B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2018 Resource Program

September 2018

Section 1: Introduction

1.1 Overview

The 2018 Resource Program represents an evolutionary step forward as Bonneville expands its methodology, time frame and granularity for analyzing its needs and solutions. This expansion includes an end use load forecast, Bonneville-specific demand response and conservation potential assessments, and the introduction of an optimization model to evaluate possible solutions. The results yield a refined vision into Bonneville's needs and low-cost resource strategies across a broad spectrum of future market conditions.

Bonneville's 2018-2023 Strategic Plan describes the actions it will take over the next five years to become more competitive. To support these efforts, the 2018 Resource Program endeavors to examine uncertainty in loads, water supply, resource availability, natural gas prices, and electricity market prices to help inform Bonneville about potential low-cost, low-risk acquisition strategies that meet its obligations. Additionally, as noted in the Strategic Plan, the Resource Program seeks to align Bonneville's energy efficiency and demand response initiatives with its long-term power supply needs.

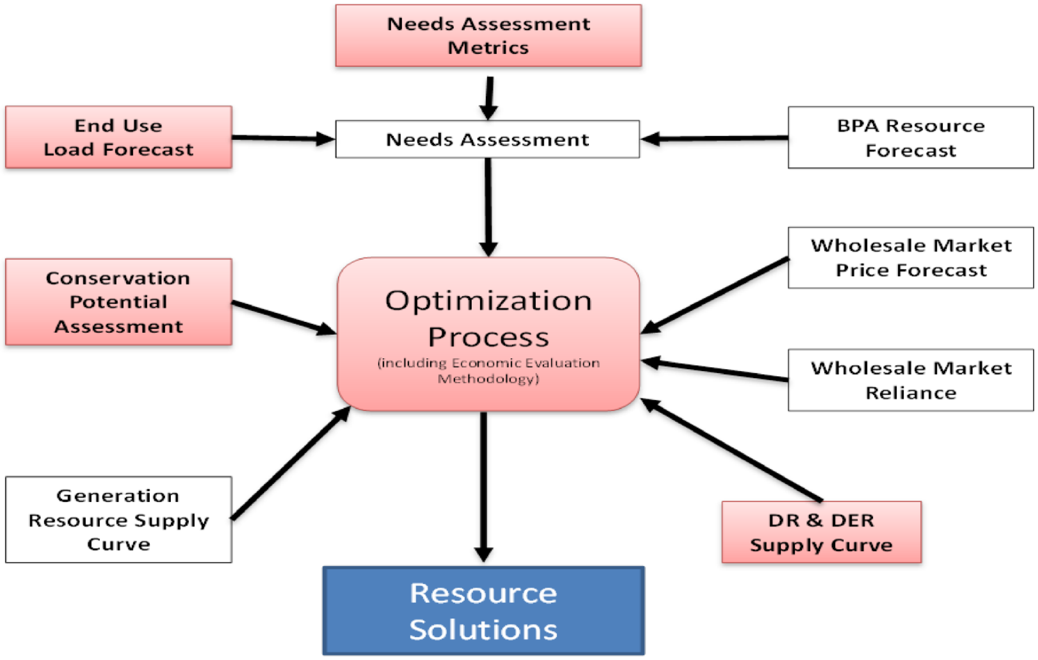
While the Resource Program is neither a decision document nor an established requirement; its purpose is to inform acquisition strategies and provide valuable insight into how Bonneville can meet its obligations in a cost-competitive manner.

1.2 Methodology

The Resource Program begins with a forecast of Bonneville's power obligations and existing resources and then determines needs (Needs Assessment). It then identifies and evaluates potential solutions to meeting those needs including energy efficiency (conservation supply curves), demand response (DR & DER Supply Curve), and power purchases (Generation Resource Supply Curve, Wholesale Market Price Forecast and Wholesale Market Reliance). The Resource Program then outlines potential strategies for meeting Bonneville's needs. Figure 1.1 provides a high-level diagram of the Resource Program process.

To appropriately assess the costs and values of these resources, Bonneville used AURORA® to create an electricity price forecast. AURORA® is a computer software tool that can be used to produce electric market price forecasts, value and uncertainty analyses, and automated system optimization. This 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.

Figure 1.1 Resource Program Process



AURORA® (Optimization Process) was used to perform portfolio optimizations that assessed the 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.

1.3 Conclusions

The following summarizes the main conclusions of the 2018 Resource Program:

- Bonneville has seasonal heavy load hour energy needs with the largest deficits in the winter.
- There is a growing deficit in the summer 18-Hour capacity metric.
- There is surplus winter 18-hour capacity.
- Bonneville's service territory has a cumulative conservation potential of 1,812 aMW by FY 2039.
- Bonneville's service territory has is an achievable summer demand response potential of 1,602 MW by FY 2039.
- The least-cost mix of resources that will meet Bonneville's expected energy needs consists of conservation and energy purchased from the market.
- Additional granularity provided by the model results gave insight regarding which energy efficiency measures can best align with Bonneville's power needs.
- Demand response has the potential to be an economically effective solution for helping meet Bonneville's summer capacity needs.

The following sections provide a more detailed look at the 2018 Resource Program.

Section 2: Needs Assessment

2.1 Overview

The Needs Assessment forecasts Bonneville's long-term energy, capacity, and balancing reserves needs based on projected supply obligations and resource capabilities. The Needs Assessment informs the later steps of the Resource Program, namely the optimization process that evaluates potential solutions for meeting Bonneville's long-term needs.

The 2018 Needs Assessment includes two enhancements compared to previous Resource Programs. First, the forecasts cover more study years in an expanded 20-year study horizon. Second, the load obligation forecasts reflect a frozen efficiency load forecast which allows for greater transparency of how demand side initiatives impact load obligations. Collectively, these enhancements provide more granularity on both the timing and magnitude of Bonneville's needs as well as assessing conservation given other available supply and demand side resources.

2.2 Methodology

The Needs Assessment incorporates hourly forecasts of Bonneville's supply obligations and resource capabilities. These forecasts include projections of customer energy needs that Bonneville is obligated to supply under its power sales contracts, which are produced by the Agency Load Forecasting system. As stated above, this is the first Needs Assessment to include a frozen efficiency obligation forecast, meaning historical trends of energy efficiency savings achievements were not projected forward into the obligation forecast. In this initial implementation, load forecasts for 11 customers were produced using statistically adjusted end-use models. The forecasts for the remaining customers were created by applying the existing time series process.

The Needs Assessment resource capability forecasts include projections for Bonneville's regulated hydropower resources. These forecasts are produced by the Hourly Operating and Scheduling Simulator (HOSS) model. The HOSS forecasts, along with the forecasted capability of Bonneville's other hydro and non-hydro resources, are compared to projected load obligations to determine long-term energy and capacity needs.

The Needs Assessment uses the following five metrics to assess Bonneville's long-term energy, capacity, and balancing reserve needs.

- Annual Energy: Evaluates the annual energy surplus/deficit under 1937 critical water conditions, using forecasted load obligations and expected Columbia Generating Station output.
- P10 Heavy Load Hour: Evaluates the 10th percentile (P10) surplus/deficit over heavy load hours by month, given variability in hydro generation, load obligations, and Columbia Generating Station output amounts.
- P10 Superpeak: Evaluates the P10 surplus/deficit over the six peak load hours per weekday by month, given variability in hydro generation, load obligations, and Columbia Generating Station output.
- 18-Hour Capacity: Evaluates the surplus/deficit over the six peak load hours per day during three-day extreme weather events and assuming median water conditions. Winter and summer extreme weather events are analyzed, both of which assume maximum take of the Canadian

Entitlement, zero wind generation, and limited energy market purchase availability. Winter events assume reduced streamflows due to the effects of icing. Summer events assume reduced Columbia Generating Station output due to adverse weather conditions.

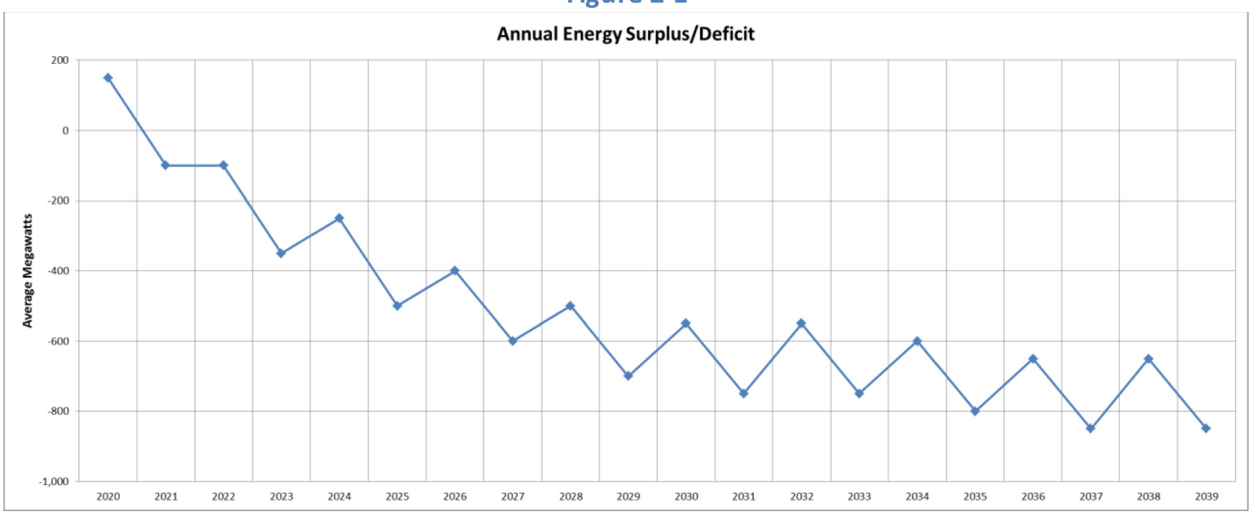
- Balancing Reserves: Evaluates the ability to meet forecasted balancing reserves demand in Bonneville's balancing authority area.

This Needs Assessment provides 20-year continuous forecasts for the three energy metrics (Annual Energy, P10 Heavy Load Hour, and P10 Superpeak). Due to the higher workload associated with producing forecasts for the 18-Hour Capacity metric, this Needs Assessment only provides capacity metric forecasts for every five years, for a total of five study results that span the 20-year horizon. Given considerable uncertainty in future demand for balancing reserves, this Needs Assessment does not include quantitative forecasts for the Balancing Reserves metric and instead provides a more qualitative analysis of balancing reserves needs.

2.3 Results

Figure 2-1 presents the results for the Annual Energy metric. Following a surplus of 150 average megawatts (aMW) in fiscal year (FY) 2020, the Annual Energy metric becomes increasingly deficit over the remainder of the 20-year study horizon, with the deficits growing to 850 aMW by FY 2039. The repeating pattern of larger deficits in odd years is caused by Columbia Generating Station's biennial refueling and maintenance outages, which results in less generation every other year.

Figure 2-1



The P10 Heavy Load Hour results for the first half of the study horizon are shown in Figure 2-2. The largest deficits under this metric occur in winter, the first half of April, and fall. Over the 20-year study horizon, the P10 Heavy Load Hour metric becomes increasingly deficit during these periods, with the largest deficits consistently occurring in January. The January deficits grow from 650 aMW in FY 2020 to 1,850 aMW in FY 2039.

Figure 2-2

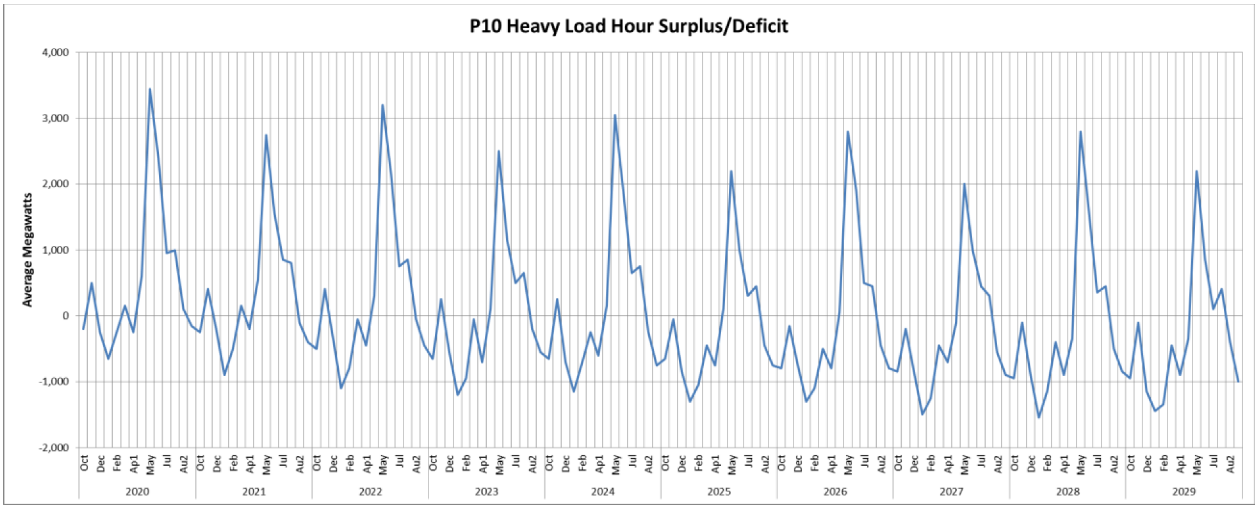
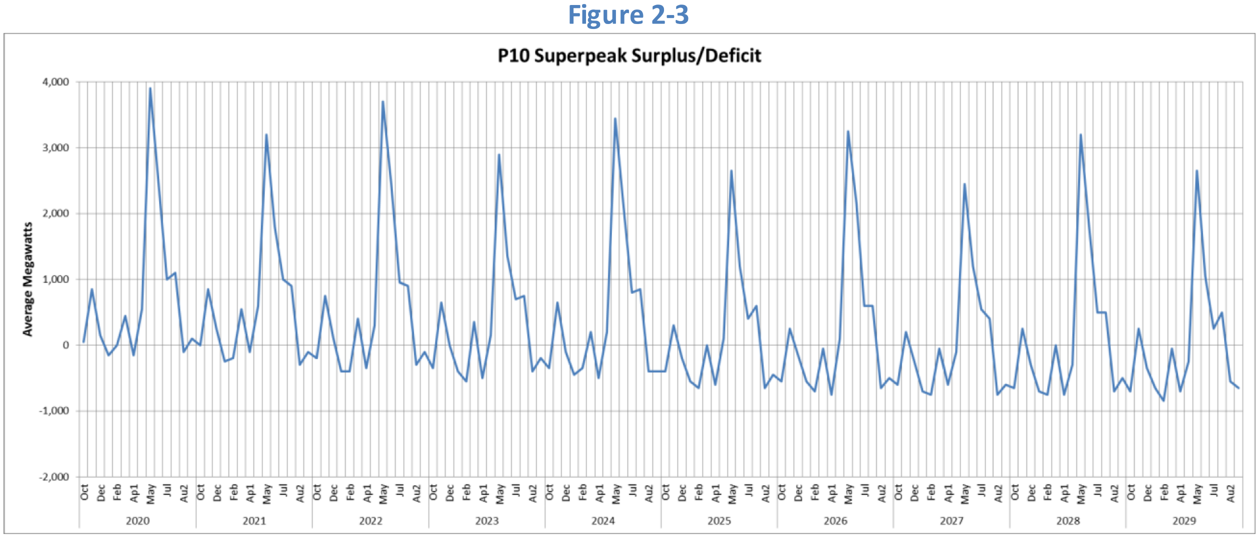


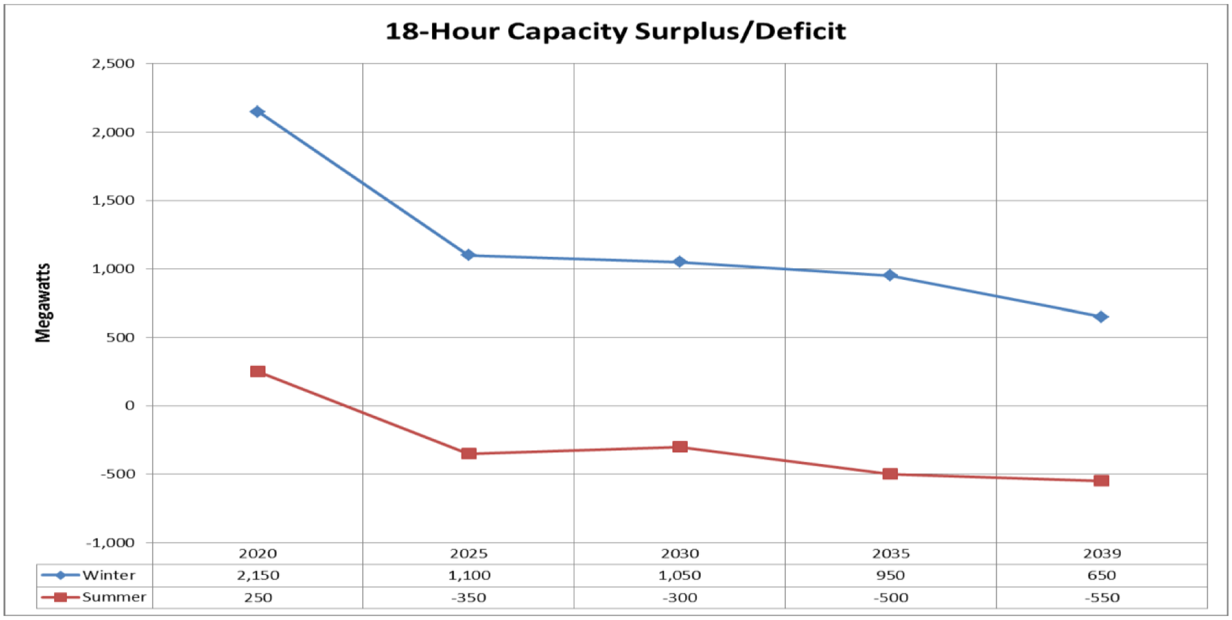
Figure 2-3 presents the P10 Superpeak results for the first half of the study horizon. The largest deficits under this metric occur in winter, the first half of April, late summer, and fall. The P10 Superpeak metric becomes increasingly deficit during these periods over the 20-year study horizon. The deficits grow from near load-resource balance in FY 2020 to 1,000 aMW by FY 2039.

Figure 2-3



The results for the 18-Hour Capacity metric are shown in Figure 2-4. Winter is surplus capacity under this metric over the 20-year study horizon. Following a surplus of 250 megawatts (MW) in FY 2020, the 18-Hour Capacity metric is deficit in summer for the remainder of the 20-year study horizon. These summer deficits grow from 350 MW in FY 2025 to 550 MW in FY 2039.

Figure 2-4



As stated earlier in Section 2.2, this Needs Assessment does not include quantitative forecasts for the Balancing Reserves metric due to considerable uncertainty in future demand for balancing reserves. This uncertainty comes from a number of factors, which include, but are not limited to:

- Amount and location of wind and solar development in the region.
- Scheduling practices and elections.
- Elections to self-supply.
- New or expanded markets.
- Departure of existing resources.

Nonetheless, a qualitative assessment of the factors listed above suggests that demand for balancing reserves, particularly in the first half of the 20-year study horizon, is unlikely to reach the 900 MW of incremental reserves that the Federal Columbia River Power System has provided in the past.

2.4 Conclusions

Overall, the 2018 Needs Assessment results indicate that Bonneville is energy- limited. For example, the P10 Heavy Load Hour deficits surpass the P10 Superpeak deficits in most months and the P10 Superpeak deficits are larger than the 18-Hour Capacity deficits. As such, meeting the P10 Heavy Load Hour needs will also solve many of the other needs identified in this Needs Assessment. Bonneville's largest projected needs for energy occur in the winter, followed by early spring and fall. Bonneville is not forecasting a winter capacity need during the 20-year forecast period but does see a summer capacity need as early as 2025.

As noted above, given considerable uncertainty in future demand for balancing reserves, this Needs Assessment includes a qualitative analysis of balancing reserve needs. Bonneville will continue to monitor the balancing reserves landscape and address the topic as warranted in future Needs Assessments.

Section 3: Resource Assessment

3.1 Generation Resources

The 2018 Resource Program relied upon the Northwest Power and Conservation Council's Seventh Power Plan for cost and performance characteristics for the generating resources considered in the optimization process. Resources were not pre-screened or selected on the basis of relative levelized costs of energy (LCOE) or capacity (LCOC). Whether a given generating resource offers an economic advantage relative to another is determined in the optimization process. What follows is a brief summary of the plant types considered herein. A more detailed exposition of each reference plant's costs and characteristics may be found in Appendix H of the Seventh Power Plan[1].

- **Simple-Cycle Combustion Turbine**: General Electric's LMS100 Single Cycle Combustion Turbine serves as the peaking thermal resource considered in the optimization portion of the Resource Program. This plant was chosen for flexibility, ability to meet a mix of load conditions, and its widespread use in the Western Electricity Coordination Council as a peaking resource. While the final draft of the Seventh Power Plan does not include the LMS100 as a reference plant for its aeroderivative class, the version of MicroFin, a tool used for calculating resource costs, used in preparation for the Resource Program contains cost and performance characteristics for the LMS100 and provides the foundation for the assumptions used here.
- **Wind**: Bonneville modeled one type of wind resource as if it were sited in the Columbia River Basin and used assumptions from the Council's Seventh Power Plan. Bonneville estimated wind output for the forecast period using its risk model designed for rate-setting evaluations in conjunction with AURORA®.
- **Solar**: Both single-axis and fixed-axis utility-scale solar resources were considered. The Seventh Power Plan assumptions were used for the single-axis resource, as those cost estimates were made available through the regional Generating Resources Advisory Committee. However, to make regionally relevant assumptions for fixed-axis resources, Bonneville compared capital cost outlooks between single and fixed-axis solar resources from forecasts provided by private consultants to determine a vector of scalars and applied them to the Council's assumptions. On average, Bonneville assumes that fixed-axis solar capital costs are 93% of their single-axis counterparts. Recognizing that the outlook for solar costs has declined since the Seventh Power Plan was drafted, Bonneville expects lower capital costs assumptions in the next Resource Program.

3.2 Conservation Supply Curves

3.2.1 Overview

Historically, Bonneville has included conservation as a fixed input in the Resource Program. In past Resource Programs, a share of the Council's Power Plan conservation target was assumed to be achieved by its public power customers, and that amount of conservation was included as a defined resource that would be applied to meet Bonneville's needs. The remaining needs, after accounting for expected savings from conservation, would be met with other potential resources.

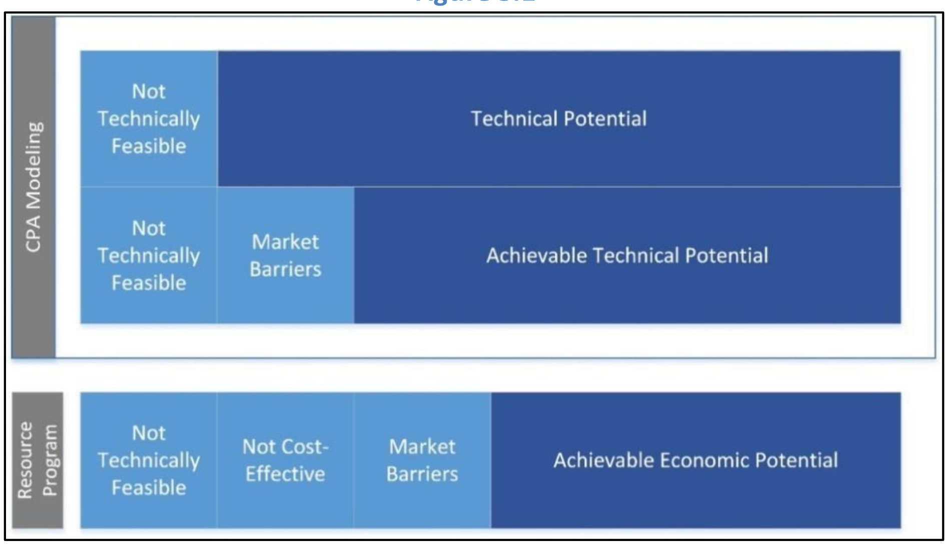
[1] https://www.nwcouncil.org/sites/default/files/7thplanfinal_appdixh_gresources_3.pdf

With the enhancement of this Resource Program, Bonneville is now able to assess conservation in line with other available supply and demand side resources. An available amount of conservation was provided to the optimization model which then compared and selected resources based on need, availability and cost. To determine the amount of conservation to be input into the optimization model, Bonneville developed a Conservation Potential Assessment (CPA). The CPA identifies the amount and costs of energy efficiency measures available from the loads supplied by Bonneville and its' customers over the planning horizon.

BPA contracted with Cadmus and EES Consulting to develop estimates of the magnitude, timing, and costs of conservation resources available over a 20-year horizon, beginning in 2020. This study identifies two types of conservation potential—technical and achievable technical—in each major sector (residential, commercial, industrial, agricultural, and distribution efficiency).

The CPA quantified two of three types of potential commonly identified by conservation potential studies. The third type of potential, economic potential, is determined by the optimization model. The three types of potential are defined below and illustrated in Figure 3.1.

Figure 3.1



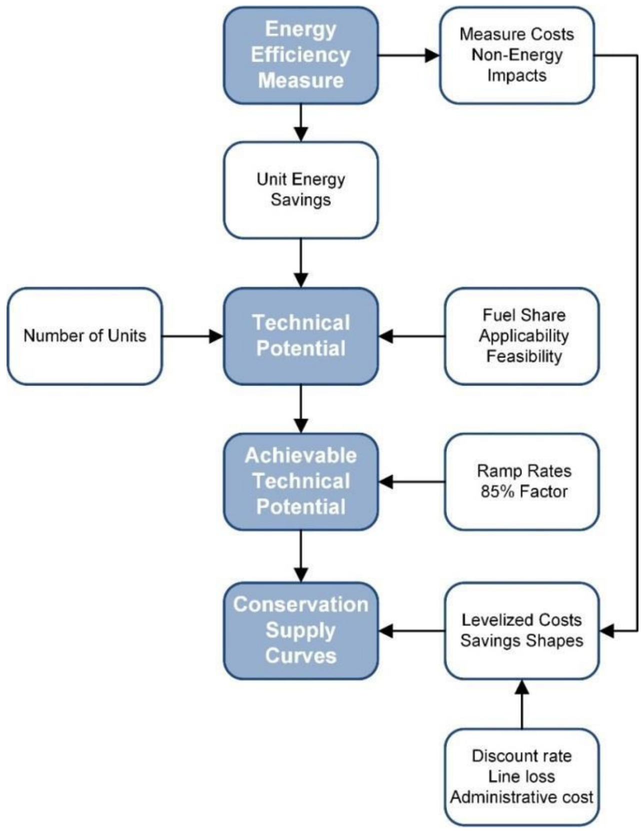
3.2.2 Methodology and Inputs

The methods used in the development of the CPA were based on the Council's Seventh Power Plan. Conservation potential supply curve workbooks were developed that replicate the calculations used for the Seventh Power Plan, incorporating market data (such as saturations, applicability, and sector loads) and planning assumptions (financial assumptions and ramp rates) specific to Bonneville/customer load obligation. To provide up-to-date estimates of conservation potential, changes that have taken place since the completion of the Seventh Power Plan were incorporated, including updates to baselines, changes to Regional Technical Forum (RTF)-approved measures, new standards, and Bonneville's load forecast.

Consistent with the Council's methodology, a units-based approach was used to forecast conservation potential in the residential, commercial, and agricultural sectors. For the industrial and distribution efficiency sectors, a top-down method, also consistent with the Council's methodology, was applied. For the distribution efficiency sector, savings were estimated as a percentage of the total utility load.

Figure 3.2 provides a general overview of the process and inputs required to estimate potential and develop conservation supply curves.

Figure 3.2



The Cadmus Team developed conservation supply curves to allow Bonneville's optimization model to identify cost-effective levels of conservation. The optimization model required hourly forecasts of conservation potential. To produce these hourly forecasts, hourly savings shapes were applied to annual estimates of achievable technical potential for each measure. These savings shapes are the same as those used in the Seventh Power Plan and by the RTF.

Cadmus worked with Bonneville to determine the format of inputs into the optimization model. The conservation potential forecasts were bundled into three categories:

1. Levelized cost bin (such as measures that cost between $10 per MWh and $20 per MWh).
2. Measure type (discretionary or lost opportunity).
3. End-use group (such as HVAC, lighting, or water heating)

Overall, 90 conservation bundles with different costs, measure types, and end use groups were used in the optimization process.

For this Resource Program, Bonneville applied a total resource cost approach to calculating the levelized cost of the savings. This approach includes costs of the measure, regardless of the entity that pays for it. Benefits are also quantified and netted off the cost, for a final net levelized cost that is input to the optimization model. Benefits include avoided generation, avoided transmission and quantifiable non-energy benefits such as water savings and reduction to operations and maintenance costs. The 10% Regional Act Credit is applied within the optimization model rather than within in the CPA. Additional details on all the costs and benefits included in the CPA and optimization model can be found on page 29 of the CPA report[2].

3.2.3 Results

Table 3.1 presents the 20-year cumulative conservation savings potential by sector. Over the 20-year period, the study identified just over 1,800 aMW of savings potential. These savings were predominately available in the residential sector due to the high saturation of electric heating usage within the loads served by Bonneville's public power utility customers.

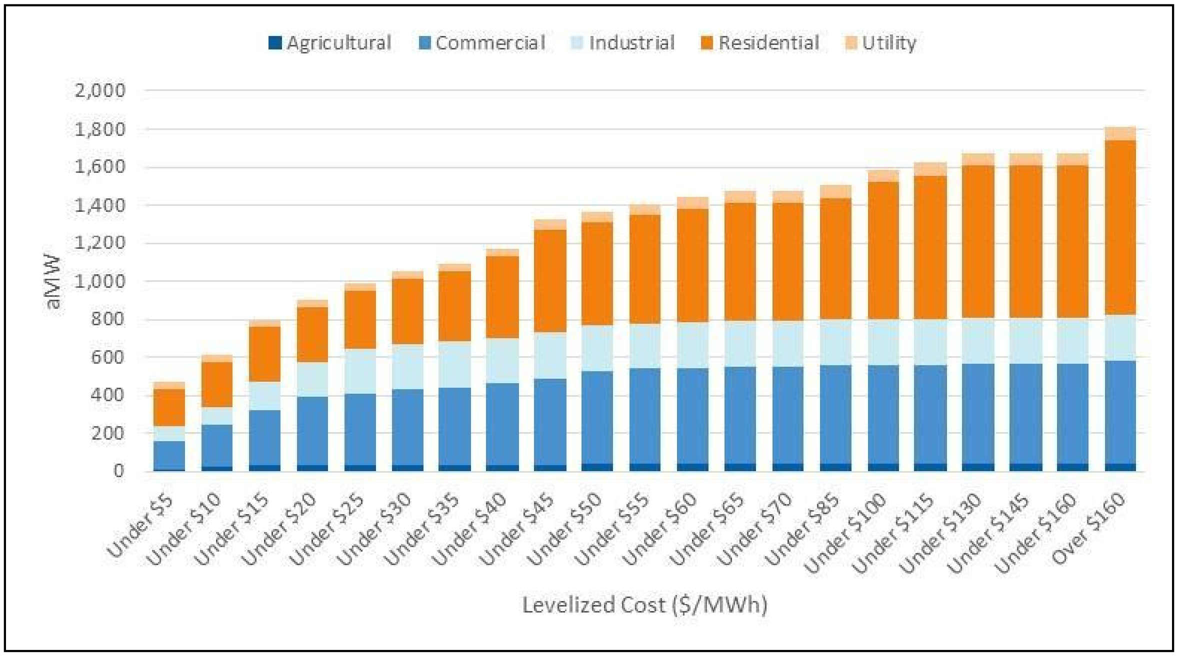
Table 3.1

20 Year Cumulative Savings Potential		
Sector	**aMW**	**% of Total Potential**
Agriculture	39	2%
Commercial	542	30%
Utility	67	4%
Industrial	243	13%
Residential	920	51%
Total	**1,812**	**100%**

Conservation savings are available at a range of levelized total resource cost (TRC). Figure 3.3 below shows the cumulative 20-year savings stacked by levelized cost bundle. As the figure demonstrates, over 400 aMW of conservation was identified at a levelized TRC less than $5/MWh. Some of these measures include a negative levelized TRC as a result of including all total quantifiable benefits and those benefits exceeding the cost of the measure.

[2] https://www.bpa.gov/EE/Utility/research-archive/Documents/BPA_Conservation_Potential_Assessment_2020-2039.pdf

Figure 3.3



3.3 Demand Response Supply Curves

Demand response is considered as a potential solution to meeting the capacity needs identified in the Needs Assessment. BPA contracted with Cadmus Group to conduct a demand response (DR) potential assessment. The assessment identified 14 DR products with distinct cost and seasonal profiles. The full potential assessment, including methodological discussion, is available on BPA's website[3].

The following tables summarize the achievable potential by season and percentage of system peak, as well as the demand response supply curves by product class for Bonneville served load. As with conservation, the determination of economic potential was done in the optimization process. Table 3.2 reflects all achievable potential.

Table 3.2

Base Case Achievable Potential				
Area	**Winter Achievable Potential (MW)**	**Percent of Area System Peak—Winter**	**Summer Achievable Potential (MW)**	**Percent of Area System Peak—Summer**
West	1061	9.9%	807	10.8%
East	490	9.6%	795	13.5%
Total	**1551**	**9.8%**	**1602**	**12.0%**

[3] https://www.bpa.gov/EE/Technology/demand-response/Pages/Resources.aspx

The base case was developed by establishing benchmarks of participation rates in common DR programs. These participation rates are generally a median value and are intended to depict participation in a robust, established DR program. Most of the products reach a full ramp within seven years, then grow according to anticipated load rate changes. The contributions to system peak that were identified for Bonneville are consistent with values observed in other regions in the United States.

The costs shown below (Table 3.3) are 20-year levelized TRC typical for long-term power planning. The TRC includes consumer costs, local utility costs, Bonneville costs, and other miscellaneous overhead (e.g., staff time, incentives, permits, marketing, etc.). Costs are escalated by the rate of inflation (~2%) in nominal terms then discounted to arrive at present-day values over the 20-year period. These costs are not comparable to, for example, one-hour spot-market capacity prices. Further, such costs are not directly comparable to costs to implement the potential DR in 2018 because they are long term planning cost estimates.

Table 3.3

Product	Winter Achievable Potential (MW)	Percent of Area System Peak - Winter	Levelized Cost ($/kW-year)	Summer Achievable Potential (MW)	Percent of Area System Peak - Summer	Levelized Cost ($/kW-year)
Residential DLC—Space Heating	206	1.3%	$53	0	0.0%	n/a
Residential DLC—Water Heating	389	2.5%	$122	285	2.1%	$167
Residential DLC—CAC	0	0.0%	n/a	113	0.8%	$74
Residential DLC—Smart Thermostat	222	1.4%	$47	120	0.9%	$88
Residential CPP	168	1.1%	$10	57	0.4%	$12
Residential Behavioral DR	37	0.2%	$110	13	0.1%	$111
Commercial DLC—CAC	0	0.0%	n/a	110	0.8%	$29
Commercial Lighting Controls	44	0.3%	$32	55	0.4%	$32
Commercial Thermal Storage	0	0.0%	n/a	9	0.1%	$51
C&I Demand Curtailment	184	1.2%	$85	205	1.5%	$85
C&I Interruptible Tariff	62	0.4%	$73	69	0.5%	$73
Industrial RTP	5	0.0%	$35	5	0.0%	$34
Agricultural Irrigation DLC	0	0.0%	n/a	420	3.1%	$44
Utility System DVR	225	1.4%	$11	133	1.0%	$12
Total	**1,541**	**9.8%**		**1,592**	**11.9%**	

In the optimization process, Bonneville only considered the summer products as solutions available for portfolio selection, given that the Needs Assessment showed no winter needs. Furthermore, since the costs presented above are levelized fixed costs, a methodology was constructed to credit the resources with an avoided energy benefit for the four-hour dispatch period in which they would most likely be called upon to avoid peak events. This methodology was implemented during the optimization phase of the model.

3.4 Wholesale Energy Market

3.4.1 Wholesale Market Price Forecast

Bonneville used AURORA® to generate a 20-year forecast of Mid-Columbia (Mid-C) prices. This forecast consists of a distribution of 400 risk-informed hourly forecasts, sampling two weeks per month. Each of the 400 forecasts is the product of a unique water year sequence, natural gas price forecast, WECC-wide load forecast, hourly wind generation pattern, schedule of Columbia Generating Station outages, and hourly transmission path rating (as applied to the AC, DC and BC interties). Price at a given hub is the cost of serving an incremental megawatt of load, as served by the least cost available resource.

The WECC load forecast is consistent with Bonneville's 2015 forecast except for California, which has been updated to be consistent with California Energy Commissions 2016 IERP Mid Demand-Mid AAEE load forecasts.

Bonneville's AURORA® resource build is informed by several processes. First, data from the U.S. Energy Information Administration's database of planned and sited additions and retirements over the horizon of the BP-18 rate period was referenced against additional data from sources such as Bonneville's Transmission Interconnection Queue, WECC's Transmission Expansion Planning Policy Committee, the California Energy Commission, the California Public Utilities Commission, and third-party consultant reports to create a set of planned additions and retirements to the default AURORA® resource stack. Bonneville then added sufficient generic resources to this stack to meet state renewable portfolio standards. Additionally, estimated levels of behind-the-meter, rooftop solar photovoltaic additions in California were included from the California Energy Commission forecast. Finally, AURORA®s long-term capacity expansion mode was used to add and retire thermal resources. AURORA® adds and retires resources based on economics and an operating reserve margin, which guarantees that sufficient generating resources are available to meet peak load plus 15 percent. Resources that are not expected to at least cover their costs are retired.

This price forecast reflects the effects from applicable state Renewable Portfolio Standards (RPS) on utilities within the WECC enacted as of January 1, 2017 (e.g., utilities in California and Oregon are set to achieve their 50 percent targets, it is assumed that California meets 80 percent of its incremental RPS needs with in-state solar resources). The updated California distributed generation forecast resulted in a doubling of the estimated rooftop solar capacity by 2030—going from about 8,500 MW of installed capacity in the 2015 price forecast to a little over 17,000 MW. In addition to the downward pressure on expected Mid-C prices, the substantial growth in California solar generation increasingly drives changes in intra-day Mid-C price shapes (Figure 3.6).

This forecast also incorporates a simplistic depiction of negative variable costs for renewable resources (driven by such things as federal production tax credits for wind resources, renewable energy credits, and power purchase agreements) in which all WECC renewable resources are given variable costs of about -$23/MWh. Impacts from including negative prices are most apparent on Mid-C prices in the near term during spring off-peak hours. As California reaches its 2030 RPS target, we see high midday solar output driving lower prices in the spring on-peak hours both in California and Mid-C markets.

The following Figures depict the results of the price forecast. Figure 3.4 depicts and annual average price for all hours by year. Figure 3.5 depicts average monthly prices for all hours by each month for the years 2025, 2030 and 2035. Figure 3.6 depicts the average hourly prices by hour in the month of May for the years 2025, 2030 and 2035.

For more information about AURORA® and the risk models employed to produce this forecast, see the Power Risk and Market Price Study, BP18-E-BPA-04.

Figure 3.4

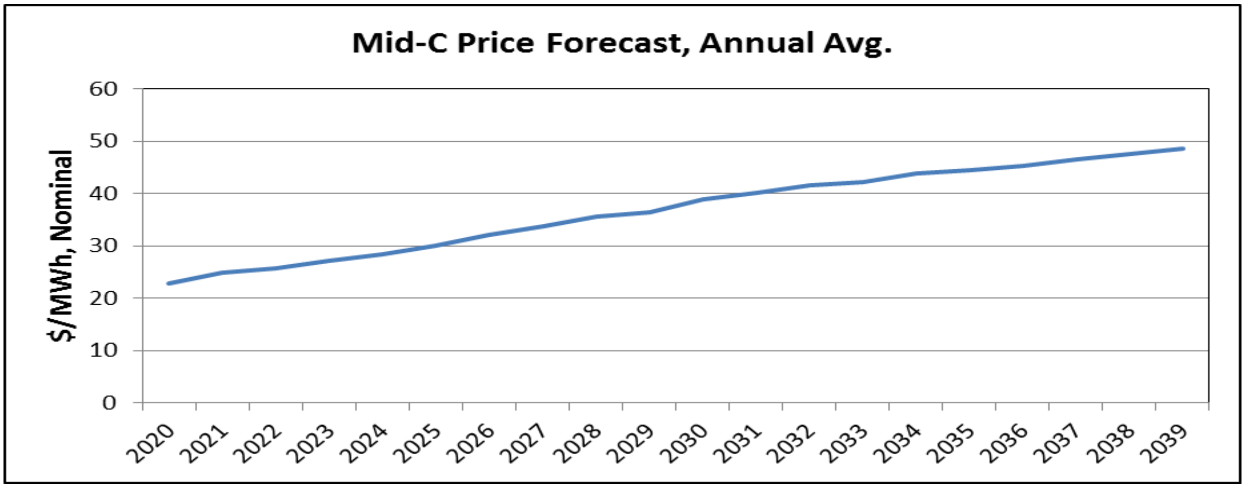


Figure 3.5

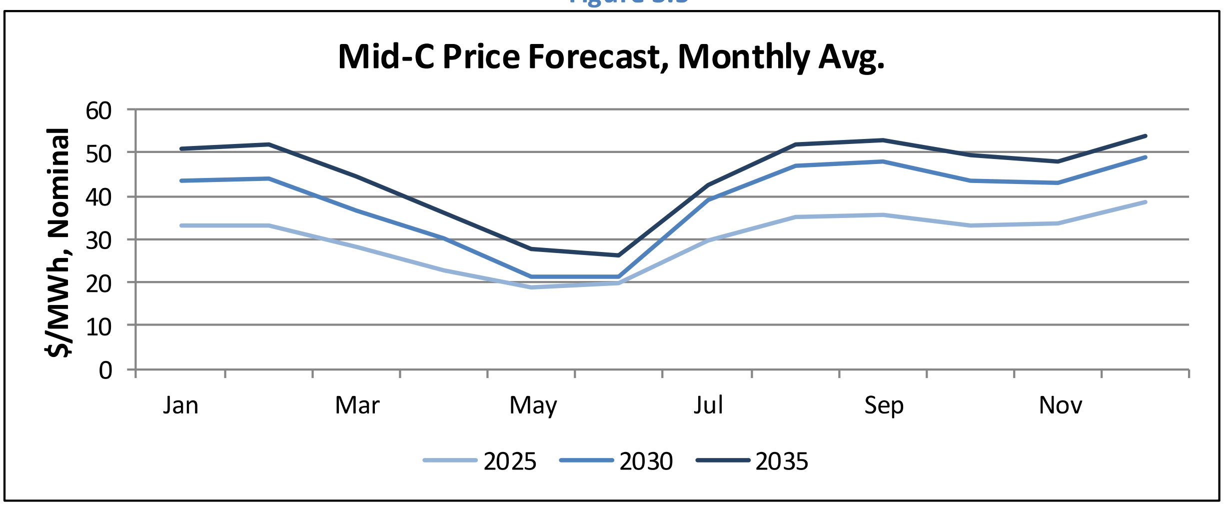
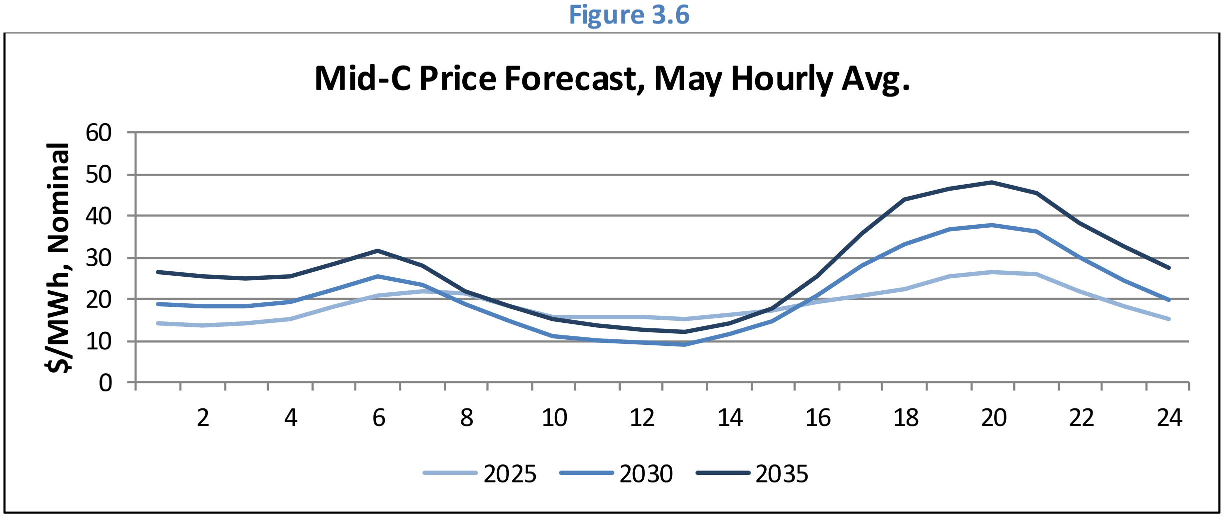


Figure 3.6



3.4.2 Market Reliance Limit

Historically, Bonneville has used an analysis of actual market availability when system conditions were stressed to determine future market reliance limits. Given expected fundamental changes in energy markets across the WECC driven by growth in renewables and sustained low natural gas prices, Bonneville used AURORA® to assess future energy availability and establish market reliance limits for the 20-year planning horizon[4]. 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 our projections of WECC load-resource balance and transmission capabilities.

Bonneville also compared the AURORA® methodology to an updated assessment using the historical method, and the two were well-aligned for the first five years of the planning horizon.

3.5 Conclusions

When exploring possible solutions to its needs, Bonneville considered a wide range of technologies including thermal generation, demand side and renewable generation. Bonneville developed much greater insight into the demand side potential within the load supplied by Bonneville and its customers via the conservation and demand response potential assessments. Additionally, Bonneville took a more detailed look to determine its market reliance thresholds with the new modeling approach.

[4] Starting with Bonneville's baseline resource build used to generate the market price forecast (see section 3.4.1), Pacific Northwest regional hydro generation is set to monthly P10 levels to represent scarcity conditions on the system, and loads are incrementally added until a 5% loss-of-load probability threshold is exceeded. It is assumed that, up until that point, the region can rely on market exchanges to meet needs rather than building or maintaining additional resources. Bonneville is then allocated a share of the load increase (market availability) proportional to its share of regional load. This is Bonneville's market reliance limit. The evaluation is done on a monthly basis with flat load additions, and the market limit is expressed in terms of monthly average heavy load hour MW.

Section 4: Optimization Model

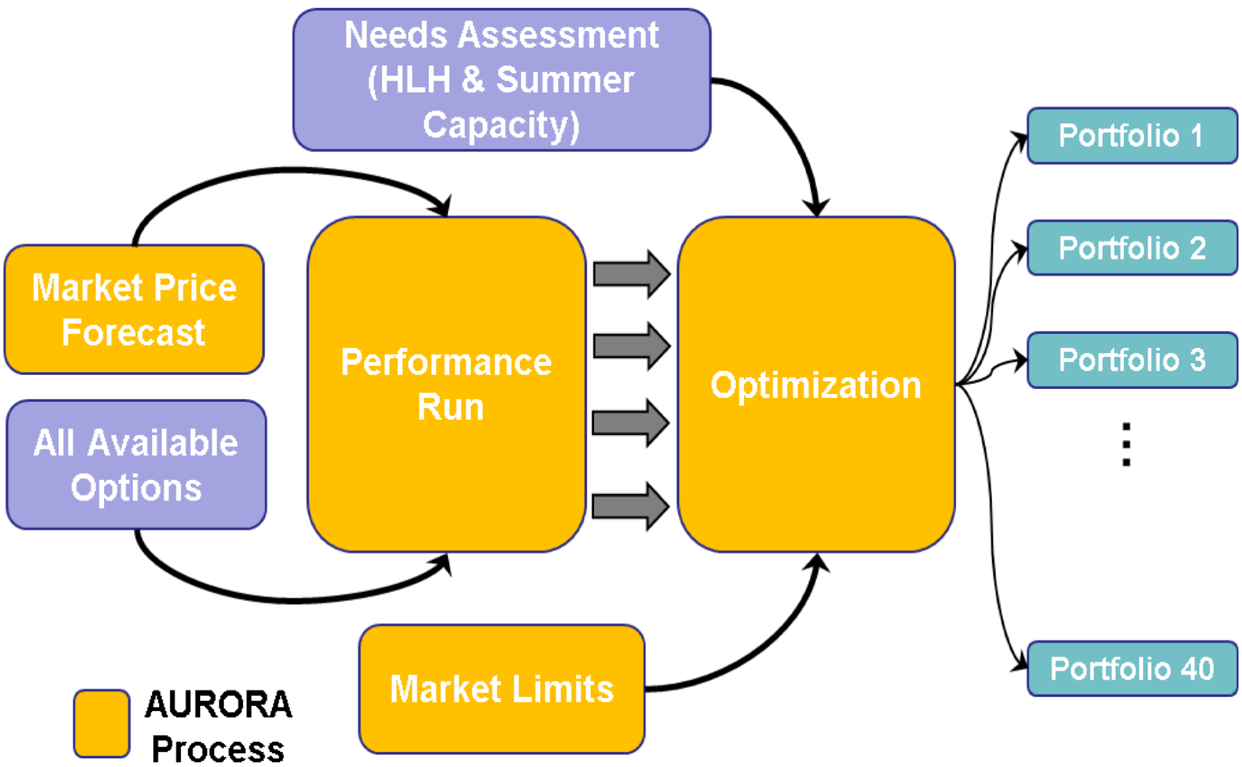
4.1 Overview

For the 2018 Resource Program, Bonneville used AURORA® to calculate combinations of resource options that satisfy its needs throughout the 20-year planning horizon at the least cost and also provide least cost alternatives that reduce risk exposure[5]. These portfolios are used to further inform Bonneville's resource strategy.

4.2 Methodology

Figure 4.1 depicts the overall process and key inputs for Bonneville's portfolio optimization. Bonneville begins by evaluating the options discussed in Section 3 against the 400 market price forecasts to assess their individual performance against the market (performance run) on an hourly basis and recording each options' contributions to the summer 18-hour capacity need. The results of the performance run, Bonneville's heavy load hour (HLH) energy and 18-hour summer capacity needs, and the market reliance limits serve as inputs for the optimization step (Figure 4.1).

Figure 4.1

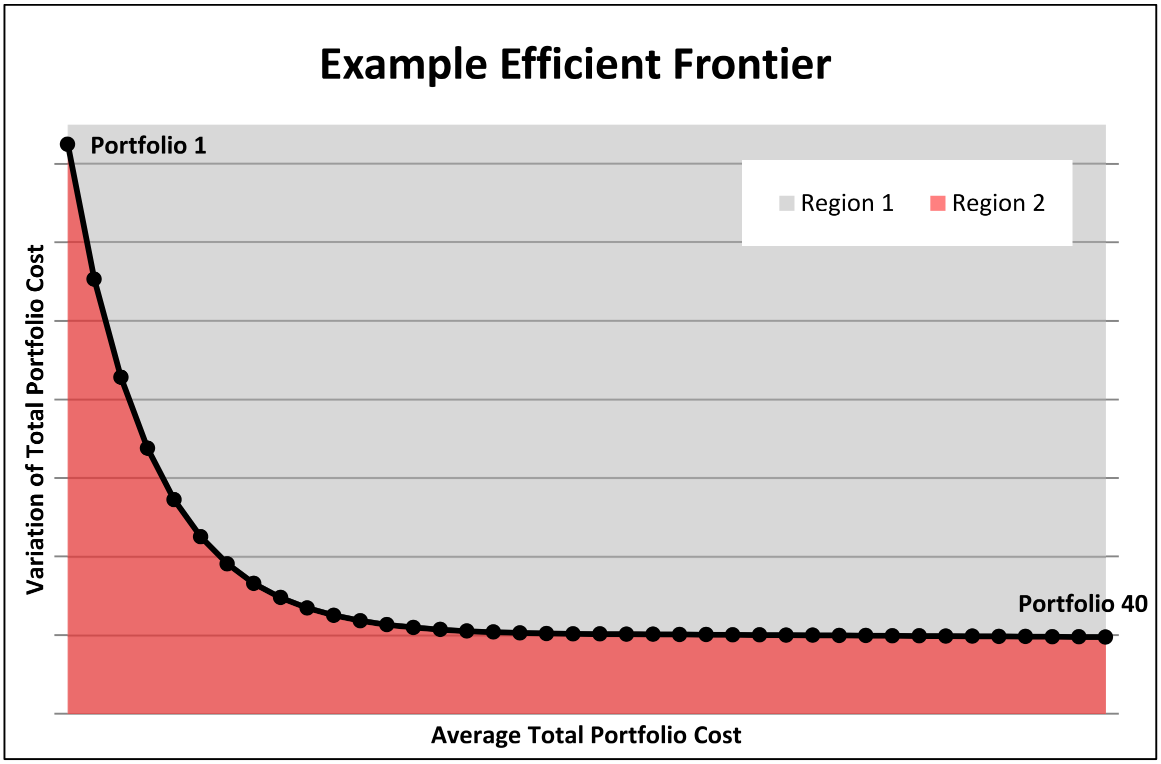


AURORA® employs a linear optimization to jointly solve for the least cost solution of meeting energy and capacity needs over the 20-year planning horizon (Portfolio 1), subject to market reliance and resource constraints. Portfolio 1 is selected without regard for variation of total portfolio costs. The process then solves for portfolios that minimize variation of total portfolio costs at progressively higher average total

[5] "Risk" is defined here as variation of total, 20-year portfolio costs across the 400 market price forecasts (see market price forecast, Section 3.4).

portfolio cost levels[6]. This results in a series of portfolios that create an efficient frontier, as demonstrated in Figure 4.2. The frontier is efficient in the sense that, at any given cost point, there is no combination of available resources that would reduce the variation of total portfolio costs; therefore, there are no viable portfolios in Region 2 (Figure 4.2).

Figure 4.2



[6] 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 (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 (Bonneville 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.

Section 5: Portfolio Optimization Results and Conclusions

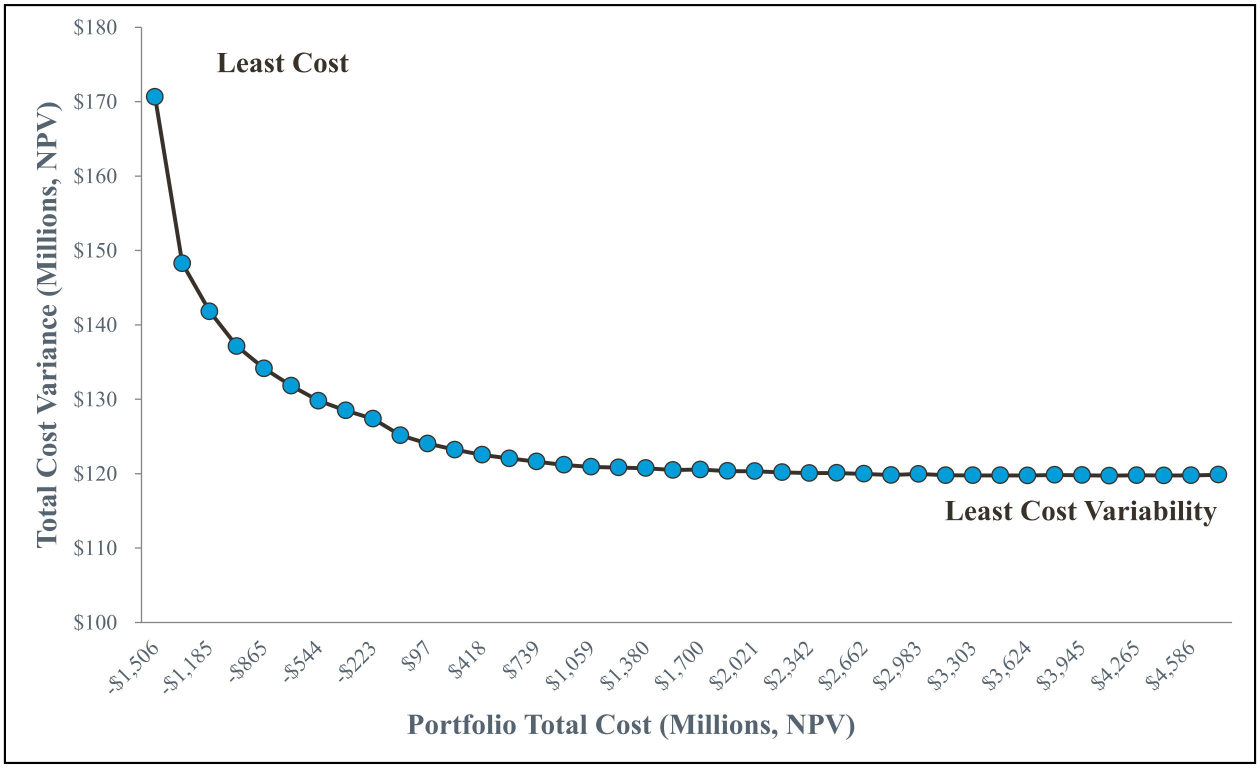
5.1 Overview

Section 5 discusses the outputs of the optimization model previously described in Section 4 and details the results.

5.2 Portfolio Results

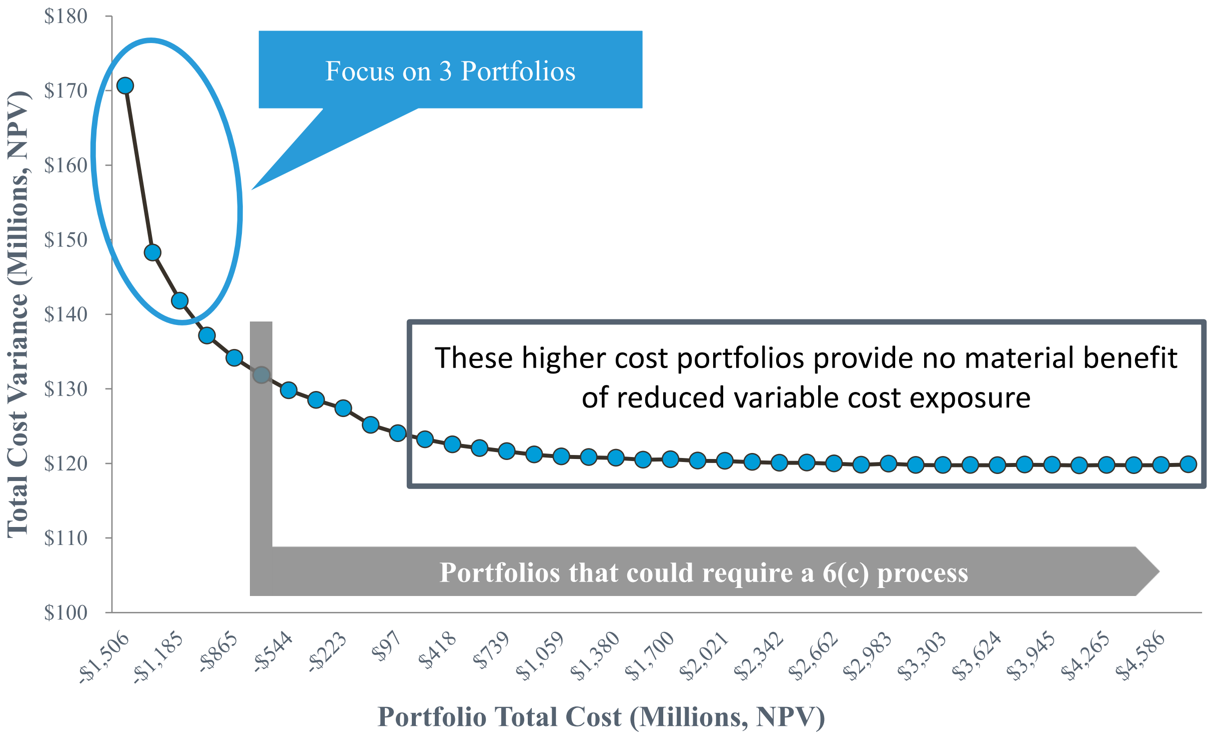
As discussed in the previous section, the AURORA® optimization process was used to produce an efficient frontier. The modeling resulted in forty different portfolios. Bonneville then analyzed the individual portfolios to evaluate the composition, magnitude of solutions selected, and cost and risk expressed in terms of net present value (NPV), of the portfolios. Figure 5.1 reflects the model output with the 40 different portfolios.

Figure 5-1



The analysis of the portfolios revealed some interesting findings. First, all the portfolios meet the stated needs from the Needs Assessment. Second, the variance in the cost of the portfolio (or risk) was relatively minor compared to the total cost of the portfolio. Additionally, as the portfolio optimization model created each subsequent portfolio, the additional total cost allowed by the model overshadowed the benefit of reduced cost variance, which quickly flattened. In other words, the costs of each subsequent portfolio increasingly outweighed the respective benefits. Further, as the model continued to acquire solutions to reduce the variability in costs, the model began to identify larger resources that would, if actually needed, trigger a major resource[7] acquisition subject to Bonneville's Section 6(c) Policy. Given the relatively minor reduction in risk compared with the increased cost of the portfolio, Bonneville focused on the three lowest cost portfolios as they offer both low cost and low relative variance. Figure 5.2 shows these three portfolios in more detail.

Figure 5.2



The three lowest cost portfolios comprise energy efficiency, market purchases and demand response. Table 5.1 provides further information about the composition of the portfolios. The Max Monthly Market Purchase reflects the maximum purchase the model made in any one month (HLH aMW). The Energy Efficiency Acquired is an annual aMW amount and the Demand Response is a MW amount. The Highest EE Cost Bundle represents the highest cost bundle from the energy efficiency supply curve the model acquired.

[7] The Northwest Power Act defines a major resource as any resource that has a planned capability greater than 50 aMw and is acquired for a period greater than five years.

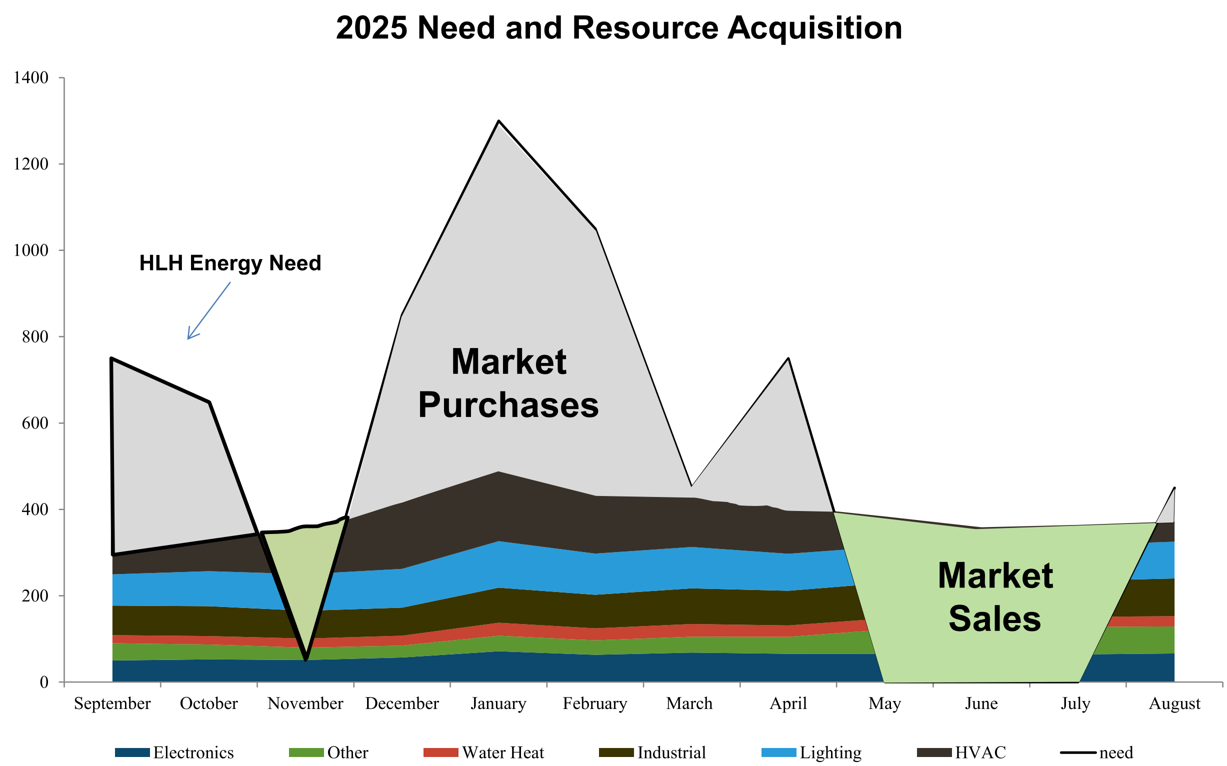
Table 5.1

Portfolio	Max Monthly Market Purchase (aMW)			Energy Efficiency Acquired (aMW)			Highest EE Cost Bundle ($/MWh)	Demand Response Acquired (MW)		
	2021	2025	2039	2021	2025	2039	All Years	2021	2025	2039
1	775	963	1,037	121	409	910	$25/MWh	40	208	255
2	737	895	887	154	516	1,141	$40/MWh	131	711	705
3	729	882	875	161	542	1,258	$50/MWh	131	711	705

The results reflect that as the model attempted to reduce the variance in costs, it did so via fewer market purchases and acquiring more energy efficiency and demand response at fixed prices in portfolios two and three.

The results of the Needs Assessment reflect that Bonneville's primary resource needs are for winter energy with additional needs in early spring and fall. Figure 5.3 depicts, in terms of average megawatt hours, the composition of the solutions the model chose to meet BPA needs in FY 2025, including energy efficiency and market purchases.

Figure 5.3



As was discussed in Section 3.2, in past Resource Programs energy efficiency was an input into the planning process. By using the prior method, information on specific measures and how they aligned with Bonneville's needs was not available. As Figure 5.3 depicts, Bonneville now has much greater insight into which energy efficiency measures are the most economical and align with the Bonneville's needs. The measures selected by the model include Heating, Ventilation and Air Conditioning (HVAC), Lighting, Industrial, Water Heat, Electronics, and "other" measures. The results also show that there are times when it is more economical to make market purchases to meet Bonneville power needs (Figure

5.3). Likewise, when Bonneville does not have the need for the energy, the model remarkets the energy at forecasted market prices and considers this in its overall economic evaluation.

5.3 Conclusions

The portfolio optimization process reveals that, in the least cost portfolios, BPA could continue to meet its energy obligations with a combination of market purchases and energy efficiency. It also concluded that demand response has the potential to be an economically effective solution for meeting Bonneville's summer capacity needs. The model results suggest that energy efficiency measures provided the best benefit in the winter and summer seasons were most favorable for meeting Bonneville's needs.

Section 6: Action Items

6.1 Next Steps

The 2018 Resource Program introduced many new concepts, methodologies and data that provided valuable new insights to meeting Bonneville's power obligations. Looking toward to the next Resource Program, Bonneville plans to further develop and refine the enhancements it has made for this Resource Program. Bonneville looks forward to working with the Northwest Power and Conservation Council, public power and interested stakeholders on these enhancements.

Bonneville will also monitor events that could change the forecasted outcomes of the 2018 Resource Program. The impacts of these events, as well as anticipated modeling enhancements and improved information and data that become available, will be incorporated into future planning activities.

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