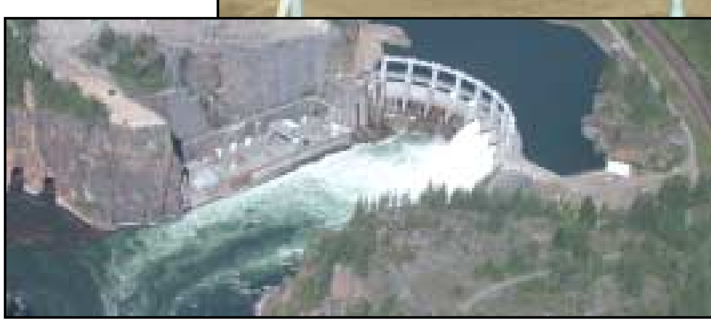
AVISTA Corp.



2003 Integrated Resource Plan

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Section

1

Introduction & Summary

Overview

The Company submits an Integrated Resource Plan (IRP) to its public utility commissions in Idaho and Washington. The electric 2003 IRP is the seventh such submittal since 1989. In Washington, IRP requirements are outlined in WAC 480-100-251 entitled "Least Cost Planning." In Idaho, the IRP requirements are outlined in Case No. U-1500-165 Order No. 22299, Case No. GNR-E-93-1 Order No. 24729, and Case No. GNR-E-93-3 Order No. 25260. The plan describes the mix of generating resources and improvements in efficiency that is expected to meet future needs at the lowest cost to the Company and its customers.

The Company has a statutory obligation to meet the electricity needs of its customers. To do so reliably and at reasonable cost, the Company develops resource acquisition strategies and business plans to acquire resources when supplies are insufficient. The Company will continue to invest in conservation and cost-effective upgrades to existing generating facilities.

The Company views this IRP as a resource evaluation process, rather than a specific resource acquisition plan. Primarily this is because significant resource deficiencies are many years ahead of today. The 2005 IRP will likely include more specific plans for addressing future needs. The 2003 IRP is focused on developing a set of tools and methods within which various potential resource decisions may be evaluated in future IRPs, requests for proposals, and other resource planning analyses.

The Company believes it is prepared, even under low water conditions, to sufficiently meet retail loads through at least 2007. The Company will continue to work with state commissions and other interested parties to ensure that our resource planning decisions are cost effective, reasonable, and responsive to an evolving industry.

Public Process

The Company strives to reach balanced business decisions by working with customers, Commission Staff, and other key constituencies. An effective public involvement process affords the opportunity to receive input from stakeholders, and exchange information and perspectives regarding the IRP. The Company expects that public participation will continue to play an important role in resource planning.

Specific to the IRP, the Company sponsored four Technical Advisory Committee (TAC) meetings beginning in May 2002. Each of the meetings was designed to discuss the process, provide preliminary results, and to obtain feedback on the IRP. Information shared at the TAC meetings may be found in *Appendix G*.

IRP Outline

In addition to this Introduction, the 2003 IRP contains the following sections:

- ***Section 2*** details current loads and resources, and provides tabulations of future energy and capacity balances.
- ***Section 3*** discusses the Company's current and future efforts in demand-side management.
- ***Section 4*** discusses those resources the Company is considering to meet future load requirements.
- ***Section 5*** details the modeling process used for the IRP, including the AURORA market price-forecasting model, the Monte Carlo models used for stochastic analyses, and the Linear Programming Module used to optimize the selection of hypothetical resource acquisitions.
- ***Section 6*** discusses the consideration of risk within the IRP, and identifies risk factors specific to each new resource alternative.
- ***Section 7*** explains the results of the IRP analyses. It provides the *Preferred Resource Strategy* and compares other strategies that the Company might pursue. Scenarios are also presented to quantify the potential impacts of specific future marketplaces.
- ***Section 8*** provides the 2003 Action Plan resulting from the IRP, as well as avoided costs for the Company.

The 2003 IRP also includes numerous appendices to support the sections listed above and provide additional details for the document's key elements. The IRP document and Technical Appendices are available for download at the Company's web site – www.avistautilities.com.

Summary

At this time, the Company has no immediate need for additional long-term resources. In fact, the Company does not anticipate a significant deficit in energy, on an annual average basis, until 2008. Furthermore, the Company does not anticipate a deficit in capacity until 2010.

For this IRP the Company undertook a significant effort in computer modeling. This effort was initiated with the acquisition of AURORA, an hourly production-cost model that dispatches resources and develops a set of forward market prices based on numerous conditions. This effort was substantiated through the development of numerous spreadsheet-based models, and the incorporation of a Linear Programming (LP) Module.

For the first ten years of the IRP timeframe (2004-2013), the IRP modeling process selected a combination of combined and simple cycle combustion turbines, wind, and coal resources. During the second ten year period of the IRP planning horizon (2014-2023), the modeling process pointed towards acquisition of coal generation due to improvements in technology and its fuel costs relative to other resources. Given no need for immediate resources, the Company will continue to evaluate available options for future generating requirements.

Section
2

Loads & Resources

Overview

An essential element in integrated resource planning is the long-term forecast of future loads and resources. The difference between the two illustrates resource needs that the Company must address through its action plan. This section details Company resources and load obligations through the twenty-year timeframe of the IRP, as well as the Company's utilization of planning reserves.

Resources and Contracts

The Company meets its load requirements through various owned and contracted resources. The following table contains a listing of Company-owned resources and major contracts, as well as some important details. Additional details on Company resources and contracts are provided in *Appendix A.* A summary of the Company's demand-side management activities may be found in *Section 3*.

Table 2.1
Resource and Major Contract Summaries

Name	River System	Fuel	Location	Start Date[1]	Capacity (MW)[2]	Energy (aMW)[2]	End Date[3]
Monroe Street	Spokane	Water	Spokane, WA	1890	15.0	13.2	07-31-07
Post Falls	Spokane	Water	Post Falls, ID	1906	18.0	9.9	07-31-07
Nine Mile	Spokane	Water	Nine Mile Falls, WA	1925	24.5	16.4	07-31-07
Little Falls	Spokane	Water	Ford, WA	1910	32.0	22.8	N/A
Long Lake	Spokane	Water	Ford, WA	1915	88.0	52.4	07-31-07
Upper Falls	Spokane	Water	Spokane, WA	1922	10.2	8.8	07-31-07
Cabinet Gorge	Clark Fork	Water	Clark Fork, ID	1952	246.0	122.2	03-01-46
Noxon Rapids	Clark Fork	Water	Noxon, MT	1959	527.0	202.9	03-01-46
Colstrip 3	N/A	Coal	Colstrip, MT	1984	111.0	95.6	N/A
Colstrip 4	N/A	Coal	Colstrip, MT	1986	111.0	95.6	N/A
Rathdrum	N/A	Gas	Rathdrum, ID	1995	176.0	167.2	N/A
Northeast	N/A	Gas/Oil	Spokane, WA	1978	66.8	63.5	N/A
Boulder Park	N/A	Gas	Spokane Valley, WA	2002	24.6	23.4	N/A
Coyote Springs 2	N/A	Gas	Boardman, OR	2003	143.5	136.3	N/A
Kettle Falls	N/A	Wood	Kettle Falls, WA	1983	50.0	48.9	N/A
Kettle Falls CT	N/A	Gas	Kettle Falls, WA	2002	6.9	6.5	N/A
Rocky Reach	Mid-C	Contract	N/A	1961	37.7	20.5	10-31-11
Wells	Mid-C	Contract	N/A	1967	28.6	9.9	08-31-18
Priest Rapids	Mid-C	Contract	N/A	1965	129.3	71.0	TBD
PacifiCorp Exchange	N/A	Contract	N/A	1954	50.0	0.0	03-31-04
PGE Capacity Sale	N/A	Contract	N/A	1992	150.0	0.0	12-31-16
Upriver Dam	Spokane	Contract	Spokane, WA	1966	14.4	10.0	06-30-04
WNP-3	N/A	Contract	N/A	1987	82.0	48.0	06-30-19
Medium-Term Purchases	N/A	Contract	N/A	2004	100.0	100.0	12-31-10

Load Forecast

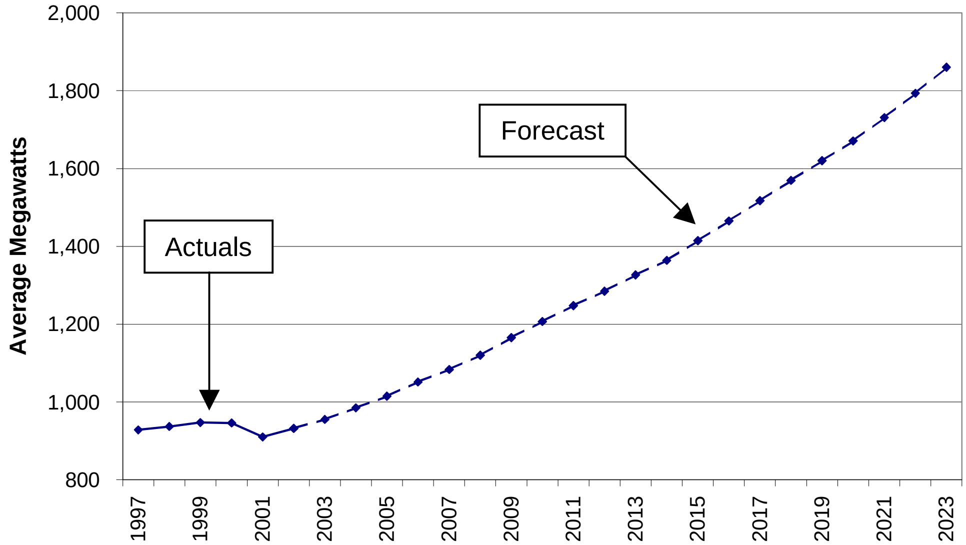
The Company develops a 20-year load forecast for the IRP process. Loads from 1997 through 2002 have been relatively flat. This is the result of several factors. The energy crisis of 2001 included the implementation of widespread conservation efforts. In 2002, higher retail electric prices reinforced customer conservation efforts modestly. Also, due to the economic slowdown in recent years, several large industrial facilities served by the Company were permanently closed.

The twenty-year forecast assumes no additional large customer closures, retail electric prices that increase slightly below the prevailing rate of inflation, and a modestly healthy economy. Conservation acquisitions are expected to continue throughout the forecast horizon and energy efficient equipment will be installed in new construction and replace retired equipment in residences and businesses. The overall growth rate of retail electricity sales averages 3.4% per

[1] indicates when ownership/contract began
[2] represents Company share of project in 2004; hydro generation assumes "average" water from NWPP 2000/01
[3] Indicates when contract/license will expire

year over the planning period. Refer to the following chart for a forecast of annual system load, including weather-adjusted actual load for 1997 to 2002. Additional information regarding the Company's load forecast may be found in *Appendix B.*

Chart 2.1
System Retail Load Forecast



Energy Position

Table 2.2 contains a summary of annual loads and resources for 2004-2008, as well as 2013, 2018, and 2023. The table shows that, on an annual basis, the Company is surplus through 2006.

Table 2.2
Loads & Resources Energy Forecast (aMW)

	2004	2005	2006	2007	2008	2013	2018	2023
Obligations								
System Retail Load	985	1,014	1,051	1,083	1,120	1,326	1,569	1,860
DSM Load	2	5	10	14	19	41	64	56
80% Conf. Interval	189	189	189	189	189	189	189	153
Total Obligations	*1,176*	*1,208*	*1,250*	*1,286*	*1,328*	*1,556*	*1,822*	*2,069*
Resources								
Hydro	550	545	530	530	529	477	471	458
DSM Resource	2	5	10	14	19	41	64	56
Net Contracts	156	157	175	177	177	58	59	12
Base Thermal	223	230	223	223	230	230	230	230
Gas Dispatch	158	156	158	158	156	158	158	156
Gas Peaking Units	181	181	181	181	181	181	181	181
Total Resources	*1,270*	*1,274*	*1,277*	*1,283*	*1,292*	*1,145*	*1,163*	*1,093*
Net Position	**94**	**66**	**27**	**-3**	**-36**	**-411**	**-659**	**-976**

As referenced in *Section 3*, demand-side management (DSM) acquisitions are prescriptive. In other words, without “programmatic” DSM acquisitions, retail loads and supply-side resource acquisitions would be higher. This is represented in the table above by including DSM as both an obligation and a resource. Subsequent tables, for simplification, net DSM obligations and resources to zero. For detailed information about interactions between DSM and the Company’s retail load forecast, refer to *Appendix B*. The DSM projections, as represented in this table, are cumulative beginning in 2004, and illustrate the Company’s commitment to future acquisitions of cost-effective DSM.

On a monthly basis, the Company expects to encounter energy deficits during some months in all years of the forecast. In 2004, for example, the Company position is deficit in March, September, and October, even though the annual position is surplus by 94 aMW. In other months, particularly during spring runoff, the Company is in a surplus position. The Company may balance its monthly positions through short-term market purchases or sales, exchanges, or other resource arrangements.

As a general guideline, the annual energy position is used to determine when the Company needs to acquire additional base-load energy resources. The first significant annual energy deficit is expected in 2008. This deficit is forecasted to grow to 411 aMW by 2013 and 976 aMW by 2023. Load growth and reduced Mid-Columbia generation account for the significant majority of increasing deficits during this period. For further details, including tabulations of annual and monthly energy positions for 2004 to 2023, refer to *Appendix F*.

Capacity Position

The Company develops a twenty-year tabulation of peak capacity loads and resources. Peak load is defined as the maximum one-hour load obligation on the expected average coldest day in January, plus operating reserves. Peak resource capability is defined as the maximum one-hour generation capability of Company resources, plus the net contract contribution. This tabulation shows whether the Company has sufficient resources to meet its maximum expected one-hour obligation.

The Company is in a surplus capacity position through 2009. Annual capacity deficits begin in 2010, with winter peak loads exceeding peak resource capability by more than 100 MW. The deficits continue to grow as peaking requirements increase with load growth, and the Company's resource base declines due to the expiration of market purchases and reductions in power from Mid-Columbia project contracts. *Table 2.3* includes the annual capacity forecast for 2004-2008, as well as 2013, 2018, and 2023. For further details, including tabulations of annual and monthly capacity positions for 2004 to 2023, refer to *Appendix F*.

Table 2.3
Loads & Resources Capacity Forecast (MW)

	2004	2005	2006	2007	2008	2013	2018	2023
Obligations								
Retail Load	1,470	1,515	1,570	1,617	1,672	1,982	2,349	2,780
Operating Reserves	110	110	108	108	108	104	103	101
Total Obligations	*1,580*	*1,625*	*1,678*	*1,725*	*1,780*	*2,086*	*2,452*	*2,881*
Resources								
Hydro	1,177	1,177	1,135	1,134	1,133	1,043	1,035	998
Net Contracts	70	19	43	45	45	-73	78	-2
Base Thermal	272	272	272	272	272	272	272	272
Gas Dispatch	176	176	176	176	176	176	176	176
Gas Peaking Units	236	236	236	236	236	236	236	236
Total Resources	*1,931*	*1,880*	*1,862*	*1,863*	*1,862*	*1,654*	*1,797*	*1,680*
Net Position	**351**	**255**	**184**	**138**	**82**	**-432**	**-655**	**-1,201**
Reserve Margin	*23.8%*	*16.8%*	*11.7%*	*8.5%*	*4.9%*	*-21.8%*	*-27.9%*	*-43.2%*

The Company currently has sufficient capacity resources, due primarily to the relative large amount of hydroelectric generation in its resource portfolio. Typically, hydroelectric resources provide a large amount of capacity in relation to the amount of energy they produce. Additional capacity resources will be acquired when new resources are secured to meet future energy deficits. For the most part, future capacity requirements will be met through the acquisition of new resources, which provide both energy and capacity. However, as new resources are added the Company's resource base will include a lower percentage of hydro, and may include resources, such as wind, which do not provide capacity.

This IRP focuses on meeting the Company's energy requirements to the eighty percent confidence level. The eighty percent confidence level generally meets capacity requirements for planning purposes. As explained in *Section 7*, only after 2009 do reserve margins fall below twelve percent where resources are built to meet the 80 percent confidence interval. The Company will address capacity planning margins in more detail in its 2005 IRP.

Planning Reserves

Planning reserves include components for meeting higher than expected loads due to severe weather, unplanned generator-forced outages, adverse hydrological conditions, and other contingencies. Historically, the Company's planning reserves have not been based on unit size or resource type; planning reserves have been set at a level equal to ten percent of the one-hour system peak load, plus 90 MW. Together, these have equated to approximately a fifteen-percent planning reserve margin during the Company's peak load hour. The Company planning reserve level, while not explicitly considered in the calculation, meets its operating reserve requirement levels of five and seven percent for hydroelectric and thermal generation, respectively.

Confidence Interval Planning

The Company has evaluated a planning reserve methodology that accounts for deviations caused by abnormal monthly weather patterns and below-average monthly hydroelectric capability. Extreme weather can change monthly obligations by as much as 30 percent. In the event the Company does not have adequate generation capability to meet this load variation, it is exposed to the volatile short-term electricity marketplace.

Potentially more significant is hydroelectric generation variability. During 2001 the Company's hydroelectric generation level was the lowest ever recorded. In total, hydroelectric generation over the year was down 181 aMW, or 33 percent, from an average of 550. Monthly reductions were even more pronounced, with generation down nearly 50 percent in both February and August.

Evaluation of the historical data shows that a superior planning criterion is the use of a "confidence interval" based on 80 percent of the monthly variability of load and hydroelectric generation. This means that for each month there is only a ten percent chance that the combination of load and hydro variability would exceed the planning criteria. In other words, for a given month there is a ten percent chance the Company would need to purchase some amount of energy from the market.

The Company has considered confidence intervals higher than 80 percent, such as 95 or 99 percent, but believes based on current analysis that the cost of constructing resources to cover this level of variability exceeds the potential benefits. For example, while building to the 99 percent confidence interval would decrease the frequency of market purchases significantly, such a criterion would require approximately 200 MW of additional generation capability. This would result in potential rate pressure resulting from additional capital expenditures.

On a monthly basis, the 80 percent confidence level varies between 77 and 268 aMW. The average of the 80 percent confidence interval across the twelve months of the year equals 153 aMW. This level is similar to critical water planning on an annual basis, but is more precise since it is based on the chance of exceedance by month.

In addition to load and hydroelectric variability, the Company's WNP-3 contract with BPA includes a return energy provision that can equate to an annual obligation of 36 aMW. The contract would be exercised under adverse conditions, such as low hydroelectric generation and/or high loads—coincident to conditions where the Company would expect its own system to require additional resources. As a result, requirements under the confidence interval are increased by 36 aMW to account for the WNP-3 obligation through its expiration in 2019.

Summary

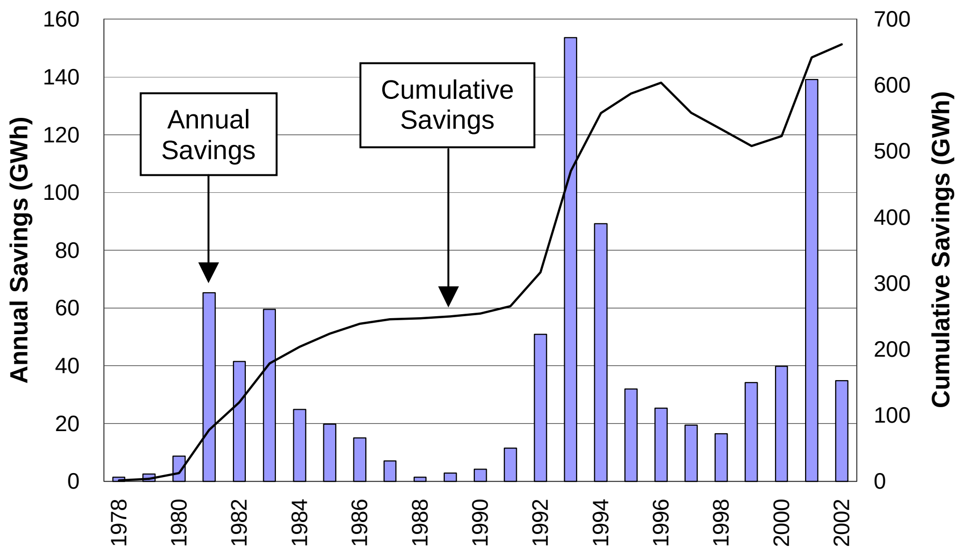
The Company has adequate resources to meet its future annual load obligations through 2007, including reserve margins and hydro and load variability. On an annual average energy basis, the Company's first significant deficit occurs in 2008. On a capacity basis, the first deficit occurs in 2010. However, on a monthly basis, the Company has deficiencies and will investigate various ways to manage them.

Section
3
Demand-Side Management

Historic DSM Activities

Since 1995 the Company has funded the acquisition of demand-side management (DSM) resources through a "tariff rider" mechanism levied upon retail electric rates (through Schedule 91). Currently, the electric tariff rider stands at an amount equal to 1.48% of retail rates in Washington and 1.95% in Idaho. Tariff rider revenues, DSM expenditures and the tariff rider balances are separately tracked by jurisdiction. The following chart represents annual and cumulative energy savings resulting from the Company's DSM activities.

Chart 3.1
Annual and Cumulative Energy Savings
1978-2002



During the summer of 2001 the Company launched a series of emergency programs and incentive enhancements to existing programs in response to the regional energy crisis. Final calculations of the January to August 2001 impact of DSM programs indicate that the Company acquired 437 percent of our energy savings goal during the first eight months of 2001 at the cost of expending 281 percent of incoming tariff rider revenues. By the close of calendar year 2001 these extraordinary programs had resulted in a negative tariff rider balance of $12.2 million ($11.6 million electric and $0.6 million natural gas).

In the fall of 2001 a four-year (2002-2005) business plan was developed to simultaneously move the tariff rider balance back to zero while continuing to deliver energy savings that are at least proportionate to the percentage of tariff rider funds being expended. Based upon tariff rider revenue projections over that time period, only 62 percent of incoming revenue will be available for expenditure. The remaining amount would be dedicated to reducing the tariff rider balance.

The DSM business plan developed for 2002 to 2005 does not include any reductions to the incentives specified to retail electric and natural gas customers (through Schedules 90 and 190), nor is there a significant reduction in the availability of residential programs.

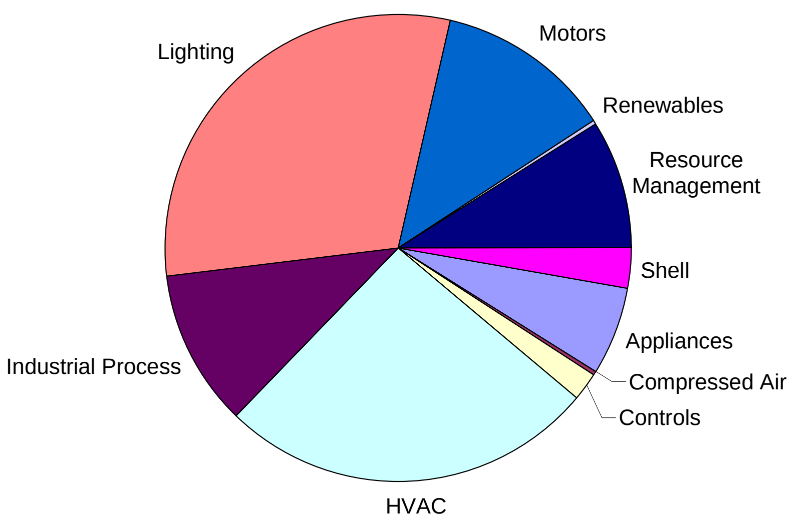
In addition to revenues generated from the DSM tariff rider, the Company also receives $394,200 annually in Conservation and Renewable Discount (C&RD) program benefits from Bonneville Power Administration (BPA). Though the C&RD funds are entirely separate from the Company's DSM funding, the two are managed to maximize the collective impact upon DSM resource acquisition.

C&RD funding extends from October 2001 to September 2006; the five-year BPA rate case period. The first year funded a 2001 compact fluorescent program. The remaining four years of funding have been reserved for limited income programs (up to 75% of the funds) and a conservation voltage reduction (CVR) pilot project that the Company is investigating with the Northwest Energy Efficiency Alliance (NEEA).

The Company plans to deliver more energy savings per dollar expended than stated in our Schedule 90 goal. Toward that end, the Company will target low-cost and no-cost efficiency measures, lost opportunities and proven cost-effective measures. The programs are expected to continue to be cost-effective.

The Company currently acquires DSM resources from a number of energy-efficiency technologies delivered through commercial/industrial, residential, and limited income portfolios. Please refer to the following chart for a depiction of each technology's contribution to the Company's total DSM savings, using 2002 as an example.

Chart 3.2
DSM Resource Acquisition by Technology
2002



Intervenor Involvement

Company DSM activities are under the continuous review of an oversight board known as the External Energy-Efficiency (Triple-E) board. This board is convened semi-annually to review the status of electric and natural gas DSM programs. Analysis of the cost-effectiveness, energy savings and other descriptive statistics are incorporated into periodic reports to the Triple-E board.

Future DSM Activities

Near-term DSM operations follow through on the existing 2002 to 2005 business plan. Though the implementation details are updated on a monthly basis, the core business plan rests upon three fundamental priorities. These priorities are, in descending order of priority:

1. Satisfy least-cost resource requirements and expectations.
2. Field an overall DSM portfolio that is cost-effective on a societal and utility basis.
3. Return the tariff rider balance to zero in a timely manner.

In order to meet these objectives the Company has targeted:

- low-cost and no-cost DSM measures;
- traditional efficiency measures which are commercially-available, reliable, and generate predictable and cost-effective energy savings; and
- lost opportunity measures.

With the exception of lost opportunities, the DSM business plan also calls for a diminished emphasis on energy-efficiency technologies in the early commercialization phase. Historically, these measures have been granted ”new technology” status that, under the provisions of Schedule 90, allow for enhanced customer direct incentives.

Current policy requires a business plan to be structured around any measure granted new technology status. New technology business plans require all avenues to be reviewed for enhancing the penetration of cost-effective measures in the early commercialization phase, including non-incentive as well as incentive approaches. Exit strategies are a required component of each new technology business plan. Under these circumstances the new technology measures are essentially local-area market transformation ventures.

Since 1997, regional market transformation beyond the scope of an individual utility has been within the realm of the Northwest Energy Efficiency Alliance (NEEA). At present, the Company is contractually committed to funding four percent of NEEA expenditures through the end of 2004. This proportion is based upon the Company’s percentage of end-use energy sales within NEEA’s four-state area. The Company will evaluate continued participation in NEEA in 2005 and beyond during the last year of the existing contract.

The Company is active in NEEA governance and operations. In recent years there has been an increased coordination with NEEA on joint regional and local utility DSM operations. This trend is expected to continue as the overlap between regional and local programs increases. As a result of the successful collaborative effort with NEEA the Company does not plan on independently initiating new energy-efficiency research and development efforts.

Conservation Voltage Reduction

Conservation voltage reduction (CVR) is likely to be the most significant measure to be coordinated across the region. The Company has experimented with various approaches to voltage control for energy-efficiency purposes in the past. Although these experiments have indicated that CVR may be a significant and cost-effective DSM resource, they were not extensive enough to be statistically significant. They have also been too limited in scope to establish the determinants of the energy savings and the non-energy impacts of various approaches to CVR.

In January 2003, NEEA adopted a CVR venture intended to complete extensive testing of a variety of approaches to CVR. The expected outcome of the venture will be a determination of the energy savings available and the non-energy impact under a variety of circumstances. The study will also develop recommended protocols for implementation of CVR measures by utilities. NEEA will also work with regulatory agencies to address the financial issues involved in the adoption of these measures.

The Company is discussing the potential for coordinating with NEEA on a CVR pilot on its system. The Company intends to contract with NEEA to complete and fully evaluate the pilot study. Such a cooperative effort would meet the requirements for use of C&RD funding. Based upon the results of this pilot, the Company will evaluate the cost-effectiveness of expanding the adoption of the measure on a wider scale.

Automated Meter Reading/Time of Use Metering

The Company continues to monitor residential and industrial time-of-use (TOU) programs, as well as ways to utilize automated meter reading (AMR) technologies to facilitate these efforts. Market conditions and the current disconnect between wholesale and retail power markets has recently been the focus of intense discussion. Wholesale power costs can vary significantly across hours, days, and seasons. However, most customers in the Northwest pay fixed retail prices. As a result, these customers do not have a price signal to incent them to manage their usage during periods of high wholesale prices.

Various demand response mechanisms have been suggested to remedy this problem. Time-of-use pricing has been studied in some detail in a variety of pilot and permanent programs. A recent study on TOU provides insight into the potential benefits of this program for the Company's customers. Approximately 100 utilities across the nation were surveyed and the analysis found that nearly 85% had some form of TOU tariff filed with their Utility Commission.

However, the research found that less than one percent of the served residential customers participated in the programs.

The Company has concluded that it is not economically viable to implement a full scale residential time-of-use program prior to the implementation of an AMR system that bears the metering and other technology costs necessary to support TOU. While an AMR system would provide certain benefits, its immediate implementation is not critical for reliability or for the ongoing business operations of the Company. The Company will continue to evaluate the costs and benefits of an AMR system.

DSM in AURORA

Historically the Company has integrated supply and demand-side resources by evaluating supply-side resource options, determining the deferrable resource and consequential avoided cost, and subsequently applying that price signal to the selection of demand-side resources. Integration of the two components of the resource plan is achieved by ensuring that demand-side resources available at or below the avoided cost of that deferrable resource are acquired. This approach does assume that demand-side resources are not a sufficiently large component of the resource plan to change the selected deferrable resource. In this plan, and in prior plans, this has been a reasonable assumption.

In the current IRP process the Company has applied a more explicit integration of supply and demand-side resources, through incorporation of Company-specific DSM programs into the AURORA model. This allowed Company DSM programs to be evaluated against hourly market prices in parallel with supply-side resources.

Model Inputs and Assumptions

Developing demand-side resources for incorporation into AURORA involved several steps. First, the Company identified six individual components of DSM measures based on actual conservation activities. Utility costs and acquisition levels were indexed based on historic data. These six components account for the vast majority of the historic energy savings, and are as follows:

1. commercial heating, ventilation, and air conditioning (HVAC)
2. commercial lighting
3. commercial domestic hot water (DHW)
4. residential HVAC
5. residential lighting
6. residential DHW

Based upon a review of current projects and project economics, it was possible to estimate the additional acquisition achievable given additional utility expenditures within each of the six DSM components. For each component, the actual and three incremental points trace out the DSM supply curve that is achievable with each incremental increase in utility expenditure. The incremental utility costs tested were based upon 25 percent increases to the current level of DSM funding and represent alternative points on the supply curve. The estimated DSM acquisition resulting from additional utility expenditure was based upon the technical and economic potential for the measures represented in each DSM component and the ability of utility DSM programs to capture that potential.

It was assumed that the Company would be able to move from the current point on the supply curve to any of the three incremental points instantaneously and at no additional cost per aMW. This assumption is based upon actual experience in ramping DSM acquisition activities up and down over time. However, in the event that very substantial increases in utility acquisition were necessary within a very short timeframe, such as was the case in the summer of 2001, it would have been wise to assume significantly higher utility costs per aMW. Graphically this would be depicted by a supply curve asymptotically approaching the vertical line representing the service territory's short-term technical DSM potential. Refer to *Appendix Q* for additional information.

In order to test each of the six DSM components against alternative resources or against the avoided cost established by the AURORA model, it was necessary to develop hourly load shapes. These 24-hour load shapes were estimated for a typical week for each of the twelve months. The result was a "24 x 7 x 12" load shape for use in AURORA. There was a certain amount of replication when, for example, there was no reason to believe that an hourly Tuesday load shape would differ from the corresponding Thursday load shape. Similarly, some monthly load shapes were combined into summer, winter, and shoulder seasons if appropriate for that particular set of DSM measures.

Specific load shapes were derived from various sources available to the Company. Actual measurement and evaluation (M&E) data from performance contracts or projects that were sampled as part of the Company's analytical process was used as much as possible. This was augmented by BPA End Use Load and Consumer Assessment Program (ELCAP) data on occasion. The results were also modified to include engineering estimates of new technologies that may not be fully represented in the Company's historic M&E process. For more detail regarding the load shapes utilized in this analysis, refer to *Appendix Q*.

DSM Modeling Results

The DSM measures listed above were incorporated into AURORA as 24 individual resources (four economic tiers for each of six measures). Each resource was modeled as non-dispatchable and forced to sell into the marketplace for every hour of the twenty-year study term. The profit or loss the resource generated was recorded for each hour, effectively resulting in the hourly market value. The following table includes the results of this exercise, summarized for 2004-2008, 2013, 2018, and 2023. The table also includes the twenty-year present value for each measure, based on a discount rate of 8.22 percent as determined in the Company's most recent Washington General Rate Case. Please refer to *Appendix Q* for a table including results for all years of the study.

Table 3.1
DSM Resource Net Market Value
2004-2008, 2013, 2018 & 2023 (in thousands of dollars)

	2004	2005	2006	2007	2008	2013	2018	2023	NPV
Com HVAC 1	-47.8	-42.6	-41.6	-33.6	-20.8	182.3	271.9	294.7	861.8
Com HVAC 2	-12.2	-11.8	-11.9	-11.2	-10.2	9.2	16.8	17.4	1.2
Com HVAC 3	-2.1	-2.1	-2.2	-2.1	-2.0	-0.2	0.4	0.2	-10.5
Com HVAC 4	-0.3	-0.3	-0.3	-0.3	-0.3	-0.2	-0.1	-0.2	-2.4
Com Ltg 1	209.5	222.1	227.8	246.9	272.3	374.4	454.1	507.4	3,159.3
Com Ltg 2	16.8	18.0	18.5	20.3	22.8	32.4	39.6	44.0	268.8
Com Ltg 3	1.2	1.3	1.3	1.5	1.7	2.6	3.2	3.6	21.0
Com Ltg 4	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	1.4
Com DHW 1	4.3	4.5	4.6	5.0	5.5	7.6	9.2	10.3	64.0
Com DHW 2	0.3	0.4	0.4	0.4	0.5	0.7	0.8	0.9	5.5
Com DHW 3	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.4
Com DHW 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Res HVAC 1	19.3	20.5	20.6	22.8	25.6	25.1	27.6	30.8	238.2
Res HVAC 2	1.3	1.4	1.4	1.6	1.9	1.7	1.9	2.0	16.5
Res HVAC 3	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.7
Res HVAC 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Res Ltg 1	102.8	112.7	117.6	131.4	148.2	373.3	495.9	555.7	2,664.5
Res Ltg 2	6.1	7.0	7.4	8.7	10.3	32.2	43.7	48.7	218.4
Res Ltg 3	0.1	0.2	0.2	0.3	0.5	2.6	3.6	4.0	15.8
Res Ltg 4	-0.1	-0.1	0.0	0.0	0.0	0.2	0.3	0.3	0.8
Res DHW 1	0.0	0.0	0.0	0.1	0.2	0.5	0.7	0.7	3.3
Res DHW 2	-0.1	-0.1	-0.1	0.0	0.0	0.0	0.0	0.0	-0.3
Res DHW 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-0.1
Res DHW 4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

As shown in the table above, each of the six DSM components and each of the four price alternatives within each component was evaluated against AURORA-defined market prices for the twenty-year planning period. This resulted in 24 streams of annual mark-to-market results.

By calculating a present value of these annual streams it is possible to determine if a resource installed in a particular year will generate future value (relative to market) sufficient to make that stream cost-effective. The most significant question lies in the appropriate term to be used for that present value calculation. At least two reasonable alternatives exist. The first would be to calculate a twenty-year present value covering the entire forecast period. The alternative would be to calculate a moving present value equal to the measure life specific to that DSM component.

For purposes of deriving actionable information out of the integrated resource planning process, this was not a significant issue. Two of the DSM components (those related to HVAC measures) have a measure life of twenty years, thus encompassing the entire forecast period. The other two measures (domestic hot water and lighting) have been deemed to generate ten years of savings in the Company's current cost-effectiveness analysis. However, most of the twenty-four individual streams of savings do not cross the zero line, and for these streams the resource would be selected or not selected regardless of the term of the present valuing methodology.

The Company intends to create an actionable plan from this AURORA analysis of DSM alternatives. Schedule 90, under which the Company acquires DSM resources, has historically been interpreted as applying to any electrical-efficiency device available in the commercial/industrial sector. Under this precedent it is not possible to exclude particular measures from inclusion in the DSM resource portfolio. The Company does, however, have the ability to target specific technology applications that appear to be more cost-effective than others. Within the commercial/industrial sector the AURORA results will be used to perform this targeting.

The Company implements residential DSM programs differently. Within this customer segment prescriptive programs are developed and made available to customers. Thus there is a greater ability to add or remove technology applications from this portfolio. The AURORA results will also be used to identify technologies to be targeted in limited income residential programs.

An additional consideration is one of the most efficient ways to acquire the resources identified as being cost-effective. Several technology applications are better pursued through a mix of regional and local programs. The Company is supportive of funding cost-effective regional market transformation when it is the most efficient way to acquire targeted DSM resources.

Section 4

New Resource Alternatives

Overview

This section will discuss the resource alternatives considered by the Company to meet its future retail load requirements. In previous IRPs the Company included analyses for a very wide range of resource alternatives. The approach in this IRP is to focus analysis on technologies likely to be part of a least-cost mix.

General Approach

This IRP considers generic resource alternatives, rather than specific projects that the Company might choose. This approach was selected for three reasons. First, the Company wants to consider the affect on its portfolio of differing resource types without project-specific economics impacting the result. This provides a more consistent comparison of technologies than site-specific economics.

Second, the approach provides greater transparency of resource alternatives and assumptions. To this end, this IRP adopts resources and associated characteristics from the forthcoming Northwest Power Planning Council (NWPPC) Fifth Power Plan. The NWPPC resource alternatives were formulated over a period of months through a committee of regional experts drawn from utilities, developers, regulators, and other interested parties.

Third, the Company does not have an immediate resource deficiency on an annual average basis. Without an immediate need on the horizon, the Company has not recently studied site-specific projects. Instead, this IRP provides a framework of analysis that the Company expects to revisit at the time it procures additional resources. At that time, assumptions would be updated to include site-specific resource alternatives. Specific resource alternatives drawn from, for example, a Request for Proposals (RFP) would be evaluated in the same manner as the NWPPC resources used in this study.

New Resource Alternatives Considered

Five new resource alternatives were incorporated into the AURORA model as part of the 2004-2023 capacity expansion plan for the WECC. Underlying assumptions for each resource were taken from recent work by the NWPPC for its forthcoming Fifth Power Plan. The assumptions were derived from a working forum of utility experts, merchant plant developers, BPA, and other interested parties. For a more detailed discussion of the assumptions behind new resource alternatives, see *Appendix P*.

The following table provides a brief description of each technology and key underlying assumptions. The resource assumptions, excluding levelized cost calculations, were taken from the NWPPC except where noted. Refer to *Section 5* for more information on the AURORA model and capacity expansion.

Table 4.1
New Resource Alternatives
(in 2000 Dollars)

Resource	Installed Cost ($/kW)	Unit Capacity (MW)	Heat Rate (Btu/kWh)	Unit Availability (percent)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Levelized Cost AURORA ($/MWh)	Levelized Cost Max Gen ($/MWh)
CCCT	686	280	6,946	92	26	2.80	56.21	51.91
SCCT	730	92	9,486	94	8	3.70	93.53	60.05
Coal	1,230	400	9,550	84	55	1.75	58.05	57.09
Wind	679	100	N/A	30	35	0.50	52.64	52.64
Solar	6,000	20	N/A	22	30	0.00	N/A	N/A
Cogen	1,000	25	5,500	85	26	2.00	74.71	57.37

Unit availability accounts for both maintenance and forced outage, and is based on assumptions from the NWPPC. Wind plant availability varies by region, but on average wind plants are modeled to generate at a thirty percent capacity factor. Solar is shaped by hour over the year with an average availability of 22 percent.

Heat rates for CCCT, SCCT, and coal plants are expected to improve over time. The NWPPC assumes that, for example, CCCT heat rates will improve from an average of 6,946 Btu/kWh today to 6,195 in 2023, a reduction of thirteen percent. Coal plant heat rates are expected to improve by 4.5 percent over the same timeframe.

Fixed operation and maintenance (O&M) figures include maintenance and transmission costs of $15 per kW-year, except for SCCT plants, where non-firm transmission service is assumed. These assumptions are based on NWPPC datasets.

The levelized cost calculations are based on a discount rate of 8.22 percent as determined in the Company's most recent Washington General Rate Case. This discount rate is used for all levelized cost and present value calculations throughout the document.

Levelized costs are presented assuming two levels of generation: the average output levels as modeled in AURORA and maximum generation levels where economic dispatch is ignored. The AURORA generation levelized costs are higher, as the plants are operated only when they are lower cost than the wholesale marketplace. The levelized costs at maximum generation levels assume that, except for maintenance and forced outage, plants run during all hours. Even though levelized costs are lower, calculations at maximum generation are unrealistic, as the marketplace dictates that most plants will not be economic during all hours of their lifetimes.

The Company diverged modestly from NWPPC resource assumptions in three areas: CCCT configuration, the federal production tax credit for wind, and transmission costs for new coal plants. The NWPPC assumes a "two-on-one" configuration for CCCTs. Two-on-one configurations consist of two gas turbines exhausting waste heat into a single heat recovery steam generator (HRSG), rather than one gas turbine matched to the HRSG as in more traditional one-on-one configuration. The NWPPC assumes that modest cost efficiencies are gained through the two-on-one configuration. However, based on its own experience, the Company is concerned that the NWPPC has assumed costs that are too low for CCCT technology. The Company believes that the larger size of the two-on-one configuration may be beyond the incremental load requirements of utility companies building them. The IRP instead uses NWPPC assumptions for a one-on-one configuration.

The NWPPC models the federal production tax credit for wind as an offset to variable O&M costs. For the IRP, the Company instead reduced capital costs by an amount equal to the present value of the NWPPC-assumed ten-year credit. The ultimate impact of this change was negligible, but it simplified modeling within the IRP process.

The Company also does not believe that the NWPPC adequately addresses the incremental cost of new transmission facilities necessary to integrate coal plants into the Northwest. Existing transmission lines out of eastern-WECC states, where coal plants likely will be built (e.g., Montana, Wyoming), into the Northwest do not have capacity adequate to integrate large coal plant developments. Therefore new and upgraded transmission facilities will be required to integrate the plants. The IRP assumes that an additional $333 per installed kW of coal-fired generation is required to cover the cost for new transmission facilities. This adjustment amounts to an incremental levelized cost of about six to seven dollars per MWh of coal-fired generation.

The Company also included a generic cogeneration plant. This resource was not explicitly modeled in the AURORA capacity expansion plan, but was evaluated as a potential future resource. In addition, to evaluate the impact of a fixed-price contract on the Company's risk profile, a 100 MW contract was modeled as a potential resource.

Resources Not Evaluated

Many resource alternatives are available to the Company, however, applying basic cost-effectiveness screens greatly reduces the opportunities. In the Company's 2001 IRP, 32 resource options were depicted, using information gathered from the NWPPC. While this list was extensive, it was mostly comprised of uneconomic alternatives. For example, various geothermal projects were evaluated, and estimated to cost more than 100 dollars per MWh. Evaluating such resources within the IRP models would clearly lead to their exclusion from consideration in a least-cost mix. Other resources not considered in this IRP include nuclear, advanced coal, bio-gasification, new hydroelectric generation facilities, and various high-cost solar projects.

Section 5

Modeling

Overview

Integrated resource planning typically considers many alternative strategies to identify an optimum portfolio of resources matching future loads. Historically, IRP analyses have relied on straightforward comparisons of future loads and resources on the basis of capacity and energy. Resources were selected to meet deficiencies in a "least-cost" manner on a twenty-year present value basis. Today, planning analyses are more quantitatively detailed for several reasons, including:

- greater computing capabilities
- a viable wholesale electricity marketplace
- more capable resource modeling tools
- higher expectations from customers, regulators, and management

The result is a greater understanding of the potential impacts of varying resource decisions, and enhanced assessment of strategies to reduce portfolio power supply risks.

In this IRP, the Company has enhanced its modeling capabilities even further, by including an hourly production-cost model that dispatches resources to a given set of market conditions and also develops a set of market prices responsive to varying levels of regional load, natural gas prices, and hydroelectric conditions.

Modeling Process

For the purposes of this IRP, the AURORA model was used to simulate the entire Western Electricity Coordinating Council (WECC) marketplace. Refer to *Appendix C* for a discussion of the selection process whereby the Company chose AURORA for its planning efforts. The WECC, as defined by AURORA, is separated into sixteen "load areas" based on geographical regions of load concentration. Refer to the following table for a listing of the load areas included in AURORA as part of the WECC. This table also provides a reference to define the acronyms utilized throughout this document to describe these load areas.

Table 5.1
AURORA Load Areas

Load Area	Region(s) Included	Load Area	Region(s) Included
AB	Alberta	IDSo	Southern Idaho
AVA	Avista	MT	Montana
AZ	Arizona	NM	New Mexico
BajaN	Baja Mexico	NVNo	Northern Nevada
BC	British Columbia	NVSo	Southern Nevada
CANo	Northern California	OWI	Oregon, Washington, and Northern Idaho
CASo	Southern California	UT	Utah
CO	Colorado	WY	Wyoming

The AVA load area listed above was developed in order to represent Company loads and resources separately from those of OWI. For each of the load areas, the AURORA database contains all of the corresponding loads and resources, and is capable of simulating the entire system on an hourly basis. This simulation is used to derive market prices for each area and the WECC as a whole. It also allows AURORA to compute statistics specific to individual generating resources (e.g., fuel costs, dispatch margins, etc.) and individual loads (e.g., cost to serve).

For this IRP, the Company utilized AURORA to simulate the WECC marketplace for twenty years (2004-2023). As part of this simulation, AURORA builds new generation from a pool of hypothetical resources to meet future load growth. This process is referred to as “capacity expansion.” For further details on capacity expansion, refer to *Appendix C*.

AURORA is also capable of incorporating market uncertainty based on such variables as load, fuel price, and hydroelectric generation. The Company utilized this capability by generating 200 sets of unique inputs for 200 distinct iterations of AURORA. Refer to *Section 6* for more information on this process. The results of the 200 iterations of AURORA were then input into a spreadsheet model that utilized a Linear Programming (LP) Module to derive an optimal solution. Refer to *Appendix C* for further details on utilization of the LP Module and a discussion of linear programming theory.

Assumptions and Inputs

AURORA contains a database with generic data sets that provide a reasonable approximation of market conditions in the future. To obtain more robust results, the Company modified many of the base data sets. The following section describes the changes made by the Company.

Hydroelectric Generation

The AURORA model contains a hydrological data set for the WECC. Northwest data includes average monthly generation levels taken from BPA 50-year hydrological studies. The Company, for its planning purposes, uses hydrological data from the Northwest Power Pool (NWPP) rather than that from BPA. Presently the NWPP performs 60-year headwater benefit studies annually for the Northwest hydroelectric system.

Data from the 2000-2001 version of this study was converted into an AURORA format and utilized in place of existing Northwest data sets for IRP modeling. Results for the Northwest are similar – the average annual generation level from the 60-year study for generation in Oregon, Washington and Northern Idaho is 1.7 percent higher than the AURORA default data set. AURORA data sets for hydroelectric systems outside the Northwest (e.g., California) were not modified.

AURORA models hydroelectric generation by load area. In other words, every hydroelectric facility located within a load area utilizes the same shaping factors. The results for each hydroelectric system are accurate, but individual projects are not necessarily represented correctly. To track Company hydroelectric resources more accurately, each of the Company's river systems was algebraically separated from the base AURORA data sets and assigned a unique set of shaping factors.

Natural Gas Prices

Natural gas is a key underlying assumption in the model because gas-fired resources presently set the marginal price for WECC electricity in many hours. Therefore the Company used a natural gas price forecast developed for its 2003 Natural Gas IRP. The forecast was developed in early July 2002 using forward prices for approximately the first five years, and then a long-term forecast purchased from DRI/WEFA.

For the 2003 Electric IRP, a forecast of Henry Hub natural gas prices was developed in addition to the traditional price forecast used in the Natural Gas IRP. This was necessary for the AURORA model, as it develops all of its natural gas prices using Henry Hub. For the Company's natural gas-fired plants, the Company developed basis differentials from Henry Hub using available market-based information.

WECC Load

The Company made two key modifications to the AURORA regional load database. The first was algebraically separating the Company's retail load forecast from the AURORA OWI load area forecast. Separating the Company's retail load allowed it to be tracked separately for IRP reporting.

The second modification was to the hourly shape of the loads in each AURORA region. The AURORA data set was based on actual hourly load shapes from calendar year 2000. The Company had already reviewed data sets from 1998 and 1999 to obtain data sets for Monte Carlo runs, and determined that this information would potentially provide a better hourly shape because calendar year 2000 loads were affected by actions taken during the 2000-2001 energy shortages. Refer to *Section 6* for more detailed information.

Resources

A Company review of the WECC resources included in the AURORA database found it to be both comprehensive and accurate for IRP purposes. The only substantial change to the AURORA database was the addition of 295 MW of wind resources per year between 2003 and 2012. These quantities were adopted from the NWPPC Fifth Power Plan model and are intended to represent the implementation of Renewable Portfolio Standards (RPS) in states presently having such requirements. This addition is miniscule in comparison to the resource quantities added by AURORA, but guaranteed that RPS requirements would be satisfied. The Company also modified the cost of capital for new resources, which is detailed further in *Appendix C*.

Integration into AURORA

The Company's departure from the AURORA risk input structure required the development of an interface to automate the 200 iterations of Monte Carlo. The Company developed a spreadsheet containing the statistical relationships for natural gas, hydroelectric generation, and load variability. A Visual Basic program was developed to write the 200 individual data sets to a database that AURORA could interface with.

A second set of Visual Basic code was then used to upload each of the iterations into AURORA and write the results back to the database. The results from AURORA were then queried from the database and input into the LP Module. For more information, including a graphical representation of the entire modeling process, refer to *Appendix C*.

Analysis of Strategies

As discussed in *Section 4*, several potential new resources were included in AURORA to meet the Company's future resource deficiencies. Based on this pool of resources, several alternative resource strategies (or "strategies") were derived. While the number of strategies can be virtually unlimited, the LP Module provided a means to evaluate portfolios the Company believed were essential to understand. Strategies considered in the IRP included the following:

- *No Additions* – used to simulate what would happen if the Company made no resource additions over the term of the IRP, and instead relied entirely on the short-term electric marketplace to serve load requirements.
- *Lowest Cost* – designed to minimize the NPV of average net power supply expense.
- *Lowest Risk* – designed to minimize the average variance of net power supply expense.
- *All CCCT* – comprised entirely of natural gas-fired combined-cycle combustion turbines.
- *All Coal* – comprised entirely of coal-fired plants.
- *Wind Strategy* – comprised of wind turbines, supplemented with simple-cycle combustion turbines (SCCTs).

The *Wind Strategy* was selected to provide a renewable portfolio. Because wind is an energy-only resource, integrating wind resources has proven to be a complicated analysis. The Company has completed various wind studies since early 2002, as provided in *Appendix H*. Still, the answer is not clear and the evaluation continues. In the absence of a definitive study, a level of 50 MW of peaking plants to support 75 MW of wind generation has been selected for the IRP. This amount might be modestly too high or too low; however, based on analyses to date, the Company believes this level is appropriate for IRP planning.

As it turns out, the *Lowest Cost* strategy is constructed entirely of CCCTs, so the *Lowest Cost* and *All CCCT* strategies are the same (referred to hereafter as *Lowest Cost/CCCT*). For more information on these strategies, including analysis results, refer to *Appendix E*.

Analysis of Scenarios

Scenarios continue to play an important role in the Company's IRP studies. Numerous scenarios were evaluated for this report. Aside from the *Base Case,* which incorporates the results of all 200 iterations of Monte Carlo simulation, there are eight scenarios included in this IRP. These scenarios were intended to represent distinct market conditions the Company may face in the future, and include the following:

- *Average* – incorporates average hydroelectric generation, natural gas prices, and loads.
- *Critical Water* – hydroelectric levels for the Northwest are set to 1936-1937 (critical year) levels.
- *High Gas* – assumes natural gas prices that are 200 percent of average.
- *High Load* – utilizes WECC loads that are 12.5 percent higher than average.
- *Load Loss* – incorporates a 300 aMW loss of the Company's retail load.
- *New Trans* – incorporates an additional 12,000 MW of transmission from Montana and Wyoming into the Northwest and Southern California.
- *Coal Build* – replaces the CCCTs built in capacity expansion with equivalent coal plants.
- *Carbon Tax* – includes carbon taxes on applicable generating resources.

For more information on these scenarios, including analysis results, refer to *Appendix E*.

Summary

Many enhancements to the modeling process were made for the 2003 IRP. The Company acquired a new hourly market price forecasting tool capable of tracking and valuing specific portfolios of resources. By developing 200 sets of potential market conditions, the Company was able to evaluate not only the expected values of various resource decisions, but also the potential risk inherent in those decisions. The LP Module provided an efficient means to select least-cost resources, account for risk considerations, and compare alternative scenarios. Overall, the Company believes that this combination of analytical tools provides an excellent framework for this type of analysis.

Section 6

Risk Analysis

Overview

This section provides a discussion of the stochastic risk analyses performed in this IRP. Risk factors include hydroelectric generation, natural gas price, and WECC load variability. This section also describes the varying risks associated with resource alternatives available to the Company.

Stochastic Risk Analysis

Stochastic risk analysis provides a method to evaluate how relationships among variables change over time. The IRP model considers variability in hydroelectric generation, natural gas prices, and WECC loads in developing a robust model that considers many possible futures. In this IRP, stochastic risk analysis is achieved by applying statistical methods to AURORA model inputs, generating numerous unique input data sets. AURORA then utilizes these input data sets in numerous iterations to generate unique sets of results. The following section describes analyses performed to obtain 200 unique iterations based on the risk components mentioned above, as well as how they were integrated into AURORA.

Hydroelectric Generation

Possibly the greatest power supply risk the Company presently faces is variation in hydroelectric generation. In 2001 the Company saw its annual generation fall to approximately 67 percent of average. Monthly generation levels can vary even further. Planning for this amount of variability has challenged Northwest utilities since the first dams were built.

The Northwest Power Pool (NWPP) provides an estimate of hydroelectric generation based on a 60-year record of stream flows. For the IRP, the Company evaluated the hydrological record stochastically in an attempt to infer statistical relationships from the data set. Each month of the year was evaluated, along with correlations between the hydroelectric plants residing in the various AURORA load areas. Special attention was paid to the Northwest load areas modeled by the NWPP, as shown in *Table 6.1*.

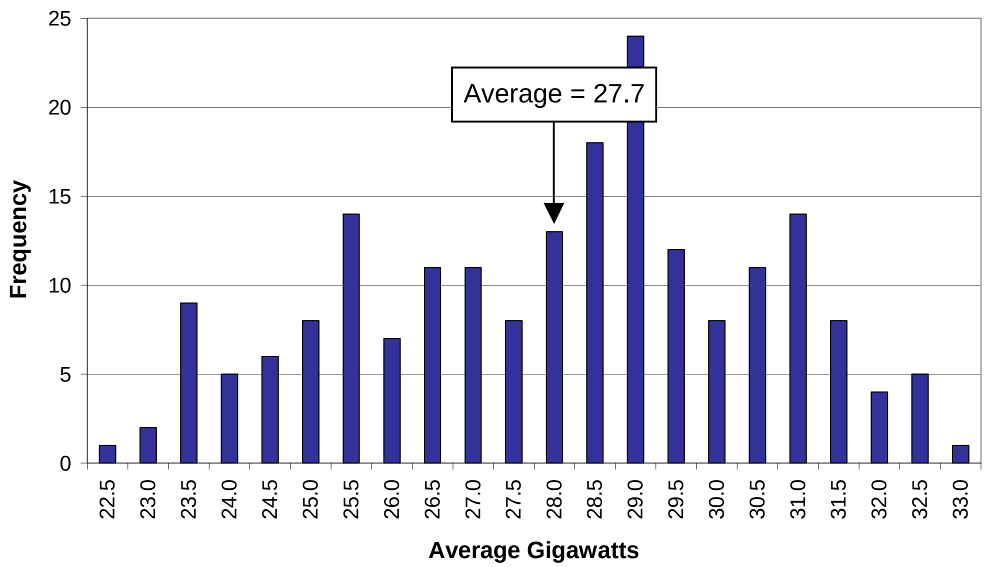
Table 6.1
WECC Hydroelectric Generation by AURORA Load Area

Area	*OWI*	*BC*	CANo	*IDSo*	CASo	*MT*	Other	Total
Capacity (MW)	*30,790*	*10,473*	7,928	*2,497*	2,433	*1,851*	6,038	62,010
Percent of Total	*49.7*	*16.9*	12.8	*4.0*	3.9	*3.0*	9.7	100.0

The Northwest areas, (indicated above in italics and gray shading), encompass nearly 75 percent of hydroelectric generation in the WECC, with the AURORA load area Oregon/Washington/ North Idaho (OWI) accounting for approximately half of the total.

Since hydroelectric generation is not normally distributed, the ability to randomly generate monthly hydroelectric generation levels is limited. As an alternative, specific water years were drawn randomly from the NWPP data set. For example, if the 1945 water year was drawn, hydroelectric generation levels for the Northwest load areas (OWI, BC, IDSo, and MT) would be based on the 1945 data set from the NWPP. Hydroelectric generation levels for load areas not modeled by the NWPP were assumed to remain constant at the levels provided in the base AURORA dataset. The following chart presents the distribution of hydroelectric generation modeled for the WECC.

Chart 6.1
Distribution of Hydroelectric Generation in WECC



Natural Gas Prices

Natural gas-fired resources have recently become the most common selection for meeting new electric load requirements. Increased reliance on natural gas has made gas-fired turbines marginal cost resources during many hours in the WECC. As more natural gas-fired plants are built, the Company expects electricity prices to become even more correlated to natural gas prices than they are today.

AURORA develops electricity prices by determining the marginal resource used to serve load in each hour. The extent to which natural gas-fired resources are the marginal resource during a given hour depends on the level of generation from other lower-cost resources. Chief among these is hydroelectric generation. Reductions in hydroelectric generation will increase the number of hours where natural gas-fired generators set the marginal price of electricity. This relationship is modeled in the IRP by inversely correlating natural gas prices by 50 percent to hydroelectric generation levels. In other words, gas prices rise as hydroelectric generation declines, and vise versa.

The IRP assumes that natural gas prices have a standard deviation of 50 percent where prices rise above the average forecast and 25 percent where prices fall below the average forecast. Half of the standard deviation is then allocated to the annual price, with the remainder applied to represent monthly volatility. Annual prices are correlated to hydroelectric generation as described above, while monthly volatility is randomized. The Company chose to reduce the standard deviation when prices fall below the average value to reflect that, while prices are effectively capped on the down side at zero, upward price movement is potentially unlimited.

The following table illustrates the natural gas prices modeled in 2005 over 200 iterations. Annual average prices ranged between $1.82 and $6.75 per decatherm, a range of 130 percent. The monthly range was 220 percent, varying between $1.14 and $9.67 per decatherm.

Table 6.2
2005 Henry Hub Natural Gas Prices Over 200 IRP Iterations
(in 2000 dollars per decatherm)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ann
Avg	4.28	3.89	3.64	3.57	3.12	3.83	4.01	4.07	3.90	3.68	3.77	4.05	3.82
Min	1.48	1.59	1.59	1.37	1.36	1.14	1.53	1.77	1.58	1.78	1.79	1.78	1.82
Max	9.67	7.27	8.61	7.75	6.26	7.77	7.62	9.59	8.64	7.42	8.31	7.68	6.75

Load Variability

AURORA includes historical data for each load area, as well as a set of annual growth rates. The historical data sets are specific to a recent calendar year. In the case of the current version of AURORA, the default data sets are based on calendar year 2000.

Due to the significant impact of high prices during 2000, the data may not be representative of future load variability. As such, the Company has used hourly load information for each utility in the WECC during 1998 and 1999 obtained from FERC Form 714, and has determined the statistical relationships between areas within the WECC.

Standard deviations for each load area were developed on a monthly basis, but the Company was interested in modeling loads in a fashion that varies them on more than just a monthly basis. This desire was based on the observation that during "average" months loads oftentimes are both significantly higher and lower than the average would indicate.

Varying loads on a weekly basis better represents weather patterns and more realistically represents WECC loads. Daily load shapes were based on actual daily loads for 1998 and 1999, and were represented as a percentage of the average load for the week within which they reside.

Without correlating loads across the WECC, higher loads in one area would be inappropriately offset by lower loads in another area during many hours of the study. To better model load variability across the WECC, correlations were identified between all load areas and the OWI load area. The FERC Form 714 data were separated into weekdays by month to remove the inherent bias that otherwise would have resulted due to normal intra-week trends. The resultant correlations were then tested for statistical significance, which eliminated approximately half of the values.

The following table describes load and correlation statistics for the Northwest and California, using January and August of 2004 as examples. “NotSig” indicates that the relationship was not statistically significant. Additional details are available in *Appendix D*.

Table 6.3
2004 Load Statistics

	OWI	BC	IDSo	Montana	CANo	CASo
January						
Load (aGW)						
Standard Deviation	6.0%	4.9%	4.3%	3.4%	6.8%	7.7%
Correlation to OWI	100%	92%	67%	89%	NotSig	NotSig
August						
Load (aGW)						
Standard Deviation	6.0%	5.0%	5.1%	3.5%	11.0%	8.5%
Correlation to OWI	100%	NotSig	79%	65%	76%	50%

Benefits and Risks of Resource Options

The Company’s current resource portfolio contains a significant level of cost variability, which is largely due to its large reliance on hydroelectric generation. This risk is significant and will be difficult to mitigate completely. By changing the mix of future resources, however, power supply cost variability can be reduced. There are several important underlying assumptions with regard to selecting a portfolio of future resources, including the following:

1. Owning resources in lieu of utilizing spot market purchases reduces risk. This is due to the fact that roughly one-third of the total resource costs (in the case of gas turbines) to almost all of the costs (in the case of wind) are fixed costs consisting of capital recovery and fixed O&M. These costs do not vary, unlike short-term market prices.

2. Risk is reduced by capital intensive, low operating cost resources with stable fuel supplies. Future resources that meet this criterion include coal and wind. Both coal and wind costs are dominated by capital recovery and fixed O&M. Both have fuel supplies that aren’t correlated with electricity prices and typically have operating costs low enough for the plant to be dispatched (or “in the money”) when available.

3. Being close to load/resource balance generally reduces risk. Being either very short or very long increases exposure to market prices, which causes power supply costs to vary. This is even the case if the resources added are lower risk resources, such as coal or wind. Individual resource alternatives have unique risk profiles. Refer to the following table for a summary of these profiles for the resource alternatives considered in this IRP:

Table 6.4
Resource Profiles

Resource Type	Capital Required	Operating Cost	Fuel Price Risk	Operating Flexibility	Other Advantages	Other Disadvantages
CCCT	Low	High	High	Medium /High	Daily dispatch	Gas price correlated with electric price
SCCT	Low	Very High	High	High	Hourly dispatch	Gas price correlated with electric price
Coal	High	Low	Low	Limited	Stable fuel price	Environmental issues Long transmission or coal haul
Wind	Very High	Very Low	None	None	No fuel cost Not correlated to market Long-term supply reliable Renewable requirements	System integration No capacity Fuel supply is unreliable
Cogen	High	Medium	Varies	Limited /None	Overall high efficiency	Need host sites Can't add when needed Contract issues
Purchases	None	NA	None	None	No fuel price risk No forced outages	Credit issues Counter-party issues Supply reliability issues
DSM	High	None	None	None	Good customer relations High efficiency	Savings hard to verify

Further details regarding particular risk factors, as well as risk characteristics for specific resources can be found in *Appendix D.*

Section

7

Results

Overview

The following section details the modeling results of the IRP. It provides the stochastic values for natural gas, hydroelectric generation, and WECC loads. It also provides details regarding the *Preferred Resource Strategy* (*PRS*) developed for the IRP, and discusses the strategies and scenarios that were considered.

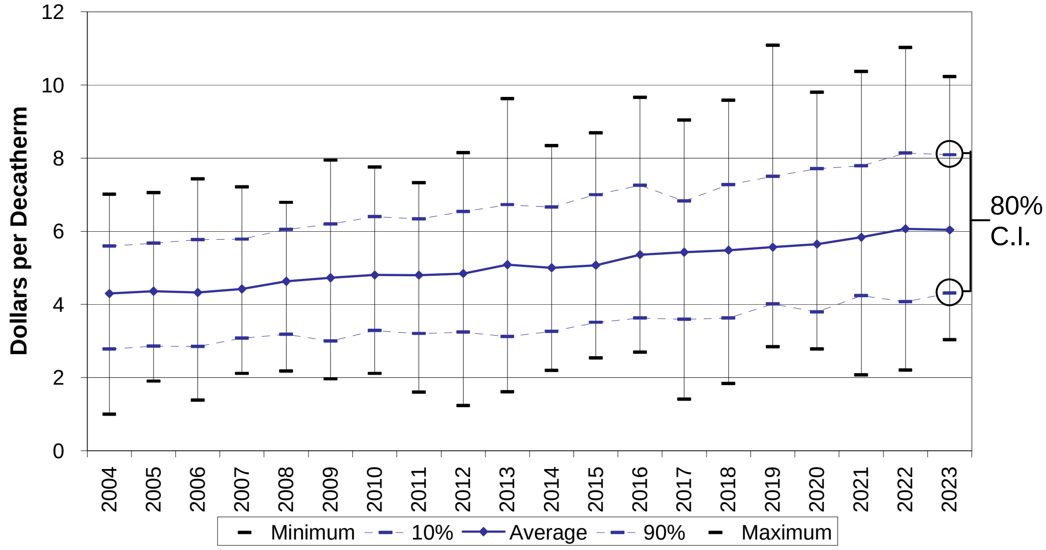
WECC Market Prices and Volatility

As discussed in *Section 5*, the Company ran 200 iterations of hydroelectric generation, natural gas prices, and load using the stochastic variables through the AURORA model. Resultant natural gas and electric market prices for each of the 200 model runs are discussed below.

Wholesale Natural Gas Prices

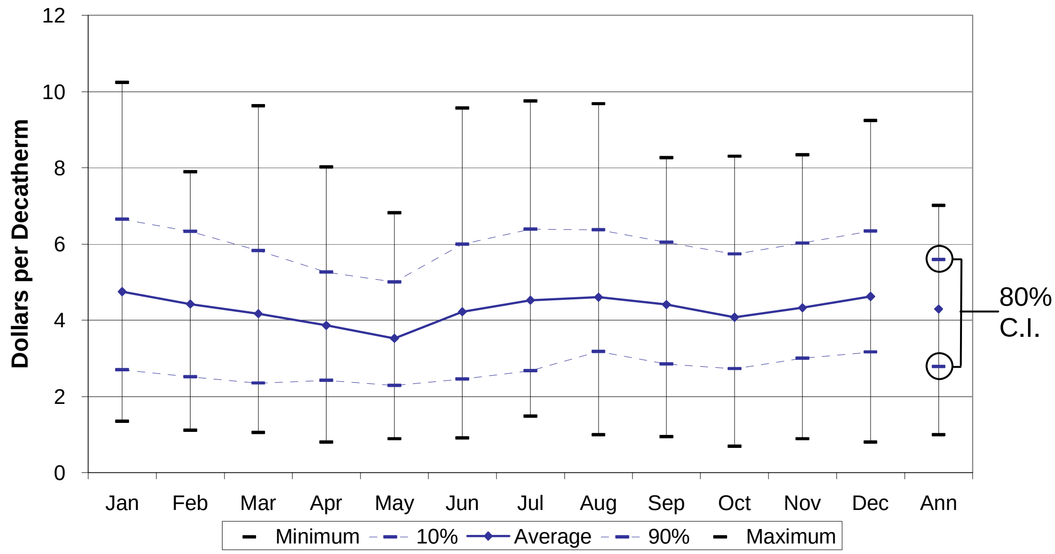
The following chart provides projected wholesale natural gas prices over the twenty-year IRP study. Natural gas prices begin in 2004 at $4.30 per decatherm and rise on average to $6.04 by 2023, for an annual increase of 1.7 percent. The larger dashes represent the lowest and highest prices observed over the 200 iterations. The smaller dashes represent the range between which 80 percent of all iterations of natural gas fell.

Chart 7.1
Annual Wholesale Natural Gas Prices
2004-2023



The following chart details monthly wholesale natural gas prices for 2004 over 200 iterations. Natural gas prices in 2004 average $4.30 per decatherm. Annual 2004 prices vary over the 200 iterations from $0.99 to $7.01. Eighty percent of all iterations fall between $2.78 and $5.59 per decatherm, on an annual average basis.

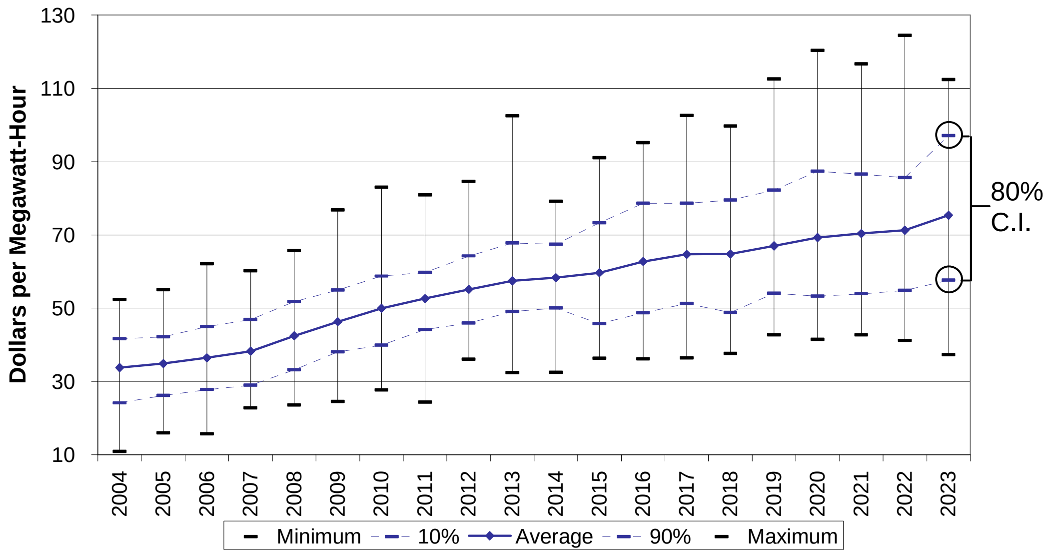
Chart 7.2
Monthly and Annual Wholesale Natural Gas Prices
2004



Northwest Wholesale Electricity Prices

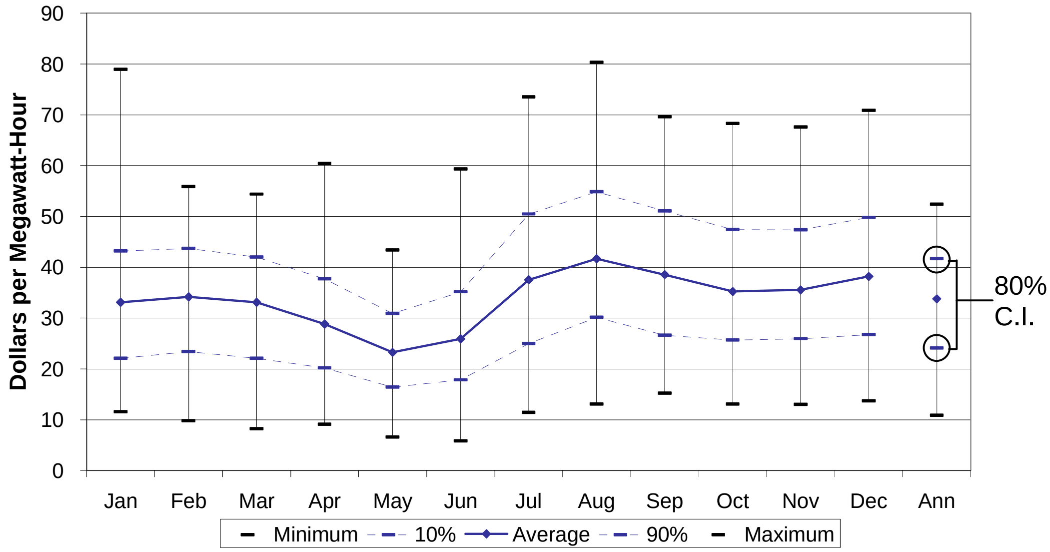
Wholesale electricity market prices in the Northwest trend upward by an average rate of 4.1 percent over the IRP study horizon. The average price in 2004 is $33.76 per MWh. In 2023, the price is $75.33 per MWh. The following chart presents annual average wholesale prices in the Northwest over the IRP term, as well as minimum and maximum annual values and the band within which 80 percent of all observations occur.

Chart 7.3
Annual Northwest Wholesale Electricity Prices
2004-2023



The following chart details average monthly and annual wholesale prices for 2004. Prices over the year average $33.77 per MWh, and range from $5.81 to $80.31. Eighty percent of the monthly iterations for 2004 fall between $16.38 and $54.88.

Chart 7.4
Monthly and Annual Northwest Wholesale Electricity Prices
2004



WECC Regional Electricity Prices

AURORA forecasts wholesale electric market prices across the WECC. While the Company is most impacted by Northwest prices, other areas can affect Northwest levels. The following table provides average annual market prices by area and the twenty-year average escalation of prices. Across the WECC average prices are forecast to rise by 3.9% annually, or 1.4 percent above the assumed rate of general price inflation.

Table 7.1
Average Market Prices by WECC Load Area

WECC Load Area	2004 Load AMW	Annual Average Market Price ($/MWh) by Year 2004	2005	2006	2007	2008	2013	2018	2023	Average Annual Growth
CASo	20,025	37.0	38.1	39.4	41.4	45.8	65.7	70.7	76.4	3.7%
OWI	19,381	33.8	34.9	36.5	38.3	42.5	57.6	64.9	75.5	4.1%
CANo	12,787	36.4	37.5	39.0	41.0	45.6	64.9	69.1	74.4	3.6%
AZ	8,267	31.2	31.8	32.2	33.7	37.0	57.7	63.8	69.7	4.1%
BC	7,074	34.6	36.2	38.4	39.7	44.5	62.2	70.6	76.4	4.0%
AB	6,401	30.6	31.4	32.5	34.1	37.2	58.8	69.9	76.2	4.7%
CO	5,368	30.1	31.1	32.0	34.0	37.9	54.3	61.2	67.7	4.1%
NM	3,518	31.4	32.1	32.8	34.6	38.0	58.8	64.7	70.1	4.1%
UT	2,824	33.1	34.0	35.3	36.4	40.6	58.0	60.5	64.9	3.4%
IDSo	2,618	33.5	34.7	36.3	38.3	42.9	63.2	65.3	70.3	3.8%
NVSo	2,441	36.5	37.6	38.8	40.8	45.3	60.8	66.6	70.7	3.4%
WY	2,301	29.0	30.1	31.2	33.1	37.4	50.2	56.7	63.2	4.0%
MT	1,768	32.2	33.4	34.9	36.8	41.1	59.6	63.6	69.1	3.9%
NVNo	1,435	35.6	36.8	38.1	40.1	44.8	64.6	66.4	70.1	3.4%
Total	**96,209**	**34.0**	**35.1**	**36.4**	**38.2**	**42.5**	**60.9**	**66.9**	**73.5**	**3.9%**

The *Preferred Resource Strategy*

The Company reviewed the modeling results and developed a preferred mix of resource additions, referred to as the *Preferred Resource Strategy* (*PRS*). This decision was made based on a number of factors which are described below.

Focus on First Ten Years of Study

The Linear Programming (LP) Module (described in *Appendix C*) utilized to optimize resource portfolios is set to weigh the first ten years of the study more heavily than the last ten. The LP Module optimizes 2014 through 2023, but does so only after providing a least-cost solution for the 2004 through 2013 timeframe. As a result, emphasis is put on the first ten years of the study period.

Risk and Cost Are Equally Weighted

The Company was asked by Commission Staff and the Technical Advisory Committee to look not only at lowest cost when evaluating various resource portfolio decisions, but also at resource risk profiles. This request recognizes that a resource portfolio should be evaluated based on low costs over time, as well as a reasonable range of variation around the expected cost.

The Company evaluated varying cost/risk relationships (i.e., varying between 30%/70% cost/risk and 70%/30% cost/risk) and found that the resource selection was not affected substantially across this range. Therefore the LP Module was set up to evaluate an optimized portfolio by weighting absolute lowest cost at 50 percent and the variation in cost over the study at 50 percent.

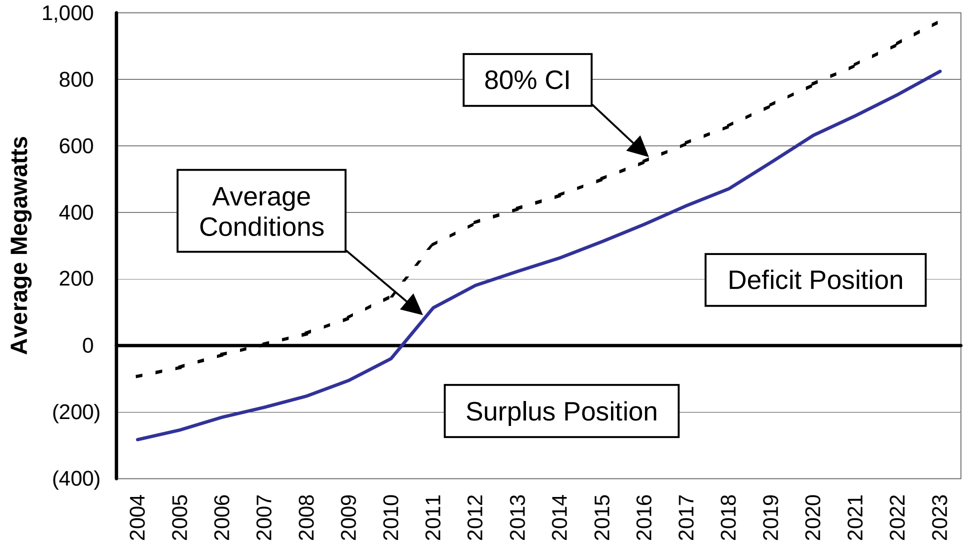
Lowering risk is beneficial to customers where the incremental cost of doing so is relatively low. To this end, the Company evaluated the expected risk of the *PRS* by using both a stochastic approach (utilizing 200 iterations of hydroelectric generation, natural gas prices, and loads) and by utilizing scenarios. The result of including risk as part of the portfolio decision criteria was a slight increase in the portfolio costs. The cost increase was small enough that results can be considered statistically equivalent to utilizing only the lowest expected cost. For further details on the use of scenarios, refer to *Comparison of Scenarios* later in this section.

Eighty Percent Confidence Interval Build Level

As described in *Section 2*, confidence interval planning has numerous advantages over critical water planning. For IRP planning, one benefit is that building to this level generally provides enough resource capacity to serve peak load conditions with Company resources.

The LP Module selects a preferred resource mix that meets the 80 percent confidence interval criteria. The following chart represents Company average requirements over the IRP timeframe, and the increased requirements resulting from the 80 percent confidence interval. The difference is approximately 189 aMW through 2018 and includes 153 aMW for load and hydro variability and 36 aMW for the WNP-3 return obligation. In 2019, the return obligation for WNP-3 drops to 20 aMW. In 2020 the WNP-3 contract expires.

Chart 7.5
Average and 80 Percent Confidence Interval Build Requirements
2004-2023



Limitations Placed on LP Module Resource Selection

Limitations on resource selections are necessary for both quantitative and qualitative reasons. These limitations do not significantly impact the lowest-risk and lowest-cost results. Listed below are specific resource types and the limitations that apply.

Long-Term Purchases

While always in the short-term marketplace to optimize its portfolio, the Company's present strategy is not to rely on long-term market purchases to serve future base-load requirements. This decision is based on a number of factors. Long-term contracts of five years or more are difficult to procure in today's marketplace. After the events of 2000-2001, fewer companies are willing to sell long-term contracts. Current liquidity and credit issues are a concern for transactions extending beyond a few months. In addition, the Company is concerned over potential margin calls and counter party risk. In the current marketplace there is an increased risk that a counter party will not remain in business long enough to deliver on future commitments.

This is not to say that the Company will not utilize the marketplace to serve some portion of customer loads, or capitalize on market opportunities as they present themselves. The Company will still consider short- to medium-term power supply contracts where they provide benefits to our customers.

Cogeneration

Cogeneration was not included as a new resource alternative for the Company. Cogeneration offers the potential to increase societal efficiencies by capturing waste heat from industrial processes, and by capturing a substantial portion of the emissions that otherwise would be released into the environment; but the Company presently is not aware of any new cogeneration alternatives within its service territory that it can rely on to meet long-term load obligations.

The exclusion of cogeneration does not indicate a Company preference to exclude this resource from its portfolio. To the contrary, the Company would welcome a cost-effective cogeneration facility to meet future resource requirements and would adjust its resource plan accordingly.

Wind

The Company has monitored the changing economics for wind generation in the Northwest. Construction costs have decreased significantly, and federal tax credits have brought wind turbines more in line with traditional generation alternatives. To further investigate wind power, the Company has completed a preliminary wind integration study to help identify the integration costs of wind. The result depicts significant integration expenses stemming primarily from increased regulating margin requirements and transmission.

The other challenge of wind is its apparent inability to provide peaking capacity. Not all generation resources may be relied on to meet the capacity requirements of the Company. Capacity resources must be available, or reasonably expected to be available, at the times where load requirements approach overall generating capability. Some wind proponents postulate that wind energy can be used to serve peak requirements. Based upon internal studies, which are included in *Appendix H*, the conclusion has been drawn that wind cannot be relied on to meet Company peak load obligations.

Since wind generation is highly correlated across the Northwest, it is not possible for the Company to acquire a wind product with enough geographic diversity to provide significant capacity. The result is that the Company would most likely need to invest in other capacity resources (e.g., SCCTs) to meet peaking requirements if significant wind resources are acquired, or purchase wind from other sources that already includes shaping services.

Given the uncertainty around wind, the Company has elected to limit the preferred strategy to 75 MW of this resource, or around 25 aMW of energy. The Company also proposes to continue the study of wind to stay well informed on issues, potential declining costs, and any future opportunities. Where the Company can purchase cost-effective wind generation that includes an integration service, it will re-evaluate this amount. However, the Company is not aware of an entity in the Northwest that is providing wind integration services at this time.

In combination with 75 MW of wind energy, the Company would consider the installation of a peaking unit as a firming service component. A peaking unit would also have the potential to provide a portion of the Company's future peaking requirements.

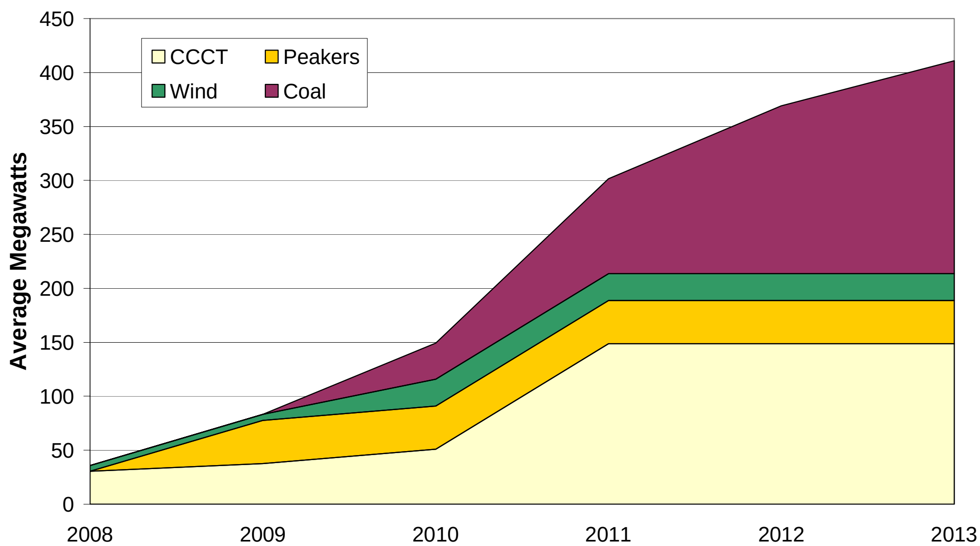
The Preferred Resource Mix

Based on the conditions and limitations listed above, the LP Module determined a preferred mix of new resources to meet the Company's future requirements. The *Preferred Resource Strategy* includes the following mix of resources and quantities during the first ten years of the study (2004-2013):

- 149 aMW of CCCT
- 25 aMW of wind
- 197 aMW coal
- 40 aMW of SCCT

By the end of the first ten years, a total of 411 aMW are developed. A depiction of the *Preferred Resource Strategy* is included in the following graph. Significant annual deficiencies do not develop until 2008, so the chart details only the years 2008 through 2013.

Chart 7.6
Preferred Resource Mix (in aMW)
2008-2013

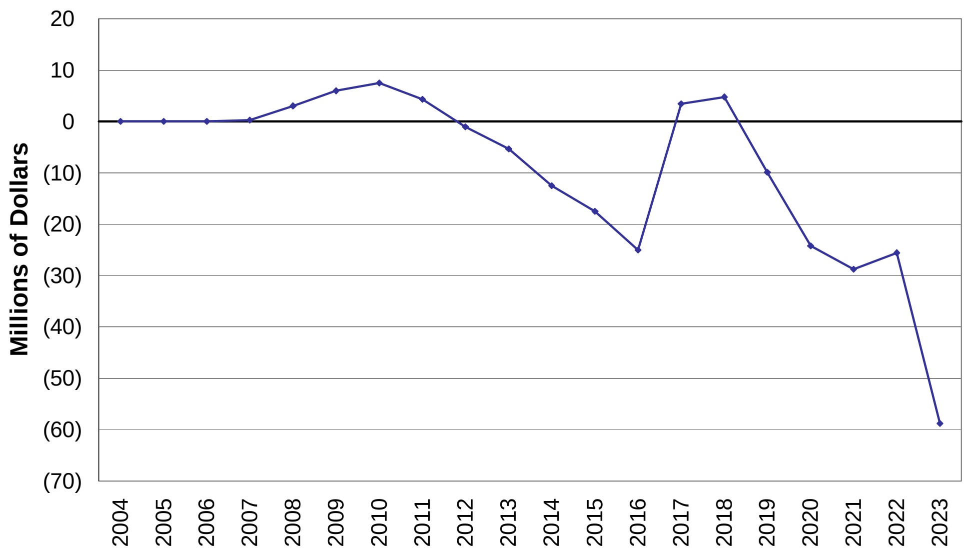


After 2013, only coal is selected as a result of a change in the relationship between natural gas and coal prices. Natural gas prices over the IRP term increase faster than coal, making coal generation less costly in later years. In total, between 2014 and 2023, an additional 566 aMW of coal resources are selected in the *Preferred Resource Strategy*.

Costs of Preferred Resource Strategy Versus "No Additions"

Expected cost over the IRP term has traditionally been the benchmark of least-cost planning; and generally includes capital recovery, operation and maintenance, fuel, and transmission costs. This IRP continues to focus on expected power supply cost on a net present value (NPV) basis. Under *No Additions*, where no resource acquisitions are made, the ten-year NPV of the power supply cost is $1.11 billion. Over twenty years, the NPV rises to $2.73 billion. The *Preferred Resource Strategy* (*PRS*) has NPV values of $1.11 and $2.69 billion, respectively. Over twenty years, the NPV for the *PRS* is 1.6 percent lower than *No Additions*. Refer to the following chart for a depiction of the difference in power supply expense between the *PRS* and *No Additions* strategy.

Chart 7.7
Annual Net Power Supply Expenses
Difference Between *PRS* and *No Additions*
2004-2023

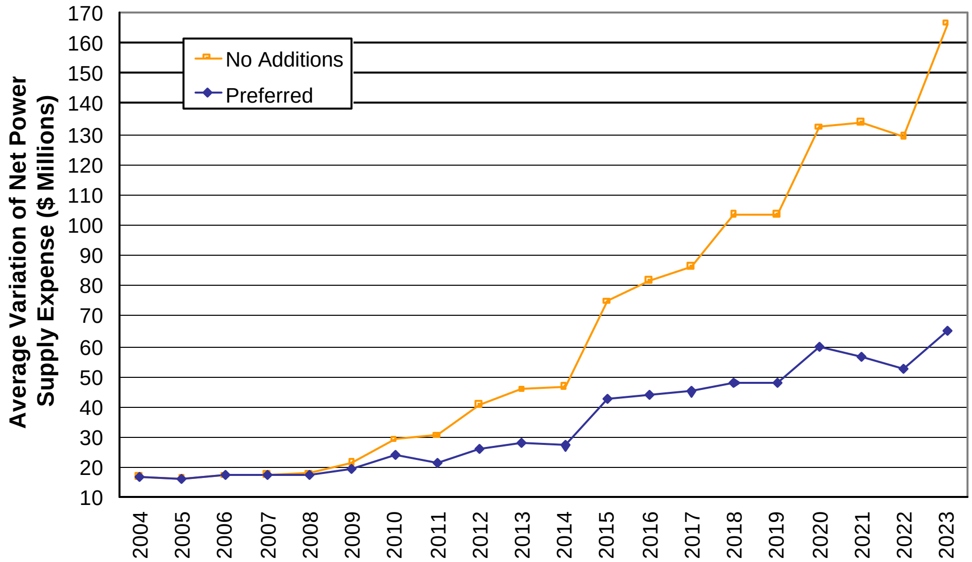


On a cost basis, the *Preferred Resource Strategy* provided a similar result to *No Additions*, with a modestly higher ten-year cost and a modestly lower twenty-year cost. The significant difference appears when assessing the risk profiles, detailed next.

Risk Assessment of Preferred Resource Strategy

Portfolio risk is based on the annual variance from the average power supply expense over 200 iterations of Monte Carlo. Over time the Company has an opportunity to lower its expected variance relative to *No Additions*. The variance in net power supply expenses for the *PRS* and *No Additions* strategy is shown in the chart below.

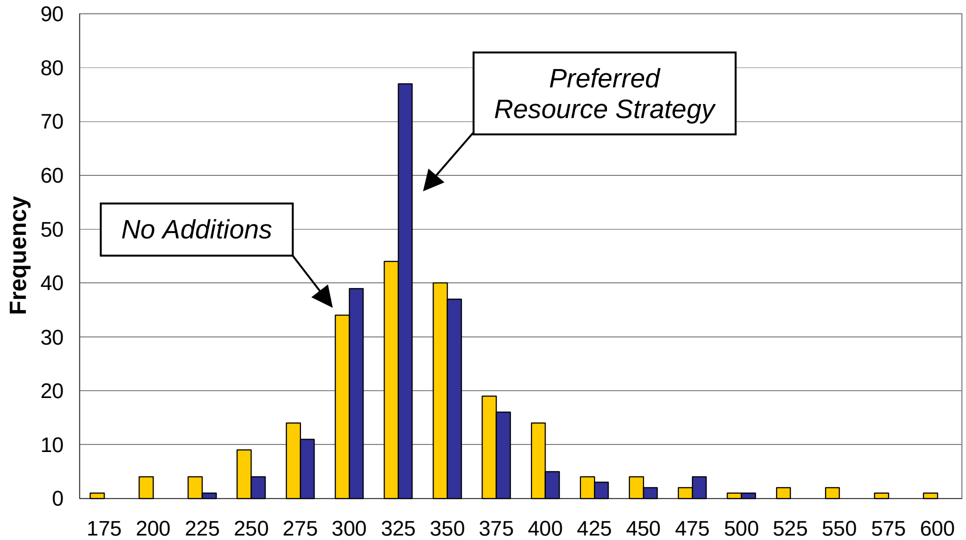
Chart 7.8
Variance in Net Power Supply Expenses
Preferred Resource Strategy* vs. *No Additions
2004-2023



As load grows, the *No Additions* strategy becomes more risky as an increasing portion of system loads are met with volatile spot market purchases. The *Preferred Resource Strategy*, on the other hand, produces a substantially lower risk profile. By the end of twenty years, volatility under the *PRS* has fallen to 40 percent of the *No Additions* strategy. In nominal dollars, variability of net power supply expense under the *PRS* is 100 million dollars lower than under the *No Additions* strategy.

The following chart shows the distribution over 200 iterations of 2013 power supply expense for the *PRS* and *No Additions* strategy. The range of net power supply expense for the *PRS* is $273 million, based on an average of $319 million. The range of net power supply expense for the *No Additions* strategy is $412 million, based on an average of $324 million. In other words, the variation in power supply expense (risk) for the *PRS* is roughly one-third lower than the *No Additions* strategy.

Chart 7.9
Distribution of Net Power Supply Expenses – 2013
Preferred Resource Strategy* vs. *No Additions
(in Millions of Dollars)



Capital Expenditure Requirements

The modeling of future resource acquisitions includes built-in assumptions regarding new construction costs. The *Preferred Resource Strategy* requires a capital investment of $725 million from 2007 to 2013 (or $610 million in 2004 dollars). Over twenty years, that amount increases to nearly $2.4 billion. Capital expenditures in nominal dollars over time are presented in the following table.

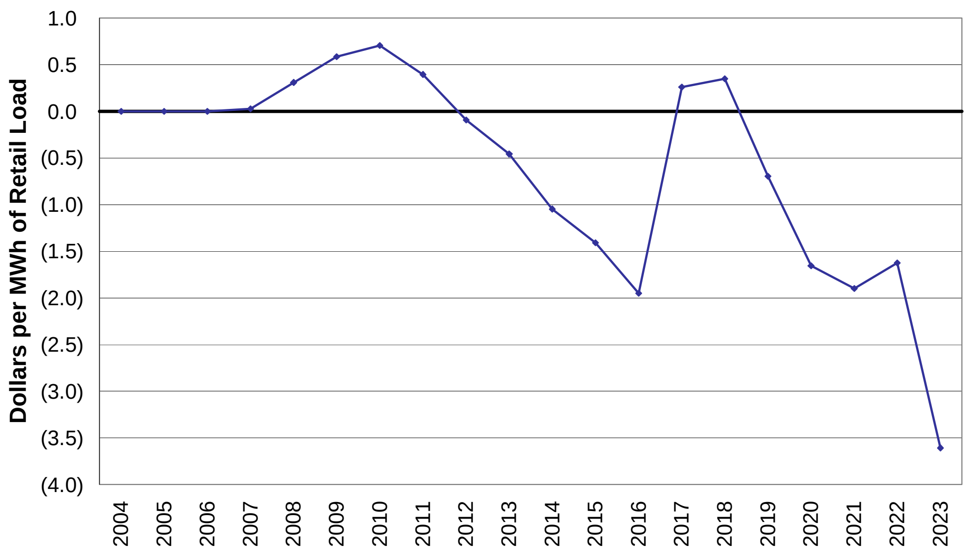
Table 7.2
Annual Capital Expenditures of *Preferred Resource Strategy*
2004-2023 ($millions)

Year	Capital		Year	Capital
2004	0.0		2014	105.3
2005	0.0		2015	127.8
2006	0.0		2016	139.3
2007	2.4		2017	153.4
2008	39.4		2018	146.1
2009	44.9		2019	181.2
2010	146.5		2020	187.2
2011	222.2		2021	176.7
2012	164.8		2022	198.4
2013	104.7		2023	225.4
Total	725.0			1,640.8
over 20 years				*2,365.9*

Rate Impact of Preferred Resource Strategy

Rate impacts of future resource acquisition strategies are difficult to accurately quantify. However, it is important to compare resource strategies in a manner that indicates their potential impact on rates. To simulate the rate impacts of the *Preferred Resource Strategy*, the Company has calculated a power supply expense equal to the twenty-year NPV of the strategy divided by the sum of energy sales over the same time. While this method does not provide the revenue requirement for power supply costs, it does explain how rates would generally be impacted. The following chart displays the difference in rate impact between the *PRS* and *No Additions* strategy over the IRP timeframe.

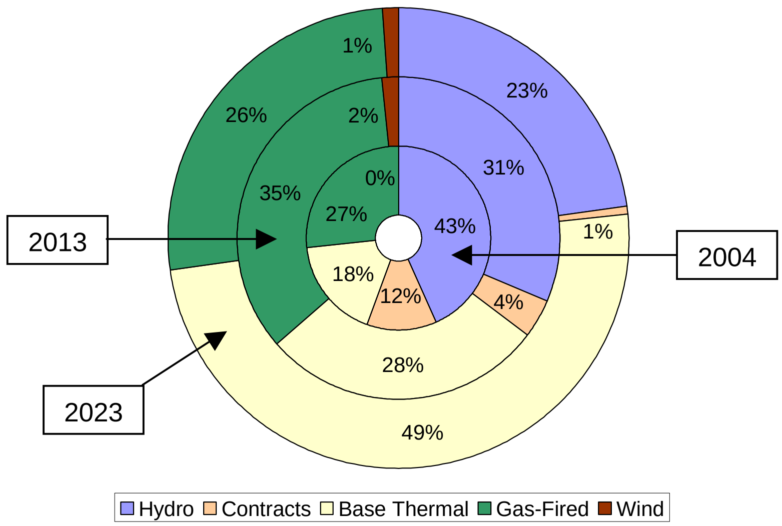
Chart 7.10
Estimated Rate Impact
Difference Between *PRS* and *No Additions*
2004-2023



Qualitative Benefits of Preferred Strategy

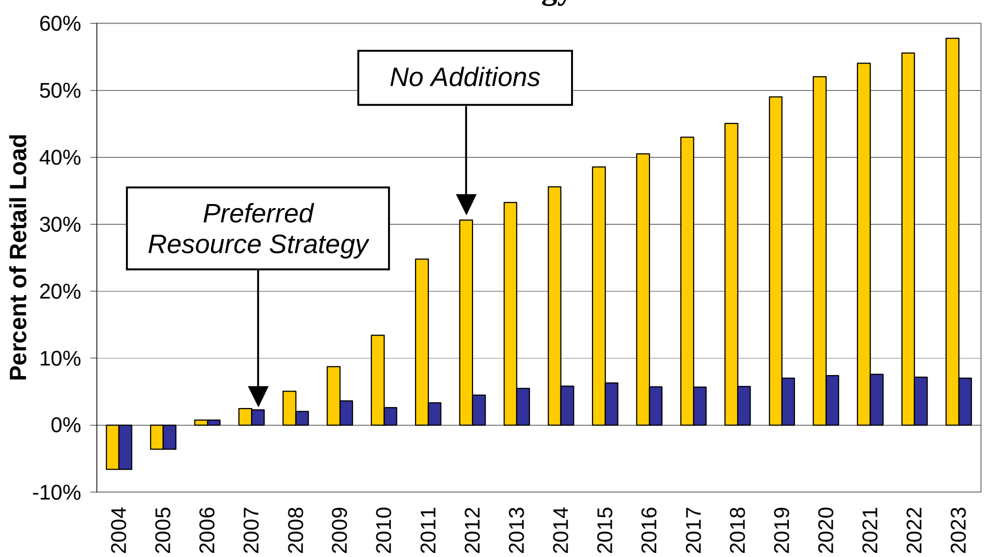
Diversity of fuel supply is an important qualitative issue. The Company relies heavily on hydroelectric generation, and is thereby subject to varying hydrological conditions. The current resource mix of coal, wood, and natural gas-fired plants has helped to diversify the mix of fuels, as well as the relationship between high capital/low variable cost and low capital/high variable cost plants. The following chart provides a picture of the Company's resource mix in 2004, 2013, and 2023 under the *PRS*.

Chart 7.11
Utility Resource Mix (aMW)
2004, 2013, and 2023



As discussed earlier, the *No Additions* strategy relies entirely on market purchases to serve load growth. As a result, the Company would rely on market power for nearly 30 percent of its annual average load over twenty years. Under the *Preferred Resource Strategy*, market purchases account for an average of four percent of retail load. Modest purchases should be expected under all strategies as the Company optimizes the operation of its gas turbines, but significant purchases are indicative of an overly short position. Refer to *Chart 7.12* for a depiction of market purchases under the two strategies.

Chart 7.12
Annual Net Market Purchases
Preferred Resource Strategy vs No Additions



Adjusted Load and Resource Balance From Preferred Resource Strategy

A discussion of the Company's forecasted load and resource balances for both energy and capacity may be found in *Section 2*. The two tables below provide adjusted balances with the inclusion of those resources selected in the *Preferred Resource Strategy*.

Table 7.3
Adjusted Loads and Resources – Energy
2004-2008, 2013, 2018, 2023

	2004	2005	2006	2007	2008	2013	2018	2023
Obligations								
Retail Load	985	1,014	1,051	1,083	1,120	1,326	1,569	1,860
80% Conf. Interval	189	189	189	189	189	189	189	153
Total Obligations	*1,174*	*1,203*	*1,240*	*1,272*	*1,309*	*1,515*	*1,758*	*2,013*
Existing Resources								
Hydro	550	545	530	530	529	477	471	458
Net Contracts	156	157	175	177	177	58	59	12
Base Thermal	223	230	223	223	230	230	230	230
Gas Dispatch	158	156	158	158	156	158	158	156
Gas Peaking Units	181	181	181	181	181	181	181	181
Total Existing Resources	*1,268*	*1,269*	*1,267*	*1,269*	*1,273*	*1,104*	*1,099*	*1,037*
PRS Resource Additions								
Wind	0	0	0	0	6	25	25	25
Base Thermal	0	0	0	0	0	197	446	763
Gas Dispatch	0	0	0	3	30	149	149	149
Gas Peaking Units	0	0	0	0	0	40	40	40
Total PRS Resources	*0*	*0*	*0*	*3*	*36*	*411*	*660*	*977*
Net Position	**94**	**66**	**27**	**0**	**0**	**0**	**1**	**1**

Table 7.4
Adjusted Loads and Resources – Capacity
2004-2008, 2013, 2018, 2023

	2004	2005	2006	2007	2008	2013	2018	2023
Obligations								
Retail Load	1,470	1,515	1,570	1,617	1,672	1,982	2,349	2,780
Operating Reserves	107	107	105	105	107	130	150	174
Total Obligations	*1,577*	*1,622*	*1,675*	*1,722*	*1,779*	*2,112*	*2,499*	*2,954*
Existing Resources								
Hydro	1,177	1,177	1,135	1,134	1,133	1,043	1,035	998
Net Contracts	70	19	43	45	45	-73	78	-2
Base Thermal	272	272	272	272	272	272	272	272
Gas Dispatch	176	176	176	176	176	176	176	176
Gas Peaking Units	236	236	236	236	236	236	236	236
Total Existing Resources	*1,931*	*1,880*	*1,862*	*1,863*	*1,862*	*1,654*	*1,797*	*1,680*
PRS Resource Additions								
Wind	0	0	0	0	0	0	0	0
Base Thermal	0	0	0	0	0	229	518	886
Gas Dispatch	0	0	0	3	32	156	156	156
Gas Peaking Units	0	0	0	0	0	42	42	42
Total PRS Resources	*0*	*0*	*0*	*3*	*32*	*428*	*716*	*1,084*
Net Position	354	258	187	144	115	-30	14	-189
Reserve Margin	*31.4%*	*24.1%*	*18.6%*	*15.4%*	*13.3%*	*5.0%*	*7.0%*	*-0.6%*

Based on the *Preferred Resource Strategy*, the Company maintains an energy balance at the 80 percent confidence level through the end of the IRP timeframe. Building to the 80 percent level generally provides an adequate capacity reserve margin. As a result, the *Preferred Resource Strategy* maintains planning reserve margins in excess of twelve percent through 2009. Falling reserve margins after 2009 are a reflection of the Company outgrowing its hydroelectric resources, which tend to have higher capacity to energy ratios than other generating facilities. The Company will need to address a reduced capacity surplus in a later study, as discussed in *Section 8*.

Resource Acquisition Under Preferred Resource Strategy

The *Preferred Resource Strategy* is designed without limitations on the quantity of megawatts purchased by the Company in any given year. This assumption, while significantly reducing the complexity of the LP Module logic, is not possible in reality. Instead, the Company would likely implement the *PRS* in a less smooth manner. For example, it is unlikely that in 2009 the Company would be able to procure 10 aMW from a CCCT plant, as directed by the LP Module. Instead it might enter into an agreement that would cover the 149 aMW needs of 2008 through 2011.

Comparison of Strategies

Section 5 describes the resource portfolio strategies considered in addition to the *Preferred Resource Strategy* (*Lowest Cost/CCCT*, *Lowest Risk*, *All Coal*, and *Wind Strategy*). Each of the strategies was compared using the same measurements used to compare the *PRS* and *No Additions* strategies. These measurements include cost, risk, capital expenditures, rate impacts, and reliance on the wholesale marketplace. The result was that the *PRS* performed well across the criteria when compared to other strategies.

The ability of the *PRS* to reduce risk at a small incremental cost was the largest impact witnessed in the comparisons. The *Lowest Risk* strategy reduced risk by an additional one percent of average power supply expense, but only through much greater capital expense and further reliance on coal. The *Lowest Risk* strategy also relied heavily on wind plants, which do not provide capacity.

The capital costs of the *Preferred Resource Strategy* fell in the middle of the range of strategies. Portfolios relying more heavily on coal have costs as much as $500 million more over twenty years (in 2004 dollars). The *Lowest Cost/CCCT* strategy, which relies exclusively on CCCTs has a substantially smaller capital requirement, but suffers from significant fuel price risk.

Rate impacts during the first ten years of the study were lower in the *Lowest Cost/CCCT* strategy. Costs were higher under each of the remaining strategies. Reliance on the marketplace was small and similar for all strategies except for *No Additions* and the *Wind Strategy*. Each of these relied more heavily on market purchases to meet load requirements.

For further results from the analysis of strategies in this IRP, refer to *Appendix E*.

Comparison of Scenarios

Section 5 also describes eight scenarios considered by the Company to capture specific marketplace futures (*Average*, *Critical Water*, *High Gas*, *High Load*, *Load Loss*, *New Trans*, *Coal Build*, and *Carbon Tax*). Each scenario was included to test the *Preferred Resource Strategy* and other strategies in the face of greatly different future market conditions. The *PRS* performed well across the scenarios, as compared to the other strategies. The following text will briefly describe the scenario results.

Under the *Critical Water* scenario, results across the strategies are similar to the results of 200 iterations of Monte Carlo included in the *Base Case*. The largest impact of low water is that it drives average wholesale market prices up. The *High Gas* scenario results in the largest impact on wholesale market prices, primarily as a result of the WECC's heavy reliance on gas turbines. Under high gas prices, the *PRS* outperforms the *Lowest Cost* strategy due to its reduced reliance on natural gas-fired resources. However, strategies with more coal-fired generation benefit even more.

The *High Load* scenario, with an increase in WECC loads, drove wholesale market prices up to levels nearly as high as the *High Gas* scenario. The *No Additions* strategy was significantly more expensive than the *PRS* and all other strategies under high loads. The greatest benefactor of the *High Load* scenario was the *Lowest Risk* portfolio, with its heavy reliance on coal and wind.

The *Load Loss* scenario, in which the Company would lose 300 aMW of retail load, reduced the amount of future resource requirements by the same amount. This scenario disadvantaged both the *All Coal* and *No Additions* strategies. The *PRS* had similar costs to the remaining strategies.

The *New Trans* scenario, in which extensive transmission is added between Montana, Wyoming, and several other load areas, actually benefited the *No Additions* strategy. Since the additional transmission resulted in extensive additions of coal-fired generation, spot market prices were kept low. See *Section 4* for a discussion of why additional investment in transmission facilities is necessary to support coal plant development.

The *All Coal* scenario benefited strategies with low capital cost investments (CCCTs) due to reduced market price volatility. The *No Additions* strategy is also an attractive option under an *All Coal* scenario, since exposure to market prices is significantly less risky.

The *Carbon Tax* scenario disadvantages coal plants, and to a lesser extent gas-fired resources. Under the *Carbon Tax* scenario, *No Additions* and *Lowest Cost* (with its focus on CCCTs) outperformed the *PRS*. The *All Coal* strategy was the highest cost, due to the new emission taxes.

For further results from the analysis of scenarios in this IRP, refer to *Appendix E*.

Summary and Conclusions

This study represents a considerable analytical effort and provides a means to evaluate the *Preferred Resource Strategy* against several alternative strategies under varying scenarios. Overall, the *PRS* fairs well, not only in the *Base Case*, but also under numerous scenarios. The *PRS* will meet not only the Company's load obligations over time, but will also provide for reserve margins in excess of twelve percent through 2009.

The *PRS* provides for a significant reduction of risk. This reduction comes at a very modest impact to expected costs. Under the *PRS*, the average variation from net power supply expenses is forecast to fall from about eighteen percent in 2004 to eight percent in 2011. The reduction in risk under the *PRS* comes despite significant future variation in hydroelectric generation, natural gas prices, and regional demand. The Company believes that customers will benefit from the focus on risk reduction through greater rate stability. The *Preferred Resource Strategy* will require significant additional investments over time. In the first ten years of the study, the Company will need to invest nearly $725 million in new capital beyond present forecasts. Over twenty years, a total of $2.4 billion will be required, nearly twice the current utility plant in service figure.

Section
8
Action Plans & Avoided Costs

Overview

This section provides a summary of the 2001 IRP Action Plan and how the Company addressed each of the items. A 2003 Action Plan follows and details the studies and actions the Company will take between now and the 2005 IRP. Finally, avoided costs are presented for the IRP timeline.

Summary Report for 2001 Action Plan

In the 2001 IRP, the Company listed specific action plan activities, which were to be accomplished during the past two-year planning cycle. Each 2001 Action Item is listed below, immediately followed by an explanation of the Company's response in italics:

Public Process

1. Continue free flowing exchange of information with TAC members.

   The number of TAC meetings was increased from three to four. Efforts were also made to increase attendance. The mailing list was expanded to include additional customers who might have an interest in resource planning. The Company now has a mailing list of 53 individuals who receive IRP information and TAC meeting invitations.

2. Propose changes to the IRP process that will be useful in the competitive market era.

   The IRP process has been modified to incorporate significant modeling of present and future market conditions. Monte Carlo risk analysis has been incorporated to evaluate volatile market conditions.

Demand-Side Management

1. Pursue energy savings for the next three years with funding from the tariff rider.

   The Company has continued to operate demand-side management programs focused on obtaining available cost-effective resources. During the summer of 2001, the Company launched a series of extraordinary temporary programs intended to immediately impact utility load during a period of extreme wholesale electric price volatility. As a result of these programs the tariff rider presently has a negative balance. Tariff rider funding is continuing and the Company anticipates this balance will return to zero by the close of 2005.

2. Consider the development of programs that will allow peak shaving.

   Proposals for peak-shaving measures were submitted to the Company in 2000 as part of the Company's All-Resource RFP. Additionally, other proposals have been evaluated. To date none of these programs have proven cost-effective. One demand-response program proposal, submitted by an external engineering firm, remains in the evaluation stage.

3. Determine the potential for time-of-use (TOU) rates.

   The Company continues evaluated the cost-effectiveness of various hypothetical TOU rate options, but has no specific plans for implementation at this time.

4. Execute and implement DSM contracts that were selected under the 2000 RFP.

   The Company selected and completed contracts for two proposals submitted under the 2000 RFP. Two resulting programs are currently available to qualifying customers.

Supply-Side Resource Options

1. Pursue the base plan for Spokane River relicensing.

   Spokane River hydroelectric relicensing is proceeding following the Alternative Licensing Procedures (ALP) used in the successful Clark Fork effort. The current license expires July 31, 2007. The ALP is a collaborative approach to decision making for relicensing. Over 100 stakeholder groups are involved in this effort. Primary studies will be conducted in 2003. Additional studies will follow in 2004, as will development of proposals guiding a new license application. The Company must file a new application by July 31, 2005.

2. Upgrade at least two units at the Cabinet Gorge hydro facility.

   The Company is currently in the initial phases of the Unit 2 upgrade at Cabinet Gorge. The construction for the replacement runner, stator rewind, rotor refurbishment, machine monitoring equipment, and other refurbishment work is scheduled to start late summer of 2003 and be completed by spring of 2004. The Unit 2 upgrade will provide a fifteen MW increase in capacity at Cabinet Gorge. This estimate is based on the actual performance realized with the upgrade of Unit 3, completed three years ago.

   The Company has also identified other hydroelectric upgrades at Cabinet Gorge and Noxon Rapids. While these upgrades are economically viable and beneficial for maintenance purposes, they have been pushed out due to capital budget restrictions.

3. Evaluate the effects of a micro turbine on the system.

   A micro turbine was added to the downtown Spokane system. The various operating characteristics, under different loadings, have been recorded. These included fixed and variable operating costs. The unit is only operated when it is economically beneficial to do so.

4. Install inlet coolers at Rathdrum Combustion turbines for additional summer peaking output.

   This was completed in July of 2000. The data shows a five MW/unit increase on hot days.

5. Evaluate RFP bids, compare to Company options, and select options that are cost effective and that best meet the Company's long-term resource needs. Complete transfer agreements for selected supply-side resource.

   The best options under the RFP were selected in December of 2000. Selected were three DSM bids and one supply-side bid (Coyote Springs 2). Transfer agreements for Coyote Springs 2 have been completed. The generating facility is essentially complete, with the exception of the transformer. The original transformer was energized on March 3, 2002. It failed due to an internal explosion on May 6, 2002. The second transformer was ordered on June 21, 2002. This transformer failed its acceptance test in the factory on August 30, 2002. The transformer had to be repaired at the factory and passed testing on November 5, 2002. It was prepared for shipment and placed on a dedicated shipping vessel, which came across the Atlantic into Houston.

   It arrived in Houston on December 4, 2002 and was immediately placed on a railcar and delivered to Coyote Springs 2 in Boardman, Oregon. It was moved to its foundation and on December 18 apparent internal damage was observed. Representatives from the manufacturer traveled to the site and performed further internal inspections. The results of the inspections were that the transformer did have internal damage, most probably caused by shipping, and that it could not be repaired onsite.

   Arrangements were made to have the transformer repaired and it was shipped to California. The initial inspection of the damage at the factory took place on February 10, 2003. The repair is now complete and the transformer has gone through a "dryout" phase. It has been filled with oil and is now in a resting stage to insure that all of the transformer insulation is saturated with oil.

   The testing of the transformer will take place the week of April 21, 2003. The transformer should be returned to Coyote Springs on May 18, 2003 and be energized by May 28, 2003. The plan is to have the plant commercial by July 1, 2003.

6. Pursue re-negotiation efforts with Mid-Columbia PUDs.

   Renegotiation of the contracts with Grant County PUD has been completed. These contracts affect the output of the Priest Rapids and Wanapum dams to the Company. As the contracts for the Rocky Reach and Wells Canyon dams come up for re-negotiation, the Company will be actively involved.

7. Evaluate the need for additional supply or generation units to handle variability in hydro, retail loads, and potential generation outages under projected market conditions.

   The evaluation of potential new supply or generation units related to various market conditions is addressed through the utilization of significant computer modeling. In this IRP, the entire WECC has been modeled under multiple scenarios incorporating Monte Carlo simulation. Numerous factors in market volatility have been simulated, including hydroelectric generation variability, load variability, and fuel price variability.

Resource Management Issues

1. Implement relicensing programs on the Clark Fork River hydro projects, as part of the "Living License" commitment.

   The Company is working with other stakeholders in fulfilling this commitment under the new license. The Company will spend about five million dollars per year for the next 45 years.

2. Continue to examine and pursue cost-effective efficiency improvements at generation facilities.

   Because of financial conditions all capital improvements are placed on hold. Future upgrades include Unit 4 at Cabinet Gorge, two units at Noxon Rapids, and a new control system at Long Lake.

2003 Action Plan

The Company's *Preferred Resource Strategy* provides direction for long-term activities. The Company's new near-term action plan outlines activities that will support this strategy and improve the planning process during 2003 and 2004. Progress on these activities will be monitored over the two-year planning cycle and reported in the Company's next Integrated Resource Plan. They are designed to improve the planning and resource acquisition processes.

Public Process

1. Propose changes to WUTC on the IRP/RFP process that will provide improvements.

2. Continue to manage the free flow of information with TAC participants.

Demand-Side Management

1. Evaluate the cost-effectiveness and resource potential of conservation voltage reduction on the Company's system.

2. Acquire electric resources that are at least proportionate to the percentage of DSM revenues being expended.

3. Field a DSM portfolio that continues to be cost-effective on a societal and utility basis.

4. Prepare contingency plans for future emergency responses to unexpected fluctuations in wholesale electric markets.

5. Prepare for a reevaluation of continued participation in the Northwest Energy Efficiency Alliance upon expiration of the current contract period (expiring at the end of 2004).

6. Convene a TAC meeting in the fall of 2003 to discuss the various alternatives for integrating DSM into the 2005 IRP process.

Supply-Side Resource Options

1. Pursue a new license for the Spokane River projects by filing a new license application by July 31, 2005.

2. Continue to evaluate the effects and costs of integrating wind generation into the Company's electrical system.

3. Consider and evaluate the potential to add coal facilities to the Company's mix of existing generating resources.

4. Determine the feasibility of entering into a medium-term firm power sale during the Company's surplus years.

5. Initiate a study to determine the optimal reserve margin for the Company, including the benefits of additional peaking capacity.

6. Continue to assess the cost-effectiveness of new resource additions.

7. Continue to work with Commission Staff on methods whereby the Company can acquire resources with development timelines beyond one or two years and increase the probability for full rate recovery.

Resource Management Issues

1. Analyze the uncertainty of decisions as the Company confronts risks and opportunities.

2. Continue to assess the electric marketplace and its effect on the Company.

Avoided Costs

The Company develops avoided costs as part of the IRP process. The Company believes that the marketplace provides the truest estimate of avoided cost. Models such as AURORA provide insight into long-term market prices and therefore can be used to develop avoided costs. Results from the 200 iterations were averaged to develop the annual avoided cost schedule for this IRP, as shown in *Table 8.1*. For background information on avoided costs, refer to *Appendix O*.

Table 8.1
Avoided Costs ($/MWh, Flat 7x24)
2004-2023

Year	Price	Year	Price	Year	Price	Year	Price
2004	33.72	2009	45.98	2014	58.28	2019	67.28
2005	35.06	2010	50.10	2015	60.20	2020	69.19
2006	36.49	2011	52.97	2016	62.63	2021	70.32
2007	38.20	2012	55.35	2017	64.87	2022	71.28
2008	42.44	2013	57.39	2018	65.41	2023	75.71

Production Credits

Given the breadth of an integrated resource plan, its development is dependent on the work and expertise of a broad range of individuals. The 2003 IRP was developed and documented by a small team of utility staff; but they relied on a larger body of skills within the Company. Following are lists of those individuals who contributed to the product.

Primary 2003 IRP Team

Individual	Contribution
Clint Kalich, Manager of Resource Planning & Analysis	Project Manager/ Author
Jason Fletcher, Power Supply Analyst	Lead Modeler/ Author/Editor
Doug Young, Senior Engineer Power Resources	Author/Historian
Randy Barcus, Chief Corporate Economist	Load Forecast Author/ Statistics Consultant
Jon Powell, Partnership Solutions Manager	Conservation & DSM Author

Other Contributors

Contributor	Contributor
Bill Johnson, Senior Power Supply Analyst	Bruce Folsom, Manager of Regulatory Compliance
George Perks, Joint Generation Manager	Curt Rettenmier, RAD Analyst
Linda Gervais, Regulatory Analyst	Ed Groce, Manager of Transmission Planning
Dick Winters, Gas Analyst	Bruce Howard, Spokane River Licensing Manager
Steve Lester, Oracle Database Administrator	Brad Simcox, Utility Intern
Ross Taylor, Telecommunications Project Engineer	Todd Bryan, Technology Coordinator
Steve Wenke, Chief Generation Engineer	Patrick Maher, Senior Transmission Contracts Analyst
Bob Anderson, Director of Environmental Affairs	Dave Heyamoto, Market Solutions Manager