BONNEVILLE POWER ADMINISTRATION

2022 Resource Program

Contents

Section 1: Introduction

This report begins with a general overview, noting the purpose of the Bonneville Power Administrations' Resource Program, highlighting changes from previous assumptions and methodology, and summarizing key findings of the analyses. Following the overview is a more in-depth look at each component of the Resource Program, including the assumptions, methodologies and study results, along with a brief section on BPA's next steps culminating from the conclusions.

1.1 Overview

BPA launched its Resource Program shortly after passage of the Northwest Power Act in 1980 to assess the agency's need for power and reserves and to develop an acquisition strategy to meet those needs. The Resource Program study provides analysis and insight into long-term, least-cost power resource acquisition strategies. This study examines uncertainty in loads, water supply, resource availability and electricity market prices to develop a least-cost portfolio of resources that meet Bonneville's obligations.

The 2022 Resource Program covers the fiscal years 2024 – 2033 and includes updates made to the optimization process and refreshes inputs. This study also includes a high policy scenario that will help BPA understand how the resource solution results may be impacted by changes in key assumptions such as loads, candidate resource costs and market prices. The results yield a vision of the agency's needs and low-cost resource strategies across a range of future market conditions and policy environments.

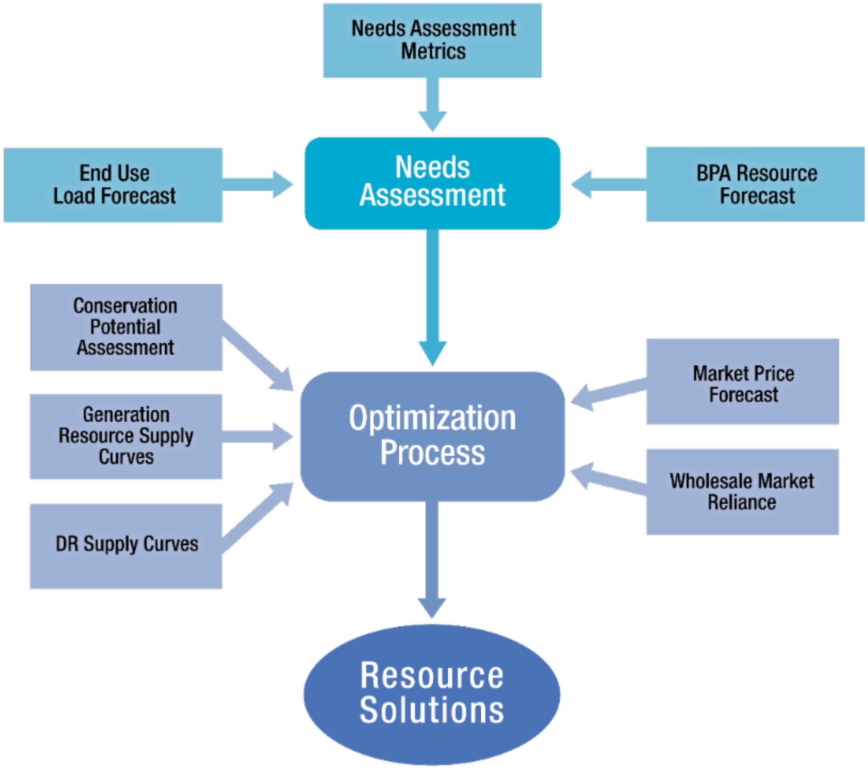
BPA's 2018-2023 Strategic Plan describes the actions it will take to remain a competitive supplier of low-cost power to its regional firm power customers. To support these strategic goals, the 2022 Resource Program details a comprehensive planning analysis that seeks to align BPA's resource acquisitions, including energy efficiency and demand response initiatives, with its long-term power supply needs.

The Resource Program is neither a decision document nor a process required by any external entity. Rather, it is a voluntary body of work, undertaken to inform acquisition strategies and provide valuable insight into how BPA can meet its obligations and strategic objectives at the least cost.

1.2 Methodology

The Resource Program begins with a forecast of BPA's obligations to supply firm power and the existing resources available to meet that demand, and then, determines any need for incremental energy or capacity in the Needs Assessment. The Resource Program next identifies and evaluates potential solutions to meeting those needs, including energy efficiency, demand response, candidate generating resources and power purchases. Finally, the Resource Program outlines potential strategies for meeting BPA's needs. Figure 1 provides a high-level diagram of the Resource Program process.

Figure 1: Resource Program Process



To assess the costs and benefits of resource solutions, BPA uses Aurora to create an electricity price forecast. Aurora is a computer software tool that can produce energy market price forecasts, value and uncertainty analyses, and automated system optimization. The energy market price forecast incorporates a natural gas price forecast, a renewables build forecast and assumptions around many other important factors, including regional generating resource retirements, negative price bidding activity and load forecasts for surrounding regions.

BPA also uses Aurora to perform a long-term capacity expansion and portfolio optimization analysis that assessed candidate resources' performances against 400 sets of potential future market conditions. The result of the optimization process is a set of 40 different portfolios that all meet Bonneville's needs at varying budget levels.

1.3 Conclusions

The below summarizes the main conclusions of the 2022 Resource Program:

- BPA has its greatest heavy load hour energy needs in October where large deficits are observed under low water conditions.

- By using a shorter historical period of streamflow record that represents the impacts of climate change on hydro generation, BPA expects more winter generation and less summer generation when compared to the use of a longer period of historical streamflows.

- BPA has surplus capacity in the winter and the summer, similar to the prior Resource Program.

- The expected market price for energy at the Mid-Columbia trading hub has increased over the market price forecast in the prior Resource Program.

- Similar to previous Resource Program findings, the least-cost mix of resources that will meet BPA's expected energy needs consists of conservation and energy purchased from the market. In addition, demand response was also included in the least-cost mix of resources for this Resource Program.

The following sections provide a more detailed look at the 2022 Resource Program. Additional files supporting the data sets shared in this report can be found at BPA's Resource Planning webpage.

Section 2: Needs Assessment

2.1 Overview

The Needs Assessment measures the federal system's[1] expected generating resource capabilities to meet projected load obligations under a range of conditions and timeframes for a 10-year study period, spanning fiscal years 2024-2033. The Needs Assessment studies occurred concurrently with a process to modernize the hydropower forecasts in the Bonneville Power Administration's long-term studies, as well as during a transition to using the 2020 modified streamflow data. BPA ultimately decided[2] to adopt the most recent 30 years of streamflow history, 1989-2018, in long-term forecasts rather than the historic 90-year record. BPA made this change in order to more realistically incorporate the impacts of climate change on federal system hydro generation.

As a result, the Needs Assessment reflects two streamflow sets: 1) the 2010 modified flows, which provide an 80-year period of record, hereafter "80-year study," and 2) the 2020 modified flows from which only 1989-2018 are used in the modeling, hereafter "30-year study." The 80-year study is included to help illustrate the change in energy and capacity positions due to climate impacts. However, the Resource Program analysis only carries the 30-year data forward into the optimization step of the process.

2.2 Methodology

The Needs Assessment incorporates hourly forecasts of federal system load obligations and resource capabilities.

Load obligations: BPA's Agency Load Forecasting system (ALF) produces load forecasts. ALF includes power sales contract obligations to public and federal agency customers and to the U.S. Bureau of Reclamation, as well as other contract obligations. ALF automatically includes projections of programmatic conservation savings expected to continue at levels established under current conservation programs. The Needs Assessment contains an ALF-produced frozen efficiency load forecast, which implements a combination of statistically adjusted end-use and econometric approaches. This means that historic energy efficiency achievement savings are projected forward in the load forecast, but the incremental conservation needed to meet the Northwest Power and Conservation Council's 2021 Northwest Power Plan targets are omitted from the load forecast.[3] ALF forecasting methodologies incorporate the most recent 15 years of regional temperatures, allowing the forecasts to incorporate the most recent climate trends. Also, the load forecast beyond the current Regional Dialogue contracts (post 2028) assumes no material contract election or rate structure differences from Regional Dialogue. ALF forecasts do not project additional temperature changes in the planning period.

Resources: BPA forecasts the resource capability using two computer models: 1) HYDSIM (Hydro System Simulator) for monthly and annual energy; and 2) Riverware for hourly energy and capacity. The models assess the resource capability to meet loads under expected load conditions and extreme temperature events over a range of possible water conditions and while meeting non-power requirements. The 80-

[1] Details on the federal system's generating capacity can be found in BPA's 2022 White Book.
[2] https://www.bpa.gov/-/media/Aep/power/hydropower-data-studies/climate-change-update-to-the-long-term-hydro-generation-forecast-letter.pdf [Accessed: 29 Aug 2022]
[3] The incremental conservation needed to meet the 2021 Northwest Power Plan targets and used to mitigate the deficits identified in this Needs Assessment will be discussed in section 4.4 – Portfolio Optimization Results.

year HYDSIM study used in the Needs Assessment is consistent with BPA's BP-22 Rate Case Final Proposal with updated flexible spill operations. To incorporate the federal system contract purchases and non-hydro generation in the study, the Riverware model operates to an hourly Federal Residual Hydro Load. The Federal Residual Hydro Load is the hourly federal load obligations minus the hourly contract purchases and non-hydro generation.

This assessment does not model any internal or regional transmission[4] constraints that may limit the ability to deliver the modeled system generation to load.

2.3 Studies & Metrics

As mentioned in the overview, the Needs Assessment focuses on two studies developed for FY 2024 through FY 2033: 80-year and 30-year. Depending on the study, up to four metrics, including annual energy and different capacity studies, were used to determine the ability of the federal system's generating capability to meet obligations.

- 80-year: This study uses data that is consistent with the federal system analysis load forecast in the BP-22 Rate Case Final Proposal, with the exception of including a frozen efficiency forecast. The 80-year study uses the 2010 modified streamflow data set, 1929-2008, and uses the 1937 water year as the critical, or firm, water condition.
- 30-year: This study uses data that is consistent with the federal system analysis load forecast in the BP-22 Rate Case Final Proposal, with the exception of including a frozen efficiency forecast. The 30-year study uses streamflow data from the most recent 30 years, 1989-2018, of the 2020 modified streamflow records from 1929-2018, or 90 water years.

The Needs Assessment used the following four metrics:

1. Annual Energy: This metric focuses on federal system annual average energy surplus/deficits under 1937-critical, or firm, water conditions. Only the 80-year study was used for this metric as it contains the 1937 water year and was consistent with the prior definition of firm annual energy at the time studies were produced. Future needs assements will instead use the "P10-by-month" definition of firm, which was recently adopted (see footnote 2 above).
2. Monthly P10 Heavy Load Hour Energy: This metric evaluates the lowest 10th percentile-by-month, or P10, of federal system surplus/deficit over heavy load hours. HLH refers to hour ending 07 to 22, totaling 16 hours each day, Monday through Friday; the other eight hours each day, Saturday and Sunday, and North American Electric Reliability Corporation holidays are light load hours. Each month is analyzed independently.
3. Monthly P10 Super-Peak Energy: This metric evaluates the P10 of federal system surplus/deficits over the six peak load hours per weekday by month. Each month is analyzed independently.
4. 18-Hour Capacity: This metric analyzes the federal system's ability to meet the six peak load hours per day over a three-day extreme weather event. Depending on the weather event, load obligations are adjusted for additional heating or cooling loads, and median water conditions are assumed for hydro generation. Additionally, load obligations assume that Canada requests maximum Canadian Entitlement energy deliveries available under terms of the Columbia River Treaty. Generating resources assume that wind generation is zero. Similarly, generation forecasts for the summer analysis— month of August—includes a 10% reduction in the Columbia Generating Station's generating capability to account for heat impacts on the CGS's cooling system. The Needs Assesment uses 80 water years to analyze the distribution of outcomes under different streamflow conditions.

[4] For additional detail on transmission, see the Transmission supplement section of BPA's 2022 Resource Program.

2.4 Results

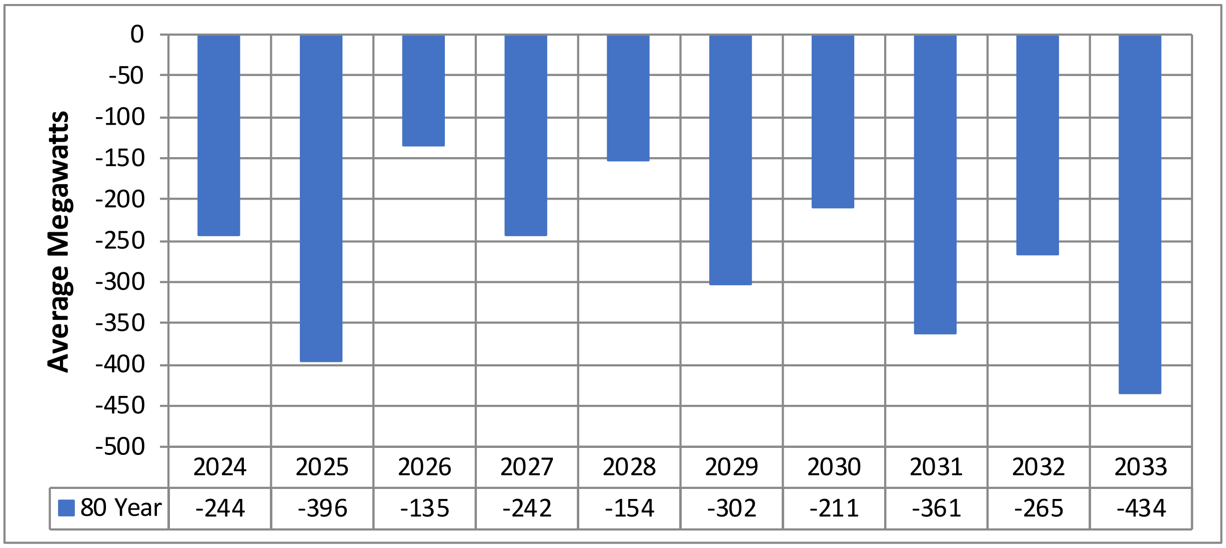
The Needs Assessment results show that the federal system has a wide range of potential deficits during the 10-year FY 2024-2033 period under the Annual Energy metric; see Figure 2. The Monthly P10 Heavy Load Hour metric shows larger deficits in October, January and the second half of April throughout the study period. The 30-year study shows less deficits in winter and more in August-October, consistent with trends of wetter, warmer winters and earlier streamflow recessions. Monthly P10 Super-Peak Energy metrics show deficits in the second half of April when low streamflows combine with significant increases in spill and restricted operating pools in the eight dams of the lower Columbia and Snake rivers; otherwise, the Super-Peak metric is surplus, and this result is consistent over the study period. Combined, the P10 HLH and Super-Peak metrics show that the system is generally able to serve the subset of six peak-load hours throughout the year under the low streamflow conditions, but the system is constrained for the full heavy load block in several months.

Lastly, the federal system is capacity surplus under the 18-Hour Capacity metric in both winter months (January) and summer months (August) when simulating increased loads due to extreme weather events. Previously, a single median water year was used to calculate this metric. Now, the full distribution of outcomes by water year is available. The distributions show that under the vast majority of water conditions, the system is able to serve the six peak-load hours each day during extreme weather over three consecutive days.

Annual Energy: The Annual Energy metric analyzes the ability of the federal system to meet energy loads on an annual basis.

> 80-year: Figure 2 shows a deficit of 244 average megawatts in FY 2024. The deficit grows to 396 aMW by FY 2025, recovers to 135 aMW in FY 2026, and then grows again to a deficit of 434 aMW by FY 2033. Hydro resources reflect the 2020 Columbia Rivers System Operations Environmental Impact Statement Preferred Alternative for the largest 14 federal dams. The difference between even and odd years is attributed to the Columbia Generating Station maintenance/refueling outage schedule. The decrease in deficit between FY 2025 to FY 2026 is due to the expiration of forward secondary surplus marketing activity that reduces obligations.

Figure 2: Annual Energy Surplus/Deficits – FY 2024 to FY 2033



Monthly P10 Heavy Load Hour Energy: Figure 3 presents the Monthly P10 HLH Energy metric for the 10-year study, and Figure 4 presents a selection of FY 2025-2026 to show the values in more detail. The metric analyzes the ability of the federal system to meet HLH loads on a monthly basis.

> <u>80-year</u>: HLH energy deficits occur in the winter months as well as late summer; the largest deficit is in the second half of April. This result is consistent over the entire study period. Large monthly HLH energy surpluses occur in the spring, which coincide with the peak Columbia River Basin runoff.
>
> <u>30-year</u>: The 30-year study presents similar results to the 80-year study, with deficits in April and over the winter months. March in the 30-year period changed to a surplus month, and the surplus in June decreased, consistent with earlier spring runoff. The 30-year study is also showing deeper deficits in the summer and fall consistent with earlier streamflow recessions.

Figure 3: P10 HLH Surplus/Deficits – FY 2024 to FY 2033

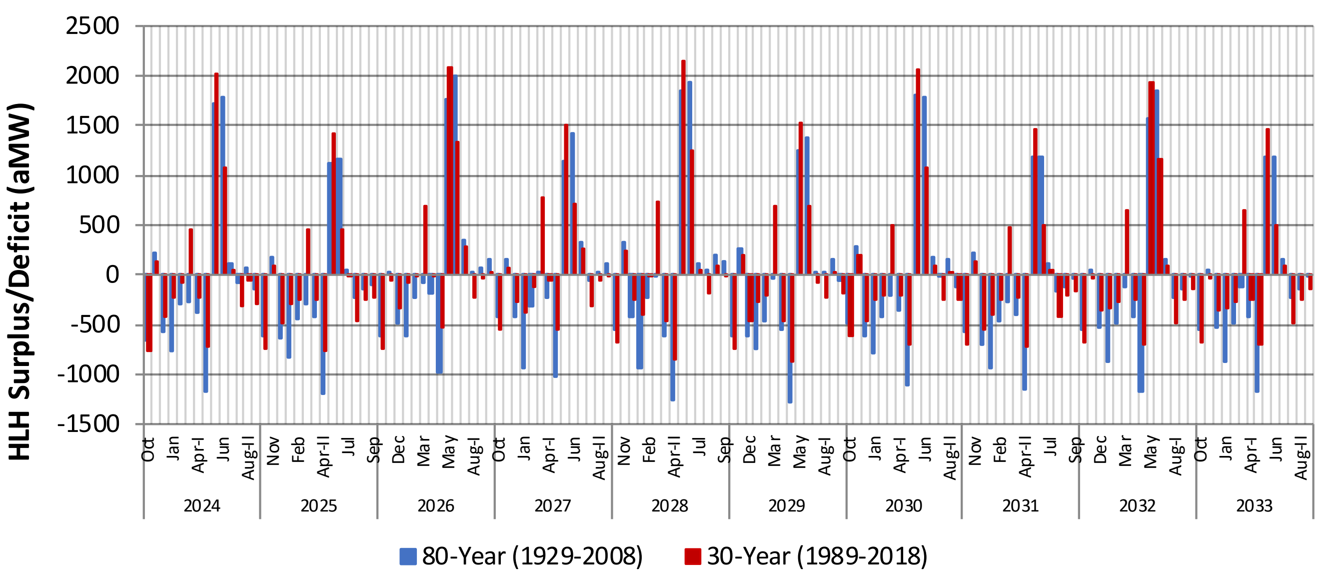


Figure 4: P10 HLH Surplus/Deficits – FY 2025 to FY 2026 (close-up look)

	2025													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr-I	Apr-II	May	Jun	Jul	Aug-I	Aug-II	Sep
80-Year (1929-2008)	-618	185	-640	-836	-453	-299	-425	-120	1120	1159	51	-220	-150	-94
30-Year (1989-2018)	-740	102	-492	-290	-255	464	-248	-761	1421	465	-7	-473	-249	-234

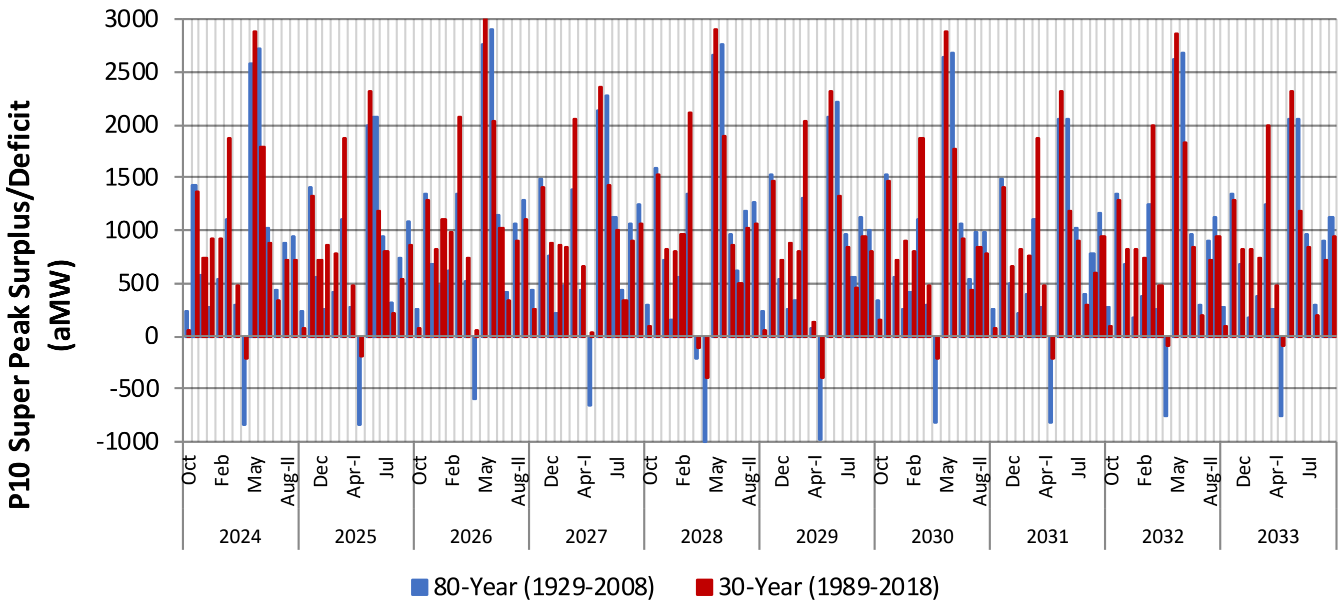
	2026													
	Oct	Nov	Dec	Jan	Feb	Mar	Apr-I	Apr-II	May	Jun	Jul	Aug-I	Aug-II	Sep
80-Year (1929-2008)	-620	30	-497	-620	-226	-69	-189	-979	1767	2008	343	31	70	166
30-Year (1989-2018)	-744	-57	-338	-86	-18	699	-13	-528	2085	1328	280	-226	-35	26

Annual P10 Super-Peak Energy: Figure 5 shows the Monthly P10 Super-Peak Energy metric, which evaluates the ability of the federal system to meet loads over the six peak-load hours per weekday by month.

<u>80-year</u>: P10 Super-Peak resulted in annual surplus throughout the study period. Monthly analysis shows deficits in April.

<u>30-year</u>: The 30-year study reflects the same finding as the 80-year study, except the April deficit is smaller. The Super-Peak shows similar changes in results as the P10 HLH metric: surplus increases in winter, relative to the 80-year study, and decreases in the summer.

Figure 5: P10 Super Peak Surplus/Deficits – FY 2024 to FY 2033

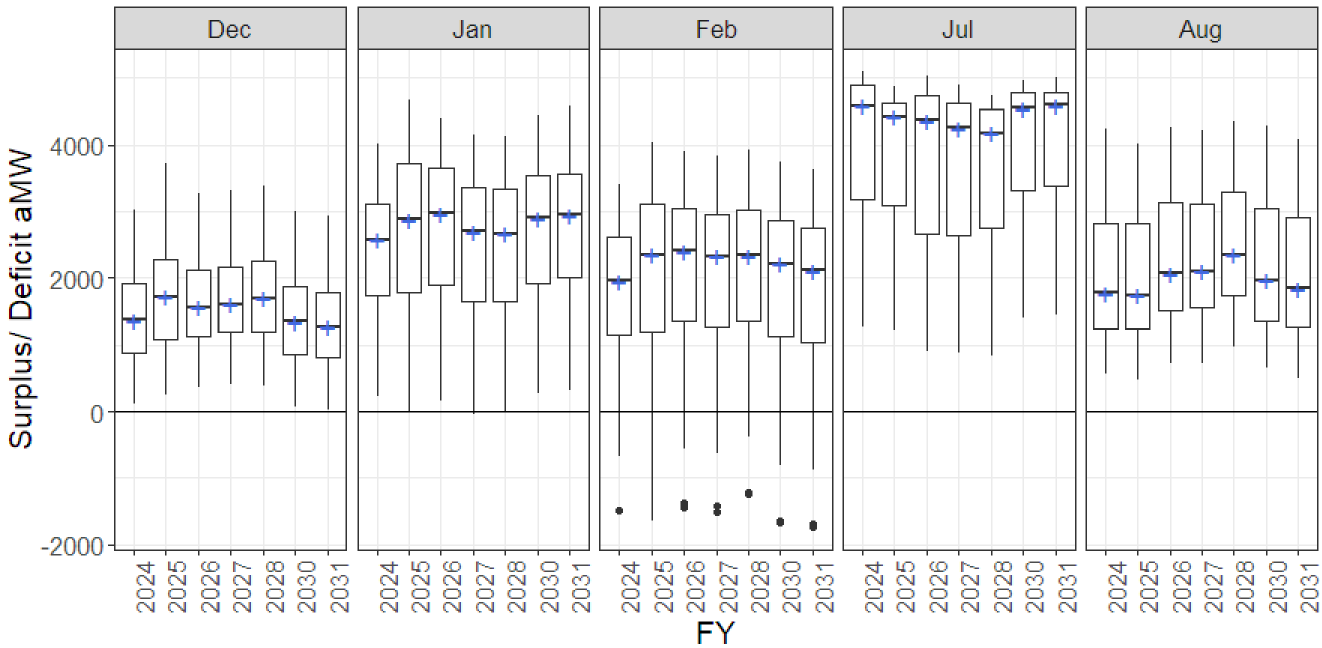


18-Hour Capacity: The 18-Hour Capacity metric analyzes the ability of the federal system to meet loads over the six peak-load hours per day during a three-day extreme weather event – a heat event during summer and cold event during winter – under median water conditions. Only the 80-year study was analyzed under this metric. The months of December, January and February were analyzed for winter seasons; the months of July and August were analyzed for summer seasons. In this Needs Assessment, the extreme weather condition can be viewed for all 80 years, instead of for only a specific year.

Figure 6 presents the distribution of results as boxplots with each end of the box representing the first quartile, or 25%, and third quartile, or 75%, of the data distribution; the middle bar with a blue (+) marks the median, or 50th percentile. The 50th percentile is used to represent the median water conditions for each month. The ends of the whiskers indicate the maximum and minimum data points, and the dark dots outside of the whisker ends are observations outside 1.5x the interquartile range from the bottom of the box, which are the outlier points.

> 80-year: Results show 18-Hour Capacity surplus/deficits for the winter (January) and summer (August) during the FY 2024-2033 period; however, there is no data for years 2029 and 2032 as unresolvable data issues were discovered. The 18-Hour capacity results show a range of surpluses between approximately 2,500 MW to almost 3,000 MW in the winter, and a range of roughly 1,700 MW to 2,300 MW in the summer over the study period.

Figure 6: Distributions of 18-Hour Capacity Surplus/Deficits



2.5 Conclusions

The current Needs Assessment shows that BPA would need to supplement existing federal system generation in order to meet existing and projected load obligations during the conditions modeled. With expected load growth, the federal system is projected to have annual energy deficits under critical water conditions across the study period.

Under low-water conditions, the federal system is projected to have HLH energy deficits, most notably in the winter and late summer, and to have surpluses under the Super-Peak and the 18-Hour Capacity metrics. The 18-Hour Capacity metric does not show constraints for either winter or summer seasons. Of the energy and capacity metrics analyzed, HLH energy is projected to have the largest deficits, and therefore, is the most constraining metric.

Under current climate change expectations, the federal system is projected to have lower HLH energy deficits or higher energy surpluses during the winter period. This is due to higher winter streamflows resulting from the warmer temperatures. Conversely, the federal system is projected to have higher HLH energy deficits in the summer due to lower summer streamflows.

Overall, the Needs Assessment results are consistent with that of the 2019 Needs Assessment results with respect to the P10 HLH metric deficits representing the most constrained periods and conditions for BPA to meet its obligations. BPA will continue to assess the need for additional generation based upon potential changes to environmental obligations, participation in the Western Resource Adequacy Program, and the loads placed upon BPA through the Provider of Choice process. Changes to the Needs Assessment in future Resource Programs will include an updated annual energy metric, which will be based on monthly P10 hydropower and potentially include enhancements to how capacity is modeled.

Section 3: Candidate Resource Assessment

3.1 Candidate Generating Resources

The 2022 Resource Program includes an expanded array of zero-emission resources and updated resource costs to reflect developments in renewable generation technologies after the publication of the 2020 Resource Program.

Resources are selected for the optimization based on technical availability within the region and over the study horizon; they are not pre-screened based on relative levelized costs of energy or capacity. The optimization process evaluates the value of expected generation and expected capital in addition to the operation costs of each resource.

The section below summarizes the resource plant types considered for the 2022 Resource Program.

- **Wind:** BPA modeled two types of wind resource, Columbia Basin onshore wind and Oregon coast offshore wind, using costs based on the U.S. Energy Information Administration, or EIA, Annual Energy Outlook,[5] estimates from the National Renewable Energy Laboratory, or NREL, and wind cost forecasts provided by consultants. For Columbia Basin wind, BPA estimated wind output for the forecast period using its risk model designed for rate-setting evaluations in conjunction with Aurora.
- **Solar:** Single-axis tracking utility-scale solar resource costs likewise reflect a blend of EIA, NREL, and consultant cost forecasts and include the latest information on tax credits and tariffs. BPA chose three representative solar generation shapes – southeast Idaho, south-central Washington, and Oregon west of the Portland metropolitan area – to reflect different possible solar output profiles in the BPA region, differing installation costs in metropolitan areas, and a list of locations provided by BPA Transmission Services that may benefit BPA's transmission system.
- **Paired solar and storage:** BPA added three solar and storage resources to the set of available resources for the 2022 Resource Program. The representative generation shapes for these resources are the same as above and are paired with a four-hour battery storage system where capacity is equal to half of the solar nameplate capacity.
- **Standalone six-hour battery storage:** BPA added one standalone battery storage option, modeled as a six-hour lithium-Ion battery system.
- **Zero-emission firm flexible resources:** BPA modeled two zero-emission firm flexible resource options with availability starting in 2028 and later. These resources are not intended to represent a specific generation type, but rather, provide a plausible cost trajectory for several types of zero- or net-zero emissions resources.
    - Base: High-fixed cost, low-variable cost resource. Modeled after small modular nuclear reactor characteristics; also comparable to a traditional fossil fuel base resource with carbon capture and sequestration.
    - Peaker: Low-fixed cost, high-variable cost resource. Modeled after a hydrogen combustion turbine with onsite electrolysis and storage; also comparable to combustion turbine running on other bio/renewable fuels or traditional resources.

[5] https://www.eia.gov/outlooks/aeo/

3.2 Conservation Supply Curves

3.2.1 Overview

Prior to the 2018 Resource Program, BPA had included conservation as a fixed input. In the past, a share of the conservation target from the Northwest Power and Conservation Council's Power Plan was assumed to be achieved by its public power customers. That amount of conservation was included as a predetermined resource that would be applied to meet BPA's needs. The remaining needs would then be met with other potential resources after accounting for expected savings from conservation.

Since the 2018 Resource Program enhancements, BPA now assesses conservation in line with other available supply and demand-side resources. An available amount of conservation is input into the optimization model, which then compares and selects resources based on need, availability and cost. To determine the amount of conservation to be used in the optimization model, BPA relies on a conservation potential assessment (CPA). The CPA identifies the amount and costs of energy efficiency measures available from the forecasted customer loads supplied by BPA over the planning horizon. This ensures all potential conservation is included and evaluated against competing alternatives in the optimized selection process.[6] In preparation for the 2022 Resource Program, BPA contracted with Cadmus Group and Lighthouse Energy Consulting to conduct a CPA.

3.2.2 Adjusting for 2022 and 2023 Energy Efficiency Accomplishments

While the Resource Program's evaluation period begins with 2024, the load forecast developed by BPA for use in the Resource Program was developed in 2020 and does not incorporate future energy efficiency savings achieved by BPA and its customer utilities in 2020-2023. To ensure that the Resource Program properly accounted for BPA's loads and resources, BPA's Energy Efficiency Organization supplied the Resource Program team with adjustments to account for the additional savings that would be achieved in these years. The adjustments were provided as "must take" resources—resources the Resource Program was forced to select, since they reflected energy efficiency that would be accomplished by 2024.

For the portion of 2020 not included in BPA's load forecast and all of 2021, the Cadmus/Lighthouse team mapped BPA's actual accomplishments to load profiles and developed hourly inputs for the Resource Program.

For 2022 and 2023, the CPA potential was not provided to the Resource Program. In its place, the Cadmus/Lighthouse team provided hourly estimates based on BPA's overall expected level of savings mapped to different distributions of savings. Forecasts developed by BPA projected 37.85 average megawatts per year of energy efficiency. The Cadmus/Lighthouse team used the distribution of BPA programmatic achievements in 2021 to estimate the distribution of savings in 2022 and the distribution of CPA potential in 2024 below a levelized cost of $45 per megawatt hour for 2023.

Incorporating these adjustments developed a more accurate forecast for the potential conservation savings starting in 2024, the beginning of the 2022 Resource Program's evaluation period.

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[6] The full CPA, including methodological discussion, is available on BPA's website: BPA-Conservation-Potential-Assessment-2022-2043.pdf

3.3 Demand Response Supply Curves

Since the 2018 Resource Program, BPA also assesses demand response equivalent to other available supply and demand-side resources. As with conservation, available amounts of demand response are input into the optimization model, which then compares and selects resources based on need, availability and cost. To determine the amount of demand response to be used in the optimization model, BPA relies on a demand response potential assessment (DRPA). The DRPA ensures all potential demand response is included and evaluated against competing alternatives in the optimized selection process.

In preparation for the 2022 Resource Program, BPA contracted with Cadmus Group and Lighthouse Energy Consulting to conduct a DRPA. The assessment identified 19 DR products with distinct cost and seasonal profiles. The full potential assessment, including methodological discussion, is available on BPA's website[7].

3.4 Wholesale Energy Market

3.4.1 Wholesale Market Price Forecast

Bonneville used Aurora with the Western Interconnection, a zonal topology, to generate a 10-year forecast of Mid-Columbia prices. This forecast consists of a distribution of 400 risk-informed hourly forecasts sampled two weeks per month.[8] Each of the 400 forecasts is based on a unique water year sequence, natural gas price forecast, Western Electricity Coordinating Council-wide load forecast, hourly wind generation pattern, Columbia Generating Station outages schedule and hourly transmission path rating, as applied to the alternating current, direct current and British Columbia-United States interties. The price at a given energy hub is determined by the cost of delivering an incremental megawatt of energy to load, including transmission costs and energy losses, provided by the least-cost available resource.

The WECC load forecast is consistent with BPA's 2020 baseline projection, except for California, which has been updated to be consistent with California Energy Commission's 2019 Integrated Energy Policy Report's Mid Demand-Mid Available and Achievable Load Forecasts.[9]

Natural gas prices are typically a significant determinant of electricity prices because gas generators tend to be the marginal unit, or the least-cost generator available to supply an incremental unit of energy, and the price of natural gas is the predominant factor affecting the dispatch, or production, cost of natural gas-fired generators. Relative to the 2020 Resource Program, there were modest declines in projected natural gas prices over the forecast horizon. The declines are a result of the expectation for plentiful production of low-cost associated gas produced by oil-focused extraction activity.

Several processes inform BPA's forecast of WECC-wide resource retirements and builds used in the price forecast and market depth studies. First, data from the EIA's database of planned and sited resource additions and retirements over the horizon of the BP-22 rate period were referenced against additional data from sources such as BPA's Transmission Interconnection Queue, WECC's Transmission Expansion

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[7] https://www.bpa.gov/-/media/Aep/energy-efficiency/demand-response/bpa-demand-response-potential-assessment-2022-2043.pdf

[8] For more information about Aurora and the risk models employed to produce this forecast, see the Power Market Price Study and Documentation, BP-22-FS-Bonneville-04.

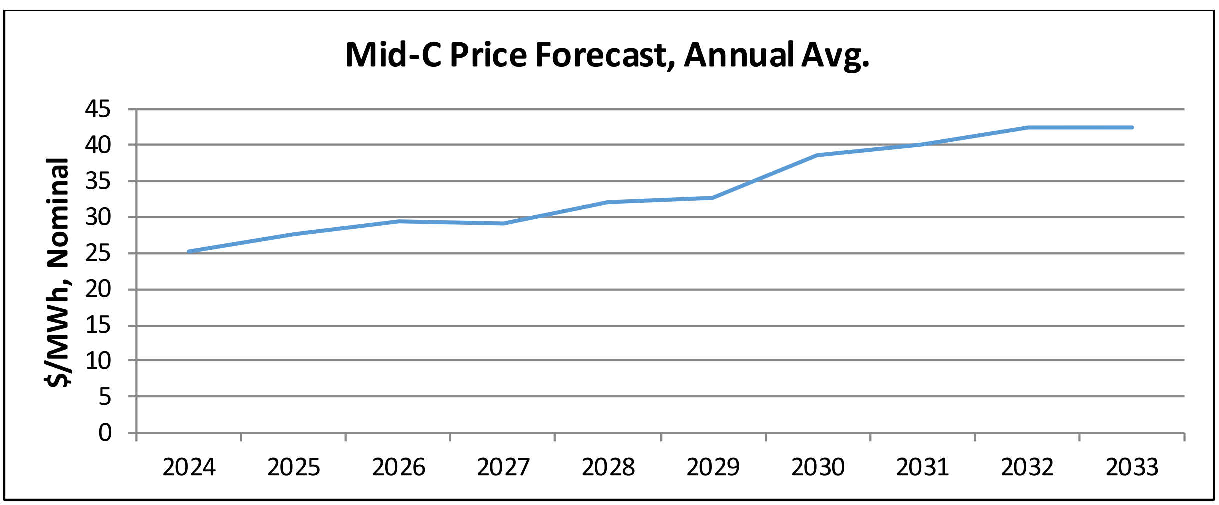
[9] https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03, accessed Mar 2, 2021.

Planning Policy Committee, the California Energy Commission, the California Public Utilities Commission, and third-party consultant reports to update the default Aurora resource stack. Additionally, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California were included from the California Energy Commission forecast and from integrated resource plans of utilities in the Southwest. Finally, the Aurora long-term capacity expansion model was used to build and retire additional resources based on economics to satisfy pool planning reserve margins and meet all relevant state, municipal and utility policies, including renewable portfolio standards, zero emission targets and electric sector emission caps.[10]

BPA's Aurora price forecast also adds two adjustments to resource bidding behavior that have substantial impacts on the resulting distributions of price forecasts. First, BPA runs Aurora using a recent historical period, i.e., 2014-2019, and calibrates thermal resource bidding behavior to better align Aurora prices with actual, day-ahead hub prices during the period. Second, BPA includes a simplistic depiction of negative bid behavior for renewable resources driven, for instance, by federal production tax credits for wind resources, renewable energy credits and power purchase agreements. All WECC renewable resources are given bid adjustments of about -$23 per megawatt-hour, which is nominal. These assumptions and additional modeling enhancements, such as the use of Aurora's commitment optimization logic, resulted in a distribution of price forecasts that is higher than the price distribution used in the previous Resource Program. The main driver for higher prices is the combination of a tighter resource buildout, where reliability requirements are just barely met, and the addition of calibrated thermal resource bidding behavior. Price increases are most acute in summer and winter months and in iterations with low hydro conditions.

The following figures depict the Mid-C price forecasts. Figure 7 shows an annual average price for all hours by year. Figure 8 presents average monthly prices for all hours by each month for the years 2024, 2028 and 2032. Figure 9 depicts prices averaged by hour for the years 2024, 2028 and 2032. Figure 10 is a comparison between the Mid-C price forecasts for the 2020 and 2022 Resource Programs for heavy load hours (HLH) and light load hours (LLH).

Figure 7



[10] State policy requirements within the WECC enacted as of July 1, 2021. Additional clean energy goals and policies at the municipal and utility level are included, but have been discounted by 20% to represent uncertainty about the extent to which these commitments will be upheld over the forecast horizon.

Figure 8

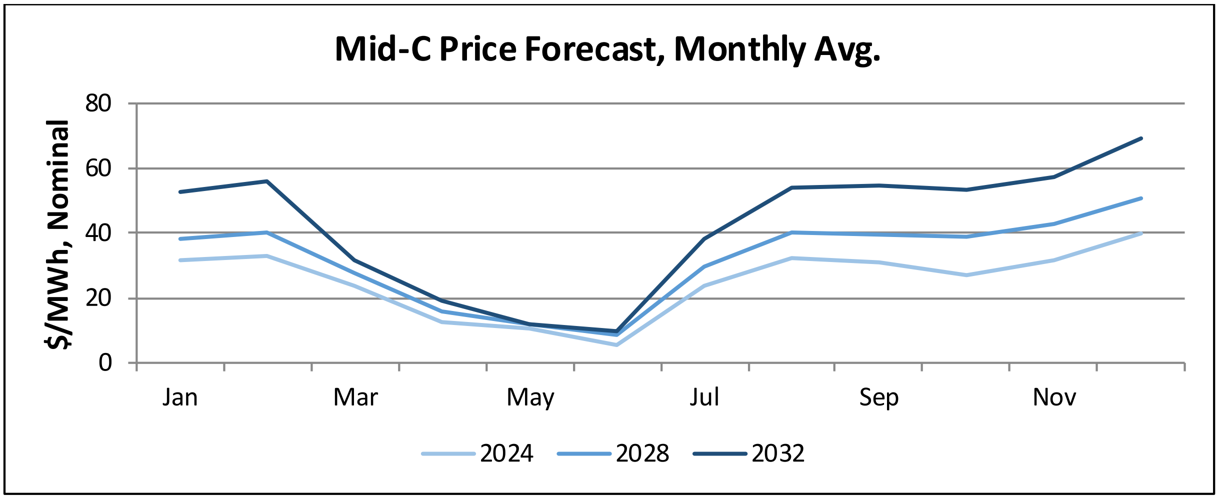


Figure 9

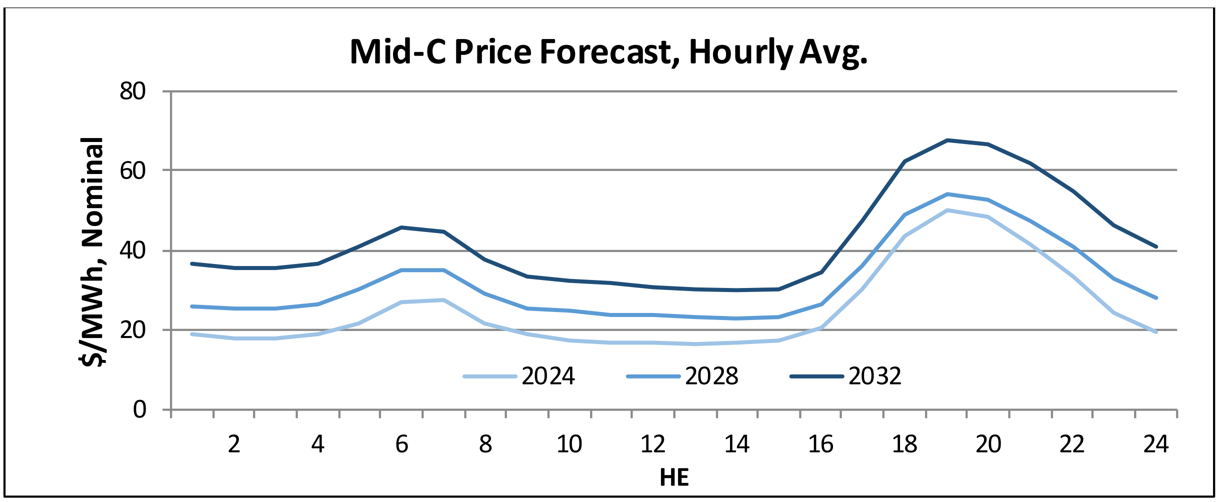
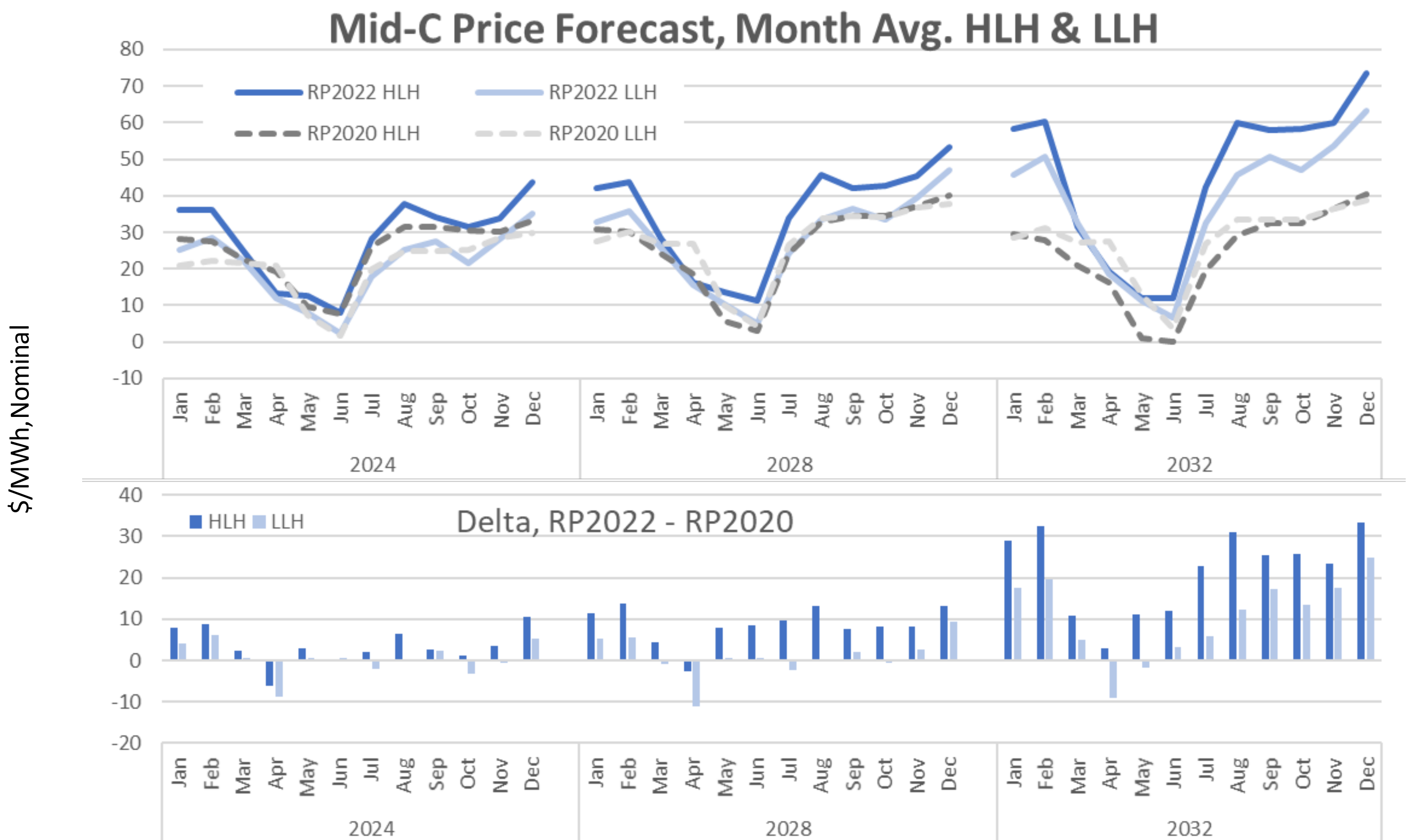


Figure 10



3.4.2 Market Reliance Limit

Given expected fundamental changes in energy markets across the WECC driven by growth in zero-emission resources, BPA used Aurora to assess future energy availability and establish monthly market reliance limits for the 10-year planning horizon. The process begins with a resource build assumed to reflect zero market reliance, i.e., all balancing authorities meet their reliability needs individually, without relying on other BAs or regions. Next, BPA uses incremental reductions in regional resources[11] to represent increases in market reliance. Higher levels of market reliance are tested until the exceedance of the 5% loss-of-load probability threshold. Up until that point, it is assumed that the region can rely on market exchanges to meet energy needs rather than building or maintaining additional resources. BPA is then allocated a share of the market availability proportional to its share of regional load. This sets BPA's market reliance limit, expressed in terms of monthly average heavy-load-hour megawatts. It should be noted that this methodology does not anticipate or account for evolving market structures, such as wider adoption of an Energy Imbalance Market or a WECC-wide Independent System Operator. The estimate simply reflects expected physical energy availability given projections of WECC load-resource balance and transmission capabilities.

[11] Testing all combinations of resource removal would be computationally prohibitive; instead, BPA uses monthly flat load increases to represent the loss of resource availability.

Section 4: Resource Optimization

4.1 Overview

The Bonneville Power Administration uses Aurora to calculate least-cost and risk-reducing[12] resource options that satisfy its needs throughout the 10-year planning horizon. These portfolios further inform BPA's resource strategy, including information on the amount of Energy Efficiency Incentive funding, which may be invested over the upcoming rate period.

4.2 Long-term Capacity Expansion

The 2022 Resource Program added a resource optimization step using the Aurora long-term capacity expansion study type. This study uses an iterative mixed-integer program to solve for the least-cost set of resource options that meet BPA's 10th-percentile, or p10, heavy load hour needs. It does so at greater granularity than the portfolio optimization and ensures that existing resources and new selections are meeting system energy and capacity obligations, if present.

While the portfolio optimization study optimizes over the distribution of 400 traces at the monthly diurnal level, the long-term capacity expansion, or LTCE, uses hourly granularity for the resources available to meet BPA's p10 HLH obligations. This allows a more precise optimization of least-cost resource strategies while using more detailed market costs and availability, generation resource output profiles and cost, and energy-efficiency and demand-response savings profiles and costs. The least-cost resources built in the LTCE meet BPA's p10 HLH obligations and are then fed to the portfolio optimization study as "must-build" resources. The portfolio optimization will then evaluate these resources according to the varying loads, resources, market prices and applicable wind risk in each of the 400 traces in the input distribution. Portfolio optimization then uses the performance of each resource in each run to conduct the portfolio analysis.

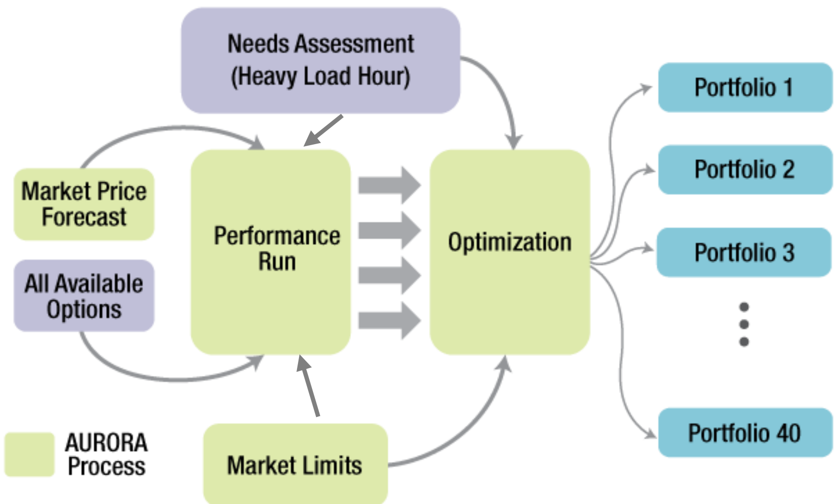
4.3 Portfolio Optimization

Figure 11 depicts the overall process and key inputs for the portfolio optimization study. Resource Program staff begin by evaluating all resource options discussed in Section 3 to assess their individual performance in each of the 400 sets of inputs. The 400 zonal runs, called the performance runs, each contain a different mix of needs, market prices, gas prices and wind risk and allow the portfolio optimization study to evaluate each resource according to those differing conditions.

Market reliance limits are also applied in the 400 zonal runs via a second zone that represents the Mid-C hub as well as transmission links between the BPA zone and the market zone that correspond to the monthly HLH market reliance limit. These limits also serve as constraints for the optimization step.

[12] "Risk" is defined here as variation of total portfolio costs across the 400 market price forecasts; see market price forecast, Section 3.4).

Figure 11



Aurora employs a linear optimization to jointly solve for the least-cost solution of meeting energy needs over the 10-year planning horizon – or Portfolio 1 – subject to market costs, market reliance limits and resource constraints. Portfolio 1 is selected by lowest average cost, over the 10-year study horizon, across the 400 price sets without considering the variance in portfolio cost across the 400 iterations. The model then solves for portfolios that minimize variation of total portfolio costs at progressively higher total portfolio cost levels on average.[13] The risk-minimizing portfolios can be thought of as hedges against market price volatility or streamflow conditions, or both. Each successive portfolio has a higher budget constraint and allows for the purchase of more resources that are not least-cost but provide greater insulation against market price swings or streamflow conditions.

This results in a series of portfolios that create an efficient frontier, as demonstrated in Figure 12. The frontier is efficient in the sense that at any given cost point, there is no other combination of available resources that would reduce the variation of total portfolio costs. Therefore, all portfolios above the efficient frontier are suboptimal because their costs can either be reduced without an increase in variance, or their variance can be reduced without an increase in cost. Alternatively, both cost and variance can be reduced to arrive at a better performing portfolio.

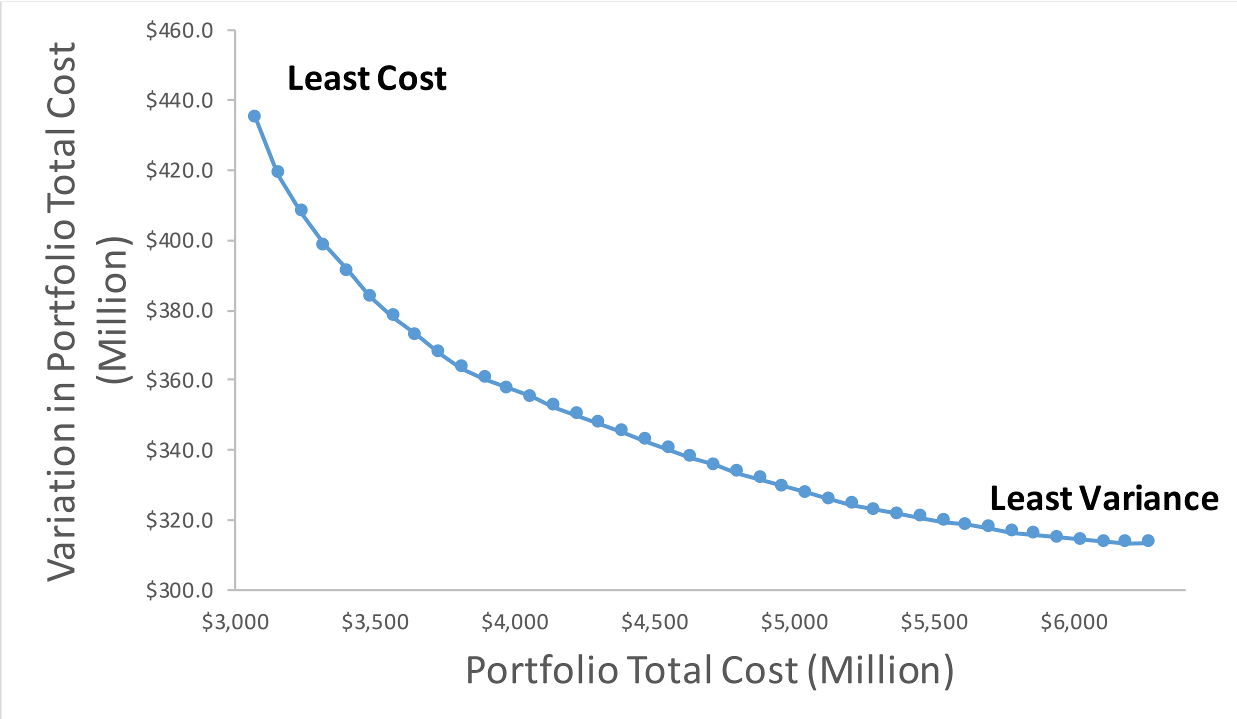
4.4 Portfolio Optimization Results

The Aurora portfolio optimization process produces an efficient frontier with 40 different resource portfolios. Figure 12 shows the model output of the 40 different portfolios for the 2022 Resource Program. These results are characterized by diminishing returns to the risk-reducing portfolios – the

[13] After finding the least-cost portfolio, the optimization model then solves for a portfolio with the lowest total cost variation, in terms of total portfolio cost standard deviation, without regard for total cost level, known as Portfolio 40. These two portfolios become end points of an efficiency curve. The range of average total portfolio cost is then split up according to the number of desired portfolios - BPA selected 40. For each point along this range, the optimization model solves for a portfolio of resources that minimizes total portfolio variation without exceeding that particular total cost level.

greatest reduction in variance is from the first portfolio to the second, and each successive portfolio achieves a smaller decrease than the last.

Figure 12



Given the changes in resource costs, BPA's loads and resources, the market prices forecast and market purchase limit, results have shifted from the 2020 Resource Program. The Resource Program team also made a number of improvements to the Aurora model that is used for the Resource Program analysis. The primary drivers of the difference from the prior Resource Program are as follows.

1. **Updated water years in the needs assessment:** The set of water years used to calculate BPA's p10 HLH needs has been updated since the prior Resource Program. The agency now bases its forecasts on the 30 water years between 1989 and 2018 rather than the 80 water years comprising the 1929 to 2008 period. This updated set of historical streamflows better captures the impacts of climate change on BPA's system and results in a shift of the monthly period with the greatest needs from January HLH to October HLH.
2. **Improved resource selection:** Refinements to the Aurora model for the 2022 Resource Program, in comparison to the 2020 Resource Program, allow resource selection in any year, rather than in one year, for energy efficiency and demand response, or two years, for generating resources. This allows the model to consider the cost effectiveness of each resource in each year, rather than the overall cost effectiveness of each resource across the entire study horizon. The main effect of this is that resource selections are lower in the initial years, approximately the same in the middle years, and substantially higher in the later years in comparison to the prior Resource Program as resource selections ramp up to meet load growth beyond 2029.
3. **Higher market price forecast:** On average, higher market prices make energy purchases more expensive and surplus energy more valuable. In general, because purchases tend to be made in expensive hours, higher market prices lead to higher overall portfolio total cost while also

increasing the opportunity for energy efficiency and demand response to be less expensive than market purchases.

In the basecase for the 2020 Resource Program, all 40 portfolios contained only energy efficiency and market purchases. For the 2022 Resource Program, in addition to energy efficiency and market purchases, demand response was also selected in all 40 portfolios, and generating resources were selected in portfolios two through 40.

Table 1 shows the energy efficiency acquisitions in the three lowest-cost portfolios. Compared to the 2020 Resource Program, energy efficiency acquisitions in the least-cost portfolio are slightly lower in the first two years of the 2022 Resource Program, but ramp up quickly, acquiring nearly 200 aMW more energy efficiency by the final year of the study than the 2020 Resource Program.

Table 1. Energy Efficiency Acquisitions of the Lowest-Cost Portfolios

	Cumulative Energy Efficiency Acquired (aMW)		
Portfolio	**2-Year**	**4-Year**	**10-Year**
1	96	223	723
2	103	242	785
3	105	245	787

Table 2 and Table 3 show the DR and generating resource selections in the three lowest-cost portfolios.

Table 2. Demand Response Acquisitions of the Lowest-Cost Portfolios

	DR Acquired (Peak MW)					
Season	**Summer**			**Winter**		
Portfolio	**2-Year**	**4-Year**	**10-Year**	**2-Year**	**4-Year**	**10-Year**
1	213	436	371	158	283	243
2	213	474	488	158	283	260
3	213	474	488	158	283	260

Table 3. Generating Resource Acquisitions of the Lowest-Cost Portfolios

	Generating Resource Solutions					
Resource	**Offshore Wind (Nameplate Capacity, MW)**			**Solar PV (Nameplate Capacity, MW)**		
Portfolio	**2 Year**	**4 Year**	**10 Year**	**2 Year**	**4 Year**	**10 Year**
1	0	0	0	0	0	0
2	0	0	106	0	0	500
3	0	0	428	0	0	500

4.5 Conclusions

The resource solutions produced by portfolio optimization and detailed in section 4.4 indicate that the most economical solution for BPA to meet its energy obligations continues to be a combination of market purchases and demand-side resources. Energy efficiency and low-cost demand response were acquired in the least-cost portfolio up until it was as expensive as market purchases, and then the optimization solved for the remaining needs with market purchases. Low-cost energy efficiency remains BPA's preferred resource to meet identified energy needs.

The demand response resources were selected to meet short-duration energy needs in the months with the highest market prices. BPA did not identify a capacity need in the Needs Assessment, so these demand response resources are being dispatched to satisfy short-duration energy needs in the most expensive hours.

It is important to note that while the Needs Assessment looks at Bonneville's loads and resources in isolation, other regional studies have identified future capacity shortfalls in meeting the entire Pacific Northwest's load. BPA's system is expected to have surplus capacity, which is anticipated to become increasingly valuable as thermal generation continues to be retired from the grid in accordance with de-carbonizing legislative goals.

Additionally, the Needs Assessment does not analyze the use of the federal system to provide balancing services for variable energy resources. Instead, it specifically retains the federal system's capacity for service to BPA's statutory obligations. These and other issues are addressed in separate forums; the 2022 Resource Program results should not be viewed as representing the capacity needs for the entire region or any other specific entities within it.

Section 5: High Policy Scenario

5.1 Purpose

The Bonneville Power Administration modeled a high policy scenario in addition to the basecase. This scenario represents a plausible high electrification and decarbonization case while also providing a look at the least-cost resource builds that would be required to meet BPA's obligations in such a future.

The Resource Program team does not place any specific likelihood on the high policy scenario assumptions occurring. BPA will continue to monitor future load growth; should conditions such as those assumed in the high policy scenario begin to materialize, the high policy scenario enables the agency to adapt its resource strategies accordingly.

5.2 Assumptions

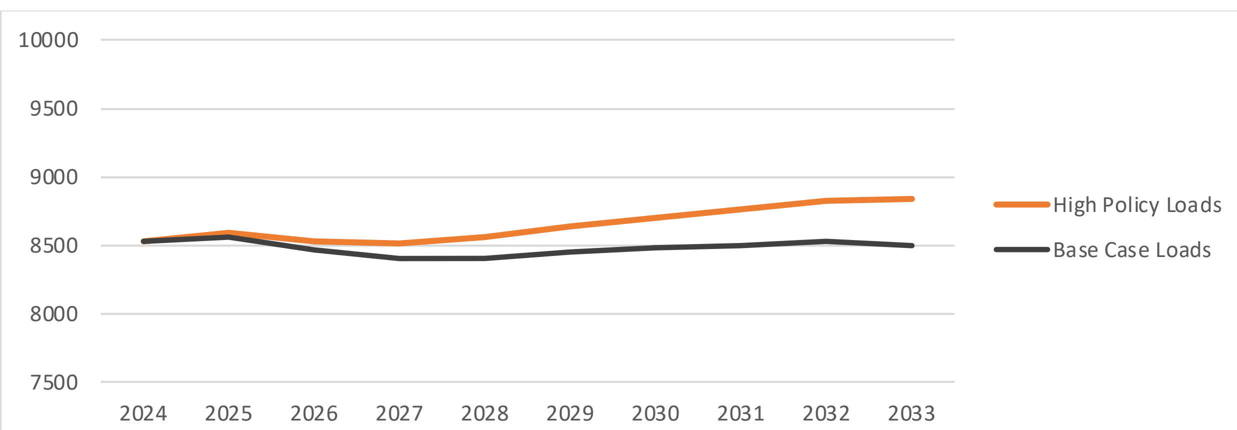
The high policy scenario represents a possible outcome given accelerated electrification and decarbonization policies in the western U.S. In this scenario, California carbon pricing is applied to Oregon and Washington, Western Electricity Coordinating Council-wide carbon pricing begins in 2030, and all states aim for 100% zero-emissions by 2050. Specific changes to the basecase assumptions are detailed below.

5.2.1 Obligations

The Resource Program team escalated the basecase distribution of BPA's monthly heavy load hour obligations using regional load growth rates provided by BPA Load Forecasting. The high policy load forecast assumed no change in the BPA customer base post-2028. It does assume accelerated adoption rates for electrification technologies and practices, such as electric vehicles, behind-the-meter solar and fuel switching from gas to electricity.

Excluding large new loads, which would be served at the New Resource rate, BPA estimated average annual growth of 0.43% over the study horizon. This results in roughly 4.5% growth over the basecase for the 10 years in the study horizon. The growth over the basecase is shown in Figure 13.

Figure 13



5.2.2 Resources

The Resource Program team made small reductions to the cost of renewable resources and battery storage for the high policy scenario. These adjustments reflect policies in the high policy scenario designed to facilitate the adoption of renewable generation and energy storage technologies.

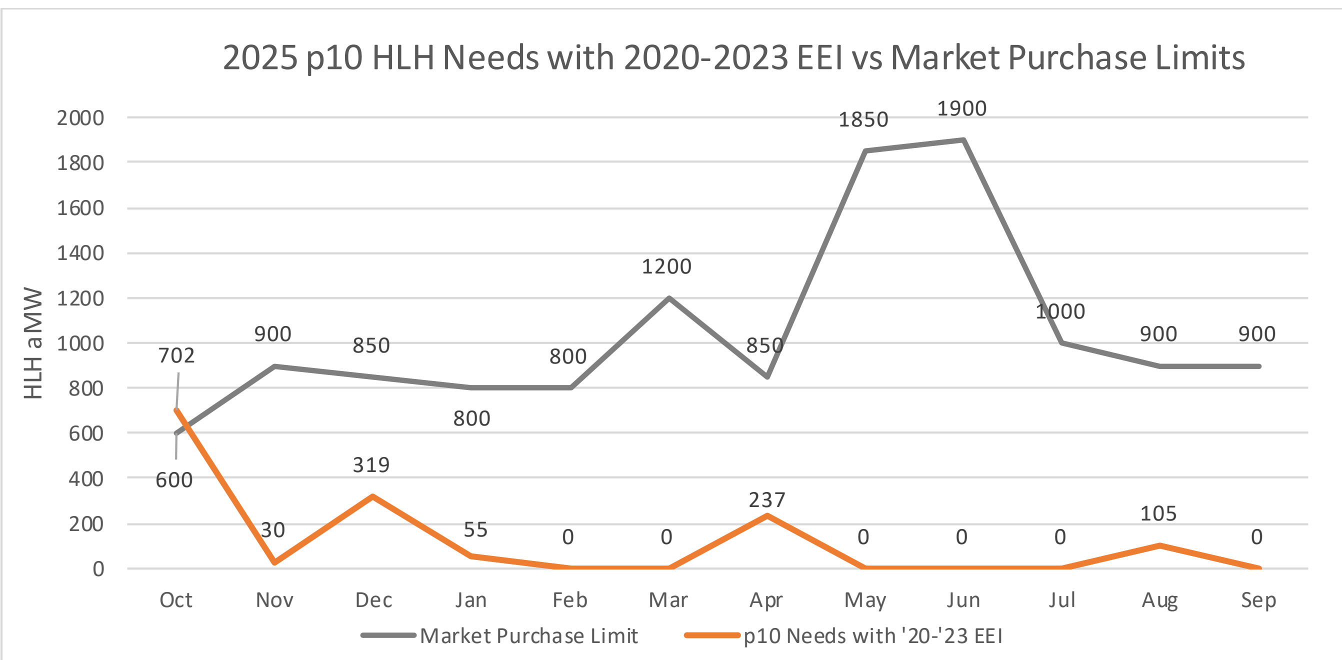
5.2.3 Market Prices and Limits

The policies associated with the high policy scenario result in a decrease in the overall market price forecast for the high policy scenario versus the basecase. Market prices are also lower in the high policy scenario during both January and October heavy load hours across the study horizon. January HLHs are typically characterized by higher-than-average market prices, and October HLHs have the greatest deficit between BPA's needs and market purchase availability. Periods with high market prices and periods with low market availability but high system needs will influence the resources selected in the portfolio analysis.

5.3 Results

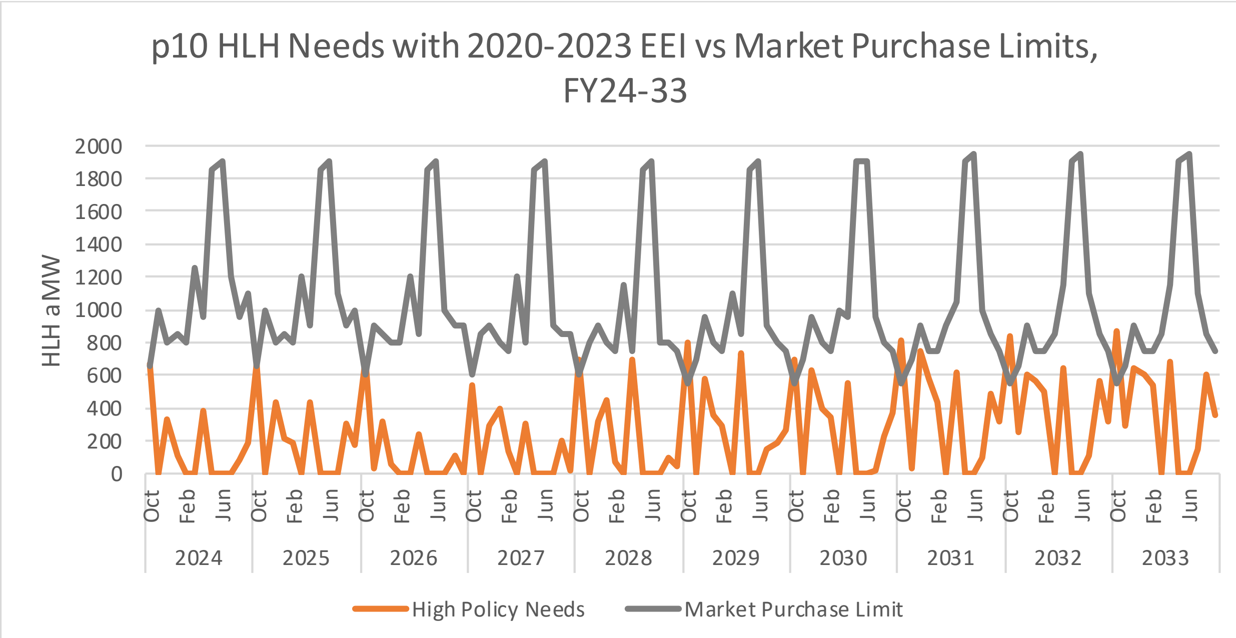
The increase in obligations for the high policy scenario caused the difference between BPA's October HLH needs and October HLH market purchase limit to increase to 102 average megawatts by fiscal year 2025, the second year of the study; see Figure 14.

Figure 14



This pattern continues later in the study, where the growth in BPA's obligations increases the difference between Bonneville's needs and the market purchase limit in every year from 2028 onward; see Figure 15.

Figure 15



Months where BPA's needs exceed the market purchase limit are months where the model will acquire resources above market purchases in the resource stack. It will have already acquired all resources that are cheaper than the market before moving to market purchases. Once the market purchase limit is exhausted, the optimization must add one or more resources that meet the remaining need for that month.

Table 4, Table 5 and Table 6 show the high policy scenario resource builds for conservation and generation resources for the three lowest-cost portfolios.

Table 4. High Policy Scenario Energy Efficiency Acquisitions of the Lowest-Cost Portfolios

	Cumulative Energy Efficiency Acquired (aMW)		
Portfolio	**2-Year**	**4-Year**	**10-Year**
1	95	221	696
2	98	229	755
3	102	238	786

Table 5. High Policy Scenario Demand Response Acquisitions of the Lowest-Cost Portfolios

	DR Acquired (Peak MW)					
Season	Summer			Winter		
Portfolio	2-Year	4-Year	10-Year	2-Year	4-Year	10-Year
1	213	437	373	176	336	269
2	213	475	490	176	336	283
3	213	513	492	176	336	303

Table 6. High Policy Scenario Generating Resource Acquisitions of the Lowest-Cost Portfolios

	Generating Resource Solutions					
Resource	Offshore Wind (Nameplate Capacity, MW)			Solar PV (Nameplate Capacity, MW)		
Portfolio	2 Year	4 Year	10 Year	2 Year	4 Year	10 Year
1	0	31	31	42	42	42
2	0	31	31	212	212	462
3	0	56	105	250	250	750

5.4 Discussion and Comparison

Energy efficiency and demand response acquisitions in the high policy scenario are little changed from the basecase. In both cases, energy efficiency and demand response resources are acquired up to the point that the marginal resource is no cheaper than market purchases. The 102-aMW gap between the market purchase limit and BPA's needs in early FY 2025 is too sizeable to be filled with energy efficiency and demand response alone. This, coupled with the reduction in cost for renewable resources, led to the acquisition in 2025 of some additional winter demand response and a small amount of solar photovoltaic (PV) resources.

The continued growth of BPA's load obligations from 2027 onward also supports the acquisition of a small amount of generation with an output profile similar to offshore wind. The need to acquire generating resources in the early and middle years of the study period, combined with the lower market price forecast in the high policy scenario – which influences every resource's expected revenue – results in a small amount of substitution from energy efficiency to renewable generation compared to the basecase.

This substitution occurs mostly in the later years of the study. Up through 2029, there is little difference in energy efficiency acquisitions from the basecase. In 2029, energy efficiency acquisitions in the high policy scenario are just four aMW lower than the basecase. By 2033, energy efficiency acquisitions are roughly 25 aMW lower than in the basecase.

It is also worth noting that both the basecase and high policy scenario for the 2022 Resource Program have substantially higher energy efficiency acquisitions in the later years than in the 2020 Resource Program. The 2020 Resource Program acquired more energy efficiency in the first two years, nearly the same amount over four years, and a much lower amount overall than either scenario in the 2022 Resource Program.

In 2020, the least-cost portfolio contained just over 500 aMW of energy efficiency by the last year of that study. In 2022, the basecase acquires approximately 215 aMW more energy efficiency over the study period, and the high policy scenario acquires 190 aMW more when compared to 2020. Table 7 below presents the least-cost portfolio for 2-, 4- and 10-year cumulative energy efficiency acquisitions from both resource programs.

Table 7: Comparison of 2022 Energy Efficiency Acquisitions to 2020 Resource Program

	2-year	4-year	10-year
2020 Resource Program	111	229	506
2022 Resource Program - Base	96	223	723
2022 Resource Program - High Policy	95	221	696

Section 6: Action Items

6.1 Next Steps

In the coming months, BPA will publish its Energy Efficiency Action Plan (Action Plan), describing its conservation goals, portfolio management strategy and program measures. The Action Plan will be informed by the Council's 2021 Power Plan, BPA's Resource Program and Integrated Program Review. BPA will also consider customer needs and other benefits of conservation such as capacity, resiliency and avoided emissions. During the Action Plan development process, low-cost flexible load management solutions that can be frequently deployed with minimal customer impacts will also be assessed.

Looking toward the next Resource Program, BPA plans to further develop and refine the enhancements it has made for the 2022 Resource Program, including updates to energy storage and demand response modeling, and refinements to the optimization process and risk analysis.

BPA will also monitor events that could change the forecasted outcomes of the 2022 Resource Program, such as new clean energy legislation, changes to resource costs or loads, or as yet unforeseen changes to the operations of the Federal Columbia River Power System. The impacts of these and other events, as well as anticipated modeling enhancements and improved information and data that become available, will be incorporated into future planning activities.

Section 7: Transmission Supplement Summary

The Bonneville Power Administration's Transmission Services organization is instrumental to ensuring BPA Power Services' existing generating resources and market purchases are delivered to load in the BPA balancing authority area. Therefore, including a Transmission Supplement is intended to show the deliverability aspect, not just the generation aspect, of how BPA approaches resource adequacy for its obligations. BPA also relies heavily on other regional utility transmission providers to ensure that Power Services' load is served in balancing authority areas outside of BPA's. That portion of deliverability is not described in this Transmission Supplement.

If and when Power Services identifies and pursues the acquisition of resources other than energy efficiency and potentially demand response, Power Services would have to actively coordinate with Transmission Services. Such resource acquisitions are, however, unlikely in the near-term based on the results of the 2022 Resource Program analyses. Power Services and Transmission Services do actively coordinate and collaborate on near-term and long-term system planning activities, including model inputs, load forecasts, resource retirement estimates, and several other planning topics of mutual interest. Expanded active coordination would occur if Power Services resource acquisitions beyond demand side resources occurred. For a detailed description of Transmission's planning processes, read the Transmission Supplement attached in the Appendix.

Section 8: Appendix: Transmission Supplement Continued

This section was provided by the Bonneville Power Administration's Transmission Services organization. It describes the transmission planning process in Transmission Services and how the organization collaborates with BPA Power Services to serve the long-term transmission needs of network transmission, or NT, and point-to-point, or PTP, customers. It also describes how its available transfer capacity, also known as ATC or transmission inventory, is managed to respond to customer requests for long-term transmission service. Transmission Services and Power Services work and collaborate closely to manage the hydro resources of the Federal Columbia River Power System to serve the needs of BPA's NT customers. Besides Power Services, Transmission Services has a wide range of customers for PTP transmission services to deliver power from regional resources to many bulk electric power customers.

The chapter starts with an overview of BPA and its strategic objectives. It then reviews the trends Transmission Services believes will most affect its future: decarbonization, decentralization, technology, regulatory reform and regional cooperation. Each of these brings risks and opportunities to consider in the analytical, modeling and decision-making part of the process.

The analytical process starts with Transmission Planning having a good understanding of NT and PTP customers and their needs and load growth patterns. Transmission Planning also reviews resources, customers' technology, fuel prices, government policy and more. Forecasted loads and resources are the basis for transmission planning in addition to existing obligations and committed long-term firm transmission service.

Once the system conditions are defined, the analysis turns to developing corrective action plans for problem areas not meeting the applicable reliability standards. Finding solutions for these problem areas requires multiple analytical tracks: (a) consideration of non-wires solutions in cooperation with cross-agency organizations at BPA; and (b) coordination with Power Services and multiple organizations in Transmission Planning to collaborate on integrated solutions.

Once Transmission Services completes the system assessment, including the proposed transmission corrective action plans and flowgate ATCs, the capacity becomes eligible to meet the needs of BPA customers who submit Transmission Service Requests for transmission capacity for their loads and resources. The TSRs are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. In the cluster study, the network is analyzed to define reinforcements and non-wire solutions necessary to serve the TSR needs. Customers are then informed so they can make their project decisions, proceed to contract negotiations and ultimately to construction. Throughout the planning process, Transmission Services and Power Services work closely in a joint process called Agency Integrated Planning. The AIP process ensures a high level of coordination among the different groups in Transmission Services and Power Services to achieve an efficient data collection, analytical evaluation and optimal recommendations.

8.1 Introduction

BPA energizes the region through more than 15,000 circuit miles, or 24,000 kilometers, of transmission lines and 261 substations in the Pacific Northwest, controlling approximately 75% of the high-voltage transmission system in the region. BPA also maintains interconnections with other regional power grids: British Columbia to the north; Rocky Mountains, Idaho and Montana to the east and southeast; and California to the south. BPA shares two interties with California: (a) the California-Oregon Intertie with northern California utilities; and (b) the Pacific DC Intertie with the Los Angeles Department of Water and Power.

Transmission Services is dedicated to public service, and its mission is to deliver the best value for BPA customers and constituents as it acts in concert with others to ensure the Pacific Northwest has a transmission system that is prepared to integrate and transmit power from federal and non-federal generating units, provide service to BPA's customers, supply interregional interconnections, and maintain electric reliability and stability.

Transmission Services is an open access transmission provider that aligns its provision of transmission service with the Federal Energy Regulatory Commission's regulatory framework. The FERC framework is designed to prevent undue discrimination in providing access to wholesale transmission capacity. Transmission Services maintains an open access transmission tariff, and seeks to align its OATT with the FERC pro forma OATT to the maximum extent possible. The OATT process is flexible and allows for considerations from other governance structures.

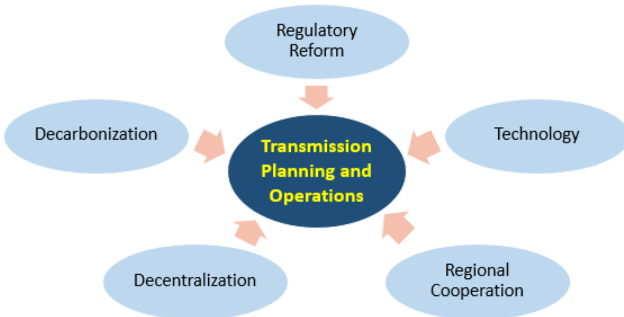
Transmission Services manages over 2,700 transmission service contracts that enable more than 30,000 transmission reservations and over 200,000 scheduling tags to be processed each month through BPA's commercial systems. Transmission's revenues are about $1.01 billion annually. Transmission Services provides transmission service to BPA Power Services customers, investor-owned utilities, independent power producers and any other business requiring the use of the Federal Columbia River Transmission System. Interested parties request transmission services and follow a well-defined process.

BPA's 2018 – 2023 strategic plan lists four agency objectives:

1. Strengthen financial health.
2. Modernize assets and system operations.
3. Provide competitive power products and services.
4. Meet transmission customer needs efficiently and responsively.

BPA's transmission objectives and strategies are based on its ability to deliver power efficiently and responsively.

Figure 8.1 – Major Trends Impacting Transmission



For 2022, Transmission Services continues to operate in a landscape of trends that started 10 to 15 years ago. The 2022 Resource Program incorporates the regional trend of new resources, such as wind – including offshore wind – and solar, and the continuing decline of coal generation, while hydro and natural gas continue to hold their share. The major trends for Transmission Services are:

- **Decarbonization:** The prevalent public policy of decarbonization from state regulators in the power and transportation industry has a variety of effects on BPA's future resource mix and load profile. The growth of variable solar and wind resources in the Northwest and California has already changed transmission operations relative to historic patterns, such as shifting the time of peak flows on some paths to be closer to sunset hours to manage the "duck curve" resulting from the ramping up of solar resources in California. BPA anticipates these trends to continue and likely become more pronounced as solar penetration continues to increase across the West. Decarbonization policies also influence the electrification of the transportation industry. The Northwest has the second largest penetration of electric vehicles in the country. BPA expects load profile changes and increased energy demand with a higher penetration of electric vehicles.

- **Decentralization:** More decentralized wind and solar generators are replacing centralized coal plants near major load centers, e.g., Centralia, Washington, and in more remote locations, e.g., Colstrip, Montana and Point of Rocks, Wyoming. Residential solar is not common in the region, but utility scale wind and solar projects are, and they tend to be located in rural areas in BPA's service territory. These individual wind and solar projects are generally smaller increments than single coal units, and there are numerous projects proposed or moving forward. The transmission grid of the future will be able to serve a growing number of these smaller generators, in addition to the larger ones in a very diverse set of locations.

- **Technology:** Technology affects every part of the power industry. The faster pace of innovation in a range of areas will affect Transmission Services in different ways.

    - **Data centers:** The dramatic growth of digital products has increased the need for data centers, and the rural Northwest is one of the preferred locations. BPA expects that trend to continue.

- **Electrification:** Changing technologies for the end user, such as increased electrification of the transportation sector, will change the load curve. Other examples of the end-user electrification is the continuing shift to more digital technologies in lighting and increased use of batteries in consumer electronics.
- **Smart grid:** The development of a variety of digital technologies and tools offer Transmission Services the opportunity to improve its operations, security and customer support.
- **Solar and wind resources:** Solar and wind technologies will be the prevailing resources developed in the planning horizon. In addition, there is increased interest in developing offshore wind along the Washington and Oregon coasts.
- **Storage:** The development of utility-scale batteries is a relatively new development in the industry. Batteries are being piloted and developed for a range of applications, but there is still a lot to learn. Costs are expected to come down over time because of volume manufacturing and chemistry advances, making their use more possible in the latter part of the decade or later. Batteries will also play a central role in the advancement of distributed energy resources, demand response, grid integration and shifting energy usage.

- **Regional cooperation:** BPA cooperates with regional partners to gain efficiencies in transmission planning and operations. BPA is active in NorthernGrid, the Western Power Pool, Western Electricity Coordinating Council workgroups and other regional planning industry organizations. In 2022, BPA joined the Western Energy Imbalance Market and is currently considering other power market initiatives.

- **Regulatory Reform:** In the last few years, federal and state regulation has been more proactive in promoting decarbonization goals. At the federal level, FERC and the Department of Energy have been active in promoting regional and inter-regional planning as well as enhancing transmission planning and generation interconnection. These regulatory reforms will have a significant impact on transmission planning in the future.

Long-Term Transmission Planning conducts production cost modeling and studies system optimization models to gauge market availability of resources, predicting future trends in resource types and location, including assumed transmission needs. Transmission Planning conducts power flow analysis to define system expansion over the planning horizon to ensure BPA’s transmission system can reliably deliver resources to load and meet its transmission obligations. These analyses will inform the Resource Program in the future on market availability, transmission deliverability for future resource scenarios conducted, and transmission needs for reliable delivery of resources to loads.

8.2 Loads and Resources

8.2.1 Resources

Located on the mainstream Columbia River and on several of its major tributaries (Figure 8.2), including the Snake and Willamette rivers, the Federal Columbia River Power System, or FCRPS, comprises 31 hydroelectric projects in the Columbia River Basin and provides carbon free energy that accounts for about one-third of the electricity used in the Pacific Northwest. These federal hydro projects are operated by the Bureau of Reclamation and the U.S. Army Corps of Engineers.

Through its transmission system of more than 15,000 circuit miles of high-voltage facilities, BPA delivers and distributes the power generated from both federal and non-federal projects of all resource types such as hydro, wind, solar, etc. The revenues collected from the use of the system cover the cost of operating and maintaining the transmission facilities that comprise the Federal Columbia River Transmission System, or FCRTS.

Figure 8.2 – FCRPS Resources

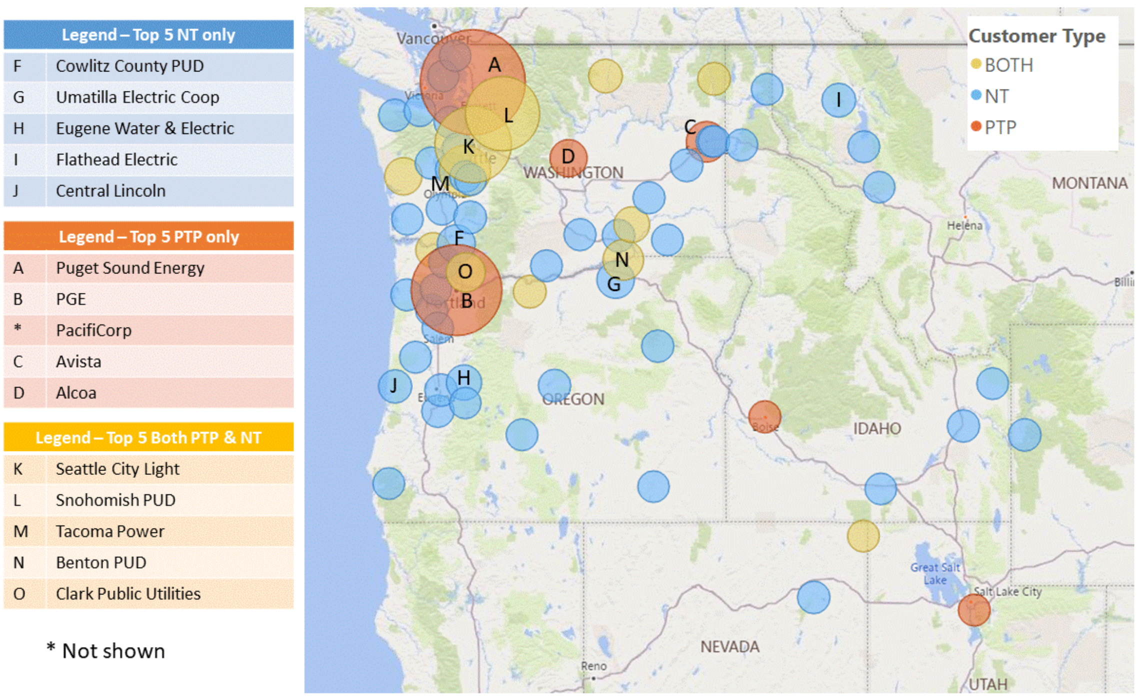
BPA delivers power from both federal hydro projects and non-federal resources, i.e. solar, thermal, wind, etc., to a wide range of customers in accordance with its OATT. Transmission service is generally divided into two products: Network Transmission, or NT, and Point-to-Point, or PTP. The traditional municipalities, public utility districts and cooperatives with load-serving priorities utilize mostly NT transmission service, while a wider variety of customers, such as investor-owned utilities, independent power producers, marketers and others utilize the more flexible and marketable PTP transmission service to access a greater mix of resources for delivery to either load or market.

8.2.2 Loads

BPA will serve 139 NT customers in the planning horizon, from 2022-2032, for a total forecast of 6,018 average megawatts in 2022 and 7,488 aMW in 2032, plus 24.4% in ten years. In 2022, 36 of these customers have demand of 5 aMW or less. A few of the NT customers will experience significant growth, while others will be mostly flat, and in some cases, negative. Among the top 10, Umatilla Electric Coop, Cowlitz PUD and Northern Wasco PUD will experience significant growth, while many municipalities remain mostly flat or even negative. The growth in the rural areas and small towns has been in large part due to data centers and industrial customers attracted to the Northwest for its low- cost power. Through the planning horizon, the forecasted NT customer peak demand will be winter peaking at 9,513 MW in 2022 and 11,311 MW in 2032.

Figure 8.3 displays projected loads for NT customers of 25 MW or greater. The load circle area is proportionally sized according to the customer load. The top five NT customers only are ranked by demand, measured in aMW, on the legend. The map includes NT and the larger PTP customers with loads of 25 aMW or more. While shown in the key, the map itself does not include PacifiCorp, delineated with an asterisk, which receives transmission service across the Northwest. The map also does not include loads smaller than 25 aMW, which aggregated to 784 aMW in 2022. Figure 8.3 also shows PTP customers, with the top five PTP customers being Puget Sound Energy, Portland General Electric, PacifiCorp, BPA Power Services and Snohomish County PUD.

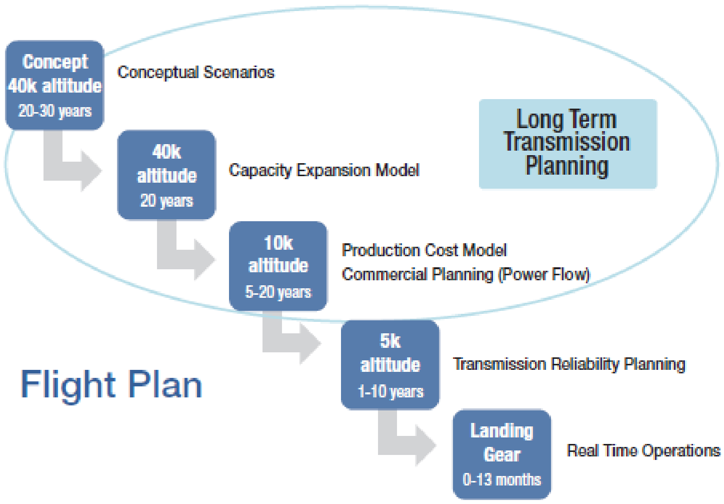
Figure 8.3 – 2022 Transmission Loads



8.3 BPA Transmission Planning

Transmission planning is done at different levels for multiple purposes. To better understand this process, Figure 8.4, Transmission Planning Flight Plan, is a graphical representation, or overview, of the various transmission planning processes within Transmission Planning and Asset Management. These processes include transmission planning from a reliability viewpoint and long-term transmission planning from a commercial planning viewpoint.

Figure 8.4 – Transmission Planning Flight Plan



A. Transmission Reliability Planning

Every year, BPA Transmission Planning conducts a comprehensive assessment of the FCRTS to determine its ability to provide reliable service over a 10-year planning horizon. Transmission Planning studies 27 load service areas and 16 paths under defined limiting system conditions in order to identify any potential performance deficiencies. The analysis is used to identify system reinforcements needed to continue to provide reliable transmission service over the planning horizon.

The system assessment allows BPA to demonstrate that existing and forecasted load and projected firm transmission service can be reliably served through, at least, the 10-year planning horizon. It also allows BPA to show that identified corrective action plans, such as system reinforcement, are adequate for reliable performance.

The main objectives of the system assessment are to demonstrate that BPA meets the mandatory North America Electric Reliability Corporation, or NERC, TPL Standard known as Transmission System Planning Performance Requirements, reliably serve loads, and fulfills obligations to reliably deliver resources to load. The NERC standard requires that BPA conduct an annual assessment to ensure that the BPA network is adequately planned to supply projected customer demand and projected firm transmission service over the expected range of forecast system demands following a wide range of probable contingency outages.

Transmission Planning evaluates the transmission system for the near-term, one to five years, and long-term, six to ten years, planning horizons to determine whether system performance meets performance requirements of the NERC TPL Standard, WECC System Performance Regional Criterion and BPA Reliability Criteria for Transmission Planning. If the system assessment identifies any potential system performance deficiencies, corrective actions, including transmission reinforcements, are developed to address the potential system deficiencies.

Load Forecast

The Transmission Planning organizations work closely with the Load Forecasting group, using a common process to identify more efficient ways of collecting and evaluating customer-provided information. This ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning process between Transmission Services and Power Services.

The overall system assessment starts with developing technical basecases. A basecase is a database used by the power flow software program to model the loads, topology and generation. Then, contingency outages as required by the NERC TPL Standard are studied using the basecases to assess required system performance. Assumptions are made in the system assessment basecases for load forecasts, resource forecasts and transmission service. The basecases start from WECC-approved basecases. These include initial load forecasts from BPA's Load Forecasting and Analysis group, the same initial load forecast used by Power Services for the power Needs Assessment and Resource Program, and load forecasts for other utilities represented in the basecases. If necessary, the load forecasts are then updated with the most up-to-date load forecast data available from the other utilities.

The transmission planning organizations work closely with the load forecasting group to use common processes to identify more efficient ways of collecting and evaluating customer-provided information. This ensures that customer load information is properly modeled and analyzed. This effort is part of the Agency Integrated Planning process.

Resource Forecast

Resource forecasts for the system assessment include existing and committed future resources that are expected or forecasted to operate as determined in coordination with Power Services. Specific generation patterns are assessed that are expected to create higher transmission system stress consistent with historical usage to determine the limits of the transmission system.

Existing Obligations and Committed Long-Term Firm Transmission Service

In addition to load and resource forecasts, the system assessment includes existing transmission service obligations and committed long-term firm transmission services. These transmission service obligations and commitments are identified during transmission expansion planning by BPA Long-Term Transmission Planning. System assessments conducted by Transmission Planning capture these transmission service obligations and commitments through path flows resulting from the load forecast and the generation patterns that are assessed.

Non-Wires

BPA Transmission Planning, in collaboration with the BPA Cross-Agency Non-Wires team, considers the feasibility of non-wires solutions as alternatives to or as deferrals of transmission reinforcement projects. The range of non-wires solutions that are considered include demand-side management, which includes energy efficiency and demand response, distributed energy resources such as energy storage and distributed generation, and generation re-dispatch. BPA Transmission Planning conducts a non-wires assessment to identify feasible candidates, following its annual system assessment. Non-wires alternatives to reliability projects are considered where feasible. For areas that have performance deficiencies and corrective action plans identified within the planning horizon, the potential for non-wires alternatives is identified to either correct the deficiency or defer the date when a project is required to comply with the NERC Standards. Following the system assessment, Transmission Planning summarizes the areas with the potential for non-wires projects. In collaboration with the Cross Agency

Non-Wires team, areas are prioritized, and a recommendation is made regarding which area justifies further analysis by the team.

Coordination Between Power Services and Transmission Services

Throughout the planning process, Transmission Services and Power Services work closely in a joint process called Agency Integrated Planning. The AIP process ensures a high level of coordination among the different groups to achieve efficient data collection, an analytical evaluation and optimal recommendations. Specifically, BPA coordinates between Transmission Planning, Long-Term Transmission Planning and Long-Term Power Planning in their planning activities, processes and decision-making in a way that enables the agency to meet and deliver on its statutory load-serving obligations to its regional firm power and transmission customers.

- Transmission Planning coordinates input resource assumptions for system assessment basecases with Long-Term Power Planning and Long-Term Transmission Planning. This includes ensuring that the peak period generator capacities are reasonable and properly allocated for all generating plants. Transmission Planning also collaborates on information regarding generation retirements.
- Transmission Planning coordinates long duration generator outage assumptions for basecases with federal hydro projects to include in the system assessment studies.
- System assessments and the Resource Plan start from common agency load forecasting information for BPA customers. Transmission Planning and Long-Term Power Planning coordinate with Load Forecasting and Analysis to gain a common understanding of the load forecast process, methodology and outputs.
- When the system assessment is completed, results and corrective action plans are coordinated with Power Services and Transmission Long-Term Transmission Planning to collaborate on possible integrated solutions between Transmission and Power.
- Non-wires potential, prioritization, and analysis are done in collaboration between Transmission Services and Power Services.

B. Commercial Planning

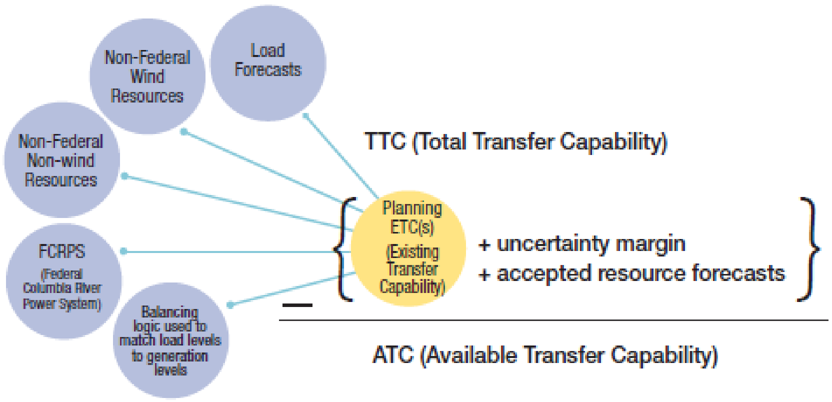
Long-Term Transmission Planning is responsible for the Transmission Service Expansion Planning for future transmission service requests, a process that starts with calculating the available transfer capacity, or ATC, for each transmission flowgate. The capacity then becomes eligible to meet the needs of BPA customers who submit transmission service requests, requesting capacity for their loads and resources. These TSRs are then combined for the cluster study's needs assessment, which serve as load scenario conditions for the cluster study. With the cluster study, the network can be analyzed for reinforcements necessary to serve the TSR needs. Customers are informed so they can make their project decisions, proceed to contract negotiations and ultimately go to construction. More on how this process works follows.

Long-Term Available Transfer Capability

On an annual cycle, BPA Long-Term Transmission Planning uses a power-flow based model to calculate Existing Transmission Commitments on BPA's monitored Network Flowgates under various system conditions and seasons. Using the calculated ETCs and the total transfer capability, the algorithm ATCFirm = TTC – ETCFirm informs the available transfer capability inventory across Network Flowgates for the long-term market. The annual LT ATC update allows BPA Transmission

Services to manage long-term firm transmission sales as well as inform the cluster study. Refer to Figure 8.5 below for a graphical representation.

Figure 8.5 – Inputs to Long-Term ATC Calculations for Network Flowgates



To calculate long-term ATC, Long-Term Transmission Planning engineers utilize five- and 10-year- out basecases for winter and summer, which originates from WECC-approved basecases. These winter and summer basecases represent a normal one-in-two non-coincidental peak load forecast. The basecases include initial load forecasts from BPA's Load Forecasting and Analysis group, the same initial load forecasts used by BPA Power Services for their Needs Assessment and Resource Program, and load forecasts for other utilities represented in the basecases. The load forecasts are then updated with the most up-to-date load forecast data available from the other utilities. A light spring basecase is derived from a summer peak basecase by reducing loads and adjusting generation patterns appropriately to reflect historical spring hydro conditions.

Resource forecasts for the FCRPS are provided by Power Services. The resource forecasts take into account forecasted FCRPS generator outages for the season. The FCRPS is modeled with three dispatches that separately stress the hydro system at the upper Columbia, lower Columbia and lower Snake projects.

Non-federal wind resources identified in PTP and NT contracts are modeled in "off" and "on" scenarios. In the "on" scenarios, PTP wind is modeled at the contract demand and capped by its nameplate, and NT wind is modeled at the designated MW level for the generator. In the "off" scenarios, PTP wind is replaced with FCRPS generation using a balancing logic method. Non-federal non-wind resources are modeled at contract demand, capped at the lower of the nameplate or historical peaks/seasonal capability.

Transmission Service Request Study and Expansion Process

Every year, Transmission Planning conducts a Transmission Service and Expansion Process, or TSEP, to analyze requests for new long-term firm transmission service. This includes a needs assessment to identify capacity deficiencies across the transmission system for future requests, and a cluster study to identify system reinforcements to provide the requested capacity. A benefit of using the TSEP is that Transmission Services can study transmission requests in aggregate, to identify "right-sized" transmission solutions to meet the demand. In addition, multiple customers then have the opportunity to participate in cost sharing of any needed transmission infrastructure, resulting in lower cost to individual customers and higher project subscription levels.

As part of the TSEP, BPA Long-Term Transmission Planning conducts a needs assessment to identify capacity needs across the transmission system in response to long-term firm TSRs, which feeds into the cluster study process. The needs assessment starts with developing a robust range of plausible scenarios that would adequately capture anticipated utilization of BPA's Network Flowgates. These scenarios consider similarly situated resources, expected resource type, and market and weather conditions in the scenario development. The needs assessment also utilizes data from production cost modeling to inform an estimated economic merit order dispatch in the scenarios, as well as new plausible scenarios of predicted congestion.

The scenario basecases used for the needs assessment are power flow models that are derived from five-year-out long-term ATC basecases for the winter, spring and summer seasons. Since the starting LT ATC basecases already include load forecasts, resource forecasts and existing transmission service commitments, the derivative scenario cases include modeling of the long-term firm transmission service requests in BPA's Long-Term Pending Queue as well as accepted NT load growth forecasts from the NT dialogue. Analysis of the set of scenario basecases determines which flowgates are deficient in capacity and the amount of capacity needed to accommodate requested future transmission service.

For those transmission paths where capacity deficiencies are identified, Transmission Planning conducts cluster studies to identify the system reinforcements needed to provide the required capacity both across the transmission paths and within local areas where associated resources are located.

Once Transmission Planning completes the cluster study and provides the results and defined transmission reinforcements, study participants decide whether to continue pursuing the requested transmission service. After the study participants have made decisions whether to support the identified transmission reinforcements, Transmission Services then initiates the next year's cluster study cycle to respond to new transmission requests submitted since the beginning of the previous study. This cyclical study process enables Transmission Services to efficiently and timely meet customer needs and satisfy its tariff obligations.

An area of recent interest for Transmission Services is the assessment of battery storage to potentially meet commercial planning needs. The exploration addresses technology improvements, increasing cost reductions in energy storage and the role of energy storage in the commercial planning space. Long-Term Transmission Planning is developing a framework to evaluate potential battery use cases, ownership models, impacts to BPA policies and an overall cost structure.

C. Long-Term Capacity Expansion

Long-Term Transmission Planning utilizes the Long-Term Capacity Expansion, or LTCE, tool to co-optimize resource and transmission capacity expansions over a long-term, 20-to-30-year horizon. The tool identifies future resource capacity and energy deficits in the various sub-regions of the Northwest and computes an optimal mix of both transmission and resource capacity additions.

The initial model is populated with at least 20 years of load, resource and transmission data at a zonal level of granularity for the Western Interconnection. Inputs in refining this base data are extracted from a variety of sources such as BPA's Transmission Planning, Load Forecasting and Analysis, and Long-Term Power Planning groups; the Northwest Power and Conservation Council; WECC; and the Northwest Power Pool.

Long-Term Transmission Planning is utilizing LTCE with the intent to evaluate several major trends in the external market landscape that affect transmission. The model has the capability to address how state carbon policies can influence the timing of transmission needs and performance in the Pacific Northwest. It can also assess how a combination of energy storage, variable energy resources and hydro perform with respect to adequacy.

D. Production Cost Model

Long-Term Transmission Planning simulates security constrained economic dispatch and unit commitment with the GridView software in order to quantify how uncertainties, such as load growth and public policy requirements, will affect transmission congestion and utilization. Scenario analysis best practices are used to identify “least regrets” transmission reinforcements.

Long-Term Transmission Planning supplements the WECC Anchor Data Set with additional data from BPA load forecasters, power planners and transmission planners. The transmission system is modeled at a nodal level of granularity with constraints approximated by path and flowgate transfer limits.

E. Intra-agency Coordination

There are several other examples of coordination between Transmission Services and Power Services for large and small projects in addition to those discussed above. One significant effort in the recent past is the Columbia River System Operations Environmental Impact Statement. For the CRSO EIS, the analytical process between the two organizations followed six steps over the course of two years. The process included linkage of changes in how and where power is generated to effects on the transmission system reliability and congestion.

Another example of coordination between Power Services and Transmission Services is the cross-agency Southeast Idaho Load Service initiative focused on how to best serve six preference customers in southeast Idaho that have long-term power and transmission contracts with BPA. This included commercial negotiations related to the Boardman – Hemingway transmission project, as well as resource acquisition and transmission service options.

There is also coordination between Transmission Services and Power Services reviewing impacts of river operations on the transmission system. This includes analyzing minimum generation levels on the lower Columbia River to maintain system reliability and to determine if other significant changes to generation patterns are expected.

Section 9: Glossary of Terms

18-Hour Capacity – Metric used for evaluating capacity surplus/deficit over the six peak load hours per day during a simulated three-day extreme weather event, such as a cold snap or heat wave, and assuming median water conditions.
Available transfer capacity – Also "available transfer capability." Measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses.
Balancing authority – Synonym for load control area agency. The responsible entity that schedules generation on transmission paths ahead of time, maintains load-interchange-generation balance within a balancing authority area, and supports interconnection frequency in real time.
Balancing authority area – The collection of generation, transmission and loads within the metered boundaries of the balancing authority. The balancing authority maintains load-resource balance within this area.
Balancing reserves – Incremental and decremental generation flexibility or demand response that is connected to BPA's Automatic Generation Control system and is capable of responding to signals requesting Regulation Service and Within-hour Following Service in proportion to the AGC signal requirements.
Behind-the-meter generation – Energy generated on-site and on the consumer side of the meter facility, such as residential solar.
Canadian Entitlement – The Canadian Entitlement is one-half of a treaty formula that measures the increase in usable energy and dependable capacity for an imaginary 1960-level hydrothermal power system with procedures designed to provide acceptable cost/benefits during the life of the treaty.
Capacity – Capacity is defined and measured in various ways. BPA measures the capacity of its system by determining its maximum output in its 18-hour capacity studies, which represent the most stressful type of event BPA's power system could expect to experience approximately once in every 10 years.
Conservation Potential Assessment – Study conducted to assess the amount and costs of energy efficiency measures available from BPA's forecasted customer loads over the planning horizon.
Critical water – The second-lowest historical streamflows on record used to model the amount of power the regional hydropower system could produce, given today's generating facilities and constraints.
Cut plane – Group of transmission lines.
Decarbonization – Reducing the carbon content of all transformed energies such as electricity, heat, liquids and gases. In the power sector, this means replacing coal, as well as gas and oil, with renewable energy.
Decentralization – Energy generated off the main grid and produced near to where it will be used, rather than at a large plant elsewhere and sent through the grid.
Demand response – Programs intended to reduce the use of electricity during times of peak demand.
Demand-side resources – Load management programs, such as energy efficiency, implemented by utilities. These resources can also include demand response, load shifting measures, and Behind-the-meter generation and storage.
Distributed energy resources – Systems such as small-scale power generation or storage technologies – typically in the range of 1-10,000 kilowatts – used to provide an alternative to or an enhancement of the traditional electric power system.
Efficient frontier – Result from the Resource Program analysis that produces the least-cost combination of available resources that meets the given constrains. It also identifies various other combinations of resources that minimize portfolio variance for a given cost point.

Energy – The amount of electricity demanded, produced or required, over a specific period of time, sometimes measured in annual average megawatts, aMW, or in megawatt hours, MWh.
Energy efficiency – Using less energy to perform the same function or service.
Federal Energy Regulatory Commission (FERC) – An independent government agency delegated by Congress with the authority to regulate the energy infrastructure of the United States, including the transmission of electricity.
Flowgate – 1) Individual or group of transmission facilities, i.e., transmission lines, transformers, known or anticipated to be limiting elements in providing transmission service; or 2) designated point(s) on the transmission system through which the Interchange Distribution Calculator calculates the power flow from interchange transactions.
Heavy load hours – Times of highest electricity usage; for BPA, heavy load hours are hours ending at 7 a.m. to 10 p.m., Monday through Saturday, excluding North American Electric Reliability Corporation holidays.
Hub – Combination of the electrical grid and other networks, such as natural gas pipelines, for the production, conversion, storage and consumption of different energy generators.
Independent power producer – A non-utility producer of electricity that operates one or more generation plants under the 1978 Public Utility Regulatory Policies Act, PURPA. Many independent power producers are co-generators who produce power for their own use and sell the extra power to their local utilities.
Integrated Resource Plan – A long-term resource planning process conducted to help ensure a utility meets its expected future obligations at low cost and with minimum practical risk.
Intertie – A system of transmission lines permitting a flow of energy between major power systems. The BPA transmission grid has interties to British Columbia, California and eastern Montana.
Investor-owned utility – A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders; a private utility.
Light load hours – Generally, times of low electricity usage; for BPA, light load hours are hours ending 11 p.m. to 6 a.m., Monday through Saturday, all day Sunday and holidays as designated in the North American Electric Reliability Corporation Standards.
Load – The amount of electric energy delivered or required at any specified point or points on a system.
Market depth limit – Result of a study used to determine how much energy BPA could reliably purchase from the wholesale market.
Market transformation savings – Associated with the Northwest Energy Efficiency Alliance's programs and initiatives that focus on long-term market change and push the region toward more efficient technologies.
Momentum savings – BPA tracks and reports momentum savings for select markets. Momentum savings are defined as all the energy efficiency occurring above the Northwest Power and Conservation Council's plan baseline that are not directly reported by utilities and not part of the Northwest Energy Efficiency Alliance's market transformation savings.
Network transmission – Transmission contract or service described in a transmission provider's Open Access Transmission Tariff, OATT.
North American Electric Reliability Corporation (NERC) – A not-for-profit international regulatory authority appointed by the Federal Energy Regulatory Commission whose mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.
Northwest Energy Efficiency Alliance (NEAA) – A group of 140 Northwest utilities and energy efficiency organizations that fund activities and programs dedicated to accelerating energy efficiency in the region.
Open Access Transmission Tariff – Tariff for use of high-voltage transmission lines required by FERC under its Order 888. Designed to facilitate open, nondiscriminatory access to all transmission facilities by all power providers; terms and conditions by which BPA provides nondiscriminatory transmission service

that is similar to the Federal Energy Regulatory Commission's pro forma tariff mandated for FERC jurisdictional utilities.
Outage – In a power system, an either scheduled or unexpected period during which the transmission of power stops or a particular power-producing facility ceases to provide generation.
P10 – The 10th percentile of a distribution.
P10 heavy load hour – Criteria that evaluates the 10th percentile, or P10, surplus/deficit over heavy load hours by month, given variability in hydropower generation, load obligations and Columbia Generating Station output amounts.
P10 Super-Peak – Criteria that evaluates the 10th percentile, or P10, surplus/deficit over the six peak load hours per weekday by month, given variability in hydropower generation, load obligations and Columbia Generating Station output.
Peak load – The highest amount of one-hour load on the entire system in a stated period of time. It may be the maximum load at a given instant in the stated period or the maximum average load within a designated interval of the stated period of time.
Peak runoff – The period of time during which the maximum volume of precipitation, snowmelt or irrigation water that runs off the land into streams or other surface water within a watershed or basin. BPA forecasts the amount of water expected to enter the Federal Columbia River Power System based on winter snowpack measurements and historical volumes.
Point-to-point transmission – Reservation and/or transmission of energy on either a firm basis and/or a non-firm basis from point(s) of receipt to point(s) of delivery, including any ancillary services provided by the transmission provider in conjunction with such service.
Ramp rates – 1) The amount of conservation or demand response that a program can acquire annually; 2) The rate at which the power output of a generator or generating project can be increased or decreased.
Redispatch – Management of generation patterns to overcome cut plane or outage problems.
Resource portfolio/stack – A set of resources, such as nuclear, natural gas, wind, solar and/or hydropower, used to provide power products. Demand side resources such as conservation, storage, rooftop PV, and demand response can also be in a resource portfolio.
Spill – Water that goes over the spillway of a dam rather than through its turbines, meaning it is not used to generate electricity.
Supply-side – Generating resources or activities on the utility's side of the customer's meter used to supply electric power products or services to customers, rather than meeting load through energy-efficiency/conservation measures or on-site generation on the customer's side of the meter.
Western Interconnection – Synchronously operated interconnected electric transmission systems located in the Western United States, Baja California, Mexico, and Alberta and British Columbia, Canada.
Western Electricity Coordinating Council (WECC) – An independent, non-profit organization delegated by NERC and FERC to promote the reliability of the power system in the geographic area known as the Western Interconnection.

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P.O. Box 3621, Portland, Oregon 97208-3621
DOE/BP-5201 • October 2022