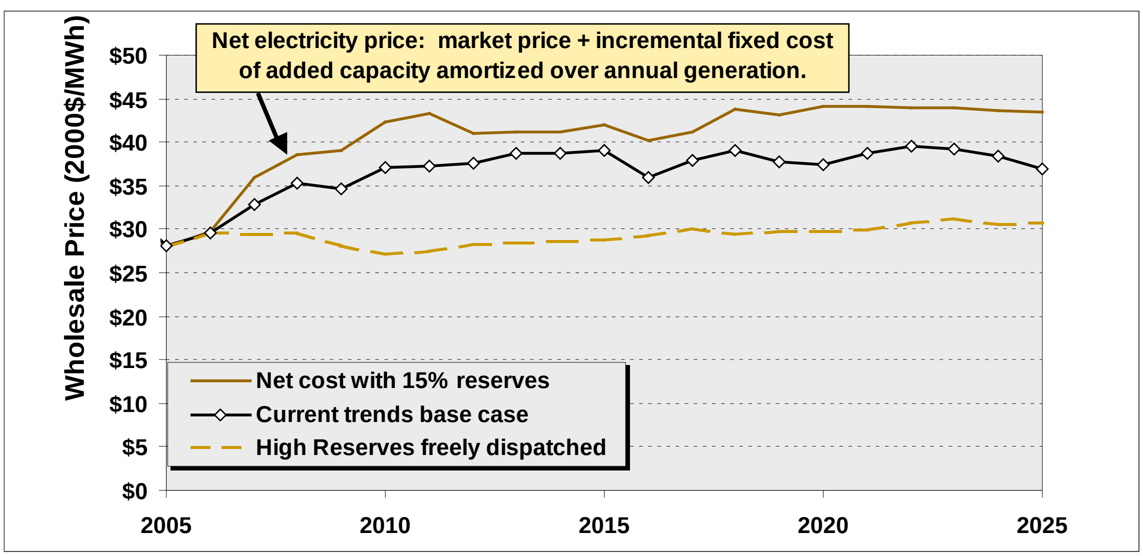

Figure C-22: Average Annual Mid-Columbia Prices: Base & High Reserves Cases

Additional reserves also greatly suppress peak period prices. Average monthly prices for the highest ten percent of months are 45 percent lower in the 15 percent reserves case.

BUSINESS AS USUAL

Since the final assumptions of the Current Trends base case were settled upon, the Council staff has received comments suggesting that several of the base case assumptions are too optimistic. These include assumptions regarding future natural gas prices, success of efforts to secure demand reduction capability, the level and renewable resource development incentives and the aggressiveness of efforts to reduce CO_2 production. The future suggested by these comments is not implausible so they were combined into a "Business as Usual" scenario to explore the net effect of changing these assumptions on the electricity price forecast and the related power system characteristics.

The assumptions of the base Current Trends case are modified as follows for the Business as Usual scenario:

- The extended high natural gas price forecast is used in lieu of the Council's medium gas price forecast. Coal and fuel oil prices are unchanged.
- An Oregon-type CO_2 offset standard for new fossil fuel resources is assumed to be in place for Oregon and Washington by 2004 and for California, British Columbia and Alberta by 2007. No additional CO_2 controls are assumed for the WECC region. Because of the resulting lowered demand for CO_2 offsets, the value of green tags is assumed to remain constant at $6 per megawatt-hour (real). In comparison, in the Current Trends scenario the rest of the West is assumed to adopt an Oregon-type standard in 2012. Green tag values are assumed to substantially increase over the remaining forecast period as a result.
- Demand Response capability of 12 1/2 percent of potential is secured by the end of the forecast period in lieu of the 50 percent of potential assumed in the Current Trends scenario.
- The federal renewable resource production tax credit is renewed at its former level ($15 per megawatt-hour in 2000$) for wind resources for a three-year period beginning in 2005. It is renewed for a final five-year period beginning in 2009 at the rate of $10 per megawatt-hour for wind and solar resources. The production tax credit in the Current Trends scenario is assumed to continue at $15 per megawatt-hour throughout the forecast period.
- Renewable portfolio standard and system benefit charge programs are successful in achieving 50 percent of targeted acquisitions in lieu of 75 percent assumed in the current trends case.
- The current FERC price cap of $250 (real) was retained throughout the forecast period. The cap is not in effect in the Current Trends scenario.

The levelized Mid-Columbia electricity price forecast of the Business as Usual scenario is $35.70, 1 percent less than the $36.10 of the Current Trends scenario (Table C-3). Higher natural gas prices appear to offset cost reductions resulting from less aggressive carbon control efforts and reduced federal subsidies resulting from the assumed reduction in the production tax credit. Seasonal peak prices are significantly curtailed, probably by the effect of the price cap, as indicated by the 31 percent reduction in the average of the top ten percent of monthly prices. The effect on resource development is pronounced. Coal increases from 18 percent of the mix in 2025 in Current Trends to 28 percent in Business as Usual. Wind and solar decline from 20 percent to 12 percent. This has a significant effect on fuel consumption and CO_2 production. Coal use over the forecast period is up 15 percent and gas use down 19 percent, largely due to higher natural gas prices. Carbon dioxide production increases 6 percent over the planning period. Though the electricity price effects of the Business-as-Usual future on the region may not be great, the resource and environmental consequences could be significant compared to the Current Trends scenario.

SUMMARY OF CASE RESULTS

Selected results of the base and sensitivity cases are provided in Table C-3. Column definitions are as follows:

Case: Name of the scenario or sensitivity case.

Changes from base: Summarized changes in assumptions from base Current Trends case.

Electricity price forecast: Annual average electricity price forecast for the Mid-Columbia trading hub, discounted and levelized over the 2005-25 forecast period (year 2000 dollars per megawatt-hour).

Average of top10 percent of monthly prices: Average of the highest 10 percent of average monthly forecast prices at the Mid-Columbia trading hub (2000$ per megawatt-hour).

2025 WECC resource mix: The forecast resource mix for WECC as a whole in 2025. Codes are: H - hydropower; C - coal; G - natural gas and I - wind and solar (percent of total capacity).

WECC coal use (2005-2025): Total forecast coal use for WECC as a whole over the forecast period (trillions of Btu).

WECC gas use (2005-25): Total forecast natural gas use for WECC as a whole over the forecast period (trillions of Btu).

WECC CO_2 production (2005-25): Total forecast carbon dioxide production for WECC as a whole over the forecast period (millions of tons CO_2).

WECC long-term reserve margin: Average capacity reserve margin WECC as a whole for the years 2016-2025 (percent).

PNW long-term L/R Balance: Average Pacific Northwest energy load-resource balance for the years 2016-25 (average megawatts).

Appendix C1

FORECAST ANNUAL AVERAGE POWER PRICES FOR NORTHWEST LOAD-RESOURCE AREAS (2000$ PER MEGAWATT-HOUR)

Year	West of Cascades (PNW Westside)	Mid-Columbia (PNW Eastside)	S. Idaho	E. Montana
2004	33.66	33.10	32.52	31.76
2005	28.58	28.05	27.51	26.71
2006	30.17	29.65	29.29	28.37
2007	33.25	32.87	32.57	31.32
2008	35.69	35.24	35.41	33.69
2009	35.23	34.71	33.79	33.13
2010	37.62	37.09	35.56	34.97
2011	37.85	37.34	36.26	35.42
2012	37.97	37.55	35.95	35.28
2013	39.39	38.72	37.01	35.46
2014	39.42	38.73	36.90	34.43
2015	39.77	39.03	37.19	34.07
2016	36.53	35.95	34.10	31.30
2017	38.39	37.85	36.10	33.19
2018	39.56	39.09	38.40	34.72
2019	38.18	37.76	36.87	33.41
2020	37.94	37.46	36.56	32.96
2021	39.21	38.71	38.05	34.53
2022	40.16	39.59	38.74	35.25
2023	39.82	39.28	39.34	35.27
2024	39.53	38.47	38.05	34.11
2025	37.93	36.94	36.95	32.54

Current Trends forecast (022004)

Appendix C2

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

Appendix C3

BASE YEAR LOADS AND FORECAST LOAD GROWTH RATES FOR THE WECC LOAD-RESOURCE AREAS

	Base (Year 2000) Load[a] (Average Megawatts)	**Average Annual Load Growth, 2000-2025**
PNW Eastside (WA & OR E. of Cascade crest, Northern ID & MT west of Continental Divide.	5901	0.1 percent
PNW Westside (WA & OR W. of Cascade crest)	13219	0.7 percent
PNW Southern ID (~IPC territory)	2377	1.1 percent
PNW Eastern MT (MT east of Continental Divide)	808	0.3 percent
BC	7324	1.3 percent
Alberta	5824	1.5 percent
Northern CA (N. of Path 15)	13111	1.4 percent
Southern CA (S. of Path 15)	17451	1.6 percent
WY	1764	0.6 percent
CO	5451	2.2 percent
NM	2755	2.9 percent
AZ	7706	2.4 percent
UT	2938	2.7 percent
Northern NV (~ SPP territory)	1173	2.0 percent
Southern NV (~ NPC territory)	2340	2.6 percent
Baja California Norte	1015	2.5 percent
Total	**91158**	**1.6 percent**

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

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Appendix D. 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 just over 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

Achievable Conservation Potential - Medium Forecast and Natural Gas Prices with Average Hydro Generation Output			
Sector and End-Use	Cost-Effective Savings Potential (MWa in 2025)	Average Real Levelized Cost (Cents/kWh)[6]	Benefit-to-Cost Ratio[7]
Residential Compact Fluorescent Lights	535	1.7	2.3
Residential Heat Pump Water Heaters	195	4.3	1.1
Residential Clothes Washers	135	5.2	2.6
Residential Existing Space Conditioning - Shell	95	2.6	1.9
Residential Water Heaters	80	2.2	2.3
Residential HVAC System Conversions	70	4.3	2.1
Residential HVAC System Efficiency Upgrades	65	2.9	1.2
Residential New Space Conditioning - Shell	40	2.5	2.0
Residential Hot Water Heat Recovery	25	4.4	1.1
Residential HVAC System Commissioning	20	3.1	1.9
Residential Dishwashers	10	1.6	2.6
Residential Refrigerators	5	2.1	2.2
Commercial New & Replacement Lighting	245	1.2	9.1
Commercial New & Replacement HVAC	148	3.0	1.5
Commercial Retrofit HVAC	117	3.4	1.3
Commercial Retrofit Lighting	114	1.8	2.2
Commercial Retrofit Equipment[3]	109	3.4	2.1
Commercial Retrofit Infrastructure[4]	105	2.2	1.8
Commercial New & Replacement Equipment[3]	84	2.2	1.8
Commercial New & Replacement Shell	13	1.6	2.0
Commercial New & Replacement Infrastructure[4]	11	1.4	2.4
Commercial Retrofit Shell	9	2.9	1.3
Industrial Non-Aluminum	350	1.7	2.0
Agriculture - Irrigation	80	1.6	3.2
New & Replacement AC/DC Power Converters[5]	156	1.5	2.7
Total	**2814**	**2.4**	**2.7**

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] Commercial equipment includes refrigeration equipment and controls, computer and office equipment controls and laboratory fume hoods.
[4] Commercial infrastructure includes sewage treatment, municipal water supply, LED traffic lights, and LED exit signs.
[5] Measure occurs in residential, commercial and industrial sectors

conservation is 2.4 cents per kilowatt-hour (2000$).[6] In aggregate, these resources have a benefit-to-cost ratio of 2.5-to-1.0.[7] 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.[8] 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

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[6] These levelized costs do not include the 10-percent credit given to conservation in the Northwest Power Act.
[7] 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.
[8] 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.

acquisition should reach an 85 percent penetration rate. Under the medium forecast this would be about 70 average megawatts per 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.[9] 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.

[9] 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.

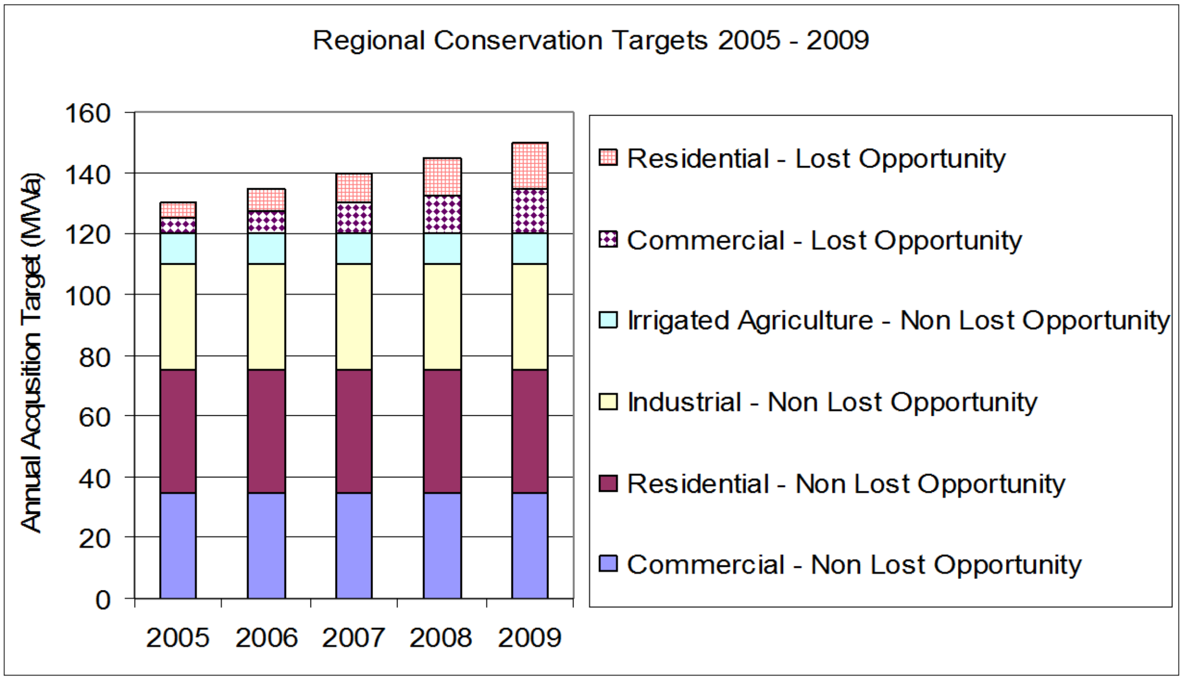
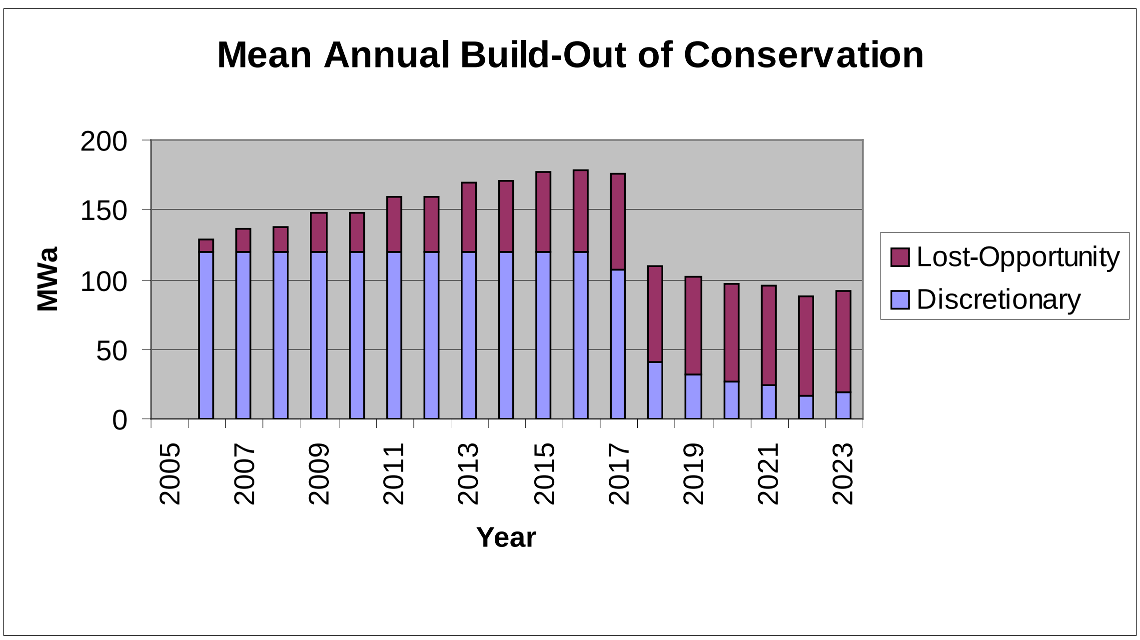


Figure D-1: Regional Conservation Targets 2005 -



2009

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.[10] 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 conservationpotential 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.[11] 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,

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10 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.

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

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.

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.[12] 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.

[12] 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.

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.

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.[13] The Council envisions continued market transformation efforts will yield similarly impressive results at similarly low costs.

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

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[13] 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

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[14] 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.

14 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,[15] 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

[15] 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.[16]

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

[16]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.[17] 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.[18] 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.

[18] 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

	Acquisition Mechanism									
	Market Transformation					Regional Program			Local Program	
Measure	**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 two-thirds 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	155	2.3	4.7	$2,739	14%
Lighting Equipment	125	0.3	12.3	$211	11%
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	1%
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	1	2.8	0.7	$4,073	0.1%
Perimeter Day Lighting	1	6.3	0.9	$7,441	0.1%
Evaporative Assist Cooling	0				0.0%
Total	**655**	**1.8**	**4.7**	**$1,830**	**59%**

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	9.6	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	0.1	Yes		Continue		Continue			
Perimeter Day Lighting	0.1	Yes	Continue			Continue			
Evaporative Assist Cooling	0.0	Potential	Continue	New	New	New	New		
Total	**50**								

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 125 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	6.8%
Network Computer Power Management	61	2.8	1.3	$1,008	5.5%
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	2.2%
Office Plug Load Sensor	13	3.1	1.2	$2,664	1.2%
LED Traffic Lights	8	1.9	1.8	$3,234	0.7%
High-Performance Glass	9	2.9	1.3	$4,156	0.8%
Adjustable Speed Drives	3	4.3	1.1	$7,545	0.3%
Total	**454**	**2.5**	**1.7**	**$1,879**	**41%**

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	
LED Traffic Lights	3.0	Yes						
High-Performance Glass	3.3	Yes			Continue			
Adjustable Speed Drives	1.3	Yes		Continue				
Total	**175**							

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 9 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, 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.

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.

Appendix E. 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.

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[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.

Value of Energy Saved

Given the interconnected nature of the West, regional wholesale power prices reflect the significant demand for summer air conditioning in California, Nevada and the remainder of the desert Southwest. Consequently, wholesale power prices are 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.

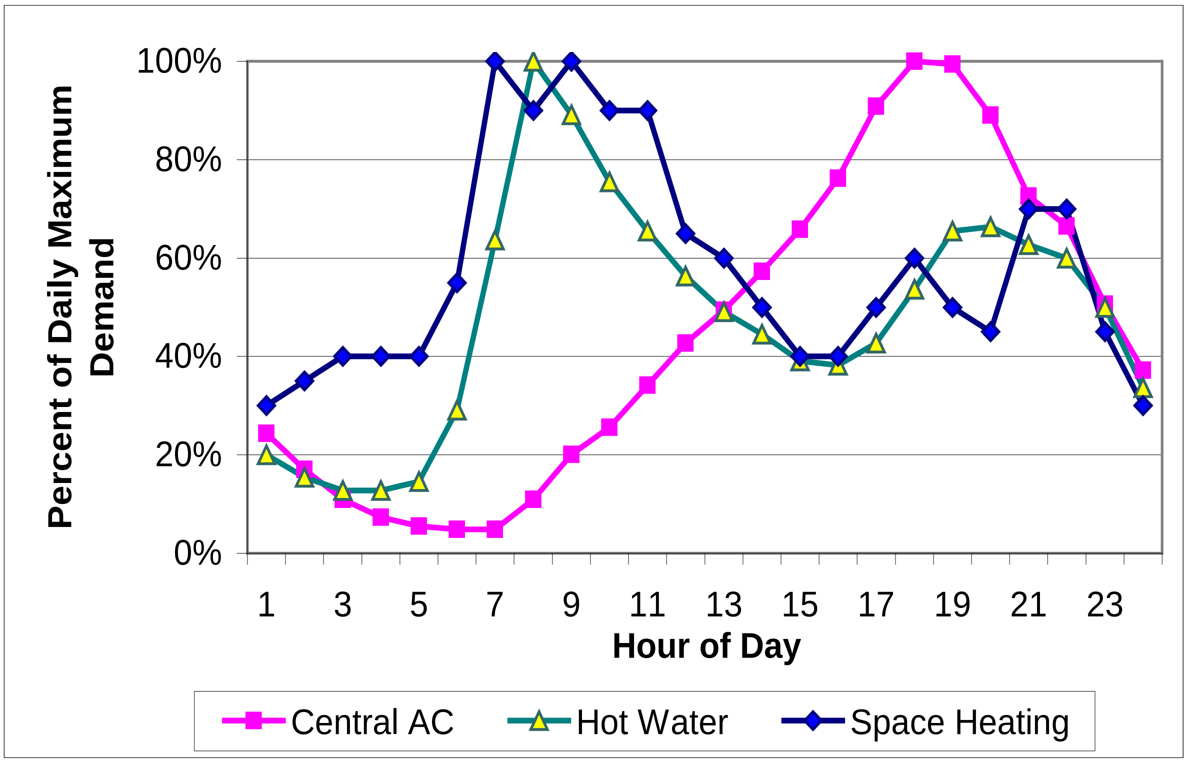

Figure E-1: Hour Load Profile for Residential Central Air Conditioning Water Heating and Space Heating Conservation Savings

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.

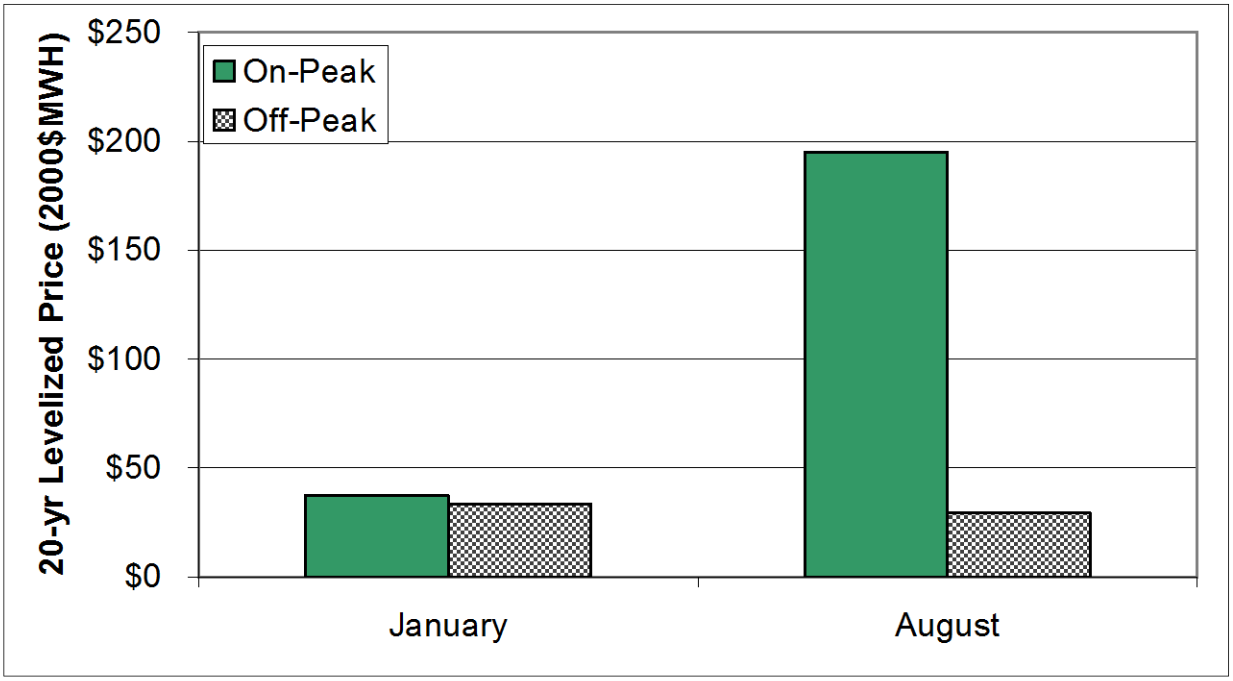

Figure E-2: Forecast Levelized "On" and "Off-Peak" Wholesale Power Market Prices for January and August at Mid Columbia Trading HUB

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.

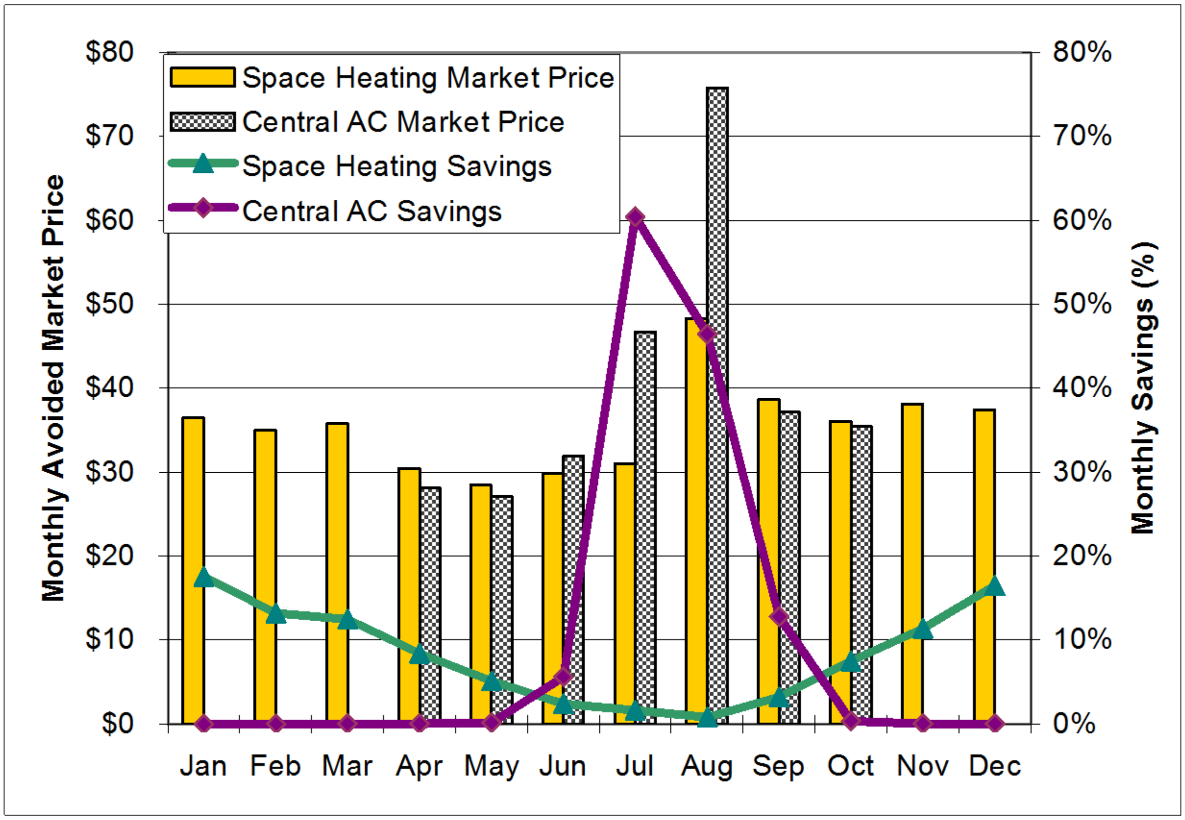

Figure E-3: Illustrative Levelized Wholesale Market Price by Month Compared to Monthly Energy Savings for Space Heating and Central Air Conditioning

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.

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[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.

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 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

[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.

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
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

Appendix F. 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. 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:

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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.]

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. 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.

[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 7,500 heating degree days.

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]

Component	Climate Zone 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 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 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.

The Council finds that measures required to meet the ASHRAE Standard 90.1-2001 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 90.1-2001do not capture all regionally cost-effective savings.

As with the residential model conservation standard, flexibility is encouraged in designing paths to achieve the commercial model conservation standards.

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.

Appendix G. 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.

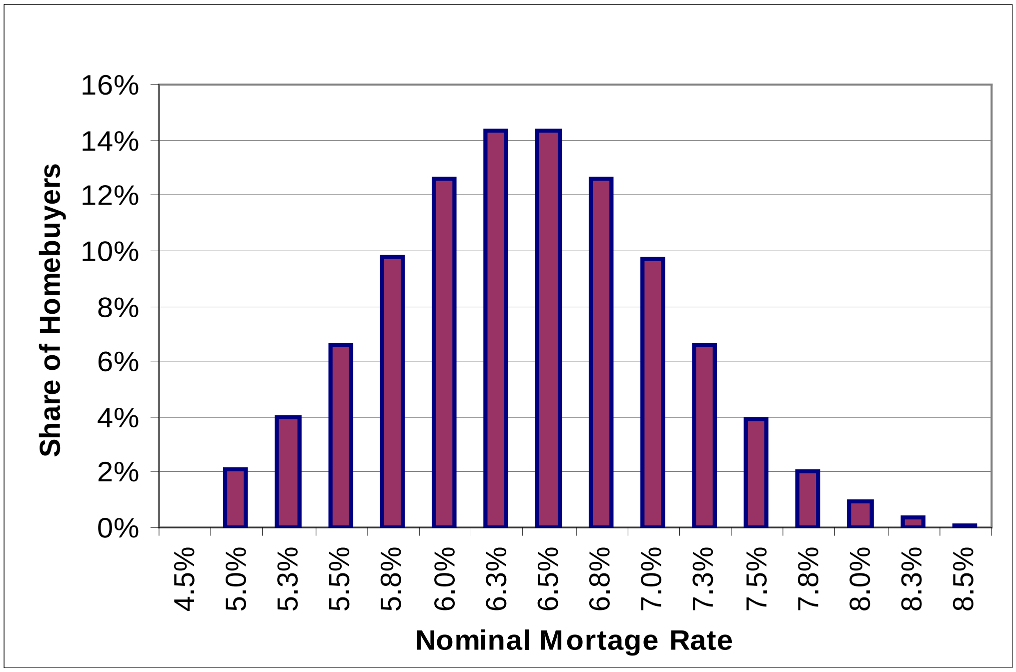

Figure G-1: Nominal Mortgage Rates - All Climate Zones for Single Family Homes

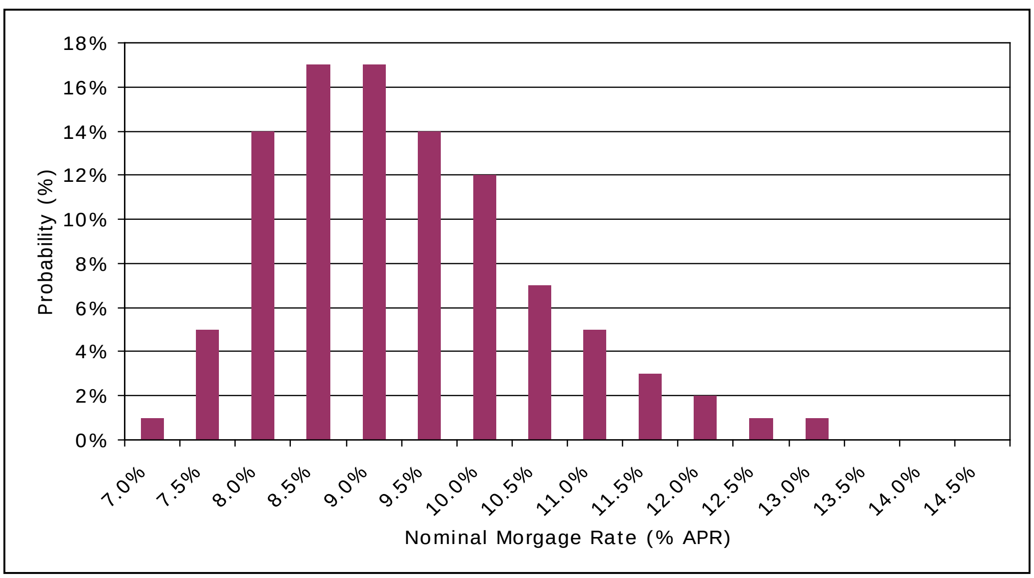

Figure G-2: Nominal Mortgage Rates - All Climate Zones for Manufactured Homes

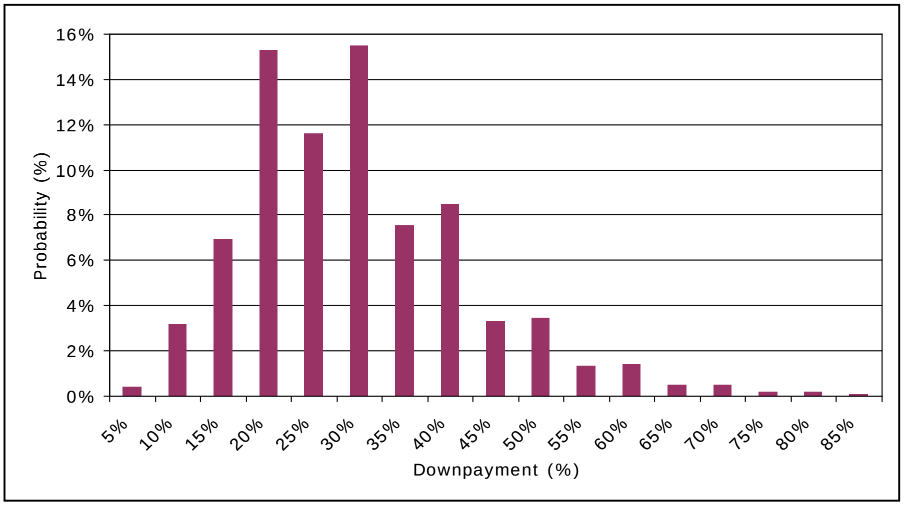

Figure G-3: Down payment Fraction for Single Family and Manufactured Homes- All Climate Zones

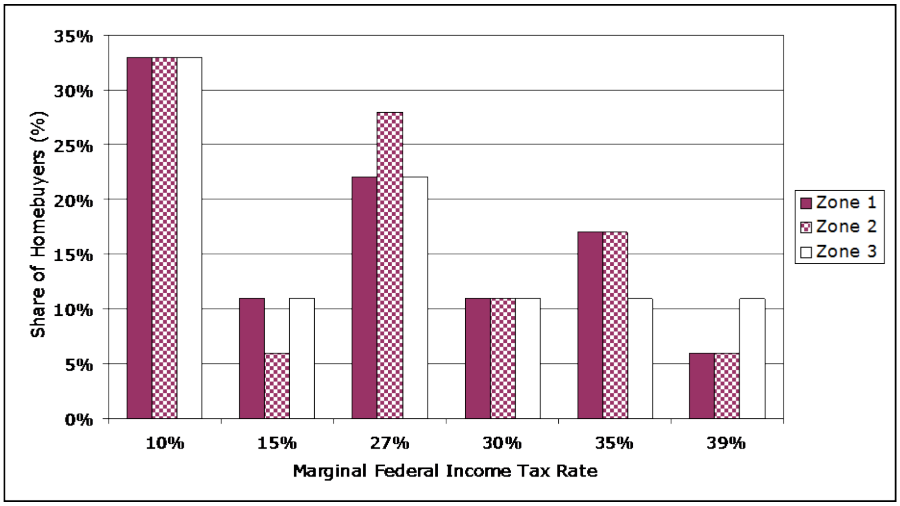

Figure G-4: Marginal Federal Income Tax Rates for Single Family and Manufactured Homes by Climate Zone

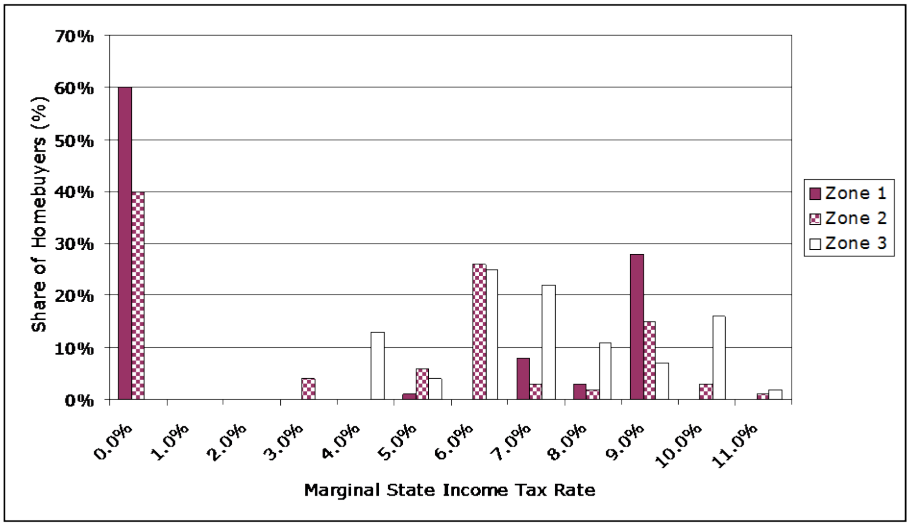

Figure G-5: Marginal State Income Tax Rates for Single Family and Manufactured Homes by Climate Zone

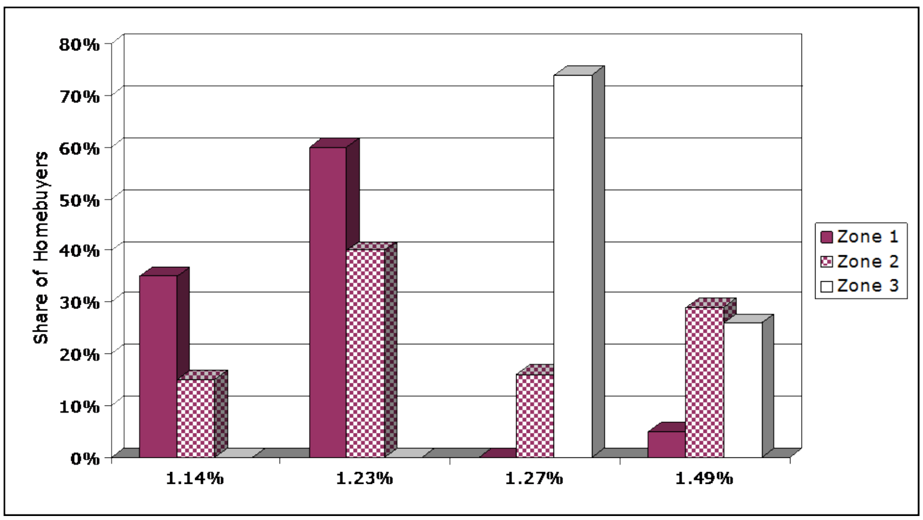

Figure G-6: Property Tax Rates by Climate Zone

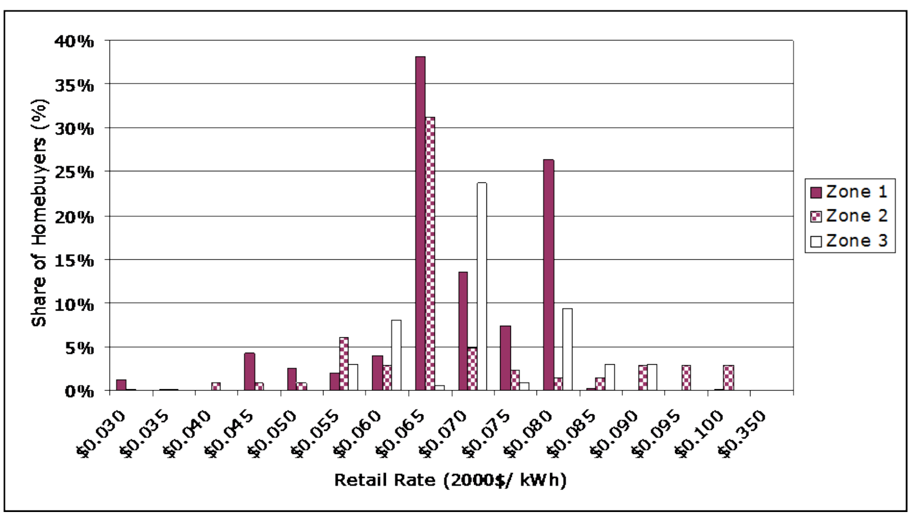

Figure G-7: Base Year Retail Electric Rates by Climate Zone

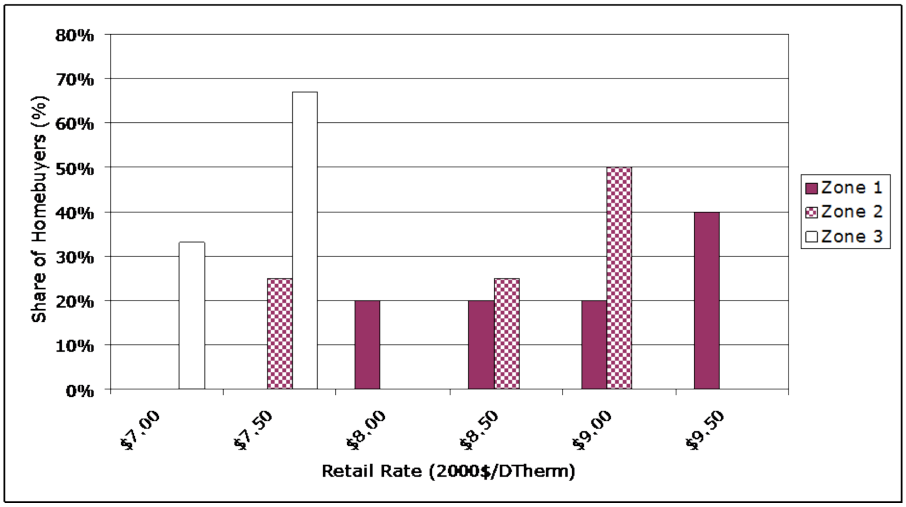

Figure G-8: Base Year Retail Natural Gas Rates by Climate Zone

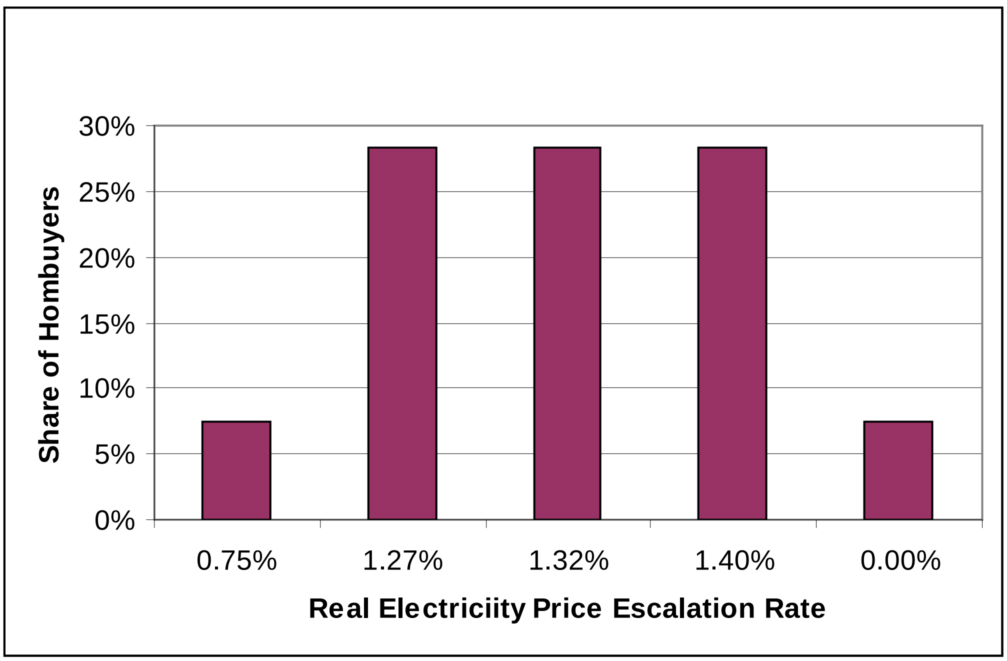

Figure G-9: Real Escalation Rates for Electricity Prices - All Climate Zones

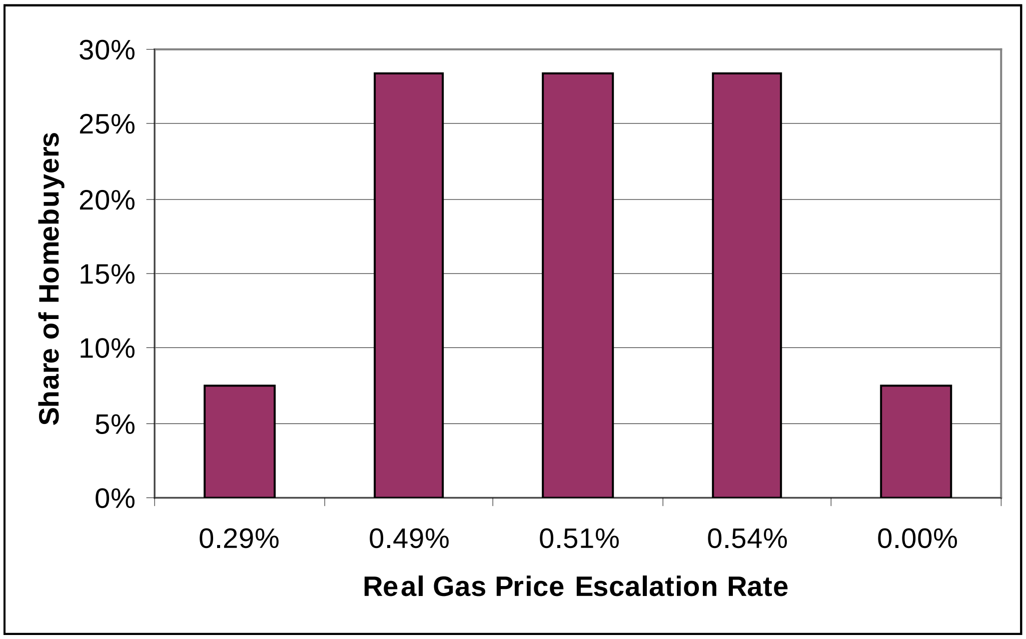

Figure G-10: Real Escalation Rates for Natural Gas Prices - All Climate Zones

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.

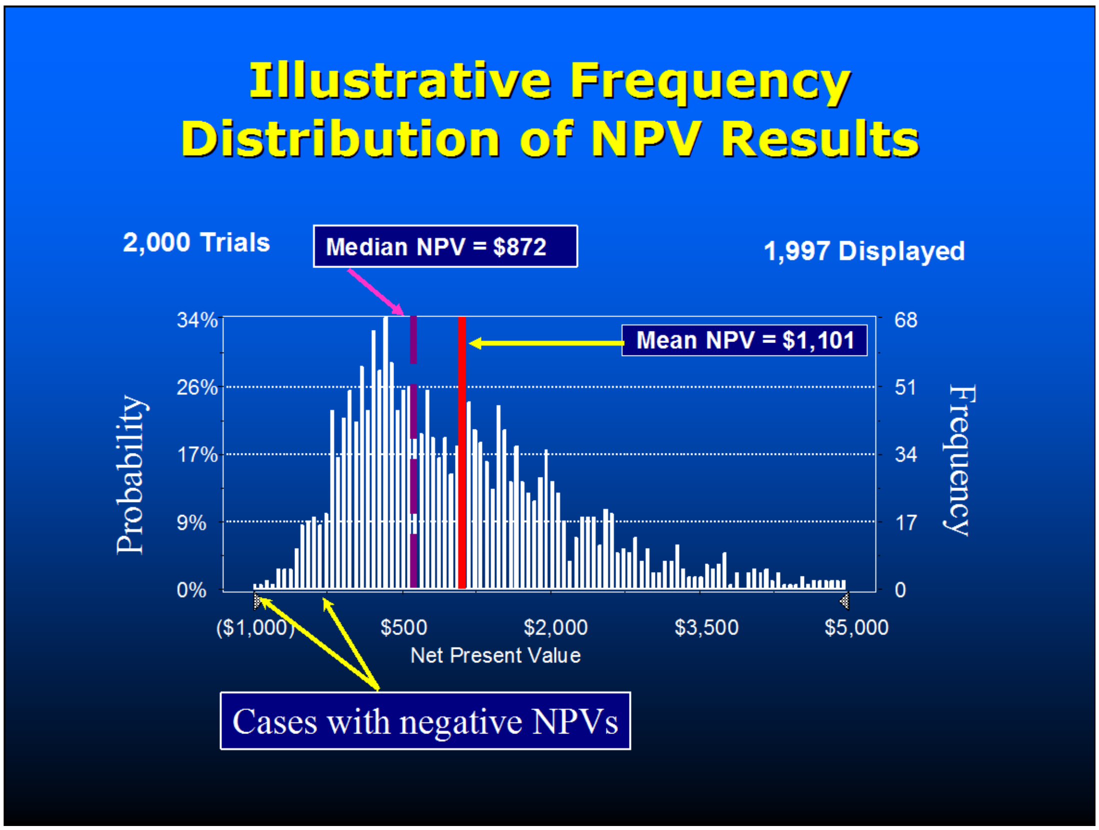

Figure G-11: Illustrative Distribution of Net Present Value Results

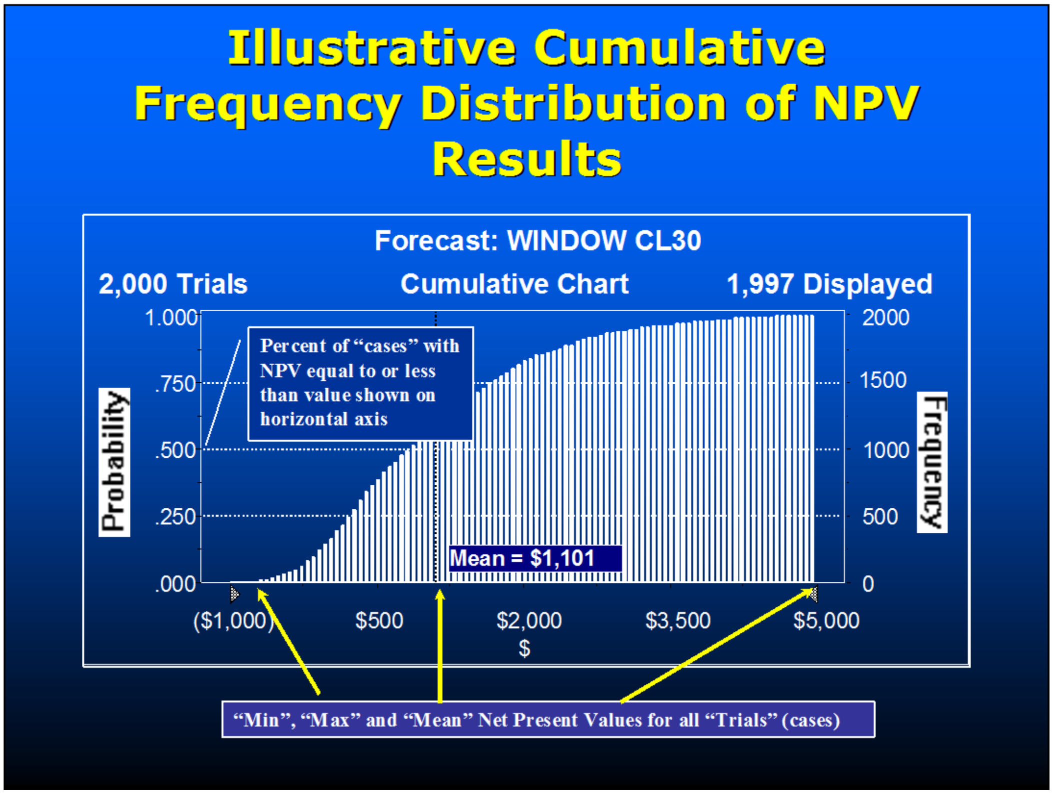

Figure G-12: Illustrative Cumulative Distribution of Net Present Value Results

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

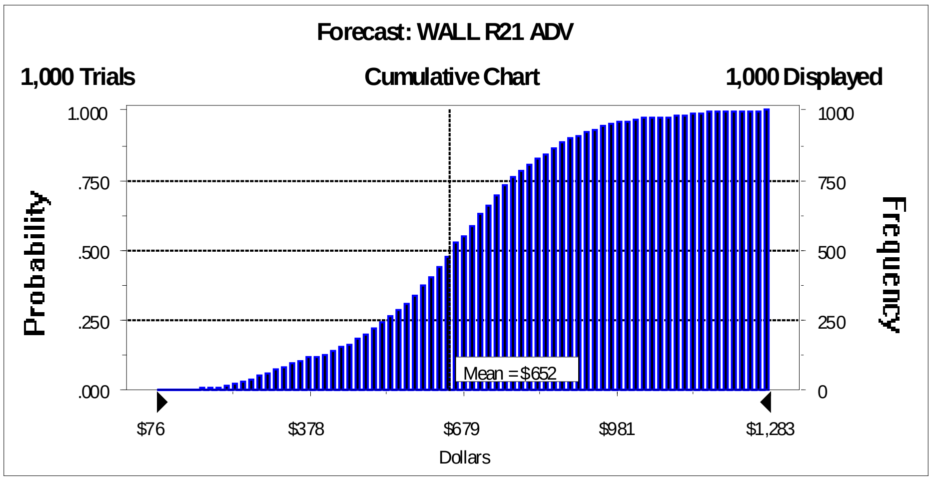

Figure G-13: Climate Zone 1 R21 Above Grade Wall NPV Results for Heat Pumps

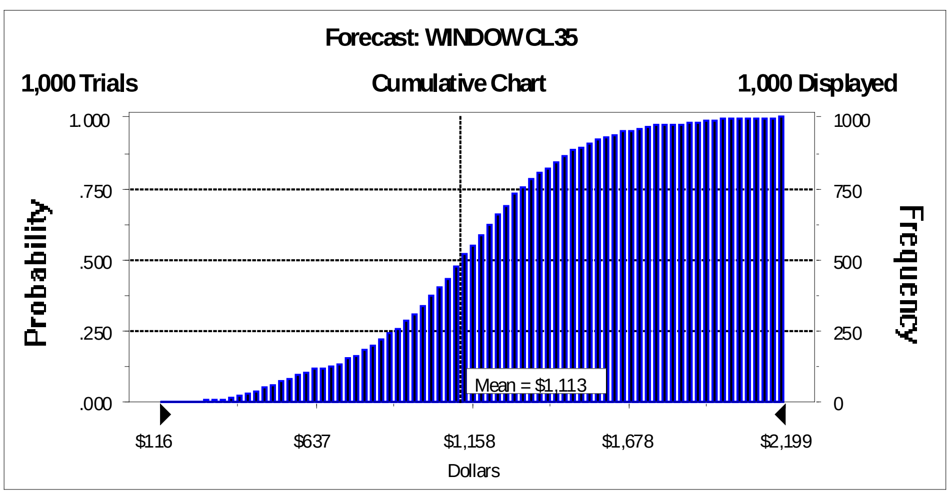

Figure G-14: Climate Zone 1 Class 35 Window NPV Results for Heat Pumps

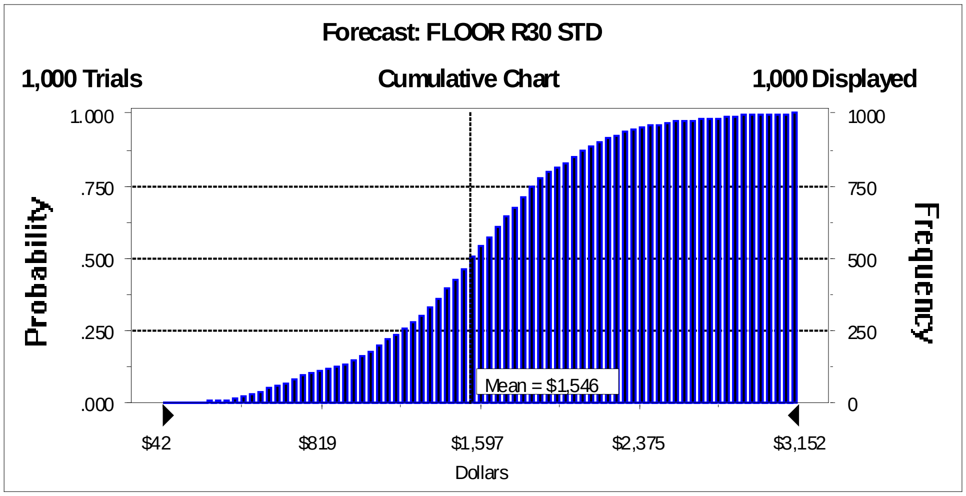

Figure G-15: Climate Zone 1 R30 Under floor NPV Results for Heat Pumps

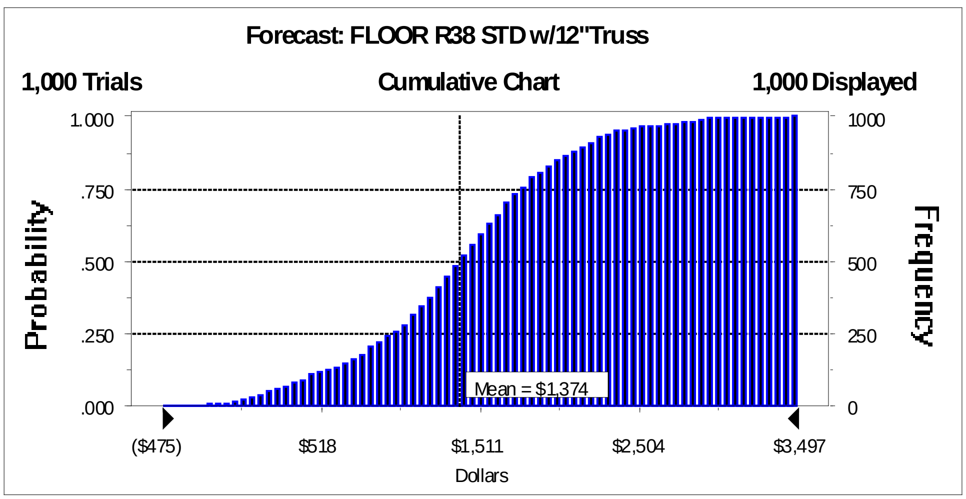

Figure G-16: Climate Zone 1 R38 Under floor NPV Results for Heat Pump

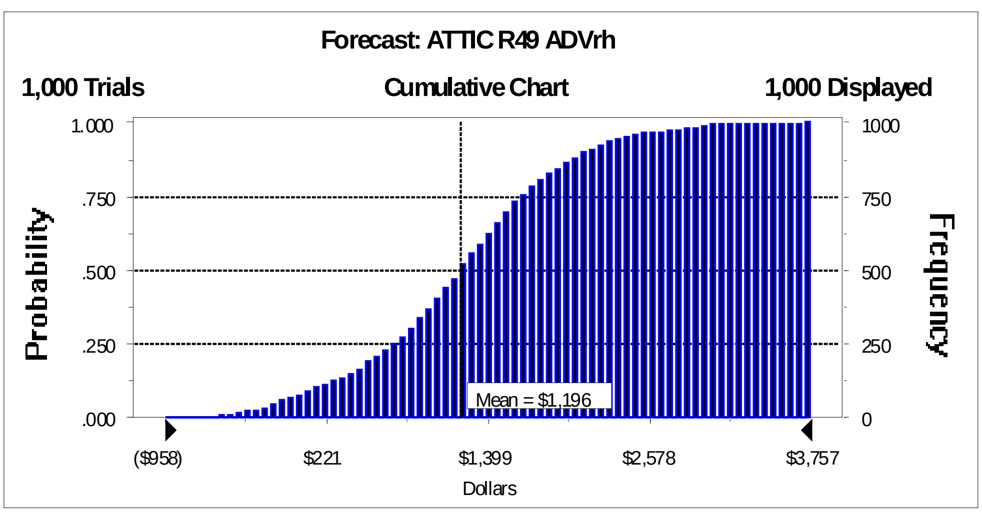

Figure G-17: Climate Zone 1 R49 Advance Framed Attic NPV Results for Heat Pumps

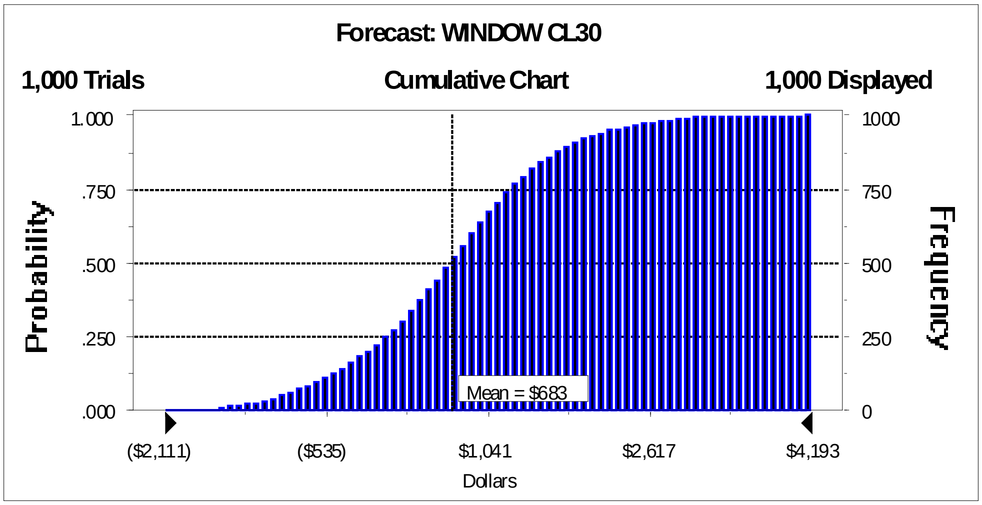

Figure G-18: Climate Zone 1 Class 30 Window NPV Results for Heat Pumps

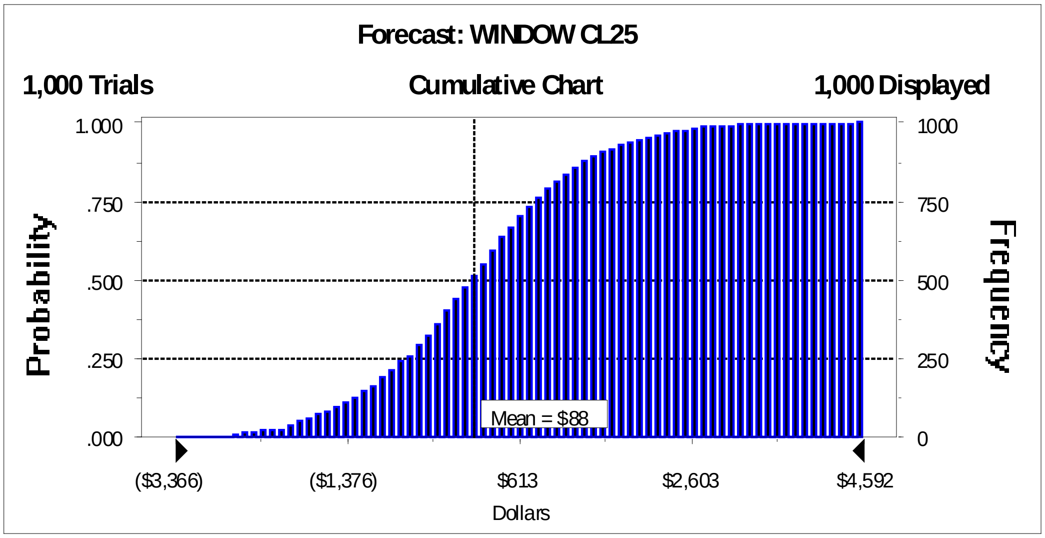

Figure G-19: Climate Zone 1 Class 25 Window NPV Results for Heat Pumps

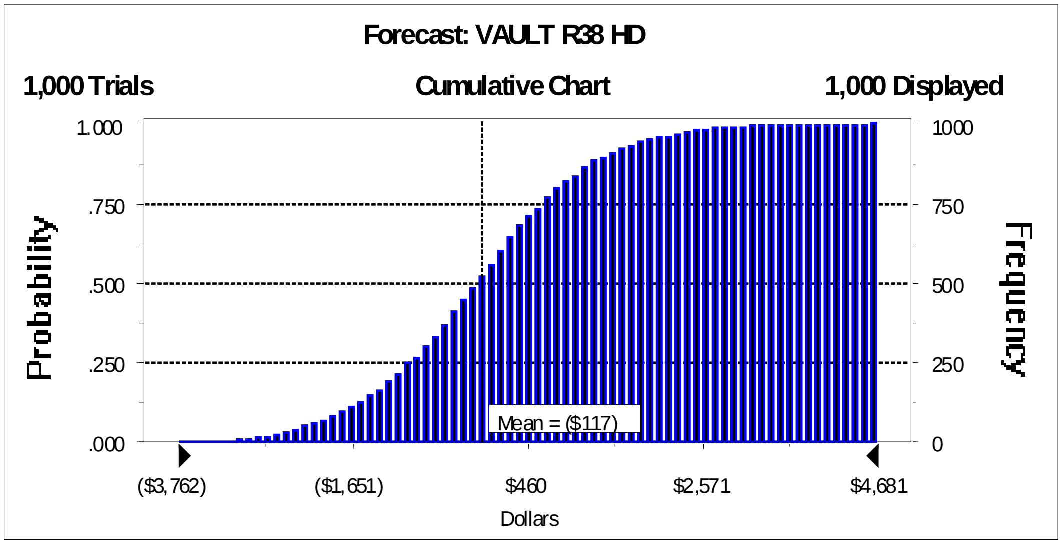

Figure G-20: Climate Zone 1 R38 Vaulted Ceiling NPV Results for Heat Pumps

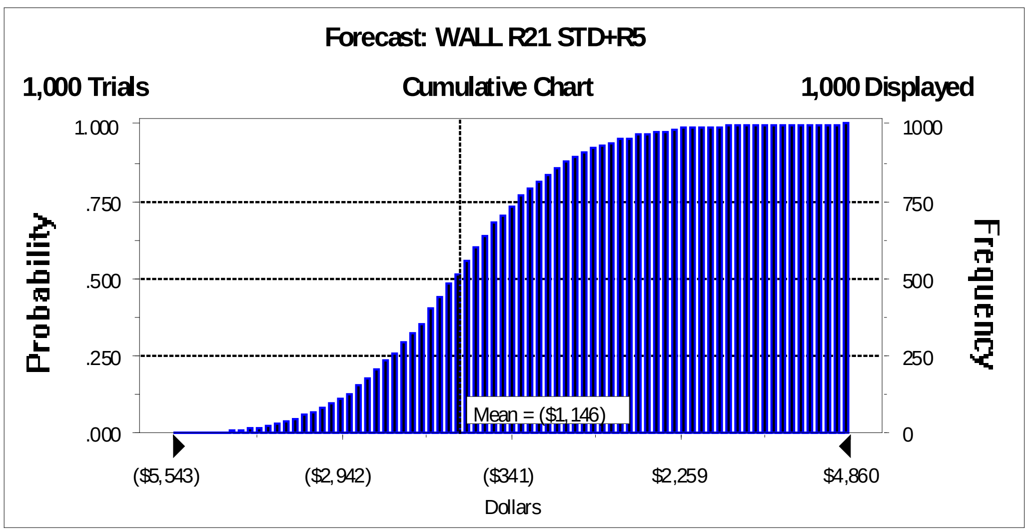

Figure G-21: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Heat Pumps

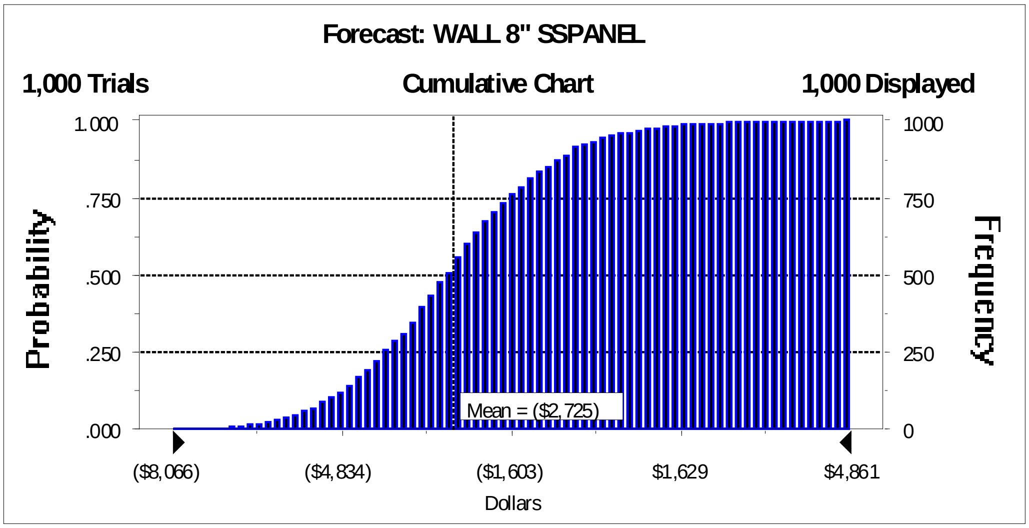

Figure G-22: Climate Zone 1 R33 Wall NPV Results for Heat Pumps

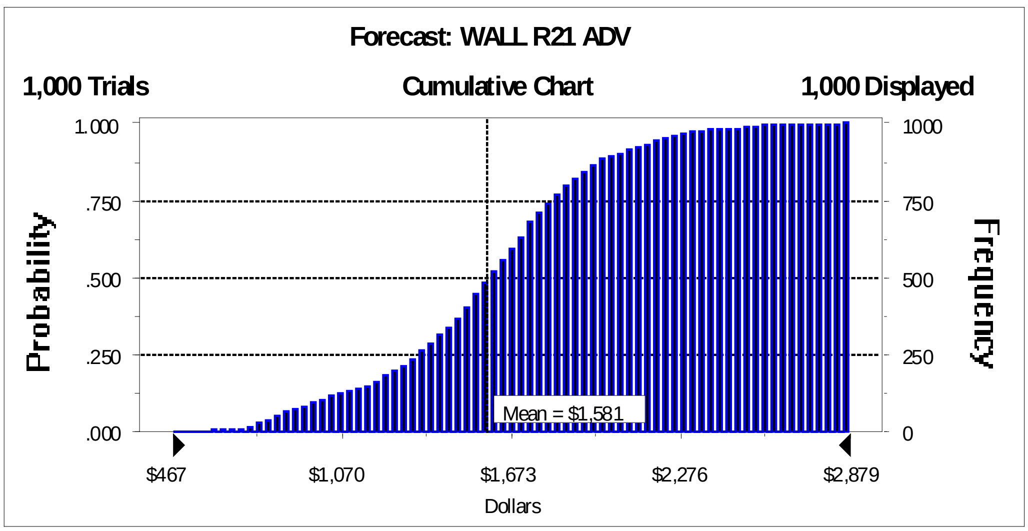

Figure G-23: Climate Zone 1 R21 Above Grade Wall NPV Results for Electric FAF

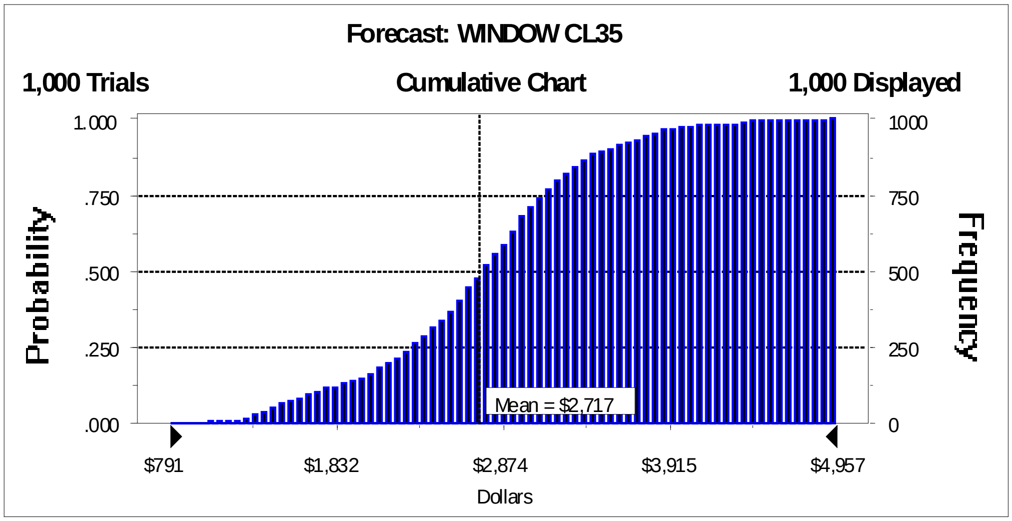

Figure G-24: Climate Zone 1 Class 35 Window NPV Results for Electric FAF

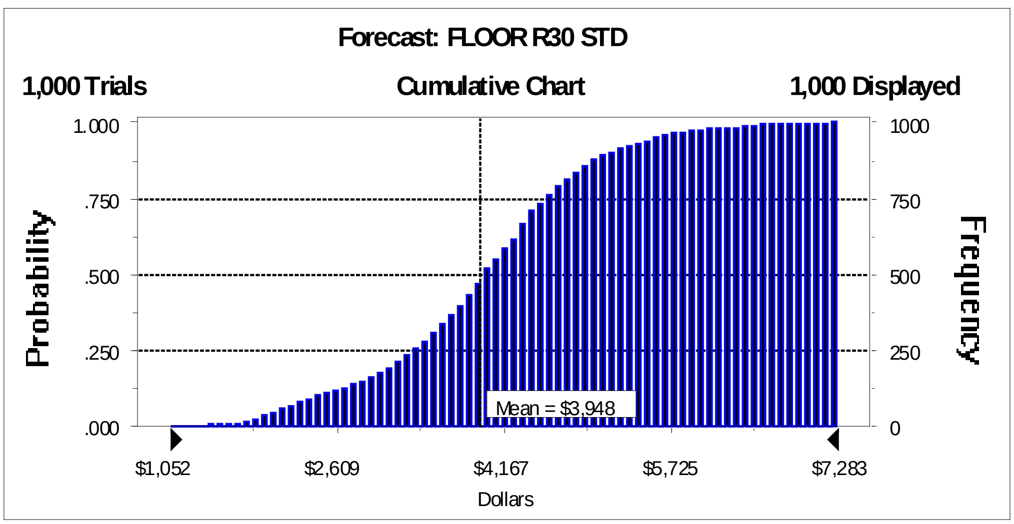

Figure G-25: Climate Zone 1 R30 Under floor NPV Results for Electric FAF

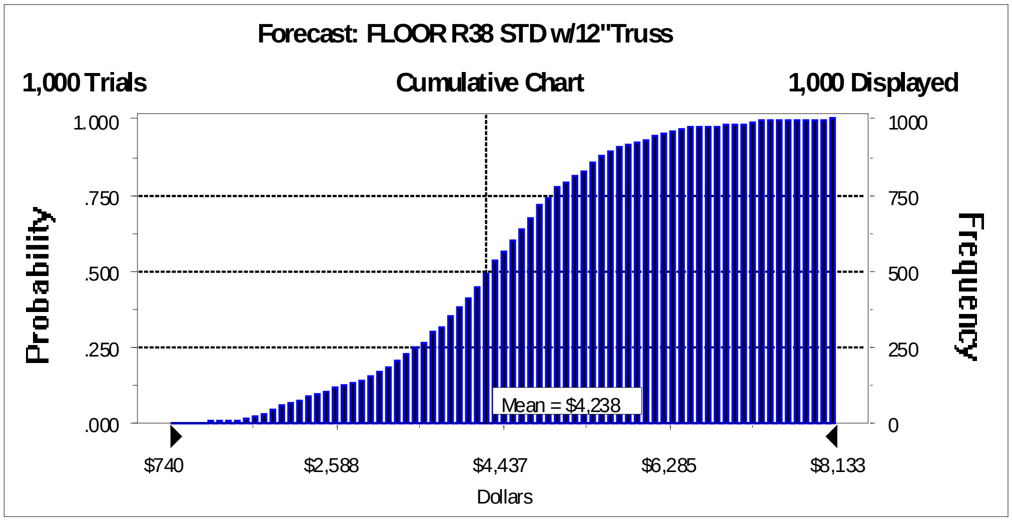

Figure G-26: Climate Zone 1 R38 Under floor NPV Results for Electric FAF

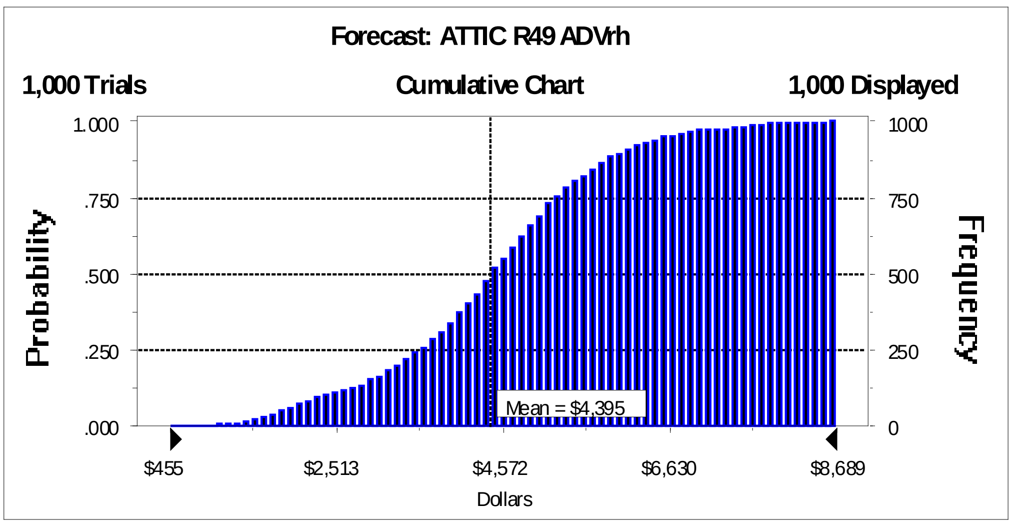

Figure G-27: Climate Zone 1 R49 Advanced Framed Attic NPV Results for Electric FAF

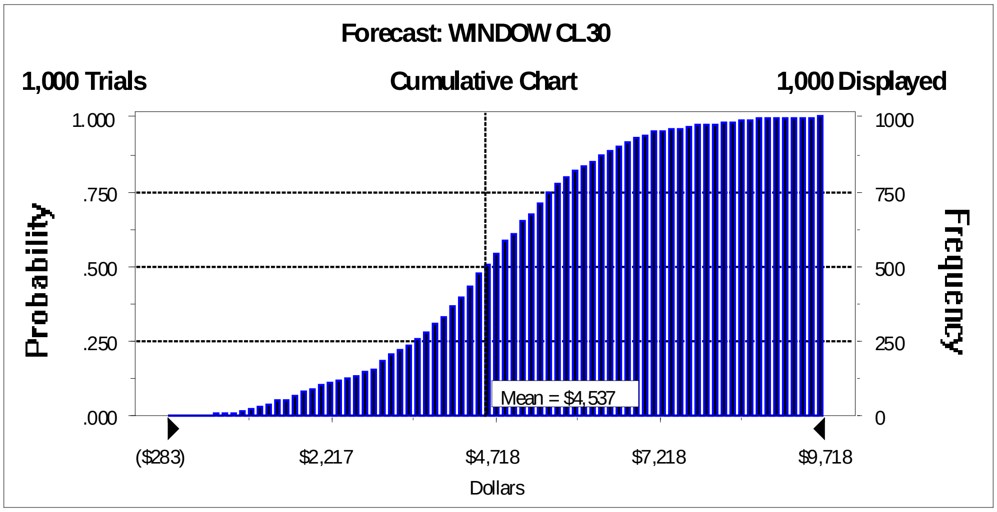

Figure G-28: Climate Zone 1 Class 30 Window NPV Results for Electric FAF

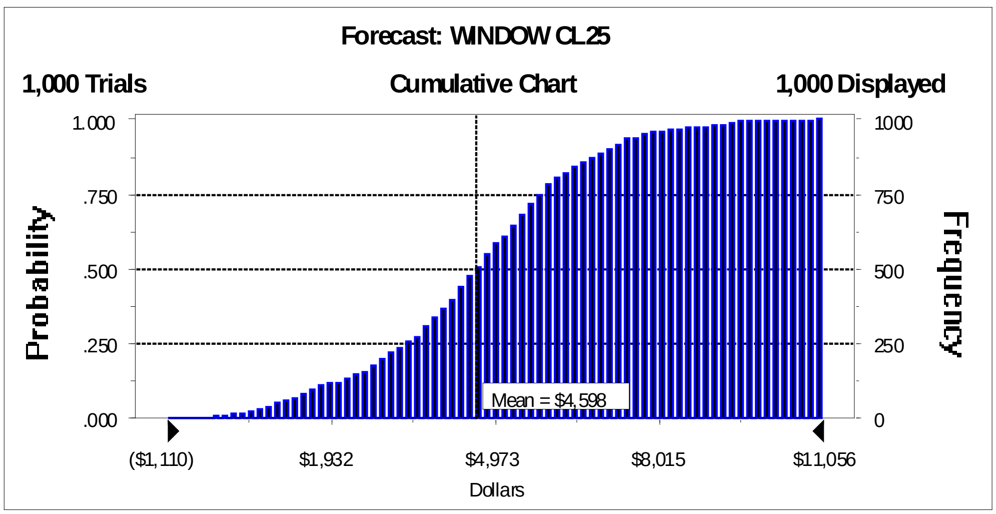

Figure G-29: Climate Zone 1 Class 25 Window NPV Results for Electric FAF

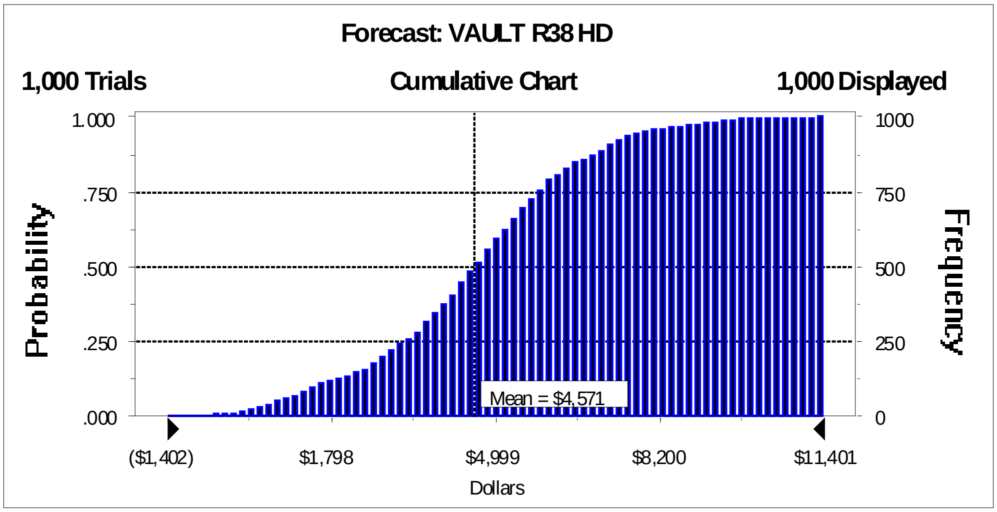

Figure G-30: Climate Zone 1 R38 Vaulted Ceiling NPV Results for Electric FAF

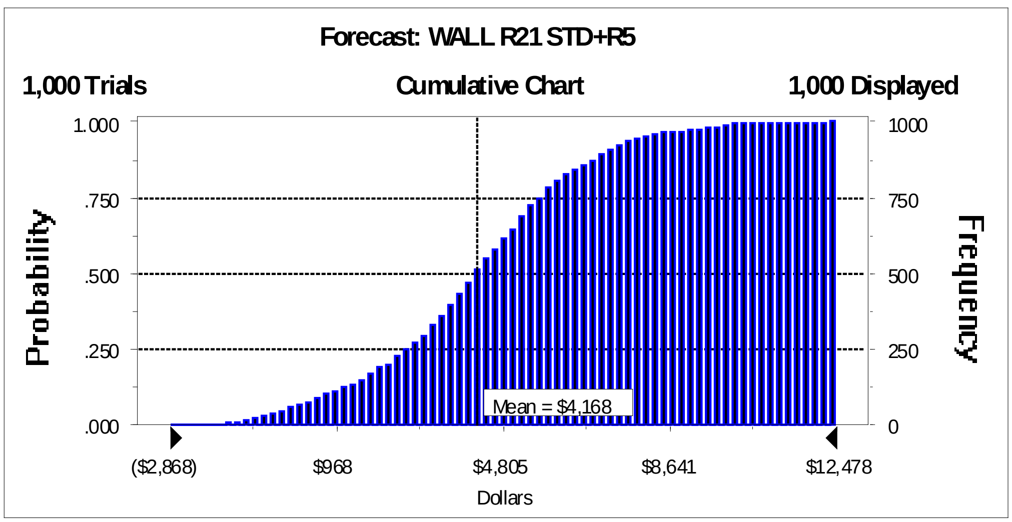

Figure G-31: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Electric FAF

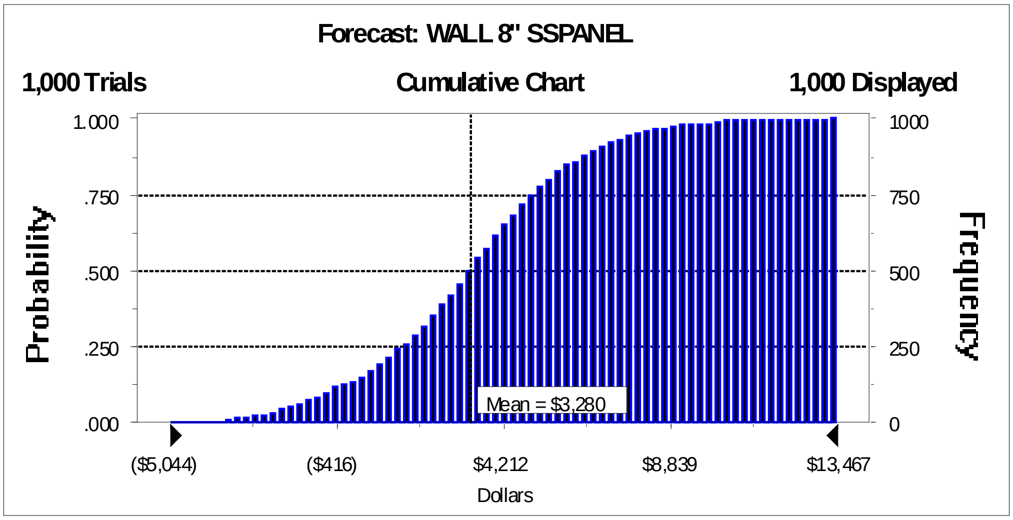

Figure G-32: Climate Zone 1 R33 Wall NPV Results for Electric FAF

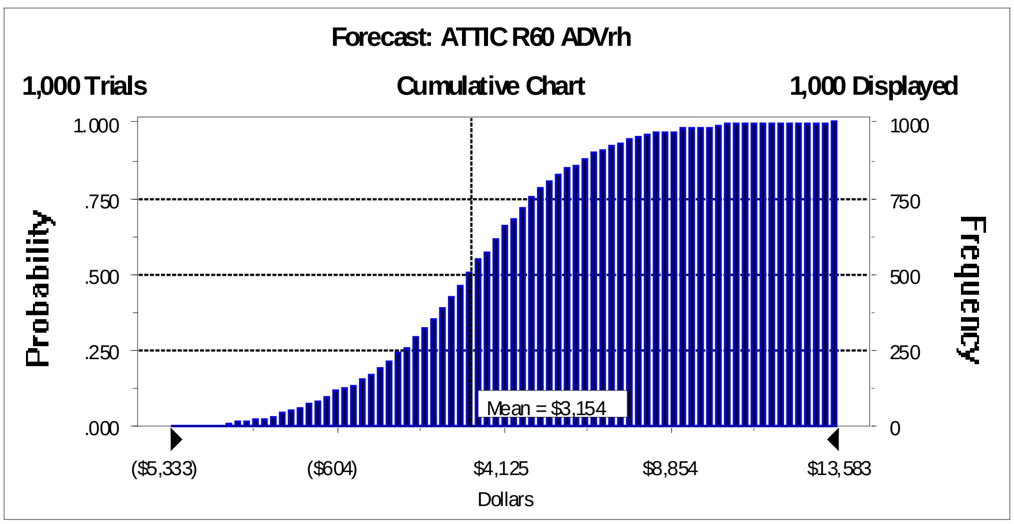

Figure G-33: Climate Zone 1 R60 Attic NPV Results for Electric FAF

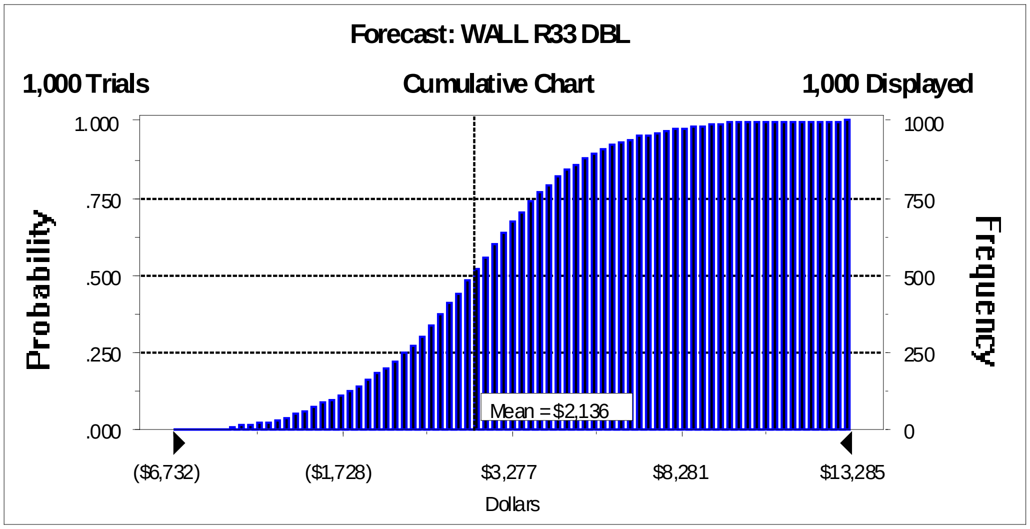

Figure G-34: Climate Zone 1 NPV Results for Electric FAF

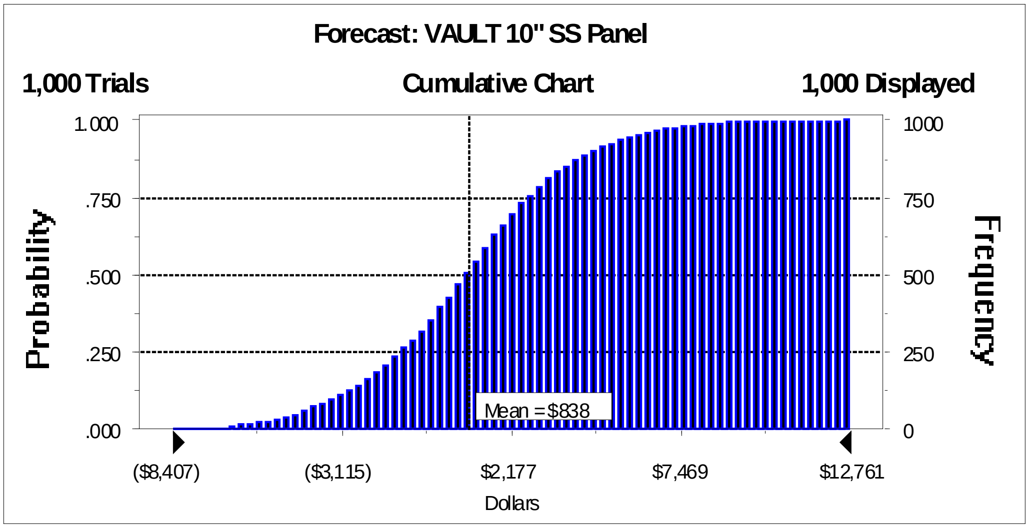

Figure G-35: Climate Zone 1 R38 Wall NPV Results for Electric FAF

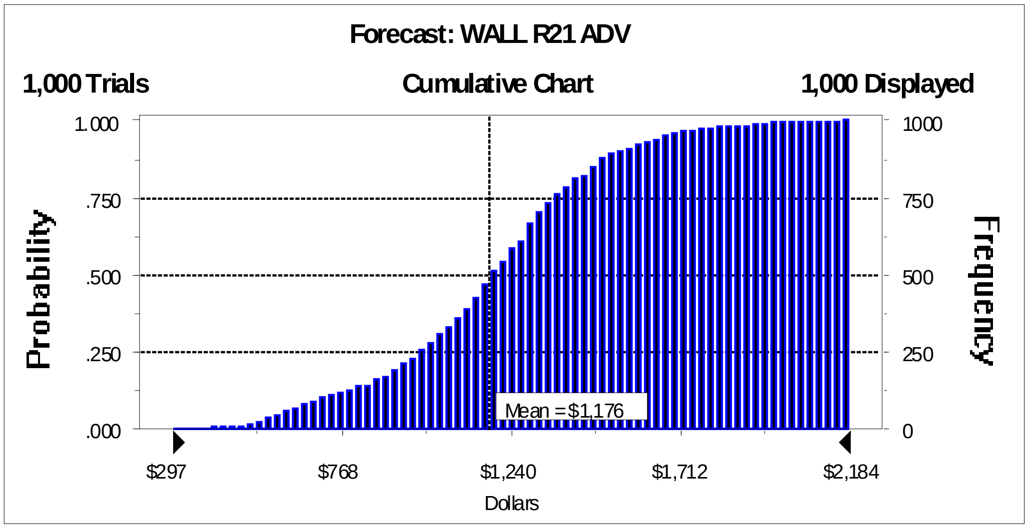

Figure G-36: Climate Zone 1 R21 Wall NPV for Electric Zonal

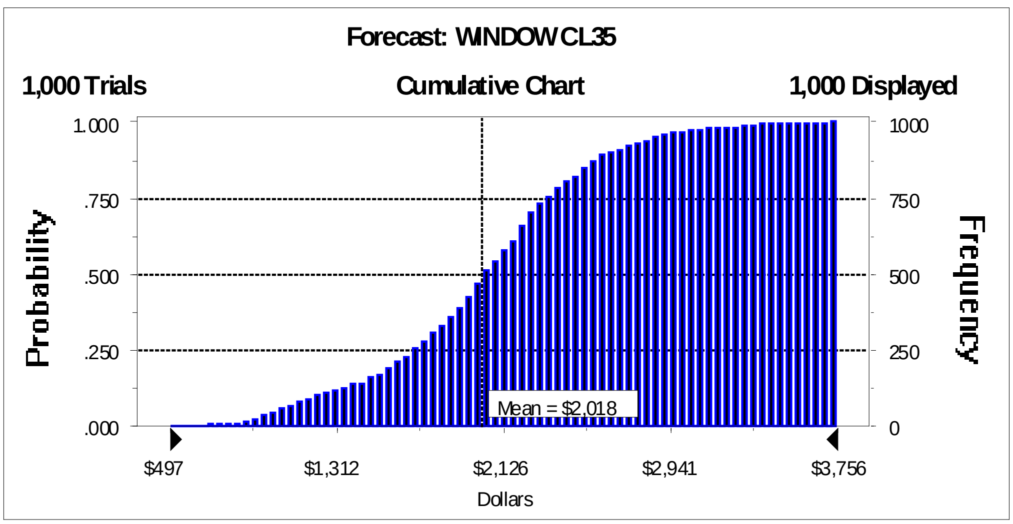

Figure G-37: Climate Zone 1 Class 35 Windows NPV Results for Electric Zonal

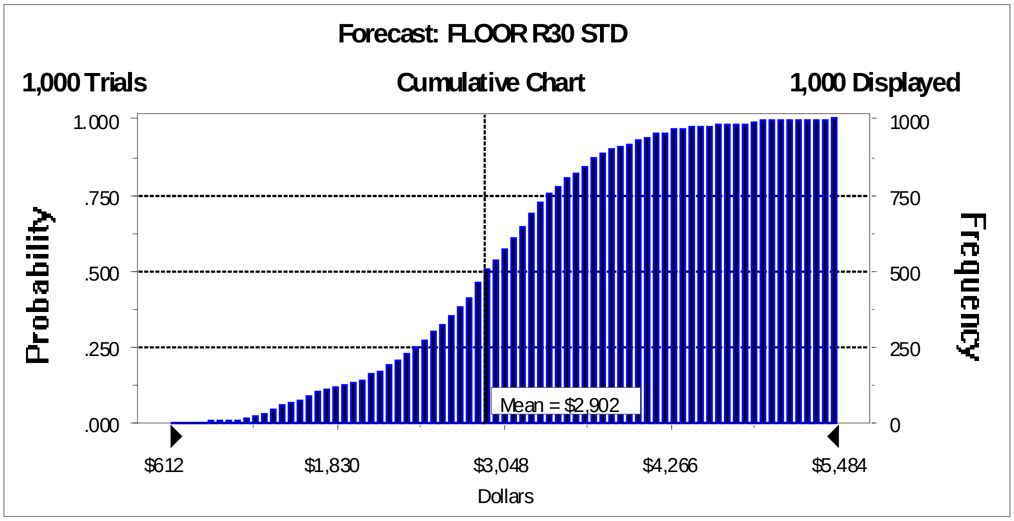

Figure G-38: Climate Zone 1 R30 Under floor NPV Results for Electric Zonal

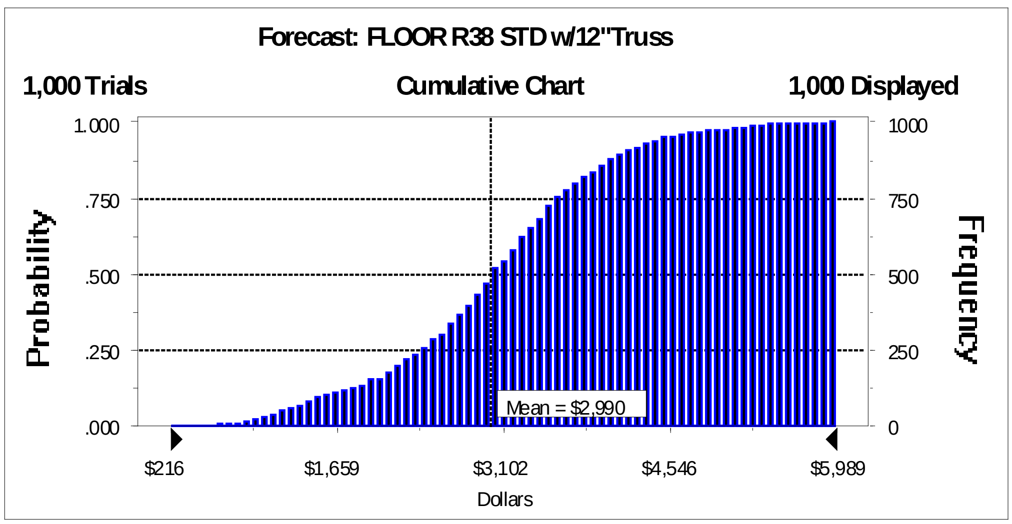

Figure G-39: Climate Zone 1 R38 Under floor NPV Results for Electric Zonal

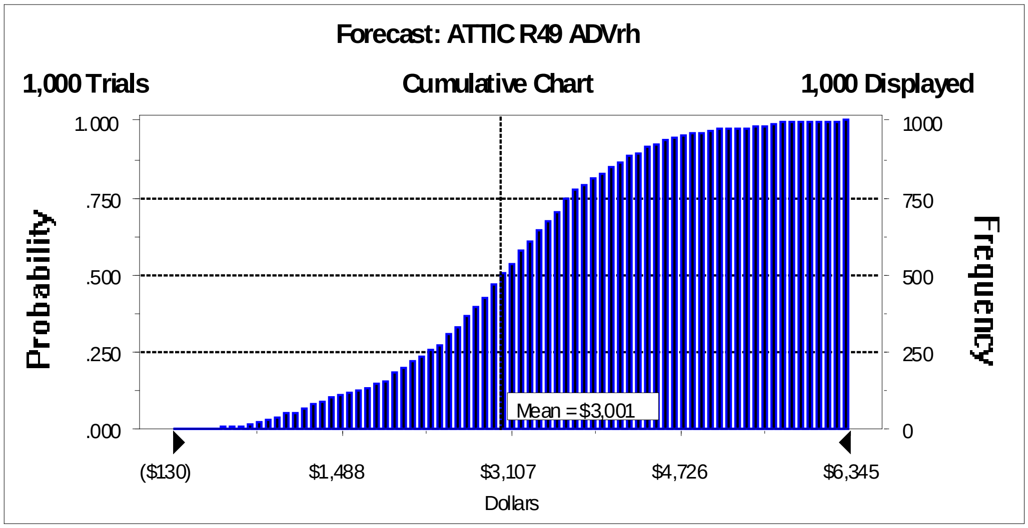

Figure G-40: Climate Zone 1 R49 Advanced Framed Attic NPV Results for Electric Zonal

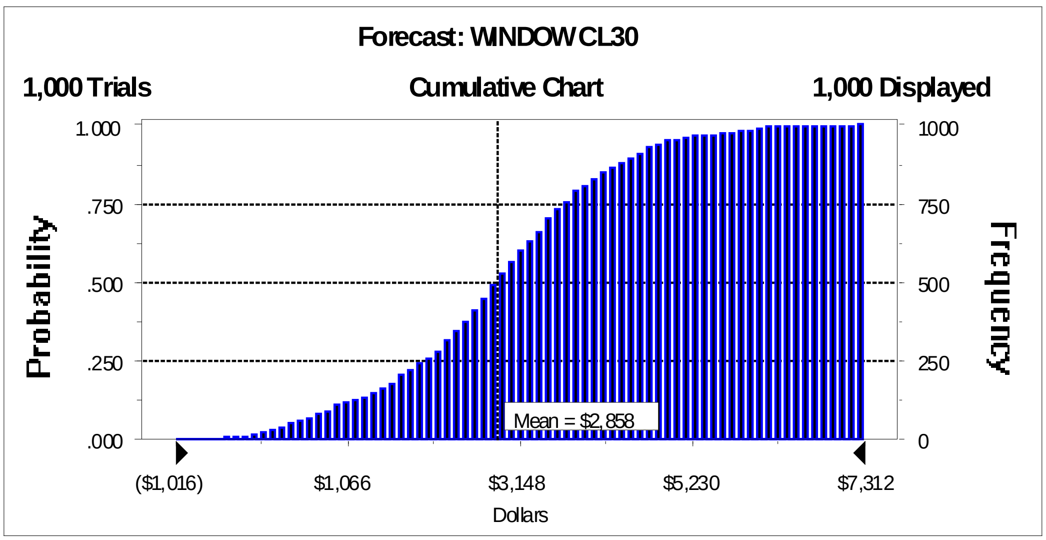

Figure G-41: Climate Zone 1 Class 30 Window NPV Results for Electric Zonal

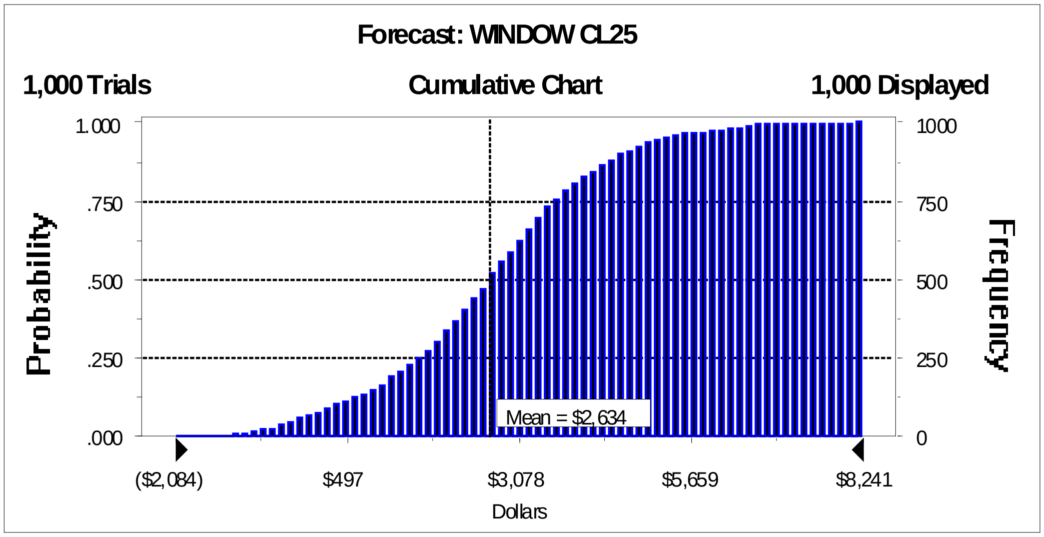

Figure G-42: Climate Zone 1 Class 25 Window NPV Results for Electric Zonal

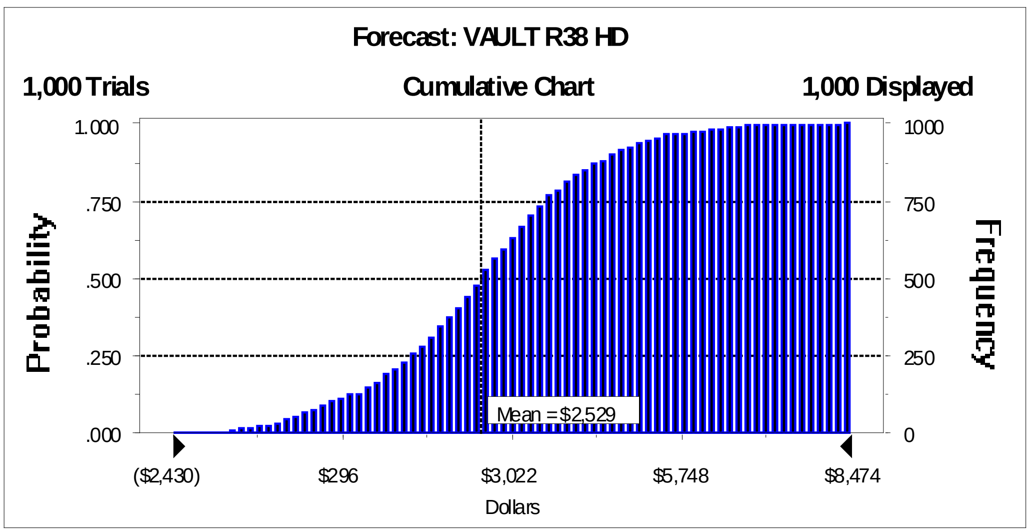

Figure G-43: Climate Zone 1 R38 Vaulted Ceiling NPV Results for Electric Zonal

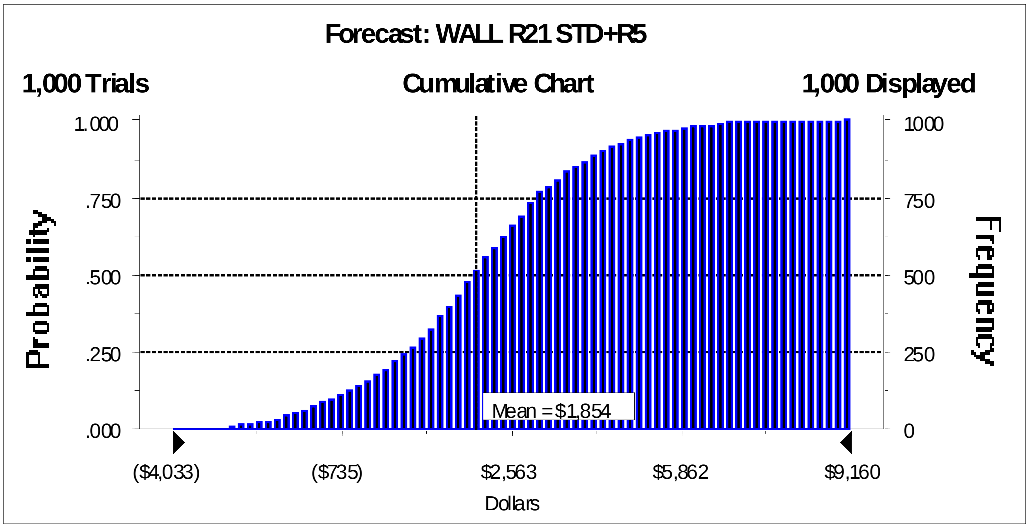

Figure G-44: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Electric Zonal

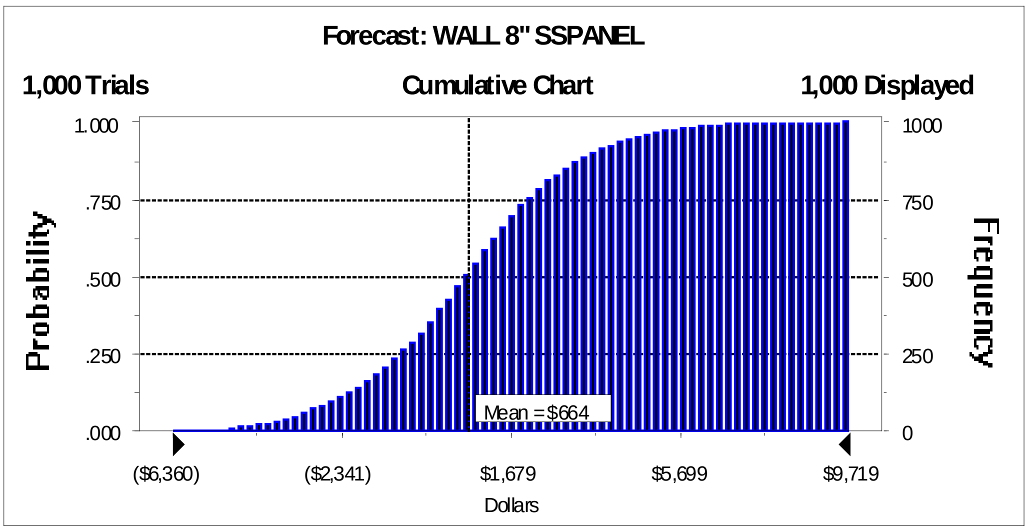

Figure G-45: Climate Zone 1 R33 Wall NPV Results for Electric Zonal

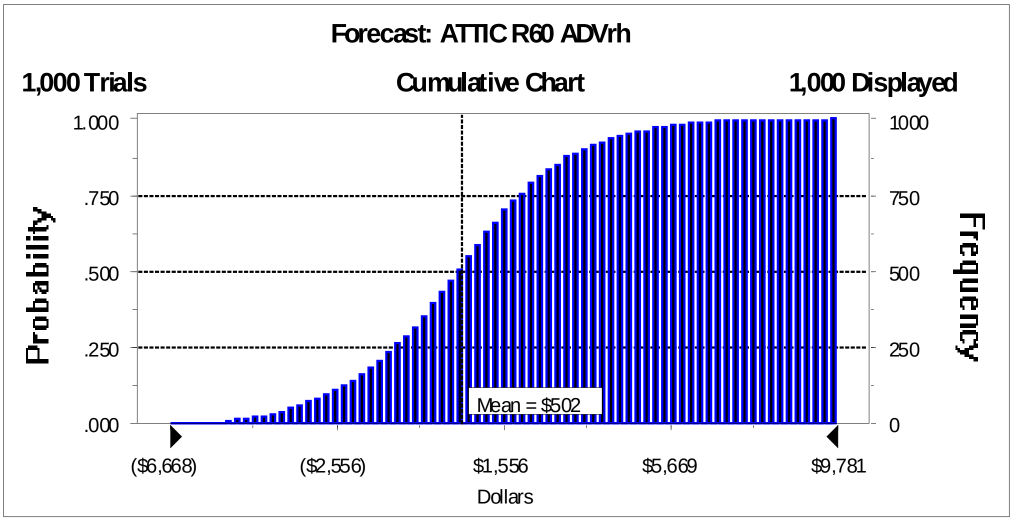

Figure G-46: Climate Zone 1 R60 Advanced Framed Attic NPV Results for Electric Zonal

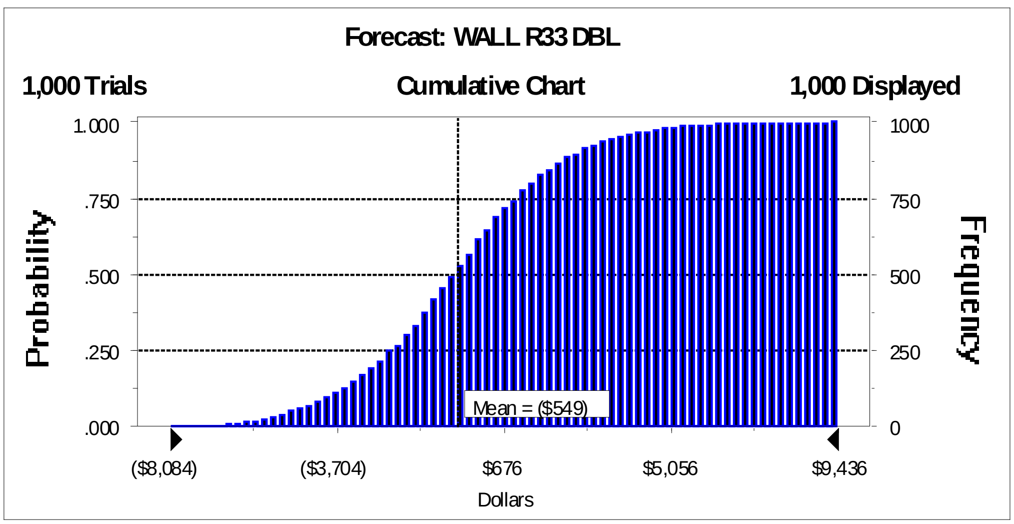

Figure G-47: Climate Zone 1 R38 Wall NPV Results for Electric Zonal

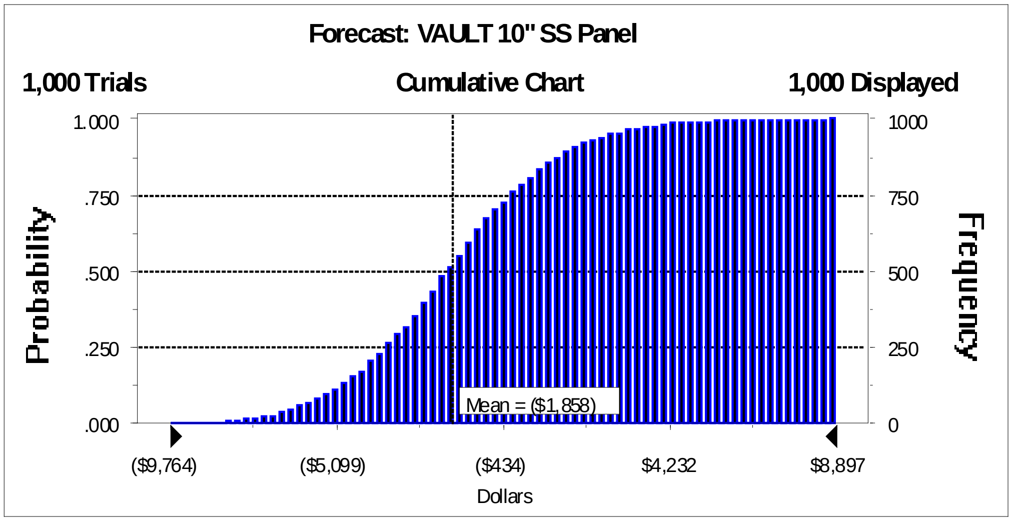

Figure G-48: Climate Zone 1 R49 Vault NPV Results for Electric Zonal

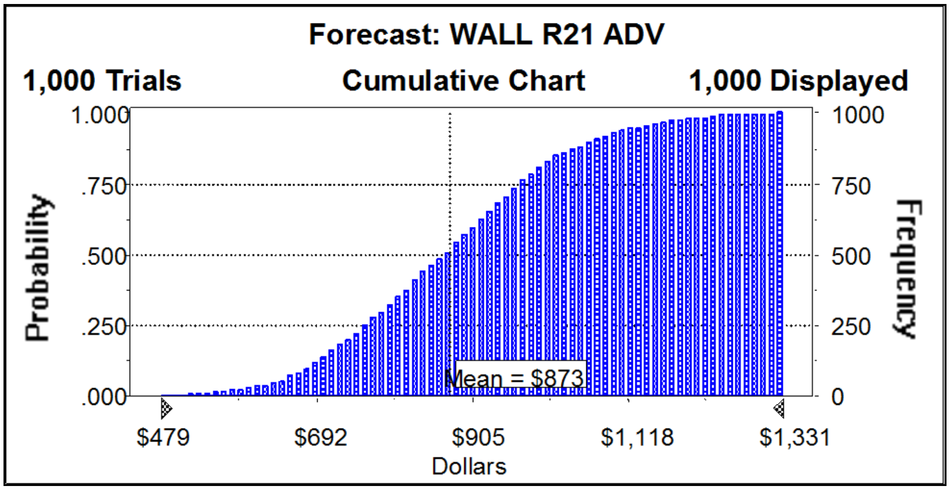

Figure G-49: Climate Zone 1 R21 Advanced Framed Wall NPV Results for Gas FAF

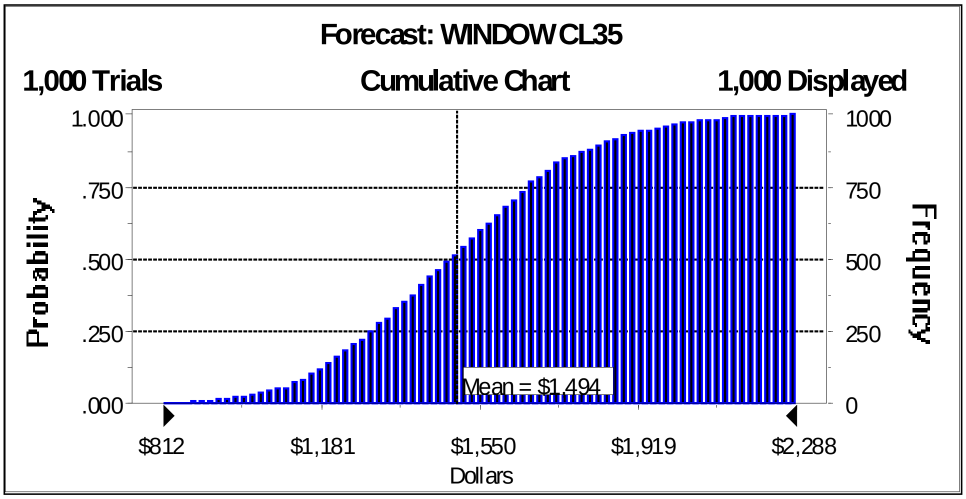

Figure G-50: Climate Zone 1 Class 35 Window NPV Results for Gas FAF

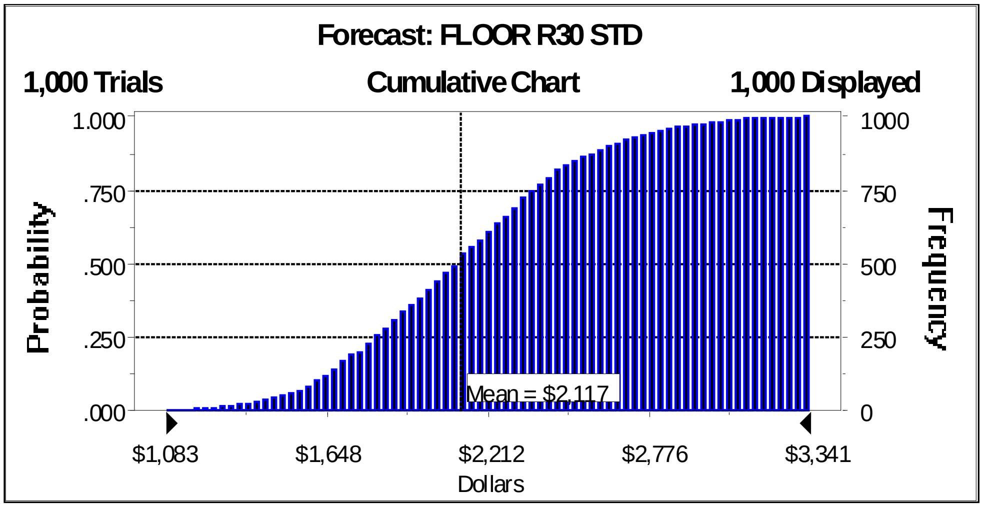

Figure G-51: Climate Zone 1 R30 Under floor NPV Results for Gas FAF

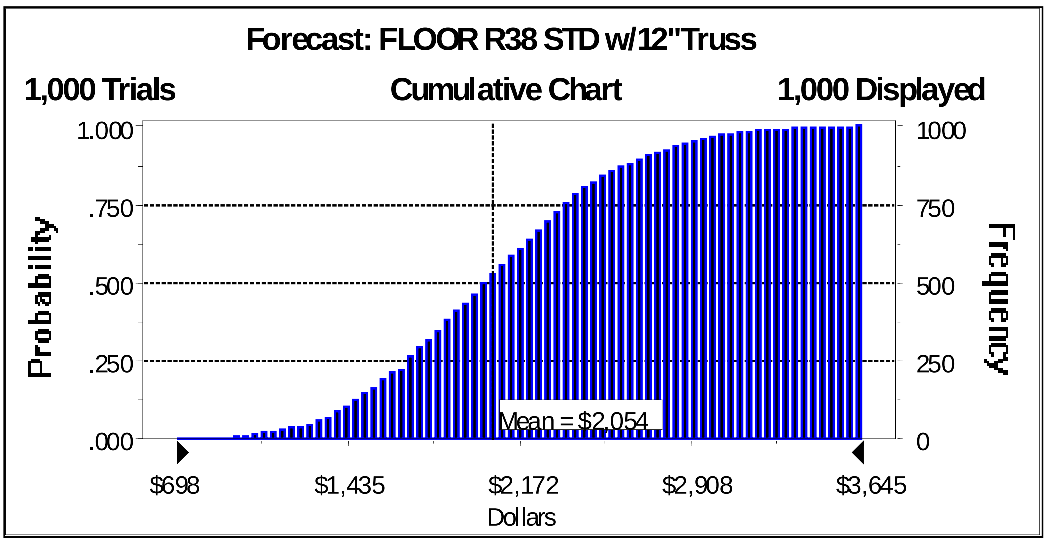

Figure G-52: Climate Zone 1 R38 Under floor NPV Results for Gas FAF

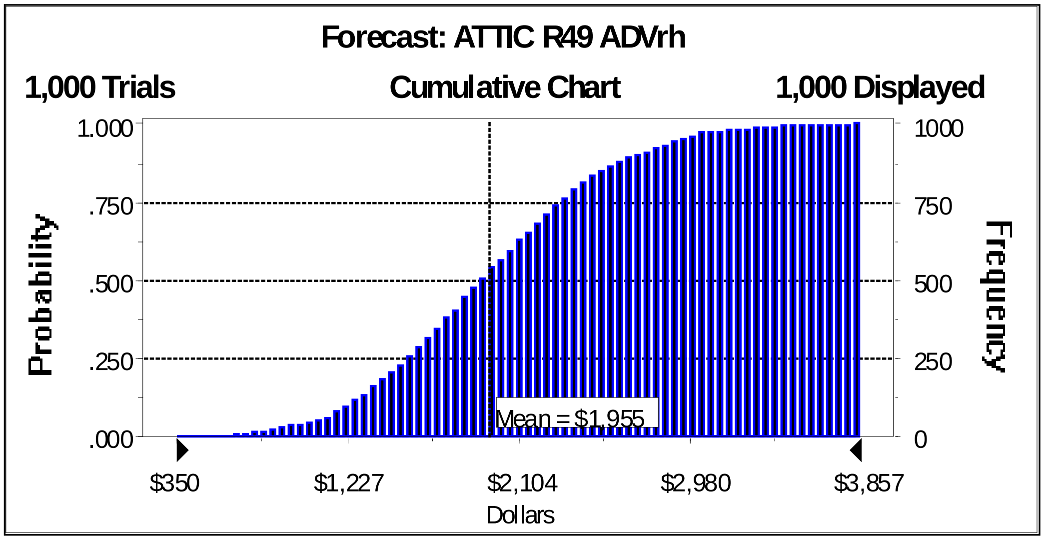

Figure G-53: Climate Zone 1 R49 Advanced Framed Attic NPV Results for Gas FAF

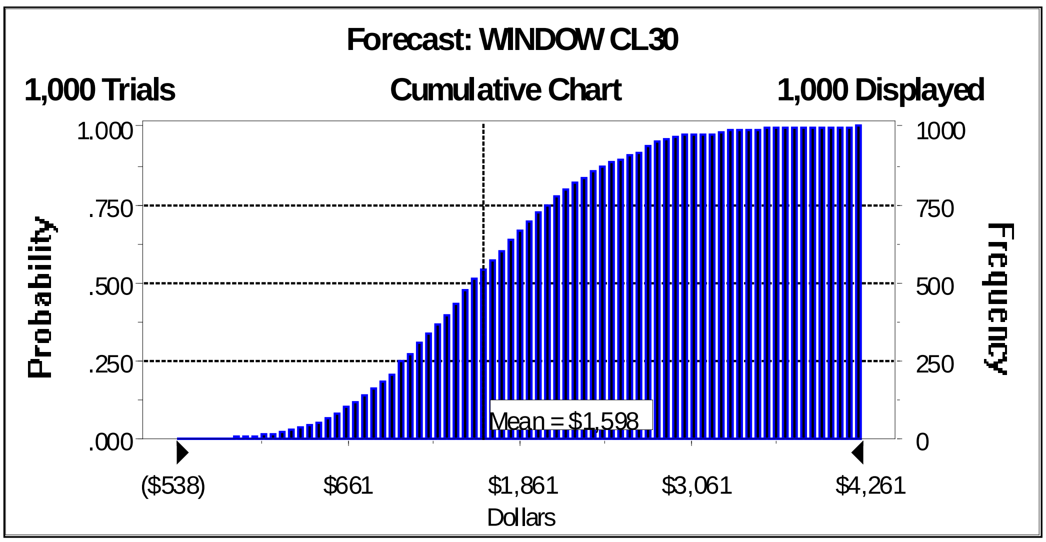

Figure G-54: Climate Zone 1 Class 30 Window NPV Results for Gas FAF

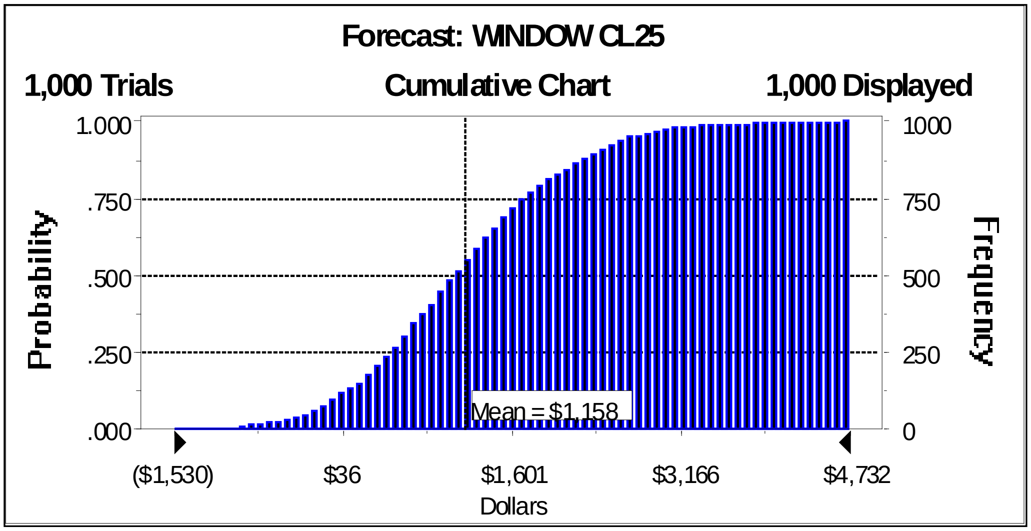

Figure G-55: Climate Zone 1 Class 25 Window NPV Results for Gas FAF

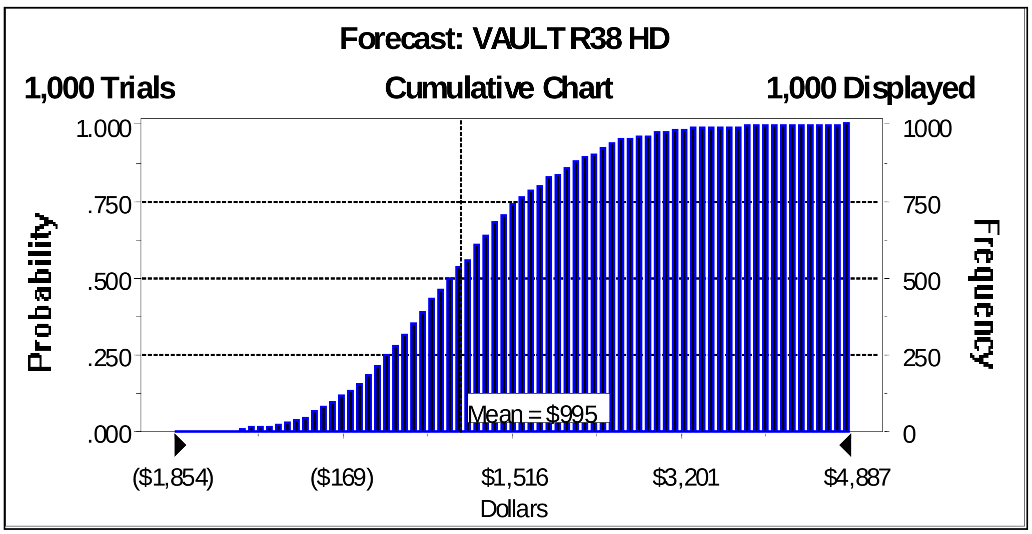

Figure G-56: Climate Zone 1 R38 Vault NPV Results for Gas FAF

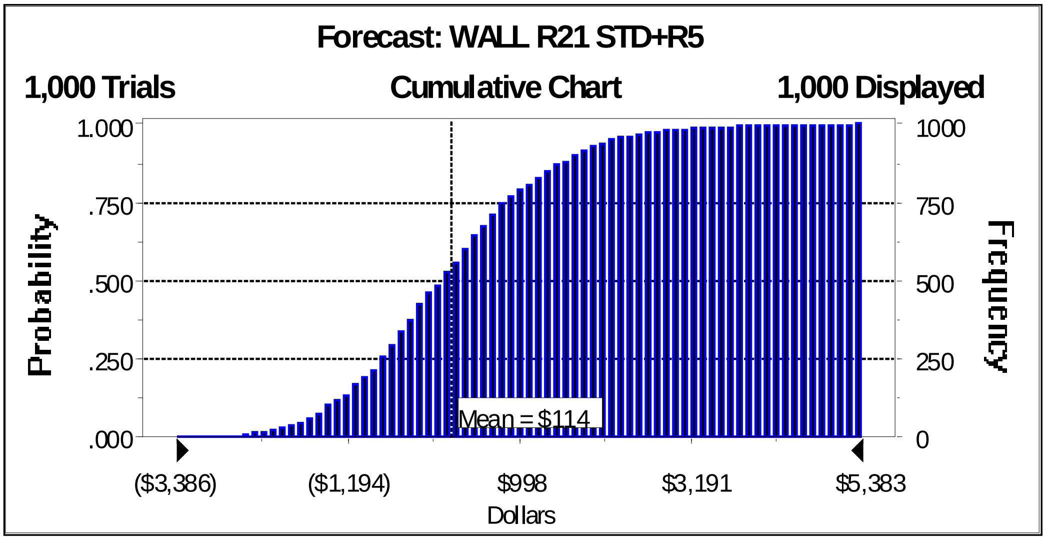

Figure G-57: Climate Zone 1 R26 Advanced Framed Wall NPV Results for Gas FAF

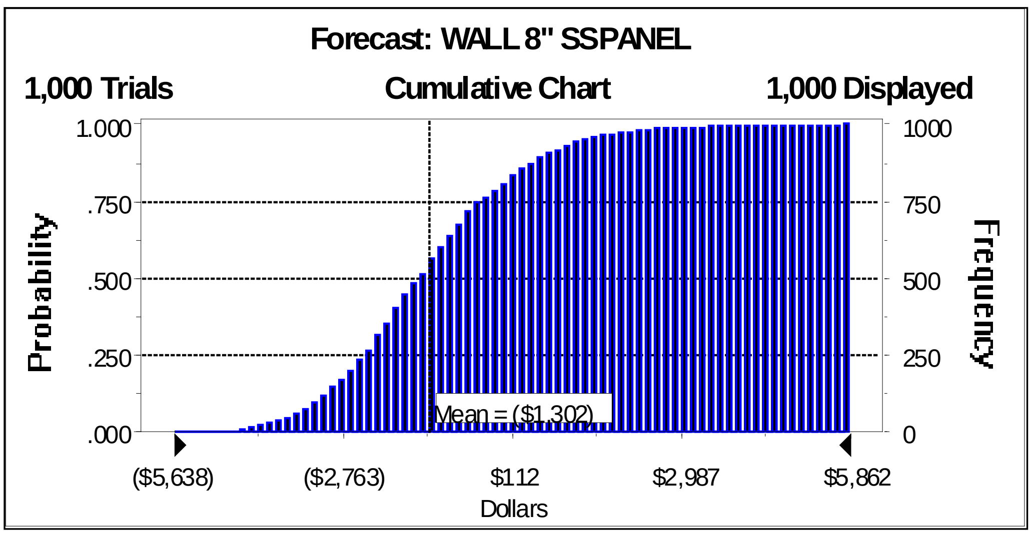

Figure G-58: Climate Zone 1 R33 Wall NPV Results for Gas FAF

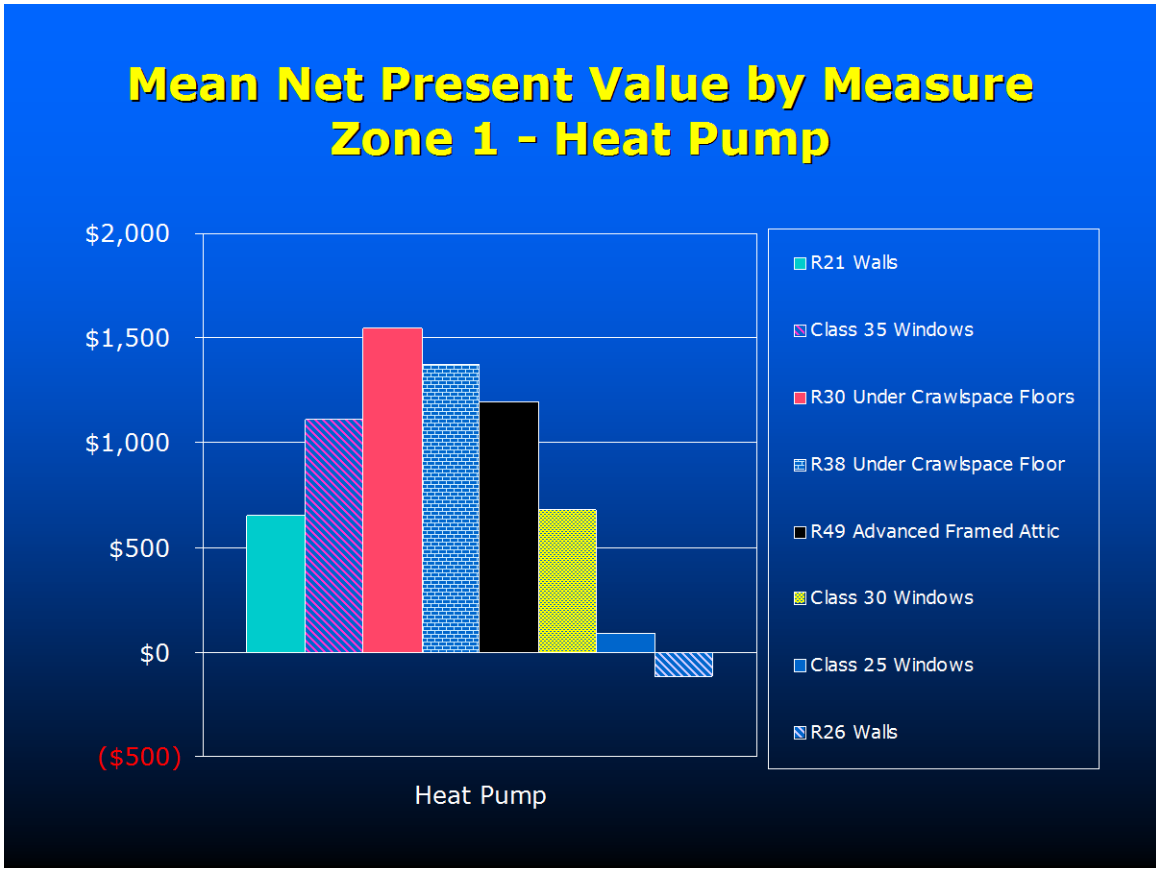

Figure G-59: Climate Zone 1 Mean NPV by Measure for Heat Pumps

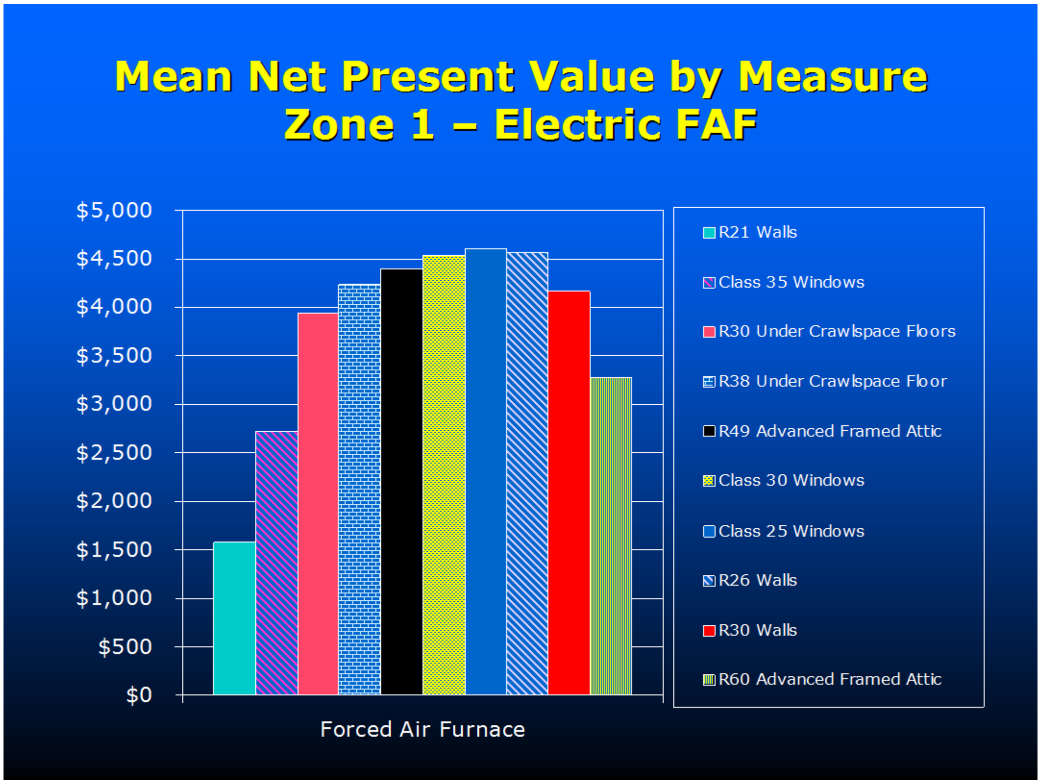

Figure G-60: Climate Zone 1 Mean NPV by Measure for Electric FAF

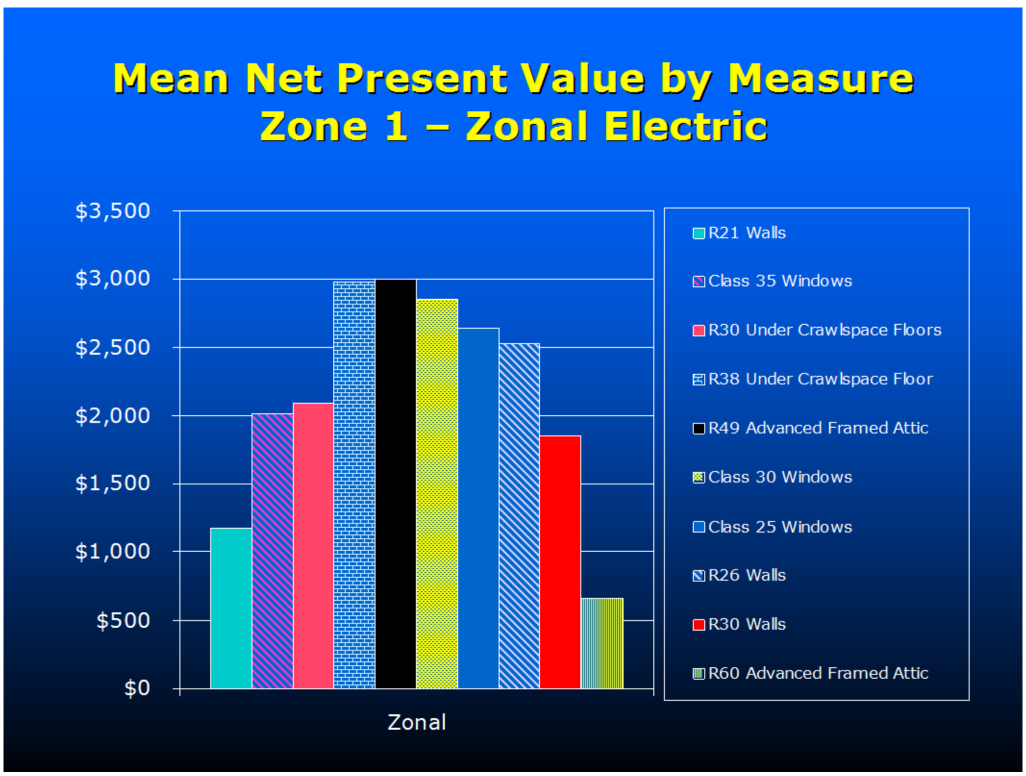

Figure G-61: Climate Zone 1 - Mean NPV by Measure for Electric Zonal

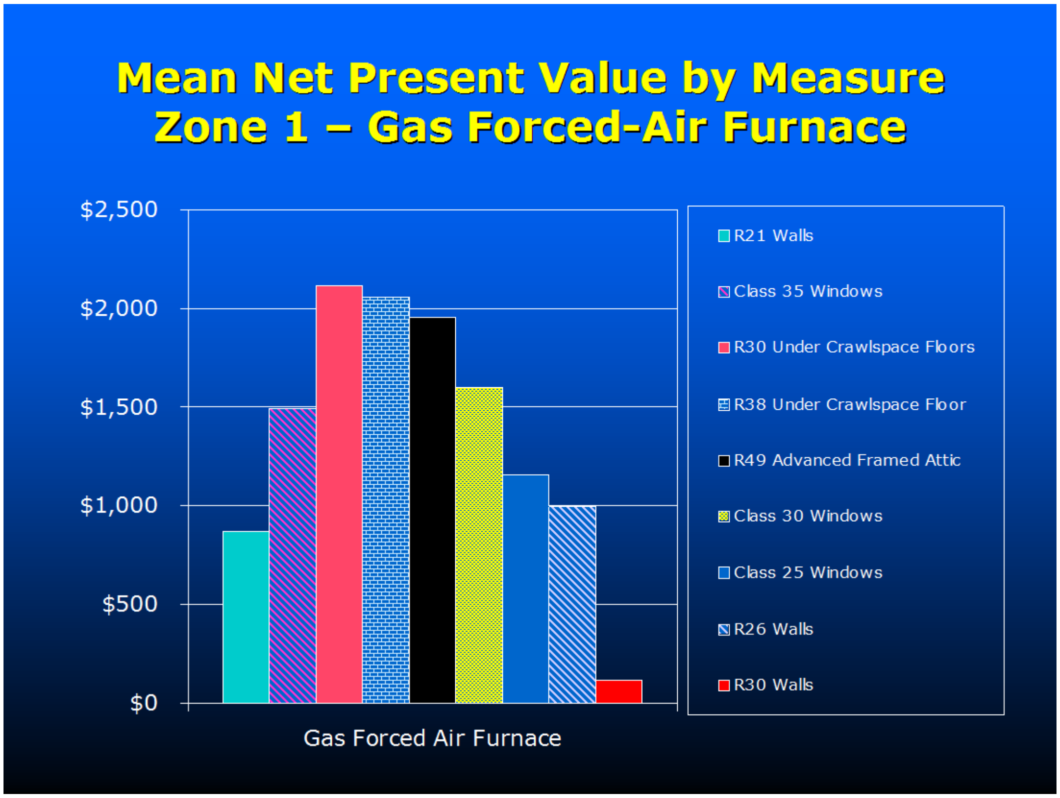

Figure G-62: Climate Zone 1 - Mean NPV by Measure for Gas FAF

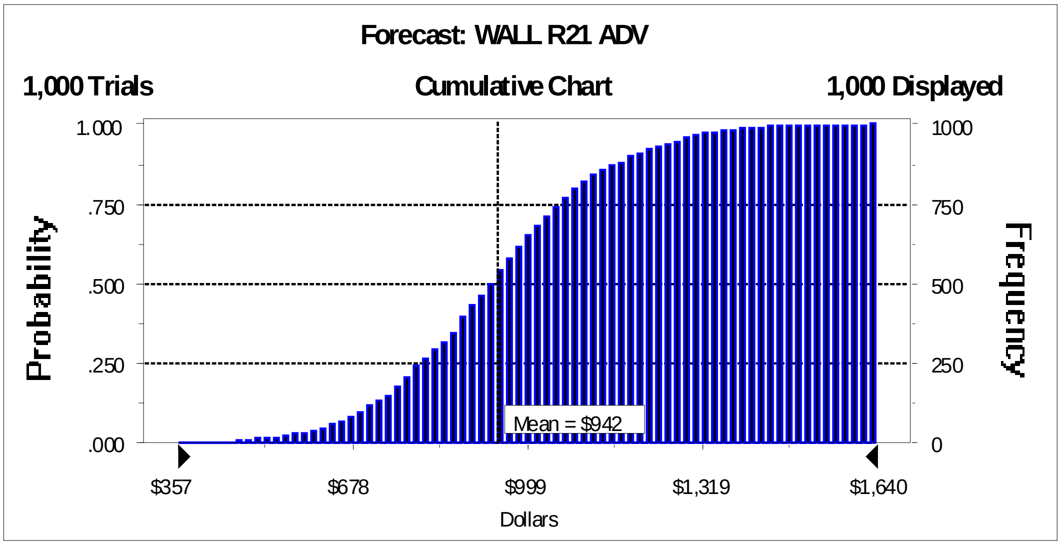

Figure G-63: Climate Zone 2 R21 Advanced Framed Wall NPV Results for Heat Pump

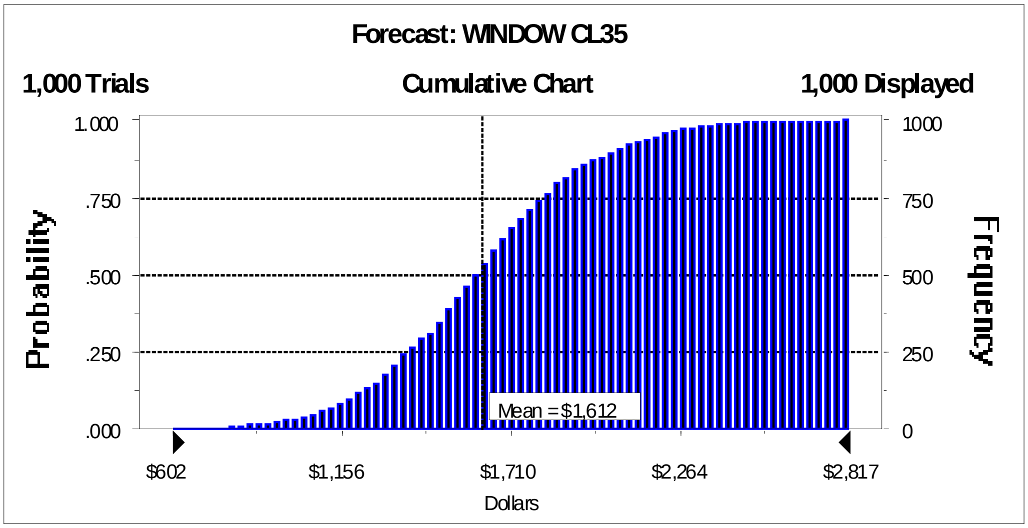

Figure G-64: Climate Zone 2 Class 35 Window NPV Results for Heat Pumps

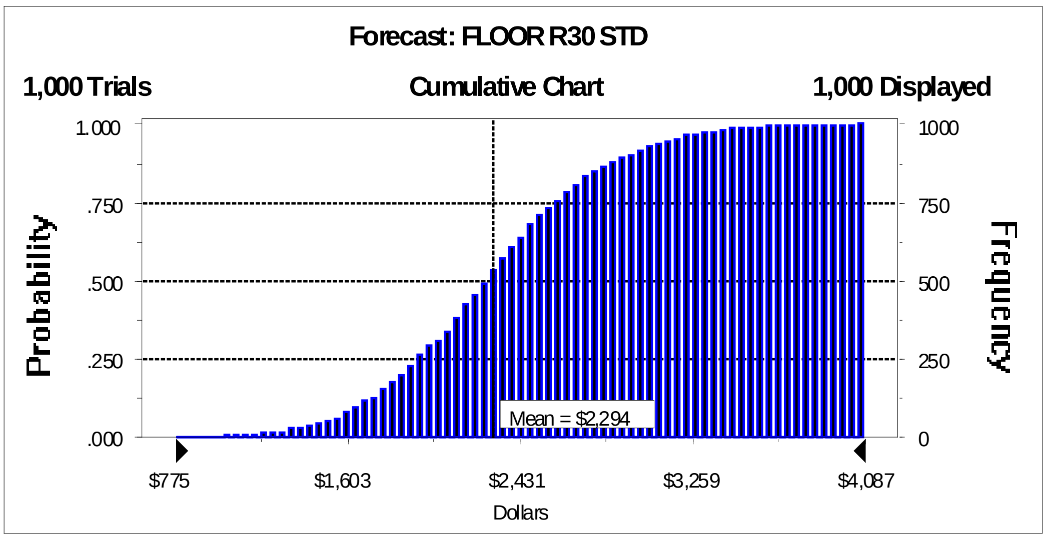

Figure G-65: Climate Zone 2 R30 Under floor NPV Results for Heat Pumps

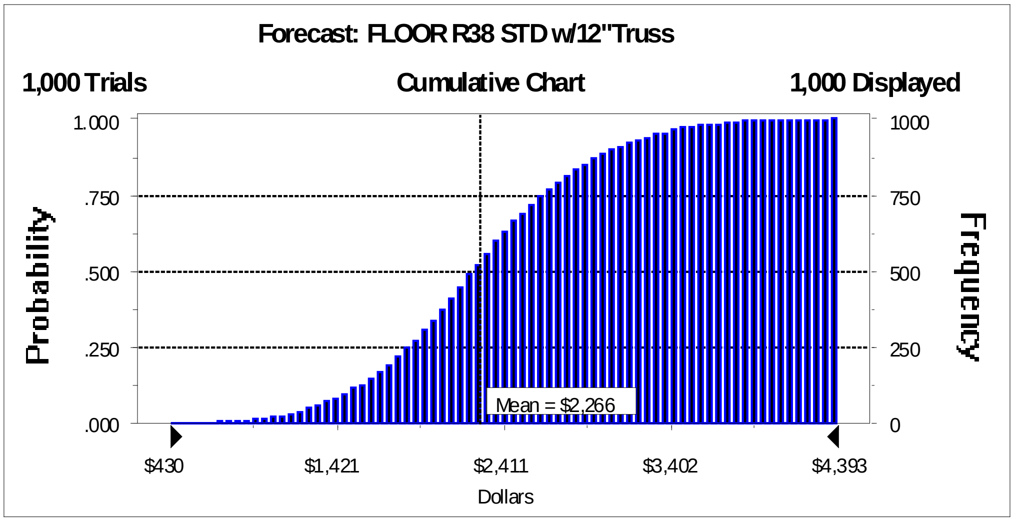

Figure G-66: Climate Zone 2 R38 Under floor NPC Results for Heat Pumps

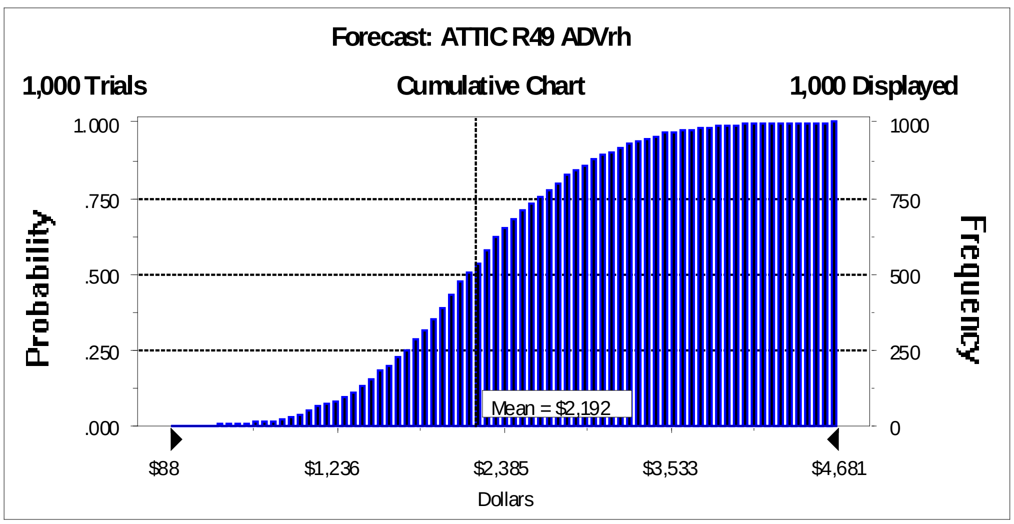

Figure G-67: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Heat Pumps

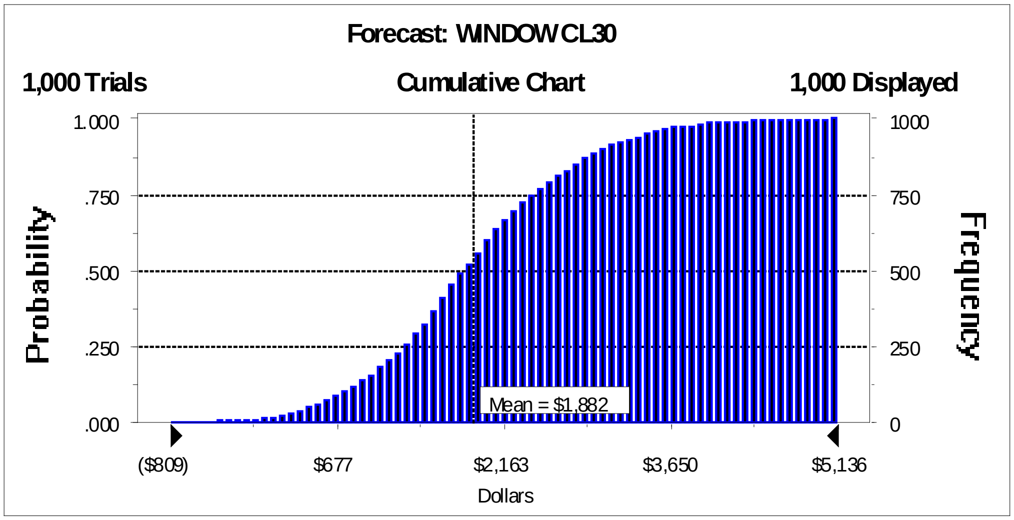

Figure G-68: Climate Zone 2 Class 30 Window NPV Results for Heat Pumps

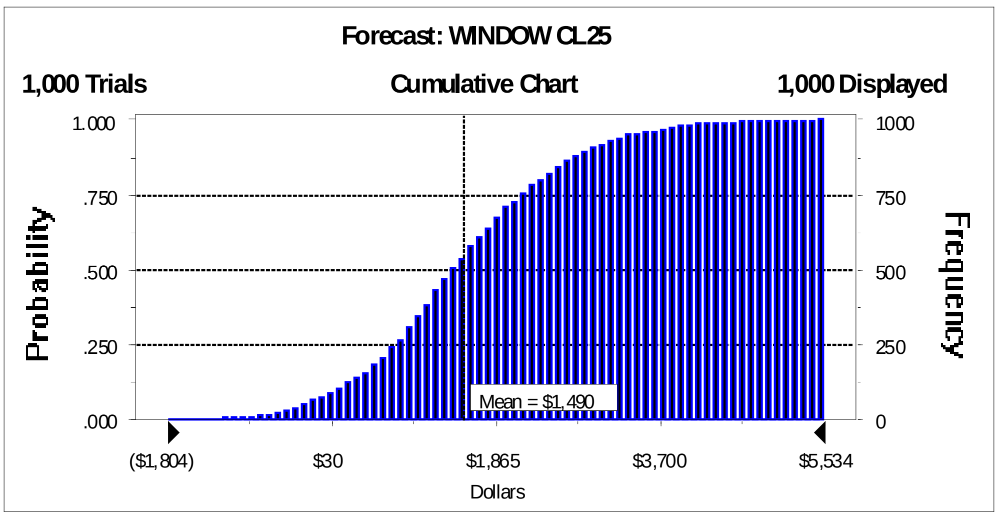

Figure G-69: Climate Zone 2 Class 25 Window NPV Results for Heat Pumps

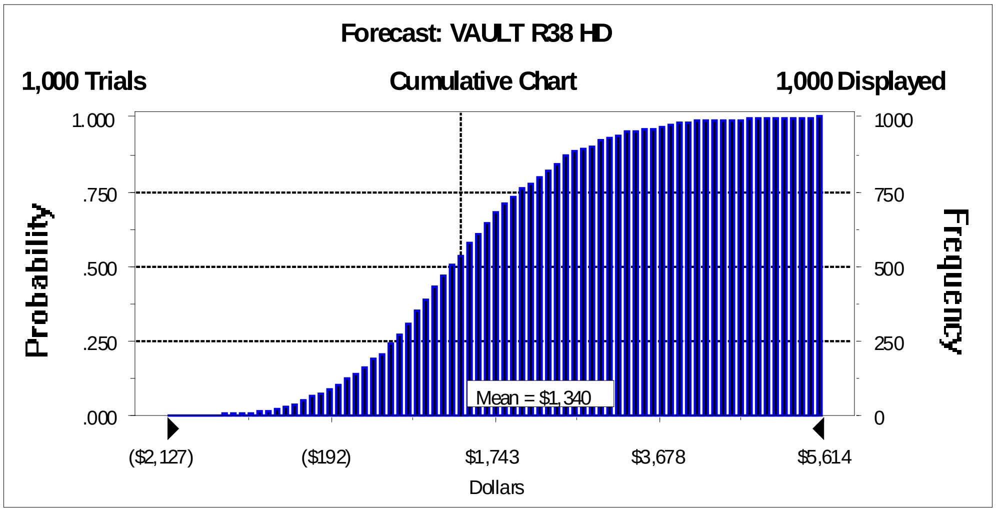

Figure G-70: Climate Zone 2 R38 Vault NPV Results for Heat Pumps

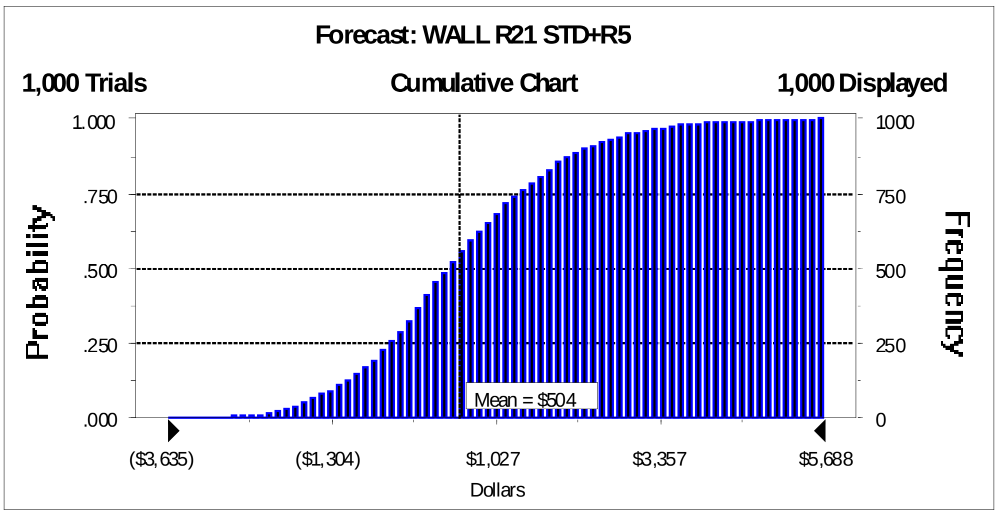

Figure G-71: Climate Zone 2 R26 Advanced Framed Walls NPV Results for Heat Pumps

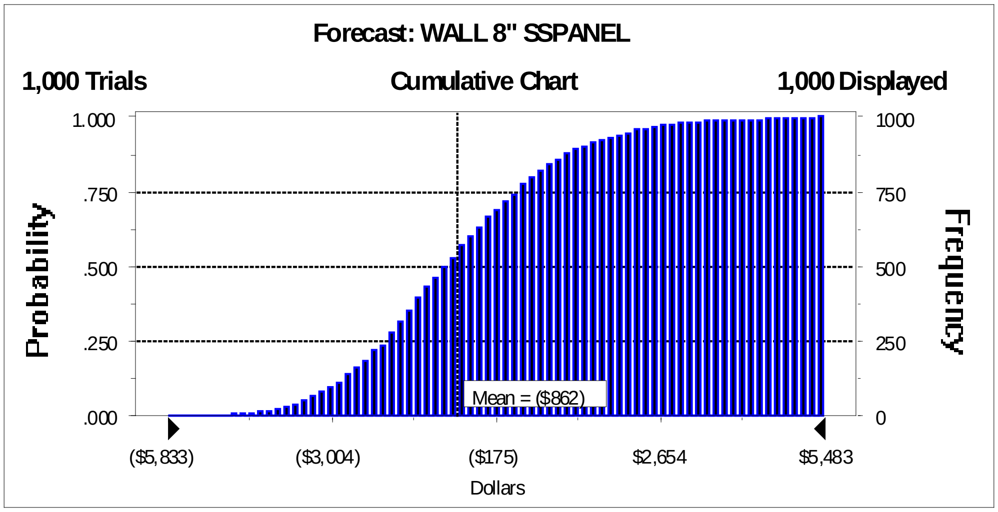

Figure G-72: Climate Zone 2 R33 Wall NPV Results for Heat Pumps

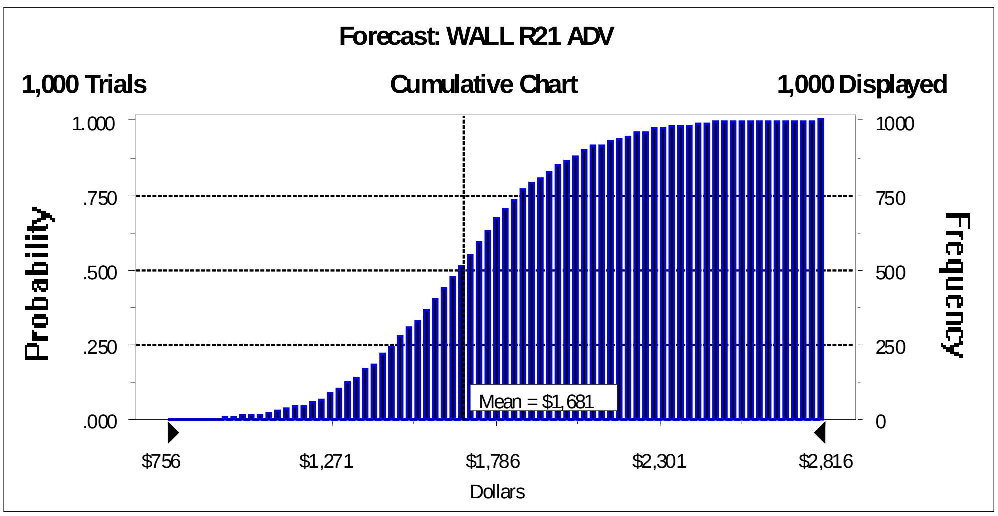

Figure G-73: Climate Zone 2 R21 Advanced Framed Walls NPV Results for Electric FAF

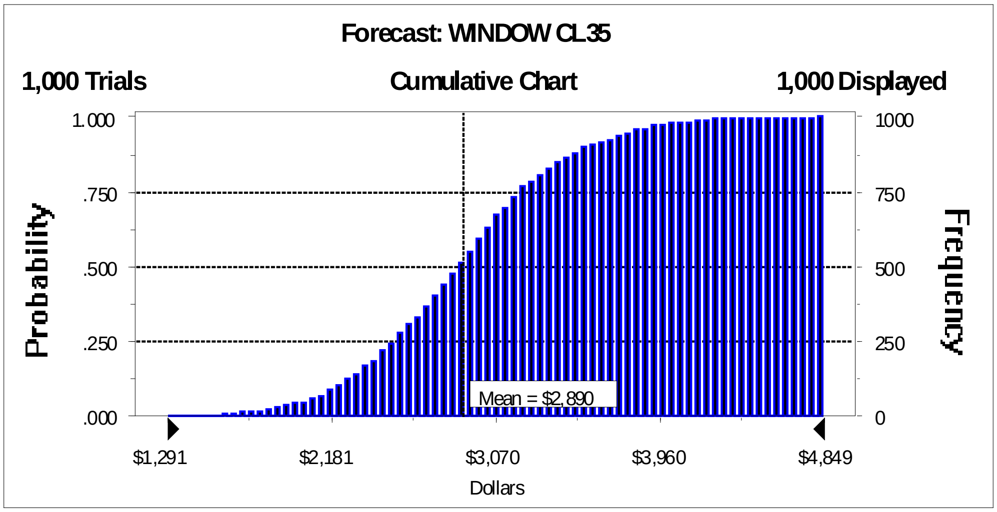

Figure G-74: Climate Zone 2 Class 35 Windows NPV Results for Electric FAF

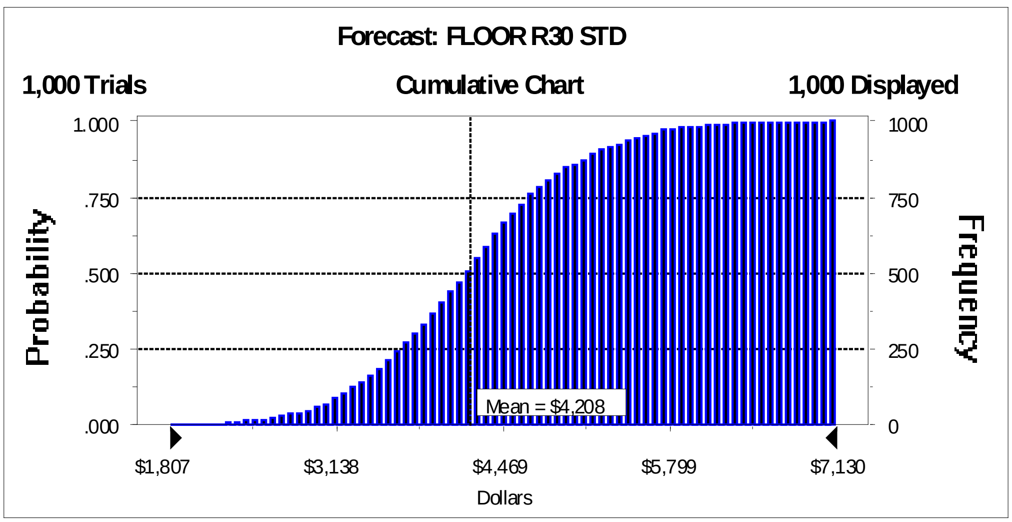

Figure G-75: Climate Zone 2 R30 Under floor NPV Results for Electric FAF

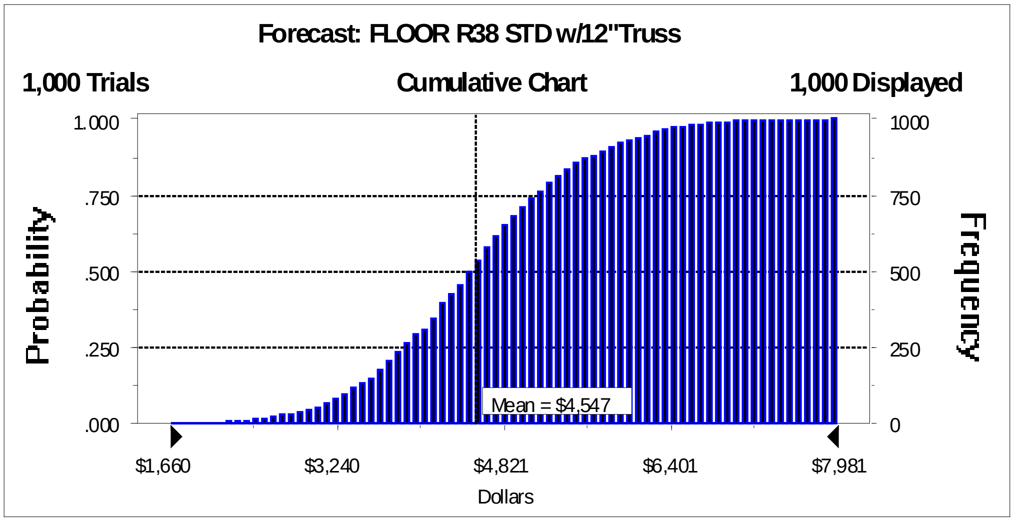

Figure G-76: Climate Zone 2 R38 Under floor NPV Results for Electric FAF

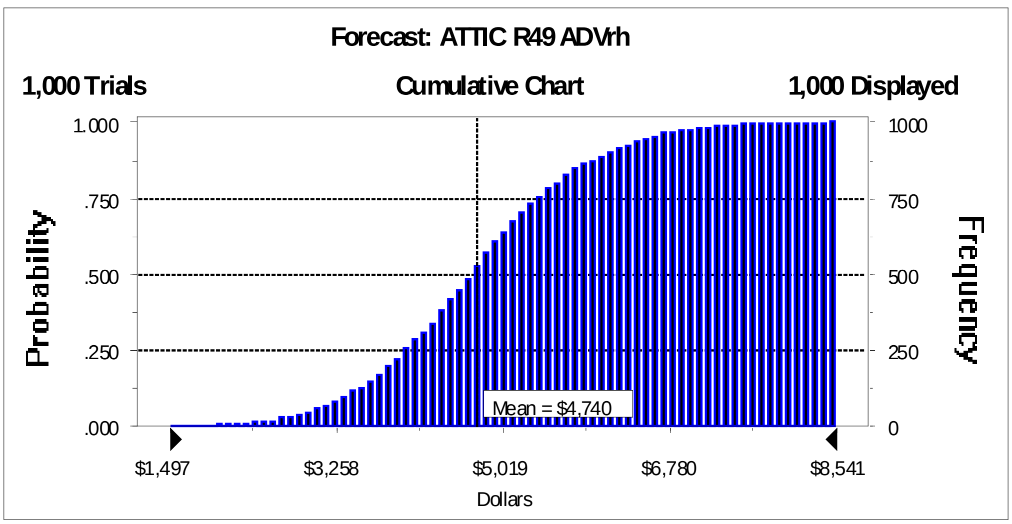

Figure G-77: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Electric FAF

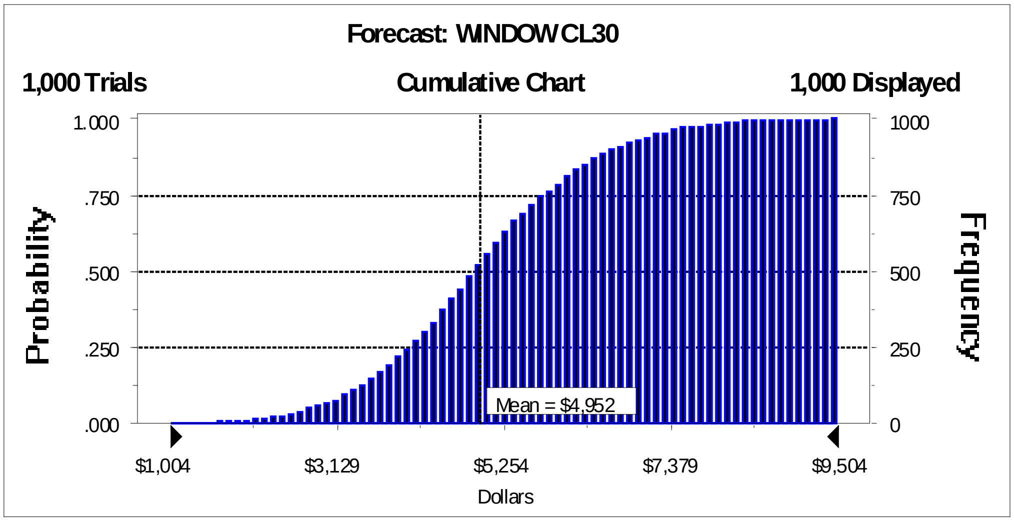

Figure G-78: Climate Zone 2 Class 30 Window NPV Results for Electric FAF

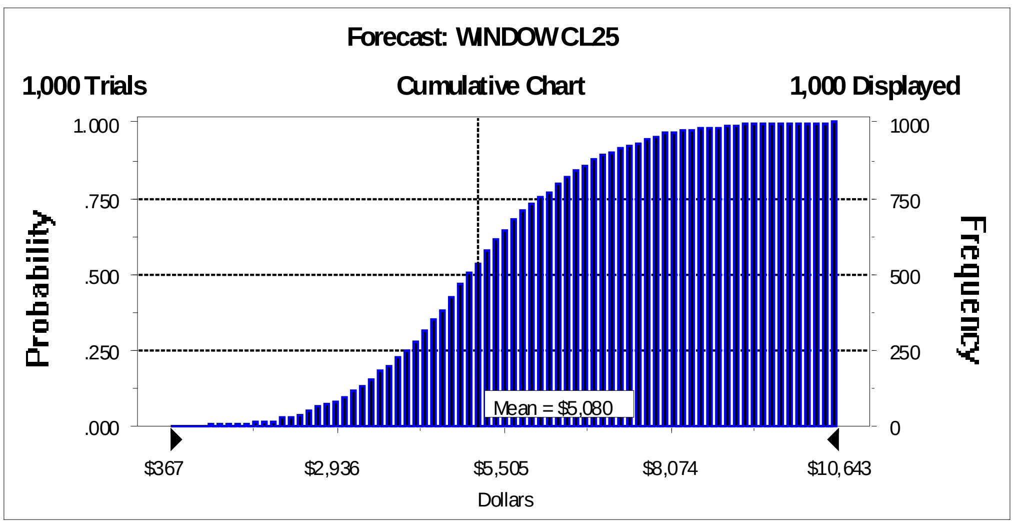

Figure G-79: Climate Zone 2 Class 25 Window NPV Results for Electric FAF

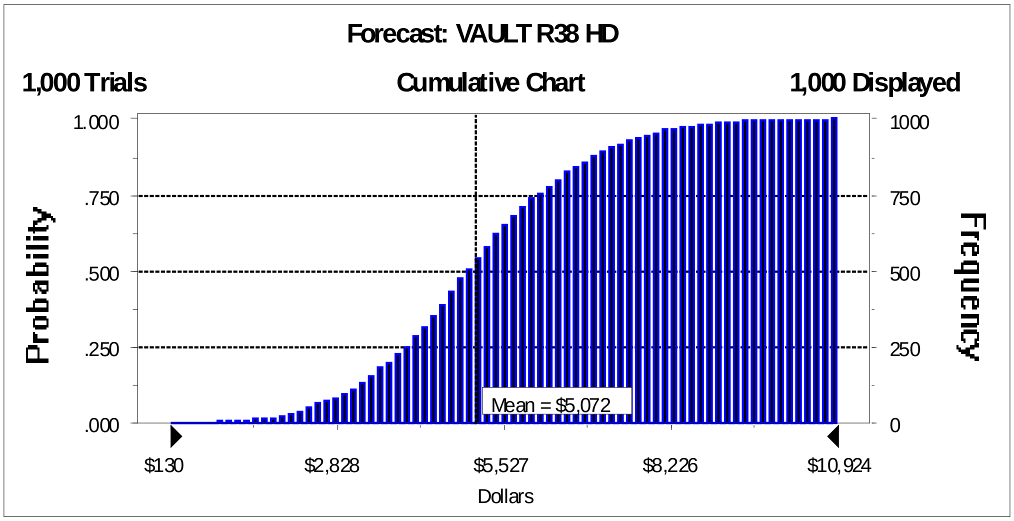

Figure G-80: Climate Zone 2 R38 Vault NPV Results for Electric FAF

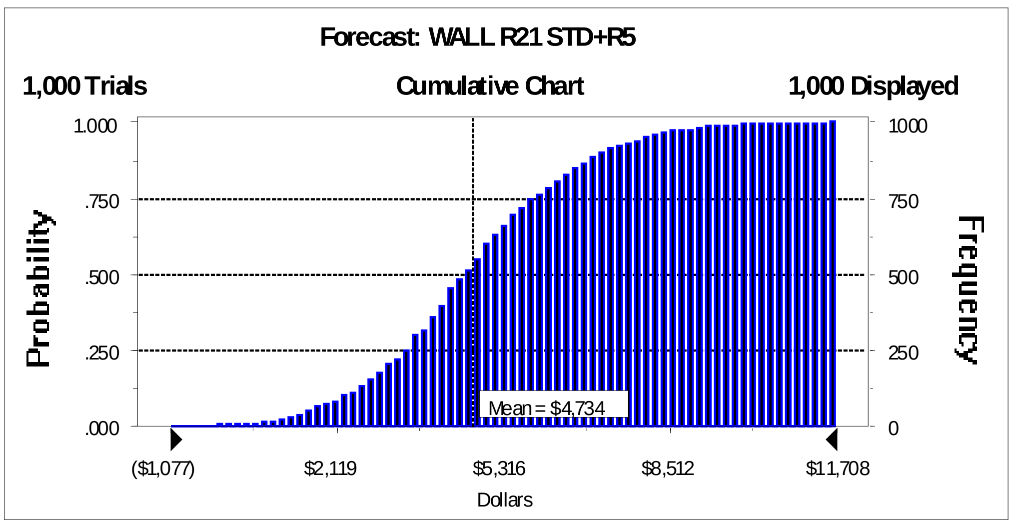

Figure G-81: Climate Zone 2 R26 Advanced Framed Wall NPV Results for Electric FAF

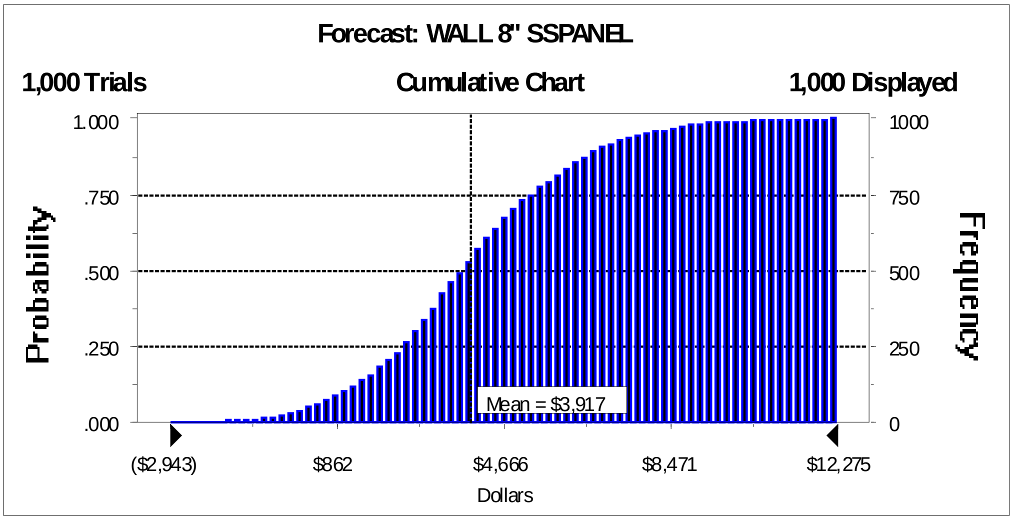

Figure G-82: Climate Zone 2 R33 Wall NPV Results for Electric FAF

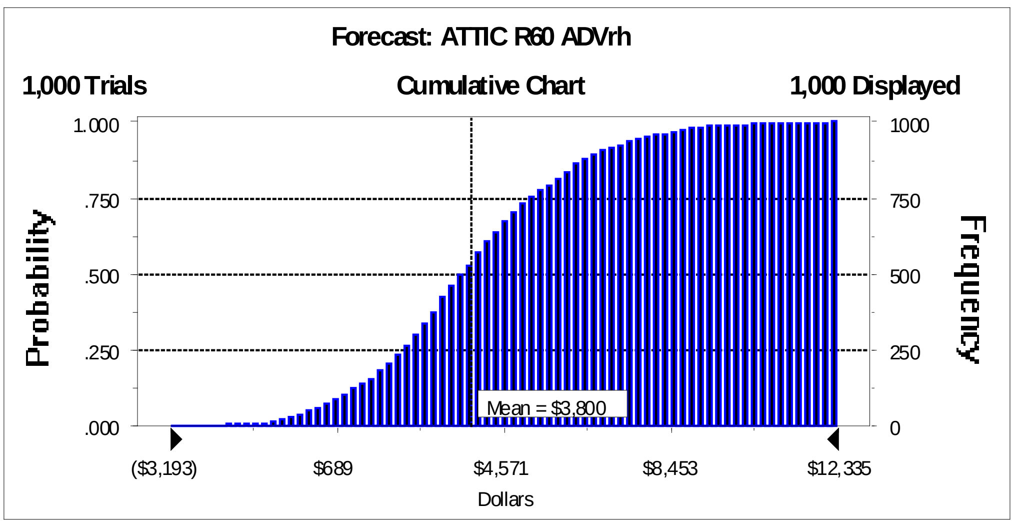

Figure G-83: Climate Zone 2 R60 Advanced Framed Attic NPV Results for Electric FAF

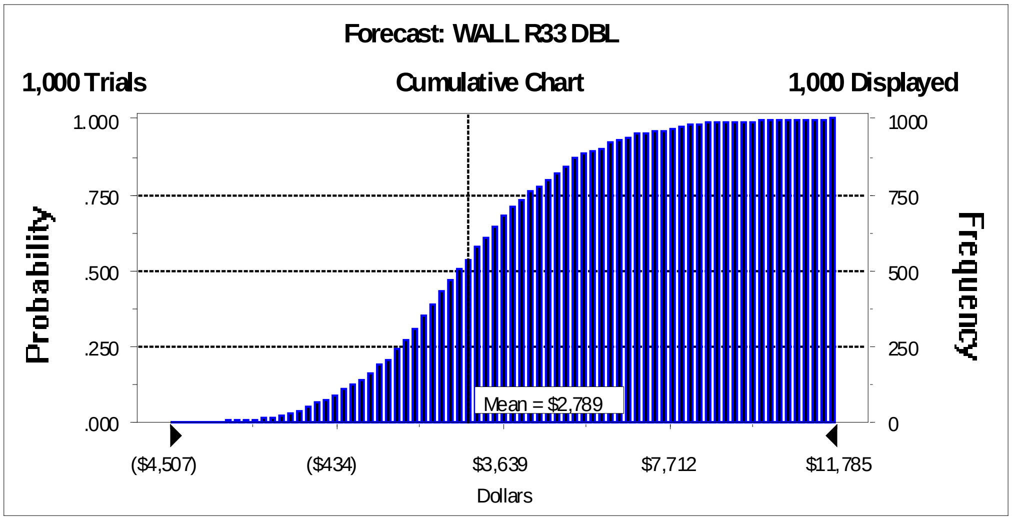

Figure G-84: Climate Zone 2 R38 Wall NPV Results for Electric FAF

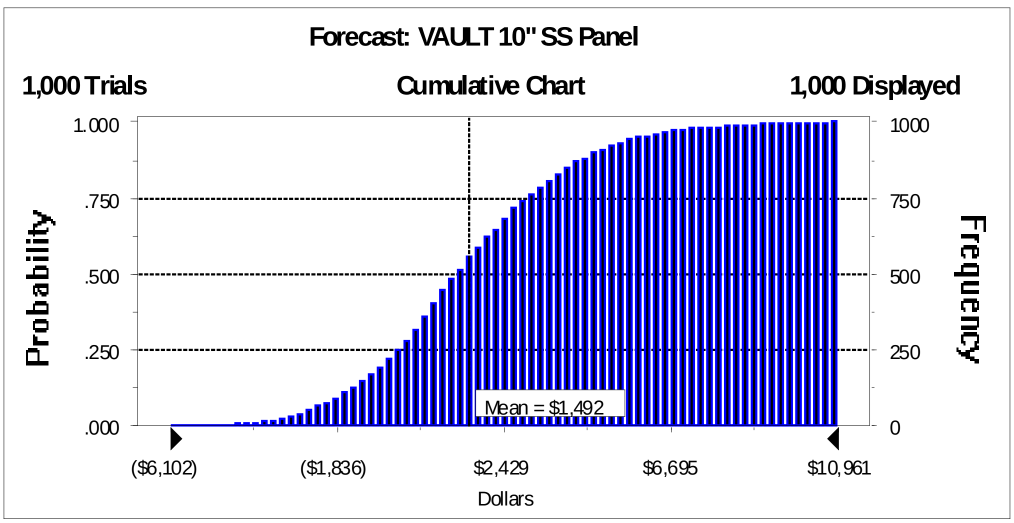

Figure G-85: Climate Zone 2 R49 Vault NPV Results for Electric FAF

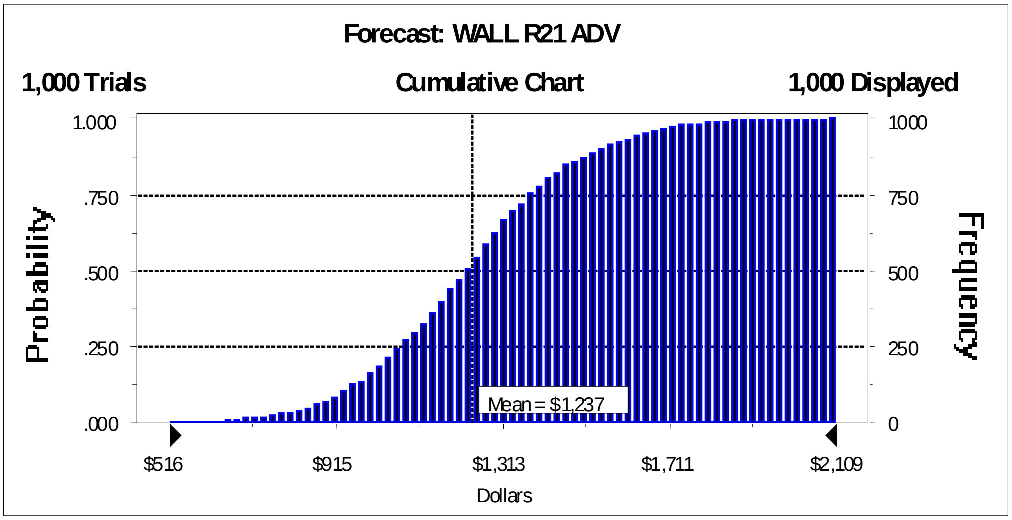

Figure G-86: Climate Zone 2 R21 Advanced Framed Walls NPV Results for Electric Zonal

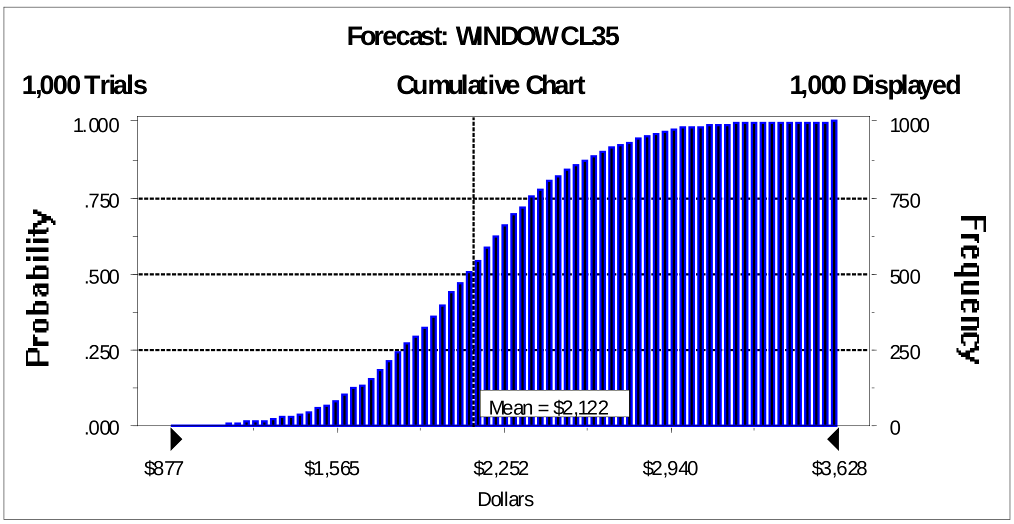

Figure G-87: Climate Zone 2 Class 35 Window NPV Results for Electric Zonal

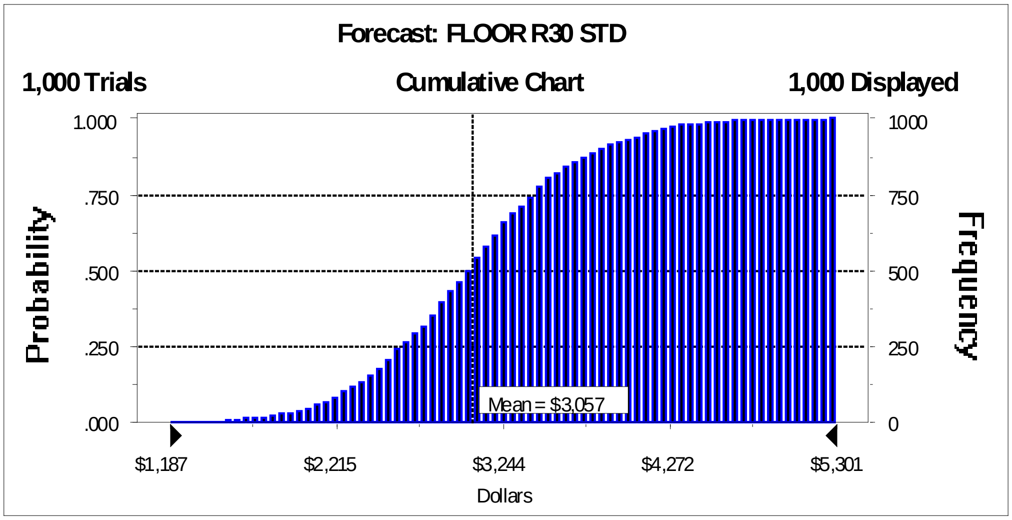

Figure G-88: Climate Zone 2 R30 Under floor NPV Results for Electric Zonal

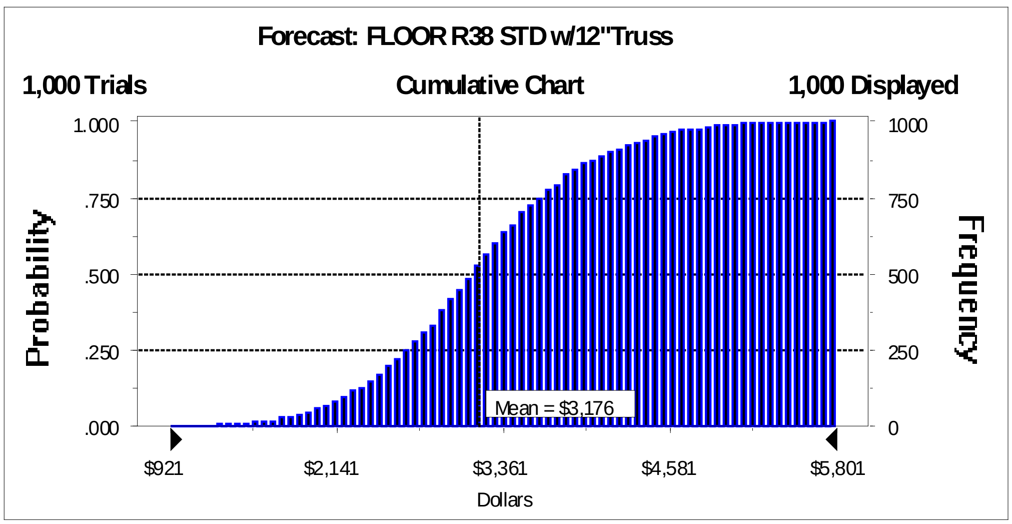

Figure G-89: Climate Zone 2 R38 Under floor NPV Results for Electric Zonal

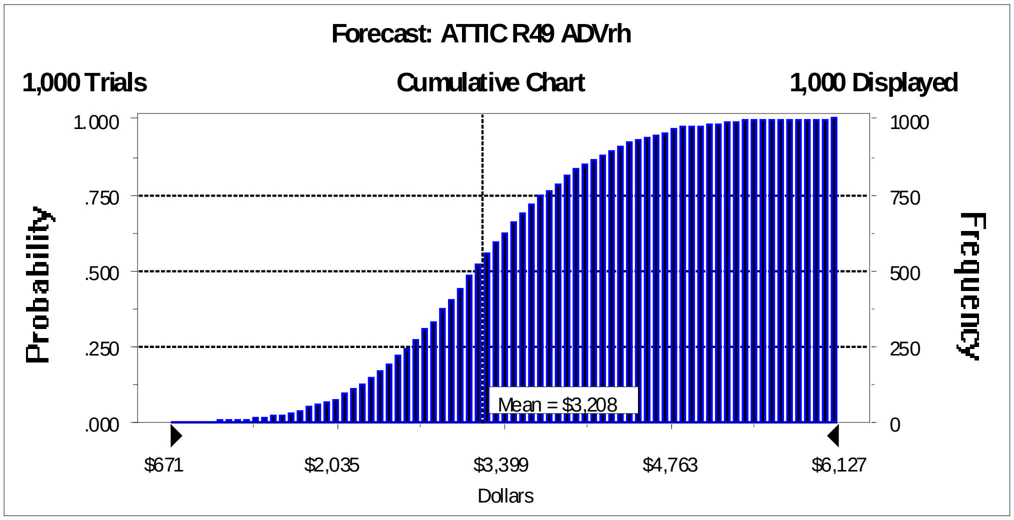

Figure G-90: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Electric Zonal

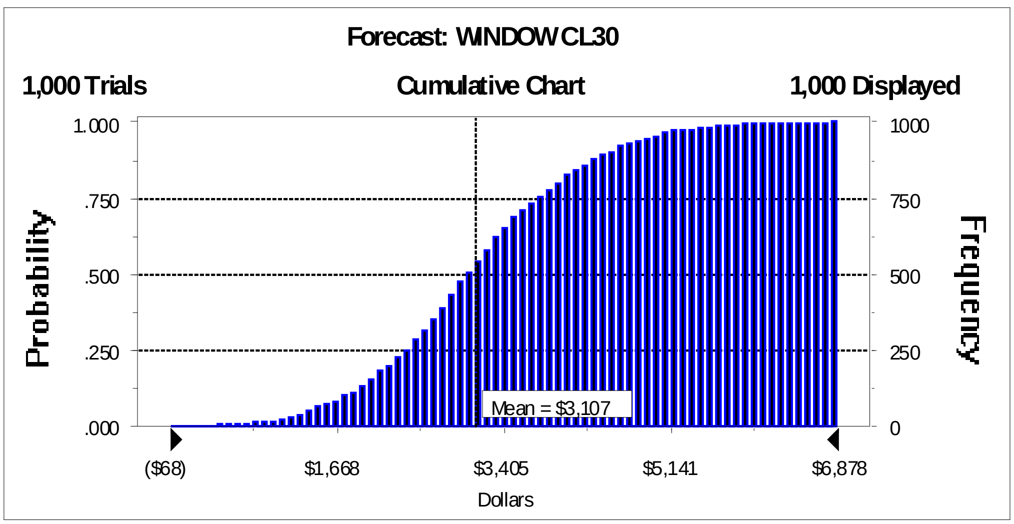

Figure G-91: Climate Zone 2 Class 30 Window NPV Results for Electric Zonal

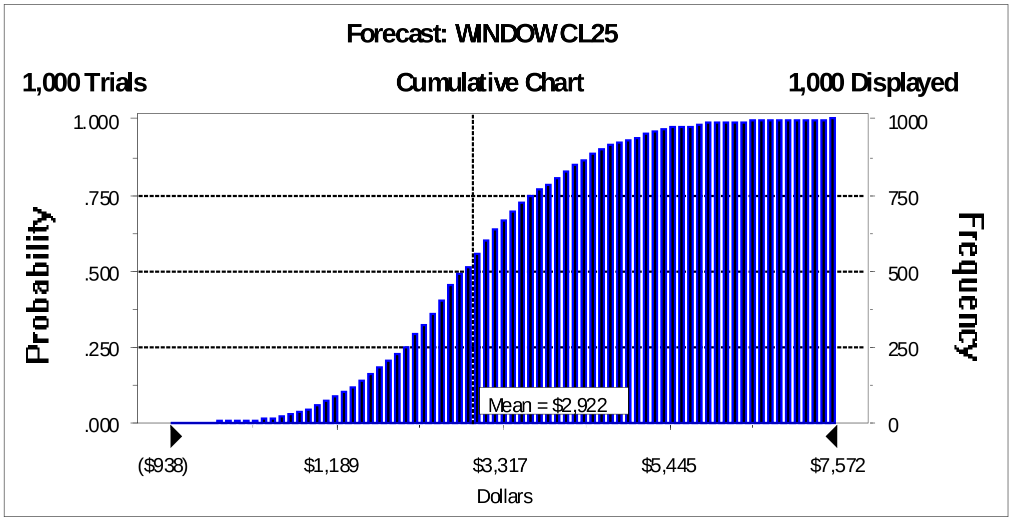

Figure G-92: Climate Zone 2 Class 25 Window NPV Results for Electric Zonal

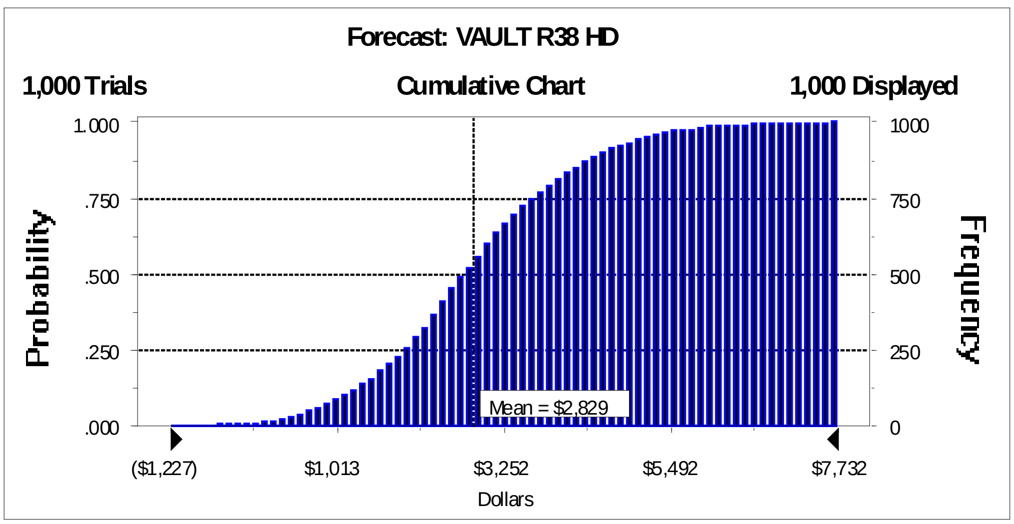

Figure G-93: Climate Zone 2 R38 Vault NPV Results for Electric Zonal

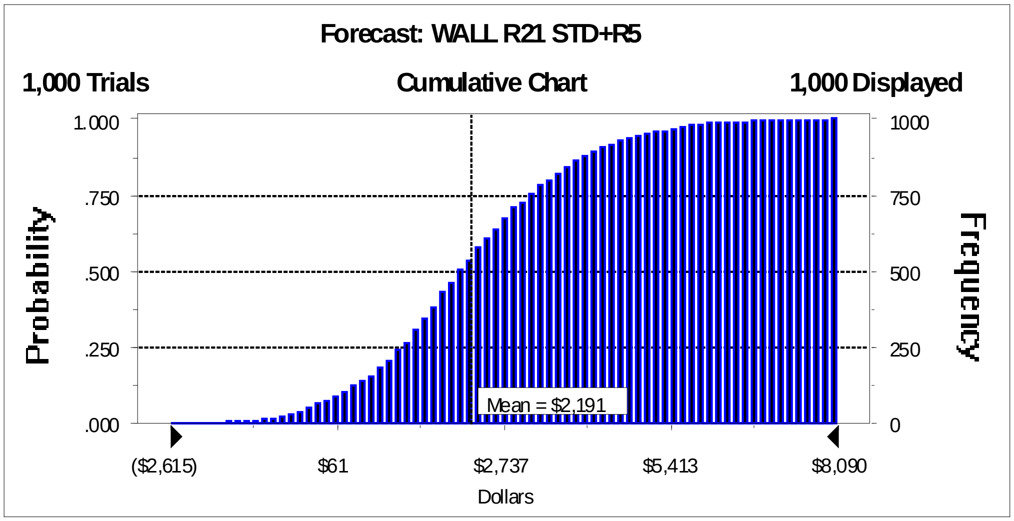

Figure G-94: Climate Zone 2 R26 Advanced Framed Wall NPV Results for Electric Zonal

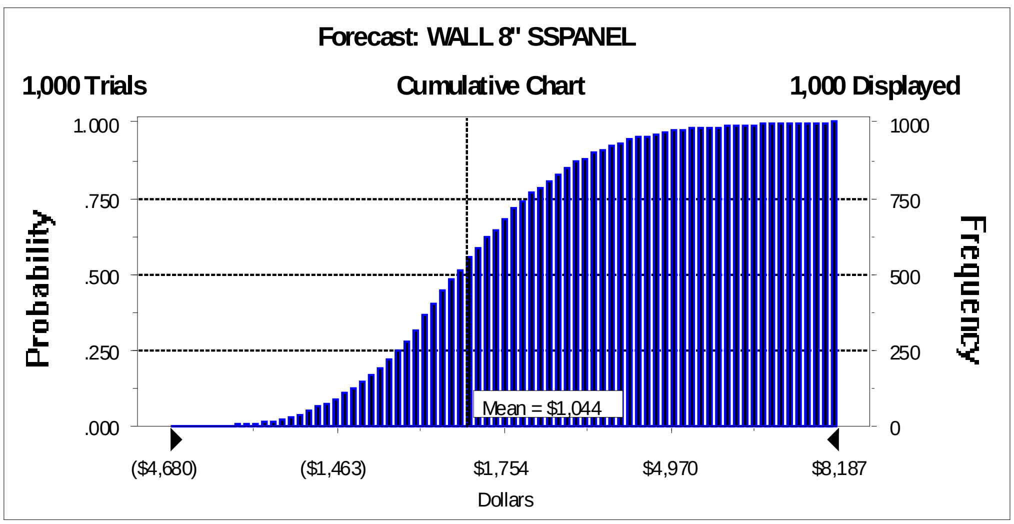

Figure G-95: Climate Zone 2 R33 Wall NPV Results for Electric Zonal

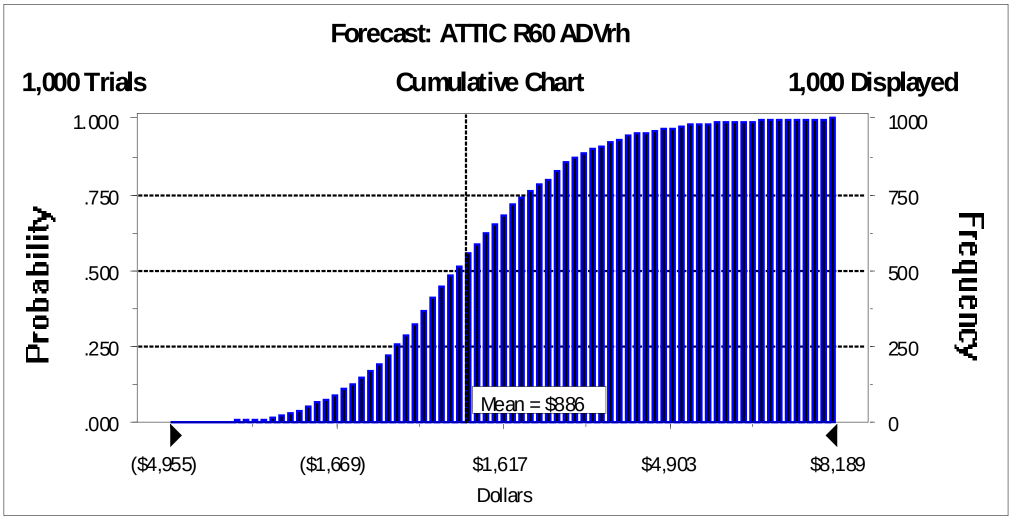

Figure G-96: Climate Zone 2 R60 Advanced Framed Attic NPV Results for Electric Zonal

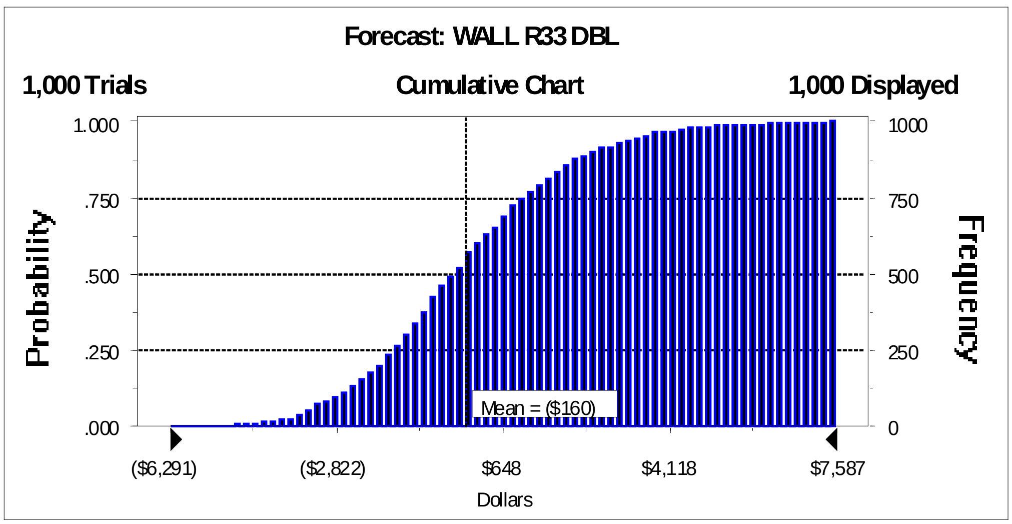

Figure G-97: Climate Zone 2 R33 Wall NPV Results for Electric Zonal

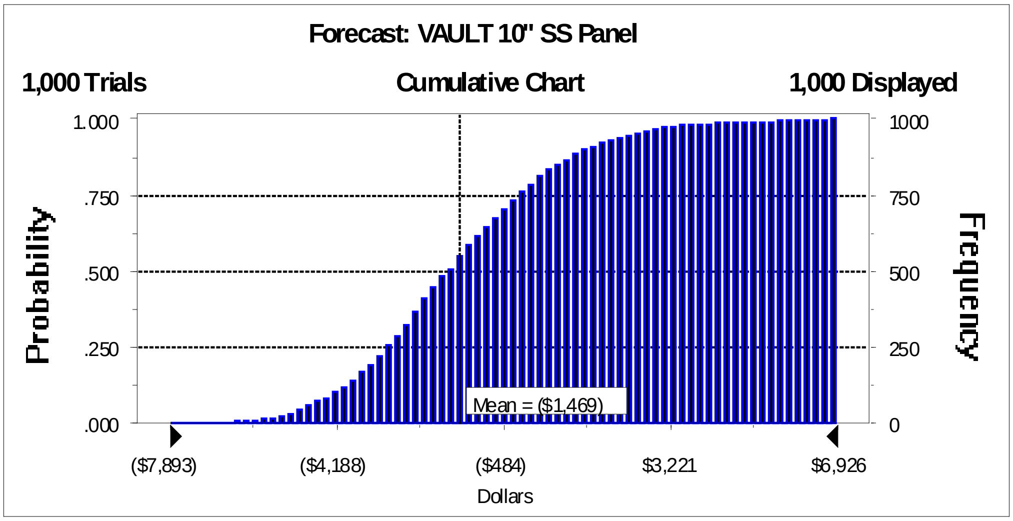

Figure G-98: Climate Zone 2 R49 Vault NPV Results for Electric Zonal

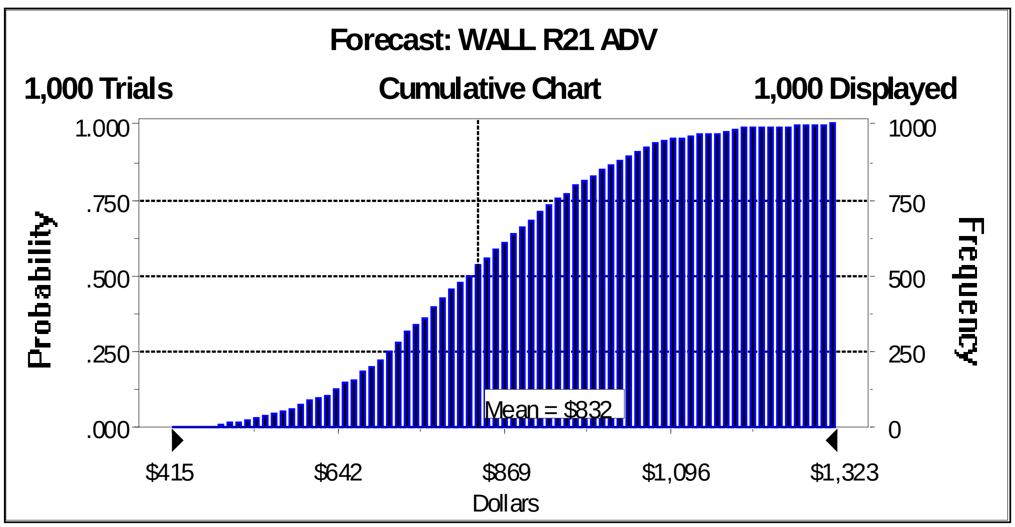

Figure G-99: Climate Zone 2 R21 Advanced Framed Wall NPV Results for Gas FAF

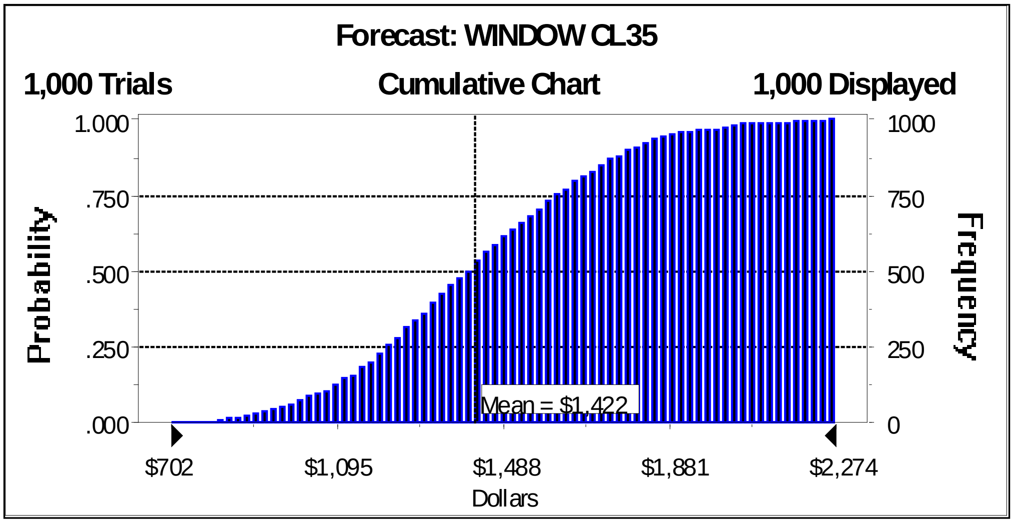

Figure G-100: Climate Zone 2 Class 35 Windows NPV Results for Gas FAF

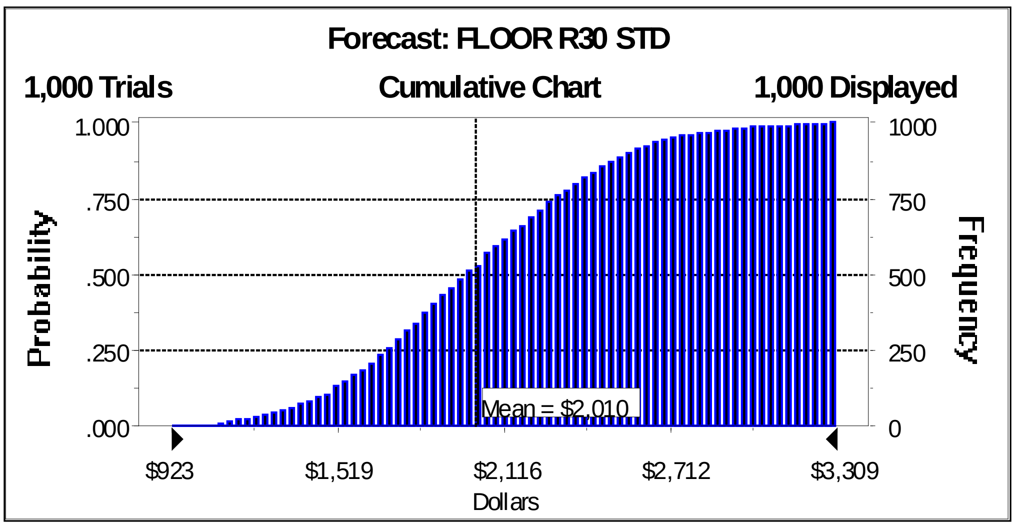

Figure G-101: Climate Zone 2 R30 Under floor NPV Results for Gas FAF

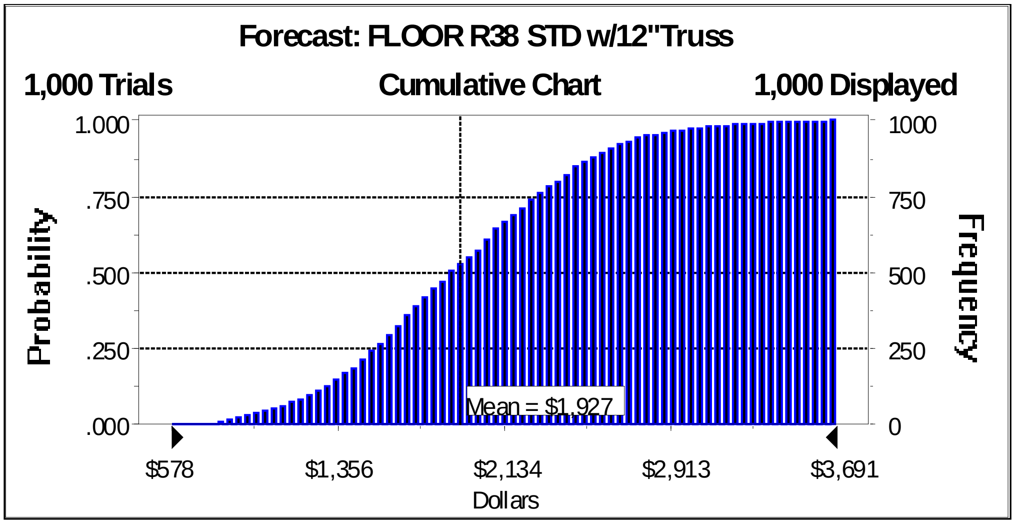

Figure G-102: Climate Zone 2 R38 Under floor NPV Results for Gas FAF

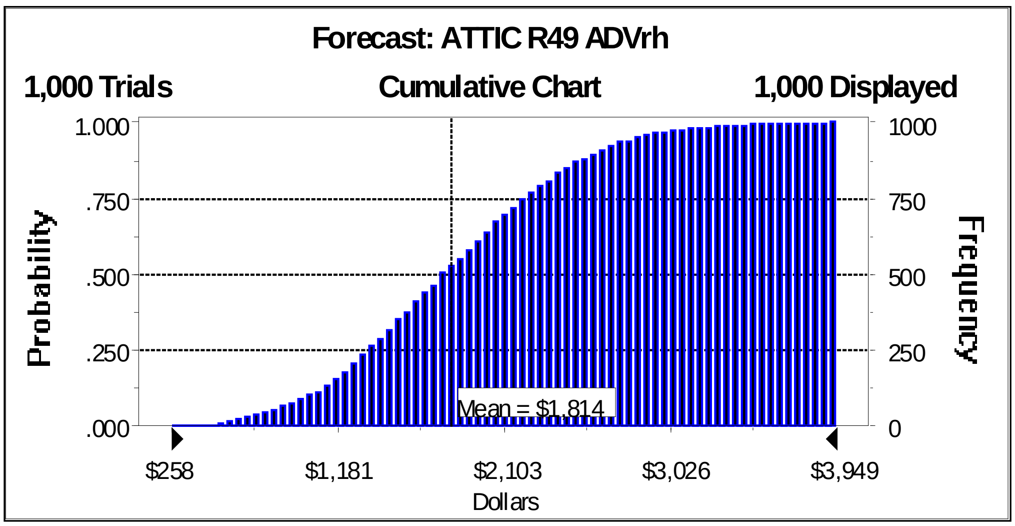

Figure G-103: Climate Zone 2 R49 Advanced Framed Attic NPV Results for Gas FAF

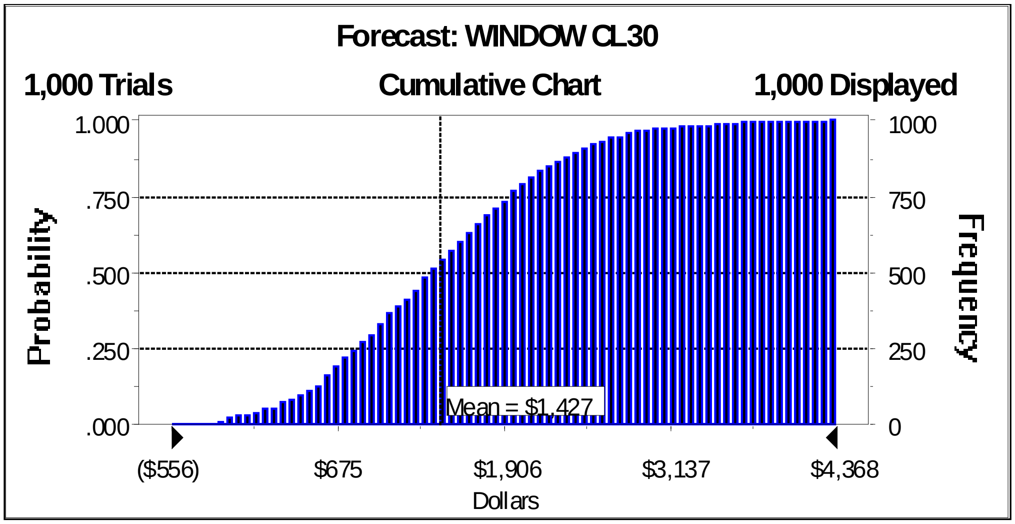

Figure G-104: Climate Zone 2 Class 30 Window NPV Results for Gas FAF

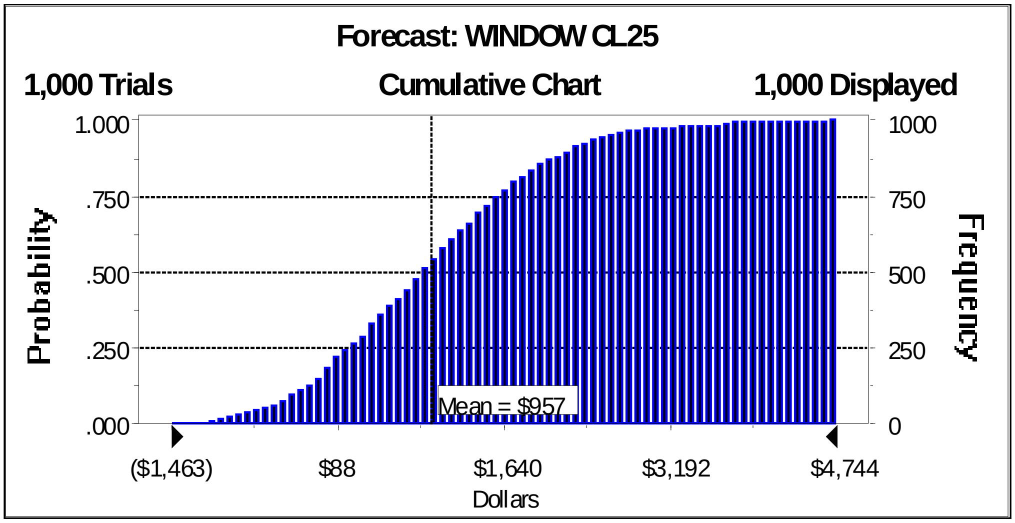

Figure G-105: Climate Zone 2 Class 25 Window NPV Results for Gas FAF

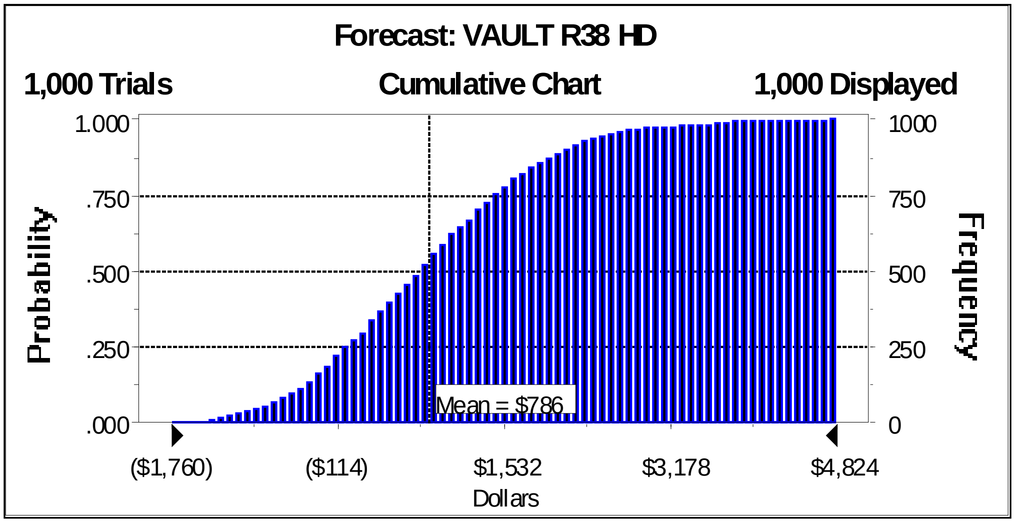

Figure G-106: Climate Zone 2 R38 Vault NPV Results for Gas FAF

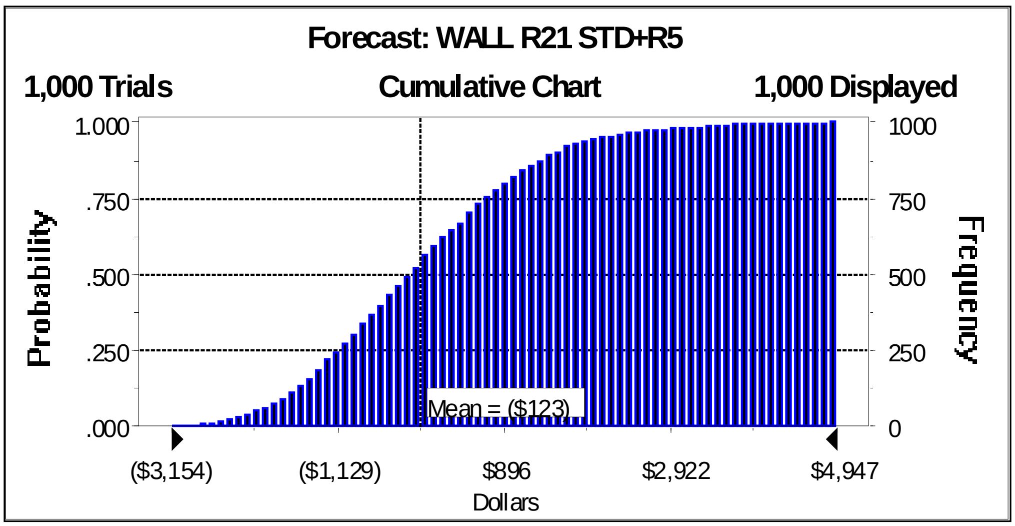

Figure G-107: Climate Zone 2 R26 Advanced Framed Wall NPV Results for Gas FAF

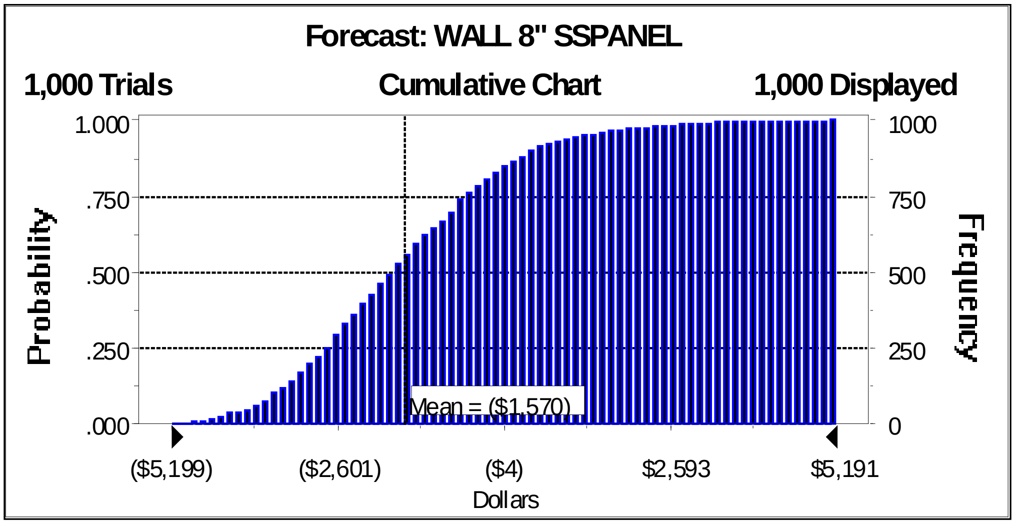

Figure G-108: Climate Zone 2 R33 Wall NPV Results for Gas FAF

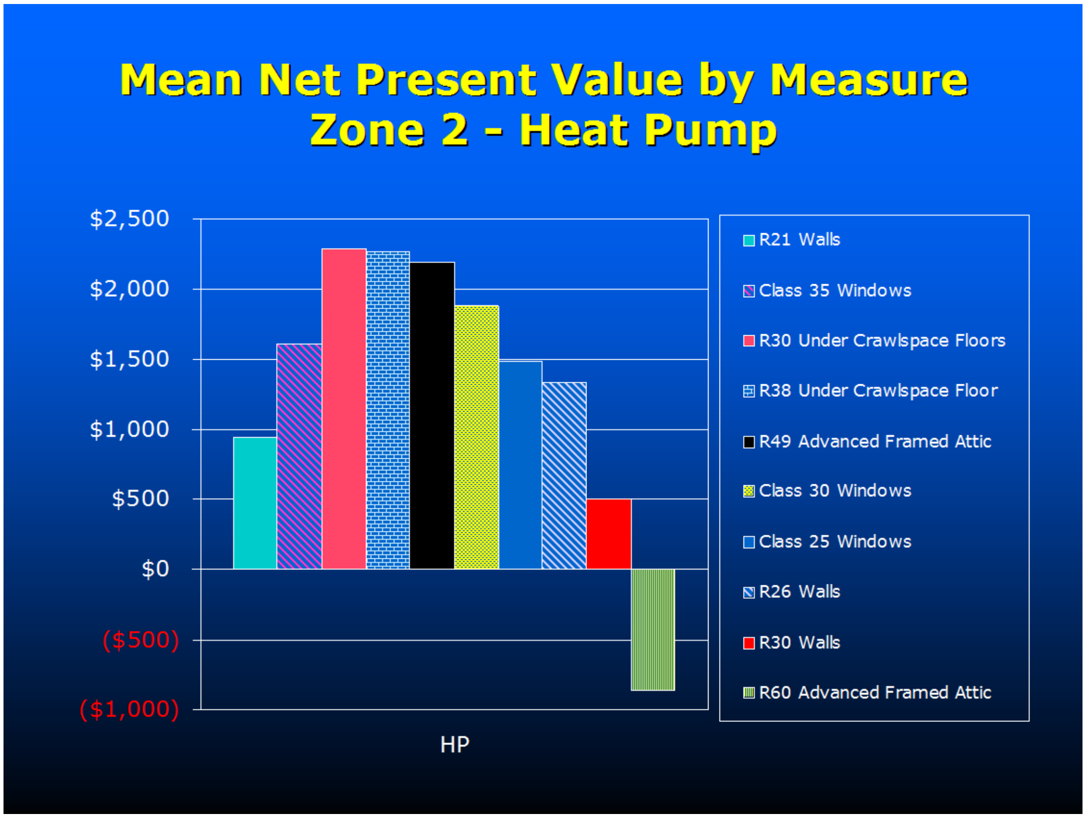

Figure G-109: Climate Zone 2 Summary of Mean NPV by Measure for Heat Pumps

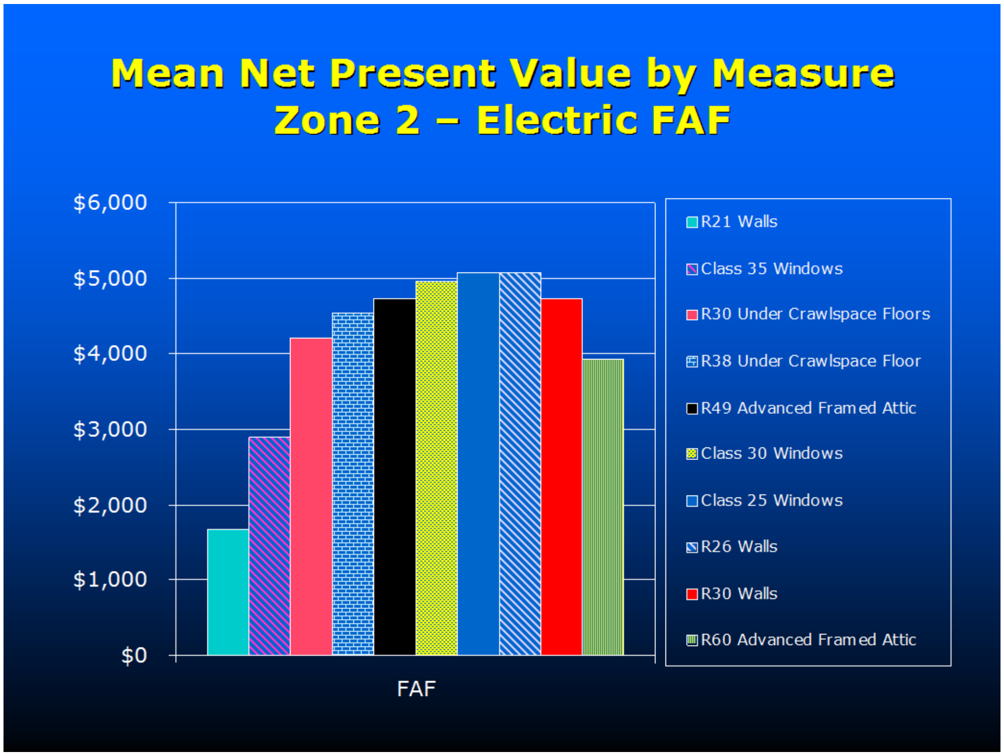

Figure G-110: Climate Zone 2 Mean NPV by Measure for Electric FAF

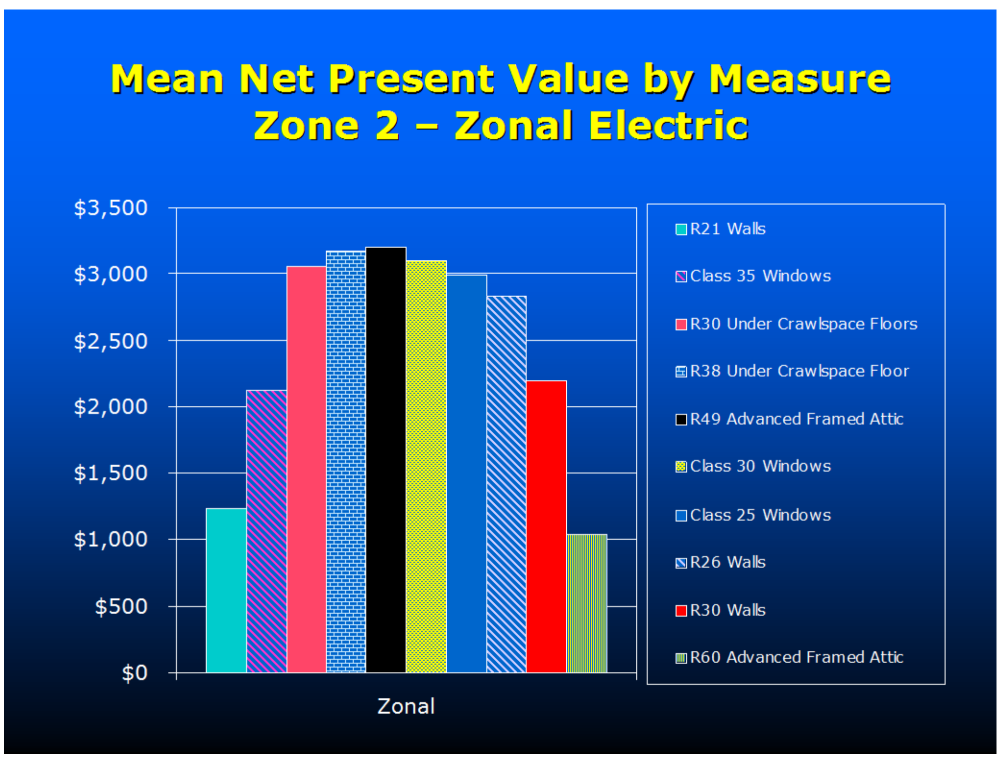

Figure G-111: Climate Zone 2 Mean NPV by Measure for Electric Zonal

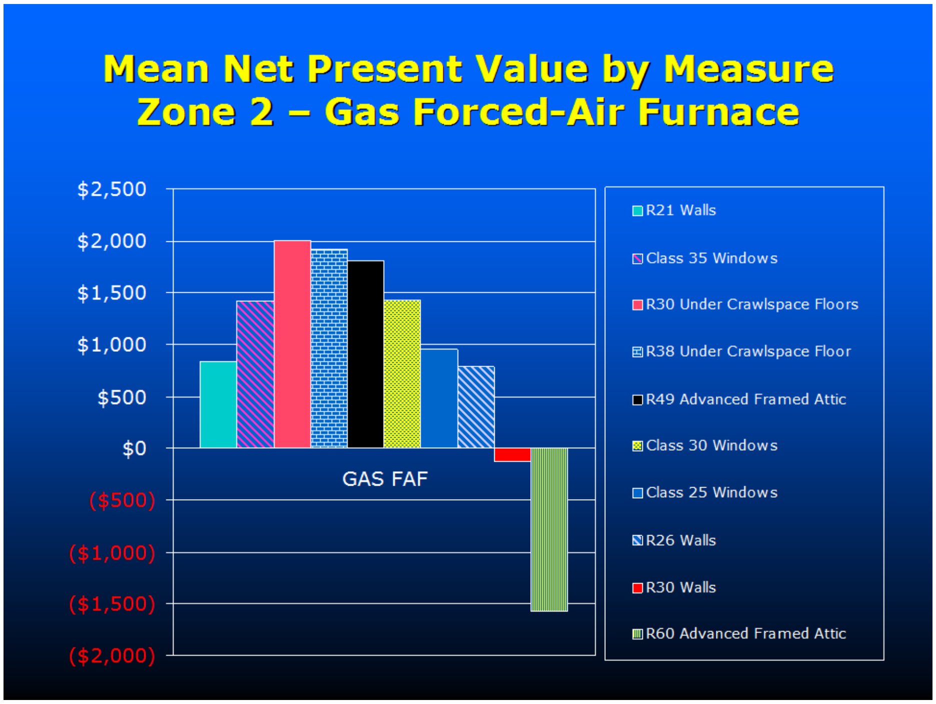

Figure G-112: Climate Zone 2 Mean NPV by Measure for Gas FAF

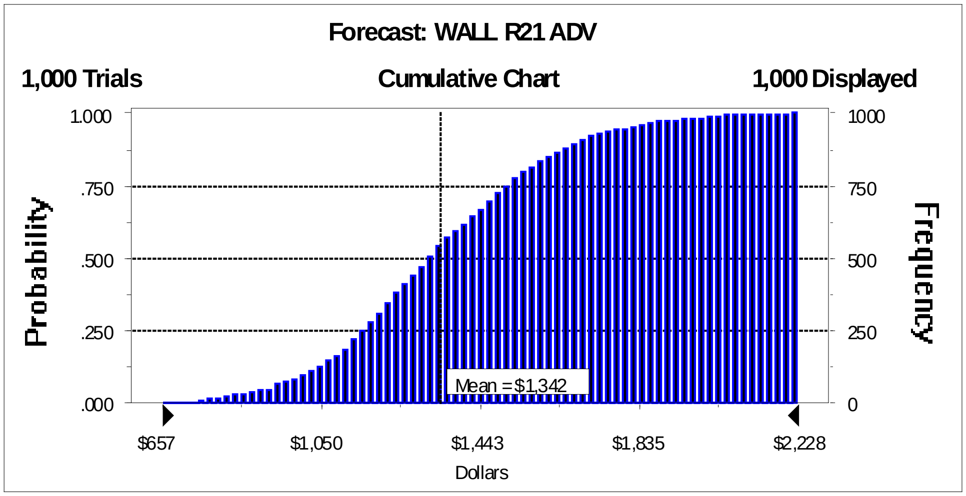

Figure G-113: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Heat Pumps

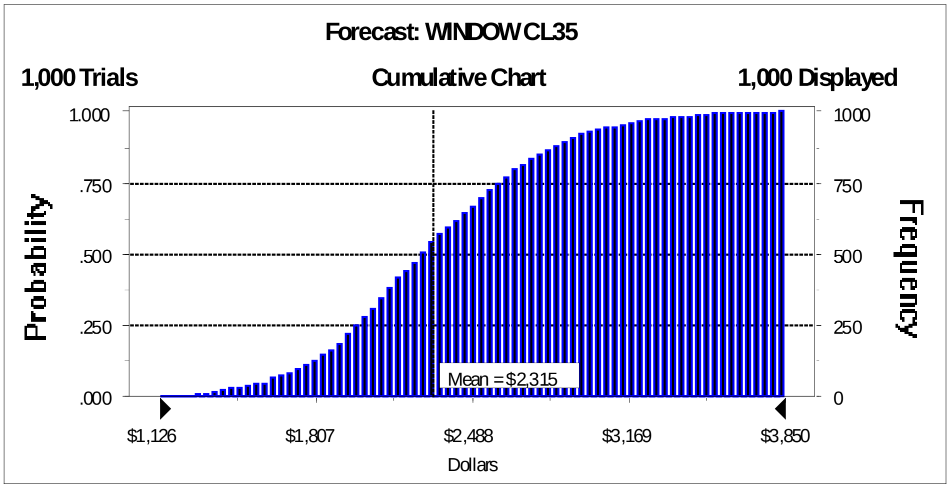

Figure G-114: Climate Zone 3 Class 35 Window NPV Results for Heat Pumps

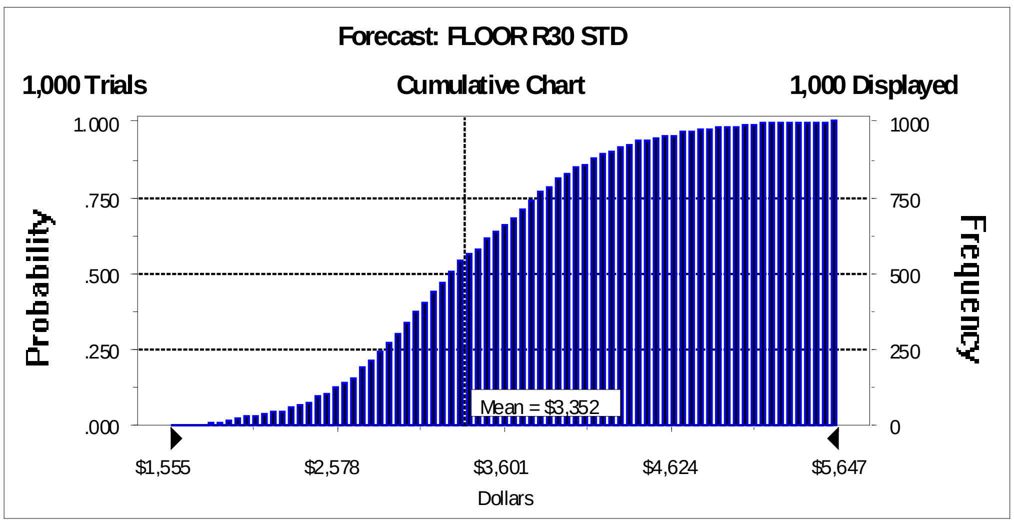

Figure G-115: Climate Zone 3 R30 Under floor NPV Results for Heat Pumps

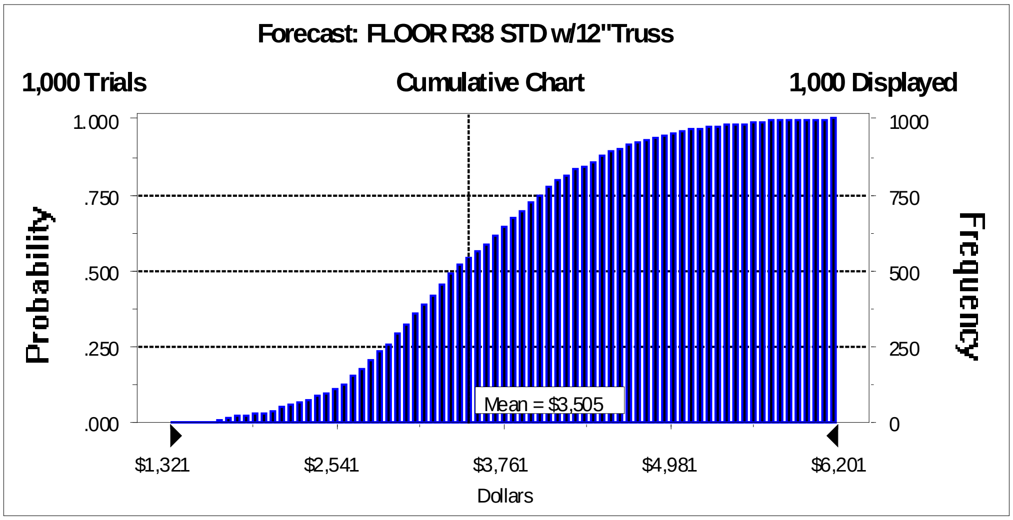

Figure G-116: Climate Zone 3 R38 Under floor NPV Results for Heat Pumps

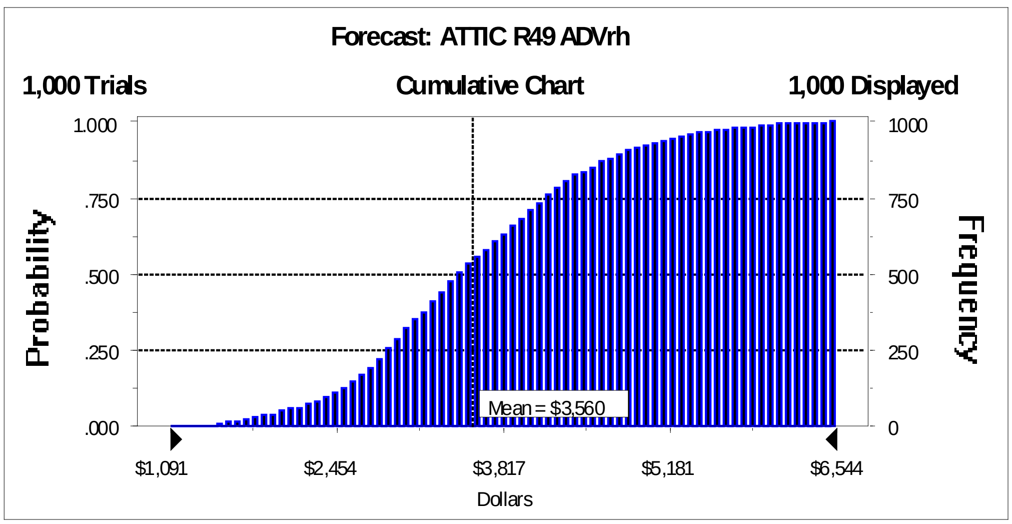

Figure G-117: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Heat Pumps

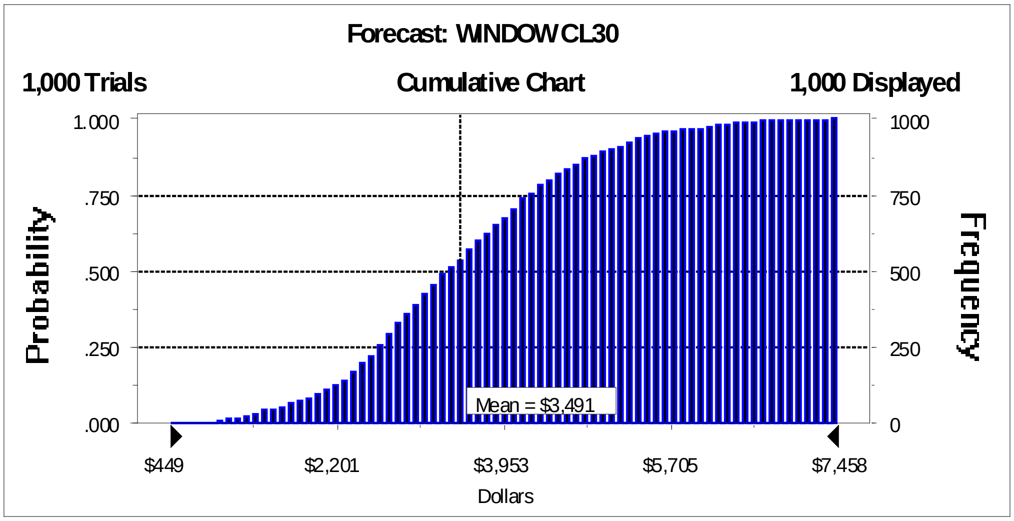

Figure G-118: Climate Zone 3 Class 30 Window NPV Results for Heat Pumps

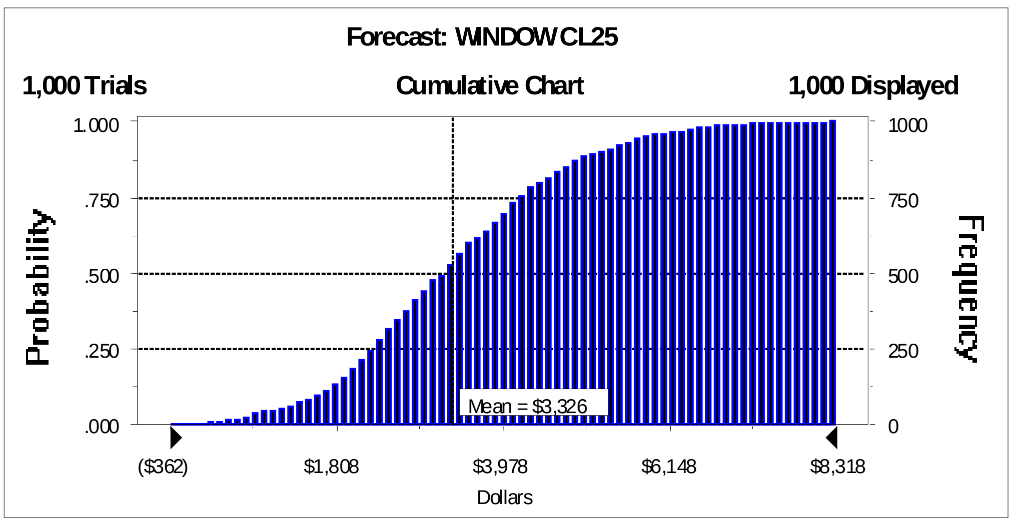

Figure G-119: Climate Zone 3 Class 25 Window NPV Results for Heat Pumps

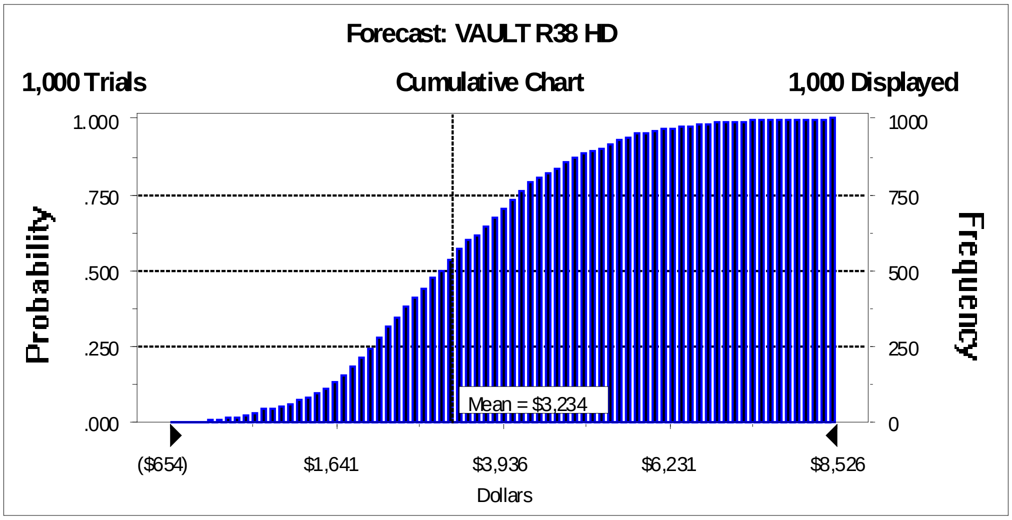

Figure G-120: Climate Zone 3 R38 Vault NPV Results for Heat Pumps

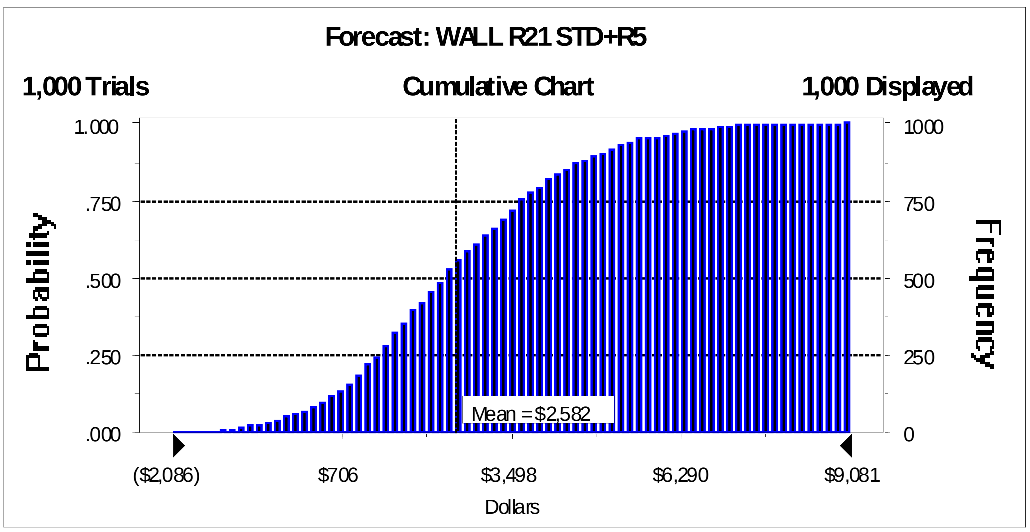

Figure G-121: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Heat Pumps

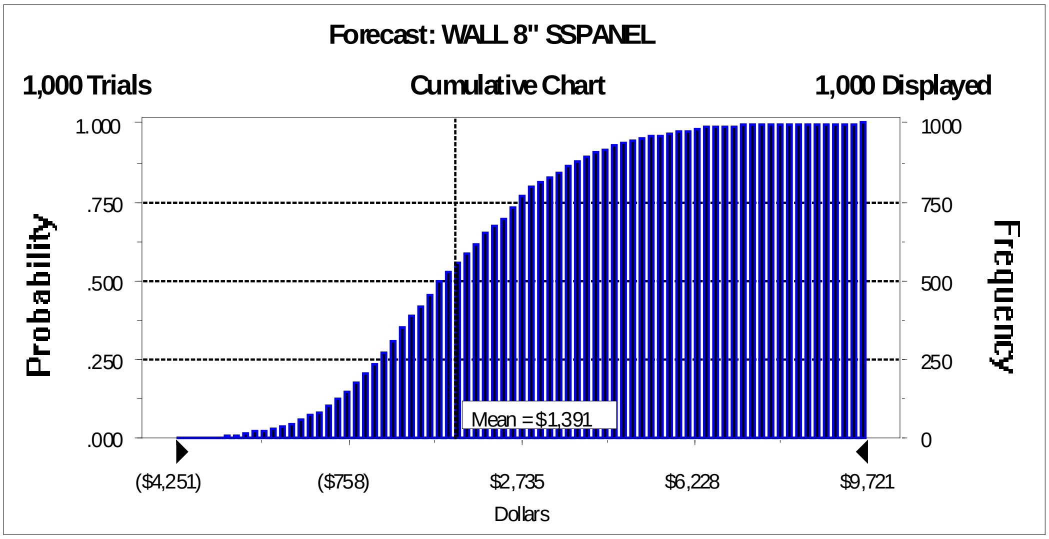

Figure G-122: Climate Zone 3 R33 Wall NPV Results for Heat Pumps

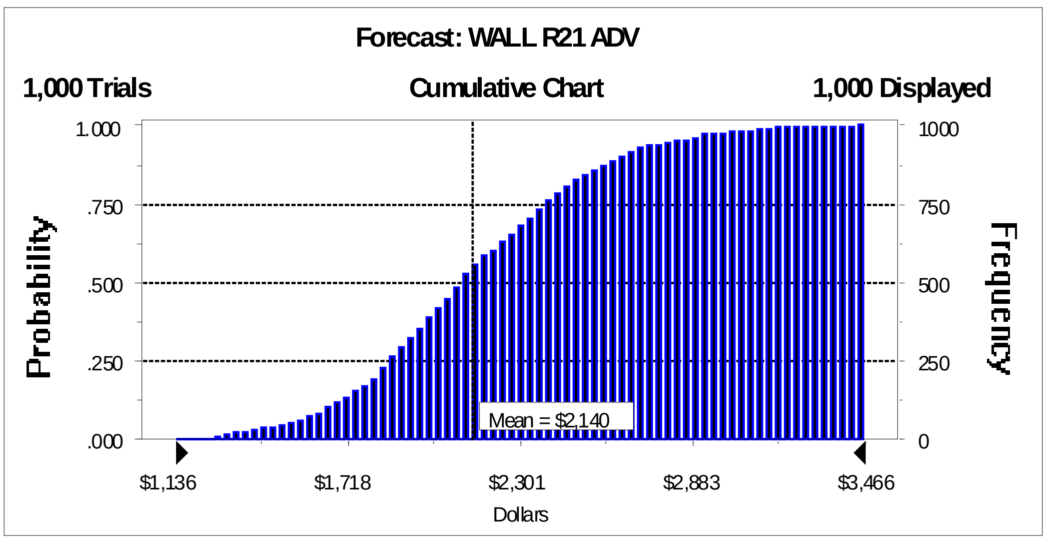

Figure G-123: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Electric FAF

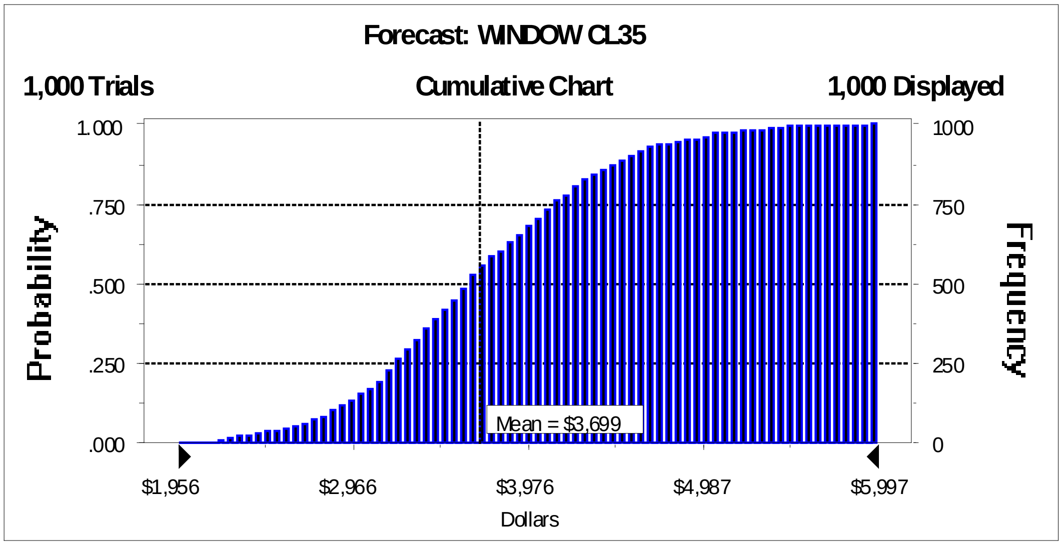

Figure G-124: Climate Zone 3 Class 35 Window NPV Results for Electric FAF

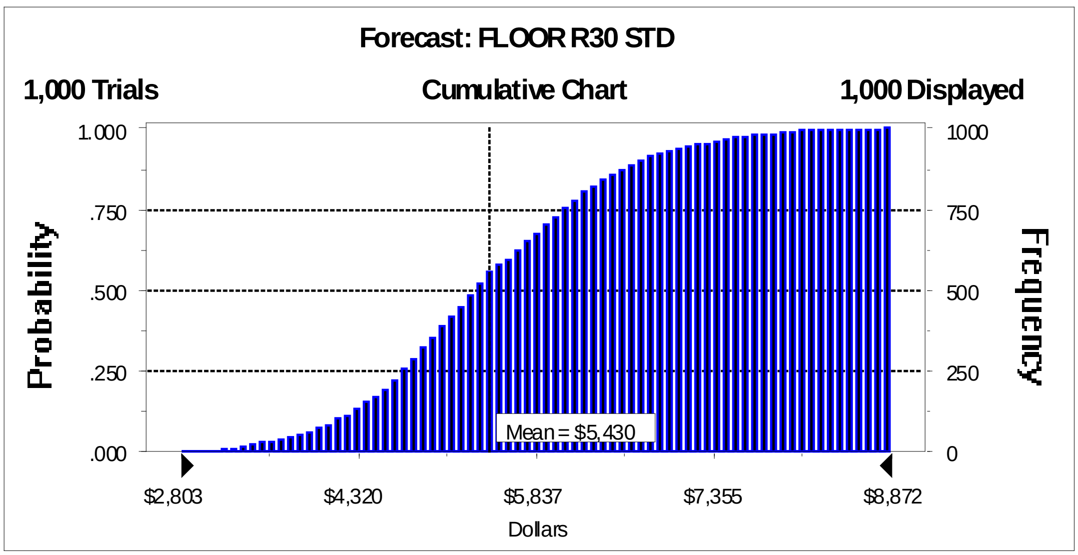

Figure G-125: Climate Zone 3 R30 Under floor NPV Results for Electric FAF

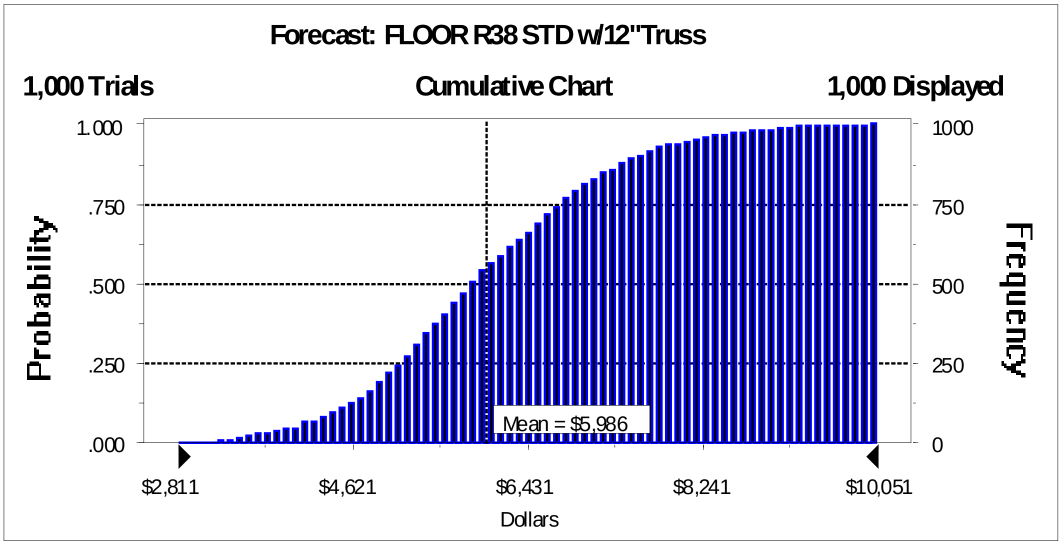

Figure G-126: Climate Zone 3 R38 Under floor NPV Results for Electric FAF

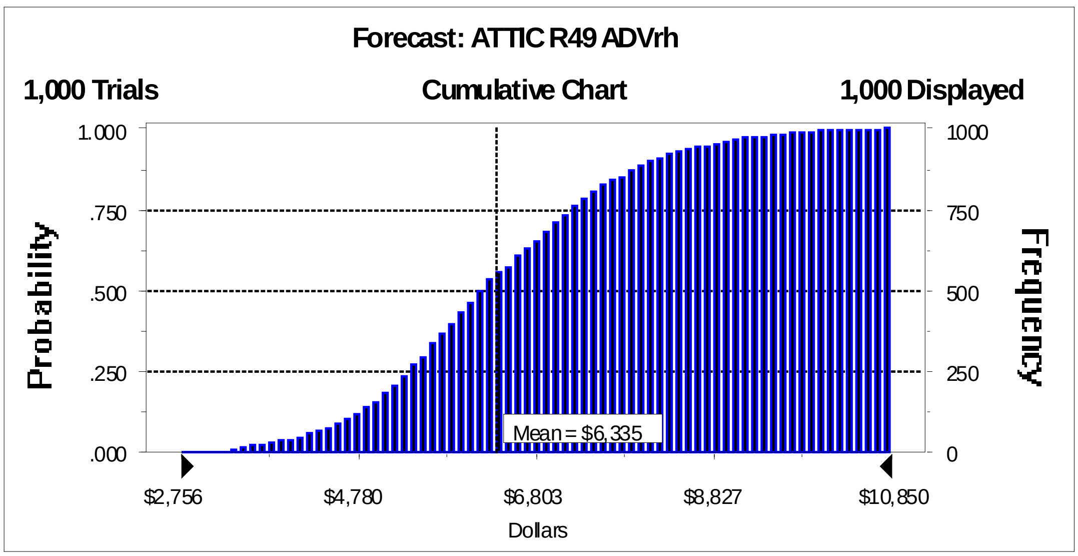

Figure G-127: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Electric FAF

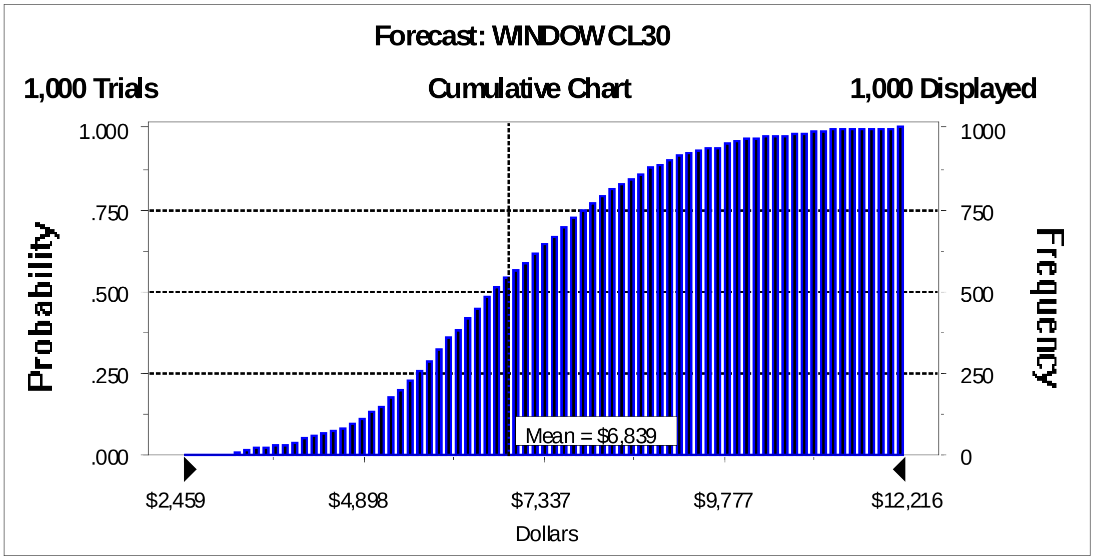

Figure G-128: Climate Zone 3 Class 30 Window NPV Results for Electric FAF

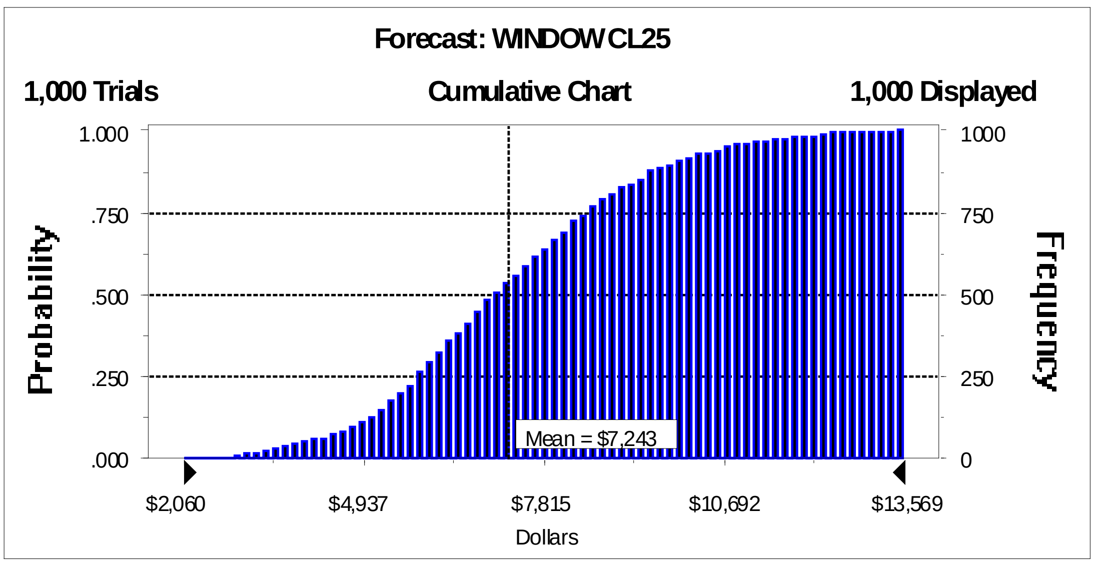

Figure G-129: Climate Zone 3 Class 25 Window NPV Results for Electric FAF

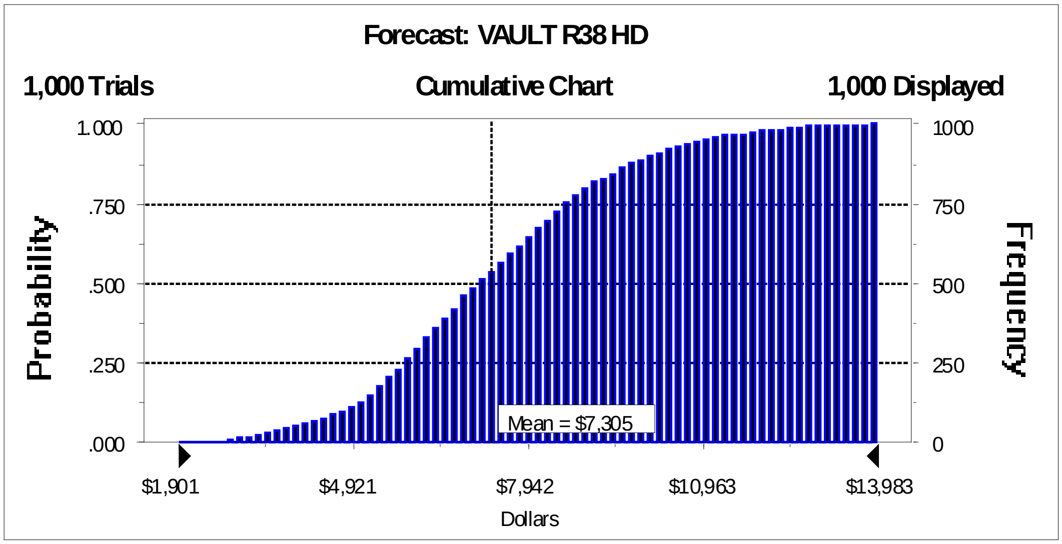

Figure G-130: Climate Zone 3 R38 Vault NPV Results for Electric FAF

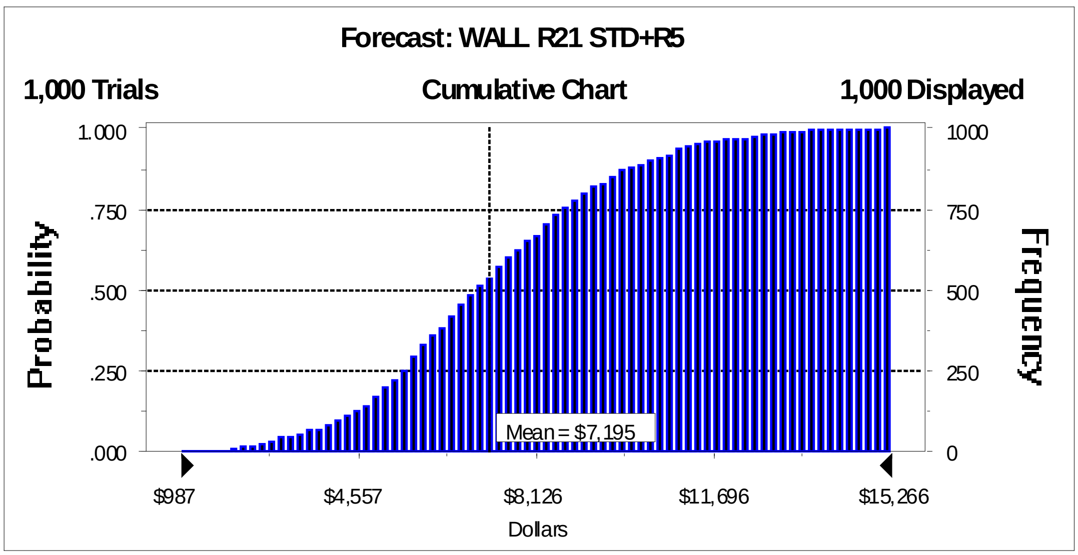

Figure G-131: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Electric FAF

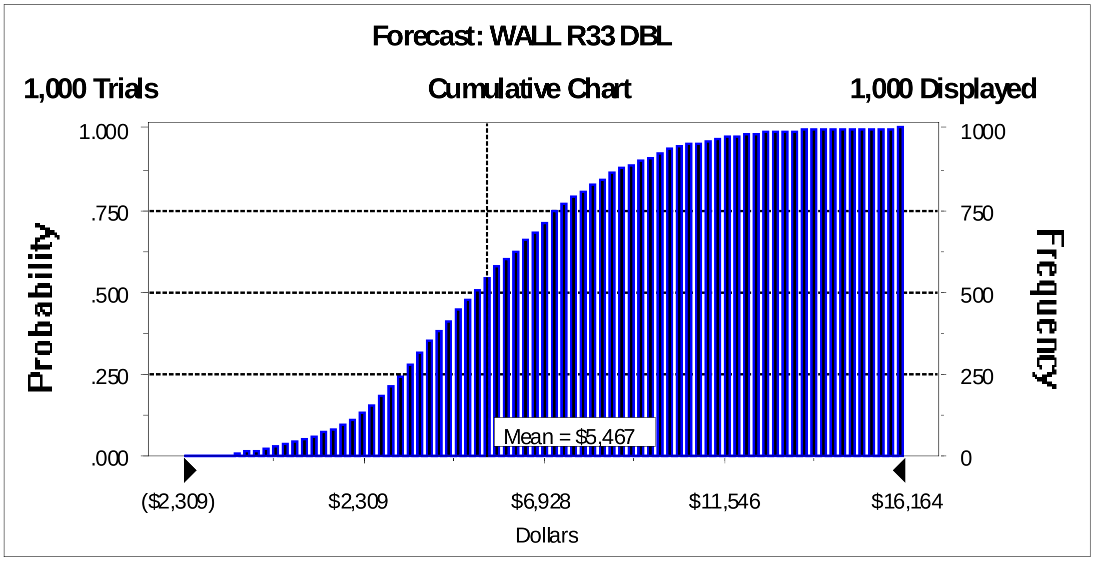

Figure G-132: Climate Zone 3 R33 Wall NPV Results for Electric FAF

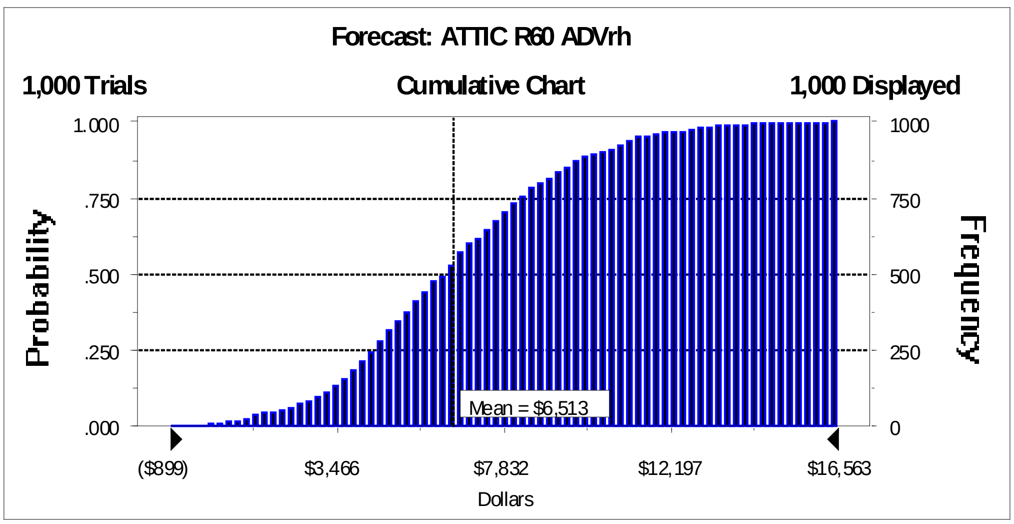

Figure G-133: Climate Zone 3 R60 Advanced Framed Attic NPV Results for Electric FAF

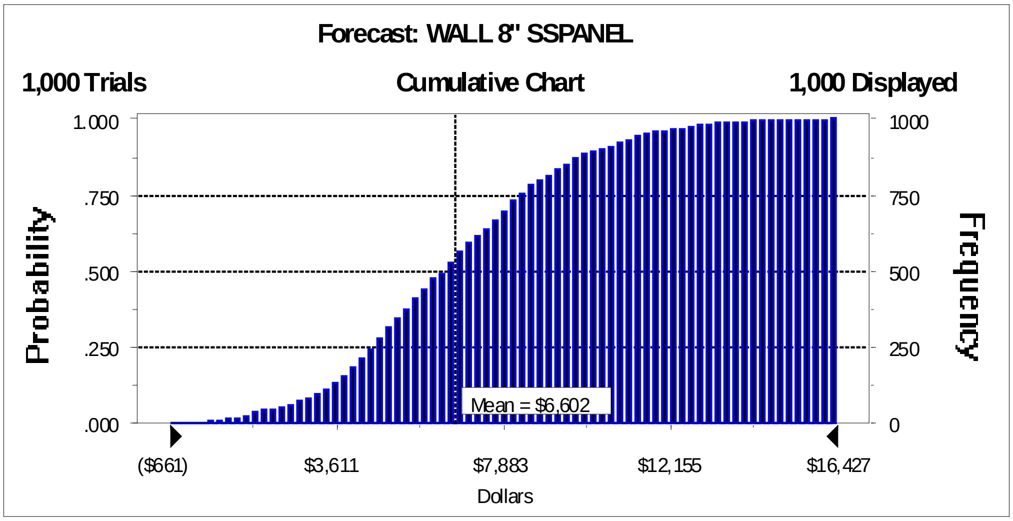

Figure G-134: Climate Zone 3 R38 Wall NPV Results for Electric FAF

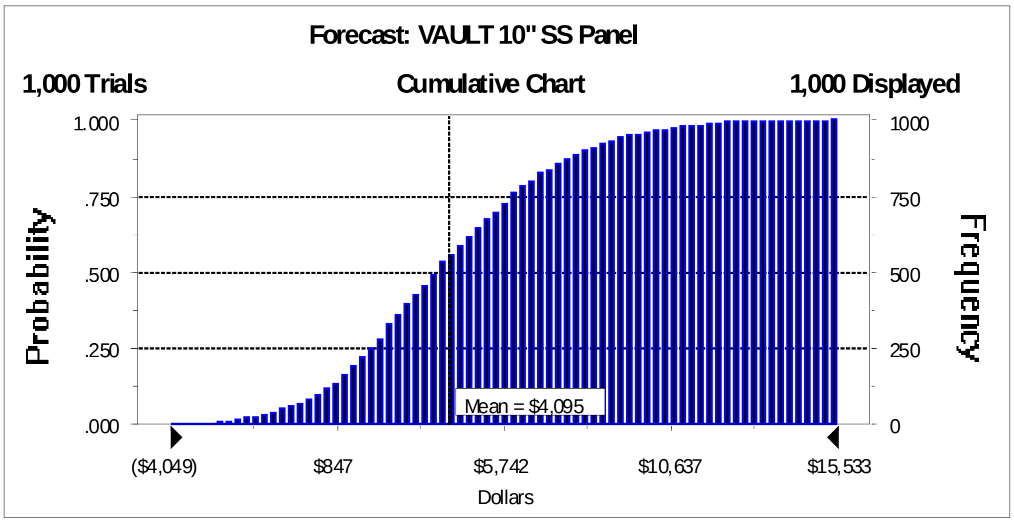

Figure G-135: Climate Zone 3 R49 Vault NPV Results for Electric FAF

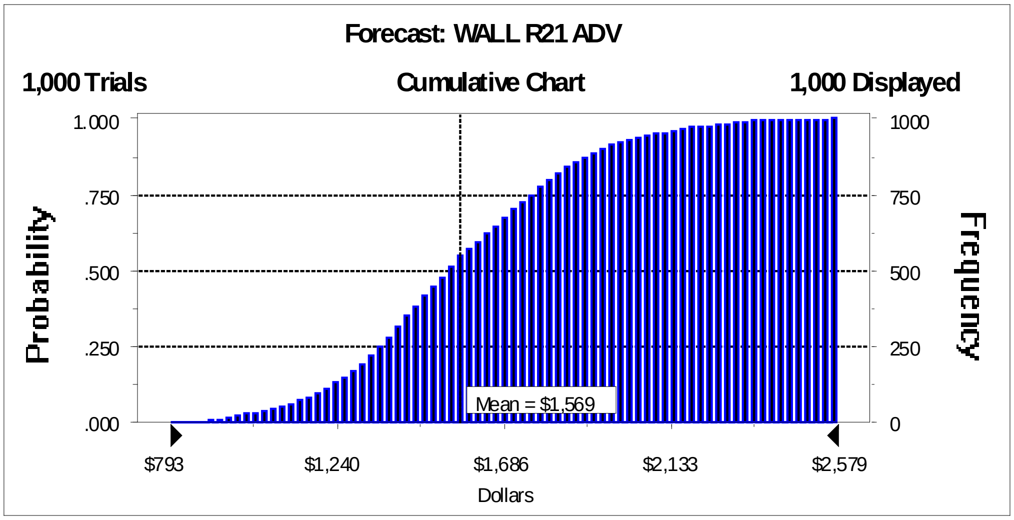

Figure G-136: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Electric Zonal

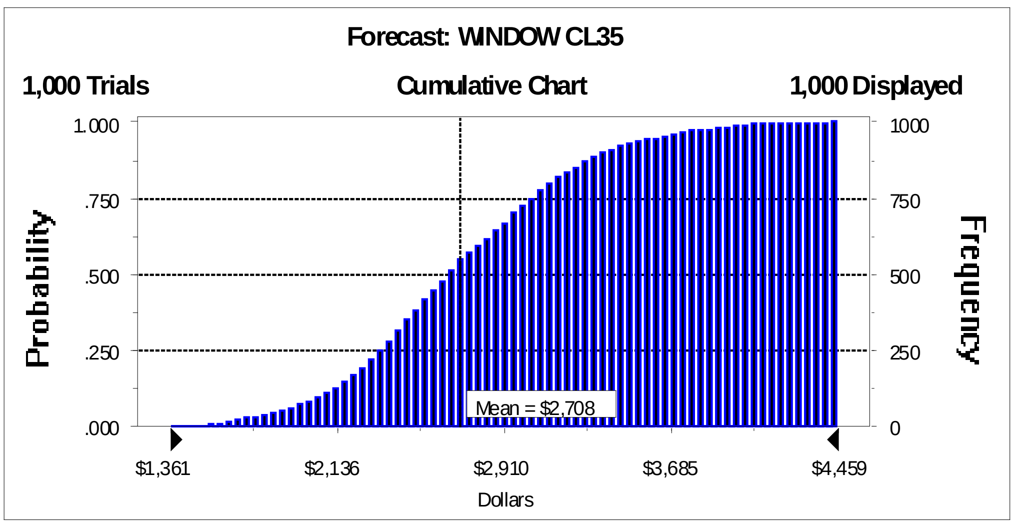

Figure G-137: Climate Zone 3 Class 35 Window NPV Results for Electric Zonal

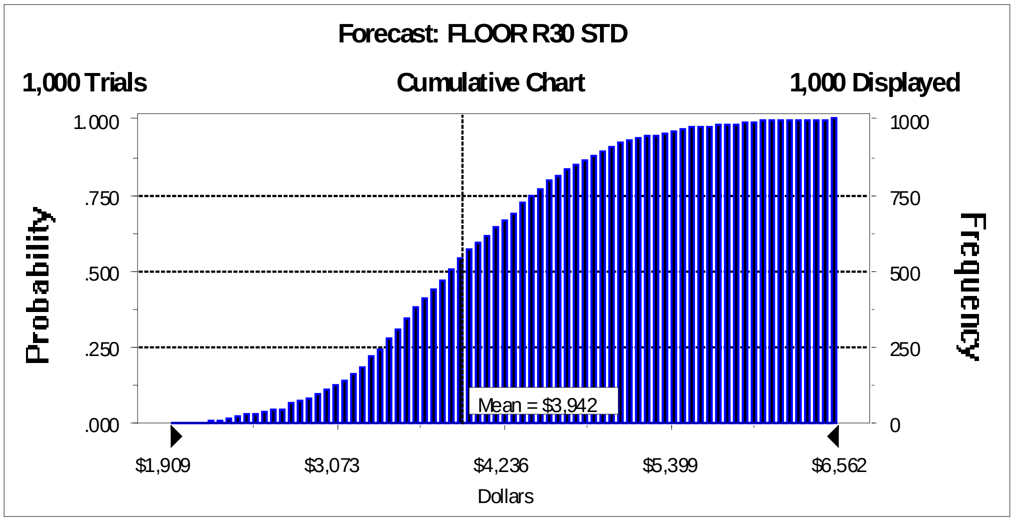

Figure G-138: Climate Zone 3 R30 Under floor NPV Results for Electric Zonal

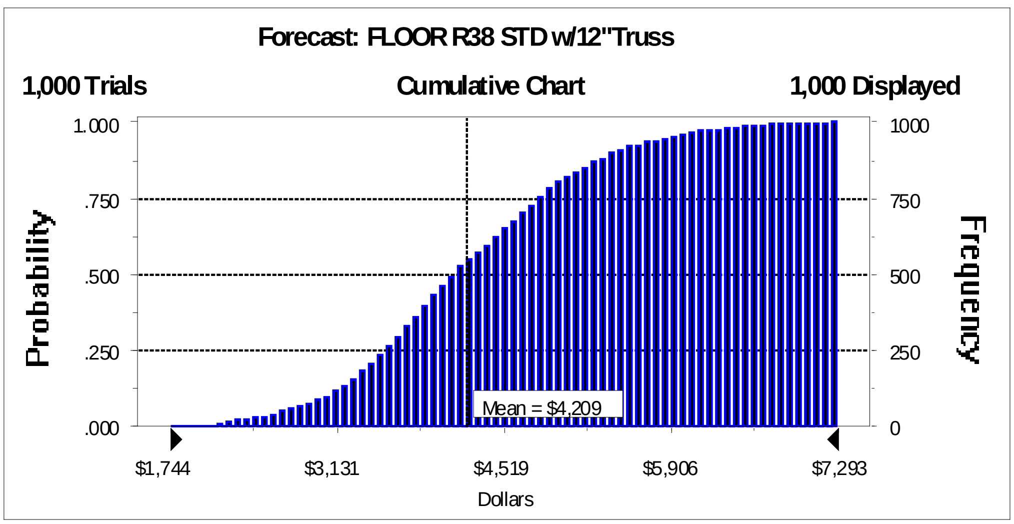

Figure G-139: Climate Zone 3 R38 Under floor NPV Results for Electric Zonal

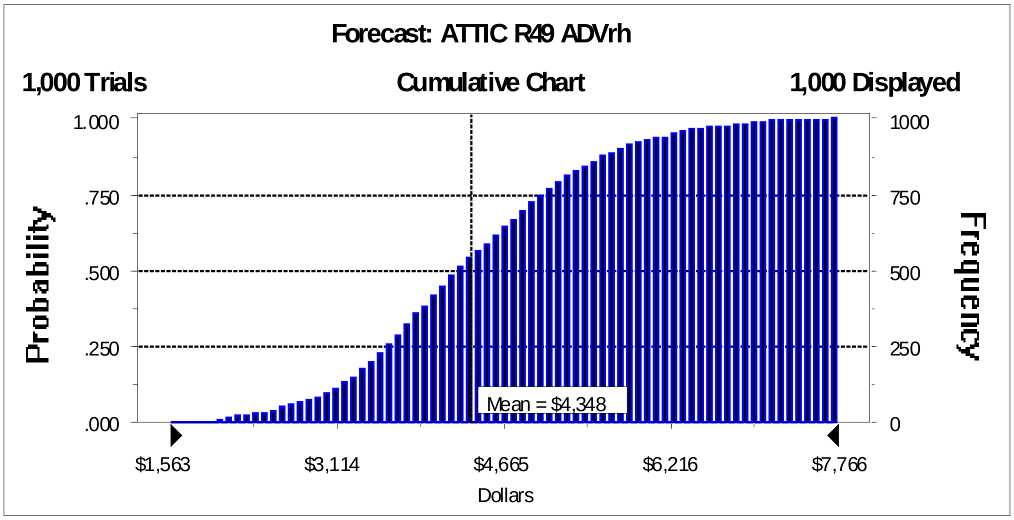

Figure G-140: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Electric Zonal

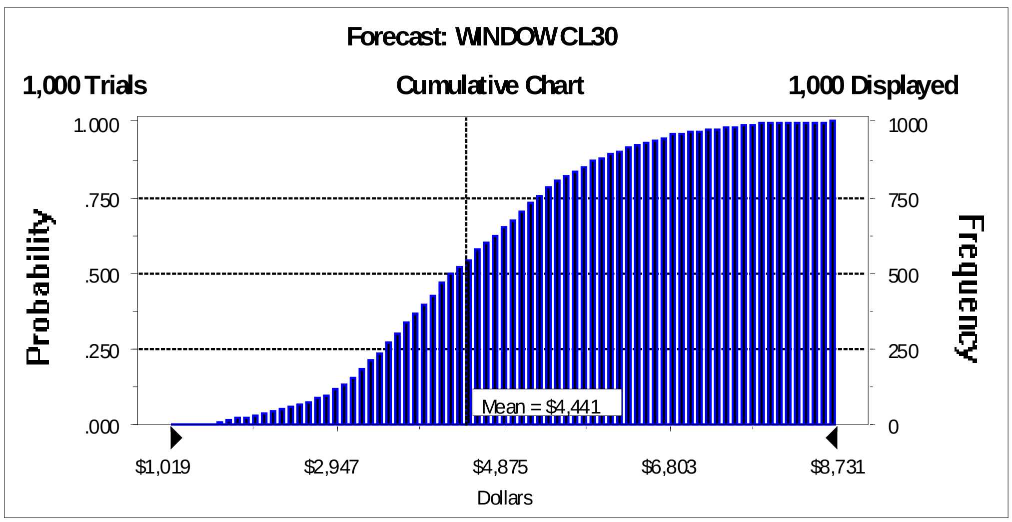

Figure G-141: Climate Zone 3 Class 30 Window NPV Results for Electric Zonal

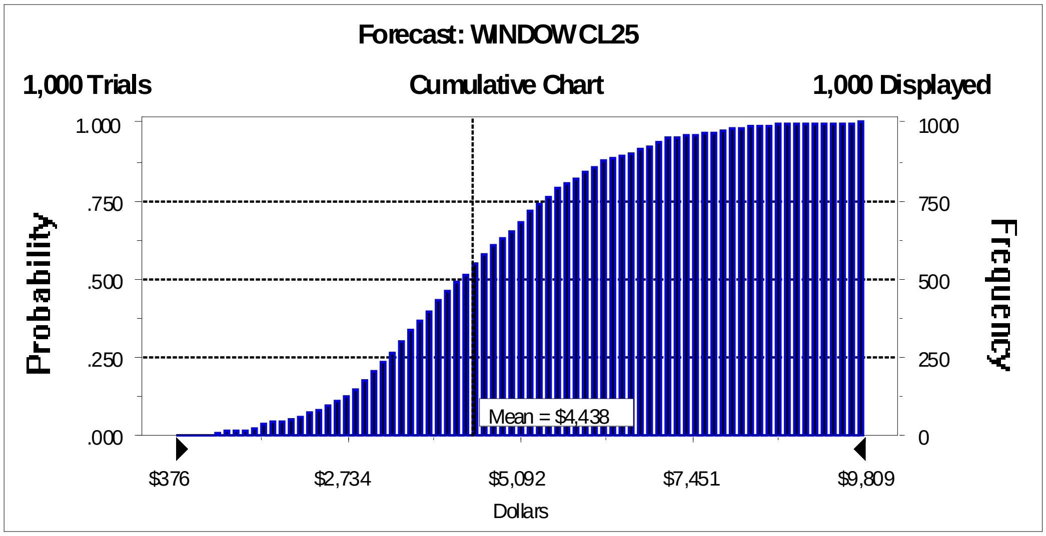

Figure G-142: Climate Zone 3 Class 25 Window NPV Results for Electric Zonal

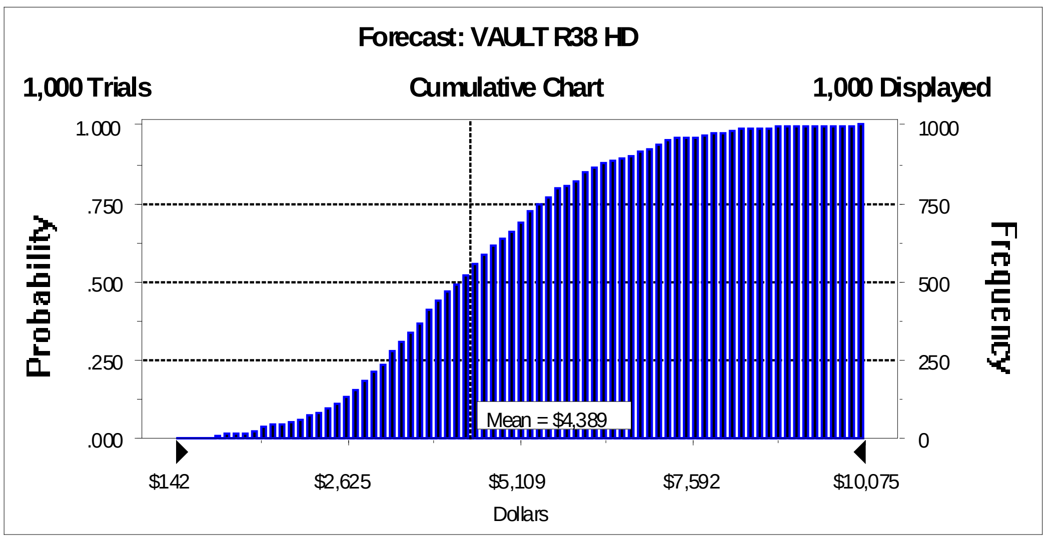

Figure G-143: Climate Zone 3 R38 Vault NPV Results for Electric Zonal

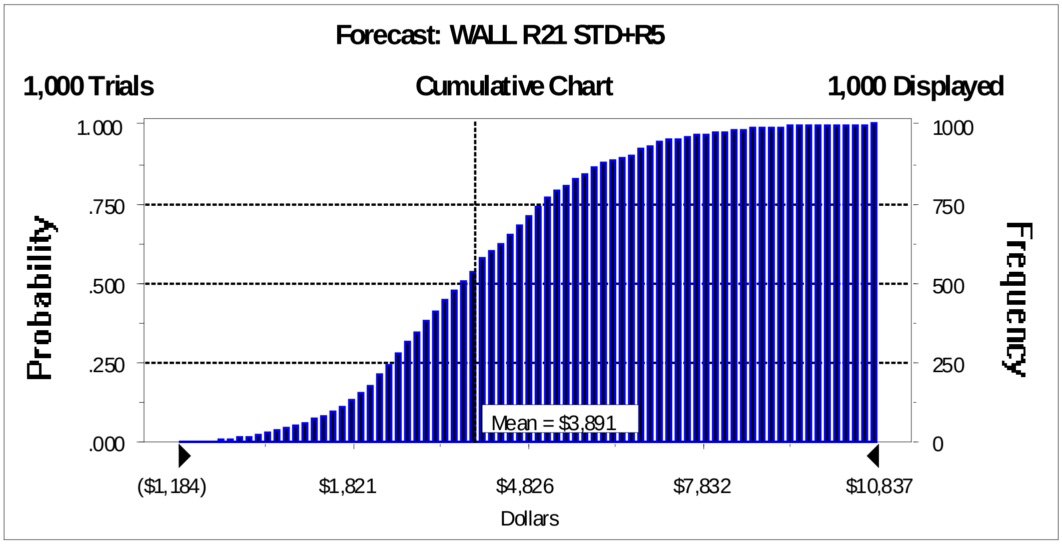

Figure G-144: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Electric Zonal

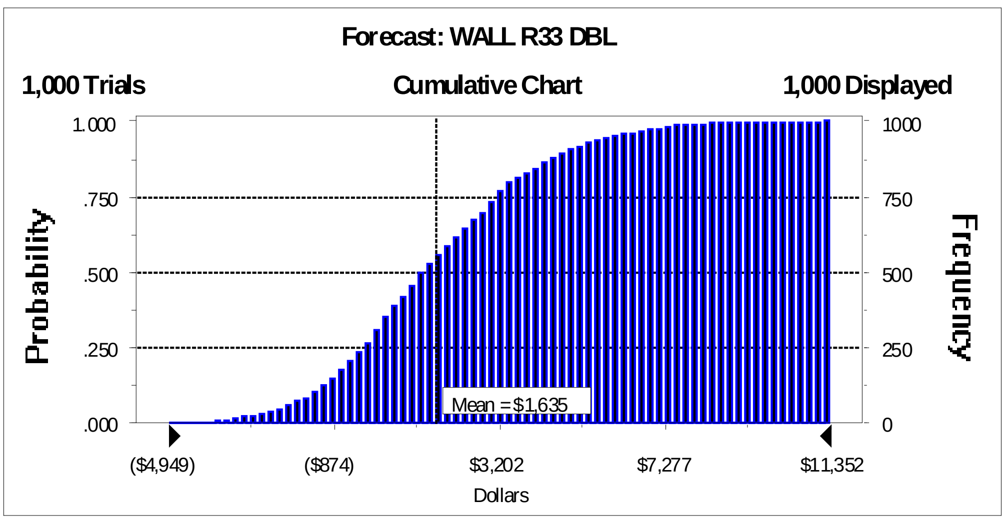

Figure G-145: Climate Zone 3 R33 Wall NPV Results for Electric Zonal

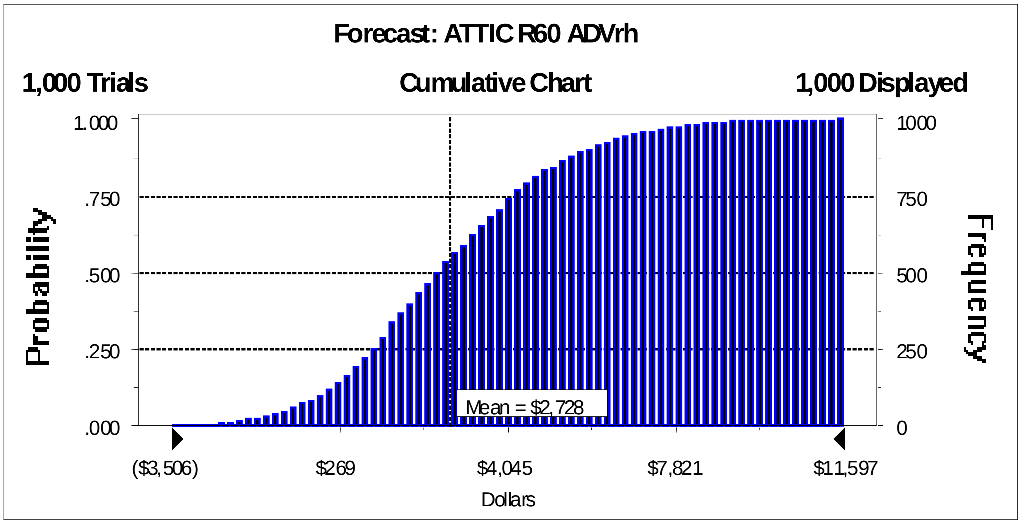

Figure G-146: Climate Zone 3 R60 Advanced Framed Attic NPV Results for Electric Zonal

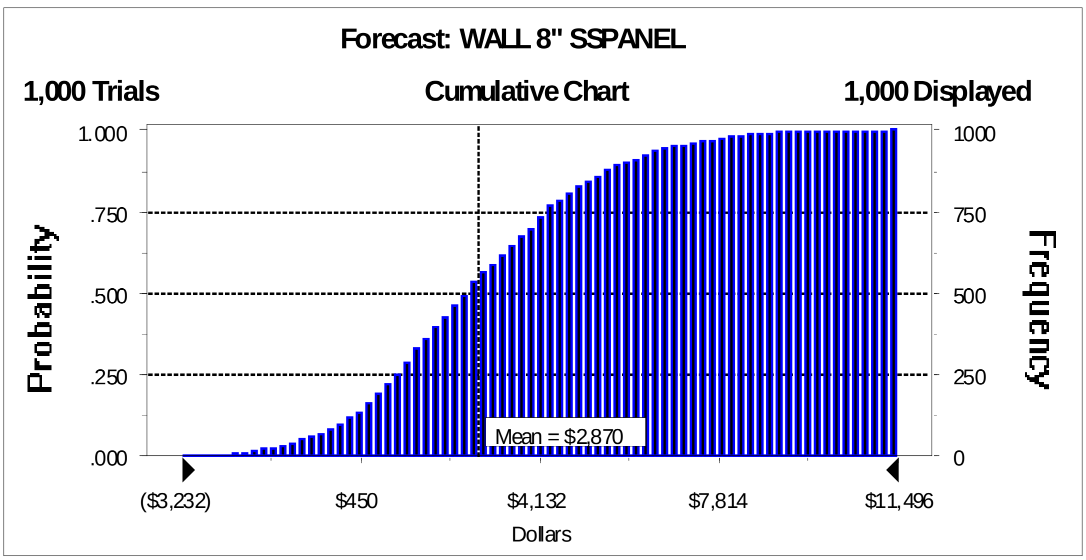

Figure G-147: Climate Zone 3 R38 Wall NPV Results for Electric Zonal

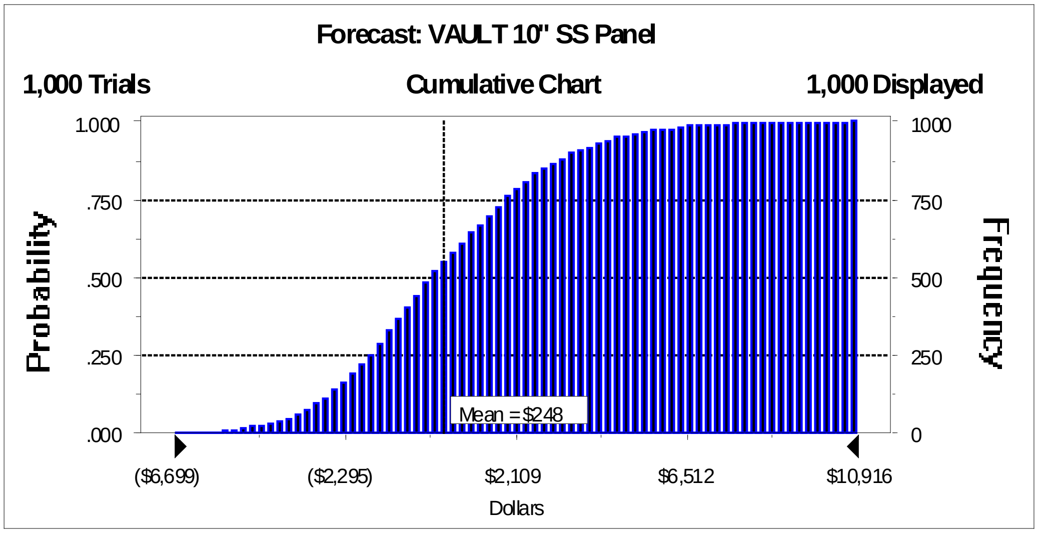

Figure G-148: Climate Zone 3 R49 Vault NPV Results for Electric Zonal

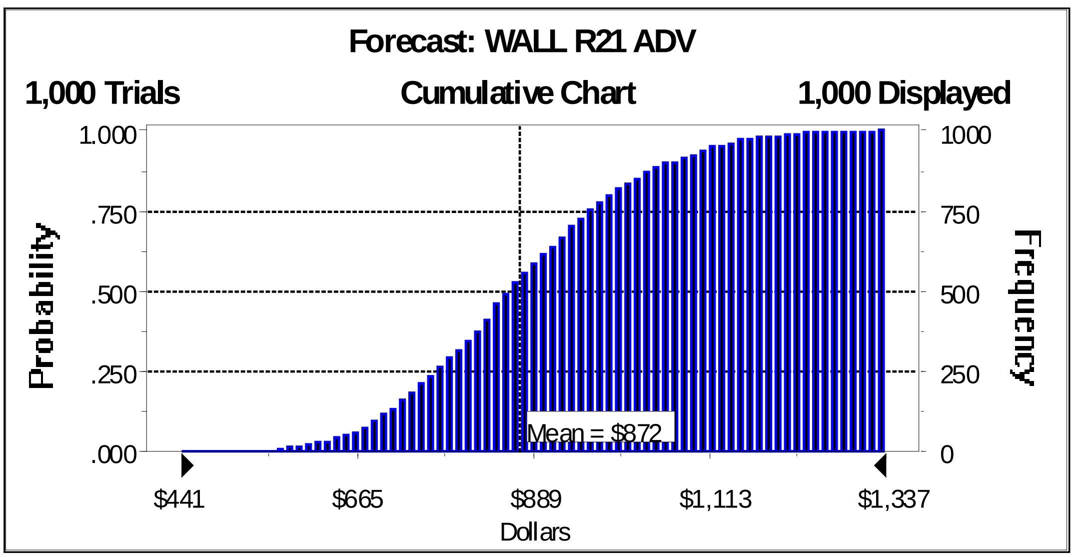

Figure G-149: Climate Zone 3 R21 Advanced Framed Wall NPV Results for Gas FAF

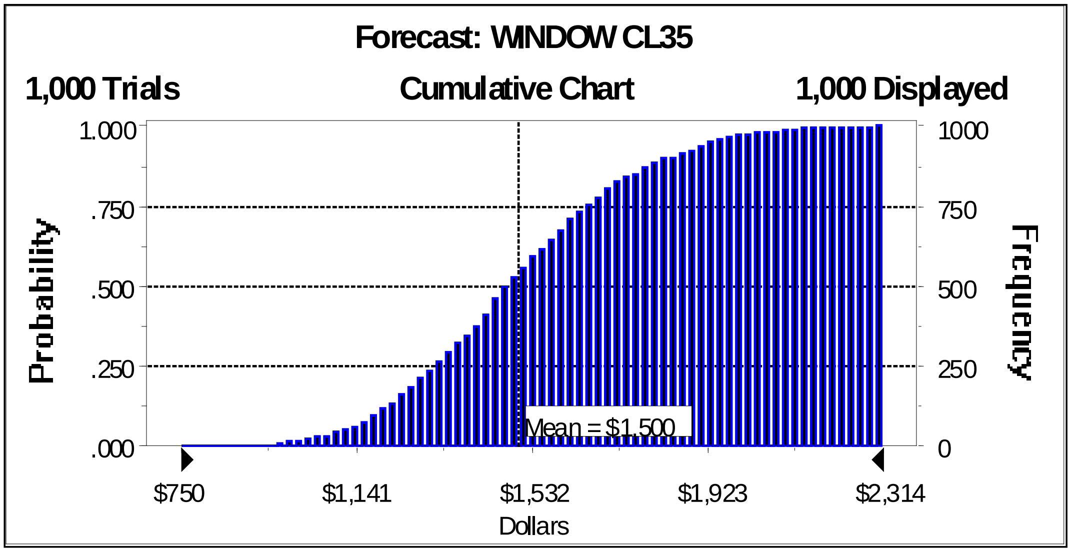

Figure G-150: Climate Zone 3 Class 35 Window NPV Results for Gas FAF

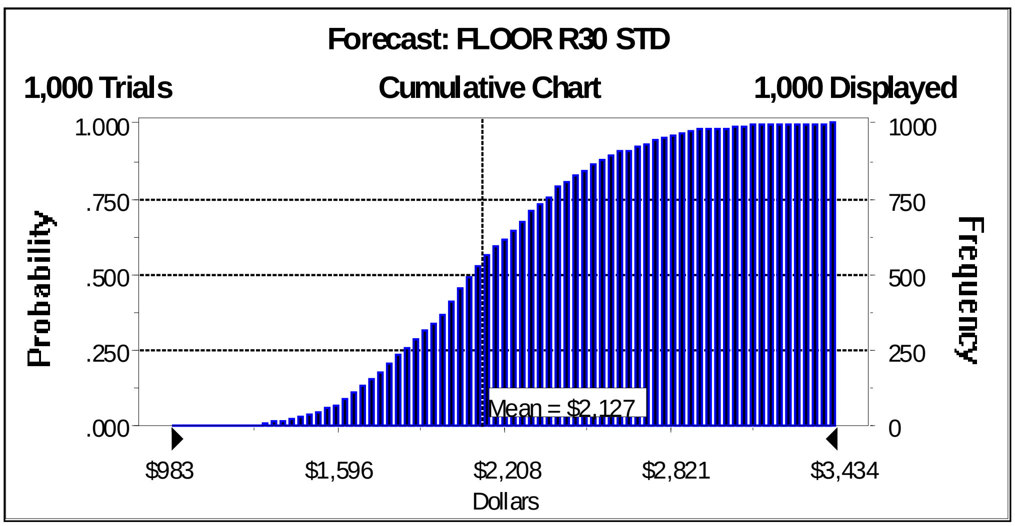

Figure G-151: Climate Zone 3 R30 Under floor NPV Results for Gas FAF

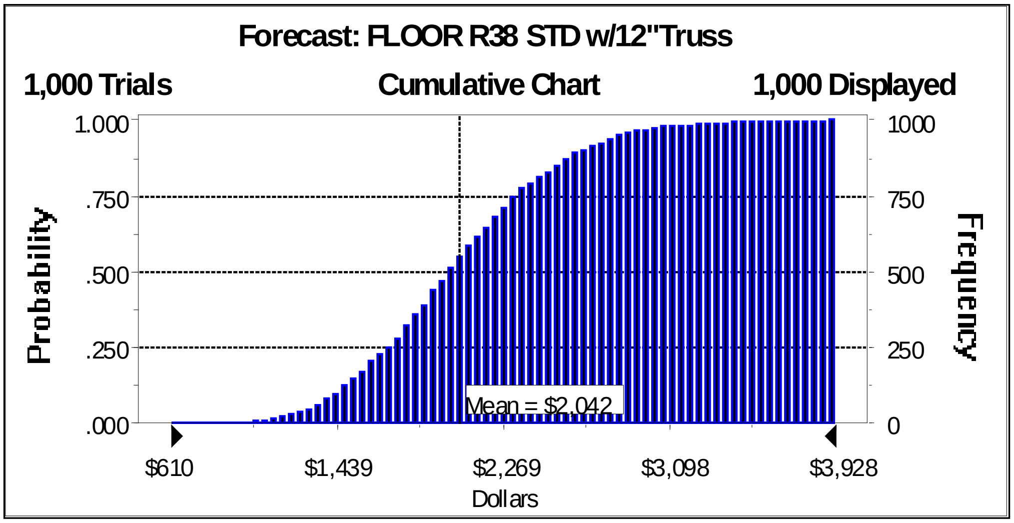

Figure G-152: Climate Zone 3 R38 Under floor NPV Results for Gas FAF

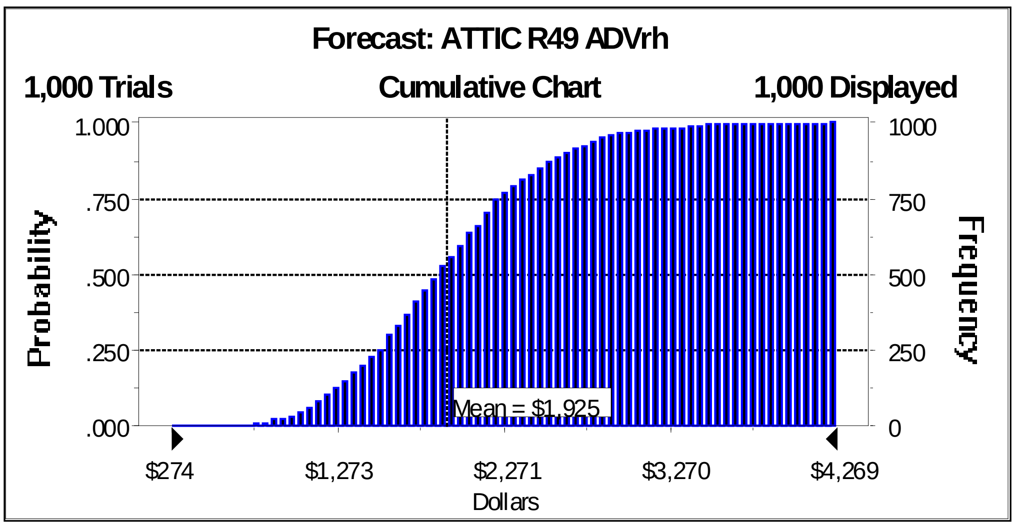

Figure G-153: Climate Zone 3 R49 Advanced Framed Attic NPV Results for Gas FAF

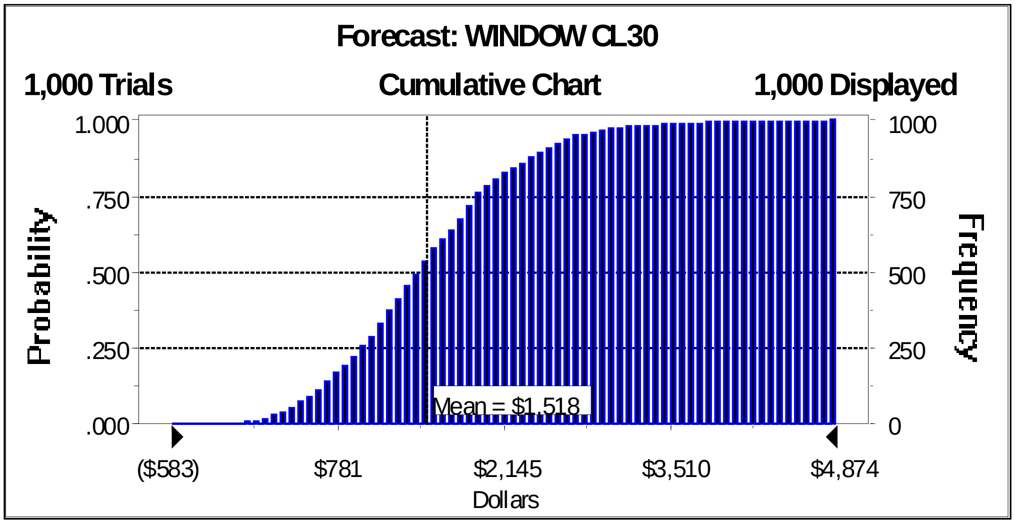

Figure G-154: Climate Zone 3 Class 30 Window NPV Results for Gas FAF

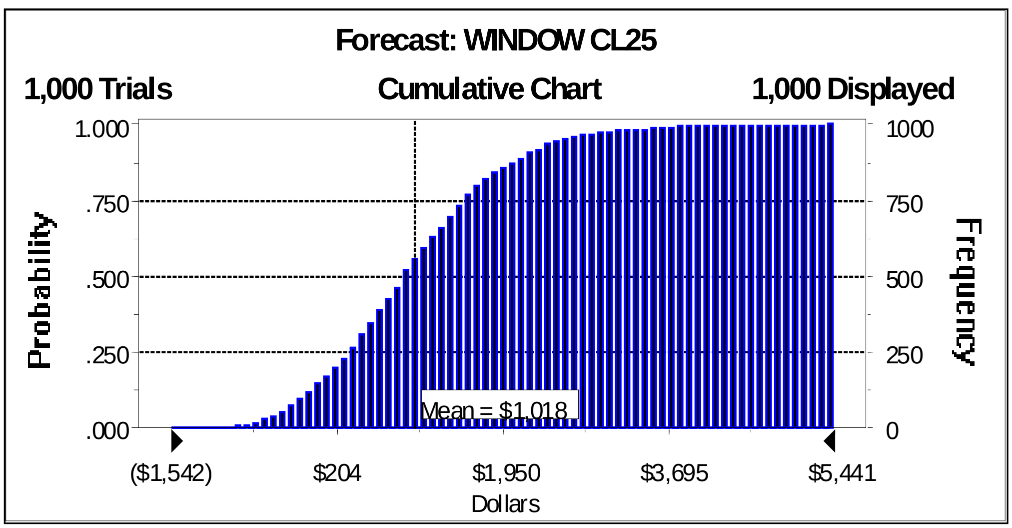

Figure G-155: Climate Zone 3 Class 25 Window NPV Results for Gas FAF

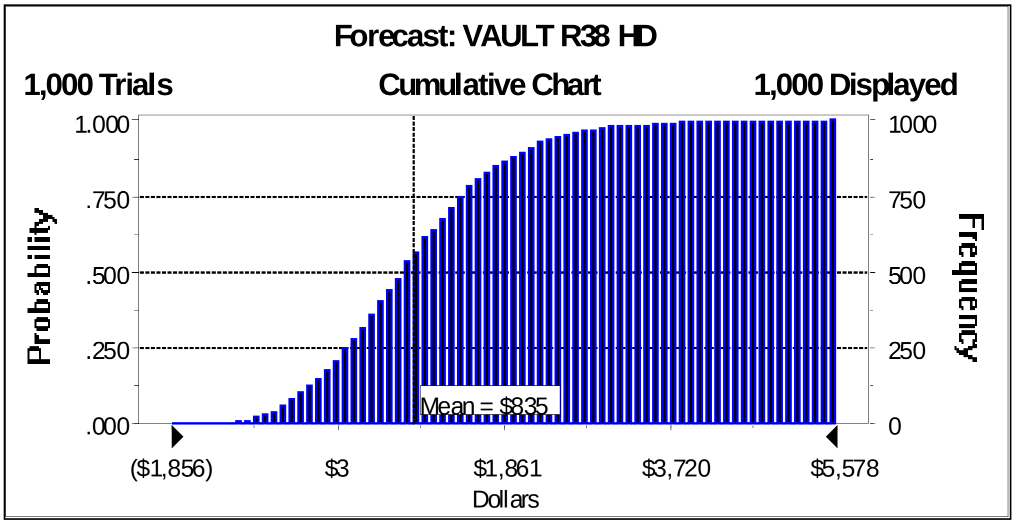

Figure G-156: Climate Zone 3 R38 Vault NPV Results for Gas FAF

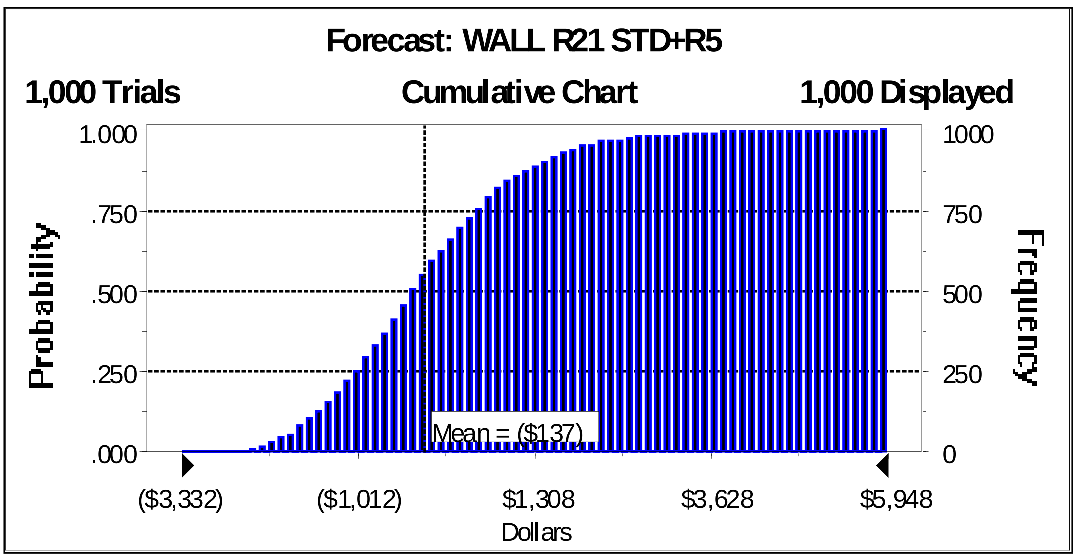

Figure G-157: Climate Zone 3 R26 Advanced Framed Wall NPV Results for Gas FAF

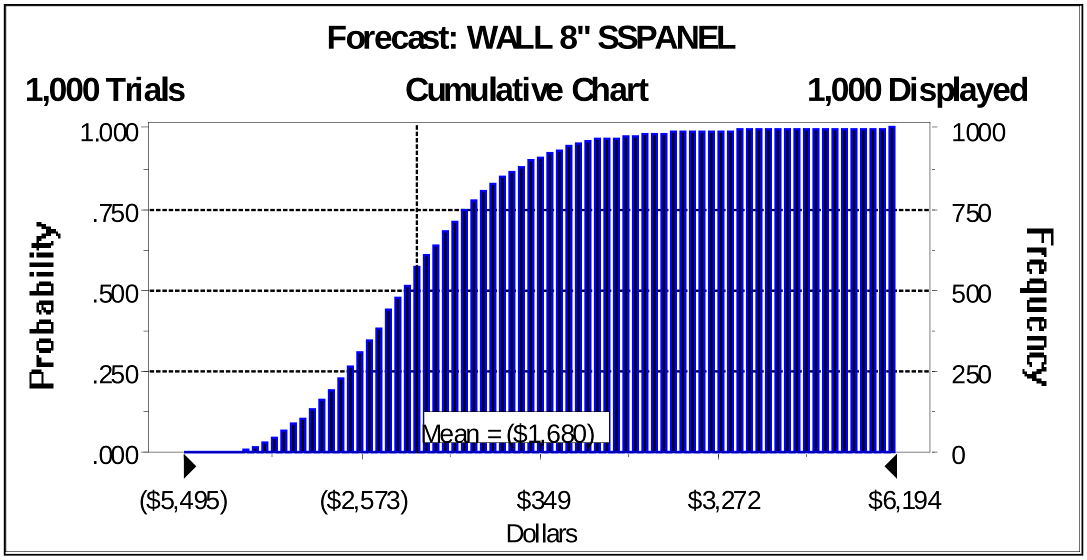

Figure G-158: Climate Zone 3 R33 Wall NPV Results for Gas FAF

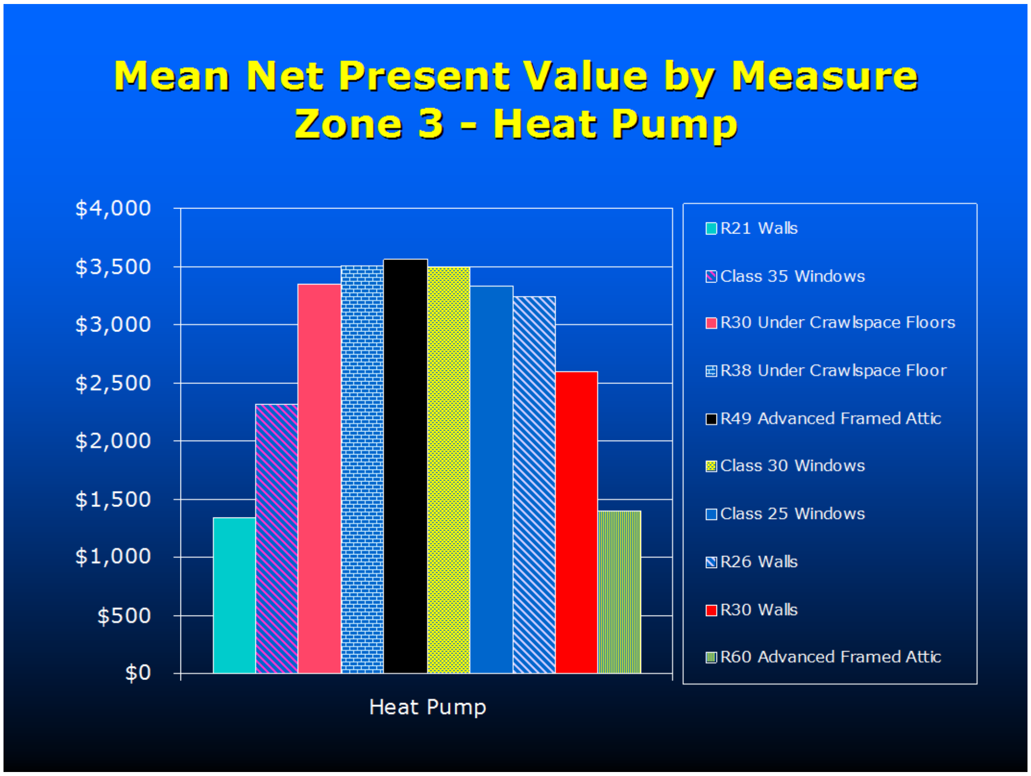

Figure G-159: Climate Zone 3 Mean Net Present Value by Measure for Heat Pumps

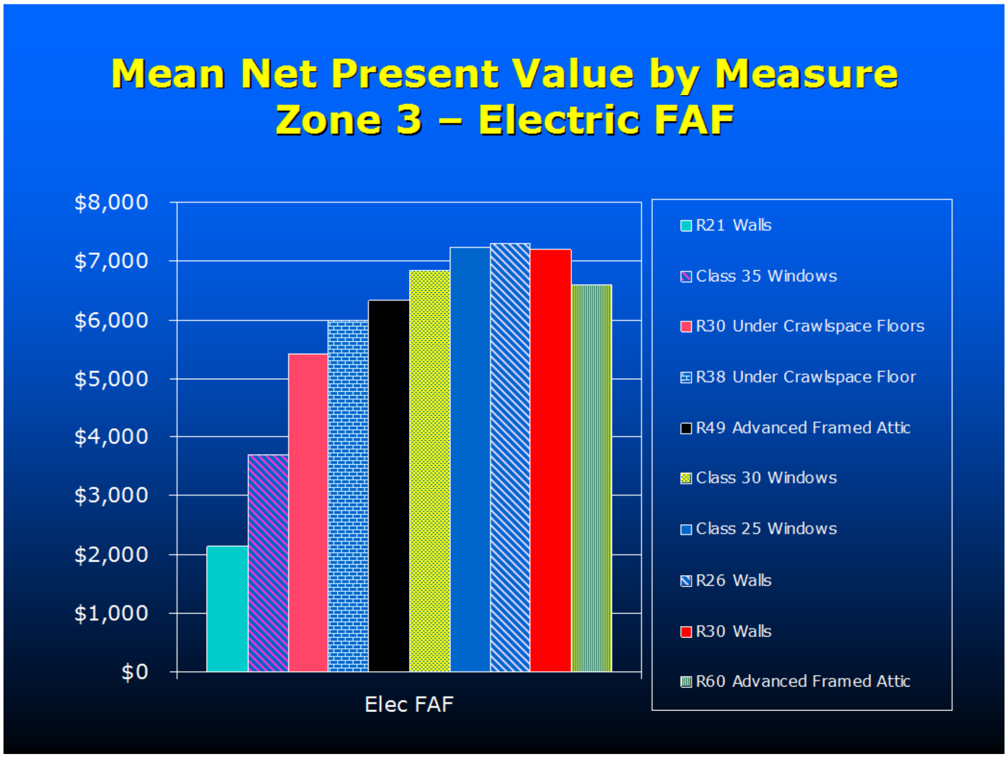

Figure G-160: Climate Zone 3 Mean Net Present Value by Measure for Electric FAF

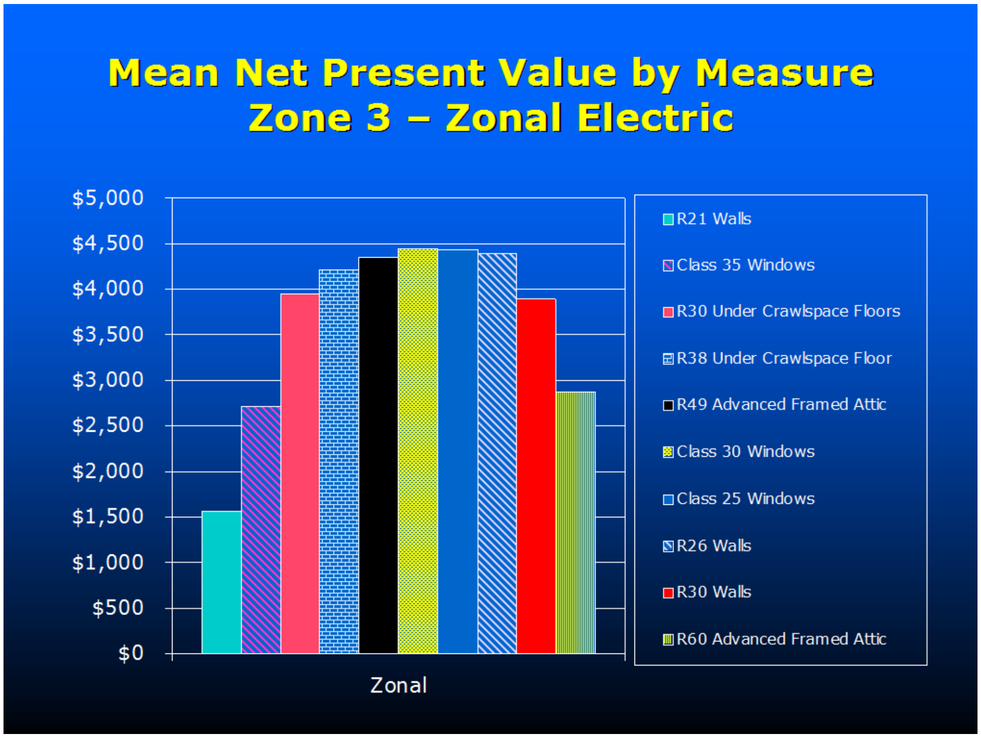

Figure G-161: Climate Zone 3 Mean Net Present Value by Measure for Electric Zonal

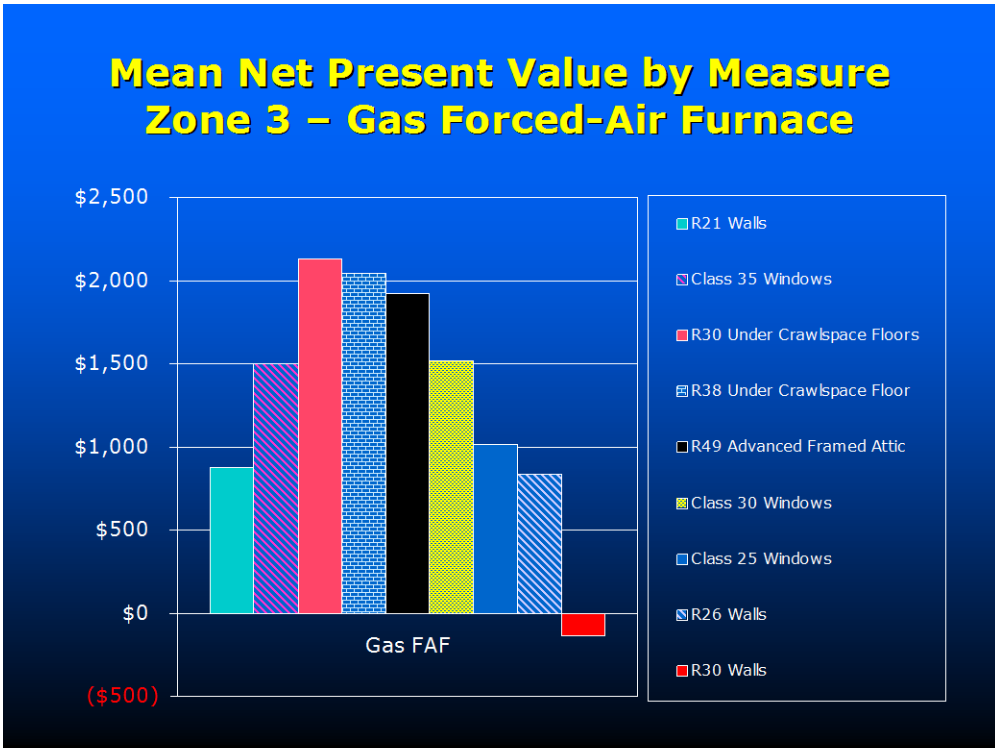

Figure G-162: Climate Zone 3 Mean Net Present Value by Measure for Gas FAF

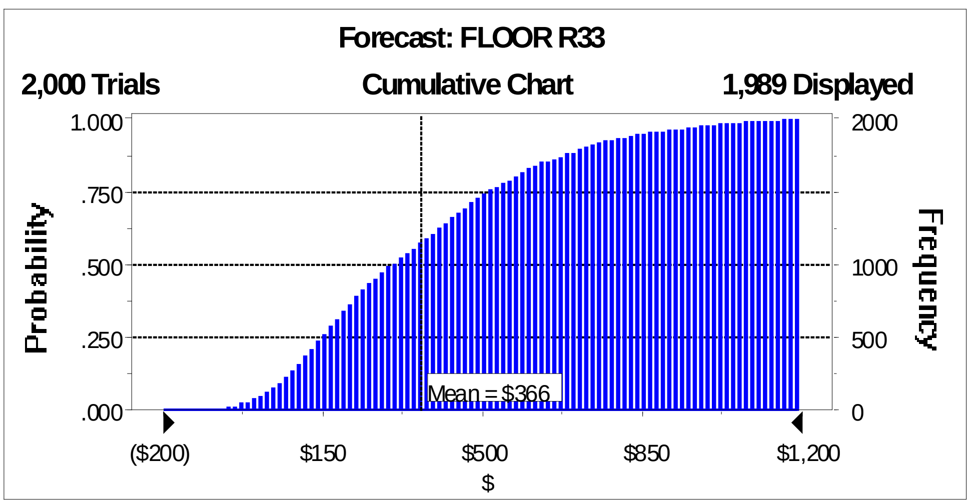

Figure G-163: Climate Zone 1 Net Present Value Results for Manufactured Homes for R33 Floors

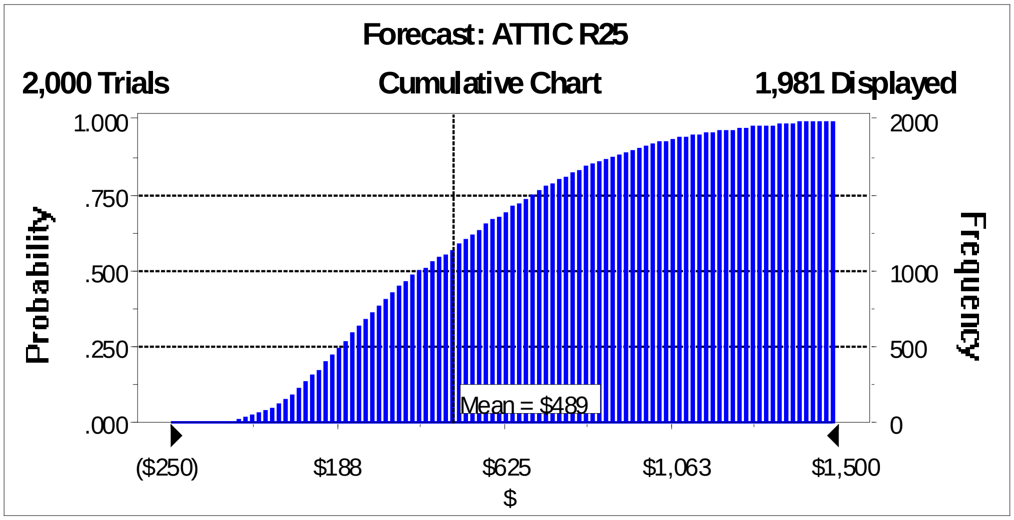

Figure G-164: Climate Zone 1 Net Present Value Results for Manufactured Homes for R25 Attic

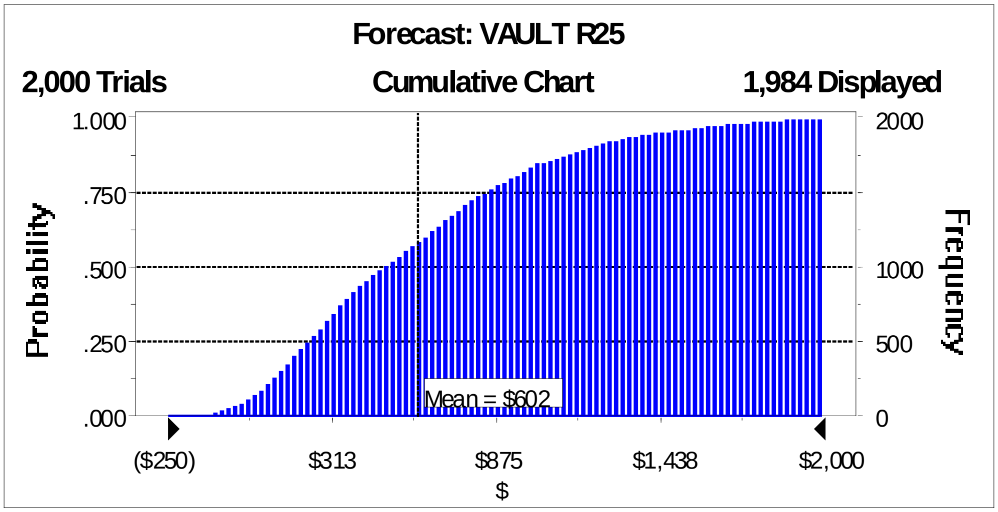

Figure G-165: Climate Zone 1 Net Present Value Results for Manufactured Homes for R25 Vault

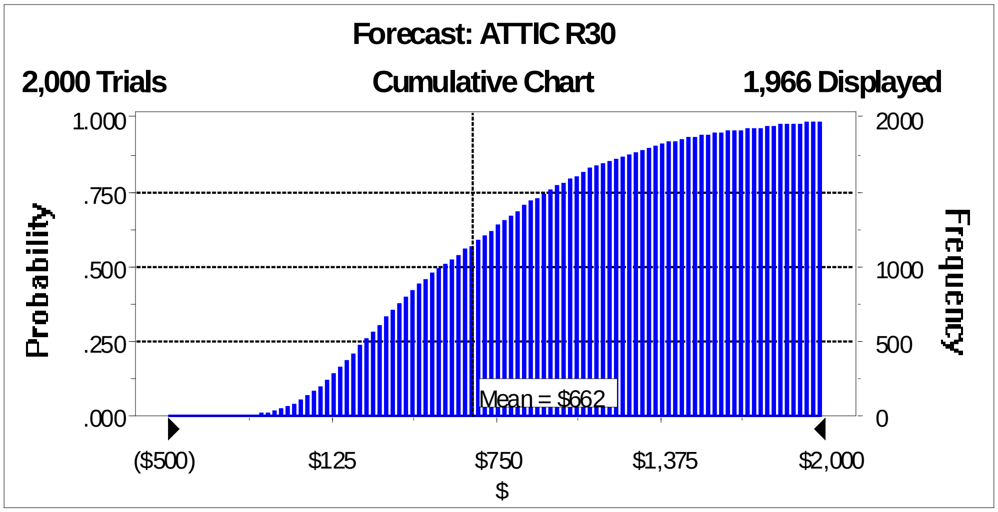

Figure G-166: Climate Zone 1 Net Present Value Results for Manufactured Homes for R30 Attic

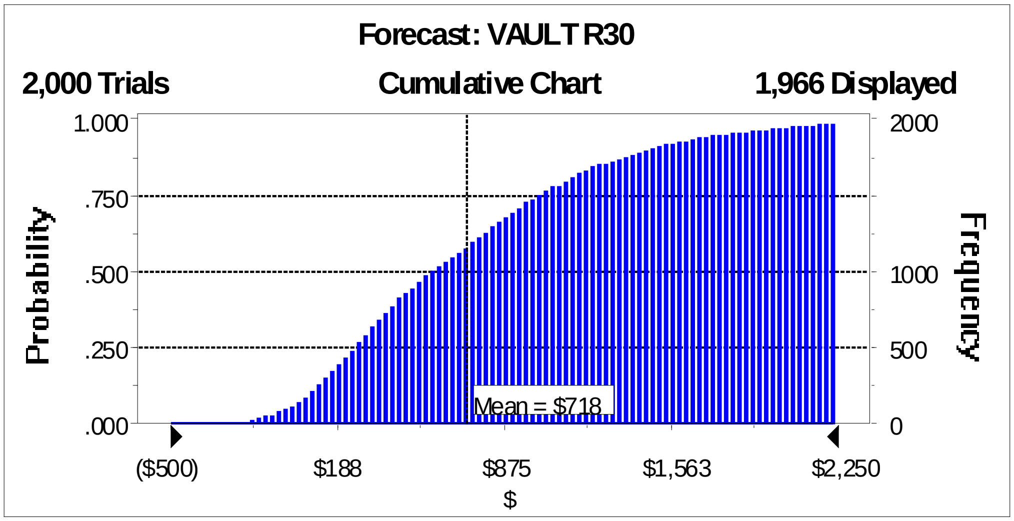

Figure G-167: Climate Zone 1 Net Present Value Results for Manufactured Homes for R30 Vaults

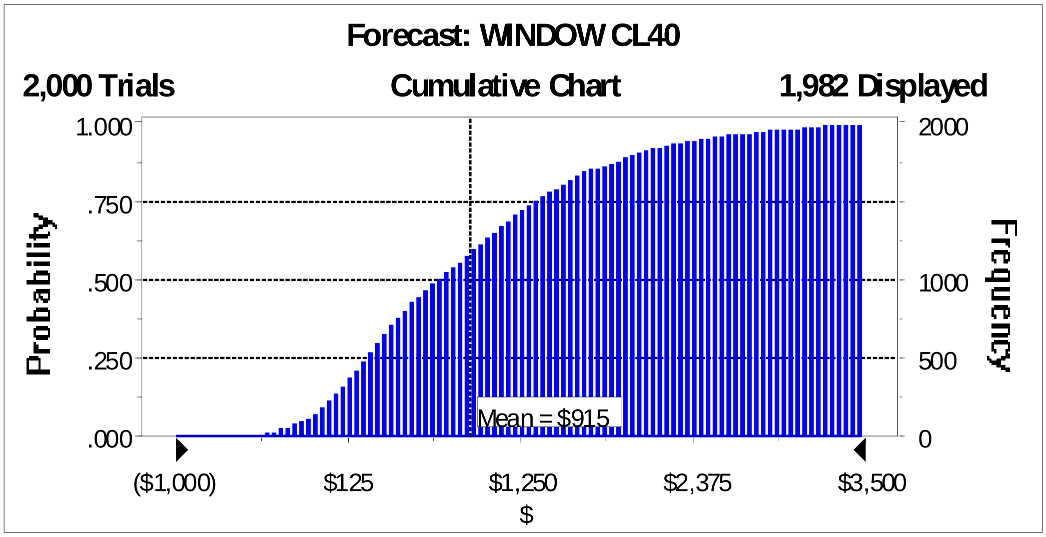

Figure G-168: Climate Zone 1 Net Present Value Results for Manufactured Homes for Class 40 Windows

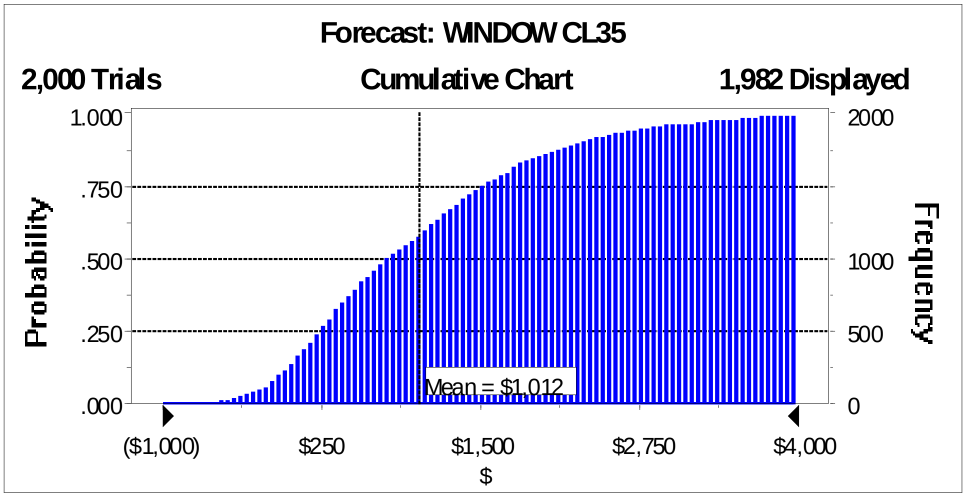

Figure G-169: Climate Zone 1 Net Present Value Results for Manufactured Homes for Class 35 Windows

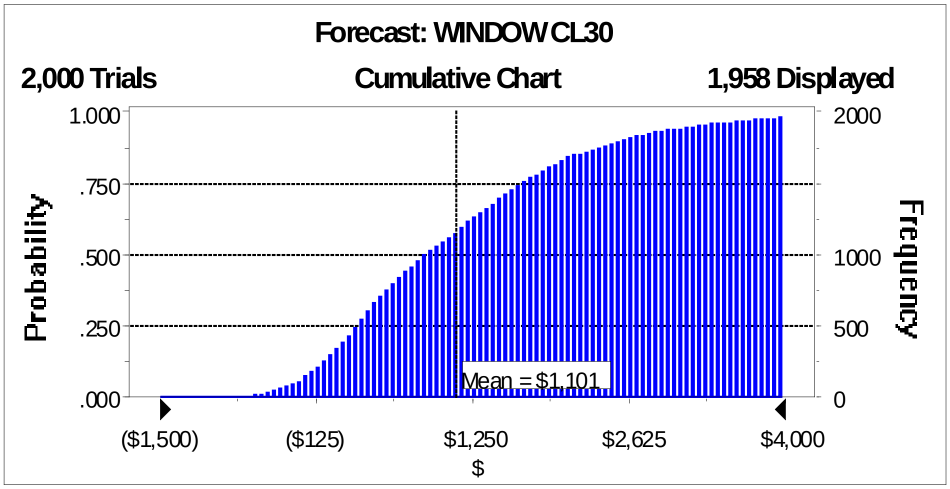

Figure G-170: Climate Zone 1 Net Present Value Results for Manufactured Homes for Class 30 Windows

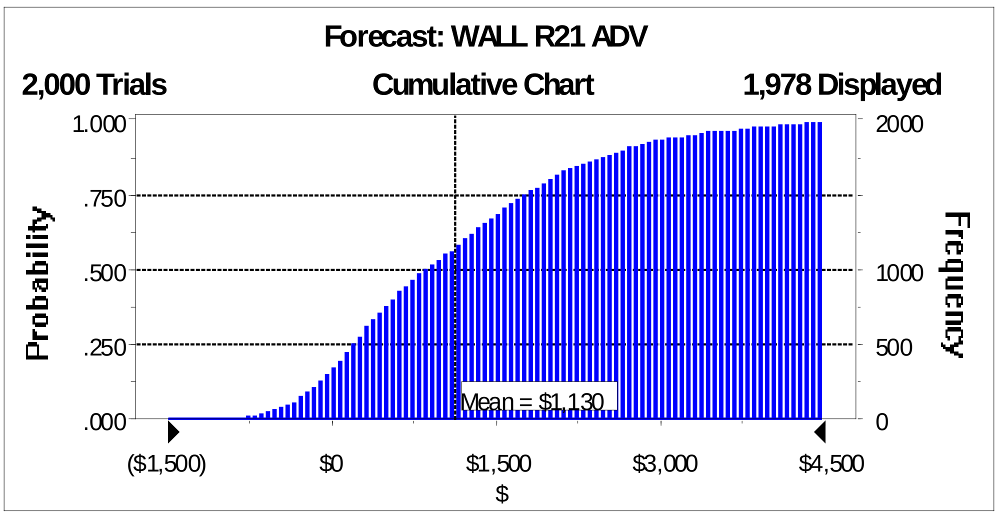

Figure G-171: Climate Zone 1 Net Present Value Results for Manufactured Homes for R21 Advanced Framed Walls

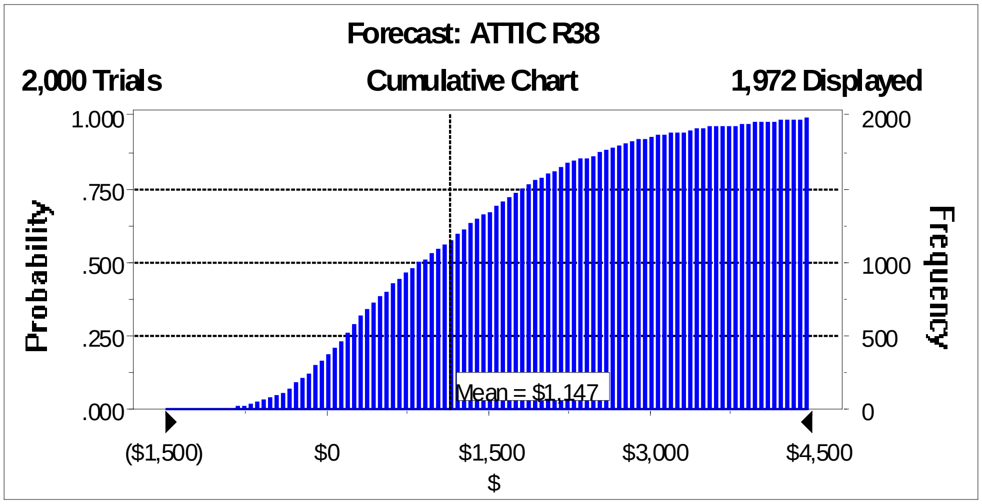

Figure G-172: Climate Zone 1 Net Preset Value Results for Manufactured Homes for R38 Attics

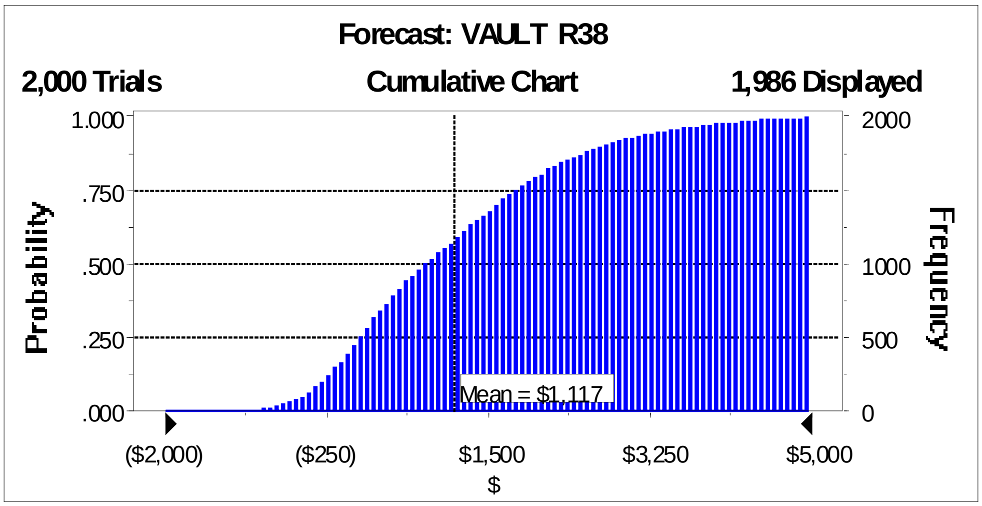

Figure G-173: Climate Zone 1 Net Present Value Results for Manufactured Homes for R38 Vaults

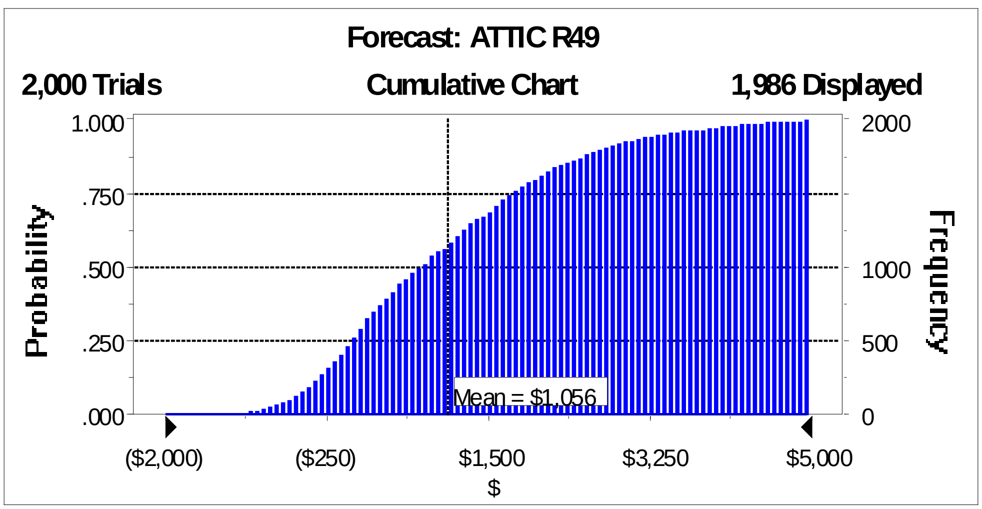

Figure G-174: Climate Zone 1 Net Present Value Results for Manufactured Homes for R49 Attics

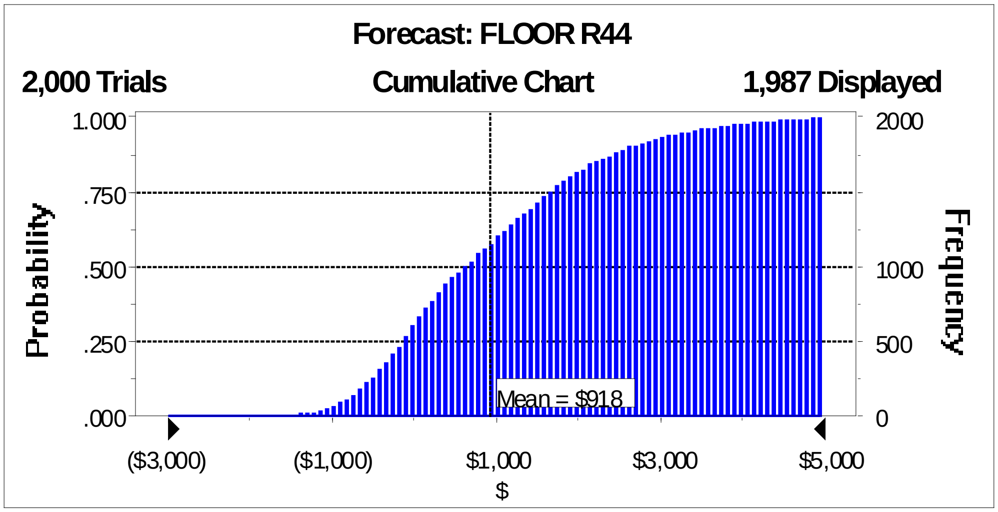

Figure G-175: Climate Zone 1 Net Present Value Results for Manufactured Homes for R44 Floors

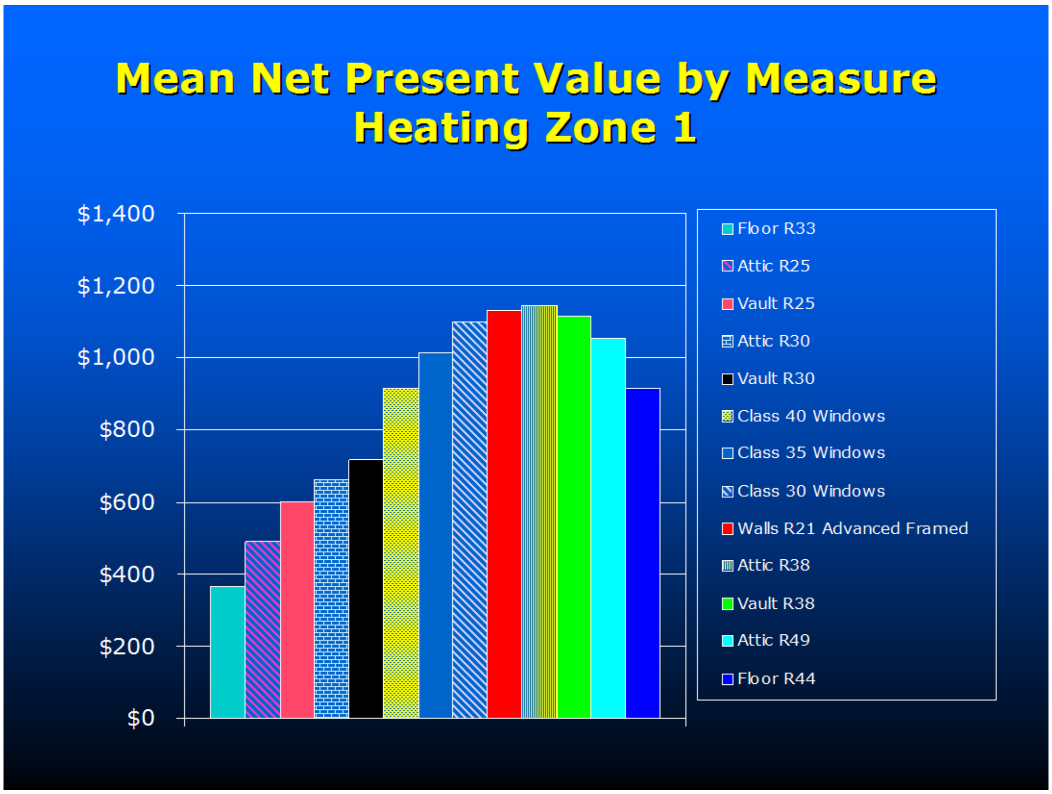

Figure G-176: Climate Zone 1 Expected Value Mean Net Present Value Results for Manufactured Homes

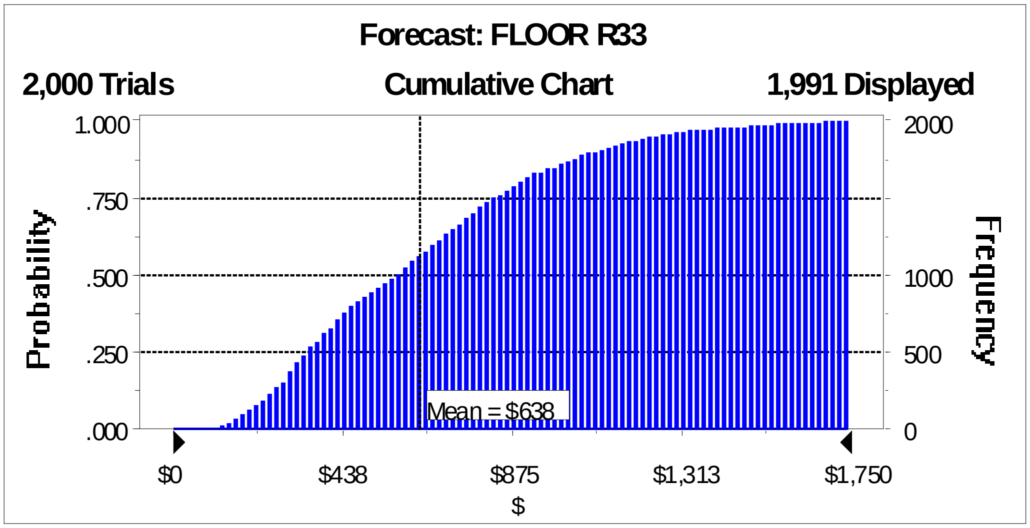

Figure G-177: Climate Zone 2 Net Present Value Results for Manufactured Homes for R33 Floors

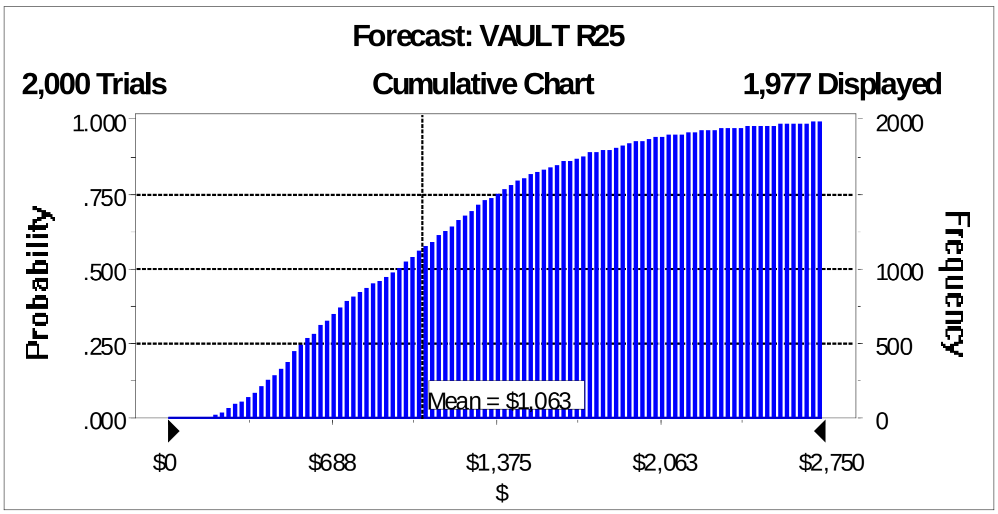

Figure G-178: Climate Zone 2 Net Present Value Results for Manufactured Homes for R25 Attics

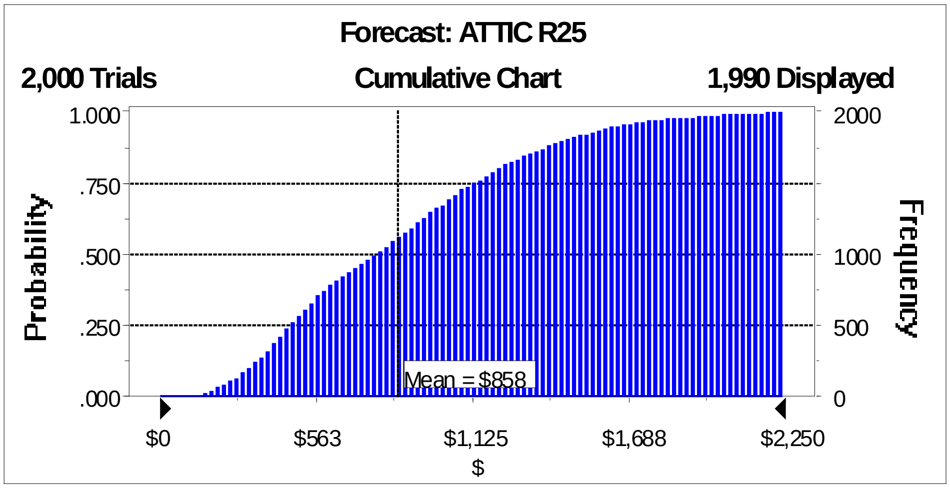

Figure G-179: Climate Zone 2 Net Present Value Results for Manufactured Homes for R25 Vaults

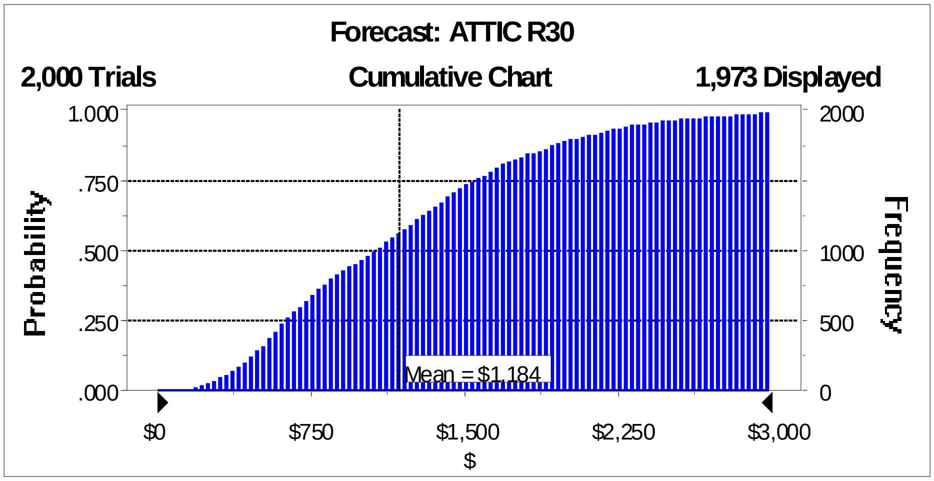

Figure G-180: Climate Zone 2 Net Present Value Results for Manufactured Homes for R30 Attics

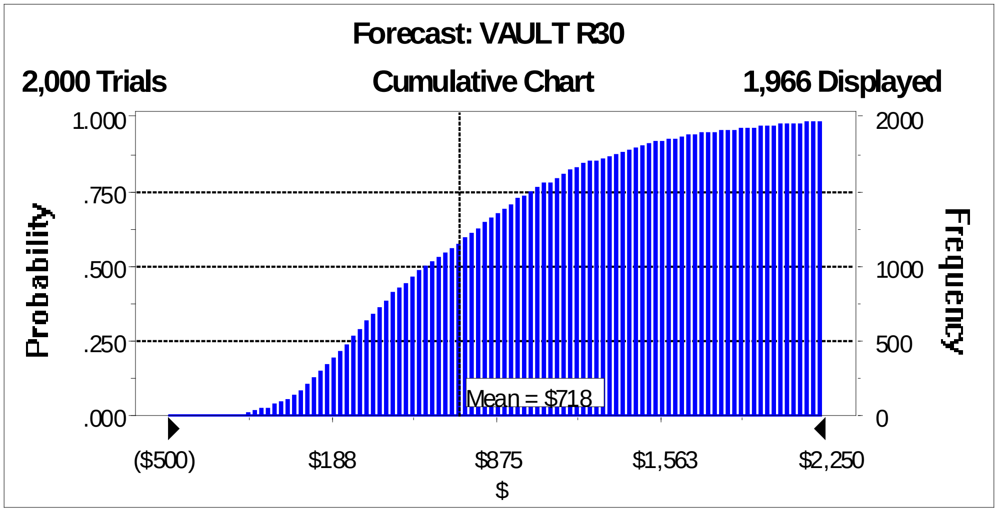

Figure G-181: Climate Zone 2 Net Present Value Results for Manufactured Homes for R30 Vaults

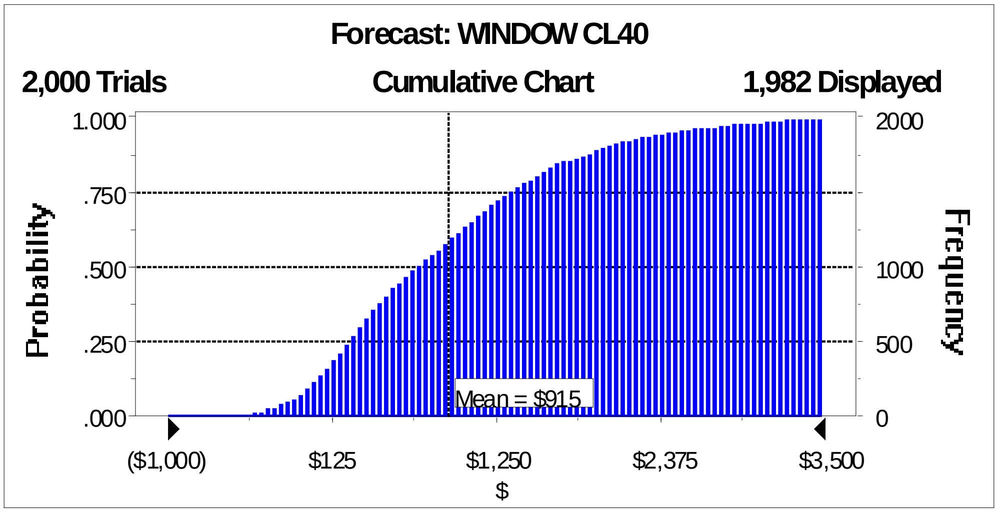

Figure G-182: Climate Zone 2 Net Present Value Results for Manufactured Homes for Class 40 Windows

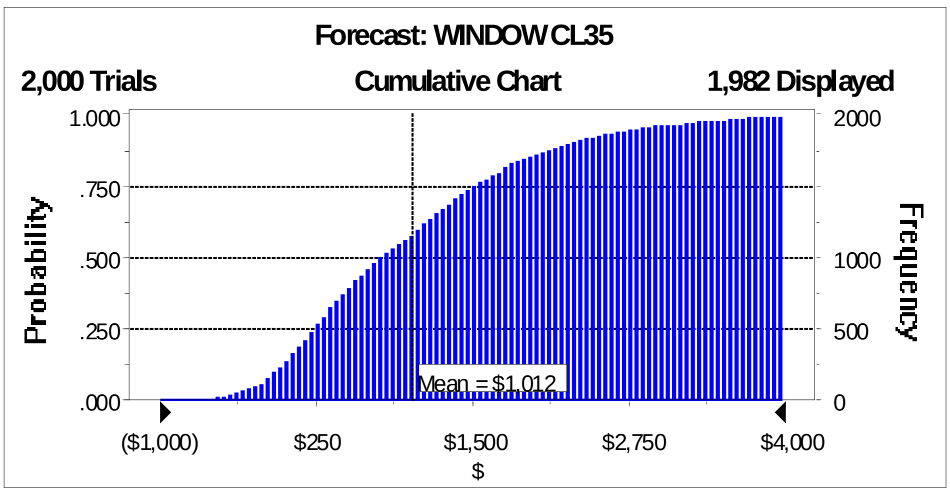

Figure G-183: Climate Zone 2 Net Present Value Results for Manufactured Homes for Class 35 Windows

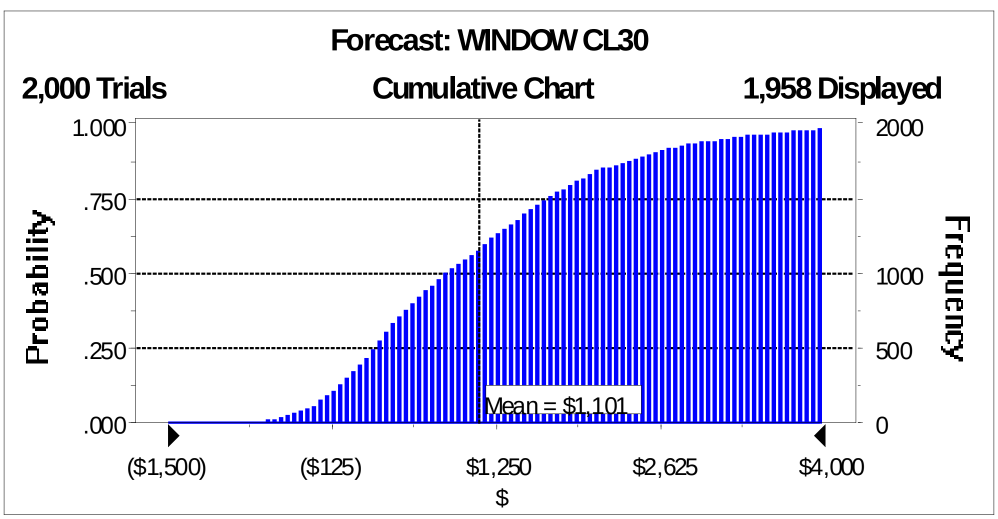

Figure G-184: Climate Zone 2 Net Present Value Results for Manufactured Homes for Class 30 Windows

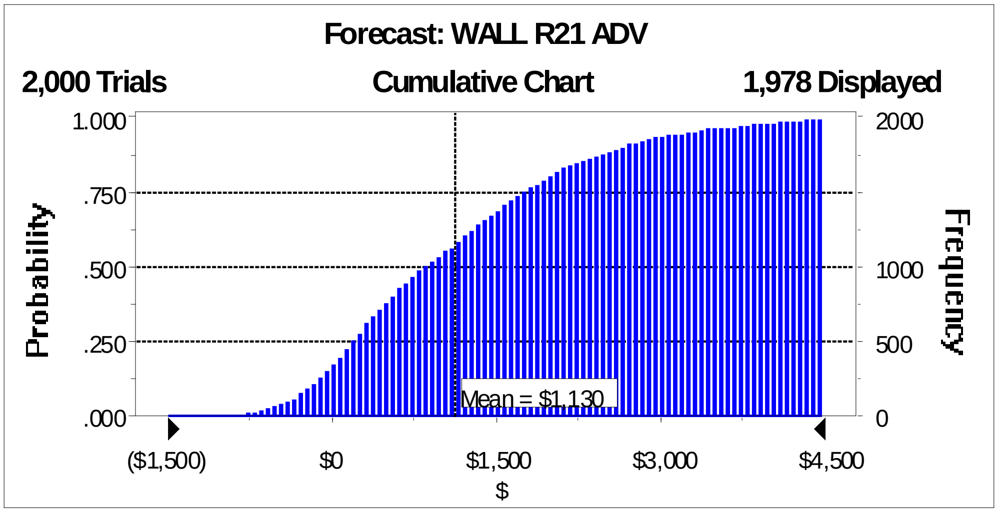

Figure G-185: Climate Zone 2 Net Present Value Results for Manufactured Homes for R21 Advanced Framed Walls

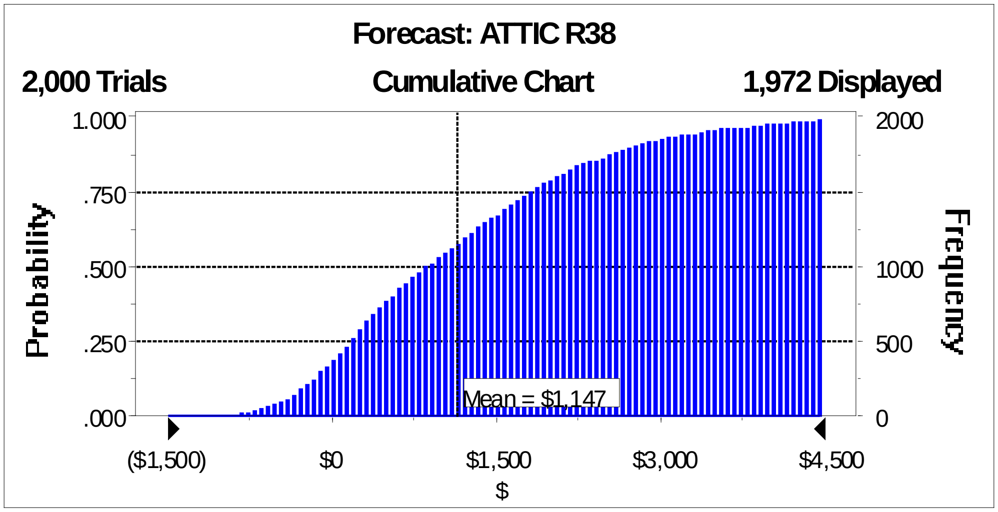

Figure G-186: Climate Zone 2 Net Present Value Results for Manufactured Homes for R38 Attics

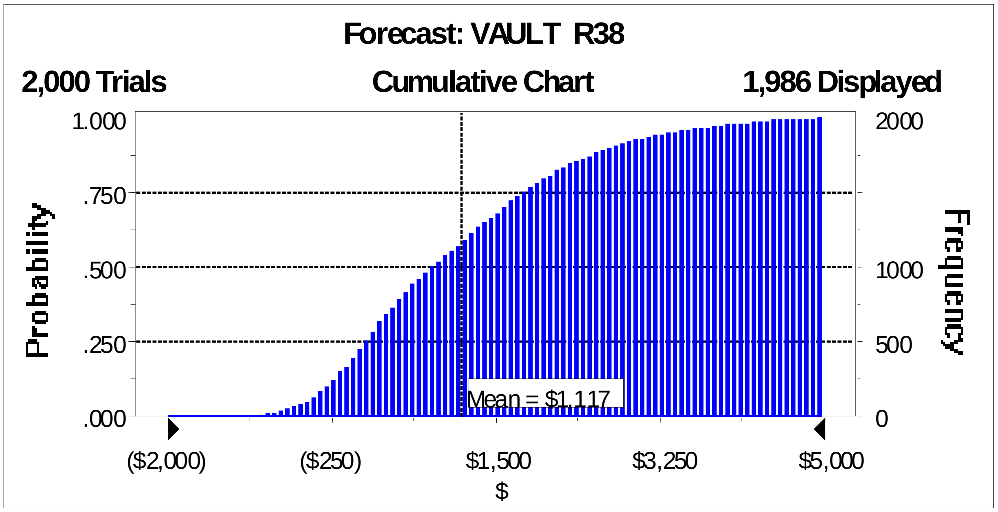

Figure G-187: Climate Zone 2 Net Present Value Results for Manufactured Homes for R38 Vaults

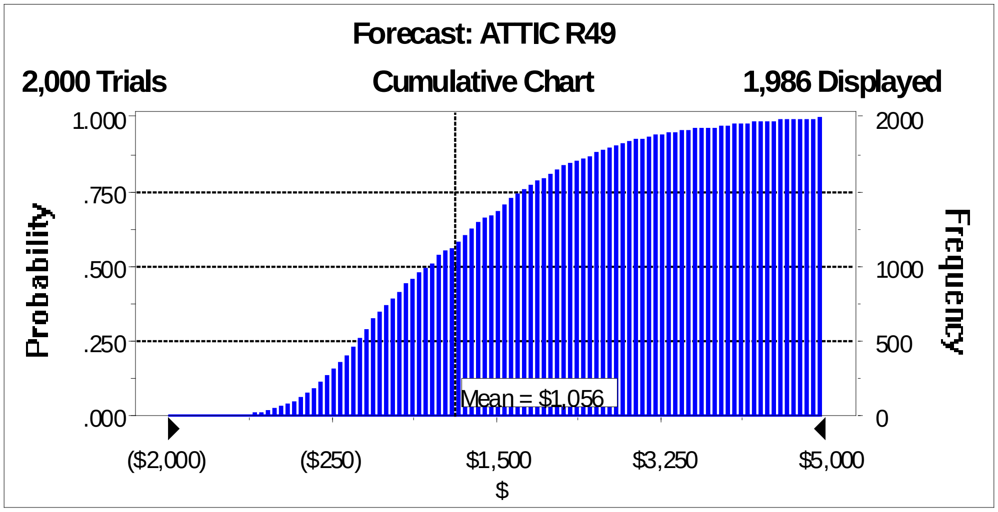

Figure G-188: Climate Zone 2 Net Present Value Results for Manufactured Homes for R49 Attics

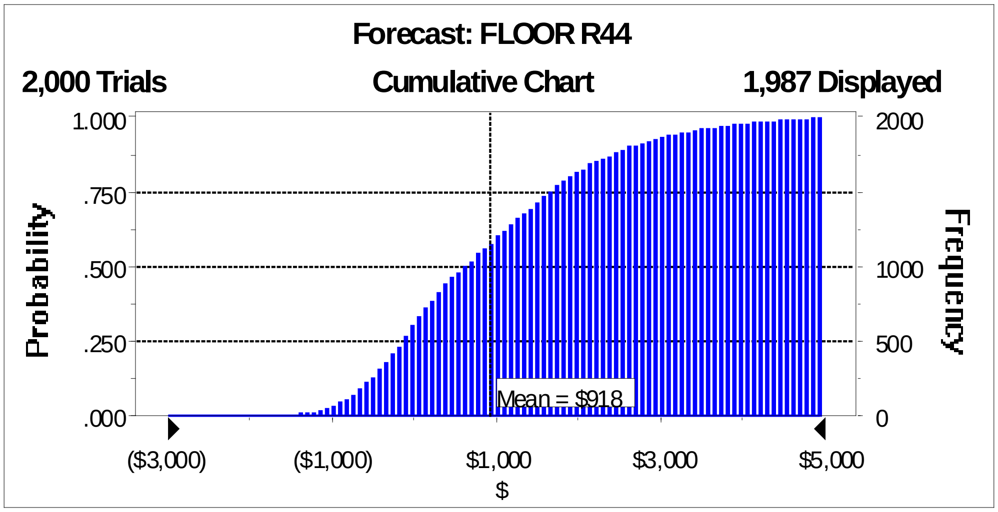

Figure G-189: Climate Zone 2 Net Present Value Results for Manufactured Homes for R44 Floors

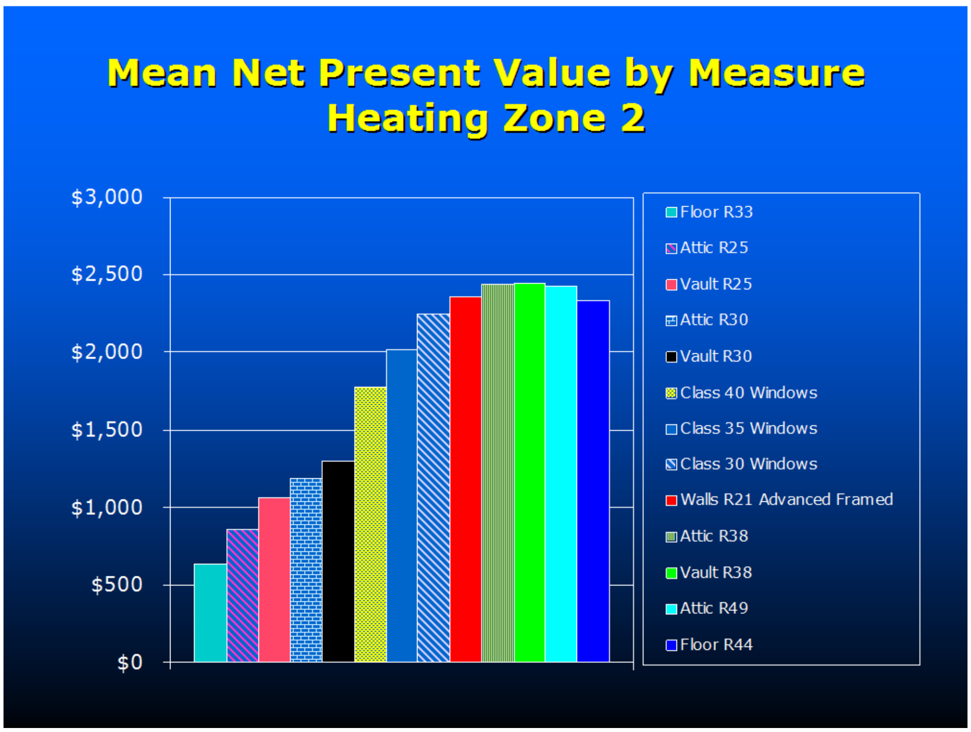

Figure G-190: Climate Zone 2 Expected Value Mean Net Present Value Results for Manufactured Homes

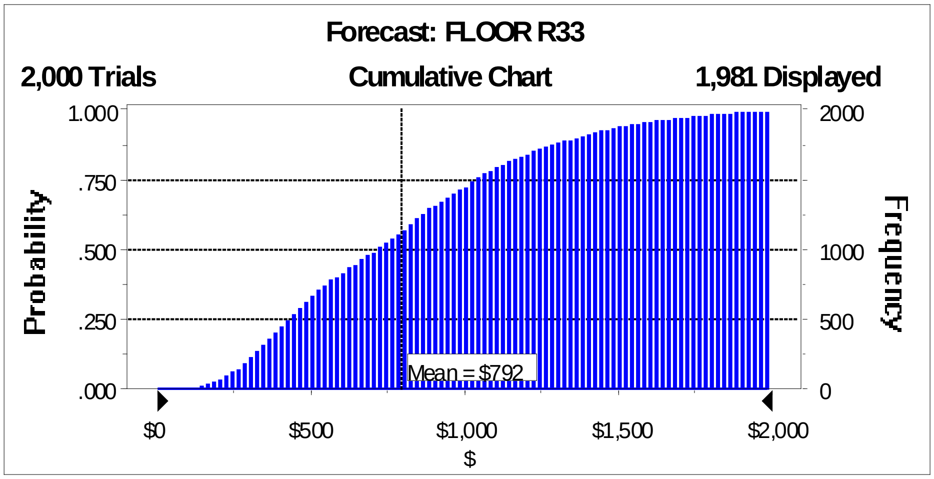

Figure G-191: Climate Zone 3 Net Present Value Results for Manufactured Homes for R33 Floors

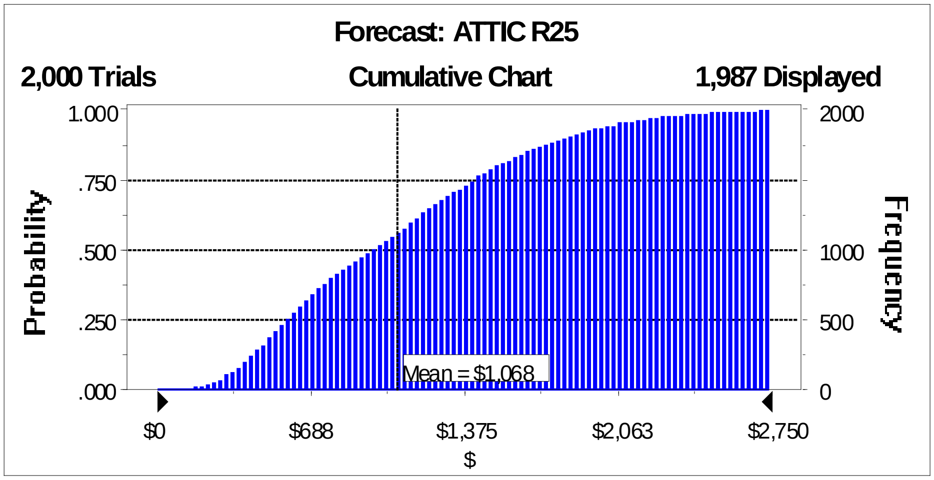

Figure G-192: Climate Zone 3 Net Present Value Results for Manufactured Homes for R25 Attics

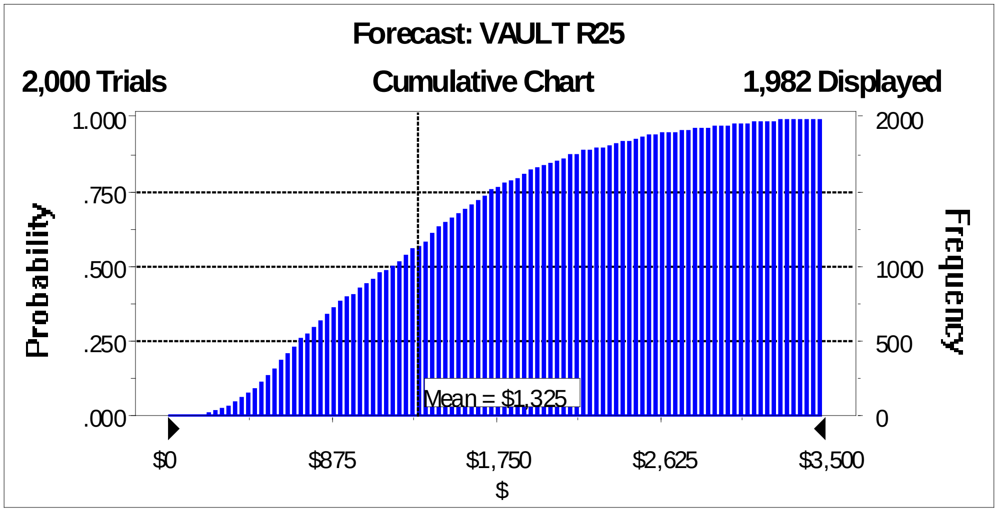

Figure G-193: Climate Zone 3 Net Present Value Results for Manufactured Homes for R25 Vaults

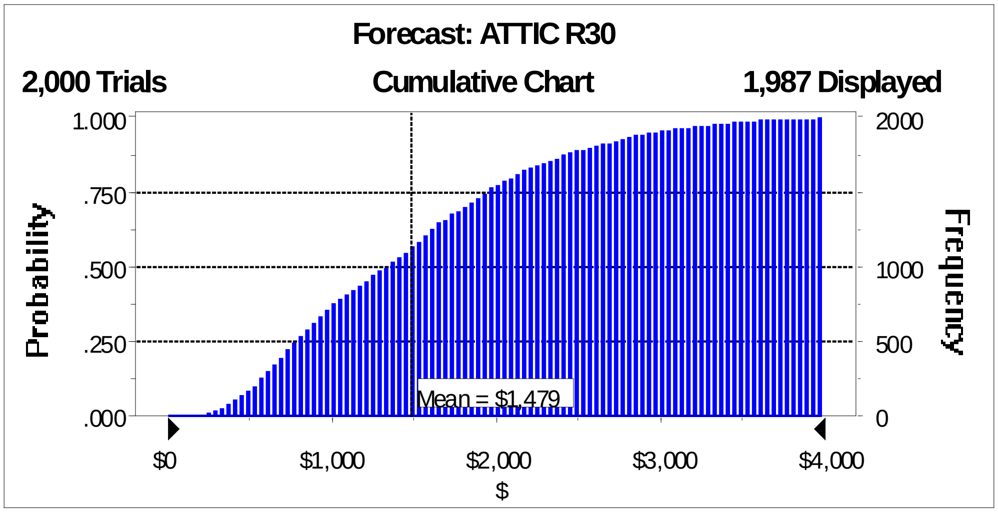

Figure G-194: Climate Zone 3 Net Present Value Results for Manufactured Homes for R30 Attics

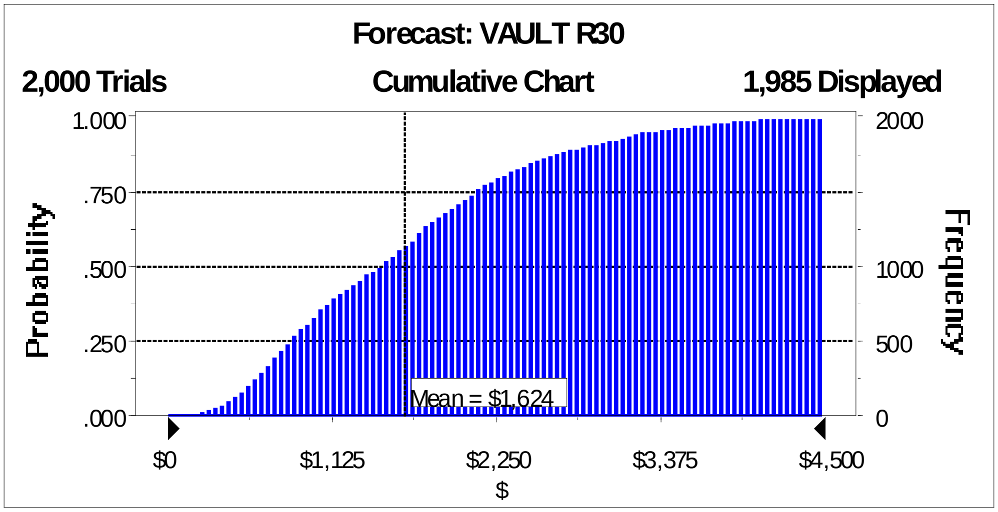

Figure G-195: Climate Zone 3 Net Present Value Results for Manufactured Homes for R30 Vaults

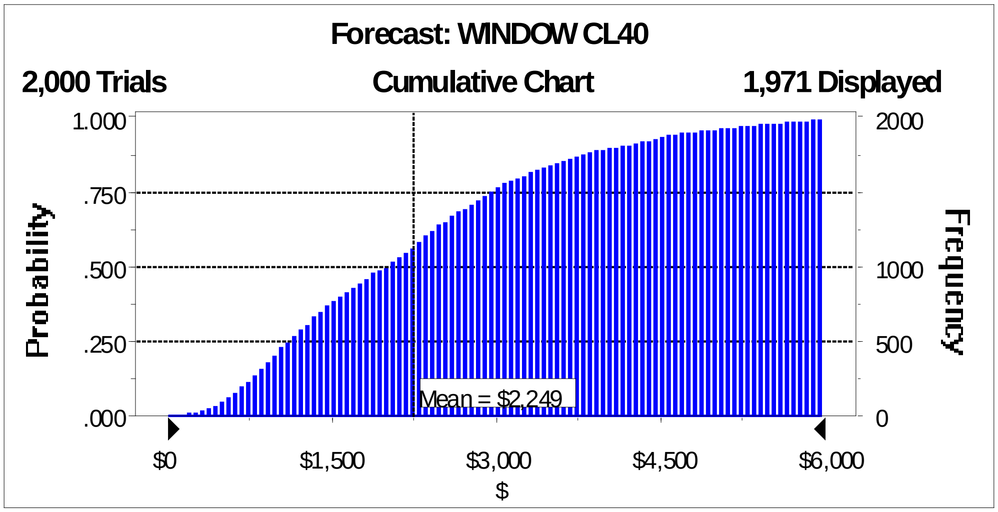

Figure G-196: Climate Zone 3 Net Present Value Results for Manufactured Homes for Class 40 Windows

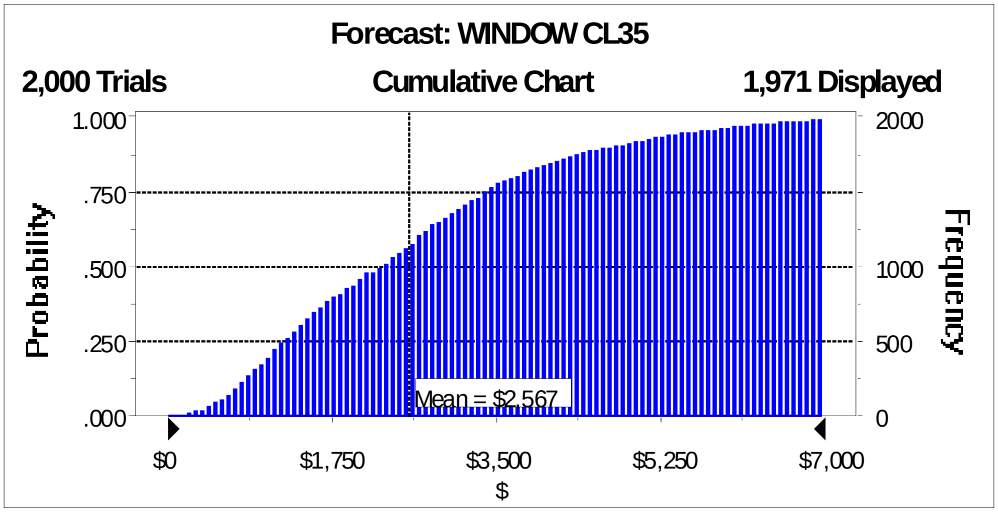

Figure G-197: Climate Zone 3 Net Present Value Results for Manufactured Homes for Class 35 Windows

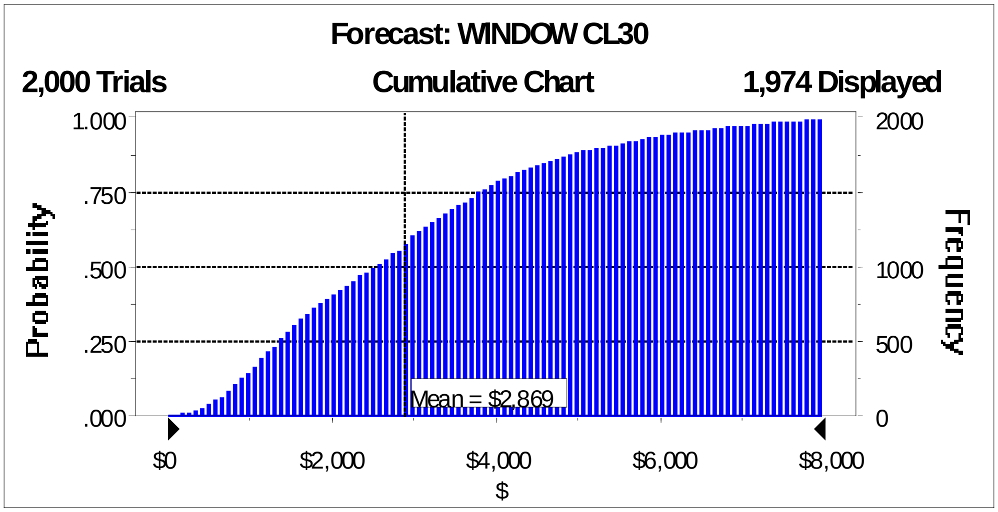

Figure G-198: Climate Zone 3 Net Present Value Results for Manufactured Homes for Class 30 Windows

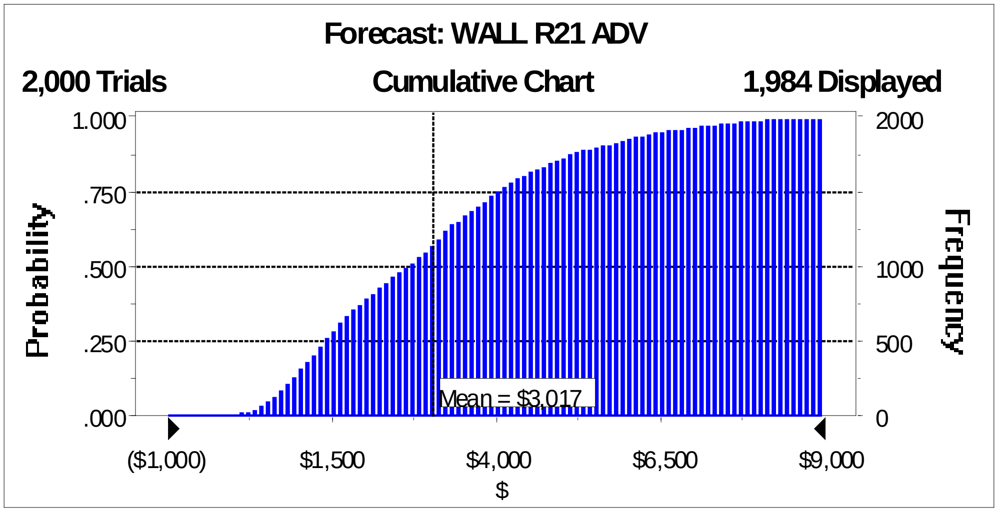

Figure G-199: Climate Zone 3 Net Present Value Results for Manufactured Homes for R21 Advanced Framed Walls

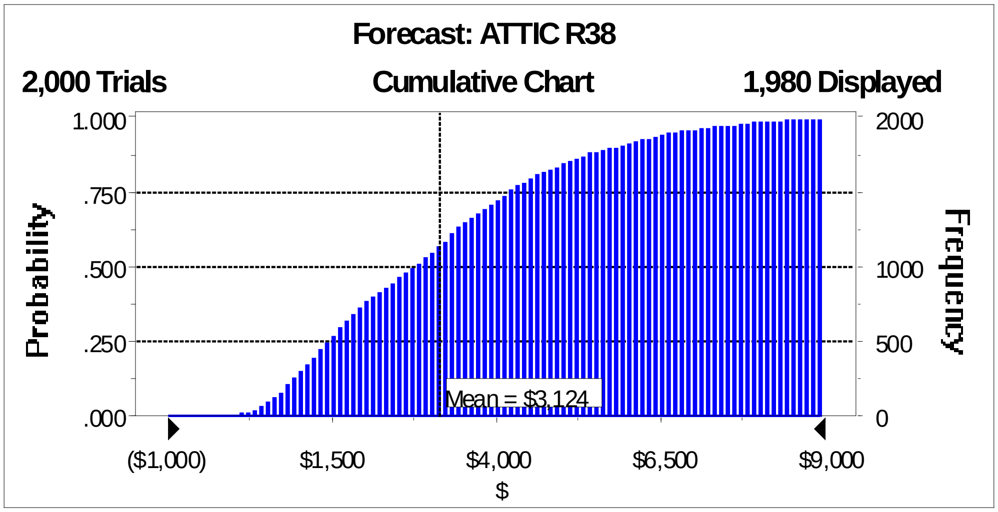

Figure G-200: Climate Zone 3 Net Present Value Results for Manufactured Homes for R38 Attics

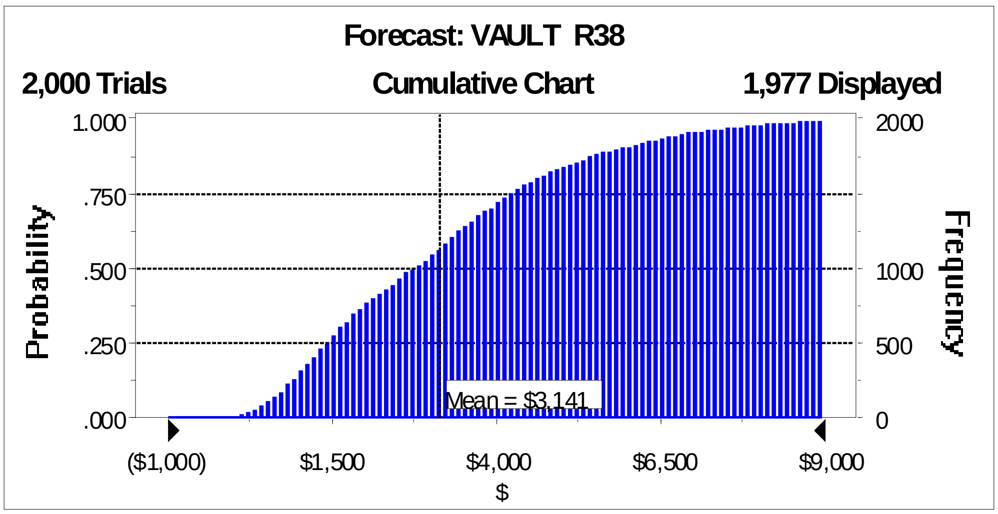

Figure G-201: Climate Zone 3 Net Present Value Results for Manufactured Homes for R38 Vaults

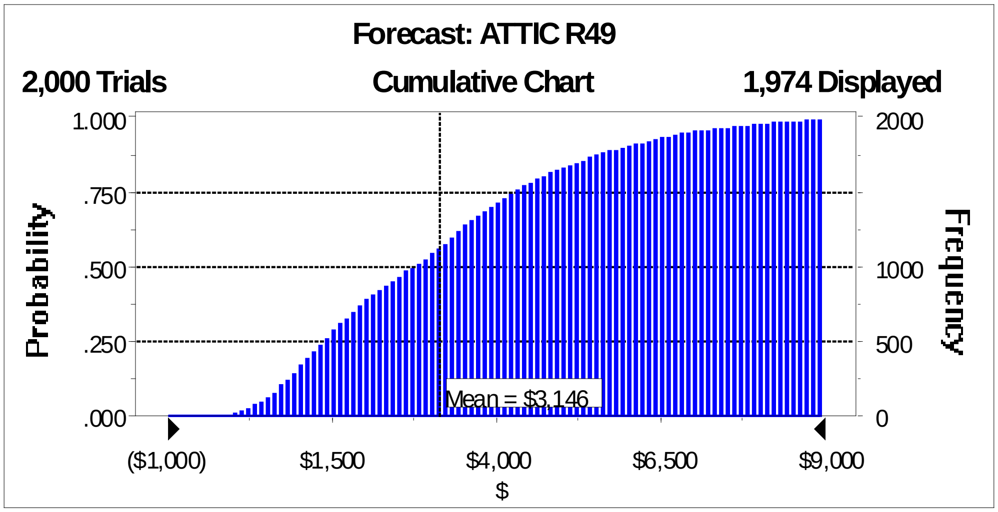

Figure G-202: Climate Zone 3 Net Present Value Results for Manufactured Homes for R49 Attics

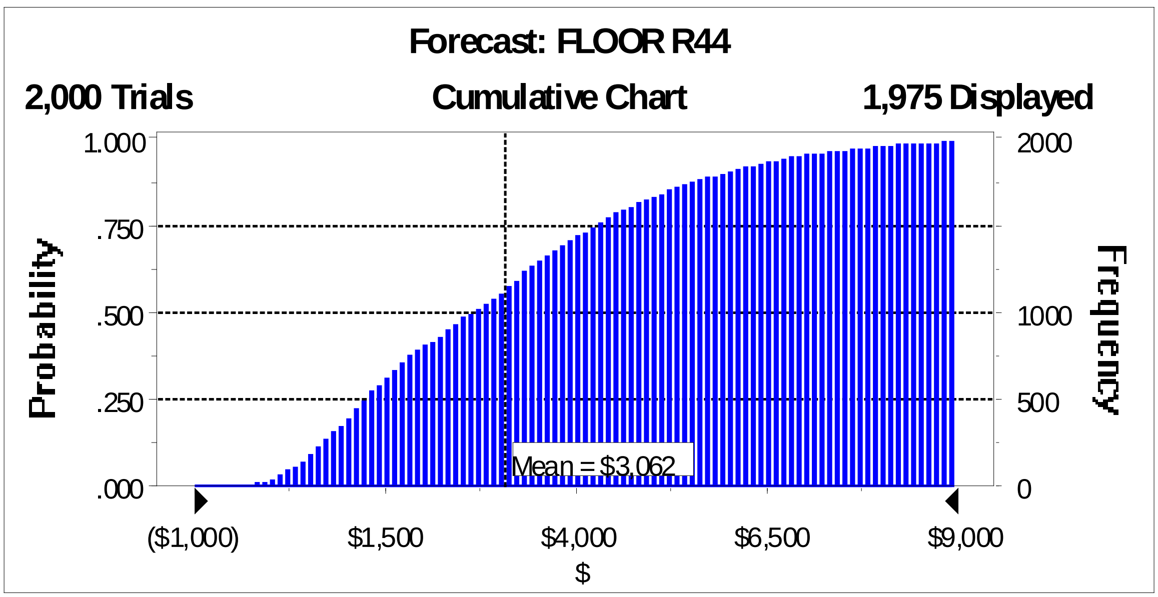

Figure G-203: Climate Zone 3 Net Present Value Results for Manufactured Homes for R44 Floors

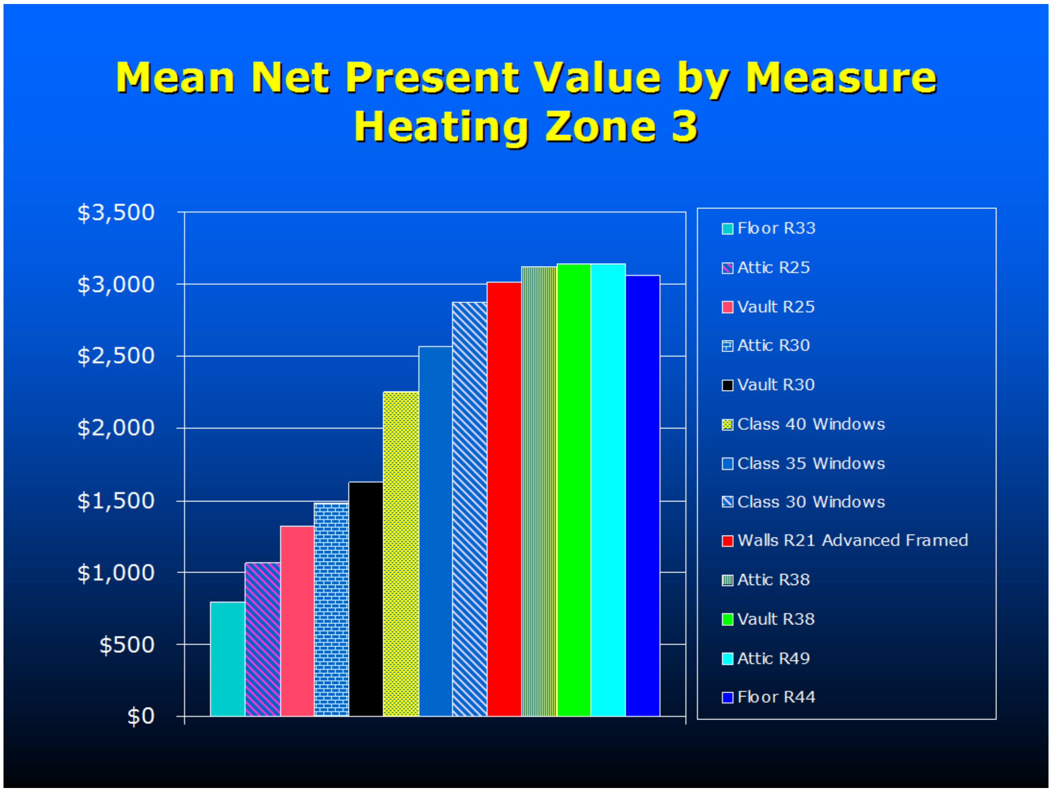

Figure G-204: Climate Zone 3 Expected Value Mean Net Present Value Results for Manufactured Homes

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Appendix H. 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

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[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]

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[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.

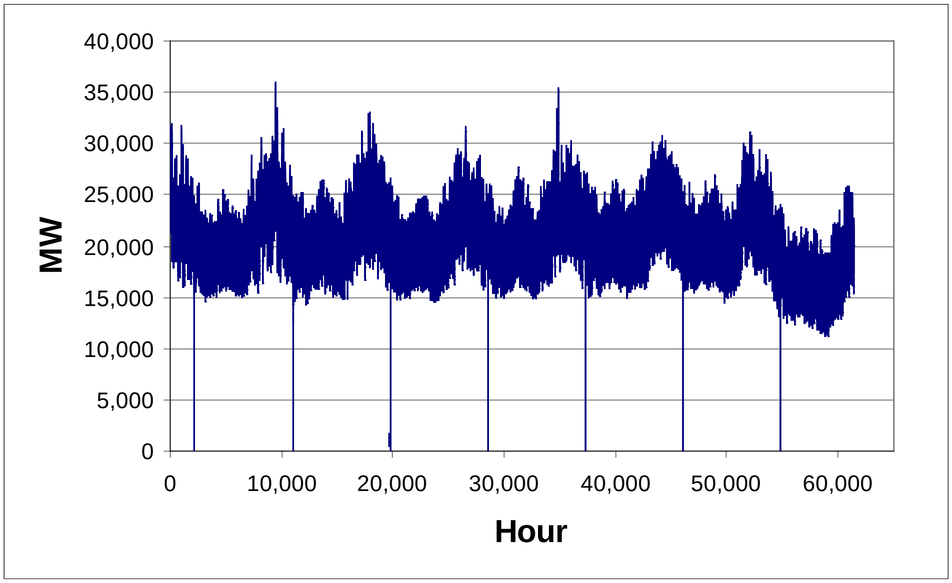

Figure H-1: Pacific Northwest Hourly Loads 1995-2001

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.

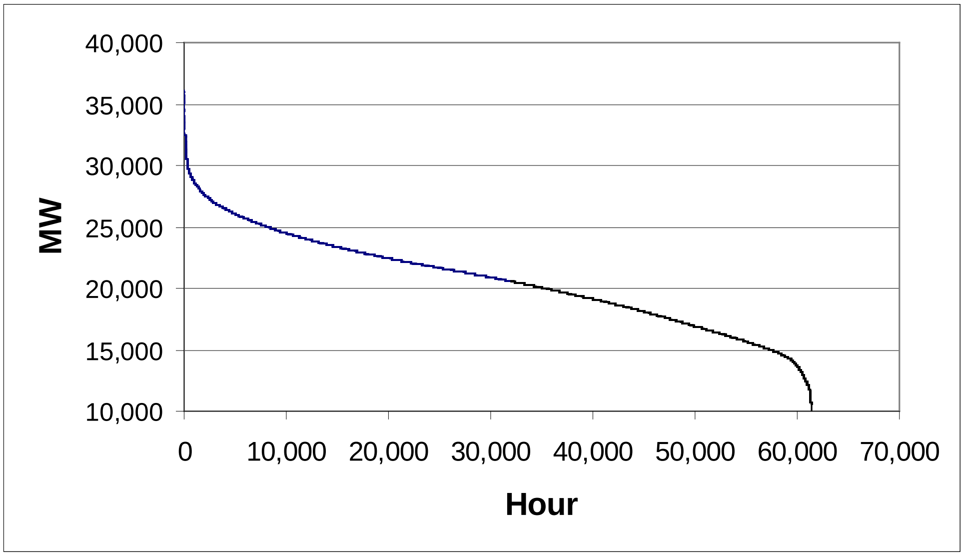

Figure H-2: Pacific Northwest Load Duration Curve 1995-2001

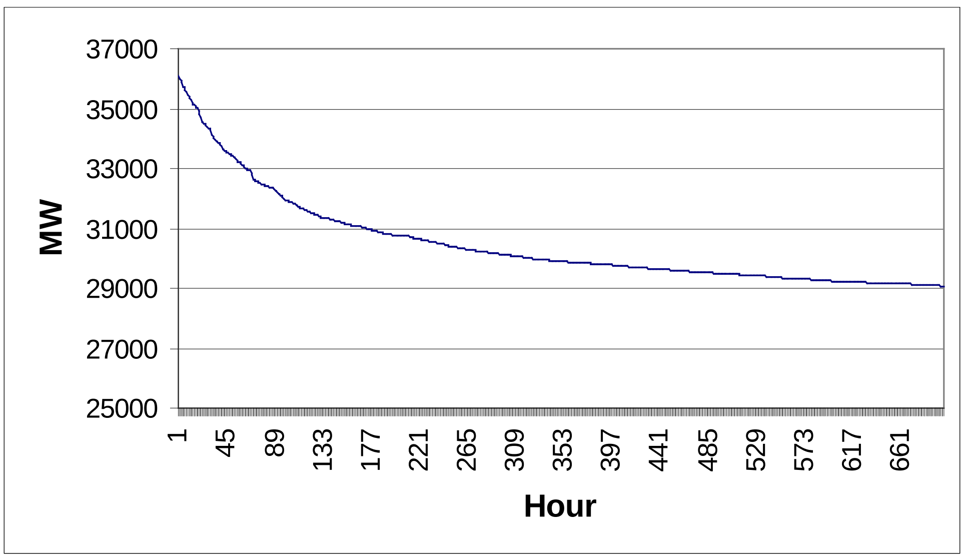

Figure H-3: Loads of Highest 700 hours 1995-2001

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

[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]

[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 megawatts, a maintenance cost of $1,000 per megawatts 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.

XXX Change this figure when new sensitivity case is done.

[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.

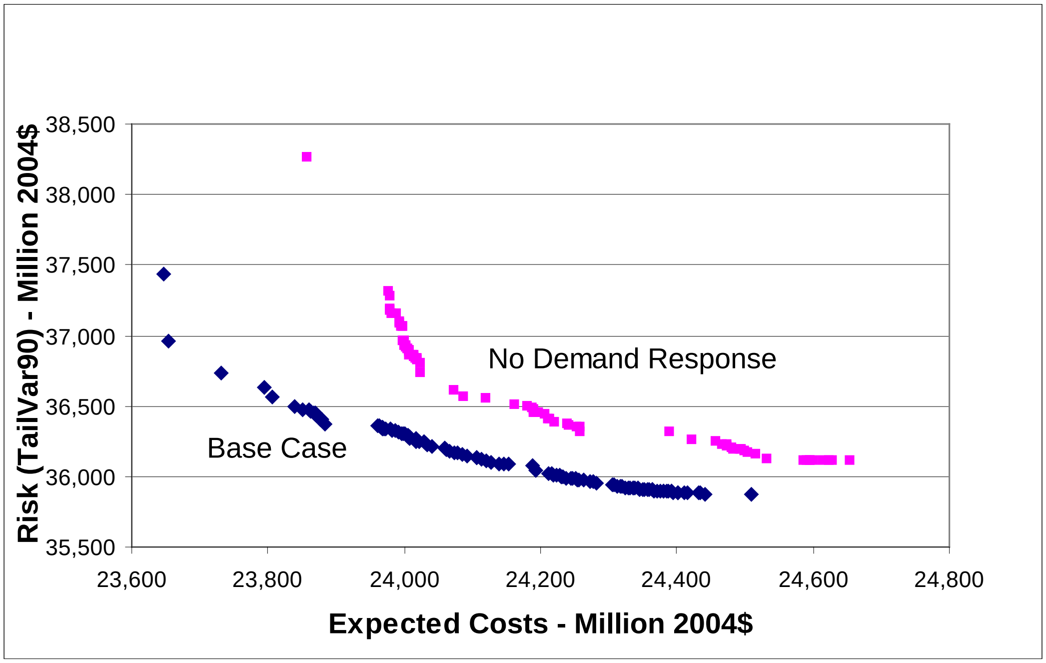

Figure H -4: Effect of Demand Response on Efficient Frontier

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.

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Appendix I. 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 future bulk power generation needs. 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%
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.

[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.

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.

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).

[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.

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, 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.

[4] U.S. Department of Energy. *Market-based Advanced Coal Power Systems.* March 1999.
[5] The recent run-up in coal prices is attributed to short-term supply-demand imbalances.

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 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.

[6] U.S. Environmental protection Agency. Control of Mercury Emissions from Coal-fired Electric Utility Boilers. January 2004.

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 desulphurization, 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; Montana coal, medium case price forecast; 80 percent capacity factor, year 2000 dollars. No CO_2 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^{o}F/1000^{o}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 petrochemical industry for processing

[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.

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 feed stocks 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 to $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 megawatt 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 megawatts 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

[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 CO_2 penalty.

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.
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.	

Description and technical performance			
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.
CO2 transportation and sequestration	n/a	See Appendix K	
Byproduct credits	None assumed	None assumed	Potential sulfur and CO2 byproduct credit (CO2 for enhanced gas or oil recovery).
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 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	--

[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.

	Development	Optional Construction	Committed Construction
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. 1,330 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 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 “aero derivative” machines - aircraft engines adapted to stationary applications. The higher pressure (compression) ratios of aero derivative machines result in a more efficient and compact unit than frame machines of equivalent output. Because of their lighter construction, aero derivative machines provide superior operational flexibility including rapid black start capability, short run-up, rapid cool-down and overpower operating capability. Aero derivative 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 aero derivative 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 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 liquefied 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 run-up of 2000 and 2001, equipment prices ran 25 to 30 percent higher than current levels. The reported construction cost of aero derivative 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 aero derivative 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

[12] Chilling the compressed air between air compression stages.

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: aero derivative, no cogeneration - 9,955 Btu per kilowatt-hour; industrial, combined-cycle - 7,340 Btu per kilowatt-hour; aero derivative, 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 aero derivative 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:

- Aero derivative, 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 aero derivative 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.

[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 CO_2 penalty.

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.
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.

[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.

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-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

[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.

(2,370^{o} F) and basic [17]HHV heat rates of 6,640 to 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 (2,550^{o} F) and basic HHV heat rates of 6,490 to 6,510 Btu per kilowatt-hour in combined-cycle configuration. H-class machines, entering commercial demonstration, feature steam cooling 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.

[17] Higher heat value, new and clean, excluding air intake, exhaust and auxiliary equipment losses.

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 lbs. CO_2 per kilowatt-hour output, whereas a new coal-fired power plant would produce about 2 lbs. 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

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.

[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 CO_2 penalty.

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.
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.
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.	

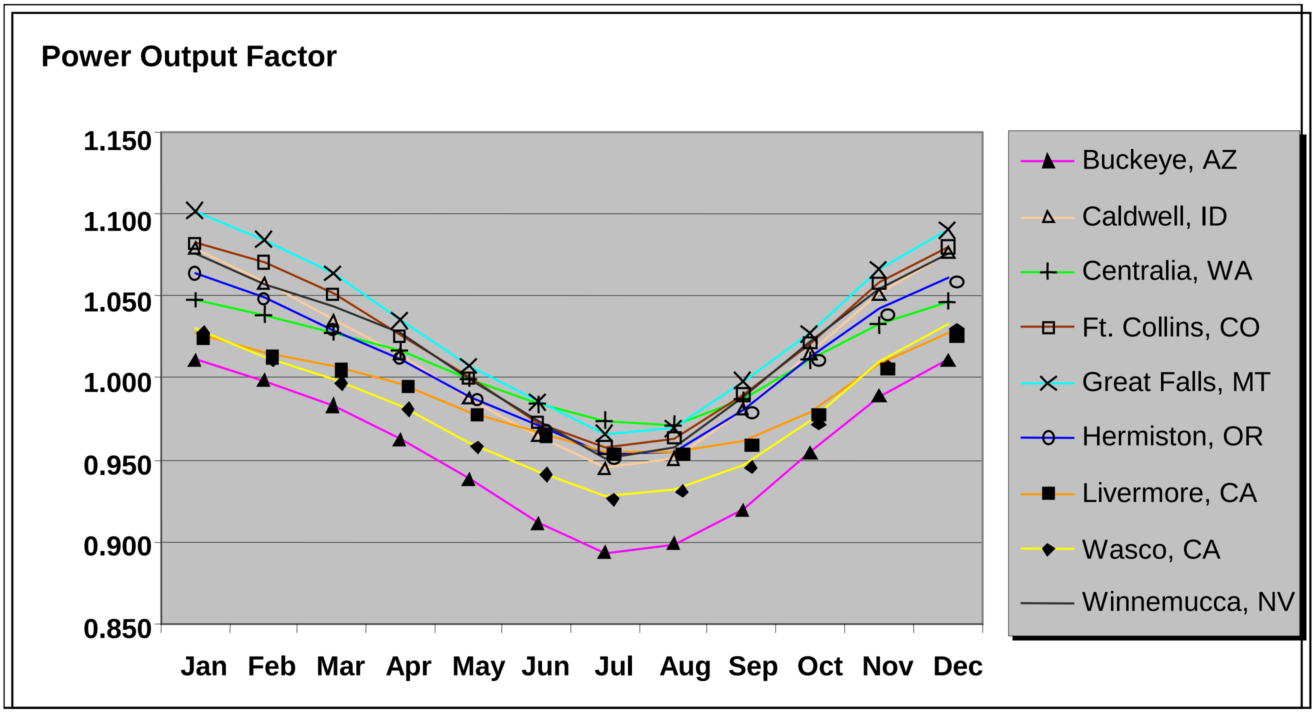

Figure I-1: Gas turbine combined-cycle average monthly power output temperature correction factors for selected locations (relative to ISO conditions)

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 development is expected to resume following the recent extension of the production tax credit through 2005.

[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.

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 kilowatt 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 to 4.5 megawatt) 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 to $50 dollars 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. For the draft plan we assume a $4 per megawatt hour shaping cost for the next 2,500 megawatts of wind capacity. The cost of shaping the second 2,500 megawatts of wind capacity is assumed to be $8 per kilowatt-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 500 kV 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 miles per hour, 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 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 $8 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 $8 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)

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/MWh West of Continental Divide Block 2: $8/MWh East of Continental Divide Block 3: $8/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	$4	--
Maximum hold time from end of phase	60 months	60 months	--
Cost of termination following suspension ($/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.

[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.
[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.

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.

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 megawatt 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 +/- 500 kV 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:

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

[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 CO_2 penalty.

Costs		
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)	
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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Appendix K. Carbon Dioxide Sequestration

Industrial processes are available for separating carbon dioxide from the post-combustion flue gas of a steam-electric power plant or from the synfuel of a coal gasification plant power plant. The separated carbon dioxide could be compressed to a liquid or gas state and transported by pipeline for injection into suitable geologic formations for permanent storage.

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 selective regenerative sorbant processes currently used to remove sulfur compounds from the synthesis gas of existing gasification plants. 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 Dakota Gasification plant. 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 significantly 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 an IGCC 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 or oil and coalbed methane recovery is the byproduct value of the recovered oil and 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. However, there would be no byproduct value. Because the objective of existing carbon dioxide injection has been enhanced oil or gas recovery and not carbon dioxide storage, additional research and development for monitoring and 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 to over $16 per ton CO_2 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 including 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 (\$/TonCO_2, 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.

Appendix L. 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. The feasibility space and efficient frontier, in turn, requires 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. Within a model's period -- the hydro-year quarter -- non-trivial cost estimation techniques are necessary, which the section outlines. The discussion next turns to specific uncertainties, like load and hydro generation, and then portfolio elements, like thermal generation. Explanation for the reason for this distinction between uncertainties and portfolio elements is below.

Many important 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 27, the appendix discusses the inter-period nature of correlations and behaviors. The notion of imperfect foresight and causality contribute to the structure of calculations in the portfolio model. Causality, in particular, helps us simplify and stabilize calculations. The description returns to the longer-term chronological nature of uncertainties and resource behavior.

It is important to note that a portion of the description of the portfolio model is in Appendix P. As the reader will learn, the modeling of the uncertain futures is to some extent separable from the rest of the model. Because a probabilistic description of uncertainties appears in Appendix P, it makes sense to describe the regional model's treatment of those uncertainties in the same place.

After outlining the principles of the model, "Resource Data" on page 29 fills in any remaining data gaps with the detailed data about resource representations, and so forth. [More here? We'll know when we do it]

[1] Chapter 6 defines the terms "plan," "future," and "scenario" as they are used in this document and describes the concept and application of the feasibility space.

The appendix next presents some of the results of the Council's modeling efforts. It provides an explanation of the value of conservation under uncertainty. Deterministic models fail to capture this value. The appendix also outlines the conclusions of dozens of sensitivity studies performed to test assumptions about representations and uncertainty distributions.

The appendix concludes with an introduction to ***Olivia***, the meta-model that created the regional portfolio model. ***Olivia*** is available free to any individual or agency that wants to create a portfolio model describing their unique situation. ***Olivia*** creates Crystal Ball-aware Excel workbooks ready for use under OptQuest or other Decisioneering applications. The resulting workbook model can also run without Crystal Ball. An analyst with knowledge of Microsoft Visual Basic could modify the workbook to perform Monte Carlo simulation.

There are two distinctive differences between uncertainties and portfolio elements. First, uncertainties differ conceptually, because they define a future. A future is that which we cannot control. Portfolio elements, like generation resource, belong to the category of things we can control. Second, the workbook calculates the values of futures differently. While futures obviously affect resources, resources do not affect futures -- except for some notable exceptions like the future of electricity price. Because of this, the workbook computes the values for uncertainties and futures only one time, at the beginning of the game. On the other hand, the workbook must recalculate the values for portfolio elements iteratively within a period and progressively across periods.

Of course, nothing is quite that clear cut. There is, in fact, a well-defined twilight zone within the worksheet, where futures and portfolio elements interact. The example of electricity price is an important inhabitant of that region. Long-term load elasticity is another. Properly speaking, any variable that depend on these, such as a decision criterion, are also citizens of the twilight zone. For the purposes of discussion in this appendix, the section "Multiple Periods" will address those. There the reader will find a description of the necessarily careful treatment of these denizens.

The reader may want to refer to the following Table of Contents for orientation to the remaining appendix.

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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[2] 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.

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.

[2] Decisioneering's Crystal Ball®. Olivia produces a workbook that is compatible with Crystal Ball.

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.

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.[3] 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.

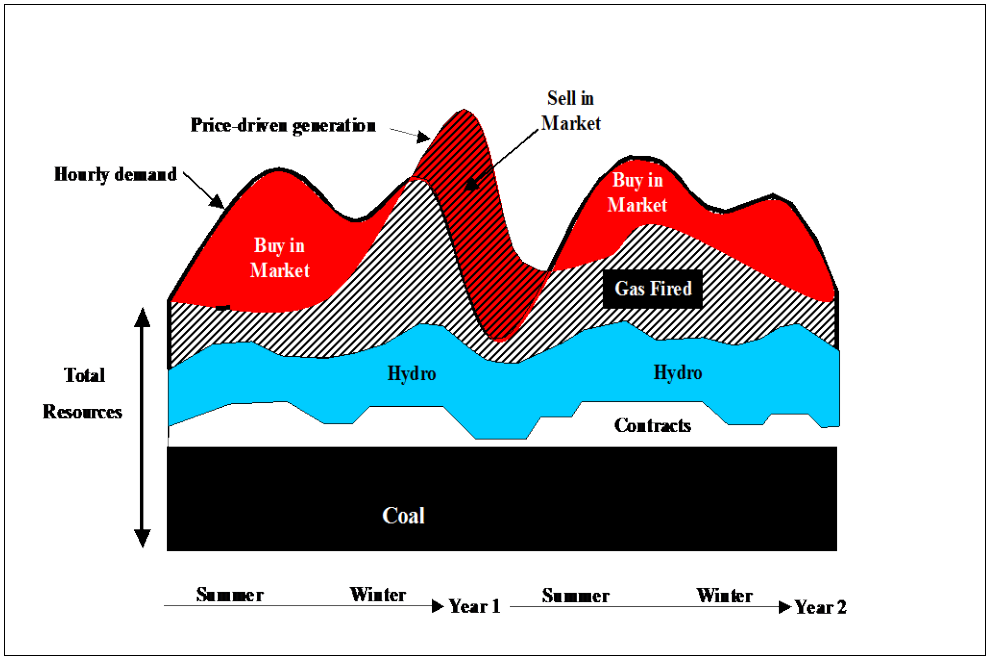

Figure L-1: Portfolio Model Calculation

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.[4] Transmission constraints within the region are considered outside the model. Existing regional thermal resources 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.

[3] One estimate using AURORA® run times put the study at a little over 85 years.
[4] Contracts may be fully counter-scheduled.

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 steps. The first steps will describe calculations that pertained to a single period. These include, for example, the use of correlation among load requirements, electricity prices, and natural gas prices within the period to estimate thermal generation. These 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 steps will describe calculations involving several periods. These include price processes, and the description of underlying trends for natural gas price and loads. These also include more complex load and resource behaviors, such as decisions to shut down or restart a smelter and whether or not to proceed with the construction of power generation resources. The final steps describe the rules for adding new resources to the system.

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 the workbook containing 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-376-P2.zip). References to the workbook appear in curly brackets ("{}"). Understanding the description does not require reference to the workbook, however. References to data sources appear in square brackets (“[]”). The References section at the end of the appendix lists the sources.

ICON KEY
🗁 Key idea
◆ Definition

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, Decisioneering's 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.

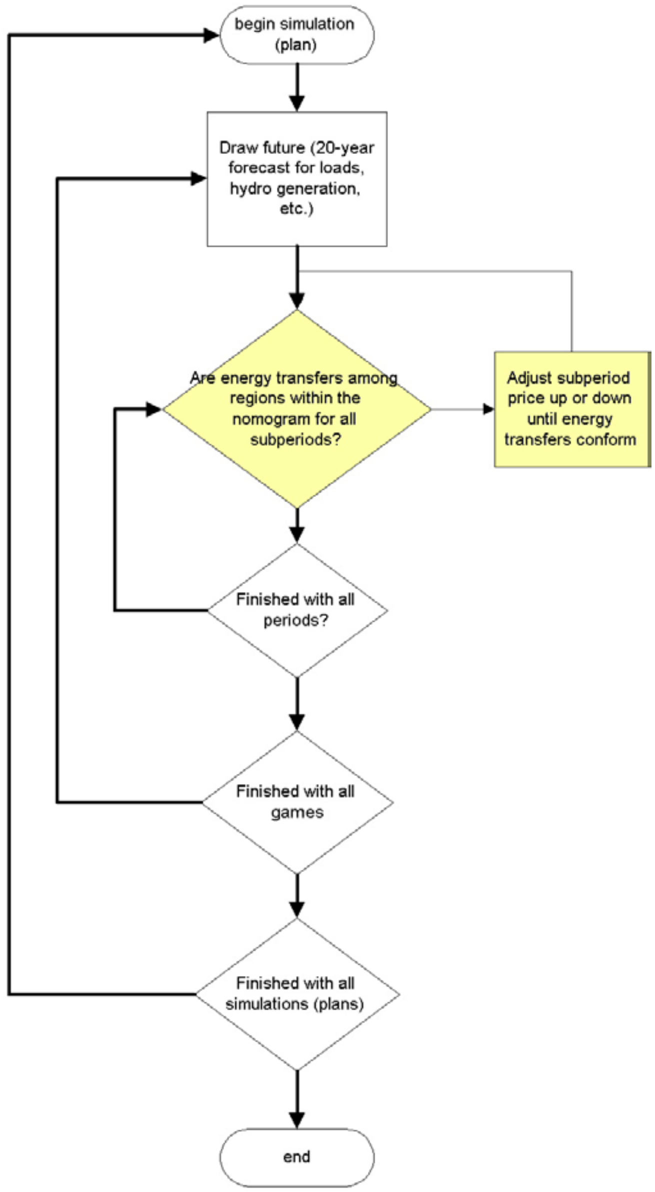

Figure L-2: Logic Flow for Overall Risk Modeling

Figure L-3 gives a more specific description of the process that takes place in the outer-most loop. (The inner loops of Figure L-2 take place within the box, "Determine the distribution of costs for plan" in Figure L-3.) 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 the same 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 in reference [**1**].

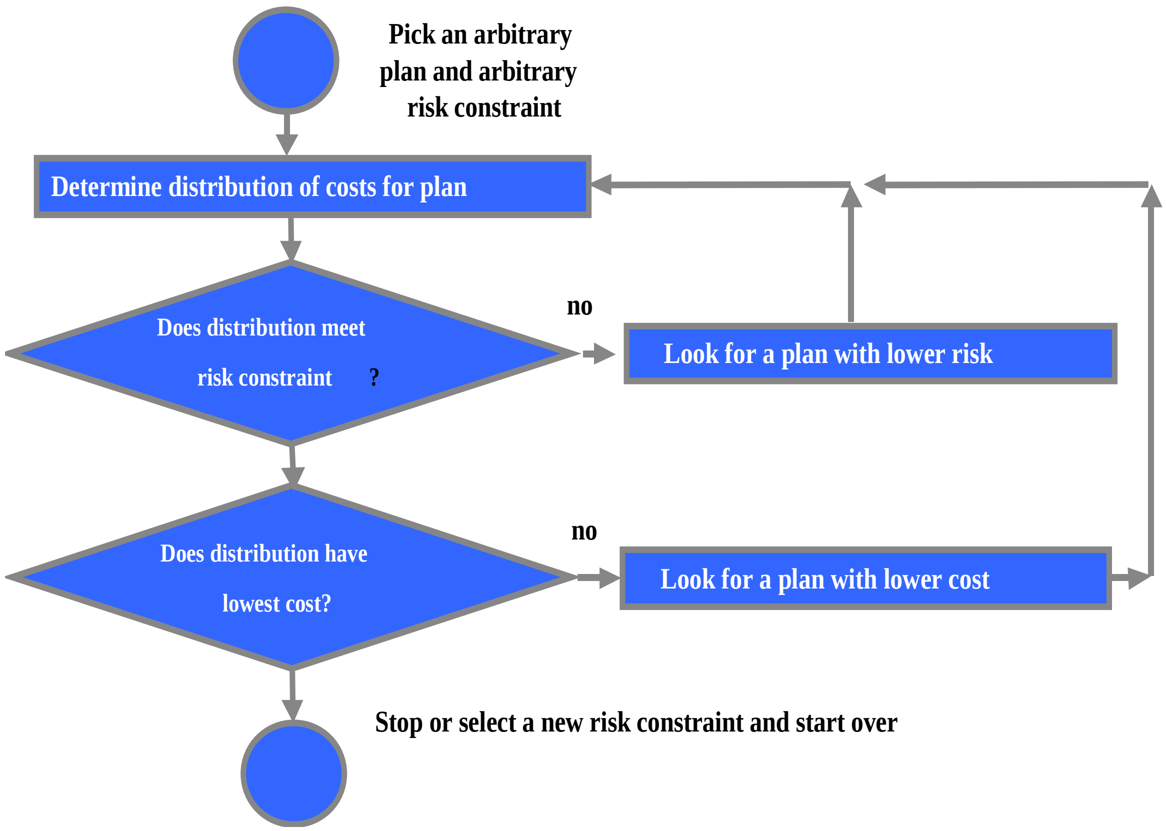

Figure L-3: Finding the Risk-Constrained Least-Cost Plan

OptQuest, in turn, controls Decisioneering's 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 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 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-4. Before Crystal Ball gets results from the worksheet, the macro modCBM.subAfterGame recalculates energy and cost, period by period, in the strict order described on page 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}.

[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.

After the simulation for a given plan is complete and Crystal Ball has captured the results for all the games, the macro modCBM.subAfterSim in Figure L-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 90^{th} Quintile.

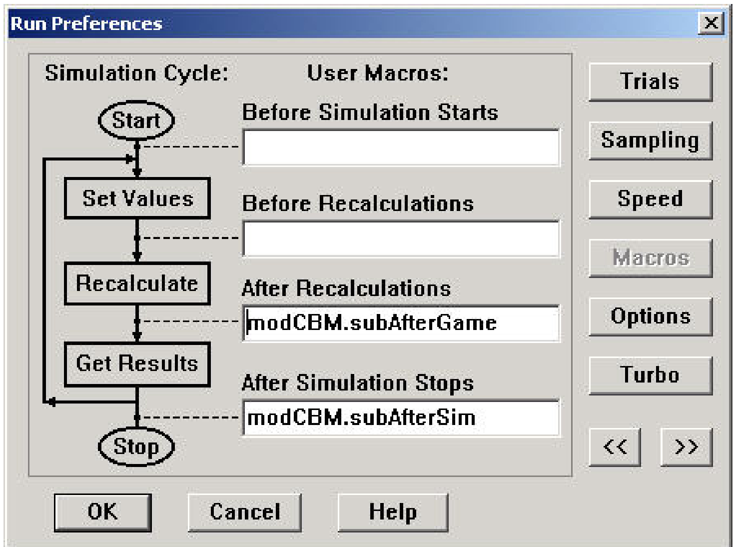

Figure L-4: Crystal Balls Macro Loop

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.

The portfolio model performs roughly the duties of the innermost loop 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 address the occupants of the worksheet’s twilight zone, mentioned in the introduction. Before the model adjusts prices for the current period, it recalculates twilight zone cells, which control the long-term interaction of futures, prices, and resources. 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 only once for the period, immediately before iterating to a feasible on-peak electricity price. A single recalculation is sufficient because the formulas use results only from prior periods, never the current period.

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.

The portfolio model worksheet, however, must solve several energy balancing problems by iteration. 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, efficiencies obtain by turning off automatic calculation. The model instead controls the recalculation of all cells with a VBA range recalculation.

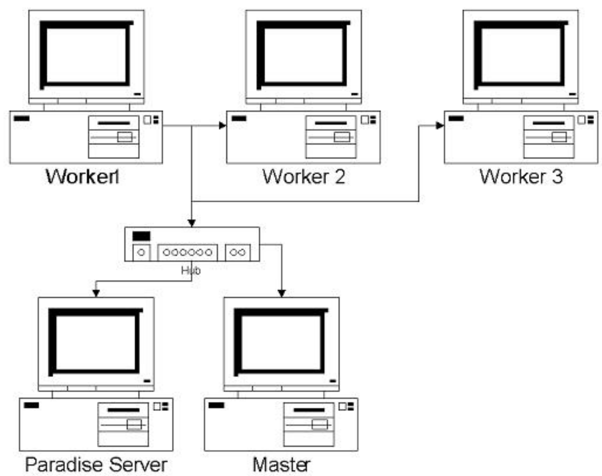

Figure L-5: Distributed Processing

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 only once per period 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}.

[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

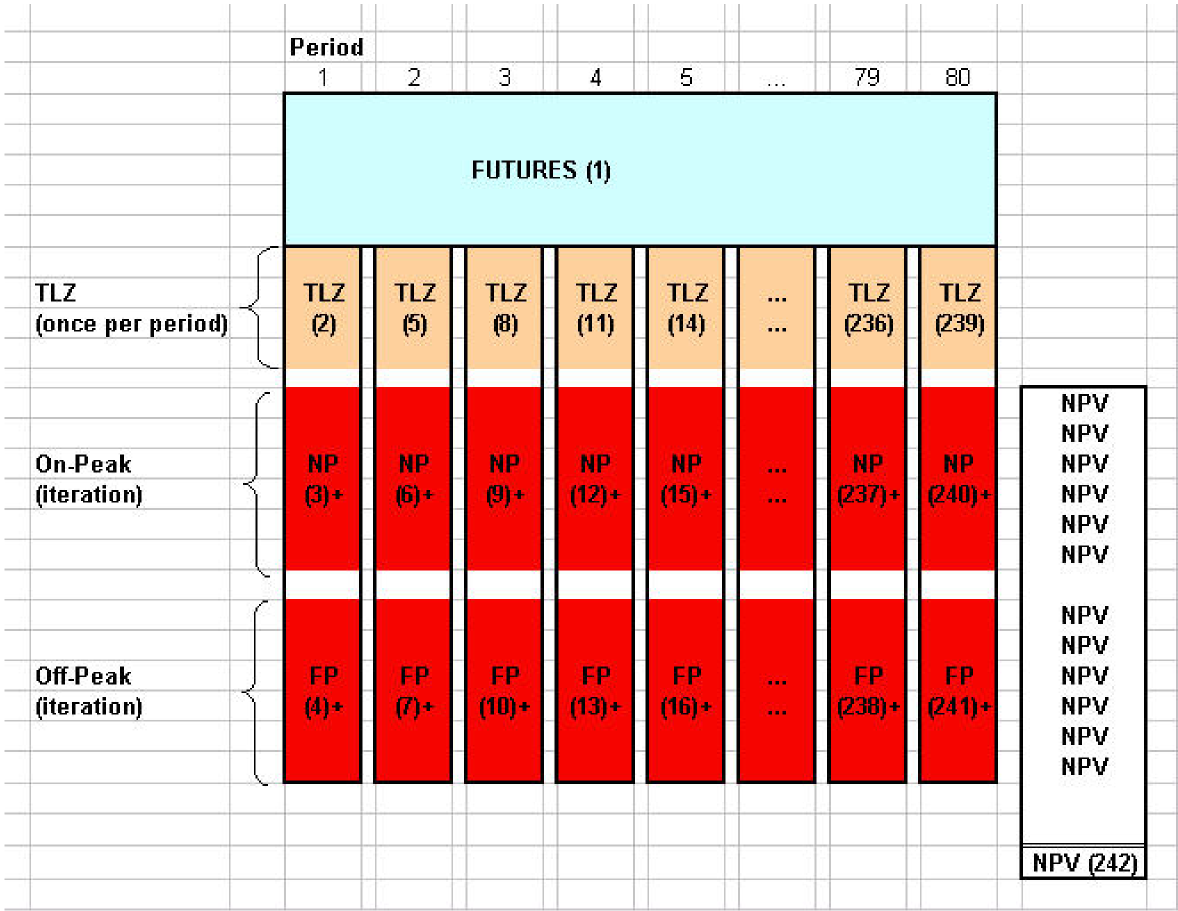

Figure L-6: Portfolio Model Calculation Order

Figure L-6 permits us to restate the scope of this appendix, with respect to discussion of the portfolio model. Appendix P describes and explains the calculations in the area of the worksheet denoted by "FUTURES (1)". This Appendix M discusses all remaining areas.

With this overview, it makes sense to start with perhaps the simplest region 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, September through November of 2012 {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 always has four Saturdays and four Sundays. This convention eliminates several sources of complexity, but it also introduces one. 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. If an analyst needed to know the energy and costs associated with a particular month and year, the fact that the number of hours on peak and off peak is fixed makes scaling the results on a month-to-month basis easy and accurate.

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 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.

In addition to specifying the period that serves as our example, this description will assume a specific plan under a specific future.[9] Working with specific choices should

[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.
[9] Chapter 6 provides definitions for the terms "future," "plan," and "scenario."

Table L-1: Plan DW02

Conservation: $10/MWh higher on the supply curve in all periods, for both non-lost opportunity and discretionary conservation.[11]
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

make the calculations more concrete and easy to follow. The plan appears in Table L-1.[10]
The behavior of this plan under the 750 futures is illustrated in a workbook that the reader can obtain from the Council: http://www.nwcouncil.org/dropbox/Olivia_and_Portfolio_Model/L24X-DW02-P.zip
The behavior of this plan under future number six appears in Figure L-7. It 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-9 through Figure L-13 show other aspects of future six and the behavior of this plan under future six.

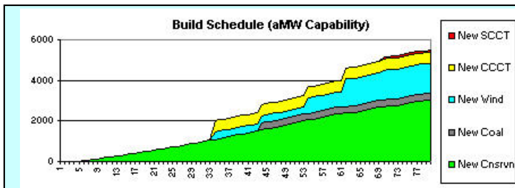

Figure L-7: Build 0ut of Future 6

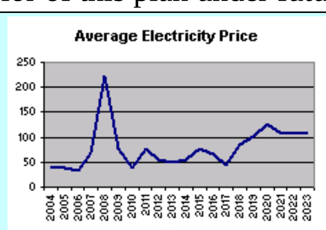

Figure L-9: Electricity Price Future

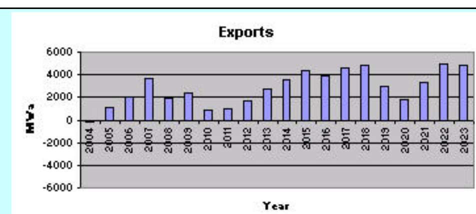

Figure L-8: Exports

[10] L24X-DW02.xls -- Move start dates for wind and CCCT ahead; keep total by the end of the study the same. Adjust the size of the early wind to 400MWa. Do not adjust size of the CCCT. This has cost of 17.4B and TV90 of 26.20B

[11] 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.

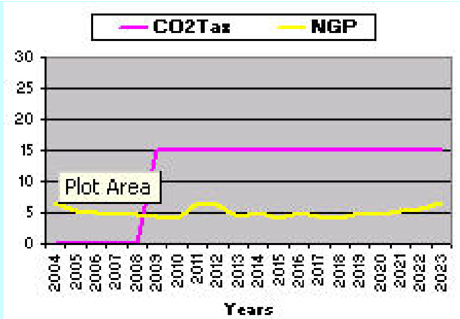

Figure L-11: Natural Gas Price and CO2 penalty

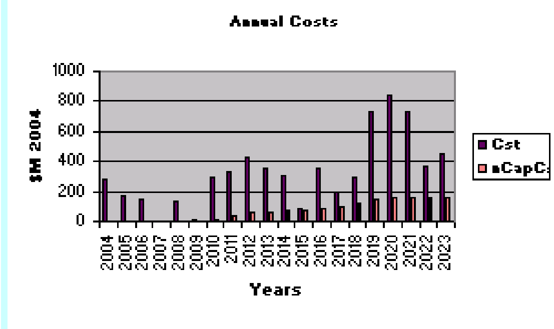

Figure L-10: Total Annual Costs and Capital Costs Only

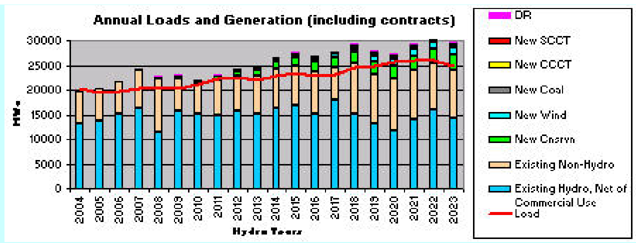

Figure L-13: Annual Energy Generation and Load

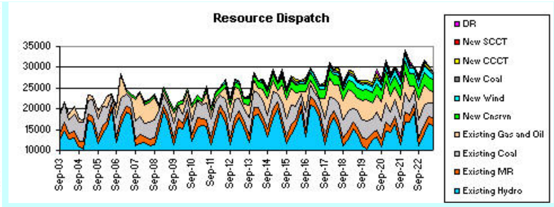

Figure L-12: Quarterly Energy Generation

Valuation Costing

Period costs can be tricky to estimate because of the intra-period correlations that exist between market price for electricity, fuel prices, requirements, and so forth. For example, consider two simplified systems, System A and System B, which face a common market price over some period, say a week. (See Figure L-14.) The task is to calculate the cost of market purchases. Even if these 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.

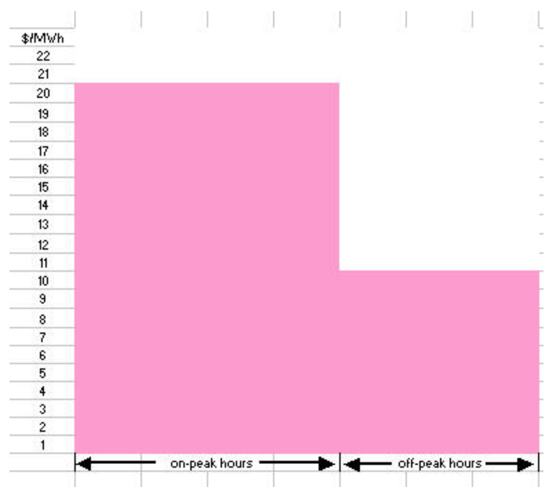

Figure L-14: Prices over on- and off-peak hours

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.

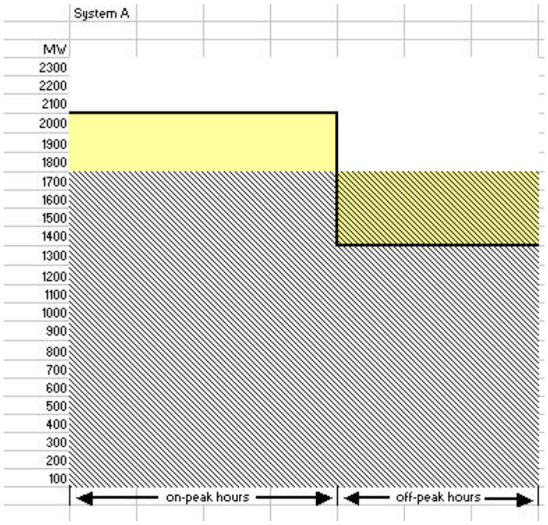

Figure L-16: System A

System A has loads -- constant over the subperiods -- shown as the heavy line in Figure L-16. 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-16. A simple calculation shows the net cost of market purchases over the week is $119,000.

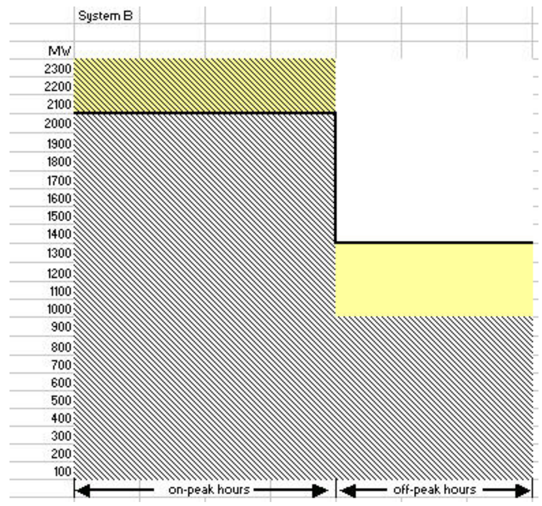

Figure L-15: System B

The System B has hydro generation (the cross-hatch area in Figure L-15) 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 ***p*** denotes hourly price, ***q*** represents hourly position, ***E(pq)*** is expected revenue, ***E(q)*** is average position, ***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 $\boldsymbol{(Q\text{-}\Sigma q_i)}$ 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. In the more complex case of thermal generation, where fuel prices may correlate with market prices, a well understood equation provides an estimate of value in the market. This equation is precisely the topic of the section “Thermal Generation.”

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 27 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.[12] If ***E(p)*** and $\boldsymbol{\sigma_p}$ denote the expected price and standard deviation after log transformation and ***E(P)*** and $\boldsymbol{\sigma_P}$ before transformation, and similarly and ***E(q)***, $\boldsymbol{\sigma_q}$, ***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 28, 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 28.

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.

[12] 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 dispatchable generation and value of generation with financial option valuation methods. 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 29, 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 a European call option on electricity models thermal dispatch. It then generalizes this approach to a European call option on the spread in price between electricity and natural gas and presents some of the computational advantages of an exchange-of-assets option over those of spread options. Finally, it documents the Excel user-defined function that implements the exchange option.

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-17.

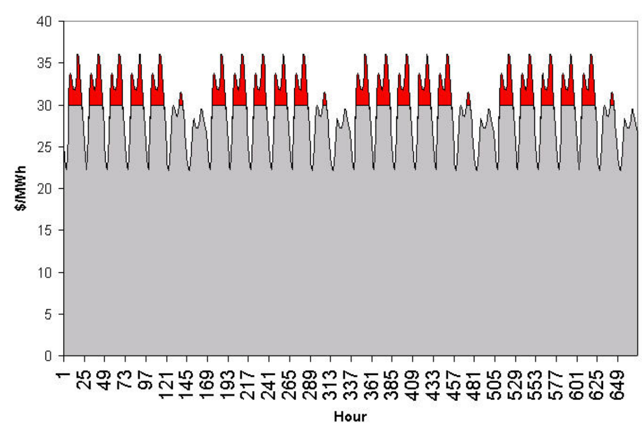

Figure L-17: Thermal Dispatch

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 $C\ max(0, p_e(h)-p_g(h))$, where C is the capacity of the turbine, $p_e(h)$ is the price of electricity and $p_g(h)$ 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-17 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

$$V = C \sum_{h \in H} \max\left(0, p_e(h) - p_g(h)\right)$$

$$= CN_H \frac{\sum_{h \in H} \max\left(0, p_e(h) - p_g(h)\right)}{N_H}$$

or

$$V = CN_H E\left[\max\left(0, p_e(h) - p_g(h)\right)\right]$$

where E is the expectation operator and N_H is the number of hours in the period (672 in this case).

How does one evaluate the expectation in this formula? The solution is to find a similar formula to which we know the solution. The formula happens to belong to the value of quite a different kind of asset.

The value of a European call option[13] on a share of stock is[14]

$$c = E[e^{-rT} \max(0, S - X)]$$

where
E is the expectation operator
r is the annual discount rate
T is the time to expiration (years)
S is the price of the stock
X is the strike price

Part of the trick, then, is to set the product $\boldsymbol{rT}$ to zero and associate $\boldsymbol{S}$ with $\boldsymbol{p_e}$ and $\boldsymbol{X}$ with $\boldsymbol{p_g}$. This representation, however, still lacks concrete instructions on how to calculate the expected value in the formula. To solve that problem, we use the equation that Black and Scholes developed in their Nobel Prize-winning research in economics[15].

$$c = SN(d_1) - Xe^{-rT}N(d_2)$$

where
S is the stock price
X is the strike price of the option
N is the cummulative distribution function
for a normally distributed random variable with
mean of zero and standard deviation of 1.0
σ_S is standard deviation of $\ln(\mathrm{S_t}/\mathrm{S_{t\text{-}1}})$
r is the discount rate

$$d_1 = \frac{\ln(S/X) + (r + \sigma_S{}^2/2)T}{\sigma_S\sqrt{T}}$$

$$d_2 = d_1 - \sigma_S\sqrt{T}$$

This is the version of the equation for a stock that pays no dividends.

Much of the value of Black and Scholes' work lay in determining the correct value to use for the discount rate $\boldsymbol{r}$. They showed that, given some simple assumptions about stock

[13] A European option can only be exercised at expiration; an American option can be exercised at any time up to expiration.
[14] Hull, op. cit., page 295.
[15] See, for example, http://en.wikipedia.org/wiki/Black-Scholes

prices, the discount rate r should be the risk-free rate. Fortunately, perhaps, the valuation of a turbine does not use the discount rate r or these assumptions.[16] (See also [**2**].)

Black and Scholes also assumed that prices for stock are lognormally distributed, a conclusion that is consistent with choices for prices in the portfolio model. (See Appendix P.) Lognormal distribution of prices leads to uncertainty in stock price over time that goes as the product of the annualized stock price volatility σ_s and the square root of time T, expressed in years. Because the product rT is zero and because $\sigma_s \sqrt{T}$ is positive, T is necessarily positive and the discount rate r must therefore be zero.

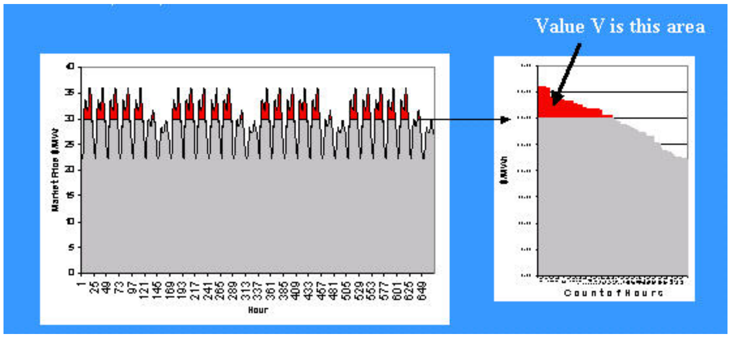

Figure L-18: Sorting by Market Price

In the portfolio model, the variation in electricity market price over the month period corresponds to stock price uncertainty at expiration. To see how this arises, sort the hours illustrated in Figure L-17 by the market price, yielding the market price duration curve in Figure L-18. 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-19 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. 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.

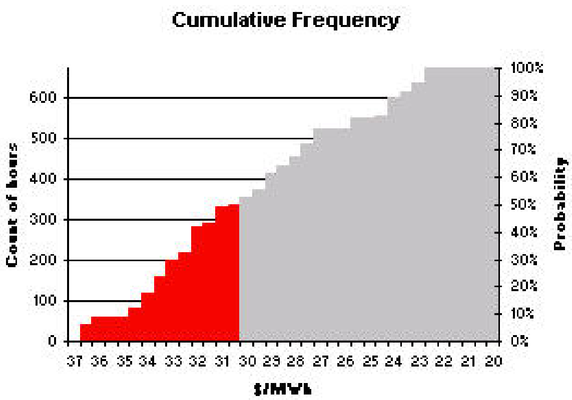

Figure L-19: Cumulative Probability Function

[16] These assumptions require, for example, nearly continuous change in stock prices and the ability to hedge the value of the option with those stocks. Both of these assumptions are arguably inapplicable to the turbine. The aspect of the option price formula used for valuing the turbine, however, is simply the expected value of positive differences between a lognormal price and the strike price. A direct calculation of that expected value requires only a page of calculus, but even that is unnecessary if the option price formula is reinterpreted as is done in this section.

Now let σ_e be the variation of electricity prices over the month. More specifically, let σ_e be the standard deviation of the log-transformed electricity prices, $\ln(p_e(h))$, taken from the month. (The order of the hours makes no difference.) From the preceding discussion, it follows that by setting $r = 0$, $T = 1$, $X = p_g$, $\sigma_s = \sigma_e$, and S equal to the average of the hourly electricity prices $p_e(h)$, the expectation $E(0,p_e(h)-p_g(h))$ is:

$$c = \overline{p}_e N(d_1) - p_g N(d_2) \qquad (3)$$

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 $\ln(p_e(h))$

$$d_1 = \frac{\ln(\overline{p}_e / p_g)}{\sigma_e} + \sigma_e / 2$$

$$d_2 = d_1 - \sigma_e$$

With these identifications, the previous equation shows that **the value of the turbine** is $V = CN_Hc$.

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.

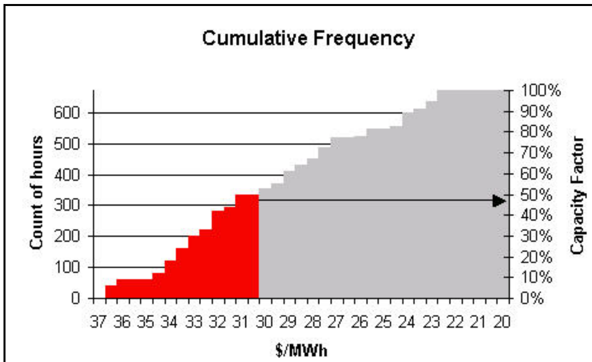

Figure L-20: Capacity Factor

To estimate generation, note that the CDF for generation already specifies the capacity factor for the turbine, as illustrated in Figure L-20. 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 p_e, and the expectation $E(0,p_e(h)-p_g(h))$ is the integral of the CDF(p_e) for p_e from infinity down to p_g. Moreover, the capacity factor is just CDF(p_g). These relationships are evident from Figure L-20. Algebraically, the capacity factor ***cf*** is derived as follows:

$$V = C \cdot N_H \int_{\infty}^{p_g} \mathrm{CDF}(p_e)\, dp_e$$

$$\Rightarrow \text{(Fund Thm of Calculus)}$$

$$\left.\frac{\partial V}{\partial p_g}\right|_{p_g = p_g^*} = -C \cdot N_H \cdot \mathrm{CDF}(p_g^*)$$

$$\Rightarrow$$

$$\mathrm{cf} = \mathrm{CDF}(p_g^*) = -\frac{1}{C \cdot N_H} \left.\frac{\partial V}{\partial p_g}\right|_{p_g = p_g^*}$$

To find the value of the partial derivative in the last equation, use the fact that $V=CN_Hc$ and take the derivative of equation (3) with respect to the strike price [**3**].

$$\frac{\partial c}{\partial p_g} = -N(d_2)$$

$$\text{where}$$

$$d_2 = \frac{\ln(\bar{p}_e / p_g)}{\sigma_e} - \sigma_e / 2$$

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 ***N(d₂)*** 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 that capacity factor 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. One approach to solving this issue is to 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. 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.

To implement the option model, therefore, the portfolio model uses an "exchange of assets" option. The application of this option is typically to situations where one holds a given amount of one commodity, say aluminum, and wants to trade it for another commodity, say steel, at a given price if the value of the steel exceeds the value of the aluminum. In the case of the turbine, the commodity we are holding is natural gas. When the value of the corresponding amount of electricity exceeds that for the gas, the turbine operator can exchange the gas for electricity.

The formula for the value ε and for the probability of "in the money" expiration of an exchange option are analogous to those for a European call option. The value for an exchange option[17] on commodities that pay no dividends is:

$$\varepsilon = S_1 N(d_1) - S_2 N(d_2)$$

$$d_1 = \frac{\ln(S_1 / S_2) + \sigma^2 T / 2}{\sigma\sqrt{T}}$$

$$d_2 = d_1 - \sigma\sqrt{T}$$

$$\sigma = \sqrt{\sigma_{S_1}{}^2 + \sigma_{S_2}{}^2 - 2\rho\sigma_{S_1}\sigma_{S_2}}$$

where

S_2 the value of the commodity currently held

S_1 the value of the commodity for which hold the option

σ_{S_1} is standard deviation for $\ln(S_{1,t} / S_{1,t-1})$

$\sigma_{S_{12}}$ is standard deviation for $\ln(S_{2,t} / S_{2,t-1})$

ρ is the correlation in values between S_1 and S_2

[17] Hull, op. cit., page 468. (Note that S_1 and S_2 are reversed here from the notation Hull uses.)

There are several issues to point out. First, the discount rate $\boldsymbol{r}$ does not appear in this equation. Second, the variables $\boldsymbol{S_1}$ and $\boldsymbol{S_2}$ here are total values, not prices. This means that, whereas in the case of the European call, the value $\boldsymbol{V = CN_H c}$ used the quantity $\boldsymbol{CN_H}$ times the unit value $\boldsymbol{c}$, we now have $\boldsymbol{V = \varepsilon}$, the value of the option. Using the convention $\boldsymbol{T = 1}$, $\boldsymbol{S_1}$ for the average of the hourly values for electricity generation, and $\boldsymbol{S_2}$ for the average of the hourly values of gas that we must hold to produce the generation, the preceding equation means

$$V = \varepsilon = S_1 N(d_1) - S_2 N(d_2)$$
$$cf(\overline{p}_g, \overline{p}_e) = N(d_2)$$
$$d_1 = \frac{\ln(S_1 / S_2)}{\sigma} + \sigma / 2$$
$$d_2 = d_1 - \sigma$$
$$\sigma = \sqrt{\sigma_{S_1}{}^2 + \sigma_{S_2}{}^2 - 2\rho\sigma_{S_1}\sigma_{S_2}}$$

where

$$S_1 = \mathrm{CN_H}(\overline{p}_e - p_{VOM})(1 - FOR)$$
$$S_2 = \mathrm{CN_H}(\overline{p}_g + p_{CO_2})(1 - FOR)$$

p_{VOM} is the variable O & M rate ($/MWh)

p_{CO_2} is the carbon tax penalty ($/MWh)

σ_{S_1} is standard deviation for $\ln(\mathrm{S}_{1,\mathrm{t}} / S_{1,t-1}) \approx \ln(p_{e,t} / p_{e,t-1})$

σ_{S_2} is standard deviation for $\ln(\mathrm{S}_{2,\mathrm{t}} / S_{2,t-1}) \approx \ln(p_{g,t} / p_{g,t-1})$

ρ is the correlation in values between S_1 and S_2

FOR is the unit's forced outage rate $(0 \le FOR \le 1.0)$

where, as before, we have adjusted the price of gas ($/MMBTU) and the price of the CO2 tax ($/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.

The portfolio model performs the exchange-of-assets option valuation 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)
```

Although the function's name is "SpreadOption," examination of the code will reveal that it is really the exchange option described above. The function's declaration for the parameters is

```
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 CO2. 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 CO2 per MMBTU, and carbon produces 212 pounds of CO2 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

- Contract as a resource
- Impact on counter-scheduling transmission and import/export constraints
- Energy
- Source: BPA & filenames
- Cost -- on- and off-peak we assume zero correlation with price.

Supply Curves: Conservation

Supply Curves, Cont'd: Price-Responsive Hydro

ds

Conventional Hydro

The Market and Export/Import Constraints

RRP algorithim

Multiple Periods

Concept Of Causality

avoids instabilities and inefficient recalculation

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 was covered in 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 [**4**] 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 perhaps 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.

Supply Curves: Conservation
Possibly unnecessary

Supply Curves, Cont'd: Price-Responsive Hydro
Possibly unnecessary

DSIs
This kind of logic could be applied to industries other than smelters.

Planning Flexibility
Full discussion

Present Value Calculation
Gotta' make that final estimate, with conversion to calendar year from standard year.

New Resource Selection

Decision Criteria
What they are and how they are used

Alternative Decision Criteria

Forward Prices Only

Resource-Load Balance Only

Wind

CCCT

SCCT

Coal

Demand Response

Conservation

Resource Data

Tables and all that
on and off-peak

Existing Resources

New Resources

Using The Regional Model

Control - I

Insights

Sensitivities

Conservation Value Under Uncertainty

Portfolio Model Reports And Utilities

Olivia

Description of the model, with images.

New structure

References

j:\power\power plan\appendix\appendix l (portfolio model).doc

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2 Direct Calculation of Expected Value.doc

3 XXX Document 10/25/04 calculations

4 Terry Morlan, Ph.D., Northwest Power and Conservation Council

Appendix M. 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 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 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 greenhouse gas emissions, there is a good deal of climate policy action both in the U.S. and

[1] U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks1990 - 2002. April 2004.

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 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 effort to control CO_2 production using carbon-proportional constraints on both existing and new generating resources.

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

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[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 CO_2 Storage. August 2003.

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.

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Appendix N. Effects of Climate Change on the Hydroelectric System

SUMMARY

There is still much debate surrounding scientific data regarding climate change. However, a preponderance of scientific opinion asserts that the Earth is warming. 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 maximum 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 Northwest Power and Conservation Council is currently reviewing the status of the global climate change issue, including the current understanding of possible effects on the Northwest climate and hydropower system. In addition, the Council is using 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 involves 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.[1] 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.

[1] Source: U.S. National Climatic Data Center, 2001

Figure N-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.

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.

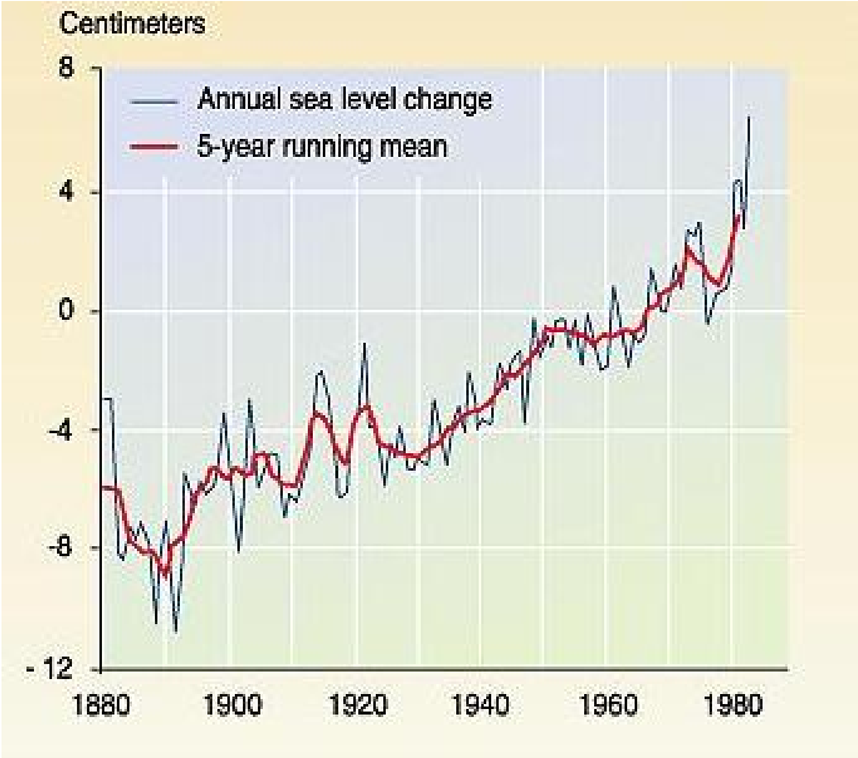
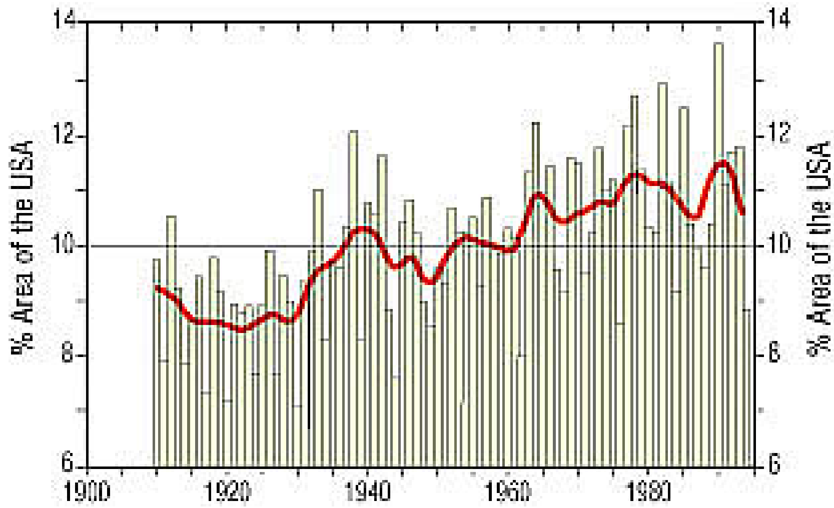


Figure N-2: Historical Rise in Sea Level

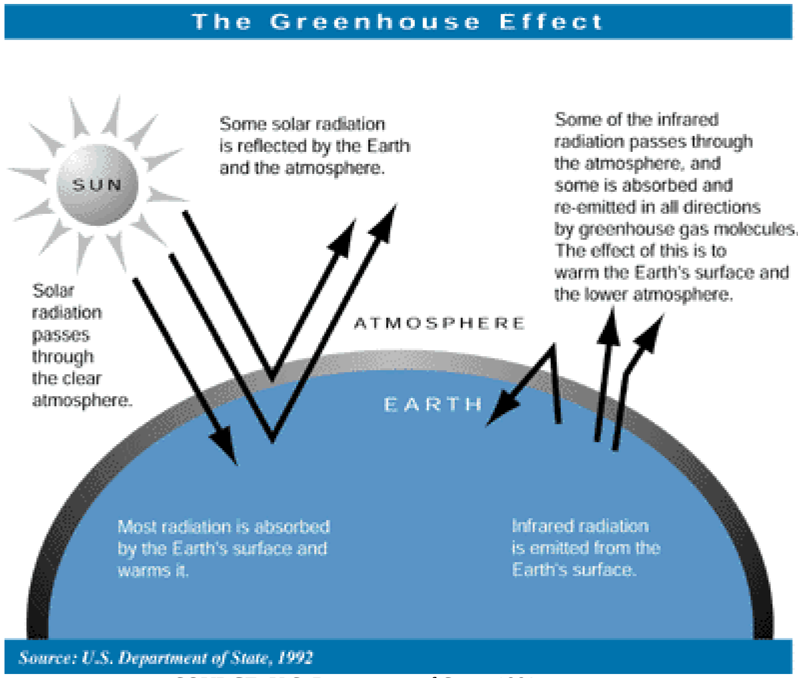


SOURCE: Center for Climate Change and Environmental Forecasting (www.climate.volpe.dot.gov/precip.html)

Figure N-3: Percentage of Area in the US Experiencing more Extreme Rainfall

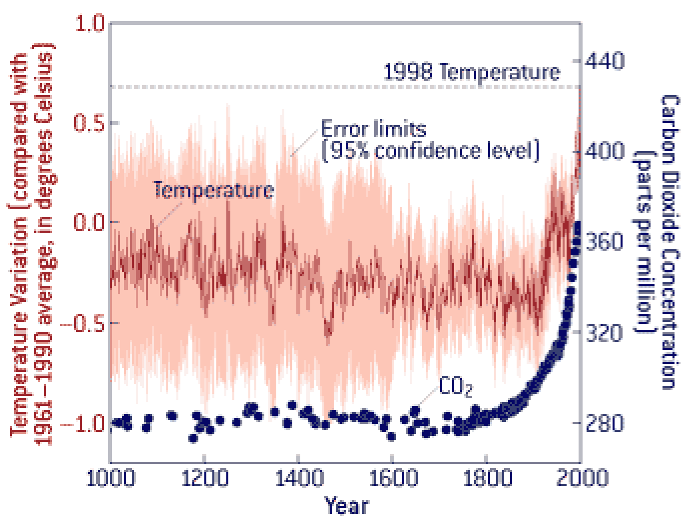
Causes of Global Warming

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.



SOURCE: U.S. Department of State, 1992

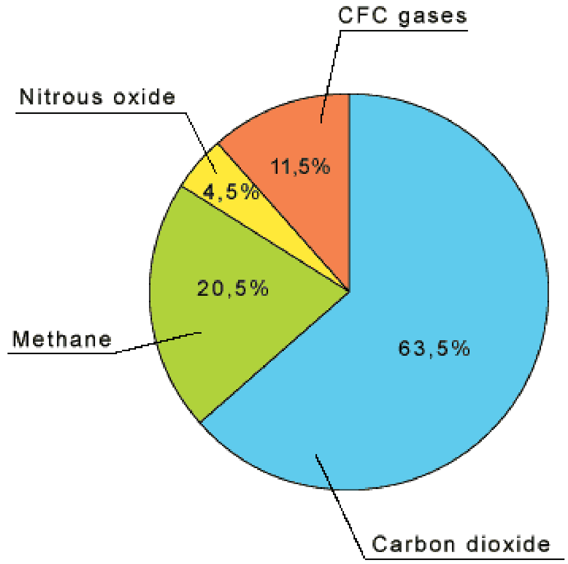
Figure N-4: The Greenhouse Effect



SOURCE: *Intergovernmental Panel on Climate Change*

Figure N-5: Temperature and Carbon Dioxide Concentration over the last Century

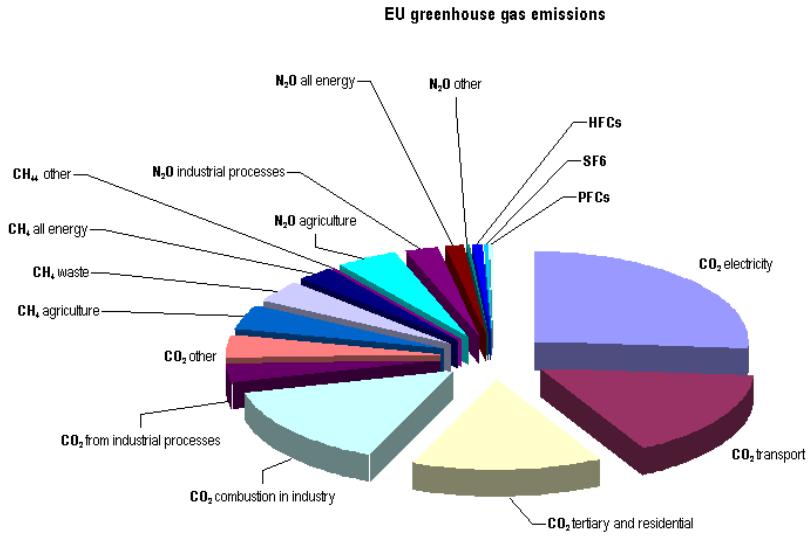
Though ninety-eight percent of total global greenhouse gas emissions are *naturally* produced (mostly water vapor) and only 2 percent are from man-made sources, over the last few hundred years, the concentration of man-made greenhouse gases in the atmosphere has increased dramatically. Since the beginning 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).



SOURCE: Institut Français du Pétrole (IFP) (http://www.ifp.fr/IFP/en/images/fb/gaz-effet-serre-fb04.gif)

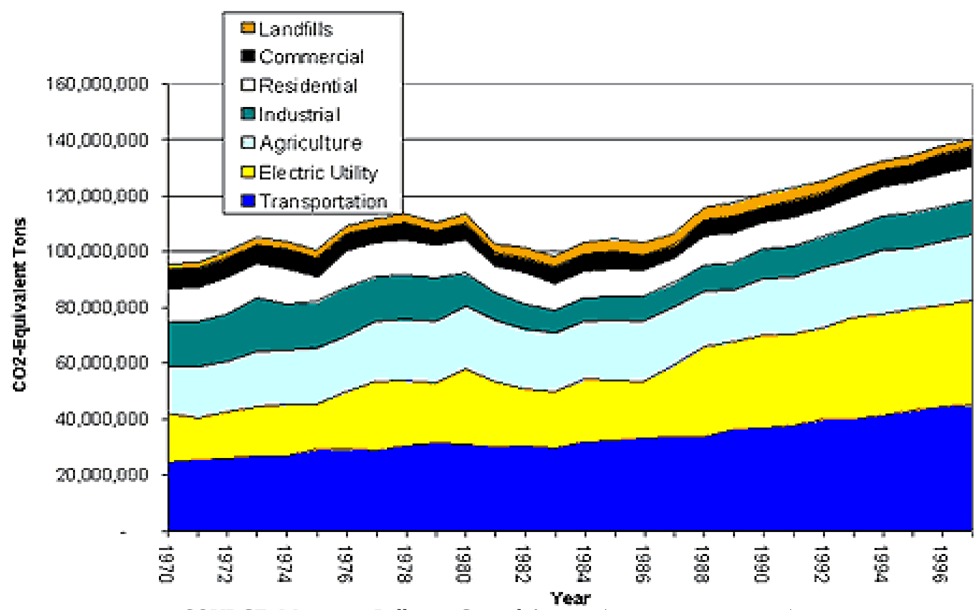
Figure N-6: Greenhouse Gases Worldwide

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.



SOURCE: Climate Action Network Europe (www.climnet.org)

Figure N-7: Sources of Greenhouse Gases



SOURCE: Minnesota Pollution Control Agency (www.pca.state.mn.us)

Figure N-8: Sources of Carbon Dioxide Production

Figuring out to what extent the human-induced accumulation of greenhouse gases since pre-industrial times is responsible for the global warming trend is not easy. 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 accelerate and conservative assumptions about how the climate will react to that, the IPCC projects further global warming of 2.2-10°F (1.4-5.8°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 the 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.

Part of the debate over global warming also centers on disparities between surface temperature and upper-air temperature. While the Earth's surface temperature has risen, data collected by satellites and balloon-borne instruments since 1979 indicate little if any warming of the low-to mid-troposphere. This concurs with a previous Research Council report that said despite these differences, "the warming trend in the global mean surface temperature observations during the past 20 years is undoubtedly real and is substantially greater than the average rate of warming in the 20th century."

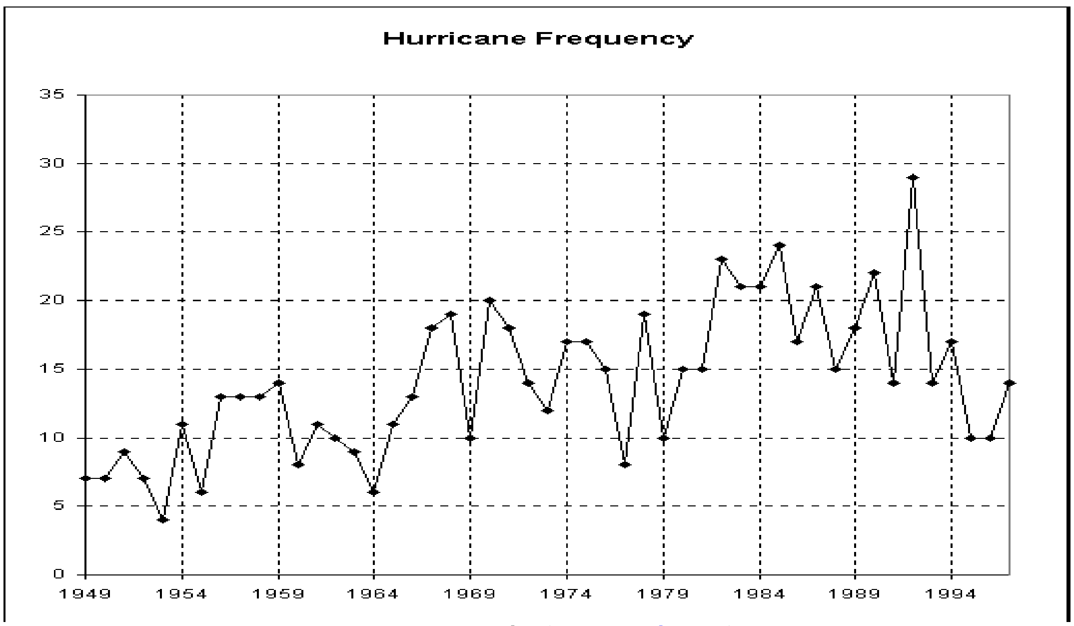
Scientists who work on climate change models are quick to point out that they are far from perfect representations of reality, and are probably not advanced enough for direct use in policy implementation. Interestingly, as the computer climate models have become more sophisticated in recent years, the predicted increase in temperature has gotten smaller. Nonetheless, most climatologists concur that the warming trend is real and could have serious impacts worldwide.

While the debate rages on, the Council recognizes that it is imperative to examine potential impacts of global warming and to continue to monitor advances in this area.

Potential Impacts of Global Warming

The fear that global warming would melt the ice caps and flood coastal cities is probably not warranted (except perhaps at some low-lying Pacific islands or at Venice, Italy). A slight increase in temperature -- whether natural or mankind induced -- is not likely to lead to a massive melting of the earth ice caps. Also, sea-level rises over the centuries probably relate more to warmer and thus expanding oceans, not to melting ice caps. The concern regards possible shifts in ocean upwelling and currents and their 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 does exist toward more frequent occurrences, which is predicted by climate change models.



SOURCE: TV Weather (www.tvweather.com)

Figure N-9: Frequency of Hurricanes

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 melts earlier and results 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.

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 2008-2012. 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.[2] 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

[2] http://stommel.tamu.edu/~baum/climate_modeling.html

known as "general circulation models" or GCMs. These models take into account the interaction of the atmosphere, oceans and land surfaces.[3] 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 models has been developed.[4] 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)[5] Climate Impacts Group[6] at the University of Washington. This data was derived primarily from two GCMs, the Hadley Centre model (HC)[7] and the Max Planck Institute model (MPI)[8] 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.[9] 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

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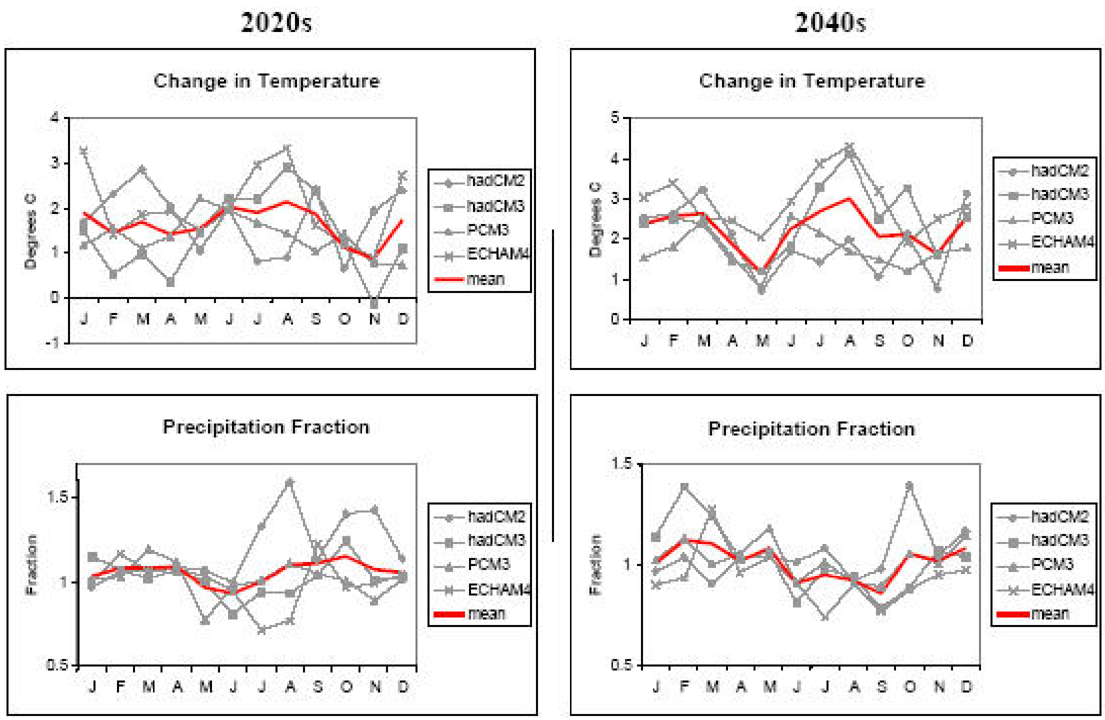
[3] http://gcrio.org/CONSEQUENCES/fall95/mod.html
[4] Wood, A.W., Leung, L. R., Sridhar, V., Lettenmaier, Dennis P., no date: "Hydrologic implications of dynamical and statistical approaches to downscaling climate model surface temperature and precipitation fields."
[5] http://tao.atmos.washington.edu/main.html
[6] http://tao.atmos.washington.edu/PNWimpacts/index.html
[7] http://www.met-office.gov.uk/research/hadleycentre/models/modeltypes.html
[8] http://www.mpimet.mpg.de/en/web/
[9] 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.

condition was not yet available, the analysis assumed that mean monthly temperature changes would apply to each water condition examined.



SOURCE: JISAO Climate Impacts Group

Figure N-10: Temperature and Precipitation Change Forecasts[10]

[10] 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.

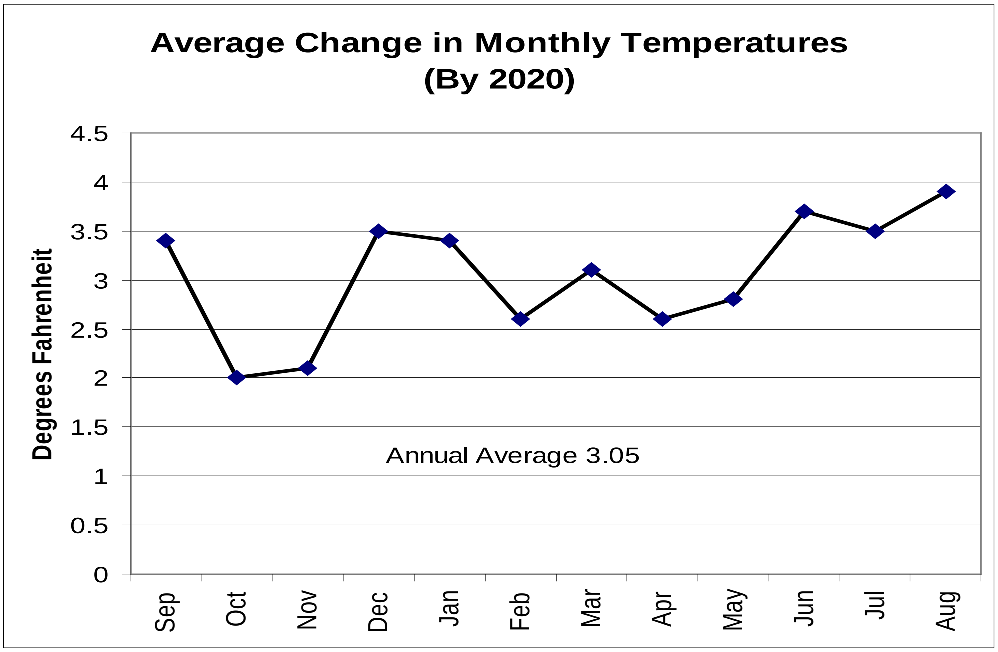


Figure N-11

Table N-1: Forecast Temperature Increases for 2020 and 2040 in 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 12a and 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 1930-1978 were used.

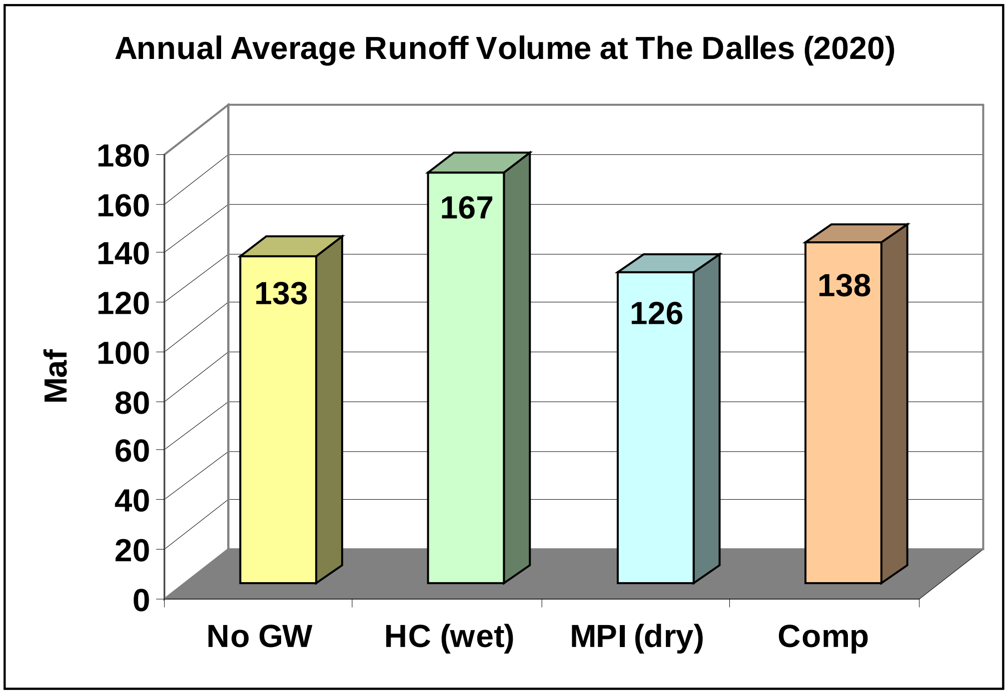


Figure N-12a

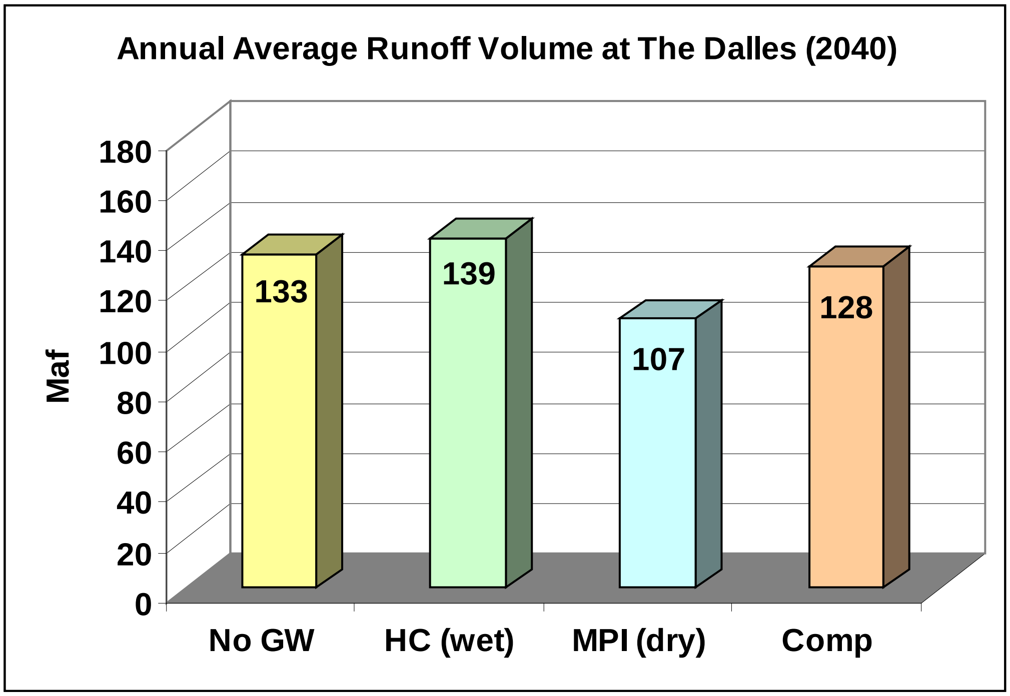


Figure N-12b

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[11] 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 1930-1978 water conditions (out of the 1929-1978 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)
- This analysis is a deterministic study, in the sense that each adjusted water condition was given an equal likelihood of occurring.

[11] Power planners in the Northwest generally define an operating year to be from September through August.

- 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 13a, 13b and 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.

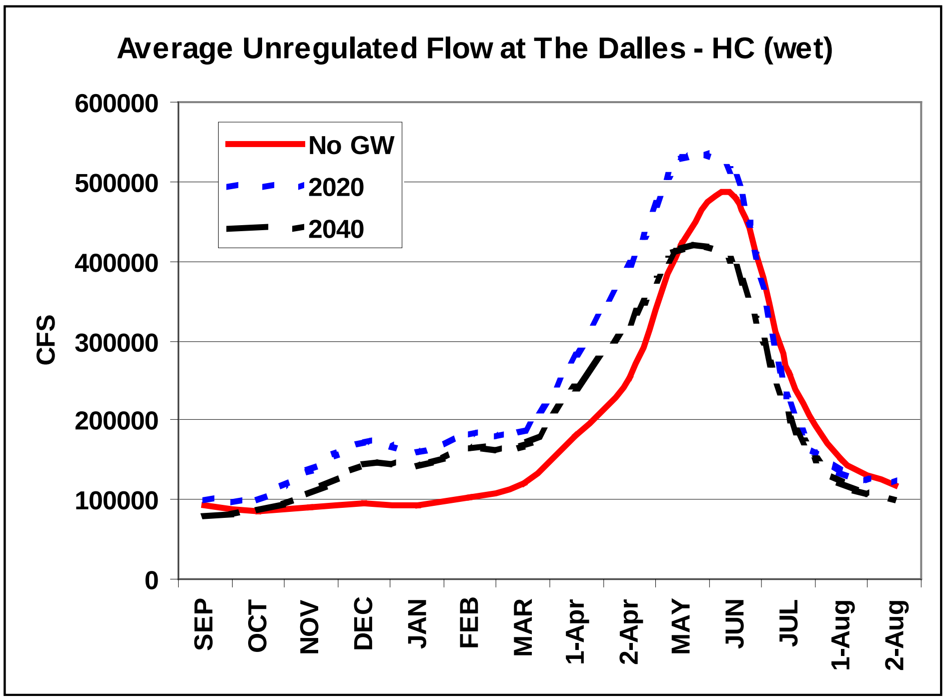


Figure N-13a

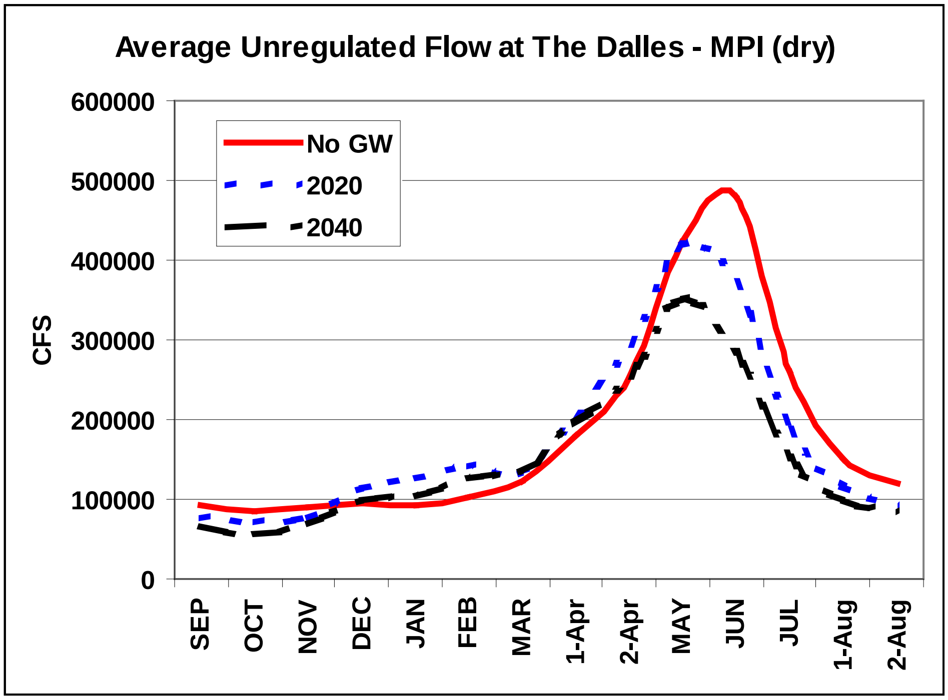


Figure N-13b

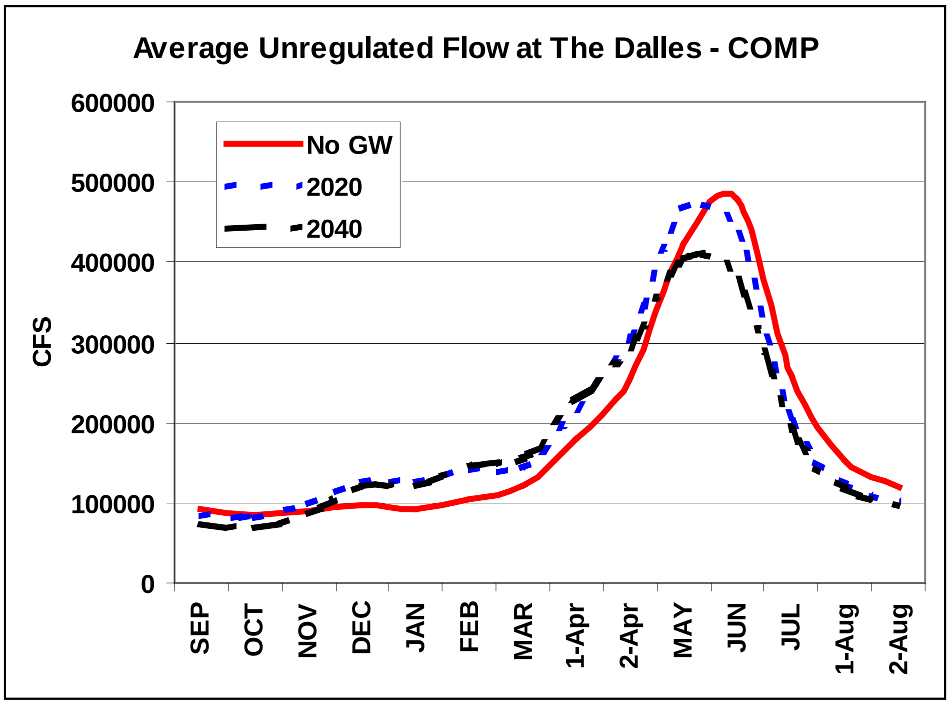


Figure N-13c

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 1,500-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. The Northwest Power Pool does not have anecdotal values for the relationship between temperature and demand for summer months. 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.

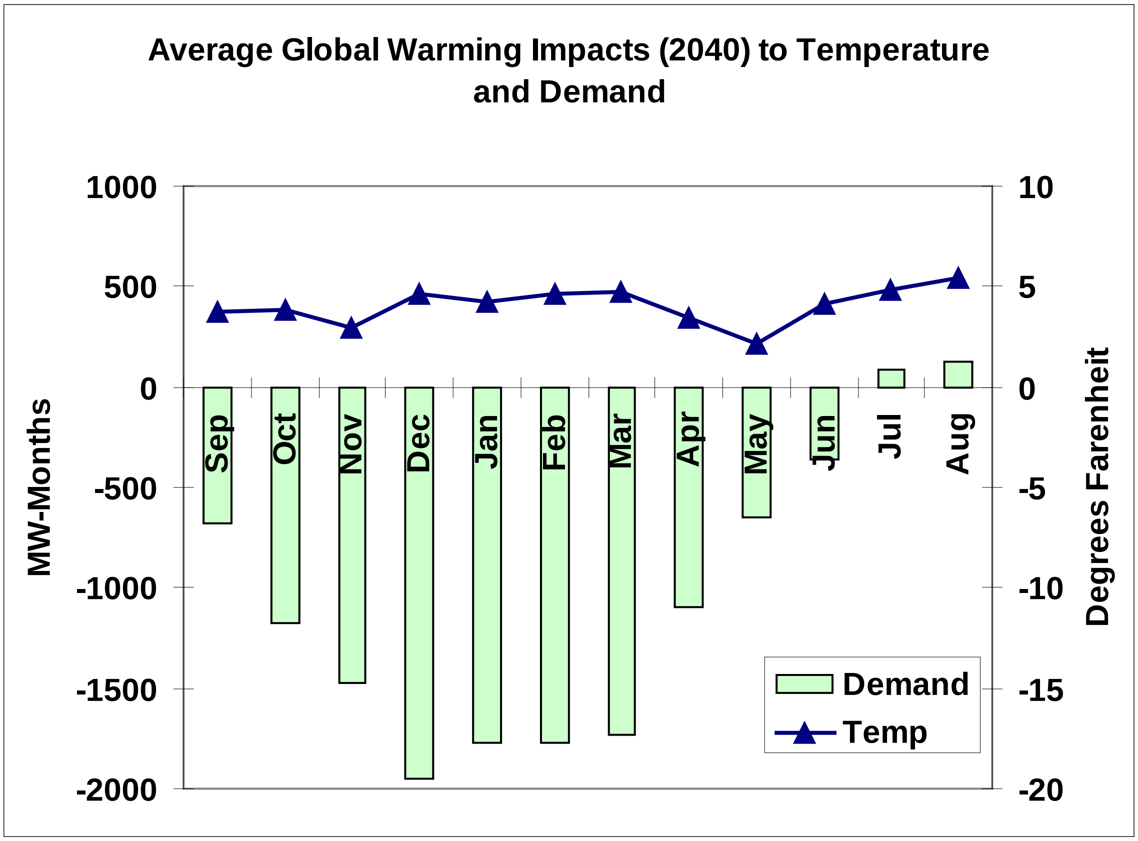


Figure N-14

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[12] 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

[12] See www.nwcouncil.org/GENESYS

adjustments to intertie capacities, whenever appropriate, as a function of line loading. Outages on the cross-Cascade and inter-regional transmission lines are not modeled.

The important stochastic variables are hydro conditions, temperatures (as they affect electricity loads) and forced outages on thermal generating units. The model typically runs hundreds of simulations for one or more calendar years. For each simulation it samples hydro conditions, temperatures and the outage state of thermal generating units according to their probability of occurrence in the historic record.

The model also adjusts the availability of northern California imports based on temperatures in that region. Non-hydro resources and contractual commitments for import or export are part of the GENESYS input database, as are forecasted prices and costs and escalation rates.

Key outputs from the model include reservoir elevations, regulated river flows and hydroelectric generation. The model also keeps track of reserve violations and curtailments to service. Physical impacts of climate change are presented as changes in elevations and *regulated* flows due to the adjusted *natural* flows discussed earlier. Economic impacts are calculated by multiplying the change in hydroelectric generation with the forecasted monthly average electricity price.

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.[13] 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 N-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.

[13] 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 16 and 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.

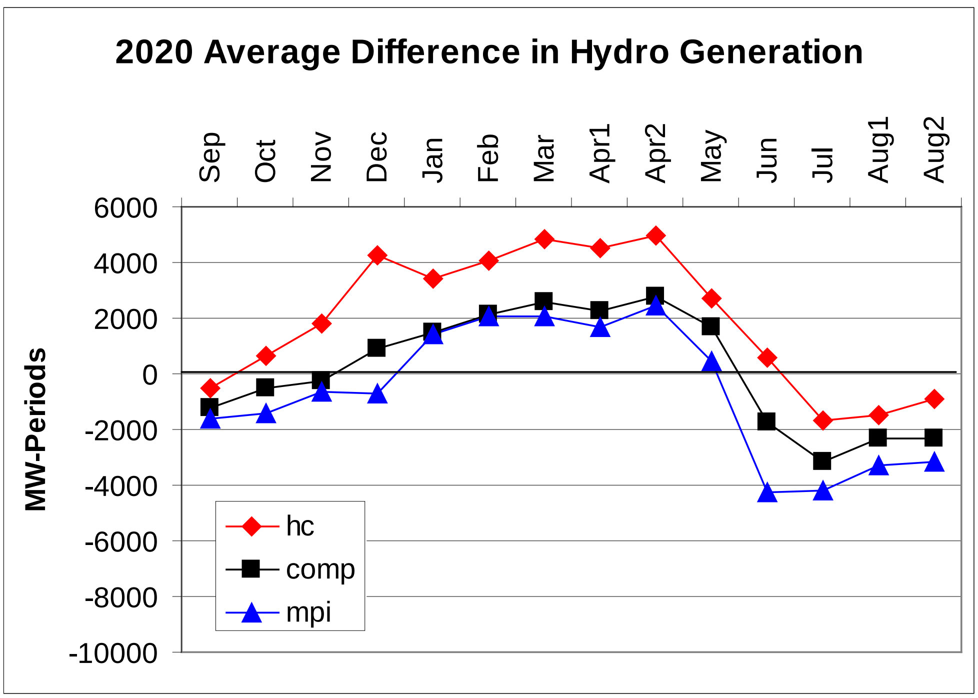


Figure N-15

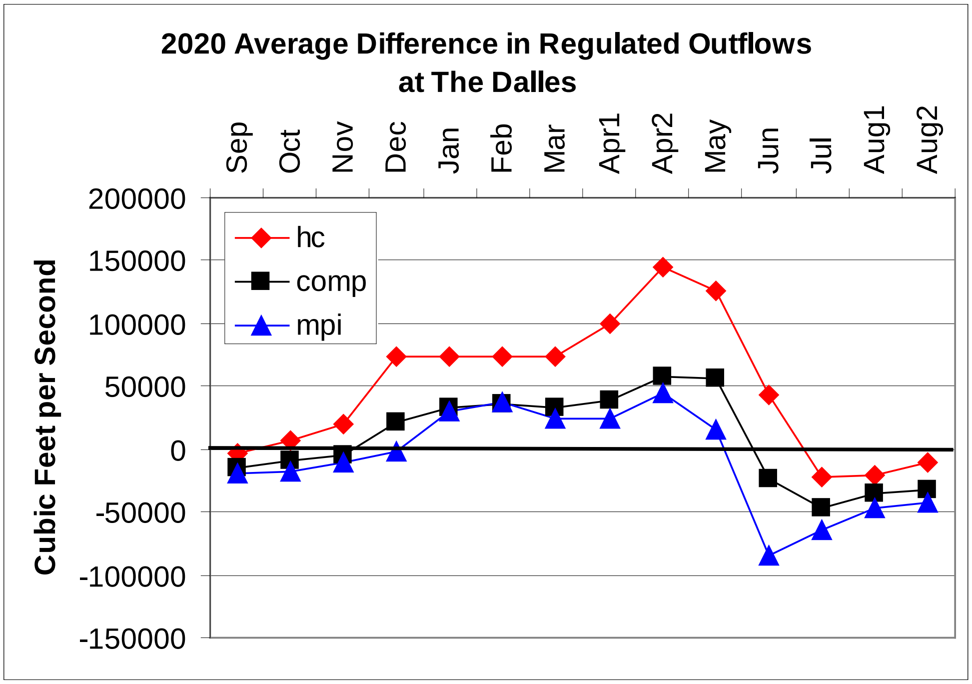


Figure N-16

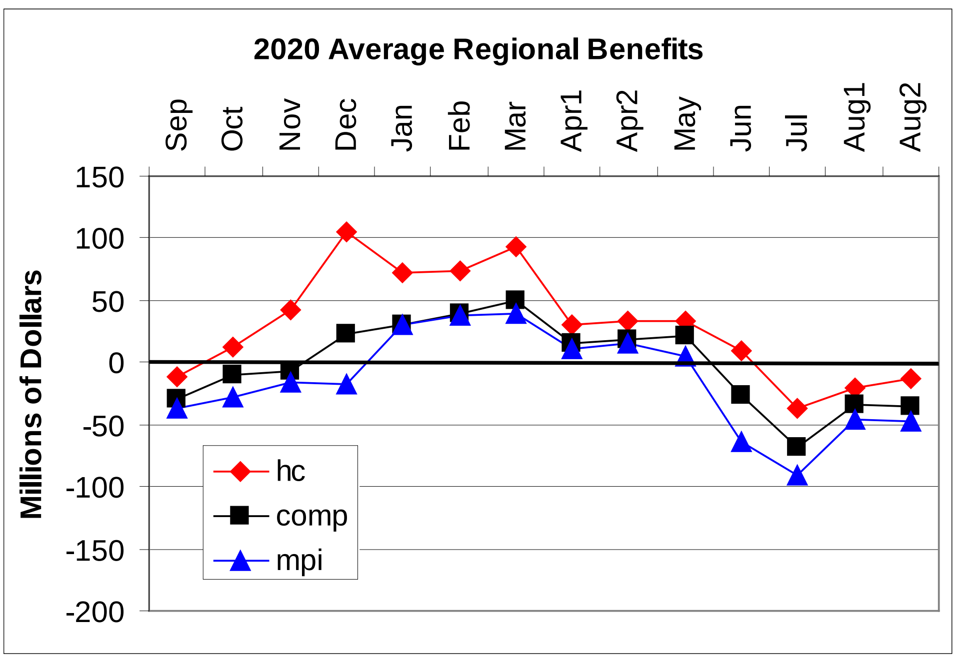


Figure N-17

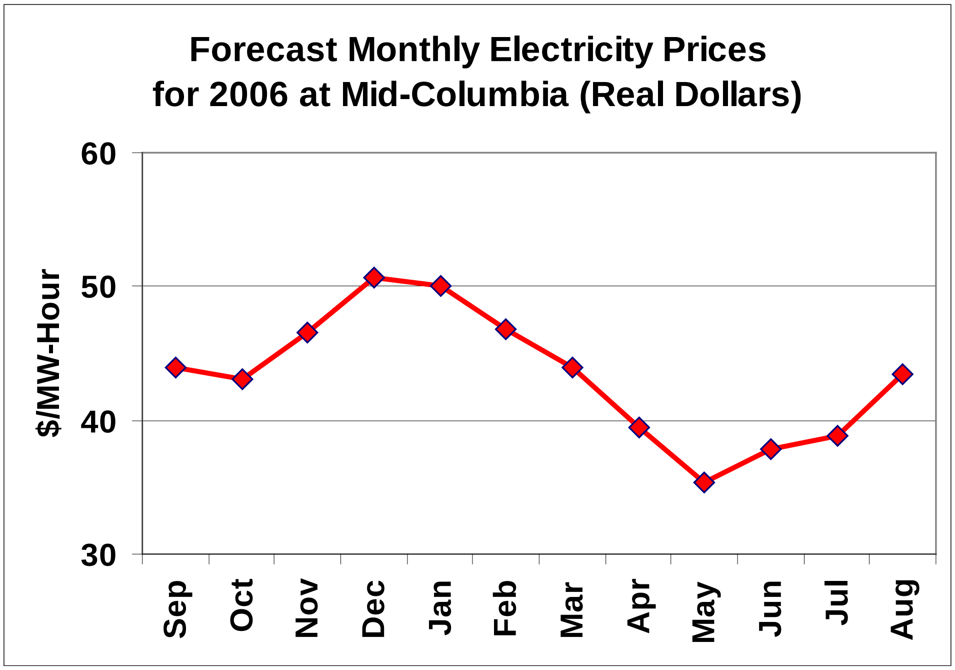


Figure N-18

Figures 19 and 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.

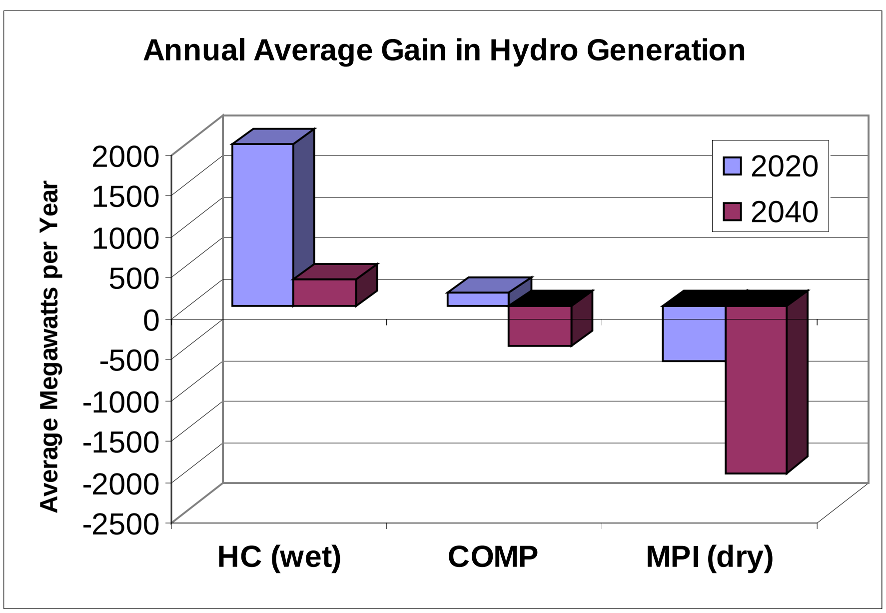


Figure N-19

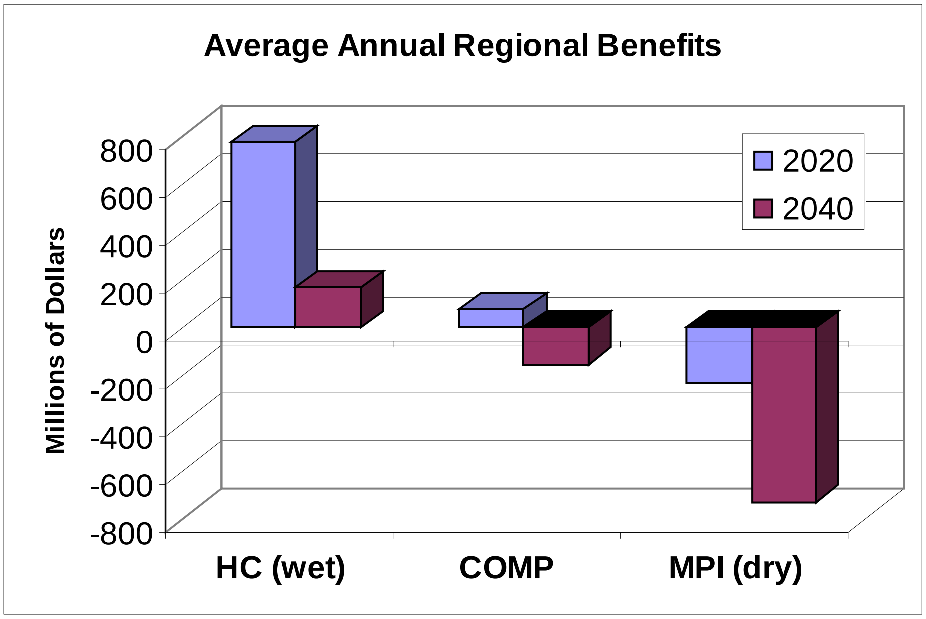


Figure N-20

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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Appendix O. 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 decisions to allocate portions of this resource as equitably as possible. In particular, measures developed to aid fish and wildlife survival have diminished the generating capability of the hydroelectric system. And, 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 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 that also provides adequate implementation of fish and wildlife measures.

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 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.

In the current effort to produce the fifth power plan, the Council assumes that measures in the program will be implemented. Strategies for new resource and conservation development incorporate the relationship between non-hydro resources and the operation of the hydroelectric system, which include measures for fish and wildlife. However, it is not possible in the context of this power plan to compare, on an equivalent basis, power system costs and benefits of specific fish operations (or deviations from those operations) with the corresponding biological costs and benefits.

RECOMMENDATIONS

This issue must be resolved so that fish and wildlife survival is not inordinately threatened and so that the region can maintain a reliable and economic power system. Reliability and cost are directly related. In the Northwest, electric utility planners have relied on the inherently large capacity of the hydroelectric system to keep costs low while maintaining a high level of reliability. However, due to operating constraints placed on the hydroelectric system, demand growth and reluctance during the 1990s for entities in the region to build power resources, the adequacy and reliability of the power system had come under question by the year 2000.

As a practical matter, 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.

[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.

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.

ACTION ITEMS

The following action items are aimed at improving the interaction between power planning efforts and fish and wildlife program development.

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.

PRACTICAL "INTEGRATION" OF PLANNING EFFORTS

Given the current level of uncertainty of biological information and considering the irresolvable task of assigning a dollar value to preserving salmon runs, a total integration of power and fish-and-wildlife planning is impossible. However, that does not mean that these processes must be done independently of each other. 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.

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.

Physical data (reservoir elevations and river flows) is an important input to both passage survival and biological life-cycle models. But economic data is also very important to biologists for at least three reasons:

- To guide decisions on how to spend limited biological research money
- To prepare a fish-and-wildlife operation curtailment plan in the event of a power emergency
- Whenever possible, to choose the least costly measures to achieve the same biological objectives

There will always be a need to refine our understanding of the relationships between survival and changes in the physical environment. Unfortunately, there is never sufficient research money to perform all desired experiments and tests. By knowing how much individual measures in a fish and wildlife program cost, biologists will have a better idea of how to spend limited research money. Measures that are most costly and have large uncertainties surrounding their biological benefits would make the best candidates for research money.

In addition to aiding biologists to spend research money more effectively, economic data can be used to reduce the total cost of a fish and wildlife program. In cases where two different measures provide the same biological result, it makes sense to implement the least costly operation. Practically speaking such decisions are rarely simple to make because of the uncertainty surrounding biological benefits. However, just as power planners are obliged to provide an adequate power supply at the lowest cost, it seems appropriate that biologists should at least attempt to develop the least cost program, that achieves their biological objectives.

Economic impacts of fish and wildlife measures also help biologists in other ways. The biological opinion contains specific language that allows for curtailment of fish and wildlife operations in the event of a power emergency. Such an event occurred in 2001 that was severe enough to result in most bypass spill being curtailed (more on that subject in the following section). Had that event not been so severe, necessitating the need to curtail only some operations, the region would have had to scramble to determine which measures to curtail. To avoid such a situation in the future, an emergency curtailment policy should be established ahead of time. Having cost and biological impacts for individual measures allows biologists to prepare such a policy and have it in place prior to a power emergency.

Components of a Fish and Wildlife Operation

The mainstem portion of the fish and wildlife program consists of two major 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.

We can use these simulated refill probabilities as a baseline for assessing whether the reservoir system is “doing the best it can” to provide the appropriate volume of water for flow augmentation. (We should note that the above refill probabilities were calculated assuming that adequate non-hydro resources are available.) When analyses are done using the existing non-hydro resources in a probabilistic manner (i.e. simulating forced outages), quite often reservoirs must be drafted below the 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, 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.

[5] Reference the Council’s Fish and Wildlife program and NOAA Fisheries 2000 Biological Opinion here.
[6] Reference the Council’s paper on the transmission impacts of drawing down John Day Dam.

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, tentatively naming it the "Loss Of Fish-operations Probability" or LOFP 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). The hope is that this idea will be discussed in more detail in the long-term planning committee that the Council is recommending to be established.

Contingency Operations

An important factor to consider when discussing reliability is the difference between the planning process and the actual operation of the power system. Using a 5 percent limit for the LOLP during the planning process should assure the region a reliable power system. However, there still obviously remains a non-zero likelihood of curtailment. Furthermore, the planning process and tools used in that process are not perfect. It could happen that during the operation of the power system, unaccounted for events would cause the system to be more unreliable than planned for. To accommodate these possibilities, a set of contingency actions is normally developed to address such occurrences.[7] During emergency events, these contingency actions are implemented. Such actions might include purchasing from out of region utilities, leasing expensive running but portable generators, etc. with final actions including a priority list of who to curtail if all else fails.

The same situation exists for fish and wildlife measures. An adequate power system can be planned but the region may still face situations when fish and wildlife operations will have to be curtailed. To be better prepared for such emergencies, a set of contingency actions, which identifies the order to curtail fish and wildlife measures, must be developed and put in place ahead of such events. The following section on the cost of fish and wildlife measures may help prioritize those actions that may have to be taken.

[7] All load serving entities in the region have developed an emergency curtailment protocol.

COST OF INDIVIDUAL FISH AND WILDLIFE MEASURES

The analysis presented here is an attempt to identify the most costly measures in the fish and wildlife program. This effort is not designed to be a cost-effectiveness analysis. The Council, in its fish and wildlife program, specifies that bypass spill should be revisited in terms of assessing its biological benefits. During that process, the Council examined benefits to fish and wildlife from alternative main stem operations (the timing, quantities and locations of flow and spill) relative to the effects on the power system. Over the next few years, more information should be available to help solidify the measures to be implemented for fish and wildlife.

It may be possible, through careful consideration of the relative priorities of different operations for fish and power, to better manage the operational interaction to minimize the adverse effects for fish while achieving increases in power production and storage during power emergencies. Otherwise continued financial incentives to maximize power operations will overcome the incentives to operate for fish, particularly under financial or power emergencies. To negate the financial incentive to curtail fish operations, a dollar penalty could be prescribed for such deviations. The money raised, if and when fish measures are curtailed, would be used to fund other fish and wildlife recovery activities.

The Council proposes to investigate both operational strategies and potential incentives to minimize impact on fish from deviations from prescribed fish operations and the options available to mitigate these impacts.

Methodology

This analysis begins with a simulation of current river operations (BiOp). The simulation is performed with the GENESYS model.[8] 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.[9] 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.

[8] See http://www.nwcouncil.org/genesys.
[9] Electricity prices are forecast using the Aurora model, created and leased by EPIS.

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 O-1) 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. The average annual net cost or benefit of a particular scenario can be calculated for the region. Figure O-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 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.

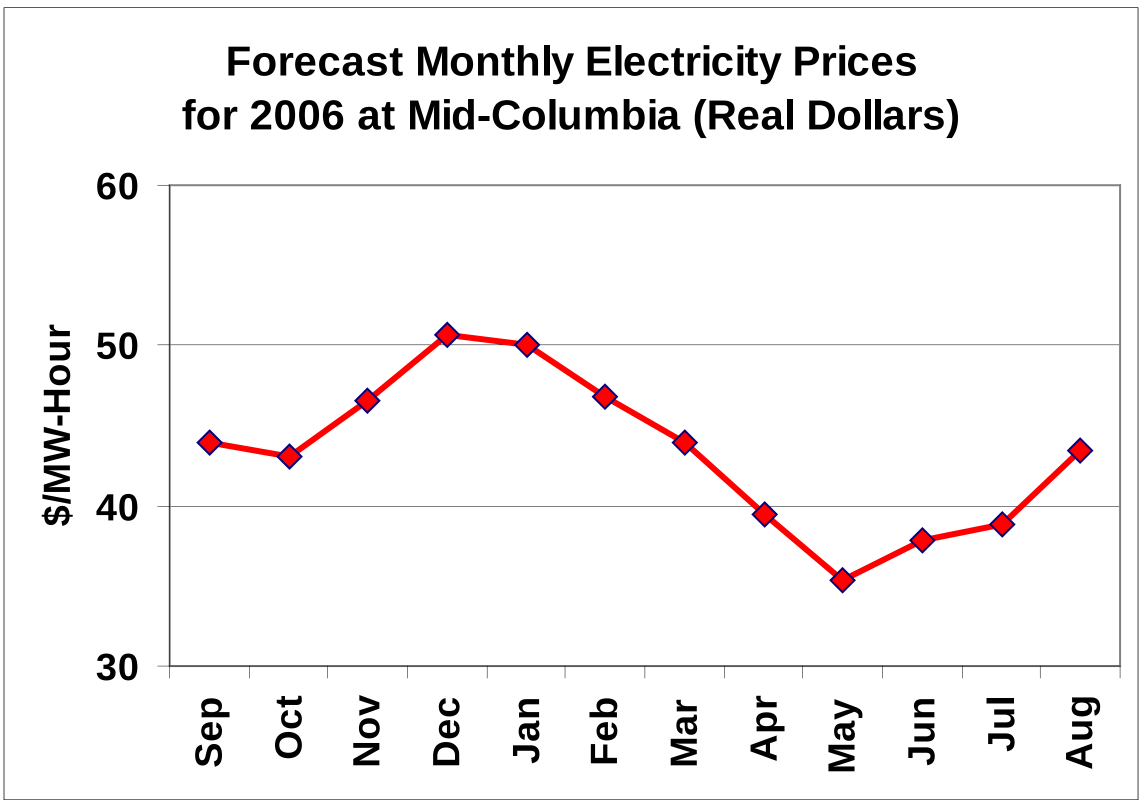

Figure O-1

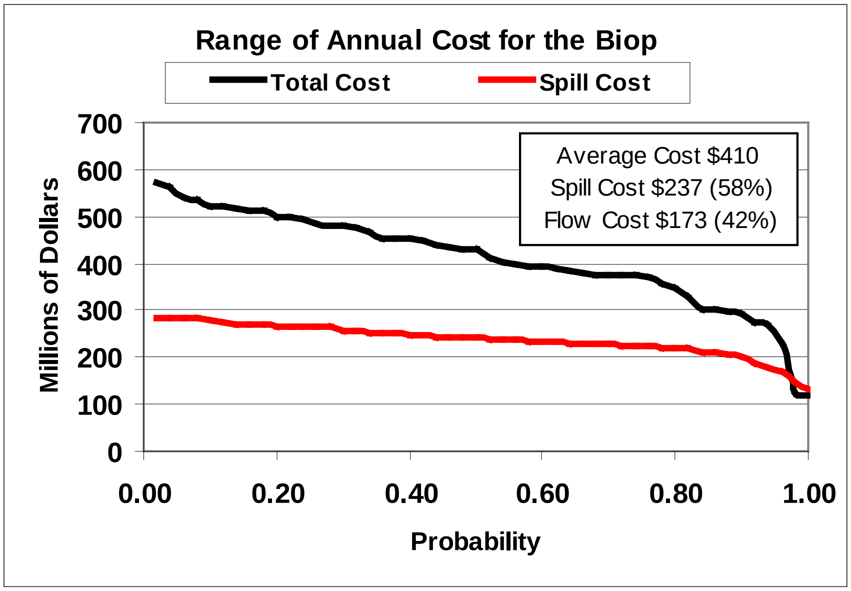

Figure O-2: Average Annual Cost of Fish and Wildlife Operations

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 per megawatt-hour into spring months when the price can be as low as $35 per megawatt-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 O-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 O-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 O-3.

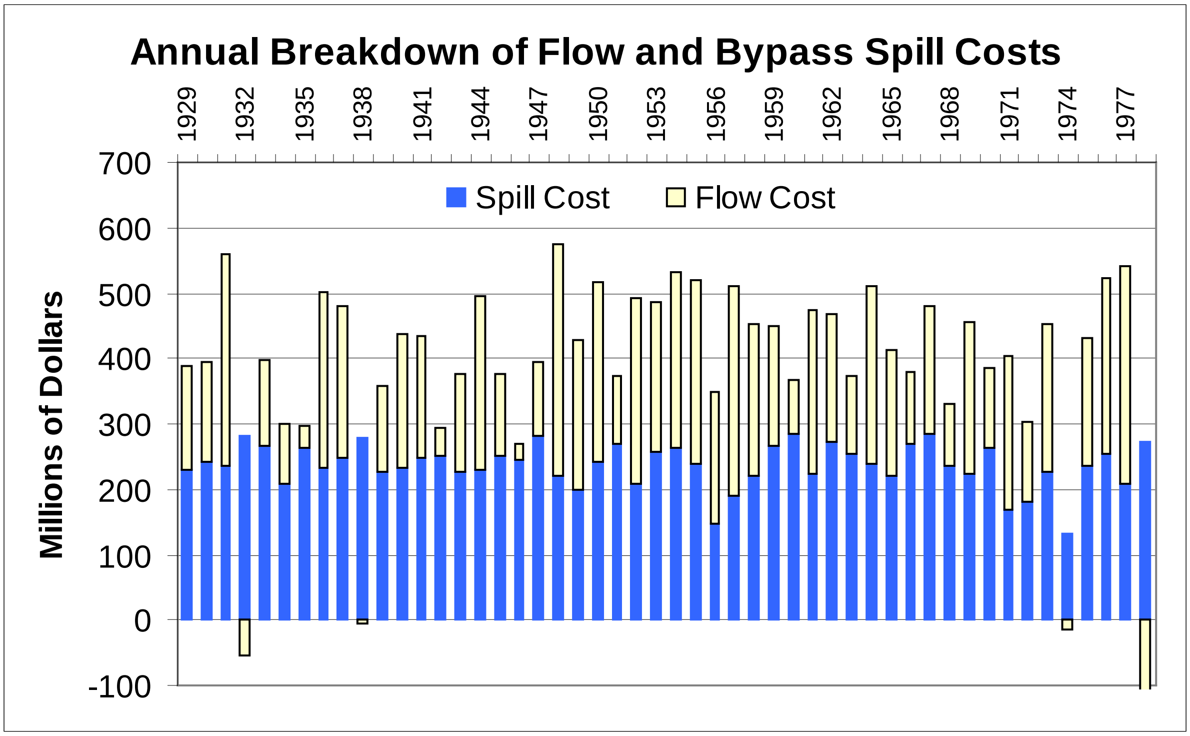

Figure O-3: Annual Breakdown of Flow and Bypass Spill Costs

It is of interest to understand how fish and wildlife operation costs vary with water conditions. Figure O-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 O-5 illustrates only the spill costs as a function of runoff volume. At first bypass spill costs increase slightly as runoff increases, then they seem to level off before decreasing. 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 O-6.

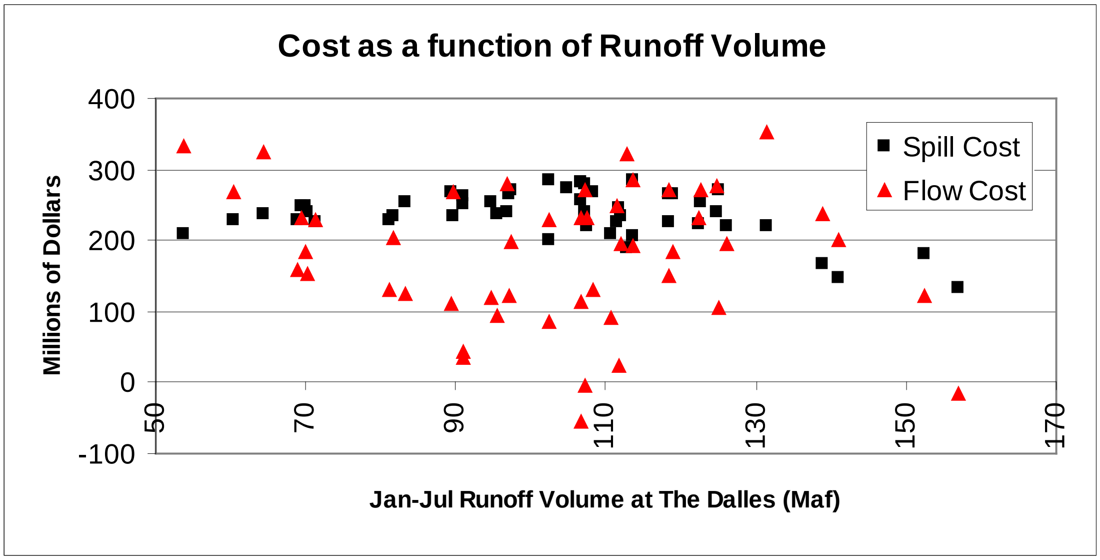

Figure O-4: Cost as a function of January-July Runoff Volume at The Dalles

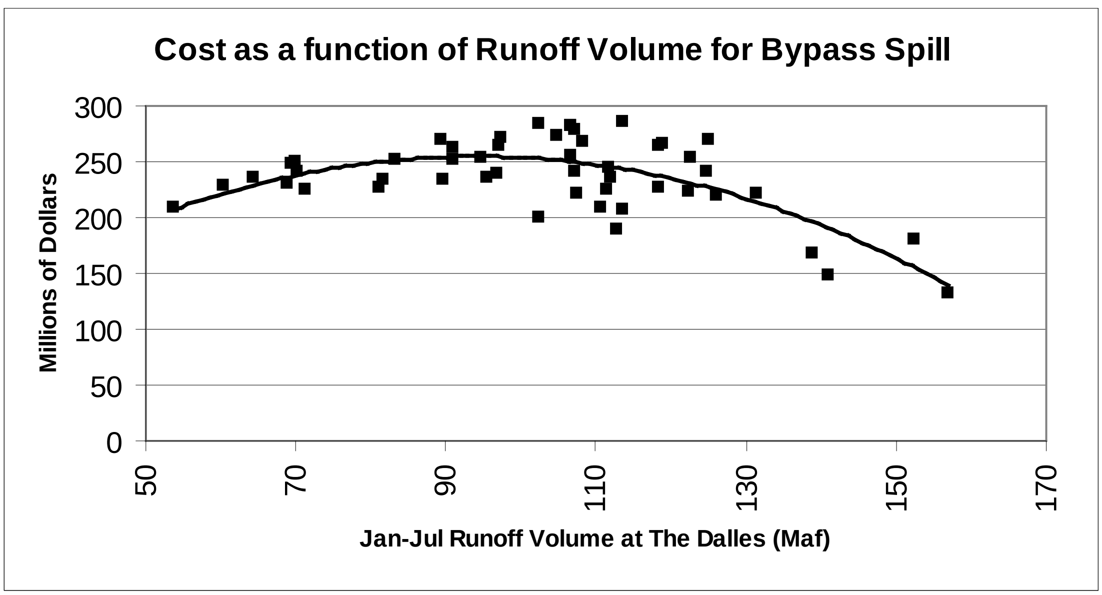

Figure O-5: Bypass Spill Cost as a function of Runoff Volume

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]

[10] See Council document number 98-3.

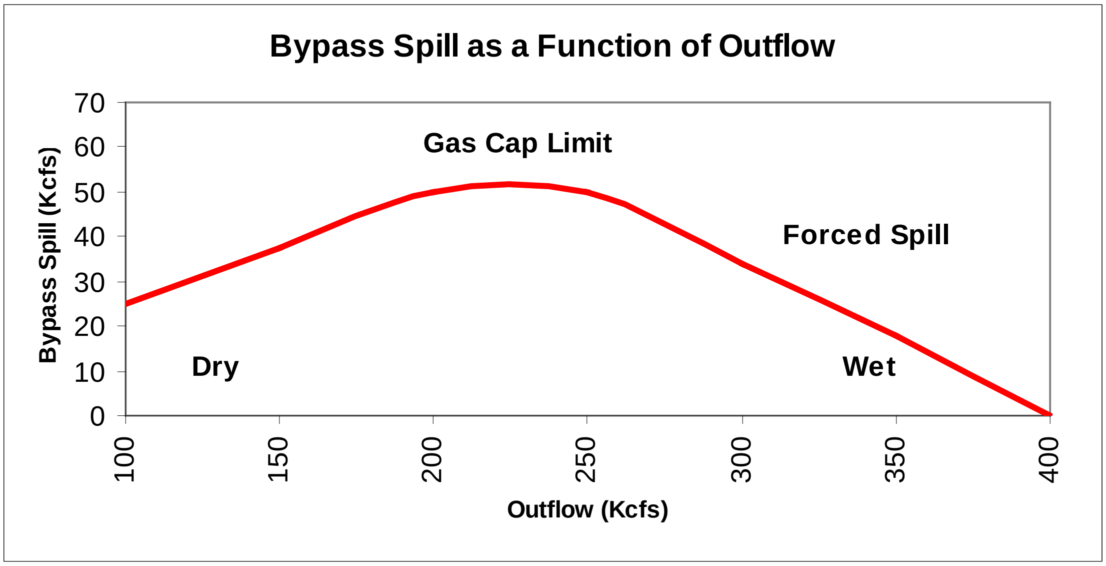

Figure O-6

Because of the Council's commitment to re-examine bypass spill, the remaining analysis focuses on that operation. Table O-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 O-7 shows the average cost for bypass spill at each of the eight lower river dams. Figure O-8 breaks those costs down into spring and summer periods, just like the data in Table O-1. Using this information helps direct money and research efforts to the right projects.

Table O-1: Annual Average Cost and Energy Loss of Bypass Spill

(Sorted by Cost)

Fish and Wildlife Component	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 (average megawatts)	**237**	**693**

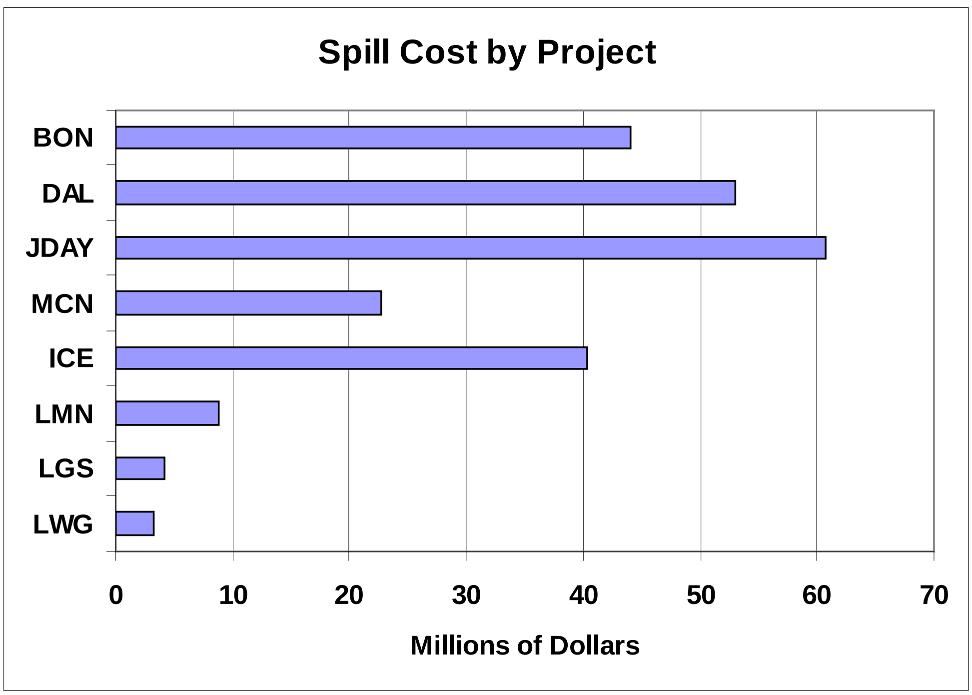

Figure O-7

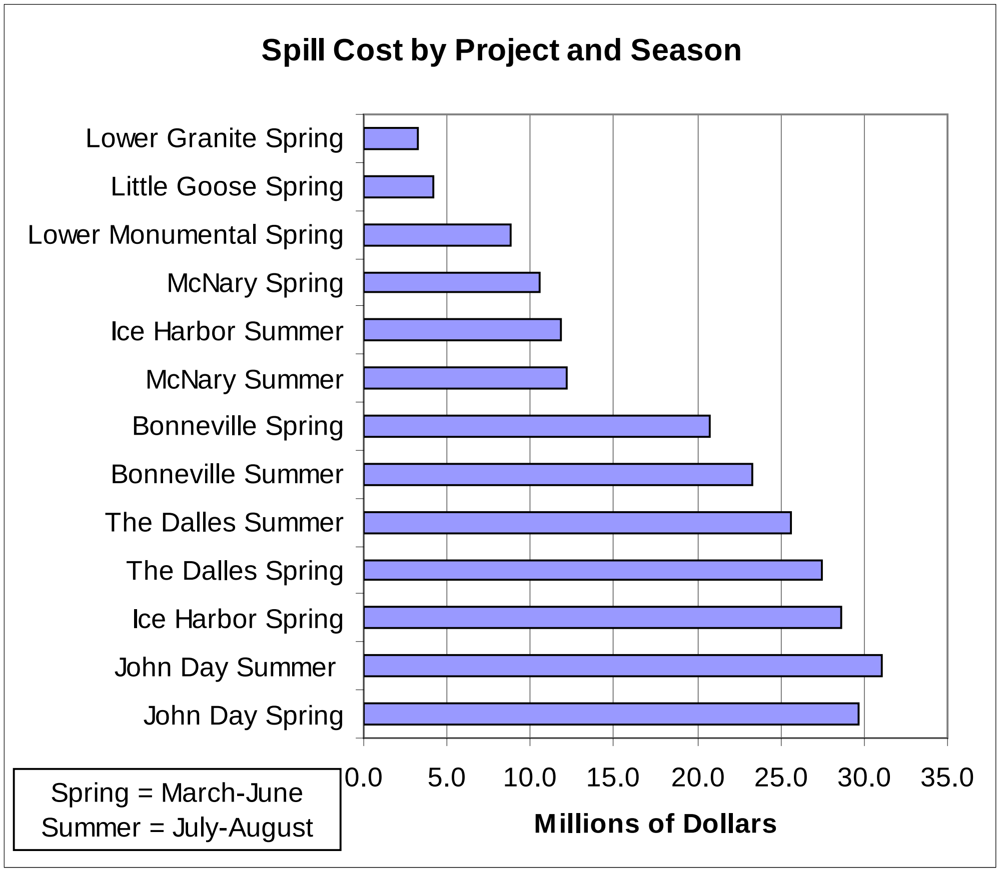

Figure O-8

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Appendix P. Risk and Uncertainty

INTRODUCTION

There are two distinctive differences between uncertainties and portfolio elements. First, uncertainties differ conceptually, because they define a future. A future is that which we cannot control. Portfolio elements, like generation resource, belong to the category of things we can control. Second, the workbook calculates the values of futures differently. While futures obviously affect resources, resources do not affect futures -- except for some notable exceptions like the future of electricity price. Because of this, the workbook computes the values for uncertainties and futures only one time, at the beginning of the game. On the other hand, the workbook must recalculate the values for portfolio elements iteratively within a period and progressively across periods.

Of course, nothing is quite that clear cut. There is, in fact, a well-defined twilight zone within the worksheet, where futures and portfolio elements interact. The example of electricity price is an important inhabitant of that region. Long-term load elasticity is another. Properly speaking, any variable that depend on these, such as a decision criterion, are also citizens of the twilight zone. For the purposes of discussion in this appendix, the section "[missing bookmark" will address those. There the reader will find a description of the necessarily careful treatment of these denizens.

The reader may want to refer to the following Table of Contents for orientation to the remaining appendix.

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Risk Measures

This will include a more thorough description of the alternative risk measures, including rate impact, etc.

Start out with standard deviation from last writeup, chap 6

Background

Coherent Measures of Risk

TailVaR$_{90}$

CVaR$_{20000}$

Standard Deviation

VaR$_{90}$

90th Quintile

Loss of Load Probability (LOLP)

Resource - Load Balance

Incremental Cost Variation

Average Power Cost Variation (Rate Impact)

Maximum Incremental Cost Increase

Exposure to Wholesale Market Prices

Imports and Exports

Uncertainties

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 the workbook containing 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-376-P2.zip). References to the workbook appear in curly brackets ("{}"). Understanding the description does not require reference to the workbook, however. References to data sources appear in square brackets ("[]"). The References section at the end of the appendix lists the sources.

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.

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?[1]

Figure P-1 illustrates the overall logic structure for the modeling process. The optimization application, Decisioneering's 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.

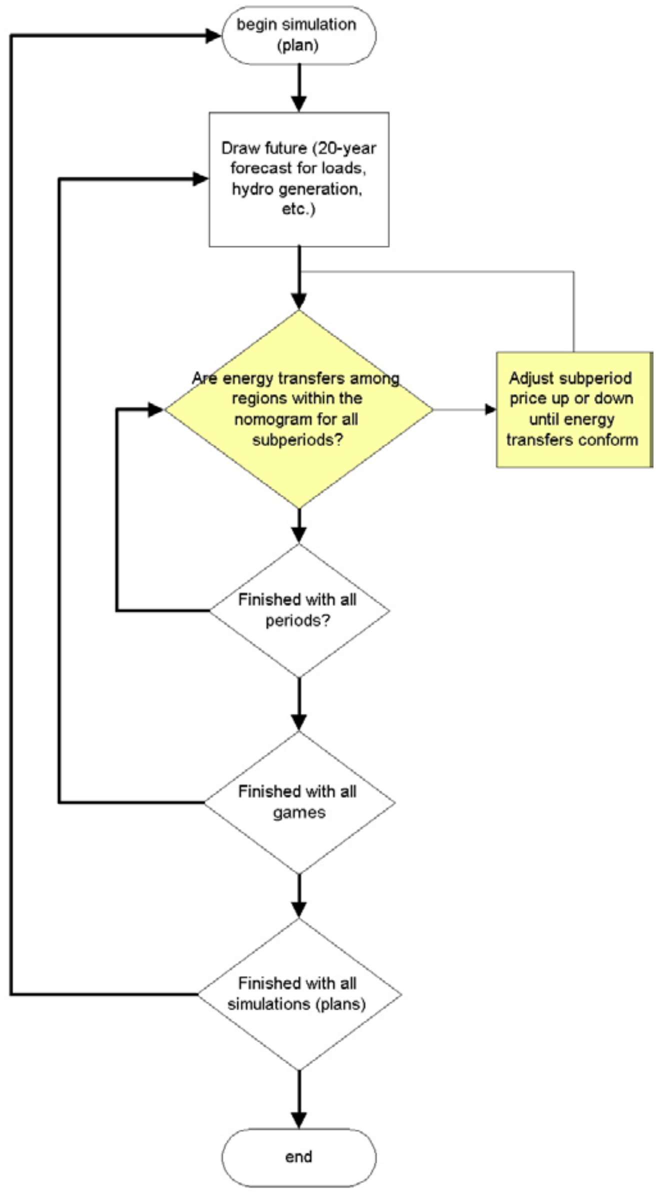

Figure P-1: Portfolio Model Logic Flow

[missing bookmark] gives a more specific description of the process that takes place in the outer loop. (The inner loops take place within the box, "Determine the distribution of costs for plan.") 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 the same 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 in reference.

OptQuest, in turn, controls Decisioneering's 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 {R3:CE9}. Crystal Ball then performs the function of the second-outer-most loop in Figure P-1. It exposes the selected plan to 750 futures and returns the cost and risk measures associated with each future to OptQuest.

[1] Chapter 6 describes the concept and application of the feasibility space.

For each future, Crystal Ball assigns random values[2] 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 [missing bookmark]. 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 (see

The portfolio model performs roughly the duties of the innermost loop in Figure P-1. 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 address the occupants of the twilight zone mentioned earlier. Before the model adjusts prices for the current period, it recalculates a portion of the worksheet that controls the long-term interaction of futures, prices, and resources. This portion of the worksheet contains formulas for price elasticity of load and decision criteria. As explained in the section "[missing bookmark]", these adjustments are made once for the period. A single recalculation is sufficient because the formulas use results only from prior periods, never the current period. The formula values are then used by the current period to establish behavior before finding the current period's price.

Figure P-2 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 only once per period by TLZ {rows 202-316}. 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}.

[2] 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.

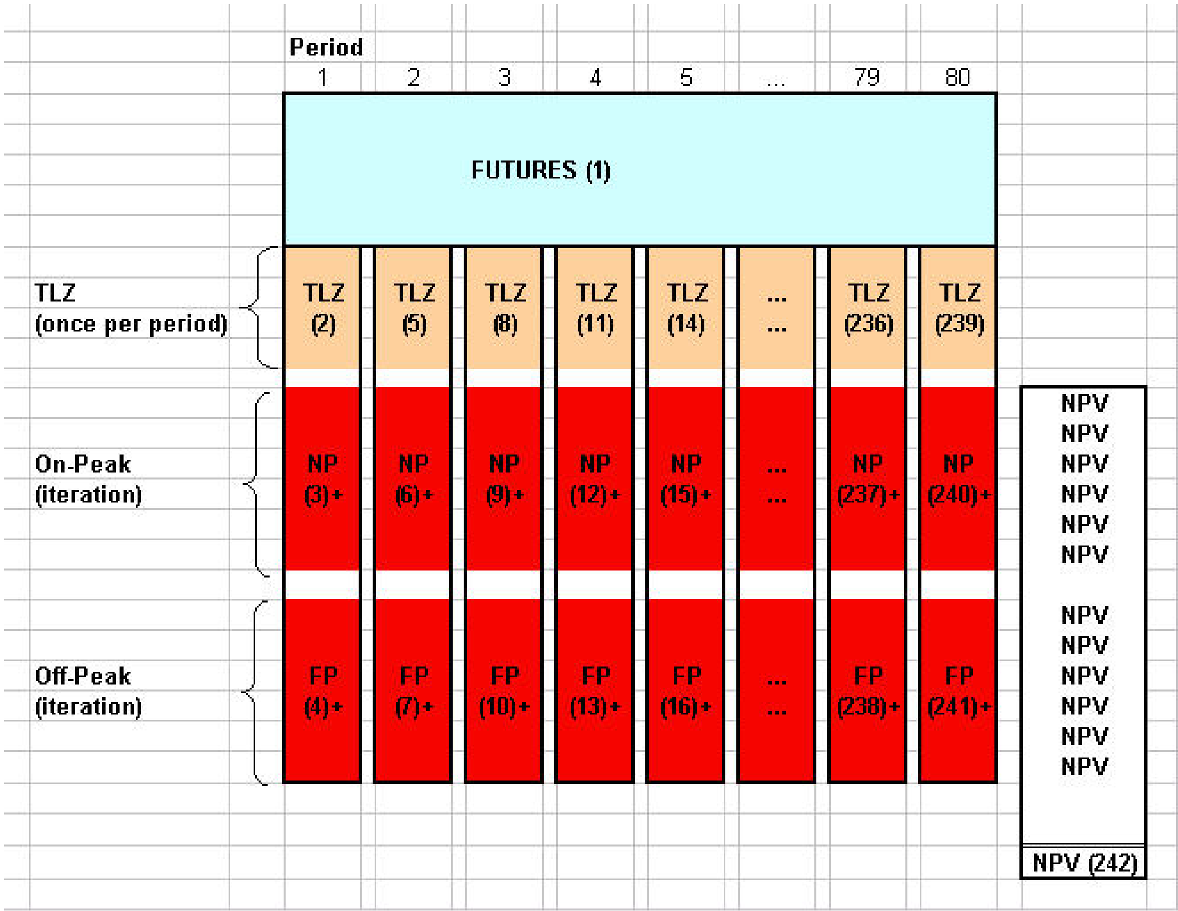

Figure P-2: Portfolio Model Calculation Order

Lognormal Distributions

Lay out the motivation for using Lognormal distributions for price and loads…..

Load

There are several components to load representation. There is an underlying trend, possible jumps associated with economic cycles, and a seasonal variance. There is also a long-term sensitivity of loads to electricity price. Of these, only the seasonal variance is period specific.

The total energy requirement (megawatts average) {row 125} is the product of a baseline load forecast and the inverse transformation of a lognormal process. Using a lognormal process guarantees that resulting energies are always positive. The baseline load forecast {row 113} corresponds to the Council's weather-adjusted, non-DSI load forecast [**1**] and reflects the following assumptions.

- nine percent losses for distribution and transmission
- existing conservation through hydro-year 2003

- frozen efficiency for hydro year 2004 and beyond [3]
- monthly distribution of annual energies, and the aggregation of those monthly energies into quarterly energies

In the total energy requirement calculation {row 125}, the baseline load forecast is adjusted by terms for the underlying path of loads {row 120}, any jumps {row 123}, and seasonal variation of loads {row 124}. The term for seasonal variation of loads is a normal distribution with mean zero and standard deviation of 0.05 [**2**]. The seasonal variation pertains to winter and summer quarters and captures normal weather variation. Discussion of price elasticity of load, the underlying path, and jumps appears in the section "[missing bookmark]" below.

After the model calculates total period energy, it determines on- and off-peak energy. These are simple fractions of the total energy.

Costing for loads: xxx

Price elasticity of demand
Opposite sign as short-term correlation

Gas Price

Hydro

yellow

Electricity Price

Correlations or 1 mean and 2 hourly values

Aluminum Price

CO2 tax

[3] The frozen efficiency load forecasts assume no new conservation of any kind. This includes conservation that would be cost effective or is likely under new codes and standards. Instead, conservation supply curves represent those measures. Of course, the frozen efficiency load forecast does incorporate any prior conservation and the effect of existing codes and standards.

Forced outage rates

Production Tax Credits

Green Tag Value

Single draw of the hydro year determines flows in all periods belonging to that hydro year.

Hydro that depends on price described *** below *** in supply curves

Sensitivity Studies

Gas Price

CO_2 Policy

No CO2 Tax

High CO2 Tax

CO2 Tax of Varying Levels of Probability

PacifiCorp IRP CO2 Tax

IPP Value

Conservation

Constrained Conservation

Conservation SOD

Value of DR

Wind

The Value of Wind

Non-Decreasing Wind Cost

ICG

Alberta Oil Sands Project

Alternative Decision Criteria (See Appendix M)

References

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1 Regional NonDSI Loads_correction_040623.xls
2 Terry Morlan, Council Staff