Chapter 1 – Executive Summary

Summary of Determinations

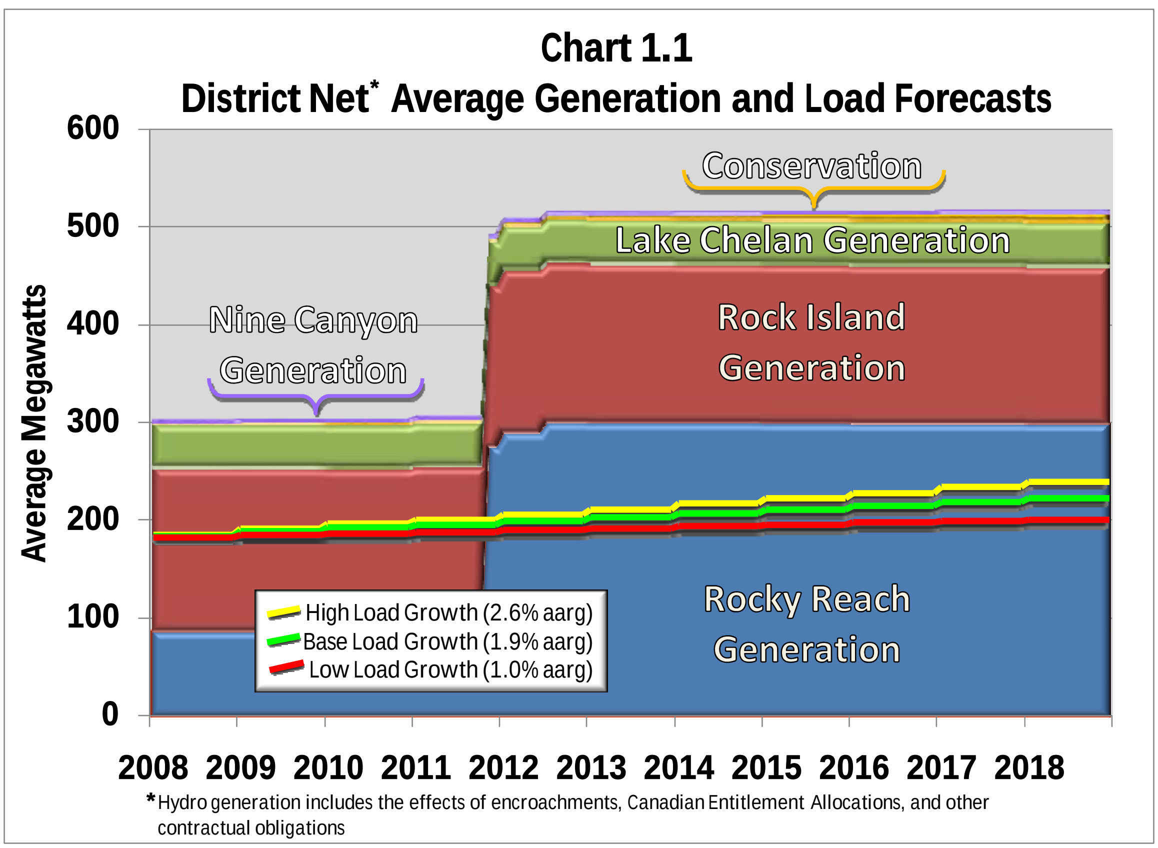
Based upon the analysis of the Integrated Resource Plan (IRP) over the 2008-2018 planning period, the Board of Commissioners of Chelan County PUD determines that:

- 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

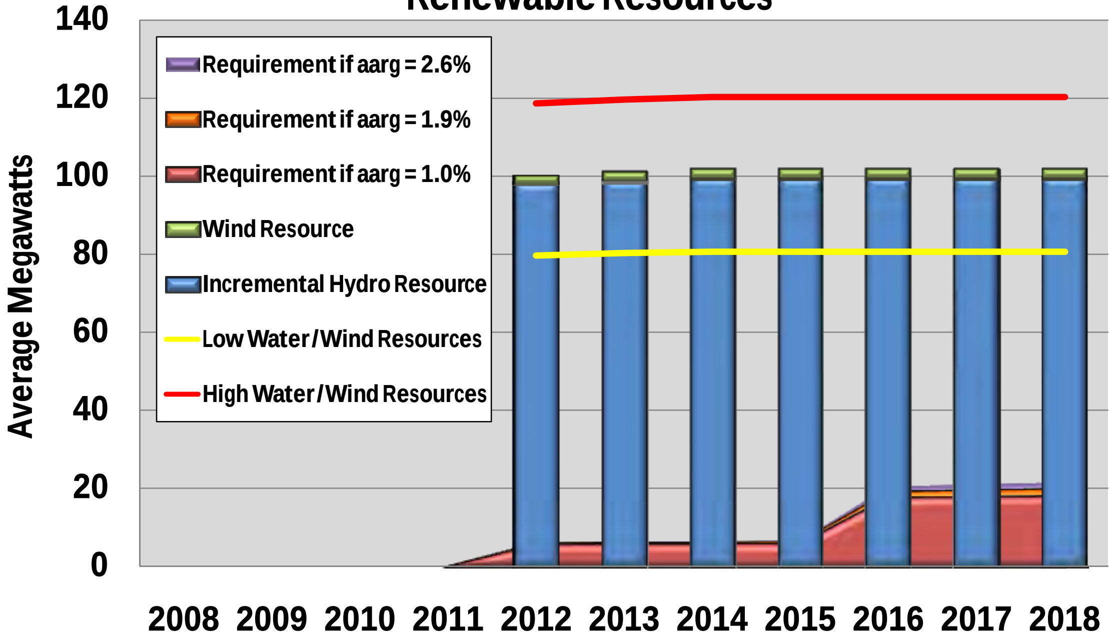
The District must comply with Washington State RPS renewable requirements beginning in 2012. The renewable energy section of the initiative requires utilities to serve percentages of retail load, which increase over time, with eligible renewable energy, RECS or a combination of both. Most hydropower 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.

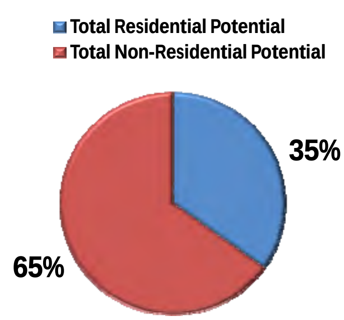
Conservation

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 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 compliments 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 and 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

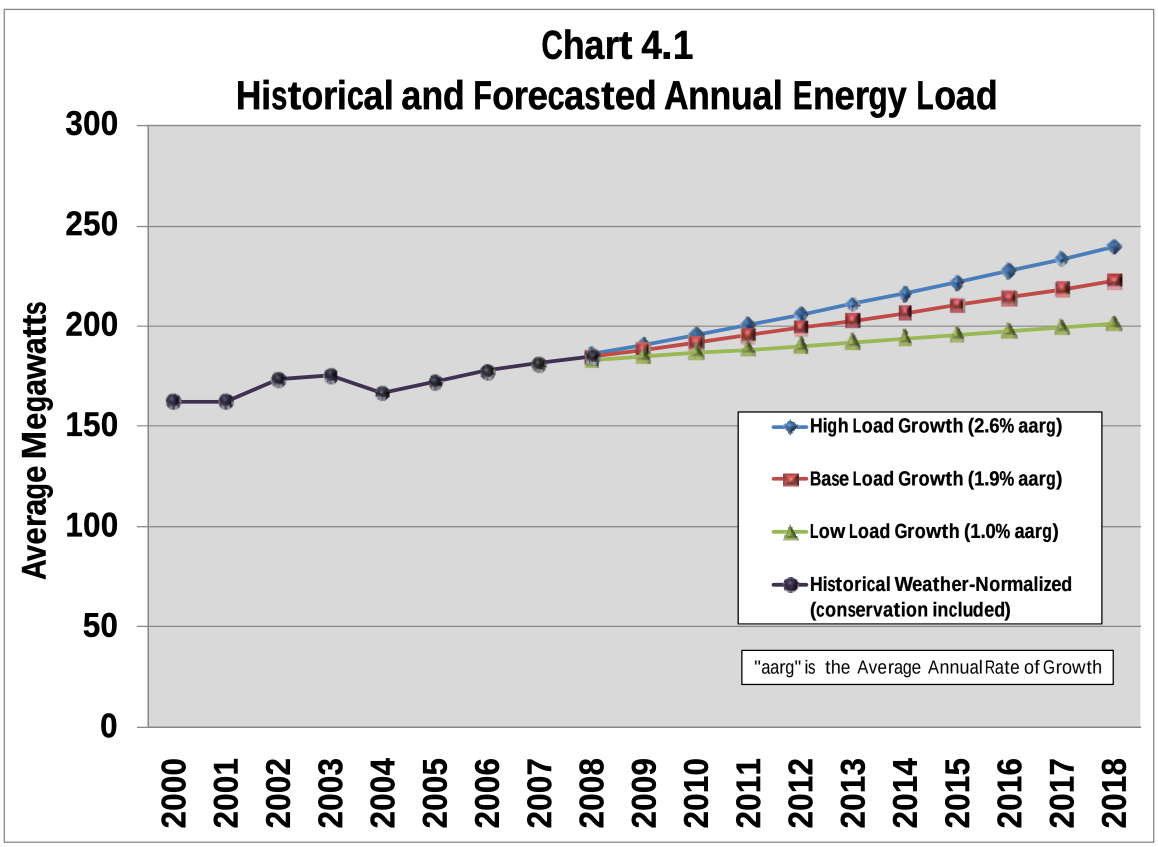
The City of Cashmere, which buys power from the District, is the one area in Chelan County that has operated its own electrical distribution system. Currently, the District is in the process of negotiating with the City to purchase this system. For this forecast, historical sales data (total annual megawatt-hours) 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.