AVISTA Utilities

ELECTRIC INTEGRATED RESOURCE PLAN
2005

AUGUST 31, 2005

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 the Company's reports filed with the Securities and Exchange Commission. The forward-looking statements contained in this document speak only as of the date hereof. 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. New factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the impact of each such factor on the company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

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List of Acronyms

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
EF	Efficiency
EIA	Energy Information Administration
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
GWh	Gigawatt-hour
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
IS	Information Systems
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LIRAP	Low Income Rate Assistance Program
LP	Linear Programming
MW	Megawatt
MWh	Megawatt-hour
NCEP	National Commission for Energy Policy
NEB	Non-Energy Benefits
NPCC	Northwest Power and Conservation Council (formerly Northwest Power Planning Commission)
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
psig	Pounds Per Square Inch Gauge
PTC	Production Tax Credit
PUD	Public Utility District
PURPA	Public Utility Regulatory Policies Act of 1978
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

EXECUTIVE SUMMARY

The Company's 2005 Integrated Resource Plan (IRP) identifies a strategic resource portfolio that meets future load requirements, promotes environmental stewardship and satisfies regulatory obligations. A series of robust analyses are used to evaluate resource options based on expected value and levels of market volatility over the next 20 years. These analyses assist in comparing resource portfolio options, guiding the Company in the selection of a Preferred Resource Strategy (PRS). The PRS provides a balance between the objectives of low cost, reliable service and reasonable future rate volatility.

Avista's management and stakeholders in the Technical Advisory Committee (TAC) play a key role and have a significant impact in guiding the plan to its final conclusions. TAC members include customers, commission staff, consumer advocates, academics, utility peers, government agencies and other interested parties. The TAC provides important input on modeling, planning assumptions and the general direction of the planning process.

The Company has made significant progress in resource acquisitions since the last IRP. The Company demonstrated the need to acquire 75 megawatts (MW) of wind and 140 MW of combined-cycle combustion turbine generation in the 2003

Section Highlights

- Avista has added 35 MW of wind generation, 140 MW of gas-fired generation and 8 MW of conservation to its portfolio since the 2003 IRP.
- Energy and capacity deficits begin in 2010 and 2009, respectively, growing to 640 aMW and 901 MW by the end of the study in 2026.
- Electricity sales are forecast to grow 2.1 percent annually through 2026.
- Avista uses AURORA^{XMP} to model the entire Western Interconnect; market conditions outside the Northwest affect Mid-Columbia market prices.
- Conservation acquisition is 50 percent higher than in the 2003 IRP.
- Acquiring additional transmission is critical to Company plans.
- The PRS strikes a reasonable balance between keeping average costs and variation in year-to-year costs low.
- The 2016 PRS includes 400 MW of wind, 250 MW of coal, 80 MW of biomass, 52 MW of plant upgrades and 69 MW of conservation.
- Over half of future energy needs are met with renewables, plant upgrades and conservation.

IRP. Avista contracted with PPM Energy for 35 MW of wind capacity from the Stateline project in 2004. Upgrades were completed at Cabinet Gorge Unit 2 in 2004, bringing seven MW of new capacity and three average megawatts (aMW) of energy. The Company also reacquired the second half of the natural gas-fired Coyote Springs 2 plant from Mirant Corporation in January 2005.

Incremental upgrades to existing resources are forecast in this plan to provide additional energy and capacity at costs lower than acquiring new generation assets. The Company's upgrade plans for the Clark Fork River project forecasts 45 MW of capacity gains by 2012. Planned upgrades to Colstrip Units 3 and 4 in 2006 and 2007 will boost Avista's output share by 8 MW.

Resource Needs

Recent resource purchases, plant upgrades and conservation acquisition are inadequate to meet all future load growth. Annual energy deficits begin in 2010, with loads exceeding resource capability by 40 aMW. Energy deficits rise to 360 aMW in 2016 and 640 aMW in 2026. The Company will be short 5 MW of capacity in 2009. In 2016 and 2026 capacity deficits rise to 508 MW and 901 MW, respectively. Table 1 presents Company positions between 2007 and 2026.

Increasing deficits are a result of forecasted 2.1 percent annual average load growth and expirations of some long-term contracts. Figure 1 provides a graphical synopsis of the Company's load and resource balances over the next 20 years.

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 West. A Western Interconnect-wide study was performed to understand the impact of regional markets on Avista. We believe that the additional efforts to develop this study were necessary given the significant impact other western regions can have on the Northwest electricity marketplace. Existing resources were combined with the present transmission grid to simulate hourly operations for the Western Interconnect from 2007 to 2026.

Table 1: Net Position Forecast

Year	Energy Position (aMW)	Capacity Position (MW)	Year	Energy Position (aMW)	Capacity Position (MW)
2007	82	118	2011	-157	-256
2008	50	71	2016	-360	-508
2009	12	-5	2021	-491	-673
2010	-40	-75	2026	-640	-901

Cost-effective new resources and transmission were added as necessary to meet growing loads. Monte Carlo-style analysis varied hydro, wind, load and gas price data over 200 iterations of potential future conditions. The simulation results were used to estimate the Mid-Columbia electric market. The iterations collectively formed the Base Case for this IRP.

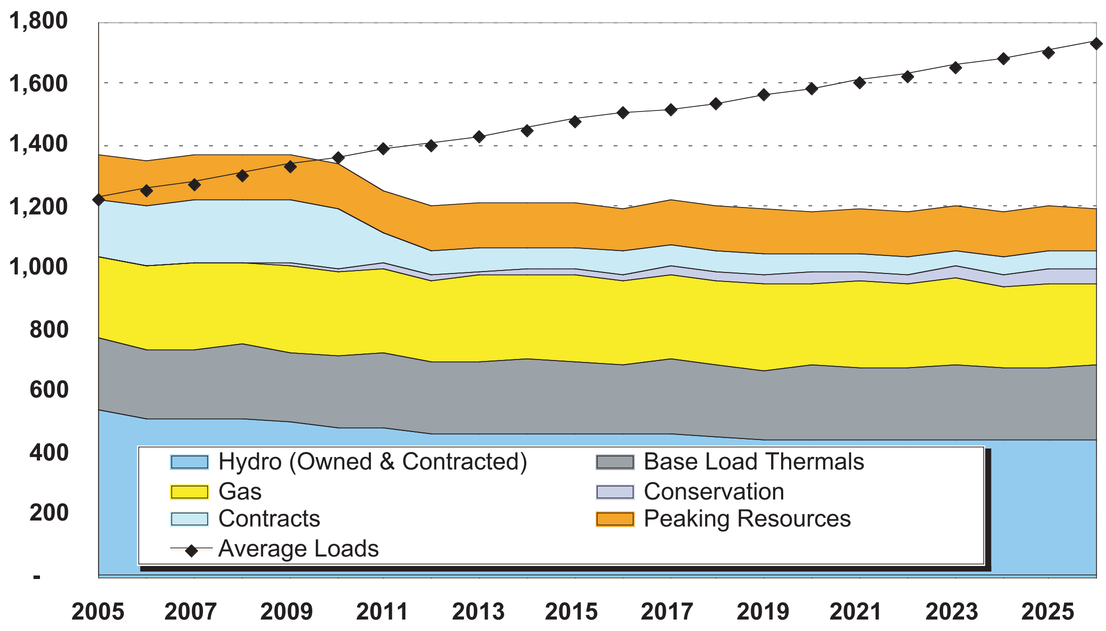
Estimated market prices were used to analyze potential conservation initiatives and available supply-side resources to meet forecasted Company requirements. Each new resource option was valued against the Mid-Columbia market to identify the future value of each asset to the Company, as well as its inherent 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.

The Company's Linear Programming model then assisted in selecting the PRS for serving future load. The selection of the PRS was based on forecasted energy and capacity needs, resource values and limiting power supply expense variability.

Futures and scenarios were used to identify performance of the PRS under conditions beyond the Base Case. Futures are stochastic studies using a Monte Carlo approach to quantitatively assess risk around an expected mean outcome.[1] This time-intensive and multi-variable approach is the most robust method used for risk assessment. Two futures were modeled for the 2005 IRP: the Base Case, and a High Gas Volatility case with increased natural gas price variability.

1 Stochastic studies use a statistical approach using probability distributions (i.e., means and standard deviations) to forecast variables into the future.

Figure 1: Load Resource Balance–Energy (aMW)

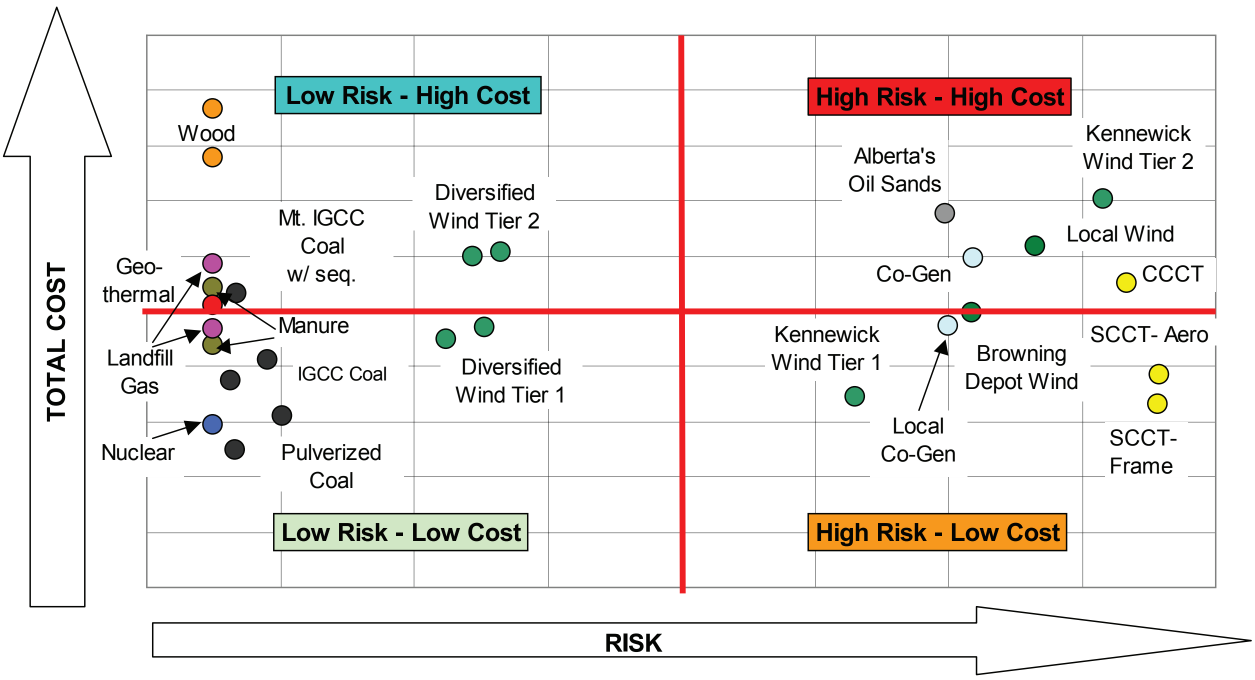


A scenario is a deterministic study that changes one significant underlying assumption to assess the impact of that change. Scenario results are easier to understand and require less analytical effort than futures, but they do not quantitatively assess the variability or risk around the expected outcome. Eighteen scenarios were modeled for the 2005 IRP, including high and low natural gas prices, carbon emission taxes and the loss of major hydroelectric generation projects.

This IRP values potential resource options by considering their costs, defined as expected incremental power supply expenses.[2] Financial risk—variability measured as the standard deviation of the incremental power supply expense—is also considered. Figure 2 plots the costs of various resource options against their inherent risks. Resources using natural gas and wind are riskier than those using fuels with more stable prices and availability, such as coal, nuclear, biomass and geothermal. The information in Figure 2 does not attempt to quantify potential risks beyond operational risk. For example, the potential for construction cost overruns and nuclear waste disposal risks are not considered. A geographically diversified wind portfolio, with ownership across the Northwest and into eastern Montana, appears to reduce some of the financial risk created by intermittent wind availability.

2 Incremental power supply expense is defined as variable O&M expenses and fuel for existing Company resources and fixed and variable O&M and capital recovery costs for new resources.

Figure 2: Resource Cost Versus Resource Risk



The IRP further enhances portfolio analysis by identifying an "Efficient Frontier." The Efficient Frontier is a financial theory that develops a curve of optimal portfolio returns based on the level of risk an investor is willing to accept. Figure 3 illustrates the Efficient Frontier developed for the 2005 IRP. This figure shows the PRS, along with other portfolios formed for the 2005 IRP, and its position relative to the Efficient Frontier.

Resource portfolios in the Efficient Frontier are subject to coal and wind limitations; hence some unrestricted portfolios, like All-Coal, theoretically can outperform the Efficient Frontier. The exercise was limited to 400 MW of wind and 250 MW of coal in 2016, and 650 MW of wind and 550 MW of coal in 2026. The wind limitation reflects Company agreement with the Northwest Power and Conservation Council (NPCC) that a limited amount of economically viable wind potential exists in the Northwest. The NPCC estimates Northwest wind potential to be 5,000 MW. Avista serves approximately five percent of Northwest loads; the prorated Company share is 250 MW. Therefore, the 650 MW target by 2026 is substantially higher than the Company's share of Northwest wind potential. The coal limitation is based on the Company's desire to acquire a cost effective and diverse fuel mix, and the risks of future carbon tax legislation.

Electricity and Natural Gas Market Forecasts

Our analyses explain that natural gas and Mid-Columbia electricity market prices are becoming increasingly correlated because of the increase in gas-fired plant construction across the Western Interconnect. Figure 4 represents the Company's electric and natural gas price forecasts. 2003 IRP forecasts are provided for reference.

Figure 3: Avista Efficient Frontier ($millions)

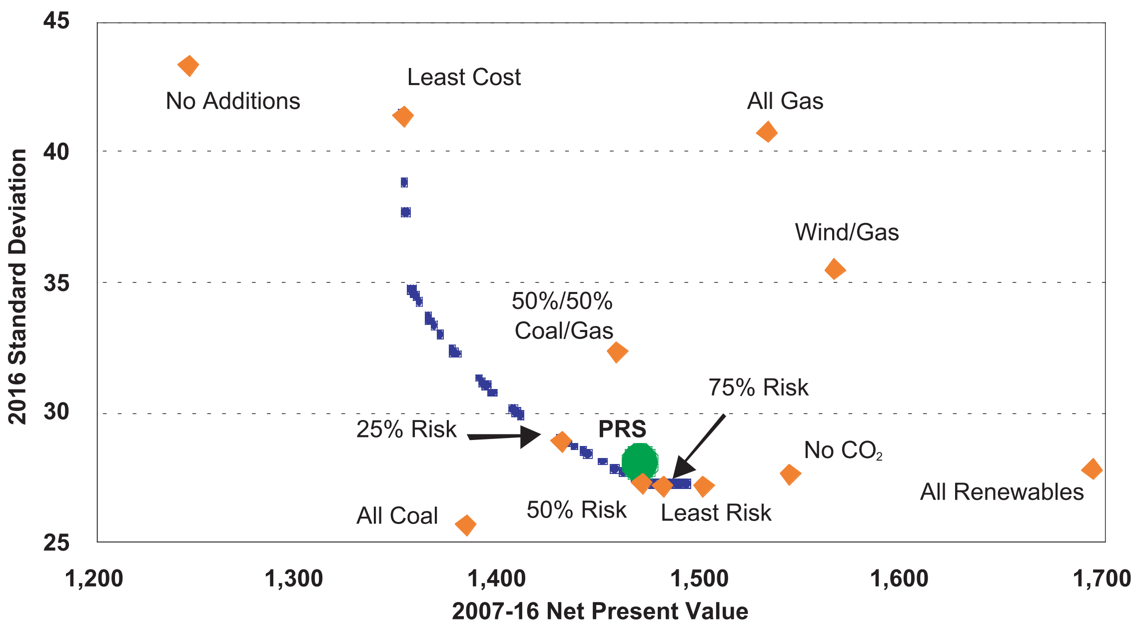


Figure 4: Nominal Electricity and Gas Prices

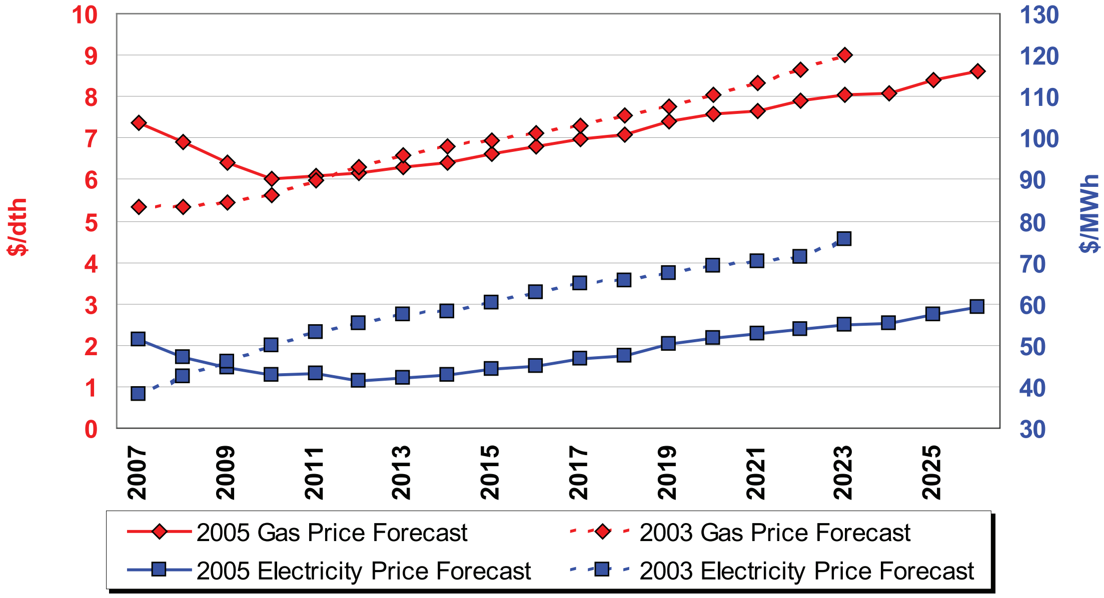
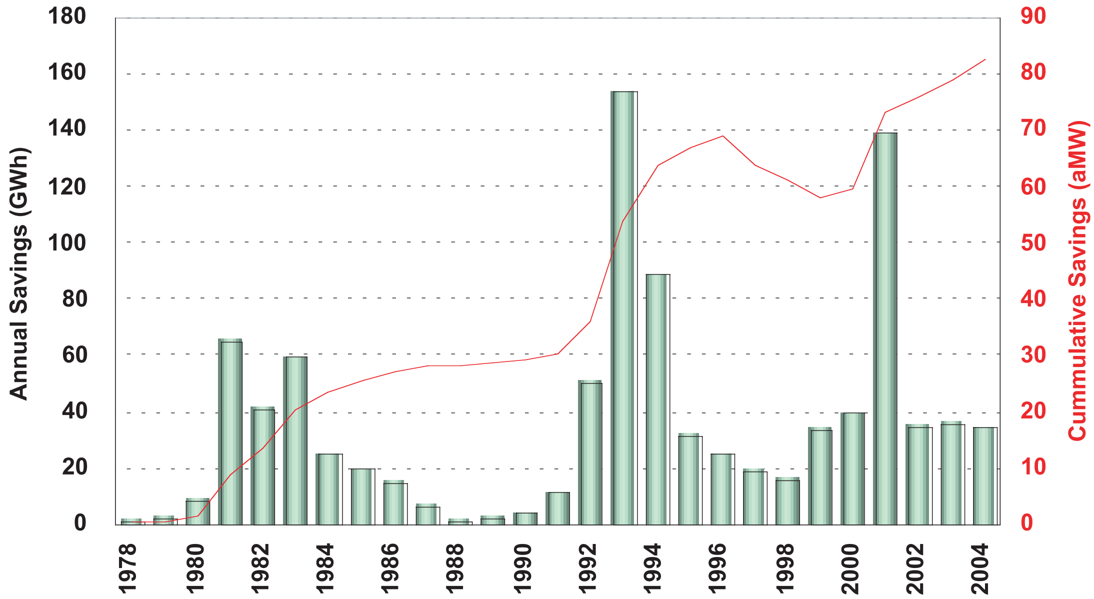


Figure 5: Cumulative Conservation Acquisitions



Conservation Acquisition

Figure 5 shows how conservation has lowered Company requirements by approximately 83 aMW since programs began in the 1970's.[3] With additional funding recommended by the IRP, the Company expects conservation to lower load growth in its service territory by 6.9 MW per year, totaling 138 MW over 20 years. The 2005 IRP conservation acquisition schedule is approximately 50 percent higher than what was included in the 2003 IRP.

Preferred Resource Strategy

The Company's Preferred Resource Strategy is defined by five resource categories: conservation, upgrades to existing generation facilities, wind, other small renewables and coal. In total, conservation, plant upgrades and renewables provide more than half of new load requirements over the IRP time frame. The 2003 IRP included more coal-fired generation to meet requirements. Both the 2005 and 2003 IRPs provide similar insulation from price volatility. In 2016 newly installed capacity includes 400 MW of wind, 250 MW of coal and 80 MW of other small renewable projects. Resource requirements are 69 MW lower because of conservation measures, and plant upgrades reduce requirements by an additional 52 MW.

By 2026 new capacity installations equal 1,332 MW: 650 MW of wind generation, 450 MW of coal-fired generation, 180 MW of other renewable generation and 52 MW of plant efficiency upgrades. Resource needs are 138 MW lower because of conservation. Figure 6 illustrates the Company's PRS.

A portion of the PRS requires construction of new transmission capacity. The Company will continue to work with regional entities and other utilities to identify low cost solutions to move power across the Northwest. Without new transmission, the Company's future resource portfolio likely will be different than presented herein.

Carbon Emissions

Two carbon emission scenarios were developed for the 2005 IRP. The National Commission on Energy Policy study, completed in late 2004, provided the basis for the first carbon emission scenario.[4] The second looked to an Energy Information Administration study of the McCain-Lieberman Climate Stewardship Act.[5] These scenarios illustrate the potential risk inherent in relying too heavily on traditional coal-fired technologies.

Table 2 explains how the 2005 plan includes more non-carbon emitting resources relative to the 2003 IRP. The 2005 plan endeavors to acknowledge and reduce greenhouse gas emissions by building significantly more renewable resources than recommended in the 2003 IRP. Acquisition of the second half of the Coyote Springs 2 gas plant fulfilled much of the 2003 IRP gas goal displayed in the table.

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3 Actual energy savings total nearly 111 aMW; however, due to expected degradation of historical measures (16-year average measure life), cumulative savings are estimated at 83 aMW.

4 See www.energycommission.org

5 See www.eia.doe.gov

Figure 6: Preferred Resource Strategy–Capacity (MW) [6]

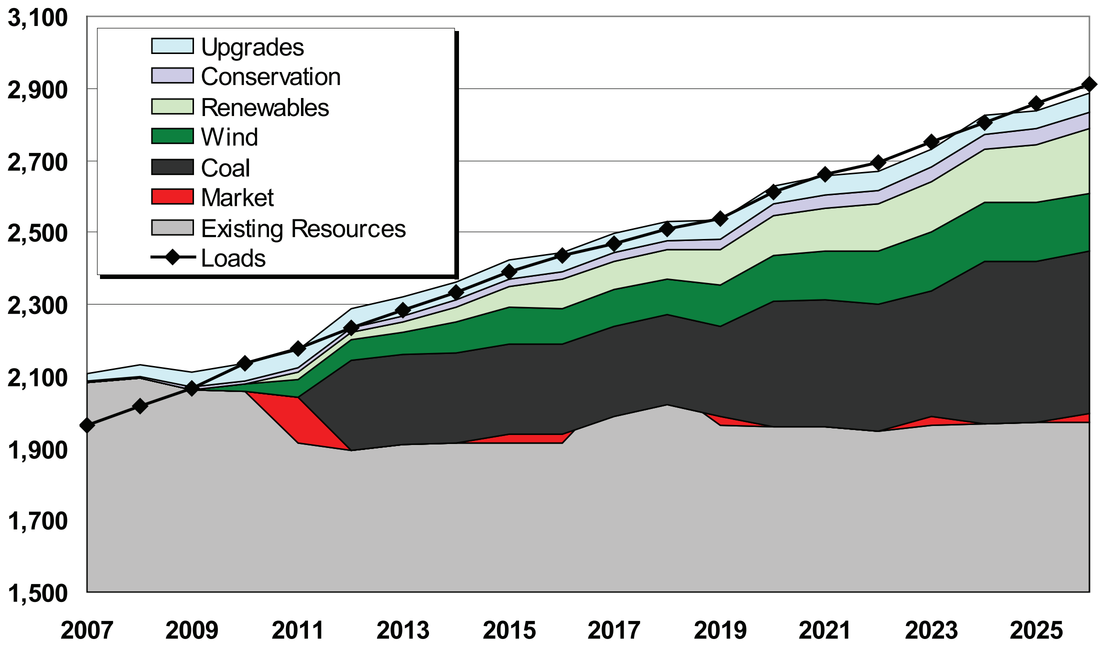


Table 2: 2005 to 2003 IRP Comparison

Time Period	Resource Type	2005 IRP	2003 IRP
2007-2016	Coal	215	350
	Wind	122	25
	Gas	121	178
	Other Renewables	65	0
	Conservation and Plant Upgrades	105	46
2007-2026	Coal	388	770
	Wind	188	25
	Gas	121	178
	Other Renewables	145	0
	Conservation and Plant Upgrades	174	92

6 Wind capacity is shown at its contribution to meeting system peak demand. Wind is assumed to contribute 25 percent of nameplate capacity to peak loads. See "Wind Contribution to Meeting System Peaks" in Section 5 for further discussion.

This acquisition is shown in the 2005 IRP column for comparative purposes.

PRS Acquisition

The PRS is very capital intensive. It will require outlays of approximately $1.5 billion by 2016. This level equals more than 80 percent of the utility's present depreciated book value. The Company might explore power purchase agreements with third parties that include options to acquire the underlying asset as a way to manage the financial impacts. Medium and short-term market purchases also are expected to fill in modest gaps between resource acquisitions and load requirements.

The Company believes that acquiring the amount of wind and biomass included in the PRS will be challenging, especially in light of our preference to acquire smaller portions of geographically diverse projects. Wind and biomass acquisitions therefore might begin as early as 2007. In the 2005 IRP Action Plan, the Company commits to continuing its research into wind and biomass potential, clean coal technologies, transmission solutions and conservation. Each of these aspects will be critical to successful implementation of the Preferred Resource Strategy.

Action Items

The Company's 2005 Action Plan outlines the activities developed by the Company's staff with advice from its management and the Technical Advisory Committee that will be undertaken to support the PRS and improve the planning process over the next two years. The Action Plan is found in Section 8, *Action Items*. Action Item categories include renewable energy and emissions, modeling enhancements, transmission modeling and research, and conservation. Progress on 2005 action items will be monitored, and the results will be reported in Avista's 2007 IRP.

INTRODUCTION AND STAKEHOLDER INVOLVEMENT

The Company submits an Integrated Resource Plan (IRP) to public utility commissions in Idaho and Washington every two years as required by state regulation[1]. Starting with the 1989 Least Cost Plan, the 2005 electric IRP represents our ninth plan. It describes the Preferred Resource Strategy meeting future customer requirements.

The Company has a statutory obligation to provide reliable electricity service to customers at rates, terms and conditions that are fair, just, reasonable and sufficient. We assess resource acquisition strategies and business plans to acquire resources when our supplies are insufficient and to optimize the value of our current resources. Avista regards the IRP as a tool for resource evaluation, rather than an acquisition plan for a particular project. The 2005 IRP therefore focuses on developing a methodology for evaluating various resource decisions and bids received in response to requests for proposals and other resource acquisition efforts.

IRP Process

The Company actively seeks input from customers, Commission Staff and other stakeholders in the IRP process and other resource planning activities. To facilitate stakeholder involvement in the 2005 IRP, the Company sponsored seven Technical Advisory Committee (TAC) meetings. The first meeting convened on October 23, 2003, and the last meeting was held on June 23, 2005. Over 70 people were invited to the meetings. Each meeting focused on specific planning topics, reviewed the status and progress of planning activities, and solicited ongoing input as the IRP was developed. The agendas and presentations for all of the TAC meetings are located electronically in Appendices A-C.

Stakeholder Involvement

Opportunity for stakeholder input into Avista's planning activities is substantial. The Company's public involvement efforts take three forms. First, the Integrated Resource Planning process provides several meetings for interested parties,

1 In Washington, IRP requirements are outlined in WAC 480-100-251 entitled "Least Cost Planning." In Idaho, the IRP requirements are outlined in Case No. U-1500-165 Order No. 22299, Case No. GNR-E-93-1, Order No. 24729, and Case No. GNR-E-93-3, Order No. 25260.

generally, the "expert public." This group reviews key assumptions, assists in framing IRP studies and analyses, and reviews the results of the work performed by the Company. Second, Avista takes the approach of "niche" public involvement. This recognizes that some customers and interested parties are focused on issues important to them. Examples include transmission corridor planning and wildlife enhancement efforts. Lastly, Company representatives participate in regional planning efforts to obtain critical insights for incorporation into Avista's planning efforts. Examples of these forums include Western Electricity Coordinating Council and Northwest Power Pool committee involvement.

Public Process

The 2005 IRP was developed very much as a public document. Each presentation given at the TAC meetings was made available to the general public on Avista's Internet web site shortly after the meeting. The presentations, along with a list of active TAC members, may be found at www.avistautilities.com. The 2005 IRP, including its technical appendices, can be downloaded at this location. A copy of our 2003 IRP is also archived at the site.

IRP Technical Advisory Committee

Avista's Integrated Resource Plan is informed by significant public input. The Company scheduled seven meetings with its TAC during the preparation of this plan. Topics included conservation, market drivers, available resource options and technical modeling issues. The 2001 IRP cycle included three TAC meetings. The 2003 IRP benefited from four meetings. The larger number of meetings for

Table 3: TAC Participants

Participant	Organization	Participant	Organization
Aliza Seelig	PSE	John Seymour	FPL Energy
Andy Ford	WSU	Ken Canon	ICNU
Charlie Grist	NPCC	Leonard Coldiron	Potlatch
Chris Bevil	PSE	Liz Klumpp	WCTED
Chris Turner	PacifiCorp	Lynn Anderson	Idaho PUC
Danielle Dixon	NW Energy Coalition	Mallur Nandagopal	City of Spokane
Dave Van Hersett	NW Energy Services	Patrick Saad	Dana-Saad Company
Doug Loreen	PSE	Richard Nagy	U. of Idaho
Hank McIntosh	WUTC	Rick Sterling	Idaho PUC
Harry McLean	City of Spokane	Terry Morlan	NPCC
Howard Ray	Potlatch	Tom Eckman	NPCC
Jamie Stark	Idaho Power	Tom McLaughlin	Potlatch
Joelle Steward	WUTC	Yohannes Mariam	WUTC

the 2005 IRP reflects the Company's interest in obtaining more insight and review from third party stakeholders, and the number and complexity of topics and analyses included in the plan.

The TAC mailing list includes more than 70 individuals representing 47 organizations. The Company recognizes the significant efforts necessary to participate in its TAC process. Table 1 recognizes individuals who actively participated in the IRP planning process by attending one or more of our TAC meetings and their respective organizations. Table 2 details meeting dates and

Table 4: TAC Meeting Dates and Agendas

Meeting Date	Agenda Items
October 23, 2003	• Review of 2003 IRP DSM Approach • Conservation Integration Methodologies • Issues to Consider
August 4, 2004	• Review of Process and IRP Schedule • IRP Topics Brainstorm • Load Forecast • 20-Year Loads and Resources Tabulation
January 25, 2005	• Overview of Natural Gas Forecast • Capacity Planning Overview • Load Forecast Update • Loads and Resources Update • Imputed Debt
February 17, 2005	• IRP Modeling Overview • Modeling Futures and Scenarios • More on Modeling Assumptions • Modeling Emissions in IRP • Supply-Side Resource Alternatives • Selection of Future TAC Dates
March 23, 2005	• Conservation Integration in 2005 IRP • Stochastic Risk Modeling • Preliminary Capacity Expansion • Update on Scenarios and Futures • 2005 IRP Draft Outline
May 18, 2005	• Natural Gas Price Forecast Update • Base Case Results • LP Module/Selection Criteria • Transmission Planning • Scenario Results • Avoided Costs • Action Items for 2005 IRP
June 23, 2005	• Hydro Upgrades • Emissions • Conservation Results • Draft Preferred Resource Strategy

agenda topics presented by the Company. The Company has worked diligently to obtain input from the "general public." We actively sought participation through advertisements including display ads in major circulation newspapers. Unfortunately, in the past, very few customers attended our scheduled meetings or otherwise showed interest in Avista's long-term planning efforts.

General public customers can be very interested in collaboration, focusing on issues dear to them. Some are motivated by a specific interest such as an upgrade to, or construction of, transmission corridor close to their property. The Company has provided several opportunities for input on specific issues, as described below.

Issue-Specific Public Involvement Activities

Avista convenes collaborative processes to address issues that have significant public interest.

External Energy Efficiency ("Triple E") Board

The Triple E has met at least twice a year to guide conservation efforts since 1995. The Triple E predecessor, the DSM Issues Group, was instrumental in shaping Avista's DSM tariff rider, 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 in 1998 to the first all-party settlement filed with a FERC relicensing application. The nationally recognized "Living License" concept was an outgrowth of this stakeholder process. The relicensing collaborative formed as part of the Living License is now in its implementation phase, with subsets of stakeholders participating in project mitigation activities including the establishment of conservation areas for wildlife preservation.

FERC Hydro Relicensing—Spokane River Projects

The Company has convened a process similar to the Clark Fork River Projects effort in relicensing its Spokane River projects. Approximately 100-stakeholder groups participated in this collaborative effort. Draft license applications were filed with FERC on July 28, 2005.

Transmission Upgrade—Spokane Valley

Avista is constructing two new transmission substations—Boulder in the Spokane Valley and Dry Creek in southeast Clarkston, Washington—to meet growing electricity demand in these areas. Avista also is reconstructing the 230 kilovolt (kV) transmission line linking Coeur d'Alene and Spokane. Construction on each of these projects began after numerous public meetings. Customer input led the Company to choose alternative locations for the Boulder substation and corridor expansion.

Transmission Upgrade—Palouse

Avista is working on a new transmission line in the Palouse region. This project also benefits from public involvement.

Low Income Rate Assistance Program (LIRAP)

LIRAP progress is shared with the four community action agencies in the Company's Washington service territory through regular meetings. At the inception of the program in 2001, meetings were held monthly to review administrative issues and needs. Meetings are now convened on a quarterly basis.

Participation in Regional Planning

The Pacific Northwest generation and transmission system operates in a coordinated fashion. Avista is an active participant in several regional organizations with planning efforts that inform the Company's integrated resource planning process. Among the organizations Avista participates in are:

- Western Electricity Coordinating Council
- Northwest Power and Conservation Council
- Northwest Power Pool
- Pacific Northwest Utilities Conference Committee
- Grid West
- Transmission Improvements Group
- Northwest Transmission Assessment Committee
- Seams Steering Group-Western Interconnection
- North American Electric Reliability Council

Future Public Involvement

The Company will continue to actively seek input from its customers and other interested parties. Advice will be requested where major impacts are expected. For the IRP process specifically, TAC meetings will remain open to the general public.

Outline of 2005 IRP Report

The 2005 IRP report contains eight sections, an executive summary and this introduction. Technical appendices are included as a supplement to this report.

Executive Summary

This section summarizes the results and highlights of the 2005 IRP.

Introduction & Stakeholder Involvement

This section introduces the IRP and explains the involvement of all interested parties.

Section 1: Electricity Sales Forecast

This section covers the relevant local economic and Company load forecasts.

Section 2: Resource Requirements

This section provides descriptions of Company-owned generating resources, major contractual obligations and rights, capacity and energy tabulations, and a discussion about reserve margins.

Section 3: Conservation Initiatives

This section covers Avista's conservation programs, the methodology and analysis of conservation measures, descriptions of the conservation measures, and a discussion of the results.

Section 4: Transmission Planning

This section discusses the Company's transmission system, and summarizes the Company's and regional transmission issues.

Section 5: Modeling Approach

This section covers the market simulation modeling assumptions and inputs, risk modeling, the Avista Linear Program Model, new resource alternatives available to the Company and wind modeling.

Section 6: Modeling Results

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

Section 7: Preferred Resource Strategy

This section provides details about the Company's Preferred Resource Strategy and how the PRS compares to theoretical portfolios under stochastic and scenario analyses.

Section 8: Action Items

This section recaps progress made on 2003 IRP action items, and details action items for the 2005 IRP.

1. ELECTRICITY SALES FORECAST

This section summarizes a variety of Company, customer and load forecasts for our service territory. The section concludes with discussions of both the high and low load forecasts developed for the 2005 Integrated Resource Plan (IRP) and an overview of recent enhancements made to the forecasting models and processes.

1.1 Economic Conditions in the Service Area

The Avista Utilities electric service territory covers a wide swathe of Eastern Washington and Northern Idaho. The geography is as diverse as the economy. Rugged mountains, fertile river valleys and glacially created plains provide natural resources, farmlands and cityscapes for over 800,000 residents of the Inland Northwest. Avista Utilities serves most of the urbanized and suburban areas in 24 counties. See Figure 1.1 for a map of the Company's service territory.

1.2 Electric Operating Division Economy

Over the last 20 years, the economy of the Inland Northwest has transformed from a natural resource-based manufacturing economy to diversified light manufacturing and services. Manufacturing employment has declined along with mining reserves in Shoshone County, Idaho, and Stevens County, Washington. Much of the mountainous area of the region is owned by the Federal government and managed by the United States Forest Service. Severe curtailments of timber harvest on public lands have led to the closure of many sawmills throughout the region. Two pulp and paper plants served by Avista Utilities have large private holdings of forested lands; they continue to face stiff domestic and international competition for their products.

Section Highlights

- Avista will serve 350,000 electric customers in 2007, and nearly 485,000 in 2026.
- 135,716 new jobs are forecast for Bonner, Kootenai and Spokane Counties by 2026, a 61 percent increase from 2004 levels.
- Electric sales are forecast to grow 2.1 percent annually.
- 2007 retail load (absent conservation) is forecast at 9,142 gigawatt-hours; 2026 is forecast at 13,542 gigawatt-hours.
- Several large industrial facilities permanently closed in Washington and Idaho because of the 2001-02 economic recession; the electric retail sales forecast assumes these closures are permanent.

Two national recessions strongly impacted the Inland Northwest during the 1980s. Economic slowdowns typically are reflected in employment data, with employment expanding during expansionary times and contracting during recessions. The 1980s exemplified that pattern with high levels of regional unemployment. The U.S. recession in the early 1990s bypassed much of the area's economy. The most recent recession, beginning in 2001, provided a harsh reminder of the difficulty in insulating a regional economy from national events. Historical patterns of employment for the three principal counties in the Company's electric service area are shown in Figure 1.2. Population levels often are more stable than employment levels during times of economic prosperity and decline; however, during severe economic downturns, total population often contracts as people leave in search of job opportunities. The Company last experienced population loss during the early 1980s. Figure 1.3 details population changes in Spokane, Kootenai, and Bonner counties. Figure 1.4 shows total population in the three counties.

1.3 The Economic Forecasts

Avista Utilities purchases national and county-level employment and population forecasts from Global Insight, Inc. (formerly Data Resources, Inc.), an internationally recognized economic forecasting consulting firm.

The Company purchases data for the three principal counties comprising over 80 percent of the service area economy, namely, Spokane County in Washington; and Kootenai and Bonner Counties

Figure 1.1: Service Territory Map

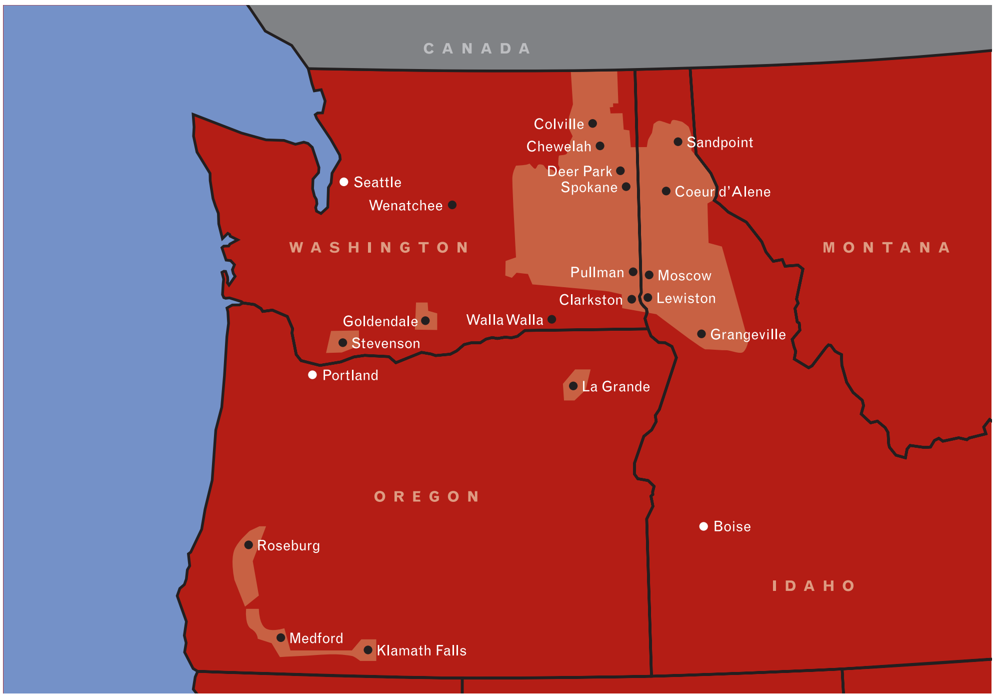


Figure 1.2: Idaho and Washington Job Change by County (thousands)

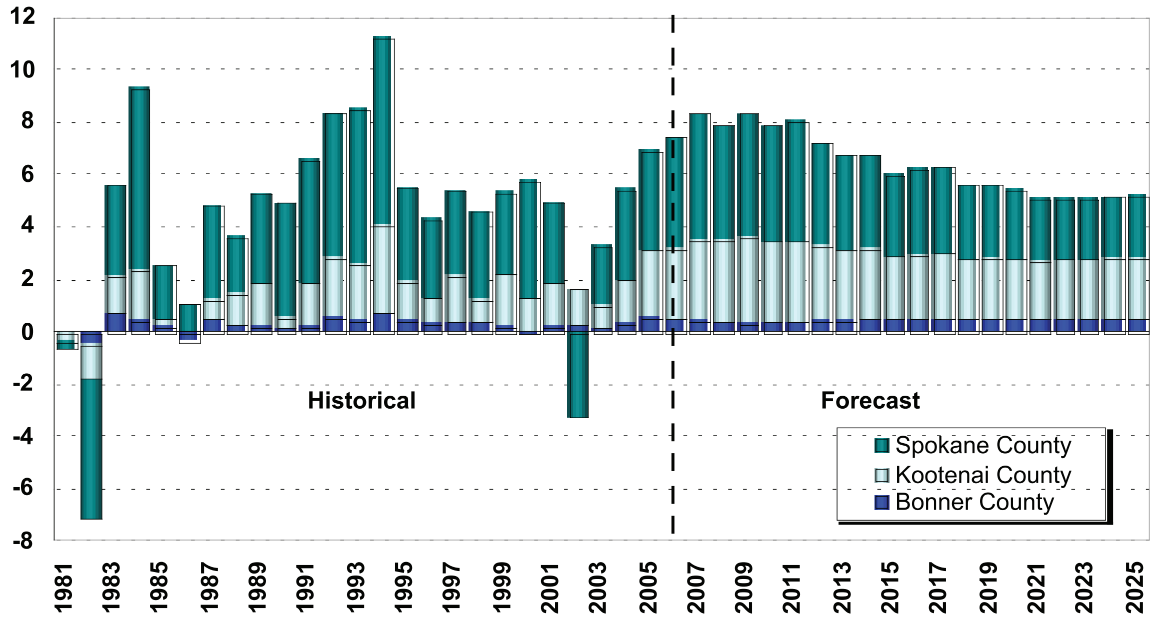
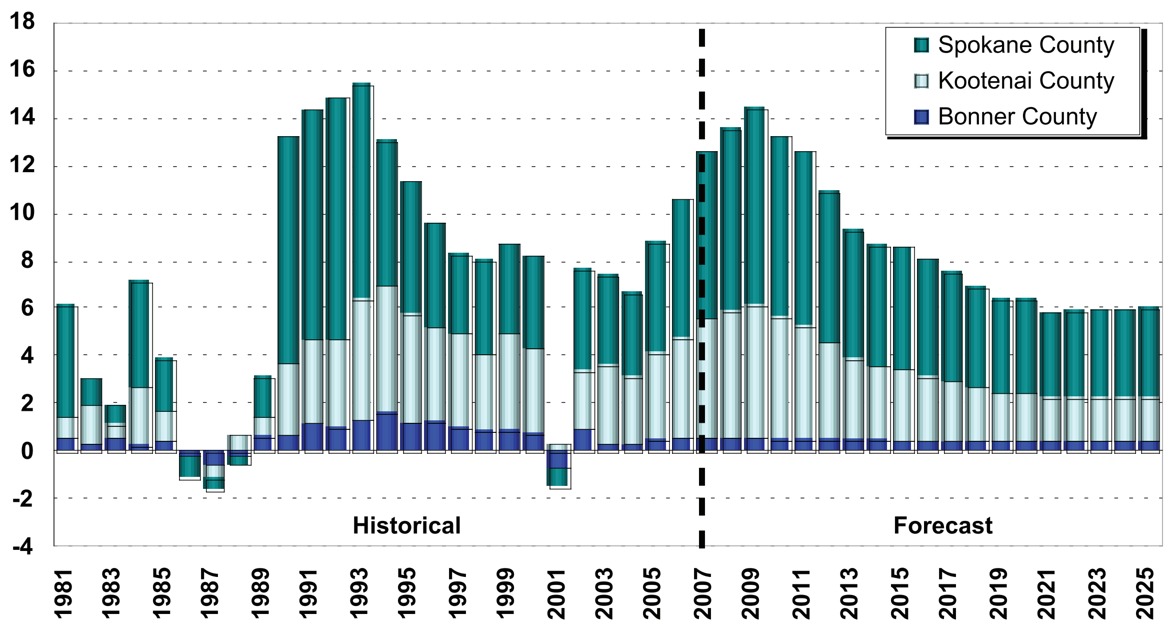


Figure 1.3: Idaho and Washington Population Change by County (thousands)



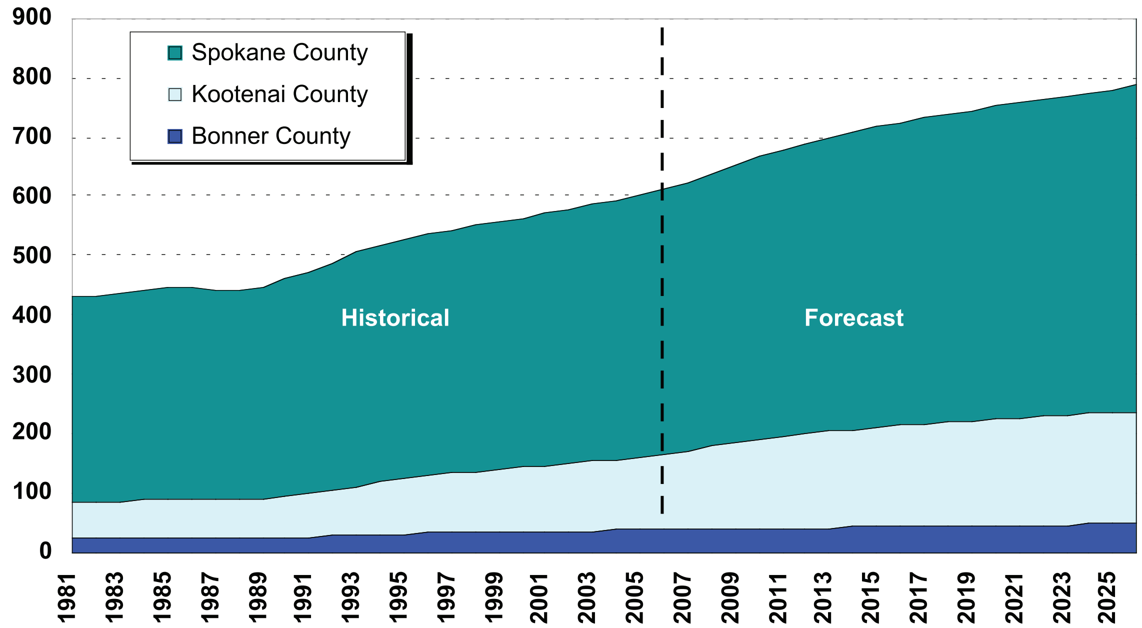
in Idaho. The national forecast, on which these regional forecasts are based, was prepared in March 2004; the county-level estimates were completed in June 2004.

Employment and population forecasts provide the basis for electric customer projections. Spokane County, dominated by the economy of the City of Spokane, is expected to exhibit moderate and steady growth for the next 20 years. Kootenai County, including the City of Coeur d'Alene, was one of the fastest growing areas in the U.S. during the 1990s. Our forecast anticipates continued and significant growth in this area. Bonner County, located north of Kootenai County, is forecast to experience steady but more modest growth over the IRP timeframe.

1.4 Electricity Customer Forecasts

The key driver of the electricity customer market is population growth. Population drives the housing market, a fundamental driver of commercial customer expansion. Commercial markets expand as more retail stores, schools, and other businesses are attracted to an area to serve markets created by the increased population. Other factors influencing housing demand include interest rates, apartment vacancy rates and student housing construction on college campuses. The region's housing market has tightened substantially in recently years, absorbing the surplus generated after the early 1990s population boom. Low interest rates in 2004 nearly doubled residential building permits in Spokane and Kootenai County when compared to 2001 levels, increasing the numer of retail customers. The unsold housing inventory also is at

Figure 1.4: Total Service Territory Population (thousands)



a cyclical low. The region's strong housing market is expected to continue, at a more modest rate, over the next decade.

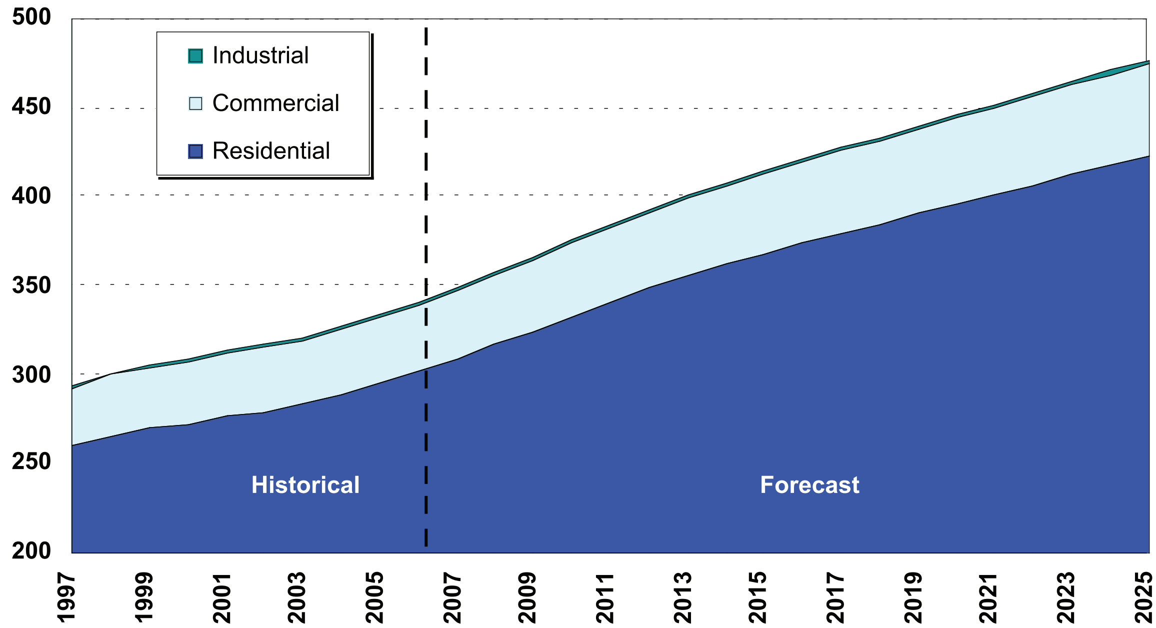
Over the 20-year horizon, overall customer growth is estimated to average 1.8 percent per year in for the period 2005-2025. This level of growth is somewhat faster than the 1.3 percent experienced during the past five years. Figure 1.5 provides detail about the forecasted growth in lighting, industrial, commercial and residential accounts. Relative to the other customer classes, street lighting loads are very small and are not included in the figure.

1.5 Retail Electricity Sales Forecast

Between 1997 and 2004, 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 reinforced conservation efforts. Several large industrial facilities served by the Company permanently closed during the 2001-02 economic recession. The electric retail sales forecast takes a conservative approach, assuming these closures are permanent. However, if any of these major industrial facilities reopen, the annual electric retail sales forecast will be adjusted accordingly.

Retail electricity consumption rose 1.2 percent annually from 1998 through 2004. This increase was in spite of the combined impacts of higher prices and decreased electricity demand during the energy crisis. The forecasted annual increase in firm sales over the 2005 to 2025 period is 2.1 percent.

Figure 1.5: Electric Utility Customer Forecast (thousands)



The forecast is broken into several customer classes in Figure 1.6.

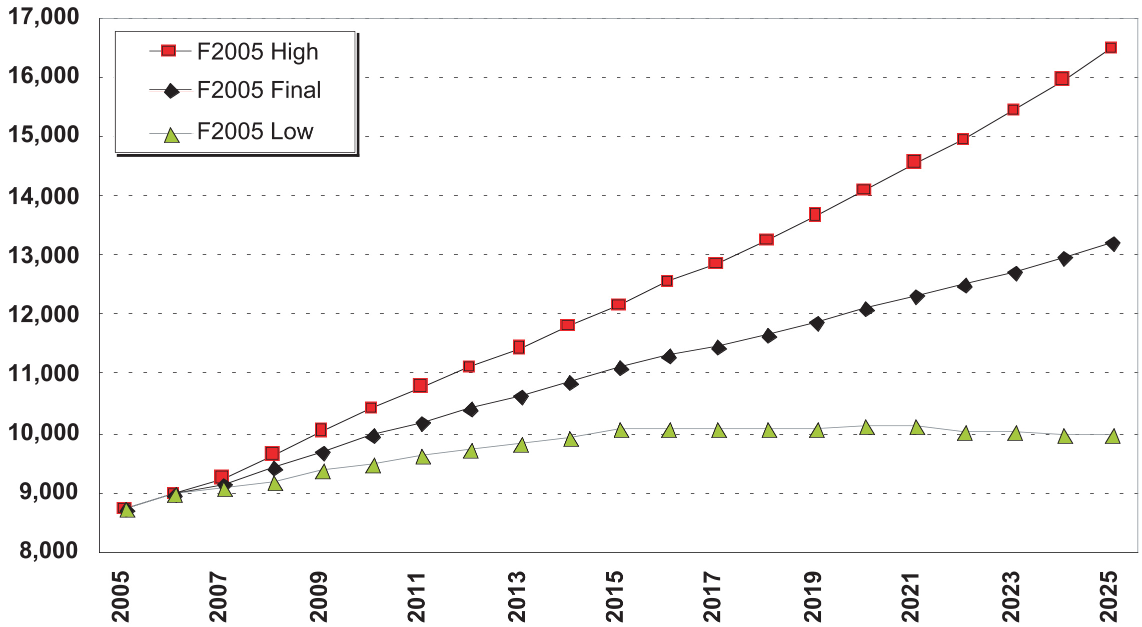
1.6 Price Elasticity[1]

Elasticity is one of the central concepts of economics and must be considered when forecasting electricity demand. Price elasticity of demand, or "own price" elasticity, is the ratio of the percentage change in the quantity demanded of a good or service, in this forecast electricity, to a one-percent change in its price. In other words, elasticity measures the responsiveness of buyers to a price change. A consumer who is very responsive to a price change has a relatively elastic demand, whereas a customer who is unresponsive to price changes has a relatively inelastic demand.

1 The elasticity definitions used in this section were paraphrased from Economics: Principles, Problems, and Policies by Campbell R. McConnell and Stanley L. Brue, 14th edition.

Consumers illustrated elastic electricity demand during the 2000-01 energy crisis, reducing 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 other good, consumers shift their consumption to the second good. Complementary goods are used together, so increases in the price of one good will result in a decrease in demand for the second good as consumers reduce consumption of the first good. For Avista, the dominant impact on electricity

Figure 1.6: 2005 Electric Utility Retail Sales Forecast (GWh)

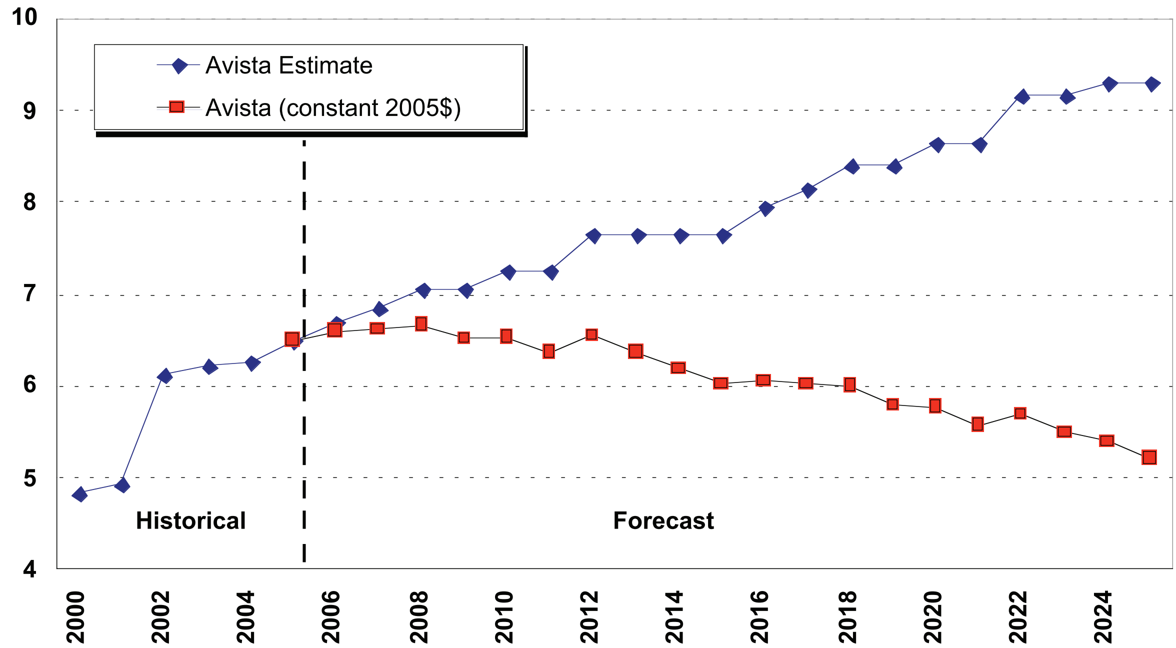


demand is the substitutability of natural gas in some applications, such as water and space heating. Income elasticity of demand is the ratio of the percentage change in the quantity demanded of a good to a one-percent change in consumer income. Income elasticity measures the responsiveness of consumer purchases to income changes. For electricity demand, there are two impacts on consumption. The first impact is the affordability impact. As income increases, a consumer's ability to pay for products and services increases. The second income-related impact is the amount and number of customers using equipment within 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. Avista estimates price elasticity by customer class in its computation of electricity and natural gas usage. Residential customer price elasticity is estimated at negative 0.15; for each one percent increase in the price of electricity, usage falls by 0.15 percent. Commercial customer price elasticity is negative 0.10. The cross-price elasticity of natural gas with electricity is estimated to be positive 0.10. The income elasticity is estimated at positive 0.75. Figures 1.7 and 1.8 illustrate how the price projections are used to determine elasticity impacts. As rates increase or decrease, consumers will adjust electricity usage according to their elasticity.

Price elasticity at these levels will not greatly affect the demand forecast. Real income per household is forecast to increase at an average of

Figure 1.7: Residential Retail Rate Projection for Retail Load Forecast (cents/kWh)



1.3 percent annually between 2005 and 2025. This increase results in flat residential usage and a small upward drift in commercial usage per customer. Commercial growth is attributed mostly to a higher concentration of big box retailers, office buildings and future school construction.

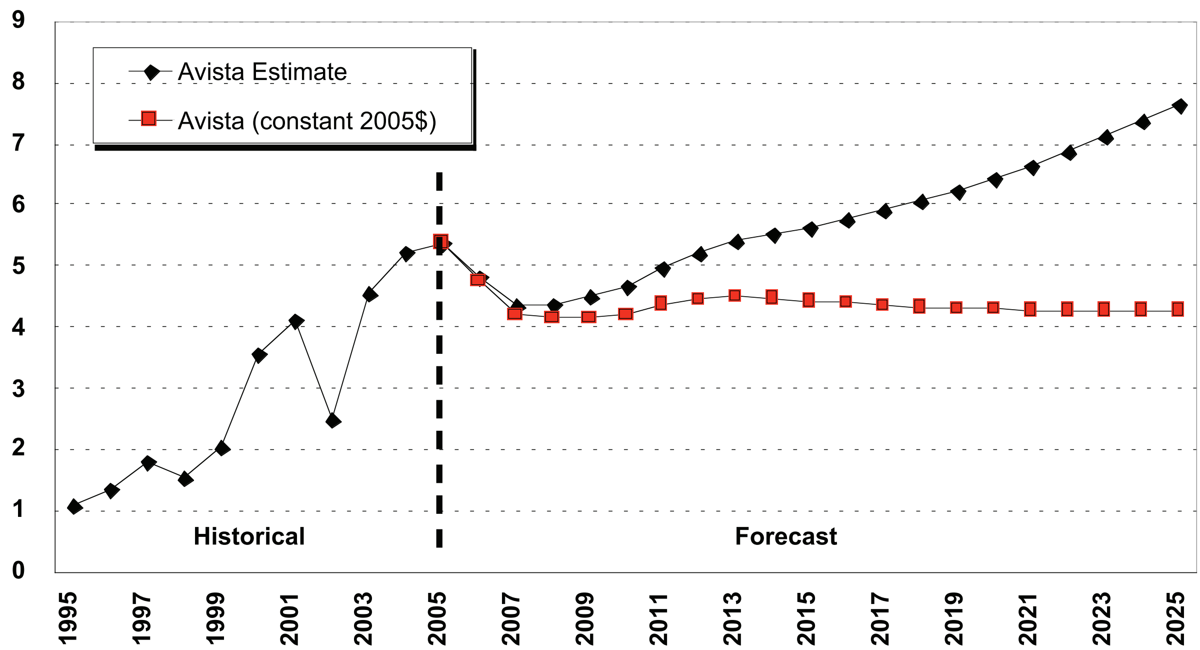
1.7 Alternative Scenarios

The discussion so far has concentrated on the "Base Case," medium or "most-likely" forecast for electricity consumption by our customers. Forecasting is necessarily uncertain, so alternative electricity growth scenarios are used to provide insight and guidance for resource acquisition plans.

With the advice and consultation of the Technical Advisory Committee, "high" and "low" economic forecasts were prepared. The principal determinant of these alternatives was population change within the Company's existing service area. As such, no assumptions for service area expansion or integration of existing electricity customers located within the service area, but served by other utilities, is expressed or implied by these alternatives. For example, the Kaiser Aluminum Rolling Mill in the Spokane Valley is assumed to continue to be served by the Bonneville Power Administration even though it is located within our service territory.

The alternative forecasts are presented in Figure 1.9. The scenarios are specific to this IRP; they should not be confused with other Company or agency forecasts. The scenarios also are not boundary forecasts, in that the high forecast should

Figure 1.8: Wholesale Natural Gas Price Forecast for Retail Load Forecast ($/dth)

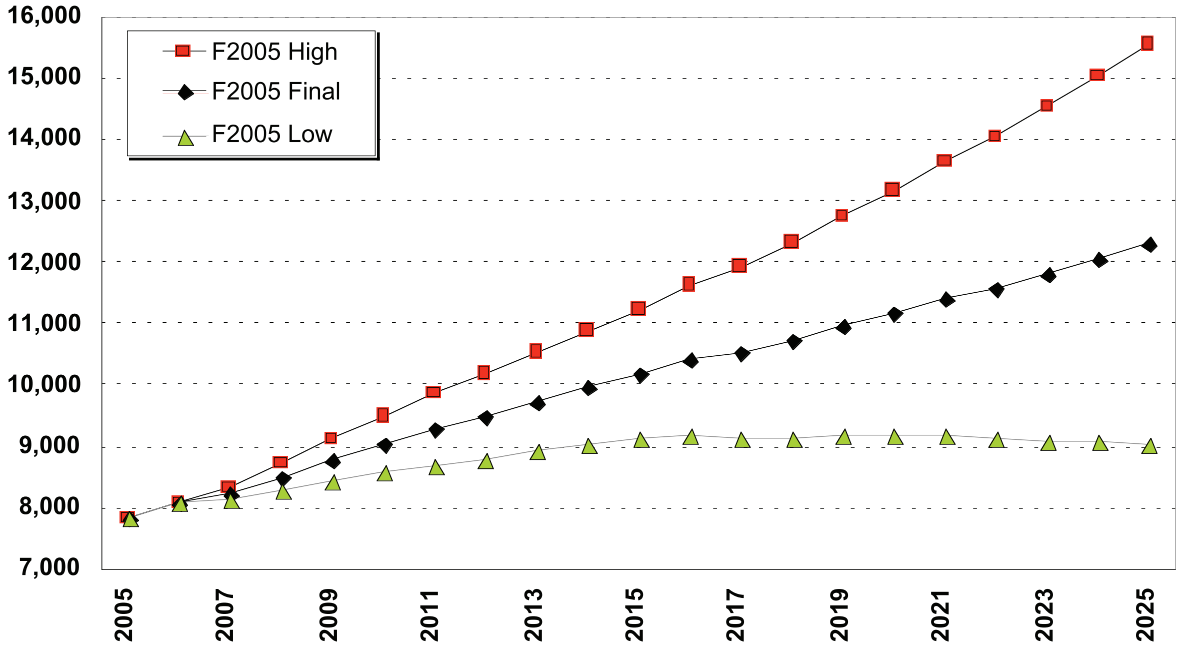


not be considered the highest possible load trajectory, and the low forecast does not represent the lowest possible forecast.

1.8 Enhancements to the Forecasting Models and Process

The forecasting models were updated with the latest energy consumption profiles for the 2005 IRP. The model's coefficients were checked for price elasticity impacts, and the updated values were incorporated into the forecast. Recent electricity consumption levels, driven largely by the recent increase in electricity and natural gas prices, showed a reduction in price elasticity for our residential and commercial customers. We use conservative elasticity estimates for industrial customers, because rising commodity prices can curtail their international competitiveness.

Figure 1.9: Retail Sales Forecast Scenarios (GWh)



2. RESOURCE REQUIREMENTS

A critical aspect of integrated resource planning is the long-term tabulation of loads and resources. Loads refer to projections of how much capacity and energy customers are expected to consume over the length of the planning period. Resources refer to the generating assets owned, or controlled through contracts, by the Company. The differences between loads and resources illustrate potential needs the Company must address through its future actions. This section details Company-projected resources and loads for the next 20 years. A summary of the Company's conservation initiatives—they also affect requirements—is contained in Section 3- *Conservation Initiatives*.

2.1 Utility-Owned Resources

The Company uses a diversified portfolio of generating assets to provide electricity to its customers. Avista owns and operates eight hydroelectric projects on the Spokane and Clark Fork Rivers. The Company 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 wood waste generating plant near Kettle Falls, Washington. Each resource is described herein.

Section Highlights

- The Company requires new generation resources as early as 2009.
- The IRP includes a planning margin of approximately 15 percent.
- Although in balance on an annual basis, every year of the IRP horizon contains monthly deficits.
- Approximately half of customer requirements in 2007 will be met with renewable resources, including various hydro plants, our biomass facility at Kettle Falls and a wind contract from the Stateline Wind Farm.
- Our largest hydroelectric facilities, on the Clark Fork River, operate under a federal license through 2046; the Spokane River project license expires in 2007 and presently is in the renewal process.
- Approximately 25 percent of our portfolio is natural gas-fired; medium-term market contracts will serve nine percent of customer requirements in 2007.

Hydroelectric Projects on the Spokane River

The Company 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. Following is a short description of the Spokane River projects with the maximum capacity and nameplate ratings listed for each. 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 stated by the manufacturer. Figure 2.1 is a map of all Company owned hydroelectric projects.

Post Falls

The Post Falls project was completed in 1906 at Post Falls, Idaho. The plant was updated in 1980 with an additional unit. Its five units have a maximum capacity of 18.0 MW and a nameplate rating of 14.8 MW.

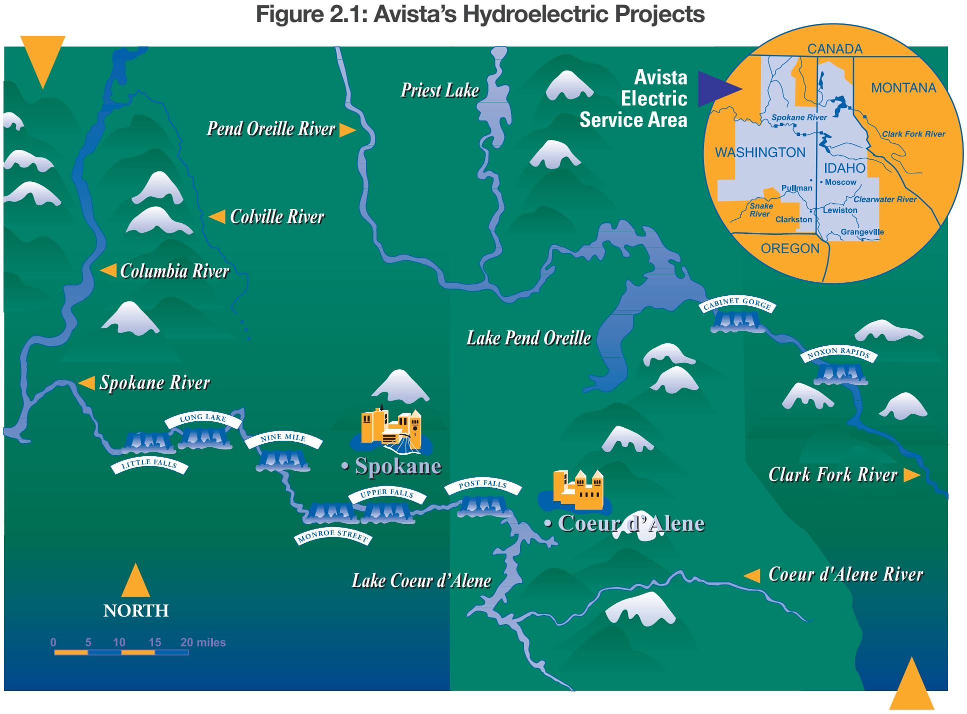
Upper Falls

The Upper Falls project was completed in 1922 in downtown Spokane. The single unit project has a maximum capacity of 10.2 MW and a nameplate rating of 10.0 MW.

Monroe Street

The Company's first generating plant, Monroe Street, was built on the Spokane River in 1890. It is located in downtown Spokane at Riverfront Park.

Figure 2.1: Avista's Hydroelectric Projects



The plant was rebuilt in 1992. Its single unit has a maximum capacity of 15.0 MW and a nameplate rating of 14.8 MW.

Nine Mile

The Nine Mile project was constructed in 1908 by a private developer near Nine Mile Falls, Washington. The Company acquired Nine Mile in 1925 from the Spokane & Eastern Railway. The four units at the facility have a combined maximum capacity of 24.5 MW and nameplate rating of 26.4 MW.

Long Lake

The Long Lake project was built in 1915 above Little Falls. It was “the world’s highest spillway dam” with the largest turbines in existence at that time. The plant was upgraded in 1999 with the installation of new runners. The total maximum capacity of its four units is 88.0 MW; it has a nameplate rating of 70.0 MW.

Little Falls

The Little Falls project is located on the Spokane River near Ford, Washington. Completed in 1910, it has four units with a combined maximum capacity of 36.0 MW and a nameplate rating of 32.0 MW.

Clark Fork River Projects

The Clark Fork River Project consists of two large hydroelectric plants in Clark Fork, Idaho, and Noxon, Montana. The two plants operate under a FERC license that was extended in 1999 to 2046.

Cabinet Gorge

Cabinet Gorge began generating power in 1952. Two additional units, bringing the total to four, were added in 1953. The current maximum capacity of the plant is 261.0 MW; its nameplate rating is 265.2 MW.

Noxon Rapids

Noxon Rapids consists of four units installed between 1959 and 1960. A fifth unit was installed in 1977. The plant currently has a maximum capacity of 527.0 MW and a nameplate rating of 466.2 MW.

Total Hydroelectric Generation

In total, our hydroelectric plants are capable of generating as much as 979.7 MW. Table 2.1 summarizes the Company’s hydro projects.

Thermal Resources

The Company owns or leases and maintains several thermal resources across the Northwest. Each plant is expected to remain available through the duration of the Integrated Resource Plan (IRP) study period. The Company's thermal resources provide dependable low cost resources that serve base load needs as well as provide peak load serving capabilities. Table 2.2 provides a summary of 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 facility. The Company 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 capacity of 111.0 MW and a nameplate rating of 116.7 MW.

Rathdrum

Rathdrum is a two-unit, simple-cycle, gas-fired plant near Rathdrum, Idaho, that entered service in 1995. The plant has a maximum capacity of 176.0 MW and a nameplate rating of 167.2 MW.

Northeast

The Northeast plant, located in northeast Spokane, is a two-unit aero-derivative simple-cycle plant completed in 1978. The plant can burn either natural gas or fuel oil, although current permits prevent the use of fuel oil. The combined maximum capacity of the units is 66.8 MW with a nameplate rating of 61.8 MW.

Table 2.1: Company-Owned Hydro Resources

Project Name	River System	Location	Project Start Date	Nameplate Capacity (MW)	Maximum Capability (MW)	60-Year Energy (aMW)	License End Date
Monroe Street	Spokane	Spokane, WA	1890	14.8	15.0	13.2	7/2007
Post Falls	Spokane	Post Falls, ID	1906	14.8	18.0	9.9	7/2007
Nine Mile	Spokane	Nine Mile Falls, WA	1925	26.4	24.4	16.4	7/2007
Little Falls	Spokane	Ford, WA	1910	32.0	36.0	22.8	N/A
Long Lake	Spokane	Ford, WA	1915	70.0	90.4	52.4	7/2007
Upper Falls	Spokane	Spokane, WA	1922	10.0	10.2	8.8	7/2007
Cabinet Gorge	Clark Fork	Clark Fork, ID	1952	265.2	261.0	122.2	3/2046
Noxon Rapids	Clark Fork	Noxon, MT	1959	466.2	527.0	202.9	3/2046
Total	All Hydro			879.3	979.7	442.9	

Boulder Park

The Boulder Park project was completed in Spokane Valley in 2002. The site has six natural gas-fired internal combustion engines. The combined maximum capacity and the nameplate rating of all of the units is 24.6 MW.

Coyote Springs 2

Coyote Springs 2 is a natural gas-fired combined-cycle combustion turbine located near Boardman, Oregon. The plant entered service in 2003. The maximum capacity is 269.0 MW. Its nameplate rating is 287.0 MW. A duct burner provides the unit with an additional capability of up to 25.0 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 hog fuel (wood). It has a maximum capacity of 50.0 MW and a nameplate rating of 50.7 MW.

Kettle Falls CT

The Kettle Falls CT is a natural gas-fired combustion turbine that began service in 2002. It has a maximum capacity 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 independent of the biomass steam plant.

Power Purchase and Sale Contracts

The Company utilizes several power supply purchase and sale arrangements of various lengths to meet a portion of its load requirements. This section describes various contracts in effect during the IRP timeframe. The contracts provide a number of benefits to the Company, including low-cost hydro and wind power. An annual summary of our contracts is contained in Table 2.3.

Table 2.2: 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	111.0	93.3
Colstrip 4 (15%)	Colstrip, MT	Coal	1986	116.7	111.0	93.3
Rathdrum[1]	Rathdrum, ID	Gas	1995	166.5	176.0	135.6
Northeast	Spokane, WA	Gas/Oil	1978	61.8	66.8	9.8
Boulder Park	Spokane Valley, WA	Gas	2002	24.6	24.6	23.2
Coyote Springs 2	Boardman, OR	Gas	2003	287.0	274.0	233.8
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			886.2	821.0	651.4

1 *The Rathdrum generating plant is operated under a third party lease.*

Bonneville Power Administration (BPA) – Residential Exchange

The Company entered into a settlement agreement of the BPA Residential Exchange Program effective on October 1, 2001. Over the first five years of the ten-year settlement, the Company receives financial benefits equivalent to purchasing 90 aMW at BPA's lowest cost-based rate. Beginning October 1, 2006, the Company's benefit level increases to 149 aMW. 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.

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 for 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 provides the Company with approximately 42 aMW of energy from BPA through 2019, subject to a contract minimum of 5.8 million mega-watt hours (MWh). The Company is obligated to pay BPA operating and maintenance costs associated with the energy exchange as determined by a formula that has a range of $16 to $29 per MWh, expressed 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

Table 2.3: Significant Contractual Rights & Obligations

Contract Name	Start Date	Capacity (MW)	Energy (aMW)	End Date
Grant County Purchase	2005	129.3	71.0	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 Purchase	2004	100.0	100.0	Dec-2010
PPM Wind Purchase	2004	35.0	9.8	Mar-2013
Total Contract		577.0	268.0	

under the Confidence Interval Planning heading of this section 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 of these plants was very large compared to the loads then served by the PUDs. To assist with financing, and to ensure a market for the surplus power, long-term contracts were signed with other public, municipal, and investor-owned utilities throughout the Northwest.

The Company entered into long-term contracts for the output of four of these projects "at cost." In 2007, the contracts provide energy, capacity, and reserve capabilities; they provide approximately 138 MW of capacity and 70 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 2005 IRP does not include energy or capacity for these contracts beyond their expiration dates.

The Company recently renewed its contract with Grant PUD 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, is 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

The Company purchased 100 MW of "flat" power from 2004 through 2010 from several suppliers in late 2001 and early 2002.[2]

Nichols Pumping Station

The Company provides energy to operate its share of the Nichols Pumping Station, the supplier of water for the Colstrip plant. The Company's share of the Nichols Pumping Station load is approximately one aMW.

2 Delivery will occur in every hour of the contract term.

Table 2.4: Mid-Columbia Contract Quantities Summary

Project Name	2007		2012		2017		2022		2026	
	MW	aMW	MW	aMW	MW	aMW	MW	aMW	MW	AMW
Rocky Reach	37.7	19.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Wells	28.5	15.4	28.5	15.4	28.5	15.4	0.0	0.0	0.0	0.0
Grant County	72.2	35.1	21.8	10.8	17.1	8.3	11.9	5.8	7.8	3.8
Totals	138.4	70.1	50.3	26.2	45.6	23.7	11.9	5.8	7.8	3.8

Portland General Electric

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

Stateline Wind Energy Center

The Company entered into a contract with PPM Energy in 2004 for 35 MW of wind capacity out of the Stateline Wind Energy Center located on the border of Oregon and Washington. This 35 MW contract does not include firming services. It was entered into in part to meet a 2003 IRP Action Item.

2.2 Capacity Tabulation

The Company develops a twenty-year service territory forecast of peak capacity loads and resources for the IRP. Peak load is the maximum one-hour obligation on the expected average coldest day in January, including operating reserves. Peak resource capability is the maximum one-hour generation capability of Company resources,

Table 2.5: Loads & Resources Capacity Forecast (MW)

	2007	2008	2009	2010	2011	2016	2021	2026
Obligations								
Retail Load[3]	1,704	1,754	1,799	1,860	1,898	2,137	2,343	2,573
Operating Reserves	260	265	269	274	278	299	317	338
Total Obligations	1,964	2,019	2,068	2,134	2,176	2,436	2,660	2,911
Existing Resources								
Hydro	1,100	1,100	1,066	1,059	1,028	1,016	983	978
Conservation	5	9	14	18	23	46	69	92
Net Contracts	159	159	165	164	48	49	118	118
Coal	222	222	222	222	222	222	222	222
Biomass	50	50	50	50	50	50	50	50
Gas Dispatch	303	308	303	303	307	303	303	308
Gas Peaking Units	243	243	243	243	243	243	243	243
Total Existing Resources	2,082	2,090	2,062	2,059	1,920	1,928	1,988	2,010
Net Position	118	71	-5	-75	-256	-508	-673	-901
Planning Margin	21.8%	18.5%	13.7%	9.6%	-0.1%	-11.7%	-17.6	-24.6%

3 Retail load is absent historical conservation acquisitions levels. Historical conservation levels are counted as a resource, thereby increasing retail load for purposes of the load and resource charts presented in this plan. This treatment has no impact on power generation acquisitions going forward.

including net contract contribution at the time of the one-hour system peak. This calculation is performed to insure that the Company has sufficient resources to meet its load obligations.

The Company has surplus capacity through 2008. Annual capacity deficits begin in 2009, with loads exceeding resource capabilities by five MW. The deficits continue to grow as peaking requirements increase with load growth, and the Company's resource base declines due to the expiration of market purchases and reductions in power from Mid-Columbia hydroelectric project contracts. Some year-to-year variation occurs in the forecast because of maintenance schedules. Table 2.5 summarizes the forecast.

The Company 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. In general, future capacity requirements will be addressed by acquiring new resources that provide both energy and capacity.

2.3 Energy Tabulation

Table 2.6 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. Confidence interval planning is discussed later in this section.

Table 2.6: Loads & Resources Energy Forecast (aMW)

	2007	2008	2009	2010	2011	2016	2021	2026
Obligations								
Retail Load	1,125	1,160	1,197	1,232	1,268	1,424	1,566	1,725
90% Conf. Interval	193	193	193	189	188	184	148	148
Total Obligations	1,318	1,353	1,390	1,420	1,456	1,608	1,715	1,873
Existing Resources								
Hydro	510	510	506	487	483	464	447	444
Conservation	5	9	14	18	23	46	69	92
Net Contracts	234	234	234	235	131	104	57	57
Coal	182	193	181	181	193	181	181	193
Biomass	42	44	40	44	42	43	42	44
Gas Dispatch	282	268	282	272	282	268	282	272
Gas Peaking Units	145	145	145	141	145	142	146	132
Total Existing Resources	1,400	1,403	1,402	1,380	1,299	1,248	1,224	1,233
Net Position	82	50	12	-40	-157	-360	-491	-640

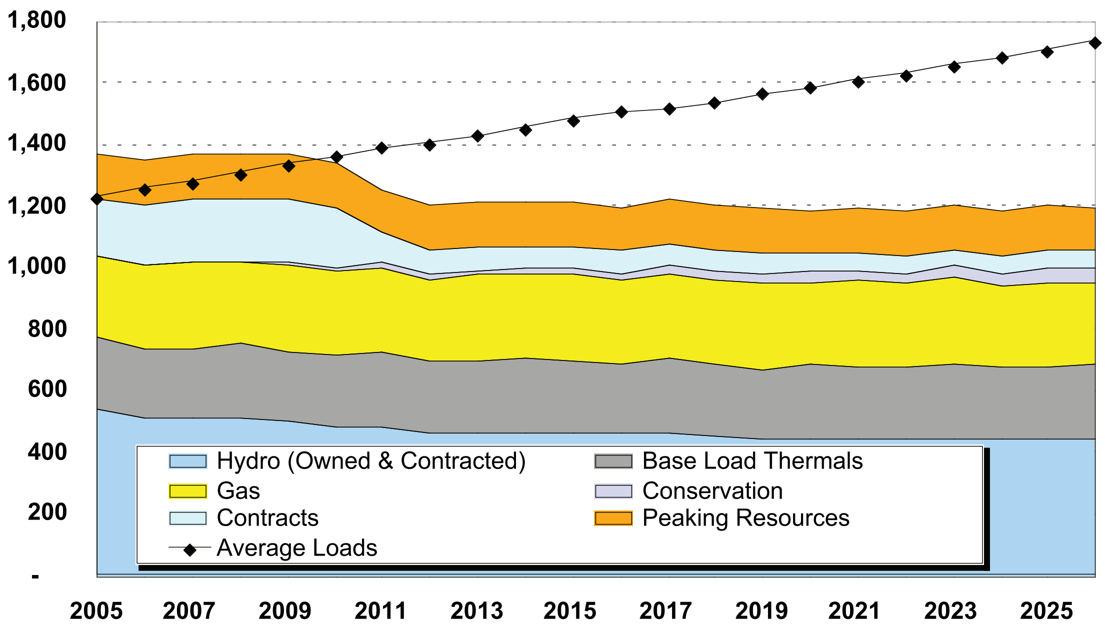
Similar to Table 2.5, maintenance schedules affect the output of various plants over the IRP timeframe. Specifically, coal, biomass, gas dispatch and gas peaking units are affected.

As shown, only after 2009 are new resources necessary to continue meeting the 90 percent confidence interval criterion. The table shows that the Company is in a surplus position through 2009 on an annual basis. Figure 2.2 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 instead includes 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 in Table 2.6 are cumulative beginning in 2007 and illustrate the Company's commitment to continued acquisition of cost-effective conservation. Activities beyond current levels are discussed in Section 3- *Conservation Initiatives* and are shown as new resources in later tabulations.

The Company expects to encounter energy deficits during some months in all forecast years. As an example, the Company anticipates deficits in January, March, August, September, October and December of 2007 even though the annual position is surplus by 82 aMW. Surplus positions occur in the remaining months, particularly during spring runoff. The Company balances its monthly positions

Figure 2.2: Energy Load and Resource Tabulation (aMW)



through short-term market purchases or sales, exchanges or other resource arrangements. The annual energy load and resource projections are used to determine when the Company needs to acquire additional resources to meet firm loads. The first annual energy deficit of 40 aMW is expected in 2010. This deficit is forecasted to grow to 360 aMW by 2016 and 640 aMW by 2026. A significant portion of the projected deficits results from the loss of Mid-Columbia contracts as well as retail load increases.

2.4 Reserve Margins

Planning reserves accommodate situations at times when loads exceed 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 of the disagreements stem from differences between systems, such as resource mix, system size and transmission interconnections. For example, a hydro-based utility generally has a higher ratio of capacity to energy than a thermal-based company. Some advocate carrying reserve levels equal to the largest resource on a specified system. Others, including the authors of FERC's recent Standard Market Design, believe that margins should be set between 12 and 18 percent of forecast peak load. California requires that all load serving entities under its jurisdiction carry a 15 percent planning margin calculated as a percentage of peak load.

Reserve margins, on average, increase customer rates when compared to resource portfolios without reserves. A 100 MW block of reserve resources currently costs between $35 and $50 million in capital expenditure, or $5 to $7 million per year. Reserve resources have the physical capability to generate electricity, but their high operating costs limit economic dispatch and the potential to create revenues to offset capital costs. Some argue that regions with deregulation, or "customer choice," provide strong incentives for industry participants to underestimate their reserve obligations and lower costs.

Reserve margin obligations can be reduced in a larger system comprised of many market participants. Table 2.7 uses an operating reserve example to explain how margins can be reduced for all participants when entities commit to sharing reserve obligations. The example is based on one matrix of operating reserve margin—reserves should be carried in an amount equal to a company's single largest resource. Total resource obligations are reduced by one-third to 9.1 percent from 11.4 percent in the example.

When one load serving entity violates its reserve

Table 2.7: Reserve Sharing Example

	Total Resources (MW)	Largest Resource (MW)	Margin (%)
Utility A	10,000	1,000	10.0
Utility B	1,000	250	25.0
Total	11,000	1,250	11.4
Utilities A&B	11,000	1,000	9.1

margin obligation, especially under a larger multi-entity reserve sharing agreement, there likely will not be a system-wide emergency during tight market conditions. The violating company, as well as its customers, will benefit as free riders from lower system costs at the expense of other market participants. If several entities simultaneously violate their planning margin obligations, high wholesale prices and/or load curtailment might occur. Therefore, it is important for utilities to be diligent in carrying adequate reserve levels to insure system reliability. To this end, many in the industry advocate for the definition and enforcement of reserve levels.

Avista 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 ten percent of our one-hour system peak load plus 90 MW. The 90 MW figure accounts for approximately 60 MW of hydro and 30 MW of Colstrip reserves. During extremely cold conditions, flows into our hydroelectric plants taper off as ice forms along the river banks. Experience shows that fuel-handling problems can limit Colstrip production during cold snaps. This amounts to roughly a 15 percent planning reserve margin during the Company's peak load hour.

Confidence Interval Planning

The Company uses confidence interval planning to insure it has resources adequate to meet its customers' 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 exposes the Company to increased volatility in the short-term marketplace.

Evaluation 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 ten percent chance of the combined load and hydro variability exceeding the planning criteria for each month. In other words, there is a ten percent chance the Company would need to purchase energy from the market in any given month. The criterian is identical to the 2003 IRP level of 80 percent. Based on 2003 IRP feedback, the Company learned that using a two-tail statistical measurement was confusing to readers. Shifting to a single-tail test better illustrates the concept of a one-in-ten probability.

The Company has considered using larger confidence intervals, but analysis suggests that the cost of adding 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 such a criterion 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 94 aMW and 258 aMW on a monthly basis in 2007, or 160 aMW across the twelve-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 chance of exceedance rather than an annual figure. 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 lies 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 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 2.8 details the assumption differences between the Company's planning approach and the sustained capacity approach.

The preliminary results gathered from work on the 2005 IRP suggest the Company should study this topic further. It is included as an action item in Section 8. Where the additional study supports changing the planning criteria, we will review such a move with our Technical Advisory Committee.

Table 2.8: 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	Average 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

3. CONSERVATION INITIATIVES

Avista Utilities began offering conservation programs in 1978 to encourage efficient energy use. Since 1978, 111 aMW of energy has been acquired through Company programs.[1] In 1995, the Company initiated the nation's first non-by-passable distribution charge, otherwise known as the DSM tariff rider, to ensure long-term stable conservation funding. Avista's current conservation programs are operationally divided into commercial/industrial, residential and limited income portfolios. Figure 3.1 details the Company's acquisition successes over time.

1 Due to expected degradation of historical measures (16-year average measure life), cumulative savings in effect today are estimated at 83 aMW.

The flexible nature of Avista's programs allows it to offer customized conservation services and technical assistance for any cost-effective commercial or industrial electric efficiency measure. The Company also provides prescriptive conservation programs for specific common measures.

The comprehensive nature of Avista's commercial and industrial programs impacts the methodology used to evaluate conservation options in this IRP and the evaluation of future business planning. The limited income program is offered through several community agencies with broad discretion to pursue energy-efficiency measures among limited income and vulnerable customer groups. There also is limited funding for health and human safety measures designed to enhance the life of efficiency measures, the habitability of the residence, and

Section Highlights

- In 1978 Avista began acquiring conservation, focusing on residential audits, and providing incentives for shell and water heater insulation.
- Residential programs were ramped up in 1980 to focus on weatherizing, infiltration reduction, windows and water heater insulation measures.
- Avista regulators approved the nation's first non-by-passable distribution charge in 1995.
- Responding to the 2000-01 Western Energy Crisis, the Company acquired over 20 aMW of conservation in 2001 alone.
- Avista reached a milestone in 2002—100 MW of conservation.
- The 2005 IRP increases our conservation acquisition goal by 50 percent.

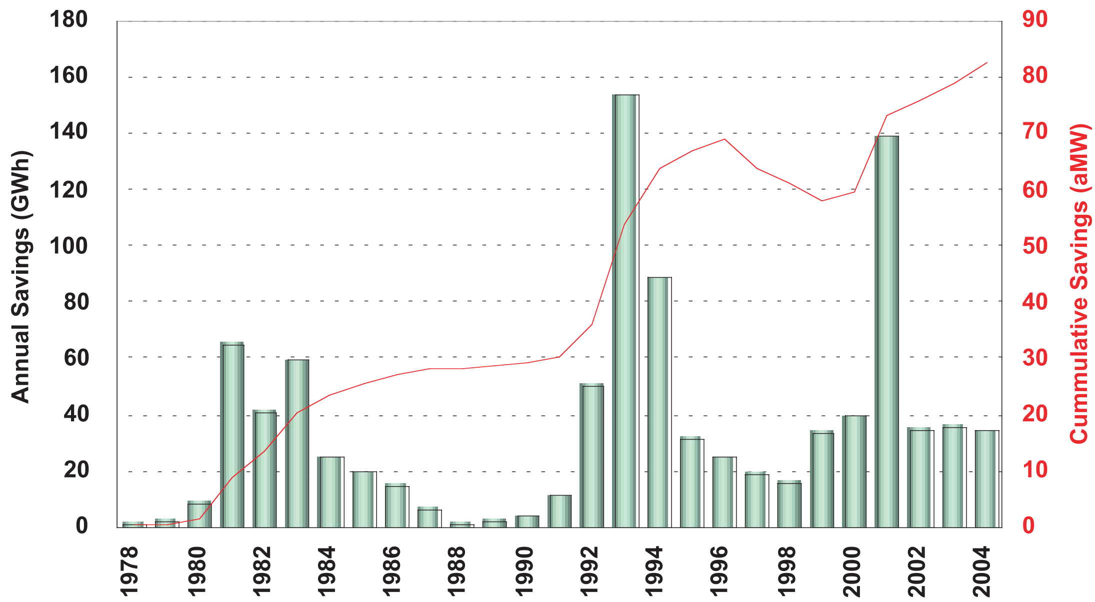
energy safety. Avista augmented agency funding with Conservation and Renewable Discount dollars received from the Bonneville Power Administration beginning in 2003.

Residential programs are exclusively prescriptive in nature because of the relatively small nature of residential electric usage. The Company offers a number of programs in this class, including improved space and water heating efficiencies, improved shell efficiency and more efficient residential lighting. The space and water heating components of these programs include the conversion of space and water heating appliances from electricity to natural gas. All existing and several new and promising residential measures are incorporated in the 2005 IRP evaluations.

The Company launched a major conservation response to the 2001 western states energy crisis. The acceleration was a cost-effective strategy that helped mitigate the impacts of abnormally high wholesale energy prices. Program funding was derived from the DSM tariff rider. As a result of this extraordinary utility effort, the Company spent $12.4 million more on conservation measures than was collected from the tariff rider in 2001. To address the resultant tariff rider deficit, the Company established a 2002-2005 business plan designed to meet regulatory obligations, to field a cost-effective conservation portfolio and to expeditiously return the tariff rider balance to zero.

The return to a zero balance was and continues to be achieved through a series of sustainable and non-sustainable cost containment measures and through the targeting of low- or no-cost measures and lost opportunities. As individual tariff rider balances approach zero in each state, the target markets of each component are redefined to include

Figure 3.1: Historical Electric Conservation Acquisition



all cost-effective measures, and program support is increased to meet available opportunities.

Even with the Company's recent cost-containment measures, it has continued to materially achieve the conservation goal specified in the electric tariff rider, as illustrated in Figure 3.2.[2] Avista's prorata share of the Northwest Power and Conservation Council's Fifth Power Plan conservation goal is shown for reference.

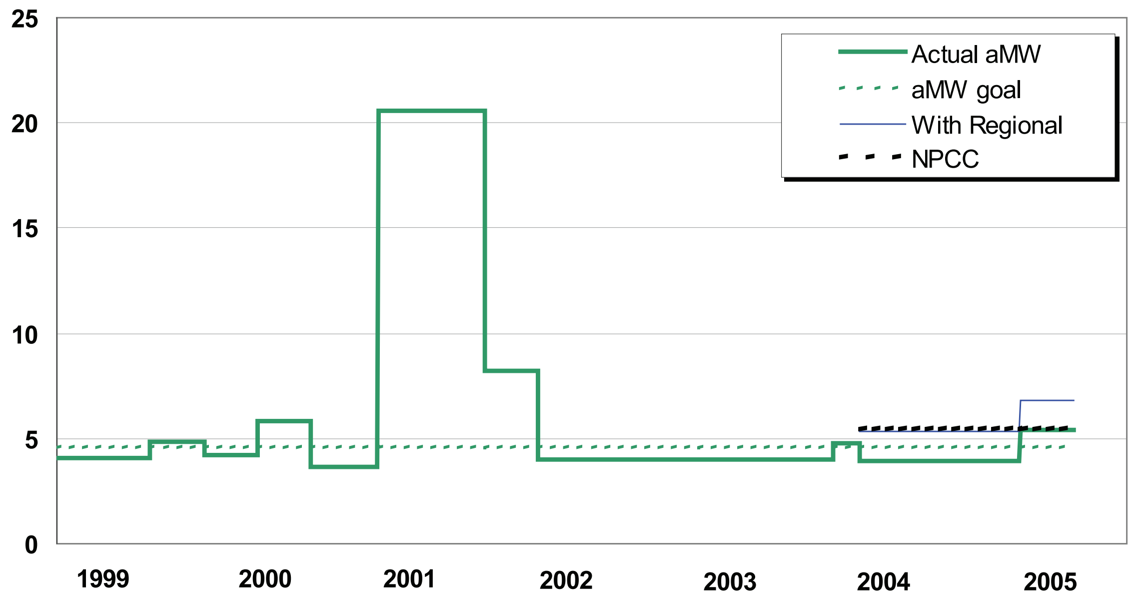
The Company reviewed its 2002-05 business plan in early 2004, concluding that a 10 to 25 percent conservation funding increase was needed to support the 2005 electric IRP. The anticipated increase led to program revisions and to the acceleration of selected program components in anticipation of additional cost-effective opportunities. The ramp-up included the launch of several projects piloting alternative implementation strategies for prescriptive air conditioning and lighting measures, as well as larger commercial and industrial site-specific projects.

Analyses of these pilots, along with an assessment of contracts acquired under Avista's 2000 all-resource request for proposal process, indicates that direct customer incentives are insufficient to support the programs necessary to achieve future goals. Revisions to the Company's electric conservation tariff that would roughly double customer direct incentives was approved in Idaho (effective March 2005) and Washington (effective July 2005).

The aggregate tariff rider deficit approached zero in August 2005. The Company is in the final stages of transitioning to the 2006 conservation business plan.

2 Figure 3.2 includes resources acquired through a cooperative program with the Northwest Energy Efficiency Alliance.

Figure 3.2: Electric Conservation Acquisition Versus Goals (aMW)



It will focus on acquiring all cost-effective conservation opportunities given the results of the 2005 IRP. The IRP process enables the Company to determine the level of conservation acquisition, the target markets and the measures that will be incorporated into the future business plan.

3.1 IRP Objective

The primary purpose of the IRP evaluation for conservation is to:

- Establish an aggregate level of cost-effective projects for acquisition through local utility programs. This becomes the future conservation goal.
- Assess individual markets and measures on which to focus future acquisition efforts. This is applied to future business planning efforts, including marketing and staffing decisions.
- Identify specific prescriptive conservation programs for the residential sector. All measures will be thoroughly defined as part of the 2006 conservation business plan.

Results of the IRP do not displace tariff rider obligations. There is significant variation within the measure categories evaluated in the IRP process. It is not uncommon for specific applications of generally cost-ineffective measures to be individually cost-effective. Similarly, not all applications of generally cost-effective measures will always be cost-effective for individual projects. The Company has incorporated in our incentive calculation model an assessment of a "sub TRC" calculation to provide cost-effectiveness feedback on an individual project basis. The "total resource cost" (TRC) test is designed to ascertain whether an investment is economically justified when all of its costs and benefits are included. The "sub TRC" calculation excludes relatively fixed non-incentive utility costs that are difficult to ascribe to individual projects. The sub TRC represents each project's individual contribution to portfolio cost-effectiveness. This level of detail augments general findings of the IRP process with individual customer data for continuous program refinement and target marketing.

3.2 IRP Methodology and Analysis

The resources acquired in our current conservation portfolio generally are not dispatchable and are acquired in small quantities on a continuous basis. Consequently, the aggregate level and type of acquired conservation resources do not affect the generating resources used to establish market prices. Under these circumstances conservation is a price-taker. In other words, lower or higher acquisition levels are not expected to change overall prices in the wholesale electricity marketplace.

Conservation resources were modeled independently of supply-side resources in the IRP due to the complexity and the relatively small size of the conservation resources, because it is sufficient to acquire all cost-effective resources relative to the IRP market price signal.

IRP market prices were used at a finer level of detail for conservation planning than in the past.

A 20-year hourly avoided cost price signal was used to determine the cost-effectiveness of individual conservation measures and the aggregate level of cost-effective conservation available within the service territory. A ten percent adder was tiered on all hours of the avoided cost to reflect transmission and distribution savings, and the risk reduction values inherent in conservation resources.

Using a more detailed avoided cost required the development of unique hourly load shapes for each conservation measure. Load shapes were developed through comparable engineering simulations of base case and high-efficiency scenarios. Hourly load shapes allowed for an evaluation of load-shifting opportunities. This was not possible in past IRPs, since, for the most part, load–shifting measures can increase overall kWh usage as loads are shifted to off-peak periods. Without hourly prices to value the shift, higher usage did not appear cost-effective.

The initial survey of conservation inventory was subdivided into an assortment of independent measures. Potentially feasible measures were then added to the list. Particular attention was paid to residential measures, as they are an exception to the all-inclusive conservation portfolio approach and are not evaluated on a customer-by-customer basis. Engineers and program planners involved in this process were encouraged to err on being overly inclusive in their evaluations of different conservation measures.

The 2005 IRP exercise resulted in an initial definition of 52, and the subsequent evaluation of 51, conservation measures. The controlled voltage reduction and rooftop air conditioning measures were excluded from further consideration because both measures are currently being piloted.[3] Each will be evaluated further when the pilots are complete; results will be included in the 2007 IRP.

TRC inputs were collected for the remaining 51 measures, including customer cost, non-incentive utility cost, non-energy benefits, natural gas impact, electric energy savings and avoided cost. During the initial iteration of the 51-measure package, inputs for cost and benefit characteristics were reasonably close to those observed in the 2003 conservation program portfolio. Acquirable resource potential therefore was indexed to 2003 levels. This initial iteration provided a realistic baseline assessment to compare against actual historical operations.

Subsequent iterations involved reassessment of each measure and modifications to all inputs, including acquirable potential, with the intent of maximizing net TRC benefits. The measures were defined assuming that each was independent; however, it was necessary to perform a collective assessment of non-incentive utility costs to ensure that they were reasonably allocated across measures.

3 Insufficient results were available for evaluation of these two measures because of delays in the completion of pilot studies for each respective measure.

A "stacking" of the measures was completed for each iteration of the 51-measure portfolio. This stacking ensured reasonableness and consistency in the overall analysis. Measures were stacked in order of total resource benefit-to-cost ratio. This helped define acceptable measures and determined the shape of the IRP conservation supply curve.

3.3 Conservation Measure Definitions

A brief description of each measure considered for the IRP is presented below. The measures are divided into three main categories: industrial measures, commercial measures and residential measures.

Industrial Measures— 24,523 MWh Annual Potential

Industrial Refrigeration – 6,062 MWh Annual Potential

Cooling systems are used in a variety of processes including food storage and preparation, ice making and other large scale cooling requirements. Savings potential includes tighter control of coolant pressures and temperatures, the use of variable frequency drives (VFD), operation of ancillary fans and new control options.

Industrial Hydraulics – 667 MWh Annual Potential

Industrial hydraulics systems utilize high-pressure fluids for power transmission in a variety of industries, including wood products, plastics and mining. Hydraulic systems are used for precise control and applications requiring high power density, such as extruding, lifting or pressing. Potential savings exist in a number of ways, including better-part or no-load controls.

Industrial Pumps – 4,775 MWh Annual Potential

Industrial pumps refer to all processes designed to move fluids. This includes, but is not limited to, process, irrigation, and heating, ventilation and air conditioning (HVAC) applications. Savings potential exists in tighter control of pressures and flows, the use of VFDs for flow control and optimized pump selection.

Industrial Fans and Blowers – 2,808 MWh Annual Potential

Industrial fan and blower applications denote all processes that include the movement of a gas up to about 30 pounds per square inch gauge (psig). This includes, but is not limited to, a variety of industrial processes, HVAC and conveying applications. Potential savings exists in tighter pressure control and flows, the use of VFDs for flow control and system designs using high efficiency fans and blowers.

Industrial Compressed Air – 8,711 MWh Annual Potential

Industrial compressed air refers to all processes that include the movement of a gas above 30 psig. Savings potential exists in better-part or no-load controls, the use of VFDs and high-efficiency compressors. Demand-side application optimizations reduce actual consumption without affecting system production.

Industrial Lighting – 1,500 MWh Annual Potential

Three industrial lighting measures were evaluated:

- Metal halide to T-5 fluorescent lighting in manufacturing facilities
- T-12 to T-8 fluorescent lighting retrofits in industrial facilities
- Metal halide to pulse start lighting in manufacturing facilities

T-5 fluorescent lamps are the basis for a new generation of fluorescent lighting products. The smaller lamp diameter provides good optical control and may be used in applications traditionally lit by alternate systems, such as metal halide. The most significant barrier for T-5 systems is the initial cost associated with replacing existing fixtures. Utility rebates help overcome the T-5 conversion cost barrier.

T-12 fluorescent lighting is far less efficient than T-8 technology. Pulse start technology provides improved light output from metal halide fixtures and longer lamp life. The measure is most cost effective when existing metal halide lamps need to be replaced for reasons other than energy efficiency.

Commercial Measures – 15,641 MWh Annual Potential

Commercial conservation measures are performed in or on commercial properties, including schools. This group comprises the bulk of conservation project potential. Commercial measures generally require and utilize engineering resources because of the sheer size and magnitude of this segment.

Commercial Lighting – 7,641 MWh Annual Potential

The incandescent light bulb is the least efficient form of electric lighting. It wastes most of the energy it uses in the form of heat, increasing air conditioning loads. Furthermore, the life of an incandescent bulb is very short when compared to a compact fluorescent lamp (CFL). An equivalent CFL can last an average of 10 times longer than its incandescent counterpart. CFL measures generally are implemented through prescriptive incentives.

There are many existing commercial buildings not yet retrofitted to T-8 technology. Incentives for retrofitting T-12 to T-8 lighting are offered primarily through a prescriptive program. T-12 fluorescent lighting often is used in schools and there are many opportunities to retrofit T-8 fixtures.

The different categories of commercial lighting retrofits are identified as follows:

Incandescent to Compact Fluorescent Lighting – 1,200 MWh Annual Potential

- CFLs in commercial buildings
- CFLs in schools

Metal Halide to Pulse Start Lighting – 1,100 MWh Annual Potential

- Metal halide to pulse start lighting in commercial buildings
- Metal halide to pulse start lighting in gymnasiums
- Metal halide to pulse start lighting in parking lots

Metal Halide to Fluorescent Lighting Conversions – 800 MWh Annual Potential

- Metal halide to T-5 in commercial buildings
- Metal halide to T-5 in gymnasiums

Incremental Fluorescent Lighting Retrofits – 4,541 MWh Annual Potential

- T-12 to T-8 retrofits in convenience stores
- T-12 to T-8 retrofits in commercial buildings
- T-12 to T-8 retrofits in schools

Commercial Air Conditioning Measures – 2,500 MWh Annual Potential

Buildings that require mechanical cooling are identified in two different ways, skin load or internal load facilities. High-efficiency air conditioning measures for both building types were evaluated for the IRP. A skin load building is one that is highly sensitive to environmental or weather conditions. Internal processes operating within a structure impact internal facility load. An internal load building can require mechanical cooling year round if its internal processes create waste heat.

One facility can have characteristics of both internal and skin load structures, but when defining the system being changed, one type generally is predominant. A skin load building requires less air conditioning when compared to an internal load building, because it requires mechanical cooling only when the outside environment is near to or hotter than the building's temperature set point.

Corporate Network Personal Computer Controls – 800 MWh Annual Potential

Present Information Systems (IS) require processing actions to take place many times during the day in present network systems. Employees are often asked to leave their computer running after hours so that software and security systems may be updated.

A personal computer (PC) consumes between 60 and 120 watts in standby mode, even when the monitor is shut off. New network software-hardware combinations allow IS to turn on and shut off PCs during maintenance cycles, saving up to 12 hours of run time per night per PC. Individual personal computer control options were combined with corporate personal computer control conservation options.

Building Exit Signs – 1,000 MWh Annual Potential

Exit signs are excellent targets for energy savings, as they are illuminated 24 hours a day, 365 days a year. Replacing existing exit signs with more efficient models generally is cost effective.

Variable Frequency Drives – 2,550 MWh Annual Potential

VFDs are used to control motors on fans and pumps to optimize the flow of fluid. Two fluid types (liquid and vapor) are used in these applications. Liquid VFDs operate continually and generally have higher savings than vapor VFDs.

Commercial High-Efficiency Heat Pumps – 150 MWh Annual Potential

High-efficiency air source heat pumps are cost-effective only in areas without natural gas service. Natural gas furnaces and heat pumps have similar operating costs. As heat pumps have higher upfront costs than gas systems, heat pumps are not cost-effective where natural gas is available.

Non-Residential Appliance Efficiency Measures – 200 MWh Annual Potential

Non-residential appliance efficiency measures include water heating, cooking, and refrigeration end-uses. Restaurant and hospitality segments are primary targets for these measures.

Non-Residential Shell Efficiency Measures – 800 MWh Annual Potential

Shell measures increase building envelope efficiencies. Measures include insulation upgrades and window replacements.

Rooftop HVAC Measures – Annual Potential Currently Being Studied

The Company is piloting a rooftop maintenance program in our Idaho service territory. Certified contractors are using the latest tools and technology to diagnose and service problems in rooftop units. Program cost effectiveness will be determined after the pilot ends in December 2005.

Residential Measures – 10,632 MWh Annual Potential

Residential customers make up the largest group in our system, but savings opportunities on a per-customer basis are small. Therefore, it is necessary to offer residential measure through prescriptive programs. Prescriptive programs are calculated using historical average unit savings and costs. Incentives are provided based on the device being replaced or retrofitted. Customers send in documentation to verify that they have installed the measure prior to receiving an incentive.

Residential Compact Fluorescent Lamps – 3,600 MWh Annual Potential

Residential CFLs generally are offered through point-of-purchase coupons, bulb giveaways and manufacturing buy downs. In any case, replacing incandescent bulbs with CFLs appears cost-effective in a residential conservation portfolio.

Residential Shell Measures – 703 MWh Annual Potential

Residential shell measures include changes to the building shell, HVAC systems or envelope, which reduce energy use without affecting customer comfort. Residential window measures were evaluated on both a new and retrofit basis. Many of the measures in this segment use the R-Value as a measurement. The thermal resistance normally indicated in insulation as the R-Value gives a higher value for more thermal resistance. Residential shell measures include duct, wall, roof and floor insulation.

A rebate of 75 cents per linear foot of R-10 insulation presently is available for installing insulation on heating ducts in unconditioned areas, such as attics and crawlspaces. A 12 cents-per-square-foot rebate is available for the addition of new insulation that increases R-Value by R-10 or greater. Rebates are available if existing insulation is less than R-22 in attics, R-11 in walls and R-11 in floors. Attic, floor, and wall insulation must be installed only where cavities separate areas that either have or do not have air conditioning. Any insulation installed outside the cavity, such as siding, does not meet rebate requirements.

Residential Programmable Thermostat Programs – 659 MWh Annual Potential

Residential programmable thermostat programs offer incentives to residents who control heating with a set-back thermostat. Three residential programmable thermostat measures were evaluated for the IRP: electric resistance heating, heat pumps and air conditioning. The Company used to offer a rebate of up to $40 to homeowners replacing their manual thermostats with an approved programmable thermostat. The program has been reevaluated for the IRP.

Residential HVAC Efficiency Measures – 3,889 MWh Annual Potential

This group of residential efficiency measures includes high-efficiency air conditioning, electric-to-natural gas space heat conversion in ducted homes, electric-to-natural gas space heat conversion in non-ducted homes and heat pumps.

A rebate offering could be developed for homeowners who install an air conditioner with 12.0 SEER (cooling efficiency) or greater. We will evaluate whether to offer an incentive to new construction customers, retrofit customers or both. A $200 rebate is currently available to homeowners who replace primary electric heat (forced air furnace or baseboard heat) with a central natural gas heating system. A $100 rebate is available to replace electric heat with a natural gas wall heater. This rebate can be claimed in addition to the $150 high-efficient natural gas furnace rebate. A $300 rebate is available to homeowners whose primary heating source is electric heat and who install an air-source heat pump of 8.0 HSPF (heating efficiency) with 13.0 SEER or greater. Homeowners are eligible at the 7.5 HSPF and 12.0 SEER levels for manufactured homes. Replacement of an existing heat pump qualifies for a $50 rebate.

Residential Water Heating Measures – 1,475 MWh Annual Potential

Three residential water-heating measures were evaluated for this study. The measures included water heating appliance efficiency, electric-to-natural gas water heating conversion, heat pump water heaters and water heating blankets.

These measures are designed to upgrade existing water heaters to more efficient units or to improve the efficiency of an existing water heater by adding additional insulation. A $50 rebate is currently available to install tank-type electric water heaters that are at least 0.91 efficiency (EF) or to tank-type natural gas water heaters that are at least 0.62 EF for 40-gallon and at least 0.60 EF for 50-gallon units. A rebate of $60 is available to electric customers who replace an electric water heater with a new tank-type natural gas water heater. The $60 rebate can be claimed in addition to the $50 high-efficient water heater rebate. A rebate offering could be developed to provide an incentive for increasing exterior insulation of water heater tanks.

Residential Windows – 305 MWh Annual Potential

Residential windows initially were evaluated based on the direction they were installed: north, south, east or west. The categories ultimately were combined because of an inability to adequately distinguish the difference between them. A rebate could be developed for the addition of energy efficient windows installation with increased U-Value. The U-value is the measure of thermal conductivity. A higher value means a material is more thermally conductive. For example, a lost opportunity is targeting new construction with incentives encouraging installation of windows with U-values above current building code. Bringing older windows up to current standards would also provide energy savings and significant non-energy benefits.

Distribution Measures Impacting Customer End-Use Efficiency

Controlled Voltage Regulation (CVR) – Annual Potential Currently Being Studied

CVR incorporates a variety of measures that may be physically located on the customer or utility side of the meter to control end-use voltage.

Maintaining voltage levels closer to the appropriate levels for end-use equipment generally improves efficiency and increases equipment life. Avista is participating in a regional market transformation venture, incorporating 17 pilot sites and several alternative technologies, to determine the cost-effectiveness, non-energy impact, total energy savings and the load shape of savings under various circumstances. All of this information is highly dependent on the end-use mix and utility distribution characteristics. At this time there is insufficient data to characterize CVR for evaluation in the IRP process.

3.4 Evaluation of Measures

Each measure was evaluated based on characteristics relevant to total resource cost analysis. A description of these characteristics, and the approach used to quantify the inputs, is briefly described below.

Measure Load Shape

Measure load shapes are engineering calculations of the shape of efficiency measure savings. Generally, savings shapes mimic the end-use load shape. Exceptions, such as heat pumps and programmable thermostats, were modeled to only include energy savings. Industrial measure load shapes benefited from actual metering data acquired from various industrial end-use projects. The load shapes are characterized as 8,760-hour but are often of a repetitive nature (e.g., similar weekday or weekend shapes repeated throughout the year).

Non-Energy Benefits

The first iteration of non-energy benefits (NEB) for each measure was based on the 2003 historical non-energy benefits per kilowatt-hour (kWh), disaggregated by customer segment and measure type based on the External Energy Efficiency (Triple-E) board-reporting format. The measures defined for the IRP analyses were not necessarily consistent with those used in past Triple-E board reports, so it was necessary to modify these in later iterations. Avista traditionally reports only quantifiable NEB for purposes of providing external cost-effectiveness analysis of past program activity. This primarily consists of maintenance savings, reduction in usage of other inputs to the production process, and other quantifiable benefits. Other NEB that may not have been observed in the past or suitable for inclusion in Triple-E board analysis were included to the extent that they were appropriate for individual measures. The technology for several measures has been changing so rapidly that it is necessary to modify even recent calculations to reflect the nature of the current and near-future market.

Natural Gas Impact

Several of the evaluated electric efficiency measures impact natural gas usage. This could result in increased or decreased natural gas usage. Natural gas impacts were quantified and incorporated into the analysis of applicable measures. The seasonal nature of the natural gas impact, either “annual” or “winter,” was characterized by measure, and a natural gas avoided cost forecast was applied over the estimated life of the measure.

Customer Cost

Customer cost has been at least 75 percent of the total resource cost of Avista’s historical conservation portfolio. The incremental cost over the appropriate baseline scenario was quantified for each measure. The assumption of base case and high-efficiency scenarios was consistent for the calculation of customer costs and energy savings.

Non-Incentive Utility Cost

Non-incentive utility costs incorporate labor and non-incentive expenses associated with utility acquisition programs. Direct customer incentives are not incorporated in this calculation. Initial iterations applied historic average non-incentive utility costs to each measure. As programs were optimized over subsequent iterations, costs were changed to recognize program design revisions.

Measure Life

Measure life represents the life of the energy savings inherent in the defined measure. For the most part, the measure life is equal to the shorter of the physical or economic life of the end-use equipment.

Utility Incentive Cost

Utility incentive cost is not part of the total resource test, but incentive level and structure assumptions were incorporated into alternative program designs to create a complete program. This was necessary to provide a basis for an informed estimate of energy savings. Incentive assumptions were not necessarily limited to a particular tariff structure, but Avista’s current Idaho Schedule 90 and filed Washington Schedule 90 incentive structures were used as a guide. Incentives were not permitted to exceed 100 percent of measure cost, and in most cases customer direct incentives of 40 to 50 percent were deemed to be adequate.

Energy Savings

Based on inherent measure characteristics and program design developed per iteration, an estimate of annual energy acquisition for each measure was developed. Generally speaking, annual acquisition levels were considered to be a reasonable estimate for a five-year period.

Based on these measure categories and characterizations, a TRC analysis was performed on each measure. In addition to traditional cost-benefit analysis two different calculations of TRC levelized cost were performed. The first calculation applied the customer and non-incentive utility cost, measure life, discount rate and annual energy savings. This calculation excludes the benefit (or cost) of non-energy benefits and the impact on natural gas usage from the calculation, because these are not considered costs for purposes of the cost-benefit analysis. An alternative calculation of the TRC levelized cost treats non-energy benefits and natural gas impact as offsets (or additions to) the TRC cost of the measure. The latter, more inclusive TRC levelized cost calculation, is more suitable for evaluating the total resource value of the measure in almost any circumstance.

3.5 Results of the Analysis

The final evaluation accepted 36 measures as cost-effective, which resulted in 5.5 aMW of aggregate local conservation acquisition. This excludes acquisition attributed to Avista through participation the Northwest Energy Efficiency Alliance efficiency programs. The total energy acquisition evaluated for all programs (including non-cost effective programs) ranged from 4.1 to 7.0 aMW. Tables 3.1 through 3.6 summarize the results of the analysis of individual measures.

Ranking measures by cost-benefit ratio is related, but not identical, to ranking the same measures by TRC levelized cost. This is due to the inclusion of the value of alternative load shapes in the cost-benefit analysis; it is not considered in the calculation of the TRC levelized cost. For example, a measure with a TRC levelized cost of $37 per MWh may actually have a more favorable cost-benefit ratio than another measure costing $35 per MWh. This would happen if the energy savings of the higher-cost measure occurred during relatively higher-value periods of the year. For these reasons, the cost-benefit ratio is a superior means of ranking measures, but it is also true that load shapes are generally not different, nor the hourly avoided cost differentials so extreme, to result in a significant difference in the ranking of the measures.

Seven measures have a negative total resource cost, as non-energy benefits fully offset customer and utility costs. These measures include all three compact fluorescent lighting measures and four industrial measures.

Figure 3.3 is a graphical representation of the supply curve “stacked” in descending order of cost-benefit ratio. The descending order of this ratio, with the most cost-effective measure to the left, results in an untraditional downward sloping supply curve. Measures where the total resource costs were less than zero are not represented as points on this curve, but the savings are incorporated into the acquisition potential. A negative incremental replacement cost will create values less than zero.

Figure 3.4 is a graphical representation of measures with cost-benefit ratios below 10. This view provides more detail on the majority of evaluated measures.

The TRC levelized cost of these measures, sorted in descending order, is represented in Figure 3.5. The aberrations in this TRC levelized cost supply curve are the result of the distinction between the rankings of measures by cost-benefit ratio vs. ranking by TRC levelized cost previously mentioned.

Figure 3.6 represents TRC levelized cost, excluding residential window and non-residential shell measures. The figure allows for a more detailed scale of the majority of the measures.

3.6 Review of the Results

The 5.5 aMW (47,500,000 first year kWh), identified as cost-effective and appropriate for local acquisition, represents a 19 percent increase above Avista's current Schedule 90 tariff goal. Additionally, Avista has 1.4 aMW of attributed resource acquisition based on participation in regional energy-efficiency ventures through the Northwest Energy Efficiency Alliance. This avoids double counting by attributing all efficiency measures, participated in by local utility programs, entirely to the local utility. A residential compact fluorescent program is not currently offered by Avista to any significant extent but is currently offered as a regional program.

Figure 3.7 describes three goals: Avista's 2003 current tariff goal labeled "Current Tariff," an extrapolation of Avista's share of the NPCC goal labeled "NPCC," and the aggregation of the cost-effective potential for our local acquisition program, the overlapping adoption of previously regional programs into a local utility program (residential CFLs) and additional regionally-acquired energy

4 This figure is based on Avista being 4.0 percent of the regional end-use load.

Table 3.1: Summary of Individual Industrial Measures

Measure	Savings (MWh)	Measure Life (Years)	Electric Avoided Cost ($000s)	Non-Energy Benefits ($000s)	Gas Avoided Cost ($000s)	Non-Incentive Utility Cost (000s)	Customer Cost ($000s)
Hydraulics	667	15	261	64	0	33	20
Fans Blowers	2,808	15	1,101	270	0	140	86
Pumps	4,775	15	1,867	459	0	239	146
Refrigeration	6,062	15	2,364	583	0	303	185
Compressed Air	8,711	15	3,411	285	0	436	500
T12-T8 Fluor.	500	12	182	75	-7	10	160
MH to T5 Fluor.	500	15	207	75	-8	10	185
MH to PS Fluor.	500	15	207	75	-8	10	200
Total	24,523		9,601	1,887	-24	1,181	1,483

extrapolated from 2004 activity[4] labeled "IRP." The distribution of the 39 cost-effective measures is approximately 50 percent industrial, 30 percent commercial and 20 percent residential. The plan is significantly more reliant on industrial acquisition than in the past. Commercial acquisition has decreased as a share of the total but is approximately equal to recent acquisition levels on an energy basis. Residential acquisition is not significantly revised, except by the addition of the residential CFL program. Figure 3.8 represents the distribution of energy saving by customer segment. This distribution of energy savings into more detailed categorizations by segment is represented in Figures 3.9 through 3.11.

Table 3.2: Summary of Individual Commercial Measures

Measure	Savings (MWh)	Measure Life (Years)	Electric Avoided Cost ($000s)	Non-Energy Benefits ($000s)	Gas Avoided Cost ($000s)	Non-Incentive Utility Cost (000s)	Customer Cost ($000s)
School CFL	200	10	66	30	-3	4	0
Commercial CFL	1,000	7	253	150	-10	20	30
A/C, Internal Load	1,455	15	597	154	0	29	131
Avista Network Comp	800	20	339	0	0	16	8
Exit Signs	1,000	12	339	150	-15	20	170
T12-T8 Conv. Retail	2,000	12	679	300	-29	40	400
VF Drives, Liquid	1,050	20	478	0	0	21	168
MH to PS Fluor.	500	15	208	75	-8	10	145
MH to T5 Fluor.	500	15	208	75	-8	10	145
Heat Pumps	150	15	63	16	-3	3	44
VF Drives, Vapor	1,500	20	683	0	0	30	360
T12-T8 Fluorescents	2,041	12	756	306	-30	41	714
A/C, Skin Load	1,045	15	424	111	-18	21	355
MH to PS Park Lots	300	15	106	45	0	6	144
MH to T5 Gyms	300	15	127	45	-5	6	165
Appliances	200	20	94	40	-11	4	128
MH to PS Gyms	300	15	127	0	-5	6	165
T12-T8 Schools	500	12	188	75	-7	10	350
Shell	800	25	403	64	0	16	7,856
Total	15,641		6,137	1,637	-152	313	11,478

Table 3.3: Summary of Individual Residential Measures

Measure	Savings (MWh)	Measure Life (Years)	Electric Avoided Cost ($000s)	Non-Energy Benefits ($000s)	Gas Avoided Cost ($000s)	Non-Incentive Utility Cost (000s)	Customer Cost ($000s)
CF Lighting	3,600	10	1,215	549	-46	62	288
Duct Insulation	285	25	144	0	0	6	31
Roof Insulation	108	25	55	0	0	2	18
Water Htr Blanket	121	12	41	0	0	2	17
Wall Insulation	158	25	79	0	0	3	46
W/H Elec-Gas Conv.	606	12	212	0	-84	12	73
Prog Ts, Elec Resist.	295	20	109	0	0	6	89
Air Conditioning	353	0	147	0	0	7	120
FAE-G Conv. Ducted	2,606	0	1,264	0	-567	52	521
Prog Ts, Heat Pump	198	20	74	0	0	4	69
Res Heat Pump	470	15	196	0	0	5	207
Floor Insulation	128	25	64	0	0	3	68
FAE-G Conv. No Duct	460	0	223	0	-100	9	170
W/H Appliance Eff	485	12	170	0	0	10	310
Prog Ts, Air Cond	167	20	66	0	0	3	135
East Windows, retro	89	12	30	0	0	2	311
West Windows, retro	98	12	33	0	0	2	346
South Windows, retro	49	12	17	0	0	1	212
North Windows, retro	69	12	23	0	0	1	677
East Windows, new	8	12	3	0	0	0	1
West Windows, new	8	12	3	0	0	0	1
South Windows, new	6	12	2	0	0	0	1
North Windows, new	3	12	1	0	0	0	1
Heat Pump Water Heaters	263	12	89	0	0	5	121
Total	10,633		4,260	549	-749	197	3,832

Table 3.4: TRC Costs and Benefits for Industrial Measures

Measure	TRC AC Benefits ($000s)	TRC Net of Gas AC and NEB Benefits ($000s)	Net TRC Benefits ($000s)	TRC Benefit to Cost Ratio	TRC Levelized Cost ($/MWh)
Hydraulics	287	-10	298	Infinite	-2.0
Fans Blowers	1,211	-44	1,255	Infinite	-2.0
Pumps	2,053	-75	2,128	Infinite	-2.0
Refrigeration	2,601	-95	2,695	Infinite	-2.0
Compressed Air	3,752	651	3,101	5.76	9.0
T12-T8 Fluor.	200	102	98	1.96	28.0
MH to T5 Fluor.	228	128	100	1.78	31.0
MH to PS Fluor.	228	143	85	1.59	35.0
Total	10,561	801	9,760		

Table 3.5: TRC Costs and Benefits for Commercial Measures

Measure	TRC AC Benefits ($000s)	TRC Net of Gas AC and NEB Benefits ($000s)	Net TRC Benefits ($000s)	TRC Benefit to Cost Ratio	TRC Levelized Cost ($/MWh)
School CFL	73	-15	89	Infinite	-12.0
Commercial CFL	279	-90	369	Infinite	-18.0
HE A/C, internal load buildings	657	6	651	110.72	0.0
Network computer	373	24	349	15.54	3.0
Exit signs	373	54	319	6.85	7.0
T12-T8 convenience retail	746	169	578	4.42	12.0
VFD, liquid	526	189	337	2.78	19.0
MH to PS, commercial	228	88	140	2.58	21.0
MH to T5, commercial	228	88	140	2.58	21.0
HE heat pumps	69	34	36	2.07	27.0
VFD, vapor	751	390	361	1.93	28.0
T12-T8 commercial	831	479	353	1.74	32.0
HE A/C, skin load buildings	466	284	182	1.64	33.0
MH to PS, parking lots	117	105	12	1.11	42.0
MH to T5, gyms	139	131	8	1.06	53.0
Non residential appliances	103	103	1	1.01	54.0
MH to PS, gyms	139	176	-37	0.79	71.0
T12-T8 schools	207	292	-85	0.71	80.0
Non residential shell	443	7,808	-7,365	0.06	956.0
Total	6,750	10,314	-3,564		

Table 3.6: TRC Costs and Benefits for Residential Measures

Measure	TRC AC Benefits ($000s)	TRC Net of Gas AC and NEB Benefits ($000s)	Net TRC Benefits ($000s)	TRC Benefit to Cost Ratio	TRC Levelized Cost ($/MWh)
CF Lighting	1,336	-153	1,489	Infinite	-6.0
Duct Insulation	158	37	121	4.26	13.0
Roof Insulation	60	21	39	2.91	19.0
Water Htr Blanket	45	19	26	2.33	22.0
Wall Insulation	87	49	38	1.79	30.0
W/H Elec-Gas Conv.	234	169	65	1.39	38.0
Prog Ts, Elec Resist.	120	94	26	1.27	34.0
Air Conditioning	162	127	34	1.27	43.0
FAE-G Conv. Ducted	1,391	1,140	251	1.22	46.0
Prog Ts, Heat Pump	81	73	8	1.11	39.0
Res Heat Pump	215	212	4	1.02	54.0
Floor Insulation	71	70	0	1.01	54.0
FAE-G Conv. No Duct	245	279	-34	0.88	64.0
W/H Appliance Eff	187	320	-133	0.58	90.0
Prog Ts, Air Cond	72	138	-66	0.52	88.0
East Windows	33	313	-280	0.11	481.0
West Windows	37	347	-311	0.11	481.0
South Windows	18	213	-195	0.09	590.0
North Windows	26	678	-652	0.04	1,342.0
East Windows, new	3	2	1	1.91	27.0
West Windows, new	3	2	1	1.91	27.0
South Windows, new	2	1	1	1.58	32.0
North Windows, new	98	126	-28	0.78	65.0
Heat Pump Water Heaters	1	1	0	0.73	70.0
Total	4,579	4,147	431		

Figure 3.3: Conservation Supply Curve Stacked by Levelized TRC Cost ($)

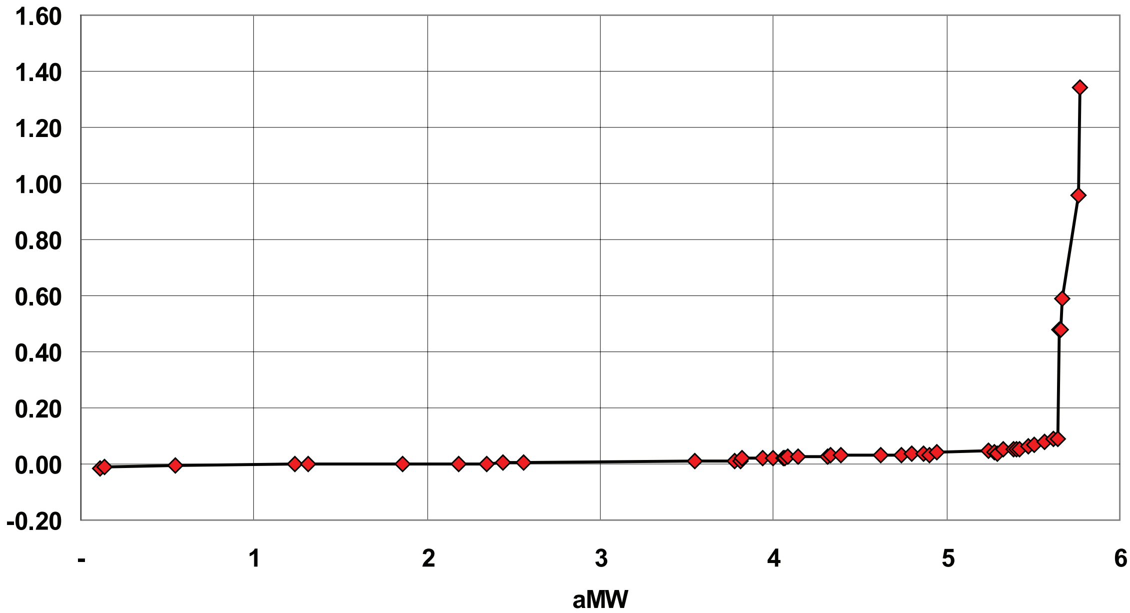


Figure 3.4: Conservation Supply Curve Stacked by Levelized TRC Cost <0.10 ($)

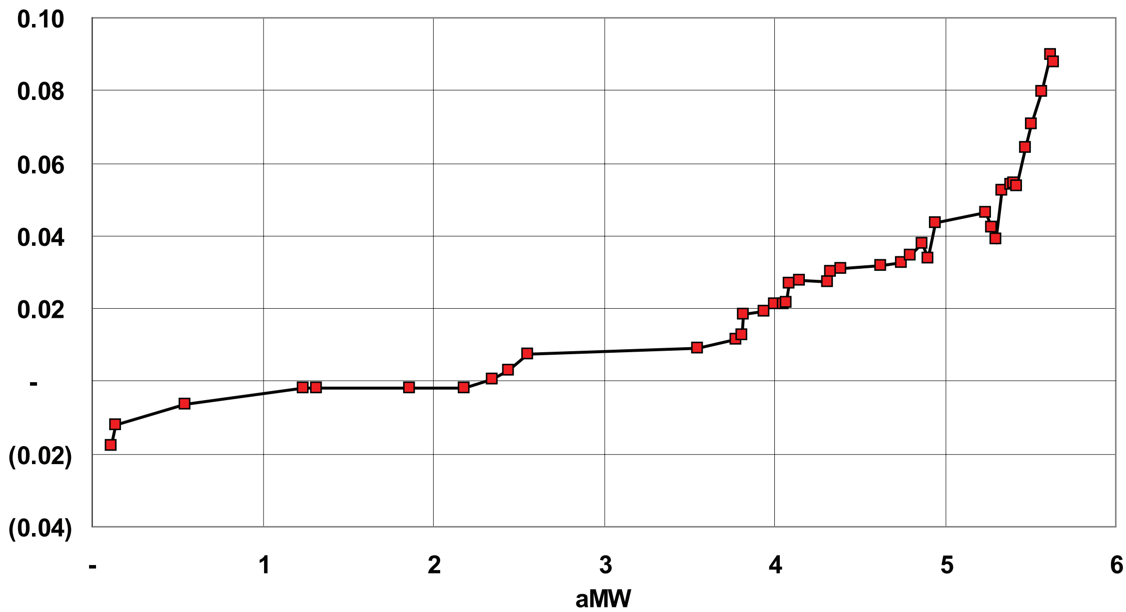


Figure 3.5: Conservation Supply Curve (TRC B/C Ratios)

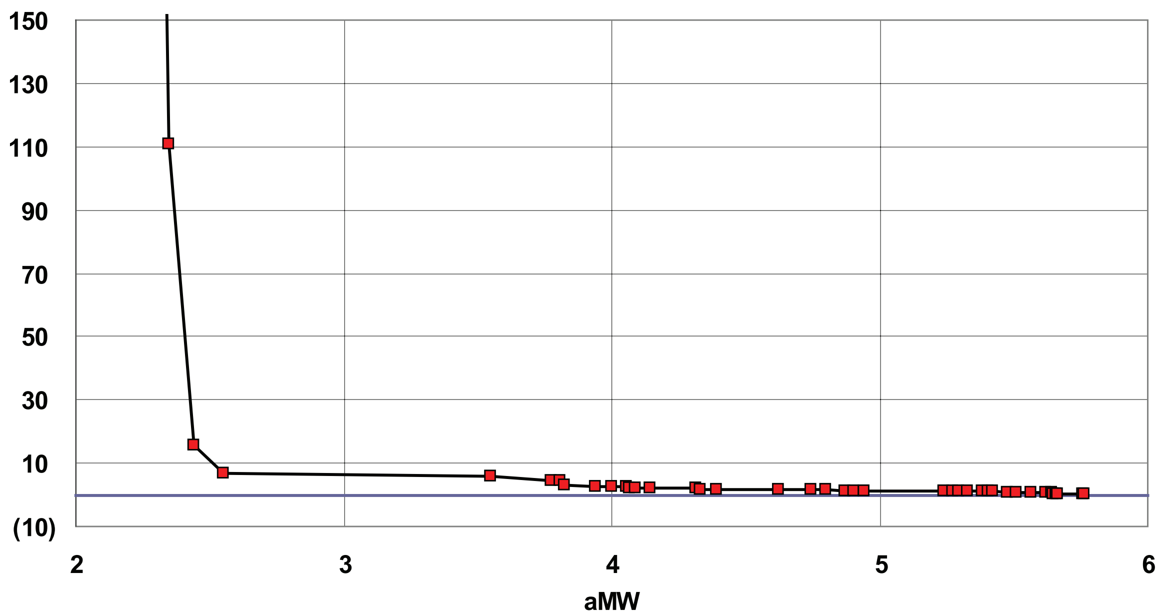


Figure 3.6 Conservation Supply Curve (TRC B/C Ratios < 10.0)

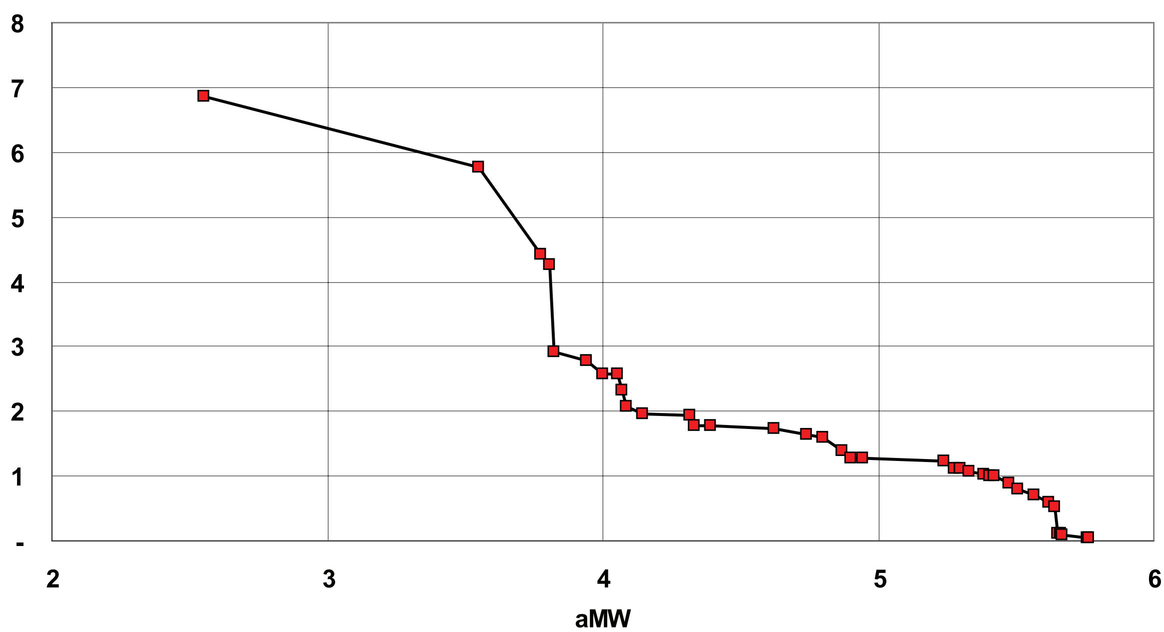


Figure 3.7: Aggregate Conservation Goal Comparison (aMW)

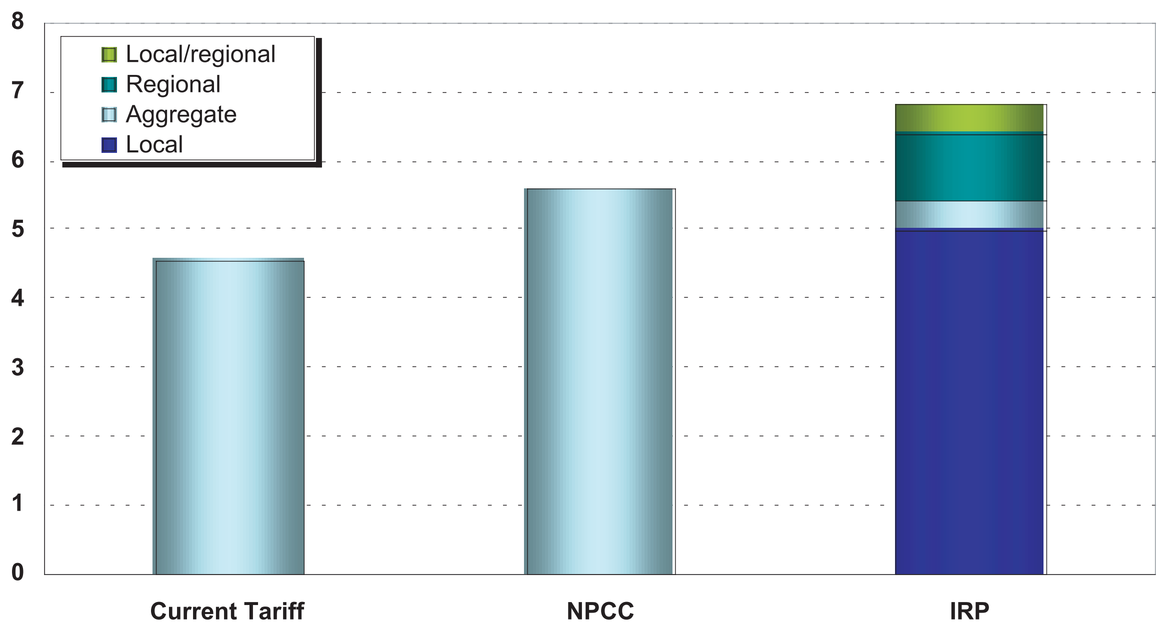


Figure 3.8: Customer Segment Savings Distribution

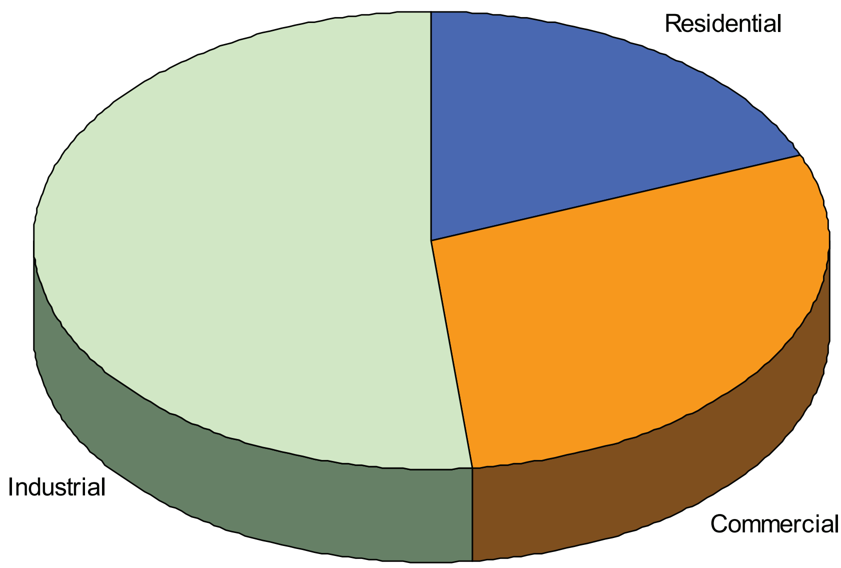


Figure 3.9: Industrial Segment Savings Distribution

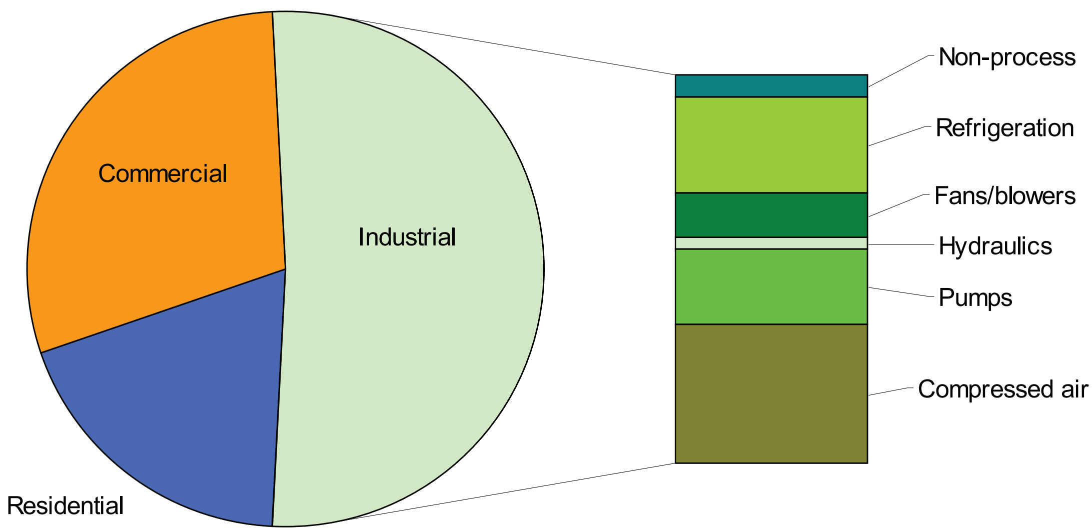


Figure 3.10: Commercial Segment Savings Distribution

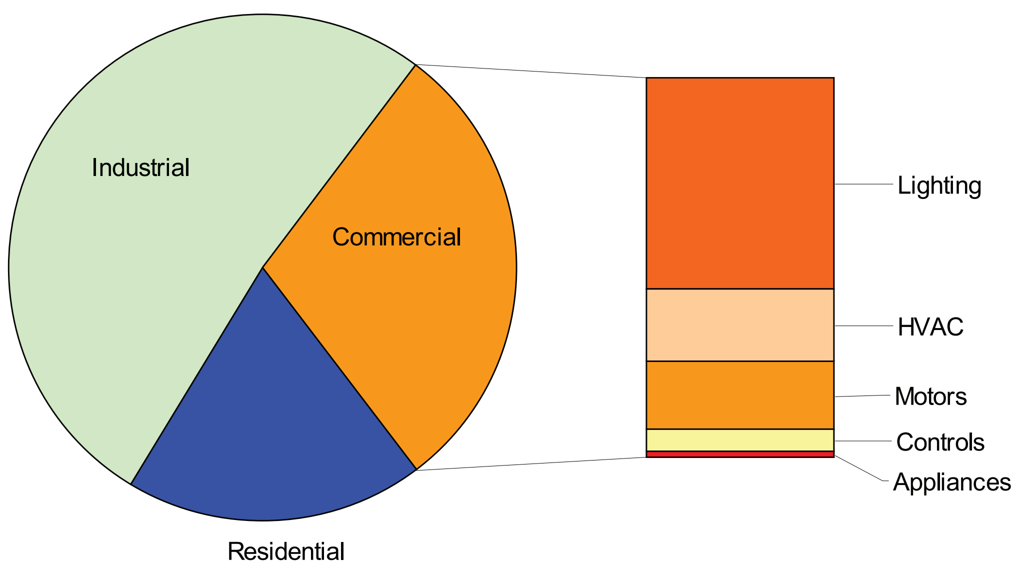
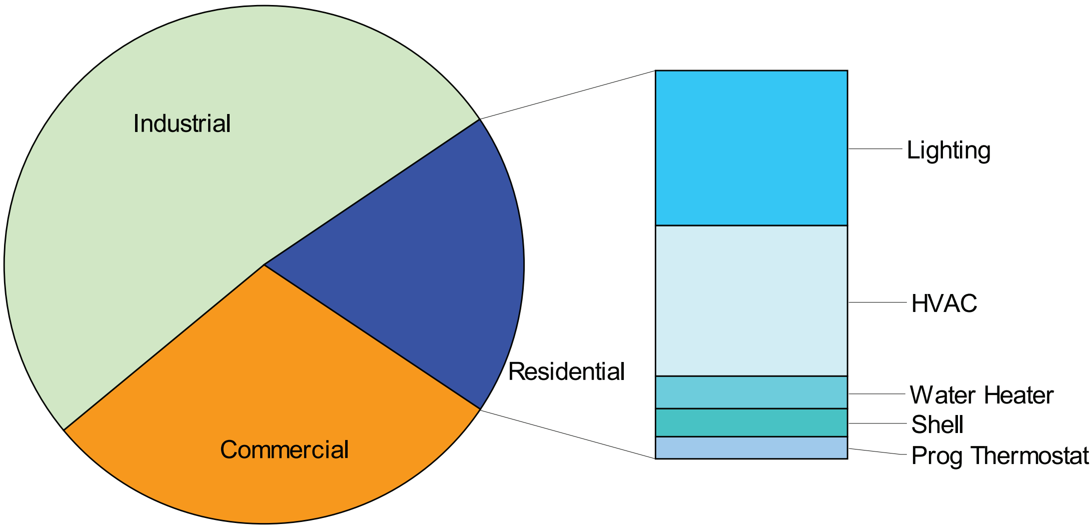


Figure 3.11: Residential Segment Savings Distribution



3.7 Conservation Business Planning

Avista has recently assumed that the 2005 IRP would identify a 10 to 25 percent increase in cost-effective conservation potential. In late 2003, the Company began ramping up conservation programs to coincide with the Idaho electric tariff riders reaching a zero balance. It is anticipated that the aggregate tariff rider balance will reach zero in 2005. Once the balance reaches zero, the Company will transition to a long-term business plan structured toward acquiring all cost-effective conservation potential available through local programs.

As part of the 2004 ramp-up process the Company piloted several alternative implementation approaches intended to enhance cost-effective acquisition. Based on an analysis of the conservation pilot projects, a review of existing Avista implementation efforts and conservation contracts acquired under the 2000 All-Resource Request For Proposals, it was determined current incentive levels are insufficient to meet future conservation acquisition goals.

The Company requested revisions to Idaho Schedule 90 in early 2005 to approximately double the incentive levels offered in Idaho. The revised schedule became effective in March 2005. A similar filing has been made in Washington to become effective July 2005. The Company anticipates annual revisions of the tariff rider funding mechanism to provide adequate funding for future programs and to recover any individual tariff rider balances, positive or negative, carried into a calendar year.

The Company has increased staffing in 2004 and will continue to evaluate additional staff in 2005 and beyond. The results of the IRP, and in particular the identification of significant increases in cost-effective industrial conservation potential, will play a key role in the development of infrastructure that is capable of delivering our new conservation goals.

Avista will continue to work with regional entities, and in particular the Northwest Energy Efficiency Alliance, to acquire cost-effective conservation resources. This is likely to play its greatest role in the acquisition of residential resources. Based on a review of historical Northwest Energy Efficiency Alliance venture success there is a strong indication that residential programs are typically more cost-effectively acquired through a combined local utility and regional market transformation approach.

4. TRANSMISSION PLANNING

Comprehensive coordination of transmission system operations and planning activities among the region's transmission providers is necessary to maintain reliable and economical transmission service and to integrate the output of generation resources to serve the region's end-use customers. Regional transmission providers and interested stakeholders are working toward implementing changes in the region's approach to planning, constructing and operating the regional transmission system under new rules promulgated by the Federal Energy Regulatory Commission (FERC), and under state and local siting.

This section was developed in full compliance with Avista's FERC Standards of Conduct governing communications between Avista Utilities Merchant and Transmission functions.

4.1 Avista 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, Montana, and Townsend, Montana. The transmission system includes switching stations and high-voltage substations with transformers, monitoring and metering devices, and other equipment related to the operation of the system. It is used to transfer power from the Company's generation resources to its retail load centers. The Company also has network interconnections:

- Bonneville Power Administration (BPA)
- Idaho Power Company

Section Highlights

- Avista has over 2,200 miles of high voltage transmission.
- The Company is involved in many regional transmission organizations and studies.
- Regional transmission groups, Grid West and the Transmission Improvement Group (TIG) are continuing development.
- New transmission construction costs associated with the integration of new generation projects can vary greatly, ranging from $10 million to $1.5 billion depending on location and project size.
- New transmission upgrade costs are included in the Preferred Resource Strategy.

- Northwestern Energy
- PacifiCorp
- Puget Sound Energy
- Chelan County PUD
- Grant County PUD
- Pend Oreille County PUD

In addition to providing enhanced reliability in the operation of the transmission system, these network interconnections serve as points of receipt of power from generating facilities outside the Company's service area, including the Colstrip generating station, Coyote Springs 2 and Mid-Columbia hydroelectric generating facilities. These interconnections provide for the interchange of power with entities within and outside the Pacific Northwest, including the integration of long-term and short-term contract resources. Additionally, the Company has a number of interconnections with government-owned or cooperative utilities at transmission and distribution voltage levels, representing non-network, radial points of delivery for service to wholesale loads.

Avista is in the process of implementing a transmission upgrade plan to add over 100 circuit miles of new 230 kV transmission line to its system and will later increase the capacity of another 50 miles. Avista is also constructing two new 230 kV substations and is reconstructing three existing transmission substations. Related projects at six 230 kV substations are necessary to meet capacity requirements, upgrade protective relaying systems, and to meet regional and national reliability standards.

In total, Avista will perform work in 11 of its 230 kV substations or 85 percent of its system. The most significant projects are described below.

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

Avista constructed a new 230 kV substation near Clarkston, Washington, that enables existing transmission lines to form a 35-mile transmission "ring" around the Lewiston, Idaho, and Clarkston, Washington, areas. The project serves load and improves reliability by reducing congestion during peak energy flows.

Spokane Valley Reinforcement

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

Pinecreek Substation

The Company recently completed the reconstruction of this 230 kV facility located in Pinehurst, Idaho.

Palouse Reinforcement

The Company plans to construct 60 miles of 230 kV transmission line between the Benewah and Shawnee substations to relieve congestion on the existing Benewah-Moscow 230 kV line and to provide an alternative source of power to the Shawnee Substation.

Beacon-Bell 230 kV
The Company is increasing the capacity of two parallel path transmission lines from its Beacon substation to BPA's Bell substation.

The overall cost of the above-mentioned transmission projects is estimated at over $100 million.

As set forth in an August 2002 agreement with BPA known as the West of Hatwai letter agreement, these projects are coordinated with the federal entity. Company upgrades support and enhance BPA transmission projects. By working together, both parties have achieved a least-cost service plan that addresses commercial transactions, load service and regional reliability issues.

This Avista and BPA plan was reviewed by peer utilities and 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 Company and BPA stand-alone plans separately executed.

The Company plans and operates its transmission system pursuant to applicable criteria established by the North American Electric Reliability Council, 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 or revised criteria and coordinates the planning and operation of its transmission system with neighboring transmission systems. The Company is subject to periodic performance audits through participation in these regional organizations.

Portions of the Company transmission system are fully subscribed for the purpose of transferring the 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 by the Company necessary to optimize its resource portfolio, 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 in specific cases can occasionally restrict our ability to optimize our system resources. 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 making transmission capacity available to other parties. Furthermore, to the extent a third party has secured firm capacity rights on Avista's transmission system, including future roll-over rights, that transmission capacity will not be available for Company use to serve native load.

4.2 Regional Transmission System

BPA operates more than 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 and its 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 nine of its remote retail load areas.

The Company participates in a number of regional and BPA-specific forums to coordinate system reliability issues and planning issues, and to manage costs associated with the BPA transmission system. NWPP forums include the following work groups: the Transmission Planning Committee provides coordinated analysis of proposed transmission projects in the Northwest sub-region and resolves technical transmission planning issues; the Northwest Transmission Assessment Committee reviews transmission needs in a broad sense, performing studies and developing cost estimates for future resource development alternatives; and the Northwest Operations and Planning Study Group reviews near-term seasonal operating capacity on constrained portions of the Northwest grid.

The Company also 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 that they support system reliability and access.
The Company also works with BPA and other regional utilities to coordinate major transmission facility outages.

4.3 Regional Transmission Issues

While coordinated transmission planning takes place through various NWPP workgroups, process improvements can further increase responsiveness and timeliness of major regional transmission project decisions. A more formalized organization is under consideration in the Northwest to develop a regional transmission plan, assess transmission alternatives (including non-wires alternatives) and provide a forum for decision-making for new projects and cost allocation methods.

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 what is essentially long-term financing for BPA in order to facilitate needed transmission project construction on its system.

The formation of a regional transmission organization (RTO) to address the transmission issues discussed above has been studied for some time. State and/or federal jurisdiction over such a regional transmission organization has also been the subject of much debate. Accordingly, at the end of September 2005, regional parties are slated to make a determination as to whether to move forward with either of two alternatives to address a number of regional transmission issues: Grid West or the Transmission Improvements Group (TIG) proposal.

Grid West

FERC Order 2000 requires all jurisdictional utilities either to file a proposal to form an RTO, or a description of efforts to participate in an RTO, or a list of any existing obstacles to RTO participation. FERC Order 2000 is a follow-up to FERC Orders 888 and 889 issued in 1996. It requires transmission owners to provide non-discriminatory transmission service to third parties.

The Company participated in a negotiation process with nine Western state utilities, incorporating the involvement of a broad spectrum of additional regional stakeholders, on the possible formation of "RTO West," a non-profit organization. The utilities and regional stakeholders have since shifted to an approach intended to respond to identified problems and inefficiencies in how the region's integrated transmission grid is managed, as opposed to attempting to develop an RTO that is fully compliant with specified functions and characteristics outlined by FERC. This revised process has resulted in the adoption, on December 9, 2004, of interim bylaws governing continuing developmental activities for this non-profit corporation under the new name Grid West.

Building on earlier RTO development work, regional stakeholders participating in the Grid West process identified a number of transmission-related "problems and opportunities" that need to be addressed. Among these are current rules and practices that prevent full utilization of the transmission infrastructure and impede the ability to facilitate more efficient, region-wide transactions. Congestion management by curtailment was viewed as problematic. Additionally, difficulties in efficiently and effectively planning and constructing needed transmission infrastructure in the region were identified, and the lack of an independent market monitor was raised as an issue.

The Grid West proposal seeks to improve transmission services and infrastructure development through the establishment of a new, non-profit corporation with board membership independent of any specific electric wholesale or retail market interest. The Grid West proposal intends to

1. Implement a system to manage and offer transmission rights to attain greater utilization of the transmission grid while preserving existing transmission rights;
2. Provide voluntary consolidation of control area operations to create organized market structures for the provision of ancillary services;
3. Implement a regional transmission system planning process and provide for backstop authority to resolve issues regarding;

financing, cost allocation and construction of new transmission facilities;

4. Provide a market monitoring function.

By the end of 2005, participants in the development of the Grid West proposal are expected to determine if Grid West will hold elections to seat the independent board and move forward with further developmental activities in preparation for reaching operational status.

Transmission Improvements Group

In its review of whether or not to move forward with Grid West, the Company recognizes the prudence in assessing other alternatives to address regional transmission issues. Other regions of the U.S. that have implemented RTO structures have experienced significant costs associated with such organizations. Many regional stakeholders are skeptical as to whether implementation of the Grid West proposal will ultimately provide meaningful and sustainable net benefits to customers. Several regional parties explored how regional transmission issues might be addressed using a coordination contract model and relying upon the enhancement of existing organizational structures to mitigate some of the jurisdictional and cost control concerns associated with broader RTO structures, specifically Grid West. In March 2005, a group of regional stakeholders, TIG, agreed to fund the development of proposals for improving the planning, operation and oversight of the Northwest transmission system.[1]

TIG intends to identify effective, low-cost solutions to known transmission issues within the general geographic area covered by the NWPP. TIG participants plan to make immediate, substantive, incremental steps to improve access to, and the efficiency of, the region's transmission system. The TIG approach intends to address the same transmission-related "problems and opportunities" outlined in the GridWest process. TIG is focusing on five areas of development:

1. A common region-wide Open Access Same-time Information System (OASIS) to manage access to the systems of all regional transmission providers;
2. A regional transmission planning and expansion model for coordinated planning and the authority to resolve decisions regarding what new transmission facilities are be constructed, who should finance and construct these facilities, and to whom such costs should be allocated;
3. Enhanced reliability and security functions, including broader functionality of the Pacific Northwest Security Coordinator and providing for the voluntary consolidation of certain control area operations functions;
4. Region-wide implementation of a flow-based determination of available transmission capacity;
5. The implementation of a market monitoring function.

Parties developing the TIG proposal have established work groups to address these five areas. The work groups hope to develop their proposals in

1 TIG participants include Avista, BPA, Chelan County PUD, Clark County PUD, Cowlitz County PUD, Douglas County PUD, Grant County PUD, Portland General Electric Company, Power Resource Managers, Public Power Council, Puget Sound Energy, City of Seattle, Tacoma Power and the Washington PUD Association.

sufficient detail to allow for a reasonable comparison between the TIG and Grid West proposals by the end of 2005. To the extent possible, approaches developed by the TIG work groups will utilize existing organizations and contracts and avoid creating new institutions.

4.4 Modeling Transmission Costs in the Integrated Resource Plan

Transmission costs to integrate new resources into the Company's system were estimated by Avista's Transmission Department. Estimates were not modeled in AURORA^{XMP}, but rather in the proprietary LP model that matches resources with Avista's resource requirements. A rigorous study has not been completed for any of these transmission alternatives; estimates are engineering judgment only and are not "construction estimate" quality. As the size of the resource increases, the certainty of the estimates diminishes. A 50 MW resource can be integrated in many places on Avista's (or another) system. A 350 MW plant can be integrated at some locations, while a 750 MW plant has very limited placement options. At the 1,000 MW plant level, a generic integration cost of $1.5 billion has been assigned because of the uncertainty of impacts to the Company's system and/or the neighboring systems. A detailed regional process likely would be undertaken to determine the precise impacts and integration costs before an actual plant placement decision would be made.

Table 4.1 describes the location for potential resources, capacity, required upgrades, and the cost of the upgrade for the requested locations. Transmission costs are allocated on a per-kilowatt basis. For example, if Avista purchased half of a 750 MW plant with an estimated transmission expense of $400 million, the portion allocated to Avista would be $200 million.

In summary, there are a number of issues and uncertainties regarding future expansion of the Northwest transmission system to accommodate the integration of future resources needed to serve the region's load growth. Among these are the following:

1) The Northwest transmission system is fully subscribed in many areas with scarce firm transmission capacity to accommodate the integration of new large-scale resources;
2) Current FERC policies and practices restrict the flexible use of transmission assets to facilitate resource portfolio optimization in hydro-based systems;
3) There is no comprehensive and authoritative regional planning process for transmission expansion issues, including transmission siting, financing, construction, ownership and cost recovery;
4) Restrictions on federal borrowing authority hinder BPA's financing of new transmission construction;

5) There are multi-jurisdictional siting and permitting issues for new large-scale transmission expansion;
6) The regional transmission organization forum is still being resolved, as is the subsequent jurisdiction over the organization.

Table 4.1: Avista Generation Integration Cost Estimates (2005$)

From	Capacity (MW)	Potential Upgrade	Approximate Capital Cost ($millions)
Eastern MT	350	Install 500 kV series capacitors on existing lines	100-150
	750	Install 500 kV series capacitors & reinforcements such as 230 kV reinforcements in Eastern WA	400-450
	1,000	New 500kV line	1,500
Eastern WA to Mid-Columbia	350	N/A	100
	750	N/A	150
	1,000	N/A	600-800
Eastern WA – Adjacent to Existing 230kV System	350	Additional substation	10
	750	Additional 230 kV reinforcement	80
Northern ID – Adjacent to Existing 230kV System	350	New substation	10
	750	230 kV reinforcement	70
Eastern WA – Remote From Existing 230kV System	350	New double circuit 230 kV line east of Spokane	50
	750	New double circuit 230 kV line - Spokane to Mid-Columbia	100
Eastern WA (Wind)	80-150	Depending on the size	10-70

5. MODELING APPROACH

The analytical foundation for this IRP was to model the Western states' electric system and markets to quantify impacts on Avista. The Company used this approach to derive electric prices for the Mid-Columbia market, taking into account physical systems outside the Northwest. Understanding all the geographic areas within the Western Interconnect is important because the area functions as one larger market with various sub-markets.

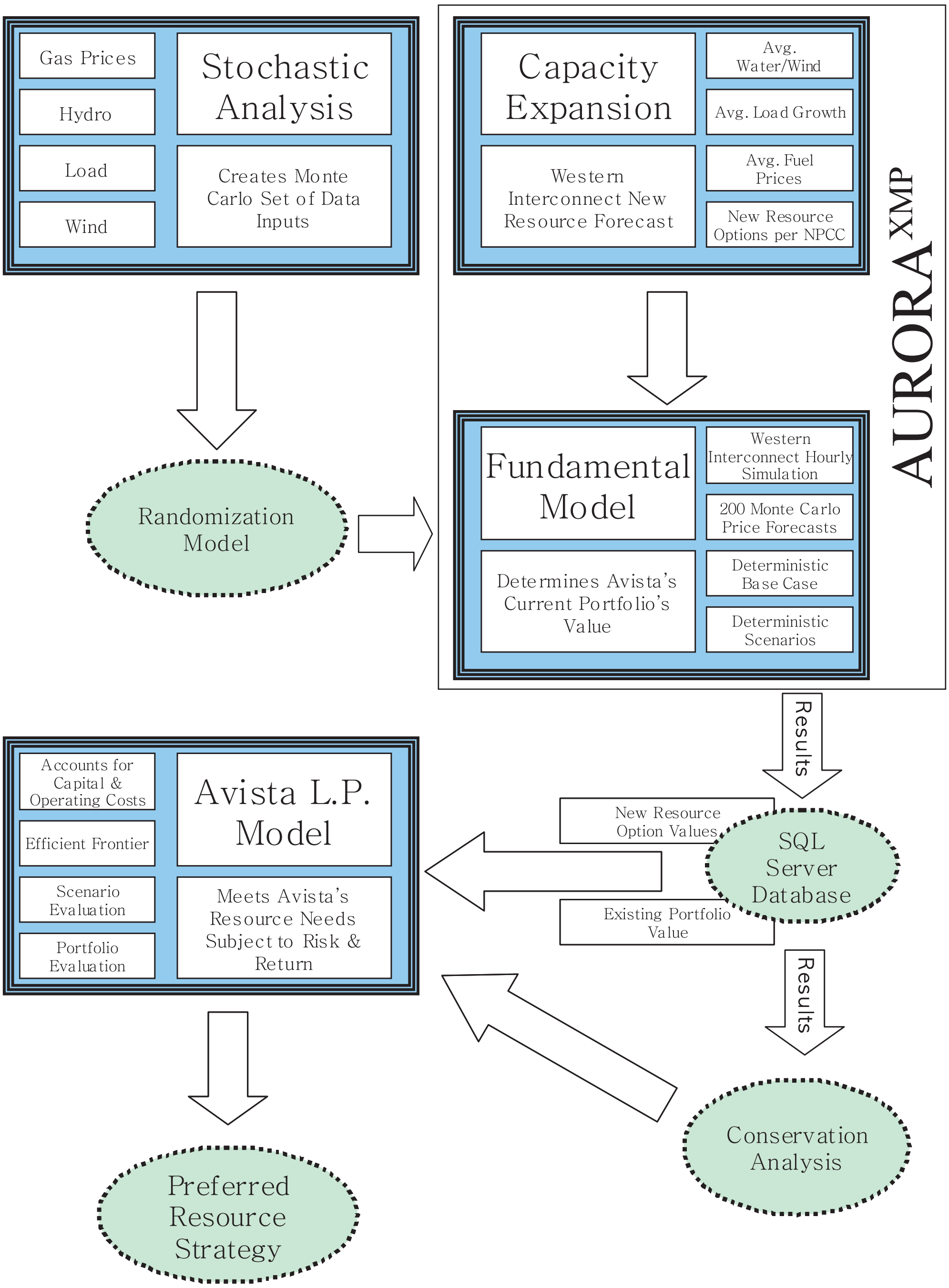
Prior to 2003, Company IRPs relied on market price forecasts modeled exogenously, breaking the link between the market price forecast and modeling of Company operations. This IRP combines these efforts by tracking Company-owned and contracted resources as they dispatch into the modeled marketplace. The resource portfolio then is linked to its loads, resources and contractual arrangements to calculate expected power supply costs.

The Company used a multi-step approach to develop the Preferred Resource Strategy (PRS).

Section Highlights

- Avista uses AURORA^{XMP} to model hourly operations of the entire Western Interconnect; market conditions outside the Northwest affect local market prices.
- The Company performed Monte Carlo market analyses, varying load, hydro, wind and natural gas price data over 200 iterations.
- The 2005 IRP benefits from significant wind modeling enhancements.
- The proprietary Avista Linear Programming Model helped direct the Preferred Resource Strategy.
- The IRP adopts many assumptions from the Northwest Power and Conservation Council's Fifth Power Plan.
- The federal production tax credit for renewables is assumed throughout the IRP timeframe, except in carbon tax scenarios where the credit terminates.
- The IRP accounts for transmission costs necessary to bring distant generation sources into the Northwest (e.g., Montana coal and wind).

Figure 5.1: Modeling Process Diagram

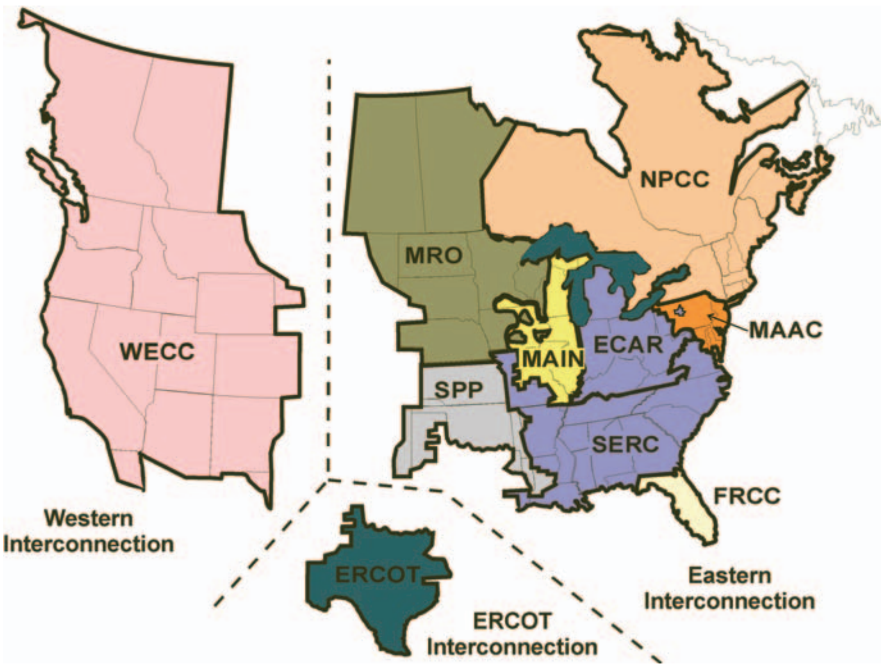


Potential new resources were identified to serve future demand in the Western Interconnect. New resources were combined with existing resources and then used to simulate hourly operations from 2007 to 2026, using a Monte Carlo analysis varying hydro, wind, load, and gas prices. The simulation results were used to estimate Mid-Columbia electric market prices. These prices were used to analyze potential new conservation initiatives and supply side resources. This step values plant operations and weighs those values against capital requirements using Avista's Linear Programming (LP) model; the LP model selects optimal resources to serve load based on energy and capacity needs, cost, value and risk. Figure 5.1 presents a visual interpretation of the modeling process.

5.1 Western Interconnect Simulation: AURORA^{XMP}

The AURORA^{XMP} model was used to simulate the Western Interconnect market for the 2005 IRP. The Western Interconnect includes the states west of the Rocky Mountains, as well as British Columbia, Alberta, and Baja, Mexico. This area is highlighted on the map in Figure 5.2. The Western Interconnect is separated from the Eastern Interconnect and ERCOT systems except for eight inverter stations between the three systems. The Western Interconnect follows operation and reliability guidelines administered by the Western Electric Coordinating Council (WECC).

Figure 5.2: NERC Interconnections Map [1]



1 *Graphic courtesy of NERC and can be found at* http://www.nerc.com

Table 5.1: AURORA^{XMP} Zones

Zone	Area(s) Included	Zone	Area(s) Included
AB	Alberta	IDS	Southern Idaho
AZ	Arizona	MT	Montana
BAJA	Baja Mexico	NM	New Mexico
BC	British Columbia	NNV	Northern Nevada
NCAL	Northern California	SNV	Southern Nevada
CCAL	Central California	OWI	OR, WA, & Northern Idaho
SCAL	Southern California	UT	Utah
CO	Colorado	WY	Wyoming

AURORA^{XMP} separates the Western Interconnect into sixteen "zones" based on load concentration and transmission constraints. Table 5.1 lists the Western Interconnect zones included in AURORA^{XMP}. This table also provides a reference to the zone acronyms used later in this document.

The AURORA^{XMP} database contains hourly loads and resources for each zone in Table 5.1. These components along with fuel prices, transmission constraints, hydro conditions and wind conditions allow the model to simulate the Western Interconnect system on an hourly basis. This simulation is used to derive market-clearing prices for each zone. Market-clearing prices are derived from the marginal cost to supply the next megawatt of energy plus any applicable wheeling charges for each unit.

The model meets future loads by choosing new generating assets from a pool of hypothetical user-defined resources. Hypothetical construction of new resources is referred to as "capacity expansion." In capacity expansion, the model calculates a net present value for each new resource by subtracting fuel costs, variable operations and maintenance (O&M), fixed O&M, emissions costs and capital investment from its expected market value. The model uses an iterative process that places plants into the system and selects those with positive net present values. After the expansion studies are completed, the model simulates the system using the optimal set of new resources for all 175,320 hours of the 20-year study.

After capacity expansion, a stochastic analysis is performed in AURORA^{XMP} to incorporate market uncertainty. Stochastic analysis is performed using probability distributions for load, fuel price, hydroelectric and wind generation data, rather than by simply using single point estimates. The Company generated 200 sets of unique inputs for 200 distinct 20-year iterations of AURORA^{XMP}. In total, the Company simulated more than 70 million market hours for the 2005 IRP, requiring nearly 5,000 hours of computer processing and 300 gigabytes of data storage for each stochastic study. In addition to stochastic studies, Avista looks at individual deterministic scenarios to understand how certain variables drive results.

5.2 Key Assumptions and Inputs

AURORA^{XMP} contains a database with generic data developed by EPIS, Inc. The database provides a reasonable approximation of future market conditions. The Company modified many of the base data sets to obtain more robust results. The following section describes the changes made by the Company for the 2005 IRP.

Hydroelectric Generation

The AURORA^{XMP} model is shipped with hydrological data sets for the entire Western Interconnect. For the Northwest, data includes average monthly generation levels taken from Bonneville Power Administration (BPA) 50-year hydrologic studies. The Company uses hydrologic data from the Northwest Power Pool (NWPP) rather than BPA data for planning and ratemaking. Presently, the NWPP performs 60-year headwater benefit studies annually for the Northwest hydroelectric system.

Data from the 60-year NWPP Headwater Benefits Study was converted into an AURORA^{XMP} format and Northwest data sets for IRP modeling. AURORA^{XMP} data for zones outside the Northwest (e.g., California) were not modified.

AURORA^{XMP} models hydroelectric generation by load area or zone. This means that every hydroelectric facility located within a zone utilizes the same shaping factors.[2] The results for the entire hydroelectric system are accurate, but individual projects may not be correctly represented. To track Company-owned hydroelectric resources more accurately, each Company river system was separated from the base hydroelectric data set. A unique set of shaping factors, based on historic generation, was assigned to each project. Figure 5.3 demonstrates monthly capacity factors for the OWI zone, and the Company's hydroelectric projects in an average water year.

The model dispatches hydro resources based on demand changes. Hydro units are dispatched before thermal, wind or other resources. To dispatch hydro, the model takes several factors into consideration including available annual and monthly energy, minimum and maximum capacity, and load following ability. Figure 5.4 demonstrates hydro load following in one hypothetical week.

Natural Gas Prices

The price of natural gas is a key model assumption because gas-fired resources presently set the marginal electricity price for the majority of hours at trading hubs across the Western Interconnect.

2 Shaping factors determine how much each hydroelectric facility can vary its operations to serve peak loads.

Figure 5.3: NW & Avista Monthly Hydro Capacity Factors Modeled in AURORA[XMP] (%)

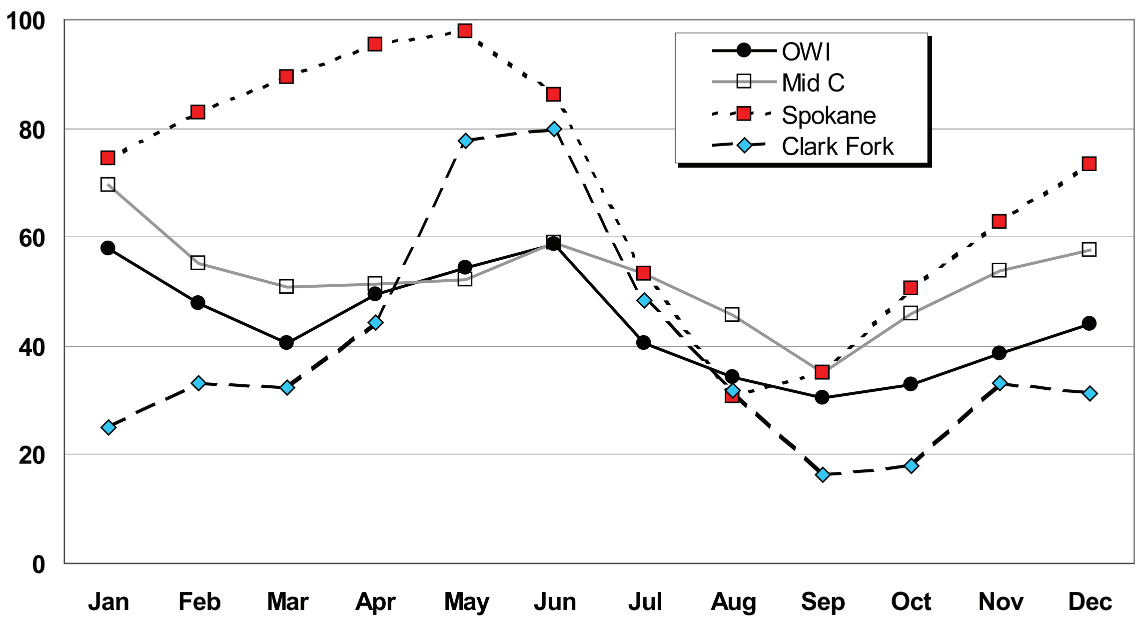
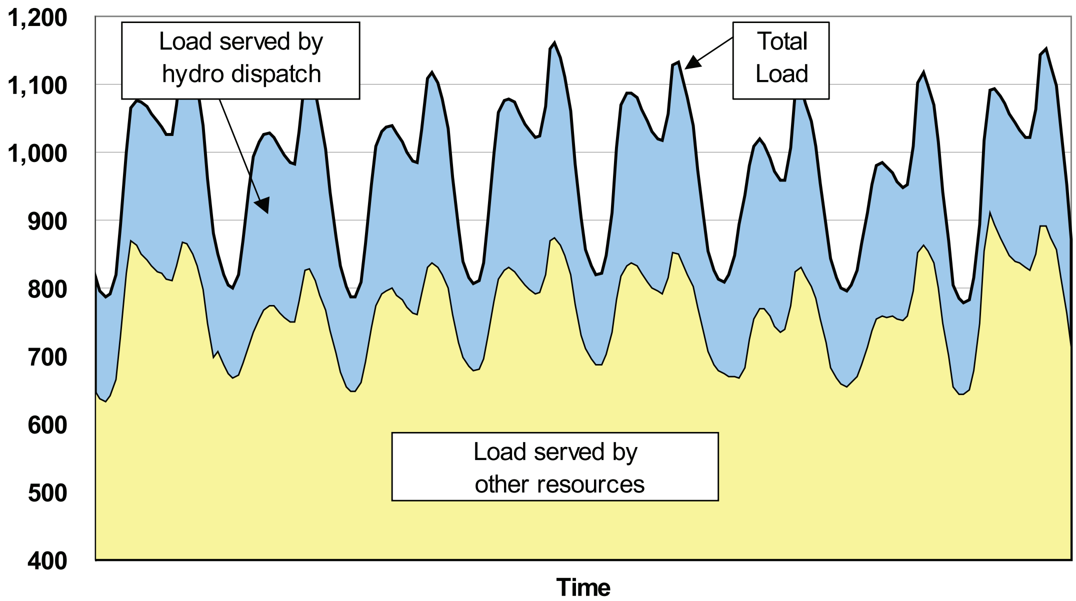


Figure 5.4: One Week Hydro Dispatch Example (MW)



The gas price forecast was developed in April 2005. It uses a blend of NYMEX forward prices and Global Insight Inc.'s Gas Escalation Forecast. NYMEX monthly forward prices for Henry Hub were obtained on April 6, 2005, for 2007 through 2010. Global Insight's escalation rates are used from 2011 through the duration of the forecast period.

To accurately model the Western Interconnect, additional natural gas basin forecasts are required. Northern basins at AECO, Malin, and Sumas, and southern basins at Opal, Topock, and San Juan were added to the model. Northern basins use forward market differentials and southern basins use generic differentials included with the AURORA^{XMP} database. The difference in handling northern and southern basins is due to the minimal relative impact of southern gas on Company costs and southern basin differentials not being readily available to the Company. The Company's natural gas procurement group reviewed the differentials provided by the AURORA^{XMP} database and determined that they were reasonable for IRP modeling purposes. Table 5.2 contains the natural gas price forecasts used for the 2005 IRP. An additional transportation charge was added to move gas between basins and plant locations.

Table 5.2: Trading Hub and Zone Natural Gas Price Forecast ($/dth)

Hub/Zone	2007	2008	2009	2010	2011	2012	2016	2020	2024	2026
AECO Hub	6.68	6.25	5.75	5.36	5.39	5.41	5.87	6.46	6.70	7.05
Henry Hub	7.37	6.92	6.41	6.01	6.07	6.15	6.81	7.57	8.07	8.60
Malin Hub	7.01	6.55	6.03	5.62	5.66	5.72	6.33	7.04	7.49	7.97
Sumas Hub	6.86	6.40	5.88	5.46	5.49	5.54	6.13	6.83	7.25	7.72
AB	6.80	6.37	5.87	5.48	5.52	5.54	6.01	6.62	6.88	7.23
AZ	6.58	6.16	5.65	5.26	5.28	5.29	5.74	6.32	6.55	6.89
BAJA	7.27	6.81	6.30	5.89	5.95	6.03	6.68	7.43	7.94	8.46
BC	6.80	6.37	5.87	5.48	5.52	5.54	6.01	6.62	6.88	7.23
CCAL	7.44	6.98	6.48	6.08	6.14	6.22	6.89	7.67	8.19	8.73
CO	6.55	6.13	5.62	5.22	5.25	5.25	5.70	6.28	6.51	6.84
IDS	7.09	6.64	6.12	5.71	5.74	5.80	6.42	7.14	7.60	8.09
MT	6.92	6.49	5.99	5.61	5.65	5.67	6.16	6.78	7.05	7.42
NCAL	7.12	6.67	6.16	5.75	5.78	5.85	6.47	7.20	7.66	8.16
NM	6.55	6.13	5.62	5.22	5.25	5.25	5.70	6.28	6.51	6.84
NNV	6.52	6.04	5.51	5.08	5.13	5.18	5.82	6.58	7.06	7.58
OWI	6.97	6.52	6.00	5.59	5.61	5.67	6.27	6.98	7.42	7.90
SCAL	7.44	6.98	6.48	6.08	6.14	6.22	6.89	7.67	8.19	8.73
SNV	6.63	6.15	5.63	5.20	5.24	5.30	5.96	6.73	7.22	7.74
UT	6.46	5.98	5.45	5.01	5.06	5.11	5.75	6.50	6.96	7.48
WY	6.40	5.92	5.39	4.95	5.00	5.05	5.68	6.42	6.88	7.39

Figure 5.5 shows annual average natural gas prices at Henry Hub used in the Base Case analysis. The chart shows prices in both 2005 and nominal year dollars.

Resources

A Company review of existing Western Interconnect resources included in the AURORA^{XMP} database found it to be comprehensive and accurate for IRP purposes after some modification. Two substantial changes were made to the AURORA^{XMP} database for new construction and Renewable Portfolio Standard (RPS) resources. New generating resources currently under construction and likely to be constructed as defined by the California Energy Commission were included in the resource base. RPS resources were included based on data from the Northwest Power and Conservation Council (NPCC) Fifth Power Plan.

Plants under Construction

Figure 5.6 describes approximately 9,900 aMW of resources presently under construction and expected to be online during the study's time frame. These resources were included in all studies and scenarios. New gas represents 88 percent of the new energy, while wind accounts for three percent and coal seven percent.

Renewable Portfolio Standards

States with RPS legislation were explicitly modeled in AURORA^{XMP} The methodology to select renewable resource types is either consistent with the NPCC's Fifth Power Plan or follows state statute. Plants identified as RPS resources are fixed within the model and are consistent across all studies and scenarios.

Figure 5.5: Henry Hub Natural Gas Price Forecast ($/dth)

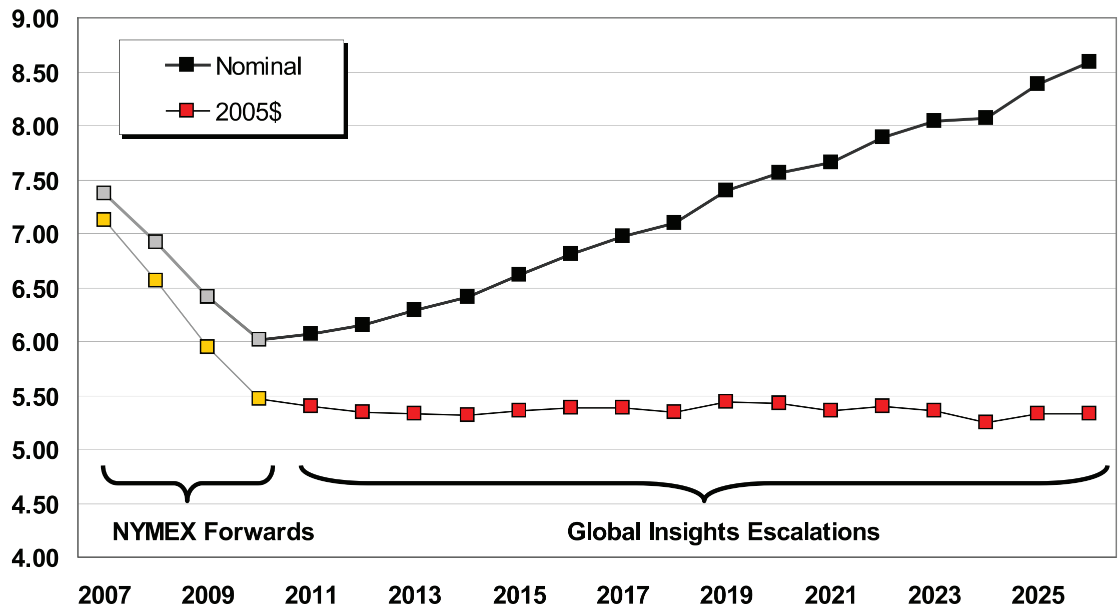


Table 5.3: Renewable Portfolio Standards by State

State	RPS Date	Level (%)
Arizona	2007	1.10
California	2017	20.00
Colorado	2015	10.00
Nevada	2013	15.00
New Mexico	2011	10.00

Table 5.3 shows states that have renewable portfolio standards and the RPS requirement that was modeled.

Future Resource Alternatives

As part of the AURORA^{XMP} simulation, new resources are identified to meet future load growth. This IRP considers generic resource alternatives identified in the NPCC Fifth Power Plan that could be built across all AURORA^{XMP} zones. The Company believes that NPCC resource assumptions provide greater transparency in the IRP process. The NPCC resources were formulated through a committee of regional experts drawn from utilities, developers, regulators and other interested parties.

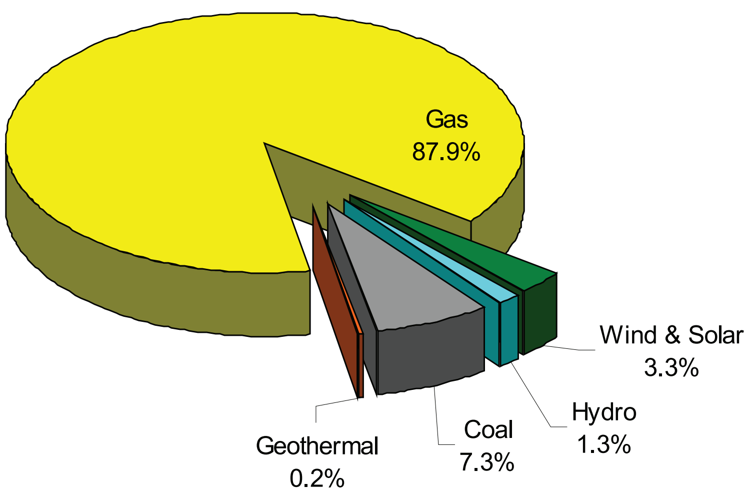
The Company does not have a resource deficiency until 2009; therefore the Company has not recently studied site-specific projects. This IRP provides a framework of analysis that the Company expects to utilize for future resource procurements. Assumptions will be updated at that time to include site-specific resource alternatives. Specific resource alternatives drawn from a Request for Proposals, or other acquisition process, would be evaluated in the same manner as the NPCC resources used in this study.

AURORA^{XMP} Modeling Divergences from the NPCC

The Company diverged modestly from NPCC resource assumptions in three areas: the federal production tax credit (PTC) for renewables; transmission costs for new coal, wind and oil sand plants; and the use of capacity credits.

The Company also has updated certain datasets with more recent information than was available to the NPCC.

Figure 5.6: New Resources Under Construction (MW)



Production Tax Credit

The NPCC models the wind PTC as an offset to variable O&M costs directly within AURORA^{XMP}. The Company chose to reduce fixed costs in each year by an amount equal to the tax credit in its revenue requirements model. The ultimate impact of this change was negligible, but it more accurately accounted for the credit value, including the impact on the Company's federal income tax obligations. In addition, the modeling accounts for the PTC as extended to other renewables (geothermal, biomass, solar) by the Federal 2004 HB 4520 Jobs Act. The PTC is assumed to be available throughout the timeframe of the study, except where carbon legislation is enacted. Where carbon legislation is enacted, the PTC is assumed to expire.

Incremental Transmission

The Company sought to improve the NPCC's incremental transmission cost estimates for integrating plants into the Northwest and the Western Interconnect. Existing transmission lines out of eastern regions in the Western Interconnect to the Northwest do not have adequate capacity to integrate large coal or wind plant developments. A combination of new and upgraded transmission facilities likely will be required to integrate such plants. To account for new transmission construction, the capital and operating costs of the new transmission are added to the costs of new generation resources.

Capacity Credits

Capacity credits provide a financial incentive for the model to build more generation than is needed under average conditions. The AURORA^{XMP} model has perfect foresight and builds just enough resources to meet future load growth assumptions. It does not build additional resources for planning margin. Providing credits is similar to the regulated environment where planning margins are retained to meet load under adverse conditions. The capacity credit is applied by reducing the capital cost of new generating resources. A final credit was developed by testing various values until the wholesale marketplace reached a balance.

The credit amount is equal to $31.22 per kilowatt-year for a plant with 90-percent availability. The credit is smaller for plants with lower availability such as wind or solar plants. For example, a 25-percent availability wind plant is credited $8.22 per kilowatt-year.

Table 5.4: IRP Differences from Fifth Power Plan

Data	Source Used
Inflation	Company Forecast is Based on Global Insight, Inc.
Load Escalation	WECC 2004 Load & Resource Report and the 2004 PacifiCorp IRP for Utah
Coal Escalation	EIA's Annual Energy Outlook 2005
Wind	Monthly Generation Replaced by Hourly Shapes
Start Up Costs	Fuel Price Adders Replaced With Start Fuel and O&M Start-Up Costs

Other Changes

The Company chose to incorporate other data that became available after the NPCC Fifth Power Plan was drafted. Table 5.4 lists the remaining major differences between this IRP and the NPCC Fifth Power Plan.

5.3 Risk Modeling

The 2005 IRP relies on work initially developed for the 2003 IRP. It continues to enhance the risk evaluation capabilities of Company models. In addition to stochastically modeling hydroelectric output, natural gas prices and load variability, the 2005 IRP models wind plant generation stochastically. Natural gas prices also were reevaluated, and a new approach to obtaining stochastic variables was pursued.

Background

Stochastic risk analysis offers a powerful means to understand the potential impact of portfolio options under various "draws" of future conditions. The life-cycle costs of long-lived resources are critical to the Company and its customers. For example, the Company's oldest active generation facility the Monroe Street hydroelectric project was built in 1890. Company investments in Colstrip Units 3 & 4, made in the mid-1980s, generate cost-effective electricity for our customers today.

Resource decisions therefore must provide cost-effective power for years to come. Reducing cost volatility for customers and shareholders is also important when considering long-term investments. The energy crisis in 2000-01 changed utility planning views of electric market price volatility risk. Stochastic analysis helps us understand possible variations inherent in future resource options and how to diversify resource types to arrive at a portfolio that reduces cost and minimizes variation.

Implementation

Preparing a stochastic analysis requires a large number of unique datasets. To understand the impact of varying customer load conditions on the resource decisions made for this IRP, 200 unique 20-year datasets for each zone in the Western Interconnect were created. More than 46 million daily loads were ultimately evaluated through the stochastic process. Similar work was performed for natural gas prices, hydroelectric generation and wind. A separate model was developed to evaluate historical relationships and project possible futures for each stochastic variable. Each stochastic variable is further described below.

Hydroelectric Generation

The Company portfolio is dominated by hydroelectric generation. Over 40 percent of customers' electricity is generated by hydroelectric projects today. NWPP estimates of hydroelectric generation over the 1929–1988 period were used to develop the stochastic variables for Northwest hydroelectric generation. As the Company learned in the 2003 IRP process, streamflows are normally distributed but hydroelectric generation is not. Therefore, using the simplified mean/standard deviation approach to create hydroelectric datasets was not possible. Generation levels were estimated by taking random draws from the 60-year NWPP dataset, with each draw containing a full year of the hydroelectric record.

Hydroelectric generation levels outside of the Northwest were held constant throughout the stochastic process due to a lack of available data. The Company believes this decision still provides a robust analysis of hydroelectric generation since Northwest hydroelectric plants account for 85 percent of all hydroelectric generation in the Western Interconnect. Table 5.5 illustrates that the OWI zone by itself accounts for more than half of all hydroelectric generation. Figure 5.7 presents the distribution of hydroelectric generation modeled for the Western Interconnect.

Table 5.5: Hydroelectric Generation Statistics by Zone (aMW)

Zone	%WI	Avg	Min	Max
OWI	54	14,091	10,604	17,672
BC	23	6,048	5,588	6,558
NCAL	7	1,850	1,850	1,850
IDs	5	1,331	885	1,850
AZ	3	829	829	829
MT	3	709	526	866
SCAL	2	583	583	583
SNV	2	429	429	429
AB	0	126	126	126
CO	0	81	81	82
UT	0	54	54	54
NM	0	17	17	17
WY	0	15	15	15
NNV	0	6	6	6
CCAL	0	1	1	1
BAJA	0	0	0	0
Total[3]	100	26,171	21,801	30,515

3 Minimums and maximums are Western Interconnect-wide coincident totals

Natural Gas Prices

Natural gas and electricity prices are highly correlated across the Western Interconnect.   The correlation reflects the region's increased reliance on natural gas-fired generation, a relationship expected to continue, because natural gas-fired plants set marginal electricity prices in most hours.

Figure 5.8 shows the relationship of prices in the Northwest as the correlation between Mid-Columbia electricity prices and the Malin hub gas prices in January, June and August over the IRP time horizon. Correlations rise modestly over time, especially in the month of June. The change in June reflects forecasted additions of gas-fired generation in the Southwest as the Western Interconnect continues to outgrow its hydroelectric generation base.

Changes Since The 2003 IRP

Two natural gas assumptions were changed for this IRP: 1) Hydroelectric conditions are no longer modeled to affect natural gas prices directly; and 2) the distribution is log-normally distributed rather than normally distributed. Evaluations of the wholesale marketplace since the 2003 IRP indicate that hydroelectric generation levels do not significantly impact natural gas prices.

Figure 5.7: Western Interconnect Hydroelectric Generation Distribution

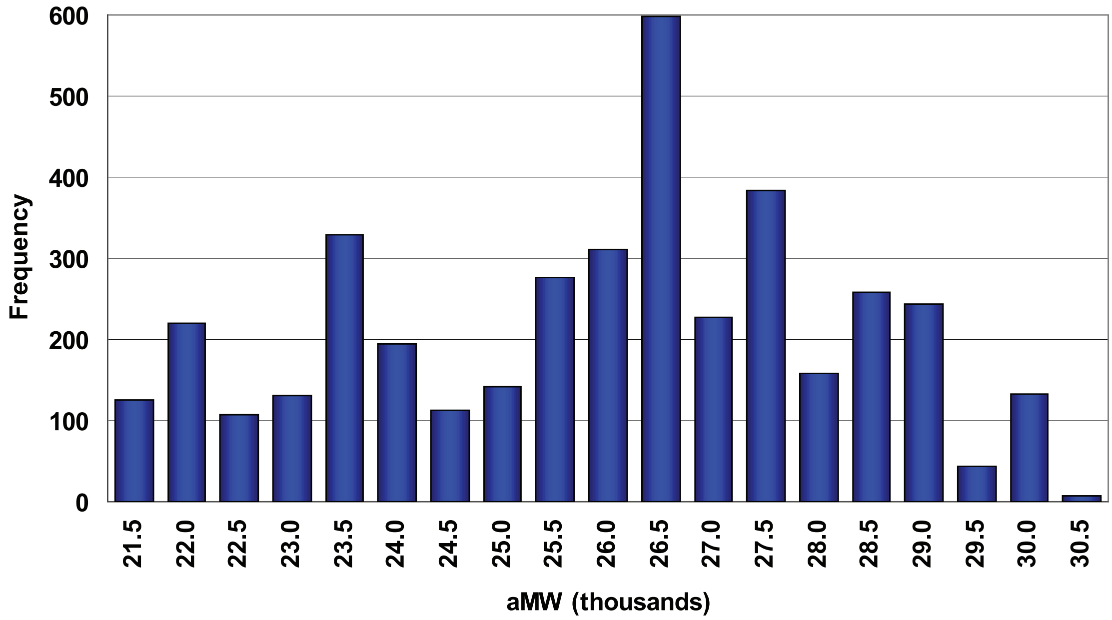
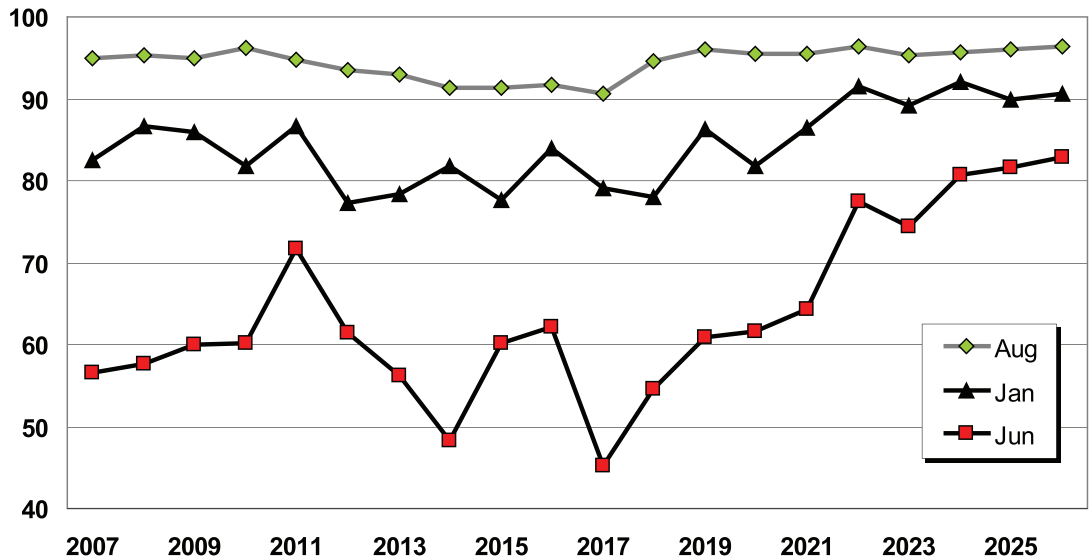


Figure 5.8: Mid-Columbia Electricity and Malin Natural Gas Price Correlations (%)



A "critical" water year in the Northwest reduces hydroelectric generation by approximately four thousand average megawatts. Replacing this hydroelectric generation with gas-fired generation would increase total U.S. natural gas consumption by less than one percent. Smaller reductions seen in other hydroelectric generation years would impact the U.S. marketplace even less. Given the modest impact of hydroelectric conditions on natural gas consumption, natural gas prices and hydroelectric generation levels are not correlated in 2005 IRP analyses.

The decision to adopt a lognormal distribution for natural gas prices reflects input received by the Company since the 2003 IRP was published. Many peer utilities, and other groups evaluating wholesale natural gas markets, assume a lognormal price distribution.

As with any stochastic forecast, the 2005 IRP necessarily must assume a mean (average) price and sigma (standard deviation). The 2005 IRP continues with the 2003 IRP natural gas sigma assumption of 50 percent. This means that two-thirds of all gas prices in the study fall within 50 percent of the mean. Because the 2005 mean forecast for natural gas prices has increased by approximately one third from the 2003 IRP, nominal sigma values are also increased. Figure 5.9 and Figure 5.10 illustrate statistics for 2007 and 2016.

Load Variability

Loads across the Western Interconnect are not independent. In other words, often times heat waves and cold snaps occur at the same time in the Northwest and Southwest. Representing this relationship is important when developing a representation of the future wholesale marketplace.

The 2005 IRP relies on Western Interconnect-wide statistical relationships developed for the 2003 IRP. The earlier work developed monthly and weekly distributions based on hourly data from all utilities obtained from FERC Form 714. Correlations between the Northwest and other Western Interconnect load areas were found and represented in the stochastic load model. Correlating zone loads avoids oversimplification. Absent correlation data, the stochastic models would offset load changes in one zone with load changes in another zone. Given the high degree of interdependency across the Western Interconnect (e.g., the Northwest and California), this additional accuracy is considered crucial for understanding wholesale electricity market price variation.

Tables 5.6a and 5.6b illustrate the correlations used for the 2005 IRP. Tables 5.7a and 5.7b provide mean and sigma values for each zone in 2007. The BAJA area has no load and was not included in this study. "NotSig" indicates that no statistically valid correlation was found in the evaluated data. "Mix" represents that the relationship was not consistent across time, and that it was not used.

Figure 5.9: Natural Gas Price Statistics-2007 ($/dth)

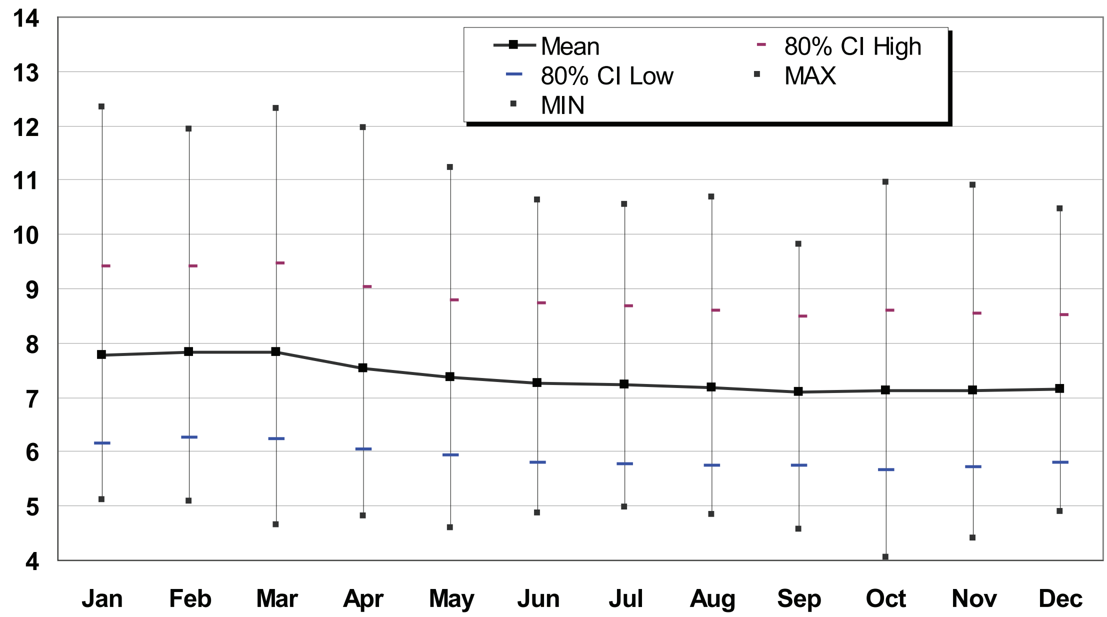


Figure 5.10: Natural Gas Price Statistics-2016 ($/dth)

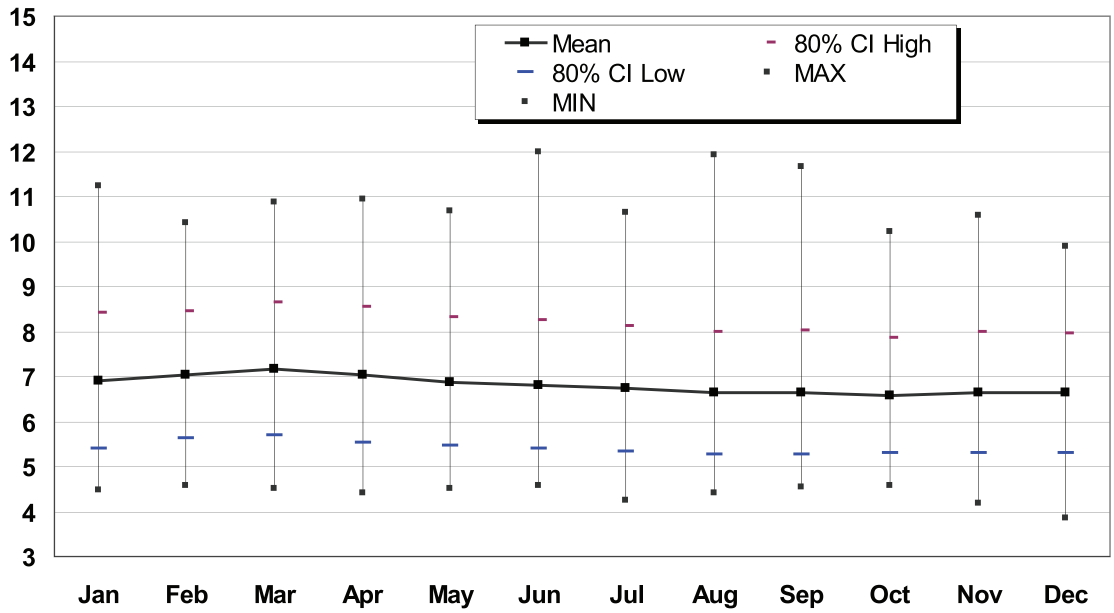


Table 5.6a: Western Interconnect Load Correlations—Jan through Jun

Area	Jan	Feb	Mar	Apr	May	Jun
AB	0.659	NotSig	0.481	NotSig	Mix	0.635
AZ	0.44	0.664	NotSig	Mix	-0.29	0.666
BC	0.918	0.838	0.825	0.733	0.617	NotSig
CCAL	NotSig	0.734	NotSig	NotSig	NotSig	0.771
CO	0.623	NotSig	0.567	Mix	Mix	NotSig
IDs	0.673	0.747	0.882	NotSig	NotSig	0.758
MT	0.894	0.773	0.755	0.651	0.405	0.599
NCAL	NotSig	0.734	NotSig	NotSig	NotSig	0.771
NM	0.384	Mix	Mix	NotSig	NotSig	Mix
NNV	Mix	NotSig	NotSig	NotSig	NotSig	NotSig
SCAL	NotSig	Mix	NotSig	NotSig	Mix	0.68
SNV	NotSig	0.641	0.513	Mix	NotSig	0.729
UT	0.816	NotSig	0.669	0.697	0.61	0.698
WY	0.765	Mix	0.641	NotSig	Mix	Mix

Table 5.6b: Western Interconnect Load Correlations—Jul through Dec

Area	Jul	Aug	Sep	Oct	Nov	Dec
AB	0.668	Mix	Mix	0.479	NotSig	NotSig
AZ	NotSig	NotSig	NotSig	NotSig	Mix	NotSig
BC	0.56	NotSig	0.638	0.809	0.525	0.89
CCAL	Mix	0.757	0.789	NotSig	Mix	NotSig
CO	NotSig	NotSig	NotSig	0.655	0.629	0.571
IDs	Mix	0.789	0.733	0.561	0.587	0.813
MT	0.786	0.648	0.752	NotSig	0.856	0.898
NCAL	Mix	0.757	0.789	NotSig	Mix	NotSig
NM	NotSig	Mix	NotSig	NotSig	Mix	Mix
NNV	NotSig	NotSig	NotSig	Mix	0.476	NotSig
SCAL	Mix	0.5	0.778	NotSig	NotSig	NotSig
SNV	Mix	NotSig	Mix	NotSig	0.461	Mix
UT	0.703	0.604	0.611	NotSig	0.561	0.837
WY	NotSig	NotSig	0.483	NotSig	0.522	0.633

Table 5.7a: Western Interconnect Load Statistics–Jan through Jun (2007 aGW)

Area	Value	Jan	Feb	Mar	Apr	May	Jun
AB	Mean	7.98	7.19	7.61	6.98	7.12	7.00
	StDev	0.29	0.22	0.25	0.22	0.22	0.25
AZ	Mean	8.26	7.53	7.48	7.28	8.22	9.39
	StDev	0.56	0.50	0.32	0.47	0.69	1.15
BC	Mean	8.76	7.74	8.06	7.27	7.20	6.82
	StDev	0.43	0.31	0.40	0.35	0.41	0.29
CCAL	Mean	1.52	1.42	1.44	1.40	1.43	1.55
	StDev	0.10	0.08	0.09	0.10	0.10	0.16
CO	Mean	6.37	5.96	5.87	5.57	5.49	5.81
	StDev	0.28	0.25	0.26	0.24	0.27	0.37
IDS	Mean	2.50	2.17	2.20	2.10	2.29	2.52
	StDev	0.11	0.07	0.11	0.09	0.16	0.23
MT	Mean	1.48	1.31	1.33	1.22	1.19	1.17
	StDev	0.05	0.03	0.04	0.03	0.04	0.04
NM	Mean	2.74	2.49	2.56	2.47	2.62	2.83
	StDev	0.09	0.08	0.07	0.08	0.11	0.15
NVN	Mean	1.12	1.00	1.04	1.03	1.18	1.34
	StDev	0.02	0.02	0.02	0.03	0.03	0.06
NVS	Mean	2.66	2.38	2.46	2.45	2.80	3.19
	StDev	0.10	0.09	0.06	0.14	0.24	0.47
NCAL	Mean	14.82	13.87	14.04	13.65	13.95	15.09
	StDev	1.00	0.74	0.85	0.95	1.01	1.58
OWI	Mean	20.43	18.99	18.47	16.96	16.55	16.13
	StDev	1.38	1.01	1.12	1.18	1.20	1.69
SCAL	Mean	22.43	20.99	21.24	20.66	21.10	22.83
	StDev	1.72	1.45	1.47	1.57	1.75	1.92
UT	Mean	3.32	3.01	3.05	2.91	3.04	3.18
	StDev	0.27	0.23	0.31	0.28	0.30	0.37
WY	Mean	2.13	2.06	2.09	1.96	1.94	1.93
	StDev	0.02	0.02	0.02	0.01	0.02	0.01

Table 5.7b: Western Interconnect Load Statistics—Jul through Dec (2007 aGW)

Area	Value	Jul	Aug	Sep	Oct	Nov	Dec
AB	Mean	7.38	7.37	7.11	7.54	7.74	8.23
	StDev	0.29	0.29	0.23	0.23	0.22	0.29
AZ	Mean	11.00	11.36	10.66	8.87	7.50	8.10
	StDev	0.70	0.55	0.80	0.68	0.35	0.54
BC	Mean	6.93	7.03	6.88	7.65	8.14	8.77
	StDev	0.32	0.35	0.32	0.34	0.34	0.43
CCAL	Mean	1.65	1.75	1.71	1.61	1.46	1.50
	StDev	0.18	0.19	0.16	0.11	0.09	0.10
CO	Mean	6.34	6.47	6.23	5.76	5.74	6.35
	StDev	0.36	0.33	0.35	0.25	0.29	0.32
IDS	Mean	2.83	2.62	2.24	2.16	2.19	2.46
	StDev	0.13	0.13	0.17	0.08	0.09	0.13
MT	Mean	1.23	1.27	1.19	1.19	1.30	1.40
	StDev	0.06	0.04	0.04	0.02	0.04	0.05
NM	Mean	3.05	3.04	2.86	2.64	2.53	2.74
	StDev	0.12	0.11	0.11	0.09	0.09	0.10
NVN	Mean	1.55	1.55	1.31	1.13	1.07	1.18
	StDev	0.06	0.06	0.06	0.03	0.04	0.04
NVS	Mean	3.70	3.70	3.13	2.69	2.55	2.82
	StDev	0.25	0.21	0.27	0.18	0.07	0.12
NCAL	Mean	16.10	17.06	16.64	5.68	14.20	14.59
	StDev	1.78	1.87	1.56	1.05	0.92	0.93
OWI	Mean	16.41	16.32	15.63	15.90	16.93	19.43
	StDev	1.82	1.79	1.46	1.07	1.09	1.24
SCAL	Mean	24.35	25.81	25.18	23.72	21.48	22.07
	StDev	2.50	2.19	2.81	1.79	1.61	1.61
UT	Mean	3.55	3.55	3.18	3.12	3.16	3.50
	StDev	0.38	0.35	0.36	0.24	0.29	0.38
WY	Mean	1.88	2.01	1.88	2.00	2.06	2.12
	StDev	0.02	0.01	0.02	0.01	0.02	0.02

Wind Generation

The 2005 IRP benefits from the addition of stochastic wind analysis. Evaluations of wind traditionally have oversimplified assumptions due to a lack of data. Some analyses have simplified to the point of assuming that wind generation is flat over all hours of each month. Other analyses have developed stochastic relationships that ignore serial correlation. Ignoring serial correlation disregards the fact that current-hour generation tends to be highly correlated with what happened in the previous hour. The importance of this is illustrated in the next three tables. Each table includes 1,000 hours of wind generation values.

Figure 5.11 provides actual generation from a Northwest wind facility. The scale has been adjusted to a maximum capability of 200 MW to protect the identity of the site. Figure 5.12 provides a simple stochastic representation of the data with no serial correlation assumed.

Figure 5.13 shows the results of the model developed by the Company for the 2005 IRP. The time period of the Company-generated data is different in Figure 5.13 than in Figure 5.11; even though total generation is higher, the general pattern is similar. In summary, the three charts explain that a simplified wind model significantly misstates the variability when compared to a simulation of actual operations. The Company's modeling more accurately reflects wind output.

In today's marketplace oversimplification might not greatly affect wind resource decisions, as it is not a significant enough power source to affect

Figure 5.11: Actual Wind Data - 1000 Continuous Hours (aMW)

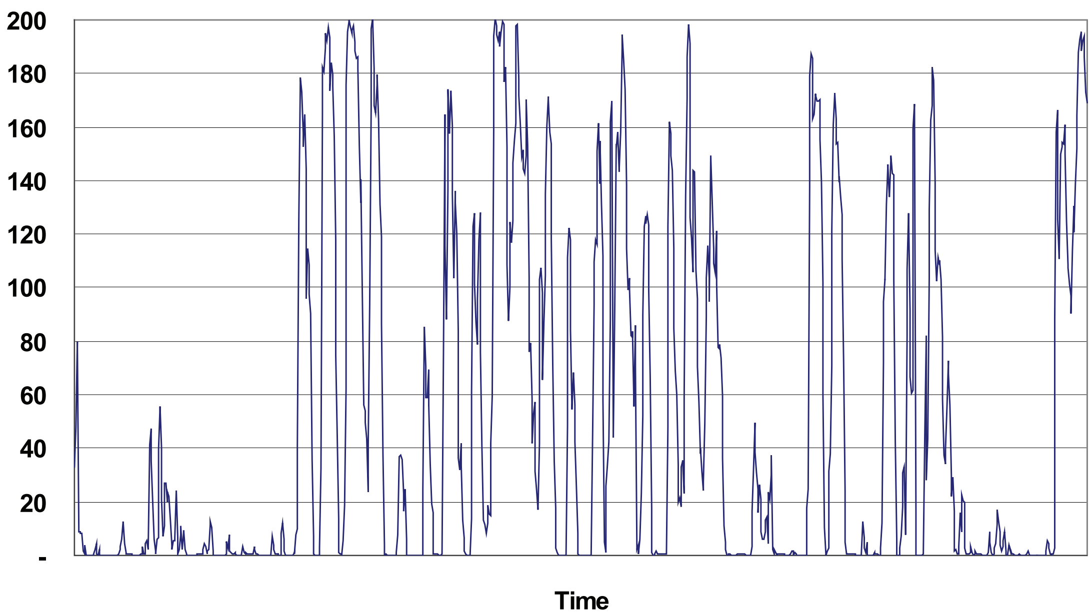


Figure 5.12: Stochastic Wind Model Absent Serial Correlation (aMW)

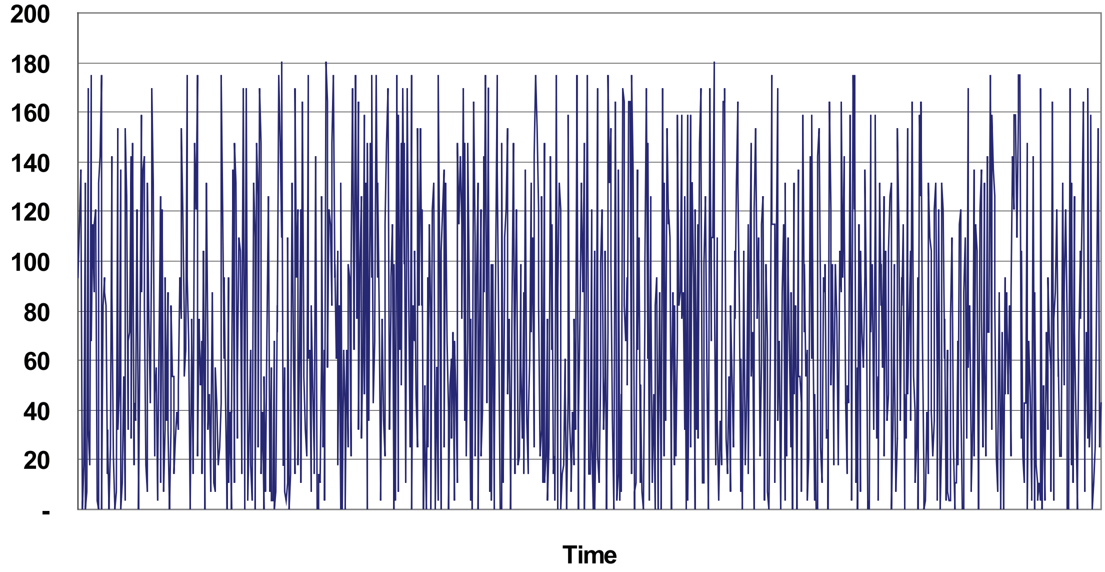
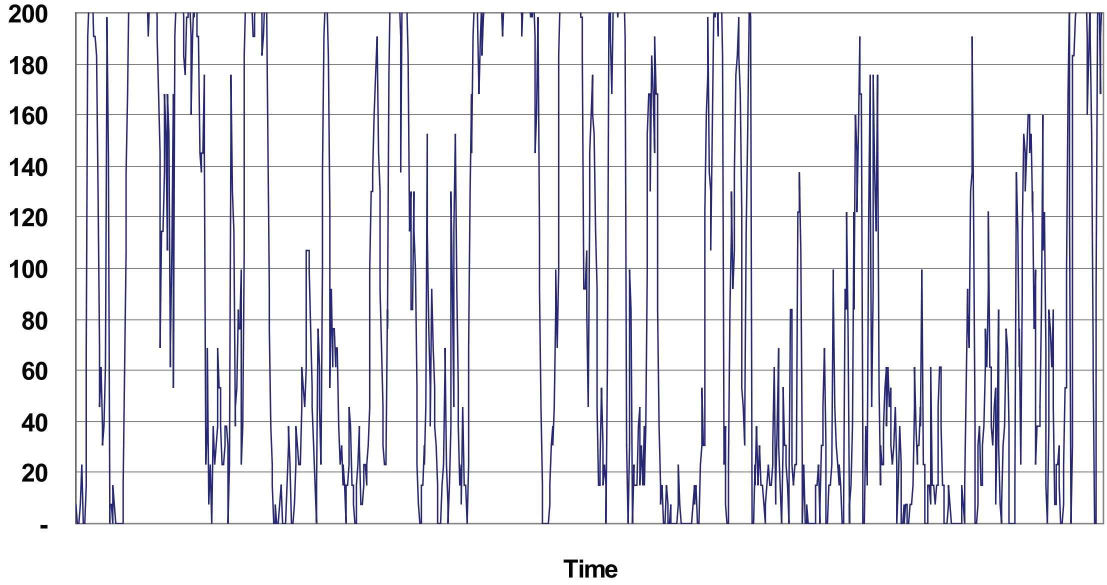


Figure 5.13: Stochastic Wind Model With Serial Correlation (aMW)



market prices; however, wind energy is expected to represent a growing part of the Western Interconnect resource mix throughout the planning horizon. Continuing to simplify the characteristics of this resource is no longer appropriate.

The 2003 IRP action plan stated that Avista would study wind further. Based on analyses completed since the filing of our 2003 IRP, more robust wind data underlie assumptions used for the 2005 IRP. Northwest wind speed data from Oregon State University (OSU) was evaluated hourly from 1985 through 2000 to develop statistical distributions for sample wind sites. Five separate wind sites were assessed to develop a combined distribution for Northwest wind generation. This approach is similar to how AURORA^{XMP} dispatches hydroelectric generation. Market prices are affected by the total dispatch of hydro resources in any given hour, irrespective of how one hydroelectric plant operates. The same logic holds true for wind power.

The stochastic wind model developed by Avista for the 2005 IRP produces daily generation levels and shapes them based on the monthly average hourly wind shape over the 1985-2000 period. With daily generation levels changing, the model more accurately represents the variability inherent in the resource.

Absent equivalent data for areas outside the Northwest, Avista looked to the Seams Steering Group-Western Interconnect to obtain average monthly generation and variance levels.[4]

4 http://www.ssg-wi.com

Due to the lack of multi-year datasets, each load area outside of the Northwest was assigned a sigma value equivalent on a percentage basis to the information obtained from the OSU database. Independent models were run to generate synthesized stochastic wind data for the entire Western Interconnect.

5.4 The Avista LP Model

The Company uses a proprietary linear programming (LP) model to assist in developing its Preferred Resource Strategy, rather than relying on a set of predetermined resource portfolios. Avista believes that using this approach is superior to simply using portfolios. Predetermined portfolios are simpler to understand, but they ignore the thousands of potential resource mixes available to the Company to serve future loads. For example, a wind portfolio can be comprised of many different wind projects, each with varying characteristics (e.g., location). The Avista Linear Programming model approach looks at 180 different wind options nine different wind basins, each available for selection over the 20-year forecast horizon. The LP model does not preclude the Company from using portfolios to help readers understand the effect of different market scenarios on several generic resource types. Instead, the LP model helps develop portfolios used later in the results section to help illustrate the relative performance of specific resource strategies.

The LP model relies on three primary datasets: 1) Avista load requirements (capacity and energy) over time; 2) capital recovery costs associated with new resource alternatives, inclusive of locational transmission pricing; and 3) the value of each new resource alternative over 200 iterations of 20-year stochastic analysis performed in the market forecasting model AURORA^{XMP}.[5] The LP model is guided by various constraints to arrive at a least-cost solution defined in terms of the present value of expected power supply expenses and risk, measured as the standard deviation of the same expenses.

Constraints

Various constraints were placed on the LP model. The model ensures that sufficient capacity and energy are constructed in every year to serve annual customer demand. Energy quantities were defined as minimum levels, allowing more energy than necessary to be constructed. This assumption reflected actual utility planning requirements. Capacity was a capped constraint. The model matched forecasted capacity requirements in every year.

An optimization algorithm gave the model a strong bias to limit market purchases and sales. Legislation and regulation in the Northwest is not favoring further rulemakings that would limit or discourage utility resource acquisition or construction to serve load growth; therefore, it is unlikely in the current environment that independent generators will develop adequate resources on a speculative basis to serve utility requirements. For this and for other financial and credit reasons, the Company believes it would be inappropriate to rely on large purchases from the market in the long term to serve firm load obligations.

Wind generation has become more attractive relative to other resource options because of rising natural gas costs and the related rise in wholesale electricity prices. Wind power economics were questioned in the past because of their similar busbar cost to natural gas-fired generation and the uncertainty surrounding additional integration costs necessary to "firm" the resource. Now that natural gas-fired projects have become costlier, the difference between the busbar cost of gas and wind has grown to a point that likely exceeds wind integration costs. The model recognizes this condition and builds significant amounts of wind resources absent constraints.

Though preferred by the Avista LP model, it is unlikely that the high level of wind resources identified in early runs would be obtainable. The model was constrained to select no more than 650 MW of wind in any given resource mix. The limit is discussed later in the section. The LP model also was constrained to allow no more coal reliance than 350 MW in 2016, 450 MW in 2021, and 550 MW in 2026. Ultimately, the 550 MW coal constraint was not necessary, as the Preferred Resource Strategy identified a need for 450 MW.

5 AURORA^{XMP} accounts for variable O&M and fuel costs for each resource valuation

Efficient Frontier

The Avista LP model was used to define a 1,000-point "efficient frontier" of resource options over the full range of risk and cost. This method provides an optimal resource build for each level of willingness to accept more volatility. Figure 5.14 provides the efficient frontier. To create an efficient frontier, the LP model is directed to find the lowest cost resource mix for each level of risk or variation in power costs. Capital costs generally tend to be inversely correlated with risk.

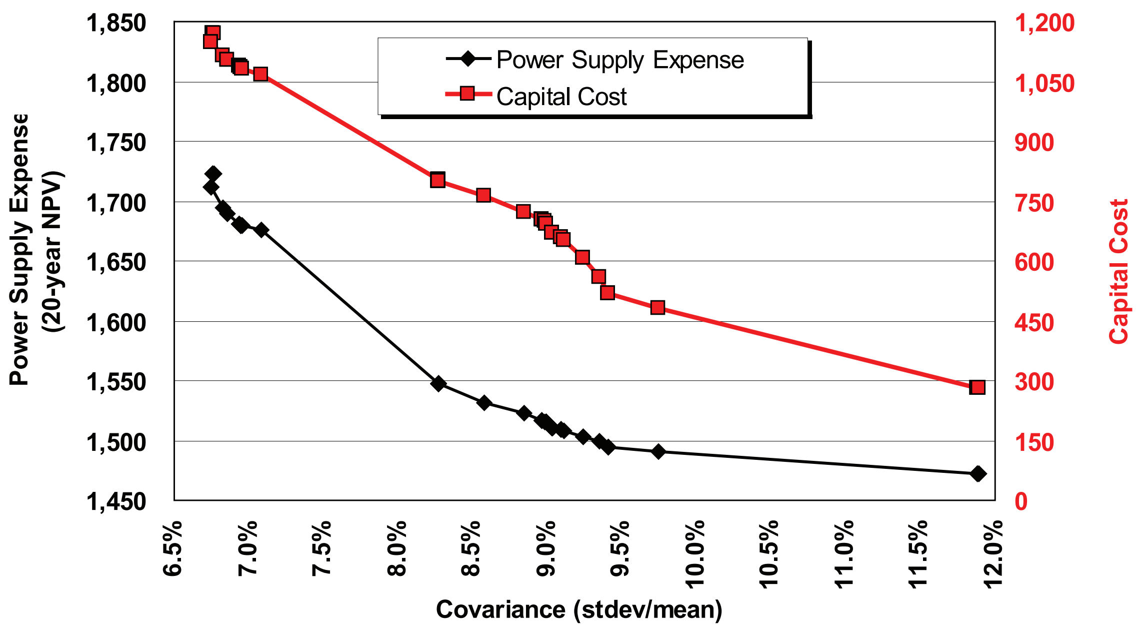
5.5 New Resource Alternatives

Each zone modeled in AURORA^{XMP} has the potential to build a wide variety of resource types. Resource availability varies between geographic areas because of the potential for renewables, the cost of new transmission and the difference in each region's attitude toward certain fuel types. For example, Wyoming and Montana are open to new coal plants. California is not assumed to be building any new coal plants in the 2005 IRP. This assumption is based on decisions made by the NPCC in its Fifth Power Plan.

Underlying assumptions for each new resource are based on recent work by the NPCC. For further detail on generator assumptions see the NPCC website.[6] In addition, transmission cost estimates used to set the market price forecast are based on research from regional transmission studies such as those prepared by the Rocky Mountain Area Transmission Study[7] and the Northwest Transmission Assessment Committee.[8] Regional transmission assumptions were derived from a working forum of utility experts, merchant

6 http://www.nwcouncil.org
7 http://psc.state.wy.us/htdocs/subregional/home.htm
8 http://www.nwpp.org/ntac/

Figure 5.14: Efficient Frontier Versus Capital Expenditure ($millions)



plant developers, BPA, Western Area Power Adminstration and other interested parties. The Avista Transmission Department developed estimates to provide a better understanding of the transmission costs associated with building generators to serve Avista's native load. These cost estimates may be found in Table 4.1 in Section 4-*Transmission Planning*. Resource options available to serve future demand in the West, as well as those available to meet resource deficits that face Avista in the future, are discussed below.

Combined-Cycle Combustion Turbines (CCCT)

Combined-cycle combustion turbines were modeled using a two-on-one (2x1) configuration. This configuration consists of two gas turbines exhausting waste heat into a single heat recovery steam generator (HRSG), rather than one gas turbine matched to the HRSG as in the traditional one-on-one configuration. The NPCC assumes that modest cost efficiencies are gained through the 2x1 configuration. All CCCT plants that could be selected by the model have 610 MW of capacity; 540 MW is assumed to be base load and 70 MW is duct fire. The actual monthly capability of these plants varies across regions based on NPCC assumptions. The Company did not restrict the quantity of CCCT plants built by AURORA^{XMP} for market forecasting.

Simple-Cycle Combustion Turbines (SCCT)

Two simple-cycle technologies were modeled, aero-derivative and frame machines. These two resources have a trade off between capital and efficiency. Aero-derivative machines are more capital intensive and have higher operating costs than frame machines, but their heat rate is lower and the plants have more flexible start times of 10 to 15 minutes. The Company did not restrict the quantity of SCCT plants that could be built by AURORA^{XMP} for market forecasting purposes.

Coal Plants

Three types of coal technologies were modeled for the 2005 IRP, pulverized, integrated gasification combined cycle (IGCC), and IGCC with carbon sequestration.

Pulverized: Sub-critical pulverized plants were modeled with low-NO_X burners, nitrogen oxide and mercury controls. Capital cost estimates assume that more than one unit will be built on a site and that the plant is wet cooled. Air-cooled plants reduce thermal efficiency by about 10 percent.

IGCC: Integrated Gasification Combined Cycle plants convert coal into a gas, and then burn it using technology similar to CCCT plants. IGCC plants significantly reduce emission levels through the gasification process. These plants are expected to cost 15 to 20 percent more than their pulverized counterparts, but they offer greater efficiency and the opportunity to sequester carbon emissions.

IGCC with Carbon Sequestration: These plants use the same technology as the IGCC plant, except that carbon is captured and sequestered into deep geological pockets in the earth or in the ocean. ICGG with sequestration has the potential to capture approximately 90 percent of plant carbon emissions.

As constraints prevented new coal plants from being built in California, coal plants built to serve the Golden state are constructed in Wyoming or Utah, and power is transmitted on new or upgraded transmission lines. Other regions, including Idaho, the Northwest and Utah, have the option to build coal plants locally or construct plants in other states (e.g., Wyoming or Montana) and transmit the power over transmission lines. Colorado, Northern Nevada, Arizona and New Mexico built coal plants locally. The Northwest was limited to two pulverized and five IGCC coal units. The Company did not include any clean coal tax benefits that may become available by pending federal legislation or a carbon tax adder for the Base Case. Since no federal law limits carbon emissions, the Company chose not to include any carbon tax in the Base Case, though the Company will continue to study potential carbon taxes for future resource acquisitions. The 2005 IRP includes two carbon-limited scenarios to help understand the potential impacts of such a tax.

Wind

Improving wind modeling has been a focus for this resource plan. The major improvement is the use of hourly generation shapes rather than a flat monthly capacity factor. Consistent with the NPCC, wind plants are assumed to require new transmission with the exception of the first 1,000 MW of wind generation added to the Northwest Region. It is also assumed that the capacity factor for wind will fall after the first 1,000 MW are installed. For example, the first sites (Tier 1) have 33 to 37 percent capacity factors. Tier 2 are assumed to be 80 percent of Tier 1 potential. Furthermore, Tier 1 sites can be integrated without significant transmission construction, whereas Tier 2 sites require new transmission construction.

Alberta Oil Sands

The oil sands of Northern Alberta are often called "tar sands." According to the NPCC Fifth Power Plan, the oil sands have an estimated 1.6 trillion barrels of petroleum deposits. The petroleum is in the form of bitumen and methane contained in the sands. The bitumen can be extracted and processed to create synthetic crude oil. The process used to extract the bitumen uses steam produced from natural gas or coke plants. Developers of the oil sands would like to build additional co-generating natural gas plants near Fort McMurray, Alberta, to process the bitumen, and then sell the electric byproduct to markets in the Northwest and/or California. This plan requires the costly construction of new high-voltage DC transmission lines to reach U.S. markets.

Nuclear

Nuclear-powered generation is a prominent energy source throughout the world and the United States (approximately 20 percent of generation in the U.S.). The U.S. has not licensed a new plant since 1978. Based on new cost data provided by the NPCC, nuclear generation appears competitive compared to coal. Great uncertainty remains with new nuclear plants because of concerns with plant siting, historical issues with cost overruns, and long-term waste storage. Future carbon emission standards, potential tax benefits and federal loan guarantees could make nuclear power more economically attractive in the future. Given uncertainties surrounding nuclear plants, the model was allowed to construct only one plant in Arizona after 2020. The option was provided only to test the relative economics of the nuclear option.

Other Resources

Several other resources also were modeled in this study. The resources are relatively small compared to the other options described by the NPCC, and were limited based on location. Solar projects were limited only to the southern states. Wood, landfill gas and manure biomass were only allowed in the Northwest to simplify the modeling exercise. Table 5.8 provides a brief description of each technology type and key underlying assumptions. The resource assumptions were taken from the NPCC except where noted. Capital is shown as overnight cost, meaning that allowances for funds used during construction are not included.

Unit availability accounts for both maintenance and forced outage and is based on NPPC assumptions. Wind plant availability varies by region and season; on average, wind plants are modeled with a 34 percent capacity factor. Solar is shaped by hour over the year with an average availability of 22 percent.

Table 5.8: New Resource Alternatives (2005$)

Resource	Gen. Cost ($/kW)	Unit Capacity (MW)	Heat Rate (Btu/kWh)	Unit Availability (percent)	Fixed O&M ($/kW/yr)	Variable O&M ($/MWh)
CCCT/Duct (2x1)	567	540/70	7,030	90	8.76	3.02
SCCT- Aero	648	94	9,900	90	8.64	8.64
SCCT- Frame	405	94	10,500	90	6.48	4.32
Coal- Standard	1,343	400	9,550	84	43.19	1.89
Coal- IGCC	1,512	425	7,915	83	48.59	1.62
Coal- IGCC w/seq	1,949	401	9,290	83	57.23	1.73
Wind	1,191	100	N/A	Avg. 34	18.90	1.08
Geothermal	1,976	50	9,300	92	103.66	0
Adv. Nuclear	1,566	1,100	9,600	88	43.19	1.08
Solar	7,558	2	N/A	Avg. 22	34.55	4.32
Oil Sands	611	180	5,800	85	0	3.00
Landfill Gas	1,468	1	11,100	80	134.97	1.08
Manure	3,347	1	11,100	90	72.34	0
Wood	2,159	25	14,500	90	86.38	9.72
Co-Gen	1,080	25	5,500	85	31.31	2.16

Heat rates for CCCT, SCCT, and coal plants are expected to improve over time. For example, the NPCC assumes that CCCT heat rates will improve by 10 percent from an average of 7,030 Btu per kWh today to 6,359 Btu per kWh in 2026. Coal plant heat rates are expected to improve by 6 percent over the same period.

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

Certain resources benefit from capital cost reductions over time due to anticipated technology improvements. These reductions are shown in Table 5.9

Resources Not Evaluated for the Western Interconnect

There are many resources that could be a vital part of an energy future but were not modeled in this analysis because of problems with commercial viability at this point in time. The resource types include nuclear, 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 model was allowed to build a single nuclear plant in Arizona, with the assumption that a new unit could be added to the Palo Verde generation station after 2020. The lone facility was included to show the potential for cost effective nuclear power provided that safety, security, waste storage and political issues can be rectified in the future.

Table 5.9: Forecast Capital Cost Reductions (%)

Resource Type	2007-2009	2010-2014	2015-2026
Wind	3.1	2.3	1.9
Solar	8.0	8.0	8.0
CCCT - Gas	0.5	0.5	0.5
CT - Gas	0.5	0.5	0.5
IGCC	1.5	1.5	1.5

Resources Not Evaluated for the Northwest

Table 5.8 includes many resources that were not included in the Western Interconnect. Large-scale solar, nuclear and coal with carbon sequestration most likely will not be constructed in the Northwest because of cost, siting or other concerns.

Western Interconnect Generic Transmission Cost Estimates

New resources built far from load centers, such as coal and oil sands, will require transmission investments. Cost adders to account for transmission were included in the IRP analysis. In the Northwest, several resources are available that would require new transmission:

- New coal plants located in the Oregon/Washington region
- New wind farms located in Oregon/Washington that are in excess of the 1,000 MW of Tier 1 wind
- New coal plants located outside the Northwest
- New wind farms located outside the Northwest
- Oil sands located in Northern Alberta

Other regions, including California and Southern Nevada, also may import coal generation from other regions or oil sands generation from Alberta. In these cases, new transmission costs are included in the delivered price of energy.

Transmission estimates generally are based on figures from regional transmission studies, such as the Rocky Mountain Area Transmission Study and the Northwest Transmission Assessment Committee. The values used for the 2005 IRP are shown in Table 5.10. These studies provide rough estimates for specific lines of various sizes and locations. Transmission estimates use approximate mileage of the new transmission lines, the size required for the connecting plant and the locations of the new line. Specific transmission costs for Avista resource options are provided in Section 4-*Transmission Planning.*

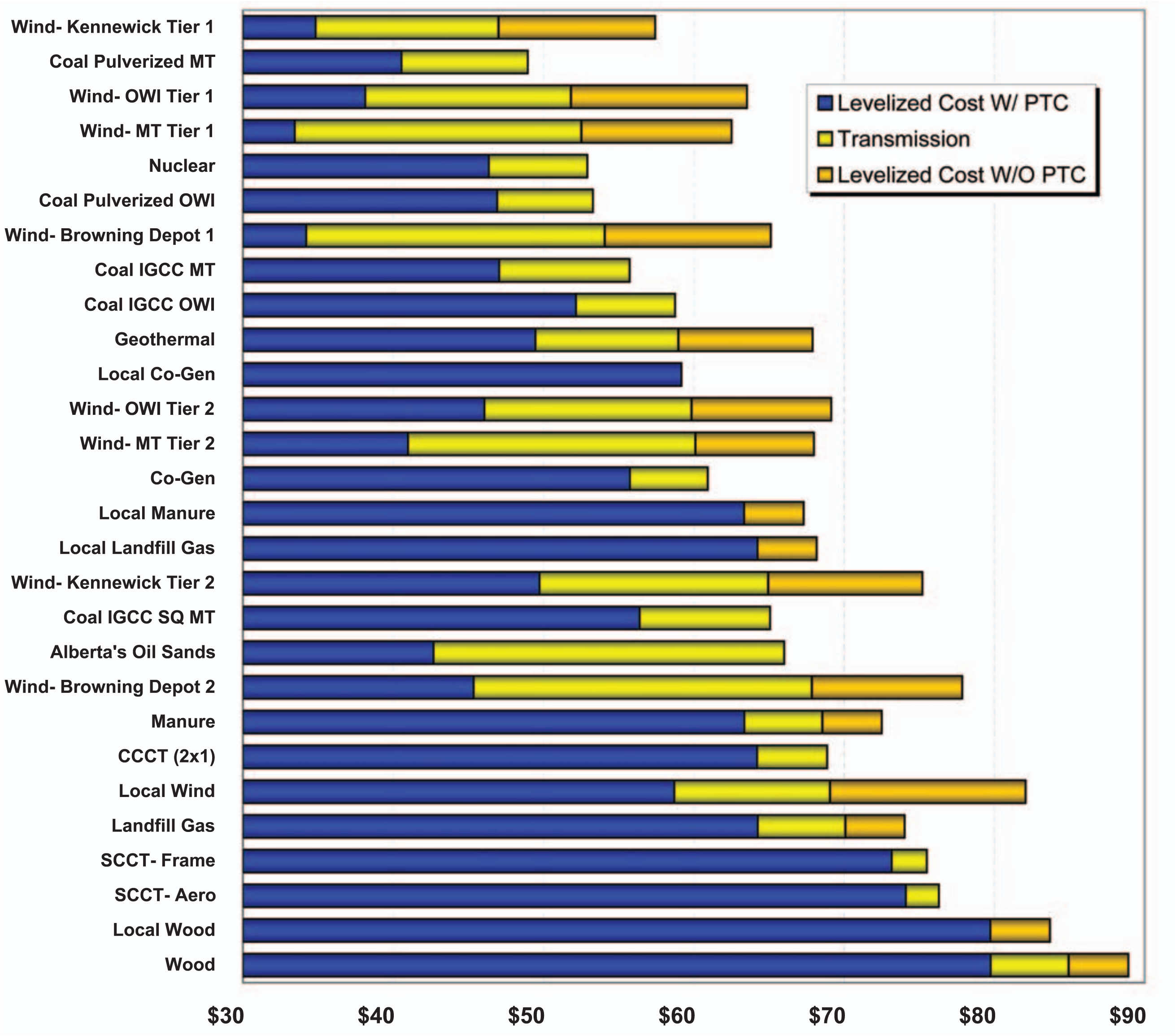
Levelized Costs

Figure 5.15 is a graphic showing levelized costs of each resource alternative assuming full plant capability. At full capability, certain Tier 1 wind and Montana coal are still the lowest cost resources, excluding any carbon mitigation costs. Nuclear is also a low cost resource based on cost estimates provided by the NPCC. Renewable resources are competitive when the federal the production tax credit is applied. Similar values in real levelized dollars are presented in Apendix H.

Table 5.10: Regional Transmission Cost Estimates (2005$)

Resource Type	To	From	Line Size (KV)	Capacity (MW)	Miles	Cost Per Mile ($Mil)	Substation Costs ($Mil)	Total Cost ($Mil)	($/kW)	Fixed O&M (kW/yr)
Coal	Inter-regional		500	1,200	300	1.20	40	400	333	8.9
Wind	Inter-regional		500	1,200	100	0.90	40	130	108	8.9
Coal	OWI	MT	500	1,200	672	0.85	50	621	518	8.9
Wind	OWI	MT	500	1,200	600	0.85	50	560	467	8.9
Coal	IDs	WY	500	1,200	450	1.20	10	550	458	8.9
Coal	UT	WY	500	1,200	200	1.50	20	320	267	8.9
Coal	UT	UT	500	1,200	100	1.20	15	135	113	8.9
Coal	SCAL	WY	500	1,200	1,500	1.80	100	2,800	2,333	8.9
Coal	NCAL	WY	500	1,200	1,600	1.80	100	2,980	2,483	8.9
Coal	SNV	WY	500	1,200	1,100	1.70	100	1,970	1,642	8.9
Oil Sands	OWI	AB	500 DC	1,500	1,200	N/A	N/A	1,400	933	8.9
Oil Sands	SCAL	AB	500 DC	2,000	1,730	N/A	N/A	2,000	1,000	8.9
Oil Sands	AB	AB	500 DC	500	475	N/A	N/A	500	1,000	8.9
Gas/Other	Inter-regional		N/A	N/A	N/A	N/A	N/A	N/A	N/A	16.8

Figure 5.15: 2016 Resource Option Costs (2005$/MWh, Levelized)



5.6 Wind Modeling

Avista has a distinguished history of using renewable energy to serve its customers. Hydroelectric and wood-fired generation currently accounts for more than half of all electricity consumed in our service territory. Wind power presents an avenue for the Company to generate more renewable energy. Wind resources benefit from having no fuel costs and low operations and maintenance costs when compared to other renewable generation technologies. Wind power has similar financial benefits to traditional generation facilities like coal and nuclear plants, as well as other renewable facilities, because its costs are not highly correlated to the wholesale electricity marketplace.

The 2003 IRP identified 75 MW of wind as a part of the Preferred Resource Strategy. The Action Plan for the 2003 IRP also committed the Company to study wind generation further. Over the past two years the Company has researched wind generation and the potential financial and operational impacts of wind integration. In early 2004, the Company signed a ten-year wind power contract for 35 MW of installed capacity from the Stateline Wind Energy Center. The contract is for busbar (i.e., delivered when the wind blows) power, this allows the Company to experience and evaluate the actual impacts of a wind resource on its system. It also provided actual data to assist in evaluating wind, including access to a state-of-the-art wind generation forecasting package.

Wind Integration

Wind integration entails costs associated with firming and shaping the resource to meet customer needs. Wind energy is "controlled" by weather patterns rather than utility operators, thereby creating a generation resource that is significantly different than traditional types. To integrate wind, other resources must be dispatched in a different and often costlier manner. Wind behaves more like a load, because it requires other resources to follow its intermittent output. This impacts the opportunity costs of operating non-wind generating assets differently than they would be absent wind generation.[9] This higher incurred cost is attributed to the wind resource and charged against its generation value.

Various studies have been performed to address wind integration costs. Actual integration costs have been estimated from less than one dollar per MWh to more than $20 per MWh. Company studies have shown that integration costs can range upward of $20 per MWh where penetrations exceed 20 percent of total system installed capability. A wind integration model developed by the Company showed that modest levels of wind installation, around 50 MW, were expected to incur integration costs below $3 per MWh. Levels near 100 MW incurred costs closer to $5 per MWh. The model showed that both system capabilities and

9 Opportunity cost is the cost of an item in terms of the next best-forgone alternative. In the case of wind power, an alternative asset, such as a hydroelectric project must be taken off of optimal economic dispatch and be used to shape the non-firm power coming from the wind project.

transmission location and costs affect the actual level of wind integration cost. For the 2005 IRP, the Company used wind integration assumptions from the NPPC. The NPPC assumes integration costs of $4.50 (2005$) per MWh for Tier 1 wind resources and $9.00 (2005$) per MWh for Tier 2 wind resources.

Wind Forecasting

Many in the wind industry tout the ability of wind forecasting to reduce wind integration costs. If wind generation could be forecast on a day-ahead basis with higher levels of accuracy, then the resource would become more reliable and valuable. Preliminary Company analysis found that wind forecasting does not enhance the ability to forecast wind generation; therefore wind integration costs cannot presently be reduced substantially through forecasting. Ideally, a forecast would provide accurate information about wind generation for the period four hours or more into the future so that utility operations can be modified to accommodate the wind energy. In its study, the Company found that the results of a third-party weather forecast were not superior to simple persistence forecasting.[10] Table 5.11 compares the accuracy of wind forecasting methods to persistence over the July 2004 through March 2005 time period for the Stateline Wind Energy Center. Avista believes that there is room for improvement in wind forecasting and is analyzing additional data. It is hoped that wind-forecasting methods can be improved to bring down wind integration costs.

Table 5.11: Wind Forecasting Accuracy (%)

Hours Ahead	Weather Forecast	Simple Persistence	Difference
1	94.9	95.6	-0.7
2	95.0	88.9	6.1
4	90.0	76.2	13.8
8	42.0	57.4	-15.4
12	32.4	44.3	-11.9
24	19.6	32.3	-12.7
48	11.8	11.4	0.4

Wind Contribution to Meeting System Peaks

The Company must own or control adequate resources to serve customer loads during adverse weather or other events. The Company's last IRP gave wind resources a zero value for meeting system peaks because of the erratic nature of wind and our lack of experience with the resource. Using data from the Oregon State University Wind Research Project, Avista was able to estimate the contribution of wind resources to meeting system peaks. The evaluation of individual sites, such as Stateline, supports our 2003 IRP assumption that wind does not possess significant capacity value. An analysis of wind sites located across the Northwest showed that a portion of installed capability could be relied on to meet system peak.

Using a method called "Energy Load Carrying Capability," the Company found that a mix of five Northwest sites scattered from the Oregon Coast to the eastern side of the Rocky Mountains could support a capacity level of approximately 25 percent.[11] The level appears low in relation to a

10 Persistence forecasting assumes that the last hour of generation will represent future hours of generation.

11 Energy load carrying capability represents the expected portion of nameplate capacity available during a system's peak demand.

plant's nameplate rating, but not when compared to the expected capacity factor. The 25 percent peak capacity value is used when evaluating wind contribution to meeting system coincident peaks for the 2005 IRP.

Wind In The Preferred Resource Strategy

Cost

Wind energy costs are driven by several factors: the capacity factor of the wind site, availability of the federal PTC, integration costs, and transmission costs to deliver wind energy to customers. Capacity factor accounts for the largest difference between wind site values. Changing from a 33 percent capacity factor to 25 percent equates to an energy loss of around 25 percent. The 2005 IRP assumes that two tiers of wind energy exist in the Northwest and in eastern Montana: Tier 1 equals 33 percent in the Northwest and 35 percent in eastern Montana; Tier 2 equals 26.4 percent in the Northwest and 28 percent in eastern Montana. Montana wind sites have a higher wind capacity factor, which explains their modestly higher generation levels. Tier 2 wind levels are estimated at 80 percent of Tier 1 levels. The lower generation level, while based on limited information, reflects data obtained from various sources over the past few years. The reference to eastern Montana in the IRP is for illustrative purposes only. There are various regions remote to Avista (including eastern Montana) that have better wind patterns than found in the Northwest. This plan does not preclude the Company from purchasing wind energy from these sites.

The federal PTC plays a significant role in wind project economics. To determine the importance of the PTC, a Base Case scenario using a 50/50 weighting of cost, measured as the net present value of expected power supply expenses, and risk, measured as the standard deviation of the expected power supply expense, was run absent the PTC. The result showed that no Tier 2 wind resources were selected, which reduced overall wind penetration by one-third. The Base Case runs, and most scenarios, assume the PTC remains at its 2005 level through the 20-year study. The PTC might be eliminated or modified, but Avista believes that the PTC is a good alternative to a carbon-based fee, and it likely will remain absent carbon legislation. However, the PTC is phased out in scenarios where carbon emissions are regulated.

Availability of Wind Generation

The 2003 IRP limited total installed wind generation to 75 MW of installed capability. The PRS would have selected more wind without the constraint. The reasoning for the limitation was based on many perspectives at that time, including:

1. The Company had limited experience with wind;
2. The two-year planning cycle allowed for later revisions to the estimate without compromising the Company's future resource mix because no new resources were required before 2008;
3. Avista's analysis of integration costs found that higher wind penetration resulted in higher costs than assumed by the resource selection model;
4. Significant modeling changes for the 2003 IRP precluded the Company from fully addressing

capacity planning and therefore was cautious about selecting resources with low abilities to contribute to system peaks;

5. Based on preliminary work, the capacity contribution to system peak was assumed to be zero, which compromised the value of wind generation to the Company.

The 2005 IRP analyses benefit from substantially more information than was available for the 2003 effort. Studies have shown that wind integration costs are more manageable than forecast at that time. The NPCC has evaluated wind integration and the costs have been included in the present analysis. Results of the 2005 IRP indicate that substantial amounts of wind would be cost-effective within certain limits. The NPCC Fifth Power Plan discusses a potential of 5,000 MW of installed wind capacity in the Northwest. Avista's pro-rata share of wind generation would be approximately 250 MW.

The Company has determined that it makes sense to limit the overall level of wind energy within Avista's resource portfolio due to our concern over adequate levels being available to serve our requirements. To enforce the limit, the Avista Linear Programming model allows 250 MW of wind generation from the Northwest, plus 150 MW of wind capability in Avista's own service territory over the 20-year study. Two hundred fifty additional megawatts are assumed to be available to Avista from outside the Northwest (e.g., eastern Montana). The total potential wind resource available to Avista is 650 MW over the 20-year IRP timeframe.

5.7 Summary

The 2005 Integrated Resource Plan is a comprehensive modeling effort that not only studies Avista's generation needs but also those of the entire Western Interconnect. The modeling approach allows the Company to identify costs and benefits of large changes to the electric industry, such as fuel price volatility, carbon emission standards and lower future hydro energy.

The modeling approach relies heavily on estimates provided by the NPCC Fifth Power Plan and the resource database provided by EPIS, Inc. The Company's approach differs from other integrated resource plans by deriving price forecasts from the same model that evaluates resource option values instead of simply inputting electricity prices into the study as exogenous variables. This approach more fully accounts for changes made to the input assumptions and eliminates the need to make assumptions about the correlations and statistics of and between natural gas and electricity prices. This creates a fully integrated generation evaluation of how Company resources would act in the marketplace.

6. MODELING RESULTS

Avista's Preferred Resource Strategy (PRS) is tied to the Mid-Columbia electric market forecast more than to any other variable. The *Modeling Approach* section describes four major drivers of market prices: natural gas prices, electricity demand, hydro generation levels and wind generation levels. There are several ways to evaluate future market prices with AURORA^{XMP}. The most common approach is to forecast the market using averages. In this case, average hydro conditions, base line fuel prices, average wind conditions, average load projections and other variables discussed in the key assumptions portion of Section 5- *Modeling Approach* are input into the model. The Company used this approach to develop the Base Case electricity forecast.

After the Base Case forecast was completed, two methodologies for risk assessment were utilized:

Futures: stochastic studies that use a Monte Carlo approach to quantitatively assess the risk around an expected mean outcome.[1] This time-intensive and multi-variable approach is the most robust method used for risk assessment.

1 A stochastic study is a statistical approach that uses probability distributions to forecast the future.

Section Highlights

- Gas-fired resources continue to serve the majority of new loads in the West through the IRP timeframe; however, load growth in Washington, Oregon and Northern Idaho is primarily served by new wind and coal-fired resources.
- Market prices are forecast to fall from today's level through 2010, rising approximately with inflation thereafter.
- Electricity and natural gas prices are expected to remain highly correlated in the future.
- The IRP analyses are based on more than 300 gigabytes of data generated by 24 computers running continuously for nine days.
- The 2005 IRP modeled 18 unique market scenarios.
- Utility avoided costs are modestly higher than the electricity market price forecast because of resources built to support planning margins.

Scenarios: deterministic studies that change one significant underlying assumption to assess the impact of the change.[2] This approach is easier to understand and takes less time to prepare than a future, but does not quantitatively assess risk.

This section is split into three parts: Base Case results, futures results, and scenario results. It discusses resources AURORA^{XMP} built to serve load growth in the Western Interconnect over the next 20 years, the Northwest electric market price forecast, and variables driving the results. All figures representing prices are in nominal (i.e. not inflation adjusted) dollars unless otherwise stated.

6.1 Base Case

The Base Case is a deterministic study with a baseline set of assumptions for each variable entered into the AURORA^{XMP} model. They are described in the Key Assumption section of Section 5- *Modeling Approach*. This case also assumes continued availability of the federal production tax credit (PTC) for renewable resources and that no carbon or greenhouse gas (GHG), emissions legislation will be enacted. The PTC and GHG legislation are interconnected because the PTC provides a financial incentive to build plants with low or no GHG emissions. If carbon legislation were enacted, the PTC for renewable resources would most likely be terminated because the new legislation would provide an incentive similar to the present PTC. Two different GHG emissions scenarios were developed for this IRP to provide a better understanding of the financial impacts of potential emissions legislation. They are discussed later in this section.

AURORA^{XMP} builds future resources to serve regional load growth based on construction costs, return on capital, availability, and operation costs, before it can create a price forecast. Understanding the new resources built by AURORA^{XMP} is the key to understanding what drives future prices. The Base Case price forecast includes two 400 MW coal units for the Northwest in 2012; 500 MW of wind capacity will be constructed in 2016 and 2017.

New resources shown in Figure 6.1 are primarily natural gas-fired. In addition to the gas plants, the model built some coal and wind. Fixed RPS resources account for 10 percent of new generation capacity and 9 percent of total energy.

The model chose two coal plants outside of their native load area, connected by new or upgraded transmission facilities. The first coal plant, constructed in Utah, is wheeled to Southern California via an upgrade to the IPP DC line that runs from Intermountain, Utah to Adelanto, California. The second is a new coal plant in Wyoming that serves load in southern Idaho.

The large penetration of gas-fired generation is driven by the IRP assumption that no new coal-fired plants will be constructed within the state. Gas-fired generation, even with its higher fuel costs, is less expensive than transporting coal-fired generation from other states such as Montana.

2 *A deterministic study assumes there is only one future and uses single point estimates to determine it.*

Figure 6.2 details resource additions absent California. This figure is presented to explain that while gas-fired generation is significant across the West, absent California its contribution is more modest.

Figure 6.3 shows that Base Case electric prices are expected to fall between 2007 and 2010 in line with falling natural gas prices. The large coal plant added in 2012 will help keep prices relatively flat in real-dollar terms.

Northwest electricity prices in the future will be highly correlated with the natural gas market. Since market prices are set by the operating cost of the resource that is on the margin, recently built gas turbines will continue to set market prices. Company analysis found that 79 percent of the time electric market prices are correlated to natural gas markets in the future. Figure 6.4 is a scatter plot that shows the correlation between Malin natural gas prices and Mid-Columbia electricity prices over the IRP timeframe. Excluding the second quarter of the year, when hydro contributes large amounts of energy to the system, the correlation is 89 percent. These correlations indicate that natural gas plants will continue to set the marginal price of electricity, and that the dependence on natural gas likely will cause future market prices to be substantially higher than historic levels.

Another useful price forecast statistic is what resources are being used to serve loads. The Base Case forecast uses existing resources, along with new natural gas, coal, and renewables, to serve electricity demand. Figure 6.5 illustrates resources used to meet requirements over the forecast period.

Figure 6.1: Cumulative Western Interconnect Resource Additions (GW)

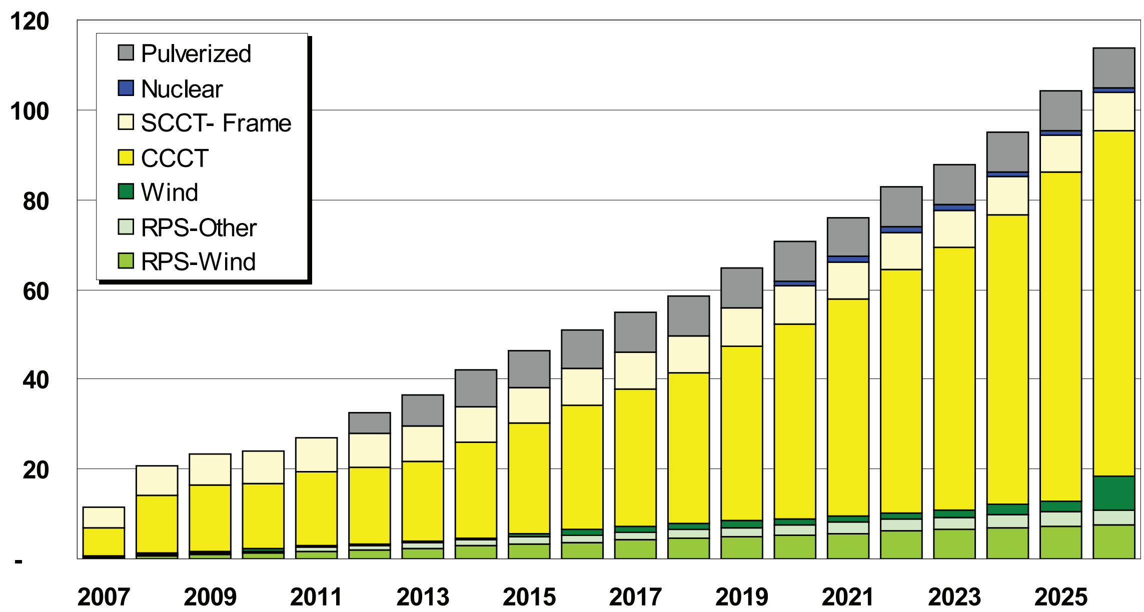


Figure 6.2: Cumulative Western Interconnect Resource Additions Absent California (GW)

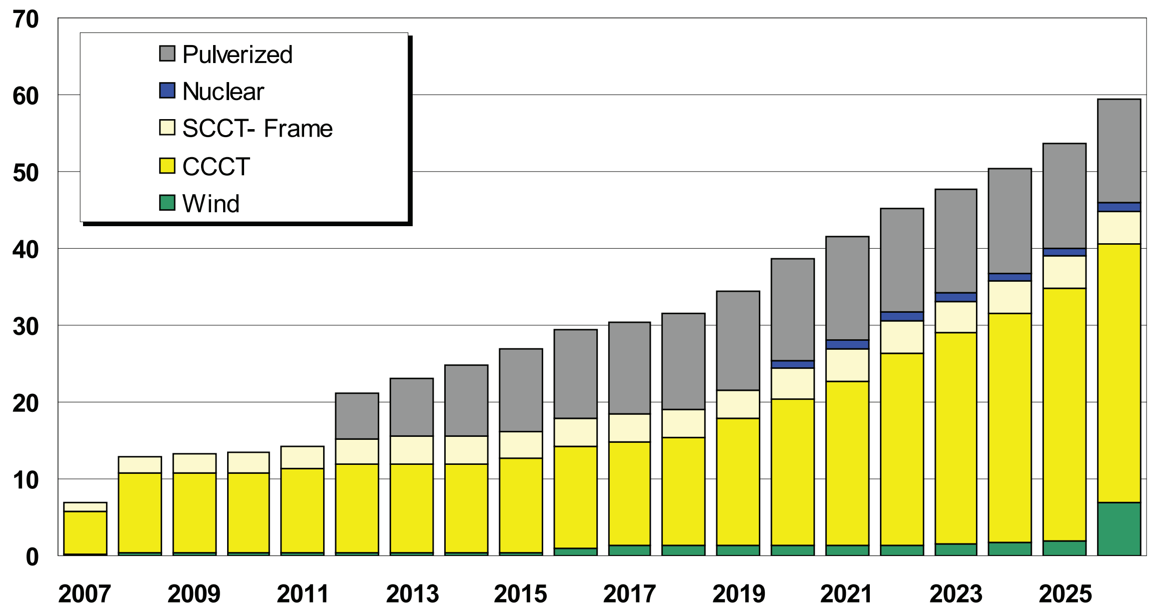


Figure 6.3: Mid-Columbia Electric Price Forecast ($/MWh)

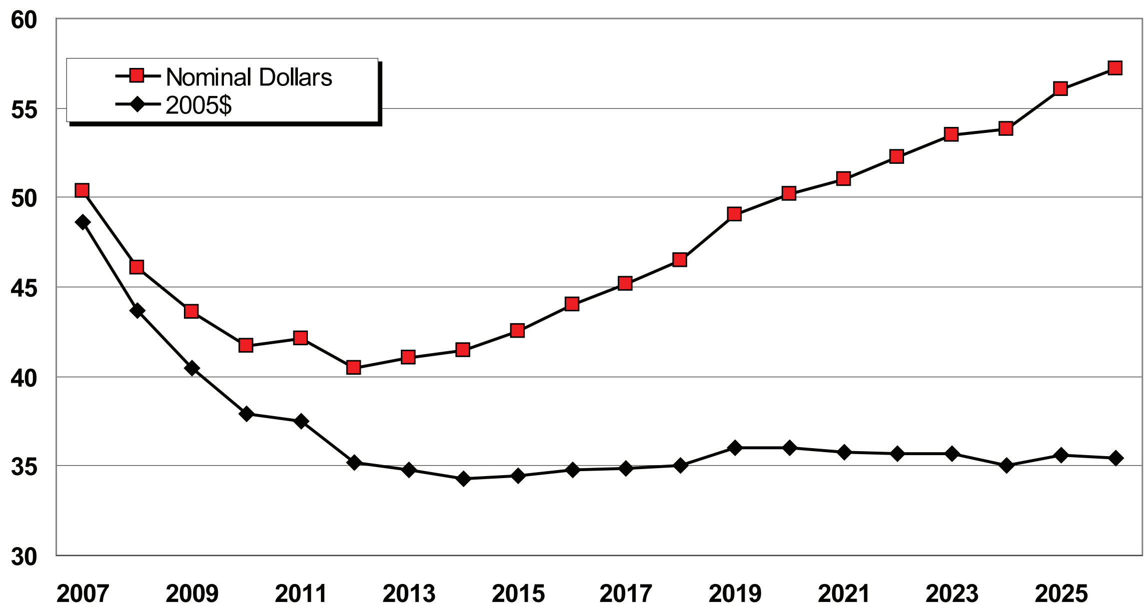


Figure 6.4: Malin Natural Gas and Mid-Columbia Electricity Correlation Plot

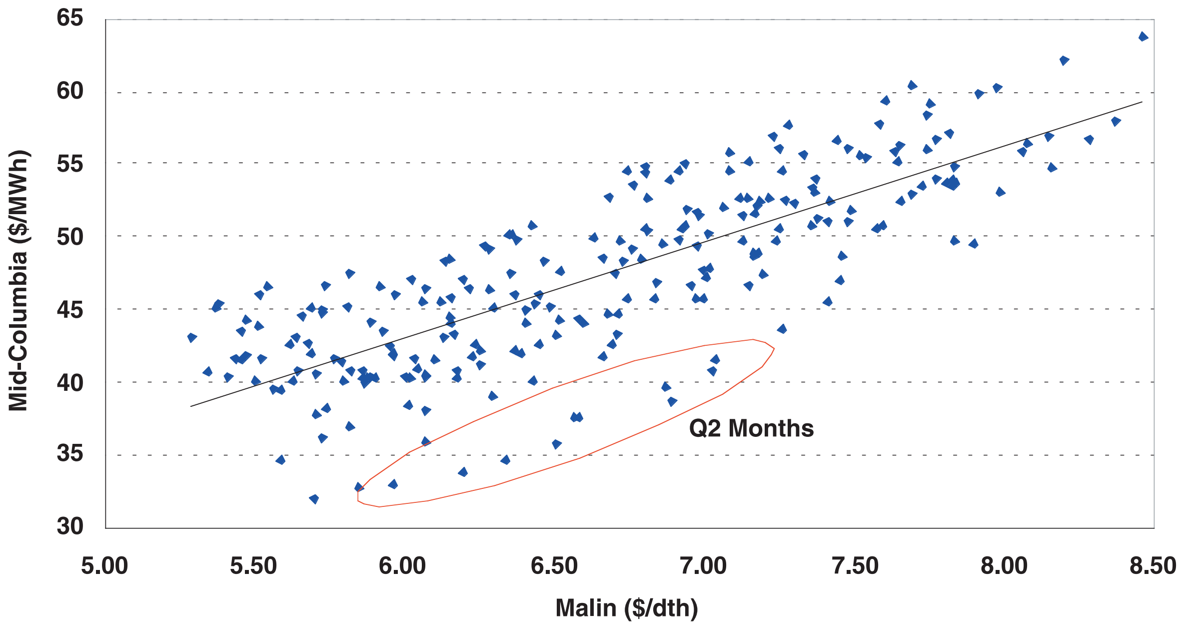


Figure 6.5: Western Interconnect Resource Contribution (%)

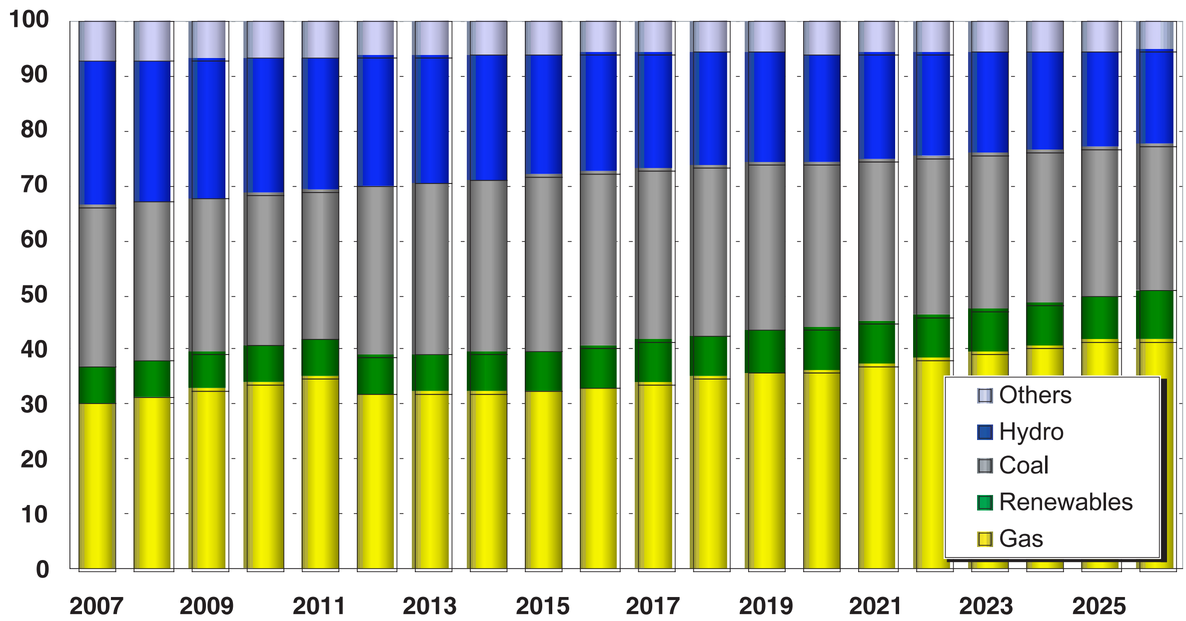


Table 6.1 presents annual average electricity market price forecasts for each zone modeled in AURORA^{XMP}. Zone prices differ because of transmission and congestion costs to move power from one zone to another. Market prices also are affected by natural gas transportation and delivery costs across the Western Interconnect. Congestion costs are economic costs derived when a transfer line between two areas is fully utilized, effectively closing the path between two areas. When the path is closed, the higher-cost zone is islanded from the rest of the system, and it must rely on higher cost internal resources to meet load requirements. Transportation costs are the physical cost or rent to move power and natural gas from the supplier to the end-use consumer.

Stochastic Results

Stochastic studies are necessary to understand the probability, or risk, of an outcome. A stochastic Base Case electric price forecast is created with AURORA^{XMP} by simulating the study period multiple times and varying key input values in each simulation.

Natural Gas prices, hydro conditions, load and wind conditions were allowed to vary in each study. Using different probability distributions, 200 random draws were transferred to a database linked to the AURORA^{XMP} model. Using 24 processors over four and a half days, the model was run 200 times to create 200 unique price forecasts in each stochastic study. The results

Table 6.1: Electric Market Prices By Western Interconnect Zone ($/MWh)

Area	2007	2008	2009	2010	2011	2012	2016	2020	2024	2026
AB	52.57	45.23	43.28	41.74	42.94	39.35	43.36	49.28	52.51	56.40
AZ	50.23	45.18	42.30	40.25	40.33	39.93	44.97	48.65	51.39	53.50
BAHA	53.51	49.99	46.84	44.66	45.37	45.75	50.26	54.64	59.24	61.47
BC	53.09	46.50	44.30	42.67	43.61	40.73	42.94	49.50	51.95	55.58
CCAL	53.23	48.73	45.94	43.99	44.31	43.92	48.80	53.61	57.07	60.32
CO	49.51	45.21	42.56	40.59	40.61	38.70	41.61	47.56	47.84	49.44
MT	49.01	44.62	42.05	40.09	40.53	38.21	29.86	38.40	41.11	39.37
NCAL	53.52	48.88	46.15	44.23	44.45	43.93	48.39	53.09	56.70	59.39
NM	48.90	44.34	41.73	39.71	39.86	39.24	44.34	48.21	50.27	52.94
NNV	50.90	45.96	43.29	41.24	41.68	40.19	43.58	49.43	53.18	55.69
OWI	50.35	46.12	43.60	41.69	42.16	40.47	44.05	50.20	53.83	57.22
SCAL	54.34	49.64	46.88	45.01	45.45	45.23	50.80	55.58	59.00	62.35
IDs	49.90	45.49	43.01	41.10	41.53	39.62	42.87	48.85	52.52	55.65
SNV	52.46	47.25	44.37	42.29	42.44	42.07	47.13	51.46	54.51	57.68
UT	49.48	45.00	42.39	40.38	40.73	38.91	41.69	47.19	50.37	53.55
WY	48.96	44.55	41.96	39.96	40.25	38.07	39.24	42.23	47.82	49.10

were queried from a single SQL Sever database containing all iterations. The Avista LP model quantified the return and risk of each new resource option available to Avista.

Two stochastic studies were completed for the 2005 IRP. The first was the Base Case. It used assumptions described in the Modeling Approach section. The second used the same underlying assumptions as the Base Case, but gas prices were assumed to be twice as volatile. Both studies were variances on the deterministic Base Case, and each of their mean price forecasts is within 2.7 percent of the deterministic Base Case study. See Figure 6.6.

Stochastic studies are necessary to quantify the standard deviation, or risk, around the expected outcome, or mean value. To quantify the standard deviation at Mid-Columbia, the AURORA^{XMP} model was run 200 times. The risks surrounding average expected market prices for the Base Case run are shown in Figure 6.7. The solid line represents the average market price, while the inner tick marks are the 80 percent confidence interval. This interval describes the range within where 80 percent of all observations lie. The outer tick marks are the maximum and minimum average annual prices observed in the study.

To approximate recent natural gas price volatility, the natural gas price standard deviation was increased from 50 to 100 percent of the mean in the Volatile Gas Case. Mean market prices in this case are similar when compared to the Base Case, but the 80 percent confidence interval has a larger range, as shown in Figure 6.8.

Figure 6.6: Mid-Columbia Electric Price Forecast Comparison ($/MWh)

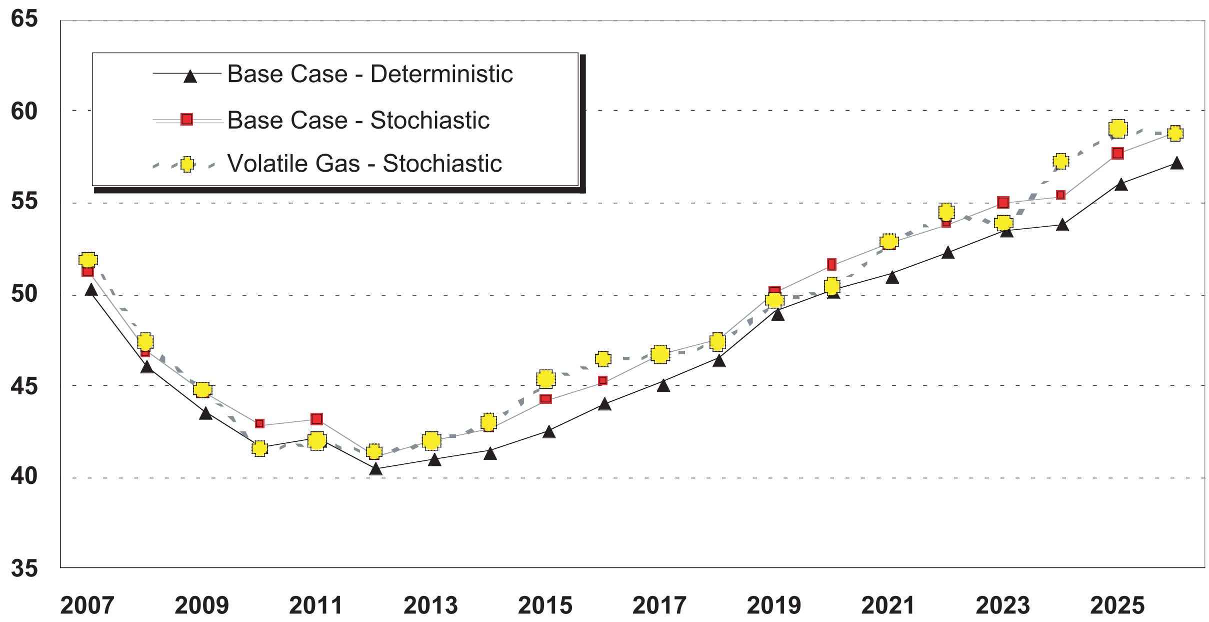


Figure 6.7: Stochastic Base Case Mid-Columbia Electric Price Forecast ($/MWh)

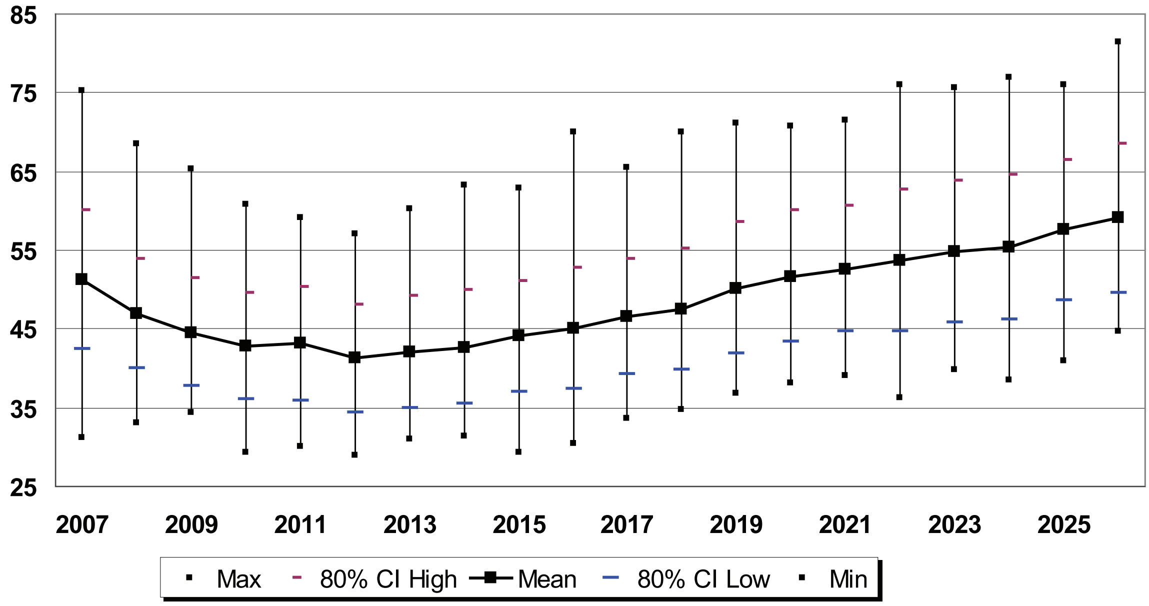


Figure 6.8: Base Case and Volatile Gas Mid-Columbia Price Comparison ($/MWh)

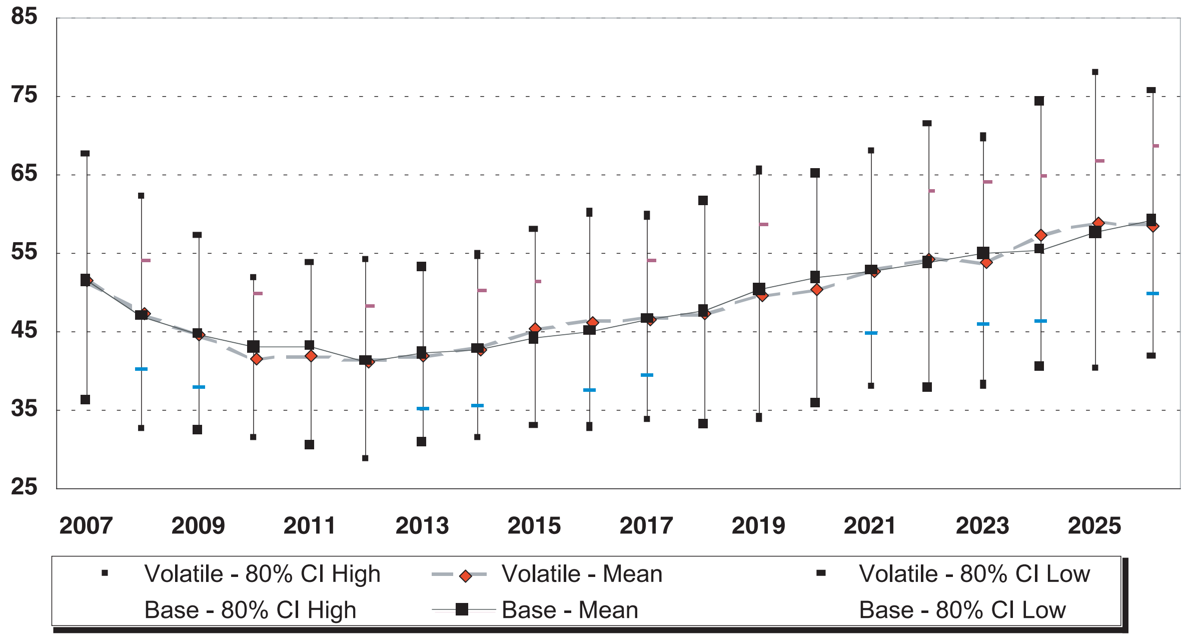


Table 6.2 displays levelized cost data for each resource option modeled in AURORA^{XMP} at full capability and at modeled operation levels, both with and without the renewable production tax credit levels. AURORA^{XMP} calculated levelized costs using the model's expected dispatch levels to value each resource; natural gas plants such as SCCT and CCCT do not operate at full capacity. This skews their levelized costs, since their fixed costs are levelized over the small number of operating hours. Base load plants, including coal and nuclear, are running at full capacity, and their levelized costs at expected dispatch levels compare almost equally to levelized costs at full output. Wind plants are not dispatched by AURORA^{XMP}, due to their very low operating cost; their values under each method are equal.

Table 6.2 illustrates plant costs, but it does not detail risks inherent to them. Figure 6.9 allows both cost and risk to be evaluated in one view. The figure compares the average cost of each resource necessary to acquire one average megawatt of electricity over a year. For example, a wind plant produces one-third of a megawatt of energy for each megawatt of installed capacity. Three megawatts of wind capacity are necessary to average one megawatt of energy. A coal plant with an 85 percent capacity factor is assumed to require approximately 1.2 megawatts to generate one average megawatt of energy. Only natural gas-fired resources, due to their high capacity factors, are not scaled up.

Costs in Figure 6.9 are defined as all fixed and variable operation and maintenance costs plus fuel and capital recovery. Risk is measured as the variation around the expected average value of these costs over the 200 Monte Carlo iterations. The figure accounts only for operational risks from changing fuel and market prices. Other risks, such as nuclear waste disposal or construction cost overruns for new coal or nuclear plants, are not accounted for in this view. These risks are quantitatively addressed in the selection of the PRS.

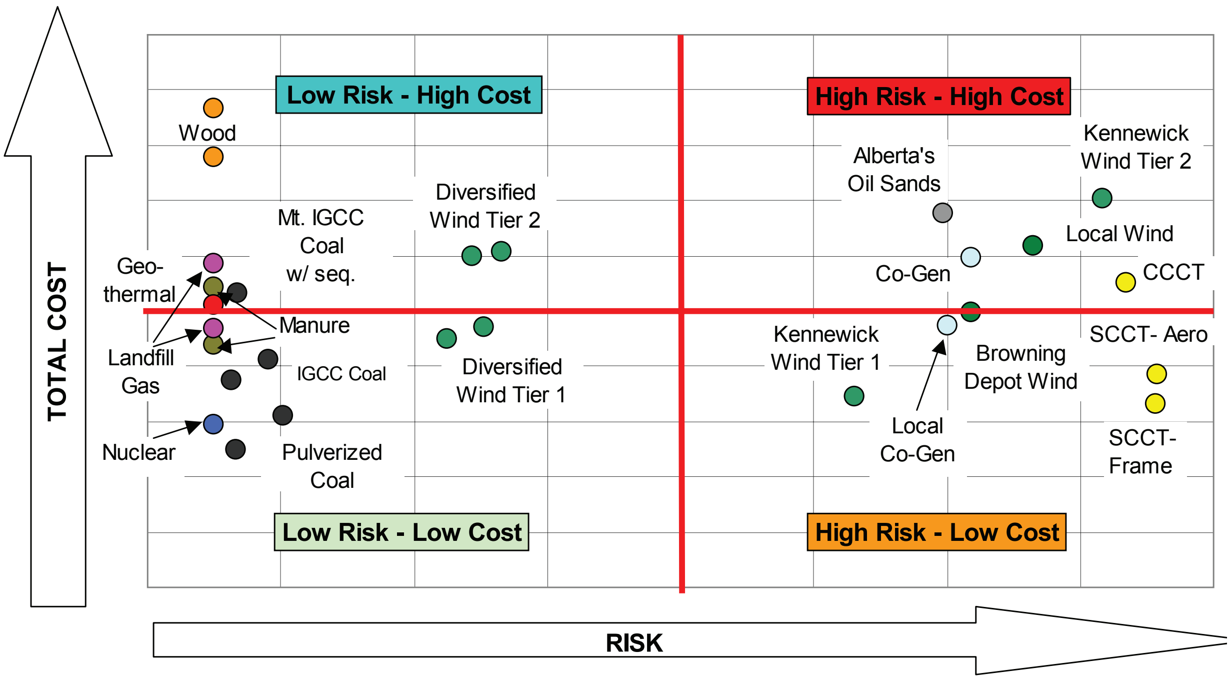
Higher-cost resources are shown in the upper regions of Figure 6.9. The plant costs assume "economic" dispatch of each resource type, with market purchases replacing operating costs during times where the resources are not running. The horizontal axis represents risk, with higher risk resources landing to the right side of the figure. Risk is derived from fuel cost variation, such as gas price volatility and wind speed variations.

In the Base Case, coal and renewable resources such as manure and geothermal provide the most risk protection, though their costs are somewhat higher than other alternatives. Wind is one of the lowest cost resources when the federal production tax credit is accounted for. Wind power has fuel risk because of the variation of wind or weather. Wind variation can be avoided to some extent if a utility purchases portions of several wind sites across the Northwest to create a diversified portfolio. Like equity portfolios, wind diversification adds cost, as seen in Figure 6.9. Gas-dependent resources such as CCCT, SCCT, and co-generation can have low cost; however, correlation to electric and gas markets results in riskier returns.

Table 6.2: 2007 Resource Option Costs (2005$/MWh)

	AURORA^{XMP}		Full Output	
	w/ PTC	W/O PTC	w/ PTC	W/O PTC
Coal Pulv MT	50.13	50.13	50.07	50.07
Nuclear	52.77	52.77	52.80	52.80
Coal Pulv OWI	53.81	53.81	53.44	53.44
Wind- Kennewick Tier 1	55.88	68.63	55.88	68.63
Coal IGCC MT	57.56	57.56	57.54	57.54
Coal IGCC OWI	59.85	59.85	59.61	59.61
Local Manure	61.40	65.22	61.44	65.27
Wind- OWI Tier 1	62.06	76.40	62.06	76.40
Local Landfill Gas	63.14	66.94	63.17	66.98
Wind- MT Tier 1	63.23	75.46	63.23	75.46
Local Co-Gen	63.48	63.48	60.34	60.34
Wind- Browning Depot 1	64.85	78.36	64.85	78.36
Geothermal	65.55	73.55	65.58	73.58
Coal IGCC SQ MT	66.88	66.88	66.83	66.83
Manure	67.60	71.42	67.64	71.47
Landfill Gas	70.12	73.92	70.15	73.96
Co-Gen	70.63	68.15	66.54	64.40
Wind- OWI Tier 2	70.78	82.15	70.78	82.15
Wind- MT Tier 2	71.32	80.99	71.32	80.99
Local Wind	71.90	84.46	71.90	84.46
Alberta's Oil Sands	75.35	75.35	75.37	75.37
Wind- Kennewick Tier 2	76.95	89.52	76.95	89.52
Wind- Browning Depot 2	80.94	93.18	80.94	93.18
CCCT (2x1)	100.09	100.09	72.45	72.45
Local Wood	152.09	160.97	89.27	93.10
Wood	166.48	175.36	95.47	99.30
SCCT- Frame	3,534.29	3,534.29	79.55	79.55
SCCT- Aero	6, 337.13	6,337.13	80.62	80.62

Figure 6.9: Resource Cost and Resource Risk Comparison



6.2 Scenarios

Scenarios are non-stochastically modeled futures that rely on average hydro generation, wind generation, natural gas prices and load conditions with a single significant change to the future. This type of analysis is performed to better understand the impact of a fundamental change to one of the Base Case assumptions. Scenario analysis allows for quicker solutions, and the results are easier to understand. The major disadvantage with scenarios is their inability to quantitatively assess market volatility risks.

Some scenarios are calculated using AURORA^{XMP} because the entire Western Interconnect marketplace is affected. Other scenarios are more easily and quickly solved outside of the AURORA^{XMP} model because the change only impacts the Company's resource portfolio.

Fuel Risk Scenarios

One of the biggest unknown variables in the future is the price of fuel. Whether the fuel is coal, natural gas, uranium, or manure, the price paid will depend on supply and demand for the fuel. In the 2005 IRP the Company chose to test natural gas prices under high and low price scenarios to understand how the Preferred Resource Strategy stands up against natural gas variation.

Coal may be an option for the Northwest in the future, and it is part of many resource plans across the west. The cost of the abundant resource has been stable or declining for several years. A scenario was tested to see how the electric market and Preferred Resource Strategy would be affected if coal prices started to rise rather than follow historical patterns. Other fuels such as wood, manure and refuse have price risk, but the small overall contribution of these resources when compared to the entire market limits their impact on market prices.

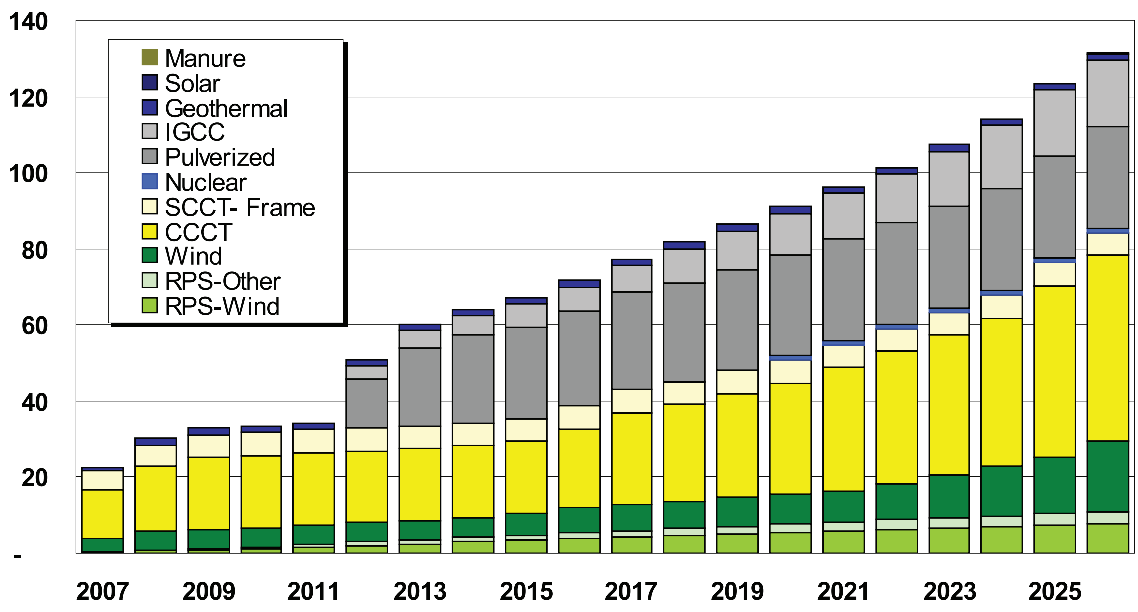
High Gas

The High Gas scenario was designed to understand the market impacts of a permanent increase in natural gas prices. This scenario started with Base Case gas price assumptions and increased price by 50 percent. The Company expected this scenario to push some natural gas projects further from economic viability and increase the viability of alternative resources such as wind and coal.

Figure 6.10 shows that if high natural gas prices were expected to persist, fewer natural gas resources would be built when compared to the Base Case. Natural gas would be replaced with additional wind, coal, and geothermal resources. In the High Gas case, AURORA^{XMP} built a substantial amount of coal across the West, as well as a significant amount of new transmission to wheel power into southern California and Nevada.

In 2012, large quantities of Rocky Mountain coal come online to serve West Coast load centers. Electric prices are driven down to within 20 percent of Base Case levels. This scenario provides a glimpse of how the region might respond to a permanent increase in overall natural gas prices. Figure 6.11 shows the electric market price forecast resulting from a 50 percent increase in natural gas prices.

Figure 6.10: Cumulative Western Interconnect Resource Additions–High Gas (GW)



Low Gas

The Low Gas scenario was designed to reflect changes in the market resulting from a permanent decrease in natural gas prices. This scenario started with Base Case natrual gas price assumptions and then decreased the cost of natural gas by 50 percent. The Company expected this scenario to maintain current practice and build only new CCCT projects. Figure 6.12 shows the annual resources that were built across the west in the Low Gas scenario. Natural gas resources were built exclusively except for RPS resources required by some states in the Western Interconnect. Low natural gas prices contribute to low market prices when compared to the Base Case, as shown in Figure 6.13.

High (Doubled) Coal Price Escalation

The High Coal Price Escalation scenario is designed to show the possible impact of higher coal prices over time. This particular scenario doubles coal price escalation as a response to increased demand for coal in the West. Figure 6.14 shows the price of coal in the Base Case, and in the High Coal Price Escalation scenario.

Where coal prices dramatically increase in the future, the likely result will be fewer new coal plants. The scenario results show a 35 percent reduction in new coal plant construction in the West when compared with the Base Case under the High Coal Price Escalation scenario. Figure 6.15 shows the resource mix with higher coal price escalation.

Higher coal prices result in slightly more expensive market prices when compared to the Base Case. Figure 6.16 provides an electric price forecast comparison to the Base Case.

Figure 6.11: Base Case and High Gas Mid-Columbia Electric Price Forecasts ($/MWh)

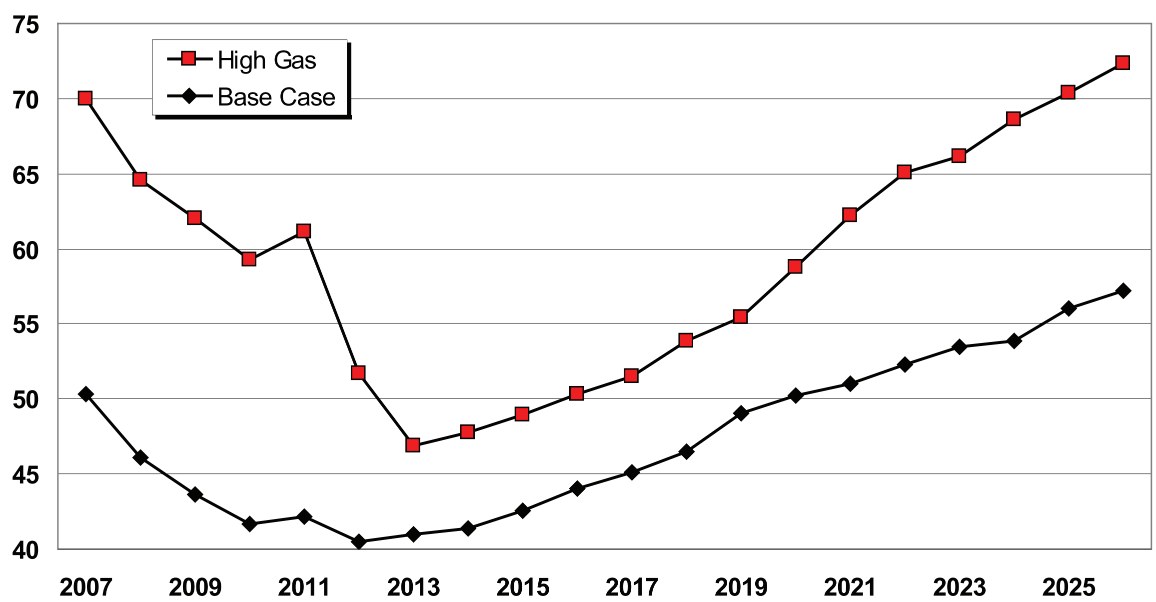


Figure 6.12: Cumulative Resource Selection for the Western Interconnect–Low Gas (GW)

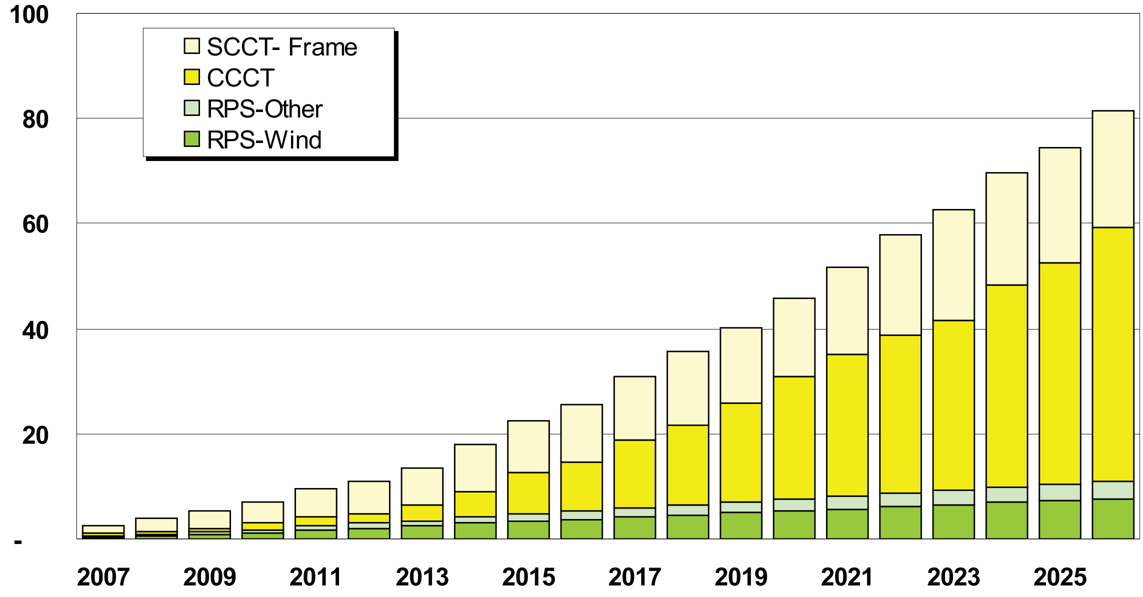


Figure 6.13: Base Case and Low Gas Mid-Columbia Electric Price Forecasts ($/MWh)

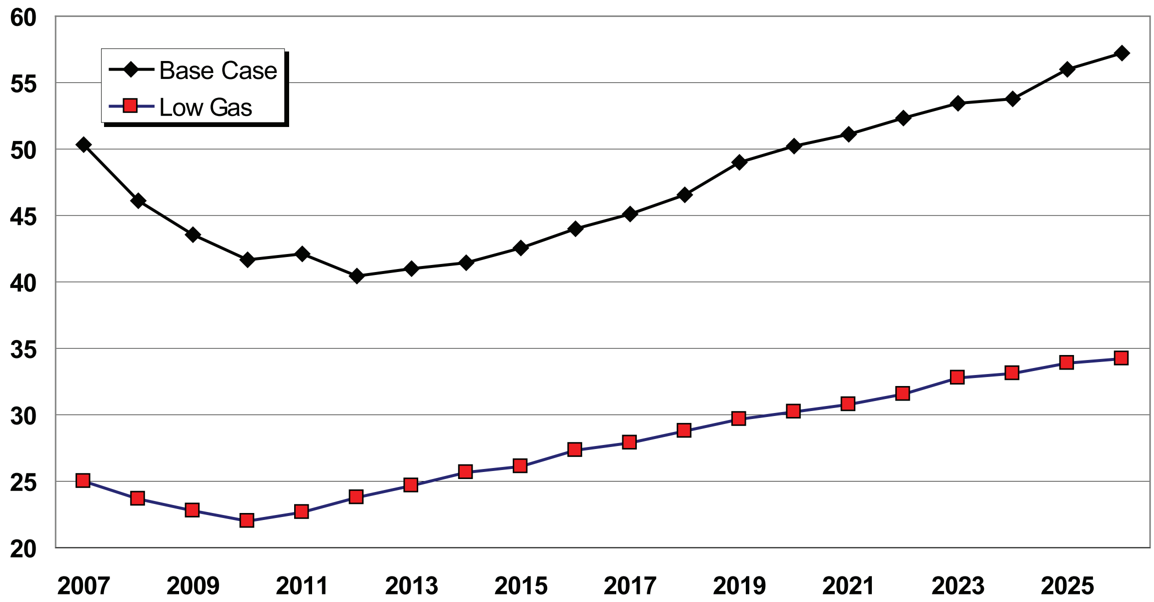


Figure 6.14: Base Case and High Coal Price Escalation Coal Price Forecasts-
Montana Mine Mouth ($/dth)

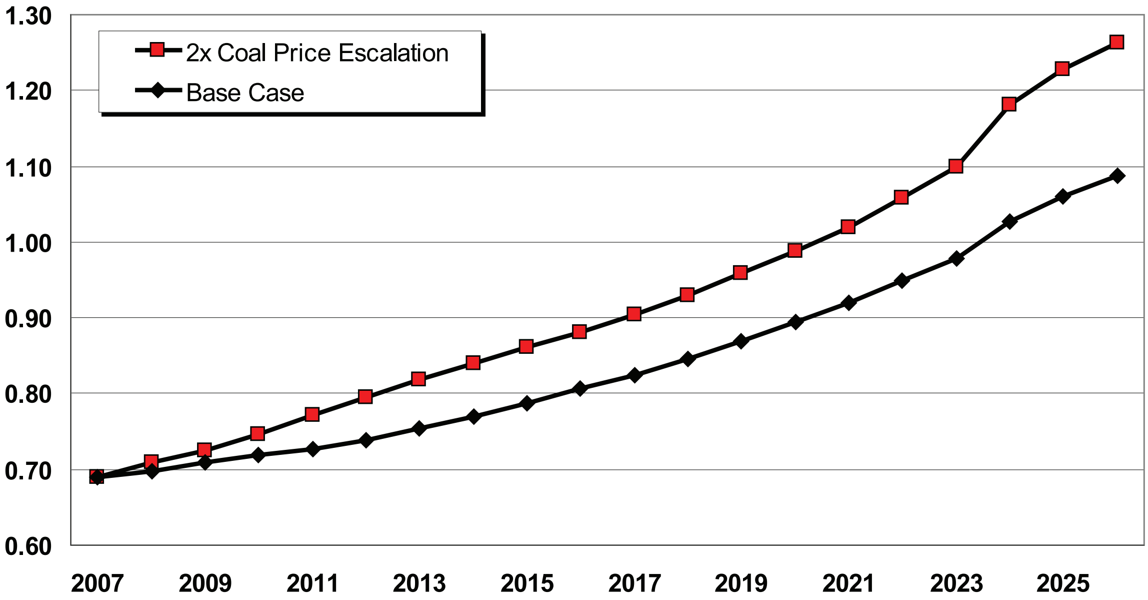


Figure 6.15: Cumulative Resource Selection for the Western Interconnect–
High Coal Price Escalation (GW)

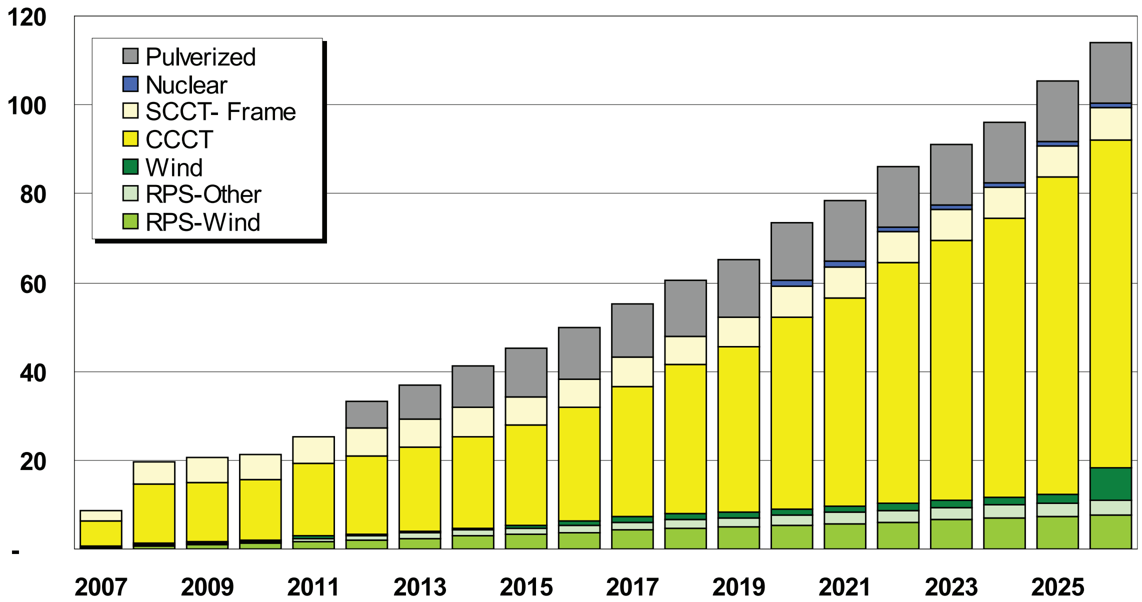


Figure 6.16: Base Case and High Coal Price Escalation Mid-Columbia Electric Price Forecasts ($/MWh)

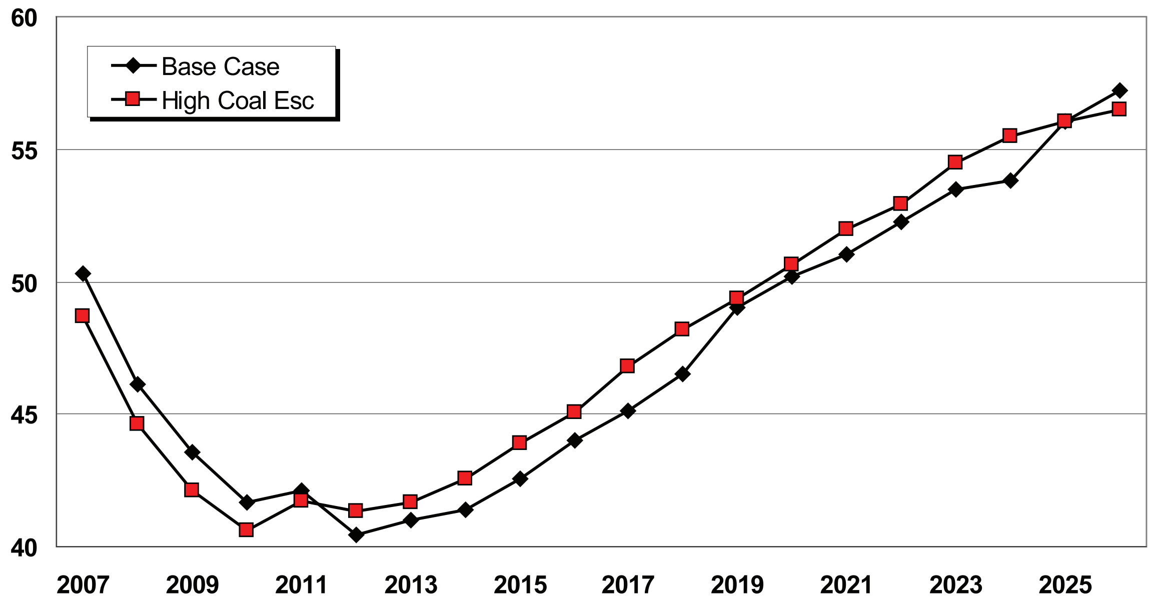
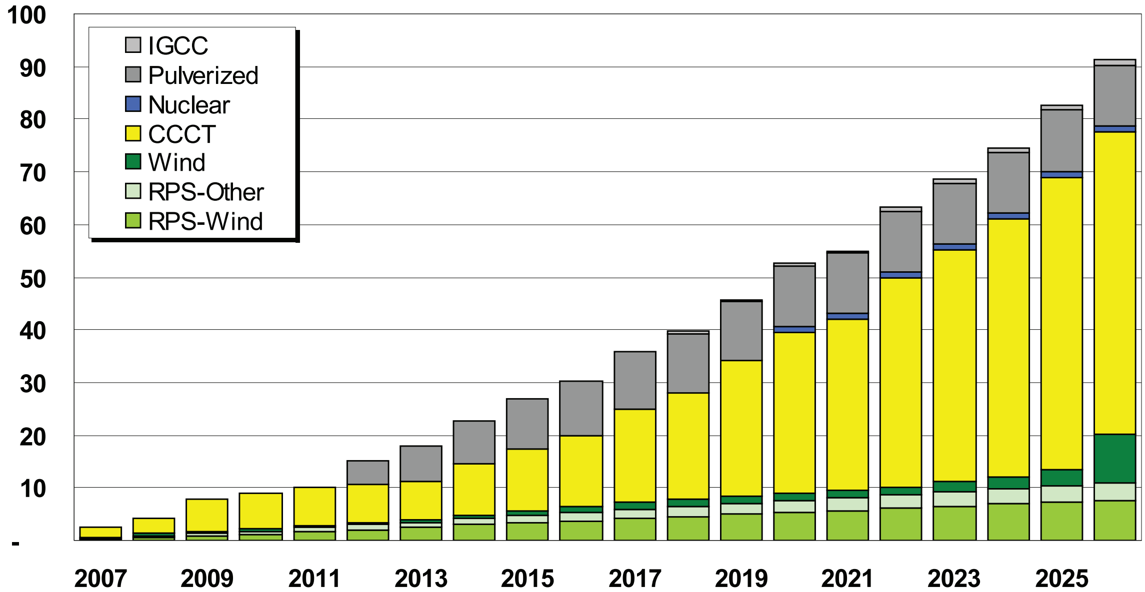


Figure 6.17: Cumulative Resource Selection for the Western Interconnect–No Capacity Credit (GW)



Market Structure Scenarios

Though the AURORA^XMP model makes sound economic decisions for the marketplace under assumptions derived by the Company and its Technical Advisory Committee, some market drivers and assumptions are only estimates of possible futures. Market structure scenarios target macro changes to the electric market, including low capacity planning margins, federal or state legislation capping carbon emissions, more efficient transmission construction, climate change forcing long-term hydro conditions down, Northwest wind-heavy construction, and companies following a boom-bust build cycle similar to the 1998-2001 time period.

No Capacity Credit

Capacity credits are a financial incentive for the model to build more generation than is needed to serve forecasted load under average conditions. This is similar to building a planning margin into utility resource portfolios. Excess capacity stabilizes prices even in cases of extended outage or spiked demand. Extra capacity results in slightly higher average costs, but it spares customers from large price swings. Removing the capacity credit also provides an estimation of avoided costs for a utility. Figure 6.17 shows the results of this scenario.

The model builds approximately 23 GW less capacity than in the Base Case. This scenario illustrates what could happen in a marketplace if utilities had no incentive to build planning margins into their forecasts. Analysis shows that fewer resources result in greater market volatility, higher prices and greater price risk as a result of extended shortages. Figure 6.18 shows that Mid-Columbia market prices are higher than in the Base Case in most years, and that prices are more volatile from year to year.

Figure 6.18: Base Case and No Capacity Credit Mid-Columbia Electric Price Forecasts ($/MWh)

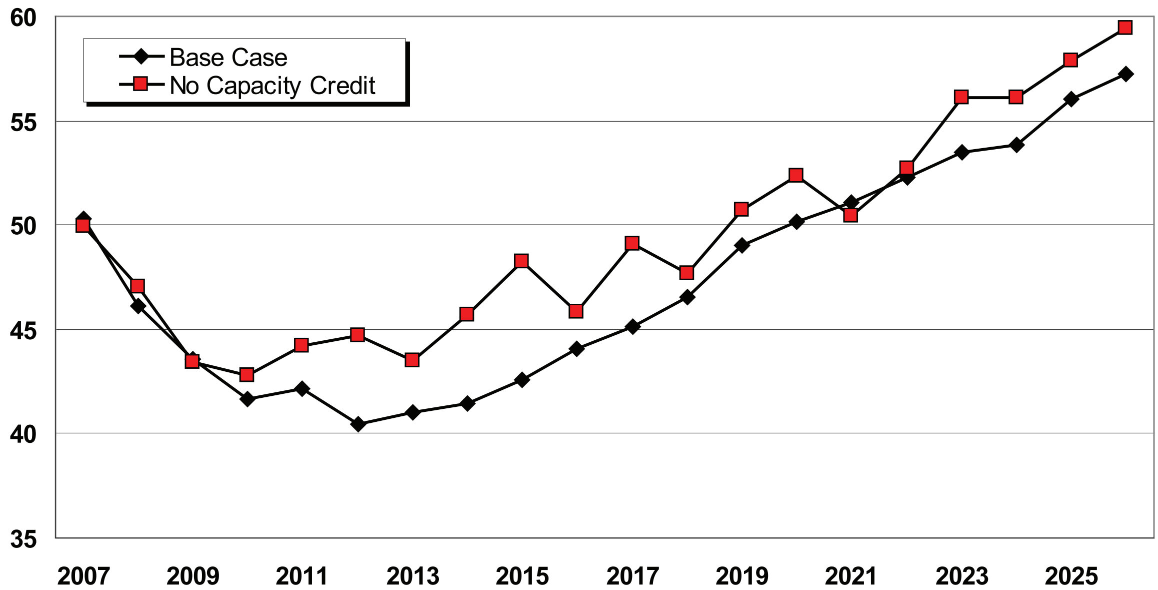


Figure 6.19: Cumulative Resource Selection for the Western Interconnect – 30% Lower Transmission Capital Cost (GW)

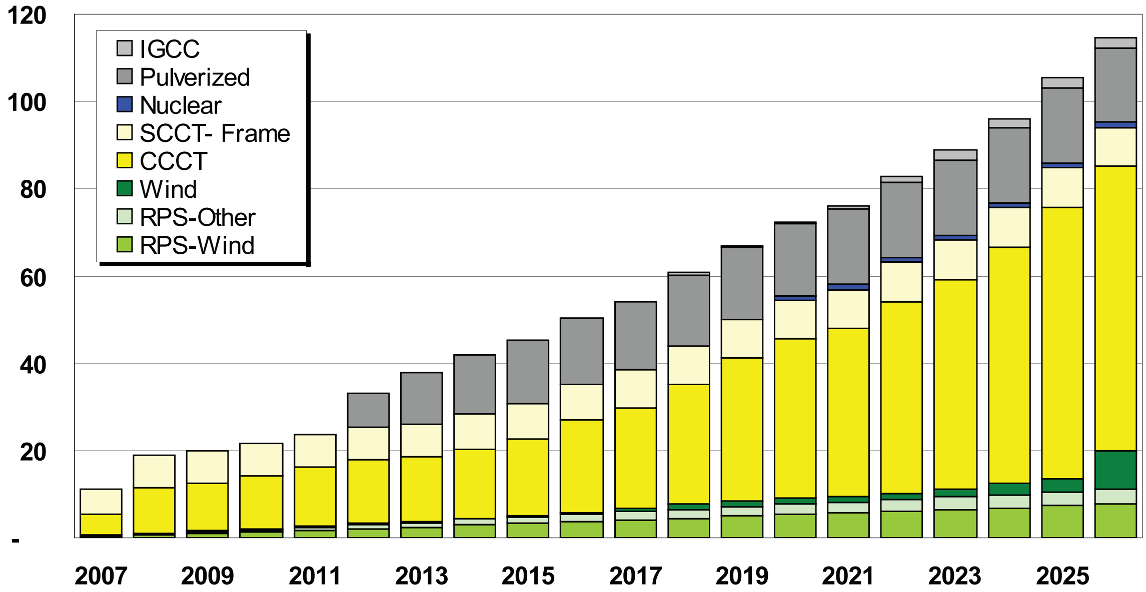
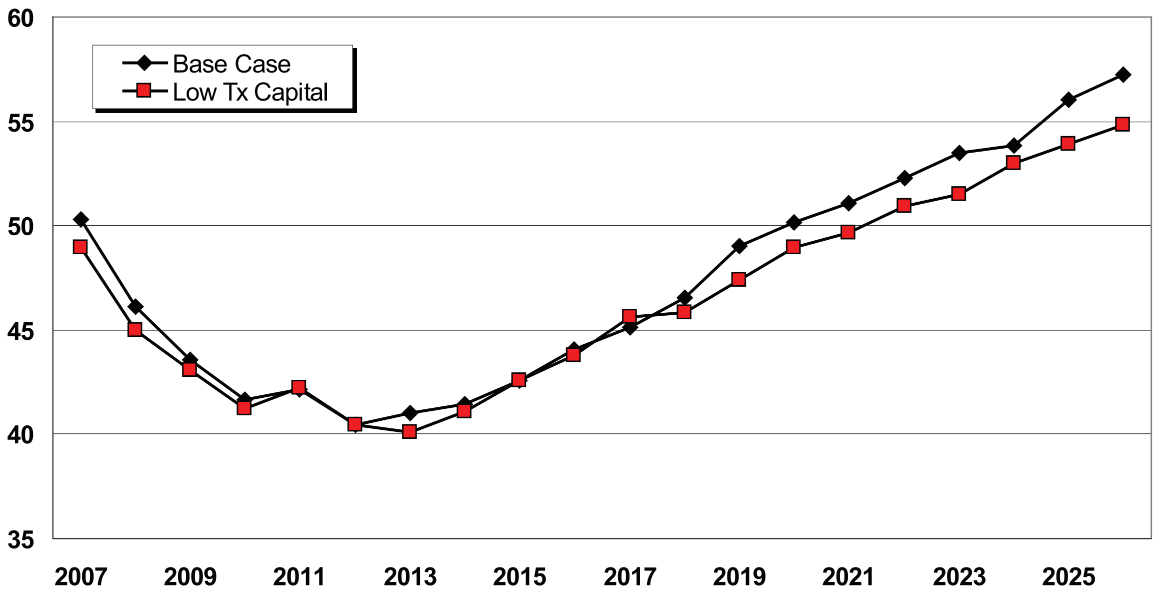


Figure 6.20: Base Case and 30% Lower Transmission Capital Cost Mid-Columbia Electric Price Forecasts ($/MWh)



30 Percent Lower Transmission Capital Costs

The 30 Percent Lower Transmission Capital Costs scenario assumes a 30 percent reduction in transmission construction costs due to possible efficiencies gained from a regional approach to transmission siting. This scenario benefits capital-intensive resources like wind and coal. Providing a lower cost transmission scenario enables the Company to see how resource selections will change under a range of transmission costs.

With lower transmission capital costs, the expectation was that AURORA^{XMP} would build additional wind and coal units. The model built 21 percent more wind capacity, 42 percent more coal capacity and decreased gas construction by nine percent. Figure 6.19 shows the annual resource builds for this scenario.

The model built more coal outside native load regions, including a plant in Montana to serve the Northwest, and several plants in Wyoming to serve Utah and southern Idaho. The scenario even allowed construction of a new IGCC coal plant in the Northwest.

The Mid-Columbia price results of this scenario are shown in Figure 6.20. Though market prices did not drop substantially, total fuel costs across the Western Interconnect dropped by an average of 2.8 percent, or $563 million annually, because of the switch from natural gas to coal and wind.

The results of this scenario explain that transmission costs are a barrier to bringing power over mid-range distances of 400 to 600 miles. It also shows that where regional estimates for transmission costs are too high, models will underestimate the level of new wind and coal project construction.

Hydro Shift

The Hydro Shift scenario was developed to help the Company understand the ramifications of a long-term shift to lower hydroelectric generation levels witnessed over the past half decade across the Western Interconnect. This scenario was accomplished by reducing average hydro generation by 10 percent during the IRP study horizon.

Moving average hydro energy down by 10 percent did not have a large effect on the resource selection, as shown in Figure 6.21. Lower hydro levels allowed IGCC coal plants into the regional resource mix.

Reducing hydroelectric energy by 10 percent lowers hydro output in the Western Interconnect by 1,400 aMW. It also moves a higher percentage of available hydro energy from low load hours to high load hours as shown by the change in market prices in Figure 6.22. As in the Base Case, market prices did not change substantially under this scenario because gas resources continue to set market prices like in the Base Case. To understand the monetary effect of lower hydro generation in the West, the total incremental fuel expense to replace lost hydroelectric generation was calculated. Fuel expenses increased by $642 million annually (2005$), a 3.5 percent increase.

Figure 6.21: Cumulative Resource Selection for the Western Interconnect–Hydro Shift (GW)

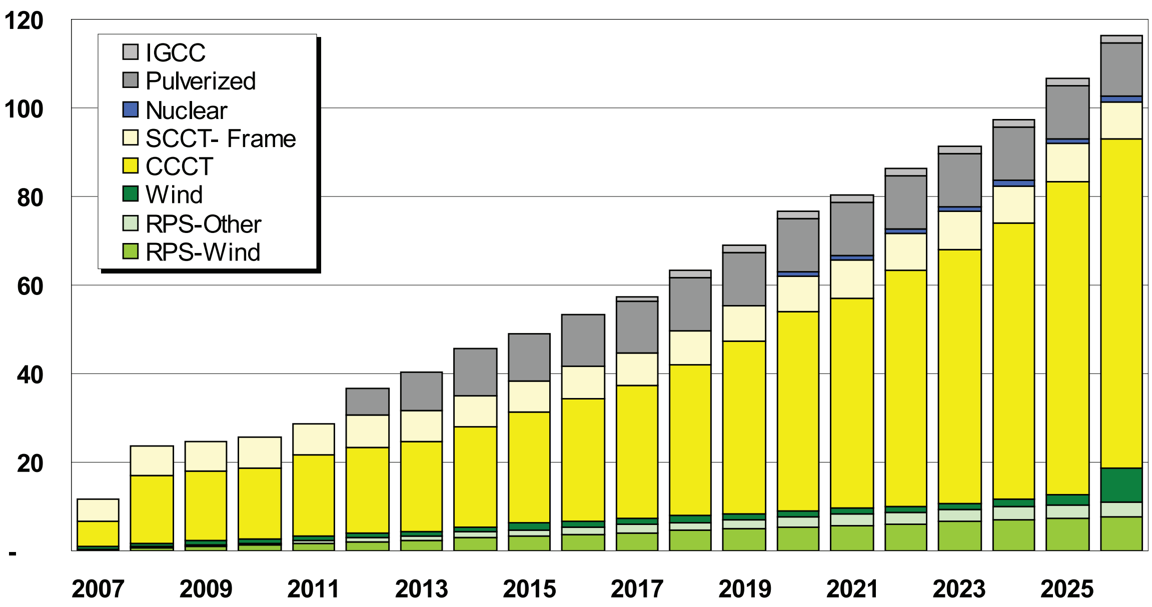
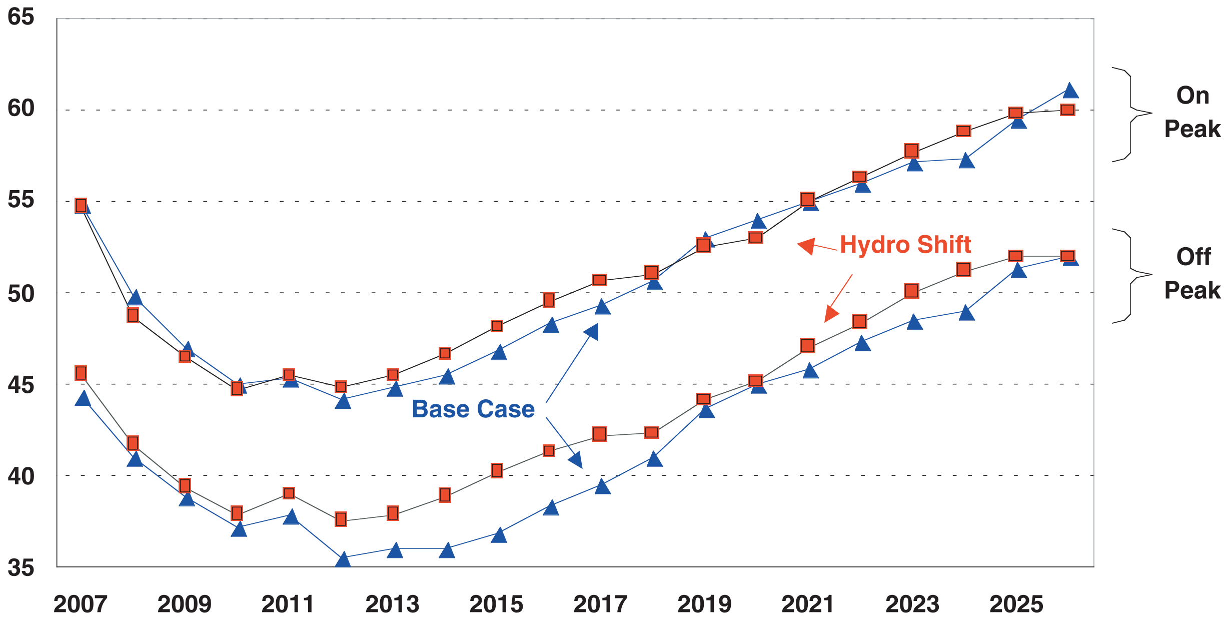


Figure 6.22: Mid-Columbia On & Off Peak Price Comparison For The Hydro Shift ($/MWh)



High Wind Penetration

The High Wind Penetration scenario was developed to understand potential costs and market effects of integrating a large amount of wind generation into the Northwest grid. In this case, the resource build was modified by the addition of 5,000 MW of wind placed in service in 2007. Intra-month market volatility rose by an average of 15 percent. The higher variation is highly dependent on hydro levels. See Figure 6.23.

Boom and Bust

The Boom and Bust scenario models a potential future where the electricity industry behaves more like the real estate market—speculation and under-investment initially drive prices to spectacular highs. These highs are followed by equally spectacular lows as over-investment pushes speculators out of the marketplace. The Technical Advisory Committee requested this scenario to help understand the ramifications of market cycles like those experienced between 1998 and 2001 across the Western Interconnect.

The resource build for this scenario is the same as the No Capacity Credit scenario, except that resources are only allowed to come online every five years. The movement of resource development schedules strains the marketplace. Figure 6.24 shows market prices for the Northwest in the Boom and Bust scenario. When resources come online in 2010, 2015, 2020, and 2025 market prices fall, while the resource-constrained years attain higher prices.

Figure 6.23: Monthly Market Price Volatility From Increased Wind Penetration (%)

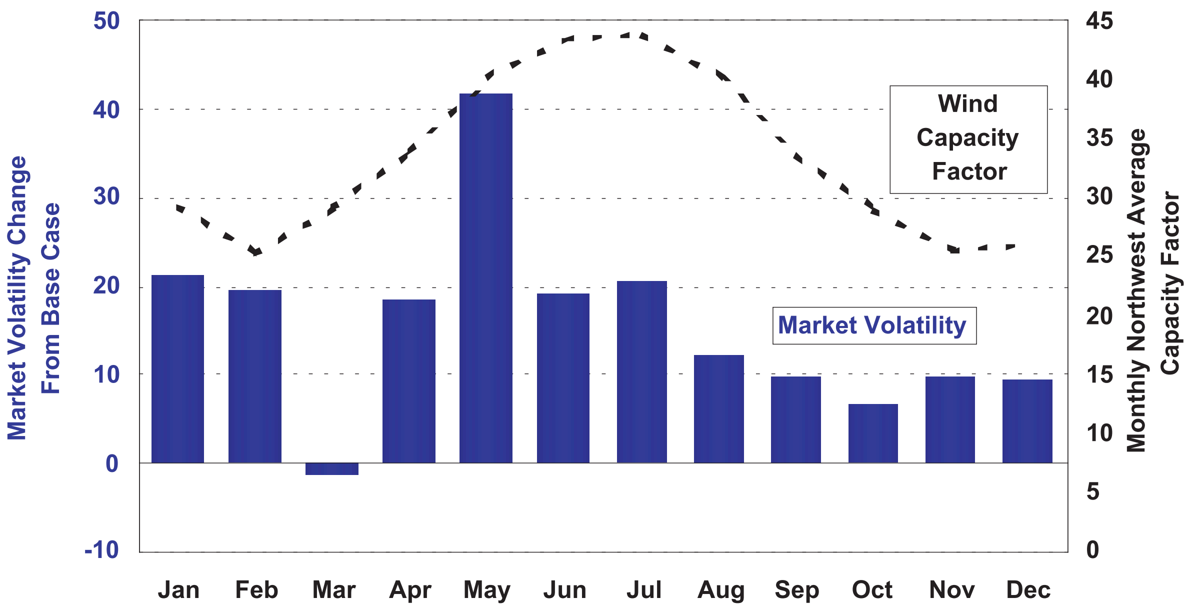
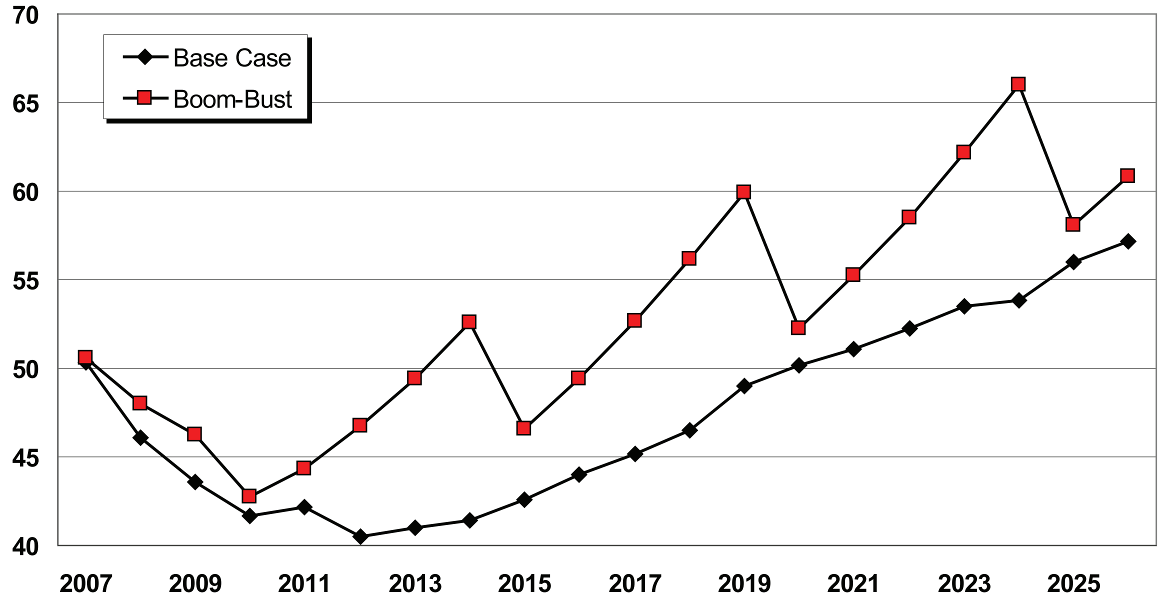


Figure 6.24: Base Case and Boom and Bust Mid-Columbia Electric Price Forecasts ($/MWh)



6.3 Carbon Emission Scenarios

The Company developed two carbon scenarios to address increasing concern over the environmental effects of greenhouse gases, including carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur heaxafluoride. The GHG issue is often referred to as a carbon, carbon dioxide (CO_2), or carbon dioxide equivalents problem. Internationally, GHG emissions are regulated by the Kyoto Treaty. The treaty was developed in 1997 and implemented in February 2005. The Kyoto Treaty established a carbon emissions trading market in Europe, which began trading this year. The U.S. did not ratify the Kyoto Treaty and current laws in the United States do not regulate GHG emissions. The main legislative proposal for limiting GHG emissions is the McCain-Lieberman bill in the U.S. Senate. This bill is described later in this section.

Several states in the West are starting to regulate GHG emissions through law or policy. California laws limit carbon and noxious oxide emissions in vehicles. The California Public Utility Commission also requires the inclusion of a carbon adder in any thermal based generation proposals to account for the potential future costs of GHG emissions.

Oregon established the first CO_2 standards in the U.S. in 1997, requiring new carbon emitting generation projects to offset a portion of their CO_2 emissions through efficiency improvements, cogeneration projects, other offset projects like tree planting, or payments into the Climate Trust of Oregon. Washington State requires CO_2 mitigation for new fossil-fueled thermal electric generation plants exceeding 25 MW of nameplate capacity.

Though there is no national GHG law or policy today, the Company believes that some form of GHG emissions regulation will occur at some point in the future. The challenge arises in assessing when the new requirements might begin and how expensive future emissions of GHG will be. Large costs enacted early in the IRP timeframe would push the Company away from high carbon emitting resources. A carbon tax implemented late in the forecast horizon would not significantly impact the economics of carbon emitting resources.

It is difficult to analyze carbon emissions, absent a specific federal law or mandate. However, the Company believes that it is prudent to study the potential impact of carbon regulation on its Preferred Resource Strategy. If there is a clear mandate at the federal or state level to reduce carbon emissions so that the higher costs associated with greener generation can be calculated in the future, the Company will be able to forecast its impact on future generating capacity choices.

SB 342 Carbon Tax

SB 342, otherwise known as the McCain-Lieberman Bill or Climate Stewardship Act (CSA) of 2005, initially was introduced to the Senate in October 2003. It was intended as a comprehensive plan for the U.S. to reduce heat-trapping gas emissions to year 2000 levels by 2010. The bill would have reduced emissions through a market-based tradable allowance system patterned after the sulfur dioxide emission permit market established by the Clean Air Act of 1990. It was expected to make carbon emissions costly enough to shift our economy away from carbon producing technologies.

There are several different opinions on the necessity of the CSA, ranging from it reflecting a crisis that requires immediate action, to it needlessly destroying the national economy. Several groups and governmental agencies have studied the CSA and have attained different results. The Massachusetts Institute of Technology performed an economic study of the CSA and found the overall cost would be $20 per household per year. Charles River Associates determined that the cost would be $350 per household in 2010 and would increase to $530 per household by 2020, with the potential for costs to increase to $1,300 per household per year. The Energy Information Administration (EIA) also performed an analysis of the CSA. It found that the discounted per capita cost would be $56 annually per person (2005$).

The Company chose to use results of the EIA study for this carbon tax scenario. It appears to be the most comprehensive analysis and has more information on the effects to the electricity marketplace.

A large carbon tax on electric generating facilities implemented in 2010 would likely stop or severely restrict construction of new carbon-emitting coal plants. The new resource mix would still rely on natural gas, as shown in Figure 6.25; however wind, solar, geothermal and carbon sequestration coal plants would also enter the mix. If the CSA passes, many existing coal plants may shut down because carbon credits likely would be more valuable than the electricity they produce. This is described in Figure 6.26. When the carbon tax peaks in 2023, 60 percent of remaining coal output is from plants with carbon sequestration technology.

An additional assumption of note is that renewables in this scenario do not receive the PTC. The 2005 IRP follows the NPCC Fifth Power Plan assumption that the PTC would not be renewed once a carbon tax is enacted. The incentive to generate power through renewable resources would be replaced by the financial disincentive of a carbon tax on fossil fueled assets. If the PTC for wind continued after a carbon tax was added, it would effectively double the net incentive to construct renewable resources. The Company does not believe this is likely over the long run.

Carbon dioxide emissions might fall 20 percent in 2014 from the Base Case and 50 percent by 2022 for the Western Interconnect generating fleet under the CSA. See Figure 6.27.

A carbon tax likely will not end carbon production by the U.S. electricity industry. New wind and other renewable resources are not capable of serving the entire need of the Western Interconnect. Without a fundamental change in the industry, such as a shift to nuclear power, market prices still will be set by carbon emitting combined-cycle gas plants.

Our modeling shows that lowering emission levels across the Western Interconnect will come at a high cost to customers. Figure 6.28 illustrates that Mid-Columbia electric prices could increase by 47 percent from the Base Case in 2014 and 66 percent in 2020. Increased market prices are driven by higher taxes and higher fuel costs.

Figure 6.25: Cumulative Resource Selection for the Western Interconnect – SB 342 Carbon Tax (GW)

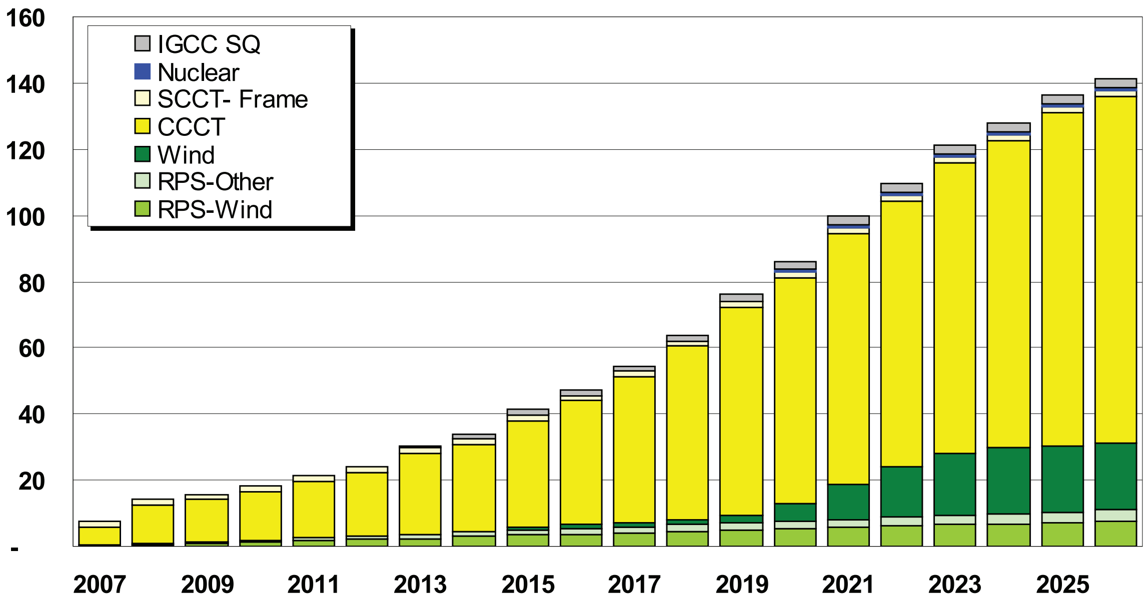


Figure 6.26: Coal Dispatch Between Base Case and SB 342 Scenario (millions of tons)

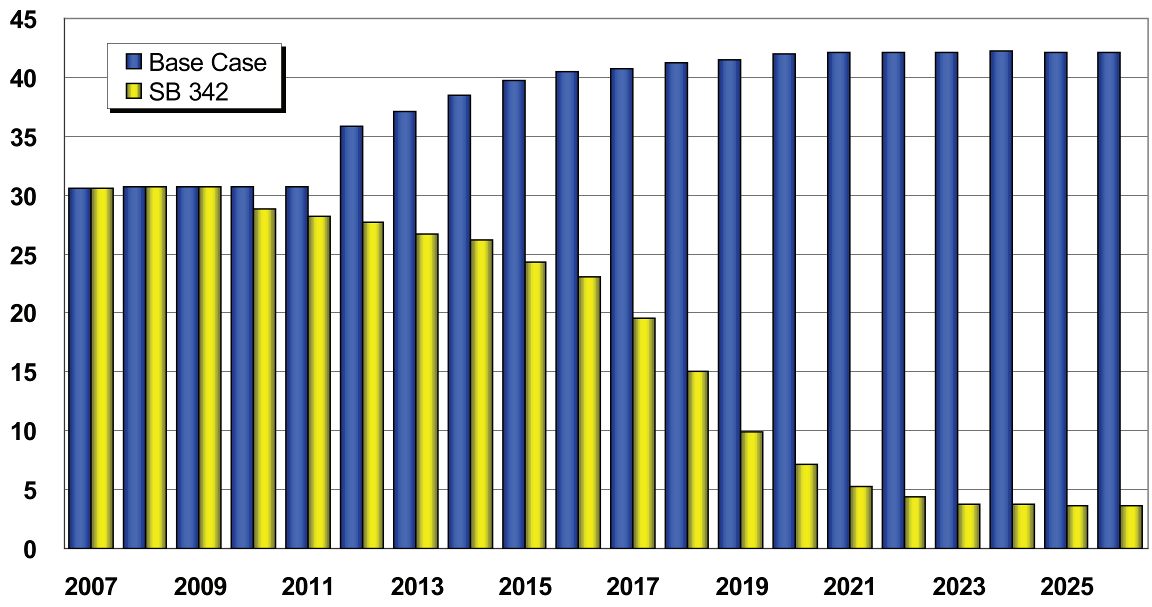


Figure 6.27: CO_2 Emissions and Cost Forecast for the Base Case and SB 342

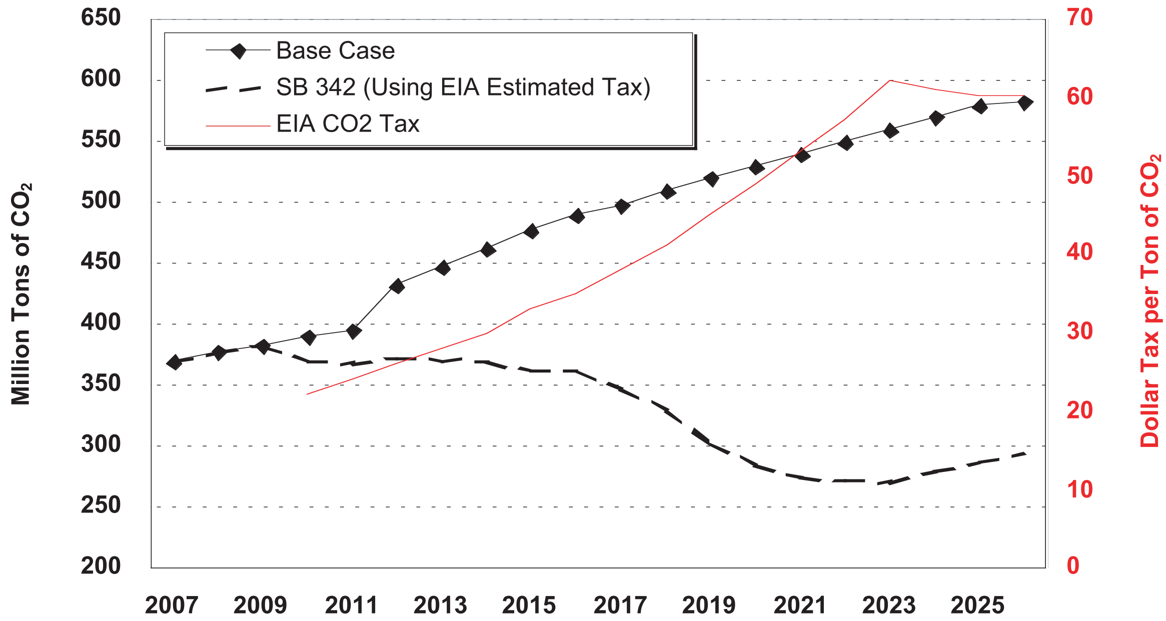
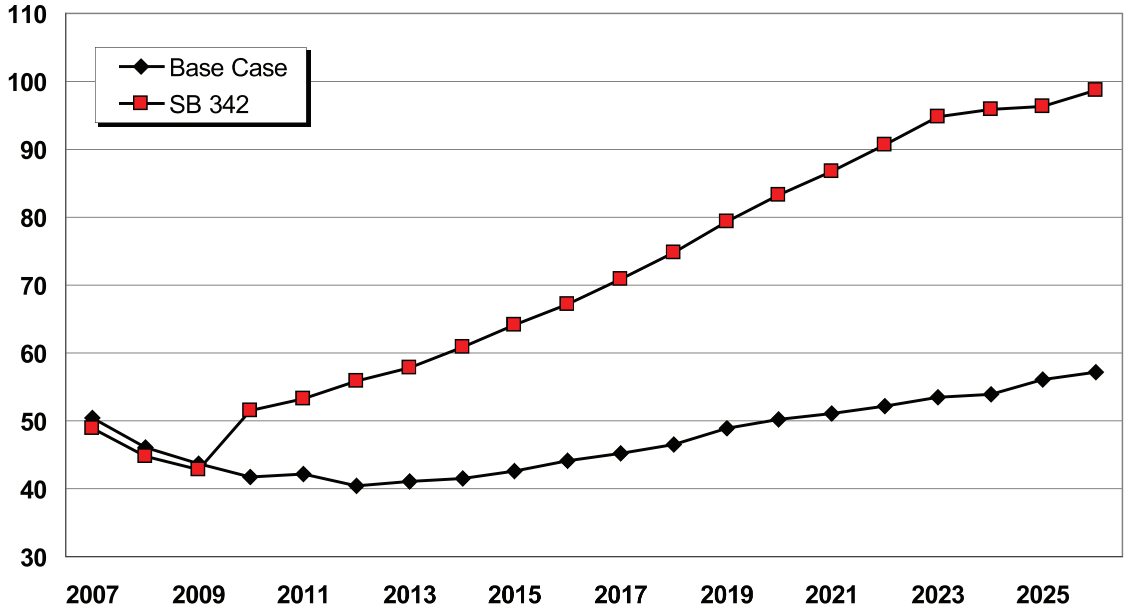


Figure 6.28: Base Case and SB 342 Mid-Columbia Electric Price Forecasts ($/MWh)



Nearly 14 billion dollars of CO_2 allowances would be exchanged annually between 2010 and 2026 to keep the western United States within carbon limits. The Western Interconnect would see $2.5 billion in increased fuel costs every year as a result of switching from coal to gas-fired plants. Higher electricity prices, driven by a carbon tax, will decrease future loads as customers respond to higher prices. Based on work from the EIA study, Western Interconnect loads are forecast to fall by 0.33 percent annually after 2010 to reflect reduced demand caused by higher electricity prices.

National Commission for Energy Policy Carbon Tax

The National Commission for Energy Policy (NCEP) is a non-governmental group of 18 energy experts funded by several private foundations and trusts to develop a national energy strategy for the United States. In December 2004, NCEP published "Ending the Energy Stalemate: A Bipartisan Strategy to Meet America's Energy Challenges." A section of the report is devoted to the risks of climate change and calls for the establishment of a national tradable–permits program for GHG. The Company considered an alternative because a carbon tax has not been established in the U.S. at this time and because of the significant impacts of the SB 342 Carbon Tax Scenario described above. The NCEP study calls for an initial cost of around $7 per metric ton of CO_2 equivalent beginning in 2010. The price is forecast to rise to approximately $15 per ton in 2026.

The Company assumed that legislation based on the NCEP analysis would eliminate the federal production tax credit for renewables. The results of the study found that the tax would essentially eliminate new pulverized coal plants. The study also found that the loss of the federal PTC under the NCEP Carbon Tax scenario disadvantaged wind relative to the Base Case. Figure 6.29 shows the resource build for this scenario. It maintains the status quo with continued construction of natural gas resources and modest investments in other resources.

If Congress passes a carbon allowance program that result in a CO_2 tax similar to that of the NCEP forecast, carbon emissions would continue to rise because new natural gas resources would be built and existing coal resources would remain online. NCEP carbon tax levels likely would succeed in prohibiting new coal-fired resources that did not sequester their carbon emissions. Figure 6.30 shows that carbon emissions are expected to increase from Base Case levels, but at a slower rate of growth. NCEP carbon tax levels will still affect marginal electric prices significantly. See Figure 6.31.

Emission Scenarios Summary

Where federal legislation limits carbon emissions, electricity prices are likely to increase sharply. The carbon tax likely will eliminate proposals to build new coal plants unless future technologies reduce carbon emission levels from these plants. In today's tight natural gas market, it is plausible that the necessary large shift to natural gas-fired resources would drive natural gas prices to new highs not seen before. In this case, electricity prices might rise even more substantially than presented in this study.

Figure 6.29: Cumulative Resource Selection for the Western Interconnect – NCEP Carbon Tax (GW)

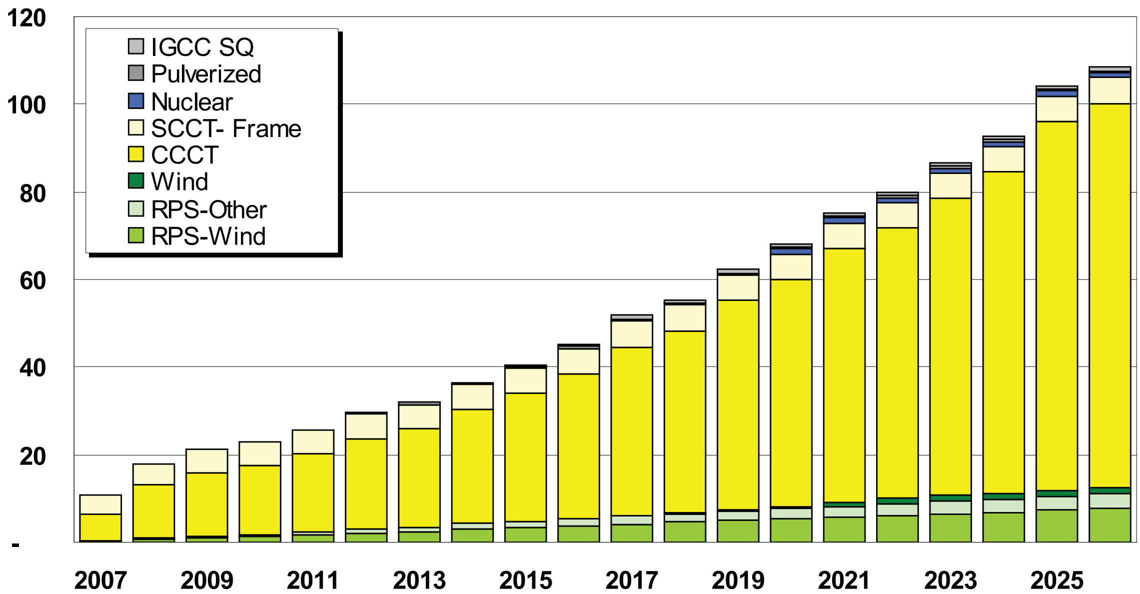


Figure 6.30: Western Interconnect Generator CO_2 Emissions Forecast

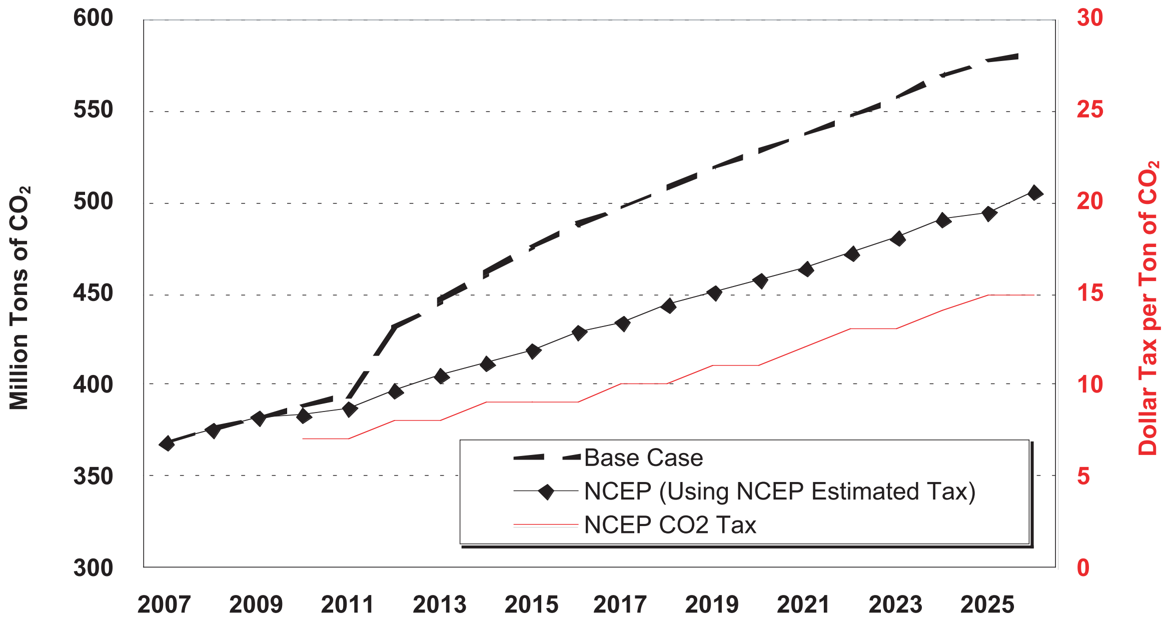
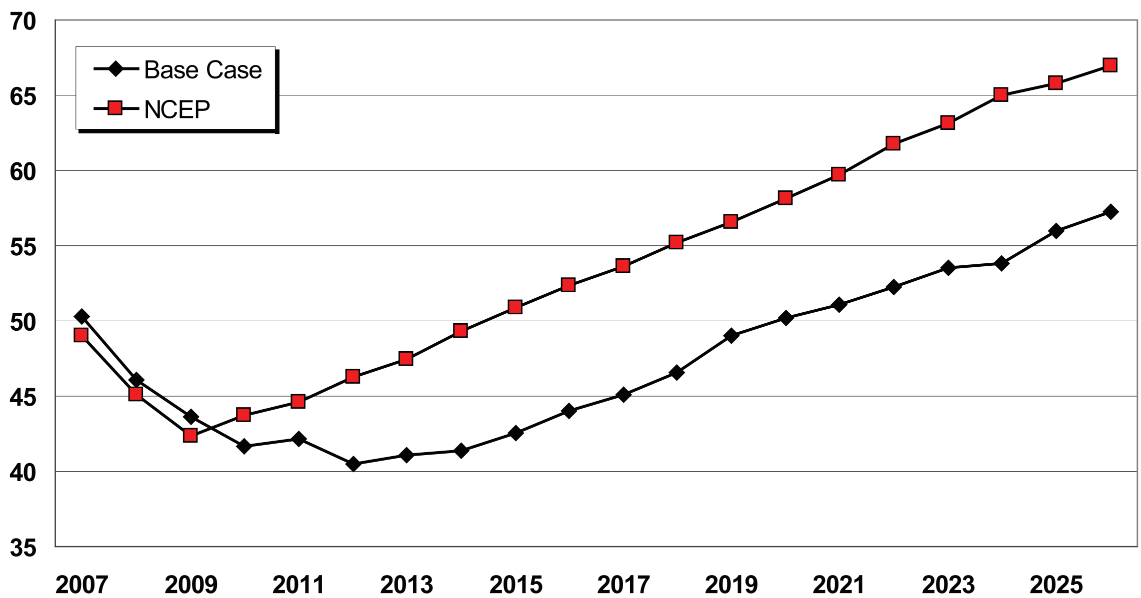


Figure 6.31: Base Case and NCEP Carbon Tax Mid-Columbia Electric Price Forecasts ($/MWh)



6.4 Avista-Centric Scenarios

Avista-centric scenarios are scenarios that do not affect the marketplace but do affect the Company. Because the marketplace isn't affected, the scenarios were not modeled with AURORA^{XMP}. The following is a list of the Avista-centric scenarios:

- Green Growth Initiative
- Loss of Spokane River Projects
- Intermediate-Term Loss of Noxon Rapids Powerhouse
- High Load Growth Trajectory
- Low Load Growth Trajectory
- Long Haul Coal Option
- Double Conservation Acquisition

Green Growth Initiative

The Green Growth Initiative became the "All Renewables" resource portfolio discussed in Section 7- *Preferred Resource Strategy*.

Loss of Spokane River Projects

The Spokane River projects are licensed through June 2007. The Company expects to renew its federal license to operate these facilities. The Technical Advisory Committee asked the Company to assess the financial impact of losing these assets. The Company found that a loss of the projects would increase power supply costs by $458 million net present value over the 20-year IRP timeframe.[3]

3 This estimate does not consider significant cost reductions stemming from ceasing operations at the projects.

Intermediate-Term Loss of Noxon Rapids Powerhouse

Noxon Rapids is the Company's largest hydroelectric resource and its most flexible asset. A short-term loss likely would be offset with intermediate-term market purchases. The Technical Advisory Committee asked the Company to produce scenarios detailing potential causes for such an outage and the financial impact of the outages. Avista's engineering department identified three possible outage scenarios: earthquakes causing the wash out of earthen embankments (two to three years), powerhouse flooding (nine months), and a major transformer or switchyard failure (nine months).[4] Table 6.3 illustrates the value of Noxon Rapids in each year of the IRP study.

4 The capital replacement costs for these outages depends on the level of damage to existing assets. These costs are not included in the cost estimates of Table 6.3

Table 6.3: Market Value of Noxon Rapids Project ($millions)

Year	Cost	Year	Cost
2007	89.5	2017	79.6
2008	82.6	2018	81.8
2009	77.3	2019	86.4
2010	73.6	2020	89.1
2011	74.7	2021	90.0
2012	71.4	2022	92.6
2013	72.2	2023	95.1
2014	73.2	2024	95.9
2015	74.9	2025	99.4
2016	77.3	2026	101.8

High and Low Load Trajectory

The *Electricity Sales Forecast* section discussed high and low Company load scenarios. Avista currently has adequate resources until 2009. As the IRP is updated every two years, the Company will have the opportunity to adjust its load forecast based on changes in expected load levels. We believe that a shift in load growth will not substantially change the mix of resource types, but potentially could change the quantity.

Long Haul Coal Option

The Company studied the potential for locating a new coal plant in or near its service territory. The Company believes that plant capital costs will not be substantially different whether located outside of the Northwest or closer to our load. A plant located in Montana, for example, will require substantially higher transmission investment than a plant located closer to Avista. A plant located in our service territory will have a higher fuel expense driven primarily by rail transportation costs necessary to bring in coal from distant mining regions. Overall, the long-haul coal option appears cost competitive when compared to a mine-mouth coal plant located outside of the Northwest. The Company will continue to study various coal plant locations, including local sites, as part of its action plan.

Double Conservation Acquisition

Section 3 of this IRP explained that the Company would work to acquire 6.9 aMW of conservation in each year of the IRP study period. The Company was asked during its Technical Advisory Committee meeting to quantify the cost were the Company to double its conservation acquisition levels. The Company found that if it acquired 13.8 aMW annually, then program costs would rise to 2.5 times the Preferred Resource Strategy level. The increase in conservation also would reduce the need for new resources.

6.5 Avoided Costs

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

The Washington and Idaho Commissions interpret which resources are eligible for PURPA avoided cost rates. PURPA developers with projects that exceed certain levels are eligible for a negotiated rate based on utility avoided cost. Published rates are provided for smaller PURPA facilities. In Washington PURPA resources below 1 MW are eligible for published fixed rate schedules with a term of up to five years. The five-year schedules are tied to forward market prices. In Idaho, facilities up to 10 aMW may obtain published avoided cost rates for up to 20 years.

Avoided Costs Versus the Wholesale Marketplace

There is some disagreement in the industry over what constitutes avoided cost. In Idaho, administratively-determined avoided cost rates presently are based on a gas-fired CCCT as a surrogate to represent the Company's next lowest cost investment. 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

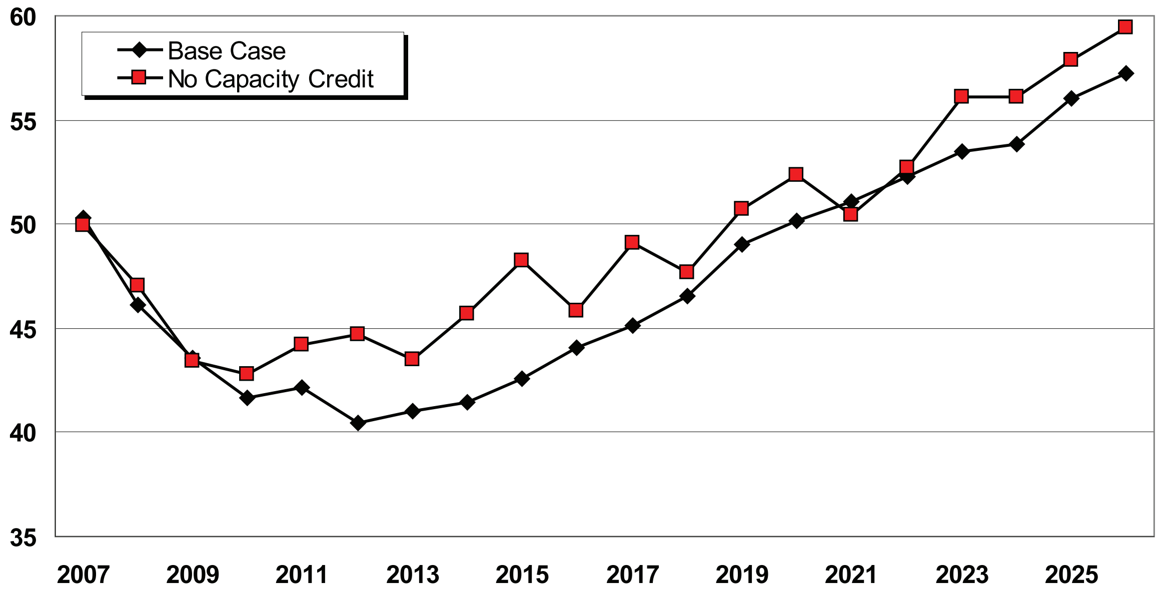
The 2003 IRP ignored planning margins and only built resources that could recover all costs, including capacity payments, in the marketplace. The 2003 IRP market prices included all costs associated with constructing new resources; the market equaled avoided cost.

The 2005 IRP uses capacity credits to insure planning margins adequate to prevent large price spikes during various adverse market conditions. With capacity credits lowering the installed cost of new resources, the wholesale marketplace modeled for the IRP more accurately represents the wholesale electricity marketplace we witness today. The drawback is that the modeled wholesale marketplace does not represent full utility avoided costs. A secondary step, essentially reverting to the 2003 IRP methodology, is necessary to extract avoided costs from the IRP modeling.

Once all 2005 IRP modeling assumptions were finalized, an additional run was launched without capacity credits reducing resource construction costs. The Base Case run, the basis for our 20-year market price forecast, and the new avoided cost run are displayed below in Figure 6.32.

The same data may be found in tabular format in Table 6.4, along with both ten- and 20-year levelized costs.

Figure 6.32: Base Case Mid-Columbia Price Forecast and Avoided Costs Comparison ($/MWh)



6.6 Summary

Using a regional approach to calculate market prices, and to calculate the value of resource options, provides for more robust results when compared to an analysis that separates resource modeling from price forecasting. The Company also believes that using a stochastic approach to evaluate risk is more valuable than simply creating scenarios.

This section focused on market prices used to select the Preferred Resource Strategy, and discussed many regional costs and benefits of certain market actions. The next section will focus on how the Company used this information in creating the PRS, and the effect of the various scenarios and futures on the PRS.

Table 6.4: Avista Avoided Costs Compared to Mid-Columbia Price Forecast ($/MWh)

Year	BC Market Forecast	Avoided Cost	Year	BC Market Forecast	Avoided Cost
2007	51.25	49.99	2017	46.56	49.12
2008	46.91	47.04	2018	47.49	50.59
2009	44.57	44.42	2019	50.17	51.71
2010	42.82	42.80	2020	51.71	52.37
2011	43.11	44.21	2021	52.63	54.67
2012	41.22	44.11	2022	53.75	54.62
2013	42.04	44.83	2023	54.88	56.11
2014	42.71	45.73	2024	55.35	57.32
2015	44.08	46.63	2025	57.57	57.90
2016	45.09	47.84	2026	59.07	59.42
10-Yr. Lev. Cost	44.78	45.84	20-Yr. Lev. Cost	47.05	48.28

7. PREFERRED RESOURCE STRATEGY

The Preferred Resource Strategy (PRS) contains the Company's forecasted preferred mix of new resources over the IRP time horizon. The PRS must strike a balance between the many (and oftentimes conflicting) criteria of resource planning. One potential future mix of resources might result in the lowest absolute cost over time but does so at the expense of volatile costs from one year to the next. Another future might keep rates reasonably stable over time but suffer from an unacceptably higher average rate level. The PRS generally is not capable of providing an optimal outcome when measured against each resource-planning criterion and/or market condition individually. Instead, a PRS should perform strongly across the various criteria and the range of possible future market conditions, when compared to other resource strategies. Herein lies the largest challenge facing electric utility resource planners today.

This section will introduce and then later detail the Company's 2005 IRP PRS. It will introduce 12 alternative resource strategies developed to illustrate the relative strengths and weaknesses of resource options under varying models of future market conditions. Next, the Company's work to develop an Efficient Frontier is detailed. The last few pages tabulate the Company's load and resource balance with the inclusion of PRS resources.

7.1 The Preferred Resource Strategy—An Introduction

The wholesale marketplace is comprised of thousands of generating assets located across the western United States. This market is available to the Company to help manage its assets to the benefit of retail customers. At certain times it is less costly to shut down owned generation plants and purchase power from other market participants. At other times Company-owned assets provide electricity at the least cost.

Section Highlights

- The Preferred Resource Strategy meets more than 50 percent of load growth with conservation, plant efficiency upgrades, and renewables.
- Our annual conservation target is 50 percent higher than in 2003.
- The 2005 IRP Efficient Frontier, a tool for comparing the tradeoff between price volatility and expected cost, is the product of 1,000 Avista Linear Programming model simulations.
- The PRS reduces portfolio price volatility by 55 percent in 2016 when compared to relying exclusively on market purchases.

Prior to the energy crisis of 2000-01, many within our industry, including policy makers, utilities, and customers believed that the wholesale marketplace could serve customers at costs below traditional regulation. To varying degrees, utilities relied more heavily on the energy market than they had in the past.

Avista believes that a prudent strategy for serving its customers in the future contains a mix of resources and/or contracts backed by generation assets. A portfolio comprised substantially of actual generation property, owned or held under contract, is necessary to ensure reliable service at risk-adjusted least-cost. The Preferred Resource Strategy was developed in part by using results from Avista's Linear Programming model discussed in Section 5- *Modeling Approach*.

The Company's Preferred Resource Strategy was developed after careful review of the Efficient Frontier, the relative performance of 12 alternative resource strategies (described later in this section), and results of 18 alternative marketplace scenarios and Avista-centric possibilities. The PRS is defined by three generation categories: wind generation, coal-fired generation and other small renewables. It contains upgrades to existing Avista resources and a significant increase in conservation acquisition from today's level.

The PRS does not recommend additional natural gas-fired generation due to the high level of gas-fired generation already in the Company's portfolio, the high price of natural gas, and the resource's tendency to introduce additional volatility into Avista's portfolio. In 2016 total installed capacity is 400 MW of wind, 250 MW of coal, and 80 MW of other small renewable projects. Resource requirements are 69 MW and 52 MW lower because of conservation and efficiency upgrades to existing resources, respectively. By 2026, the end of the IRP study timeframe, total installed capacity equals 1,332 MW and is comprised of 650 MW of wind generation, 450 MW of coal-fired generation, 180 MW of other renewable generation, and 52 MW of plant efficiency upgrades. Needs are 138 MW lower because of conservation. Figure 7.1 illustrates the Preferred Resource Strategy developed by the Company.

This PRS mix differs from the 2003 IRP primarily by the replacement of a significant portion of the coal-fired resource with wind and other renewable generation projects. The 2003 IRP Preferred Resource Strategy is shown below in Figure 7.2.

Three factors explain the differences between the 2003 IRP and this plan. First, the acquisition of the second half of Coyote Springs 2 in January 2005 brought 140 MW of natural gas-fired combined-cycle combustion generation into the Company's portfolio. That purchase met the natural gas-fired component of the 2003 IRP.

Second, higher natural gas and electricity market prices have allowed resources that previously were uncompetitive, namely wind and other renewable

Figure 7.1: 2005 Preferred Resource Strategy Build (MW)

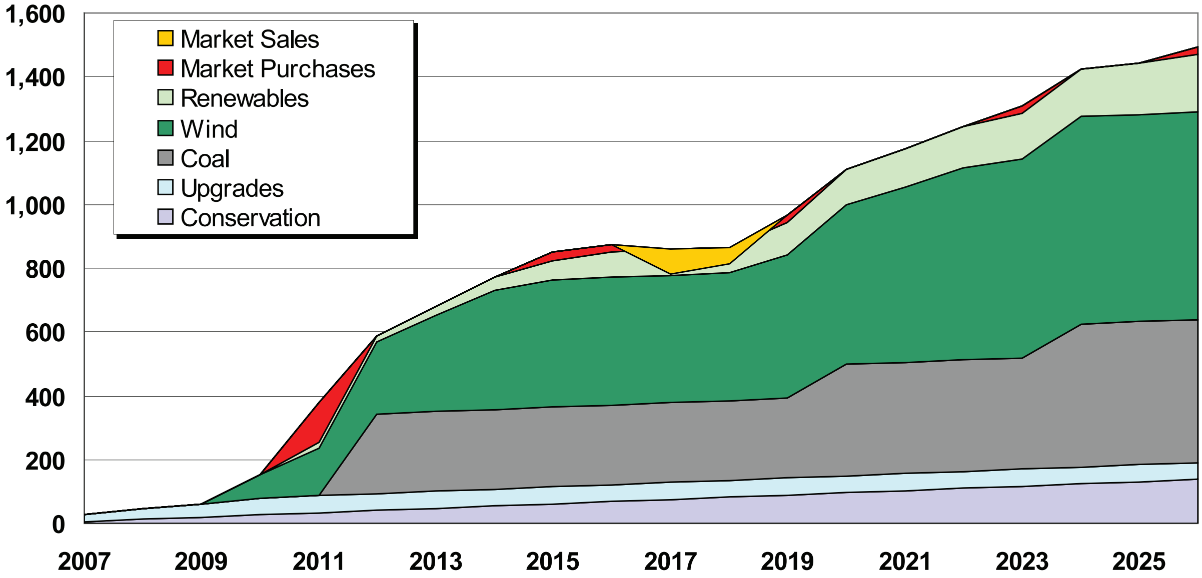
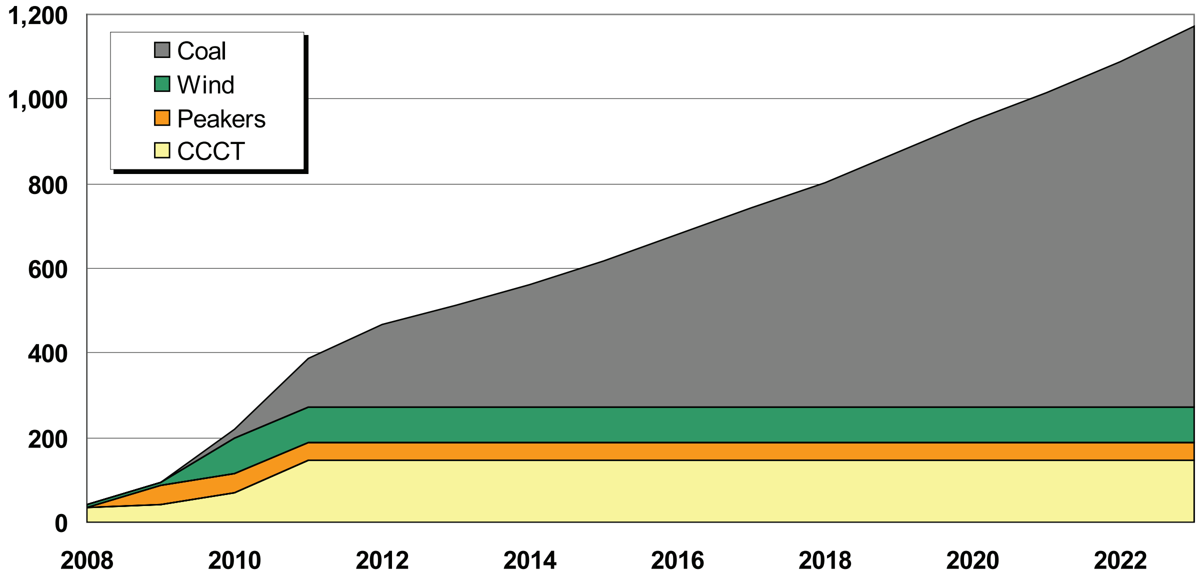


Figure 7.2: 2003 IRP Preferred Resource Strategy Build (MW)

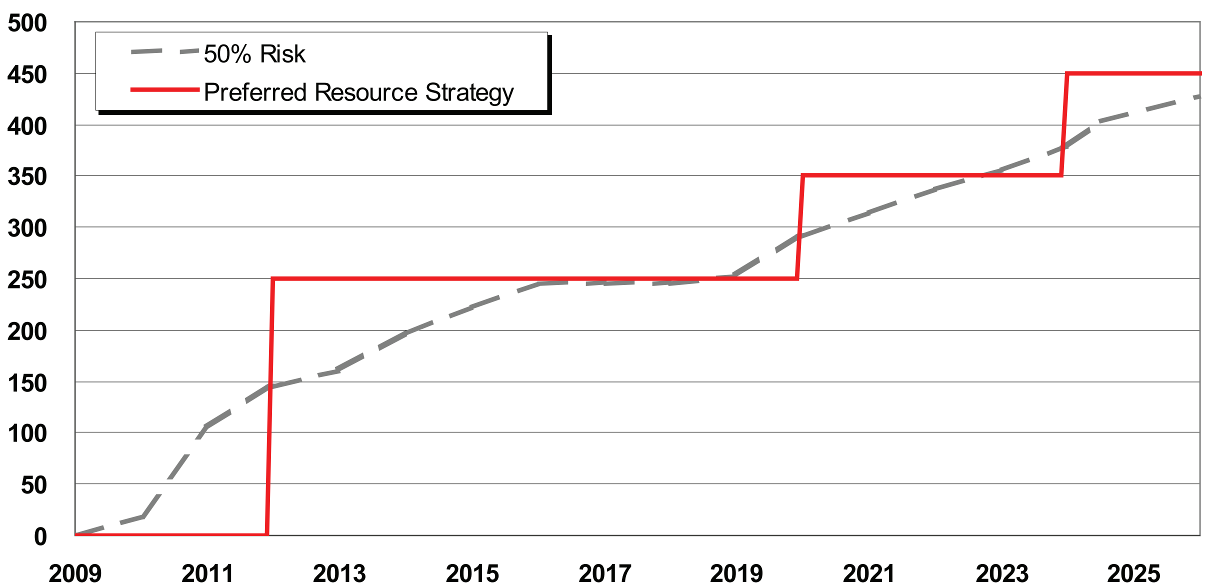


resources, to now become competitive. Finally, wind integration studies and actual experience with integrating wind into the Company's system lead us to believe that we can rely more heavily on this resource.

The PRS adds "lumpiness" to the acquisition schedule when compared to Efficient Frontier and alternative scenario resource mixes. The lumpy nature more closely reflects how the Company might expect to add resources. This contrasts with the portfolios selected by the Avista LP model for the Efficient Frontier. The Efficient Frontier resource selections are not constrained by lumpiness. For example, the 50 Percent Risk mix allows annual acquisition levels of 49.3 MW, 2.6 MW, and 36.6 MW of new coal in various years of the study.

It would be nearly impossible either to construct plants, or obtain contract provisions, allowing for these capacity levels. Instead, resource acquisitions likely will occur as shown in the Preferred Resource Strategy, with blocks of no less than 100 MW in any given year for coal plants, blocks of no fewer than 25 MW for wind, and no fewer than five MW for biomass plants. Medium term market purchases of up to five years can also be made to allow added flexibility on the timing of new power plant acquisitions. Modest market purchases included in the PRS have blocks no smaller than 25 MW. Bringing new resources into the portfolio on a less granular schedule increases costs slightly when compared with resource mixes developed for the Efficient Frontier and other resource mix alternatives that are not constrained by lumpiness. Figure 7.3 compares the 50 Percent Risk and PRS acquisition patterns.

Figure 7.3: Preferred Resource Strategy Coal Build vs. LP Module Build (MW)



7.2 Preferred Resource Strategy Details

Wind Resources in the PRS

Wind comprises the largest nameplate capacity component of the Preferred Resource Strategy, contributing 400 MW by 2015 and 650 MW by 2024. The Company's reliance on wind technology in the 2005 plan also represents a large strategic shift from the 2003 IRP and is the result of two major changes since the last plan further research on wind resources and wind integration and rising wholesale market prices.

The Company committed to "continu[ing] to evaluate the effects and costs of integrating wind generation..." in its 2003 IRP Action Plan. Various data and internal evaluations, combined with actual experience gained from integration of 35 MW of wind generation from the Stateline Wind Energy Center, were completed since the release of the 2003 plan. This work indicated that the Company might be able to include significant, but not unlimited, additional wind resources into its future plans. It also was learned that the Company might need to purchase wind integration services from third parties for some or all of its wind resource due to rising integration costs incurred as installed wind capacity levels grow. The 2005 IRP adopts NPCC wind integration cost estimates.

How much wind can Avista reasonably expect to include in its future? Exhausting wind's cost-effective regional potential becomes a concern as utilities in the Northwest, including Avista, begin to include wind plants in their future plans. Idaho Power's 2004 Integrated Resource Plan identifies 350 MW of wind over their ten-year planning horizon. PacifiCorp plans to include 600 MW for its west-side service territories. Puget Sound Energy has committed to 845 MW of wind. Portland General Electric includes 200 MW in its latest IRP. Add Avista's 400 MW by 2016 and the region's investor-owned utilities are looking to add 2,395 MW of nameplate wind capacity. Table 7.1 details the five utilities, with a comparison of their loads and wind plans.

The NPCC estimates that total Northwest wind generation potential is 5,000 MW. The five Northwest investor-owned utilities are planning to develop nearly 50 percent of regional potential over the next ten years.

Though aggressive, Avista believes it is possible to acquire 400 MW by 2016 and 650 MW by the end of 2026 by pursuing three different wind resource strategies. First, the 2005 IRP assumes that Avista will acquire 250 MW of Northwest regional wind generation outside of its service territory. This amount approximately equates to its pro-rata share based on Northwest loads. Second, the PRS selects 150 MW of wind within Avista's service territory. While in-territory wind resources are estimated on average to generate 21 percent less energy than sites presently being developed across the Northwest, transmission savings are significant and make the sites potentially attractive.

Finally, the plan assumes another 250 MW of wind generation will be available from outside the Northwest (e.g., eastern Montana or Wyoming). These sites have relatively higher capacity factors when compared to Northwest wind sites. Higher transmission costs therefore can be offset somewhat by higher generation levels. Acquisitions from outside the Northwest will be dependent on the availability of transmission at costs allowing them to be acquired economically.

Other Renewables in the PRS

The LP model selected a mix of renewables besides wind power, namely landfill and manure biomass, in many of the Efficient Frontier portfolios. This result indicates the possibility of further cost-effective investments in renewable energy technologies above 650 MW of wind. The PRS includes 80 MW of biomass resources, both from landfill gas and manure methane, by 2016. Other renewables are forecasted to provide 180 MW by the end of the IRP timeframe.

As with wind, Avista's ability to include significant renewable resources in its future resource portfolio ultimately will depend on how close NPCC cost estimates for these resources come to actual offers received by the Company. Integration also will depend on commercial availability. The NPCC Fifth Power Plan expresses concern over the viability and potential of biomass renewable resource options. The Company will explore this issue as an action item in the 2005 IRP and provide further information in its 2007 plan.

Conservation in the PRS

The 2005 IRP supports increasing annual conservation acquisitions from approximately 4.6 aMW today, to 6.9 aMW. This equals a nearly 50 percent increase, due primarily to higher avoided

Table 7.1: Northwest IOU Loads and Estimated Wind Acquisition Plans through 2016

Utility	IRP Wind Capacity (MW)	2016 Load (aMW)	IRP Wind Energy[1] (aMW)	Wind Contribution to Load (percent)
Avista	400	1,424	132	9.3
Idaho Power[2]	350	2,187	116	5.3
PacifiCorp West[3]	600	2,678	198	7.4
Portland General Electric[4]	200	3,075	66	2.1
Puget Sound Energy[5]	845	2,790	279	10.0
Total	2,395	12,154	790	6.5

1 Assumes all wind resources have a 33 percent capacity factor for comparative purposes.

2 2013 levels from 2004 Integrated Resource Plan: pages 2 and 30.

3 See pages 30 and 38 of 2004 Integrated Resource Plan Appendix.

4 Load is found on page 100 of 2002 Integrated Resource Plan.

5 2013 statistics. Includes existing wind at Hopkins Ridge and Wild Horse. See PSE 2005 IRP, pages 1X-8 and X-22 cost estimates that include a ten percent adder over generation-based acquisition, and a movement toward 8,760-hour evaluation of the various available measures. Refer to Section 3- *Conservation Initiatives* for further detail on the significant enhancements made in conservation program analyses for the 2005 IRP.

On a cumulative basis, the acquisition of conservation will offset 69 aMW of new generation by 2016; in 2026 customer loads are estimated to be 138 aMW lower than absent conservation efforts.

Project Upgrades

The Preferred Resource Strategy includes upgrades at both its Cabinet Gorge and Noxon Rapids hydroelectric facilities, as well as at Colstrip. These modifications will bring additional energy and capacity with no incremental fuel costs. The various improvements will be completed between 2005 and 2011.

Coal in the PRS

In reviewing forecasted future customer requirements it becomes clear that conservation and renewable resources, while having the potential to contribute significantly to our future mix, cannot fill the gap entirely. We believe that conservation and renewables have the potential to meet approximately two-thirds of our capacity and one-half of our energy requirements in 2016. After selecting cost-effective conservation and renewable resources, the Company looks to more traditional base load supply-side resources. As discussed in Section 5, these options include natural gas, nuclear, Alberta oil sands, and coal located in and outside of the Northwest. The best option among these resources for Avista's resource mix is coal-fired generation. Coal benefits from low variable costs, helping to keep power supply expense volatility low.

Coal was selected in the 2003 IRP, though customer costs were expected to be modestly higher than an all-gas plan. With higher natural gas prices, coal-fired generation also brings lower customer costs. The PRS contains 250 MW of coal-fired generation entering service during the middle of next decade. In 2026, coal–fired generation equates to 450 MW, or 30 percent of our new requirements.

7.3 Efficient Frontier

The Efficient Frontier is a key component of an academic body of work in "portfolio theory." First applied to finance, the Efficient Frontier measures tradeoffs between expected return and risk inherent in securities portfolios. With IRP planning, a similar exercise in portfolio management, the concept is applied when selecting future mixes of supply- and demand-side resources. Figure 7.4 illustrates the concept by showing risk on the vertical axis, measured as the 2016 standard deviation of incremental power supply expenses, and cost on the horizontal axis, measured as the 2007-16 net present value of the incremental power supply expenses.[6] Risk and cost are both at their lowest point in the bottom-left corner of the chart.

6 Incremental power supply expense includes fuel and variable O&M for existing resources, as well as fuel, variable O&M, fixed O&M, and capital recovery for new resources.

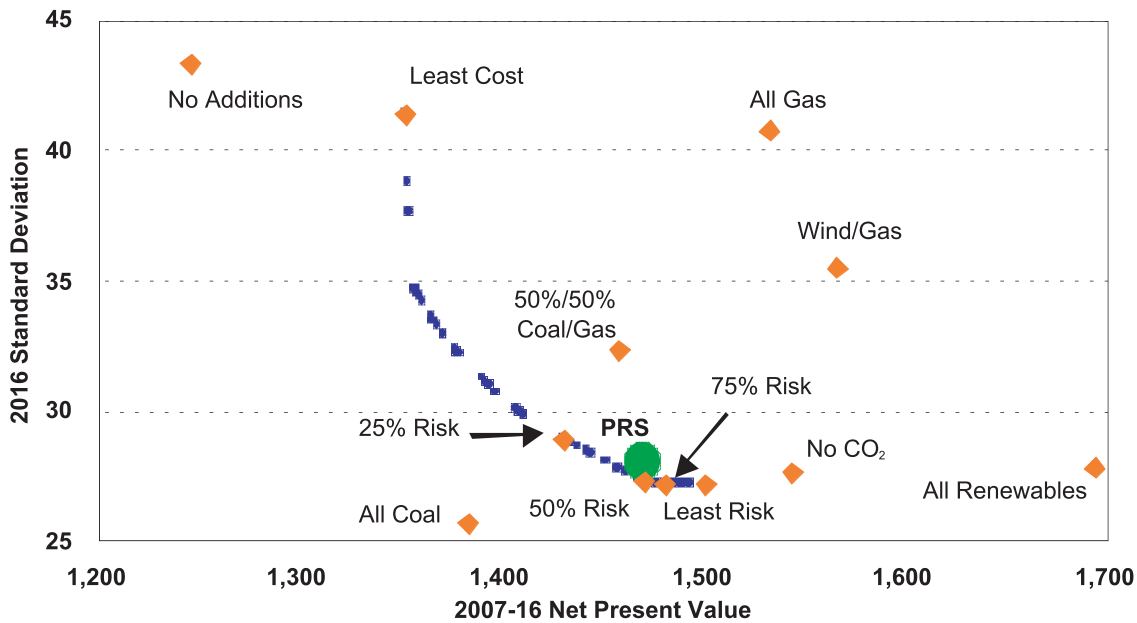
The blue curve explains simultaneously the optimal measure of risk at any cost point, and conversely the optimal cost point given a level of acceptable risk. Notice how it is impossible to attain a lowest risk and lowest cost position concurrently. This curve represents the quandary facing resource planners—selecting a position on the Efficient Frontier. The 12 alternative scenarios selected by the Company to compare to the Preferred Resource Strategy are displayed as orange diamonds. The Preferred Strategy itself is shown as a large green circle.

Efficient Frontier Concerns

The Efficient Frontier may work well where risk and cost matrixes are reasonably well known. For example, natural gas spot markets have a many-year historical data series. Natural gas price and volatility therefore can be reasonably estimated. The Efficient Frontier concept does have limitations. Future carbon emission regulations are not easy to define. There presently is significant disagreement about the magnitude and timing of future carbon regulations.

Should the planner then assign carbon tax levels and associated probabilities to add this variable into an Efficient Frontier? The Efficient Frontier also has limitations when considering risk such as nuclear plant siting and waste disposal, carbon emissions and project cost overruns. The Efficient Frontier approach appears unable to address future cost and risk challenges like these in a meaningful way. The Company will continue to evaluate the Efficient Frontier as a means to measure the tradeoffs inherent in resource decisions.

Figure 7.4: Efficient Frontier ($millions)



7.4 Twelve Alternative Portfolio Strategies

This section details 12 portfolios developed while defining the PRS. Each provides a different mix intended to illustrate the strengths and weaknesses of resource strategies.

1) No Additions (Market Purchases Backed by Peaking Plants)

In the No Additions portfolio, the Company would plan to rely on the wholesale marketplace to meet all of its future load requirements. No additional investments in generation plants or transmission are envisioned. This strategy, by definition, would limit Company ownership of generation assets to its existing mix of resources. Customer rates would vary depending on price levels in the wholesale marketplace. In higher priced years customers would see their power bills rise, potentially substantially. For example, prices in calendar year 2002 averaged $22 per MWh, below the Company's present production cost. However, in both 2003 and 2004 average prices were nearly double 2002 levels. With direct exposure to the wholesale marketplace, customer rates would have the potential to rise or fall substantially in any given year. Customers would also be exposed to extreme market conditions where prices could range well above $100 per MWh. With half of the Company's power supply expenses tied directly to the wholesale marketplace, such a condition could increase power supply expenses in a given year by 250 percent.

By its nature of having no new assets, the No Additions alternative is not a portfolio the Company will pursue. Instead, the strategy is included as a benchmark for comparison against the other portfolios evaluated for the 2005 IRP.

2) All Coal

Coal-fired generation serves more than 50 percent of the nation's electricity needs today Avista relies on coal-fired generation to meet approximately 18 percent of its needs. Coal reserves in the United States are so vast that some industry experts believe they will extend to the middle of this millennium, an attractive feature given recent run-ups in the prices of commodities tied to crude oil and natural gas. Coal generation benefits from its historical independence of the oil and natural gas markets, and its relatively low fuel cost. There is some risk that this independence might be compromised over time as existing and new technologies for converting coal into various synthetic petroleum products are driven to commercialization by rising crude oil and natural gas prices.

The All Coal portfolio meets all new load requirements with coal-fired generation. Coal-fired generation presently provides 222 MW of generating capacity in the Company's portfolio of resources and approximately 185 aMW of energy. Under the All Coal portfolio, coal's contribution would rise to 714 MW in 2016 and 1,078 MW in 2026. At the end of the study, coal would meet 43 percent of all utility capacity requirements.

3) All Gas

Natural gas-fired generation has been the predominant resource constructed across the United States in the past decade. Its benefits include low capital costs, simpler permitting and engineering, and moderate emission levels. Recent rises in the price of natural gas are forecast to continue well into the future. This option does not provide much customer protection against market volatility because natural gas-fired generators are the marginal resource of today's wholesale marketplace.

In the All Gas portfolio, the Company would add 492 MW and 856 MW of natural gas-fired combined cycle natural gas-fired generation by 2016 and 2026, respectively. Natural gas would become the dominant generating resource used by the Company to meet customer requirements. In 2016, fully 46 percent of the Company's generation capacity would be from gas-fired generation; 52 percent would come from natural gas in 2026.

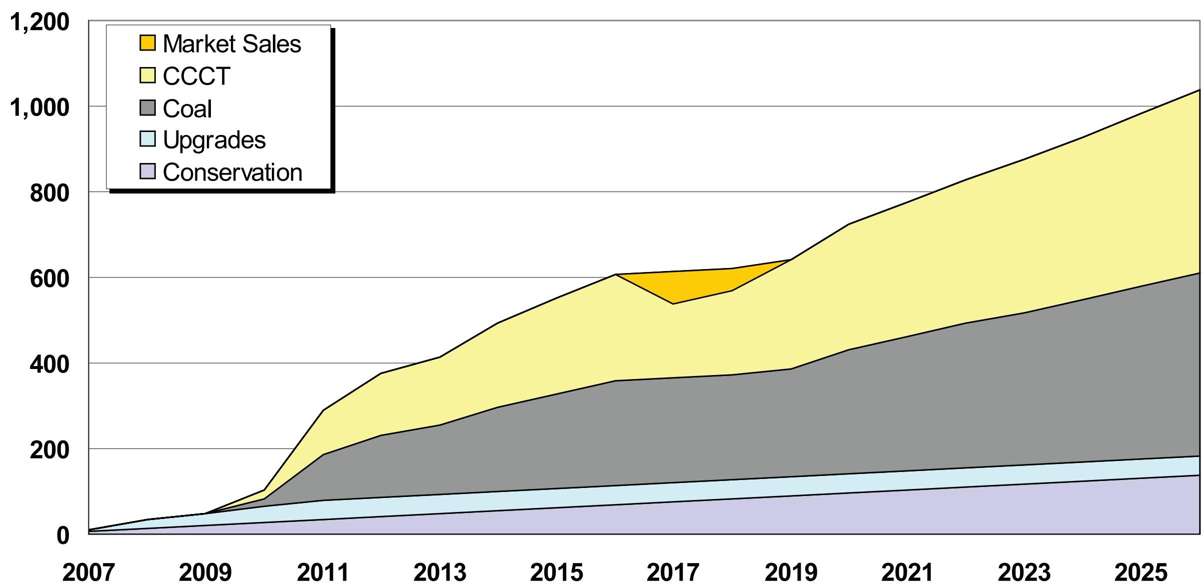
4) 50/50 Gas and Coal

The 50/50 Gas and Coal portfolio would split capacity additions equally between these resources, providing some balance between the lower capital costs of natural gas-fired generation and the lower fuel cost of coal-fired generation. Figure 7.5 illustrates the 50/50 Gas and Coal portfolio.

5) Wind and Gas

The Wind and Gas portfolio benefits from a greater reliance on wind, a resource absent fuel costs and air emissions. It is comprised of approximately 400 MW each of wind and combined-cycle combustion turbines (CCCT) in 2016. In 2026, the end of the IRP study timeframe, wind provides 650 MW of nameplate capacity with CCCTs contributing nearly 700 MW. Wind generation is limited to 650 MW

Figure 7.5: 50/50 Gas and Coal Build (MW)



of capacity over 20 years, a level the Company believes is aggressive for this resource. The Company's decision to constrain wind's contribution to our future mix is based on the limited availability of this resource. More detailed discussions of the limit are contained in Sections 5 and 6. The Wind and Gas portfolio may be found in Figure 7.6.

6) No CO_2

The No CO_2 scenario was developed to illustrate a mix of net-zero CO_2-emitting resources that may consist of wind, nuclear, other renewables, and cogeneration additions. This strategy brings wind generation into the Company's portfolio sooner and more aggressively, reaching the full 650 MW potential by 2016. The other major contributor to the portfolio is nuclear energy, at 176 MW in 2016. Renewables besides wind contribute 70 MW by 2016, while cogeneration adds another 25 MW. By 2026, the contributions of nuclear and renewables rise to 494 and 170 MW, respectively. Cogeneration grows slightly to 30 MW. The No CO_2 portfolio is shown below in Figure 7.7.

7) All Renewables

The All Renewables case ignores potential wind generation limitations, and constructs a portfolio mix comprised of 1,406 MW wind and 140 MW of other renewable resources by 2016. The totals rise to 2,225 MW of wind and 300 MW of other renewables in 2026. The large wind capacity requirements of this scenario were necessary given the limited on-peak capacity contribution of wind (25 percent of nameplate capacity). More than 2,500 MW of nameplate generation was constructed to meet load growth of just less than 900 MW in the All Renewables portfolio. Substantial surplus generation therefore must be sold into the volatile wholesale marketplace. All Renewables is shown

Figure 7.6: Wind and Gas Build (MW)

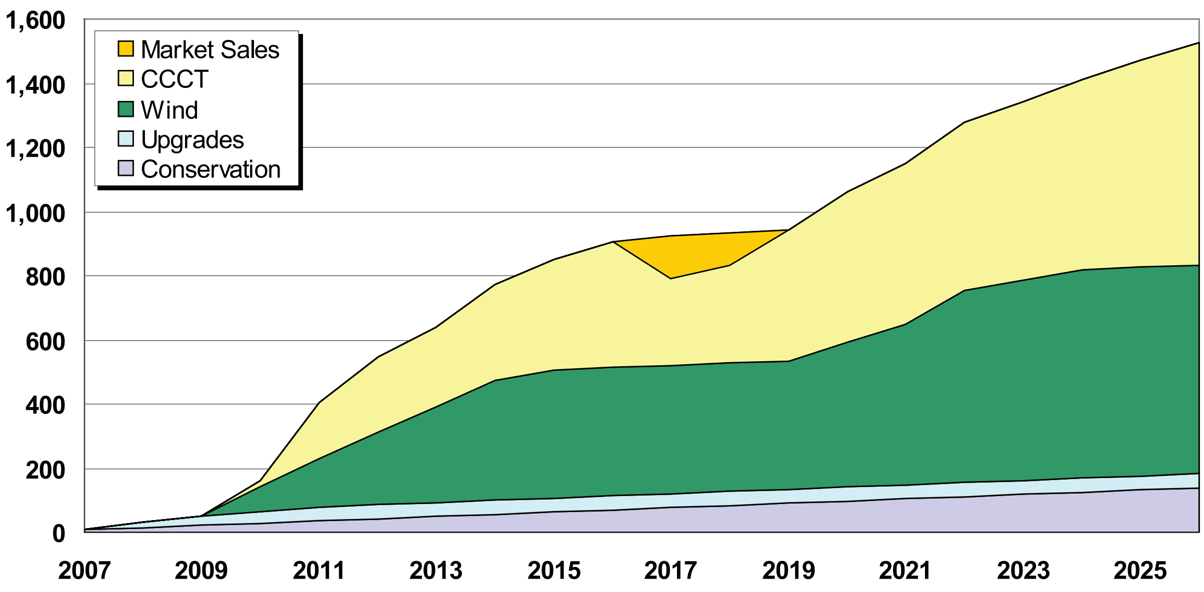


Figure 7.7: No CO_2 Emissions Build (MW)

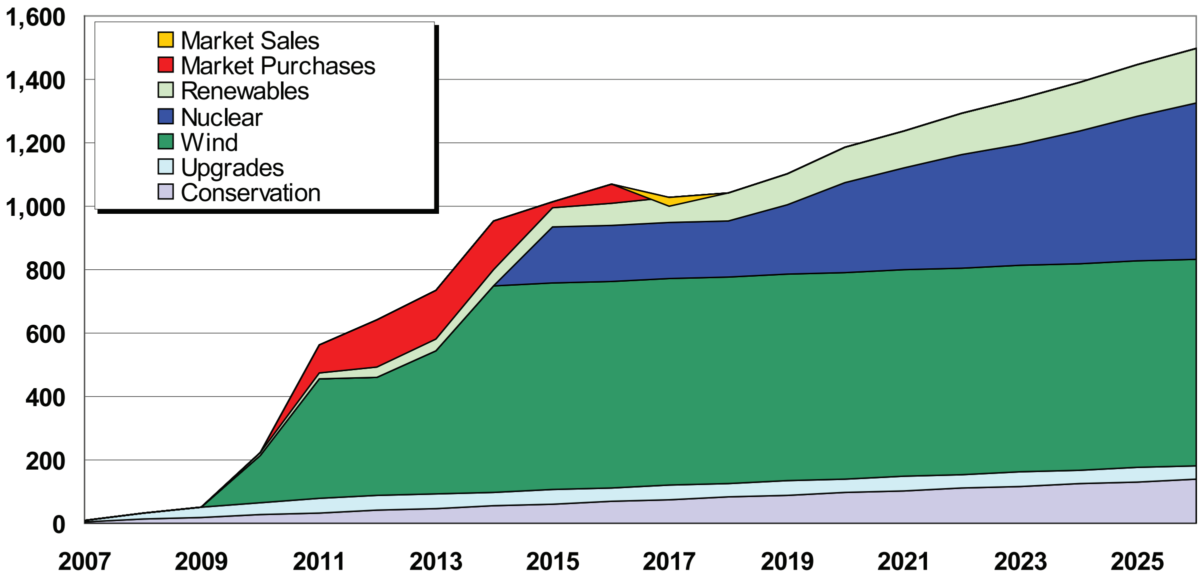
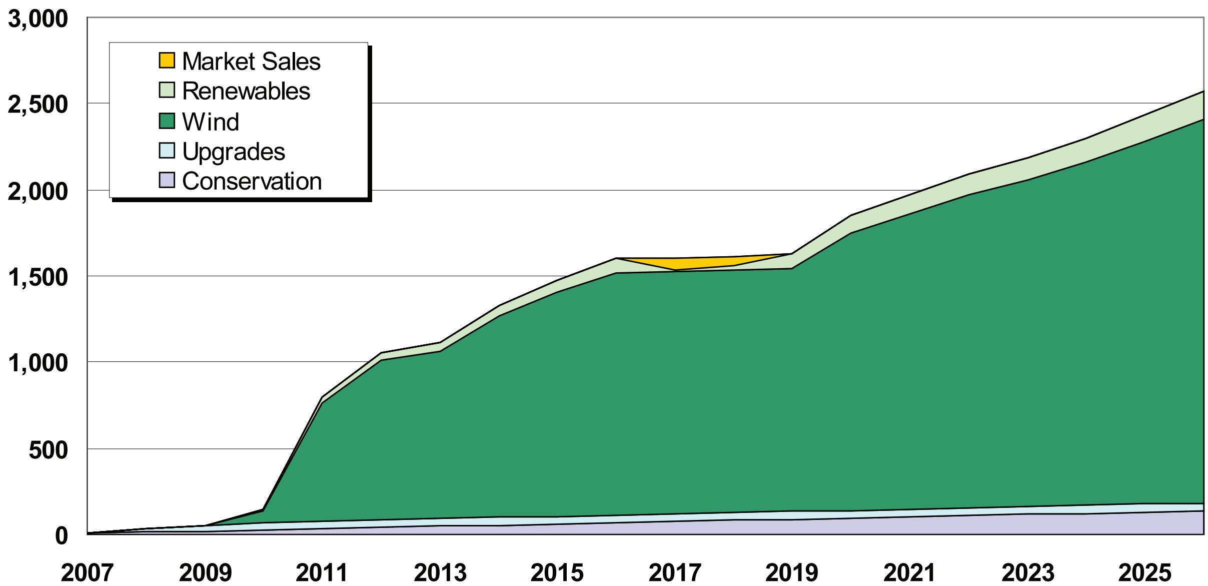


Figure 7.8: All Renewables Build (MW)



in Figure 7.8. Like the No Additions case, the Company does not believe that the All Renewables portfolio is realistic due to a lack of adequate wind sites and the intermittent nature of the resource; however the scenario is included in this IRP at the request of the Technical Advisory Committee.

8-12) Risk-Adjusted Portfolio Strategies

Five portfolios were selected from the Efficient Frontier exercise to illustrate various resource combinations and their performance under the alternative market scenarios and futures. The points on the Efficient Frontier represent varying combinations of risk, defined as the standard deviation of expected incremental power supply expenses, and cost, defined as the expected net present value of incremental power supply expenses, between 2007 and 2016. The 2003 IRP Preferred Resource Strategy was based predominantly on a mix of resources defined by weighting cost and risk at 50 percent each. Each risk-adjusted portfolio resource mix is shown in Tables 7.2 and 7.3 for calendar years 2016 and 2026, respectively.

Table 7.2: 2016 Resource Strategies (MW)

Resource	Least Cost	25% Risk	50% Risk	75% Risk	Least Risk
Coal	0	205	243	243	133
Gas CT	444	105	31	0	0
Gas CCCT	0	0	0	21	21
Wind	0	275	400	400	400
Other Renew/Cogen	0	75	80	90	200
Market	47	38	38	38	38
Total	492	698	792	792	792

Table 7.3: 2026 Resource Strategies (MW)

Resource	Least Cost	25% Risk	50% Risk	75% Risk	Least Risk
Coal	0	550	550	550	323
Gas CT	856	105	31	0	0
Gas CCCT	0	0	0	21	21
Wind	0	400	650	650	650
Other Renew/Cogen	0	75	105	165	400
Nuclear	0	77	58	8	0
Market	0	0	0	0	0
Total	856	1,206	1,394	1,394	1,394

Figure 7.9: Least Cost Build (MW)

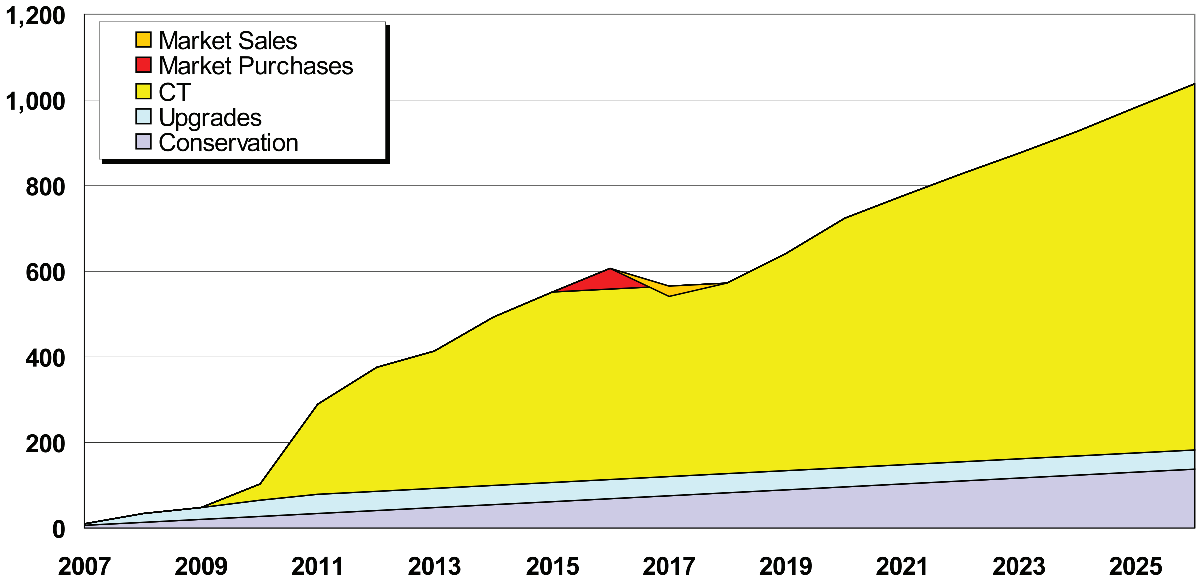


Figure 7.10: 25% Risk Build (MW)

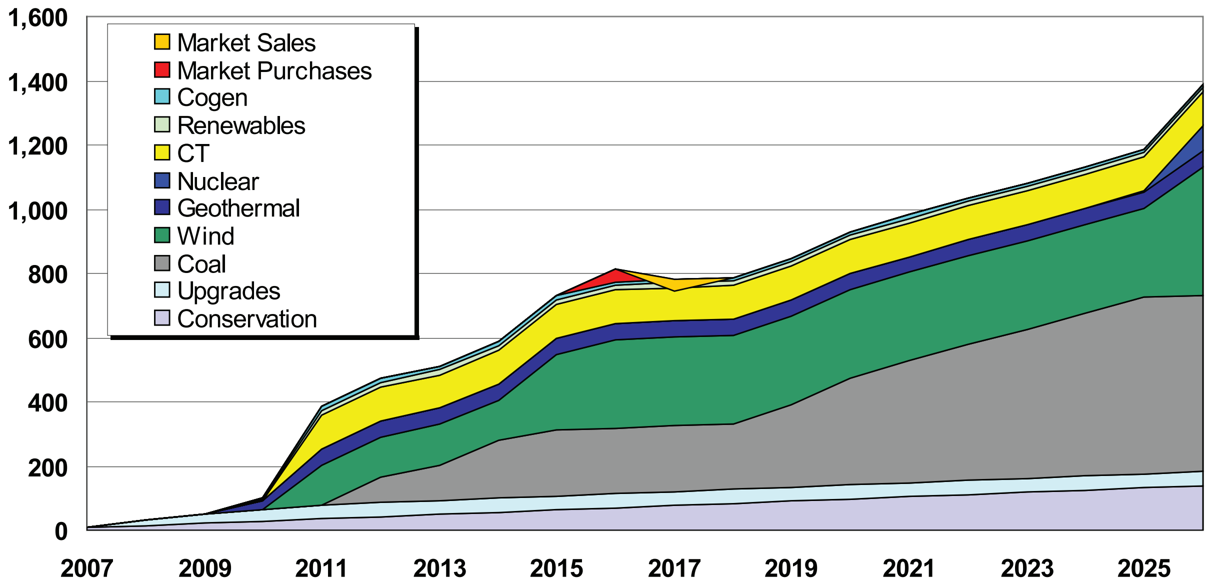


Figure 7.11: 50% Risk Build (MW)

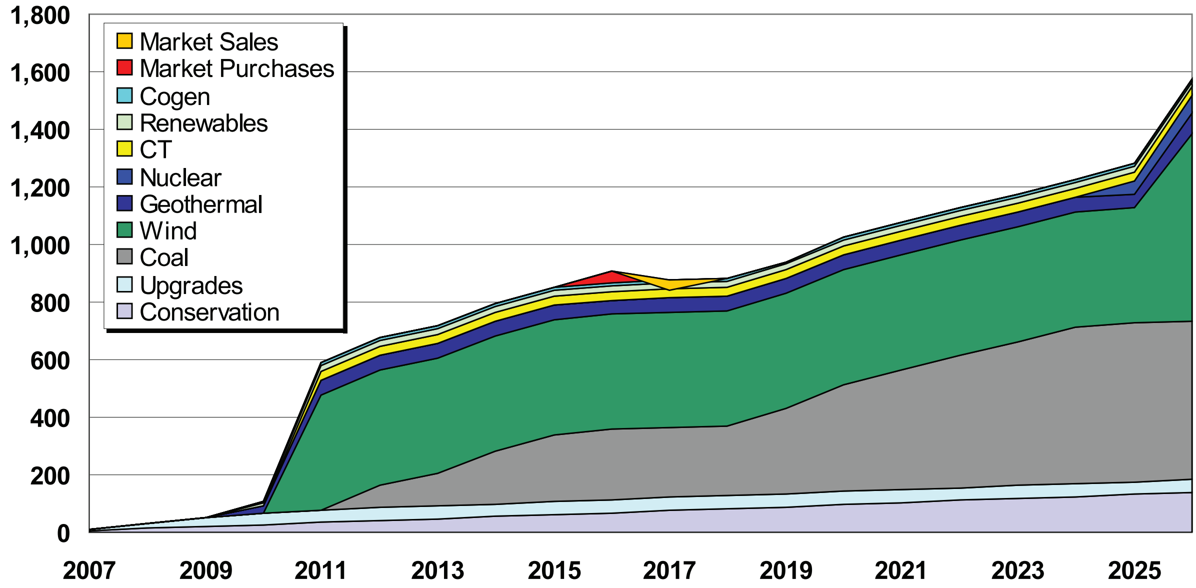


Figure 7.12: 75% Risk Build (MW)

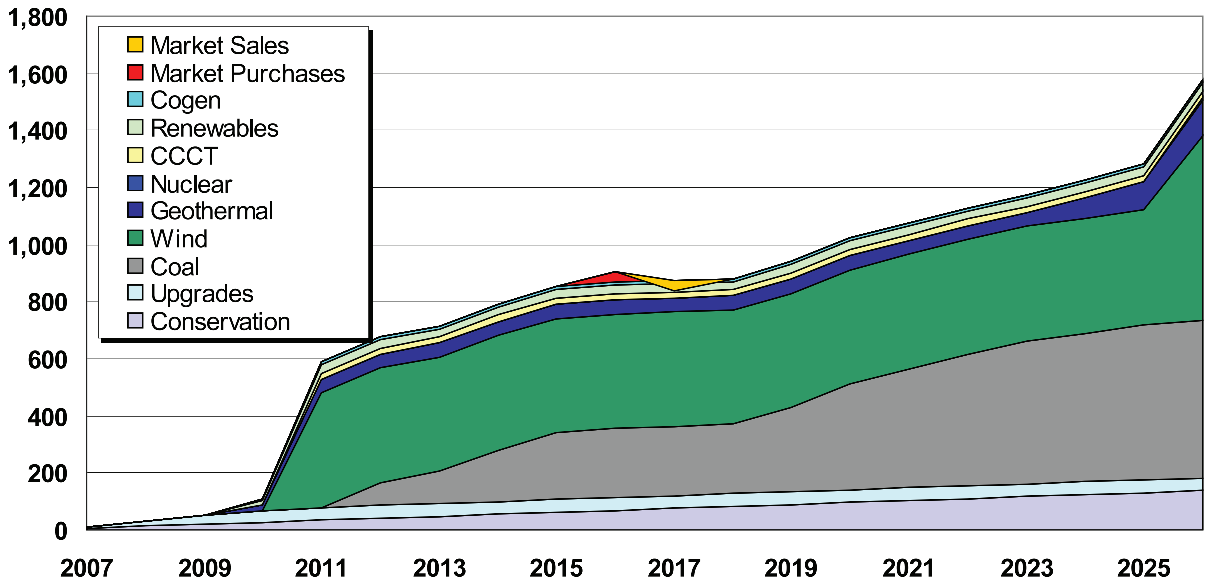


Figure 7.13: Least Risk Build (MW)

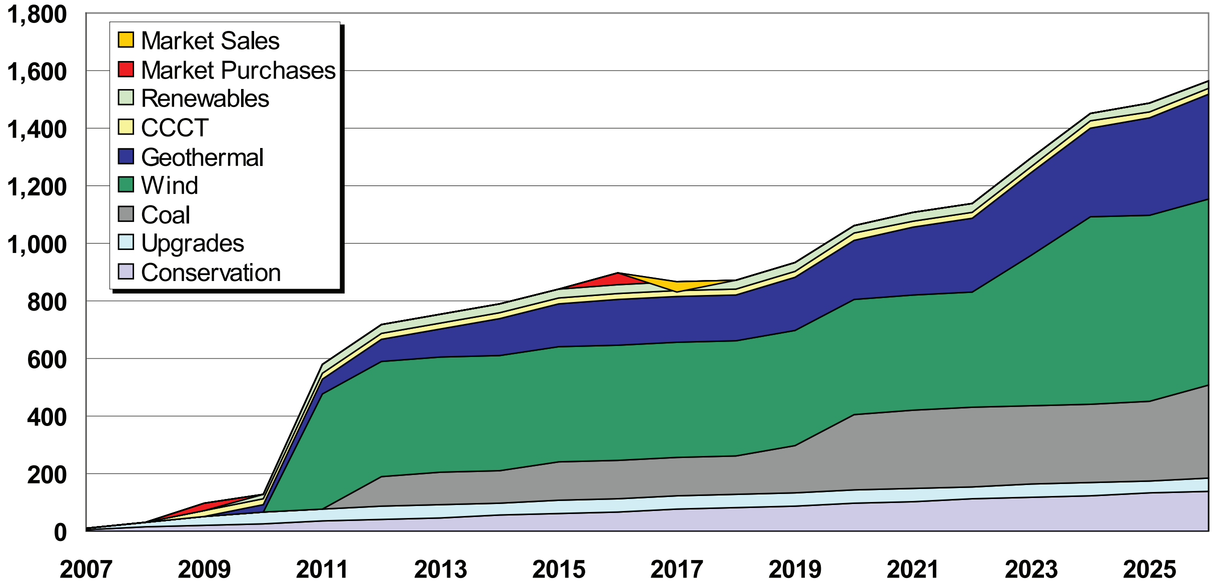


Figure 7.14: Preferred Resource Strategy Build (MW)

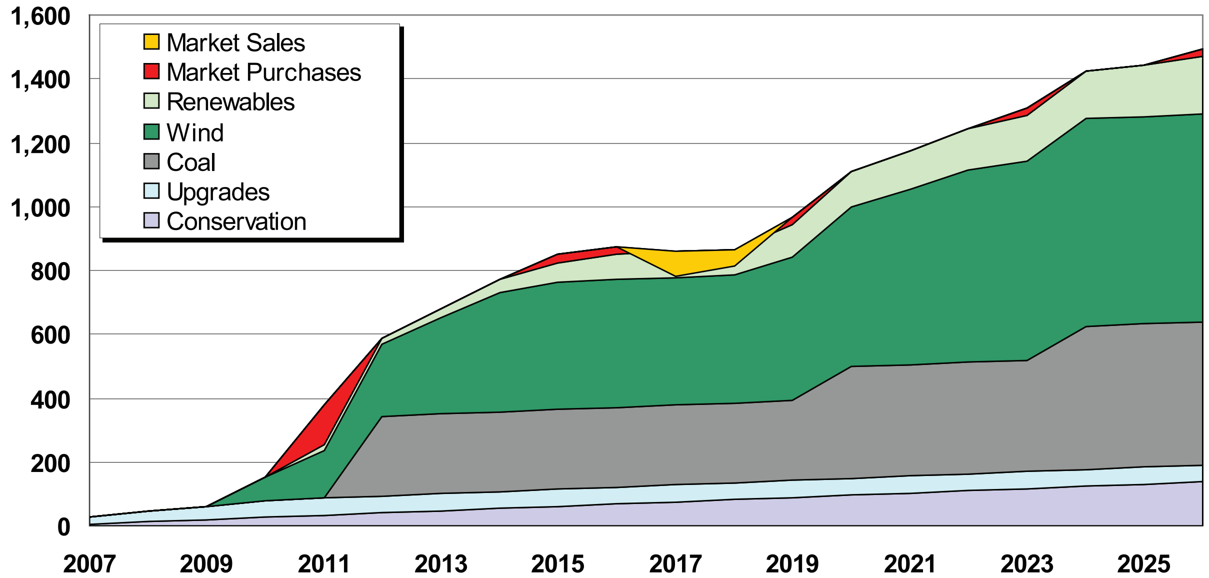


Figure 7.9 through Figure 7.13 illustrate the various Efficient Frontier resource strategies described above.

7.5 Performance of PRS Compared to 12 Resource Strategies

The Preferred Resource Strategy developed for the 2005 IRP provides the following benefits to customers when compared across the alternative resource strategies:

- Large contribution from renewable resources
- 50 percent higher level of conservation acquisition
- Significant reduction in year-on-year rate volatility
- Reasonable rate impacts when compared to other alternatives

The PRS is shown graphically in Figure 7.14.

Renewable Resource Contributions

The Preferred Resource Strategy contains among the highest contribution of renewable resources in the 13 resource strategies. The three portfolios with higher levels of renewables were allowed to violate the wind limitation of 400 MW by 2016 and were developed to illustrate certain characteristics of wind resources. The 100 percent Risk strategy does contain 100 MW more of non-wind renewables in 2016. Figure 7.15 shows the renewables contribution of the 13 alternative resource portfolios.

Conservation

Conservation plays an increased role in the 2005 Integrated Resource Plan compared to the 2003 IRP. Acquisition levels are increased 50 percent, from approximately 4.6 aMW per year to 6.9 aMW per year. Figure 7.16 details the impact of

Figure 7.15: Renewable Resource Contribution in 2016 (MW)

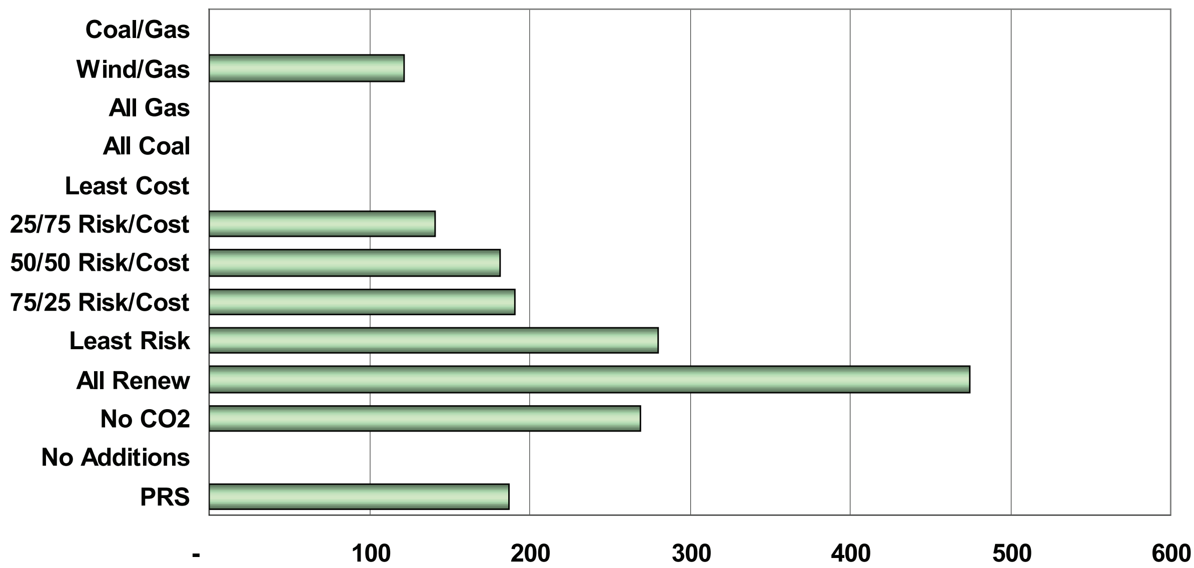


Figure 7.16: Conservation Acquisition (aMW)

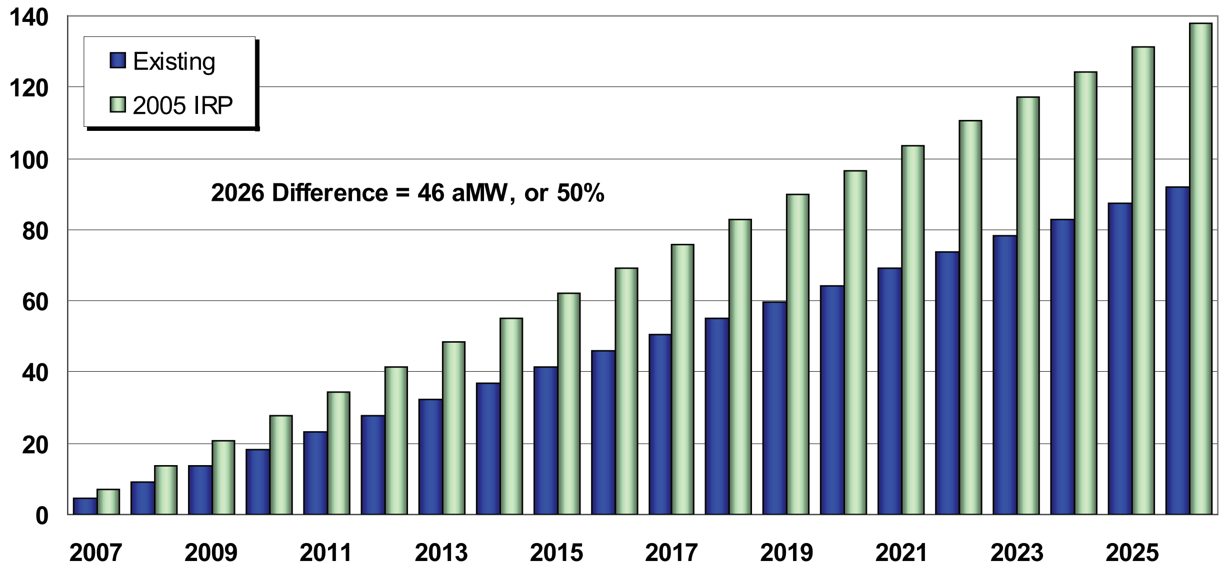
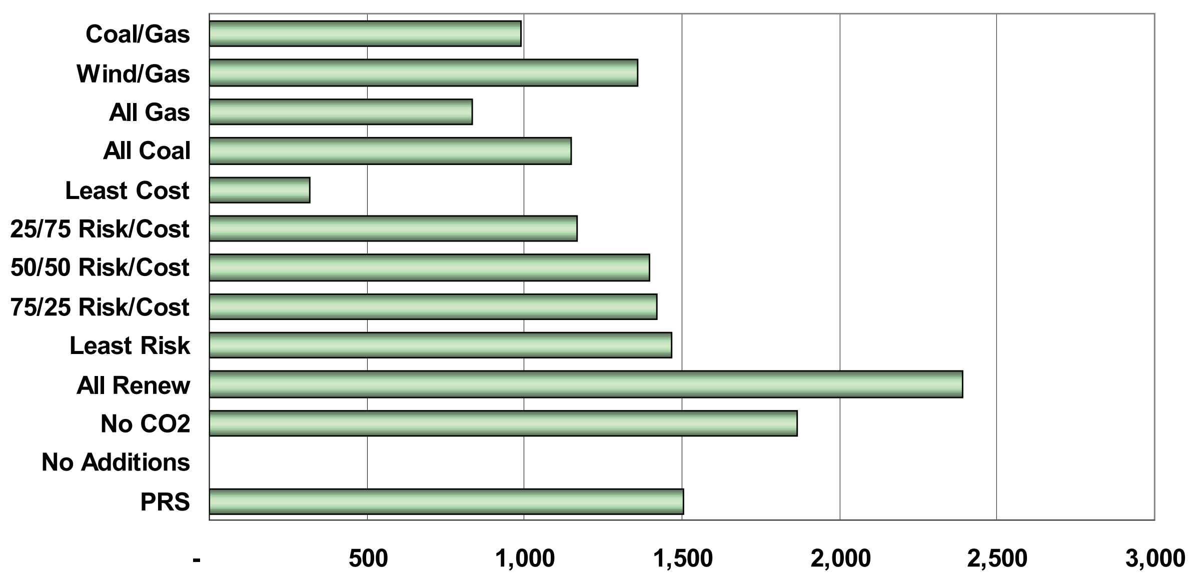


Figure 7.17: 2007-16 Portfolio Capital Cost ($millions)



higher conservation acquisition targets. More detailed information may be found in Section 3-*Conservation Initiatives.*

Capital Intensity

Resource strategies require differing levels of capital investment over the IRP timeframe. Lower-risk portfolios tend to be more capital intensive than higher-risk ones. The portfolios illustrate this in Figure 7.17. The capital requirement for the 0% Risk strategy, composed exclusively of simple-cycle combustion turbines, requires a comparatively modest $246 million investment over the first ten years of the IRP. The All Coal portfolio requires $1.1 billion. Capital requirements of the PRS—$1.5 billion in nominal dollars by 2016—will be significant for Avista. The Company might explore power purchase agreements with third parties that include purchase options as a way to manage the financial impacts of the overall acquisition strategy. Medium- and short-term market purchases are also expected to fill in small gaps between resource acquisition and load requirement timelines.

Rate Volatility

The Preferred Resource Strategy contains a mix of resources with low and stable fuel prices. The mix helps the Company's resource portfolio reduce year-on-year power supply expense rate volatility. Figure 7.18 compares the risk inherent in the various portfolio strategies developed for the 2005 IRP. The statistics presented are the 20-year average covariance of each portfolio strategy. Covariance is the quotient of the standard deviation divided by the mean. Higher covariance indicates a higher risk profile. For example, a 10 percent covariance means that two-thirds of all expected outcomes will fall between plus and minus 10 percent of the expected value. Covariance is a somewhat abstract concept, but useful for comparing portfolio strategy risk in a consistent manner over time. Figure 7.19 illustrates risk in calendar year 2016 by displaying the actual standard deviation of the incremental power supply expense. 2007 risk levels, adjusted to 2016 dollars, are provided to illustrate the risk-reduction benefits of the various resource acquisition strategies.

2007 risk under this measurement is constant, as the Company has not added any new resources. Notice that the Least Cost and No Additions strategies provide modest reductions from the risk of today's portfolio mix. This result is due to heavy reliance on the wholesale marketplace or SSCTs. The Preferred Resource Strategy reduces risk from more than $42 million (2016$) to $28 million.

The risk picture is consistent when looking at "tail distribution." Figure 7.20 illustrates the risks inherent in each portfolio at the extreme end of the distribution curve. The 95th percentile cost statistic explains that costs in any given portfolio are not expected to exceed the presented value except once in 20 years. The figure presents the net present value (NPV) of the difference between the average and the 95th percentile revenue requirement for each portfolio.

Figure 7.18: 2007-26 Portfolio Risk Comparison–Average Covariance (%)

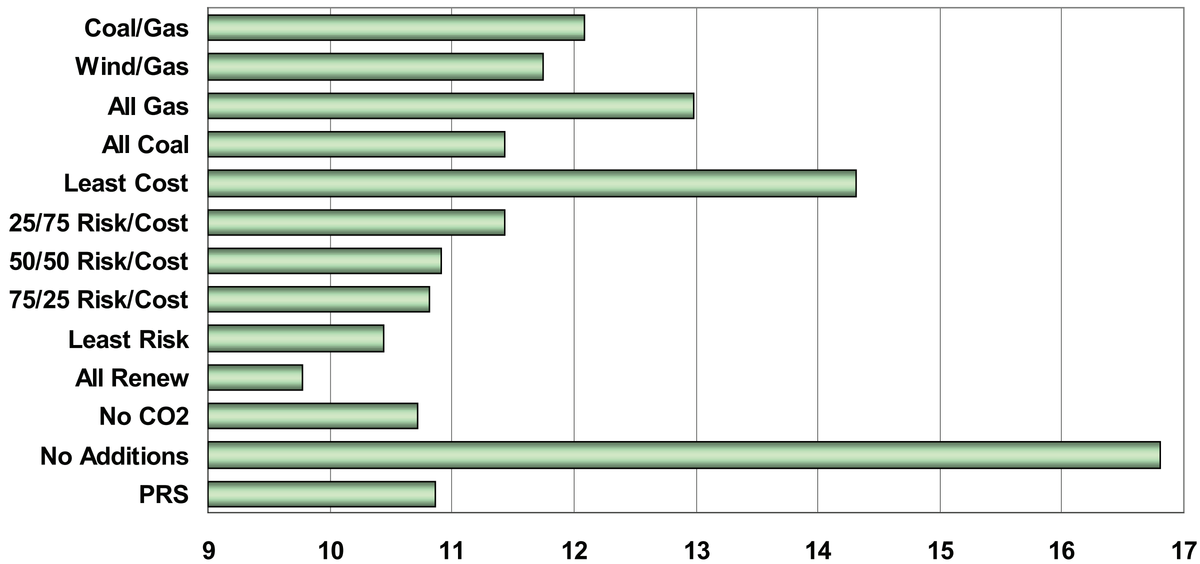
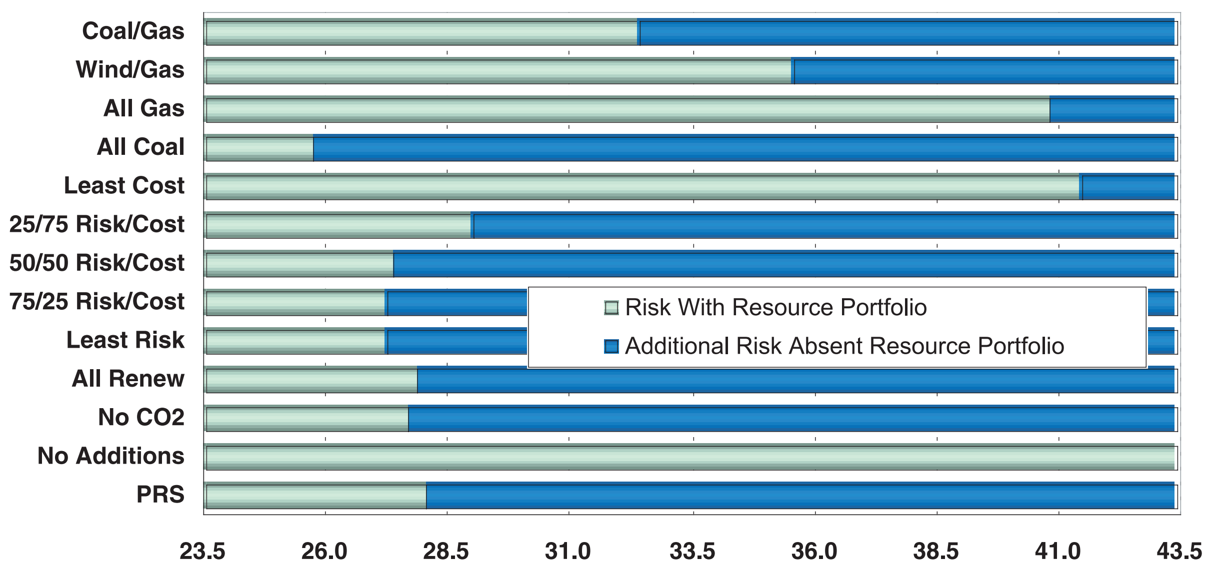


Figure 7.19: 2016 Portfolio Risk Comparison–Standard Deviation of Incremental Power Supply Expense ($millions)



Rate Impacts

The Preferred Resource Strategy forecasts rate impacts from incremental power supply expenses only (i.e., incremental variable O&M and fuel for new and existing resources, as well as capital and fixed O&M for new resources). Other cost increases are not included in these rate impact estimates. Figure 7.21 shows an average rate increase of approximately 4.4 percent between 2007 and 2016 due to new resource construction and increases in variable costs associated with existing generation assets. This relative level of increase is consistent across all resource portfolios that do not rely on gas-fired resources, on coal resources exclusively, or the marketplace entirely. Annual rate increases could be modestly less than 4.4 percent were the Company to choose one of these plans; however, the Company believes that the overall cost increases associated with the PRS are reasonable given its ability to greatly reduce risk and its renewables resource levels. While the No Additions case appears attractive in this view, and in Figures 7.22 through 7.24, its underlying assumptions are unrealistic. No new resources are constructed thereby leaving the portfolio exposed to wholesale marketplace volatility. Additionally, no new transmission costs are included to allow increasing market purchases. Please refer back to the No Additions scenario discussion presented earlier in this discussion.

Another way to look at the cost of the PRS is to consider annual power supply expense levels. Figure 7.22 contains a summary of "Incremental Power Supply Expense," defined for the 2005 IRP to be the summation of the variable O&M and fuel costs of existing portfolio resources and the total of capital, variable O&M, fuel, and fixed O&M costs of new resources.

Figure 7.20: 2007-16 Portfolio Risk Comparision-95th Percentile Difference From Mean Value (%)

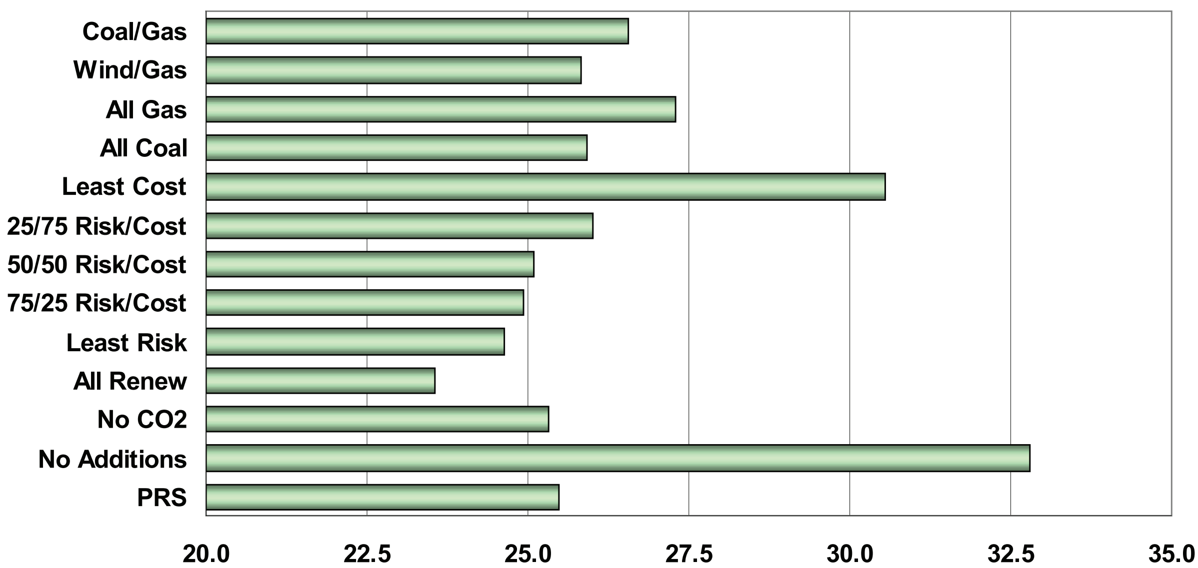


Figure 7.21: 2007-16 Average Incremental Power Supply Expense–Induced Rate Increases (%)

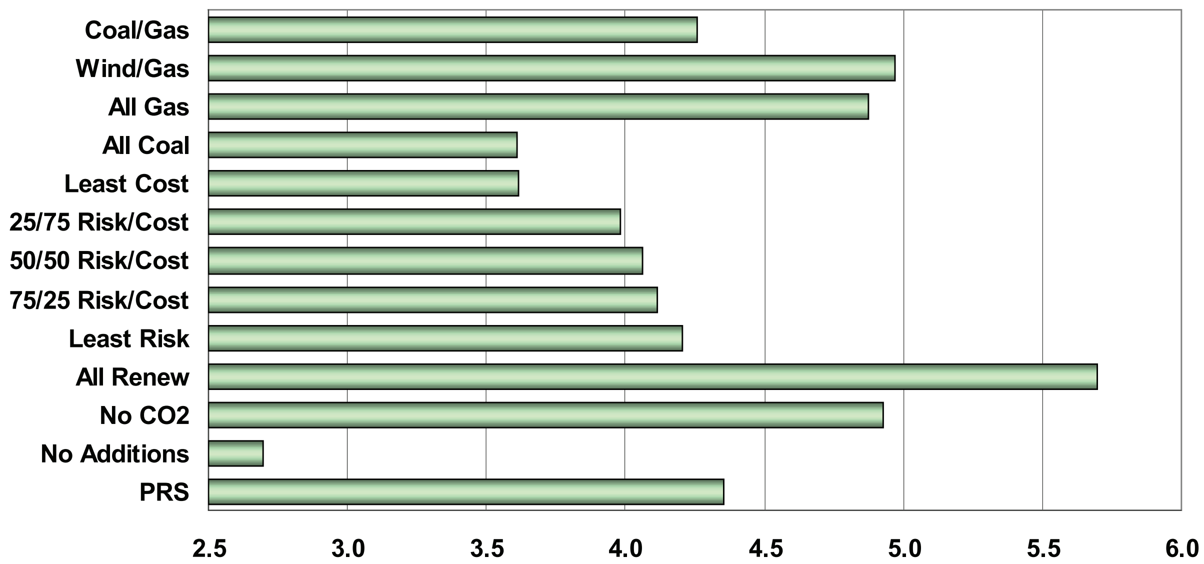


Figure 7.22: 2016 Incremental Power Supply Expense ($millions)

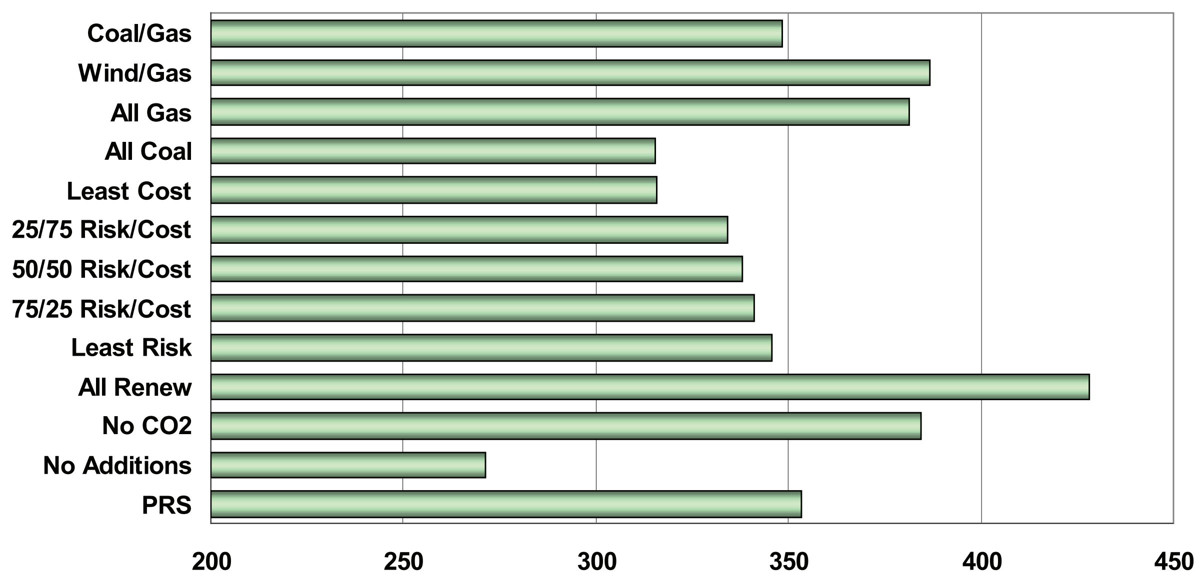


Figure 7.23: 2007-16 Incremental Power Supply Expense NPV ($millions)

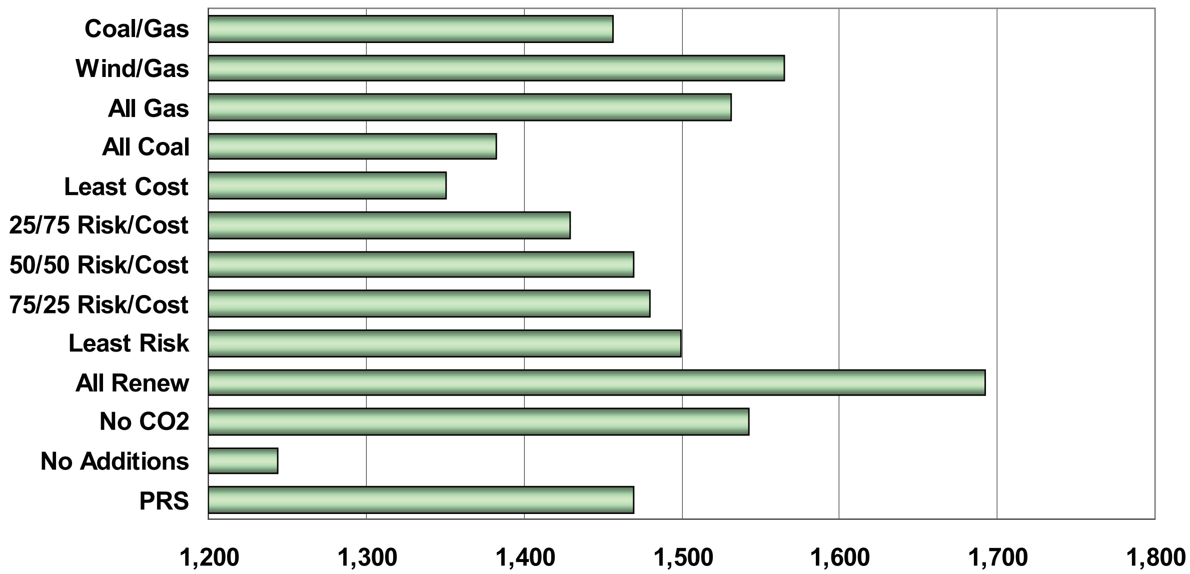
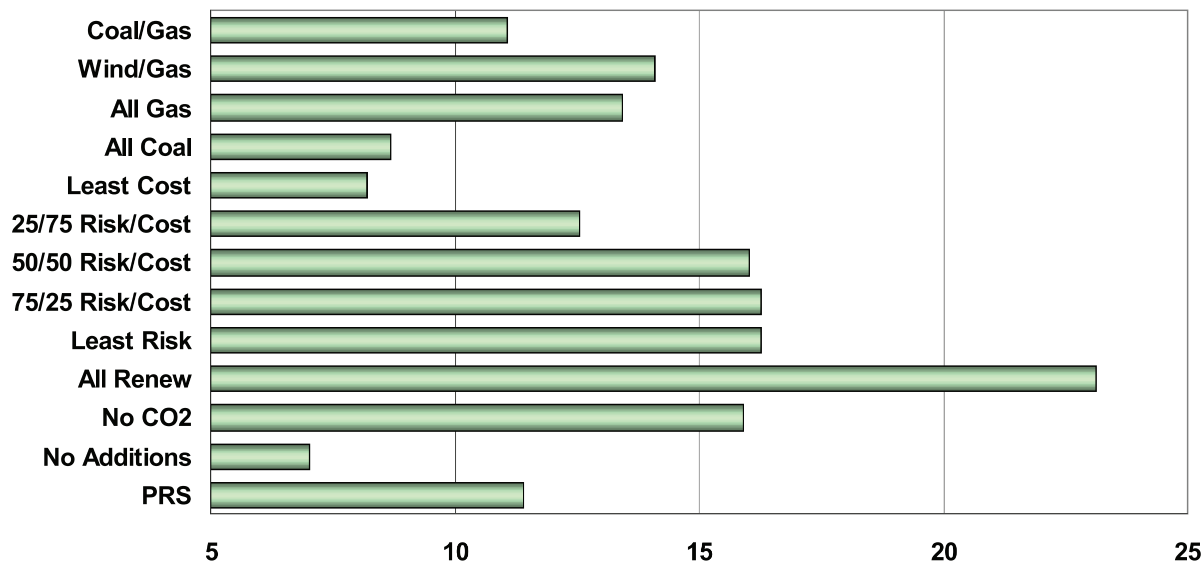


Figure 7.24: 2007-16 Maximum Single-Year Rate Increase (%)



The picture is similar for the NPV of incremental power supply expenses. Figure 7.23 details the statistics over the first ten years of the IRP.

Rate increases generally are not level over time; instead they reflect the inherent lumpiness of resource additions. The maximum rate impact in the PRS is 9.4 percent in 2012. See Figure 7.24. As with power supply expenses, those portfolios relying exclusively on the wholesale marketplace and natural gas- or coal-fired resources perform modestly better than the PRS under this measure. All other strategies that include renewables and modest levels of coal-fired generation have rate impacts that exceed the PRS.

7.6 Performance of PRS and 12 Resource Strategies In Market Structure Scenarios

The Preferred Resource Strategy was compared to 18 market structure scenarios detailed in Section 6- *Modeling Results.* Similar scenarios are grouped into categories.

Fuel Risk Scenarios

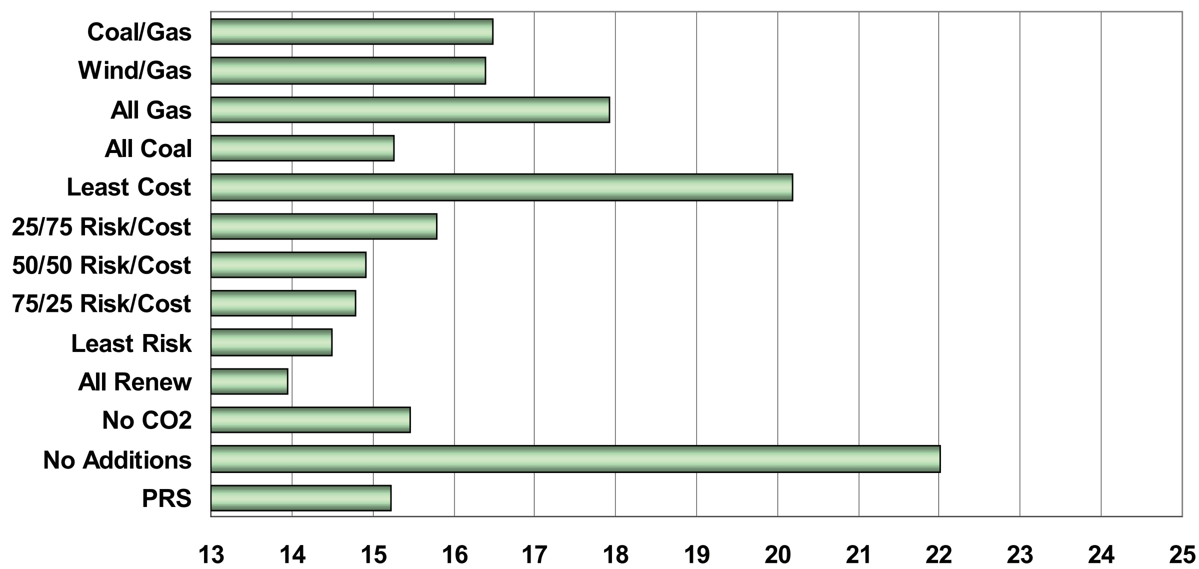
Volatile Natural Gas

The most interesting result of the Volatile Natural Gas market scenario was its lack of impact on the resource portfolios. Although the risk measures rose across the board, the relative position of the various portfolios did not change. See Figure 7.25.

Low Natural Gas Prices

When natural gas prices fall by 50 percent over the IRP timeframe, many portfolios relying on the natural

Figure 7.25: 2007-16 Power Supply Expense Average Covariance–Volatile Gas (%)



gas marketplace fare well when compared to the Preferred Resource Strategy and other portfolios without new gas generation. Incremental power supply expenses in the All Gas portfolio fall from $378 million under the Base Case in 2016 to $275 million, a change of just over $100 million. The PRS experiences a correlated reduction due to the gas resources already in the Company's portfolio, but the figure is much smaller: $38 million. Figure 7.26 compares the Base and Low Gas Cases.

High Natural Gas Prices

The High Natural Gas Prices market scenario increases natural gas prices from the Base Case by 50 percent. Instead of portfolios relying heavily on gas-fired generation performing well as in the Low Natural Gas Prices case, the opposite occurs. Incremental power supply expenses rise in the All Gas portfolio mix from $378 million in the Base Case in 2016 to $431 million, or by $53 million. The PRS rises by a more modest $30 million. Figure 7.27 provides a comparison across all of the illustrative portfolios.

Many of the portfolios saw higher maximum single year rate impacts under the High Gas scenario. For example, the No Additions case saw its maximum single-year increase rise by 5.3 percent, from 7.5 percent in the Base Case to just under 12.8 percent under the High Gas scenario. Many of the portfolios saw similar increases, including the PRS, which saw its maximum one-year rate increase rise by around four percent, from nine percent to 13 percent. Figure 7.28 displays the differences between the Base Case and the High Gas market scenarios.

Figure 7.26: 2016 Incremental Power Supply Expense–Low Gas ($millions)

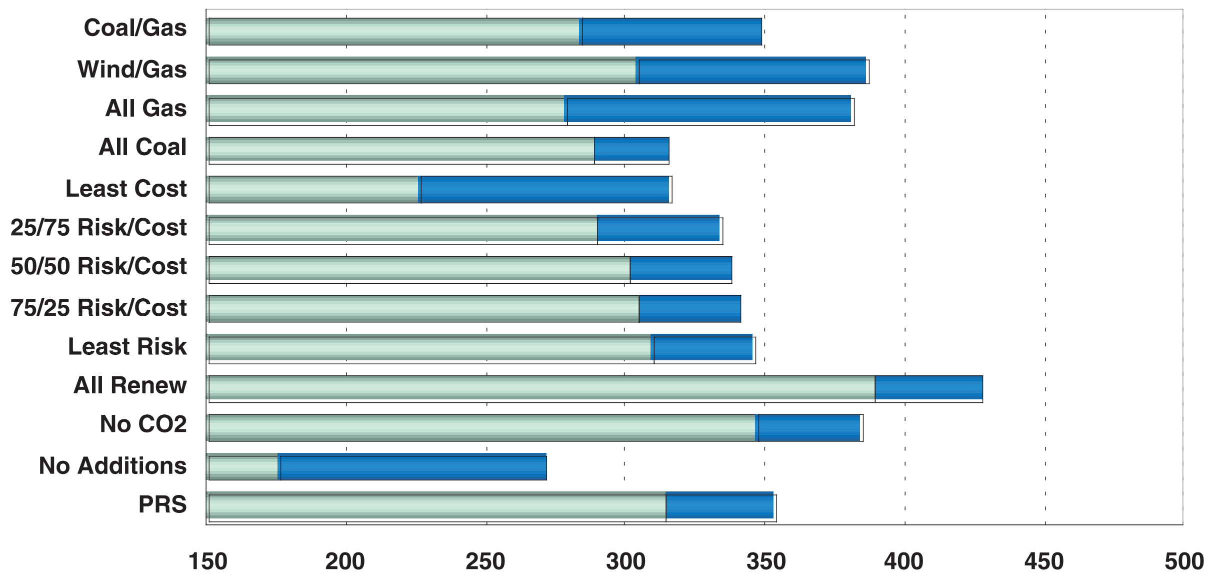


Figure 7.27: 2016 Incremental Power Supply Expense ($millions)

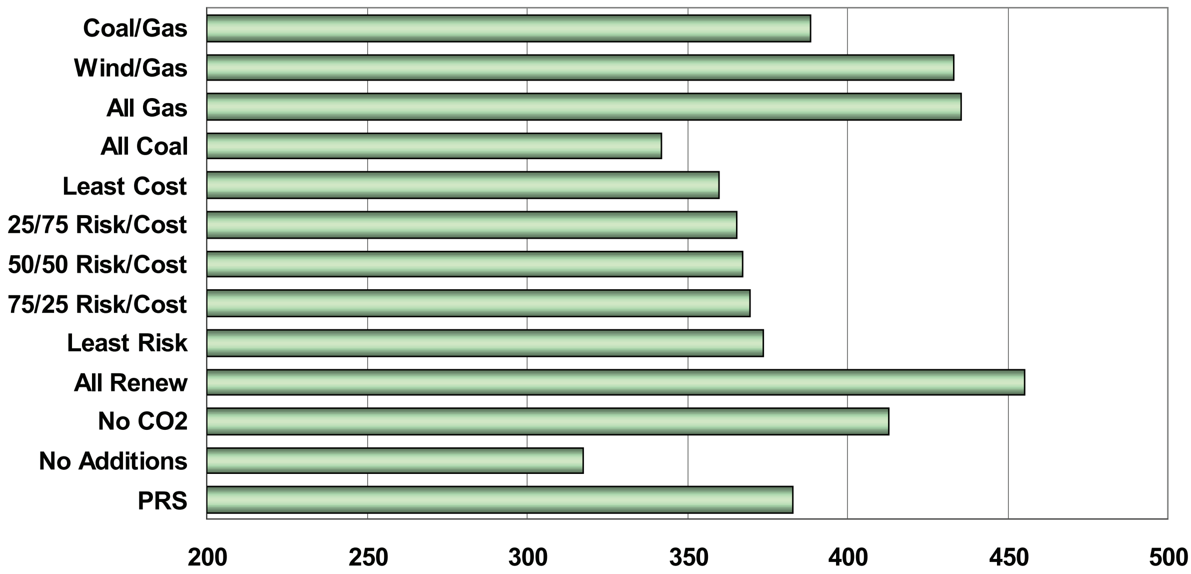
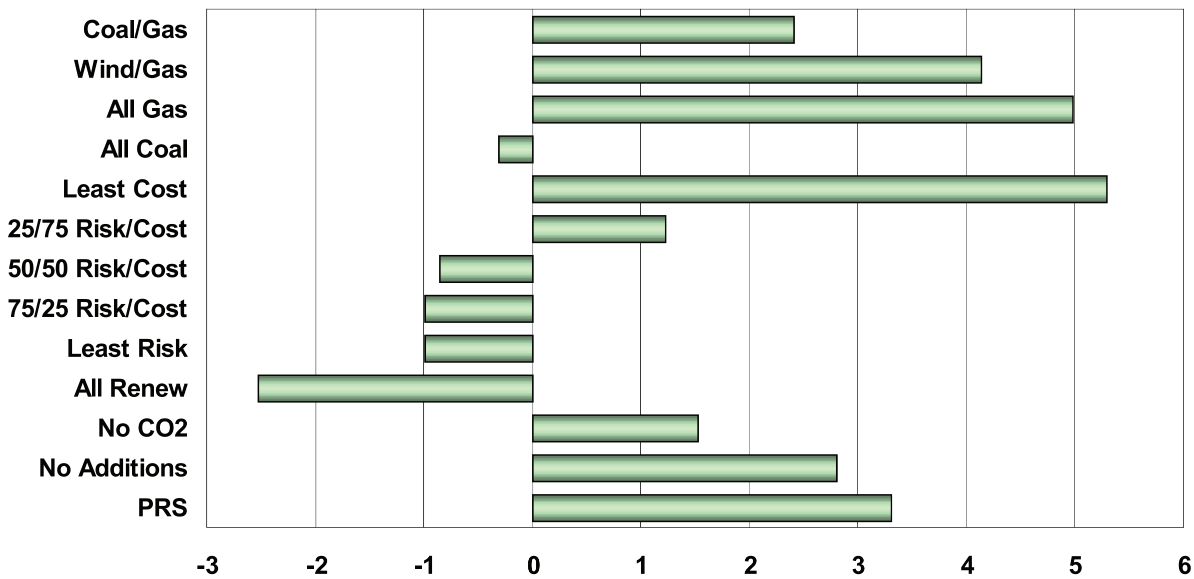


Figure 7.28: Maximum Annual Rate Change from Base Case (%)



Carbon Emission Scenarios

The carbon emission scenarios illustrate how the various resource mixes might perform were a carbon-limited future imposed. Carbon emission scenarios drive Company costs higher under any future resource strategy that is pursued. Avista's existing portfolio of resources contains both coal- and gas-fired resources that emit carbon into the atmosphere.

National Commission on Energy Policy Carbon Emissions

The National Commission on Energy Policy (NCEP) Carbon Emissions market future drives portfolio power supply expenses up under all portfolio options. Carbon emissions are forecast in this future to begin at $7 per ton in 2010, rising in a linear fashion to equal $15 per ton in 2026. Even the All Renewables and No CO_2 portfolios see increases under this case due to the Company's present ownership of carbon-emitting resources.

The Preferred Resource Strategy remains competitive under the NCEP Carbon Emissions case; however, the No CO_2 and All Renewables cases become more competitive with the PRS. Power supply expenses under the PRS are $41 million and $143 million higher under the NCEP Carbon Emissions case than under the Base Case. This equates to cost increases of 12 and 24 percent, respectively. Figure 7.29 provides a comparison of 2007-16 incremental power supply expenses under both the Base Case and the NCEP Carbon Emissions case.

SB 342 Carbon Emissions

The SB 342 Carbon Emissions market scenario assumes carbon emission rates that on a present value basis are three times the level of those assumed in the NCEP Carbon Emissions scenario. Prices start at $22 per ton in 2010, rising to $60 per ton by the end of the IRP timeframe. Incremental power supply expenses are significantly higher across the board in this market scenario, as shown in Figure 7.30. The All Renewables and No CO_2 portfolios fared better under this market scenario. Heavily coal-dependent resource strategies did less well.

Avista-Centric Scenarios

Avista-centric scenarios are scenarios that do not affect the marketplace but do affect the Company. A number of the Avista-centric scenarios did not affect resource acquisition. They were provided to illustrate certain future conditions (for example, the loss of the Noxon Rapids powerhouse for some period of time). The impacts of these scenarios are covered in Section 6– *Modeling Results*. The Avista-centric scenarios were used to help develop the Preferred Resource Strategy are discussed below.

Base Case Monte Carlo–No Production Tax Credits

Removing production tax credits drives the cost of most example resource portfolios higher because each of them contains a significant amount of wind and other renewables. Only the All Gas, All Coal, Coal/Gas, and No Additions cases are insulated. The PRS incremental power supply expenses, measured as NPV between 2007 and 2016, rises by 1.6 percent or $24 million, from $1.47 billion to $1.49

Figure 7.29: 2007-16 Incremental Power Supply Expense NPV ($millions)

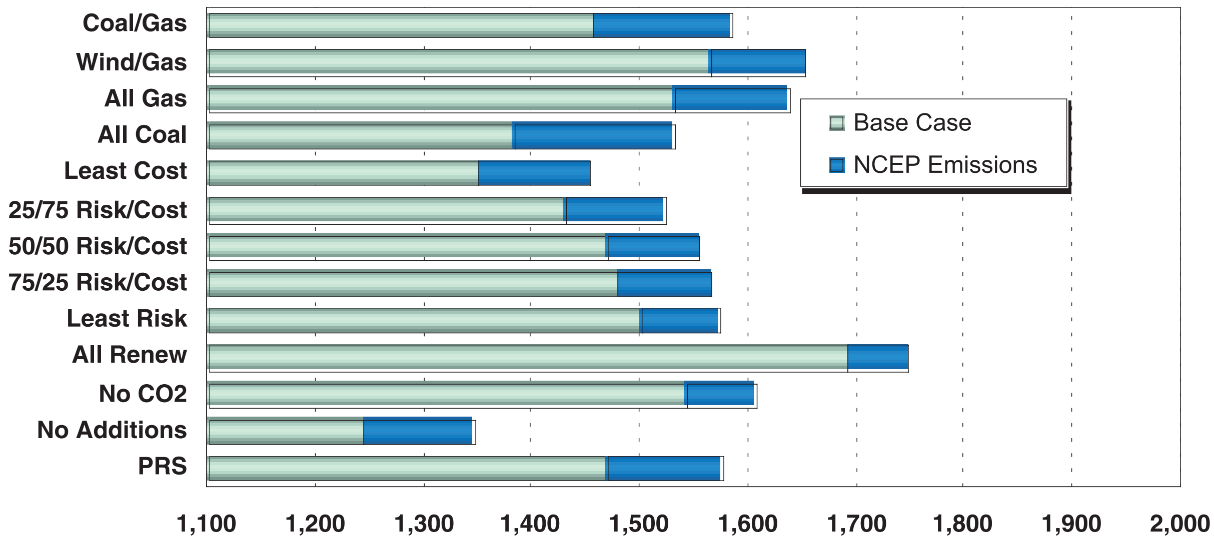
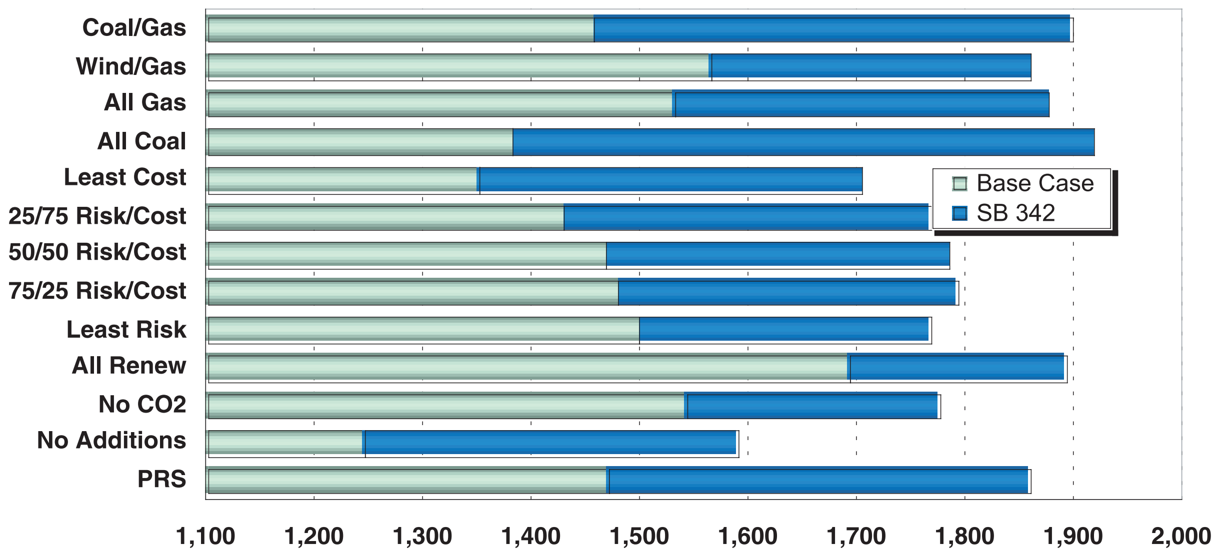


Figure 7.30: 2007-16 Incremental Power Supply Expense NPV ($millions)



billion without production tax credits. The magnitude over 20 years is about the same at $58 million, or 2 percent. See Figure 7.31.

Hydro Shift (90% Base Case Hydro) Scenario

The Hydro Shift scenario reduces hydro capability across the Western Interconnect by 10 percent. The relative results of the various resource portfolios were consistent with the Base Case results. Overall average rate increases were lower on a percentage basis due to average power supply expenses being higher initially. The higher initial cost is due to the loss of approximately 50 MW of Avista hydroelectric generation in this case. 2016 power supply expenses are shown to be approximately $15-$20 million higher in Figure 7.32.

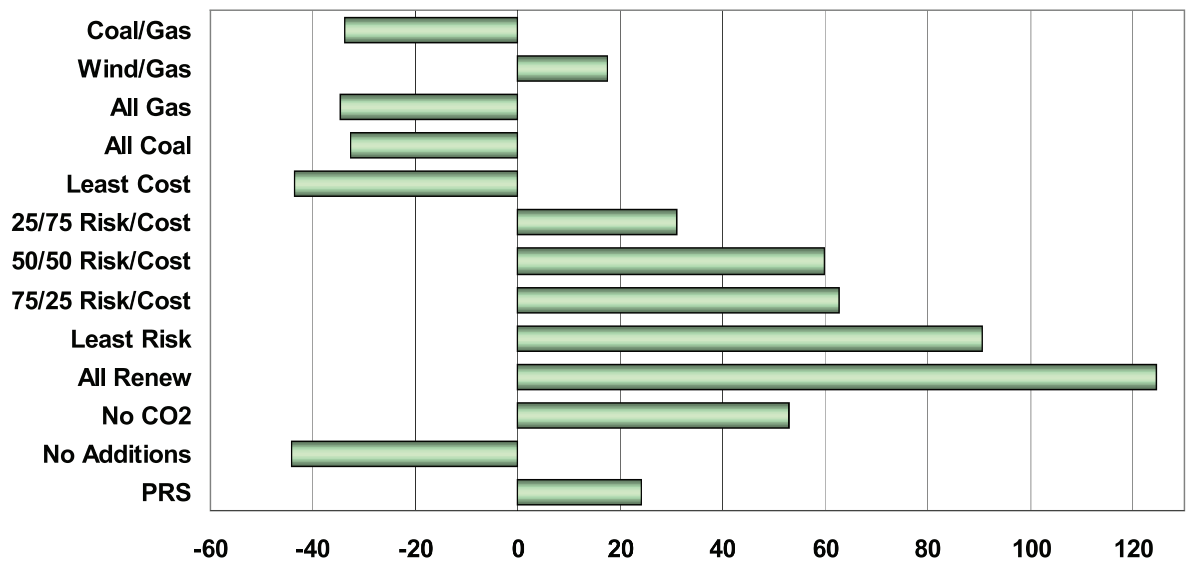
7.7 Acquisition of PRS Resources

The 2005 IRP envisions a diversified mix of new resources acquired beginning as early as 2007. Each of the five major categories of resource acquisition—conservation, plant upgrades, wind, biomass, and coal—is described below.

Conservation

The 2005 PRS relies on conservation to meet 69 aMW of future load growth by 2016 through reductions in existing customer usage. Analyses developed for the 2005 IRP found potential savings in all customer sectors. The Company expects to acquire this resource through both utility-sponsored programs and programs acquired on its behalf by third parties through an RFP process. An initial RFP for conservation resources is expected to follow Commission acknowledgement of the plan.

Figure 7.31: 2007-16 Power Supply Expense NPV Change ($millions)



Coal Acquisition

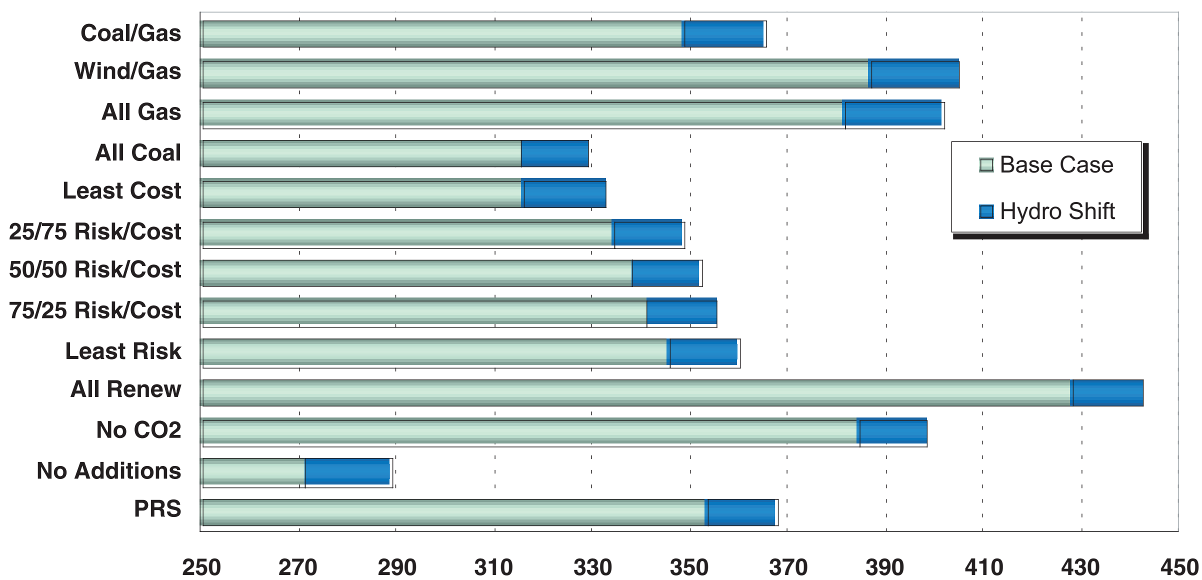
New coal is forecast to enter the Company's portfolio in the 2012-15 timeframe at an initial level of 250 MW. Similar to our assumptions around wind and renewable resources, we believe that bringing new coal-fired resources into our portfolio by 2012 will be a challenge. Lead times for green field coal development range between seven and ten years. Some time might be shaved off of this estimate were the Company to join with partners in a project already under way. The Company will have to remain flexible when acquiring this resource given the need to work with partners to gain necessary economies of scale.

The amount of coal ultimately might be modestly lower or higher than included in the PRS. In any event, the Company will continue to evaluate timelines for coal development and update its plans as necessary. The Company does not expect that its acquisition of coal-fired generation will be completed through a "traditional" RFP process that includes "turn-key" bid prices. Instead, the Company envisions a screening process that will include a "due diligence" process comparing key cost and feasibility factors between projects.

Wind Acquisition

Through study, the benefit of geographical diversity becomes evident. Having a single erected wind turbine brings greater variability day-to-day, hour-to-hour, and minute-to-minute, than erecting 100 wind turbines at a given site. Similarly, spreading wind turbine sites apart from one another geographically appears to lessen variability. The Company believes that taking modest ownership shares in multiple wind projects will benefit its customers by reducing the variability within its wind generation portfolio. This reduction in variability will lower integration

Figure 7.32: 2007-16 Incremental Power Supply Expense NPV ($millions)



costs, provide a higher level of dependable capacity, and help lower power supply expense volatility.

To acquire a 400 MW portfolio of diversified wind generation assets by 2016 the Company might begin acquiring this resource as early as 2007. The early start date reflects the Company's belief that acquiring 400 MW of wind from multiple projects over a five-year period beginning in 2010 may not be possible. While this acquisition schedule might bring new generation into the portfolio slightly ahead of new load requirements, the level should be modest and within an historical range of reasonable utility surplus. An early start to wind resource acquisition should assist the Company in the event where coal-fired generation acquisition slips beyond 2012. Acquisition of wind generation likely will occur both within and without an RFP process, based on Company experience with this resource.

Wind and Coal Link

Initial wind acquisition in the PRS is expected to occur in the Northwest and within Avista's service territory. Tier 1 Northwest wind and local wind projects are expected to require modest levels of new transmission. This assumption is in-line with the NPCC Fifth Power Plan. Later acquisitions of Tier 2 wind, and wind located outside the Northwest, likely will require significant new transmission investment.

Construction of new coal facilities outside of the Northwest will provide an excellent opportunity for wind resource development. The large transmission investments necessary to import coal into the Northwest likely can be leveraged to provide low incremental cost transmission capacity for wind projects. Absent construction for coal-fired generation, the Company believes that transmission costs would be too high to provide cost-effective transfer of the extra-regional 250 MW of wind generation planned in the PRS.

Biomass Acquisition

The performance of landfill gas and manure biomass projects indicates that renewables besides wind generation have the potential to meet future customer requirements. The Company is hopeful that it can acquire as much as 70 MW between the years 2010 and 2016; however, the potential for landfill gas and manure biomass could be limited. Manure biomass, while having a significant potential, has not been proven on a large commercial scale. Landfill gas also has limited potential given its fuel source. The Company will continue to monitor the potential for biomass resources.

7.8 Adjusted Energy and Capacity Positions

With the addition of new PRS resources, the Company ensures adequate resources for serving customers through the IRP timeframe. Table 7.4 details the energy forecast, and resources planned to meet it. The PRS envisions modest market purchases during the IRP timeframe; they are necessary to balance the level of annual load growth with the lumpiness of resource acquisition.

- Figure 7.33 details the Company's resource mix graphically over time.
- Figure 7.34 details Company resource mixes of energy in 2007, 2016 and 2026 graphically.
- Table 7.5 illustrates the Company's capacity forecast and resources forecast to meet it.
- Figure 7.35 provides capacity forecast and resources graphically.
- Figure 7.36 explains the Company's mix of capacity resources in 2007, 2016, and 2026.

Table 7.4: Loads & Resources Energy Forecast with PRS (aMW)

	2007	2008	2009	2010	2011	2016	2021	2026
Obligations								
System Retail Load[7]	1,125	1,160	1,197	1,232	1,268	1,424	1,566	1,725
90% Conf. Interval	193	193	193	189	188	184	148	148
Total Obligations	1,318	1,353	1,390	1,420	1,456	1,608	1,715	1,873
Existing Resources								
Hydro	510	510	506	487	483	464	447	444
Conservation	5	9	14	18	23	46	69	92
Net Contracts	234	234	234	235	131	104	57	57
Coal	182	193	181	181	193	181	181	193
Biomass	42	44	40	44	42	43	42	44
Gas Dispatch	282	268	282	272	282	268	282	272
Gas Peaking Units	145	145	145	141	145	142	146	132
Total Existing Resources	1,400	1,403	1,402	1,380	1,299	1,248	1,224	1,233
PRS Resources								
New Conservation	2	5	7	9	12	23	35	46
Plant Upgrades	7	11	23	36	36	36	36	36
Wind	0	0	0	23	63	122	162	188
Other Renewables	0	0	0	0	16	65	97	145
Coal	0	0	0	0	0	215	302	388
Market	0	0	0	0	125	25	0	25
Total PRS Resources	10	16	30	68	251	486	630	828
Net Position	92	66	42	28	94	126	139	188

7 Retail load is absent historical conservation acquisitions levels. Historical conservation levels are counted as a resource. This treatment has no impact on power generation acquisitions going forward

Figure 7.33: Preferred Resource Strategy—Energy (aMW)

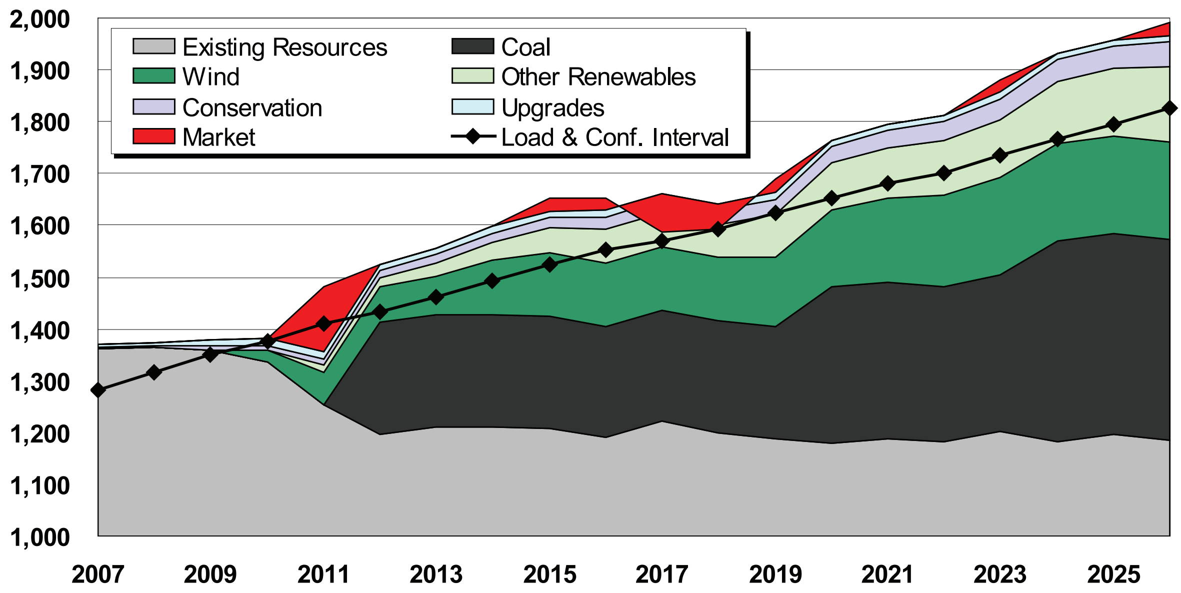


Figure 7.34: Company Resource Mixes (% of Energy) 2007, 2016, and 2026

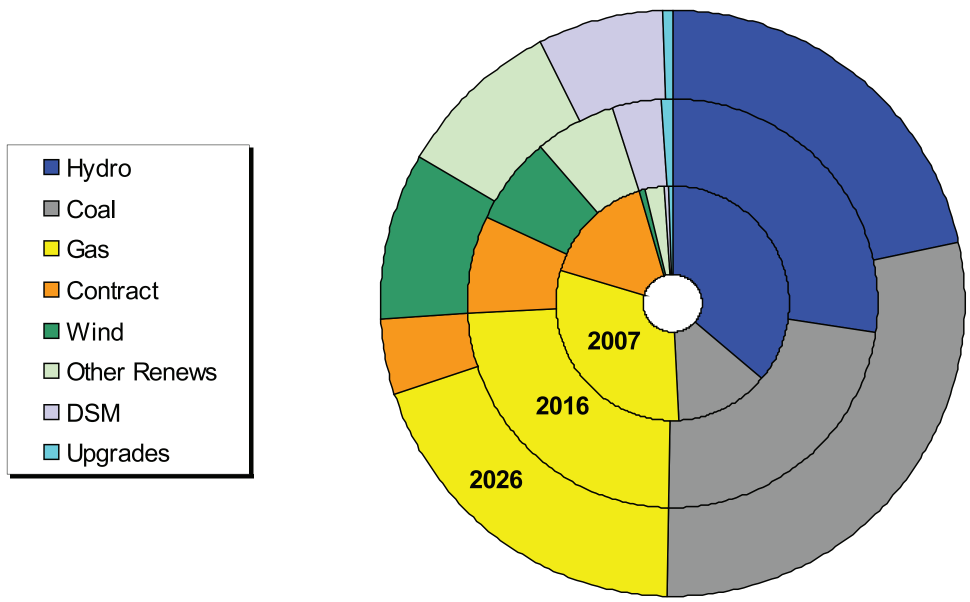


Table 7.5: Loads & Resources Capacity Forecast with PRS (MW)

	2007	2008	2009	2010	2011	2016	2021	2026
Obligations								
Retail Load	1,704	1,754	1,799	1,860	1,898	2,137	2,343	2,573
Operating Reserves	260	265	269	274	278	299	317	338
Total Obligations	1,964	2,019	2,068	2,134	2,176	2,436	2,660	2,911
Existing Resources								
Hydro	1,100	1,100	1,066	1,059	1,028	1,016	983	978
Conservation	5	9	14	18	23	46	69	92
Net Contracts	159	159	165	164	48	49	118	118
Coal	222	222	222	222	222	222	222	222
Biomass	50	50	50	50	50	50	50	50
Gas Dispatch	303	308	303	303	307	303	303	308
Gas Peaking Units	243	243	243	243	243	243	243	243
Total Existing Resources	2,082	2,090	2,062	2,059	1,920	1,928	1,988	2,010
PRS Resources								
New Conservation	2	5	7	9	12	23	35	46
Upgrades	20	34	41	52	52	52	52	52
Wind[8]	0	0	0	19	50	100	138	163
Other Renewables	0	0	0	0	20	80	120	180
Coal	0	0	0	0	0	250	350	450
Market	0	0	0	0	125	25	0	25
Total PRS Resources	22	39	48	80	259	530	694	916
Net Position	140	110	42	5	3	22	21	14
Planning Margin	23.1%	20.7%	16.4%	13.9%	13.4%	15.7%	14.7%	14.0%

8 Wind is presented as its contribution to meeting system peak. The IRP assumes a peak contribution for wind of 25 percent. For example, the 100 MW value shown in 2016 equals 400 MW (400 x 25% = 100 MW)

Figure 7.35: Preferred Resource Strategy—Capacity (MW)[9]

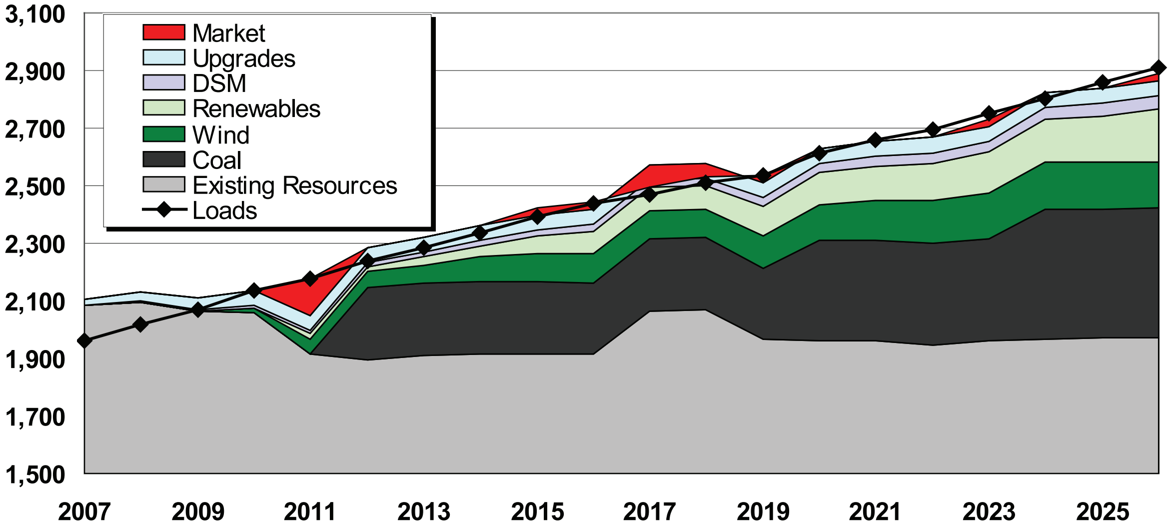
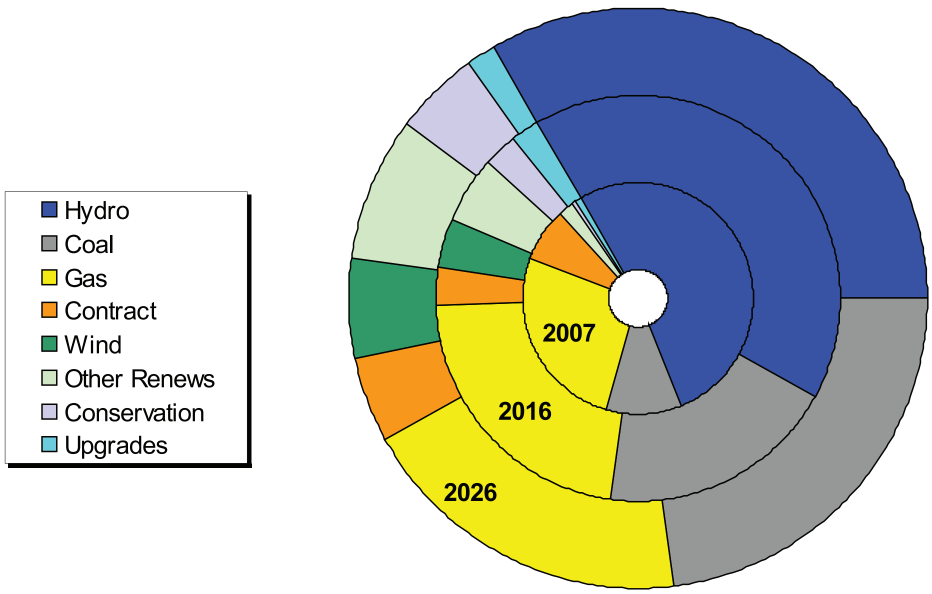


Figure 7.36: Company Resource Mixes (% of Capacity) 2007, 2016, and 2026[10]



9 *Ibid*

10 *Ibid*

8. ACTION ITEMS

This section reviews the 2003 IRP Action Plan and provides an update concerning how the Company addressed each item in the 2003 plan. The Action Plan for 2005 provides details concerning the research and actions the Company will take as it prepares the 2007 IRP.

8.1 Summary Report for 2003 Action Plan

In the 2003 IRP, the Company listed several activities to be accomplished during the two-year planning cycle. The items in the Action Plan included activities to further develop the Company's planning and resource acquisition processes. The Action Items for 2003 are listed below, followed by an explanation of the Company's progression for each item.

Public Process Action Items

Two action items were identified to support and develop the public process of integrated resource planning. The action items follow:

1. Propose changes to the WUTC on the IRP/RFP process that will provide improvements.
2. Continue to manage the free flow of information with TAC participants.

Avista is working with state regulators to improve the IRP/RFP process. In May 2005, the Company participated in a hearing to make editorial revisions to the Washington IRP and bidding rules and to request additional language to address long lead-time assets.

Avista continued to expand the Technical Advisory Committee process by increasing the number of meetings from three for the 2001 IRP to four for the 2003 IRP to seven for the 2005 IRP. The number of invitees has also increased from 53 in the 2003 IRP process to 73 invitees on the current list. The TAC meetings enhanced the Company's relationship with the academic community, resulting in several additional meetings regarding future collaboration with Washington State University's Program in Environmental Science and Regional Planning. Avista is extremely grateful for the core group of members who made a sincere effort to attend most of the TAC meetings and provided thoughtful and meaningful input. However, we would like to increase the overall number of stakeholders who actively attend TAC meetings in the future. The current TAC members will be queried about other people they would like to have invited to the process in the future and what changes we can make to the process to improve attendance.

Conservation Action Items

The 2003 IRP identified six areas in the DSM arena:

1. Evaluate the cost-effectiveness and resource potential of conservation voltage reduction (CVR) on the Company's system;
2. Acquire electric resources that are at least proportionate to the percentage of DSM revenues being expended;
3. Field a DSM portfolio that continues to be cost-effective on a societal and utility basis;
4. Prepare contingency plans for future emergency responses to unexpected fluctuations in wholesale electric markets;
5. Prepare for a reevaluation of continued participation in the Northwest Energy Efficiency Alliance upon expiration of the current contract period (expiring at the end of 2004);
6. Convene a TAC meeting in the fall of 2003 to discuss the various alternatives for integrating DSM into the 2005 IRP process.

Avista has instituted a CVR pilot project at the Francis & Cedar substation as part of a 17-site regional evaluation of several different approaches to voltage control. The project is funded and sponsored by the Northwest Energy Efficiency Alliance. Avista's project, along with other regional pilots, has been delayed due to unexpected system communication infrastructure issues. The NPCC was also unable to include CVR in its Fifth Power Plan for similar reasons.

The Company calculates cost-effectiveness as part of our ongoing Triple-E Reporting process. The portfolio has remained cost-effective since the last IRP and is projected to continue to be cost-effective into the future.

During 2001, the Company initiated an emergency business plan for conservation operations that resulted in the acquisition of over three times our goal. The contingency plan for this response has been re-initiated, on a much smaller scale, in our 2005 Drought Contingency Plan. This response is an example of our continuing ability to respond on a real-time basis to market conditions.

The Company has reevaluated its participation in the Northwest Energy Efficiency Alliance. Based on that evaluation, Avista signed funding contracts with the Alliance for an additional five-year period.

In October 2003 Avista convened a joint meeting of the IRP TAC and the Triple-E Board to discuss issues relating to the future integration of conservation into the IRP. Consensus achieved in that meeting led to the integration methodology used in the 2005 IRP.

Action Items for Supply Side Resource Options

There were seven action items for the Supply Side Resource Option area:

1. Pursue a new license for the Spokane River projects by filing a new license application by July 31, 2005;
2. Continue to evaluate the effects and costs of integrating wind generation into the Company's electrical system;

3. Consider and evaluate the potential to add coal facilities to the Company's mix of existing generating resources;
4. Determine the feasibility of entering into a medium-term firm power sale during the Company's surplus years;
5. Initiate a study to determine the optimal reserve margin for the Company, including the benefits of additional peaking capacity;
6. Continue to assess the cost-effectiveness of new resource additions;
7. Continue to work with Commission Staff on methods whereby the Company can acquire resources with development timelines beyond one or two years and increase the probability for full rate recovery.

The Company continues its pursuit of a new license for the Spokane River projects. In July 2005 Avista filed a draft license and is hopeful that the process will be completed before the existing license expires in July 2007.

Wind integration and cost studies performed since the 2003 IRP support the inclusion of 650 MW of wind generation into the Company's 2005 IRP Preferred Resource Strategy (PRS). This compares to 75 MW included in the 2003 IRP. The studies found that integration costs can be significant at high penetration levels; however, at lower levels costs can be more manageable. The Company also learned that geographical wind diversification can help reduce wind risk, both financially and operationally.

Coal-fired generation still makes a significant contribution to the PRS. The Company continues its work with partners to solve the locational challenges associated with this resource. During the past two years the Company has reviewed proposals for six coal sites.

The Company considered and ultimately rejected signing a medium-term firm power sale based on its resource position. Recent poor hydro conditions have limited our surplus generation potential.

The Company has performed various analyses in its effort to define an optimal reserve margin. The 2005 IRP looked at sustained peaking capability and concluded that our existing method of determining planning margins will continue for at least the next two years. Results of the sustained capacity exercise did lead to questions that could not be answered promptly. The 2005 Action Items include further study on this significant issue. Additionally, the Company continues to work in the various regional forums in this area.

Evaluating cost-effective new resource options is a continual process. The 2005 IRP includes significant additional work beyond the 2003 plan to assess the potential for various new resource alternatives. The Company will continue this exercise going forward.

The Company believes that risks associated with long lead-time assets may not be adequately addressed in present regulations. We are actively participating in regulatory proceedings that strive to clarify this issue further.

Action Items for Resource Management Issues

1. Analyze the uncertainty of decisions as the Company confronts risks and opportunities.
2. Continue to assess the electric marketplace and its effect on the Company.

The Action Items concerning resource management issues are intertwined with the IRP process. The 2005 IRP built on work prepared for the 2003 IRP, further enhancing the evaluation of market interactions across the Western Interconnect. The Efficient Frontier provides another method to evaluate the PRS and compare it to other resource portfolios.

8.2 Action Plan For 2005

The Company's Preferred Resource Strategy provides direction for long-term activities. The Company's 2005 Action Plan outlines activities that will be undertaken to support this strategy and improve the planning process over the next two years. Progress will be monitored and reported in Avista's 2007 Integrated Resource Plan. Each item was developed with the advice of the Technical Advisory Committee or by Company staff during the IRP process.

Renewable Energy and Emissions

1. Commission a study to assess wind potential in Avista's service territory;
2. Continue to monitor emissions legislation and its potential effects on markets and the Company;
3. Research clean coal technology and carbon sequestration;
4. Asses biomass potential within and outside Avista's service territory;
5. Continue to study various, including local sites.

Modeling Enhancements

1. Evaluate 70-year water record for inclusion in 2007 IRP studies.
2. Add more functionality to the Avista Linear Programming model (e.g., direct consideration of cash flow and rate impacts versus after-the-fact reviews).

Transmission Modeling and Research

1. 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;
2. Continue involvement in BPA transmission business practice processes and rate proceedings to minimize costs of integrating existing resources outside of the Company's service area;
3. 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;
4. Evaluate costs to integrate new resources across Avista's service territory and from regions outside of the Northwest.

Conservation

1. Review the potential for cost-effective load shifting programs using hourly market prices.
2. Complete the conservation control project currently underway as part of the Northwest Energy Efficiency Initiative for future evaluation as a potential conservation resource.

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