

Public Utility District No. 1 of Chelan County

Integrated Resource Plan

2008



2008 Integrated Resource Plan

August 2008

PUD No. 1 of Chelan County

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Acronyms

Glossary

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Chapter 1 – Executive Summary

Summary of Determinations

Based upon the analysis of the Integrated Resource Plan (IRP) over the 2008-2018 planning period, the Board of Commissioners of Chelan County PUD determines that:

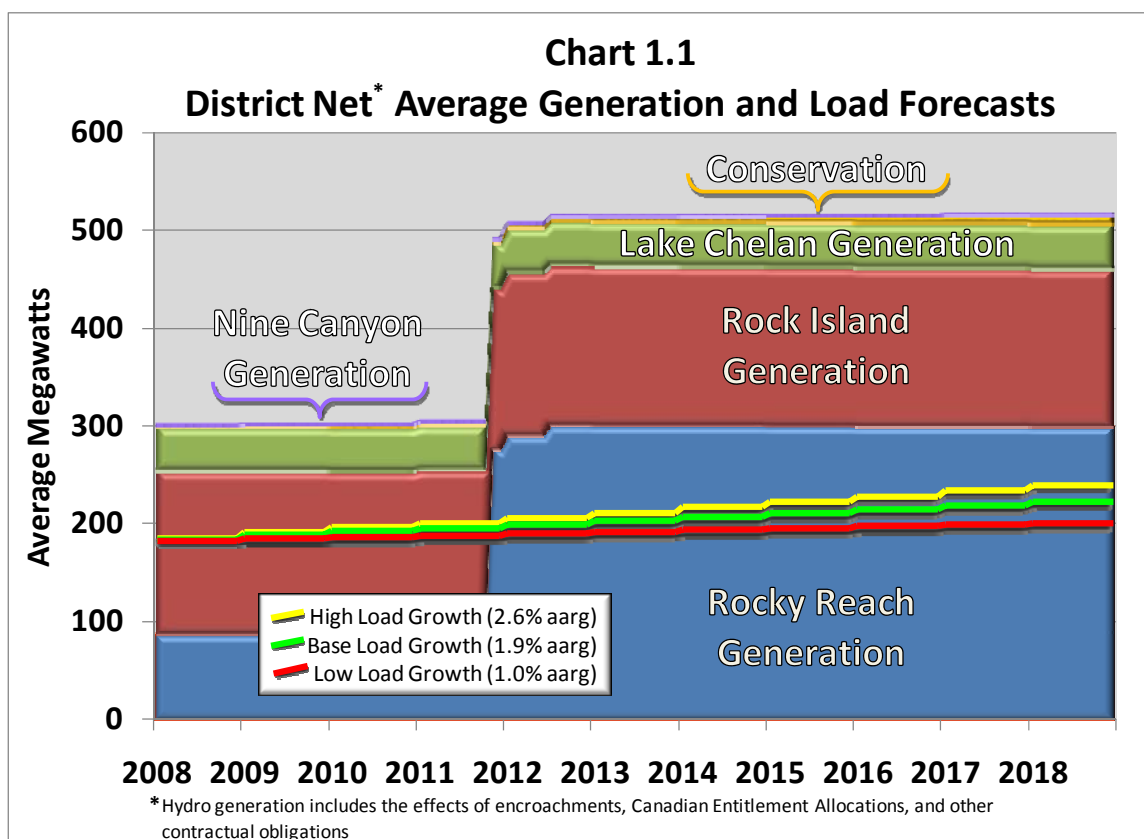
- The District retain its current mix of generating resources
- Build upon the initial conservation potential study performed for this IRP with more detailed analysis and prepare to meet the Washington State renewable portfolio standard (RPS) requirements
- Proceed to develop and analyze strategies for additional long and/or short-term power sales contracts

These determinations provide the platform for the District to continue to serve its customer/owners with

reliable, low-cost, clean energy resources for the foreseeable future. Chart 1.1 represents the District's mix of generating resources in relation to the low, base and high load growth forecasts. The resources are not shown in any particular order and do not represent the order in which resources are used to serve load.

IRP Overview

Chelan PUD has been analyzing its load/resource position since the District's inception. The 2008 IRP represents a formal long-term resource plan. This IRP has been prepared in order to comply with Washington State House Bill (HB) 1010 (Revised Code of Washington (RCW) 19.280) passed by the legislature in June, 2006. According to the statute, "it is the intent of the legislature to encourage the development of new safe, clean and reliable energy



resources to meet demand in Washington for affordable and reliable electricity. To achieve this end, the legislature finds it essential that electric utilities in Washington develop comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet their customers' electricity needs in both the short-term and the long-term." The enacted legislation requires investor-owned and consumer-owned utilities with more than 25,000 retail customers to produce a progress report every two years and a fully updated 10-year plan every four years.

To meet the requirements of RCW 19.280, the development of Chelan's 2008 IRP included the following:

- Gathering human resources from within and outside the District to perform specific IRP tasks
- Acquiring resource portfolio planning software and configuring it for modeling the District's resource portfolio and power contracts
- Preparing long-term forecasts of retail electric customer demand
- Developing a resource adequacy measure
- Obtaining long-term forecasts of market prices for wholesale power supplies
- Gathering information about Chelan PUD's existing generating resources
- Assessing conservation potential in Chelan PUD's service area
- Gathering costs, operating characteristics and other information about new power supply resources
- Gathering data on long-term interest rates and other financial assumptions
- Modeling the District's existing portfolio of resources, performing scenario analysis and stress tests to the existing portfolio, evaluating results against the key criteria of cost, risk, reliability and environmental impacts and communicating with customers and the public

- Responding to requests for additional information and analyses
- Recommending a long-term resource strategy and short-term plan to the Board for final approval of the 2008 IRP
- Submitting the final IRP Report to Washington State's Department of Community, Trade and Economic Development (CTED) by September 1, 2008

Regulatory & Statutory Requirements

In addition to the integrated resource planning requirements of RCW 19.280, the District is directly affected by other regulatory and legislative actions that relate to resource planning. The policies below were specifically evaluated during the IRP process.

Renewable Portfolio Standard (RPS)

Of great focus in this IRP is RCW 19.285, The Energy Independence Act. In November 2006, a ballot initiative known as I-937 which instituted a renewable portfolio standard (RPS) was passed by the voters of Washington. Under the initiative, utilities with a retail load of more than 25,000 customers are required to use eligible renewable resources (excluding most existing hydroelectric power) or acquire equivalent renewable energy credits (REC), or a combination of both, to meet 3% of retail load by January 1, 2012, 9% by January 1, 2016 and 15% by January 1, 2020. Under the initiative, the District can count recent efficiency gains at its existing hydropower projects toward meeting the RPS. Additionally, the District's entire share of the Nine Canyon Wind Project qualifies as an eligible renewable resource for meeting the requirement of the RPS. The initiative also requires that by January 1, 2010, utilities evaluate conservation resources and pursue all conservation that is cost-effective, reliable and feasible. This 2008 IRP includes an evaluation of both the renewable and conservation sections of I-937. Chelan's existing mix of generating resources complies with the District's understanding of the renewable

requirement of the RPS throughout the planning period. In addition, the District has begun analysis on conservation potential and will continue to evaluate, in greater detail, the potential for cost-effective, reliable and feasible conservation measures and build upon the history of conservation at the District.

Hydroelectric Licensing

The District's hydroelectric projects are subject to licensing by the Federal Energy Regulatory Commission (FERC). Licenses contain the conditions under which the licensee must comply. Numerous federal and state environmental laws and regulations, most notably the Endangered Species Act and the Clean Water Act, affect the mandatory conditions in the license. In 2006, FERC issued a new 50-year license for the Lake Chelan Project. The new license contains requirements for operating the hydro project that are expected to cost Chelan PUD \$65 million to \$70 million over the next 50 years. The current license for Rocky Reach expired in 2006. The Rocky Reach Project is currently operating under an annual license issued by the FERC until a new license is issued. The license for the Rock Island Project expires in 2028. The anticipated costs and expected operational impacts in the new licenses were incorporated into the resource portfolio modeled during the IRP process.

Resource Adequacy

Reliability Standards

The Energy Policy Act of 2005 (EPACT 2005) mandates the Electric Reliability Organization (ERO) to implement mandatory reliability standards for the bulk-power system under the purview of the FERC, "to conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America." The North American Electric Reliability Corporation (NERC), which was certified as the ERO in 2006, is in the process of developing a standard for resource adequacy assessments.

Pacific Northwest Resource Adequacy Forum

In April, 2008, the Northwest Power and Conservation Council (NWPCC or the Council) adopted a voluntary adequacy standard for the Northwest (Council document 2008-07) which was developed by the Pacific Northwest Resource Adequacy Forum. Although this is currently a voluntary adequacy standard, such standards are likely to become mandatory in the future. The standard is intended to be an early warning for the region should resource development fall dangerously short. It is not intended to be a resource planning target. The standard includes both energy and capacity metrics and targets. The regional standards feature a minimum threshold for energy of a zero average annual load/resource balance. The minimum capacity threshold is for a 23% planning reserve margin in the winter and a 24% planning reserve margin in the summer. The standard is meant to be a gauge used to assess whether the Northwest power supply is adequate in a physical sense, that is, in terms of "keeping the lights on." This effort ties directly to current Western Electricity Coordinating Council (WECC) efforts to establish a West-wide resource adequacy standard as well as the resource adequacy requirements from EPACT 2005 discussed previously. Analysis for the 2008 IRP addressed resource adequacy for the District.

Load Forecast

Three different load forecasts, a low, base and high, were developed to reflect uncertainty about future power consumption for Chelan's retail load. Demographic trends and economic conditions were the primary drivers used to arrive at the forecasted retail electricity sales by sector. In addition, the resulting forecasts are an integration of economic evaluations and inputs from the District's own customer service planning areas.

The growth percentages from the sum of the sector energy sales forecasts, with system losses added, were applied to the 2007 weather-normalized load to arrive at total projected megawatt-hours through the planning period. **The low, base and high average**

annual composite energy sales forecast growth rates, including system losses, otherwise known as the forecasted annual energy load growth rates, are 1.0%, 1.9% and 2.6%, respectively. Historical load growth at the District was approximately 1.5% for the 10-year period from 1998-2007 as well as the 17-year period from 1990-2007.

Expected future conservation measures have not been included in the District's load forecast. Future cost-effective conservation is considered as a resource for purposes of this IRP, so it can be evaluated on the same basis as other resources.

Chelan's Resource Portfolio

The District owns three hydroelectric projects and is a participant in the Nine Canyon Wind Project, located in Benton County, Washington. Two of Chelan's hydro projects, Rocky Reach and Rock Island, are located on the Columbia River. The District's third hydro project, Lake Chelan, serves a dual purpose of generating power and regulating the level of 50-mile-long Lake Chelan. All three projects are located in Chelan County, and together, they have capacity to generate nearly 2,000 megawatts of power. Currently, 30.2% of the electricity is available to benefit Chelan PUD retail customers and meet local electric load. The balance is sold to the following long-term wholesale power purchasers throughout the Pacific Northwest: Alcoa, Puget Sound Energy, Avista Corp., PacifiCorp, Douglas County PUD and Portland General Electric. The District continues to invest in modernization and relicensing at the projects to ensure reliable, locally controlled operation of resources for future generations.

Hydropower has many characteristics that make it highly desirable. It is free of the emissions associated with fossil fuel-fired generating resources. Operational flexibility allows hydropower to quickly follow load changes and provide reserves to the electric grid in a timely manner, which contributes to overall system reliability. In addition, hydropower provides backup for intermittent resources such as wind. The District avoids transmission availability issues, in relation to serving retail load, by using its own hydropower generation, which is located in

Chelan County, near the District's retail load. The amount of hydropower the District is able to generate depends on water availability, which is variable and hinges on a number of factors, primarily snow pack in the mountains upstream of its hydroelectric facilities, precipitation in its watershed and resulting stream flow conditions. Wind energy is also variable and somewhat seasonal in nature.

Renewables

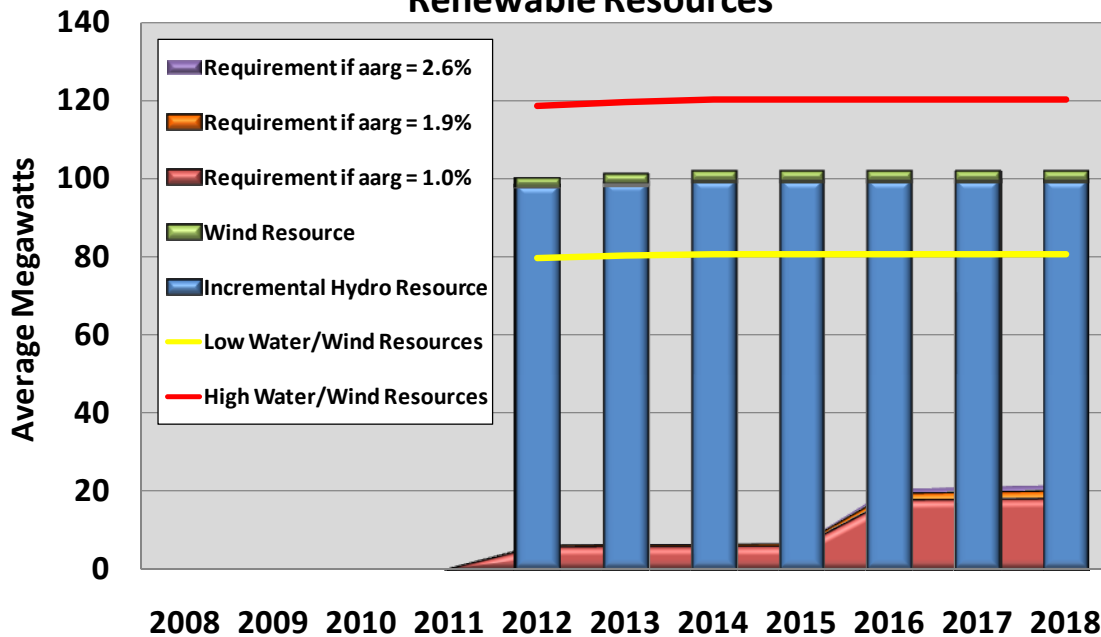
The District must comply with Washington State RPS renewable requirements beginning in 2012. The renewable energy section of the initiative requires utilities to serve percentages of retail load, which increase over time, with eligible renewable energy, RECS or a combination of both. Most hydropower is not an eligible renewable resource under the Washington RPS statute, though certain efficiency gains resulting in incremental hydropower are eligible.

The District plans on meeting these renewable requirements with incremental hydropower and wind power from the Nine Canyon Wind Project. Incremental hydropower is derived from efficiency gains at the District's existing hydropower projects resulting from equipment and operational upgrades, or more power generation with the same amount of water.

The District has made significant investments in equipment upgrades such as generator and turbine rehabilitations, new transformers and trash rack installations. In addition, the District has installed systems designed to optimize generation which have resulted in operational efficiency gains. Only those equipment and operational improvements placed in-service after March 31, 1999 qualify under Washington State RPS rules.

The District will be required to have eligible renewable resources beginning in 2012 to comply with the RPS. Based upon the current base load forecast, the amount of renewable resources required will be approximately 6 aMW in 2012-2015 and approximately 18 aMW in 2016-2019. Chart 1.2 shows the amount of District eligible renewable resources and the potential target requirements based on the three load forecasts. The quantity of the

Chart 1.2
Washington RPS Requirement and District's Eligible Renewable Resources



District's eligible renewable resources is subject to variability given the underlying uncertainty in hydro and wind production. Chart 1.2 does not necessarily represent the order in which eligible resources will be used to meet the RPS requirements.

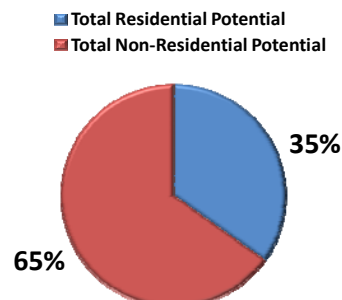
Conservation

By 2010, the District must identify achievable cost-effective conservation potential through 2019 and establish a biennial acquisition target for the conservation potential to comply with the conservation portion of the Washington State RPS.

EES Consulting (EESC) was retained by the District to develop the Conservation Potential Study (CPS). EESC evaluated the amount of conservation potential for Chelan County and provided initial conservation target estimates consistent with RCW 19.285, The Energy Independence Act. Currently employed programs and technologies and new, available conservation programs that are specific to Chelan's service area were included in the analyses of demand response.

A target of 0.82 aMW/year for conservation savings, which is more than a 100% increase over historical levels, is recommended by District Conservation and Customer Service staff, with additional detailed work in conservation planning to take place prior to 2010. This "Conservation Foundation" level of savings is achieved by increasing the District's current conservation programs to include all cost-effective measures as defined by the Council's Total Resource Cost (TRC) test. Measures that pass the TRC test have benefit/cost ratios greater than or equal to 1. Chart 1.3 compares the residential and non-residential potential for how the "Conservation Foundation" target may be achieved.

Chart 1.3
Conservation Foundation Potential



Even though the District may pursue conservation efforts that are projected to lead to achievements consistent with the Council's target, actual achievability rates may fall short. In the Conservation Foundation scenario, achievability rates for residential and commercial measures are 65% of the full achievability rates defined in the Fifth Power Plan. These lower achievability rates are due to changes in conservation potential due to differences between the Fifth and Sixth Power Plans, primarily new codes and standards, and lower customer participation rates attributable to the District's low retail electric rates.

Portfolio Analysis

The District used a long-term resource portfolio/risk analysis model for the electric utility industry to perform the portfolio analysis for this IRP. The model quantifies the risk and correlations between key variables – such as hydro availability, conservation, load and market prices – using built-in Monte Carlo simulation and scenario analyses.

The District focused on three major categories of risk which include uncertainties related to:

- Electricity usage by the utility's retail electric customers (loads)
- Stream flows that affect the availability of hydroelectric generation (including amount and timing)
- Cost of production at the District's existing hydroelectric facilities

Both short-term and long-term risks were addressed, as follows:

- Short-term uncertainties (e.g., weather-induced fluctuations in retail loads) were represented by probability distributions
- Long-term uncertainties (e.g., trends in the overall level of hydropower costs) were represented by scenario forecasts

Chelan PUD identified reliability, cost, risk and environmental impacts as the four criteria to be used in the evaluation of its resource portfolio. These criteria represent long-held philosophies of the

District and the measures for each are described below.

- Reliability – a positive load/resource balance on an average annual basis
- Cost – 11-year net present value (NPV) of the net portfolio cost for the District's resource portfolio scenarios
- Risk – the variability in the NPV of the net portfolio cost
- Environmental impacts – qualitative analysis of air emissions

For this IRP, the District's existing mix of supply-side resources was stressed with the differing load forecasts, varying hydroelectric costs and an increased ramp rate for certain conservation measures. The differences between the scenarios are as follows:

Scenario 1 – Base Case

- Base Load Growth (1.9% average annual rate of growth)
- Base Hydro Costs (O&M, Capital)
- Straight line ramp on both retrofit and lost opportunity conservation measures

Scenario 2 - Low Bookend

- Low Load Growth (1.0% average annual rate of growth)
- Low Hydro Costs (Base Hydro costs minus 5%)
- Straight line ramp on both retrofit and lost opportunity conservation measures

Scenario 3 – High Bookend

- High Load Growth (2.6% average annual rate of growth)
- High Hydro Costs (Base Hydro costs plus 20%)
- Accelerated ramp on retrofit conservation measures and straight line ramp on lost opportunity conservation measures

Modeling results indicate that Chelan is expected to be able to serve its retail load throughout the planning

period without any new resource additions and is also expected to be able to meet Washington State RPS renewable requirements through that time frame. For these reasons, and the ability of the existing resource portfolio to perform well against the evaluation criteria because it is comprised primarily of reliable, low-cost hydroelectric resources, no new supply-side resources were modeled. However, for demand-side resources, an increase is recommended with a starting point of 0.82 aMW/year for conservation savings. Conservation has the effect of reducing the amount of renewable generation required under Washington's RPS because that requirement is based on a percentage of retail load. Because the District does not anticipate the need to acquire additional renewable resources through the planning period to meet the RPS, conservation primarily has the effect of increasing the amount of power sold into the wholesale market and further decreasing net portfolio costs. Costs relating to increasing the ramp rate for conservation savings were not specifically evaluated nor were specific program types developed. The District will be examining the cost-effectiveness and feasibility of specific measures in greater detail over the next year or two in order to establish a conservation target for the Washington State RPS and implement steps to reach that target.

The District is facing expiring long-term power sales contracts during the planning period. New long-term

sales contracts will begin when the current contracts expire. No additional potential strategies for short-term or long-term power contracts were modeled or recommended as a result of this IRP. Strategies for additional power sales contracts will be analyzed in a separate District process after completion of this IRP.

Chelan continues to stay informed of resource options and will continue to evaluate its resource portfolio to ensure that the overall portfolio continues to perform well against the evaluation criteria and that regulatory requirements, specifically the RPS, are satisfied.

Chelan's existing resource portfolio is not without risk, but it performs very well when compared against the evaluation criteria. The District has adequate capacity and energy to meet its retail customers' load through the planning period thus providing for service reliability. In addition, the District has resources in excess of its retail customers' load that it can sell into the wholesale market and because the resource portfolio is comprised of primarily low-cost hydroelectric resources, the net portfolio cost to the District is much lower than for many other utilities. Table 1.1 tabulates the 11-year net portfolio cost for the District's existing portfolio for all three scenarios and illustrates the variability around the expected net portfolio cost for each scenario.

Table 1.1 Net Portfolio Cost Uncertainty Probabilistic Outcomes (\$ Millions)					
Scenarios	5% level of the Confidence Interval	Difference between Expected and 5% level of the Confidence Interval	Expected	Difference between Expected and 95% level of the Confidence Interval	95% level of the Confidence Interval
Base Case	-\$27.2	\$148.3	\$121.1	\$137.4	\$258.5
Low Bookend	-\$103.3	\$153.2	\$49.9	\$137.5	\$187.4
High Bookend	\$137.4	\$145.1	\$282.5	\$139.7	\$422.2

To assess this variability or risk, the District uses the 90% confidence interval, or the range of iterations that fall within the 5% and 95% tails of the probability distributions from the Monte Carlo simulations for each portfolio scenario. Several of the key factors affecting the District's portfolio are variable and it is the exposure to these variables where the District experiences the highest risk. Hydroelectric production costs are the primary variable creating the difference in net portfolio cost between the scenarios. The volatility around the expected net power cost for each scenario is driven by underlying short-term uncertainties.

Hydroelectric generation – subject to wide swings from year to year depending upon snow pack levels, precipitation and other factors – is the primary variable creating the uncertainty (range of possible outcomes) within each scenario. This, in turn, creates great variability in the amount of energy the District has to serve load and ultimately, the amount of surplus energy available to sell into the wholesale market. Wholesale sales have a tremendous effect on reducing the net portfolio cost to the District.

Future uncertainties surrounding operational capability of the District's resources and the impacts of environmental legislation continue to challenge the District's planning efforts. Although the District's hydropower and wind generation do not produce any emissions, it is expected that any climate change legislation or other developments regarding climate change will affect the energy markets in which the District participates. The District currently participates in the voluntary carbon and REC markets and will be carefully monitoring any new developments in the climate change arena.

Short Term Plan

Over the next two to four years, the District has objectives related to conservation resources and resource planning as outlined below.

Conservation Resources

- Continue to develop conservation potential by refining demographic data for customer classes
- Study available energy efficiency measures and programs
- Evaluate conservation potential using automated metering technologies and rate design
- Look for economies of scale in conservation efforts with other utilities
- Develop a system for tracking goals and conservation achievements
- Produce a business plan for conservation, including conservation targets to meet Washington State RPS
- Implement cost-effective conservation programs, which comply with requirements of the Washington State RPS

Resource Planning

- Use 2008 IRP as a foundation to start internal evaluations of long and short-term contracts in the post 2011/2012 period when current long-term contracts expire
- Track the development of the NWPCC's Sixth Power Plan including:
 - Conservation potential
 - Wholesale electric market price forecasts
 - Potential new regional resources and costs
 - Resource adequacy
- Continue to monitor the development of the Council's resource adequacy standards and utility-specific guidance that is developed and plan for changes in standards

- Continue to track climate change and other environmental legislation, including cap and trade programs, and how they may impact the District's resource portfolio
- Continue to update incremental hydro generation estimates in preparation for complying with Washington State RPS requirements beginning in 2012
- Implement IRP model upgrades as they become available
- Research potential methods of performing IRP analyses in more granular time periods
- Continue to revise and update model inputs as new information becomes available
- Research and evaluate the potential effects that plug-in hybrid and/or electric cars may impose on the District's retail load

Chapter 2 – Introduction

“Prediction is very difficult, especially about the future.” – Niels Bohr (Nobel Prize winner in physics)

This chapter provides a brief overview of Chelan County PUD as well as some background behind the IRP, the process for developing it and a summary of the remainder of the document.

Chelan PUD Overview

Chelan County Public Utility District was created by a vote of the people of Chelan County in 1936. It delivered its first electric power to a small group of rural customers 11 years later. Today, the District provides electricity to more than 41,000 retail customers, serving all of Chelan County and delivers clean, affordable power to major power purchasers through long-term contracts serving 7 million homes and businesses in the Northwest.

Chelan PUD’s portfolio of generating power resources is comprised of approximately 99% hydroelectricity and 1% wind. The utility owns and operates two hydroelectric projects on the Columbia River – Rocky Reach and Rock Island – as well as the Lake Chelan project. In an average year, the total power production of the three projects amounts to over 9 million megawatt hours of power, enough to run a city of 900,000 people. In addition, the District is a participant in the Nine Canyon Wind Project located in Kennewick, Washington. Chelan PUD has an 8.3% share of the total Nine Canyon project output. In an average year, the District’s share is approximately 20,000 MWh of wind power. In order to serve its local customers, Chelan PUD operates a local distribution system of 1,950 miles of power lines.

The District is directed by a five-member Board of Commissioners (the Board) elected by the voters of Chelan County. These Commissioners oversee a utility system that now includes local water, wastewater and wholesale fiber-optic services in addition to electric service.

IRP Overview

The 2008 IRP represents a formal long-term resource plan. The IRP has been prepared in order to comply with Washington State House Bill (HB) 1010 (RCW 19.280) passed by the legislature in June, 2006.

According to the bill, “it is the intent of the legislature to encourage the development of new safe, clean and reliable energy resources to meet demand in Washington for affordable and reliable electricity. To achieve this end, the legislature finds it essential that electric utilities in Washington develop comprehensive resource plans that explain the mix of generation and demand-side resources they plan to use to meet their customers’ electricity needs in both the short-term and the long-term.” To a certain extent, HB 1010 codifies standard IRP practices that a number of investor-owned utilities have already implemented, including analytical processes and public involvement opportunities. The enacted legislation requires investor-owned and consumer-owned utilities with more than 25,000 retail customers to produce a progress report every two years and a fully updated 10-year plan every four years. Consumer-owned utilities shall encourage participation of their consumers in development of their IRPs and progress reports after providing public notice and hearing.

The Western energy crisis of 2001 demonstrated the risks of a utility not having adequate resources and thus relying on unregulated power supply markets to make up the shortfall. It highlighted the need for each utility to plan and implement a portfolio of dependable resources to reliably and cost-effectively meet the future needs of its retail electric customers. An IRP process provides a structured means to develop and adopt the utility’s long-term strategy for configuring its portfolio of electric resources. The strategy identifies preferred new long-term resources, including the amounts, types and timing of resources. The IRP process typically focuses on formulating and evaluating alternative strategies to meet a growing

need for new electric resources. A broad range of generic resource types is considered, including power generating resources (supply-side) and conservation resources (demand-side). Rather than focusing on individual projects or transactions on a stand-alone basis, the analysis for an IRP treats the utility's portfolio as a whole system, including interactions between its existing resources and candidate mixes of new resources, when needed.

Such analysis is designed to assist a utility's policy-makers by showing how different candidate resource strategies would affect future performance of the overall portfolio in terms of key criteria such as reliability, cost, risk and environmental impacts. The analysis also helps examine trade-offs between the multiple objectives. This approach helps to identify resource strategies that are robust, by weeding out strategies whose success depends on factors beyond the utility's control, turning out exactly as expected or hoped, and revealing strategies that can be successful across ranges of possible future outcomes and which are more effective at mitigating risks.

Standard IRP practices (formalized by the state law described earlier) include performing a comparative evaluation of renewable and nonrenewable generating resources and conservation resources using "lowest reasonable cost" as a criterion. In this context, "lowest reasonable cost" has been defined to mean the lowest cost mix of generating resources and conservation and efficiency resources determined through a detailed and consistent analysis of a wide range of commercially available resources. At a minimum, this analysis must consider resource cost, market volatility risks, demand-side resource uncertainties, resource dispatchability, resource effects on system operation, the risks imposed on the utility and its ratepayers, public policies regarding resource preference adopted by state or federal government and the cost of risks associated with environmental effects, including emissions of carbon dioxide.

It is important to recognize that the primary focus for an IRP is on long-term issues, resulting in selection of the utility's preferred strategy for its overall resource portfolio. The results of an IRP provide useful information that can then be used to guide and support decision-making about specific resource

transactions. However, the IRP process should not be used to make final decisions about actual commitments or determine near-term budgets for resource acquisition. Instead, it is helpful to view the IRP process as a group learning experience and a valuable opportunity to "rehearse the future" for the utility's resource portfolio.

IRP Development

Development of an IRP involves the use of several types of analytical tools, which in turn requires the collection, development, review, documentation and formatting of a broad range of forecasts, assumptions and other data inputs. The development of Chelan's 2008 IRP, which covers the period 2008 through 2018 to meet the data requirements of RCW 19.280, included:

- Gathering human resources from within and outside the District to perform specific IRP tasks (software selection and work plan assistance provided by Charles J. Black Energy Economics)
- Acquiring resource portfolio planning software and configuring it for modeling the District's resource portfolio and contracts (The Cadmus Group, Inc.)
- Preparing long-term forecasts of retail electric customer load
- Developing a resource adequacy measure
- Obtaining long-term forecasts of market prices for wholesale power supplies
- Gathering information about Chelan PUD's existing resources
- Assessing conservation potential in Chelan PUD's service area (EES Consulting, Inc.)
- Gathering costs, operating characteristics and other information about new power supply resources
- Gathering long-term interest rates and other financial assumptions
- Modeling the District's existing portfolio of resources, performing scenario analysis or stress tests to the existing portfolio,

evaluating results against the key criteria of reliability, cost, risk and environmental impacts and communicating with customers and the public

- Responding to requests for additional information and analyses
- Final Board consideration of a long-term resource strategy and short-term plan for the the 2008 IRP
- Submitting final IRP Report to Washington State’s Department of Community, Trade and Economic Development (CTED) by September 1, 2008

Public Process

The review process for the District’s 2008 IRP has been designed to provide valuable and timely opportunities for Board guidance and customer and public comment. Five public meetings were held during the planning, development and approval of the IRP. A legal advertisement was posted in the *Wenatchee World* newspaper, recognized as the legal publication for Chelan County, for the final meeting, at which the Board approved the IRP. The first public meeting was an explanation and overview of the IRP process and key issues, including some assumptions that would be used. The second public meeting presented more detail about the assumptions and the results of the initial analysis of the District’s existing resource portfolio. The third public meeting continued the discussion about the District’s current resource portfolio and presented details about the key model inputs as well as how the portfolio performed against the District’s evaluation criteria. At the fourth public meeting, the final draft IRP report was presented and a week later, at a fifth public meeting, the Board approved the resolution accepting the final IRP report. Board guidance on the process, analysis and resource strategy was gathered throughout the series of meetings. Time for questions and comments from the public was provided at each meeting. The schedule of public meetings is represented in Table 2.1.

Table 2.1 Public Process Timeline Board of Commissioners’ Meetings	
January 28, 2008	IRP process and key issues
May 12, 2008	Initial portfolio analysis
June 9, 2008	Continued discussion and detail of inputs into the portfolio analysis
August 4, 2008	Present final draft IRP report
August 11, 2008	Board approval of final IRP report

IRP Website

A website (<http://www.chelanpud.org/IRP.html>) to inform interested parties about the development of the IRP was established at the beginning of the series of public Board meetings. All meeting notices, public presentation materials and the final draft IRP were posted on the site.

In addition to the public meetings, the website also provided a format for interested parties to ask questions and provide comments regarding the IRP process and development. As a reminder, a new IRP will be developed every four years under state law. The next will be due in 2012. Public input will be accepted throughout the development of each future IRP.

IRP Format

This IRP document is organized in a primarily chronological manner in relation to the actual development of the plan itself. Following the Executive Summary and the Introduction, the remaining chapters include:

- Chapter 3 – presents an overview of the District’s resource planning situation and the current electric industry environment and details federal, regional and state regulatory requirements that impact Chelan’s resource planning decisions.
- Chapter 4 – explains the details behind the load forecast scenarios that were developed for

and used in the portfolio modeling for the 2008 IRP.

- Chapter 5 – summarizes the District’s existing resource portfolio as well as outlines other commercially available resources and compares resource costs. The chapter concludes with a discussion about the conservation potential study that was performed for the District by EES Consulting for use in the IRP modeling. Both renewable resources and conservation are discussed in terms of how the District is preparing to comply with Washington State renewable portfolio standard (RPS) requirements.
- Chapter 6 – brings together the District’s loads and resources for an overview of the portfolio modeling that was performed for the IRP. The

IRP modeling software is explained and then the portfolio scenarios that were modeled, including assumptions and parameters, are described and summarized in terms of the District’s resource portfolio evaluation criteria.

- Chapter 7 – summarizes the District’s current resource portfolio situation and lays out the actions that Chelan intends to pursue over the course of the next two to four years, focusing on conservation enhancement and resource planning considerations.

At the end of the document, there is also an appendix for the *Washington State Electric Utility Integrated Resource Plan Cover Sheet*, a required submittal to CTED. Additionally, there is a list of acronyms and a glossary of technical terms used in the IRP.

Chapter 3 – Planning Environment

Chelan PUD is influenced and guided by internal policies, external requirements, legislation and power markets that all affect its resource planning situation.

This chapter begins by discussing the District's resource planning situation, overviewing the current electric industry environment and summarizing the topics and evaluation criteria used for the District's first formal IRP. The remainder of the chapter focuses in more detail on federal, regional and state issues that impact the District's resource planning decisions.

Chelan PUD

The District's 2008 IRP was developed to provide relevant information and useful analyses that can then be used to guide and support major upcoming resource decisions. Within that context, it is necessary for the IRP to maintain focus by addressing a manageable and limited number of key topics that directly involve long-term resource strategy. The process for the 2008 IRP was conducted to begin developing the District's integrated resource planning capabilities including processes, methods and analytical tools. This process will be repeated in the future and opportunities to enhance the analyses and address additional topics will be available in subsequent IRPs.

Chelan's Resource Planning Situation

For the majority of utilities, the resource planning situation is characterized by a need to develop or acquire new electric resources to deal with: 1) forecasted growth in customer loads, 2) declining future output from the utility's existing generating resources and 3) mandates for development of renewable resources and conservation. As a result, it is typical for most utilities' IRPs to reflect a net purchaser's perspective of the wholesale power supply market.

Chelan PUD's resource planning situation is quite different. Several of the District's long-term

contracts for the sale of power from its hydroelectric generating projects will expire during the 11-year planning period for the 2008 IRP (2008-2018). This will create the opportunity for Chelan PUD to begin using some of the power from these expiring contracts to meet future growth in its retail electric customers' needs. Because the total amount of power from the expiring sales contracts is larger than the expected growth in retail loads, the District will also need to make decisions about the disposition of power that will be surplus to its own needs. Thus, Chelan PUD's IRP recognizes a net power seller's perspective, making it relatively unique compared with many other utilities' IRPs. In the analysis of the District's resource portfolio, one set of assumptions about the quantity of power to be sold under new long-term contracts, based on newly executed future contracts, was used. No assumptions about the pricing or revenues from these new post 2011/12 wholesale contracts were made. In effect, the power under new wholesale contracts was "set aside" and the District's remaining resource portfolio was modeled. The strategies for additional new long-term/short-term wholesale contracts will be analyzed in a separate process outside of the 2008 IRP. The information in such analysis is commercially sensitive and the timing for definitive conclusions is premature.

Chelan PUD's resource planning situation related to new renewable resources and conservation is also somewhat unique. There is new state legislation, discussed later in this chapter, requiring utilities to serve a certain percentage of their retail load with renewable resources and acquire all cost-effective conservation. Because the District does not have a growing need to acquire new resources, acquiring new renewable resources and conservation would have the net effect of increasing the amount of power from Chelan PUD's existing hydroelectric resources available for sale in the wholesale power markets. This, in turn, increases the impact and importance of uncertainties regarding wholesale power supply markets and prices. In other words, the District's unique resource planning situation involves

interactions between several factors that differ from the typical utility's situation.

Electric Industry Environment

Ongoing structural changes in the U.S. electric utility industry and shifts in energy markets and policies are creating significant uncertainties regarding future prices for wholesale power supplies. These changes are creating significant opportunities and risks for Chelan PUD and thus are major influences on the District's resource planning situation.

For example, recent large increases in world oil and natural gas prices and growing pressures to limit greenhouse gas (GHG) emissions have the potential to increase the value of the District's existing hydroelectric resources. Chelan PUD does not have any resources in its own generating portfolio that produce GHG emissions from the combustion of fossil fuels, but the environment in which the District operates and conducts business will quite likely be impacted by such regulation. The cost of certain carbon dioxide emitting resources, the principal emission associated with climate change, could increase, affecting the overall cost of resources in the region and possibly wholesale electric market prices. However, ongoing changes in energy policies and power markets may significantly reshape how prices will be determined in the wholesale power market. For example, it is becoming apparent that changes in energy policies and electricity market structures may create prolonged impacts that could keep short-term market prices for wholesale power significantly below the full cost of new resources. Resource adequacy requirements and renewable portfolio standards, discussed later in this chapter, may cause more renewable resources to be developed than are needed to meet load which may cause the short-term, or spot, market to have a continuing surplus of capacity. In turn, spot market prices may swing between the variable costs of different resources, including those with very low variable costs, such as hydro and wind, as power supplies and demands fluctuate. The demand for power fluctuates as a result of economic, demographic, regulatory, weather and other factors.

Electric utilities are subject to continuing environmental regulation, including that associated

with the operational impacts of endangered species. Federal, state and local standards and procedures that regulate the environmental impact of electric utilities are subject to change. Consequently, there is no assurance that the facilities operated by the District will remain subject to the regulations currently in effect, will always be in compliance with future regulations or will always be able to obtain all required operating permits. An inability to comply with environmental or regulatory standards could result in reduced operating levels or the shutdown of facilities not in compliance. The District cannot predict whether additional legislation or rules will be enacted which will affect the operations of the District. If such laws or rules are enacted, the District cannot predict future costs due to such action.

The electric utility industry is also subject to changes in technologies. Recent and continuing advances in electrical generation may render electrical generation on a smaller scale more feasible or make alternative forms of generation more or less economic. Such technology would provide certain purchasers of the power generated by the District's facilities with the ability to generate increased portions of their own electrical power needs and reduce the market price for power provided by the District. The District cannot predict the timing of the development or availability of such technologies and the ultimate impact they would have on the revenues of Chelan PUD.

Topics to be Addressed in the IRP

Chelan PUD's 2008 IRP has been designed to address the characteristics of its resource planning situation described above.

Key topics to be addressed in the District's 2008 IRP process are:

- Impacts of new requirements created by Washington State Initiative 937 (RCW 19.285) (see discussion below) for the District to meet predefined percentages of retail load with qualified renewable resources and pursue all cost-effective, reliable and feasible conservation
- Uncertain future hydroelectric production costs due to FERC licensing requirements

and Habitat Conservation Plan (HCP) as well as project rehabilitation and improvements

- Uncertain load growth
- Expiration of existing long-term power sales contracts and implications for the District's resource portfolio

Criteria for Evaluating Portfolio Modeling Results

The District's goals and objectives for its resource portfolio are reflected in several existing policy statements, including the District's Mission and Vision, Strategic Planning Guiding Principles, Balanced Scorecard, Statement of Environmental Stewardship and Climate-Change Principles.

The following criteria have been identified for the purposes of presenting and comparing candidate resource strategies:

- Reliability
- Cost
- Risk
- Environmental Impacts

These topics and criteria are more fully discussed in Chapter 6 – Portfolio Modeling.

External Requirements for IRP

There are a significant number of new external requirements being placed upon the District and other utilities. The District's 2008 IRP process has been designed to help meet or prepare for external resource planning requirements as noted below.

Federal Energy Legislation

Energy Policy Act of 2005 (EPACT 2005)

The first major energy legislation passed by Congress in 13 years, the Energy Policy Act of 2005 (EPACT 2005), made fundamental changes in the federal regulation of the electric utility industry, including issues regarding generating resources, climate

change, reliability standards and amendments to the Public Utility Regulatory Policies Act (PURPA).

Generating Resources

Hydroelectricity

EPACT 2005 encourages hydroelectric production at non-federal dams by amending the federal dam licensing process. Hydroelectric license applicants may propose an alternative to mandatory conditions placed on hydropower licenses by federal resource agencies. If a proposed alternative meets the statutory environmental and resource protection standards, the alternative would be accepted.

EPACT 2005 also authorizes incentives for improving the efficiency of existing hydroelectric dams and for modifying existing non-federal dams to produce electricity. Generation owners or operators of non-federal qualified hydroelectric facilities that add capacity to existing dams could apply for a payment of 1.8 cents per kilowatt-hour (kWh) for electricity generated. The capacity addition must increase generating capacity without requiring construction or enlargement of impoundment or diversion structures. The maximum amount payable to any facility is \$750,000 per year, and such payments will only be made during the first 10 years of eligibility. EPACT 2005 authorizes \$10 million per year from 2006 through 2015 for this payment. Also, owners or operators of qualified hydroelectric facilities who make capital improvements on existing dams that improve efficiency by at least 3% are entitled to receive up to 10% of the cost of capital expenditures. The maximum amount payable to a single facility is \$750,000. Appropriations of \$10 million per year from 2006 through 2015 are authorized for this payment. These incentives have yet to be made available through the congressional appropriations process.

Renewable Energy

Provisions to increase renewable energy production, advance technology development and promote commercial development of renewable energy are included in EPACT 2005.

A new category of tax-exempt bonds, Clean Renewable Energy Bonds (CREBs) was created by EPACT 2005. Electric cooperatives and public power utilities may issue the bonds to be used to finance capital expenditures incurred at qualifying facilities. Qualifying facilities include wind, closed-loop biomass, open-loop biomass (including agricultural livestock waste), geothermal, solar, municipal solid waste (including landfill gas and trash combustion facilities), small irrigation and hydropower. The provision applies to bonds issued after December 31, 2005, and authority to issue such bonds originally expired on December 31, 2007. The Tax Relief and Health Care Act of 2006 extended the placed-in-service deadline for projects by one year to December 31, 2008. A CREB is a special type of bond, known as a “tax credit bond” that offers the equivalent of an interest-free loan and is an incentive comparable to the Production Tax Credit (PTC) that is available to private developers and investor-owned utilities. The PTC is described later in this section.

Originally enacted as part of the Energy Policy Act of 1992, the Renewable Energy Production Incentive (REPI) was amended by EPACT 2005. It provides incentive payments for electricity generated and sold from new qualifying renewable energy generation facilities. Qualifying facilities are eligible for annual incentive payments of 2.1 cents (in 2008, adjusted for inflation) per kilowatt-hour (kWh) for the first 10-year period of operation. Qualifying facilities include solar, wind, geothermal (with certain restrictions), biomass, landfill gas, livestock methane or ocean (including tidal, wave, current and thermal) generation technologies. Eligible facility owners include a variety of not-for-profit types, including public utilities. EPACT 2005 reauthorized appropriations for fiscal years 2006 through 2026 and expanded the list of eligible technologies and facilities owners. Potentially significant effects could come from a broadening of the REPI payment for electricity generation by renewable energy facilities, depending on the amount of future appropriations. Appropriations in recent years, however, have diminished and eligible projects have received only a fraction of expected payments, including the Nine Canyon Wind Project, of which the District is a participant. REPI complements the PTC incentive

provided to private sector entities for certain types of new renewable energy facilities.

The Production Tax Credit (PTC) is a corporate tax credit. It provides a benefit for the first 10 years of a renewable energy facility’s operation. The production tax credit amount is 2.1 cents (in 2008 adjusted for inflation) per kilowatt-hour (kWh) for wind, geothermal and “closed-loop” biomass facilities. Other technologies, such as “open-loop” biomass, incremental hydropower, small irrigation systems, landfill gas, and municipal solid waste receive a lesser value tax credit.

The PTC was also originally enacted as part of the Energy Policy Act of 1992 and extended by EPACT 2005. The placed-in-service date for solar facilities and refined coal facilities was not extended by EPACT 2005. The Tax Relief and Health Care Act of 2006 provided a one-year extension (through 12/31/08) of the PTC. The on again/off again status that has historically been associated with the PTC contributes to a boom-bust cycle of development that plagues the wind industry.

Under EPACT 2005, the Department of Energy (DOE) is required to report annually on the resource development potential of solar, wind, biomass, ocean (tidal, wave, current and thermal), geothermal and hydroelectric energy resources. Authorizations are provided for DOE research and development programs for renewable energy. Existing research and development programs for solar, wind, geothermal, hydropower, ocean and bioenergy are authorized, as well as new programs for integrated systems such as low-cost renewable hydrogen, kinetic hydro turbines and renewable energy in public buildings.

Climate Change

EPACT 2005 establishes a new governmental structure to develop a national response strategy to promote technologies and practices to reduce greenhouse gas intensity, coordinate federal climate change technology activities, identify barriers to technologies that improve carbon intensity and recommend technology deployment projects. Various authorizations for research and

demonstration projects for climate-friendly technologies are included.

Reliability Standards

EPACT 2005 mandates the Electric Reliability Organization (ERO), established by the act to implement mandatory reliability standards for the bulk-power system under the purview of the Federal Energy Regulatory Commission (FERC), “to conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America.” The North American Electric Reliability Council (NERC), which was certified as the ERO on July 20, 2006, is in the process of developing a standard for resource adequacy assessments. FERC said in its final rule on implementation of the ERO provision of the legislation that it intends to require the ERO to make recommendations where entities are found to have inadequate resources following the assessments.

Amendments to the Public Utility Regulatory Policies Act (PURPA)

The Public Utility Regulatory Policies Act (PURPA) was enacted in 1978. Among other things, PURPA was intended to encourage 1) the conservation of energy supplied by electric utilities, 2) optimal efficiency of electric utility facilities and resources, and 3) equitable rates for electric consumers. The law has been amended several times, notably by the Energy Policy Act of 1992 and most recently by EPACT 2005. EPACT 2005 amended Section 111(d) of PURPA to require utilities to consider, and make a determination about whether it is appropriate to implement, five new federal standards relating to electric generation and efficiency. These federal standards are 1) net metering (EPACT Section 1251), 2) fuel diversity (EPACT Section 1251), 3) fossil fuel generation efficiency (EPACT Section 1251), 4) time-based metering and communications (EPACT Section 1252) and 5) interconnection (EPACT Section 1254).

EPACT 2005 sets various deadlines for commencing and completing consideration of these standards. The District’s Board of Commissioners began consideration of three of these standards (net

metering, time-based metering/communications and interconnection) on August 8, 2006. A public hearing was held on November 13, 2006 to consider adopting proposed standards for net metering service to electric consumers served by the electric utility delivery system, time-based metering and communications and interconnection of third-party generation facilities to the electric utility delivery system.

The Chelan PUD Board determined that it is not in the best interest of the District to adopt the federal net metering standard based on staff’s recommendations. Rather, the Board decided that the District’s Rate Schedule 20 should be updated to reflect recent state legislation. With regard to interconnection service, the Board determined it is not in the best interest of the District to adopt the federal standard, based on staff’s recommendations. Rather, the District should continue to provide interconnection service to customer generators of up to 10MW and adopt the specific interconnection services developed by the Washington PUD Association Public Power Ad-hoc Interconnection Standards Committee for customer generators of 25kW or less.

The Board also declined to adopt federal standards for time-based rates and communications. Instead, District staff will continue to study and evaluate the benefits, technology and costs of time-based rates and communications (or smart metering) in conjunction with automated meter reading.

EPACT 2005 required that the Board complete a determination of the last two standards (fuel diversity and fossil fuel efficiency) by August 8, 2008. The Board began consideration in July, 2007. A public hearing was held on November 19, 2007 to consider adoption. On December 3, 2007, the Board made a determination not to adopt the fuel source diversity standard, but determined that it may be in the best interests of the District to adopt a fuel source diversity standard before 2011, if appropriate. Continued monitoring of the District’s resource portfolio in conjunction with Washington’s RPS, (discussed later in this chapter) will assist with this determination. The Board also declined to adopt the fossil fuel efficiency standard, after finding it not applicable to the District.

Energy Independence and Security Act of 2007 (EISA 2007)

The Energy Independence and Security Act of 2007 (EISA 2007) is an omnibus energy policy law that consists mainly of provisions designed to increase energy efficiency and the availability of renewable energy and was driven by high energy prices, growing concerns about global warming and a change in leadership in the House and Senate after the 2006 elections. Provisions include the first federal mandatory efficiency standards for appliances and lighting, programs to encourage energy savings in buildings and industry and new PURPA standards.

The two reportedly very controversial provisions that were not included in EISA 2007 were the proposed federal RPS and most of the tax provisions, which included a repeal of tax subsidies for oil and gas and new incentives for energy efficiency and renewable energy.

Efficiency Standards

Appliance and Equipment Efficiency Standards

EISA 2007 includes a variety of new minimum efficiency standards for residential and commercial appliance equipment. The equipment includes residential refrigerators, freezers, refrigerator-freezers, clothes washers, dishwashers, dehumidifiers, boilers, electric motors, external power supplies and commercial walk-in coolers and freezers. Further, DOE is directed to set standards by rulemaking for furnace fans and battery chargers. Also, energy efficiency labeling is required for consumer electronic products.

Lighting Efficiency Standards

EISA 2007 provides energy efficiency standards for broad categories of incandescent lamps (light bulbs), CRS-2 incandescent reflector lamps and fluorescent lamps. Lamp efficiency standards for common light bulbs include requiring them to use about 20-30% less energy than present incandescent bulbs by 2012-2014 (phasing in over several years) and requiring a DOE rulemaking to set standards that will reduce energy use to no more than about 65% of current lamp use by 2020.

Regional Standards

The legislation allows DOE to set up to one regional standard for heating products and two regional standards for cooling products, in addition to the main national standard. The intent is to better accommodate the range of climatic conditions across the U.S.

Commercial Building Initiative

The development of more energy-efficient “green” commercial buildings is encouraged by EISA 2007. A Commercial Building Initiative combining research, development, and deployment, to be run by DOE with input from an industry consortium is authorized. The goal of the initiative is for all new commercial buildings to use net zero energy after 2025 (i.e. they produce as much energy as they use) and all existing buildings to meet the same goal by 2050.

Amendments to PURPA

Sections 532 and 1307 of the EISA 2007 also added three new PURPA standards which the District must consider and determine whether to adopt. The standards are related to 1) integrated resource planning, 2) rate design to promote energy efficiency and 3) smart grid information. The District began considering the integrated resource planning standard as part of the 2008 IRP process. The District intends to begin considering the other standards by December 2008 and make a determination whether to implement any of the standards by December 2009, as required by law.

Hydroelectric Licensing

Chelan PUD owns and operates the nation's second largest non-federal, publicly owned hydroelectric generating system. All three projects – Rocky Reach, Rock Island and Lake Chelan – operate under licenses issued by the FERC.

Hydropower has many characteristics that make it highly desirable. It is clean energy that is free of the emissions associated with thermal generation. Operational flexibility allows it to excel at following load and providing reserves to the grid in a timely

manner, both of which enhance overall system reliability. In addition, hydropower provides backup, otherwise known as firming, for intermittent resources such as wind. The District avoids transmission availability issues, associated with its retail load, by using its own hydropower generation, which is located in Chelan County, near the District's retail load.

The FERC issues licenses for the operation of hydropower projects under the provisions of the Federal Power Act. Licenses contain the conditions, presented as a series of license articles, under which the licensee must comply. Numerous other federal and state environmental laws and regulations, most notably the Endangered Species Act and the Clean Water Act, affect the mandatory conditions in the license. Stakeholders, including agencies, Indian tribes, non-governmental organizations and local communities and governments may all be involved in the relicensing process. FERC must weigh, with "equal consideration", the impacts of the project on fish and wildlife, cultural activities, recreation, land-use and aesthetics against the project's energy production benefits. Varying interests may compete and result in potentially contrary, or additive, licensing requirements.

As a licensee, Chelan PUD cannot modify project operations or works prescribed by the license without prior approval by FERC. FERC and other agencies expect a licensee to understand, observe and monitor license compliance requirements throughout the life of the license.

On November 6, 2006, FERC issued a new 50-year license for the Lake Chelan Project. The new license extends until November 1, 2056 and contains requirements for operating the 48-MW hydro project that are expected to cost the PUD \$65 million to \$70 million over the next 50 years. The PUD began the project's relicensing process in 1997 and submitted its final settlement agreement to the FERC in October 2003.

The current license for Rocky Reach expired on June 30, 2006. The Rocky Reach Project is currently operating under an annual license issued by the FERC until a new license is issued. The relicensing process for the Project began in 1998. Settlement negotiations formally began on this Project on June

23, 2003. The parties actively engaged in settlement meetings throughout 2004 and 2005. Final agreement was reached and submitted to FERC on March 17, 2006.

The license for the Rock Island Project expires December 31, 2028.

Fish survival is a significant part of FERC license requirements. The Chelan and Douglas PUDs worked cooperatively with state and federal fisheries agencies and tribes to develop the first Hydro Power Habitat Conservation Plans (HCPs) for anadromous salmon and steelhead. Chelan PUD developed plans for the Rocky Reach and Rock Island Projects. Douglas PUD developed a plan for their Wells Project. The plans commit the two utilities to a 50-year program to ensure that their hydro projects have no net impact on Mid-Columbia (Mid-C) salmon and steelhead runs. This will be accomplished through a combination of fish bypass systems, spill at the hydro projects, off-site hatchery programs and evaluations and habitat restoration work conducted in Mid-C tributary systems.

The anticipated costs and expected operational impacts in the new licenses were incorporated into the resource portfolio modeled during the IRP process.

Regional Policies

The Northwest Power and Conservation Council (NWPCC/Council)

The Northwest Power and Conservation Council (NWPCC or the Council) was authorized in the Northwest Power Act of 1980 and approved by a vote of the legislatures of Idaho, Montana, Oregon and Washington. The governor of each state appoints two members to serve on the Council. The Council is a unique organization that helps the Pacific Northwest states make critical decisions that balance the multiple purposes of the Columbia River and its tributaries. The Power Act contains three principal mandates for the Council to carry out:

- Develop a 20-year electric power plan that will guarantee adequate and reliable energy

at the lowest economic and environmental cost to the Northwest

- Develop a fish and wildlife program to protect and rebuild populations affected by hydropower development in the Columbia River Basin
- Conduct an extensive program to educate and involve the public in the Council's decision-making processes

Adopted in December 2004, the NWPCC's Fifth Power Plan is the most recent. The first key conclusion embodied in this Plan was that the region should acquire improved energy efficiency at an aggressive and sustained pace. The benefits of this strategy were both lower costs and lower risks. A second conclusion of the Plan was that wind energy is potentially cost effective, but the Plan also recognized that wind, and other intermittent generating resources, pose challenges for integration into the Northwest power system. Ultimately, the Plan found that up to 5,000 megawatts of wind could be developed over the 20 years of the Plan, assuming that transmission and integration issues could be addressed. The Plan found that the region had surplus generating capability and that the need for new generation from coal or natural gas likely would not occur until after 2012. Work has begun on the Sixth Power Plan which is expected to be completed in 2009.

In its January 2007 Biennial Monitoring Report of major developments since the Fifth Power Plan, the NWPCC outlined that energy markets, globally, nationally and locally have continued to experience high and volatile prices. These prices, combined with prominent attention to climate change, have provided the impetus for aggressive conservation activity, new federal energy policies and increasing attention to renewable resource requirements at the state and utility level. High energy prices and concerns about potential climate change policy have also led to aggressive development of wind power in the Pacific Northwest. New generation capacity and slow demand growth have increased the electrical supply surplus in the region, which further delays the need for new generation capability.

Pacific Northwest Resource Adequacy Forum

In the wake of the lack of West-wide resource acquisition in the mid-to-late 1990's, the 2001 energy crisis and the provisions of EPACT 2005 mandating adequacy assessments, the electric utility industry has been working to develop new reliability standards. These new standards include resource adequacy requirements that need to be addressed at the regional level and by individual utilities.

For three years, the NWPCC and the Bonneville Power Administration (BPA) have been leading an effort to establish a consensus-based resource adequacy framework for the Pacific Northwest region via the Pacific Northwest Resource Adequacy Forum. The purpose of this framework is to provide a consistent and unambiguous means of assessing whether the region has adequate deliverable resources to meet its electricity demands reliably and to develop an effective implementation approach to assure an adequate supply for future years.

In April, 2008, the Council adopted the forum's proposed voluntary adequacy standard for the Northwest (Council document 2008-07). The standard is intended to be an early warning for the region should resource development fall dangerously short. It is not intended to be a resource planning target. The standard includes both energy and capacity metrics (something that can be measured) and targets (an acceptable value for that metric). The regional standards feature a minimum threshold for energy of zero average annual load/resource balance, and for capacity, a 23% planning reserve margin in winter and a 24% planning reserve margin in summer. The standard is meant to be a gauge used to assess whether the Northwest power supply is adequate in a physical sense, that is, in terms of "keeping the lights on." However, the description refers both to a physical standard, the minimum threshold adopted by the Council, and to an economic standard, a higher threshold that provides more resources than simply enough to avoid a loss of load. The Council's implied economic threshold developed in the Fifth Power Plan is an example of a possible economic standard. Developed by analyzing the exposure of the Northwest power system to a

large variety of risks, including the risk of high market prices, such as were experienced in 2000-01, this threshold would give the region approximately an additional 3,000 MW of resources, above the level that would be developed pursuant to the minimum threshold adopted in the adequacy standard. The forum recommended that the Council's power plan be used to set the threshold for the economic standard.

Under the new standards, the region is currently well above minimum resource adequacy thresholds for energy and capacity. An updated assessment is planned for later in 2008. The Council and the Pacific Northwest Utilities Conference Committee (PNUCC) will annually and collaboratively assess regional resource adequacy three and five years ahead. A traffic-light system--green, yellow or red--will indicate aggregated findings. Yellow would serve as an early warning, while red would trigger additional Council and regional scrutiny of the situation. However, these standards have no enforcement mechanism, nor are they intended to replace integrated resource planning and acquisitions by individual utilities. For the hydro-rich Northwest as a whole, energy capability is most likely the limiting factor in winter but recent analysis shows that capacity might be the limiting factor in summer. This effort ties directly to current Western Electricity Coordinating Council (WECC) efforts to establish a West-wide resource adequacy standard as well as the resource adequacy requirements discussed earlier under EPACT 2005. Analysis for the 2008 IRP addressed resource adequacy for Chelan PUD.

State Energy Legislation

Integrated Resource Planning

As described in detail in Chapter 2, the Washington State Legislature passed House Bill 1010 (RCW 19.280) in 2006 which requires investor-owned and consumer-owned electric utilities with more than 25,000 customers to develop integrated resource plans and submit them to Washington State's Department of Community, Trade and Economic Development (CTED). This IRP has been prepared in order to comply with this legislation.

Renewable Portfolio Standard (RPS)

A renewable portfolio standard (RPS) is a policy that obligates each retail seller of electricity to include in its resource portfolio a certain amount of electricity from renewable energy resources, such as wind and solar energy. The retailer can satisfy this obligation by either: 1) owning a renewable energy facility and producing its own power or 2) purchasing renewable electricity from someone else's facility. Some RPS statutes or rules allow the retail seller of electricity to purchase tradable credits that demonstrate that someone else has generated the required amount of renewable energy rather than maintaining the renewable energy in its own energy resource portfolio. RPS policies are currently implemented at the state level and vary considerably in their requirements with respect to time frame, resource eligibility, treatment of existing plants, arrangements for enforcement and penalties and whether they allow trading of renewable energy credits (RECs). As of the end of 2007, 24 states and the District of Columbia had adopted RPS regulations. In the West, standards are in effect for Washington, Oregon, California, Montana, Nevada, Arizona, New Mexico and Colorado.

In Washington State, a ballot initiative known as I-937 (RCW 19.285, The Energy Independence Act) was passed by the voters in November, 2006. Under the initiative, utilities with a retail load of more than 25,000 customers are required to use eligible renewable resources (excluding most existing hydroelectric power) or acquire equivalent RECs, or a combination of both, to meet 3% of load by January 1, 2012, 9% by January 1, 2016 and 15% by January 1, 2020. The initiative also requires that by January 1, 2010, utilities evaluate conservation resources using methods consistent with those used by the NWPCC and pursue all conservation that is cost-effective, reliable and feasible. Each utility must also establish and make publicly available a biennial acquisition target for cost-effective conservation.

The new law is specific about what types of renewable generation are eligible to meet the Washington State RPS. Most existing hydropower is not eligible, but incremental hydropower is included as a renewable if it is produced as a result of efficiency improvements completed after March 30,

1999 to hydroelectric projects owned by a qualifying utility or to hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional generation does not result in new water diversions or impoundments. Therefore, under the initiative, the District can count efficiency gains at its existing hydropower projects toward meeting the RPS. Additionally, the District's entire share of the Nine Canyon Wind Project qualifies for meeting the renewable requirement of the RPS.

In March of 2008, CTED issued final regulations for implementing the requirements of I-937 as it pertains to consumer-owned utilities. The District continues to evaluate the impacts of I-937, specifically to what extent the District's current portfolio meets the Washington State RPS and how much additional renewable energy generation it may need to acquire at a future date to ensure compliance. In addition, the District continues to evaluate the potential for cost-effective, reliable and feasible conservation measures that could be derived from more efficient energy use, production and distribution within its system. The 2008 IRP included tasks to begin assessing the costs of, and alternatives for, implementing I-937 requirements.

Climate Change

The term "climate change" refers to any significant change in measures of climate, such as temperature, which lasts for decades or longer. Climate change may result from natural causes or human activities. The National Academy of Sciences, the Inter-Governmental Panel on Climate Change and the United States' Climate Change Science Program have concluded that human activities, such as greenhouse gas (GHG) production, are the likely cause of climate change during the last several decades. Several states have set GHG emissions targets, including Arizona, California, New Mexico, Oregon and Washington. Most of the targets have been set by agencies or by executive order and typically use a 1990 baseline to measure reductions. The targets are usually characterized as "goals."

Executive Order No. 07-02 Setting Washington State GHG Emissions Goals

On February 7, 2007, Washington Governor Chris Gregoire signed Executive Order No. 07-02 establishing goals for reductions in GHG emissions, increases in clean energy sector jobs and reductions in expenditures on imported fuel. The executive order also directs the Department of Ecology (ECY) and CTED to lead stakeholders in a process that will consider a full range of policies and strategies to achieve the emissions goals. This statewide effort is intended to address climate change, grow the clean energy economy and move Washington toward energy independence. Emissions reductions and clean energy economy goals for Washington State include:

- By 2020, reduce GHG emissions in the state of Washington to 1990 levels, a reduction of 10 million metric tons below 2004 emissions
- By 2035, reduce GHG emissions in the state of Washington to 25% below 1990 levels, a reduction of 30 million metric tons below 2004 emissions
- By 2050, the state of Washington will do its part to reach global climate stabilization levels by reducing emissions to 50% below 1990 levels or 70% below our expected emissions that year, an absolute reduction in emissions of nearly 50 million metric tons below 2004 emissions
- By 2020, increase the number of clean energy sector jobs to 25,000 from the 8,400 jobs the state had in 2004
- By 2020, reduce expenditures by 20% on fuel imported into the state by developing Washington resources and supporting efficient energy use

Among many others, the following actions are intended to move Washington State to at least 60% of the 2020 goal and grow the clean energy economy:

- Maintaining the highest levels of efficiency in our state's energy code and regularly updating and enhancing those standards
- Examining compliance with appliance efficiency standards and updating and enhancing those standards
- Implementing the requirements of the state RPS by adopting rules that help utilities to succeed in meeting their renewable energy targets

Achieving at least the remaining 40% toward the 2020 goal for Washington State and planning for the future, Governor Gregoire further directed the ECY and CTED, in consultation with a broad range of stakeholders, to develop a climate change initiative, Washington Climate Change Challenge, to achieve the goals of the Executive Order. They shall include representatives from business, including transportation, forestry and energy sectors, agriculture, local, county and regional governments, institutions of higher education, labor unions, environmental groups and other interested residents, as appropriate, in the development of Washington Climate Change Challenge. The Challenge shall address the following elements and process steps:

- Consider the full range of policies and strategies for the state of Washington to adopt or undertake to ensure the economic and emission reductions goals are achieved, including policy options that can maximize the efficiency of emission reductions including market-based systems, allowance trading and incentives
- Determine specific steps the state of Washington should take to prepare for the impact of global warming, including impacts to public health, agriculture, the coast line, forestry and infrastructure
- Assess what further steps the state of Washington should take to be prepared for the impact of global warming to water supply and management
- Initiate active involvement by the state of Washington in the development of regional

and national climate policies and coordination with British Columbia

- Recommend how the state of Washington, as an entity, can reduce its generation of GHG emissions
- Work with the state of Washington's local governments to maximize coordination and effectiveness of local and state climate initiatives
- Inform the general public of the process, solicit comments and involvement and develop recommendations for future public education and outreach

Western Climate Initiative

In February of 2007, five Western state governors, including Governor Gregoire, established the Western Climate Initiative (WCI) to collaborate in identifying, evaluating and implementing ways to reduce GHG emissions. The initiative includes setting an overall regional reduction goal for GHG emissions, developing a design to achieve the goal and participating in The Climate Registry, a multi-state registry to enable tracking, management and crediting for entities that reduce their GHG emissions.

Washington's Emission Performance Standard for Fossil-Fueled Electric Generation (2007)

In May 2007, Governor Gregoire signed Senate Bill 6001, which among other things, adopted the Governor's Climate Change Challenge goals (see Executive Order No. 07-02 above) into statute (RCW 80.50) and created a performance standard for electrical utilities that serve our state. Utilities may capture and store (sequester) carbon associated with the production of electricity to meet the performance standard, but not by purchasing offsets. The bill essentially ends the construction of pulverized coal plants to serve loads, makes the price of IGCC power reflect some of its emissions disposal costs and jumpstarts the process toward a comprehensive GHG emissions reduction plan for the state. By June 2008, ECY was to have rules on implementing the standard and how sequestration plans will be approved.

In addition to the emissions reductions and clean energy economy goals under Executive Order 07-02, the bill contains the provisions discussed below.

By December 31, 2007, the ECY and CTED had to report to the appropriate committees of the legislature the total GHG emissions for 1990 and totals in each major sector for 1990. By December 31 of each even-numbered year beginning in 2010, the ECY and CTED must report to the Governor and the legislature the total GHG emissions for the preceding two years and totals in each major source sector.

The Governor must develop policy recommendations on how the state can achieve the specified GHG emissions reduction goals. The recommendations must include such issues as how market mechanisms would assist in achieving the goals. The recommendations must be submitted to the legislature during the 2008 legislative session.

Beginning July 1, 2008, the GHG emissions performance standard for all baseload electric generation for which electric utilities enter into long-term (five years or more) financial commitments on or after such date is the lower of:

- 1,100 pounds of GHG per megawatt-hour or
- The average available GHG emissions output as updated by CTED

In general, all baseload electric generation that begins operation after June 30, 2008, and is located in Washington, must comply with the performance standard. The following facilities are deemed to be in compliance with the performance standard:

- All baseload electric generation facilities in operation as of June 30, 2008, until they are the subject of long-term (five years or more) financial commitments
- All electric generation facilities or power plants powered exclusively by renewable resources and
- All cogeneration facilities in the state that are fueled by natural gas or waste gas in operation as of June 30, 2008, until they are the subject of a new ownership interest or are upgraded

- The following emissions produced by baseload electric generation do not count against the performance standard:
 - Emissions that are injected permanently in geological formations
 - Emissions that are permanently sequestered by other means approved by the ECY and
 - Emissions sequestered or mitigated under a plan approved by the Energy Facility Site Evaluation Council (EFSEC), as specified in the act

A facility, such as a coal plant, proposing to meet the emissions performance standard (EPS) by sequestering CO₂ emissions must provide substantial technical documentation and financial assurances that the sequestration will be safe, reliable and permanent. A plant gets five years to implement the sequestration plan or face financial penalties. The legislation includes a special provision for large Washington State power plants already in the permitting process. Such plants must comply with all the sequestration planning rules, but if the sequestration plan fails, the developer may meet the EPS by paying to reduce an equivalent amount of emissions from another power plant on the West Coast grid.

By June 30, 2008, ECY and EFSEC had to coordinate and adopt rules to implement and enforce the GHG emissions performance standard, including the evaluation of sequestration and mitigation plans. In addition, CTED must consult with specified groups, such as the BPA, and consider the effects of the standard on system reliability and the overall costs to electricity customers.

In order to update the standard, CTED must conduct a survey every five years of new combined-cycle natural gas thermal electric generation turbines commercially available and offered for sale by manufacturers and purchased in the United States. CTED must use the survey results to adopt by rule the average available GHG emissions output. The survey results must be reported to the Legislature every five years, beginning June 30, 2013.

Electric utilities may not enter into long-term financial commitments for base load electric generation unless the generation complies with the performance standard. For a consumer-owned utility, the governing board must review a long-term financial commitment in consultation with ECY, after which the State Auditor is responsible for auditing compliance with the performance standard and the Attorney General is responsible for enforcing compliance. The governing board of a consumer-owned utility may exempt a utility from the performance standard for unanticipated electric system reliability needs, catastrophic events, or threat of significant financial harm arising from unforeseen circumstances.

ECY, in consultation with CTED, EFSEC, the Washington Utilities and Transportation Commission (WUTC) and the governing boards of consumer-owned utilities, must review the GHG emissions performance standard no less than every five years or upon the implementation of a federal or state law or rule regulating CO₂ emissions of electric utilities and report to the legislature.

By December 31, 2007, the Governor had to report to the legislature the potential benefits of creating tax incentives to encourage base load electric facilities to upgrade their equipment to reduce CO₂ emissions, the nature and level of tax incentives likely to produce the greatest benefits and the cost of providing such incentives.

Washington's Greenhouse Gas Reduction Legislation and Creation of "Green Collar Jobs" (2008)

In 2008, the Washington State legislature passed, and the Governor signed, E2HSB 2815, a bill relating to GHG emissions and creating green collar jobs. Under the bill, the state must limit emissions of GHG to achieve the following statewide emission reductions:

- By 2020, reduce overall GHG emissions in the state to 1990 levels
- By 2035, reduce overall GHG emissions in the state to 25% below 1990 levels

- By 2050, reduce overall GHG emissions in the state to 50% below 1990 levels, or 70% below the state's expected GHG emissions that year

ECY, in coordination with the WCI, will develop a design for a regional multi-sector market-based system to limit and reduce GHG emissions. By December 2008, the DOE and CTED will provide the state legislature with specific recommendations for implementing the design for the multi-sector market-based system. The recommendations will include: 1) the schedule for implementing the design by January 1, 2012, 2) any necessary changes to the reporting requirements and 3) recommendations for actions that would prevent manipulation of the multi-sector market-based system.

ECY must adopt rules requiring persons/entities to report their GHG emissions. Any fees for reporting will be determined by ECY and deposited into the state's Air Pollution Control Account.

The bill requires that owners or operators of a fleet of on-road motor vehicles that emit at least 2,500 metric tons of direct GHG emissions annually in the state, or a source or combination of sources that emit at least 10,000 metric tons of direct GHG emissions annually in the state, must report their total annual GHG emissions beginning in 2010 for the prior year. ECY must establish an annual reporting schedule where reports must be submitted by October 31 each year.

If the federal government adopts rules governing the reporting of GHG emissions, ECY and DOE must propose amendments to its rules to ensure consistency and non-duplicative reporting with the federal rules.

The bill also establishes statewide benchmarks to reduce vehicle miles traveled.

By 2020, the state's goal is to increase the number of clean energy jobs to 25,000. State agencies and education boards will work together to conduct labor market research to analyze the current labor market and projected job growth in the green economy, the current and projected recruitment and skill requirement of green industry employers, the wage and benefits ranges of jobs within green economy industries and the education and training requirements of entry-level and incumbent workers in

those industries. The bill also created a new account, the Green Industries Job Training Account, in the state treasury.

Related District Activities

Chelan PUD and Climate Change

State and national policymakers are debating how to manage and mitigate for GHG emissions from many sectors of the economy, including electric generation. The District's three hydroelectric generating projects provide low-cost, clean, renewable power that does not generate GHG emissions. As an electric generator that relies on emission-free hydropower to serve its retail load plus thousands of other Northwest customers, Chelan PUD has a significant interest in the role that hydropower plays in climate change policy. District management and staff have taken an active role by commenting on state and regional policy proposals. For example, the District's General Manager, Rich Riazzi, is participating on Governor Gregoire's Washington State Climate Change Challenge Advisory Team that was developed to help lay out the full range of policies and strategies that may be adopted to achieve the goals in Executive Order 07-02 and SB 6001 (discussed earlier). District staff also continues to monitor federal policy development.

The District has been following and researching the fundamentals and ideas behind cap-and-trade programs. This is an example of a climate-change policy that may affect the District. The programs appear to work as follows:

- A cap on total emissions will be set by a regulatory authority
- The government will issue a certain number of allowances to give utilities the right to emit CO₂ (One ton of CO₂ emissions will be called "one allowance")
- The fixed number of allowances will be allocated to emitters
- The number of available allowances will be reduced over time

- Emission sources will be allowed to acquire or purchase allowances to offset emissions
- A verification program will be developed

The idea is to create a market mechanism for the cap-and-trade program. Cap-and-trade programs may create problems for low CO₂-emitting utilities, particularly in areas of growing demand, where there are few opportunities to reduce CO₂. This may require hydro utilities to purchase emission credits to meet cap-and-trade requirement even though they have a lower carbon footprint than coal-based utilities. Examples of offsets to reduce or displace CO₂ emissions could include renewable energy, reforestation, agricultural projects or geological sequestration. Currently, there is no universal standard defining offsets.

Key climate change issues for Chelan PUD are:

- The interaction among federal, regional, state and voluntary programs
- The need to recognize hydropower as a renewable resource
- The use of an allowance allocation that does not disadvantage hydropower utilities
- Early action credits to acknowledge reduction
- Investment in renewable technology
- Incentives to invest in new carbon-free generation and technology

Chelan PUD is committed to climate change programs; however, the District feels strongly that hydropower needs to be included as a qualified renewable resource and hydropower should not be treated unfairly within cap-and-trade policies.

Chicago Climate Exchange (CCX)

The District has already taken steps to ensure hydropower generation is recognized as part of the solution in the climate change debate. In December, 2007, the Chicago Climate Exchange (CCX) approved a portion of the hydropower generated at Rocky Reach to be traded to offset GHG emissions from other sources. Approximately 1.75 million additional megawatt-hours generated at the project as

a result of operational and equipment efficiency improvements since 2003 are eligible to be traded as carbon offset credits.

Rocky Reach produces approximately 730 average annual MWh of clean, renewable hydropower. As equipment and operational improvements have been made since 1999 for increased hydro unit efficiency, additional capacity and energy has become available. Emission displacement from these incremental megawatt-hours of hydropower generated since 2003 are now available for purchase as “offsets” by other CCX members. Chelan PUD has full flexibility to decide whether to market its offsets, which qualify to replace the equivalent of about 700,000 metric tons of CO₂.

Low Impact Hydropower Institute (LIHI)

On January 24, 2008, the District’s Lake Chelan Hydro Project was certified as “low impact” by the Low Impact Hydropower Institute (LIHI). Receiving certification as low-impact hydro means the dam and

powerhouse are recognized for meeting criteria related to river flows, water quality, fish passage and protection, watersheds, threatened and endangered species, cultural resources, and public access and recreation. If any of the electricity generated at the Lake Chelan Project is ultimately certified as “green power,” the energy or environmental attributes could potentially be sold in green markets. LIHI certification has been considered an important first step toward green certification, but the green markets are still developing.

LIHI is a national independent nonprofit organization established in 1999 and headquartered in Portland, Maine. LIHI’s mission is to reduce the impacts of hydropower projects through market incentives. To earn certification as low-impact hydro, Chelan PUD submitted an application to LIHI detailing the Lake Chelan Project’s environmental record and explaining the new license provisions. The cost to Chelan PUD for participation is \$15,750 and covers five years.

Chapter 4 – Load

The District has developed an 11-year forecast (2008-2018) of future power consumption (load) for its service territory which includes all of Chelan County. This load forecast is a key input to the model (*Resource Portfolio Strategist*, a product of The Cadmus Group, Inc.) used to develop Chelan PUD's IRP.

Load Forecast Summary

Three different load forecasts, a low, base and high, were developed to reflect uncertainty about future load growth. The primary drivers affecting these forecasts are demographic trends and economic conditions. In addition, the resulting forecasts are an integration of economic evaluations and inputs from the District's own customer service planning areas.

Historical Chelan County population and sales revenue data and population projections for Chelan County were obtained from the Washington State Office of Financial Management (OFM). The historical data (1996-2006) was used in the various sector regression analyses in this chapter. The three population projections used in the forecast were specifically from OFM's September, 2007 Growth Management Act Provisional County Projection Update. Chelan County sales revenue projections, unavailable from OFM, were generated internally after assessing recent historical OFM data (1996-2006). These inputs were quantified and qualified using an econometric model (*EViews*, a product of Quantitative Micro Software) in terms of their impact on the future demand for electricity.

The long-term energy forecast is comprised of retail electric sales forecasts for five major load sectors: residential, commercial, industrial, the City of Cashmere and all "other." A total District peak-hour load forecast was also developed. This chapter describes how forecasts were developed for each component of the long-term forecast.

Weather is always a key factor that affects Chelan's

retail energy sales and peak demand. Volatility due to temperature fluctuations was incorporated into the IRP modeling. For the retail energy sales forecast, a distribution of average monthly temperatures was developed from 1995-2006 temperature data. A factor representing the load change per degree was developed for each month. These factors were multiplied by temperatures along the distribution and then divided by the monthly 2007 weather-normalized energy loads. The resulting percentage deviations around the expected, or weather-normalized load, were used within the model to simulate change in load due to temperature uncertainty. A similar temperature distribution around peak loads was also developed from 1995-2006 monthly peak temperature data. Temperatures along these monthly distributions can be used to stress monthly peak load by using them in the regression equation for peak loads that is discussed later in this chapter.

Expected future conservation measures have not been included in the District's load forecast. Future cost-effective conservation is considered as a resource for purposes of this IRP, so it can be evaluated on the same basis as other resources. Conservation is discussed with other resources in Chapter 5.

Energy Load Forecast by Sector

Long-term forecasts of electricity sales were developed for each sector for the forecasting period of 2008-2018. An electric loss factor on the District's system of 2.5%, based on transmission and distribution system analysis, was added to the energy sales forecast for each sector, so the combined sector forecasts could be compared to the total District energy load forecast for reasonableness. The methodologies used to develop energy sales forecasts for each sector and total District energy load forecast are outlined below.

Residential Sales

Based upon regression analysis, population was found to be the best predictor of the residential sector customer count for the District. Per capita income was also analyzed. The number of residential electric customers was estimated for a given year by using a regression equation that uses projected Chelan County population as the independent variable. The resulting customer count was then multiplied by an average usage per customer, based on historical observations and estimates of the future, to arrive at the energy sales forecast for the class. The low, base and high average annual growth rates for the residential sector are forecast to be 1.05%, 1.92% and 2.60%, respectively. Residential sales currently account for approximately 45% of total retail sales for the District and this is expected to remain fairly constant through the planning period.

Commercial Sales

The commercial sales forecast was also developed using a regression equation. Commercial sales were found to be a function of population and total sales revenues for Chelan County. Employment levels were also examined as a driver, but not found to be significant. The number of commercial electric customers was estimated for a given year by using a regression equation that uses both projected Chelan County population and sales revenues as independent variables. The resulting customer count was then multiplied by an average usage per customer, based on historical observations and estimates of the future, to arrive at the energy sales forecast for the class. The low, base and high average annual growth rates for the commercial sector are forecast to be .99%, 1.45% and 1.95%, respectively. Commercial sales currently account for approximately 27% of total retail sales for the District and this is estimated to decrease slightly through the planning period as industrial sales increase slightly.

Industrial Sales

The industrial sector has historically been the “wild card” sector for Chelan PUD. It makes up nearly 20% of the District’s load and is the hardest sector to forecast. Econometric modeling did not prove to be

very well suited for projecting industrial sales. Industrial loads can be very large and can come and go very quickly depending upon the industry, the local economy and much broader regional, national and global economic conditions. Industrial sales were manually estimated based upon ranges of use per customer amounts multiplied by ranges of customer counts with some larger load additions. This was based primarily on internal estimates with few actual known changes coming to the sector. Additionally, this forecast assumes no changes to the rate structure for industrial customers. The low, base and high average annual growth rates for the industrial sector are forecast to be .97%, 2.89% and 3.91%, respectively. This represents a fairly broad range of growth rates due to increased uncertainty in relationship to the other sectors. Industrial sales are estimated to increase slightly as a percentage of the District’s total load through the planning period as commercial sales as well as those falling into the “Other” sector and those to the City of Cashmere decrease slightly.

City of Cashmere

The City of Cashmere, which buys power from the District, is the one area in Chelan County that has operated its own electrical distribution system. Currently, the District is in the process of negotiating with the City to purchase this system. For this forecast, historical sales data (total annual megawatt-hours) for the City of Cashmere was run through regression analysis as was done with the residential and commercial classes to develop an equation for projecting future sales to this customer. Population proved to be a strong independent variable for predicting sales for this sector. If the District does purchase Cashmere’s system, the sales that currently make up the total sales to Cashmere will become part of the more descriptive sectors (e.g. residential, commercial) along with the rest of the county, but the total energy sales forecast will remain the same. The low, base and high average annual growth rates for the City of Cashmere are forecast to be .44%, .87% and 1.25%, respectively. The City of Cashmere currently accounts for approximately 4% of total retail sales for the District and this is estimated to decrease slightly through the planning period as industrial sales in the county increase slightly.

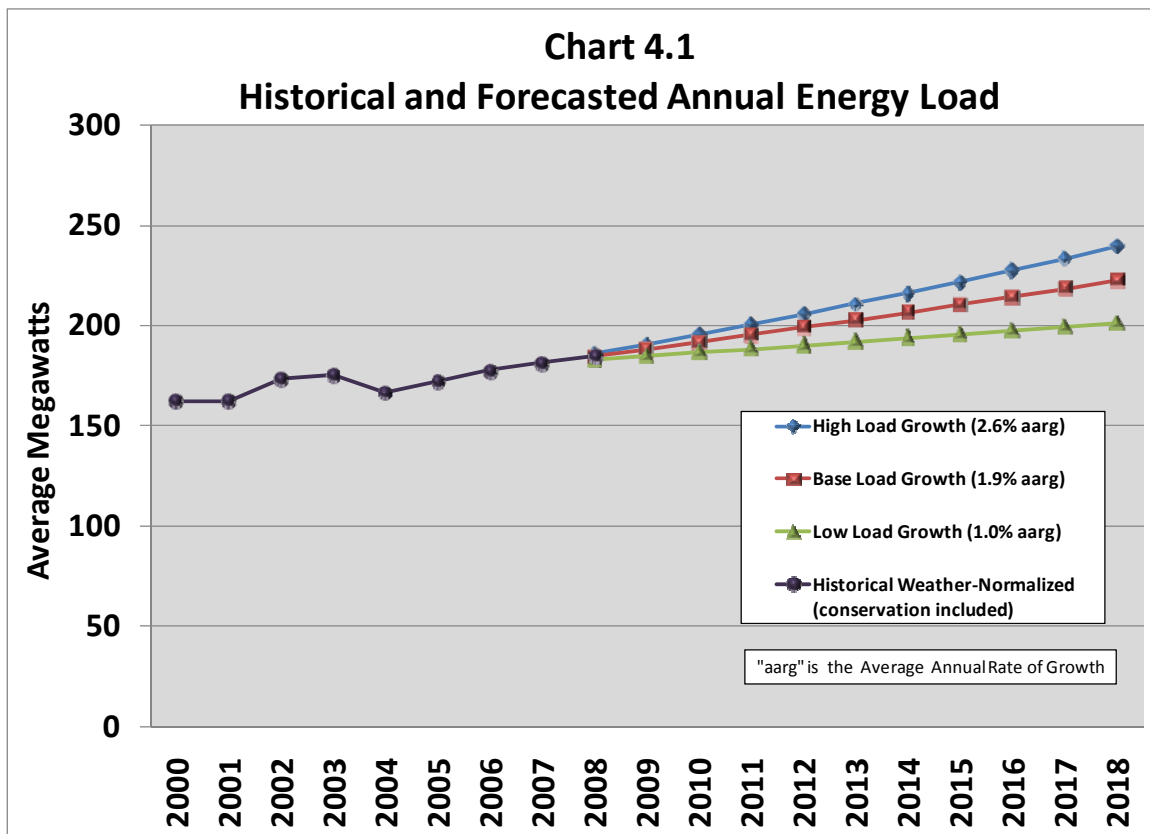
Other

The “other” energy sales sector consists of street lights, interdepartmental use, frost protection and irrigation. Although regressing customer count in this sector against population produced similar results, the energy sales for this sector were manually projected based on ranges of use per customer and ranges of customer counts after looking at the subcomponents of this sector. After observing 1996-2006 data, it appears that both the customer count and the use per customer, on average for the entire sector, have remained quite stable. The growth for this sector is projected at 0% in all three load cases. The “other” sector remains a small portion of the District’s total energy sales, currently about 5%, and this percentage is expected to decrease slightly over the planning period as the industrial sector increases slightly.

Total District Energy Load Forecast

The total District energy load forecast was developed using a regression equation with population

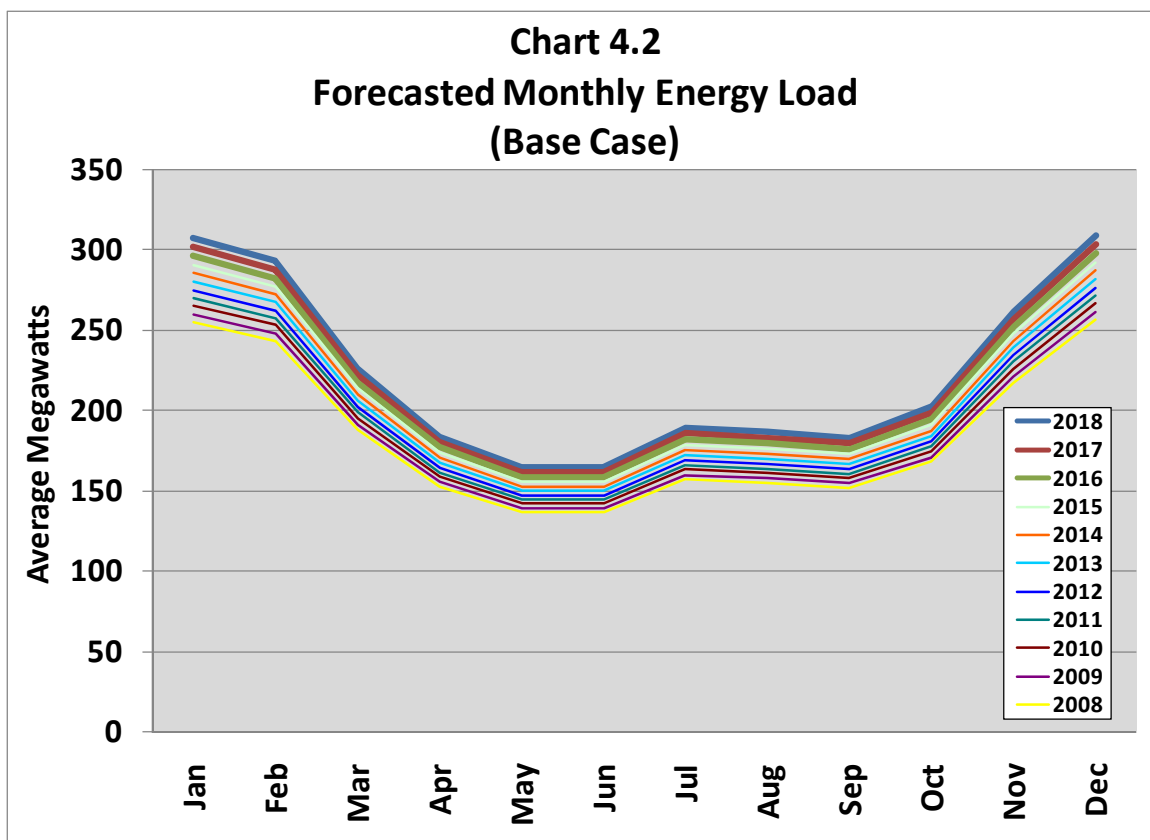
projections as the independent variable. Once the total District energy load forecast was obtained using the above-mentioned methodology, the results were compared for reasonableness to the sum of the individual sector sales forecasts plus system losses. The results were very similar between the two methods over the planning period. The load growth percentages developed from the combined individual sector forecasts (with system losses) were applied to the 2007 weather-normalized load to arrive at total projected megawatt-hours through the planning period. **The low, base and high average annual composite energy sales forecast growth rates, including system losses, otherwise known as the forecasted annual energy load growth rates, are 1.0%, 1.9% and 2.6%, respectively.** This forecast for the years 2008-2018 as well as the actual weather-normalized total District energy load for 2000-2007 are presented in Chart 4.1. For comparative purposes, the District’s weather-normalized annual average rate of growth for total load was approximately 1.5% for the 10-year period from 1998-2007 as well as the 17-year period from 1990-2007.

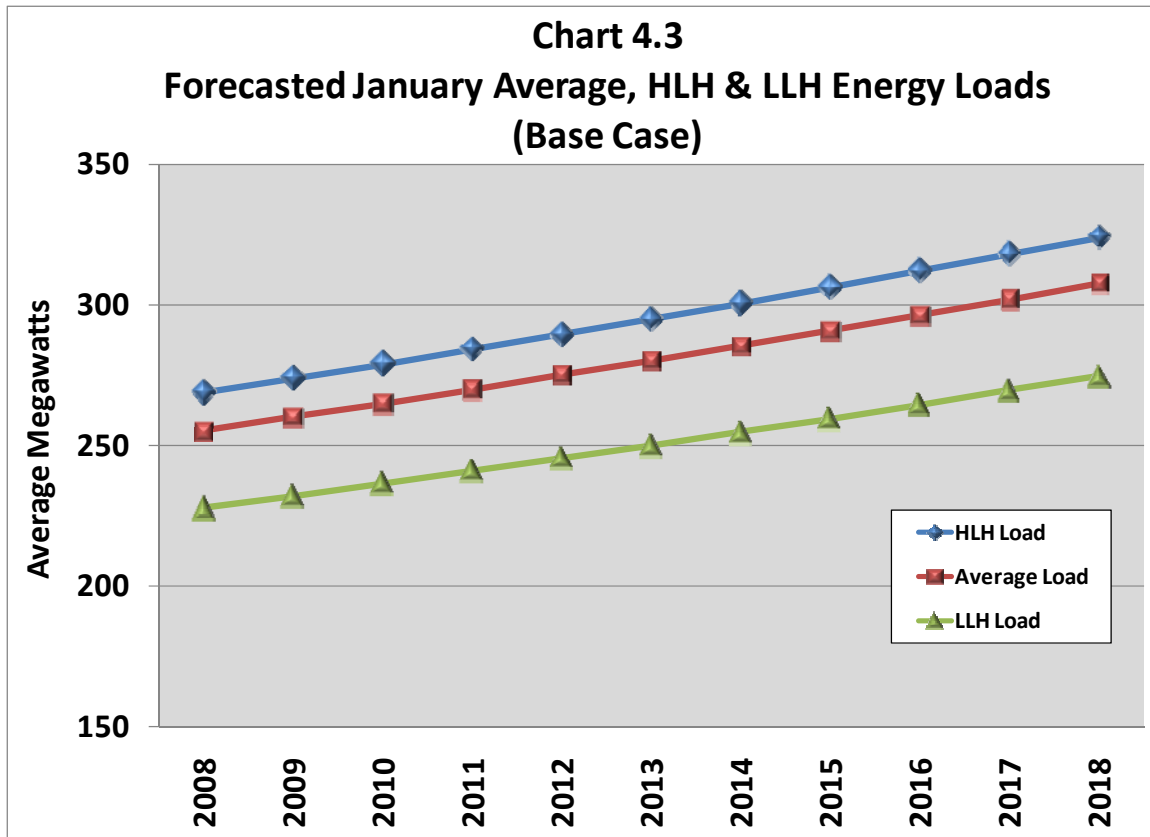


Due to seasonal, monthly and hourly variability in key drivers that affect Chelan’s long-term planning outlook, all variables with a time component, including load, were evaluated on a monthly heavy load hour (HLH) and light load hour (LLH) basis in the IRP modeling. Historically, the District’s highest winter loads are usually in January and the highest summer loads are in July. For modeling purposes only, HLHs were defined as 6:00 AM to 10:00 PM every day of the week and LLHs were defined as all other hours in all months except July, August and September. In those months, the HLHs were broken out into shoulder hours (6:00 AM – 12 Noon and 8:00 PM – 10:00 PM) and peak heavy load period (12 Noon – 8:00 PM).

The annual load forecast was allocated to HLH and LLH periods for each month of the 11-year study

period in a two-step process. First, the annual load forecast was allocated to each month of the year based on the monthly shape of the weather-normalized 2007 load. Second, the monthly load forecast was allocated to HLH and LLH periods as defined above for each month. The allocation of the annual load forecast of monthly HLH and LLH periods is based on historical (2003-2007) actual average load data for the District. The variability of monthly and HLH and LLH periods is illustrated in Charts 4.2 and 4.3. Chart 4.2 represents the monthly load forecast of the base case from 2008-2018. Chart 4.3 shows the forecasted January monthly overall average, LLH average and HLH average of the base case for 2008-2018.





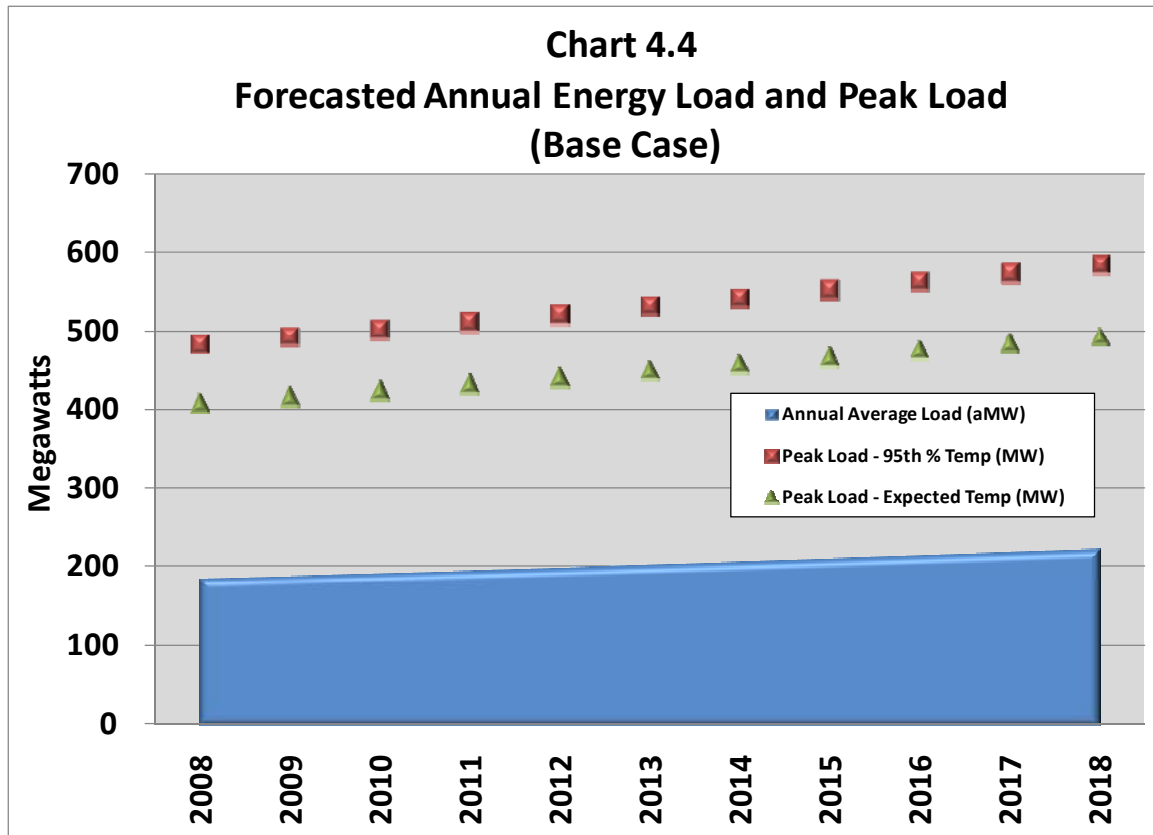
Peak Load Forecast

In addition to forecasting average energy sales, it is also necessary to forecast peak loads to ensure the District has enough resources to meet peak demand. The District's peak load occurs in the winter, usually in January. The highest historical peak for Chelan PUD's retail load of 440 MW was recently established on January 23, 2008. The temperature at the time was approximately 2 degrees Fahrenheit. The forecasting methodology for monthly peak loads is discussed below.

Monthly Peak Forecasts

The District's peak load is the maximum load on the system in any hourly period. The monthly peak

forecast developed based upon the process described earlier assumes that the relationship between energy load and peak load will remain constant over the forecasting period. A regression equation with temperature at time of peak as the independent variable was developed to arrive at a load factor, that when applied to the monthly energy forecast, is used to project the peak load at a given temperature. Monthly peak temperature distributions were developed from 1995-2006 peak temperature data. A 95th percentile level in extreme temperature has been established at the District in regards to planning for peak load. Chart 4.4 illustrates both the base case annual energy load forecast with the base case peak load forecast at both an average, or expected, peak temperature and at a 95th percentile extreme peak temperature for 2008-2018.



Chapter 5 – Resources

This chapter describes both supply-side and demand-side resources. The District's existing resource portfolio is analyzed and discussed as well as other supply-side resource technologies that are currently available or may become available to electric utilities. Conservation measures are analyzed and the conservation potential study is presented.

Transmission

The Pacific Northwest has a highly constrained and congested transmission network. It is operating in a new environment, where markets, generation resources and transmission patterns have changed dramatically. Much of the Northwest transmission was built to deliver the Columbia Basin's abundant hydroelectric power to existing and potential regional markets. Over the years, the system has been expanded to meet regional needs and to support the sale of surplus power out of the region. The last couple of decades have seen dramatic changes in both the operation of the hydro system and in West coast power markets that have led to changes in the way the transmission grid is used. Many of these changes were not envisioned when the system was built and now test its resilience. With the amount of new wind generation planned and under construction, the transmission system will be further tested with the integration of an increasing number of intermittent resources.

Regional transmission entities have been formed in the past to try to address the transmission issues, but all have failed and have since disbanded. However, many Northwest utilities are committed to solving these transmission issues and in 2006, formed ColumbiaGrid, an organization started to improve the operational efficiency, reliability and planned expansion of the Northwest transmission grid. Chelan PUD is a founding member of ColumbiaGrid and hopes that through ColumbiaGrid, a coordinated effort is made to expand the interconnected system in order to integrate new resources without compromising system reliability.

It is preferred to locate new generating resources in proximity to existing transmission lines, eliminating the need for new construction since transmission lines are costly and require long lead times to construct. However, most existing transmission lines have limited available transfer capability (ATC) and often renewable generating resources are located in remote areas where there is no existing transmission. Transmission costs can quickly make a once economical generating resource no longer cost-effective.

Chelan PUD offices and all three hydro projects are physically located at the Mid-C marketing hub where all of the District's wholesale activity occurs. The District currently only transacts at the Mid-C hub, which eliminates many of the transmission issues other utilities face. The Nine Canyon wind project is located in Benton County, and a long-term firm BPA transmission contract is in place to deliver the energy from the project into the District's service territory.

Supply-Side Resources

Both existing and new generating technologies are discussed in this chapter. Although analysis shows that the District does not need to acquire any new resources to meet load demand or Washington State RPS requirements during the IRP planning period, it is prudent to be well informed of current generating technology issues.

Existing Resource Portfolio

As mentioned in the introductory chapter, the District owns three hydro projects and is a participant in the Nine Canyon Wind Project. Two of Chelan's hydro projects, Rocky Reach and Rock Island, are part of an 11-project system on the U.S. portion of the Columbia River. The District's third hydro project, Lake Chelan, serves a dual purpose of generating power and regulating the level of 50-mile-long Lake Chelan, the third deepest body of fresh water in North America. Together, the three projects have capacity to generate nearly 2,000 MW of power.

Currently, 30.2% of the electricity is available to benefit Chelan County and meet local retail electric demand. The balance is sold to the following long-term wholesale power purchasers throughout the Pacific Northwest: Alcoa, Puget Sound Energy, Avista Corp., PacifiCorp, Douglas County PUD and Portland General Electric. The District continues to invest in modernization and relicensing at the projects to ensure reliable, locally controlled operation for future generations.

Rocky Reach

Rocky Reach is Chelan's largest resource. The initial seven generating units were placed in commercial operation in 1961. The second phase of construction was completed in 1971 adding four more generating units, bringing the project total to eleven units. Power from the project is delivered to the District's distribution system at 115,000 volts. Other 230,000-volt transmission lines deliver energy to the project's power purchasers. Power also flows into the regional grid of the BPA.

Rocky Reach Quick Facts

- 11 generators
- 1,300 MW nameplate capacity
- Average annual generation of 5,806,000 Mwh
- Average gross head of 89 feet
- 12 spillway gates
- Original construction started in 1956
- Commercial operation 1961 (seven generators)
- Four generators added in 1969-1971

The District has completed a major upgrade of the powerhouse. Starting in 1995, the District installed new adjustable-blade turbine runners (more fish-friendly) on all 11 generating units. The District also rehabilitated generators on all the units. The work improved the efficiency and reliability of the project. The end result is more power generation with the same amount of stream flows and lower maintenance costs.

Rock Island

Rock Island is the District's second largest resource. The development of Rock Island occurred over a period of some 50 years. Development began in 1930 and the dam, powerhouse and first four operating units were commercially active in 1933. Work on completion of the dam, powerhouse expansion and installation of six additional units began in 1951 and was completed in 1953. A second powerhouse with eight turbine generators was placed in commercial operation in 1979. Currently, 50% of the electricity from Rock Island is available to the District. The balance is delivered to Puget Sound Energy via a long-term power purchaser contract.

Rock Island Quick Facts

- 19 generators
- First Powerhouse – 11 generators (including 1 small house unit)
- Second Powerhouse – 8 generators
- 624 MW nameplate capacity
- Average annual generation of 2,973,312 Mwh
- Average gross head of 39 feet
- 31 spillway gates
- Original construction of first powerhouse completed in 1933
- Capacity expanded in 1951-1953 for Alcoa
- Second powerhouse was constructed in 1979

Rock Island is currently under a major rehabilitation effort. The project to rebuild six units in the original powerhouse and upgrade the four remaining generators will continue through 2014 and is estimated to cost \$200 million.

Lake Chelan

The first generating unit at the Lake Chelan powerhouse was placed in commercial operation in 1927. The second generating unit began operation 11 months later. Water to power the turbine generators

is delivered through an underground penstock, or enclosed pipe, connecting the dam and the powerhouse. This penstock has nearly 350 feet of vertical drop and is approximately 2.2 miles in length.

Lake Chelan Quick Facts

- 2 generators
- 48 MW nameplate capacity
- Average annual generation of 380,871 Mwh
- Average gross head of 384 feet
- 8 spillway gates
- Original constructed in 1927

Lake Chelan is also currently the focus of modernization and the implementation of new license measures. Plans to modernize the 1920s powerhouse were recently finalized, with a four-year project cost estimated at \$42 million to \$45 million. After receiving a new, 50-year license in 2006, implementation of the license articles, estimated to cost \$65 million to \$70 million, will take center stage.

Nine Canyon Wind

The Nine Canyon Wind Project is owned and operated by Energy Northwest and is located in Benton County, Washington. There are ten purchasers of power output from the project, and all are public utility districts in the state of Washington. The project was developed in three phases. The District has a 12.5% share in phase 1 and phase 2. The District is not a participant in phase 3.

Nine Canyon Quick Facts

- Located in Benton County, Washington
- Total project capacity is 96 MW
- Approximately 30% capacity factor
- Project was developed in three phases
- Phase 1: thirty-seven 1.3 MW turbines for a total capacity of 48 MW, commercially operational in 2002

- Phase 2: twelve 1.3 MW turbines added for a total capacity of 15.6 MW, commercially operational in 2003
- Phase 3: fourteen 2.3 MW turbines added for a total capacity of 32 MW, commercially operational in 2008

Because the District is not a participant in phase 3, Chelan's share of the combined project has decreased to 8.3%. This is the percentage of total project output and combined maintenance and operation costs attributable to the District. Although the District's combined project share percentage is lower, the District's capacity remains the same at approximately 7.96 MW because the expanded project has a larger capacity with the addition of phase 3.

Existing Portfolio Costs

The cost of production for the District's existing portfolio is shown in Table 5.1. These costs represent all costs incurred, including debt service, operations and maintenance and certain costs for transmission integration facilities at the hydro projects. The Nine Canyon cost of production is a combined cost for both phase 1 and phase 2. No transmission costs to bring the Nine Canyon wind energy from Benton County to Chelan County are included in Table 5.1.

Table 5.1 District's Existing Portfolio Cost of Production (2006 \$ Values) (98% of average water year)	
Project	\$/MWh
Rocky Reach	\$12.06
Rock Island	\$24.10
Lake Chelan	\$10.95
Nine Canyon	\$82.01

Hydro

The District forecasts the future cost of production of the hydro projects by analyzing short-term trends in operations, maintenance and capital programs, as

well as longer-term needs associated with significant capital replacements and/or operational expenses associated with additional program-level requirements.

Examples of short-term trends in operations and maintenance include, but are not limited to:

- Labor market trends (internal and external)
- Commodity pricing trends
- Inflationary trends

Examples of significant capital and or operational requirements include, but are not limited to:

- Costs associated with future license and Habitat Conservation Plan (HCP) Implementation
 - Fish survival, hatchery programs, etc.
- Plant rehabilitation and improvements

Sensitivity analyses are then performed around projected costs to identify reasonable bookends around expected outcomes to establish cost risk.

The forecasted hydro costs for the base case scenario in this IRP assumes a general ongoing O&M maintenance escalator of 5.5% for labor and a 3.5% escalator for non-labor maintenance. Other project-specific O&M such as relicensing, fish, hatchery (including new license requirements) and major park maintenance are accounted for by each project. The average project O&M growth rates are:

- Rocky Reach – 4.5 %
- Rock Island – 4.8%
- Lake Chelan – 5.4%

Debt service is driven by existing debt schedules and forecasted financing needs that are driven by specific project requirements.

Nine Canyon Wind

The projected future costs of production at the Nine Canyon Wind Project are taken from an annually updated current year and projected future budget developed by Energy Northwest in conjunction with project participants. In the last couple of years, future cost projections have risen dramatically due to

higher than expected maintenance and repair costs to the generating equipment as well as much lower than expected REPI payments as discussed in Chapter 3. In addition, the District makes an estimate of future BPA transmission costs that are incurred to bring the wind energy from Benton County to the District's service territory in Chelan County.

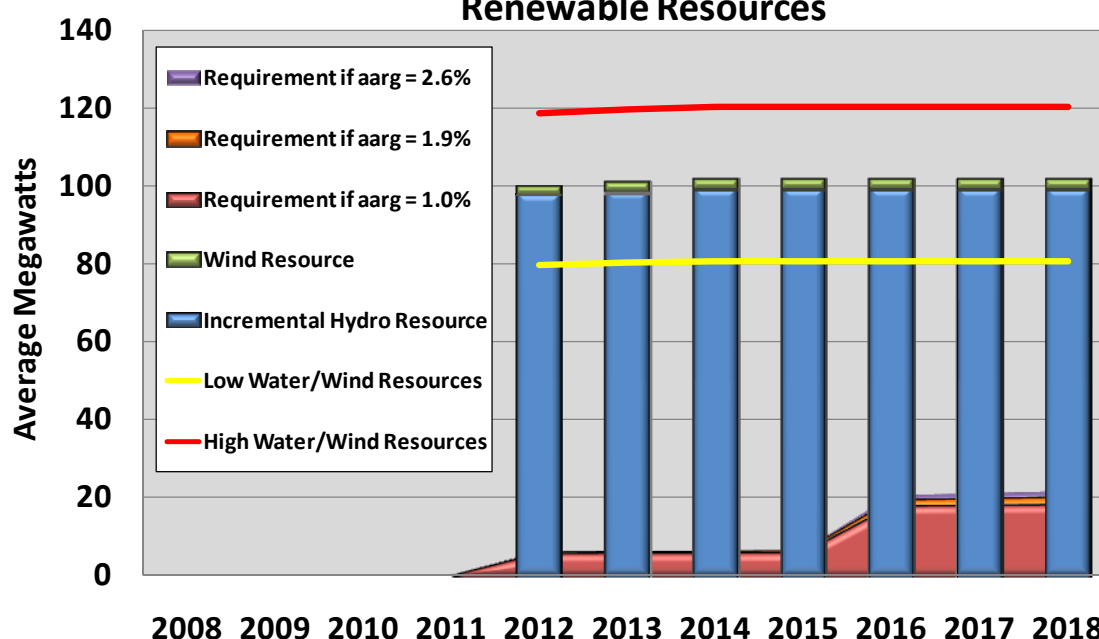
Existing Portfolio Renewables

The District must comply with Washington State RPS requirements beginning in 2012. The initiative requires that 3% of retail load be obtained from eligible renewable energy, RECs or a combination of both by 2012, 9% by 2016 and 15% by 2020. Most hydropower is not an eligible renewable resource under the Washington's RPS statute, though certain efficiency upgrades resulting in incremental hydropower are eligible. The District will be required to have eligible renewable resources beginning in 2012 to comply with the RPS. Amounts shown in Chart 5.1: approximately 6 aMW in 2012-2015, and approximately 18 aMW in 2016-2018 will be required based on the current base load forecast. Conservation, which reduces retail load, has the effect of reducing the amount of renewable generation required under the state's RPS because that requirement is based on a percentage of retail load.

The District plans on meeting these renewable requirements with incremental hydropower and wind power from the Nine Canyon Wind Project. Incremental hydropower is derived from efficiency gains at the District's existing hydropower projects resulting from equipment and operational upgrades, or more power with the same amount of water. The District has made significant investments in equipment upgrades such as generator and turbine rehabilitations, new transformers and trash rack installations. In addition, the District has installed systems designed to optimize generation which have resulted in operational efficiency gains. Only those equipment and operational improvements placed in-service after March 31, 1999 qualify under state RPS rules.

The amount of hydropower the District is able to generate depends on a number of factors, primarily snow pack in the mountains upstream of its

Chart 5.1
Washington RPS Requirement and District's Eligible Renewable Resources



hydroelectric facilities, precipitation in its watershed and resulting stream flow conditions. Incremental hydropower is exposed to the same hydro variability as base hydropower generation, and therefore will fluctuate depending on favorable and unfavorable hydro conditions. Wind energy is variable and somewhat seasonal in nature. The upper and lower boundaries shown in Chart 5.1 show the expected variability of the District's eligible renewables given historical hydro and wind variability.

The District faces an ever-changing environment with regard to GHG emissions. Although the District's hydropower and wind generation do not produce any emissions, it is expected that any legislative or other changes regarding climate change will affect energy markets and the District will be impacted. The District is currently an active participant in both the voluntary carbon and REC markets and will be carefully monitoring any new developments in the climate change arena.

Available Resource Technologies

A broad array of supply-side resources were researched in this IRP. The generating technologies

addressed in this IRP are not inclusive of all types of power generation, but rather ones that are proven or are available to electric utilities. The following types of supply-side resources are discussed in this IRP:

- Wind
- Geothermal
- Solar (photovoltaic and concentrating)
- Natural Gas (single and combined-cycle combustion turbines)
- Conventional pulverized coal generation
- Integrated coal gasification combined-cycle generation (IGCC)
- Nuclear

Capital costs for new power plants have dramatically increased in the last few years. Wind turbines are in high demand, while material prices, such as copper and steel, have escalated. Global demand from emerging economies has also put pressure on capital construction costs. According to the Power Capital Costs Index, Feb.14, 2008, developed by HIS Inc. and Cambridge Energy Research Associates, the cost

of new power plant construction has increased 19% in the most recent six months, 27% over the past year, and 130% since 2000. The District used the Council's New Resource Option Planning Assumptions spreadsheet (as of June 10, 2008) for the various costs of new resources and District data for the costs of Chelan's existing resources. The Council's spreadsheet contains multiple sources for cost information. This data is shown in Table 5.2. A more thorough analysis of costs would need to be performed if these generating technologies were to be considered potential additions to the District's resource portfolio.

Overnight Costs are the amount of cash needed to build a new resource overnight in \$/kW of installed capacity. It assumes no financing structure. The District's existing capital costs for its hydro and wind resources are historical and a comparison cannot be made to the overnight costs of new resources. Fixed O&M costs are those that remain the same regardless of the amount of power production. Fixed O&M costs would be the same for a project whether it is running at 100% of capacity or at 50% of capacity or 0%. Variable O&M costs are volume sensitive and

dependent on project output. A project running at 100% capacity would have higher variable O&M costs than when it is running at 50% capacity. This can be attributed to using more fuel, more wear of machine, etc. Regulation and load following (Reg. & L.F) are the costs of integrating an intermittent resource into a usable energy product. Since intermittent resources cannot be dispatched, capacity needs to be reserved for regulation and to follow load. Transmission costs can vary depending on the location of the resource. For example, a remote wind resource may require multiple transmission segments to bring the power to the District, but a wind resource built in neighboring county would require very little transmission for Chelan County to receive the energy.

Wind Power

Wind power has grown rapidly over the last decade. With over 5,000 MW of wind capacity installed during 2007, expanding the nation's total wind capacity by 45%, wind power proves to be the leading renewable resource. Tax credits, renewable portfolio standards and environmental concerns will

Table 5.2
New Resource Costs
(2006 \$ Values)

Existing Resources	Overnight Costs* (\$/kW)	Fixed O&M (\$/kW/Yr)	Variable O&M (\$/MWh)	Fuel Cost	Reg. & L.F** (\$/MWh)	Transmission Costs (\$/kW/yr)
Wind	\$1,650.00	\$22.30	\$1.00	-	\$5.39	\$20.00
Geothermal	\$2,865.00	\$111.00	-	-	-	\$15.00
Solar (Photovoltaic)	\$6,000.00	\$140.00	-	-	\$5.39	No Estimate
Solar (Thermal Concentrating)	\$3,900.00	\$117.00	-	-	\$5.39	No Estimate
Gas (SCCT)	\$520.00	\$6.80	\$4.50	\$6.02/MMBtu	-	\$15.00
Gas (CCCT)	\$730.00	\$9.10	\$3.00	\$6.02/MMBtu	-	\$15.00
Pulverized Coal	\$1,900.00	\$47.00	\$2.00	\$1.42/MMBtu	-	\$15.00
IGGC (w/ CO2 capture)	\$2,700.00	\$62.00	\$1.90	\$1.42/MMBtu	-	\$15.00
Nuclear	\$2,550.00	\$40.00	\$1.00	\$49.27/lb	-	\$15.00

* Overnight Costs are the amount of cash needed to build a new resource overnight in \$/kW of installed capacity. It assumes no financing structure.

** Regulation and load following are the costs of integrating an intermittent resource into a usable energy product.

continue to increase demand for and promote new development of wind power.

Technology

A wind energy system transforms the kinetic energy of the wind into mechanical or electrical energy. Almost all wind turbines producing electricity consist of rotor blades which rotate around a horizontal hub. The hub is connected to a gearbox and generator, which are located inside the nacelle. The nacelle houses the electrical components and is mounted at the top of the tower. Towers are mostly cylindrical and made of steel and can range from 80 feet to over 260 feet in height. Rotor blades can range from 100 to over 260 feet, and the electricity output is directly dependent on the length of the blades. Currently, the average size of new machines being installed is above the 1 MW mark. The trend is moving toward larger machines as they can produce electricity at a lower price.

The varying nature of wind power is controlled by the amount of wind available to harness, therefore, the site location is the most important design criteria. The power output increases dramatically as wind speed increases. All other things being equal, a turbine at a site with an average wind speed of 16 feet per second (ft/s) will produce nearly twice as much power as a turbine at a location where the wind averages 13 ft/s. Most wind turbines start operating at a speed of 13-16 ft/s and reach maximum power between 30-50 ft/s. Machines are stopped electronically at very high wind speeds to protect them from damage.

Current Issues and Projections

Most projections have wind projects continuing to grow and lead renewable resources in terms of capacity added. Local manufacturing of turbines and components is also anticipated to continue to grow as announced manufacturing facilities come on line and existing facilities reach capacity and expand. Even though wind power pricing is projected to continue its upward climb in the near term, the rising costs of fossil fuels, the possibility of carbon regulation and the growing number of states interested in continued

support through policy measures give wind power an optimistic future.

Geothermal Power

The United States is the leader in geothermal energy production, yet geothermal accounts for less than 1% of the electricity consumed nationwide. As of May 2007, geothermal electric power was generated in five U.S states: Alaska, California, Hawaii, Nevada and Utah, with Idaho and Wyoming soon to be added to the list.

Technology

There are three different technologies used to create electricity from hydrothermal fluids: dry steam, flash, and binary cycle. The type of conversion depends on the state of the fluid (steam or water) and its temperature. All of the energy is derived from heat deep in the earth's crust. The heat rises to near the surface by thermal conduction and by intrusion of molten magma originating from great depths upward into the earth's crust, heating nearby groundwater and/or rock formations. This naturally creates geothermal energy which can be extracted to create electricity.

Dry steam plants capture steam (over 455 degrees Fahrenheit) directly from the geothermal reservoir and run a turbine and generator. Flash plants use high temperature water (over 300 degrees Fahrenheit) from the ground and the steam is separated in a surface vessel and delivered to the turbine and generator. Binary plants use lower temperature water (212 degrees Fahrenheit to 302 degrees Fahrenheit) and pass it through a heat exchanger to heat another liquid that boils at a lower temperature than water. The secondary liquid vaporizes and runs a turbine and generator.

Most utility scale geothermal power plants are built as 20 – 50 MW units. Costs can vary significantly depending on size, location, project configuration and other site-specific factors. Costs of a geothermal plant are heavily weighted toward early expenses and geothermal power plants run at greater than 90% availability, compared to about 75% for coal plants.

Current Issues and Projections

The output from a geothermal power plant is relatively constant and can be used as a base load resource. Geothermal projects provide a highly reliable and clean power supply but are often capital intensive to build. Recently, interest in geothermal power has increased in Oregon, where the city of Klamath Falls has operated a geothermal heating utility for years, using the energy for everything from heating buildings to melting snow on streets and sidewalks. The Cascade mountain range has great potential for geothermal resources and preliminary studies are presently being conducted near Mt. Baker.

Natural Gas Generation

During the last couple decades, natural gas-fired generation has been the primary resource constructed and now accounts for about 20% of total U.S power generation. Relatively low natural gas prices and development of efficient, low-cost, environmentally attractive gas-fired power plants led to a surge of construction early in the 1990s and again during the energy crisis of 2000 and 2001. During this rapid growth in natural gas generation, many projects were developed by non-utility generation companies for sale of power into competitive wholesale power markets.

Technology

A gas turbine is a compact, modular generating plant with flexible startup and load following characteristics. The two primary types of natural gas generation are Simple-Cycle Combustion Turbines (SCCT) and Combined-Cycle Combustion Turbines (CCCT).

Simple-Cycle Combustion Turbines (SCCT)

A wide range of unit sizes is available, from less than 1 to greater than 170 MW. Low to moderate capital costs, superb operating and site flexibility and moderate electrical efficiency make gas turbine generators attractive for peaking and grid support applications. SCCTs also feature highly modular

construction, short construction time, compact size, low air emissions and low water consumption.

A gas turbine works much like an airplane engine. Compressed air is forced into combustion chambers, where it is mixed with natural gas fuel. The mixture is then burned, making combustion gas. This hot combustion gas expands through the turbine. Its heat energy drives a generator, producing electricity.

Combined-Cycle Combustion Turbines (CCCT)

CCCT plants have been the bulk power generation resource of choice since the emergence of efficient and reliable gas-turbine generators in the early 1990s. Over half of the total generation constructed in the Northwest since 1990 has been from CCCTs, and these plants now comprise about 10% of the Northwest region's electric capacity. Reasons for this popularity include an extended period of low natural gas prices, reliable and efficient equipment, low capital costs, short lead-time, operating flexibility and low air emissions. However, higher natural gas costs for the last few years have slowed the pace of development.

Adding a second cycle to a SCCT greatly improves the efficiency at little extra cost. CCCTs make the process more efficient because the heat that's left over in the expanded gas is captured in a boiler and used to change water into steam. This steam goes to another turbine to produce more electricity. For extra efficiency, the expanded steam is then re-condensed back into water and recycled through the boiler.

Current Issues and Projections

Applications for simple-cycle gas turbines in the Northwest include backup for non-firm hydropower in poor water years, peak load service, emergency system support and as an alternative source of power during periods of high power prices. If natural gas use continues to grow, additional regional gas transportation or storage capacity may be needed. Transmission is unlikely to be constrained because of the ability to site gas turbine generators close to loads. However, air emissions can be of concern as gas-fired generation produces moderate levels of carbon dioxide per unit of energy output.

Solar Power

Solar power uses the energy from the sun to generate electricity. Methods for capturing solar energy for practical uses have been around for centuries. A major factor determining the success of a utility-scale solar project depends on the amount of solar radiation reaching the ground available for conversion into electricity. This depends primarily on latitude, atmospheric conditions and local shading.

Technology

Photovoltaic and concentrating solar power are the two primary technologies used to generate electricity from solar energy. Concentrating solar power uses the sun's heat to create electricity while photovoltaic uses the sun's light. Currently, in Chelan County, there are multiple distributed photovoltaic resources at local school district buildings and nonprofit agencies through the Sustainable Natural Alternative Power (SNAP) program. This program is more fully described later in this chapter.

Photovoltaic Solar Power

This technology is commercially available and widely employed to serve small remote loads where it is too costly to extend grid services. Solar power output is intermittent and battery storage is required for loads demanding a constant power supply. Photovoltaic is the technical word for solar panels that create electricity. Panels wrapped in semi-conducting material, most commonly silicon, converts sunlight directly into electricity. When sunlight strikes the material, electrons are dislodged, creating an electrical current which can be captured and harnessed. Photovoltaic cells power many of the small calculators and wrist watches in everyday use. Photovoltaics are also making inroads as supplementary power for utility customers already served by the electric grid, such as SNAP participants.

Concentrating Solar Power (CSP)

Many proposed and recently developed utility-scale solar power plants use concentrating solar technology. CSP systems use lenses or mirrors and

tracking systems to focus a large area of sunlight into a small beam that is concentrated on to a heat transfer fluid. Once heated, the liquid converts water into steam, which turns a turbine to create electricity, much like a traditional power plant. The amount of power generated depends on the amount of direct sunlight available. CSP technologies make use of only direct-beam (rather than diffuse) sunlight, so they are of limited use in locations with significant cloud cover. Technologies have been developed to help power production when direct sunlight is unavailable. A working fluid, like molten salt, inside large thermos-like buildings will be heated by the thermal energy instead of immediately creating steam. Then, if electricity is needed when the sun is not shining, the fluid can be heated by running it through the heated salt. However, electricity can only be made for a very limited time using this process.

Current Issues and Projections

Many of the Southern states (Arizona, Nevada, California, etc.) have ideal conditions and locations to take advantage of solar energy. The resource potential in the Northwest is greater east of the Cascade mountain range where there are fewer clouds, however, even the most ideal locations in the Northwest pale in comparison to areas in the Southwest states. The strong summer seasonality of Northwest solar resources suggests that while a solar resource has potential for serving local summer-peaking loads, such as irrigation and air conditioning, it is less suitable for serving winter-peaking heating loads. This is in conflict with the District's current annual load profile. Current peak usage for the District is during the winter when heating loads are high.

Costs for utility-scale solar resources are presently too high for economic consideration. However, some sources say that solar power will be fully competitive with conventional power-generating technologies within a decade. Concentrating solar power could harness enough of the sun's energy to provide large-scale electricity, especially in the Southwestern United States. Photovoltaic technical breakthroughs may be required to achieve the cost reductions required for large-scale deployment.

Conventional Pulverized Coal Generation

Coal is a combustible black or brownish-black sedimentary rock composed mostly of carbon and hydrocarbons. It is the most abundant fossil fuel in the United States and fuels about half of all electricity produced in the nation. The principal coal resources available to the Northwest include the Powder River basin fields of Eastern Montana and Wyoming, the East Kootenay fields of Southeastern British Columbia, the Green River basin of Southwestern Wyoming, the Uinta basin of Northeastern Utah and Northwestern Colorado and extensive deposits in Alberta. Coal plants were the choice for new resource development until the late 1980's when natural gas combined-cycle combustion turbines eclipsed coal projects due to superior environmental and economic advantages.

Technology

In the most common type of coal plants, coal is pulverized and blown into a furnace where it burns while airborne. Water flows through tubes that run into the furnace. The water is heated to boiling while under pressure. This pressurized steam blasts through a turbine, which turns a generator to produce electricity. After the steam has passed through the turbine, it is condensed into water and cooled and sent back into the furnace.

When the coal burns, it gives off sulfur dioxide, nitrogen dioxide and carbon dioxide, among other gases. Air emission control equipment reduces most of the pollutants, but smaller particulates are less likely to be absorbed and can pass out the smokestack into the air.

Current Issues and Projections

Recent reports and articles have shown the costs to construct and operate a pulverized coal plant are escalating at an alarming rate. In addition to escalating costs, the possibility of a carbon tax on GHG could add enormous costs in penalties. Coal plants emit more than twice the carbon dioxide of modern natural gas-fired plants. Even federally backed loans and subsidies to develop coal plants are

becoming scarce due to the high risk and uncertainty about environmental regulations.

Washington State only has one coal plant, and it is located near Centralia. Recently, there has been a rapidly growing opposition to using coal to generate electricity, fueled by the intense policy debate regarding carbon dioxide emissions and GHG effects. The lack of consistency in how states and federal agencies are addressing air quality issues creates enormous uncertainty about future operational and financial burdens on existing and future fossil-fueled generation. Coal is still considered a cheap fuel, yet prices have become volatile and have escalated sharply in recent years. Due to higher environmental and regulatory risks, soaring construction costs and the surging of coal prices, many proposed coal plants are now either being postponed or cancelled.

Integrated Coal Gasification Combined-Cycle Generation (IGCC)

Increasing concerns regarding GHG emissions are prompting interest in advanced coal generation technologies promising improved control of these emissions at lower cost. EPACT 2005 included subsidies and federally backed loans for "clean coal". Integrated coal gasification combined-cycle (IGCC) technology is emerging as one of the most promising "clean coal" technologies to produce relatively clean electricity from coal. However, recent political and regulatory issues threaten the attractiveness of this technology and have reduced interest from potential investors.

Technology

Other than using coal as the primary fuel, pulverized coal plants and IGCC plants have little in common. Generally, the capital and operating costs for an IGCC plant are substantially more than a conventional coal plant. An IGCC plant uses less water, generates less solid by-products and acts more like a natural gas-fired CCCT plant. The operational characteristics can be described in two parts, the chemical process (gasification) and the power production process (combined-cycle turbine).

Gasification is a process that converts carbonaceous materials, such as coal, petroleum or biomass, into

carbon monoxide and hydrogen by reacting the raw material at high temperatures with a controlled amount of oxygen. The resulting gas mixture is called synthesis gas or syngas and is itself a fuel. The raw syngas is then processed to remove most contaminants such as particulates, sulfur and chlorides.

The syngas can then be fed to a gas turbine/steam turbine combined-cycle unit to generate electricity. This power production process is very similar to the natural gas-fired combined-cycle combustion technology. This also allows for the possible capture of carbon dioxide for the control of GHG emissions.

IGCC technology combines the efficiency of a natural gas-fired CCCT with the abundant supply and relatively low cost of coal.

Current Issues and Projections

Energy Northwest announced in 2005 that it intended to build a 600 MW IGCC plant at the Port of Kalama in Cowlitz County, Washington. However, in a recent Energy Northwest newsletter it was disclosed that the development has been discontinued due to state legislation (SB 6001 discussed in Chapter 3) requiring power generation to have a maximum of 1,100 pounds of carbon dioxide per megawatt or sequester the carbon in the ground permanently. Since sequestration is not technically proven or able to be permitted under current regulations, the new requirement imparted additional risk that Energy Northwest could not legally accept.

There are currently two IGCC power plants operating in North America, one in Indiana and one in Florida. Many of the next generation IGCC plants currently proposed or under development are labeled as “capture ready” and could potentially capture and store carbon dioxide. However, many experts do not think that the technology to prevent carbon dioxide emissions will be available any time soon. Even if technology is available, sequestering carbon dioxide will likely decrease plant efficiency, increase water usage and add additional costs.

Nuclear Power

Nuclear power is designed to extract usable energy from atomic nuclei via controlled nuclear reactions. All current methods of nuclear power involve heating a working fluid such as water, which is then converted into mechanical work. Energy was first generated by nuclear power in 1951, and nuclear power plants first started supplying energy to the grid in 1954, with the first one in the United States in 1957. Today, about 17% of the world’s electricity is generated by nuclear power. European countries, like France, depend on nuclear power for about 75% of electricity, whereas nuclear power makes up about 15% of total generation in the United States. More than 400 nuclear power plants are in operation, with more than 100 in the United States. The Northwest region has only one nuclear power plant, located in Richland, Washington. The Columbia Generating Station, owned and operated by Energy Northwest, has a capacity of 1,150 MW and first started producing energy in 1984.

Technology

A nuclear power plant produces electricity from energy released by the controlled fission of certain isotopes of heavy elements such as uranium, thorium, and plutonium. Power is created by a controllable nuclear fission process. Nuclear fission occurs when a uranium-235 nucleus captures a stray neutron. When the stray neutron is captured, the atom breaks into two lighter atoms and two or three neutrons are released. These neutrons then collide with other uranium-235 nuclei and the domino effect occurs. Enormous amounts of energy in the form of heat and gamma radiation is released when an atom splits. The two atoms that result from the fission later release beta radiation and gamma radiation of their own as well. In order for uranium-235 to work, a sample of uranium must be enriched so that it contains 2% to 3% or more of uranium-235. The uranium is formed into pellets with approximately the same diameter as a dime and length of an inch or so. The pellets are arranged into long rods, and the rods are collected together into bundles. The bundles are then typically submerged in water, which acts as a

coolant, inside a pressure vessel. The uranium bundles act as an extremely high-energy source of heat. It heats the water and turns it to steam which then drives a steam turbine, which spins a generator creating power. The amount of power production is controlled via control rods. Control rods are made of material that absorbs neutrons, thus absorbing some of the neutrons creating the nuclear fission. These rods are raised or lowered to control the fission and therefore power production.

Current Issues and Projections

The year 1996 marks the year the last United States commercial nuclear reactor came on-line. However, with the potential electricity shortages, fossil fuel price increases, global warming and heavy emissions from fossil fuel use, nuclear power is gathering some interest. The Northwest region has been scarred by the Washington Public Power Supply System (WPPSS) fallout. In the 1970's, a plan to construct five nuclear plants in the Northwest was created. Eventually, only one was constructed and the other four unfinished projects have since been demolished. Since the unfinished plants generated no power and brought in no money, the WPPSS was forced to default on \$2.25 billion in bonds in 1982. As of 2007, nearly \$4 billion of outstanding bond debt remains. The lone operating plant is the Columbia Generating Station.

Nuclear plant development is very capital intensive and requires long lead times, and most agree that a new operating nuclear plant likely wouldn't open in the region until at least the 2020's. The Council has pledged to take a detailed and methodical look at nuclear power for their Sixth Power Plan, due in 2009. Two primary attractions are cited in support of nuclear as a future resource option. The first is carbon-free generation and the second is nuclear's potential to supply a large and relatively low-fuel-cost amount of base load power to help meet rising demand. However, there are many unresolved concerns such as the fate of nuclear-waste storage, fears over plant safety, financial and construction risk, permitting and the public's opinion. Nuclear power would be attractive under high natural gas prices and aggressive GHG control, but there are

many hurdles it must overcome before a nuclear plant is added to the Northwest regional resource mix.

Demand-Side Resources

For more than 50 years, the District has maintained a strong record in promoting conservation and encouraging efficient use of electricity. Beginning in the mid-1950s, the District provided three technical representatives to advise residential, commercial/industrial and irrigation pumping customers about how to make the most efficient use of their power. Free heat loss and heat gain studies were provided.

These efforts progressed in the 1960s, leading to the first established residential standards for insulation in the county, known as the Gold Medallion Home Program. It was active for about 15 years.

In the early 1980s, the District formed a conservation section within the Customer Service and Engineering Department, instituting a more sophisticated energy analysis and a customer education program. The District participated in conservation programs under the auspices of the BPA, including hot water efficiency, an energy buy-back weatherization program and marketing for energy-efficient new homes. In 1985, the BPA Super Good Cents Program for new home energy efficiency was initiated by the District. Also in 1985, an agreement was reached to channel some weatherization funds directly to the local Chelan-Douglas Community Action Council (CDCAC) for low-income weatherization assistance. That program evolved in 1994 to a direct grant to CDCAC, which enabled the funds to be directly matched by a Washington State energy program, effectively doubling the money available.

In 1995, the department name was changed to Energy Services, with one division for residential assistance and another for the commercial/industrial sector.

Commercial programs have included complete audits of commercial buildings, efficient lighting retrofits, monitoring and testing of specific equipment and training and education of building operators. The primary focus of the industrial programs has been on the fruit storage and fruit processing industry, the

mainstay of the local economy. Programs include audits, research projects and education. Another program funded by BPA helped replace streetlights with energy-efficient models.

Residential programs have been varied and extensive. For new construction, the District offered services to encourage the purchase of energy-efficient manufactured homes, design assistance and advice on meeting energy codes and information on proper installation of heating, ventilation and air conditioning (HVAC) systems.

Energy Services continued to evolve, and the department was restructured again in 2000. During that period, staff began planning the introduction of optional alternative energy programs for its customers. These efforts culminated in the introduction of the SNAP program in 2001. This very successful program facilitates the installation of small-scale, locally owned solar and wind generators through a voluntary extra payment on customers' utility bills. The award-winning SNAP program helped get a solar power system installed at every public school in Chelan County.

In the industrial and commercial sectors, high wholesale energy prices enabled Energy Services to expand its ResourceSmart program. This program purchases energy through conservation measures in industrial and large commercial facilities by offering cost-sharing incentives based on confirmed energy savings.

For existing construction, the District continues to promote energy audits by contractors, offers weatherization loans and promotes HVAC duct sealing.

The District is currently testing the performance of two new air-source heat pumps that are reported to be the world's most energy efficient air-source heat pumps. In addition to being very energy efficient, the new Cold Climate and Acadia heat pumps are also reported to operate at very low temperatures without the need for electrical resistance back up heat. This would decrease the District's winter peaking load. The District was the first to install the heat pumps west of the Mississippi River. If the performance of these new heat pumps is as advertised, the District

will promote their installation in homes and businesses in Chelan County.

In addition, training and education is offered on a wide-scale to building professionals, manufactured home dealers, customers, realtors and school officials. Customer assistance for all energy efficiency questions is available.

Services provided by the District over the years have included the following and have provided the results shown in Table 5.3:

Residential:

- Energy analyses of existing residences
- Home energy loan, retrofit weatherization program
- HVAC duct-sealing services
- Customer and professional training and education
- Residential energy code support
- Promotion of energy-efficient lighting
- Promotion of energy-efficient manufactured homes
- Promotion of Super Good Cents construction
- District staff person is a member of the advisory board for the building sciences program at the community college
- Water heater retrofit insulation program (9,424 tanks wrapped in 1982-83)
- Energy Star appliance instant rebate promotion
- Energy Star energy kit including a compact fluorescent lamp (CFL) and coupons for additional CFLs, thermostats, exterior motion sensors and CFL fixtures
- Halogen torchiere lamp trade-in for coupon good for the purchase of a CFL torchiere
- Promotion of conservation through workshops, public meetings and informational marketing

Table 5.3 District Energy Efficiency Incentives and Program Results		
Residential Customer Services home audits	(residential)	*9,448
Super Good Cents construction	(single family)	323
	(multifamily)	269
	(manufactured)	73
Homes weatherized	(residential)	2,805
Water heaters retrofitted with insulation	(residential)	9,424
Street lights replaced with energy-efficient models		2,375
Annual savings (kWh)	(residential)	14,958,466
Measures cost (loaned)	(residential)	\$7,704,097
Energy Kit and coupons (CFL for every customer and discount coupons for more)	(residential)	\$158,610 9,811,200 kWh
Energy Star appliance incentive	(residential)	\$44,577 267,500 kWh
“Energy Edge” buildings - Energy Smart Design program (30% more efficient than standard code)	(commercial)	14 buildings (1992-93)
Resource\$mart	(industrial)	\$2,266,774 3.7 aMW
SNAP	(residential & commercial)	79 kW of Solar Power 50 kW of Wind 5 kW Micro hydro

*Data begins in the early 1980s and is through 2007

Commercial:

- Expanded energy audits
- Nonresidential energy code support
- Efficient lighting retrofits
- Energy code plan review
- Design assistance for new construction and remodeling
- Training and education
- Demonstration lighting project
- Research and demonstration projects
- Street light replacement program
- LED replacement lights in downtown holiday lighting display

- BPA Energy Savings Plan program
- BPA Energy Smart Design program
- Energy Star® Portfolio Manager

Industrial:

- Expanded energy audits
- Account executives (specific District staff members assigned to work with specific customers)
- Seminars
- District staff member as part of advisory board for refrigeration program at community college
- Resource\$mart program: rebates for industrial energy conservation projects

SNAP:

An optional program promoting installation of locally owned alternative energy systems. In 2003, through a collaborative effort with the ALCOA Foundation and IBEW labor union, solar photovoltaic arrays were installed on all schools and several non-profit social service agencies in Chelan County as part of the SNAP program.

Current Demand-Side Offerings

Resource\$mart

Resource\$mart is the District's program for helping commercial and industrial customers install energy efficiency measures that would otherwise not be cost-effective. Depending on the predicted amount of electrical energy savings, the District may pay up to 75% of the customer's cost to install energy efficiency measures. The maximum Resource\$mart funding is determined by summing the three year value of the conserved power on the wholesale market, less three years of lost revenue that the customer would otherwise have paid to the District.

Any measure that reduces the consumption of electrical energy use is eligible for funding under the Resource\$mart program. This includes lighting projects, fast-acting doors on large refrigerated spaces, energy efficient fruit warehouse-controlled

atmosphere equipment and improved heating and cooling equipment.

Commercial Plan Review and Code Compliance

In 2006, the District reestablished a program originally operated in the mid 1990's to offer support to local building code jurisdictions by reviewing complex commercial building plans for energy code compliance and assisting, where requested by the code officials, with energy code-related construction compliance verification. This program has identified many potential non-compliance issues in plans and construction installation practices that have resulted in assuring achievement of lost opportunity energy savings.

Energy Star® Portfolio Manager Support

The Portfolio Manager is an on-line software program that allows building facilities managers to monitor the energy consumption of their buildings and rate how they compare with like buildings throughout the nation. Buildings receive an energy rating and can be certified as meeting Energy Star® standards if proven to be more energy-efficient than 75% of comparable buildings in the portfolio manager database. Knowledge of a building's energy rating gives building operators the ability to concentrate their resources on the worst performing buildings and take steps to improve their facilities energy use rating.

Home Energy Loan Program

The Home Energy Loan Program offers 10-year, low-interest loans to customers whose homes are electrically heated and use at least 4,000 kWh for heating during the winter. Loan caps are \$10,000 for single family dwellings and up to five unit multi-family structures and \$2,000 per unit for multifamily structures with more than 5 units. Eligible measures include: Energy Star® certified replacement windows, insulated exterior doors, insulation in ceilings, walls, basements and crawlspaces, ventilation improvements and programmable thermostats. The measures are installed by approved local contractors and inspected by the District.

Low-income Weatherization

The District has partnered with the CDCAC to weatherize income-eligible electrically heated residences. Income eligibility is based on 125% of federal poverty guidelines. The PUD offers an annual grant of \$65,000, which is matched by the Washington State Energy Matchmaker program administered by CTED. CDCAC crews complete the weatherization measures which are inspected by CTED and District staff.

National Conservation Focus

Throughout the nation there is a new focus on energy efficiency and renewable energy as a result of climate change concerns and the high cost of fossil fuels. Two recent legislative acts, one Federal and one Washington State, contain energy efficiency mandates. The Federal legislation (EISA 2007 described in Chapter 3) uses standards and tax incentives to promote efficiency improvements. The Washington State legislation mandates resource plans be developed and conservation and efficiency measures be pursued by qualifying utilities (Washington RPS/RCW 19.285 described in Chapter 3). As a result, in November 2007, the District implemented a conservation potential study as an initial step in meeting the requirements of RCW 19.280, Electric Utility Resource Plans, and providing an initial planning document for RCW 19.285, Energy Independence Act, that were both discussed in Chapter 3.

Conservation Potential Study Objective

EES Consulting (EESC) was retained by the District to develop the Conservation Potential Study (CPS). Most of the analysis and discussion profiled in the remainder of this chapter was produced by EESC. This CPS was meant to explore demand-side management (conservation) resources for the District. In doing so it evaluated the amount of conservation potential for Chelan County and provided initial conservation target estimates consistent with the Energy Independence Act.

RCW 19.280, Electric Utility Resource Plans, mandates that the resource plans must include assessments of commercially available conservation and efficiency measures. The CPS was designed to assist in meeting these requirements for conservation analyses. Included in this report were analyses of demand response and load management programs, currently employed programs and technologies and new, available conservation programs.

Background

Conservation involves planning, implementing and monitoring activities of utilities that are designed to encourage consumers to modify their level and pattern of electricity usage. The utility undertakes these activities primarily because they can be less expensive than acquiring the power to serve load, or they sell saved power at a price higher than the cost of the conservation on the wholesale electric market. Conservation can include conservation programs as well as load management or demand response programs. Currently the demand response (or load management) area is not very active in the Northwest. However, this may change depending on how the region handles future peak energy pricing.

The process used to develop detailed conservation program potential estimates is complex. The analysis requires the compilation of large amounts of data on available technologies, costs, current appliance saturations and the number of customers to which a program would apply. In addition, assumptions regarding codes and standards, consumer behavior and persistency of savings need to be made.

For reference, the conservation targets of the NWPCC's Fifth Power Plan are shown in Table 5.4. These programs have total resource cost (TRC) benefit/cost (BC) ratios above 1.0, which indicates that the regional benefits outweigh the regional costs for these programs. According to the Council's analysis, these programs are both cost-effective and achievable in the region.

The methodologies used by the Council to develop the Fifth Power Plan are the basis for setting the targets prescribed by the Energy Independence Act. The information presented in this IRP was developed

Table 5.4
Regional Conservation Targets and Cost
Power Council's Fifth Power Plan

Sector and End Use	Cost Effective Savings Potential (aMW in 2025)	Average Levelized Costs (Cents/kWh)	Benefit/Cost Ratio
Residential Measures			
Residential Compact Fluorescent Lights	535	1.7	2.3
Residential Heat Pump Water Heaters	195	4.3	1.1
Residential Clothes Washers	135	5.2	2.6
Residential Existing Space Conditioning - Shell	95	2.6	1.9
Residential Water Heaters	80	2.2	2.3
Residential HVAC System Conversions	70	4.3	2.1
Residential HVAC System Efficiency Upgrades	65	2.9	1.2
Residential New Space Conditioning – Shell	40	2.5	2
Residential Hot Water Heat Recovery	25	4.4	1.1
Residential HVAC System Commissioning	20	3.1	1.9
Residential Dishwashers	10	1.6	2.6
Residential Refrigerators	5	2.1	2.2
Non-Residential Measures			
Industrial Non-Aluminum	350	1.7	2
Commercial New & Replacement Lighting	245	1.2	9.1
New & Replacement AC/DC Power Converters	156	1.5	2.7
Commercial New & Replacement HVAC	148	3	1.5
Commercial Retrofit HVAC	117	3.4	1.3
Commercial Retrofit Lighting	114	1.8	2.2
Commercial Retrofit Equipment	109	3.4	2.1
Commercial Retrofit Infrastructure	105	2.2	1.8
Commercial New & Replacement Equipment	84	2.2	1.8
Agriculture - Irrigation	80	1.6	3.2
Commercial New & Replacement Shell	13	1.6	2
Commercial New & Replacement Infrastructure	11	1.4	2.4
Commercial Retrofit Shell	9	2.9	1.3
Total	2,816	2.6	2.7

utilizing the Council's methodologies as well as some of the Council's data assumptions where appropriate.

Avoided Cost

Avoided costs for electricity are used to calculate measure benefits (i.e. the value of energy saved). The Council uses a forecast of wholesale market electricity prices to assign values to the energy savings of each measure. For the potential study, the District chose to use an updated market forecast from

the Council. This draft interim forecast was released in November 2007. Since measure data from the Fifth Power Plan is used in the study, new BC ratios were calculated to reflect the difference in market avoided costs. The avoided costs used in the Fifth Power Plan have a 20-year levelized cost of \$38.90/MWh. The draft forecast, released in November, is about 8.8% lower than the Fifth Power Plan or \$35.50/MWh. To adjust for the difference, all energy benefit data is reduced by 8.8%. The results are slightly lower BC ratios.

Since the study uses the draft forecast for energy prices, there are some issues to note. As mentioned above, the new forecast is lower than the previous forecast. Currently, the Northwest is experiencing increasing capital costs for new wind projects in light of state RPS requirements and subsequently higher demand for renewable resources. The forecast may not fully reflect the changing environment, including escalating capital costs for power plants. It is possible that the true value for wholesale market prices is higher than the November 2007 forecast suggests.

In April of 2008, the Council adopted the interim forecast in final form. At \$39.90/MWh, it is higher than the draft November 2007 forecast and 2.6% higher than that used by the Council in the Fifth Power Plan. This final interim forecast is expected to be used as the basis for the Sixth Power Plan. The final interim forecast is used as the basis for valuing wholesale market purchases and sales of electricity in this IRP (fully discussed in Chapter 6), but it was released too late to modify the CPS. As a result, the use of the final interim forecasts would result in slightly higher BC ratios for conservation measures than what was suggested in the CPS.

Measure Cost-Effectiveness

The total resource BC ratio is used to determine measure cost-effectiveness. The BC ratio is the net present value of all the measure benefits divided by the net present value of all measure costs over the life of the measure. The Council's methodology primarily uses the TRC perspective which includes both the consumer and the utility costs and all benefits. All costs and benefits for each measure are evaluated in present value over the life of the measure. A measure passes the TRC test if the ratio of benefits to cost is greater than or equal to one. Also, the TRC test does not take into account utility and customer costs individually, so there is no

prescriptive share of conservation costs between the two groups. WAC 194-37-070 (subsection (6)(v) (Energy Independence Act) states that under the utility analysis documentation procedure for conservation target-setting, that the planners must "conduct a *total resource cost analysis* (emphasis added) that assesses all costs and all benefits of conservation measures regardless of who pays the costs or receives the benefits."

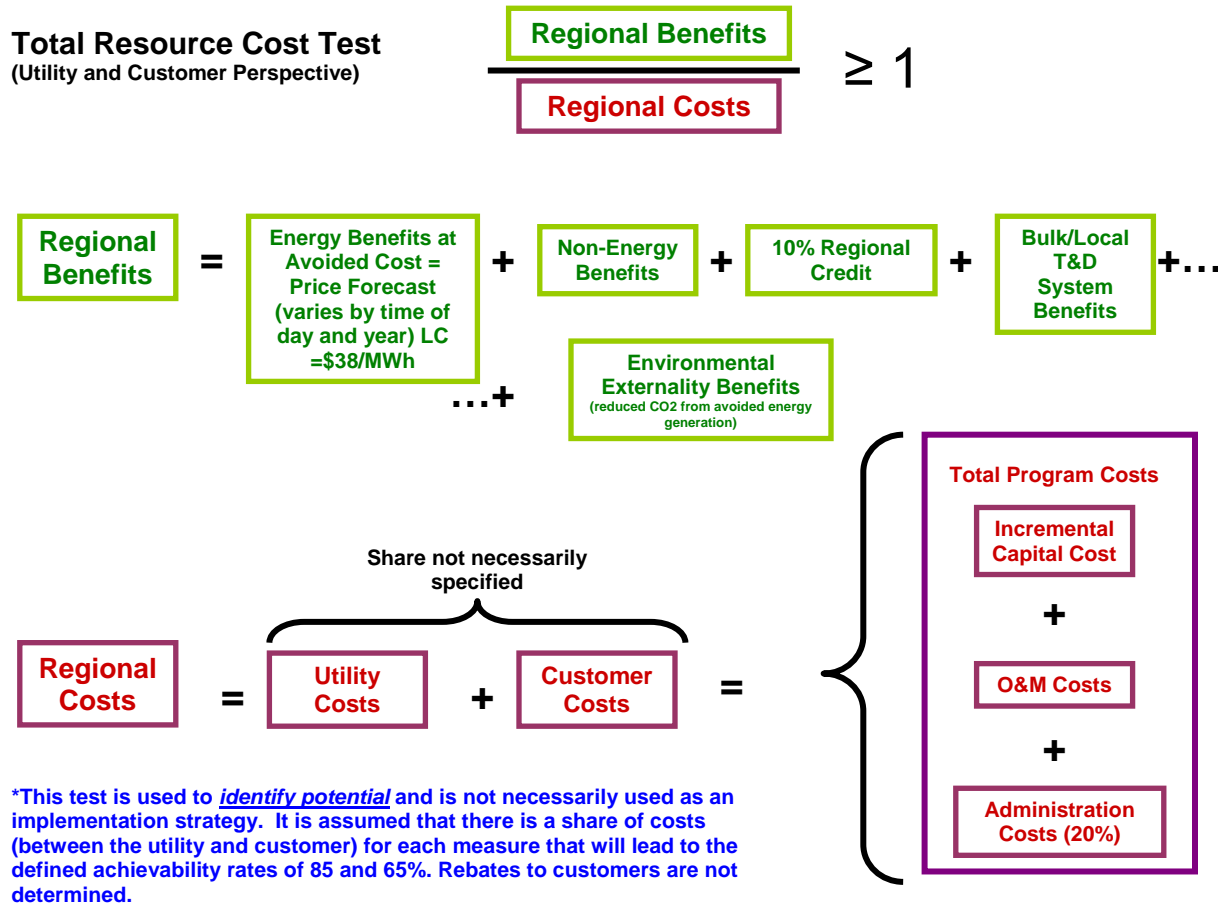
Figure 5.1 is a flow chart illustrating the TRC test used by the Council. The TRC test determines cost-effectiveness from the standpoint of both the utility and the customer together. As such, several benefits such as non-energy or environmental externalities are counted as part of conservation benefits. Also, the costs include both customer and utility costs. The TRC does *not* determine the share of costs paid by the utility nor does the methodology prescribe rebates. Finally, the TRC test is used to determine the amount of conservation potential available to the District.

Energy Independence Act

RCW 19.285, the Energy Independence Act, requires that "each qualifying utility pursue all available conservation that is cost-effective, reliable and feasible." The timeline for conservation requirements of the Energy Independence Act are detailed below:

- By January 1, 2010: Identify achievable cost-effective conservation potential through 2019 using methodologies consistent with the NWPCC's latest power planning document.
- Beginning January 2010, each utility shall establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share for the two-year period of the cost-effective conservation potential for the subsequent 10 years.

Figure 5.1
Total Resource Cost Test



- By June 2012, each utility shall submit an annual conservation report to the department. The report shall document the utility's progress in meeting the targets established in RCW 19.285.040.

There are two primary components of the Energy Independence Act related to the CPS:

1. Documenting the development of conservation targets (i.e. setting the targets) and
2. Documenting the savings (i.e. demonstrating how the targets are being met)

Setting Conservation Targets

In order to set the conservation targets, utilities can use one of three documentation procedures:

- The NWPCC's conservation calculator
- A modified version of the calculator
- Utilities can perform their own custom analyses

Each of these approaches is further described below.

Conservation Calculator

If a utility chooses to calculate conservation potential using the NWPCC's calculator, the biennial target and 10-year potential must be equal to or greater than

the targets calculated by the model. If the targets are set accordingly, the utility is said to have effectively documented the requirement for customer conservation.

The conservation calculator provides an estimate for each utility's share of the regional conservation target based on its share of regional load. The calculator utilizes utility-specific data for the various sectors of retail sales in megawatt-hours: residential, commercial, industrial and irrigated agriculture. The calculator itself has three options for calculating targets. The first option bases achievable targets on total retail sales and is appropriate for utilities with customer bases similar to the regional characteristics. The second option is a modified version of the first, where achievable savings are presented by sector. This option is appropriate for utilities that do not

have significant irrigated agricultural load. Table 5.5 shows results in the case that the District uses the conservation calculator to set biennial targets.

Documentation procedure 1 shows 1.47 aMW as the average annual target. Documentation procedure 2 shows a slightly lower number of 1.46 aMW.

The last option allows for utilities with significant irrigated agricultural sales to account more accurately for this difference between the utility customer base and the regional data. This third option requires that utilities enter their total irrigated agricultural retail sales. Table 5.6 shows that the documentation procedure 3 result is even lower than documentation procedure 2 at 1.45 aMW per year.

This last option requires input of irrigated agriculture sales for the year 2005. In 2005, the District sold approximately 45,185 MWh to irrigated agriculture

Table 5.5
Council Target Calculator
Documentation Procedures 1 and 2

Annual Conservation Target (aMW)												Avg Annual Target
	200 5	200 6	200 7	200 8	200 9	201 0	201 1	201 2	201 3	201 4	Total	
Documentation Procedure 1												
All Sectors	1.2	1.30	1.35	1.40	1.45	1.50	1.55	1.59	1.64	1.69	14.73	1.47
Documentation Procedure 2												
Residential	0.49	0.52	0.55	0.57	0.60	0.63	0.66	0.68	0.71	0.74	6.14	0.61
Commercial	0.35	0.37	0.39	0.41	0.44	0.46	0.48	0.50	0.52	0.55	4.47	0.45
Industrial & Irrigated Agriculture	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	3.93	0.39
All Sectors	1.23	1.28	1.33	1.38	1.43	1.48	1.53	1.58	1.63	1.68	14.55	1.46

Table 5.6
Council Target Calculator
Documentation Procedure 3

	Annual Conservation Target (aMW)											Average Annual Target
	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	Total	
Residential	0.49	0.52	0.55	0.57	0.60	0.63	0.66	0.68	0.71	0.74	6.14	0.61
Commercial	0.35	0.37	0.39	0.41	0.44	0.46	0.48	0.50	0.52	0.55	4.47	0.45
Industrial	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.31	3.11	0.31
Irrigated Agriculture	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.08	0.79	0.08
All Sectors	1.23	1.28	1.33	1.38	1.43	1.48	1.53	1.57	1.62	1.67	14.52	1.45

customers. However, sales in irrigated agriculture (as a percent of total retail sales) have decreased since 2005. In 2006, only about 39,146 MWh were sold to irrigated agriculture customers. The annual target decreases to 1.4 aMW when the 2006 sales are entered into the calculator.

The program costs and savings in each sector are pre-determined by the Council based on regional data and studies on conservation measures (Regional Technical Forum, RTF). The Conservation Calculator is appropriate for utilities that do not have significantly different characteristics from the regional data. The next documentation procedure allows for some changes to the predetermined values calculated by the RTF.

Modified Conservation Calculator

This second documentation procedure allows for the modification of customer-base data in order to arrive at targets lower than a utility's share of regional conservation. Modifications that can be made are the following:

- Add or deduct measures as they apply to the service area
- Modify the number or ratio of applicable units (percent of homes with electric heat)
- Increase or reduce per unit incremental resource savings
- Changes in forecasted program costs
- Changes in retail sales growth rates
- Changes in avoided distribution capacity cost savings

Typically the methodology for assessing the impact of differences between a specific utility's service area and that of the region is to weight the amount of savings achieved through conservation by a factor not equal to one. The factor is determined by analyzing changes to conservation potential as the variables above are adjusted.

To illustrate, Table 5.7 shows an estimate of the District's share of the regional potential by simply taking the District's share of regional load by sector and multiplying it by the Council's appropriate

measure category from Table 5.4. Extrapolating from the Cost-Effective Savings Potential column in Table 5.4 results in the average megawatt savings the Council estimates is achievable in year 10 for the District. In Table 5.7, the Average Annual Target is the yearly conservation target. The total for both residential and non-residential measures is 1.36 aMW or approximately the output from the Council's target calculator.

The difference between the annual savings target in Table 5.7 and the 1.47 aMW target from the Council's calculator is due to the subtraction of measures that do not apply to the District's service territory. Also, Table 5.7 does not include potential from some measures that are no longer cost-effective (heat pump water heaters). The Council's Target Calculator, however, does include potential from these measures, so the Council's target is higher.

If a utility chooses either the Conservation Calculator or the Modified Conservation Calculator, planning beyond the 10-year horizon must be done using the third option. However, since the law requires conservation targets for only the first 10-year period, and further studies will be completed prior to the end of the 10-year period, it is not necessary to plan beyond a 10-year horizon. For an extended outlook on conservation, the District had EESC complete a full 20-year potential study. The first 11 years of the study were used as input into the IRP modeling. The extended CPS may make it desirable to use the third option for target planning. The District continues to study this alternative.

Utility Analysis

This last documentation procedure uses the Council's method to establish targets but allows utilities to calculate the savings, costs and applicability of measures for their service areas. This is the documentation procedure used by EESC for the CPS. Detailed below are the requirements of the utility analysis:

1. Analyze a broad range of energy-efficiency measures that are technically feasible.
2. Perform a life-cycle cost analysis which includes incremental costs and savings of

Table 5.7
Chelan's Share of Regional Conservation Savings
Based on Fifth Power Plan

Sector and End Use	10 Year Savings Potential (aMW)	Average Annual Target aMW	Average Levelized Costs (Cents/kWh)	Benefit Cost Ratio
Residential Measures				
Residential Compact Fluorescent Lights	2.6	0.26	1.7	2.3
Residential Clothes Washers	0.7	0.07	5.2	2.6
Residential Existing Space Conditioning - Shell	0.5	0.05	2.6	1.9
Residential Water Heaters	0.4	0.04	2.2	2.3
Residential HVAC System Conversions	0.3	0.03	4.3	2.1
Residential HVAC System Efficiency Upgrades	0.3	0.03	2.9	1.2
Residential New Space Conditioning – Shell	0.2	0.02	2.5	2
Residential Hot Water Heat Recovery	0.1	0.01	4.4	1.1
Residential HVAC System Commissioning	0.1	0.01	3.1	1.9
Residential Dishwashers	0.05	0.005	1.6	2.6
Residential Refrigerators	0.02	0.002	2.1	2.2
Residential Heat Pump Water Heaters	0.00	0.00	4.3	1.1
Total Residential	5.2	0.52		
Non-Residential Measures				
Industrial Non-Aluminum	3.1	0.31	1.7	2
Commercial New & Replacement Lighting	1.0	0.10	1.2	9.1
New & Replacement AC/DC Power Converters	0.6	0.06	1.5	2.7
Commercial New & Replacement HVAC	0.6	0.06	3	1.5
Commercial Retrofit HVAC	0.5	0.05	3.4	1.3
Commercial Retrofit Lighting	0.5	0.05	1.8	2.2
Commercial Retrofit Equipment	0.4	0.04	3.4	2.1
Commercial Retrofit Infrastructure	0.4	0.04	2.2	1.8
Commercial New & Replacement Equipment	0.3	0.03	2.2	1.8
Agriculture - Irrigation	0.8	0.08	1.6	3.2
Commercial New & Replacement Shell	0.1	0.01	1.6	2
Commercial New & Replacement Infrastructure	0.04	0.004	1.4	2.4
Commercial Retrofit Shell	0.04	0.004	2.9	1.3
Total Commercial	8.4	0.84		
Total	13.6	1.36	2.6	2.7

3. measures or resources with different measure lifetimes.
4. Use a forecast of regional market prices for avoided costs.
5. Calculate value of energy savings based on when the energy is saved.
6. Use a TRC test which takes into account all costs and benefits of the measures regardless of who incurs those costs or benefits. Measures that pass the TRC test are those with BC ratios greater than or equal to one.
7. Include increases or decreases in annual or periodic operating and maintenance costs due to conservation.
8. Include deferred capacity expansion benefits for transmission and distribution, administration costs and non-power benefits in cost-effectiveness analysis.
9. Use discounting where rates are based on a weighted, after-tax, cost of capital for utilities and their customers for the measure lifetime.
10. Include estimates of achievable participation for retro-fit and lost opportunity measures. The NWPCC 20-year achievable rates are 85% for retrofit and 65% for lost opportunity measures.
11. Include a 10% bonus for conservation measures as defined in 16 United States Code Section 839a.
12. Analyze results of multiple scenarios, especially scenarios where conservation is accelerated in the first few years.
13. Analyze costs of estimated future environmental externalities in multiple scenarios (measure risk).
14. Utility may also vary other inputs such as incremental costs and savings and retail growth rates.

Approach

The starting point for the potential study includes measure data primarily from NWPCC. The data for

these measures are taken from the Council's model and are included to calculate technical potential.

EESC selected a wide range of measures appropriate for the District's service territory, which satisfies the first requirement above. The specific measure data used includes incremental costs (capital and operating and maintenance), incremental savings, measure lives, levelized costs and the present value of regional costs and benefits. Because this data is from the NWPCC, requirements 4-7, 10, and 12 above are satisfied.

Along with the measure data, customer building stock data for the District's service territory is required. Since the suggested Council achievable rates are used in the analysis, requirement 9 is also met. Secondly, a life-cycle cost analysis (requirement 2) is performed by analyzing the costs of each measure over its life using a utility discount rate (requirement 8). The calculations yield levelized costs for each measure. These levelized costs take into account the different measure lives, so the costs can be compared across measures.

Requirement 3 states that avoided costs are forecasted market prices. To meet this requirement, the CPS uses the Council's updated draft interim price forecast released in November 2007 as previously mentioned.

From the customer data, achievable rates, avoided costs and measure data, EESC calculated utility cost tests and TRC tests specific to the service area. If a measure's BC ratio is greater than or equal to one (using the TRC test), the measure is counted as conservation potential.

Lastly, EESC analyzed four conservation scenarios (Business as Usual, Conservation Foundation, Phase 1 Utility Analysis and Accelerated Base) to attain biennial and long-term conservation targets. Conservation Foundation and Phase 1 Utility Analysis are descriptions developed by District staff. Also, the EESC conservation potential model has the capability to produce results for plans with accelerated conservation efforts. The model also has the capability to increase or decrease incremental savings, incremental costs and retail sales growth. This model functionality meets requirement 11 and allows for the possibilities within requirement 13.

Conservation Potential Estimates

Technical Potential

Technical potential is the amount of conservation that is technically feasible without consideration of costs. A technical potential for the District is estimated using measures regardless of cost and savings. For example, residential solar water heating is a measure with a BC ratio of 0.38 and provides savings of 5,300 MWh/year. The savings is included in technical potential even though the BC ratio is less than one and the levelized cost of the measure far exceeds the avoided cost of electricity. The avoided cost of electricity, for the purposes of this study, is the Mid-C energy forecast by the Council described earlier in

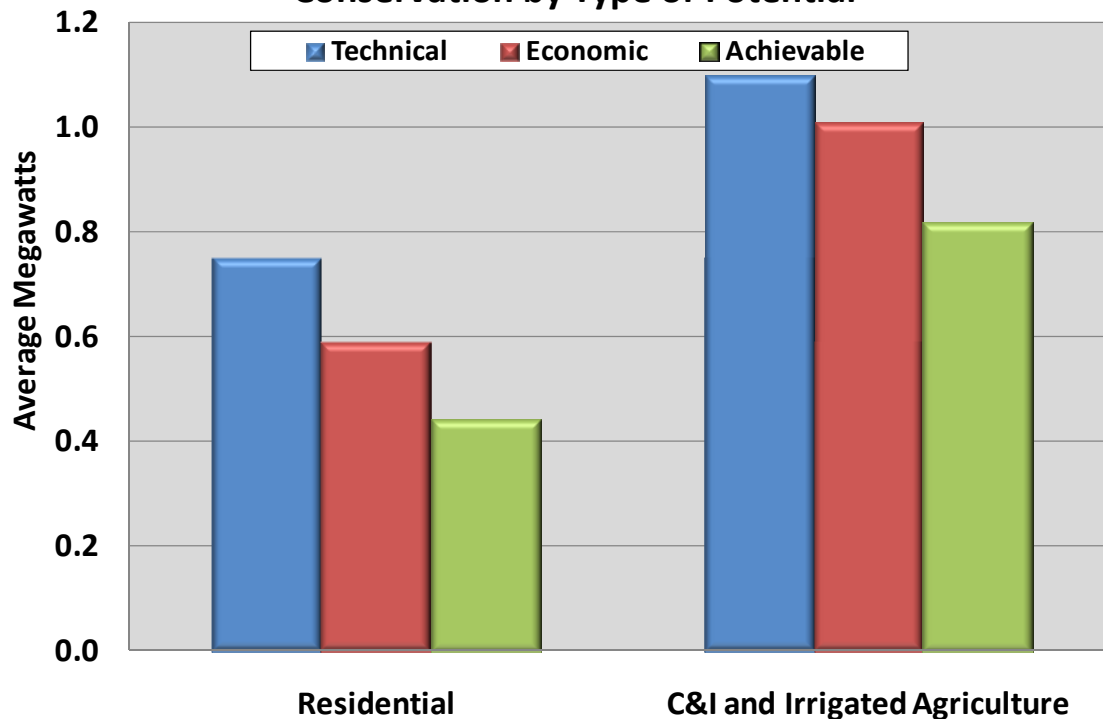
this chapter. The technical potential by sector is aggregated by measure category in Table 5.8. The most achievable potential for any one sector (discussed below) is for residential since this sector makes up almost half of all retail sales. Chart 5.2 illustrates the information provided in Table 5.8.

Economic Potential

Economic potential is conservation potential that considers the costs of the measures and is calculated using only those measures that are cost-effective. If the BC ratio exceeds one, then the measure is deemed cost-effective. Both the economic and technical potential estimates will change as the avoided cost of

Table 5.8 Phase One Utility Analysis Potential Savings aMW/Year			
End Use	Technical Potential	Economic Potential	Achievable Potential
Residential			
Heat Pump	0.11	0.06	0.04
Lighting	0.26	0.26	0.22
Refrigeration	0.03	0.02	0.01
Room AC	0.00	0.00	0.00
Weatherization and Duct Sealing	0.10	0.10	0.07
Water Heat	0.12	0.08	0.06
Customer-Side Solar	0.04	0.00	0.00
Appliances	0.07	0.05	0.03
Energy Star New Home	0.02	0.02	0.01
Total	0.75	0.59	0.44
Non-Residential			
Lighting	0.49	0.48	0.37
Weatherization	0.03	0.03	0.02
Equipment	0.01	0.01	0.01
HVAC	0.07	0.05	0.03
Water Heat	0.01	0.01	0.01
Industrial and Custom Commercial Projects	0.41	0.35	0.30
Irrigated Agriculture	0.08	0.08	0.08
Total	1.10	1.01	0.82
All Sector Total			1.26

Chart 5.2
Conservation by Type of Potential



electricity rises. For example, if the avoided cost rises to above \$150/MWh, Energy Star® Window replacement in small office buildings becomes cost-effective whereas it would not be if the cost were below \$144/MWh, the levelized cost of the measure. The savings from this measure would then be counted as both technical and economic potential.

Achievable Potential

Achievable potential is defined as the portion of economic potential that is attainable by specified participation rates. Achievable potential is calculated using expected participation rates from the Council. The Council separates measures into two categories which have different levels of expected achievability. The measures in which a unit is replaced or modified before the end of the natural life of the unit are “retrofit” measures. These measures have shorter measure lives since the application does not involve total replacement of the unit. Units that are not fully replaced are not expected to last as long. Retrofit measures for a 20-year study are assigned participation rates of 85%.

The second type of measure is lost opportunity. Lost opportunity measures arise from the assumption that units are replaced as they expire or, in the case of new construction, units are installed with 100% of their measure life intact. Lost opportunity measures have longer measure lives since the installed applications are completely new. In general, however, lost opportunity measures have fewer savings associated with them. The reason for fewer savings is that the energy-efficient unit is assumed to provide fewer savings than the alternative unit, which is dictated by current codes. Lost opportunity measures are assigned participation rates of 65%.

Overall, achievable potential is lower than economic potential. The achievable potential annual savings is calculated from the per-unit savings and the number of units that could be installed during the 20-year timeframe. This achievable number of units is a function of the number of facilities, the measures already in place, the percent with the applicable type (e.g., electric, gas or oil) and then the expected achievability rate.

Based on the District's data, the current programs pursued and data available from the Council's technical database, a Chelan County-specific conservation potential assessment and BC analysis was performed. In addition to the Council data, this analysis used census and regional data and information from the District to determine household type, building type, fuel type, appliance saturations and other pertinent information needed to determine the potential for implementation of conservation measures. While this analysis provided a guide to potential savings and costs in the District's service area, a more detailed study is required before programs are implemented or expanded.

The final list of measures is based on the applicability of measures to the District. Data such as incremental cost, savings and measure life for each of these measures was obtained from the RTF database with the exception of the industrial sector data. The industrial measure data is specific to the District's service territory, and the data was provided by the District.

Residential and Commercial Sector Conservation

Chart 5.3 and Chart 5.4 show the breakdown of conservation potential for the residential and commercial sectors under the Phase 1 Utility Analysis case scenario. The Phase 1 Utility Analysis case level of conservation assumes that programs for all cost-effective measures are pursued and achievability rates set by the Council are attained.

The residential sector annual savings are 0.44 aMW, or about 0.17 aMW below the Council's target for this sector (using the target calculator documentation procedure 3). The difference is primarily due to the exclusion of heat pump water heaters as a measure. In the Fifth Power Plan, the Council found significant achievable potential for this measure. However, since the Fifth Power Plan, heat pump water heaters have become unavailable commercially. As a result, there are fewer savings in the residential sector, about 0.095 aMW less. Another difference is that the average-sized single family house in the District's service area is smaller than the average-sized home in the region. With smaller houses, the District has less

Chart 5.3
Residential Conservation Potential

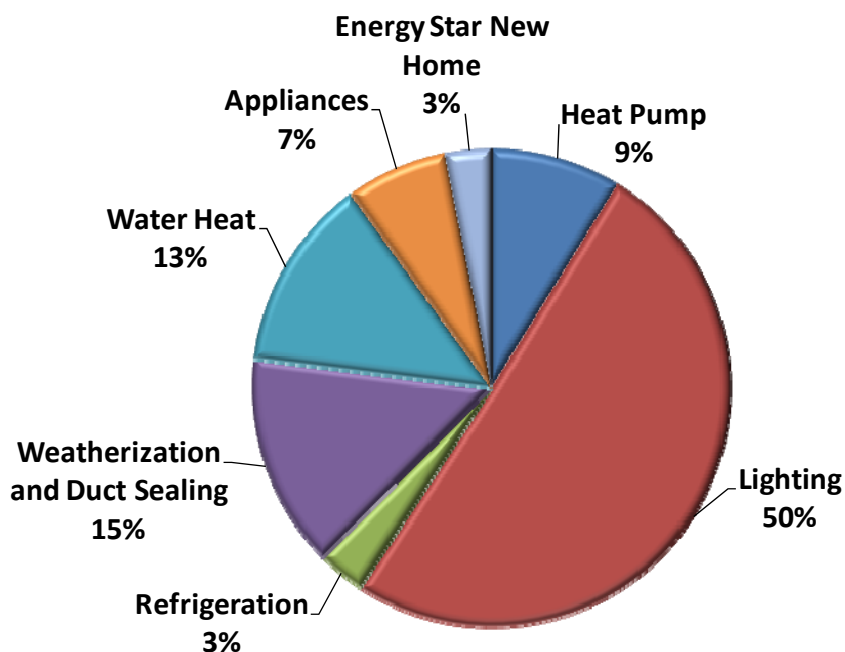
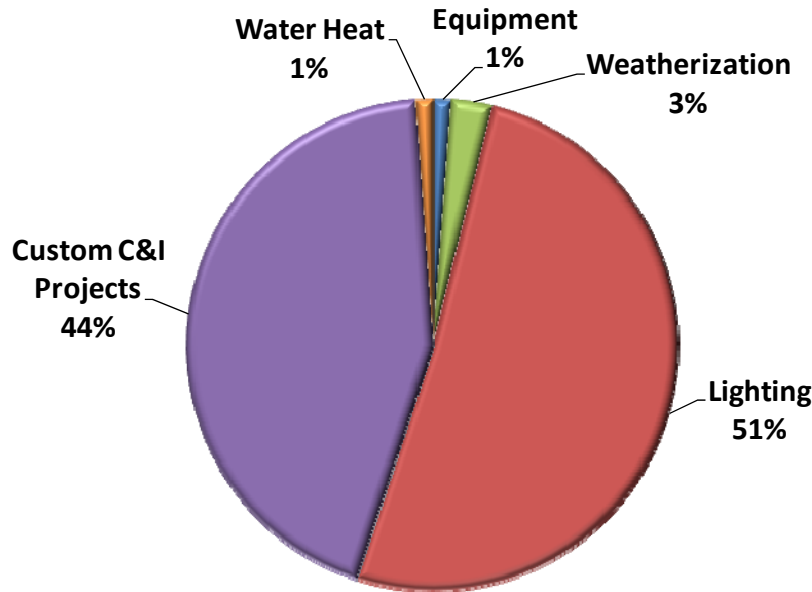


Chart 5.4
Commercial Conservation Potential



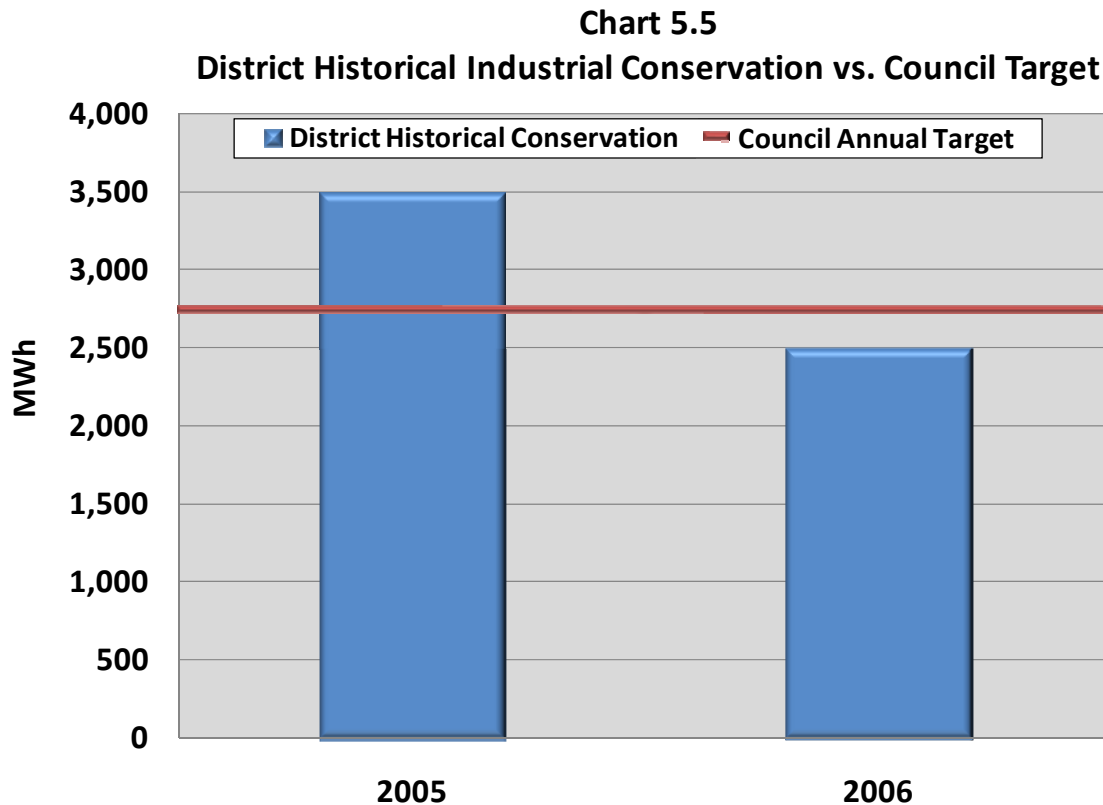
conservation potential. The average home in Chelan County is 500 to 700 square feet smaller than the average home in the entire region.

Industrial Sector Conservation

The Council's Fifth Power Plan does not detail industrial sector savings by measure, nor is data available for applicable measure savings and costs. This CPS uses data from the District to evaluate potential based on past conservation efforts and industry segmentation and other attributes.

Also, the Fifth Power Plan states that regional economic potential for the industrial sector is about 85% of technical potential, while achievable potential is approximately 85% of economic potential. Using this relationship and the Council's annual target, technical and economic potential are calculated. These potentials are shown in Table 5.8. The Council's annual target for conservation savings in the District's industrial sector is calculated to be about 2,725 MWh or 1.02% of the 2006 load.

The Council's annual target for industrial sector savings is approximately equal to recent historical ResourceSmart savings (District's industrial conservation program). Chart 5.5 compares the Council's annual target with the District's historical ResourceSmart savings. In the past, measures like fast-acting doors, variable fan drives and fan cycling controls have been implemented in many of the industrial buildings of District customers. However, substantial conservation potential exists for several measures. Future conservation savings in the industrial sector consist of lighting measures, motor efficiency and upgrades, compressors, refrigeration, pump and fan efficiency and system improvements in process and energy. Table 5.9 shows estimates of conservation potential for the region and is included for reference. The measure categories in Table 5.9 include the following industry segments: pulp and paper, food products, transportation, computers and electronics and other. The percents in column 2 are taken from the study "A Strategic Plan for Market Transformation in the Industrial Sector in the Pacific Northwest 2004 -2009." This study was finalized in



July 12, 2004 and was completed by the Northwest Energy Efficiency Alliance. Motor efficiency upgrades have the most potential of all the measures making up almost 27% of savings. Pump efficiency measures are second with 13% of savings in the industrial sector. Table 5.10 is a custom table developed from data provided by the District. This table more accurately reflects the specific industries in the District's service area and also reflects the amount of conservation potential available to the District. The future conservation savings are based on historic savings and estimates of the amount of potential still available according to District staff.

It is estimated that the District's industrial sector conservation target is 0.3 aMW per year. This target is consistent with the target calculated by the Council.

Anomalies in District Industrial Data

The Council's TRC calculations do not differentiate between utility and customer costs. Since the Council has limited data on industrial conservation,

and the District has considerable experience in industrial conservation achievements, the CPS used the District's cost and benefit data from previous Resource\$mart projects. Historically, in the District's Resource\$mart program, the District pays

Table 5.9
Regional Industrial Savings by Measure

Measure	Percent of Savings
Motor Efficiency Upgrade	27%
Motor Downsizing	6%
Rewind Improvements	5%
Compressed Air	8%
Lighting	8%
Electrical System	2%
Refrigeration	5%
Pump System Efficiency	13%
Fan System Efficiency	5%
System Improvements: Energy	8%
System Improvements: Process	4%
O&M	11%

Table 5.10
Chelan PUD Industrial Measures

Measure	Percent of 2008-2027 Savings	Levelized Cost \$/MWh
Fast-Acting Doors	15%	10.60
Air Source Heat Pump	0%	100.02
Energy Management Controls	1%	33.07
CO ₂ Scrubbers	15%	34.51
VFD Fan	24%	18.90
Thermal Siphon & Condenser	2%	37.81
ASD	0%	14.15
Refrigeration Heat Recovery	1%	18.35
Free-Cooling System	0%	616.46
New Chiller & Controls	1%	87.95
Water Treatment Lagoon Aerators	6%	21.25
Lighting	8%	10.63
Other	27%	37.77

an incentive calculated on an internal rate of return from the conservation, not the Council's TRC. In some cases, industrial customers have gained additional benefits besides energy efficiency improvements. An example is improved fruit quality in a controlled-atmosphere storage facility. The industrial company may decide to contribute more for a measure than what would normally be determined cost-effective, even though the District's contribution to the project was cost-effective. The results are that some of the levelized costs in the industrial data, using the Council's TRC, do not have a BC ratio of 1 or greater and may have a levelized cost in excess of \$600/MWh.

Irrigated Agriculture Sector Conservation

Many orchards in Chelan County rely on gravity to irrigate water to the fruit trees, however, pumps are used significantly enough to consume about 40,000 MWh of electricity annually. The Council's target for the District's irrigated agriculture sector is about 0.08 aMW per year, or 1.78% of the District's 2006 retail sales to irrigated agriculture. In the past, the District has not pursued conservation potential in this sector, however, several conservation measures exist for small and large-scale irrigation. The District may

wish to pursue the implementation of the irrigated agriculture conservation measures presented in Table 5.11. The measures in Table 5.11 are all cost-effective with average estimated costs of about \$27/MWh (2.7 cents/kWh) of savings.

Chart 5.6 shows the Council's breakdown of irrigated agriculture savings by measure type. The data is from the Council's Fifth Power Plan. The costs of these measures are given beside the percent of savings. The graph shows that most of the savings comes from replacing high and medium pressure systems with low pressure center-pivot systems. Also, a significant amount of savings is due to replacing gaskets and nozzles on leaky irrigation systems.

Conservation Scenarios

Several factors may influence the level of conservation the District attains during the study period. For instance, achievability rates and thus achievable conservation may be lower than expected. Reduced achievability rates may be due to high administration costs or low customer incentives. Also, energy prices may increase more than forecasted and cause conservation potential to

increase. This next section is meant to explore the District's conservation potential under a range of scenarios.

Business as Usual

The Business as Usual case reflects the scenario where the District does not make any changes to the way conservation programs are currently

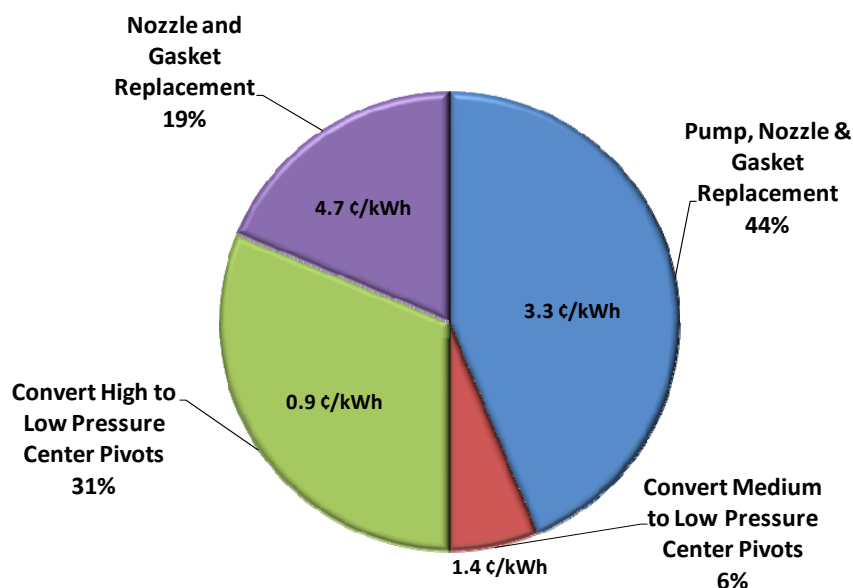
implemented. The result is conservation levels that are equal to the historic average annual conservation of approximately 0.3 aMW per year.

Conservation Foundation

The Conservation Foundation level of conservation is achieved by increasing the District's current conservation programs to include all cost-effective

Table 5.11 Irrigated Agriculture Measures	
Measure	Levelized Cost (\$2007/MWh)
Rebuilt/New Impact Sprinklers	57
Low-Pressure Regulators	57
Replace Nozzle: Impact Sprinklers	6
Flow Control Nozzle: Impact Sprinklers	57
New Hubs for Wheel-Lines	57
New Gaskets	13
New Base Boot Gasket	56
New Drains	13
Rebuild or New Wheel-line Levelers	17
New Goose Neck Elbow	19
Premium New Motors	18

Chart 5.6
Irrigated Agriculture Savings Potential Breakdown



measures as defined by the TRC test. Measures that pass the TRC test have BC ratios greater or equal to 1.

Even though the District may pursue conservation efforts that are projected to lead to achievements consistent with the Council's target, actual achievability rates may fall short. In the Conservation Foundation scenario, District Conservation staff estimates achievability rates for residential and commercial measures are 65% of the full achievability rates defined in the Fifth Power Plan. These lower achievability rates are due to changes in conservation potential due to differences between the Fifth and Sixth Power Plans, primarily due to new codes and standards, and lower customer participation rates attributable to the District's low retail rates. As a result of the estimated lower achievability rates, the average annual megawatt savings is 0.82 which is lower than the Council's target of 1.45 aMW (target calculator documentation procedure 3). Of this total, residential consumers conserve about 30 % or 0.29 aMW per year.

Phase 1 Utility Analysis

Next, the Phase 1 Utility Analysis level of conservation savings assumes that the District pursues conservation at a level beyond current programs. In this scenario, all cost-effective conservation is pursued at achievability rates set by the Council. Cost-effective potential is defined as those measures that pass the TRC test defined by the Energy Independence Act. Achievability rates are 85% for retrofit measures and 65% for lost opportunity measures as previously mentioned. At 1.26 aMW per year, this level of conservation is slightly lower than Council's suggested target for the District using the target calculator documentation procedure 3.

Accelerated Conservation

Lastly, in the Accelerated Conservation scenario, the District is able to quickly ramp up conservation savings consistent with the base level of the Phase 1 Utility Analysis. However, in this case, several retrofit measures are implemented in the first 10-year period rather than during the whole 20-year period.

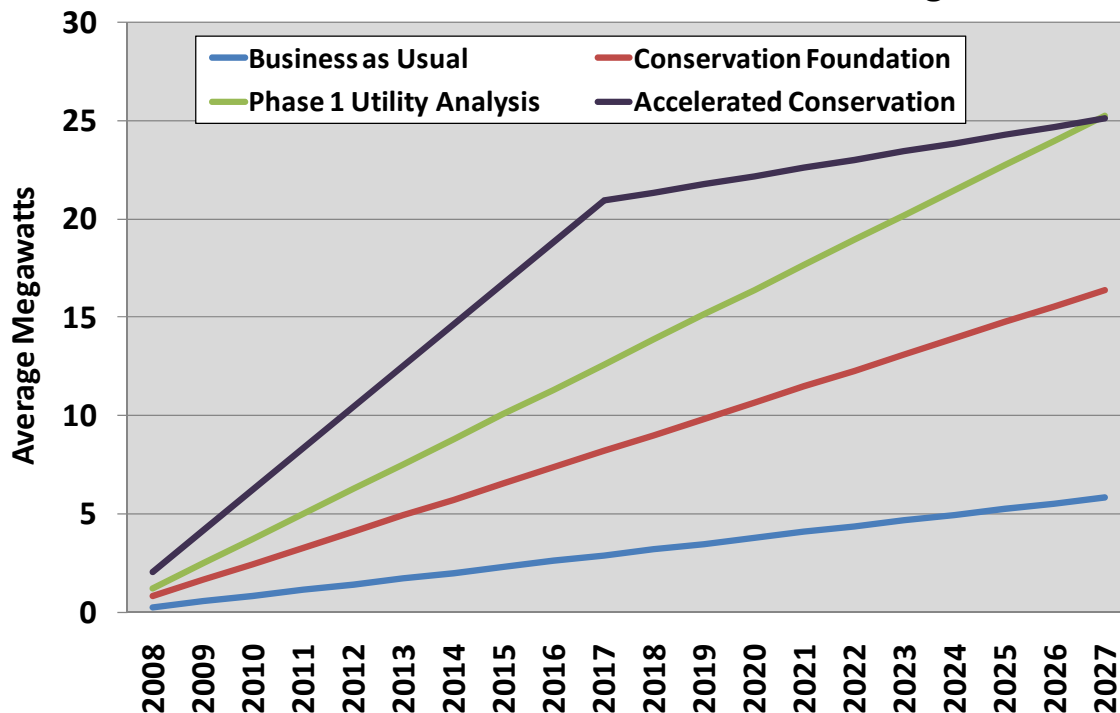
The District may wish to aggressively pursue conservation resources at the beginning of the planning period in order to take advantage of increasing, perhaps unexpectedly, market prices. Unexpected market price increases may be the result of new legislation or accelerated targets of current legislation like RPS requirements. Such RPS changes, restrictions on GHG emissions, retirement of old resources (hydro permitting issues) or other unknown types of legislation will increase generation costs of new resources. Increased generation costs could, in turn, raise electric wholesale market prices thus making more conservation viable for the District which sells excess energy on the wholesale market. For the last several years, these wholesale market prices have been higher than the District's retail rates during the vast majority of months and hours of the year. The first 10-year period, in the Accelerated scenario, has 2.11 average annual MW savings. By 2017, over 80% of the 20-year target (25.5 aMW) is achieved. An accelerated conservation plan may require higher upfront costs to achieve greater market saturations.

Scenario Assumptions

In all cases but the accelerated scenario, savings are modeled assuming the District would ramp up to the total annual savings over the full 20-year period. Also, in all cases, it was assumed that additional funding would not occur after the implementation periods end for each specific measure. However, it was assumed that markets and legislation would be the driving forces for continued conservation. This assumption would keep the level of savings constant after the programs are fully implemented and through the end of the 20-year planning timeframe.

The results of these four scenarios are shown in Chart 5.7. The implementation periods can be extended or ramped up more slowly, depending on the District's goals and customer acceptance. To achieve the higher levels of conservation, it is anticipated that, at least for a time, the conservation costs (e.g. customer marketing, incentives, and rebates) would be higher to encourage the increased participation. The Phase 1 Utility Analysis level of conservation is approximately equal to the Council's target, assuming heat pump water heaters are unavailable.

Chart 5.7
Cumulative Potential Conservation Savings



Initial Conservation Target

The District's Conservation Department staff's chosen conservation target for the IRP is 0.82 aMW. This conservation total is characterized as the Conservation Foundation level outlined in the CPS as opposed to the Phase 1 Utility Analysis Level conservation target of 1.26 aMW or the Accelerated Conservation of 2.11 aMW (in the first 10 years). The District recognizes this is below the NWPCC's conservation target but believes this is a pragmatic and conservative first step in establishing a foundation for conservation targets for Chelan County. The District's reasons for selecting this target for use in modeling for the IRP are:

- EISA 2007 was signed into law by the President in December of 2007, years after publication of the NWPCC's Fifth Power Plan conservation goals, which are the basis for RCW 19.285, Energy Independence Act. This legislation creates new Federal standards for lighting that will essentially make CFLs the standard for area lighting beginning in 2012. In the CPS, 48% of

the residential conservation potential and 49% of the commercial conservation potential are in lighting upgrades, which rely heavily on CFL lighting. There is no other lighting technology currently available, including Light-Emitting Diodes (LED), that meets or exceeds these standards in a cost-effective manner. This conservation potential will be eliminated beginning in the second year of the 10-year target, substantially reducing the conservation potential available in Chelan County.

- Final rules for the Energy Independence Act have just recently been published and were not available at the time the CPS was developed.
- The most recent wholesale price forecasts from the NWPCC were draft interim forecasts at the time Chelan conducted its CPS. The final interim forecasts were not published until April of this year. The initial draft forecast, the basis for the District's CPS, reduced the District's conservation potential when compared to current wholesale prices. The draft forecast has a

levelized value of \$35.50 per megawatt-hour, while the recent final interim forecast is valued at \$39.90, approximately 11% higher. The District recognizes that higher wholesale rates will slightly raise the BC ratios found in the CPS but reiterates that the chosen target for the initial IRP is seen as a foundation for additional study and that the Council cautions on using the interim forecasts for calculating avoided costs (see full related discussion in Chapter 6).

- Much of the data used in phase 1 of the CPS is regional data from the Fifth Power Plan and not specific to Chelan County. The targets for the Energy Independence Act are not required until 2010, a year and half after the due date for the IRP. During this period, The District will refine its conservation potential data to be more specific to Chelan County, including penetration rates for retrofit and lost opportunity conservation.
- Conservation requirements in the Energy Independence Act will significantly increase conservation efforts throughout the state. Many utilities impacted by this legislation are currently planning on expanding their conservation efforts which includes ramping up their programs during the same time period while relying on an energy conservation infrastructure not yet developed for the scope of work required by the legislation. Many utilities are looking at expanding their programs by three to four times their current levels. There is currently a shortage of experienced conservation professionals to meet new staffing requirements and a shortage of energy conservation service providers to accomplish the work. The District believes this situation will be remedied but will initially impact achievable conservation potential.
- The District supports establishing sound and realistic conservation targets that comply with the intent and spirit of the Energy Independence Act. The decision to choose 0.82 aMW for an

initial conservation target is viewed as the foundation for a long-term focus on energy conservation as a resource and in compliance with the Energy Independence Act.

Next Steps

District staff continues to develop the conservation potential by refining the demographic data of customer classes. A major part of this review is looking at both the conservation calculator and the utility-specific analysis and the different impacts each option has on the District's customers. Included in this review is an in-depth look at industrial and commercial classes that will include a survey of our large commercial customers specific to their facilities. These large commercial customers account for over 75% of the load from our commercial class.

In addition, District staff is reviewing residential programs – both regional efforts and local program potential. As part of this review, specific program measures and costs are being studied and a Request for Information, which will verify available energy efficiency programs, will be sent to regional energy services providers.

The District is participating in a statewide forum of utilities impacted by the Energy Independence Act that are sharing program ideas and issues and looking for ways to partner to create economies of scale in conservation efforts.

Automatic metering and cost-of-service studies are being conducted in an effort to determine conservation potential using metering technologies and rate design.

A system for tracking goals and conservation achievements is being developed to improve upon and replace existing systems.

Beginning in July of 2008, a business plan for conservation was started with completion targeted for the 2009 budget and potential ramp up of conservation activities.

Chapter 6 – Portfolio Modeling

In this chapter, the loads and resources previously discussed are brought together, culminating in the District's resource portfolio that was stressed and evaluated for this IRP. An overview of the modeling software that was used for this evaluation is presented as well as many of the required assumptions and parameters that went into the portfolio modeling. Finally, the District's resource portfolio is discussed in terms of Chelan PUD's somewhat unique resource position and how it compares against the evaluation criteria.

As mentioned in Chapter 3, Chelan is unique by having resources in excess of the retail loads that it serves. This is expected to remain the case throughout the planning period (2008-2018). In addition, as previously discussed in Chapter 5, the District is also expected to have sufficient renewable resources throughout this period to meet Washington State RPS requirements.

For these reasons and the fact that the District's existing resource portfolio is comprised primarily of base load, reliable, low-cost hydro resources (see resource discussion in Chapter 5), no new supply-side resources were modeled during this IRP process. Instead, the District's existing mix of supply-side resources was stressed with differing load forecasts (Chapter 4), differing forecasts of hydroelectric power costs and in one scenario, an accelerated ramp rate on certain conservation measures.

The result of the IRP modeling supports the recommendation that Chelan retain its current mix of generating resources through the planning period. Further, a starting point of 0.82 aMW/year for conservation savings, which is over a 100% increase compared to historical levels, is recommended with a good deal of additional detailed work in conservation planning to take place prior to 2010. As mentioned in Chapter 3, the District is facing expiring long-term power sales contracts during the planning period. New long-term sales contracts will begin when the current contracts expire in 2011/2012. Executed new long-term contracts are included and reduce the District's "available" power supply for modeling

purposes. No additional potential strategies for short-term or long-term power contracts were modeled or recommended as a result of this IRP. Strategies for additional power sales contracts will be analyzed in a separate process after completion of this IRP. Instead, the focus of this IRP is the District's long/short resource position after covering retail load and accounting for known long-term power sales contracts. Any surplus or deficit positions are satisfied by spot-market transactions.

Market failures and other events of the last decade have shown that utilities have an essential responsibility to understand and manage the risks associated with their energy resource portfolios. Accordingly, the District has incorporated risk analysis into the analytical process for this IRP. Although the District is not modeling new resources in this IRP, the risk analysis is still important as a means to highlight those variables that affect the District's current portfolio of generating resources and ultimately the potential variability in the net portfolio cost of the District.

The District focused on three major categories of risk which include uncertainties related to:

- Load - electricity usage by the Chelan's retail electric customers
- Hydroelectric Generation - stream flows affect the availability of hydroelectric generation (including amount and timing)
- Hydroelectric Production Cost - cost of production at the District's existing hydroelectric facilities

The modeling analysis of the District's existing resource portfolio addressed each of these three categories of risk factors as well as others. Both short-term and long-term risks were addressed, as follows:

- Short-term uncertainties (e.g., weather-induced fluctuations in retail loads) were represented by probability distributions.

- Long-term uncertainties (e.g., trends in the overall level of hydro power costs) were represented by scenario forecasts.

Wholesale spot-market prices for electricity are an additional risk factor for utilities, including Chelan. The NWPCC included eight price forecast scenarios in its recent wholesale spot market electric price forecast, however, for this IRP, the District chose to use the same forecast scenario in each resource portfolio scenario. This was due, in part, to the uncertainty in the electric industry surrounding the outcome of the Council's various forecast scenarios and how they may be appropriately used by utilities. Additionally, the District wanted to focus on uncertain variables in the IRP about which the District has more internal expertise and the ability to develop and model with greater confidence. Also, the District wanted to maintain focus on the significant uncertainty surrounding future costs at its hydroelectric projects. The Council's wholesale electric spot market forecast is discussed in detail below.

Market Price Forecast

As previously mentioned, the IRP model assumes that any excess or deficiency in the resource position would be sold into, or purchased from, the short-term spot market. Therefore, a forecast of spot market prices is necessary for resource portfolio modeling in terms of valuing spot market purchases and sales and arriving at an overall net portfolio cost. For this IRP, the District used the "high capital cost case" from the NWPCC's Final Interim Wholesale Power Price Forecast for the Mid-C that was published in April, 2008. The District chose to use the "high capital cost case" because it is reflective of what the Council expects will become their base case in the Sixth Power Plan due to the rising costs of construction.

The Council prepares and periodically updates 20-year forecasts of wholesale electricity prices for the Pacific Northwest. This forecast is used to establish benchmark capacity and energy costs for conservation and generating resource assessments for the Council's power plan. The forecasting model, once updated and otherwise set up for the forecast, is also used to support the analysis of issues related to

power system composition and operation, such as the effectiveness of GHG control policies. Finally, the Council's price forecast is used by other organizations for assessing resource cost-effectiveness and for other purposes.

The Council's wholesale power price forecast was last fully updated following completion of the Fifth Power Plan resource portfolio in late 2004 and then updated as an interim measure in 2006 for the Biennial Monitoring Report of the Fifth Power Plan. This update incorporated higher near term natural gas prices and recent new resource development. Significant changes potentially affecting the price forecast have occurred since that review. These include unforeseen rapid escalation in the construction cost of many generating resources, sustained fuel prices above the base forecast of the Fifth Power Plan, construction of substantial amounts of wind and combined-cycle capacity during a period of regional surplus of generating capacity, adoption of ambitious renewable portfolio standards by Oregon and Washington and adoption of regional energy and capacity reserve margin targets by the Council. These changes affect future wholesale energy prices, as well as the conventional use of long-term market prices as a determinant of resource cost-effectiveness. For these reasons, the Council revisited the wholesale power price forecast prior to beginning work on the Sixth Power Plan. The next update of the power price forecast will follow the development of the conservation and generating supply curves and the initial demand forecast for the Sixth Power Plan. The final Sixth Power Plan power price forecast will be prepared following development of the recommended resource portfolio from that plan.

The Council uses the AURORA[®] Electric Market Model, available from EPIS, Inc., to forecast wholesale electricity energy prices for the Pacific Northwest. The forecast is developed in a two-step process. First, using AURORA[®] long-term resource optimization logic, a forecast of resource additions and retirements is developed. In the second step, the forecasted resource mix is then dispatched on an hourly basis to serve forecasted loads. The variable cost of the most expensive generating plant or increment of load curtailment needed to meet load for each hour of the forecast period establishes the

forecast price. The Council recently updated its AURORAxmp software to version 8.4. As a result, this is the first time that the Council has implemented the capacity reserve margin capability of AURORAxmp®. The capacity reserve margin modeling is an extension of the long-term resource optimization logic and, therefore, affects the first-step of the Council's electricity price forecast process. Prior to this enhancement, the AURORAxmp® optimization logic iteratively added new resources and retired existing resources based on a resource's ability to cover its fully-allocated go-forward costs at forecasted energy market prices. With the new enhancement, the AURORAxmp® optimization logic not only builds resources to meet target planning reserve margins, but also simultaneously produces estimates of the capacity prices needed to achieve or maintain the target reserve margin. The resulting forecast of resource additions and retirements now depends on the revenues derived from the capacity prices, as well as the hourly energy prices.

The Council's forecast included the impact of RPS recently implemented in Washington, Oregon, Montana and many other Western states. The mandated addition of large amounts of renewable generating resources to the Western power system is forecast to dampen wholesale power prices in the near term. In the long-term, regulation of carbon dioxide emissions offsets the dampening effect of the RPS additions and is expected to significantly increase wholesale power prices.

In competitive wholesale power markets, generating resources are typically brought on-line in order of their variable operating costs. In other words, resources with low variable operating costs such as hydro and wind, primarily due to the "free" fuel, are dispatched before higher cost resources (with some exceptions due to operational limitations.) Wind will operate regardless of prices when the wind blows. The market price is determined by the operating cost of the last, or most expensive, generating unit needed to meet demand. The addition of RPS resources, with their lower operating costs, will displace higher variable cost resources, primarily natural gas, and is expected to result in lower variable cost resources, such as coal, clearing the wholesale market and setting the market price during many hours of the year.

Wholesale power prices vary by season, month, day of the week and time of the day because the marginal power plant changes with load which is concealed by the average, levelized price projections. Gas-fired power plants with relatively high variable costs are typically on the margin during heavier load hours, whereas coal-fired plants with lower variable costs are frequently on the margin during nighttime and weekend light load hours. During periods of high runoff, hydro generation is often the marginal generating resource.

Hydro, coal and natural gas, in descending order, are forecast to dominate the region's dispatched resource mix over the next two decades, although wind is anticipated to nearly equal natural gas energy by the early 2020s.

The Council projects Mid-C spot market wholesale power prices to fall slightly through 2011, reflecting the mandated surge in RPS eligible resources like wind power and its low operating costs. A sharp rise in Mid-C prices in 2012 and a steady increase thereafter, driven by higher CO₂ and natural gas prices is foreseen. The Council projects Mid-C prices averaging \$39.90/MWh levelized (real dollars) from 2007-2026, a 2.6% increase from the base case projection in the council's Fifth Power Plan released in late 2004.

The Council anticipates a pattern of Mid-C spot market prices declining in the near-term, from about \$42/MWh in 2007 to about \$33/MWh in 2011, then rising sharply to nearly \$40/MWh in 2012, and then steadily increasing to slightly more than \$50/MWh in 2026. RPS requirements in several states, including Washington, are the key influence for this near-term trend. From 2012 to 2026, the Council's base case projection for CO₂ goes from about \$10/ton to \$15/ton, with a levelized value of \$7.80/ton over the 20-year planning horizon. Under a high CO₂-price scenario, however, the 20-year levelized Mid-C spot market price jumps to \$52.30/MWh. This is the only case modeled that actually would reduce West-wide electricity-related CO₂ emissions.

As previously mentioned, for this IRP, Chelan used the "high capital cost case" from the Council's recent forecast due to the rising costs of construction. The "high capital cost case" had a significant impact on the forecast mix of incremental resources added to

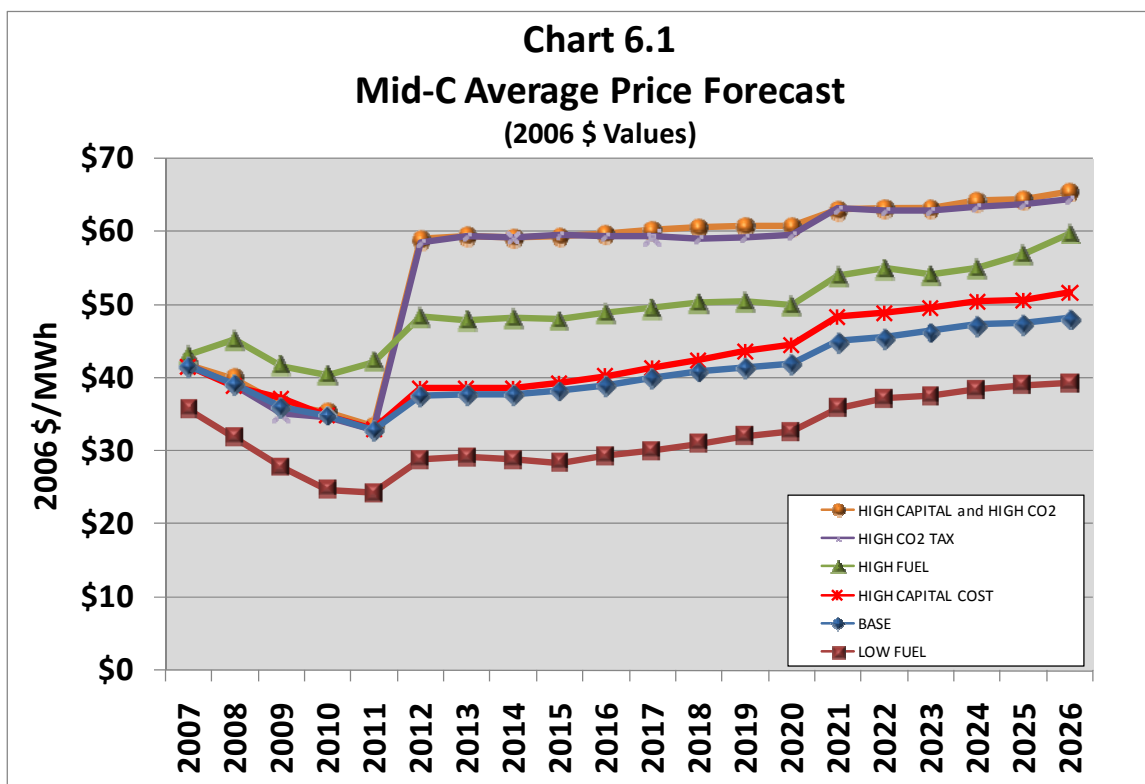
the WECC area over the planning period. Capital-intensive conventional coal-fired resources become relatively more costly and were no longer included in the incremental resource mix. Coal-gasification resources, also capital-intensive were reduced to a small increment at the end of the forecast period. Compared to the “base case” incremental resource mix, the “high capital cost case” shows a 16,247 aMW reduction in energy from these resource types in 2026. The energy output is replaced in the “high capital cost case” with 5,763 aMWs of additional output from incremental natural gas-fired resources. Though the capital costs of new natural gas resources are higher than in the “base case”, the increase is not as significant as for the coal resources because of the relatively small contribution of capital costs to the overall cost of power from natural gas-fired power plants. Incremental wind and RPS resources replace 4,045 aMWs. The remaining 6,439 aMWs of energy in 2026 are replaced by relying more heavily on currently operating resources. These changes in resource mix impact both wholesale power prices and CO₂ production. **The “high capital cost case” had a levelized wholesale power price of \$41.30/MWh, a \$1.40 increase over the “base case”.** With less reliance on incremental coal-fired resources, the

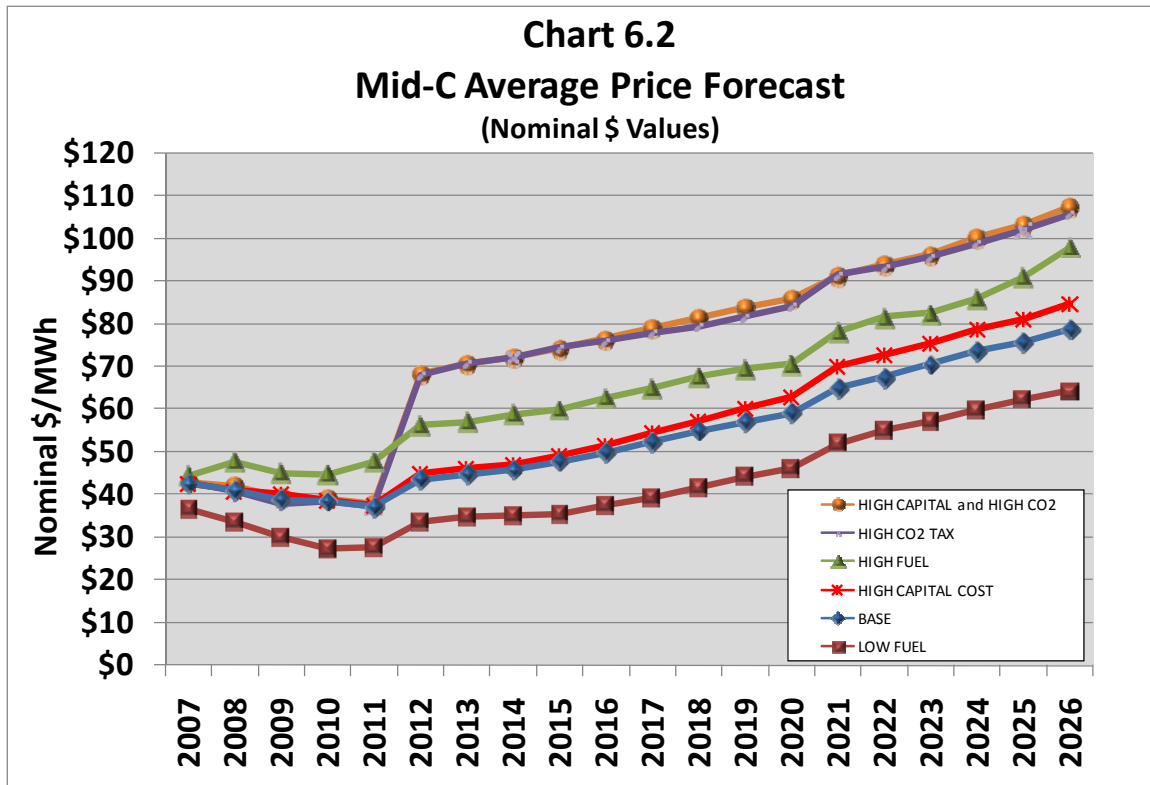
“high capital cost case” shows lower CO₂ production than the “base case”, however, annual CO₂ production continues to increase over the planning period.

The Council provided the District with data for six of the eight market forecast cases and these can be seen in real dollars in Chart 6.1 and nominal dollars in Chart 6.2.

Some regional energy officials question the message of relatively low spot market prices at a time when costs for virtually all new resources are substantially rising, owing to such factors as higher commodity expenses, a weak U.S. dollar and labor and equipment shortages. Mid-C spot market prices for 2008 have averaged \$67/MWh through May.

The Council’s forecasts predict wholesale power prices below levels where independent developers can expect to recover the full cost of constructing and operating the new renewable generating resources by selling power into the wholesale spot market. An important implication of this result is that Northwest ratepayers and utility regulators could see, at the same time, declining wholesale power prices and rising retail rates.





In the Northwest, retail electricity rates are predominately cost-based rates. The electricity rates of both consumer-owned and investor-owned utilities are administratively set to recover the expected cost of providing service. Therefore, unlike the Council's forecast near-term competitive wholesale power market prices, utilities' retail electricity rates can be expected to reflect the full capital cost associated with construction of the new RPS resources, as well as the cost of operating the resources.

The possible divergent direction of wholesale power prices and retail electricity rates can create strong incentives for utilities and their customers to rely more heavily on the short-term wholesale power markets for their energy needs. However, as the region saw during the Western electricity crisis of 2000-01, there can be significant risk associated with this strategy.

Another important implication of a possible growing divergence between wholesale and retail prices is that direct use of the Council's forecasted power prices as "avoided costs" in conservation and generating resource assessments may not be appropriate in all cases. The cost of future resource development,

measured in dollars per MWh (or cents per kWh) is often referred to as an avoidable cost or more commonly as an "avoided cost." By comparing the cost of specific conservation measures or generating resources to the region's avoided cost, the Council and others have evaluated the cost-effectiveness of pursuing these resources. In the past, the Council used its wholesale power price forecast as its best estimate of the region's future resource development cost. The region may need a different methodology for estimating its avoided cost not only because of the divergence between wholesale power prices and retail electricity rates, but also because the terms and conditions of the region's RPS statutes make it difficult to consider conservation a full alternative to RPS resource development. For example, under Washington's 15% renewable by 2020 target, every megawatt-hour of conservation only avoids 0.15 megawatt-hours of RPS resource development. In other words, the RPS avoidance rate of conservation is 15%. In Washington, and many other RPS states, conservation can be expected to primarily result in utility surplus sales or avoided purchases in the wholesale power market. A utility facing an unfilled 15% RPS mandate will see an avoided cost

comprised of 15% of the full cost of the least-cost available qualifying RPS resource plus 85% of the forecast wholesale power market prices. Avoided costs can be expected to differ for different utilities. For a utility, like Chelan, that expects to be resource sufficient after complying with state RPS requirements, avoided costs are largely determined by the rate at which the RPS resource additions are avoidable by pursuing conservation. As indicated above, under most state RPS statutes conservation and renewable resource development do not compete on an equal basis. For a surplus utility that does not face a state RPS requirement, avoided costs would equal forecasted wholesale power market prices. This is the cost of avoided purchases or the value of surplus sales in the wholesale power market. For a utility that expects to be resource deficient, avoided costs are determined by the full cost of its expected resource expansion. This is the case for a utility that does not face a state RPS requirement or a utility that is deficit after complying with a state RPS requirement. The Council intends to more fully address avoided cost issues and the role of conservation in reducing the region's carbon emissions in its upcoming Sixth Power Plan.

Further information regarding the Council's Final Interim Wholesale Power Price Forecast is found at www.nwcouncil.org/library/2008/2008-05.pdf.

Portfolio Modeling

The Model

The District purchased *Resource Portfolio Strategist* from the Cadmus Group, Inc. to perform the analysis for the IRP. It is a Microsoft Excel-based, long-term resource portfolio/risk analysis model built specifically for the electric utility industry. Users build portfolios using logical bundles of various resource options and the model provides outputs (cost and benefits) along with risk assessments and parameters. The model quantifies the risk and correlations between key variables, such as hydro availability, conservation, load and market prices, using built-in Monte Carlo simulation and scenarios analysis. Further, the model has extensive flexibility for modeling uncertainty for variables such as those previously mentioned.

The spreadsheet environment of the model has the benefit of transparency, an accelerated learning curve for analysts and flexibility relative to locked code, "black-box" models. A spreadsheet model focused on portfolio development will integrate the dynamic nature of such variables as resources, contracts, loads and markets and the uncertainties and correlations between them. Also, a spreadsheet model can be easily adjusted for various scenarios and explicit consideration of random variables.

Resource Portfolio Strategist is capable of modeling conventional generation resources, renewable resources and demand-side resources such as conservation. All resources and loads can be shaped into a maximum of eight pre-defined periods per month. The model is designed to allow, if the user specifies, addition of new capacity, retirement of existing capacity and expiration or renewal of purchase and sale contracts. It assumes that any excess or deficiency position would be either sold into, or purchased from, short-term spot markets.

Monte Carlo simulation has become the method of choice for conducting risk assessments. In this probabilistic approach, the uncertainty associated with key portfolio drivers is defined by specifying their underlying probability distributions and correlations. Key variables (such as spot market prices and load forecasts) can be adjusted and represented as probability distributions that incorporate risk for prices and availability and reliability of resources (e.g. hydro system, wind and conservation). The model's Monte Carlo method uses random sampling to draw from the defined distributions, thus generating a simulated forward time-path. After hundreds of simulations over all the appropriate variables (a combination of simulated variables is an iteration), one can glean the impacts of the underlying uncertainty on key results. This type of Monte Carlo simulation methodology is a best practice for analyzing portfolio costs under the conditions of uncertain variables. Within *Resource Portfolio Strategist*, users can specify random variables for:

- Load
- Hydro availability
- Wind (or other renewable) availability

- Conservation availability/penetration
- Electric market prices
- Natural Gas and Coal market prices, if needed
- Forced outages
- Other customizable variables

Possibly the most important risk analysis issue is the incorporation of simultaneous relationships between some of these variables. Correlations between key variables are used to better approximate real world conditions. For example, the correlation between high hydro availability and low market prices and vice versa is recognized. Correlations can be assigned between any random variables defined in the model.

In summary, *Resource Portfolio Strategist* produces results that allow comparisons to be made between differing portfolios. The user can then analyze each portfolio and determine the optimum portfolio. The process of developing an overall portfolio strategy involves three stages:

1. Development of a base case that includes existing resources
2. Development of alternative portfolios that represent different resource strategies for the utility, if necessary
3. Scenario and Monte Carlo analysis for stress testing, risk analysis and portfolio performance evaluation

Analysis Overview

Due to the District's long position in terms of resources, no new resources were added to the portfolio scenarios evaluated for this IRP. Chelan PUD is able to serve its retail load throughout the study period (2008-2018) without any new resource additions and is also expected to be able to meet Washington State RPS requirements through that time frame. For these reasons, and the ability of the existing resource portfolio to perform well against the evaluation criteria (as described later in this chapter), no new resources were modeled. However, the

District continues to stay informed of resource options (Chapter 5) and will continue to evaluate its resource portfolio on an on-going basis to ensure that the overall portfolio continues to perform well against the evaluation criteria and that regulatory requirements, specifically the Washington State RPS, are being met. For this IRP, the District's existing resource portfolio was stressed with the three load forecasts presented in Chapter 4, varying hydroelectric costs presented in Chapter 5 and an increased ramp rate for certain conservation measures also presented in Chapter 5.

Long-Term Purchaser Contracts

As mentioned in Chapter 5, Chelan has several long-term power purchaser contracts in place for the Rocky Reach and Rock Island projects that it owns and operates. The contracts are for a percentage share of the project output and projects costs. Puget Sound Energy, Portland General Electric, Avista Corp., PacifiCorp, Douglas County PUD and Alcoa Power Generating Inc. /Alcoa Inc. are purchasers at the Rocky Reach project. Puget is the only purchaser at the Rock Island project. All these contracts are set to expire in 2011 and 2012.

The District has new executed contracts with both Puget Sound Energy and Alcoa for a share of both Rocky Reach and Rock Island that will begin when their current contracts expire. Douglas County PUD has notified Chelan of their intent to extend their current agreement and increase their share of Rocky Reach per their existing contract rights.

The capacity and energy associated with all these current and future contracts were modeled and included in every portfolio, which reduced the amount of available power to the District. The project shares assumed available to the District throughout the planning period are detailed in the Modeling Assumptions and Parameters presented next.

Modeling Assumptions and Parameters

The following elements were common to all modeled scenarios:

Resources

Hydro

- To represent the generation associated with stream flow uncertainty, capacity factors were calculated using historical re-regulated stream flow data, 1929-1997, supplied by PNUCC and actual hydro project data from 1998-2007. The capacity factors reflect the reduced generation due to fish spill operations.
- Actual hourly hydro project data from 1987-2007 was used to shape the annual capacity factors into more granular time periods. This period was assumed to be most representative of current project operations. This annual shape is constant for every year of the planning period.
- Generation is net of all project obligations (i.e. Canadian Entitlement Allocations (CEAs) and encroachments)
- All operational and equipment-related incremental hydro was included (discussed in Chapter 5)
- Rocky Reach – Chelan’s share
 - 15.13% - through 10/2011
 - 41.96% - 11/2011 through 6/2012
 - 43.46% - 7/2012 through end of planning period
- Rock Island – Chelan’s share
 - 50% - through 6/2012
 - 49% - 7/2012 through end of planning period
- Lake Chelan – Chelan’s share
 - 100% - through end of planning period
- Costs of O&M and debt service detailed in Chapter 5 were each represented by scenario forecasts

Wind

- To represent the generation associated with wind uncertainty, all available historical Nine Canyon hourly wind generation (2004-2007) was used to calculate capacity factors for the on-peak, shoulder and off-peak time periods.
- Current operation of facility (i.e. historical turbine availability rates)
- Costs of O&M, debt service and transmission discussed in Chapter 5

Conservation

- Used the “Conservation Foundation” target of adding 0.82 aMW/year and related costs as detailed in Chapter 5
- All scenarios were modeled with a 20-year ramp rate on retrofit and lost opportunity measures with the exception of Scenario 3 (High Bookend) which used a 10-year accelerated ramp rate for retrofit measures

Contracts

Portland General Electric Exchange

- Seasonal exchange contract that expires 2/28/2011
- Swap of summer capacity (June-mid October) for winter energy (November-February)

Alcoa Power Sales Agreement

- Agreement between Chelan and Alcoa where Alcoa can use up to 42 MW of additional power above their project share in order to meet their power requirement that expires 10/31/2011
- The average industrial rate is used to price this additional power (assuming Alcoa remains at a 2 line operation)

Load

- The three load forecasts detailed in Chapter 4 were each represented by scenario forecasts
- Operating reserve requirements set at 6% of load (varied by scenario forecast)

Market Prices

- Electricity – The NWPCC’s “high capital cost case” from their Final Interim Wholesale Power Price Forecast that was published in April, 2008 (detailed earlier in this chapter).

Transmission

- All market purchase and sale transactions occurred at the Mid-C assuming a liquid market and no transmission constraints
- Costs associated with bringing Nine Canyon Wind generation to Chelan’s load servicing area were included in the total cost of the resource

Time-Dependent Variables (e.g. resources, contracts, load, market prices)

- HLH and LLH periods with a shoulder

period in the summer months (detailed in Chapter 4)

Financial Inputs

- All inputs were in nominal dollars
- A discount rate of 7% was used in the net present value calculations of net portfolio cost

Table 6.1 shows the District’s average annual resources for the planning period. The generation is the amount available to serve load under normal hydro conditions and includes the effects of encroachments, fish and other spill, CEA’s, the PGE exchange contract and the additional power available under the Alcoa Power Sales Agreement.

Random Variables and Correlations

As discussed earlier, *Resource Portfolio Strategist*, the District’s IRP model, captures uncertainty in key input variables by utilizing probability distributions and Monte Carlo simulation. Random samples or draws are made from the probability distributions associated with the random variables being modeled. For the District, many potential outcomes exist for each of the following variables:

- Load
- Hydro availability

Table 6.1 District’s Average Annual Resources (aMW)											
	<u>2008</u>	<u>2009</u>	<u>2010</u>	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>
Net Rocky Reach Gen	88	88	88	120	296	300	300	300	300	300	300
Net Rock Island Gen	167	167	167	167	165	163	162	162	162	162	161
Net Lake Chelan Gen	46	46	46	46	46	46	46	46	46	46	46
Net Nine Canyon Gen	2	2	2	2	2	2	2	2	2	2	2
Conservation	0.82	1.64	2.46	3.28	4.1	4.92	5.74	6.56	7.38	8.2	9.02

- Wind availability
- Conservation availability/penetration
- Electric market prices
- Forced outages

During a given “run” of the model, a random time-path is simulated for each uncertain variable. The results of these simulations for each variable were then combined together to create a single iteration. Chelan generated 500 of these iterations for each portfolio scenario so the overall result would encompass a wide range of possibilities thus giving a good representation of the uncertainty surrounding the portfolio. The resulting overall distribution of results reflects the underlying probability distributions and correlations for all the uncertain variables.

There are three components to uncertainty modeling in the model. First, the model uses a highly flexible probability distribution that can easily reflect expectations, variance and excessive skewness and kurtosis. Second, the model can incorporate mean

reversion, a statistical property found in many economic variables that are fundamentally driven by some natural process (e.g., weather or streamflows). Finally, the model is able to correlate variables, thus accounting for the relationship among variables.

Table 6.2 lists the correlations and mean reversion factors used in the IRP modeling. A more detailed description of volatility, correlations and mean reversion for specific key variables is presented next.

Load

As detailed in Chapter 4, for the overall energy sales forecast, a distribution of average monthly temperatures was developed from historical data and a percentage change in load per degree of temperature change was developed. The resulting percentage deviations around the expected weather-normalized load were used to develop weather-related probability distributions for load. There is a slight positive relationship between loads and market prices, whereas when unexpected increases in loads occur, multiple parties enter the market to make

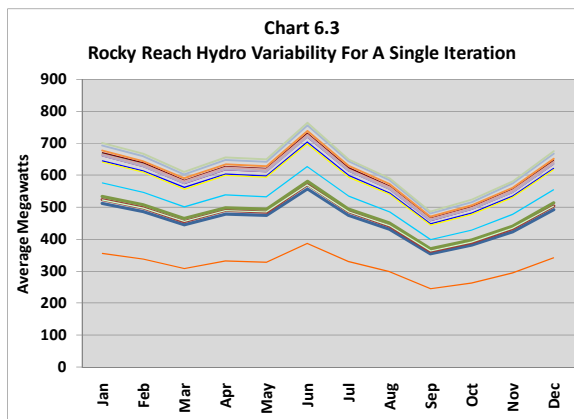
Table 6.2
Correlation Matrix and Mean Reversion Factors for Annualized Stochastic Simulations

Random Variable	Mean Reversion Factor	Load	Electric Market Prices	Conservation: Retrofit	Conservation: Lost Opportunity	Nine Canyon Wind	Rocky Reach	Rock Island	Lake Chelan
Load	-	1	.25	.35	.35	-	-	-	-
Electric Market Prices	.50	.25	1	-	-	-	-	-	-
Conservation: Retrofit	.90	-	-	1	.80	-	-	-	-
Conservation: Lost Opportunity	.90	-	-	.80	1	-	-	-	-
Nine Canyon Wind	.99	-	-	-	-	1	-	-	-
Rocky Reach	.55	-	-.15	-	-	-	1	.99	.99
Rock Island	.55	-	-.15	-	-	-	.99	1	.99
Lake Chelan	.55	-	-.15	-	-	-	.99	.99	1

system balancing purchases thus putting upward pressure on market prices.

Hydro Availability

Hydro generation variability was developed from historical generation. PNUCC supplied re-regulated project generation data for the time period 1929-1997 and District data was used for the 1998-2007 time period. Statistics were developed from this combined data set and a distribution function representing the annual variability of the historical data was created. Within a model iteration, a different annual generation amount for each project is used for every year of the planning period. This is more representative of historical patterns, rather than assuming one generation level for all years within the planning period. The hydro availability for a single iteration is shown in Chart 6.3. A mean reversion factor was applied to the annual hydro generation. This is reflective of precipitation and weather patterns that often develop over several years at a time. Since the three hydro projects are close in proximity and tend to have the same climatology and experience nearly the same hydrological conditions (e.g. precipitation, snow pack) the generation from all three hydro projects was highly correlated.



Wind Availability

The volatility and intermittency of wind was developed using four years (2004-2007) of hourly data. This volatility was applied to the on-peak, shoulder and off-peak time periods, differing each month. By applying volatility to the individual time periods, every period within each iteration can have a

different generation output. The annual generation was also allowed to vary year to year.

Conservation Availability/Penetration

The volatility of conservation achieved was provided by the Cadmus Group based on their extensive experience in the field of conservation. A fairly strong positive correlation between retrofit and lost opportunity conservation savings was used to inform the model. Additionally, a fairly weak asymmetrical correlation was applied to load and conservation, where the amount of load influences the amount of conservation. A relatively high mean reversion factor was used for conservation, meaning it will deviate little from the average and return quickly when deviations do occur.

Electric Market Prices

The NWPCC's electric market price forecast was developed using fundamental economic drivers under expected conditions, such as average stream flows and average loads based on normal temperatures. Because these conditions are often not normal, market price volatility was built into *Resource Portfolio Strategist* to reflect what can happen when stream flows and/or loads deviate from expected. During the runoff period (April through July) in the Northwest, market power prices tend to decrease due to an abundance of hydro generation that displaces higher-priced fossil fuel generation.

Both load and hydro availability are correlated with electric market prices. An asymmetrical negative correlation whereas when the amount of hydro generation increases the level of electric market prices tends to decrease was utilized. A mean reversion factor was applied to account for the fact that market prices may drift away from a long-term forecast, but over time, prices tend to revert back to the long-term forecast.

A random "price shock" was expected to take effect in 2.5% of the iterations for each portfolio. The median time from the start of the planning period for the price shock to begin was 36 months and the median duration of the shock was 18 months. The median price spike level was 2.5 times greater than prices under normal conditions. This "price shock" is

meant to represent price excursions that can happen similar to that of the Western energy crisis of 2000-2001.

Forced Outages

Although the forced outage rates at the District's hydroelectric projects are very low, a relatively small probability distribution for forced outages was developed and used in the model.

Portfolio Scenario Analysis

Three scenarios for the District's existing resource portfolio were modeled. Scenario 1 represents a base case in terms of the three major variables discussed. Scenarios 2 and 3 represent bookends to the base case. The differences between the scenarios are as follows:

Scenario 1 – Base Case

- Base Load Growth (1.9% average annual rate of growth)
- Base Hydro Costs (O&M, Capital)
- Straight line ramp on both retrofit and

Scenario 2 - Low Bookend

- Low Load Growth (1.0% average annual rate of growth)
- Low Hydro Costs (Base Hydro costs minus 5%)
- Straight line ramp on both retrofit and lost opportunity conservation measures

Scenario 3 – High Bookend

- High Load Growth (2.6% average annual rate of growth)
- High Hydro Costs (Base Hydro costs plus 20%)
- Accelerated ramp on retrofit conservation measures and straight line ramp on lost opportunity conservation measures

Evaluation Criteria

IRP analysis is generally designed to show how different resource strategies affect future performance of the overall resource portfolio in terms of key objectives. The analysis can also help examine trade-offs between multiple objectives. An example of this would be that lower net portfolio cost over the portfolio life may be a trade-off for more portfolio risk (cost volatility) or less service reliability (chance of loss of load greater). Examining trade-offs helps to identify resource strategies that are robust, by weeding out strategies whose success depends on having factors that are beyond the utility's control, (e.g. market prices, hydro generation) turn out exactly as expected or hoped, and revealing strategies that can be successful across ranges of possible future outcomes and which are more effective at mitigating risks.

Although the District did not model any new resource additions in this IRP, it is still prudent to evaluate the District's current mix of resources against a set of defined criteria. This helps set a benchmark going forward for the District in its resource planning as well as illustrates the effect of the stress scenarios on the District's current mix of generating resources. Chelan has identified reliability, cost, risk and environmental impacts as the four criteria to be used in the evaluation of its resource portfolio. These criteria represent long-held philosophies of Chelan PUD and are described below.

Service Reliability

Chelan PUD has a long tradition of providing reliable electric service to its customer/owners. Reliable service includes having enough power supply to meet customer demand as well as having enough distribution infrastructure to carry the power supply to the end user. Although the distribution system was not specifically evaluated for this IRP, the District does and is continually working to meet reliability standards that apply to the distribution infrastructure.

WECC is working toward but does not currently have a regional resource adequacy, or planning reserve, requirement. Without a standard, the risk of a deficit load resource balance within WECC or its sub-regions increases.

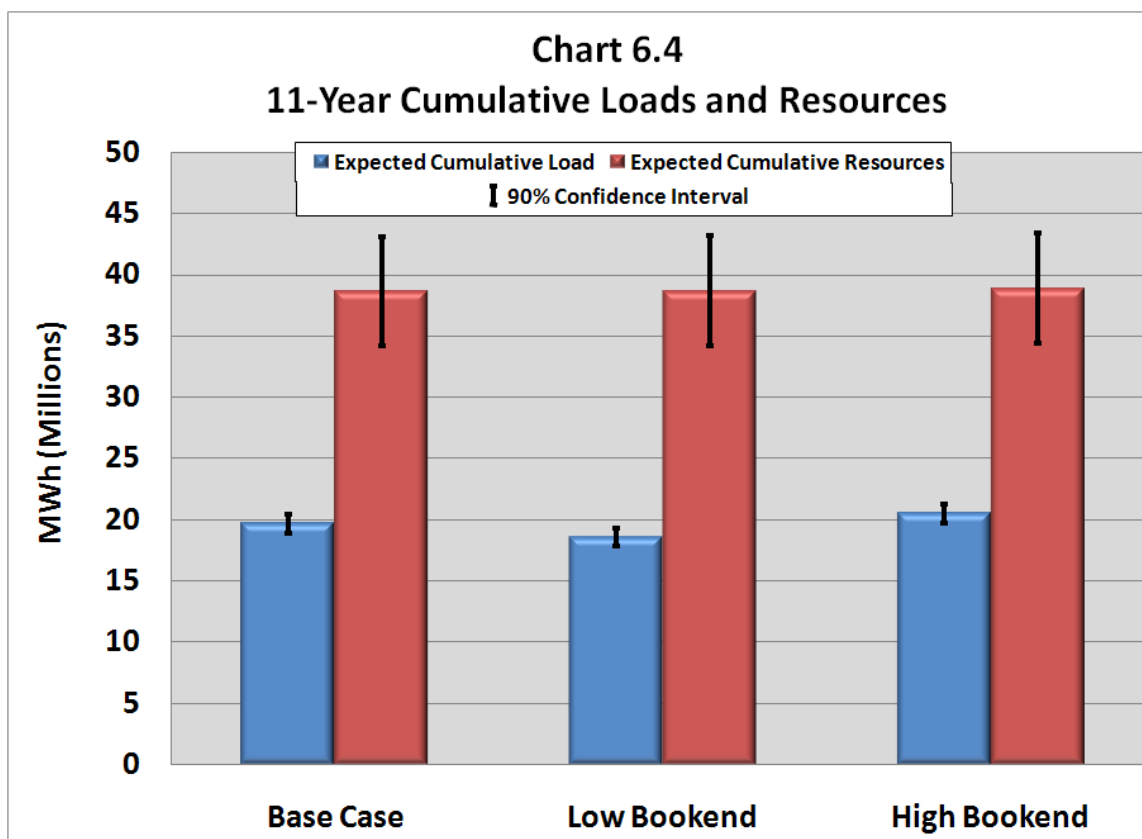
As discussed in Chapter 3, the NWPCC and BPA have been leading an effort to establish a consensus-based resource adequacy framework for the Pacific Northwest region. The newly adopted voluntary adequacy standards feature a minimum threshold for energy of zero average annual load/resource balance and for capacity, a 23% planning reserve margin in winter and a 24% planning reserve margin in summer. These thresholds incorporate a number of assumptions, including certain availabilities of uncommitted northwest independent power generation and out-of-region market power, along with firm hydropower under critical water conditions. Further work on the availability of nonfirm hydropower at a regional level is planned to refine the capacity standard.

The standards are an early warning for the region and are not intended to be a resource planning target. They are also not intended to replace regional planning efforts like the NWPCC's power plan or individual utility planning processes as each utility has to plan for its own unique resource position.

Currently, Chelan's IRP model is focused on energy

resource adequacy and not on capacity resource adequacy. As mentioned in the load discussion – Chapter 4 – all variables with a time component were evaluated on a monthly HLH and LLH basis. In July, August and September, the heavy load hours are further broken out into shoulder hour and peak heavy load periods. To more thoroughly evaluate capacity resource adequacy, loads and resources would need to be simulated on a more granular level. An hourly model is ideal for such analysis. Although the District's model is not an hourly model, it does allow for up to eight periods to be entered. The District may consider more granular data in the future.

The District has a positive load/resource balance on an average annual basis through the planning period in all three portfolio scenarios, meeting the new NWPCC regional standard with its existing resource portfolio. Chart 6.4 shows the cumulative 11-year load/resource balance. All three scenarios show a positive load/resource balance, even when the loads and resources are stressed under critical conditions. The "I-bars" on Chart 6.4 represent volatility and are the 90% confidence interval, or the percentage of



iterations that fall within the 5% and 95% tails of the probability distributions for loads and resources. For loads this volatility is from weather/temperature uncertainty. For resources, the volatility is primarily from uncertainty in stream flow and run off conditions.

An additional stress test was performed on the District's existing portfolio where the base, on-peak energy load forecast, was stressed with extreme temperatures (95% level) each month. The results showed that even at extreme temperatures, the load is covered under critical water hydro conditions. Critical hydro conditions are defined as those experienced from August 1936 through July 1937, the worst stream flows on record for the entire Pacific Northwest region. Although the District is confident in its capacity adequacy, without being able to model at an hourly granularity, this stressing of on-peak load under critical hydro conditions provided another level of analysis and comfort in terms of capacity adequacy since the NWPCC's capacity standard calls for loads during an 18-hour sustained peaking period (six hours over three consecutive days) under normal temperature conditions and also allows for an additional amount of hydropower to be available beyond critical water conditions.

Chelan's generating portfolio is comprised of hydroelectric and wind resources. The specific operational characteristics of each type of resource, including the uncertainty surrounding how much generation will be available from each type of resource, as described earlier in the chapter, was incorporated into the modeling for energy resource adequacy. Hydroelectric generation is dependent upon snow pack as well as operational limitations due to fish issues, for example, and wind generation is an intermittent resource, only available when the wind is blowing at a rate of speed required by the wind turbines.

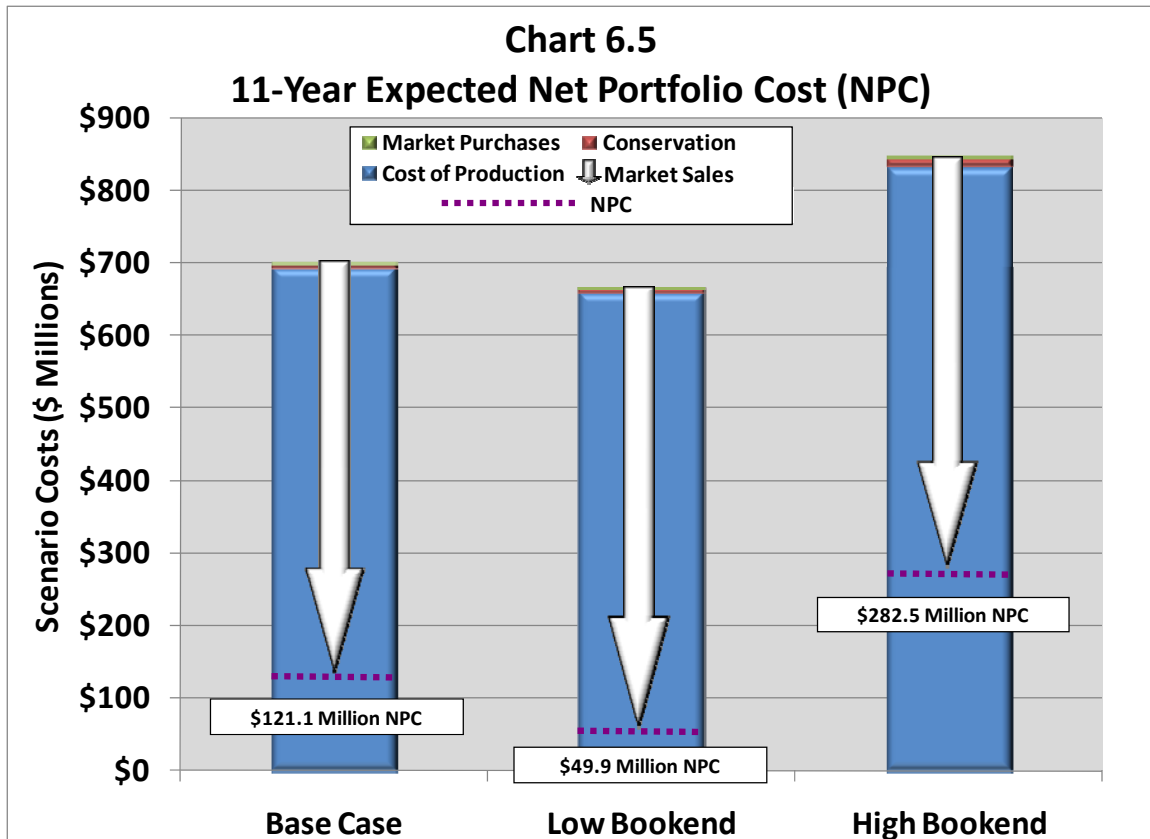
Cost

Chelan and other utilities enjoy an overall low cost of power in the Pacific Northwest due to large amounts of hydroelectric generation. Resource costs for different types of generation and the associated rising costs were highlighted in Chapter 5.

Net portfolio cost is another evaluation criterion for the District. Net portfolio cost for the District is its share of resource costs (including hydro, wind and conservation) netted with that of purchases and sales in the wholesale spot market. Specifically, the measure is an 11-year net present value (NPV) of the portfolio cost for the District's resource portfolio. Because this IRP did not add any resources to the District's existing resource portfolio for evaluation, all costs associated with District resources, including sunk capital costs, were part of the net portfolio cost measurement to illustrate the expected total costs to the District over the planning period. The results for net portfolio costs for the portfolio scenarios that were modeled are detailed in Chart 6.5.

As expected, Scenario 1 (Base Case) results in the mid-range expected net portfolio cost, while Scenario 2 (Low Bookend) results in the lowest expected net portfolio cost due to the lowest long-term load growth forecast, allowing more energy to be sold into the wholesale spot market, as well as the lowest forecast for hydro production costs. Scenario 3 (High Bookend) results in the highest expected net portfolio cost due to the highest long-term load growth forecast, a substantially higher hydro production cost forecast (+20% over the Base Case) as well as an accelerated rate of conservation. Higher load growth leads to less surplus sales into the wholesale market. Because the wholesale electric spot market forecast is higher than the District's hydro production costs, higher load growth scenarios will increase the overall net portfolio cost of the District by reducing the revenues received from surplus sales. Higher hydro production costs obviously result in higher net portfolio costs, and it is the primary factor causing the majority of the differences between the three scenario results. The accelerated rate of conservation in Scenario 3 (High Bookend) actually decreases the net portfolio cost of that scenario slightly because the cost of the conservation is less than the wholesale price of electricity as modeled.

Conservation decreases the net portfolio cost. Scenario 3 (High Bookend) has the effect of selling more power into the wholesale market sooner as a result of accelerated conservation savings. The conservation study performed for this IRP was done at a fairly high level. The same average cost per megawatt-hour for achievable conservation was used



for each scenario even though costs per megawatt-hour for an accelerated ramp may be higher. Costs to increase this ramp rate were not specifically evaluated nor were specific program types developed. The District will be examining the cost-effectiveness and feasibility of specific measures in greater detail over the next year or two. In addition, because conservation was modeled without respect to who would pay for a specific measure and to what degree, either the utility or the customer/owner, program development will also need to analyze this aspect more closely including the effect the programs will have on conservation achievability. As previously discussed, the actual costs associated with accelerating conservation and specific programs have yet to be determined.

Risk

This IRP highlights risk factors for Chelan within its existing portfolio of resources. As previously mentioned, the District has several uncertain variables within its overall load/resource outlook. Key variables include: hydro availability, wind

availability, conservation availability/penetration, load, market prices of electricity and hydro production costs.

Chelan's portfolio scenarios include underlying volatility and correlations (short-term uncertainties) as described earlier with stresses in long-term uncertainties that were represented by scenario forecasts. The differences in the expected or average net portfolio cost between the scenarios is due to changes in long-term load growth, changes in hydro production costs and an accelerated rate of conservation in one scenario.

After evaluating the three scenarios stressed for these long-term uncertainties, the District's current resource portfolio of primarily hydroelectric generation still emerges a viable long-term resource portfolio. Although future hydroelectric production costs are uncertain, the District's hydroelectric generation is still a reliable, base load, low-cost resource.

In addition to the long-term scenario risk highlighted in these expected net portfolio cost results, another

measure of risk used by the District is the variability in the net present value of the net portfolio cost. The volatility around the expected net portfolio cost for each scenario is driven by the underlying short-term uncertainties. This is expressed as a probability distribution from the Monte Carlo simulations. To assess risk, the District uses the 90% confidence interval that was discussed earlier. Table 6.3 shows the variability around the expected net portfolio costs for each scenario. It can be noted that the difference between expected and 5% level of the confidence interval is slightly greater than the difference between expected and 95% level of the confidence interval. This means that the District has a slightly greater chance at lower net portfolio costs rather than higher net portfolio costs. This is due primarily to more upside opportunity in electric wholesale spot market prices, meaning prices are assumed to have more room to go higher than lower. Chart 6.6 illustrates this same variability around the Base Case scenario using a histogram. The shape of this histogram is representative of all scenarios.

The primary driver affecting the variability of each scenario is the amount of hydro production available to the District. This is the District's greatest short-term uncertainty, and the same District existing mix of generation resources was modeled in all three scenarios. In all three scenarios, the affects of market

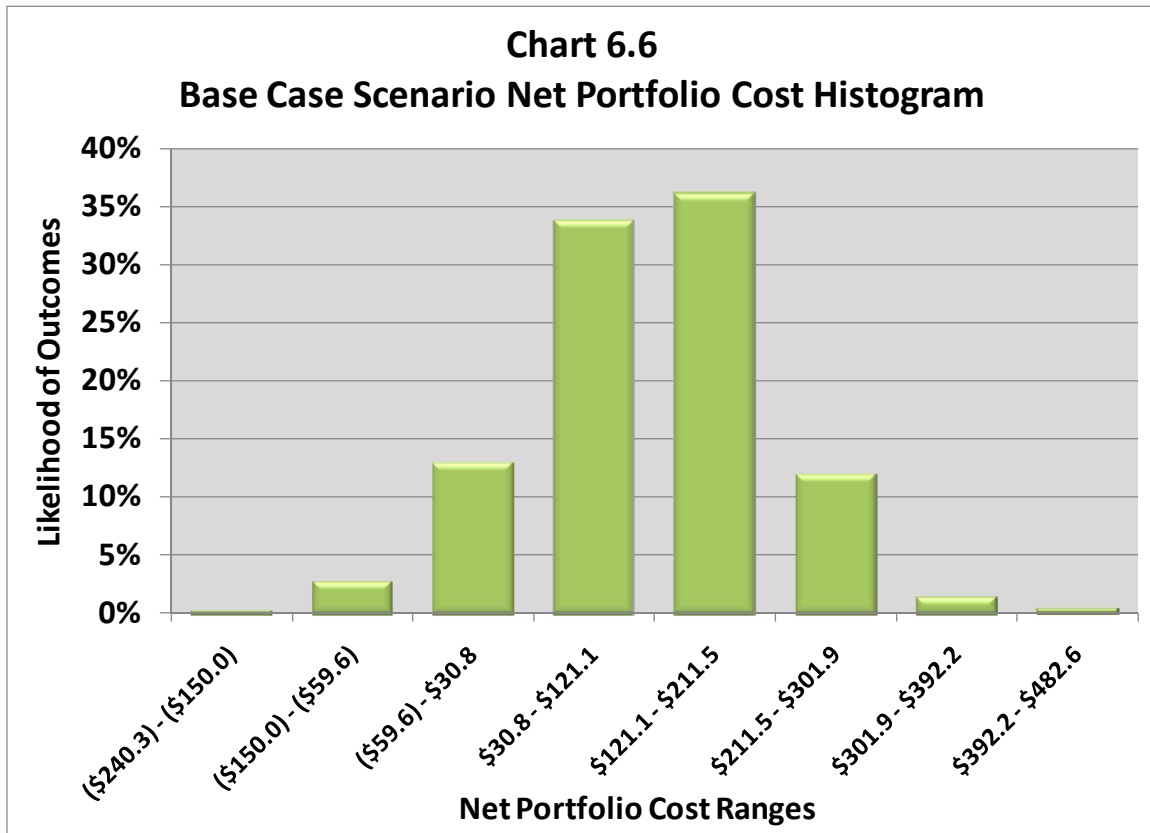
prices create slightly greater potential for lower net portfolio costs. Other utilities that are in need of new resources to meet load or other requirements that model portfolios with different mixes of generating resources would find differences in the variability around those portfolios depending upon the operating characteristics and costs of the resources that were modeled. That would be a particularly valuable measure when evaluating new resources. For the District, slight variations in volatility around the different load-growth forecasts due to weather and a slight variability increase surrounding the accelerated conservation scenario caused very small differences in variability between the scenarios. Hydro production costs were not modeled with short-term uncertainty or volatility, but rather with long-term scenario changes only.

As discussed in Chapter 3, the District and other electric utilities also face some large, rather unquantifiable risks. Federal, state and local environmental and regulatory standards could result in reduced operating levels of District facilities. Such legislation and regulation cannot be predicted. Technology changes in electric generation are also a possibility. Effects on revenues and costs due to these types of changes are unknown.

The risk to the District of environmental regulation for air emissions is being monitored but not

Table 6.3
Net Portfolio Cost Uncertainty
Probabilistic Outcomes
(\$ Millions)

Scenarios	5% level of the Confidence Interval	Difference between Expected and 5% level of the Confidence Interval	Expected	Difference between Expected and 95% level of the Confidence Interval	95% level of the Confidence Interval
Base Case	-\$27.2	\$148.3	\$121.1	\$137.4	\$258.5
Low Bookend	-\$103.3	\$153.2	\$49.9	\$137.5	\$187.4
High Bookend	\$137.4	\$145.1	\$282.5	\$139.7	\$422.2



quantitatively evaluated at this time as discussed next.

Environmental Impacts

Although other factors such as water quality and land use issues fall into the category of environmental impacts, air emissions are another significant environmental factor affecting electric power generation today. Air emissions include those from carbon dioxide (CO₂), sulfur dioxide (SO₂), nitrogen oxides (NO_x), mercury (Hg) and other particulates. The District did not explicitly model costs associated with air emissions in its portfolio scenarios because of the uncertainty surrounding future regulations for air pollutants and what costs may be associated with such regulation. As such, the net portfolio costs of the District's portfolio scenarios do not include any costs and/or benefits associated with air emissions.

The District's current portfolio of generating resources, which includes hydroelectric and wind-powered generation, does not emit any air pollutants. At any given time, air emissions are driven by whatever generating unit is on the margin in the spot

market at that point in time. When the District is selling into the wholesale market and its resources are supplying power to "the grid," that generation is assumed to be reducing generation from thermal resources in the region that do emit air pollutants. Conversely, during certain periods and hours of the year, depending upon load and hydro conditions, the District is a purchaser in the wholesale power market.

Even though the District is a net seller on an annual basis, these market purchases are deemed to take on a regional "fuel mix" per the CTED reporting detailed below. All load-serving entities in Washington have been reporting their loads and resources to CTED each year since 2003 in compliance with RCW 19.29A.010, Fuel Mix Disclosure. The Northwest Power Pool (NWPP) Net System Fuel Mix is calculated by deducting what utilities use for their own generation to cover their customer load, generation facility use and specific out of region exports. The amount of generation left over for each specific generation type becomes part of the net system mix with each generation type making up a certain percentage of the total mix. When utilities

purchase from the wholesale market, they are deemed to purchase from this “leftover” system mix. Based on the amount of wholesale purchases the District made in 2007, CTED calculated Chelan’s overall fuel mix for serving its load. Table 6.4 compares Chelan’s fuel mix with the overall NWPP Net System Fuel Mix for 2007.

It should be noted that if a utility sells the environmental attributes associated with renewable generation (e.g. wind, solar or hydro), then the actual generation itself takes on the NWPP Net System Fuel Mix so those environmental benefits are not counted twice. Chelan has sold RECs, or the environmental attributes, for its Nine Canyon wind generation as well as CCX offsets for Rocky Reach energy thus increasing the District’s overall amount of load that is deemed to be served by the NWPP Net System Fuel Mix. Therefore, purchasing from the wholesale market and selling environmental attributes associated with renewable generation has the effect of increasing a utility’s deemed emissions.

Chelan intends to continue monitoring air emissions regulation closely and what effect it may have on the District. Additionally, any proposed change to the District’s mix of generating resources in the future would need to be evaluated for its environmental impacts.

Summary of Portfolio Performance

Chelan’s existing resource portfolio is not without risk, but it performs very well when compared against the evaluation criteria. The District has adequate capacity and energy to meet its customers’ demand through the planning period thus providing for service reliability. In addition, the District has resources in excess of its customers’ demand that it can sell into the wholesale market and because the resource portfolio is comprised of primarily low-cost hydroelectric resources, the net portfolio cost to the District is much lower than for many utilities. Several of the key variables affecting the District’s portfolio are uncertain and it is the exposure to this uncertainty where the District faces some of its greatest risk. Hydroelectric generation is subject to

Table 6.4 2007 CTED Fuel Mix		
Generation Type	District Calculated Fuel Mix	NWPP Net System Fuel Mix
Biomass	0.15%	0.84%
Coal	8.25%	46.14%
Cogeneration	0.00%	0.00%
Geothermal	0.00%	0.00%
Hydro	88.09%	33.79%
Landfill Gases	0.01%	0.04%
Natural Gas	3.02%	16.77%
Nuclear	0.32%	1.81%
Other	0.01%	0.07%
Petroleum	0.07%	0.10%
Solar	0.00%	0.00%
Waste	0.08%	0.44%
Wind	0.00%	0.00%
TOTAL	100.00%	100.00%

wide swings from year to year depending upon snow pack levels, precipitation and other factors. This, in turn, creates great variability in the amount of energy the District has to cover its retail load obligation and ultimately what it has to sell into the wholesale market. As previously demonstrated, wholesale sales have a tremendous effect on reducing the net portfolio cost to the District. Facing uncertain hydroelectric production costs in the future, which could drive net portfolio costs up, makes the value of wholesale sales all the more important. Future uncertainties surrounding operational capability of the District’s resources and the impacts of environmental legislation continue to challenge the District’s planning efforts.

Chapter 7 – Short Term Plan

This 2008 IRP is a formal resource plan and will be an ongoing process. As discussed in the introductory chapter, RCW 19.280 now requires the District to produce a progress report to previously published IRPs after two years and an updated IRP every four years. This reflects the fact that resource planning is dynamic and key variables and assumptions can quickly change.

At this time, the District intends to retain its existing supply-side resource portfolio without additions or deletions except as detailed through existing contracts and obligations as outlined in Chapter 6. Additional new long and/or short-term sales contracts could potentially be executed and begin during the planning period. Further, the District plans to increase conservation over historical levels. The District is in a somewhat unique situation by having clean, reliable and low-cost (thus performing well under the evaluation criteria) resources that are surplus to its retail load as well as having enough renewable resources to meet Washington State RPS requirements through the planning period of this IRP (2008-2018).

Short-term uncertainty such as hydro and wind availability and longer-term uncertainty such as hydroelectric production costs affect the District's resource portfolio. Some key variables are subject to both short-term and long-term uncertainty. For example, load can vary day to day and season to season due to temperature fluctuations, but the underlying load growth is a longer-term issue. Similarly, wholesale market prices for electricity face daily volatility based on such factors as streams flows and natural gas prices, but are also subject to underlying long-term fundamental drivers and market structures.

The District will continue, as it has in a less formal manner for several decades, to track load growth, follow the dynamics of the ever-evolving electricity wholesale markets and monitor the regulatory environment for changes that may affect the performance of the District's existing resource portfolio. Additionally, Chelan will continue to monitor the development of new generating

technologies and how these resources may potentially affect the District. In other words, Chelan will continue to closely monitor the risks and challenges that it faces everyday while managing its resource portfolio to best meet the needs of its customer/owners.

In the Short Term

Over the next two to four years, the District has objectives related to conservation resources and resource planning as outlined below.

Conservation Resources

- Continue to develop conservation potential by refining demographic data for customer classes
- Study available energy efficiency measures and programs
- Evaluate conservation potential using automated metering technologies and rate design
- Look for economies of scale in conservation efforts with other utilities
- Develop a system for tracking goals and conservation achievements
- Produce a business plan for conservation, including conservation targets to meet state RPS
- Implement cost-effective conservation programs, which comply with requirements of the Washington State RPS

Resource Planning

- Use the 2008 IRP as foundation to start internal evaluations of long and short-term contracts in the post 2011/2012 period when current long term contracts expire

- Track the development of the NWPCC's Sixth Power Plan including:
 - Conservation potential
 - Wholesale electric market price forecasts
 - Potential new regional resources and costs
 - Resource adequacy
- Continue to follow the Council's development of resource adequacy standards and utility-specific guidance that is developed and plan for changes in standards
- Continue to track environmental legislation, including cap and trade programs and how they may impact the District's resource portfolio
- Continue to update incremental hydro generation estimates in preparation for complying with state RPS requirements beginning in 2012
- Implement *Resource Portfolio Strategist* upgrades as they become available
- Research potential methods of performing IRP analyses in more granular time periods

- Continue to revise and update model inputs as new information becomes available
- Research and evaluate the potential effects that plug-in hybrid and/or electric cars may impose on the District's retail load

Final Thoughts

Many widely-held assumptions regarding the District's resource portfolio were confirmed through the analysis in this IRP. It was expected that the District's current resource portfolio would perform well against different load forecasts and hydro production cost forecasts. However, through the development and analysis of this IRP, a significant result was the development of structured tools and processes for the District to comply with Washington's requirement for electric utility resource plans. In the future, as Chelan's loads and resources outlook changes and the regulatory environments in which the District operates evolve, the practices put into place during the development of this IRP will serve as a good foundation for future evaluation. An ongoing effort to keep improving analytical procedures and broaden resource planning capabilities will continue.

Appendix A – Washington State Electric Utility Integrated Resource Plan Cover Sheet 2008 “Long Form”

Washington State Electric Utility Integrated Resource Plan Cover Sheet									
2008 "Long Form"									
Utility Name	PUD No. 1 Of Chelan County								
Prepared By	Becky King								
Address	327 N. Wenatchee Ave.								
City	Wenatchee								
State	WA								
Zip	98801								
Phone	(509) 661-4544								
Email	becky.king@chelanpud.org								
Resource Plan Year	Base Year			2013			2018		
From	Jan-07								
To	Dec-07								
	Winter Peak (MW)	Summer Peak (MW)	Annual Energy (MWa)	Winter Peak (MW)	Summer Peak (MW)	Annual Energy (MWa)	Winter Peak (MW)	Summer Peak (MW)	Annual Energy (MWa)
Requirements									
Loads	404.80	222.81	181.28	532.00	245.00	202.80	585.00	268.00	222.70
Exports	-	50.00	2.08						
Total Requirements	404.80	272.81	183.36	532.00	245.00	202.80	585.00	268.00	222.70
Resources									
Conservation/Efficiency				5.70	6.06	4.92	10.45	11.11	9.02
Demand Response									
Cogeneration	-	-	-	-	-	-	-	-	-
Hydro (critical)	512	512	220	846	561	359	842	556	357
Wind	0.01	0.37	2.30	0.00	0.01	2.08	0.00	0.01	2.08
Other Renewables	-	-	-	-	-	-	-	-	-
Thermal - Gas	-	-	-	-	-	-	-	-	-
Thermal - Coal	-	-	-	-	-	-	-	-	-
Long Term: BPA Base Year or Tier 1	-	-	-	-	-	-	-	-	-
Net Long Term Contracts: Other	-18.00	-18.00	-28.00	-	-	-	-	-	-
Net Short Term Contracts	-	-	-	-	-	-	-	-	-
Other	-	-	-	-	-	-	-	-	-
Imports	-	-	3.33	-	-	-	-	-	-
Total Resources	494.01	494.37	197.63	851.70	567.07	366.00	852.45	567.12	368.10
Load Resource Balance	-89.21	-221.56	-14.27	-319.70	-322.07	-163.20	-267.45	-299.12	-145.40

The following notes help to describe the numbers in the table above.

- Requirements
 - Loads
 - Peak and annual energy loads are based on the District’s Base Load Growth Forecast.
 - Peak and annual energy loads, including the base year (2007), are adjusted for normal weather (i.e. an expected or 1 in 2 peak).
 - Peak and annual energy loads, including the base year (2007), do not include conservation savings.
 - Exports
 - Portland General Electric Exchange

- Resources
 - Hydro
 - For all years, it was assumed that during a single hour peak demand period, all projects would be at full seasonal capability. Values reported are net of encroachments and CEAs.
 - For all years, annual energy was calculated by using 1936-37 PNUCC critical period generation data. Values reported are net of encroachments and CEAs.
 - Wind
 - Base year (2007) wind data reflects actual Nine Canyon experience in that year.
 - 2013 and 2018 projected peak wind capacity is based on low (95th percentile) hourly Nine Canyon historical generation (2004-2007).
 - 2013 and 2018 projected average annual wind energy is based on low (95th percentile) average annual energy from Nine Canyon historical generation (2004-2007).
 - Net Long Term Contracts: Other
 - Alcoa Power Sales Agreement
 - Imports
 - Portland General Electric Exchange

Acronyms

aarg	Average Annual Rate of Growth
aMW	Average Megawatt
ATC	Available Transfer Capability
BC	Benefit/Cost Ratio
BPA	Bonneville Power Administration
CCCT	Combined-Cycle Combustion Turbine
CCX	Chicago Climate Exchange
CDCAC	Chelan-Douglas Community Action Council
CEA	Canadian Entitlement Allocation
CFL	Compact Fluorescent Lamp
CPS	Conservation Potential Study
CREB	Clean Renewable Energy Bond
CSP	Concentrating Solar Power
CTED	Community, Trade, and Economic Development (Washington State)
DOE	Department of Energy
ECY	Department of Ecology
EESC	EES Consulting, Inc.
EFSEC	Energy Facility Site Evaluation Council
EISA	Energy Independence and Security Act of 2007
EPACT	Energy Policy Act of 2005
EPS	Emissions Performance Standard
ERO	Electric Reliability Organization
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HCP	Habitat Conservation Plan
HLH	Heavy Load Hour

HVAC	Heating, Ventilation and Air Conditioning
IBEW	International Brotherhood of Electrical Workers
IGCC	Integrated Coal Gasification Combined-Cycle
IRP	Integrated Resource Plan
kW, kWh	Kilowatt, Kilowatt-hour
LED	Light-Emitting Diode
LIHI	Low Impact Hydropower Institute
LLH	Light Load Hour
Mid-C	Mid-Columbia
MW, MWh	Megawatt, Megawatt-hour
NERC	North American Electric Reliability Corporation
NPC	Net Portfolio Cost
NPV	Net Present Value
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
O&M	Operations and Maintenance
OFM	Office of Financial Management (Washington State)
PNUCC	Pacific Northwest Utilities Conference Committee
PTC	Production Tax Credit
PUD	Public Utility District
PURPA	Public Utility Regulatory Policy Act (Federal)
RCW	Revised Code of Washington
REC	Renewable Energy Credit
REPI	Renewable Energy Production Incentive
RPS	Renewable Portfolio Standard
RTF	Regional Technical Forum
SCCT	Simple-Cycle Combustion Turbine
SEPA	State Environmental Policy Act

SNAP	Sustainable Natural Alternative Power
TRC	Total Resource Cost
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
WPPSS	Washington Public Power Supply System
WUTC	Washington Utilities and Transportation Commission

Glossary

Asymmetric Correlation

See Correlation

Available Transfer Capability (ATC)

A measure of unutilized capability of a transmission system at a given time.

Average Annual Rate of Growth (aarg)

The average percentage increase in value of a given item over the period of a year. The energy load forecast is referred to in terms of the average annual rate of growth.

Average Megawatt (aMW)

A unit of energy for either load or generation that is the ratio of energy (in megawatt-hours) expected to be consumed or generated during a period of time to the number of hours in the period (total energy in megawatt-hours divided by the number of hours in the time period).

Avoided Cost

The marginal cost that a utility avoids by not having to acquire one more unit of power whether by producing the power from owned resources, building new resources or purchasing it from another entity.

Base Load Generation Resource

Electric generation plants that run at all times, except in the case of repairs or scheduled maintenance, to at least cover a minimum level of demand on an electrical supply system that exists 24 hours a day through the year.

Benefit/Cost Ratio

The net present value of all of a given conservation measure's benefits divided by the net present value of all the measure's costs over the life of the measure.

Biomass

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants and municipal wastes.

Canadian Entitlement Allocations (CEAs)

Energy returned to Canada to fulfill the obligation under the Columbia River Treaty between Canada and the United States for additional water storage constructed in Canada to help regulate hydroelectric generation. Canada is entitled to one half the downstream power benefits resulting from Canadian storage under the treaty.

Capacity

The maximum amount of power that a generator can physically produce.

Capacity Factor

The portion of full generation capacity that is actually used on average over a specified period of time.

Chelan County PUD; Chelan PUD; Chelan

In this IRP, all these references mean the legal entity of Public Utility District No. 1 of Chelan County. It is also referenced as the “District”.

Chicago Climate Exchange

North America’s only and the world’s first global marketplace for integrating voluntary, legally binding emissions and reductions with emissions trading and offsets for all six greenhouse gases.

Climate Change

Any long-term significant change in the “average weather” that a given region experiences. It involves changes in the variability or average state of the atmosphere over durations ranging from decades to millions of years.

Commercial Operation

The point at which a power plant is ready and able to generate at its full capability and deliver electricity to the transmission system.

Confidence Interval

An estimated range of values, calculated from sample data, which has a specified probability of containing a true value.

Conservation

Any reduction in electric power consumption that results from increases in the efficiency of energy use, production, transmission or distribution (from RCW 19.280 and RCW 19.285).

Conservation Potential Study (CPS)

A study designed to estimate the potential for electricity conservation in a given geographical area.

Correlation

In statistics, it is the indication of the strength and direction of a linear, symmetric relationship between two random variables. It refers to the departure of two variables from independence. Conversely, in asymmetric correlation, one variable is distinguished as being an explanatory or independent variable while the other variable has some level of dependency upon it.

Council

See Power Plan (Fifth, Sixth, etc.)

Demand

The rate at which electric energy is delivered to or by a system at a given instant; usually expressed in megawatts.

Demand-Side Resource

Peak and energy savings from conservation measures, efficiencies and load control programs that are considered a resource because they serve increased demand without obtaining new power supplies.

Dependent/Independent Variable

Dependent and independent variables refer to values that change in relationship to each other. Dependent variables are those that are observed to change in response to independent variables. Independent variables are those that are deliberately manipulated to invoke a change in dependent variables.

Dispatchable Resource

A resource whose electrical output can be controlled or regulated to match the instantaneous electrical energy requirements of the electric system.

Distribution System

The utility facilities and equipment that distribute electricity from convenient points on the transmission system to the end-use customer.

District

See Chelan County PUD; Chelan PUD; Chelan.

Econometric

The application of mathematical and statistical techniques to economics in the analysis of data and the development and testing of theories and models.

Eligible Renewable Resource

a) Electricity from a generation facility powered by a renewable resource other than fresh water that commences operation after March 31, 1999, where: (i) The facility is located in the Pacific Northwest; or (ii) the electricity from the facility is delivered into Washington state on a real-time basis without shaping, storage, or integration services; or b) Incremental electricity produced as a result of efficiency improvements completed after March 31, 1999, to hydroelectric generation projects owned by a qualifying utility and located in the Pacific Northwest or to hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional generation in either case does not result in new water diversions or impoundments (from RCW 19.285).

Encroachments

When a downstream hydro project is built and increases the tail water elevation of an upstream hydro project, capacity and energy of the upstream hydro project is reduced. To compensate for the loss of capacity and energy, the downstream project delivers energy to the upstream project.

Energy Independence Act

Refers to RCW 19.285, a ballot initiative passed in Washington State in November, 2006. It is otherwise known as the Washington State Renewable Portfolio Standard (RPS.) Under the initiative, utilities with a retail load of more than 25,000 customers are required to use eligible renewable resources or acquire equivalent RECs, or a combination of both, to meet 3% of load by January 1, 2012, 9% by January 1, 2016 and 15% by January 1, 2020. The initiative also requires that by January 1, 2010, utilities evaluate conservation resources using methods

consistent with those used by the NWPCC and pursue all conservation that is cost-effective, reliable and feasible. Each utility must establish and make publicly available a biennial acquisition target for cost-effective conservation.

Expected Value

The sum of the probability of each possible outcome of a random variable multiplied by the outcome value. Thus, it represents the average amount one “expects” as the outcome of the random trial when identical odds are repeated many times.

Fifth Power Plan

See Power Plan (Fifth, Sixth, etc.)

Fossil Fuels

They are hydrocarbons found within the top layer of the Earth’s crust.

Greenhouse Gas

Gases that are present in the earth’s atmosphere which reduce the loss of heat into space and therefore, contribute to global temperatures through the “greenhouse effect”.

Histogram

A graphical display of tabulated frequencies for a given probability distribution showing what proportion of outcomes fall into each of several categories.

Hydro Resources

Facilities used to produce electricity from the energy contained in falling water (river, locks or irrigation systems).

Incremental Generation

Electricity produced as a result of efficiency improvements completed after March 31, 1999, to hydroelectric generation projects owned by a qualifying utility and located in the Pacific Northwest or to hydroelectric generation in irrigation pipes and canals located in the Pacific Northwest, where the additional generation in either case does not result in new water diversions or impoundments (from RCW 19.285).

Integrated Resources Plan (IRP)

An analysis describing the mix of generating resources and conservation and efficiency resources that will meet current and projected needs at the lowest reasonable cost to the utility and its ratepayers (from RCW 19.280).

Intermittent Resource

An electric generator that is not dispatchable and cannot store its fuel source, and therefore, cannot respond to changes in system demand.

Kilowatt (kW) and Kilowatt-Hour (kWh)

One thousand watts; the standard measure of electric power consumption of retail customers. A kilowatt-hour (kWh) is a measure of electric energy equal to one kilowatt of power supplied to or taken from an electric circuit for one hour.

Kurtosis

A measure of the "peakedness" of the probability distribution of a random variable. Higher kurtosis means more of the variance is due to infrequent extreme deviations, as opposed to frequent modestly-sized deviations.

Levelized Cost

The constant stream of values that produces the same present value as the non-constant stream of values, using the same discount rate. In this IRP, levelized cost is used to refer to the cost for 1) conservation measures over EESC's 20-year CPS and 2) the NWPCC's 20-year wholesale electric market price forecasts. For the CPS, equal annual payments were divided by annual kilowatt-hours saved and for the electric market price forecast, the cost is expressed in dollars per MWh. Costs are levelized in real dollars. For example, the amount borrowed from a bank is the present value of buying a house; the mortgage payment including interest on a house is the levelized cost of that house.

Load

The amount of electric power delivered or required at any specified point or points on a system. Load originates primarily at the power-consuming equipment of the customer.

The amount of kilowatt-hours of electricity delivered in the most recently completed year by a qualifying utility to its Washington retail customers (from RCW 19.285).

Load Following

A utility's practice of adding additional generation to available energy supplies to meet moment-to-moment demand in the distribution system served by the utility, and/or keeping generating facilities informed of load requirements to insure that generators are producing neither too little nor too much energy to supply the utility's customers.

Load Forecasting

The procedures used to estimate future consumption of electricity. Load forecasts are developed either to provide the most likely estimate of future load or to determine what load would be under a set of specific conditions; e.g., extremely cold weather or changing demographics.

Low Impact Hydropower Institute (LIHI)

A non-profit organization dedicated to reducing the impacts of hydropower generation through the certification of hydropower projects that have avoided or reduced their environmental impacts pursuant to the Low Impact Hydropower Institute's criteria.

Mean Reversion

The tendency for a random variable to remain near, or tend to return over time to a long-term average. A variable can have a high or low mean reversion factor depending on how quickly the variable moves back to its average.

Megawatt (MW) and Megawatt-Hour (MWh)

One thousand kilowatts, or 1 million watts; the standard measure of electric power plant generating capacity. A megawatt-hour (MWh) is a measure of electric energy equal to one megawatt of power supplied to or taken from an electric circuit for one hour.

Monte Carlo Simulation

In the 1940's, scientists at Los Alamos National Laboratory created a computer program to create random combinations of known, uncertain variables to simulate the range of possible nuclear-explosion results. They nicknamed the program Monte Carlo, after that city's famous casinos. The District's resource portfolio/risk analysis model, *Resource Portfolio Strategist*, uses Monte Carlo simulation to model the risk and correlations between key variables, such as hydro availability, conservation and load and market prices.

Nominal Dollars

Dollars that are paid for a product or service at the time of the transaction. Nominal dollars are those that have not been adjusted to remove the effect of changes in the purchasing power of the dollar (inflation); they reflect buying power in the year in which the transaction occurred.

Northwest Power and Conservation Council (NWPCC)

See Power Plan (Fifth, Sixth, etc.)

Peak Capacity

The maximum output of a generating plant or plants during a specified peak load period.

Peak Demand (Load)

The maximum demand imposed on a power system or system component during a specified time period.

Peak(ing) Power

Power generated by a utility system component that operates at a very low capacity factor; generally used to meet short-lived and variable high demand periods.

Planning Reserve Requirement

The requirement that a utility have capacity at its disposal that exceeds its expected peak demand by a certain percentage.

Portfolio

A set of supply-side and demand-side resources currently or potentially available to a utility.

Power Plan (Fifth, Sixth, etc.)

A 20-year electric power plan that guarantees adequate and reliable energy at the lowest economic and environmental cost to the Northwest. A new plan is developed every five years as a result of the Northwest Power Act of 1980 that authorized the formation of the Northwest Power and Conservation Council (NWPCC or the Council.) The Fifth Power Plan, the most recent, was adopted in December 2004. Work on the Sixth Power Plan is underway. The NWPCC is also mandated to develop a fish and wildlife program to protect and rebuild populations affected by hydropower development in the Columbia River Basin and conduct an extensive program to educate and involve the public in their decision-making processes.

Probability

The likelihood or chance that something will happen.

Probability Distribution

Describes the values and probabilities associated with a random event. The values must cover all the possible outcomes of the event, while the total probabilities must sum exactly 1, or 100%.

Random Variable

A function that associates a unique numerical value with every outcome of an experiment. The value of the random variable will vary from trial to trial as the experiment is repeated.

Real Dollars

Dollars that have been adjusted to remove the effects of inflation. Real dollars are sometimes called uninflated dollars.

Regional Technical Forum (RTF)

An advisory committee established in 1999 to develop standards to verify and evaluate conservation savings. Members are appointed by the NWPCC and include individuals experienced in conservation program planning, implementation and evaluation.

Regression Analysis

A technique used for the modeling and analysis of numerical data consisting of values of a dependent variable (response variable) and of one or more independent variables (explanatory variables).

Renewable Energy Credit (REC)

A tradable certificate of proof of at least one megawatt-hour of an eligible renewable resource where the generation facility is not powered by fresh water, the certificate includes all of the nonpower attributes associated with that one megawatt-hour of electricity, and the certificate is verified by a renewable energy credit tracking system selected by the department (from RCW 19.285).

Renewable Resource

A resource whose energy source is not permanently used up in generating electricity.

Electricity generation facilities fueled by: (a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; (f) biomass energy utilizing animal waste, solid organic fuels from wood, forest, or field residues or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (g) byproducts of pulping or wood manufacturing processes, including but not limited to bark, wood chips, sawdust, and lignin in spent pulping liquors; (h) ocean thermal, wave, or tidal power; or (i) gas from sewage treatment facilities (from RCW 19.280).

Means: (a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; (f) wave, ocean, or tidal power; (g) gas from sewage treatment facilities; (h) biodiesel fuel as defined in RCW 82.29A.135 that is not derived from crops raised on land cleared from old growth or first-growth forests where the clearing occurred after December 7, 2006; and (i) biomass energy based on animal waste or solid organic fuels from wood, forest, or field residues, or dedicated energy crops that do not include (i) wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (ii) black liquor byproduct from paper production; (iii) wood from old growth forests; or (iv) municipal solid waste (from RCW 19.285).

Resource Adequacy

A measure defining when a utility has sufficient resources to meet customer needs under a range of conditions that affect supply and demand for electricity.

Resource Mix

The different types of resources that contribute to a utility's ability to generate power to meet its loads.

Scenario

A possible course of future events. In the IRP, scenarios are used to compare the District's existing portfolio of generating resources under a range of possible future conditions including: various load forecasts, various hydro production cost forecasts and differing ramp rates for conservation.

Seasonal Exchange

An agreement between two electricity suppliers to send each other electricity at different times, so they can shape their resources to fit customer demand. Such agreements work best between suppliers whose peak demands occur in different seasons. For example, Chelan usually has surplus energy during the summer while its heaviest load is in the winter. Other utilities may be the reverse of that.

Shape

Refers to the nature of power generation capability and loads to change in quantity over time; changing from day to day and month to month.

Sixth Power Plan

See Power Plan (Fifth, Sixth, etc.)

Skewness

The degree to which a probability distribution departs from symmetry about its expected, or average, value.

Sunk Costs

Costs that have been incurred and which cannot be recovered to any significant degree. These should not normally be taken into account when determining whether to continue a project or abandon it because they cannot be recovered either way.

Supply-Side Resources

Those power resources that come from a power generating plant or facility.

Surplus Energy

Energy that is not needed to meet a utility's load or contractual commitments to supply firm or non-firm power.

Total Resource Cost (TRC)

The sum of all costs associated with a conservation measure, including both consumer and utility costs.

Transmission System

Often referred to as the “grid”, it is the system of electrical lines that allows the bulk delivery of electricity to consumers typically between a power plant and a substation near a populated area. Due to the large amount of power involved, transmission normally takes place at high voltage (110 KV or above) and because of the long distances often involved, overhead transmission lines are usually used.

Weather-Normalized Load

Actual energy load data that has been mathematically adjusted to represent an energy load that would have occurred in an average weather year.