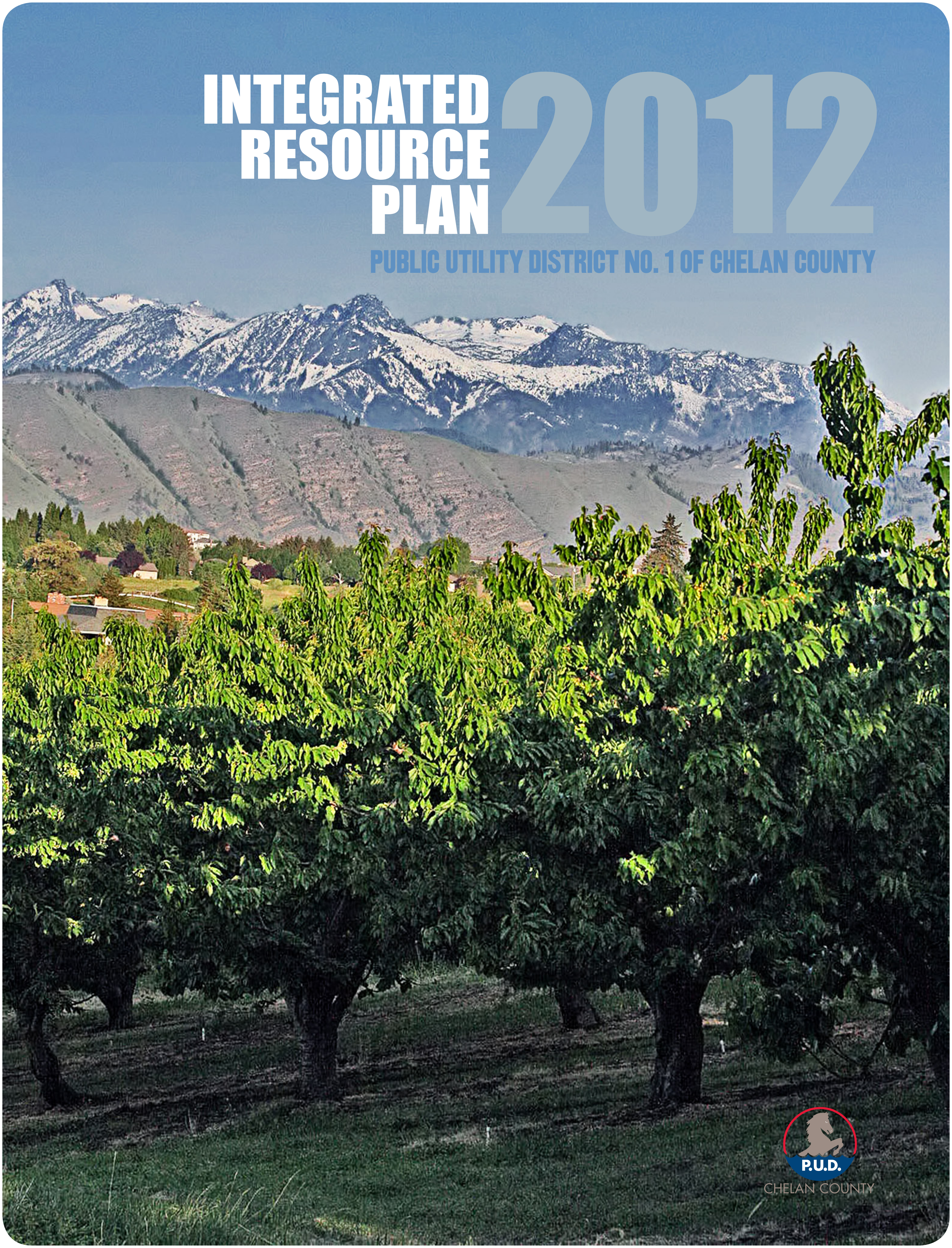
INTEGRATED RESOURCE PLAN 2012

PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY



P.U.D.
CHELAN COUNTY

2012 Integrated Resource Plan

July 2012

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Cover Photo by: Bob King

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2012 Integrated Resource Plan

Summary of Determinations

The District has completed its 2012 Integrated Resource Plan (IRP). This IRP is required by the Revised Code of Washington (RCW) 19.280: Electric Utility Resource Plans passed by the legislature in 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. Consumer-owned utilities shall encourage participation of their consumers in development of their IRPs and progress reports after providing public notice and hearing.

Based upon the analysis over the 2012-2022 planning period, the Board of Commissioners of Chelan County Public Utility District (Chelan PUD or District) has approved this 2012 IRP and determined that:

- The District retain its current mix of generating resources.

And additionally:

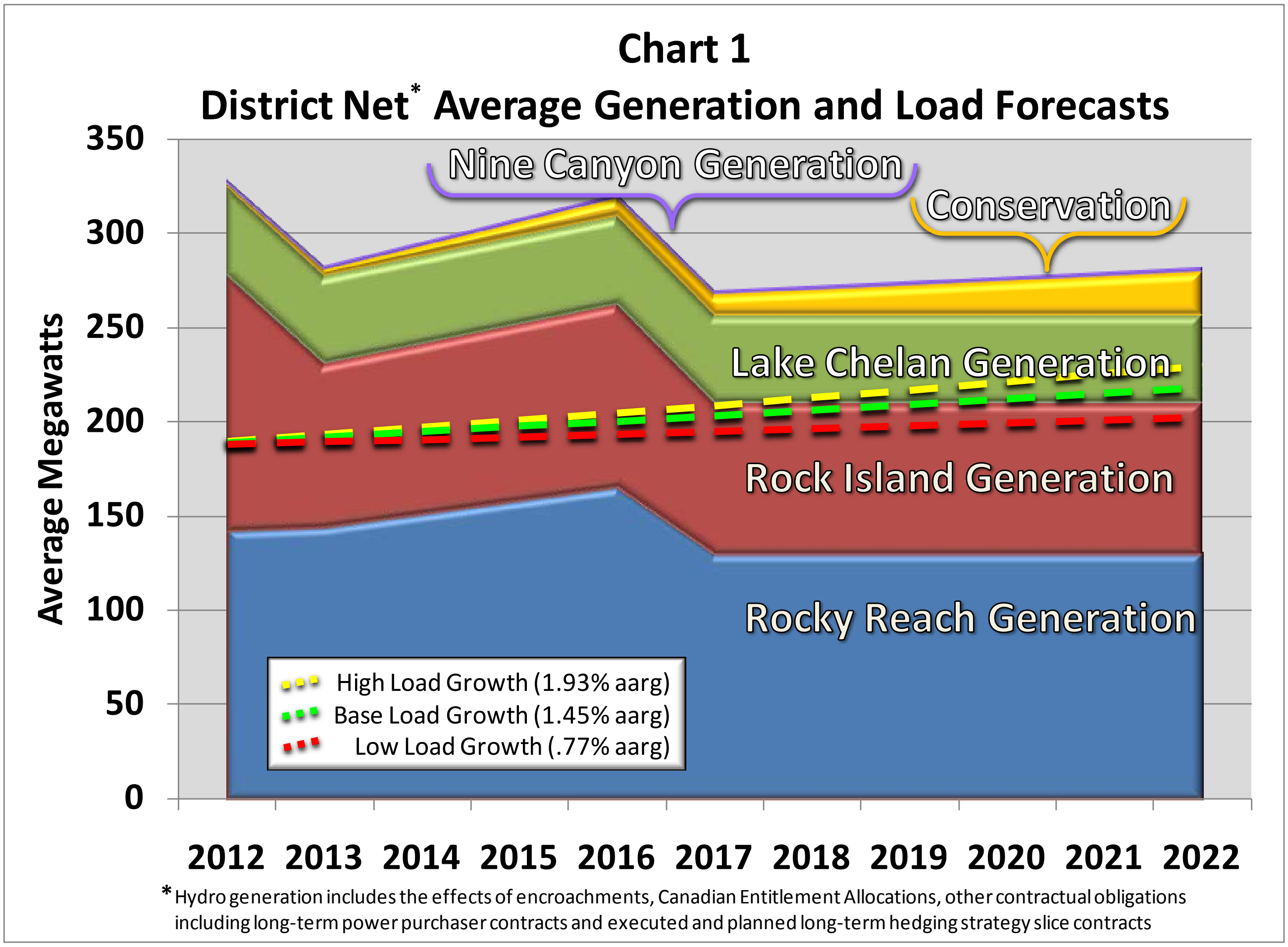
- The District continue to evaluate and implement conservation programs based on the foundational work performed in the 2011 conservation potential assessment (CPA).
- The District carry on the evaluation and implementation of strategies for additional power sales contracts and ancillary services contracts consistent with financial policies and the hedging strategy.

These determinations continue to provide the platform for the District to serve its customer/owners with reliable, low-cost, renewable energy resources for the foreseeable future. Chart 1 represents the District's mix of generating resources in relation to the latest 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.

Report Overview

To meet the requirements of RCW 19.280, the development of Chelan PUD's 2012 IRP includes the following:

- An update of the long-term forecasts of retail electric customer demand
- Utilizing a forward price curve of market prices for wholesale power
- Revised costs and operational information for Chelan PUD's existing generating resources
- Updated data in regards to the District's existing and planned operational and power sales contracts
- Amended conservation inputs to align with Chelan PUD's January 2012 10-year conservation plan submittal to the Washington State Department of Commerce (Commerce) as required
- Refreshed data on long-term interest rates and other financial assumptions
- A reevaluation of Chelan PUD's resource adequacy measures
- Studied costs, operating characteristics and other information about power supply resources available to utilities
- Modeled the District's existing portfolio of resources, performing scenario analysis or



stress tests, with the aforementioned input changes, evaluating results against the key criteria of cost, risk, reliability and environmental impacts and communicating with customers and the public

- Board approval of the long-term resource strategy and short-term plan
- Submittal of the final IRP report to Commerce by September 1, 2012 as required

Planning & Regulatory Environment

Resource Planning Situation

Chelan PUD is forecasted to be surplus to its own retail load needs throughout the current planning period (2012-2022). Most utilities need to develop or acquire new electric resources to deal with: 1) forecasted growth in customer loads (although to a lesser degree since the recent economic turndown), 2) declining future output from the utility's existing generating resources and 3) mandates for development of renewable resources and conservation. On November 1, 2011, several long-term Rocky Reach power purchaser contracts expired, and going forward, the District has retained a larger portion of the output at Rocky Reach and entered into shorter-term contracts for a portion of the output providing the District more flexibility. A long-term contract also expires at Rock Island in mid 2012. The net effect of the changes at both projects is an increase in generation resources for Chelan PUD. The shorter-term contracts, part of the District's hedging policy, are discussed more fully in the Portfolio Modeling section.

The Washington State RPS (Energy Independence Act of 2006) requires utilities to serve a certain percentage of their retail load with renewable resources and acquire all cost-effective conservation. This legislation has the net effect of increasing the amount of power available for sale in the wholesale power markets when utilities are forced to acquire resources beyond what they need to serve their retail load growth. This is a future possibility for the District (discussed in further detail below).This magnifies the impact and importance of uncertainties regarding wholesale power supply markets and prices. Market price forecasts are explored more fully in the Portfolio Modeling section.

Additionally, the District and other utilities have new direction to consider for the state's energy future. The 2012 Washington State Energy Strategy, Washington's first comprehensive plan for meeting future energy needs since 1993, addresses three goals: 1) maintain competitive energy prices, 2) foster a clean energy economy and jobs and 3) reduce greenhouse gas emissions. The legislation established nine principles to guide the development and implementation of the state's energy strategy and to meet these goals. They are:

- Pursue all cost-effective energy efficiency and conservation as the state's preferred energy resource, consistent with state law
- Ensure that the state's energy system meets the health, welfare, and economic needs of its citizens with particular emphasis on meeting the needs of low-income and vulnerable populations
- Maintain and enhance economic competitiveness by ensuring an affordable and reliable supply of energy resources and by supporting clean energy technology innovation, access to clean energy markets worldwide, and clean energy business and workforce development
- Reduce dependence on fossil fuel energy sources through improved efficiency and development of cleaner energy sources, such as bioenergy, low-carbon energy sources, and natural gas, and leveraging the indigenous resources of the state for the production of clean energy
- Improve efficiency of transportation energy use through advances in vehicle technology, increased system efficiencies, development of electricity, biofuels, and other clean fuels, and regional transportation planning to improve transportation choices
- Meet the state's statutory greenhouse gas limits and environmental requirements as the state develops and uses energy resources
- Build on the advantage provided by the state's clean regional electrical grid by expanding and integrating additional carbon-free and carbon-neutral generation, and improving the transmission capacity serving the state
- Make state government a model for energy efficiency, use of clean and renewable energy, and greenhouse gas-neutral operations
- Maintain and enhance our state's existing energy infrastructure

National Climate and Energy Legislation

In the 2010 IRP Progress Report, several competing climate change legislative proposals were outlined. 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 extent and cause of climate change is a topic of great debate and controversy. The National Academy of Sciences, the Inter-Governmental Panel on Climate Change and the Unites 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. No further action was taken by the U.S. Congress on any of the proposals from 2009 and 2010 (see the 2010 IRP Progress Report for proposal details). Due to the current split in party control between the two houses of U.S. Congress, any national climate change legislation will almost certainly not take place until after the 2012 elections.

In September 2009, the Environmental Protection Agency (EPA), using existing authority under the Clean Air Act, published an endangerment finding, required annual reporting and proposed regulations for regulating GHG emissions from vehicles and stationary sources. In January 2011, the EPA began requiring big emitters, such as coal-fired power plants and oil refineries, to obtain permits to emit carbon dioxide (CO2), just as they do for emissions that cause smog and acid rain. Next, the EPA plans to begin laying down performance standards, or limits on the amount of CO2 that big power plants and factories can emit. It expects to finalize those rules in 2012. Several legal challenges to the EPA's endangerment finding have been filed in court, but at least some have been rejected by the U.S. Circuit Court of Appeals. Oral arguments are being heard by the Court in 2012 and a ruling is likely by this summer. Additionally, a few pieces of congressional legislation were introduced in 2011 that would stop, limit or delay the EPA from regulating GHG emissions. In early 2011, President Obama proposed a Clean Energy Standard. The standard calls for 80% clean electricity production, from low carbon sources, by 2035 and up to 95% by 2050. It allows for production from renewable resources, including hydro, nuclear, natural gas and coal with carbon capture and sequestration.

There continues to be support in Congress for hydropower. In replacement of the Hydropower Improvement Act of 2010, Senator Lisa Murkowski (R-AK) and nine co-sponsors, including Patty Murray (D-WA) and Maria Cantwell (D-WA), introduced the Hydropower Improvement Act of 2011 in March 2011. According to Murkowski, it "achieves common sense regulatory reform, spurs economic growth and takes advantage of hydropower's position as the country's leading source of clean, renewable energy." Co-sponsor, Jeff Bingaman (D-NM), pointed out that the bill includes provisions that address hydropower development from smaller sources, emphasizes the need to improve efficiency at existing facilities and encourages development of hydropower at existing, non-electrified dams. The bill supports hydropower development by: authorizing a competitive grant program to support efficiency improvements or capacity additions at existing hydropower facilities, adding generation to non-electrified dams, addressing aging infrastructure, conduit projects, environmental studies and mitigation measures; allowing inquiry into the federal licensing process for minimal impact projects; requiring more enforcement and tracking of federal hydropower development; providing for research, development, demonstration and deployment programs; and studying pumped storage projects on federal and non-federal lands near intermittent renewable resource development and directing the Bureau of Reclamation to study barriers to non-federal development at Bureau projects.

Senate Energy and Natural Resources Committee Chairman, Jeff Bingaman (D-NM), worked for a year to develop clean energy standard legislation. He had requested the Energy Information Administration (EIA) to analyze several scenarios in order to better understand how the policy should be designed, including which energy sources should be included, the overall cost and the potential emissions reductions. The bill, introduced March 1, 2012, lacks Republican co-sponsors and little chance of passage in an election year. It would phase in a standard requiring energy suppliers to source an increasing percentage of kilowatt-hour sales from "clean" sources, including renewables, nuclear and combined heat and power systems that achieve at least 50% efficiency. The standard would begin at 24% in 2015 and ramp up by three percentage points per year through 2035. Utilities selling fewer than two million MWhs per year would be exempt beginning in 2015. The exemption threshold would fall by 100,000 MWhs per year until reaching one million MWhs in 2025. Utilities could earn partial compliance credits for gas or carbon-sequestered coal generation that is less carbon-intensive than new supercritical coal plants. Bingaman pushed back against critics who said the legislation would increase electricity rates. He said an EIA study showed "that a properly designed clean energy standard would have almost zero impact on gross domestic product growth and little or no impact on nationally averaged electricity rates for the first decade of the program."

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. Those of greatest focus for Chelan PUD and the region are discussed below. These requirements were specifically evaluated in the preparation and adoption of this IRP.

Renewable Portfolio Standard (RPS)

On the District's radar since 2006, RCW 19.285, The Energy Independence Act, requires utilities with a retail load of more than 25,000 customers 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 law, the District can count recent efficiency gains (i.e., those made after March 31, 1999) 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 law also required that by January 1, 2010, utilities evaluate conservation resources, submit their initial 10-year conservation plans and begin pursuing all conservation that is cost-effective, reliable and feasible. This 2012 IRP includes updates to the evaluations and required reporting under both the renewable and conservation portions of the RPS which are discussed further below.

Resource Adequacy

Pacific Northwest Resource Adequacy Forum

In April, 2008, the Northwest Power and Conservation Council (NWPCC or the Council) adopted a **voluntary** resource adequacy standard for the Northwest (Council document 2008-07) which was developed by the Pacific Northwest Resource Adequacy Forum (Forum). After three years of testing and a comprehensive peer review of the methodology, the Forum proposed a revision to the standard and the Council adopted it on December 6, 2011.

The new standard does not mandate compliance or imply any enforcement mechanisms. Regional adequacy assessments are not intended to apply directly to individual utilities because no utility has the same load and resource profile as the region. However, the probabilistic methodology imbedded in the new standard is recommended for utilities to do their own assessments.

Like the original, the revised standard is intended to be an early warning for the region should resource development fall dangerously short, in a physical sense rather than an economic sense. It is not intended to be a resource planning target. Also like the original standard, the revised standard uses the system's loss of load probability (LOLP) as the adequacy metric with a maximum allowable LOLP of 5%. However, instead of calculating separate LOLP values for energy, winter capacity and summer capacity, a single annual value will be assessed. The original standard included both energy and capacity metrics and targets. It featured a minimum threshold for energy of a zero average annual load/resource balance. The minimum capacity threshold was for a 23% planning reserve margin in the winter and a 24% planning reserve margin in the summer (based on consideration of the highest average demand for a three-day 18-hour sustained peak period). Unfortunately, the use of deterministic adequacy metrics became problematic. Each time the system changed, deterministic thresholds had to be recalibrated to the 5% LOLP standard. Also, it was difficult to compare the annual load/resource balance and the planning reserve margins to similar metrics published in utilities' reports because the purposes of each were different. Because of the issues with the deterministic metrics, the Forum chose to focus on the probabilistic LOLP metric. The original standard calculated three LOLPs, energy, winter capacity and summer capacity, and implied that as long as all of those LOLP values were 5% or less, the power supply was adequate. This was faulty because each LOLP value was assessed independently of the others. Situations could easily occur when all three LOLP values were less than 5% but the overall likelihood of experiencing a problem in either winter or summer was greater than 5%. This would happen if winter and summer shortfalls occurred in different simulations. The Forum conceded that using multiple LOLP metrics was faulty and suggested using a single annual LOLP value, which identifies both energy and capacity problems.

Also, assumptions about the use of standby resources have been refined. They are now limited to only non-modeled resources and load management operations that are contractually available to regional utilities. Regarding the use of non-firm resources, the new standard maintains the current philosophy that they should be included in adequacy assessments. The amount is open for discussion and will need to be reviewed periodically.

In addition to assessing the LOLP, a State Of The System report will be produced which will include 1) statistical information regarding potential shortfall events (frequency, duration and magnitude), 2) conditions under which events may occur, 3) timing of events (e.g. which month are more susceptible), 4) expected use of market resources and 5) likelihood of having to take emergency actions. Thus, the new standard is designed to be simpler and provide more information than the original standard and should prove to be much more useful to regional planners, commissioners, policy makers and others.

The most recent official regional assessment, published in the Council's Sixth Power Plan (February 2010) using the original standard, stated that over the next five-year period, the region's existing resources (and those under construction), in aggregate, exceeded the standard's minimum threshold for annual energy needs and for winter hourly needs. However, existing resources appeared to just barely fall short of meeting the summer hourly adequacy requirement by 2015, which placed the region in a yellow-alert status. Under the implementation plan agreed to by Forum members, a yellow alert status calls for an adequacy report to be released and for the Forum to convene to discuss appropriate actions to take. The Forum met and decided that since the summer capacity shortfall was minimal and because regional utilities were already in a resource acquisition mode, no additional resource actions were recommended. The next official assessment, using the new standard, will be completed by the summer of 2012 for the 2017 operating year.

The District analyzed its resource adequacy in the preparation of this 2012 IRP.

Load Forecast

A new 11-year econometric retail load forecast was developed for this IRP's 2012-2022 planning period. These low, base and high forecasts are prior to planned conservation savings. Future cost-effective conservation is considered as a resource for integrated resource planning purposes, so it can be evaluated on the same basis as other resources.

Demographic trends and economic conditions remain 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 District continues to watch trends in end uses of the residential sector, in particular, driven by recent substantial increases in home electronics.

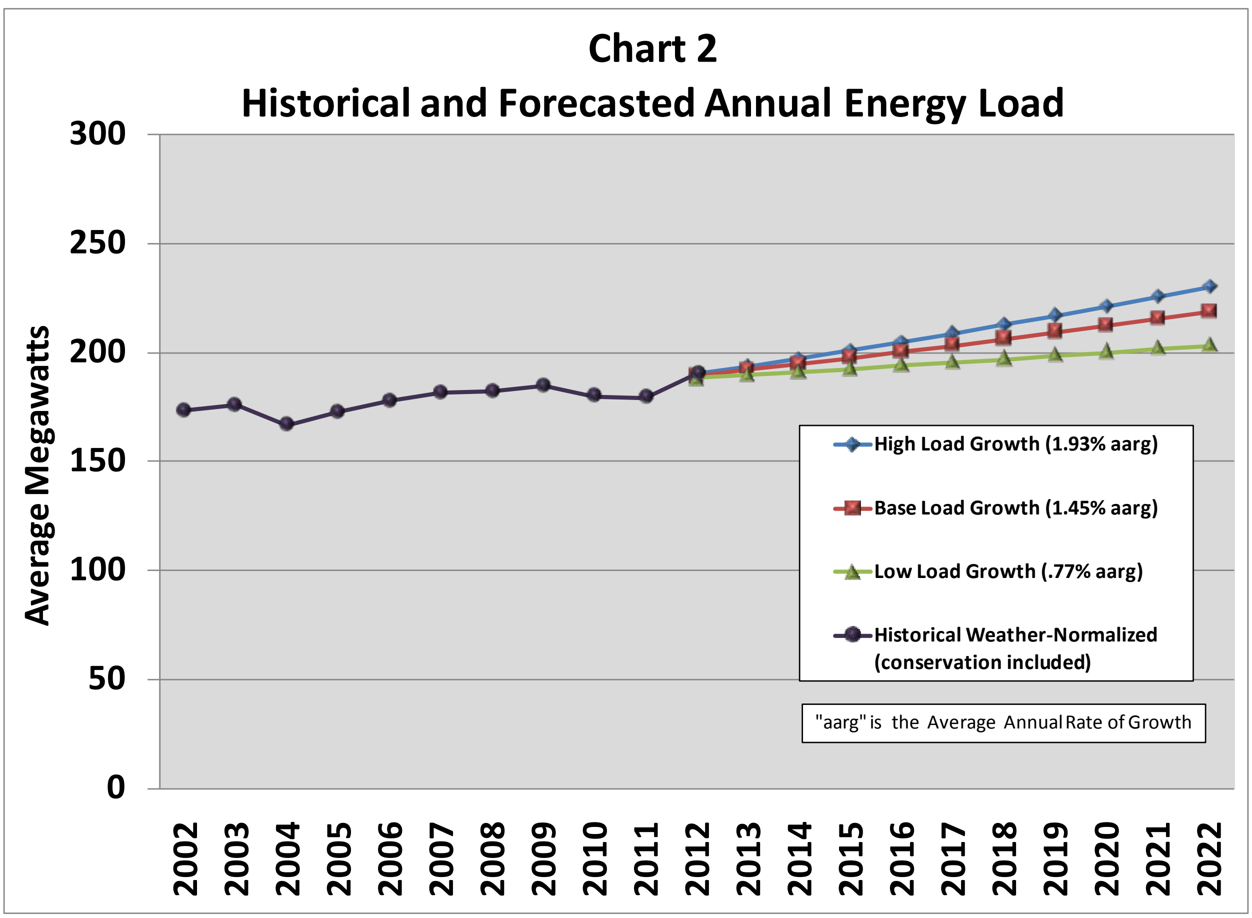
The growth percentages from the sum of the sector energy sales forecasts, with system losses added, were applied to the 2011 weather-normalized load to arrive at total projected megawatt-hours through the planning period. For this 2012 IRP, the low, base and high electric vehicle (EV) (discussed further below) load forecasts were combined with the usual sector forecasts to create the District's total composite retail load forecast. Additionally, a significant increase in system losses is occurring in the calculation of total District load (2.2% used in 2010, now 4.6%). Some system losses attributable to the generation of long-term power purchasers that previously had been allocated to their hourly generation is now being "paid back" to the District after-the-fact in a financial and/or return of megawatt-hour fashion. This has the net effect of increasing the District's total hourly load. **The low, base and high average annual composite retail energy sales forecast growth rates, including system losses, otherwise known as the forecasted annual energy load growth rates, are .77%, 1.45% and 1.93%, respectively.** The low forecast has increased slightly from the 2010 Progress Report while the base and high forecasts have decreased slightly. The base rate now approximates recent historical growth rates experienced by the District. The weather-normalized average annual rate of growth at the District (before the effects of cumulative conservation) was approximately 1.4% for the 10-year period from 2001-2011. The net of cumulative conservation growth percentage was approximately 1.0% for the same 10-year period. This historical growth average is unchanged from the

1999-2009 percentage presented in the 2010 Progress Report. The three forecasts for 2012-2022 as well as the actual weather-normalized total District energy load for 2002-2011 are presented in Chart 2. The increase in system losses previously mentioned accounts for the majority of the jump in the forecasted loads from the 2011 historical actual load (an expected increase in 2012 industrial load is also discussed below.) The NWPCC's Sixth Power Plan region-wide low, medium and high energy forecasts for the 2010-2020 period are .8%, 1.2% and 1.5%, respectively. The Sixth Plan's forecasts increase some for the 2010-2030 period at .8%, 1.4% and 1.8%, respectively. Like the District's forecasted annual energy load growth rates, these forecasts do not include any new conservation measures.

Sector Energy Sales

Demographic and economic data used for the load forecast was updated. The Washington State Office of Financial Management (OFM) has not released any new Chelan County population projections since 2007, although they are expected to do so sometime in 2012. To update, the average annual rates of growth from the 2007 projections (low, base, high) were retained and applied to the OFM actual population estimate for Chelan County for 2011 to arrive at updated population estimates. Additional actual Chelan County population data from the OFM (through 2011) was used to update the various sector regression analyses. Actual sales revenue data through 2010 was obtained from the Washington State Department of Revenue for the same purpose. Internally generated Chelan County sales revenue growth projections were updated.

Residential load continues to be projected based upon population. As in 2010, per capita income was again studied with statistically significant results, but an additional two years of data was available for population that was not available for income, so only population was used.



The forecast low, base and high average annual growth rates for the residential sector have decreased again, but just slightly, with the recent slowing of population growth and building.

The commercial sales forecast continues to be a function of population and total sales revenues for Chelan County. The low, base and high average annual growth rate projections for the commercial sector have also decreased just slightly with the recent slowing of population growth and building as well as the 2009 decrease in county sales revenue. Sales revenue has since begun to rebound slightly.

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 again manually estimated based upon ranges of use per customer amounts and ranges of customer counts with some larger load additions. The District is expecting an existing industrial customer to increase its load by 2 to 3 aMW in mid 2012. That is the only significant known change coming to the sector. This forecast still assumes no changes to the District's rate structure for industrial customers. The low average annual growth rate for the industrial sector has increased due to the known load addition previously mentioned, while the base and high average annual growth rates have decreased some since the 2010 Progress Report due to a decrease in the size of the larger load addition projections. The three forecasts still represent a broad range of growth rates due to increased uncertainty in relationship to the other sectors. Industrial sales are still estimated to increase slightly as a percentage of the District's total load through the planning period as residential and commercial sales and those falling into the "other" sector decrease slightly.

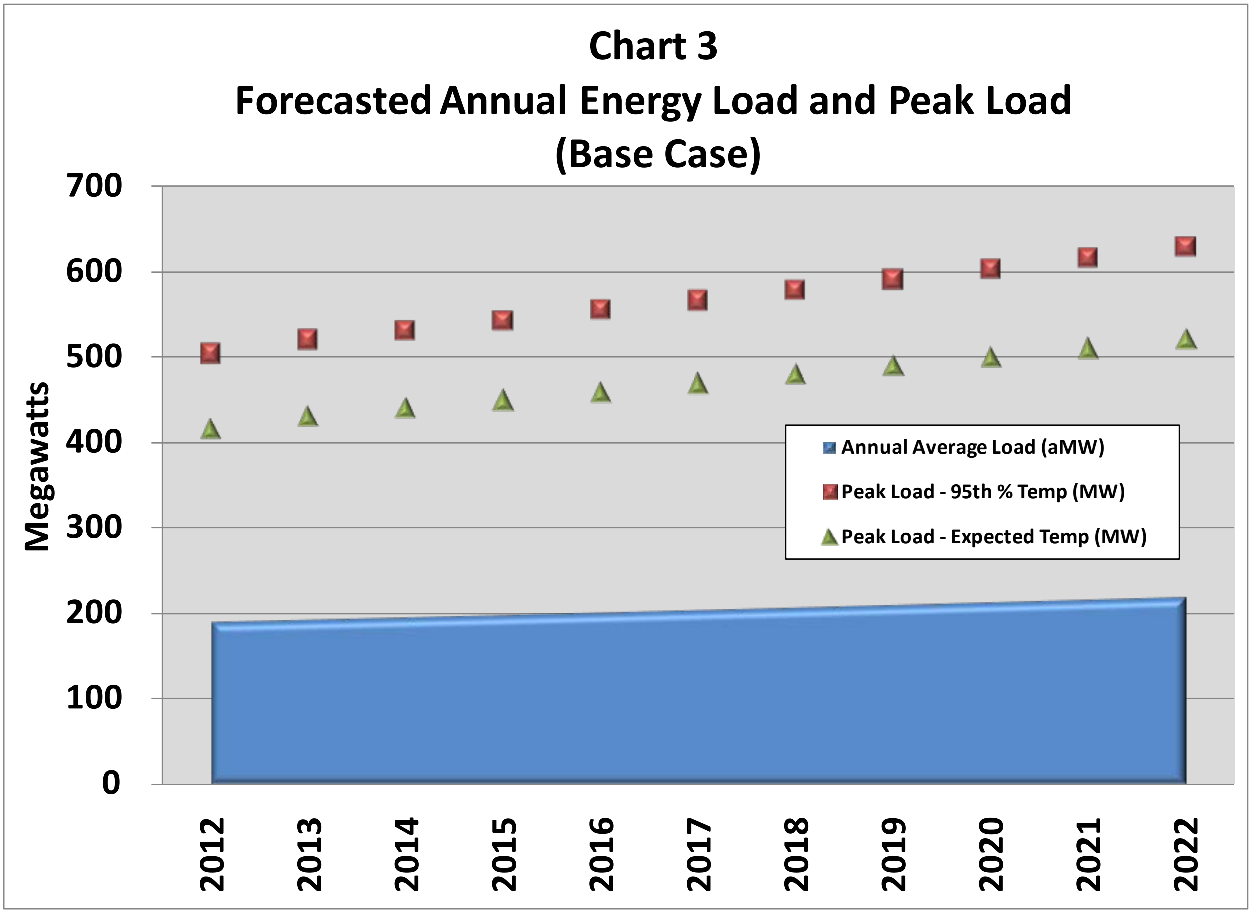
The aggregate of "other" energy sales (street lights, interdepartmental use, frost protection and irrigation) growth projections remains at 0% for all three load cases. This sector was again manually projected based on ranges of use per customer and ranges of customer counts after looking at the subcomponents of this sector.

Volatility in load due to temperature fluctuations can be significant and was incorporated into the IRP modeling. A distribution of average monthly temperatures was developed, and a factor representing the load change per degree has been updated for each month. These factors were multiplied by temperatures along the distribution and then divided by the monthly 2011 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 has also been developed. Temperatures along these monthly distributions can be used to stress monthly hourly peak load by using them in the regression equations for peak loads that is discussed next.

Peak Load Forecast

The peak load forecast was also updated to ensure the District has enough resources to meet peak demand, or the maximum one hour average system peak load. The District's peak retail load occurs in the winter, and contrary to historical trends, the latest all time retail load peak occurred in December rather than January. The peak of 442 MW was established on December 20, 2008. The temperature at the time was approximately -5 degrees Fahrenheit. This was a Saturday morning, and almost certainly, the peak would have been higher at this same temperature on a weekday. Chelan PUD has not experienced a peak hour at that low of a temperature since that time.

Seasonal regression equations with temperature at time of peak as the independent variable were developed from recent peak hour load and temperature data to project peak load at a given temperature. The base average annual rate of growth from the energy forecast (shaped by month) was applied throughout the planning period. This resulted in an average annual peak load growth rate in January of 2.09%. This lines up closely with peak growth rates over the last eight years or so (the period over which good hourly data is available for comparison purposes.) Chart 3 illustrates both the base case annual energy load forecast with the base case peak load forecast at both an average, or expected, peak temperature and at a 95^{th} percentile extreme peak temperature for 2012-2022.



Electric Vehicles (EVs)

In the 2010 IRP Progress Report, the District performed some initial analysis to evaluate the potential effects that EVs may have on the District's future retail load. A new load/resource portfolio scenario was created that included the addition of the middle case, or base, projections for this potential new load. For this 2012 IRP, low, base and high estimates for potential electric vehicle load were updated and added to the usual sector forecasts to arrive at the District's overall low, base and high retail load forecasts as previously mentioned. Based on feedback from an electric vehicle workshop at Snohomish County PUD in the fall of 2011, 1) public infrastructure, notably charging stations, is expanding rapidly, 2) public policies and incentives for EVs are robust, 3) EV operating experiences to date seem generally fine, 4) EV promise remains tantalizing, from a host of environmental, economic, geopolitical and utility-system perspectives and 5) utilities are closely monitoring EV development.

In July 2011, the Washington State Department of Transportation awarded a $1 million contract to outfit I-5 and U.S. Highway 2 with a network of at least nine fast-charging stations. The completion date has slipped to 2012 as lease agreements are worked out for the charging locations. Plans are to install six stations every 40 to 60 miles along I-5 in shopping malls, fueling stations and restaurants with easy access to the highway. Three more stations will be built along U.S. Highway 2 to the north and potentially two more along I-90, near Seattle.

Utilities face the difficulty of tracking locations of EV charging stations and vehicle owners. The District has discussed a separate rate schedule for charging stations, but has not implemented one. 240 volt AC charging is known as level 2 charging and 500 volt DC high-current charging is known as DC Fast Charge (formerly known as level 3 charging). 120 volt AC (generally residential) charging is known as level 1 charging. Residential charging may also include level 2 charging. Chelan PUD has no direct meter charging stations at this time. However, there are two known DC Fast Chargers and probably no more than 10 level 2 and possibly a few more level 1 chargers in Chelan County. There are a few more non-residential chargers planned but unconfirmed.

In 2009, Link Transit received a federal grant for five all-electric buses with the buses originally scheduled for delivery that same year. They have been delayed due to debugging the cutting-edge technology. The performance of the buses has increased with each change. A single charge is now good for 35 miles when the original specs were for 18 miles on a charge. The batteries now have a six-year warranty when they were originally thought to have three or four years of life. The designers think they will last 10 to 12 years. Currently, Link has three of the five buses, with the remaining two expected by late summer 2012. In the meantime, Link has received a second grant for $2.5 million to get another four all-electric buses. They have reported that they will not sign another contract until the others are all delivered.

Public policy in Washington State includes requiring local governments to allow charging infrastructure in all areas, with a handful of exceptions, including residential zones. Financial incentives include the state waiving sales and use taxes for EVs as well as emissions inspections. In addition, there is a $7,500 federal tax credit for EVs.

Operationally, a few issues were raised at the Snohomish PUD workshop. Those include sometimes confusing EV signage, incomplete standardization of connecting plugs and questions about the accuracy of battery range monitors in vehicles.

EV adoption results in less pollution (from power plants providing the electricity) than equivalent gas-powered vehicle releases in tailpipe emissions. Because Chelan County and the Pacific Northwest rely heavily on hydropower, which does not generate carbon emissions, the overall carbon footprint of EVs in Chelan County and the region is much lower than other areas of the country. Because the District is expected to be able to serve its retail load, including EV load, throughout the planning period without any new resource additions (including those that would produce emissions), the introduction of EVs in Chelan County would serve to reduce vehicle emissions in the county.

The number of choices in EVs is expected to continue to grow through 2015, when most major manufacturers plan on releasing at least one EV, some as many as four or five. Battery Electric Vehicles (BEV) are vehicles that use only batteries as their source of energy to move a car. They typically have ranges of 100 to 200 miles between charges. Plug-in Hybrid Electric Vehicles (PHEV) are vehicles that use both batteries and petroleum fuel to move vehicles. They differ from conventional hybrids in that the batteries are bigger to store energy from being plugged in, and they can operate on electric power only for between 15 and 50 miles before switching over to using fuel. 2012 will be a pivotal year for BEVs such as the Nissan Leaf and PHEVs such as the Chevy Volt. General Motors had high hopes for the Volt in its first full year on the market, but the company expected to miss its sales target of 10,000 cars in 2011, coming up short by more than 3,800, according to Bloomberg. Sales were stronger toward the end of the year.

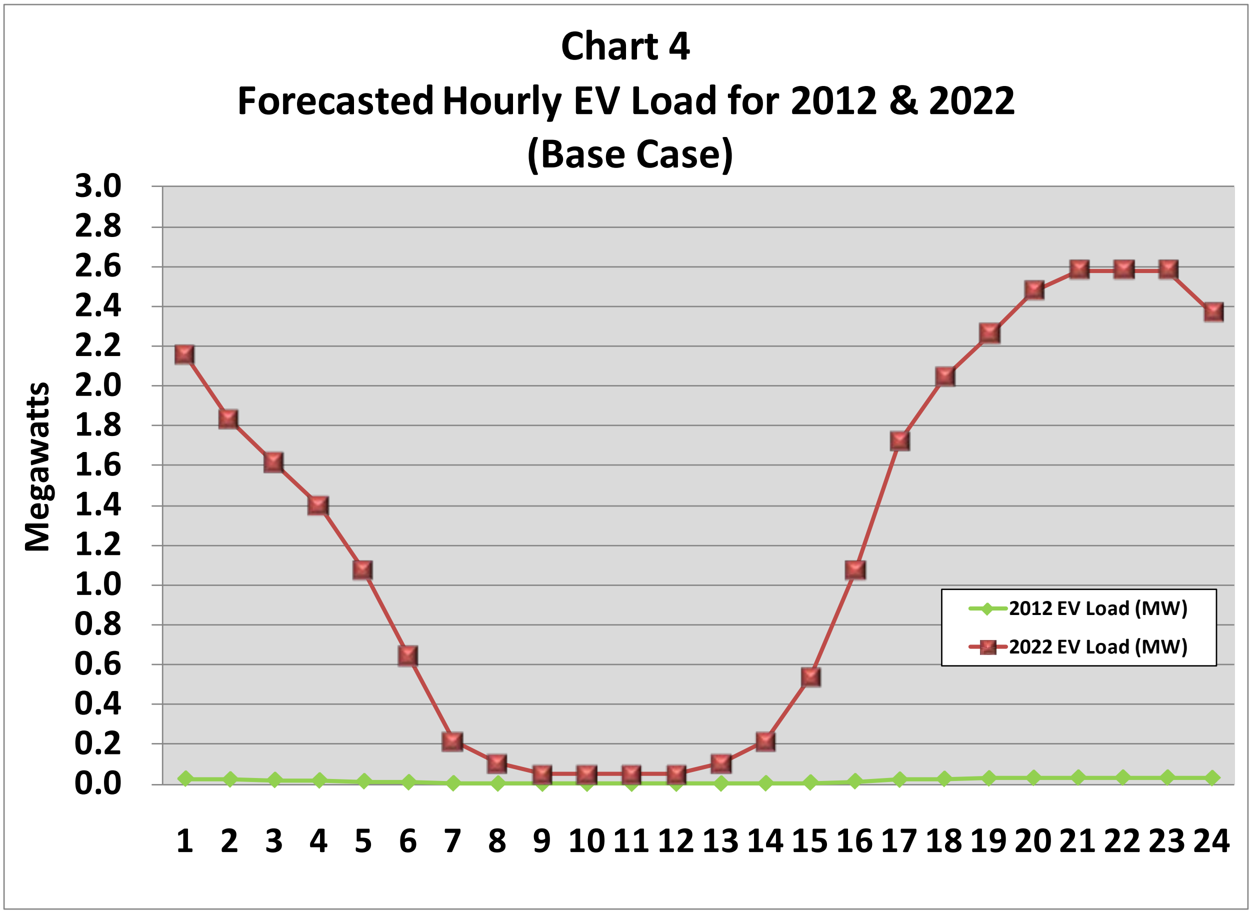
EVS are generally more expensive than gasoline cars. The primary reason is the high cost of car batteries. Tesla Motors is using laptop battery technology for the battery packs of their EVs that are three to four times cheaper than dedicated EV battery packs that other automakers are using. While dedicated battery packs cost $700-$800 per kilowatt hour, battery packs using small laptop cells cost about $200. This technology could potentially drive down the cost of EVs. In a 2011 study by Belfer Center, Harvard University, over the next 10 to 20 years, assuming that battery costs decrease while gasoline prices increase, BEVs will be significantly less expensive than conventional cars to own and operate, while PHEVs will be more expensive than BEVs in almost all comparison scenarios, and only less expensive than conventional cars in a scenario with very low battery costs and high gas prices. This is because BEVs are simpler to build and do not use liquid fuel, while PHEVs have more complicated powertrains and still have gasoline-powered engines. In 2010, the District relied on the Council’s Sixth Power Plan for several assumptions used in the computation of the potential new EV load. For this IRP, the District decided to rely on the same basic methodology and assumptions after studying current information available. The Council's analysis focused on PHEVs, but Chelan PUD believes that the analysis is applicable to PHEVs and BEVs in combination. Three EV load forecasts were developed. The forecasts are based on three growth rates for new light vehicles, a portion of which is assumed to be EVs. The Council's forecast of new vehicles was provided by Global Insight's October 2008 regional forecast. Three growth rates in market share for EVs were estimated by the Council and will depend on consumer consideration of EV purchase price and reliability, available incentives, cost of gasoline and the price of alternative vehicles. These market share, or penetration rates, are very low for the first five years as it is assumed that market share will be slow to start as with most new technologies. The lowest case has a .3% market share in 2012 and the highest case includes a 33% rate in 2022. The District took the Council's estimated regional counts of EVs and calculated a number for Chelan County based on the county's pro rata share of total vehicles in the region.

The District further utilized the following assumptions from the Sixth Power Plan. EVs were assumed to have an initial average energy requirement of .3 kWh per mile. This was based on a "composite vehicle" made up of a compact sedan, a midsize sedan and a midsize SUV that ranged from .26 to .46 kWh per mile. For this composite vehicle, a 10 kW lithium-ion battery is assumed to power the vehicle. It was also assumed that the energy efficiency of the vehicle would improve by 5% each year. These vehicles are assumed to travel 33 miles per day, the current average.

Based on these inputs, Chelan PUD estimates that by the end of the planning period in 2022, Chelan County could have between approximately 1,250 and 6,600 EVs (net of vehicle retirements) out of approximately 35,000 to 41,000 total new vehicles. Some of these vehicles would replace existing vehicles and some would meet new transportation requirements of a growing population. Chelan County currently has approximately 64,800 registered light passenger vehicles. This translates into an additional electric load of between 0.36 and 1.93 aMW by 2022.

A major part of analyzing EV load centers around the assumptions made with regard to the timing of recharging of the EV batteries. An emerging view from the recent workshop at Snohomish County PUD and elsewhere anticipates that a large majority of charging will be done at home. Because of this, the District retained previous work from the 2010 IRP Progress Report developed from a January 2010 study by Pacific Northwest National Laboratory to help develop a daily "shape" to the EV load. The actual load shape of electrifying our transportation system is subject to many variables that are not fully known. For example, the charging behavior of vehicle owners and the impact that fast chargers may have are still not known at this time. The shape retained by Chelan PUD at this time assumes that a majority of the charging will take place overnight at standard 110 volt outlets in residential homes as opposed to charging during the day at work or other locations. Chart 4 shows the forecasted hourly EV load for 2012 and 2022. The chart indicates that charging is expected to pick up late in the afternoon and largely take place throughout the evening and night. As mentioned previously, the District's annual peak demand generally occurs in the winter, usually between 7 am and 8 am. The EV load is expected to have very little impact on this peak. A summertime afternoon peak (which is only about half as much as a winter morning peak) would be affected a little more, however, the amount projected here is just slightly more than 2.5 MW in 2022 for the base EV load case. Because the Districts' peak load demand occurs during the day, recharging at night when the District has additional capacity to generate without having to acquire additional generating resources is desirable from the District's prospective.

While there are skeptics, others believe the electric vehicle will ultimately succeed due to 1) the commitment from auto manufacturers, 2) advances in battery technology, 3) the national desire to reduce dependence on foreign oil and 4) the public concern over climate change. The mass-market future for EVs likely depends upon them becoming a realistic and affordable mode of transportation.



Resources

Existing Portfolio

Chelan PUD's resource mix remains unchanged. The District owns and operates three hydroelectric projects, all located in Chelan County, and is a participant in the Nine Canyon Wind Project, located in Benton County, Washington. The three hydroelectric projects, Rocky Reach, Rock Island and Lake Chelan, together, have capacity to generate nearly 2,000 MW of power. The District continues to invest in modernization and relicensing at the projects to ensure reliable, locally-controlled operation of resources for future generations.

In 2011, several Rocky Reach long-term wholesale power sales contracts, including those with Alcoa, Puget Sound Energy, Avista Corp., PacifiCorp and Portland General Electric, expired. An existing contract with Douglas County PUD remained, and new long-term wholesale sales contracts with Alcoa Power Generating Inc./Alcoa Inc. and Puget Sound Energy have begun. In mid 2012, a Rock Island long-term wholesale power sales contract with Puget will expire and new long-term wholesale contracts with Puget and Alcoa will begin. Once all the new contracts are implemented, 47% of the District's hydroelectric power is available to benefit Chelan PUD retail customers and meet local electric load. With the increased surplus, the District has implemented a hedging policy as a method of reducing wholesale power revenue risk. District power contracts and the hedging strategy are more fully discussed in the Portfolio Analysis section.

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, the operations of upstream storage reservoirs and certain operating agreements.

In 2011, Chelan PUD completed 11 years of a juvenile salmon and steelhead survival testing at Rocky Reach for the project's Habitat Conservation Plan (HCP). The studies showed that survival standards were achieved for all spring migrating fish passing the project by utilizing the project's juvenile fish bypass system, without the use of additional fish spill from the project. Beginning in the spring of 2012, Chelan PUD was able to eliminate the long-standing requirement of spring spill at Rocky Reach. Summer fish spill is still required at 9% of daily flow as HCP survival testing still remains for juvenile summer Chinook at Rocky Reach.

At Rock Island in 2012, spring fish spill is required at 10% of day average river flow. HCP studies from 2003-2006 showed survival standards were met with a 20% spill level and also achieved with spill reduced to 10% as confirmed by studies from 2007-2010. Summer fish spill at Rock Island is 20% of river flow because survival testing still remains for juvenile summer Chinook at Rock Island.

In 2009, the Climate Impacts Group (CIG) released the Washington Assessment of Climate Change Impacts, which found that April 1 snowpack is projected to decrease by 28% across Washington state by the 2020s, 40% by the 2040s, and 59% by the 2080s (relative to the 1916-2006 historical average). The assessment was funded by the Washington State Legislature through House Bill 1303 in 2007. The CIG, which is located in Seattle at the University of Washington, performs basic research aimed at understanding the consequences of climate fluctuations for the Pacific Northwest and promoting application of this information in regional decisions. The 2009 assessment is providing the technical basis for adaptation planning efforts by the state of Washington.

According to the CIG, warmer temperatures would result in more winter precipitation falling as rain rather than snow throughout much of the Pacific Northwest. This potential shift in precipitation could result in less winter snow accumulation, higher winter stream flows, earlier spring snowmelt, earlier peak spring stream flow and lower summer stream flows in rivers that depend on snowmelt. Under the scenarios studied by the CIG, many water users could be adversely impacted, including irrigators, fish and summertime hydropower production.

In response to public policy efforts related to climate change, Chelan PUD has reviewed the 2009 findings and has evaluated the District's ability to adapt to the potential risks associated with a changing climate in the Pacific Northwest. Anticipated hydrologic changes would require modifications to existing managed flood control and reservoir refill timing. Responding to these potential flow changes will be critical for the Columbia River basin hydropower system.

Water managers currently use a system based on historical stream flow records to make decisions regarding flow releases that affect hydropower generation, flood risks, irrigation and other needs between regions. Civil engineers at the University of Washington and the U.S. Army Corps of Engineers' Seattle office have created a computer program that uses long-term forecasts rather than historical records to recalculate when to begin filling and emptying the major storage reservoirs in the Columbia River basin in a warmer climate. The simulations help identify optimized flood control operating rules for a global warming scenario of approximately two degrees Celsius. This research found that incorporating climate change in flood management plans can improve the performance of existing water systems in future climates.

To the extent that regional warming increases the average temperature in the watershed that feeds Lake Chelan and the Columbia River, such warming could result in earlier runoff and affect the timing and/or amount of power generation at the District's hydroelectric projects. At this point, the District is unable to predict the effects on the District's business operations and financial condition. This is due to the fact that Rocky Reach and Rock Island are downstream from Grand Coulee and several other storage projects. These storage projects will bear the burden for reshaping natural inflows, and Chelan PUD's response will depend significantly on how Grand Coulee reregulates flow changes. Therefore, it will be extremely difficult for the District to predict changes to its generation under a future climate change scenario. However, Chelan PUD will remain attentive to regional discourse on this issue as science and experience help shed light on the best methods for predicting water and snowpack inventories and reshaping flood curves.

In addition, Chelan PUD has evaluated the feasibility of several projects which could increase the ability of the region to adapt to climate change through the use of water storage, specifically a possible three foot increase in the reservoir behind Rocky Reach and an investigation of off-stream water storage opportunities adjacent to the District's existing hydroelectric projects. At this time, neither project is considered economically viable. However, Chelan PUD is prepared to revisit these projects should environmental and economic conditions warrant additional analysis.

Wind energy is more variable than hydro and also somewhat seasonal in nature. Both hydro and wind reduce carbon emissions by replacing generators such as gas and coal that produce emissions and offer a low, stable fuel price. However, the level of variability and supply uncertainty between the two resources is significant. Hydro can be stored in limited reservoirs, while wind cannot be stored. Hydro's variability is measured in years, months and weeks while wind's variability is measured in days, hours and minutes. The intermittency of wind power increases the need for reserve power on the system.

The wind industry's development boom started to slow in 2011 as Northwest utilities continued to lock up wind energy to meet their first RPS benchmarks and California moved to limit imported renewable energy. Despite a slowing of new development, Bonneville Power Administration (BPA) had more than 3,750 MW of wind capacity at the end of 2011 and expects 5,000 MW by the fall of 2012 on its roughly 10,500 MW peak load balancing area. The Northwest, in whole, had around 6,000 MW of wind at year-end 2011. The Columbia River hydro system now serves multiple purposes: serving load, meeting non-power requirements (e.g., fish flows, irrigation, flood control and recreation) and supporting intermittent generation such as wind.

Wind is a key addition to the Pacific Northwest renewable generation mix, however, integration of wind presents new challenges. Integrating wind in the Northwest grid moved to center stage last year, thanks mainly to BPA's Environmental Redispatch (ER) policy. BPA offered an intra-hour scheduling pilot for wind, and Iberdrola Renewables announced it would continue its self-supply pilot for reserves and BPA's wind integration team reformed. On May 18, 2011, faced with huge amounts of water (what turned out to be the fourth largest water year in history), nearly 3,500 MW of wind capacity on its system and Endangered Species Act-driven fish concerns, BPA, for the first time, enacted its ER policy and curtailed about 1,400 MWhs of wind. Over the next two months, BPA curtailed an estimated 97,557 MWhs of wind generation, with the last episode occurring July 10th.

Wind developers who were offered free hydropower but missed out on tax and renewable credit during these episodes, asked the Federal Energy Regulatory Commission (FERC) for relief and filed a lawsuit in the 9th U.S. Circuit Court of Appeals. On December 7, 2011, FERC ruled BPA's policy is unduly discriminatory and required the agency to file tariff modifications within 90 days. On March 6, 2012, BPA filed a response to FERC outlining a plan referred to as Oversupply Management Protocol. Under the new protocol, BPA would first work with the U.S. Army Corps of Engineers and Bureau of Reclamation to manage federal hydroelectric generation and spill water up to dissolved gas limits. BPA would then offer low-cost or free hydropower to replace the output of thermal and other power plants, with the expectation that many would voluntarily reduce their generation to save fuel costs. If supply still exceeds demand, BPA would then reduce the output of remaining generation within its system, including wind energy, in order of least cost. BPA would compensate the affected generation for lost revenues, including RECs and production tax credits, subject to verification by an independent evaluator. BPA proposes to cover the cost of compensating generators in 2012 from its transmission reserve account until a rate can be established to recover the costs. BPA will initiate a new rate case in which it will propose dividing compensation costs roughly equally between users of BPA's federal base system and generators eligible for compensation from BPA. The intertwining of wind and hydro has dramatically changed the way BPA manages its balancing authority and there will likely be many more changes. In addition to the intra-hour scheduling pilot, improved wind forecasting, new technology, new operating protocols and demand response are expected to play bigger roles in meeting this challenge.

The District's share of Nine Canyon wind is a relatively small portion of its overall resource portfolio (less than 2%), so in most cases, the District is able to integrate this wind without issue.

Renewables

The District must comply with Washington State RPS renewable requirements beginning this year. 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.

Chelan PUD's existing mix of generating resources complies with the District's understanding of the renewable requirement of the RPS throughout the planning period. The District plans on meeting these renewable requirements with incremental hydropower. Incremental hydropower is derived from efficiency gains at the District's existing hydropower projects resulting from equipment and operational upgrades, or increased 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 uses a Hydro Optimization Model to calculate its qualified incremental hydropower under average water conditions.

Based upon the current base load forecast, the amount of renewable resources required will be approximately 5-6 aMW in 2012-2015, approximately 17-18 aMW in 2016-2019 and approximately 30-31 aMW in 2020-2022. Chart 5 shows the potential target requirements based on the District's three load forecasts.

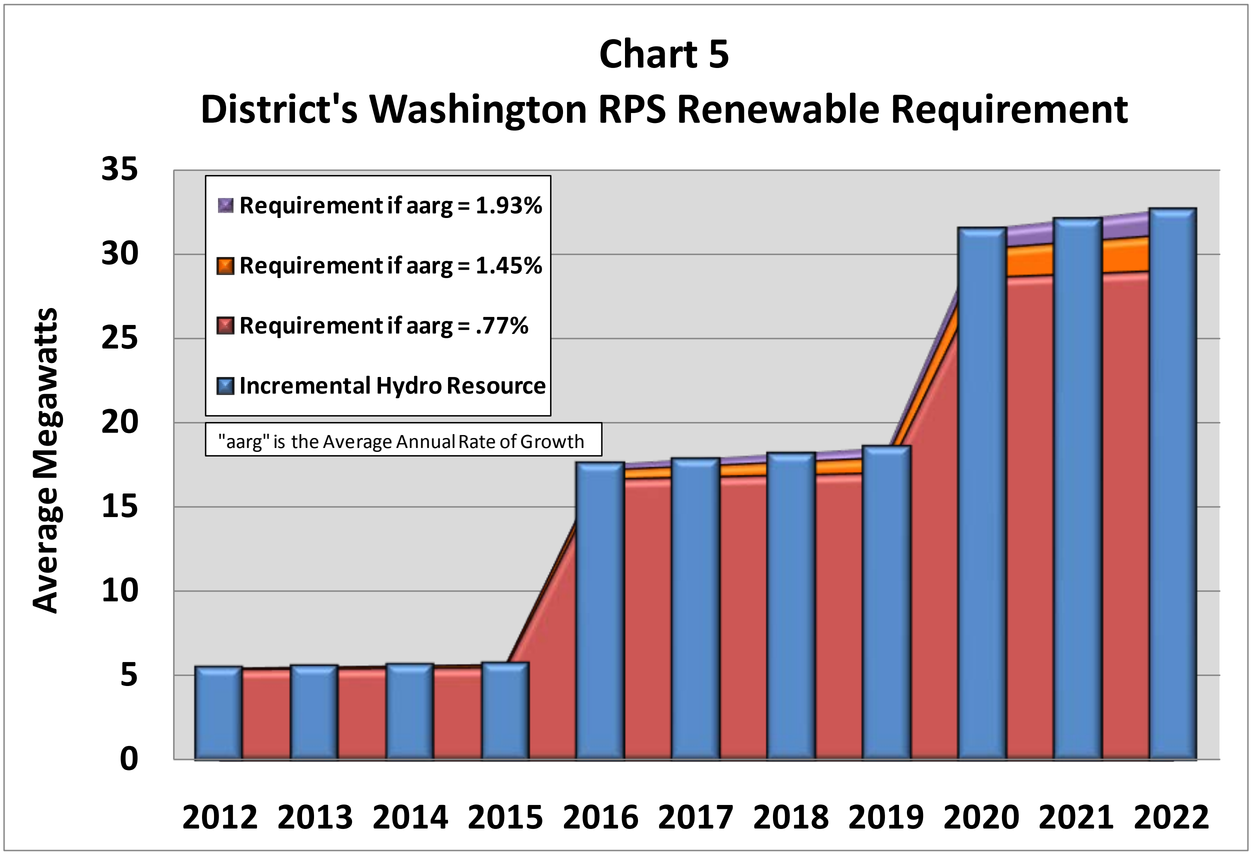
The District continues to evaluate options to meet compliance requirements. For the purpose of evaluating the financial impact of the RPS, the District will analyze the cost of renewables as compared to its existing hydro resources. Because Chelan PUD is long resources relative to its retail load, the District's existing hydro resources are considered its "substitute resource" as defined by the Washington Administrative Code (WAC) rules that pertain to the RPS.

Legislative changes to the RPS were approved in March 2012. The definition of eligible renewable resources was expanded to include qualified biomass energy. In addition, a Commerce pre-approval process for eligible renewable resources was authorized to provide additional clarity and certainty. The District is monitoring and evaluating the impact of these changes as appropriate.

The western renewable markets continue to evolve as compliance rules change and renewable targets become a reality for utilities. Chelan PUD is monitoring these renewable compliance markets and evaluating the potential impacts. The District continues to look for opportunities in both the voluntary and compliance renewable markets.

Available Resource Technologies

Although the District is expected to be surplus to its own retail load needs with its existing resource portfolio through the planning period, a broad array of supply-side resources were explored during the preparation of this IRP. The generating technologies addressed in this IRP are not inclusive of all types of power generation, but rather ones that are proven or



are available to electric utilities. The following types are further discussed:

- Wind
- Geothermal
- Solar (photovoltaic and concentrating)
- Natural Gas (single and combined-cycle combustion turbines)
- Coal (steam-electric and gasification combined-cycle
- Nuclear

The cost of new generating plants plays an important role in determining the mix of capacity additions that will serve growing loads in the future. New plant costs also help to determine how new capacity competes against existing capacity and the response of the electricity generators to the imposition of environmental controls on conventional pollutants or any limitations on GHG emissions.

The District used the EIA's Updated Capital Cost Estimates for Electricity Generation Plants published in November 2010 for the various costs of new resources that is shown in Table 1. Fuel costs represent current pricing as of April 2012 from various sources as noted in the table. Regulation and load following (Reg. & L.F.) as well as transmission costs were obtained from the Council's Sixth Power Plan.

Since the EIA's last update a year earlier, some capital costs have gone up and some have gone down. Coal and nuclear went up 25 to 37% due to the rising costs of capital intensive technology, higher global commodity prices and the fact that there are relatively few construction firms with the ability to complete complex engineering studies for such advanced plants. Natural gas plants remained about the same, while solar plant costs dropped due to the assumption of larger plant capacities and falling component costs. Wind plant costs rose 21% and geothermal plants were up over 50%. A more thorough analysis of costs would need to be performed if these generating technologies were to be considered potential additions to the District's resource portfolio.

Overnight Costs are the amount of cash needed to build a new resource overnight in $/kW of installed capacity. It assumes no financing structure. The District's existing capital costs for its hydro and wind resources are historical and a comparison cannot be made to the overnight costs of new resources. Fixed O&M costs are those that remain the same regardless of the amount of power production. Fixed O&M costs would be the same for a project whether it is running at 100% of capacity or at 50% of capacity or 0%. Variable O&M costs are volume sensitive and dependent on project output. A project running at 100% capacity would have higher variable O&M costs than when it is running at 50% capacity. This can be attributed to using more fuel, more wear of machine, etc. Regulation and load following are the costs of integrating an intermittent resource into a usable energy product. Since intermittent resources cannot be dispatched, capacity needs to be reserved for regulation and to follow load. Transmission costs can vary depending on the location of the resource. For example, a remote wind resource may require multiple transmission segments to bring the power to the District, but a wind resource built in neighboring county would require very little transmission for Chelan County to receive the energy.

Wind Power

As of mid 2011, the Northwest power system had about 6,000 megawatts of wind generating capacity, most of it built in the last five years. The Council estimates that the region could see 5,000 to 10,000 more megawatts of capacity by 2025.

Wind power is a mature, relatively low-cost source of low-carbon energy. It has little firm capacity, and

Table 1
New Resource Costs

Existing Resources	**Overnight Costs*** ($/kW) (2010 $ values)	**Fixed O&M** ($/kW/yr) (2010 $ values)	**Variable O&M** ($/MWh) (2010 $ values)	**Fuel Cost****	**Reg. & L.F***** ($/MWh) (2006 $ Values)	**Transmission Costs******* ($/MW) (2006 $ Values)
Wind	$2,438.00	$28.07	$0.00	-	$9.14	$8.02
Geothermal (Binary)	$4,141.00	$84.27	$9.64	-	-	$3.79
Solar (Photovoltaic)	$4,755.00	$16.70	-	-	$9.14	$14.53
Solar (Thermal Concentrating)	$4,692.00	$64.00	-	-	$9.14	No Estimate
Gas (SCCT)	$974.00	$6.98	$14.70	$2.52/MMBtu	-	$6.41
Gas (CCCT)	$978.00	$14.39	$3.43	$2.52/MMBtu	-	$3.74/6.07*****
Pulverized Coal	$3,167.00	$35.97	$4.25	$2.33/MMBtu	-	No Estimate
IGGC (w/ CO2 capture)	$5,348.00	$69.30	$8.04	$2.33/MMBtu	-	No Estimate
Nuclear	$5,339.00	$88.75	$2.04	$51.25/lb	-	No Estimate

* Overnight Costs are the amount of cash needed to build a new resource overnight in $/kW of installed capacity. It assumes no financing structure.
** Gas is average 2012 Henry Hub spot price from Short-Term Energy Outlook, May 2012 (source: www.eia.gov); Coal is average 2012 spot price from Short-Term Energy Outlook, May 2012 (source: www.eia.gov); Nuclear is 4/16/2012 spot price (source: www.uxc.com).
*** Regulation and load following are the costs of integrating an intermittent resource into a usable energy product (source: Sixth Power Plan, Appendix I (2012 service year)).
**** Transmission costs (source: Sixth Power Plan, Appendix I (2010 service year)).
***** Baseload/incremental duct firing.

therefore, requires supplemental firm capacity and balancing reserves. An existing surplus of balancing reserves and firm capacity within the Northwest has enabled the growth of wind power without the need or cost of additional capacity reserves. However, the concentration of installed wind capacity east of the Columbia River Gorge and within a single balancing area (BPA) has led to significant ramping events, putting pressure on BPA's ability to integrate additional wind development.

A 2011 Council document (2011-09) assessing regional wind and found that 1) developing resources to serve Northwest state RPS requirements tends to increase the frequency of excess energy events until the final RPS targets are met. After meeting the final targets, in the early to mid-2020s, the frequency of excess energy events is expected to slowly decline. 2) Additional wind development beyond Northwest RPS requirements would increase the frequency of excess energy events. Changes to California's RPS signed into law in April 2011 appear to reduce the likelihood of significant renewable resource development in the Northwest to supply California beyond contracts already in place (imports from outside the state have been restricted). 3) The probability of excess energy events increased during good water years and declines during poor water years. As demonstrated in June 2010, unusual runoff patterns can create excess energy conditions even in average water years. 4) Current RPS targets and financial incentives tend to encourage RPS-qualifying energy production that exceeds load growth. Market prices will also be lower, including market value of non RPS-qualifying electricity. 5) The average impact of lower market prices on the energy value of Northwest generation as a whole will be moderate. The value of hydropower will be particularly affected. Growth in variable generation increases market price volatility. 6) Measures are available to reduce the frequency of excess energy events, to alleviate the economic and operational issues associated with excess energy events, to counter equity issues, and to use available low-cost, low-carbon energy more productively. Policy-related measures are generally low-cost and quickly effective, but may be politically difficult to implement. Structural measures tend to be capital-intensive and may take a long time to implement.

The least cost and fastest solutions to integrating additional wind development appear to be reducing the demand for system flexibility and fully assessing the flexibility of the existing system. Measures such as improved load forecasting, up-ramp curtailment and sub-hourly scheduling can reduce the amount of flexibility required to integrate a given amount of wind capacity. Longer-term, increasing the geographic diversity of wind development by importing wind from remote areas could also reduce the demand for flexibility. Existing system flexibility, scattered across numerous Northwest balancing areas, can be more fully accessed by developing mechanisms to trade balancing services and by expanding dynamic scheduling capability both within the region and with other load areas. Issues of cost allocation need to be resolved. Following these steps, new balancing reserves and firm capacity from generation, storage or demand-side resources may be required.

Geothermal Power

Geothermal energy is a relatively low-cost (although initial capital costs for exploration can be high), clean, baseload generating resource with a capacity factor of greater than 90%.

Although recent research suggests that while local hydrothermal systems may exist in the Cascades, geothermal potential for generation outside of these local systems is limited or absent. Additionally, development of much of the Cascades' potential would be prevented by land-use constraints with the exceptions of Newberry Volcano (Oregon) and Glass Mountain (California). These structures may be capable of supporting several hundred megawatts of geothermal generation.

The natural presence of the high-temperature permeable rock and fluid conditions required for conventional geothermal plants at feasible drilling depths is uncommon. Much more common are high-temperature, but insufficiently permeable formations. Enhanced geothermal systems (EGS) create the necessary permeability by fracturing or other means. Experts say that seismic activity induced by EGS techniques such as fracturing, fluid injection and acidization have caused thousands of earthquakes all over the world, but most have been so small they were not felt by people. EGS technology is one of several emerging geothermal technologies that could vastly increase the developable geothermal resources. A 2004 MIT assessment of geothermal potential identified three areas of special EGS interest in the Northwest. Two, Oregon Cascades and Snake River Plain, are unique to the Northwest. The U.S. Geological Survey study identified 104,000 average megawatts of EGS potential at a 95% confidence level in the four Northwest states. The Council encourages Northwest utilities to support efforts to develop and demonstrate EGS technology.

Natural Gas Generation

Natural gas power plants represent about 16% of Northwest generating capacity. Relatively low natural gas prices and development of efficient, low-cost, environmentally attractive gas-fired power plants led to a surge of construction early in the 1990s and again during the energy crisis of 2000 and 2001.

Rising natural gas prices following the energy crisis prompted interest in constructing liquefied natural gas (LNG) terminals to secure access to lower-cost overseas supplies. Interest in LNG import facilities has waned because of declining gas prices due to falling demand and expansion of unconventional sources such as coal-bed methane and tight formations. Significant new natural gas supply has come on line in the U.S. over the last few years due to improved drilling technology and techniques.

All gas turbines feature highly modular construction, short construction time, compact size and low water consumption. Applications include: base-load energy production, regulation and load-following, peaking, cogeneration and distributed generation. Gas turbine generators, combined-cycle plants and reciprocating engines are expected to continue to play a major role in electricity production. Fuel cells and microturbines may see some specialized applications, but appear unlikely to be major players in the near to mid-term because of cost and reliability issues. Simple-cycle combustion turbines (SCCT) and combined-cycle combustion turbines (CCCT) are the two primary types of natural gas generation.

Simple-Cycle Combustion Turbines (SCCT)

Simple-cycle gas turbine power plants consist of one or two combustion gas turbines driving an electric generator. They range in size from sub-megawatt to to 270 megawatts. They have a rapid-response startup and load-following capability and are extensively used for meeting short-duration peak load. Low to moderate capital costs and superb operating flexibility make simple-cycle gas turbines attractive for peaking and grid support applications. SCCTs also feature low air emissions. Though the inherent operating flexibility of these units is suitable for providing regulation and load following, they are not often used for this purpose because of their relatively low efficiency. Higher-efficiency intercooled gas turbines have recently been introduced with the objective of providing regulation and load-following services.

Combined-Cycle Combustion Turbines (CCCT)

CCCTs consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam-turbine generator, increasing the overall thermal efficiency compared to SCCTs. CCCT plants have been the bulk power generation resource of choice since the emergence of efficient and reliable gas-turbine generators in the early 1990s due to low capital costs, short lead-time, operating flexibility and low air emissions. CCCTs represent over 76% of regional natural gas generation.

Solar Power

Solar generation depends on the amount of solar radiation available which depends primarily on latitude, atmospheric conditions and local shading. The inter-mountain basins of south-central and southeastern Oregon and the Snake River plateau of southern Idaho are the best solar resources in the Northwest but still pale in comparison to the Southwest. There have not been any comprehensive studies of site suitability for development, although the potential is believed to be large. The Northwest solar resource, due to strong summer seasonality, has potential for serving summer-peaking loads such as irrigation and air conditioning, but is less suitable for the region's (and the Districts) overall winter-peaking heating load. Photovoltaic and concentrating solar power are the two primary technologies used to generate electricity from solar energy.

Photovoltaic Solar Power

Photovoltaic solar power uses the sun's light to produce electricity. Panels wrapped in semi-conducting material, most commonly silicon, converts sunlight directly into electricity. It is commercially available and widely employed to serve small remote loads where it is too costly to extend grid services. Currently, in Chelan County, there are multiple distributed photovoltaic resources at local school district buildings and nonprofit agencies through the Sustainable Natural Alternative Power (SNAP) program. Photovoltaic generating capacity was roughly 64 gigawatts worldwide at the end of 2011. Solar power output is intermittent and battery storage is required for loads demanding a constant power supply. Despite the high cost and low productivity, strong public and political support has let to financial incentives and grid-connected installations of several hundred kilowatts and more in the Northwest. Larger plants are appearing in the Southwest where production is higher. A relatively low-cost photovoltaic plant employs thin film photovoltaic cells mounted on fixed racks. The energy conversion efficiency and overall productivity of this design is low. Plant productivity can be improved by mounting cell arrays on tracking devices to improve daily and seasonal orientation.

Concentrating Solar Power (CSP)

Concentrating solar power (CSP) uses the sun's heat to create electricity. CSP systems use lenses or mirrors and tracking systems to focus a large area of sunlight into a small beam that is concentrated on a heat exchanger to heat a working fluid. Once heated, the liquid converts water into steam, which turns a turbine to create electricity. Worldwide, about 740 megawatts of generating capacity were added between 2007 and 2010, bringing the global total to 1095 megawatts. Spain and the U.S. are leading the way. The three basic types of CSPs are parabolic trough, central receiver and Sterling dish. Parabolic trough, the most mature technology, can be equipped with auxiliary natural gas boilers to stabilize output during periods of less direct sunlight. Central receiver plants utilize a field of tracking reflectors that direct solar radiation on an elevated central receiver where energy is transferred to a working fluid, usually a molten salt. The hot molten salt is circulated through heat exchangers to generate steam. Thermal storage is provided through molten salt storage tanks that are, again, utilized to stabilize energy output during periods of less direct sunlight. Stirling dish consists of a tracking parabolic mirror that concentrates solar radiation on the heat exchanger of a small Stirling reciprocating engine at the focal point of the mirror. Because of the small size of individual units, this technology may benefit from economies of standardization and production. It is not suitable for thermal storage and is in the demonstration stage.

The Southwest is most suitable for solar energy with its clear skies and level of irradiation. Technological improvements and economies of production are expected to result in lower power plant costs. The added cost and investment risk of long distance transmission needed to bring energy from Southwest plants to the Northwest make them less attractive for this region.

Coal-Fired Steam-Electric Plants

Coal is a combustible sedimentary rock composed mostly of carbon and hydrocarbons. It is the most abundant fossil fuel in the U.S. and has the highest carbon content. In the most common type of coal plants, coal is pulverized and blown into a furnace where it burns while airborne. Water flows through tubes that run into the furnace. The water is heated to boiling while under pressure. This pressurized steam blasts through a turbine, which turns a generator to produce electricity. After the steam has passed through the turbine, it is condensed into water and cooled and sent back into the furnace.

In the Northwest, coal constitutes 13% of the generating capacity and 25% of the electric energy generated. Sufficient coal is available to the region to easily support all regional electric power needs through the planning period and beyond. Improvements in mining and rail haul productivity have resulted in generally declining real dollar production costs. Climate policy and overseas demand are the important factors affecting future coals prices. Though GHG penalties would tend to depress future demand and prices, commercialization of technologies for separating and sequestering CO2 would rejuvenate demand for coal.

New steam-electric coal-fired power plants increasingly employ supercritical or ultra-supercritical technology utilizing increasingly higher steam pressure and temperature. Fuel prices and variable costs are low, and these plants operate as baseload units. The key challenge to continued use of this technology is developing an economical technology to separate CO2 from the products of combustion and establishing commercial-scale carbon sequestration facilities. One approach to CO2 separation for steam-electric plants is oxy-firing, in which the furnace is supplied with pure oxygen, rather than air for combustion. This would produce a flue gas consisting largely of CO2 and water vapor from which the CO2 could be readily separated. An alternative approach is chemical separation of CO2 from the flue gas of a conventional air-fired furnace. The latter appears to be the leading technology, but is unlikely to be commercially available before 2020.

Washington State's emission performance standard for fossil-fueled electric generation (2007) (RCW 80.50) essentially ended the construction of coal-fired steam-electric plants to serve load. Utilities may capture and sequester CO2 to meet the performance standard, but not by purchasing offsets. In 2011, a deal was struck between the owner of Washington's only coal plant, located near Centralia, and local environmentalists to shut down both the plant's coal boilers. The first is to be shut down in 2020 and the second in 2025, with a schedule of emissions reductions to be met along the way. The Washington State Senate approved the deal.

Coal-Fired Gasification Combined-Cycle Plants

Pressurized fluidized-bed combustion and coal gasification technologies allow the application of efficient gas turbine combined-cycle technology to coal-fired generation. This reduces fuel consumption, improves operating flexibility and lowers CO2 production. Of the two technologies, coal gasification is further along in commercial development and offers the benefits of low-cost mercury removal, superior control of criteria air emissions, optional separation of carbon for sequestration and optional co-production of hydrogen, liquid fuel or other petrochemicals.

Several coal gasification projects were announced in North America during the early 2000s. However, escalating costs and refined engineering indicating the non-carbon emissions and plant efficiency would not be significantly better than supercritical steam-electric plants has dampened enthusiasm. Uncertainties regarding the timing and magnitude of GHG regulation and the availability of carbon sequestration facilities have further clouded the future of these plants and only a handful of proposals remain active.

Nuclear Power

As with many conventional thermal resources that generate electricity by harnessing the thermal energy released from burning fossil fuels, nuclear power plants convert the energy released from the nucleus of an atom via nuclear fission that takes place in a nuclear reactor. The heat from the reactor core is used to generate water vapor steam which drives a steam turbine connected to a generator which produces electricity. All current methods of nuclear power involve light water reactor (LWR) technology which was first developed in the 1950s. Today, nuclear power makes up about 19% of total electricity generated in the U.S. at more than 100 plants. The Northwest region has one nuclear power plant, the Columbia Generating Station, in Richland, Washington. It is owned and operated by Energy Northwest, has a capacity of 1,150 MW and first started producing energy in 1984.

Nuclear development activity in the U.S. has picked up due to improved plant designs, the need for low carbon, baseload resources and financial incentives in the Energy Policy Act of 2005. As of 2011, more than 20 units are in the application process at the U.S. Nuclear Regulatory Commission. Most proposals are for units in the southeast and northeast. The proposed plants utilize evolutionary light water reactor designs with increased use of passively operated safety systems and factory-assembled standardized modular components. These features should improve safety, reduce cost and increase reliability.

Although nuclear generating units provide relatively low fuel cost, baseload, low carbon energy that is largely unaffected by carbon policies and natural gas prices, risks include escalating capital costs, construction delays, regulatory uncertainty and the reliability uncertainty associated with a large single-shaft machine. Concerns also remain over nuclear waste storage and plant safety. Small modular reactors (SMRs) are modular, scalable, largely factory-assembled plants of 25 to 350 megawatts of generating capacity. They are currently being developed. Although the SMR concept is not new, there is now unprecedented interest in SMR technology due to their ability to mitigate some of the risks previously mentioned. Reduced capital costs, shorter construction time and scalability to customer need and reduction of large capacity outage risk are favorable and provide flexibility. Improved safety through integral construction (all reactor coolant systems contained within a single pressure vessel), below-ground emplacement and lifetime, factory-installed fuel supplies. Completion of the first demonstration SMRs is a decade or more away.

Conservation

Since 2010, Washington's RPS has required that "each qualifying utility pursue all available conservation that is cost-effective, reliable and feasible." The RPS defines conservation as any reduction in electric power consumption resulting from an increase in the efficiency of energy use, production or distribution.

Each utility shall establish a biennial acquisition target for cost-effective conservation that is no lower than the utility's pro rata share for the two-year period of the cost-effective conservation potential for the subsequent 10 years. Every succeeding two years, utilities must review and update their 10-year assessment. In January 2012, Chelan PUD submitted its most recent update. By June 2012, the District will submit its first annual conservation report to Commerce. The report will document the District's progress in 2010 and 2011 toward meeting the targets that were established in 2010 to comply with the RPS.

There are two primary components of the RPS as it relates to conservation:

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

In 2011, the District retained EES Consulting (EESC) to develop a utility-specific analysis, also known as a Conservation Potential Assessment (CPA), of Chelan County's conservation potential. Since the District's last 10-year plan and IRP Progress Report in 2010, the District has experienced two years of accelerated conservation activities and conducted research on Chelan County demographics and building construction data. Although the District previously used the Fifth Power Plan conservation calculator developed by the Council to set its 10-year plan and two-year conservation target, it was decided that using a utility-specific analysis, Option 3 in the RPS, provided the best representation of the District's conservation potential. The CPA was developed in a manner consistent with the Council's methodology, therefore, the results of the CPA have been used to establish the District's recent conservation targets for RPS compliance. Also, the resulting conservation supply curves can be used as modeling inputs in the District's IRP.

Conservation Potential Results

The District has pursued conservation and energy efficiency resources since the early 1980s. Historically, the utility offered several programs for both residential and non-residential applications. Industrial projects have dominated past conservation, however, beginning in 2010, there has been an increased emphasis on residential projects. During the two-year period from 2010 through 2011, the District achieved its greatest conservation totals in its history with over 3.2 aMW saved.

The 2011 CPA provides estimates of energy savings by sector for the period 2012-2031. The assessment considers a wide range of conservation resources that are cost-effective, reliable and feasible for Chelan

PUD's service territory within the 20-year CPA planning period.

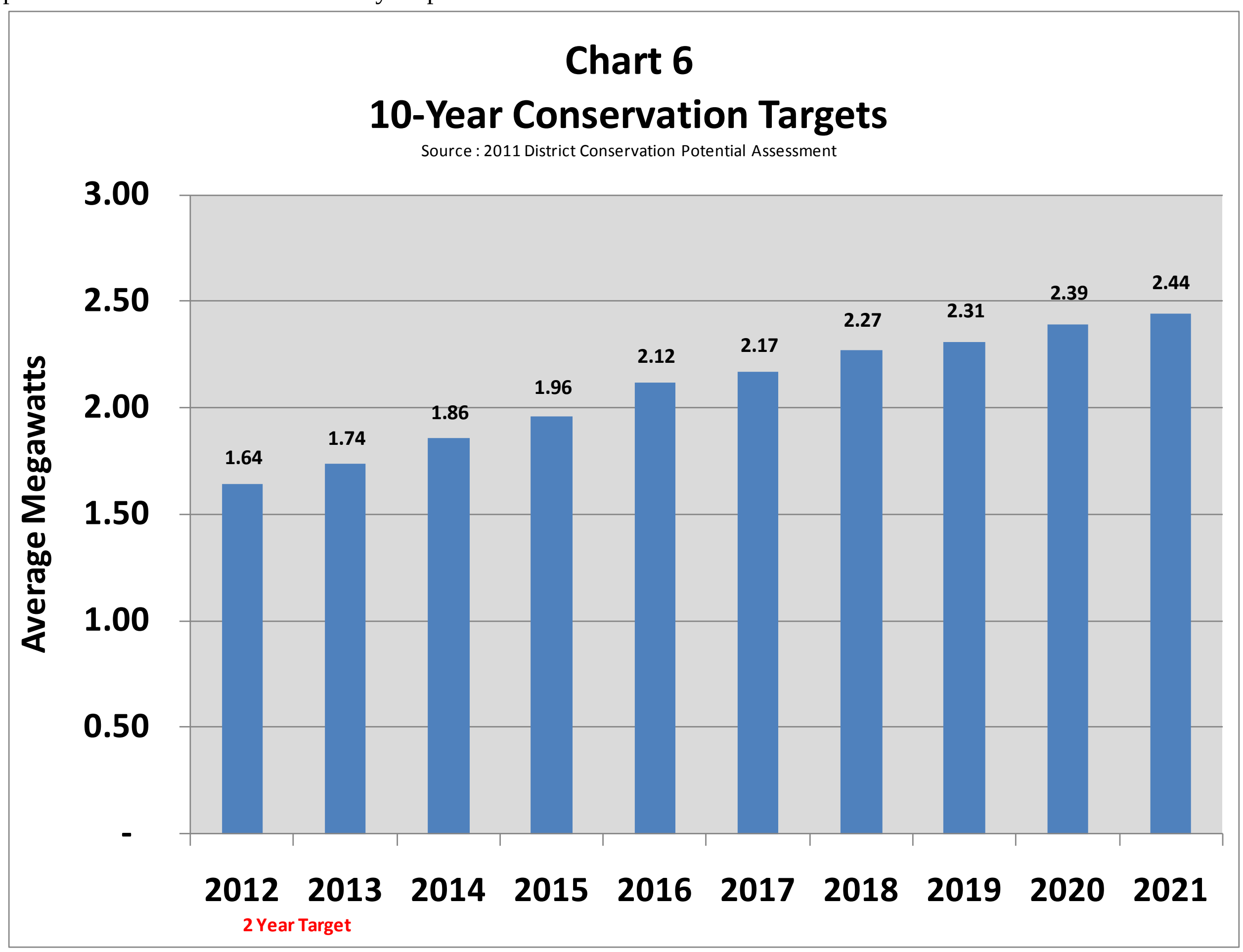
Energy efficiency potential was assessed for the residential, commercial, industrial and agriculture sectors, as well as the distribution system. Developing conservation goals involved analyzing approximately 1,500 energy efficiency measures (all of the Sixth Power Plan measures) by applying Chelan County service territory information, such as the number of electrically heated homes and the saturation from previous conservation programs. The savings from these measures are added together to produce the total conservation potential estimates specifically for the District.

Table 2 shows the high level results of this assessment. The economically achievable potential by sector in two, five, 10 and 20-year increments is included. The total 20-year energy efficiency potential is over 42 aMW. The 10-year potential is nearly 21 aMW, or about 11% of the current electric retail load in Chelan County.

Table 2
2011 Conservation Potential Assessment
Cost-Effective & Achievable Savings
aMW

Sector	2 Year	5 Year	10 Year	20 Year
Residential	1.83	4.56	9.68	21.11
Commercial	0.68	2.13	5.12	9.76
Industrial	0.67	1.83	3.90	8.04
Distribution	0.13	0.65	1.92	3.38
Agriculture	0.06	0.15	0.31	0.31
TOTAL	**3.37**	**9.32**	**20.93**	**42.60**

Chart 6 illustrates the 10-year conservation potential and two-year target on an annual basis.



This assessment shows potential starting at just over 1.6 aMW in 2012 and ramping upward over the 10-year planning period.
This "ramping" effect was used in both the Council's Fifth and Sixth Power Plans and accounts for measures that aren't readily available in the early years of the planning horizon.

Also embedded in these potential estimates are savings from regional market transformation efforts as well as new codes and standards. The Northwest Energy Efficiency Alliance (NEEA) conducts region-wide market transformation efforts which will also impact savings in Chelan County. NEEA defines market transformation as "the strategic process of intervening in a market to create lasting change in market behavior by removing identified barriers or exploiting opportunities to accelerate the adoption of all cost-effective energy efficiency as a matter of standard practice." The District became a funding member of NEEA in January 2012 and can apply a pro-rata share of these regional NEEA savings toward meeting biennial targets.

Residential

The majority of the potential in this assessment is in the residential sector. On average, it represents just under one aMW per year for the next 10 years. The potential is concentrated in five end-use categories: lighting, heat pumps, envelope retrofit, such as insulation measures and window and door replacement, water heating and consumer electronics. Expanded programs may include compact fluorescent lamp (CFL) giveaways, window rebates and insulation rebates. New programs may include low-flow showerhead rebates, HVAC rebates and new home construction energy incentives.

Residential CFL potential remains available through 2014, prior to full adoption of new federal lighting efficiency standards. Heat pumps are a measure with a large and steady amount of potential. Since the District has significant electric space heating, both heat pumps and weatherization measures will yield significant savings. Low-flow showerheads contribute significantly to savings potential within the water heating end-use. Savings potential from heat pump water heaters is expected to grow over the planning period and is ramped accordingly. Consumer electronics is aggressively ramped up, though the majority of the potential is expected to be achieved through market transformation.

Commercial

Similar to the residential sector, the commercial sector increases steadily over the planning period, starting at 0.3 aMW per year and increasing to around 0.5 aMW per year by the end of the 10-year planning period.

Lighting remains the largest source of potential throughout the period. Lighting controls for retrofit applications provide some potential, with lighting power density measures that reduce the watts needed per square foot, providing a larger portion of the potential.

Industrial

Energy conservation potential in the industrial sector accounts for 8 aMW over the 20-year planning period and is dominated by fruit storage measures. Upgraded refrigeration systems found largely in these facilities account for approximately 70% of industrial potential.

Agriculture

The agriculture sector is quite small, accounting for only 0.3 aMW over 10 years. Savings in agriculture will be in irrigation hardware replacements. More efficient water usage lowers electricity consumption by reducing pumping energy. After 10 years, it is assumed this potential will be fully realized.

Distribution

Included in distribution efficiency are major system improvements and light system improvements, but potential largely comes from a reduction in system voltage. Total savings over the 20-year planning period in distribution efficiency improvements accounts for 3.38 aMW, with half of that coming from voltage reduction. The distribution system efficiency measures can be implemented within a relatively short time frame (two to three years).

Cost

Increased conservation requirements will mean increased investment in conservation and conservation marketing. To meet increasing levels of energy efficiency potential, the District will need to expand existing programs and develop new ones.

Conservation is good for customers, the District and the region. Although the District is expected to be a net surplus generator (to local retail energy needs) of electricity throughout the current IRP planning period (2012-2022), during certain hours of the year, Chelan PUD must purchase power on the wholesale market to meet peak demand, particularly during the winter heating season. Energy saved in homes and businesses reduces the need to purchase higher-cost power on the wholesale market. Also, conservation provides additional resources that can be sold into the wholesale electric market when the District is already surplus to its own local retail load. Both cases, in turn, help keep local electric rates low.

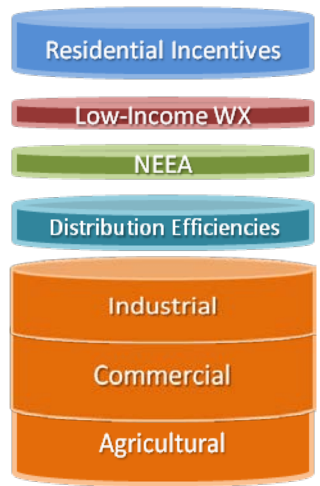
As mentioned previously, EESC utilized the utility-specific methodology as allowed by the RPS when completing the CPA. Chelan PUD utilizes a forward projection of wholesale market power prices (see Market Price Forecast under Portfolio Analysis below) as its avoided cost for future energy acquisitions, including for the evaluation of the cost-effectiveness of potential conservation measures. The levelized cost for all conservation measures that resulted from the assessment was $15.50/MWh over the 2012-2031 period (2011 real dollars). The costs that resulted from the CPA were used for the IRP modeling.

As noted previously, utilities must review and update their 10-year assessment every two years. The District will be updating its avoided costs as well as potential conservation measures with each update.

Current Demand-Side Offerings

The goal of Chelan PUD conservation programs is to offer diversified, cost-effective conservation programs that maximize the value to District ratepayers while striving to meet the RPS conservation targets. The District offers a variety of conservation programs to its customers. These programs include several rebates for residential customers, commercial funding assistance and industrial projects. Recent programs offered by the District are detailed below. The 2012 "stack" of expected energy savings is represented in Figure 1.

Figure 1
2012 Conservation Program "Stack"



Insulation Rebates

For residential customers, the District pays 25 cents per square foot for added insulation. Requirements to qualify include: new insulation must increase the R-value by 10 or greater, existing attic insulation must be R-19 or less, wall or floor insulation must be R-5 or less and only in-cavity insulation may be used.

Window and Glass Door Rebates

Incentives are available to residential customers who replace older inefficient windows and glass doors. This rebate offers customers $3 per square foot on qualifying glass doors and windows. To qualify, new windows must have a U-factor of .30 or lower. Qualifying glass doors must have a U-factor of .35 or lower.

Low-income weatherization

The District provides funds to the Chelan-Douglas Community Action Council (CDCAC) for low-income home weatherization. The District has partnered with the CDCAC to weatherize income-eligible electrically heated residences. Income eligibility is based on 200% of federal poverty guidelines. Chelan PUD offers an annual grant of $65,000, which is matched by the Washington State Energy Matchmaker program administered by Commerce. CDCAC crews complete the weatherization measures which are inspected by Commerce and the District. In addition to the weatherization funding, in 2010 and in 2011, the District provided CFLs that CDCAC supplied to their clients.

Compact Fluorescent Lamp (CFL) Distribution

The District distributed 80,000 CFLs in 2010 and 2011combined to residential customers in the District's service area. In 2010, lamps were handed out free of charge at District offices while supplies lasted. In 2011, the District held a CFL event in August at all three District public offices. Lamps were also handed out at various smaller events throughout the two-year period. This program was very popular with District customers with available supplies of lamps going quickly. Plans for 2012 and 2013 are to purchase additional lamps and a bid is forthcoming to purchase an additional 20,000 lamps for distribution. In addition, the District will pilot a program in 2012 where installers would replace all incandescent lights with CFLs in a home. Plans are to install an average of 27 lamps in 950 homes.

Retail buy-down of CFL specialty bulbs

The District buys down a portion of the wholesale cost of certain energy efficient specialty lamps sold in local retail stores. The District pays an incentive at the wholesale level and retailers agree to pass the savings on to customers in Chelan PUD's service area. This program is operated regionally by a third party vendor.

Commercial Plan Review and Code Compliance

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

Energy Star® Portfolio Manager Support

The Portfolio Manager is an on-line software program that allows facility managers to monitor the energy consumption of their buildings and rate how they compare with similar buildings throughout the nation. Buildings receive an energy rating and can be certified as meeting Energy Star® standards if proven to be more energy efficient than 75% of comparable buildings in the portfolio manager database. Knowledge of a building's energy rating gives building operators the ability to concentrate their resources on the worst performing buildings and take steps to improve their facility's energy use rating. This program is now required (by RCW 19.27A) for public buildings in Washington State.

Resource$mart

Resource$mart is the District's program for helping commercial and industrial customers install energy efficiency equipment in their facility by paying a portion of the up-front costs. The District can pay up to 75% of each energy efficient project. Measures include lighting projects, fast-acting doors on large refrigerated spaces, energy efficient fruit warehouse controlled atmosphere equipment and improved heating and cooling equipment.

Next Steps

The District completed an in-house conservation tracking system linking conservation measures to specific service points throughout Chelan County and will continue to evaluate and develop its conservation potential by refining the demographic data of all customer classes and survey participation rates for various conservation programs. In addition, the District is reviewing options for achieving a more comprehensive CPA, which would be used as the basis for future utility-specific analysis.

BPA's Energy Efficiency (EE) Central reporting system is the new replacement for the obsolete

Planning, Tracking and Reporting system required for utility reporting, or a pre-approved alternative, by the RPS. Chelan PUD will integrate "deemed measures" from EE Central into its approved in-house tracking system, when EE Central goes online.

Portfolio Analysis

The District continues to utilize the same long-term resource portfolio/risk analysis model as in 2008 and 2010. The model quantifies the risk and correlations between key variables – such as resource availability, load and market prices – using built-in Monte Carlo simulation and scenario analyses. A more detailed description of the model and an explanation of this type of analysis can be found in Appendix A – Modeling Detail & Assumptions.

Chelan PUD is still long in terms of its resource position. The District is expected to be able to serve its retail load throughout the planning period (2012-2022) without adding new resources and is also expected to meet Washington State RPS renewable requirements through this period as well. Additionally, Chelan PUD's resource portfolio is comprised primarily of base load, reliable, low-cost hydro resources and it performs well against the portfolio evaluation criteria established by the District (described below). For all these reasons, as in prior analyses, no new resources were added to the portfolio scenarios detailed below.

Although it is not adding new resources, the District remains 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 (volume 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

Portfolio Costs

The 2011 cost of production for the District's existing portfolio is shown in Table 3. These costs were calculated two ways. The second column, reading left to right, are the actual cost per megawatt hour based on actual costs and actual generation in 2011. Water runoff conditions were 125% of average in 2011. Wind conditions at Nine Canyon were also above average. The column on the right was calculated using actual 2011 costs and average hydro and wind generation for any given year. This column illustrates what current costs are without the effects of runoff and wind variability. As seen in the table, cost per megawatt hour of generation can vary significantly depending upon actual generation. This is because almost all costs are fixed, that is, they don't vary with the amount of generation (e.g., debt service, taxes).

For Chelan PUD's hydroelectric facilities, these costs represent all costs incurred, including debt service, operations and maintenance (O&M), taxes, reserve fund requirements, contractual fees and certain costs for network transmission. The Nine Canyon cost of production includes the District's monthly power purchase contract payments to Energy Northwest and the BPA transmission costs to bring the Nine Canyon wind energy from Benton County to Chelan County.

Table 3
District's Existing Portfolio
Cost of Production
2011

Project	$/MWh w/actual generation	$/MWh w/average generation
Rocky Reach	$10.96	$13.91
Rock Island	$23.78	$26.89
Lake Chelan	$23.93	$27.89
Nine Canyon	$69.06	$70.14

Hydro

The District forecasts the future cost of production of the hydro projects by compiling long-term operating plans and capital replacement programs, which are then incorporated into the forecasted debt service requirements of each facility. This cost-based activity is then adjusted to include other long-term power contract requirements to determine the overall cost of production.

Examples of long-term power contract requirements include, but are not limited to:

- Capital Recovery Charge (base scenario-50% of average annual capital expenditures)
- Debt Reduction Charge (base scenario-3% of outstanding project debt)

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

- Costs associated with license and habitat conservation plan implementation
  - Fish survival, hatchery programs, etc.
  - Plant rehabilitation and improvements

The forecasted hydro O&M costs for the base case scenario in this IRP consist of general cost growth rates for standard programs, while project-specific O&M such as licensing, fish, hatchery and major park maintenance are accounted for with specific forecasts for each project. The average project O&M growth rates are:

- Rocky Reach – 5.5%
- Rock Island – 4.0%
- Lake Chelan – 3.5%

Debt service is driven by existing debt schedules and forecasted financing needs that are driven by specific project capital requirements. In addition, the anticipated use of other long-term power contract requirements such as the debt reduction charge account and capital recovery charge account are included as offsets to future debt service needs.

Nine Canyon Wind

The projected future costs of production at the Nine Canyon Wind Project are taken from an annually updated budget that includes the next year and projected future years. The budget is developed by Energy Northwest in conjunction with project participants. In addition, Chelan PUD makes an estimate of future BPA transmission costs that will be incurred to bring the wind energy from Benton County to the District's service territory in Chelan County.

Since increasing approximately 70% in 2008 due to higher than expected maintenance and repair costs and lower than anticipated federal Renewable Energy Production Incentive payments, the cost of production rates have remained and are expected to remain fairly stable. In early 2012, Energy Northwest was able to refinance the original Phase II construction bonds during historically low rates at a substantial savings to Phase II purchasers. Once Phase I and Phase II debt is completely repaid in 2022, cost of production rates are expected to decrease significantly throughout the remainder of the purchase contract which expires in 2030.

Market Price Forecast

Wholesale spot-market prices for electricity provide an additional risk factor for Chelan PUD and other utilities. For the 2010 Progress Report, the District used the "base case" market price forecast for the Mid-C from the NWPCC's Sixth Power Plan, adopted in February, 2010, in each resource portfolio scenario. The "base case" had a wholesale power price of $55.50/MWh levelized for 2010-2029 (2006 real dollars). This forecast was significantly higher than the forecast used in 2008 due, in large part, to higher natural gas and CO2 price forecasts. Prices were projected to increase from $30/MWh in 2010 to $74/MWh in 2030 (2006 real dollars). For comparison, Mid-C wholesale power prices averaged $56/MWh in 2008, dropping sharply to $29/MWh in 2009 (2006 real dollars) with the collapse of natural gas prices and the reduction of demand due to the economic downturn. Prices have remained low since that time averaging $30/MWh in 2010 and dropping further to $21/MWh in 2011 (2006 real dollars). Further decreases in natural gas prices and higher than average hydro generation combined with an expanding regional wind fleet, discussed in greater detail at the end of this section, were primary drivers of the low prices in 2011.

In 2011, the NWPCC proposed changes to their long-term natural gas price forecast based on changes in the outlook for natural gas supplies that began in 2010 and appear to qualify as a fundamental shift in expectations about future natural gas supplies. The development of technologies to cost-effectively obtain natural gas trapped in shale formations has changed the view of natural gas supplies from declining and constrained (as used to develop the Sixth Plan) to plentiful for many decades to come. Although the possible potential for shale had been recognized in the Sixth Plan, the expected cost of developing it has been reduced through technological breakthroughs so that expected future prices are now lower. The rapid development of shale gas has created a glut of natural gas that is likely to last for several years and depress prices.

One likely effect of the revised natural gas price forecast on a revised power plan would be to reduce the forecast of electricity prices. The future cost of CO2 production and renewable resource development associated with the state RPS are additional factors that will affect the variable cost of the hourly marginal resource and hence the wholesale power price. Because natural gas has been a relatively expensive fuel, although now to a lesser degree, natural gas-fired plants are often the marginal generating unit and therefore, determine the wholesale price of electricity during most hours of the year. Potential CO2 allowance prices or taxes could raise the variable cost of coal-fired units more than that of gas-fired units because of the greater carbon content of coal. Lower CO2 costs would raise the variable cost of both gas and coal units, but not enough to push coal above gas to the margin. High CO2 costs could move coal to the margin, above gas. In either case, the variable cost of the marginal unit will increase, however, CO2 costs have not yet materialized as has been anticipated. State RPSs are expected to force the development of large amounts of wind, solar and other low-variable cost resources in excess of the growth in demand. This could, at times of lower power demand, force lower variable cost fossil units, such as coal, to the margin, tending to reduce market prices. The NWPCC is expected to revisit its wholesale power price forecast and release an interim forecast in 2012 that will take all these factors into account. However, the interim forecast was not yet available for inclusion in this IRP.

Due to the Council's new view on future natural gas prices and the unavailability of an updated wholesale power price forecast as well as the District's own observations of current and forward natural gas and power markets, the District felt it should use more current pricing of forward power markets in the IRP modeling. A forward broker price curve from Platts from March 1, 2012 was used, in part. Platts aggregates multiple data sources to produce a single cross-checked series of forward curves using an open and validated methodology, offering clients a view of forward values that can be used for independent evaluation, mark-to-market validation processes, strategic decision support or other portfolio risk management processes. Platt's forward curve extended through 2018. The District used the rate of growth from 2017 to 2018 to produce prices throughout the remainder of the planning period (four additional years). Likewise, to get monthly pricing, the monthly shape of the average price in 2018 was also retained for the remaining years in the planning period. The aggregated forward price curve resulted in a $27.00/MWh levelized price for 2012-2022 (2006 real dollars).

The aggregated forward price curve was used in each resource portfolio scenario. The District continues to focus on uncertain variables in the IRP, including load and hydropower costs, about which the District has more internal expertise and the ability to develop and model with greater confidence. There remains significant uncertainty surrounding future costs at its hydroelectric projects. In the future, when the Council has new market price forecast scenarios available, Chelan PUD may consider varying power price forecasts between its resource portfolio scenarios. The base case price forecast from the Sixth Plan used in 2010 and the aggregated forward price curve used for this IRP can be seen in Chart 7 in real dollars and in Chart 8 in nominal dollars. The decrease in the markets' expectations of future power prices is evident. The Sixth Plan base case assumed medium fuel prices and mean CO2 prices as projected in 2010, 95% achievement of state RPS, average hydropower conditions, medium load growth

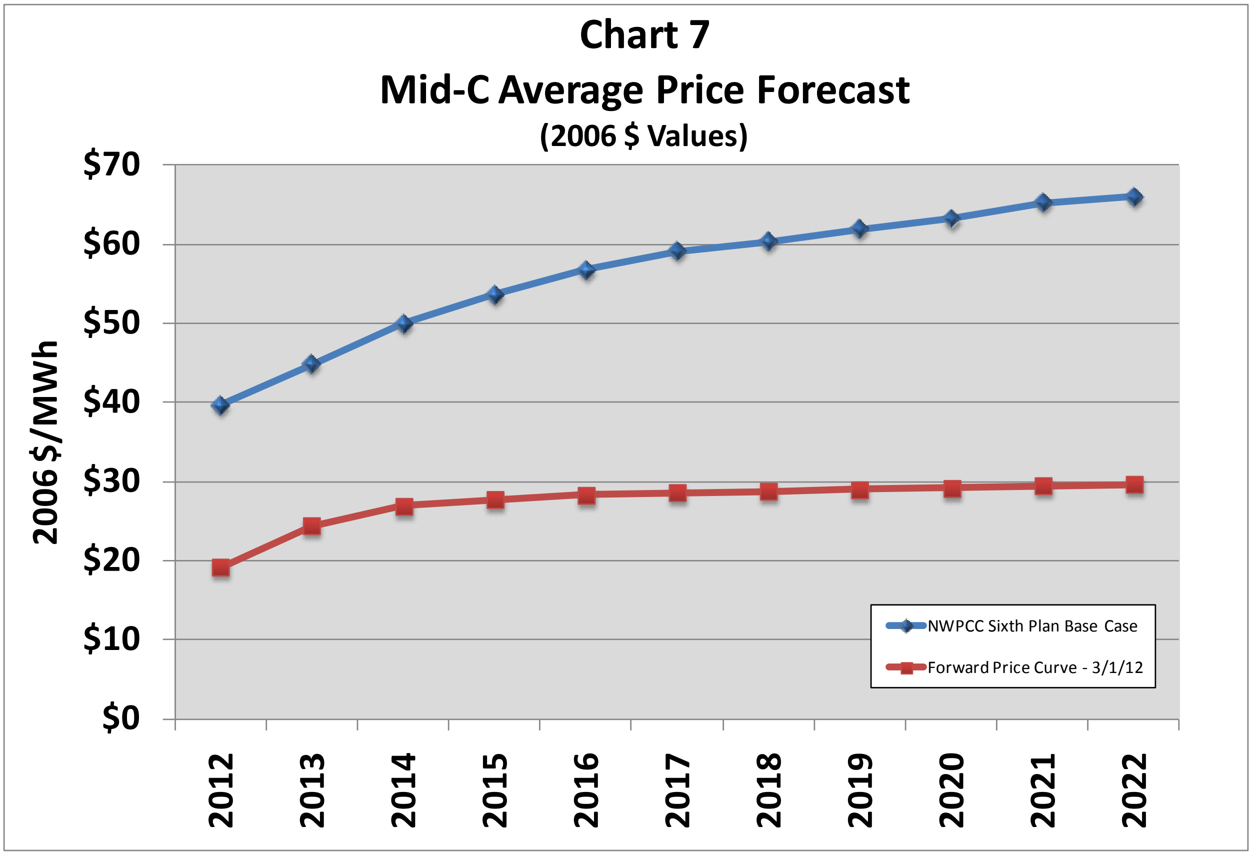


Chart 7
Mid-C Average Price Forecast
(2006 $ Values)
2006 $/MWh
$70
$60
$50
$40
$30
$20
$10
$0
NWPCC Sixth Plan Base Case
Forward Price Curve - 3/1/12
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022

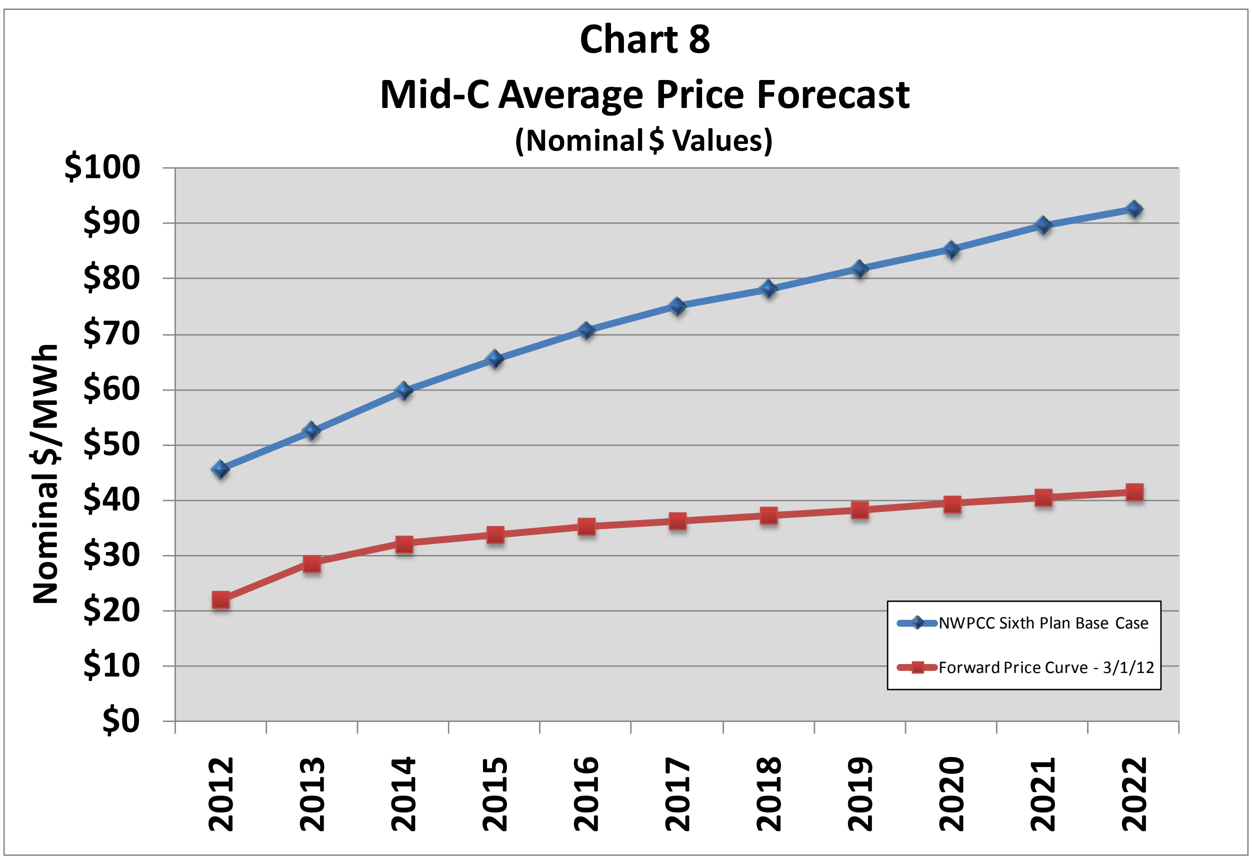


Chart 8
Mid-C Average Price Forecast
(Nominal $ Values)
Nominal $/MWh
$100
$90
$80
$70
$60
$50
$40
$30
$20
$10
$0
NWPCC Sixth Plan Base Case
Forward Price Curve - 3/1/12
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022

and achievement of all cost-effective conservation. Platt's forward curve through 2018 presumably encompasses the markets' views of all of these elements as of the date of the curve.

As mentioned in the 2010 Progress Report, at times, hydro and wind, which are very low variable cost resources (i.e., free fuel), may even be forced to the margin during periods of low load and high hydro and/or wind production. This results in very low or even negative spot market prices. Negative spot market prices mean that a utility or other market participant has to pay another entity to take unwanted power (i.e., power for which no load exists). The negative pricing occurs for two primary reasons. Sometimes hydro generators are must-run due to operational constraints, thus adding additional energy to an over-supplied market. Additionally, many wind generators receive federal incentive credits and/or payments based upon their amount of wind generation. They can also sell the RECs for this generation. The value of these items combined is somewhere in excess of $20/MWh today. These generators can afford to withstand some degree of negative pricing and still make a profit due to these other payments. This scenario played out to the greatest degree ever experienced in the Pacific Northwest in 2011. With stream flows on the Mid-Columbia at 125% of average and an expanding wind generation fleet in the region, as previously discussed, a sustained two-month period of negative spot market prices resulted. As of the publication of this IRP, the federal Production Tax Credit for certain wind producers is set to expire December 31, 2012. A possible phase-out or extension has made news, but no legislative action has been taken.

Hedging Strategy

As previously mentioned, the District saw the expiration of several long-term power sales contracts for Rocky Reach in the fall of 2011. The same will be true for Rock Island in the summer of 2012. New long-term sales contracts have begun for Rocky Reach and soon will for Rock Island, however, collectively, the new long-term contracts are not for as much of the output as the previous contracts. The additional surplus means additional wholesale power revenue risk. As mentioned in the 2010 Progress Report, Chelan PUD has developed a comprehensive forward hedging strategy.

The three-year and one-year hedging strategies are intended to provide hedging sideboards and targets for hedging the surplus energy. The three-year strategy is for hedging one to three years out and the one-year strategy is for hedging one to eight months out within the calendar year. The minimum and maximum targets for both the three-year and one-year strategies are based on projected surplus energy at various confidence levels. Surplus energy projections are uncertain, primarily due to stream flow and retail load variability, but ranges are quantifiable using statistics as discussed more fully under Scenario Results.

In addition to the three-year and one-year hedging strategies, the District is also pursuing the sale of market-based products such as slice contracts (i.e., a percentage share of project capacity and energy), block sales (i.e., a predetermined quantity of energy) and/or other products approved by the District's internal Power Risk Management Committee to help manage wholesale revenue risk and stabilize such revenue five years into the future. These contracts will have a maximum term of five years and can be executed up to one year in advance of a five-year term. These five-year transactions may be sold using a laddered approach, meaning the total amount of slice or block contracts in any given year would have been executed at different points in time. These longer-term contracts will not be subject to the one-year and three-year targets. It is anticipated that approximately two-thirds of the surplus power available after 2011 will be sold through these longer-term contracts. Laddered five-year slice contracts are being implemented. As of early 2012, slice and block contracts have been executed for as far out as 2017. The portfolios modeled for this IRP include the slice contracts that have been executed as well as those that are expected through the planning period. The slice contracts vary slightly in the earlier years, but reach a maximum of 25% of the capacity and energy at Rocky Reach and Rock Island by 2017 and remain there through the term. For slice contracts that have already been executed and awarded through a bid process, actual contract pricing was used for modeling purposes. For planned, but unexecuted slice contracts, the same market pricing discussed earlier was used. These slice contract assumptions have been further refined since the 2010 Progress Report and were determined to be a reasonable approach to modeling the affects of the five-year term portion of the hedging strategy and are further discussed under Scenario Results.

Scenario Results

The District uses reliability, cost, risk and environmental impacts as the four criteria in the evaluation of its resource portfolio. These criteria represent long-held philosophies of Chelan PUD and the measures for each are described below.

- Reliability – a single, annual probabilistic LOLP value of less than 5% for both energy and capacity
- 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 low, base and high load forecasts and varying hydroelectric costs. The differences between the scenarios are as follows:

Scenario 1 – Base Case

- Base Load Growth (1.45% average annual rate of growth)
- Base Hydro Costs

Scenario 2 - Low Bookend

- Low Load Growth (.77% average annual rate of growth)
- Low Hydro Costs (Base Hydro costs minus 5%)

Scenario 3 – High Bookend

- High Load Growth (1.93% average annual rate of growth)
- High Hydro Costs (Base Hydro costs plus 20%)

As mentioned previously, modeling results continue to indicate that Chelan PUD is expected to be able to serve its retail load throughout the planning period without any new resource additions. Conversely, the amount of demand-side resources included in the modeled portfolios has increased from what was included in the 2010 Progress Report. The 2010 quantity of conservation of 1.50 aMW per year through the planning period has been increased to match Chelan PUD's January 2012 required 10-year conservation plan submittal to Commerce that is 2.12 aMW per year through the study period (based on the 2011 CPA previously discussed). 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.

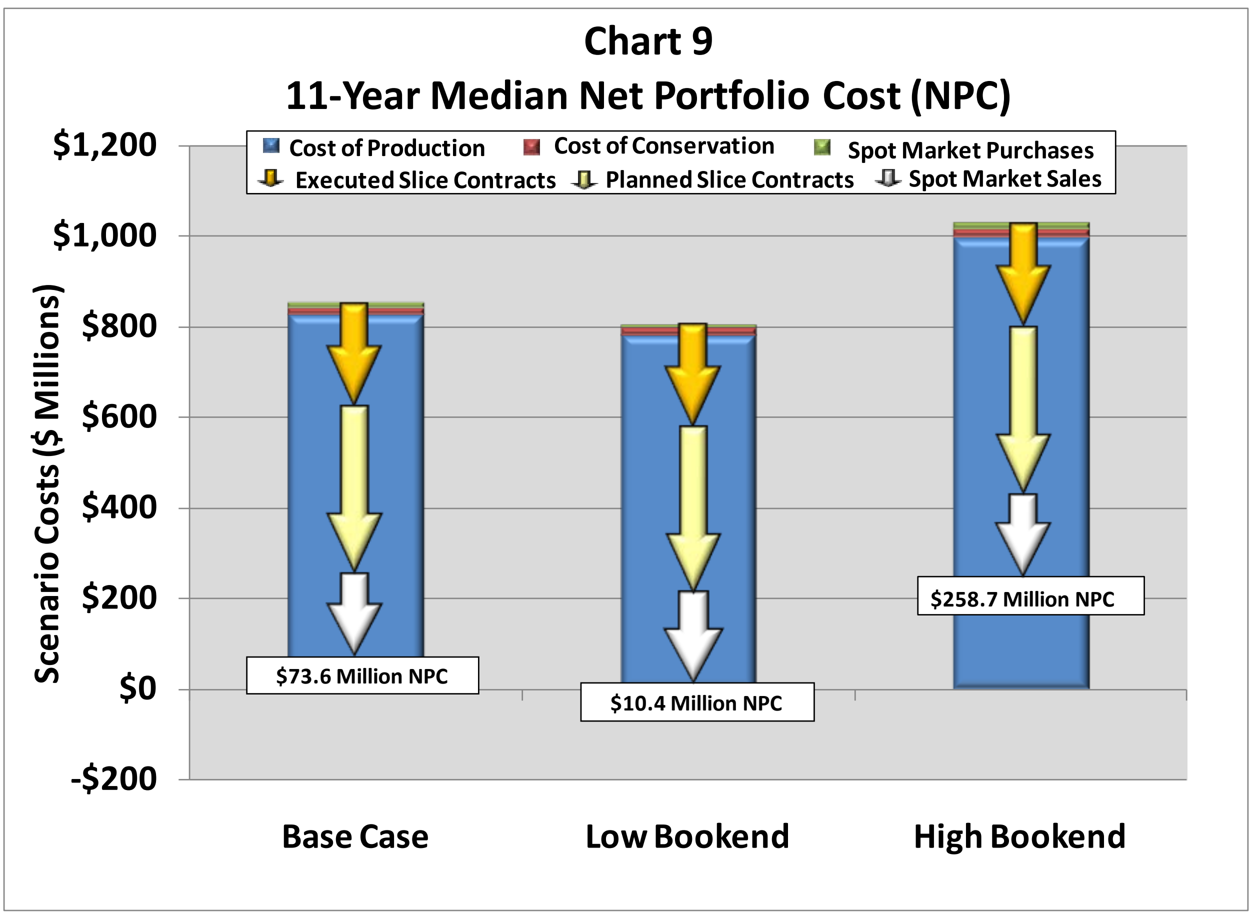
Service Reliability

Chelan PUD's existing resource portfolio is not without risk, but it performs very well when compared against the evaluation criteria. Based on the new voluntary regional resource adequacy standard discussed previously, the District has adequate capacity and energy to meet its retail customers' load through the planning period thus providing for service reliability.

Cost

Net portfolio cost for the District is total costs for Chelan PUD's resources (including hydro, wind and conservation) plus the cost associated with purchasing power in the wholesale spot market, netted with revenues from any and all power sales, including those in the wholesale spot market. 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. For this IRP, the median net portfolio cost for all three scenarios is positive, meaning the costs of all its resources and any wholesale market purchases is greater than the revenue the District is expected to earn from selling surplus power (after serving local load) under longer-term contracts, including slice contracts, and into the wholesale power spot market. Retail revenue from local load is not modeled in the net portfolio cost.

Scenario 1 (Base Case) results in the mid-range median net portfolio cost. Scenario 2 (Low Bookend) results in the lowest median net portfolio cost due to the lowest long-term load growth forecast, allowing more energy to be sold into the wholesale spot market, as well as the lowest forecast for hydro production costs. Scenario 3 (High Bookend) results in the highest median net portfolio cost due to the highest long-term load growth forecast and a substantially higher hydro production cost forecast (+20% over the Base Case). Higher load growth leads to less surplus sales into the wholesale market. Because the aggregated forward price curve (despite market prices decreasing substantially as previously discussed in Market Price Forecast) is higher than the District's hydro production costs, higher load growth scenarios will increase the overall net portfolio cost of the District by reducing the revenues received from surplus sales. Higher hydro production costs obviously result in higher net portfolio costs, and it is the primary factor causing the majority of the differences between the three scenario results. Chart 9 shows the 11-year median net portfolio costs for the three portfolio scenarios that were modeled. In Chart 9, "cost of production" represents all costs associated with Chelan PUD's share of its hydro projects (including slice shares) and Nine Canyon power costs. Executed and planned slice contracts are represented separately on the chart. As mentioned in the hedging strategy section, for slice contracts that have already been executed and awarded through a bid process, actual contract pricing was used for modeling purposes. For planned, but unexecuted slice contracts, the aggregated forward price curve was used.



Just as the net portfolio cost results in 2010 (2010-2020) varied greatly from those in 2008 (2008-2018), the results this year vary greatly from those in the 2010 Progress Report. Median net portfolio costs all went from being negative in 2010, meaning that over the planning period, portfolio costs were less than portfolio revenue, to all being positive now. This means that over the planning period, portfolio costs are more than portfolio revenue as previously mentioned. This shift is due primarily to the dramatic decrease in market prices in the last couple of years, thus decreasing wholesale revenue, including that from slice contracts, and increasing net portfolio costs. The aggregated forward price curve still remains above the hydro cost of production throughout the planning period, however serving local load (rather than selling all power into the market) causes a net positive portfolio cost over the planning period. Retail revenue is not generally included in IRP modeling, and it has not been here, as previously mentioned.

Risk

To assess 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 greatest risk. Hydroelectric production costs continue to be the primary variable creating the difference in net portfolio cost between the scenarios, with load growth being the other contributing factor. The volatility around the median net portfolio 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 – as well as wholesale market prices are the primary variables creating the uncertainty (i.e., 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 revenue, depending upon the level of market prices, can have a tremendous effect on reducing the net portfolio cost to the District.

The difference between the median and 5% level of the confidence interval is greater than the difference between the median and 95% level of the confidence interval. This means that the District has a greater chance at lower net portfolio costs rather than higher. This is due primarily to more upside opportunity in electric wholesale spot market prices, meaning prices are assumed to have more room to go higher than to go lower.

Slice contracts are sold as a percentage of project energy and capacity, not as a fixed amount of megawatts, for a fixed amount of revenue. Selling slice contracts allows the District to reduce both hydro volatility risk as well as price risk (as evidenced by comparing the portfolio results to a baseline scenario that did not include the planned, but unexecuted, slice contracts). Net portfolio cost is higher to the District at the 5% level of the confidence interval than if planned, but unexecuted, slice contracts were not sold. This is a result of dampening "upside" wholesale revenue potential that could occur from taking this energy to the wholesale spot market when hydro production and market prices are higher than expected rather than selling it at a somewhat lower fixed price under the slice contract. Conversely, net portfolio cost is lower at the 95% level of the confidence interval than if slice contracts were not sold. Some "downside" risk associated with wholesale revenue is mitigated. This mitigation is because when hydro production and market prices are lower than expected, this share of project output has been sold at a somewhat higher fixed price that was originally established based on a higher expected amount of hydro production by slice purchasers.

Table 4 tabulates the 11-year net portfolio cost for all three scenarios and illustrates the variability around the median net portfolio cost for each scenario.

Table 4 Net Portfolio Cost Uncertainty Probabilistic Outcomes ($ Millions)					
Scenarios	**5% level of the Confidence Interval**	**Difference between 50% and 5% level of the Confidence Interval**	**50% level (median) of the Confidence Interval**	**Difference between 50% and 95% level of the Confidence Interval**	**95% level of the Confidence Interval**
Low Bookend	**-$84.0**	$94.4	**$10.4**	$88.4	**$98.8**
Base	**-$20.6**	$94.2	**$73.6**	$89.0	**$162.6**
High Bookend	**$164.8**	$93.9	**$258.7**	$89.6	**$348.3**

Environmental Impacts

The District's hydropower and wind generation do not produce any air emissions, but during certain hours of the year, depending upon load and hydro conditions, the District is a net purchaser in the wholesale power market. Those market purchases come from a "market mix" of different generating resources. Some of those resources produce air emissions. Table 5 shows Chelan PUD's calculated fuel mix for 2010, based on the amount of wholesale purchases the District made, as well as the overall Northwest Power Pool Net System Fuel Mix for 2010.

The cost of air emissions from CO2 remain an industry uncertainty as evidenced by the wide variety of potential federal climate change legislation discussed previously. As in the past, the District did not explicitly model costs associated with air emissions in its portfolio scenarios because of this uncertainty surrounding future regulations for air pollutants. As such, the net portfolio costs of the District's portfolio scenarios do not include any costs and/or benefits associated with air 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. Any proposed change to the District's mix of generating resources in the future would need to be evaluated for its environmental impacts.

Table 5 2010 Fuel Mix		
Generation Type	**District Calculated Fuel Mix**	**NWPP Net System Fuel Mix**
Biomass	0.07%	0.99%
Coal	3.51%	47.33%
Cogeneration	0.00%	0.00%
Geothermal	0.00%	0.00%
Hydro	94.93%	32.02%
Landfill Gases	0.01%	0.14%
Natural Gas	1.25%	16.76%
Nuclear	0.13%	1.79%
Other	0.01%	0.12%
Petroleum	0.03%	0.08%
Solar	0.00%	0.00%
Waste	0.06%	0.77%
Wind	0.00%	0.00%
TOTAL	100.00%	100.00%

Short-Term Plan

As required by RCW 19.280, the District has completed a new "short-term plan" for this IRP.

Conservation Resources

- Continue to develop conservation potential by refining demographic data for customer classes. In 2011, EESC conducted a detailed conservation potential assessment of Chelan County using new data developed locally since 2009. The District will add to the knowledge gained from this assessment to further refine conservation potential in the future. Sources for this data include the Residential Building Stock Assessment, a regional survey conducted by Ecotope, Inc. for NEEA and a field audit of Chelan County residential construction conducted as part of a direct-installation energy efficiency lighting program.
- Study available energy efficiency measures and programs. Chelan PUD joined NEEA in January of 2012 and is represented on the governing board. This partnership will help enhance the District's knowledge of energy efficiency programs and emerging technologies. In addition, the District educates itself through the Regional Technical Forum, BPA workshops, energy efficiency roundtables, others dealing with emerging technologies and attending BPA's Annual Energy Efficiency Summit. New measures are reviewed for cost-effectiveness, reliability and feasibility and the most promising are added to the list of prospective energy efficiency offerings.
- Evaluate conservation potential using automated metering technologies and rate design. The District uses automated metering to verify energy efficiency and potential in the industrial sector, primarily fruit controlled atmosphere facilities. Evaluations of current and emerging efficiency technologies is ongoing. Effective January 1, 2012, the District eliminated its conservation rate design and established a flat electrical rate.
- Look for economies of scale in conservation efforts with other utilities. Funding constraints eliminated the shared Resource Conservation Manager between several public agencies and the District. Another potential program developed to weatherize low-income multi-family dwellings is also in jeopardy due to funding constraints. Chelan PUD is currently monitoring an initiative by BPA for shared purchase of conservation materials. The District plans on participating in several BPA-sponsored programs in order to take advantage of economies of scale.
- Refine and expand the District's in-house system to better track and report goals and conservation achievements. Continue the development of this in-house tracking and reporting tool to quickly and easily produce reports that can be used as key performance indicators. Add connectivity with BPA's EE Central software to facilitate compliance with the RPS.
- Produce a business plan for conservation, including conservation targets to meet Washington State RPS. In 2011, the conservation group became part of Chelan PUD's Energy Resources Group in order to enhance conservation's role as an energy resource. The business plan for 2012 was completed as part of Energy Resource's goals and objectives. The most cost-effective programs were selected and added to a business plan, which included a two-year target and 10-year goal. A budget was developed for 2012-2013. The budget and conservation targets were presented as the "stack" to the District's Board and public on November 21, 2011 at a public hearing.
- Implement cost-effective conservation programs, which comply with requirements of the Washington State RPS. The budget, targets and goals were approved by the Board on December 5, 2011. The programs approved for 2012 include residential

weatherization, CFL distribution, specialty CFL retail buy-down, low-income weatherization, ductless heat pump installation, NEEA membership, commercial lighting incentives, irrigation pumps, commercial code review of new buildings and remodels, industrial lighting, industrial evaporative fan incentives and CO_2 scrubbers for fruit warehouses. The conservation target for 2012 is 1.64 aMW with a two-year target of 3.38 aMW of savings.

Resource Planning

- Continue to refine modeling and implementation of the hedging strategy utilizing the IRP model as well as other more granular, shorter-term modeling tools to inform the District about uncertainty in wholesale revenue and to focus on robust strategies that will return favorable results given different uncertain outcomes.
- Study the fundaments of the NWPCC's interim wholesale power price forecast expected to be released in 2012 including the price of natural gas, the cost of new generating resources, the potential cost associated with CO_2 regulation, the development of RPS resources surplus to regional needs and regional energy and capacity reserve margin targets. Consider the application of one or more of their forecast scenarios in future District IRP modeling and other wholesale revenue modeling.
- Continue to study Council and Forum development, implementation and documentation on the new resource adequacy standard. Consider application in and ability to model in current and/or potential new District load/resource modeling.
- Evaluate the change in how system losses are accounted for as contracts for long-term power purchasers change and the effect on District load is observable. Refine loss percentage in econometric load forecast model to accommodate for the effects of these changes.
- Continue to track climate change and other environmental legislation, federal, state and regional, and how they may impact the District's resource portfolio.
- Continue to monitor for any changes to the Washington State RPS that may impact the District's renewable portfolio.
- Continue to review emerging research and regional discussions regarding the impact of climate change on regional hydrology and the potential effect on the District's future hydro generation.
- Continue to observe the impact of increasing amounts of wind capacity and generation on the regional power grid and effect on reliability, reserves and wholesale power market prices. In conjunction, monitor the development and implementation of BPA's Oversupply Management Protocol and its effect on the aforementioned elements. Consider the effect on the District's risk associated with any of those elements.
- Continue to monitor the growth of EVs in the automobile marketplace and their presence in Chelan County as well as applying the latest in technical developments to the modeling of projected EV load in the District's service territory. Based on the District's current analysis, the potential impacts remain very minimal during the planning period.

Final Remarks

As with previous plans, Chelan PUD's resource portfolio performed well against the evaluation criteria. The District intends to retain its existing supply-side resources while implementing its 2011 CPA results and continuing the increase in conservation levels that began in 2010. Complying with both the renewable resources and conservation portions of the Washington State RPS will remain a significant focus as initial reportings and audits will take place within the next year or two. The District will continue to monitor uncertain variables that affect its wholesale revenues, including available stream flows and wholesale power market prices that are both facing potential increased uncertainty in the future. Additionally, the District will continue to evaluate and implement its hedging strategy to help reduce the risk associated with these and other uncertainties.

Chelan PUD will publish a progress report to this IRP in 2014.

Appendix A – Modeling Detail & Assumptions

The Model

In 2008, the District purchased *Resource Portfolio Strategist* from the Cadmus Group, Inc. to perform integrated resource planning analysis. It is a Microsoft Excel-based, long-term resource portfolio/risk analysis model built specifically for the electric utility industry. Users build portfolios using logical bundles of various resource options and the model provides outputs (cost and benefits) along with risk assessments and parameters. The model quantifies the risk and correlations between key variables, such a hydro availability, conservation, load and market prices, using built-in Monte Carlo simulation and scenarios analysis. Further, the model has extensive flexibility for modeling uncertainty for variables such as those just mentioned.

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

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

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

- Load
- Hydro availability
- Wind (or other renewable) availability
- Conservation availability/penetration
- Electric market prices
- Natural Gas and Coal market prices, if needed
- Forced outages
- Other customizable variables

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

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

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

Modeling Assumptions and Parameters

The following elements were common to all modeled scenarios:

Resources

Hydro

- To represent the generation associated with stream flow uncertainty, capacity factors were calculated using historical re-regulated stream flow data, 1929-1997, supplied by PNUCC and actual hydro project data from 1998-2011. The capacity factors reflect the reduced generation due to fish spill operations
- Actual hourly hydro project data from 1987-2007 was used to shape the annual capacity factors into more granular time periods. This period was assumed to be most representative of current project operations. This annual shape is constant for every year of the planning period
- Generation is net of all project obligations (i.e., Canadian Entitlement Allocations (CEAs) and encroachments)
- All operational and equipment-related incremental hydro was included
- Rocky Reach – Chelan PUD's share (net of long-term purchaser contracts and executed and planned slice contracts)
    - 14.96% - 1/2012 through 6/2012
    - 25.46% - 7/2012 through 12/2012
    - 20.46% - 1/2013 through 12/2013
    - 21.46% -1/2014 through 12/2014
    - 22.46% -1/2015 through 12/2015
    - 23.46% -1/2016 through 12/2016
    - 18.46% -1/2017 through end of planning period
- Rock Island – Chelan PUD's share (net of long-term purchaser contracts and executed and planned slice contracts)
    - 50% - 1/2012 through 6/2012
    - 31% - 7/2012 through 12/2012
    - 26% - 1/2013 through 12/2013
    - 27% - 1/2014 through 12/2014
    - 28% - 1/2015 through 12/2015
    - 29% - 1/2016 through 12/2016
    - 24% - 1/2017 through end of planning period
- Lake Chelan – Chelan PUD's share
    - 100% - through entire planning period
- Costs for O&M, debt service, taxes, reserve fund requirements, contractual fees and certain costs for network transmission were each represented by scenario forecasts

Wind

- To represent the generation associated with wind uncertainty, all available historical Nine Canyon hourly wind generation (2004-2011) was used to calculate capacity factors for the on-peak, shoulder and off-peak time periods

- Current operation of facility (i.e., historical turbine availability rates)
- Costs of O&M, debt service and transmission

Conservation

- Used the quantities from the 2011 CPA (also used for RPS compliance in January 2012) totaling 42 aMW over 20 years. Used the corresponding CPA levelized cost of $15.50/MWH (2011 real dollars)
- All scenarios were modeled with a 20-year ramp rate on all measures

Contracts

Long-term Power Sales

- Rocky Reach
  - Puget – 25% through end of planning period
  - Alcoa – 27.5% through 6/2012, 26% - 7/2012 through end of planning period
  - Douglas – 5.54% through end of planning period
- Rock Island
  - Puget – 50% through 6/2012, 25% - 7/2012 through end of planning period
  - Alcoa – 26% - 7/2012 through end of planning period

Executed and Planned Slices of Rocky Reach & Rock Island

- Executed and proposed "slice of the system" contracts as part of long-term hedging strategy
- Slice contracts represent between 18% and 27% of the capacity and energy of Rocky Reach and Rock Island from 2012-2022
- Slice contracts are removed from Chelan PUD's shares of Rocky Reach and Rock Island listed under "Resources" above

Load

- The three load forecasts (low, base and high) were each represented by scenario forecasts
- Operating reserve requirements set at 6% of load (varied by scenario forecast)

Market Prices

- Electricity – Used an aggregated forward price curve developed from Platts 3/1/2012 forward price curve that extended through 2018. The rate of growth from 2017 to 2018 was used to produce annual heavy load hour prices and light load hour prices throughout the remainder of the planning period through 2022. The monthly shape of the average price in 2018 was used to shape the annual price projections for the remaining years in the planning period.

Transmission

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

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

- Heavy Load Hours = 6:00 AM to 10:00 PM every day except in July, August and September
- Light Load Hours = all other hours
- Shoulder Hours = 6:00 AM to 12 Noon and 8:00 PM to 10:00 PM in July, August and September

Table 6 District’s Average Annual Resources (aMW)											
	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Net Rocky Reach Gen	142	144	151	158	165	130	130	130	130	130	130
Net Rock Island Gen	136	87	90	94	97	80	80	80	80	80	80
Net Lake Chelan Gen	47	47	47	47	47	47	47	47	47	47	47
Net Nine Canyon Gen	2	2	2	2	2	2	2	2	2	2	2
Conservation	1.64	3.38	5.24	7.21	9.33	11.50	13.77	16.09	18.48	20.93	23.36

- Peak Heavy Load Hours = 12 Noon to 8:00 PM in July, August & September

Financial Inputs

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

Table 6 shows the District’s average annual resources for the planning period. The generation is the amount available to serve load under normal hydro conditions and includes the effects of encroachments, fish and other spill, CEA’s, the long-term power purchaser contracts and the executed and planned slice contracts.

Random Variables and Correlations

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

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

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

There are three components to uncertainty modeling in the model. First, the model uses a highly flexible probability distribution that can easily reflect expectations, variance and excessive skewness and kurtosis. Second, the model can incorporate mean reversion, a statistical property found in many economic variables that are fundamentally driven by some natural process (e.g., weather or stream flows). Finally, the model is able to correlate variables, thus accounting for the relationship among variables.

Table 7 lists the correlations and mean reversion factors used in the report modeling. A more detailed description of volatility, correlations and mean reversion for specific key variables is presented next.

Load

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

Hydro Availability

Hydro generation variability was developed from historical generation. PNUCC supplied re-regulated project generation data for the time period 1929-1997 and District data was used for the 1998-2011 time period. Statistics were developed from this combined data set and a distribution function representing the annual variability of the historical data was created. Within a model iteration, a different annual generation amount for each project is used for every year of the planning period. This is more representative of historical patterns, rather than assuming one generation level for all years within the planning period. A mean reversion factor was applied to the annual hydro generation. This is reflective of precipitation and weather patterns that often develop over several years at a time. Since the three hydro projects are close in proximity and tend to have the same climatology and experience nearly the same hydrological conditions (e.g., precipitation, snow pack) the generation from all three hydro projects was highly correlated.

Wind Availability

The volatility and intermittency of wind was developed using eight years (2004-2011) of hourly data. This volatility was applied to the heavy load, shoulder and light load time periods, differing each month. By applying volatility to the individual time periods, every period within each iteration can have a different generation output. The annual generation was also allowed to vary year to year.

Conservation Availability/Penetration

The volatility of conservation achieved was provided by the Cadmus Group in 2008 based on their

Table 7
Correlation Matrix and Mean Reversion Factors for Annualized Stochastic Simulations

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

extensive experience in the field of conservation. It provides a fairly tight distribution, or low volatility, which coincides with the District's requirement of meeting long-term conservation potential assessments based on the state RPS. A fairly weak asymmetrical correlation was applied to load and conservation, where the amount of load influences the amount of conservation. A relatively high mean reversion factor was used for conservation, meaning it will deviate little from the average and return quickly when deviations do occur, again corresponding to the RPS requirement.

Electric Market Prices

The aggregated forward price curve presumably encompasses assumptions about a number of fundamental economic drivers under expected conditions, including average loads based on normal temperatures. Because conditions are often not normal, market price volatility was built into *Resource Portfolio Strategist* to reflect what can happen when loads and/or other variables deviate from expected.

Due to changing market fundamentals, annual hydro availability is not correlated to annual electric market prices. If the model allowed for more granular than annual correlations, a price/water correlation in the second quarter of each year (during snow pack runoff) would generally be appropriate. Load is correlated with electric market prices as mentioned previously. A mean reversion factor was applied to account for the fact that market prices may drift away from a long-term forecast, but over time, prices tend to revert back to the long-term forecast.

A random "price shock" was expected to take effect in 2.5% of the iterations for each portfolio. The median time from the start of the planning period for the price shock to begin was 36 months and the median duration of the shock was 18 months. The median price spike level was 2.5 times greater than prices under normal conditions. This "price shock" is meant to represent price excursions that can happen similar to that of the Western energy crisis of 2000-2001.

Forced Outages

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

Appendix B – Washington State Electric Utility Integrated Resource Plan Cover Sheet 2012 "Long Form"

PUD No 1 of Chelan County									
Washington State Utility Resource Plan									
Integrated Resource Plan Update Year	2012								
Base Year Start	01/01/11								
Base Year End	12/31/11								
Five Year Report Year	2017								
Ten Year Report Year	2022								
Report Years		**Base Year**			**2017**			**2022**	
Period	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**	**Winter**	**Summer**	**Annual**
Units	**(MWh)**	**(MWh)**	**(MWa)**	**(MWh)**	**(MWh)**	**(MWa)**	**(MWh)**	**(MWh)**	**(MWa)**
Loads	413.00	220.00	179.31	469.00	243.00	203.03	520.00	258.00	218.39
Exports									
Resources									
Conservation/Efficiency				18.40	18.00	11.49	37.40	36.50	23.34
Demand Response									
Cogeneration									
Hydro	474.00	307.00	200.00	419.00	284.00	181.00	419.00	284.00	181.00
Wind	0.06	2.26	2.56	0.15	0.04	2.22	0.15	0.04	2.22
Other Renewables									
Thermal - Gas									
Thermal - Coal									
Long Term: BPA Base Year or Tier 1									
Net Long Term Contracts: Other									
Net Short Term Contracts									
Other									
Imports									
Total Resources	474.06	309.26	202.56	437.55	302.04	194.71	456.55	320.54	206.56
Load Resource Balance	61.06	89.26	23.25	-31.45	59.04	-8.32	-63.45	62.54	-11.83

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

- Requirements
    - Loads
        - Peak and annual energy loads are based on the District's Base Load Growth Forecast.
        - Peak and annual energy loads, including the base year (2011), are adjusted for normal weather (i.e. an expected or 1 in 2 peak).
        - Peak and annual energy loads, including the base year (2011), do not include conservation savings.

- Resources
    - Hydro
        - For all years, it was assumed that during a single hour winter peak demand period, all projects would be at full seasonal capability. For all years, it was assumed that during a single hour summer peak demand period, 1936-37 PNUCC critical period generation was available to all projects. Values reported are net of encroachments and CEAs.
        - For all years, annual energy was calculated by using 1936-37 PNUCC critical period generation data. Values reported are net of encroachments and CEAs.
        - For all years, hydro is reported net of long-term purchaser contracts, executed slice contracts and planned slice contracts.
    - Wind
        - Base year (2011) wind data reflects actual Nine Canyon experience in that year.
        - 2017 and 2022 projected peak wind capacity is based on median (50th percentile) hourly Nine Canyon historical generation (2004-2011).
        - 2017 and 2022 projected average annual wind energy is based on median (50^{th} percentile) average annual energy from Nine Canyon historical generation (2004-2011).

Acronyms

aarg	Average Annual Rate of Growth
aMW	Average Megawatt
BEV	Battery Electric Vehicle
BPA	Bonneville Power Administration
CCCT	Combined-Cycle Combustion Turbine
CDCAC	Chelan-Douglas Community Action Council
CEA	Canadian Entitlement Allocation
CFL	Compact Fluorescent Lamp
CIG	Climate Impacts Group
CO2	Carbon Dioxide
CPA	Conservation Potential Assessment
CSP	Concentrating Solar Power
EE	Energy Efficiency
EESC	EES Consulting, Inc.
EGS	Enhanced Geothermal System
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ER	Environmental Redispatch
EV	Electric Vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse Gas
HCP	Habitat Conservation Plan
HVAC	Heating, Ventilation and Air Conditioning

IRP	Integrated Resource Plan
kW, kWh	Kilowatt, Kilowatt-hour
LNG	Liquefied Natural Gas
LOLP	Loss of Load Probability
Mid-C	Mid-Columbia
MW, MWh	Megawatt, Megawatt-hour
NEEA	Northwest Energy Efficiency Alliance
NPC	Net Portfolio Cost
NPV	Net Present Value
NWPCC	Northwest Power and Conservation Council
O&M	Operations and Maintenance
OFM	Office of Financial Management (Washington State)
PHEV	Plug-in Hybrid Electric Vehicle
PUD	Public Utility District
RCW	Revised Code of Washington
REC	Renewable Energy Credit
RPS	Renewable Portfolio Standard
SCCT	Simple-Cycle Combustion Turbine
SMR	Small Modular Reactor
SNAP	Sustainable Natural Alternative Power
WAC	Washington Administrative Code

Glossary

Asymmetric Correlation

See Correlation

Average Annual Rate of Growth (aarg)

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

Average Megawatt (aMW)

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

Avoided Cost

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

For evaluating future energy acquisitions, including conservation, Chelan PUD uses a forecast of wholesale power market prices as its avoided cost measure due to its surplus energy resource position.

Base Load Generation Resource

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

Battery Electric Vehicle (BEV)

A vehicle that uses only batteries as the source of energy to move the vehicle.

Biomass Resource

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants and municipal wastes. Resulting biogas is recovered and burned for heat and energy production. These biofuels are considered to be short-term "CO_2 neutral", meaning they typically remove CO_2 from the atmosphere and give up the same amount when burnt.

Block Power Sales

A power sales contract that establishes a fixed amount of energy to be sold for a specific period of time at a fixed price.

Canadian Entitlement Allocations (CEAs)

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

Capacity

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

Chelan PUD

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

Climate Change

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

Coal-Mine Methane Resource

Methane gas naturally dissipates from coal mining operations both above and below ground. It is recovered and burned for heat and energy production. Burning methane converts it from a highly potent GHG (methane has 22 times the GHG impact of CO_2) to CO_2, which is much less potent.

Cogeneration

The production of electricity using waste heat (as in steam) from an industrial process or the use of steam from electric power generation as a source of heat.

Confidence Interval

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

Conservation

Any reduction in electric power consumption that results from increases in the efficiency of energy use, production, transmission or distribution (from RCW 19.280: Electric Utility Resource Plans and RCW 19.285: The Energy Independence Act).

Conservation Potential Assessment (CPA)

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

Correlation

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

Council

See Power Plan (Fifth, Sixth, etc.)

Demand

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

Demand Response

Changes in electric usage by end-use customers (e.g., residential, commercial, industrial) from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized.

Demand-Side Resource

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

Dependent/Independent Variable

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

Discount Rate

Interest rate used in determining the present value of future cash flows in a net present value computation.

Dispatchable Resource

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

Distributed Generation

Generation of electricity from many small energy sources.

Distribution System

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

District

See Chelan PUD.

Econometric

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

Electric Vehicle (EV)

A broad class of vehicles that are powered, at least in part, by rechargeable batteries that can be restored to full charge by connecting a plug to an external electric power source. A plug-in hybrid electric vehicle (PHEV) shares the characteristics of both a conventional hybrid electric vehicle, having an electric motor and an internal combustion engine, and of a battery electric vehicle (BEV), which uses batteries as its only source of energy to move the vehicle. The combustion engine in a PHEV works as a backup when the batteries are depleted.

Eligible Renewable Resource

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

Encroachments

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

Energy Independence Act

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

Fifth Power Plan

See Power Plan (Fifth, Sixth, etc.)

Fossil Fuels

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

Geothermal Resource

Energy from rock and/or water that is heated by contact with molten rock deep in the earth's core. The heat can be extracted and used for space heating or to generate electricity.

Greenhouse Gas (GHG)

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

Hedging

Establishing positions in the wholesale power markets with the intent of reducing financial risk resulting from uncertain fluctuations in all the variables that affect the District's net wholesale power revenue, of which stream flows, retail load and wholesale power market prices are primary drivers.

Hydro Resource

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

Hydrokinetic (Marine) Resource

Facilities that generate electricity from waves or directly from the flow of water in ocean current, tides or inland waterways.

Incremental Generation

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

Integrated Resources Plan (IRP)

An analysis describing the mix of generating resources and conservation and efficiency resources that will meet current and projected needs a the lowest reasonable cost to the utility and it ratepayers (from RCW 19.280: Electric Utility Resource Plans).

Intermittent Resource

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

Kilowatt (kW) and Kilowatt-Hour (kWh)

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

Kurtosis

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

Landfill Gas

Methane gas from landfills, created when organic waste decomposes, is recovered and burned for heat and energy production. Burning methane converts it from a highly potent GHG (methane has 22 times the GHG impact of CO_2) to CO_2, which is much less potent.

Levelized Cost

The constant stream of values that produces the same present value as the non-constant stream of values, using the same discount rate. In this report, levelized cost is used to refer to the cost for the NWPCC's 20-year wholesale electric market price forecasts. For the electric market price forecast, the cost is expressed in dollars per MWh. Costs are levelized in real dollars. For example, the amount borrowed from a bank is the present value of buying a house; the mortgage payment including interest on a house is the levelized cost of that house.

Load

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

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

Load Forecasting

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

Loss of Load Probability

A measure of the probability that a system load demand will exceed capacity during a given period; often expressed as the estimated number of days over a longer period.

Mean Reversion

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

Median

In probability theory and statistics, a median is described as the numeric value separating the higher half of a sample, a population or probability distribution from the lower half.

Megawatt (MW) and Megawatt-Hour (MWh)

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

Monte Carlo Simulation

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

Net Portfolio Cost

Net portfolio cost for this report is total costs for Chelan PUD's resources (including hydro, wind and conservation) plus the cost associated with purchasing power in the wholesale spot market, netted with revenues from any and all power sales, including those in the wholesale spot market.

Net Present Value

The difference between the present value of a stream of benefits, or income, and that of a stream of costs. It measures the excess or shortfall of future benefits versus costs cash flows, in present value terms, taking into account the time value of money using a given discount rate.

Nominal Dollars

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

Northwest Power and Conservation Council (NWPCC)

See Power Plan (Fifth, Sixth, etc.)

Peak Demand (Load)

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

Peak(ing) Power

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

Planning Reserve Margin

Capacity at a utility's disposal that exceeds its expected peak demand by a certain percentage.

Plug-In Hybrid Electric Vehicle (PHEV)

A vehicle that shares the characteristics of both a conventional hybrid electric vehicle, having an electric motor and an internal combustion engine, and of a battery electric vehicle (BEV), which uses batteries as its only source of energy to move the vehicle. The combustion engine in a PHEV works as a backup when the batteries are depleted.

Portfolio

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

Power Plan (Fifth, Sixth, etc.)

A 20-year electric power plan that guarantees adequate and reliable energy at the lowest economic and environmental cost to the Northwest. A new plan is developed every five years as a result of the Northwest Power Act of 1980 that authorized the formation of the Northwest Power and Conservation Council (NWPCC or the Council.) The Sixth Power Plan, the most recent, was adopted in February 2010. The NWPCC is also mandated to develop a fish and wildlife program to protect and rebuild populations affected by hydropower development in the Columbia River Basin and conduct an extensive program to educate and involve the public in the their decision-making processes.

Probability

The likelihood or chance that something will happen.

Probability Distribution

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

Progress Report

A requirement of RCW 19.280.030: Electric utility resource plans, which reads "At a minimum, progress reports reflecting changing conditions and the progress of the integrated resource plan must be produced every two years…" Chelan PUD's next Progress Report will be published in 2014.

Real Dollars

Dollars that have been adjusted to remove the effects of inflation. Real dollars are sometimes called uninflated dollars, today's dollars or constant dollars.

Regression Analysis

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

Renewable Energy Credit (REC)

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

Renewable Portfolio Standard (RPS)

A regulation that an electric power provider generate or purchase a specified percentage of the power it supplies/sells from renewable energy resources. Washington State's RPS is codified in RCW 19.285: The Energy Independence Act.

Renewable Resource

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

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

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

Resource Adequacy

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

Resource Mix

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

Scenario

A possible course of future events. In the report, scenarios are used to compare the District’s existing portfolio of generating resources under a range of possible future conditions including: various load forecasts and various hydro production cost forecasts.

Shape

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

Sixth Power Plan

See Power Plan (Fifth, Sixth, etc.)

Skewness

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

Slice Power Sales

A power sales contract for a specific percentage share of a generation project’s capacity and energy for a specific period of time at a fixed price (i.e., there is no guarantee of the amount of energy that will result from the contract for resources such as hydro and wind where the fuel is driven by nature).

Solar Resource

The generation of electricity from sunlight. This can be direct as with photovoltaics, or indirect as with concentrating solar power, where the sun’s energy is focused to boil water which in then used to provide power.

Substitute Resource

Reasonably available electricity or generating facilities, of the same contract length or facility life as the eligible renewable resource the utility invested in to comply with chapter 19.285 RCW requirements, that otherwise would have been used to serve a utility's retail load in the absence of chapter 19.285 RCW requirements to serve that retail load with eligible renewable resources (from WAC 194-37: Energy Independence).

Supply-Side Resources

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

Surplus Energy

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

Transmission System

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

Waste-to-Energy Resource

Incineration process in which solid waste is converted into thermal energy to generate steam that drives turbines for electricity generators.

Wastewater-Treatment Gas Resource

Methane gas, given off in the digestion of sewage, is recovered and burned for heat and energy production. Sewage gas consists of approximately 66% methane and 34% CO_2. Burning methane converts it from a highly potent GHG (methane has 22 times the GHG impact of CO_2) to CO_2, which is much less potent.

Weather-Normalized Load

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

Wind Resource

Energy generated when wind turns the blades of a wind turbine which drive a generator. The longer the blades and the faster the wind speed (up to a point), the more electricity that is generated.