Avista Corp.
1411 East Mission PO Box 3727
Spokane, Washington 99220-3727
Telephone 509-489-0500
Toll Free 800-727-9170

AVISTA Corp.

August 29, 2007

AVU-E-07-08

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
Statehouse Mail
W. 472 Washington Street
Boise, Idaho 83720

Dear Ms. Jewell:

RE: Avista Utilities 2007 Electric Integrated Resource Plan

Per IPUC's Integrated Resource Plan Requirements 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 , Avista Corporation d/b/a/ Avista Utilities, hereby submits for filing an original, an electronic copy and 7 copies of its 2007 Electric Integrated Resource Plan.

The Company submits the IRP to public utility commissions in Idaho and Washington every two years as required by state regulation. Avista regards the IRP as a methodology for identifying and evaluating various resource options and as a process by which to establish a plan of action for resource decisions.

The 2007 Plan is notable for the following:

- The Company is currently long on energy and capacity until 2011, this position will be extended to 2017 for energy and 2015 for capacity with the addition of the Lancaster Generation Facility in 2010;
- Avista's Preferred Resource Strategy Model (PRiSM) developed an efficient frontier that balances both portfolio risk and cost considerations;
- The Preferred Resource Strategy (PRS) includes 350 MW of CCCT, 300 MW of wind, 35 MW of other renewables, and 87 MW of conservation between 2007 and 2017;
- Conservation acquisition is approximately 25 percent higher than in the 2005 IRP;
- The PRS no longer includes coal-fired generation; fixed price natural gas takes its place;
- Greenhouse gas emission costs are included in the Base Case;
- Washington State's Energy Independence Act (I-937) requirements up through 2016 will be met primarily with plant upgrades; and
- Paper use and printing costs have been reduced by putting supporting documents on our web site at www.avistautilities.com/resources/plans/electric.asp.

Please direct any questions regarding this report to Clint Kalich at (509) 495-4532.

Sincerely,

Linda Gervais

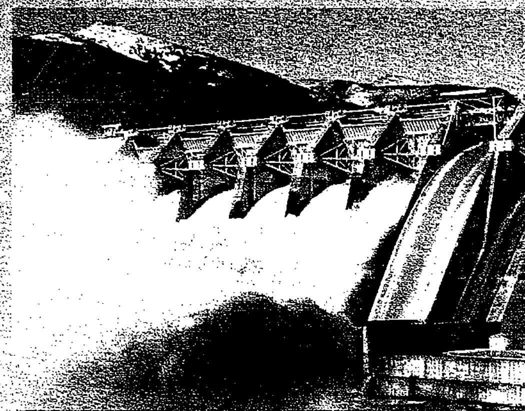
Linda Gervais
Regulatory Compliance, State and Federal Regulation

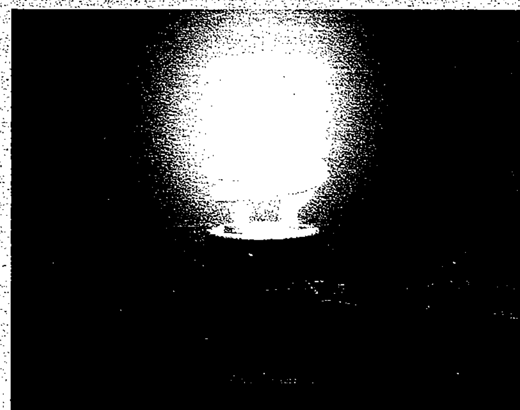
c: Mr. Rick Sterling

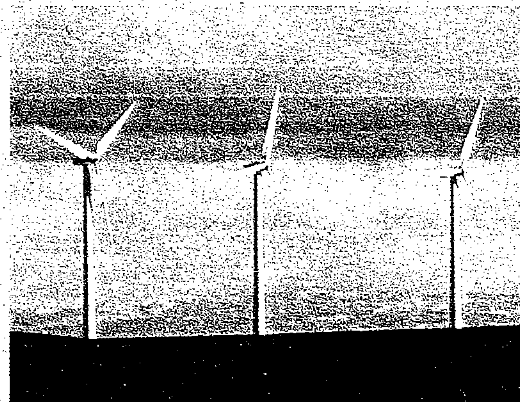
AVU-E-07-08

2007 Electric
Integrated Resource Plan

August 31, 2007







www.avistautilities.com

AVISTA®

PHOTO CREDITS

- Avista's investment in transmission infrastructure crosses the wheat fields of Washington state's Palouse region. Photo by Hugh Imhof, Avista.
- Three key components of Avista's renewable energy and DSM plans include the Noxon Rapids Hydro Facility on the Clark Fork River in Montana, education about energy efficient compact flourescent bulbs, and including power generated at the Stateline Wind Farm on the Southeast border of Washington and Oregon.

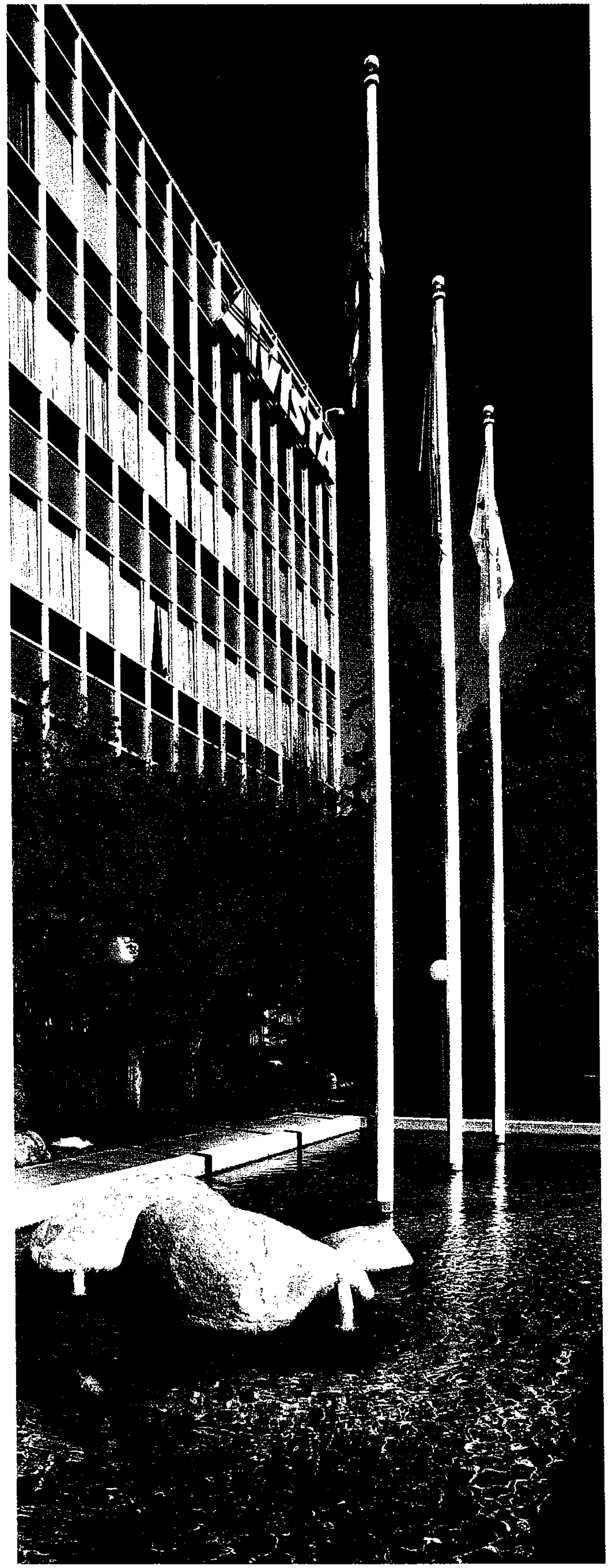
SPECIAL THANKS TO OUR TALENTED VENDORS FROM THE SPOKANE AREA WHO PRODUCED THIS IRP:

Ross Printing Company

Thinking Cap Design

Printed on recycled paper.

TABLE OF CONTENTS



SAFE HARBOR STATEMENT

This document contains forward-looking statements. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control, and many of which could have a significant impact on the company's operations, results of operations and financial condition, and could cause actual results to differ materially from those anticipated.

For a further discussion of these factors and other important factors, please refer to our reports filed with the Securities and Exchange Commission which are available on our website at www.avistacorp.com. The company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events.

TABLE OF TABLES

TABLE OF TABLES (continued)

TABLE OF FIGURES

TABLE OF FIGURES (continued)

TABLE OF FIGURES (continued)

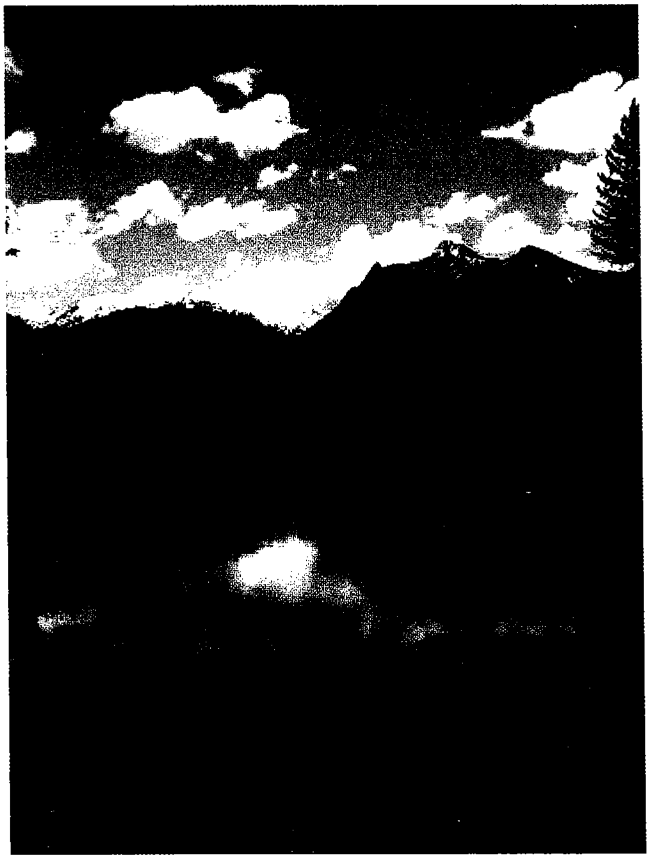
LIST OF ACRONYMS AND KEY TERMS

AARG	Annual Average Rate of Growth
AVA	Avista
aMW	Average Megawatts
BPA	Bonneville Power Administration
CCCT	Combined-Cycle Combustion Turbine
CFL	Compact Fluorescent Lamp
CO_2	Carbon Dioxide
CSA	Climate Stewardship Act (also known as the McCain-Lieberman Bill)
CVR	Controlled Voltage Reduction
Dth	decatherm
EF	Efficiency
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GE	The General Electric Company
GHG	Greenhouse Gas
GWh	Gigawatt-hour
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning (HVAC)
IDP	Idaho Power Company
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IS	Information Systems
kV	kilo-volt
kW	kilowatt
kWh	kilowatt-hour
LIRAP	Low Income Rate Assistance Program
LP	Linear Programming
Mmbtu	Million British Thermal Units, 1 mmbtu = 1 dth of Natural Gas
MW	megawatt
MWh	megawatt-hour
NCEP	National Commission for Energy Policy
NEB	Non-Energy Benefits
Nominal	Discounting Method that Includes Inflation
NPCC	Northwest Power and Conservation Council (formerly Northwest Power Planning Council)
NPV	Net Present Value
NWPP	Northwest Power Pool
O&M	Operations and Maintenance
OASIS	Open Access Same-Time Information System
OSU	Oregon State University
PC	Personal Computer
PGE	Portland General Electric
PRS	Preferred Resource Strategy
PRiSM	Preferred Resource Strategy Line Programming Model
psig	Pounds Per Square Inch Gauge
PTC	Production Tax Credit
PUD	Public Utility District
PURPA	Public Utility Regulatory Policies Act of 1978
Real	Discounting Method that Excludes Inflation
RPS	Renewable Portfolio Standards
RTO	Regional Transmission Organization
SCCT	Simple-Cycle Combustion Turbine
TAC	Technical Advisory Committee
TIG	Transmission Improvements Group
TRC	Total Resource Cost
Triple E	External Energy Efficiency Board
VFD	Variable Frequency Drive
WECC	Western Electricity Coordinating Council
WNP-3	Washington Public Power Supply System (WPPSS, now Energy Northwest) – Washington Nuclear Plant No. 3

2007 IRP KEY MESSAGES

- Resource deficits start in 2014 with loads exceeding resource capability by 49 MW. Deficits are driven by electricity sales growth averaging 2.3 percent over the next decade.
- The 2007 Preferred Resource Strategy (PRS) differs substantially from the 2005 PRS in three main areas: the removal of coal as a resource, the challenge of acquiring renewables and the need for natural gas-fired plants.
- The PRS includes 350 MW of natural gas-fired plants, 300 MW of wind, 87 MW of conservation, 38 MW of hydro plant upgrades and 34 MW of other renewables by 2017.
- The coal-fired generation forecast in previous plans is replaced entirely with natural gas-fired resources.
- Conservation acquisition is 25 percent higher than in the 2005 plan and 85 percent higher than the 2003 IRP. The company is implementing an enterprise-wide conservation and energy efficiency initiative called the "Heritage Project." It builds on the company's long-time commitment to energy conservation and efficiency, introducing new products and services to increase customers' energy savings.
- Fewer renewables meet our planned requirements due to tightening market conditions; renewables legislation in Washington and Oregon has artificially increased and accelerated the demand for these resources and therefore increased their costs. For example, wind generation costs have increased more than 50 percent since the 2005 IRP.
- Avista supports national climate change legislation and is actively participating to ensure cost-effective solutions for our customers.
- Avista has one of the smallest carbon footprints in the U.S. because of its renewable energy resources. According to a Natural Resources Defense Council study, only seven other major utilities have a smaller footprint.
- Avista's high percentage of existing renewable hydro resources, combined with a lack of available cost-effective renewable resource options, means we must continue to acquire carbon-emitting generation to meet future load growth. This increases our total carbon footprint, but our emissions per MWh of generation fall over time.
- The enactment of new laws imposing emission performance standards on fossil fueled generation resources acquired by electric utilities in Washington, Oregon and California narrows our cost-effective options, at least in the short term, to natural gas-fired generation.
- The PRS strikes a reasonable balance between keeping average costs and variation in year-to-year costs low.
- Fixing gas prices does not lower absolute cost, but it does limit price volatility.
- The power purchase contract for the Lancaster Generating Plant, previously held by Avista Energy and transferred to Coral Energy in 2007, will be available to Avista beginning in 2010. This will provide approximately 275 MW of natural gas-fired generation and will be a good resource to serve customer load.
- Action items being developed for the 2009 IRP include renewable energy and emissions, enhancements to modeling systems, transmission modeling and research, and conservation.
- The 2007 IRP was substantially complete when the company announced the availability of the Lancaster gas-fired plant to the utility. The Preferred Resource Strategy, as detailed above, includes 350 MW of natural gas-fired generation over its first 10 years. The Lancaster plant is assumed to replace a significant portion of this component. As the IRP was not re-run due to the Lancaster addition, in some places within the 2007 IRP our resource deficiencies and tabulations are shown with and without the Lancaster plant.

EXECUTIVE SUMMARY



Bull River Valley, Montana

Avista's 2007 Integrated Resource Plan (IRP) will guide utility resource acquisitions over the next two years and beyond. Besides providing a snapshot of its current resources and loads, the IRP shows where our resource portfolio is heading through the Preferred Resource Strategy (PRS). The PRS is made up of renewable resources, conservation, efficiency upgrades at existing facilities and new gas-fired generation. The most significant change from the 2005 IRP is the exclusion of coal-fired generation due to changing economics and recent legislation effectively barring its use.

Conservation acquisition is forecast to rise approximately 25 percent over the 2005 IRP level and by more than 85 percent from the 2003 IRP.

The IRP balances low cost, reliable service and reasonable future rate volatility. Avista's management and stakeholders from the Technical Advisory Committee (TAC) play a key role in directing the IRP process. TAC members include customers, Commission Staff, consumer advocates, academics, utility peers, government agencies and interested internal parties. The TAC provides significant input on modeling, planning assumptions and the general direction of the planning process.

RESOURCE NEEDS[1]

Plant upgrades and conservation acquisition are inadequate to meet all future load growth. Annual energy deficits begin in 2011, with loads exceeding resource capabilities by 83 aMW. Energy deficits rise to 272 aMW in 2017 and to 513 aMW in 2027. The company will be short 146 MW of capacity in 2011. In 2017 and 2027, capacity deficits rise to 300 MW and 835 MW, respectively. Table 1 presents the company's net position forecast during the first 10 years of the study.

Increasing deficits are a result of 2.3 percent energy and capacity load growth through 2017. Expirations of certain long-term contracts also add to the deficiencies. Figures 1 and 2 provide graphical presentations of Avista's load and resource balances. The annual forecasted load is the summation of our peak forecast plus planning and operating reserve obligations.

Table 1: Net Position Forecast

Net Position	2008	2009	2010	2011	2012	2015	2017
Energy (aMW)	121	79	33	-83	-170	-228	-272
Capacity (MW)	148	94	5	-146	-251	-357	-300

[1] Energy and Capacity positions exclude the acquisition of Lancaster. The impact of Lancaster on the company's L&R position is detailed later in this chapter.

Figure 1: Load Resource Balance—Capacity (MW)

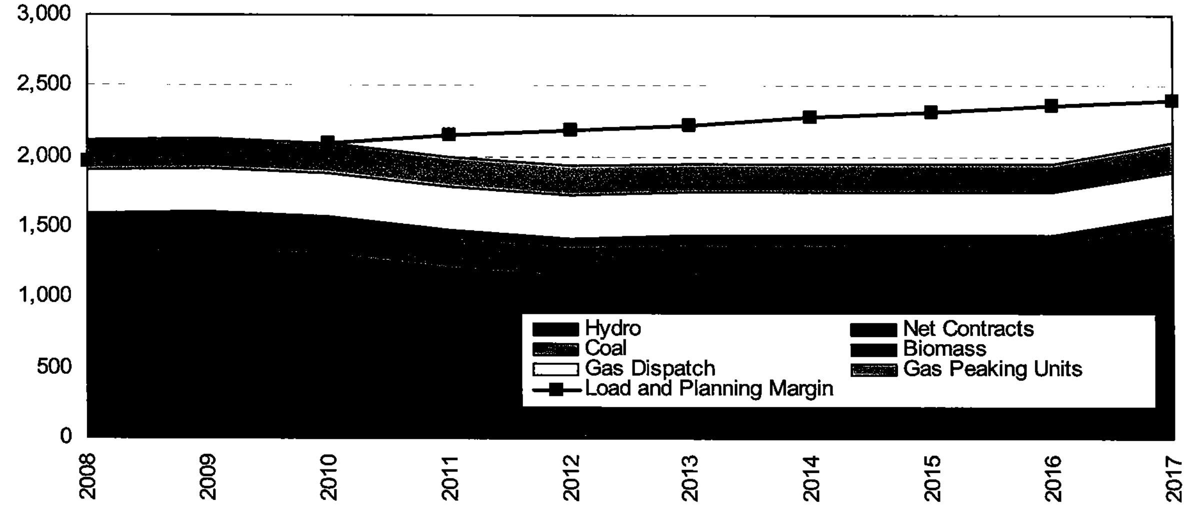
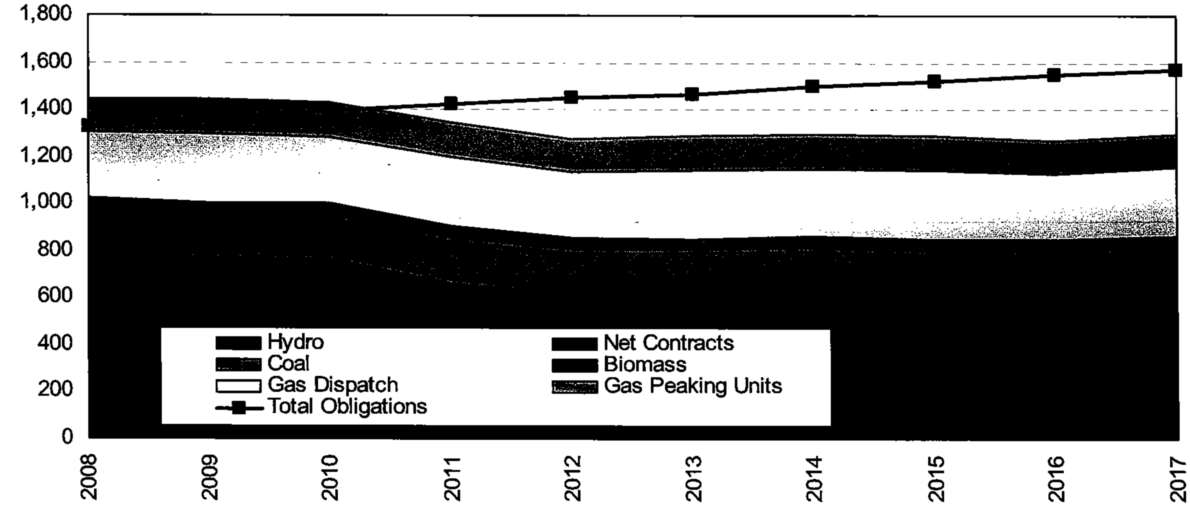


Figure 2: Load Resource Balance—Energy (aMW)

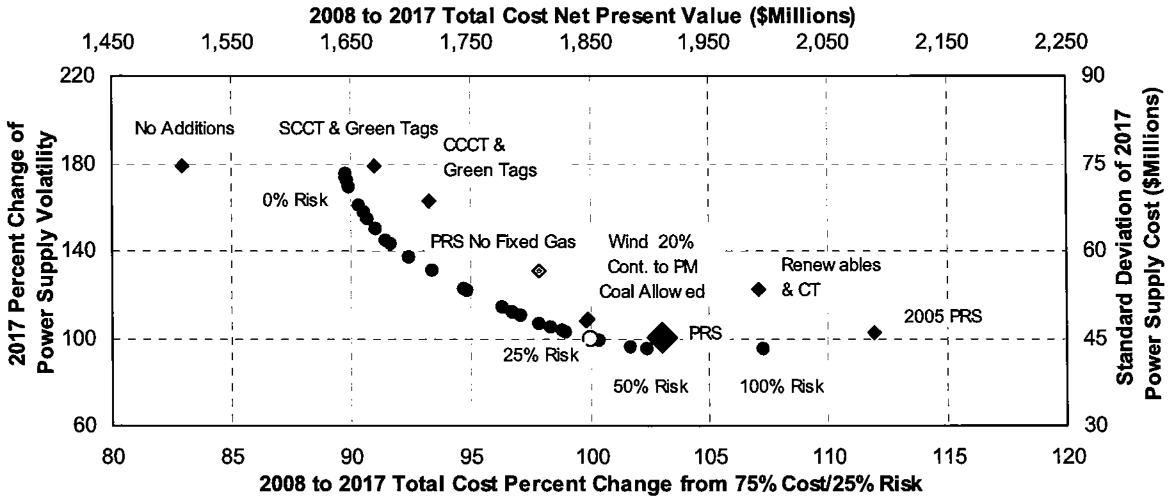


MODELING AND RESULTS

The company used a multi-step approach to develop its Preferred Resource Strategy. The process began by identifying potential new resources to serve future demand across the Western United States. A Western Interconnect-wide study was performed to understand the impact of regional markets. We believe that the additional efforts to develop this study were necessary given the significant impact other regions can have on the Northwest electricity marketplace. Existing resources were combined with the present transmission grid to simulate hourly operations from 2008 through 2027. Cost-effective new resources and transmission were added to meet growing loads. Monte Carlo-style analysis varied hydro, wind, load and gas price data over 300 iterations of potential future conditions. The simulation results were used to estimate the Mid-Columbia electricity market. The iterations collectively formed the Base Case.

Estimated market prices were used to analyze potential conservation initiatives and available supply-side resources to meet forecasted company requirements. Each new resource option was valued against the Mid-

Figure 3: Efficient Frontier and Traditional Resource Portfolios



Columbia market to identify the future value of each asset to the company, as well as its inherent risk (e.g., year-to-year volatility). Future market values and risk were compared with the capital and fixed operation and maintenance (O&M) costs that would be incurred. Avista's Preferred Resource Strategy Linear Programming Model (PRiSM) assisted in selecting the PRS. Its selection was based on forecasted energy and capacity needs, resource values and limiting power supply expense variability.

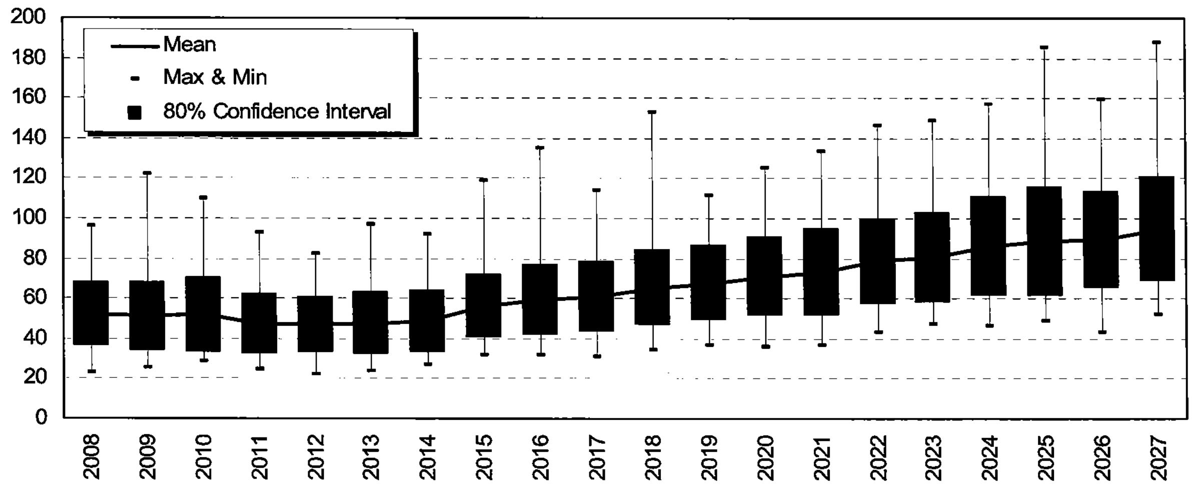
Futures and scenarios test the PRS under alternative conditions beyond the Base Case and illustrate how certain resource mixes perform in alternative market conditions. Futures are stochastic studies using a Monte Carlo approach to quantitatively assess risk around an expected mean outcome.[3] This time-intensive and multi-variable approach is the most robust method used for risk assessment. Four futures were modeled for the 2007 IRP: Base Case, Volatile Gas, Unconstrained Carbon and a High Carbon Charges.

A scenario is a deterministic study that changes a significant underlying assumption to assess the impact of that change. Scenario results are easier to understand and require less analytical effort than futures, but they do not quantitatively assess the variability or risk around the expected outcome. Seven scenarios were modeled for the 2007 IRP, including high and low natural gas prices, varying regional load growth and a scenario in which the Western Interconnect shifted all passenger automobiles to electricity instead of petroleum fuel.

Two key challenges are addressed when developing a resource portfolio—cost and risk mitigation. An efficient frontier finds the optimal level of risk given a desired level of cost and vice versa. This approach is similar to finding the optimal mix of risk and return in a personal investment portfolio. As the expected return increases, so do risks; but reducing risk decreases overall investment returns. Choosing the PRS is similar to the investor's dilemma, but the trade-off is future costs against future power supply cost variation. Figure 3 presents the changes in costs and risks from the 75/25 cost/risk position on the Efficient Frontier. It also shows alternative resource portfolios to illustrate generic resource strategies. The lower horizontal axis displays the 2008-2017 percentage change in the present value of existing and future costs. The upper horizontal axis presents actual present value dollars. The right-hand

[3] Stochastic studies use probability distributions (i.e., means and standard deviations) to forecast future variables.

Figure 4: Base Case Stochastic Mid-Columbia Prices ($/MWh)



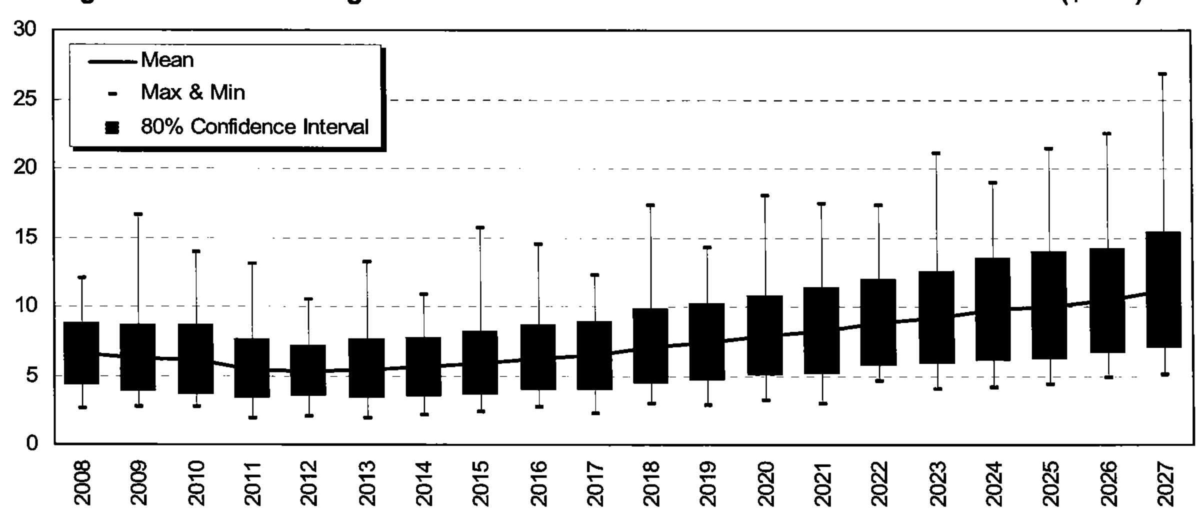
vertical axis shows power supply volatility as a single standard deviation of the average power supply expense. The left-hand vertical axis shows the percent change in 2017 power supply volatility. Both axes are shown as percentages of the 75/25 cost/risk mix to illustrate the relative impacts of moving between resource strategies.

The blue dots represent the Efficient Frontier of various resource portfolios developed by PRiSM to meet future resource requirements. The PRS is not on the Efficient Frontier curve because resource lumpiness is assumed in the first 10 years of the study.[4] The PRS is based on the 25/75 risk/cost portfolio weighting.

ELECTRICITY AND NATURAL GAS MARKET FORECASTS

Figure 4 represents Avista's Base Case electricity price forecast and the range of prices across its Monte Carlo runs. The selected resource portfolio must provide a hedge against such price movement.

Figure 5: Annual Average Sumas Natural Gas Price Results from 300 Iterations ($/Dth)



[4] Resources enter a utility portfolio in blocks that do not perfectly match load in a given year. For example, it is difficult to cost-effectively acquire a 35 MW share of a CCCT plant. Instead, resources enter the utility portfolio in larger blocks and manage deficiencies for a period of years.

Electricity prices are highly correlated with natural gas prices. Base Case natural gas prices across the Monte Carlo simulations at the Sumas trading hub are shown in Figure 5. Natural gas volatility is similar to electricity price volatility in Figure 4.

DEMAND SIDE MANAGEMENT ACQUISITION

Figure 6 shows how conservation and energy efficiency have decreased Avista's energy requirements by nearly 100 aMW since programs began in the late 1970s.[5] With additional funding recommended by the IRP and through the Heritage Project, the company expects accumulated conservation to lower its load growth 87 aMW by 2017. The 2007 IRP conservation acquisition schedule is approximately 25 percent higher than the 2005 IRP and 85 percent higher than the 2003 IRP.

PREFERRED RESOURCE STRATEGY

The Preferred Resource Strategy is developed after careful consideration of the information gathered

Figure 6: Cumulative Efficiency Acquisitions

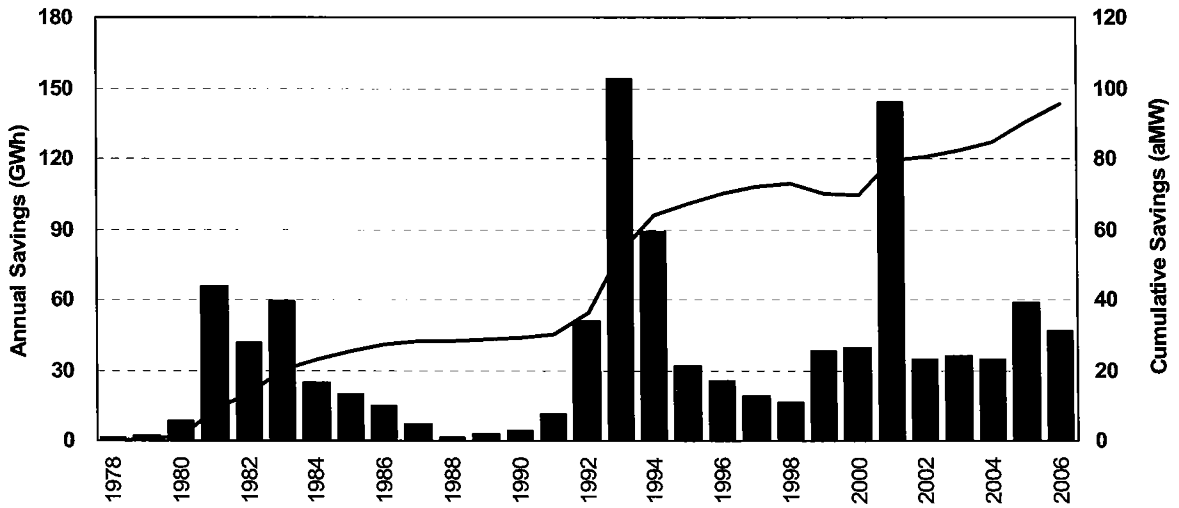
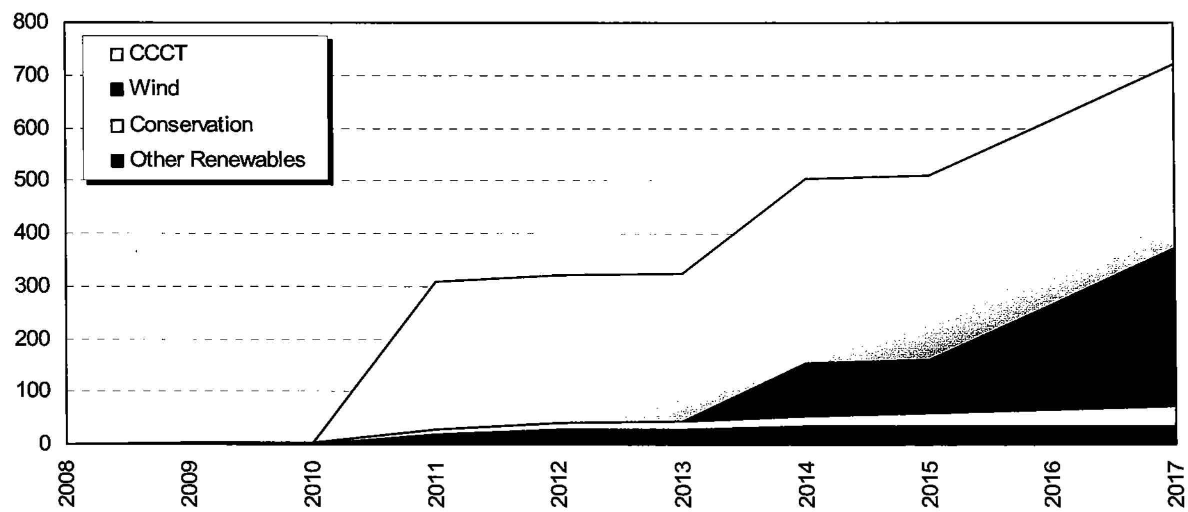


Figure 7: The 2007 Preferred Resource Strategy (aMW)



[5] Actual energy savings total 124 aMW; however, due to expected degradation of historical measures (18-year average measure life), cumulative savings are lower.

Table 2: 2007 Preferred Resource Strategy Selections (Nameplate MW)

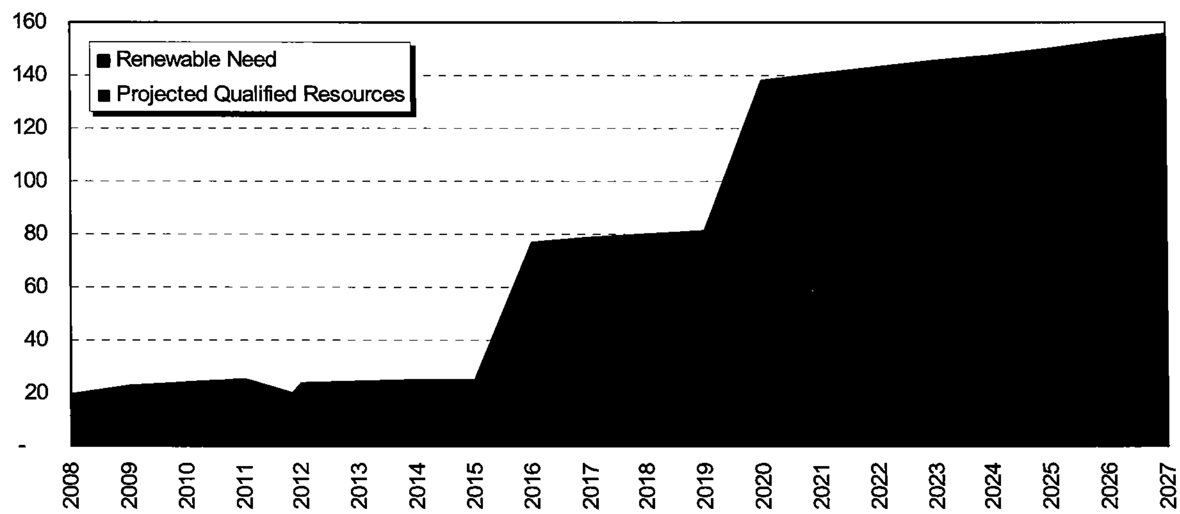
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CCCT	0	0	0	280	280	280	350	350	350	350
Coal	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	100	100	200	300
Other Renewables	0	0	0	20	30	30	35	35	35	35
Conservation	6	13	20	27	36	46	56	66	76	87
Total	6	13	20	327	346	356	541	551	661	772

through the IRP process. The PRS is reviewed by management and the Technical Advisory Committee. The 2007 plan relies on conservation, system efficiency upgrades, renewable resources and gas-fired combined-cycle combustion turbines (CCCTs). Figure 7 illustrates the company's Preferred Resource Strategy for the 2007 IRP.

The specific resources contained within the PRS, in nameplate capability, are shown in Table 2.

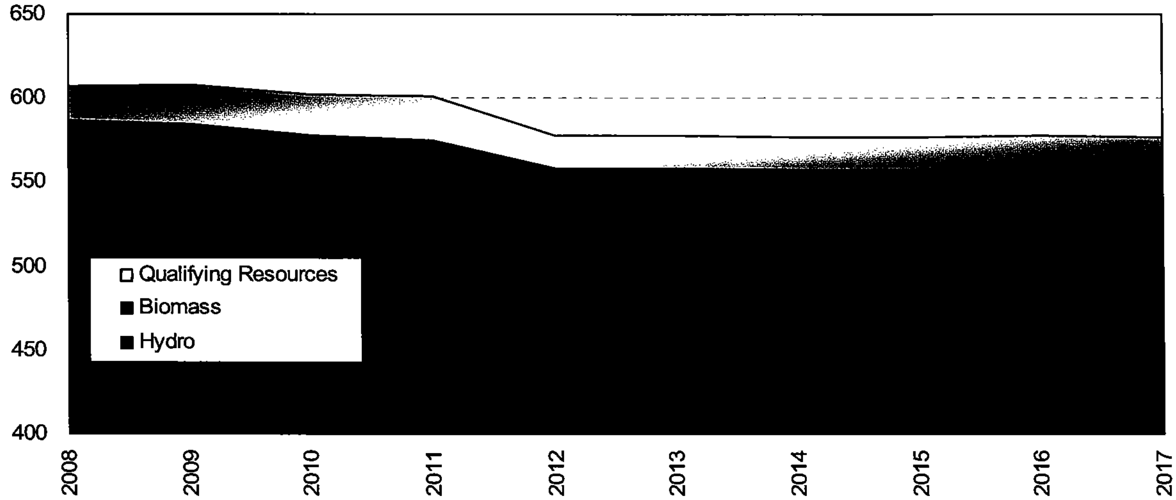
The PRS requires between \$1.0 and \$1.5 billion in new investments over the next 10 years.[6] The 2007 IRP contains lower amounts of wind and other renewable resources than were included in the 2005 IRP. Conditions have changed since the 2005 IRP which have and will impact the cost of renewable resources relative to traditional thermal alternatives. Recent legislation promoting renewable resources in Washington and throughout the West have reduced the amount of cost-effective renewable resources available to Avista by increasing and accelerating demand in the short run. Wind generation costs have increased by more than 100 percent over the past six years and by more than 50 percent since the 2005 IRP. Renewable resources are being acquired to meet the Washington Energy Independence Act, Initiative 937 (I-937), passed in November 2006. This legislation requires larger utilities in Washington to serve 15 percent of retail load with renewables by 2020; intermediate targets are 3 percent in 2012 and 9 percent in 2016. Under I-937, Avista must acquire renewable resources regardless of physical resource balance. We forecast that by 2017 approximately 90 aMW of I-937-qualifying resources will serve customers loads, as shown in Figure 8.

Figure 8: Amount of Renewable Energy Forecasted to Meet RPS (aMW)



[6] The range reflects the possibility that the company might need to invest approximately \$0.5 billion to fix the long-term price of its natural gas (e.g., purchase of coal gasifier to create pipeline-quality natural gas).

Figure 9: I-937 Qualifying and Non-Qualifying Avista Renewables (aMW)



Avista currently serves approximately one-half of customer requirements with renewable resources (hydro, wind and biomass), and these resources will meet 40 percent of our load obligations in 2017. Unfortunately, only a small portion of our current renewable resource portfolio qualifies under I-937, see Figure 9.

LOWERING VOLATILITY WITH LONG-TERM FIXED PRICE GAS

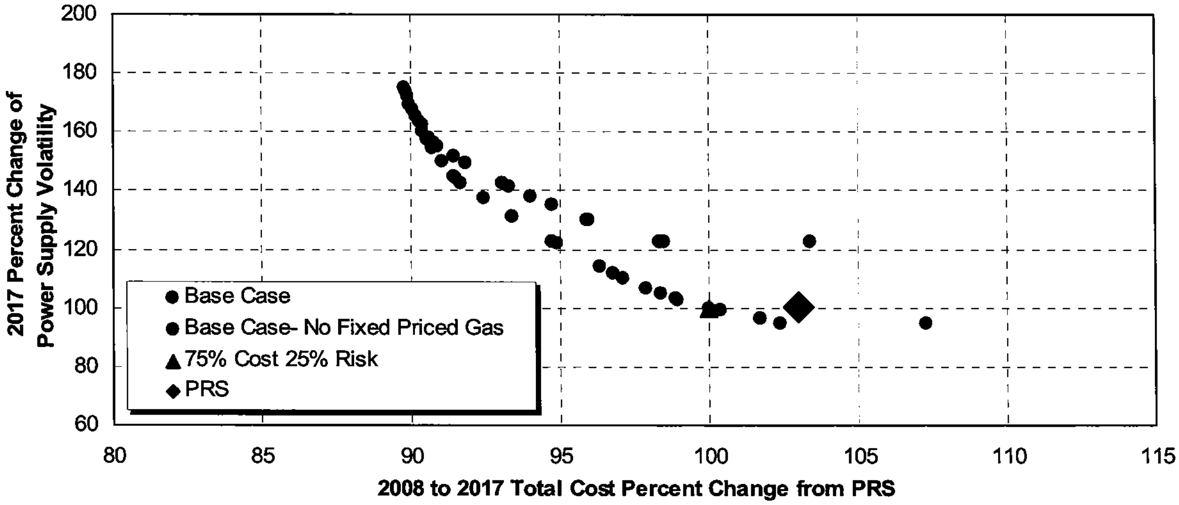
Coal-fired generation accounted for a significant portion of the Avista's PRS mix in both the 2003 and 2005 IRPs. Coal-fired plants provide a hedge against volatile electricity and natural gas prices because 60 percent or more of their costs are fixed through large capital investments. Variable operating and fuel costs at a coal plant are modest compared to gas-fired resources. A resource profile containing coal contributes to stable power supply expenses.

The cost of operating gas-fired resources, on the other hand, is highly correlated with the electricity marketplace. Natural gas prices are volatile. The fixed costs of natural gas plants are low relative to their all-in cost, approximately 20 percent, reflecting a low capital investment. Utility portfolios with large concentrations of gas-fired generation can suffer from costs that are less stable than utilities who rely on other sources of generation.

Gas-fired plants have not experienced the same rise in capital costs that coal-fired plants have. In fact, recent experience by Avista (Coyote Springs 2) and Puget Sound Energy (Goldendale) indicate that independent power producers in the Northwest marketplace are willing to sell their gas-fired plants at prices below the green field costs assumed in this plan. The enactment of new laws imposing emission performance standards on fossil-fueled generation resources acquired by electric utilities in Washington and California will narrow baseload technology options, at least in the short-term, to gas-fired generation. This restriction, coupled with regional load growth and the prospect of additional greenhouse gas regulations on fossil-fueled generation resources, particularly coal-fired generation, may ultimately increase demand for and the cost of gas-fired plants.

Locking in natural gas costs through a long-term fixed-price contract, an investment in a pipeline-quality coal gasification plant, an investment in gas fields or through other means makes a gas-fired combined cycle combustion turbine (CCCT) cost structure behave

Figure 10: Efficient Frontier With and Without Fixed Price Gas Contracts Option



financially like a coal-fired resource. Variable costs are greatly reduced and are much less volatile because a significant portion of its largest variable component—gas fuel—is not tied to the natural gas market. In both high and low gas market conditions the price paid by customers is the same. In years where natural gas prices are high, the fixed-cost contract looks very attractive financially and customers pay less than if the company relied on shorter-term purchases. On the other hand, years with low natural gas prices make the fixed-cost contract look financially unattractive compared to a short-term purchase. Over time, the long-run cost of operations with fixed-price gas should parallel the cost of operations where a gas plant is fueled with short-term gas.

The company tested the benefits of fixed price contracts with PRiSM and found that the model had a general preference for fixed price gas because of its ability to reduce risk. Even with premiums as high as 75 percent above the forecasted short-term gas price, the PRiSM model selects this resource option for a portion of the preferred portfolio. In the Base Case, where a 30 percent fixed gas price premium is modeled, risk is reduced by approximately 20 percent, as shown in Figure 10. An empirical study by Avista explains that year-on-year volatility for a hypothetical CCCT plant could have been reduced by 50 percent during the years 2002-2006 were fixed price gas used to fuel the plant.[7]

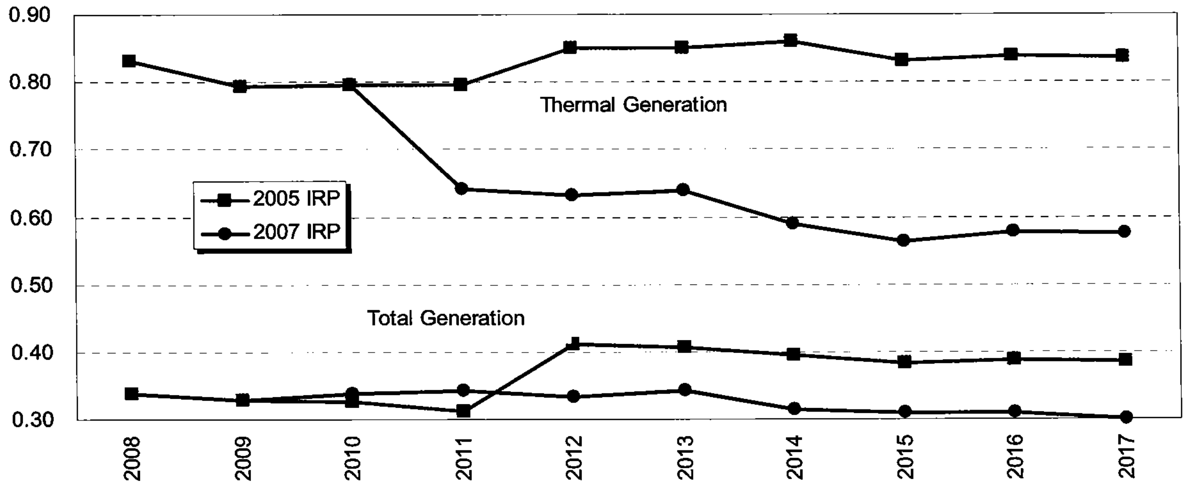
CARBON EMISSIONS

Carbon emissions are included in the Base Case for the first time in this IRP cycle. The National Commission on Energy Policy study, completed in late 2004, provided the basis for pricing carbon emissions in the Base Case.[8] To quantify potential risks inherent in a higher carbon emission cost scenario, the company looked to an Energy Information Administration study of the McCain-Lieberman Climate Stewardship Act.[9] These two cases illustrate the potential risk inherent in relying too heavily on traditional carbon-emitting technologies.

Avista has one of the smallest carbon footprints in the United States because of its existing renewable energy resources. Out of the top 100 producers of electric power in the 2006 Benchmarking Air Emissions study by the Natural Resources Defense Council, only seven other utilities have a smaller footprint. However, the

[7] A broader discussion of this study is presented in Chapter 8.
[8] See www.energycommission.org
[9] See www.eia.doe.gov

Figure 11: Carbon Footprint (Tons per MWh)



company's carbon footprint is forecast to rise over the IRP timeframe because it would be very difficult to acquire sufficient amounts of additional cost-effective renewable resources to meet all future load growth. Figure 11 forecasts Avista's carbon footprint for generation and compares it to the 2005 IRP. Our emissions footprint is approximately 25 percent lower.

LANCASTER

The company announced the sale of its energy marketing company, Avista Energy, in April 2007. It subsequently announced that Avista Energy's contract for the Lancaster Generation Facility output is available to the utility beginning in 2010. The announcement came after the company had substantially completed its IRP analysis and Preferred Resource Strategy. Given that Lancaster is the same technology and available in the same timeframe as the 280 MW gas-fired combined cycle resource identified in the PRS, the resource strategy was not updated. Instead, an alternative portfolio including Lancaster is compared to the PRS to illustrate its impacts. The Lancaster Generation Facility is a 245 MW gas-fired combined-cycle combustion turbine with an additional 30 MW of duct firing capability. It is a newer General Electric Frame 7FA that began commercial service in 2001. Avista controls plant operations under a tolling arrangement through 2026. Recently completed preliminary analysis has identified Lancaster as a potentially cost-effective resource to meet customer load requirements. The plant is located in Rathdrum, Idaho, in the center of Avista's service territory. It is significantly lower in cost than a green field plant.

LANCASTER IMPACT ON L&R BALANCES

Lancaster substantially replaces the identified gas-fired CCCT plant included in the PRS. Table 3 presents the company's net position with the inclusion of Lancaster. Figure 12 reflects Lancaster's inclusion in our loads and resources tabulation.

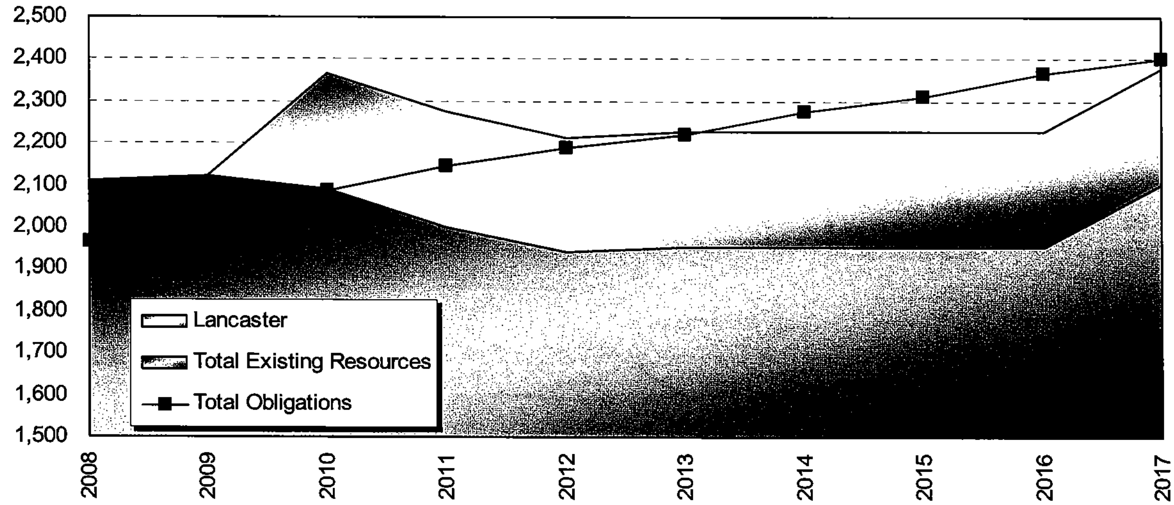
ACTION ITEMS

Avista's 2007 Action Plan outlines the activities and studies to be developed and presented in the 2009 Integrated Resource Plan. The Action Plan was developed with input from Commission Staff, Avista's management team, and the Technical Advisory

Table 3: Net Position Forecast with Lancaster

Net Position	2008	2009	2010	2011	2012	2015	2017
Energy (aMW)	121	79	288	181	79	37	-8
Capacity (MW)	148	94	280	129	24	-82	-25

Figure 12: Loads & Resources Capacity Forecast with Lancaster (MW)



Committee. The Action Plan is found in Chapter 9. Categories of action items include renewable energy and emissions, modeling enhancements, transmission modeling and research, and conservation.

1. INTRODUCTION AND STAKEHOLDER INVOLVEMENT

Avista submits a biennial Integrated Resource Plan (IRP) to the Idaho and Washington public utility commissions.[1] The 2007 IRP is Avista's 10th plan. It describes the Preferred Resource Strategy for meeting customers' future requirements while balancing cost and risk.

The company has a statutory obligation to provide reliable electric service to customers at rates, terms and conditions that are just, reasonable and sufficient. We assess resource acquisition strategies and business plans to meet resource adequacy and renewable portfolio requirements, and to optimize the value of our current resource portfolio. Avista uses the IRP as a resource evaluation tool rather than an acquisition plan. The 2007 IRP focuses on refining our processes for evaluating resource decisions, requests for proposal and other acquisition efforts.

IRP PROCESS

Avista actively seeks input from a variety of constituents including Commission Staff, customers, academics and other interested parties. The company sponsored five Technical Advisory Committee (TAC) meetings for the 2007 IRP, including a two-day meeting in August 2006. The TAC process began on February 24, 2006, and ended with a final meeting on April 25, 2007. Over 90 people were invited. Each TAC meeting covered different aspects of the 2007 IRP planning activities and solicited contributions and assessments of modeling assumptions, processes and results. The 2007 IRP marked the first time that the company provided TAC members with a draft Preferred Resource Strategy (PRS) in the middle of the IRP process. The PRS was presented at the second TAC meeting. It gave TAC participants an opportunity to understand the potential results of the IRP modeling process.

STAKEHOLDER PARTICIPATION

The IRP process provides substantial opportunities for stakeholders to participate in Avista's resource planning activities. Avista utilizes three different groups of stakeholders. The main contingent involves stakeholders with some level of expertise in utility planning, who provide input concerning the IRP studies, resource data, modeling efforts, and critical review of the modeling results. This group includes Commission Staff, planners from other utilities, academics and consultants. The second group includes parties who are involved with a critical aspect of the IRP. Examples of members of this group include environmental advocates and government agencies. The third group includes delegates from regional planning efforts, such as the Northwest Power and Conservation Council and the Western Electricity Coordinating Council.

PUBLIC PROCESS

The 2007 IRP is a publicly-developed document. All of the 2007 IRP TAC presentations, along with past IRPs and TAC presentations, are available for review at www.avistautilities.com. The entire 2007 IRP, its technical appendices, and its supporting documents can be downloaded from this location.

TECHNICAL ADVISORY COMMITTEE

Avista's Integrated Resource Plan benefits from public input and involvement. The company held six full days of TAC meetings, which were supplemented with phone and email contact, to develop this plan. Some of the topics included in the 2007 TAC series were resource options, conservation, modeling, fuel price forecasts, load forecasts, market drivers and emissions issues.

[1] Washington IRP requirements are contained in WAC 480-100-251 Least Cost Planning. Idaho 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.

Table 1.1: TAC Participants

Participant	Organization
Andy Ford	WSU
Brad Blegan	City of Spokane
Dan Pfeiffer	IPUC
Dave Van Hersett	Resource Development Associates
Hank McIntosh	WUTC
Joelle Steward	WUTC
Yohannes Mariam	WUTC
Doug Kilpatrick	WUTC
Steve Johnson	Public Counsel
Hugh Nguyen	Puget Sound Energy
Kirsten Wilson	WA State Gen Admin
Rick Sterling	IPUC
Mark Stokes	Idaho Power
Terry Morlan	NPCC
Liz Klumpp	CTED
Mike Kersh	Inland Empire Paper

The TAC mailing list includes more than 90 individuals from 42 different organizations. Avista greatly appreciates all of the time and effort expended by participants in the TAC process and we look forward to their continued involvement in future IRPs. The company would like to particularly thank the participants listed in Table 1.1 for their input and involvement.

ISSUE-SPECIFIC PUBLIC INVOLVEMENT ACTIVITIES

In addition to the TAC, Avista sponsors and participates in other collaborative processes involving public interests.

External Energy Efficiency ("Triple E") Board

Since 1995 the Triple E Board has been meeting biannually to gather and provide guidance on conservation efforts. The Triple E grew out of the DSM Issues Group, which was influential in developing the country's first distribution surcharge for conservation acquisition.

FERC Hydro Relicensing – Clark Fork River Projects

Over 50 stakeholder groups participated in the Clark Fork hydro-relicensing process beginning in 1993. This led to the first all-party settlement filed with a FERC relicensing application and eventual issuance of a 45-year Federal Energy Regulatory Commission (FERC) operating license in February 2003. The nationally recognized Living License concept was a result of this process. This collaborative process continues implementing the Living License with stakeholders participating in various protection, mitigation and enhancement measures. These measures include the purchase of over 1,100 acres of wetland and upland habitat for the bull trout, fish passage programs and improvements to 19 recreational facilities along the reservoir.

FERC Hydro Relicensing – Spokane River Projects

Our Spokane River Project license expires in August 2007. Avista's hydro relicensing process for the Spokane River Projects mimics the Clark Fork process. Approximately 100 stakeholder groups participate in this collaborative effort. Draft license applications were filed with FERC on July 28, 2005. FERC recently released a draft Environmental Impact Statement and held a public hearing in Spokane on February 8, 2007.

Low Income Rate Assistance Program (LIRAP)

LIRAP is developed through regular meetings with four

Table 1.2: TAC Meeting Dates and Agenda Items

Meeting Date	Agenda Items
TAC 1 – February 24, 2006	• IRP Rules and Regulations • Work Plan Discussion • 2005 IRP and TAC Comments • 2007 IRP Topic Discussions: Resource Planning, Conservation, Analytical Process, and Capacity Planning
TAC 2 (Day 1) – August 31, 2006	• Review of 2005 Action Plan • IRP Modeling Overview: Emissions, Fuel Price Forecasting, Modeling Assumptions, Preliminary Transmission Costs and Paths, Resource Options and Cost Assumptions, and Futures and Scenarios • 2006 Renewables RFP • Future Resource Requirements (L&R) • Review of Futures and Scenarios Market Results • Preliminary Preferred Resource Strategy (PRS)
TAC 2 (Day 2) – September 1, 2006	• Preliminary PRS Discussion: Portfolio Selection Criteria, Futures & Scenarios, PRS Selection Model, and Results • Alternative Energy
TAC 3 – January 10, 2007	• Draft PRS Review • Fuel Price Forecast • Clean Coal Presentation • Emissions Update • Load Forecast • Conservation
TAC 4 – March 28, 2007	• Market Analysis • Conservation Program Update • Portfolio Selection Criteria • Cost of Service • Transmission Estimates • 2007 IRP Draft Outline
TAC 5 – April 25, 2007	• Presentation of the 2007 PRS • 2007 IRP Action Items

community action agencies in the company's Washington service territory. The program began in 2001 to review administrative issues and needs. Meetings are held quarterly.

REGIONAL PLANNING

The Pacific Northwest's generation and transmission system is operated in a coordinated fashion. Avista participates in the activities of many organizations' planning efforts. Information from this participation is used to supplement its integrated resource planning process. Some of the organizations that Avista participates in include:

- Western Electricity Coordinating Council
- Northwest Power and Conservation Council
- Northwest Power Pool
- Pacific Northwest Utilities Conference Committee
- ColumbiaGrid
- Northwest Transmission Assessment Committee
- Seems Steering Group – Western Interconnection
- North American Electric Reliability Council

FUTURE PUBLIC INVOLVEMENT

Avista will continue to actively solicit input from interested parties. Advice will be requested from members of the Technical Advisory Committee on a wide variety of resource planning issues. We will continue to work on diversifying TAC membership and will strive to maintain the TAC meetings as an open, public process.

2007 IRP OUTLINE

The 2007 IRP consists of eight chapters plus an executive summary and this introduction. A series of technical appendices supplement this report.

EXECUTIVE SUMMARY

This chapter summarizes the overall results and highlights key aspects of the 2007 IRP.

CHAPTER 1: INTRODUCTION AND STAKEHOLDER INVOLVEMENT

This chapter introduces the IRP and provides details concerning public participation and involvement in the integrated resource planning process.

CHAPTER 2: LOADS AND RESOURCES

The first half of this chapter covers Avista's load forecast along with relevant local economic forecasts. The last half of this chapter describes the company's owned generating resources, major contractual rights and obligations, capacity and energy tabulations, and reserve issues.

CHAPTER 3: DEMAND SIDE MANAGEMENT

This chapter provides an overview of Avista's energy efficiency programs, descriptions and analysis of efficiency measures for the IRP and the selected programs for the 2007 IRP.

CHAPTER 4: ENVIRONMENTAL ISSUES

This chapter covers emissions issues that were modeled in the 2007 IRP. The chapter focuses on modeling efforts and issues surrounding SO_x, NO_x, Hg and CO_2. State and federal emissions regulations and policies are also discussed.

CHAPTER 5: TRANSMISSION PLANNING

This chapter reviews Avista's distribution and transmission systems, as well as regional transmission planning issues. Transmission cost studies used in modeling efforts are also covered in this chapter.

CHAPTER 6: MODELING APPROACH

This chapter provides the Mid-Columbia and Western Interconnect market results for the Base Case and scenario analyses.

CHAPTER 7: MARKET MODELING RESULTS

This chapter covers the results of the Base Case and scenario analyses for the Western Interconnect and Mid-Columbia electricity market.

CHAPTER 8: PREFERRED RESOURCE STRATEGY

This chapter provides details about Avista's 2007 Preferred Resource Strategy. It compares the PRS to a variety of theoretical portfolios under stochastic and scenario based analyses.

CHAPTER 9: ACTION ITEMS

This chapter reviews the progress made on the 2005 IRP Action Items and describes the 2007 IRP Action Items.

2. LOADS AND RESOURCES

INTRODUCTION & HIGHLIGHTS

Loads and resources represent two key components of the IRP. The first half of this chapter summarizes customer and load forecasts for our service territory, including high and low forecasts, load scenarios and an overview of recent enhancements to our forecasting models and processes. The second half covers our resources, including company owned and operated resources, as well as long-term contracts.

UTILITY LOADS

ECONOMIC CONDITIONS IN THE ELECTRIC SERVICE TERRITORY

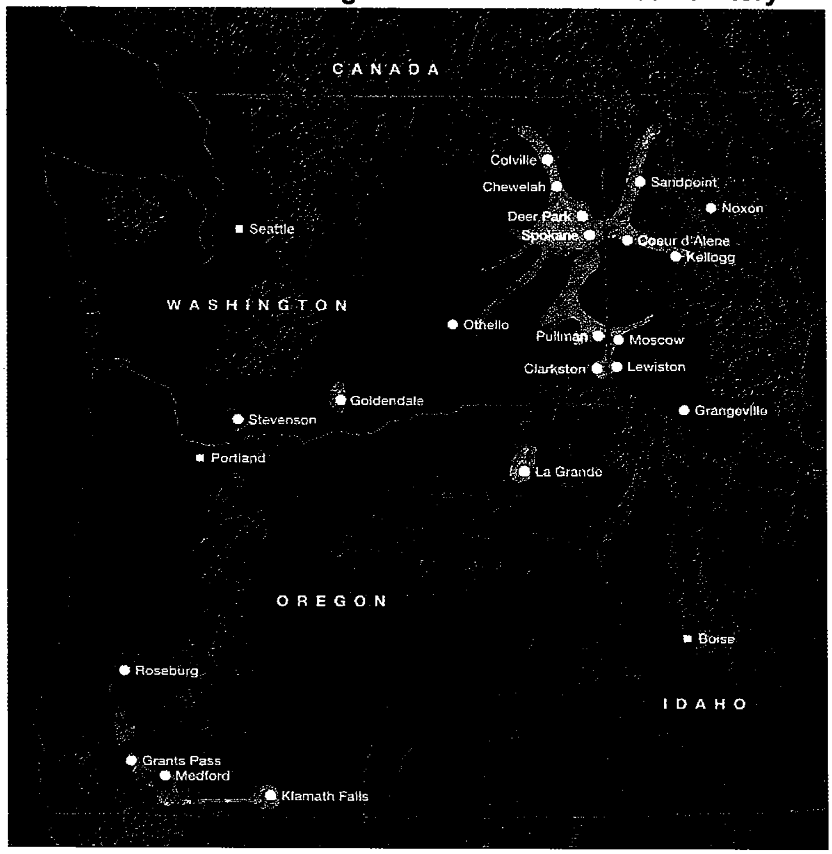
Avista serves a wide area of Eastern Washington and Northern Idaho. This area is geographically and economically diverse. Avista serves most of the urbanized and suburban areas in 24 counties. Figure 2.1 is a map of the company's electric and natural gas service territory.

Sandpoint, Idaho

CHAPTER HIGHLIGHTS

- Strong economic growth continues throughout the company's service territory.
- Historic conservation acquisitions are included in the load forecast; higher acquisition levels envisioned in this plan will be in addition to levels included in the forecast.
- Electricity sales growth averages 2.3 percent over the next 10 years (254 aMW) and 2.0 percent over the entire 20-year forecast.
- Peak loads are expected to grow at 2.4 percent over the next 10 years (400 MW) and 2.1 percent over the entire 20-year forecast.
- Avista's resource deficits begin in 2011, 2014 with the Lancaster plant.
- Capacity deficiencies drive our resource needs.

Figure 2.1: Avista's Service Territory



The economy of the Inland Northwest has transformed over the past 20 years, from natural resource-based manufacturing to diversified light manufacturing and services. Much of the mountainous area of the region is owned by the Federal government and managed by the United States Forest Service. Timber harvest reductions on public lands have closed many local sawmills. Two pulp and paper plants served by Avista have large forest land holdings, but they continue to face stiff domestic and international competition for their products.

Employment expands during expansionary times and contracts during recessions. Our service territory experienced large scale unemployment during two national recessions in the 1980s. Avista's service territory was mostly bypassed by the 1991/92 national recession, but it was not as fortunate during the 2001 recession. The effects of recessions and economic growth are best illustrated by employment for the three principal counties in the company's electric service area. Regional employment data is provided later in this chapter. Population levels often are more stable than employment levels during times of economic change; however, total population often contracts during severe economic downturns as people leave in search of job opportunities. Over the past 20 years, only in 1987 did the region experience a net loss in population. Figure 2.2 details annual population changes in Bonner, Kootenai and Spokane counties. Figure 2.3 shows total population in these three counties.

ECONOMIC, CUSTOMER, AND SALES FORECASTS

People, Jobs and Customers

Avista purchases national and county-level employment and population forecasts from Global Insight, Inc. Global Insight is an internationally recognized economic forecasting consulting firm used by various agencies in Washington and Idaho. The data encompasses the three

Figure 2.2: Population Change for Spokane, Kootenai and Bonner Counties (Thousands)

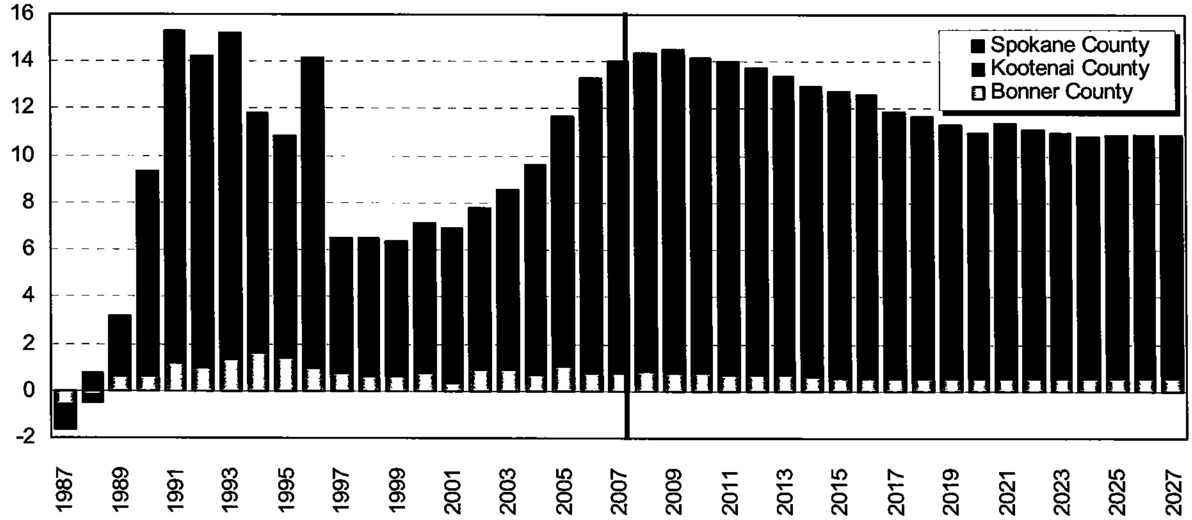


Figure 2.3: Total Population for Spokane, Kootenai and Bonner Counties (Thousands)

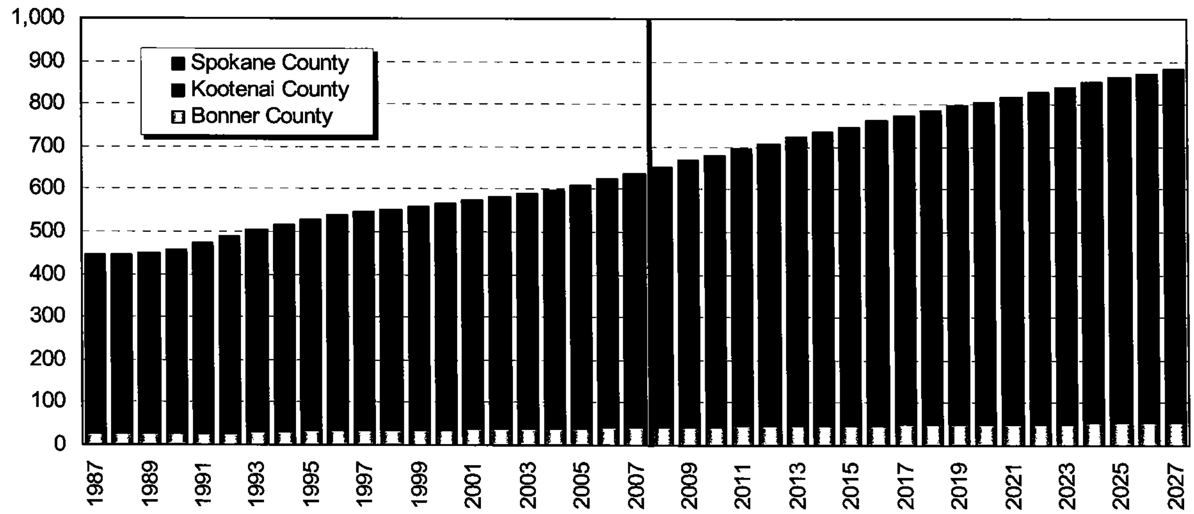


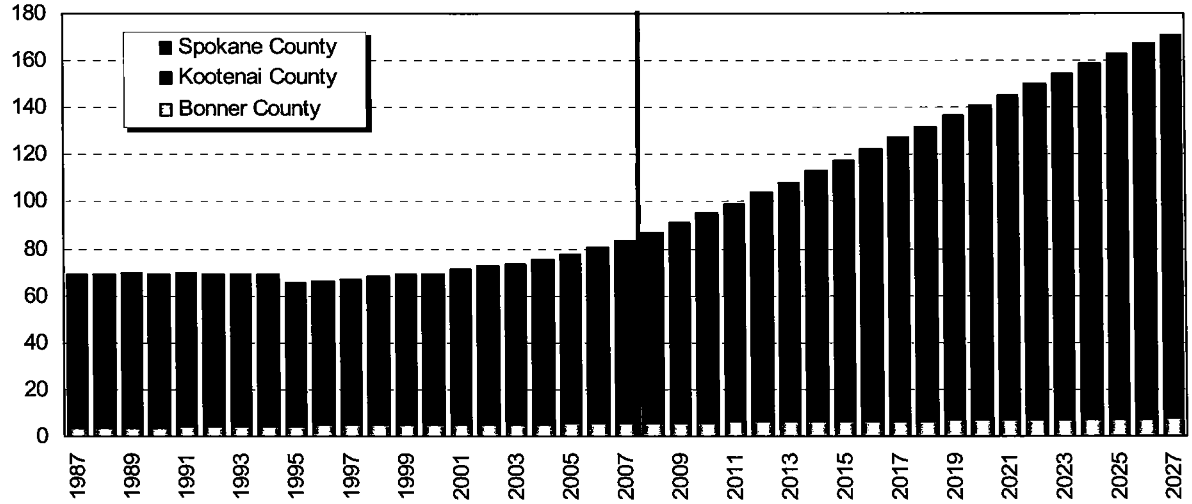
Table 2.1: Global Insights National Forecast Assumptions

Assumption	Range	Assumption	Range
Gross Domestic Product	2.5-3.5%	Housing Starts (mil.)	2.60-2.75
Consumer Price Index	2.5%-2.0%	Job Growth	0.5%-2.0%
West Texas Crude	\$60-\$65	Worker Productivity	2%
Treasury Bonds	5.0%-5.5%	Consumer Sentiment	90
Unemployment Rate	<5.0%		

principal counties which comprise over 80 percent of our service area economy, namely Spokane County in Washington and Kootenai and Bonner counties in Idaho. The national forecast is based on regional forecasts prepared in March 2006; county-level estimates were completed in June 2006.

The forecast and underlying assumptions used in this IRP were presented at the third Technical Advisory Committee meeting for Avista's 2007 Integrated Resource Plan on January 10, 2007. Key forecast assumptions are shown in Table 2.1.

Figure 2.4: Three-County Population Age 65 and Over (Thousands)



Looking forward, the national economy slowed after recovering from the 2001 recession, setting the stage for regional economic performance in Avista's service area in Eastern Washington and Northern Idaho. As shown in the charts above, population growth has rebounded after slow growth from 1997 to 2002. Population growth is expected to continue its recent trend through 2010.

Regional population growth is supported by the emigration of retirees, representing between 10 and 20 percent of overall population growth. Figure 2.4 presents the population history and forecasts for individuals 65 years and over in the three-county area. Between 1986 and 2006 this segment grew by compound growth rates of 2.4 percent in Bonner County, 2.0 percent in Kootenai County and 0.5 percent in Spokane County. This age group represented 13 percent of the overall population in 2006. The forecast predicts growth of 2.5 percent, 4.5 percent and 3.5 percent, respectively, pushing the overall contribution of this age group to 19 percent in 2027.

Employment growth drives population growth. Figure 2.5 shows employment trends in the prior two and future two decades.

Overall non-farm wage and salary employment over the past 20 years averaged 3.7 percent for Bonner County,

Figure 2.5: Three-County Job Change (Thousands)

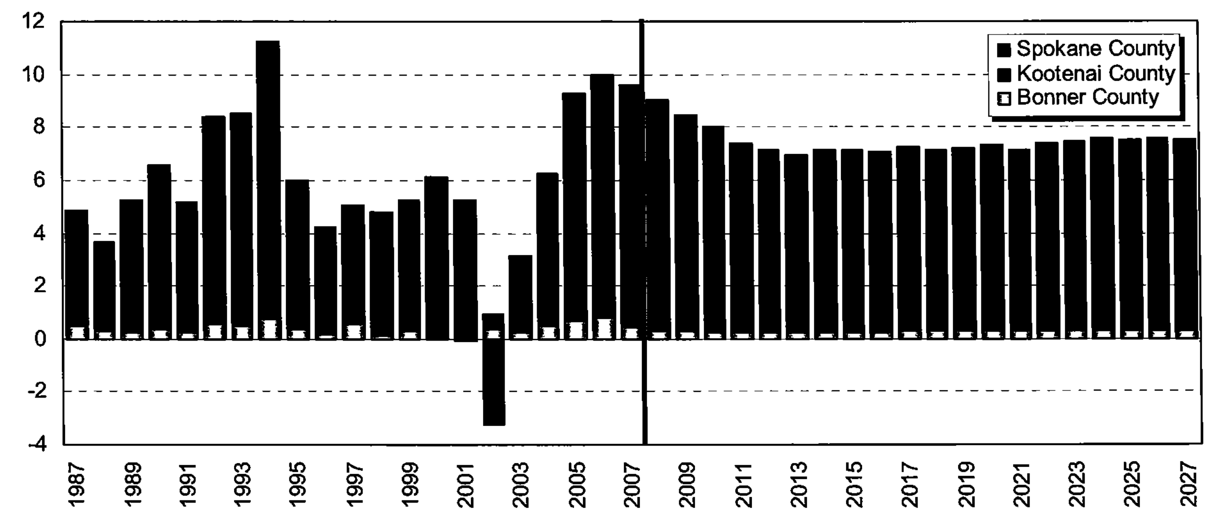
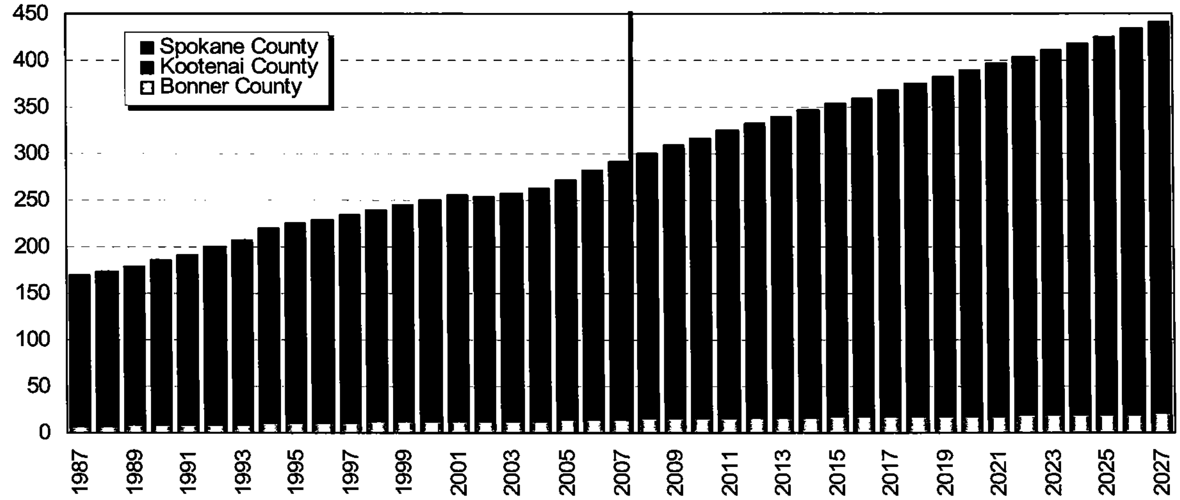


Figure 2.6: 3-County Non-Farm Jobs (Thousands)



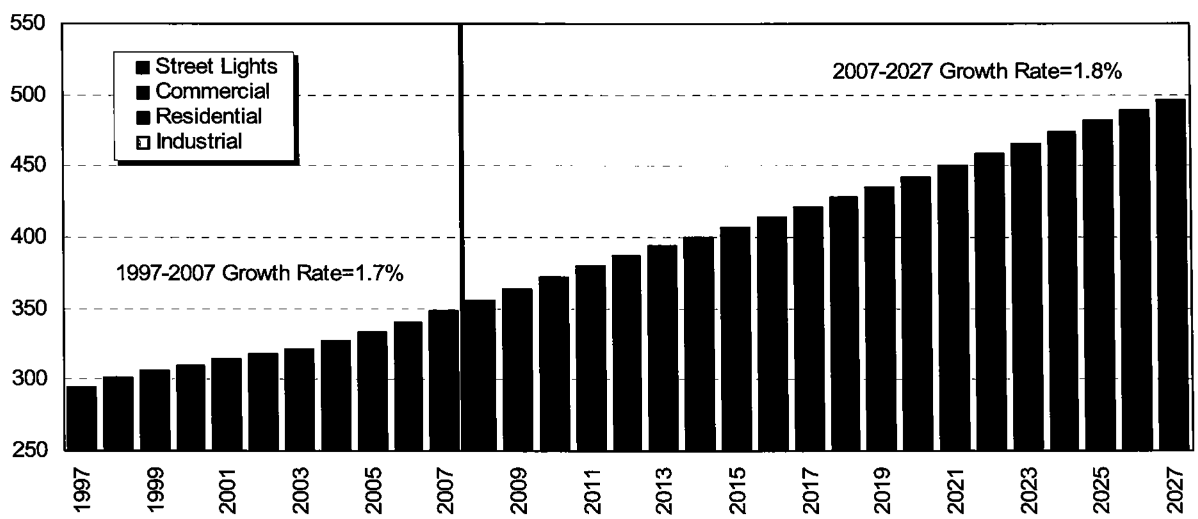
5.1 percent for Kootenai County and 2.1 percent for Spokane County. See Figure 2.6. Over the forecast horizon, growth rates are predicted at 2.6 percent, 3.6 percent and 2.6 percent, respectively. As indicated in the following chart, employment growth is expected to equal approximately 7,500 new jobs annually.

Customer growth projections follow from baseline economic forecasts. The company tracks four key customer classes–residential, commercial, industrial and street lighting. Residential customer forecasts are driven by population. Commercial forecasts rely more heavily on employment and residential growth trends. Industrial customer growth is correlated with employment growth. Street lighting trends with population growth.

Avista forecasts sales by rate schedule. The overall customer forecast is a compilation of the various rate schedules of our served states. For example, the residential class forecast is comprised of separate forecasts prepared for rate schedules 1, 12, 22 and 32 for Washington and Idaho. See Figure 2.7

Avista served 300,928 residential customers, 37,911 commercial customers, 1,388 industrial customers and 425 street lighting customers, or a total of 340,652 retail

Figure 2.7: Avista Annual Average Customer Forecast (Thousands)



electricity customers in 2006. The 2027 forecast predicts 440,789 residential, 53,322 commercial, 1,795 industrial and 625 street lighting customers for a grand total of 496,532. The 20-year compound growth rate averages 2.8 percent.

WEATHER, PRICE ELASTICITY, PRICES, CONSERVATION AND USE PER CUSTOMER

Weather Forecasts

The baseline electricity sales forecast is based on 30-year normal temperatures for the station at the Spokane International Airport, as tabulated by the National Weather Service from 1971 through 2000. Daily values go back as far as 1890. There are several other weather stations with historical records in the company's electric service area; however that data is available over a much shorter duration. Sales forecasts are prepared using monthly data, as more granular load information is not available. The company finds high correlations between the Spokane International Airport and other weather stations in its service territory. It uses heating degree days to measure cold weather and cooling degree days to measure hot weather in its retail sales forecast.

In response to questions from its Technical Advisory Committee, the company has prepared a study of the possible impacts of climate change on its retail load forecast. Ample evidence of cooling and warming trends exists in the 115-year record. In recent years the trend has been one of a warming climate when compared to the 30-year normal. Recent trends in heating and cooling degree days for Spokane are roughly equal to the scientific community's predictions for this coordinate on the globe, implying a one-degree warming every 25 years. Extrapolating the trend finds that in 20 years summer load would be approximately 26 aMW, a 2.6 percent, higher than the Base Case. In the winter, loads would be approximately 40 aMW, or 2 percent, lower. This change likely would occur gradually, and it appears that approximately one-third to one-half of this trend is already captured in our load forecast. The company will continue to study these data trends in its two-year Action Plan and report any additional findings in the 2009 Integrated Resource Plan.

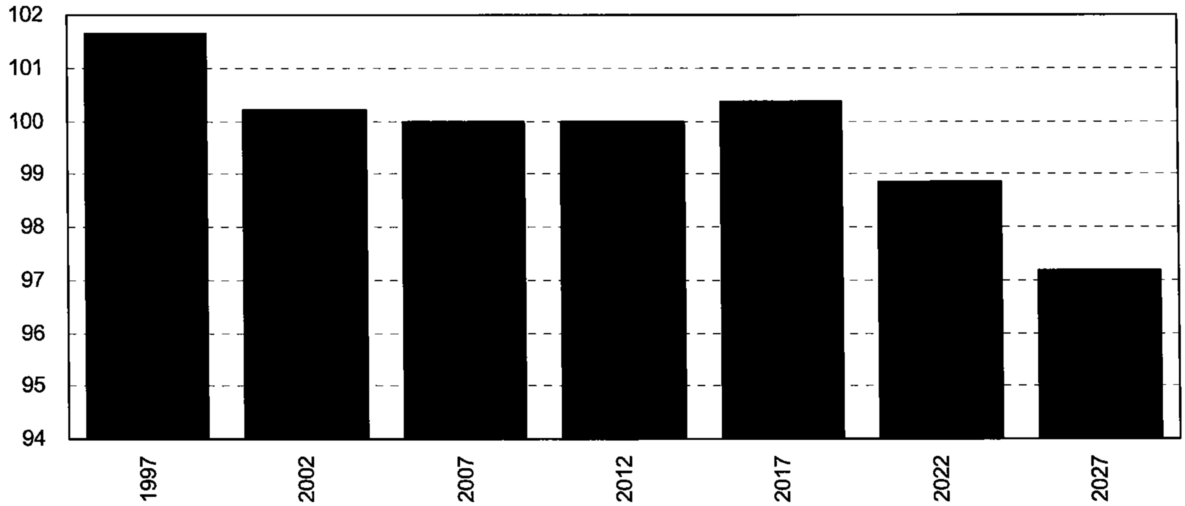
Price Elasticity

Price elasticity is a central economic concept of projecting electricity demand. Price elasticity of demand is the ratio of the percent change in the quantity demanded of a good or service to a percentage change in its price. In other words, elasticity measures the responsiveness of buyers to changes in electricity prices. A consumer who is sensitive to price changes has a relatively elastic demand profile. A customer who is unresponsive to price changes has a relatively inelastic demand profile. During the 2000-01 energy crisis customers showed their sensitivity, or price elasticity, of demand, reducing their overall electricity usage in response to price increases.

Cross elasticity of demand, or cross-price elasticity, is the ratio of the percentage change in the quantity demanded of one good to a one percent change in the price of another good. A positive coefficient indicates that the two products are substitutes; a negative coefficient indicates they are complementary goods. Substitute goods are replacements for one another. As the price of the first good increases relative to the price of the second good, consumers shift their consumption to the second good. Complementary goods are used together; increases in the price of one good result in a decrease in demand for the second good along with the first. The principal cross elasticity impact on electricity demand is the substitutability of natural gas in some applications, including water and space heating.

Income elasticity of demand is the ratio of the percentage change in the quantity demanded of one good to a 1 percent change in consumer income. Income elasticity measures the responsiveness of consumer purchases to

Figure 2.8: Household Size Index (% of 2007 Household Size)



income changes. Two impacts affect electricity demand. The first is affordability. As incomes rise, a consumer's ability to pay for goods and services increases. The second income-related impact is the amount and number of customers using equipment within their homes and businesses. Simply stated, as incomes rise consumers are more likely to purchase more electricity-consuming equipment, live in larger dwellings and use their electrical equipment more often.

The correlation between retail electricity prices and the commodity cost of natural gas has increased in recent years. We estimate customer class price elasticity in our computation of electricity and natural gas demand. Residential customer price elasticity is estimated at negative 0.15. Commercial customer price elasticity is estimated at negative 0.10. The cross-price elasticity of natural gas and electricity is estimated to be positive 0.05. Income elasticity is estimated at positive 0.75, meaning electricity is more affordable as incomes rise.

Retail Price Forecast

The retail sales forecast is based on retail prices increasing an average of 3.5 percent annually from 2007 to 2027. The rate changes are lumpy, rising by 17.5 percent every five years (five percent above the overall inflation rate).

Conservation

It is very difficult to separate the interrelated impacts of rising electricity and natural gas prices, rising incomes and conservation programs. We only have data on total demand and must derive the impacts associated with consumption changes. The company has offered conservation programs to its customers since 1978. The impact of conservation on electrical usage is fully imbedded in the historical data; therefore, we concluded that existing conservation levels (5 aMW) are imbedded in the forecast. Where conservation acquisition decreases from this level, retail load obligations would increase. As this IRP forecasts growing conservation acquisition, this growth reduces retail load obligations.

Use per Customer Projections

Monthly electricity sales and customers by rate schedule, customer class and state from 1997 to 2006 make up the database used to project usage per customer. Historical data is weather-normalized to remove the impact of heating and cooling degree day deviations from expected normal values, as discussed above. Retail electric price increase assumptions are applied to price elasticity estimates to estimate price-induced reductions in electrical use per customer.

The underlying increase in residential use per customer over the long term is 0.5 percent per year, consistent with the income elasticity and growth rate per customer. As shown by Figure 2.8, the number of persons per household declines slightly over the next 20 years.

Residential customers tend to be homogeneous relative to the size of their dwellings. Commercial customers, on the other hand, are heterogeneous, ranging from small customers with varying electricity intensity per square foot of floor space to big box retailers with generally high intensities. The addition of new large commercial customers, specifically the largest universities and hospitals, can greatly skew the average use per average customer. Customer usage is illustrated in Figure 2.9. Estimates for residential usage per customer across all schedules are relatively smooth. Commercial usage per customer is forecast to increase for several years, due to additional buildings either built or anticipated to be built at several existing very large customers and in particular at Washington State University campuses in Spokane and Pullman. For very large customers, we include expected additions through 2011; after 2011 no additions are included in the forecast. We will include publicly-announced long lead time buildings into the forecast included in future IRPs.

RETAIL ELECTRICITY SALES FORECAST

Between 1997 and 2006 the region was affected by major economic changes, not the least of which was a marked increase in retail electricity prices. The energy crisis of 2000-01 included the implementation of widespread, permanent conservation efforts by our customers. In 2004, rising retail electricity rates further reinforced conservation efforts. Several large industrial facilities served by the company closed permanently during the 2001-02 economic recession.

The electric retail sales forecast takes a somewhat conservative approach by assuming closures are permanent. If these industrial facilities reopen, the annual electricity retail sales forecast presented in this plan will be adjusted. Retail electricity consumption rose 2.3 percent annually from 1997 through 2006. This increase was despite the combined impacts of higher prices and decreased electricity demand during the energy crisis. The forecasted average annual increase in firm sales over the 2007 to 2027 period is 2.0 percent.

The sales forecast takes a "bottom up" approach, summing forecasts of the number of customers and usage per customer to produce a retail sales forecast. Individual forecasts for our largest industrial customers (Schedule 25) include planned or announced production increases

Figure 2.9: Use per Customer

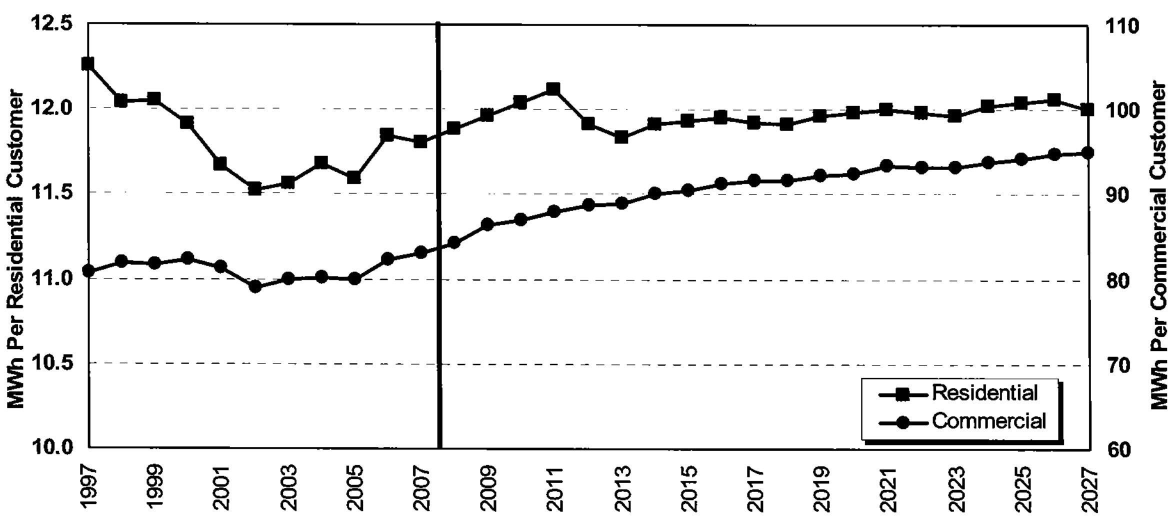
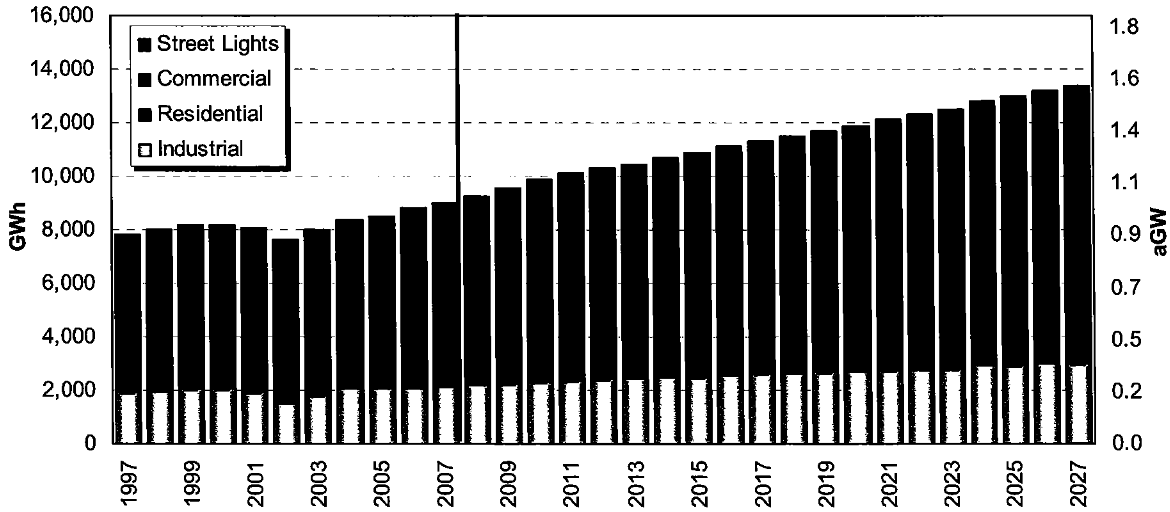


Figure 2.10: Avista's Retail Sales Forecast



or decreases. Lumber and wood products industries are ramping down from very high production levels, which is consistent with the decline in housing starts at the national level. The load forecasts for these sectors were reduced to account for decreased production levels. Anticipated sales to aerospace and aeronautical equipment suppliers have increased and local plants have announced plans to hire more workers and increase their output.

Actual (i.e., not weather corrected) retail electricity sales to Avista customers in 2006 were 8.78 billion kWh. Heating degree days in 2006 were 93 percent of normal, almost completely offset in terms of energy use by 156 percent of normal cooling degree days. The forecast for 2027 is 13.4 billion kWh, representing a 2.0 percent compounded increase in retail sales. See Figure 2.10.

Load Forecast

Load forecasts are derived from retail sales. Retail sales in kilowatt hours are converted into average megawatt hours using a regression model to ensure monthly load shapes conform to history. The company's load forecast is termed its Native Load. Native Load is net of line losses across the Avista transmission system.

Native Load growth is indicated in Figure 2.11. Note the significant drop in 2001 during the energy

Figure 2.11: Annual Net Native Load (aMW)

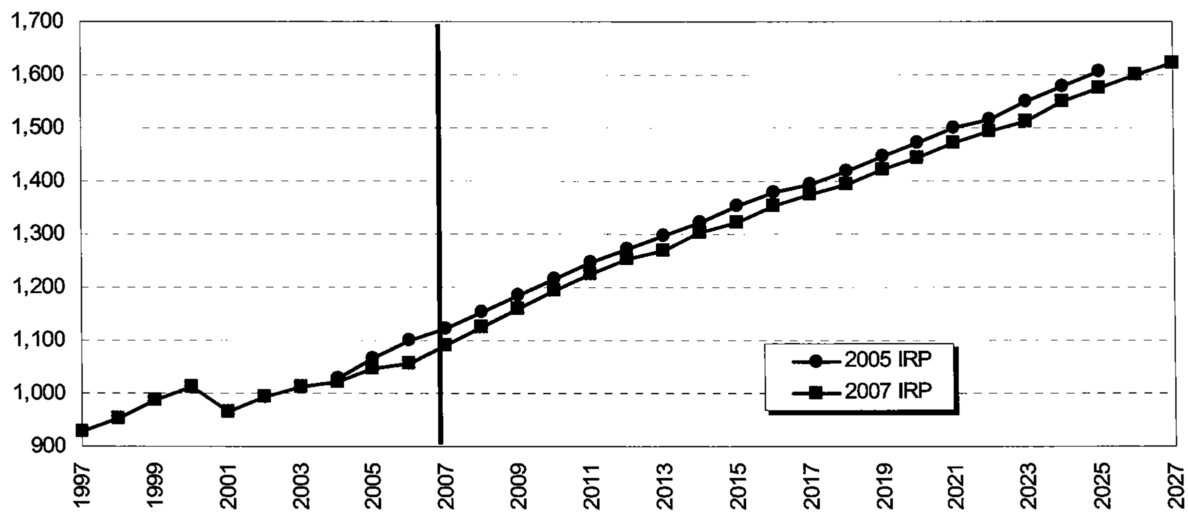
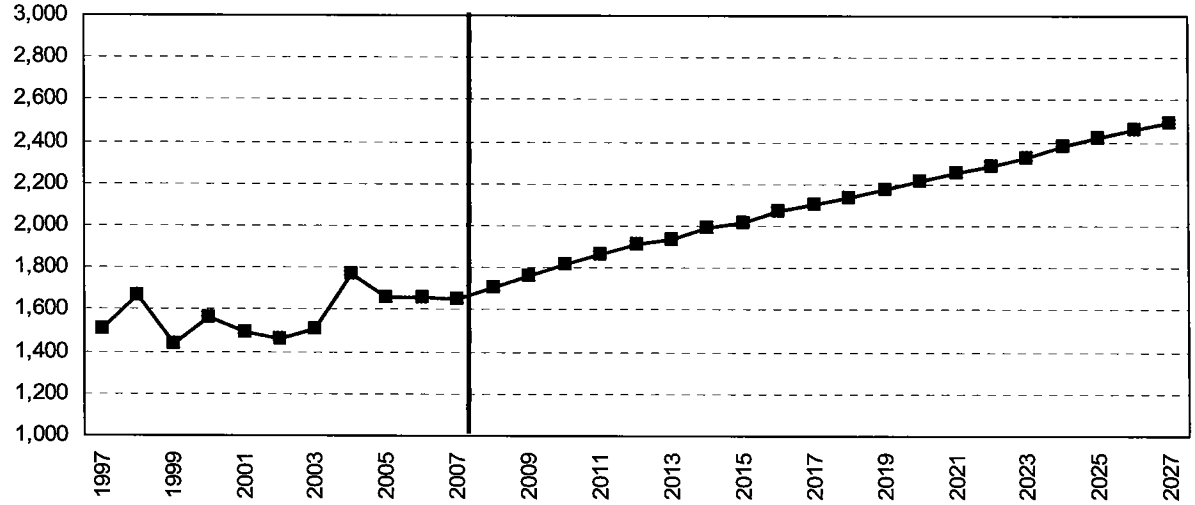


Figure 2.12: Calendar Year Peak Demand (MW)



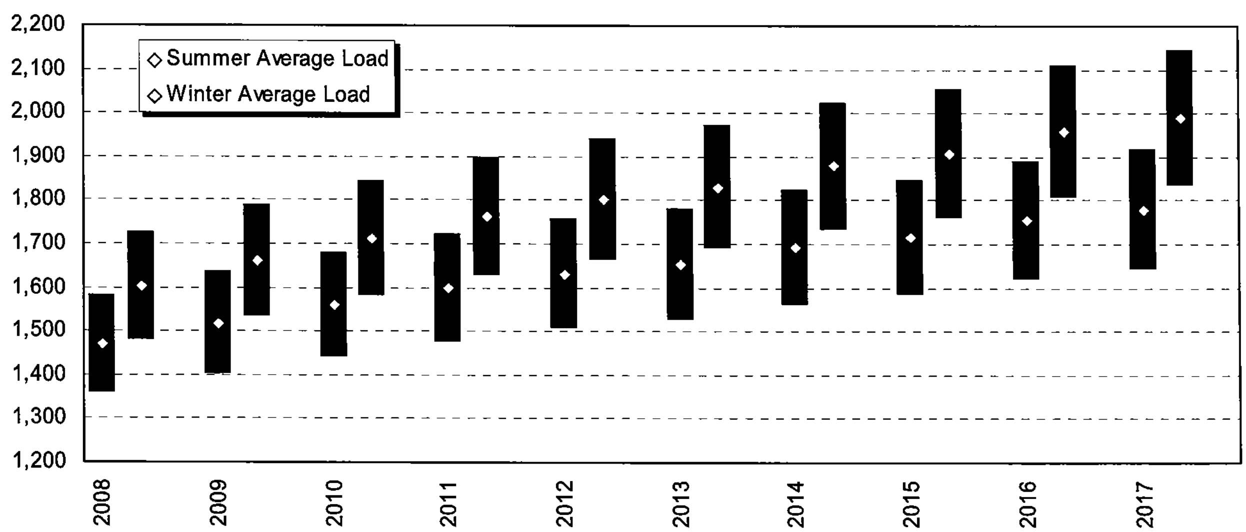
crisis. The loads from 1997 to 2006 are not weather normalized. The 2005 IRP load forecast is presented for comparison purposes. Loads are modestly lower in the 2007 IRP compared with the 2005 IRP.

Peak Demand Forecast

The peak demand forecast in each year represents the most likely value for that year. It does not represent the extreme peak demand. In statistical terms, the most likely peak demand has a 50 percent chance of exceedance in any year. The peak forecast is produced by running a regression between actual peak demand and net native load. The peak demand forecast is in Figure 2.12. Peak loads are expected to grow at 2.4 percent between 2007 and 2017 (400 MW) and 2.1 percent over the entire 20-year forecast.

Historical data are significantly influenced by extreme weather data. The comparatively low 1999 peak demand figure was the result of a warmer-than-average winter peak day; the peak in 2006 was the result of a below-average winter peak day. The 1999 and 2006 peak demand values illustrate why relying on compound growth rates for the peak demand forecast is an oversimplification and why the company plans to own or control enough generation assets and contracts to exceed expected peak demand.

Figure 2.13: Comparison of Summer and Winter Peak Demand (MW)



Avista has witnessed significant summer load growth as air conditioning penetration has risen in its service territory. That said, Avista expects to remain a winter-peaking utility in the foreseeable future. It is possible that very mild winter weather and extremely hot summertime temperatures could result in our summer peak load exceeding our wintertime demand level. This will be an anomaly. Figure 2.13 illustrates our forecast of winter and summer peak demands through 2017 and the expected range of the forecasts at the 80 percent confidence level. We expect that loads in the summer and winter of each year have a 10 percent probability of being higher than shown. Winter peak demand exceeds summer peak demand in all years; the possibility of a summer peak being higher than a winter peak in the same year is possible.

FORECAST SCENARIOS

The discussion so far has concentrated on the Base Case, or most-likely, electricity sales forecast. Forecasting is inherently uncertain, and alternative electricity growth scenarios are used to provide insight and guidance for our resource acquisition plans. At the request of the Technical Advisory Committee, high and low economic forecasts were prepared to illustrate how variable our load forecast might be.

The principal driver of these alternatives is the standard deviation of annual loads between 1997 and 2006. The average growth rate for the 10-year period was 2.4 percent, and the standard deviation was 2.5 percent. Approximately 75 percent of year-on-year variation is driven by weather, leaving 25 percent to the non-weather factors we are interested in evaluating here. The 80 percent confidence interval (with a 10 percent chance of exceedance on the high side and a 10 percent chance of exceedance on the low side) produced a range of growth for the 20-year period between 0.9 percent and 3.1 percent. This range is roughly in line with other Pacific Northwest forecast scenarios.

Avista is not forecasting any changes to its service territory in these scenarios. Such changes, were they to occur, would be outside of the scope of this exercise. Alternative forecasts are presented in Figure 2.14. Developed specifically for the IRP, these alternative forecasts should not be confused with other company or agency forecasts. The scenarios are not boundary forecasts in that the high forecast should not be considered the highest possible load trajectory; the low forecast does not represent the lowest possible forecast.

Figure 2.14: Electric Load Forecast Scenarios (aMW)

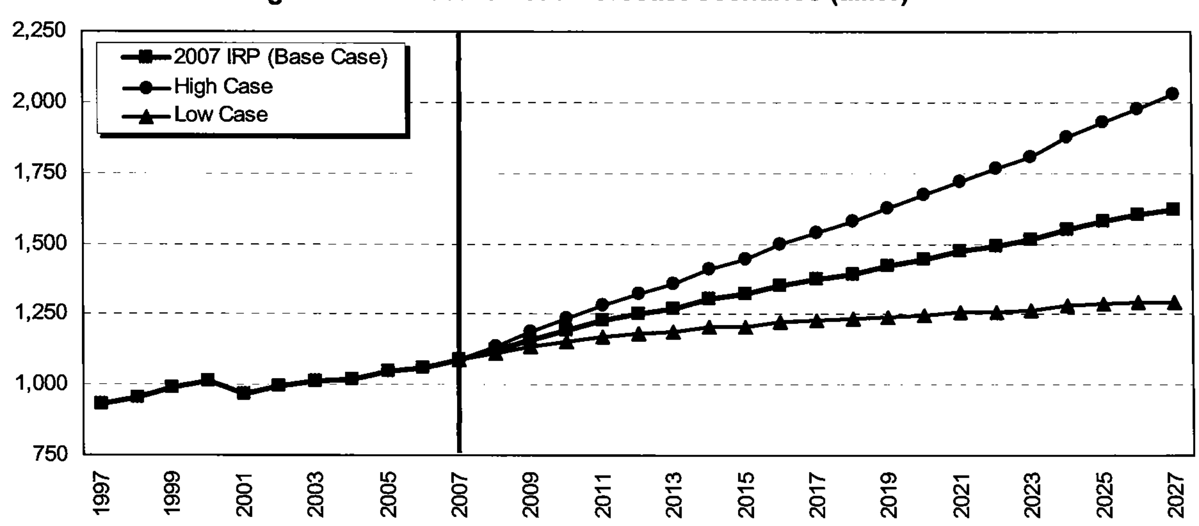
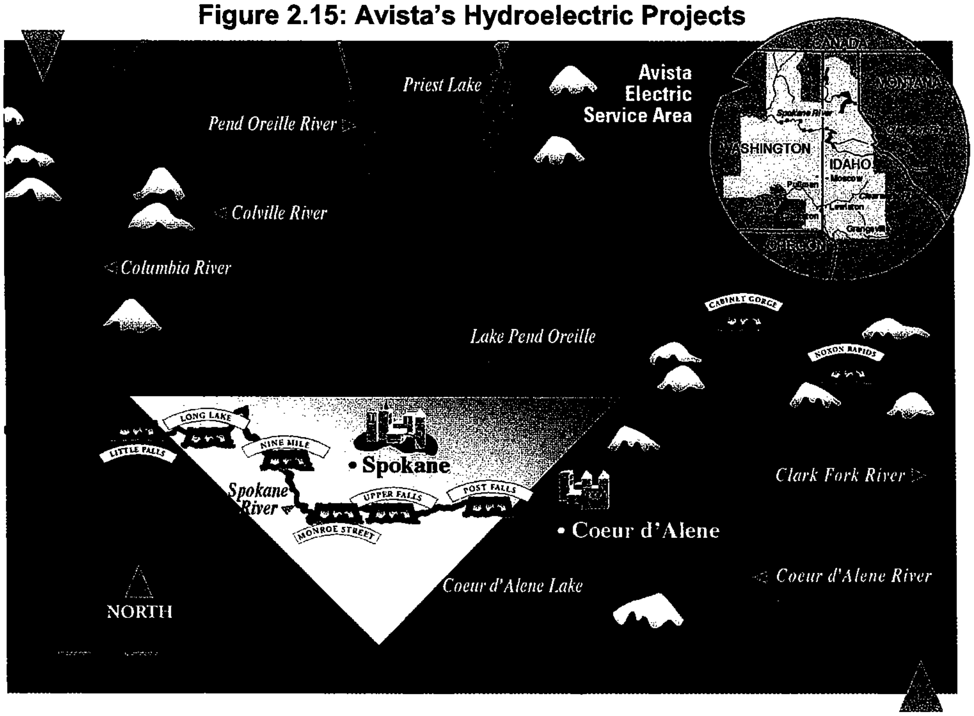


Figure 2.15: Avista's Hydroelectric Projects



LOADS & RESOURCES

The company relies on a diversified portfolio of generating assets to meet customer loads. Avista owns and operates eight hydroelectric projects located on the Spokane and Clark Fork Rivers. Its thermal assets include partial ownership of two coal-fired units in Montana, three natural gas-fired projects within its service territory, another natural gas-fired project in Oregon and a biomass plant near Kettle Falls, Washington.

SPOKANE RIVER HYDROELECTRIC PROJECTS

Avista owns and operates six hydroelectric projects on the Spokane River. FERC licensing for these projects expires on July 31, 2007 (except for Little Falls, which is state licensed). The company is actively working with stakeholders on relicensing for the Spokane River Project. Following is a short description of the Spokane River projects, including the maximum capacity and nameplate ratings for each plant. The maximum capacity of a generating unit is the total amount of electricity that a particular plant can safely generate. This is often higher than the nameplate rating because of facility upgrades.

The nameplate, or installed capacity of a plant, is the plant's capacity as rated by the manufacturer. Figure 2.15 is a map of all company-owned hydroelectric projects.

Post Falls

The Post Falls plant, located at its Idaho namesake, began operation in 1906. Generation was expanded in 1980 with an additional unit. This plant has an 18.0 MW maximum capability and a 14.8 MW nameplate rating.

Upper Falls

The Upper Falls project began generating in 1922 in downtown Spokane. This project is comprised of a single unit with a 10.2 MW maximum capability and 10.0 MW nameplate rating.

Monroe Street

The Monroe Street plant was the company's first generating unit. It started service in 1890 near what is now Riverfront Park. Rebuilt in 1992, the single generating unit now has a 15.0 MW maximum capability and a 14.8 MW nameplate rating.

Nine Mile

The Nine Mile project was built by a private developer in 1908 near Nine Mile Falls, Washington. The company purchased it in 1925 from the Spokane & Eastern Railway. Its four units have a 24.4 MW maximum capability and a 26.4 MW nameplate rating.

Long Lake

The Long Lake project is located above Little Falls in Eastern Washington. It was the highest spillway dam with the largest turbines in the world when it was completed in 1915. The plant was most recently upgraded with new runners in 1999. The four units in this project provide 90.4 MW in combined maximum capability and 70.0 MW nameplate rating.

Little Falls

The Little Falls project was completed in 1910 near Ford, Washington. The four units at this project provide 36.0 MW of maximum capability and have a 32.0 MW nameplate rating.

CLARK FORK RIVER HYDROELECTRIC PROJECT

The Clark Fork River Project is comprised of hydroelectric projects in Clark Fork, Idaho, and Noxon, Montana. The plants operate under a FERC license expiring in 2046.

Cabinet Gorge

The Cabinet Gorge plant started generating power in 1952 with two units. The plant was expanded with two additional generators in the following year. The current maximum capability of the plant is 263.2 MW; it has a nameplate rating of 272.2 MW. Upgrades at this project began with the replacement of turbine Unit 1 in 1994. Unit 3 was upgraded in 2001. Unit 2 was upgraded in 2004. The final unit, Unit 4, received a $6 million turbine upgrade in 2007, increasing its generating capacity from 55 MW to 64 MW and adding 2.1 aMW of energy.

Noxon Rapids

The Noxon Rapids project includes four generators

Monroe Street Hydroelectric Facility, Spokane, Washington

Table 2.2: Company-Owned Hydro Resources

Project Name	River System	Location	Project Start Date	Nameplate Capacity (MW)	Maximum Capability (MW)	70-Year Energy (aMW)
Monroe Street	Spokane	Spokane, WA	1890	14.8	15.0	13.2
Post Falls	Spokane	Post Falls, ID	1906	14.8	18.0	9.9
Nine Mile	Spokane	Nine Mile Falls, WA	1925	26.4	24.4	16.4
Little Falls	Spokane	Ford, WA	1910	32.0	36.0	22.8
Long Lake	Spokane	Ford, WA	1915	70.0	90.4	52.4
Upper Falls	Spokane	Spokane, WA	1922	10.0	10.2	8.8
Cabinet Gorge	Clark Fork	Clark Fork, ID	1952	272.2	263.2	122.2
Noxon Rapids	Clark Fork	Noxon, MT	1959	466.2	527.0	202.9
Total	**All Hydro**			**905.4**	**984.2**	**442.9**

Table 2.3: Company-Owned Thermal Resources

Project Name	Location	Fuel	Start Date	Nameplate Capacity (MW)	Maximum Capability (MW)	Energy Capability (aMW)
Colstrip 3 (15%)	Colstrip, MT	Coal	1984	116.7	114.6	93.3
Colstrip 4 (15%)	Colstrip, MT	Coal	1986	116.7	114.6	93.3
Rathdrum	Rathdrum, ID	Gas	1995	166.5	176.0	135.6
Northeast	Spokane, WA	Gas/Oil	1978	62.8	66.8	9.8
Boulder Park	Spokane, WA	Gas	2002	24.6	24.6	23.2
Coyote Springs 2	Boardman, OR	Gas	2003	287.0	284.7	250.2
Kettle Falls	Kettle Falls, WA	Wood	1983	46.0	50.7	42.2
Kettle Falls CT	Kettle Falls, WA	Gas	2002	6.9	6.9	6.1
Total	**All Thermal**			**827.2**	**838.9**	**653.7**

installed between 1959 and 1960, and a fifth unit added in 1977. The current plant configuration has a maximum capability of 527.0 MW and a nameplate rating of 466.2 MW. Upgrades to all four units at the Noxon Rapids facility are scheduled from March 2009 to March 2012. The upgrades are expected to add 38 MW of capacity and 6 aMW of energy to the company's resource portfolio.

Total Hydroelectric Generation

In total, our hydroelectric plants are capable of generating as much as 984.2 MW. Table 2.2 summarizes the company's hydro projects. This table also includes the average annual energy output of each facility based on the 70-year stream flow record.

THERMAL RESOURCES

Avista owns and maintains several thermal assets located across the Northwest. Each thermal plant is expected to continue to be available through the 20-year duration of the 2007 IRP. The company's thermal resources provide dependable low-cost energy to serve base loads and provide peak load serving capabilities. Table 2.3 summarizes the company's thermal projects.

Colstrip

The Colstrip plant, located in Eastern Montana, consists of four coal-fired steam plants owned by a group of utilities. PPL Global operates the facilities. Avista owns 15 percent of Units 3 and 4. Unit 3 was completed in 1984 and Unit 4 was finished in 1986. The company's share of each Colstrip unit has a maximum capability of 114.6 MW and a nameplate rating of 116.7 MW. Capital improvements to both units were completed in 2006 and 2007 to improve efficiency and reliability and to increase generation. The upgrades included new high-pressure steam turbine rotors and conversion from analog to digital control systems. These capital improvements increased the company's share of generation by 4.2 MW at each unit without any additional fuel consumption.

Rathdrum

Rathdrum is a two-unit, simple-cycle, gas-fired plant located near Rathdrum, Idaho. The plant entered service in 1995. It has a maximum capability of 176.0 MW and a nameplate rating of 166.5 MW.

Northeast

The Northeast plant, located in northeast Spokane, is a two-unit, aero-derivative, simple-cycle plant completed in 1978. The plant is capable of burning natural gas or fuel oil, but current air permits prevent the use of fuel oil. The combined maximum capability of the units is 66.8 MW with a nameplate rating of 62.8 MW.

Boulder Park

The Boulder Park project was completed in Spokane Valley in 2002. The site uses six natural gas-fired internal combustion engines to produce a combined maximum capability and nameplate rating of 24.6 MW.

Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined cycle combustion turbine located near Boardman, Oregon. The plant began service in 2003. The maximum capability is 264.3 MW and the duct burner provides the unit with an additional capability of up to 20.4 MW. The nameplate rating is 287.0 MW.

Kettle Falls

The Kettle Falls biomass facility was completed in 1983 near Kettle Falls, Washington. The open-loop biomass steam plant is fueled by waste wood products and has a maximum capability of 50.7 MW. Its nameplate rating is 46 MW.

Kettle Falls CT

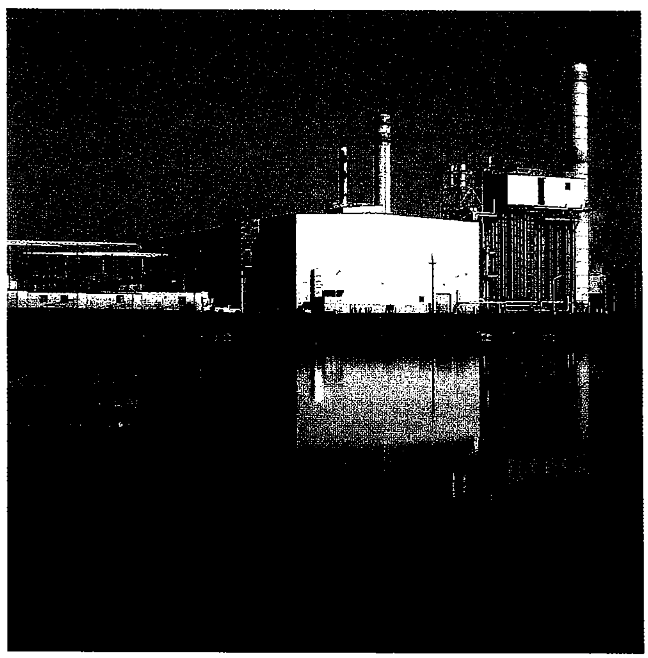
The Kettle Falls CT is a natural gas-fired combustion turbine that began service in 2002. It has a maximum capability rating of 6.9 MW. Exhaust heat from the plant is routed into the Kettle Falls biomass plant boiler to increase its efficiency. The plant is capable of running independently of the biomass steam plant.

POWER PURCHASE AND SALE CONTRACTS

The company utilizes several power supply purchase and sale arrangements of varying lengths to meet a portion of its load requirements. This section describes the contracts in effect during the scope of the 2007 IRP. The contracts provide a number of benefits to the company, including environmentally low-impact and low-cost hydro and wind power. An annual summary of our contracts is contained in Table 2.5.

Bonneville Power Administration (BPA) – Residential Exchange

The company first entered into settlement agreements to resolve BPA's Residential Exchange obligation on October 31, 2000. Over the first five years of the 10-year settlement, the company received financial benefits equivalent to purchasing 90 aMW at BPA's lowest cost-based rate. The company's benefit level increased to 149



Coyote Springs 2, Boardman, Oregon

aMW on October 1, 2006. At BPA's option, the 149 aMW may be provided in whole or in part as financial benefits or as a physical power sale; the IRP assumes the former based on regional discussions.

On May 3, 2007, the Ninth U.S. Circuit Court of Appeals issued opinions holding that BPA exceeded its settlement authority and acted in a manner that was inconsistent with the Northwest Power Act when it entered into the settlement agreements. As a result, on May 21, 2007, BPA notified Avista that it was suspending payments.

Bonneville Power Administration – WNP-3 Settlement

On September 17, 1985, the company signed settlement agreements with BPA and Energy Northwest (formerly the Washington Public Power Supply System or WPPSS), ending construction delay claims against both parties. The settlement provides an energy exchange through June 30, 2019, with an agreement to reimburse the company for certain WPPSS – Washington Nuclear Plant No. 3 (WNP-3) preservation costs and an irrevocable offer of WNP-3 capability for acquisition under the Regional Power Act.

The energy exchange portion of the settlement contains two basic provisions. The first provision provides approximately 42 aMW of energy to the company from BPA through 2019, subject to a contract minimum of 5.8 million megawatt-hours. The company is obligated to pay BPA operating and maintenance costs associated with the energy exchange as determined by a formula that ranges from $16 to $29 per megawatt-hour in 1987 dollars.

The second provision provides BPA approximately 33 aMW of return energy at a cost equal to the actual operating cost of the company's highest-cost resource. A further discussion of this obligation, and how the company plans to account for it, is covered under the Confidence Interval Planning heading of this chapter of the IRP.

Mid-Columbia Hydroelectric Contracts

During the 1950s and 1960s, various public utility districts (PUDs) in central Washington developed hydroelectric projects on the Columbia River. Each plant was large compared to the loads served by the PUDs. Long-term contracts were signed with public, municipal and investor-owned utilities throughout the Northwest to assist with project financing and to ensure a market for the surplus power.

The company entered into long-term contracts for the output of four of these projects "at cost." The contracts provide energy, capacity and reserve capabilities. In 2008 they will provide approximately 95 MW of capacity and 51 aMW of energy. Over the next 20 years, the Wells and Rocky Reach contracts will expire. While the company may be able to extend these contracts, it has no assurance today that extensions will be offered. The 2007 IRP does not include energy or capacity for these contracts beyond their expiration dates.

The company renewed its contract with Grant PUD in 2005 for power from the Priest Rapids project. The contract term will equal the term in the forthcoming Priest Rapids and Wanapum dam FERC licenses. A license term of 30 to 50 years is expected. The company acquired additional displacement power in the Priest Rapids settlement. Displacement power, through September 30, 2011, includes project output available due to displacement resources being used to serve Grant PUD's load. A summary of Mid-Columbia contracts is included in Table 2.4.

Medium-Term Market Purchases

Avista has power purchase contracts for 100 MW of power from 2004 through 2010 from several suppliers.

Table 2.4: Mid-Columbia Contract Summary

	2008		2012		2017	
Project Name	MW	aMW	MW	aMW	MW	aMW
Rocky Reach	37.7	20.0	0.0	0.0	0.0	0.0
Wells	28.6	15.8	28.6	15.8	28.6	15.8
Grant County	28.9	14.8	63.2	35.7	63.2	32.6
Totals	**95.2**	**50.6**	**92.8**	**52.5**	**92.8**	**48.4**

Nichols Pumping Station

The company provides energy to operate its share of the Nichols Pumping Station, which supplies water for the Colstrip plant. The company's share of the Nichols Pumping Station load is approximately one aMW. Avista is also under contract to provide pumping energy to other Colstrip owners.

Portland General Electric – Firm Capacity Sale

The company contracted to provide Portland General Electric (PGE) with 150 MW of firm capacity through December 31, 2016. PGE may schedule deliveries up to its capacity limit during any 10 hours of each weekday. Within 168 hours PGE returns energy delivered under the contract.

Stateline Wind Energy Center

The company contracted with PPM Energy in 2004 for 35 MW of nameplate wind capacity from the Stateline Wind Energy Center located on the Oregon-Washington border. This 35 MW contract does not include firming services.

A summary of all company obligations and rights is presented in Table 2.5.

RESERVE MARGINS

Planning reserves accommodate situations when loads exceed and/or resources are below expectations because of adverse weather, forced outages, poor water conditions or other contingencies. There are disagreements within the industry on adequate reserve margin levels. Many stem from system differences, such as resource mix, system size and transmission interconnections. For example, a hydro-based utility generally has a higher capacity-to-energy ratio than a thermal-based utility.

Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves. For example, inexpensive 100 MW peaking resources overnight costs are around $42 million; this translates to a $6 million annual expense. Reserve resources have the physical capability to generate electricity, but high operating costs limit economic dispatch and the potential to create revenues to offset capital costs. Some argue

Table 2.5: Significant Contractual Rights and Obligations

Contract Name	Start Date	Capacity (MW)	Energy (aMW)	End Date
Grant County Purchase	2005	129.3	72.0	TBD
Rocky Reach Purchase	1961	37.7	19.3	Oct-2001
Wells Purchase	1967	28.6	9.9	Aug-2018
PGE Capacity Sale	1992	150.0	0.0	Dec-2016
Upriver Dam Purchase	1966	14.4	10.0	Dec-2011
WNP-3 Purchase & Sale	1987	82.0	48.0	Jun-2019
Medium-Term Purchases	2004	100.0	100.0	Dec-2010
PPM Wind Purchase [1]	2004	35.0	9.8	Mar-2011
Total Contract		**577.0**	**268.0**	

[1] The PPM wind purchase is shown at its nameplate rating.

that regions with deregulation, or "customer choice," provide strong incentives for industry participants to underestimate their reserve obligations and lower their costs at the expense of system reliability.

AVISTA'S PLANNING MARGIN

Avista's planning reserves are not directly based on unit size or resource type. Planning reserves are set at a level equal to 10 percent of our one-hour system peak load plus 90 MW. The 90 MW accounts for approximately 60 MW of hydro because of icing on river banks and 30 MW of Colstrip reserves because of coal handling problems in cold weather situations. This amounts to roughly a 15 percent planning reserve margin during the company's peak load hour.

CONFIDENCE INTERVAL PLANNING

Avista uses confidence interval planning to ensure it has resources adequate to meet customer energy requirements. Extreme weather conditions can affect monthly energy obligations by up to 30 percent. If the company lacks generation capability to meet high load variations, it is exposed to increased short term market volatility. Analysis of historical data indicates that an optimal criterion is the use of a 90 percent confidence interval based on the monthly variability of load and hydroelectric generation. This results in a 10 percent chance of the combined load and hydro variability exceeding the planning criteria for each month. In other words, there is a 10 percent chance that the company would need to purchase energy from the market in any given month. Avista has considered larger confidence intervals, but analysis suggests that the cost of additional resources to cover higher levels of variability would exceed the potential benefits. Building to the 99 percent confidence interval could significantly decrease the frequency of market purchases but would require approximately 200 MW of additional generation capability. Additional capital expenditures to support this level of reliability would put upward pressure on retail rates.

The 90 percent confidence level varies between 84 aMW and 301 aMW on a monthly basis in 2008, or 166 aMW across the 12-month period. This level is similar to critical water planning on an annual basis, but is more precise because it is based on the monthly instead of annual chance of exceedance.

Additional variability is inherent in the WNP-3 contract with BPA. The contract includes a return energy provision that can equal 33 aMW annually. The contract would be exercised under adverse conditions, such as low hydroelectric generation or high loads, which the company would also expect to be experiencing. Requirements under the confidence interval are increased by 33 aMW to account for the WNP-3 obligation through its expiration in 2019.

SUSTAINED PEAKING CAPACITY

Parallel to planning margins is the "gray area" between energy and capacity planning termed sustained peaking capacity. Sustained peaking capacity is a tabulation of loads and resources over a period exceeding

Table 2.6: Capacity L&R Versus Sustained Capacity

Item	Capacity L&R	Sustained Capacity
Period	One Hour	One Hour to Three Days or More
Peak Load	Average Coldest Day Temperature	Highest Load on Record
Thermals	Lowest Temperature & Colstrip Reduced for Freeze (~30 MW)	Lowest Temperature & Colstrip Reduced for Freeze (~30 MW)
Hydro	Maximum Capability Reduced for Freeze (~60 MW)	Maximum Capability Reduced for Freeze (~60 MW)
Contracts	Actual Forecast	Actual Forecast

the traditional one-hour definition. It is also a measure of reliability and recognizes that peak loads do not stress the system for just one hour. Table 2.6 details the assumption differences between the company's planning approach and the sustained capacity approach.

The company has actively participated in the Northwest Power and Conservation Council's Resource Adequacy committees over the past few years. Preliminary work indicates that the Northwest should carry approximately a 25 percent planning margin in the wintertime and a 17 percent planning margin in the summertime. These levels are much higher than the 12 to 15 percent levels recommended in California or for other markets, primarily due to the Northwest's heavier reliance on hydroelectric generation. Given the various uncertainties surrounding these higher planning margin levels, and the fact that they are not yet finalized, the company's plan will not change for this planning cycle. Avista will continue to participate in this important regional process and use the results in its future planning when they become more finalized.

RESOURCE REQUIREMENTS

The differences between loads and resources illustrate potential needs the company must address through its future resource acquisition actions. The company plans to meet both its energy and capacity needs.

CAPACITY TABULATION

The company regularly develops a 20-year service territory forecast of peak capacity loads and resources. Peak load is the maximum one-hour obligation, including operating reserves, on the expected average coldest day in January. Peak resource capability is the maximum one hour generation capability of company resources, including net contract contribution, at the time of the one-hour system peak. This calculation is performed to ensure that the company has sufficient resources to meet its load obligations. Avista has surplus capacity through 2009 without the addition of the Lancaster plant. Capacity deficits begin in 2010, with loads exceeding resource capabilities by five MW. The deficits continue to grow as peaking requirements

Table 2.7: Loads & Resources Capacity Forecast (MW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,703	1,763	1,815	1,868	1,909	2,019	2,103	2,214	2,492
Planning Margin	260	266	272	277	281	292	300	311	339
Total Obligations	***1,964***	***2,029***	***2,087***	***2,145***	***2,190***	***2,311***	***2,404***	***2,525***	***2,831***
Existing Resources									
Hydro	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,070	1,070
Net Contracts	172	172	173	73	58	58	208	128	128
Coal	230	230	230	230	230	230	230	230	230
Biomass	50	50	50	50	50	50	50	50	50
Gas Dispatch	308	308	308	308	308	308	308	308	308
Gas Peaking Units	211	211	211	211	211	211	211	211	211
Total Existing Resources	***2,111***	***2,123***	***2,092***	***1,999***	***1,939***	***1,954***	***2,104***	***1,996***	***1,996***
Net Positions	**148**	**94**	**5**	**-146**	**-251**	**-357**	**-300**	**-530**	**-835**
Planning Margins (%)	**24.0**	**20.4**	**15.2**	**7.0**	**1.6**	**-3.2**	**0.0**	**-9.9**	**-19.9**
Lancaster	0	0	275	275	275	275	275	275	0
Net Positions with Lancaster	**148**	**94**	**280**	**129**	**24**	**-82**	**-25**	**-255**	**-835**
Planning Margins with Lancaster (%)	**24.0**	**20.4**	**30.4**	**21.7**	**16.0**	**10.4**	**13.1**	**2.6**	**-19.9**

Figure 2.16: Capacity Loads and Resources (MW)

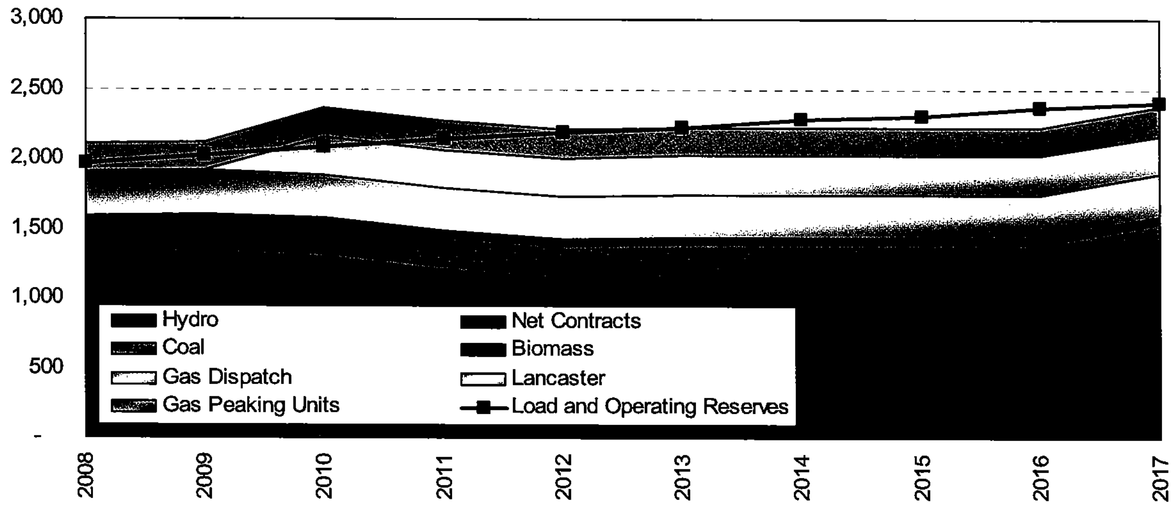


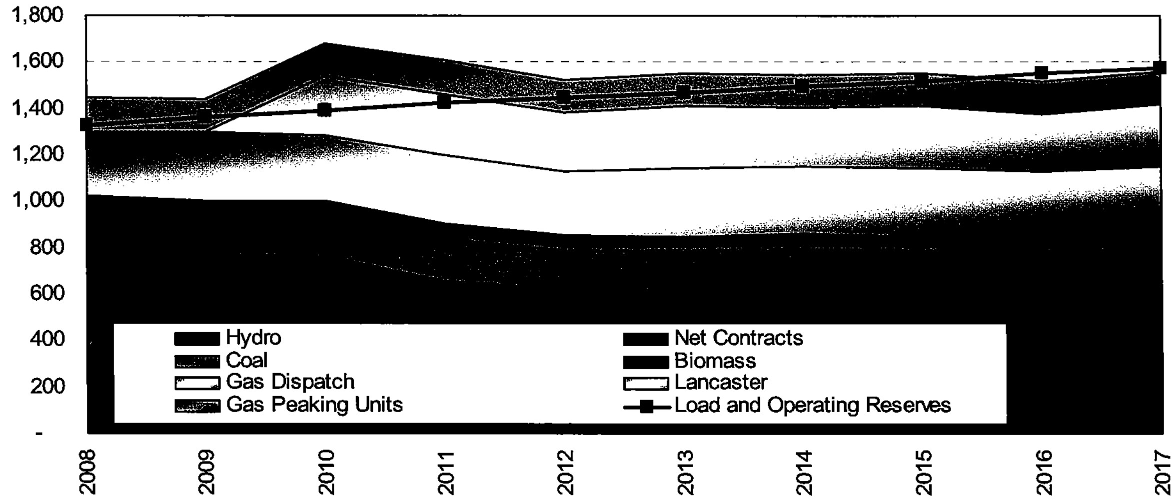
Table 2.8: Loads & Resources Energy Forecast (aMW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,125	1,163	1,196	1,230	1,256	1,326	1,379	1,450	1,627
90% Confidence Interval	200	199	196	196	192	192	192	156	156
Total Obligations	***1,324***	***1,362***	***1,392***	***1,425***	***1,448***	***1,518***	***1,571***	***1,606***	***1,783***
Existing Resources									
Hydro	540	538	531	528	512	510	509	491	491
Net Contracts	234	234	234	129	107	105	105	106	106
Coal	199	183	188	198	187	187	198	199	186
Biomass	47	47	47	47	47	47	47	47	47
Gas Dispatch	280	295	285	295	280	295	295	280	295
Gas Peaking Units	145	145	141	146	145	146	145	141	145
Total Existing Resources	***1,446***	***1,442***	***1,426***	***1,342***	***1,278***	***1,290***	***1,299***	***1,265***	***1,270***
Net Positions	**121**	**79**	**33**	**-83**	**-170**	**-228**	**-272**	**-341**	**-513**
Lancaster	0	0	254	264	249	264	264	228	0
Net Positions with Lancaster	**121**	**79**	**288**	**181**	**79**	**37**	**-8**	**-114**	**-513**

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 hydroelectric project contracts. Some year-to-year variation occurs in the forecast because of maintenance schedules. With Lancaster included in the planning, our deficit year moves out to 2014. Table 2.7 summarizes the forecast.

Avista currently has sufficient capacity resources, primarily because of the relatively large amount of hydroelectric generation in its resource portfolio. Hydroelectric resources can provide large amounts of short-term capacity in relation to the energy they produce because of storage associated with each project. Future capacity requirements will be addressed by acquiring new resources that provide both energy and capacity, or in the case of intermittent resources like wind, other resources that provide capacity. Figure 2.16 shows this information graphically.

Figure 2.17: Energy Loads and Resources (aMW)



ENERGY TABULATION

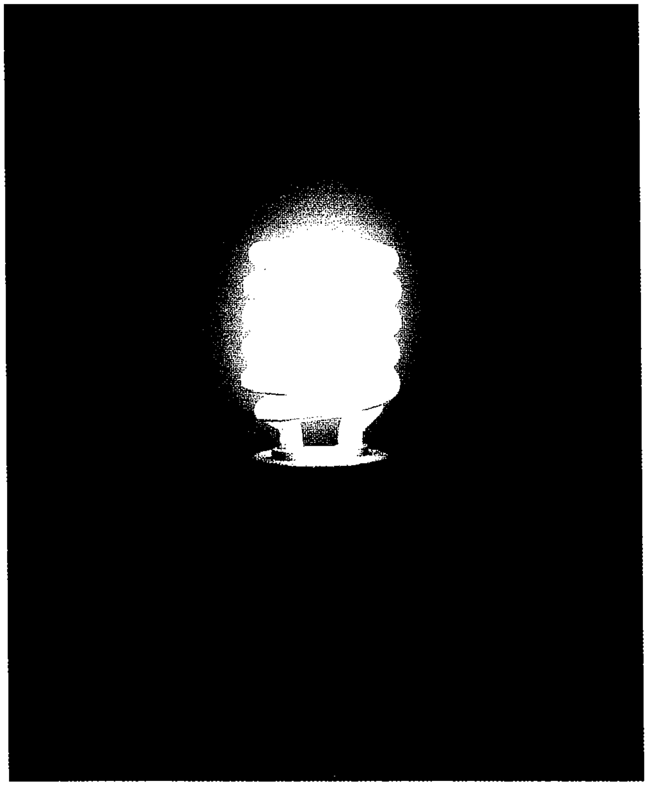
Table 2.8 summarizes annual energy loads and resources for the IRP time horizon. This IRP focuses on meeting the company's energy requirements to the 90 percent confidence level. Similar to Table 2.8, maintenance schedules affect the output of plants over the IRP timeframe. Specifically, coal, biomass, gas dispatch and gas peaking units are affected.

After 2010 new resources are necessary to continue meeting the 90 percent confidence interval planning margin criterion. The table shows that the company is annually in a surplus position through 2010. With the Lancaster plant, our surplus position moves out to 2016. Figure 2.17 provides the same information graphically.

Conservation acquisitions are prescriptive, meaning that customers must take action to lower their energy usage. Without "programmatic" conservation acquisitions, retail loads and supply-side resource acquisitions would be higher. Historically, conservation acquisition levels were included as reductions to retail load. The 2005 IRP included load that will be met by programmatic conservation, as an increase to load, and then displays the conservation resource separately in the table. The conservation projections shown in Tables 2.7 and 2.8 are cumulative and illustrate the company's commitment to continued acquisition of cost-effective conservation. Activities beyond current levels are discussed in Chapter 3 – Demand Side Management – and are shown as new resources in later tabulations.

The company expects to experience energy deficits during some months of all forecast years. As an example, the company anticipates deficits in January and October of 2008 even though the annual position has a 121 aMW surplus. Surplus positions occur in the remaining months, particularly during spring runoff. The company balances its monthly positions through short-term market purchases or sales, exchanges, or other resource arrangements.

3. DEMAND SIDE MANAGEMENT

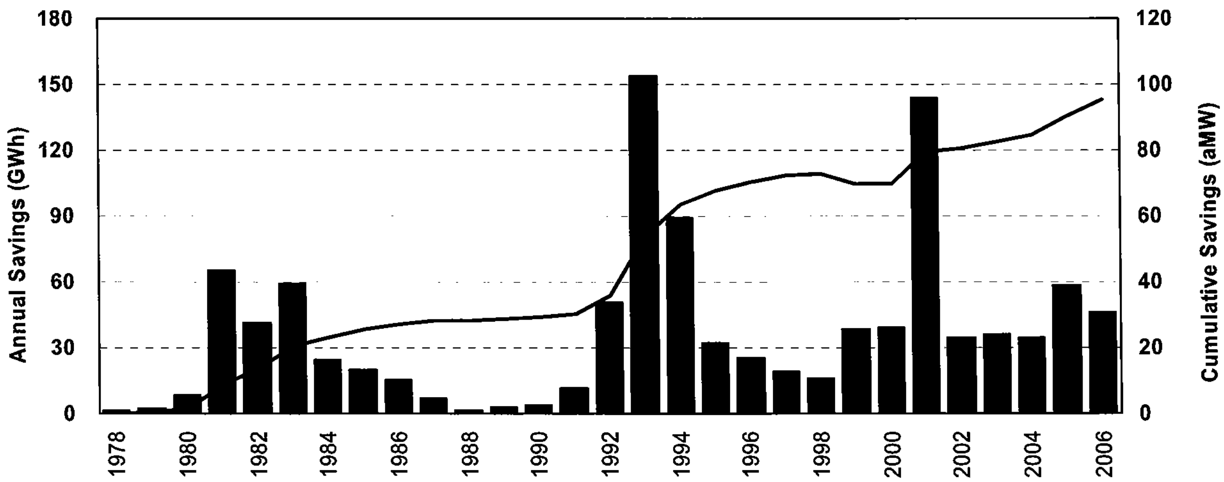


A High Efficiency Compact Flourescent Light Bulb

INTRODUCTION

Avista's Demand Side Management (DSM) programs provide a range of energy efficiency options for residential, commercial and industrial customers. They fall into prescriptive and site-specific categories. Prescriptive programs offer cash incentives for standardized products such as compact fluorescent light bulbs and high efficiency appliances. Site-specific programs provide cash incentives for cost-effective energy savings measures with a payback greater than one year. These programs are customized services for commercial and industrial customers because many applications need to be tailored to customer premises and processes. Avista has continuously offered electric efficiency programs since 1978. Some of Avista's most notable efficiency achievements include the Energy Exchanger programs, which converted over 20,000 homes from electric to natural gas for space or water

Figure 3.1: Historical Conservation Acquisition



SECTION HIGHLIGHTS

- Avista has assisted its customers in acquiring cost-effective energy efficiency for 30 years.
- Avista has acquired 124 aMW of electric-efficiency in the past three decades; an estimated 96 aMW is currently online.
- 20,000 customers heat their homes with natural gas today because of the company's fuel-switching programs.
- The company has developed and will maintain the infrastructure necessary to respond quickly in the event another energy crisis occurs.
- The Heritage Project is re-evaluating our traditional programs, updating economic benchmarks, and revising the scope to include transmission, distribution and generation facility efficiencies.

Table 3.1: Current Energy Efficiency Programs

Residential/Limited Income	Commercial/Industrial
High-efficiency natural gas furnaces/boilers	Site specific (any measure)[2]
High-efficiency heat pumps	Efficient lighting and controls
High-efficiency variable speed motors	Food service equipment
High-efficiency and tankless water heaters	Rooftop HVAC maintenance (AirCare Plus)
Electric to natural gas space and water heating	Variable frequency drives
Electric to heat pump	LEED certification
Electric to natural gas water heaters	Premium efficiency motors
Ceiling/attic, floor and wall insulation	Supermarket and warehouse refrigeration
Windows	Power management for computer networks
Limited income measures including health/safety[3]	LED traffic signals
Multi-family, electric to natural gas domestic hot water	Spray head efficiency

heating from 1992-1994; pioneering the country's first system benefit charge for energy efficiency in 1995; and the immediate conservation response during the 2001 Western energy crisis, which tripled annual energy savings at only twice the cost, in half the time, to meet the customer demand for reducing energy usage during a period of high prices. The company's programs provide savings that regularly meet or exceed its regional share of energy efficiency savings as outlined by the Northwest Power Planning and Conservation Council. Historical electricity conservation acquisition is illustrated in Figure 3.1.

During the 30 years that Avista has actively acquired electric efficiency resources, a total of 124 aMW of energy savings has been achieved. We believe that the 96 aMW acquired during the last 18 years is still online and yielding resource value today.[1]

In this IRP planning cycle, all demand-side management (DSM) measures and programs have been examined based on surrogate generation costs. New savings targets have been established, and the company is planning a significant ramp-up of energy efficiency activity. Avista is also expanding the breadth of its efficiency activities to include demand response initiatives and is revisiting the potential for transmission and distribution efficiency measures. These expanded programs are in development and are not reflected in this IRP, but they are included as an action item for the 2009 IRP.

THE HERITAGE PROJECT

The company's new demand response initiative is called the Heritage Project. The Heritage Project focuses on revamping existing energy efficiency targets by applying the best practices within the utility industry. This project continues our legacy of innovation in energy efficiency efforts and customer education. The goal of the Heritage Project is to increase the acquisition of sustainable and cost-effective energy and demand savings through a comprehensive, state-of-the-art demand response initiative. The project examines and implements expanded energy efficiency programs, peak shaving/shifting programs and other options (e.g., distribution system efficiencies).

The Heritage Project focuses on five areas: energy efficiency, load management, transmission and distribution efficiencies, analytics and communications. Each area is supported by analyses and attributes unique to that function.

[1] Cumulative conservation is based upon an 18-year weighted average measure life.
[2] NEEA's website, www.nwalliance.org, offers additional details regarding their ventures, governance, proceedings, reports and evaluations.
[3] It was assumed that historic acquisition would remain flat at the most recent level because there are no reliable 20-year estimates of regional program acquisition. This assumption is speculative and dependent on the opportunities for regional market transformation during this period, but it is consistent with the recent history of flat funding of the NEEA organization.

ENERGY EFFICIENCY

The energy efficiency review evaluated the company's current electric and natural gas efficiency programs to determine what additional programs can be cost-effectively acquired in the near-term (2007) and intermediate term (2008-2010). Avoided costs based on the 2007 IRP, including factors such as risk and capacity, were established to determine the cost-effectiveness of and potential for program expansion. Current delivery mechanisms and outreach efforts were assessed to ensure that all customers have knowledge and adequate opportunities to participate in the company's efficiency programs. Table 3.1 summarizes the DSM programs.

The company's existing efficiency programs are thorough, but several additional opportunities were identified. New programs that are currently under evaluation are outlined in Table 3.2.

REQUEST FOR INFORMATION/REQUEST FOR PROPOSALS

In addition to soliciting internal parties and key stakeholders for concepts to improve the energy efficiency portfolio, the company also released a broad request for information (RFI) in 2006 to obtain the benefit of the opinions outside of our normal range of contacts. The RFI sought ideas for the company to cost-effectively enhance its conservation portfolio through new programs, measures or revisions to existing programs. A total of 53 RFI responses were received. An evaluation of these responses led to two recently released requests for proposals (RFPs) for electric and natural gas efficiency programs within the commercial refrigeration and the residential multi-family housing markets. Four proposals have been received in response to each of these RFPs, and the bids are being evaluated.

LOAD MANAGEMENT

Going forward, peak prices are expected to be significantly higher than prevailing average market prices. For example, the current AURORAxmp model forecast shows average highest day prices between two and three times higher ($80 to $100 per MWh) than average day prices. In addition, the highest prices will be an additional two to three times the average of those prices. This is consistent with recent events in the summer of 2006 where market prices exceeded $200 per MWh. The company does not anticipate that the summer 2006 event will repeat itself frequently, but it remains to be seen whether this was an anomaly or an event that will occur every few years.

With higher peak day prices and additional volatility likely during super critical peak events, demand reduction (DR) measures and distributed generation (DG) has the potential to mitigate cost impacts to customers and utilities.

Table 3.2: Proposed New Energy Efficiency Program[4]

Start Time	Residential and Small Commercial/Industrial	Commercial/Industrial/ Institutional
Q1 2007	Fireplace Dampers	C&I Quick Hits Program
Q2 2007	Super Efficient Habitat for Humanity (HFH) Homes Something For Everyone Measures	Side-Stream Filtration Energy/Heat Recovery Ventilation (ERV/HRV) Demand Control Ventilation (DCV) Steam Traps
Q3 2007	Geographic Saturation Program	Retro-Commissioning Program Behavioral Program
Q4 2007	Regional Natural Gas Market Transformation Program	Facilities Model Program (ongoing)

[4] Due to the accelerated nature of the Heritage Project and the simultaneous IRP evaluation, it was not possible to incorporate all of these measures within the current DSM targets without causing an unnecessary delay in their developement and launch.

Load management opportunities are identified that could be implemented in the near-term (2007) and the medium term (2008-2010). As with the energy efficiency examination, an inventory of all potential load management programs and offerings. The analysis included a review of trade ally data, industry literature, vendor research and a consultant evaluation. The cost of new technologies that enable more precise measurement and control of energy is declining. In order to expedite implementation of these candidate programs the analysis was often performed concurrently with the IRP evaluation, so it was not possible to fully quantify the impacts of these programs within this IRP cycle. This quantification has been identified as an action item for the 2009 IRP.

Five projects, outlined below, have been identified for immediate implementation with a framework established for future activities. This framework evaluates infrastructure needs, system and hardware requirements, costs and benefits, and customer acceptance

Residential Demand Response Pilot – This pilot includes the installation of smart communicating thermostats at specified locations.

Small Commercial Demand Response Pilot – This pilot project includes the installation of wireless dimmable ballasts and/or other technologies in small commercial premises.

Large Commercial/Industrial Interruptibility – Agreements with larger commercial/industrial customers to curtail load during specific events have been successful. This project would expand and formalize the process to include prearranged structured agreements. These agreements could be handled on a buy-back basis in the near-term and on interruptible rate schedules over the long-term.

Avista Facilities Demonstration Project – Avista will test wireless dimming ballasts and other technologies in our own facilities. Other demand response options will be considered and tested, as appropriate.

Large Commercial/Industrial Distributed Generation – In addition to bilateral agreements for curtailment, the company is examining a distributed generation program with selected customers in return for utility-controlled dispatchability.

TRANSMISSION AND DISTRIBUTION

System losses—or lost energy in the form of heat—naturally occur on utility systems in two ways: first, as the power is moved over distances and second, by transfers of electricity through distribution equipment as the power is "stepped-down" from high-voltage to end-user voltages. The company's system losses are estimated to be between 6 percent and 8 percent. Advances in efficient equipment such as improved transformer technology may yield system improvements. Design processes, such as conservation voltage reduction (CVR) and substation engineering and siting, can also provide energy savings on the distribution system.

The company's Transmission and Distribution (T&D) Planning group is examining different ways to economically reduce system losses. The quantification of T&D losses and potential loss reductions is in progress. The cost/benefit relationship will be assessed after the quantification process has been completed. Several projects are underway and pilots are under consideration. Significant time will be required to fully evaluate the results of the near-term potential projects and to ascertain potential resource opportunities. It is premature to incorporate these efforts into the IRP targets, so they have been identified as an action item for the 2009 IRP.

ANALYTICS

The identification of the cost-effectiveness of alternative supply resources and appropriate cost-recovery depends upon an analytical approach that is technically sound and transparent. Several departments collaboratively developed an analytical process to determine overall resource values of energy and capacity. Resource valuation for the Heritage Project is based upon seven categories: five categories are reflected in a total avoided cost of energy usage and the other two are based upon system-coincident demand reductions.

Analytical values contributing to an overall resource value of energy include the avoided cost of energy and carbon emissions, reduced volatility, reduced transmission and distribution system losses. Analytical values contributing to overall avoided costs of system-coincident capacity include the value of deferring capital investments for generation and transmission and distribution. A summary of these calculations has been provided in the Appendices.

COMMUNICATIONS PLANNING

Communicating the availability of conservation programs is critical to achieving energy savings. The Heritage Project is developing a sustained outreach campaign. This plan is staged for new program roll-outs and is tailored to select the optimal tool for communicating each program. This focus includes communications to all Avista employees, as well as enhanced training for employees with customer contact.

COOPERATIVE REGIONAL MARKET TRANSFORMATION PROGRAMS

Avista is a funding and fully participating member of the Northwest Energy Efficiency Alliance (NEEA).[5] NEEA is funded by investor-owned and public utilities throughout the Northwest to acquire electric efficiency measures that are best achieved through market transformation efforts. These efforts reach beyond individual service territories and consequently require regional cooperation to succeed.

NEEA has proven to be a cost-effective component of regional resource acquisition. Avista has and will continue to leverage NEEA ventures when cost-effective enhancements to the programs can be achieved for our customers.

Attributing regionally acquired resources to individual utilities is difficult. In order to ensure that resources are not double-counted at both regional and local levels, NEEA has excluded from their claims all energy for which local utility rebates have been granted. Therefore it is correct to sum the local and regional acquisition to obtain the total impact within the effected markets. Avista has typically applied our funding share of slightly less than 4 percent to NEEA's annual claim of energy savings.

DSM PROGRAM FUNDING

As previously noted, in 1995 the company changed its approach to cost-recovery of DSM investments from the traditional capitalization of the investments to cost-recovery through a non-bypassable public benefits surcharge (the DSM tariff rider). The company currently manages four separate DSM tariff riders for Washington electric, Idaho electric, Washington natural gas and Idaho natural gas investments. Based upon the demand for funds and incoming DSM tariff rider revenues, this balance can be positive or negative at any particular point in time.

In 2005 the aggregate DSM tariff rider balance was returned to zero from a $12.4 million deficit in the aftermath of the 2001 Western energy crisis. Recent demand for DSM services has outstripped the incoming DSM tariff rider revenue. The most recent projection

[5] NEEA's website, www.nwalliance.org, offers additional details regarding their ventures, governance, proceedings, reports and evaluations.

forecasts a $3.8 million negative balance in the Washington electric DSM tariff rider at the close of 2007. The Idaho electric DSM balance is projected to be close to zero at that time.

The company has proposed the capitalization of electric DSM investments in Washington. The proposal would continue the current tariff rider mechanism, with the revenues generated from the tariff rider funding the revenue requirement of the DSM investments.

Additionally there is a proposal for the recovery of lost electric margin (or fixed cost recovery) associated with the company's DSM efforts. Both of these proposals have been advanced to provide a more level playing field for demand and supply-side resource investments.

At present the company is not compensated for the fixed costs associated with reductions in load resulting from electric DSM achievements. The company submitted a proposal to the Washington Utilities and Transportation Commission for fixed cost recovery between general rate cases.

OVERVIEW OF ELECTRIC-EFFICIENCY IN THE 2007 IRP

The implementation of the Heritage Project began in the midst of the 2007 IRP evaluation. Some, but not all, of the Heritage Project initiatives have been incorporated in this version. The 2009 IRP cycle will fully explore some of the details and resulting efforts.

CONSISTENCY BETWEEN THE IRP EVALUATION AND DSM OPERATIONS

For each IRP, the company evaluates energy-efficiency potential in a manner that can augment the conservation business planning process and ultimately lead to appropriate revisions in DSM acquisition operations.

Avista has utilized the IRP process as an opportunity to comprehensively re-evaluate the market. This assessment evaluates individual technologies (generally prescriptive programs) where possible and program potential when a technology approach is infeasible. The evaluation is based upon an assessment of resource characteristics and the construction of a conservation supply curve based upon the levelized total resource cost (TRC) and acquirable resource potential for each technology. Cost-effective technologies, compared to the defined avoided cost, are incorporated into the IRP acquisition target.

The program evaluation is necessary when technologies in the program cannot be defined to permit their individual evaluation. This is the case in the company's comprehensive limited income and non-residential programs.[6] The target acquisition for these programs is based upon modifying the historical baseline for known or likely changes in the market. This includes but is not necessarily limited to modifying the baseline for price elasticity and load growth.[7]

EVALUATION OF EFFICIENCY TECHNOLOGY OPPORTUNITIES

Avista initiated an internal review of the company's response to the July 24, 2006, heat wave and short-term escalation of regional wholesale electric prices. An exploration of possible future responses to short-term price spikes and other longer term approaches to reduce the impact of market volatility was a key component of that process. Approximately 140 concepts came out of a series of meetings attended by a cross-section of the company.

[6] It was assumed that historic acquisition would remain flat at the most recent level because there are no reliable 20-year estimates of regional program acquisition. This assumption is speculative and dependent on the opportunities for regional market transformation during this period, but is consistent with the recent history of flat funding of the NEEA organization.

[7] The portions of the non-residential market that could be identified and evaluated based upon technology applications were included in that portion of the study. These components were excluded from the historical baseline for the remaining non-residential technologies evaluated under programmatically.

Avista's DSM analysis staff and Navigant Consulting performed a six-stage review of this concept list. The process first evaluated concepts with easily obtained data and gradually moved toward the more difficult analyses. Some measures did not rank well enough to warrant further consideration. The individual phases of the analytical process follow:

Defining: Refinement and redefinition of the concept list eliminated duplicative concepts and allowed an opportunity to develop common definitions for each concept.

Qualitative ranking: The more clearly defined concepts from the prior phase were ranked on a qualitative assessment of feasibility. Opportunities which were clearly not acquirable by utility intervention were eliminated from further consideration.

Defining cost characteristics: Those concepts that were determined to have a reasonable potential for eventual incorporation into the conservation portfolio were evaluated on preliminary assessments of cost-effectiveness. This step required obtaining estimates of incremental customer cost, non-energy benefits, energy savings and measure life to develop a TRC levelized cost. Concepts were sorted based upon these cost characteristics.

Defining resource potential: Acquirable potentials specific to the Avista service territory were estimated for the remaining concepts. These acquirable potentials were the result of an assessment of technical and economic potential tempered by the realization that utility intervention cannot successfully address all customer adoption barriers regardless of the economics. The acquirable resource potential for some technologies has been modified, generally upward, as a result of Heritage Project.

Developing load profiles: This IRP evaluation is the first time that Avista has specifically incorporated the value of capacity contribution (transmission, distribution and generation) into the overall avoided cost. Additionally the company is basing the avoided cost of energy upon a 20-year, 8760-hour avoided cost matrix. It was necessary to extrapolate the 20-year avoided cost projection to 40 years given the longevity of some of the measures. As a consequence of this avoided cost structure it was necessary to develop an 8760-hour load profile for each measure to be evaluated. Navigant Consulting Group provided 22 residential and non-residential load profiles for use in this part of the exercise.[8]

Calculating TRC cost-effectiveness: A full TRC cost-effectiveness evaluation was performed upon the remaining 39 residential and 36 non-residential concepts.[9] Four concepts were removed from this list due to questions regarding the viability of the data obtained in earlier stages or the discovery of previously undetected fatal flaws to the program. The following section provides a more detailed evaluation of the review and acceptance or rejection of these concepts.

A summary list of the concepts reaching the evaluation stage is included in the Appendices.

EVALUATION OF TRC COST-EFFECTIVENESS FOR FINALIST CONCEPTS

The construction of the TRC cost for each measure was based upon the incremental customer cost. Non-energy benefits were considered, but none of the evaluated measures had a large enough non-energy benefit to

[8] See the Appendices for a list of these load profiles.

[9] Three residential and one non-residential concept were subsequently excluded due to concerns over the validity of key resource characteristic assumptions.

materially change the final cost-effectiveness evaluation.[10]

Estimating the TRC values was more difficult. This required a present value calculation of the avoided energy and capacity cost over the measure life. The avoided cost of energy was based upon an application of the measures 8760-hour load profile to the 8760-hour avoided cost structure. Five energy and two capacity avoided cost values developed within the Heritage Project Analytical Roadmap were applied to the load shapes of each measure concept.[11]

The valuation of capacity based upon these load shapes and capacity avoided cost values had never been incorporated into the evaluation of DSM opportunities at Avista. The per kW present values for T&D and generation capacity estimated in the Analytical Roadmap were based upon a single fixed period of time. Escalating streams of annual values that were consistent with the values within the Analytical Roadmap allowed for the development of capacity values for varying measures lives. The details of this calculation are contained within the Appendices.

The consensus of opinion held that, for purposes of the evaluation of DSM measures, it was appropriate to focus upon deferring a summer space-cooling-driven load. The 71 concepts to be evaluated had significant differences in their impact upon system coincident load, and these differences were not always apparent based upon the general pattern of the measure load shape. To determine the expected impact upon the deemed space cooling-driven system peak load, the 71 concepts and 23 load shapes (including a flat load option) were categorized into three groups.

Zero impact: Measures that would not have any impact on a summer space-cooling-driven peak received a zero valuation regardless of their load profile. This would include measures such as residential space-heating efficiencies.

Non-Drivers: Measures that were not related to space cooling but would potentially contribute to system load during a space cooling-driven peak received a capacity valuation based upon the average demand of their specific load profile during eight hour summer peak load periods.[12] These measures include commercial lighting, residential appliances and so on.

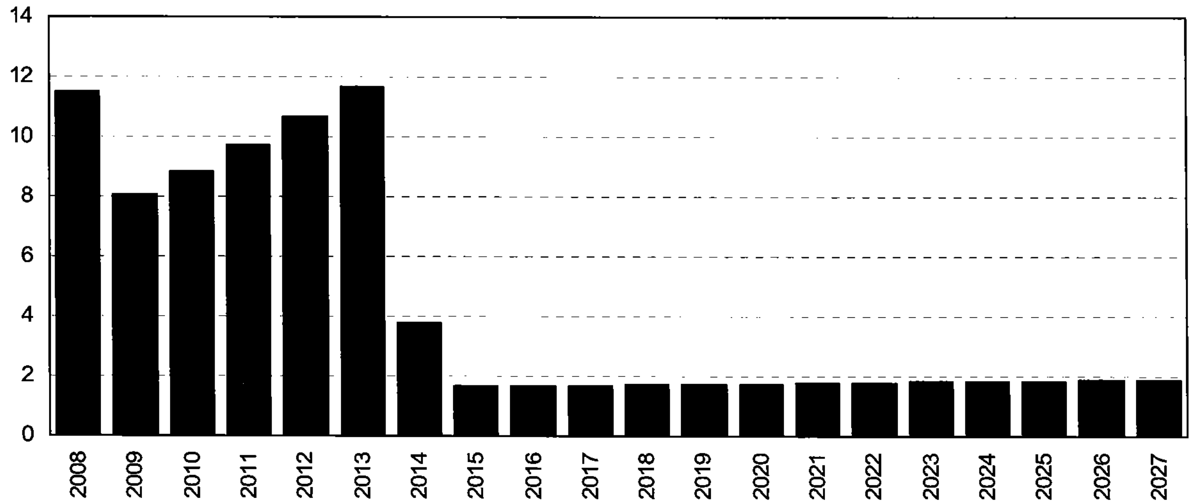
Drivers: Those measures that would drive a space cooling peak received a capacity valuation based upon the maximum hourly demand identified in their 8760-hour load profile. This would include measures such as residential and non-residential air conditioning efficiency measures.

Once the TRC cost and benefit calculations were completed, a TRC ratio was developed. Even though this analysis limits the identification of future DSM acquisition to measures that fully pass the TRC cost-effectiveness test, the company plans on evaluating all measures with a benefit-to-cost ratio of 0.75 or higher.

Having identified TRC cost-effective measures it was necessary to determine the annual acquisition of the identified potential. Inspection of the results to date indicated that there was clearly more potential than identified in the 2005 IRP process (5.4 aMW, excluding regional acquisition efforts, or 47.5 million first-year kWh). Thus the acquisition of the potential conservation requires a ramping-up of DSM operations, which is being done through the Heritage Project. A ramp

[10] The non-energy benefit, or cost, could have been represented as a TRC cost or benefit as long as the appropriate sign was used in the evaluation without impacting the ultimate passing or failing of the measure.
[11] The specific components of the avoided cost are summarized in the Appendices.
[12] The eight peak hours were 1 p.m. to 8 p.m., weekdays only, between June 15 and September 15.

Figure 3.2: Year-On-Year Conservation Acquisition (%)



rate was developed based upon the sales cycle of the customer decisions and the speed at which programs could be developed, incorporated into trade ally efforts and communicated to the customer base. This ramp rate is represented graphically in Figure 3.2 and outlined in more detail in the Appendices.

This completed the evaluation of those concepts that were suitable for review by technology within the IRP. These results are revisited following the explanation of the programmatically reviewed elements of the DSM portfolio.

EVALUATION OF COMPREHENSIVE PROGRAM ELEMENTS

As a consequence of the all-inclusive nature of Avista's non-residential and limited income portfolio, it was not feasible to generically evaluate all possible efficiency measures. Nevertheless it is necessary to develop an estimate of the potential of these markets in order to establish a meaningful business planning process. Unique efficiency measures could not be generically evaluated as individual technologies. In place of this approach the company established a historical baseline level of acquisition and modified it to incorporate the impact of known or likely changes in the market.

The company's limited income portfolio of qualifying efficiency measures is all-inclusive. It is implemented in cooperation with community action agencies given wide latitude in their approaches. Given that no changes were expected in the ability of the agency infrastructure to deliver these programs, nor were there any known market or technology changes that would cause a significant change in the ability to obtain efficiency resources from this segment, it was determined that a historical baseline would be the most appropriate starting point for estimating future throughput. This historical baseline was modified for load growth and retail price elasticity based upon assumptions consistent with the forecasts available at the time. This resulted in a forecast of limited income acquisition for incorporation into the final conservation forecast.

Although some of the measures incorporated into the site-specific program were specifically evaluated, a large portion of non-residential acquisition comes from measures which could not be generically evaluated. As with the limited income program, the historical baseline was modified for anticipated load growth and retail price elasticity to develop a forecast. Unlike the limited income program, it was necessary to separate the specifically evaluated measures from the historical baseline, and then combine the two again as part of the final expected conservation acquisition.

This process is illustrated in a flowchart in the Appendices.

COMPILATION OF THE FINAL DSM RESOURCE ESTIMATES

The following conservation targets were developed by summing individually evaluated concepts and the evaluated programs over a 20-year period. The first two years of those targets are detailed in Table 3.3.[13]

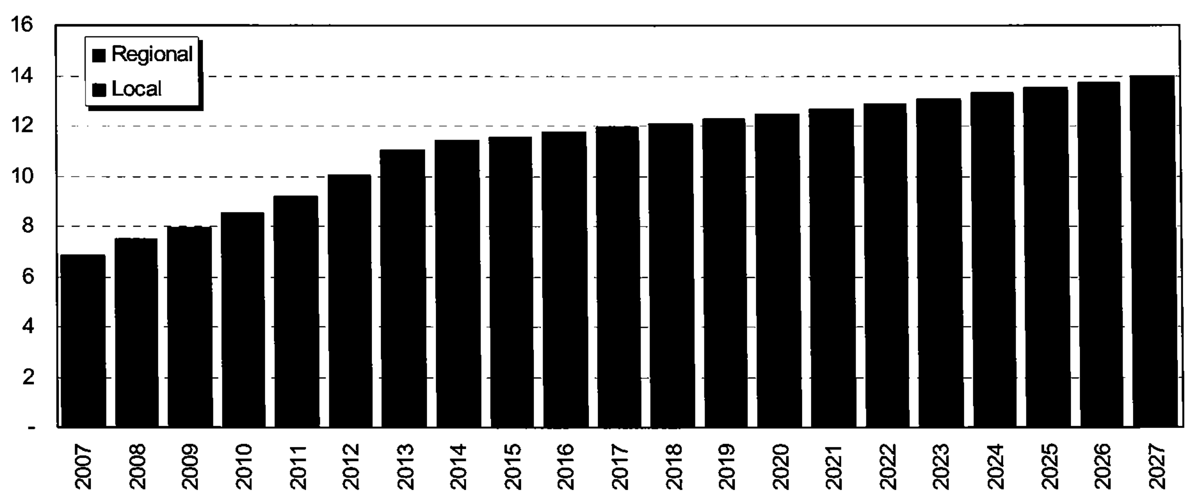
A graphical representation of the annual conservation targets for the full 20-year horizon is illustrated in Figure 3.3. A flat 1.4 aMW estimate of Avista's share of regional resource acquisition (Avista's pro-rated share of NEEA's annual savings) is included in the estimate.[14]

A measure-by-measure stacking of the 71 evaluated concepts, in ascending order of levelized total resource cost, leads to a traditional upward-sloping supply curve for this component of the energy efficiency target, as illustrated in Figure 3.4. Supply curves for both 2008 and 2009 have been shown to represent the two years

Table 3.3: Current Avista Energy Efficiency Programs (kWh)

Portfolio	2008 Target	2009 Target
Limited Income Residential	1,562,956	1,594,215
Residential	10,939,762	13,674,702
Prescriptive Non-Residential	1,279,711	1,599,639
Site-Specific Non-Residential	39,184,260	40,359,787
Total Local Acquisition	**52,966,686**	**57,228,343**

Figure 3.3: Forecast of Efficiency Acquisition (aMW)



[13] This application of price elasticity is consistent with but not incorporated within forecast assumptions since the efficiency savings quantified through the company's DSM programs are limited to those which are in excess of the higher of code-minimum or industry standard practice.

[14] In the absence of reliable 20-year estimates of acquisition through regional programs, it was assumed that the historic acquisition would remain flat during that time at their most recent level. This assumption is speculative and dependent on the opportunities for regional market transformation during this period but is consistent with the recent history of flat funding of NEEA.

Figure 3.4: Supply of Evaluated Efficiency Measures

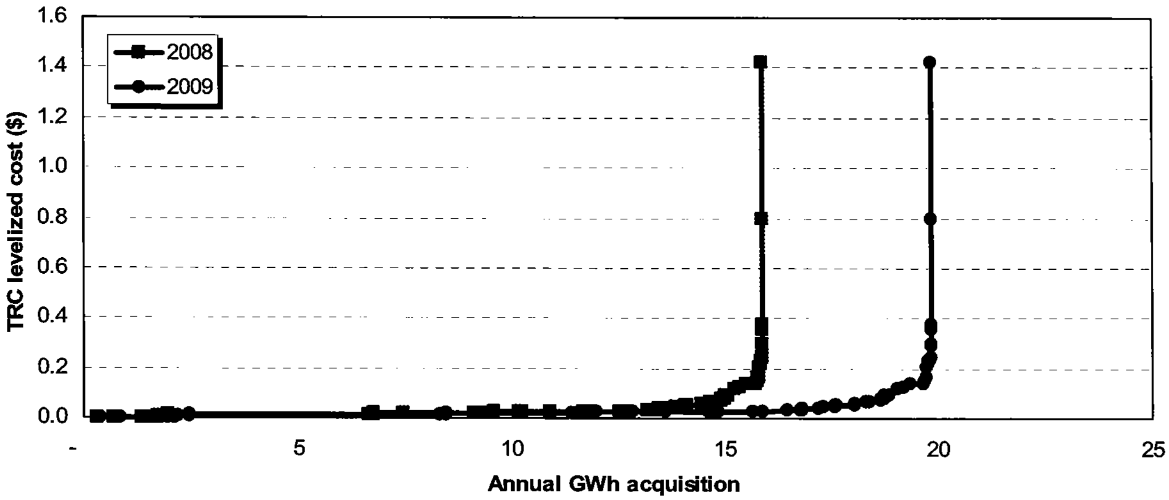
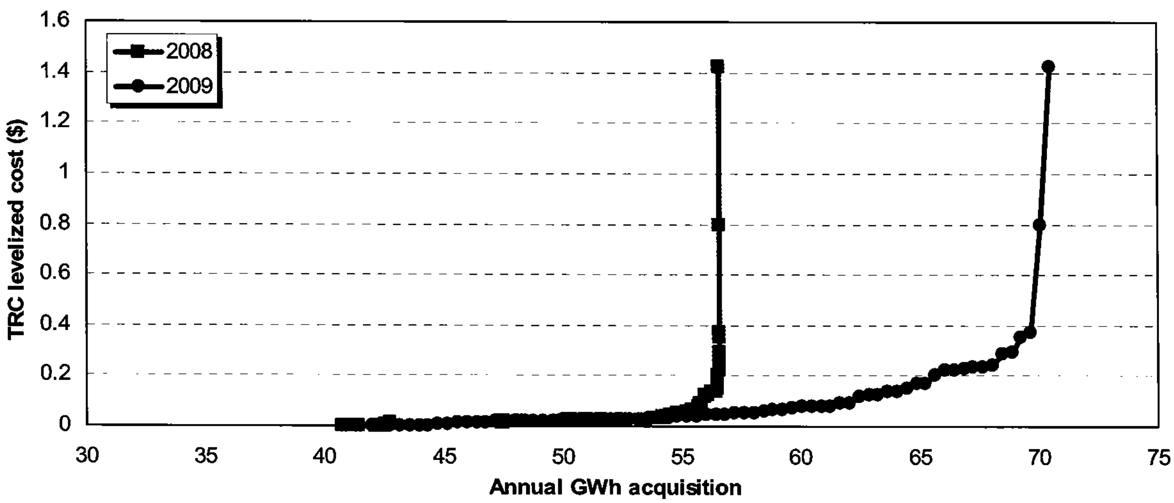


Figure 3.5: Efficiency Supply Curves Including All Measures



which will elapse before the next IRP. The rightward shift of the supply curve over time is a consequence of the assumptions made in the ramping-up of these programs.

The rapid sloping of the supply curve tails are the result of including a few measures that were later determined to be far more costly than previously anticipated.[15] These programs, though small, significantly extended the vertical axis of the supply curve developed for the efficiency measures.

By adding the target for programmatically-evaluated energy efficiency efforts to the left portion of the supply curve, a full assessment of the estimated efficiency targets can be illustrated. This is shown in Figure 3.5.

INTEGRATING IRP RESULTS INTO THE BUSINESS PLANNING PROCESS

The IRP evaluation process provides a high-level estimate of cost-effective energy efficiency acquisition. Based upon these results the company can establish a budget, determine the size and skill sets necessary for

[15] These two measures were residential induction cook tops and non-residential demand-controlled ventilation. The measures exceeded a levelized TRC cost of approximately 80 cents per kWh. Four other measures exceeded levelized TRC costs of 25 cents per kWh: non-residential window films, non-residential light colored roofs, residential smart appliances and non-residential Energy Star office equipment.

future conservation operations and identify general target markets.

The results of the IRP analysis will establish baseline goals for the ongoing development of the Heritage Project's enhancements to Avista's energy efficiency programs. The near-term planning is summarized by portfolio in the following sections.

RESIDENTIAL PORTFOLIO

A review of residential concepts and their sensitivity to key assumptions indicate that more detailed assumptions based upon actual program plans and target markets may improve the cost-effectiveness of many concepts that marginally failed in this analysis. To account for this marginal failure rate, all concepts with TRC benefit-to-cost ratios of 0.75 or better will be evaluated as part of the business planning process. Twenty-seven of the 36 evaluated residential concepts meet this criterion.

Measures that were developed too late for the IRP evaluation will also be inserted into this re-evaluation process. One of the recent additions, top-mounted fireplace dampers, has completed the program planning and evaluation process and was launched prior to the completion of this IRP.

LIMITED INCOME RESIDENTIAL PORTFOLIO

Avista has committed to maintaining stable annual funding and program flexibility for the six community action agencies delivering limited income energy efficiency implementation services. The flexibility of these programs requires periodic updates to program expectations due to changes in fuel focus and target measures. The company will also be working to quantify the future potential impacts of the three-year Northwest Sustainable Energy for Economic Development project.

NON-RESIDENTIAL PORTFOLIO

Similar to the residential program, it was determined that there is potential for improvement in evaluated program concepts to warrant the re-evaluation of any measure determined to have a TRC cost-to-benefit ratio of 0.75 or better. Of the 35 fully evaluated non-residential concepts, 25 of these meet the TRC criteria. These programs will be reviewed for target marketing, the creation of a prescriptive program or for targeting under the site-specific program.

All electric-efficiency measures qualify for the non-residential portfolio. The IRP provides account executives, program managers and end-use engineers with information regarding potentially cost-effective target markets, but specific characteristics of customers' facilities override any high-level program prioritization.

UNDERLYING RESOURCE ACQUISITION COMMITMENT

The IRP evaluation process is both a business planning process and regulatory requirement. The company uses this opportunity for comprehensive evaluation as a part of the management of the company's energy efficiency portfolio. The acquisition targets provide valuable information for future budgetary, staffing and resource planning needs. However, numerical targets do not displace the company's fundamental obligation to pursue a resource strategy that best meets the customer needs under continually changing environments. The targets established within this IRP planning process may be modified as necessary to meet these obligations.

SUPPLY SIDE EFFICIENCY

Avista also actively works on improving efficiency of its generation fleet. The following section highlights planned and potential hydroelectric efficiency upgrades. Recent thermal upgrades to the Colstrip plants are detailed in chapter two.

NOXON RAPIDS

The company plans to upgrade Noxon Rapids units

1-4 beginning in March 2009. The current maximum capability at Noxon Rapids is 554 MW; however, operating restrictions limit the plant to 532 MW. The upgrades will eliminate the operating restrictions and add an additional 16 MW to the project, increasing the plant capability to 570 MW and add 5.8 aMW of energy.

NINE MILE

The company currently uses flashboards at its Nine Mile plant to increase water storage during the fall and winter months. The flashboards are released downstream during spring runoff when the reservoir level must be lowered to accommodate the increased flow of water. The flashboards are re-installed every summer. The company is considering replacing the flashboards with a permanent pneumatic rubber dam which would automatically adjust the reservoir level to the flow rate, increasing the reservoir level when flow is low and decreasing the level when flows increase. The rubber dam would stabilize the Nine Mile project as well as eliminate the need to purchase and reinstall flashboards each year. This project would increase annual generation by about 6,500 MWh.

Also two of the four generators at the Nine Mile project require repair or replacement in the near future. The company is studying the replacement of these units in-kind or replacing with larger units to increase the maximum capacity and maximum flow at the project.

UPPER FALLS

The Upper Falls project, located in downtown Spokane, has one generating unit. The company is currently studying the advantages of upgrading the turbine runner and refurbishing other generator components.

LITTLE FALLS

Turbine runners at two of the four generators at Little Falls have recently been replaced. The company is studying the benefits of replacing the turbine runners in the remaining units. Other potential projects include replacing the step-up transformers and upgrading other generator components.

A summary of the various hydro efficiency studies is shown in Table 3.4.

Table 3.4: Recent Hydro Efficiency Upgrade Studies

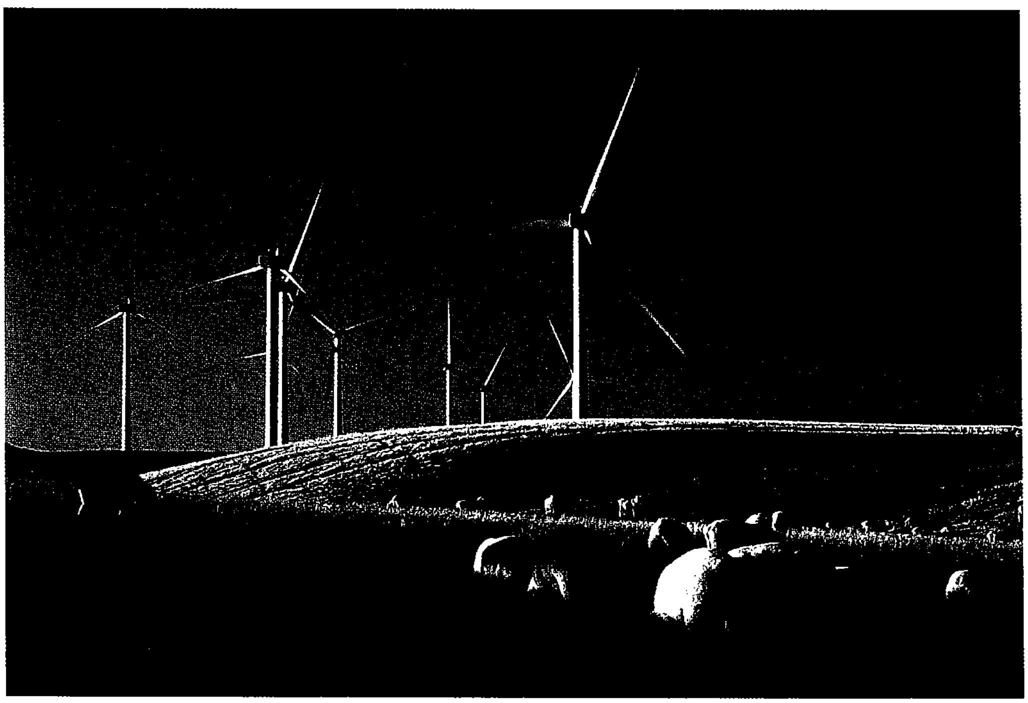
Project	Potential Additional Annual Energy (MWh)	Potential Additional Annual Energy (aMW)	Potential Additional Capacity (MW)	Total Project Capacity (MW)
Noxon Rapids	50,808	5.80	16.0	570.0
Nine Mile				
Rubber Dam	6,500	0.74	-	26.4
Turbine Upgrades	87,000	9.93	8.0	34.4
Upper Falls	63,000	7.19	6.4	15.0
Little Falls	52,000	5.94	8.0	44.1

4. ENVIRONMENTAL ISSUES

Environmental issues cover a wide variety of topics. To keep the concepts manageable, this chapter highlights some of the more important environmental issues affecting resource planning, the most notable being thermal plant emissions. The chapter is not intended to debate the merits or weaknesses of environmental science or the effects of power generation emissions. Instead, it covers state and federal laws and pending legislation affecting sulfur dioxide (SO_2), nitrogen oxide (NO_x), mercury (Hg), and carbon dioxide (CO_2) emissions. The modeling assumptions used for each emission types are explained. Particular attention is paid to greenhouse gases (GHG) because their regulatory future is the most uncertain and has the potential to affect resource decisions most significantly.

ENVIRONMENTAL CHALLENGES

Emissions present a unique challenge for resource planning because of continuously evolving scientific understanding and legislative developments. If environmental concerns were the only issue faced by utilities, resource planning would be reduced to choosing the amount and type of renewable generating technology to use. However, utility planning is compounded by requiring cost effectiveness. Each type of generating resource has distinctive operating characteristics, cost structures, and environmental challenges. Traditional generation technologies are well understood. Coal-fired units have high capital costs, long lead times, and low and stable fuel costs. Coal plants are difficult to site and are affected by a host of environmental issues from Hg to



Sheep Grazing Near a Wind Farm in Washington State

CHAPTER HIGHLIGHTS

- The company includes greenhouse gas emissions costs in its Base Case.
- Avista relies on its Climate Change Committee to develop climate change policy and mitigation plans.
- SO_2, NO_x, Hg, and CO_2 emissions costs are included in the modeling for the 2007 IRP.
- Avista supports national greenhouse gas legislation that is workable, cost effective, fair, protects the economy, supports technological innovation and addresses emissions from developing nations.
- Avista is a member of the Clean Energy Group.

GHG. Natural gas-fired plants have relatively low capital costs and more acceptable emission levels but rely on fuel that has proven to be both high in price and price volatility. Renewable energy plants, including wind, biomass and solar, have different problems to contend with. Renewables benefit from potential low or no fuel costs and low or no emissions, but they are plagued by capacity problems, wildlife issues, high capital costs, uncertainty regarding production tax credits and an increasing number of siting issues.

The most uncertain aspect of emissions is future GHG legislation. There recently has been a tremendous upsurge in the amount of scientific, public and legislative attention regarding climate change. There are five main aspects to consider with climate change: scientific, public, government, legal and financial. The scientific community has shown increasing evidence of human involvement in global warming, culminating with the Intergovernmental Panel on Climate Change (IPCC) Fourth Assessment Report, which was released in February 2007. This report stated that there is a greater than 90 percent chance that global warming is the result of human intervention through greenhouse gas emissions. The public is becoming increasingly aware of climate change issues and is pressing for governmental and corporate action. Legislatively, there are increasing numbers of local, state, regional, and federal GHG initiatives, renewable portfolio standards and emissions standards. On the legal front there are issues of state versus federal jurisdiction, project-specific pressures and attempts at class action lawsuits. Examples of legal issues include the April 2, 2007, U.S. Supreme Court decision that the Environmental Protection Agency had a duty to regulate greenhouse gases; the environmentally-pressured decisions in the leveraged buyout case of TXU not to build eight new coal plants; and the climate change lawsuits filed against utilities, auto makers and oil companies in the wake of hurricanes along the Gulf Coast. Financially, there are potential compliance costs, increasing demand for renewable resources driving up prices and shareholder pressure regarding climate change issues.

AVISTA'S ENVIRONMENTAL INITIATIVES AND POLICIES

One of the 2005 IRP action items was to "continue to monitor emissions legislation and its potential effects on markets and the company." This action item has received significant attention throughout the company over the past two years which resulted in an interdepartmental meeting on June 8, 2006, to cover climate change topics including: Congress and climate change, Avista's GHG inventory, Coyote Springs 2 emissions offsets, emissions assumptions included in the IRP and state commissions' guidance on climate change. After this meeting, a core group of employees from Environmental Affairs, Governmental Affairs and Resource Planning began meeting regularly to discuss current climate change information and legislative activities affecting the company. This group also reviewed climate change policies from other organizations, worked on drafting Avista's climate change statement and developed educational pieces.

The core group met with the company's Strategic Planning Council in March 2007 to discuss current climate change activities and developments. This meeting resulted in the appointment of an officer to spearhead the formalization of Avista's Climate Change Council (CCC). The CCC has been chartered to be a clearinghouse on all matters related to climate change. The CCC:

- anticipates and evaluates strategic needs and opportunities;
- analyzes the implications of various trends and proposals;
- develops recommendations on company positions and action plans; and
- facilitates internal and external communications.

The core team of the CCC includes members from the Environmental Affairs, Government Relations, Corporate Communications, Engineering, Energy Solutions and Resource Planning departments. Other areas of the company are invited as needed.

Monthly meetings divide work into immediate and long-term concerns. Immediate concerns include reviewing and analyzing state and federal legislation, developing a corporate climate change policy and responding to external data requests regarding climate change issues. Longer term issues involve emissions tracking and certification, reviewing alternatives and providing recommendations for GHG reduction goals and activities, evaluating the merits of joining various GHG reduction programs, actively participating in the development of GHG legislation, and benchmarking climate change policies and activities with other organizations.

Avista recently joined the Clean Energy Group which includes Calpine, Entergy, Exelon, Florida Power and Light, PG&E and Public Service Energy Group. This group acts collectively to evaluate and support different GHG legislation such as the Clean Air Planning Act of 2007 sponsored by Tom Carper (D-DE). This legislation seeks to establish multi-pollutant limits using a market-based approach to "reducing power plant emissions of nitrogen oxides, sulfur dioxide, mercury and carbon dioxide."

AVISTA'S POSITION ON CLIMATE CHANGE LEGISLATION

The company expects federal greenhouse gas legislation to be enacted within the next two to four years. The absence of definitive legislation on climate change creates an uncertain environment as the company develops its plans for meeting future customer loads. Avista does not have a preferred form of GHG legislation at this time. However, the company supports federal legislation that:

- anticipates and evaluates the strategic needs and opportunities;
- is workable and cost effective;
- is fair;
- is protective of the economy;
- is supportive of technological innovation; and
- is inclusive of emissions from developing nations.

Workable and cost effective legislation would be carefully crafted to produce actual emission reductions through a single system, as opposed to competing state, regional and federal systems. The legislation also needs to be fair in that it is equitably distributed across all sectors of the economy based on relative contribution to GHG emissions. Protecting the economy is of utmost importance. The legislation cannot be so onerous that it stalls the economy or fails to have any sort of adjustment mechanism in case the market solution fails and prices skyrocket. Supporting a wide variety of technological innovations should be a key component of any GHG reduction legislation because innovation can help maintain costs, as well as provide a potential boost to the economy through an increased manufacturing base. The final piece to the legislative solution to climate change involves developing nations. China will soon overtake the U.S. as the leading source of GHG emissions. Legislation should include strategies for working with other nations directly or through international bodies to control world-wide emissions.

EMISSIONS CONCERNS FOR RESOURCE PLANNING

The main emissions concerns for resource planning involve balancing environmental stewardship and cost effectiveness, and mitigating the financial impact of emissions risks. The 2007 IRP focuses on four types of emissions that are significant to electric generation: SO_2, NO_x, Hg, and CO_2. Sulfur dioxide is a cause of acid rain; the Clean Air Act of 1990 capped its emissions at 8.9 million tons per year starting in 2008. This pollutant is actively regulated through a cap-and-trade program. Nitrogen oxide is also regulated by the Clean Air Act of 1990 at 2.0 million tons per year starting in 2008. Mercury is an emission with planned regulation by the federal government under a cap-and-trade program. However, many states are opting out of that program. Carbon dioxide is a primary greenhouse gas. It is beginning to be regulated in some states and is the focus of federal legislation.

EMISSIONS LEGISLATION

There are several themes that emerge from all of the recently developed climate change legislation. These include:

- Scientific questions about human contributions to climate change – is it an anthropogenic or human-developed phenomenon need to be settled;
- Actions need to be economy-wide, rather than one or two sectors at a time;
- Technology will be a key component to the climate change solution. There will most likely need to be significant investments in carbon capture and sequestration technology, since coal likely will continue to be an important part of the U.S. generation fleet;
- Developing countries should be engaged as developing nations to expand their economies and carbon footprints; and
- Long delays in federal legislation increase the probability of a menagerie of inconsistent regulatory schemes that may obstruct the efficient operation of regional or national businesses.

These themes point to national comprehensive GHG legislation implemented in a timely manner to ensure the best environmental and fiscal outcomes.

FEDERAL EMISSIONS LEGISLATION

The federal government is currently reviewing at least six different market-based programs to reduce greenhouse gas emissions. This is the culmination of many previously failed attempts at national legislation, the most significant being the McCain-Lieberman Climate Stewardship Act submitted to Congress in January 2003 and annually thereafter. Most legislation relies on a market-based cap-and-trade system in an attempt to emulate the success of the national acid rain program. There are many questions that still need to be resolved before national GHG legislation can be enacted. These include:

- the allocation of allowances – emissions or generation-based;
- economy-wide or sector specific;
- offsets;
- incentives for early action;
- economic safety valves;
- up or downstream regulation; and
- cap-and-trade or tax.

There are indications from Congress that federal legislation will be passed in 2007, but great uncertainty still remains over the specifics of the legislation or when it will be passed into law. The company believes that some form of market-based GHG legislation is inevitable and includes it in its Base Case IRP assumptions. The company introduces CO_2 emission charges in 2015. Recent developments in GHG legislation lean toward an earlier start date, but 2007 IRP modeling was substantially complete before recent Congressional activity began. Upon review of the modeling results, the company does not believe that adding charges sooner would in any way impact its Preferred Resource Strategy.

STATE LEVEL EMISSIONS LEGISLATION

Federal inaction on climate change has spurred many states to develop their own laws and regulations. Climate change legislation has taken many forms, including GHG emissions caps, renewable portfolio standards (RPS) and mandated efficiency levels. A patchwork of competing rules and regulations has sprung up for utilities to follow, making resource planning for utilities with multi-jurisdictional responsibilities like Avista more difficult. Currently there are 23 states and the District of Columbia with active renewable portfolio standards. California, Connecticut, North Carolina and Rhode Island are working on legislation to phase out the use of incandescent light bulbs.

Some of the more notable state-level GHG initiatives outside of the Pacific Northwest include the Regional Greenhouse Gas Initiative (RGGI): an agreement between 10 Northeastern states (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont) to develop a cap-and-trade program for power plant CO_2 emissions. The District of Columbia, Pennsylvania and some Canadian Provinces are participating as observers in the RGGI process.

The Western Regional Climate Action Initiative was developed from a Feb. 26, 2007, agreement between Washington, Oregon, California, New Mexico, Arizona and British Columbia to reduce GHG emissions through regional reduction goals and the establishment of a market-based trading system. There are a number of regional municipalities participating in the U.S. Mayors Climate Protection Agreement to reduce GHG emissions to 93 percent of 1990 levels by 2012.

Nationally the Clean Air Mercury Rule (CAMR) established permanent caps to reduce mercury reduction from coal-fired power plant emissions. CAMR allows states to participate in a nation-wide mercury trading allowance program. States are allowed to determine if their national allocations are distributed among existing emitters, auctioned or some combination of the two methods.

IDAHO EMISSIONS LEGISLATION

Idaho does not actively regulate greenhouse gases or set renewable portfolio standards for its electric utilities. Idaho governor Butch Otter issued an executive order in May 2007 directing the Idaho Department of Environmental Quality (IDEQ) to work on "a policy on the role of state government in reducing greenhouse gases." The IDEQ is to develop a GHG emissions inventory and reduction strategy. Idaho has demonstrated concerns with coal-fired power plants; most notably, HB 791 (2006) established a moratorium on new merchant coal-fired power plants for a two-year period. The state has decided to opt out of CAMR, meaning that a plant located in Idaho could not purchase mercury credits to offset its emissions. By opting out of CAMR, the state has effectively stopped coal plant development.

MONTANA EMISSIONS LEGISLATION

The Montana Global Warming Solutions Act (HB753) was submitted in late 2006 to establish greenhouse gas reductions goals through 2020. The legislation did not make it out of committee. Montana limits mercury emissions to 0.9 pounds per decatherm for plants using sub-bituminous coal, and 1.5 pounds for lignite-fired plants. Montana requires 15 percent of all electricity to come from new renewables by 2015.

OREGON EMISSIONS LEGISLATION

Oregon has been actively developing greenhouse gas, renewable portfolio standards and mercury emission legislation. Oregon's climate change legislation goes back to its December 2004 Oregon Strategy for Greenhouse Gas Reduction. It called for development of a detailed GHG report by the end of 2007 and for stabilization of all six GHGs by 2010, a 10 percent reduction from 1990 levels by 2020 and a 75 percent reduction from 1990 levels by 2050. The goals are in addition to the 1997 regulation requiring utilities to offset CO_2 emissions exceeding 83 percent of the emission level of a state-of-the-art gas-fired CCCT. State Senate Bill 838 requires large electric utilities to generate 25 percent of annual electricity sales with new renewable resources by 2025.

Shorter term renewable goals include 5 percent by 2011, 15 percent by 2015, and 20 percent by 2020. Oregon has set mercury emissions levels equaling 90 percent reduction or 0.60 pounds per Dth by July 1, 2012, with some allowances for compliance alternatives if the targets cannot be met using best available emissions controls.

WASHINGTON EMISSIONS LEGISLATION

Washington State is quite active on global warming and renewable energy issues, recently passing an RPS initiative and GHG legislation. This is in addition to a 2004 law requiring new fossil-fueled thermal electric generating facilities of more that 25 MW to have a CO_2 mitigation plan of third-party offsets, purchased carbon credits or cogeneration.

The Washington Clean Energy Initiative (I-937) passed in the November 2006 election. This initiative established an RPS for Washington equal to 3 percent of retail load by 2012, 9 percent by 2016, and 15 percent by 2020. The 2007 IRP has been developed so that the I-937 RPS goals will be achieved by the company for its Washington retail load.

Governor Christine Gregoire signed Executive Order 07-02 in February 2007, establishing the following GHG emissions goals:

- return to 1990 levels by 2020;
- 25 percent below 1990 levels by 2035;
- 50 percent below 1990 levels by 2050, or 75 percent below expected emissions in 2050;
- increase clean energy jobs to 25,000 by 2020; and
- reduce statewide fuel imports by 20 percent.

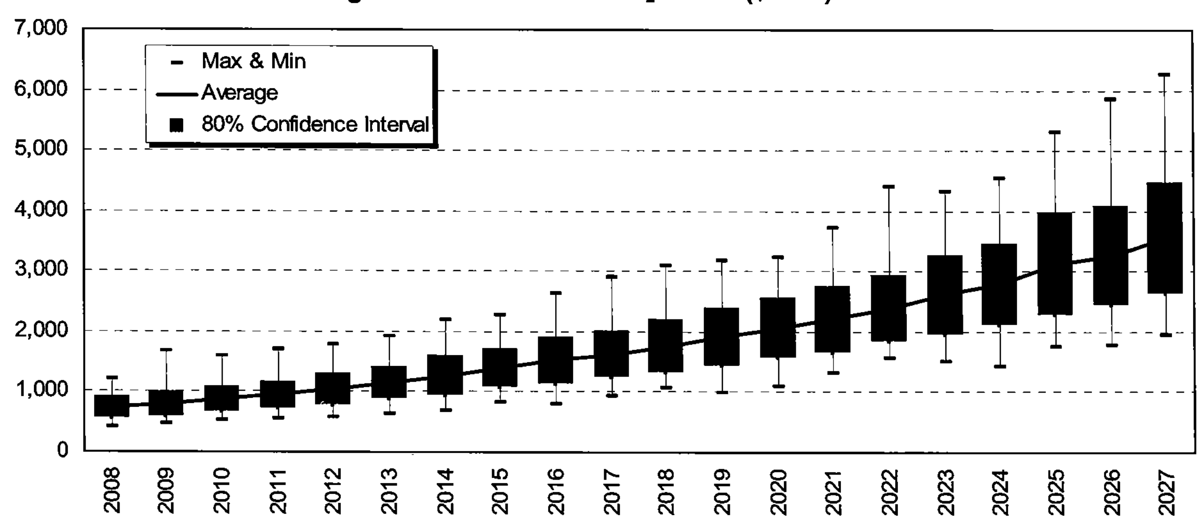
The goals of this Executive Order became law when SB 6001 was signed on May 3, 2007. The law reduces the GHG emissions of electric utilities by establishing an emissions performance standard of 1,100 pounds of GHG per MWh of new base load generation.

Washington state has proposed mercury legislation levels of 8.7 lb/MWh from all sources by 2013, with mandatory plant compliance of utilities by 2017. Trading is allowed for the first three years. The allocation base is tentatively set at 70 percent to existing sources, 5 percent to new sources, and the balance held for possible future distribution. Final mercury rules are expected by September 2007.

EMISSIONS MEASUREMENT AND MODELING

To evaluate the impact of emissions regulation on market prices and resource dispatch, estimates of the amounts of dollars to "tax" certain emissions were made. This tax is used as an economic indicator of lower emissions.

Figure 4.1: Base Case SO_2 Costs (\$/Ton)



Valuing emissions is an important part of the IRP modeling process. Mercury, SO_2, and NO_x are modeled using a lognormal distribution, whereas CO_2 is modeled based on a sampling distribution of 300 Monte Carlo iterations. Each of the four modeled emissions types is discussed below.

SO_2 emissions average \$808 per ton in 2008 and escalate to \$2,571 per ton in 2027 in nominal dollars. SO_2 has an actively traded market so emissions costs and projections are readily obtained. Figure 4.1 shows the minimum, maximum and average levels of SO_2 emissions costs.

NO_x emission costs are \$2,248 per ton beginning in 2010 when regulations begin and escalate to \$3,875 per ton in 2027. The NO_x market will operate in a manner that is very similar to the SO_2 market. Figure 4.2 shows the data for NO_x cost projections.

Mercury is somewhat problematic to model because trading does not begin until 2010 and many states have decided to opt out of the national trading market under CAMR. Projections of mercury costs are not readily available. The IRP bases its cost estimates on a variety of governmental and private sources. Mercury costs start

Figure 4.2: Base Case NO_X Costs (\$/Ton)

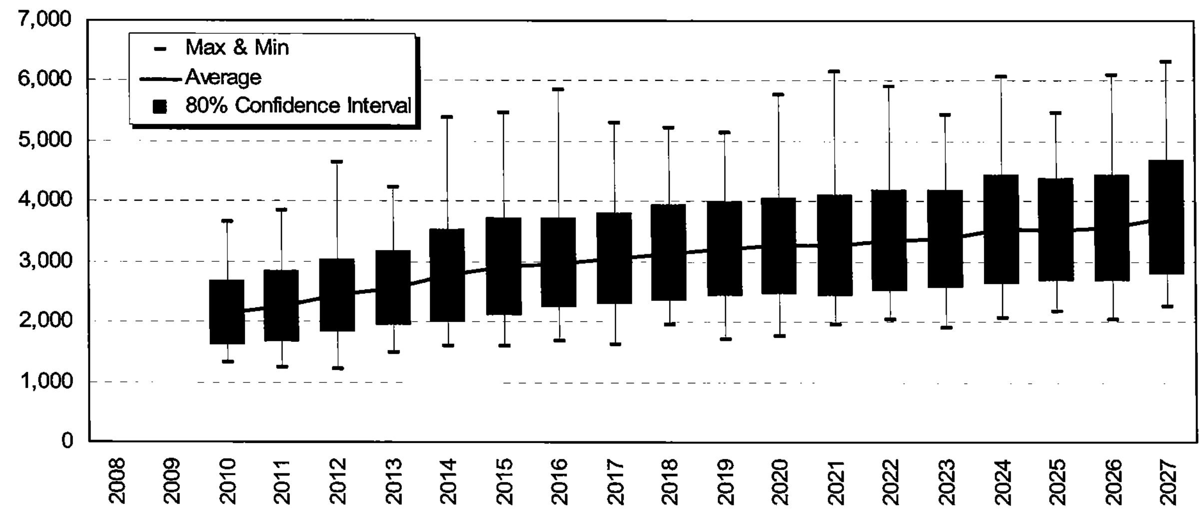
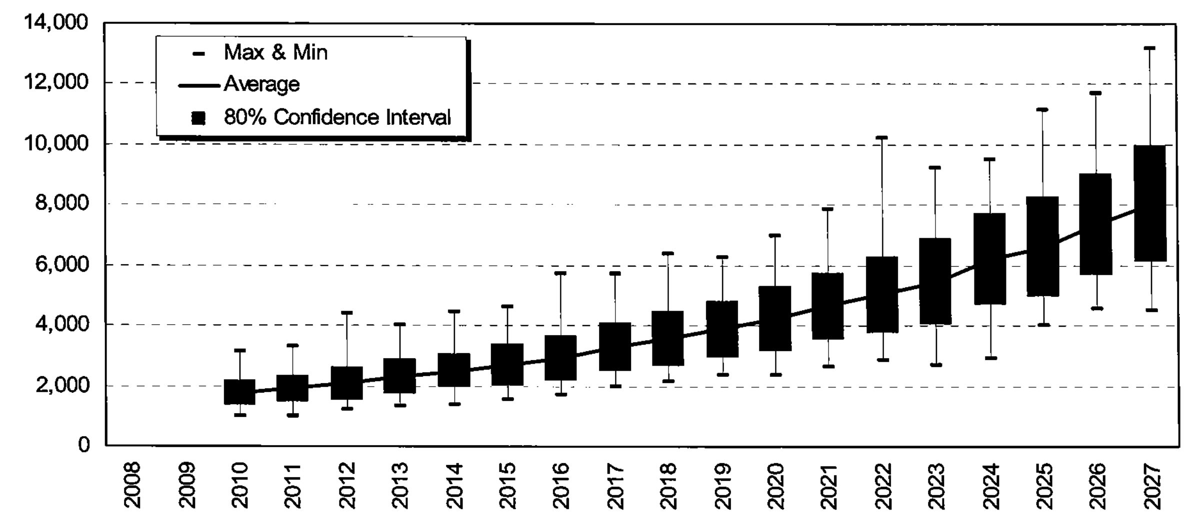


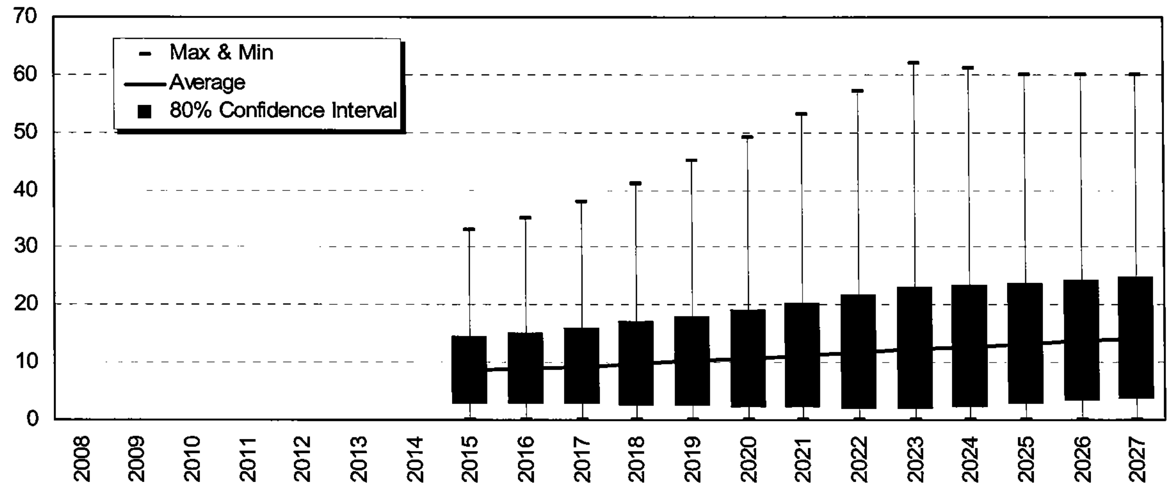
Figure 4.3: Base Case Mercury Costs (\$/Ounce)



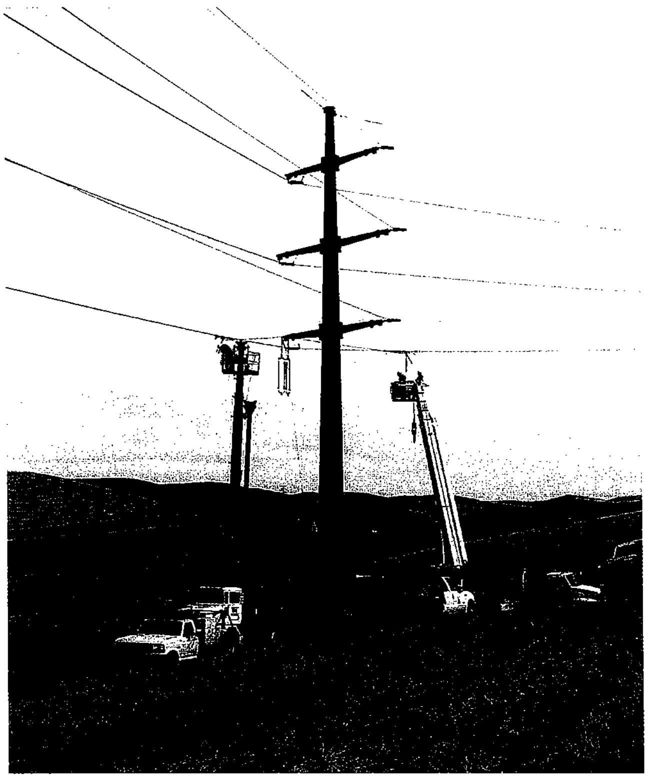
in 2010 at $1,739 per ounce and escalate to $4,863 per ounce in 2027 (nominal dollars). Mercury emission cost estimates are shown in Figure 4.3.

CO_2 emissions are modeled based on a probability distribution of the 300 Monte Carlo iterations of AURORAxmp run for the Base Case. The mean value of the probability distribution equals the projected cost of the National Commission on Energy Policy recommendations in their 2004 study. The projected costs from that study have been escalated to account for inflation. Figure 4.4 shows the projected CO_2 values by year. Costs average $8.94 per ton in 2015 and increase to $14.34 per ton in 2027.

Figure 4.4: Base Case CO_2 Costs ($/Ton)



5. TRANSMISSION PLANNING



Transmission Construction in the Palouse Region, Southeastern Washington

INTRODUCTION

Comprehensive coordination of transmission system operations and planning activities with regional transmission providers is necessary to maintain reliable and economic transmission service for the region's end-use customers. Transmission providers and interested stakeholders are implementing changes in the region's approach to planning, constructing and operating the system under new rules promulgated by the Federal Energy Regulatory Commission (FERC) and under state and local siting agencies. This section was developed in full compliance with Avista's FERC Standards of Conduct, governing communications between Avista's merchant and transmission functions.

AVISTA'S TRANSMISSION SYSTEM

Avista owns and operates an electric transmission system comprised of approximately 623 miles of 230 kilovolt (kV) line and 1,537 miles of 115 kV line. The company also owns an 11 percent interest in 495 miles of a 500 kV line between Colstrip and Townsend, Montana. The transmission system includes switching stations and high-voltage substations with transformers, monitoring and metering devices, and other system operation-related equipment. The system is used to transfer power from the company's generation resources to its retail load centers. Avista also has network interconnections with the following utilities:

- Bonneville Power Administration (BPA)
- Chelan County PUD
- Grant County PUD
- Idaho Power Company
- NorthWestern Energy
- PacifiCorp
- Pend Oreille County PUD
- Puget Sound Energy

In addition to providing enhanced transmission system reliability, these network interconnections serve as points of receipt for power from generating facilities outside the company's service area, including the Colstrip generating station, Coyote Springs 2 and the Mid-Columbia hydroelectric facilities. These interconnections provide for the interchange of power with entities within and outside of the Pacific Northwest, including the integration of long-term and short-term contract resources. Additionally, the company has interconnections with several government-owned and cooperative utilities at transmission and distribution

CHAPTER HIGHLIGHTS

- Avista is in the fifth year of a $130 million transmission improvement project.
- Avista has over 2,100 miles of high voltage transmission.
- The company is actively involved in the regional transmission planning efforts of ColumbiaGrid.
- The cost of new transmission lines and upgrades are included in the 2007 Preferred Resource Strategy.
- New construction costs approximately $1.4 million per mile of 500 kV transmission line.

voltage levels, representing non-network, radial points of delivery for service to wholesale loads.

Avista is currently in the fifth year of a multi-year, $130 million, transmission upgrade project. The planned upgrades will add over 100 circuit miles of new 230 kV transmission line to the company's system and increase the capacity of an additional 50 miles of transmission line. The transmission upgrade project also includes the construction of two new 230 kV substations and the reconstruction of three existing transmission substations. Upgrades at six 230 kV substations are being undertaken to meet capacity requirements, to upgrade protective relaying systems and meet reliability standards. In total, Avista will work on 11 of 13, or 85 percent, of its 230 kV substations. The telecommunication system is also being upgraded with the installation of fiber and digital microwave systems to improve system control, monitoring and protection. The company's most significant transmission projects are described below.

BEACON-BELL 230 KV

The company increased the capacity of two parallel path transmission lines from its Beacon substation to BPA's Bell substation. The project doubled the line capacity to 800 MVA and increased equipment ratings from both substations. The project mitigates overloads between the largest Avista and BPA substations in Spokane to improve load service to the Spokane area. The upgrade to Bell #4 was completed in December 2005 and Bell #5 was energized in April 2007.

BEACON-RATHDRUM 230 KV

Avista recently reconstructed 25 miles of single circuit 230 kV transmission line to a double circuit 230 kV line between Rathdrum, Idaho, and Spokane, Washington.

DRY CREEK

A second 230/115 kV transformer was added to the Dry Creek substation to improve load service and system reliability in the Lewiston-Clarkston area. The new transformer provides back-up for the North Lewiston 230-115 kV transformer. This project also included the construction of the 115 kV portion of the Dry Creek Substation and the loop-in of an area 115 kV transmission line. This project was completed in the fall of 2006.

PALOUSE REINFORCEMENT

The company is constructing 60 miles of 230 kV transmission line between the Benewah and Shawnee substations to relieve congestion on the existing Benewah-Moscow 230 kV line. The project provides a second 230 kV transmission line between the company's northern and southern load service areas, which significantly improves system reliability. Several components of the Palouse Project were energized and placed into service in 2006, including the double circuit Shawnee-Colfax 230 kV and 115 kV line section and the Benewah Substation rebuild.

PINE CREEK SUBSTATION

The company reconstructed the Pine Creek 230 kV Substation in November 2003. This facility is located in Pinehurst, Idaho.

SPOKANE VALLEY REINFORCEMENT

Avista is adding 500 MVA of 230 kV to 115 kV transformation at the new Boulder Substation.

WEST OF HATWAI TELECOM PROJECT

The ability to communicate, monitor and control transmission equipment is vital to providing reliable service. The West of Hatwai (WOH) Telecom Project is comprised of several sub-projects. The Noxon-Pine Creek fiber project completes a telecommunication ring from Spokane to the Noxon Rapids Hydroelectric Project. The ring provides redundant communication paths, so the loss of one side of the ring will not eliminate the ability to control equipment. The ring is also required to implement the Clark Fork Remedial Action System (RAS), which drops generation at the Clark Fork Projects after critical transmission outages to ensure system reliability. Another component of the Clark Fork RAS includes the addition of fiber from the Cabinet Gorge generation units to the 230 kV Cabinet Substation. The Hatwai-North Lewiston fiber project completed a fiber ring around the Lewiston-Clarkston load service area. This project is also part of a RAS to improve reliability in the Lewiston area. All three projects were completed in 2006.

As noted in the August 2002 West of Hatwai letter of agreement with BPA, these projects are coordinated to support and enhance BPA transmission projects. Collaboration has allowed both parties to achieve a least-cost service plan addressing commercial transactions, load service and regional reliability issues. The Avista and BPA plan was reviewed by peer utilities, approved by other Northwest transmission owners and by utility members of the Western Electricity Coordinating Council (WECC). The Northwest Power Pool (NWPP) Transmission Planning Committee agreed that a blended plan was superior to stand-alone plans separately executed by the company and BPA.

Avista plans and operates its transmission system pursuant to applicable criteria established by the North American Electric Reliability Corporation (NERC), WECC and the NWPP. Through its involvement in WECC and the NWPP standing committees and sub-committees, the company participates in the development of new and revised criteria, and coordinates planning and operation of its transmission system with neighboring systems. The company is subject to periodic performance audits through participation in these regional organizations.

Portions of the company's transmission system are fully subscribed for transferring power output of company generation resources to its retail load centers. Transmission capacity that is not reserved to move power to satisfy long-term (greater than one year) obligations is used to facilitate short-term purchases and sales to optimize the company's resources, as well as to provide wholesale transmission service to third parties pursuant to FERC requirements under Orders 888 and 889. It is important to note that the implementation of FERC policies and practices under Orders 888 and 889, and subsequent FERC orders, can occasionally restrict our ability to optimize transmission system resources in specific cases. Transmission capacity that might have been either reserved or recalled to deliver lower-cost short-term resources for service to native load customers may not be available because of FERC policies requiring transmission capacity to be available for other parties. To the extent a third party has secured firm capacity rights on Avista's transmission system, including future rollover rights, that transmission capacity will not be available for the company to serve native load.

REGIONAL TRANSMISSION SYSTEM

BPA operates over 15,000 miles of transmission facilities throughout the Pacific Northwest. BPA's system represents approximately 75 percent of the region's high voltage (230 kV or higher) transmission grid. The company uses the BPA transmission system to transfer output from its remote generation sources to the company's transmission system, such as Colstrip, Coyote Springs 2 and the Washington Public Power Supply System Washington Nuclear Plan No. 3 settlement contract. The company also contracts with BPA to transfer power from the company's local resources to 10 of its remote retail load areas.

The company participates in a number of regional and BPA-specific forums to coordinate system reliability issues and to manage costs associated with the BPA transmission system. The company participates in BPA transmission and power rate case processes and in BPA's Business Practices Technical Forum, to ensure BPA transmission charges remain reasonable and support system reliability and access. The company also works with BPA and other regional utilities to coordinate major transmission facility outages.

Future regional resource development will require new transmission assets. BPA has indicated that financing restrictions may hamper its ability to construct new transmission to support these resources. BPA transmission customers seeking firm capacity for their new resources may be required to provide a form of long-term financing for BPA to facilitate needed transmission project construction on its system.

REGIONAL TRANSMISSION ISSUES

Coordinated transmission planning has historically occurred through various NWPP workgroups. ColumbiaGrid is a more formalized Northwest organization that has been created to develop a regional transmission plan, assess transmission alternatives (including non-wires alternatives) and provide a decision-making forum for new projects and cost allocation methods. ColumbiaGrid was formed on March 31, 2006, as a non-profit, membership, Washington state corporation. The current members of ColumbiaGrid are Avista, BPA, Chelan County PUD, Grant County PUD, Puget Sound Energy, Seattle City Light and Tacoma Power.

During the first quarter of 2007, Avista signed a transmission planning agreement with ColumbiaGrid to address regional transmission issues. ColumbiaGrid will perform a number of services under the Planning Agreement. It will prepare a Biennial Transmission Plan and, as part of that process, will perform system assessments of the parties' transmission systems and identify projected transmission needs. ColumbiaGrid will also facilitate a coordinated planning process for the development of multi-transmission system projects.

THE BIENNIAL TRANSMISSION PLAN

Under the planning agreement, ColumbiaGrid will prepare and adopt a Biennial Transmission Plan during each two-year planning cycle. The plan will have a 10-year planning horizon, or longer if required by FERC's pro forma open access transmission tariff. Throughout the planning process, drafts of the Biennial Plan will be posted on the ColumbiaGrid website as they become available.

As a primary component of the plan, ColumbiaGrid will perform annual system assessment of the parties' transmission systems. The system assessment will determine the ability of each planning party to serve, consistent with the planning criteria, its network load and native load obligations, and other existing long-term firm transmission obligations anticipated to occur during the planning horizon. Projected inabilities to meet such obligations are identified and solutions proposed, outlining those solutions that can be implemented by a party on a single system basis versus those transmission solutions that impact the regional transmission grid ("multi-system projects"). Those transmission system modifications that will impact only a single party's transmission system are included in ColumbiaGrid's biennial plan for informational purposes.

COORDINATED PLANNING OF MULTI-SYSTEM PROJECTS

ColumbiaGrid will facilitate coordinated planning of all multi-system transmission projects. If the annual system assessments identify a need that implicates a multi-system transmission project, ColumbiaGrid will develop conceptual transmission solutions through the creation and use of study teams made up of members from a number of stakeholder categories. The objective of a study team will be to develop a transmission plan that will resolve a reliability need or provide sufficient capacity for a request for transmission service in a timely fashion.

ColumbiaGrid's unique structure provides a means for resolving disputes related to multi-system projects. Transmission system modifications that will impact more than one transmission system must be approved by a majority vote of the ColumbiaGrid board before they can be incorporated into the final biennial plan. Projects where all affected parties have reached agreement will be included in the draft biennial plan submitted to the board. In the event agreement is not reached by all affected parties, ColumbiaGrid staff may make a recommendation to the Board on whether to include it in the draft biennial plan and affected parties may provide comment to the ColumbiaGrid board. ColumbiaGrid staff's recommendation can include an equitable allocation of costs to construct the facilities and an allocation of transmission capacity increased or maintained. Upon a majority vote by the ColumbiaGrid Board, such a project, with its respective allocations, will be included in the final biennial plan which ColumbiaGrid planning parties are obligated to uphold. The process provides a means to further address any such disputes with the Federal Energy Regulatory Commission.

The ColumbiaGrid coordinated planning process will be conducted in an open and transparent manner with ColumbiaGrid seeking to notify all affected and interested parties regarding study team activities. Additionally, ColumbiaGrid will also develop a protocol to foster the collaborative involvement of affected tribes and states, including agencies responsible for facility siting, utility regulation and general energy policy. The ColumbiaGrid planning process will provide the necessary coordination and dispute resolution to enable the construction of necessary transmission facilities to integrate needed new resources identified in Avista's 2007 IRP.

MODELING TRANSMISSION COSTS

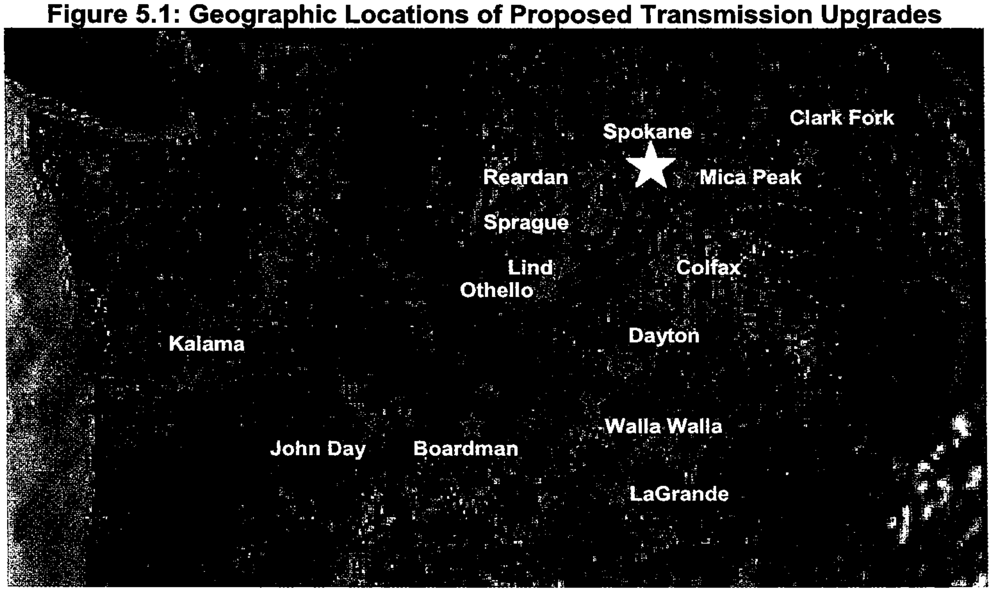
Transmission costs to integrate new resources into the company's system were estimated by Avista's Transmission Department. Estimates were not modeled in AURORAxmp, but rather in the proprietary PRiSM model that matches different generating resources with company-specific resource requirements. Construction quality estimates have not been completed for any of the transmission alternatives included in this IRP; estimates are based on engineering judgment only. There is an inverse relationship between transmission project size and the certainty of the estimates. A 50 MW resource can be integrated in many places on the system. A 400 MW plant can be integrated at some locations, while a 750 MW or 1,000 MW plant has very limited placement options. A detailed regional process would probably be undertaken to determine the precise impacts and integration costs before an actual plant placement decision would be made.

The Estimated Resource Integration Costs for the 2007 IRP study evaluated 50 MW, 100 MW, 250 MW and greater than 400 MW generation sizes at 23 different locations. The study was indifferent to the generation asset fuel type. Wind projects have a low capacity factor, in the 30-40 percent range, but still require transmission that corresponds to the nameplate capacity of the project. This is the same transmission requirement as a natural gas-fired turbine or any other resource type. The study was divided into 10 generic project areas located outside of the company's service territory and nine major areas within the company's service territory. Areas located within Avista's service area tend to be higher quality estimates because of the increased level of system knowledge.

ESTIMATED RESOURCE INTEGRATION COSTS FOR THE 2007 IRP STUDY

The following sections provide an overview of the Avista Estimated Resource Integration Costs for the 2007 IRP Study. A copy of the complete study may be found at the company's IRP Website (www.avistautilities.com). Several different project sizes were requested for this work has been done for the alternatives within our system because detailed machine parameters are only available when an actual project is specified. In regard to neighboring system impacts, an approximate worst case cost estimate has been assigned to these resources based on engineering judgment. Interconnection costs are listed for locations within the Avista transmission system.

Figure 5.1: Geographic Locations of Proposed Transmission Upgrades



analysis. Because transmission capability comes in "lumps," and plant sizes may be altered based upon available transmission capacity at a particular site, the alternatives were broken into 50, 100, 400, 750 and 1,000 MW sizes.

Integration points were roughly divided into points that are inside and outside of Avista's transmission system. There is some overlap for larger amounts of generation, which could have broad impacts to our system as well as neighboring systems. A rigorous study has not been completed for any of the foreign system alternatives because it is impossible to provide meaningful study results without the knowledge, input and approval of the owners of those systems. Only limited study

All internal cost estimates are in 2015 dollars and are based on engineering judgment with a 50 percent error band. Time to construct is defined from the beginning of the permitting process to when the line is energized. An illustration of various northwest transmission upgrade projects is shown in Figure 5.1.

External to the Avista System

For areas outside of Avista's transmission system, Avista-LSE would be required to undertake a transmission request on the BPA or another transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area. Preliminary construction estimates are $1.4 million per mile of new 500 kV lines.

Boardman, Oregon

The present transmission system serving the Boardman generating complex consists of two 500 kV circuits which are owned and operated by Portland General Electric (PGE). The PGE circuits integrate into several 500 kV circuits owned and operated by the Bonneville Power Administration (BPA). Boardman is located to the north and east of several transmission constraints, which could be an issue with BPA's transmission pricing and availability policies.

Integrating 400, 750 or 1,000 MW at Boardman would likely require reinforcement of PGE's and BPA's local 500 kV system and might require additional 500 kV facilities downstream of the plant.

John Day, Washington

The transmission system serving the John Day generating complex consists of several 500 kV circuits which are owned and operated by BPA. John Day is located northeast of several transmission constraints, which could be an issue with respect to BPA's transmission pricing and availability policies.

The North of John Day Path is constrained, depending upon generation on the upper and mid-Columbia River. Because of the existing constraints, a transmission integration study on the BPA system would be required to determine if 50 to 100 MW could be integrated at a low cost.

Kalama, Washington

The transmission system serving the Kalama area consists of two 500 kV and two 230 kV circuits owned and operated by BPA. This area is located in the center of several transmission constraints which could be an issue with BPA's transmission pricing and availability policies. Integrating 400 MW would most likely require reinforcement to BPA's local 500 kV system and might require additional 500 kV facilities "downstream" of the plant. Integrating 750 or 1,000 MW would require reinforcement to BPA's local 500 kV grid and additional 500 kV facilities downstream of the plant. Preliminary construction estimates are $1.4 million for each mile of new 500 kV line. Because the amount of new transmission will be unknown until studies are completed, total integration costs are not known. Costs for this alternative could easily exceed $1.5 billion.

LaGrande, Oregon

The transmission system serving the LaGrande area consists of a 230 kV BPA line terminating at McNary and a 230 kV Idaho Power Company (IPC) line, which terminates at Brownlee. IPC also owns a 69 kV line out of LaGrande which is normally operated in a radial configuration. LaGrande lies in the center of one of the four lines which make up the Idaho to Northwest transmission path (the Brownlee-McNary 230 kV line). There is presently a WECC rating process that is being undertaken for the Idaho to Northwest path which could affect available capacity on these lines. Because of the rating study, there is no way to perform a reasonable study for the 50 to 100 MW of additional generation in this area until that study has been resolved.

Northeast Wyoming

The transmission system serving northeastern Wyoming consists of several 230 kV circuits, which are owned and operated by PacifiCorp and Black Hills Power Company. Additional circuits are owned or planned by Basin Electric. Northeast Wyoming is presently surrounded by several transmission constraints.

Moving between 400 and 1,000 MW from this area into our native system would be difficult, time consuming and most likely expensive because of all of the constraints surrounding this area. In the lowest power and lowest cost case at least one 500 kV line would be required into the IPC system. In the 1,000 MW case, two 500 kV lines might be required. Depending upon the arrangements, wheeling expense might also be incurred. Because the amount of new transmission will not be known until studies on the area are completed, total integration costs are presently unknown, but are estimated to be $2.0 to $3.0 billion.

Southeast Idaho

The transmission system serving southeastern Idaho consists of a 500 kV line, several 345 kV lines, and several 230 kV circuits which are owned and operated by PacifiCorp and IPC. Southeastern Idaho is east and west of several transmission constraints. Because Avista owns no transmission in southeastern Idaho, Avista-LSE would be required to undertake a transmission request on either the PacifiCorp or IPC systems in the area. This work would be required to determine integration costs and wheeling service to deliver energy to the Avista load area. Because there are constraints from this area to the east and west, moving 400 to 1,000 MW from this area into our native system would be difficult, time consuming and expensive from a construction standpoint. In the lowest power, lowest cost case at least one additional 345 kV line would be required into the center of the IPC system. In the 1,000 MW case, two 500 kV lines might be required to connect the Avista system. Wheeling expense might also be incurred. Because the amount of new transmission will not be known until studies on the area are completed, total integration costs are presently unknown, but are estimated to be $1.0 to $3.0 billion.

Central Alberta, Canada

There is currently no available transfer capability or suitable method of inexpensively integrating energy from central Alberta into the Avista system. Because of the distances and costs involved, integration into the United States power grid at capacity levels less than 2,000 to 3,000 MW is unlikely. Transmission from central Alberta would probably be a direct current (DC) 500 kV line because of the capacity required for the economics of the project. It is assumed that one of the DC terminals would be either in the Spokane area or at the Mid-Columbia. Avista could purchase portions of this energy to be delivered to its system from either location. A regional scoping effort to estimate costs for this and similar projects has been completed and may be obtained from the Northwest Power Pool, assuming that the Critical Infrastructure Information requirements are met. Estimates for these projects are $2.0 to $5.0 billion.

A 300 MW transmission interconnection project between southern Alberta and northern Montana (MATL) has been proposed. Available capacity on this project is unknown at this time. However, additional transmission would be required between central Alberta and southern Alberta, as well as from northern Montana to the Spokane area. Until it is known if the MATL project will be constructed, it is difficult to provide estimates on whether 50 MW of energy can be economically integrated into our system from central Alberta. Avista-LSE would need to undertake a transmission request on the BPA system to determine integration costs and wheeling service to deliver the energy to the Avista load area.

Integrating anything over 300 MW would probably require a high voltage DC tie directly from the resource, which would most likely be integrated into the Mid-Columbia area. Integration of more than 400 MW from the Mid-Columbia could cost $300 to $500 million, exclusive of the 500 kV DC tie project.

Central Washington

The transmission system serving central Washington consists of multiple 500 kV and 230 kV circuits that are owned and operated by several entities. One 230 kV line into the Mid-Columbia area is owned by Avista and PacifiCorp. Presently there is no long term available transfer capability from central Washington into the Avista system via the jointly owned transmission line. There is a regional study, through the Northwest Power

Pool in progress, analyzing resource integration in the Mid-Columbia area (including Avista's system). This study should be completed in 2007.

The mid-Columbia area is presently in a constrained state, depending upon generation on the mid-Columbia River. Because of existing constraints, a transmission integration study (most likely on the BPA or Avista system) would be required to determine if 50 to 1,000 MW could be integrated. Integrating more than 400 MW from the Mid-Columbia would be expected to cost $300 to $500 million.

Eastern Montana

The present transmission system to the west of (and serving) the present generation in Montana is a double circuit 500 kV line and two 230 kV lines. In a regional study, under the auspices of the Northwest Power Pool (NWPP), NTAC indicated that either additional transmission or upgrades would be required to integrate energy from Montana. Eastern Montana also lies east of several transmission constraints, which could be an issue with BPA's transmission pricing and availability policies.

A more detailed study effort focusing on constraints from central and eastern Montana will be released in 2007. This study will identify integration constraints and costs. Avista-LSE would need to undertake a transmission request on the NWE system and fund a study to determine potential impacts on the BPA system. This work would be required to determine integration costs and wheeling service to deliver energy to the Avista load area. Since two transmission systems (BPA and Northwestern Energy) may be involved in the integration of this project, the merchant may pay two wheeling charges for transmission service.

Walla Walla, Washington

The transmission system serving the Walla Walla area is a single 230 kV line owned by Avista and PacifiCorp. There is also a 115 kV line owned by BPA and a 69 kV line owned by PacifiCorp. Avista has contractual transmission rights, but owns no transmission in the Walla Walla area. Therefore, Avista-LSE would be required to undertake a transmission request on the PacifiCorp transmission system. This work would be required to determine integration costs and wheeling service to deliver the energy to the Avista load area. Due to the presently constrained paths in the area, such as the Idaho to Northwest path, a transmission integration study on the PacifiCorp system would be required to determine integration costs.

INTEGRATION WITHIN THE AVISTA TRANSMISSION SYSTEM

Table 5.1 provides a summary view of the estimated integration costs the company would expect for various resources connected to its transmission system. Discussions of each interconnection area follow.

Table 5.1: Estimated Integration Costs Inside Avista's Systems ($Millions)

Location	50 MW	100 MW	250 MW	400+ MW
Sprague, Wash.	N/A	N/A	$58	$80+
Spokane/Coeur d'Alene	$3	$7	$32	up to $500
Mica Peak	$4	N/A	N/A	N/A
Clark Fork Hydro	$0	N/A	N/A	N/A
Dayton, Wash.	$32	$32	N/A	N/A
Reardan, Wash.	$2	$13	N/A	N/A
Lind, Wash.	$1.5	$6	N/A	N/A
Othello, Wash.	$1.5	N/A	N/A	N/A
Colfax, Wash.	$1.5	N/A	N/A	N/A
Sprague, Wash.	N/A	N/A	$58	$80+

Sprague, Washington

The transmission system serving the Sprague area is a low capacity 115 kV line. It is not suited for integrating 250 to 400 MW in its present configuration. Each connection below (which are the major transmission interconnection points in the area), would require 230 kV transmission and substation work for the generation integration. Any added generation greater than 400 MW will increase costs and have regional impacts.

To integrate 250 MW at Westside, the existing 115 kV line would have to be rebuilt as 230/115 double circuit back to the main BPA corridor. An additional 230 kV line could be constructed utilizing BPA's transmission corridor or by building a new 230 kV line. This project would take approximately four years and $58 million to construct.

To integrate 250 MW at Rosalia on the Benewah-Shawnee 230 kV line, 30 miles of new 230 kV line would have to be constructed to Rosalia and a 230 kV switching station would need to be built. This project would take about four years and $35 million to complete.

To integrate 400 MW at Westside, the existing 115 kV would have to be rebuilt as a 230/115 kV double circuit back to the main BPA corridor. To connect at Westside, an additional 230 kV line would need to be constructed utilizing BPA's transmission corridor or by building a new 230 kV line. This project would cost approximately $80 million and take four years to complete.

In order to integrate 400 MW at Rosalia on the Benewah-Shawnee 230 kV line, a new 30-mile long 230 kV line would have to be constructed to Rosalia and a 230 kV switching station would also have to be built. This project would take four years and approximately $50 million to complete.

Spokane/Coeur d'Alene

There are a number of 230 kV stations and transmission lines in the Spokane/Coeur d'Alene area that would make good generation interconnection points. Westside, Beacon, Bell, Boulder and Rathdrum are all large stations with 230/115 kV transformation in the Spokane/Coeur d'Alene area. However, integrating large generation in this area could pose thermal loading problems on the underlying 115 kV system. Without a specific interconnect point, all of the needed 115 kV work is an approximation. The Spokane/Coeur d'Alene area covers too much land to be more specific on costs. Additional generation greater than 250 MW will further increase costs and regional impacts.

Integrating 50 MW of new generation in the Spokane/Coeur d'Alene area can be done with 10 or less miles of 115 kV reconductor work. This type of project would take approximately one year and $3 million to complete. 100 MW could be integrated into this area with less than 30 miles of 115 kV line reinforcement. This type of project would take approximately two years and $7 million to complete.

Integrating more than 250 MW of generation in the Spokane/Coeur d'Alene area would require 230 kV work. This would necessitate extensive levels of 115 kV reconductoring. The radial operation of Avista's 115 kV lines in Spokane and Coeur d'Alene or generation dropping for 230 kV outages would probably be needed. Additional 230 kV work would likely be needed depending on the interconnection point. This project could cost $32 to $500 million and take five years to complete.

Mica Peak

Mica Peak is near existing Avista 115 kV lines with available capacity. 50 MW could be integrated at the

Post Falls substation with six miles of 115 kV line and a new breaker position at Post Falls. This project would cost about $4 million and take one year to complete.

Clark Fork Hydro Upgrades

The present transmission system in the Clark Fork area consists of both Avista and BPA 230kV lines that integrate the western Montana hydro (WMH) projects. The WMH refers to the four major hydroelectric plants operated in northwestern Montana and on the northern Montana-Idaho border. These include the federally-operated Libby and Hungry Horse projects and Avista's Cabinet Gorge and Noxon Rapids (Clark Fork) projects. After completion of planned upgrades to Cabinet Gorge and Noxon Rapids, these projects will have peak generation capacities of 268 MW and 558 MW, respectively, for a combined capacity of 826 MW.

Avista and BPA have a WMH operating agreement that provides a 50-50 allocation of a 1,700 MW operating limit between the federal and Avista projects. This agreement pertains to Avista-LSE's ability to operate its Clark Fork Projects for service to Avista's bundled retail native load customers. After completion of upgrades, Avista's total Clark Fork hydro generation capacity will be 24 MW below Avista's WMH operational allocation of 850 MW. Dependent upon continuation of the operational allocation of WMH hydro capability between Avista and BPA, no new transmission upgrades will be needed for Avista to integrate the planned upgrades of its Clark Fork hydro projects.

Dayton, Washington

The present transmission system serving the Dayton, Wash., area is a single 230 kV line with dual ownership by Avista and PacifiCorp. There is also a 115 kV line in the area owned by BPA and a 69 kV line owned by PacifiCorp.

Fifty to 100 MW could be integrated on the Dry Creek-Walla Walla 230 kV line at the ownership change between Avista and PacifiCorp with a new switching station and a 15 mile 230 kV line to this location. This line lacks capacity to support 50 to 100 MW due to current contractual obligations. Therefore, the Dry Creek-Walla Walla 230 kV line would need to be re-conductored to support additional capacity. The project would take approximately four years and $32 million to complete. There may be a potential real time solution using real time thermal monitoring and the Valley Group's Cat-1 or similar technology.

Reardan, Washington

The present transmission system serving the Reardan, Wash. area is a low capacity 115 kV line. Fifty MW could be integrated at the Reardan substation by re-conductoring the 115kV line from Garden Springs to Sunset along with a new air switch at Westside on the Nine Mile line. This project would require approximately one year of construction time and cost about $2 million. One hundred MW could be integrated by re-conductoring the 115 kV line from Reardan to Devils Gap along with a new line out of Reardan. The 100 MW project would cost approximately $13 million and take two years to complete.

Lind, Washington

The transmission system serving the Lind area is a low capacity 115 kV line and two 115 kV lines that are operated in a radial configuration. Very little new transmission would be required to integrate 50 MW at the Lind substation. The project would take about one year and $1.5 million to complete. Integrating 100 MW would require re-conductoring the 115kV line from Lind to Warden. The project would take about one year and $6 million to complete.

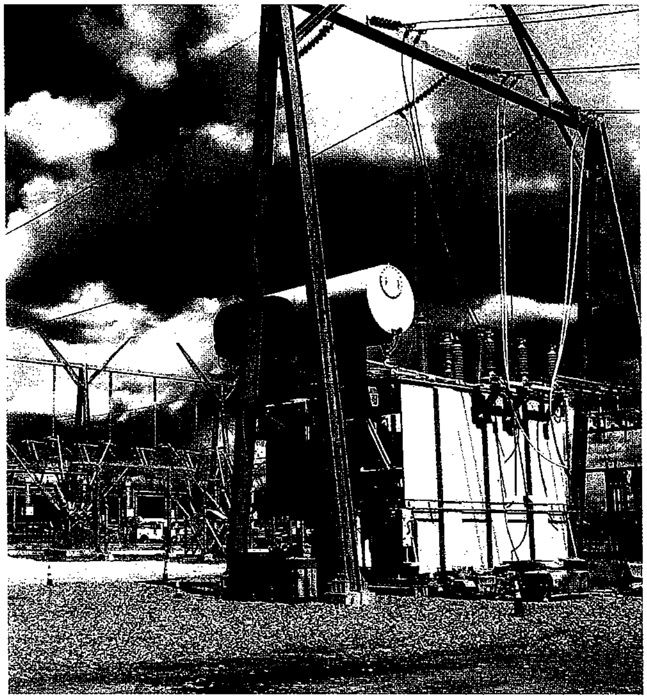
Othello, Washington

The transmission system serving the Othello, Wash, area consists of low capacity 115 kV lines. Fifty MW could be integrated at the Othello substation with very little new transmission. The project would take about one year to complete at a cost of $1.5 million.

Colfax, Washington

The present transmission system serving the Colfax, Wash., area is a low capacity 115 kV line. Fifty MW could be integrated at the East Colfax substation with very little new transmission being required. The project would cost about $1.5 million and take approximately one year to finish.

6. MODELING APPROACH



Transformer at Coyote Springs 2

INTRODUCTION

This section discusses market modeling assumptions used to value each resource option and the combination of costs and benefits to select the Preferred Resource Strategy (PRS). The analytical foundation for the 2007 IRP is a fundamentals-based electricity model of the entire Western Interconnect (WI). Understanding market conditions in the different geographic areas of the WI is important because many areas are linked by transmission facilities and the regional markets are correlated.

Avista's IRPs prior to 2003 relied on externally generated market price forecasts that did not consider company operations. This IRP builds on prior analytical work by maintaining the link between the WI market and the changing value of company-owned and contracted resources. The company's portfolio value is linked to its loads, resources and contractual arrangements, both for existing and prospective resource options, and for meeting future obligations.

The Preferred Resource Strategy is developed using a multi-step approach. New and existing resources are combined to simulate hourly operations for the WI to develop a long-term hourly electricity market price forecast. This market forecast values each resource option Avista might select as part of its PRS. Figure 6.1 illustrates the company's IRP modeling process.

MARKET MODELING

AURORAxmp is a fundamentals-based electricity market forecasting tool that tracks the value of the company's existing resource portfolio as well as potential new resource portfolios. Additional details about AURORAxmp can be found in Technical Advisory Committee presentations at the company's IRP Website. AURORAxmp is used to simulate the WI for this IRP. The WI includes the states west of the Rocky Mountains, the Canadian provinces of British Columbia and Alberta and the Baja region of Mexico, as shown in Figure 6.2. The WI is separated from the Eastern Interconnect and ERCOT systems, with the exception of eight inverter stations. The WI follows operation and reliability guidelines administered by the Western Electricity Coordinating Council (WECC).

CHAPTER HIGHLIGHTS

- AURORAxmp is used to model hourly operations for the entire Western Interconnect.
- The company performed 300 iterations of Monte Carlo market analysis with varying wind, hydro, load, natural gas prices, emissions and thermal outages for each evaluated future.
- The Preferred Resource Strategy was developed using the proprietary Avista Preferred Resource Strategy Model (PRiSM).
- This IRP considers generation, transmission and emissions costs.

Figure 6.1: Modeling Process Diagram

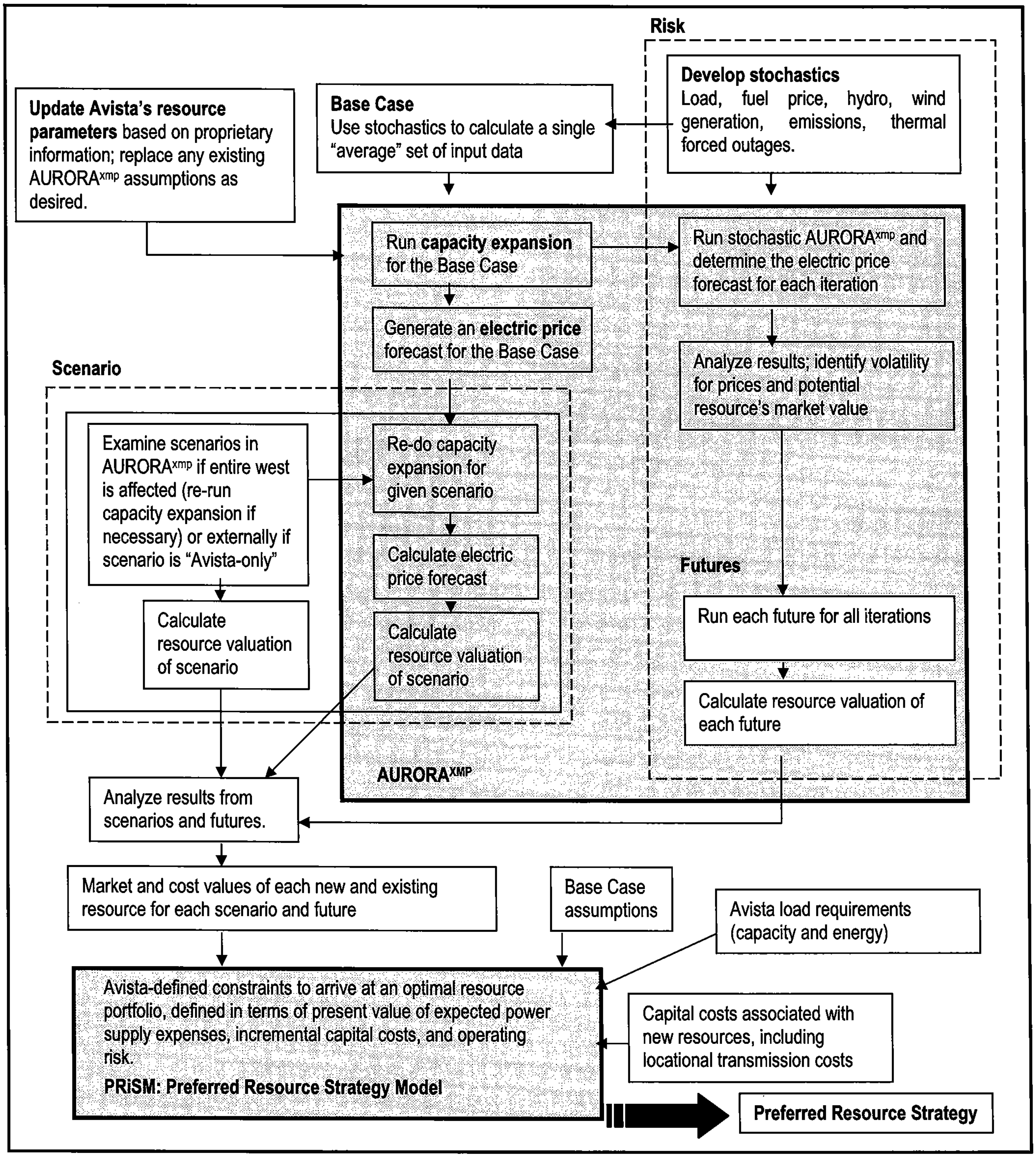


Figure 6.2: NERC Interconnection Map

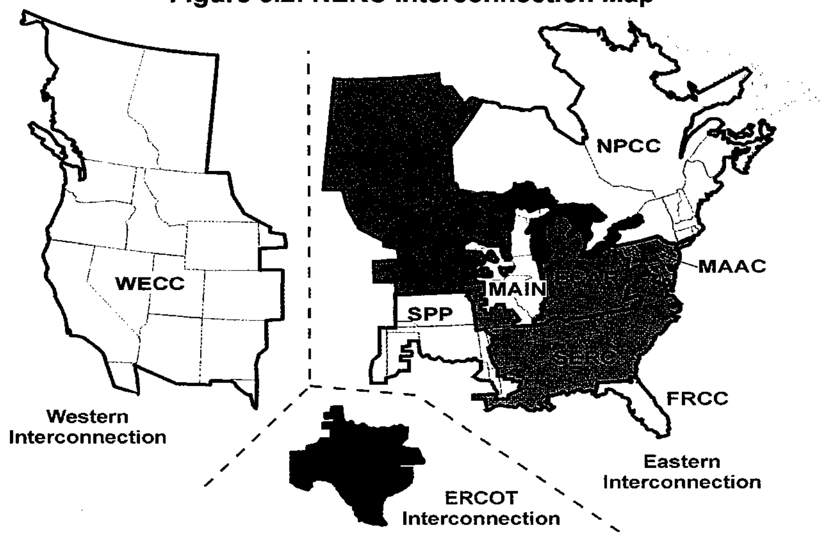


Table 6.1: AURORAxmp Pools and Zones

Northwest	California	Rocky Mountain	Desert Southwest	Independent
W. Wash.	Northern	Wyoming	Arizona	British Columbia
W. Oregon	Central	Colorado	New Mexico	Alberta
E. Wash.	South	Utah	S. Nevada	E. Montana
C. Oregon	Baja	N. Nevada		S. Idaho
W. Montana				

The model separates the WI into 20 zones based on load concentrations and transmission constraints. Zones are grouped into pools for regional capacity planning. The pools do not reflect regional transmission agreements or reserve sharing but are designed for regional proximity of resources. Table 6.1 shows the geographic pools and zones modeled in the IRP. Some zones are modeled independently due to significant transmission constraints and/or international boundaries.[1]

Electric models range in their ability to emulate power systems. Some models account for every bus and transmission line; others utilize regions or zones. An IRP requires regional price and plant dispatch information. Table 6.1 provides a list of zones contained in each pool.

The Northwest is modeled as five separate zones. This differs from the 2005 IRP where the Northwest was modeled as a single zone. Montana is split into east and west load areas to reflect transmission constraints on the Northwestern system. AURORAxmp has the ability to model the Northwest as nine separate zones. The nine-area topology was not selected because of long solution times and because the five-area topography was found to better represents Northwest market operations.

KEY ASSUMPTIONS AND INPUTS

HYDROELECTRIC GENERATION

The Northwest and British Columbia have substantial hydro generation capacity. A favorable characteristic of hydro power is the ability to provide short periods of

[1] Baja, Mexico, is included in the California pool because of tight interconnection with Southern California. This zone could have been modeled as an independent zone, but it has no impact on Avista's resource strategy or the Northwest's electricity marketplace.

near-instantaneous generation. This characteristic is particularly valuable for meeting peak load demands, shaping load and selling surplus energy during peak hours. A drawback of hydro is the potential lack of energy, since hydro is constrained by weather patterns and subsequent stream flows. The amount of energy available at a particular plant depends on its location and characteristics of its river system.

This IRP relies on information provided by the Northwest Power Pool (NWPP) to model regional hydro resources. The NWPP maintains a hydrological model providing energy amounts that each hydroelectric plant could produce from 1928 to 1999. This plan uses the 2004-05 Headwater Benefits Study. To accurately model British Columbian hydro projects, historical generation data from the Canadian Government was blended with the NWPP data set.

Many of the analyses in this IRP use an average of the 70-year record; stochastic studies randomly draw from the 70-year record (see stochastic modeling). Hydroelectric plants are lumped into geographic regions and represented as a single plant in each zone. The company models its Clark Fork, Spokane and Mid-Columbia projects to extract greater detail for portfolio modeling.

AURORAxmp represents hydro plants using annual and monthly information regarding energy generating capabilities, minimum and maximum generation levels, and abilities to sustain peak generating levels. The model's objective, subject to the constraints, is to move hydro generation into peak hours to follow daily load increases. This maximizes the value of the hydro system in a manner that approximates actual operations.

FUEL PRICES

The IRP uses fuel price assumptions in the most up-to-date EPIS database, with the exception of natural gas and coal prices. The price of fuel is the single most important modeling assumption in AURORAxmp. Natural gas sets the market price of power in the Northwest about three-quarters of the year and in more hours in other areas of the WI. Coal generally sets market prices during the spring when significant hydroelectric generation pushes natural gas-fired plants off of the margin.

NATURAL GAS PRICES

Avista retains several consultants who specialize in developing long- and short-term, fundamentals-based natural gas price forecasts. The company also reviews the Energy Information Association's Annual Energy Outlook (AEO) and monitors and participates in the New York Mercantile Exchange (NYMEX) forward natural gas price market. Each of these price curves uses different assumptions and provides the company with additional data about natural gas pricing.

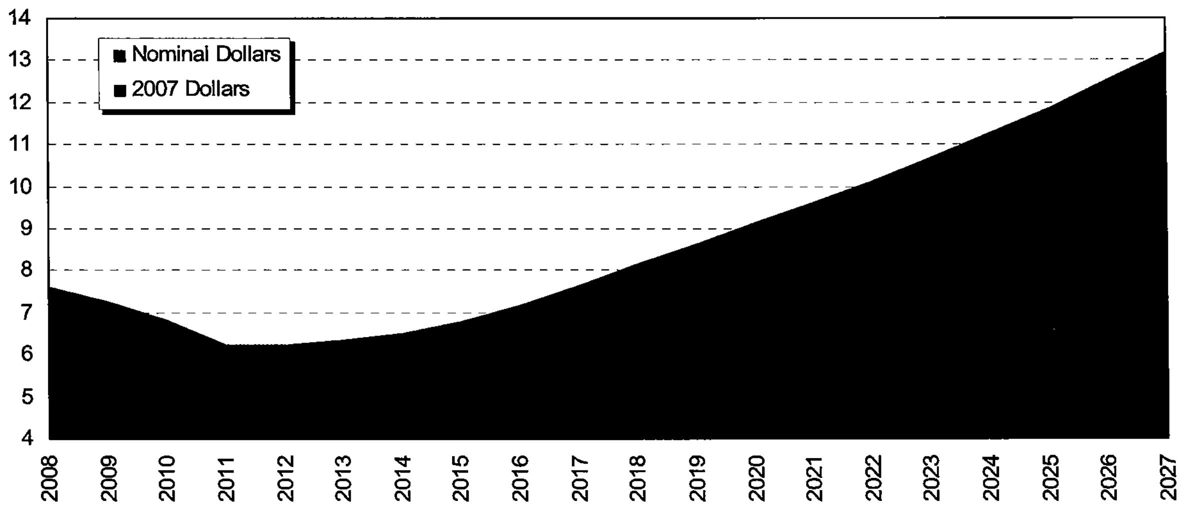
A multitude of factors were considered before choosing a price forecast. These factors included assumptions for economic growth, natural gas production levels, new infrastructure (i.e. Mackenzie Delta and Alaskan Pipelines), Canadian imports and demand (i.e. residential, commercial, industrial and electric generation). In particular, the selected consultant's forecast included more reasonable electric generation demand, liquid natural gas (LNG) imports, and overall natural gas supply and demand balance assumptions than the other price forecasts.

The natural gas price forecast provides annual average prices per decatherm at the Henry Hub basin in Louisiana. Annual average prices are converted into a series of monthly values before being entered into AURORAxmp. The monthly shape is based on NYMEX forward prices, which is consistent with Avista's 2006 Natural Gas IRP. Table 6.2 presents seasonal natural gas price factors. Monthly price shapes are derived by

Table 6.2: Seasonal Natural Gas Price Factors

Month	Percent of Annual	Month	Percent of Annual
January	113	July	93
February	113	August	94
March	110	September	95
April	93	October	96
May	92	November	101
June	92	December	106

Figure 6.3: Henry Hub Natural Gas Forecast ($/Dth)



applying these percentages to annual average prices. This approach reasonably reflects the actual seasonal weighting in the natural gas market.

The natural gas price forecast blended the January 3, 2007, NYMEX forward price with the consultant's price forecast. Blending the two prices acknowledges that the forward market is the price which can be currently purchased and that forward and fundamental prices should converge in the long-run. The weighting of the NYMEX forward price begins at 50 percent in 2008 and is decreased by 10 percent annually through 2012. The Henry Hub price forecast is shown in Figure 6.3.

Avista has historically used monthly natural gas prices in its IRP forecasts, but natural gas prices vary daily. This IRP is our first to include a daily adjustment from the monthly price forecast. Daily prices are calculated using 2003 to 2006 historical prices to determine a daily percent change from the monthly average price. This percentage is applied to the monthly price. Figure 6.4 illustrates the variability of daily natural gas prices around the monthly averages.

The final component of a natural gas price forecast is development of basis differentials from Henry Hub. Henry Hub is a trading point in Louisiana on the Gulf of Mexico, widely recognized as the most important natural gas pricing point in the United States. Henry Hub holds this distinction because of its spot and forward market trading volumes and its proximity to a large portion of U.S. natural gas production. NYMEX uses Henry Hub as a trading hub for futures contracts. All other production and market pricing points can be traded with a "basis differential" on the Henry Hub. The Western U.S. does not rely on Henry Hub for its physical gas

Figure 6.4: Daily Natural Gas Prices Shape ($/Dth)

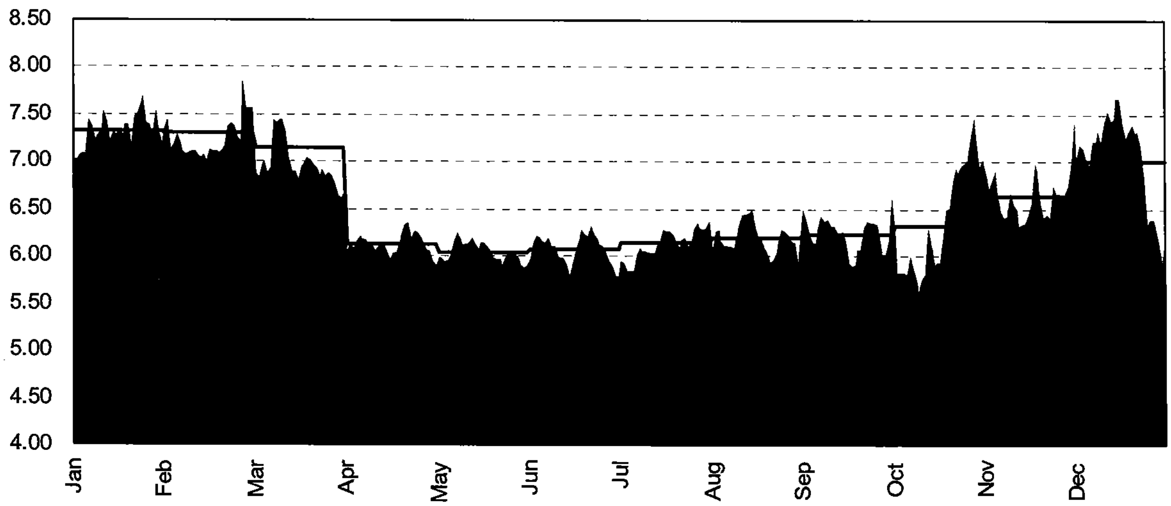


Table 6.3: Natural Gas Basin Prices as % of Henry Hub

Rockies	Sumas	AECO	Malin	Stanfield	Topock
83.1	86.1	85.1	88.3	86.9	89.5

deliveries. Instead it relies on physical supply points including AECO in Alberta, Canada, and the U.S. Rockies. Market trading hubs include Sumas, Wash.; Malin, Ore.; Stanfield, Ore.; and Topock, Calif. Natural gas at these supply points typically trade at a significant discount to Henry Hub. This discount is commonly referred to as the basis differential. Basis differentials exist because of a more favorable supply/demand balance in the West, closer physical proximity to these supplies and longer distances from the large natural gas demand centers of the Eastern U.S.

Most natural gas price forecasts do not include Northwest or Western U.S. pricing, so Avista estimates the basis differential between Henry Hub and the pricing points the company uses to fuel both its power plants and other plants across the Western Interconnect. The company uses an average of recent basis differentials to estimate price differences between the Henry Hub forecast and these markets. The company has adopted the percentages shown in Table 6.3, consistent with its 2006 Natural Gas IRP.

COAL PRICES

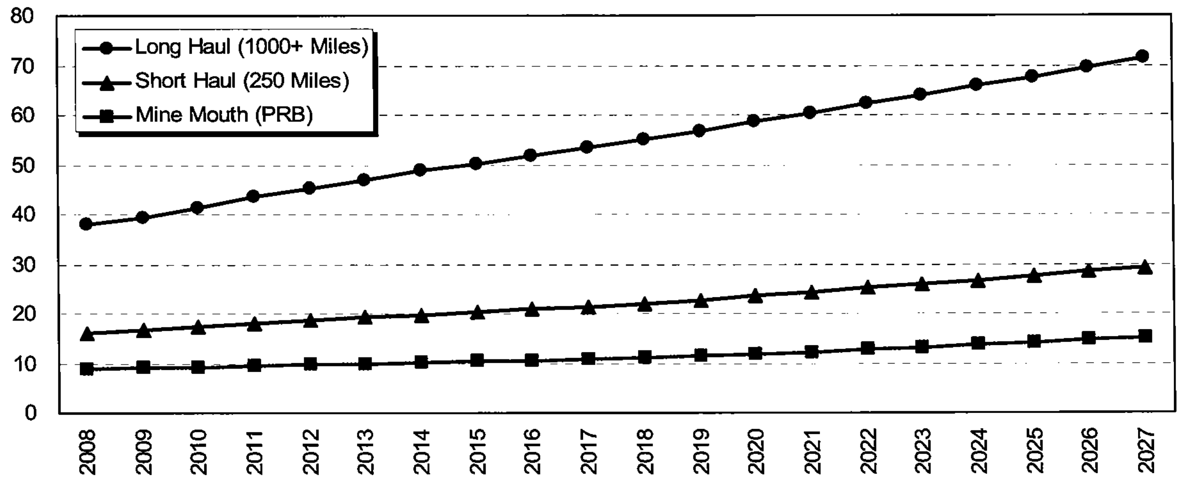
Coal prices and coal transportation costs in this IRP rely on data provided by the Energy Information Administration (EIA) in its February 2006 fuels forecast and its 2002 transportation cost study.[2] The IRP coal price for new coal-fired generation is based on the forecast of Western mine mouth coal prices. Transportation costs are added based on an assumed plant distance from its source of coal supply. This plan assumes three representative coal plant delivery distances for all plants: mine mouth, short haul (500 miles) and long haul (1,200 miles). Figure 6.5 shows the coal price forecast for new coal-fired resources options in the 2007 IRP. AURORAxmp contains coal price assumptions for existing coal-fired plants based on existing contracts. However, some plants also rely on market-based coal. These contracts are tied to the 2007 IRP coal price forecast.

EMISSIONS

Environmental factors are an increasingly important part of resource planning. Emission charges are used

[2] http://www.eia.doe.gov/cneaf/coal/ctrdb/tab55.html

Figure 6.5: Coal Prices for New Coal Resources ($/Ton)

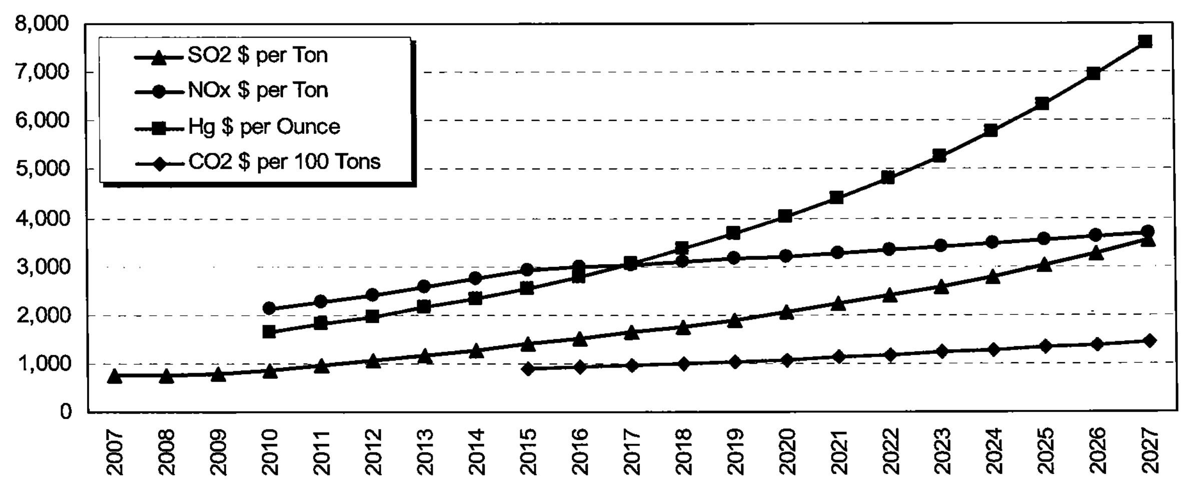


to encourage more environmentally-friendly resource options. The charge is calculated by estimating the financial penalty needed on certain types of emissions to accomplish a stated goal, such as reducing carbon emissions to 1990 levels. In the 2007 IRP, emissions charges are assigned to all resources to model the opportunity cost of generating and producing emissions or choosing not to generate and selling the right to produce emissions. This methodology implies that a cap-and-trade system is in place to trade emissions credits. Additional emissions discussions are located in Chapter 4.

The IRP tracks four emission types: carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrous oxygen compounds (NO_X), and mercury (Hg). CO_2 charges are estimated using the National Commission on Energy Policy (NCEP) carbon regulation proposal. There is currently a great deal of state and federal level legislation regarding carbon emissions which could significantly impact power prices. The uncertain state of carbon emissions legislation requires additional analysis to better understand the issues. This analysis is described in Chapter 7.

The remaining three emissions charges are estimated by a third-party consultant. Figure 6.6 shows the Base Case emission price forecasts. Emissions charges are set to a level necessary to cause existing plants to install mitigation equipment to reduce their average emissions

Figure 6.6: Emission Charges Summary



below certain thresholds. Emissions generally do not have a significant impact on electric market prices in Western U.S. markets because gas-fired plants usually set the marginal price of power. These plants have low overall emission profiles, with the exception of CO_2.

RESOURCES

The AURORAxmp model is populated with all current power generation resources and the operating characteristics important for modeling electricity markets (e.g., plant capacity, heat rate, and start-up costs). Resources under construction or otherwise expected to generate power in the future are also modeled. The AURORAxmp vendor has a rigorous plant data collection methodology that makes certain assumptions for each plant. The company has maintained many of these assumptions for the IRP model database but has made various changes where the company has access to better information. Resources not currently under construction, or a part of other companies' IRPs or plans, are modeled indirectly by two methods. The first method adds resources to meet future load growth for the West by using expansion logic in AURORAxmp; the second method adds generation needed to meet active or impending renewable portfolio standards (RPS). For example, Washington Initiative 937 requires all utilities with more than 25,000 customers to serve 15 percent of their 2020 load with new renewable resources.[3]

The AURORAxmp expansion logic used for this plan differs from the 2005 IRP. The 2005 plan built a level of generation across the West to meet the energy needs of the gross system. The 2007 IRP relies on a capacity planning target. In general, utilities build resources to cover adverse load conditions, meaning that resources are constructed to exceed average needs. This ensures that adequate resources are available to meet system requirements in all but the most extreme conditions, driving electric market prices and volatility down. The availability of firm resources to meet retail loads under a broad range of operating conditions reduces exposure to significant purchases of energy from the financially volatile short-term wholesale energy market.

The resources available to meet regional load growth are: combined-cycle combustion turbines (CCCTs), single-cycle combustion turbines (SCCTs), pulverized coal, integrated gasification combine-cycle (IGCC) coal, IGCC coal with sequestration (certain scenarios) and wind turbines. Other small renewable resource options are added using the RPS method discussed in the next paragraph. New resource options are limited depending on regional location and the presence of an active RPS in the region. For example, renewable resource construction in states with RPS requirements is limited by their RPS; no additional renewables are constructed. West coast states cannot rely on coal-fired plants due to legislative mandates preventing their construction. Detailed assumptions about these resources are discussed later in this section. Specific details on which resources were selected for each study are presented in Chapter 7. New resource options affect market prices which in turn affect the resource mix Avista will consider as it makes investment decisions over its planning horizon.

Renewable portfolio standards change the mix of resources utilities choose to build. Historically utilities built resources with the lowest expected future cost and rate volatility. RPS requirements and other legislative mandates have changed this approach. Utilities must build a specified amount of renewable resources or are limited in their ability to construct certain resource types. Resources procured under these circumstances may not be the lowest cost in a traditional sense, but they will meet a legislative mandate in one or more states and might reduce rate volatility where free or fixed fuel prices and fuel supply are available. Table 6.4 shows the incremental energy needed to meet existing renewable

[3] I-937 has earlier targets of 3 percent in 2012 and 9 percent in 2016.

Table 6.4: New RPS Resources Added to Existing System (aMW)

State	2010	2015	2020	2025
California	187	3,656	5,106	5,991
Oregon	0	519	914	1,867
Washington	0	328	988	1,260
Nevada	400	684	764	900
Montana	24	239	271	324
Arizona	187	556	1,113	1,964
Colorado	100	606	663	757
New Mexico	177	289	326	389

requirements in the Western Interconnect. Actual resources in each state will vary depending on how utilities choose to meet their requirements.

These additions represent company assumptions for the amount of renewable resources necessary to meet various state laws. In states where RPS laws were still pending at the time of the IRP modeling, we made our best estimate based on draft legislation.

A difficult part of forecasting renewable resources is determining where they will be located. Some states require utilities to acquire resources within certain geographic areas, which can greatly increase the price of those projects. New regional transmission may also be required. While recognizing that some regions will meet their RPS requirements by importing renewable power from other regions, the 2007 IRP assumes that all RPS resources are added in the geographic region where they are required. This simplifying assumption was based on the lack of a comprehensive study of regional renewable resource availability. The company does not believe that this simplifying assumption has any significant impact on the wholesale marketplace or the value of resource options available to it.

LOADS

A load forecast is developed for the entire region to forecast western electric prices. This IRP relies on several external sources to quantify load growth across the Western Interconnect. These sources include integrated resource plans, the Western Electricity Coordinating Council (WECC) and the Alberta Electric System Operator (AESO). Peak regional load growth is shown by area in Table 6.5. New resources are added to each area to meet capacity planning margins. The 2007

Table 6.5: Annual Average Peak Load Growth (%)

Area	Load Growth	Area	Load Growth
W. Wash.	1.40	California	2.50
W. Oregon[4]	1.40	Baja, Mexico	2.50
E. Wash.[5]	1.70	Wyoming	3.10
C. Oregon	0.90	Colorado	2.60
Montana	2.60	Utah	4.30
S. Idaho	2.60	Arizona	3.20
British Columbia	1.70	New Mexico	3.20
Alberta	2.10	Nevada[6]	3.10

[4] Southern Oregon is estimated to grow at 1.2 percent and Portland Metro Area is 2.6 percent.
[5] Spokane is estimated to grow at 2 percent, other eastern Washington areas 1 percent.
[6] Southern Nevada peak is expected to grow at 3.2 percent, while northern Nevada is at 2.6 percent.

Table 6.6: Annual Average Energy Load Growth (%)

Area	Load Growth	Area	Load Growth
W. Wash.	1.50	California	2.00
W. Oregon[7]	2.25	Baja, Mexico	2.00
E. Wash.[8]	1.57	Wyoming	2.80
C. Oregon	1.20	Colorado	2.00
Montana	2.50	Utah	3.30
S. Idaho	1.30	Arizona	2.50
British Columbia	1.40	New Mexico	2.50
Alberta	1.80	Nevada	2.50

IRP planning margins are assumed to be 25 percent for the Northwest and Idaho, 17 percent for California and 10 percent for all other zones.

Peak load growth estimates are important for estimating new capacity; however, market prices are more highly correlated to actual energy load growth. Energy growth estimates are shown in Table 6.6.

RISK MODELING

The power industry has fundamentally changed since the 2001 energy crisis. Historically, northwest utilities planned for variability inherent in their hydroelectric plants and load forecast. Now northwest utilities must consider natural gas price volatility, thermal plant forced outages, wind speed, extra-regional load and resource balances, and the ever changing face of emissions legislation. This IRP utilizes a Base Case with an underlying set of assumptions to anchor the modeling effort. Several alternative scenarios and futures are modeled to provide information about what could happen in the electric market under different sets of assumptions. All of the modeling efforts are combined with the judgment of planners, senior management and members of the Technical Advisory Committee to develop a Preferred Resource Strategy used to guide company resource acquisitions.

The Base Case for this study uses average values for most estimates, such as hydro conditions, peak and energy loads growth, and gas prices. These key market drivers will probably not be average in every year, but instead will regress to average levels over the 20-year planning horizon. Scenarios and stochastic studies help the company understand how the market might look and behave if the long-term averages in the Base Case did not materialize. This section focuses on the stochastic assumptions for these studies. The IRP models include several key assumptions that are modeled stochastically, including natural gas, hydro, load, wind, forced outages, and emissions charges (SO_2, NO_X, Hg and CO_2).
The 2007 IRP simulates 300 hourly iterations or "games," using the AURORAxmp for the years 2008-2027. This level of analysis required the use of 25 computers writing their results to a SQL database. Each set of stochastic analysis took the equivalent of four days, or 2,160 computer hours, to complete. The company prepared four stochastic futures for the IRP, consuming 8,500 hours of central processing unit time and creating a 450 gigabyte SQL database.

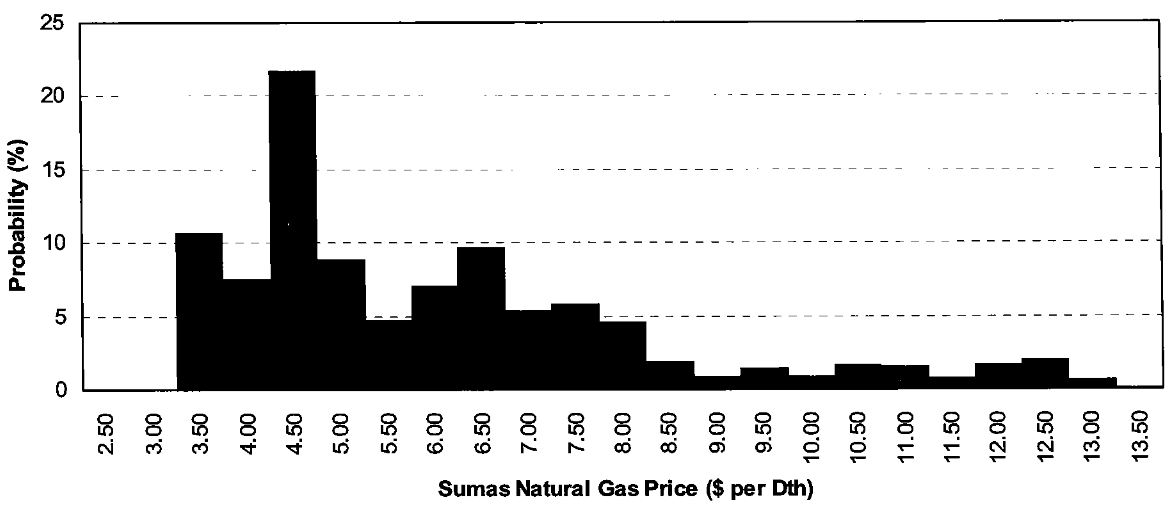
Running the electricity model stochastically provides a measure of volatility for forecasted electricity prices and resource values. This measure is essential to our selection of new resources, because the company's long-term objective is to manage rate variability, as well as limit customer costs.

[7] Southern Oregon is estimated to grow at 1.2 percent and Portland Metro Area is 2.6 percent.
[8] Spokane is estimated to grow at 2 percent, other eastern Washington areas 1 percent.

Table 6.7: Coefficient of Variation of Forward Sumas Natural Gas Prices (%)

Month	2005	2006	2007	2008
January	21	39	22	22
February	22	39	22	22
March	22	39	22	23
April	21	35	20	19
May	23	34	20	19
June	23	34	20	19
July	23	34	20	20
August	24	33	20	20
September	26	33	20	20
October	30	33	21	21
November	36	37	20	20
December	37	39	21	21

Figure 6.7: March 2006 Sumas Natural Gas Contact Price Distribution



NATURAL GAS PRICES

There are several approaches for stochastically modeling natural gas prices, as well as a number of assumptions that need to be made. The 2007 IRP begins with the deterministic natural gas price forecast discussed earlier in this chapter. The forecast represents mean prices in each forecast period. Table 6.7 shows the coefficient of variation (the standard deviation divided by the mean value) of historically traded forward natural gas contracts for the months of 2005 through 2008. We believe that forward market price volatility is a reasonable indicator of future natural gas price volatility. The Base Case assumes 30 percent volatility to capture projected market risk. This assumption differs from the 2005 IRP, which instead represented natural gas volatility with a 50 percent coefficient of variation.

The Base Case distribution is assumed to be lognormal based on a statistical review of the forward price datasets. A review of historical data shows that a majority of the contracts have lognormal characteristics; Figure 6.7 presents the distribution of the March 2006 Sumas forward contract. The Monte Carlo model draws a gas price curve using the lognormal distribution, but each

Figure 6.8: 2008 Sumas Natural Gas Price (Deterministic & First 30 Draws)

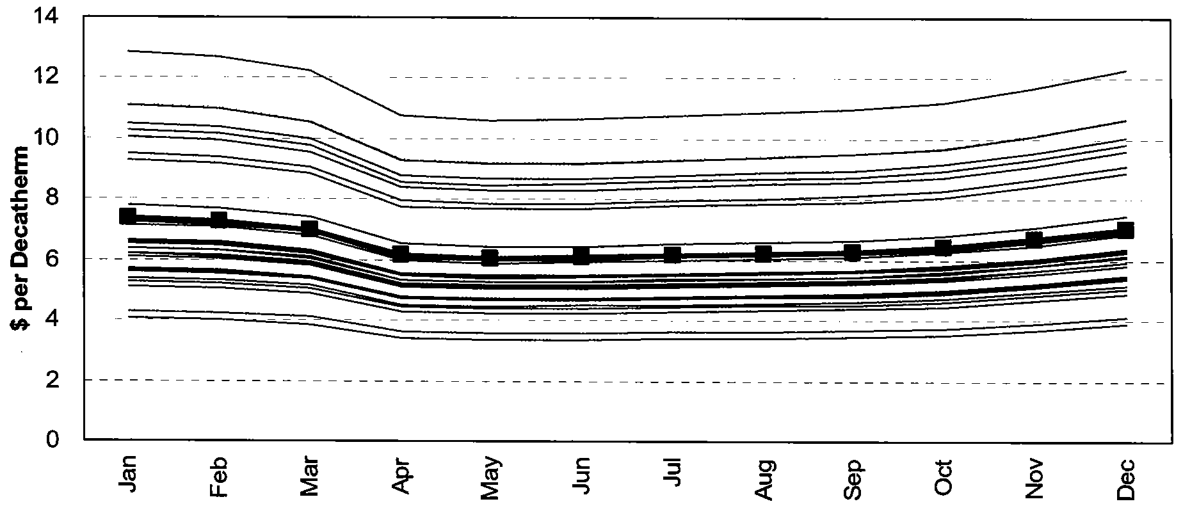


Figure 6.9: Annual Average of 300 Iterations of Sumas Natural Gas Prices ($/Dth)

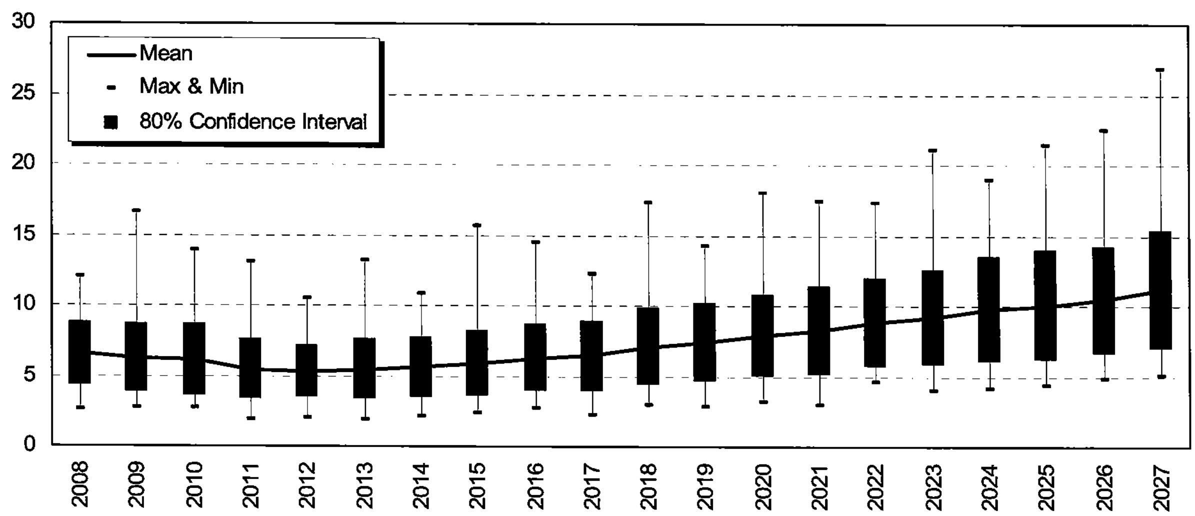


Figure 6.10: Hydro Capacity Factor and Statistics for Selected Areas (%)

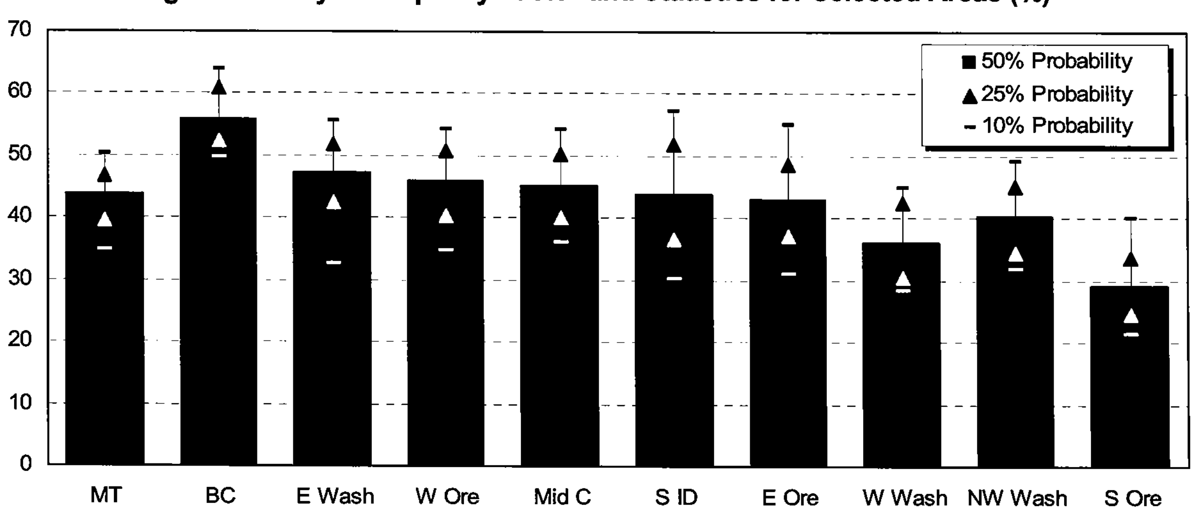


Figure 6.11: Water Year Distribution

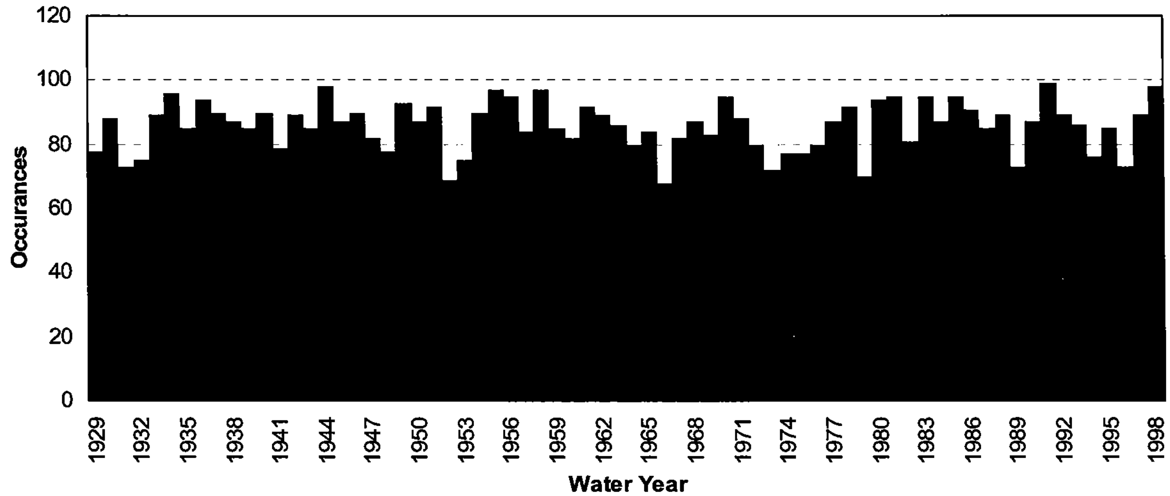
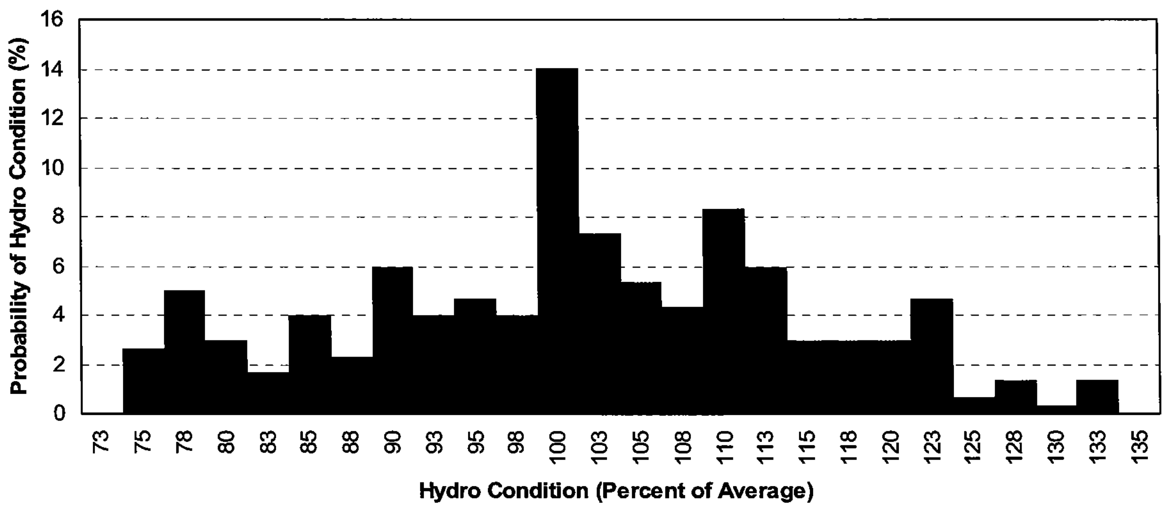


Figure 6.12: Distribution of Stochastic Hydro as a Percent of the Mean



draw has the same shape as the Base Case; the draw is either above or below the Base Case forecast. See Figure 6.8 for a graphical illustration.

Annual average results of this methodology are displayed in Figure 6.9. The chart shows the expected (deterministic) price, the mean of the 300 Monte Carlo iterations, the 80 percent confidence interval, and maximum and minimum prices.

HYDROELECTRIC GENERATION

The Northwest's electricity market, as well as the company's own resource portfolio, is significantly impacted by hydro generation. Figure 6.10 shows the hydro capacity factors assumed for zones and sub zones (areas) that have substantial hydro capacity.

To account for hydro variability, a random generator was used to select different hydro generation amounts for each year and for each of the 300 iterations. Hydro available in each draw was selected from 70 historical water years from 1928/29 to 1998/99. Figure 6.11 presents a distribution of the Base Case draws. The draws show a uniform distribution, or no bias, between water year selections.

Table 6.8: Selected Zone's Load Correlations to Eastern Washington (Jan-June)

Zone	Jan	Feb	Mar	Apr	May	Jun
Alberta	Not Sig	Not Sig	Mix	Mix	Mix	0.3270
Arizona	0.3504	0.3505	Mix	Mix	0.2027	0.4499
Baja	Not Sig	Not Sig	-0.2109	Not Sig	Mix	0.2171
British Columbia	0.7856	0.6762	0.8047	0.0997	0.1058	0.1089
Colorado	0.7852	0.4468	Mix	Mix	Not Sig	Mix
E. Oregon	0.9099	0.8822	0.8893	0.7400	0.4262	0.8613
Montana	0.8440	0.5508	0.8588	Not Sig	Not Sig	0.3487
N. California	Not Sig	Not Sig	Not Sig	Mix	Mix	Mix
N. Nevada	0.2456	0.3232	0.4272	Not Sig	0.1026	0.7609
New Mexico	Not Sig	Mix	Mix	Mix	Not Sig	Mix
S. California	0.1991	Not Sig	Not Sig	Mix	Mix	Mix
S. Idaho	0.6807	0.7163	0.6042	0.3317	0.2114	0.7373
S. Nevada	0.8003	0.3343	Not Sig	Mix	Mix	0.0968
Utah	0.8988	0.8770	0.8435	0.7345	0.4246	0.8451
W. Oregon	0.8177	0.5723	0.8781	0.1043	Mix	0.3152
W. Washington	0.8284	0.4689	0.9031	0.1043	Mix	Mix
Wyoming	0.9089	0.9004	0.9300	0.6906	0.4186	0.5850

Table 6.9: Selected Zone's Load Correlations to Eastern Washington (July-Dec)

Zone	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	0.7575	0.1003	Not Sig	Not Sig	Not Sig	0.4306
Arizona	0.2134	Mix	Not Sig	Not Sig	Not Sig	0.4233
Baja	0.1999	0.3011	Mix	Not Sig	Mix	0.1100
British Columbia	0.6397	0.3084	Mix	0.6985	0.5887	0.8158
Colorado	Not Sig	Not Sig	Not Sig	Not Sig	Not Sig	0.3321
E. Oregon	0.7343	0.7871	0.5924	0.8831	0.8324	0.4573
Montana	0.8310	0.2095	0.2979	0.8342	0.8199	0.8107
N. California	0.4874	Mix	Mix	Not Sig	0.2096	0.2104
N. Nevada	0.6583	0.2339	0.5424	Not Sig	0.1029	0.7235
New Mexico	Not Sig	Mix	Not Sig	Not Sig	0.1036	Not Sig
S. California	0.5017	0.1044	Mix	Not Sig	0.2025	0.2284
S. Idaho	0.2093	0.6807	0.7406	0.2317	0.8991	0.4475
S. Nevada	Not Sig	Mix	0.3208	Not Sig	0.1020	0.6617
Utah	0.6201	0.7815	0.8238	0.8590	0.8515	0.5825
W. Oregon	0.8337	0.4289	0.4410	0.8547	0.5755	0.3413
W. Washington	0.8645	0.3171	Mix	0.8724	0.8854	0.4803
Wyoming	0.5902	0.3100	0.6721	0.8919	0.8685	0.3487

The historical water record's distribution is shown in Figure 6.12. Generation is shown as a percent of the mean for the entire Northwest, encompassing British Columbia, Washington, Oregon, Idaho and Montana.

LOAD VARIABILITY

The 2007 IRP relies on Western Interconnect-wide methodology developed for the 2003 IRP. The earlier work developed monthly and weekly distributions of hourly load data for each Western Interconnect utility using FERC Form 714 data. The 2007 IRP updates the 2003 data, using FERC Form 714 data for the years 2002-2005. Correlations between the Northwest and other Western Interconnect load areas were calculated

Table 6.10: Selected Zone's Load Coefficient of Variation (Jan-Jun %)

Zone	Jan	Feb	Mar	Apr	May	Jun
Alberta	2.9	2.5	3.3	3.2	2.7	4.0
Arizona	5.2	5.6	4.8	6.7	11.0	6.3
Baja	10.0	8.2	9.4	9.9	10.9	6.7
British Columbia	5.4	3.9	5.6	4.7	4.6	4.5
Colorado	4.9	5.2	5.4	5.0	7.7	6.9
S. Idaho	5.3	5.6	7.1	6.1	9.9	8.3
LADWP	7.2	7.2	7.3	8.3	10.1	8.2
Montana	4.9	4.8	5.6	4.8	5.5	5.3
W. Montana	4.9	4.8	5.6	4.8	5.5	5.3
New Mexico	4.6	4.9	4.6	4.8	6.9	4.8
N. Nevada	3.0	2.7	3.5	3.7	5.3	4.7
S. Nevada	3.7	4.1	4.1	6.4	13.9	8.4
E. Washington	6.6	5.4	6.9	5.5	5.6	7.3
W. Washington	7.5	5.8	7.1	5.7	6.3	5.2
E. Oregon	5.1	4.9	5.8	5.4	6.6	6.4
W. Oregon	7.4	6.0	6.9	6.3	6.6	7.8
N. California	5.4	5.5	5.7	6.5	9.2	9.5
S. California	7.3	7.2	7.2	8.1	10.0	8.1
Utah	5.1	5.1	5.9	5.4	6.9	6.5
Wyoming	5.2	5.0	5.8	5.3	6.4	6.4
C. California	5.4	5.6	5.8	6.5	8.8	9.0

Table 6.11: Selected Zone's Load Coefficient of Variation (July-Dec %)

Zone	Jul	Aug	Sep	Oct	Nov	Dec
Alberta	3.8	3.3	2.9	2.9	2.4	3.0
Arizona	6.5	7.6	10.2	9.5	4.5	6.2
Baja	6.4	6.2	9.7	9.3	7.7	10.6
British Columbia	4.9	4.9	4.4	5.5	4.7	4.2
Colorado	7.8	7.2	7.2	5.3	5.1	5.0
S. Idaho	6.2	7.5	7.8	4.9	5.4	5.1
LADWP	9.3	8.0	9.7	8.1	7.7	7.1
Montana	6.4	5.3	4.6	5.2	4.7	4.1
W. Montana	6.4	5.3	4.6	5.2	4.7	4.1
New Mexico	6.0	5.8	6.4	5.0	4.8	5.0
N. Nevada	4.7	5.1	4.7	3.1	3.1	3.5
S. Nevada	6.8	8.2	10.0	9.1	4.1	4.3
E. Washington	7.1	6.9	5.7	6.1	5.9	4.9
W. Washington	6.5	5.6	4.9	6.8	6.2	5.1
E. Oregon	6.0	6.2	6.3	5.2	5.0	4.8
W. Oregon	9.6	8.4	7.2	6.6	6.0	5.5
N. California	8.9	8.0	9.3	6.7	5.9	5.9
S. California	9.2	7.8	9.7	8.2	7.8	7.2
Utah	5.9	6.3	6.5	5.2	5.1	4.8
Wyoming	6.1	6.0	6.2	5.3	5.2	5.0
C. California	8.7	7.7	9.0	6.7	6.0	6.1

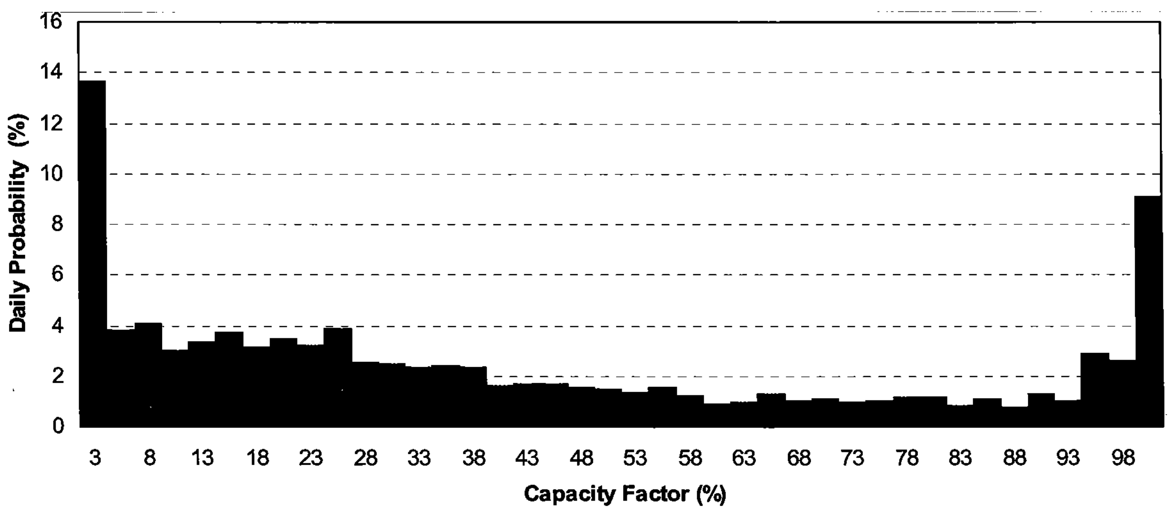
and represented in the stochastic load model. Correlating zone loads avoids oversimplifying the Western Interconnect load picture. Absent correlation data, stochastic models would offset load changes in one zone with load changes in another, thereby virtually eliminating the possibility of modeling West-wide load excursions. Given the high degree of interdependency across the Western Interconnect (e.g., the Northwest and California), this additional accuracy is crucial for understanding variation in wholesale electricity market prices.

Tables 6.8 and 6.9 illustrate the correlations used for the 2007 IRP. Tables 6.10 and 6.11 provide the coefficient of variation (standard deviation devided by the mean) for each zone in 2007. "NotSig" indicates that no statistically valid correlation was found in the evaluated data. "Mix" indicates that the relationship was not consistent across time and was not used in the 2007 IRP analysis.

WIND GENERATION

Wind is one of the most volatile energy resources available to utilities. Since storage, apart from some integration with hydro, is not a financially viable option, capturing the resource's volatility in the power supply model is necessary to correctly determine its impacts on the overall market as well as the value of any acquisition. Accurately modeling a wind resource requires hourly generation shapes. For regional analyses, wind variability is modeled in a manner similar to how AURORAxmp models hydroelectric resources. A single wind plant and generation shape is developed for each area. This generation shape is smoother than individual plant characteristics, but closely represents how a large number of wind farms across a geographical area would operate together.

Figure 6.13: August Hourly Wind Generation Distribution



This simplified wind methodology works well for forecasting electricity prices across a large market, but it does not represent the volatility of specific wind resources that the company might select. A different wind shape was used for each company resource option in each of the 300 Monte Carlo iterations. This analysis uses historical wind data for potential wind sites in the Columbia Basin and eastern Montana. A statistical analysis of the wind data showed that a wind plant would either generally be at or near full output or at no generation most of the time. This U-shaped or beta general distribution is shown in Figure 6.13. This shape demonstrates that a wind plant with an annual average 33 percent capacity factor rarely produces energy at this

Figure 6.14: Actual Stateline Generation August 9th Through 15th, 2006

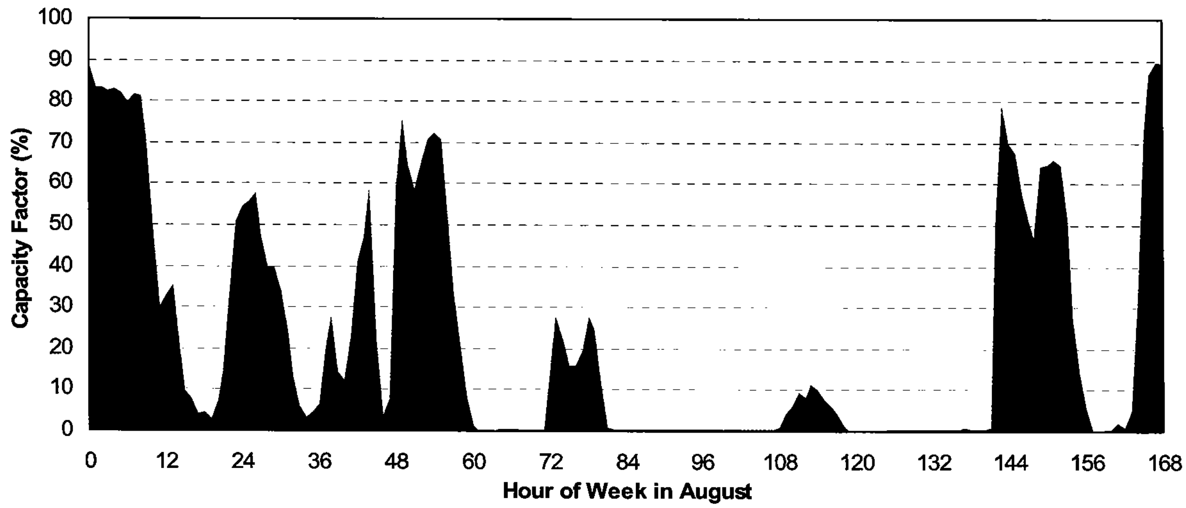


Figure 6.15: Simulated Hourly Columbia Basin Wind Generation for August

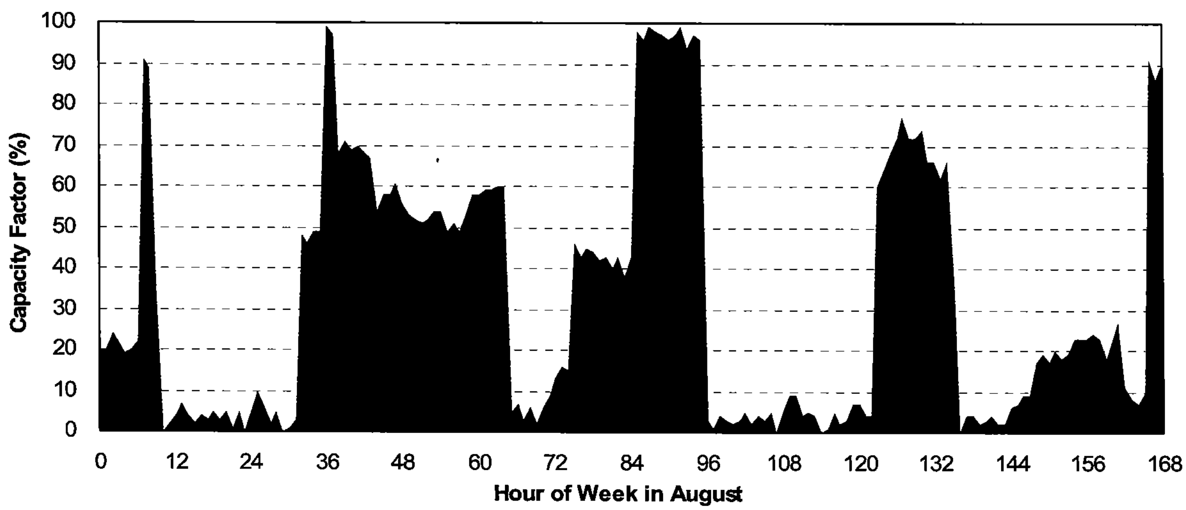


Table 6.12: Simulated Average Annual Wind Capacity Factors (%)[9]

	Columbia Basin	Montana
Mean	33.3%	38.8%
80% Confidence Interval (High)	30.4%	35.9%
80% Confidence Interval (Low)	36.3%	41.6%

level for a specific period of time but does so over an extended period.

The Monte Carlo model randomly draws a capacity factor from the distribution for each hour of each month. This method creates probabilities for good, average and poor wind years. Serial correlation between hours ensures that the hour-to-hour wind generation relationship is retained, preventing an entirely random wind generation profile. Figure 6.14 presents actual Stateline generation from August 2006. The forecast does not try to replicate historical wind data; instead it tries to maintain the underlying statistics of the wind patterns. The Stateline data never reaches 100 percent capacity

[9] Includes losses and the mean of stochastic studies does not guarantee the expected value.

factor due to maintenance and forced outages. The simulated data in Figure 6.15 includes maintenance and forced outage normalized as part of the average capacity factor. Table 6.12 presents the average capacity factors for Columbia Basin and Montana wind sites, along with their modeled confidence interval.

FORCED OUTAGES

In the 2005 IRP, forced outages were modeled as de-rates to plant capacity because AURORAxmp was unable to integrate random forced outages with other stochastic inputs. The modeling software now has this capability. Forced outages are based on a rate and a mean time to repair. Over the 300 iterations forced outages average mean outage rate levels. The 2007 IRP models forced outages stochastically for all CCCT, coal and nuclear plants. These plants represent the marginal resources running during the majority of the modeled hours; they are of the most interest. Hydro, wind, SCCT and other renewables were not modeled stochastically.

EMISSIONS CHARGES

This IRP uses consultant forecasts for SO_2, NO_X and Hg emission costs based on current and projected national emissions policies. Certain state limits, particularly for Hg, make emissions modeling problematic at best. The Base Case emission prices described earlier represent the mean values for each emission. History shows that emission costs vary depending on market conditions. For stochastic analysis, each emission price was assumed to have a 20 percent standard deviation.

Greenhouse gases, or CO_2, emission prices were selected for each iteration by using a probability of different price levels because of the greater uncertainty of pending state and federal regulation. Each iteration uses a different carbon emission charge. Table 6.13 shows the probability distribution of CO_2 emissions.

NEW RESOURCE ALTERNATIVES

This section describes each of the resource alternatives considered in the model to meet Avista's future resource deficits. These resources reflect generic options that might differ from actual projects for a variety of siting or engineering reasons. Actual characteristics and assumptions will likely be developed through a Request for Proposal (RFP) process.

COMBINED-CYCLE COMBUSTION TURBINES (CCCT)

Combined-cycle combustion turbines are modeled using a two-on-one configuration. This configuration consists of two gas turbines using a single heat recovery steam generator (HRSG), rather than one gas turbine matched with a HRSG. These plants generally range between 200 and 600 MW. Capital cost estimates are based on a 280 MW 7FA General Electric (GE) machine. Operation and maintenance costs are based on estimates from the Northwest Power and Conservation Council (NPCC), adjusted for inflation.

The heat rate modeled for this resource begins at 6,722 Btu/kWh in 2008 and decreases by 0.5 percent each year to account for technological improvements.

Table 6.13: Probability Matrix of Carbon "Taxes" ($/Ton)

Probability	Tax Amount (2015)	Tax Amount (2025)
10.0%	0.00	0.00
1.5%	1.76	2.66
15.0%	6.60	9.96
50.0%	8.80	13.28
15.0%	11.00	16.60
2.0%	15.84	23.90
5.0%	16.50	30.00
1.5%	33.00	60.00

Figure 6.16: Capacity Levels for Northwest Gas-Fired Plants (%)

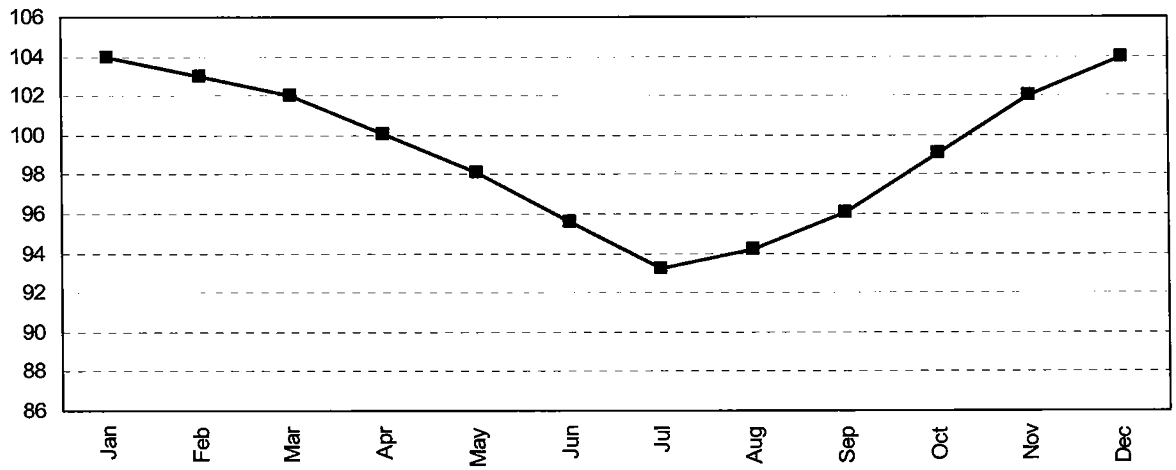


Table 6.14: Real 2007 Levelized Costs for 2013 CCCT (Full Availability)

Item	$/MWh
Fuel Cost	47.17
VOM	2.71
Fixed O&M	1.15
Non-Capital Transmission	0.00
Emissions	3.31
Generation Capital Recovery and Overheads	9.50
Transmission Capital Recovery and Overheads	1.30
Value of Losses	0.00
Total	65.14

The plants are modeled so that 7.7 percent of the capability is for duct firing at a higher heat rate of 8,300 Btu/kWh. Forced outage rates are estimated as 5 percent per year; 14 days of maintenance will occur biennially. Cold startup costs are assumed to be $35 and 6.3 decatherms per megawatt per start.[10] CCCT plants are modeled to back down as far as 50 percent of their nameplate capacity and ramp from zero to full load in three hours. The maximum capability of each plant is highly dependent on temperature. Figure 6.16 illustrates the average capacity by month for a Northwest CCCT relative to its nameplate rating.

No limitations were placed on the number of CCCTs that could be selected for any area.
CCCT Resource Capital and Operating Costs (2007$):

- Capital Cost: $786 per kW
- Fixed O&M: $9.40 per kW-yr

SIMPLE-CYCLE COMBUSTION TURBINES (SCCT)

The 2005 IRP includes two simple-cycle combustion turbine options: Frame (GE 7EA) and aero-derivative (GE LMS 100) machines. Aero-derivative plants can ramp up quickly and have low heat rates and start-up costs, but their upfront costs are significantly higher than frame units. Operations and maintenance costs are based on inflation-adjusted NPCC estimates.

The heat rates for SCCT plants are 8,910 Btu/kWh (Aero) and 10,139 Btu/kWh (Frame) in 2008, decreasing by 0.5 percent each year to account for technological improvements. Forced outage rates are estimated at 3.6

[10] For example, a 250MW plant would cost $18,987.50 to start up: $8,750 ($35 * 250 MW) for O&M and $10,237.50 (6.3 Dth * 250 MW * $6.50/Dth) for fuel.

Table 6.15: Real 2007 Levelized Costs for 2013 SCCT (Full Availability)

Item	Aero ($/MWh)	Frame ($/MWh)
Fuel Cost	62.48	72.91
VOM	9.40	4.69
Fixed O&M	1.11	0.85
Non-Capital Transmission	0.00	0.00
Emissions	4.38	5.11
Generation Capital Recovery and Overheads	7.48	4.99
Transmission Capital Recovery and Overheads	0.67	0.67
Value of Losses	0.00	0.00
Total	**85.52**	**89.22**

percent per year, with no modeled maintenance outages (maintenance will occur in shoulder months where these plants do not operate). Cold startup costs were not modeled. The maximum capabilities of these plants are highly dependent on temperature conditions and are assumed to have the shape as CCCT plants, see Table 6.15. No limits were placed on SCCT construction.

SCCT Resource Capital and Operating Costs (2007$):

- Capital Cost: $628 per kW for Aero, $419 per kW for Frame
- Fixed O&M: $9.16 per kW/yr for Aero, $7.05 per kW-yr for Frame

COAL PLANTS

As identified in the 2005 IRP as an action item, in 2005 and 2006 Avista partnered with Idaho Power to analyze coal plant costs. After the consultant study was complete, a Request for Qualifications (RFQ) was issued to learn about coal projects currently in the development pipeline. The RFQ identified projects in Washington, Idaho, Montana, Utah, Wyoming and Nevada. Each project's cost and non-cost factors were studied. As a result of this effort, combined with recent legislative mandates, Avista has decided that it will no longer pursue a new coal-fired plant. The resource however, does warrant review in the 2007 IRP.

Two main types of coal plants were studied: pulverized and IGCC. Pulverized options are sub-critical, super-critical, ultra-critical and circulating fluidized bed (CFB). These different technologies have different boiler temperatures and pressures, resulting in different capital cost and operating efficiencies. IGCC plants may include a back-up coal gasifier and/or a carbon sequestration option.

The market studies limited coal plant construction to the Rocky Mountains, Canada and the Desert Southwest. Plants built in these areas were not allowed to serve loads

Table 6.16: Coal Plant Technology Characteristics and Assumed Costs

Technology	Plant Sizes (MW)	Heat Rate (Btu/kWh)	Capital Cost (2007$)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)	Forced Outage (%)
Sub-critical	175-1000	9,371	1,905	44.57	3.91	6
Super-critical	375-1000	8,955	2,004	45.50	3.86	6
Ultra-critical	600-1000	8,825	2,010	46.55	3.90	6
CFB	50-425	9,289	2,155	48.43	6.15	6
IGCC	250-650	8,131	2,378	54.98	3.21	7 or 10[11]
IGCC w/ seq.	250-650	9,595	3,045	64.87	3.45	7 or 10

[11] Forced outage rate is lower if a spare gasifier is available.

Table 6.17: Regional Coal Transmission Capital Costs

Location	Capital Cost ($Millions)	Size (MW)	Cost ($/kW)
Northwest	500	1,000	500
Eastern Montana	1,000	1,000	1,000
Wyoming	3,000	2,000	1,500

Table 6.18: Real 2007 Levelized Costs for 2013 NW Coal Plants (Full Availability $/MWh)

Item	Sub-critical	Super-critical	Ultra-critical	CFB	IGCC[12]	IGCC w/ Seq[13]
Fuel Cost	26.19	25.03	24.67	25.96	22.73	27.90
VOM	3.98	3.94	3.97	6.27	3.19	3.40
Fixed O&M	5.62	5.74	5.88	6.11	7.06	8.33
Non-Capital Transmission	1.12	1.12	1.12	1.12	1.17	1.17
Emissions	10.85	10.36	10.21	11.83	8.97	2.21
Generation Capital Recovery and Overheads	24.34	25.59	25.67	27.52	31.71	42.17
Transmission Capital Recovery and Overheads	5.23	5.23	5.23	5.23	5.46	5.67
Value of Losses	0.68	0.68	0.68	0.68	0.68	0.82
Total	**78.02**	**77.70**	**77.43**	**84.73**	**80.97**	**91.68**

in other Western Interconnect areas. This plan assumes that a new coal plant could not be constructed until 2013 at the earliest.

The various coal plant technologies each have unique characteristics. Table 6.16 illustrates some of these key operational and cost differences between them.

TRANSMISSION ESTIMATES:

Coal plant costs are highly dependent on the amount of transmission necessary to bring their power to load centers. Estimating transmission costs in regions outside of the Northwest is difficult, as we are not as familiar with the unique challenges faced by transmission planners in those regions. Even with good transmission cost estimates, the method for cost allocation is unknown. The 2007 IRP relies heavily on other studies for estimating transmission costs. Table 6.17 illustrates the transmission costs assumed for the 2007 IRP. Table 6.18 presents the 2007 real levelized costs of the various coal plant technologies.

WIND

Concerns over carbon-based generation technologies' impacts on the environment have greatly increased the demand for wind generation. Governments, through tax credits, renewable portfolio standards and eminent carbon caps are also promoting development. Wind is currently the major renewable resource with commercial-scale development potential. Strong demand has increased the price of acquiring these assets by about 70 percent since the 2005 IRP.

Three wind resource locations were studied: Columbia Basin, Montana and plants within Avista's service territory. Each location has a capacity factor and transmission cost. All locations were assumed to have the same capital cost.

TRANSMISSION ESTIMATES:

- Columbia Basin: BPA wheel and $50 per kW for local interconnection
- Montana: Northwestern wheel and $50 per kW

[12] A spare gasifier is not included.
[13] This assumes that a plant is built without a spare gasifier in 2018 or later.

Table 6.19: Wind Location Capacity Factors (Excludes Losses)

Location	Capacity Factor
Columbia Basin Tier 1	33.2%
Columbia Basin Tier 2	27.7%
Montana Tier 1	40.8%
Montana Tier 2	32.7%
Avista Service Territory Tier 1	30.0%
Avista Service Territory Tier 2	21.7%

Table 6.20: Wind Integration Costs[14]

Wind Location	Wind Capacity (MW)	System Penetration	$/MWh
Columbia Basin	100	5%	2.75
50/50 Mix CB & MT	200	10%	6.99
Diversified Mix	400	20%	6.65
Diversified Mix	600	30%	8.84

for local interconnection

- Avista Service Territory: No wheel and $30-130 per kW for interconnection; it is likely to be cheaper to integrate a tier 2 wind site than a tier 1 site to Avista due to the distance of existing transmission
- BPA wheel: $16.90 per kW-yr
- BPA losses are 1.9 percent
- Northwestern wheel: $40.80 per kW-yr
- Northwestern losses are 4.0 percent
- No losses or wheel on Avista system

Each regional wind area is modeled with two capacity factor levels: tier 1 and tier 2. Tier 2 wind has a 20

Table 6.21: Real 2007 Levelized Costs for 2013 Wind Plants (Full Availability)

Item	Columbia Basin Tier 1 ($/MWh)	Columbia Basin Tier 2 ($/MWh)	Montana Tier 1 ($/MWh)	Montana Tier 2 ($/MWh)	Avista Service Territory Tier 1 ($/MWh)	Avista Service Territory Tier 2 ($/MWh)
Fuel Cost	0.00	0.00	0.00	0.00	0.00	0.00
VOM and Integration	4.67	4.67	6.38	6.38	4.58	4.58
Fixed O&M	7.49	9.00	6.23	7.78	8.14	11.25
Non-Capital Transmission	7.19	8.64	14.53	18.13	0.00	0.00
Emissions Taxes	0.00	0.00	0.00	0.00	0.00	0.00
Generation Capital Recovery and Overheads	55.22	68.43	46.89	62.25	63.29	87.50
Transmission Capital Recovery and Overheads	1.45	1.74	1.21	1.51	4.10	1.31[15]
Value of Losses	0.83	0.83	1.78	1.78	0.00	0.00
Total	**76.84**	**77.02**	**93.30**	**97.82**	**80.12**	**104.64**

[14] See http://www.avistautilities.com/resources/plans/documents/AvistaWindIntegrationStudy.pdf

[15] Transmission estimates near Tier 2 wind sites in Avista's service territory tend to be lower than higher capacity factor wind sites due to the proximity of transmission lines.

percent lower capacity factor than tier 1 wind. The capacity factors in Table 6.19 are mean values for each region; a statistical method based on regional wind studies was used to arrive at a range of capacity factors depending on the wind regime in each year. Table 6.21 presents the 2007 real levelized costs of the various wind plant locations.

Capital and Operating Costs (2007$):

- Capital Cost: $1,884 per kW,
- Fixed O&M: $17.50 per kW-yr,
- Variable O&M: $1.00 per MWh and
- Wind Integration Costs: see Table 6.20.

ALBERTA OIL SANDS

Alberta Oil Sands are potentially an attractive co-generation resource option for the United States and Canada. It must overcome the significant transmission investment required to transport generated power to the Northwest. It also requires a partnership between oil and utility firms to make the project viable. For all of the discussion around this resource, cost and operating data is hard to come by.

Transmission for this project has been extensively studied by the Northwest Transmission Assessment Committee (NTAC) Discussed below are the assumptions used for modeling the Oil Sands as a resource option for the 2007 IRP.

OIL SANDS TRANSMISSION ESTIMATES (PRIMARILY FROM NTAC):

- DC Line: $1,365,433,000
- Terminals: $500,000,000
- Communications: $30,000,000
- Total Transmission Capital Cost: $1,895,433,000
- Capital Cost: $3,963 $/kW (2007$)
- Transmission O&M: $8.90 per kW-yr
- BPA wheel: $16.90 per kW-yr
- Losses are expected to be 7.7 percent to Celilo and 1.9 percent back to Spokane

OIL SANDS RESOURCE

The heat rate of this resource is modeled at 5,000 Btu/kWh. This rate allocates potential emission and fuel costs to the utility.[16] The resource would probably have a gasifier to transform the residual oil to synthetic gas and a combustion turbine to generate steam for the oil recovery process. The fuel price equals the fixed and operating costs of the gasifier.

An IGCC plant designed for coal gasification is a similar resource to Alberta Oil Sands because both require gasification and the use of a combustion turbine unit. Given a lack of good price information on this resource, we base our estimate on an IGCC plant capital cost of $2,378 per kW. As one-third of the plant's heat value is for electric generation, only that portion is applied to

Table 6.22: Real 2007 Levelized Costs for 2013 Alberta Oil Sands Project (Full Availability)

Item	$/MWh
Fuel Cost	0.00
VOM	3.55
Fixed O&M	7.45
Non-Capital Transmission	3.48
Emissions Taxes	4.85
Generation Capital Recovery and Overheads	53.34
Transmission Capital Recovery and Overheads	14.20
Value of Losses	3.70
Total	**91.58**

[16] The IRP assumes no fuel costs, but arrangements could have a fuel charge.

the electricity side of the operation. To this cost a heat-recovery steam generator is added, bringing the total plant cost to $3,963 per kW.

OTHER MODELED RESOURCES

A number of other resource options are modeled in this IRP. These include biomass, geothermal, small cogeneration and nuclear. Nuclear plants are not currently considered as a resource option to Avista, but, like coal plants, need to be studied for each plan because they are an option to other areas of the Western Interconnect. Over time, this could change as national policy priorities focus attention on de-carbonizing energy supply. Nuclear capital costs are difficult to determine, as a new nuclear project has not been built in the U.S. in more than 25 years. Better nuclear cost

Table 6.23: Real 2007 Levelized Costs for Other Resources (Full Availability)

Item	Biomass ($/MWh)	Geo-thermal ($/MWh)	Small Co-Gen ($/MWh)	Nuclear ($/MWh)
Fuel Cost	0.00	0.00	33.48	8.06
VOM	6.88	6.88	2.55	5.63
Fixed O&M	5.34	11.03	1.09	7.11
Non-Capital Transmission	2.56	2.65	0.00	2.17
Emissions Taxes	0.00	0.00	2.38	0.00
Generation Capital Recovery and Overheads	51.30	43.13	24.56	42.81
Transmission Capital Recovery and Overheads	0.69	0.72	0.64	5.65
Value of Losses	0.83	0.83	-1.97	0.87
Total	**67.60**	**65.23**	**62.72**	**72.30**

Operation and maintenance costs are assumed to be similar to that of an IGCC plant. Fixed O&M is modeled at $55 per kW-yr and $3.00 per MWh. The forced outage rate is assumed to be 5 percent, and planned maintenance occurs biennially for 21 days. Table 6.22 presents the 2007 real levelized costs of the Alberta Oil Sands resource.

Figure 6.17: Real Levelized Costs for Selected Resources at Full Availability ($/MWh)

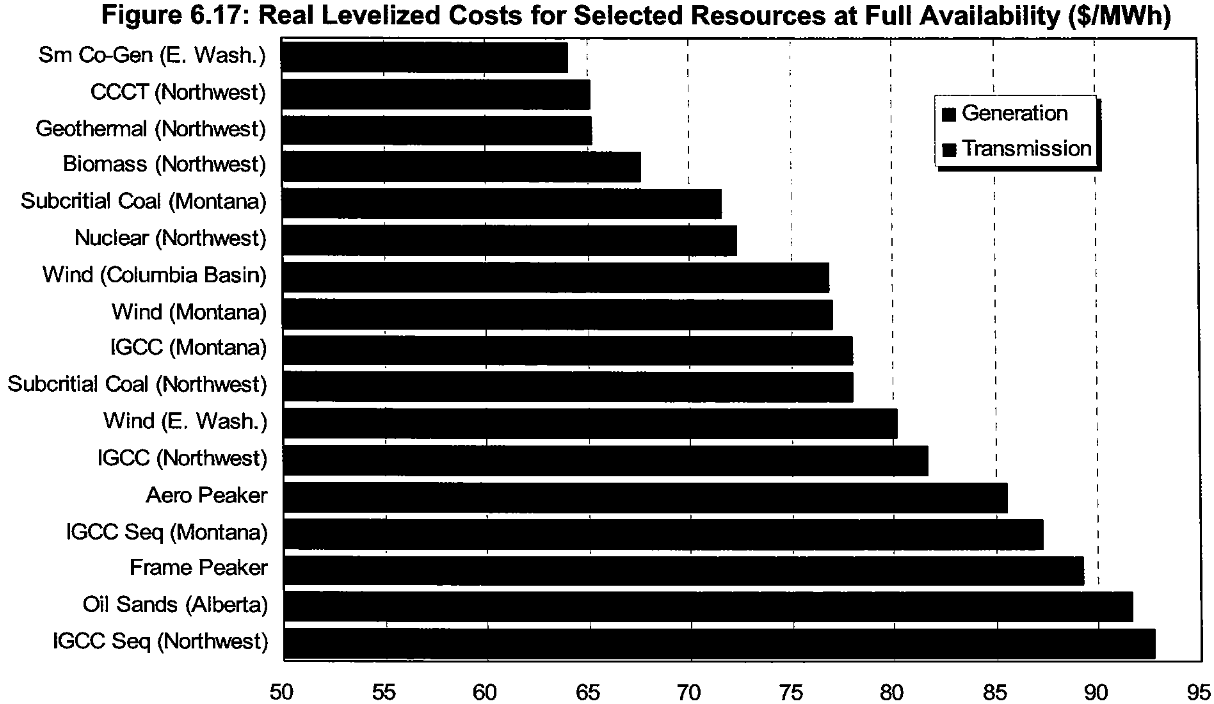
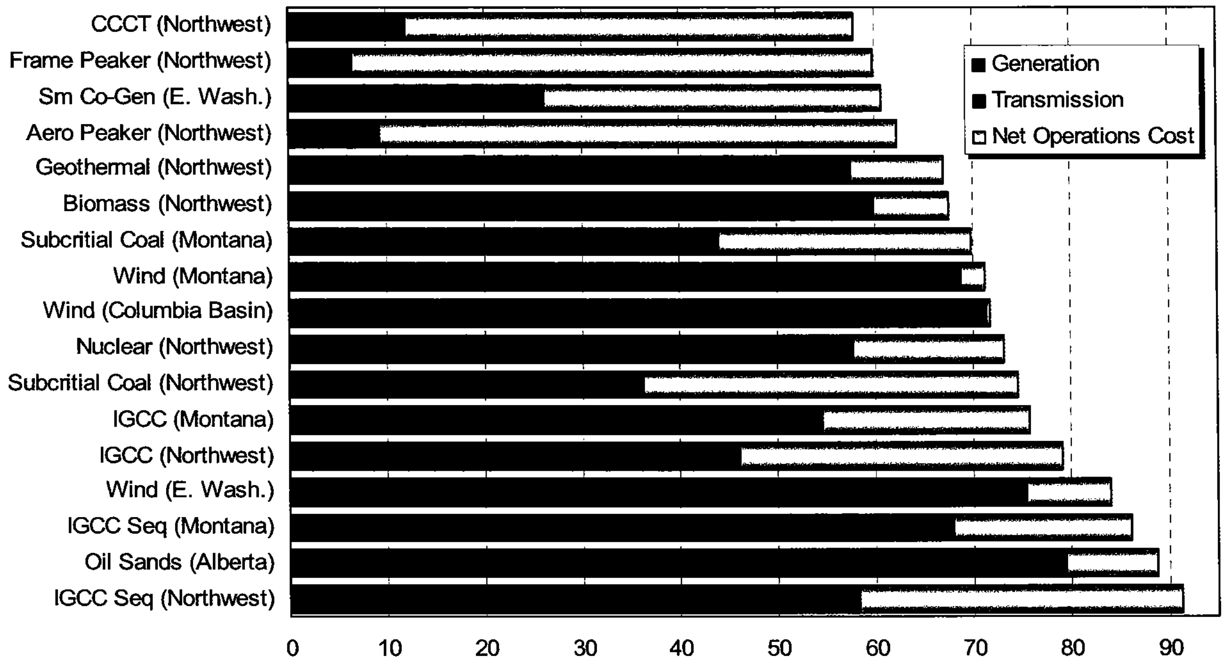


Figure 6.18: Real Levelized Costs for Selected Resources with Market Operations ($/MWh)



estimates should be available for the next IRP because several plants are being planned to start construction after 2010. Table 6.23 illustrates the levelized cost assumptions for each of the remaining plant alternatives.

SUMMARY OF RESOURCE OPTIONS

Figure 6.17 provides a comparison of the real levelized costs for each modeled resource option. Costs range from a low of $65 per MWh for a Northwest CCCT plant to more than $90 per MWh for a Northwest IGCC plant. Costs are divided between busbar generation and the transmission necessary to transport or integrate the new resource into the company's portfolio. These costs are based on the resource dispatching at full availability and at expected costs. This chart does not consider operational dispatch and other risk factors.

All-in levelized costs based on the full availability of a generating unit can be misleading. Another way to look at generation cost is to consider what the plant would cost when operated in a marketplace. In hours where the plant is uneconomic, it is not operated and market purchases replace plant output. Total fixed and variable costs, including fuel, are then combined with market displacement purchases to develop an all-in levelized cost. Figure 6.18 attempts to address these costs; it shows Generation and Transmission fixed costs per dispatch capability. The Net Operations Cost takes into account operations cost and market value. For example the cost of a CCCT in Figure 6.17 is $65 per MWh, taking into account the market value its net cost is $58 per MWh.

Resources that are not commercially viable or are prohibitively expensive over the IRP planning horizon are not modeled in this plan. Examples include: pulping chemical recovery, new hydroelectric facilities, diesel, ocean current, ocean thermal gradients, petroleum, salinity gradients, tidal energy, wave energy and distributed generation, including small scale solar and micro-turbines.

THE PRiSM MODEL

The company developed the PRiSM model to help select its Preferred Resource Strategy. The model quantifies the cost and risk of Avista's current resource portfolio and potential new resources. Each existing and future resource option has an expected operating value. Some resources provide protection against market price volatility while others do not. Combining the company's current resource portfolio with an optimal mix of new resources creates the company's Preferred Resource Strategy. Additional information is needed, including capital and fixed operating costs, to determine an optimal mix. Resource acquisition target amounts must also be considered along with the net value of the resource option.

The PRiSM model uses a linear programming routine. Linear programs help support complex decision making that have single or multiple objectives. Developing these tools requires advanced portfolio and market analysis and can be expensive and complicated. Linear programming has been used by many industries for decades, although the utility industry has been slow to adopt it for resource planning.

OVERVIEW OF THE PRiSM MODEL

PRiSM has four basic inputs: resource shortages for peak load and energy, existing resource portfolio costs and volatility, new resource options over the 300 Monte Carlo iterations market values and capital costs for potential new resources. With these inputs, the model solves for the optimal mix by year to meet capacity and energy needs given a specified level of cost and risk tolerance. The model gives a larger weighting to the first 10 years of the 20-year study. A simplified view of the linear programming objective function formula is shown in Equation 6.1.

Equation 6.1: PRiSM Objective Function

Minimize:

$$(X_1 * NPV_{2008-2017} + X_2 * DEV_{2017} * F) + (X_1 * (10\% * NPV_{2018-2027}) + X_2 * (10\% * DEV_{2027}) * F)$$

Where:

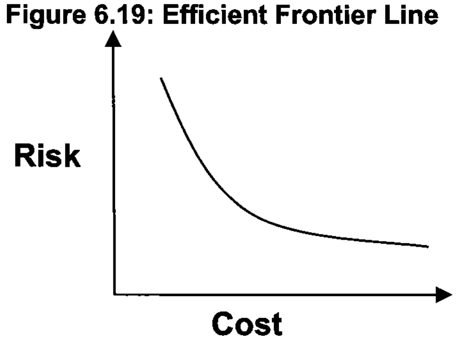
X_1 = Weight of cost reduction (between 0 and 1)
X_2 = Weight of risk reduction (1 - X_1)
F = Factor to adjust risk to equal cost in 50/50 case
DEV is the absolute deviation of power supply costs
NPV is the net present value of total cost

Subject to:

Capacity Need +/- deviation
Energy Need +/- deviation
Wash St. Renewable Portfolio Standard
Resource Limitations and Timing
Capital Spending

The PRiSM model creates a hypothetical resource selection given that a utility could add resources in exact increments as needs specify. It relies on a preferred cost and risk level for the company. The decision on what level of cost and risk reduction (X1 and X2) can be studied further using the efficient frontier approach. An efficient frontier captures the optimal amount of cost and risk reduction given the constraints of each level of weighting for cost and risk Figure 6.19 provides an example of the efficient frontier. The best point to be on the efficient frontier curve depends on the level of risk the company and its customers are willing to accept.

Figure 6.19: Efficient Frontier Line



CONSTRAINTS

As discussed above, various model constraints are necessary to solve for the optimal resource strategy. Some of the constraints are physical while others are societal. The major constraints modeled are capacity needs, energy needs, the Washington state renewable portfolio standard and resource limitations and timing.

Approximately 65 percent of the company's retail electricity load is in Washington. New state law requires that utilities with more than 25,000 customers meet 3 percent of their load by 2012, 9 percent by 2016 and 15 percent by 2020 with new renewable resources. The model selects qualified resources even if they are more expensive than other alternatives, provided that the additional cost does not exceed 4 percent of overall utility revenue requirement. Where costs are more expensive, the model can instead purchase qualified green tags; however, in the absence of a liquid forward market in green tags, their value is assumed to equal the 4 percent cap.

The model has the ability to limit annual capital expenditures for power plant and associated transmission construction. Given the resources selected in this study, we implemented a capital spending constraint. A number of resource constraints were necessary to ensure the PRiSM model selected a reasonable portfolio. The following list of resource constraints were placed on PRiSM:

- Wind acquisition is limited to 100 MW of nameplate capacity each year.
- Only carbon-sequestered coal plants are allowed.
- Acquisition of other renewables is limited to 35 MW over the first 10 years and 45 MW over the last 10 years.
- The model can sell in the short-term electricity marketplace up to 25 MW in all years except 2017 and 2018, where expiration of the PGE Capacity Sale creates a 150 MW capacity surplus that must be managed through a larger sale in that year.

The PRiSM model helps make portfolio decisions by quantifying the costs and risks associated with each resource option. It does not replace the judgment of management. Instead, this method more accurately quantifies the impact of various resource decisions and, once developed, can evaluate alternatives more efficiently than simplified portfolio analysis.

CHAPTER SUMMARY

The 2007 Integrated Resource Plan is a comprehensive modeling effort that studies the company's generation needs and needs of the entire Western Interconnect. This modeling approach allows us to identify the impacts of major fundamental changes to the electric industry, such as fuel price volatility and carbon regulations. The IRP has three main components: electric market price forecasting, risk valuation, and a combination of these two components into the PRiSM model to select the Preferred Resource Strategy.

7. MARKET MODELING RESULTS

OVERVIEW

An optimal resource portfolio must account for optionality inherent in the resource choices. For the 2007 IRP, a simulation was conducted comparing each resource's expected hourly output at a forecasted Mid-Columbia hourly price. This exercise was repeated for 300 iterations of Monte Carlo analysis. Resources that generate during on-peak hours generally contribute a higher margin to a portfolio than resources that do not. This enables certain higher average cost resources to be more cost effective than other options which generate electricity during off-peak hours.

Mid-Columbia prices are forecasted using AURORAxmp, an electric market fundamentals model developed by EPIS, Incorporated. Chapter 6 discusses the modeling assumptions used to develop the electric price forecast. In general, the hourly electricity price is set by either the operating cost of the marginal unit in the Northwest or the economic cost to move power into or out of the Northwest.

To create an electricity market price projection, a forecast of available future resources must be determined. This study uses regional (instead of the summation of individual utility needs) planning margins to set minimum capacity requirements. Western regions can be long on resources, while individual utilities may need additional resources. This imbalance can be due to ownership of certain generating resources by independent power producers and possible differences in planning methodologies for those utilities.

AURORAxmp does not select Avista's Preferred Resource Strategy (PRS); rather, it assigns values to resource alternatives used in the PRS exercise. Using several market price forecasts can determine the value and volatility of a resource portfolio. Since we do not know what will happen in the future with a significant degree of certainty, it relies on scenario planning to help determine the best resource strategy. Scenario planning is done by developing many different market price forecasts using different assumptions than the Base Case or by changing the underlying statistics of a study. These alternate cases are split into two different categories: futures and scenarios.

A future is a stochastic study using Monte Carlo analysis to quantify risks. These studies include 300 iterations of varying gas prices, loads, hydro, thermal outages, wind shapes and emissions prices. A scenario is a deterministic study made by changing one or more specific underlying model assumptions. These cases are generally used to understand specific changes, but they do not quantitatively assess all risks facing the company.

STUDIED FUTURES

The company studies four primary futures for the 2007 IRP, including: Base Case, Volatile Gas, Unconstrained Carbon and the Climate Stewardship Act of 2005 (High Carbon Charges). Each future provides information to help the company identify its Preferred Resource Strategy and to help explain the impact of changing conditions on its Preferred Resource Strategy.

CHAPTER HIGHLIGHTS

- Gas-fired resources continue to serve the majority of new loads in the West through the IRP timeframe.
- Market prices are forecast to fall from today's level through 2011, and then steadily rise after 2015; 2008-2027; levelized Mid-Columbia prices are forecasted to be $51.25 (real 2007 dollars).
- Electricity and natural gas prices are expected to remain tightly correlated.
- National Commission on Energy Policy's carbon reduction strategy is included in the Base Case.
- This IRP models four stochastic futures.
- Avoided costs consider capacity and risk reduction when the company is resource deficit.

Table 7.1: Base Case Key Assumptions

	Entire Study	2008	2017	2027
Natural Gas Price @ Sumas ($/Dth)	5.42 (Real)	6.54 (Nominal)	6.44 (Nominal)	11.18 (Nominal)
Natural Gas Price @ Henry Hub ($/Dth)	6.31 (Real)	7.62 (Nominal)	7.50 (Nominal)	13.02 (Nominal)
Northwest Load (aMW), (WA, OR, N. Idaho)	1.72% (AAGR)	17,584	20,708	24,715
Western Interconnect Load (aMW)	1.95% (AAGR)	100,056	120,056	147,348
Northwest Non-Coincident Peak Demand (MW), (WA, OR, N. Idaho)	1.38% (AAGR)	25,749	29,311	33,863
Western Interconnect Non-Coincident Peak Demand (MW)	2.37% (AAGR)	162,672	202,388	259,667
Hydro Energy (aMW)	14,152	14,067	14,162	14,162
CO_2 Tax ($/Ton)	4.35 (Real)	0.00	9.54 (Nominal)	14.45 (Nominal)

BASE CASE FUTURE

The Base Case future study represents Avista's best estimate of future costs and prices. It uses average conditions and expected values for its assumptions. Many of the key assumptions for this case are described in Chapter 6; a summary of them is shown in Table 7.1. Future load growth is served primarily by natural gas-fired, combined-cycle plants, although many simple-cycle plants are built to meet planning margin targets. Renewable resources are included to meet various states' renewable portfolio standards (RPS), as well as to provide resource diversification. The Base Case assumes that states with RPS requirements will not construct renewable resources in exceedance of such requirements because of the relative scarcity of these resources. The federal production tax credit, a large subsidy that offsets a significant portion of the higher development and operation costs of renewable resource, is assumed to be extended until 2014.

The Base Case assumes that coal resources can be built only in Rocky Mountain states to serve local electrical loads; the energy cannot be exported due to various state import laws preventing it. Constraining coal plant construction leaves natural gas-fired resources to meet most of the future load growth in the West. Table 7.2 provides cumulative new generation resources assumed in the Base Case.

As a region, the Northwest is forecast to be in a surplus position through 2020. New resource construction before 2020 occurs to meet RPS and sub-regional requirements. Figure 7.1 illustrates the Northwest resource position during the system's one-hour peak

Table 7.2: Cumulative Western Interconnect Resource Additions (Nameplate MW)

	2010	2015	2020	2027
CCCT	5,280	15,360	23,040	46,080
SCCT	17,002	31,793	46,661	52,761
Pulverized coal	0	2,800	3,600	5,200
IGCC coal	0	0	2,550	11,900
IGCC coal w/ sequestration	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**24,936**	**61,629**	**100,228**	**151,484**

Figure 7.1: Oregon, Washington and Northern Idaho Resource Positions (GW)

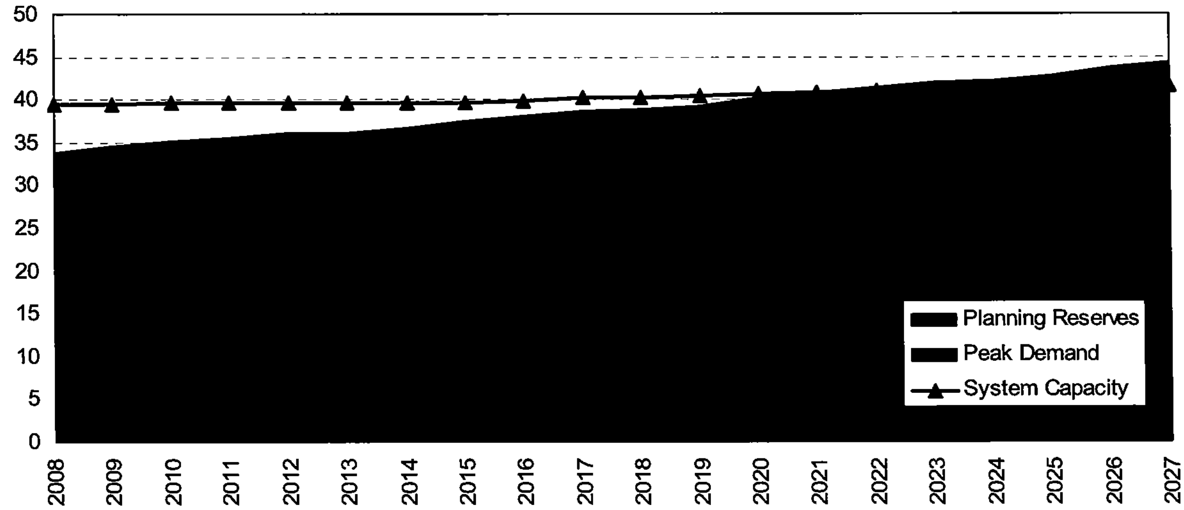
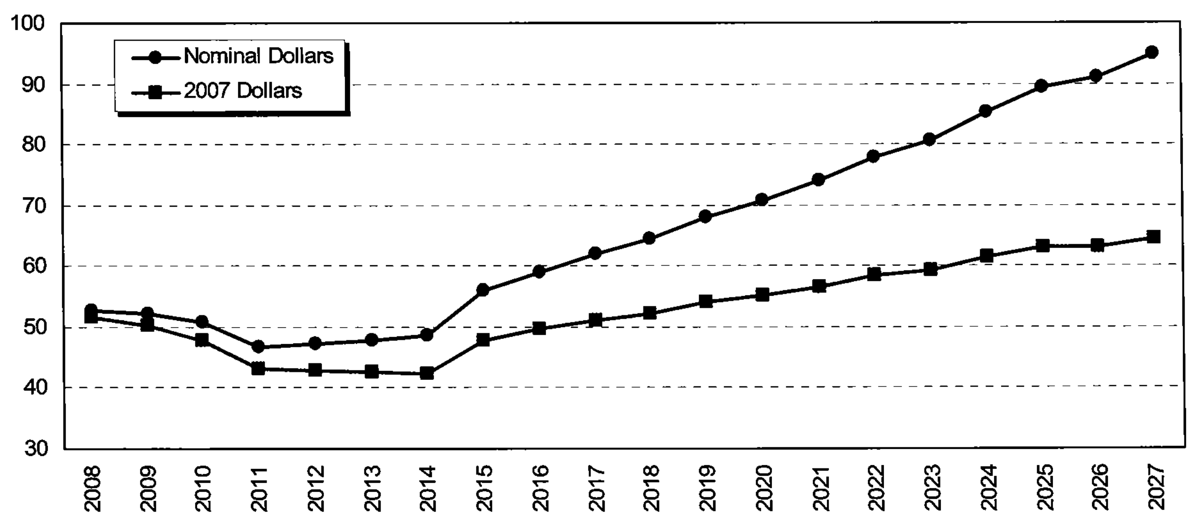


Table 7.3: Oregon, Washington and Northern Idaho Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	0	0	0	1,920
SCCT	0	0	0	540
Pulverized coal	0	0	0	0
IGCC coal	0	0	0	0
IGCC coal w/ sequestration	0	0	0	0
Wind (nameplate)	0	44	2,832	5,835
Other Renewables	150	261	1,017	1,871
Total Nameplate Capacity	**150**	**305**	**3,849**	**10,166**

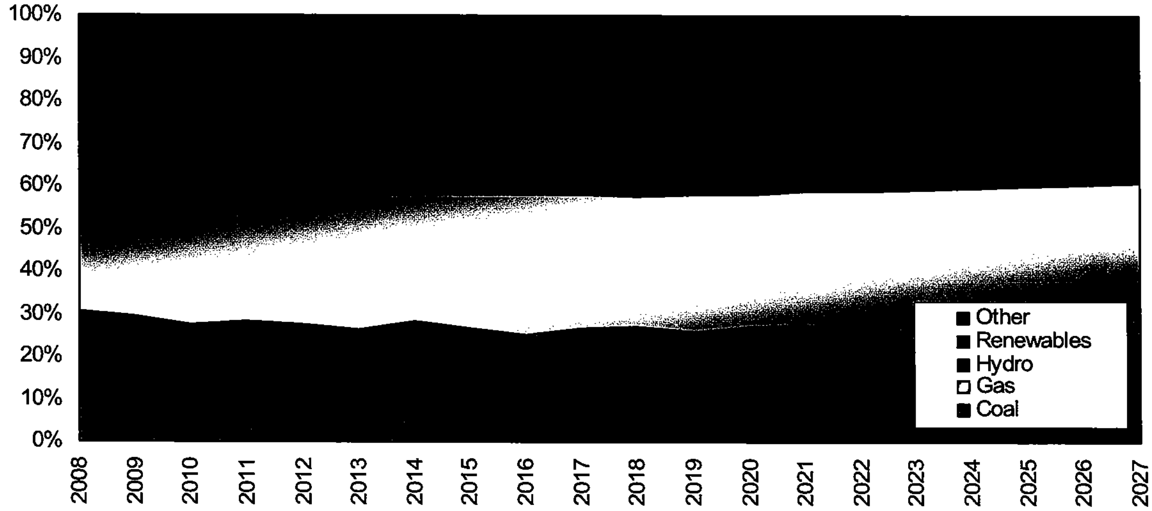
Figure 7.2: Mid-Columbia Electric Price Forecast ($/MWh)



load condition. Regional resource deficiencies begin in 2021, and the model begins non-RPS driven resource construction at this time. Table 7.3 shows new Northwest resources included in the Base Case.

Individual utilities with short positions are building additional resources even though the Northwest is in surplus. Some level of new resource construction is likely; however, utilities will probably cover at least a

Figure 7.3: Western Interconnect Resource Dispatch Contribution



portion of their needs by purchasing existing resources that presently are surplus to the region's needs. Regional resources not currently owned by local utilities will probably be less expensive and entail less acquisition risk than green field options.

Between 2008 and 2027, projected annual average power prices for the Mid-Columbia market are $51.25 in 2007 real dollars. Taking inflation into account, the cost of power is forecast at $60.26 in 2007 nominal dollars. Figure 7.2 illustrates the nominal and real price of Mid-Columbia power on an annual average basis. Prices are forecast to decline in real terms until 2015, and then rise with the imposition of carbon taxes and higher natural gas prices.

Natural gas plants are the primary source of new generation in the Western Interconnect forecast. Coal serves a large portion of load, though few new plants are built. Figure 7.3 illustrates how each resource category contributes to serving loads over the IRP timeframe.

Figure 7.2 shows expected annual prices, but each year likely will not experience average conditions or witness each of our modeling assumptions. The company conducts a stochastic study to quantify the risk of varying

Figure 7.4: Base Case Stochastic Mid-Columbia Prices ($/MWh)

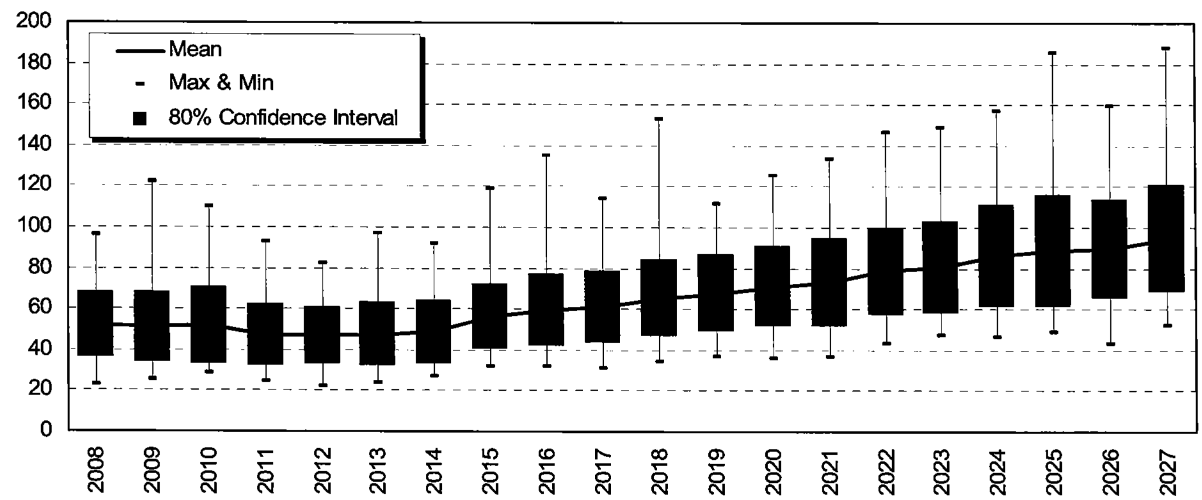
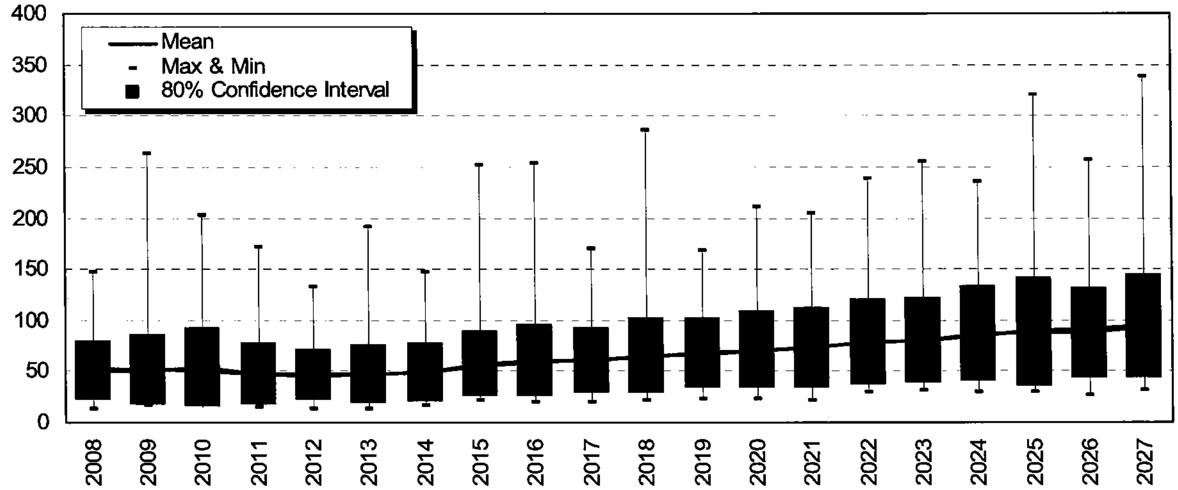


Figure 7.5: Volatile Gas Future Stochastic Mid-Columbia Electric Forecast ($/MWh)



future prices. Figure 7.4 shows average annual prices for the deterministic and stochastic studies. In past studies, including the 2005 IRP, stochastic results were slightly higher than deterministic results. In the current study, higher planning margins keep the stochastic mean at the same level as the deterministic values. There is an 80 percent probability that the 2008 annual average price at Mid-Columbia will be between $35 and $75. The figure also shows minimum and maximum annual average prices recorded across the stochastic Base Case study.

VOLATILE GAS FUTURE

To illustrate the potential for greater price volatility in the natural gas marketplace, a stochastic study assuming a more volatile gas distribution was developed. The standard deviation of expected natural gas prices was doubled to create more volatility. Figure 7.5 shows the results of the study. The 80 percent confidence level of 2008 prices increased by slightly more than 50 percent, to between $21 and $82 per MWh.

UNCONSTRAINED CARBON FUTURE

The Unconstrained Carbon future is identical to the Base Case, except that no carbon emission costs are included in the market forecast. Table 7.4 presents Western Interconnect resource selections under this future. Compared to the Base Case, the Unconstrained Carbon future builds the same quantity of resources, but the mix differs. This case selects fewer SCCTs and more coal-fired power plants.

This future shows that the National Commission on Energy Policy's proposed carbon mitigation strategy, included in the company's Base Case future, will not

Table 7.4: Unconstrained Carbon Future Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	2,400	15,360	23,040	48,000
SCCT	19,860	31,693	45,299	49,031
Pulverized coal	0	3,600	4,400	6,800
IGCC coal	0	425	6,375	11,900
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**24,914**	**62,754**	**103,491**	**151,274**

Figure 7.6: Unconstrained Carbon Future Mid-Columbia Electric Price Forecast ($/MWh)

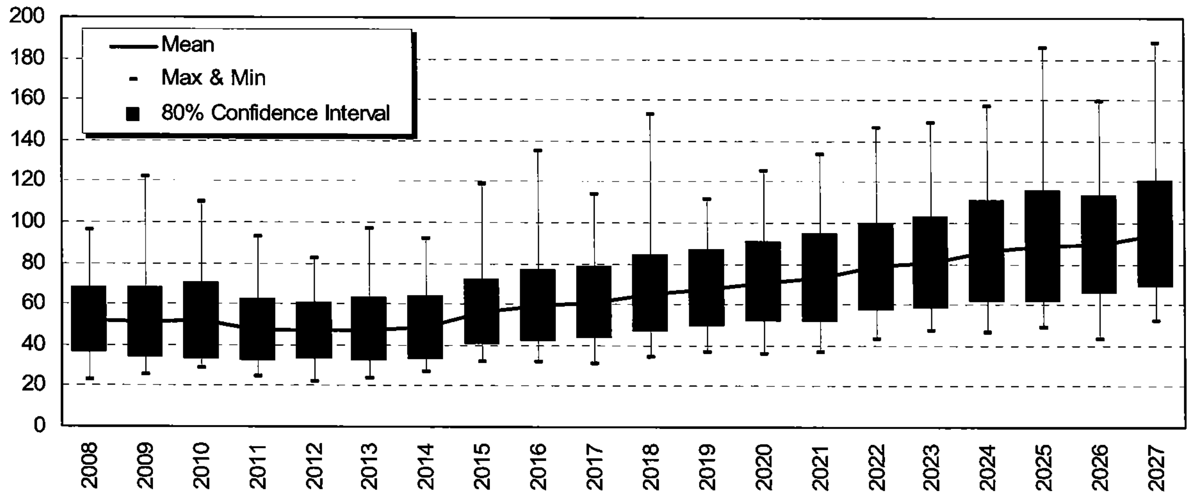


Table 7.5: CSA Carbon Charge Future, Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	6,240	12,000	23,520	46,560
SCCT	15,176	33,206	44,010	50,573
Pulverized coal	0	1,200	1,200	1,600
IGCC coal	0	0	0	2,975
IGCC coal w/ sequestration	0	0	1,203	5,213
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**24,070**	**58,082**	**94,310**	**142,464**

significantly affect the future resource mix, but it will increase electricity prices by approximately 7 percent, or $3.69 per MWh levelized real 2007 dollars, as shown in Figure 7.6.

THE CLIMATE STEWARDSHIP ACT OF 2005 (HIGH CARBON CHARGES) FUTURE

The Climate Stewardship Act of 2005 (CSA), otherwise known as the McCain-Lieberman Bill, was first introduced in the U.S. Senate in October 2003. This comprehensive plan was designed to reduce greenhouse gas emissions to year 2000 levels by 2010. The bill would reduce emissions through a market-based tradable allowance system patterned after the sulfur dioxide emissions permit market established by the Clean Air Act of 1990.

The company used the results of an EIA study of this bill for its High Carbon Charges future, as it is the most comprehensive analysis available. The CSA was used in this study as a proxy for all of the pending federal legislation. More up-to-date studies, or possibly federal laws and subsequent economic analyses, will be available and used in the Base Case for the 2009 IRP. Large carbon charges on electricity generating facilities will likely stop or severely restrict construction of new non-sequestered coal plants. In this future, utilities will probably rely most heavily on gas-fired resources, as shown in Table 7.5.

In this future, existing coal plants dispatch many fewer hours than in the Base Case, because carbon credits are more valuable than electricity generated by these plants.

Figure 7.7: CSA Carbon Charge Future: WI Resource Dispatch Contribution

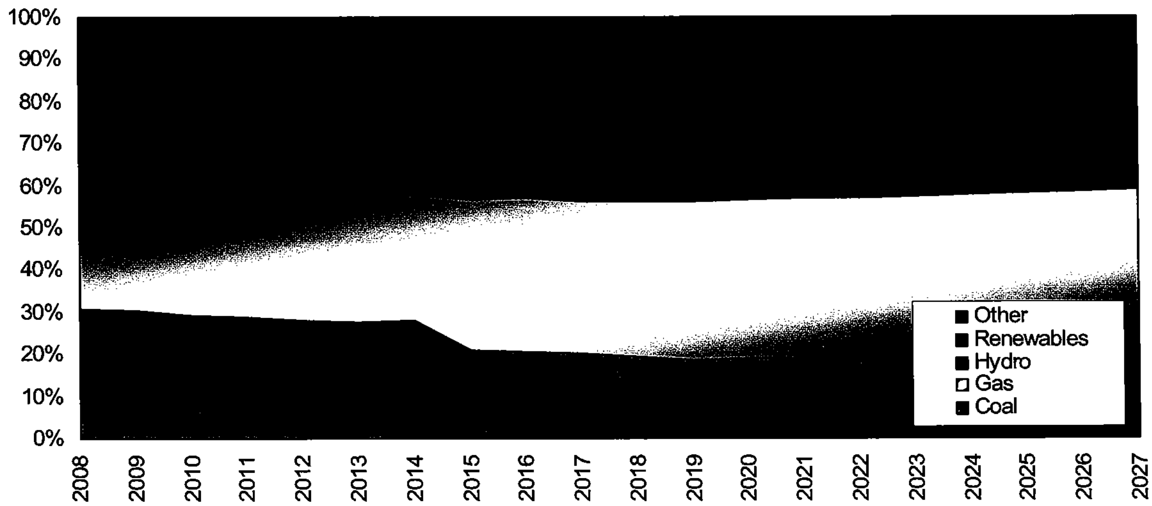


Figure 7.8: CSA Carbon Future, Mid-Columbia Electric Price Forecast ($/MWh)

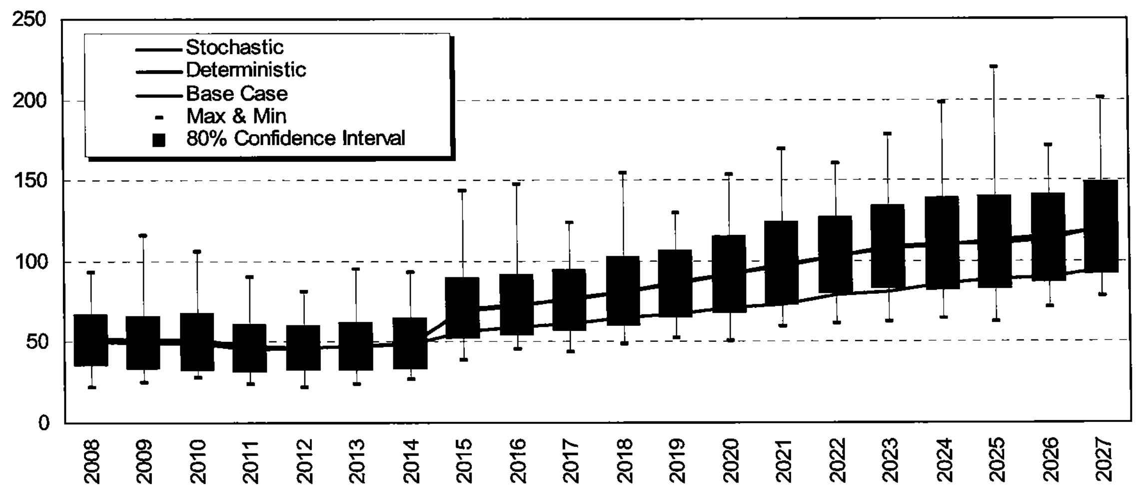


Figure 7.9: Western Interconnect Total Carbon with Different Futures (Million Tons of CO_2)

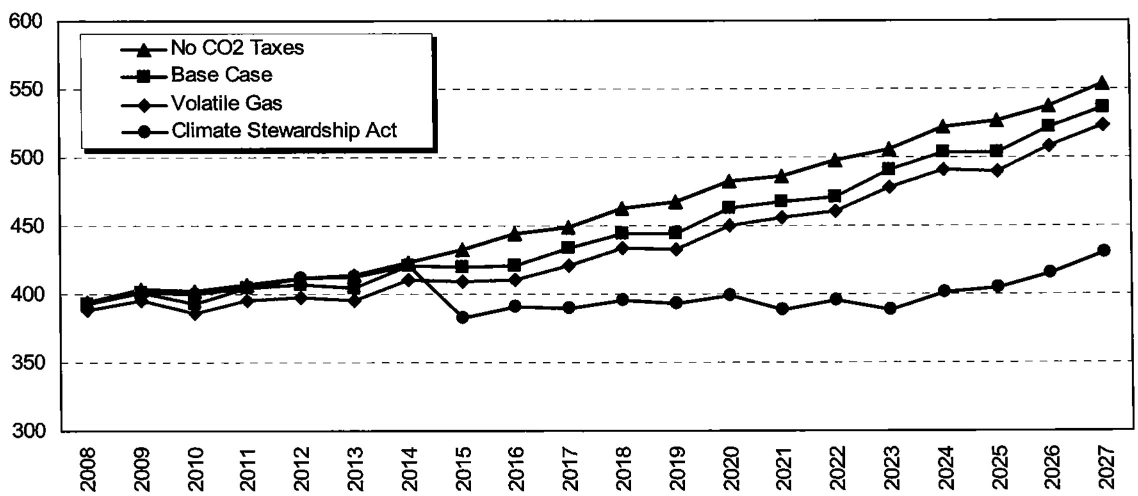


Table 7.6: Comparative Levelized Mid-Columbia Prices and Risk (Real 2007 Dollars)

Future	Mean	Standard Deviation	Coefficient of Variation	80% Confidence Range	
				Low	High
Base Case	$51.02	$12.23	24%	$35.35	$66.70
Volatile Gas	$51.02	$23.43	46%	$20.99	$81.05
Unconstrained Carbon	$47.38	$11.74	25%	$32.34	$62.42
Climate Stewardship Act	$58.63	$12.96	22%	$42.03	$75.25

Table 7.7: Comparative Levelized Mid-Columbia Prices and Risk (Nominal 2007 Dollars)

Future	Mean	Standard Deviation	Coefficient of Variation	80% Confidence Range	
				Low	High
Base Case	$60.13	$14.42	24%	$41.65	$78.61
Volatile Gas	$60.12	$27.62	46%	$24.72	$95.51
Unconstrained Carbon	$55.84	$13.83	25%	$38.11	$73.57
Climate Stewardship Act	$69.07	$15.28	22%	$49.50	$88.65

Figure 7.7 highlights a significant reduction in coal dispatch beginning in 2015 when carbon charges start.

Figure 7.8 illustrates the impact higher carbon charges would have on the Mid-Columbia price forecast. The chart shows that prices increase significantly in 2015 when the carbon charges begin.

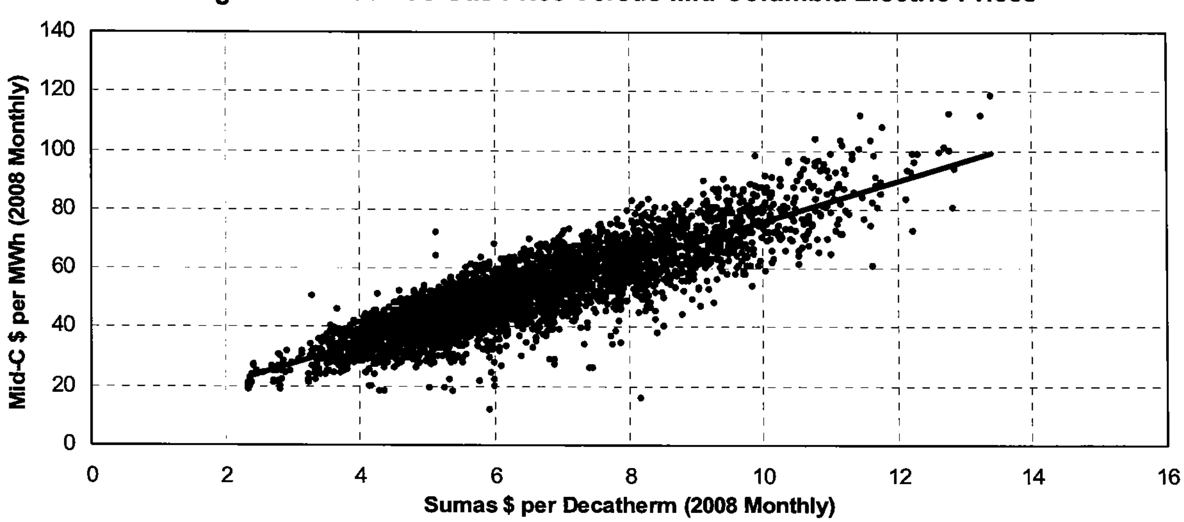
Higher carbon emission prices significantly decrease carbon emissions in the Western Interconnect when compared to the other futures. This reduction is illustrated in Figure 7.9.

FUTURES SUMMARY AND COMPARISON

The results of the futures analyses show that average electricity prices vary from the Base Case by as much as 15 percent. Tables 7.6 and 7.7 show levelized prices for each future in real and nominal 2007 dollars. Natural gas prices are a key volatility driver; though carbon charges push prices up, they do not significantly affect price volatility.

The company conducted a regression and correlation analysis to study natural gas price impacts on the electricity marketplace. The study was conducted for

Figure 7.10: Sumas Gas Price Versus Mid-Columbia Electric Prices



Equation 7.1: 2008 Natural Gas Price to Electric Price Regression Equation

$$PRICE_{2008} = 6.8436 * G + 7.2168$$

Where:

G is the estimated annual average 2008 Sumas natural gas price

Equation 7.2: 2016 Electric Price Regression Equation

$$PRICE_{2016} = 31.22 + 6.86 * G + 0.56 * C - 25.74 * H + 361.84 * D$$

Where:

G is the nominal Sumas natural gas price in 2016
C is the nominal carbon tax amount in 2016
H is an index of hydro conditions compared to average conditions
D is the annual average demand (load growth) for energy in the Northwest

calendar year 2008 and uses monthly Mid-Columbia electric and monthly Sumas natural gas prices for all 300 iterations of the Base Case. Figure 7.10 shows the high level of correlation, 86 percent, with 75 percent of the variation in electricity prices explained by variation in natural gas prices. See Equation 7.1 for the regression equation.

The regression equation shows that electricity prices will rise by $6.85 for each dollar change in natural gas prices. By including other independent variables, the regression equation is able to predict 99 percent of overall price volatility. Equation 7.2 identifies each additional variable's coefficient used to forecast the average annual electricity prices in 2016.

Table 7.8 provides annual average electric price estimates using the Base Case regression equation for each of the studied futures. The equation performs well at predicting electricity prices across the cases, even though the CSA future uses a different stochastic methodology to model carbon charges. Further work in this area could simplify future IRP analyses by limiting the number of stochastic futures run through AURORAxmp.

SCENARIOS

The 2007 IRP evaluates fewer scenarios than the 2005 IRP. Many of the market structure impacts from assumption changes were discovered by analysis of those cases and in the draft 2007 IRP. The following scenarios were studied for this plan:

- Constant natural gas prices,
- 20 percent decrease in gas price escalation,
- 20 percent increase in gas price escalation,
- Western Interconnect loads increasing 50 percent faster,
- Western Interconnect loads decreasing 50 percent slower,
- Nuclear plant availability beginning in 2015 and
- Electric car.

Table 7.8: Multiple Regression Coefficient Results

Variable (Nominal $)	Base Inputs	CSA Future	No CO_2 Tax
Sumas Natural Gas Price	$6.25	$6.25	$6.25
CO_2 Price	$8.88	$34.05	$0.00
Hydro Percent of Avg	100%	100%	100%
Annual Avg Load Growth	1.70%	1.70%	1.70%
Predicted Price	**$59.50**	**$73.56**	**$54.53**
AURORAxmp Price	**$59.44**	**$75.93**	**$52.26**
% Error	***0.1%***	***-3.1%***	***4.3%***

Figure 7.11: Natural Gas Forecasts, Constant Gas Growth Versus the Base Case ($/Dth)

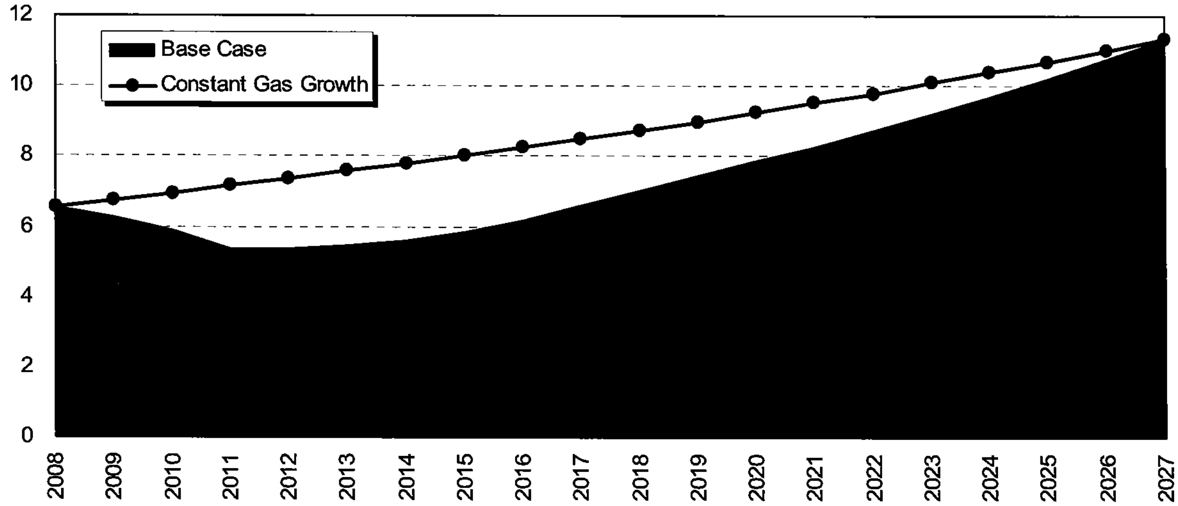


Table 7.9: Constant Gas Growth Scenario, Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	2,400	4,320	17,760	46,080
SCCT	18,339	34,645	44,680	52,556
Pulverized coal	0	4,000	4,000	4,400
IGCC coal	0	6,375	8,925	12,750
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**23,393**	**61,016**	**99,742**	**151,329**

Figure 7.12: Natural Gas Price Forecast Scenarios Versus the Base Case ($/Dth)

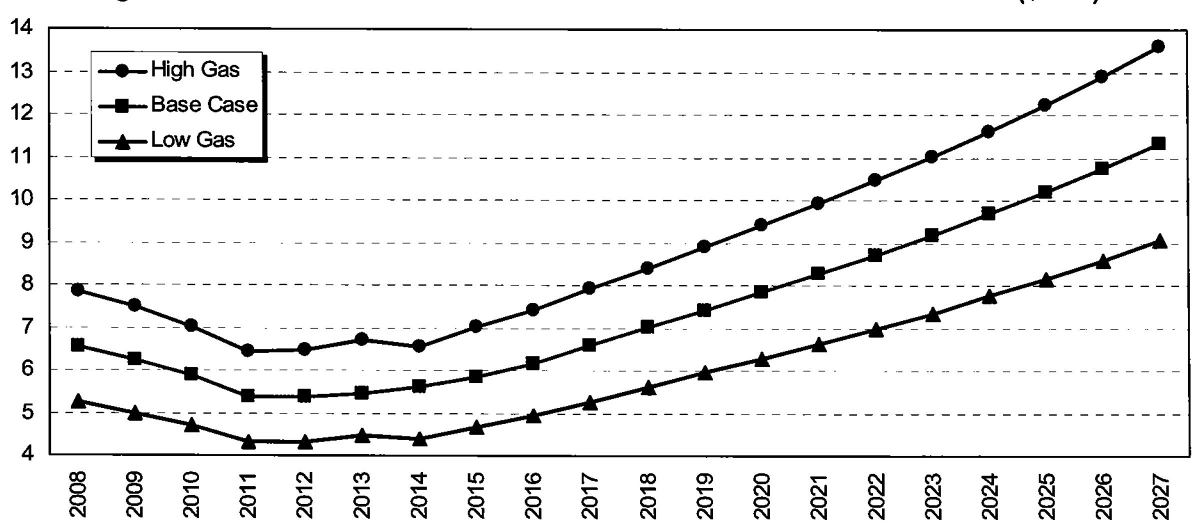


Table 7.10: High Natural Gas Price Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	5,280	14,400	20,640	39,840
SCCT	15,924	33,083	44,788	52,096
Pulverized coal	0	2,800	3,200	8,800
IGCC coal	0	2,550	7,225	16,575
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**23,858**	**64,509**	**100,230**	**152,854**

For comparative purposes, all market scenario Mid-Columbia prices are shown in the summary on in Table 7.19 later in this chapter. A detailed price forecast for each scenario, including scenarios studied for the draft IRP, can be found at the company's IRP website.

CONSTANT NATURAL GAS PRICES SCENARIO

This scenario illustrates the effect on electric prices and the Preferred Resource Strategy if gas prices do not fall for several years but continue to increase from the current price level. As discussed in Chapter 5, gas prices are forecast to fall from 2008 to 2012. Since the gas forecast relies on many assumptions, this alternative was studied to quantify the risk of gas prices continuing to rise throughout the forecast horizon. Figure 7.11 illustrates the scenario's gas price assumption and compares it to the Base Case forecast. Levelized gas prices rise from $6.85 in the Base Case to $8.19 in this scenario (nominal 2007 dollars).

Table 7.9 presents incremental resources selected to meet future loads in this scenario. Fewer combined-cycle plants are built early in the study compared to the Base Case. Gas-fired resources are replaced by coal-fired generation. The Mid-Columbia electricity price forecast from this scenario can be found in Table 7.17.

INCREASING AND DECREASING NATURAL GAS PRICE FORECAST SCENARIOS

High and low natural gas price forecasts would significantly affect resource planning. Figure 7.12 illustrates the natural gas prices used in these scenarios; prices are assumed to be 20 percent higher or lower than the Base Case forecast.

Table 7.11: Low Natural Gas Price Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	3,360	14,880	24,000	53,280
SCCT	19,087	34,162	47,307	54,564
Pulverized coal	0	400	3,200	4,000
IGCC coal	0	0	0	4,250
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	**25,101**	**61,118**	**98,884**	**151,637**

Table 7.12: Western Interconnect Average Demand (aGW)

Scenario	2008	2015	2020	2025
Base Case	102	116	129	143
High Load	103	126	147	172
Low Load	101	108	113	119

Table 7.13: High Load Escalation Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	9,120	22,080	45,600	112,320
SCCT	24,080	48,670	61,507	66,320
Pulverized coal	0	2,000	3,600	8,800
IGCC coal	0	0	7,650	16,150
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	35,854	84,426	142,734	239,133

Table 7.14: High Load Escalation Scenario: Change Cumulative Resources (%)

	2010	2015	2020	2027
CCCT	73	44	98	144
SCCT	42	53	32	26
Pulverized coal	0	-29	0	69
IGCC coal	0	0	200	36
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	0	0	0	0
Other Renewables	0	0	0	0
Total Nameplate Capacity	44	37	42	58

Table 7.15: Low Load Escalation Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	2,400	2,400	2,400	8,160
SCCT	12,140	21,680	28,443	35,052
Pulverized coal	0	2,000	2,800	3,600
IGCC coal	0	0	425	3,825
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	17,194	37,756	58,445	86,180

Table 7.16: Low Load Escalation Scenario: Change Cumulative Resources (%)

	2010	2015	2020	2027
CCCT	-55	-84	-90	-82
SCCT	-29	-32	-39	-34
Pulverized coal	0	-29	-22	-31
IGCC coal	0	0	-83	-68
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	0	0
Wind (nameplate)	0	0	0	0
Other Renewables	0	0	0	0
Total Nameplate Capacity	-31	-39	-42	-43

Tables 7.10 and 7.11 present the resources selected for each of the gas price scenarios. As gas prices increase, new coal generation increases and fewer resources are built. When gas prices decrease, fewer coal-fired and more SCCT plants are built relative to the Base Case.

INCREASING AND DECREASING REGIONAL LOAD SCENARIOS

Increases and decreases to Western Interconnect load growth will affect future market conditions. These scenarios were developed to provide a better understanding of how the market and resource mixes would change if higher or lower overall load growth patterns developed across the Western Interconnect. Table 7.12 compares these scenarios to the Base Case. Resources selected are similar to the Base Case, but more or fewer resources are added in the high and low cases, respectively.

Tables 7.13 through 7.16 show the absolute and percentage changes in the asset mix from the Base Case. Market prices are also similar to the Base Case, as seen in Table 7.19. These scenarios did not assume any adjustments to the RPS levels because the company does not believe this will significantly impact market prices or the value of resource options available.

NUCLEAR PLANTS SCENARIO

The Northwest has not considered nuclear plants as a viable new resource option for over 20 years. This scenario illustrates the market impact if new nuclear resources were available. Nuclear plants would not materially impact Mid-Columbia prices, assuming nuclear plant capital costs of $3,100 per kW.[1] Few new nuclear plants would be constructed at this high capital cost. The NPCC's Fifth Power Plan estimated nuclear capital cost to be $1,735 per kW.[2] Nuclear plants could significantly impact Mid-Columbia markets at this lower level. When one or more of the plants proposed in the Eastern U.S. are constructed, we should have access to better cost information. Table 7.17 presents the resources selected for the Nuclear Plant scenario. A single 1,100 MW nuclear plant was selected between 2015 and 2020; 13 nuclear plants were selected between 2020 and 2027 in this scenario.

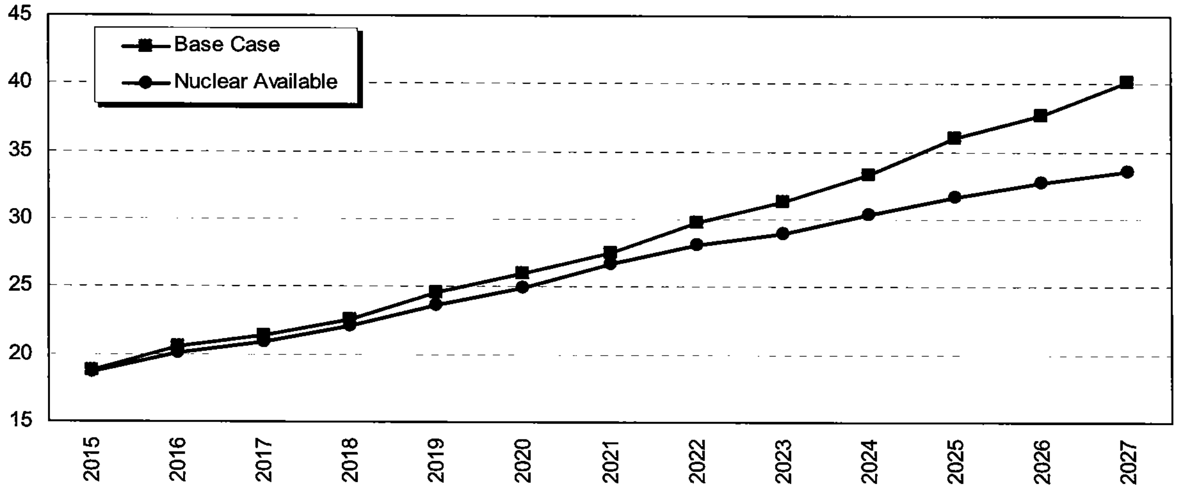
Nuclear plants would provide substantial fuel savings relative to the Base Case. Even though few nuclear plants are constructed because of high capital costs, fuel savings equal $10 billion net present value over 20 years. If more nuclear plants were constructed, the fuel savings would increase linearly. Figure 7.13 shows the fuel saving from the Base Case between 2015 and 2027.

Table 7.17: Nuclear Plants Scenario: Cumulative Resource Selection (MW)

	2010	2015	2020	2027
CCCT	5,280	14,400	19,680	32,640
SCCT	16,438	27,832	43,395	51,885
Pulverized coal	0	2,400	2,800	4,000
IGCC coal	0	0	4,675	10,625
IGCC coal w/ sequestration	0	0	0	0
Nuclear	0	0	1,100	15,400
Wind (nameplate)	2,016	9,499	20,046	29,086
Other Renewables	638	2,177	4,331	6,457
Total Nameplate Capacity	24,372	56,308	96,027	150,093

[1] This represents overnight costs.
[2] The NPCC 5th Power Plan estimates a nuclear plant to cost $1,450 per kW in 2000 Dollars.

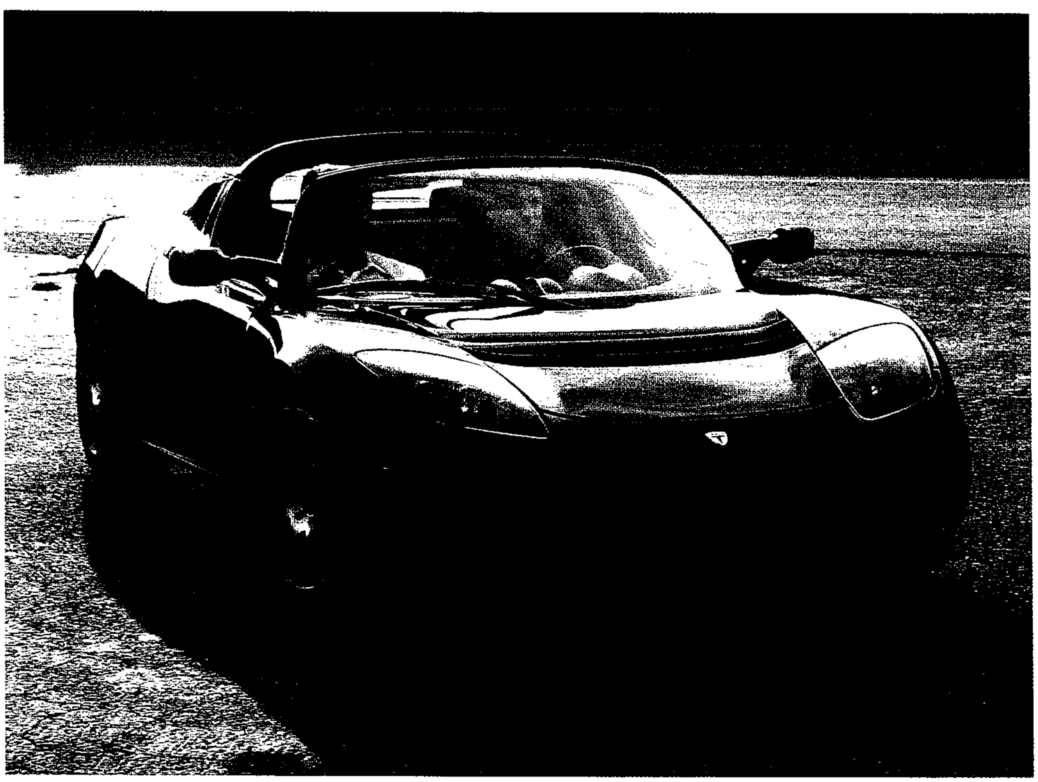
Figure 7.13: Western Interconnect Fuel Costs, Nuclear Beginning in 2015 (Nominal $Billions)



Lower fuel costs are not the only societal benefit of nuclear power; a commensurate reduction in greenhouse gases and other emissions would occur if nuclear power were added to the preferred resource mix. Figure 7.14 demonstrates that carbon emissions stabilize across the Western Interconnect as more nuclear plants come on-line in the nuclear scenario. While there are clear financial and societal benefits from nuclear power, the benefits are currently outweighed by capital cost uncertainties, waste management issues and other public policy considerations.

ELECTRIC CAR SCENARIO

Rising energy costs combined with concerns over the energy security of the United States have stimulated efforts to find alternatives to fueling transportation



The Tesla All-Electric Roadster Photo Credit: Tesla Motors

Figure 7.14: Western Interconnect Carbon Emissions (Million Tons of CO_2)

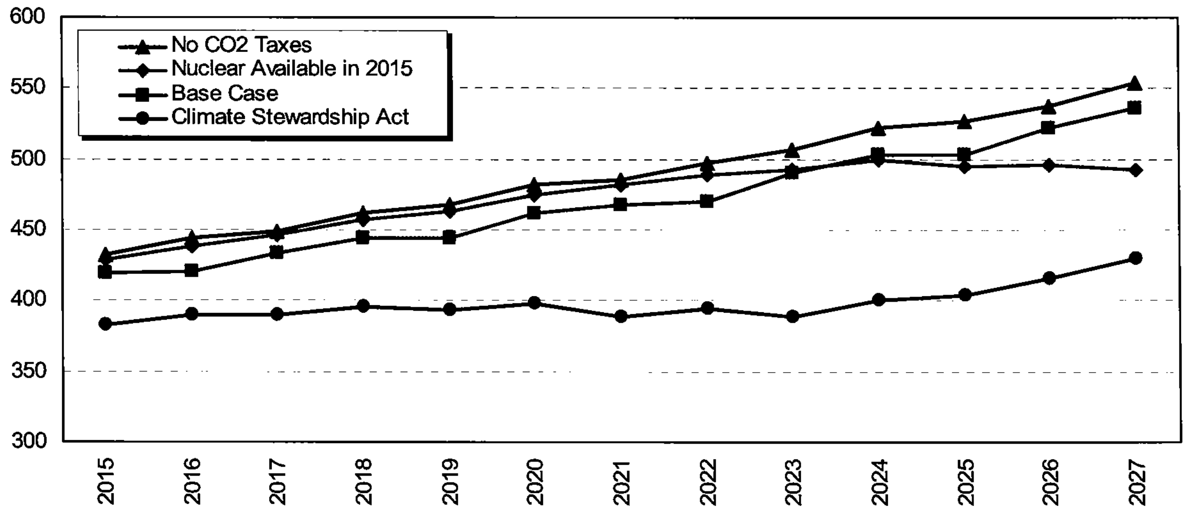
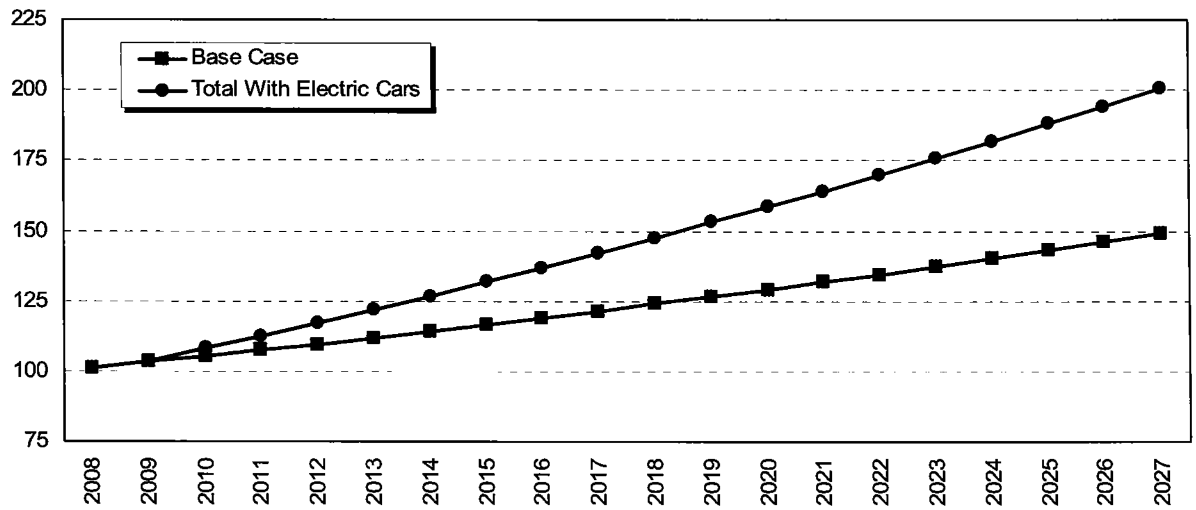


Figure 7.15: Impact of Electric Cars on the Western Interconnect (aGW)



vehicles with petroleum. There are many significant subsidies provided for hybrid cars, ethanol and bio-diesel production, and hydrogen fuel cells. Though significant, subsidies for hybrid cars arguably do not make them financially attractive to most buyers.

Properly designed, electric cars have the potential to help optimize electric system infrastructure. Some initial analyses have been completed, but to-date no study has attempted to holistically quantify the costs and benefits of converting the U.S. car and light truck fleet to all- or mostly electric fuel.[3]

Avista developed an Electric Car scenario to consider the potential benefits an electric car fleet might have on the U.S. power industry and how some or all of these benefits might be used to more rapidly transition the automobile industry toward electric-only or electric-hybrid technologies.

[3] Most other studies on electric vehicles are conducted in foreign countries and focus on social costs and benefits http://www.kfb.se/pdfer/R-00-46.pdf and http://www.cenerg.ensmp.fr/francais/themes/impact/pdf/ElecVehicle(Funk&Rabl1999).pdf. Estimates of the number of vehicles are assumed to be at the 1999-2003 annual rate of vehicle change taken from a recent Polk Company study.

Scenario Description

The Electric Cars scenario assumes that all passenger cars and light trucks across the Western Interconnect are fueled primarily with electricity by 2020.[4] The existing fleet is replaced or retrofitted entirely over this timeframe at a rate of 10 percent per year, a rate modestly lower than the natural replacement of vehicles in the United States.[5] An estimated 31.8 million electric passenger cars and 34.8 million electric passenger trucks and SUVs will be found in the Western Interconnect fleets by 2020. Each vehicle will travel an average of 12,500 miles per year and will consume a net (including charging losses) 0.22 kWh per mile, while heavier trucks and SUVs will consume 0.39 kWh per mile.[6] Figure 7.15 illustrates the incremental electric-car load.

Total estimated incremental electrical load in 2020 will equal 85.8 billion kWh (9.8 aGW) and 169.3 billion kWh (19.3 aGW) for cars and light trucks, respectively. This creates an increase in total Western Interconnect load of approximately 25 percent in 2020. Because the projected growth rate of electric vehicle purchases is higher compared to traditional electricity load growth, by the end of the study electric vehicles will consume one-third of all electricity. However, as future electric cars become more efficient, the growth trajectory of the new demand could become more gradual.

In addition to the benefits electric cars provide to non-utility interests, electric cars also provide a number of benefits from a utility perspective. The most obvious of these benefits is the ability to increase load factor, thereby raising the utilization of infrastructure and lowering per-unit delivered energy costs. Other utility benefits might be even more significant. The Western Interconnect electricity grid is currently comprised of approximately 200,000 MW of generating capacity. This study estimates that approximately 15 percent, or 30,000 MW, of this capacity stands ready to meet load requirements during extreme weather events or for back-up when larger plants experience forced outages. Except during these short intervals, this capacity sits idle. By 2027, capacity in the Western Interconnect will grow to 300,000 MW in the Base Case, with 45,000 MW held in reserve. Utilities also reserve generation capacity to follow intra-hour load and resource fluctuations. This study estimates that the Western Interconnect reserves 6 percent (12,000 MW today, 18,000 MW in 2027) of its capacity for reserve services.

"Raw" capacity—in other words, the portion of a peaking plant that cannot be recovered through energy sales over its lifetime—is assumed in this scenario to be worth $300/kW, or $45/kW-year in 2007 dollars. At this price, back-up capacity today costs the Western Interconnect approximately $1.3 billion annually. Regulation reserves at this price equal an additional $0.5 billion annually. Between 2010 and the end of the IRP study timeframe in 2027, total savings from reduced back-up and reserve capacity equals $25 billion on a present value basis.

An electric automobile fleet also would have the potential to assist the grid in managing wind integration. Recent studies confirm that wind generation consumes increasing amounts of generation flexibility. They show that wind integration costs range from $2 to $10 per MWh. This Base Case IRP future estimates that 35,000 MW of wind generation will be installed in the Western Interconnect by 2027, generating approximately 99.3

[4] Though this scenario focuses on the Western Interconnect due to modeling limitations, its results likely could be extrapolated across the U.S.

[5] 37BetterMotors states the average length of vehicle ownership in the U.S. is between 5 and 10 years. http://37signals.com/better_motors.php. Full Scrappage rate of passenger vehicles in the U.S. was 4.5 percent in 2005 according to Green Car Congress. http://www.greencarcongress.com/2006/02/us_vehicle_flee.html

[6] This baseline assumption of .22 kWh per mile comes from data released on the Tesla Roadster. A pro-rata increase based on vehicle weights was applied to SUVs and light trucks.

million MWh annually. The wind integration costs could vary between $0.2 and $1 billion. Between 2010 and 2027, the total value ranges from $1 to $5 billion.

Electric vehicles could eliminate the need for a majority of transportation-related gasoline and diesel fuel. This study assumed that gasoline and diesel prices average $3 per gallon, escalating at 3 percent annually through the forecast. Total fuel savings from the projected use of electric cars equal 3.6 billion gallons in 2010, rising to 48.0 billion gallons per year by 2020. Over the 2010 to 2027 period, total fuel savings equal approximately $986 billion dollars, net present value.

Transportation in the United States is responsible for roughly one-third of U.S. carbon dioxide emissions. Converting transportation vehicles to electricity should drastically reduce overall pollutant levels. Assuming a 50 percent reduction in carbon emissions, each electric vehicle would reduce carbon emissions by approximately 2.5 tons annually.[7] Valuing this savings at $10 per ton would provide a $25 benefit per year per vehicle. Over the IRP timeframe, using the Base Case CO_2 emission price would equal a CO_2 emission savings of $11.8 billion present value for the Western Interconnect.

Converting the Western Interconnect fleet of cars and light trucks to electricity would require significant new capital investments. This being said, the study's assumed the replacement rate falls below the natural rate of vehicle replacement in the United States; therefore, the only significant costs resulting from the conversion are the increased costs of electric vehicles versus traditional vehicles and the infrastructure necessary to provide for charging vehicles both at home and away.[8] Table 7.18 details the costs and benefits of the electric car scenario.

Electric vehicles have the potential to provide back-up capacity, reserves and wind integration services. Theoretically, each vehicle would be capable of providing more than 200 kW of instantaneous power to the electrical grid when connected. However, at this rate a vehicle would drain its batteries in approximately 15 minutes. A more conservative estimate for vehicle capacity is 10 kW for cars and 20 kW for light trucks and SUVs, the approximate charging rate of today's technology. At this rate of discharge, each vehicle could provide up to five hours of continuous grid support, though it is unlikely that the electricity industry would need even a fraction of this capability to support the grid. In total, electric vehicles could be capable of providing 1

Table 7.18: Electric Car Scenario Costs ($Billions)

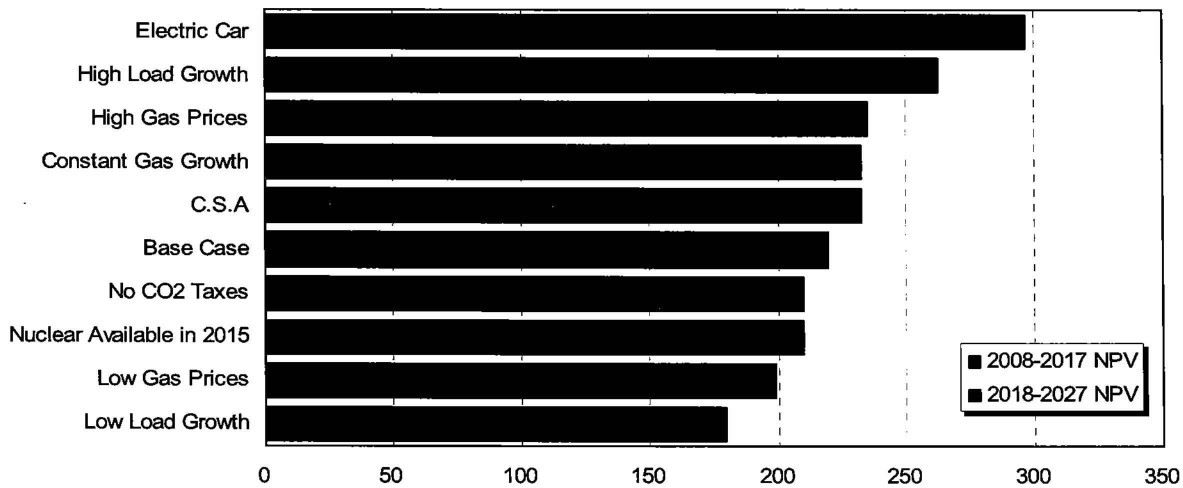
Item	Value
Back-Up Capacity	25
Reserves	10
Emissions	12
Wind Integration	2
Reduced Petroleum Consumption	986
Incremental Car/Truck Cost	-221
New Electricity System Infrastructure (new plants)	-32
Electricity Fuel and O&M	-83
Net Value	**699**
Electricity Industry Benefit	5%

[7] Emissions based on 2005 EIA study. http://www.eia.doe.gov/oiaf/1605/ggrpt/carbon.html. 50 percent reduction in emissions assumption based on 2006 study by Sherry Boschert featured in Plug-in Hybrids: The Cars That Will Recharge America.
[8] This study assumes that the cost of infrastructure for changing the automobile industry over to electric-fueled vehicles only is covered in the cost of those vehicles.

Table 7.19: Future and Scenario Market Price Comparisons ($/MWh)

Scenario	20-Year Levelized Prices Real 2007	20-Year Levelized Prices Nominal 2007	Calendar Year Prices 2010	Calendar Year Prices 2015	Calendar Year Prices 2020	Calendar Year Prices 2027
Base Case	51.25	60.26	50.79	55.91	70.69	94.86
Constant Gas Growth	58.46	68.82	59.18	69.12	78.45	105.35
High Gas Price	58.32	68.59	58.93	61.76	80.57	82.43
Low Gas Price	43.43	51.03	41.68	47.62	61.44	92.84
High Load Growth	51.57	60.65	50.63	57.37	71.76	94.39
Low Load Growth	50.22	59.05	49.45	54.47	69.76	92.84
Nuclear Available	50.43	59.29	49.38	54.89	69.76	93.87
Electric Car	56.37	66.26	52.03	65.32	81.63	99.65
C.S.A	59.24	69.46	49.42	68.90	92.29	119.89
Unconstrained Carbon	47.56	55.99	50.27	49.35	62.98	85.11

Figure 7.16: Comparison of Total Fuel Costs for the WI in 2017 and 2027 ($Billions)



million MW of grid capacity, approximately three times the total installed capacity of the Western Interconnect in 2020.

Each automobile could be fitted with a device that could respond to system frequency or other signals to allow charging to occur with the following order of preference: (1) meet customer need to maintain a "full tank" of fuel when needed and (2) provide a storage system to meet fluctuating changes on the electricity grid.

Charging is expected to occur mainly during lower-cost off-peak hours of the day, though customers would have the option of charging their vehicles at other times when necessary.

Impacts on the Larger Economy

The Electric Car scenario would have significant impacts on the utility, automobile manufacturing and automotive fueling industries. It would also impact infrastructure at consumers' homes and where they work and play. A number of assumptions are necessary to envision the impacts of the Electric Car scenario. This study is utility-centric and does not attempt to quantify all of the wealth transfers that might occur under the scenario. However, a return of more than one trillion dollars on an investment of $350 billion over 20 years is impressive.

FUTURES AND SCENARIOS SUMMARY TABLES AND CHARTS

A comparison of all of the futures and scenarios run for the 2007 IRP are contained in Table 7.19 below. Total fuel consumption is included Figure 7.16. The large increase necessary to support the Electric Car scenario is offset by even larger reductions in automotive fuel.

AVOIDED COSTS

Avista is obligated to purchase certain third-party generation under the Public Utility Regulatory Policies Act of 1978 (PURPA). Federal law states that such purchases will be at prices equal to avoided cost. State regulatory commissions implement PURPA provisions in their states.

PURPA developers whose projects exceed certain levels are eligible for a negotiated rate based on utility avoided cost, and published rates are provided for smaller PURPA facilities. In Washington, PURPA resources below one MW are eligible for published fixed-rate schedules up to a five-year term. The five-year schedules are tied to forward market prices. In Idaho, facilities up to 10 aMW may obtain published avoided cost rate for up to 20 years.

AVOIDED COSTS VERSUS THE WHOLESALE MARKETPLACE

There is some disagreement within the industry about what specifically constitutes avoided cost. In Idaho, administratively determined avoided cost rates use Avista's next lowest cost investment to set rates. The published figure explicitly includes the cost of installing capacity. In Washington, published rates are based entirely on the forward wholesale market price.

AVOIDED COSTS APPROACH

Avoided costs are a function of energy and capacity cost. Some resources, such as wind, provide little or no capacity. Most coal- and gas-fired plants provide both energy and capacity. Other resources, including hydro and peaking plants, provide a lot of capacity relative to their expected energy generation profile. Both capacity and energy have value. Energy is easily valued by electric market pricing such as the Mid-Columbia index, while capacity valuation is more difficult because there is not an active Northwestern capacity market.

Capacity traditionally has been valued at the cost to build a SCCT plant, even though this plant would provide some energy value over time. The IRP provides a better means of extracting capacity value using the PRSiM Model. As described in Chapter 6, the PRiSM model helps the company select new resources to meet future needs. All of the selected resource options are expected to cost more than the electric market price. The difference in cost between the Preferred Resource Strategy and the energy market price represents an avoided cost for capacity, and the subsequent lowering of future portfolio risk. Capacity value alone can be separated from risk by comparing the cost of the Preferred Resource Strategy to a mix of new resources that ignore portfolio risk.

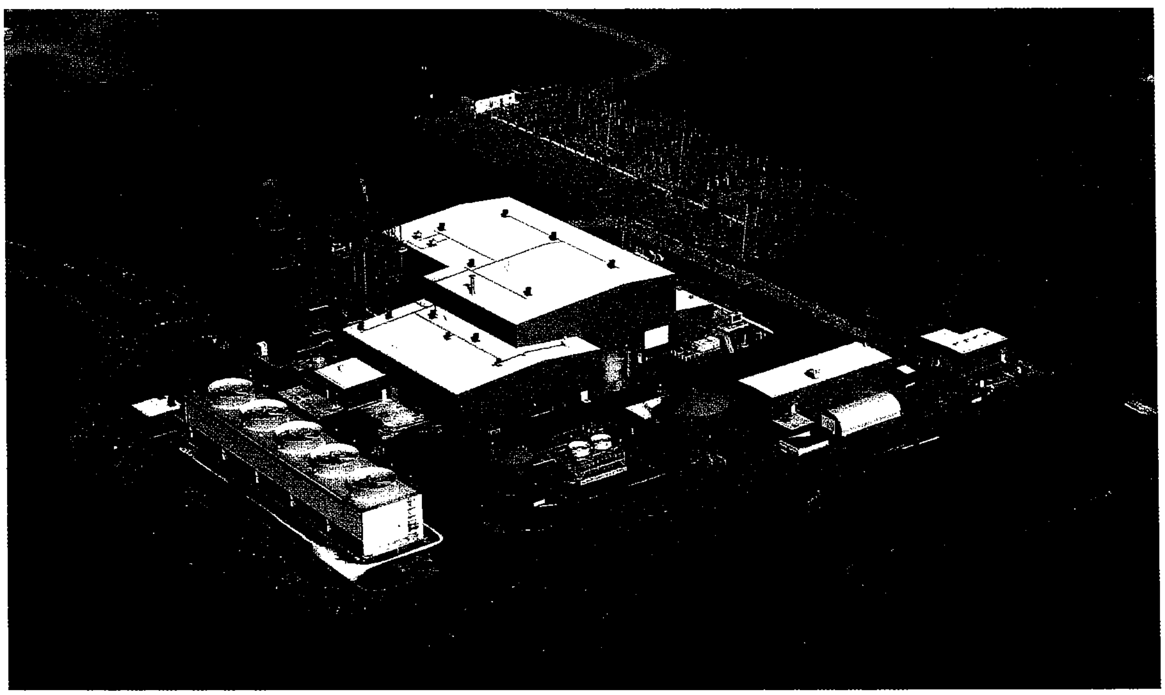
The lowest-cost portfolio is made up of simple cycle turbines and purchasing green tags to meet the Washington State Renewable Standard. This portfolio is expected to cost $9.32 per MWh over the market price, which represents the capacity value of new generation. The difference between the lowest-cost portfolio and the PRS indicates the value the company and its customers are placing on risk reduction. The risk reduction premium equals $9.39 per MWh. Where a PURPA resource provides both risk and capacity benefits on-par with the PRS mix, the avoided cost payment made under PURPA should equal the cost of the PRS. If a PURPA resource provides more or less value, the payment should be adjusted accordingly.

8. PREFERRED RESOURCE STRATEGY

INTRODUCTION

The 2007 Preferred Resource Strategy (PRS) differs substantially from the company's 2005 plan in three main areas: coal, renewables and gas-fired plants. Avista is no longer willing to rely on traditional coal-fired technologies to meet future customer needs. This reflects recent emissions standards legislation in Washington, imminent federal carbon limiting legislation and higher coal-fired generation costs. There is a lower contribution from wind and other renewables due to: (1) recent legislation promoting renewables in Washington and Oregon that has reduced the amount of cost-effective renewables available by increasing demand for such resources, and (2) wind generation costs have more than doubled over the past six years and increased more than 50 percent since the 2005 IRP. The final change is that natural gas-fired plants have returned to the PRS. Gas resources have not increased as significantly as the other resource options.

The charts and tables presented in this chapter focus on the first 10 years of the plan, as these years are the most relevant for developing our near-term acquisition strategy. All IRP studies were based on 20-year analyses.



Lancaster Generation Facility

CHAPTER HIGHLIGHTS

- Capital costs for coal and wind generation have increased drastically over the past two years; this greatly affects our future plans.
- Coal-fired generation in previous plans is replaced entirely with gas plants.
- Preliminary analyses show that fixed-price gas contracts can reduce year-to-year rate volatility substantially; the PRS "hedges" the portfolio with fixed-price gas even though costs are higher.
- Fewer renewables meet our future loads due to tightening market conditions.
- Conservation acquisition is 25 percent higher than in the 2005 plan and 85 percent higher than in the 2003 IRP.
- The PRS includes 350 MW of gas, 300 MW of wind, 87 MW of conservation, 38 MW of hydro plant upgrades, and 34 MW of other renewables by 2017.
- Lancaster, a currently running CCCT plant, will be available to the utility in 2010.

The result is a PRS that relies primarily on natural gas generation, wind and other renewables. The elimination of coal from our future, combined with reduced contributions from renewable resources opens the possibility of more power supply cost volatility relative to the 2003 and 2005 plans. The costs of these more price-stable resources simply were too high relative to other options. In the absence of a new strategy our customers will be forced to bear this rising volatility. Fortunately, there appears to be an affordable option to reduce the volatility of gas-fired generation resources. We are hopeful that long-term fixed gas contracts will reduce overall volatility. Make special note of Figure 8.13 later in this chapter and consider the superior risk profile of the PRS relative to the "PRS-No Fixed Gas" portfolio. Power supply expenses are reduced significantly for a modest increase in average power supply expense by "locking in" a significant portion of our natural gas supply under long-term contracts. There is a more in-depth discussion of how the company might fix its gas prices for the long term later in this chapter.

The 2007 IRP finds that recent legislation promoting renewables and reducing greenhouse gases and other emissions has driven power supply expenses and customer rates higher than they would be absent these mandates and will continue to do so. While sensitive to and concerned about higher costs that translate into higher rates, we do not oppose society's desire to reduce its impact on global warming and diversify power production away from carbon-emitting sources. This plan simply is intended to inform our management, investors, regulators and customers of the costs of complying with new environmental mandates.

PRiSM DECISION SUPPORT SYSTEM MODEL

As with the 2003 and 2005 IRPs, we continue to use our decision support system software (PRiSM) to help guide resource planning decisions. This differs from the traditional approach many utilities undertake in which a simplified set of resource portfolios is developed to illustrate the impacts of one resource decision over another.[1]

The PRiSM model brings together the value of Avista's existing portfolio of resources, its load obligations and resource opportunities available to meet future load requirements. To capture the optionality inherent in each

Table 8.1: Resource Options Available to Avista for the 2005 and 2007 IRP, First 10 Years

2005 IRP	2007 IRP
Simple-Cycle Gas	Simple-Cycle Gas
Combined-Cycle Gas	Combined-Cycle Gas
Sub-Critical Pulverized Coal	Wind
Critical Pulverized Coal	Biomass
Super-Critical Pulverized Coal	Geothermal
IGCC Coal, Not Sequestered	Cogeneration
IGCC Coal, Sequestered	
Alberta Oil Sands	
Nuclear	
Wind	
Biomass	
Geothermal	
Cogeneration	

[1] The company still develops portfolios, both to illustrate the benefits and costs of certain resource decisions and for comparison to the Preferred Resource Strategy portfolio selected by PRiSM.

of these categories, the results from of the 300 Monte Carlo AURORAxmp runs are considered. Capital, transmission and fixed operations and maintenance costs attributable to each new resource option are evaluated.

PRiSM reviews our existing portfolio and selects an optimal mix of new resources from the available options. A more in-depth discussion of the PRiSM model, and its inputs and outputs, may be found in Chapter 6.

CHANGING POLITICAL ENVIRONMENT

The 2007 IRP responds to major state and federal policy changes to reduce greenhouse gas emissions and encourage development of renewable energy sources. Avista moved away from natural gas-fired resources in its 2005 IRP because of the fuel's inherent price volatility. Recent trends and legislation, such as Washington's Senate Bill 6001 (SB 6001), prevent the company from entering into any long-term financial commitment for resources that exceed a greenhouse gas emissions performance standard of 1,100 lbs/MWh. The bill provides for the standard to be lowered even further after 2012, making compliance even more costly. The emission performance standard effectively precludes the company from acquiring any new pulverized coal plant or a long-term contract with an exiting one, and therefore compels us to rely on natural gas resources. Table 8.1 illustrates the increasingly limited resource options available to Avista in this plan.

These limitations stem primarily from new and expected mandates at the state and federal levels. In the State ofWashington, limitations have come from Citizen's Initiative 937 (Energy Independence Act, or I-937), SB 6001, Executive Order No. 07-02 (Washington Climate Change Challenge) and the Western Regional Climate Action Initiative signed by the governors of five Western states. Collectively, the legislation and order seek to decrease greenhouse gas (GHG) emissions, increase employment levels in green energy resources, reduce fuel imports and increase overall renewable generation levels. Oregon has similar renewable and emissions goals and laws in place or in development. Other states throughout the Western Interconnect are also developing or have already enacted GHG reductions and renewable portfolio standards. No RPS or carbon emission standard presently exists in Idaho.

There is a strong regional and national push toward developing a market-based GHG reduction program. It involves several competing cap-and-trade legislative proposals in Congress, as well as an effort to design and implement a regional mechanism to achieve GHG reduction goals. It is also apparent that Congress may enact renewable portfolio standards in the near future. This IRP assumes that there will be GHG constraints and models its Base Case on policy recommendations contained in the National Commission on Energy Policy December 2004 report.

The combination of actual and pending state and national legislation creates considerable uncertainty and novel resource conditions and challenges. First, while the company anticipates that federal GHG and RPS legislation will eventually become law, we can neither accurately predict the final form of these measures, nor can we determine if problems may arise from complying with state and federal mandates governing the same subject matter. At this time, the company can only make general assumptions about future regulatory requirements, with two exceptions: Washington state's I-937 and SB 6001. Second, competition and demand for renewable generating assets has increased substantially since the 2005 IRP, as will be discussed later. That competition is principally a factor of five circumstances:

- RPS requirements, including the accelerated compliance schedule for California's RPS law,
- political considerations associated with pending climate change policies, which, for example, impel RPS-exempt municipal utilities in California to

acquire renewable generating assets even in the absence of applicable mandates,

- the need for resource diversity to mitigate utility exposure to volatile natural gas,
- the ambition of electric utilities to acquire the most economical wind generation sites before they are purchased by competitors, and
- uncertainty about the renewal and duration of federal tax incentives.

Heightened competition for renewable resources has caused a dramatic increase in their cost. Short-term renewals of the federal production tax credit (PTC) also exacerbate the supply and demand balance for wind power as developers try to finish projects before the PTC expires. Lastly, legislation impacts the availability of resources available to serve utilities' retail loads.

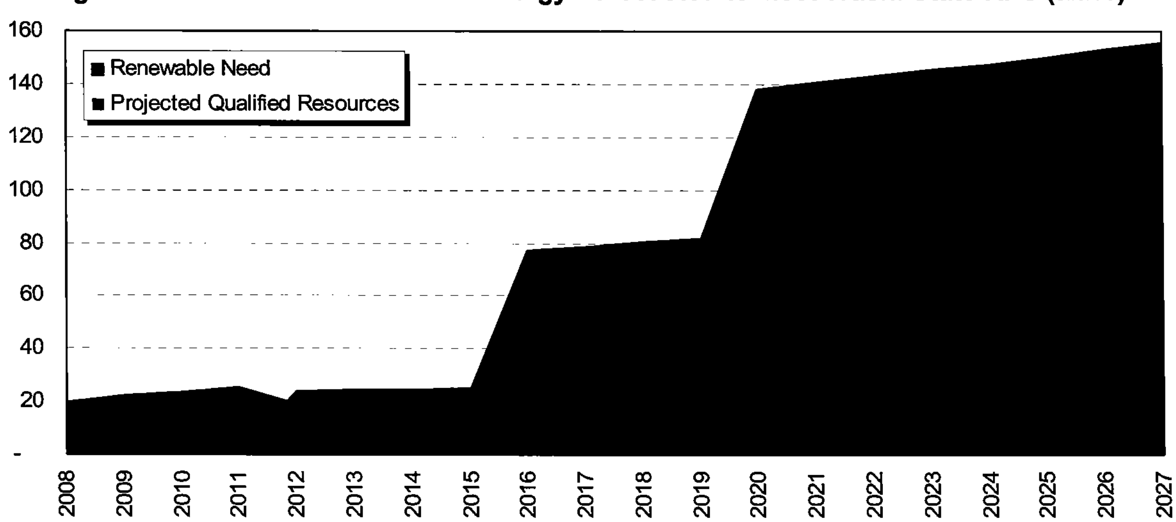
Traditional coal-fired generation provides stable, cost-effective energy that meets more than half of current U.S. power needs. It also emits a tremendous amount of carbon dioxide (CO_2) relative to other generation options. For every MWh a coal-fired plant generates, it emits approximately one ton of CO_2. This is a level three times higher than from gas-fired CCCT plants. In a carbon-constrained economy, traditional coal-fired generation will become expensive as these generators scramble to acquire carbon offset credits, weigh the reduced value of generation against the value of selling carbon offsets into a tight marketplace, or install carbon mitigation technology. Coal-fired technology is also significantly more expensive than forecasted in the 2005 IRP.

WASHINGTON STATE RPS

The passage of I-937 requires all Washington state electric utilities with more than 25,000 customers to acquire new "eligible renewable resources" to meet 3 percent of their energy needs by 2012, 9 percent by 2016, and 15 percent by 2020. Figure 8.1 demonstrates Avista's incremental renewable resource needs. In 2016 more than 80 aMW of I-937 qualifying renewable resources are needed; if met by wind resources alone, it would require Avista to build approximately 240 MW of nameplate capacity. If non-wind renewables options such as biomass or geothermal can be acquired at an attractive price, the required renewable resource capacity will be approximately 90 MW.

Wind generation has thus far proven to be the most commercially viable technology for meeting RPS requirements. It is necessary to acknowledge the

Figure 8.1: Amount of Renewable Energy Forecasted to Meet Wash. State RPS (aMW)



limitations of relying on wind for these purposes. The American Wind Energy Association (AWEA) ranks Washington state 24th in the nation for wind energy potential. Specifically, AWEA estimates the state's annual wind energy potential to be 3,740 MW. By comparison, Montana is ranked fifth with 116,000 MW of annual potential. Montana has approximately 10 times the combined wind potential of the states of Washington, Idaho and Oregon combined. Unfortunately Montana's wind power potential exists east of the Rocky Mountains and therefore is not an "eligible renewable resource" under I-937. This limitation makes compliance more difficult than it otherwise might be. Transferring wind energy generated in eastern Montana westward is also hindered by a present lack of transmission and integration capacity.

The Fifth Power Plan, published by the Northwest Power and Conservation Council (NPCC), estimates the potential wind power capacity of the Pacific Northwest to be approximately 6,000 MW. The NPCC acknowledges that this potential will have a capacity factor between 28 and 30 percent. Most of the economically viable and readily developable wind power sites in the region have already been or are in the process of being acquired. As Pacific Northwest electric utilities proceed to comply with RPS mandates, they will be forced to compete for a diminishing pool of cost-effective wind power sites and to do so within governmentally-mandated periods of time. This is a recipe for even higher renewable resource costs and retail prices in the future.

The limited economic availability of renewable resources poses planning and regulatory challenges for Avista. While we are committed to meeting the requirements of I-937, we are cognizant of the near-term cost impacts of those requirements. The company is also concerned about the potential financial ramifications of failing to proceed expeditiously to acquire renewable resources, lest their cost continue to rise compared to alternative resources. This planning uncertainty is compounded by I-937, which challenges the conventional regulatory paradigm. This law dictates the company's "need" to acquire renewable energy or renewable energy credits. Though the purchase of renewable energy credits would enable the company to comply with I-937, it does not afford us any certainty about meeting renewable energy standards in perpetuity. Renewable energy credit purchases might delay the acquisition of renewable resources to a point in time when those resources are more expensive still.

DECREASED RELIANCE ON RENEWABLE RESOURCES

The 2005 IRP recommended the acquisition of nearly 500 MW of renewable resources between now and 2016, and 750 MW by 2026. Wind resources at that time, though not expected to be inexpensive, were competitive with other options. Other renewable technologies, including geothermal and biomass, were slated to make up nearly 20 percent of the renewable resources contribution in the 2005 plan. The company identified its overall renewables acquisition strategy as a stretch goal.

Wind plant costs have increased by approximately 50 percent since the 2005 plan, a trend that the 2005 IRP identified as then beginning to occur. As described earlier, several factors including RPS requirements have dramatically increased demand for renewable resources. Both higher costs and lower availability have reduced the expected contribution of renewable resources over the first 10 years of the plan from 500 MW in the 2005 plan to below 350 MW (300 MW wind) in this plan; no additional wind is selected, where the 2005 IRP included an additional 350 MW of renewable resources.

To ensure the company has a RPS-compliant portfolio, it is likely that resources will need to be acquired prior to the traditional load and resource balance metric.

Obtaining resources in an environment with significant competition has already resulted in a scramble to obtain the best resources. The company will consider turnkey or power purchase agreements, as well as investing in potential renewable energy sites for future development. We will also consider purchasing qualifying renewable energy credits to meet our statutory obligations.

NATURAL GAS PLANTS RETURN TO THE RESOURCE MIX

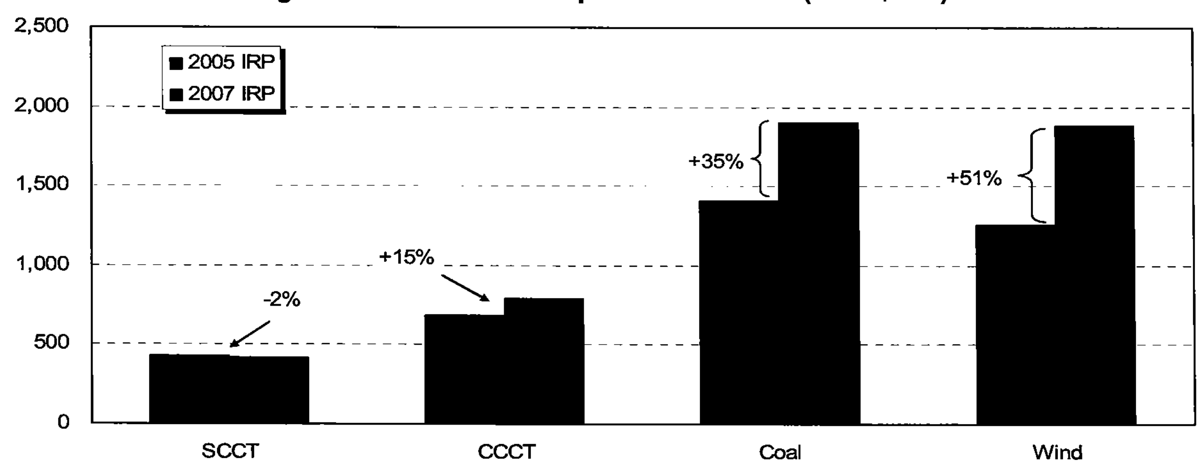
Natural gas prices rose drastically between the 2003 and 2005 plans. Compared to other resource options, namely traditional coal-fired resources, natural gas became both costly and volatile. With a high contribution by wind and other renewables, natural gas was not selected in the 2005 plan. Conditions are different today. Natural gas-fired plant costs have not risen as significantly as other options. In addition, traditional coal-fired technologies are not available to the company in this planning exercise due to recent legislative changes in Washington state. Figure 8.2 compares capital cost assumptions of various resource options in the 2005 and 2007 IRPs.
Rising capital costs make gas-fired generation more attractive because it is a less capital-intensive resource than coal, wind or other renewable options. CCCT generation was forecast in the 2005 IRP to cost approximately $59 per MWh (real levelized 2007 dollars), while the lowest-cost coal-fired option was approximately $42.[2] The 2007 IRP forecasts equivalent costs to be $62 and $61 per MWh for CCCT and Montana-based coal plants, respectively. The gas-fired CCCT cost rose a modest 5 percent overall, even though its capital costs are 15 percent higher than in the 2005 plan; the overall cost increase was lower than the capital cost increase. Coal-fired generation moved in the opposite direction, rising almost 50 percent compared with a 35 percent capital cost increase. Gas represents a comparatively more attractive resource today than it was in 2005, even absent changing social policies.

Though potentially representing a more volatile future when compared to the 2005 PRS, the absence of traditional coal-fired technologies and fewer cost-effective renewables in the 2007 IRP leave natural gas as the major new resource. The 2007 Preferred Resource Strategy includes nearly 350 MW of natural gas-fired CCCT plants in the first 10 years.

DEMAND-SIDE CONSERVATION PROGRAMS UP 25 PERCENT

The 2005 IRP increased DSM by 50 percent over the 2003 IRP, primarily in response to rising market and supply-side resource costs. Studies developed by our conservation groups find approximately 25 percent

Figure 8.2: Generation Capital Cost Trends (2007 $/kW)



[2] Excluding emission costs.

more conservation potential in 2007 than in 2005. The avoided costs against which conservation options are compared continue to rise. As explained above, resource alternative costs are higher in the 2007 IRP. This raises the value of energy saved by conservation measures. Additionally, the 2007 IRP recognizes other factors for the first time that increase the value of this resource; namely capacity value, risk reduction, transmission and distribution savings. These additional factors are inherent in the selection of supply-side resources. The application of new analytical techniques enables the company to assign values for these benefits. Refer back to Chapter 3 for a detailed discussion of the methods we employed and the values assigned to these new benefit categories. The company forecasts it will acquire 87 aMW of conservation over the next decade, thereby reducing the need for new supply-side resources.

SUPPLY-SIDE CONSERVATION EFFORTS CONTINUE

The company continues to explore ways to increase the generation it receives from existing resources and the efficiency with which it is delivered. Upgrades at our Cabinet Gorge and Colstrip plants have increased generation by approximately 20 MW since the 2005 IRP. The company has evaluated numerous upgrade options at its hydroelectric projects over the past two years. This plan incorporates upgrades to the Noxon Rapids hydroelectric project, increasing generation capacity by 38 MW. Future upgrade evaluations will be made considering the same new factors being applied to the conservation resource options.

PREFERRED RESOURCE STRATEGY

SUMMARY AND COMPARISON TO 2005 IRP

The PRS includes wind, other renewable resources, combined-cycle combustion turbines, and supply- and demand-side efficiency improvements. Table 8.2 provides the quantity and timing of proposed resources for the first 10 years of the plan. Comparing this strategy to the 2005 IRP, shown in Table 8.3, this plan moves away from coal toward gas-fired resources, scales down wind due to rising capital costs and lowers the amount of expected capacity from other renewables. More conservation is acquired.

Another key difference between this plan and the 2005 plan is that the first new base load resource enters service

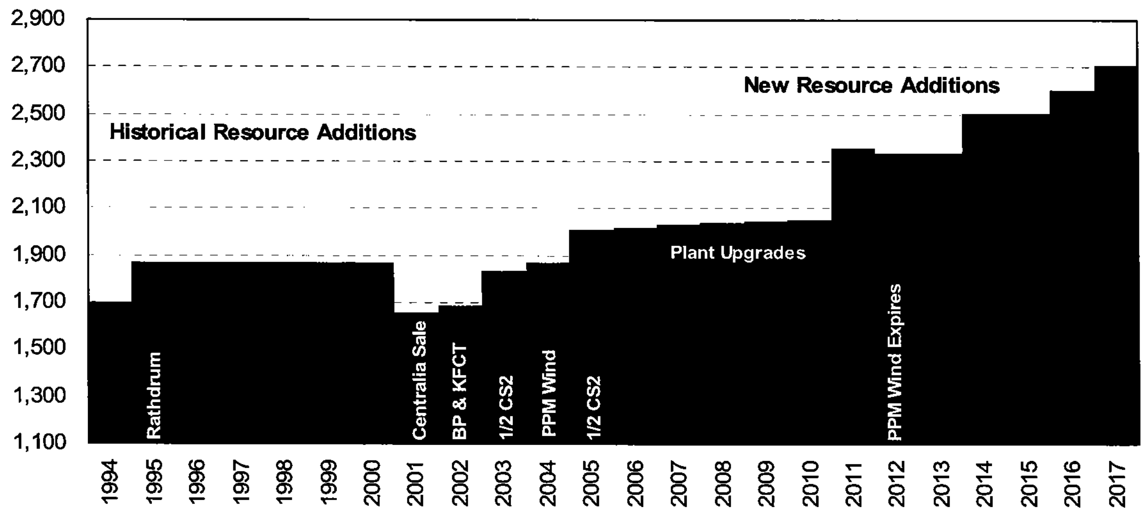
Table 8.2: 2007 IRP Preferred Resource Strategy Selection (Nameplate MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CCCT	0	0	0	280	280	280	350	350	350	350
Coal	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	100	100	200	300
Other Renewables	0	0	0	20	30	30	35	35	35	35
Conservation	6	13	20	27	36	46	56	66	76	87
Total	6	13	20	327	346	356	541	551	661	772

Table 8.3: 2005 IRP Preferred Resource Strategy Selection (Nameplate MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
CCCT	0	0	0	0	0	0	0	0	0	0
Coal	0	0	0	0	250	250	250	250	250	250
Wind	0	0	75	150	200	250	325	400	400	400
Other Renewables	0	0	10	20	30	40	50	60	70	80
Conservation	7	14	21	28	35	42	49	56	63	70
Total	7	14	106	198	515	582	674	766	783	800

Figure 8.3: Historical and Future Nameplate Capacity Acquisition (MW)



in 2011 rather than 2012. The 2005 IRP assumed that a coal resource would not be available until 2012, so the 2011 deficit was filled with short-term contracts until that resource was available. This IRP selects a natural gas plant to meet the 2011 shortfall.

RESOURCE ACQUISITION IS LUMPY

PRiSM does not select the Preferred Resource Strategy; rather it informs the utility on the resources that should be selected. The exact PRiSM strategy cannot be used because the model selects resources in perfect quantities to meet resource deficits. It also lacks the ability to quantify all of the experience of Avista's management team. Actual resource acquisition will likely not be so perfect and will be acquired in a lumpy, or stepwise, pattern. Figure 8.3 shows historical and future resource acquision. This chart shows that the company traditionally adds resources in blocks; at times the company has been able to acquire shares of a plant to reduce the dependence on large plant acquision. Figure 8.4 shows the total amount of resources selected by PRiSM's 25/75 risk/cost strategy compared to the PRS. The key difference is that resources added between 2011 and 2013 by PRiSM are added in 2011 as a single block. Resource selections in the second 10 years of the plan are not changed from the PRiSM model selection. Acquisitions in this timeframe will be quantified in future plans. Later in this chapter the PRS will be

Figure 8.4: Lumpy Resource Acquisition (MW)

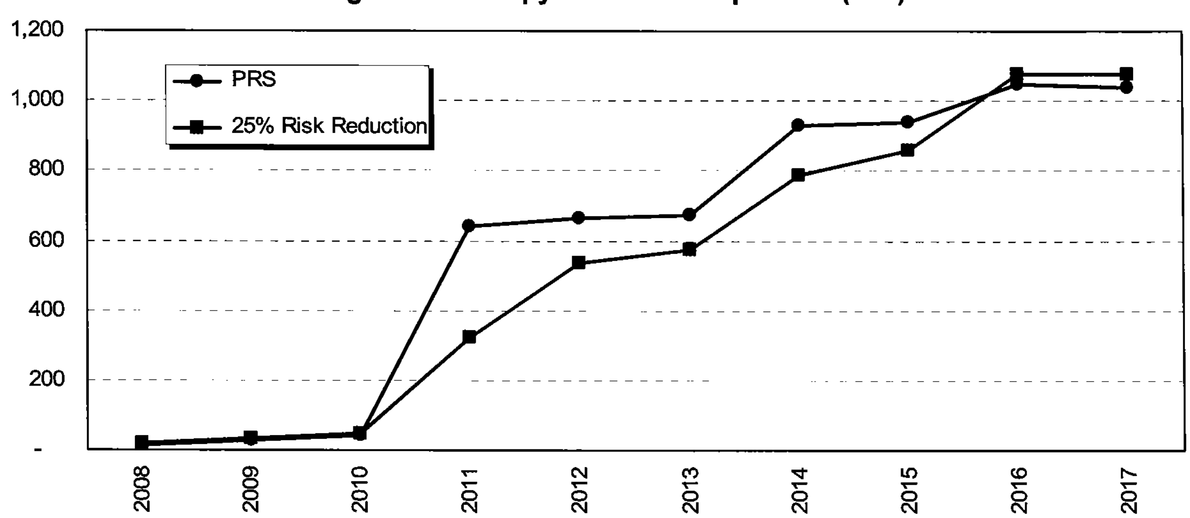


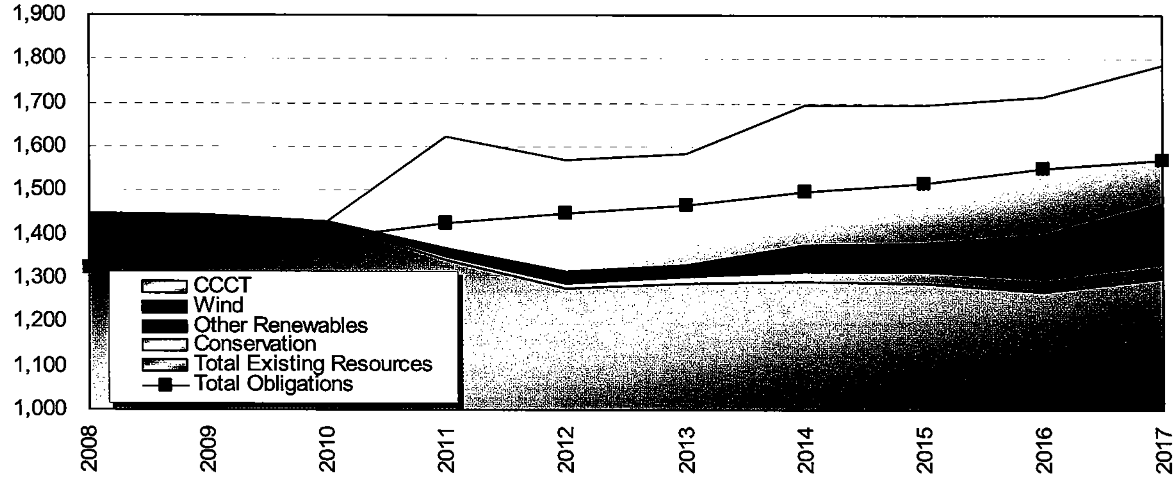
Table 8.4: Loads & Resources Energy Forecast with PRS (aMW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,125	1,163	1,196	1,230	1,256	1,326	1,379	1,450	1,627
90% Confidence Interval	200	199	196	196	192	192	192	156	156
Total Obligations	***1,324***	***1,362***	***1,392***	***1,425***	***1,448***	***1,518***	***1,571***	***1,606***	***1,783***
Existing Resources									
Hydro	540	538	531	528	512	510	509	491	491
Net Contracts	234	234	234	129	107	105	105	106	106
Coal	199	183	188	198	187	187	198	199	186
Biomass	47	47	47	47	47	47	47	47	47
Gas Dispatch	280	295	285	295	280	295	295	280	295
Gas Peaking Units	145	145	141	146	145	146	145	141	145
Total Existing Resources	***1,446***	***1,442***	***1,426***	***1,342***	***1,278***	***1,290***	***1,299***	***1,265***	***1,270***
PRS Resources									
CCCT	0	0	0	253	253	316	316	389	612
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	33	103	103	103
Other Renewables	0	0	0	18	27	32	32	41	54
Conservation	1	3	5	7	11	26	37	54	103
Total PRS Resources	***1***	***3***	***5***	***279***	***291***	***406***	***487***	***587***	***871***
Net Positions	122	82	38	196	121	179	215	246	359

Table 8.5: Loads & Resource Capacity Forecast with PRS (MW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,703	1,763	1,815	1,868	1,909	2,019	2,103	2,214	2,492
Planning Margin	260	266	272	277	281	292	300	311	339
Total Obligations	***1,964***	***2,029***	***2,087***	***2,145***	***2,190***	***2,311***	***2,404***	***2,525***	***2,831***
Existing Resources									
Hydro	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,070	1,070
Net Contracts	172	172	173	73	58	58	208	128	128
Coal	230	230	230	230	230	230	230	230	230
Biomass	50	50	50	50	50	50	50	50	50
Gas Dispatch	308	308	308	308	308	308	308	308	308
Gas Peaking Units	211	211	211	211	211	211	211	211	211
Total Existing Resources	***2,111***	***2,123***	***2,092***	***1,999***	***1,939***	***1,954***	***2,104***	***1,996***	***1,996***
PRS Resources									
CCCT	0	0	0	280	280	350	350	431	677
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0
Other Renewables	0	0	0	20	29	34	34	44	59
Conservation	1	3	5	7	11	26	37	54	103
Hydro Upgrades	0	0	0	0	0	0	0	0	0
Total PRS Resources	***1***	***3***	***5***	***307***	***321***	***410***	***421***	***530***	***839***
Net Positions	**149**	**97**	**10**	**161**	**70**	**53**	**122**	**0**	**4**
Planning Margins (%)	**24.0**	**20.6**	**15.5**	**23.4**	**18.4**	**17.1**	**20.1**	**14.1**	**13.8**

Figure 8.5: Loads & Resources Energy Forecast with PRS (aMW)



compared to other resource portfolios created by PRiSM. In these comparisons the PRS will be represented by the 25/75 risk/cost portfolio to ensure an apples-to-apples comparison (i.e., not biased by lumpiness).

LOAD & RESOURCE TABULATIONS

Preferred Resource Strategy resources balance the company position over time, retaining the lowest possible cost and risk mix of assets to meet customer needs. Table 8.4 and Figure 8.5 illustrate how our present energy positions will be supplemented with PRS resources to meet future load growth. Table 8.5 and Figure 8.6 illustrate the same information for our capacity positions.

The PRS affects the company's mix of resources over time. Today energy needs are met with a mix of resources that is approximately two-thirds fueled by hydro and natural gas. These resources will contribute approximately the same level of energy in 2017; however, hydroelectric generation will fall from 35 percent in 2008 to 29 percent in 2017. Remaining needs in both periods are met by coal, contracts, conservation and renewable energy sources.

Hydro in 2008 represents approximately 50 percent of the company's generating capacity. Gas- and coal-fired plants account for approximately 25 percent and

Figure 8.6: Loads & Resource Capacity Forecast with PRS (MW)

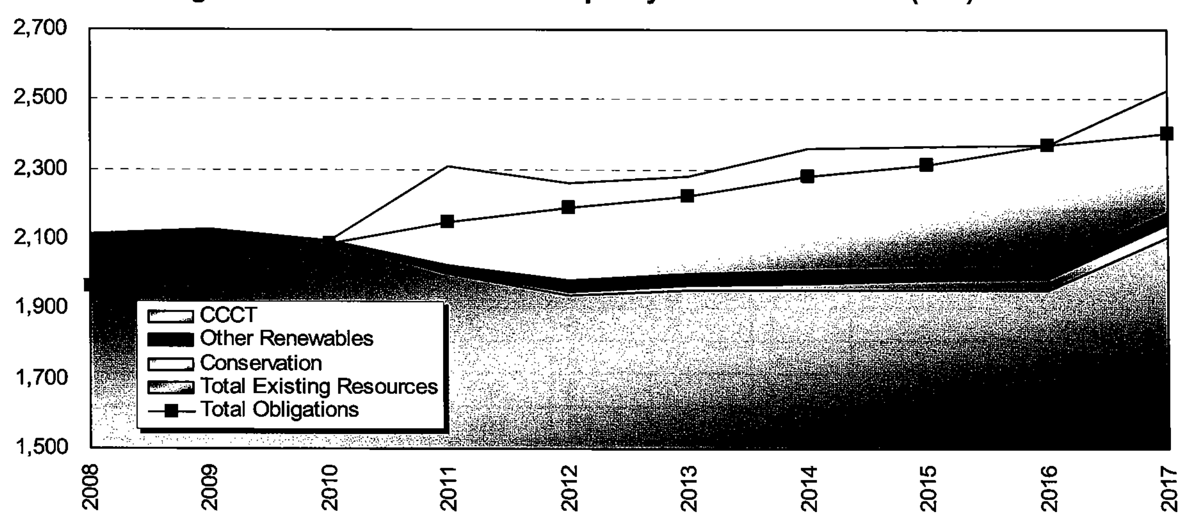


Figure 8.7: Company Resource Mix (% of Energy)

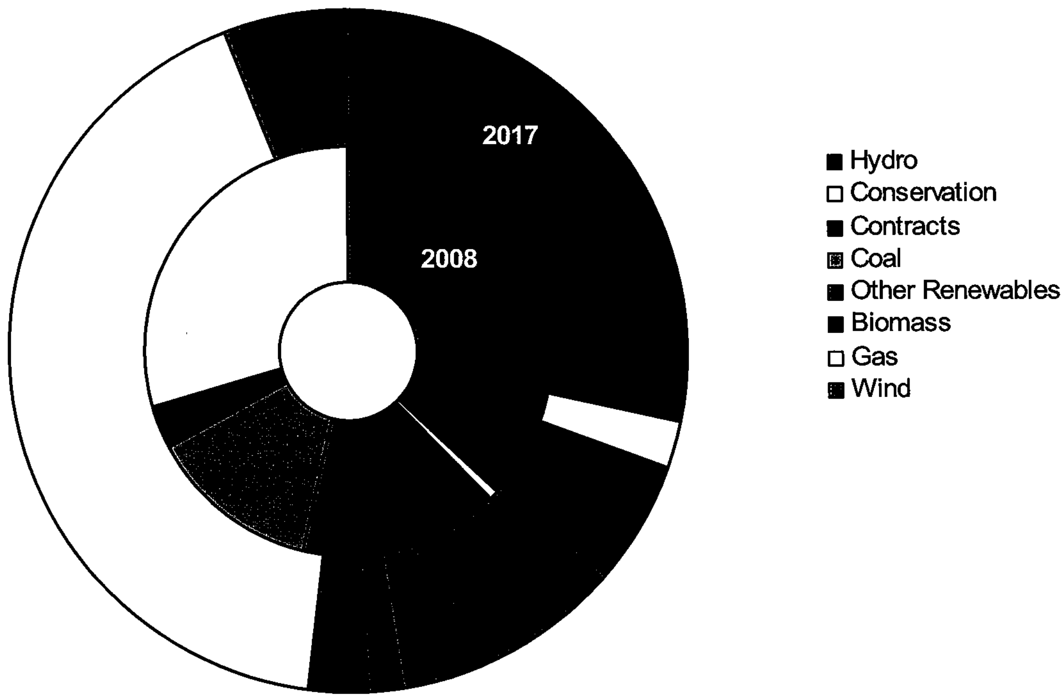
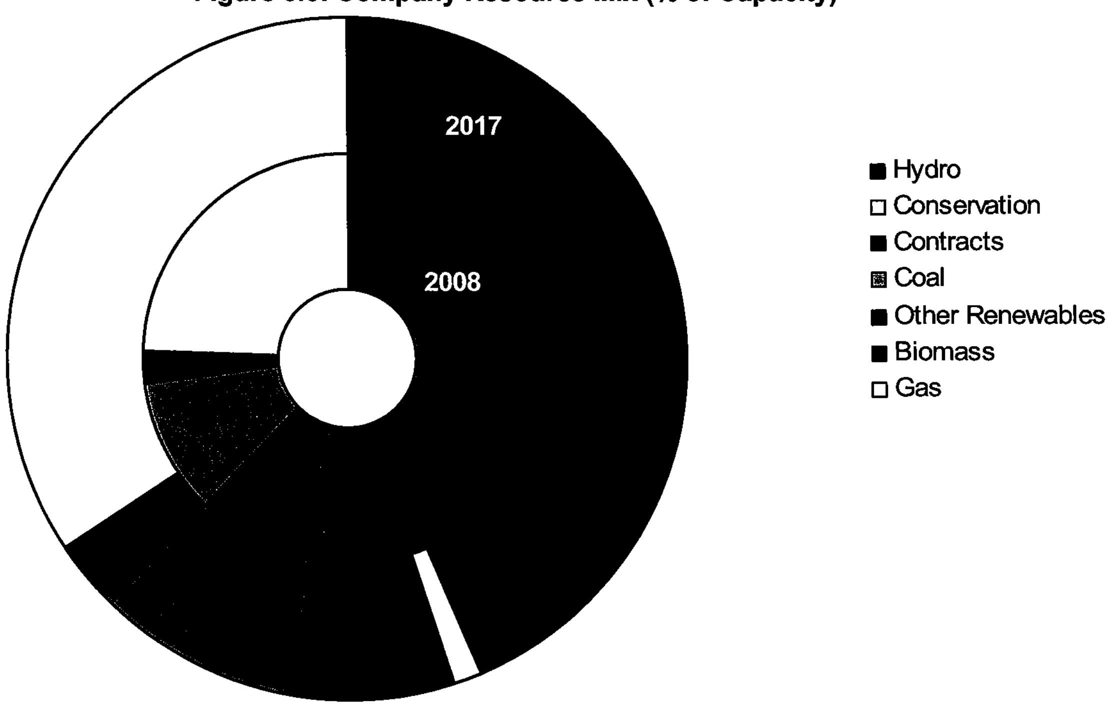


Figure 8.8: Company Resource Mix (% of Capacity)



10 percent, respectively. Contracts and non-hydro renewables complete the capacity mix. The 2017 resource mix is more heavily weighted toward gas-fired generation, as our hydro base does not grow and wind generation is not included in our capacity tabulation. See Figures 8.7 and 8.8 for charts of energy and capacity mixes in 2008 and 2017.

CAPITAL REQUIREMENTS OF THE PREFERRED RESOURCE STRATEGY

PRS capital requirements equal approximately $782 million between 2008 and 2018. This amount could increase by as much as 50 percent when the company finds that the best method for acquiring fixed-price gas involves investments in gas fields, a coal gasification facility and/or other capital-intensive strategies. Table 8.6 illustrates the annual capital investments necessary to support the PRS absent investments in fixed-price gas.

ANNUAL POWER SUPPLY EXPENSES AND VOLATILITY

Power supply expenses including fuel, variable O&M and carbon compliance will grow over time at a compounded annual rate of 9 percent between 2008 and 2017; however, market conditions will likely affect this rate of growth, making some years higher and some lower. This level might appear high to the casual reader, but this figure does not equate to changes in retail rates. Retail rate effects will be mitigated by higher retail sales and lower escalation in non-power supply portions of our business. The IRP forecasts that the average PRS change on per-MWh power supply costs will equal 6.8 percent per year. This increase should translate into even lower retail rate impacts, as non-production costs are expected to increase at a slower rate. Figure 8.9 illustrates forecasted annual power supply expenses from 2008 through 2017.

The trade-off for rising power supply expenses is lower year-on-year volatility. Power supply expense risk decreases as new resources are brought on-line. Figure 8.10 illustrates the falling trend in risk measured by the coefficient of variation of power supply expenses.[3]

CARBON FOOTPRINT

The company has one of the smallest carbon footprints in the United States because of its renewable energy resources. Of the top 100 producers of electric power in the 2006 Benchmarking Air Emissions study by the Natural Resources Defense Council, only seven other utilities have a smaller carbon footprint. The company's carbon footprint is forecast to increase over the IRP timeframe, as it would be nearly impossible to acquire all future resource requirements from non carbon-emitting resources. Our per-MWh emissions will remain essentially flat, and the carbon intensity of our thermal fleet will fall as natural gas plants are added. Figure 8.11 forecasts our carbon footprint explaining that our resources will emit approximately 2.5 million tons of carbon dioxide in 2008, rising to 3.75 million tons by 2017. Figure 8.12 illustrates our emissions on the basis of total sales, total generation, and thermal plant generation. The 2007 PRS emits approximately 6 million fewer tons

Table 8.6: Company Resource Capital Requirements ($ Millions)

Year	Investment	Year	Investment
2008	4.9	2013	60.3
2009	27.3	2014	270.6
2010	98.4	2015	37.5
2011	247.9	2016	249.8
2012	36.2	2017	218.7
		Net Present Value	781.9

[3] Coefficient of variation is calculated as the standard deviation of power supply expense divided by the expected (mean or average) power supply expense in each study year.

Figure 8.9: Annual Power Supply Expense ($Millions)

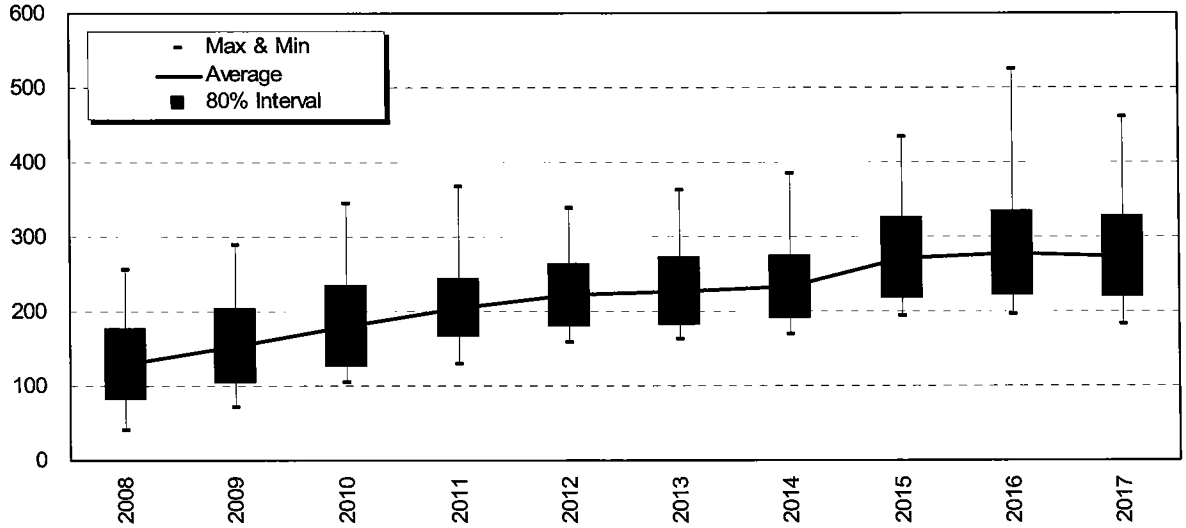


Figure 8.10: Annual Portfolio Volatility (%)

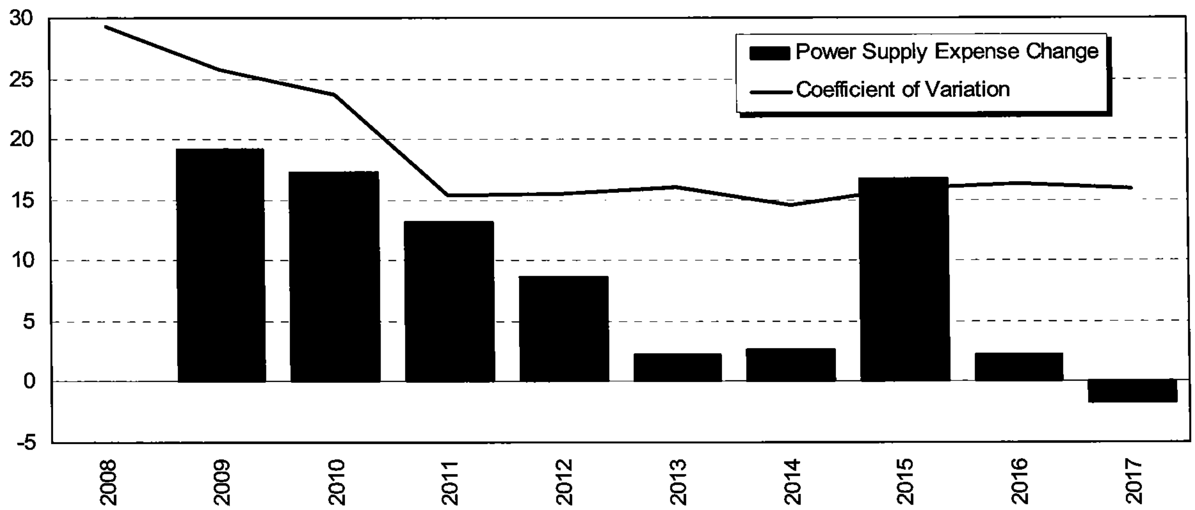


Figure 8.11: Forecasted CO_2 Tons of Emissions (Thousands)

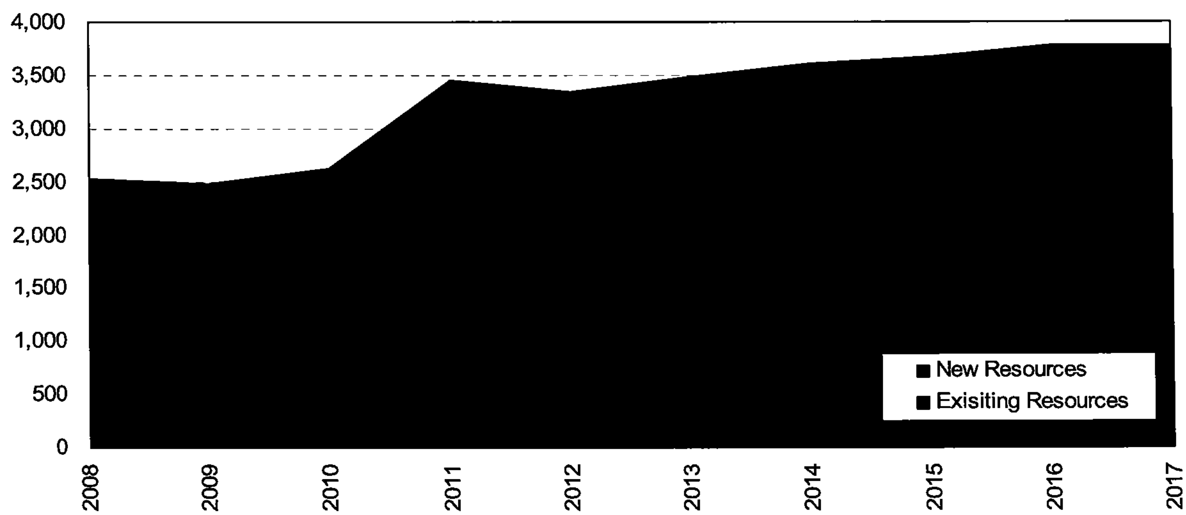


Figure 8.12: Forecasted CO_2 (Tons/MWh)

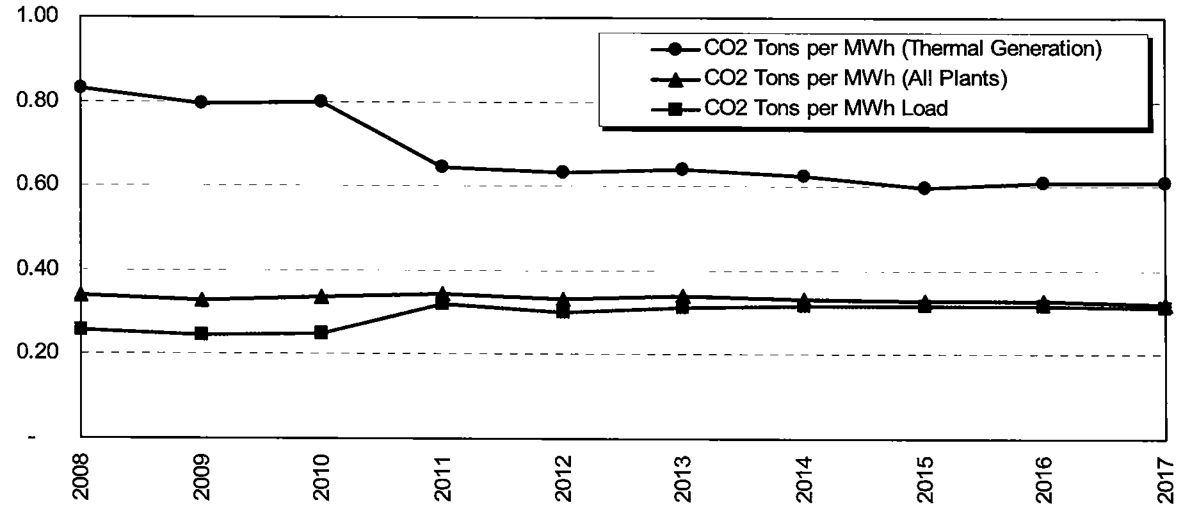
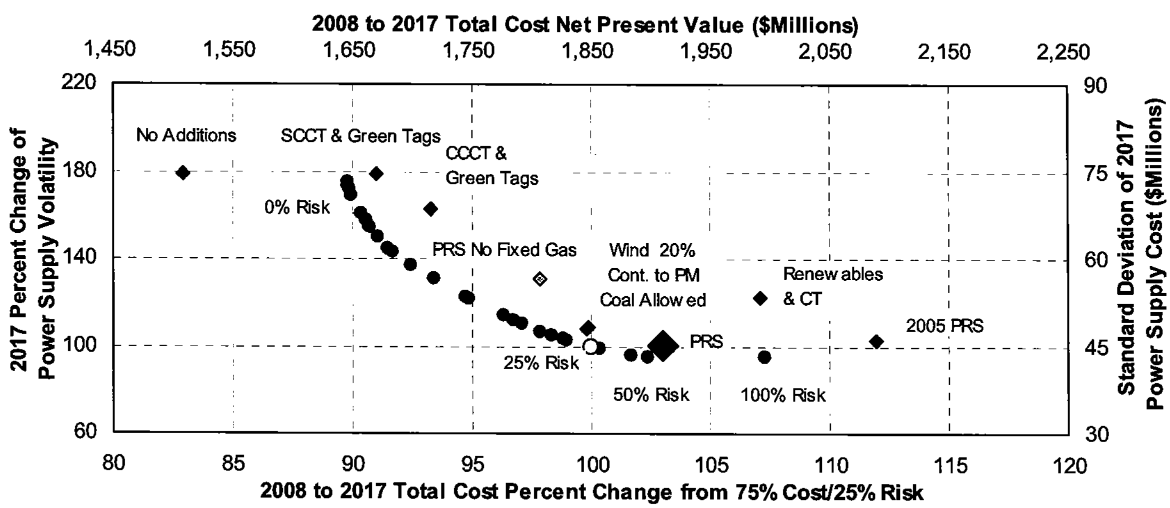


Figure 8.13: Efficient Frontier and Traditional Resource Portfolios



of CO_2 from 2008 to 2017 than the 2005 PRS.

EFFICIENT FRONTIER ANALYSES

When developing a resource portfolio, two key challenges must be addressed—how the portfolio mitigates future costs and how it mitigates year-to-year volatility. An efficient frontier identifies the optimal level of risk given a desired level of costs and vice versa. This approach is similar to finding the best mix of risk and return when developing a personal investment portfolio. As the expected average return increases, so do risks; reducing risk reduces overall returns. Finding the PRS is very similar to this investor's dilemma, but the trade-off is expected average future power supply costs against future power supply cost variation. Figure 8.13 presents the change in cost and risk from the Preferred Portfolio Strategy on the Efficient Frontier. It also shows alternative resource portfolios to illustrate various generic resource strategies. The lower horizontal axis displays the 2008-2017 percent change in the present value of existing and future costs from where the PRiSM model weights its optimization goals 75 percent to cost reduction and 25 percent to risk reduction (75/25 cost/risk). The upper horizontal axis presents actual present value dollars. The right-hand vertical axis shows power supply volatility as a single standard deviation of the average power supply expense. The left-hand vertical axis shows the percent change in 2017 power supply volatility from the 75/25 cost/risk point.

The blue dots represent the efficient frontier of various resource portfolios developed by PRiSM to meet future company requirements. Recall that the PRS is not on the efficient frontier because resource lumpiness is assumed in the first 10 years of the study. It is based on the 75/25 portfolio weighting.

ALTERNATIVE FUTURES

The 2007 IRP studied alternative stochastic futures to measure how the PRS would perform under different assumptions. Figure 8.14 illustrates these differences. This chart is similar to Figure 8.13, but it shows how the efficient frontier would change from the Base Case given the following three futures:

- unconstrained carbon emissions;
- more volatile natural gas prices; and
- high future carbon constraints.

Figures 8.15 through 8.17 provide a more detailed comparison of each future, and display the performance of the various portfolios chosen by the company.

ALTERNATIVE PORTFOLIO STRATEGIES

This chapter details how the company could serve future needs using alternative resource portfolios. It helps benchmark the efficient frontier and the Preferred Resource Strategy. These portfolios, like the efficient frontier, assume the company could acquire resources in perfect increments (i.e., no lumpiness) and that green tags are available to meet the Washington State Renewable Portfolio Requirement. Each portfolio's costs and benefits are compared to the Preferred Resource Strategy. The specific resource contributions for each portfolio are detailed in Table 8.9.

NO ADDITIONS

This portfolio theoretically assumes that the company would not acquire any additional resources and instead would rely on the market for all future capacity and energy needs. Figure 8.18 shows that this is the lowest absolute cost portfolio, however, it has the highest level of risk. Graphically this strategy looks attractive because it sits to the left of the efficient frontier, but it ignores the company's responsibility to adequately meet its customer requirements.

Figure 8.14: Efficient Frontier for All Futures

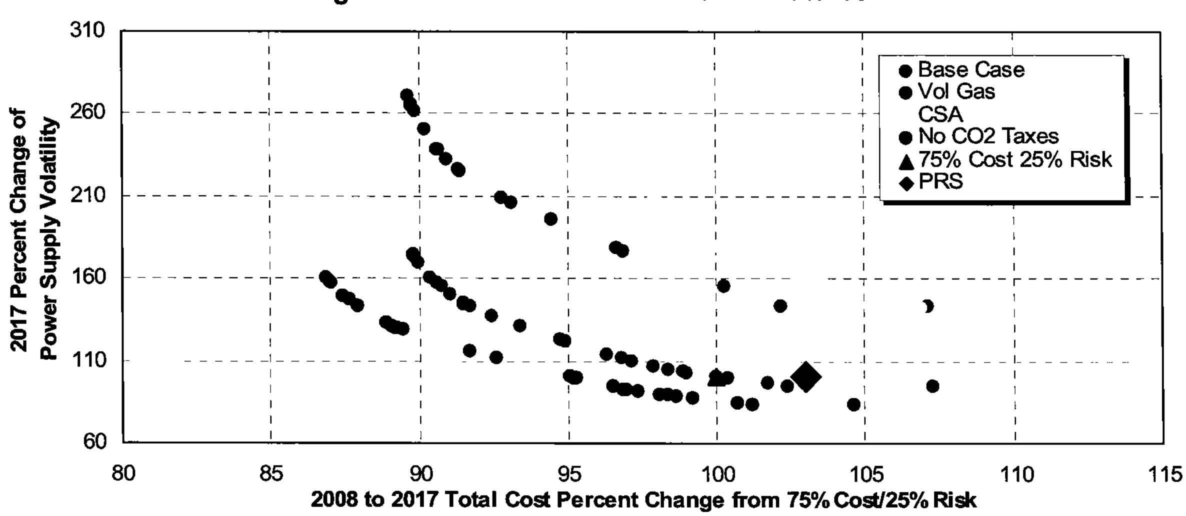


Figure 8.15: Unconstrained Carbon Future's Efficient Frontier Portfolios

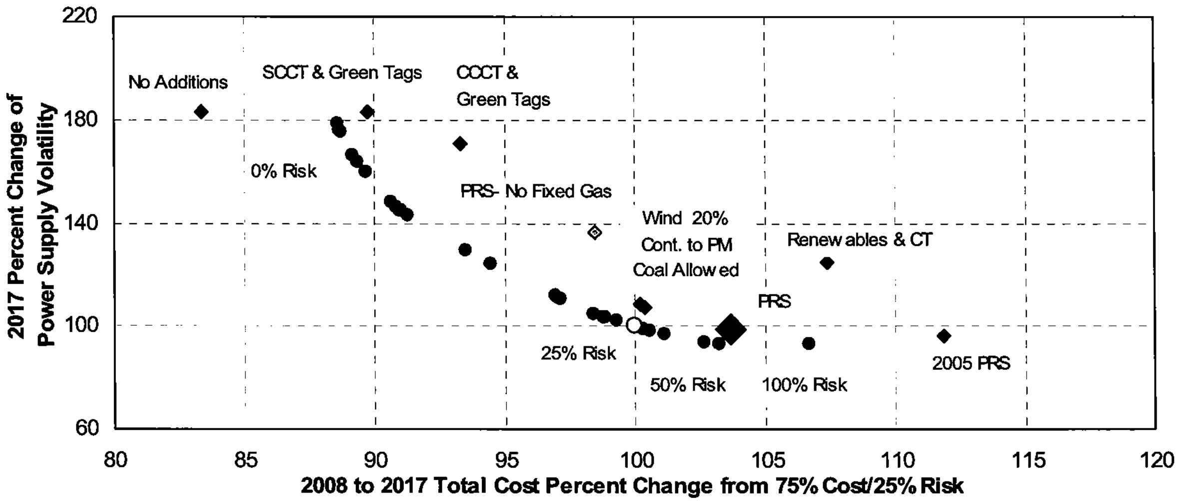


Figure 8.16: Climate Stewardship Future Efficient Frontier Portfolios

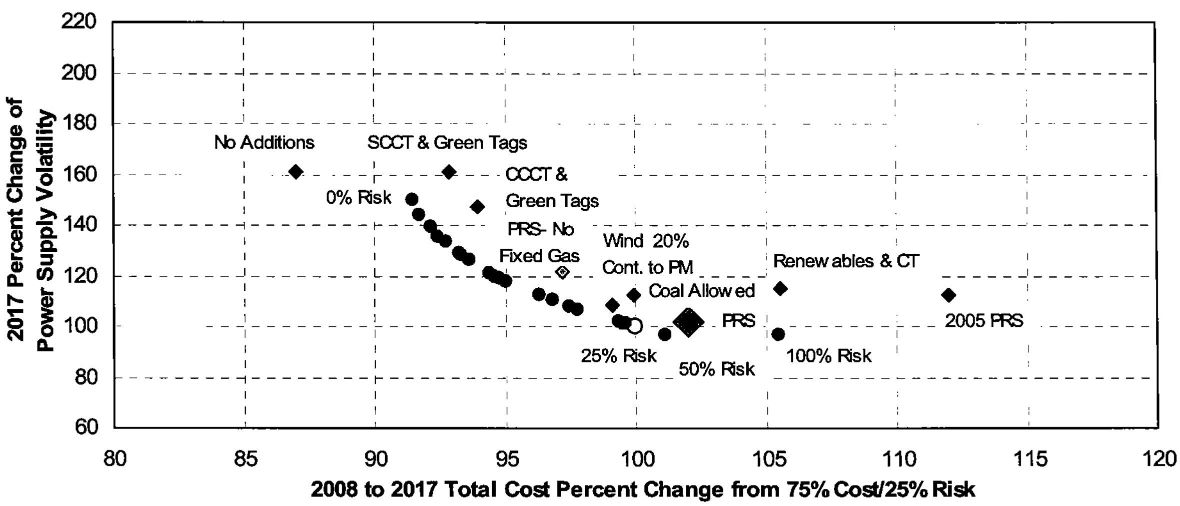


Figure 8.17: Volatile Gas Future Efficient Frontier Portfolios

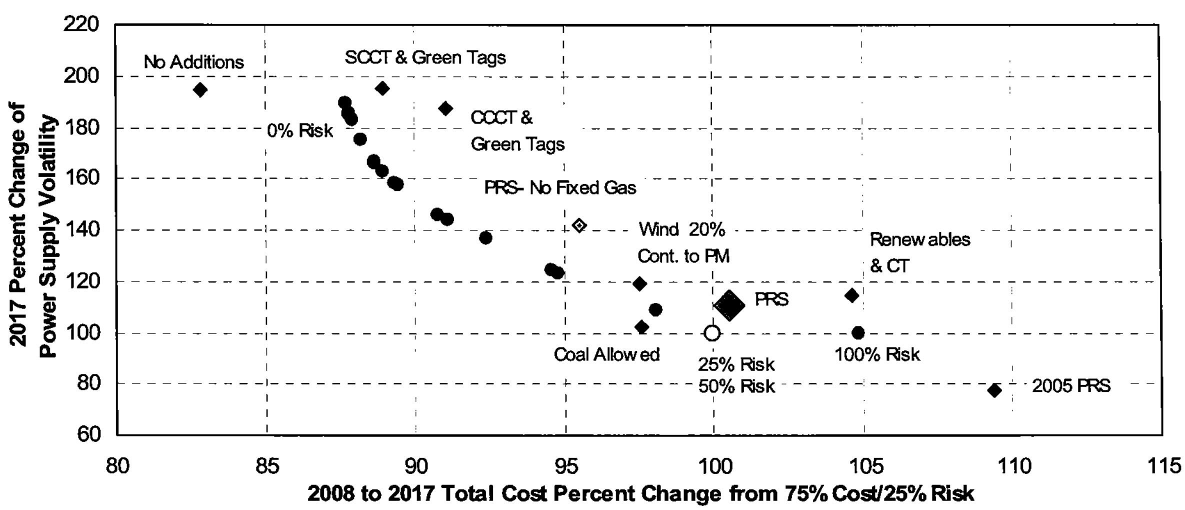
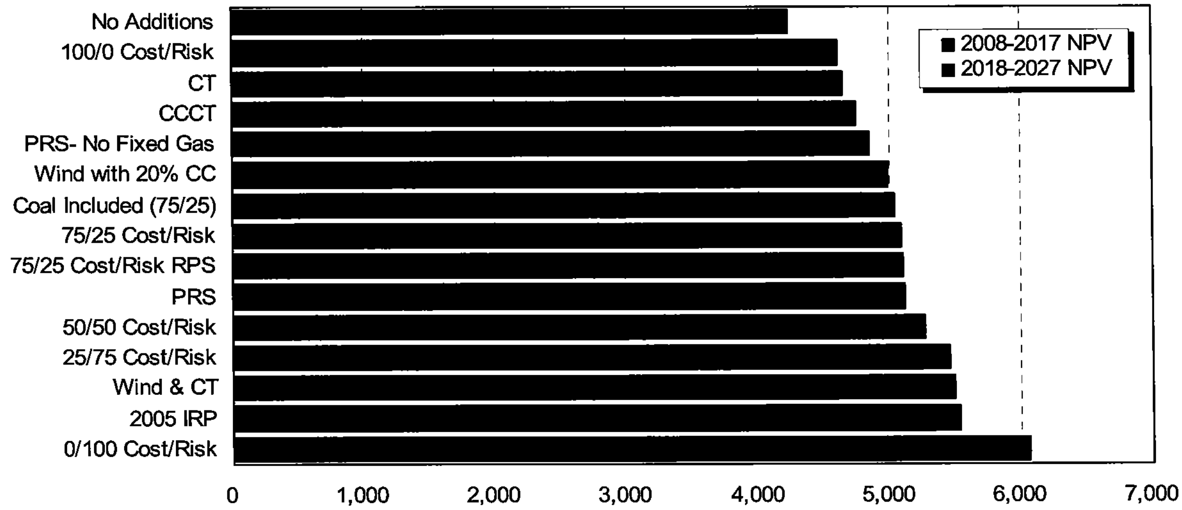


Figure 8.18: Net Present Value of New Resource and Power Supply Costs by Portfolio (2007 $Millions)



SIMPLE CYCLE CTS AND GREEN TAGS

This portfolio assumes that the company would acquire only simple-cycle gas turbines to meet future capacity needs. Given the high operating costs of these plants, this scenario is actually one where future energy needs are met through purchases from the volatile wholesale electricity marketplace. The turbines sit idle a vast majority of the time. The portfolio meets our capacity needs unlike the No Additions Portfolio, but it still contains a high level of volatility due to its heavy reliance on the marketplace and natural gas. The PRiSM model identified the timing of SCCT construction to meet the objectives of this portfolio. Renewable energy requirements are met by acquiring green tags.

COMBINED CYCLE CTS AND GREEN TAGS

This portfolio assumes that the company only acquires combined-cycle gas turbines to meet its capacity and energy needs. The PRiSM model identified the optimal amount and timing of resource additions to meet this portfolio objective. Capacity targets are met and market risk is reduced compared to relying on less-efficient simple-cycle CTs. Green tags meet our RPS requirements.

RENEWABLES AND SIMPLE-CYCLE CTS

Future requirements are met only with renewable resources and simple-cycle CTs in this strategy. The PRiSM model identifies the optimal amount and timing of resources to meet this portfolio objective. SCCTs are included to meet capacity needs, and renewables are added to serve energy needs and reduce risk. This green portfolio requires a 1,200 MW wind penetration level over the next 20 years. Power supply cost variability is reduced in exchange for higher power supply expenses.

COAL ALLOWED

This portfolio allows coal to be selected by the PRiSM model rather than fixed price natural gas plants. The portfolio is based on the same risk level as the PRS. The portfolio is made up of a combination of wind, combined cycle CT, other renewables and coal. Coal is selected after 2013, but not before the 2011 resource need that is met by a combined cycle CT. Because non-sequestered coal is not allowed in our analyses except in this one-off for comparative purposes, this portfolio has a superior performance to the efficient frontier.

Table 8.7: Impacts to Wind & Green Tag Selection (2008-2017)

	With WA RPS	Without WA RPS
Base Case: PRS	300	300
CSA	400	400
Unconstrained CO_2	274 + green tags	274
Volatile Gas	400	400

Table 8.8: Impact to Wind Selection with Idaho RPS (MW)

	With Idaho RPS	Without Idaho RPS
Base Case: PRS	307 + green tags	300
CSA	400	400
Unconstrained CO_2	307 + green tags	274
Volatile Gas	400	400

WIND CONTRIBUTES 20 PERCENT TO CAPACITY PLANNING MARGIN

The IRP assumes that wind generation will provide no capacity to the portfolio in the near- to medium-term. This assumption is based on a wind integration study completed by the company in March 2007. Ignoring this result and assuming a 20 percent capacity contribution for wind makes it much more attractive, though it still sits above the points of the efficient frontier. This portfolio quantifies the impact of the Base Case wind capacity assumptions.

IMPACT OF RPS REQUIREMENTS ON THE PRS

RPS sensitivity portfolios were developed to illustrate the impact of renewable resource cost increases on the level of renewable resources ultimately included in the PRS. The portfolio analysis is based on the 75/25 cost/risk weighting mix, the same as assumed in the PRS. The analysis found that in the Base Case, without a Washington state RPS, the resource strategy would not change under any of the market futures. This indicates that renewables were selected primarily to reduce risk and not to meet the RPS targets. In the unconstrained CO_2 future, fewer renewable resources are built. The model purchases green tags because absent the RPS fewer renewables would be selected. See Table 8.7.[4]

If the company had an RPS requirement in Idaho that mirrored the Washington state requirement, the amount of renewables in our portfolio would not increase significantly. Instead, we likely would purchase green tags, as illustrated by Table 8.8. The RPS would cause the company to build renewable resources that it otherwise might prefer not to.

RISK-ADJUSTED PORTFOLIO STRATEGIES

Portfolios were selected from the Efficient Frontier to illustrate various resource combinations and their performance under alternative market scenarios and futures. Utility-specified portfolios were created to help describe the benefits and risk of certain resource mixes. The portfolios' performances are shown in the figures below.

The charts quantify each portfolio's cost, risk and other factors on a comparative basis. The focus of these charts is on the 2008-2017 time period, but some information is provided for the entire 20-year study. These charts are for the Base Case only. The same information for each market future is provided in the IRP Appendices.

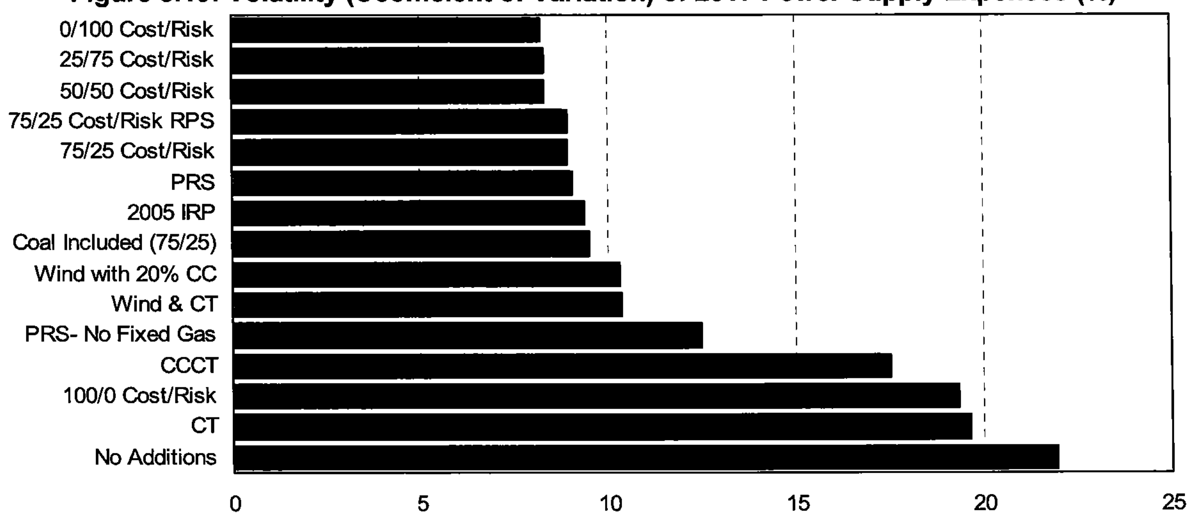
Table 8.9 first provides an overview of the resources included in each alternative portfolio. Figure 8.18 shows the present value of each portfolio's incremental costs,

[4] All cases limit wind to 400 MW of capability between 2008 and 2017.

Table 8.9: 2008-17 Resources for Each Portfolio (Capability MW)

Portfolio	SCCT	Wind	Other Renew-ables	Pulverized Coal	CCCT	DSM	Hydro Upgrades	Total
0/100 Cost/Risk	0	400	35	0	350	87	38	910
25/75 Cost/Risk	0	400	35	0	350	87	38	910
50/50 Cost/Risk	0	400	35	0	350	87	38	910
75/25 Cost/Risk	0	300	35	0	350	87	38	810
100/0 Cost/Risk	363	0	20	0	0	87	38	507
2005 IRP	0	650	140	350	0	87	38	1,265
CCCT	0	0	0	0	384	87	38	509
Coal Included	0	365	35	127	228	87	38	880
CT	382	0	0	0	0	87	38	507
No Additions	0	0	0	0	0	87	38	125
PRS	0	300	35	0	0	87	38	460
PRS w/o fixed gas	0	300	35	0	350	87	38	810
RPS	0	307	35	0	0	87	38	467
Wind & CT	350	675	35	0	0	87	38	1,185
Wind & 20% CC	0	273	35	0	0	87	38	433

Figure 8.19: Volatility (Coefficient of Variation) of 2017 Power Supply Expenses (%)



including new capital and O&M. The costs represented by the blue area of the chart bars are the same as those used on the x-axis of the efficient frontiers.

Risk in the 2007 IRP is measured by the volatility of annual power supply expenses, driven by modeled variations in natural gas costs, loads, emission uncertainty, hydro conditions and forced outages. Figure 8.19 illustrates volatility by displaying the coefficient of variation for each portfolio.[5]

The PRS has lower risk because of the investment into capital intensive and fixed priced assets. The expected power supply costs for 2017 are shown in Figure 8.20. Customer rates will be impacted by new resource investments. Actual rate increases are likely to be lower because power supply expense is only one contributor to rate base. Average power supply cost increases by scenario are shown in Figure 8.21, and the highest single-year increases are shown in Figure 8.22.

[5] The coefficient of variation is calculated by dividing the standard deviation of the total annual cost by the expected power supply cost.

Figure 8.20: 2017 Total Power Supply Expenses ($Millions)

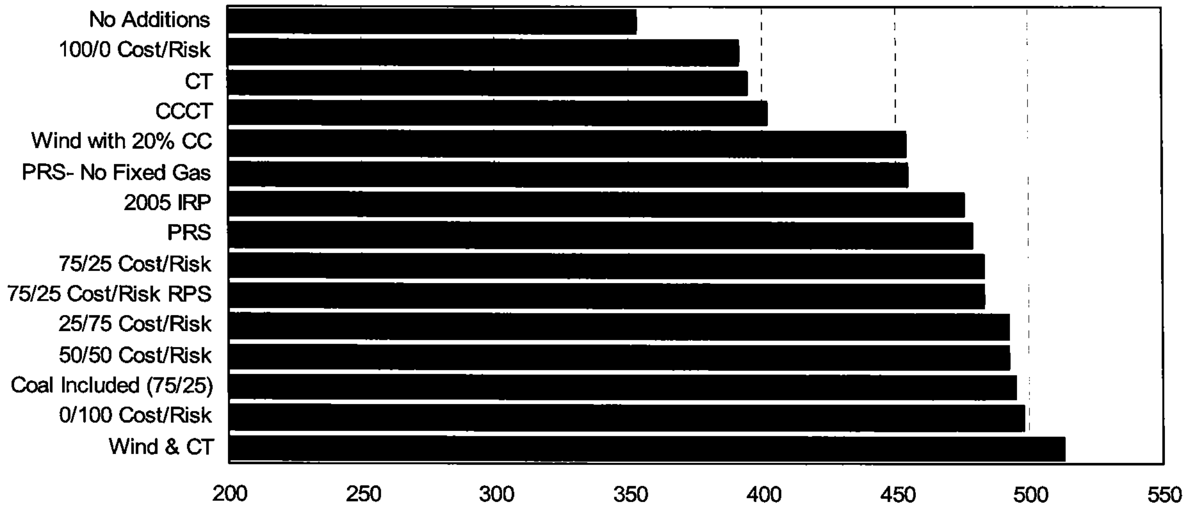


Figure 8.21: Average Annual Power Cost Component Change 2008-2017 (%)

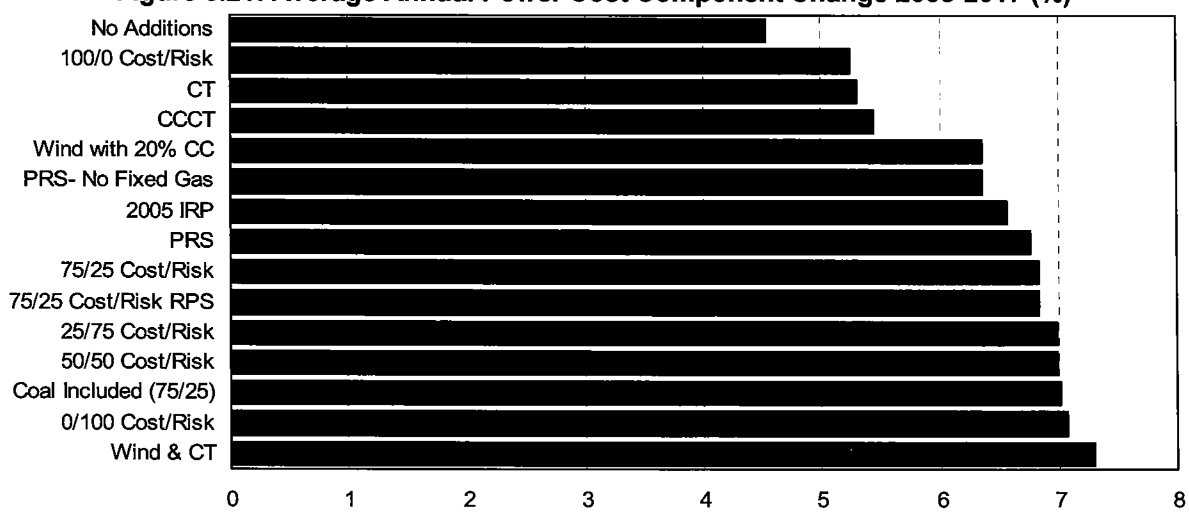


Figure 8.22: Maximum Annual Cost Change for Power Supply (%)

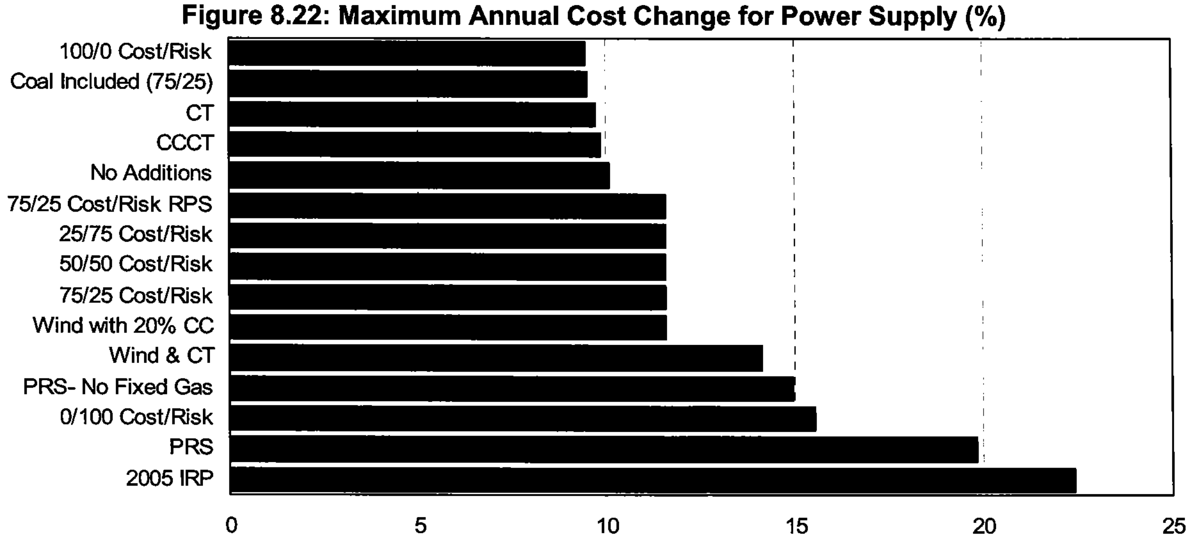


Figure 8.23: 2008-2017 NPV of Capital Investment (2007 $Millions)

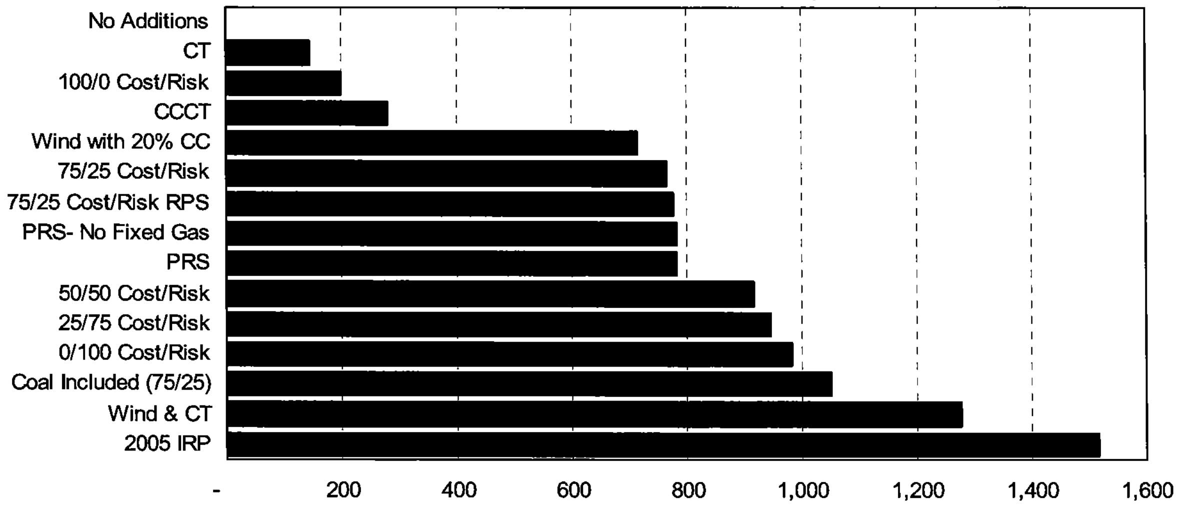
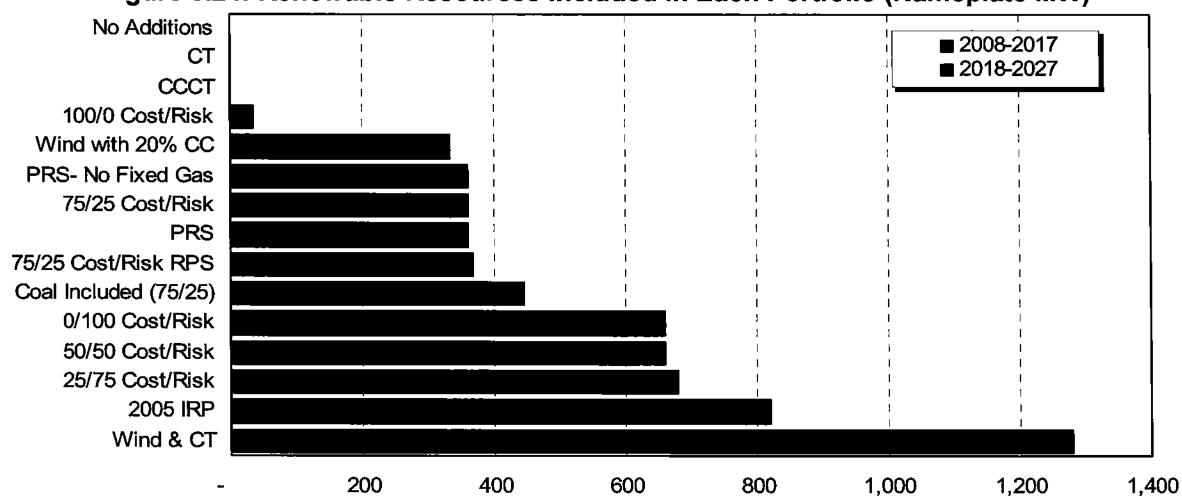


Figure 8.24: Renewable Resources Included in Each Portfolio (Nameplate MW)



Additional capital will be required to meet future load growth. Each portfolio has a unique capital requirement. Figure 8.23 shows the present value of capital requirements for each portfolio option. Capital requirements shown on this chart are for resource capital only and do not include associated capital or debt equivalents needed to firm the price of natural gas as recommended in the PRS.

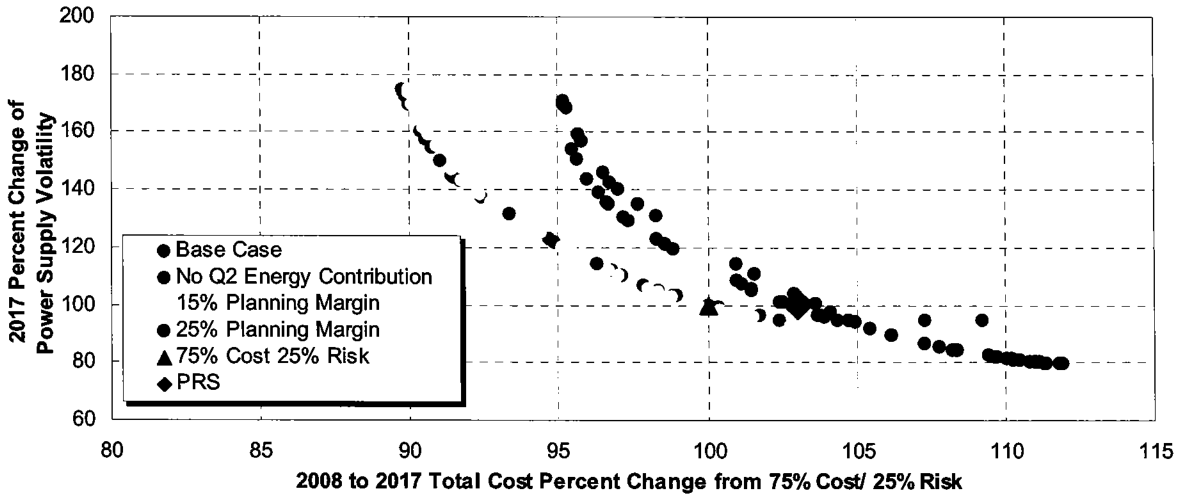
Figure 8.24 presents new renewable resources included in each portfolio between 2008 and 2027. These values are shown in nameplate capacity, not energy or contribution to system planning margins.

PLANNING CRITERIA

The Northwest continues to debate the proper level of planning reserves utilities should carry above their expected peak demand. We also have evaluated eliminating second quarter resource surpluses to ensure that resource deficiencies in the remaining three quarters of the year are not masked by an annual average position covered with excess second quarter hydro energy. This planning level would be similar to moving from an 80 percent to a 95 percent confidence interval planning level.

The PRS currently meets a planning margin equal to 10 percent above expected peak load, plus 90 MW. Energy

Figure 8.25: Alternative Resource Planning Criteria (Efficient Frontier Results)



planning margin is currently based on an 80 percent confidence level of historical hydro and load variance on an annual basis. An analysis was performed to quantify the cost and risk of moving to alternative planning methodologies. Three planning criteria alternatives were modeled:

- 15 percent planning margin;
- 25 percent planning margin; and
- exclude second quarter energy from the annual forecast need.

Each of these alternatives has a different impact on resource acquisition, costs and risks. Figure 8.25 shows the impacts using efficient frontiers. If the company moved to a 15 percent planning margin, there would be little impact on future risks or costs compared to our current methodology. If the company built additional capacity to meet a 25 percent planning margin, as the NPCC recommends in its draft resource adequacy target, costs would probably increase and risk might decrease if the selected incremental resources were one of the lower-risk options. Alternatively, where the company simply met a higher planning margin with market purchases or spot gas-fueled plants, no additional benefit would be seen by moving from a 15 percent to a 25 percent planning margin. Removing second quarter energy surpluses from the company's load and resource position would simply increase costs without a commensurate risk reduction benefit.

CAPITAL COST SENSITIVITIES

Resource capital costs have increased substantially since the 2005 IRP. The largest impact in this plan is a 50 percent reduction in the amount of wind generation stemming from an approximate 50 percent increase in capital costs for wind resources. The Efficient Frontier can illustrate the impact of varying levels of capital cost. Table 8.10 identifies the capital cost sensitivities studied for this IRP. These sensitivities determine how changes would impact not only the cost of the efficient frontier but how our resource selections might change.

The sensitivity results are informative and explain that overall power supply costs change in response to

Table 8.10: Capital Cost Sensitivities ($2007/kW)

Resource	Low	Base Case	High
Wind	1,300	1,884	2,500
Combined Cycle	600	786	1,000
IGCC Coal w/Sequestration	2,500	3,232	N/A
Alberta Oil Sands	2,000	3,963	N/A

Table 8.11: Wind Capacity Selected for 25% Risk Reduction (MW)

	2008-2017	2017-2027
Base Case	300	0
Low	400	200
High	143	0

Table 8.12: Resource Selection Comparison (MW)

	50/50	40/60	25/75	0/100
Base Case				
Other	59	78	66	59
Wind	600	600	600	600
CCCT	677	657	527	350
IGCC w/Sequestration	0	0	130	101
Alberta Oil Sands	0	0	0	226
IGCC @ $2,500/kW				
Other	59	78	78	59
Wind	600	600	600	600
CCCT	0	0	0	280
IGCC w/Sequestration	0	66	299	101
Alberta Oil Sands	0	0	0	226
Oil Sands @ $2,000/kW				
Other	59	59	78	59
Wind	600	600	600	600
CCCT	467	451	350	350
IGCC w/Sequestration	0	0	0	101
Alberta Oil Sands	210	226	226	226

varying capital cost levels; however, the variations did not significantly change the overall strategy during the first 10 years of the plan. The one exception is where wind costs vary significantly. See Table 8.11. Lower wind acquisition is offset by more green tag purchases.

Sequestered IGCC coal and Alberta Oil Sands would be selected at the expense of gas resources if their capital costs were to fall significantly from what is assumed in the Base Case. See Table 8.12.

FIXED GAS PRICE

Coal-fired generation accounted for a significant portion of the Avista's PRS mix in both the 2003 and 2005 IRPs. Coal-fired plants provide a hedge against volatile electricity and natural gas prices because 60 percent or more of their costs are fixed through large capital investments. Variable operating and fuel costs at a coal plant are modest compared to gas-fired resources. A resource profile containing coal contributes to stable power supply expenses.

The cost of operating gas-fired resources, on the other hand, is highly correlated with the electricity marketplace. Natural gas prices are very volatile. The fixed costs of natural gas plants are low relative to their all-in cost of generation, approximately 20 percent, reflecting a low capital investment. Utility portfolios with large concentrations of gas-fired generation suffer from rates that are less stable than utilities that rely on other sources of generation.

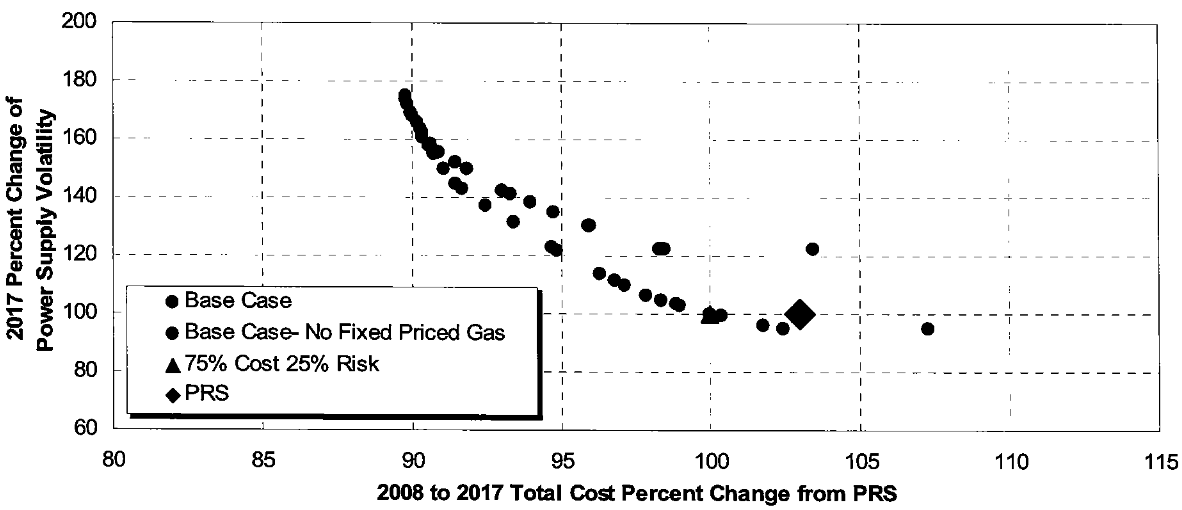
Gas-fired plants have not experienced the same capital cost increases seen in new coal-fired plants. In fact, recent experience by Avista (Coyote Springs 2) and Puget Sound Energy (Goldendale) indicate that independent power producers in the Northwest marketplace are willing to sell their gas-fired plants at prices below the green field costs assumed in this plan. The enactment of new laws imposing emission performance standards on fossil-fueled generation resources acquired by electric utilities in Washington and California will narrow base load technology options, at least in the short-term, to gas-fired generation. This restriction, coupled with regional load growth and the prospect of additional greenhouse gas regulations on fossil-fueled generation resources, particularly coal-fired generation, may ultimately increase demand for and the cost of gas-fired plants.

Locking in natural gas costs through a long-term fixed-price contract, an investment in a pipeline-quality coal gasification plant, an investment in gas fields or through other means makes a gas-fired combined cycle combustion turbine (CCCT) behave financially like a coal-fired resource. Variable costs are greatly reduced and are much less volatile because a significant portion of its largest variable component—gas fuel—is not tied to the natural gas market. In both high and low gas market conditions the price paid by customers is the same. In years where natural gas prices are high, the fixed-cost contract looks very attractive financially and customers pay less than if the company relied on shorter-term purchases. On the other hand, years with low natural gas prices make the fixed-cost contract look financially unattractive compared to a short-term purchase. Over time, the long-run cost of operations with fixed-price gas should parallel the cost of operations where a gas plant is fueled with short-term gas.

Fixing gas prices does not lower absolute cost, but it does limit price volatility. As with any long-term fixed price option, prices over time likely will be higher than if the company relied exclusively on spot market gas purchases. Asking a third party to absorb price risk always entails a premium in exchange for accepting that risk. This is similar to purchasing an automobile insurance policy. A policy is not purchased to lower driving costs but to decrease the amount of financial risk to the driver if an accident were to occur. A financially-fixed natural gas price would be higher than average spot market gas purchases, but that premium would limit the upside exposure of the company and its customer to gas price spikes.

The company has identified three potential avenues to lower natural gas price risk. There might be more. The first, and most probable option, would involve purchasing a long-term fixed price gas contract. Until recently, the market did not offer these types of contracts because of experiences in the 2000/01 energy crisis. Recent

Figure 8.26: Efficient Frontier With and Without Fixed Price Gas Contract Option



informal market surveys have found sellers offering terms up to 20 years. A second option would involve investing in a gasification plant to convert coal to pipeline-quality gas. A third option would be investment in a gas field.

The company tested the benefits of fixed price contracts with PRiSM and found a general preference for fixed price gas because of its ability to reduce risk. Even with premiums as high as 75 percent above the short-term gas prices, the PRiSM model selects fixed-price gas for a portion of the preferred portfolio. In the Base Case, where a 30 percent fixed gas price premium is modeled, risk is reduced by approximately 20 percent, as shown in Figure 8.26.

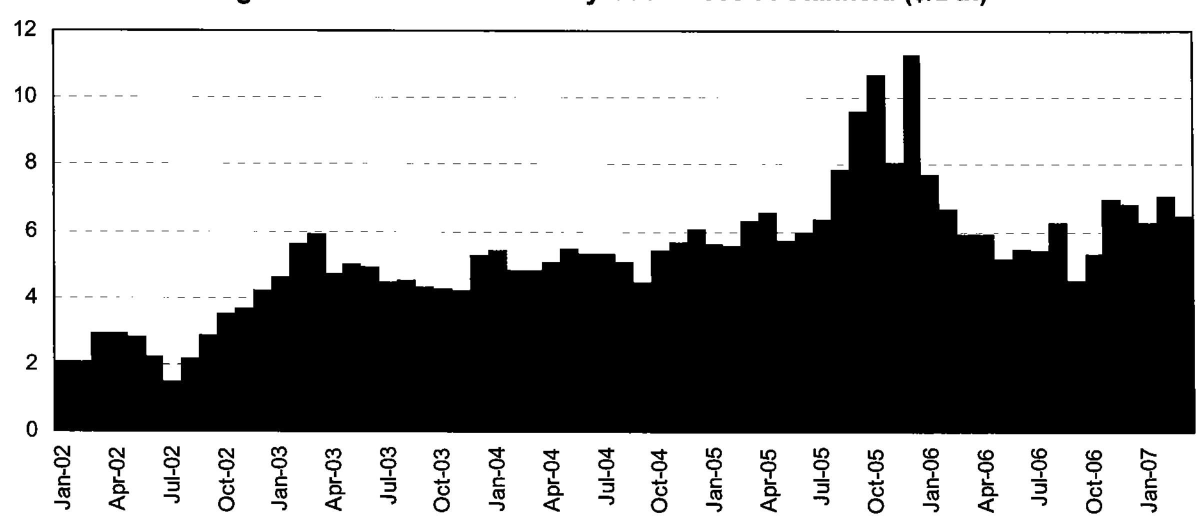
AN EMPIRICAL EXAMPLE

Avista has historically purchased fuel for our gas-fired plants in the short- to medium-term markets, making purchases from time periods as short as one day up to 18 months into the future. Generation costs have varied greatly over this time with the price of natural gas. Figure 8.27 illustrates historical monthly natural gas prices at the Stanfield hub, where Coyote Springs 2 procures its natural gas. Prices are shown from January 2002 through March 2008.

As shown, gas prices have been quite volatile. Gas prices ranged from a low of $1.52 per Dth to a high of $11.29 per Dth. Translated to monthly gas expense, a company model shows the cost ranges from zero in four months, where market conditions did not support operating the plant, to as high as $14.4 million in December 2005.[6] The standard deviation of this hypothetical cost stream is large, at $2.9 million, or 62 percent of the average.

Greater reliance on gas-fired generation has the potential to introduce significantly more volatility in company power supply costs than has been witnessed in the past. The first ten years of the PRS acquires 350 MW of CCCT capacity, more than doubling the size both of our CCCT fleet and gas purchasing budget. To illustrate, a $1.72 per Dth annual increase in natural gas prices would drive up fuel expenses by approximately $21 million at Coyote Springs 2; with an additional 350 MW of gas-fired CCCTs, the exposure would be $48 million.[7] The largest annual swing in gas prices over this period was

Figure 8.27: Historical Monthly Gas Prices at Stanfield ($/Dth)



[6] Assuming theoretical operation absent both maintenance and forced outage costs.

[7] $1.72 per Dth equals one standard deviation of annual Stanfield natural gas prices between 2002 and 2006. Price swings would be expected to exceed this amount in one in three calendar years. 160 dth/MW * 280 MW * 365 days * 75 percent capacity factor * $1.72/Dth = $21.2 million; 160 dth/MW * 630 MW * 365 days * 75 percent capacity factor * $1.72/Dth = $47.8 million.

$2.22 per Dth between 2002 and 2003. Reviewing the 2002 through 2006 period, history shows a $48.4 million range in annual gas procurement costs, and a maximum year-on-year change of as much as 50 percent. Hedging a portion or all of our natural gas purchases might reduce fuel expense volatility by 50 percent where the 2002 through 2006 years provide guidance.[8]

DECIDING THE QUANTITY OF NATURAL GAS TO HEDGE

One challenge of fixing natural gas prices is deciding how much of a plant's portfolio should be hedged. Should all expected generation be hedged? Should the hedge be placed equally across all months of the year, or differently in each month to reflect expected generation levels? As discussed earlier, fixing gas prices likely will incur higher average cost. This is illustrated by Figure 8.28. The lowest average cost is where the plant does not hedge any of its gas costs with fixed prices. The mean variable fuel cost of the plant is approximately $40 per MWh, with a range of $10 to $85 in any given year of the study. Hedging 25 percent of natural gas consumption reduces the expected range of operating costs by about a third, but raises the average variable fuel cost of the plant to about $45 per MWh. Hedging 75 percent of natural gas consumption tightens the distribution of costs by 75 percent, but it also increases expected variable fuel costs to $54 per MWh.

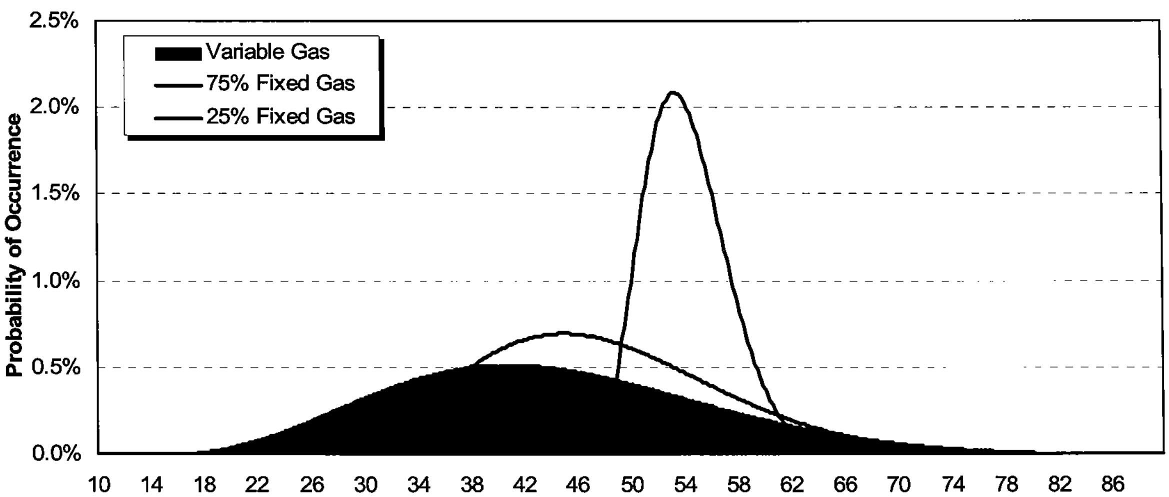
The answer to this question is too broad for resolution in an IRP, and the company will further analyze the question as part of its action plan. The IRP took a simpler approach and assumed that the natural gas price was fixed for 75 percent of annual average expected generation.

More analysis of fixed price options is necessary to confirm that a fixed price gas strategy is in the best interest of our customers. This work is included as an action item for the 2009 IRP.

PORTFOLIO PERFORMANCE ACROSS MODELED SCENARIOS

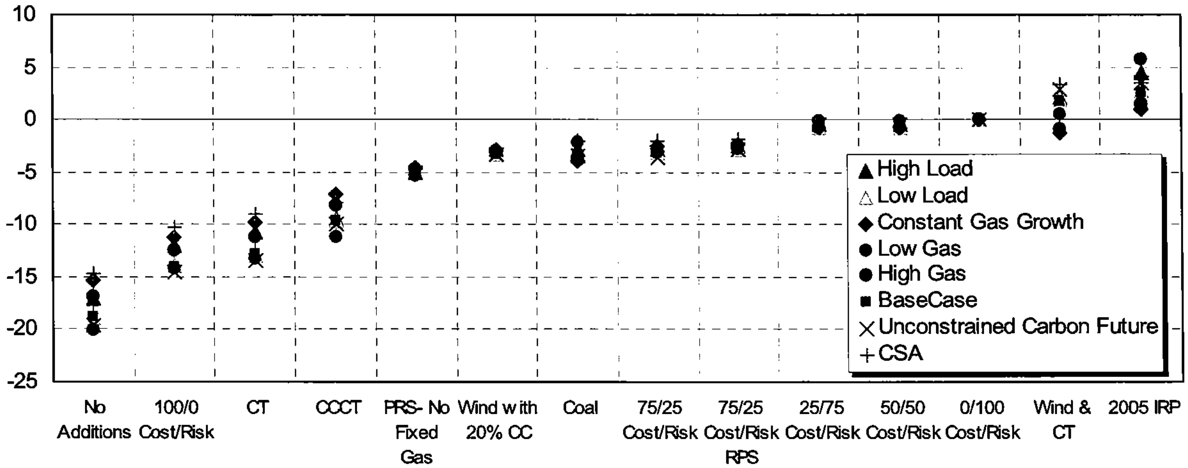
Resource portfolios perform differently in the different market scenarios detailed in Chapter 7. For example,

Figure 8.28: Variable Fuel Costs of CCCT Plant at Various Gas Hedging Levels ($/MWh)



[8] This analysis is based on dispatching a CCCT plant during the years 2002-06 using daily average Mid-C and Stanfield natural gas prices. In the case of fixed price gas, fixed price gas was assumed to be purchased in an amount equal to 75 percent of the annual operating capability of the unit, approximately the level of operation the company would expect out of a CCCT plant. Purchasing between 60 and 75 percent of annual capability provides a similar result. The fixed price was set equal to the average price over the 5-year period. On days in which the plant operated, the remaining 25 percent of needs not covered by the fixed purchase was purchased at the daily index price. On days in which the plant was not economical to run, gas was sold into the spot market. Change in volatility is defined as the change in the standard deviation of fuel expense.

Figure 8.29: Portfolio Cost Comparison Versus PRS for Each Market Scenario (%)



portfolios including higher concentrations of carbon-emitting resources will perform poorly in a high-cost carbon environment when compared to portfolios not relying as heavily on them. The expected costs of gas-reliant portfolios will vary more under low and high gas scenarios than portfolios not relying on gas. The performance of various portfolios studied in the plan is displayed in Figure 8.29. The figure explains how the different portfolios compare relative to the Preferred Resource Strategy, when measured by the 2008-17 NPV of total power supply expenses. For example, the "No Additions" portfolio is expected to cost as much as 20 percent less than the PRS (shown in this chart as the "25/75 Cost/Risk" portfolio) portfolio under the Low Gas market scenario. The alternative's savings from the PRS fall to 15 percent in the Constant Gas Growth scenario.

Figure 8.29 identifies which portfolios are on average lower and/or more costly than the PRS, and show which portfolios' expected average costs are more volatile compared across the market scenarios. Riskier portfolios have a larger cost range while the performance of less risky portfolios does not vary much.

Risk across scenarios is not the same risk being measured in the efficient frontiers displayed in this section. Scenario and paradigm risks help explain how robust portfolios are where significant changes from the Base Case occur. Risk measured by the efficient frontier is how well the portfolio behaves under varying stochastic parameters (i.e., natural gas, forced outage, carbon price, and wind and hydro variations). The PRS-No Fixed Gas portfolio best illustrates this difference. When shown in Figure 8.29 it appears that the PRS with no fixed gas performs exceptionally well across the scenarios while providing five-percent lower average costs than the PRS. But in looking back at the efficient frontier of Figure 8.13, not fixing gas prices actually creates a higher risk profile than the PRS (by approximately 35 percent) in the expected Base Case due to the portfolio's greater exposure to shorter-term variations in natural gas prices.

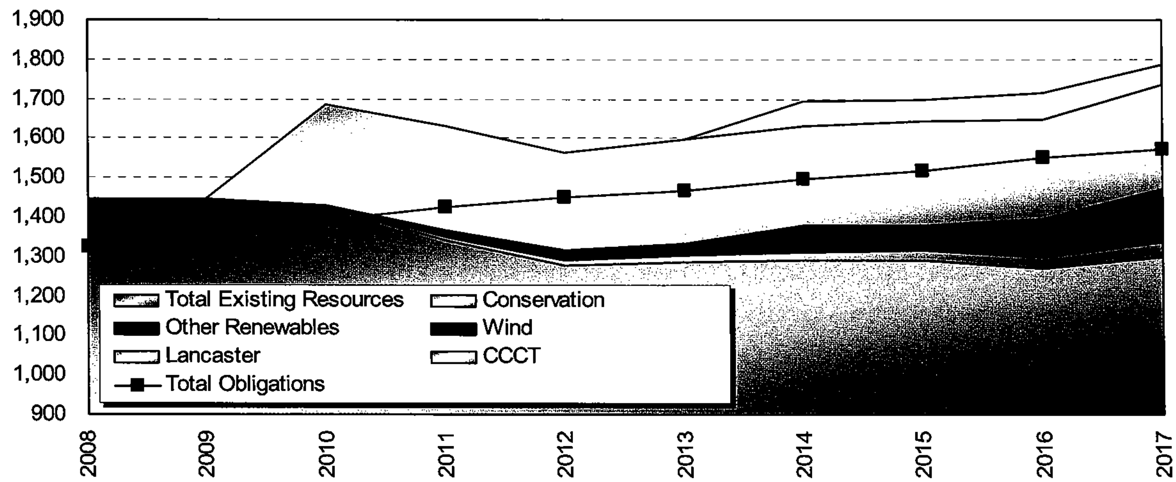
THE LANCASTER GENERATION FACILITY

The company announced the sale of its energy marketing company, Avista Energy, in April 2007. As part of this transaction Avista Energy's tolling contract for the Lancaster Generating Plant output will become available to the utility beginning in 2010. The announcement came after we had substantially completed our IRP analysis and PRS. Given that Lancaster is the same technology as the 280 MW gas-fired combined cycle resource identified in the PRS at roughly the same timeframe and is available to the utility, the resource

Table 8.13: Loads & Resources Energy Forecast with PRS (aMW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,125	1,163	1,196	1,230	1,256	1,326	1,379	1,450	1,627
90% Confidence Interval	200	199	196	196	192	192	192	156	156
Total Obligations	***1,324***	***1,362***	***1,392***	***1,425***	***1,448***	***1,518***	***1,571***	***1,606***	***1,783***
Existing Resources									
Hydro	540	538	531	528	512	510	509	491	491
Net Contracts	234	234	234	129	107	105	105	106	106
Coal	199	183	188	198	187	187	198	199	186
Biomass	47	47	47	47	47	47	47	47	47
Gas Dispatch	280	295	285	295	280	295	295	280	295
Gas Peaking Units	145	145	141	146	145	146	145	141	145
Total Existing Resources	***1,446***	***1,442***	***1,426***	***1,342***	***1,278***	***1,290***	***1,299***	***1,265***	***1,270***
Net Positions	**121**	**79**	**33**	**-83**	**-170**	**-228**	**-272**	**-341**	**-513**
PRS Resources									
Lancaster	0	0	254	264	249	264	264	228	0
CCCT	0	0	0	0	0	52	52	162	612
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	33	103	103	103
Other Renewables	0	0	0	18	27	32	32	41	54
Conservation	1	3	5	7	11	26	37	54	103
Total PRS Resources	***1***	***3***	***259***	***290***	***288***	***406***	***487***	***587***	***871***
Net Positions	**122**	**82**	**292**	**207**	**117**	**179**	**215**	**246**	**359**

Figure 8.30: Loads & Resources Energy Forecast with Lancaster in PRS (aMW)



strategy was not updated. Instead an alternative portfolio with Lancaster is compared to the PRS to illustrate its impacts. The Lancaster Generation Facility is a 245 MW gas-fired combined-cycle combustion turbine with an additional 30 MW of duct firing capability. It is a General Electric Frame 7FA plant that began commercial service in 2001. Lancaster is located in Rathdrum, Idaho, in the center of Avista's service territory. It is significantly lower in cost than a green field plant and would not expose the company to construction risk.

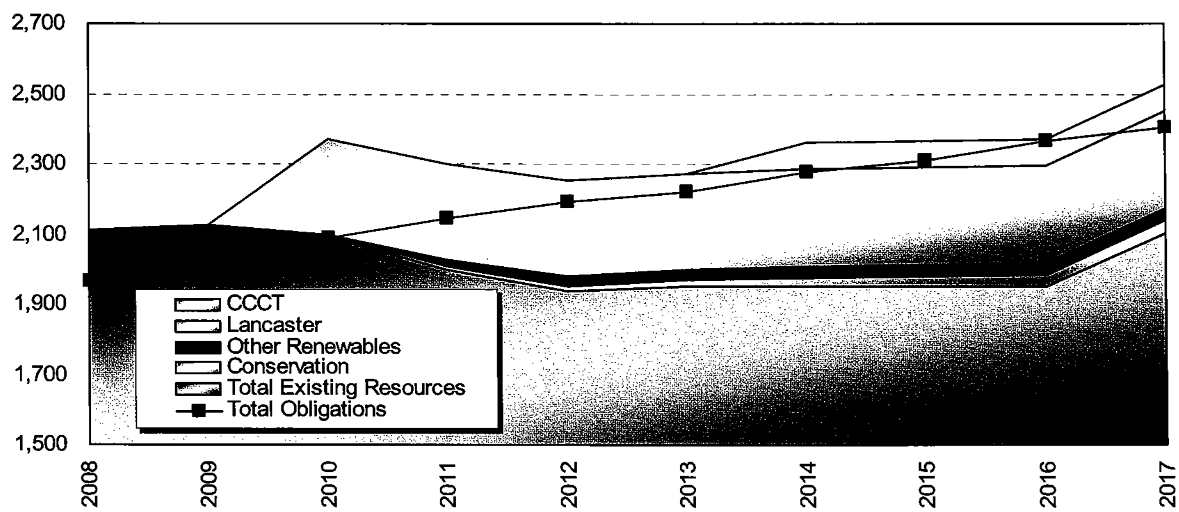
LANCASTER IMPACT ON L&R BALANCES

Lancaster substantially replaces the identified gas-fired CCCT included in the preferred resource strategy. Tables 8.13 and 8.14, and figures 8.30 and 8.31, present the PRS with Lancaster replacing a significant portion of

Table 8.14: Loads & Resource Capacity Forecast with PRS (MW)

	2008	2009	2010	2011	2012	2015	2017	2020	2027
Obligations									
Retail Load	1,703	1,763	1,815	1,868	1,909	2,019	2,103	2,214	2,492
Planning Margin	260	266	272	277	281	292	300	311	339
Total Obligations	***1,964***	***2,029***	***2,087***	***2,145***	***2,190***	***2,311***	***2,404***	***2,525***	***2,831***
Existing Resources									
Hydro	1,142	1,154	1,121	1,128	1,084	1,098	1,098	1,070	1,070
Net Contracts	172	172	173	73	58	58	208	128	128
Coal	230	230	230	230	230	230	230	230	230
Biomass	50	50	50	50	50	50	50	50	50
Gas Dispatch	308	308	308	308	308	308	308	308	308
Gas Peaking Units	211	211	211	211	211	211	211	211	211
Total Existing Resources	***2,111***	***2,123***	***2,092***	***1,999***	***1,939***	***1,954***	***2,104***	***1,996***	***1,996***
Net Positions	**148**	**94**	**5**	**-146**	**-251**	**-357**	**-300**	**-530**	**-835**
PRS Resources									
Lancaster	0	0	275	275	275	275	275	275	0
CCCT	0	0	0	0	0	75	75	156	677
Coal	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0
Other Renewables	0	0	0	20	29	34	34	44	59
Conservation	1	3	5	7	11	26	37	54	103
Total PRS Resources	***1***	***3***	***280***	***302***	***316***	***410***	***421***	***530***	***839***
Net Positions	**149**	**97**	**285**	**156**	**65**	**53**	**122**	**0**	**4**
Planning Margins (%)	**24.0**	**20.6**	**30.6**	**23.2**	**18.1**	**17.1**	**20.1**	**14.1**	**13.8**

Figure 8.31: Loads & Resources Capacity Forecast with Lancaster in PRS (MW)

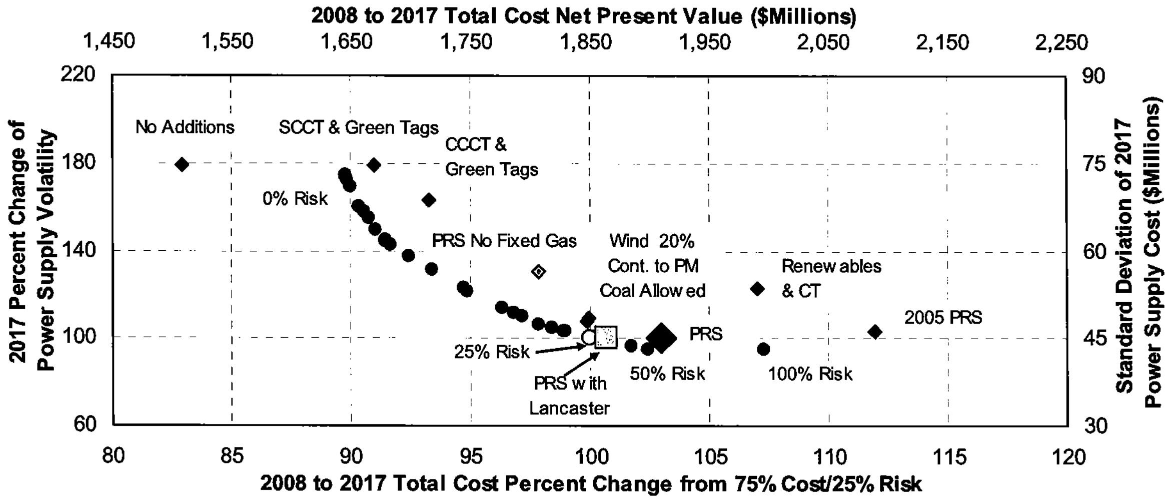


the CCCT needs identified for the PRS. The addition of Lancaster pushes the company's resource need out to 2014.

LANCASTER IMPACT ON PORTFOLIO COSTS AND RISK

The Lancaster plant costs less than an equivalent new gas-fired CCCT while providing the same benefits. Another way to compare the addition of Lancaster to the Preferred Resource Strategy is to plot a new PRS with Lancaster's costs on the Efficient Frontier. Figure 8.32 provides an updated efficient frontier where Lancaster replaces a majority of the PRS gas-fired acquisition during the first decade of the plan. Including Lancaster reduces costs approximately 6 percent under the original

Figure 8.32: Efficient Frontier with Lancaster Plant



PRS for the same amount of risk. Savings are created by acquiring a more cost-effective plant and an adjustment to new resource additions.

9. ACTION ITEMS

The Integrated Resource Plan (IRP) is an ongoing and iterative process attempting to balance the need for regular publications with pursuing the best 20-year forecast possible. The set biennial publication date means that there is always room for improvements or additional research. This section provides an overview of the progress that has been made regarding the 2005 IRP Action Plan. The 2007 IRP Action Plan provides details about the issues and improvements that were developed or raised during this planning cycle and those that need to be deferred to the 2009 IRP.

SUMMARY OF THE 2005 ACTION PLAN

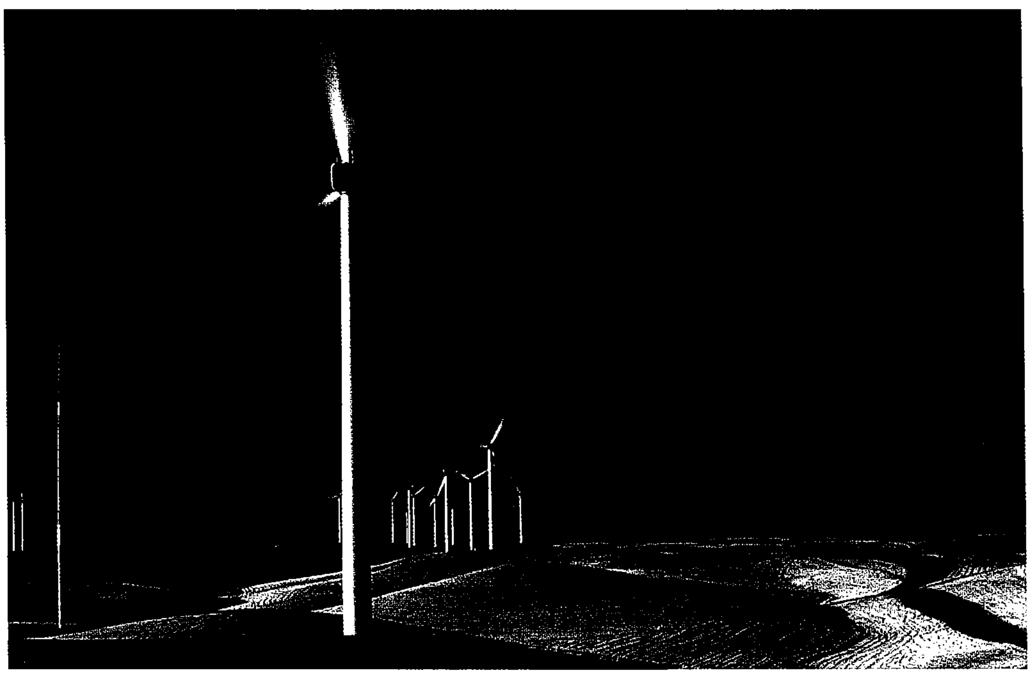
The 2005 IRP includes Action Items in four separate areas: renewable energy and emissions, modeling enhancements, transmission modeling and research, and conservation.

RENEWABLE ENERGY AND EMISSIONS

- Commission a study to assess wind potential within Avista's service territory.
- Continue to monitor emissions legislation and its potential effects on markets and the company.
- Research clean coal technology and carbon sequestration.
- Assess biomass potential within and outside of Avista's service territory.

Avista hired a meteorological consultant who completed map and aerial studies of wind potential within the company's service territory. Several promising sites were located that warrant further consideration and assessment. The next steps involve contacting landowners to assess their interest in allowing the installation of anemometers to test wind speeds and shapes for at least a one-year period. This research will be ongoing and will be reported in the 2009 IRP.

Avista has actively monitored state and federal emissions legislation which has resulted in the company taking several steps forward in this area. Most notably, an entire section of this IRP has been dedicated to emissions issues, greenhouse gas emissions cost estimates have been included in the Base Case, and an Avista Climate Change Council has been convened to bring all of the functional areas of the company together address climate change issues.



Wind Turbines Generating Electricity

A variety of different coal technologies have been researched for this IRP through the joint request for information with Idaho Power. The research for this process has resulted in more up-to-date capital costs for sub-critical, supercritical and ultra-critical pulverized coal, circulating fluidized bed and integrated gas combined cycle technologies. These have been included in the Technical Advisory Committee (TAC) presentations available at the company's IRP Website. Presentations on clean coal technologies and carbon capture and sequestration are also included in the TAC presentation. The steep increases in capital costs, recent Washington state legislation and changes in Avista management directives have moved non-sequestered coal completely out of the plan. However, we will continue to research coal technologies to help us better understand resources throughout the Western Interconnect and in case new, clean coal technologies become cost effective in the future.

Some initial assessments of biomass potential within and outside of Avista's service territory have been researched. Recent studies have indicated total amounts of biomass availability by county in Washington, but further work needs to be done to determine the amount of biomass that is economically recoverable and feasible to obtain. One benefit of the recent RPS legislation should be more research into renewable technologies, including biomass. This action item will need to be carried forward to the 2009 IRP.

MODELING ENHANCEMENTS

- Evaluate the 70-year water record for inclusion in 2007 IRP studies.
- Add more functionality to the Avista Linear Programming Model (e.g., direct consideration of cash flow and rate impacts versus after-the-fact reviews).

The 70-year water record has been reviewed and implemented in the modeling for this IRP. The Avista Linear Programming Model or PRiSM has been enhanced to handle 300 iterations, cash flow, power supply rate impacts, and improved the overall functionality and reporting abilities.

TRANSMISSION MODELING AND RESEARCH

- Work to maintain/retain existing transmission rights on the company's transmission system, under applicable FERC policies, for transmission service to bundled retail native load.
- Continue involvement in BPA transmission practice processes and rate proceedings to minimize costs of integrating existing resources outside of the Company's service area.
- Continue participation in regional and sub-regional efforts to establish new regional transmission structures (Grid West and TIG) to facilitate long-term expansion of the regional transmission system.
- Evaluate costs to integrate new resources across Avista's service territory and from regions outside of the Northwest.

Chapter 4 contains details about Avista transmission modeling and research. These Action Items will continue to be important in the 2009 IRP.

CONSERVATION

- Review the potential for cost-effective load shifting programs using hourly market prices.
- Complete the conservation control project currently underway as part of the Northwest Energy Efficiency Initiative for future evaluation as a potential conservation resource.

Several new programs and measures are being developed in addition to enhancements to the company's existing programs. Load management pilot programs are being developed for implementation beginning in 2007 in Moscow and Sandpoint, Idaho. Large customer interruption and distributed generation projects are also being researched. Nine potential transmission and distribution efficiency measures were identified and studied. Three of these projects are currently at the work-in-progress phase of development.

2007 IRP ACTION PLAN

The company's 2007 Preferred Resource Strategy provides direction and guidance for resource acquisitions. The 2007 IRP action plan lists the activities that will be carried out for inclusion in the 2009 IRP. Progress will be monitored and reported in Avista's 2009 Integrated Resource Plan. Each item in the action plan was developed using input from Commission Staff, the company's management team and the Technical Advisory Committee.

RENEWABLE ENERGY

- Continue studying wind potential in the company's service territory, possibly including the placement of anemometers at the most promising wind sites.
- Commission a study of Montana wind resources that are strategically located near existing company transmission assets.
- Learn more about non-wind renewable resources to satisfy renewable portfolio standard requirements and decrease the company's carbon footprint.

DEMAND SIDE MANAGEMENT

- Update processes and protocols for integrating energy efficiency programs into the IRP to improve and streamline the process.
- Study and quantify transmission and distribution system efficiency concepts.
- Determine the potential impacts and costs of load management options currently being reviewed as part of the Heritage Project.
- Develop and quantify the long-term impacts of the newly signed contractual relationship with the Northwest Sustainable Energy for Economic Development organization.

EMISSIONS

- Continue to evaluate the implications of new rules and regulations affecting power plant operations, most notably greenhouse gases.
- Continue to evaluate the merits of various carbon quantification methods and emissions markets.

MODELING AND FORECASTING ENHANCEMENTS

- Study the potential for fixing natural gas prices through financial instruments, coal gasification, investments in gas fields or other means.
- Continue studying the efficient frontier modeling approach to identify more and better uses for its information.
- Further enhance and refine the PRiSM LP model.
- Continue to study the impact of climate on the load forecast.
- Monitor the following conditions relevant to the load forecast: large commercial load additions, Shoshone county mining developments and the market penetration of electric cars.

TRANSMISSION PLANNING

- Work to maintain/retain existing transmission rights on the company's transmission system, under applicable FERC policies, for transmission service to bundled retail native load.
- Continue involvement in BPA transmission practice processes and rate proceedings to

minimize costs of integrating existing resources outside of the Company's service area.

- Continue participation in regional and sub-regional efforts to establish new regional transmission structures (ColumbiaGrid and other forums) to facilitate long-term expansion of the regional transmission system.
- Evaluate costs to integrate new resources across Avista's service territory and from regions outside of the Northwest.

PRODUCTION CREDITS

Primary 2007 IRP Team

Individual	Contribution	Contact
Clint Kalich, Manager of Resource Planning & Analysis	Project Manager/Author	clint.kalich@avistacorp.com
John Lyons, Power Supply Analyst	Research/Author/Editor	john.lyons@avistacorp.com
James Gall, Power Supply Analyst	Modeling and Analysis /Author	james.gall@avistacorp.com
Heidi Heath, Power Supply Analyst	Author/Editor	heidi.heath@avistacorp.com
Randy Barcus, Chief Corporate Economist	Load Forecast	randy.barcus@avistacorp.com
Jon Powell, Partnership Solutions Manager	Conservation	jon.powell@avistacorp.com

Other Contributors

Bruce Folsom, Manager of Demand Side Management	Thomas Dempsey, Manager of Thermal Engineering
Kevin Christie, Director of Gas Supply	Scott Waples, Chief System Planner
Kelly Irvine, Natural Gas Analyst	Randy Gnaedinger, Transmission Planning Engineer
Bob Lafferty, Manager of Wholesale Marketing & Contracts	Sara Koeff, Transmission Planning Engineer
Todd Bryan, Power Supply Analyst	Jeff Schlect, Manager Transmission Services
Doug Pottratz, Manager Corporate Environmental Affairs	James McDougall, Regulatory Analyst
Linda Gervais, Regulatory Analyst	Steve Silkworth, Manager of Wholesale Power
Dave Moeller, Market Service Engineer	Jessie Wuerst, Communications Manager