PUBLIC UTILITY DISTRICT NO. 1 OF CHELAN COUNTY

INTEGRATED RESOURCE PLAN 2021

P.U.D.
CHELAN COUNTY

2021 Integrated Resource Plan

December 2021

PUD No. 1 of Chelan County
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https://www.chelanpud.org/environment/operating-responsibly/integrated-resource-plan

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2021 Integrated Resource Plan

Summary of Determinations

The District has completed its 2021 Integrated Resource Plan (IRP). This IRP is required by the Revised Code of Washington (RCW) 19.280: Electric Utility Resource Plans originally 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 2021–2030 planning period, the Board of Commissioners of Chelan County Public Utility District (Chelan PUD or District) has approved this 2021 IRP and determined that:

- The District retain its current mix of generating resources.

And additionally:

- The District continue to evaluate and implement conservation and demand response programs based on the foundational work performed in the 2021 Conservation Potential Assessment (CPA).
- The District carry on the evaluation and implementation of strategies for additional power and ancillary sales 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.

Report Overview

To meet the requirements of RCW 19.280, the development of Chelan PUD's 2021 IRP includes the following:

- An update of the long-term forecasts of retail electric customer demand
- Revised costs and operational information for Chelan PUD's existing generating resources
- Updated data in regards to the District's existing operational and power sales contracts
- Amended conservation inputs to align with Chelan PUD's December 2021 10-year conservation targets submittal to the Washington State Department of Commerce (Commerce) as required
- Evaluate demand response (DR) potential from the 2021 demand response potential assessment
- An update on regional and Chelan PUD's resource adequacy (RA) development
- Analyze the forecasted load/resource balance (using the District's existing portfolio of resources) with the aforementioned input changes, additionally evaluating service reliability and environmental impacts and communicating with customers and the public
- Ensure the District's 2021 Clean Energy Implementation Plan (CEIP), as required by the Washington Clean Energy Transformation Act (CETA), is informed by this 2021 IRP
- A ten-year Clean Energy Action Plan (CEAP) for implementing portions of the CETA
- Board approval of the IRP
- Submittal of the final IRP to Commerce by September 1, 2022, 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 (2021–2030).

The District has some longer-term power sales contracts and also enters into shorter-term contracts for a portion of its hydro output providing the District flexibility. The shorter-term contracts, part of the District's hedging policy, are discussed more fully in the Portfolio Analysis section.

Although the District is currently surplus to its own retail load, resource adequacy (RA) is a topic of great concern to the region and individual utilities alike. Demand resource (DR) has been identified as a resource to help meet capacity demands in the region. RA and DR are required to by identified and evaluated under CETA. Both topics are discussed more fully below.

Resource Adequacy

The current, voluntary RA standard was adopted in December 2011 by the Northwest Power and Conservation Council (NWPCC or Council). 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 standard is recommended for utilities to do their own assessments. The standard uses the system's loss of load probability (LOLP) as the adequacy metric with a maximum allowable LOLP of 5%. A single annual value is assessed, which identifies both energy and capacity problems. It is not intended to be a resource planning target.

The 2021 adequacy assessment differs from past assessments in three significant ways. First, the Council is using climate change projections of temperature and precipitation to forecast future electrical demand and river flows. These data are a better predictor of future conditions than assuming a repeat of observed historical conditions (which were used for past assessments). Second, the low cost of renewable resources along with clean-air laws and policies and renewable portfolio standards across the Western states are the impetus behind the expected acquisition of significant levels of renewable resources. The effect of these resources is to create a large mid-day market supply of very inexpensive energy, which will change the dynamics of the regional power supply operation. Third, because of the significant levels of renewable resources, it was necessary for the Council to redevelop its adequacy model to more accurately represent hourly operations. It was especially important to implement more hourly-specific hydroelectric system constraints. The existing regional power supply has about 12,000 megawatts of winter rate-based thermal generating capacity (not including about 2,600 megawatts of thermal resources in the region but not rate-based). By 2023, the Northwest will have nearly 11,000 megawatts of installed wind nameplate capacity but only about 7,300 megawatts are dedicated to serving the regional electric demand. Also, by 2023 the region will have about 1,100 megawatts of installed solar nameplate capacity. The Pacific Northwest hydroelectric system's nameplate capacity totals nearly 35,000 megawatts. Finally, the region has been extremely successful in implementing cost-effective energy efficiency saving measures. Since the early 1980s, the region has avoided the need to build at least 7,000 average megawatts of additional electricity generation.

While the total nameplate capacity of the region's power supply is significantly higher than the expected 2023 winter peak electrical demand of about 32,600 megawatts, the deliverable (effective) capacity of the system is much lower. For example, the effective capacities of the wind and solar fleets are about 22% and 46% of the nameplate, respectively. While the hydroelectric system nameplate capacity is nearly 35,000 megawatts, it only generates about 12,000 average megawatts during a very dry year and about 16,000 average megawatts over an average year. Because of limited storage and operating constraints, it provides about 25,000 megawatts of two-hour sustained-peaking capacity during winter and about 22,000 megawatts of two-hour sustained-peaking capacity during summer. One way to gauge the sufficiency of the power supply is to compare its energy and effective capacity generating capabilities with the annual average electrical demand and with the peak electrical demand, respectively. Based on expected electrical demands and assuming critical water conditions (lowest stream flow year), the power supply's total annual average generating capability exceeds the expected 2023 annual electrical demand by about 2,570 average megawatts. Under the same conditions, the power supply's effective capacity exceeds the 2023 winter peak electrical demand by about 5,700 megawatts and exceeds the summer peak electrical demand by about 2,800 megawatts. However, using these simple comparisons does not accurately reflect the adequacy of the power supply because future conditions can vary significantly, and situations can occur when low wind and solar output combine with extreme temperature and low river flow conditions. This is why the Council uses probabilistic methods to assess RA. Their adequacy model indicates the power supply does not meet the Council's adequacy criteria in 2023 but does meet it by 2025. In 2023, market prices are frequently low, causing many thermal units to not commit to service and therefore not be available should unexpected conditions arise that lead to a shortfall event. A thermal plant will commit if forecasted prices indicate that it can operate at a profit. When forecasted prices are low, the plant is not committed, and fuel is not allocated for its operation. When the Council reran the 2023 case forcing all thermal plants to commit regardless of market price, the model indicated the power supply exceeded the Council's standard for adequacy. Thus, utilization of the existing thermal fleet could be a cost-effective way to maintain adequacy. For example, requiring thermal resources to carry additional balancing reserves forces them to commit, which makes them available during potential shortfall events. In 2025, the Council estimates the power supply meets the Council's adequacy standard. The Council's 2025 estimate includes 400 average megawatts of energy efficiency savings incremental to their frozen-efficiency demand forecast. However, it also includes the retirement of the Jim Bridger 1 coal plant (530-megawatt nameplate). While this results in less total regional resource in 2025, forecast electrical demand and prices have sufficiently increased at times that prompt more thermal units to commit. Thus, fewer shortfalls driven by operational challenges are seen. To maintain adequacy, the region will need about 1,600 megawatts of effective capacity (or some combination of added capacity and additional balancing reserves) before 2023.

The Council's adequacy assessment does not go beyond 2025, but the power plan's planning horizon is 20 years. Therefore, all future expected resource retirements are accounted for in the Council's resource expansion model. In addition, the Council has also examined multiple sensitivity scenarios to determine the effects of early retirement, different West-wide resource buildouts, greater load growth due to electrification programs and others.

It should be emphasized that these results reflect the adequacy of the aggregate regional power supply and there has been controversy in the region about some of the assumptions made in the Council's adequacy assessment. Individual utilities within the Northwest are facing a wide range of future resource needs and are preparing for those needs in their IRPs. The District analyzed its own RA in the preparation of this 2021 IRP.

In addition to the region wide RA assessments mentioned above, the NWPP is currently working to develop a robust capacity RA program, known as the Western Resource Adequacy Program (WRAP). The NWPP is pursuing Phase 3A of the WRAP, which is scheduled to run from Oct 1st, 2021 through Dec 31st, 2022 and includes the beginning of implementation and the forward showing for the first two non-binding seasons. Participant data submission will be required so that the Program Operator, the Southwest Power Pool, can run models to deliver RA metrics (planning reserve margin, qualifying capacity contribution, effective load carrying capability, etc.) back to participants. As such, individual entities will gain an understanding of their individual RA position. The WRAP is voluntary, but becomes binding when a utility commits to the program past the non-binding phase. Below summarizes some key elements of the program:

- The WRAP looks out 1–4 years to ensure adequate resource capability is available to meet customer demand.
- In a large portion of the NWPP footprint, utilities manage RA individually and with different methods. The WRAP will allow utilities to forecast and manage RA in a coordinated manner.
- The WRAP will respect local autonomy over investment decisions and operations and will continue to respect the rights and characteristics of individual utilities, transmission service providers, BAs and other entities.
- The WRAP will be voluntary to join, but once a utility joins, it will be contractually committed to the requirements of the RA Program.
- The WRAP will consider:
  - Common measures of adequacy, including peak load standards and methods of measurement;
  - Common measures of resource contribution to RA;
  - An approach for the allocation of the regional adequacy requirement;
  - Methods for accessing the regional diversity and unlocking investment savings; and
  - Incentive and enforcement mechanisms.

The District has signed up for the non-binding forward program and is actively involved with this effort and will continue to contribute to the WRAP development.

Demand Response

The Council's Demand Response Advisory Committee (DRAC) is supporting the Council in development of updated DR supply curves for the Eighth Power Plan, now expected to be finalized in 2022.

In June 2017, the DRAC adopted a definition for DR:

> *"Demand response is a non-persistent intentional change in net electricity usage by end-use customers from normal consumptive patterns in response to a request on behalf of, or by, a power and/or distribution/transmission system operator. This change is driven by an agreement, potentially financial, or tariff between two or more participating parties."*

In April 2021, Council staff presented results from a DR sensitivity study exploring the impact of modifying the DR supply curve. The DR supply curves were developed by staff, with significant input from the DRAC. Starting in 2019, DRAC meetings were focused on determining and vetting the inputs and assumptions, such as: products incorporated, impacts and costs. The starting point for many of the assumptions were based on the Seventh Plan DR supply curve and regional utility potential assessments but were modified and enhanced through stakeholder expertise and utility experience. For example, Portland General Electric has recently launched several DR programs that informed the supply curve. A notable update from the Seventh Plan is that non-firm DR products were added. These include price-based DR, such as time-of-use (TOU), critical peak pricing and peak time rebates. These price-based DR products are considered “non-firm” because the utility has less control over the impact. End-use customers will determine how they will respond to that price signal. TOU DR is also non-dispatchable in that the on and off-peak time periods and rates are predetermined and generally long-standing (e.g., for an entire season or year). In addition, demand voltage regulation (DVR) was a new product not previously incorporated. Several Bonneville Power Administration (BPA) utility customers have successfully utilized DVR during peak hours to trim demand charges. BPA staff were instrumental in developing Council assumptions for DVR, as well as the related energy efficiency option of conservation voltage regulation (CVR) that reduces the voltage for all hours. When the supply curves were developed, the primary expected purpose of DR in the power system was reducing demand during peak hours to support adequacy needs. Thus, the assumptions built into the curves were around this attribute of how to reduce a short-term need during what would be assumed to be a very high-price period. The bins representing DR were developed to represent this need and differentiated by levelized cost. In addition, a conservative dispatch assumption of 4 hours per event, 5 events per season was used uniformly, along with a dispatch cost of $150 per megawatt-hour. However, as the plan analysis proceeded, staff learned that the system needs were less about peak adequacy and more about a persistent need to mitigate rapid changes in net load (load net of primarily renewable resources). Due to these effects on the power system, the peak pricing in the Regional Portfolio Model (RPM) can be high and the emissions associated with it may be considerable. However, the price of peak energy in the RPM is not necessarily high enough to dispatch DR very often at $150 per megawatt-hour. Since that dispatch price assumption was primarily formulated for certain products, and the assumption was used for all products principally for simplicity in binning strategy, this meant that by binning lower dispatch price DR with higher dispatch price DR, the Council might be missing a signal that DR might play a role in peak energy cost mitigation. With this learning came a recognition that likely some DR could provide value within this system, but not as currently incorporated in the supply curves. Specifically, the DR products that could provide the most value are those that either have minimal customer impact when deployed and thus could be dispatched frequently or are intended to result in a day-to-day shift in usage pattern (namely TOU). For products that have minimal customer impact and could be dispatched frequently, DVR is a key option. (Another option could be load control of grid-enabled water heaters, but this product is still expensive with current limited applicability and so were not considered in the Council’s sensitivity analysis).

The DRAC and BPA had previously identified barriers to DR. The identified economic/market barriers were the most significant to DR adoption. Without a clear valuation metric (e.g. currently no capacity market), it is difficult for many to justify DR investment. Other identified barriers included: regulatory (lack of established tariffs), infrastructure (data handling protocols), organizational (intra-organizational communication), and perceptual (customer understanding). The DRAC has been exploring ways the region may mitigate these barriers.

Although there are significant barriers, the region has several characteristics that support expansion of DR. These include the long history of energy efficiency and regional collaboration, growing participation in the western Energy Imbalance Market (EIM) and high potential for DR due to its high electric water heater penetration and growing penetration of electric vehicles. Utilities are finding value in DR not only as a means to mitigate peak load capacity constraints, but also as part of the solution set for non-wires alternatives.

CETA requires utilities to develop a DR potential assessment (DRPA). The District developed a DRPA in conjunction with its CPA. DR is not currently cost-effective for the District to acquire. Therefore, the target is set at 0 MW. Chelan PUD has one legacy agreement falling under the umbrella of DR. It is a load shedding agreement with Alcoa Power Generating, Inc. (APGI) and Alcoa, Inc. (Alcoa). In December 2015, Alcoa idled their Wenatchee Works plant. The District does not have any DR available while the Alcoa plant is idled.

Additional assessments are planned for 2022 around energy management and managed electric vehicle charging. This additional and more detailed assessment will inform future potential DR programs.

Regulatory & State 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)

The Washington State Renewable Performance Standard (RPS), 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 have met 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 efficiency gains 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 2021 IRP includes updates to the evaluations and required reporting under both the renewable and conservation portions of the RPS which are discussed further below.

This legislation and other regional efforts have increased the amount of renewable energy in the wholesale power markets. The new Washington CETA adds additional utility requirements surrounding use of renewable and nonemitting resources. The effect of increased wind capacity and overgeneration events in the region is discussed in the Resources section.

Clean Energy Transformation Act (CETA)

In May 2019, Governor Jay Inslee signed into law The Washington Clean Energy Transformation Act (CETA), which added requirements that relate to resource planning.

Key sections of CETA that may impact a utility's resource portfolio include: 1) section 3 — elimination of coal-fired resources from a utility's allocation of electricity by the end of 2025; 2) section 4 — a greenhouse gas (GHG) neutral policy requiring a utility to use electricity from renewable and nonemitting resources in an amount equal to 100% of its retail electric load over multiyear compliance periods starting in 2030 (up to 20% may be met with alternative compliance options); and 3) section 5 — a policy that electricity from renewable and nonemitting resources supply 100% of all sales of electricity to Washington retail customers by 2045. Unlike the Washington RPS, CETA considers all existing hydroelectric resources to be renewable.

Among other requirements, CETA also requires utilities to include 10-year clean energy actions plans (CEAP) in their IRPs for implementing sections 3 through 5 of CETA and requires utilities to consider the social cost of GHG emissions when developing their IRPs and CEAPs. The CEAP section of this IRP includes the District's second CETA 10-year CEAP, the first being in the 2020 IRP.

Additionally, during the development of this IRP, the District concurrently developed its first Clean Energy Implementation Plan (CEIP) as required under CETA. Both planning processes utilized the same resource mix and retail customer load assumptions. A CEIP is intended to identify a utility's plans over the following four years to meet CETA's 2030 GHG neutral standard and 2045 100% clean electricity standard. The CEIP includes 1) an interim target for the percentage of retail load to be served using renewable and nonemitting resources during 2022–2025; 2) specific targets for energy efficiency, DR and renewable energy for 2022–2025; 3) specific actions Chelan PUD will take between 2022–2025 to reach those targets; 4) identification of highly impacted communities and vulnerable populations; 5) a report of the forecasted distribution of energy and nonenergy costs and benefits for the District's portfolio of specific actions; 6) a description of how Chelan PUD intends to reduce risks to highly impacted communities and vulnerable populations associated with the transition to clean energy.

CETA is a complex law with many components. Rulemaking is still ongoing and is currently expected to continue into late 2022. The District will continue to closely follow the rulemaking process and that process will inform the District's understanding and future assessment of how CETA's requirements will impact the District's resource planning.

The Climate Commitment Act

In May 2021, Governor Inslee signed into a law a comprehensive climate law, the Climate Commitment Act (SB 5126), that establishes a "cap and invest" program that sets a limit on the amount of GHG that can be emitted in and imported into Washington and then auctions off allowances for companies and facilities that emit GHG until that cap is reached. Over time, the cap will be reduced, allowing total emissions to fall to match the GHG emission limits set in state law. Those limits were set in 2020 by the Washington legislature and are as follows: 2020–reduce to 1990 levels, 2030–45% below 1990 levels, 2040–70% below 1990 levels and 2050–95% below 1990 levels and achieve net zero emissions. Auction proceeds will go toward investing in climate resiliency, reducing pollution in disproportionately affected communities and expanding clean transportation. Rulemaking for the act begins in 2021, and the first compliance period will begin in 2023.

The District does not own, operate or import emitting generation into Washington state. Therefore, the District does not anticipate the Climate Commitment Act will materially impact District integrated resource planning during the 2021-2030 planning horizon.

Zero Emissions Vehicle (ZEV) Standard

In 2020, Governor Inslee signed the ZEV standard (SB 5811), and Department of Ecology (DOE) will complete rulemaking for the new regulations by the end of 2021. The ZEV standard requires automakers to deliver a certain number of zero emission vehicles each year, and earn credits based on the number of vehicles produced and delivered for sale.

Clean Fuel Standard

In May 2021, Governor Inslee signed into law HB 1091, the Clean Fuel Standard, which directs the DOE to develop a low carbon fuel standard for the state. The overall goal is to reduce the GHG emissions attributable to each unit of fuel to 20% below 2017 levels by 2038. The rules must establish a start date for the program of no later than January 1, 2023.

Zero Emissions Vehicle Preparedness

In May 2021, Governor Inslee also signed into law HB 1287, zero emission vehicles preparedness, which directs the State Building Code Council to adopt rules for electric vehicle infrastructure at new and retrofitted buildings and directs the Washington State Department of Transportation to develop an online map of charging locations and a forecast for the future growth of zero emission vehicles.

National Climate and Energy Policy and Legislation

In June 2019, the Environmental Protection Agency (EPA) issued its final Affordable Clean Energy (ACE) rule and repealed the Clean Power Plan (CPP) originally introduced by President Obama in 2015. The CPP, which proposed emission guidelines for states to follow in developing plans to address GHG from existing fossil fuel-fired electric generating units, was stayed by the U.S. Supreme Court for exceeding EPA's authority under the Clean Air Act. Under the Trump Administration, the EPA repealed the CPP, arguing that the language of Section 111(d) was clear and unambiguous in constraining the EPA's authority and that, when determining the best system of emission reduction, the agency could only consider emission-reduction measures that can be applied at and to a single stationary source.

The ACE had several components: a determination of the best system of emission reduction for GHG emissions from coal-fired power plants, a list of "candidate technologies" states could use when developing their plans, a new preliminary applicability test for determining whether a physical or operational change made to a power plant may be a "major modification " triggering New Source Review, and new implementing regulations for emission guidelines under Clean Air Act section 111(d). On January 19, 2021, the U.S. DC Circuit Court of Appeals vacated the ACE. The DC Circuit also remanded the question to the EPA to consider a new regulatory framework to replace the ACE Rule, allowing the Biden Administration to implement its own climate change agenda. In its decision, the Court found that nothing in Section 111(d) supports the revised limited interpretation. The Supreme Court's ongoing skepticism of such actions presents possible barriers to the bolder policies the Biden Administration may propose.

Since 2009, several national climate bank bills have been introduced. Most recently, in February 2021, Senator Edward Markey (D-MA) introduced the National Climate Bank Act. This bill establishes and capitalizes a National Climate Bank. The independent, nonprofit bank must invest in clean energy technologies and infrastructure to reduce GHG emissions. The national bank's investments and procurements division must seek to facilitate affordable investment and procurement, including in low-income communities and communities of color, in key project areas (e.g., renewable energy or climate resiliency measures). Its start-up division must support the creation of new green banks by states or other political subdivisions. The new banks must be public or nonprofit specialized finance entities that use finance tools to mitigate climate change. The national bank may provide financing for such entities. In addition, the bank must explore the establishment of a cash for carbon program to remove GHG emissions from the power system. The program may use market mechanisms to expedite the retirement of carbon-intensive power generation facilities (e.g., coal-fired power generation facilities), acquire carbon assets for the purpose of reducing emissions, and invest in communities negatively affected by the loss of those facilities or assets.

After taking office in January 2021, President Joe Biden paused the construction of the Keystone XL Pipeline by revoking a permit needed for a US stretch of the 1200-mile project. The project was proposed in 2008 to bring oil from Canada's western tar sands to US refiners. In June 2021, project owner, Canadian company TC Energy, cancelled the project. The pipeline was expected to carry 830,000 barrels per day of Alberta oil sands crude to Nebraska, but the project was delayed for the past 12 years due to opposition from US landowners, Native American tribes and environmentalists. Opposition has expressed concern about spills and fossil fuels contributing to climate change. TC Energy said it would continue to coordinate with regulators, stakeholders and Indigenous groups to meet its environmental and regulatory commitments and ensure a safe termination of and exit from the project. "We remain disappointed and frustrated with the circumstances surrounding the Keystone XL project, including the cancellation of the presidential permit for the pipeline's border crossing," the Alberta premier, Jason Kenney, said in a statement.

On November 1, 2021, the White House released a long-term climate plan. It's five-prong strategy for hitting net-zero GHG emissions economy-wide by 2050. The plan, announced as the U.N. climate conference, calls for decarbonizing the electric power sector; electrifying transportation and industry; boosting energy efficiency; cutting emissions of other GHGs in addition to carbon dioxide (CO2), including methane and hydrofluorocarbons; and scaling up CO2 sequestration. Reaching the net-zero goal would require reduction of annual net emissions from about 5.7 billion metric tons of CO2-equivalent in 2020 to zero by 2050. About 4.5 billion metric tons of reductions would come from energy, the plan estimated.

Load Forecast

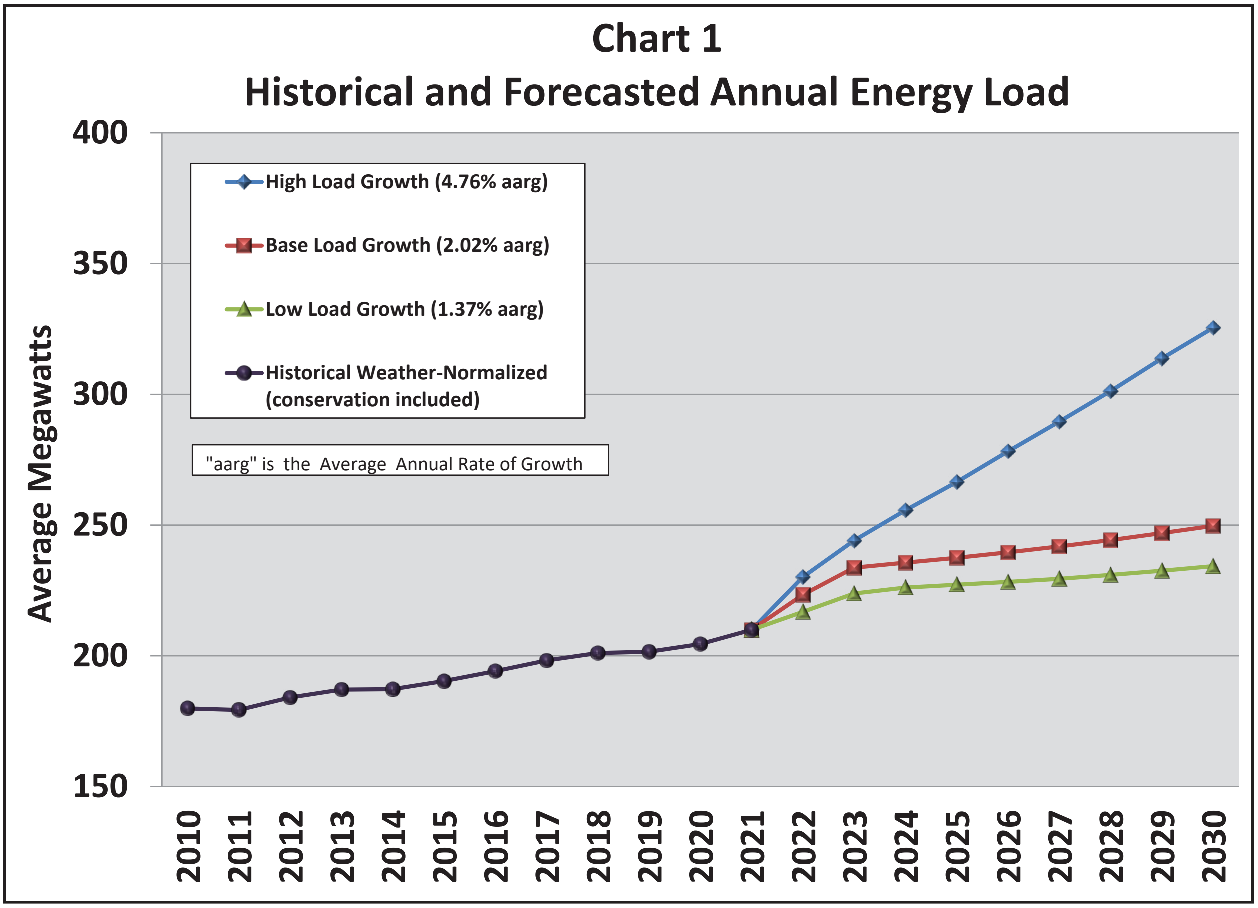
A new 10-year econometric retail load forecast was developed for this IRP's 2021-2030 planning period. These low, base and high forecasts are prior to planned conservation savings. Future cost-effective conservation is considered as a resource for integrated resource planning purposes, so it can be evaluated 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.

Total annual projected megawatt-hours through the planning period were forecasted on an annual incremental or decremental basis by sector, including system losses at 3.5%, using 2020 weather-normalized loads as the starting point. **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 1.37%, 2.02% and 4.76%, respectively.** The low and base forecasts have increased from the 2020 IRP. The weather-normalized average annual rate of growth at the District (before the effects of cumulative conservation) was approximately 1.71% for the 10-year period from 2010-2020. The net of cumulative conservation growth percentage was approximately 1.23% for the same 10-year period. This historical net of cumulative conservation growth average has increased since 2020. While the residential, high-density loads (HDL) and large customer loads have increased some during this period, increased conservation achievements that began in earnest in 2010 continue to mitigate load growth. The three forecasts for 2021-2030 as well as the actual weather-normalized total District energy load for 2010-2020 are presented in Chart 1. The NWPCC's Eighth Power Plan region-wide forecast for 2021-2041 are between -.17% and 1.02% per year. Like the District's forecasted annual energy load growth rates, these forecasts do not include any new conservation measures. The Eighth Power Plan is expected to be finalized in 2022.

COVID-19

Although the COVID-19 pandemic has generated some disruption to local economic development, construction and jobs, load growth has continued the same pattern in the various sectors as it has for the last several years as detailed later in this section. In 2020, restaurants, bars and hotels were among the highest impacted. Chelan PUD continues to actively work with the economic development community, businesses, building contractors and developers to gain insights into how economic development projects are moving forward in the near term and future.



Sector Energy Sales

Demographic and economic data used for the load forecast was updated. The Washington State Office of Financial Management (OFM) released its latest Chelan County population projections in 2017. Growth rates over the planning period were increased some in the low and base cases and decreased some in the high case to reflect District staff's judgement about the range of Chelan County potential population changes. The growth rates were applied to the OFM actual population estimate for Chelan County for 2021 to arrive at updated population estimates through the planning period. Actual Chelan County population data from the OFM (through 2021), along with actual per capita income data from the U.S. Bureau of Economic Analysis and actual sales revenue data from the Washington State Department of Revenue were used to update the various sector regression analyses.

After various regression studies, residential load was projected based upon population only based on statistical significance. The results were adjusted just slightly based upon known and expected changes coming to the sector. The three average annual growth rates for the residential sector are forecasted at 0.44%, 0.86% and 1.48%. The low and base have increased slightly while the high has decreased slightly since 2020. There are several large new residential developments underway and others in the application process. It is likely not all of these will be come to fruition, and it is likely full build out of these developments will take five to 10 years. It is important to note that Chelan PUD is infrastructure limited to serve power to the full build out of these developments. The District has already identified the need for new substation capacity along the Wenatchee foothills for new development and expects it will need to add a new substation, add capacity at existing substations or a combination of both. Additionally, the District continues to be on the lookout for changing end uses including changing federal standards (i.e. more efficient appliances, lighting, etc.) and slower growth in home electronics. It is expected that a significant amount of these changing end uses will continue to be ongoing and take place outside of the District's organized conservation programs.

For this load forecast, the commercial sales forecast is a function of population and sales revenue based on statistical significance. The results were adjusted in the low, base and high cases due to known and expected changes coming to the sector. The final average annual growth rates for the commercial sector are forecasted at 0.91%, 1.71% and 3.13%. Since 2020, all cases have increased some with population actuals coming in higher than previously projected and some recovery expected in the sector after a few years of decreases. As with residential load, the District still believes that ongoing efficiency improvements, particularly in commercial lighting, will lead to longer term decreases in per customer usage.

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 loads have been historically quite stable with low growth rates in Chelan County. Industrial sales were again manually estimated based upon ranges of use per customer amounts and ranges of customer counts with some known probable and other potential larger load additions. The average annual growth rates for the industrial sector are forecasted at 1.32%, 1.32% and 1.86%. These have all decreased some since 2020, primarily due to minor adjustments with existing customers.

High Density Loads (HDL) are those loads with intense energy use–250 kWh per square foot or more per year, where the energy is used for server farms, cryptocurrency mining or similarly situated loads. As of the end of 2020, HDL load in Chelan County is about 10.6 aMW. Most small HDL operations of less than one MW have suspended energy use or shut down completely. The District has one newer larger load that began ramping up operations and load in 2019 and is expected to continue to do so over the next two or three years. For aggregation purposes, this load has been included in the HDL forecast. There are currently no other known changes coming to the sector, but the high load forecast includes the possibility of other future HDL load growth. The low, base and high cases were estimated taking into account existing approved applications, infrastructure timing limitations and general interest and economic conditions. The average annual growth rates for the HDL sector are forecasted at 8.70%, 10.93% and 22.39% for the planning period.

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.

Based on a high-level assessment, the District forecasts the potential effects of distributed solar photovoltaic generation or other distributed energy resources on retail load in its service area to be negligible during the current planning period.

As previously mentioned in the DR section, in December 2015, Alcoa idled their Wenatchee Works plant. Alcoa's load is not forecasted nor considered for District IRP purposes as it is not considered to be Chelan PUD retail load.

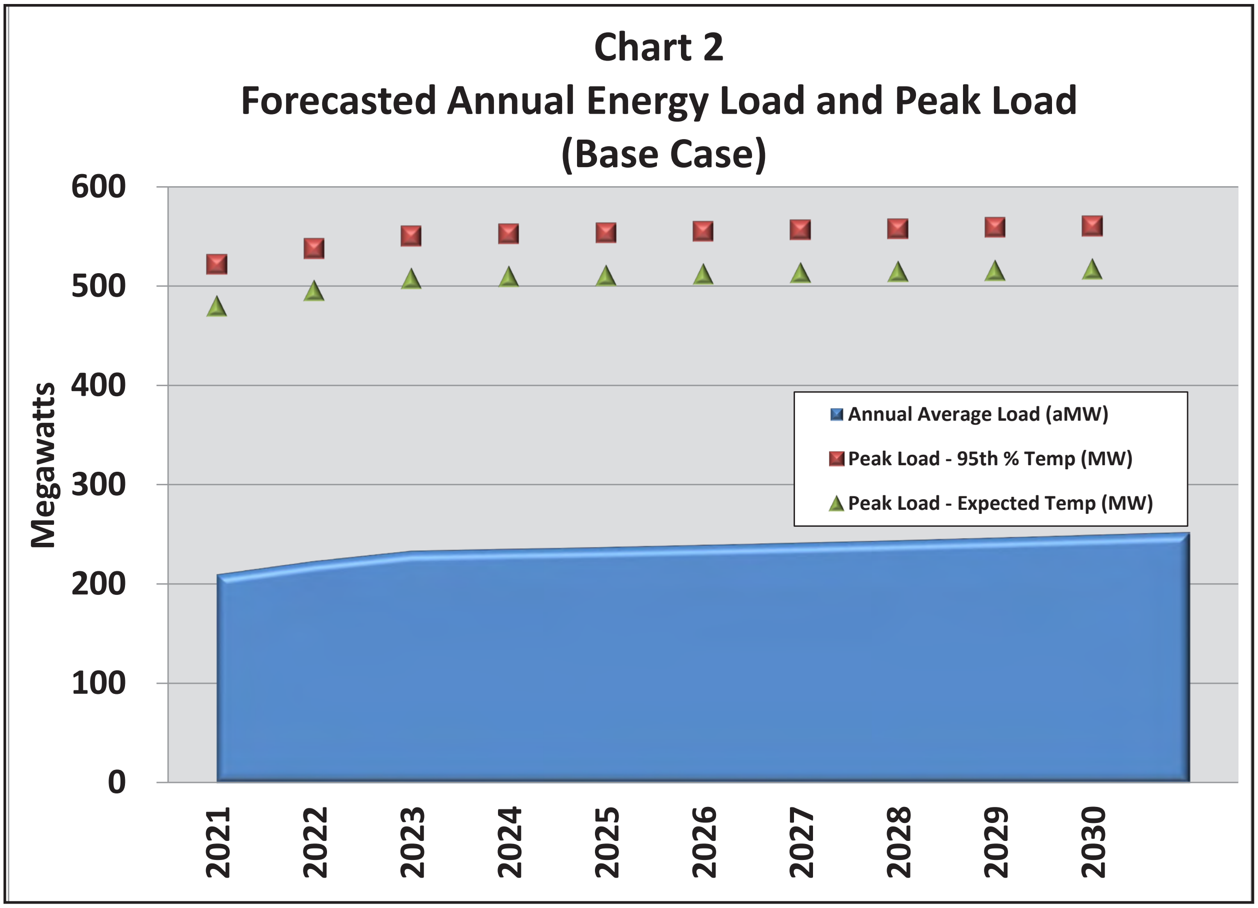
Peak Load Forecast

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. The all-time high retail load peak occurred in January 2017. The peak of 491 MW was established when the temperature was approximately -0.7 degrees Fahrenheit. This occurred on a weekday (Thursday) morning when peak demands are usually higher given business and other commercial needs.

The District's peak forecast is broken down by sector, and the expected load factor for each sector is applied to the annual energy forecast for that sector. The load factors are adjusted, as appropriate, to forecast the peak at varying temperatures. District staff believe this methodology potentially provides more forecast accuracy, particularly if the total retail load shifts over time between the sectors as provided in all the energy forecasts. Most HDL loads are not very weather-sensitive, and therefore, do not add much additional peak load beyond their normal energy load. The new peak forecasts resulted in average annual peak load growth rates in winter of between .2% and 2.8% (net of conservation) for the three energy growth forecasts. The weather-normalized winter peak growth rate over the last 10 years was approximately .84% (net of conservation). Chart 2 illustrates both the base case annual energy load forecast with the base case peak load forecast at both an average, or expected, peak temperature and at a 95th percentile extreme peak temperature for 2021-2030.

Electric Vehicles (EVs)

The District began taking a close look at potential future EV retail load in 2010. For these purposes, EVs include both plug-in hybrid electric vehicles (PHEV) and battery electric vehicles (BEV). As of mid-2021, there were almost 77,000 EV light vehicles registered in the state of Washington, 436 of which are in Chelan County. That is a 117% increase over the previous 2 ½ years.



Global and U.S. EV sales forecasts continue to vary greatly. Several variables will have significant impact on the timing of EV adoption. These variables include gas and battery prices, regulations, battery range, charger speed and availability, supply of new EV models and general economic conditions amongst others.

Recent automotive company announcements have made it clear that they plan on substantially more EV models commercially available over the next decade than previously thought. In the U.S., IHS Markit predicts there will be 130 available models by 2026, offered by 43 brands.

Investment Bank UBS recently stated that in a world of EVs that are cheaper than conventional cars, with regulation that increasingly penalizes the ownership of combustion engines, they think the transition towards a 100% EV world could happen as soon as potentially limiting factors like the availability of batteries and charging infrastructure allow for it. Breakthroughs in new battery technologies like solid-state that help ease potential raw material bottlenecks and further drive down EV costs could enable this scenario. UBS said the biggest threat to their bullish EV thesis is the upstream part of the battery chain. The ultimate bottleneck is not cell (battery) supply, (it takes 2-3 years to build a large greenfield cell plant), but commodities. Their commodity team highlighted the risk of potential bottlenecks in lithium, nickel and even copper. The supply would have to come from new projects that are not known yet, and commodity prices would have to reflect new entrant costs to attract investment. This would lead to higher battery prices for longer, so delaying the sticker price parity of EVs.

The District continues to use the Council's basic EV load forecasting methodology, with updated inputs the Council has prepared for the Eighth Power Plan that is expected to be finalized in 2022. Based on EV market share, or penetration rates, experienced in the District's service area and various recent national forecasts, the District updated Chelan County's EV load forecast with the same market rates the Council is using in the Eighth Power Plan for the base and high cases for the region as a whole. The Council did not provide low case scenario rates. The market rates are slightly increased for the base case and greatly increased for the high case forecasts through the 2021-2030 planning period from the 2020 IRP. The low case market rates, generated by District staff, have also increased. By the end of the planning period, the rates vary from 15% to 83% in the three cases. This translates into approximately 2,900 to 12,500 EVs in Chelan County (after EV retirements) in 2030. The three cases now result in forecasts of between 1.79 and 7.78 aMW by 2030.

Peak load estimates now range from 3.72 MW to 16.19 MW in 2030. Future assumptions about charging behavior have a substantial effect on the peak forecast. The District's peak forecast for EV load occurs in the evening after most cars are assumed to be plugged in at home at the end of the day. Although assumptions about where, how and when EV charging occurs can vary greatly, the District does not expect the peak to be in the morning when Chelan PUD experiences its highest peaks in the winter.

The District will continue to monitor the development of the EV industry and its potential impact on future retail electric load in Chelan County.

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.

Long-term power sales contracts are currently in place with Douglas County PUD, Alcoa Power Generating Inc./Alcoa Inc., Puget Sound Energy and Avista Corporation. The Alcoa contract expires in 2028 during this planning period (2021-2030). 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 and solar. The District avoids transmission availability issues, in relation to serving retail load, by being able to use 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, certain operating agreements and the operation of the downstream reservoir from Rock Island belonging to the Wanapum project.

As previously reported, in September 2013, three additional large generating units at Rocky Reach were taken out of service after discovering that the fourth large turbine, out of service since March 2013, had a deep crack in a stainless steel rod that delivers oil to a servo motor. The motor adjusts the angle of the turbine blades. The four units share the same design and were put into service between 1998 and 2002. After making interim repairs, including temporarily fixing the blade positions, all four units were back online in early 2014. Beginning in 2015, the units are being taken out of service one at a time to make more permanent repairs. All servo rod repairs have been completed on C8 and C9 along with governor upgrades. C10 and C11 are now scheduled to be repaired in the 2022-2024 timeframe. The remaining seven smaller units at Rocky Reach do not share the same design in regards to either of these issues.

The seven smaller generating units at Rocky Reach were all in need of trunnion bushing replacement. The C1 and C2 turbine bushings were replaced, and the units returned to service in January 2020 and December 2020, respectfully. The C7 turbine bushings were replaced, and the unit returned to service in 2021. C3 and C6 are currently out of service and undergoing the same repairs. Units C4 and C5 are all in service and scheduled for their replacements in the 2021-2022 timeframe. The schedule is dependent on the repairs being completed within 7 months per unit. Due to COVID-19 supply chain issues, the recent turbine repairs took 11 months to complete. The District has made several equipment purchases in advance to minimize future delays due to material unavailability. However, there remains the potential discovery of other previously unknown problems requiring the replacement of turbine components resulting in longer outage durations.

During the Rock Island B2 generator stator replacement work, fatigue cracks were observed on the blades of the turbine. From October 2015 through January 2016, District staff made repeated attempts to grind out the cracks and repair the resulting excavations with various welding procedures. After each repair procedure, inspections resulted in the observation of new fatigue cracks. Engineering analysis indicated the B2 turbine is experiencing a phenomenon known as corrosion fatigue. The turbines of B1, B3 and B4 are of similar design and vintage as B2. These three units were taken out of service and inspected to determine if similar cracking existed in their turbine runner blades. These turbines also had significant cracking due to corrosion fatigue. All four turbines will remain out of service until the District can install replacement turbine runners. The District completed the development of specifications for the procurement of turbine runners for B1 through B4 and awarded a construction contract in late 2016. Repairs and replacement on unit B4 were completed in August 2021. The remaining three units will follow in 2022 through 2024.

The District initiated a series of sequential outages in January 2007 to modernize units B5 through B10. The scope of work for the modernization contract included the replacement of turbine runners, governor systems, generator stators and rotor poles and control systems. By May 2017, the contractor selected for this work had completed work on units B10, B9, and B6. In June of 2017, unit B9 suffered a Kaplan pipe failure and remained out of service until repairs were complete on October 3, 2018. In June 2019, unit B10 was removed from service to perform an overhaul and conduct turbine inspections. During the inspection, the District discovered a few internal turbine components had failed or were near failure. Subsequent inspections on unit B9 and B6 yielded similar observations of failed internal turbine components as B10. It was determined that it was safe to run the units in this condition until the final repair could be made so B6 and B9 are currently "in service". The modernization contractor conducted a root cause analysis of these failures and reviewed their findings with the District in August 2019. The District concurs with the contractor's findings and is currently negotiating, with the contractor, the cost to the District to restore the units and also the schedule to complete the work. Four repairs were identified to restore B6, B9 and B10. Once final negotiations with the contractor are completed, the District estimates an additional six-month outage to implement the repairs. Since the remaining units in the modernization project (B5, B7 and B8) are of similar design, the repairs identified above will be performed during the modernization outage. The repairs were completed on B10, and the unit returned to service in April 2021 followed by B7 returning to service in December 2021. Modernization and turbine repairs on B5, B6, B8 and B9 are scheduled during the 2021-2023 timeframe.

The second Rock Island powerhouse was constructed in 1979 and consists of eight horizontal bulb generating units. In the late 1980's, stator frames and stator windings were either replaced or repaired to due deficiencies in design. Since then, no other significant repairs or replacements of turbines or generators has occurred. A modernization contract is in place for the future replacement of the generator stators and rotors, governor systems and to convert the turbines to "oil-free" hubs. The work is scheduled to be performed in the 2022-2029 timeframe.

The risk management plans Chelan PUD has in place are working very effectively. The long-term wholesale sales contracts and hedging program (discussed in the Portfolio Analysis section), insurance program and strong financial policies continue to reduce the impact to the District from the lost generation revenue, repair costs and associated risk mitigation efforts for the aforementioned operational challenges.

Columbia River Treaty

The 1964 Columbia River Treaty (Treaty) between Canada and the U.S. was based on the development and operation of dams in the upper Columbia River basin for power and flood control benefits in both countries. The Treaty provides for the sharing with Canada of one-half of the downstream U.S. power and flood benefits and allows the operation of Treaty storage for other benefits. The Treaty has no expiration date, but operational elements of a basic feature of the Treaty, flood control, expire in 2024. Either party must provide 10 years notice for Treaty termination, so 2014 was a pivotal decision year.

In 2013, the Northwest and a variety of stakeholders endorsed the U.S. Army Corps of Engineers and the BPA's (collectively the U.S. Entity) final recommendation on the Treaty. The recommendation noted that "the region's goal is for the U.S. and Canada to develop a modernized framework for the Treaty that ensures a more resilient and healthy ecosystem-based function throughout the Columbia River basin while maintaining an acceptable level of flood risk and assuring reliable and economic hydropower benefits." A consortium of U.S. utilities has laid down negotiation markers that call for notification of termination if its principles are not met. A primary U.S. concern is the Canadian Entitlement, half of the originally calculated increase in U.S. downstream power benefits that is delivered to Canada. The utilities argue that the payment should be adjusted for diminished downstream benefits and the expense of subsequent U.S. environmental legislation imposed on the hydro system.

In March 2014, British Columbia, on behalf of Canada, released a 14-point position for updating the Treaty. Their principles include that the Treaty should primarily maximize benefits to both countries, the Canadian Entitlement currently does not account for all U.S. benefits or impacts to B.C., post-2024 flood control should include effective use of U.S. reservoirs and a coordinated flood risk management approach, ecosystems are an important consideration and adaption to climate change should be incorporated.

The process is a federal, interagency review under the general direction of the National Security Council on behalf of the President. The Department of State has been designated as the agency to coordinate and oversee this process on behalf of the National Security Council. The U.S. Entity is committed to supporting this effort. In May 2018, Treaty negotiations began between the U.S. and Canada. Negotiations are taking place in private. U.S. tribes were not originally involved, but tribal representatives are now involved as of later 2019. The Department of State reported that, in 2020 during a 10th round of negotiations, Canada responded to a framework proposal previously tabled by the U.S. and presented a Canadian-developed proposal. No details have been provided. In June 2021, Representatives DeFazio (OR-04) and McMorris Rodgers (WA-05) and Senator Patty Murray (D-WA) led a bicameral, bipartisan letter to President Biden urging his administration to speedily renegotiate the Treaty and to provide regular, substantial updates to members of Congress on the status of negotiations. There is no timeline yet on when or if the modernization of the Treaty will be finalized.

Climate Impacts to Loads and Resources

Chelan PUD has been following regional efforts to assess the future impacts of climate change on the power industry, including changes to hydroelectric generation and electricity demand. The prediction for the Northwest is for less snow and more rain during winter months, resulting in a smaller spring snowpack and lower summer flows. Winter electricity demands would decrease with warmer temperatures, easing generating requirements. In the summer, demands driven by air conditioning and irrigation loads would rise.

Other potential climate change impacts include increased flooding concerns in fall and winter, reduced salmon migration survival due to lower summer river flows combined with higher water temperatures and increased summer electricity prices.

The River Management Joint Operating Committee (RMJOC) (BPA, the Corps of Engineers and the Bureau of Reclamation) leads this regional effort. Most recently, in 2018, the RMJOC along with researchers in the University of Washington Hydro/Computational Hydrology research group (UW), in conjunction with the Oregon Climate Change Research Institute at Oregon State University, completed an updated study known as RMJOC-II. They have a web-based database that includes temperature, precipitation, snowpack and streamflow forecast projections for the entire Columbia River system.

The key research objective of the project was to determine, if possible, to what degree each methodological choice made in the hydroclimate modeling chain introduces additional spread into future projections. For the Columbia Basin as a whole, future climate scenarios depicted by global climate models as forecasted by the representative concentration pathways (RCPs) and downscaled by different methods, are the largest source of variability in future streamflows. The RCPs describe different 21st century pathways of GHG emissions and atmospheric concentrations, air pollutant emissions and land use. However, the choice of hydrologic model itself, the hydrologic model's particular calibration parameters, the choice of bias correction technique and the historical data set used for model calibration, are all important drivers for increasing the spread of the hydrologic projections.

It was noted that this study did not make a determination on which climate model, downscaling method, or hydrologic models will perform "better" or "worse" in the future. Because considerable scientific rigor was applied to each step in the process, the diversity of the methods used should be respected and maintained for possible downscaled selection for subsequent scenario-based studies. One important finding is that uncertainties introduced in each step of the modeling chain must be included if planners seek to represent a fuller range of potential hydroclimate change impacts.

The District is focusing on the following areas:

1. Columbia River mainstem modeling–power generation impacts, aquatic resources impacts and water quality impacts
2. Lake Chelan Basin modeling–Lake management impacts (power generation, Chelan River operations impacts and water quality impacts)
3. Wenatchee and Methow rivers modeling–Habitat Conservation Plan (HCP) hatchery program impacts
4. Distribution system load forecasting

Previously, Chelan PUD reviewed the effects on Rocky Reach generation under various climate change scenarios using RMJOC-I regulated hydro data. As anticipated, the result was more generation during winter and spring months (December through June) and less generation during summer months (July through September) with little change during October and November with changes becoming larger over time. The "2020s" (a 30-year period spanning 2010 to 2039) and the "2040s" (a 30-year period spanning 2030 to 2059) were studied. RMJOC II data for Rocky Reach and Rock Island has been received by the District. Updated analysis using the RMJOC II data confirmed the previous study as the data showed more flow and generation in the winter/spring and less in the summer. In addition to the changing shape of annual inflow, the data also showed an increase in total annual volume of water received over time.

The District has worked with the University of Washington (UW) Climate Impacts Group to determine which data sets to use to complete its own modeling of future climate change scenarios on Lake Chelan operations and reservoir management. In 2020, Chelan PUD conducted internal modeling of the 2050 timeframe and determined the current operating structure and modeling approach for Lake Chelan is sufficient. Climate change modeling for Lake Chelan will be updated to reflect changing conditions and updated data sets when it is available.

UW researchers have provided data sets (1980-2010), enabling District staff to perform basic calculations to predict changes to monthly District peak loads (based on 2007-2016 average peak loads and 1980-2010 average temperatures at Saddlerock substation). The current data shows increasing average temperatures for every month, increasing over time and does not account for load growth. The results were as expected; reduced winter demands and increased summer demands. The District continues work to determine its usefulness and how it can be used to help with planning.

Chelan PUD will remain attentive to regional work on this issue as science and experience help shed light on the best methods for predicting load changes and water and snowpack inventories and reshaping flood curves.

Integrating Renewable Resources and Overgeneration Events

In 2013, by legislative action, a new requirement was added to Washington State IRPs: an assessment of methods, technologies or facilities for integrating renewable resources and addressing overgeneration events, if applicable to the utility's resource portfolio. In 2019, that requirement was clarified to include battery storage and pumped storage among the methods, technologies or facilities to be assessed. The assessment must also include a description of how overgeneration events are mitigated at the lowest reasonable cost and risk to the utility and its ratepayers. An overgeneration event is defined as an event within an operating period of a BA when the electricity supply, including generation from intermittent renewable resources, exceeds the demand for electricity for that utility's energy delivery obligations and when there is a negatively priced regional market.

Negatively priced regional market occurs, at times, when hydro and wind, which are very low variable cost resources (i.e., free fuel), are forced to the margin during periods of low load and high hydro and/or wind and solar production. This results in very low or 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 and other 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 wind production. They can also sell the RECs from this generation. The value of these items combined can be in excess of $20/MWh. These generators can afford to withstand some degree of negative pricing and still make a profit due to these other payments.

The federal Production Tax Credit (PTC), established in 1992, provides a tax credit to a facility for 10 years on a per kWh of electricity generated basis. It had been inflation adjusted every year. At the end of December 2020, Congress extended the PTC at 60% of the full credit amount, or $0.018 per kWh ($18 per megawatt hour in 2020), for another year through December 31, 2021. In 2020, the credit was also 60% of the full credit amount. Under the new PTC legislation, qualifying wind projects must begin construction by December 31, 2021. Tax credits for other technologies, including, geothermal, biomass, landfill gas and certain hydropower and marine hydrokinetic, may be claimed at the full rate. In the fall of 2021, Build Back Better legislation was introduced that would extend the PTC through 2026 with modifications to current provisions.

Currently, the solar investment tax credit (ITC), for projects the construction of which began prior to January 1, 2020, is equal to 30%, but it steps down to 26% for projects the construction of which begins prior to January 1, 2021, and to 22% for projects the construction of which begins prior to January 1, 2022 (in each case, as long as the energy property is placed in service prior to January 1, 2024). The ITC drops to 10% where the construction begins after December 31, 2021. Additionally, for a project to be eligible for more than a 10% ITC, it must be placed in service before January 1, 2024. The ITC has been extended and the 26% ITC remains available for solar projects that begin construction prior to January 1, 2021, by two years, allowing the 26% ITC for projects that begin construction before January 1, 2023. A 22% credit would then be available for projects that begin construction before January 1, 2024, with the credit phased out afterwards. In the case of wind facilities, a taxpayer may elect to treat these facilities as "energy property" and thereby claim the ITC in lieu of the PTC, subject to a phase-down similar to the PTC phase-down. Current legislation allows taxpayers to elect to receive the ITC with a 40% reduction (i.e., to 18%) for wind facilities the construction of which begins before January 1, 2022. Like with the PTC, the Build Back Better legislation introduced proposals to extend the ITC. The proposals also extend the ITC through 2026 in most cases with modifications to current provisions.

Chelan PUD's share of Nine Canyon wind is a relatively small portion of its overall resource portfolio (less than 1%). In most cases, the District is able to integrate this wind operationally without issue due to its hydro resource reserves. The District may have to sell at negative prices when it has already reduced its hydro generation as much as possible under certain operating circumstances.

Oversupply in the region continues to have a financial impact to utilities. In spite of the Northwest seeing a rapid slowdown to the wind fleet buildout as many financial incentives are ending and good wind locations have diminished, state and regional policies, California markets and solar energy continue to create oversupply conditions throughout the Western Interconnect.

For comparison, the spring runoff period (April-July) of 2020 had 25 day-ahead days with negative local prices (2019 had 2 days, 2018 had 35 days, 2017 had 35 days, and 2016 had 2 days). In the hourly balancing or real-time market, 2020 had 324 hours with negative local prices (2019 had 17 hours, 2018 had 129 hours, 2017 had 368 hours, and 2016 had 23 hours). Snowpack and timing of spring runoff can affect the number of days and hours with oversupply and negative prices as evidenced by 2019's low number of negative days and hours. 2021 has had a very low number of negative priced days with a lower-than-average snowpack and regional drought.

As wind's intermittent nature can push a region into oversupply, behind-the-meter or unmetered solar (residential) and metered (utility-sized) solar continue to increase due to an exponential drop in solar panel cost and similar growth in solar panel output. Full solar output can just as easily push a region into oversupply as wind alone once did. The opposite is true when the sun sets and there is an increased need for electricity generators to quickly ramp up energy production as solar falls. In 2020, on a low load, high renewable generation day, almost 60% of California's demand could be met with renewables.

In the Northwest, the BPA has business practices that push the burden of oversupply back to the market and away from themselves. These practices include not selling at negative prices until spilled water reaches dissolved gas limits, holding renewable generators to a fixed schedule, not accepting unplanned surplus and canceling transmission loss returns. The cancelling of transmission loss return scheduled megawatts from utilities to BPA can add hundreds of megawatts to an already oversupplied period and drive prices even more negative for the loss-returning entity.

The extension of California's Energy Imbalance Market (EIM) into the Northwest and Canada allows California utilities to expand their market boundary when wind and solar push California into oversupply or create shortages as the sun sets. By optimizing renewables throughout a larger footprint, participants now see similar price signals and react to grid needs in a similar way. In the EIM market, when excess energy floods the market, Northwest hydro utilities have to sell their surplus at very low or even negative prices to compete while managing water quality requirements. Conversely, when solar production drops off each day, California can meet peak loads by accessing flexible Northwest generation thus increasing local competition for power and therefore, increasing power prices during hours the District is also in the market to buy power for load.

Energy Imbalance Market

An EIM is a balancing energy market that optimizes generator dispatch within and between participating Balancing Authority Areas (BAAs) every 15 and five minutes. The Western Energy Imbalance Market (WEIM) currently does not replace the day ahead or hour ahead markets and scheduling procedures that exist in the Western Interconnection today. By allowing BAs to pool load and generation resources, the WEIM has the potential to lower total flexibility reserve requirements and minimizes curtailment of intermittent or variable energy resources for the region as a whole. An EIM dispatches generators in a way that attempts to minimize the total cost to serve load (and exports) while honoring all system constraints.

In the fall of 2014, PacifiCorp joined the California Independent System Operator (CAISO) in its WEIM. The WEIM uses advanced technologies to automatically find and deliver the lowest cost energy to consumers across eight western states. By optimizing resources from a larger and more diverse pool, the WEIM better facilitates the integration of renewable energy that may otherwise be curtailed at certain times of the day, providing an added environmental benefit.

Since then, a number of entities have followed suit by either joining or announcing their intention of joining the WEIM.

ACTIVE

- Northwestern Energy–entered 2021
- Los Angeles Department of Power & Water–entered 2021
- Public Service Company of New Mexico–entered 2021
- Turlock Irrigation District–entered 2021
- Salt River Project–entered 2020
- Seattle City Light–entered 2020
- Balancing Authority of Northern California–entered 2019
- Idaho Power Company–entered 2018
- Powerex–entered 2018
- Portland General Electric–entered 2017
- Puget Sound Energy–entered 2016
- Arizona Public Service–entered 2016
- NV Energy–entered 2015
- PacifiCorp–entered 2014
- CAISO–entered 2014

PENDING

- Avista Corp–entry 2022
- Tucson Electric Power–entry 2022
- Tacoma Power–entry 2022
- Bonneville Power Administration–entry 2022
- Avangrid–entry 2023
- El Paso Electric–entry 2023
- WAPA Desert Southwest Region–entry 2023

By 2023, participants representing 82% of Western Electric Coordinating Council's (WECC) total load are expected to be active in the WEIM.

In addition to the WEIM expansion, the Southwest Power Pool launched its Western Energy Imbalance Service (WEIS) market to interested utilities beginning February 1, 2021. Also, CAISO is still exploring opening its day ahead market to the WEIM footprint. Entities in the region moving towards organized markets and the expansion of these markets are a key development in the industry. The District is actively following the transition towards more organized markets and will continue to assess the impact to the region and the District.

Figure 1- Energy Imbalance Market Footprint

https://www.westerneim.com/Pages/About/default.aspx

Renewables

The District has been complying with Washington State RPS renewable requirements since it became mandatory in 2012. The renewable energy section of the initiative now requires utilities to serve 15% of retail load 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 renewable requirement of the RPS throughout the planning period. The District meets its 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.

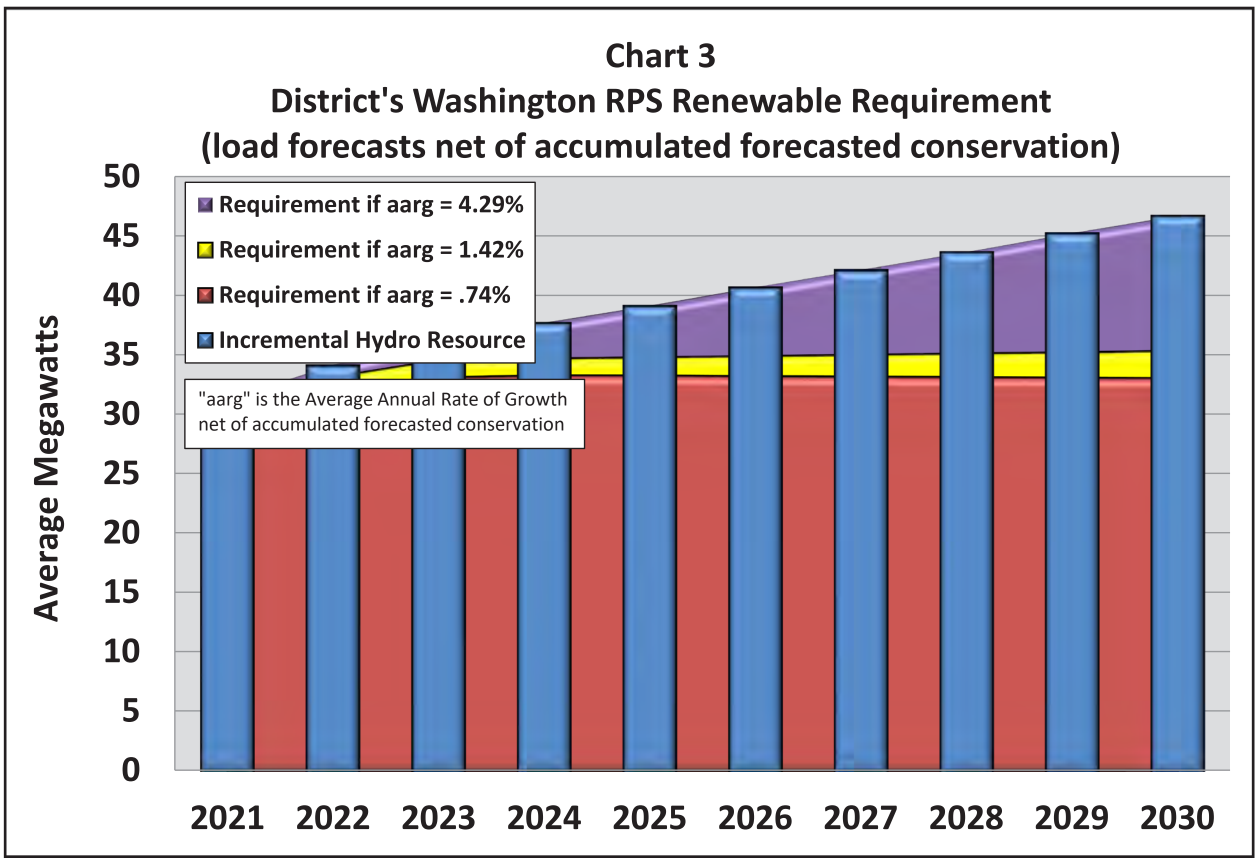
Based upon the current base load forecast, net of accumulated forecasted conservation, the amount of renewable resources required will be approximately 31-35 aMW in 2021-2030. Chart 3 shows the potential target requirements based on the District's three load forecasts.

The District continues to evaluate options to meet its renewable compliance requirements. For the purpose of evaluating the financial impact of the RPS, the District analyzes 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 WAC rules that pertain to the RPS.

In 2012, an advisory opinion process for eligible renewable resources was authorized to provide additional clarity and certainty. The District uses this process to confirm incremental hydropower from both Rocky Reach and Rock Island as qualified under the Washington State RPS and registered the incremental hydro in the Western Renewable Energy Generation Information System (WREGIS).

The western renewable and clean energy markets continue to evolve as compliance rules change and higher renewable targets and new clean energy standards become a reality for utilities. California passed Senate Bill (SB) 100 requiring zero-carbon resources supply 100% of electric retail sales to end-use customers by 2045. Oregon's RPS now requires that 50% of the electricity used by retail customers come from renewable resources by 2040. As previously mentioned, Washington State passed the CETA requiring all electric utilities to use renewable and nonemitting resources in an amount equal to 100% of their retail electric loads starting in 2030. For 2030-2044, utilities can use alternative compliance to



offset the use of emitting electricity for up to 20% of their CETA requirement. CETA considers all existing hydropower to be renewable. Chelan PUD continues to monitor the potential impacts of other state policies and actively participate in CETA rulemaking.

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.

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).

To set its 10-year plan and two-year conservation target for the 2022-23 biennium, in 2021 the District used a utility-specific analysis, also known as a conservation potential assessment (CPA). This CPA, which was conducted by Lighthouse Energy Consulting, established the conservation targets that are used in this 2021 IRP. The CPA used data specific to Chelan County on demographics and building construction to more accurately estimate local conservation potential. The CPA was developed in a manner consistent with the Council's methodology. The resulting conservation supply curves are used in the analysis of this 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 savings, but since 2014, there has been an increased emphasis on residential and commercial projects.

The 2021 CPA provides estimates of energy and peak demand savings by sector for the period 2022-2041. The methodology complies with RCW 19.285.040 and WAC 194-37-070 section 6 parts (a)(i) through (xv) and is consistent with the methodology used by the Council in developing the Sixth and Seventh Power Plans.

The primary baseline changes in the 2021 CPA included the following:

- Code changes–significant impacts of recent code changes that have taken effect result in lower remaining potential (e.g., new lighting standards).
- Accounting for past achievements including:
  - Internal programs, especially in the industrial and commercial sectors
  - NEEA programs
- Revised/updated measure data from the Regional Technical Forum (RTF) is included.

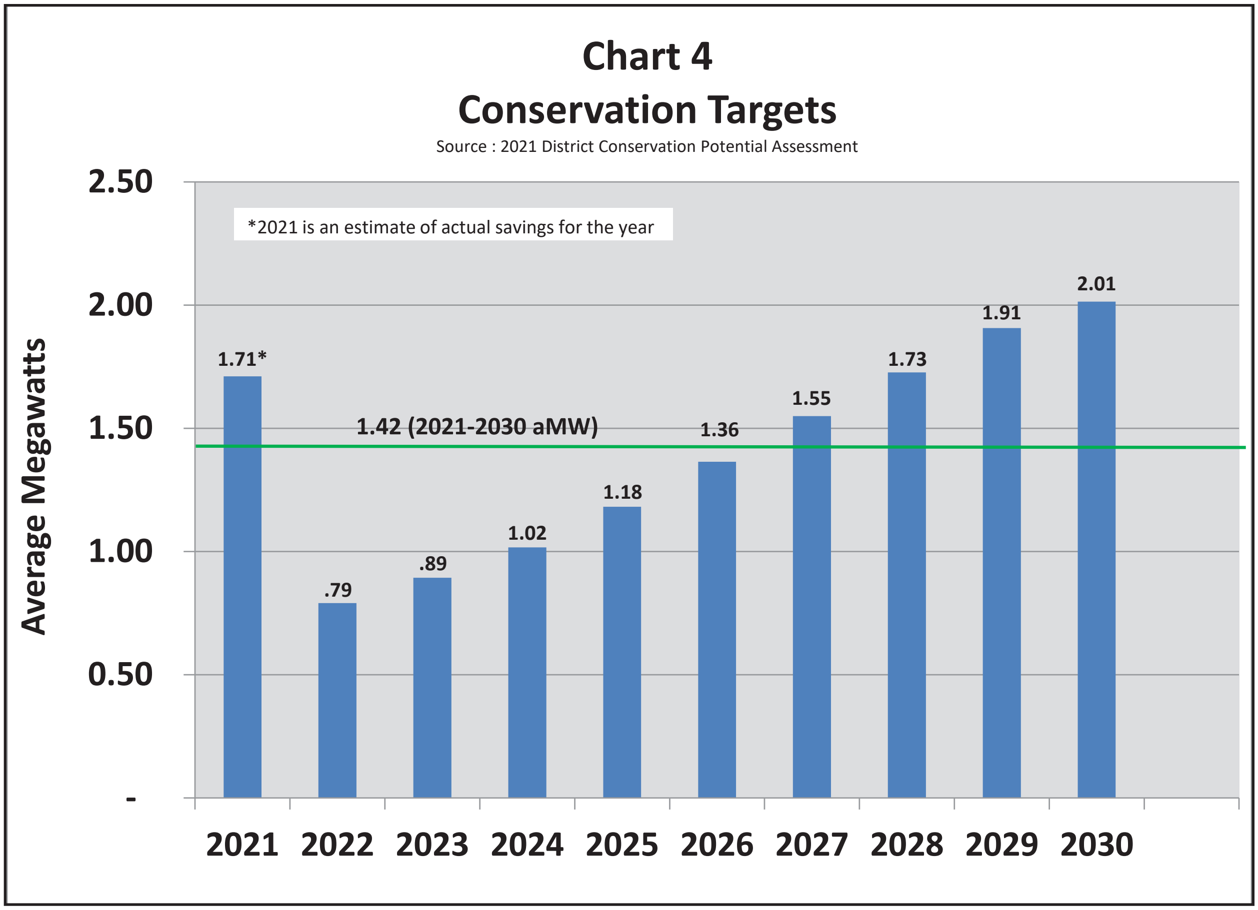
Table 1
2021 Conservation Potential Assessment
Cost-Effective & Achievable Savings
aMW

Sector	2 Year	6 Year	10 Year	20 Year
Residential	0.18	1.13	3.49	10.73
Commercial	1.02	3.78	7.30	14.70
Industrial	0.46	1.77	3.42	6.35
Distribution	0.00	0.05	0.20	0.58
Agriculture	0.02	0.06	0.13	0.23
TOTAL	**1.68**	**6.77**	**14.53**	**32.58**

Table 1 shows the high-level results of this CPA. The economically achievable potential by sector in two, six, 10 and 20-year increments is included. The 10-year potential is approximately 14.53 aMW. The total 20-year energy efficiency potential is approximately 32.58 aMW.

Chart 4 illustrates the conservation potential targets through the planning period.

Embedded in these potential estimates are savings from regional market transformation efforts, as well as new codes and standards. Regional market transformation is achieved through the Northwest Energy Efficiency Alliance (NEEA). As a member, the District applies a pro-rata share of regional NEEA saving projections toward meeting biennial targets. 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."



Residential

The two-year pro-rata share of the 2041 potential is 0.18 aMW and the 10-year potential is 3.49 aMW.

Commercial

The two-year pro-rata share of the 2022-41 potential is 1.02 aMW and the 10-year potential is 7.30 aMW.

Industrial

Industrial potential for this assessment was calculated based on the Council's top-down methodology that utilizes annual consumption by industrial segment and then disaggregates total electricity usage by process shares to create an end-use profile for each segment. Estimated measure savings were then applied to each sector's process shares. The two-year pro-rata share of the 2022-41 potential in the industrial sector is 0.46 aMW, eventually reaching a total of 3.42 aMW after 10 years.

Agriculture

The two-year pro-rata share of the 2022-41 potential is 0.02 aMW and the 10-year potential is .13 aMW.

Cost

Energy saved in homes and businesses reduces the need to purchase power on the wholesale market or 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.

The 2021 CPA identified a total of 1.68 aMW of cost-effective and achievable conservation for 2022 and 2023 combined.

For its 2021 CPA, Chelan PUD utilized a forward market projection of wholesale market power prices and carbon pricing as its avoided cost for the evaluation of the cost-effectiveness of potential conservation measures. The levelized costs for all conservation measures that resulted from the 2021 CPA were $35.18/MWh over the 2022-2031 period and $37.08/MWh over the 2022-2041 period (2016 real dollars). The higher levelized cost of conservation is primarily due to the removal of low-cost lighting measures, a higher value attributed to peak demand savings on the distribution system and an increase in capacity values on the wholesale market.

Current Demand-Side Offerings

The goal of Chelan PUD conservation programs is to offer diversified, cost-effective measures 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. All of the programs support meeting Chelan PUD's RPS targets. Additionally, the two low-income programs help the District support CETA targets.

Insulation Rebates

For residential customers, the District pays 50 cents to $1.00 per square foot for added insulation, depending on current insulation levels. Requirements to qualify include:

- Existing attic insulation must be R19 or less. Customers must add insulation to achieve R38 or greater.
- For walls, there can be no existing insulation. Added wall insulation must achieve R11 or greater.
- For floors, there can be no existing insulation. Added floor insulation must achieve R19 or greater.

Exterior Entry Doors, Window and Glass Door Rebates

Incentives are available to residential customers who replace older inefficient windows, and glass and substandard exterior entry doors.

This rebate offers customers:

- $6 per square foot on qualifying double pane glass doors and windows. To qualify, new windows must have a U-factor of 0.30 or lower. Qualifying glass doors must have a U-factor of 0.35 or lower.
- The rebate for upgrading single-pane windows is $8 to $12 per square foot, depending on heat source.
- $40 rebate per door for replacement of substandard entry doors with new Energy Star® rated insulated doors.

Multi-Family Window and Glass Door Rebates

- Incentives are available to residential multi-family apartment owners who replace older inefficient windows and glass doors. This rebate offers owners $4 per square foot on qualifying glass doors and windows. To qualify, new windows must have a U-factor of 0.30 or lower. Qualifying glass doors must have a U-factor of 0.35 or lower.

The District is currently in the process of evaluating its weatherization (windows and insulation) rebate amounts to increase the incentive to provide more participation throughout the county.

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 $90,000, which is matched by the Washington State Energy Matchmaker program administered by the state Department of Commerce. CDCAC crews complete the weatherization measures which are inspected by the Department of Commerce and the District. In addition to the weatherization funding, CDCAC may install Ductless Heat Pumps in selected dwellings.

Low Income Energy Efficiency program

The District is developing a low income (LI) program to meet both internal goals and also to stay in compliance with CETA. This program has three phases of targeting customers who are considered high energy burdened, or pay more than 6% of their annual income to their energy bill. The first stage will be reaching out to all identified customers with a low-cost energy saver gift (light bulbs, thermostatic shower valves and low flow showerheads). Along with the gift, customers can opt into additional measures like smart thermostats. These customers will also fill out information that will help us roll into phase two of the program. Phase two begins the deeper dive of replacing old appliances, water heaters and insulating homes that are in need. This will be rolled out to homeowners and will be targeted at 60-80 homes a year beginning sometime in 2022. The final phase of the LI program will be retrofitting homes with more efficient heating, ventilating and air conditioning (HVAC) equipment. This phase will not begin for another few years (five to seven) and has not received final funding approval from Chelan PUD's Board of Commissioners.

Super-Efficient Heat Pumps and Heat Pump Water Heaters

Air Source Heat Pumps

The District offers a rebate to customers installing or upgrading to a super-efficient heat pump. In order to qualify, the customer must install a 9.0 heating season performance factor (HSPF) or greater and a 14 seasonal energy efficiency ratio (SEER) or greater heat pump. The install must be done by a performance tested comfort system (PTCS) qualified contractor and must be commissioned to PTCS standards. If the customer is replacing an electric furnace, the rebate is $1,400. If the customer is updating a heat pump, installing a heat pump above code for new construction or installing a heat pump with natural gas backup, the customer qualifies for a $500 rebate.

Ductless Heat Pump

Customers who are displacing zonal electric, radiant or electric furnaces with a qualified ductless heat pump system in Chelan County qualify for a $1000 rebate. Customers must get pre-approved for the application and must use an authorized contractor (through the NW Ductless Heat Pump Project) for the installation.

Heat Pump Water Heaters

Single-family existing home customers in Chelan County are eligible for a heat pump water heater rebate. These products are given qualifications through the Northern Climate Heat Pump Water Heater Specifications. The District offers an $800 rebate for a Tiers 3 and above for any water heater size.

Residential Single Family New Construction

The District has a New Construction program. Homes built 20% above current building code will receive a $2,000 incentive. To receive this incentive, the builder works with a local home energy rater to model that a home that uses 20% less energy than a code standard home of the same size.

Residential Audits

The District started offering home energy audits in 2019. This is a web-based software tool that provides customer data that gives them details on what programs and rebate amounts the homeowner would qualify for based on current Chelan PUD program offerings.

Commercial/Industrial Energy Efficiency Programs

The District has programs for helping commercial and industrial customers install energy efficiency equipment in their facilities by paying a portion of the project's costs. Measures include interior and exterior lighting, weatherization, HVAC, water heating, a suite of measures for restaurants and grocery stores along with a strategic energy management program.

Lighting Rebates

The District uses a lighting calculator to generate energy savings for interior and exterior lighting projects. For retrofit projects the District pays the lessor of $0.18/kWh or 75% of the project costs. New construction projects are paid $0.06/kWh.

Weatherization Rebates

The District's weatherization measures include windows and insulation. Customers replacing single-pane (with or without storm windows) or double-pane with metal frame windows with windows that have a u-value of 0.30 or less with electric resistance heat receive $20/sq ft. Customers with heat pumps receive $10/sq ft. Customers may upgrade wall and attic insulation. Walls must have no existing insulation and attics must have insulation levels less than R5. Customers must fill the wall cavity and bring the attic levels up to R49 to receive the $1.00/sq ft rebate.

HVAC Rebates

The District has a suite of HVAC rebates for commercial and industrial customers. These include heat pump (HP) & ductless heat pump (DHP) upgrades and conversions, packaged terminal heat pumps (PTHP) and thermostats. All HVAC equipment must meet program efficiency requirements. Customers who upgrade an existing HP or DHP receive a rebate of $300/ton. It is the same for new construction as well. Customers converting electric resistance heat to a HP or DHP receive $2000/ton.

Residential care facilities who install a PTHP as a retrofit or new construction will receive $1000/unit. Customers in the lodging sector receive $750/unit.

Customers replacing a non-web enabled thermostat with a qualifying unit will receive $250/unit.

Water Heating Rebates

Customers can replace an existing hot water tank with a hybrid hot water tank. The District will rebate $1200 for a tier 2 tank and $1400 for a tier 3 tank.

Grocery and Restaurant Rebates

Customers with small and large grocery stores along with restaurants can take advantage of the numerous measures offered by the District. These measures include ovens, food holding cabinets, fryers and kitchen ventilation as well as strip curtains, anti-sweat controls and evaporator motors for coolers. All equipment must meet program standards.

Strategic Energy Management (SEM)

SEM is a program for commercial and industrial customers. The program takes a close look into systems that use energy and how the customers operate those systems in their facility. The District identifies ways to operate those systems more efficiently. Low-cost upgrades are prioritized as well as larger custom projects that would improve the energy efficiency of their facility. The District takes this information and forms a dual path to success for the customer. The first path is called a tune up. This is where staff helps them implement system changes and work through the no to low-cost items. The second path utilized is the identification and implementation of custom projects. The District aids the customer with obtaining quotes and analysis around the costs versus the energy savings. A report is delivered to the customer.

Local Government Initiative

Under this program, local government officials are encouraged to participate in a Chelan PUD initiative to improve the energy efficiency of public buildings. To assist local governments improve the energy efficiency of their facilities and equipment, the District provides financial incentives that can cover up to 100% of the local government's cost of implementing the energy efficiency measures. The maximum amount of the incentives is capped at the net present value of the energy savings over the projected life of the projects.

Portfolio Analysis

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 (2021-2030) without adding new resources and is also expected to meet Washington State RPS renewable requirements and CETA requirements through this period as well. Additionally, Chelan PUD's resource portfolio is comprised primarily of carbon-free, base load, reliable, low-cost hydro resources. For all these reasons, as in prior analyses, no new resources were added to the portfolio of resources.

Portfolio Costs

The hydroelectric facilities' costs shown in Table 2 and Chart 5 represent all costs incurred, including debt service, operations and maintenance (O&M), taxes, reserve fund requirements and contractual fees. The Nine Canyon cost is the District's power purchase contract payments to Energy Northwest.

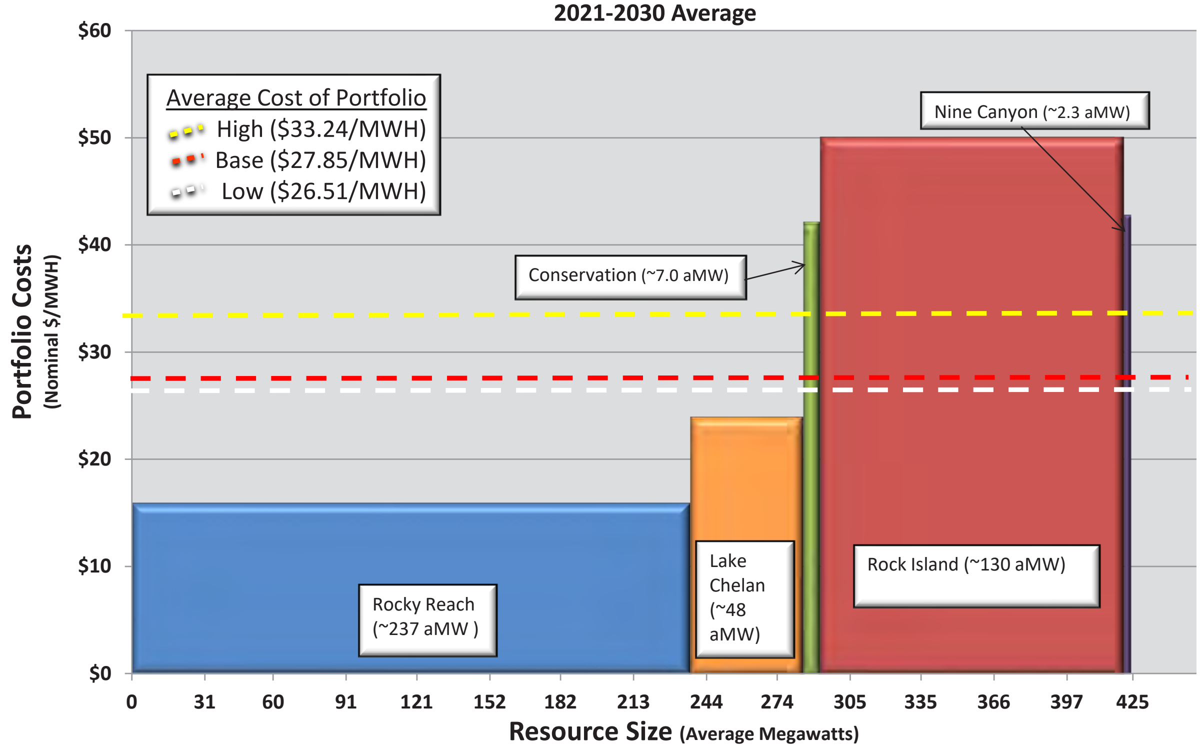
The 2020 cost for the District's existing portfolio is shown in Table 2. These costs were calculated two ways. The second column, reading left to right, are the actual cost per megawatt hour based on actual costs and actual generation in 2020. Columbia River runoff conditions were 100% of average and Lake Chelan runoff conditions were 92% of average in 2020. Wind generation conditions at Nine Canyon were well above average at 114%. The column on the right was calculated using actual 2020 costs and average hydro and wind generation for any given year. This column illustrates what current costs were without the effects of runoff (including timing), wind variability and other factors, including unit outages and spill. As seen in the table, cost per megawatt hour of generation can vary significantly depending upon actual generation including the aforementioned variables. This is because almost all costs are fixed, that is, they don't vary with the amount of generation (e.g., debt service, taxes).

Table 2
District's Existing Portfolio Cost
2020

Project	$/MWh w/<u>actual</u> generation	$/MWh w/ <u>average</u> generation
Rocky Reach	$15.58	$14.24
Rock Island	$47.95	$43.61
Lake Chelan	$27.29	$26.35
Nine Canyon	$58.40	$66.97

Chart 5 describes the projected base District portfolio costs by resource and relative size of each resource. To address the uncertainty in the District's hydro portfolio costs, two additional scenarios were developed along with the base costs' projection. The high scenario represents a 20% overall increase in hydro costs and the low scenario represents a 5% overall decrease in hydro costs. The weighted average cost of all resources under these scenarios are shown as dotted lines.

Chart 5
District Portfolio Costs
2021-2030 Average



Hydro generation includes the effects of encroachments, Canadian Entitlement Allocations, other contractual obligations including long-term power purchaser contracts and short-term hedging strategy slice contracts

Hydro

The District forecasts the future costs 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 HCP 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 unit overhauls, 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–2.0-3.0%
- Rock Island–2.0-3.0%
- Lake Chelan–2.0-3.0%

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.

Since increasing approximately 70% in 2008 due to higher than expected maintenance and repair costs and the cessation of anticipated federal Renewable Energy Production Incentive payments, the cost of production rates has lowered just slightly. They are projected to hold steady through mid-2022 at which time the Phase I and II debt is scheduled to be paid in full. Rates are then expected to decline by over 50% and hold steady through the remaining life of the purchase contract which expires in 2030.

Hedging Strategy

Chelan PUD has a comprehensive forward hedging strategy. The District pursues 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 and outlined in its Power Risk Management Policy to help manage wholesale revenue risk and stabilize such revenue at least five years into the future. Typically, the District uses a stair-stepped approached to hedging with more hedged in the near-term years and less hedged in future years. As of mid-2021, hedges have been executed for as far out as 2033.

Portfolio Results

The District analyzes its forecasted portfolio of resources in relation to its load forecasts. The load/resource balance, service reliability and environmental impacts are all factors considered and evaluated.

Although it is not adding new resources, the District is 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)
- Operational or outage risk

Load/Resource Balance

For this IRP, the District's existing mix of resources, at low, average and high levels of hydro generation, was stressed with the low, base and high load forecasts. Chart 6 represents each of these net positions and load projections.

As mentioned previously, analysis continues to indicate that Chelan PUD is expected to be able to serve its retail load throughout the planning period without any new supply-side resource additions. The amount of demand-side resources included in this evaluation has decreased just slightly from what was included in the 2020 IRP to match Chelan PUD's 2021 required 10-year conservation plan submittal to Commerce that is approximately 1.42 aMW per year through the study period (based on the 2021 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.

More detail behind the District's load forecasts, resources and contracts can be found in Appendix A–Portfolio Detail & Assumptions.

Service Reliability

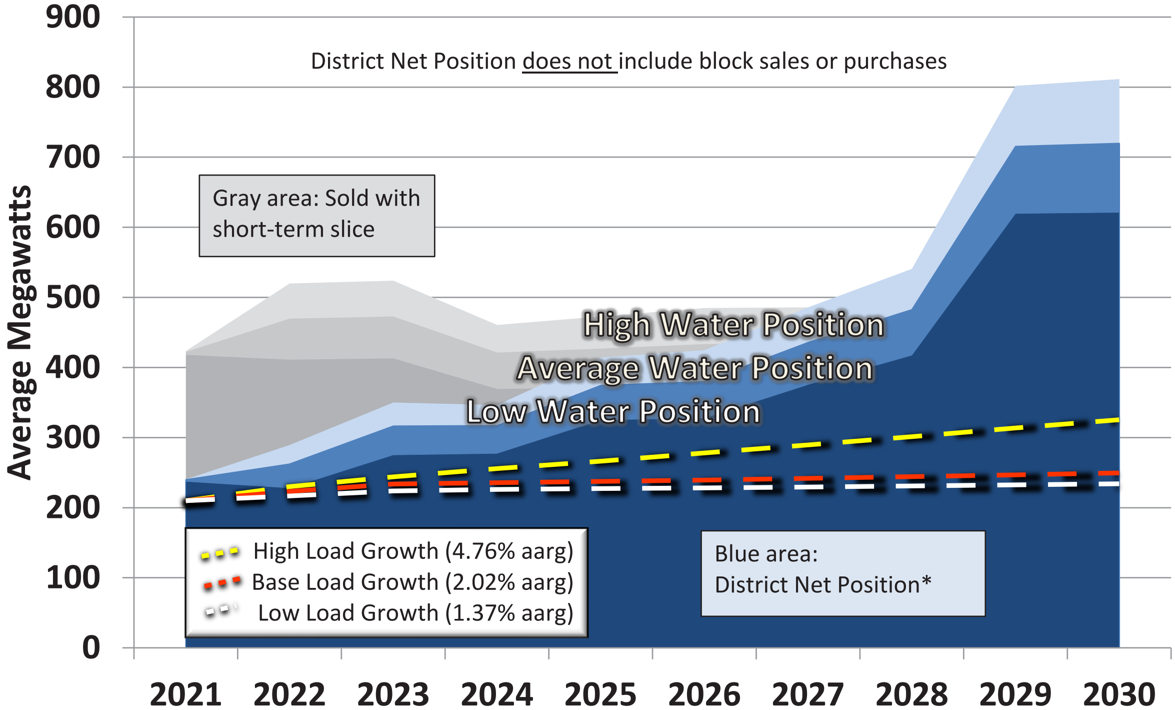
The District's load/resource balance throughout the planning period was modeled using three hourly time periods per month. The District expects to have enough resources available to exceed the expected hourly peak load forecast for each month, along with meeting reliability operating reserve requirements through the planning period, thus providing for service reliability. In addition, to consider the impact of streamflow variability in resource adequacy planning, the District currently assesses this metric under adverse (1 in 20) streamflow conditions. As previously mentioned in the Resource Adequacy section, Chelan PUD is involved in a NWPP effort to develop a robust Northwest capacity RA program that would allow utilities to forecast and manage RA in a coordinated manner.

Environmental Impacts

The District's hydropower and wind generation do not produce any air emissions. Table 3 shows Chelan PUD's calculated fuel mix for 2020 on an annual basis. The District does sell a portion of its hydro-electric and wind energy in resource specific transactions. These are accounted for in the District's fuel mix disclosure. Additionally, during certain hours of the year, depending upon load and hydro conditions, the District is a net purchaser in the wholesale market . In its 2021 CEIP, the District's target for the percentage of retail load to be served using renewable resources during 2022–2025 is 90%. This target reflects Chelan PUD's plan to continue to serve its traditional retail electric customers using existing hydropower resources. Chelan PUD did not set its target at 100% because it has a large industrial customer that has not committed to purchasing hydropower during 2022–2025. Establishing a 90% target places Chelan PUD in the position of meeting CETA's 2030 requirement to serve at least 80% of retail load with renewable and nonemitting resources eight years early.

Chart 6

District Net Position and Load Forecasts



*District net position includes the effects of encroachments, Canadian Entitlement Allocations, other contractual obligations including long-term power purchaser contracts and short-term hedging strategy slice contracts

The cost of air emissions from carbon dioxide (CO2) remains an industry uncertainty. It is expected that any carbon-reducing regulations 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.

Beginning in 2019, RCW 19.280.030 requires utilities to consider the social cost of GHG emissions when i) evaluating and selecting conservation policies, programs and targets; (ii) developing integrated resource plans and clean energy action plans; and (iii) evaluating and selecting intermediate term and long-term resource options. In response to that requirement, the District notes that its resource portfolio does not contain intermediate or long-term emitting resources.

Table 3

2020 Fuel Mix

Generation Type	District Calculated Fuel Mix
Hydro-electric	99.98%
Wind	0.02%
TOTAL	100.00%

10-year Clean Energy Action Plan (CEAP)

The following is the District's 10-year CEAP as required by RCW 19.280. The CEAP is intended to identify the specific long-term resource planning actions to be taken by a utility for implementing sections 3 through 5 of CETA at the lowest reasonable cost while meeting an acceptable resource adequacy standard. Additional information on CETA is provided in the Regulatory and State Statutory Requirements section.

CETA section 3

CETA section 3 requires a utility to eliminate coal-fired resources from its allocation of electricity by the end of 2025. As detailed in the Resources and Portfolio Analysis sections, the District's current resource portfolio consists of hydro and wind resources. Through this IRP, the District determined it will retain that mix of generating resources through the 2021-2030 planning period.

Historically, the District engaged in purchasing unspecified electricity from the energy market for purposes of hedging risk. Unspecified electricity is electricity where the generation source is unknown at the time of purchase. Due to the lack of upfront identification of a generation source, unspecified electricity purchases pose a unique challenge for CETA compliance. The District anticipates that after 2025, it may need to modify its use of longer-term unspecified electricity hedging purchases due to CETA.

CETA section 4

CETA section 4 requires utilities, beginning in 2030, to meet a GHG neutral standard by (i) pursuing all cost-effective, reliable and feasible conservation and efficiency resources to reduce or manage retail electric load, using the methodology established in RCW 19.285.040, if applicable; and (ii) using electricity from renewable resources and nonemitting electric generation in an amount equal to 100% of the utility's retail electric loads over defined multi-year compliance periods. Utilities may satisfy up to 20% of their compliance obligation for part (ii) with an alternative compliance option.

Through this IRP, the District determined it will retain its existing mix of renewable generating resources (hydro and wind) through the 2021-2030 planning period. The Conservation section details the conservation and efficiency actions the District has and intends to pursue from 2021 through 2030. The District does not anticipate needing to take any other specific resource planning actions during the 2021-2030 planning period in preparation for the start of the CETA GHG neutral standard in 2030.

CETA section 5

CETA section 5 adopts a state policy that nonemitting electric generation and electricity from renewable resources supply 100% of all sales of electricity to Washington retail electric customers by January 1, 2045.

Through this IRP, the District determined it will retain its existing mix of renewable generating resources (hydro and wind) through the 2021-2030 planning period. The District does not anticipate needing to take any other specific resource planning actions during the 2021-2030 planning period in preparation for the start of the new state policy in 2045.

Final Remarks

Chelan PUD intends to retain its existing supply-side resources while implementing its 2021 CPA results. Complying with both the renewable resources and conservation portions of the Washington State RPS remains a significant focus for the District and the addition of demand response potential through CETA is a new focus. As detailed in the CEAP, the District's retention of its existing supply-side resources should comply with CETA requirements that are applicable during this planning period. The District will continue to monitor uncertain variables that affect its load/resource balance, including stream flows, District load and the availability of generating units undergoing significant repair. Additionally, the District will continue to evaluate and implement its hedging strategy to help reduce the risks associated with these and other uncertainties.

Chelan PUD will publish an IRP Progress Report in 2023.

Appendix A — Portfolio Detail & Assumptions

Resources

Hydro

- To represent the stream flow uncertainty, historical monthly re-regulated stream flow data, 1929-2007, supplied by PNUCC and actual hydro project data from 2008-2016 was grouped together to create average, low and high stream flow scenarios. The average scenario is the average of the entire dataset, the low scenario is the bottom 20th percentile and the high scenario is the top 20th percentile. The monthly values in each scenario were then allocated to each hour using normalized historical hourly flow values.
- A model that is informed with system constraints (capacity, pond limits, outage estimates, etc.) is used to convert the hourly stream flow estimates into generation.
- For each month, three time periods are modeled; one representing Monday – Friday, one representing Saturday and one representing Sunday. The model requires hourly inputs for each time period. The model optimizes the generation within each time period. The outputs are then aggregated up to a monthly and annual granularity for reporting.
- Generation is net of all project obligations (i.e., Canadian Entitlement Allocations (CEAs) and encroachments)
- Rocky Reach – Chelan PUD's share (net of long-term purchaser contracts and executed slice contracts)
    - 18.46% -1/2021 through 12/2022
    - 23.46% -1/2023 through 1/2025
    - 28.46% -2/2025 through 12/2026
    - 33.46% -1/2027 through 10/2028
    - 59.46% -11/2028 through 12/2030
- Rock Island – Chelan PUD's share (net of long-term purchaser contracts and executed slice contracts)
    - 24%–1/2021 through 12/2022
    - 29%–1/2023 through 1/2025
    - 34%–2/2025 through 12/2026
    - 39%–1/2027 through 10/2028
    - 65%–11/2028 through 12/2030
- Lake Chelan – Chelan PUD's share
    - 100%–1/2021 through 12/2030

Wind

- All available historical Nine Canyon hourly wind generation (2004-2020) was used to calculate average energy

Conservation

- Used the quantities from the 2021 CPA (also used for RPS compliance in January 2022)

Contracts

Long-term Power Sales

- Rocky Reach
  - Puget – 25%–1/2021 through 12/2030
  - Alcoa – 26%–1/2021 through 10/2028
  - Douglas – 5.54%–1/2021 through 12/2030
- Rock Island
  - Puget – 25%–1/2021 through 12/2030
  - Alcoa – 26%–1/2021 through 10/2028

Executed Slices of Rocky Reach & Rock Island

- Executed "slice of the system" contracts as part of long-term hedging strategy
- Slice contracts represent between 10% and 25% of the capacity and energy of Rocky Reach and Rock Island between 2021-2030
- Slice contracts are removed from Chelan PUD's shares of Rocky Reach and Rock Island listed under "Resources" above

Load

- The three load forecasts represent average annual rates of growth of : 1.37%-low, 2.02%-base, 4.76%- high

Table 4 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 slice contracts.

Table 4

District's Average Annual Resources (aMW)

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Net Rocky Reach Gen	130	130	165	165	200	200	236	266	419	419
Net Rock Island Gen	80	80	97	97	114	114	131	145	218	218
Net Lake Chelan Gen	47	47	47	47	47	47	47	47	47	47
Net Nine Canyon Gen	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3
Conservation	1.71	2.50	3.40	4.41	5.59	6.96	8.51	10.23	12.14	14.16

Appendix B – Washington State Electric Utility Integrated Resource Plan Cover Sheet 2021

	Base Year			5 Year Estimate			10 Year Estimate		
Estimate Year		2020			2025			2030	
Period	Winter	Summer	Annual	Winter	Summer	Annual	Winter	Summer	Annual
Units	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)	(MW)	(MW)	(MWa)
Loads	446.00	243.00	204.50	522.93	274.73	238.00	547.16	289.01	250.00
Exports									
Resources:									
Future Conservation/Efficiency				11.93	6.73	5.59	30.16	17.01	14.16
Demand Response									
Cogeneration									
Hydro	419.00	220.00	189.00	770.00	386.00	338.00	1,227.00	603.00	532.00
Wind	0.37	0.33	2.58	1.38	0.76	2.25	1.38	0.76	2.25
Other Renewables									
Thermal - Natural Gas									
Thermal - Coal									
Net Long Term Contracts									
Net Short Term Contracts									
BPA									
Other									
Imports									
Distributed Generation									
Undecided									
Total Resources	419.37	220.33	191.58	783.31	393.49	345.84	1,258.54	620.77	548.41
Load Resource Balance	-26.63	-22.67	-12.92	260.38	118.76	107.84	711.38	331.76	298.41

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

Requirements

Loads

- Peak loads are based on expected load factors, by temperature and by sector, applied to the annual sector energy forecasts.
- Annual energy loads are based on the District's Base Load Growth Forecast of 2.02%.
- Peak and annual energy loads, including the base year (2020), are adjusted for normal weather (i.e. an expected or 1 in 2 peak).
- Future peak and annual energy loads 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 and executed slice contracts.

Wind

- Base year (2020) wind data reflects actual Nine Canyon experience in that year.
- 2025 and 2030 projected peak wind capacity is based on median (50th percentile) hourly Nine Canyon historical generation (2004-2020).
- 2025 and 2030 projected average annual wind energy is based on median (50th percentile) average annual energy from Nine Canyon historical generation (2004-2020).

Acronyms

aarg	Average Annual Rate of Growth
ACE	Affordable Clean Energy
aMW	Average Megawatt
APGI	Alcoa Power Generating, Inc.
BA	Balancing Authority
BAA	Balancing Authority Area
BEV	Battery Electric Vehicle
BPA	Bonneville Power Administration
CAISO	California Independent System Operator
CDCAC	Chelan-Douglas Community Action Council
CEA	Canadian Entitlement Allocation
CEAP	Clean Energy Action Plan
CEIP	Clean Energy Implementation Plan
CETA	Clean Energy Transformation Act
CO2	Carbon Dioxide
CPA	Conservation Potential Assessment
CPP	Clean Power Plan
CVR	Conservation Voltage Regulation
DHP	Ductless Heat Pump
DOE	Department of Ecology
DR	Demand Response
DRAC	Demand Response Advisory Committee
DRPA	Demand Response Potential Assessment
DVR	Demand Voltage Regulation
EIM	Energy Imbalance Market
EPA	Environmental Protection Agency
EV	Electric Vehicle
GHG	Greenhouse Gas
HB	House Bill
HCP	Habitat Conservation Plan
HDL	High Density Load
HP	Heat Pump
HSPF	Heating Season Performance Factor
HVAC	Heating, Ventilating and Air Conditioning
IRP	Integrated Resource Plan
ITC	Investment Tax Credit
KW, kWh	Kilowatt, Kilowatt-hour
LI	Low Income
LOLP	Loss of Load Probability
MW, MWh	Megawatt, Megawatt-hour
NEEA	Northwest Energy Efficiency Alliance
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
O&M	Operations and Maintenance
OFM	Office of Financial Management (Washington State)
PHEV	Plug-in Hybrid Electric Vehicle
PTC	Production Tax Credit
PTCS	Performance Tested Comfort System
PTHP	Packaged Terminal Heat Pumps
PUD	Public Utility District
RA	Resource Adequacy
RCP	Representative Concentration Pathways
RCW	Revised Code of Washington
REC	Renewable Energy Credit
RMJOC	River Management Joint Operating Committee
RPM	Regional Portfolio Model
RPS	Renewable Portfolio Standard
RTF	Regional Technical Forum
SB	Senate Bill
SEER	Seasonal Energy Efficiency Ratio
SEM	Strategic Energy Management
TOU	Time of Use
UW	University of Washington Hydro/ Computational Hydrology Research Group
WAC	Washington Administrative Code
WECC	Western Electric Coordinating Council
WEIM	Western Energy Imbalance Market
WEIS	Western Energy Imbalance Service
WRAP	Western Resource Adequacy Program
WREGIS	Western Renewable Energy Generation Information System
ZEV	Zero Emission Vehicle

Glossary

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 as well as an adder for the forecast of carbon value 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

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 "CO2 neutral", meaning they typically remove CO2 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".

Clean Energy Implementation Plan (CEIP)

A requirement under Washington's CETA, a Clean Energy Implementation Plan (CEIP), is intended to identify a utility's plans over the following four years to meet CETA's 2030 GHG neutral standard and 2045 100% clean electricity standard. A CEIP includes: 1) Interim target for the percentage of retail load to be served using renewable and nonemitting resources; 2) Specific targets for energy efficiency, demand response and renewable energy; 3) Specific actions to be taken to reach those targets; 4) Identification of highly impacted communities and vulnerable populations; 5) Report of the forecasted distribution of energy and nonenergy costs and benefits for the portfolio of specific actions; 6) Description of how the utility intends to reduce risks to highly impacted communities and vulnerable populations associated with the transition to clean energy.

Clean Energy Transformation Act (CETA)

The Washington Clean Energy Transformation Act (CETA) (RCW 19.405), signed into law in May 2019, added requirements that relate to resource planning. Key sections of CETA include: 1) section 3—elimination of coal-fired resources from a utility's allocation of electricity by the end of 2025; 2) section 4— a GHG neutral policy requiring a utility to use electricity from renewable and nonemitting resources in an amount equal to 100% of its retail electric load over multiyear compliance periods starting in 2030 (up to 20% may be met with alternative compliance options); and 3) section 5— a policy that electricity from renewable and nonemitting resources supply 100% of all sales of electricity to Washington retail customers by 2045. Unlike the Washington RPS, CETA considers all existing hydroelectric resources to be renewable.

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.

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.

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.

Cryptocurrency

A digital currency in which encryption techniques are used to regulate the generation of units of currency and verify the transfer of funds, operating independently of a central bank.

Council

See Power Plan (Seventh, Eighth, 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.

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

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

District
See Chelan 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.

Eighth Power Plan
See Power Plan (Seventh, Eighth, etc.)

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 Imbalance Market
An EIM is a balancing energy market that optimizes generator dispatch within and between participating Balancing Authority Areas (BAAs) every 15 and five minutes.

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.

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 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.

High Density Load (HDL)
Chelan PUD has defined as those loads with intense energy use of 250 kWh per square foot or more per year where the energy is used for server farms or similarly situated loads.

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

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

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. 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).

Load/Resource Balance

A comparative evaluation of future load forecasts in relation to the availability of demand-side and supply-side resources available to meet those future load needs.

Loss of Load Probability (LOLP)

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.

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.

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 or Council)

See Power Plan (Seventh, Eighth, etc.)

Overgeneration Event

A requirement of RCW 19.280.020: “means an event within an operating period of a balancing authority when the electricity supply, including generation from intermittent renewable resources, exceeds the demand for electricity for that utility’s energy delivery obligations and when there is a negatively priced regional market.”

Peak Demand (Load)

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

Peak(ing) Resource
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.

Plug-In Hybrid Electric Vehicle
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 (Seventh, Eighth, 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 Seventh Power Plan, the most recent, was adopted in February 2016. The NWPCC is also mandated to develop a fish and wildlife program to protect and rebuild populations affected by hydropower development in the Columbia River Basin and conduct an extensive program to educate and involve the public in their decision-making processes.

Probability
The likelihood or chance that something will happen.

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…"

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 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; or (i) biomass energy (from RCW 19.285: The Energy Independence Act).

Means: (a) Water; (b) wind; (c) solar energy; (d) geothermal energy; (e) renewable natural gas; (f) renewable hydrogen; (g) wave, ocean, or tidal power; (h) biodiesel fuel that is not derived from crops raised on land cleared from old growth or first growth forests; or (i) biomass energy (from RCW 19.405: the Clean Energy Transformation 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.

Seventh Power Plan

See Power Plan (Seventh, Eighth, etc.)

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.

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 (Generation) 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.