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2020 PSE PCORC
WITNESS: CINDY L. SONG**

**BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION**

**WASHINGTON UTILITIES AND
TRANSPORTATION COMMISSION,**

Complainant,

v.

PUGET SOUND ENERGY,

Respondent

Docket UE-20____

**SECOND EXHIBIT (NONCONFIDENTIAL) TO THE
PREFILED DIRECT TESTIMONY OF**

CINDY L. SONG

ON BEHALF OF PUGET SOUND ENERGY

DECEMBER 9, 2020



2017 PSE Integrated Resource Plan



Chapters 1-8

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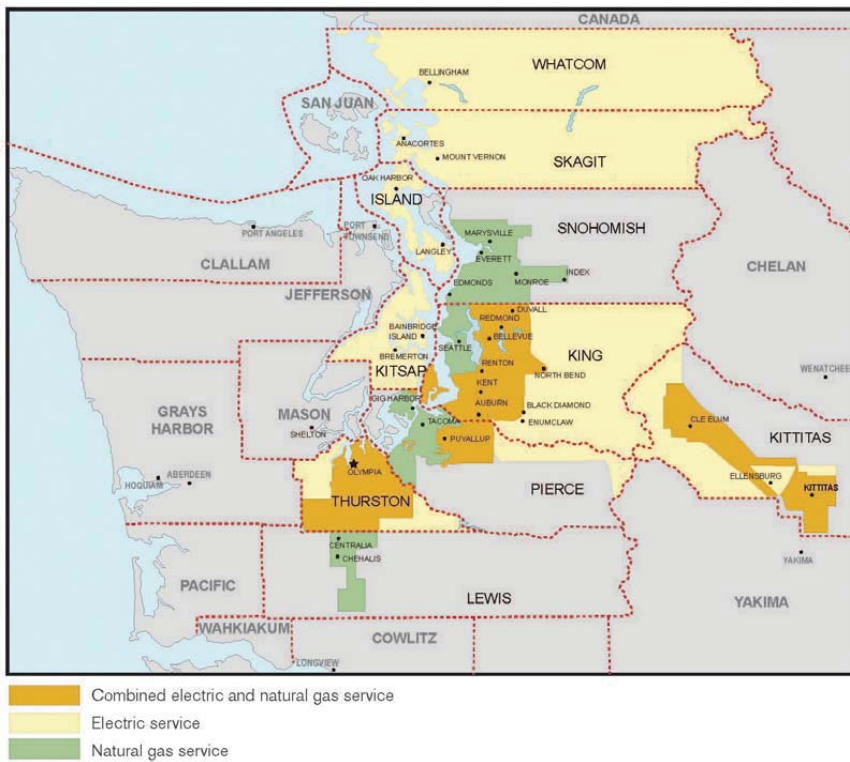
 **PUGET SOUND ENERGY**



2017 PSE Integrated Resource Plan

About PSE

Puget Sound Energy is Washington state's oldest local energy company, providing electric and natural gas service to homes and businesses primarily in the vibrant Puget Sound area. Our service area covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula. We serve more than 1.1 million electric customers and more than 800,000 natural gas customers in 10 counties.





2017 PSE Integrated Resource Plan

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*2017 PSE Integrated Resource Plan***Key Definitions and Acronyms**

| Term/Acronym | Definition |
|--------------------|---|
| AARG | average annual rate of growth |
| AB32 | The California Global Warming Solutions Act of 2006, which mandates a carbon price be applied to all power generated in or sold into that state. |
| ACE | Area Control Error |
| AECO | Alberta Energy Company, a natural gas hub in Alberta, Canada. |
| AMI | advanced metering infrastructure |
| AMR | automated meter reading |
| aMW | The average number of megawatt-hours (MWh) over a specified time period; for example, 175,200 MWh generated over the course of one year equals 20 aMW (175,200 / 8,760 hours). |
| AOC | Administrative Order Of Consent |
| ARMA | autoregressive moving average |
| AURORA | One of the models PSE uses for integrated resource planning. AURORA uses the western power market to produce hourly electricity price forecasts of potential future market conditions. |
| BA | Balancing Authority, the area operator that matches generation with load. |
| BAA | Balancing Authority area |
| BACT | Best available control technology, required of new power plants and those with major modifications, pursuant to EPA regulations. |
| balancing reserves | Reserves sufficient to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves must be able to ramp up and down as loads and resources fluctuate instantaneously each hour. |
| BART | Best available retrofit technology, an EPA requirement for certain power plant modifications. |
| Base Scenario | In an analysis, a set of assumptions that is used as a reference point against which other sets of assumptions can be compared. The analysis result may not ultimately indicate that the Base Scenario assumptions should govern decision-making. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|----------------------|---|
| Baseload gas plants | Baseload generators are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year. Generally combined-cycle combustion turbines (CCCTs). |
| baseload resources | Baseload resources produce energy at a constant rate over long periods at lower cost relative to other production facilities; typically used to meet some or all of a region's continuous energy need. |
| Bcf | billion cubic feet |
| BEM | Business Energy Management sector, for electric energy efficiency programs. |
| BES | Bulk Electric System |
| BPA | Bonneville Power Administration |
| BSER | Best system of emissions reduction, an EPA requirement for certain power plant construction or modification. |
| BTU | British thermal units |
| CAISO | California Independent System Operator |
| capacity factor | The ratio of the actual generation from a power resource compared to its potential output if it was possible to operate at full nameplate capacity over the same period of time. |
| CAP | Corrective action plans. A series of operational steps used to prevent system overloads or loss of customers' power. |
| CAR | the Washington state Clean Air Rule |
| CARB | California Air Resources Board |
| CCCT | Combined-cycle combustion turbine. These are baseload gas plants that consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine exhaust and use it to produce additional electricity via a steam turbine generator. |
| CCR | coal combustion residuals |
| CCS | carbon capture and sequestration |
| CDD | cooling degree day |
| CEC | California Energy Commission |
| CI | confidence interval |
| CNG | compressed natural gas |
| CO ₂ | carbon dioxide |
| CO ₂ e | carbon dioxide equivalents |
| COE | U.S. Army Corps of Engineers |
| contingency reserves | Reserves added in addition to balancing reserves; contingency reserves are intended to bolster short-term reliability in the event of forced outages and are used for the first hour of the event only. This capacity must be available within 10 minutes, and 50 percent of it must be spinning. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|------------------------|--|
| CPI | consumer price index |
| CPP | federal Clean Power Plan |
| CPUC | California Public Utilities Commission |
| CRAG | PSE's Conservation Resource Advisory Group |
| CT | Natural gas-fired combustion turbine, also referred to as a "peaker." |
| CVR | conservation voltage reduction |
| Demand response | Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. |
| demand-side resources | These resources reduce load and originate on the customer side of the meter. PSE's primary demand-side resources are energy efficiency and customer programs. |
| Deterministic analysis | Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity. |
| distributed generation | Small-scale electricity generators like rooftop solar panels, located close to the source of the customer's load. |
| DOE | U.S. Department of Energy |
| DSM | demand-side measure |
| DSO | Dispatcher Standing Order |
| DSR | demand-side resources |
| Dth | dekatherms |
| dual fuel | Refers to peakers that can operate on either natural gas or distillate oil fuel. |
| EIA | U.S. Energy Information Agency |
| EIM | The Energy Imbalance Market operated by CAISO. |
| EIS | environmental impact statement |
| EITEs | energy-intensive, trade-exposed industries |
| ELCC | Expected load carrying capacity. The peak capacity contribution of a resource relative to that of a gas-fired peaking plant. |
| ELCC | expected load carrying capacity |
| EMC | Energy Management Committee |
| energy need | The difference between forecasted load and existing resources. |
| energy storage | A variety of technologies that allow energy to be stored for future use. |
| EPA | U.S. Environmental Protection Agency |
| EPRI | Electric Power Research Institute |
| EPS | Washington state law RCW 80.80.060(4), GHG Emissions Performance Standard |
| ERU | Emission reduction units. An ERU represents one MtCO ₂ per year. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|------------------------|---|
| ESS | energy storage systems |
| EUE | Expected unserved energy, a reliability metric measured in MWhs that describes the magnitude of electric service curtailment events (how widespread outages may be). |
| EV | electric vehicle |
| FERC | Federal Energy Regulatory Commission |
| FIP | final implementation plan |
| GDP | gross domestic product |
| GENESYS | The resource adequacy model used by the Northwest Power and Conservation Council (NPCC). |
| GHG | greenhouse gas |
| GPM | gas portfolio model |
| GRC | General Rate Case |
| GTN | Gas Transmission Northwest |
| GW | gigawatt |
| HDD | heating degree day |
| HVAC | heating, ventilating and air conditioning |
| I-937 | Initiative 937, Washington state's renewable portfolio standard (RPS), a citizen-based initiative codified as RCW 19.285, the Energy Independence Act. |
| iDOT | Investment Optimization Tool. An analysis tool that helps to identify a set of projects that will create maximum value. |
| IGCC | Integrated gasification combined-cycle, generally refers to a model in which syngas from a gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier. |
| intermittent resources | Resources that provide power that offers limited discretion in the timing of delivery, such as wind and solar power. |
| IOU | investor-owned utility |
| IPP | independent power producer |
| IRP | integrated resource plan |
| IRPAG | PSE's Integrated Resource Plan Advisory Group |
| ISO | independent system operator |
| ITA | independent technical analysis |
| ITC | investment tax credit |
| KORP | Kingsvale-Oliver Reinforcement Project pipeline proposal |
| kV | kilovolt |
| kW | kilowatt |
| kWh | kilowatt hours |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|---------------------------------|--|
| LAES | liquid air energy storage |
| LNG | liquified natural gas |
| load | The total of customer demand plus planning margins and operating reserve obligations. |
| LOLH (or LOLE) | Loss of load hours (or loss of load energy), a reliability metric focused on the duration of electric service curtailment events (how long outages may last). |
| LOLP | Loss of load probability, a reliability metric focused on the likelihood of an electric service curtailment event happening. |
| LP-Air | vaporized propane air |
| LSR | Lower Snake River Wind Facility |
| MATS | Mercury Air Toxics Standard |
| MDEQ | Montana Department of Environmental Quality |
| MDQ | maximum daily quantity |
| MDth | thousand dekatherms |
| MEIC | Montana Environmental Information Center |
| MESA | Modular Energy Storage Architecture. A protocol for communications between utility control centers and energy storage systems. |
| Mid-Columbia (Mid-C) market hub | The principle electric power market hub in the Northwest and one of the major trading hubs in the WECC, located on the Mid-Columbia River. |
| MMBtu | million British thermal units |
| MMtCO ₂ e | million metric tons of CO ₂ equivalent |
| MSA | metropolitan statistical area |
| MW | megawatt |
| MWh | megawatt hour |
| NAAQS | National Ambient Air Quality Standards, set by the EPA, which enforces the Clean Air Act, for six criteria pollutants: sulfur oxides, nitrogen dioxide, particulate matter, ozone, carbon monoxide and lead. |
| nameplate capacity | The maximum capacity that a natural gas fired unit can sustain over 60 minutes when not restricted to ambient conditions. |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Council |
| net maximum capacity | The capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads. |
| net metering | A program that enables customers who generate their own renewable energy to offset the electricity provided by PSE. |
| NGV | natural gas vehicles |
| NO ₂ | nitrogen dioxide |
| NOS | Network Open Season, a BPA transmission planning process |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|----------------------------|--|
| NO _x | nitrogen oxides |
| NPCC | Northwest Power & Conservation Council |
| NPV | net present value |
| NRC | Nuclear Regulatory Commission |
| NREL | National Renewables Energy Laboratories |
| NRF | Northwest Regional Forecast of Power Loads and Resources, the regional load/balance study produced by PNUCC. |
| NSPS | New source performance standards, new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction. |
| NUG | non-utility generator |
| NWE | NorthWestern Energy |
| NWGA | Northwest Gas Association |
| NWP | Northwest Pipeline |
| NWPP | Northwest Power Pool |
| OASIS | Open Access Same-Time Information System |
| OATT | Open Access Transmission Tariff |
| OTC | once-through cooling |
| PACE | PacifiCorp East |
| PACW | Pacificorp West |
| PCA | power cost adjustment (electric) |
| PCORC | power cost only rate case |
| peak need | Electric or gas sales load at peak energy use times. |
| peaker (or peaking plants) | Peaker is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. They are not intended to operate economically for long periods of time like baseload generators. |
| peaking resources | Quick-starting electric generators that can ramp up and down quickly in order to meet short-term spikes in need, or gas sales resources used to meet load at times when demand is highest. |
| PEFA | ColumbiaGrid's planning and expansion functional agreement, which defines obligations under its planning and expansion program. |
| PEV | plug-in electric vehicle |
| PG&E | Pacific Gas and Electric Company |
| PGA | purchased gas adjustment |
| PGE | Portland General Electric |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PIPES Act | Pipeline Inspection, Protection, Enforcement, and Safety Act (2006) |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|-----------------------|--|
| planning margin or PM | These are amounts over and above customer peak demand that ensure the system has enough flexibility to handle balancing needs and unexpected events. |
| planning standards | The metrics selected as performance targets for a system's operation. |
| PLEXOS | An hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real-time to match changes in supply and demand on a 5-minute basis. |
| PM | particulate matter |
| PNUCC | Pacific Northwest Utilities Coordinating Committee |
| PNW | Pacific Northwest |
| portfolio | A specific mix of resources to meet gas sales or electric load. |
| PPA | Purchased power agreement. A bilateral wholesale or retail power short-term or long-term contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point. |
| PRP | Pipeline Replacement Program |
| PSE | Puget Sound Energy |
| PSIA | Pipeline Safety Improvement Act (2002) |
| PSM | Portfolio screening model, a model PSE uses for integrated resource planning, which tests electric portfolios to evaluate PSE's long-term revenue requirements for those portfolios. |
| PSRC | Puget Sound Regional Council |
| PTC | Production Tax Credit, a federal subsidy for production of renewable energy that applied to projects that began construction in 2013 or earlier. When it expired at the end of 2014, it amounted to \$23 per MWh for a wind project's first 10 years of production. |
| PTP | Point-to-point transmission service, meaning the reservation and transmission of capacity and energy on either a firm or non-firm basis from the point of receipt (POR) to the point of delivery (POD). |
| PTSA | Precedent Transmission Service Agreement |
| PUD | public utility district |
| pumped hydro | Pumped hydro facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station. |
| PV | photovoltaic |
| R&D | research and development |
| RAM | Resource Adequacy Model. RAM analysis produces reliability metrics (EUE, LOLP, LOLH) that allow us to assess physical resource adequacy. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|-------------------------|--|
| rate base | The amount of investment in plant devoted to the rendering of service upon which a fair rate of return is allowed to be earned. In Washington state, rate base is valued at the original cost less accumulated depreciation and deferred taxes. |
| RCRA | Resource Conservation Recovery Act |
| RCW | Revised Code of Washington |
| RCW 19.285 | Washington's state's Energy Independence Act, commonly referred to as the state's renewable portfolio standard (RPS) |
| RCW 80.80 | Washington state law that sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh. |
| REC | Renewable energy credit. RECs are intangible assets which represent the environmental attributes of a renewable generation project – such as a wind farm – and are issued for each MWh of energy generated from such resources. |
| REC banking | Washington's renewable portfolio standard allows for RECs unused in the current year to be “banked” and used in the following year. |
| redirected transmission | “Redirecting” transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change. |
| regulatory lag | The time that elapses between establishment of the need for funds and the actual collection of those funds in rates. |
| REM | Residential Energy Management sector, in energy efficiency programs. |
| repowering | Refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015. |
| revenue requirement | Rate Base x Rate of Return + Operating Expenses |
| RFP | request for proposal |
| RPS | Renewable portfolio standard. It requires electricity retailers to acquire a minimum percentage of their power from renewable energy resources. Washington state mandates 3 percent by 2012, 9 percent by 2016 and 15 percent by 2020. |
| RTO | regional transmission organization |
| SCADA | supervisory control and data acquisition |
| SCCT | Simple-cycle combustion turbine, natural gas-fired unit used for meeting peak resource need (also called a “peaker”) |
| scenario | A consistent set of data assumptions that defines a specific picture of the future; takes holistic approach to uncertainty analysis. |
| SCR | selective catalytic reduction |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|-----------------------|--|
| SENDOUT | The deterministic gas portfolio model used to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads. |
| sensitivity | A set of data assumptions based on the Base Scenario in which only one input is changed. Used to isolate the effect of a single variable. |
| SEPA | Washington State Environmental Policy Act |
| SIP | State Implementation Plan |
| SNCR | selective non-catalytic reduction |
| SO ₂ | sulfur dioxide |
| SOFA system | separated over-fire air system |
| Solar PV | solar photovoltaic technology |
| Stochastic analysis | Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how different portfolios perform with regard to cost and risk across a wide range of potential future power prices, gas prices, hydro generation, wind generation, loads, plant forced outages and CO ₂ prices. |
| supply-side resources | Resources that generate or supply electric power, or supply natural gas to gas sales customers. These resources originate on the utility side of the meter, in contrast to demand-side resources. |
| T&D | transmission and distribution |
| TAG | Technical Advisory Group |
| TailVar90 | A metric for measuring risk defined as the average value of the worst 10 percent of outcomes. |
| TCPL-Alberta | TransCanada's Alberta System (also referred to as TC-AB) |
| TCPL-British Columbia | TransCanada's British Columbia System (also referred to as TC-BC) |
| TC-Foothills | TransCanada-Foothills Pipeline |
| TC-GTN | TransCanada-Gas Transmission Northwest Pipeline |
| TC-NGTL | TransCanada-Nova Gas Transmission Pipeline |
| TEPPC | WECC Transmission Expansion Planning Policy Committee |
| TF-1 | Firm gas transportation contracts, available 365 days each year. |
| TF-2 | Gas transportation service for delivery or storage volumes generally intended for use during the winter heating season only. |
| thermal resources | Electric resources that use carbon-based fuels to generate power. |
| TOP | transmission operator |
| transmission redirect | "Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|----------------------------|--|
| Transport customers | Customers who acquire their own natural gas from third-party suppliers and rely on the gas utility for distribution service. |
| UPC | use per customer |
| VectorGas | An analysis tool that facilitates the ability to model price and load uncertainty. |
| VERs | Variable energy resources |
| WAC | Washington Administrative Code |
| WACC | weighted average cost of capital |
| WCI | Western Climate Initiative |
| WCPM | Wholesale Market Curtailment Model |
| WECC | Western Electricity Coordinating Council |
| WECo | Western Energy Company |
| WEI | Westcoast Energy, Inc. |
| Westcoast | Westcoast Energy, Inc |
| Wholesale market purchases | Generally short-term purchases of electric power made on the wholesale market. |
| WSPP | Western Systems Power Pool |
| WUTC | Washington Utilities and Transportation Commission |
| ZLD | zero liquid discharge |



1

2017 PSE Integrated Resource Plan

Executive Summary

The IRP is best understood as a forecast of resource additions that appear to be cost effective given what we know today about the future. We know these forecasts will change as the future unfolds and conditions change. PSE's commitments to action are driven by what we learn through the planning exercise. These commitments are embodied in the Action Plans.

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Chapter 1: Executive Summary



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- *Gas Sales Resource Need*
- *Gas Portfolio Resource Additions Forecast*

5. THE IRP AND THE RESOURCE ACQUISITION PROCESS 1-27



1. OVERVIEW

The resource plan forecast presented in the 2017 IRP presents exciting changes in resource outlook and preserves a strategic agility that will allow PSE to respond to rapidly changing conditions as renewable and storage technologies mature, as the impacts of carbon regulation and climate change become clearer, and as customer behavior changes. The forecast relies on additional transmission to market to meet peak capacity need, continued strong investment in conservation, utility-scale solar to meet renewable resource need, and energy storage. While many of these changes have been on the horizon for some time and discussed extensively in the media and by advocacy groups, this is the first time that some appear to truly be part of a low-cost, low-risk resource plan for PSE's customers.

Exciting Changes in Resource Outlook

- **EMERGENCE OF SOLAR POWER.** Wind has dominated new renewable resource additions in the Pacific Northwest. This IRP finds solar power in eastern Washington appears to be a cost-effective renewable resource for the first time.
- **ENERGY STORAGE AND DEMAND RESPONSE INSTEAD OF FOSSIL FUEL GENERATION.** Energy storage and demand response resources can help push PSE's need for capacity resources out eight years, to 2025. This is a low-cost and low-risk strategy that helps avoid locking PSE's customers into a long-lived fossil fuel plant while alternative technology is evolving rapidly and greenhouse gas policies are being developed.
- **REDIRECTING TRANSMISSION TO INCREASE MARKET ACCESS.** PSE can reassign some transmission from intermittent wind resources to the Mid-C market in a way that will allow PSE to expand its access to short-term bilateral markets on a firm basis, while still allowing us to deliver that wind energy to our customers. Increasing market reliance is low cost alternative for our customers. This IRP includes a comprehensive analysis of market risk in relation to Pacific Northwest's resource adequacy outlook, built on Northwest Power and Conservation Council (NPCC), Bonneville Power Administration (BPA) and Pacific Northwest Utilities Conference Committee (PNUCC) analyses. It finds the region is nearly meeting its resource adequacy target, and with continued strong conservation programs, it may become even more reliable in the future. This is not without risk, but PSE has analyzed these risks extensively and concluded the risks are reasonable. Redirecting transmission supports the strategy to push out the need for additional fossil fuel plants to 2025, while rapidly evolving technology drives down the



costs of resource alternatives and uncertainty in greenhouse gas regulation can be resolved.

- **ENERGY EFFICIENCY.** One thing remains the same in this IRP – PSE's commitment to strong investment in encouraging customers to use energy more efficiently. Devoting significant resources to help our customers use energy more wisely is a tried and true way of reducing costs, cost risks and the environmental footprint of PSE's operations as well as our customers'.
- **NATURAL GAS UTILITY RESOURCE PLAN.** Strategic agility is also the hallmark of the natural gas utility resource plan. Continued conservation investment, completion of the Tacoma LNG peaking facility and the option to upgrade PSE's propane peaking facility (Swarr) push out the need to lock our natural gas customers into lengthy contracts to expand regional pipeline infrastructure. Again, this is a low-cost and low-risk resource strategy for our gas customers.

Impact of Uncertainty in Carbon Regulation

PSE recognizes the importance of mitigating climate change. The Base Scenario in this IRP models the impacts of Washington state's Clean Air Rule (CAR) and the federal Clean Power Plan (CPP). Even though the fate of both regulatory programs is uncertain at this time, some form of carbon regulation is likely to be enacted during the next 20 years, so it is important to reflect this possibility in the analysis. We expect these rules to evolve and for new ones to be developed. The resource plan presented here gives us the flexibility and agility to adapt to changes without having to commit our customers to long-lived fossil fuel resources at this time.

The design of carbon regulation is critically important to achieving meaningful carbon reductions and avoiding unintended consequences. For instance, the IRP analysis indicates that CPP rules may distort the value of peaking plants, making them appear more economic than energy storage. And, it is likely that the CAR will shift dispatch to less carbon-efficient plants by focusing only on Washington gas-fired plants, which are some of the most carbon-efficient in the Western Energy Coordinating Council (WECC), increasing carbon emissions in the region even though emissions in Washington state decline.

PSE is committed to working with policy makers and others to help modify and create approaches to greenhouse gas regulation that are effective at reducing carbon emissions in a way that minimizes the impact of costs on our customers. See Chapter 3, Planning Environment, for further discussion of this issue.



The Future of Colstrip

The coal-fired Colstrip plant emits a significant amount of greenhouse gasses, but it has historically been a very low cost resource, and PSE is obligated to minimize costs to customers within existing legal frameworks. The multiple ownership structure of Colstrip includes an independent power producer and utilities that serve load in six states, which creates a very complex decision-making process.

Units 1 & 2 are scheduled to retire no later than July, 2022, and the analysis indicates that retiring those plants earlier would be uneconomic. After Units 1 & 2 retire, additional conservation, demand response, energy storage batteries and firm transmission to market are expected to meet resource needs until 2025.

The continued operation of Units 3 & 4 is highly dependent on future environmental regulation. Analysis in this IRP demonstrates that a carbon regulation policy that adds to the dispatch cost of Colstrip would challenge its continued economic operation. Absent such a policy, Colstrip 3 & 4 appear to be economic to operate for the foreseeable future.

In the absence of Colstrip Units 3 & 4, the analysis currently indicates that peaking plants are the most cost-effective alternative to meeting need, but this conclusion will be revisited as the entire region continues to invest heavily in energy efficiency, emerging technologies continue to evolve, and the impacts of carbon regulation become clearer.



A Forecast, Not a Prescription

The IRP process is a legal mandate that requires PSE to identify the least cost combination of energy conservation and energy supply resources to meet the needs of our customers. Specific energy efficiency and supply-side resource decisions are not made in the context of the IRP. The primary value of the IRP is what we learn from the opportunity to do three things: develop key analytical tools to aid in making prudent decision making for long-term energy efficiency and energy supply, create and manage expectations about the near future, and think broadly about the next two decades.

The portfolio analysis presented in the IRP is best understood as a forecast of resource additions that appear to be cost effective given what we know today about the future. We know these forecasts will change as the future unfolds and conditions change. PSE's commitments to action are driven by what we learn through the planning exercise. These commitments are embodied in the Action Plans presented next.



2. ACTION PLANS

Action Plans vs. Resource Plan Forecasts

In recent years, the IRP has attracted more attention from policy makers, the public and advocacy groups. Many tend to interpret the resource plans produced in the IRP analysis as the plan that PSE intends to execute against. This is not the case. The resource plans are more accurately understood as forecasts of resource additions that look like they will be cost effective in the future, given what we know about the future today. What we learn from this forecasting exercise determines the Action Plan. The Action Plans describe the activities PSE will execute resulting from the forecasting exercise.

Electric Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement programs that will put us on a path to achieve an additional 374 MW of energy efficiency by 2023 through program savings combined with savings from codes and standards.

2. Demand Response

Clarify the acquisition, prudence criteria and cost recovery process for demand response programs. Issue a demand response RFP based on those findings. Re-examine the peak capacity value of demand response programs in the 2019 IRP to include day-ahead demand response programs, and use the sub-hourly flexibility modeling capability developed in this IRP to value sub-hourly demand response programs.

Pursuant to the 2015 IRP action plan, PSE issued an RFP for demand response programs in 2016. That led PSE to identify policy issues that need to be resolved with regard to demand response programs.

POLICY ISSUES. Demand response is a portfolio of programs that involves relationships with customers. Some programs are pricing structures that require revised tariffs and updates to metering and billing systems. Thus, in terms of program planning, demand response is more like conservation programs than power plants. However, demand response has been excluded from the program planning design and cost recovery process used for conservation. The current processes for establishing prudence related to acquiring power plants or contracts and recovering costs through a Power Cost Only Rate Case (PCORC) do not fit for a portfolio of demand



response programs that build over time. The WUTC has begun exploring these issues. PSE will be fully engaged, as this is a critical path item for being able to execute demand response to meet resource need and an essential component for postponing the need to build fossil fuel generation.

DEMAND RESPONSE RFP. Once there is line of sight on resolving policy barriers, PSE will issue a demand response RFP. This IRP applied the PSE resource adequacy modeling framework used for other kinds of resources to demand response. These findings will be included in the demand response RFP to provide better guidance to bidders on the value of duration, frequency, and the interval between demand response events.

VALUING ADDITIONAL TYPES OF DEMAND RESPONSE PROGRAMS. Fast-acting demand response is able to respond quickly, creating additional sub-hourly flexibility value in addition to potentially offsetting or delaying the need for a peaking generator. PSE will use its sub-hourly flexibility modeling capability to value sub-hourly demand response programs in the 2019 IRP. Another category of demand-response to examine in more detail is day-ahead programs. Although day-ahead demand response programs will not deliver the same benefit, they may still be a valuable resource, so PSE will also examine the peak capacity value of day-ahead demand response programs in its 2019 IRP.

3. Energy Storage

Install a small-scale flow battery to gain experience with the operation of this energy storage system in anticipation of greater reliance on flow batteries in the future.

4. Supply-side Resources: Issue an All-source RFP

Issue an all-source RFP in the first quarter of 2018 that includes updated resource needs and avoided cost information.

PSE has a need for renewable and capacity resources as early as 2022, after cost-effective conservation and demand response are accounted for.

RENEWABLE RESOURCES. Bringing on future additional renewable resources, whether in PSE's balancing authority or in BPA's, may require transmission system upgrades that will require long lead times to study, design, permit and construct. While this IRP finds eastern Washington solar power is more cost effective than wind, the results are close. Montana wind would be a "qualifying renewable resource" if it were delivered to Washington state on a real-time basis without shaping or storage. Addressing this qualification constraint will likely require a complex set of transmission studies, coordinated with Northwestern in Montana, BPA and



possibly the WECC. Issuing an RFP in 2018 for delivery beginning in 2022 will provide potential respondents time to address such transmission issues.

SUPPLY-SIDE RESOURCES FOR CAPACITY. While we believe that demand response and energy storage will be a reasonable, cost-effective resource that is sufficient to meet the capacity need that appears in 2022, this assumption will be investigated further in an RFP. Issuing an RFP in 2018 for delivery in 2022 is reasonable because the regional transmission system is becoming constrained, and potential respondents may need time to address these constraints, depending on the location of the proposed resources. Furthermore, some resources, like pumped hydro storage, may have long lead times. Finally, some kinds of renewable resources can contribute to meeting peak capacity, so considering capacity resources in this RFP will help align valuation processes.

5. Develop Options to Mitigate Risk of Market Reliance

Develop strategies to mitigate the risk of redirecting transmission and increasing market reliance.

PSE relies heavily on the short-term market to meet the energy and peak capacity needs of our customers. Risk associated with this exposure to market is managed in the short term; long term, however, regional resource adequacy cannot be addressed without adding new resources. If regional resource adequacy assessments are off or unexpected demand-side or supply-side shocks happen that render the region short of resources, the burden of the resulting deficits would fall on PSE's customers. Therefore, PSE will develop strategies mitigate this risk. These strategies may include:

- maintaining options to build capacity resources quickly;
- re-examining PSE policies with regard to how much of its market reliance should be managed via short-term purchases versus long-term contracts; and
- working with others in the region on options for PSE to join or to help develop functioning wholesale markets that incorporate, energy, capacity and flexibility services.



6. Energy Imbalance Market (EIM)

Continue to participate in the California Energy Imbalance Market for the benefit of our customers.

PSE's participation in the EIM allows PSE to purchase sub-hourly flexibility at 15- and 5-minute increments from other EIM participants to meet our flexibility needs when market prices are cheaper than using our own resources. Participation also gives PSE the opportunity to sell flexibility to other EIM participants when we have surplus flexibility. The benefits of lower costs on the one hand and net revenue from EIM sales on the other reduces power costs to our customers.

7. Regional Transmission

Examine regional transmission needs in the 2019 IRP in light of efforts to reduce the region's carbon footprint.

Future progress on reducing the region's carbon footprint will necessarily involve both retirement of less carbon-efficient thermal resources and the addition of renewable resources. This will make the ability of the region's transmission resources to move power to where it is needed an increasingly important issue. This examination will include the following.

- Assess the operational risk associated with redirecting transmission from PSE's existing wind resources and address those risks if necessary.
- Coordinate with the WUTC, other utilities and stakeholders to study the alternatives for re-purposing transmission used for Colstrip 1 & 2 as these units are retired.
- Begin to coordinate with other utilities and transmission providers to understand alternatives for re-purposing transmission from Colstrip 3 & 4, so that PSE will be prepared should the plant be retired earlier than anticipated.



Natural Gas Sales Action Plan

1. Acquire Energy Efficiency

Develop two-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting. This includes 14 MDth per day of capacity by 2022 through program savings and savings from codes and standards.

2. LNG Peaking Plant

Complete the PSE LNG peaking project located near Tacoma.

Construction of the facility is under way and should be completed in time for the storage project to be filled for the 2019/20 heating season. This resource is essential to delaying investment in additional interstate and international year-round pipeline capacity.

3. Option to Upgrade Swarr

Maintain the ability upgrade the Swarr propane-air injection system in Renton, which the plan forecasts will be needed by the 2024/25 heating season.

Upgrading the Swarr LP-Air facility's environmental safety and reliability systems to return the facility to its maximum output of 30 MDth per year was selected as least cost in all but the low demand scenarios in the IRP analysis. This short lead time project is also within PSE's control, and the timing of the upgrade can be fine-tuned by PSE in response to load growth.



3. ELECTRIC RESOURCE PLAN FORECAST

Electric Resource Need

PSE must meet the physical needs of our customers reliably. For resource planning purposes, those physical needs are simplified and expressed in terms of peak hour capacity for resource adequacy, hourly energy and sub-hourly flexibility. Operating reserves are included in physical needs; these are required by contract with the Northwest Power Pool and by the North American Electric Reliability Corporation (NERC) to ensure total system reliability. Beyond operating reserves, sub-hourly flexibility is also required. The robust sub-hourly analytical framework implemented in this IRP determined that PSE has sufficient sub-hourly flexibility at this time, although we will continue to refine this analysis. In addition to meeting customers' physical and sub-hourly flexibility needs, Washington state law (RCW 19.285) also requires utilities to acquire specified amounts of renewable resources or equivalent renewable energy credits (RECs). There are details in the law such that complying with RCW 19.285 may not directly correspond to meeting reliability needs, so this is expressed as a separate category of resource need.

- Figure 1-1 presents electric peak hour capacity need.
- Figure 1-2 presents the electric energy need (the annual energy position for the 2017 Base Scenario).
- Figure 1-3 presents PSE's renewable energy credit need.

Electric Peak Hour Capacity Need

Figure 1-1 compares the existing resources available to meet peak hour capacity¹ with the projected need over the planning horizon. The electric resource outlook in the Base Scenario indicates the initial need for an additional 215 MW of peak hour capacity by 2023. This includes a 13.5 percent planning margin (a buffer above a normal peak) to achieve and maintain PSE's 5 percent loss of load probability (LOLP) planning standard. Figure 1-1 shows four noticeable drops in PSE's resource stack. The first, in 2022, is caused by retirement of Colstrip 1 & 2, approximately 300 MW of capacity. The second is at the end of 2025, when PSE's 380 MW coal-transition contract with Transalta expires upon retirement of the Centralia coal plant.² The third occurs in 2031, when PSE contracts with Chelan PUD for 481 MW of hydro output expire. The final significant drop is in 2035, the year that the Base Scenario assumes retirement of Colstrip Units 3 & 4, of which PSE owns 370 MW. This could occur sooner, depending on how future

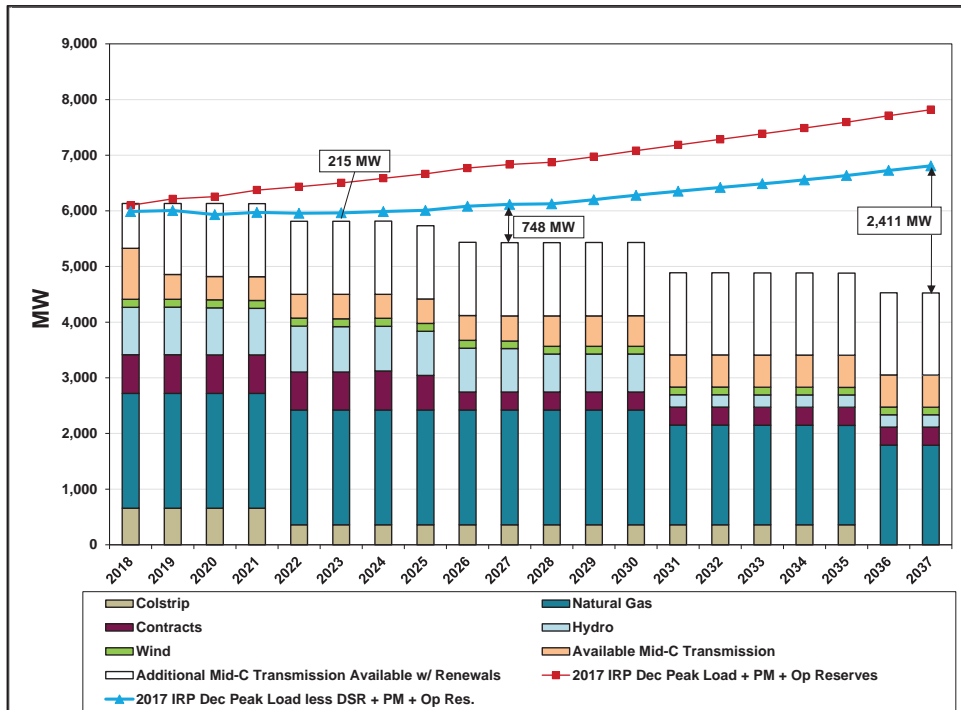
¹ / Resource capacities illustrated here reflect the contribution to peak, not nameplate capacity, so PSE's approximate 130 MW update with Skookumchuck of owned and contracted wind appear very small on this chart. Refer to Chapter 6, Electric Analysis, for how peak capacity contributions were assessed.

² /PSE entered the coal transition contract with Transalta under RCW 80.80 to facilitate the retirement of the only major coal-burning power plant in Washington state.



environmental regulations affect the economics of running the plant. The important role demand-side resources play in moderating the need to add supply-side resources in the future can be seen in the peak load lines in Figure 1-1; the lower line includes the benefit of DSR while the upper line does not.

Figure 1-1: Electric Peak Hour Capacity Resource Need
(Projected peak hour need and effective capacity of existing resources)





Electric Energy Need

Compared to the physical planning constraints that define peak resource need, meeting customers' "energy need" for PSE is more of a financial concept that involves minimizing costs. Portfolios are required to cover the amount of energy needed to meet physical loads, but our models also examine how to do this most economically, and this includes the ability to purchase energy from the wholesale market.

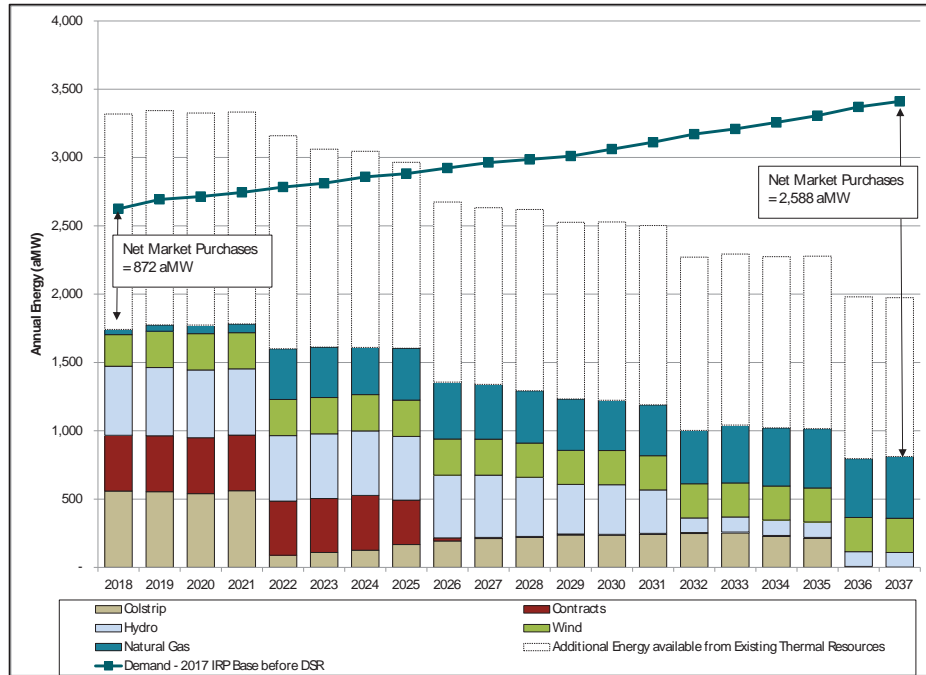
Unlike utilities in the region that are heavily dependent on hydro, PSE has thermal resources that can be used to generate electricity if needed. This resource diversity is an important difference. In fact, on an average monthly or annual basis, PSE could generate significantly more energy than needed to meet our load, but it is often more cost effective to purchase wholesale market energy than to run our high-variable cost thermal resources. We do not constrain (or force) the model to dispatch resources that are not economic; if it is less expensive to buy power than to dispatch a generator, the model will choose to buy power in the market. Similarly, if a zero (or negative) marginal cost resource like wind is available, PSE's models will displace higher-cost market purchases and use wind to meet the energy need.

Figure 1-2 illustrates the company's energy position across the planning horizon, based on the energy load forecasts and economic dispatches of the 2017 IRP Base Scenario presented in Chapter 4, Key Analytical Assumptions.³ The dashed box at the top indicates the total energy available from PSE's thermal resources if they were run without regard to economic dispatch. This chart shows that without any additional demand-side or supply-side resources, PSE could generate enough energy on an annual basis through 2025 to make wholesale market purchases unnecessary. The challenge for PSE is shaping that energy into peak hours. Should regional resource deficits in the future result in periods where market purchases were unavailable, PSE's thermal resources would be able to ramp up to minimize the number of non-peak hours that PSE customers were affected, but we would still face peak need constraints. This is why PSE has a peak capacity constraint, not an energy constraint.

³ / Wind in this chart shows more prominently in Figure 1-5 than in the peak capacity need chart, because this reflects the expected annual generation of wind, not just what can be relied upon to meet peak capacity needs.



Figure 1-2: Annual Energy Position, Economic Resource Dispatch from Base Scenario



Renewable Need

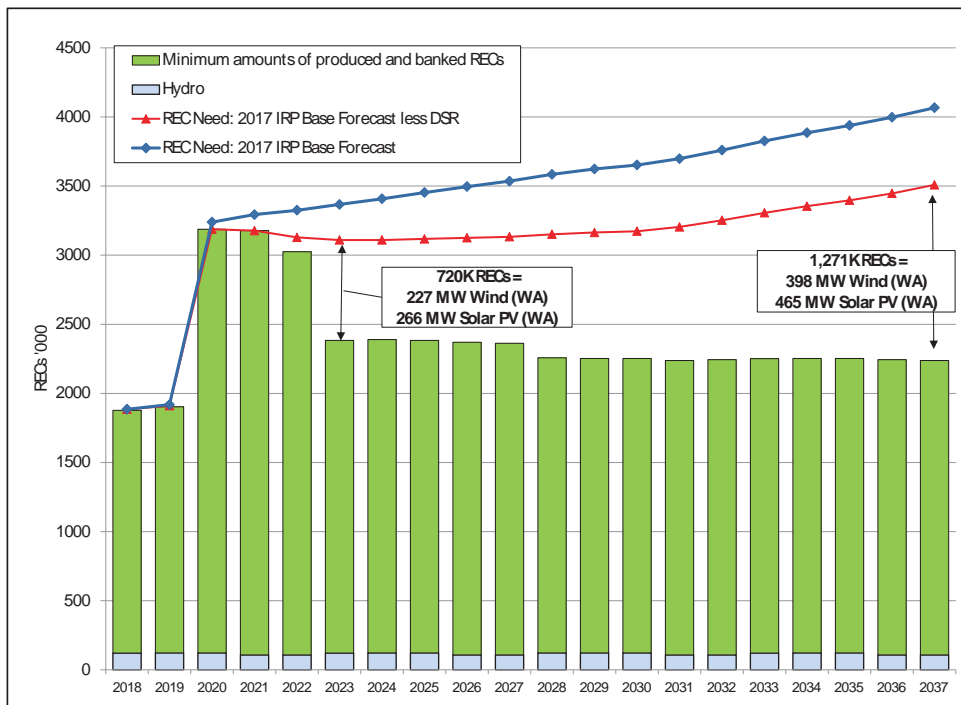
In addition to reliably meeting the physical needs of our customers, RCW 19.285 – the Washington State Energy Independence Act – establishes 3 specific targets for qualifying renewable energy, commonly referred to as the state’s renewable portfolio standard. Sufficient “qualifying renewable energy” must equal at least 3 percent of retail sales in 2012, 9 percent in 2016, and 15 percent in 2020. Figure 1-3 compares existing qualifying renewable resources with these targets, and shows that PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law until 2022. By 2023, PSE will need approximately 720,000 qualifying renewable energy credits. To put that need into context, it would equate to approximately 227 MW of Washington wind or 266 MW of eastern Washington solar power.⁴

⁴ / Slightly more MW of solar are needed because the annual output of solar in eastern Washington is slightly less than wind, so more MW of installed capacity are needed to generate the same quantity of energy in MWh.



Qualifying renewable energy is expressed in annual qualifying renewable energy credits (RECs) rather than megawatt hours, because the state law incorporates multipliers that apply in some cases. For example, generation from PSE's Lower Snake River wind project receives a 1.2 REC multiplier, because qualifying apprentice labor was used in its construction. Thus the project is expected to generate approximately 900,000 MWh per year of electricity, but contribute about 1,080,000 equivalent RECs toward meeting the renewable energy target. Note this is a long-term compliance view. PSE has sold surplus RECs to various counterparties in excess of those needed for compliance and will continue to do so as appropriate to minimize costs to customers.

Figure 1-3: Renewable Resource/REC Need





Electric Portfolio Resource Additions Forecast

As explained above, the lowest reasonable cost portfolio produced by the IRP analysis is not an action plan; rather, it is a forecast of resource additions PSE would find cost effective in the future, given what we know about resource and market trends today. It incorporates significant uncertainty in several dimensions.

Figure 1-4 summarizes the forecast for additions to the electric resource portfolio in terms of peak hour capacity over the next 20 years. This forecast is the “integrated resource planning solution.”⁵ It reflects the lowest reasonable cost portfolio of resources that meets the projected capacity, energy and renewable resource needs described above. Similar to prior IRPs, it accelerates acquisition of energy conservation and calls for additional demand response resources; however, it also includes significant changes. This IRP finds energy storage to be part of the lowest reasonable cost solution. It also finds that eastern Washington solar power may be more cost effective than wind. Additionally, it includes redirecting some firm transmission from existing wind resources to the Mid-C market in the resource plan forecast. Taken together, the “early” actions in this resource plan push the need to acquire additional fossil-fuel peakers out beyond 2024. This should not be interpreted to mean PSE *will* acquire new fossil fuel resources in 2025. Rather, this strategy provides a significant amount of time for technological innovations in energy efficiency, demand response, energy storage and renewable resources to develop, in the hope that additional fossil-fuel peaking generation plants will not be needed for our customers. Also, the resource plan shown here should not be interpreted as a statement of the ownership structure of resource additions; more accurately, it is a forecast of what technologies will appear cost effective in the future. For example, instead of PSE developing additional renewables or purchase power contracts, it may be lower cost and lower risk for customers to acquire unbundled RECs from independent power producers, who would then shoulder the technology and market price risk, instead of PSE’s customers.

⁵ / Chapter 2 includes a detailed explanation of the reasoning that supports each element of the resource plan.



Figure 1-4: Electric Resource Plan Forecast,
Cumulative Nameplate Capacity of Resource Additions

| | 2023 | 2027 | 2037 |
|------------------------------|------|------|-------|
| Conservation (MW) | 374 | 521 | 714 |
| Demand Response (MW) | 103 | 139 | 148 |
| Solar (MW) | 266 | 378 | 486 |
| Energy Storage (MW) | 50 | 75 | 75 |
| Redirected Transmission (MW) | 188 | 188 | 188 |
| Baseload Gas (MW) | 0 | 0 | 0 |
| Peaker (MW) | 0 | 717 | 1,912 |

Demand-side Resources (DSR): Energy Efficiency

This plan – like prior plans – includes aggressive, accelerated investment in helping customers use energy more efficiently. That is, significant changes in avoided cost had little impact on how much conservation could be acquired cost effectively. PSE’s analysis indicates that although current market power prices are low, accelerating acquisition of DSR continues to be a least-cost strategy.

Demand-side Resources: Demand Response

In this IRP, we continue to find a ramp-up in demand response programs is part of the lowest reasonable cost portfolio. Demand response includes voluntary interruptible rate schedule programs for residential customers.

Renewable Resources

The timing of renewable resource additions is driven by requirements of RCW 19.285, as renewable resources still do not appear to be an effective or cost effective way to manage the financial risk of market exposure. This IRP found that eastern Washington solar power is expected to be more cost effective than wind from the Pacific Northwest or in Montana; however, costs between wind and solar are very close, especially in the first half of the planning horizon. As in prior IRPs, PSE’s analysis shows we anticipate remaining comfortably below the four percent revenue requirement cap in RCW 19.285. PSE has acquired enough eligible renewable resources and RECs to meet the requirements of the law until 2022.



Energy Storage

This IRP finds energy storage, specifically flow batteries, to be a cost-effective part of the resource plan. While batteries are more expensive than peakers on a dollars per kW basis, batteries are more scalable, so they fit well in a portfolio with a small, flat need, as shown above in Figure 1-1 (Peak Capacity Need). Also, batteries provide more sub-hourly flexibility value than peakers, and this value is reflected in the IRP forecast.

Redirected Transmission to Market

In all future scenarios, redirecting 188 MW of BPA transmission from PSE's Hopkins Ridge and Lower Snake River wind facilities was shown to be part of the least cost solution. PSE will still be able to deliver the wind energy to our customers, but do so in a way that also helps to push the need for new generation into the future, which provides risk mitigation benefits as well. However, redirecting transmission and increasing PSE's reliance on wholesale market does entail financial and physical resource adequacy risk. Those risks were comprehensively examined in this IRP and determined to be manageable.⁶

Baseload Natural Gas Plants

The Pacific Northwest appears flush with renewable energy – hydro power, wind power and surplus solar power from California. Building additional baseload gas plants in PSE's service territory appears cost effective under only a few unlikely scenarios. Therefore, the resource plan includes no baseload gas plants.

Peakers

Beyond 2025, dual fuel peaking units appear to be the most cost-effective resource to meet larger capacity resource needs. These are units that can run off either natural gas, fuel oil or a blend of both. These peakers act as a low cost insurance policy, in case they are needed to meet loads due to extremely cold weather conditions, when another unit experiences a forced outage, or very low regional hydro conditions. A key reason why these units are so cost effective, is that backup fuel oil tanks negate the need for firm natural gas pipeline capacity. The resource adequacy implications of relying on peakers with backup fuel were examined rigorously in this IRP. The analysis shows the reliability risk of relying on backup fuel is extremely low. While PSE hopes technology innovations in energy efficiency, demand response, energy storage and renewable resources will eclipse the need for additional fossil-fuel plants of any kind in the future, dual fuel peakers appear to be the least cost resource in the later part of the planning horizon, except in unlikely scenarios where baseload natural gas plants appear cost effective.

⁶ / See Appendix G, Wholesale Market Risk.

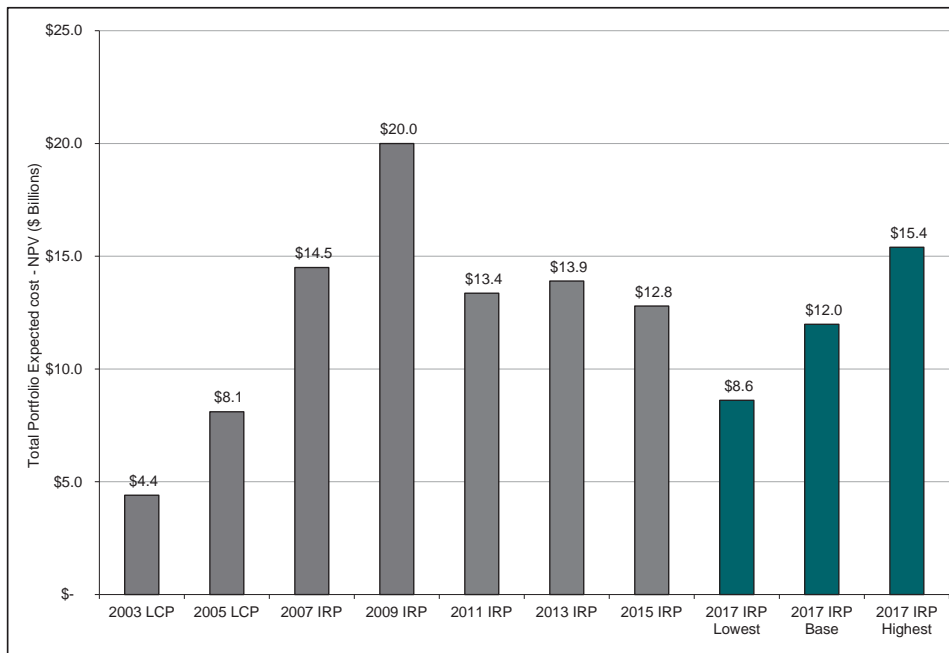


Portfolio Cost and Carbon Emissions

Portfolio Costs

The long-term outlook for incremental portfolio costs has been dynamic across IRP planning cycles since 2003, driven by changing expectations about natural gas prices and costs associated with potential carbon regulation. Figure 1-5 illustrates how incremental portfolio costs have changed over time, along with the context for the range of costs examined in this IRP. This figure shows the long-term cost projection is down slightly from the 2015 IRP. This is primarily due to lower natural gas prices and lower capital costs for generation plants. Note that in this IRP, carbon costs on baseload natural gas and coal plants are applied across the entire WECC in the IRP Base Scenario assumptions, to simulate the effect of the Clean Power Plan if interstate carbon trading was adopted.

Figure 1-5: Incremental Portfolio Costs Over Time





Portfolio Carbon Emissions Associated with Electric Service

We are keenly aware of our customers' interest in reducing PSE's carbon emissions, and we share their concern and commitment to achieving meaningful carbon reduction that will mitigate climate change. Although PSE's portfolio carbon emissions can yield helpful insights, achieving the kind of results we all want will also require region-wide coordination as we continue this effort. The carbon emission profile presented in this section does not represent PSE's "preferred" outcome – we would prefer emissions to be lower. These emissions result from policies that require PSE to serve customers with the least cost combination of demand- and supply-side resources and carbon regulation policies that have been or may be enacted.

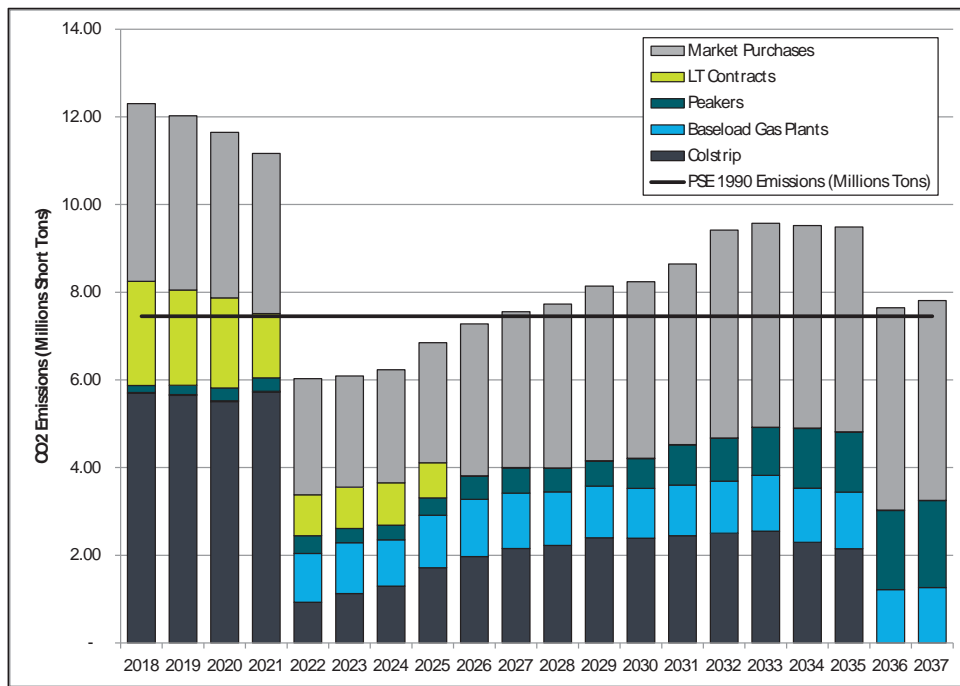
In estimating portfolio carbon emissions, PSE evaluates each of the resources in its portfolio. This is fairly straightforward when dealing with PSE-owned resources, but evaluating the wholesale market purchases that make up nearly a third of PSE's portfolio is more complicated because those purchases come from an integrated WECC-wide electric system. PSE's approach to addressing this carbon accounting issue is to calculate a WECC-wide average carbon intensity forecast in tons of CO₂ per MWh for each year in the planning horizon, and apply that average to market purchases. This is similar to the method used by the WUTC's compliance protocol, but that protocol uses the Northwest Power Pool average instead of the WECC average. Averages may satisfy reporting rules, but using an average emission rate is not appropriate for estimating how different policies or resource alternatives will affect greenhouse gas emissions. In reality, changes in emissions will be impacted by marginal resource decisions (i.e., which resources are being dispatched), not average resource dispatch. To understand how different factors will affect greenhouse gas emissions in total, one must examine impacts across the entire WECC. This kind of analysis is presented in Chapter 6 in the discussion on cost of carbon abatement.

Figure 1-6 illustrates the portfolio carbon emissions resulting from the resource plan forecast under the Base Scenario economic dispatch. The horizontal line shows PSE's estimated 1990 emissions. The stacked bars are the annual carbon emissions by resource type. The top of each stack does not represent direct PSE emissions – these are average emissions associated with market purchases. The rest of the stack relates directly to PSE resources or specific contracts. The first large drop in emissions occurs in 2022. This is caused by retirement of Colstrip 1 & 2, but also by the assumed implementation of a WECC-wide carbon price on coal and baseload gas plants, which significantly curtails the economic dispatch of Colstrip 3 & 4. From 2022 through 2034, direct emissions rise as natural gas prices increase relative to coal costs, causing the economic dispatch of Colstrip 3 & 4 to increase despite the WECC-wide carbon price. By 2037, PSE's direct emissions will be quite low, as all four units of Colstrip will have been retired – this drop would occur earlier if Colstrip 3 & 4 were retired sooner.



While this chart appears to show PSE's emissions will be in line with 1990 emissions by 2035, this is misleading. The Base Scenario assumes the most important and most difficult policy change is enacted in 2022 – the imposition of a WECC-wide carbon market. Policy makers, environmental advocates and those concerned about greenhouse gas emissions (including PSE) should not be comforted by this chart.

Figure 1-6: Projected Annual Total PSE Portfolio CO₂ Emissions and Savings from Conservation





4. NATURAL GAS SALES RESOURCE PLAN FORECAST

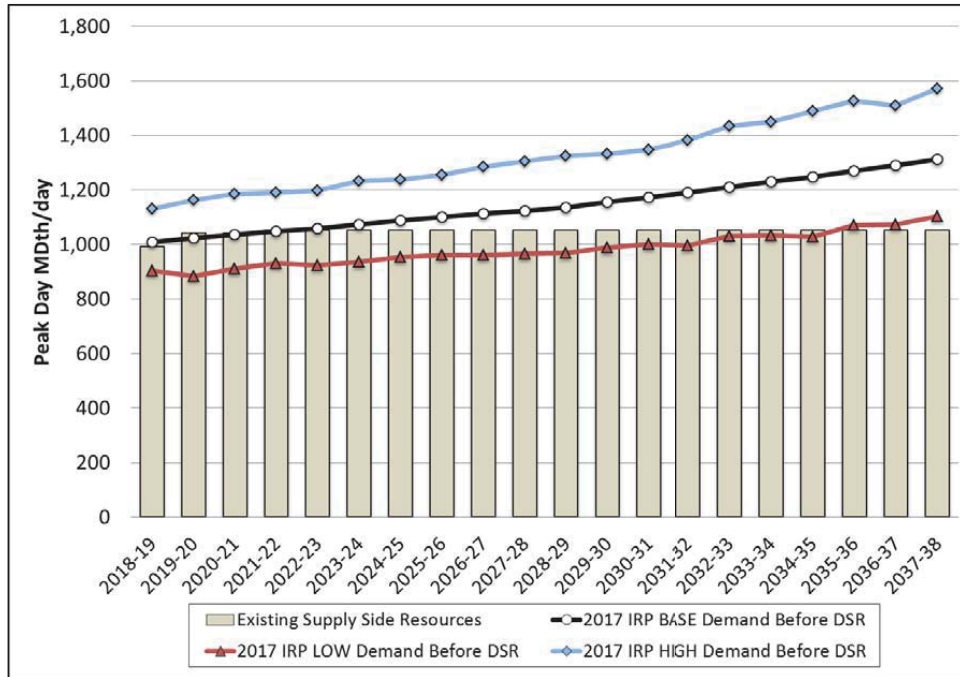
PSE develops a separate integrated resource plan to address the needs of more than 800,000 retail natural gas sales customers. This plan is developed in accordance with WAC 480-90-238, the IRP rule for natural gas utilities. (See Chapter 7 for PSE's gas sales analysis.)

Gas Sales Resource Need – Peak Day Capacity

Gas sales resource need is driven by design peak day demand. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD). Like electric service, gas service must be reliable every day, but design peak drives the need to acquire resources. Figure 1-7 illustrates the load-resource balance for the gas sales portfolio. The chart demonstrates PSE has a small resource need in 2018, but the LNG storage facility in Tacoma is expected to come online for the 2019/20 heating season, which will meet the peak capacity needs of our customers until the winter of 2023/24. The 2018 need can be met with a one-year capacity contract on Northwest Pipeline, rather than investing in a long-lived resource to meet need for a single year.



Figure 1-7: Gas Sales Design Peak Day Resource Need



Gas Sales Resource Additions Forecast

Figure 1-8 summarizes the gas resource plan additions PSE forecasts to be cost effective in the future in terms of peak day capacity and MDth per day. As with the electric resource plan, this is the “integrated resource planning solution.” It combines the amount of demand-side resources that are cost effective with supply-side resources in order to minimize the cost of meeting projected need. Again, this is not PSE’s action plan – it is a forecast of resource additions that look like they will be cost effective in the future, given what we know about resource trends and market trends today.



Figure 1-8: Gas Resource Plan Forecast, Cumulative Additions in MDth/Day of Capacity

| | 2025/26 | 2029/30 | 2037/38 |
|----------------------------|---------|---------|---------|
| Conservation (DSR) | 27 | 49 | 84 |
| Swarr | 30 | 30 | 30 |
| LNG Distr Upgrade | 0 | 16 | 16 |
| Additional NWP + Westcoast | 0 | 53 | 133 |

Demand-side Resources (DSR)

Analysis in this IRP applies a 10-year ramp rate for acquisition of DSR measures. Analysis of 10- and 20-year ramp rates in prior IRPs has consistently found the 10-year rate to be more cost effective. Ten years is chosen because it aligns with the amount of savings that can practically be acquired at the program implementation level.

Swarr Upgrade

This IRP finds that upgrading the Swarr LP-Air facility's environmental safety and reliability systems and returning its production capacity to Swarr's original 30 MDth per day capability would be a cost effective resource as early as the 2024/25 heating season. Swarr is a propane-air injection facility on PSE's gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the mixture injected into the distribution system maintains the same heat content as natural gas. Upgrading Swarr is a short lead time project that is totally within PSE's control (it does not require the regional coordination needed for large, mainline pipeline expansion) so the project also adds strategic agility to the resource plan. If needed sooner, PSE could move quickly to upgrade Swarr, and if need is delayed, PSE could defer the upgrade. In either circumstance, the upgrade would put off the need for large, long-lived mainline pipeline expansions.



PSE LNG Distribution Upgrade

The PSE LNG peaking facility currently under construction in Tacoma allows the company to withdraw gas from the storage tank and deliver it directly into PSE's local distribution system. This upgrade is not an expansion of the LNG facility itself, but an expansion of the distribution network's capacity east of Tacoma that will allow more gas to flow from the LNG facility into PSE's gas supply network. The analysis forecasts that this will be needed and cost effective by the 2027/28 heating season. As with Swarr, this resource provides the portfolio with the strategic agility to determine timing based customer need as it develops.

Northwest Pipeline/Westcoast Expansion

Additional transportation capacity from the gas producing regions in British Columbia at Station 2 south to PSE's system on the Westcoast pipeline is also forecast as cost effective beginning in the 2029/30 heating season.

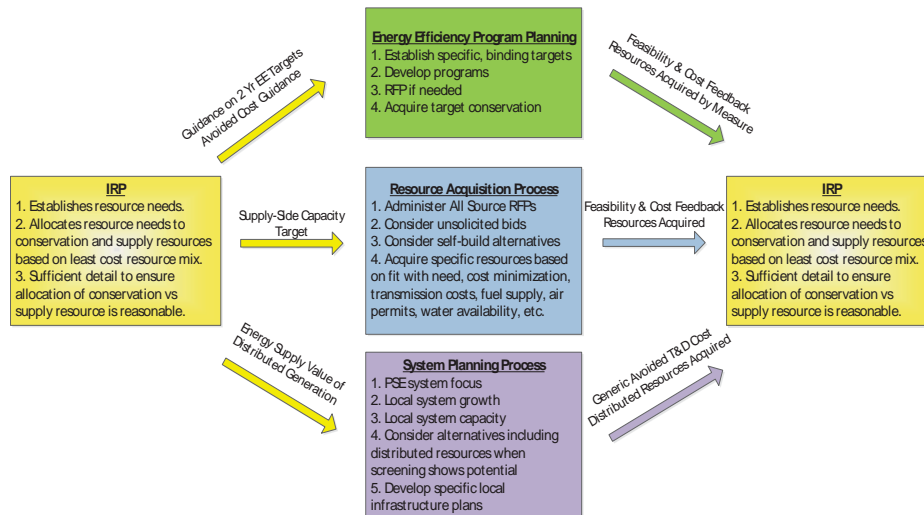


5. THE IRP AND THE RESOURCE ACQUISITION PROCESS

The IRP is not a substitute for the resource-specific analysis done to support specific acquisitions, though one of its primary purposes is to inform the acquisition process. The action plans presented here help PSE focus on key decision-points it may face during the next 20 years so that we can be prepared to meet needs in a timely fashion.

Figure 1-9 illustrates the relationship between the IRP and activities related to resource acquisitions. Specifically, the chart shows how the IRP directly informs other acquisition and decision processes. In Washington, the formal RFP processes for demand-side and supply-side resources are just one source of information for making acquisition decisions. Market opportunities outside the RFP and self-build (or PSE demand-side resource programs) must also be considered when making prudent resource acquisition decisions. Figure 1-9 also illustrates that information from the IRP provides information to the local infrastructure planning process.

Figure 1-9: Relationship of IRP to Resource Decision Processes





2

2017 PSE Integrated Resource Plan

Resource Plan Decisions

This chapter summarizes the reasoning for the additions to the electric and gas resource plan forecasts.

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1. OVERVIEW

The resource plan forecast in this IRP represents “...the mix of energy supply and conservation that will meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.”¹

The resource plan forecast described here is not simply the output of a deterministic portfolio optimization model. It incorporates what we learned from the deterministic analysis of how different long-term economic conditions and other factors affect risk across scenarios, from a stochastic portfolio analysis that includes consideration of how short-term variability impacts risk, and from the application of judgment given a qualitative assessment of the market in which we operate, which is more complex than can be simplified to a mathematical model. First, this chapter summarizes resource additions in the resource plan forecast. Then we present a high-level summary of the findings from the deterministic optimization analysis and stochastic portfolio risk analysis. Finally, after establishing context from the analysis, we step through each element of the resource plan to explain how judgment was applied.

This discussion assumes the reader is familiar with the key assumptions described in Chapter 4. Further information on the analyses discussed here can be found in Chapters 4, 5, 6, 7 and the Appendices.

¹ / WAC 480-100-238 (2) (a) Definitions, Integrated Resource Plan.



2. ELECTRIC RESOURCE PLAN

Resource Additions Summary

Figure 2-1 summarizes the forecast of resource additions to the company's electric portfolio that resulted from the 2017 IRP analysis. Most notably, this resource plan postpones the need for new thermal peaking plants out to 2025. We accomplish this by accelerating conservation investments, acquiring demand response, redirecting transmission to market, and using energy storage in the first seven years of the study period. This pushes fossil fuel peaking plant additions out into the realm of hypothetical resources. The further into the future that the need for such plants can be pushed, the better the chances are that technological innovations will reduce the relative cost of energy storage, conservation and demand response, such that development of new dual-fuel peaker plants will continually be pushed into the future. And, as the need for new resources gets pushed out, it gives the region more time to continue heavy investments in conservation, which will continue to improve the reliability of market purchases.

*Figure 2-1: Electric Resource Plan Forecast,
Cumulative Nameplate Capacity of Resource Additions*

| | 2023 | 2027 | 2037 |
|-------------------------------------|------|------|-------|
| Conservation (MW) | 374 | 521 | 714 |
| Demand Response (MW) | 103 | 139 | 148 |
| Solar (MW) | 265 | 377 | 486 |
| Energy Storage (MW) | 50 | 75 | 75 |
| Redirected Transmission (MW) | 188 | 188 | 188 |
| Baseload Gas (MW) | 0 | 0 | 0 |
| Peaker (MW) | 0 | 717 | 1,195 |

Portfolio Optimization Results across Scenarios

PSE examined 14 different market scenarios. The scenarios included different combinations of load, gas/power prices, and carbon costs/forms of regulation. Each scenario is a unique combination of factors that could affect market power prices or load. Scenario analysis is an important form of risk analysis. It helps us understand how specific assumptions that represent very different futures would affect the least-cost mix of resources. Figure 2-2, below summarizes



the relationship between these scenarios and sensitivities. Additional detail is provided in Chapter 4.

Figure 2-2: 2017 IRP Scenarios

| | Scenario Name | Demand | Gas Price | CO ₂ Price |
|----|--|--------|-----------|---|
| 1 | Base Scenario ^{1, 2, 3} | Mid | Mid | Mid |
| 2 | Low Scenario | Low | Low | Low |
| 3 | High Scenario | High | High | High |
| 4 | High + Low Demand | Low | High | High |
| 5 | Base + Low Gas Price | Mid | Low | Mid |
| 6 | Base + High Gas Price | Mid | High | Mid |
| 7 | Base + Low Demand | Low | Mid | Mid |
| 8 | Base + High Demand | High | Mid | Mid |
| 9 | Base + No CO ₂ | Mid | Mid | None |
| 10 | Base + Low CO ₂ w/ CPP ² | Mid | Mid | Low + CPP |
| 11 | Base + High CO ₂ | Mid | Mid | High |
| 12 | Base + Mid CAR only (electric only) | Mid | Mid | Mid CAR only |
| 13 | Base + CPP only (electric only) | Mid | Mid | CPP only |
| 14 | Base + All-thermal CO ₂ (electric only) | Mid | Mid | CO ₂ price applied to all thermal resources in the WECC (baseload and peakers) |

NOTES

1. Washington CAR (Clean Air Rule) regulations apply to both electric and gas utilities. These are applied to all scenarios.

2. Federal CPP (Clean Power Plan) regulations affect only baseload electric resources, so the gas portfolio models scenarios 1 through 11 only. CPP rules are modeled as if the entire WECC is part of an integrated carbon market, with carbon prices applied to all baseload generation, so that even if the CPP is ultimately not put into effect, the analysis still represents a form of carbon price regulation.

3. Carbon regulations are assumed to transition from CAR to CPP in 2022.

Chapter 2: Resource Plan Decisions



Figures 2-3 and 2-4 summarize the demand- and supply-side resource additions to PSE's existing resource portfolio across scenarios; this picture is the product of the deterministic portfolio optimization analysis. The scenario risk examined in this IRP includes a wide range of different kinds of carbon regulations, load growth assumptions and natural gas prices, which drive wholesale power prices.

That is, Figures 2-3 and 2-4 summarize the least-cost solution across all the market scenarios that were examined. For each scenario, the analysis considered supply- and demand-side resources on an equal footing. All were required to meet three objectives: physical capacity need (peak demand), energy need (customer demand across all hours), and renewable energy need (to meet RCW 19.285 targets). The portfolios in Figures 2-3 and 2-4 minimize long-term revenue requirements (costs as customers will experience them in rates), given the market conditions and resource costs assumed for each scenario.

Chapter 2: Resource Plan Decisions



Least-cost portfolio builds are similar across most scenarios, with respect to redirecting transmission, demand side resources, energy storage, renewables and dual-fueled peakers to meet remaining capacity needs. This consistency is a powerful finding. It means that the wide variety of external market factors modeled in these scenarios will have little impact on the selection of renewables and demand-side resources.

Figure 2-3: Resource Builds by Scenario, Scenarios 1-9
Cumulative Additions by Nameplate (MW)

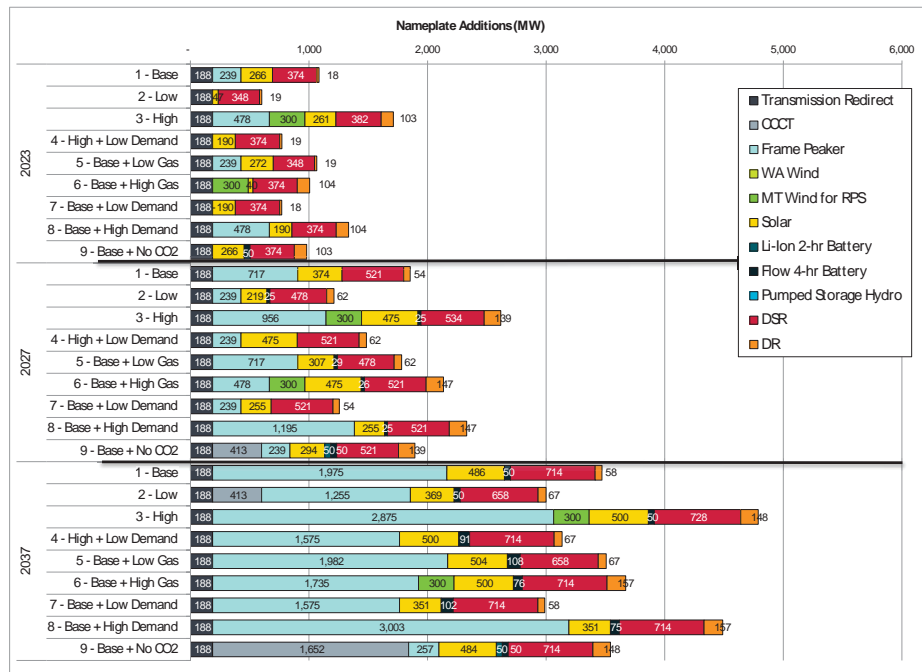
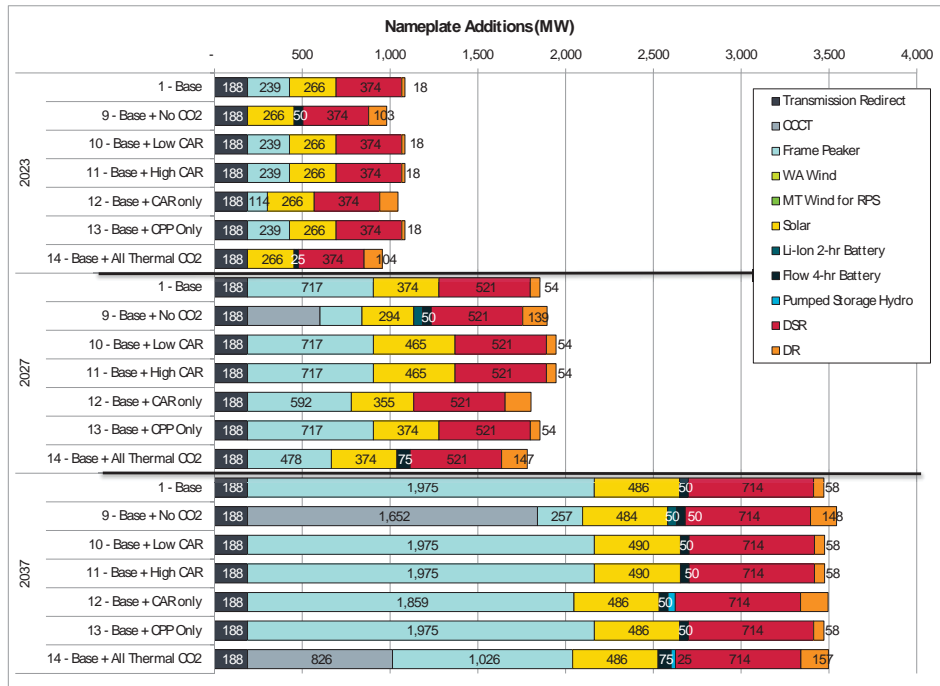




Figure 2-4: Resource Builds by Scenario, Scenarios 9-14
Cumulative Additions by Nameplate (MW)



Portfolio Optimization Results by Resource Type

Conservation

Cost-effective conservation does not vary across scenarios. This is consistent with findings in prior IRPs, where the variability in costs across scenarios has little impact on the amount found to be cost effective, which highlights it is a low-risk resource with regard to possible changes in carbon regulation, load growth and gas market conditions across the 14 scenarios and sensitivities examined.



Demand Response

All scenarios have at least 60 MW of demand response, with a few scenarios having as much as nearly 160 MW. In the context of a portfolio that needs over 3,000 MW of resources by 2037, this is a small degree of variability.

Redirected Transmission

Increasing market reliance by redirecting 188 MW of transmission from Hopkins Ridge and Lower Snake River is least cost across all scenarios and sensitivities, meaning it is a low-risk long-term decision from a deterministic risk perspective. Increasing market reliance could have risks that would be unseen in a deterministic analysis; these must be examined from a stochastic perspective.

Energy Storage

A small amount of utility-scale batteries appears cost effective at some point in the planning horizon in every scenario, given the assumed transmission and distribution benefits. By 2037, all scenarios have at least 50 MW, while a few have approximately 100 MW. It appears batteries are cost effective primarily because they can be sized to fit needs with slowly growing loads, in addition to being very flexible.

Renewable Resources – Eastern Washington Solar

Solar appears to be the most cost-effective renewable resource to comply with RCW 19.285, given the assumed transmission costs. PSE spent considerable resources refining our wind data, only to find solar appears more cost effective, so this was an unexpected shift. Solar provides no peak capacity value to PSE, because we are a winter peaking utility. The sun rises after PSE's system peaks on winter mornings and sets before our winter peaks begin in the afternoon. Despite the fact that solar had no peak capacity value, it still appears to be the least cost renewable resource for compliance with RCW 19.285. Figure 2-5 illustrates that the levelized cost of solar, even if it required transmission, is lower than Montana or Pacific Northwest wind. However, this figure shows the levelized costs including peak capacity value are close. Actual bids in an RFP process could yield a different conclusion.

Renewable Resources – Montana Wind

Wind in eastern Montana would not be a qualifying renewable resource under RCW 19.285, unless it were delivered all the way to Washington state on a real-time basis without shaping or storage. In this IRP, we examined whether being designated as a qualifying renewable resource would make Montana wind appear cost effective. It did not. However, Montana wind was reasonably close to being cost effective, as shown in Figure 2-5, below. In the acquisition process where actual projects are bid to the company and depending on the transmission costs, it is possible that PSE will find Montana wind projects could be more cost effective than Washington



solar projects. However, there are three key barriers to Montana wind being designated an eligible renewable resource under RCW 19.285.

- 1. TRANSMISSION STUDY PROCESS.** Montana wind would have to be scheduled into Washington state on a real-time basis without shaping or storage in order to qualify as a renewable resource under RCW 19.285. Being able schedule wind from Montana all the way to Washington state in this manner would require coordination of transmission studies across Northwestern, BPA and possibly the WECC. Recently, BPA scheduled a workshop in December 2017 in Montana to begin discussion about issues relating to transmission for Montana resources. For the region to move forward on this question is an optimistic step. A blanket policy that ensured wind from Montana could be “dynamically scheduled” to Washington without the need to do transmission studies on a project-by-project basis would avoid the issue described below about who pays for such studies. PSE supports addressing the challenges concerning transmission of Montana wind resources and will participate in BPA’s workshop and other regional discussions on this issue.
- 2. CHALLENGES WITH PROJECT-BY-PROJECT DETERMINATION – TIMING AND WHO PAYS.** Incentives may not be aligned to facilitate completion of studies for individual projects. Montana wind developers may be reluctant to pay for such studies without knowing that PSE would purchase the resource if it was determined to be a qualifying resource. If the study did not support dynamic scheduling capability, or if the costs to facilitate dynamic scheduling were significant, the resource would have no value to Washington state utilities as a renewable resource under RCW 19.285. PSE would also be reluctant to pay for these studies based on incentives created under current regulatory policies. For example, if PSE paid for such studies, we may not be allowed to recover the cost of the study if it did not directly lead to a resource acquisition (via PPA or ownership). Had this IRP found RPS-eligible Montana wind to clearly be a least-cost resource, the prudence risk associated with paying for such study might be reasonable – but that conclusion was not supported by the analysis. In addition, timing during the acquisition process could also be a challenge. If PSE has the choice of two resources that are very close in cost but one clearly meets eligibility requirements of RCW 19.285 while the other requires additional study to make that determination, it may not make sense to expose PSE’s customers to that risk. The study could take several months, and should it determine the Montana wind resource would not being a qualifying resource, the alternative opportunity may no longer be available.
- 3. DELIVERY TO PSE.** For Montana wind to have a peak capacity value, the resource must be delivered all the way to PSE. This IRP assumes additional transmission to PSE’s

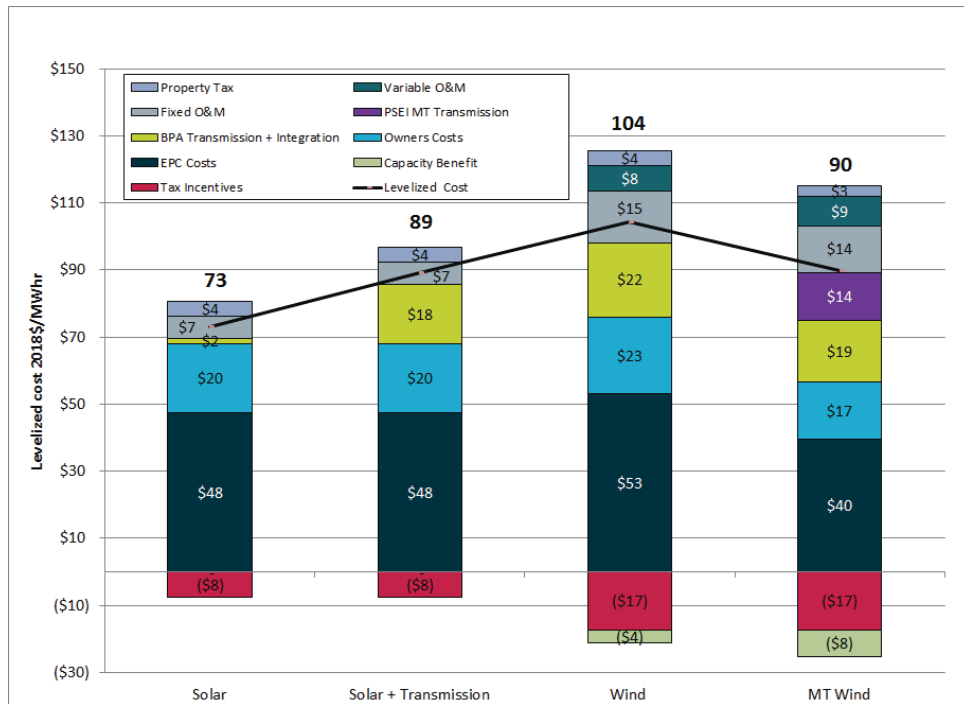


system is available at a price from BPA. However, that may not be the case. If the developer (or PSE) cannot obtain additional cross-Cascades transmission, the power may be delivered only to Mid-C. If PSE has to use existing transmission to Mid-C to transport that power to load, no capacity value is created at all. It simply offsets market purchases, since we have already counted on the transmission as a capacity resource. It is possible that contracts PSE uses to deliver energy from Colstrip to PSE could be used to deliver Montana wind. This topic will need to be explored more fully in future studies.

Pacific Northwest Wind

Wind in the Pacific Northwest did not appear to be a cost-effective resource in any scenario. Solar has lower costs and Montana wind has greater value because of the higher capacity factor and higher peak capacity value. As with Montana wind, this IRP assumes additional cross-Cascades transmission will be available at a price. If additional cross-Cascades transmission cannot be acquired, there will be no peak capacity value associated with Pacific Northwest wind – just like Montana wind. However, Figure 2-5, below, illustrates the levelized cost of solar, Montana wind, and Pacific Northwest wind are all fairly close – assuming Montana wind could qualify as a renewable resource.

Figure 2-5: Wind and Solar Cost Components





Baseload Gas Plants

Combined-cycle natural gas plants do not appear cost effective in most scenarios. Scenario 2 (Low) has 413 MW and Scenario 9 (Base + No CO₂) has over 1,650 MW. Both of these scenarios essentially have no long-term carbon pricing. The pricing in Scenario 14 (Base + All-thermal CO₂) on all thermal plants shows just over 800 MW of baseload gas plants being added. This highlights that the way carbon regulation will be implemented is important. In scenarios where carbon regulation primarily affects baseload gas plants but not peakers, baseload gas plants are not cost effective. The only two carbon regulation rules currently on the books that may affect PSE's operations – the CAR² and the CPP – generally affect baseload gas plants, but not peakers.

Peakers

Dual fuel frame peakers were found cost effective in every scenario. Most scenarios show it as the go-to capacity resource later in the planning horizon, with at least 1,000 MW by 2037. The only exception is in Scenario 9 (Base + No CO₂), which has only 257 MW of dual fuel peakers – but it seems unlikely there will be no carbon regulation of any kind. In many scenarios, carbon regulation is applied unevenly – to baseload gas but not peakers. This tends to increase the value of peakers relative to other capacity resources, such as energy storage and demand response. This can be seen by comparing energy storage and demand response in the Base Scenario and Scenario 13 (the CPP Only Scenario), which impose carbon costs on baseload gas plants but not peakers, with the results from Scenario 9 (Base + No CO₂) and Scenario 14 (Base + All Thermal CO₂), which treat peakers and baseload gas plants equally with respect to carbon pricing. The two scenarios with uneven application of carbon pricing (1 and 13) show about 60 MW of demand response would be cost effective by 2037, but scenarios with consistent application of carbon regulation (9 and 14) find about 150 MW of demand response cost effective. Application of carbon costs only on baseload gas also reduces the amount of energy storage. Scenarios 1 and 13 (carbon costs only on baseload plants) have 50 MW of energy storage as least cost, compared to 100 MW in scenarios 9 and 14 (consistent application of carbon costs to all resources).

2 / Under the CAR, peakers are not exempt, but they also do not dispatch enough to hit the limits that would trigger compliance. For this IRP, PSE capped run times for new peakers to ensure they would not hit the emission triggers under CAR, so that we would avoid inflating the economic value of dispatching peakers.



Adequate backup fuel oil makes peakers significantly less costly than baseload gas plants. Baseload gas plants require firm pipeline capacity in lieu of backup fuel. Firm pipeline capacity is expensive relative to a fuel-oil storage tank. The firm pipeline cost for a 300 MW baseload gas plant would be about \$20 million per year. An oil tank for a 300 MW peaker would be a one-time cost of about \$15 million. There is a reliability concern with extensive reliance on dual fuel peakers. That is, will the backup fuel inventory be adequate? In this IRP, we present a comprehensive analysis demonstrating 48 to 72 hours of backup fuel supply would be adequate, even if PSE added several hundred MW of dual fuel peakers.

Summary of Stochastic Portfolio Analysis

The deterministic scenario analysis described above is helpful in understanding how changes in key assumptions would affect the least-cost mix of resources. It is not, however a complete picture of risk. The deterministic analysis assumes perfect foresight, so we know what factors – such as natural gas prices or carbon policies – will be far in advance of having to make decisions. It also assumes all markets and weather conditions are “normal.” In reality, we do not know what natural gas prices will be, what hydro or wind conditions will be, or what kinds of carbon regulation will be imposed by 2025. To examine the implications of these risks, we develop a number of portfolios and run them through 250 simulations (or draws)³ that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO₂ regulations/prices. From this analysis, we can observe how costs change across portfolios and identify whether differences occur when risk is analyzed.

We chose eight different portfolios to test in the stochastic analysis. The portfolios examined in this analysis were designed to test whether different resource alternatives would have a significant impact on expected cost or risk. PSE defines “risk” as the TailVar90 metric – which we adopted from the NPCC several years ago. That is the average value of all observations above the 90th percentile in the distribution of costs. TailVar90 of revenue requirement is a clear risk metric. It specifically focuses on how bad portfolio costs could be over the planning horizon. It allows us to see how different resources would affect bad outcomes. The portfolios tested included the following.

³ / Each of the 250 simulations is for the twenty-year IRP forecasting period, 2018 through 2037.



1. **BASE SCENARIO.** This is the least cost mix of resources that resulted from the Base Scenario. The primary capacity resources after conservation are dual fuel peaking units.
2. **RESOURCE PLAN.** The resource plan relies on additional demand response and batteries to push out the first dual fuel peaker to 2025.
3. **BASE + NO CO₂.** This was the least cost mix of resources that resulted from the Base + No CO₂ Scenario. It includes 1,652 MW of baseload gas plants by the end of the planning horizon.
4. **NO ADDITIONAL DSR.** This is the least cost portfolio in the Base Scenario, if we did not consider any additional DSR. The purpose is to illustrate the impact of conservation on both cost and portfolio risk.
5. **ADD 300 MW OF SOLAR.** This portfolio adds 300 MW of solar beyond RPS requirements in 2022 to the least cost portfolio from the Base Scenario. Solar was chosen because it was found to be the least-cost renewable resource across all scenarios. Adding solar would avoid exposure to market purchases if prices run up – though it also reduces the ability to take advantage of low prices. The purpose is to examine whether adding solar beyond requirements would reduce portfolio risk, and if so, would it reduce risk enough to justify the cost of including more in the resource plan.
6. **NO TRANSMISSION REDIRECT.** To develop this scenario, we excluded the transmission redirect as a resource choice, and re-optimized the portfolio, which added more peakers. However, increasing PSE's reliance on firm transmission backed by short-term market purchases could also increase risk. Even a dual fuel peaker could mitigate risk of very high power prices. This analysis was performed to test whether the transmission redirect that was chosen as low cost in every scenario would create unreasonable risk exposure.
7. **NO NEW THERMAL RESOURCES.** This is the least-cost portfolio from the No New Thermal Resources portfolio sensitivity, which was developed in the Base Scenario. When no new thermal resources were allowed, pumped hydro storage became the go-to capacity resource. The deterministic analysis showed it was expensive; this analysis is to determine if reducing exposure in high market cost conditions justified the high cost of pumped hydro.
8. **MORE CONSERVATION.** This portfolio adds 70 aMW of energy efficiency which provides an additional 4 MW of capacity, to explore whether an incremental increase in conservation would reduce portfolio risk, and if so, whether the reduction would justify adding conservation beyond what was found to be least cost.



Summary of Stochastic Portfolio Results

KEY FINDING. Resource additions have little impact on portfolio risk. This is primarily because the portfolio is already quite large – 6,000 MW today – and what’s being added to it is small. The resource plan forecast calls for approximately 2,750 MW of resources by 2037. However, only 1,150 MW of those resources reduce exposure to wholesale natural gas or power market risk – namely, conservation and solar. While we can examine cost versus risk of individual resources, aggregated up to the portfolio level, additions are small in relation to the portfolio. The take-away is that resource additions do not appear to be a meaningful way to try and manage portfolio risk. Instead, natural gas price and wholesale power price risk needs to be financially managed in the shorter-run – which is exactly what PSE does.

Results Across Portfolios Tested

There were some differences between the mean, or expected costs, of the various portfolios and the TailVar90 risks. Some are intuitive, others are not, and will be explained in the following discussion. Figure 2-6, below, summarizes results of the stochastic analysis. The mean, or expected values, from the stochastic analysis are relationally the same as results of the deterministic analysis. That is, the deterministic analysis showed the optimal Base Scenario portfolio was slightly lower cost than resource plan. We see the same in the stochastic analysis. All the other scenarios show expected portfolio costs greater than the resource plan forecast.



Figure 2-6: NPV of Portfolio Cost Metrics – Costs are NPV \$Millions

| NPV (\$Billion) | "Average" Conditions | | | Worst Conditions | | |
|----------------------------------|----------------------|----------------------|----------|------------------|----------------------|----------|
| | Mean | Difference from Base | % Change | TVar90 | Difference from Base | % Change |
| 1 – Base Scenario Portfolio | 10.52 | | | 11.79 | | |
| 2 – Resource Plan | 10.57 | 0.05 | 0.5% | 11.84 | 0.05 | 0.4% |
| 3 – Base + No CO2 Portfolio | 11.13 | 0.61 | 5.8% | 12.5 | 0.71 | 6.0% |
| 4 – No DSR | 10.84 | 0.32 | 3.1% | 12.8 | .4 | 3.4% |
| 5 – Add 300 MW Solar in 2023 | 10.54 | 0.03 | 0.3% | 11.8 | .01 | 0.1% |
| 6 – No Transmission redirect | 10.62 | 0.1 | 0.9% | 11.89 | 0.1 | 0.8% |
| 7 – No new thermal | 12.69 | 2.18 | 20.7% | 14.65 | 2.86 | 24.3% |
| 8 – More conservation (Bundle 5) | 10.81 | 0.29 | 2.7% | 12.06 | 0.27 | 2.3% |



Key Observations from Figure 2-6

RESOURCE PLAN COMPARED TO BASE SCENARIO PORTFOLIO. The resource plan includes more demand response and early batteries in order to delay the need for peakers until 2025, otherwise it is quite similar to the Base Scenario least-cost portfolio. The Base Scenario portfolio incorporates significant amounts of peaker units. The expected cost of the resource plan is slightly higher than the Base Scenario portfolio – by about 0.5 percent, or an NPV increase of \$50 million over the planning horizon. Risk is also slightly higher: The mean of the worst 10 percent of cases (TailVar90) is higher by 0.4 percent. This illustrates that including more demand response and early batteries will not have a material effect on portfolio risk.

PEAKERS COMPARED TO BASELOAD GAS. A portfolio with baseload gas plant (CCCT) additions has an expected value significantly higher than the Base Scenario portfolio, which includes peakers instead of baseload gas plants. Substituting over 1,600 MW of baseload gas plants for peakers increases expected costs – by \$610 million, a 5.8 percent increase. Risk increases as well, by about the same amount – 6 percent. This illustrates baseload gas plants do not reduce risk relative to peakers. Both substitute exposure to wholesale electric prices for exposure to wholesale natural gas prices. Both plants protect against market heat rate blow-outs, in which the price of electricity increases relative to natural gas prices. Focusing just on variable costs, baseload gas plants provide a better hedge against market heat rates because they use less natural gas. However, baseload gas plants come at a significantly higher initial cost. This risk analysis shows baseload gas plants provide no additional risk protection. Additional discussion on this issue appears below.



VALUE OF DSR. Conservation reduces both cost and risk relative to the alternative, which would be to add more dual fuel peaker capacity. The stochastic analysis demonstrates that cost-effective DSR saves \$320 million on an expected value basis – a 3.1 percent savings. DSR also reduces risk, but not quite as much as it reduced cost. One might expect the risk reduction to be greater than the cost reduction, but there is an important difference between conservation and peakers. Conservation for PSE reduces exposure to gas and power prices by reducing load – typically winter loads – which avoids the need to build additional generation resources. Peakers represent an option to generate that can be exercised at any time. There may be circumstances in which summer market prices and heat rates are quite high. Conservation programs that primarily target heating loads have no value during those periods. Peakers, on the other hand, can provide value in the summer during times when natural gas and power prices diverge and capture margins that pass through to customers as an offset to power costs in rates. The analysis still shows conservation provides a significant reduction in risk.

ADDING 300 MW OF SOLAR. Adding solar beyond requirements of RCW 19.285 increases expected portfolio costs somewhat – by \$30 million, or 0.3 percent. The additional solar also increases risk very slightly – by \$10 million, or 0.1 percent. The much smaller reduction in risk means solar is reducing power costs during bad market conditions, but still not quite enough to offset the higher fixed cost. Also, something to consider is that solar output is lower in the winter when PSE's loads are highest, but solar output is higher in the summer, when prices can be high and volatile. Thus, the risk reduction is mostly a financial benefit, not a physical one – which is not a problem as we are trying to minimize costs of complying with RCW 19.285. With such close results, should PSE add solar to mitigate risk? That conclusion is not supported by this analysis. However, if solar costs continue to fall, it is possible that PSE will find solar reduces risk in future IRPs. Because PSE is winter peaking, we would need to develop planning standards to ensure such additions do not exceed loads so that PSE does not acquire more generation resources than our customers can use just so the surplus could be sold into the market.

INCREASING MARKET RELIANCE – IMPACT OF THE TRANSMISSION REDIRECT. The transmission redirect to access more short-term market energy is low-cost capacity. This comparison shows that if PSE did not pursue the transmission redirect, expected portfolio costs would be higher – by \$100 million, or 0.9 percent. Risk would also be higher, again by \$74 million, or 0.8 percent. The minor increase in risk means that an additional peaker would reduce variable power costs when power prices are high, but not enough to cover the higher cost. It is also interesting to compare the percentage change in risk from adding solar with the percentage change in risk from substituting a peaker for market purchases. Relative to cost, on a percentage basis solar performs as a better hedge because it avoids electric *and* natural gas price risk, whereas a peaker does not avoid the fuel price risk.



NO NEW THERMAL RESOURCES. This analysis illustrates that peakers are quite valuable to the portfolio. This portfolio covers much of the peak capacity need with pumped hydro storage as the most cost-effective alternative. This would be costly. The expected value is more than \$2 billion higher than the Base Scenario portfolio, about a 20.7 percent increase. Risk is even higher, too – by over \$2.8 billion, which is a 24.3 percent increase. This illustrates that energy storage does not effectively protect against natural gas price or power price risk. At best, energy storage allows for some short-term arbitrage between hours, but it is still charged with electricity, and therefore subject to the variability of market electric prices.

ADDITIONAL CONSERVATION. In this IRP we tested an increase in conservation beyond what was found cost effective across all scenarios. The deterministic analysis showed Bundle 3 was cost effective in every scenario. We included two additional bundles (through Bundle 5), which added 4 more MW of conservation and 68 aMW more energy savings. We tested this portfolio to determine if the additional conservation would reduce risk, and if so, whether the risk reduction benefits were worth the higher cost. Expected costs for this portfolio are \$290 million higher than the Base Scenario portfolio, an increase of approximately 2.7 percent. The additional conservation did not, however, lower risk. Risk increased by \$270 million (2.3 percent), meaning the higher cost of conservation was not offset by power cost savings, on average, in the worst 10 percent of simulations. While conservation that addresses heating loads is helpful for reducing peak capacity needs and reducing exposure to winter power and natural gas price risk, it provides no value outside the heating season. Peakers can help mitigate power price risk in the winter and present a year-round option to generate savings in excess of fuel costs that will flow back to customers.



Resource Plan Forecast: Application of Judgment

Discussion above summarizes key findings from the deterministic and stochastic portfolio analyses. These analyses do not necessarily drive an answer, but provide information upon which decisions can be made. While the models are comprehensive, there are risks and opportunities that are not reflected in the resource modeling. This section will step through each element of the resource plan and provide an explanation of why it is reasonable.

Increased Demand Response and Energy Storage: The Resource Plan Through 2024

Increasing demand response and energy storage, relative to the least cost mix of resources in the Base Scenario is an important risk mitigation decision. Technology is driving down the cost of alternative resources. Solar and energy storage appear cost effective for the first time in this IRP. While we do reflect improving technology costs in the portfolio analysis, it is possible energy storage costs will fall even faster than expected. Additionally, as we analyze additional kinds of demand response programs in the 2019 IRP, those could prove a cost effective way to avoid new fossil fuel generation. In addition to technology reducing cost of alternative resources, carbon regulation looms as a significant source of uncertainty. Even the form of carbon regulation is uncertain. The way carbon regulation is implemented is just as important as the per-unit cost of carbon. Additional demand response and batteries, sufficient to push the need for additional fossil fuel plants to 2025 or beyond is a reasonable strategy. This will provide time for technology to work on reducing alternative resource costs as well as time for carbon regulations to become clearer.

The specific amounts of additional demand response and energy storage were taken from the least cost portfolios under Scenario 9 (Base + No CO₂) and Scenario 14 (Base All-thermal CO₂). We substituted the early builds from these scenarios for the early peaker build from the Base Scenario, as shown in Figure 2-7. Both of those scenarios had sufficient demand response and energy storage to push the need for additional fossil fuel generation resources out to 2025. These scenarios have an unbiased application of carbon regulation, whereas the CAR and CPP in the other scenarios create an unintended bias that favors peakers over other capacity resources. In the Base Scenario, substituting demand response and energy storage increased NPV of portfolio costs by about \$9 million – less than 0.1 percent. This is an insignificant cost to avoid building a fossil fuel plant that will have at least a 35-year life, to make sure it will be a good long-term investment on behalf of our customers.



Cost-effective Conservation

The same level of conservation was found cost effective across all the scenarios. This provides a high degree of confidence that we have the right amount of conservation in the resource plan. As described above, we tested adding more conservation to determine if it would provide a reasonable way to mitigate financial portfolio risk. It did not. Therefore, the decision on conservation is very well supported by both the deterministic and stochastic analysis.

Transmission Redirect

Similar to conservation, redirecting transmission to increase our firm access to short-term wholesale markets was least cost across all scenarios. This resource addition does cause some concern for PSE, as we already rely on a significant amount of firm transmission to access wholesale market. This transmission redirect clearly appears cost effective, but it is not without risk. One important risk is BPA operational/policy risk—it is possible that in the future, BPA may not facilitate this redirect. There are two other important risks to consider. One is physical resource adequacy risk. PSE performed a robust wholesale market risk analysis – one that is tied to the regional resource adequacy framework developed and implemented by the NPCC and BPA. This analysis shows wholesale market is nearly as reliable as a new peaker. The other risk is financial. The stochastic portfolio risk analysis confirms that increasing reliance on wholesale markets does increase risk. However, as described above, the increase in risk is reasonable, given the significant cost savings.

Renewables – Eastern Washington Solar

Every scenario showed eastern Washington solar was the most cost-effective qualifying renewable resource, so this is a very durable answer across all scenarios. While our base assumption had no transmission costs, it appears solar would be cost effective even if it required transmission – as shown above in Figure 2-5. The other primary qualifying renewable resource is wind in eastern Washington. While Montana wind was analyzed as if it were a qualifying resource, RCW 19.285 would have to be changed for that to be the case. Montana wind did not appear cost effective relative to eastern Washington solar, so the issue is resolved for this IRP. The stochastic risk analysis showed that solar beyond that needed for compliance with RCW 19.285 would reduce portfolio risk, but not sufficient to justify the up-front investment.

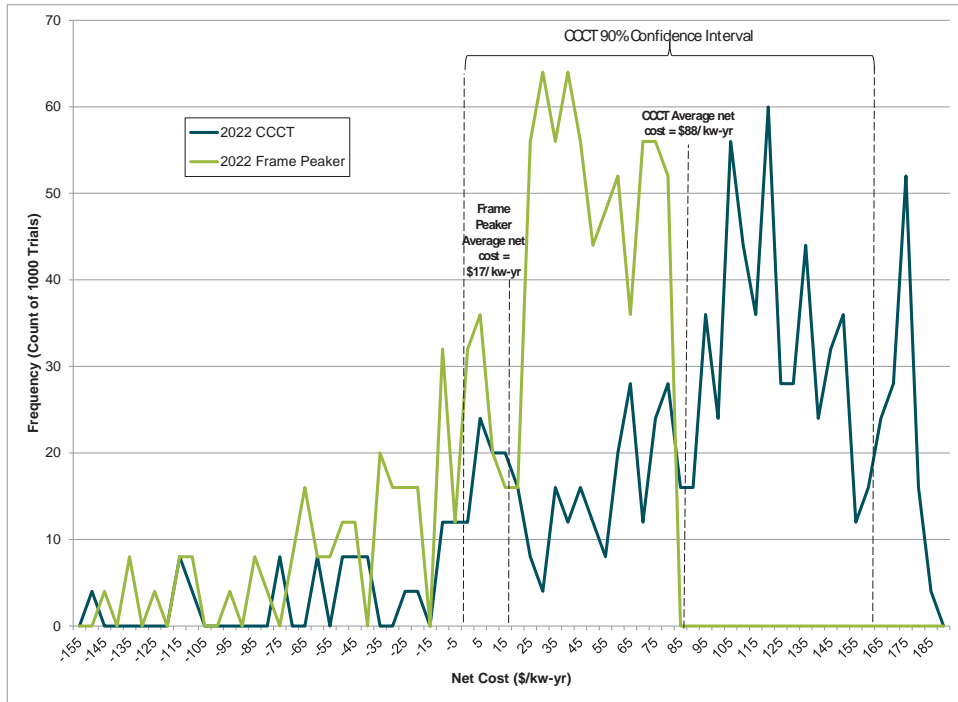


Peakers Instead of Baseload Gas Plants – Capacity Resources Later in the Planning Horizon

Dual-fuel peakers were found to be the least cost capacity resource in most scenarios. The exceptions were Scenario 9 (Base + No CO₂), which had 1,652 MW of baseload gas plants by 2035 instead of peakers, and Scenario 14 (Base + All Thermal CO₂), which had 826 MW of baseload gas plants instead of peakers. The stochastic analysis results in Figure 2-6 illustrated that baseload gas plants increased both cost and risk. While baseload gas plants use natural gas more efficiently and will be economically dispatched more often than peakers, the margin (market price – variable cost) is not sufficient to overcome the significantly higher fixed costs, both capital costs for the plant and firm pipeline capacity costs. Figure 2-7, below, shows the frequency distributions for the net cost of both peakers and baseload gas plants. “Net cost” means the revenue requirement of the plant (including recovery of both fixed and variable costs) minus the market value of the energy it generates. Each plant is economically dispatched for each hour, using the AURORA model, and this net cost is calculated for each simulation to create the distribution of net costs. This figure shows the expected value for net peakers is near the lower end of the baseload gas plant’s 90 percent confidence interval of net cost. There were some simulations where both kinds of plants created enough margin to offset the fixed costs. Notice the tail on the left for both plants is quite similar. This is because as power prices diverge from gas prices, both plants will capture increasing margins, though baseload plants will capture a bit more because they are more efficient. However, in general, the greater margins do not appear to overcome the higher fixed costs of the plants. On the other end of the distribution, baseload gas plants have net costs that go significantly higher than peakers. In fact, the *mean* net cost for baseload gas plants is \$85/kW-yr, which is slightly higher than the *worst* case for a peaker, at just over \$85/kW-yr.



Figure 2-7: Comparison of Net Cost Distribution
 Baseload Gas and Peakers with Oil Backup (in 2018 dollars per kW)

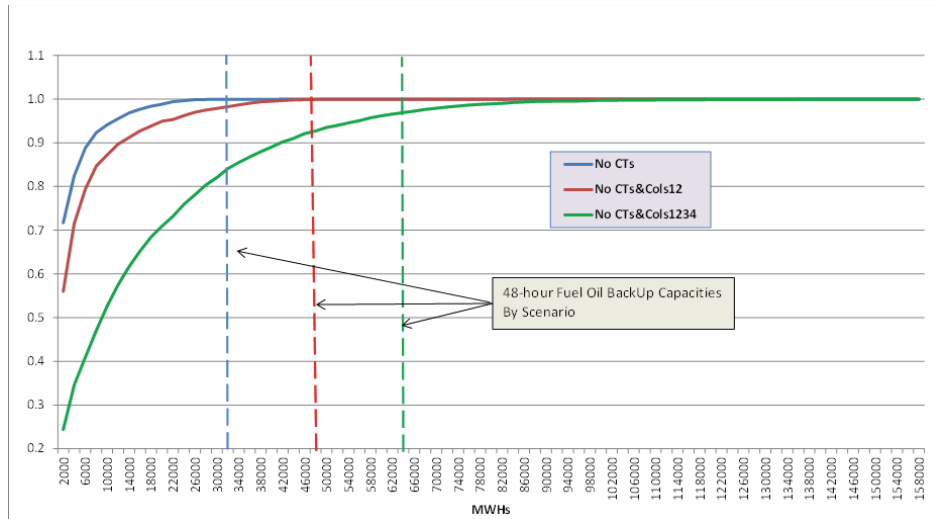


The other concern PSE has had with dual-fuel peakers is whether the backup fuel would be adequate. In this IRP, we examined whether backup fuel was sufficient for our existing dual fuel peaker generators and also examined implications of adding several hundred additional MW. We used our resource adequacy modelling framework to identify the number of hours in a year that we would physically need to rely on backup fuel. This was performed by first removing all peakers from the portfolio and calculating the number of hours the portfolio would be physically short. Then we also subtracted Colstrip 1 & 2 from the portfolio, followed by Colstrip 3 & 4. Figure 2-8 demonstrates that 48 hours of backup fuel was adequate to cover 100 percent of the needs for the existing fleet and new peakers when Colstrip 1 & 2 are retired. When we removed Colstrip 3 & 4 from the portfolio, 48 hours of backup fuel for the new and existing peakers would cover the need for approximately 95 percent of the simulations in the RAM. However, if the backup fuel tank were increased to 72 hours, that would cover 100 percent of the needs. Air permits to operate on backup fuel for 72 hours per year would probably not be a problem.



Therefore, PSE included dual fuel peakers later in the planning horizon – though we hope advances in energy storage will continue to push out the need for fossil fuel generation in all future IRPs.

Figure 2-8: Cumulative Distribution of Incremental Deficit for Bad Simulations in MWh/yr





3. GAS SALES RESOURCE PLAN

Resource Additions Summary

The gas sales resource plan is summarized in Figure 2-9, followed by a discussion of the reasoning that led to the plan. The years shown here reference the gas year, so 2025/26 means the gas year starting November 2025 through October 2026.

Figure 2-9: Gas Sales Resource Plan – Cumulative Capacity Additions (MDth/day)

| | 2025/26 | 2029/30 | 2037/38 |
|-----------------------------------|---------|---------|---------|
| Conservation | 27 | 49 | 84 |
| Swarr Upgrade | 30 | 30 | 30 |
| LNG Distr. Upgrade | 0 | 16 | 16 |
| Additional NWP + Westcoast | 0 | 61 | 140 |

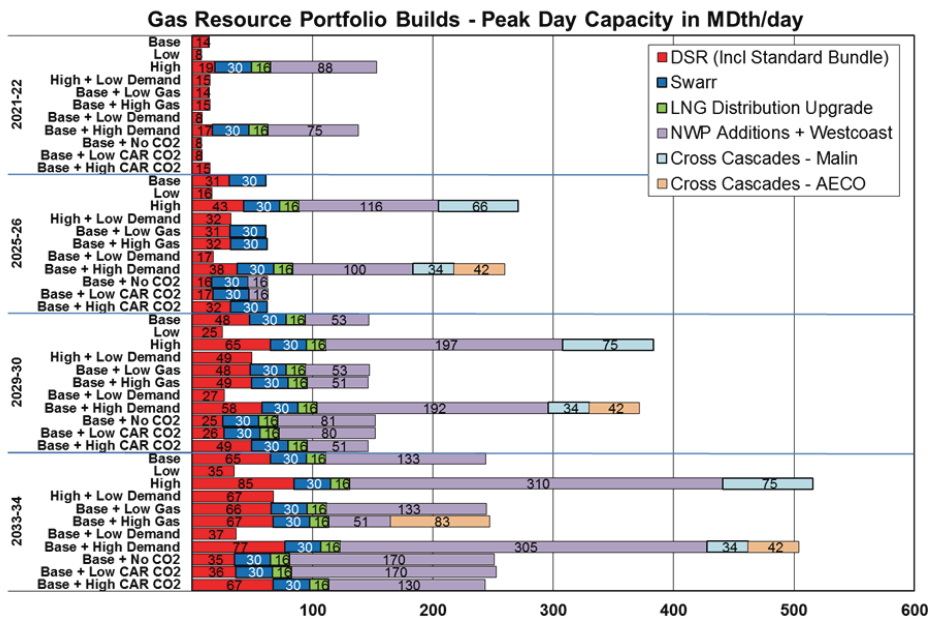
The gas sales resource plan integrates demand-side and supply-side resources to arrive at the lowest reasonable cost portfolio capable of meeting customer needs over the 20-year planning period.



Gas Sales Results across Scenarios

As with the electric analysis, the gas sales analysis examined the lowest reasonable cost mix of resources across a range of scenarios. Figure 2-10 illustrates the lowest reasonable cost portfolio of resources across those eleven potential future conditions.

Figure 2-10: Gas Sales Portfolios by Scenario (MDth/day)



Key Findings by Resource Type

Demand-side Resources

Cost effective DSR (conservation) does not vary dramatically across scenarios, especially in the early years, which is most important for program planning. Figure 2-11, below, shows the results of cost-effective DSR sorted by low, medium and high levels by 2022/23. The lowest levels of cost-effective DSR correspond to scenarios with low demand or low carbon costs. The highest levels of cost-effective DSR correspond to cases with high load growth. The mid-level cost-effective DSR includes scenarios with mid load growth and mid-to-high carbon costs.



Figure 2-11: DSR Results Sorted by Cost Effective Levels

| | Low DSR 8 MDth/Day | Mid DSR 14-15 MDth/Day | High DSR 17-19 MDth/Day |
|-----------|-----------------------|---------------------------|----------------------------|
| Scenarios | Low | Base | High |
| | Base + Low Demand | High + Low Demand | Base + High Demand |
| | Base + No CO2 | Base + Low Gas | |
| | Base + Low CAR CO2 | Base + High Gas | |
| | | Base + High CAR CO2 | |

Swarr Upgrades

Upgrades to PSE's propane injection facility, Swarr, is a least cost resource in every scenario except for the three scenarios with low demand, which do not require any resources beyond DSR. The timing of the Swarr upgrade is driven by the load forecast. In scenarios with high load forecasts, Swarr is needed by 2021/22. In the mid-growth scenarios, Swarr is needed by 2025/26. Upgrades to Swarr are essentially within PSE's ability to control, so we have the flexibility to fine-tune the timing. PSE has less control over pipeline expansions, as expansions often require a number of shippers to sign up for service in order for an expansion to be cost effective. We focused on this flexibility in the Timing Optimization Sensitivity, and found we could push the Swarr upgrade out one year, from 2022/23 to 2023/24. A decision on the timing of the Swarr upgrade is not needed now; the upgrade has a short lead-time, and we have the flexibility to adjust as the future unfolds.

LNG Distribution Upgrade

The cost effectiveness of upgrades to the distribution system to allow more gas to be withdrawn from PSE's Tacoma LNG storage facility are driven by the load forecast. In the three low-growth scenarios, this resource is not needed. In the high-growth scenarios, the LNG Distribution Upgrade is needed by 2021/22. The Base Scenario shows a need for it by 2029/30. Similar to Swarr, PSE has significant control over when the distribution system could be upgraded to increase withdrawal volumes from our Tacoma LNG peaking facility, so we have the flexibility to adjust the timing as the future unfolds.



NWP + Westcoast Pipeline Additions

Additional firm pipeline capacity on Northwest and Westcoast Pipelines North, to Station 2, is cost effective in every scenario, except those with low load growth. In the high load growth scenarios, 75-88 MDth/day is needed by 2021/22, growing to more than 300 MDth/day by the end of the planning horizon. In the mid-load growth scenarios, there are some slight timing differences. The Base + No CO₂ and Base + Low CAR CO₂ Scenarios show 16 MDth/Day of NWP + Westcoast Pipeline additions would be cost effective by 2025/26, but the other scenarios with mid-load growth do not. This is the effect of less conservation being cost effective in these two scenarios. Notice in Figure 2-10, above, those two scenarios have about 16 MDth less DSR than the other mid-growth scenarios – 16-17 MDth/day DSR in the former scenarios versus 31-32 MDth of DSR in the other mid-load growth scenarios.

Cross Cascades to Malin or AECO

These resources appear cost effective primarily in the high load growth scenarios. 83 MDth/day of Cross Cascades to AECO appears in the Base + High Gas Scenario by the end of the planning horizon as well. This is primarily being driven by price differentials between the different supply basins.

Resource Plan Forecast – Decisions

The resource plan forecast additions identified above are consistent with the optimal portfolio additions produced for the Base Scenario by the SENDOUT gas portfolio model analysis tool, including results of the Resource Timing Optimization Sensitivity. SENDOUT is a helpful tool, but results must be reviewed based on judgment, since real-world market conditions and limitations on resource additions are not reflected in the model. The following summarizes key decisions for the resource plan.

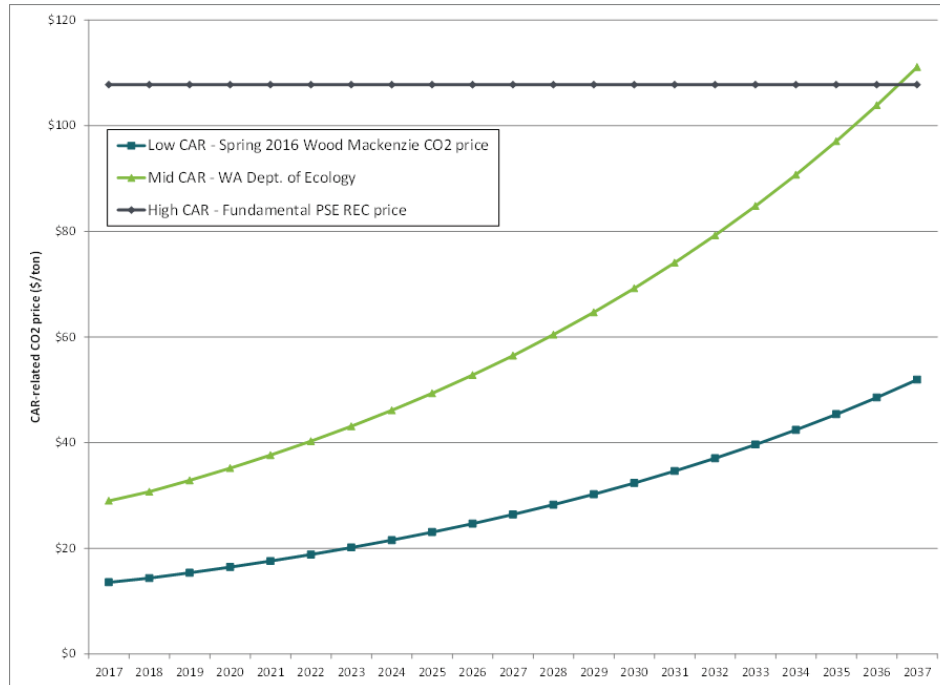


Conservation (DSR)

The resource plan incorporates cost-effective DSR from the Base Scenario – the same as several other scenarios, as shown in the table in Figure 2-10, above. Gas prices appear to have little impact on DSR within the mid-load growth forecast. The primary variable that affects the resource decision is the assumption for carbon prices. CAR is being challenged in court, so it may not be implemented, but even if it is, and carbon prices are in the range of the low carbon prices modeled, cost-effective DSR would be cut in half. Figure 2-12 illustrates the different carbon prices. At this time, we need to make a decision which significantly affects the result, with no confidence in our ability to forecast carbon prices. However, even if CAR is not implemented, PSE believes some kind of carbon regulation will affect our gas utility operations in the future. Low carbon prices have no effect on the cost effectiveness of conservation, but the base and high carbon cases have the same result; they include twice the amount of conservation. These results lead us to conclude that it would be more reasonable to incorporate DSR from the Base and High CO₂ scenarios. While in the future we may not see carbon prices in this range, conservation programs take years to accumulate savings. We believe this is a reasonable hedge against the risk of higher carbon prices.



Figure 2-12: Annual Range of CAR-related CO₂ Prices Used in the 2017 IRP



Supply-side Resources

The supply-side resources – Swarr, LNG Distribution Upgrade, and pipeline expansions – follow the Base Scenario resource additions, including results of the Timing Optimization Sensitivity, which moves Swarr out one year relative to the Base Scenario. All the resource plan forecasts based on mid-load growth have the same set of least-cost resource additions, once we account for the difference in DSR due to the No or Low CO₂ price scenarios. The only exception is in the Base + High Gas Scenario. In that scenario, some pipeline capacity on Cross Cascades up to AECO appears cost effective after 2030. This is driven by forecasted widening price differentials between AECO and Station 2, probably due to higher LNG exports from Northern British Columbia in that scenario. This is not an urgent issue to resolve, as PSE-controlled resources appear adequate to meet our customer’s needs until 2029/30. It does highlight the importance of continuing to monitor the long-term outlook of natural gas prices at our different supply basins. We will file four more IRPs by the end of 2025, and we will be doing just that.



3

2017 PSE Integrated Resource Plan

Planning Environment

This chapter reviews the conditions that defined the planning context for the 2017 IRP.

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1. GREENHOUSE GAS EMISSIONS

At present, the future of greenhouse gas (GHG) regulation at the federal, state and local levels is uncertain at best. However, PSE cannot ignore the possibility that *some* level of change to regulatory policies regarding carbon-emitting generating resources and/or the use of natural gas as a heating source is likely to occur during the 20-year planning horizon of this IRP. Summarized below are some of the current regulatory initiatives that have the potential to impact the operation of PSE's existing power supply portfolio, future resource acquisition decisions and the operation of PSE's natural gas distribution system.

Clean Air Rule

The Clean Air Rule (CAR) promulgated by the Washington State Department of Ecology (DOE) is effective beginning in 2017. This rule is intended to address GHG emissions from in-state non-mobile sources, petroleum product producers and importers, and natural gas distributors. While CAR would establish emission standards to "cap and reduce" GHG emissions, it would not be a full "cap and trade" program like California's existing program. New emission sources, like new baseload gas plants, are permitted. CAR would allow covered sources to create emission reduction units (ERUs) if a source's emissions levels are below the targets set by the state – or to purchase ERUs if the source operated above the targets. An emissions source may then bank its ERUs for future use or sell them. With CAR just beginning in 2017, the volume of ERUs is unknown at this point and likely very limited. So, instead of sources having the option to purchase large volumes of CO₂ credits to offset their physical GHG emissions (as in California's program), compliance with CAR will be achieved primarily through actual GHG reductions or through the purchase of carbon credits available from emissions programs outside of Washington state.

The CAR program has a significant impact on both PSE's existing power resource portfolio and any new PSE resource additions, because it will generally increase the costs of carbon emitting generating resources like natural gas-fired plants compared to carbon-free resources such as wind and solar. PSE's natural gas distribution customers will also be affected because PSE will need to purchase ERUs (if available) to offset a portion of its customers' natural gas usage. Quantifying the potential financial impacts of CAR on PSE and its customers is challenging, given that prices for ERUs will likely be established via a market-based negotiation process that could result in PSE's actual compliance costs being significantly higher or lower than forecast.



CAR is the subject of several lawsuits challenging the validity of the rule, but the rule is in effect nevertheless. Accordingly, PSE needs to be prepared to incorporate CAR into its long-term electric and natural gas resource planning processes. This situation necessitates that PSE maintain flexibility in evaluating the risks associated with the potential acquisition of any new power supply resources until the full impacts of CAR are known and quantified.

Clean Power Plan

The federal Clean Power Plan (CPP) applies carbon costs to all existing and new baseload generating facilities located in the U.S based upon a set of state-specific GHG reduction targets and associated compliance plans. Potential consequences for PSE include higher operating costs for its existing fleet of natural-gas and coal-fired generating plants as well as increasing the forecasted cost of adding new carbon-emitting resources. The CPP could be implemented as a cap and trade system in which trade may or may not be implemented across different states. Or, it could be implemented as a carbon intensity system that targets a tons per MWh metric in which some elements of interstate trading may or may not be implemented. Different applications of the CPP could lead to different results.

Twenty-seven states and other entities have filed lawsuits to block the Environmental Protection Agency's (EPA) implementation of CPP on the grounds that the EPA lacks the authority under the Clean Air Act to regulate GHG emissions. In 2016, the United States Supreme Court stayed the EPA's implementation of CPP pending judicial review (the case is currently pending in the D.C. Circuit Court). In addition, the current federal administration issued an Executive Order on March 28, 2017 in favor of energy independence that calls for review of specific regulations affecting the energy industry including the Clean Power Plan. On April 4, 2017, the EPA announced that it is reviewing CPP regulations, and if appropriate, will initiate proceedings to suspend, revise or rescind the CPP. While implementation in the short term is uncertain, it is still possible (and likely) that some form of the CPP could be implemented during the 20-year planning horizon of this IRP. This situation again requires that PSE maintain flexibility in the evaluation of, and potential acquisition of, new power supply resources while the future of the CPP is being debated.



Other State and Local Government Policies

In addition to the EPA's proposed CPP and Washington state's CAR, various entities within the state, including several local government bodies, have recently adopted or are currently discussing additional carbon-reduction initiatives. For example, Washington voters rejected a ballot initiative in 2016 to create a statewide carbon tax, but several state lawmakers continue to support this concept. In addition, stakeholders are currently reviewing carbon pricing policies, and have filed three such measures with the Office of the Secretary of State. Local jurisdictions have also discussed potentially restricting the development of new carbon-emitting resources, including coal and natural gas-fired combustion turbines. King County's Strategic Climate Action Plan and King County Cities Climate Collaboration (K4C) set renewable energy goals to use 100 percent carbon-neutral energy in county operations by 2025, to phase out coal-fired electricity sources by 2025 and to limit new natural gas based electricity power plants. The City Councils of Seattle and Olympia have passed resolutions calling on PSE to stop operating Colstrip by 2025. The City of Edmonds City Council recently approved amendments calling for city-owned buildings be powered completely by renewable energy by 2019 and for the city's community electricity to come from renewable sources by 2025, and a number of counties and cities have also passed similar resolutions. These are not binding regulatory requirements, but clearly demonstrate a significant number of the political leaders in our service territory are concerned about climate change and the role Colstrip plays in it.

Changing Customer Priorities

Beyond the political activities mentioned above, PSE has been partnering with customers seeking ways to meet their electricity needs with renewable resources. These include large commercial customers, small to mid-size businesses and residential customers. To serve these customers, PSE has developed a number of elective programs that are approved and monitored by the WUTC such as the Green Direct, Solar Choice and Green Power Programs, and we are committed developing further such products. These programs are important, because they provide customers with the ability to express their own preferences about the energy used to supply them, beyond the standard regulatory compact that requires PSE to minimize costs. Our first offering of Green Direct, marketed to larger commercial customers and government entities, was very successful. This program directly supported development of the Skookumchuck wind facility. PSE is working toward a second open season for the Green Direct Program and will continue to look for ways to partner with customers in meeting their energy needs.



2. REGIONAL RESOURCE ADEQUACY

Because PSE relies on more than 1,600 MW of wholesale market purchases to meet its current and forecasted energy and peak demand obligations,¹ we must monitor regional resource adequacy issues closely and be prepared to modify our purchase strategy accordingly should changing conditions warrant. To this end, PSE will continue working in conjunction with other regional planning entities such as the Northwest Power and Conservation Council (NPCC), Bonneville Power Association (BPA), and the Pacific Northwest Utilities Conference Committee (PNUCC) in order to improve existing analytical tools and to develop consensus assumptions for use in regional resource adequacy assessments.

For more than a decade, the Pacific Northwest region's large capacity surplus has kept wholesale power prices relatively low and made these existing resources a lower cost alternative to filling PSE's peak capacity need than building new generation. However, the long-term load/resource studies developed by the region's major energy organizations, NPCC, PNUCC and BPA,² while they differ in some details, generally point in the same direction: The current Pacific Northwest (PNW) energy and capacity surplus is expected to cross over to deficit at some point in the next decade unless new supply-side and/or demand-side resources are developed. This IRP analysis is aligned to the analytical results of the NPCC's 2016 Regional Resource Adequacy Assessment, but that assessment was updated in July of 2017.³ The 2017 update forecasts the region will be short of the 5 percent LOLP target by 2022, requiring 400 MW of effective capacity to achieve the target under the NPCC base assumptions.

Fortunately, recent evidence suggests that the region is in the process of adding new resources (mainly in the form of additional investments in conservation) to fill this forecasted resource gap. In fact, NPCC staff highlighted that if the region follows the guidance from the Seventh Power Plan, it will be adding approximately 600 MW of conservation every year. In addition, regional utility load forecast growth rates are continuing to trend downwards, thereby also closing some of the projected gap. Also, the amount of power that can be reliably imported into the region during winter and summer peak load events may be higher than the figures currently being used in the NPCC's resource adequacy model. Finally, PSE's shift to a 5 percent LOLP metric in this IRP for its capacity planning standard (as opposed to the Value of Lost Load approach used in the 2015 IRP) has resulted in a higher level of reliability being assigned to wholesale market purchases. While there is still some level of risk to PSE in relying on up to 1,600 MW of wholesale market

¹ / See Chapter 6, *Electric Analysis*, and Appendix G, *Wholesale Market Risk*, for more detail on wholesale market purchases and peak need.

² / These studies are included in Appendix F, *Regional Resource Adequacy Studies*.

³ / <https://www.nwccouncil.org/media/7491213/2017-5.pdf>



purchases to meet resource need, this risk appears to be significantly reduced from the level presented in the 2015 IRP.

The extensive analysis performed in the 2017 IRP indicates that PSE wholesale market purchases above the 1,600 MW level, when paired with additional firm transmission import rights that PSE may have during peak load events, is both a reliable and cost-effective way for PSE to meet its forecasted resource need when compared against other available new resource alternatives. These conditions allow PSE to maintain a considerable amount of flexibility regarding future resource acquisitions while also allowing it to effectively manage other uncertainties in the planning environment such as future GHG regulation, climate change, potential changes in customer behavior and the increasing effectiveness of emerging and maturing technologies.

These are all reasons for increased confidence, however, uncertainties remain. Should the region be unable to achieve forecasted conservation targets, should the specific timing of some of the region's coal-fired generating plants change, or should unexpected demand-side or supply-side shocks render the region short of resources, risk to PSE's customers would increase substantially. PSE has also expressed concern that the 5 percent LOLP metric, which measures the likelihood of deficit events, may not adequately describe the duration or magnitude of potential regional deficit events. The diversity of PSE's resource portfolio means that we would be able to mitigate some of these effects by using thermal resources to fill gaps during non-peak hours, but we would still be unable to meet peak need under such circumstances. For this reason, it may be advisable to develop a supply-side resource option that could be built in less than two years, in case wholesale market risk changes significantly.



3. CLIMATE CHANGE

Climate change is happening at a global level,⁴ and these changes are affecting the Puget Sound region. Already, the region has experienced “long-term warming, a lengthening of the frost-free season, and more frequent nighttime heat waves,”⁵ according to a study by the University of Washington.

Climate change could affect PSE’s power system operations and the IRP planning process in a number of ways. Changes in temperature, the frequency and duration of extreme weather events, hydro conditions, customer energy use and the number of customers served, will affect how much power PSE needs for its customers’ energy demand and how much power is needed at times of peak energy usage.

PSE needs detailed climate projections to forecast how climate change will affect our service territory to understand and plan for the range of probable futures so that we can adapt to the climate of the future. By detailed climate projections, we mean fundamental, scientific climate models, not just statistical analysis of recent trends.

At this time, there is not enough data to do a robust analysis of how our service territory, peak need, energy demand and conservation programs will change as a result of climate change. In the next section, we describe the data we believe is needed to do robust modelling of how climate change will affect our service territory and therefore our long-term capacity needs.

⁴ / IPCC, 2014: *Climate Change 2014: Synthesis Report. Contribution of Working Groups I, II and III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Core Writing Team, R.K. Pachauri and L.A. Meyer (eds.)]. IPCC, Geneva, Switzerland, 151 pp.

⁵ / Mauger, G.S., J.H. Casola, H.A. Morgan, R.L. Strauch, B. Jones, B. Curry, T.M. Busch Isaksen, L. Whitely Binder, M.B. Krosby, and A.K. Snover. 2015. *State of Knowledge: Climate Change in Puget Sound. Report prepared for the Puget Sound Partnership and the National Oceanic and Atmospheric Administration. Climate Impacts Group, University of Washington, Seattle. doi:10.7915/CIG93777D*



Impacts on Peak Need

Changes in weather are important for the IRP planning process because PSE forecasts are based on “normal” temperatures (last 30 years) and “normal” hydro conditions (1929 - 2008). If those normals are changing, we need to plan for that change and account for it in our modelling.

First and foremost, we need to understand how peak temperatures may change, because peak demand drives the need for additional capacity to meet the peak needs of both electric and natural gas service customers. Forecasting peak need is critically important for resource planning, and therefore understanding how extreme weather events may change is vitally important for integrated resource planning. We need data that will enable us to better understand these key questions:

- Are changes in extreme temperatures expected to change summer and winter peaks?
- Are sustained peaking events expected to increase or decrease?
- How will the severity and frequency of extreme events change?
- Will changes in the jet stream air currents mean arctic air dips into the region more frequently?⁶
- Will there be a change in humidity in the future?
- Could PSE’s service territory become a summer peaking utility, and if so, when?

A number of global climate models exist and could be downscaled to this region, but at this time it is not clear whether they can provide the needed information; simply scaling down large-scale averages is not sufficient.

Figure 3-1 shows the possible consequences to PSE of changes in extreme weather events. If extreme weather becomes more frequent and more severe than forecast, then PSE will likely need more flexible resources to respond to those events. If extreme weather events become less frequent and less severe, PSE will likely need fewer resources to respond. If there is no change in frequency or severity, we would expect no change in the planning process. However, if extreme weather events are more frequent but less severe, or more severe but less frequent, we need to understand these events better to forecast how they will affect our existing portfolio and new resource decisions. Currently, PSE is a winter peaking utility, however, the concept applies equally should climate change transition PSE to a summer peaking utility.

⁶ / Mooney, Chris “The Arctic is showing stunning winter warmth, and these scientists think they know why.” *The Washington Post*, 23 December 2016.
<https://www.google.com/search?q=The+Arctic+is+showing+stunning+winter+warmth&dq=The+Arctic+is+showing+stunning+winter+warmth&aq=chrome..69i57j69i60.1774j0j7&sourceid=chrome&ie=UTF-8>



Figure 3-1: Possible Effects of Climate Change on Extreme Weather

| | less severe than forecast | no change | more severe than forecast |
|-----------------------------|---------------------------|-----------|---------------------------|
| less frequent than forecast | | | ? |
| no change | | - | |
| more frequent than forecast | ? | | |

| | |
|--|--------------------------------------|
| | need fewer resources than forecasted |
| | need more resources than forecasted |

Impacts on Energy Need

In addition to impacting peak need, climate change may also impact customer load growth in two ways: by changing customer energy usage patterns, and/or by changing the number of customers we can expect to serve.

First, we need data to better understand how climate change will affect individual energy usage. For example: How will customer energy usage change seasonally? Will there be an increase in air conditioner saturation over time, causing more energy usage at a given temperature? Will we see more solar PV installations, thus lowering customer demand in the summer? Will we see additional air conditioning load in the summer? PSE is working to develop an end-use load forecasting model that could be used to analyze energy usage at the customer level. Also, there are regional efforts to collect new end-use data that could be used in the model PSE is developing.

Second, we need data to better understand how climate change will affect the number of customers that PSE serves. How will regional, national or global changes affect migration patterns into or out of this region? Will other locations become less hospitable (due to sea level rise, desertification or increased temperatures) forcing people to move to more hospitable places,



such as the Pacific Northwest as climate refugees? Will changes in the economy or the number of jobs cause people to move into or out of the service territory?

Figure 3-2 shows possible effects of climate change on energy demand. If PSE has more customers and higher use per customer than forecasted in a given season, then PSE may need more resources than forecasted. Similarly, if there are fewer customers and lower use per customer PSE will need fewer resources. However, the impact on resources is more uncertain if we see higher use per customer and lower customer counts or vice-versa.

Figure 3-2: Possible Effects of Climate Change on Loads

| | less usage per customer than forecast | no change | more usage per customer than forecast |
|-------------------------------|---------------------------------------|-----------|---------------------------------------|
| fewer customers than forecast | | | ? |
| no change | | - | |
| more customers than forecast | ? | | |

| | |
|--|--------------------------------------|
| | need fewer resources than forecasted |
| | need more resources than forecasted |

Impacts on the Hydroelectric System

Climate change may also bring changes to the regional hydroelectric system, changing the timing of runoff, the amount of runoff, or both. Changes to the hydroelectric system could affect PSE’s hydroelectric generation as well as Mid-C wholesale prices and regional energy availability. Assuming that PSE and the Pacific Northwest region remains winter peaking, direct effects to PSE’s peak capacity need should be minimal; that is, we could anticipate sufficient hydro power



to shape generation to meet peaking needs in the winter. Changes in other seasons, however, could also impact operations. For example, changes in operating conditions on the Columbia River could reduce the amount of energy and capacity available in the summer. In addition, power markets could be impacted by larger minimum flows requiring longer periods of time to manage dissolved gases and water temperature for fish. This could lead to a loss of flexibility and ancillary services from the hydro sector.

To understand changes to the hydroelectric system we need to understand changes in snowpack and runoff and how these changes will affect hydro operations and the re-shaping of natural stream flows across the year. This could include changes in daily temperatures, precipitation changes, and seasonal weather trends and new environmental constraints on the hydro system. Also, it is possible that climate change could affect withdrawals of water from the region's reservoirs for non-power purposes such as irrigation or domestic water supply.

Understanding these changes will be useful for energy planning and planning for ancillary services, especially in the summer when natural stream flows into the hydroelectric system are at their lowest point. If we see an earlier peak and less water overall in the system, we would expect much less water and less energy from the hydro system in the summer.

There are regional efforts through BPA, the U.S. Army Corps of Engineers, and the Bureau of Reclamation to better understand the effects of climate change on the Columbia River hydroelectric system in terms of timing, overall annual runoff volumes, and the hydro system's ability to meet non-power constraints. PSE will be following these efforts closely to better understand how climate change will affect this regional resource.

Next Steps

This is not an exhaustive list of how climate change could affect PSE, its resources or the service territory. (For example, changes to cloud cover, winds, or wildfire could affect PV installation, wind generation or transmission lines.) We do not need a complete understanding of how climate change will unfold before starting to model some of its effects on the PSE system, however, we do need more information to perform a robust analysis, particularly fundamental, scientific climate change models that focus on the region. Developing or getting access to regional forecasts that will give us the information outlined above is a priority for PSE.



4. EMERGING RESOURCES/ENERGY STORAGE

Previous IRP's have included emerging resources and energy storage devices, however, PSE's ability to fully evaluate the potential benefits and associated costs of these resources was hampered by several factors. These include: 1) lack of historical industry operating data for grid-scale applications of these technologies, 2) a wide range of cost estimates for some devices, 3) uncertainties regarding potential future cost reductions and/or efficiency gains, 4) difficulties in valuing some of the attributes that emerging resource/energy storage devices can provide due to a lack of available pricing data, and 5) lack of an analytical tool that would allow PSE to fully incorporate the flexibility value of emerging resources/energy storage alternatives in its IRP planning process.

While some challenges remain (such as the lack of some historical pricing data), PSE has made great strides in this IRP in expanding its analysis of emerging resources/energy storage devices. In particular, PSE's acquisition of the PLEXOS model now allows PSE to model both conventional resources and energy storage devices down to a five-minute time interval as opposed to the hourly time interval previously used for PSE's evaluation of energy storage technologies. The addition of PLEXOS allows PSE to model the intra-hourly operational characteristics of both conventional resources and energy storage devices; this capability, in turn, expands PSE's ability to quantify the full value stream that energy storage devices can bring to PSE's resource portfolio.⁷

The 2017 PSE IRP modeled five different energy storage devices that incorporate three different technologies and operating characteristics: lithium-ion batteries, vanadium-flow batteries and pumped hydro storage.⁸

⁷ / See Appendix H, *Operational Flexibility*, for a detailed summary of the PLEXOS model and PSE's operational flexibility analysis.

⁸ / Chapter 6, *Electric Analysis*, describes each of the energy storage alternatives analyzed.



While energy storage technologies other than batteries and pumped hydro storage exist – such as compressed air and flywheels – PSE did not model these technologies for several reasons. Compressed air storage facilities can be developed only at sites that have very specific geological conditions, which severely limits where these types of plants can be sited in the Pacific Northwest. And, while flywheel storage facilities can potentially be sited at a large number of different locations, this technology has yet to be proven in grid-scale operations. PSE therefore focused its evaluation of energy storage devices that: 1) are commercially available in grid-scale operations, and 2) can be reasonably sited in PSE's service territory and/or the Pacific Northwest region.

Battery storage technologies, in particular, are maturing, and manufacturing costs are being driven down by economies of scale, especially for lithium-ion batteries. In fact, the results of PSE's operational flexibility analysis for this IRP indicate that batteries are very close to being a cost-effective resource for PSE's portfolio.⁹ PSE will continue to fine tune its flexibility analysis and the role that energy storage devices may have in future resource portfolios. In addition, it will be important for PSE to assemble additional data regarding the performance characteristics of energy storage technologies in actual utility grid-scale applications and to assess PSE's potential need for additional system flexibility as more intermittent resources are integrated into PSE's Balancing Authority Area.

⁹ / See Appendix H, *Operational Flexibility for additional details.*



5. GAS SUPPLY AND PIPELINE TRANSPORTATION

Natural gas supplies in the basins that serve PSE continue to exceed expectations due to the abundant supply of natural gas from shale formations and improving production techniques, despite the decreased likelihood of an LNG export terminal in the region. Long-term projections of natural gas's affordability continue to augment the role of natural gas in our region's environment and economy. Natural gas remains a good economic value as an energy source, especially compared to its price levels of just a few years ago and the price of substitute fuels like oil. This remains true even in the current environment of lower-priced oil.

Though the regional gas transportation system is adequate to meet current demand, it is likely to experience increasing stress as gas customer growth continues – for example, if more of the region's electric generation requires natural gas for fuel, if liquefied natural gas (LNG) exports materialize, if large industrial uses such as methanol plants are developed, and as the transportation sector¹⁰ continues to adopt natural gas as an attractive fuel option. However, increased demand for natural gas could be offset by new carbon policies, such as CAR. Significant additions of gas peak loads will certainly require expanded pipeline capacity for certain locations (see Chapter 7, Gas Analysis). Given the scale of new industrial demand, it is important to note that large new industrial gas users may have more control over timing and location of future infrastructure expansions than existing users, including utilities.¹¹

¹⁰ / In this context, transportation sector includes maritime and heavy truck shipping and CNG vehicle use.

¹¹ / Northwest Gas Infrastructure Landscape Looking Forward, a paper produced by NWGA and PNUCC, discusses the development of large industrial gas loads. <http://www.nwga.org/wp-content/uploads/2015/07/Northwest-gas-inf-FINAL-Jul-2015-v21.pdf>



6. THE ACQUISITION PROCESS

The IRP provides a forecast of demand- and supply-side resources that could be used to meet resource needs. When PSE must fill an actual capacity need, it begins an acquisition process in which specific resource decisions must be made in a dynamic environment. In this process, PSE considers the IRP results along with several additional factors. These factors include the actual availability and cost of proposed resources, specific issues related to proposed resources such as the availability of transmission and gas transportation, changing needs and external influences.

A utility can acquire resources in a number of ways: through competitive bids in a request for proposals (RFP) process, by evaluating unsolicited or opportunistic offers, by constructing resources, by operating conservation programs or by purchasing power with negotiated contracts.

WAC 480-107-015 outlines the timing of an RFP. Under the WAC, an RFP must be filed if the IRP shows a capacity need within the first three years of the IRP's planning horizon, though PSE can issue an RFP for a need further out than three years. The process unfolds as follows.

PSE issues an RFP to interested parties and posts it on its website. The proposals submitted are evaluated in a two-phase process using these criteria:

- Compatibility with resource need
- Cost minimization
- Risk management
- Public benefits
- Strategic and financial benefits.

Phase 1 screens proposals to eliminate those with high costs, unacceptable risks or feasibility constraints. It uses a quantitative analysis to screen bids and a qualitative analysis to identify fatal flaws. Phase 1 produces a short list of candidates that advance to Phase 2 of the RFP process. In general, proposals on this list have positive economic benefits and no fatal flaws.



Phase 2 is a due diligence process. Input assumptions such as load and gas prices are updated as needed, more extensive quantitative analysis is performed to evaluate resource portfolios using various assumptions, and qualitative analysis is conducted based on the evaluation criteria. Phase 2 produces a list of proposals with the lowest reasonable cost and risk that best meet PSE's identified resource and timing needs.

PSE officers are kept apprised throughout the process, and updates are provided to the company's Energy Management Committee¹² (EMC). When Phase 2 is completed, a short list of proposals is formally recommended to the EMC for approval. PSE then enters negotiations with short-listed counterparties, and if agreements are reached then possible acquisitions are submitted to the EMC and, in some cases, the Board of Directors for approval. If an acquisition is made, PSE requests a prudence determination from the Washington Utilities and Transportation Commission (WUTC) when the company proposes in a rate proceeding to include the new resource's costs in its rate base and revenue requirement.

HOW RESOURCE SIZE IS DETERMINED. The capacity and RPS needs are determined in the IRP and updated on an ongoing basis as new information becomes available. The IRP provides a theoretical picture of the future resource portfolio using a range of generic resources that could be used to meet the capacity and RPS needs under different sets of assumptions. The size and cost of each generic resource are based on what is currently available in the market for that type of resource.

An RFP involves evaluating specific proposals submitted by counterparties as well as internally developed proposals for self-build options. In both the IRP and RFP, PSE uses the Portfolio Screening Model (PSM) to optimize PSE's energy portfolio by minimizing total portfolio cost subject to the two constraints of meeting peak capacity need and the RPS requirement. In both the IRP and RFP analyses, new resources are added in blocks to meet load over the 20-year planning horizon, which results in excess capacity when new resources are added. Gradually, this excess capacity decreases as load grows until there is another build requirement driven by peak capacity need. Evaluation of resource alternatives assumes that excess energy and RECs can be sold into the market. A given bid is evaluated based on its impact on total portfolio cost, its ability to meet the capacity and RPS needs,

¹² / PSE's EMC provides policy-level and strategic direction for the company's energy resource planning, operations, portfolio management and acquisition decisions.



and qualitative factors. Results are re-evaluated as time passes and new information becomes available.

For example, with respect to how large a wind farm should be, PSE must consider multiple factors when deciding how many turbines to install. Factors that influence this decision include:

- **The type and size of turbine.** This impacts the spacing of turbines on the site and the number that can be installed.
- **Geography of the site.** This can dictate how spread out the turbines are, the number of turbines and the amount of infrastructure such as substations, transmission and roads that are required. The equipment is arranged to be as efficient as possible.
- **Schedule.** A short construction period that includes two summers and one winter is preferable to a longer construction period so that the assets can be placed into service as soon as possible.
- **Interconnection agreements.** Transmission requirements can influence the timing and planning for how the work is done.
- **Contracts with counterparties for delivery of materials and construction.** The turbine supply agreement and balance of plant agreements need to be integrated to avoid gaps in the schedule.

A wind farm is planned to be large enough to capture economies of scale while being small enough to have a relatively short construction period. Some of the required infrastructure is the same for a plant ranging from 100 MW to 250 MW, so if the plant is on the larger side, there are economies of scale as fixed costs are spread over greater plant output. Beyond some size threshold, adding turbines would also require additional infrastructure and construction time, thus delaying the in-service date of the assets.



4

2017 PSE Integrated Resource Plan

Key Analytical Assumptions

This chapter describes the forecasts, estimates and assumptions that PSE developed for this IRP analysis; the scenarios created to test how different sets of economic conditions affect portfolio costs and risks; and the sensitivities used to explore the impact of individual resources on the portfolio.

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1. OVERVIEW

Economic Scenarios

Scenarios allow us to test how different combinations of three fundamental **economic conditions** impact the least-cost mix of resources. Given the set of static assumptions that define the scenario, deterministic optimization analysis is used to identify the least-cost portfolio of demand- and supply-side resources that will meet need under those conditions. For this IRP, PSE developed 14 scenarios for the electric portfolio and 11 scenarios for the gas portfolio.

Three Fully Integrated Economic Scenarios

Low, Base and High scenarios reflect different sets of assumptions for each of the three key economic inputs: customer demand, natural gas prices and CO₂ prices.

Eleven One-off Economic Scenarios

The one-off scenarios start with one of the fully integrated scenarios and change just one of the three fundamental economic inputs. In reality, when one economic condition changes, others usually do, too; however, one-off scenarios allow us to identify which of the three fundamentals has the most significant impact on the least-cost mix of resources.

To complete the scenarios, we create wholesale power price forecasts for each one using production cost analysis described later in this chapter. Figure 4-1 illustrates the relationship between the fully integrated and one-off scenarios.

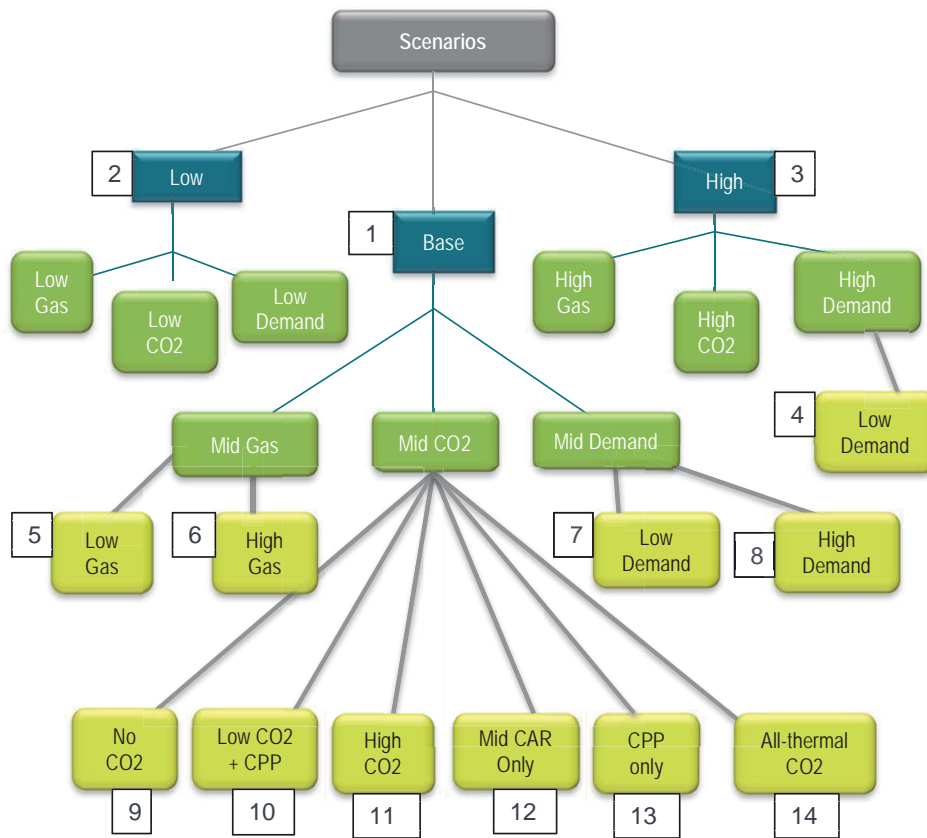
Portfolio Sensitivities

Portfolio sensitivities focus on the cost-effectiveness of a specific **resource** and the value it brings to the portfolio. First, PSE uses a portfolio optimization analysis to identify the least cost resource portfolio for each scenario. Then, starting with the least cost portfolio for the Base Scenario, the sensitivities change a single resource in the portfolio. Sensitivity analysis also allows us to explore how PSE might need to respond to unexpected changes in resource availability. The sensitivities are summarized in Figure 4-3.



Scenarios test how different combinations of three fundamental economic conditions impact the least cost mix of resources – demand, gas prices and CO₂ costs.

Figure 4-1: Diagram of 2017 IRP Scenarios



NOTES
 CAR refers to Washington state Clean Air Rule regulations.
 CPP refers to federal Clean Power Plan regulations.

Chapter 4: Key Analytical Assumptions



The figure below presents the scenarios in tabular format.

*Figure 4-2: 2017 IRP Scenarios
(A detailed description of scenarios begins on page 26.)*

| | Scenario Name | Demand | Gas Price | CO ₂ Price |
|----|--|--------|-----------|---|
| 1 | Base Scenario ^{1,2,3} | Mid | Mid | Mid |
| 2 | Low Scenario | Low | Low | Low |
| 3 | High Scenario | High | High | High |
| 4 | High + Low Demand | Low | High | High |
| 5 | Base + Low Gas Price | Mid | Low | Mid |
| 6 | Base + High Gas Price | Mid | High | Mid |
| 7 | Base + Low Demand | Low | Mid | Mid |
| 8 | Base + High Demand | High | Mid | Mid |
| 9 | Base + No CO ₂ | Mid | Mid | None |
| 10 | Base + Low CO ₂ w/ CPP ² | Mid | Mid | Low + CPP |
| 11 | Base + High CO ₂ | Mid | Mid | High |
| 12 | Base + Mid CAR only (electric only) | Mid | Mid | Mid CAR only |
| 13 | Base + CPP only (electric only) | Mid | Mid | CPP only |
| 14 | Base + All-thermal CO ₂ (electric only) | Mid | Mid | CO ₂ price applied to all thermal resources in the WECC (baseload and peakers) |

NOTES

1. Washington CAR (Clean Air Rule) regulations apply to both electric and gas utilities. These are applied to all scenarios.
2. Federal CPP (Clean Power Plan) regulations affect only baseload electric resources, so the gas portfolio models scenarios 1 through 11 only. CPP rules are modeled as if the entire WECC is part of an integrated carbon market, with carbon prices applied to all baseload generation, so that even if the CPP is ultimately not put into effect, the analysis still represents a form of carbon price regulation.
3. Carbon regulations are assumed to transition from CAR to CPP in 2022.



Portfolio sensitivities test the cost-effectiveness of a specific resource on the portfolio. Starting with the Base Case least cost portfolio, they change one resource.

Figure 4-3: 2017 IRP Portfolio Sensitivities
(A detailed description of portfolio sensitivity reasoning begins on page 38.)

| | Sensitivities | Alternatives Analyzed |
|---|---|---|
| ELECTRIC ANALYSIS | | |
| A | Colstrip How do different retirement dates affect decisions about replacing Colstrip resources? | <i>Baseline – Retire Units 1 & 2 mid-2022, Units 3 & 4 remain in service into 2035.</i> 1. Retire Units 1 & 2 in 2018 2. Retire Units 3 & 4 in 2025 3. Retire Units 3 & 4 in 2030 |
| B | Thermal Retirement Would it be cost effective to accelerate retirement of PSE's existing gas plants? | <i>Baseline – Optimal portfolio from the Base Scenario Retire baseload gas plants early.</i> |
| C | No New Thermal Resources What would it cost to fill all future need with resources that emit no carbon? | <i>Baseline – Fossil fuel generation is an option in the optimization model.</i> Renewable resources, energy storage and DSR are the only options for future resources. |
| D | Stakeholder-requested Alternative Resource Costs What if capital costs of resources are different than the base assumptions? | <i>Baseline – PSE cost estimate for generic supply-side resources</i> 1. Lower cost for recip peakers 2. Higher thermal capital costs 3. Lower wind and solar development costs Apply more aggressive solar cost curve. |
| E | Energy Storage What is the cost difference between a portfolio with and without energy storage? | <i>Baseline – Batteries and pumped hydro included only if chosen economically.</i> 1. Add 50 MW battery in 2023 instead of economically chosen peaker. 2. Add 50 MW pumped hydro storage in 2023 instead of economically chosen peaker. |
| F | Renewable Resources + Energy Storage Does bundling renewable resources with energy storage change resource decisions? | <i>Baseline – Evaluate renewable resources and energy storage as individual resources in the analysis.</i> Bundle 50 MW battery + 200 MW solar. |
| G | Electric Vehicle Load How much does electric vehicle charging affect the resource plan? | <i>Baseline – IRP Base Demand Forecast</i> Add the forecasted electric vehicle load. |
| DEMAND-SIDE RESOURCES (CONSERVATION) | | |
| H | Demand-side Resources (DSR) How much does DSR reduce cost, risk and emissions? | <i>Baseline – All cost-effective DSR per RCW 19.285 requirements.</i> No DSR. All future needs met with supply-side resources. |
| I | Extended DSR Potential What if future DSR measures extend conservation periods through the second decade of the study period? | <i>Baseline – All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.</i> Assume future DSR measures will extend conservation benefits to the following 10-year period. |

Chapter 4: Key Analytical Assumptions



| Sensitivities | | Alternatives Analyzed |
|--------------------------|--|---|
| <i>ELECTRIC ANALYSIS</i> | | |
| J | Alternate Residential Conservation Discount Rate How would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation? | <i>Baseline: Assume the base discount rate.</i> Apply a societal discount rate to residential conservation savings to examine whether changing the discount rate for conservation impacts cost effectiveness of conservation. |
| <i>WIND RESOURCES</i> | | |
| K | RPS-eligible Montana Wind ¹ What is the cost difference between a portfolio with "regular" Montana wind and RPS-eligible Montana wind? | <i>Baseline – Montana wind included only if chosen economically by the analysis.</i> 1. Add RPS-eligible Montana wind in 2023 instead of solar 2. Montana wind tipping point analysis to determine how close it is to being cost effective compared to other resources. |
| L | Offshore Wind Tipping Point Analysis How much would costs of offshore wind need to decline before it appears to be a cost-effective resource? | <i>Baseline – Base Scenario portfolio</i> Offshore wind tipping point analysis to determine how much costs would have to drop to be cost effective compared to other resources. |
| M | Hopkins Ridge Repowering ² Would repowering Hopkins Ridge for the tax incentives and bonus RECs be cost effective? | <i>Baseline – Hopkins Ridge repowering is not included in the portfolio.</i> Include Hopkins Ridge repowering in the portfolio to replace the current facility. |

| Sensitivities | | Alternatives Analyzed |
|-----------------------------|--|---|
| <i>NATURAL GAS ANALYSIS</i> | | |
| A | Demand-side Resources (DSR) How much does DSR reduce cost, risk and emissions? | <i>Baseline – All cost-effective DSR per RCW 19.285 requirements.</i> No DSR. All future needs met with supply-side resources. |
| B | Resource Addition Timing Optimization How does the timing of PSE-controlled resource additions affect resource builds and portfolio costs? | <i>Baseline – PSE-controlled additions offered every 2 years.</i> PSE-controlled resource additions offered every year. |
| C | Alternate Residential Conservation Discount Rate Would using a societal discount rate on conservation savings from residential energy efficiency impact cost effective levels of conservation? | <i>Baseline – Assume the base discount rate.</i> Apply a societal discount rate to residential conservation savings. |
| D | Additional Gas Conservation What happens if DSR is added beyond what is cost-effective per RCW 19.285? | <i>Baseline – All cost-effective DSR per RCW 19.285 requirements.</i> Add 2 additional demand-side bundles. |

NOTES

1. Montana wind is not currently an RPS-eligible resource; however, PSE has asked BPA under what conditions it could be qualified as an RPS-eligible resource.
2. Repowering refers to refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015. These sensitivities capture the impact of tax credit incentives and increased operating efficiency on cost.



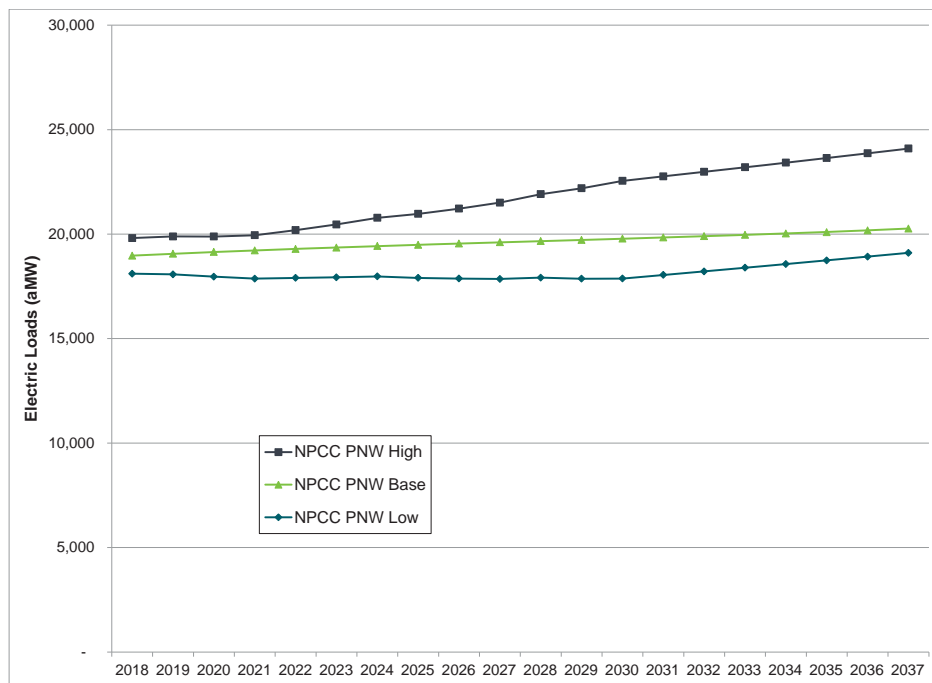
2. KEY INPUTS

Demand Forecasts

Regional Demand

Regional demand significantly affects power prices, so it must be taken into consideration. This IRP uses the regional demand developed in the Seventh Power Plan by the Northwest Power and Conservation Council (NPCC or “the Council”).¹ Regional demand is used only in the WECC-wide² portion of the AURORA analysis that develops wholesale power prices for the scenarios.

Figure 4-4: NPCC Regional Demand Forecast for Pacific Northwest (PNW) – Average, not Peak



1 / The NPCC has developed some of the most comprehensive views of the region’s energy conditions and challenges. Authorized by the Northwest Power Act, the Council works with regional partners and the public to evaluate energy resources and their costs, electricity demand and new technologies to determine a resource strategy for the region.

2 / WECC, the Western Electricity Coordinating Council, is the regional forum for promoting regional electric service reliability in the Western United States.



PSE Demand

PSE customer demand is the single most important input assumption to the IRP portfolio analysis. The demand forecast is discussed in detail in Chapter 5, and the analytical models used to develop it are explained in Appendix E, Demand Forecasting Models. For long-range planning, customer demand is expressed as if it were evenly distributed throughout PSE's service territory, but in reality demand grows faster in some parts of the territory and slower in others.

The three demand forecasts used in this IRP analysis represent estimates of energy sales, customer counts and peak demand over a 20-year period. Significant inputs include information about regional and national economic growth, demographic changes, weather, prices, seasonality and other customer usage and behavior factors. Known large load additions or deletions are also included.

The **2017 IRP BASE DEMAND FORECAST** is based on 2016 macroeconomic conditions such as population growth and employment. *The 2017 IRP Base Scenario uses this forecast.*

The **2017 IRP LOW DEMAND FORECAST** represents a pessimistic view of the macroeconomic variables modeled in the base forecast. It creates lower demand on the system and is used in the 2017 IRP Low Scenario.

The **2017 IRP HIGH DEMAND FORECAST** is a more optimistic view of the base forecast. It creates a higher demand on the system and is used in the 2017 IRP High Scenario.

Why don't demand forecasts in rate cases and acquisition discussions match the IRP forecast?

The IRP analysis takes 12 to 18 months to complete. Demand forecasts are so central to the analysis that they are one of the first inputs we need to develop. By the time the IRP is completed, PSE will have updated its demand forecast. The range of possibilities in the IRP forecast is sufficient for long-term planning purposes, but we will always present the most current forecast for rate cases or when making acquisition decisions.

The graphs below show the peak demand and annual energy demand forecasts for electric service and gas sales without including the effects of conservation. Both the electric and gas demand forecasts include sales (delivered load) plus system losses. The electric peak demand forecast is for a one-hour temperature of 23° Fahrenheit at SeaTac airport. The gas sales peak demand forecast is for a one-day temperature of 13° Fahrenheit at SeaTac airport.

Chapter 4: Key Analytical Assumptions

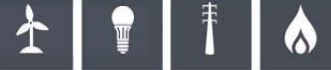


Figure 4-5: PSE Electric Peak Demand Forecast (Low, Base, High)

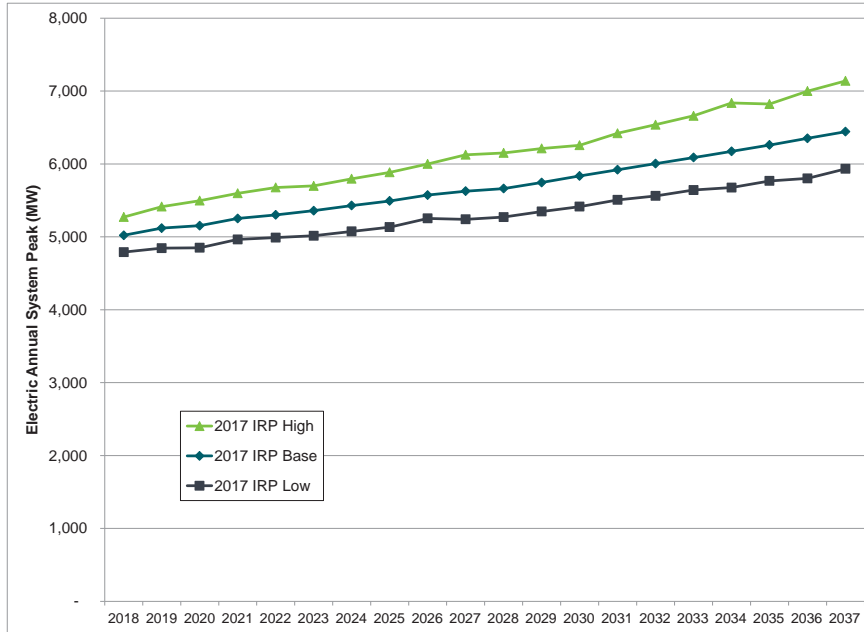
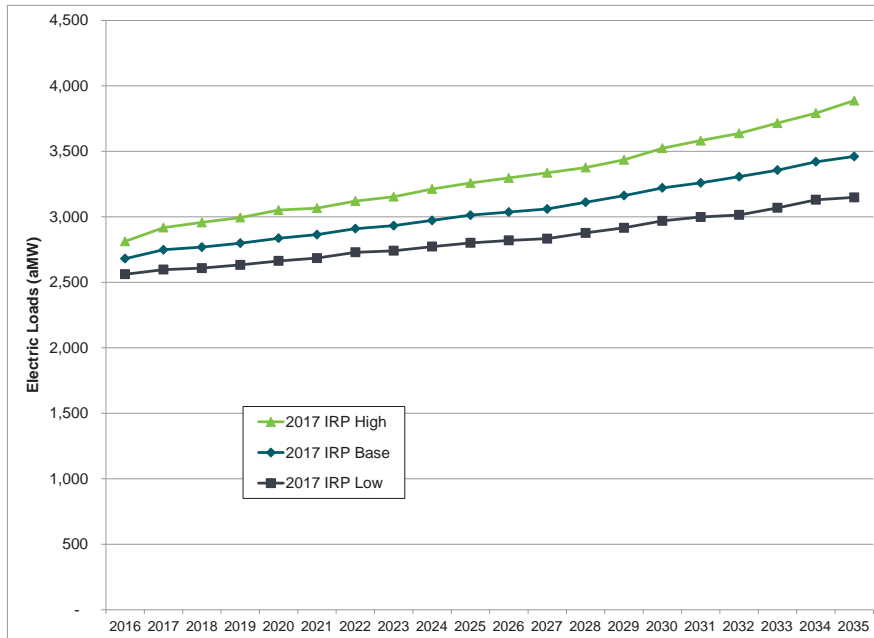


Figure 4-6: PSE Annual Electric Energy Demand Forecast (Low, Base, High)



Chapter 4: Key Analytical Assumptions



Figure 4-7: PSE Peak Day Gas Sales Demand Forecast (Low, Base, High)

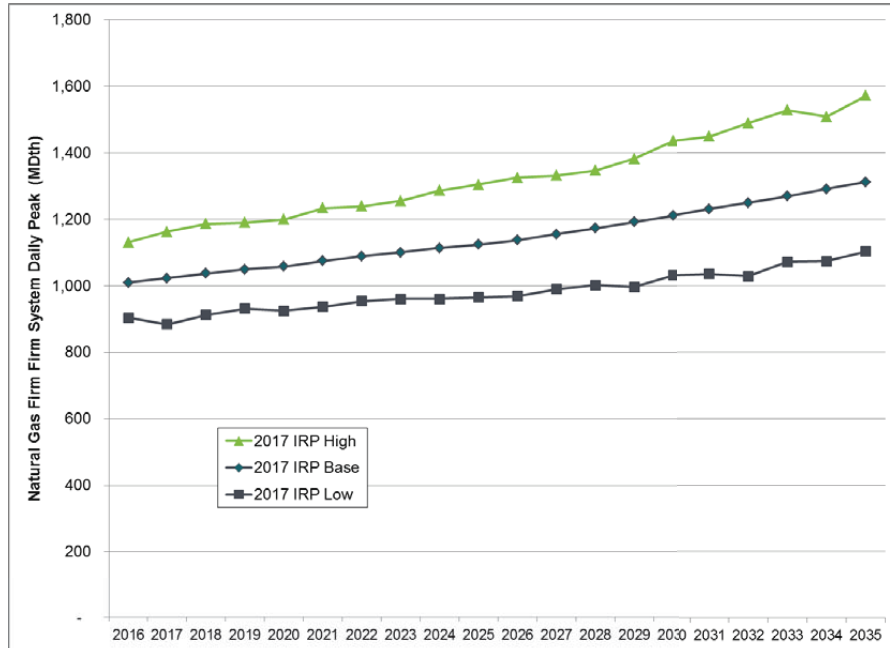
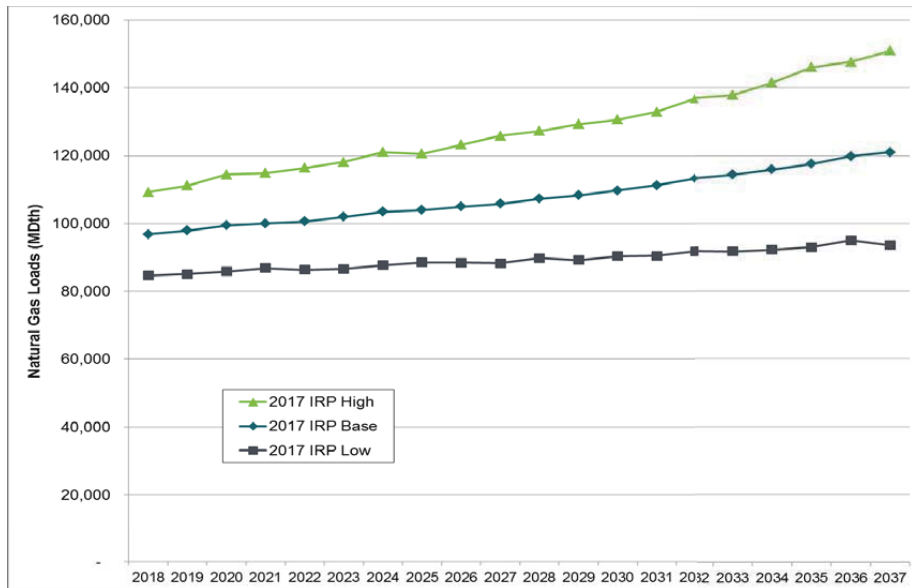


Figure 4-8: PSE Annual Gas Sales Demand Forecast (Low, Base, High)





Gas Prices

For gas price assumptions, PSE uses a combination of forward market prices and fundamental forecasts acquired in November 2016 from Wood Mackenzie. Wood MacKenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas (LNG) exports. Three gas price forecasts are used in the scenario analysis.

MID GAS PRICES. From 2018-2021, this IRP uses the three-month average of forward marks for the period ending December 27, 2016. Forward marks reflect the price of gas being purchased at a given point in time for future delivery. Beyond 2021, this IRP uses Wood Mackenzie long-run, fundamentals-based gas price forecasts that were published in Fall 2016. *The 2017 IRP Base Scenario uses this forecast.*

LOW GAS PRICES. These reflect Wood Mackenzie's long-term low price forecast for 2018-2037.

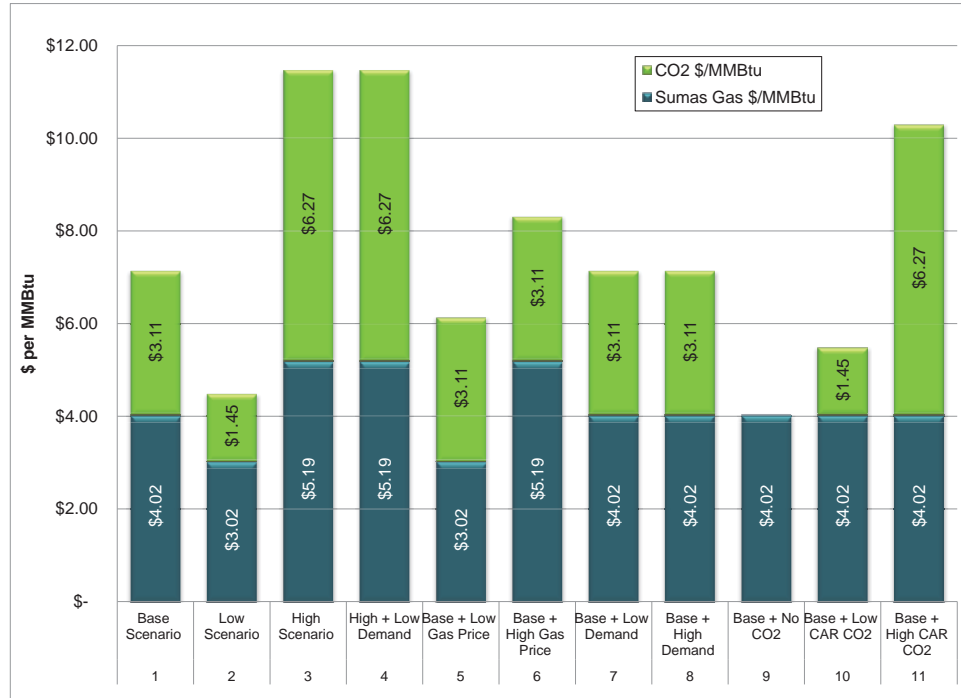
HIGH GAS PRICES. These reflect Wood Mackenzie's long-term high price forecast for 2018-2037.

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Figure 4-9 below illustrates the range of 20-year levelized gas prices and associated CO₂ costs used in this IRP analysis.

Figure 4-9: Levelized Gas Prices by Scenario
(Sumas Hub, 20-year levelized 2018-2037, nominal \$)

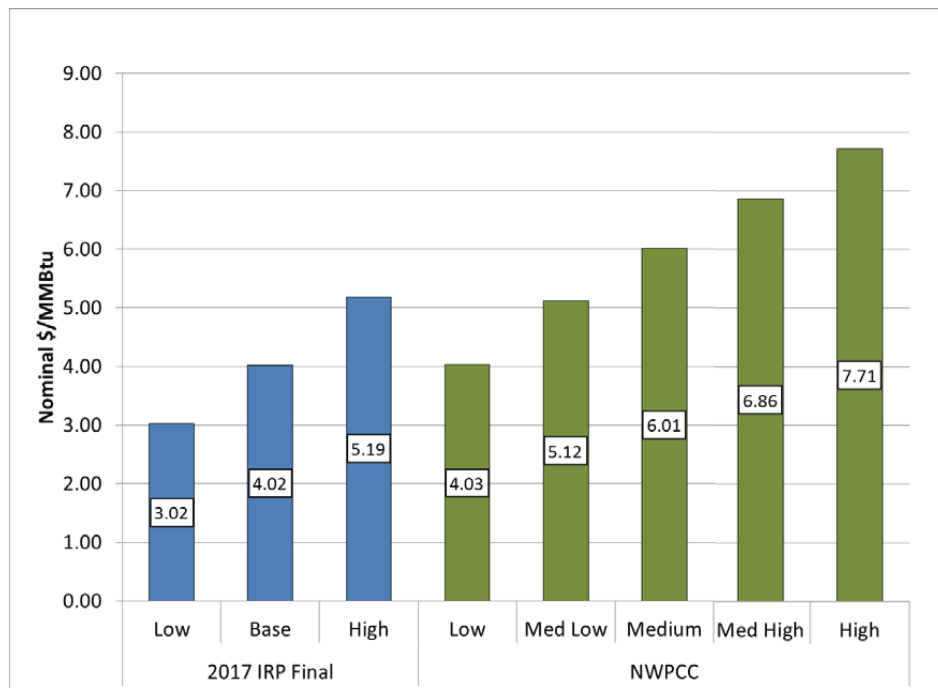


Chapter 4: Key Analytical Assumptions



Figure 4-10 below, compares the levelized gas prices PSE used in this IRP with those used by the NPCC in its Seventh Power Plan.³ This illustrates that the range of PSE's gas prices are consistent with the range of gas prices being used by the Council. It also shows PSE's Base Scenario gas price is slightly lower than the Council's medium gas price forecast.

Figure 4-10: PSE 2017 IRP Gas Prices Compared to NPCC Seventh Power Plan Gas Prices (adjusted to nominal values)



³ / PSE's input assumptions use nominal dollars (inflation adjusted) whereas the Council uses real dollar input assumptions (excluding the effects of inflation). Figure 4-10 converts the Council's assumptions to a nominal basis for an apples-to-apples comparison.

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Figure 4-11 below compares the levelized gas prices used in past PSE IRP analyses. The 2017 IRP gas price of \$7.60 per MMBtu includes an estimated CO₂ price for the Washington Clean Air Rule (CAR).

Figure 4-11: PSE 2007 IRP – 2017 IRP Levelized Gas Prices





CO₂ Prices

The carbon prices in this IRP reflect the range of potential impacts from several key pieces of carbon regulation. The two most important are Washington state's Clean Air Rule (CAR) and the federal Environmental Protection Agency Clean Power Plan (CPP) rules. CAR regulations apply to both electric and gas utilities, and CPP regulations apply only to baseload electric resources. Even if CAR and CPP are ultimately not implemented, some form of carbon regulation is likely to be enacted during the 20-year period covered in this IRP, so it is important that the analysis reflect this possibility.

The Base Scenario in this IRP assumes the current rules – the Clean Air Rule and Clean Power Plan – will be implemented because it is impossible to model a generic carbon regulation scheme. Carbon taxes, carbon caps, or carbon cap and trade schemes could produce very different resource plans. Likewise, applying carbon regulation in one state versus the entire WECC would also produce very different results.

CAR. Washington state's CAR regulations took effect in January 2017. These regulations require state electric and gas utilities that exceed state CO₂ emissions to buy CO₂ allowances to compensate. Low, mid and high CAR prices have been developed as inputs to the analysis, because these allowances will come from a variety of sources whose costs can vary substantially. On the electric side, CAR only applies to in-state electric generating sources. CAR allows development of a carbon trading market, but it is not really a “cap and trade” system, because there is no cap. Under CAR, PSE (or any market participant) can build new natural gas plants that will essentially receive carbon allowances that diminish over time.

CPP. Federal CPP regulations are scheduled to take effect in 2022. These rules apply carbon costs to existing and new baseload electric generating facilities throughout the country. In this analysis, they are reflected as a carbon cost of \$19 per ton in 2022, rising to \$51 per ton in 2037. This cost is applied to all affected generating units in WECC states. CPP rules do not apply to gas utilities.

BASE CASE ASSUMPTIONS. PSE's Base Case assumes that federal CPP rules will supersede state CAR regulations in 2022. While it is possible that neither the CAR or CPP will actually be enforced, it is likely that some form of carbon regulation will be enacted during the 20-year study period. This IRP also examines a scenario in which no carbon regulation is ever implemented (the Base + No CO₂ Scenario), in the event that policy makers are unable to implement any binding regulations.



A table showing the annual CO₂ prices modeled can be found in Appendix N, Electric Analysis. All prices shown below are in short tons.

Mid CO₂ prices

The 2017 IRP Base Scenario uses this forecast.

MID CAR TO 2022 - \$30 PER TON IN 2018 TO \$111 PER TON IN 2037

CPP FROM 2022-2037 – \$19 PER TON IN 2022 TO \$51 PER TON IN 2037

CAR estimate is based on the Washington Dept. of Ecology's cost/benefit analysis of the CAR. CPP estimate is based on Wood MacKenzie's estimated CO₂ price for California AB32 and is applied WECC-wide as a CO₂ price to all existing and new baseload generating units affected under the CPP.

Low CO₂ prices

LOW CAR CO₂ PRICE TO 2022: \$14 PER TON

IN 2018 TO \$51 PER TON IN 2037

NO CPP

CAR estimate is based on Wood MacKenzie's estimated CO₂ price for California.

High CO₂ Prices

HIGH CAR CO₂ PRICE TO 2022: \$108 PER TON

IN 2018 TO \$108 PER TON IN 2037

CPP FROM 2022-2037: \$19 PER TON IN 2022 TO \$51 PER TON IN 2037

CAR estimate is based on PSE's fundamental REC price from the 2015 IRP. (The 2015 REC price was used because an input was needed before the 2017 IRP analysis output was available.) It reflects the difference between the levelized cost of power and the levelized cost of wind in the 2015 IRP. CPP estimate is based on Wood MacKenzie's estimated CO₂ price for California AB32 and is applied WECC-wide as a CO₂ price to all existing and new baseload generating units affected under the CPP.

In addition, PSE modeled the following CO₂ prices in one-off scenarios.

Why model carbon price regulation instead of the societal cost of carbon?

By rule, the IRP focuses on the costs and benefits that will be experienced by the utility and its customers. Costs and benefits outside of this construct are called externalities. The societal cost of carbon does not fit this regulatory model. Reducing carbon emissions may benefit society as a whole, but the population of our service territory is only 2.6 million (0.04 percent of world population). To reflect the externality impact of carbon reductions to PSE's customers would require either a reasonable estimate of the economic impact on the Pacific Northwest region (which is not available) or prorating the societal benefits that will accrue to our customers only. This explains why internalizing these externalities in typical IRP analyses is not a substitute for federal-level carbon regulation policies.



No CO₂ prices

Low CO₂ + CPP

LOW CAR CO₂ PRICE TO 2022: \$14 PER TON IN 2018 TO \$51 PER TON IN 2037

CPP FROM 2022-2037 – \$19 PER TON IN 2022 TO \$51 PER TON IN 2037

Mid CAR only (No CPP)

MID CAR TO 2037: \$30 PER TON IN 2018 TO \$111 PER TON IN 2037

CPP only (No CAR)

CPP FROM 2022-2037: \$19 PER TON IN 2022 TO \$51 PER TON IN 2037

All-thermal CO₂

\$19 PER TON IN 2022 TO \$51 PER TON IN 2037, APPLIED TO ALL CO₂ EMITTING RESOURCES IN THE REGION

This estimate is based on Wood MacKenzie's estimated CO₂ price for California AB32 and is applied WECC-wide to all CO₂ emitting resources, peaking plants and baseload generators. (CPP and CAR apply only to baseload generators).



Figure 4-12: Annual Range of CAR-related CO₂ Prices Used in the 2017 IRP

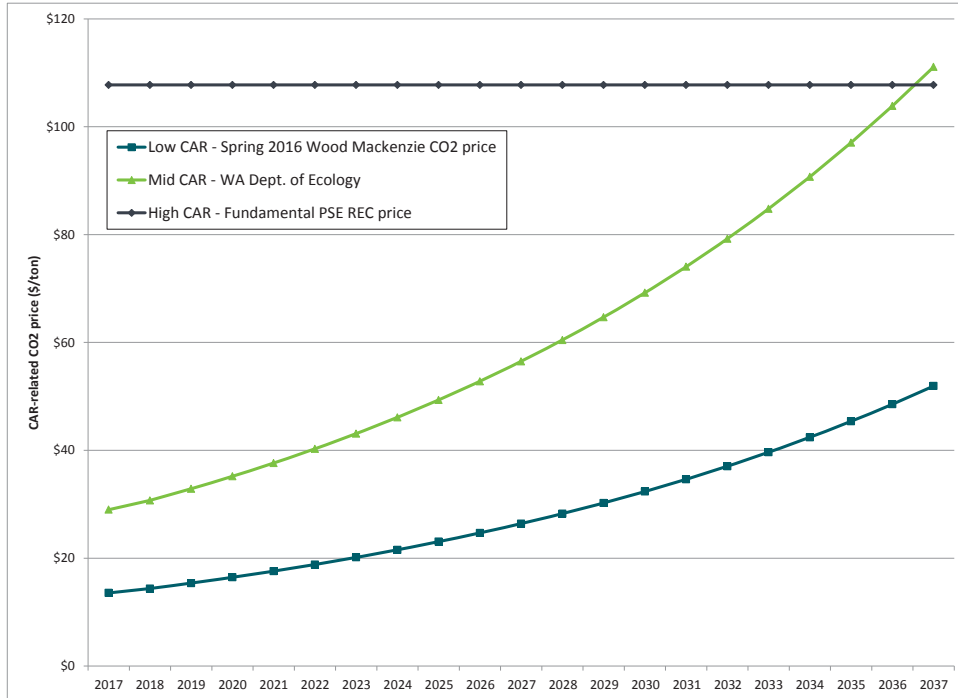
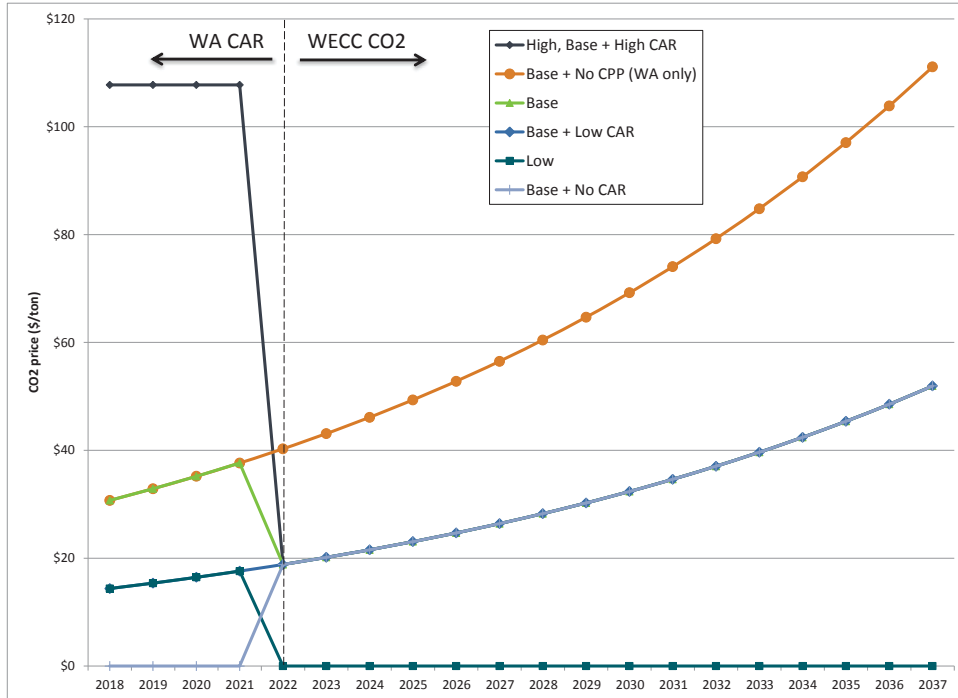




Figure 4-13: Annual CO₂ Prices for the Electric Price Modeling





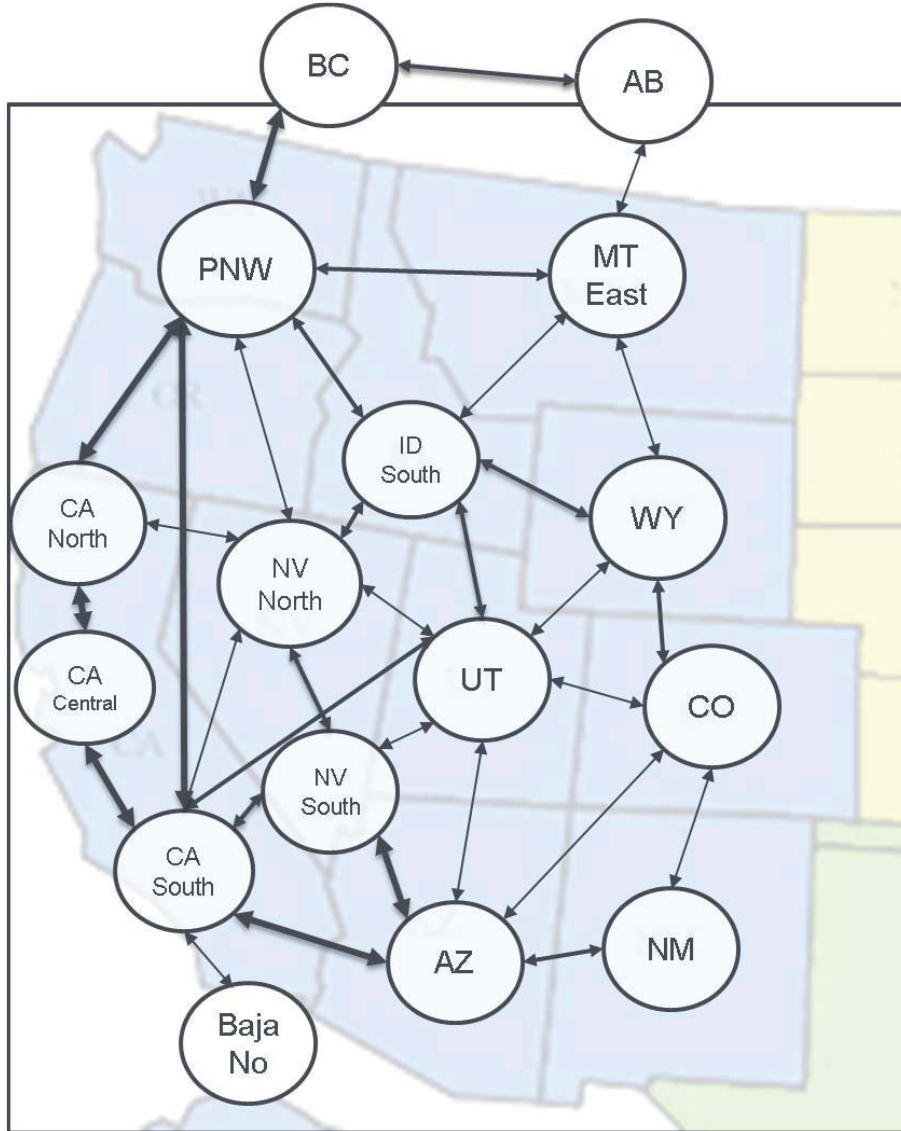
Developing Wholesale Power Prices

A wholesale power price forecast is developed for each of the 14 scenarios modeled. In this context, “wholesale power price” does not mean the rate charged to customers, it means the price to PSE of purchasing or selling 1 megawatt hour (MWh) of power on the wholesale market given the economic conditions that prevail in that scenario. This is an important input to the analysis, since market purchases make up a substantial portion of PSE’s resource portfolio. Wholesale market prices are also very important with respect to establishing the value of energy supply resources or conservation; e.g., if wholesale power prices are \$45 per MWh, the value of 1 MWh of energy saved by a conservation measure or produced by a generator is \$45.

AURORAxmp is an hourly chronological price forecasting model based on market fundamentals. The model reflects the dispatch and operating costs of about 3,700 individual generators, representing approximately 250 GW of installed generation capacity that are interconnected throughout the Western Electric Coordinating Council region (WECC). AURORA also reflects transmission constraints between sub-regions. Creating wholesale power price assumptions requires performing two WECC-wide AURORA model runs for each of the 14 scenarios (AURORA is discussed in more detail in Appendix N, Electric Analysis). The first run identifies needed capacity expansion to meet regional loads. AURORA considers loads and peak demand plus a planning margin, and then identifies the most economic resource(s) to add to make sure that the entire system maintains adequate resources. Results of the capacity expansion run are included in Appendix N, Electric Analysis. The second AURORA run produces hourly power prices. A full simulation across the entire WECC region simulates power prices in all 16 zones shown in Figure 4-14 below. The lines and arrows in the diagram indicate transmission links between zones. The heavier lines represent greater capacity to flow power from one zone to another.



Figure 4-14: AURORA System Diagram

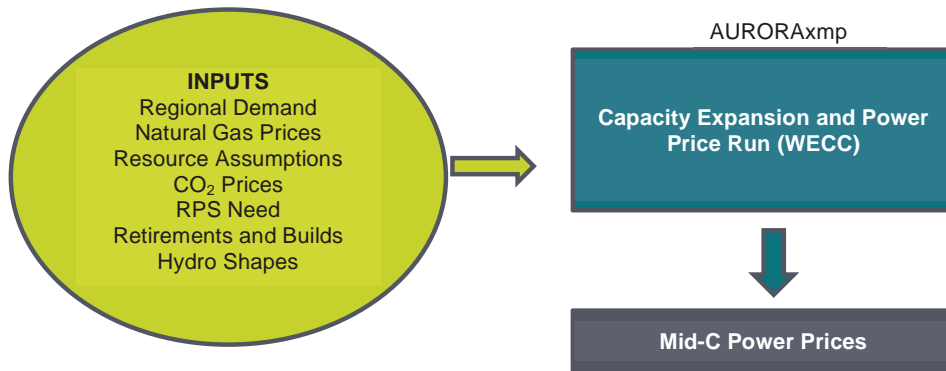




The Pacific Northwest Zone, labeled PNW in the preceding diagram, is modeled as the Mid-Columbia (Mid-C) wholesale market price. The Mid-C market includes Washington, Oregon, Northern Idaho and Western Montana.

Figure 4-15 illustrates PSE's process for creating wholesale market power prices.

Figure 4-15: PSE IRP Modeling Process for AURORA Wholesale Power Prices



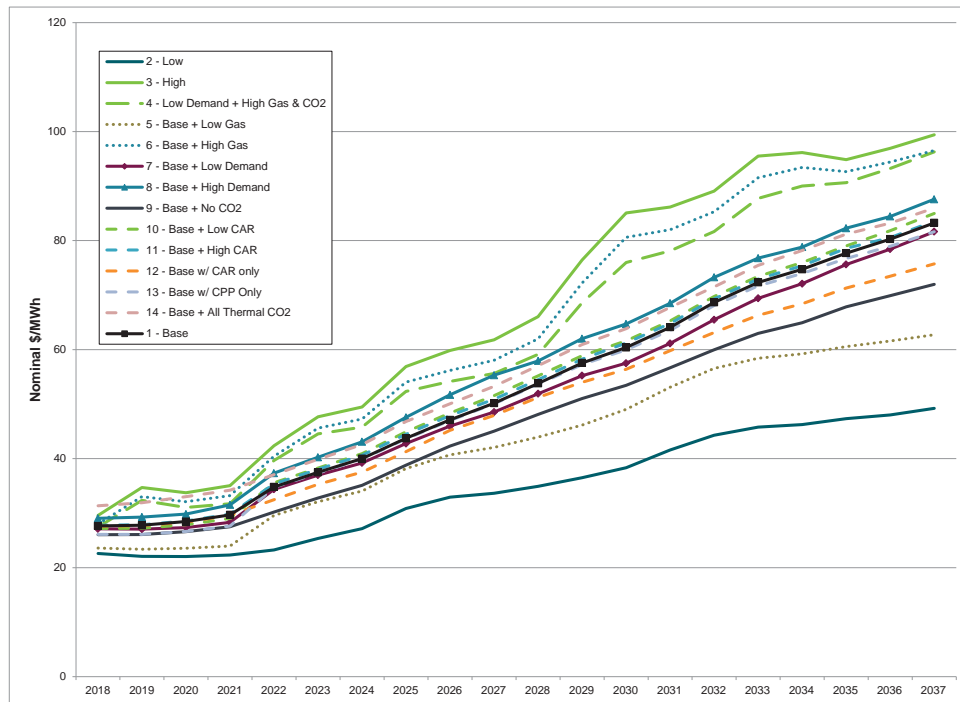
The database of inputs for AURORA starts with inputs and assumptions from the EPIS 2016 v3 database. PSE then includes updates such as regional demand, natural gas prices, resource assumptions, CO₂ prices, RPS need, and resource retirements and builds. Details of the inputs and assumptions for the AURORA database are included in Appendix N, Electric Analysis.

Chapter 4: Key Analytical Assumptions



Figure 4-16 shows the 14 power prices produced by the 14 scenario conditions.

Figure 4-16: Power Price Inputs by Scenario,
Annual Average Flat Mid-C Power Price (nominal \$/MWh)



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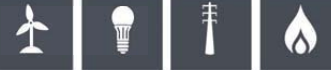
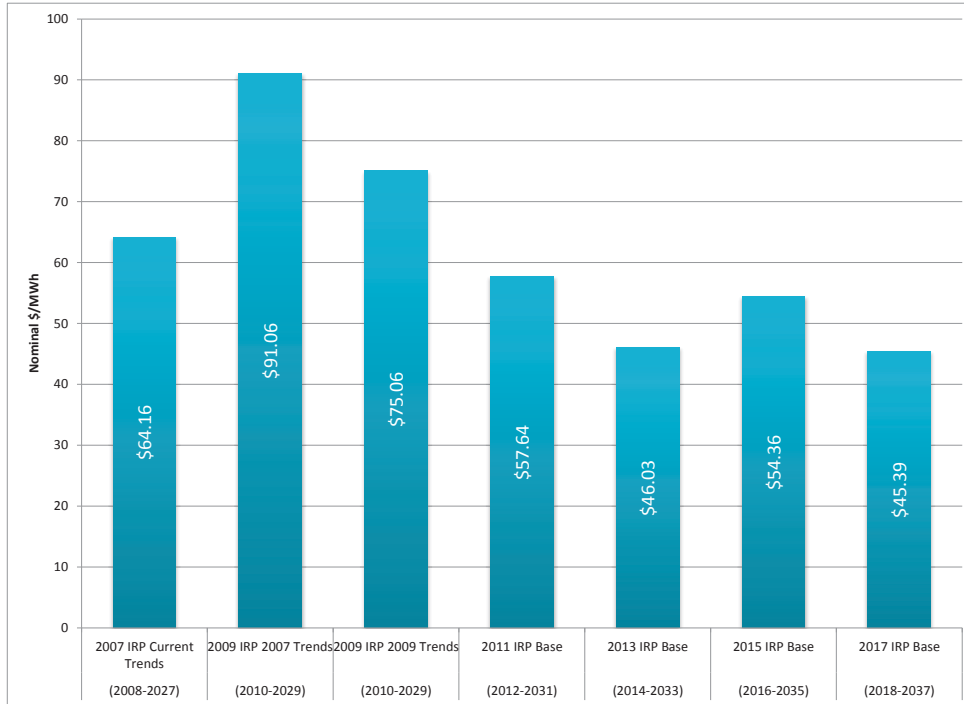


Figure 4-17 below compares the 2017 Base Scenario power prices to past IRP power prices. The downward revisions in forecast power prices correspond to the downward revisions in natural gas prices, as shown in Figure 4-11.

Figure 4-17: Levelized Power Price Compared to Past IRPs (\$/MWh)





3. SCENARIOS AND SENSITIVITIES

The scenarios developed for the IRP enable us to test portfolio costs and risks in a wide variety of possible future economic conditions using deterministic optimization analysis. Sensitivities enable us to isolate the effects of an individual resource on portfolio builds. The full range of scenarios is described first, followed by a description of the baseline assumptions that apply to all scenarios. The reasoning behind the sensitivities is explained after that.

Fully Integrated Scenarios

Three fully integrated scenarios model a complete range of key economic indicators: customer demand, natural gas prices and CO₂ prices.⁴

1. Base Scenario

- The Base Scenario applies the NPCC Seventh Power Plan regional demand forecast to the WECC region and the 2017 IRP Base Demand Forecast for PSE.
- Mid gas prices are applied, a combination of forward market prices and Wood Mackenzie's fundamental long-term base forecast.
- The Washington Clean Air Rule (CAR) is modeled on affected power plants in Washington state using mid CAR CO₂ prices from 2018-2021 for the electric portfolio and from 2018-2037 for the gas portfolio: \$30 per ton in 2018 to \$111 per ton in 2037. In 2022, when the EPA Clean Power Plan takes effect, electric utilities will move to the CPP price: \$19 per ton in 2022 to \$51 per ton in 2037. From 2022 – 2037, the CPP price is applied to all WECC states.

2. Low Scenario

- This scenario models weaker long-term economic growth than the Base Scenario. Customer demand is lower in the region and in PSE's service territory. The NPCC Seventh Power Plan low demand forecast is applied for the WECC region, and the 2017 IRP Low Demand Forecast is applied for PSE.
- Natural gas prices are lower due to lower energy demand; the Wood Mackenzie long-term low forecast is applied to natural gas prices.
- Low CAR CO₂ prices are modeled from 2018-2021 for the electric portfolio and from 2018-2037 on the gas portfolio: \$14 per ton in 2018 to \$51 per ton in 2037. No CO₂ price is applied to the WECC for compliance with the CPP.

⁴ / See Figures 4-1 and 4-2.



3. High Scenario

- This scenario models more robust long-term economic growth, which produces higher customer demand. The NPCC Seventh Power Plan high demand is applied for the WECC, and the 2017 IRP High Demand Forecast is applied for PSE.
- Natural gas prices are higher as a result of increased demand, so the high gas price assumptions are modeled (Wood Mackenzie long-term high forecast for 2018-2037).
- High CAR CO₂ prices are modeled from 2018-2021 for the electric portfolio and from 2018-2037 for the gas portfolio: \$108 per ton in 2018 to \$108 per ton in 2037. In 2022 the CPP price is then applied to all WECC states: \$19 per ton in 2022 to \$51 per ton in 2037.

One-off Scenarios

Eleven one-off scenarios start with one of the fully integrated scenarios and change just one of the three key economic conditions.

4. High Scenario + Low Demand

This stakeholder requested scenario models low customer demand in the context of High Scenario assumptions (high gas prices and high CO₂ prices); it applies the 2017 IRP Low Demand Forecast.

5. Base + Low Gas Price

This scenario models the impact of a weak long-term gas price by applying the Wood Mackenzie long-term low gas price forecast to Base Scenario assumptions.

6. Base + High Gas Price

This scenario models the impact of a higher long-term gas price by applying the Wood Mackenzie long-term high gas price forecast for 2018-2037 to Base Scenario assumptions.

7. Base + Low Demand

This scenario models low customer demand in the context of Base Scenario assumptions; it applies the 2017 IRP Low Demand Forecast.



8. Base + High Demand

This scenario models high customer demand in the context of Base Scenario assumptions; it applies the 2017 IRP High Demand Forecast.

9. Base + No CO₂

This scenario removes a CO₂ price for CAR and CPP from Base Scenario assumptions.

10. Base + Low CO₂ w/ CPP

This scenario models a low CO₂ price for CAR compliance from 2017-2021 and the CPP carbon price from 2022-2037 in the context of the Base Scenario assumptions.

11. Base + High CO₂

This scenario models a high CO₂ price for CAR compliance from 2018-2021 and the CCP carbon price from 2022-2037 in the context of the Base Scenario assumptions.

12. Base + Mid CAR only (electric only)

This scenario removes CPP compliance for the electric portfolio in the context of the Base Scenario assumptions. CAR is modeled from 2018-2037.

13. Base + CPP only (electric only)

This scenario removes CAR compliance for the electric portfolio in the context of the Base Scenario assumptions. CPP is modeled from 2022-2037.

14. Base + All-thermal CO₂ (electric only)

Both CAR and CPP target baseload resources only, which excludes peaking plants. This scenario models a CO₂ price applied to all thermal resources in the WECC in the context of Base Scenario assumptions for demand and gas prices.



Baseline Scenario Assumptions – Electric

Baseline scenario assumptions are constant in all scenarios and portfolios and do not change.

Resource Assumptions

PSE modeled the following generic resources as potential portfolio additions in this IRP analysis. (See Appendix D, Electric Resources and Alternatives, for more detailed descriptions of the resources listed here.)

Demand-side resources included the following.

ENERGY EFFICIENCY MEASURES. This label is used for a wide variety of measures that result in a lower level of energy being used to accomplish a given amount of work. These include three categories: retrofit programs that have shorter lives, such as efficient light bulbs; lost opportunity measures that have longer lives, such as high-efficiency furnaces; and codes and standards that will drive down energy consumption through government regulation. (Codes and standards have no direct cost to utilities).

DEMAND RESPONSE. Demand response resources are like energy efficiency in that they reduce customer load, but unlike energy efficiency, they are also dispatchable. These programs involve customers curtailing load when needed. The terms and conditions of demand response programs vary widely, and are discussed in more detail in Appendix J, Conservation Potential Assessment.

DISTRIBUTED GENERATION. Distributed generation refers to small-scale electricity generators (like rooftop solar panels) located close to the source of the customer's load. This also includes combined heat and power systems.

DISTRIBUTION EFFICIENCY. Voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing eliminates total current flow losses that can reduce energy loss.

GENERATION EFFICIENCY. Energy efficiency improvements at PSE generating plant facilities.



CODES AND STANDARDS. No-cost energy efficiency measures that work their way to the market via new efficiency standards that originate from federal and state codes and standards.

For detailed information on demand-side resource assumptions, see Appendix J, Demand-side Resources.

Renewable supply-side resources included the following.

WIND. Wind was modeled in southeast Washington and central Montana. Washington wind is assumed to have a capacity factor of 30.4 percent. Montana wind is assumed to be located east of the continental divide and have a capacity factor of 46 percent.

OFFSHORE WIND. Although wind off the coast of Washington is not a commercially available resource at this time, it was modeled in the portfolio analysis in response to stakeholder interest. Wind off the coast would have to be located in deep water more than 22 miles offshore since established shipping lanes run the entire length of the Washington coast. The only technology suitable for such depths would be floating platforms, and so far there has been only a one-turbine demonstration project. Offshore wind is described in more detail in Appendix D.

ENERGY STORAGE: BATTERIES. Two battery storage technology systems are analyzed: lithium-ion and flow technology. These systems are modular, and made up of individual units that are generally small. Batteries provide both peak capacity and sub-hourly flexibility value. In addition, since they are small enough to be installed at substations, they can potentially defer local transmission or distribution system investments. PSE analyzed 2-hour, 4-hour and 6-hour battery systems for both technologies.

ENERGY STORAGE: PUMPED HYDRO. Pumped hydro resources are generally large, on the order of 250 to 3,000 MW. This analysis assumes PSE would split the output of a pumped hydro storage project with other interested parties. Pumped hydro resources can provide sub-hourly flexibility values similar to batteries, and they are utility scale. Because they are located remote from substations, they cannot contribute the transmission and distribution benefits that smaller battery systems can provide at the local system level. Pumped hydro can provide some benefits to the bulk transmission system, however, such as frequency response and black start capability.

SOLAR. Utility-scale solar PV was modeled in central Washington in PSE's service territory and southern Idaho. This solar is assumed to use a tracking system and have a capacity factor of 27 percent in Washington and 30 percent in Idaho.



Other supply-side resources included the following.

BASELOAD GAS PLANTS (COMBINED-CYCLE COMBUSTION TURBINES OR CCCTS).

F-type, 1x1 engines with wet cooling towers are assumed to generate 359 MW plus 54 MW of duct firing, and to be located in PSE's service territory. These resources are designed and intended to operate at base load, defined as running more than 60 percent of the hours in a year.

FRAME PEAKERS. (SIMPLE-CYCLE COMBUSTION TURBINES). F-type, wet-cooled turbines are assumed to generate 239 MW and to be located in PSE's service territory. Those modeled without oil backup were required to have firm gas supplies and storage.

AERO PEAKERS. (AERODERIVATIVE COMBUSTION TURBINES). The 2-turbine design with wet cooling is assumed to generate a total of 227 MW and to be located in PSE's service territory. Those modeled without oil backup were required to have firm gas supplies and storage.

RECIP PEAKERS. (RECIPROCATING ENGINES). This 12-engine design with wet cooling (18.7 MW each for gas-only and 17.1 MW for dual fuel), is assumed to generate a total of 222 MW (202 MW dual fuel) and to be located in PSE's service territory.

REDIRECTED TRANSMISSION. "Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change.

Baseload and peakers

"Baseload" generators are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year.

"Peaker" is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. They are not intended to operate economically for long periods of time like baseload resources.



Resource Cost Assumptions

The estimated cost of generic thermal resources are based on a September 2016 study by Black and Veatch done on behalf of PSE (see Appendix N for the full report). Renewable resource costs are based on information from a different consultant, DNV-GL.

Resource costs are generally expected to fall in the future, as technology advances push costs down. The declining cost curves applied to different resource alternatives come from the Energy Information Administration (EIA) Annual Energy Outlook (AEO). A sensitivity that examines more aggressive cost reductions for utility-scale solar was also examined. Appendix D, Electric Resources and Alternatives, contains a more detailed description of resource cost assumptions, including transmission and gas transport assumptions.

In general, cost assumptions represent the “all-in” cost to deliver a resource to customers; this includes plant, siting, sales tax, system upgrades and financing costs. PSE’s activity in the resource acquisition market during the past ten years informs resource cost assumptions, and our extensive discussions with developers, vendors of key project components and firms that provide engineering, procurement and construction services lead us to believe the estimates used here are appropriate and reasonable.

- Figure 4-18 summarizes generic resource assumptions.
- Figure 4-19 displays the monthly capacity factor for Washington wind, Montana wind, Washington solar.
- Figure 4-20 summarizes annual capital cost by vintage year for supply-side resources and energy storage.



Figure 4-18: New Resource Cost Assumptions

| IRP Modeling Assumptions (2016 \$) | Name-plate (MW) | First year available | Capacity Factor ¹ (%) | Overnight Capital Cost (\$/kw) | Fixed O&M ² (\$/kw-yr) | Variable O&M (\$/MWh) | Baseload Heatrate ³ (Btu/kWh) |
|--|-----------------|----------------------|----------------------------------|--------------------------------|-----------------------------------|-----------------------|--|
| F-Class CCCT 1x1 with DF | 413 | 2022 | N/A | \$1,267 | \$8.10 | \$2.50 | 6,650 |
| Frame Peaker Duel-Fueled 1x0 with Oil Back-up | 239 | 2021 | N/A | \$639 | \$11.23 | \$0.95 | 9,823 |
| Frame Peaker NG only 1x0 | 239 | 2021 | N/A | \$571 | \$6.40 | \$0.95 | 9,823 |
| Aero Peaker Duel-Fueled 2x0 with Oil Back-up | 227 | 2021 | N/A | \$1,070 | \$10.92 | \$10.20 | 8,986 |
| Aero Peaker NG only 2x0 | 227 | 2021 | N/A | \$1,004 | \$6.50 | \$10.20 | 8,986 |
| Recip Peaker Duel-Fueled 12x0 with Oil Back-up | 202 | 2021 | N/A | \$1,477 | \$10.70 | \$7.80 | 8,527 |
| Recip Peaker NG only 12x0 | 222 | 2021 | N/A | \$1,277 | \$6.50 | \$7.80 | 8,425 |
| Wind Plant - Washington | 100 | 2020 | 30% | \$1,939 | \$27.12 | \$3.15 | N/A |
| Wind Plant - Montana | 300 | 2022 | 46% | \$2,065 | \$33.79 | \$3.50 | N/A |
| Offshore Wind | 100 | 2022 | 35% | \$7,150 | \$77.30 | \$3.15 | N/A |
| Central Station Solar Tracking PV | 25 | 2020 | 26% | \$2,041 | \$10.00 | \$0.00 | N/A |
| Biomass | 15 | 2021 | 85% | \$3,950 | \$113.70 | \$5.66 | N/A |
| 2-hour Lithium Ion Battery | 25 | 2019 | N/A | \$1,514 | \$23.68 | \$0.00 | N/A |
| 4-hour Lithium Ion Battery | 25 | 2019 | N/A | \$2,439 | \$36.49 | \$0.00 | N/A |
| 4-hour Flow Battery | 25 | 2019 | N/A | \$2,324 | \$26.82 | \$0.00 | N/A |
| 6-hour Flow Battery | 25 | 2019 | N/A | \$3,042 | \$23.40 | \$0.00 | N/A |
| Pumped Storage Hydro | 25 | 2030 | N/A | \$2,400 | \$15.00 | \$0.00 | N/A |

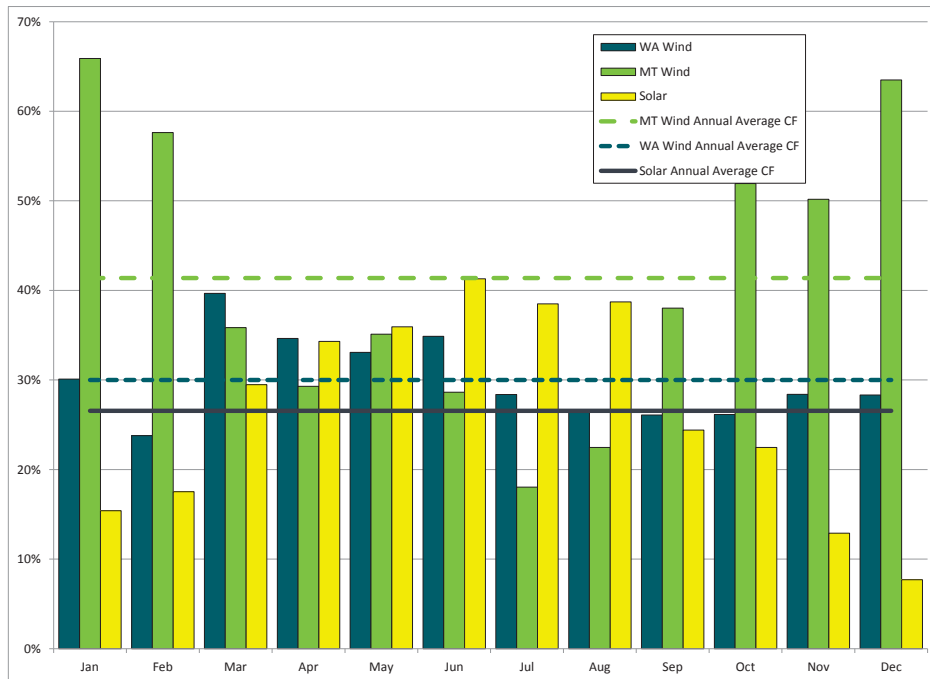
NOTES

1. Expected factor for wind, solar and Biomass; for thermal resources, the capacity factor is dependent on dispatch cost for the scenario.
2. Fixed O&M with oil backup includes the cost for 48 hours worth of oil.
3. Heat rate for CCCT is for the primary unit, the heat rate for the secondary duct firing is expected to be 8,500 Btu/kWh.

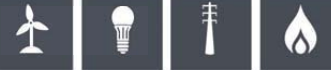


Figure 4-19 displays the monthly capacity factor for Washington wind, Montana wind, and Washington solar.

Figure 4-19: Capacity Factor for Wind and Solar

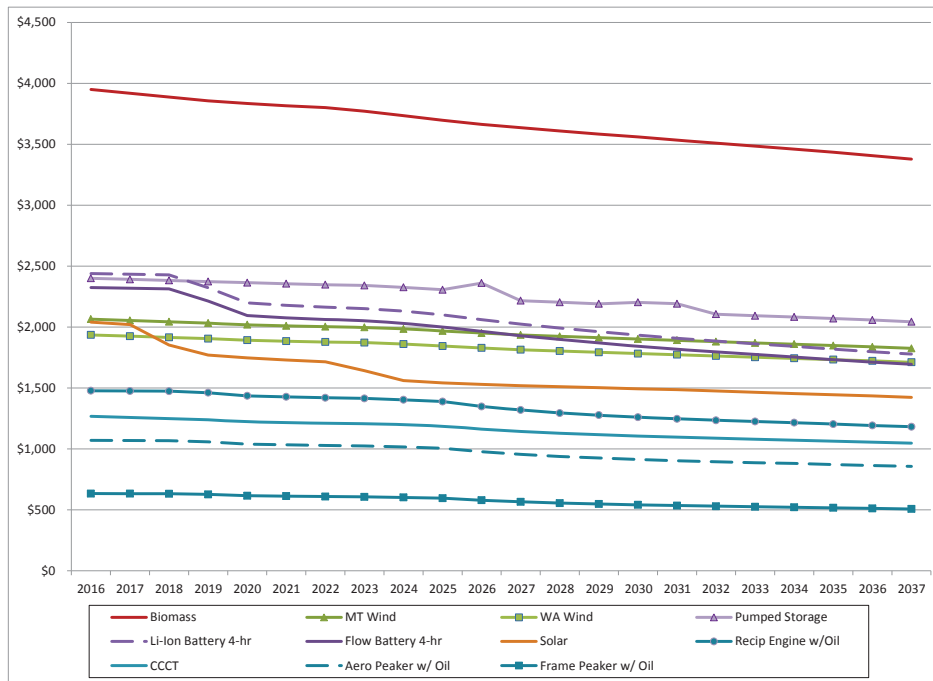


Chapter 4: Key Analytical Assumptions



The change in capital cost by vintage year (year the plant is built) is based on the EIA AEO 2015 Overnight Cost curves. These costs are decreasing on a real basis, but we then add a 2.5 percent annual inflation rate for nominal costs. Figure 4-20 shows the annual capital cost of a resource by year built in 2016 real dollars.

Figure 4-20: Annual Capital Costs by Vintage Year (real 2016 dollars)





Heat Rates

PSE applies the improvements in new plant heat rates as estimated by the EIA in the AEO Base Case Scenario. New equipment heat rates are expected to improve slightly over time, as they have in the past. PSE also applies a 2 percent increase to the heat rates to account for the average degradation over the life of the plant.

Federal Subsidies

Two federal subsidies are currently available to reduce renewable resource costs in the U.S; the production tax credit (PTC) and the investment tax credit (ITC). Both wind and solar projects are given the option to choose between the PTC or ITC.

PTC. The PTC is phased down over time for wind facilities (starting at 100 percent) and expires for other technologies commencing construction after December 31, 2016.

- For wind facilities commencing construction in 2017, the PTC amount is reduced by 20 percent
- For wind facilities commencing construction in 2018, the PTC amount is reduced by 40 percent
- For wind facilities commencing construction in 2019, the PTC amount is reduced by 60 percent

To meet the safe harbor rules, a project must meet the “physical work” test or show that 5 percent or more of the total cost of the project was paid during that year. For example, if a project began construction or paid 5 percent or more in costs in the year 2019, it will receive the 40 percent PTC even if the facility doesn’t go online until 2022. The PTC is received over 10 years and is the rate prescribed annually by the IRPs in dollars per MWh.



ITC. The ITC is a one-time benefit based on the total capital cost invested in the project. The phase-down over time varies depending on the technology;

- wind: 30 percent in 2016, 24 percent in 2017, 18 percent in 2018 and 12 percent in 2019;
- solar: 30 percent 2016-2019, 26 percent in 2020, and 22 percent in 2021, , and 10 percent in years after 2021.
- Batteries if matched with a solar project can receive ITC if 75 percent of the energy comes from the project.

ITC benefit is based on the year that construction begins. For example, if a wind project starts construction in 2016 but does not go online until 2018, it will receive a 30 percent tax credit based on the total capital cost. So, if the project cost \$300 million, then the developer will receive \$90 million in tax benefits.

BONUS DEPRECIATION. This is an additional amount of tax deductible depreciation that is awarded above and beyond what would normally be available in the first year of a project. Bonus depreciation is available for all technology types, not just renewable resources, and is based on the when the plant is placed in service. This incentive is designed to promote investment sooner rather than later. The bonus depreciation is also phased down over time; 50 percent in 2016, 50 percent in 2017, 40 percent in 2018 and 30 percent in 2019.

Renewable Portfolio Standards

Renewable portfolio standards (RPS) currently exist in 29 states and the District of Columbia, including most of the states in the WECC and British Columbia. They affect PSE because they increase competition for development of renewable resources. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources.

To model these varying laws, PSE identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS; e.g., 3 percent in 2012, 9 percent in 2016, then 15 percent in 2020 for Washington state. Then we apply these requirements to each state's load. No retirement of existing WECC renewable resources is assumed, which may underestimate the number of new resources that need to be constructed. After existing and renewable resources are accounted for, the difference is taken from the total RPS need and the existing resources and the net RPS need is then added to AURORA as a constraint. We then run the long-term capacity expansion with the RPS constraint, and AURORA adds renewable resources to meet the RPS need. Technologies modeled included wind and solar.



California Carbon Prices

The California Global Warming Solutions Act of 2006 (AB32) mandates a carbon price be applied to all power generated in or sold into that state. To model this cost, PSE used the Wood MacKenzie forecast of California CO₂ prices based on AB32.

Build and Retirement Constraints

PSE added constraints on different technologies to the AURORA model. Specifically:

- No new coal builds are allowed in Washington. State law RCW 80.80 (Greenhouse Gases Emissions – Baseload Electric Generation Performance Standard) prohibits construction of new coal-fired generation within the state without carbon capture and sequestration.
- No new coal builds are allowed in any state in the WECC. In addition, all WECC coal plants must meet the National Ambient Air Quality Standards (NAAQS) and the Mercury and Air Toxics Standards (MATS).
- Any plant that has announced retirement is reflected in the database.
- California power plants that would be shuttered by that state's Once-through Cooling regulations are retired.

Further discussion of planned builds and retirements in WECC are discussed in Appendix N, Electric Analysis.



Electric Portfolio Sensitivity Reasoning

Starting with the optimized, least cost Base Scenario portfolio, sensitivities change one resource assumption within the portfolio in order to isolate the effect of that resource change on the portfolio.

NOTE: The table in Figure 4-3 presents this information in abbreviated form.

A. Colstrip

Several proposed or recently enacted rules will affect the operation of the Colstrip plant in eastern Montana in coming years, so this sensitivity tests reducing reliance on Colstrip and eliminating it entirely.

BASELINE ASSUMPTION: Units 1 & 2 retire in 2022 and Units 3 & 4 remain in service into 2035.

SENSITIVITY 1 > Retire Units 1 & 2 in 2018.

SENSITIVITY 2 > Retire Units 3 & 4 in 2025.

SENSITIVITY 3 > Retire Units 3 & 4 in 2030.

B. Thermal Retirement

This sensitivity examines whether it would be cost effective to accelerate retirement of PSE's existing gas plants.

BASELINE ASSUMPTION: Optimal portfolio from the Base Scenario

SENSITIVITY 1 > Retire baseload gas plants early.

C. No New Thermal Resources

This sensitivity looks at the cost of filling all future supply-side portfolio resource needs with resources that emit no carbon.

BASELINE ASSUMPTION: Fossil fuel generation is an option in the model.

SENSITIVITY 1 > Renewable resources, energy storage and DSR are the only options for future resources.



D. Stakeholder-requested Alternative Resource Costs

This sensitivity models changes to the generic resource cost assumptions based on recommendations from IRP stakeholders.

BASELINE ASSUMPTION: PSE cost estimates for generic supply-side resources.

SENSITIVITY 1 > Lower cost for recip peakers: \$1,105 per kW without oil backup, \$1,257 per kW with oil backup

SENSITIVITY 2 > Higher thermal resource costs, based on the 2015 IRP capital cost estimates. Numbers are in 2016 dollars and include 30 percent owner's costs consistent with the 2017 IRP instead of the 40 percent owner's costs modeled in the 2015 IRP.

Frame peaker with oil: \$879 per kW

Recip peaker: \$1,563 per kW

Aero peaker with oil: \$1,214 per kW

Baseload CCCT: \$1,227 per kW

SENSITIVITY 3 > Lower wind and solar development cost (includes 30% owner's costs)

Wind: \$1,478 per kW

Solar: \$1,755 per kW

SENSITIVITY 4 > Apply more aggressive solar cost curve.

E. Energy Storage

This sensitivity examines the cost difference between a portfolio with energy storage and a portfolio without energy storage.

BASELINE ASSUMPTION: Batteries and pumped hydro included only if chosen economically.

SENSITIVITY 1 > Add 50 MW battery in 2023 instead of economically chosen peaker.

SENSITIVITY 2 > Add 50 MW pumped hydro storage in 2023 instead of economically chosen peaker.



F. Renewable Resources + Energy Storage

The baseline assumption is that the battery storage will be placed in an optimal location on the system to get the maximum transmission and distribution benefit. This sensitivity pair pairs 50 MW of battery storage with 200 MW of solar. If 75 percent of the energy used to charge the battery comes from a renewable resource, the battery storage will receive the same investment tax credit as the solar resource. However, locating the battery near the solar project in eastern Washington means it will no longer deliver the transmission and distribution benefit.

BASELINE ASSUMPTION: Solar and batteries modeled individually.

SENSITIVITY 1 > 200 MW solar bundled with 50 MW batteries

G. Electric Vehicle Load

This sensitivity examines how much electric vehicle charging loads will affect the resource plan forecast.

BASELINE: IRP Base Demand forecast

SENSITIVITY > Add forecasted electric vehicle load

The following three sensitivities test the impact of different demand-side resource configurations.

H. Demand-side Resources (DSR)

This sensitivity looks at the effect of no additional DSR on portfolio cost and risk; all future needs are met with supply-side resources.

BASELINE ASSUMPTION: All cost-effective DSR per RPS requirements (RCW 19.285).

SENSITIVITY 1 > Existing DSR measures stay in place, but all future needs are met with supply-side resources.

I. Extended DSR Potential

The baseline assumption applies a 10-year ramp rate to all DSR identified as cost-effective in this IRP, meaning that all of these DSR measures are applied in the first decade of the study period. This sensitivity models future DSR measures that extend conservation benefits through the second decade of the study period.

BASELINE ASSUMPTION: All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.

SENSITIVITY 1 > Assume future DSR measures will extend conservation benefits through the second 10 years of the study period.



J. Alternate Residential Conservation Discount Rate

This sensitivity examines how using a societal discount rate on conservation savings from residential energy efficiency would impact cost-effective levels of DSR.

BASELINE ASSUMPTION: Assume the base discount rate.

SENSITIVITY 1 > Apply a societal discount rate to residential conservation savings.

The next five sensitivities test the impact of different wind resource configurations.

K. RPS-eligible Montana Wind

The baseline assumption is that Montana wind does not qualify as an RPS-eligible resource. To qualify under RCW 19.285, Montana wind would have to be dynamically scheduled into Washington state on a real-time basis without shaping or storage. “Dynamically scheduled” means PSE’s balancing authority would have to balance real-time changes in wind energy output as if it were located in PSE’s balancing authority. This would require coordination and agreement between Northwestern (the balancing authority where the wind plant would be built) and BPA (which would transmit the power to PSE). Complex studies on both systems would be required to determine if each transmission system could facilitate the dynamic transfer without adversely affecting the other transmission customers on its system. PSE formally requested assistance from BPA in April 2017, explaining the potential importance to PSE customers of finding a way to resolve this issue, and asking specifically: 1) what information and studies would be required to determine whether Montana wind qualified as a renewable resource under RCW 19.285, and 2) for any summary information concerning the information and studies, and/or whether tariffs or regulations would need to be addressed before qualifying studies could be conducted. Since that request was sent, BPA has announced its intention to convene with a forum with the State of Montana and other regional stakeholders to work on these issues, and PSE will participate and contribute to the identification and implementation of solutions concerning Montana wind. While Montana wind is not currently an RPS-eligible resource, this sensitivity examines whether Montana wind would be a cost-effective resource if it did qualify and therefore capture the extra 20 percent apprenticeship credit. If RPS-eligible Montana wind does not appear to be cost effective, a second sensitivity estimates how close its cost comes to other cost-effective resources.

BASELINE ASSUMPTION: Montana wind included only if economically chosen as a non-RPS resource

SENSITIVITY 1 > Add Montana wind in 2023 as an RPS-eligible resource instead of solar.

SENSITIVITY 2 > Montana wind tipping point analysis



L. Offshore Wind Tipping Point Analysis

This sensitivity examines how much the costs of offshore wind would need to decline before it appears to be a cost-effective resource.

BASELINE ASSUMPTION: Base Scenario portfolio

SENSITIVITY 1 > Offshore wind tipping point analysis to determine how much costs would have to drop to be cost effective compared to other resources.

M. Hopkins Ridge Repowering

Repowering refers to refurbishing or renovating a plant with more efficient, updated technology and equipment to qualify for Renewable Production Tax Credits under the PATH Act of 2015. Repowering would make the facility operate more efficiently and capture savings from the production tax credit. This sensitivity examines whether it would be cost effective to repower the Hopkins Ridge wind facility for the tax incentives and bonus RECs that would result.

BASELINE ASSUMPTION: Repowering Hopkins Ridge is not included in the portfolio.

SENSITIVITY 1 > Include repowering Hopkins Ridge in the portfolio to replace the existing facility.



Gas Sales Assumptions

Transportation and storage are key resources for natural gas utilities. Transporting gas from production areas or market hubs to PSE's service area generally requires assembling a number of specific pipeline segments and/or gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. See Chapter 7, Gas Sales Analysis, for further information.

In this IRP, six alternatives were tested in the analyses.

Combination # 1 & 1a – NWP Additions + Westcoast

This option expands access to northern British Columbia gas at the Station 2 hub beginning November 2021, with expanded transport capacity on Enbridge/Westcoast Energy pipeline to Sumas and then on expanded NWP to PSE's service area. Gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be necessary to acquire Enbridge/Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity at Sumas.

COMBINATION #1A – NWP-TF-1. This is a short-term pipeline alternative that represents excess capacity on the existing NWP system from Sumas to PSE that could be contracted to meet PSE needs from November 2017 to October 2020 only. PSE believes that the vast majority of under-utilized firm pipeline capacity in the I-5 corridor will be absorbed by other new loads by the fall of 2020. Beyond October 2020, other long-term resources would be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal, which is in the development stages and sponsored by FortisBC and Enbridge/Westcoast. Availability is estimated beginning November 2021. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE.



Combination # 3 – Cross Cascades - AECO

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come from Alberta (AECO hub) via existing or new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

Combination # 4 – Cross Cascades - Malin

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come directly from Malin or from the Rockies hub on the Ruby pipeline to Malin, with backhaul on the TC-GTN pipeline to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

Combination # 5 – LNG-related Distribution Upgrade

This combination assumes completed construction and successful commissioning of the LNG peak-shaving facility for the 2019/20 heating season, providing 59.5 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because gas otherwise destined for the Tacoma system is displaced by vaporized LNG and delivered to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on two years' notice starting as early as winter 2021/22.

Combination # 6 – Mist Storage and Redelivery

This option provides for PSE to lease storage capacity from NW Natural after an expansion of the Mist storage facility. Delivery of gas would require expansion of pipeline capacity from Mist to PSE's service territory for Mist storage redelivery service. The expansion of pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland with significant additional volume contracting by other parties.

Combination # 7 – Swarr Propane/Air Upgrade

This is an upgrade to the existing Swarr LP-air facility. This upgrade would increase the peak day planning capability from 10 MDth per day to 30 MDth per day. This plant is located within PSE's distribution network.



Build Constraints

Gas expansions are done in multi-year blocks to reflect the reality of the acquisition process. There is inherent “lumpiness” in gas pipeline expansion, since expanding pipelines in small increments every year is not practical. Pipeline companies need minimum capacity commitments to make an expansion economically viable. Thus the model is constrained to evaluate pipeline expansions in four-year blocks: 2021, 2025, 2028 and 2033, 2037. Similarly, some resources have more flexibility. The Swarr LP gas peaking facility’s upgrade and the LNG distribution system upgrade were made available in two year increments since these resources are PSE assets.

Gas Sales Sensitivities

A. Demand-side Resources (DSR)

This sensitivity looks at the effect of no additional DSR on portfolio cost and risk; all future needs are met with supply-side resources.

BASELINE ASSUMPTION: All cost-effective DSR per RPS requirements (RCW 19.285).

SENSITIVITY 1 > Existing DSR measures stay in place, but all future needs are met with supply-side resources.

B. Resource Addition Timing Optimization

Two of the resource additions selected in most scenarios are within PSE’s control, the Swarr upgrade and the LNG-related distribution upgrade. This sensitivity examines how the timing of those PSE-controlled resource additions affect resource builds and portfolio costs.

BASELINE ASSUMPTION: Swarr and the LNG-related distribution upgrade are offered every two years in the model.

SENSITIVITY 1 > Allow these resources to be offered every year in the model.



C. Alternate Residential Conservation Discount Rate

This sensitivity examines how using a societal discount rate on conservation savings from residential energy efficiency would impact cost-effective levels.

BASELINE ASSUMPTION: Assume the base discount rate.

SENSITIVITY 1 > Apply a societal discount rate to residential conservation savings.

D. Additional Conservation

This sensitivity examines what happens if we add DSR above the levels found cost effective.

BASELINE ASSUMPTION: All cost-effective DSR per RCW 19.285.

SENSITIVITY 1 > Add two additional DSR bundles above those chosen as cost effective.



5

2017 PSE Integrated Resource Plan

Demand Forecasts

The system-level demand forecast that PSE develops for the IRP is an estimate of energy sales, customer counts and peak demand over a 20-year period. These forecasts are designed for use in long-term resource planning.

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1. OVERVIEW

Overall, the 2017 IRP Electric Base Demand Forecast before conservation for both energy and peak is lower than the 2015 IRP forecast. For energy, the average annual growth rate forecast in 2017 is 1.4 percent, compared to 1.7 percent in 2015. For peak demand, the average annual growth rate forecast in 2017 is 1.3 percent, compared to 1.6 percent in 2015. The forecast also shows higher near-term loads due to several large customers coming on line, and a lower forecast in later years, which reflects slower customer growth and the inclusion of 2015's unusually warm weather in the calculation of "normal"¹ weather assumptions.

The 2017 IRP Gas Base Demand Forecast before conservation for energy and peak loads is also lower than in the 2015 IRP. For energy, the average annual growth forecast in 2017 is 1.2 percent, compared to 1.7 percent in 2015. For peak demand, the the average annual growth rate forecast in 2017 is 1.4 percent, compared to 1.8 percent in 2015. Slower population growth has resulted in fewer new gas customers, and the inclusion of the 2015's unusually warm weather in calculating normal weather assumptions also reduced demand.

Demand is reduced significantly when forward projections of conservation savings are applied. However, it is necessary to start with forecasts that do not already include forward projections of conservation savings in order to identify the most

| Base Forecast At 2037 | Before DSR | After DSR |
|-----------------------|------------|-----------|
| Electric Load (MW) | 3,461 | 2,879 |
| Electric Peak (MW) | 6,511 | 5,664 |
| Gas Load (Mdth) | 120,970 | 113,100 |
| Gas Peak (Mdth) | 1,311 | 1,229 |

cost-effective amount of conservation to include in the resource plan. Throughout this chapter, charts labeled "before DSR" include only demand-side resource (DSR) measures implemented **before the study period begins in 2018**. Charts labeled "after applying DSR" include the cost-effective amount of DSR identified in the 2017 IRP.

To model a range of potential economic conditions, weather conditions and potential modeling errors in the IRP analysis, PSE also prepares Low and High forecasts in addition to the Base Forecast. The Low forecast models reduced population and economic growth compared to the Base Forecast; the High Forecast models higher population and economic growth compared to the Base Forecast.

¹ / For the IRP analysis, normal weather is defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2015.



2. ELECTRIC DEMAND FORECAST

Highlights of the base, high and low demand forecasts that PSE developed for the electric service area are presented below in Figures 5-1 through 5-4. The population and employment assumptions for all three forecasts are summarized beginning on page 5-32, and explained in detail in Appendix E, Demand Forecasting Models.

Only DSR measures implemented through December 2017 are included, since the demand forecast itself helps to determine the most cost-effective amount of conservation to include in the portfolio.

Electric Load Growth

In the 2017 IRP Base Demand Forecast, total load before DSR is expected to grow at a rate of 1.3 percent annually from 2018 to 2027 and 1.4 percent annually from 2027 to 2037, for an average annual growth rate of 1.4 percent over the 20-year study period. Total load is expected to grow from 2,681 aMW in 2018 to 3,461 aMW in 2037.

Residential and commercial loads are driving this growth; they represent 49 percent and 44 percent of load in 2016, respectively. On the residential side, use per customer is relatively flat, so growth in this category is being driven by the increase in the number of customers. On the commercial side, both use per customer and rising customer counts are driving growth.

The 2017 IRP High Demand Forecast projects an average annual growth rate of 1.7 percent; the Low Demand Forecast projects 1.1 percent.

Chapter 5: Demand Forecasts



Figure 5-1: Electric Demand Forecast before DSR
Base, High and Low Scenarios (aMW)

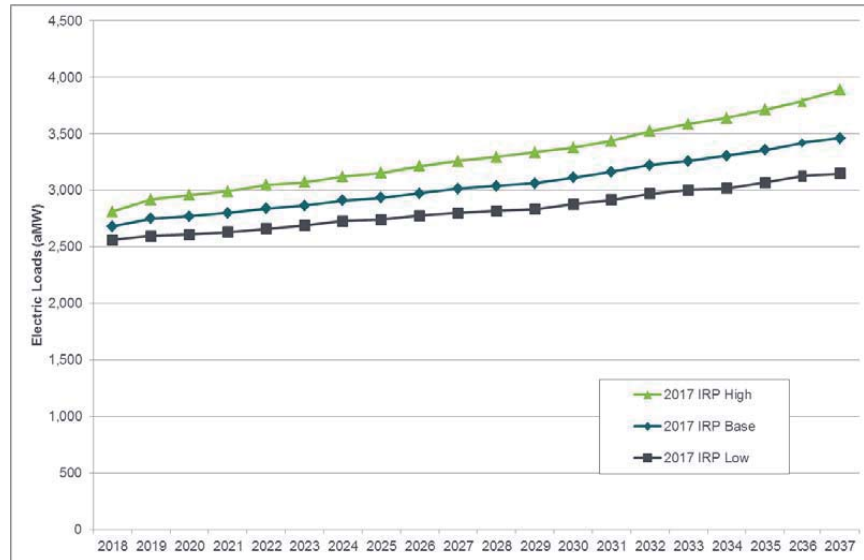


Figure 5-2: Electric Demand Forecast before DSR (Table)
Base, High and Low Scenarios

| ELECTRIC DEMAND FORECAST SCENARIOS (aMW) | | | | | | |
|--|-------|-------|-------|-------|-------|-------------------|
| Scenario | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| 2017 IRP Base Demand Forecast | 2,681 | 2,837 | 3,013 | 3,221 | 3,461 | 1.4% |
| 2017 IRP High Demand Forecast | 2,812 | 3,048 | 3,257 | 3,525 | 3,886 | 1.7% |
| 2017 IRP Low Demand Forecast | 2,561 | 2,660 | 2,800 | 2,970 | 3,148 | 1.1% |

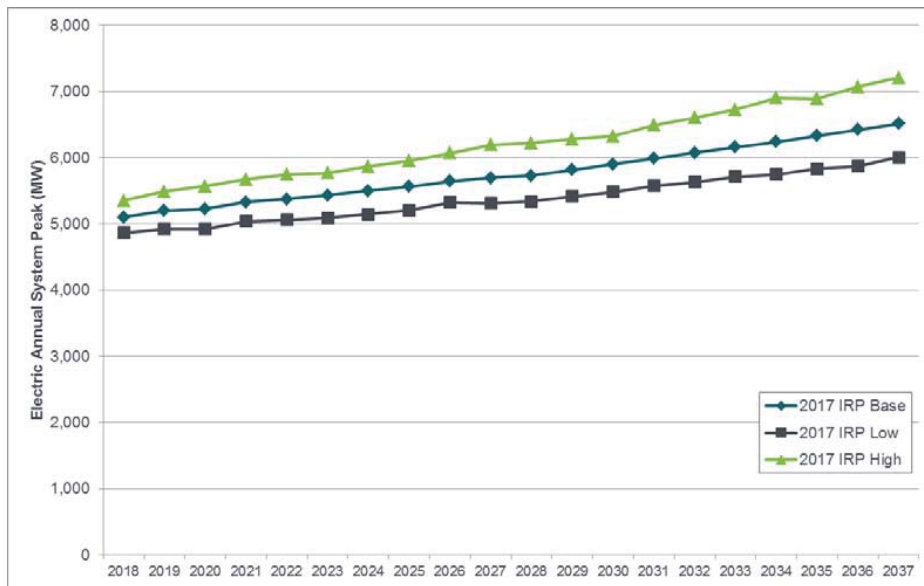


Electric Peak Demand

The normal electric peak hour load is modeled using 23 degrees Fahrenheit as the design temperature. Since PSE is still a winter peaking utility, this peak usually occurs in December. The 2017 IRP Base Demand Forecast shows an average annual peak load growth of 1.3 percent and an increase in peak load from 5,098 MW to 6,511 MW between 2018 and 2037.

The 2017 IRP High Demand Forecast shows an average annual peak load growth of 1.6 percent, and the Low Demand Forecast shows a 1.1 percent annual peak load growth rate.

*Figure 5-3: Electric Peak Demand Forecast before DSR
Base, High and Low Scenarios, Hourly Annual Peak (23 Degrees, MW)*



Chapter 5: Demand Forecasts



Figure 5-4: Electric Peak Demand Forecast before DSR (Table)
Base, High and Low Scenarios, Hourly Annual Peak (23 Degrees, MW)

| ELECTRIC PEAK DEMAND FORECAST SCENARIOS (MW) | | | | | | |
|--|-------|-------|-------|-------|-------|-------------------|
| Scenario | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| 2017 IRP Base Demand Forecast | 5,098 | 5,374 | 5,695 | 6,072 | 6,511 | 1.3% |
| 2017 IRP High Demand Forecast | 5,348 | 5,749 | 6,194 | 6,606 | 7,208 | 1.6% |
| 2017 IRP Low Demand Forecast | 4,867 | 5,062 | 5,308 | 5,629 | 6,001 | 1.1% |

Peak demand in the 2017 IRP Electric Base Demand Forecast is lower than the 2015 IRP Base Demand Forecast due primarily to the lower population forecast which led to a lower customer forecast, and to higher retail rates leading to lower customer usage.

Figure 5-5: Electric Peak Demand Forecast before DSR,
2017 IRP Base Scenario versus 2015 IRP Base Scenario
Hourly Annual Peak (23 Degrees, MW)

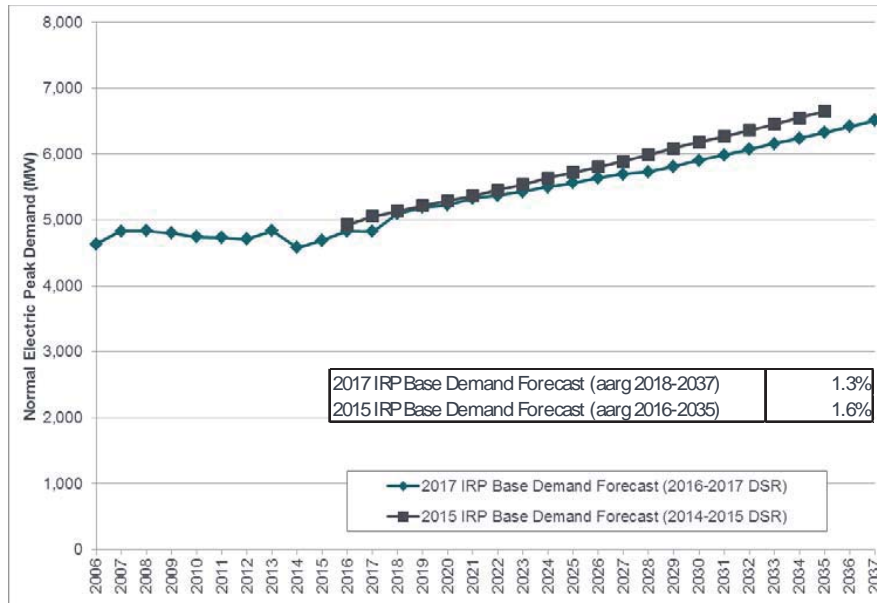




Illustration of Conservation Impacts

The system-level demand forecasts shown above apply only the energy efficiency measures targeted for 2016 and 2017, because those forecasts serve as the starting point for identifying the most cost-effective amount of demand-side resources for the portfolio from 2018 to 2037.

However, we also examine the effects of conservation on the system load and peak forecasts over the 20-year planning horizon. The load forecast net of conservation is used internally at PSE for financial planning and for transmission and distribution system planning. We apply the cost-effective demand-side resources identified in this IRP² to the Base Scenario load and peak forecasts for 2018 to 2037. To account for the 2013 general rate case Global Settlement, an additional 5 percent of conservation is also applied for that period. The result is illustrated in Figures 5-6 and 5-7, below.

DSR IMPACT ON LOAD: When the DSR bundles chosen in the 2017 IRP portfolio analysis are applied to the load forecast:

- Total system demand is 2,657 aMW in 2018 increasing to 2,879 aMW in 2037, or an 0.4 percent growth rate per year.
- Average annual growth is -0.3 percent from 2018 to 2027 and 1.1 percent from 2027 to 2037. Load grows more slowly in the first half of the forecast because that is when the majority of the demand-side measures are expected to be implemented.

DSR IMPACT ON PEAK: When the DSR bundles chosen in the portfolio analysis are applied to the peak forecast:

- The system peak is 5,060 MW in 2018 increasing to 5,664 MW in 2037, or a 0.6 percent growth per year.
- From 2018 to 2027 peak loads are flat (average annual growth is 0.0 percent), and from 2027 to 2037 average annual growth is 1.1 percent. Again, peak load grows more slowly in the first 10 years when DSR is more heavily concentrated.

² / For demand-side resource analysis, see Chapter 6, *Electric Analysis*, and Appendix J, *Conservation Potential Assessment*.

Chapter 5: Demand Forecasts



Figure 5-6: 2017 IRP Electric Base Demand Forecast (aMW), before DSR and after applying DSR

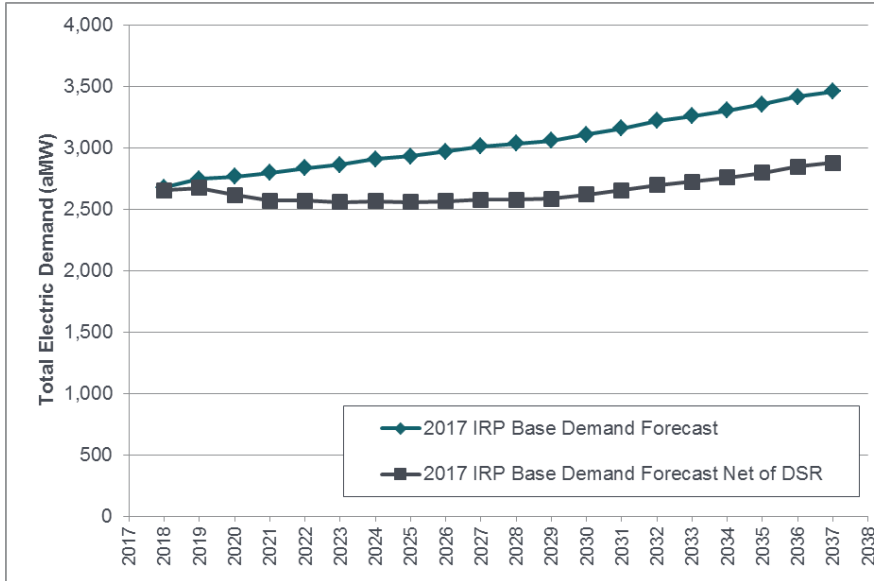
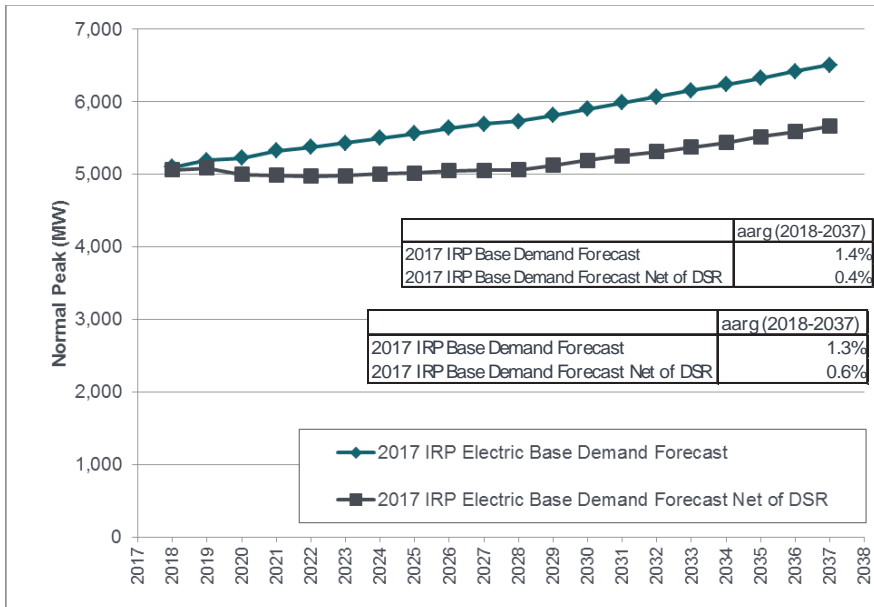


Figure 5-7: Electric Peak Base Demand Forecast (MW), before DSR and after applying DSR





Details of Electric Forecast

Electric Customer Counts

System-level customer counts are expected to grow by 1.2 percent per year on average, from 1.15 million customers in 2018 to 1.45 million customers in 2037. This is slightly lower than the average annual growth rate of 1.5 percent projected in the 2015 IRP Base Demand Forecast due to the lowered population forecast.

Residential customers are driving the customer count increase; they represent 88 percent of the PSE's electric customers in 2018. The next largest group, commercial customers, is expected to grow at an annual rate of 1.6 percent from 2018 to 2037. Industrial customer counts are expected to decline, following a historical trend. These trends are expected to continue as the economy in PSE's service territory grows more commercial and less industrial.

Figure 5-8: December Electric Customer Counts by Class, 2017 IRP Base Demand Forecast

| DECEMBER ELECTRIC CUSTOMER COUNTS BY CLASS, BASE DEMAND FORECAST | | | | | | |
|--|-----------|-----------|-----------|-----------|-----------|-------------------|
| Class | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| Total | 1,150,954 | 1,213,022 | 1,291,755 | 1,369,925 | 1,446,944 | 1.2% |
| Residential | 1,011,079 | 1,064,616 | 1,131,808 | 1,197,449 | 1,261,057 | 1.2% |
| Commercial | 130,424 | 139,048 | 150,671 | 163,279 | 176,764 | 1.6% |
| Industrial | 3,366 | 3,277 | 3,172 | 3,069 | 2,971 | -0.7% |
| Other | 6,085 | 6,081 | 6,104 | 6,128 | 6,152 | 0.1% |

Electric Load by Class

Over the next 20 years, the commercial sector is expected to contribute most to the total growth of system loads (60 percent). This is driven by the growth of commercial employment in the high tech sectors, which serve not only local but national and international markets. As the population increases, the need for commercial services such as health care, retail, education and other public services also increases.

Chapter 5: Demand Forecasts



Figure 5-9: Electric Demand by Class, 2017 IRP Base Demand Forecast before DSR

| ELECTRIC LOAD BY CLASS, BASE DEMAND FORECAST (aMW) | | | | | | |
|--|-------|-------|-------|-------|-------|-------------------|
| Class | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| Total | 2,681 | 2,837 | 3,013 | 3,221 | 3,461 | 1.4% |
| Residential | 1,194 | 1,258 | 1,336 | 1,414 | 1,499 | 1.2% |
| Commercial | 1,133 | 1,231 | 1,323 | 1,445 | 1,586 | 1.8% |
| Industrial | 150 | 132 | 126 | 120 | 117 | -1.3% |
| Other | 10 | 9 | 8 | 7 | 7 | -1.8% |
| Losses | 196 | 207 | 220 | 235 | 253 | 1.4% |

Electric Use per Customer

Residential use per customer before conservation is expected to be flat in the future, absent the impacts of demand-side resources. Multifamily housing growth and the increasing use of natural gas for space and water heating will tend to reduce electric use per customer, but this should be balanced by growth in plug loads and declining real electric rates. As the economy continues to grow steadily, commercial use per customer is expected to rise slowly due to higher employment levels and lower vacancy rates in the near term.

Figure 5-10: Electric Use per Customer, 2017 IRP Base Demand Forecast before DSR

| ELECTRIC USE PER CUSTOMER, BASE DEMAND FORECAST (MWh) | | | | | | |
|---|------|------|------|------|------|-------------------|
| Type | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| Residential | 10.4 | 10.4 | 10.4 | 10.4 | 10.5 | 0.04% |
| Commercial | 76.1 | 78.1 | 77.4 | 78.0 | 79.1 | 0.20% |
| Industrial | 389 | 353 | 348 | 342 | 343 | -0.66% |



Electric Customer Count and Load Shares by Class

Customer counts as a percent of PSE's total electric customers are shown in Figure 5-11. Load shares by class are shown in Figure 5-12. These tables show the flat growth trajectory of residential classes compared to the robust growth of commercial classes.

Figure 5-11: December Electric Customer Count Shares by Class, 2017 IRP Base Demand Forecast

| ELECTRIC CUSTOMER COUNT SHARES BY CLASS, BASE DEMAND FORECAST | | |
|---|---------------|---------------|
| Class | Share in 2018 | Share in 2037 |
| Residential | 87.8% | 87.2% |
| Commercial | 11.3% | 12.2% |
| Industrial | 0.3% | 0.2% |
| Other | 0.5% | 0.4% |

Figure 5-12: Electric Load Shares by Class, 2017 IRP Base Demand Forecast

| ELECTRIC LOAD SHARES BY CLASS, BASE DEMAND FORECAST | | |
|---|---------------|---------------|
| Class | Share in 2018 | Share in 2037 |
| Residential | 44% | 43% |
| Commercial | 42% | 46% |
| Industrial | 6% | 3% |
| Other | 0.4% | 0.2% |
| Losses | 7% | 7% |



Figure 5-13: PSE Electric Service Territory

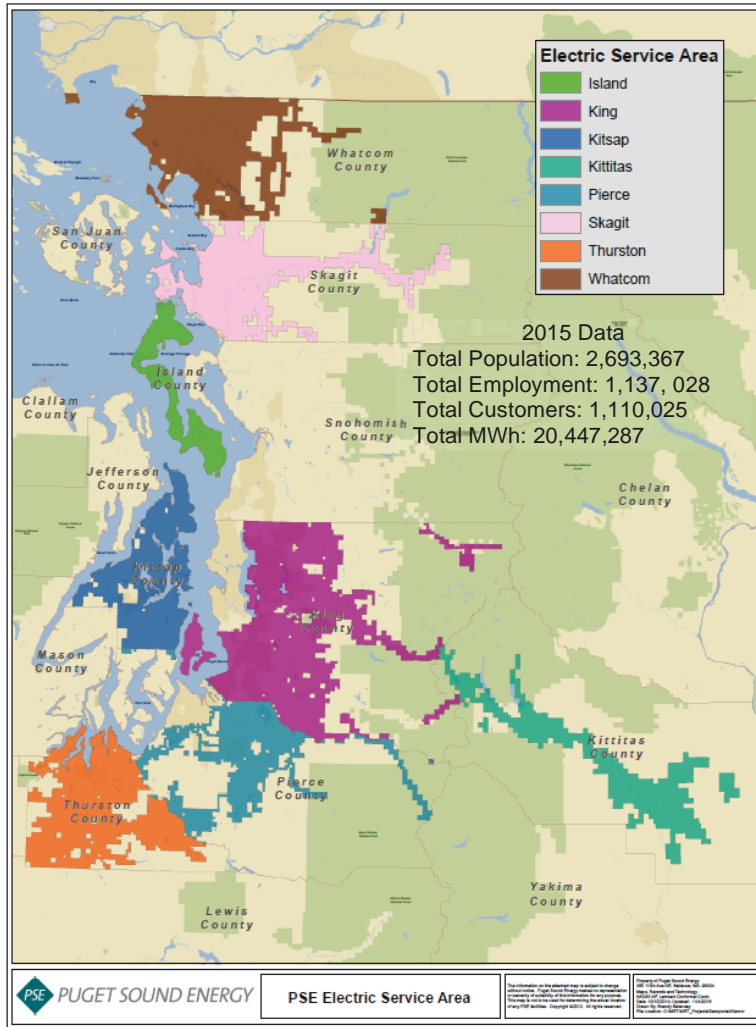


Figure 5-14: Electric Service Area, County Share as a Percent of PSE Total, 2015 Data

| COUNTY | POPULATION | EMPLOYMENT | CUSTOMERS | SALES |
|----------|------------|------------|-----------|-------|
| King | 48% | 58% | 49% | 53% |
| Thurston | 10% | 10% | 11% | 11% |
| Pierce | 15% | 10% | 10% | 10% |
| Kitsap | 10% | 8% | 11% | 9% |
| Whatcom | 8% | 8% | 9% | 8% |
| Skagit | 4% | 4% | 5% | 6% |
| Island | 3% | 1% | 3% | 2% |
| Kittitas | 2% | 1% | 1% | 1% |



3. GAS DEMAND FORECAST

Highlights of the base, high and low demand forecasts developed for PSE's gas sales service are presented below. The population and employment assumptions for all three forecasts are summarized on page 5-34, and explained in detail in Appendix E, Demand Forecasting Models.

Only demand-side resources implemented through December 2017 are included, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio.

Gas Load Growth

The 2017 IRP Gas Base Demand Forecast is a forecast of both firm and interruptible loads, because this is the volume of natural gas that PSE is responsible for securing and delivering to customers. For distribution planning, however, transport loads must be included in total load; transport customers purchase their own natural gas, but contract with PSE for delivery.

In the 2017 IRP Base Demand Forecast, gas load is projected to grow 1.2 percent per year on average from 2018 to 2037; this would increase load from 96,808 Mdth in 2018 to 120,970 Mdth in 2037. This is lower than the annual growth rate of 1.7 percent in the 2015 IRP Base Demand Forecast.

The 2017 IRP High Gas Demand Forecast projects an average annual growth rate of 1.7 percent; the Low Demand Forecast projects a growth rate of 0.5 percent per year.

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Figure 5-15: Gas Demand Forecast before DSR
Base, High and Low Scenarios, without Transport Load (Mdth)

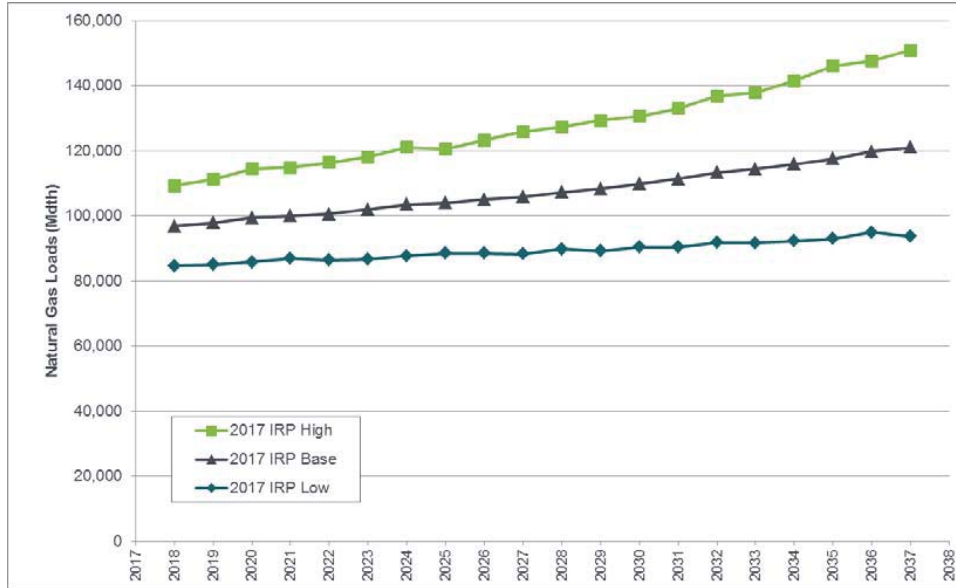


Figure 5-16: Gas Demand Forecast before DSR (Table)
Base, High and Low Scenarios without Transport Load (Mdth)

| GAS LOAD FORECAST SCENARIOS (Mdth), WITHOUT TRANSPORT | | | | | | |
|---|---------|---------|---------|---------|---------|----------------|
| Scenario | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| 2017 IRP Base Demand Forecast | 96,808 | 100,612 | 105,806 | 113,288 | 120,970 | 1.2% |
| 2017 IRP High Demand Forecast | 109,228 | 116,376 | 125,840 | 136,868 | 150,861 | 1.7% |
| 2017 IRP Low Demand Forecast | 84,673 | 86,395 | 88,275 | 91,779 | 93,603 | 0.5% |



Gas Peak Demand

The gas design peak day is modeled at 13 degrees Fahrenheit average temperature for the day. Only firm sales customers are included when forecasting peak gas loads; transportation and interruptible customers are not included.

For peak gas demand, the 2017 IRP Base Demand Forecast projects an average increase of 1.4 percent per year for the next 20 years; peak demand would rise from 1,010 Mdth in 2018 to 1,311 Mdth in 2037. The High Demand Forecast projects a 1.7 percent annual growth rate, and the Low Demand Forecast projects 1.1 percent.

Gas peak day growth rates are slightly higher than the rates for load growth because the classes that contribute most to peak demand (the weather-sensitive residential and commercial sectors) are growing faster than the classes that don't contribute to peak demand. Rising baseloads are also contributing to peak demand because gas is increasingly being used for purposes other than heating (such as cooking, clothes drying and fireplaces). This effect is slightly offset by higher appliance and home efficiencies.



Figure 5-17: Gas Peak Day Demand Forecast before DSR
Base, High and Low Scenarios (13 Degrees, Mdth)

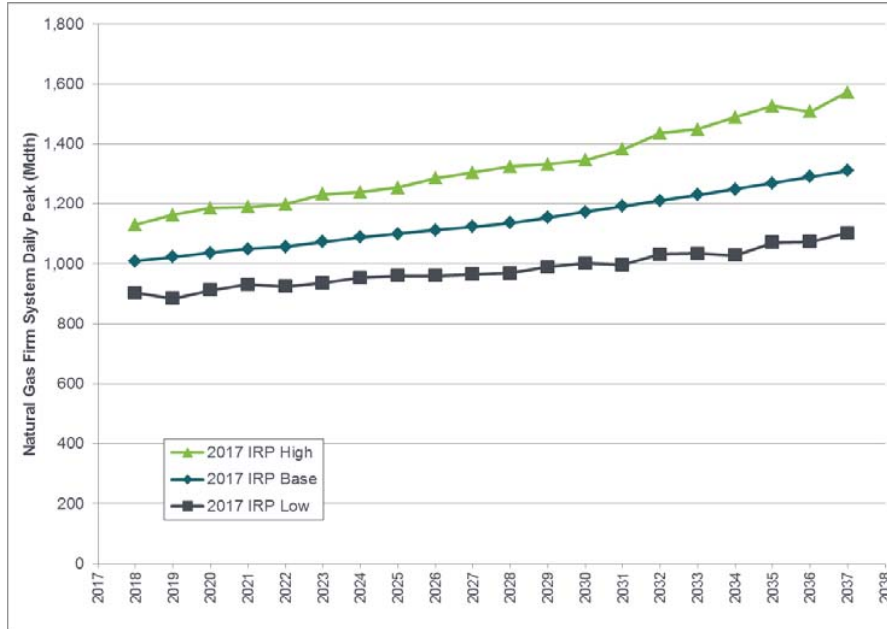


Figure 5-18: Gas Peak Day Demand Forecast before DSR (Table)
Base, High and Low Scenarios (13 Degrees, Mdth)

| FIRM GAS PEAK DAY FORECAST SCENARIOS (Mdth) | | | | | | |
|---|-------|-------|-------|-------|-------|----------------|
| Scenario | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| 2017 IRP Base Demand Forecast | 1,010 | 1,058 | 1,123 | 1,211 | 1,311 | 1.4% |
| 2017 IRP High Demand Forecast | 1,130 | 1,199 | 1,304 | 1,435 | 1,571 | 1.7% |
| 2017 IRP Low Demand Forecast | 903 | 925 | 965 | 1,031 | 1,102 | 1.1% |

The 2017 IRP Base Demand growth rate is lower than the 2015 IRP Base Demand growth rate of 1.8 percent (2016 to 2035), mainly due to the lower customer count forecast.



Figure 5-19: Firm Gas Peak Day Forecast before DSR
 2017 IRP Base Scenario versus 2015 IRP Base Scenario
 Daily Annual Peak (13 Degrees, Mdth)

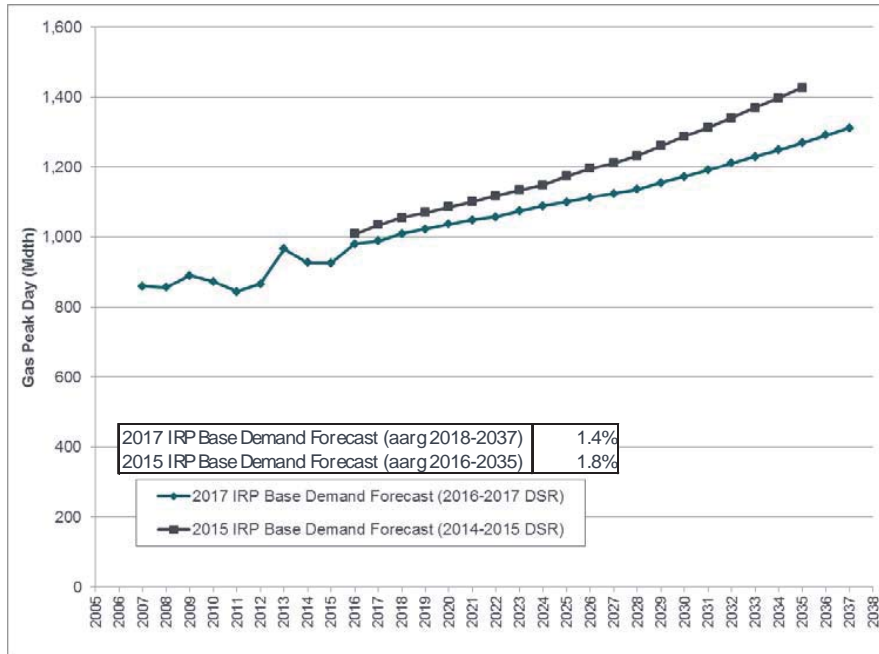


Illustration of Conservation Impacts

As explained at the beginning of the chapter, the gas demand forecasts include only demand-side resources implemented through December 2017, since the demand forecast itself helps to determine the most cost-effective level of DSR to include in the portfolio. To examine the effects of conservation on the system load and peak forecasts, the cost-effective amount of DSR determined in this IRP³ is applied to the system load (without transport loads) and peak forecast for 2018 to 2037. This forecast is used internally at PSE for financial and system planning decisions.

³ For demand-side resource analysis, see Chapter 7, Gas Analysis, and Appendix J, Conservation Potential Assessment.

Chapter 5: Demand Forecasts



When the DSR bundles chosen in the 2017 IRP portfolio analysis are applied:

- System load (without transport but with losses) grows at an average annual rate of 0.6 percent from 2018 to 2027 and 1.1 percent from 2027 to 2037, or 0.8 percent per year over the next 20 years; volume rises from 96,808 Mdt in 2018 to 113,100 Mdt in 2037. Load grows more slowly in the first half of the forecast because that's when the majority of the demand-side measures are expected to be implemented.
- The design system peak is expected grow at an average annual rate of 0.8 percent from 2018 to 2027 and 1.3 percent from 2027 to 2037, or 1.1 percent per year over the next 20 years; volume rises from 1,008 Mdt in 2018 to 1,229 Mdt in 2037. Again, peak load grows more slowly in the first half of the forecast because that is when the majority of the demand-side measures are expected to be implemented.

Figure 5-20: 2017 IRP Gas Base Demand Forecast, before DSR and after applying DSR

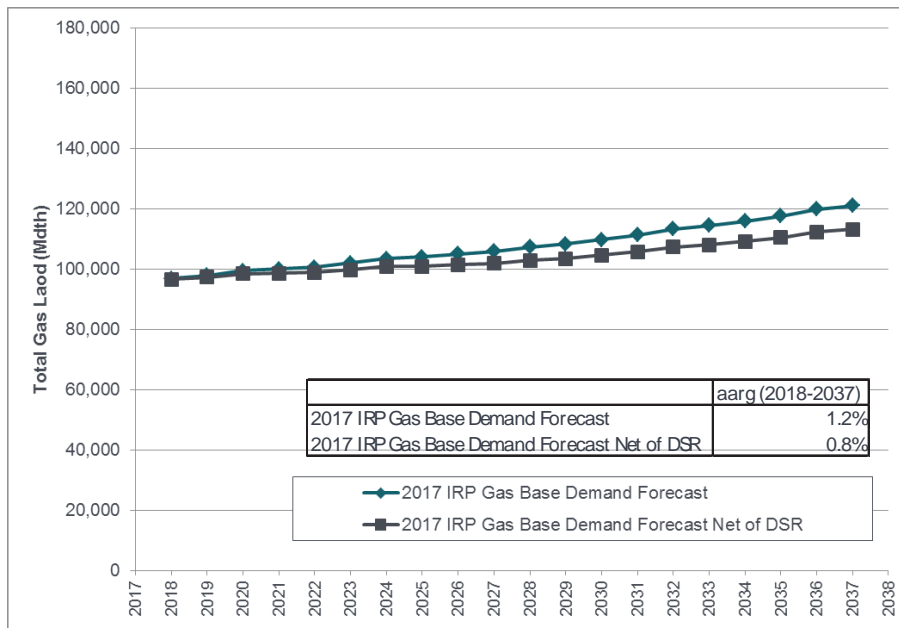
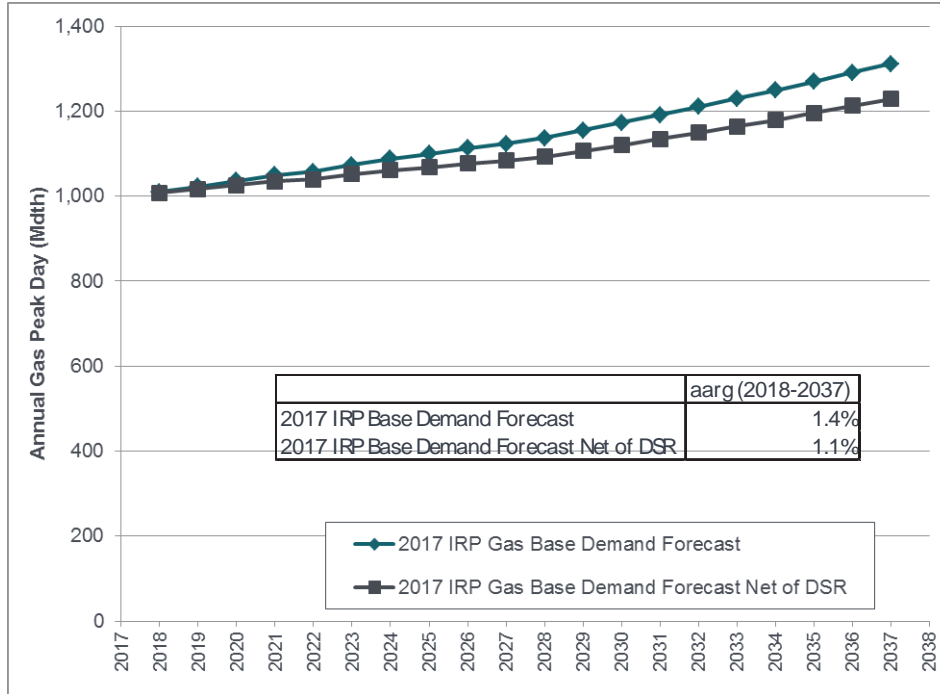




Figure 5-21: 2017 IRP Gas Peak Day Base Demand Forecast, Before DSR and after applying DSR



Details of Gas Forecast

Gas Customer Counts

The Base Demand Forecast projects natural gas customer counts will increase at a rate of 1.3 percent per year on average between 2018 and 2037, reaching almost 1.06 million customers by the end of the forecast period for the system as a whole. A lower population forecast has resulted in a lower growth rate than the 1.9 percent growth rate projected in the 2015 IRP (2016 to 2035).

Residential customer counts drive the growth in total customers, since this class makes up 93 percent of PSE’s gas sales customers. The next largest group, commercial customers, is expected to grow at an annual rate of 1.5 percent from 2018 to 2037. Industrial and interruptible customer classes are expected to continue to shrink, consistent with historical trends.

Chapter 5: Demand Forecasts



Figure 5-22: December Gas Customer Counts by Class,
from 2017 IRP Base Demand Forecast

| DECEMBER GAS CUSTOMER COUNTS BY CLASS FROM 2017 IRP BASE DEMAND FORECAST | | | | | | |
|---|---------|---------|---------|---------|-----------|-----------------------|
| Customer Type | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018- 2037 |
| Residential | 768,811 | 811,203 | 865,093 | 921,391 | 982,574 | 1.3% |
| Commercial | 56,374 | 59,802 | 64,263 | 69,027 | 74,146 | 1.5% |
| Industrial | 2,313 | 2,201 | 2,071 | 1,947 | 1,832 | -1.2% |
| Total Firm | 827,499 | 873,206 | 931,427 | 992,365 | 1,058,551 | 1.3% |
| Interruptible | 266 | 235 | 206 | 184 | 167 | -2.4% |
| Total Firm & Interruptible | 827,765 | 873,441 | 931,633 | 992,549 | 1,058,718 | 1.3% |
| Transport | 224 | 224 | 224 | 224 | 224 | 0.0% |
| System Total | 827,989 | 873,665 | 931,857 | 992,773 | 1,058,942 | 1.3% |

Gas Use per Customer

Residential use per customer before conservation is declining slightly, showing a -0.2 percent average annual growth for the forecast period. Commercial use per customer is expected to rise 0.4 percent annually over the forecast horizon. Industrial use per customer has been declining in recent years and is expected to decline at an annual rate of -0.3 percent.

Figure 5-23: Gas Use per Customer, 2017 IRP Gas Base Demand Forecast before DSR

| USE PER CUSTOMER (THERMS) FROM 2017 IRP GAS BASE DEMAND FORECAST | | | | | | |
|--|--------|--------|--------|--------|--------|-------------------|
| Customer | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| Residential | 798 | 783 | 765 | 761 | 762 | -0.2% |
| Commercial | 4,887 | 4,958 | 5,032 | 5,166 | 5,313 | 0.4% |
| Industrial | 11,296 | 10,264 | 10,948 | 11,007 | 10,761 | -0.3% |



Gas Load by Class

Total system load, including transport load, is expected to increase at a rate of 0.8 percent annually between 2018 and 2037. Residential loads, which represent 51 percent of load in 2018, are expected to increase by 1.0 percent annually during the forecast period. Commercial loads, which represent 23 percent of 2018 load, are expected to increase 1.9 percent annually.

Population growth and electric-to-gas conversions are driving residential load growth. Commercial load growth is driven by increases in both customer counts and use per customer. Some sectors, among them industrial, interruptible and transport, are expected to decline slightly, continuing a more than decade-long trend of slowing manufacturing employment.

Figure 5-24: Gas Loads by Class (Mdt), 2017 IRP Gas Base Demand Forecast before DSR

| LOAD (Mdt) BY CLASS FROM 2017 IRP GAS BASE DEMAND FORECAST | | | | | | |
|--|---------|---------|---------|---------|---------|-------------------|
| Class | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| Residential | 61,449 | 63,571 | 66,264 | 70,476 | 74,846 | 1.0% |
| Commercial | 27,930 | 30,058 | 32,717 | 36,162 | 39,708 | 1.9% |
| Industrial | 2,632 | 2,288 | 2,294 | 2,176 | 1,999 | -1.4% |
| Total Firm | 92,011 | 95,917 | 101,275 | 108,814 | 116,553 | 1.3% |
| Interruptible | 4,313 | 4,192 | 4,002 | 3,907 | 3,812 | -0.6% |
| Total Firm and Interruptible | 96,324 | 100,109 | 105,277 | 112,722 | 120,365 | 1.2% |
| Transport | 23,859 | 22,522 | 20,822 | 20,134 | 19,555 | -1.0% |
| System Total before Losses | 120,183 | 122,630 | 126,099 | 132,856 | 139,920 | 0.8% |
| Losses | 604 | 616 | 634 | 668 | 703 | 0.8% |
| System Total | 120,787 | 123,247 | 126,732 | 133,523 | 140,623 | 0.8% |



Gas Customer Count and Load Shares by Class

Customer counts as a percent of PSE's total gas customers are shown in Figure 5-25. Load shares by class are shown in Figure 5-26.

Figure 5-25: Gas Customer Count Shares by Class, 2017 IRP Base Demand Forecast

| GAS CUSTOMER COUNT SHARES BY CLASS, BASE DEMAND FORECAST | | |
|---|---------------|---------------|
| Class | Share in 2018 | Share in 2037 |
| Residential | 92.8% | 92.8% |
| Commercial | 6.8% | 7.0% |
| Industrial | 0.3% | 0.2% |
| Interruptible | 0.03% | 0.02% |
| Transport | 0.03% | 0.02% |

Figure 5-26: Gas Load Shares by Class, 2017 IRP Base Demand Forecast

| GAS LOAD SHARES BY CLASS, BASE DEMAND FORECAST | | |
|---|---------------|---------------|
| Class | Share in 2018 | Share in 2037 |
| Residential | 50.9% | 53.2% |
| Commercial | 23.1% | 28.2% |
| Industrial | 2.2% | 1.4% |
| Interruptible | 3.6% | 2.7% |
| Transport | 19.8% | 13.9% |
| Losses | 0.5% | 0.5% |



Figure 5-27: PSE Gas Service Territory

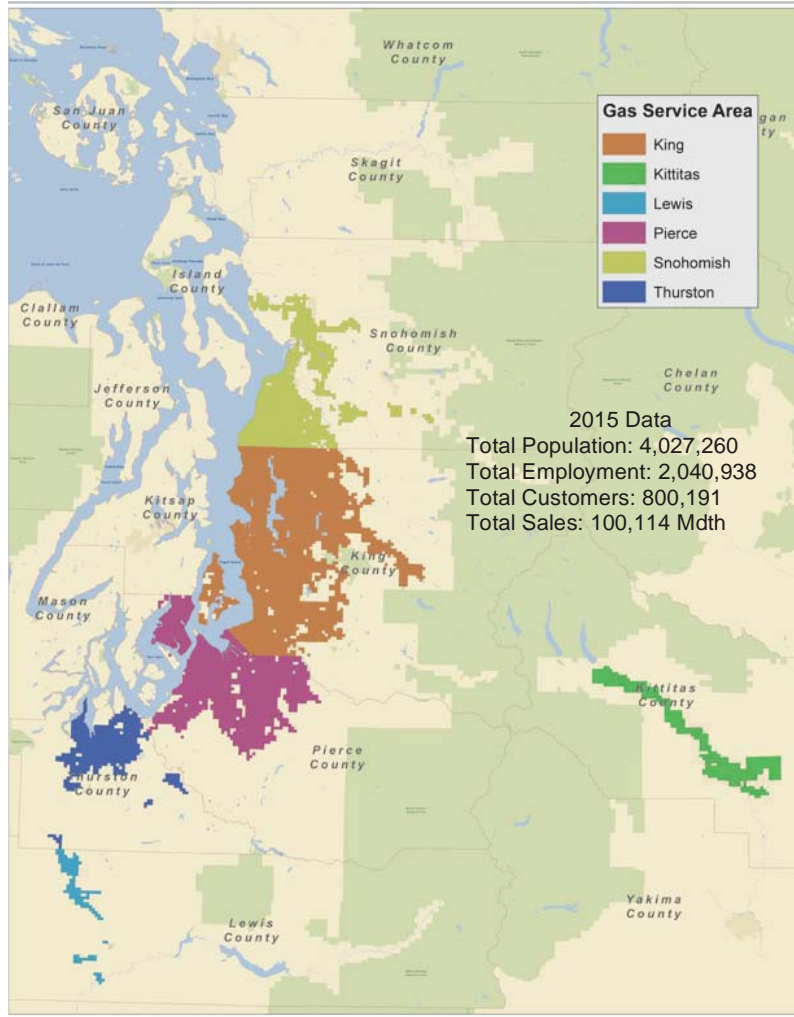


Figure 5-28: Gas Service Territory, County Share as a Percent of PSE Total, 2015 Data

| COUNTY | POPULATION | EMPLOYMENT | CUSTOMERS | SALES |
|-----------|------------|------------|-----------|-------|
| King | 51% | 64% | 57% | 57% |
| Pierce | 21% | 15% | 19% | 22% |
| Snohomish | 19% | 14% | 17% | 15% |
| Thurston | 7% | 5% | 6% | 5% |
| Lewis | 2% | 1% | 1% | 1% |
| Kittitas | 1% | 1% | <1% | <1% |



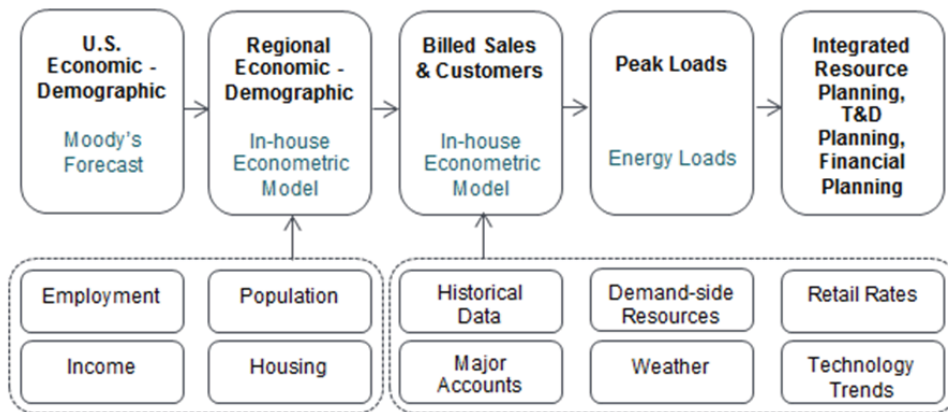
4. METHODOLOGY

Forecasting Process

PSE has made significant updates to the load forecast inputs and equations since the 2015 IRP, which enable us to make more accurate projections of customer counts, use per customer and load shapes. These innovations and updates are described starting on page 5-28.

PSE's regional economic and demographic model uses both national and regional data to produce a forecast of total employment, types of employment, unemployment, personal income, population, households, consumer price index (CPI) and building permits for both the PSE electric and gas service territories. The regional economic and demographic data used in the model are built up from county-level or MSA (metropolitan statistical area)-level information from various sources. This economic and demographic information is combined with other PSE internal information to produce energy and peak load forecasts for the service territory. The load-forecasting process is illustrated in Figure 5-29, and the input data sources are listed in Figure 5-30.

Figure 5-29: PSE Load Forecasting Process



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Electricity and natural gas are inputs into different end uses.

- For residential customers, typical energy uses include space heating, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions, computers and various other plug loads.
- Commercial and industrial customers use energy for production processes; space heating, ventilation and air conditioning (HVAC); lighting; computers; and other office equipment.

To forecast energy sales and customer counts, customers are divided into classes and service levels that use energy for similar purposes and at comparable retail rates. The different classes are modeled separately using variables specific to their usage patterns.

- Electric customer classes include residential, commercial, industrial, streetlights, resale and transport (customers purchasing their power not from PSE but from third-party suppliers).
- Gas customer classes include firm (residential, commercial, industrial, commercial large volume and industrial large volume), interruptible (commercial and industrial), and transport (commercial firm, commercial interruptible, industrial firm and industrial interruptible).

Transport Customers

“Transport” in the natural gas industry has historically referred to customers that acquire their own natural gas from third-party suppliers and rely on the gas utility for distribution service. It does not refer to natural gas fuel for vehicles.

Econometric/regression equations are used to forecast the number of customers by class as well as the use per customer (UPC) by class. These are multiplied together to arrive at the billed sales forecast. The main drivers of these equations include population or households, housing permits, unemployment rates, retail rates, personal income, weather, total employment and manufacturing employment. Weather inputs are based on temperature readings from Sea-Tac Airport. Peak system loads are also projected by examining the historical relationship between actual peaks, temperature at peaks, and also the economic and demographic impacts on system loads.

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For detailed technical descriptions of the econometric methodologies used to forecast billed energy sales, customer counts, peak loads for electricity and natural gas, hourly distribution of electric loads and forecast uncertainty, see Appendix E, Demand Forecasting Models.

High and Low Scenarios

PSE also develops high and low growth scenarios by performing 250 stochastic simulations of PSE's economic and demographic model combined with stochastic draws of weather. These simulations reflect variations in key regional economic and demographic variables such as population, employment and income, and also a historic weather scenario instead of "normal weather." For the IRP analysis, normal weather is defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2015. The historic weather scenarios in each of the 250 simulations use 20 years of continuous historic weather randomly drawn between 1929 and 2015. The low and high scenarios represent the 5th and 95th percentile of the 250 simulations, respectively. More detailed discussion of the stochastic simulations is presented in Appendix E, Demand Forecasting Models.

Chapter 5: Demand Forecasts



Figure 5-30: Sources for U.S. and Regional Economic and Demographic Data

| DATA USED IN ECONOMIC AND DEMOGRAPHIC MODEL | |
|---|--|
| County-level Data | Source |
| Labor force, employment, unemployment rate | U.S. Bureau of Labor Statistics (BLS) www.bls.gov Puget Sound Regional Council (PSRC) www.psrc.org |
| Total non-farm employment, and breakdowns by type of employment | WA State Employment Security Department, using data from Quarterly Census of Employment and Wages https://fortress.wa.gov/ |
| Personal income | U.S. Bureau of Economic Analysis (BEA) www.bea.gov |
| Wages and salaries | |
| Population | U.S. Bureau of Economic Analysis (BEA) / WA State Office of Financial Management (OFM) www.ofm.wa.gov |
| Households, single- and multi-family | U.S. Census www.censtats.census.gov |
| Household size, single- and multi-family | |
| Housing permits, single- and multi-family | U.S. Census / Puget Sound Regional Council (PSRC) / City Websites / Building Industry Association of Washington (BIAW) www.biaw.com |
| Aerospace employment | Puget Sound Economic Forecaster www.economicforecaster.com |
| US-level Data | Source |
| GDP | Moody's Analytics www.economy.com |
| Industrial Production Index | |
| Employment | |
| Unemployment rate | |
| Personal income | |
| Wages and salary disbursements | |
| Consumer Price Index (CPI) | |
| Housing starts | |
| Population | |
| Conventional mortgage rate | |
| T-bill rate, 3 months | |



Updates to Inputs and Equations

PSE has made significant updates to the load forecast inputs and equations since the 2015 IRP. These updates are summarized below.

MODEL SELECTION TOOL. In conjunction with a University of Washington econometric consultant, PSE developed a model selection tool to develop a set of key drivers that contribute most to explaining the changes in use per customer or customer additions in the historical period. For example, the model selection tool was used to test different base temperatures for the heating degree day (HDD) and cooling degree day (CDD), economic and demographic variables, seasonal or monthly variables, dummy variables, autoregressive moving average (ARMA) terms, and polynomial distributed lag terms and orders.

SERVICE TERRITORY POPULATION AND EMPLOYMENT. The 2015 IRP used county-level population, employment and housing permit growth to predict customer additions and load growth for counties within the service territory. The 2017 IRP removes population and employment from non-PSE areas within those counties to reflect actual PSE service territory population and employment growth more accurately.

RESIDENTIAL ELECTRIC CUSTOMER ADDITIONS. The 2017 IRP uses total households as an explanatory variable for residential electric customer additions instead of total single- and multi-family housing permits, as in the 2015 IRP. The amount of multi-family housing permits in PSE's service territory has increased, but the monthly number of multi-family housing permits can be quite volatile, and therefore add more volatility to the customer forecast. At this time, growth in total households is a more stable indicator of long-term growth.

GAS CUSTOMER ADDITIONS. The 2017 IRP calculates gas customer additions using single-family housing permits as an explanatory variable instead of using total housing permits (single- and multi-family). Most of the new gas customers in PSE's service territory are still in single-family houses, but growth in small commercial customers also needs to be monitored.



RETAIL ELECTRIC FORECAST. The 2017 IRP smooths the retail rates forecast for the electric forecast to the rolling 12-month average of retail rates. This reflects the fact that while customers experience seasonal fluctuations in their retail rate, they tend to respond more to their total bill than the actual electric rates. This also removes the impact of seasonality on price per kWh.

MONTHLY BILLING CYCLE DEGREE DAY CALCULATION. The 2015 IRP used a generic degree day calculation to match up billing cycle data with the weather that occurred during that monthly billing cycle. The 2017 IRP uses PSE's actual 21 billing cycles to calculate a more precise degree day for each monthly billing cycle. The 2017 IRP also uses historical data to weight the degree day calculation based on the amount of load that occurs in each cycle within each month.

MONTHLY LOAD SHAPE. In the 2017 IRP, the monthly load shape is only applied to the years 2016 to 2018. Beyond 2018 the load shape is not applied. This allowed for shaping trends based on the historical data to be incorporated in the long-term forecast.

CONDITIONED SALES. Billing errors or back-billing can be present in recorded or "booked" billed sales. "Conditioned" sales correct for errors in billing and reallocate sales into the month where they occurred. The 2017 IRP uses conditioned sales instead of booked sales to create a better correlation between temperature, economic factors, and amount of energy or natural gas used.

LARGE VOLUME AND FIRM TRANSPORT GAS CUSTOMERS. The 2013 update to PSE's billing system made it difficult to determine the number of customers that had firm gas service in addition to interruptible or transport gas service. These customers are now counted based on usage in the last 6 months, instead of estimating their number based on historical data.



5. KEY ASSUMPTIONS

To develop PSE's demand forecasts, assumptions must be made about economic growth, energy prices, weather and loss factors, including certain system-specific conditions. These and other assumptions are described below.

Economic Growth

Economic activity has a significant effect on long-term energy demand. While the energy component of the national GDP has been declining over time, energy is still an essential input into various residential end uses such as space heating/cooling, water heating, lighting, cooking, dishwashing/clothes washing and various electric plug loads. The growth in residential building stock therefore directly impacts the demand for energy over time. Commercial and industrial sectors also use energy for space heating and cooling, water heating, lighting and for various plug loads. Energy is also an important input into many industrial production processes. Economic activities in the commercial and industrial sectors are therefore important indicators for the overall trends in energy consumption.

National Economic Outlook

Because the Puget Sound region is a major commercial and manufacturing center with strong links to the national economy, PSE's IRP forecast begins with assumptions about what is happening in the broader U.S. economy. The U.S. economy has established a steady, positive growth path; however, recovery from the effects of the 2008 recession has been modest compared to the strong recovery cycles experienced after prior recessions. Relative to the 2015 IRP economic forecasts, the U.S. economy is expected to grow steadily but more modestly in the 2017 IRP as a result of modest international economic growth and slowing U.S. population growth in the long term. Near term, however, the employment growth rate is expected to be slightly more robust relative to the 2015 IRP projections, leading to slightly faster near-term employment growth in parts of the PSE service territory.

We rely on Moody's Analytics U.S. Macroeconomic Forecast, a long-term forecast of the U.S. economy, for both economic and population growth rates. The March 2016 Moody's forecast was used for this IRP.

Chapter 5: Demand Forecasts



Moody's forecast calls for:

- U.S. GDP to continue growing modestly from the past recession, reaching 3 percent in 2017. This is a slower economic recovery than the Moody's forecast used in the 2015 IRP of nearly 4 percent GDP growth by 2015. Moody's forecasts of economic recovery have been tempered over the last few years by lower GDP growth rates.
- Average annual population growth of 0.66 percent for 2018-2037. This is down from the 0.76 percent growth rate Moody's forecast in the 2015 IRP for 2016-2035.

Slower population growth is attributed to lower birth rates due to an aging population and lower international migration now that developing countries' economies are growing faster than they have in the past.

Economic growth could slow if demand from China and Euro Zone economies continues to slow; if the Federal Reserve becomes aggressive in its interest rate setting; if international trade policies become more protectionist; or if geopolitical tensions increase, especially in Eastern Europe or the Middle East. Alternatively, if U.S. and international growth rates continue to diverge, the U.S. could be more attractive to domestic investors. Low oil prices could spur spending in the short term but weigh on U.S. oil companies in the long term. However, many believe that the U.S. economy will be able to withstand these threats and continue to follow a steady, positive growth path.

Regional Economic Outlook

PSE is the largest investor owned utility in Washington; it provides gas services to almost 60 percent of state's population and electric services to about 40 percent of the state's population. Within PSE's service territory, demand growth is uneven. Most of the economic growth is driven by the growth in the high tech or information technology sectors, and this growth is concentrated in King County, which accounts for half or more of the system's electric and gas sales demand today. Other counties are growing, but slowly; most have yet to reach their pre-recession population or employment growth rates.

PSE prepares regional economic and demographic forecasts using econometric models whose primary inputs are the macroeconomic forecasts of the United States plus historical economic data for the counties in PSE's service area.



Electric Scenario Outlooks

BASE SCENARIO OUTLOOK. The following forecast assumptions are used in the 2017 IRP Base Electric Demand Forecast scenario.

- Employment is expected to grow at an average annual rate (aarg) of 0.8 percent between 2018 and 2037, which is slightly faster than the annual growth rate of 0.7 percent forecasted in the 2015 IRP.
- Local employers are expected to create about 320,000 total jobs between 2018 and 2037 as compared to about 297,000 jobs forecasted in the 2015 IRP, mainly driven by growth in the commercial sectors.
- Manufacturing employment is expected to decline by 0.3 percent annually on average between 2018 and 2037 due to the outsourcing of manufacturing processes to lower wage states or countries, and also due to the continuing trend of capital investments that create increases in productivity.
- An inflow of more than 590,000 new residents (by birth or migration) is expected to increase PSE's electric service territory population to more than 4.6 million by 2037, for an average annual growth rate of 0.7 percent. This is lower than the 2015 IRP forecast, which projected an average annual population growth of 0.9 percent, which would have resulted in almost 4.8 million service territory residents by 2035.

In the region, long-term growth is driven by a diverse group of employers that includes Microsoft, Amazon, Costco, REI, Boeing and Starbucks among others. Also, other prominent high technology companies are beginning to establish or have already established their presence in the Puget Sound area. Boeing's strong historical employment growth is not necessarily expected to continue, due to outsourcing and an increase in the number of planes assembled in other states.

HIGH SCENARIO OUTLOOK. For the High Electric Demand Forecast scenario, population grows by 0.8 percent annually from 2018 to 2037, and employment grows by 1.3 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Low Electric Demand Forecast scenario, population grows by 0.6 percent annually from 2018 to 2037. Employment grows 0.3 percent annually from 2018 to 2037.

Chapter 5: Demand Forecasts



The Base, High and Low population and employment forecasts for PSE's electric service area are compared in Figures 5-31 and 5-32.

Figure 5-31: Population Growth, Electric Service Area

| POPULATION GROWTH, ELECTRIC SERVICE AREA (1,000s) | | | | | | |
|---|-------|-------|-------|-------|-------|-------------------|
| Scenario | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| 2017 IRP Base Demand Forecast | 4,031 | 4,187 | 4,363 | 4,509 | 4,622 | 0.7% |
| 2017 IRP High Demand Forecast | 4,033 | 4,214 | 4,414 | 4,571 | 4,698 | 0.8% |
| 2017 IRP Low Demand Forecast | 3,961 | 4,096 | 4,250 | 4,375 | 4,471 | 0.6% |

Figure 5-32: Employment Growth, Electric Service Area

| EMPLOYMENT GROWTH, ELECTRIC SERVICE AREA (1,000s) | | | | | | |
|---|-------|-------|-------|-------|-------|-------------------|
| Scenario | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| 2017 IRP Base Demand Forecast | 2,089 | 2,156 | 2,236 | 2,320 | 2,409 | 0.8% |
| 2017 IRP High Demand Forecast | 2,193 | 2,336 | 2,476 | 2,619 | 2,784 | 1.3% |
| 2017 IRP Low Demand Forecast | 1,973 | 1,989 | 2,000 | 2,040 | 2,105 | 0.3% |



Gas Scenario Outlooks: Base, High and Low

BASE SCENARIO OUTLOOK. In the Base Gas Demand Forecast scenario, population grows by 1.0 percent annually from almost 4.2 million people in 2018 to 5 million people by 2037. Employment is expected to grow by 1.3 percent annually from 2018 to 2037.

HIGH SCENARIO OUTLOOK. For the High Gas Demand Forecast scenario, population grows by 1.1 percent annually from 2018 to 2037, and employment grows by 1.9 percent per year during that period.

LOW SCENARIO OUTLOOK. For the Low Gas Demand Forecast scenario, population grows by 0.9 percent annually from 2018 to 2037. Employment grows 0.7 percent annually from 2018 to 2037.

The Base, High and Low population and employment forecasts for PSE's gas sales service area are compared in Figures 5-33 and 5-34.

Figure 5-33: Population Growth, Gas Service Area

| POPULATION GROWTH, GAS SERVICE AREA (1,000s) | | | | | | |
|--|-------|-------|-------|-------|-------|----------------|
| Scenario | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| 2017 IRP Base Demand Forecast | 4,189 | 4,392 | 4,633 | 4,852 | 5,049 | 1.0% |
| 2017 IRP High Demand Forecast | 4,213 | 4,442 | 4,713 | 4,967 | 5,203 | 1.1% |
| 2017 IRP Low Demand Forecast | 4,155 | 4,330 | 4,541 | 4,722 | 4,887 | 0.9% |

Figure 5-34: Employment Growth, Gas Service Area

| EMPLOYMENT GROWTH, GAS SERVICE AREA (1,000s) | | | | | | |
|--|-------|-------|-------|-------|-------|----------------|
| Scenario | 2018 | 2022 | 2027 | 2032 | 2037 | AARG 2018-2037 |
| 2017 IRP Base Demand Forecast | 2,187 | 2,313 | 2,467 | 2,628 | 2,801 | 1.3% |
| 2017 IRP High Demand Forecast | 2,265 | 2,460 | 2,694 | 2,960 | 3,266 | 1.9% |
| 2017 IRP Low Demand Forecast | 2,133 | 2,200 | 2,272 | 2,354 | 2,431 | 0.7% |



Energy Prices

Retail energy prices – what customers pay for energy – are included as explanatory variables in the demand forecast models, because in the long run, they affect customer choices about the efficiency level of newly acquired appliances, how they are used, and the type of energy source used to power them. The energy price forecasts draw on information obtained from internal and external sources.

Electric Retail Prices

PSE projects that between 2018 and 2037, nominal retail electric rates will grow at an average annual rate of 2.1 percent, which is higher than the 1.1 to 1.3 percent rate increase modeled in the 2015 IRP. However, the growth of retail electric rates is expected to trail inflation rates of 2.5 percent per year.

In the near term, the retail price forecast assumes rate increases resulting from PSE's general and power cost only rate cases. Long-term retail rates were derived from PSE's internal financial model, which showed higher power costs compared to the 2015 IRP, hence the higher growth rate assumed here.

Gas Retail Prices

PSE expects nominal retail gas rates to rise between 2.8 percent and 3.1 percent per year between 2018 and 2037, depending on the customer class. This is slightly more than the long-term inflation rate of 2.5 percent. Gas prices for residential and commercial customers are higher in this forecast compared to the forecast in the 2015 IRP; interruptible and transport classes have similar or slightly higher retail rates and industrial rates are slightly lower.

Two components make up gas retail rates: the cost of gas and the cost of distribution, known as the distribution margin. The near-term forecast of gas rates includes PSE's purchased gas adjustment and general rate case considerations. Forecast gas costs reflect Kiodex gas prices for the 2016 to 2020 period as of September 18, 2015 and inflation projections beyond. The distribution margin is based on PSE's projection for the near term and inflation projections for the longer term.



Other Assumptions

Weather

The billed sales forecast is based on normal weather, defined as the average monthly weather recorded at NOAA's Sea-Tac Airport station over the 30 years ending in 2015. While the climate may change during the 20-year planning horizon, reliable forecasts for these changes are not yet available. Future IRPs will incorporate new climate information as it becomes available.

Loss Factors

The electric loss factor is 7.3 percent, compared to 6.9 percent in the 2015 IRP. The gas loss factor in this IRP is 0.5 percent, compared to 0.8 percent in the 2015 IRP.

Block Load Additions from Major Accounts

Beyond typical economic change, the demand forecast also takes into account known major load additions and deletions, using information from PSE's system planners. These adjustments add 291 MW to demand over the next 7 years for the electric system as a whole. King County has the most additions.

Block load additions are ramped into the forecast and then ramped out when population and employment have grown enough to account for these additions. This avoids double counting block load additions.

The electric forecast includes the following load additions:

- 109 MW of commercial load additions are expected between 2016 and 2018, and 67 MW between 2019 and 2022. Approximately 2.1 MWs of these additions are expected for horticultural lighting.
- Residential additions are expected to be 36 MW between 2016 and 2018, and 18 MW between 2019 and 2022.
- Expected industrial additions are 56 MW before 2019 and 5 MW between 2019 and 2022.

The gas forecast includes the following block load additions:

- 0.6 Mdth per day is added for transport customers.
- 1.5 Mdth per day is added for commercial customers.



Compressed Natural Gas Vehicles

Compressed natural gas (CNG) vehicles were added to the 2017 IRP Gas Base Demand Forecast. CNG vehicles include marine vessels, buses, light-duty vehicles, medium-duty vehicles and heavy-duty vehicles. In 2017, this adds 27.6 Mdth to the forecast. This load is expected to grow at an average annual rate of 2.0 percent, based on the Annual Energy Outlook 2015 published by the U.S. Department of Energy.

Distributed Generation/Electric Vehicles

Distributed generation, including customer-level generation via solar panels, was not included in the load forecast; this energy production is captured in the IRP scenario modeling process. Electric vehicle loads, which are expected to increase in the future, will also be treated in the IRP modeling process.

Interruptible Loads

PSE has 163 electric interruptible customers; five of these are commercial and industrial customers and 158 are schools. The school contracts limit the time of day when energy can be curtailed. The other customers represent 7 MW of coincident peak load. Since this 7 MW is so small compared to PSE's peak load, it was included in the firm load forecast. For a number of gas customers, all or part of their volume is interruptible volume. The curtailment of interruptible gas volumes was included when forecasting peak gas loads.



6

2017 PSE Integrated Resource Plan

Electric Analysis

This chapter presents the results of the electric analysis.

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1. ANALYSIS OVERVIEW

The electric analysis in the 2017 IRP followed the seven-step process outlined below. Steps 1, 3, 4 and 5 are described in detail in this chapter. Other steps are treated in more detail elsewhere in the IRP.

1. Analyze Resource Need

Three types of resource need are identified: peak capacity need, renewable need and energy need.

2. Determine Planning Assumptions and Identify Resource Alternatives

- Chapter 4 discusses the scenarios and sensitivities developed for this analysis.
- Chapter 5 presents the 2017 IRP demand forecasts.
- Appendix D describes existing electric resources and alternatives in detail.

3. Deterministic Analysis of Scenarios and Sensitivities

Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity.

- All scenarios and sensitivities were analyzed using deterministic optimization analysis.

4. Stochastic Risk Analysis

Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how the different portfolios developed in the deterministic analysis perform with regard to cost and risk across a wide range of potential future power prices, gas prices, hydro generation, wind generation, loads, plant forced outages and CO₂ prices.

- PSE analyzed eight portfolios against 250 combinations of variables in the stochastic risk analysis.

5. Analyze Results

Results of the quantitative analysis – both deterministic and stochastic – are studied to understand the key findings that lead to decisions about the resource plan forecast.

- Results of the analysis are presented in this chapter and in Appendix N.



6. Make Decisions

Chapter 2 describes the reasoning behind the strategy chosen for this resource plan forecast.

7. Commit to Action

Resource decisions are not made in the IRP. What we learn from the IRP forecasting exercise determines the Action Plan; this is “the plan” that PSE will execute against.

- The Action Plan is presented in the Executive Summary, Chapter 1.

Figure 6-1 illustrates this process.

Figure 6-1: 2017 IRP Process





2. RESOURCE NEED

For PSE, resource need has three dimensions. The first is physical: Can we provide reliable service to our customers at peak demand hours and at all hours? The second is economic: Can we meet the needs of customers across all hours cost effectively? The third is policy driven: Are there enough renewable resources in the portfolio to fulfill the state's renewable standard requirements?

Components of Physical (Peak) Need

Physical need refers to the resources required to ensure reliable operation of the system. It is an operational requirement that includes three components: customer demand, planning margins and operating reserves. The word “load” – as in “PSE must meet load obligations” – specifically refers to customer demand plus planning margins plus operating reserve obligations. The planning margin and operating reserves are amounts over and above customer demand that ensure the system has enough flexibility to handle balancing needs and unexpected events such as variations in temperature, hydro and wind generation; equipment failure; or transmission interruption with minimal interruption of service.

When we compare physical need with the peak capacity value of existing resources, the resulting gap identifies resource need. Each of these four components – customer demand, planning margins, operating reserves and existing resources – is reviewed below.

Customer Demand

PSE develops a range of demand forecasts for the 20-year IRP planning horizon using national, regional and local economic and population data.¹ Chapter 5 presents the 2017 IRP Base, Low and High Demand Forecasts, and Appendix E delivers a detailed discussion of the econometric models used to develop them.

PSE is a winter-peaking utility, so we experience the highest end-use demand for electricity when the weather is coldest. Projecting peak energy demand begins with a forecast of how much power will be used at a temperature of 23 degrees Fahrenheit at SeaTac. This is considered a normal winter peak for PSE's service territory. We also experience sustained strong demand during the summer air-conditioning season, although these highs do not reach winter peaks.

1 / The demand forecasts developed for the IRP are a snapshot in time, since the full IRP analysis takes more than a year to complete and this input is required at the outset. Forecasts are updated continually during the business year, which is why those used in acquisitions planning or rate cases may differ from the IRP.



Planning Margin

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability (LOLP). The 5 percent LOLP is an industry standard resource adequacy metric used to evaluate the ability of a utility to serve its load, and one that is used by the Pacific Northwest Resource Adequacy Forum.² Appendix N provides a detailed discussion of how PSE's Resource Adequacy Model is used to develop the planning margin.

Using the LOLP methodology, we determined that we need 123 MW of resources by 2020. In order to establish this need, we went through three steps.

1. Use PSE's resource adequacy model (RAM) to find the capacity need for the period October 2020 – September 2021. The RAM is consistent with GENESYS, the resource adequacy model used by the Northwest Power and Conservation Council (NPCC or the Council). In the NPCC's GENESYS, Colstrip 1 & 2 are retired during this time period, so Colstrip 1 & 2 were retired in RAM as well. With Colstrip 1 & 2 retired, PSE needs 503 MW of resources by December 2020.
2. Determine the planning margin for a 503 MW need, with Colstrip 1 & 2 retired. This comes to 13.5 percent.
3. Using the 13.5 percent planning margin, Colstrip 1 & 2 were added back to the 503 MW need because they do not retire until 2022, so the resulting need for October 2020 – September 2021 is 123 MW.

STEP 1: USE RAM TO FIND CAPACITY NEED. This analysis looked at the likelihood that load will exceed resources on an hourly basis over the course of a full year. Included are uncertainties around temperature impacts on loads before conservation, hydro conditions, wind, and forced outage rates (both their likelihood and duration), and uncertainties in market reliance based on the Council's regional adequacy model, GENESYS. Because of PSE's large reliance on the market, it is important that PSE's resource adequacy analysis is consistent with the regional assessment of resource adequacy. Both GENESYS and RAM use a Monte Carlo simulation that consists of 6,160 draws that model different temperature conditions, hydro conditions and thermal forced outage rate assumptions. Each of the draws and study year are consistent for both models. This analysis resulted in the need for 503 MWs of additional resources for PSE to achieve a 5 percent LOLP in the study year October 2020 – September 2021.³

² / See <http://www.nwccouncil.org/library/2008/2008-07.htm>

³ / The 503 MW need is before including additional cost-effective conservation. We need to establish resource need first, and then we determine how much of that need would cost effectively be met by conservation.



STEP 2: DETERMINE PLANNING MARGIN. Figure 6-2 shows the calculation of the planning margin to achieve the adequate level of reliability. Given that PSE has a winter peaking load, any capacity brought in to meet the planning margin in the winter is also available to meet capacity in other seasons. The 503 MW need in December 2020 was calculated with Colstrip Units 1 & 2 retired, consistent with the NPCC GENESYS assumptions. The 503 MW capacity need translates to a 13.5 percent planning margin, not including reserves.

Figure 6-2: Planning Margin Calculation

| | December 2020 w/o Colstrip 1 & 2 |
|--|----------------------------------|
| Peak Capacity Need from LOLP | 503 MW |
| Total Resources (No DSR) | 4,103 MW |
| Available Mid-C Transmissions | 1,714 MW |
| | 6,320 MW |
| Operating Reserves | (399) MW |
| | 5,921 MW |
| BPA Loss Return | (71) MW |
| Peak Need | 5,850 |
| Normal Peak Load | 5,156 |
| Planning Margin (Peak Need/Peak Load) | 13.5% |

STEP 3: DETERMINE RESOURCE NEED WITH COLSTRIP 1 & 2. Since Colstrip Units 1 & 2 do not retire till mid-2022, we add its capacity back into the calculation (that is, subtract it from the 503 MW capacity need). This results in a capacity need in December 2020 of 123 MW. See Figure 6-3, below, for peak need calculation. This is the reverse of Figure 6-2, above. In Figure 6-2, we were trying to find the planning margin. Now, we know the planning margin is 13.5 percent, so we have reversed the calculation to find the peak need.



Figure 6-3: December Peak Need in 2020, with Colstrip 1 & 2

| | December 2020 w/ Colstrip 1 & 2 |
|---|---------------------------------|
| Peak Demand | 5,153 MW |
| Planning Margin | 13.5% |
| Normal Peak Load + PM | 5,836 MW |
| Operating Reserves | 415 MW |
| Total Capacity Need | 6,251 MW |
| Total Resources (No DSR) | (4,401) MW |
| Available Mid-C Transmissions | (1,731) MW |
| Total | 119 MW |
| Operating Reserves on new resources | 15 MW |
| Total Resource Deficit/(Surplus) | 123 MW |

EFFECTIVE LOAD CARRYING CAPABILITY (ELCC). ELCC refers to the peak capacity contribution of a resource relative to that of a gas-fired peaking plant. It is calculated as the change in capacity of a generic natural gas peaking plant that results from adding a different resource with any given energy production characteristics to the system while keeping the target reliability metric constant. In this way, we can identify the capacity contribution of different resources such as wind, solar, wholesale market purchases and other energy limited resources such as batteries, demand response programs and backup fuel for thermal resources. (For a more detailed explanation of ELCC, see Appendix N, Electric Analysis.) Figure 5-4 below shows the estimated ELCC for the resources listed.



Figure 6-4: ELCC Estimates

| Resource | Nameplate (MW) | Peak Capacity Credit Based on 5% LOLP |
|--|----------------|---------------------------------------|
| Generic gas-fired generation | 239 MW | 100% |
| Existing Wind | 823 | 11% |
| Skookumchuck (DNV GL data ⁴) | 131 | 40% |
| Generic Montana Wind (DNV-GL data) | 100 | 49% |
| Generic Washington Wind (DNV-GL data) | 100 | 16% |
| Generic Offshore Washington Wind (DNV-GL data) | 100 | 51% |
| Market Reliance | 1,580 | 99% |
| Generic Washington Solar | 50 | 0% |

| Resource | Nameplate (MW) | Peak Capacity Credit Based on EUE at 5% LOLP ¹ |
|---|----------------|---|
| Batteries | | |
| Lithium-ion, 2hr, 25 MW max per hour | 25 | 60% |
| Lithium-ion, 4hr, 25 MW max per hour | 25 | 88% |
| Flow Battery, 4hr, 25 MW max per hour | 25 | 76% |
| Demand Response | | |
| 3hr duration, called every other 6 hours ² | 100 | 77% |

NOTE

1. Since batteries and demand response are energy-limited resources, using the loss of load probability metric does not capture the frequency, magnitude and duration of outages. For these resources, PSE uses expected unserved energy (EUE) to appropriately capture the risks associated with these resources.
2. Peak capacity credit of for demand response is applicable for incentive-based demand response such as direct load control (DLC) and third-party curtailment. In the IRP, this number was applied to both incentive-based and price-based programs.

⁴ / PSE contracted with DNV GL for sets of stochastic wind outputs from these locations, which PSE used as an input to its ELCC analysis. DNV GL did not calculate the peak capacity credits, but provided PSE with inputs to preform that analysis. Please refer to Appendix M for the DNV GL study.



Although a generic wind project could be located in many parts of the Northwest,⁵ a southeast Washington wind location was chosen as the generic wind for this IRP. Good historical wind data exists for the area, PSE already owns development rights at the Lower Snake River site, and transmission to the grid already exists in this location. Comparison of improvements in the ELCC for other wind sites must account for the incremental transmission costs required to connect the site to the regional grid.

Operating Reserves

North American Electric Reliability Council (NERC) standards require that utilities maintain “capacity reserves” in excess of end-use demand as a contingency in order to ensure continuous, reliable operation of the regional electric grid. PSE’s operating agreements with the Northwest Power Pool, therefore, require the company to maintain two kinds of operating reserves: contingency reserves and regulating reserves.

CONTINGENCY RESERVES. In the event of an unplanned outage, NWPP members can call on the contingency reserves of other members to cover the resource loss during the 60 minutes following the outage event.

The Federal Energy Regulatory Commission (FERC) approved a rule that affects the amount of contingency reserves PSE must carry – Bal-002-WECC-1 – which took effect on October 1, 2014. The rule requires PSE to carry reserve amounts equal to 3 percent of online generating resources (hydro, wind and thermal) plus 3 percent of load to meet contingency obligations. The terms “load” and “generation” in the rule refer to the total net load and all generation in PSE’s Balancing Authority (BA).

BALANCING AND REGULATING RESERVES. Utilities must also have sufficient reserves available to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves do not provide the same kind of short-term, forced-outage reliability benefit as contingency reserves, which are triggered only when certain criteria are met. Balancing reserves must be resources with the ability to ramp up and down instantaneously as loads and resources fluctuate each hour.⁶

For PSE, the amount of reserves needed for the December peak is 128 MW. This is calculated as the difference between the day ahead schedule and the actuals. Regulation looks at the 5-minute

⁵ / PSE examined the incremental capacity equivalent of a central Washington wind project in the 2011 IRP.

⁶ / System flexibility needs are discussed in more detail in Appendix H, Operational Flexibility.



changes in generation and balancing looks at the 10-minute changes in generation. A full description of how this number was calculated can be found in Appendix H, Operational Flexibility.

Existing Resources

Figure 6-5 summarizes the winter peak capacity values for PSE's existing supply-side resources.

*Figure 6-5: Existing Supply-side Resources
Nameplate Capacity and Winter Peak Capacity for December 2018*

| Type of Generation | Nameplate Capacity (MW) | Winter Peak Capacity (MW) |
|------------------------------------|-------------------------|---------------------------|
| Hydro | 973 | 853 |
| Colstrip | 677 | 658 |
| Natural Gas | 1,905 ¹ | 2,061 |
| Renewable Resources | 956 ² | 143 |
| Contracts | 614 | 695 |
| Available Mid-C Transmission | 2,331 | 1,722 |
| Total Supply-side Resources | 7,456 | 6,132 |

NOTES

1. The nameplate capacity for the natural gas units is based on the net maximum capacity that a unit can sustain over 60 minutes when not restricted to ambient conditions. Natural gas plants are more efficient in colder weather, so the winter peak capacity at 23 degrees F is higher than the nameplate capacity.
2. Includes Klondike III (50 MW) and Skookumchuck (131 MW) as a wind resource.

For the winter months of 2016, PSE is currently forecast to have a total of 1,881 MW of BPA transmission capacity and 450 MW of owned transmission capacity, for a total of 2,331 MW. A portion of the capacity, 609 MW, is allocated to long-term contracts and existing resources such as PSE's portion of the Mid-C hydro projects. This leaves 1,722 MW of capacity available for short-term market purchases. The specific allocation of that capacity as of December 2018 is listed below in Figure 6-6. The capacities and contract periods for the various BPA contracts are reported in Appendix D, and PSE's forecast Mid-C peak transmission capacities are included as part of the resource stack in Figure 6-7, Electric Peak Capacity Need.

Figure 6-6: PSE Mid-C Transmission Capacity as of December 2016

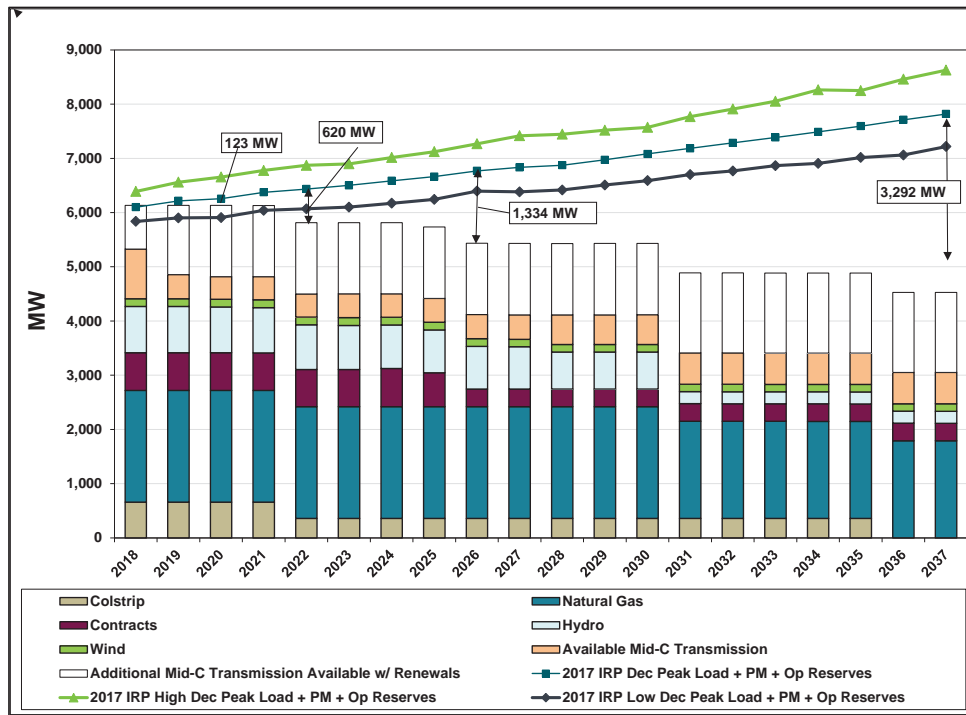
| | Winter Peak Capacity (MW) |
|---|---------------------------|
| Total Mid-C Transmission | 2,331 |
| Allocated to Long-term Resources & Contracts | (609) |
| Available for short-term wholesale market purchases | 1,722 |



Peak Capacity Need

Figure 6-7 shows the physical reliability (peak) need for the three demand scenarios modeled in this IRP. Before any additional demand-side resources, peak capacity need in the Base Demand Forecast plus reserves is almost 620 MW by 2022 and over 3,200 MW by the end of the planning period. This picture differs from Figure 1-1 in Chapter 1, because it includes no demand-side resources past the study period's start date. One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan, and to accomplish this it is necessary to start with peak need forecasts that do not include forward projections of conservation savings.

Figure 6-7: Electric Peak Capacity Need
(Physical Reliability Need, Peak Hour Need Compared with Existing Resources)





NOTE: The physical characteristics of the electric grid are very complex, so for planning purposes we simplify physical resource need into a peak hour capacity metric using PSE's Resource Adequacy Model. The RAM analysis produces reliability metrics that allow us to assess physical resource adequacy risk; these include LOLP (loss of load probability), EUE (expected unserved energy) and LOLH (loss of load hours). We can simplify physical resource need in this way because PSE is much less hydro-dependent than other utilities in the region, and because resources in the IRP are assumed to be available year-round. If PSE were more hydro-dependent, issues like the sustained peaking capability of hydro and annual energy constraints could be important; likewise, if seasonal resources or contracts were contemplated, supplemental capacity metrics may be appropriate to ensure adequate reliability in all seasons.

Energy Need

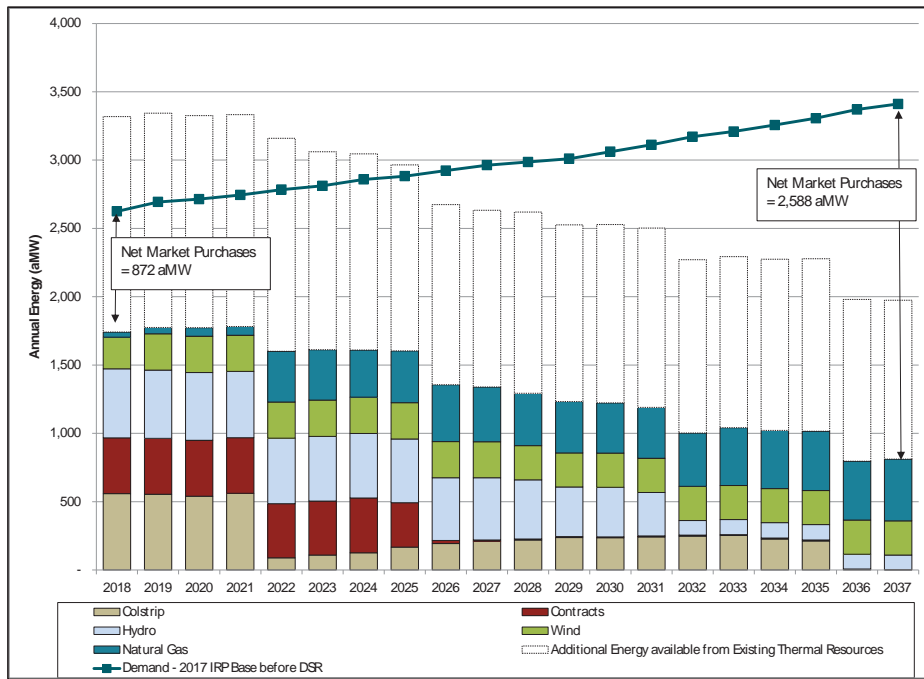
Compared to the physical planning constraints that define peak resource need, meeting customers' "energy need" for PSE is more of a financial concept that involves minimizing costs. Portfolios are required to cover the amount of energy needed to meet physical loads, but our models also examine how to do this most economically.

Unlike utilities in the region that are heavily dependent on hydro, PSE has thermal resources that can be used to generate electricity if needed. In fact, PSE could generate significantly more energy than needed to meet our load on an average monthly or annual basis, but it is often more cost effective to purchase wholesale market energy than to run our high-variable cost thermal resources. We do not constrain (or force) the model to dispatch resources that are not economical; if it is less expensive to buy power than to dispatch a generator, the model will choose to buy power in the market. Similarly, if a zero (or negative) marginal cost resource like wind is available, PSE's models will displace higher-cost market purchases and use the wind to meet the energy need.



Figure 6-8 illustrates the company's energy position across the planning horizon, based on the energy load forecasts and economic dispatches of the 2017 IRP Base Scenario presented in Chapter 4, Key Analytical Assumptions. The white box at the top of the stack, "Additional Energy Available from Existing Thermal Resources," indicates the total energy available from PSE's thermal resources regardless of economic dispatch.

Figure 6-8: Annual Energy Position
Resource Economic Dispatch from Base Scenario





Renewable Need

Washington State's renewable portfolio standard (RPS) requires PSE to meet specific percentages of our load with renewable resources or renewable energy credits (RECs) by specific dates. The main provisions of the statute (RCW 19.285) are summarized below.

Washington State RPS Targets

Renewable resources must comprise:

- 3 percent of supply-side resources by 2012
- 9 percent of supply-side resources by 2016
- 15 percent of supply-side resources by 2020

PSE has sufficient qualifying renewable resources to meet RPS requirements until 2022, including the ability to bank RECs. Existing hydroelectric resources may not be counted towards RPS goals except under certain circumstances for new run of river plants and efficiency upgrades.

MATURING RESOURCES. PSE continues to monitor emerging resources that may develop effective utility applications. This IRP incorporates renewable resources such as battery storage, distributed solar generation and utility-scale solar. The results of these analyses are discussed later in this chapter.

RENEWABLE RESOURCES INFLUENCE SUPPLY-SIDE RESOURCE DECISIONS. Adding intermittent resources to the portfolio increases the need for stand-by backup generation that can be turned on and off or adjusted up or down quickly. The amount of electricity supplied to the system by intermittent renewable resources drops off when the wind or sun ramp down, but customer need does not, therefore, as the amount of intermittent resources in the portfolio increases, so does the need for reliable backup generation.

DEMAND-SIDE ACHIEVEMENTS AFFECT RENEWABLE AMOUNTS. Washington's renewable portfolio standard calculates the required amount of renewable resources as a percentage of megawatt hour (MWh) sales; therefore, if MWh sales decrease, so does the amount of renewables we need. Achieving demand-side resources (DSR) targets has precisely this effect: DSR decreases sales volumes, which then decreases the amount of renewable resources needed.

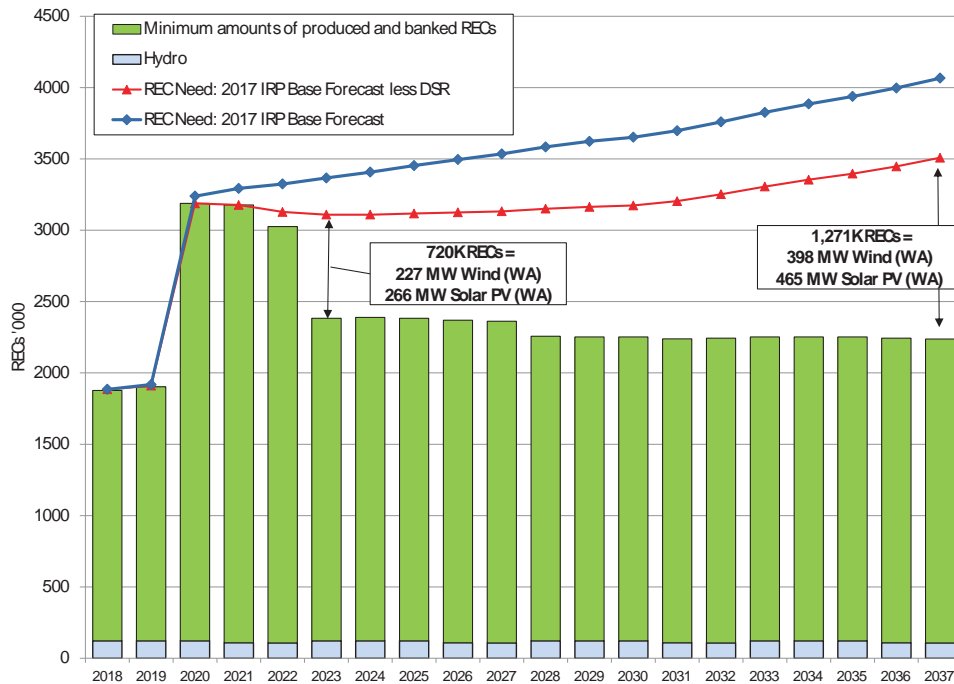


REC Banking Provision

Washington’s renewable portfolio standard allows for REC banking. Unused RECs can be banked forward one year or can be borrowed from one year in the future. In this IRP, PSE assumes that the company would employ a REC banking strategy that would push the need for additional RECs further into the future.

Figure 6-9 illustrates the need for renewable energy – wind or solar – after accounting for REC banking and the savings from demand-side resources that were found cost effective for the 2017 IRP.

Figure 6-9: REC Need Based on Achievement of All Cost-effective DSR





3. ASSUMPTIONS AND ALTERNATIVES

The scenarios, sensitivities and resource alternatives used in the electric analysis are summarized here for convenience.⁷

Scenarios and Sensitivities

Scenarios enable us to test how resource portfolio costs and risks respond to changes in economic conditions, environmental regulation, natural gas prices and energy policy. Sensitivities start with the Base Scenario assumptions and change one resource; this allows us to isolate the effect of an individual resource on the portfolio, so that we can consider how different combinations of resources would affect costs, cost risks and emissions.

⁷ / Chapter 4 presents the scenarios and sensitivities developed for this IRP analysis and discusses in detail the key assumptions used to create them, including customer demand, natural gas prices, possible carbon dioxide (CO₂) prices, resource costs (both demand-side and supply-side) and power prices. Appendix D presents a detailed discussion of existing electric resources and resource alternatives.



Figure 6-10: 2017 IRP Scenarios

| | Scenario Name | Demand | Gas Price | CO ₂ Price |
|----|--|--------|-----------|---|
| 1 | Base Scenario | Mid | Mid | Mid |
| 2 | Low Scenario | Low | Low | Low |
| 3 | High Scenario | High | High | High |
| 4 | High + Low Demand | Low | High | High |
| 5 | Base + Low Gas Price | Mid | Low | Mid |
| 6 | Base + High Gas Price | Mid | High | Mid |
| 7 | Base + Low Demand | Low | Mid | Mid |
| 8 | Base + High Demand | High | Mid | Mid |
| 9 | Base + No CO ₂ | Mid | Mid | None |
| 10 | Base + Low CO ₂ w/ CPP | Mid | Mid | Low + CPP |
| 11 | Base + High CO ₂ | Mid | Mid | High |
| 12 | Base + Mid CAR only (electric only) | Mid | Mid | Mid CAR only |
| 13 | Base + CPP only (electric only) | Mid | Mid | CPP only |
| 14 | Base + All-thermal CO ₂ (electric only) | Mid | Mid | CO ₂ price applied to all thermal resources in the WECC (baseload and peakers) |



Fig 6-11: 2017 IRP Portfolio Sensitivities

| Sensitivities | | Alternatives Analyzed |
|---|--|---|
| ELECTRIC ANALYSIS | | |
| A | Colstrip How do different retirement dates affect decisions about replacing Colstrip resources? | <i>Baseline – Retire Units 1 & 2 mid-2022, Units 3 & 4 remain in service into 2035.</i> 1. Retire Units 1 & 2 in 2018 2. Retire Units 3 & 4 in 2025 3. Retire Units 3 & 4 in 2030 |
| B | Thermal Retirement Would it be cost effective to accelerate retirement of PSE's existing gas plants? | <i>Baseline – Optimal portfolio from the Base Scenario</i> Retire baseload gas plants early. |
| C | No New Thermal Resources What would it cost to fill all future need with resources that emit no carbon? | <i>Baseline – Fossil fuel generation is an option in the optimization model.</i> Renewable resources, energy storage and DSR are the only options for future resources. |
| D | Stakeholder-requested Alternative Resource Costs What if capital costs of resources are different than the base assumptions? | <i>Baseline – PSE cost estimate for generic supply-side resources</i> 1. Lower cost for recip peakers 2. Higher thermal capital costs 3. Lower wind and solar development costs 4. Apply more aggressive solar cost curve. |
| E | Energy Storage What is the cost difference between a portfolio with and without energy storage? | <i>Baseline – Batteries and pumped hydro included only if chosen economically.</i> 1. Add 50 MW battery in 2023 instead of economically chosen peaker. 2. Add 50 MW pumped hydro storage in 2023 instead of economically chosen peaker. |
| F | Renewable Resources + Energy Storage Does bundling renewable resources with energy storage change resource decisions? | <i>Baseline – Evaluate renewable resources and energy storage as individual resources in the analysis.</i> Bundle 50 MW battery + 200 MW solar |
| G | Electric Vehicle Load How much does electric vehicle charging affect the resource plan? | <i>Baseline – IRP Base Demand Forecast</i> Add the forecasted electric vehicle load. |
| DEMAND-SIDE RESOURCES (CONSERVATION) | | |
| H | Demand-side Resources (DSR) How much does DSR reduce cost, risk and emissions? | <i>Baseline – All cost-effective DSR per RCW 19.285 requirements</i> No DSR. All future needs met with supply-side resources. |
| I | Extended DSR Potential What if future DSR measures extend conservation periods through the second decade of the study period? | <i>Baseline – All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.</i> Assume future DSR measures will extend conservation benefits to the following 10-year period. |
| J | Alternate Residential Conservation Discount Rate How would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation? | <i>Baseline: Assume the base discount rate.</i> Apply a societal discount rate to residential conservation savings to examine whether changing the discount rate for conservation impacts cost effectiveness of conservation. |

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| | Sensitivities | Alternatives Analyzed |
|--------------------------|---|--|
| ELECTRIC ANALYSIS | | |
| WIND RESOURCES | | |
| K | RPS-eligible Montana Wind ¹ What is the cost difference between a portfolio with "regular" Montana wind and RPS-eligible Montana wind? | <i>Baseline – Montana wind included only if chosen economically by the analysis.</i> 1. Add RPS-eligible Montana wind in 2023 instead of solar 2. Montana wind tipping point analysis to determine how close it is to being cost effective compared to other resources to being cost effective |
| L | Offshore Wind Tipping Point Analysis How much would costs of offshore wind need to decline before it appears to be a cost-effective resource? | <i>Baseline – Base Scenario portfolio</i> Offshore wind tipping point analysis to determine how close it is to being cost effective compared to other cost-effective resources. |
| M | Hopkins Ridge Repowering ² Would repowering Hopkins Ridge for the tax incentives and bonus RECs be cost effective? | <i>Baseline – Hopkins Ridge repowering is not included in the portfolio.</i> Include Hopkins Ridge repowering in the portfolio to replace the current facility. |

NOTES

1. Montana wind is not currently an RPS-eligible resource; however, PSE has asked BPA under what conditions it could be qualified as an RPS-eligible resource.

2. Repowering refers to refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015. This sensitivity captures the impact of tax credit incentives and increased operating efficiency on cost.



Cost of Carbon Abatement Alternatives Analyzed

In this IRP, we examined several alternatives for reducing the greenhouse gas emissions. The purpose of this analysis was to estimate a supply curve for carbon abatement. The curve presents different carbon reduction alternatives and how much carbon reductions are achieved at various costs.

Figure 6-12: Carbon Abatement Alternatives Analyzed

| COST OF CARBON ABATEMENT ALTERNATIVES ANALYZED | | |
|--|--|---|
| <i>PSE Portfolio Alternatives</i> | | |
| A | Additional Wind | Add 300 MW of wind beyond RPS requirements. |
| B | Additional Utility-scale Solar | Add 300 MW of utility-scale solar beyond RPS requirements. |
| C | Additional Electric Conservation – Incremental | Increase conservation by 2 bundles relative to least-cost portfolio. |
| D | Additional Electric Conservation – All | Increase conservation to incorporate the entire conservation potential assessment available at any cost. |
| E | Cost-effective Electric DSR | Impact of acquiring all cost-effective electric conservation. |
| <i>Policy Alternatives</i> | | |
| F | 50% RPS in Washington | Increase Washington RPS to 50% by 2040. |
| G | CAR Cap on Washington CCCT plants | Reduce the emissions of the CCCT plants in Washington to comply with the Washington Clean Air Rule CO ₂ emission baseline. |
| H | Early Colstrip 3 & 4 Retirement | Retire Colstrip 3 & 4 in 2025, rather than 2035, replacing it with the least-cost resources. |
| <i>Gas Utility Alternatives</i> | | |
| I | Additional Gas Conservation – Incremental | Increase conservation by 2 bundles relative to least-cost portfolio. |
| J | Additional Gas Conservation – All | Increase conservation to incorporate the entire conservation potential assessment available at any cost. |
| K | Cost-effective Gas DSR | Impact of acquiring all cost-effective gas conservation. |



Available Resource Alternatives

Existing resources and resource alternatives are described in detail in Appendix D.

Supply-side Resources

SHORT-TERM WHOLESALE MARKET PURCHASES. PSE relies on short-term wholesale market purchases for both peak capacity and energy. The short-term market purchases use the transmission contracts with Bonneville Power Administration to carry electricity from contracted wholesale market purchases to PSE's service territory. A more detailed discussion of the wholesale market is included in Appendix G.

BASELOAD GAS (CCCTS). F-type, 1x1 engines with wet cooling towers are assumed to generate 335 MW plus 50 MW of duct firing and be located in PSE's service territory.

PEAKERS (FRAME PEAKERS). F-type, wet-cooled turbines are assumed to generate 228 MW and located in PSE's service territory. They are modeled with 48 hours of oil backup and no firm pipeline capacity.

PEAKERS (AERO PEAKERS). The 2-turbine design with wet cooling is assumed to generate a total of 203 MW and to be located in PSE's service territory. They are modeled with 48 hours of oil backup and no firm pipeline capacity.

PEAKERS (RECIP PEAKERS). This 12-engine design (18.3 MW each) with wet cooling is assumed to generate a total of 220 MW and to be located in PSE's service territory. They are modeled with 48 hours of oil backup and no firm pipeline capacity. It is not clear if these units could meet emission thresholds for fine particulate matter in PSE's service territory, but they were modeled as being available to determine if follow-up on that issue is warranted.

WIND. Wind was modeled in southeast Washington, central Montana and offshore of the Washington coast. Southeast Washington wind is assumed to have a capacity factor of 30 percent. Montana wind is assumed to be located east of the continental divide and have a capacity factor of 46 percent. Offshore wind is assumed to have a capacity factor of 34 percent.



SOLAR. Utility-scale solar PV is assumed to be located in eastern Washington, use a tracking system, and have a capacity factor of 27 percent.

ENERGY STORAGE. Two energy storage technologies are modeled: batteries and pumped hydro. Two generic battery resources are modeled, lithium-ion batteries and flow batteries. Pumped hydro resources are generally large, on the order of 400 MW to 3,000 MW. This analysis assumes PSE would split the output of a pumped hydro storage project with other interested parties.

Demand-side Resources

ENERGY EFFICIENCY MEASURES. This label is used for a wide variety of measures that result in less energy being used to accomplish a given amount of work. These measures often focus on retrofitting programs and new construction codes and standards and include measures like appliance upgrades, building envelope upgrades, heating and cooling systems and lighting changes.

DEMAND RESPONSE. Demand response resources are flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.

DISTRIBUTED GENERATION. Distributed generation refers to small-scale electricity generators (like rooftop solar panels) located close to the source of the customer's load.

DISTRIBUTED EFFICIENCY (VOLTAGE REDUCTION AND PHASE BALANCING). Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy consumption. Phase balancing eliminates total current flow losses that can reduce energy loss.

GENERATION EFFICIENCY. Energy efficiency improvements at PSE generating plant facilities.

CODES AND STANDARDS. No-cost energy efficiency measures that work their way to the market via new efficiency standards. These originate from federal and state codes and standards.



4. TYPES OF ANALYSIS

PSE uses deterministic optimization analysis to identify the lowest reasonable cost portfolio for each scenario. We then run a stochastic risk analysis to test different resource strategies.⁸

DETERMINISTIC PORTFOLIO OPTIMIZATION ANALYSIS. All scenarios and sensitivities are subjected to deterministic portfolio analysis in the first stage of the resource plan analysis. This identifies the least-cost integrated portfolio – that is, the lowest cost mix of demand-side and supply-side resources that will meet need under the given set of static assumptions defined in the scenario or sensitivity. This stage helps us to learn how specific input assumptions, or combinations of assumptions, can impact the least-cost mix of resources.

STOCHASTIC RISK ANALYSIS. In this stage of the resource plan analysis, we examine how different resource strategies respond to the types of risk that go hand-in-hand with future uncertainty. We deliberately vary the inputs that were static in the deterministic analysis to create simulations called “draws,” and analyze the different portfolios. This allows us to learn how different strategies perform with regard to cost and risk across a wide range power prices, gas prices, hydro generation, wind generation, loads, plant forced outages and CO₂ prices.

Deterministic Portfolio Optimization Analysis

Deterministic analysis helps to answer the question: How will different resource alternatives dispatch to market given the assumptions that define each of the scenarios and sensitivities? All of PSE’s existing resources are modeled, plus all of the generic resource alternatives.

⁸ / To screen some resources, we also use simpler, levelized cost analysis to determine if the resource is close enough in cost to justify spending the additional time and computing resources to include it in the two-step portfolio analysis.

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Four analytical tools are used during this stage of the analysis: AURORA, PLEXOS, the Portfolio Screening Model III (PSM III) and Frontline System's Risk Solver Platform.

The initial AURORA input price run produces:

1. **Annual Energy Estimates (MWh).** This is the sum of the total energy produced by each resource for the entire year.
2. **Annual Variable Cost Estimates (\$000).** This includes fuel price plus variable pipeline charges, fuel use and taxes; variable operations and maintenance (O&M) cost; variable transmission cost; start-up costs; any emissions cost where applicable; and PPA costs.
3. **Annual Revenue (\$000) Estimates.** This is the revenue that a resource produces when its excess energy production is sold into the market.
4. **CO₂ Emissions Estimates (tons).** For tracking total emissions in the portfolio.

PLEXOS is a production cost model similar to AURORA, but PLEXOS has the ability to do a sub-hourly dispatch of resources to meet all of PSE's load and reserve requirements. PLEXOS can perform a day-ahead simulation for unit commitment and a real-time simulation to re-dispatch resources to meet sub-hourly changes in demand and supply. PLEXOS is used to do a 5-minute dispatch for one (1) year to answer the following questions.

1. Does PSE have adequate capability to ramp resources up and down?
2. When new resources are added to the portfolio, what benefits do they have and do they help to reduce the operating cost of the portfolio?

A full discussion of the operational flexibility analysis can be found in Appendix H. The analysis resulted in a portfolio cost reduction by adding in different resources to the portfolio. The portfolio cost reduction was then divided by the size of the resource to get a \$/kW-yr. For example, adding a 25 MW 4-hour flow battery had a benefit of \$117/kW-yr. This benefit was input into the PSM model as a cost reduction for the resource. Figure 6-13 below shows the results of the operational flexibility analysis. The inputs to the PSM model are highlighted in green. Most of the benefits come from the day-ahead simulation. For thermal plants, the day-ahead benefits are captured in the AURORA portfolio analysis. For storage resources, the PLEXOS analysis captures and incorporates day-ahead and real-time benefits. The real-time vs. day-ahead difference isolates the benefits associated with flexibility.



Figure 6-13: Flexibility Benefit

| IRP Resource | Annual Variable Cost Savings (\$/kW-yr) | RT vs. DA Variable cost savings (\$/kW-yr) |
|----------------------|---|--|
| CCCT | (\$46) | - |
| Frame Peaker | (\$26) | (\$1) |
| Aero Peaker | (\$56) | (\$7) |
| Recip Peaker | (\$97) | (\$11) |
| 2-hr Li-Ion Battery | (\$119) | (\$3) |
| 4-hr Li-Ion Battery | (\$131) | (\$8) |
| 4-hr Flow Battery | (\$117) | (\$2) |
| 6-hr Flow Battery | (\$128) | (\$7) |
| Pumped Storage Hydro | (\$144) | (\$10) |

The Portfolio Screening Model III (PSM III) is a spreadsheet-based capacity expansion model that the company developed to evaluate incremental costs and risks of a wide variety of resource alternatives and portfolio strategies. This model produces the least-cost mix of resources using a linear programming, dual-simplex method that minimizes the present value of portfolio costs subject to planning margin and renewable portfolio standard constraints.

The solver used for the linear programming optimization is Frontline System's Risk Solver Platform. This is an excel add-in that works with PSM III. Incremental cost includes: 1) the variable fuel cost and emissions for PSE's existing fleet, 2) the variable cost of fuel emissions and operations and maintenance for new resources, 3) the fixed depreciation and capital cost of investments in new resources, 4) the booked cost and offsetting market benefit remaining at the end of the 20-year model horizon (called the "end effects"), and 5) the market purchases or sales in hours when resource-dispatched outputs are deficient or surplus to meet PSE's need.



The primary input assumptions to the PSM III are:

- PSE's peak and energy demand forecasts,
- PSE's existing and generic resources, their capacities and outage rates,
- expected dispatched energy (MWh), variable cost (\$/MWh) and revenue (\$/MWh) from AURORAXmp for existing contracts and existing and generic resources,
- capital and fixed-cost assumptions of generic resources,
- financial assumptions such as cost of capital, taxes, depreciation and escalation rates,
- capacity contributions and planning margin constraints, and
- renewable portfolio targets.

A mathematical representation of PSM III can be found in Appendix N, Electric Analysis.

Stochastic Risk Analysis

With stochastic risk analysis, we test the robustness of different portfolios. In other words, we want to know how well the portfolio might perform under a range of different conditions. The goal is to understand the risks of different candidate portfolios in terms of costs and revenue requirements. This involves identifying and characterizing the likelihood of bad events and the likely adverse impacts they may have on a given portfolio.

For this purpose, we take the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and run them through 250 draws⁹ that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO₂ regulations/prices. From this analysis, we can observe how risky the portfolio may be and where significant differences occur when risk is analyzed. For example, in the deterministic analysis for this IRP, the first renewable build under the Base Demand Forecast is in 2023 (Figure 6-12: Renewable need). When we perform the stochastic analysis with varying loads and wind generation, we find it is most likely that we will need the new renewable generation in 2022 to make sure we remain in compliance with RCW 19.285.

⁹ / Each of the 250 simulations is for the twenty-year IRP forecasting period, 2018 through 2037.

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ANALYSIS TOOLS. A Monte Carlo approach is used to develop the stochastic inputs. Monte Carlo draws of inputs are used to generate a distribution of resource outputs (dispatched to prices and must-take power), costs and revenues from AURORAxmp. These distributions of outputs, costs and revenues are then used to perform risk simulations in the PSM III model where risk metrics for portfolio costs and revenue requirements are computed to evaluate candidate portfolios. Appendix N, Electric Analysis, includes a full description of how PSE developed the stochastic inputs.



5. KEY FINDINGS

The quantitative results produced by this extensive analytical and statistical evaluation led to the following key findings. These are summarized below and discussed in more detail in the following pages.

Scenarios

1. **PORTFOLIO BUILDS.** Portfolio additions across scenarios are very similar. The most common differences were whether battery storage or gas-fired generation is added to meet the first resource need, and which type of gas-fired generation was selected, peakers or baseload plants, in the latter part of the study period.
2. **EMISSIONS.** Emissions results vary across portfolios, with the economic dispatch of coal generation as the primary factor that differentiates results.
3. **COST OF CAPACITY.** Market conditions affect the net cost of peakers vs. baseload plants, not resource need. The value of flexibility and avoided transmission and distribution (T&D) costs affect the net cost of energy storage resources.
4. **BACKUP FUEL CAPACITY.** 48 hours of oil backup for the peakers is sufficient to meet winter demand.
5. **RENEWABLES.** RPS requirements and load forecasts drive renewable builds.
6. **WIND VS. SOLAR.** In this IRP, the cost of utility-scale solar dropped so much that it became more cost-effective than wind.



Sensitivities

- A. COLSTRIP.** Carbon regulation that adds dispatch cost will challenge the economics of Colstrip.
- B. THERMAL RETIREMENT.** The retirement of PSE's existing baseload gas plants in 2030 will be driven by how carbon tax regulation is implemented. In the case where the carbon tax is applied only to baseload plants and not to the alternative resources (frame peakers), there is a minimal benefit to shutting some of the baseload plants early. However, if the carbon tax is applied to both baseload and peaking plants, there is no longer a benefit to shutting the baseload plants early.
- C. NO NEW THERMAL RESOURCES.** If PSE added only renewable and energy storage resources to the portfolio in the future, the only resource large enough to replace the capacity is pumped hydro storage. Solar would be replaced by Montana wind, and frame peakers would be replaced by pumped hydro storage.
- D. STAKEHOLDER-REQUESTED ALTERNATIVE RESOURCE COSTS.** Changing the resource cost assumptions does not change the optimal portfolio, it just changes the cost of the portfolio.
- E. ENERGY STORAGE.** Batteries and pumped hydro storage are higher cost than traditional peaking plants, but energy storage can provide valuable flexibility. When its flexibility benefit is combined with avoided T&D costs, battery technology becomes a cost-competitive resource because it is more scalable than thermal resources.
- F. RENEWABLE RESOURCES + ENERGY STORAGE.** Combining renewable resources and energy storage results in tax credits that reduce cost, but the flexibility and T&D benefits that are gained from separating battery storage and renewable resources are greater than the cost reductions captured by combining them.
- G. ELECTRIC VEHICLE LOAD.** By 2035, electric vehicles could increase the peak demand by 230 MW, roughly equivalent to one frame peaker.



Demand-side Resources

- H. **DEMAND-SIDE RESOURCES.** Energy efficiency and other demand-side resources are consistently cost effective and reduce risk. The level of cost-effective DSR varies little across scenarios.
- I. **EXTENDED DSR POTENTIAL.** Extending the DSR potential to maintain the same level of achievement for the entire 20 years does not change the cost-effective amount of DSR chosen, but it does reduce the number of peakers built by 2037 by one peaker.
- J. **ALTERNATE RESIDENTIAL CONSERVATION DISCOUNT RATE.** Changing the residential discount rate does not change the cost-effective amount of DSR chosen.

Wind Resources

- K. **RPS-ELIGIBLE MONTANA WIND.** Based on current assumptions, Montana wind is not expected to be cost effective because of transmission cost. Given the solar cost curve assumptions, even if Montana wind is eligible for the Washington RPS, Washington solar is more cost effective than wind.
- L. **OFFSHORE WIND TIPPING POINT ANALYSIS.** Offshore wind capital costs would have to drop by 73 percent to become a cost-competitive resource.
- M. **HOPKINS RIDGE REPOWERING.** The analysis indicates that repowering Hopkins Ridge would add \$40 million in costs. Based on these results, PSE would not move forward with the repowering of this wind facility.

Carbon Abatement Cost Curve

This analysis focuses on investigating overall WECC-wide impacts of different policies aimed at carbon abatement. This perspective allows the overall effectiveness of such policies to be examined. Policies that affect the economic operation of carbon-emitting resources in one part of the WECC can affect neighboring areas through adjusted interchange transactions. In other words, disincentivizing carbon emissions in one region can make imports from regions without carbon abatement policies more attractive.



6. SCENARIO ANALYSIS RESULTS

Portfolio Builds

The portfolio builds for all scenarios look very much alike since resource alternatives are so limited. Small variations occurred due to load variations in the high and low load forecasts, but the similarities are striking. The main difference was the type of gas-fired generation chosen. Baseload gas plants were selected as lower cost in some scenarios, while frame peakers were selected as lower cost in others. Also, in the High and Base + High Gas Scenarios, solar was cheaper than market due to such high gas and carbon prices, so in these scenarios, it was necessary to constrain solar to 500 MW. If solar did become cheaper than market, independent power producers would rush to build resources, driving up costs in many segments of the supply chain and causing solar costs to go up – a key assumption that was not reflected in our modeling. Additionally, as PSE’s resources could greatly exceed load, PSE would have to adopt an energy planning standard to ensure the company operates as a utility rather than a wholesale power marketer. That is, that we add resources to meet the needs of customers, rather than taking a speculative position in the energy market. Figure 6-14 summarizes resource additions and net present value of portfolio costs across all 14 scenarios.

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*Figure 6-14: Relative Optimal Portfolio Builds and Costs by Scenario
(Cumulative nameplate capacity for each resource addition, in MW by 2037)
Dollars in billions, NPV including end effects*

| | | NPV | DR | DSR | Trans. Redirect | CCCT | Peaker | Solar | MT Wind for RPS | Energy Storage |
|----|--|---------|-----|-----|--------------------|-------|--------|-------|--------------------|-------------------|
| 1 | Base | \$11.98 | 58 | 714 | 188 | - | 1,975 | 486 | - | 50 |
| 2 | Low | \$8.61 | 67 | 658 | 188 | 413 | 1,255 | 369 | - | 50 |
| 3 | High | \$15.40 | 148 | 728 | 188 | - | 2,875 | 500 | 300 | 50 |
| 4 | High + Low Demand | \$11.77 | 67 | 714 | 188 | - | 1,575 | 500 | - | 91 |
| 5 | Base + Low Gas Price | \$10.77 | 67 | 658 | 188 | - | 1,982 | 504 | - | 108 |
| 6 | Base + High Gas Price | \$13.27 | 157 | 714 | 188 | - | 1,735 | 500 | 300 | 76 |
| 7 | Base + Low Demand | \$10.70 | 58 | 714 | 188 | - | 1,575 | 351 | - | 102 |
| 8 | Base + High Demand | \$13.75 | 157 | 714 | 188 | - | 3,003 | 351 | - | 75 |
| 9 | Base + No CO2 | \$10.45 | 148 | 714 | 188 | 1,652 | 257 | 484 | - | 100 |
| 10 | Base + Low CO2 w/ CPP | \$11.93 | 58 | 714 | 188 | - | 1,975 | 490 | - | 50 |
| 11 | Base + High CO2 | \$11.98 | 58 | 714 | 188 | - | 1,975 | 490 | - | 50 |
| 12 | Base + Mid CAR only (electric only) | \$10.73 | 157 | 714 | 188 | - | 1,859 | 486 | - | 91 |
| 13 | Base + CPP only (electric only) | \$11.87 | 58 | 714 | 188 | - | 1,975 | 486 | - | 50 |
| 14 | Base + All- thermal CO2 (electric only) | \$12.66 | 157 | 714 | 188 | 826 | 1,026 | 486 | - | 100 |

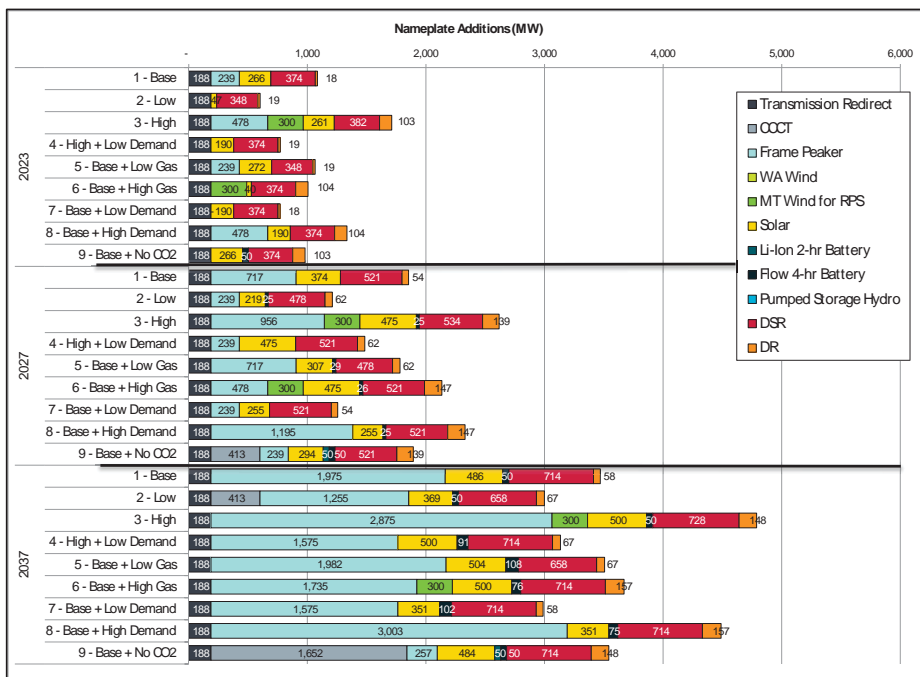


Summary of Deterministic Optimization Analysis

Figure 6-15 below displays the megawatt additions for the deterministic analysis optimal portfolios for all scenarios in 2023, 2027 and 2037. No new resources are added until 2022. See Appendix N, Electric Analysis, for more detailed information.

Figure 6-15: Resource Builds by Scenario, Cumulative Additions by Nameplate (MW)

Scenarios 1-9

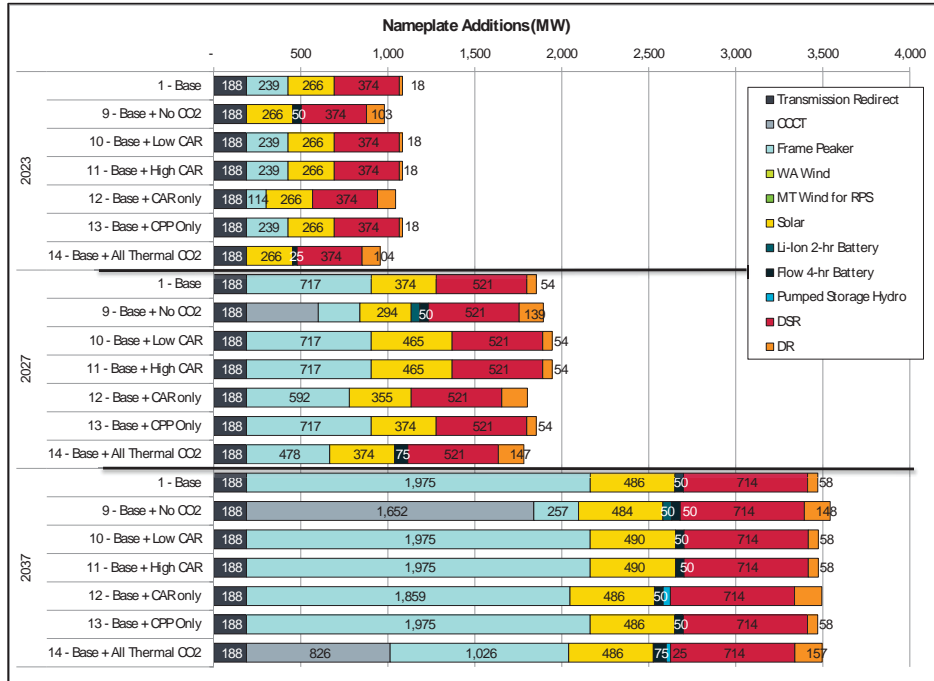


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Figure 6-15 (continued)

Scenarios 9-14



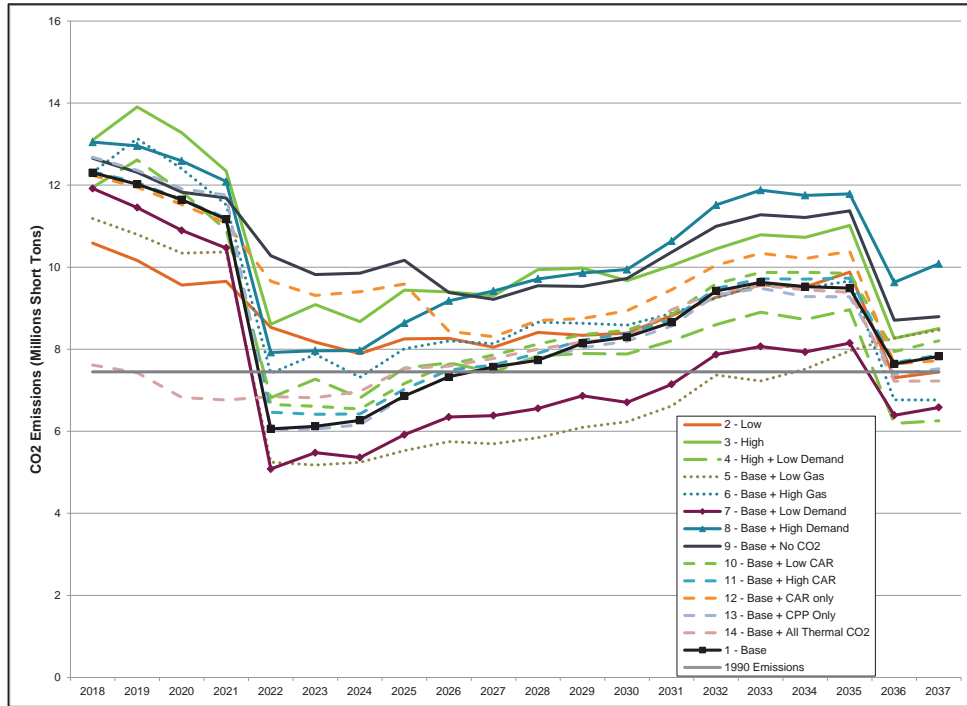


Portfolio Emissions

In this section we present results of our “portfolio emissions” analysis. An important detail is that this chart applies an average annual carbon intensity to the market purchases that make up nearly a third of PSE’s portfolio. PSE’s approach to accounting for market purchases is to calculate a WECC-wide average carbon intensity forecast in tons of CO₂ per MWh for each year in the planning horizon, and apply that average to market purchases. This is similar to the method used by the WUTC’s compliance protocol, but that protocol uses the Northwest Power Pool average instead of the WECC average. Because this analysis applies an average emission rate, not a marginal emission rate, comparing these different lines will not accurately forecast how total emissions will change. In reality, changes in emissions will be impacted by marginal resource decisions (i.e., which resources are being dispatched, not average resource dispatch). For example, under the CAR, it may appear that PSE’s emissions will go down, but under CAR, PSE’s highly efficient baseload gas plants would ramp down and other, less efficient gas plants in the WECC would ramp up, for a net increase in carbon emissions. Increasing carbon emissions is clearly not the intended goal of CAR – but one could draw that conclusion from examining portfolio emissions only. A more reliable carbon analysis is presented in the section on carbon abatement costs. Figure 6-16 shows CO₂ emissions for the least-cost portfolio in each scenario.



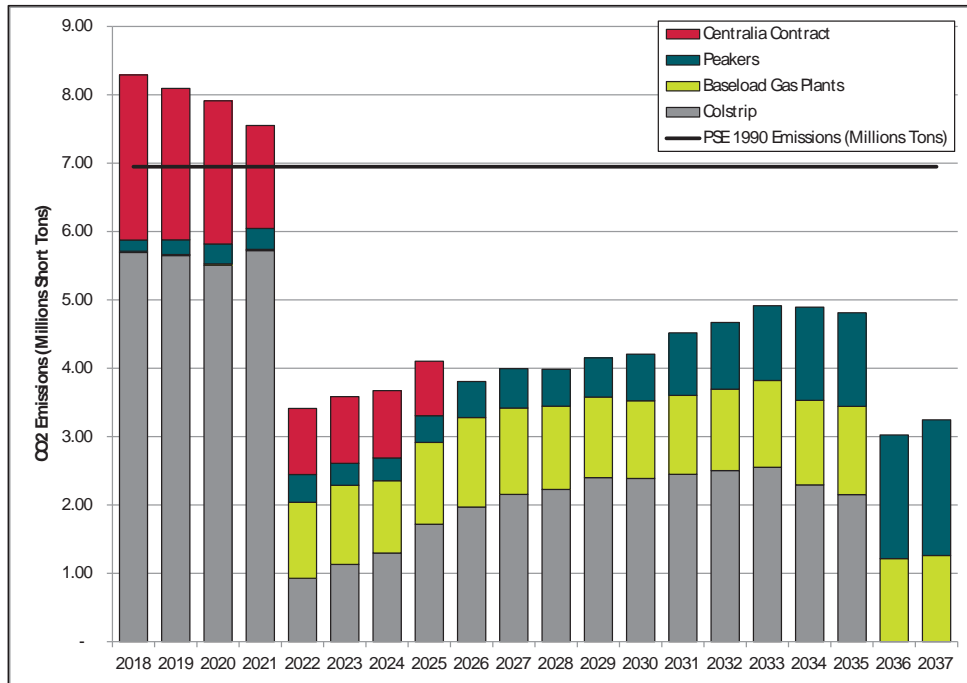
Figure 6-16: CO₂ Emissions by Portfolio



Examining direct carbon emissions of PSE's portfolio may be more helpful, as it avoids the complications of addressing market purchases. Figure 6-17, below, shows the breakdown of emissions by resource type for the resource plan. The chart illustrates that PSE's emissions are driven by dispatch of thermal plants. This chart shows PSE's direct emissions from our resources are expected to fall significantly. This drop is caused by retirement of Colstrip 1 & 2 in 2022 and a significant drop in the economic dispatch of Colstrip 3 & 4 (given a WECC-wide carbon price assumed to become effective in 2022). The final large drop is in 2035, when Colstrip 3 & 4 are retired.



Figure 6-17: PSE's CO₂ Emissions for the Resource Plan Forecast in the Base Scenario





Cost of Capacity

In the latter part of the planning horizon, peakers and baseload gas plants were the primary supply-side resources that appear cost effective at large scale. Energy storage appears cost effective in certain situations, based in part on their small scale and the flexibility and T&D benefits they deliver.

Whether peakers or baseload gas plants are most cost effective varies across some of the scenarios. Net revenue requirements were calculated by taking all capital and fixed costs of a plant and then subtracting the margin (market revenue less variable costs). This calculation lets one quickly compare how the model evaluated these resources.

- Peaking units were modeled with oil backup.
- Plants are assumed to be located on the west side of the Cascades.
- The levelized cost for the peakers and baseload gas plants was calculated over the 35-year life of the plant.

Figure 6-18 compares the cost of peakers and baseload gas plants across scenarios. In the scenarios where the baseload gas plants look more cost effective, the dispatch of the baseload plants is high, so the plant produces a lot of excess power to sell into the market; this creates revenue that lowers the net cost of the plant to customers, resulting in baseload gas plants being chosen in the lowest cost portfolio. Frame peaker costs vary across scenarios depending on the CO₂ regulation modeled. In the scenario where a CO₂ price is applied to baseload plants only, the peakers are more valuable and more frequently dispatched, resulting in a lower net cost. In the Base + No CO₂ and the All-thermal CO₂ Scenarios, where peakers and baseload plants are treated equally, peakers dispatch less and therefore have a higher net cost.



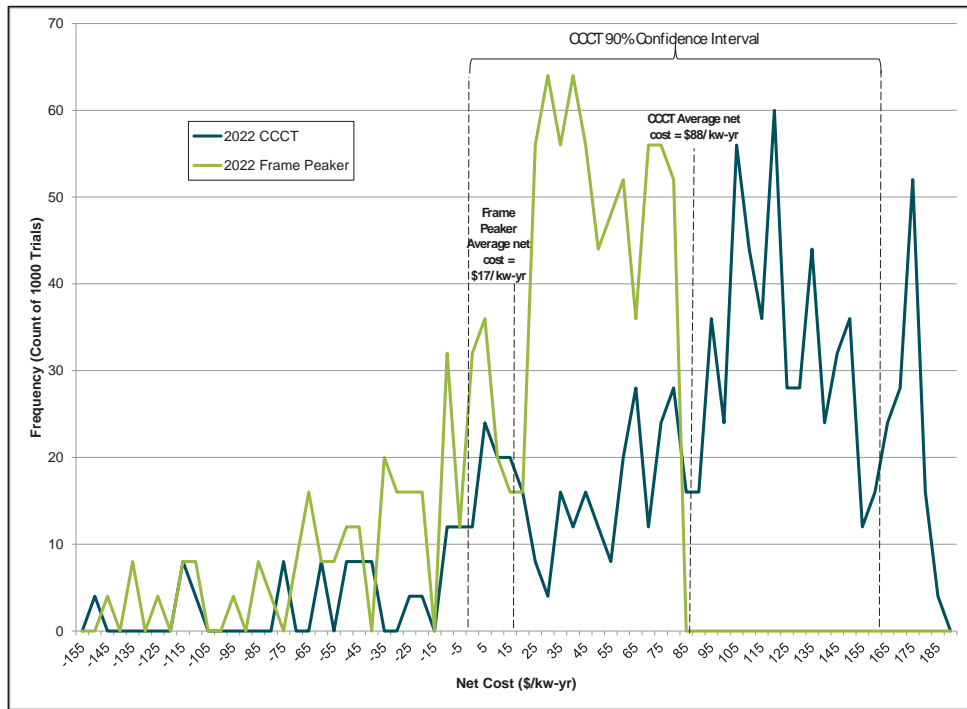
Figure 6-18: Peaker and Baseload Gas Net Costs Compared

| | Levelized Net Cost (2018 \$/kW) | 2022 CCCT | 2022 Frame Peaker | 2022 Aero Peaker | 2022 Recip Peaker |
|----|---|-----------|----------------------|---------------------|----------------------|
| 1 | Base | 131 | 64 | 106 | 125 |
| 2 | Low | 122 | 76 | 119 | 153 |
| 3 | High | 101 | 64 | 105 | 119 |
| 4 | High + Low Demand | 138 | 71 | 112 | 137 |
| 5 | Base + Low Gas Price | 142 | 60 | 104 | 122 |
| 6 | Base + High Gas Price | 124 | 69 | 110 | 131 |
| 7 | Base + Low Demand | 143 | 66 | 108 | 131 |
| 8 | Base + High Demand | 100 | 54 | 96 | 103 |
| 9 | Base + No CO2 | 87 | 75 | 117 | 148 |
| 10 | Base + Low CO2 w/ CPP | 121 | 59 | 100 | 116 |
| 11 | Base + High CO2 | 126 | 61 | 103 | 120 |
| 12 | Base + Mid CAR only (electric only) | 139 | 72 | 114 | 140 |
| 13 | Base + CPP only (electric only) | 135 | 66 | 109 | 130 |
| 14 | Base + All-thermal CO2 (electric only) | 107 | 76 | 118 | 151 |



Net cost is not specifically used as part of the cost minimization function; however, showing net cost may provide useful insights. Figure 6-19 illustrates how the net cost of a baseload gas plant is significantly affected by the margin it generates. A 250-simulation Monte Carlo analysis for a 2022-vintage plant shows how the net cost per kW of peakers and baseload plants are distributed under different market conditions. The margins for both baseload gas plants and peakers are widely dispersed; this spreads out the probability distribution more broadly.

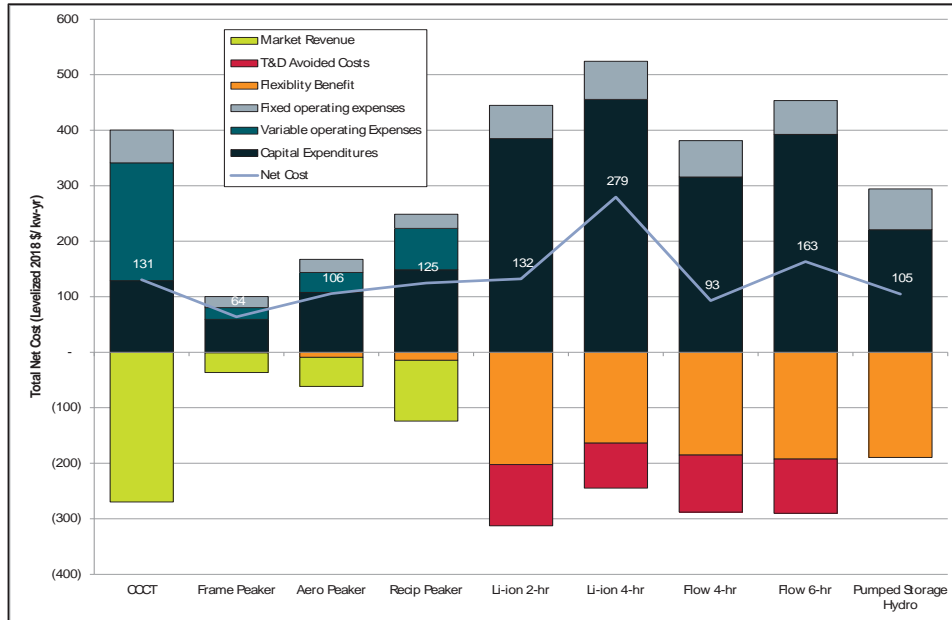
Figure 6-19: Comparison of Net Cost Distribution
 Baseload Gas and Peakers with Oil Backup (in 2018 dollars per kW)



Peakers, baseload gas plants and energy storage resources traded off being the lower cost resource, depending on the scenario. Figure 6-20 compares the cost of peakers, baseload gas plants and energy storage resources in the Base Scenario. In this IRP, the flexibility benefit was only evaluated in the Base Scenario, so the net cost of the resources did not vary across scenarios. We assumed the avoided transmission and distribution cost from the Council's 7th power plan, and this benefit reduces the net cost of the 4-hour flow battery by \$103/kW-yr. Avoided T&D cost is a large driver in making the battery a cost effective resource.



Figure 6-20: Net Cost of Capacity in the Base Scenario



As shown in the Figure above, the net cost of the frame peaker is the lowest cost resource, closely followed the 4-hour flow battery. Since these resources are so close in costs, many scenarios have a flow battery as the first build in 2023 instead of the frame peaker.



Backup Fuel Capacity

PSE has relied on spot gas supply to operate its fleet of peakers, combined with a 48-hour fuel oil backup in lieu of more expensive firm gas supply contracts, since the peakers have low capacity factors. Two key issues arise from this reliance on 48-hour fuel oil backup:

1. Is the current 48-hour fuel oil backup adequate to run the peakers if spot gas is not available for the season?
2. If backup fuel oil is used for the season, does PSE exceed the annual maximum run hours constraint of 300 hours required to meet air emission standards?

Currently, PSE stores about 48 hours of fuel oil backup for each peaker with the total amount varying depending on the capacity of the peaker. This enables the peaker to run for a cumulative 48 hours within the season without fuel replenishment since replenishment within the season is usually expensive. PSE's peaker fleet consists of Fredonia Units 1-4, Whitehorn Units 1 & 2, and Frederickson Units 1 & 2 for a total of 696 MW of maximum capacity (temperature adjusted). In PSE's RAM, these units are assumed to be supplied with gas from the spot market with no risks to their availability. To analyze the adequacy of the 48-hour fuel oil backup, we looked at the case in which the fuel oil backup is not available AND the market is unable to provide spot gas for the entire season. Under these circumstances the entire peaker fleet is not available in the resource adequacy model, which leads to more frequent and severe outage events. The MWhs of outages resulting from the absence of the peakers are then summed up for the season. Then, the sum of MWhs that the 48-hour fuel oil backup is able to provide is compared with the MWhs of outages resulting from the absent peakers in the resource adequacy model. If the MWhs from the 48-hour fuel oil backup is greater than the sum of MWhs from being unable to run the peakers, then we can conclude that the 48-hour fuel oil backup is adequate.

Note that the relevant MWh outages include only those from the incremental outages in the resource adequacy model, which results in some outage events 5 percent of the time since it is based on the 5 percent LOLP reliability standard. Also, to avoid inflating the MWh outages, this analysis included the impacts of conservation based on the 2015 IRP.

Since the resource adequacy model is also able to identify and count the incremental hours when new outage events occur, we also sum up all of the hours for the incremental outages to determine if this exceeds the maximum allowed run hours for fuel oil according to current air emission standards.



To determine if the results of the analysis are invariant to the scale of the capacity that is not available to meet resource adequacy, three scenarios were examined.

SCENARIO 1. Remove all existing peakers (696 MWs)

SCENARIO 2. Scenario 1, plus remove Colstrip Units 1 & 2 (298 MWs) and assume that peakers replace Colstrip 1 & 2 for a total of 994MWs

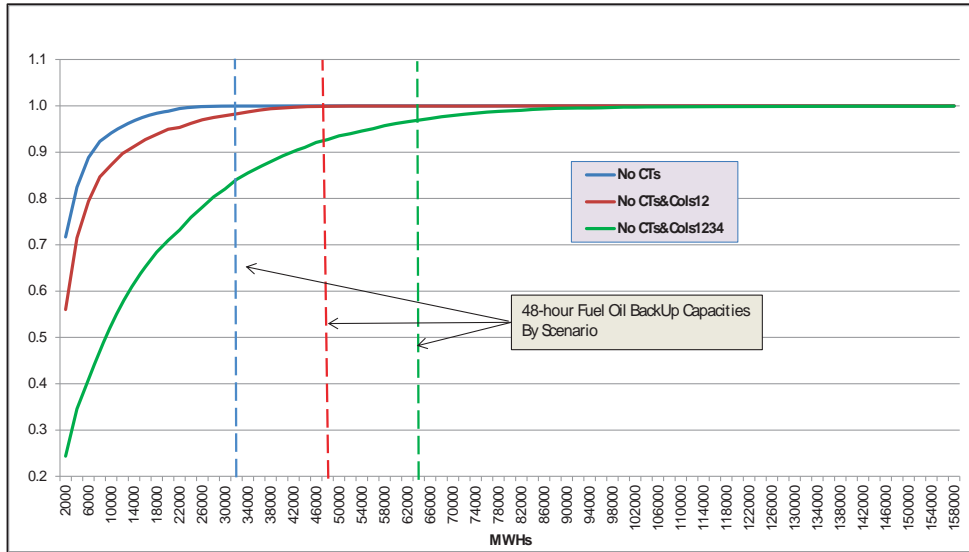
SCENARIO 3. Scenario 2, plus remove Colstrip 3 & 4 (359 MWs) and assume peakers replace Colstrip 3 & 4 for a total of 1,353 MWs

The resource adequacy model is run under each of the three scenarios and the resulting incremental outages are examined both for MWh outages and hours of outages. Because RAM is a stochastic model over 6,160 draws, both the MWh outages and hours of outages are presented as a cumulative distribution, and compared to the thresholds for the 48-hour fuel oil backup and maximum run hour constraints, respectively.

The chart below shows the cumulative distribution of MWhs resulting from the incremental outage events for each of the three scenarios. The higher the level of capacity that is unable to run due to the lack of gas supply, the greater the amount of deficit MWhs. This is shown by the rightward shift in the cumulative distribution curve. The vertical lines show the cumulative MWhs that the peakers are able to supply with the 48-hour fuel oil backup. For scenarios 1 and 2, where the peaker capacity level goes up to almost 1,000 MWs, the 48-hour fuel oil back is adequate to cover 100 percent of the deficit MWhs resulting from the incremental outage events. When the peaker capacity level that is not able to operate goes up to 1,353 MWs, the 48-hour fuel oil back is only able to cover about 97 percent of all the deficit MWhs. For PSE's current fleet of peakers, the study results show that the 48-hour fuel oil backup is adequate.



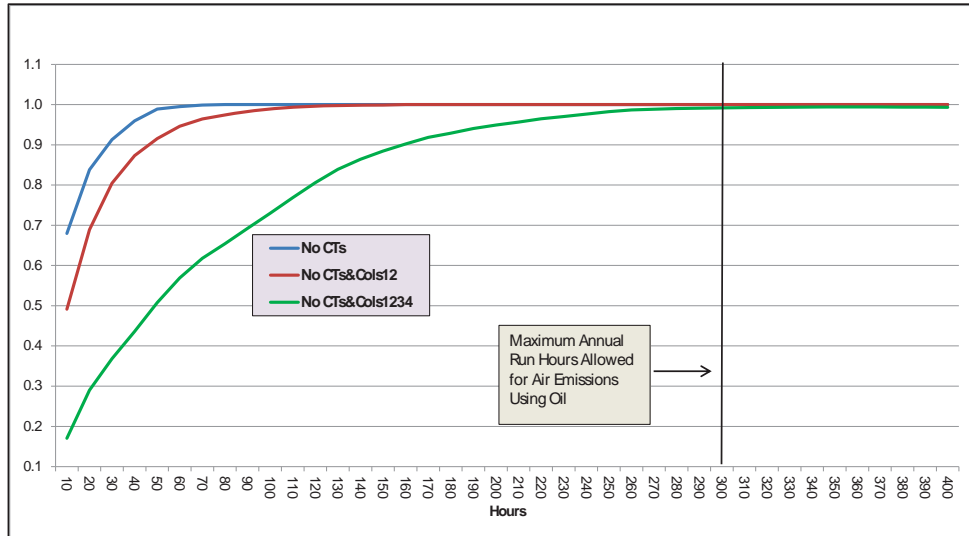
Figure 6-21: Cumulative Distribution of Incremental Deficit for Bad Simulations in MWh/yr



The next chart displays the cumulative distribution of the run hours where incremental outage events occur for each of the three scenarios. Again, the higher the amount of peaker capacity that is not able to operate due to the lack of spot gas supply, the greater the amount of deficit events, so the cumulative distribution curve shifts to the right. The vertical line shows the 300 maximum run hours in a season required by current air emission standards. This chart illustrates that the maximum 300 run hours constraint is always greater than the 100 percent level of cumulative hours experiencing outage events for all of the scenarios tested in this study. This implies that for the existing PSE peaker fleet, or even with potential additions to the fleet, the 48-hour fuel oil backup meets the air emission standard for maximum run hours.



Figure 6-22: Cumulative Distribution of Incremental Deficit for Bad Simulations (in MWh/year)





Renewable Builds

The amount of renewable resources included in portfolios is driven by RPS requirements. In all but the High and Base + High Gas Price Scenarios, solar resources are only added to meet the minimum requirements of RCW 19.285, not because they are least cost. See Figure 6-14 above for total solar builds by scenario.

RPS Incremental Cost Cap Analysis

As part of RCW 19.285, if the incremental cost of the renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then the utility will be considered in compliance with the annual renewable energy target.¹⁰

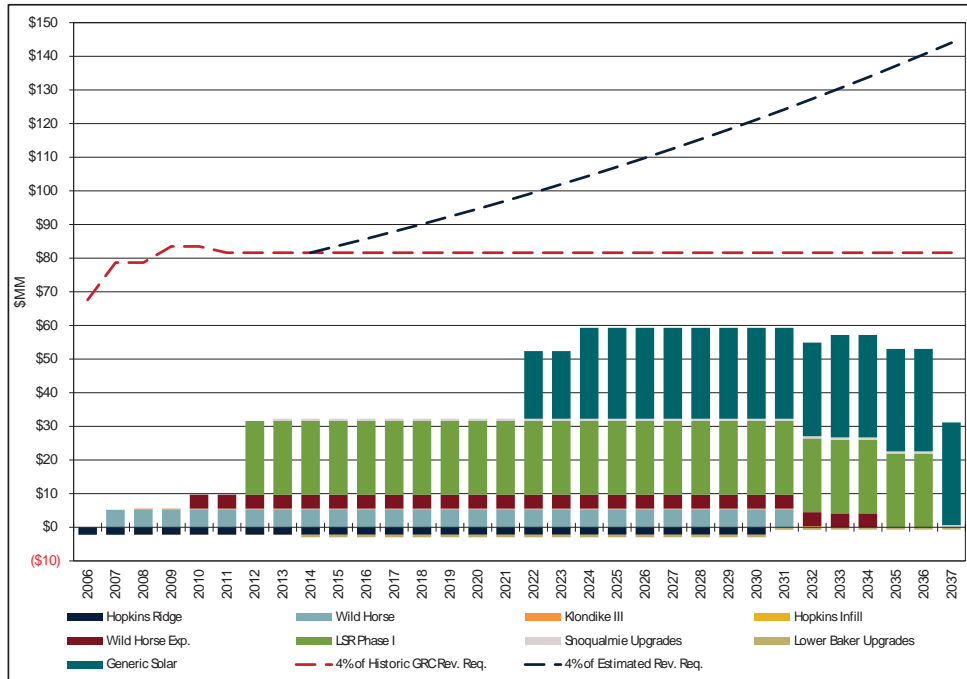
Each renewable resource that counts towards meeting the renewable energy target was compared to an equivalent non-renewable resource starting in the same year and levelized over the book life of the plant: 25 years for wind power and 40 years for hydroelectric power. Figure 6-23 presents results of this analysis for existing resources and projected resources. This demonstrates that PSE expects to meet the physical targets under RCW 19.285 without being constrained by the cost cap. A negative cost difference means that the renewable was lower cost than the equivalent non-renewable, while a positive cost means that the renewable was a higher cost.

¹⁰ / RCW 19.285.050 (1) (a) (b) "The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resource that does not qualify as eligible renewable resources."

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Figure 6-23: Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4% of 2011 GRC Revenue Requirement + 2014 PCORC Adjustment





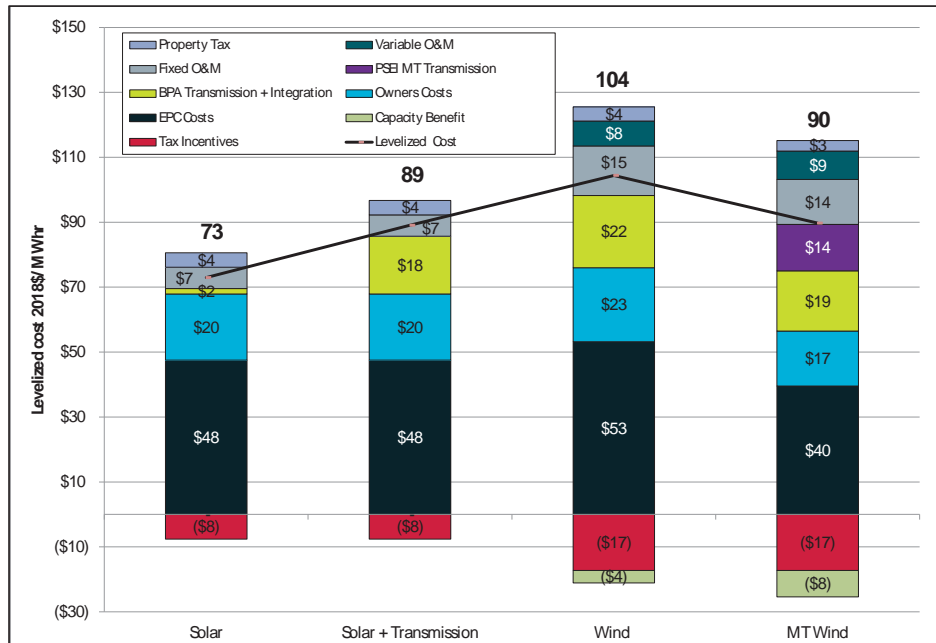
Renewable Resource Costs

Renewable resource costs are in flux. Over the last decade, photovoltaic technology costs have declined to the point that this technology now appears to be lower cost than wind. Figure 6-24 compares wind and solar cost components. Solar resources have a lower capacity factor, but also a lower capital cost, making them the lowest cost renewable resource. Assuming solar resources could be built in eastern Washington and interconnected to PSE's system, they would have no transmission cost and a total levelized cost of \$73/MWh. Even if solar resources were located where they were burdened with BPA transmission costs, they still appear to be the lowest cost resource at this time.

The next lowest cost renewable resource is Montana wind. Due to its higher capacity factor, the \$/MWh capital cost for Montana wind is lower than for solar; however, Montana wind has to overcome significant transmission costs to get from Montana to PSE. Also, wind resources from eastern Montana do not qualify as a renewable resource under RCW 19.285. To qualify, Montana wind would have to be delivered to Washington state on a real-time basis without shaping or storage. It is unclear whether such a designation could ever be made. This is not a short-coming in the industry – it highlights that the law is inconsistent with how bulk transmission systems plan and operate systems. However, PSE assumed Montana wind could be a qualifying renewable resource to help understand whether the designation would make or break its cost effectiveness.



Figure 6-24: Wind and Solar Cost Components





7. SENSITIVITY ANALYSIS RESULTS

A. Colstrip

How do different retirement dates affect decisions about replacing Colstrip resources?

Baseline: Retire Units 1 & 2 mid-2022, Units 3 & 4 remain in service into 2035.

Sensitivity 1: Retire Units 1 & 2 in 2018.

Sensitivity 2: Retire Units 3 & 4 in 2025.

Sensitivity 3: Retire Units 3 & 4 in 2030.

This sensitivity tested a “replacement power” portfolio analysis that took Colstrip out of PSE’s portfolio in the Base and Base + No CO₂ Scenarios, so that we could compare the different portfolio builds and costs.

KEY FINDINGS: Carbon regulation could render Colstrip Units 3 & 4 uneconomic. The key takeaway from this analysis is that carbon regulation has a much greater impact than specific retirement dates. We do not know when (or whether) comprehensive carbon regulation will be implemented across the WECC and we do not know the form of that regulation, which could significantly affect these findings.

BASELINE COLSTRIP SHUTDOWN DATES. The Base Scenario assumes the theoretical implementation of CPP carbon pricing in 2022, which severely restricts the economic dispatch of Colstrip Units 1 & 2. Economics would likely force the shutdown at the beginning of 2022 instead of mid-2022, which differs from the Base Scenario portfolio

The Base + No CO₂ Scenario assumes Colstrip Units 1 & 2 retire in mid-2022 and Units 3 & 4 retire in 2035.

ASSUMPTIONS. The costs for Colstrip operations include fixed and variable operations and maintenance, coal costs, capital costs, relevant taxes, transmission, operational and ongoing environmental costs past the shutdown date, and depreciation expenses. In the Base Scenario, the Washington Clean Air Rule (CAR) is assumed to affect Washington baseload gas plants from 2018-2021, and starting in 2022 the EPA Clean Power Plan (CPP) is assumed to affect all U.S. baseload gas and coal plants. When Colstrip units were retired early, depreciation expenses were changed to match retirement dates and avoided on-going capital costs were eliminated. The analysis did not reflect changes in amortization of transmission related capital costs, which may tend to slightly overstate the benefit of early retirement. The eastern interconnect contract expires in 2027, and the Garrison to PSE transmission contract (BPAT) is up for renewal in 2019.



COLSTRIP 1 & 2 RESULTS. Under the Base Scenario, retiring Colstrip Units 1 & 2 in 2018 would cost an additional \$30 million in the Base Scenario or \$14 Million in the Base + No CO₂ Scenario. The cost is greater in the Base Scenario is because of CAR. CAR adds a CO₂ cost to Washington baseload gas plants but not to other plants in the WECC, so its effect is to increase the relative value of Colstrip.

COLSTRIP 3 & 4 RESULTS. Carbon regulation could render continued operation of Colstrip 3 & 4 uneconomic, depending on how the regulation is structured. In the Base Scenario, in which the CPP adds a CO₂ price that affects the dispatch cost of the plant starting in 2022, retiring Colstrip 3 & 4 in 2025 would lower portfolio costs. Under these conditions, the power plant has a greatly reduced capacity factor and is not able to recover the cost of operating. In contrast, under the Base + No CO₂ Scenario in which there is no CO₂ price, Colstrip continues to operate at a high capacity factor and continues to hold value, so the portfolio costs more if the units are retired early.

Figure 6-25: Portfolio Cost Results, Colstrip Sensitivity (\$ Millions)

| | Base Scenario | | Base + No CO2 Scenario | |
|----------------------|----------------|----------------|------------------------|----------------|
| | Portfolio Cost | Benefit/(Cost) | Portfolio Cost | Benefit/(Cost) |
| Base portfolio | \$11,915 | | \$10,442 | |
| Colstrip 1&2 in 2018 | \$11,944 | (\$30) | \$10,456 | (\$14) |
| Colstrip 3&4 in 2025 | \$11,766 | \$149 | \$10,647 | (\$192) |
| Colstrip 3&4 in 2030 | \$11,833 | \$82 | \$10,462 | (\$66) |



B. Thermal Retirement

Would it be cost effective to accelerate the retirement of PSE's existing baseload gas plants?

Baseline: Baseload gas plants continue to run through the end of the time horizon.

Sensitivity 1: Baseload gas plants retire in 2031.

KEY FINDINGS. Carbon regulation could significantly diminish the value of PSE's baseload gas fleet. In the Base Scenario, some slight portfolio cost savings could be created by replacing those plants with peakers. However, the Base Scenario has a biased application of carbon regulation and even then, the cost benefits of retiring those plants are minor. The findings differ under the Base + No CO₂ and the Base + All-thermal CO₂ Scenarios, where carbon regulation extends to peakers as well as baseload natural gas plants. It does not appear PSE needs to plan on retiring its baseload gas plants in the near future, but the issue should be re-examined as regulations and technologies evolve.

SUMMARY. This sensitivity was run in three scenarios: Base, Base + No CO₂, and Base + All Thermal CO₂. In the Base Scenario, baseload gas plant capacity factors decline significantly. The exact opposite happens in the Base + No CO₂ Scenario and Base + All Thermal CO₂ where the capacity factor is in the 80 percent range. The sensitivity retired each plant in 2031 and replaced it with a frame peaker (the lowest cost resource in the Base Scenario portfolio). Figure 6-26 below compares the cost of continuing to run the baseload plant vs. retirement. The baseload plants are burdened with firm pipeline costs, whereas the frame peakers are not. Also, Mint Farm and Goldendale both incur transmission charges on BPA's system, because those plants are outside PSE's balancing authority. Under the Base Scenario, it is cost effective to retire the baseload gas plants and replace them with frame peakers because the CO₂ regulation affects only baseload CCCT plants, except for Ferndale. Under the Base + No CO₂ and Base + All Thermal CO₂ scenarios, it is cost effective to keep the baseload gas plants running.



Figure 6-26: Impact of Early Closure for PSE's Baseload Gas Plants in 2031 (\$ Millions)

| | Base Scenario | | Base + No CO2 Scenario | | Base + All Thermal CO2 | |
|----------------|----------------|--------------------|------------------------|--------------------|------------------------|--------------------|
| | Portfolio Cost | Benefit/ (Cost) | Portfolio Cost | Benefit/ (Cost) | Portfolio Cost | Benefit/ (Cost) |
| Base portfolio | \$11,982 | | \$10,705 | | \$12,644 | |
| Encogen | \$11,975 | \$7 | \$10,721 | (\$16) | \$12,668 | (\$4) |
| Ferndale | \$12,013 | (\$31) | \$10,787 | (\$82) | \$12,702 | (\$38) |
| Goldendale | \$11,971 | \$11 | \$10,782 | (\$77) | \$12,663 | \$1 |
| Mint Farm | \$11,974 | \$6 | \$10,805 | (\$100) | \$12,664 | \$0 |
| Sumas | \$11,977 | \$5 | \$10,795 | (\$90) | \$12,665 | (\$2) |

C. No New Thermal Resources

What would it cost to fill all future need with resources that emit no carbon?

Baseline: Fossil fuel generation is an option in the optimization model.

Sensitivity 1: Renewable resources, energy storage and DSR are the only options for future resources.

KEY FINDINGS. Adding no new thermal resources to the portfolio in the latter part of the planning horizon would increase both cost and risk, given current forecasts for resource costs, although those costs may change. To fill the gap, Montana wind and over 1,600 MW of pumped hydro storage would be needed. Additional analysis would be required to determine what kinds of operational issues this could create. For example, pumped hydro may provide flexibility benefits, but 1,600 MW of pumped hydro could create concerns about energy constraints.

SUMMARY. With no new thermal resources available, the only resource large enough to meet the capacity need is pumped storage hydro. This sensitivity analysis adds another DSR bundle to the portfolio (compared to the Base Scenario portfolio) and adds all the available demand response. It also switches the renewable resource to Montana wind because of Montana wind's capacity advantage over solar. This portfolio costs \$1.36 billion more than the Base Scenario portfolio.

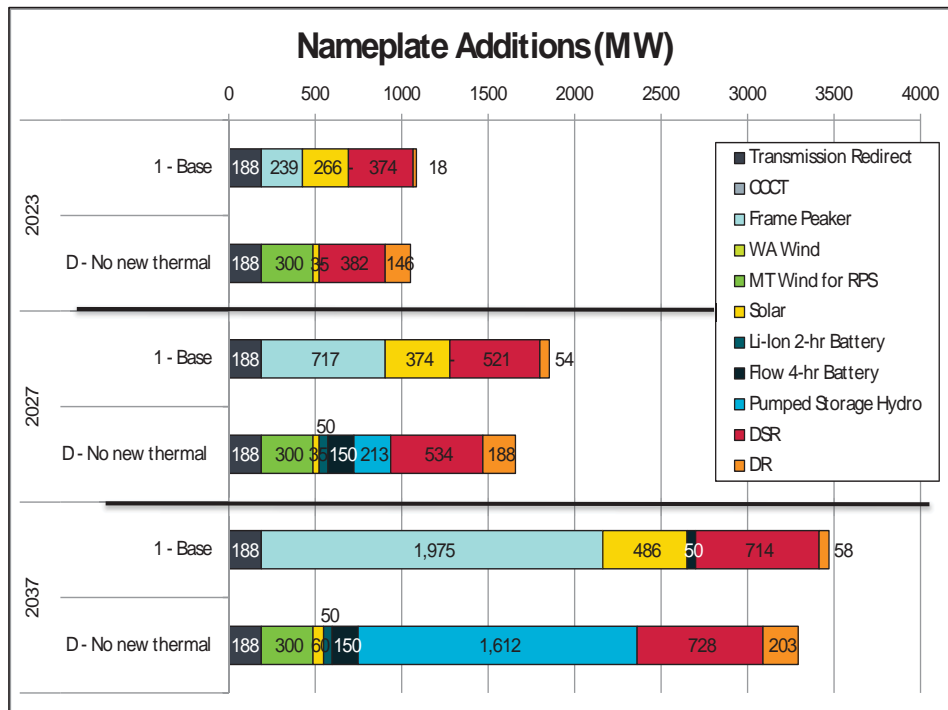
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Figure 6-27: No New Thermal Portfolio Cost (\$ Millions) and Builds (Nameplate MW)

| Portfolio Cost (\$Millions) | NPV |
|------------------------------|----------------|
| 1 – Base | \$11,981 |
| D – No New Thermal Resources | \$13,343 |
| Difference in Cost | \$1,362 |

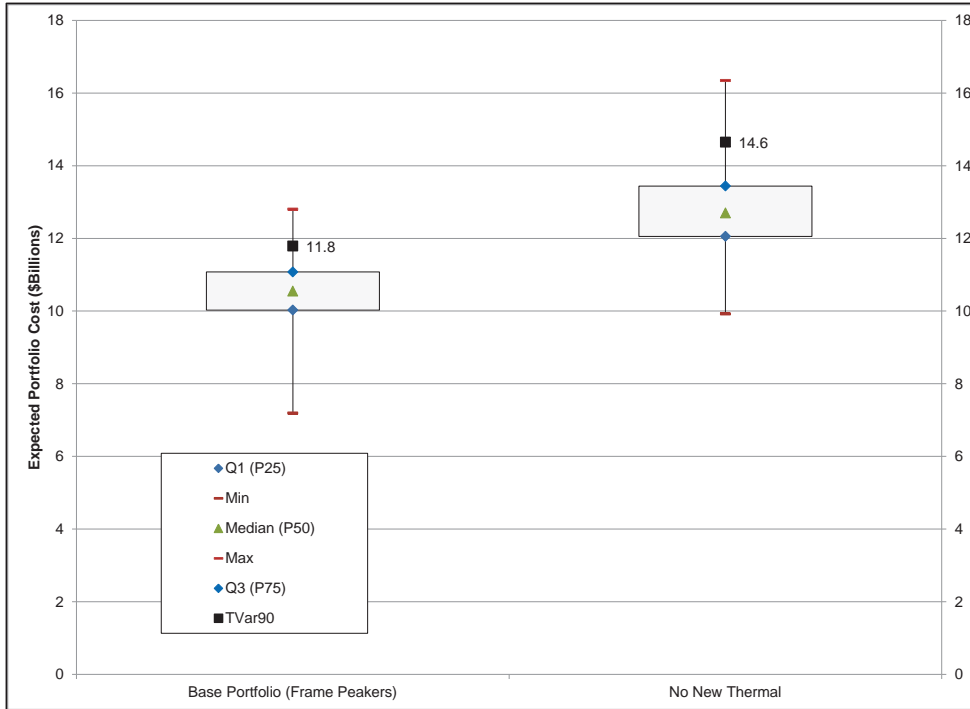
Figure 6-28: Nameplate Additions, No New Thermal Resources Sensitivity





A portfolio with no new thermal resources is also a high risk portfolio as shown in Figure 6-29, which compares expected costs and cost ranges. The TVar90 of the portfolio with no new thermal is \$2.8 billion more than the Base Scenario portfolio that includes frame peakers.

Figure 6-29: Effect of No New Thermal Resources on Costs and Risks



D. Stakeholder-requested Alternative Resource Costs

What if capital costs of resources are different than the base assumptions?

Baseline: PSE cost estimate for generic supply-side resources.

Sensitivity 1: Lower cost for recip peakers.

Sensitivity 2: Higher thermal capital costs.

Sensitivity 3: Lower wind and solar development costs.

Sensitivity 4: Apply more aggressive solar cost curve.



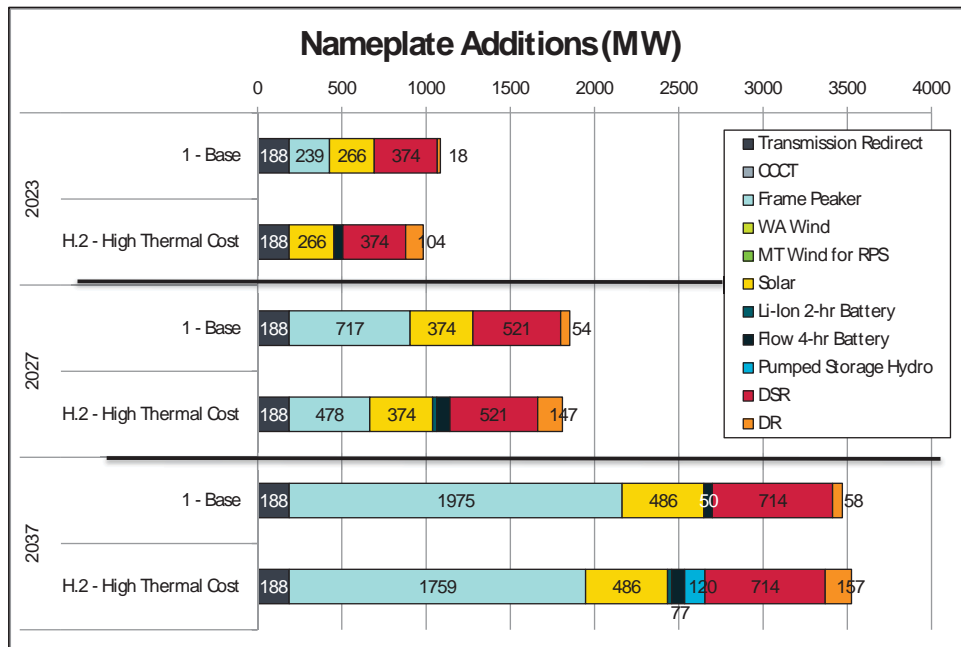
SENSITIVITY 1: LOWER COST FOR RECIP PEAKERS. This sensitivity tested a lower capital cost of recip peakers of \$1,257/kW for a dual fuel unit with oil backup. This change did not affect the least-cost mix of resources. The total capital cost of the recip peakers would have to be reduced by more than 15 percent (to approximately \$1,054) to be cost competitive. Additionally, it is not clear whether a dual fuel recip peaker could meet current air emissions standards. The analysis illustrates that further analysis into this issue is not warranted.

SENSITIVITY 2: HIGHER THERMAL CAPITAL COSTS. This sensitivity tested higher thermal capital costs from the 2015 IRP.

- Frame peaker with oil: \$879 per kW
- Recip peaker: \$1,563 per kW
- Aero peaker with oil: \$1,214 per kW
- Baseload CCCT: \$1,227 per kW

The result was that battery storage plus higher demand response was added in 2023 instead of a frame peaker; then frame peakers were added to meet capacity need starting in 2025. This result is consistent with the resource plan forecast. Total portfolio cost increased by \$213 million.

Figure 6-30: Higher Thermal Cost Portfolio Builds





SENSITIVITY 3: LOWER WIND AND SOLAR DEVELOPMENT COSTS. This sensitivity used the lower development costs from the DNV GL study which is included as Appendix M.

Wind: \$1,478 per kW (2016 \$)

Solar: \$1,755 per kW (2016 \$)

Lower wind and solar development costs did not change the optimal portfolio. Solar is still added to only to meet the renewable need under RCW 19.285. Because the solar cost curve is much lower than the wind cost curve at this time, wind capital costs would have to drop by 44 percent to \$1,210 per kW (in 2022 dollars) to be cost competitive with solar.

SENSITIVITY 4: APPLY MORE AGGRESSIVE SOLAR COST CURVE. When this sensitivity was developed in consultation with external stakeholders, we had not anticipated that base solar costs would be more cost effective than wind. We continued pursuing this sensitivity to determine whether solar costs could become lower cost than market using the more aggressive solar costs developed by the Northwest Energy Coalition.

With the more aggressive cost curve on solar, the levelized cost of a 2023 resource drops to \$58/MWh instead of \$73/MWh for the baseline assumption. The portfolio builds under this sensitivity do not change, but the total portfolio cost is down to \$11.64 billion. This is a decrease of \$340 million from the Base Scenario portfolio.

E. Energy Storage

What is the cost difference between a portfolio with and without energy storage?

Baseline: Batteries and pumped hydro included only if chosen economically by the analysis.

Sensitivity 1: Add 50 MW battery in 2023 instead of economically chosen peaker.

Sensitivity 2: Add 50 MW pumped hydro storage in 2022 instead of economically chosen peaker.

MODIFICATION OF SENSITIVITY. This sensitivity was developed in consultation with external stakeholders before results of the portfolio analysis showed batteries as cost effective across all scenarios. Since the resource plan includes 50 MW of batteries by 2023, we modified this sensitivity to examine the cost impact of using pumped hydro storage in 2023 rather than a flow battery.



KEY FINDINGS. Pumped hydro storage would be slightly more expensive than batteries. However, 50 MW is a very small change. A key value stream from batteries is the ability to create transmission and distribution benefits that cannot be derived from pumped hydro.

Batteries

Historically, electricity is consumed immediately after it is created. The emergence of a new generation of advanced batteries which allow for storage on the grid has led to the first instances of large-scale energy storage being implemented in the electric distribution network. Batteries can also provide ancillary services such as spinning reserves and frequency regulation, along with peak capacity.

Pumped Hydro Storage

Pumped hydro is a proven storage technology that can also provide flexibility benefits. However, the facilities are expensive and may have controversial environmental impacts. Additionally, depending on where pumped hydro is located, transmission may be a challenge. Pumped hydro resources also may have more extensive permitting processes and require sites with specific topologic and/or geologic characteristics. On the positive side, if significant quantities of capacity are needed, pumped hydro resources may be more practical than batteries.

In this IRP, the total net cost of the pumped storage hydro project is \$105/kW-yr as compared to \$64/kW-yr for a peaker. Pumped storage projects are usually very large, so realistically PSE would have to partner with other owners for a share of the project. For example, the proposed JD Pool pumped storage hydro project in southern Washington is estimated to be 1,500 MW. The analysis tested adding 50 MW of pumped storage hydro plus more demand response in 2023, similar to the battery sensitivity. The total portfolio cost increased by \$15 million in the Base Scenario.

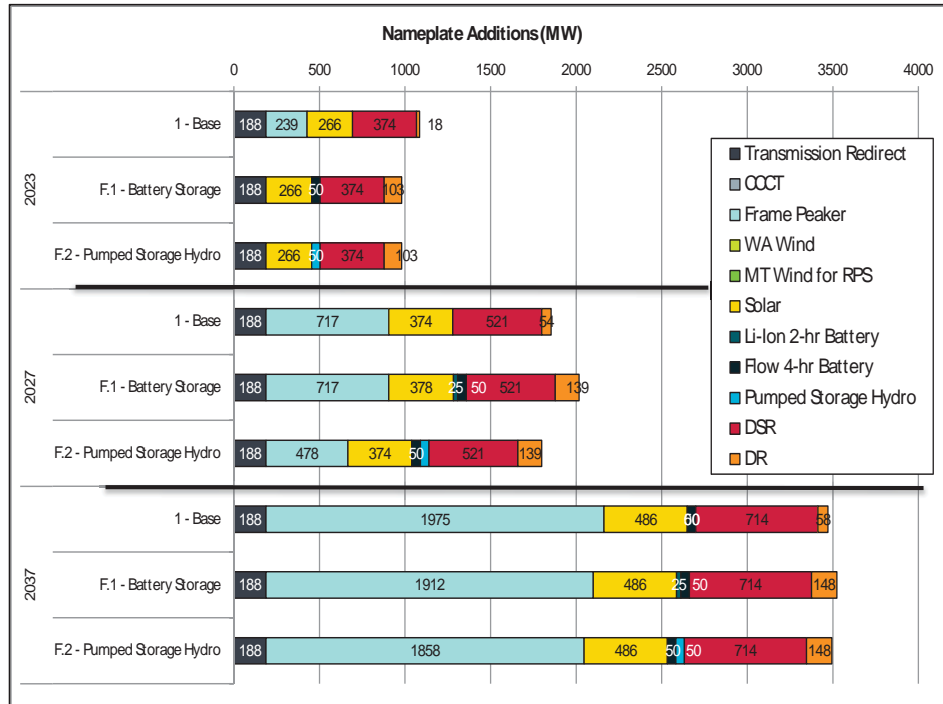
Figure 6-31: Battery and Pumped Storage Portfolio Cost

| | NPV Portfolio Cost (\$Millions) | Difference from Base |
|------------------------------------|------------------------------------|-------------------------|
| Base Portfolio | 11,981 | |
| 50 MW Battery in 2023 | 11,988 | 7 |
| 50 MW Pumped Storage Hydro in 2023 | 11,996 | 15 |

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Figure 6-32: Portfolio Additions, Energy Storage Sensitivity





F. Renewable Resources + Energy Storage

Does bundling renewable resources with energy storage change resource decisions?

Baseline: Evaluate renewable resources and energy storage as individual resources in the analysis.

Sensitivity: Bundle 50 MW battery + 200 MW solar.

When a battery storage resource is paired with a renewable resource, then the battery storage could receive an investment tax credit (ITC) in addition to the renewable tax credit. If 100 percent of the energy from the renewable resource were used to charge the battery, then the battery would receive the full 30 percent ITC; if 75 percent of the energy from the renewable resource were used to charge the battery, it would receive a 22.5 percent ITC. However, the utility must prove that the energy is coming from the renewable resource. In order to do this the battery must be located near the renewable, which most likely negates any localized transmission or distribution benefits. Additionally, this limitation would constrain the ability to use the battery for sub-hourly flexibility, as the battery would be energy constrained. This analysis tests whether using a battery in this manner to receive the ITC is worth the loss of the T&D benefit and the reduced flexibility benefit.

KEY FINDINGS. Pairing batteries with solar does not appear cost effective because no additional peak capacity value is created. If anything, this would impair the peak capacity value of the battery, because the ability to charge it would be limited based on the solar output.

ASSUMPTIONS. The T&D avoided cost was removed and the flexibility benefit was reduced by 25 percent. The peak capacity value of the battery was not reduced for this analysis, but it did not appear cost effective, so such additional analysis was not warranted.

RESULTS. Total portfolio cost increased by \$21 million. The T&D and flexibility benefit of the battery outweighed the ITC cost reduction. Figure 6-33 below compares the costs for a 4-hour flow battery combined with a solar resource under the baseline assumptions and the sensitivity assumption.



Figure 6-33: Cost of a 2022 4-hr Flow Battery (2018 \$/kw-yr)

| Net Cost (\$/kw-yr) | Baseline | Sensitivity |
|-----------------------------|-----------|-------------|
| Variable Operating Expenses | - | - |
| Fixed Operating Expenses | 65 | 65 |
| Capital Expenditures | 316 | 213 |
| Flexibility Benefit | (185) | (139) |
| T&D Avoided Cost | (103) | - |
| Total Net Cost | 93 | 140 |

G. Electric Vehicle Load

How much does electric vehicle (EV) charging affect the loads and resource plan?

Baseline: IRP Base Demand Forecast.

Sensitivity: Add forecasted electric vehicle load.

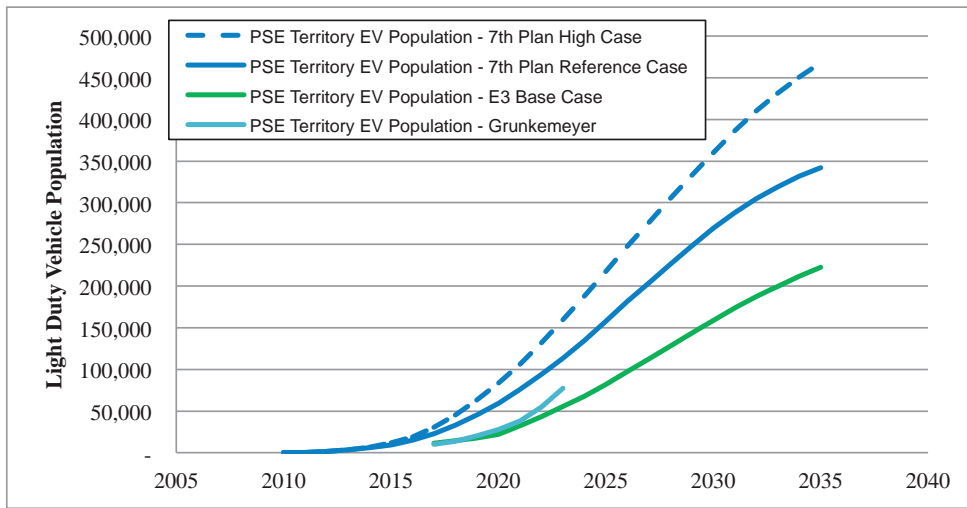
KEY FINDINGS. An increase in electric vehicle charging in PSE's service territory will increase both energy and peak needs. To meet the increased energy need, by 2037 the portfolio has 277 MW more of frame peakers to meet peak capacity needs and 44 MW more of solar to meet the increase in renewable need.

ASSUMPTIONS. This sensitivity models the impact of anticipated electric vehicle growth on resource needs. Currently, there are approximately 13,000 electric vehicles registered in PSE's electric service territory. The energy used in the sensitivity is built up from a forecast of the number of vehicles on the road and the charging patterns of the vehicles. The forward forecast for vehicles is based on joint work between PSE and Energy and Environmental Economics (E3). For Washington, the EV adoption curve starts with the plug-in electric vehicle (PEV) population as of the end of 2015 (according to the Washington State Department of Transportation, 2016), and it assumes a constant percentage population growth rate through 2020, meeting Governor Inslee's Results Washington goal of 50,000 PEVs in 2020. Between 2020 and 2030, annual sales of PEVs were assumed to have a constant, linear growth, reaching 15 percent of new passenger vehicle sales in 2030. This sales trajectory is consistent with PEV component cost reduction forecasts made by Ricardo PLC (PG&E, 2016). Annual PEV sales are then assumed to grow more slowly, at 2 percent per year until 2036. In



this study, the total Washington State PEV population reaches 528,000 vehicles by 2036. PSE's population over this time was scaled from the state-level forecast based on its current percentage of the EV population in Washington State, which is 44 percent. This forecast is compared to several other forecasts scaled to PSE's service territory in Figure 6-34 below; it is more fundamentals-based than the other forecasts shown.

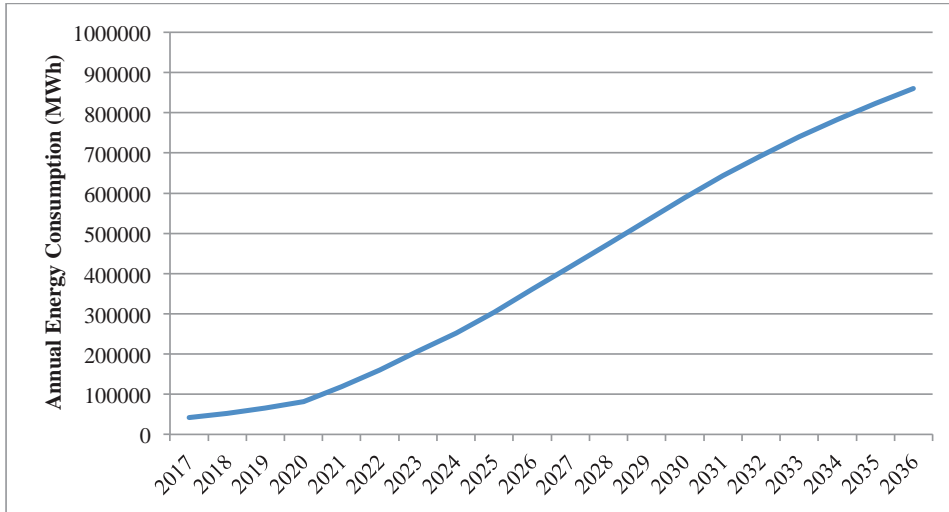
Figure 6-34: Light Duty Electric Vehicles in PSE's Service Territory, Forecast Comparison



This vehicle forecast is translated to energy delivered using data on vehicle charging from the EV Project model of how electric vehicles are charged and how often that includes residential charging, workplace charging, public charging and fast public charging.



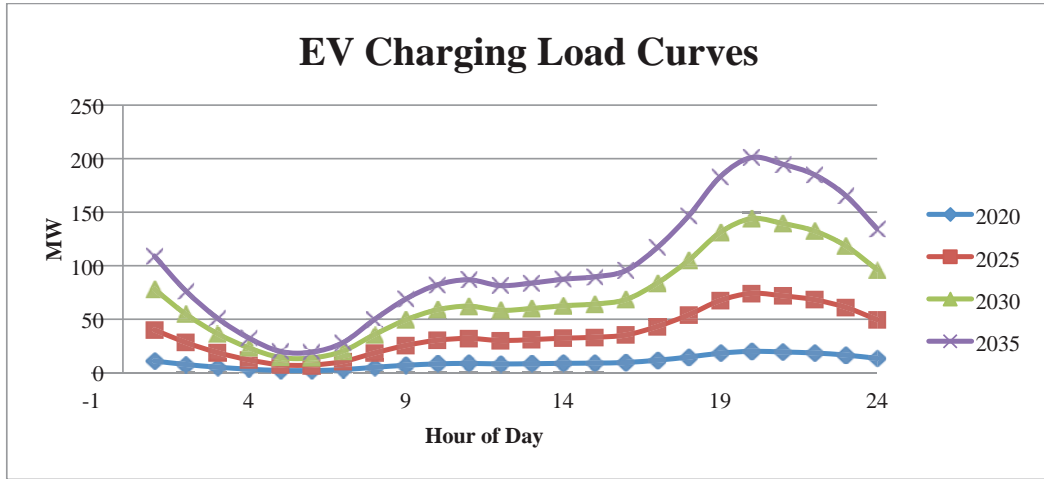
Figure 6-35: Electric Vehicle Annual Energy Consumption (MWh)



To develop the average load shape of the energy delivered, data from the EV Project and other sources were used to develop a time-based model of charging behavior that includes residential charging, workplace charging, public charging and fast public charging. The hourly profile for each of these types of charging was taken from the EV Project, and a model of how frequently each were used was applied. The result is an aggregate curve for charging. This curve, multiplied by the number of vehicles, provides the aggregate load curve used, which is shown for several time periods below. PSE anticipates updating the charging curve for residential charging based on its recent pilot project and will incorporate that into future analyses.

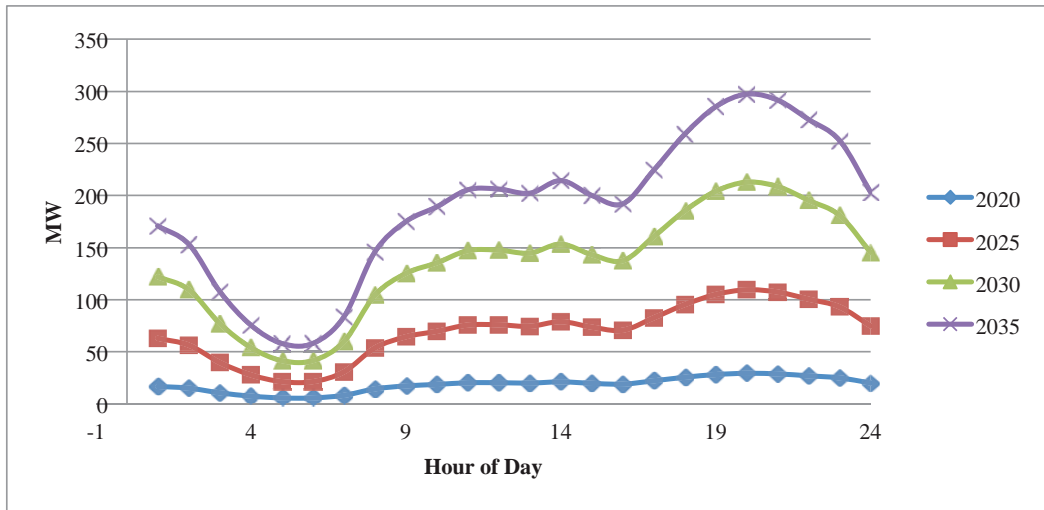


Figure 6-36: EV Charging Load Curves (MW)



Finally, an estimate of the necessary capacity was developed, which represents the highest power demanded by an aggregate population EVSEs (kW) over the course of 3 months. It is based on the highest aggregate demands observed in The EV Project and varies by weekend or weekday. PSE anticipates updating this capacity need based on its recently concluded residential electric vehicle pilot program.

Figure 6-37: EV Charging Load Curves (Peak)



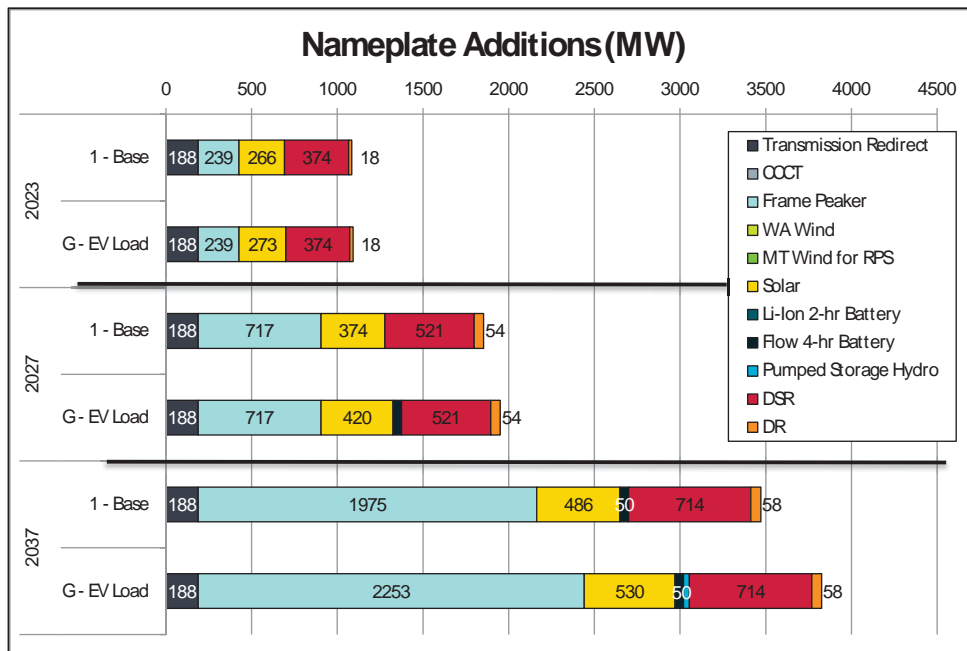
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It is important to note that these capacity curves anticipate that nothing is done to change the capacity need. In reality, utility programs would seek to minimize peak capacity impacts of electric vehicle charging, as has been recently indicated by the WUTC as a priority in Docket UE-160799.

RESULTS. Figure 6-38, below, shows the total nameplate additions for a portfolio with the EV load added to the 2017 IRP Base Demand Forecast. Both the annual energy consumption and the December peak increased, resulting in the need for more energy and capacity resources. The total portfolio cost with the EV load is \$12.3 billion, \$362 million more than the Base Scenario portfolio.

Figure 6-38: Nameplate Additions, Electric Vehicle Load Sensitivity





I. Demand-side Resources (DSR)

How much does DSR reduce cost, risk and emissions?

Baseline: All cost-effective DSR per RCW 19.285 requirements.

Sensitivity: No DSR. All needs met with supply-side resources.

Demand-side resources were found to reduce both cost and market risk in portfolios.

Figure 6-39 shows the optimal DSR bundle in each scenario. The avoided cost of capacity (this includes energy, capacity and renewable resources) plays a big role in the selection of the optimal bundle. In particular, the avoided cost of energy varies depending on the power price included in the scenario. (Detailed results by scenario, including avoided cost calculations, are presented in Appendix N, Electric Analysis.)

Demand-side resources must be cost effective to be included in the plan, so by definition they are also least-cost resources. The Base Scenario deterministic least-cost portfolio includes 772 MW of DSR by 2037.



Figure 6-39: Optimal DSR Results across Scenarios
Capacity in MW by 2037

| | | DSM | Demand Response | DE | C&S | Total |
|----|---|-----|-----------------|----|-----|-------|
| 1 | Base | 426 | 58 | 27 | 260 | 772 |
| 2 | Low | 371 | 67 | 27 | 260 | 725 |
| 3 | High | 441 | 148 | 27 | 260 | 876 |
| 4 | High + Low Demand | 426 | 67 | 27 | 260 | 781 |
| 5 | Base + Low Gas Price | 371 | 67 | 27 | 260 | 725 |
| 6 | Base + High Gas Price | 426 | 157 | 27 | 260 | 871 |
| 7 | Base + Low Demand | 426 | 58 | 27 | 260 | 772 |
| 8 | Base + High Demand | 426 | 157 | 27 | 260 | 871 |
| 9 | Base + No CO2 | 426 | 58 | 27 | 260 | 772 |
| 10 | Base + Low CO2 w/ CPP | 426 | 58 | 27 | 260 | 772 |
| 11 | Base + High CO2 | 426 | 58 | 27 | 260 | 772 |
| 12 | Base + Mid CAR only (electric only) | 426 | 157 | 27 | 260 | 871 |
| 13 | Base + CPP only (electric only) | 426 | 58 | 27 | 260 | 772 |
| 14 | Base + All-thermal CO2 (electric only) | 426 | 157 | 27 | 260 | 871 |



Demand response is a subset of DSR and is considered as part of determining the least-cost resources. A description of the demand response programs can be found in Appendix D, electric resources and Appendix J, Conservation Potential Assessment.

Figure 6-30 compares expected costs and cost ranges to illustrate how DSR reduces cost and risk in the portfolio. The amount of cost-effective conservation acquired varies across scenarios, but by 2035, the range is very tight, 725 MW to 876 MW. Compared to the Base Scenario portfolio with no DSR, the Base Scenario portfolio with DSR is lower cost and has a lower TVar90, which measures the risk of how costly a portfolio can get.

Figure 6-40: Effect of DSR on Costs and Risks

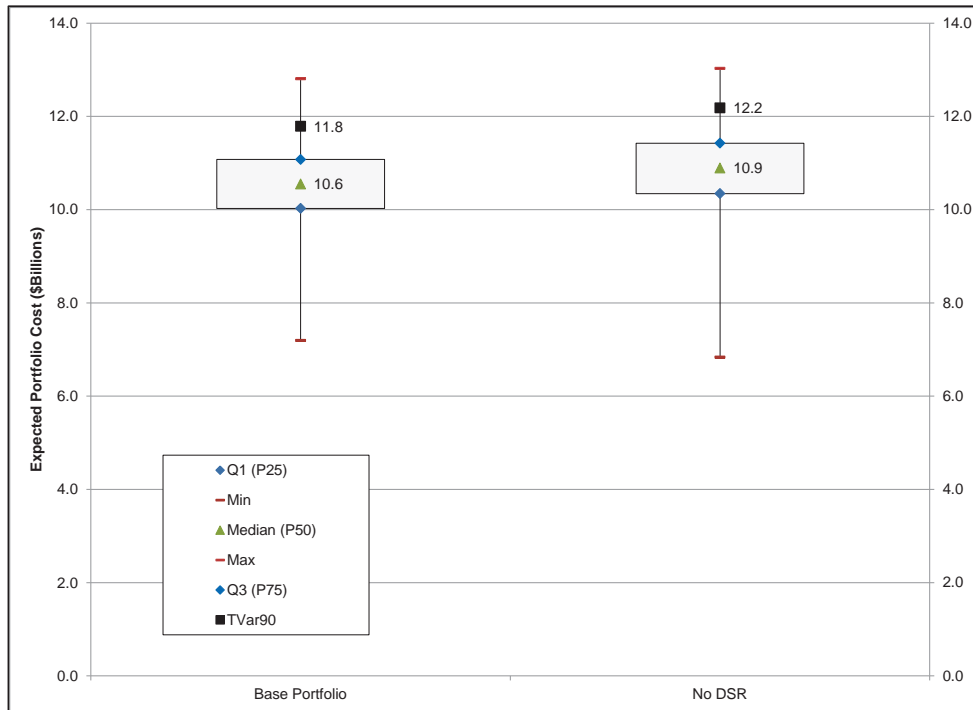




Figure 6-41 shows that DSR reduces power cost risk relative to no DSR. The TailVar90 of variable costs for the No DSR portfolio would be a little over \$297 million higher than the Base Scenario optimal portfolio with DSR. It also illustrates that the No DSR portfolio revenue requirement is \$555 billion more than the Base Scenario optimal portfolio, which reflects the higher costs of adding peakers instead of DSR. This is clearly a reasonable cost/risk tradeoff. Adding DSR to the portfolio reduces cost and risk at the same time.

Figure 6-41: Comparison of Expected Costs and Cost Ranges for No-DSR and Optimal Base Scenario Portfolios 20-yr NPV Portfolio Cost (dollars in billions)

| No CO2 Price | Base + DSR | Base + No DSR | Difference |
|---------------|------------|---------------|------------|
| Expected Cost | 11.98 | 12.54 | 0.56 |
| TVar90 | 11.8 | 12.2 | 0.40 |

J. Extended DSR Potential

What if future DSR measures extend conservation periods through the second decade of the study period?

Baseline: All DSR identified as cost-effective in this IRP is applied in the first 10 years of the study period.

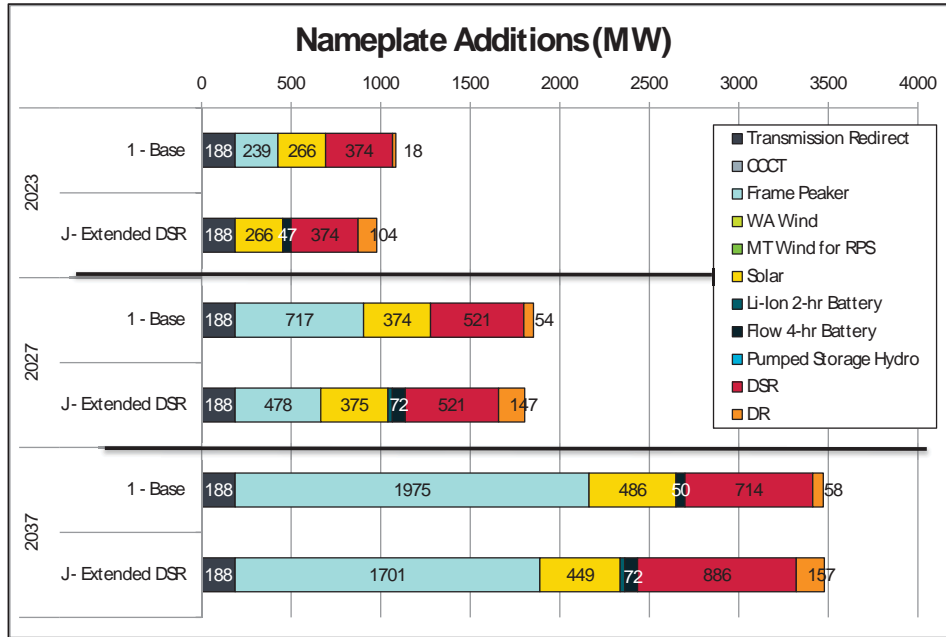
Sensitivity: Assume future DSR measures will extend conservation benefits through the second 10 years of the study period.

The conservation potential in the IRP assumes a 10-year ramp-in of all existing conservation potential, and then the conservation potential drops off to just new builds after 10 years. This leads to a large increase in loads after 10 years. Assuming the same amount of conservation is attached for the full 20 years does not change the conservation bundle chosen; however, given the increase in conservation for the later years, we have one less peaker and more demand response. Given the higher amount of demand response, the battery is chosen in the early years and the frame peaker is not built until 2025. The expected portfolio cost is \$11.89 billion, \$87 million lower than the Base Scenario portfolio.

Figure 6-42 below compares the nameplate additions of resources for the Base Scenario portfolio with the extended DSR portfolio. By 2037, the Base Scenario portfolio has 772 MW of DSR, and the extended DSR portfolio has 886 MW of DSR.



Figure 6-42: Nameplate Additions, Extended DSR Sensitivity





K. Alternate Residential Conservation Discount Rate

How would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation?

Baseline: Assume the base discount rate.

Sensitivity: Apply a societal discount rate to residential conservation savings.

An alternate discount rate was applied to the demand-side resource alternative in this sensitivity analysis (one that was lower than PSE's assigned WACC) to find out if it would result in a higher level of cost-effective DSR. The alternate discount rate was finalized as 1) the 3-month average of a long-term 30-year nominal treasury rate for residential customer class, and 2) the WACC discount rate for the commercial and industrial customer classes. The treasury rate used for developing the residential bundles was 2.94 percent. The impact was to shift measures to lower cost points on the conservation supply curve.

This alternate discount rate was used to estimate the DSR achievable potential for the new residential portion of the DSR bundles. These "alternate discount rate" bundles were then input into the portfolio model to obtain the cost-effective level of DSR.

KEY FINDINGS. Changing the discount rate for residential energy efficiency does not have a material impact on the cost-effective bundle of conservation in terms of peak capacity reduction. Changing the discount rate does change the mix of individual measures that make up the bundles. When the measures are reshuffled in this way, by 2037 the cost-effective peak capacity savings is slightly lower (by 21 MW), which is approximately a 3 percent reduction. The cumulative annual energy savings also decreases slightly, by 4 percent (17 aMW). It is possible that creating a new bundle (between Bundles 2 and 3) could show a slightly higher level of conservation, but given that this sensitivity analysis shows an immaterial impact, additional analysis is not warranted.



As shown in Figure 6-43, the electric conservation potential is pushed into lower cost bundles. However, now that the lower cost bundles have a higher level of DSR, this sensitivity is choosing Bundle 2 with a similar amount of DSR as Bundle 3 from the baseline.

Figure 6-43: DSR Potential

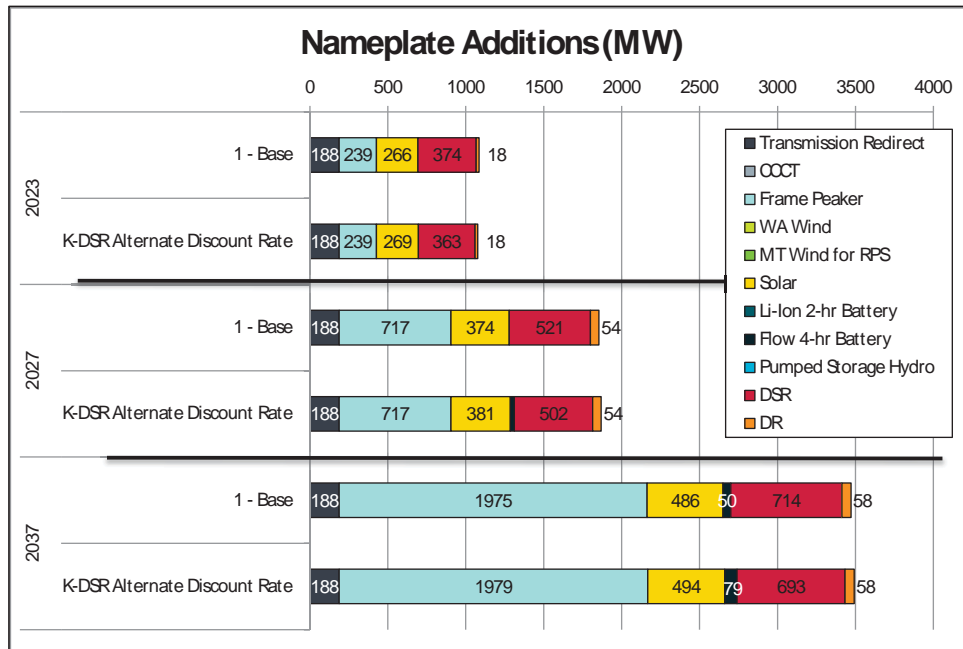


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Figure 6-44 below compares the nameplate additions of resources for both Base Scenario portfolio DSR discount rate and the alternate discount rate. The Base Scenario portfolio has 772 MW of DSR, and the alternate discount rate portfolio has 693 MW of DSR.

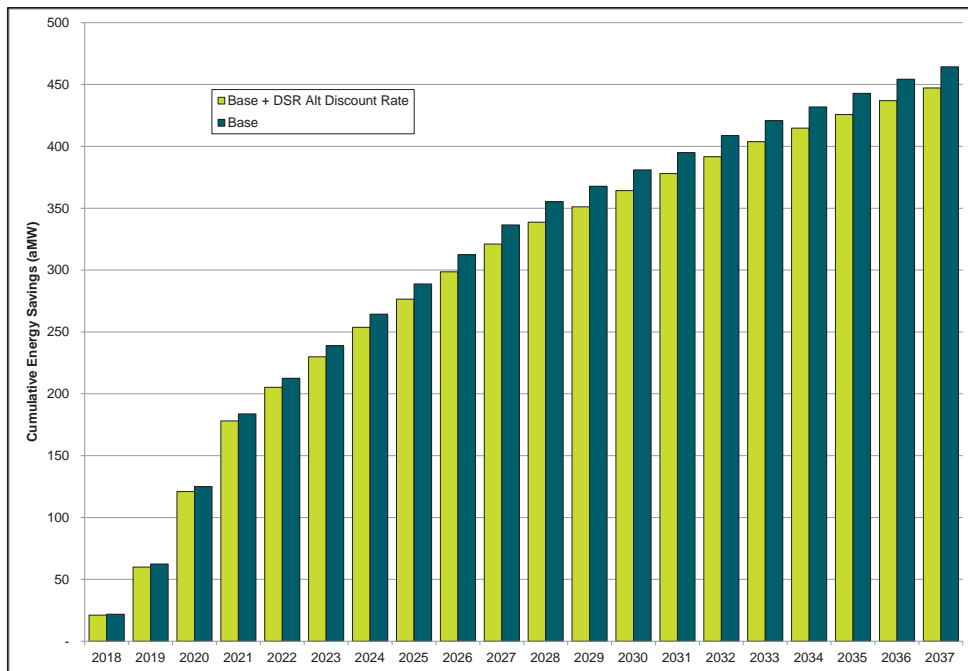
Figure 6-64: Nameplate Additions, Alternate Residential Conservation Discount Rate





The cumulative energy savings are down slightly, as a result of reshuffling measures into the cost bundles. Figure 6-45 shows a slight reduction in the cumulative energy savings over time. By 2037, the difference is 17 aMW, or about 4 percent.

Figure 6-45: Impact on Cumulative Energy Savings is Immaterial





L. RPS-eligible Montana Wind

What is the cost difference between a portfolio with and without Montana wind?

Baseline: RPS-eligible Montana wind included only if chosen economically.

Sensitivity 1: Montana wind included in 2022 instead of solar.

- a. 300 MW in 2022
- b. 150 MW in 2022
- c. 175 MW in 2022

Sensitivity 2: Add Montana wind that does not qualify as RPS resource.

Sensitivity 3: Montana wind tipping point analysis on RPS vs. non-RPS resources.

KEY FINDINGS. Montana wind does not appear to be a cost-effective resource, even if it were able to meet the requirements of a qualifying renewable resource under RCW 19.285. Although it is possible that a specific Montana wind resource could look cost effective in an RFP if it were a qualifying resource, the likelihood of achieving that designation is very small at this time. To qualify under current law, Montana wind must be delivered to Washington state on a real-time basis without shaping or storage, and this provision would require coordination across multiple non-Washington state jurisdictional transmission entities in a process that doesn't currently exist. This is probably not commercially viable process for a developer or PSE. The analysis may still be helpful in the event the law is changed.

SUMMARY. Montana wind has the benefit of higher capacity factors than Washington wind (46 percent versus 30 percent), but it also requires added transmission costs to move the power to PSE's system. In addition, whether Montana wind qualifies as a qualifying renewable resource under RCW 19.285 depends on the location of the facility, and most of the prime wind resources in Montana are outside the footprint defined in the law. A complete discussion of the costs assumed for Montana wind can be found in Appendix D, Electric Analysis.

The first part of this sensitivity added 300 MW of Montana wind in 2022 instead of the economically chosen solar. Given the wind's higher capacity factor, this was enough energy to meet all of PSE's renewable needs for the next 20 years; however, adding Montana wind to the portfolio added \$82 million to the total portfolio cost. Adding 300 MW of non-RPS qualified Montana wind would drive portfolio costs even higher. The portfolio would cost \$12.24 billion, \$257 million more than the Base Scenario portfolio and would only offset one frame peaker in 2022.

Instead of adding the full 300 MW of MT wind, we tested the assumption that PSE can share the resource with another company; allowing PSE to get a size that better fits our needs. We tested 150 MW (half a plant), but this not enough to meet the 2023 RPS needs, so solar is also added to make

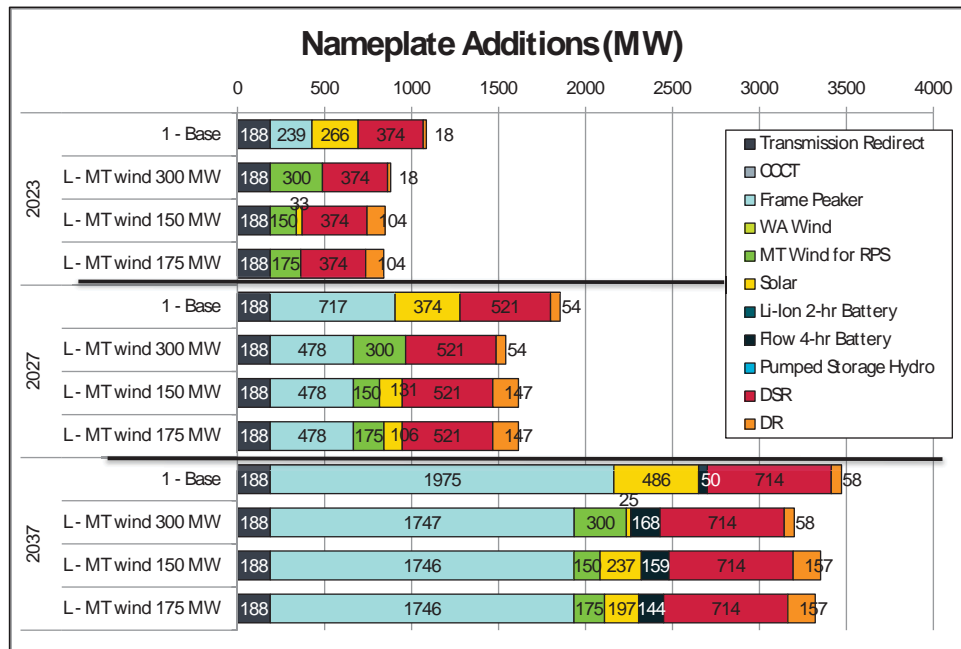
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sure the portfolio is balanced. In order to meet the 2023 RPS needs, we need 175 MW of MT wind, so we also tested this size. Adding 150 MW of RPS-eligible Montana wind increased the portfolio cost by \$35 million and adding 175 MW increased cost by \$42 million

Figure 6-46 shows the total nameplate additions for the Base Scenario portfolio and a portfolio with Montana wind.

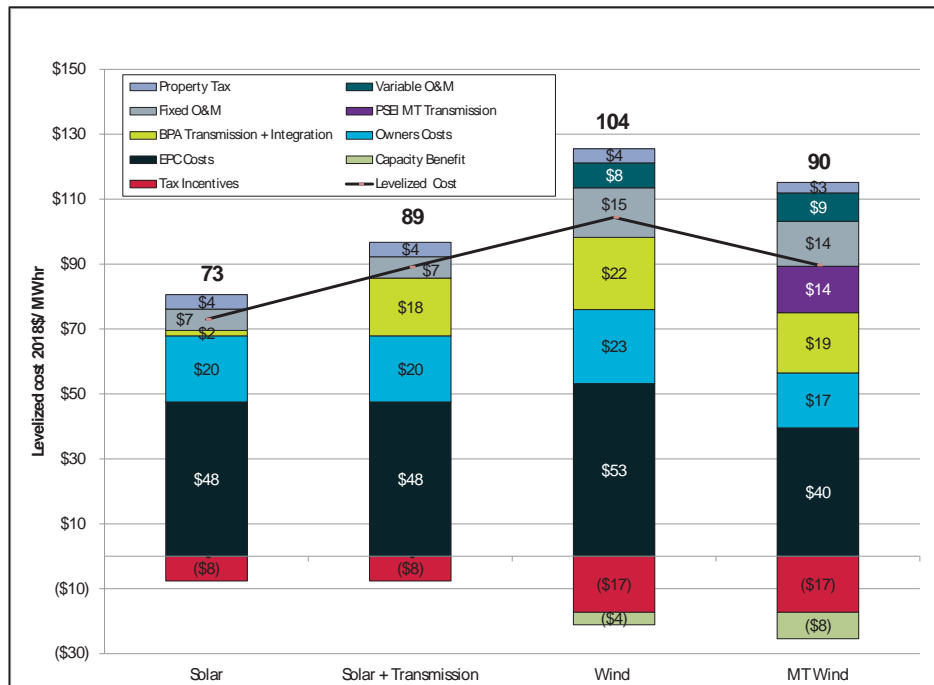
Figure 6-46: Nameplate Additions, RPS-eligible Montana Wind Sensitivity





To be cost-competitive with solar resources at this time, the total cost of Montana wind would have to decrease by 16 percent. Figure 6-47 shows that Montana wind has a total levelized cost of \$90/MWh, including the capacity value.

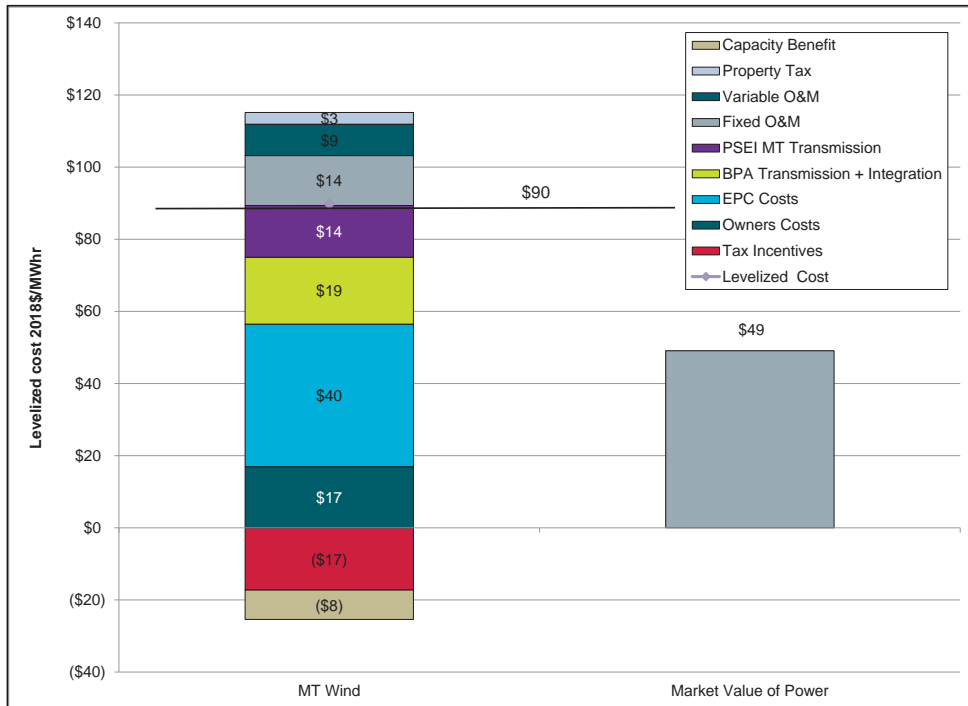
Figure 6-47: Wind and Solar Cost Components





If Montana wind is not a qualifying renewable resource, the cost reductions would have to be more significant. Figure 6-48 shows the same levelized cost of Montana wind as the prior chart – including the peak capacity value – but compared to wholesale market prices that do not include peak capacity value.

Figure 6-48: Wind and Solar Cost Components





M. Offshore Wind Tipping Point Analysis

How much would the cost of offshore wind need to drop in order for it to be a cost-competitive resource?

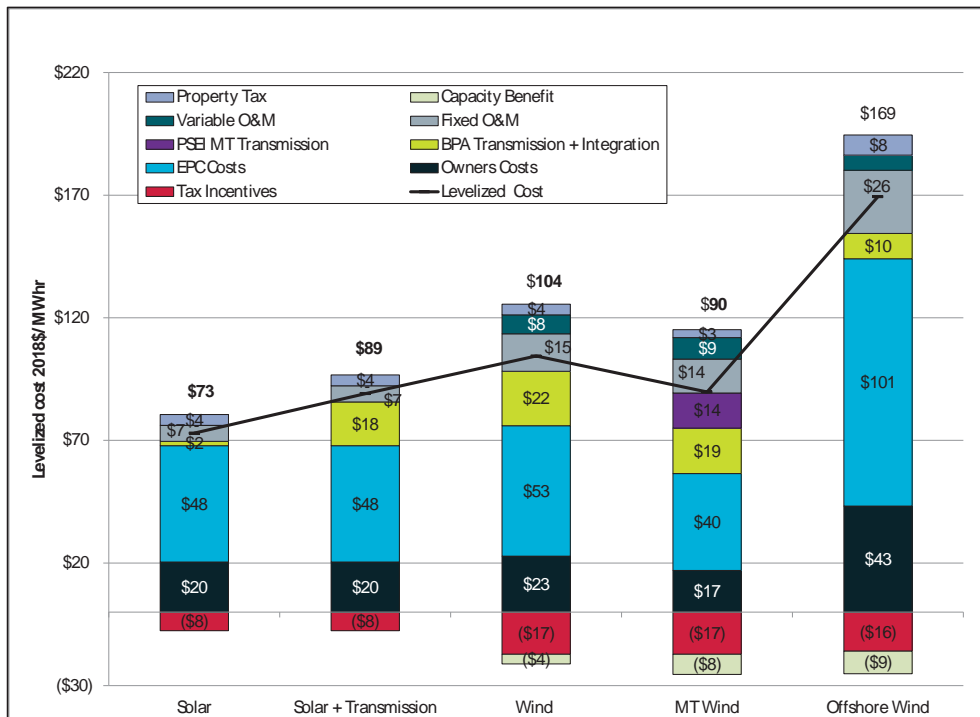
Baseline: Offshore wind not tested in the portfolio analysis.

Sensitivity: Offshore wind tipping point.

The current capital cost assumptions for wind from the DNV GL report on Washington state wind and solar costs is \$5,500/kW EPC plus 30 percent owner's cost. The capital cost of offshore wind would have to drop by 73 percent, to \$1,965/kw, including owner's costs, to be a cost-competitive resource.

Figure 6-49 below compares offshore wind costs to solar and onshore wind costs.

Figure 6-49: Offshore Wind Cost Components





N. Hopkins Ridge Repowering

Would repowering Hopkins Ridge for the tax incentives and bonus RECS be cost effective?

Baseline: Hopkins Ridge repowering is not included in the portfolio.

Sensitivity: Include Hopkins Ridge repowering in the portfolio to replace the current facility.

Repowering refers to the upgrade and renovation of an existing wind project to extend its generation life and possibly expand its production capability. The PATH Act of 2015 extends Production Tax Credits (PTCs) to repowered facilities. The economics of repowering are driven assuming the PTCs will offset the initial capital required.

KEY FINDINGS. Currently PSE is in tax loss situation where it has been unable to utilize the production tax benefit for a number of years. As a result, PSE has built a significant balance of unutilized PTCs over time. This analysis assumes the PTC can be utilized in the year of installation. The PTC rate is being phased down over time with the effective rate of 60 percent for 2018 construction start dates. To start construction any sooner than 2018 would lock PSE into a technology decision before the repowering decision was fully vetted. The results of the analysis indicate that it would add \$40 million in costs to repower Hopkins Ridge. Based on these results, PSE would not move forward with the repowering of this wind facility.

Figure 6-50: Cost-Comparison, Hopkins Ridge Repowering Sensitivity

| \$ in Millions | Base Scenario | |
|-------------------------|----------------|----------------|
| | Portfolio Cost | Benefit/(Cost) |
| Base Scenario Portfolio | \$11,981 | |
| Repower Hopkins Ridge | \$12,021 | (\$40) |
| Repower Wild Horse | \$12,023 | (\$42) |



8. COST OF CARBON ABATEMENT ANALYSIS RESULTS

This analysis focuses on investigating overall WECC-wide impacts of different policies aimed at carbon abatement. This perspective allows the overall effectiveness of such policies to be examined. Policies that affect the economic operation of carbon-emitting resources in one part of the WECC can affect neighboring areas through adjusted interchange transactions. In other words, disincentivizing carbon emissions in one region can make imports from regions without carbon abatement policies more attractive. Eleven alternatives were analyzed.

Figure 6-51: Carbon Abatement Alternatives Analyzed

| COST OF CARBON ABATEMENT ALTERNATIVES ANALYZED | | |
|--|--|---|
| <i>PSE Portfolio Alternatives</i> | | |
| A | Additional Wind | Add 300 MW of wind beyond RPS requirements. |
| B | Additional Utility-scale Solar | Add 300 MW of utility-scale solar beyond RPS requirements. |
| C | Additional Electric Conservation – Incremental | Increase conservation by 2 bundles relative to least-cost portfolio. |
| D | Additional Electric Conservation – All | Increase conservation to incorporate the entire conservation potential assessment available at any cost. |
| E | Cost-effective Electric DSR | Impact of acquiring all cost-effective electric conservation. |
| <i>Policy Alternatives</i> | | |
| F | 50% RPS in Washington | Increase Washington RPS to 50% by 2040. |
| G | CAR Cap on Washington CCCT plants | Reduce the emissions of the CCCT plants in Washington to comply with the Washington Clean Air Rule CO ₂ emission baseline. |
| H | Early Colstrip 3 & 4 Retirement | Retire Colstrip 3 & 4 in 2025, rather than 2035, replacing it with the least-cost resources. |
| <i>Gas Utility Alternatives</i> | | |
| I | Additional Gas Conservation – Incremental | Increase conservation by 2 bundles relative to least-cost portfolio. |
| J | Additional Gas Conservation – All | Increase conservation to incorporate the entire conservation potential assessment available at any cost. |
| K | Cost-effective Gas DSR | Impact of acquiring all cost-effective gas conservation. |



Methodology

The purpose of this analysis is to estimate the amount of carbon reductions possible from different alternatives and to estimate the cost per ton for those reductions. This allows us to create a carbon abatement supply curve, with total tons on the horizontal axis and annualized costs per ton on the vertical axis, as shown in Figure 6-52.

The alternatives examined can be grouped into three categories: changes to PSE's electric portfolio, larger policy changes in Washington state, and natural gas utility related alternatives. The same basic methodology was used to calculate the tons and costs per ton across all alternatives, though the tools and modeling methods needed to be different for the different categories.

ANNUALIZED COST. The cost for each abatement alternative was estimated by starting with the least cost portfolio in the Base + No CO₂ Scenario. This scenario was chosen to avoid biasing the analysis with policy changes, since some policy changes are examined. We implemented the abatement alternative, then examined the impact on cost to PSE's portfolio and the estimated emission reduction. The cost in dollars is the levelized, net present value of the annual cost impacts for 20 years. Portfolio costs were estimated using PSM III for electric alternatives and SENDOUT for natural gas utility alternatives.

ANNUALIZED TONS. Annualized tons is the levelized net present value of the annual emission reductions over 20 years for each alternative; in other words, it represents the average emission reductions on a per ton basis over the planning horizon.

COST PER TON. Using the levelized cost divided by levelized tons provides a reasonable estimate given that the timing of costs incurred and/or tons reduced are changing over time.

For electric portfolio alternatives, we used the AURORA model to estimate how the alternative would affect the dispatch of resources across the entire WECC. For example, in the Additional Utility-scale Solar Alternative, we added 300 MW of solar in eastern Washington, then re-dispatched resources across the entire WECC and calculated the change in emissions. This allows us to estimate the annual change in emissions from across the WECC, since adding solar in Washington can have impacts across the western U.S.

For the larger policy-related alternatives, estimating the cost per ton is more complicated. Our portfolio model is designed to estimate the costs to PSE's portfolio, not other investor-owned utilities or publicly owned utilities. That is, we can use AURORA to estimate the total impact on carbon emissions of a 50 percent RPS, but that analysis does not provide the cost. To address this, we estimated the cost per ton using PSE's costs as a proxy, as described below.



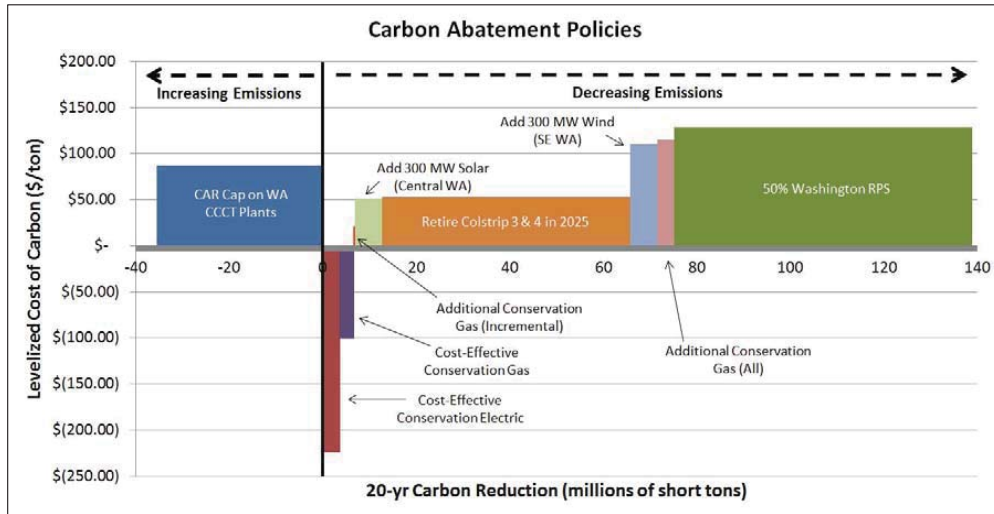
- 50 percent RPS: We used PSM III to build the optimal portfolio to meet the 50 percent RPS targets. This provided the annual portfolio costs and the schedule of resource builds. We then input the schedule of builds into AURORA and re-dispatched the entire WECC with those resources. Then we levelized the annual costs from PSM and levelized the annual carbon reductions from the WECC-wide AURORA analysis. We divided the levelized cost by the levelized tons as the estimate for the cost per ton. Estimating the total tons depicted on the horizontal axis in Figure 6-52 was more straightforward. We increased the Washington state RPS in AURORA and calculated the emission reductions compared to the Base + No CO₂ Scenario. Thus, the vertical axis in Figure 6-52 represents PSE's annualized cost per ton if we complied with a 50 percent RPS, and the horizontal axis depicts the total tons of carbon reductions assuming the policy is applied to all utilities in Washington.
- CAR Cap on Washington CCCT Plants: Similar to the 50 percent RPS, we estimated PSE's cost per ton for the vertical axis of Figure 6-52; then on the horizontal axis, we used the summation of capping all CCCT plant dispatch to estimate the impact on total tons if the policy was applied to all CCCT plants in the state.
- Colstrip 3 & 4 Early Retirement: This alternative is in the larger policy category, because PSE is only part-owner of Colstrip 3 & 4, and PSE alone does not have the ability to retire the plant. To calculate the cost per ton, we used the portfolio analysis presented in the Colstrip Early Retirement Alternative in the Base + No CO₂ Scenario for the annual revenue requirement impact. Then we ran AURORA in the Base + No CO₂ Scenario for the entire WECC, to estimate the emission reduction from retiring Colstrip 3 & 4 in 2025. PSE owns 25 percent of Colstrip, so we took 25 percent of the emission reductions and levelized them to calculate the cost per ton. The vertical axis in Figure 6-52 represents an estimate of PSE's cost per ton; the horizontal axis represents the impact of retiring the entire plant in total tons.

For the natural gas utility alternatives, dollars per ton were estimated directly, based on the volume of gas conserved (or not) for each alternative.



Figure 6-54 below lines up the emission reduction alternatives into a carbon abatement curve. The alternatives to the left of the line increase emissions in the WECC and the policies to the right of the line decrease emissions in the WECC. The vertical axis represents the levelized annual cost per ton of the CO₂ emission reductions, and the horizontal axis represents the summation of the total emissions reduction resulting from each alternative. The alternatives are lined up from least costly to most costly.

Figure 6-52: Carbon Abatement Curve
(Total tons reflects total WECC impact.)



Key Findings

Eleven alternatives were investigated in the Base + No CO₂ Scenario.

In the case of Alternative G, which models the CAR cap on Washington CCCT plants, CCCTs in Washington are emissions-limited, which increases reliance on new and existing peakers, and increases dispatch of less efficient CCCT plants and existing coal resources in WECC. This illustrates that CAR caps on CCCT plants increase carbon emissions when examined on a total WECC-wide system basis, which is why the data point is a negative abatement on the horizontal axis.

Two alternatives reduce carbon with a negative cost per ton: Alternative E and Alternative K. These are the Cost-effective Electric Conservation and the Cost-effective Gas Conservation alternatives. "Cost-effective" conservation means it saves money and reduces carbon.



For Alternative C, Additional Electric Conservation – Incremental, a very small increase in carbon emissions is observed coincident with a small decrease in net load. The small increase in CO₂ emission is caused by the economic shift in resources. In this case, the small decrease in load was enough to run the coal plants plus peakers to meet the peaks instead of cycling down the coal plants and running CCCT plants to meet loads and peaks in the reference case. However, the observed increase in carbon emissions is relatively low, and this could be statistical noise or a modeling artifact. Therefore, we chose not to include this in Figure 6-52.

Alternative A, Additional Wind, and Alternative B, Additional Utility-scale Solar, reduce carbon emissions by reducing net demand in the system through injections of wind or solar power, respectively, into Washington. The reductions in carbon emissions observed in these two cases are from the least efficient resources available: existing coal and older gas plant dispatch.

Alternative F, 50 percent RPS in Washington, would have a relatively large reduction in emissions, but it is also a relatively high-cost alternative. In reality, there would be operational issues, including transmission capacity, that could increase the costs even more. The 50 percent RPS in Washington alternative reduces emissions in the WECC by increasing the non-carbon emitting resources, and thereby reducing demand for coal and existing CCCT.

Alternative H, the early Colstrip 3 & 4 retirement shows the cost per ton is about equivalent to adding 300 MW of solar, but the potential carbon savings is significantly greater. As mentioned above, this is not simply the carbon savings from retiring Colstrip in 2025, it reflects the fact that other resources need to be ramped up; that is, these results are net of leakage.

Alternative D, Electric Conservation – All, would produce a relatively large reduction in carbon emissions, but at a very high cost. The cost is so high that we chose not to include it on this chart, as it is not realistic and would make it difficult to see differences in some of the other alternatives on the chart.

Carbon abatement through gas conservation was investigated in Alternatives, I, J and K, and all were found to reduce emissions. The incremental conservation that was investigated in Alternative I had a negligible impact on emissions, while pursuing the entire gas conservation potential in Alternative J, Additional Gas Conservation – All, was found to be relatively high cost, but slightly less costly than the 50 percent RPS alternative.

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Figure 6-53 below is a table of the total portfolio costs (in millions), regional emissions (in tons of CO₂) and the dollars per ton cost for the emission reduction.

Figure 6-53: Emission Reduction Costs for 9 Electric Portfolios

| | Deterministic Portfolio Cost (Levelized Millions \$) | Difference from Base (Millions \$) | Regional Emissions (Levelized Millions Tons) | Difference from Base (Millions Tons) | Cost of Carbon Reduction (\$/ton) |
|--|--|------------------------------------|--|--------------------------------------|-----------------------------------|
| 1 – Base + No CO2 Scenario | 1,025 | | 334.91 | | |
| A – Additional Wind | 1,050 | 25 | 334.68 | (0.23) | 110.56 |
| B – Additional Utility-scale Solar | 1,037 | 12 | 334.67 | (0.23) | 50.66 |
| C – Additional Electric Conservation – Incremental | 1,048 | 23 | 334.96 | 0.05 | (450.53) |
| D – Additional Electric Conservation – All | 2,683 | 1,658 | 332.53 | (2.38) | 697.72 |
| E – Cost-effective Electric DSR | 1,082 | 57 | 335.16 | (0.25) | 224.06 |
| F – 50% RPS in Washington | 1,090 | 65 | 334.40 | (0.51) | 128.29 |
| G – CAR cap on Washington CCCT plants | 1,063 | 120 | 335.34 | 0.43 | (87.41) |
| H – Early Colstrip 3 & 4 Retirement | 1,051 | 26 | 332.93 | (1.98) | 52.61 |

Figure 6-54: Emission Reduction Costs for 4 Gas Portfolios

| | Deterministic Portfolio Cost (Levelized Millions \$) | Difference from Base (Millions \$) | Regional Emissions (Levelized Millions Tons) | Difference from Base (Millions Tons) | Cost of Carbon Reduction (\$/ton) |
|---|--|------------------------------------|--|--------------------------------------|-----------------------------------|
| 2 – Base + No CO2 Scenario | 5,599 | | 59.77 | | |
| I – Additional Gas Conservation – Incremental | 5,601 | 2 | 59.69 | (0.08) | 20.45 |
| J – Additional Gas Conservation – All | 5,768 | 169 | 58.30 | (1.47) | 114.83 |
| K – Cost-effective Gas DSR | 5,716 | 117 | 60.94 | 1.16 | (100.17) |



9. SUMMARY OF STOCHASTIC PORTFOLIO ANALYSIS

With stochastic risk analysis, we test the robustness of different portfolios. In other words, we want to know how well the portfolio might perform under a range of different conditions. For this purpose, we take the portfolios (drawn from the deterministic scenario and sensitivity portfolios) and run them through 250 draws¹¹ that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO₂ regulations/prices. From this analysis, we can observe how risky the portfolio may be and where significant differences occur when risk is analyzed.

Eight different portfolios were tested in the stochastic portfolio analysis. Figure 6-55 below describes the eight different portfolios.

Figure 6-5: Portfolios Tested for Stochastic Analysis

| Portfolios Tested for Stochastic Analysis | | |
|---|--|--|
| 1 | Base Scenario Portfolio | This is the optimal portfolio for the Base Scenario. It includes frame peakers for capacity and solar for the RPS. |
| 2 | Base + No CO2 portfolio | This is the optimal portfolio for the Base + No CO2 scenario. It includes CCCT for capacity and solar for the RPS. |
| 3 | No DSR | This portfolio is from the no DSR sensitivity. |
| 4 | Add 300 MW Utility Scale Solar | This portfolio is from the carbon abatement analysis. |
| 5 | No Transmission Redirect | Remove the transmission redirect as an option in the Base Scenario portfolio. |
| 6 | No New Thermal | This portfolio is from the no new thermal sensitivity. |
| 7 | Additional Electric Conservation – Incremental | Increase conservation by 2 bundles relative to least-cost portfolio (from the carbon abatement analysis). |
| 8 | Resource Plan | Batteries plus more DR in 2023, and solar moved to 2022. |

One must approach results of this analysis carefully. This approach holds portfolios constant across the 14 different scenarios. In reality, PSE will not blindly follow any one of these resource

¹¹ / Each of the 250 simulations is for the twenty-year IRP forecasting period, 2018 through 2037.

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plan forecasts in the future – resource acquisitions will be made based on the latest information. In a resource acquisition, PSE and our customers would be locking into a decision that will be with us for a long time into an uncertain future. Additionally, the approach of measuring risk across a long planning horizon is not illustrative of annual risk profiles. Time is a hedge; that is, over 20 years, high-cost years will cancel out low-cost years, so risk is dampened by the long planning horizon. Looking at a one-year snapshot of risk may help. However, as different portfolios may have resources coming in during different years, a one-year snapshot may be misleading. Again, this is not a problem for a resource acquisition decision. Recall, one of the primary reasons for doing an IRP is to develop tools and frameworks to support making good resource acquisition decisions on behalf of our customers.

In Figure 6-56 below, the Base + No CO₂ portfolio includes baseload CCCT plants as the lowest cost resource, but since the stochastic analysis takes into account many different futures we see that the mean of the frame peaker portfolio is actually lower cost than the all-baseload gas portfolio.

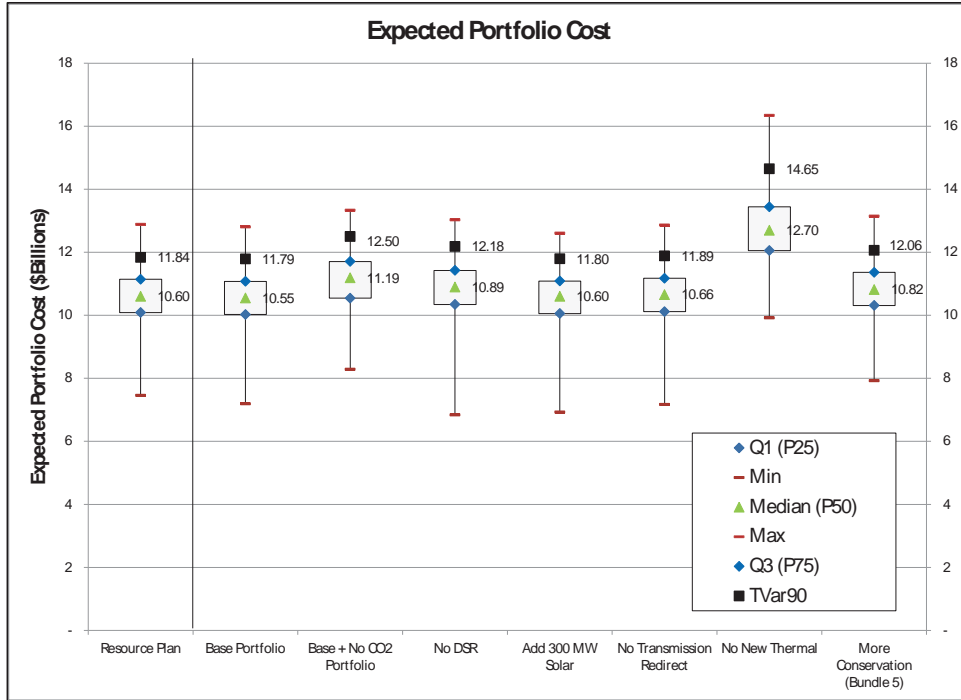
Figure 6-56: Results of Stochastic Analysis

| NPV (\$Billions) | Mean | Difference from Base | % Change | TVar90 | Difference from Base | % Change |
|--|-------|----------------------|----------|--------|----------------------|----------|
| 1 – Base Scenario portfolio | 10.52 | | | 11.79 | | |
| 2 – Base + No CO2 portfolio | 11.13 | 0.61 | 5.8% | 12.50 | 0.71 | 6.0% |
| 3 - No DSR | 10.84 | 0.32 | 3.1% | 12.18 | 0.40 | 3.4% |
| 4 - Add 300 MW Utility Scale Solar | 10.54 | 0.03 | 0.3% | 11.80 | 0.01 | 0.1% |
| 5 - No Transmission Redirect | 10.62 | 0.10 | 0.9% | 11.89 | 0.10 | 0.8% |
| 6 - No New Thermal | 12.69 | 2.18 | 20.7% | 14.65 | 2.86 | 24.3% |
| 7 - Additional Electric Conservation – Incremental | 10.81 | 0.29 | 2.7% | 12.06 | 0.27 | 2.3% |
| 8 - Resource Plan | 10.57 | 0.05 | 0.5% | 11.84 | 0.05 | 0.4% |

In this IRP, the lowest cost thermal resource varied between the frame peaker and the CCCT depending on the scenario. But the stochastic analysis indicates that frame peakers reduced the cost and risk of the portfolio. This is because the CO₂ regulations modeled targeted baseload thermal plants like CCCT and coal plants, not the peaker plants.



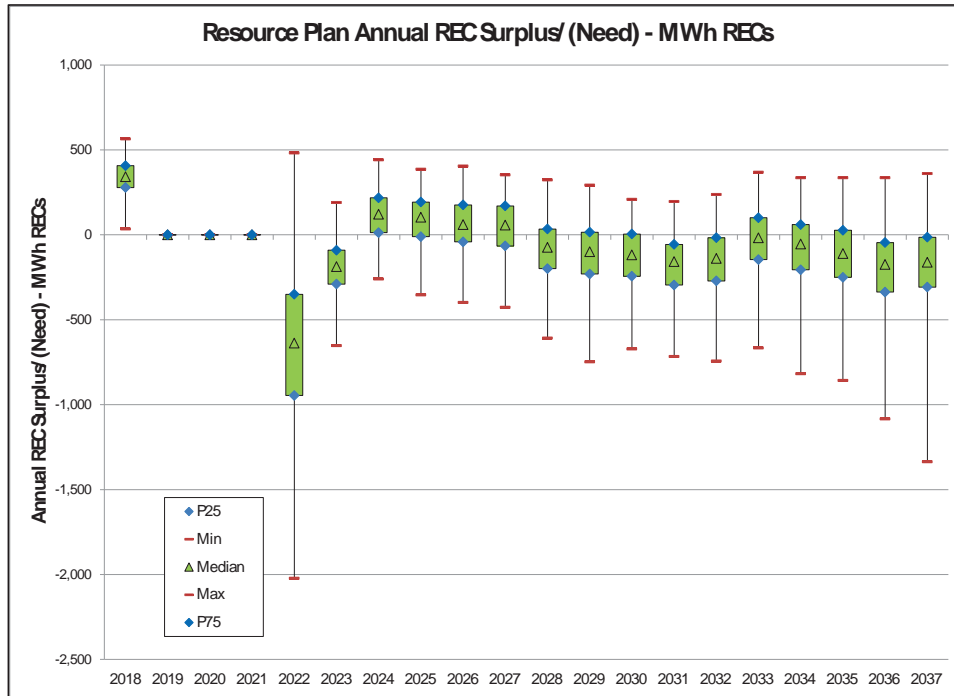
Figure 6-57: Range of Portfolio Costs across 1,000 Trials



In the Base Demand Forecast, the first large renewable build is in 2023. The Washington RPS increases to 15 percent in 2020, but with banking, we are able to push the first build to 2023. However the stochastic results in which the loads and wind generation are varied shows it is most likely there will not be enough RECs for 2022. So, PSE will need to move the 2023 build to 2022 to make sure we are in compliance with RCW 19.285.



Figure 6-58: Annual REC Surplus/(Need) for the Resource Plan Forecast (MWh RECs)





7

2017 PSE Integrated Resource Plan

Gas Analysis

This analysis enables PSE to develop valuable foresight about how resource decisions to serve our natural gas customers may unfold over the next 20 years in conditions that depict a wide range of futures.

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1. RESOURCE NEED AND KEY ISSUE

Resource Need

More than 800,000 customers in Washington state depend on PSE for safe, reliable and affordable natural gas services.

PSE's gas sales need is driven by peak day demand, which occurs in the winter when temperatures are lowest and heating needs are highest. The current design standard ensures that supply is planned to meet firm loads on a 13-degree design peak day, which corresponds to a 52 Heating Degree Day (HDD).¹ Two primary factors influence demand, peak day demand per customer and the number of customers. The heating season and number of lowest-temperature days in the year remain fairly constant and use per customer is growing slowly, if at all, so the the biggest factor in determining load growth at this time is the increase in customer count.

The IRP analysis tested three customer demand forecasts over the 20-year planning horizon: the 2017 IRP Base Demand Forecast, the 2017 IRP High Demand Forecast and the 2017 IRP Low Demand Forecast.²

- In the Low Demand Forecast, we have sufficient firm resources to meet peak day need until the winter of 2035/36.
- In the Base Demand Forecast, the first resource need occurs in the winter of 2018/19 in the study, after that, there are sufficient firm resources to meet peak day need until the winter of 2022/23.
- In the High Demand Forecast, we do not have sufficient firm resources to meet peak day need throughout the study.

Figure 7-1 illustrates gas sales peak resource need over the 20-year planning horizon for the three demand forecasts modeled in this IRP. Figure 7-2 shows the resource need surplus/deficit for the Base Demand Forecast.

¹ / HDDs are defined as the number of degrees relative to the base temperature of 65 degrees Fahrenheit. A 52 HDD day is calculated as 65° less the 13° temperature for the day.

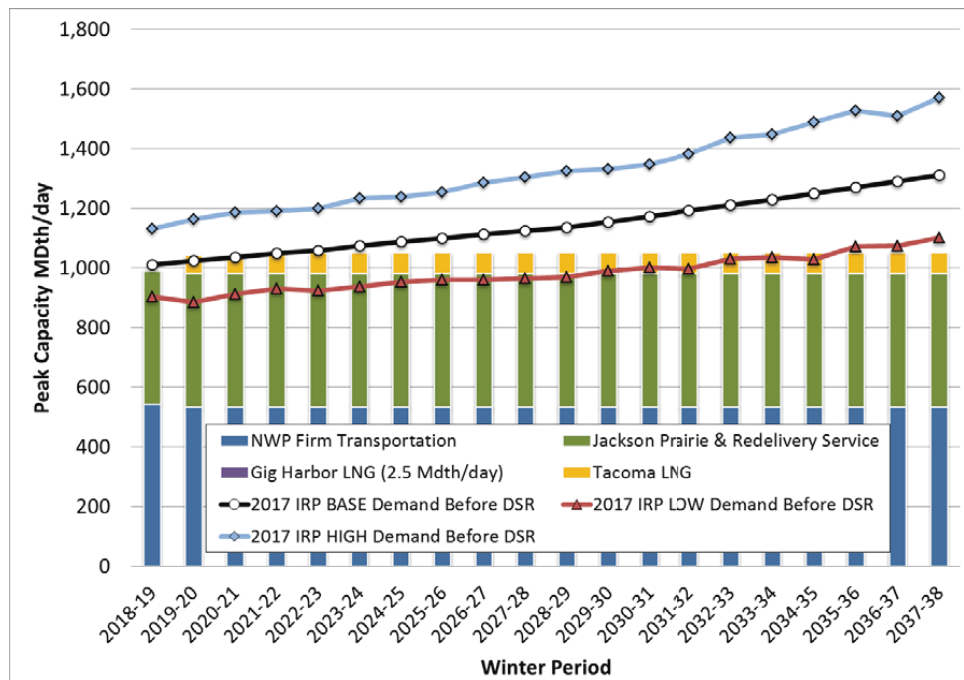
² / The 2017 IRP demand forecasts are discussed in detail in Chapter 5, Demand Forecast.

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In Figure 7-1, the lines rising toward the right indicate peak day customer demand before demand-side resources (DSR),³ and the bars represent existing gas supply resources to deliver gas to our customers. These resources include contracts for transporting natural gas on interstate pipelines from production fields, storage projects and on-system peaking resources.⁴ The gap between demand and existing resources represents the resource need.

Figure 7-1: Gas Sales Peak Resource Need before DSR, Existing Resources Compared to Peak Day Demand (Meeting need on the coldest day of the year)

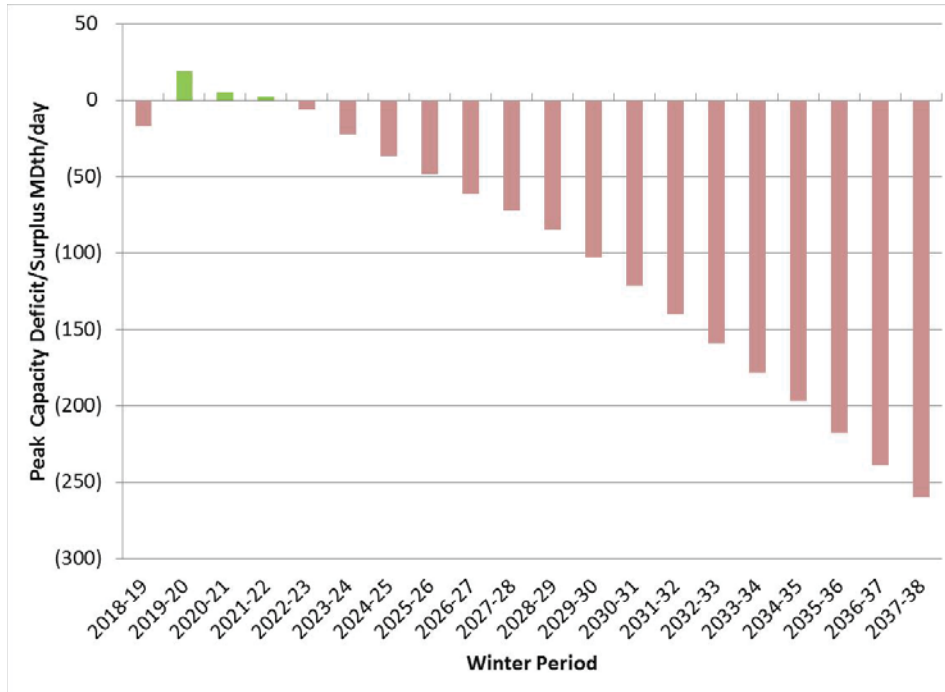


³ / One of the major tasks of the IRP analysis is to identify the most cost-effective amount of conservation to include in the resource plan. To accomplish this, it is necessary to start with demand forecasts that do not already include forward projections of conservation savings. Therefore the IRP Gas Demand Forecasts include only DSR measures implemented before the study period begins in 2018. These charts and tables are labeled "before DSR."

⁴ / Tacoma LNG is shown as an existing resource, as the facility is currently under construction and anticipated to be in service and available by the winter of 2019.



Figure 7-2: Gas Sales Peak Resource Need Surplus/Deficit in Base Demand Forecast before DSR



Gas Sales Key Issue

Adequacy of Sumas Market

The Sumas market (the Huntingdon, British Columbia / Sumas, Washington hub) is essentially an interconnection between the Enbridge/Westcoast Energy Pipeline (Westcoast) and Northwest Pipeline (NWP). Unlike other market hubs, there is no gas production and no convergence of several supply pipelines. PSE implemented a strategy to hold firm capacity on Westcoast for approximately 50 percent of its peak demand for gas from British Columbia (B.C.). This strategy provides a level of reliability (physical access to gas in the production basin) and an opportunity for pricing diversity, as often there is a significant pricing differential between Station 2 and Sumas that more than offsets the cost of holding the capacity.

Since its last major expansion in 2002, Westcoast has had capacity to transport adequate supplies to satisfy all firm demand relying on gas from northeast British Columbia (NE B.C.). Subsequent to the expansion, as Station 2 to Sumas price differentials decline, some shipper

Chapter 7: Gas Analysis



contracts expired and were not renewed. This left much of the Westcoast system uncontracted on a firm basis. Then, at the very time the Pacific Northwest (PNW) demand for natural gas to serve gas customer growth and electric generation fuel needs was increasing, conventional production in B.C. began to decline and prices rose, leaving PNW demand to consider the less expensive supplies in the Rockies. The region and California considered new pipeline proposals from the Rockies, and ultimately Ruby Pipeline was built.

The shale revolution changed everything. As production costs fell and supply increased, the abundant and low-cost production of NE B.C. and the Montney region, in particular, is now trapped by a shortage of pipeline capacity leaving the basin. Westcoast is now fully contracted as NE B.C. producers have sought a market outlet for their growing production. In the last two years Westcoast has run at its maximum available capacity nearly year-round (limited by maintenance restrictions). This has resulted in adequate supply at Sumas in winter months and an excess in summer months.

A recently completed Westcoast capacity offering was fully subscribed and will drive construction of an additional 105,000 Dth/d of firm capacity on Westcoast and the availability of 94,000 Dth of capacity previously held back for maintenance and reliability reasons, but this is available only on a best-efforts basis. While these new contracts of 199,000 Dth/d will bring more firm gas reliably to the Sumas hub beginning in November 2020, two new large-volume firm demands of approximately 420,000 Dth/d are expected to come online between 2020 and 2023. Because these two new loads have acquired the firm Westcoast capacity necessary to serve their demand, they will control their own supply and destiny. The firm gas supply controlled by these new industrial loads will effectively remove the supply available at Sumas for other customers on most days.

PSE is comfortable with the notion that there will be adequate supplies at Sumas at most times of the year with the increased capacity on Westcoast beginning in 2020, and that PSE would be able to compete (on price) to obtain sufficient supplies in peak periods, even with the new loads.

The table in Figure 7-3 illustrates an approximation of the supply and demand balance at Sumas, currently and in 2020 and 2023. Interruptible loads are shown in blue. The potential start-up of the first of the two new large-volume firm loads – each of which holds their own capacity on Westcoast and thus controls their own supply – may fully absorb all remaining supply at Sumas in winter peak conditions, forcing a rationing of supply among interruptible loads based on price. When the second of the new large-volume firm loads is added, the shortfall in supply (307 MDth/d) is greater than the total interruptible loads (300 MDth/d), which may result in a lack of sufficient gas supply for some firm loads. This would suggest that any additional firm load would require an expansion of Westcoast in order to maintain reliability.



Figure 7-3: Projected Supply and Demand at Sumas

| Projected Supply & Demand at Sumas | Current 2017-18 | | Expected 2020-21 | | Expected 2023-24 | |
|---|-----------------|--------|------------------|--------|------------------|--------|
| | Winter | Summer | Winter | Summer | Winter | Summer |
| | MDth/d | MDth/d | MDth/d | MDth/d | MDth/d | MDth/d |
| Max Westcoast capacity (pre-expansion) | 1,518 | 1,518 | 1,518 | 1,518 | 1,518 | 1,518 |
| Westcoast Winter Only Firm Service (WOFS) | 168 | - | 168 | - | 168 | - |
| Westcoast AOS capacity (absorbed by Expansion) | 94 | 94 | - | - | - | - |
| WEI Proposed Expansion (eff. 11/2020) | - | - | 199 | 199 | 199 | 199 |
| Max Westcoast capacity -total gas available at Sumas | 1,780 | 1,612 | 1,885 | 1,717 | 1,885 | 1,717 |
| PSE - Guaranteed Access-Firm T-South for Firm Reqmts | 219 | 219 | 219 | 219 | 219 | 219 |
| PSE - AOS T-South@ 50% for Firm Reqmts | 12 | 11 | - | - | - | - |
| Remaining Gas Supply available at Sumas | 1,550 | 1,383 | 1,666 | 1,498 | 1,666 | 1,498 |
| Other Demand | | | | | | |
| PSE - Purchase at Sumas for Firm Reqmts | 247 | 123 | 259 | 123 | 259 | 123 |
| PSE - Purchase at Sumas -Peakers | 155 | 155 | 155 | 155 | 155 | 155 |
| Fortis BC Energy Firm load | 525 | 275 | 525 | 275 | 525 | 275 |
| Other Firm Gen. (PGE, Pac.,) | 170 | 170 | 170 | 170 | 170 | 170 |
| Other Firm LDC (NWN, CNGC, InterMtn, Sierra) | 220 | 125 | 220 | 125 | 220 | 125 |
| Other Firm Indust. Load (I-5 corridor) | 80 | 70 | 80 | 70 | 80 | 70 |
| Other Interruptible Gen. (Grays H) | 105 | 105 | 105 | 105 | 105 | 105 |
| Other Interruptible Indust. Load (I-5 corridor) | 40 | 35 | 40 | 35 | 40 | 35 |
| NWIIW-Kalama from Sumas (eff. 11/2020) | - | - | 180 | 180 | 180 | 180 |
| WoodFibre LNG demand at Sumas (eff. 11/2023) | - | - | - | - | 240 | 240 |
| Total Demand | 1,542 | 1,058 | 1,734 | 1,238 | 1,974 | 1,478 |
| Uncommitted supply at Sumas potential unserved | 8 | 325 | (67) | 261 | (307) | 21 |
| | - | - | 3% | n/a | 14% | n/a |
| Percent of PSE Firm Requirements covered by T-South | 48.3% | 65.2% | 45.8% | 64.1% | 45.8% | 64.1% |
| Percent of PSE Total Requirements covered by T-South | 36.5% | 45.2% | 34.6% | 44.0% | 34.6% | 44.0% |
| PSE Pro-rata share of unserved volume (MDth/d) | - | - | 16 | n/a | 64 | n/a |

Because there is an equilibrium of supply and firm demand in peak winter periods and a surplus in summer periods, PSE does not believe it is necessary to secure additional firm Westcoast capacity beyond the current level, which is approximately 50 percent of PSE's peak period demand. However, we do believe that there is a potential for inadequate capacity to bring sufficient supply to Sumas in peak periods beyond 2023, assuming the two new large-volume loads materialize. Therefore, in this IRP, we are continuing to assume that any new NWP capacity from Sumas that PSE would consider using to serve incremental PSE firm loads would need to be coupled with additional firm capacity on Westcoast from the supply source in NE B.C., in order to be deemed a reliable new resource. PSE will continue to monitor developments in the NE B.C. supply and capacity market and to analyze the implications on an ongoing basis.



2. ANALYTIC METHODOLOGY

In general, analysis of the gas supply portfolio begins with an estimate of resource need that is derived by comparing 20-year demand forecasts with existing long-term resources. Once need has been identified, a variety of planning tools, optimization analyses and input assumptions help PSE identify the lowest-reasonable-cost portfolio of gas resources in a variety of scenarios. Such resources would include the consideration of renewal or extension of existing resources.

Analysis Tools

PSE uses a gas portfolio model (GPM) to model gas resources for long-term planning and long-term gas resource acquisition activities. The current GPM is SENDOUT Version 14.3.0 from ABB Ventyx, a widely-used model that employs a linear programming algorithm to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads. While the deterministic linear programming approach used in this analysis is a helpful analytical tool, it is important to acknowledge this technique provides the model with "perfect foresight" – meaning that its theoretical results may not be achievable. For example, the model knows the exact load and price for every day throughout a winter period, and can therefore minimize cost in a way that is not possible in the real world. Numerous critical factors about the future will always be uncertain; therefore we rely on linear programming analysis to help *inform* decisions, not to *make* them. See Appendix O, Gas Analysis, for a more complete description of the SENDOUT gas portfolio model.



Deterministic Optimization Analysis

As described in Chapter 4, Key Analytical Assumptions, PSE developed 11 scenarios for this IRP gas analysis. Scenario analysis allows the company to understand how different resources perform across a variety of economic and regulatory conditions that may occur in the future. Scenario analysis also clarifies the robustness of a particular resource strategy. In other words, it helps determine if a particular strategy is reasonable under a wide range of possible circumstances.

PSE also tested four sensitivities in the gas sales analysis; these are described below. Sensitivity analysis allows us to isolate the effect a single resource has on the portfolio.

1. **DEMAND-SIDE RESOURCES.** How much does DSR reduce cost and risk? This sensitivity compares a portfolio with all cost-effective DSR per RCW 19.285 to a portfolio with no DSR in which all future needs are met with supply-side resources.
2. **RESOURCE ADDITION TIMING OPTIMIZATION.** How does the timing of PSE-controlled resource additions affect resource builds and portfolio costs? Instead of offering PSE-controlled resources every two years, the model is allowed to offer them every year.
3. **ALTERNATE RESIDENTIAL CONSERVATION DISCOUNT RATE.** Would using a societal discount rate on conservation savings from residential energy efficiency impact cost-effective levels of conservation? This sensitivity applies an alternate discount rate that is lower than PSE's approved weighted average cost of capital (WACC) on residential savings.
4. **ADDITIONAL GAS CONSERVATION.** What happens if DSR is added beyond what is cost-effective per RCW 19.285? This sensitivity adds two additional demand-side bundles above the bundles chosen as cost effective.

Gas portfolio analysis is discussed in more detail in Appendix O, Gas Analysis.



3. EXISTING SUPPLY-SIDE RESOURCES

Existing gas sales resources consist of pipeline capacity, storage capacity, peaking capacity, gas supplies and demand-side resources.

Existing Pipeline Capacity

There are two types of pipeline capacity. “Direct-connect” pipelines deliver supplies directly to PSE’s local distribution system from production areas, storage facilities or interconnections with other pipelines. “Upstream” pipelines deliver gas to the direct pipeline from remote production areas, market centers and storage facilities.

Direct-connect Pipeline Capacity

All gas delivered to our gas distribution system is handled last by PSE’s only direct-connect pipeline, Northwest Pipeline (NWP). We hold nearly one million dekatherms (Dth) of firm capacity with NWP.

- 532,872 Dth per day of year-round TF-1 (firm) transportation capacity
- 447,057 Dth per day of firm storage redelivery service from Jackson Prairie

Receipt points on the NWP transportation contracts access supplies from four production regions: British Columbia, Canada (B.C.); Alberta, Canada (AECO); the Rocky Mountain Basin (Rockies) and the San Juan Basin. This provides valuable flexibility, including the ability to source gas from different regions on a day-to-day basis in some contracts.

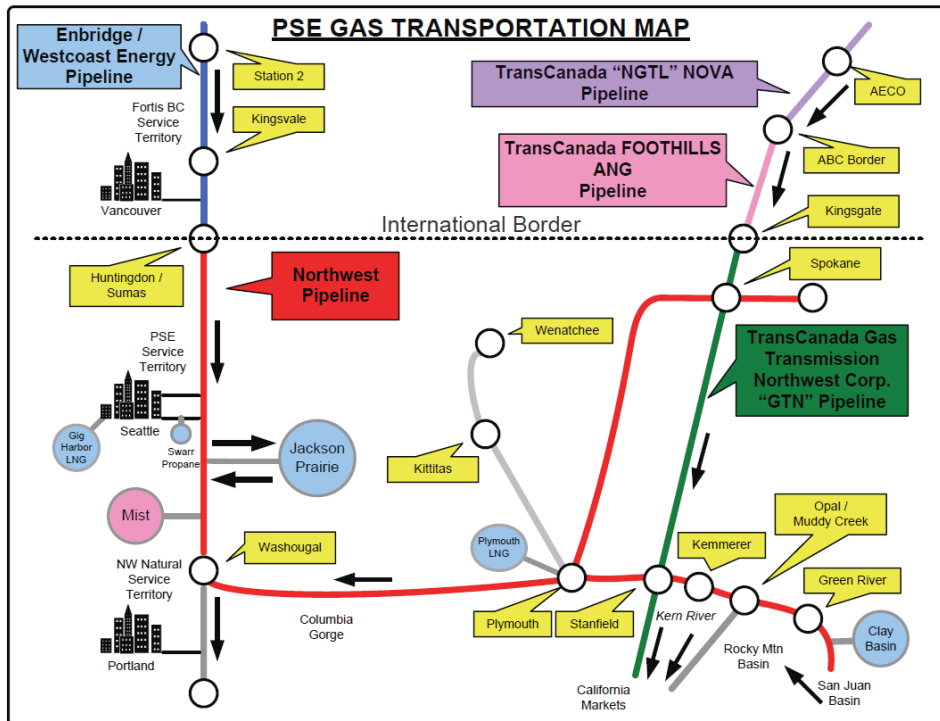


Upstream Pipeline Capacity

To transport gas supply from production basins or trading hubs to the direct-connect NWP system, PSE holds capacity on several upstream pipelines.

A schematic of the gas pipelines for the Pacific Northwest region is provided in Figure 7-4 below. In addition, please see Figure 7-5 for details of PSE's gas sales pipeline capacity.

Figure 7-4: Pacific Northwest Regional Gas Pipeline Map



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Figure 7-5: Gas Sales - Firm Pipeline Capacity (Dth/day) as of 03/31/2017

| Pipeline/Receipt Point | Note | Total | Year of Expiration | |
|--|------|----------------|--------------------|----------------|
| | | | 2018-22 | 2023+ |
| Direct Connect | | | | |
| NWP/Westcoast Interconnect (Sumas) | 1,2 | 277,237 | 20,416 | 256,821 |
| NWP/TC-GTN Interconnect (Spokane) | 1 | 75,936 | - | 75,936 |
| NWP/various in US Rockies | 1 | 179,699 | 840 | 178,859 |
| Total TF-1 | | 532,872 | 21,256 | 511,616 |
| NWP/Jackson Prairie Storage Redelivery Service | 1,3 | 447,057 | - | 447,057 |
| Storage Redelivery Service | | 447,057 | 0 | 447,057 |
| Total Capacity to City Gate | | 979,929 | 21,256 | 958,673 |

| Pipeline/Receipt Point | Note | Total | Year of Expiration | |
|--|----------|----------------|--------------------|---------------|
| | | | 2018-22 | 2023+ |
| Upstream Capacity | | | | |
| TC-Alberta/from AECO to TC-BC Interconnect (A-BC Border) | 4 | 79,744 | 79,744 | - |
| TC-BC from TC-Alberta to TC-GTN Interconnect (Kingsgate) | 4 | 78,631 | 70,604 | 8,027 |
| TC-GTN from TC-BC Interconnect to NWP Interconnect (Spokane) | 5 | 65,392 | - | 65,392 |
| TC-GTN from TC-BC Interconnect to NWP Interconnect (Stanfield) | 5,6 | 11,622 | - | 11,622 |
| Westcoast/from Station 2 to NWP Interconnect (Sumas) | 7,8 | 132,401 | 132,401 | - |
| Total Upstream Capacity | 9 | 367,790 | 282,749 | 85,041 |

NOTES

1. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
2. After planned transfer of 10,000 Dth/day effective 11/1/2019 to Puget LNG to provide service to TOTE.
3. Storage redelivery service (TF-2 or discounted TF-1) is intended only for delivery of storage volumes during the winter heating season, November through March; these annual costs are significantly lower than year-round TF-1 service.
4. Converted to approximate Dth per day from contract stated in gigajoules per day.
5. TC-GTN contracts have automatic renewal provisions, but can be canceled by PSE upon one year's notice.
6. Capacity can alternatively be used to deliver additional volumes to Spokane.
7. Converted to approximate Dth per day from contract stated in cubic meters per day.
8. The Westcoast contracts contain a right of first refusal upon expiration.
9. Upstream capacity is not necessary for a supply acquired at interconnects in the Rockies and for supplies purchased at Sumas.



Transportation Types

TF-1

TF-1 transportation contracts are “firm” contracts, available every day of the year. PSE pays a fixed demand charge for the right, but not the obligation, to transport gas every day.

Storage Redelivery Service

PSE holds TF-2 and winter-only discounted TF-1 capacity under various contracts to provide for firm delivery of Jackson Prairie storage withdrawals. These services are restricted to the winter months of November through March and provide for firm receipt only at Jackson Prairie; therefore, the rates on these contracts are substantially lower than regular TF-1 transportation contracts.

Firm versus Non-firm Transportation Capacity

Firm transportation capacity carries the right, but generally not the obligation (subject to operational flow orders from a pipeline), to transport up to a maximum daily quantity of gas on the pipeline from a specified receipt point to a specified delivery point. Firm transportation requires a fixed payment, whether or not the capacity is used, plus variable costs when physical gas is transported. The rate for interruptible capacity is negotiable, and is typically billed as a variable charge.

Primary firm capacity is highly reliable when used in the contracted path from receipt point to delivery point. Firm shippers have the right to temporarily alter the contractual receipt point, the delivery point and even the flow direction – subject to availability of capacity for that day. The reliability of this use of “alternate firm” can be reasonably predicted; it is very reliable if the contract is used to flow gas in the contractual direction to or from the primary delivery or receipt point (i.e., within the primary path).

Alternate firm is much less reliable or predictable if used to flow gas in the opposite direction or “out of path.” While this capacity has higher rights than interruptible capacity, it is not considered reliable in most circumstances. Non-firm capacity on a fully contracted pipeline results from a firm shipper not fully utilizing its firm rights on a given day. This unused (interruptible) capacity, if requested (nominated) by a shipper and confirmed by the pipeline, becomes firm capacity for that day. The rights of this type of non-firm capacity are subordinate to the rights of firm pipeline contract owners who request to transport gas on an alternate basis, outside of their contracted firm transportation path.



The flexibility to use firm transport in an alternate firm manner as “within path” or “out of path” modes, along with the ability to create “segmented release” capacity has resulted in very low interruptible volumes on the NWP system.

PSE may release capacity when it has a surplus of firm capacity and when market conditions make such transactions favorable for customers. The company also uses the capacity release market to access additional firm capacity when it is available. Interruptible service plays a limited role in PSE’s resource portfolio because of the flexibility of its firm contracts and because it cannot be relied on to meet peak demand.

Existing Storage Resources

PSE’s natural gas storage capacity is a significant component of the company’s gas sales resource portfolio. Storage capacity improves system flexibility and creates significant cost savings for both the system and customers. Benefits include the following.

- Ready access to an immediate and controllable source of firm gas supply or storage space enables PSE to handle many imbalances created at the interstate pipeline level without incurring balancing or scheduling penalties.
- Access to storage makes it possible for the company to purchase and store additional gas during the lower-demand summer season, generally at lower prices.
- Combining storage capacity with firm storage redelivery service transportation allows us to contract for less year-round pipeline capacity to meet winter-only or peak-only demand.
- PSE also uses storage to balance city gate gas receipts from gas marketers with the actual loads of our gas transportation customers.

We have contractual access to two underground storage projects. Each serves a different purpose. Jackson Prairie Gas Storage Project (Jackson Prairie) in Lewis County, Wash. is an aquifer-driven storage field, located in the market area, designed to deliver large quantities of gas over a relatively short period of time. Clay Basin, in northeastern Utah, provides supply-area storage and a winter-long gas supply. Figure 7-6 presents details about storage capacity.

Figure 7-6: Gas Sales Storage Resources¹ as of 03/31/2017

| | Withdrawal Capacity (Dth/Day) | Injection Capacity (Dth/Day) | Storage Capacity (Dth) | Expiration Date |
|---|-------------------------------|------------------------------|------------------------|-----------------|
| Jackson Prairie – PSE Owned | 398,667 | 156,000 | 8,528,000 | N/A |
| Jackson Prairie – PSE Owned ² | (50,000) | (50,000) | (500,000) | 2019 |
| Net JP Owned | 348,667 | 106,000 | 8,028,000 | |
| Jackson Prairie – NWP SGS-2F ³ | 48,390 | 18,935 | 1,181,021 | 2023 |
| Jackson Prairie – NWP SGS-2F ³ | 6,077 | 2,378 | 178,460 | 2026 |
| Jackson Prairie – NWP SGS-2F ⁴ | (6,077) | (2,378) | (178,460) | 2020 |
| Net Jackson Prairie | 397,057 | 124,935 | 9,209,021 | |
| Clay Basin ⁵ | 107,356 | 53,678 | 12,882,750 | 2018/20 |
| Clay Basin ⁶ | (33,333) | (16,667) | (4,000,000) | 2018 |
| Net Clay Basin | 74,023 | 37,011 | 8,882,750 | |
| Total | 471,080 | 161,946 | 18,091,771 | |

NOTES

1. Storage, injection and withdrawal capacity quantities reflect PSE's capacity rights rather than the facility's total capacity.
2. Storage capacity made available (at market-based price) from PSE gas sales portfolio. Renewal may be possible, depending on gas sales portfolio needs. Firm withdrawal rights can be recalled to serve gas sales customers.
3. NWP contracts have automatic annual renewal provisions, but can be canceled by PSE upon one year's notice.
4. Released to Cascade Natural Gas Co. through 4/1/2020.
5. PSE expects to renew the Clay Basin storage agreements.
6. Assigned to third parties through 3/31/2018; PSE is considering renewal.



Jackson Prairie Storage

PSE, NWP and Avista Utilities each own an undivided one-third interest in the Jackson Prairie Gas Storage Project, which is operated by PSE under FERC authorization. As shown in Figure 7-5, PSE owns 398,667 Dth per day of firm storage withdrawal rights and associated storage capacity from Jackson Prairie. Some of this capacity has been made available to PSE's electric portfolio at market rates. The firm withdrawal rights – but not the storage capacity – may be recalled to serve gas sales customers under extreme conditions. In addition to the PSE-owned portion of Jackson Prairie, PSE has access to 48,390 Dth per day of firm deliverability and associated firm seasonal capacity through contracts for SGS-2F storage service from NWP. In total, PSE holds 447,057 Dth per day of firm withdrawal rights for peak day use. As shown in Figure 7-4, PSE has 447,057 Dth per day of storage redelivery service transportation capacity from Jackson Prairie. The NWP contracts renew automatically each year, but PSE has the unilateral right to terminate the agreement with one year's notice.

PSE uses Jackson Prairie and the associated NWP storage redelivery service transportation capacity primarily to meet the intermediate peaking requirements of core gas customers – that is, to meet seasonal load requirements, balance daily load and minimize the need to contract for year-round pipeline capacity to meet winter-only demand.

Clay Basin Storage

Dominion-Questar Pipeline owns and operates the Clay Basin storage facility in Daggett County, Utah. This reservoir stores gas during the summer for withdrawal in the winter. PSE has two contracts to store up to 12,882,750 Dth and withdraw up to 107,356 Dth per day under a FERC-regulated service. As shown in Figure 7-5, 4,000,000 Dth of this storage capacity has been released to third parties through March 2018. PSE is considering the extension of these arrangements.

PSE uses Clay Basin for certain levels of baseload supply, and for backup supply in the case of well freeze-offs or other supply disruptions in the Rocky Mountains during the winter. It provides a reliable source of supply throughout the winter, including peak days; it also provides a partial hedge to price spikes in this region. Gas from Clay Basin is delivered to PSE's system (or other markets) using firm NWP TF-1 transportation.



Treatment of Storage Cost

Similar to firm pipeline capacity, firm storage arrangements require a fixed charge whether or not the storage service is used. PSE also pays a variable charge for gas injected into and withdrawn from Clay Basin. Charges for Clay Basin service (and the non-PSE-owned portion of Jackson Prairie service) are billed to PSE pursuant to FERC-approved tariffs, and recovered from customers through the Purchased Gas Adjustment (PGA) regulatory mechanism, while costs associated with the PSE-owned portion of Jackson Prairie are recovered from customers through base distribution rates. Some Jackson Prairie costs are recovered from PSE transportation customers through a balancing charge.

Existing Peaking Supply and Capacity Resources

Firm access to other resources provides supplies and capacity for peaking requirements or short-term operational needs. The Gig Harbor liquefied natural gas (LNG) satellite storage and the Swarr vaporized propane-air (LP-Air) facility provide firm gas supplies on short notice for relatively short periods of time. Generally a last resort due to their relatively higher variable costs, these resources typically help to meet extreme peak demand during the coldest hours or days. These resources do not offer the flexibility of other supply sources.

Figure 7-7: Gas Sales Peaking Resources

| | Withdrawal Capacity (Dth/Day) | Injection Capacity (Dth/Day) | Storage Capacity (Dth) | Transportation Tariff | Availability |
|-----------------------------|-------------------------------|------------------------------|------------------------|-----------------------|--------------|
| Gig Harbor LNG | 2,500 | 2,500 | 10,500 | On-system | current |
| Swarr LP-Air ^{1,2} | 10,000 | 16,680 | 128,440 | On-system | Nov. 2019+ |
| Tacoma LNG ³ | 59,500 | 2,000 | 538,000 | On-system | Nov. 2019 |
| TOTAL | 92,000 | 21,680 | 682,190 | | |

NOTES

1. Swarr is currently out of service, pending upgrades to reliability, safety and compliance systems, to be considered in resource acquisition analysis for an in-service date of November 2019 or later.
2. Swarr holds 1.24 million gallons. At a refill rate of 111 gallons/minute, it takes 7.7 days to refill, or 16,680 Dth/day.
3. Planned in-service date of Nov. 1, 2019. Withdrawal capacity will rise in the future when the distribution system is upgraded, and again when an additional 10 MDth/day will be subscribed by a third party (assumed to be available starting Nov 2021).



Gig Harbor LNG

Located in the Gig Harbor area of Washington state, this satellite LNG facility ensures sufficient supply during peak weather events for a remote but growing region of PSE's distribution system. The Gig Harbor plant receives, stores and vaporizes LNG that has been liquefied at other LNG facilities. It represents an incremental supply source and its 2.5 MDth per day capacity is therefore included in the peak day resource stack. Although the facility directly benefits only areas adjacent to the Gig Harbor plant, its operation indirectly benefits other areas in PSE's service territory since it allows gas supply from pipeline interconnects or other storage to be diverted elsewhere.

Swarr LP-Air

The Swarr LP-Air facility has a net storage capacity of 128,440 Dth natural gas equivalents and can produce the equivalent of approximately 10,000 Dth per day. Swarr is a propane-air injection facility on PSE's gas distribution system that operates as a needle-peaking facility. Propane and air are combined in a prescribed ratio to ensure the compressed mixture injected into the distribution system maintains the same heat content as natural gas. Preliminary design and engineering work necessary to upgrade the facility's environmental safety and reliability systems and increase production capacity to 30,000 Dth per day is under way. The upgrade is evaluated as a resource alternative for this IRP (see Combination #7 – Swarr), and is assumed to be available on two years' notice as early as the 2019/20 winter season. Since Swarr connects to PSE's distribution system, it requires no upstream pipeline capacity.

Tacoma LNG

PSE expects the completion of construction and successful start-up of this LNG peak-shaving facility to serve the needs of core gas customers as well as regional LNG transportation fuel consumers. By serving new LNG fuel markets (primarily large marine consumers) the project will achieve economies of scale that reduce costs for core gas customers. This project is located at the Port of Tacoma and connects to PSE's existing distribution system. The 2017 IRP assumes the project is put into service in sufficient time to be a reliable resource for the 2019/20 heating season, providing 59.5 MDth per day of capacity. The full 85 MDth per day capacity will be available with additional upgrades to the gas distribution system, which are assumed to be available (as a new resource) beginning in the 2020/21 heating season.



Existing Gas Supplies

Advances in shale drilling have expanded the economically feasible natural gas resource base and dramatically altered long-term expectations with regard to gas supplies. Not only has development of shale beds in British Columbia directly increased the availability of supplies in the West, but the east coast no longer relies so heavily on western supplies now that shale deposits in Pennsylvania and West Virginia are in production.

Within the limits of its transportation and storage network, PSE maintains a policy of sourcing gas supplies from a variety of supply basins. Avoiding concentration in one market helps to increase reliability. We can also mitigate price volatility to a certain extent; the company's capacity rights on NWP provide some flexibility to buy from the lowest-cost basin, with certain limitations based on the primary capacity rights from each basin. While PSE is heavily dependent on supplies from northern British Columbia, it also maintains pipeline capacity access to producing regions in the Rockies, the San Juan basin and Alberta.

Price and delivery terms tend to be very similar across supply basins, though shorter-term prices at individual supply hubs may "separate" due to pipeline capacity shortages or high local demands. This separation cycle can last several years, but is usually alleviated when additional pipeline infrastructure is constructed. PSE expects generally comparable pricing across regional supply basins over the 20-year planning horizon, with differentials primarily driven by differences in the cost of transportation and forecasted demand increase.

PSE has always purchased our supply at market hubs. In the Rockies and San Juan basin, there are various transportation receipt points, including Opal and Clay Basin; but alternate points, such as gathering system and upstream pipeline interconnects with NWP, allow some purchases directly from producers as well as marketers. In fact, PSE has a number of supply arrangements with major producers in the Rockies to purchase supply near the point of production. Adding upstream pipeline transportation capacity on Westcoast, TransCanada's Nova (NGTL) pipeline, TransCanada's Foothills pipeline and TransCanada's Gas Transmission NW (GTN) pipeline to the company's portfolio has increased PSE's ability to access supply nearer producing areas in Canada as well.

Chapter 7: Gas Analysis



Gas supply contracts tend to have a shorter duration than pipeline transportation contracts, with terms to ensure supplier performance. PSE meets average loads with a mix of long-term (more than two years) and short-term (two years or less) gas supply contracts. Long-term contracts typically supply baseload needs and are delivered at a constant daily rate over the contract period. PSE also contracts for seasonal baseload firm supply, typically for the winter months November through March. Near-term transactions supplement baseload transactions, particularly for the winter months; PSE estimates average load requirements for upcoming months and enters into month-long or multi-month transactions to balance load. PSE balances daily positions using storage from Jackson Prairie and Clay Basin, day-ahead purchases and off-system sales transactions, and balances intra-day positions using Jackson Prairie. PSE continuously monitors gas markets to identify trends and opportunities to fine-tune our contracting strategies.

PSE's customer demand is highly weather dependent and therefore seasonal in nature. PSE's general policy is to maintain longer-term firm supply commitments equal to approximately 50 percent of expected seasonal demand, including assumed storage injections in summer and net of assumed storage withdrawals in winter; that percentage grows as we move closer to the delivery month and day.



Existing Demand-side Resources

PSE has provided demand-side resources to our customers since 1993.⁵ These energy efficiency programs operate in accordance with requirements established as part of the stipulated settlement of PSE's 2001 General Rate Case.⁶ Through 1998, the programs primarily served residential and low-income customers; in 1999 the company expanded them to include commercial and industrial customer facilities. Figure 7-8 shows that energy efficiency measures installed through 2016 have saved a cumulative total of over 5 million Dth, which equates to approximately 300,000 metric tons of CO₂ emissions – more than half of which has been achieved since 2007.

Energy savings targets and the programs to achieve those targets are established every two years. The 2014-2015 biennial program period concluded at the end of 2015. The current program cycle is January 1, 2016 through December 31, 2017. The majority of gas energy efficiency programs are funded using gas “rider” funds collected from all customers.

PSE spent over \$13.5 million for natural gas conservation programs in the most recent complete program year of 2016, compared to \$3.2 million in 2005. Spending over that period increased more than 25 percent annually. In the last ten, years the savings have been in the range of 3 to 4 millions of therms per year. Savings reached a peak in 2009 at just over 5 million therms. The low cost of gas and increasing cost of materials and equipment have put pressure in the cost-effectiveness of savings measures. PSE is engaged in collaborative regional efforts to find creative ways to make delivery and marketing of gas efficiency programs more cost-effective and to find ways to reduce barriers for promising measures that have not yet gained significant market share.

For the 2016-2017 period, PSE has a two-year target of approximately 7.4 million therms in energy savings; savings of 4,480,000 therms were achieved in 2016. This goal was based on extensive analysis of savings potentials and developed in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group and Integrated Resource Plan Advisory Group. Figure 7-8 summarizes energy savings and costs for 2014 through 2016.

⁵ / Demand-side resources, also called conservation, are resources that are generated on the customer (demand) side of the meter.

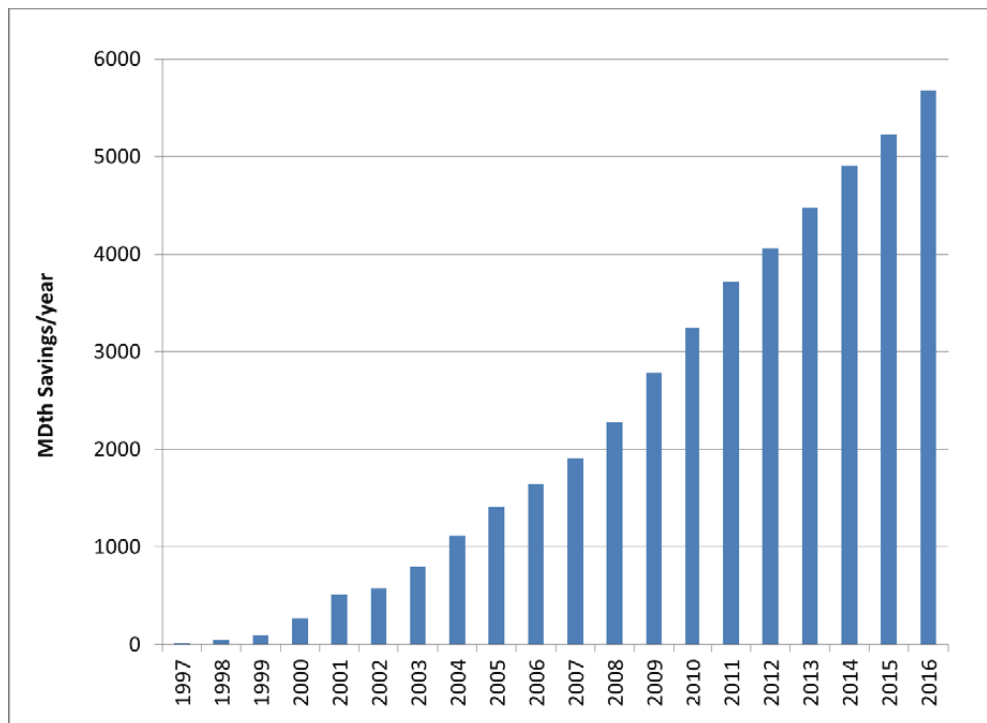
⁶ / PSE's 2001 General Rate Case, WUTC Docket Nos. UG-011571 and UE-011570.



Figure 7-8: Gas Sales Energy Efficiency Program Summary, 2014 – 2016
Total Savings and Costs

| Program Year | Actual Savings (Therms) | Actual Cost (\$) | Target Savings (Therms) | Budget (\$) |
|--------------|-------------------------|------------------|-------------------------|--------------|
| 2014 | 4,346,000 | \$ 11,888,000 | 3,880,000 | \$11,927,000 |
| 2015 | 3,242,000 | \$13,094,000 | 3,081,000 | \$13,140,000 |
| 2016 | 4,480,000 | \$13,644,000 | 3,963,000 | \$14,714,000 |

Figure 7-9: Cumulative Gas Sales Energy Savings from DSR, 1997 – 2016





5. RESOURCE ALTERNATIVES

The gas sales resource alternatives considered in this IRP address long-term capacity challenges rather than the shorter-term optimization and portfolio management strategies PSE uses in the daily conduct of business to minimize costs.

Combinations Considered

Transporting gas from production areas or market hubs to PSE's service area generally entails assembling a number of specific pipeline segments and gas storage alternatives. Purchases from specific market hubs are joined with various upstream and direct-connect pipeline alternatives and storage options to create combinations that have different costs and benefits. Within PSE's service territory, demand-side resources are a significant resource.

In this IRP, the alternatives have been gathered into seven broad combinations for analyses. These combinations are discussed below and illustrated in Figure 7-9. Note that DSR is a separate alternative discussed later in this chapter.

The following acronyms are used in the descriptions below.

- AECO – the Alberta Energy Company trading hub
- LP-Air – liquid propane air (liquid propane is mixed with air to achieve the same heating value as natural gas)
- NWP – Northwest Pipeline
- TC-Foothills – TransCanada-Foothills Pipeline
- TC-GTN – TransCanada-Gas Transmission Northwest Pipeline
- TC-NGTL – TransCanada-NOVA Gas Transmission Pipeline
- Westcoast - Enbridge/Westcoast Energy Pipeline



Combination # 1 & 1a – NWP Additions + Westcoast

This option expands access to northern British Columbia gas at the Station 2 hub beginning November 2021, with expanded transport capacity on Westcoast pipeline to Sumas and then on expanded NWP to PSE’s service area. Gas supplies are also presumed available at the Sumas market hub. In order to ensure reliable access to supply and achieve diversity of pricing, PSE believes it will be necessary to acquire Westcoast capacity equivalent to 100 percent of any new NWP firm take-away capacity at Sumas.

COMBINATION #1A – NWP-TF-1. This is a short-term pipeline alternative that represents excess capacity on the existing NWP system from Sumas to PSE that could be contracted to meet PSE needs from November 2017 to October 2020 only. PSE believes that the vast majority of under-utilized firm pipeline capacity in the I-5 corridor will be absorbed by other new loads by Fall 2020. Beyond October 2020, other long-term resources would be added to serve PSE demand.

Combination # 2 – FortisBC/Westcoast (KORP)

This combination includes the Kingsvale-Oliver Reinforcement Project (KORP) pipeline proposal, which is in the development stages and sponsored by FortisBC and Westcoast. Availability is estimated beginning November 2021. Essentially, the KORP project expands and adds flexibility to the existing Southern Crossing pipeline. This option would allow delivery of Alberta (AECO hub) gas to PSE via existing or expanded capacity on the TC-NGTL and TC-Foothills pipelines, the KORP pipeline across southern British Columbia to Sumas, and then on expanded NWP capacity to PSE.

Combination # 3 – Cross Cascades - AECO

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come from Alberta (AECO hub) via existing or new upstream pipeline capacity on the TC-NGTL, TC-Foothills and TC-GTN pipelines to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.

Combination # 4 – Cross Cascades - Malin

This option provides for deliveries to PSE via the prospective Cross Cascades pipeline. The increased gas supply would come directly from Malin or from the Rockies hub on the Ruby pipeline to Malin, with backhaul on the TC-GTN pipeline to Stanfield. Final delivery from Stanfield to PSE would be via the proposed Cross Cascades pipeline and a northbound upgrade to NWP. As a major greenfield project, this resource option is dependent on significant volume of additional contracting by other parties.



Combination # 5 – LNG-related Distribution Upgrade

This combination assumes completed construction and successful commissioning of the LNG peak-shaving facility for the 2019/20 heating season, providing 59.5 MDth per day of capacity. This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because gas otherwise destined for the Tacoma system is displaced by vaporized LNG and delivered to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on two years' notice starting as early as winter 2021/22.

Combination # 6 – Mist Storage and Redelivery

This option provides for PSE to lease storage capacity from NW Natural after an expansion of the Mist storage facility. Delivery of gas would require expansion of pipeline capacity from Mist to PSE's service territory for Mist storage redelivery service. The expansion of pipeline capacity from Mist to PSE will be dependent on an expansion on NWP from Sumas to Portland with significant additional volume contracting by other parties.

Combination # 7 – Swarr LP-Air Upgrade

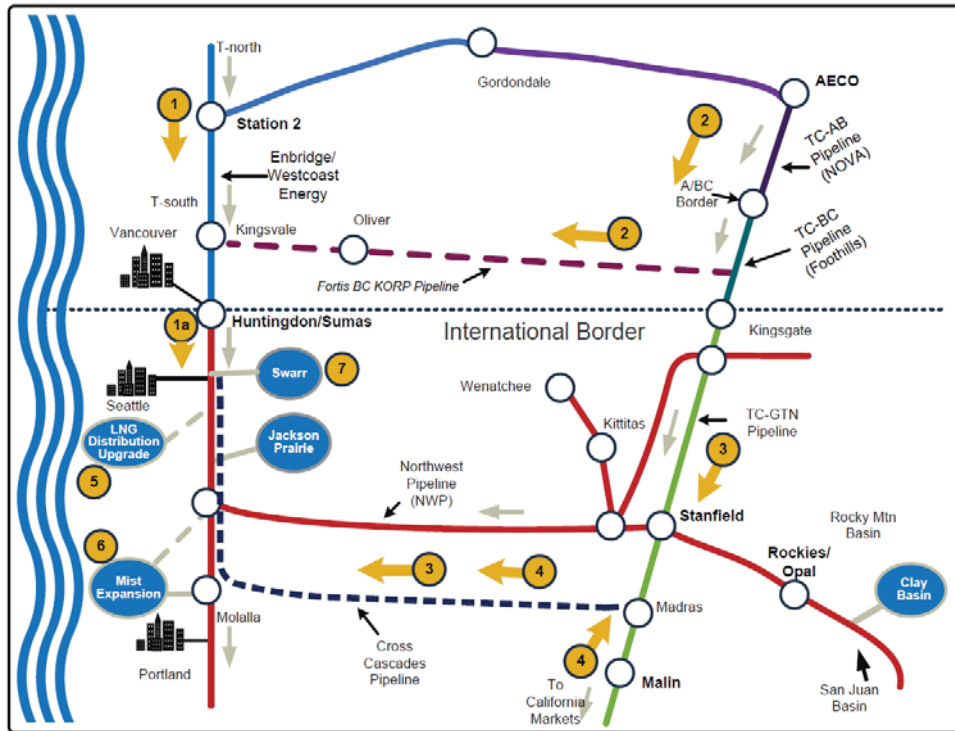
This is an upgrade to the existing Swarr LP-Air facility as discussed above. This upgrade would increase the peak day planning capability from 10 MDth per day to 30 MDth per day. This plant is located within PSE's distribution network.

NOTE: Options 2, 3, 5, and 6 include new greenfield projects and would require significant participation by other customers in order to be economic.

A schematic of the gas sales resource alternatives is depicted in Figure 7-10 below.



Figure 7-10: PSE Gas Transportation Map Showing Supply Alternatives





Pipeline Capacity Alternatives

Direct-connect Pipeline Capacity Alternatives

The direct-connect pipeline alternatives considered in this IRP are summarized in Figure 7-11 below.

Figure 7-11: Direct-connect Pipeline Alternatives Analyzed

| Direct-connect Pipeline Alternatives | Description |
|--|---|
| NWP - Sumas to PSE city gate <i>(from Combinations 1 & 2)</i> | Expansions considered either independently (from 2021), or in conjunction with upstream pipeline/supply expansion alternatives (KORP or additional Westcoast capacity) assumed available November 2021. |
| Cross Cascades – Stanfield/TC-GTN to PSE city gate <i>(from Combinations 3 & 4)</i> | Representative of costs and capacity of the proposed Cross Cascades pipeline with delivery on NWP to PSE city gate. Assumed to be available by November 2021. |

Upstream Pipeline Capacity Alternatives

In some cases, a tradeoff exists between buying gas at one point and buying capacity to enable purchase at an upstream point closer to the supply basin. PSE has faced this tradeoff with supply purchases at the Canadian import points of Sumas and Kingsgate. For example, previous analyses led the company to acquire capacity on Westcoast (Enbridge/Westcoast Energy's B.C. pipeline), which allows PSE to purchase gas at Station 2 rather than Sumas and take advantage of greater supply availability at Station 2. Similarly, acquisition of additional upstream pipeline capacity on TransCanada's Canadian and U.S. pipelines would enable PSE to purchase gas directly from suppliers at the very liquid AECO/NIT⁷ trading hub and transport it to interconnect with the proposed Cross Cascades pipeline on a firm basis. FortisBC and Westcoast have proposed the KORP, which in conjunction with additional capacity on TransCanada's Canadian pipelines, would also increase access to AECO/NIT supplies.



Figure 7-12: Upstream Pipeline Alternatives Analyzed

| Upstream Pipeline Alternatives | Description |
|---|--|
| Increase Westcoast Capacity (Station 2 to PSE) <i>(from Combination 1)</i> | Acquisition of new Westcoast capacity is considered to increase access to gas supply at Station 2 for delivery to PSE on expanded NWP capacity from Sumas. |
| Increase TransCanada Pipeline Capacity (AECO to Stanfield) <i>(from Combinations 2 & 3)</i> | Acquisition of new capacity on TransCanada pipelines (NGTL, Foothills and GTN), to increase deliveries of AECO/NIT gas to Stanfield for delivery to PSE city gate via the proposed Cross Cascades pipeline and a northbound upgrade of NWP. |
| Kingsvale-Oliver Reinforcement Project (KORP) <i>(from Combination 2)</i> | Expansion of the existing FortisBC Southern Crossing pipeline across southern B.C., enhanced delivery capacity on Westcoast from Kingsvale to Huntingdon/Sumas. This alternative would include a commensurate acquisition of new capacity on the TC-NGTL and TC-Foothills pipelines. |

The KORP alternative includes PSE participation in an expansion of the existing FortisBC pipeline across southern British Columbia, which includes a cooperative arrangement with Westcoast for deliveries from Kingsvale to Huntingdon/Sumas. Acquisition of this capacity, as well as additional capacity on the TC-NGTL and TC-Foothills pipelines, would improve access to the AECO/NIT trading hub. While not inexpensive, such an alternative would increase geographic diversity and reduce reliance on British Columbia-sourced supply connected to upstream portions of Westcoast.



Storage and Peaking Capacity Alternatives

As described in the existing resources section, PSE is a one-third owner and operator of the Jackson Prairie Gas Storage Project, and PSE also contracts for capacity at the Clay Basin storage facility located in northeastern Utah. Additional pipeline capacity from Clay Basin is not available and storage expansion is not under consideration. Expanding storage capacity at Jackson Prairie is not analyzed in this IRP although it may prove feasible in the long run. For this IRP, the company considered the following storage alternatives.

LNG-related Distribution System Upgrade

This option considers the timing of the contemplated upgrade to the Tacoma area distribution system, allowing an additional 16 MDth per day of vaporized LNG to reach more customers. The effect is to increase overall delivered supply to PSE customers because gas otherwise destined for the Tacoma system is displaced by vaporized LNG and delivered to other parts of the system. The incremental volume resulting from the distribution upgrade can be implemented on two years' notice starting as early as winter 2021/22.

Mist Expansion

NW Natural Gas Company, the owner and operator of the Mist underground storage facility near Portland, Ore., would consider a potential expansion project to be completed in 2021/22. PSE is assessing the cost-effectiveness of leasing storage capacity beginning November 2021, once the Mist upgrade is built. This would also require expansion of NWP's interstate system to PSE's city gate. PSE may be able to acquire discounted winter-only capacity from Mist to PSE's city gate if NWP expands from Sumas to Portland for other shippers, making the use of Mist storage cost-effective. Since this resource is dependent on other parties willingness to contract for an expansion, this resource availability is not in PSE's control.

Swarr

The Swarr LP-Air facility is discussed above under "Existing Peaking Supply and Capacity Resources." This resource alternative is being evaluated as PSE is in the preliminary stages of upgrading Swarr's environmental safety and reliability systems and increasing production capacity to 30,000 Dth per day. The facility is assumed to be available on two years' notice for the 2019/20 heating season or beyond.



Figure 7-13: Storage Alternatives Analyzed

| Storage Alternatives | Description |
|--|--|
| Distribution upgrade allowing greater utilization of Tacoma LNG (Combination 4) | Considers the timing of the planned upgrade to PSE's Tacoma area distribution system allowing an incremental 16 MDth/day of LNG peaking beginning the 2021-22 heating season. |
| Expansion of Mist Storage Facility (Combination 6) | Considers the acquisition of expanded Mist storage capacity, based on estimated cost and operational characteristics. Assumes a 20-day supply at full deliverability of up to 100 MDth/day beginning the 2021-22 heating season. |
| Swarr LP-Air Facility Upgrade (Combination 7) | Considers the timing of the planned upgrade for reliability and increased capacity (from 10 MDth/day to 30 MDth/day) beginning the 2019-20 heating season. |

Gas Supply Alternatives

As described earlier, gas supply and production are expected to continue to expand in both northern British Columbia and the Rockies production areas as shale and tight gas formations are developed using horizontal drilling and fracturing methods. With the expansion of supplies from shale gas and other unconventional sources at existing market hubs, PSE anticipates that adequate gas supplies will be available to support pipeline expansion from northern British Columbia or from the Rockies basin.

Additional cost and capacity data for all of the supply-side resource alternatives is presented in Appendix O, Gas Analysis.



Demand-side Resource Alternatives

To develop demand-side alternatives for use in the portfolio analysis, PSE first conducts a conservation potential assessment. This study reviews existing and projected building stock and end-use technology saturations to estimate the savings possible through installation of more efficient commercially available technologies. The broadest measure of savings from making these installations (or replacing old technology) is called the technical potential; this represents the total unconstrained savings that could be achieved without considering economic (cost-effectiveness) or market constraints.

The next level of savings is called *achievable* technical potential. This step reduces the unconstrained savings to levels considered achievable when accounting for market barriers. In this IRP, the achievability factors were changed from 75 percent to 85 percent to be consistent with the electric measures. Also, all gas measures were given a 10 percent conservation credit similar to the 10 percent conservation credit electric measures receive stemming from the Power Act of 1980. The measures are then organized into a conservation supply curve, from lowest to highest levelized cost.

Next, individual measures on the supply curve are grouped into cost segments called “bundles.” For example, all measures that have a levelized cost of between \$2.2 per Dth and \$3.0 per Dth may be grouped into a bundle and labeled “Bundle 2.” The Codes and Standards bundle has zero cost associated with it because savings from this bundle accrue due to new codes or standards that have been passed but that take effect at a future date. This bundle is always selected in the portfolio, where it effectively represents a reduction in the load forecast.

Figure 7-14 shows the twelve price bundles that were developed for this IRP. One uses the weighted average cost of capital (WACC) assigned to PSE and the other uses the alternate discount rate developed for the discount rate sensitivity analysis.

PSE currently seeks to acquire as much cost-effective gas demand-side resources as quickly as possible. The acquisition or “ramp rate” of gas sales DSR can be altered by changing the speed with which discretionary DSR measures are acquired. In these bundles, the discretionary measures are assumed to be acquired in the first 10 years; this is called a 10-year ramp rate. Acquiring these measures sooner rather than later has been tested in prior IRPs and has consistently been found to reduce portfolio costs. Ten years is chosen because it aligns with the amount of savings that can practically be acquired at the program implementation level.



Figure 7-14: DSR Cost Bundles and Savings Volumes (MDth/year)

| | WACC | | Alternate Discount | |
|-----------------------------|--------|--------|--------------------|--------|
| | 2027 | 2037 | 2027 | 2037 |
| Codes & Standards | 1,175 | 2,705 | 1,175 | 2,705 |
| Bundle 1: <\$0.22 | 657 | 961 | 519 | 710 |
| Bundle 2: \$0.22 to \$0.30 | 721 | 1,125 | 721 | 1,125 |
| Bundle 3: \$0.30 to \$0.45 | 1,183 | 1,879 | 1,202 | 1,902 |
| Bundle 4: \$0.45 to \$0.55 | 1,298 | 2,086 | 1,299 | 2,089 |
| Bundle 5: \$0.55 to \$0.70 | 1,513 | 2,458 | 1,514 | 2,462 |
| Bundle 6: \$0.70 to \$0.85 | 1,610 | 2,657 | 2,913 | 5,218 |
| Bundle 7: \$0.85 to \$0.95 | 1,697 | 2,750 | 2,918 | 5,233 |
| Bundle 8: \$0.95 to \$1.20 | 2,995 | 5,424 | 4,280 | 7,122 |
| Bundle 9: \$1.20 to \$1.50 | 3,733 | 6,536 | 4,625 | 7,604 |
| Bundle 10: \$1.50 to \$2.00 | 4,843 | 7,994 | 5,033 | 8,180 |
| Bundle 11: >\$2.00 | 10,959 | 16,151 | 10,933 | 16,107 |

More detail on the measures, assumptions and methodology used to develop DSR potentials can be found in Appendix J, Conservation Potential Assessment.

In the final step, the gas portfolio model (GPM) was used to test the optimal level of demand-side resources in each scenario. To format the inputs for the GPM analysis, the cost bundles were further subdivided by market sector and weather/non-weather sensitive measures. Increasingly expensive bundles were added to each scenario until the GPM rejected bundles as not cost effective. The bundle that reduced the portfolio cost the most was deemed the appropriate level of demand-side resources for that scenario. Figure 7-15 illustrates the methodology described above.



Figure 7-15: General Methodology for Assessing Demand-side Resource Potential

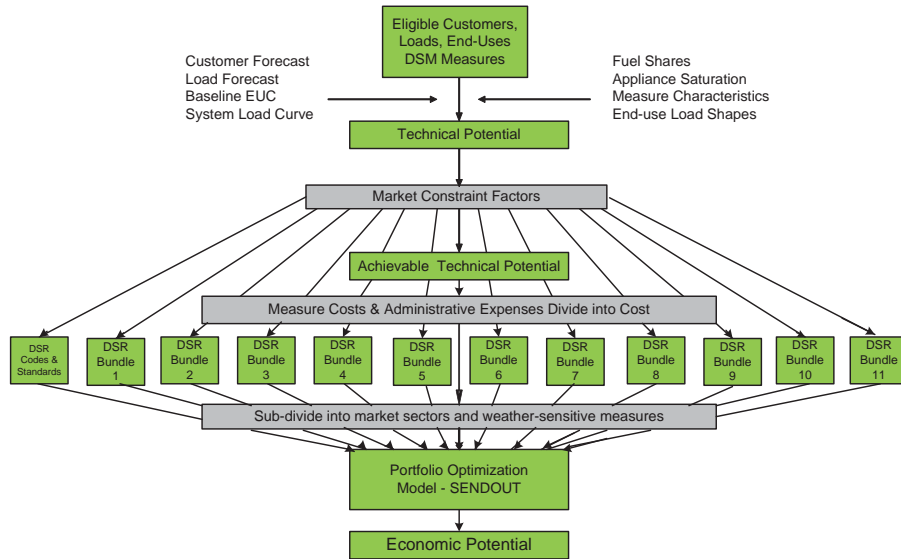




Figure 7-16 shows the range of achievable technical potential among the twelve cost bundles used in the GPM. It selects an optimal combination of each bundle in every customer class to determine the overall optimal level of demand-side gas resource for a particular scenario.

Figure 7-16: Demand-side Resources – Achievable Technical Potential Bundles

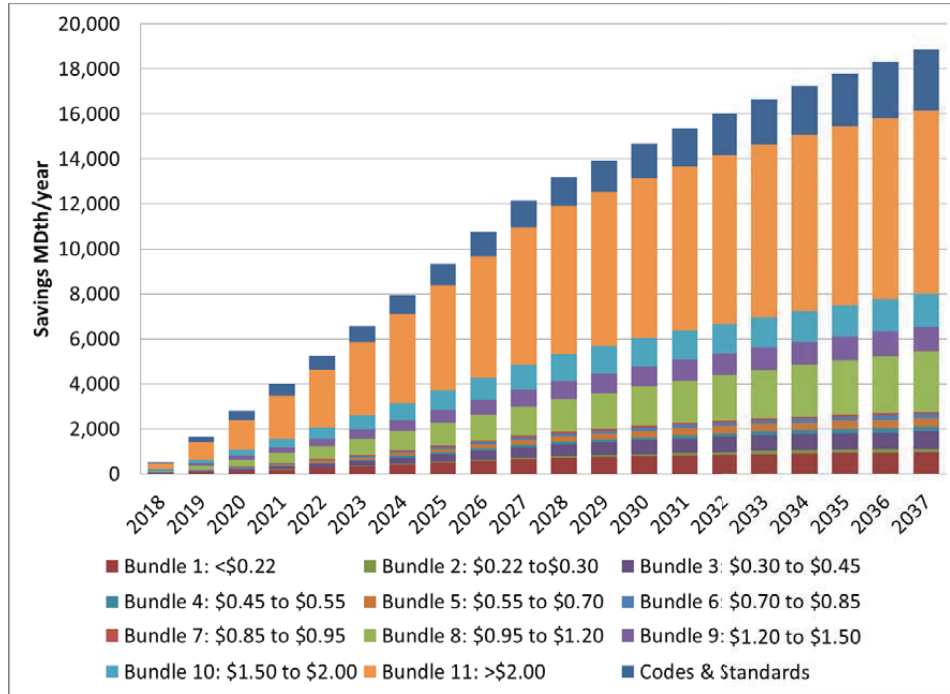
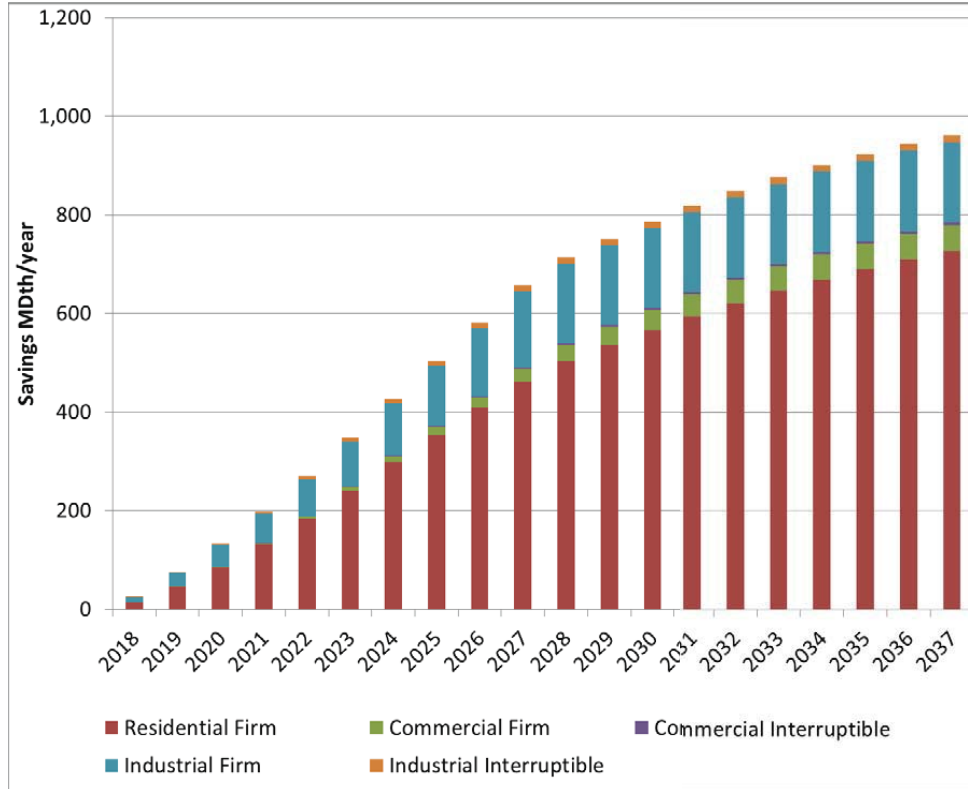


Figure 7-17 shows a sample input format subdivided by customer class for Bundle 1 (<\$2.20 per Dth) used in the GPM for all the IRP scenarios.



Figure 7-17: Savings Formatted for Portfolio Model Input by Customer Class – Bundle 1 (< \$2.20/Dth)





6. GAS SALES ANALYSIS RESULTS

Key Findings

The key findings from this analytical and statistical evaluation will provide guidance for development of PSE's long-term resource strategy, and also provide background information for resource development activities over the next two years.

- 1. In the Base Scenario, the gas sales portfolio is short resources for the winter of 2018/19 and each year beginning the winter of 2022/23.** The High Scenario shows a current and growing resource shortfall, while in the Low Scenario the gas sales portfolio is surplus until the winter of 2035/36.
- 2. Immediate short-term need will be met with combination of two resources in the Base Scenario: demand-side resources and a short-term contract for firm pipeline capacity from Sumas to PSE.** In the High Scenario the short-term pipeline contract along with immediate implementation of the Swarr LP-Air facility upgrade and the LNG related distribution upgrade will still leave PSE short until new pipeline capacity can be built for winter 2021/22.
- 3. Cost-effective DSR is slightly lower in the 2017 IRP.** The cost-effective bundle is slightly lower on the supply curve compared to the 2015 IRP. The decrease is due to two more years of conservation implementation since the last IRP, a lower demand forecast and updated measure savings and costs. Offsetting these factors was the change in the achievability factor from 75 percent to 85 percent. The result is a slightly lower amount of cost-effective DSR.
- 4. The Swarr LP-Air upgrade project is cost effective in all but low demand scenarios** and is expected to provide 30 MDth per day of peaking capacity effective November 2024.
- 5. The Tacoma area distribution system upgrade project is cost effective in all scenarios,** allowing Tacoma LNG to reach its full peaking capacity of 85,000 Dth per day starting the winter of 2027/28.
- 6. Increased Northwest Pipeline and Westcoast capacity from Station 2 is the favored pipeline alternative in most scenarios.** The GPM indicates this pipeline capacity is more cost effective as early as 2020/21 in some scenarios and by 2029/30 in most scenarios. While potentially less expensive with greater participation, this capacity does not require participation by other parties. The pipeline alternatives to purchase gas at Malin or AECO and deliver it to PSE's city gate via the TC-GTN pipeline across the proposed Cross Cascades pipeline is chosen only in high demand scenarios by winter 2023/24.



7. **Neither the Mist storage expansion or the Fortis BC KORP project are selected in any scenario.** These options required significant demand by third parties or reliance on other projects, and like the Cross Cascades pipeline project, the feasibility and timing is outside of PSE control.
8. **The carbon cost assumption was significantly higher in the 2017 IRP compared to the 2015 IRP, and this impacted resource choices.** The levelized cost of carbon was almost the same as the levelized gas price in the mid case. We can see that in the Base + No CO₂ Scenario, a lower amount of DSR was cost effective, it was the lowest of the scenarios.

Gas Sales Portfolio Resource Additions Forecast

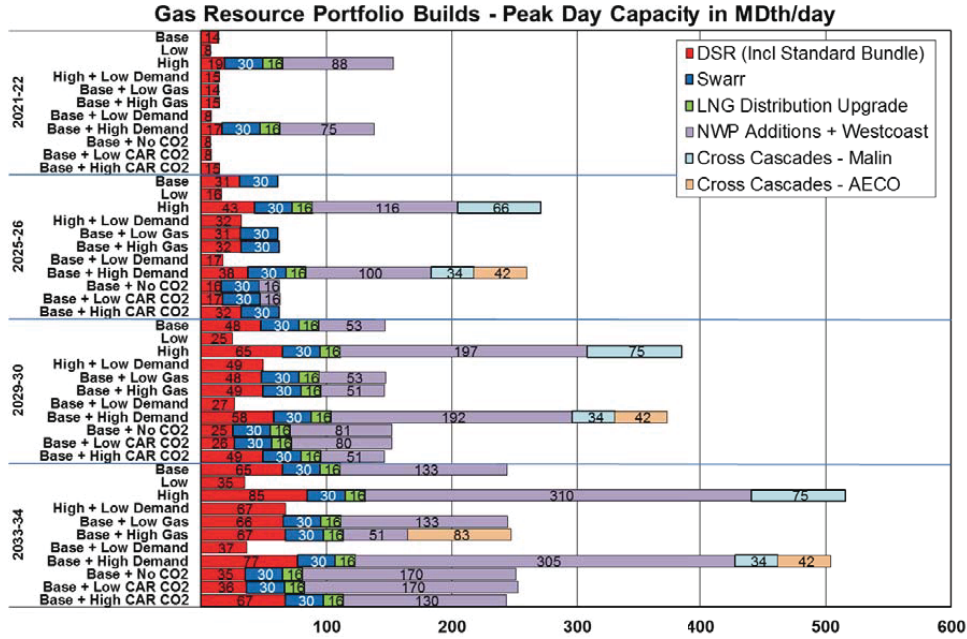
Differences in resource additions were driven primarily by three key variables modeled in the scenarios: load growth, gas prices and CO₂ price assumptions. Demand-side resources are influenced directly by gas and CO₂ price assumptions because they avoid commodity and emissions costs by their nature; however, the absolute level of efficiency programs is also affected by load growth assumptions. Also, the timing of pipeline additions was limited to four-year increments, because of the size that these projects require to achieve economies of scale.

The optimal portfolio resource additions in each of the eleven scenarios⁸ are illustrated in Figure 7-18 for winter periods 2018/19, 2022/23 and 2030/31. Combination #3, Cross Cascades – AECO, and Combination #4, Cross Cascades – Malin, are chosen only in high demand and high gas scenarios.

⁸ / Scenarios are explained in detail Chapter 4, Key Analytical Assumptions.



Figure 7-18: Gas Resource Additions in 2021/22, 2025/26, 2029/30 and 2033/34
(Peak Capacity – MDth/day)



Demand-side Resource Additions

Two categories of demand-side resources are input in to the GPM: codes and standards and program measures. Codes and standards is a no-cost bundle that becomes a must-take resource; it essentially functions as a decrement to gas demand. Program measures are input as separate cost bundles along the demand-side resource supply curve. The bundles are tested from lowest to highest cost along the supply curve until the system cost is minimized. The incremental bundle that raises the portfolio cost is considered the inflexion point, and the prior cost bundle is determined to be the cost-effective level of demand-side resources.

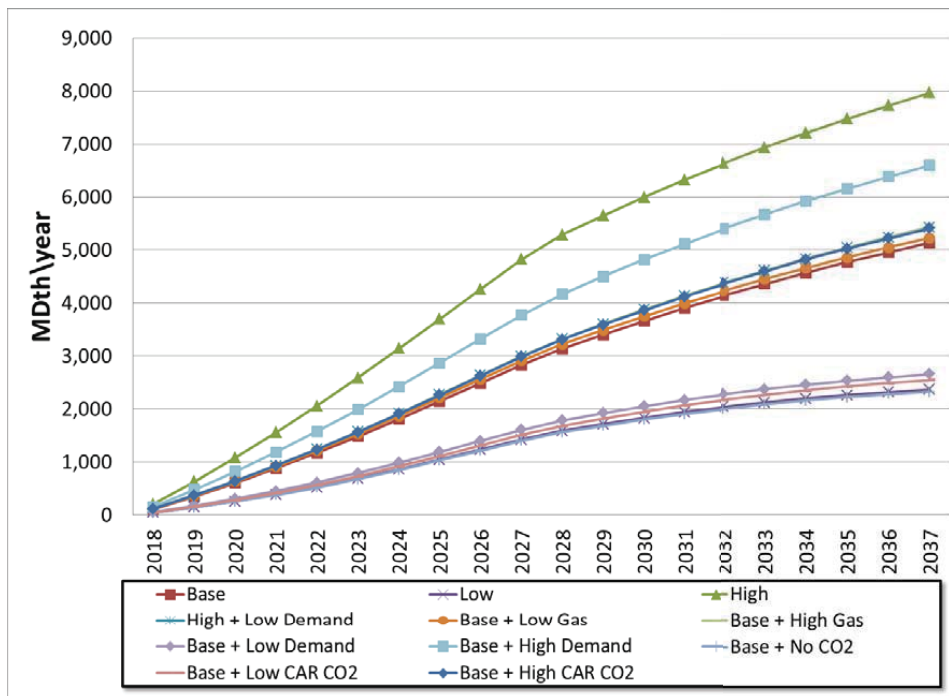
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Carbon costs do impact the amount of cost-effective DSR. Compared to the 2015 IRP, the 2017 IRP carbon costs in the Base Scenario are significantly higher relative to gas prices, which is a function of both declining gas prices and higher carbon cost assumptions. Carbon costs are almost as much as the gas prices in the mid-scenarios.

The sensitivity of DSR to carbon prices is illustrated in Figure 7-19. In the Base Scenario, which includes a CO₂ price, cost-effective DSR is 14 MDth per day by 2021/22, while in the Base + No CO₂ Scenario, the DSR level falls to 8 MDth per day. In terms of gas supply planning, 6 MDth per day is not a significant volume; however, it does highlight that including a CO₂ price in the IRP Base Scenario increases conservation. In the 2017 IRP scenarios that model high carbon price assumptions, cost-effective DSR increases by 75 percent in the 2021/22 winter period.

Figure 7-19: Cost-effective Gas Energy Efficiency Savings by Scenario



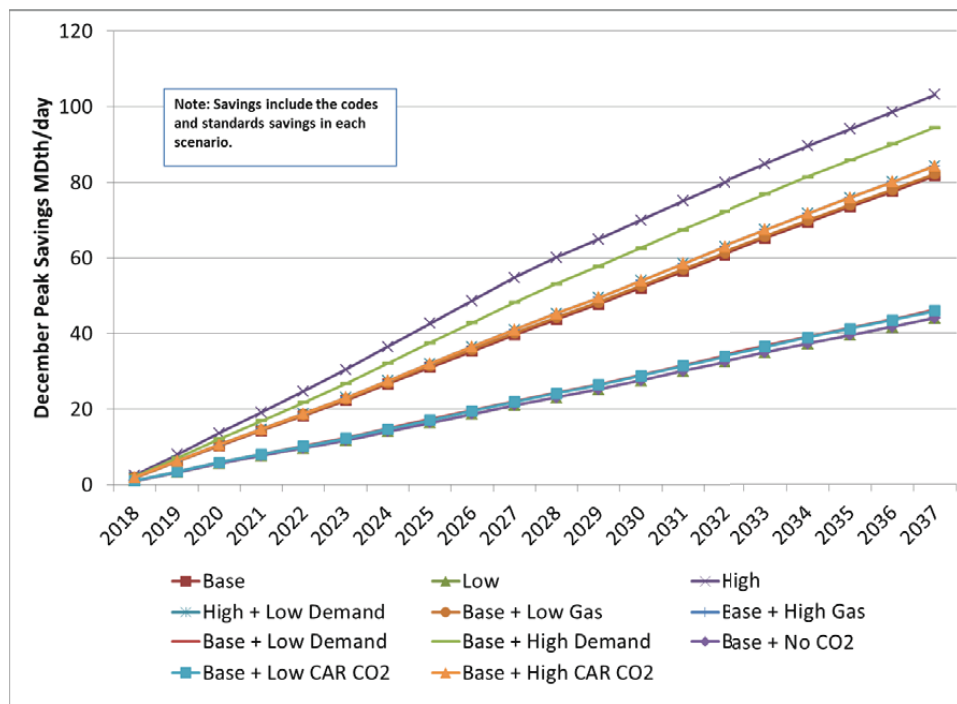
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DSR remains relatively sensitive to avoided costs in the gas analysis. The amount of achievable energy efficiency resources selected by the portfolio analysis in this resource plan forecast ranged from roughly 3,800 MDth in 2037 for the Low Scenario to nearly 50 percent higher at 5,700 MDth in 2037 in the High Scenario.

Peak savings by scenario are shown in Figure 7-20.

Figure 7-20: Cost-Effective Gas Efficiency, Peak Day Savings by Scenario



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The optimal levels of demand-side resources selected by customer class in the portfolio analysis are shown in Figures 7-21 and 7-22, below. More detail on this analysis is presented in Appendix J, Conservation Potential Assessment.

Figure 7-21: Gas Sales Cost-effective DSR Bundles by Class and Scenario

| Bundles | Base | Low | High | High + Low Demand | Base + Low Gas | Base + High Gas | Base + Low Demand | Base + High Demand | Base + No CO2 | Base + Low CO2 | Base + High CO2 |
|--------------------------|-------|-----|------|-------------------|----------------|-----------------|-------------------|--------------------|---------------|----------------|-----------------|
| Residential Firm | 5 + 8 | 4 | 10 | 8 | 8 | 8 | 5 | 9 | 4 | 4 | 8 |
| Commercial Firm | 6 | 5 | 10 | 8 | 6 | 8 | 6 | 10 | 5 | 6 | 8 |
| Commercial Interruptible | 6 | 5 | 8 | 8 | 6 | 8 | 6 | 6 | 3 | 5 | 7 |
| Industrial Firm | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Industrial Interruptible | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |

Figure 7-22: Gas Sales Cost-effective Annual Savings by Class and Scenario

| Savings (MDth/year) | Base | Low | High | High + Low Demand | Base + Low Gas | Base + High Gas | Base + Low Demand | Base + High Demand | Base + No CO2 | Base + Low CO2 | Base + High CO2 |
|--------------------------|-------|-------|-------|-------------------|----------------|-----------------|-------------------|--------------------|---------------|----------------|-----------------|
| Residential Firm | 3,346 | 776 | 5,690 | 3,436 | 3,436 | 3,436 | 867 | 4,343 | 776 | 1,388 | 3,436 |
| Commercial Firm | 1,463 | 1,101 | 1,750 | 1,282 | 1,460 | 1,463 | 1,282 | 1,750 | 1,101 | 1,282 | 1,463 |
| Commercial Interruptible | 126 | 108 | 143 | 108 | 126 | 143 | 126 | 126 | 19 | 108 | 127 |
| Industrial Firm | 353 | 353 | 353 | 353 | 353 | 353 | 353 | 353 | 353 | 353 | 353 |
| Industrial Interruptible | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 | 29 |

Overall, the economic potential of DSR in this IRP is slightly lower than in the 2015 gas sales Base Scenario, and slightly lower-cost bundles are being selected by the analysis as the most cost-effective level of DSR (see Figure 7-23 below).



The downward shift in the overall savings is due to several factors.

- Past program accomplishments have lowered future achievable potentials.
- Updates to the measure costs and savings.
- Building stock data has been updated using the Commercial Building Stock Assessment.
- A lower demand forecast in the 2017 IRP.

On the other hand, inclusion of a higher CO₂ price in the Base Scenario increased conservation, because it made the overall levelized cost of gas in the 2017 IRP Base Scenario comparable to the 2015 IRP Base Scenario, even though the underlying gas commodity prices had declined. For more information on how gas sales DSR differs in the 2017 IRP vs. the 2015 IRP, see Appendix J, Conservation Potential Assessment.

Figure 7-23: Cost-effective Gas Energy Efficiency Savings, 2015 IRP vs 2017 IRP

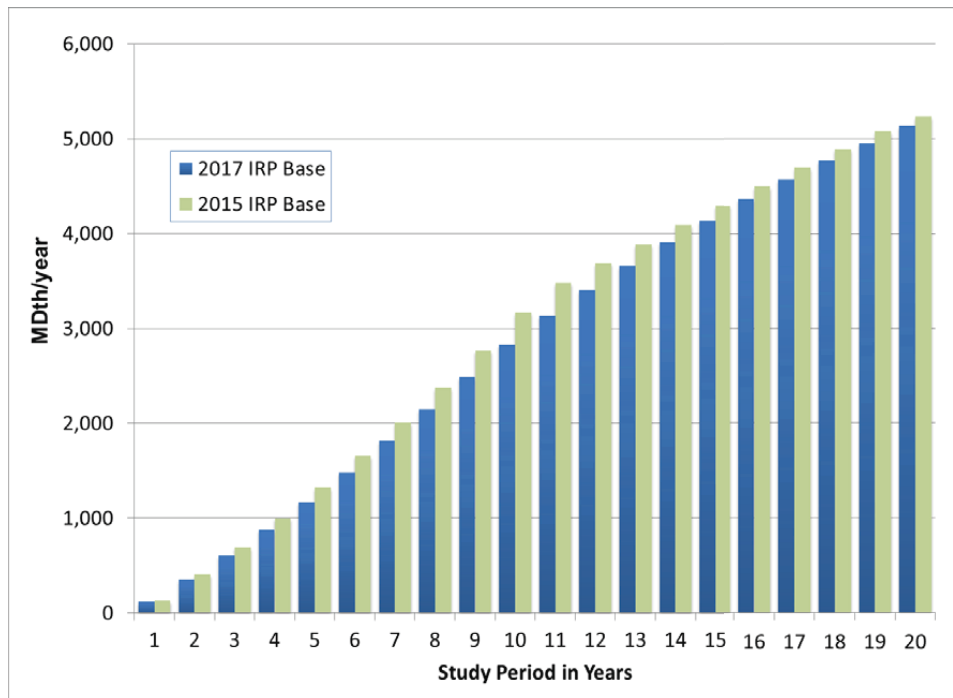


Figure 7-24 below compares PSE’s energy efficiency accomplishments, current targets and the new range of gas efficiency potentials as determined by the analysis. In the short term, the 2017 IRP indicates an economic potential savings of 397 to 618 MDth for the 2016-2017 period.⁹ The

⁹ / These savings are based on a no-intra year ramping, which are used to set conservation program targets.

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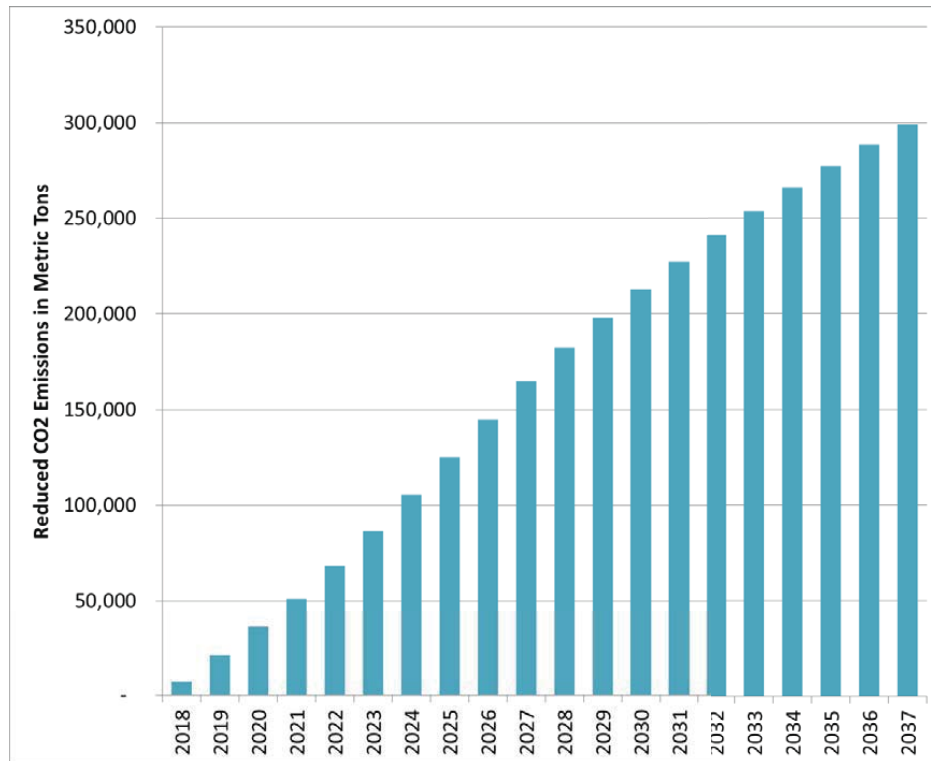
694 MDth target for the current 2016-2017 period is higher than this range. These two-year program accomplishments and projections show a downward trend for the reasons discussed above.

Figure 7-24: Short-term Comparison of Gas Energy Efficiency in MDth

| Short-term Comparison of Gas Energy Efficiency | Dth over 2-year program |
|--|-------------------------|
| 2014-2015 Actual Achievement | 759 |
| 2016-2017 Target (updated January 2017) | 801 |
| 2018-2019 Range of Economic Potential | 147-633 |

Figure 7-25 shows the impact on CO₂ emissions from energy efficiency measures selected in the Base Scenario.

Figure 7-25: CO₂ Emissions Reduction from Energy Efficiency in Base Scenario





Peaking Resource Additions

The Swarr LP-Air upgrade project was selected as least cost (and as the first long-term resource) in all but the low demand scenarios, preceding the Tacoma LNG-related distribution upgrade by two to three years.

Distribution Upgrade Related to Tacoma LNG Project

PSE is in the construction phase of this small-scale natural gas liquefaction and LNG storage facility located within its service territory, which will serve the peaking needs of PSE's core gas customers and the growing demand for LNG as a marine and vehicle transportation fuel. The Tacoma LNG Project was found to be cost effective in every scenario of the 2015 IRP, however, with the revised load forecast, the full 85 MDth per day of LNG is not required initially. In the 2017 IRP, Tacoma LNG is modeled as an existing resource of 59.5 MDth per day beginning in 2019/20, growing to 69 MDth per day by 2021/22. PSE studied the optional resource of a planned upgrade to the distribution system that would allow the plant to deliver the full 85 MDth per day. The GPM selected the distribution upgrade to be effective in 2029/30 or earlier in all but the low demand scenarios.

Pipeline Additions

Pipeline expansion alternatives were made available as early as the 2018/19 winter season, the same time that the other non-pipeline alternatives were made available. Though this timeline is too short for any realistic pipeline expansion, it allowed PSE to ensure that the other resources were selected on their own merits as least cost. A short-term, firm pipeline contract was also included as an alternative. That contract would transport gas from Sumas to PSE as a bridge contract from November 2018 through October 2019, when Tacoma LNG will be on line.



The Sumas to PSE 2018-2019 short-term contract was selected in most scenarios. Based on lower costs, in most scenarios the GPM chose some of the NWP and Westcoast pipeline expansion to purchase gas from Station 2 as cost effective by 2029/30, after the peaking resources, increasing the capacities in subsequent years.

The Cross Cascades projects which source gas from either Malin or AECO through Stanfield across the proposed Cross Cascades pipeline were selected only in high demand scenarios as early as 2022/23. The NWP + KORP pipeline alternative was more expensive and not chosen in any scenario.

Storage Additions

The Mist storage expansion was not selected in any scenario.

Observation

All of the selected resources (listed here in general order of least cost) – DSM, Swarr LP-Air, Tacoma LNG-related distribution upgrade and Northwest + Westcoast Pipeline expansion – are within PSE's control. The timing of individual projects can be fine-tuned by PSE in response to load growth, and none of these projects rely on participation by any other contracting party to be feasibly implemented.



Complete Picture: Gas Sales Base Scenario

A complete picture of the Gas Sales Base Scenario optimal resource portfolio is presented in graphical and table format in Figures 7-26 and 7-27, respectively. Note that Combination #2, Fortis BC/Westcoast (KORP), was not chosen in any of the years. Again, additional scenario results are included in Appendix O, Gas Analysis.

Figure 7-26: Gas Sales Base Scenario Resource Portfolio

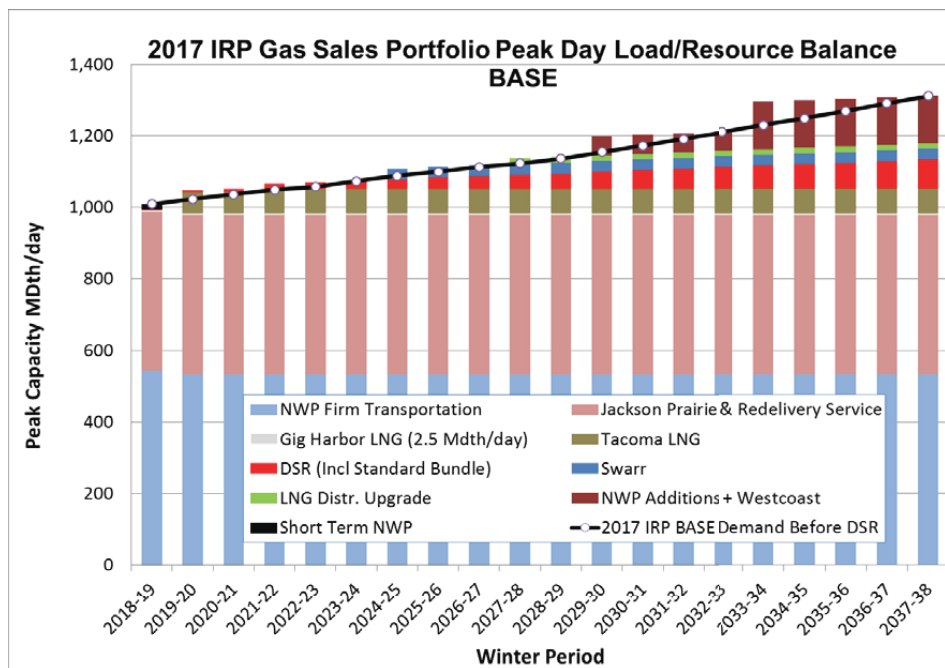




Figure 7-27: Gas Sales Base Scenario Resource Portfolio (table)

| Base Scenario – MDth/day | 2021-22 | 2025-26 | 2029-30 | 2033-34 | 2037-38 |
|--|-----------|-----------|------------|------------|------------|
| Demand-Side Resources | 14 | 31 | 48 | 65 | 82 |
| 7- Swarr Propane-Air Upgrade | - | 30 | 30 | 30 | 30 |
| 5- LNG Distribution Upgrade | - | - | 16 | 16 | 16 |
| 1- NWP/Westcoast Expansion | - | - | 53 | 133 | 133 |
| 3- Cross-Cascades from Malin Expansion | - | - | - | - | - |
| 4- Cross-Cascades from AECO Expansion | - | - | - | - | - |
| 6- Mist Storage/ NWP Expansion | - | - | - | - | - |
| 2- NWP/KORP Expansion | - | - | - | - | - |
| Total | 14 | 61 | 147 | 244 | 261 |

Average Annual Portfolio Cost Comparisons

Figure 7-28 should be read with the awareness that its value is comparative rather than absolute. It is not a projection of average purchased gas adjustment (PGA) rates; instead, costs are based on a theoretical construct of highly incrementalized resource availability. Also, average portfolio costs include items that are not included in the PGA. These include forecast rate-base costs related to Jackson Prairie storage, the PSE LNG Project and Swarr LP-Air, as well as costs for energy efficiency programs, which are included on an average levelized basis rather than a projected cash flow basis. Also, note that the perfect foresight of a linear programming model creates theoretical results that cannot be achieved in the real world.



Figure 7-28: Average Portfolio Cost of Gas for Gas Sales Scenarios

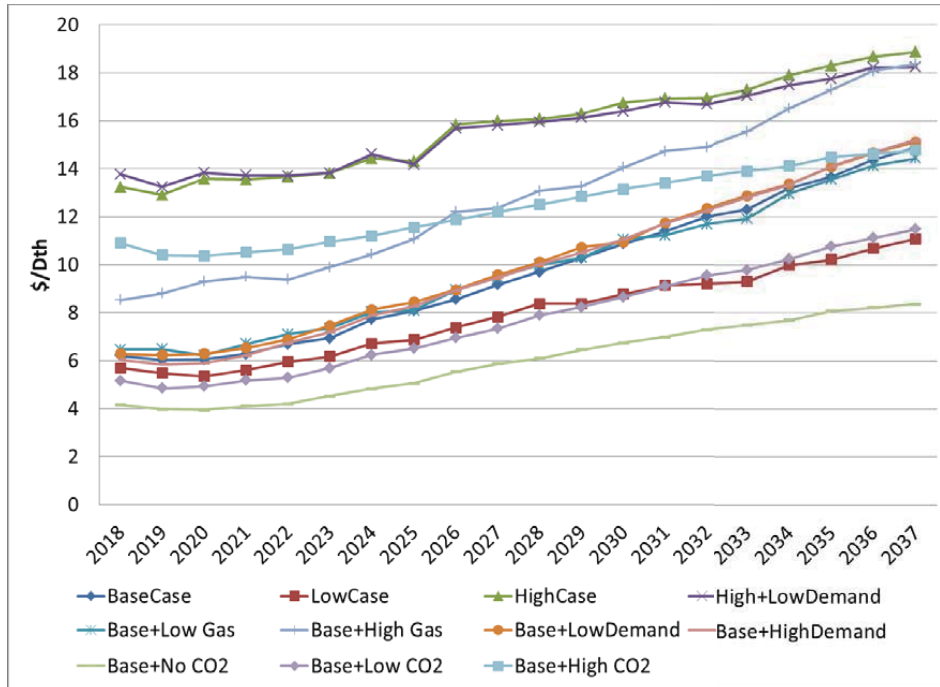


Figure 7-28 shows that average optimized portfolio costs are heavily impacted by the gas prices and CO₂ cost assumptions included in each scenario.

- Changes in customer demand cause only minimal changes in average portfolio costs as shown by the similarity of average portfolio costs in the Base, Base + Low Demand and Base + Low Gas scenarios.
- Scenario costs range from \$4.16 to \$13.23 per Dth in 2018 to \$8.37 to \$18.87 per Dth in 2037.
- The Base Scenario portfolio costs are about \$6.2 per Dth in 2018, increasing to about \$14.90 per Dth by 2037.
- The highest average system cost was in the High Scenario, which ranged from \$13.23 per Dth in 2018 to \$18.87 per Dth in 2037. The High Scenario included high CO₂ costs; this helped it track closely to the Base + Very High Gas Price Scenario which included mid CO₂ costs.
- The lowest average portfolio cost was in the Base + No CO₂ Scenario, which ranged from \$4.16 per Dth in 2018 to \$8.37 per Dth in 2037. This is because this scenario had the lowest gas plus CO₂ price assumptions. The results show that the relatively high CO₂ cost compared to the gas price has a significant impact on system costs.



Sensitivity Analyses

Four sensitivities were modeled in the gas sales analysis for this IRP. Sensitivities start with the Base Scenario portfolio and change one resource. This allows PSE to evaluate the impact of a single resource change on the portfolio.

1. DEMAND-SIDE RESOURCES

BASELINE: All cost-effective DSR per RCW 19.285 requirements.

SENSITIVITY > No DSR, all future resource needs are met in with supply-side resources.

2. ALTERNATE RESIDENTIAL CONSERVATION DISCOUNT RATE

BASELINE: All demand-side resources are evaluated using the weighted average cost of capital (WACC) assigned to PSE.

SENSITIVITY > Evaluate residential DSR using an alternate discount rate. The WACC is still applied to commercial and industrial energy efficiency measures.

3. RESOURCE ADDITION TIMING OPTIMIZATION

BASELINE: Swarr LP-Air and the LNG distribution system upgrade are built starting in 2019 and 2021 respectively, and offered every two years in the model.

SENSITIVITY > Swarr and the LNG distribution system upgrade are allowed every year starting in 2019 and 2021 respectively.

4. ADDITIONAL GAS CONSERVATION

BASELINE: All cost-effective DSR per RCW 19.285 requirements.

SENSITIVITY: Add two more demand-side bundles above the cost-effective demand-side bundles.

Demand-side Resources

In the Base Scenario the portfolio model assumes all cost-effective DSR per RCW 19.285 requirements. The portfolio model is then run a second time with demand-side resource alternatives removed as an option, and the model meets need with only supply-side resource alternatives. The results show that portfolio costs are significantly lower in the Base Scenario where demand-side resources are offered and are selected to optimize the portfolio. The net present value of the portfolio with demand-side resources is lower by about \$360 million.



Alternate Residential Conservation Discount Rate Sensitivity

An alternate discount rate was applied to the demand-side resource alternative in this sensitivity analysis (one that was lower than PSE's assigned WACC) to find out if it would result in a higher level of cost-effective DSR. The alternate discount rate was modeled as 1) the 3-month average of a long-term 30-year nominal treasury rate for residential customer class,¹⁰ and 2) the WACC discount rate for the commercial and industrial customer classes. The treasury rate used for developing the residential bundles was 2.94 percent. The impact was to shift measures to the lower cost point on the conservation supply curve.

This alternate discount rate was used to estimate the achievable DSR potential for the new DSR bundles (see Figure 7-14). These "alternate discount rate" bundles were then input into the gas portfolio model to obtain the cost-effective level of DSR.

The residential bundles chosen with the alternate discount rate were at a lower point on the supply curve for the residential class, and they remained unchanged for the commercial class of customers. The net effect was that cost-effective savings from residential customers was slightly higher. This impact was muted due to the "lumpiness" of the supply curve. The Base Scenario bundle had a significant jump in savings in Bundle 8, and when the alternate discount rate was used to redevelop the supply curve, the large savings shifted to lower point on the supply curve and moved to Bundle 6. This resulted in the model selecting Bundle 6, since it was likely able to satisfy the resource need with lower cost and a higher amount of conservation. In Bundle 6, cost-effective savings in the commercial and industrial bundles was the same as in the Base Scenario, as these bundles were not affected by the discount rate.

See Figure 7-29 for the residential customer DSR savings comparison.

There are slightly more measures – in particular in the residential bundles – since the lower discount rate shifted some of the measures on the margin to the lower cost bundles. Thus the overall cost-effective level of DSR increased slightly by the end of the twentieth year (see Figure 7-30). While the choice of the appropriate discount rate by customer class is still a topic of discussion, a lower discount rate increases the amount of cost-effective DSR, as expected. However, in a real program-level evaluation, such an increase in the level of savings will also impact acquisition costs. Higher administrative costs would need to be reflected in the assumptions, and then the bundles would need to be re-optimized.

¹⁰ / Source: <https://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yieldYear&year=2017>



Figure 7-29: Cost-effective Level of Gas DSR for Residential Customer Class, Base vs. Alternate Discount Rate

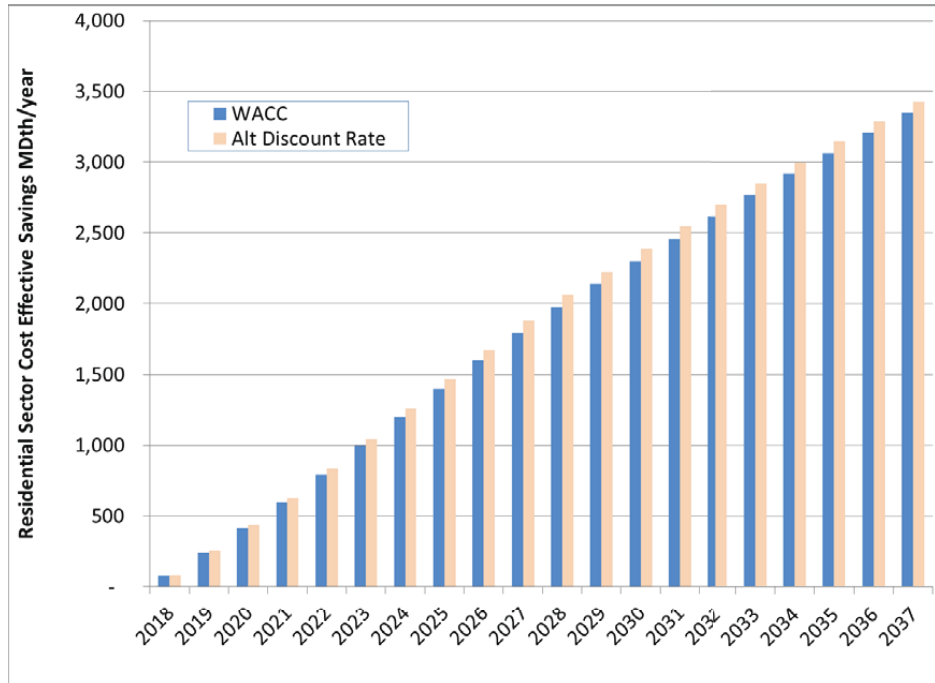
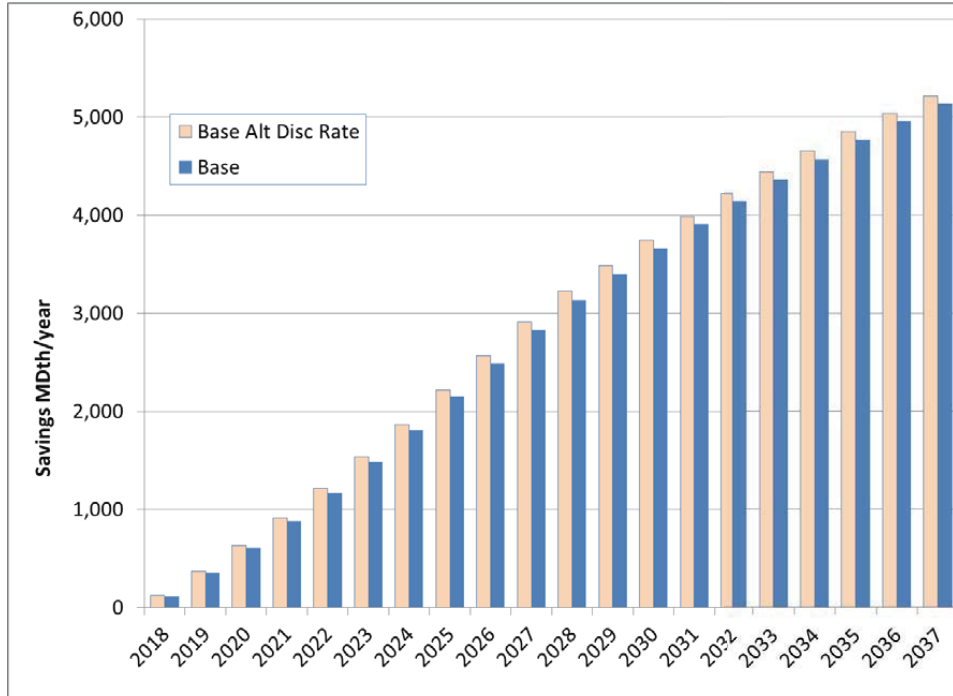




Figure 7-30: Cost-effective Level of Gas DSR, Base vs. Alternate Residential Conservation Discount Rate



Resource Addition Timing Optimization

Two of the supply-side resources are projects that PSE would implement to increase peaking capacity: Swarr and the LNG distribution system upgrade. The timing for these resources is in PSE's control, and the lead times are short enough that these resources can be developed with a year's notice. Therefore, the Base Scenario was tested to allow these resources to be built in any given year. Swarr is available starting in November of 2019 and the LNG distribution upgrade is offered first in November 2021. Given that PSE is surplus, and the first need occurs in the winter of 2022/23, these resources are not needed in the near term in any case. However, by looking at the annual expansion option, we can determine in what year the resource is needed and we can determine if that will produce a lower portfolio cost.

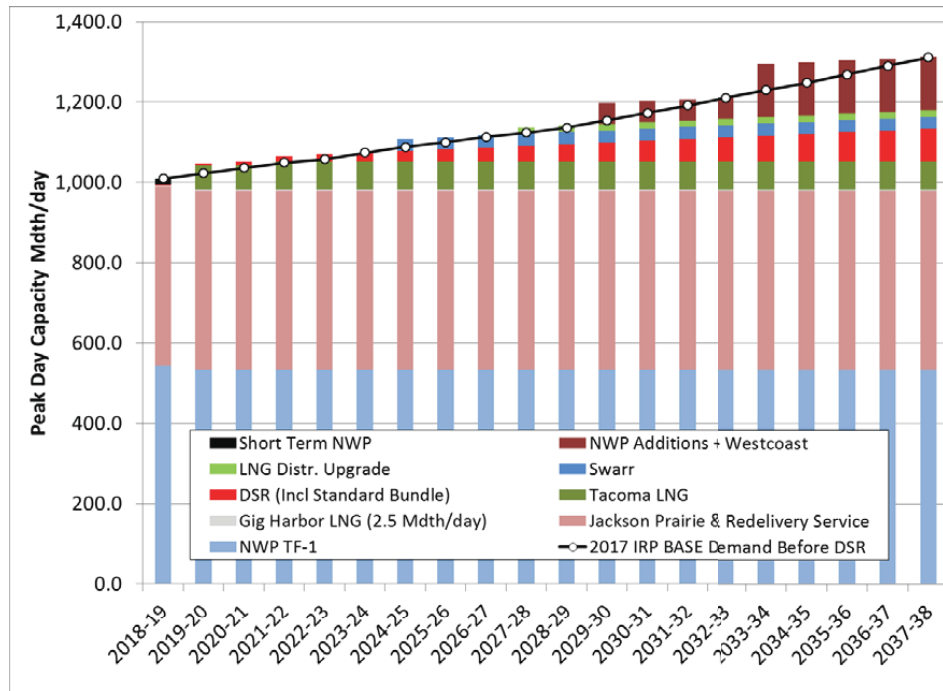
Chapter 7: Gas Analysis



KEY FINDINGS. Reflecting the flexibility PSE has in timing the Swarr and LNG distribution upgrades makes slight changes in the timing of resource builds and lowers the overall NPV portfolio cost.

As shown in Figure 7-31, the result was a slightly smoother load/resource balance in the first ten years when Swarr and LNG distribution upgrades are selected instead of the step or “lumpy” resource additions that can be seen in the latter half of the study when pipeline additions are offered every four years.

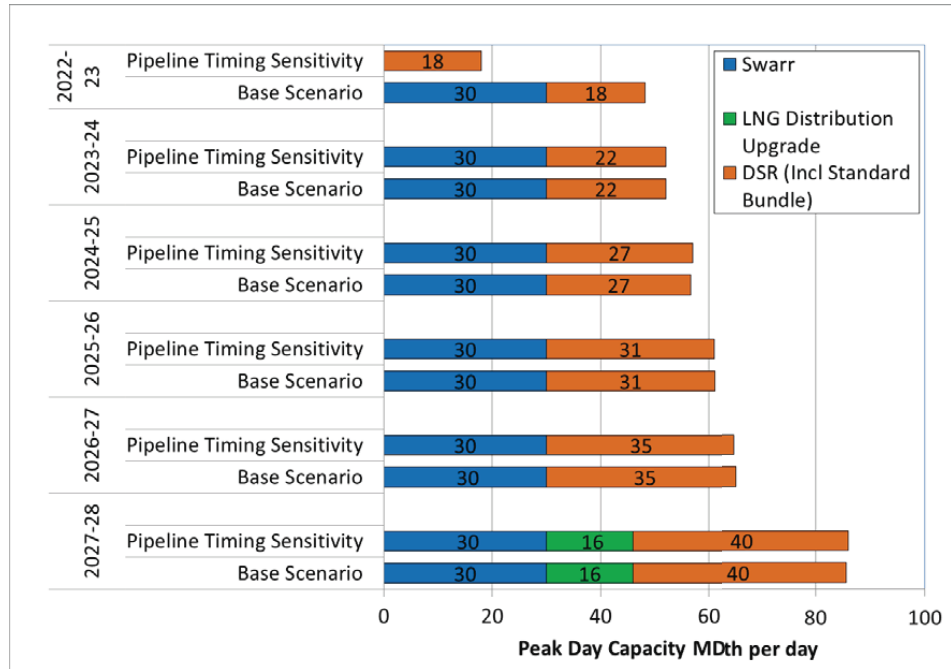
Figure 7-31: Timing Sensitivity Gas Resource Portfolio



The portfolio builds for the timing sensitivity are shown in comparison with the Base Scenario portfolio in Figure 7-32 below. The chart below shows that the Swarr and LNG distribution upgrade additions are the same in the Base Scenario as in the timing sensitivity, the only difference being that Swarr is delayed by one year in the timing sensitivity. All the other resource additions are unchanged.



Figure 7-32. Timing Sensitivity Impact on Other Resource Builds



PORTFOLIO COST IMPACTS. Results indicate the revised timing of resource additions from the pipeline timing sensitivity reduce portfolio costs. The 20-year NPV of cost for the Base Scenario portfolio was \$8,799 million. The 20-year NPV cost for the pipeline timing sensitivity portfolio was \$8,797 million – a slight reduction in portfolio cost..



Additional Gas Conservation

The cost-effective amount of conservation in the Base + No CO₂ Scenario was used as the basis for this analysis. Figure 7-33 shows the two levels of additional DSR bundles that were tested. The incremental approach estimated the cost of reducing carbon using two additional DSR bundles, and a second approach added all 10 of the DSR bundles.

Figure 7-33: Additional Conservation Bundles Tested

| DSR Bundle | Base No CO ₂ | Incremental DSR | All DSR |
|--------------------------|-------------------------|-----------------|---------|
| Residential Firm | 4 | 6 | 10 |
| Commercial Firm | 5 | 7 | 10 |
| Commercial Interruptible | 3 | 5 | 10 |
| Industrial Firm | 3 | 5 | 10 |
| Industrial Interruptible | 3 | 5 | 10 |

NOTE: Incremental DSR is two bundles over the cost effective bundles in the Base + No CO₂ portfolio.

The additional bundles in the two cases were forced into the SENDOUT portfolio optimization model and both the total system costs and incremental carbon reduction was compared to the Base + No CO₂ portfolio. The results are shown in Figure 7-34 below.

Figure 7-34: Cost of Emission Reduction with Additional Conservation

| | Base Deterministic Portfolio Cost (Levelized Millions \$) | Difference from Base (Millions \$) | Regional Emissions (Levelized Million Tons) | Difference from Base (Millions Tons) | Cost of Carbon Reduction (\$/ton) |
|---|---|------------------------------------|---|--------------------------------------|-----------------------------------|
| Base + No CO ₂ (Reference) GAS | \$5,599 | | 59.77 | | |
| Additional Conservation – Incremental GAS | \$5,601 | \$2 | 59.69 | 0.08 | \$20.45 |
| Additional Conservation – All GAS | \$5,768 | \$169 | 58.30 | 1.47 | \$114.83 |

The cost of carbon reduction increases as you move up on the gas conservation supply curve. The amount of conservation is dependent on the distribution of the conservation resources on the supply curve; it is non-linear, and so the impact on emissions can vary.



8

2017 PSE Integrated Resource Plan

Delivery Infrastructure Planning

This chapter describes the planning process for PSE-owned gas and electric delivery infrastructure and outlines the challenges and opportunities that confront the delivery system at this time.

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Chapter 8: Delivery Infrastructure



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1. OVERVIEW

Delivery system infrastructure planning is done on a 10-year basis, and those plans are updated continually as conditions, technologies and customer behavior change. This chapter reviews PSE's responsibilities and existing system, what drives infrastructure investment, the planning process, 10-year infrastructure plans, and current challenges and opportunities. It also describes the process for determining the system need, clarifying alternatives, and preliminary solutions or solutions funding approval.

System planning is a complex process that involves evaluation of system needs and alternatives to address those needs. External input is a major component of the planning process. For large projects, stakeholder engagement throughout project development is extensive. In addition to a general description of those steps, this chapter includes a detailed description of the Energize Eastside Transmission Capacity Project to illustrate the evaluation, analysis and community involvement PSE performs in the process of making system improvement decisions.

Currently, PSE is in the process of upgrading its delivery system infrastructure to support smart grid enhancements; this will enable us to achieve cost-effective efficiencies and expand customer offerings. Replacement of legacy analog networks and obsolete remote telemetry unit equipment began in 2010 and is expected to be completed within the next five years. This includes modern, IP-based SCADA networks that will be used to control and monitor substation, transmission and generation assets and replacement of aging Automated Meter Reading (AMR) communications system and electric customer meters with Advanced Metering Infrastructure (AMI) that enables two-way communication. These steps are necessary to build the foundation to efficiently integrate maturing technologies. Among those we are integrating and studying are distributed generation, energy storage, conservation voltage reduction and demand response. While PSE expands integration of these alternatives, we will need to be mindful of the dependability of the technology under all conditions such that customer reliability and rates are not harmed by technologies and applications that are not effectively scalable. Additionally, the technologies and integration must be compatible with existing grid standards and tariffs. This makes informing customers and stakeholders about the capability and viability of these technologies an important priority for PSE.



2. SYSTEM OVERVIEW

Responsibilities

PSE's delivery system is responsible for delivering natural gas and electricity through pipes and wires safely, reliably and on demand. We are also responsible for meeting all regulatory requirements that govern the systems. To accomplish this, we must do the following¹.

- Operate and maintain the system safely and efficiently on a year-by-year, day-by-day and hour-by-hour basis.
- Accomplish timely maintenance and reliability improvements.
- Meet state and federal regulations and complete compliance-driven system work.
- Ensure that gas and electric systems meet both peak demands and day-to-day demands.
- Ensure that localized growth needs are addressed when they differ from overall system growth needs.
- Meet the interconnection needs of independent power generators that choose to connect to our system.
- Plan for future needs so that infrastructure will be in place when the need arrives.

Some of these are regional responsibilities. For instance, all PSE facilities that are part of the Bulk Electric System and the interconnected western system must be planned and designed in accordance with the latest applicable and approved version of the North American Electric Reliability Corporation (NERC) Transmission Planning (TPL) Reliability Standards. These standards set forth performance expectations that affect how the transmission system – 100 kilovolts (kV) and above – is planned, operated and maintained. PSE also must follow Western Electricity Coordinating Council (WECC) reliability criteria; these can be more stringent or more specific than NERC standards at times.

PSE must also ensure that the system is flexible enough to adapt to coming changes. Smart Grid components, electric vehicles, customer distributed resources and demand response programs are some of the effective solutions the industry is moving toward in the future, and we need to be prepared to integrate them for the benefit of our customers.

¹ / Obligations defined by various codes and best practices such as Washington Administrative Code (WAC) 296 - 45 Electric Power Generation, Transmission, and Distribution; WAC 480-90 Gas Companies - Operations; WAC 480-93 Gas Companies - Safety; WAC 480-100 Electric Companies; WAC 480-108 Electric companies - Interconnection with Electric Generators; WAC 480-100-358:398 Part VI Safety and Standard Rules; National Electric Safety Code (NESC) Parts 1, 2 and 3; NERC Reliability Standards; WECC Regional Reliability Standards; Code of Federal Regulations (CFR) Title 18; CFR Title 49; FERC Order 1000; Occupational Safety and Health Administration; Washington Industrial Safety and Health Administration; National Electric Code; and Institute of Electrical and Electronics Engineers.

Chapter 8: Delivery Infrastructure



The goal of PSE's planning process is to help us fulfill these responsibilities in the most cost-effective manner possible. Through it, we evaluate system performance and bring issues to the surface; we identify and evaluate possible solutions; and we explore the costs and consequences of potential alternatives. This information helps us make the most effective and cost-effective decisions going forward.

Existing System

The table below summarizes PSE's existing delivery infrastructure as of December 31, 2016. Electric delivery is accomplished through wires, cables, substations, and transformers. Gas delivery is accomplished by means of pipes and pressure regulating stations.

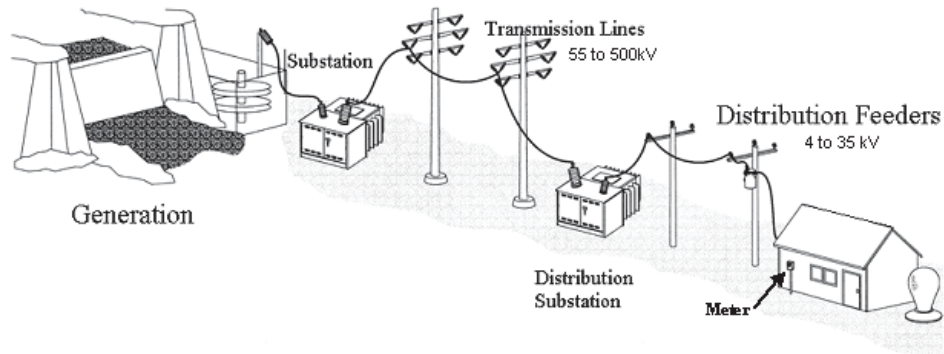
Figure 8-1: PSE-owned Transmission and Distribution System as of December 31, 2016

| ELECTRIC | GAS |
|--|--|
| Customers: 1,127,002 | Customers: 812,723 |
| Service area: 4,500 square miles | Service area: 2,800 square miles |
| Substations: 352 | City gate stations: 40 |
| Miles of transmission line: 2,608 | Pressure regulating stations: 581 |
| Miles of overhead distribution line: 10,662 | Miles of pipeline: 12,623 |
| Miles of underground distribution line: 10,529 | Supply system pressure: 150–550 psig |
| Transmission line voltage: 55-500 kV | Distribution pipeline pressure: 45-60 psig |
| Distribution line voltage: 4-34.5 kV | Customer meter pressure: 0.25 psig |
| Customer site voltage: less than 600 V | |



How Electric Delivery Systems Work

Figure 8-2: Illustration of Electric Delivery System



Electricity is transported from power generators to consumers over wires and cables, using a wide range of voltages and capacities. The voltage at the generation site must be stepped up to high levels for efficient transmission over long distances (generally 55 to 500 kilovolts).

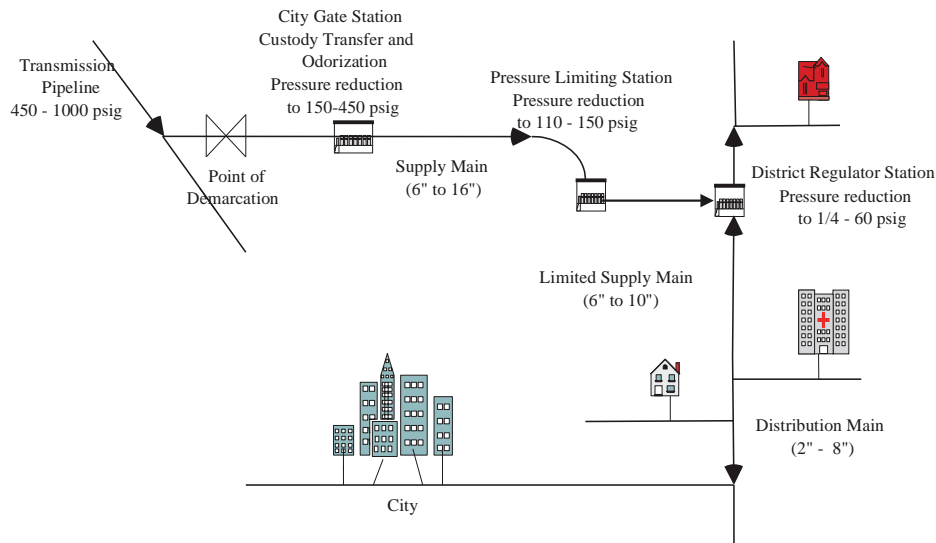
Substations receive this power and reduce the voltage in stages to levels appropriate for travel over local distribution lines (between 4 and 34.5 kV). Finally, transformers at the customer's site reduce the voltage to levels suitable for the operation of lights and appliances (under 600 volts). Wires and cables carry electricity from one place to another. Substations and transformers change voltage to the appropriate level. Circuit breakers prevent overloads, and meters measure how much power is used.

The electric grid was first built 1889, expanding in a highly radial one-way flow design. Over time, the transmission system was looped in a network manner as outages across the nation drove voluntary standards and eventually regulations that require operations with one element out of service. In urban areas a distribution system with looped feeders became common practice to improve reliability. It still operated in a radial one-way flow manner, but as automation and protection devices matured, the system was able to automatically switch to a different source. Nearly 100 percent of the transmission system is networked and portions of PSE's distribution system are looped.



How Natural Gas Delivery Systems Work

Figure 8-3: Illustration of Gas Delivery System



Natural gas is transported at a variety of pressures through pipes of various sizes. Interstate transmission pipelines deliver gas under high pressures (generally 450 to 1,000 pounds per square inch gauge [psig]) to city gate stations. City gate stations reduce pressure to between 150 and 450 psig for travel through supply main pipelines. Then district regulator stations reduce pressure to less than 60 psig. From this point the gas flows through a network of piping (mains and services) to a meter set assembly at the customer's site where pressure is reduced to what is appropriate for the operation of the customer's equipment (0.25 psig for a stove or furnace), and the gas is metered to determine how much is used.

The gas system was first built in the late 1800s, expanding in a network two-way flow design. From its beginnings as a manufactured gas system, the pipeline materials and operating pressures have changed over time. Natural gas was introduced to the area in 1956, allowing for higher pressures and smaller diameter pipes. Where older cast iron pipe was used, new plastic pipe is inserted into it as a way of cost effectively renewing existing infrastructure in urban areas. While the energy qualities and pipeline materials have changed, the technology used to operate the system has not. Now that gas pipelines are often located within increasingly congested rights-of-way, protecting pipelines from damage becomes even more important.



3. WHAT DRIVES INFRASTRUCTURE INVESTMENT?

Even with load growth being offset by PSE conservation efforts, infrastructure expenditures may stay the same or even increase. This is because load growth is only one of the drivers of infrastructure investment. Aging equipment must be maintained or replaced; regulatory requirements may require spending on system upgrades or alterations; public transportation projects can necessitate equipment relocation; and we are required to integrate new generation resources. Below, we describe the six factors that drive infrastructure investment. Some can be known in advance, others can be forecasted, and some circumstances arise from external events such as extreme weather, new codes or policies that drive behavior or actions, or new transportation projects as a result of unexpected increased funding.

Load Growth

PSE's first and foremost obligation is to serve the gas and electric loads of our customers; when customers turn on the switch or turn up the heat, sufficient gas and electricity need to be available. Load drives system investment in three ways as overall system loads, short-term peak loads and point (block) loads must be met.

Overall System Growth

Demands on the overall system increase as the population grows and economic activity increases in our service area, despite the increasing role of demand-side resources and conservation. PSE regularly evaluates economic and population forecasts in order to stay abreast of where and when additional infrastructure, including electric transmission lines, substations and high-pressure gas lines, may be needed to meet growing loads.

Peak Loads

Peak loads occur when the weather is most extreme. To prepare for these events, PSE carefully evaluates system performance during periods of peak loading each year, updates its system models and compares these models against future load and growth forecasts. This prepares us to determine where additional infrastructure investment is required to meet peak firm loads.

Electric and gas system delivery planning is based on near-term and long-term customer growth forecast updates prepared by the Resource Planning and Analysis department. The forecasts include the impact of conservation efforts and implementation of interruptible rate schedules.



Interruptible rate schedules are most commonly employed by commercial or industrial customers due to their ability to provide backup generation for critical load and willingness to tolerate an complete outage for period of time, as PSE must be able to depend on curtailment when needed. Residential customers typically do not tolerate undefined outage lengths during extreme events such as cold weather.

The gas system is designed to operate more conservatively than the electric system because during a peak event the gas system pressure declines as loads increase. As gas pressure approaches zero, customer equipment is unable to operate as intended, requiring manual intervention by PSE to restore service safely. For this reason, gas outages have much greater public and restoration impacts than electric outages and must be avoided for all but the most extreme conditions. The electric system is more flexible. For short periods of time components can often carry more current than their nameplate ratings call for with no adverse effects, and power restoration following an outage can be achieved instantly if power is rerouted through available switches.

Point Loads

System investments are sometimes required to serve specific “point loads” that may appear at a specific geographic location in our service territory. Electrical infrastructure to serve a computer server facility is one example; gas infrastructure to serve an industrial facility such as an asphalt plant is another.

Reliability and Resiliency

The energy delivery system is reviewed each year to improve the reliability of service to existing customers. Past outages, equipment inspection and maintenance records, customer feedback, and PSE field input help identify areas where improvements may be made. Additional consideration is given to system enhancements that will improve resiliency (such as being able to provide a second power line from one substation to another in order to enable a self-healing grid). Some of the investments to improve reliability and resiliency include replacing aging conductors, installing covered conductors (tree wire) and converting overhead lines to underground.



Regulatory Compliance

PSE is committed to operating our system in accordance with all regulatory requirements. The gas and electric delivery systems are highly regulated by several state and federal agencies including PHMSA (Pipeline & Hazardous Materials Safety Administration), NERC, FERC (Federal Energy Regulatory Commission), the WUTC (Washington Utilities and Transportation Commission) and various worker and public safety regulations. Infrastructure investments driven by compliance requirements include electric transmission projects that are aimed at preventing cascading power outages and system collapse that could extend outside PSE's system. Gas regulations drive very specific inspection and maintenance activities and often require the replacement of assets based upon age and/or condition.

Public Improvement Projects

PSE must respond to city, county and state jurisdictions within our service area when transportation-related public improvement projects impact our facilities both within and immediately adjacent to public rights of way. PSE gas and electric facilities may require relocation or underground conversion of electrical facilities to accommodate public transportation projects. We also work closely with local jurisdictions to identify system improvement opportunities and to minimize surface restoration costs and disruptions in association with these public improvement projects.

Aging Infrastructure

With continued maintenance, gas and electric infrastructure can provide safe, reliable service for decades. PSE has a number of programs in place that address aging infrastructure by replacing poles, pipes and other components that are nearing the end of their useful life. Our goal is to maximize the life of the system and at the same time minimize customer interruptions by replacing major infrastructure components prior to significant unplanned failure.



Integration of Resources

FERC and state regulations require PSE to integrate generation resources into our electric system according to processes outlined in federal and state codes. A new generation plant, whether it is owned and operated by PSE or by others, can require significant electric infrastructure investment to integrate and maintain appropriate electrical power flows within our system and across the region. For the gas system, integrating gas supply resources owned and/or operated by PSE or others (such as underground gas storage, on-system LNG/propane-air peak shaving, and the interstate gas transmission systems) can also require significant infrastructure investment to maintain appropriate system pressures and flows across the region.

Distributed generation (DG) – the smaller generation technologies such as roof-top solar panels – must also be reviewed and integrated, often requiring system protection enhancements to satisfy the net metering two-way flow requirements. For larger scale systems, these may also require system infrastructure improvements such as new distribution feeders or a substation.

After initial integration, PSE must monitor the impact and influx of these types of resources in order to address any developing power quality concerns and continue to support the desires of customers. The majority of customers who pursue DG today seek to do more than support their own load and desire to sell excess energy back to the utility, which requires additional consideration of infrastructure reliability. Generally, contributions from this type of generation do not occur during PSE's peak demand² necessitating the need for infrastructure to supply peak load in order to deliver reliable service. Storage and control systems to help balance DG limitations are maturing, and as control, communications, delivery infrastructure and energy storage systems are modernized, opportunities to integrate distributed generation more effectively to benefit PSE's operations will increase.

² / PSE's peak load occurs in winter when it is dark preventing solar panels from effectively operating during those times.



4. PLANNING PROCESS

The goal of the planning process is to deliver reliable energy in the near term and over the long-term planning horizon in cost-effective ways in order to meet customer needs and maximize value to customers, communities and the company.

PSE's system planning process:

- Takes into account the service quality needs of PSE's customers
- Incorporates all applicable regional and federal orders and rules as they relate to system planning
- Includes industry best practices for planning the system

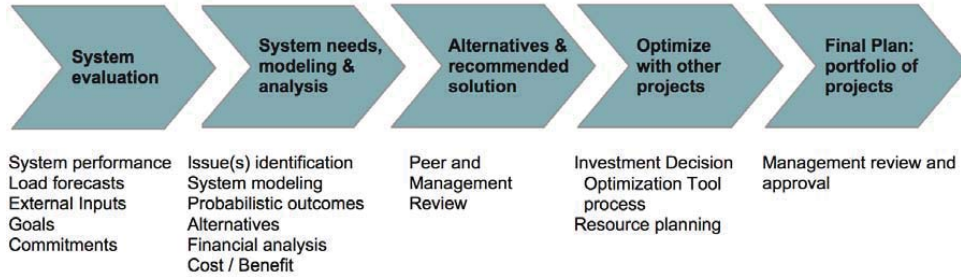
The planning process begins with an evaluation of the system's current performance and future need through data analysis and modeling tools. Planning considerations include internal inputs such as reliability indices, company goals and commitments, and reviewing the root causes of historic outages. In addition, external inputs such as service quality indices, regulations, municipalities' infrastructure plans, customer complaints and ongoing service issues are also considered. This robust process is lengthy. It starts in the spring and takes 6-8 months from initial research to finalization of the portfolio.

Next, project alternatives are developed. Those alternatives are vetted and reviewed, and projects are compared against one another. Finally, a portfolio of projects is adopted based on optimizing benefit and cost for a given funding level. The process is the same for both long-term and short-term planning. Typically utilities align investment in non-revenue producing infrastructure to customer revenue associated with growth, which further defines a given funding level or constraint for optimization of the portfolio of infrastructure work.

Even after the portfolio for a given year is approved, we continue to monitor changing conditions and make alterations as necessary. This robust process is lengthy. It starts in the spring after storm season when system performance data is available, and takes six to eight months to from initial research to finalization of the portfolio, delivering project scope and resource planning for implementation in the fall of the following year.



Figure 8-4: Delivery System Planning Process



System Evaluation

System evaluation begins with an evaluation of system performance, a review of existing operational challenges, and consideration of load forecasts, demand side management (DSM) and known commitments and obligations. Performance is measured by the system’s ability to maintain quality and continuous service during normal and peak loads throughout the year while meeting the regulatory requirements that govern them.

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Performance criteria for electric and gas delivery systems lie at the heart of the process and are the foundation of PSE's infrastructure improvement planning.

Figure 8-5: Performance Criteria for Electric and Gas Delivery Systems

| Electric delivery system performance criteria are defined by: | Gas delivery system performance criteria are defined by: |
|--|--|
| Safety and compliance (e.g., 100% compliance) | Safety and compliance (e.g., 100% compliance) |
| The temperature at which the system is expected to perform (e.g., normal winter peak, extreme winter peak) | The temperature at which the system is expected to perform (e.g., 55 DD Peak Hour) |
| The nature of service and level of reliability that each type of customer has contracted for (e.g., firm or interruptible) | The nature of service each type of customer has contracted for (e.g., firm or interruptible) |
| The minimum voltage that must be maintained in the system (e.g., no more than 5% above or below standard voltage) | The minimum pressure that must be maintained in the system (e.g., level at which appliances fail to operate) |
| The maximum voltage acceptable in the system (e.g., no more than 5% above or below standard voltage) | The maximum pressure acceptable in the system (e.g., defined by CFR 192.623 and WAC-480-93-020) |
| Thermal limits of equipment utilized to deliver power to load centers and transmission customers (e.g., per PSE Transmission Planning Guidelines) | |
| The interconnectivity with other utility systems and resulting requirements, including compliance with NERC planning standards (e.g., 100% compliance) | |



Performance Inputs

PSE collects system performance information from field charts, remote telemetry units, supervisory control and data acquisition equipment (SCADA), employees and customers. Some information is analyzed over multiple years to normalize the effect of variables like weather that can change significantly from year to year. For near-term load forecasting at the local city, circuit or neighborhood level, we use system peak-load broken down by county and customer growth trends, augmented by permitted construction activity for the next two years and including transmission customer load.

External Inputs

External inputs such as new regulations, municipal and utility improvement plans, and customer feedback, as well as company objectives such as PSE's asset management strategy or smart grid strategy, are also included in the system evaluation to understand commitments and opportunities to mitigate impact or improve service at least cost. For example, the WUTC issued a policy statement requiring natural gas utilities to file a plan for replacing pipes that represent a higher risk of failure, and PSE's commitment to this plan is considered in the evaluation.

PSE obtains the annual updates to local jurisdiction six-year Transportation Improvement Plans to gain long-term planning perspective on upcoming public improvement projects. As the transportation projects develop through design, engineering and construction, PSE works with the local jurisdictions to identify and minimize potential utility conflicts and to identify opportunities to address system deficiencies and needs. For aging and risk mitigation infrastructure programs like replacement of all DuPont gas pipe associated with the aforementioned WUTC policy statement or replacement of underground high molecular weight cable, coordination over many years becomes meaningful for all who will be impacted by utility construction and surface restoration requirements.

PSE also meets with jurisdictions in various forums such as quarterly roundtable discussions that include other utilities and agencies and in formal public presentations required through agreement or local regulation in order to gather input about concerns and coordinate solutions. For example, PSE and the City of Bellevue meet annually to exchange plans related to community development and utility system improvements, which provides an opportunity for interested stakeholders to ask questions and raise issues and concerns. Similarly, PSE engages in a multi-year coordination with Bainbridge Island stakeholders to discuss reliability and gather input regarding improvements.

PSE gains public input regarding the need for infrastructure improvement through the PSE and WUTC complaint process, as well as through open forums that result from less than satisfactory service.



System Needs, Modeling and Analysis

PSE relies on several tools to help identify needs or concerns and to weigh the benefits of alternative actions to address them. Figure 8-6 provides a brief summary of these tools, the planning considerations (inputs) that go into each and the results (outputs) that they produce. Each tool is used to provide data independently for use in iDOT which then creates the full understanding of all the benefits and risks.

Figure 8-6: Delivery System Planning Tools

| TOOL | USE | INPUTS | OUTPUTS |
|--|--|--|--|
| SynerGi® | Gas and Electric network modeling | Gas and electric distribution infrastructure from GIS and load characteristics from CIS, load approvals, load forecast | Predicted system performance |
| Power World Simulator – Power Flow | Electric network modeling | Electric transmission infrastructure from WECC base case and load/generation characteristics from CIS, load approvals, and load forecast | Predicted system performance |
| Electric Predictive Spreadsheet | Electric outage predictive analysis | Electric outage history from SAP | Predicted outage savings |
| Gas Outage Spreadsheet | Gas outage predictive analysis | Gas SynerGi system performance data for future capacity | Predicted outage savings |
| Estimated Unserved Energy (EUE) Spreadsheet | Electric financial analysis | Estimated project costs; hourly load data from EMS; load growth scenarios from load forecast | Net Present Value; income statement; load growth vs. capacity comparisons; EUE |
| Distribution / Transmission Integrity Management Risk Assessment | Gas pipeline risk analysis | Gas infrastructure operating or maintenance concerns from various databases | Program funding options to mitigate higher risk facilities |
| Asset Management Assessment | Electric maintenance analysis | Electric infrastructure operating or maintenance concerns from various databases | Program funding options to mitigate higher risk facilities |
| All data collected by the tools above are input into iDOT | | | |
| Investment Decision Optimization Tool (iDOT) | Gas and electric project data storage & portfolio optimization | Project scope, budget, justification, alternatives and benefit/risk data collected from above tools and within iDOT; resources/financial constraints | Optimized project portfolio; benefit cost ratio for each project; project scoping document |

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PSE's gas system model and electric distribution model is a large integrated model of the entire delivery system. It uses a software application (SynerGi[®] Gas and SynerGi Electric, respectively) that is updated to reflect new customer loads and system and operational changes. This model helps predict capacity constraints and subsequent system performance on a variety of temperatures and under a variety of load growth scenarios. Results are compared to actual system performance data to assess the model's accuracy.

To simulate the performance of the electric transmission system, PSE primarily uses Power World Simulator. This simulation program uses a transmission system model that encompasses infrastructure across 11 western states, 2 provinces in western Canada and parts of northern Mexico. The power flow and stability data for these models are collected, coordinated and distributed through regional organizations including ColumbiaGrid and WECC (one of eight regional reliability organizations under NERC). These power system study programs support PSE's planning process and facilitate demonstration of compliance with WECC and NERC reliability performance standards. While PSE utilizes a regional model for system evaluation and coordination, the focus is on local concerns and projects. Appendix I describes regional transmission planning and the role of ColumbiaGrid. ColumbiaGrid has had substantial responsibilities for transmission planning, reliability and other development services since 2006 in order to improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. PSE is one of 8 utilities that coordinate regional planning through ColumbiaGrid, which provides transparency and encourages broad participation and interaction with stakeholders, including customers, transmission providers, states and tribes.

Modeling is a three-step process. First, a map of the infrastructure and its operational characteristics is built from the GIS and asset management system, or in the case of transmission, provided by WECC. For gas, these include the diameter, roughness and length of pipe, connecting equipment, regulating station equipment and operating pressure. For electric infrastructure, these include conductor cross-sectional area, impedance, length, construction type, connecting equipment, transformer equipment and voltage settings. Next, we identify customer loads, either specifically (for large customers) or as block loads for address ranges. Existing customer loads come from PSE's customer information system or actual circuit readings. Finally, we take into consideration seasonal variations, types of customers (interruptible vs. firm), time of daily peak usage, the status of components (valves or switches closed or open) and forecast future loads to model scenarios of infrastructure or operational adjustments. The goal is to find the optimal solution to a given issue. Where issues surface, the model can be used to evaluate alternatives and their effectiveness. PSE augments potential alternatives with cost estimates and feasibility analysis to identify the lowest reasonable cost solution for both current and future loads.



System Alternatives

The alternatives available to address delivery system capacity and reliability issues are listed below. Each has its own costs, benefits, challenges and risks.

Figure 8-7: Alternatives for Addressing Delivery System Capacity and Reliability

| ALTERNATIVES | ELECTRIC SYSTEM | GAS SYSTEM |
|---------------------------------|--|--|
| Add energy source | Substation | City-gate station District regulator |
| Strengthen feed to local area | New conductor Replace conductor | New high pressure main New intermediate pressure main Replace main |
| Improve existing facility | Substation modification Expanded right-of-way Uprate system Modify automatic switching scheme | Regulation equipment modification Uprate system |
| Load reduction Wire/Non-wire | Rebalance load Fuel switching Distributed energy resource Battery storage Natural gas conversion Conservation/Demand response Load control equipment Possible new tariffs | Fuel switching Conservation Load control equipment Possible new tariffs |
| Do nothing | | |

The same alternatives can be used to manage short-term issues like peaking events or conditions created by a construction project. For example:

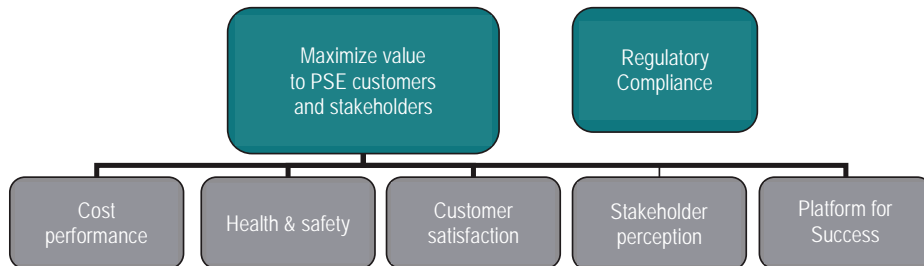
- Temporary adjustment of regulator station operating pressure, as executed through PSE's Cold Weather Action Plan
- Temporary adjustment of substation transformer operating voltage, as done using load tap changers
- Automatic capacitor bank switching to optimize VAR consumption and maintain adequate voltage
- Temporary siting of mobile equipment such as compressed natural gas injection vehicles, liquid natural gas injection vehicles, mobile substations and portable generation



Evaluating Alternatives and Recommended Solutions

To evaluate alternatives, PSE compares the relative costs and benefits of various solutions (i.e., projects) using the Investment Decision Optimization Tool (iDOT). To be comparable, alternatives (either singular solutions or a collection of solutions) must solve the need fully. iDOT, as PSE has labeled it, is PriceWaterhouse Cooper's Folio software, a project portfolio optimization and value-based decision analysis tool. iDOT allows us to capture project and program criteria and benefits and score them across thirteen factors, such as meeting required compliance with codes and regulations, net present value of the project, improvement to reliability, safety, future possible customer/load additions, deferral or elimination of future costs, customer satisfaction by eliminating concern, improved external stakeholder perception, and opportunities for future success gained by greater flexibility of the system or gained through learning about new technologies and methods or drivers of specific company objectives. iDOT makes it easier to conduct side-by-side comparisons of projects and programs of different types, thus helping us evaluate infrastructure solutions that will be in service for 30 to 50 years.

Figure 8-8: Benefit Structure to Evaluate Delivery System Projects



Project costs are calculated using a variety of tools, including historical cost analysis and unit pricing models based on estimated internal engineering costs and service provider contracts. Cost estimates are refined as projects move through detailed scoping. Through this process, alternatives are reviewed and recommended solutions are vetted and undergo an internal peer review process. Projects that address routine infrastructure replacement, such as pole or meter replacements, are proposed at a program level and incorporated into a parallel path within the iDOT process. Risk assessment tools are used to prioritize projects within these programs. An example is the Pipeline Replacement Program (PRP), developed in response to the Commission Policy Statement on Accelerated Replacement of Pipeline Facilities with Elevated Risk (Docket UG-120715). Particular vintages of wrapped steel and polyethylene facilities are prioritized for replacement based on known risks such as leakage history, pipe condition and the proximity of the pipe to certain structures. Another example is the cable remediation program which prioritizes

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based on risks such as number of past failures, number of customers impacted and system configuration that prevents timely restoration.

Historically, like many other utilities, PSE has not broadly engaged the public and stakeholders in distribution alternative analysis for several reasons; 1) short timeframes for distribution system planning as a result of solutions needing to be completed within the same or following year; 2) the number of annual projects (generally greater than 400) would be difficult to review effectively; and 3) least cost alternatives are generally apparent to the seasoned expert planning engineer. However, NERC TPL standards define a required stakeholder process that is followed for non-consequential load loss alternatives. PSE recognizes public policy is leading to a desire for greater transparency in how alternatives are selected and will need to determine how to most effectively engage stakeholders based definitions of those policies, guidelines or rulemaking. Criteria or incentives that allow utilities to choose alternatives that are not least cost will be important.

Each recommended project and program is compared using iDOT. This involves building a hierarchy of the value these benefits bring to the stakeholders against the project cost. The benefits are reviewed and reassessed periodically with senior management to ensure proper weight and priority is assigned throughout the evaluation process. Using project specific information, iDOT optimizes total value across the entire portfolio of non-mandated or discretionary system infrastructure projects (electric and natural gas) which results in a set of capital projects that provide maximum value to PSE customers and stakeholders relative to given financial constraints. Further minor adjustments are made to ensure that the portfolio addresses resource planning and other applicable constraints or issues such as foreseen permitting or environmental process concerns. Periodically PSE has reviewed this process and the optimization tool along with resulting portfolio with WUTC staff.

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Annual plans approved by operations management provide a specific portfolio of projects for the year. Final adjustments may be made as the system portfolio is compared with other objectives of the company such as necessary generator or dam work, or customer initiatives. While annual plans are considered final, throughout the year they continue to be adjusted based on changing factors (such as public improvement projects that arise or are deferred; changing forecasts of new customer connections; or project delays in permitting) so that we can ensure the total portfolio financial forecast remains within established budget parameters. As plans and projects develop through the design and permitting phases, cost and benefit are routinely evaluated and confirmed before progressing. Alternatives may be reviewed through the project development progress points along with more detailed routing and siting discussions.

The specific portfolio of projects and programs are shared with regional teams and project management teams as project planning begins. Long-range plans are communicated to the public through local jurisdictional tools such as the city and county Comprehensive plans required by the Washington State Growth Management Act. Often this information serves as the starting point for demonstrating the need for improvements to local jurisdictions, residents and businesses far in advance of a project moving to planning, design, permitting and construction. Project maps and details are updated on PSE.com as well.



Public Outreach

In addition to the methods described in the system evaluation section regarding gathering input about need and potential coordination opportunities, PSE engages the community, jurisdictions and stakeholders in various ways to arrive at the specific project that is constructed. Project-specific information provides for the greatest engagement with the public, as it enables the community and stakeholders to see specific impacts or relevant interests based on what it means to them (where the project is and what it improves). Outreach tools include community meetings, routing workshops, public open houses and online open houses, webinars, community mailers, surveys and comment cards.

PSE provides information on pse.com³ for a wide variety of projects. These include system improvements as well as an overview of the process including public discussion and outreach. The information includes a project overview, what the community can expect during construction, links to project-specific information and contact information for questions and comments. Project-specific webpages for larger and more complex projects provide details and maps. These sites invite stakeholder questions and inquiries.

Depending on the scope and complexity of the project, community advisory groups may be formed to capture the affected area's diverse interests. The goal is to share system needs and potential solutions, to identify and assess community values in the context of the project attributes, and to develop recommendations for PSE's consideration.

As we integrate environmental considerations into project planning, potential effects are identified, assessed, minimized and mitigated as required by all applicable federal, state and local regulatory codes. PSE works with these agencies to obtain all required land use and environmental permits, approvals and authorizations prior to initiation of construction. These permitting processes provide many and various opportunities for written public comment and verbal testimony at open public hearings. Typically, valid and valuable public input is taken into consideration by the agencies and often developed into conditions of final permit approval.

³ / <http://pse.com/inyourcommunity/pse-projects/Pages/default.aspx>



5. 10-YEAR INFRASTRUCTURE PLANS

PSE develops both short-range and long-range infrastructure plans that support local needs. These are reviewed and validated annually. As the plan year gets closer, the company refines plan projections based on new developments or information and performs additional analyses to reveal and evaluate additional alternatives. The plan may change as a result of these investigations.

The infrastructure additions described below are intended to indicate the scope of investment that may be required over the next ten years in order to serve our customers reliably and fulfill regulatory requirements. They are described in general terms.

Electric Infrastructure Plan

Transmission

In the next decade, PSE anticipates building approximately 104 plus miles of new transmission lines (100 kV and above) and upgrading over 122 miles of existing transmission lines. In addition, we anticipate needing to add up to three 230 kV bulk power substations across our service area. These planned improvements do not include transmission needed to support the broader region or improvements needed as a result of providing interconnections for large generation resources. As a "Transmission Provider," PSE must process all transmission interconnection requests according to applicable FERC resource interconnection procedures. NERC TPL standards establish transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of system conditions and following a wide range of probable contingencies.⁴ These requirements are a primary driver of transmission projects.

Distribution

In the next decade, PSE anticipates the need to build approximately 6 to 8 new distribution substations to serve load as existing substation capacity is exceeded and another 2 to 4 new substations to serve specific point loads. We also anticipate upgrading approximately 3 existing substations to replace aging infrastructure and adding additional capacity to serve local load growth. In total, the new or expanded substations will require 32 to 48 new distribution lines. PSE will continue work on improving reliability of its worst performing circuits as well as installing smart ready equipment for increasing the resiliency of the grid.

⁴ / http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=TPL-001-4&title=Transmission System Planning Performance Requirements&jurisdiction=United States



Ongoing Maintenance

Based upon current projections and past experience, in the next decade PSE expects to replace 1,800 miles of underground high molecular weight, failure-prone distribution cable, approximately 1,000 transmission and 10,000 distribution poles. Additionally, PSE anticipates replacement of several major substation components as a result of ongoing inspection and diagnostics. PSE anticipates replacement of its current aging and obsolete Automated Meter Reading (AMR) communication system as well as its electric customer meters with Advanced Metering Infrastructure (AMI) technology to enable smart grid enhancements and customer offerings in the future.

Figure 8-9: Summary of 10-Year Electric Infrastructure Plan

| ASSET | NUMBER | LOCATION |
|-----------------------------------|-----------------|-------------|
| New Transmission Lines | 104 miles | System-wide |
| Upgraded Transmission Lines | 122 miles | System-wide |
| New Bulk Power Substations | Up to three | System-wide |
| New Distribution Substations | Eight to Twelve | System-wide |
| Upgraded Distribution Substations | Three | System-wide |
| Distribution Lines | 32 to 48 | System-wide |
| Cable Replaced | 1,800 miles | System-wide |
| Transmission Poles Replaced | 1,000 | System-wide |
| Distribution Poles Replaced | Up to 10,000 | System-wide |



Planned Transmission System Improvements

PSE participates in coordinated, open, and transparent transmission planning processes as intended by FERC Order 1000 and outlined through the western regional planning processes of ColumbiaGrid. PSE identifies new transmission facilities and facility replacements or upgrades required to meet system needs over the ensuing ten years. This list of projects is documented pursuant to PSE's Attachment K as a participant of those processes.⁵ Transmission planning studies are performed and project requirements are updated annually. Appendix I: Regional Transmission provides more information regarding Order 1000 and Attachment K.

The following list is based on the 2016 planning results⁶ and provides a high-level description of scope of work, a footnote where more information can be found, and estimated date of completion. It is important to remember that these projects are not associated with facilitating generation resource paths, but are required to meet the local growth or reliability needs of PSE's customers, which may impact the interconnected grid.

⁵ / http://www.oatiaoasis.com/PSEI/PSEIdocs/Attachment_K_20160401.pdf
⁶ / http://www.oatiaoasis.com/PSEI/PSEIdocs/PSE_Plan_2016_Draft.pdf



PROJECTS COMPLETED SINCE LAST 2015 IRP. (Information on a variety of completed projects with in the last six months can be found on PSE's website at <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Completed-improvements.aspx>.) The format of this list of projects is intended to follow Attachment K as closely as possible in order to avoid inconsistency or confusion. The purpose is generally described in terms of improving reliability, increasing capacity to serve load growth, or meeting NERC TPL standards and the planning requirements relative to operating contingencies.

1. Blumaer – Yelm 115 kV Re-conductor⁷

Date of Operation: 2016

This project addressed capacity and reliability needs of the Yelm area by rebuilding the remaining 12-mile Blumaer – Yelm section of the 42-mile Blumaer – Electron Heights 115 kV transmission line, which mostly consists of 4/0 Cu and 336 ACSR conductors, to 115 kV Standard 1272 ACSR 100C conductor.

2. Spurgeon Creek Transmission Substation Development (Phase 1)⁸

Date of Operation: 2016

In Phase 1, this project addressed reliability of transmission service to the cities of Lacey, Olympia and Tumwater, by looping the Blumaer – St Clair 115 kV transmission line into the new Spurgeon Creek substation. This project looped the Olympia – St Clair #1 115 kV line into Spurgeon Creek.

3. Moorlands – Vitulli 115 kV Rebuild⁹

Date of Operation: 2017

This project addressed capacity and reliability needs in the Kenmore and Bothell areas and NERC planning standards requirements by rebuilding the line to increase the winter emergency line rating from 122 MVA to 249 MVA.

FUTURE PROJECTS

4. Bellingham 115 kV Substation Rebuild

Estimated Date of Operation: 2019

This project will increase system reliability in Whatcom County. It involves replacing the existing aging 115 kV main bus substation with a new breaker and a half 115 kV substation.

7 / <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Yelm-area-reliability.aspx>

8 / <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Spurgeon-Creek-substation.aspx>

9 / <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Moorlands-Vitulli-115-kv-transmission-line-upgrade.aspx>



5. Sedro Woolley – Bellingham #4 115 kV Rebuild and Reconductor

Estimated Date of Operation: 2021

This project will increase capacity and reliability between Whatcom and Skagit Counties by rebuilding the 24-mile long Bellingham – Sedro #4 115 kV line and installing higher capacity conductors.

6. Lake Hills – Phantom Lake New 115 kV Line¹⁰

Estimated Date of Operation: 2017

This project will improve reliability, which involves building a new line from Lake Hills to Phantom Lake. This line is necessary to eliminate a radial-only feed to two existing substations such that they can be served during outage conditions.

7. Sammamish – Juanita New 115 kV Line¹¹

Estimated Date of Operation: 2017+

This project will increase capacity and address NERC planning standards requirements by building a new line from Sammamish to Juanita with 1272 kcmil Bittern at 100° C.

8. Novelty – Stillwater – Cottage Brook 115 kV Rebuild

Estimated Date of Operation: 2018

This project will increase capacity and address NERC planning standards requirements by rebuilding the line from 2/0 copper conductors to 1272 kcmil Bittern at 100° C.

9. Talbot 230 kV Bus Improvements

Estimated Date of Operation: 2018+

This project will improve reliability through continuity of service during maintenance work and substation outages by constructing bus improvements on the north and south 230 kV buses at Talbot.

¹⁰ / <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Lake-Hills-Phantom-Lake.aspx>

¹¹ / <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Sammamish-Juanita.aspx>



10. Eastside 230 kV Transformer Addition and Sammamish – Lakeside – Talbot 115 kV Rebuilds (the Energize Eastside Transmission Capacity Project)¹²

Estimated Date of Operation: 2018+

These projects are intended to provide additional *capacity* to serve the projected load growth in north central King County, to reinforce the existing transmission ties between north King and central King areas, and to address *NERC planning standards requirements*. This involves the addition of a 230 kV/115 kV transformer substation in the center of the Eastside load area, and rebuilding the 115 kV Sammamish – Lakeside – Talbot #1 & #2 lines to 230 kV to provide additional transmission capacity to serve projected load growth. A detailed description of this project is presented in the next section of this chapter.

11. Electron Heights – Enumclaw 55-115 kV Conversion

Estimated Date of Operation: 2019

This project provides *capacity* and better *reliability* in southeast King county and east Pierce county and also addresses *NERC planning standard requirements* by converting an existing 55 kV transmission line and associated substations to 115 kV operation.

12. Brisco Park Substation and O'Brien – Brisco 115 kV Transmission Line

Estimated Date of Operation: 2019+

This project will provide needed *capacity* and better *reliability* to support the existing and expected load growth in this commercial/industrial area by providing a new 115 kV transmission line in Kent and a new 6-breaker 115 kV ring bus substation in Tukwila.

13. Spurgeon Creek Transmission Substation Development (Phase 2)

Estimated Date of Operation: 2020

In Phase 2, this project will improve the *reliability* of transmission service to the cities of Lacey, Olympia and Tumwater by looping the future transmission tap extension from Olympia via the Airport substation to Spurgeon Creek. This project also loops in the Olympia – St Clair #1 115 kV line into Spurgeon Creek.

14. White River – Electron Heights 115 kV Line Re-route to Alderton (Phase 2)

Estimated Date of Operation: 2017-18

This project will improve the *reliability* of transmission service to the cities of Bonny Lake, Orting and surrounding areas where major housing developments are to be built by looping the White River – Electron Heights three-terminal 115 kV transmission line into Alderton.

¹² / <https://www.energizeeastside.com>



15. Pierce County Transformer Addition

Estimated Date of Operation: 2017-18

This project is intended to provide additional capacity to serve the projected load growth in Pierce County and surrounding areas. The project will involve installation of a 230-115 kV transformer at Alderton substation and about 8 miles of 230 kV transmission line from White River to Alderton.

16. Woodland – St. Clair 115 kV (Phase 2)

Estimated Date of Operation: 2021+

This project will increase the transmission intertie capability and reliability between Pierce and Thurston counties by adding a third transmission intertie between Pierce and Thurston Counties with construction of the remaining 8 miles 115 kV line between Gravelly Lake and Woodland substations.

17. Alderton – Woodland 115 kV uprate

Estimated Date of Operation: 2021+

This project will increase capacity in the Pierce County area by uprating the Alderton – Woodland section of the White River – Fairchild – Alderton 115 kV transmission line, which consists of about 6 miles of 795 TERN 55C conductor. The line section will be uprated to 100C. This project is planned to be completed concurrent with the Woodland – St Clair Phase 2 project.

18. White River 115 kV Bus Improvement

Estimated Date of Operation: 2021+

This project improves reliability by reconfiguring the White River 115 kV main bus to multiple bus sections to reduce the number of line bay forced outages for a bus fault or 115 kV breaker failure condition.

19. West Kitsap Transmission Project

Estimated Date of Operation: 2020+

This project is intended to provide additional capacity to serve the projected load growth in Kitsap County and improve transmission reliability for customers in central and north Kitsap County. The project is planned to be staged in phases over time and will involve construction of multiple segments of 115 kV transmission lines between BPA Kitsap/South Bremerton to Valley Junction. The final step of the multi-year plan is to add a 230-115 kV transformer capacity in Kitsap County.



Areas of Future Focus

PSE will continue to improve the electric system planning process as more data regarding demand and conservation potential becomes available with technologies such as AMI (Advanced Metering Infrastructure). Additionally, as technologies mature and PSE's grid becomes more modern, alternatives will be refreshed and reevaluated when necessary. Due to the complexity of the larger planned transmission system improvement projects, the first gate of project development known as Initiation will refine the need and reconfirm preliminary alternatives and solutions and consider implementation challenges and new information. This process targets needs that are more than four to five years out in order to provide adequate review and engagement. This process will improve as PSE matures its ability to predict localized circuit-level load growth and conservation potential. Additionally, the incorporation of learnings about alternative technologies and applications will be important as well.

Energize Eastside Transmission Capacity Project

To illustrate the evaluation, analysis and community involvement PSE performs in the process of making system improvement decisions, PSE is including a detailed description of the Energize Eastside Transmission Capacity Project (project #10 above) in this chapter of the IRP.

The Energize Eastside project is needed to meet the local growth needs of the east side of King County, including Bellevue, Redmond, Kirkland, Renton, Newcastle and Issaquah. The following pages discuss the identification of need, the analysis of alternatives considered to address need and the engagement of the Eastside community in a robust public process. The needs assessment and solution identification phases of this project have been completed. Currently, the project is in the route selection and permitting phases.



Project Background

Electricity is currently delivered to the Eastside area¹³ through two 230 kV/115 kV bulk electric substations – the Sammamish substation in Redmond and the Talbot Hill substation in Renton – and distributed to neighborhood distribution substations using 115 kV transmission lines. PSE has made many system improvements in the Eastside area over the years, but the primary 115 kV lines that connect the Sammamish and Talbot Hill substations (which are the backbone of the Eastside electrical system) have not been upgraded since the 1960s. Since then, the Eastside population has grown from approximately 50,000 to nearly 400,000. This growth is expected to continue. The Puget Sound Regional Council (PSRC) is a regional planning agency with specific responsibilities under federal and state law for transportation planning, economic development and growth management. PSRC is a leading source of data and forecasting that is essential for regional and local planning. PSE has been tracking PSRC's data releases since the project was launched in December 2013, and updated project materials with the new data in July 2014. PSE has specifically used PSRC's Land Use Baseline growth projections, which model population and employment growth in the Puget Sound region. Projections by the PSRC show the Eastside population will likely grow by another third and employment will grow by more than three-quarters over the next 25 years.



¹³ / For the purpose of this project, the Eastside is defined as the area between Renton and Redmond, bounded by Lake Washington to the west and Lake Sammamish to the east.

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As required by federal regulations, PSE performs annual comprehensive electric transmission planning studies to determine if there are potential system performance violations (transformer and line overloads) under various operational scenarios and forecasted electrical use. The need for additional 230kV support for the Eastside area was identified and has been included in PSE comprehensive plans since 1993.

During the 2009 comprehensive reliability assessment, PSE determined that there was a transmission reliability supply need developing due to the loss of one of the Talbot Hill Substation transformers. Since 2009, other issues have also been identified which impact this portion of the PSE system. These issues include concerns over the projected future loading on the Talbot Hill Substation and increasing use of Corrective Action Plans (CAPs)¹⁴ to manage outage risks to customers in this portion of the PSE system.

PSE performed studies in 2013 and 2015 that revealed it could not meet federal reliability requirements by the winter of 2017/2018 and the summer of 2018 without the addition of 230 kV to 115 kV transformer capacity in the Eastside area. (Links to these studies are provided on page 30.)

To respond to the deficiencies identified in the transmission planning studies, PSE has proposed to construct and operate a new 230 kV to 115 kV electrical transformer served by approximately 18 miles of new high-capacity electric transmission lines (230 kV) extending from Renton to Redmond; this plan includes continued aggressive conservation measures. The proposed transformer will be placed at a substation site near the center of the Eastside.

Electrical power transmitted to the new substation for distribution to local customers will address a deficiency in electrical transmission capacity during peak periods identified by PSE through its system planning process. PSE's Eastside system currently experiences peak demand during the winter driven by heating loads; the summer peak is driven by cooling loads. Continuing population growth increases the risk of more severe overloading by summer 2018. To address this risk, PSE launched the Energize Eastside project in December 2013.

¹⁴ / See page 8-38 for description of a Corrective Action Plan.



Regulatory Requirements

The performance requirements of any integrated transmission system are heavily regulated at both the federal and regional levels. PSE's regulators include FERC, NERC and WECC (the Federal Energy Regulatory Commission, North American Electric Reliability Corporation and Western Electricity Coordinating Council, respectively).

NERC is the regulatory authority certified by FERC to develop and enforce reliability standards. NERC has delegated the task of monitoring and enforcing the federal reliability standards to WECC, the regional entity that has authority over transmission in the western region.

The NERC standards mandate that certain forecasts and studies must be completed to determine if the system has sufficient capability to meet expected loads now and in the future. When completing transmission planning studies, contingencies are simulated to determine if the electric system meets the mandatory NERC performance requirements¹⁵ for a given set of forecasted demand levels, generation configurations and levels, and multiple system component outages.

Even if these outage scenarios are unlikely, federal regulations require that the appropriate planning be performed proactively. This conservative planning methodology is implemented to prevent large scale, cascading, transmission system blackouts, like those that have occurred in the recent past (for example, the 2003 Northeast blackout that affected 55 million people in the Northeast and Midwest regions of the United States and Canada).

The PSE transmission planning studies performed in 2013 and 2015 determined that thermal violations on transmission line and transformer equipment might occur under foreseeable scenarios within the next few years. The thermal violations are a result of running scenarios for several component outage contingencies, as required by NERC, that take into consideration peak demand (which is heavily dependent on seasonal temperatures and daily demand profiles) and levels of conservation. In essence, this is a requirement to have redundancy in the transmission system.

¹⁵ / The NERC transmission planning standards (TPL) that were in effect in 2012-2013 were: TPL-001-3, TPL-002-0b 2nd Rev (TPL-002-2b), TPL-003-0b 2nd Rev (TPL-003-2b), and TPL-004-2. TPL-001-3, TPL-002-2b, TPL-003-2b, and TPL-004-2 are being retired as they are replaced in their entirety by TPL-001-4. Enforcement of the new standards began January 1, 2015. Visit the NERC website at <http://www.nerc.com/pa/Stand/ReliabilityStandards/TPL-001-4.pdf> for more information. Note: Compliance is mandatory irrespective of stakeholders willingness to accept greater reliability risk. See U.S. - Canada Power System Outage Task Force Final Report on the August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations, April 2004.



Needs Assessment Reports

In total, five separate studies performed by four separate parties have confirmed the need to address Eastside transmission capacity:

- **Electrical Reliability Study by Exponent, 2012 – City of Bellevue**
http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/final_electrical_reliability_study_phase_ii_report_2012.pdf
- **Eastside Needs Assessment Report by Quanta Services, 2013 – PSE**
https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2REDACTEDR1.pdf
- **Supplemental Eastside Needs Assessment Report by Quanta Services, 2015 – PSE**
https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/Eastside_Needs_Assessment_Final_Draft_10-31-2013v2REDACTEDR1.pdf
- **Independent Technical Analysis by Utility Systems Efficiencies, Inc., 2015 – City of Bellevue**
http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/cob_independent_technical_analysis_1-3.pdf
- **Review Memo by Stantec Consulting Services Inc., 2015 – EIS consultant**
http://www.energizeeastsideeis.org/uploads/4/7/3/1/47314045/stantec_review_memo_eastside_needs_assessment_report.pdf

PSE NEEDS ASSESSMENT REPORTS, 2013¹⁶ AND 2015.¹⁷ PSE transmission planning studies demonstrate that, under certain contingencies, the delivery system on the Eastside could not continue to meet reliability requirements without significant infrastructure upgrades.

The Needs Assessment reports published in 2013 and 2015, which PSE performed pursuant to the mandatory federal transmission planning standards, identified four major areas of concern.

1. **Overload of PSE facilities in the Eastside area.** Studies identified potential overloading of transformers at Sammamish and Talbot Hill substations, and several 115 kV transmission lines routing power to the Eastside area are at risk of overloading under certain conditions.
2. **Small margin of error to manage risks from inherent load forecast uncertainties.** PSE's planning studies rely in large part on load forecast data. Imbedded in PSE's load forecasts are several factors that include elements of risk. These include conservation, weather and block loads.

¹⁶ / A link to the 2013 report is provided above.

¹⁷ / A link to the 2015 report is provided above.



- Conservation: To date, PSE customers have achieved 100 percent of the company's conservation goals, which are very aggressive according to industry experts. If 100 percent of conservation goals are not achieved, then the transmission system capacity will be surpassed sooner than expected.¹⁸
 - Weather: PSE's load forecast assumes "every other year" cold weather. (Some utilities take a more conservative approach, using the coldest and hottest weather in five or ten years, as inputs to system performance studies.¹⁹) If the region experiences weather extremes outside of those used in PSE's planning studies, electricity demand will surpass the transmission system capacity sooner than expected.
 - Block loads: These include large development projects that add significant load to the system. If block load growth increases more than anticipated, demand for electricity will surpass the transmission capacity sooner than expected.
3. **Increased use and expansion of Corrective Action Plans (CAPs) to keep the system compliant.** CAPs are a series of operational steps used to prevent system overloads or loss of customers' power. They are a short-term fix to alleviate potential operational conditions that could put the entire grid at risk. They protect against large-scale, cascading power outages; however, they can put large numbers of customers at increased risk of power outages. For example, to prevent winter overloads on the Talbot Hill transformer banks, PSE is already using CAPs, which increases outage risk to customers. As growth continues, additional CAPs will be needed. By Federal standards, CAPs are not intended to be long-term solutions to system deficiencies.
4. **Impacts to interconnections identified by ColumbiaGrid.** Though the need for Energize Eastside is driven by local demand, because the electric system is interconnected for the benefit of all, it is a federal requirement to study all electric transmission projects to ensure there are no material adverse impacts to the reliability or operating characteristics of PSE's or any surrounding utilities' electric systems. ColumbiaGrid, the regional planning entity, produces a Biennial Transmission Expansion Plan that addresses system needs in the Pacific Northwest, including the PSE system.

¹⁸ / PSE tested the conservation goals at 100%, 75%, 50%, and 0%. See the 2013 and 2015 Eastside Needs Assessment reports.

¹⁹ / For example ISO-NE have plans to a 90/10 or one in ten-year weather forecast.

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PSE's 2015 Supplemental Needs Assessment Report confirmed the winter deficit findings in the 2013 Needs Assessment Report, stating that:

By winter of 2017-18, there is a transmission capacity deficiency on the Eastside that impacts PSE customers and communities in and around Kirkland, Redmond, Bellevue, Issaquah, Newcastle, and Renton along with Clyde Hill, Medina, and Mercer Island... **By winter of 2019-20, at an Eastside load level of approximately 706 MW, additional CAPs are required that will put approximately 63,200 Eastside customers at risk of outages.**

The 2015 Needs Assessment also confirmed that by summer of 2018, there would be a transmission capacity deficiency on the Eastside that impacts PSE customers and communities in and around Kirkland, Redmond, Renton, Bellevue, Issaquah and Newcastle along with Clyde Hill, Medina and Mercer Island. **By summer of 2018, CAPs will be required to manage overloads under certain multiple contingencies, and the use of these CAPs will place approximately 68,800 customers at risk and could require 74 MW of load shedding, affecting approximately 10,900 customers at a time.**

Based on the 2015 Needs Assessment, if the Energize Eastside project gets delayed until after the summer of 2018, load shedding may be used as a corrective action plan to meet the mandatory reliability requirements defined by NERC. This could result in PSE having to turn the power off to tens of thousands of customers under certain forecasted conditions and would be necessary to prevent more widespread outages beyond the Eastside area. To further study this, in 2015 PSE commissioned Nexant to simulate three scenarios of rotating outages that could be needed if no action is taken to upgrade the Eastside's transmission system. Nexant's Energize Eastside Outage Cost Study determined that if PSE must use corrective action plans that include rolling blackouts, more than 130,000 customers could be impacted as early as the summer of 2018, at a cost of tens of millions of dollars to the local economy.

Load shedding is not a practice that PSE or many other responsible utilities use unless absolutely necessary. Since load shedding adversely impacts residential, commercial and industrial customers, and surrounding cities, towns and neighboring communities, it is necessary and good utility practice to coordinate with cities, towns, municipal officials and emergency services, and to publicly inform those affected.

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CITY OF BELLEVUE-COMMISSIONED INDEPENDENT TECHNICAL ANALYSIS.²⁰ The City of Bellevue contracted with Utility System Efficiencies, Inc. (USE) to perform an independent technical analysis (ITA) of the purpose, need and timing of the Energize Eastside project, and this study confirmed the capacity deficiency in the Eastside area.

This independent analysis concluded that PSE followed industry practice in forecasting its demand load, incorporating the four major components of forecasting:

- PSE incorporated weather normalizing. The variables used in the weather normalization process were typical based on industry practice.
- PSE used typical data set elements and multiple data sources for its economic/demographic data, acquiring data at the county level, and for the Eastside area at the census-tract level, in order to differentiate growth rates within the service territory. Data on jobs and employment in the Eastside region were obtained by PSE from the Puget Sound Regional Council (PSRC) and the Washington State Office of Financial Management, and included census-tract-level analysis.
- PSE employed regression analysis at this step, an industry standard computer analysis technique, to determine the forecast before new conservation measures and block load adjustments.
- PSE acquired and developed significant end-user data via its IRP process. This includes over 4,000 Demand Side Resource (DSR) measures, incorporated National and State requirements on conservation and RPS, and optimized the achievable, technical measures with a resultant 100 percent conservation scenario which projects 135 MW of winter peak DSR by 2031. PSE gathered block load data and utilized short-term forecast adjustments (1-year ramp in based on certificates of occupancy and 2-year ramp out) to account for the impact on demand.

The ITA concluded that “PSE used reasonable methods to develop its forecast showing the Eastside area growing at a higher level [faster pace] than the county or system level.”

²⁰ / A link to the City of Bellevue ITA is provided on page 30.

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In addition, the ITA addressed common questions about the project, including:

- Is the Energize Eastside project needed to address the reliability of the electric grid on the Eastside? ***The ITA determined, “YES.”***
- If the load growth rate was reduced, would the project still be needed? ***The ITA determined, “YES.”***
- If generation was increased in the Puget Sound area, would the project still be needed? ***The ITA determined, “YES.”***
- Is there a need for the project to address regional flows, with imports/exports to Canada (ColumbiaGrid)? ***The ITA determined that by modeling zero flow to Canada, the project is still necessary to address local need.***

SEPA ANALYSIS AND PROJECT NEED. In addition to the needs analyses described above, Energize Eastside’s environmental reviews also involved needs analyses. For example, during development of the State Environmental Policy Act (SEPA) Draft Environmental Impact Statement (EIS), a review memo summarized the EIS team subcontractor’s independent analysis of project need:

“...PSE[’s] needs assessment was overall very thorough and applied methods considered to be the industry standard for planning of this nature. Based on the information that the needs assessment contains, I concur with the conclusion that there is a transmission capacity deficiency in PSE’s system on the Eastside that requires attention in the near future.” – DeClerck, Review Memo by Stantec Consulting Services Inc., July 31, 2015.²¹

²¹ / A link to the Stantec memo is provided on page 30.

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FERC FINDINGS AND CONCLUSION. In response to a complaint filed with the Federal Energy Regulatory Commission against PSE and others, specific to Energize Eastside, FERC dismissed the complaint, stating:

Based on the record before us, we find that Puget Sound [PSE] and the other Respondents complied with their transmission planning responsibilities under Order No. 890 in proposing and evaluating the Energize Eastside Project. – FERC Docket No. EL15-74-000, *Order Dismissing Complaint*, Issued Oct. 21, 2015.²²

The FERC response also concluded:

We agree with Puget Sound [PSE] and ColumbiaGrid that the Energize Eastside Project was properly classified a Single System Project because it was designed to address Puget Sound's projected inability to serve its own customers, ColumbiaGrid's Puget Sound Area Study Team did not find any Material Adverse Impacts associated with the project, and ColumbiaGrid included the project as a Single System Project in its most recent 2015 Biennial Plan. Accordingly, we find that the Energize Eastside Project was proposed and evaluated in accordance with the then-applicable transmission planning requirements. – FERC Docket No. EL15-74-000, *Order Dismissing Complaint*, Issued Oct. 21, 2015.²³

²² / https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/2015_1021_FERC_OrderDismissingComplaint.pdf

²³ / *Ibid*



Requirements for Solutions to Meet Need

Any solution to solve this deficiency must meet all NERC performance criteria, address all relevant PSE equipment overloads, and continue to meet the performance criteria for **at least 10 years** after construction. To define the solution, PSE developed criteria to evaluate potential solutions. The following excerpt is from Section 2.5.1 of the 2015 Solutions Study.

ELECTRICAL PERFORMANCE CRITERIA

- a. Must meet all performance criteria:
 - Applicable transmission planning standards and guidelines, including mandatory NERC and WECC standards (NERC TPL-001-4 and WECC TPL-001-WECC-CRT-2)
 - Within study period (2015– 2024)
 - Less than or equal to 95 percent of emergency limits for lines
 - Less than or equal to 90 percent emergency limit for transformers
 - Normal winter load forecast with [both] 100 percent and 75 percent conservation
 - Normal summer load forecast with 100 percent conservation
 - Adjust regional flows and generation to stress cases similar to annual transmission planning assessment
 - Take into account future transmission system improvement projects that are expected to be in service within the study period
 - Minimal or no re-dispatching of generation²⁴
 - No load shedding
 - No new Remedial Action Schemes
 - No Corrective Action Plans
- b. Must address all relevant PSE equipment violations
- c. Must not cause any adverse impacts to the reliability or operating characteristics of PSE's or surrounding systems
- d. Must meet performance criteria listed above for 10 or more years after construction with up to 100 percent of the emergency limit for lines or transformers.

²⁴ / See the Eastside Needs Assessment Report (October 2013)



Alternatives Considered

PSE studied a variety of potential solutions to resolve the Eastside transmission deficiencies; these included additional conservation, additional generation, demand response (DR), distributed generation (DG), energy storage, expansion of transmission substations, transmission line upgrades and new transmission lines. The results of these studies are documented in PSE’s Solutions Report (2014)²⁵ and Supplemental Eastside Solutions Study Report (2015).²⁶

Ultimately, the 2015 Solutions Study verified the findings of the 2014 Solutions Report, that the preferred solution to solve the Eastside’s transmission deficiencies was aggressive conservation combined with construction of a new 230/115 kV transformer and 230 kV line with associated ancillary facilities.

The alternatives studied are summarized in Figure 8-10, and discussed in more detail in the following pages.

Figure 8-10 Summary of Alternatives and Technologies Studied

| ALTERNATIVE STUDIED | MEETS CRITERIA | STUDIES AND REPORTS (Authors) |
|---|----------------|---|
| 1. Additional conservation within the Eastside Area | NO | 2015 Solutions Study (PSE) Non-wires Alternatives Screening Study (E3) |
| 2. Additional generation within the Eastside Area | NO | 2015 Solutions Study (PSE) |
| 3. Energy storage | NO | 2015 Solutions Study (PSE) Eastside System Energy Storage Alternatives Screening Study (Strategen) |
| 4. Transmission line reinforcements and transformer additions | YES | 2015 Solutions Study (PSE) |
| 5. Combination of solutions | NO | 2015 Solutions Study (PSE) |

25 / <https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/TransmissionSolutionStudyFebruary2014REDACTEDv2.pdf>

26 / https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/SupplementalSolutionsReport_Redacted_May2015.pdf



ALTERNATIVE 1 – ADDITIONAL CONSERVATION. PSE retained Energy and Environmental Economics, Inc. (E3) in 2014 to conduct a Non-wires Alternatives Screening Study.²⁷ E3 included energy efficiency, demand response and distributed generation measures in its evaluation of cost-effective non-wires potential in the Eastside area. The study concluded that the cost-effective non-wires potential for the Eastside is not large enough to provide sufficient load reduction to allow even a 4-year deferral of Eastside transmission upgrade needs.

The amount of additional conservation in the Eastside area required to avoid transmission upgrades ranged from a low of 138 MW to a high of 244 MW.²⁸ The minimum conservation level of 138 MW was in addition to achieving 100 percent of the projected conservation for the entire PSE system (424 MW from the 2014 Load Forecast); the high level of 244 MW was in addition to achieving 75 percent of the projected conservation for the entire PSE system (318 MW from the 2014 Load Forecast).

The study determined that the non-wires potential in the area, including energy efficiency, demand response and distributed generation measures did not represent a permanent solution to the need for the transmission upgrade options, nor was it sufficiently cost-effective to defer the need date for transmission upgrades while maintaining equivalent reliability levels. For more detail see the full report.

²⁷ / <https://energizeeastside2.blob.core.windows.net/media/Default/Library/Reports/PSEScreeningStudyFebruary2014.pdf>

²⁸ / A 70 MW to 140 MW range was identified in the 2014 Solution Study. This level was sufficient to drop below 100 percent of the Talbot Hill transformer rating in winter of 2017/18. However, a valid solution requires a transformer loading of no more than 90 percent. Therefore, the 2015 Solution Study identified a higher level of conservation, which was sufficient to drop the loading level on the Talbot Hill transformers down to 90 percent under the worst contingency.



E3's valuation of deferral savings for the project is detailed in this excerpt from its report.

The results of this savings calculation are shown in the table below. If the transmission upgrades could be deferred from the planned online date of Winter 2017 to Winter 2021, this four year deferral would create total present value savings for PSE ratepayers of \$40.24 million in transmission project costs. Assuming that PSE would require 70 MW of incremental load reduction to enable a four-year project deferral, this savings is equivalent to a capacity payment of \$575/kW for the four-year period, or annual savings of \$155/kW-year.

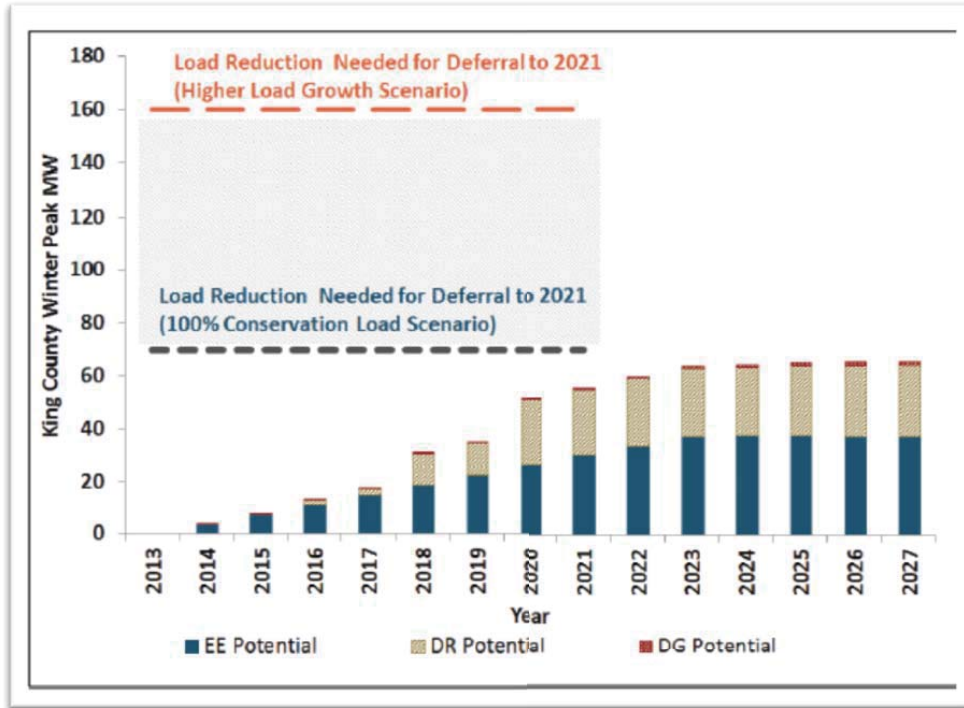
Table 3: Transmission Revenue Requirement Savings of Deferring Eastside Transmission Upgrades

| | Winter 2021 |
|---|-------------|
| Transmission Revenue Requirement Savings (\$ million) | \$40.24 |
| \$/kW (contracted) | \$575 |
| \$/kW-year (levelized) | \$155 |

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Figure 8-11: King County Non-wires Potential vs. Reduction for Needed Deferral





ALTERNATIVE 2 – ADDITIONAL GENERATION WITHIN EASTSIDE. PSE studied both conventional generation and distributed generation (DG) in its 2015 Solutions Study. To be effective, this alternative would require at least 300 MW of generation located in the Eastside area. Locating conventional generation of this size on the Eastside has major siting and environmental challenges. For DG to meaningfully impact the identified needs, DG must be installed in the right locations, available when needed and be of significant magnitude. Locating 300 MW or more of distributed renewable generation within the Eastside area by the winter of 2017/2018 was not practical. See the Supplemental Eastside Solutions Study reports (2014 and 2015) for more detail.

ALTERNATIVE 3 - ENERGY STORAGE. PSE contracted with Strategen in 2015 to perform an Eastside System Energy Storage Alternatives Screening Study,²⁹ which concluded that an energy storage system with power and energy storage ratings comparable to PSE's identified need has not yet been installed anywhere in the world. In addition, Strategen determined that the existing Eastside transmission system does not have sufficient capacity to charge energy storage systems to a level sufficient to meet PSE's operating standards.

Based on the interconnection, permitting, procurement and construction timelines provided by PSE, project development for any energy storage configuration would take approximately four years, resulting in a mid-2019 online date. Private developers who are able to take on more project risk may be able to accelerate this cycle by approximately one year.

²⁹ / http://www.energizeeastsideis.org/uploads/4/7/3/1/47314045/eastside_system_energy_storage_alternatives_screening_study_march_2015.pdf

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Strategen evaluated a baseline configuration and two alternatives that also included non-wires measures.

- Strategen estimated that the Baseline Configuration to defer the Eastside transmission system upgrade through 2021 would cost ratepayers approximately \$1.44 billion in net present value (NPV) terms, based on PSE's revenue requirement; however, the Baseline configuration is not technically feasible.
- Alternate Configuration #1 would cost ratepayers approximately \$264 million in NPV terms, based on PSE's revenue requirement. Cost-effectiveness value was derived primarily from the system capacity, flexibility and oversupply reduction benefits for PSE's customers. (Carbon emission reduction is another benefit, but it is currently non-monetizable.) With a benefit-cost ratio of approximately 1.13, this configuration does appear to be cost-effective, but it does not meet the reliability requirements for the solution.³⁰

Neither Alternative #1 nor Alternative #2 appears capable of meeting PSE's target online date of 2017/2018. The cost-benefit ratio for the Baseline and Alternative #2 were not calculated because they were not technically feasible. Figure 8-12 presents the capital cost estimates from the E3 report. See the 2014 PSE Screening Study by E3 for details.

³⁰ / Per the 2015 Strategen report, "The Baseline Configuration (a 328 MW / 2,338 MWh storage system) is not technically feasible because the existing Eastside transmission system does not have sufficient capacity to fully charge the system."



Figure 8-12: Energy Storage Configuration Summary

| Configuration | Power (MWp) | Energy (MWh) | Duration (hours) | Est. Cost (\$MM) | Includes Non-Wires Alternatives ¹¹ | Technically Feasible | Meets Requirements |
|--|-------------|--------------|------------------|------------------|---|----------------------|--------------------|
| Baseline Normal Overload Reduction | 328 | 2,338 | 7.1 | \$1,030 | ✓ | ✗ | ✓ |
| Alternate #1 Emergency Overload Elimination* | 121 | 226 | 1.9 | \$184 | ✓ | ✓ | ✗ |
| Alternate #2 Normal Overload Elimination | 545 | 5,771 | 10.6 | \$2,367 | ✓ | ✗ | ✓ |

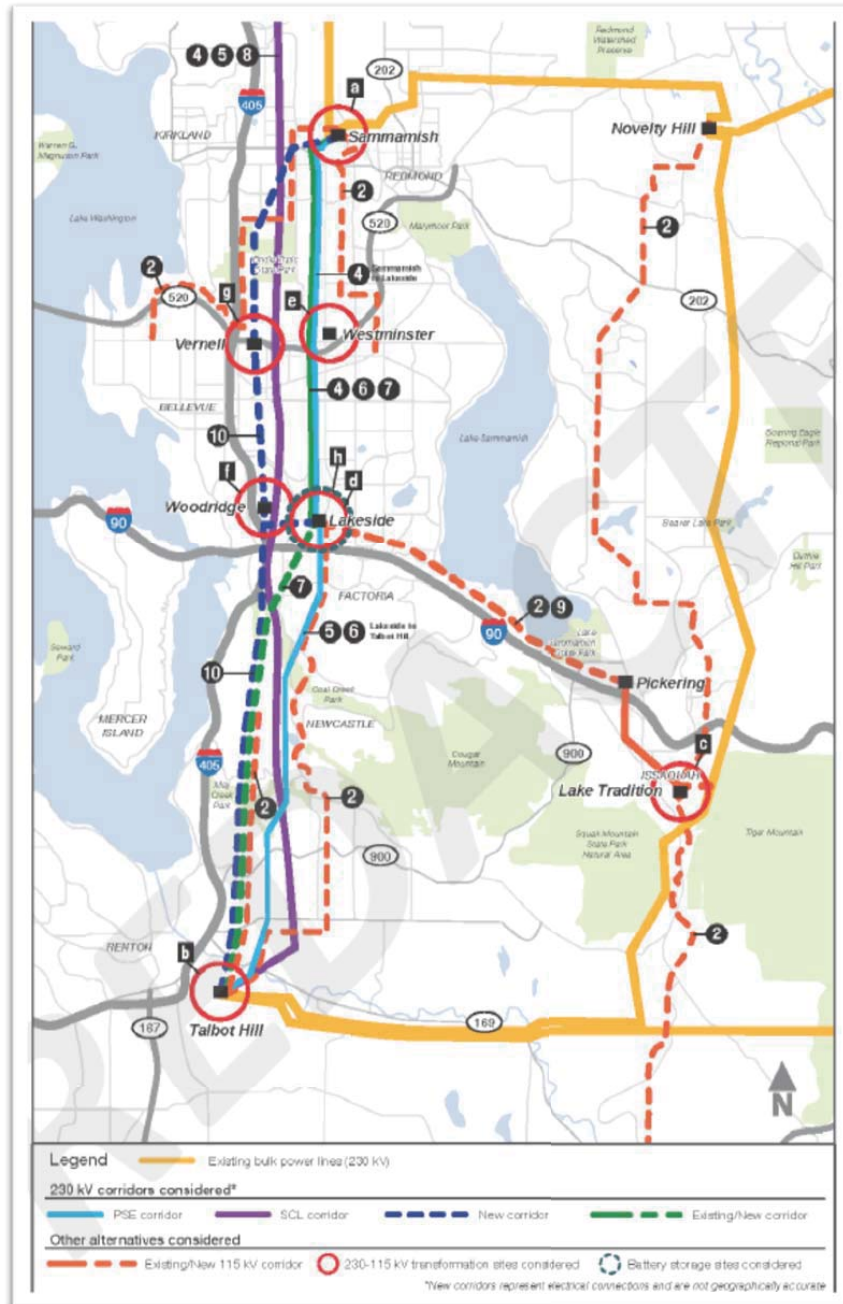
ALTERNATIVE 4 - TRANSMISSION LINE REINFORCEMENTS AND TRANSFORMER

ADDITIONS. Combinations of ten transmission line reinforcements and seven transformer additions were reviewed in PSE's 2015 Solutions study as potential solutions to the Eastside transmission deficiency. These transmission line and transformer addition locations are shown in Figure 8-13.

PSE determined that a wires option to construct a new 230/115 kV transformer and 230 kV line with associated ancillary facilities is the preferred solution to solve the Eastside's need.



Figure 8-13: Transmission and Transformer Addition Locations for Energize Easides



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ENVIRONMENTAL IMPACT STATEMENT PROCESS. The Energize Eastside project is undergoing environmental review, which includes preparation of a Washington State Environmental Policy Act (SEPA) Environmental Impact Statement (EIS).

The Phase 1 and Phase 2 Draft EIS evaluated the Energize Eastside alternatives studies, a “No Action” Alternative (as required by SEPA), and three other “action alternatives.” These alternatives were developed by the partner cities in cooperation with PSE, with the intent of providing options that could attain or approximate PSE objectives for the project at a lower environmental cost.

The No Action Alternative provides a benchmark against which the proposed project and other action alternatives can be compared. In 2015, PSE commissioned Nexant to simulate three scenarios of rotating outages that could be needed if no action is taken to upgrade the Eastside’s transmission system. Nexant determined that if PSE must use corrective action plans that include rolling blackouts, more than 130,000 customers could be impacted as early as the summer of 2018, at a cost of tens of millions of dollars to the local economy.

The table below shows the results of the study, which highlights the number of customers and economic impacts of rotating outages.

Figure 8-14: Summary of Outage Cost Analysis by Nexant

| Summary of Outage Cost Analysis by Nexant | | | | | |
|---|-------------------------|---|-------------------|--------------------|-----------------------|
| Scenario | Customer Class | Number of Customers Experiencing Rotating Outages | Total Outage Cost | Customer Load Shed | Cost per Unserved kWh |
| | | | \$ Millions | MWh | \$ |
| Scenario 1, Summer 2018 | Medium and Large C&I | 2,799 | \$65.1 | 2,419 | \$26.9 |
| | Small C&I | 7,983 | \$23.3 | 207 | \$112.5 |
| | Residential | 120,213 | \$3.8 | 2,093 | \$1.8 |
| | Scenario 1 Total | 130,995 | \$92.2 | 4,719 | \$19.5 |
| Scenario 2, Summer 2024 | Medium and Large C&I | 4,480 | \$179.3 | 5,266 | \$34.0 |
| | Small C&I | 14,086 | \$84.5 | 577 | \$146.4 |
| | Residential | 192,674 | \$10.8 | 4,751 | \$2.3 |
| | Scenario 2 Total | 211,240 | \$274.6 | 10,594 | \$25.9 |
| Scenario 3, Winter 2023/2024 | Medium and Large C&I | 3,142 | \$153.1 | 8,897 | \$17.2 |
| | Small C&I | 9,786 | \$115.7 | 875 | \$132.3 |
| | Residential | 161,890 | \$8.1 | 8,914 | \$0.9 |
| | Scenario 3 Total | 174,818 | \$276.9 | 18,686 | \$14.8 |

Source: Puget Sound Energize Eastside Outage Cost Study, Oct. 2015; by Nexant, Inc.



- Scenario #1 includes the 230 kV overhead lines, but also includes options for locations, including underground and underwater options. Of these options, the EIS team only carried forward PSE's preferred option of a new substation and 230 kV transmission line.
- Scenario #2 includes a variety of solutions that would require very limited new transmission lines next to existing substations. These would need to be implemented in combination in order to meet the project objectives. The EIS team did not carry this option forward as the solutions do not meet the project objectives, and they would rely heavily on voluntary customer actions in some cases.
- Scenario #3 would involve installing enough 115 kV lines and transformers to address the project objectives without building 230 kV lines. This option was not carried forward for further analysis.³¹

PSE's Preferred Alternative

After extensive study and evaluating and re-evaluating dozens of alternatives both independently and through the Phase I Draft EIS, PSE determined that the most effective solution that meets all criteria and complies with the federal performance requirements is the addition of a 230 kV/115 kV transformer in the center of the Eastside load area. This new transformer would be connected to new 230 kV transmission lines constructed between the Sammamish (Redmond) and Talbot Hill (Renton) substations along with continued aggressive conservation – the Energize Eastside project.

This involves constructing a new 230 kV to 115 kV substation, called Richards Creek, to be located on PSE-owned parcel 1024059130 in Bellevue. The Richards Creek substation property is located immediately south of the existing Lakeside 115 kV substation, which is situated on parcel 1024059083 in Bellevue. The new Richards Creek 230 kV to 115 kV transformer will provide a new electrical capacity source for the Eastside area.

To connect the transformer, PSE will replace two existing 115 kV lines that were last upgraded in the 1960s with two 230 kV lines. Operating both lines at 230 kV has the lowest potential for interaction with the petroleum product pipelines that share the transmission line corridor. Electricity will be transmitted to the Richards Creek substation at 230 kV and then the voltage will be lowered ("stepped down") to 115 kV for distribution to customers on the Eastside.

³¹ / Per the Phase 2 DEIS: "acquisition of up to 60 miles of right-of-way for new 115 kV lines would likely result in some displacement. Delays due to the legal steps required for such acquisition, which could include condemnation, would not meet the project objectives for timeliness to meet reliability requirements. For these reasons, this alternative was not carried forward."



The existing transmission lines are located in PSE's Sammamish – Lakeside – Talbot Hill corridor, which was established in the late 1920s and early 1930s. Within this existing corridor, the proposed pole locations for the rebuilt lines will generally be in the same locations as the existing poles. In some instances, there may be advantages to moving pole locations to accommodate landowner preferences and/or reduce potential environmental impacts (for example, to move existing pole locations out of wetlands).

These facilities are needed to address the deficiency in electrical transmission capacity during peak periods that PSE identified through its system planning process. This project will improve reliability for Eastside communities and supply the needed electrical capacity for growth and development on the Eastside.

Engaging the Community on Energize Eastside

In today's increasingly connected and rapidly changing environment, PSE recognizes the need for openness and transparency so that interested parties are able to quickly access relevant expertise and information.

Since launching the Energize Eastside project in December 2013, PSE has engaged the Eastside community in a robust public involvement process. This process has included mailings, public meetings and direct outreach efforts to ensure that stakeholders are informed about the project and have had plentiful and diverse opportunities to participate. PSE's public involvement process, especially with regards to routing, has been conducted over and above formal environmental review and permitting requirements.

To date, public outreach and involvement has included:

- **22** Community Advisory Group-related meetings
- **6** public open houses, **2** question and answer sessions, and **2** online open houses at key project milestones
- **500+** briefings with individuals, neighborhoods, cities and other stakeholder groups
- More than **2,900** comments and questions received
- **30+** email updates to more than **1,500** subscribers
- **8** project newsletters to **55,000+** households
- Ongoing outreach to **500+** property owners, including door-to-door and individual meetings
- Participation in **16** EIS-related public meetings

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In addition, PSE's Energize Eastside website provided project updates and functioned as a repository for project materials, including maps, technical studies like the need and solution studies, the Community Advisory Group Final Report, fact sheets on a wide range of topics, newsletters, meeting summaries and other materials.

An overview of the public engagement process follows.

PHASE 1: PUBLIC ROUTE DISCUSSION (2014). To provide a forum that would generate robust input from diverse community stakeholders, PSE convened a Community Advisory Group to consider community values when evaluating transmission line route options. The advisory group spent a year learning about the Eastside's electrical system, participating in meetings and workshops and evaluating 18 route options identified by PSE.

In addition to the Community Advisory Group, PSE involved the community through public meetings, neighborhood meetings, briefings and comments, which provided Eastside residents opportunities to share their community values and ask initial questions about the project. For details about the advisory group process, review the Community Advisory Group Final Report (2015).³²

PHASE 2: FIELDWORK AND ENVIRONMENTAL REVIEW (2015 – TODAY). In 2015, PSE began collecting field information necessary for design and environmental review. PSE kept stakeholders informed about these fieldwork activities to ensure residents knew when crews were expected to perform surveys near their homes and businesses.

In 2015, the project began environmental review, which includes preparation of a Washington State Environmental Policy Act Environmental Impact Statement. The City of Bellevue leads the EIS process in cooperation with Newcastle, Kirkland, Redmond and Renton. The SEPA process is a separate regulatory requirement that must be completed before any permits may be issued and includes public involvement milestones.

PSE has provided supplemental EIS notifications about major milestones and comment periods to keep stakeholders informed and to support community engagement. In addition, PSE has participated in eight scoping meetings and eight draft EIS hearings over the two-phased EIS process. The Final EIS is anticipated in early 2018.

³² / https://energizeeastside2.blob.core.windows.net/media/Default/CAG/2015_0114_Energize_Eastside_CAG_Final_Report_FINAL_for_web.pdf

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PHASE 3: PROPERTY-OWNER CONSULTATIONS (2016 – TODAY). As project design progressed, PSE began reaching out to individual property owners to share information and answer questions. In spring 2016, the project team visited neighborhoods along the existing corridor and Factoria area in Bellevue to talk with residents and business owners about the project. This door-to-door outreach was conducted to help inform customers about the project status and to address questions and concerns from property and business owners.

In September 2016, PSE began meeting with property owners and tenants along the existing corridor to discuss property-specific design and tree replacement plans. We shared our current design for that specific property, including pole locations and how we plan to access those locations during construction. These conversations have helped us refine our project design and better understand customer interests and concerns.

In May 2017, PSE began meeting with property owners to begin developing property-specific landscaping and tree replacement plans with property owners. We are currently reaching out to affected property owners about these efforts.

FUTURE PHASES: PERMITTING AND CONSTRUCTION. PSE expects to begin submitting permit applications in summer 2017 to keep the project moving forward.

We value the community's input and ongoing interest in the project, and PSE is committed to keeping property owners and the community informed about its progress. Visit the project website at www.energizeeastside.com for the latest information and for more details about how the public has been involved in Energize Eastside.



Gas Infrastructure Plan

Pressure Regulation Stations

In the next decade PSE plans to build or upgrade approximately 7 Northwest Pipeline-supplied gate or limit stations and 16 district regulator stations to serve load as existing station capacity is exceeded.

Pipelines

In the next decade, PSE expects to add approximately 24 miles of high pressure main and 23 miles of intermediate pressure main as loads grow in our service area.

Ongoing Maintenance

As with the electric system, PSE is continually addressing aging gas infrastructure within the system in accordance with regulatory requirements and operating practices. In the next decade, PSE plans to replace 200 to 300 miles of gas main that is reaching the end of its useful life. As mentioned above, PSE anticipates replacing its current aging and obsolete Automated Meter Reading (AMR) communication system and gas customer modules with Advanced Metering Infrastructure (AMI) technology to enable smart grid enhancements and future customer offerings.

Figure 8-15: Summary of 10-year Gas Infrastructure Plan

| ASSET | NUMBER | LOCATION |
|--------------------------------|---------------|-------------|
| New High Pressure Main | 24 miles | System-wide |
| New Intermediate Pressure Main | 23 miles | System-wide |
| Gate or Limit Station Upgrades | Seven | System-wide |
| District Regulation | Sixteen | System-wide |
| Gas Main Replaced | 200-300 miles | System-wide |



Planned Gas Supply System Improvements

PSE has included higher pressure projects that are associated with the operations at greater than 250 psig and which are significant in cost due to complexity. In this discussion, these are defined as costing \$10 million or greater over the next 10 years.

PROJECTS COMPLETED SINCE LAST 2015 IRP. (Information on a variety of projects completed within the last six months can be found on PSE's website at <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Completed-improvements.aspx>.)

1. Tolt Pipeline (Phase 1)³³

Date of Operation: 2015-2018

The project is intended to provide additional *capacity* and *reliability* to serve the growth from Bothell/Woodinville to Bellevue. Phase 1 of the project involves constructing 2.8 miles of 16-inch high pressure main.

FUTURE PROJECTS

2. North Seattle Reinforcement Projects

Estimated Date of Operation: 2020+

This collection of projects will increase *capacity* and *reliability* to serve existing load and growth in the north Seattle area, from Lynnwood to southern Seattle. These projects are in the planning phase and consist of upsizing or adding new high pressure main and regulation.

3. South Tacoma Distribution Upgrades

Estimated Date of Operation: 2020+

This collection of projects will increase *capacity* and *reliability* to serve growth in the Tacoma area, from Tacoma to DuPont and Bonney Lake. These projects are in the design phase, which consists of upsizing, looping or adding new intermediate pressure main.

4. Tolt Pipeline (Phase 2)³⁴

Estimated Date of Operation: 2020+

Phase 2 of this project will increase *capacity* and *reliability* to serve growth in the greater Eastside area, from Bothell/Woodinville to Bellevue. Phase 2 of the project involves constructing 1.2 miles of 16-inch natural high pressure main.

³³ / <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Tolt-Natural-Gas-Line-Project.aspx>

³⁴ / <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Tolt-Natural-Gas-Line-Project.aspx>



Areas of Future Focus

PSE will continue to improve the gas system planning process as more data regarding demand and conservation potential becomes available with technologies such as Advanced Metering Infrastructure. As technologies mature, alternatives will be refreshed and reevaluated when necessary. Generally, alternatives to date are various infrastructure solutions such as uprating, regulation or pipeline upgrades. Due to the complexity of larger planned system improvement projects the first gate of project development known as Initiation will refine the need and reconfirm preliminary alternatives and solutions and consider implementation challenges and new information. This process targets needs that are more than four to five years out in order to provide adequate review and engagement. This process will improve as PSE matures its ability to predict localized circuit-level load growth and conservation potential. Additionally, the incorporation of learnings about alternative technologies and applications will be important as well.



6. CHALLENGES AND OPPORTUNITIES

New Regulations

Regulatory compliance is a significant driver of PSE infrastructure investment, but it is difficult to anticipate what rules may be adopted in the future or to predict how they may impact spending on our delivery systems. The following examples from the last decade illustrate the kind of expenditures that regulatory activity can necessitate.

Gas System

Beginning with the Pipeline Safety Improvement Act (PSIA) of 2002 and again in 2006 with the Pipeline Inspection, Protection, Enforcement, and Safety (PIPES) Act, Congress has directed the Pipeline and Hazardous Materials Safety Administration to increase the strength of integrity management programs that cover natural gas transmission and distribution pipelines. These programs require PSE to perform detailed inspections and analysis of pipeline systems to gain more knowledge of pipeline integrity risks and to devise measures to mitigate these risks. Numerous actions have resulted from these requirements, including expanded pipe replacement programs, enhanced damage prevention activities and increased inspection intervals. These expanded pipe replacement programs have increased both the number and footage of projects.

Pipeline safety incidents which have occurred across the country continue to focus the attention of state and federal regulators and lawmakers on improving pipeline and public safety performance. Proposed legislation includes:

- expanding the mileage of pipelines subject to more rigorous inspection and testing,
- requiring the use of automatic and remote controlled shut-off valves,
- expanding the use of excess flow valves, and
- requiring more timely notification of pipeline incidents.

All would require additional investment in processes and infrastructure to support compliance.



Electric System

In 2007, new regulations mandated by The Energy Policy Act of 2005 became effective and enforceable by regional electric reliability organizations. This act was triggered by concern about the robustness and reliability of nation's electrical grid, and it moved the industry into an era in which system planning, performance and operating requirements are no longer voluntary, but mandated by law and audited and enforced by fines and sanctions. At minimum, the PSE Bulk Electric System must be planned and operated to comply with these new reliability standards. As a result, PSE is making significant investments in both hardware and software assets for the portions of our system operating above 100 kV.

Regulations of the type affecting the Bulk Electric System are not currently present on the distribution system. However, distribution planning continues to be of interest in state legislative proceedings and with regulators. Current proposed legislation would establish a new reporting requirement for utilities to define a plan to foster the application and use of distributed generation.

New drone technology and FAA regulations have the potential to gather system information that may be useful in future planning exercises. PSE began evaluating areas where this technology may be utilized in 2015/2016.

Maturing System Alternatives

Finding optimal solutions to energy delivery system problems is a priority for PSE, and we are piloting and implementing several maturing technologies and alternatives that have the potential to help meet today's challenges and future challenges. While some technologies are mature enough for customer applications, the scalability and integration for meeting system needs is still maturing for the utility. Distributed energy resources have been considered by PSE for many years in the planning model, and as they mature they will become more viable to offset the reliability of traditional infrastructure solutions. Customer reliability and rates are key considerations to intentionally advancing these ideas so that no harm comes from applications that are not effectively scalable. Informing customers and stakeholders about the capability and viability of these technologies is also an important priority for PSE.



Smart Grid Technologies

Smart Grid is a term used to describe the integration of intelligent devices and new technologies into the electrical grid that promote self-healing and enable customer choice to a degree not possible with the grid's original infrastructure. At a basic level, these technologies are a networked group of generators, storage systems, sensors and control systems that allow for an optimized response to changes. The solutions are highly complex and require new technology integrations, complementary tariffs and policies governing their use, and extensive reengineering of business processes and work practices. PSE's objectives for the smart grid include the abilities to: meet customer expectations for service and product offerings, improve reliability, find alternatives to serving energy needs, increase operational efficiencies, and improve communication and usage information for customers.

PSE has set forth plans for a smart grid in the biennial Smart Grid Technology Report³⁵ filed with the WUTC in 2016. PSE will leverage existing investments in smart grid technologies while expanding the foundational elements to more fully integrate smart grid technology. PSE will demonstrate the value of smart grid technology in both targeted locations as well as in field test beds. Demonstrations in the targeted locations will focus on technology that is more mature and ready for expanded implementation throughout our service area such as distribution automation, advanced meter infrastructure (AMI) and conservation voltage reduction. To evaluate more cutting edge and complex technologies and test the interplay and impacts that these technologies have when combined, field test beds will be conducted in small, neighborhood-sized sections of our service area.

PSE is planning for distributed generation integration and control, coupled with demand response and voltage optimization. These technologies, when successfully implemented, are the cornerstones of a smart grid. As they are implemented together successfully, PSE will look to expand to more locations.

35 / <https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=161048>



To accomplish this vision, PSE will pull from decades of experience with grid technologies, many of which were cutting edge implementations at their time, including its use of transmission automation, AMR and system-wide SCADA. With implementation and improvements to Outage Management System (OMS), Geographical Information System (GIS) and Customer Information System (CIS), Energy Management System (EMS), and Internet Protocol (IP) based Supervisory Control and Data Acquisition (SCADA) network, PSE will be able to further advance operation and efficiency. Current work includes replacement of the aging AMR system with an AMI system capable of command and control which will increase the viability of alternatives that save energy and defer or delay traditional infrastructure; investigation of an advanced distribution grid management system (ADMS) that will facilitate control of distribution assets for distribution automation, voltage optimization and distributed generation integration; and continued replacement of PSE's legacy analog networks and obsolete remote telemetry unit equipment.

Distributed Generation

Distributed generation (DG) is the incorporation of small-scale generation into the electric grid close to where its users are (close to load). Many such sources exist: internal combustion engines, fuel cells, gas turbines and micro-turbines, hydro and micro-hydro applications, photovoltaics, wind energy, solar thermal energy and waste/biomass. The collective impact of distributed generation has the potential to reduce demand for large-scale electric power generation and the associated infrastructure requirements, and it could offer alternatives to load and reliability concerns at the circuit level.

PSE has incorporated distributed generation into its planning process for many years, but the maturity of the technology and grid created barriers to implementing DG as a cost-effective alternative to system improvements; however, the maturity of the technology is increasing. PSE has already responded to over 4,000 customers who have interconnected distributed renewable generators under 100 kW (mostly solar), and the number of requests is increasing annually. Also, several customers have participated in tariffs to interconnect larger generators sized between 100 kW and 5 MW; these interconnections follow an established procedure and timeline for study and cost assignment. PSE has interconnected 20 such customers so far. Most interconnections thus far desire to redirect surplus back on to the grid which requires reliable infrastructure to make that happen. Additionally, while the growing interconnections will offset total load, peak load reduction is less likely because PSE's peak loads often occur outside of daylight hours when solar generators are not producing. PSE sizes the delivery system to meet peak loads; however, the growing use of energy storage may influence the ability for DG to impact peak loads.



Distributed generation in PSE's service territory has not yet triggered significant impacts to the grid resulting from the two-way power flow, but several challenges arising from distributed generation have yet to be fully addressed. The upstream impacts of the two-way flow require a different approach to protection and control systems. PSE is also monitoring the impact of inverter technology on power quality. Even a modest amount of distributed generation requires the distribution grid to be equipped to manage power quality, thermal and mechanical limits of the grid elements, power system stability and the security of supply. Research in states that experience high penetrations of distributed generation points to several technologies that support its adoption. These include smart inverter technology, distributed generation control systems, upgrading and uprating distribution grid elements, and integrated storage.

Energy Storage

PSE's experience with grid-scale energy storage started with a 2MW project in the town of Glacier, Wash., in Whatcom County. To integrate this storage component, PSE needed to invest in protection upgrade at the substation, replacing the substation fuses with a circuit switcher. In addition, because the storage system required communications with the central energy management control system, PSE needed to install adequate communication networks to enable this communication. PSE's 2 MW battery will support about 150 customer homes for a day.

The vision for the battery is to perform peak shaving, frequency support and local outage mitigation. The battery has demonstrated its capabilities with regard to peak shaving and frequency support, and PSE is still working to demonstrate the ability to provide local outage mitigation. Because the town of Glacier is fed by a radial transmission line and radial distribution system, when either of these lines experiences an outage, there is no redundancy or backup available to mitigate the outage. Before power can be restored, repairs must be made to the lines. The battery may provide a new alternative, if it can provide power to the town when damage occurs to the transmission line or certain sections of the distribution lines. Otherwise, alternatives for redundancy are to bring in new transmission lines and add feeder ties to other substations, but in a remote area like Glacier, adding these new circuits would require many miles of new lines, an option for which the costs outweigh the benefits. Hence, a battery that can mitigate a subset of the outages offers a unique opportunity. (Read more about energy storage in Appendix L.).

Unlike a distributed generator, energy storage acts as a load on the grid as well as a generation source. PSE will need to consider how charging the battery impacts the demands on the grid. Additionally, robust and reliable infrastructure will still be required to support alternatives such as siting large batteries to feed partial or entire circuits or siting many small batteries to feed several houses.



Conservation Voltage Reduction

Reducing the voltage at an end-user's site by a small percentage can result in energy savings without compromising the operation of customers' equipment. PSE began a conservation voltage reduction (CVR) pilot program in conjunction with Northwest Energy Efficiency Alliance (NEEA) in 2006 implementing a pilot study of 10 residential customers that achieved a 2 percent energy savings with no adverse effects. Results on more recent PSE projects are showing an average of 1.5 percent energy savings on the substation circuits.

Since then, PSE has implemented CVR at six substations. Implementation involves three categories of work: installation of AMI meters to measure voltage near the end of the line, phase balancing and adjusting voltage settings at the substation transformer and line regulators. Because CVR relies on AMI metering to measure voltage, so far the implementation has been viable in areas where PSE has piloted AMI network and metering in advance of full AMI implementation. As full AMI implementation is completed, changes to IT systems and business processes will provide the opportunity to implement CVR more broadly across PSE service territory over the next 5 to 10 years. This will improve the viability of CVR as an alternative to implementing traditional infrastructure or generation solutions to address local capacity concerns.

Demand Response Alternatives

When demand for power is at its highest and customers reduce their energy use in response, utility energy delivery system planners call this demand response (DR). Based on estimated demand response capacity for residential, commercial and industrial customer sectors in our 2007 and 2009 IRPs, PSE developed two voluntary demand response pilots, one for residential loads that was conducted from 2009 to 2011, and one for commercial/industrial loads that was conducted from 2008 to 2010. In the 2015 IRP, the analysis found demand response to be a cost-effective resource in the demand-side portion of the portfolio. Based on those findings, PSE has moved forward with an acquisition strategy for demand response.



The acquisition strategy for DR includes consideration of the technology and management needed to ensure response is effective. Viability at the local or circuit level as an alternative to traditional infrastructure solutions will depend on the confidence we have in managing this program. PSE anticipates increasing utilization of DR over time. As with CVR, the fully implemented AMI system, with its improved technology and two-way communication, will facilitate more meaningful progress in implementing DR.

Electric Vehicles

PSE's customers are adopting electric vehicles (EV). In 2014, PSE launched a pilot program to collect interval energy usage data from EV owners. Over 1,100 customers have joined the pilot, providing PSE with a large population of data points. This information is used to develop load curves which will ultimately inform cost of service, distribution system impacts, and generation and transmission system impacts. We have developed estimates of expected energy needs, performed initial assessment of distribution impacts on select circuits, and performed some tests on the effectiveness of curtailed charging.

EVs are not specifically an alternative to traditional infrastructure or generation, but the future penetration and load impact must be considered and managed effectively. To date, PSE has determined that EVs pose minimal impacts to generation and transmission systems in the short run. Near-term distribution system impacts are small and likely manageable. In significant numbers, the additional loads from EVs could enhance the efficiency and economics of operating the electric system, with greater results achieved by encouraging off-peak charging when the system has spare capacity. However, unmanaged (through tariff incentives, for example), the peak demand on a specific circuit may increase significantly and actually drive infrastructure. PSE is working with the EV community to prepare effectively as adoption increases.



2017 PSE Integrated Resource Plan



Appendices A-P

November 2017

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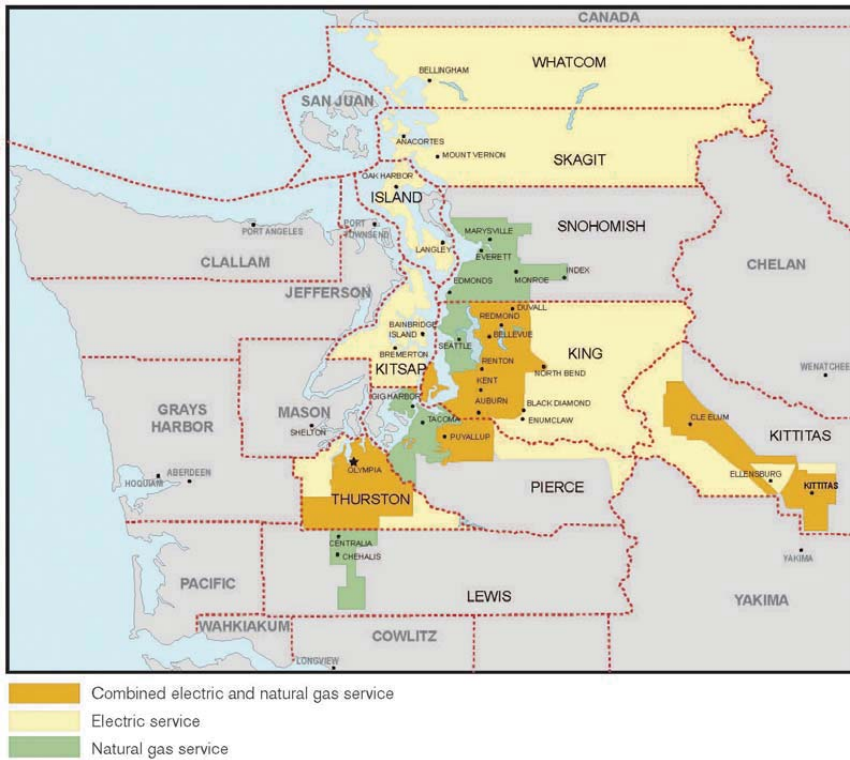




2017 PSE Integrated Resource Plan

About PSE

Puget Sound Energy is Washington state's oldest local energy company, providing electric and natural gas service to homes and businesses primarily in the vibrant Puget Sound area. Our service area covers more than 6,000 square miles, stretching from south Puget Sound to the Canadian border, and from central Washington's Kittitas Valley west to the Kitsap Peninsula. We serve more than 1.1 million electric customers and more than 800,000 natural gas customers in 10 counties.





2017 PSE Integrated Resource Plan

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*2017 PSE Integrated Resource Plan***Key Definitions and Acronyms**

| Term/Acronym | Definition |
|--------------------|---|
| AARG | average annual rate of growth |
| AB32 | The California Global Warming Solutions Act of 2006, which mandates a carbon price be applied to all power generated in or sold into that state. |
| ACE | Area Control Error |
| AECO | Alberta Energy Company, a natural gas hub in Alberta, Canada. |
| AMI | advanced metering infrastructure |
| AMR | automated meter reading |
| aMW | The average number of megawatt-hours (MWh) over a specified time period; for example, 175,200 MWh generated over the course of one year equals 20 aMW (175,200 / 8,760 hours). |
| AOC | Administrative Order Of Consent |
| ARMA | autoregressive moving average |
| AURORA | One of the models PSE uses for integrated resource planning. AURORA uses the western power market to produce hourly electricity price forecasts of potential future market conditions. |
| BA | Balancing Authority, the area operator that matches generation with load. |
| BAA | Balancing Authority area |
| BACT | Best available control technology, required of new power plants and those with major modifications, pursuant to EPA regulations. |
| balancing reserves | Reserves sufficient to maintain system reliability within the operating hour; this includes frequency support, managing load and variable resource forecast error, and actual load and generation deviations. Balancing reserves must be able to ramp up and down as loads and resources fluctuate instantaneously each hour. |
| BART | Best available retrofit technology, an EPA requirement for certain power plant modifications. |
| Base Scenario | In an analysis, a set of assumptions that is used as a reference point against which other sets of assumptions can be compared. The analysis result may not ultimately indicate that the Base Scenario assumptions should govern decision-making. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|----------------------|---|
| Baseload gas plants | Baseload generators are designed to operate economically and efficiently over long periods of time, which is defined as more than 60 percent of the hours in a year. Generally combined-cycle combustion turbines (CCCTs). |
| baseload resources | Baseload resources produce energy at a constant rate over long periods at lower cost relative to other production facilities; typically used to meet some or all of a region's continuous energy need. |
| Bcf | billion cubic feet |
| BEM | Business Energy Management sector, for electric energy efficiency programs. |
| BES | Bulk Electric System |
| BPA | Bonneville Power Administration |
| BSER | Best system of emissions reduction, an EPA requirement for certain power plant construction or modification. |
| BTU | British thermal units |
| CAISO | California Independent System Operator |
| capacity factor | The ratio of the actual generation from a power resource compared to its potential output if it was possible to operate at full nameplate capacity over the same period of time. |
| CAP | Corrective action plans. A series of operational steps used to prevent system overloads or loss of customers' power. |
| CAR | the Washington state Clean Air Rule |
| CARB | California Air Resources Board |
| CCCT | Combined-cycle combustion turbine. These are baseload gas plants that consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine exhaust and use it to produce additional electricity via a steam turbine generator. |
| CCR | coal combustion residuals |
| CCS | carbon capture and sequestration |
| CDD | cooling degree day |
| CEC | California Energy Commission |
| CI | confidence interval |
| CNG | compressed natural gas |
| CO ₂ | carbon dioxide |
| CO ₂ e | carbon dioxide equivalents |
| COE | U.S. Army Corps of Engineers |
| contingency reserves | Reserves added in addition to balancing reserves; contingency reserves are intended to bolster short-term reliability in the event of forced outages and are used for the first hour of the event only. This capacity must be available within 10 minutes, and 50 percent of it must be spinning. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|------------------------|--|
| CPI | consumer price index |
| CPP | federal Clean Power Plan |
| CPUC | California Public Utilities Commission |
| CRAG | PSE's Conservation Resource Advisory Group |
| CT | Natural gas-fired combustion turbine, also referred to as a "peaker." |
| CVR | conservation voltage reduction |
| Demand response | Flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost. |
| demand-side resources | These resources reduce load and originate on the customer side of the meter. PSE's primary demand-side resources are energy efficiency and customer programs. |
| Deterministic analysis | Deterministic analysis identifies the least-cost mix of demand-side and supply-side resources that will meet need, given the set of static assumptions defined in the scenario or sensitivity. |
| distributed generation | Small-scale electricity generators like rooftop solar panels, located close to the source of the customer's load. |
| DOE | U.S. Department of Energy |
| DSM | demand-side measure |
| DSO | Dispatcher Standing Order |
| DSR | demand-side resources |
| Dth | dekatherms |
| dual fuel | Refers to peakers that can operate on either natural gas or distillate oil fuel. |
| EIA | U.S. Energy Information Agency |
| EIM | The Energy Imbalance Market operated by CAISO. |
| EIS | environmental impact statement |
| EITEs | energy-intensive, trade-exposed industries |
| ELCC | Expected load carrying capacity. The peak capacity contribution of a resource relative to that of a gas-fired peaking plant. |
| ELCC | expected load carrying capacity |
| EMC | Energy Management Committee |
| energy need | The difference between forecasted load and existing resources. |
| energy storage | A variety of technologies that allow energy to be stored for future use. |
| EPA | U.S. Environmental Protection Agency |
| EPRI | Electric Power Research Institute |
| EPS | Washington state law RCW 80.80.060(4), GHG Emissions Performance Standard |
| ERU | Emission reduction units. An ERU represents one MtCO ₂ per year. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|------------------------|---|
| ESS | energy storage systems |
| EUE | Expected unserved energy, a reliability metric measured in MWhs that describes the magnitude of electric service curtailment events (how widespread outages may be). |
| EV | electric vehicle |
| FERC | Federal Energy Regulatory Commission |
| FIP | final implementation plan |
| GDP | gross domestic product |
| GENESYS | The resource adequacy model used by the Northwest Power and Conservation Council (NPCC). |
| GHG | greenhouse gas |
| GPM | gas portfolio model |
| GRC | General Rate Case |
| GTN | Gas Transmission Northwest |
| GW | gigawatt |
| HDD | heating degree day |
| HVAC | heating, ventilating and air conditioning |
| I-937 | Initiative 937, Washington state's renewable portfolio standard (RPS), a citizen-based initiative codified as RCW 19.285, the Energy Independence Act. |
| iDOT | Investment Optimization Tool. An analysis tool that helps to identify a set of projects that will create maximum value. |
| IGCC | Integrated gasification combined-cycle, generally refers to a model in which syngas from a gasifier fuels a combustion turbine to produce electricity, while the combustion turbine compressor compresses air for use in the production of oxygen for the gasifier. |
| intermittent resources | Resources that provide power that offers limited discretion in the timing of delivery, such as wind and solar power. |
| IOU | investor-owned utility |
| IPP | independent power producer |
| IRP | integrated resource plan |
| IRPAG | PSE's Integrated Resource Plan Advisory Group |
| ISO | independent system operator |
| ITA | independent technical analysis |
| ITC | investment tax credit |
| KORP | Kingsvale-Oliver Reinforcement Project pipeline proposal |
| kV | kilovolt |
| kW | kilowatt |
| kWh | kilowatt hours |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|---------------------------------|--|
| LAES | liquid air energy storage |
| LNG | liquified natural gas |
| load | The total of customer demand plus planning margins and operating reserve obligations. |
| LOLH (or LOLE) | Loss of load hours (or loss of load energy), a reliability metric focused on the duration of electric service curtailment events (how long outages may last). |
| LOLP | Loss of load probability, a reliability metric focused on the likelihood of an electric service curtailment event happening. |
| LP-Air | vaporized propane air |
| LSR | Lower Snake River Wind Facility |
| MATS | Mercury Air Toxics Standard |
| MDEQ | Montana Department of Environmental Quality |
| MDQ | maximum daily quantity |
| MDth | thousand dekatherms |
| MEIC | Montana Environmental Information Center |
| MESA | Modular Energy Storage Architecture. A protocol for communications between utility control centers and energy storage systems. |
| Mid-Columbia (Mid-C) market hub | The principle electric power market hub in the Northwest and one of the major trading hubs in the WECC, located on the Mid-Columbia River. |
| MMBtu | million British thermal units |
| MMtCO ₂ e | million metric tons of CO ₂ equivalent |
| MSA | metropolitan statistical area |
| MW | megawatt |
| MWh | megawatt hour |
| NAAQS | National Ambient Air Quality Standards, set by the EPA, which enforces the Clean Air Act, for six criteria pollutants: sulfur oxides, nitrogen dioxide, particulate matter, ozone, carbon monoxide and lead. |
| nameplate capacity | The maximum capacity that a natural gas fired unit can sustain over 60 minutes when not restricted to ambient conditions. |
| NEPA | National Environmental Policy Act |
| NERC | North American Electric Reliability Council |
| net maximum capacity | The capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or deratings, less the losses associated with auxiliary loads. |
| net metering | A program that enables customers who generate their own renewable energy to offset the electricity provided by PSE. |
| NGV | natural gas vehicles |
| NO ₂ | nitrogen dioxide |
| NOS | Network Open Season, a BPA transmission planning process |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|----------------------------|--|
| NO _x | nitrogen oxides |
| NPCC | Northwest Power & Conservation Council |
| NPV | net present value |
| NRC | Nuclear Regulatory Commission |
| NREL | National Renewables Energy Laboratories |
| NRF | Northwest Regional Forecast of Power Loads and Resources, the regional load/balance study produced by PNUCC. |
| NSPS | New source performance standards, new plants and those with major modifications must meet these EPA standards before receiving permit to begin construction. |
| NUG | non-utility generator |
| NWE | NorthWestern Energy |
| NWGA | Northwest Gas Association |
| NWP | Northwest Pipeline |
| NWPP | Northwest Power Pool |
| OASIS | Open Access Same-Time Information System |
| OATT | Open Access Transmission Tariff |
| OTC | once-through cooling |
| PACE | PacifiCorp East |
| PACW | Pacificorp West |
| PCA | power cost adjustment (electric) |
| PCORC | power cost only rate case |
| peak need | Electric or gas sales load at peak energy use times. |
| peaker (or peaking plants) | Peaker is a term used to describe generators that can ramp up and down quickly in order to meet spikes in need. They are not intended to operate economically for long periods of time like baseload generators. |
| peaking resources | Quick-starting electric generators that can ramp up and down quickly in order to meet short-term spikes in need, or gas sales resources used to meet load at times when demand is highest. |
| PEFA | ColumbiaGrid's planning and expansion functional agreement, which defines obligations under its planning and expansion program. |
| PEV | plug-in electric vehicle |
| PG&E | Pacific Gas and Electric Company |
| PGA | purchased gas adjustment |
| PGE | Portland General Electric |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PIPES Act | Pipeline Inspection, Protection, Enforcement, and Safety Act (2006) |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|-----------------------|--|
| planning margin or PM | These are amounts over and above customer peak demand that ensure the system has enough flexibility to handle balancing needs and unexpected events. |
| planning standards | The metrics selected as performance targets for a system's operation. |
| PLEXOS | An hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real-time to match changes in supply and demand on a 5-minute basis. |
| PM | particulate matter |
| PNUCC | Pacific Northwest Utilities Coordinating Committee |
| PNW | Pacific Northwest |
| portfolio | A specific mix of resources to meet gas sales or electric load. |
| PPA | Purchased power agreement. A bilateral wholesale or retail power short-term or long-term contract, wherein power is sold at either a fixed or variable price and delivered to an agreed-upon point. |
| PRP | Pipeline Replacement Program |
| PSE | Puget Sound Energy |
| PSIA | Pipeline Safety Improvement Act (2002) |
| PSM | Portfolio screening model, a model PSE uses for integrated resource planning, which tests electric portfolios to evaluate PSE's long-term revenue requirements for those portfolios. |
| PSRC | Puget Sound Regional Council |
| PTC | Production Tax Credit, a federal subsidy for production of renewable energy that applied to projects that began construction in 2013 or earlier. When it expired at the end of 2014, it amounted to \$23 per MWh for a wind project's first 10 years of production. |
| PTP | Point-to-point transmission service, meaning the reservation and transmission of capacity and energy on either a firm or non-firm basis from the point of receipt (POR) to the point of delivery (POD). |
| PTSA | Precedent Transmission Service Agreement |
| PUD | public utility district |
| pumped hydro | Pumped hydro facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station. |
| PV | photovoltaic |
| R&D | research and development |
| RAM | Resource Adequacy Model. RAM analysis produces reliability metrics (EUE, LOLP, LOLH) that allow us to assess physical resource adequacy. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|-------------------------|--|
| rate base | The amount of investment in plant devoted to the rendering of service upon which a fair rate of return is allowed to be earned. In Washington state, rate base is valued at the original cost less accumulated depreciation and deferred taxes. |
| RCRA | Resource Conservation Recovery Act |
| RCW | Revised Code of Washington |
| RCW 19.285 | Washington's state's Energy Independence Act, commonly referred to as the state's renewable portfolio standard (RPS) |
| RCW 80.80 | Washington state law that sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh. |
| REC | Renewable energy credit. RECs are intangible assets which represent the environmental attributes of a renewable generation project – such as a wind farm – and are issued for each MWh of energy generated from such resources. |
| REC banking | Washington's renewable portfolio standard allows for RECs unused in the current year to be “banked” and used in the following year. |
| redirected transmission | “Redirecting” transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change. |
| regulatory lag | The time that elapses between establishment of the need for funds and the actual collection of those funds in rates. |
| REM | Residential Energy Management sector, in energy efficiency programs. |
| repowering | Refurbishing or renovating a plant with updated technology to qualify for Renewable Production Tax Credits under the PATH Act of 2015. |
| revenue requirement | Rate Base x Rate of Return + Operating Expenses |
| RFP | request for proposal |
| RPS | Renewable portfolio standard. It requires electricity retailers to acquire a minimum percentage of their power from renewable energy resources. Washington state mandates 3 percent by 2012, 9 percent by 2016 and 15 percent by 2020. |
| RTO | regional transmission organization |
| SCADA | supervisory control and data acquisition |
| SCCT | Simple-cycle combustion turbine, natural gas-fired unit used for meeting peak resource need (also called a “peaker”) |
| scenario | A consistent set of data assumptions that defines a specific picture of the future; takes holistic approach to uncertainty analysis. |
| SCR | selective catalytic reduction |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|-----------------------|--|
| SENDOUT | The deterministic gas portfolio model used to help identify the long-term, least-cost combination of integrated supply- and demand-side resources that will meet stated loads. |
| sensitivity | A set of data assumptions based on the Base Scenario in which only one input is changed. Used to isolate the effect of a single variable. |
| SEPA | Washington State Environmental Policy Act |
| SIP | State Implementation Plan |
| SNCR | selective non-catalytic reduction |
| SO ₂ | sulfur dioxide |
| SOFA system | separated over-fire air system |
| Solar PV | solar photovoltaic technology |
| Stochastic analysis | Stochastic risk analysis deliberately varies the static inputs to the deterministic analysis, to test how different portfolios perform with regard to cost and risk across a wide range of potential future power prices, gas prices, hydro generation, wind generation, loads, plant forced outages and CO ₂ prices. |
| supply-side resources | Resources that generate or supply electric power, or supply natural gas to gas sales customers. These resources originate on the utility side of the meter, in contrast to demand-side resources. |
| T&D | transmission and distribution |
| TAG | Technical Advisory Group |
| TailVar90 | A metric for measuring risk defined as the average value of the worst 10 percent of outcomes. |
| TCPL-Alberta | TransCanada's Alberta System (also referred to as TC-AB) |
| TCPL-British Columbia | TransCanada's British Columbia System (also referred to as TC-BC) |
| TC-Foothills | TransCanada-Foothills Pipeline |
| TC-GTN | TransCanada-Gas Transmission Northwest Pipeline |
| TC-NGTL | TransCanada-Nova Gas Transmission Pipeline |
| TEPPC | WECC Transmission Expansion Planning Policy Committee |
| TF-1 | Firm gas transportation contracts, available 365 days each year. |
| TF-2 | Gas transportation service for delivery or storage volumes generally intended for use during the winter heating season only. |
| thermal resources | Electric resources that use carbon-based fuels to generate power. |
| TOP | transmission operator |
| transmission redirect | "Redirecting" transmission means moving a primary receipt point on BPA's system. According to BPA's business practice, PSE can redirect an existing long-term or short-term, firm or non-firm transmission that it has reserved on BPA's transmission system. BPA will grant the redirect request as long as there is sufficient capacity on the system to accommodate the change. |

Key Definitions and Acronyms



| Term/Acronym | Definition |
|----------------------------|--|
| Transport customers | Customers who acquire their own natural gas from third-party suppliers and rely on the gas utility for distribution service. |
| UPC | use per customer |
| VectorGas | An analysis tool that facilitates the ability to model price and load uncertainty. |
| VERs | Variable energy resources |
| WAC | Washington Administrative Code |
| WACC | weighted average cost of capital |
| WCI | Western Climate Initiative |
| WCPM | Wholesale Market Curtailment Model |
| WECC | Western Electricity Coordinating Council |
| WECo | Western Energy Company |
| WEI | Westcoast Energy, Inc. |
| Westcoast | Westcoast Energy, Inc |
| Wholesale market purchases | Generally short-term purchases of electric power made on the wholesale market. |
| WSPP | Western Systems Power Pool |
| WUTC | Washington Utilities and Transportation Commission |
| ZLD | zero liquid discharge |



A large white letter 'A' on a green square background.

2017 PSE Integrated Resource Plan

Public Participation

This appendix describes public involvement in the development of the 2017 PSE IRP.

Contents

- 1. PUBLIC INPUT TO THE 2017 IRP A-2*
- 2. IRPAG MISSION AND ROLE A-3*
- 3. 2016/17 IRPAG MEETINGS A-5*



1. PUBLIC INPUT TO THE 2017 IRP

PSE is committed to public involvement in the IRP planning process. In particular, the Integrated Resource Plan Advisory Group (IRPAG) meets with us regularly throughout the development of the analysis. The IRPAG is involved in all elements of the IRP.

By the time this plan was filed with the Washington Utilities and Transportation Commission (WUTC), 14 formal IRPAG meetings had been held, as well as dozens of informal meetings and communications. These meetings generated valuable constructive feedback, and the suggestions and practical information we received from both organizations and individuals helped to guide the development of this document. We want to thank those who took part for both the time and energy they invested, and we encourage their continued participation.

As a result of stakeholder suggestions and concerns in these meetings, PSE added the numerous additional analyses to the 2017 IRP. Among them are:

- An additional economic scenario that applied the 2017 Low Demand Forecast to High Scenario assumptions
- Reexamination of gas-fired resource costs conducted by Black and Veatch
- A review of renewable resource cost assumptions conducted by DNV GL
- Numerous sensitivity analyses, including:
 - No new thermal resources
 - Alternative resource costs for gas-fired resources, wind development and solar
 - An alternate discount rate for conservation in the electric analysis and gas analysis
 - Tipping point analysis on Montana wind
 - Off-shore wind
 - Repowering Hopkins and Wild Horse wind facilities
 - Coupling batteries with renewables as a joint resource

Appendix A: Public Participation



Stakeholders who actively participated in one or more meetings include:

- WUTC policy staff and advocacy staff
- Washington State Office of the Attorney General
- Northwest Industrial Gas Users (NWIGU)
- Northwest Gas Association (NWGA)
- Northwest Pipeline (NWP)
- The NW Energy Coalition (NVEC)
- The Sierra Club
- The Northwest Power and Conservation Council
- The City of Bellevue
- The Washington State Department of Commerce
- Project developers, including UET, Pascoe Energy Consulting LLC, Invenergy
- Renewable Northwest (RNW)
- Coalition of Eastside Neighborhoods for Sensible Energy (CENSE)
- King County
- Other utilities
- PSE customers

The following pages briefly describe the purpose of the IRPAG and list the formal IRPAG meetings held. Meeting agendas, presentations and notes are published on the PSE website at <http://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx>.



2. IRPAG MISSION AND ROLE

The IRPAG is the primary means of satisfying the public involvement requirements of WAC 480-90/100-238. While the IRP document is not a product of “consensus,” the IRPAG engages PSE and stakeholders in a consultative process that has proven to be an effective means for PSE planning staff to receive input on many key framework assumptions, including suggesting sensitivity analyses and related issues.

To clarify the roles and expectations of the public participation process and to provide greater transparency regarding PSE’s analytical processes, PSE retained PDSA Consulting, Inc. to facilitate the IRPAG meetings. This included setting up consensus-driven ground rules for the 2017 IRPAG process, developing meeting guidelines, the documentation of meeting notes, a listing of next steps and action items, and timing of IRPAG presentation material distribution. In January 2016, PSE also added resources to promote communication and accountability. We established a new address for written stakeholder questions and concerns (irp@pse.com), developed protocols for timely PSE response, and added the questions and answers to the online record of the 2017 IRP.



3. 2016/17 IRPAG MEETINGS

The agendas, meeting notes, handouts and copies of the full presentations made by PSE staff at the IRP Advisory Group meetings listed below are posted on PSE's website at <http://pse.com/aboutpse/EnergySupply/Pages/Resource-Planning.aspx>.

| | |
|-------------------------|------------------|
| June 17, 2016 (kickoff) | January 25, 2017 |
| July 27, 2016 | February 3, 2017 |
| August 22, 2016 | March 16, 2017 |
| September 26, 2016 | May 22, 2017 |
| October 27, 2016 | June 22, 2017 |
| November 14, 2016 | July 21, 2017 |
| | August 11, 2017 |
| | October 5, 2017 |

In addition, the IRPAG met in an informal meeting to discuss thermal RAC on July 25, 2016.



B

2017 PSE Integrated Resource Plan

Legal Requirements and Other Reports

This appendix identifies where each of the regulatory requirements for electric and gas integrated resource plans is addressed within the IRP and reports on the progress of the 2015 IRP electric and gas utility action plans. It also delivers two additional reports.

Contents

1. REGULATORY REQUIREMENTS B-2
2. REPORT ON PREVIOUS ACTION PLANS B-8
 - 2015 Electric Resources Action Plan
 - 2015 Gas Resources Action Plan
 - 2015 Gas-Electric Convergence Action Plan
3. OTHER REPORTS B-15
 - Electric Demand-side Resource Assessment: Consistency with Northwest Power and Conservation Council Methodology
 - Department of Commerce Integrated Resource Plan Cover Sheet



1. REGULATORY REQUIREMENTS

Figures B-1 and B-2 delineate the regulatory requirements for electric and natural gas integrated resource plans and identify the chapters of this plan that address each requirement.

Figure B-1: Electric Utility Integrated Resource Plan Regulatory Requirements

| Statutory or Regulatory Requirement | Chapter and/or Appendix |
|---|--|
| <i>WAC 480-100-238 (3) (a)</i> A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses. | Chapter 4, Key Analytical Assumptions Chapter 5, Demand Forecasts Appendix E, Demand Forecasting Models |
| <i>WAC 480-100-238 (3) (b)</i> An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. | Chapter 6, Electric Analysis Appendix J, Conservation Potential Assessment |
| <i>WAC 480-100-238 (3) (c)</i> An assessment of a wide range of conventional and commercially available nonconventional generating technologies. | Chapter 6, Electric Analysis Appendix D, Electric Resources and Alternatives Appendix K, Colstrip Appendix L, Electric Energy Storage Appendix M, Washington Wind and Solar Costs |
| <i>WAC 480-100-238 (3) (d)</i> An assessment of transmission system capability and reliability, to the extent such information can be provided consistent with applicable laws. | Chapter 8, Delivery Infrastructure Planning Appendix I, Regional Transmission Resources |
| <i>WAC 480-100-238 (3) (e)</i> A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using the criteria specified in WAC 480-100-238 (2) (b), Lowest reasonable cost. | Chapter 2, Resource Plan Decisions Chapter 6, Electric Analysis Chapter 8, Delivery System Planning Appendix I, Regional Transmission Resources Appendix N, Electric Analysis Appendix J, Conservation Potential Assessment |

Appendix B: Legal Requirements



| Statutory or Regulatory Requirement | Chapter and/or Appendix |
|---|---|
| <p><i>WAC 480-100-238 (3) (f)</i> Integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and projected future needs at the lowest reasonable cost to the utility and its ratepayers.</p> | <p>Chapter 2, Resource Plan Decisions</p> |
| <p><i>WAC 480-100-238 (3) (g)</i> A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission.</p> | <p>Chapter 1, Executive Summary</p> |
| <p><i>WAC 480-100-238 (3) (h)</i> A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.</p> | <p>Appendix B, Legal Requirements and Other Reports</p> |
| <p><i>WAC 480-100-238 (4)</i> Timing. Unless otherwise ordered by the commission, each electric utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.</p> | <p>2017 Integrated Resource Plan Work Plan filed with the WUTC July 14, 2016, and Updated Work Plan filed April 7, 2017</p> |
| <p><i>WAC 480-100-238 (5)</i> Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.</p> | <p>Appendix A, Public Participation</p> |
| <p><i>RCW 19.280.030 (e)</i> An assessment of methods, commercially available technologies, or facilities for integrating renewable resources, and addressing overgeneration events, if applicable to the utility's resource portfolio.</p> | <p>Appendix H, Operational Flexibility Overgeneration events are not applicable to PSE.</p> |

Appendix B: Legal Requirements



Figure B-2: Natural Gas Utility Integrated Resource Plan Regulatory Requirements

| Statutory or Regulatory Requirement | Chapter and/or Appendix |
|--|---|
| <i>WAC 480-90-238 (3) (a)</i> A range of forecasts of future natural gas demand in firm and interruptible markets for each customer class that examine the effect of economic forces on the consumption of natural gas and that address changes in the number, type and efficiency of natural gas end-uses. | Chapter 4, Key Analytical Assumptions Chapter 5, Demand Forecasts Appendix E, Demand Forecasting Models |
| <i>WAC 480-90-238 (3) (b)</i> An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. | Chapter 7, Gas Analysis Appendix O, Gas Analysis Appendix J, Conservation Potential Assessment |
| <i>WAC 480-90-238 (3) (c)</i> An assessment of conventional and commercially available nonconventional gas supplies. | Chapter 7, Gas Analysis Appendix O, Gas Analysis |
| <i>WAC 480-90-238 (3) (d)</i> An assessment of opportunities for using company-owned or contracted storage. | Chapter 7, Gas Analysis Appendix O, Gas Analysis |
| <i>WAC 480-90-238 (3) (e)</i> An assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources. | Chapter 7, Gas Analysis Appendix O, Gas Analysis |
| <i>WAC 480-90-238 (3) (f)</i> A comparative evaluation of the cost of natural gas purchasing strategies, storage options, delivery resources, and improvements in conservation using a consistent method to calculate cost-effectiveness. | Chapter 7, Gas Analysis Appendix O, Gas Analysis Appendix J, Conservation Potential Assessment |
| <i>WAC 480-90-238 (3) (g)</i> The integration of the demand forecasts and resource evaluations into a long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) integrated resource plan describing the mix of resources that is designated to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers. | Chapter 2, Resource Plan Decisions |
| <i>WAC 480-90-238 (3) (h)</i> A short-term plan outlining the specific actions to be taken by the utility in implementing the long-range integrated resource plan during the two years following submission. | Chapter 1, Executive Summary |
| <i>WAC 480-90-238 (3) (i)</i> A report on the utility's progress towards implementing the recommendations contained in its previously filed plan. | Appendix B, Legal Requirements and Other Reports |

Appendix B: Legal Requirements



| Statutory or Regulatory Requirement | Chapter and/or Appendix |
|---|---|
| <p><i>WAC 480-90-238 (4)</i> Timing. Unless otherwise ordered by the commission, each natural gas utility must submit a plan within two years after the date on which the previous plan was filed with the commission. Not later than twelve months prior to the due date of a plan, the utility must provide a work plan for informal commission review. The work plan must outline the content of the integrated resource plan to be developed by the utility and the method for assessing potential resources.</p> | <p>2017 Integrated Resource Plan Work Plan filed with the WUTC July 14, 2016, and Updated Work Plan filed April 7, 2017</p> |
| <p><i>WAC 480-90-238 (5)</i> Public participation. Consultations with commission staff and public participation are essential to the development of an effective plan. The work plan must outline the timing and extent of public participation. In addition, the commission will hear comment on the plan at a public hearing scheduled after the utility submits its plan for commission review.</p> | <p>Appendix A, Public Participation</p> |

Appendix B: Legal Requirements



Figures B-1 and B-2 delineate the regulatory requirements for electric and natural gas integrated resource plans and identify the chapters of this plan that address each requirement. B-3 details additional conditions pursuant to WUTC Order 01, dated April 13, 2017, which approved the November 15, 2017 final deadline for this IRP.

Figure B-3: Additional Conditions Pursuant to WUTC Order 01

| Order 01 request | Chapter and/or Appendix or Explanation |
|--|--|
| <i>Order 5-1(4)</i> Model the availability of transmission to import Montana wind energy resources. | Chapter 6, Electric Analysis |
| <i>Order 5-2 (4)</i> Perform area-specific analyses of wind resources in eastern Montana, off-shore from the Washington coast, at the Columbia River Gorge, and at the Skookumchuck wind site. | Chapter 4, Key Analytical Assumptions Chapter 6, Electric Analysis Appendix M, Washington Wind and Solar Costs |
| <i>Order 5-1 (5)</i> PSE will calculate the Effective Load Carrying Capacity of the area-specific wind resources from the data developed by a consulting firm. | Appendix M, Washington Wind and Solar Costs |
| <i>Order 5-2 (5)</i> PSE will adjust the cost of wind and solar resources based on data produced by a consulting firm. | Chapter 6, Electric Analysis Appendix M, Washington Wind and Solar Costs |
| <i>Order 5-3 (5)</i> The 2017 IRP will examine a number of actions to reduce carbon emissions and estimate the cost/ton of carbon abatement. This will include additional wind, solar, and conservation resources, in addition to reducing dispatch of gas plants and Colstrip as alternatives. | Chapter 6, Electric Analysis |
| <i>Order 5-4 (5)</i> PSE will formally request assistance from the Bonneville Power Administration to help clarify what information and studies are required to determine whether Montana wind qualifies as a renewable resource under RCW 19.285, the Energy Independence Act (EIA), and include a summary of those requirements. | Letter was provided to BPA dated April 28. PSE requested feedback by or before July 7, 2016 concerning: 1) what information and studies are required to determine whether Montana wind qualifies as a renewable resource under RCW 19.285, and 2) any summary information concerning the information and studies, and/or whether tariffs or regulations are needed to be addressed before (1) can be fully realized. |
| <i>Order 5-5 (5)</i> The 2017 IRP will include an analysis examining whether repowering Hopkins Ridge would be cost effective, assuming production tax credits would be available for such repowering. | Chapter 4, Key Analytical Assumptions Chapter 6, Electric Analysis |

Appendix B: Legal Requirements



| Order 01 request | Chapter and/or Appendix or Explanation |
|---|---|
| <p><i>Order 5-6 (5)</i> PSE will include a sensitivity that examines whether changing the discount rate for conservation impacts cost effectiveness of conservation.</p> | <p>Chapter 4, Key Analytical Assumptions Chapter 6, Electric Analysis</p> |
| <p><i>Order 5-7 (5)</i> For the 2019 IRP, PSE will hire a firm to do a survey of resource costs and recommend assumptions for use in the IRP. If reasonable, PSE will have the same consultants provide information for both fossil fuel plants and renewables. That study will include a detailed discussion of potential wind resources off the Washington coast, including areas that may be geographically limited for different reasons.</p> | <p>Appendix M, Washington Wind and Solar Costs Appendix P, Gas-fired Resource Costs</p> |
| <p><i>Order 5-8 (6)</i> PSE will perform portfolio sensitivity analysis to examine whether different resource costs would impact the least-cost mix of resources. PSE will also perform tipping point analyses to examine how close different resources are to each other, in terms of value to the portfolio. Furthermore, if Montana wind does not appear to be least-cost, a tipping point analysis will be used to estimate how close it is from other resources to being cost effective.</p> | <p>Chapter 4, Key Analytical Assumptions Chapter 6, Electric Analysis</p> |
| <p><i>Order 5-9</i> PSE's Chapter on System Planning, which includes a transmission and distribution planning discussion, will include an overview and explanation of the system planning process, including transmission that is not related to resources. This chapter will also identify geographic areas that may become capacity constrained in the future to guide future planning analyses. Additionally, for transmission projects that may affect the topology of PSE's transmission system, the System Planning Chapter will include the following information:</p> <ul style="list-style-type: none"> • List of transmission projects completed since the 2015 IRP; • Future planned transmission projects, brief description of the project, and references where interested parties can find additional information that may include needs, alternatives, etc., depending on the magnitude of the project. | <p>Chapter 8, Delivery Infrastructure Planning</p> |



2. REPORT ON PREVIOUS ACTION PLANS

2015 Electric Resources Action Plan

Per WAC 480-100-238 (3) (h), each item from the 2015 IRP electric resources action plan is listed below, along with the progress that has been made in implementing those recommendations.

DEMAND-SIDE RESOURCES

Acquire Energy Efficiency

Develop 2-year targets and implement programs that will put us on a path to achieve an additional 411 MW of energy efficiency by 2021.

PROGRESS. PSE reviewed the 2015 IRP guidance with its Conservation Resource Advisory Group (CRAG) beginning in May 2015. Over the following four months, PSE collaborated with the CRAG to develop its 2016-2017 electric conservation resource target, which was approved by the Commission on December 17, 2015. PSE issued an “all-comers” Request for Proposals (RFP) for possible new energy efficiency programs on May 15, 2015. An additional RFP for existing programs was issued on July 17, 2015.

To ensure that the CRAG is engaged in energy efficiency program development, PSE conducts regular CRAG meetings and provides a variety of communications about the program. These include the CRAG newsletter; routine updates of PSE’s Exhibit 3: Program Details and Exhibit 4: Measures, Incentives and Eligibility; and Annual Reports.



Acquire Demand Response

Develop and implement a demand response acquisition process and issue a Request for Proposal (RFP). The analysis supports addition of demand-response by 2021, but these programs don't fit existing energy efficiency or supply-side resource models.

PROGRESS. PSE developed two RFPs for demand response in 2016. The first focused commercial and industrial customers, and the second focused on residential and small-medium business customers, since these two groups require different technology and implementation strategies. Draft RFPs were filed with WUTC in June 2016 and approved at a WUTC open meeting in September 2016. The RFPs were subsequently released to bidders and posted on PSE's website. PSE received 10 proposals for residential and small-medium business customers and 8 proposals for commercial and industrial customers. All proposals were evaluated by the PSE demand response team, Navigant Consulting, and a group of PSE stakeholders from all departments that would be impacted by the implementation of demand response. Apparent winners were selected through a qualitative scoring process. None of the highest scoring proposals from either RFP were determined to be cost-effective under current methodology, and full-scale programs will not be implemented in 2017.

SUPPLY-SIDE RESOURCES

Clarify before Issuing an All-source RFP

Energy efficiency and demand-response additions appear sufficient to meet incremental capacity need until 2021, and additional renewables are not needed until 2023. PSE intends to issue an all-source RFP¹ in 2016, subject to an update to resource needs, most likely in early summer of 2016. This postponement will provide time to incorporate an updated regional adequacy assessment into our resource need, which is scheduled to be completed by the NPCC in the second quarter of 2016.

PROGRESS. This item was driven by a resource need identified using an updated planning standard. In the 2015 IRP, PSE used a standard driven by the value of reliability to customers instead of a 5 percent Loss of Load Probability standard (LOLP). The Commission expressed concern about adopting the new approach as the basis for resource acquisitions its 2015 IRP acceptance letter. This was extremely helpful feedback. As a result of the Commission's feedback, PSE chose not to adopt the new planning standard, and returned to the 5 percent LOLP standard in the 2017 IRP. This

¹ / Chapter 3, Planning Environment, describes the resource acquisition process.



pushed PSE's resource need out further into the future, as shown in Figure 6-5, of Chapter 6, at page 6-11 of the 2015 IRP. Therefore, PSE determined that issuing an all-source RFP would not be warranted.

Improve Analytical Capabilities

Analysis in the 2015 IRP demonstrated that initial estimates of intra-hour flexibility values could significantly affect the least cost mix of resources and possibly add reciprocating engines to the portfolio. Specifically, in the 2017 IRP planning cycle, we will:

- Define specific elements of intra-hour flexibility that need to be valued and prioritize them according to their potential to impact future resource decisions.
- Refine existing or develop new analytical frameworks to estimate, from a portfolio perspective, the value that different types of resources can provide for each element of flexibility.
- Ensure that frameworks reasonably address energy storage technologies, including batteries, pumped hydro, kinetic storage and others.

PROGRESS. PSE acquired the PLEXOS model to help analyze sub-hourly dispatch for the 2017 IRP. The company also engaged E3 Consulting to perform the analysis, using PLEXOS in consultation with PSE staff. This modeling addressed both day-ahead scheduling and sub-hourly dispatch at the 5-minute level. The analytical framework was applied to lithium ion batteries, flow batteries, pumped hydro storage, different kinds of gas or dual fuel peakers, and baseload combined-cycle gas plants.

Actively Investigate Emerging Resources

For batteries, continue to explore potential applications and demonstration projects; for solar, update market penetration studies and continue study of system planning implications; for electric powered vehicles, continue load research. Continue to explore the possibilities provided by new emerging resources.

PROGRESS. PSE continues to be a leader in the exploration and adoption of new technologies that meet customer needs and balance environmental impacts.

The 2017 PSE General Rate Case Prefiled Direct Testimony of Michael Mullally provides a summary of PSE's Glacier Battery Storage Project – currently the largest battery storage project in Washington state. PSE continues to evaluate solar technologies. At the May 22, 2017 IRPAG meeting, DNV GL provided analysis that identified solar prices are becoming more cost competitive than wind, largely driven by the current investment tax



credit (ITC) benefits. PSE continues to model battery storage as a potential resource in the IRP analysis, and we are also actively evaluating options for customer electric vehicles and how to meet the needs for the 9,000 electric vehicles residing in PSE territory, including options to encourage charging during off-peak hours.

Participate in the California Energy Imbalance Market (EIM)

PSE has committed to joining the California EIM. This market will allow PSE to purchase sub-hourly flexibility at 15- and 5-minute increments from other EIM participants to meet our flexibility needs when market prices are cheaper than using our own resources. This will also allow PSE the opportunity to sell flexibility to other EIM participants when we have surplus flexibility. The benefits of lower costs on the one hand and net revenue from EIM sales on the other will reduce power costs to our customers.

PROGRESS. PSE entered the CAISO EIM market on October 1, 2017, joining PacifiCorp, NV Energy, and Arizona Public Service as EIM Entities. As estimated by CAISO, participating in the EIM has produced \$5.43 Million in benefits for PSE customers since entering the market.

The success of the CAISO EIM has been well-documented and plans are in place for several entities to join the market. Portland General Electric, Idaho Power, Powerex, Salt River Project and Seattle City Light have all signed contracts to join the market before 2020. By 2020, most of the load in the Western Energy Coordinating Council (WECC) Balancing Authority is expected to be within the EIM footprint. PSE expects additional EIM participants will increase the diversity and liquidity of the market, potentially increasing the benefits associated market participation.



2015 Gas Resources Action Plan

Per WAC 480-90-238 (3) (i), each item from the 2015 IRP gas resources action plan is listed below, along with the progress that has been made in implementing those recommendations.

GAS DEMAND-SIDE RESOURCES

Acquire Energy Efficiency

Develop 2-year targets and implement programs to acquire conservation, using the IRP as a starting point for goal-setting.

PROGRESS. PSE reviewed the 2015 IRP guidance with its Conservation Resource Advisory Group (CRAG) beginning in May 2015. Over the following four months, PSE collaborated with the CRAG to develop its 2016-2017 natural gas conservation resource target, which was approved by the Commission on December 17, 2015. PSE issued an “all-comers” Request for Proposals (RFP) for possible new energy efficiency programs on May 15, 2015. An additional RFP for existing programs was issued on July 17, 2015.

To ensure that the CRAG is engaged in energy efficiency program development, PSE conducts regular CRAG meetings and provides a variety of communications about the program. These include the CRAG newsletter; routine updates of PSE’s Exhibit 3: Program Details and Exhibit 4: Measures, Incentives and Eligibility; and Annual Reports.

GAS SUPPLY-SIDE RESOURCES

Develop the PSE LNG Project

Continue work to develop an LNG facility for serving both the peak needs of gas customers and the transportation markets at the Port of Tacoma.

PROGRESS. PSE is in the execution phase of the PSE LNG project in Tacoma, Wash. A major transportation sector customer has executed long-term agreements. The project is currently under construction and is expected to be in service by late 2019.



Begin Upgrades to Swarr

Implement plans to ensure that the full upgraded capacity of the Swarr propane-air facility is available by the 2016/17 or 2017/18 heating season.

PROGRESS. PSE has developed plans to restore the facility to safe reliable and expanded service; however, with the slower growth and lower peak use per customer in current load forecasts, PSE has only a one- to two-year need for Swarr until the Tacoma LNG facility is online. PSE has determined that it is lower cost to serve the short-term shortfall with short-term pipeline capacity and defer the Swarr upgrade until further need is apparent.

Improve Analysis on Basin Risk

Acquiring long-term pipeline capacity to one supply basin entails risk, as the relationship between gas prices in different supply basins is uncertain and changes over time. Resources that do not rely on making a long-term commitment to one supply basin reduce risk. Such resources may include conservation, on-system storage and market-area storage. These resources avoid placing a bet on which basin-plus-transportation cost will be lowest cost in the long run. PSE will refine its analysis of this risk and work with other gas utilities on ways to improve its ability to analyze this issue in the 2017 IRP.

PROGRESS. With the addition of PSE's LNG peaking plant, the company's gas utility resource need (after cost-effective conservation) was pushed out to the 2024/2025 time frame. Therefore, PSE decided this was not a high priority item.



2015 Gas-Electric Convergence Action Plan

Non-firm Gas Supplies for PSE's Portfolio

Continue monitoring sufficiency of non-firm gas versus backup fuel as PSE begins operating in the California EIM; as regional natural gas demand grows; and as interstate pipelines become more fully utilized.

PROGRESS. In the 2015 IRP, PSE examined the adequacy of backup fuel with non-firm gas supplies for PSE's existing fleet. In the 2017 IRP, we extended that analysis to look out into the future at whether 48 hours of backup fuel would be adequate for additional dual-fuel peakers. These results are presented in Chapter 6, Electric Analysis.

Non-firm Gas Supplies for Regional Adequacy

Work with others in various industry forums on developing resource adequacy criteria for natural gas generating plants that do not have verifiable fuel supply.

PROGRESS. PSE has been an active participant in the Northwest Power and Conservation Council's Resource Adequacy Advisory Committee on this issue. At this time, the approach has been to address this issue as a "what-if" analysis; that is, the Council's study examines the impact on regional resource adequacy if gas units in the region that do not have backup fuel or firm pipeline capacity are not available. This provides reasonable book-ends. On one hand, there may be conditions when those plants are not able to acquire gas supply during extreme weather events. On the other hand, removing them completely from the analysis overstates the impact, because such plants probably can acquire fuel most of the time.



3. OTHER REPORTS

Electric Demand-side Resource Assessment: Consistency with Northwest Power and Conservation Council Methodology

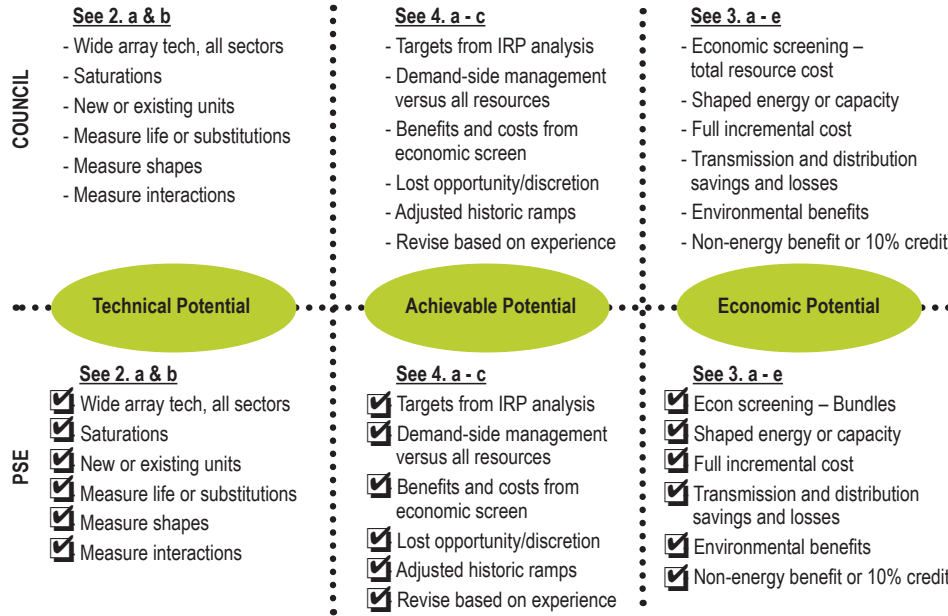
There are no legal requirements for the IRP to address the Northwest Power and Conservation Council (Council) methodology for assessing demand-side resources. Such comparison, however, may be useful for PSE and stakeholders in implementing sections of WAC 480-109. PSE has worked closely with Council staff on several aspects of our analytical process, including approaches to modeling demand-side resources. We are most grateful for the dialogue, and very much appreciate the opportunity to work with Council staff. WAC 480-109 does not define “methodology.” PSE developed the detailed checklist below to demonstrate that our IRP process is consistent with the Council’s methodology.²

² / References in Figure B-4 refer to the Council’s assessment of its methodology, found at: <https://www.nwcouncil.org/media/112474/Methodology.pdf>

Appendix B: Legal Requirements



Figure B-4: Comparison of Demand-side Resource Assessment Methodologies, PSE and the Northwest Power and Conservation Council



Department of Commerce Integrated Resource Plan Cover Sheet

The WUTC is required to provide summary information about the IRPs of investor-owned utilities to the Department of Commerce. Information for the cover sheet is included in Figure B-5, below.

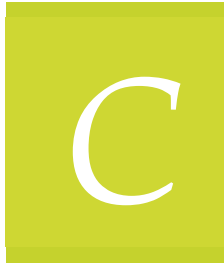
Appendix B: Legal Requirements



Figure B-5: Load-resource Balance Summary

Resource Plan Year: 2018
 Base Year Start: 01/01/2018
 Base Year End: 12/31/2018
 Five-year Report Year: 2023
 Ten-year Report Year: 2028

| Report Years | Base Year = 2018 | | | 2023 | | | 2028 | | |
|--|------------------|---------|--------|--------|---------|--------|--------|---------|--------|
| | Winter | Summer | Annual | Winter | Summer | Annual | Winter | Summer | Annual |
| Units | (MW) | (MW) | (aMW) | (MW) | (MW) | (aMW) | (MW) | (MW) | (aMW) |
| Loads | 5,021 | 3,224 | 2,681 | 5,359 | 3,498 | 2,864 | 5,662 | 3,801 | 3,036 |
| Exports | 14 | 320 | 66 | 11 | 311 | 63 | 0 | 300 | 48 |
| Resources | | | | | | | | | |
| Conservation/ Efficiency | 30 | 22 | 22 | 374 | 257 | 239 | 549 | 376 | 355 |
| Demand Response | 8 | | | 79 | | | 107 | | |
| Cogeneration | | | | | | | | | |
| Hydro | 853 | 762 | 505 | 814 | 768 | 473 | 685 | 743 | 433 |
| Wind | 143 | 90 | 242 | 143 | 143 | 275 | 137 | 137 | 261 |
| Other Renewables | | | | | | | | | |
| Thermal - Gas | 2,061 | 1,841 | 1,146 | 2,061 | 1,841 | 1,146 | 2,061 | 1,841 | 1,146 |
| Thermal - Coal | 658 | 658 | 608 | 360 | 360 | 334 | 360 | 360 | 334 |
| Long Term: BPA Base Year or Tier 1 | | | | | | | | | |
| Net Long Term Contracts | 401 | 386 | 410 | 387 | 376 | 394 | 15 | 4 | 5 |
| Net Short Term Contracts | 1,722 | 1,695 | | 1,752 | 1,670 | | 1,863 | 1,677 | |
| Other | | | | | | | | | |
| Imports | 308 | 8 | 50 | 308 | 8 | 50 | 308 | 8 | 50 |
| Total Resources, net of Exports | 6,170 | 5,142 | 2,915 | 6,267 | 5,111 | 2,847 | 6,085 | 4,847 | 2,536 |
| Load Resource Balance (Surplus)/Deficit | (1,149) | (1,918) | (234) | (908) | (1,613) | 18 | (423) | (1,046) | 500 |



2017 PSE Integrated Resource Plan

Environmental and Regulatory Matters

This appendix summarizes the recent and changing environmental rules and regulations that apply to PSE energy production activities.

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- *California Cap-and-trade Program*
- *Washington State*
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1. ENVIRONMENTAL PROTECTION AGENCY REGULATIONS

Coal Combustion Residuals

On April 17, 2015, the United States Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The CCR rule addresses the risks from coal ash disposal, such as leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash containment structures by establishing technical design, operation and maintenance, closure and post-closure care requirements for CCR landfills and surface impoundments, and corrective action requirements for any related leakage. The rule also sets out recordkeeping and reporting requirements including posting specific information related to CCR surface impoundments and landfills to a publicly-accessible website.

Mercury and Air Toxics Standard (MATS)

The EPA published the final Mercury and Air Toxics Standard in February 2012 to reduce air pollution from coal and oil-fired power plants with a capacity equal to or greater than 25 megawatts (MW). The MATS rule establishes emissions limitations at coal-fired power plants for mercury of 1.2 lbs per trillion British thermal units (TBtu), and for acid gases and certain toxic heavy metals using a particulate matter surrogate of 0.03 lb per million British thermal units (MMBtu).¹

The regulations have been challenged in the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) in *White Stallion Energy Center v. EPA*, and on appeal in the U.S. Supreme Court in *Michigan v. EPA*. Petitioners focused on EPA's finding that mercury controls for electric power plants were "appropriate and necessary," a prerequisite to regulation under Section 112(n) of the Clean Air Act. Petitioners argued that the agency found few direct benefits from controlling mercury or other air toxics. The vast majority of the monetized benefits in EPA's analysis would come from reduced emissions of particulates, specifically PM_{2.5}, which the pollution control equipment would achieve as a co-benefit. Petitioners also argued that EPA had a duty to consider cost in determining whether the standards were appropriate and necessary, and did not do so.

¹ / Appendix K, *Colstrip*, describes *Colstrip's* compliance with the MATS rule.

Appendix C: Environmental Matters



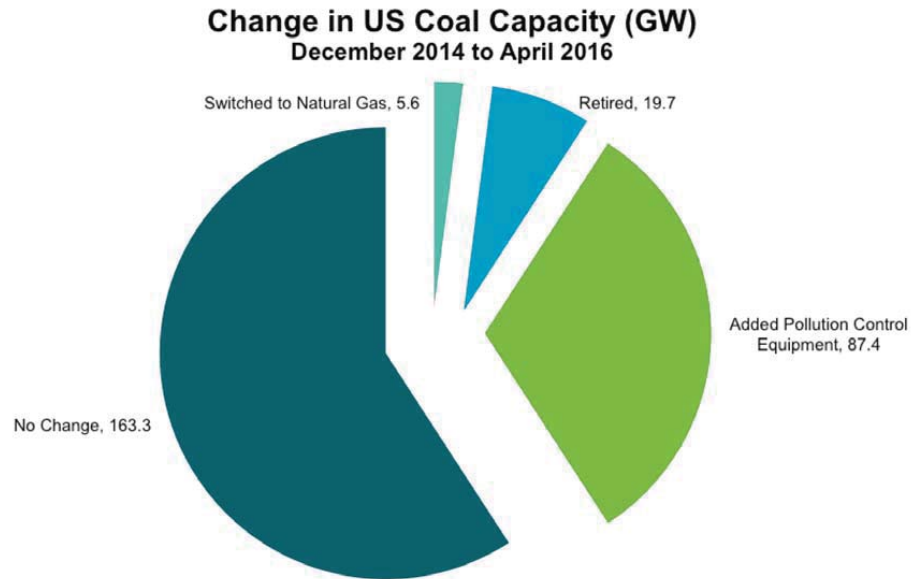
On June 29, 2015, the Supreme Court agreed in a 5-4 vote. The Court held that EPA interpreted the statute's "appropriate and necessary" language unreasonably when it deemed cost irrelevant to the decision to regulate power plants. The Court found the ratio of direct benefits from the rule to its expected cost particularly troubling: "One would not say that it is even rational, never mind 'appropriate,' to impose billions of dollars in economic costs in return for a few dollars in health or environmental benefits."

The case was remanded to the D.C. Circuit for further proceedings, and EPA prepared a "supplemental appropriate and necessary" finding that it finalized in April 25, 2016 after taking public comment. Fifteen states, led by Michigan, have filed suit challenging EPA's "Supplemental Finding that It Is Appropriate and Necessary to Regulate Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units." As of September 2016, the rule remains in effect while the D.C. Circuit considers whether EPA's action in response to the Supreme Court decision has properly addressed the Court's concerns.

According to the Energy Information Administration (EIA), \$6.1 billion was invested to comply with MATS or other environmental regulations from 2014 to 2016, with 87.4 gigawatts (GW) of total capacity adding pollution controls as a compliance option. This is less than the EPA's December 2011 estimate that MATS compliance would cost utilities and potentially consumers \$9.6 billion per year. The 19.7 GW of smaller and older coal-burning units that retired in that time frame also exceeded EPA's 2011 estimate of 4.7 GW. Overall, coal-fired generation capacity dropped from 299 GW at the end of 2014 to 276 GW as of April 2016, and its share of total electricity generation declined from 39 percent in 2014 to 28 percent in the same period.



Figure C-1: Change in U.S. Coal Capacity, December 2014 to April 2016



Clean Water Act

Cooling Water Intake and Discharge

The EPA finalized the changes to Section 316(b) of the Clean Water Act that apply to power plant standards in May 2014.

The rule's requirements address these potential fisheries impacts:

- Existing facilities with a design intake flow of greater than 2 million gallons per day, where more than 25 percent is used for cooling, are required to select from 9 compliance options related to impingement (fisheries) mortality.
- Existing facilities that withdraw at least 125 million gallons per day are required to monitor fisheries entrainment and assess the costs, benefits and other adverse environmental impacts of measures for reducing entrainment mortality. Based on these reports, the regulatory agency selects the best technology available for reducing entrainment mortality at a facility.
- New units that add electrical generation capacity at an existing facility are required to install technologies that reduce impingement and entrainment to a level equivalent to closed-cycle cooling.

Appendix C: Environmental Matters



The rule requires power plants to install any one of a variety of technologies to reduce the amount of fish and other aquatic life killed by cooling water intake pipes.

Environmental groups filed three separate challenges to the rule on September 2, 2014, in the U.S. Court of Appeals for the Second Circuit (Second Circuit). They contend that the EPA gave utilities too much flexibility in finding a way to comply and do not adequately protect fish and aquatic life. On September 4, 2014, Entergy Corporation and the Utility Water Act Group, a coalition of 191 energy companies and three utility trade associations, filed a joint challenge on behalf of utility companies. The industry coalition, while not challenging specific issues, has taken issue with the data EPA used to estimate the costs and benefits of the rule.

The Second Circuit is now tasked with deciding whether to send the rule back to the agency for further revision based on environmentalists' argument that it isn't protective enough, or to trim what industry groups contend are inappropriate components. On May 20, 2016, the Sierra Club and more than 20 other environmental groups and industry members — including the American Chemistry Council, the American Petroleum Institute and Entergy Corp. — filed opening briefs. On June 3, 2016, the Clean Air Task Force filed an amicus brief on behalf of the environmental petitioners. On October 12, 2016, EPA responded, asking the Second Circuit to uphold the agency's regulations. The EPA defended its rule saying neither group's remedy is necessary and that the agency followed Congress' direction. The lawsuit is still pending.

Steam Electric Power Generating Effluent Guidelines

On September 30, 2015, the EPA finalized a rule to regulate wastewater discharges from power plants. The new rule sets limits on dissolved pollutants permitted in these discharges, and focuses on mercury, selenium and arsenic (toxic metals previously unregulated in this context).

The final rule applies to all steam electric power plants with more than 50 megawatts in production capacity and to oil-fired plants. There are about 1,080 steam electric power plants in the U.S., and 134 of those will have to make new investments to meet the requirements of the effluent limitation guidelines according to the agency. The regulations will take effect in 2018, and compliance will be phased in through 2023.

Along with effluent limits on toxic metals and dissolved solids, the rule establishes zero discharge limits on pollutants in ash transport water and flue gas mercury control wastewater. Many units in the Pacific Northwest will be compliant with their current controls, and therefore will not incur additional compliance costs. Colstrip is a Zero Liquid Discharge (ZLD) facility, so it will not be affected by the rule.



The Regional Haze Rule (Montana)

Adopted in 1998, the Regional Haze program is a 64-year program administered by the EPA under federal law to improve visibility. Specifically, the rule is aimed at improving visibility in mandatory Class I areas (National Parks, National Forests and Wilderness Areas); it is not a health-based rule. The rule requires each state to prepare an analysis of visibility impairments to Class I areas and develop plans to eliminate man-made impairment by 2064. Major sources that began construction before 1977 (including Colstrip Units 1 & 2) must bring emission controls to Best Available Retrofit Technology (BART) standards during the initial review cycle. “Reasonable Progress” requirements call for an updated analysis of impacts every five years. States are also required to constantly decrease haze in certain scenic areas of the country over time according to a “Glide Path.” Power plant emissions contributing to haze are evaluated in phases every 10 years, and more stringent emission controls are required as needed to stay below the Glide Path.

In September 2012, the EPA published its Final Implementation Plan (FIP) for Colstrip, covering both the BART and Reasonable Progress requirements, with implementation required within five years.

There were no immediate requirements for Colstrip Units 3 & 4, but EPA determined that Colstrip Units 1 & 2 needed to upgrade pollution controls to meet new sulfur dioxide and nitrogen oxide limits. On November 15, 2012, the Sierra Club filed an appeal of the FIP with the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit), and Colstrip operator Talen Energy also filed an appeal. The case was heard on May 15, 2014, in Seattle, Wash. On June 9, 2015, a three judge panel of the Ninth Circuit reviewed EPA’s first phase requirements for Colstrip and found that the EPA had not adequately justified the need for two of the control technologies; they remanded these two issues back to EPA for revision. The ruling in no way affects the future planning periods for the Regional Haze program or the Glide Path.

The current EPA assessment is that the state of Montana will require significant emission reductions to meet the natural visibility goal by 2064. This means that additional emission reductions will be necessary in future 10-year planning periods, beginning in the 2018-2028 period, and there is risk and uncertainty regarding potential costs.

In 2013, the Sierra Club and the Montana Environmental Information Center (MEIC) filed a citizen suit alleging that the six Colstrip owners (Talen Montana LLC, PSE, Avista Corporation, Portland General Electric Company, NorthWestern Corporation and PacifiCorp) violated the Clean Air Act by making modifications without getting the proper permits or installing modern pollution controls. On July 12, 2016, a settlement was reached in which Talen Energy and PSE agreed to a six-year time frame for shutting down Colstrip Units 1 & 2, and the Sierra Club and MEIC agreed to drop

Appendix C: Environmental Matters



their suit. Originally, the suit targeted all four Colstrip units, but the environmental groups agreed to drop the whole suit when the agreement to shut down the two older units was reached. Talen Montana LLC and Puget Sound Energy will have until July 1, 2022, to completely shut down Units 1 & 2, and they also agreed to limit nitrogen oxide and sulfur dioxide emissions from those units while they continue to operate. The other four owners have stakes only in Units 3 & 4.

Oregon and Washington both recently passed legislation affecting the Colstrip power plant. Oregon Gov. Kate Brown approved legislation in March 2016 pushing the state away from importing coal-sourced electricity, and Washington Gov. Jay Inslee later signed a bill allowing PSE to set aside money for the decommissioning of the two older Colstrip units.

For more information on the EPA FIP, see <http://www2.epa.gov/sites/production/files/2014-02/documents/epafinalactonnonmontanaregionahazeplan.pdf>.

For the draft Federal Implementation Plan containing EPA's analyses and cost estimates, see <https://federalregister.gov/a/2012-8367>.

National Ambient Air Quality Standards (NAAQS)

The Clean Air Act establishes two types of national air quality standards. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation and buildings. These ambient level standards apply uniformly throughout the states.

The Clean Air Act required EPA to set NAAQS for widespread pollutants from numerous and diverse sources considered harmful to public health and the environment. EPA has set NAAQS for the "criteria" pollutants (carbon monoxide, oxides of nitrogen, oxides of sulfur, volatile organic compounds and particulate matter); periodic review of the standards and the science on which they are based is required.

Each time the NAAQS are revised, the states must evaluate whether any parts of the state exceed the standard; these are "non-attainment" areas. If a state contains any non-attainment areas, it must propose a plan and schedule to reduce emissions in order to achieve attainment approval by the EPA. Currently the Colstrip area of Montana is in attainment for all criteria pollutants. Reductions in Colstrip emissions for sulfur dioxide (SO₂), nitrogen dioxide (NO_x) and particulate matter (PM) to meet the MATS Rule and the EPA FIP are expected to keep the area in attainment with any NAAQS revisions with no further actions required.



Ozone NAAQS in Washington State

On October 1, 2015, EPA strengthened the ozone NAAQS by lowering the allowable level of ozone from 75 to 70 parts per billion (ppb).² To meet the standard, the ozone design value of an area must be equal to or less than 70 ppb.³ Non-attainment designations were to be set by October 1, 2017, and non-attainment areas would have 3, 6 or 9 years to meet the new standard, depending on the level of severity.

On October 1, 2016, Washington state's Department of Ecology (Ecology) informed EPA that overall, Washington meets the new tougher standards; however, a lack of data collected in Benton, Franklin and Walla Walla Counties required Ecology to mark these areas as "unclassified." The EPA standard requires three years of monitoring data. So far, Ecology has monitored ozone in the Tri-Cities for only one year, and the agency has discovered that ozone can reach high levels in the southern Columbia Basin. Ecology is conducting a special study to help pinpoint the origin of high Tri-Cities ozone levels.

EPA was scheduled to issue final designations by October 1, 2017, based on ozone monitoring data from 2014-2016, but instead, in June 2017 the agency determined that it needed more time to consider the designation decisions. The EPA then moved to delay the designations until October 2018; however, facing new lawsuits from environmental and public health groups as well as a handful of states, in August 2017 the agency scrapped its effort to delay the designations. On October 3, 2017, it was reported that EPA had missed its October 1, 2017 deadline for informing states which counties and regions were out of attainment with the 2015 NAAQS standards for ozone. The EPA released a statement to the press stating it had "no further information at this time." In response to the lack of action from the EPA, on October 3, 2017, Earthjustice filed a notice of intent to sue the EPA on behalf of the Sierra Club and other environmental and public health groups for missing the October 1 deadline. Due to the uncertainty now surrounding the ozone standards, PSE cannot predict the outcome of this matter.

² / 80 FR 65292, October 26, 2015

³ / The ozone design value is the fourth-highest maximum daily 8-hour ozone concentration per year, averaged over three years.



Greenhouse Gas Emissions

Section 111(b) of the Clean Air Act

On January 8, 2014, the EPA issued a proposed New Source Performance Standard (NSPS) for the control of carbon dioxide (CO₂) from new power plants that burn fossil fuels under section 111(b) of the Clean Air Act. For coal-fired sources, the EPA is proposing an emissions limit of 1,100 lb CO₂ per megawatt hour (MWh); for natural gas combined-cycle sources; limits would be set at 1,000 to 1,100 lb CO₂ per MWh, depending on the size and type of unit. (The EPA's original recommendations, issued on April 8, 2012, were rescinded after receiving 2.5 million comments.) Under the January 2014 proposal, the Agency concluded that carbon capture and storage (CCS) has been adequately demonstrated as a technology for controlling CO₂ emissions in full-scale commercial applications at coal-fired electrical generating units; however, it reached the opposite conclusion in the case of gas-fired generators: that CCS is not adequately demonstrated. PSE submitted comments before the end of the comment period on May 9, 2014.

On August 3, 2015, EPA issued a final rule combining its new and modified proposals into one rulemaking and made several changes. The final rule separates standards for new power plants fueled by natural gas and coal from existing plants. New natural gas power plants can emit no more than 1,000 lbs of CO₂ per MWh, which is achievable with the latest combined-cycle technology. New coal power plants can emit no more than 1,400 lbs CO₂ per MWh. Coal plants would not specifically be required to employ carbon capture and storage (CCS), but CCS was reaffirmed by EPA as Best System of Emissions Reduction (BSER). The 111(b) standards are implemented by the states.



Section 111(d) of the Clean Air Act

The EPA announced the final rule under section 111(d) of the Clean Power Plan for Existing Power Plants on August 3, 2015, and it was published on October 23, 2015. The final version included several changes from the draft rule. Specifically, the EPA excluded energy efficiency from the "building blocks" states could use to meet the standard, leaving just three:

- increased efficiency for coal plants,
- greater utilization of natural gas plants, and
- increased renewable sources.

In the final rule, the EPA provided more flexibility in achieving interim goals by phasing in the reduction, giving states the option to set their own interim compliance Glide Path, and pushing the start of compliance to 2022. The EPA also adjusted the 2012 baseline to address hydroelectricity variability and provided specific CO₂ mass targets by year for each state.

States have broad flexibility to pick a rate-based or mass-based approach, to design compliance options, and to decide how to allocate credits and whether to allow trading. The EPA also gave states the option of seeking additional time, if necessary, to formulate a state plan. States must submit a plan or an "initial submittal" within one year, but they can request up to two additional years to finalize a state plan. Thus, states must submit a plan for implementing CO₂ reductions to the EPA one to three years following issuance of the final rule.

In the October 2015 final version of the rule, the CO₂ goal for Montana became 26 percent more stringent than the draft version, and the CO₂ goal for Washington became 35 percent less stringent. By 2030 Montana must reduce CO₂ emissions from coal plants from 20.5 million tons of CO₂ to 11.3 million tons of CO₂, which is a 45 percent reduction in CO₂ emissions. For reference, Colstrip Units 1, 2, 3 and 4 combined emit 18 million tons of CO₂.

Soon after the EPA published the Clean Power Plan, 27 states, along with several utilities, electric cooperatives and industry groups, challenged the rule's legality in the U.S. Court of Appeals for the District of Columbia Circuit (DC Circuit). On April 28, 2017, the DC Circuit ruled to put the 27 state lawsuits challenging the plan on hold for 60 days without deciding whether the initiative is legal. That decision followed a request to halt the case from EPA.



2. STATE AND REGIONAL ACTIVITY

California Cap-and-trade Program

On December 16, 2010, the California Air Resources Board (CARB) adopted final rules to enact cap-and-trade provisions in accordance with California's Global Warming Solutions Act of 2006 (AB-32). The final rule defines the ground rules for participating in the cap-and-trade program, including enforcement and linkage to outside programs. The compliance obligations became binding on January 1, 2013.

AB 32 requires California to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. It directs power providers to account for emissions from in-state generation and imported electricity. The regulatory approach assigns the electricity importer as the "first deliverer" of imported electricity and thus the point of regulation. Cap-and-trade regulations distinguish between "specified" and "unspecified" sources of electricity. An unspecified source means electricity generation that cannot be matched to a particular generating facility; these sources are subject to the default emission factor of 0.428 metric tons (MT) of carbon dioxide equivalents (CO₂e)⁴ per MWh. A specified source is a particular generating unit or facility for which electrical generation can be confidently tracked due to full or partial ownership or due to its identification in a power contract, including any California-eligible renewable resource or an asset-owning or asset-controlling supplier. Imports from specified sources are eligible for a source-specific emission factor. To be eligible for a source-specific emission factor, imported electricity must not only come from a specified source, but any renewable energy credits associated with the electricity must be retired and verified. Imported electricity can be assigned an emission factor lower than the default emission factor only if the electricity is directly delivered, meaning the facility has a first point of interconnection with a California balancing authority or the electricity is scheduled for delivery from the specified source into a California balancing authority via a continuous transmission path.

⁴ / The major greenhouse gasses have different-sized impacts on the atmosphere. Climate scientists have developed a scale that translates the impact of other gasses into "CO₂ equivalents" to allow for an apples-to-apples comparison of the impacts of the different gasses.



Washington State

In 2008, the Washington legislature recognized that climate changes posed serious threats to the state's economic well-being, public health, natural resources and environment. To limit the impacts of climate change, the legislature required that the state reduce its greenhouse gas emissions by setting limits on those emissions (RCW 70.235). The legislature also required the limits be reviewed and recommendations be made by the Department of Ecology using the most current global, national and regional climate science. The regulations established pursuant to 70.235 to limit greenhouse gas emissions in the state are discussed in this section.

Greenhouse Gas Emissions Performance Standard

Washington state law RCW 80.80.060(4), the GHG Emissions Performance Standard (EPS), establishes a limit of 970 lbs of CO₂ emissions per MWh from new baseload generating resources, and it prohibits utilities from entering into long-term contracts of 5 years or more to acquire power from existing generating resources that exceed this standard. Contracts of less than 5 years are allowed.

This means that PSE is prohibited from building or purchasing baseload generation resources that exceed the emission performance standard. Investor-owned utilities like PSE may apply to the Washington State Utilities and Transportation Commission for exemptions based on certain reliability and cost criteria.

The law was amended in 2011. This amendment incorporated changes related to the negotiated shutdown of the TransAlta coal-fired power plant located near Centralia, Wash. The change allows TransAlta to enter into "coal transition power" contracts with Washington utilities. It exempts TransAlta and the coal transition power contracts from complying with the EPS until the dates the coal units are required to meet the EPS in 2020 (for Unit 1) and 2025 (for Unit 2).

Carbon Dioxide Mitigation Program

In 2004, the Washington state legislature passed Substitute House Bill 3141, later codified in RCW 80.70. The law requires fossil-fueled thermal power plants above 25 megawatts (net output of the electric generator) to provide mitigation for 20 percent of the CO₂ emissions it produces over a 30-year period. The mitigation requirement applies to all new power plants filing for a Site Certification Agreement or Notice of Construction after July 1, 2004. The mitigation requirement also applies to modifications of existing plants permitted by Washington's Department of Ecology or a local air quality agency that will increase power production capacity by 25 MW or more, or increase CO₂ emissions by 15 percent or more.

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If mitigation is triggered, compliance must be attained through any one or a combination of these methods:

1. Paying an “Independent Qualified Organization” to verify compliance,
2. Purchasing permanent, verifiable carbon credits, or
3. Using a self-directed mitigation program.

If the third option is chosen, the mitigation program must be identified within a plan submitted as part of the permit application. Payment to a qualified organization and the cost for a self-directed mitigation program are initially limited to an amount derived by multiplying the tons of CO₂ emissions to be mitigated by \$1.60.

Washington Clean Air Rule

On September 15, 2016, Ecology finalized the Clean Air Rule (CAR) to achieve the state’s statutory GHG emission reduction goals. Specifically, Washington has committed to reducing state GHG emissions to 1990 levels by 2020; 25 percent below 1990 levels by 2035; and 50 percent below 1990 levels by 2050. The rule went in to effect October 17, 2016.

The CAR regulations apply to certain sources that meet prescribed GHG emissions thresholds, including (1) stationary sources located in Washington (e.g., electric power generators, landfill and waste operators, chemical and material manufacturers, etc.); (2) petroleum product producers located in or importing to Washington; and (3) natural gas distributors located in Washington. Sources that fall below the applicable GHG emissions threshold may choose to participate voluntarily in the program. The threshold for the first compliance period, from 2017 to 2019, is 100,000 million metric tons of CO₂ equivalent per year (MMtCO₂e per year). Starting in 2020, the threshold is reduced every 3 years until it reaches 70,000 MMtCO₂e per year in 2035. Once a source exceeds the emissions threshold, the source is subject to CAR and must comply thereafter. However, a source may be eligible to exit the program if its GHG emissions fall below 50,000 MMtCO₂e for three consecutive years.

Due to concerns about CAR’s economic impact on entities that participate in global markets, Ecology has designated some sources as “energy-intensive, trade-exposed industries” (EITEs). EITEs include pulp and paper mills, aluminum, chemical, steel and cement facilities, and other manufacturers. EITEs, as well as petroleum product importers, are given an additional three years (until the second compliance period begins in 2020) before CAR would apply to them. EITE-covered parties also are offered an alternative and potentially less stringent compliance pathway that permits use of efficiency-based, rather than mass-based, GHG emission reduction targets. Non-EITE parties, on the other hand, must reduce emissions by 1.7 percent from their baseline GHG emissions each year until 2035.



If a covered party has attributed emissions above its emission reduction pathway level, the party must acquire emission reduction units (ERUs) from other sources equal to its excess emissions. An ERU represents one MtCO₂e per year. The ERUs can be generated by (i) other affected sources that reduce emissions below their emission reduction pathway level; (ii) acquiring allowances from other states or provinces that have established, multi-sector GHG programs (such as the CARB cap-and-trade program); or (iii) a limited list of activities that reduce or abate GHG emissions in Washington. At the end of each three-year compliance period, covered parties must submit a compliance report to Ecology. The compliance report must contain: (1) a record of ERUs generated; (2) a record of ERUs banked; (3) a record of ERU transactions; and (4) documentation that a third-party verified the compliance report. Ecology plans to develop a registry to track ERUs and also create an ERU reserve to encourage economic growth and support environmental justice.

Ecology estimates that CAR will cost between \$1.4 billion to \$2.8 billion over 20 years. The department assumes that covered parties will be able to directly reduce their emissions at a marginal cost of \$23 to \$57 per ERU. It also projects that covered parties will have the option of reducing emissions through projects at a marginal cost of \$5 to \$29 per ERU and/or obtain allowances or renewable energy credits (RECs) at a marginal cost of \$3 to \$14 per ERU.

Renewable Portfolio Standards (RPS)

Renewable portfolio standards require utilities to obtain a specific portion of their electricity from renewable energy resources. Of the 11 Western interconnection states, eight have binding renewable energy targets, one has a voluntary goal, and two have no RPS in place. PSE has met Washington's RPS requirement to meet 3 percent of load with renewable resources for target years 2012-2015 and is on track to meet the RPS requirements of 9 percent for 2016-2019 and 15 percent by 2020. RPS provisions vary widely among the different jurisdictions in the absence of a federal mandate. Differences include the specific portion of renewable resources required, the timeline to meet the requirements, the types of resources that qualify as renewable, the geographic location from which renewable resources can be sourced, eligible commercial on-line dates and any applicable technology carve-outs (such as solar). The result is a patchwork of regulatory mandates, evolving regulations and segregated environmental markets. Managing these moving parts is complex from both a resource acquisition perspective and an environmental markets perspective.

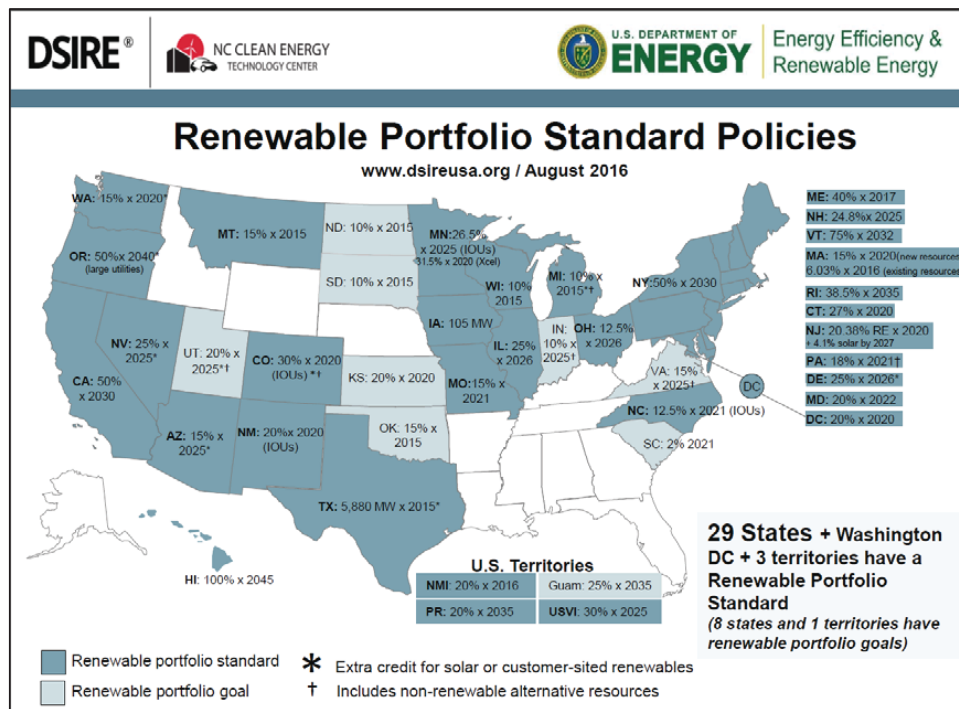
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PSE must actively monitor RPS requirements throughout the Western region, because the interconnectedness of the grid and regional energy markets means that changes in one state can have a pronounced impact on the entire system. In particular, PSE pays close attention to requirements in Oregon, California and Idaho (which currently has no RPS).

Figure C-1, below, illustrates the wide variety of RPS requirements that exist. The table in Figure C-2 lists the current RPS requirements for each state within the Western Interconnect.⁵

Figure C-1: RPS Requirements by State



⁵ / Per Figure C-2, State RPS and Eligible Technologies are drawn from the Western Interstate Energy Board's publication *Exploring and Evaluating Modular Approaches to Multi-State Compliance with EPA's Clean Power Plan in the West*, April 29, 2015, with updated RPS requirements from DSIRE.

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Figure C-2: RPS Requirements for States in the Western Interconnect

| STATE | RPS | Renewable Generation as of 10/14 | ELIGIBLE RENEWABLE ENERGY |
|------------|--|----------------------------------|---|
| Arizona | 15% by 2025 | 294 GWh | Solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, geothermal heat pumps, combined heat and power (CHP)/cogeneration (CHP only counts when the source fuel is an eligible RE resource), solar pool heating (commercial only), daylighting (non-residential only), solar space cooling, solar HVAC, anaerobic digester, small hydroelectric, fuel cells using renewable fuels, geothermal direct-use, additional technologies upon approval |
| California | 20% by 12/31/2013 25% by 12/31/2016 33% by 12/31/2020 40% by 12/31/2024 45% by 12/31/2027 50% by 12/31/2030 | 3,350 GWh | Solar thermal electric, photovoltaics, landfill gas, wind, biomass, geothermal electric, municipal solid waste, energy storage, anaerobic digestion, small hydroelectric, tidal energy, wave energy, ocean thermal, biodiesel, and fuel cells using renewable fuels |
| Colorado | Investor-owned utilities (IOUs): 30% by 2020; Co-ops serving >100,000 meters: 20% by 2020; Co-ops serving <100,000 meters: 10% by 2020; Municipal utilities serving >40,000 customers: 10% by 2020 | 666 GWh | Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, recycled energy, coal mine methane (if the Colorado Public Utilities Commission determines it is a GHG-neutral technology), pyrolysis of municipal solid waste (if the Commission determines it is a GHG-neutral technology), anaerobic digester, and fuel cells using renewable fuels |
| Idaho | None | 287 GWh | N/A |
| Montana | 15% by 2015 | 197 GWh | Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, compressed air energy storage, battery storage, flywheel storage, pumped hydro (from eligible renewables), anaerobic digester, and fuel cells using renewable fuels |
| New Mexico | IOUs: 20% by 2020; Rural electric cooperatives: 10% by 2020 | 203 GWh | Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, zero emission technology with substantial long-term production potential, anaerobic digester, and fuel cells using renewable fuels |
| Nevada | 25% by 2025 | 357 GWh | Solar water heat, solar space heat, solar thermal electric, solar thermal process heat, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, waste tires (using microwave reduction), energy recovery processes, solar pool heating, anaerobic digestion, biodiesel, and geothermal direct use |
| Oregon | Large IOUs: 50% by 2040; large consumer-owned utilities: 25% by 2025; small utilities: 10% by 2025; smallest utilities: 5% by 2025 | 499 GWh | Solar thermal electric, photovoltaics, landfill gas, wind, biomass, hydroelectric, geothermal electric, municipal solid waste, hydrogen, anaerobic digestion, tidal energy, wave energy, and ocean thermal |
| Utah | 20% of adjusted retail sales by 2025 | 90 GWh | Solar water heat, solar space heat, geothermal electric, solar thermal electric, solar photovoltaics, wind (all), biomass, hydroelectric, hydrogen, municipal solid waste, combined heat & power, landfill gas, tidal, wave, ocean thermal, wind (small), hydroelectric (small), anaerobic digestion |
| Washington | 15% by 2020 and all cost-effective conservation | 631 GWh | Solar thermal electric, photovoltaics, landfill gas, wind, bio-mass, incremental and low-head hydroelectric, geothermal electric, anaerobic digestion, tidal energy, wave energy, ocean thermal, and biodiesel |
| Wyoming | None | 357 GWh | N/A |

NOTE: Approved technologies are generated in the state (excluding hydro generation). In many cases, generation in one state is used for RPS compliance in a different state.



California Renewable Portfolio Standard

The size and aggressiveness of California's RPS mandate make it the region's primary driver of renewable resource availability and cost, REC product availability and cost, and transmission and integration.

California has one of the most aggressive RPS mandates in the nation. Senate Bill 1078 established the California RPS program in 2002. It was accelerated in 2006 by Senate Bill 107. In 2008, Executive Order S-14-08 increased the requirement to 33 percent by 2020. Two RPS bills were passed at the end of the 2009 legislative session, however, the governor elected not to sign either. Instead, he signed Executive Order S-21-09, which allowed the California Air Resources Board (CARB), under its AB 32 authority, to adopt a regulation consistent with the 33 percent RPS target established in Executive Order S-14-08. In 2010, the CARB adopted its Renewable Electricity Standard (RES), requiring 33 percent by 2020. Legislative endorsement of this standard was achieved when Governor Jerry Brown signed Senate Bill SB 2 (1X) into law in April 2011.

SB 2 (1X) extends the original RPS goal from 20 percent of retail sales by the end of 2010 to 33 percent of retail sales by 2020 for all California investor-owned utilities (IOUs), electric service providers (ESPs) and the community choice aggregators (CCAs); it also obligates publicly owned utilities to meet these goals. In addition, the new law modifies many details of the program and creates portfolio content categories for RPS procurement. The California Public Utilities Commission (CPUC) and the California Energy Commission (CEC) were tasked with implementing the expanded RPS. In December 2011, the CPUC issued a decision that addressed the criteria for inclusion in each of the new RPS portfolio content categories and the percentage of the annual procurement target that could be sourced from unbundled RECs. The use of unbundled renewable energy credits was capped at 25 percent of a utility's RPS requirement through December 31, 2013; this steps down to 15 percent in 2014 and 10 percent in 2017. The decision applies to contracts and ownership agreements entered into after June 1, 2010.



2017 PSE Integrated Resource Plan

Electric Resources and Alternatives

This appendix describes PSE's existing electric resources; current electric resource alternatives and the viability and availability of each; and estimated ranges for capital and operating costs.¹

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¹ / Operating costs are defined as operation and maintenance costs, insurance and property taxes. Capital costs are defined as depreciation and carrying costs on capital expenditures.



1. RESOURCE TYPES

It is helpful to understand some of the distinctions used to classify electric resources.

Supply-side and Demand-side

Both of these types of resources are capable of enabling PSE to meet customer loads. Supply-side resources provide electricity to meet load, and these resources originate on the utility side of the meter. Demand-side resources reduce load and originate on the customer side of the meter. An “integrated” resource plan includes both supply- and demand-side resources.

SUPPLY-SIDE RESOURCES for PSE include:

- PSE’s generating plants, including baseload gas, peakers, coal, water and wind plants
- Long-term contracts with independent producers to supply electricity to PSE (these have a variety of fuel sources)
- Transmission contracts with Bonneville Power Administration (BPA) to carry electricity from short-term wholesale market purchases to PSE’s service territory

DEMAND-SIDE RESOURCES for PSE include:

- Energy efficiency programs
- Customer programs

The contribution that demand-side programs make to meeting resource need is accounted for as a reduction in demand for the IRP analysis.

Thermal and Renewable

These supply-side resources are distinguished by the type of fuel they use.

THERMAL RESOURCES use fossil or other fuels to generate electricity (gas, oil, coal, uranium). PSE’s gas-fired and coal-fired generating facilities are thermal resources.

RENEWABLE RESOURCES use renewable fuels such as water, wind, sunlight and biomass to generate electricity. Hydroelectricity and wind generation are PSE’s primary renewable resources.



Baseload, Peaking, Intermittent and Storage

These distinctions refer to how the resource functions within the system.

BASELOAD RESOURCES produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand. Baseload resources usually have a high fixed cost but low marginal cost and thus could be characterized as the most efficient units of the fleet.

For PSE, baseload resources can be divided into two categories: thermal and hydro. These have different dispatching capabilities. Thermal baseload plants can take up to several hours to start and have limited ability to ramp up and down quickly, so they are not very flexible. Hydro plants, on the other hand, are very flexible and are typically the preferred resource to use to balance the system.

PSE's three sources of baseload energy are baseload gas plants, hydroelectric generation and coal-fired generation.

PEAKING RESOURCES are quick-starting units that can ramp up and down quickly in order to meet short-term spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. Peaking resources generally have a lower fixed cost but are less efficient than baseload plants. Historically, gas-fueled peaking units have low capacity factors because they are often not economical to operate compared to market purchases.

The flexibility of peaking resources will become more important in the future as new renewable resources are added to the system and as PSE participates in the Energy Imbalance Market.

PSE's peaking resources include simple-cycle combustion turbines and hydroelectric plants that can perform peaking functions in addition to baseload functions.

INTERMITTENT RESOURCES provide power that offers the company limited discretion in the timing of delivery. Renewable resources like wind and solar are intermittent resources because their generating patterns vary as a result of uncontrollable environmental factors, so the timing of delivery from these resources doesn't necessarily align with customer demand in the Puget Sound area. As a result, additional resources are required to back up intermittent resources in case the wind dies down or the sun goes behind a cloud.

PSE's largest intermittent resource is wind generation, and to a lesser extent, rooftop solar generation, which has achieved some market penetration within PSE's system. Smaller

Appendix D: Electric Resources



intermittent resources include small power production within the system and the 10 aMW of energy PSE is required to take from co-generation.

For planning purposes, PSE includes the randomness, forced outage rates and curtailments of each particular type of technology in its analysis.

ENERGY STORAGE has the potential to provide multiple services to the system, including efficiency, reliability, capacity arbitrage, ancillary services and backup power for intermittent renewable generation. It is capable of benefiting all parts of the system – generation, transmission, distribution and end-use customers; however, these benefits vary by location and the specific application of the product. For instance, a battery in one location could be installed to relieve transmission congestion and thereby defer the cost of transmission upgrades, while a battery at another location might be used to back up intermittent wind generation and reduce integration costs. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources. Detailed modeling is required to fully evaluate the value of energy storage at the sub-hourly level.

Capacity Values

The tables on the following pages describe PSE's existing electric resources using the net maximum capacity of each plant in megawatts (MW). Net maximum capacity is the capacity a unit can sustain over a specified period of time – in this case 60 minutes – when not restricted by ambient conditions or de-ratings, less the losses associated with auxiliary loads and before the losses incurred in transmitting energy over transmission and distribution lines. This is consistent with the way plant capacities are described in the annual 10K report² that PSE files with the U.S. Securities and Exchange Commission and the Form 1 report filed with the Federal Energy Regulatory Commission (FERC).

Different plant capacity values are referenced in other PSE publications because plant output varies depending upon a variety of factors, among them ambient temperature, fuel supply, whether a natural gas plant is using duct firing, whether a combined-cycle facility is delivering steam to a steam host, outages, upgrades and expansions. To describe the relative size of resources, it is necessary to select a single reference point based on a consistent set of assumptions. Depending on the nature and timing of the discussion, these assumptions – and thus the expected capacity – may vary.

² / PSE's most recent 10K report was filed with the U.S. Securities and Exchange Commission in March 2017 for the year ending December 31, 2016. See <http://www.pugetenergy.com/pages/filings.html>.



2. EXISTING RESOURCES INVENTORY

Supply-side Thermal Resources

Coal

Reliable, low-cost electricity from the Colstrip generating plant currently supplies 18 percent of PSE's baseload energy needs.

THE COLSTRIP GENERATING PLANT. Located in eastern Montana about 120 miles southeast of Billings, the plant consists of four coal-fired steam electric plant units. PSE owns 50 percent each of Units 1 & 2 and 25 percent each of Units 3 & 4. PSE's total ownership in Colstrip contributes 677 MW net maximum capacity to the existing portfolio.

Baseload Gas

PSE's six baseload gas plants (combined-cycle combustion turbines or CCCTs) have a combined net maximum capacity of 1,293 MW and supply 19 to 27 percent of PSE's baseload energy needs, depending on market heat rates and plant availabilities. In a CCCT, the heat that a simple-cycle combustion turbine produces when it generates power is captured and used to create additional energy. This makes it a more efficient means of generating power than the peakers (simple-cycle turbines) listed below. PSE's baseload gas fleet includes the following.

MINT FARM is located in Cowlitz County, Wash.

FREDERICKSON 1 is located in Pierce County, Wash. (PSE owns 49.85 percent of this plant; the remainder of the plant is owned by Atlantic Power Corporation.)

GOLDENDALE is located in Klickitat County, Wash.

ENCOGEN, FERNDALE and **SUMAS** are located in Whatcom County, Wash.

Appendix D: Electric Resources



Figure D-1: PSE's Owned Baseload Coal and Gas Resources

| POWER TYPE | UNITS | PSE OWNERSHIP | NET MAXIMUM CAPACITY (MW) ¹ |
|-------------------|-------------------------------|---------------|--|
| Coal | Colstrip 1 & 2 ² | 50% | 307 |
| Coal | Colstrip 3 & 4 | 25% | 370 |
| Total Coal | | | 677 |
| CCCT | Encogen | 100% | 165 |
| CCCT | Ferndale ³ | 100% | 253 |
| CCCT | Frederickson 1 ^{3,4} | 49.85% | 136 |
| CCCT | Goldendale ³ | 100% | 315 |
| CCCT | Mint Farm ³ | 100% | 297 |
| CCCT | Sumas | 100% | 127 |
| Total CCCT | | | 1,293 |

NOTES

1. Net maximum capacity reflects PSE's share only.
2. In July 2016, PSE reached a settlement with the Sierra Club to retire Colstrip Units 1 and 2 no later than July 1, 2022.
3. Maximum capacity of Ferndale, Frederickson 1, Goldendale and Mint Farm includes duct firing capacity.
4. Frederickson 1 CCCT unit is co-owned with Atlantic Power Corporation - USA.

Peakers

These gas-fired simple-cycle combustion turbines (SCCTs) provide important peaking capability and help us to meet operating reserve requirements. The company displaces these resources when their energy is not needed to serve load or when lower-cost energy is available for purchase. PSE's four peakers contribute a net maximum capacity of 612 MW. When pipeline capacity is not available to supply them with natural gas fuel, these units are capable of operating on distillate fuel oil.

FREDONIA Units 1, 2, 3 and 4 are located near Mount Vernon, Wash., in Skagit County.

WHITEHORN Units 2 and 3 are located in northwestern Whatcom County, Wash.

FREDERICKSON Units 1 and 2 are located south of Seattle in east Pierce County, Wash.

Appendix D: Electric Resources



Ownership and net maximum capacity are shown in Figure D-2 below.

Figure D-2: PSE's Owned Peakers (Simple-cycle Combustion Turbines)

| NAME | PSE OWNERSHIP | NET MAXIMUM CAPACITY (MW) |
|--------------------|---------------|---------------------------|
| Fredonia 1 & 2 | 100% | 207 |
| Fredonia 3 & 4 | 100% | 107 |
| Whitehorn 2 & 3 | 100% | 149 |
| Frederickson 1 & 2 | 100% | 149 |
| Total SCCT | | 612 |

Supply-side Renewable Resources

Hydroelectricity

Hydroelectricity supplies between 19 and 24 percent of PSE's baseload energy needs. Even though restrictions to protect endangered species limit the operational flexibility of hydroelectric resources, these generating assets are valuable because of their ability to instantly follow customer load and because of their low cost relative to other power resources. High precipitation and snowpack levels generally allow more power to be generated, while low-water years produce less power. During low-water years, the utility must rely on other, more expensive, self-generated power or market resources to meet load. The analysis conducted for this IRP accounts for both seasonality and year-to-year variations in hydroelectric generation. PSE owns hydroelectric projects in western Washington and has long-term purchased-power contracts with three public utility districts (PUDs) that own and operate large dams on the Columbia River in central Washington. In addition, we contract with smaller hydroelectric generators located within PSE's service territory.

Appendix D: Electric Resources



Figure D-3: PSE Owned and Contracted Hydroelectric

| PLANT | OWNER | PSE SHARE % | NET MAXIMUM CAPACITY (MW) ¹ | CONTRACT EXPIRATION DATE |
|---------------------------|-----------------|-------------|--|--------------------------|
| Upper Baker River | PSE | 100 | 91 | None |
| Lower Baker River | PSE | 100 | 109 | None |
| Snoqualmie Falls | PSE | 100 | 48 ² | None |
| Total PSE-owned | | | 248 | |
| Wells | Douglas Co. PUD | 29.89 | 231 ³ | 8/31/18 ³ |
| Rocky Reach | Chelan Co. PUD | 25.0 | 325 | 10/31/31 |
| Rock Island I & II | Chelan Co. PUD | 25.0 | 156 | 10/31/31 |
| Wanapum | Grant Co. PUD | 0.64 | 9 | 03/31/52 |
| Priest Rapids | Grant Co. PUD | 0.64 | 8 | 03/31/52 |
| Mid-Columbia Total | | | 725 | |
| Total Hydro | | | 973 | |

NOTES

1. Net maximum capacity reflects PSE's share only.

2. FERC license authorizes the full 54.4 MW; however, the project's water right, issued by the state Department of Ecology, limits flow to 2,500 cfs, and therefore output, to 47.7 MW.

3. Wells has one turbine out for the next many years. This reduces its total peaking capability from 840 MW to 774 MW and PSE's share to 231 MW. PSE has entered into a new agreement to purchase Wells project output through 2028 following expiration of the current agreement; additional details provided in the text below. For the purposes of this IRP, PSE assumes this contract will terminate.



BAKER RIVER HYDROELECTRIC PROJECT. This facility is located in Washington's north Cascade Mountains. It consists of two dams and is the largest of PSE's hydroelectric power facilities. The project contains modern fish-enhancement systems including a "floating surface collector" (FSC) to safely capture juvenile salmon in Baker Lake for downstream transport around both dams, and a second, newer FSC on Lake Shannon for moving young salmon around Lower Baker Dam. In addition to generating electricity, the project provides public access for recreation and significant flood-control storage for people and property in the Skagit Valley. Hydroelectric projects require a license from FERC for construction and operation. These licenses normally are for periods of 30 to 50 years, and then they must be renewed to continue operations. In October 2008, after a lengthy renewal process, FERC issued a 50-year license allowing PSE to generate approximately 710,000 MWh per year (average annual output) from the Baker River project. PSE also completed construction of a new powerhouse and 30 MW generating unit at Lower Baker dam in July 2013. The new unit improves river flows for fish downstream of the dam while producing more than 100,000 additional MWh of energy from the facility each year. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.

SNOQUALMIE FALLS HYDROELECTRIC PROJECT. Located east of Seattle on the Cascade Mountains' western slope, the Snoqualmie Falls Hydroelectric Project consists of a small diversion dam just upstream from Snoqualmie Falls and two powerhouses. The first powerhouse, which is encased in bedrock 270 feet beneath the surface, was the world's first completely underground power plant. Built in 1898-99, it was also the Northwest's first large hydroelectric power plant. FERC issued PSE a 40-year license for the Snoqualmie Falls Hydroelectric Project in 2004. The terms and conditions of the license allow PSE to generate an estimated 275,000 MWh per year (average annual output). The facility recently underwent a major redevelopment project which included substantial upgrades and enhancements to the power-generating infrastructure and public recreational facilities. Efficiency improvements completed as part of the redevelopment will increase annual output by over 22,000 MWh. This incremental energy qualifies as a renewable resource under the State of Washington Energy Independence Act, RCW 19.285.



MID-COLUMBIA LONG-TERM PURCHASED POWER CONTRACTS. Under long-term purchased-power agreements with three PUDs, PSE purchases a percentage of the output of five hydroelectric projects located on the Columbia River in central Washington. PSE pays the PUDs a proportionate share of the cost of operating these hydroelectric projects. The current agreement with Douglas County PUD for the purchase of 29.89 percent of the output of the Wells project expires in 2018. In March 2017, PSE entered into a new power purchase agreement with Douglas County PUD that begins upon expiration of the current agreement and has a 10-year term. Under this new agreement PSE will continue to purchase a percentage of the output from the Wells project. The actual percentage available to PSE will be calculated annually and based primarily on Douglas PUD's retail load requirements – as Douglas PUD's retail load grows, they will reserve a greater share of Wells project output for their customers and the percentage PSE purchases will decline. PSE expects to purchase approximately 30 percent of Wells output (232 MW) beginning at the end of 2018 with that share declining to approximately 22 percent (170 MW) by the end of the contract term.³ PSE has a 20-year agreement with Chelan County PUD for the purchase of 25 percent of the output of the Rocky Reach and Rock Island projects that extends through October 2031. PSE has an agreement with Grant County PUD for a 0.64 percent share of the combined output of the Wanapum and Priest Rapids developments. The agreement with Grant County PUD will continue through the term of the project's FERC license, which ends March 31, 2052.

Wind Energy

PSE is the largest utility owner and operator of wind-power facilities in the Northwest. Combined, the maximum capacity of the company's three wind farms is 773 MW. They are forecast to produce on average, more than 2 million MWh of power per year, which is about 8 to 9 percent PSE's energy needs. These resources are integral to meeting renewable resource commitments.

HOPKINS RIDGE. Located in Columbia County, Wash., Hopkins Ridge has an approximate maximum capacity of 157 MW. It began commercial operation in November 2005.

WILD HORSE. Located in Kittitas County near Ellensburg, Wash., Wild Horse has an approximate maximum capacity of 273 MW. It came online in December 2006 at 229 MW and was expanded by 44 MW in 2010.

LOWER SNAKE RIVER. PSE brought online its third and largest wind farm in February 2012. The 343 MW facility is located in Garfield County, Wash.

³ / The percentages referenced here are annual averages. Under the new agreement the percentage available to PSE will vary by season with a higher percentage available during the spring and summer months and a lower percentage available during the winter months. During the peak winter months (December through February), PSE's expected share of the output begins at about 26 percent (206 MW) and declines to about 14 percent (108 MW) by the end of the contract term.



Solar Energy

The Wild Horse facility contains 2,723 photovoltaic solar panels, including the first made-in-Washington solar panels.⁴ The array can produce up to 0.5 MW of electricity with full sun. Panels can also produce power under cloudy skies – 50 to 70 percent of peak output with bright overcast and 5 to 10 percent with dark overcast. The site receives approximately 300 days of sunshine per year, roughly the same as Houston, Tex. On average this site generates 780 MWhs of power per year.

Energy Storage

The Glacier Battery Demonstration Project was installed in early 2017. The 2 MW / 4.4 MWh lithium-ion battery storage system is located in Whatcom County, Wash. The Glacier battery will serve as a short-term backup power source (up to 2.2 hours at capacity with a full charge) to a core "island" of businesses and residences during outages, reduce system load during periods of high demand, and help balance energy supply and demand. The project was funded in part by a \$3.8 million Smart Grid Grant from the State of Washington Department of Commerce. Under the terms of the grant, Pacific Northwest National Laboratories is performing a study to evaluate the battery's capability.

Figure D-4 presents details about the company's wind, solar and energy storage resources.

Figure D-4: PSE's Owned Renewable Resources

| POWER TYPE | UNITS | PSE OWNERSHIP | NET MAXIMUM CAPACITY (MW) |
|-------------------------------|--|---------------|---------------------------|
| Wind | Hopkins Ridge | 100% | 157 |
| Wind | Lower Snake River, Phase 1 | 100% | 343 |
| Wind | Wild Horse | 100% | 273 |
| Total Wind | | | 773 |
| Solar | Wild Horse Solar Demonstration Project | 100% | 0.5 |
| Energy Storage | Glacier Battery Demonstration Project | 100% | 2.0 |
| Total Other Renewables | | | 2.5 |
| Total Renewables | | | 775.5 |

⁴ / Outback Power Systems (now Silicon Energy) in Arlington produced the first solar panels in Washington. The Wild Horse Facility was Outback Power Systems' launch facility, utilizing 315 of their panels. The remaining panels were produced by Sharp Electronics in Tennessee.



Supply-side Contract Resources

Long-term contracts consist of agreements with independent producers and other utilities to supply electricity to PSE. Fuel sources include hydropower, gas, coal, waste products and system deliveries without a designated supply resource. These contracts are summarized in Figure D-5. Short-term wholesale market purchases negotiated by PSE's energy trading group are not included in this listing.

POINT ROBERTS PPA. This contract provides for power deliveries to PSE's retail customers in Point Roberts, Wash. The Point Roberts load, which is physically isolated from PSE's transmission system, connects to British Columbia Hydro's electric distribution facilities. We pay a fixed price for the energy during the term of the contract.

BAKER REPLACEMENT. Under a 20-year agreement signed with the U.S. Army Corps of Engineers (COE) PSE provides flood control for the Skagit River Valley. Early in the flood control period, we draft water from the Upper Baker reservoir at the request of the COE. Then, during periods of high precipitation and runoff between October 15 and March 1, we store water in the Upper Baker reservoir and release it in a controlled manner to reduce downstream flooding. In return, PSE receives a total of 7,000 MWhs of power and 7 MW of net maximum capacity from BPA in equal increments per month for the months of November through February to compensate for the lower generating capability caused by reduced head due to the early drafting at the plant during the flood control months.

ELECTRON HYDROELECTRIC PROJECT PPA. In November 2014, PSE sold the Electron Project and associated water rights to an independent power producer. PSE will purchase the output of the Electron Project under a power purchase agreement with the new owner that extends through 2026.



PACIFIC GAS & ELECTRIC COMPANY (PG&E) SEASONAL EXCHANGE. Each calendar year PSE exchanges with PG&E 300 MW of seasonal capacity, together with 413,000 MWh of energy, on a one-for-one basis, under this system-delivery power exchange contract. PSE is a winter-peaking utility and PG&E is a summer-peaking utility, so PG&E has the right to call for the power in the months of June through September, and PSE has the right to call for the power in the months of November through February.

CANADIAN ENTITLEMENT RETURN. Under a treaty between the United States and Canada, one-half of the firm power benefits produced by additional storage capability on the Columbia River in Canada accrue to Canada. PSE's benefits and obligations from this storage are based on the percentage of our participation in the Columbia River projects. Agreements with the Mid-Columbia PUDs specify PSE's share of the obligation is to return one-half of the firm power benefits to Canada during peak hours until the expiration of the PUD contracts or expiration of the Columbia River Treaty, whichever occurs first. The Columbia River Treaty will not expire prior to 2024. This is energy that PSE provides rather than receives, so it is a negative number. The energy returned during 2016 was approximately 19.6 aMW with a peak capacity return of 34.9 MW.

COAL TRANSITION PPA. Under the terms of this agreement, PSE began to purchase 180 MW of firm, baseload coal transition power from TransAlta's Centralia coal plant in December 2014. On December 1, 2015, the contract increased to 280 MW. From December 2016 to December 2024 the contract is for 380 MW, and in the last year the contract volume drops to 300 MW. This contract advances a separate TransAlta agreement with state government and the environmental community to phase out coal-fired power generation in Washington by 2025. In 2011, the state Legislature passed a bill codifying a collaborative agreement between TransAlta, lawmakers, environmentalists and labor representatives. The timelines agreed to by the parties enable the state to make the transition to cleaner fuels, while preserving the family-wage jobs and economic benefits associated with the low-cost, reliable power provided by the Centralia plant. The legislation allows long-term contracts, through 2025, for sales of coal transition power associated with the 1,340 MW Centralia facility, Washington's only coal-fired plant.

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KLONDIKE III PPA. PSE's wind portfolio includes a power purchase agreement with Iberdrola Renewables for a 50 MW share of electricity generated at the Klondike III wind farm in Sherman County, Ore. The wind farm has 125 turbines with a project capacity of nearly 224 MW. This agreement remains in effect until November 2026.

SKOOKUMCHUCK WIND PPA. PSE has recently executed a 20-year power purchase agreement with RES to purchase the output from the Skookumchuck Wind Project. The wind project is currently in development in Thurston and Lewis counties, and it is expected to be in service by the end of 2018. The output from the facility will be used to serve subscribers to PSE's new Green Direct program, which is described in the Demand-side Customer Programs section of this appendix.

HYDROELECTRIC PPAs. Among PSE's power purchase agreements are several long-term contracts for the output of production from hydroelectric projects within its balancing area. These contracts were established through PSE's RFP process and are shown in Figure D-5 below. The projects are run-of-river and do not provide any flexible capacity.

SCHEDULE 91 CONTRACTS. PSE's portfolio includes a number of electric power contracts (included in Figure D-5) with small power producers in PSE's electric service area. These Qualifying Facilities offer output pursuant to WAC-107-095. Part one of this statute states that "A utility must purchase electric energy, electric capacity, or both from a qualifying facility on terms that do not exceed the utility's avoided costs for such electric energy, electric capacity, or both." A qualifying facility is defined by WAC 480-107-007 as a generating facility "that meet(s) the criteria specified by the FERC in 18 C.F.R. Part 292 Subpart B."

Appendix D: Electric Resources



Figure D-5: Long-term Contracts for Electric Power Generation (continued next page)

| NAME | POWER TYPE | CONTRACT EXPIRATION | CONTRACT CAPACITY (MW) ¹ |
|--|----------------------|------------------------|-------------------------------------|
| Pt. Roberts ² | System | 9/30/2019, but ongoing | 8 |
| Baker Replacement | Hydro | 9/30/2029 | 7 |
| Electron PPA | Hydro | 12/31/2026 | 23.8 |
| PG&E Seasonal Exchange-PSE | Thermal | Ongoing | 300 |
| Canadian EA | Hydro | 09/15/2024 | (34.9) |
| Coal Transition PPA | Transition Coal | 12/31/2025 | 380 ³ |
| Klondike III PPA | Wind | 11/30/2027 | 50 |
| Skookumchuck Wind | Wind | 12/31/2038 | 130 ⁴ |
| Twin Falls PPA | Hydro-QF | 2/28/2025 | 15.3 |
| Koma Kulshan PPA | Hydro-QF | 3/31/2037 | 10.9 |
| Weeks Falls PPA | Hydro-QF | 11/30/2022 | 4.6 |
| Farm Power Lynden | Schedule 91 - Biogas | 12/31/2019 | 0.75 |
| Farm Power Rexville | Schedule 91 - Biogas | 12/31/2019 | 0.75 |
| Rainier Biogas | Schedule 91 - Biogas | 12/31/2020 | 1.0 |
| Vanderhaak Dairy | Schedule 91 - Biogas | 12/31/2019 | 0.60 ⁵ |
| Edaleen Dairy | Schedule 91 - Biogas | 12/31/2021 | 0.75 |
| Van Dyk - Holsteins Dairy | Schedule 91 - Biogas | 12/31/2020 | 0.47 |
| Blocks Evergreen Dairy | Schedule 91 - Biogas | 12/31/2031 | .019 |
| Bio Energy Washington ⁶ | Schedule 91 - Biogas | 12/31/2021 | 4.88 |
| Emerald City Renewables ⁷ | Schedule 91 - Biogas | 12/31/2026 | 4.50 |
| Skookumchuck Hydro | Schedule 91 - Hydro | 12/31/2020 | 1.0 |
| Smith Creek | Schedule 91 - Hydro | 12/31/2020 | 0.12 |
| Black Creek | Schedule 91 - Hydro | 3/25/2021 | 4.2 |
| Nooksack Hydro | Schedule 91 - Hydro | 12/31/2021 | 3.5 |
| Sygitowicz - Kingdom Energy | Schedule 91 - Hydro | 12/31/2030 | .45 |
| Island Solar | Schedule 91 - Solar | 5/09/2021 | 0.075 |
| Finn Hill Solar (Lake Wash SD) | Schedule 91 - Solar | 12/31/2021 | 0.355 |
| CC Solar #1, LLC and CC Solar #2, LLC (combined) | Schedule 91 - Solar | 1/1/2021 | 0.026 |
| IKEA | Schedule 91 - Solar | 12/31/2031 | 0.331 |
| Knudson Wind | Schedule 91 - Wind | 12/31/2019 | 0.108 |
| 3 Bar-G Wind | Schedule 91 - Wind | 12/31/2019 | 1.395 |
| Swauk Wind | Schedule 91 - Wind | 12/31/2021 | 4.25 |
| Total | | | 794.2 |



NOTES

1. Capacity reflects PSE share only.
2. The contract to provide power to PSE's Point Roberts customers expires 9/30/2017, but is expected to be renegotiated and continue past that date as Point Roberts is not physically interconnected to PSE's system.
3. The capacity of the TransAlta Centralia PPA is designed to ramp up over time to help meet PSE's resource needs. According to the contract, PSE will receive 280 MW from 12/1/2015 to 11/30/2016, 380 MW from 12/1/2016 to 12/31/2024 and 300 MW from 1/1/2025 to 12/31/2025.
4. PSE is currently anticipating that contract capacity will be approximately 130 MW; however, actual capacity may be slightly higher.
5. VanderHaak has two generators with a combined capacity of .60 MW. However, VanderHaak primarily runs only the larger generator, which has a capacity of .45 MW.
6. Schedule 91 contract is a power purchase from Bio Energy, which provides gas under the Cedar Hills contract. When Bio Energy is producing gas, it will not be producing power to sell to PSE under Schedule 91. As gas is currently being produced at Cedar Hills, the Schedule 91 contract volume is considered to be zero.
7. Emerald City Renewables was formerly known as BioFuels Washington.

Supply-side Transmission Resources

Mid-C Transmission Resources

Transmission capacity to the Mid-Columbia (Mid-C) market hub gives PSE access to the principal electricity market hub in the Northwest, which is one of the major trading hubs in the Western Electricity Coordinating Council (WECC). It is the central market for northwest hydroelectric generation. The majority of PSE's transmission to the Mid-C market is contracted from BPA on a long-term basis; in addition to these contracts, PSE also owns 450 MW of transmission capacity to Mid-C.⁵

PSE's Mid-C transmission capacity is detailed in Figure D-6 below; 1,600 MW of this capacity to the Mid-C wholesale market comprises a significant portion of the capacity required to meet PSE's peak need.⁶

EIM Transmission Resources

Starting in October 2016, 300 MW of Mid-C transmission capacity contracted from BPA on a long-term basis has been redirected for the use of Energy Imbalance Market (EIM) trades. Although these redirects reduce transmission capacity available to support PSE's peak need, PSE still maintains sufficient capacity to meet the winter peak. The 300 MW of redirected Mid-C transmission will need to be renewed on an annual basis, and this will allow PSE to reevaluate its EIM transfer capacity needs in light of future winter peak needs. Figure D-7 details the transmission capacity currently redirected for EIM.

⁵ / PSE also owns transmission and transmission contracts to other markets, in addition to the Mid-C market transmission detailed here.

⁶ / See Chapter 6, *Electric Analysis*, for a more detailed discussion of PSE reliance on wholesale market capacity to meet peak need.

Appendix D: Electric Resources



Figure D-6: Mid-C Hub Transmission Resources

| NAME | EFFECTIVE DATE | TERMINATION DATE | TRANSMISSION DEMAND (MW) |
|-------------------------------------|----------------|------------------|--------------------------|
| BPA Mid-C Transmission | | | |
| Midway | 11/1/2017 | 11/1/2022 | 100 |
| Midway | 4/1/2008 | 11/1/2035 | 5 |
| Rock Island | 7/1/2007 | 7/1/2037 | 400 |
| Rocky Reach | 11/1/2017 | 11/1/2022 | 100 |
| Rocky Reach | 11/1/2017 | 11/1/2022 | 100 |
| Rocky Reach | 11/1/2014 | 11/1/2019 | 40 |
| Rocky Reach | 11/1/2014 | 11/1/2019 | 40 |
| Rocky Reach | 11/1/2014 | 11/1/2019 | 40 |
| Rocky Reach | 11/1/2014 | 11/1/2019 | 5 |
| Rocky Reach | 11/1/2014 | 11/1/2019 | 55 |
| Rocky Reach | 9/1/2014 | 11/1/2031 | 160 |
| Vantage | 11/1/2017 | 11/1/2022 | 100 |
| Vantage | 12/1/2014 | 12/1/2019 | 19 |
| Vantage | 11/1/2014 | 3/1/2025 | 3 |
| Vantage | 11/1/2014 | 11/1/2019 | 27 |
| Vantage | 11/1/2014 | 11/1/2019 | 27 |
| Vantage | 11/1/2014 | 11/1/2019 | 27 |
| Vantage | 11/1/2014 | 11/1/2019 | 3 |
| Vantage | 11/1/2014 | 11/1/2019 | 36 |
| Vantage | 10/1/2013 | 11/1/2019 | 5 |
| Wells | 1/24/1966 | 9/1/2018 | 266 |
| NWE Purchase IR Conversion | 10/01/2016 | 10/1/2021 | 94 |
| Vantage | 3/1/2016 | 2/28/2021 | 23 |
| Total BPA Mid-C Transmission | | | 1,675 |
| PSE Owned Mid-C Transmission | | | |
| McKenzie to Beverly | - | - | 50 |
| Rocky Reach to White River | - | - | 400 |
| Total PSE Mid-C Transmission | | | 450 |
| Total Mid-C Transmission | | | 2,125 |

As shown, PSE has a total of 2,125 MW of capacity to the Mid-C market hub: 1,675 MW in BPA contracts and 450 MW of owned capacity. Figure D-6 also shows the BPA contract periods.



Figure D-7: Mid-C Hub Transmission Resources Redirected for EIM as of 8/4/17

| NAME | EFFECTIVE DATE | TERMINATION DATE | TRANSMISSION DEMAND (MW) |
|---|----------------|------------------|--------------------------|
| BPA Mid-C Transmission Redirected for EIM | | | |
| Midway | 10/1/2013 | 10/1/2018 | 115 |
| Midway | 3/1/2014 | 3/1/2019 | 35 |
| Vantage | 12/1/2014 | 12/1/2019 | 150 |
| Total BPA Mid-C Transmission Redirected for EIM | | | 300 |

Demand-side Energy Efficiency Resources

Existing demand-side resource (DSR) programs consist of:

- **ENERGY EFFICIENCY**, implemented by PSE's Customer Energy Management group
- **FUEL CONVERSION**, implemented by PSE's Customer Energy Management group
- **DISTRIBUTION EFFICIENCY**, managed by the System Planning department
- **GENERATION EFFICIENCY**, evaluated by PSE's Customer Energy Management group. (This represents energy efficiency opportunities at PSE generating facilities.)
- **DISTRIBUTED GENERATION**, overseen by the Customer Renewable Energy Programs group.

Energy efficiency is by far PSE's largest electric demand-side resource. Energy efficiency programs serve all types of customers – residential, low-income, commercial and industrial. Program savings targets are established every two years in collaboration with key external stakeholders represented by the Conservation Resource Advisory Group (CRAG) and Integrated Resource Plan Advisory Group (IRPAG). The majority of electric energy efficiency programs are funded using electric "conservation rider" funds collected from all customer classes.⁷

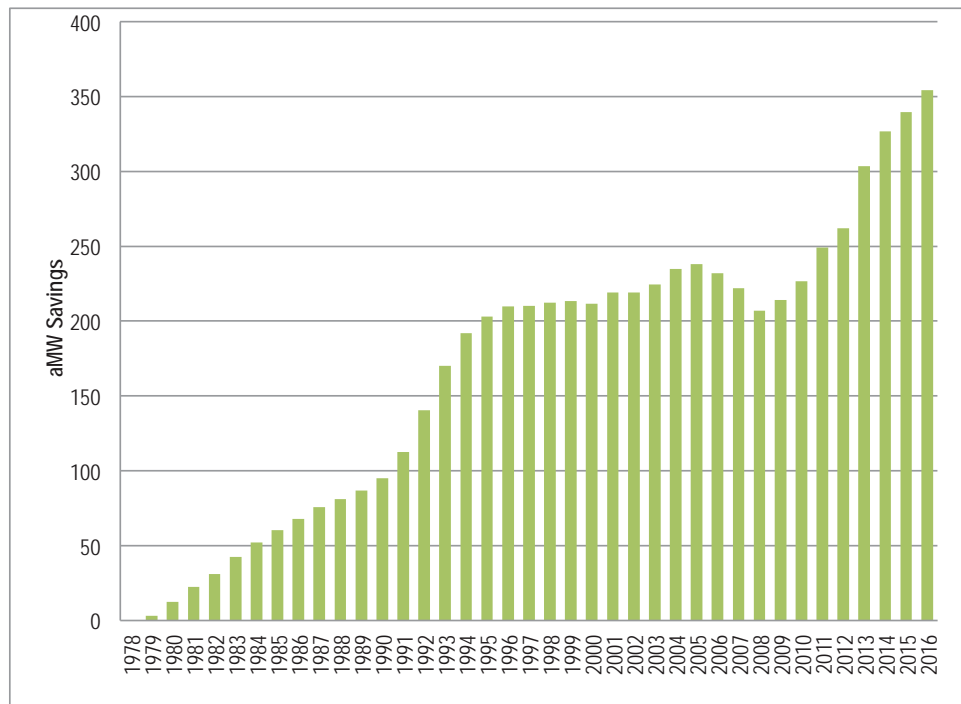
⁷ / See Electric Rate Schedule 120, Electricity Conservation Service Rider, for more information.

Appendix D: Electric Resources



Since 1978, annual first-year savings (as reported at the customer meter) have increased more than 400 percent, from 9 aMW in 1978 to 38 aMW in 2016. The cumulative investment and power savings from 1978 through 2016 are approximately \$1.3 billion and 354 aMW. The savings are adjusted for measure life, so that savings are retired at the end of the measure's life and no longer counted towards the cumulative savings. Figure D-8 shows the cumulative savings from 1978 through 2016. By 2016, those savings represented enough electrical energy to serve more than 250,000 homes for a year.

Figure D-8: Cumulative Electric Energy Savings from DSR, 1978 through 2016



In the most recently completed program cycle, the 2014-15 tariff period, energy efficiency (including fuel conversion) achieved a total savings of 75 aMW; the target for the current 2016-17 program cycle is 69.1 aMW. The savings impact from the successive program cycles is mitigated somewhat by earlier programs reaching the end of their productive lives, causing the net savings increase to be less than the program cycle savings in a given year (see Figure D-8).



Electric Energy Efficiency Programs

The savings are generally evenly split between PSE's Residential Energy Management (REM) and Business Energy Management (BEM) sectors. In the 2014-15 program cycle, REM contributed 33 aMW while BEM provided 30 aMW. Similarly, in the 2016-17 program plan, the REM target is 30 aMW and the BEM target is 34 aMW. The two largest programs within the REM and BEM sectors are the Single Family Residential Lighting Program and the Commercial and Industrial Retrofit Program.

THE SINGLE FAMILY RESIDENTIAL LIGHTING PROGRAM. This program offers rebates to single-family residential customers and builders who purchase Energy Star fixtures and compact fluorescent light bulbs. The program is delivered through various channels. The retail channel is by far the largest delivery mechanism; rebates are provided upstream to the retail stores to reduce the cost of energy efficient lighting products sold to consumers. The lighting products are also delivered using direct-install programs. In the 2014-15 program cycle, lighting in the residential sector accounted for approximately 18 aMW of the 33 aMW in REM program savings.

THE COMMERCIAL AND INDUSTRIAL RETROFIT PROGRAM. This program offers expert assistance and grants to help existing commercial and industrial customers use electricity more efficiently via cost-effective and energy efficient equipment, designs and operations. The program is not limited to any given technology or end use and allows the customers to engage in deep retrofits. In the 2014-15 program cycle, the retrofit grant program in the commercial and industrial sector accounted for approximately 15 aMW of the 30 aMW in BEM program savings.

While lighting savings have been a mainstay of the program in the past, this may change as LEDs saturate the market due to declining costs and as minimum federal lighting standards make the LED a baseline technology. Behavioral programs and technologies that use learning software will offer new ways to save energy.

Appendix D: Electric Resources



Figure D-9: PSE 2014-15 Electric Energy Efficiency Program Savings – Targeted versus Actual⁸

| | 2014 | | | 2015 | | |
|--------------|----------------|----------------|---------------------|----------------|----------------|---------------------|
| | Savings (MWh) | Goal (MWh) | Savings (% of goal) | Savings (MWh) | Goal (MWh) | Savings (% of goal) |
| Residential | 151,259 | 133,388 | 113% | 135,855 | 131,922 | 103% |
| Business | 148,830 | 130,962 | 114% | 116,210 | 112,127 | 104% |
| Pilots | 26,759 | 26,760 | 100% | 8,220 | 8,219 | 100% |
| Regional | 51,691 | 53,295 | 97% | 22,338 | 25,388 | 88% |
| Total | 378,539 | 344,405 | 110% | 282,623 | 277,656 | 102% |

Figure D-9 shows the performance of the REM and BEM sector programs compared to two-year savings goals for the biennial 2014-2015 electric energy efficiency programs. PSE's electric energy efficiency programs saved a total of 76 aMW of electricity at a cost of \$190 million during 2014-15, surpassing energy savings goals while operating under budget.

The 2016-2017 electric energy efficiency programs are targeted to save 69.1 aMW of electricity at a cost of \$199 million.

Distribution Efficiency

This energy efficiency measure is accomplished through conservation voltage reduction (CVR) accompanied by load phase balancing. PSE began implementing distribution efficiency in 2013. Two substations were adapted in 2013, another two in 2014, and work on four more substations was completed in 2015. Five more substations were targeted for completion by the end of 2015. However, the work has been postponed due to the work that was being done to transition to the advanced metering infrastructure (AMI) upgrade. Since AMI technology is needed to monitor the CVR measures once in place, the work is anticipated to resume in 2018 in this IRP, and its rollout will be closely coordinated with the AMI deployment under way to reduce cost.

⁸ / Source: PSE 2014-15 BECAR Final Report



Generation Efficiency

In 2014, PSE worked with the CRAG to refine the boundaries of what to include as savings under generation efficiency. It was determined that only parasitic loads⁹ served directly by a generator would be included in the savings calculations as available for generation efficiency upgrades; generators whose parasitic loads are served externally – from the grid – would not be included. Using this definition, PSE completed site assessments in 2015 and the assessments did not yield any cost-effective measures. Most of the opportunities were in lighting, and the issue was very low operating hours making them not cost effective. Currently there is an approach to replace the existing lamps on burnout with more efficient ones.

Demand-side Customer Programs

PSE's customer renewable energy programs remain popular options. The Green Power Program serves customers who want to purchase additional renewable energy, and Net Metering and Local Energy Development programs serve customers who generate renewable energy on a small scale. Our customers find value as well as social benefits in these programs, and PSE embraces and encourages their use.

Green Power Program

Launched in 2001, PSE's Green Power Program allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources. In 2009, we began working to increase participation in the program with 3Degrees, a third-party renewable energy credits (REC) broker that has developed and refined education and outreach techniques while working with other utility partners across the country. While customer participation since 2014 has remained relatively stable, the number of MWh sold continues to grow. In that time, the number of megawatt-hours purchased increased by approximately 3 percent, from 404,377 to 417,773.

Top 10

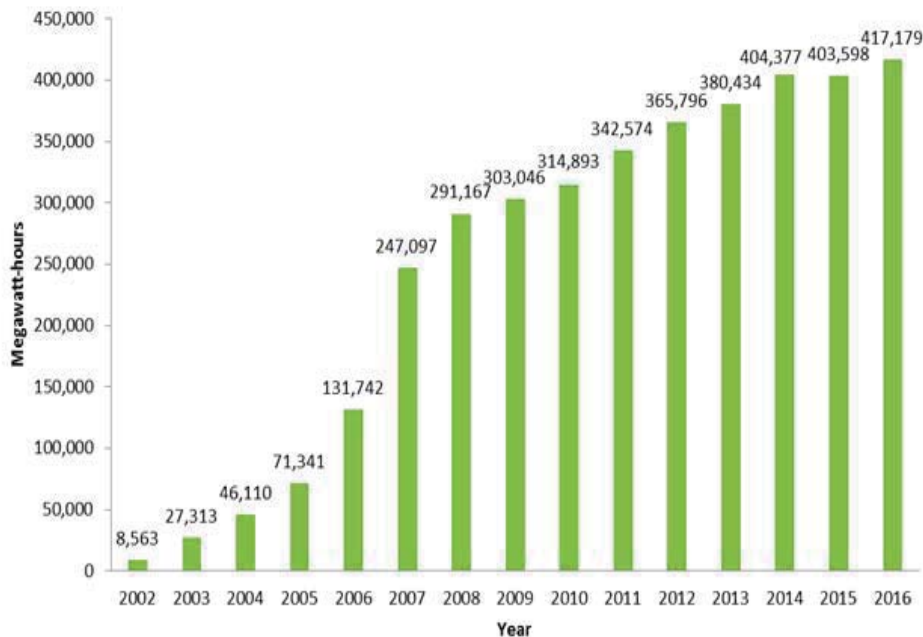
PSE has been recognized as one of the country's top 10 utilities for Renewable Energy Sales and Total Number of Green Power Participants by the National Renewable Energy Laboratory since 2005.

⁹ / Electric generation units need power to operate the unit, including auxiliary pumps, fans, electric motors and pollution control equipment. Some generating plants may receive this power externally, from the grid; however, many use a portion of the gross electric energy generated by the unit for operations – this is referred to as the "parasitic load."

Appendix D: Electric Resources



Figure D-10: Green Power Megawatt-hours Sold, 2002-2016



To supply green power, the program purchases RECs from a variety of sources. In the past two years, the majority of RECs have come from the Bonneville Environmental Foundation (BEF), a nonprofit environmental organization in Portland, Ore., and 3Degrees, a REC broker based in San Francisco, Calif. These suppliers provide PSE's Green Power Program with RECs primarily from Pacific Northwest wind facilities. In addition, the Green Power Program currently purchases RECs directly from eighteen small, local and regional producers in order to support the development of new small renewable resources. These include FPE Renewables, Farm Power Rexville, Farm Power Lynden, Edaleen Cow Power, Van Dyk-S Holsteins, Rainier Biogas, Port of Tillamook Bay, 3Bar G Community Wind, First Up! Knudson Community Wind, Swauk Wind, Ellensburg Community Solar, Skagit Community Solar, APSB Community Solar, Maple Hall Community Solar, Anacortes Library Community Solar, Greenbank Community Solar, LRI Landfill Gas and the Nooksack Hydro Facility – many of these entities also provide power to PSE under the Schedule 91 contracts discussed above.

Appendix D: Electric Resources



Over the last nine years, the Green Power Program has also committed over \$400,000 in grant funding to 15 cities for solar demonstration projects located on municipal facilities. For example, In 2016, the City of Bellingham completed its second successful Green Power Community Challenge by meeting its goal for increased enrollment in the Green Power Program, and in recognition PSE provided the city with a \$50,000 grant towards a solar project in the community. A similar campaign in Bellevue resulted in a \$50,000 grant that the city used to install a 20 kW system at the Crossroads Community Center. Other projects have been installed throughout PSE's service territory in Whidbey Island, Snoqualmie, Vashon and Olympia.

In 2015, PSE issued a RFQ that resulted in competitively awarding REC contracts to the Bonneville Environmental Foundation, Port of Tillamook Bay and 3Degrees to help supply the balance of our Green Power Program portfolio needs for up to two years, beginning in 2016. Pricing for these Pacific Northwest REC contracts was relatively low, largely due to a generous supply of renewable energy and the region's utilities having met their initial compliance targets. As a result, the Green Power Program has been able to focus on building a portfolio of RECs generated from wind, solar, biogas and low-impact hydro located primarily in Washington, with some additional supply from Oregon and Idaho. However, indications are that Pacific Northwest REC prices have increased as RPS compliance targets have stepped up to the next level in the region; Washington state's target increased from 3 percent to 9 percent in 2016. PSE plans to issue another RFQ in mid-2017.

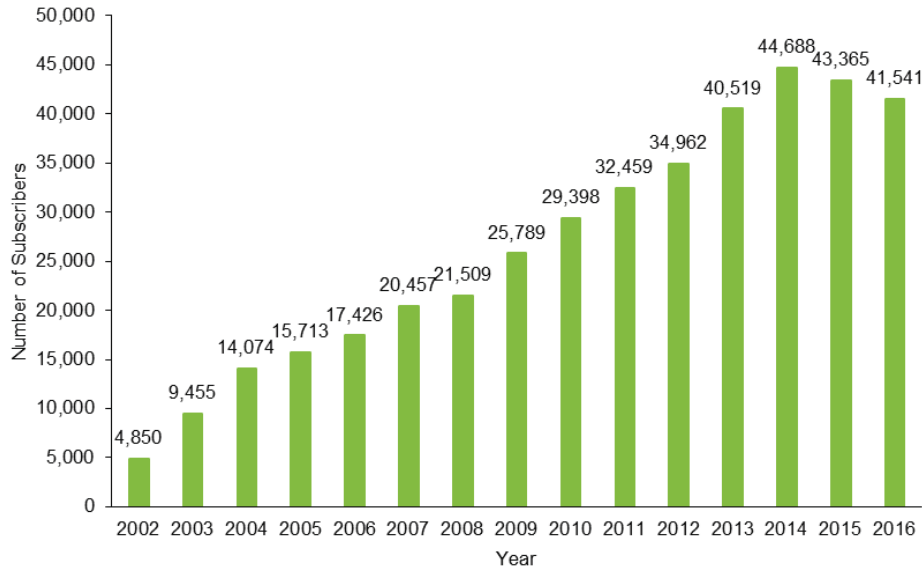
GREEN POWER RATES. In September 2016, PSE received approval from the WUTC to reduce Green Power rates. The standard rate for green power now drops from \$0.0125 per kWh to \$0.01 per kWh. Customers can now purchase 200 kWh blocks for \$2.00 per block with a two-block minimum, or they can choose to participate in the "100% Green Power Option." Introduced in 2007, this option adjusts the amount of the customer's monthly green power purchase to match their monthly electric usage. The large-volume green power rate dropped from \$0.006 per kWh to \$0.0035 per kWh for customers who purchase more than 1,000,000 kWh annually. This product has attracted approximately 30 customers since it was introduced in 2005.

In 2016, the average residential customer purchase was 640 kWh per month, and the average commercial customer purchase was 2,050 kWh. The average 2016 large-volume purchase under Schedule 136, by account, was 12,200 kWh per month.

Figure D-11 illustrates the number of subscribers by year. Of our 41,541 Green Power subscribers at the end of 2016, 40,403 were residential customers, 698 were commercial accounts, and 440 accounts were assigned under the large-volume commercial agreement. Cities with the most residential and commercial participants include Bellingham with 5,511, Olympia with 5,177 and Bellevue with 3,183.



Figure D-11: Green Power Subscribers, 2002-2016



Solar Choice

In September, 2016, the WUTC approved the addition of the Solar Choice program, a new renewable energy product offering for residential and small to mid-size commercial customers. Similar to the Green Power program, Solar Choice allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources; but in this case, all of the resources supplied are solar energy facilities located in Washington and Idaho. Customers can elect to purchase solar in \$5.00 blocks for 150 kilowatt-hours. Their purchase is added to their monthly bill. The program was officially launched to customers in April 2017.



Green Direct

Green Direct was approved by the Washington Utilities and Transportation Commission (WUTC) and became effective on September 30, 2016. Like the Green Power program and Solar Choice, Green Direct falls under the rules governing utility green pricing options found in Washington RCW 19.29A, Voluntary Option to Purchase Qualified Alternative Energy Resources. Green Direct is a product that allows the utility to procure and sell fully bundled renewable energy to large (10,000 MWh per year or more of load in PSE's service area) commercial and municipal customers from a specified wind resource, and within the Washington regulatory framework. For Phase I, PSE has signed a 20-year power purchase agreement for the output from the Skookumchuck Wind project, under development in Thurston and Lewis Counties. Customers can elect to enroll for terms of 10, 15 or 20 years. The customer will continue to receive and pay for all of the standard utility services for safety and reliability. Customers will be charged for the total cost of the energy from the new plant, but receive a credit for the energy-related power costs from the company.

Green Direct held its first open enrollment period in November and December 2016, followed by a second open enrollment period that opened on May 1, 2017. As of June 30, 21 customers had fully-subscribed to a 130 MW wind facility, which is under contract with PSE for 20 years. Enrollees include companies like Starbucks, Target Corporation and REI; and government entities like King County and the City of Olympia. PSE will issue a Request for Proposals to identify a new resource (or resources) for Phase II.

Customer Renewables Programs

PSE offers two customer renewables programs, a net metering program and a renewable energy cost recovery program.

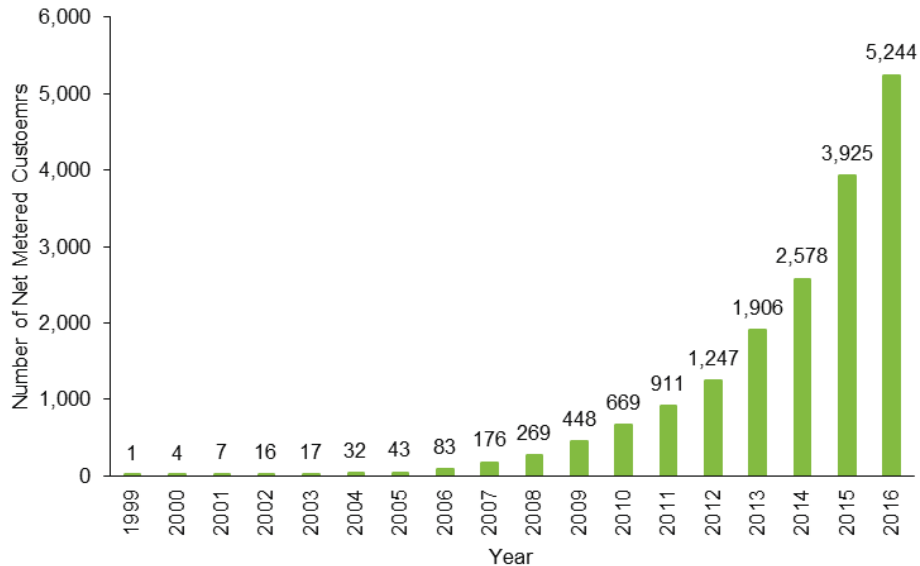
The **NET METERING PROGRAM**, which began in 1999, provides a way for customers who generate their own renewable electricity to offset the electricity provided by PSE. The amount of electricity that the customer generates and sends back to the grid is subtracted from the amount of electricity provided by PSE, and the net difference is what the customer pays on a monthly basis. A kWh credit is carried over to the next month if the customer generates more electricity than PSE supplies over the course of a month. The "banked" energy can be carried over until every April 30, when the account is reset to zero according to state law. The interconnection capacity allowed under net metering is 100 kW.

Customer interest in small-scale renewables has increased significantly over the past seventeen years, as Figure D-12 shows. For 2016, PSE added 1,319 new net metered customers for a total of 5,244.

Appendix D: Electric Resources



Figure D-12: Net Metered Customers, 1999-2016



The vast majority of customer systems (99 percent) are solar photovoltaic (PV) installations with an average generating capacity of 6.9 kW, but there are also small-scale hydroelectric generators and wind turbines. These small-scale renewable systems are distributed over a wide area of PSE's service territory. The median generating capacity of all net metered systems is 6.16 kW. Overall, the program was capable of producing more than 36.9 MW of nameplate capacity at the end of 2016.

Customer preference along with state and federal incentives continues to drive customer solar PV adoption. Residential customers were 94 percent of all solar PV by number and 87 percent by nameplate capacity. In 2016, PSE contracted with Clean Power Research to implement their PowerClerk software tool – a new online solar application. PSE continues to examine our processes to allow for continued growth in customer generation.



Figure D-13: Interconnected System Capacity by Type of System

| SYSTEM TYPE | NUMBER OF SYSTEMS | AVERAGE CAPACITY PER SYSTEM TYPE (kW) | SUM OF ALL SYSTEMS BY TYPE (kW) |
|--------------------|-------------------|---------------------------------------|---------------------------------|
| Hybrid: solar/wind | 19 | 5.90 | 106.2 |
| Micro hydro | 5 | 6.07 | 38.2 |
| Solar array | 5,185 | 7.03 | 3,433.0 |
| Wind turbine | 35 | 3.23 | 117.7 |
| Total | 5,244 | 6.13 | 3,695.1 |

Figure D-14: Net Metered Systems by County

| COUNTY | NUMBER OF NET METERS |
|--------------|----------------------|
| Whatcom | 1,041 |
| King | 1,781 |
| Skagit | 454 |
| Island | 278 |
| Kitsap | 582 |
| Thurston | 604 |
| Kittitas | 269 |
| Pierce | 235 |
| Total | 5,244 |

RENEWABLE ENERGY COST RECOVERY. In 2005, in response to Washington Administrative Code (WAC) 458-20-273, PSE launched a renewable energy production incentive payment program under tariff Schedule 151. The program is voluntary for Washington state utilities, but we embraced the opportunity to participate because we have such a large and committed group of interconnected customers. Under this program, PSE makes payments to interconnected electric customers who own and operate eligible renewable energy systems which include solar PV, wind or anaerobic digesters. The annual credits ranged from \$0.12 to \$1.08 per kWh of energy produced by their system. PSE receives a state tax credit equal to the payments made to customers, up to 0.5 percent of PSE's taxable electric sales for the previous year. For the incentive year that ended with the state fiscal year on June 30, 2016, production exceeded the allowable funds. In order to bring payments under the cap, PSE lowered the base rate by one cent – from \$0.15 to \$0.14 – before applying the appropriate multipliers. In 2016, PSE paid approximately \$9.7 Million to over 4,300 eligible customers.



3. ELECTRIC RESOURCE ALTERNATIVES

This overview of technology alternatives for electric power generation describes both mature technologies and new methods of power generation, including those with near- and mid-term commercial viability. Within each section, resources are listed alphabetically. PSE continues to explore emerging resources.

Thermal Resource Costs and Characteristics

PSE modeled two types of thermal resources in the 2017 IRP, baseload gas plants and peakers.

Generic Gas Resource Cost Assumptions

Figure D-15 summarizes the cost assumptions used in the analysis for baseload gas plants and peakers. All costs are in 2016 dollars.

PSE worked with Black and Veatch to produce a report on gas-fired generation characteristics and costs. The table below is a summary of the numbers needed for modeling; the full report can be found in Appendix P, Gas-fired Resource Costs.

Appendix D: Electric Resources



Figure D-15: Generic Gas Resource Cost Assumptions

| GENERIC GAS RESOURCES | 2016 \$ | UNITS | BASELOAD GAS | | PEAKERS | | | | | |
|---|------------|-------|--------------|----------|--------------|---------------------|--------------------|--------------------|-------------------|--------------------|
| | | | CCCT - A | CCCT - B | FRAME PEAKER | FRAME PEAKER W/ OIL | AERO PEAKER | AERO PEAKER W/ OIL | RECIP ENGINE | RECIP ENGINE W/OIL |
| ISO Capacity Primary | | MW | 359 | 405 | 239 | 239 | 227 | 227 | 222 | 202 |
| Capacity DF | | MW | 54 | 61 | | | | | | |
| Capital Cost + Duct Fire | \$/kW | | \$1,267 | \$1,299 | \$571 | \$634 | \$1,004 | \$1,070 | \$1,277 | \$1,477 |
| O&M Fixed | \$/kW-yr | | \$8.10 | \$7.30 | \$6.40 | \$11.23 | \$6.50 | \$10.92 | \$6.50 | \$10.70 |
| O&M Variable (1) | \$/MWh | | \$2.50 | \$2.40 | \$0.95 | \$0.95 | \$10.20 | \$10.10 | \$7.80 | \$7.80 |
| Start Up Costs | \$/Start | | \$2.78 | \$2.69 | \$9,250 | \$9,250 | | | | |
| Capacity Credit | % | | 100% | 100% | 100% | 100% | 100% | 100% | 100% | 100% |
| Operating Reserves | % | | 3% | 3% | 3% | 3% | 3% | 3% | 3% | 3% |
| Forced Outage Rate | | | 3% | 3% | 3% | 3% | 3% per unit | 3% per unit | 1% per unit | 1% per unit |
| Heat Rate – Baseload (HHV) (2) | Btu/KWh | | 6,650 | 6,515 | 9,823 | 9,823 | 8,986 | 8,986 | 8,425 | 8,527 |
| Heat Rate – Turndown (HHV) (2) | Btu/kWh | | 7,339 | 7,473 | 12,750 | 12,750 | 14,464 | 14,464 | 10,924 | 11,026 |
| Heat Rate – DF | Btu/kWh | | 8,500 | 8,500 | | | | | | |
| Min Capacity | % | | 50% | 42% | 45% | 45% | 13% (25% per unit) | 13% (25% per unit) | 2% (25% per unit) | 2% (25% per unit) |
| Start Time (3) | minutes | | 150 | 150 | 12 | 12 | 8 | 8 | 5 | 5 |
| Location | | | PSE | PSE | PSE | PSE | PSE | PSE | PSE | PSE |
| Fixed Gas Transport | \$/Dth/Day | | \$0.78 | \$0.78 | \$0.78 | \$0.01 | \$0.78 | \$0.01 | \$0.78 | \$0.01 |
| Fixed Gas Transport | \$/kW-yr | | \$45.44 | \$44.51 | \$67.11 | \$0.70 | \$61.40 | \$0.64 | \$57.56 | \$0.61 |
| Variable Gas Transport | \$/MMBtu | | \$0.01 | \$0.01 | \$0.01 | \$0.25 | \$0.01 | \$0.25 | \$0.01 | \$0.25 |
| Fixed Transmission | \$/kW-yr | | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 |
| Variable Transmission | \$/MWh | | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 |
| Flexibility Benefit (4) | \$/kw-yr | | \$0.00 | \$0.00 | (\$0.91) | (\$0.91) | (\$6.34) | (\$6.34) | (\$9.97) | (\$9.97) |
| Emissions: | | | | | | | | | | |
| CO ₂ (5) - Natural Gas | lbs/MMBtu | | 117 | 117 | 117 | 117 | 117 | 117 | 117 | 117 |
| CO ₂ (5) - Distillate Fuel Oil | lbs/MMBtu | | | | | 153 | | 153 | | 153 |
| Nox - Natural Gas | lbs/MMBtu | | 0.007 | 0.007 | 0.007 | 0.007 | 0.007 | 0.007 | 0.007 | 0.007 |
| Nox - Distillate Fuel Oil | lbs/MMBtu | | | | | 0.077 | | 0.077 | | 0.077 |
| First Year Available | | | 2022 | 2022 | 2021 | 2021 | 2021 | 2021 | 2021 | 2021 |
| Economic Life | Years | | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 |
| Greenfield Dev. & Const. Lead-time | Years | | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 3 |

NOTES

1. Variable costs reflect the operating costs and major maintenance for all technologies except for the frame peaker, for which major maintenance is included in startup costs.
2. Includes two percent for degradation.
3. Start time for all technologies reflects the warm start on all units. The hot start follows a shutdown period of less than 8 hours.
4. Flexibility benefit based on report by E3 as commissioned by PSE.
5. CO₂ emissions reflect natural gas as the main source of fuel under normal operating conditions. In the event that the gas pipeline is constrained, the CO₂ emissions would be higher for plants that can run on oil backup as the secondary fuel source. The minimal amount of diesel fuel required by the dual fueled reciprocating engines when operating with natural gas as the primary fuel is not captured in the emission rates.

Appendix D: Electric Resources



GAS TRANSPORTATION COSTS MODELED. Fixed and variable gas transportation cost assumptions for the gas plants assume that gas is purchased at the Sumas Hub. Gas transportation costs for resources without oil backup assume the need for 100 percent firm gas pipeline transportation capacity plus firm storage withdrawal rights equal to 13.4 percent of the plant's full fuel requirements. This applies to the baseload CCCT, frame peaker without oil, Aero peaker without oil, and the reciprocating engine without oil. The analysis assumes that the gas transportation needs for these resources will be met with 100 percent firm gas transportation on a Williams Northwest Pipeline (NWP) expansion to Sumas plus 100 percent firm gas transportation on a Westcoast Energy Inc. (Westcoast) gas pipeline expansion to Station 2. The plants are dispatched to Sumas prices, so a basis differential between Sumas and Station 2 is added back to the cost. For the peaker resources, we are assuming oil backup with no firm gas transportation.

Figure D-16 below shows the gas transport assumptions for resources with and without oil backup.

Figure D-16: Gas Transportation Costs for Western Washington Baseload Gas Plants and Peakers without Oil Backup – 100% Sumas on NWP + 100% Station 2 on Westcoast

| PIPELINE/RESOURCE | FIXED DEMAND (\$/DTH/DAY) | VARIABLE COMMODITY (\$/DTH) | ACA CHARGE (\$/DTH) | FUEL USE (%) | UTILITY TAXES (%) ⁵ |
|----------------------------------|---------------------------|-----------------------------|---------------------|--------------|--------------------------------|
| NWP Expansion ¹ | 0.5500 | 0.0083 | 0.0013 | 1.41% | - |
| Westcoast Expansion ² | 0.5000 | - | - | - | - |
| Basis Gain ³ | (0.2781) | | | | |
| Gas Storage ⁴ | 0.0081 | - | - | - | - |
| Total | 0.7800 | 0.0083 | 0.0013 | 5.5% | 3.852% |

NOTES

1. Estimated NWP Sumas to PSE Expansion

2. Estimated Westcoast Expansion Fixed Demand

3. Basis gain represents the average of the Station 2 to Sumas price spread, net of fuel losses and variable costs over the 20-year forecast period. Variable Commodity Charge includes B.C. carbon tax and motor fuel tax of \$0.0476 per Dth per day and fuel losses are 2.91 percent per Dth.

4. Storage requirements are based on current storage withdrawal capacity to peak plant demand for the gas for power portfolio (approx. 13.4 percent).

5. Utility taxes are charged by the state on fuel used at the plant.

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Figure D-17: Gas Transportation Costs for Western Washington
Peakers with Oil Backup – No Firm Gas Pipeline

| PIPELINE/ RESOURCE | FIXED DEMAND (\$/DTH/DAY) | WEIGHTED AVERAGE "VARIABLE" DEMAND (\$/DTH) | VARIABLE COMMODITY (\$/DTH) | ACA CHARGE (\$/DTH) | FUEL USE (%) | UTILITY TAXES (%) ² |
|--------------------------|---------------------------------|--|-----------------------------------|------------------------|-----------------|--------------------------------------|
| NWP Demand | 0.0000 | 0.2438 | 0.0083 | 0.0013 | 1.41% | - |
| Gas Storage ¹ | 0.0081 | - | - | - | - | - |
| Total | 0.0081 | 0.2438 | 0.0083 | 0.0013 | 1.41% | 3.852% |

NOTES

1. Storage requirements are based on current storage withdrawal capacity to peak plant demand for the gas for power portfolio (approx. 13.4 percent).

2. Utility taxes are charged by the state on fuel used at the plant.

Figure D-18: Gas Transportation Costs for Eastern Washington
Baseload Gas Plants and Peakers without Oil Backup,
100% AECO on GTN/NOVA/Foothills

| PIPELINE/ RESOURCE | FIXED DEMAND (\$/DTH/DAY) | VARIABLE COMMODITY (\$/DTH) | ACA CHARGE (\$/DTH) | FUEL USE (%) | UTILITY TAXES (%) |
|-----------------------|------------------------------|-----------------------------------|---------------------------|-----------------|----------------------|
| NOVA | 0.145 | - | - | 0% | - |
| Foothills | 0.076 | 0.0 | - | 1.00% | - |
| GTN | 0.155 | 0.004 | 0.0013 | 0.89% | - |
| Gas Storage | 0.008 | - | - | - | - |
| Total | 0.384 | 0.004 | 0.0013 | 1.89% | 3.852% |



Natural Gas Characteristics

Natural gas generation is extensively modeled in this IRP analysis due to the following characteristics.

- **Proximity.** Gas-fired generators can often be located within or adjacent to PSE's service area, thereby avoiding costly transmission investments required for long-distance resources like coal or wind.
- **Timeliness.** Gas-fired resources are dispatchable, meaning they can be turned on when needed to meet loads, unlike "intermittent" resources that generate power sporadically such as wind, solar and run-of-the-river hydropower.
- **Versatility.** Gas-fired generators have varying degrees of ability to ramp up and down quickly in response to variations in load and/or wind generation.
- **Environmental Burden.** Natural gas resources produce significantly lower emissions than coal resources (approximately half the CO₂).

Gas storage and fuel supply become increasingly important considerations as reliance on natural gas grows, so the analysis also includes gas storage for some resources. The gas-fired baseload and peaking resources modeled in this analysis are described below.

Baseload Gas

Baseload gas plants – combined-cycle combustion turbines or CCCTs – produce energy at a constant rate over long periods at a lower cost relative to other production facilities available to the system. They are typically used to meet some or all of a region's continuous energy demand.

COMBINED-CYCLE COMBUSTION TURBINES (CCCTs). These baseload gas plants consist of one or more combustion turbine generators equipped with heat recovery steam generators that capture heat from the combustion turbine (CT) exhaust. This otherwise wasted heat is then used to produce additional electricity via a steam turbine generator. Many plants also feature "duct firing." Heat rates range between 6,400 and 6,500 BTU per kWh depending on the size, because of their high thermal efficiency and reliability, relatively low initial cost and low air emissions. Duct firing can produce additional capacity from the steam turbine generator, although with less efficiency than the primary unit. CCCTs have been a popular source of baseload electric power and process steam generation since the 1960s.

In this analysis, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. This analysis assumes 13.4 percent of gas storage is available to the baseload gas plants modeled to accommodate mid-day startups or shutdowns. The unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.



This technology is commercially available. Greenfield development requires approximately four years.

Peakers

Peakers are quick-starting units that can ramp up and down rapidly in order to meet spikes in need. They also provide flexibility needed for load following, wind integration and spinning reserves. PSE modeled three types of peakers; each brings particular strengths to the overall portfolio.

SIMPLE-CYCLE COMBUSTION TURBINES (SCCT). There are two principal types of simple-cycle combustion turbines for “peaking” applications: frame and aeroderivative (aero) engines.

Frame Peakers. Frame CT peakers are also known as “industrial” or “heavy-duty” CTs; these are generally larger in capacity and feature frames, bearings and blading of heavier construction. Conventional frame CTs are a mature technology. They can be fueled by natural gas, distillate oil or a combination of fuels (dual fuel). The turndown capability of the units is 45 percent. The assumed heat rate is 9,800 BTU per kWh depending on the size. They also have slower ramp rates, on the order of 40 MW per minute for 239 MW facilities, and some can achieve full load in eleven minutes.

Frame CT peakers are commercially available. Greenfield development requires approximately three years.

AERO Peakers (Aeroderivative Combustion Turbines). Aeroderivative combustion turbines are a mature technology, however, new aeroderivative features and designs are continually being introduced. They can be fueled by natural gas, oil or a combination of fuels (dual fuel). The heat rate is 8,810 BTU per kWh. Aero units are typically more flexible than their frame counterparts, and many can reduce output to nearly 25 percent. Most can start and achieve full output in less than eight minutes and start multiple times per day without maintenance penalties. Ramp rates are 50 MW per minute for a 227 MW facility. Another key difference between aero and frame units is size. Aero CTs are typically smaller in size, from 5 to 100 MW each. This small scale allows for modularity, but it also tends to reduce economies of scale.

This technology is commercially available. Greenfield development requires approximately three years.



RECIP PEAKERS (RECIPROCATING ENGINES). The reciprocating engine technology evaluated is based on a four-stroke, spark-ignited gas engine which uses a lean burn method to generate power. The lean burn technology uses a relatively higher ratio of oxygen to fuel, which allows the reciprocating engine to generate power more efficiently. Ramp rates are 168 MW per minute for a 228 MW facility. The heat rate is 8,260 BTU per kWh. However, reciprocating engines are constrained by their size. The largest commercially available reciprocating engine for electric power generation produces 18 MW, which is less than the typical frame or Aero turbine. Larger-sized generation projects would require a greater number of reciprocating units compared to an equivalent-sized project implementing either an Aero or frame turbine, reducing economies of scale. A greater number of generating units increases the overall project availability and reduces the impact of a single unit out of service for maintenance. Reciprocating engines are more efficient than simple-cycle combustion turbines, but have a higher capital cost. Their small size allows a better match with peak loads, thus increasing operating flexibility relative to simple-cycle combustion turbine peakers.

This technology is commercially available. Greenfield development requires approximately three years.

OIL BACKUP. For peakers with oil backup, natural gas supply is assumed to be available on an interruptible basis at projected gas pipeline seasonal interruptible rates for much of the year. The oil backup is assumed to provide fuel during peak periods. For units without oil backup, natural gas supply is assumed to be firm year-round at projected incremental gas pipeline firm rates. In either case, the analysis assumes 13.4 percent of gas storage is available to the peaking gas plants modeled to accommodate mid-day startups or shutdowns. The peaker unit is assumed to be connected to the PSE transmission system and as such does not incur any direct transmission cost.



Thermal Resources Not Modeled

As discussed below, other potential thermal resource alternatives are constrained by law, practical obstacles and cost. Long-term coal-fired generation is not a resource alternative because RCW 80.80 precludes utilities in Washington from entering into new long-term agreements for coal, and new nuclear generation is neither practical nor feasible.

COAL. Coal fuels a significant portion of the electricity generated in the United States. Most coal-fired electric generating plants combust the coal in a boiler to produce steam that drives a turbine-generator. A small number of plants gasify coal to produce a synthetic gas that fuels a combustion turbine. Of the fuels commonly used to produce electricity, coal produces the most greenhouse gases (GHGs) per MWh of electricity. Technologies for reducing or capturing some of the GHGs produced are currently in the research and development phase.

Commercial availability. New coal-fired generation is not a resource alternative for PSE, because RCW 80.80 sets a generation performance standard for electric generating plants that prohibits Washington utilities from building plants or entering into long-term electricity purchase contracts from units that emit more than 970 pounds of GHGs per MWh.¹⁰ With currently available technology, coal-fired generating plants produce GHGs (primarily carbon dioxide) at a level two or more times greater than the performance standard, and carbon capture and sequestration technology is not yet effective or affordable enough to significantly reduce those levels.

There are no new coal-fired power plants under construction or development in the Pacific Northwest.

NUCLEAR. Capital and operating costs for nuclear power plants are so much higher than most conventional and renewable technologies that only a handful of the largest capitalized utilities can realistically consider this option. In addition, nuclear power also carries significant technology, credit, permitting, policy and waste disposal risks.

Cost assumptions. There is little reliable data on recent U.S. nuclear developments from which reasonable and supportable cost estimates can be made. The construction cost and schedule track record for nuclear plants built in the U.S. during the 1980s, 1990s, and 2000s has been poor. Actual costs have been far higher than projected, construction schedules have been subject to long delays, and interest rate increases have resulted in high financing charges. The Fukushima incident in 2011 has also motivated changing technical and regulatory requirements and public controversy that have contributed to project cost increases.

¹⁰ / To support a long-term plan to shut down the only coal-fired generating plant in Washington state, state government has made an exception for transition contracts with the Centralia generating plant through 2025.



Plant closings. An extensive discussion of then-existing U.S. nuclear facilities, decommissioning activities, new construction projects, and policy considerations was provided in Appendix D of PSE's 2013 IRP. Since then, facility owners have announced plans to permanently retire almost 8,500 MW of nuclear generating capacity in the next 10 years. Vermont Yankee, Fort Calhoun, Fitzpatrick, Clinton, Pilgrim, Quad Cities, Oyster Creek and Diablo Canyon will all be permanently closed by 2025 for economic reasons.

New construction. New nuclear facilities have been moving forward very slowly after many years of delays and cost overruns, with 5 units in various stages of construction. The 1,165 MW Watts Bar 2 plant finally entered commercial service in October 2016 after starting construction in the 1980s – the first new nuclear plant completed in the U.S. since 1996. The remaining units, Vogtle 3 & 4 and Summer 2 & 3, have been delayed again and are not expected to enter service until 2020 at the earliest.

With other energy options to choose from, the demonstrated high cost, poor completion track record, lack of a comprehensive waste storage/disposal solution and the uncertainty of current technology make nuclear energy an unnecessary risk for PSE at this time.

Energy Storage Resource Costs and Characteristics

PSE modeled three energy storage alternatives in the 2017 IRP: lithium-ion batteries, flow batteries and pumped hydro.

Generic Energy Storage Resource Cost Assumptions

Figure D-19 summarizes the generic costs assumptions used in the analysis for energy storage resources. All costs are in 2016 dollars.

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Figure D-19: Generic Energy Storage Cost Assumptions

| 2016 \$ | Units | Li-Ion Battery 2-hr | Li-Ion Battery 4-hr | Flow Battery 4-hr | Flow Battery 6-hr | Pumped Storage |
|--------------------------------------|----------|------------------------|------------------------|----------------------|----------------------|-------------------|
| Nameplate Capacity | MW | 25 | 25 | 25 | 25 | 25 |
| Winter Capacity | MW | 15 | 22 | 19 | 20 | 25 |
| Capacity Credit | % | 60% | 88% | 76% | 80% | 100% |
| Operating Reserves | % | 3% | 3% | 3% | 3% | 3% |
| Capital Cost | \$/kW | \$1,514 | \$2,439 | \$2,324 | \$3,042 | \$2,400 |
| O&M Fixed | \$/kW-yr | \$23.68 | \$36.49 | \$26.82 | \$23.40 | \$15.00 |
| O&M Variable | \$/MWh | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.00 |
| Forced Outage Rate | % | 0.5% | 0.5% | 0.5% | 0.5% | 0.0% |
| Degradation | %/year | 2.0% | 2.0% | 0.0% | 0.0% | 0.0% |
| Operating Range | % | 10%-90% | 10%-90% | 0%-100% | 0%-100% | 0%-100% |
| R/T Efficiency ¹ | % | 85% | 85% | 75% | 75% | 81% |
| Discharge at Nominal Power | Hours | 2 | 4 | 4 | 6 | 10 |
| Location | | PSE | PSE | PSE | PSE | PNW |
| Fixed Transmission | \$/kW-yr | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$21.48 |
| Variable Transmission | \$/MWh | \$0.00 | \$0.00 | \$0.00 | \$0.00 | \$0.33 |
| Flexibility Benefit | \$/KW-yr | (\$119) | (\$131) | (\$117) | (\$128) | (\$144) |
| First Year Available | | 2019 | 2019 | 2019 | 2019 | 2030 |
| Economic Life | Years | 10 | 10 | 20 | 20 | 60 |
| Greenfield Dev. & Const. Leadtime | Years | 1 | 1 | 1 | 1 | 15 |

NOTES

1. Round-trip efficiency means the percentage of energy input that is available for output.



Energy Storage Characteristics

Energy storage encompasses a wide range of technologies that are capable of shifting energy usage from one time period to another. These technologies could deliver important benefits to electric utilities and their customers, since the electric system currently operates on “just-in-time” delivery. Generation and load must be perfectly balanced at all times to ensure power quality and reliability. Strategically placed energy storage resources have the potential to increase efficiency and reliability, to balance supply and demand, to provide backup power when primary sources are interrupted and to assist with the integration of intermittent renewable generation. Energy storage technologies are rapidly improving and are capable of benefiting all parts of the system – generation, transmission and distribution – as well as customers. The drawbacks to energy storage are that it operates with a limited duration and requires generation from other sources.

Battery Storage

Unlike conventional generation resources such as combustion turbines, battery storage resources are modular, scalable and expandable. They can be sized from 20 kW to 1,000 MW and sited at a customer’s location or interconnected to the transmission system. It is possible to build the infrastructure for a large storage system and install storage capacity in increments over time as needs grow. This flexibility is a valuable feature of the technology.

Within the battery category, there are many promising chemistries, each with its own performance characteristics, commercial availability and costs. PSE chose to model lithium-ion and flow batteries as the generic battery resources in this IRP because both technologies are commercially available, there are successful projects in operation, and cost estimates and data are available on a spectrum of system configurations and sizes. Other advantages are described below.¹¹ A detailed discussion of battery technologies is available in Appendix L to PSE’s 2015 IRP.

¹¹ / In an actual RFP solicitation, PSE would evaluate all proposed technologies based on least-cost and best-fit criteria, including technical and commercial considerations such as warranties, performance guaranties and counterparty credit, etc.



LITHIUM-ION BATTERIES have emerged as the leader in utility-scale applications because they offer the best mix of performance specifications for most energy storage applications. Advantages include high energy density, high power, high efficiency, low self-discharge, lack of cell “memory” and fast response time. Challenges include short cycle life, high cost, heat management issues, flammability and narrow operating temperatures. Battery degradation is dependent on the number of cycles and state of the battery’s charge. Deep discharge will hasten the degradation of a lithium-ion battery. Lithium-ion batteries can be configured for varying durations (i.e., 0.5 to 6 hours), but the longer the duration, the more expensive the battery. Lithium-ion storage is ideally suited for ancillary applications benefitted by high power (MW), low energy solutions (MWh), and to a lesser extent, for supplying capacity.

FLOW BATTERIES are a type of rechargeable battery in which recharge ability is provided by two chemical components dissolved in liquids contained within the system. The two components are separated by a membrane, and ion exchange occurs through the membrane while both liquids circulate in their respective spaces. The ion exchange provides the flow of electric current. Flow batteries can provide the same services as lithium-ion batteries, but they can be used with more flexibility because they do not degrade over time. Flow batteries have very limited market penetration at this time.

Commercial availability. The U.S. installed 221 MW of battery energy storage resources in 2016, down three percent from 2015. Lithium-ion batteries continued to dominate the energy storage market with a market share of 97 percent in each quarter of 2016.¹²

In the “Energy Storage” sensitivity, this IRP tests the cost difference between a portfolio that includes battery storage and one that does not.

¹² / GTM Research, *U.S. Energy Storage Monitor, 2016 Year in Review and Q1 2017 Executive Summary*. The 221 MW of deployments represents residential, non-residential and utility solar installations in 2016.



Pumped Hydroelectric Storage

Pumped hydroelectric storage (“pumped storage” or “pumped hydro”) plants provide the bulk of utility-scale energy storage in the United States. These facilities store energy in the form of water, which is pumped to an upper reservoir from a second reservoir at a lower elevation. During periods of high electricity demand, the stored water is released through turbines to generate power in the same manner as a conventional hydropower station. Load shifting over a number of hours requires a large volume of energy storage capacity, and a storage device like pumped hydro is well suited for this type of application. During periods of low demand (usually nights or weekends when electricity costs less), the upper reservoir is “recharged” by using lower-cost electricity from the grid to pump the water back to the upper reservoir.

Reversible pump-turbine and motor-generator assemblies can act as both pumps and turbines. Pumped storage facilities can be very economical due to peak and off-peak price differentials and because they can provide critical ancillary grid services. Pumped storage projects are typically large, at 300 MW or more. Due to environmental impacts, permitting for these projects can take many years. Pumped storage can be designed to provide 6 to 20 hours of storage with 80 percent roundtrip efficiency.

Commercial availability. According to the Department of Energy’s most recent *Hydropower Market Report*, there are 42 plants with a capacity of 21.6 GW. Most of this capacity was installed between 1960 and 1990, and three-quarters of it is located at very large (>500 MW) plants. At the time the report was published in April 2015, there were 51 pumped storage projects with a potential capacity of 39 GW in the FERC development pipeline.¹³

¹³ / Source: U.S. Department of Energy 2014 *Hydropower Market Report*, published April 2015:
https://www.energy.gov/sites/prod/files/2015/04/f22/2014%20Hydropower%20Market%20Report_20150424.pdf



Energy Storage Not Modeled

LIQUID AIR ENERGY STORAGE (LAES). LAES converts energy from a variety of sources, such as natural gas or wind, and stores it as thermal energy. To charge the energy, air is cooled and compressed into a liquid state using electricity (i.e., liquefied air or liquefied nitrogen) and stored in tanks. To dispatch electrical energy back to the grid, the liquid air is heated and pressurized, bringing it back to a gaseous state. The gas is used to turn a turbine to generate electricity.

Potential benefits include the technology's suitability to deliver large-scale power for utility and distributed power applications; its suitability for long-duration energy storage; and its ability to use waste heat and cold from its own processes to enhance its efficiency. Also, LAES systems can be large in scale without requiring a large footprint, giving them greater geographical flexibility.

Commercial Availability. LAES systems combine three existing technologies: industrial gas production, cryogenic liquid storage and expansion of pressurized gasses. While the components are based on proven technology currently used in industrial processes and available from large OEMs, no commercial LAES systems are currently in operation. However, in March 2014, Highview Power Storage, a small U.K. company developing utility-scale LAES systems, signed an exclusive global licensing deal with GE to explore the potential to integrate their LAES technology into GE's natural gas peaker plants.¹⁴ Since then, both Mitsubishi Hitachi Power Systems Europe¹⁵ and The Linde Group¹⁶ have indicated that they are currently developing LAES storage solutions on their websites.

Renewable Resource Costs and Characteristics

PSE modeled wind, biomass and solar renewable resources in the 2017 IRP.

Generic Renewable Resource Cost Assumptions

Figure D-20 summarizes the generic renewable resource cost assumptions used in the analysis. All costs are in 2016 dollars.

¹⁴ / Greentech Media website. Retrieved from <https://www.greentechmedia.com/articles/read/ge-partners-with-highview-for-liquid-air-energy-storage>, March 2014.

¹⁵ / Mitsubishi Hitachi Power Systems Europe website. Retrieved from <http://www.eu.mhps.com/en/storage-technologies.html>, December 2016.

¹⁶ / The Linde Group website. Retrieved from http://www.the-linde-group.com/en/clean_technology/clean_technology_portfolio/energy_storage/liquid_air_energy_storage/index.html, December 2016.

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Figure D-20: Generic Renewable Resource Cost Assumptions

| 2016 \$ | UNITS | WA WIND | MT WIND | BIOMASS | SOLAR | OFFSHORE WIND |
|------------------------------------|-----------|---------|----------------------|------------|------------------|----------------------|
| ISO Capacity Primary | MW | 100 | 300 | 15 | 25 | 100 |
| Winter Capacity Primary | MW | 9 | 192 | 0 | 0 | |
| Capacity Credit | % | 9% | 64% | 0% | 1% | |
| Operating Reserves | % | 3% | 3% | 3% | 3% | 3% |
| Capacity Factor | % | 30% | 46% | 85% | 27% | 35% |
| Capital Cost ¹ | \$/kW | \$1,936 | \$3,950 ⁶ | \$7,150 | \$2,171 | \$7,150 ⁷ |
| O&M Fixed | \$/kW-yr | \$27.12 | \$33.79 | \$113.70 | \$10.00 | \$77.30 |
| O&M Variable ² | \$/MWh | \$3.15 | \$3.50 | \$5.66 | \$0.00 | \$3.15 |
| Degradation | %/year | | | | 0.5% | |
| Location | | SE WA | Montana | Western WA | PSE - Central WA | Coast of WA |
| Fixed Transmission ³ | \$/kW-yr | \$35.88 | \$72.94 | \$21.48 | \$0.00 | \$35.88 |
| Variable Transmission ⁴ | \$/MWh | \$1.85 | \$1.85 | \$0.35 | \$0.00 | \$1.85 |
| Loss Factor to PSE | % | 1.9% | 7.3% | 1.9% | 0.0% | 1.95% |
| Heat Rate – Baseload (HHV) | Btu/kWh | | | 13,500 | | |
| Emissions: | | | | | | |
| NO _x | lbs/MMBtu | | | 0.00 | | |
| SO ₂ | lbs/MMBtu | | | 3.152 | | |
| CO ₂ | lbs/MMBtu | | | 195.0 | | |
| First Year Available ⁵ | | 2020 | 2022 | 2021 | 2020 | 2022 |
| Economic Life | Years | 25 | 25 | 35 | 25 | 25 |
| Greenfield Dev. & Const. Leadtime | years | 3 | 3 | 4 | 3 | 5 |

NOTES

1. Solar PV cost for AC installed

2. Idaho Solar includes Spin and Supplemental from Idaho Power. WA Wind includes wind integration cost from BPA. MT Wind includes wind integration cost from NWMT. WA solar includes a solar integration charge from BPA as a placeholder.

3. BPAT variable cost includes spin, supplemental and imbalance. Idaho solar includes solar integration cost from Idaho Power.

4. MT wind includes generation tax and WET tax.

5. First year available for MT wind is 2022 to correspond to retirement of Colstrip 1 & 2.

6. Includes \$52 Million of transmission upgrades. If the resource were only 100 MW, then the capital cost would be higher since the transmission upgrades are \$52 million regardless of size of plant.

7. Offshore wind capital cost does not include the cost of the marine cable.



Biomass Characteristics

Biomass in this context refers to the burning of woody biomass in boilers. Most existing biomass in the Northwest is tied to steam hosts (also known as “cogeneration” or “combined heat and power”). It is found mostly in the timber, pulp and paper industries. This dynamic has limited the amount of power available to date. The typical plant size we have observed is 10 MW to 50 MW. One major advantage of biomass plants is that they can operate as a baseload resource, since they do not impose generation variability on the grid, unlike wind and solar. Municipal solid waste, landfill and wastewater treatment plant gas are discussed in the section on waste-to-energy technologies.

Commercial availability. This technology is commercially available. Greenfield development of a new biomass facility requires approximately four years. The costs modeled in Figure D-22 above are from the biomass section of the U.S. Energy Information Administration report, *Capital Cost for Electricity Plants* (<http://www.eia.gov/forecasts/capitalcost/>).

Solar Characteristics

Solar energy uses the light and radiation from the sun to directly generate electricity with photovoltaic (PV) technology, or to capture the heat energy of the sun for either heating water or for creating steam to drive electric generating turbines. The solar energy resource modeled in this IRP portfolio sensitivity uses central station tracking PV technology.

PHOTOVOLTAICS are semiconductors that generate direct electric currents. The current then typically runs through an inverter to create alternating current, which can be tied into the grid. Most photovoltaic solar cells are made from silicon imprinted with electric contacts; however, other technologies, notably several chemistries of thin-film photovoltaics, have gained substantial market share. Significant ongoing research efforts continue for all photovoltaic technologies, which has helped to increase conversion efficiencies and decrease costs. Photovoltaics are installed in arrays that range from a few watts for sensor or communication applications, up to hundreds of megawatts for utility-scale power generation. PV systems can be installed on a stationary frame at a tilt to best capture the sun (fixed-tilt) or on a frame that can track the sun from sunrise to sunset.

CONCENTRATING PHOTOVOLTAICS use lenses to focus the sun’s light onto special, high-efficiency photovoltaics, which creates higher amounts of generation for the given photovoltaic cell size. The use of concentrating lenses requires that these technologies be precisely oriented towards the sun, so they typically require active tracking systems.

SOLAR THERMAL PLANTS focus the direct irradiance of the sun to generate heat to produce steam, which in turn drives a conventional turbine generator. Two general types are in use or

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development today, trough-based plants and tower-based plants. Trough plants use horizontally mounted parabolic mirrors or Fresnel mirrors to focus the sun onto a horizontal pipe that carries water or a heat transfer fluid. Tower plants use a field of mirrors that focus sunlight onto a central receiver. A heat transfer fluid is used to collect the heat and transfer it to make steam.

Commercial availability. Currently, renewable portfolio standards (RPS) drive most utility-scale solar development in the United States. Decreased prices and tax incentives have helped to fuel explosive solar growth in 2016 and this trend is expected to continue. Cumulative solar PV capacity in the U.S. reached 31.1 gigawatts (GW) by mid-2016, and 10 GW_{dc}¹⁷ of utility-scale solar is slated for construction in the second half of 2016 and first half of 2017 at the time of this writing.¹⁸

With less sunlight than other areas of the country and incentive structures that limit development to smaller systems, photovoltaic development has been relatively slow in the Northwest. California continues to be the U.S. leader with 13.8 MW_{dc} of combined residential, non-residential and utility-scale solar PV installations as of September 2016.¹⁹

Likewise, concentrating PV and concentrating solar thermal systems have not been developed in the Northwest, primarily because of the relatively low irradiance and low market power prices. While there are no customer or utility-scale solar thermal installations in Washington state, such facilities have proven reliable over time; thermal solar energy generating systems have been operating successfully in California since the 1980s.

¹⁷ / Solar is installed at direct current (dc).

¹⁸ / Solar Electric Industry Association (SEIA), Q2 2016, <http://www.seia.org/research-resources/solar-industry-data>.

¹⁹ / *Ibid.*

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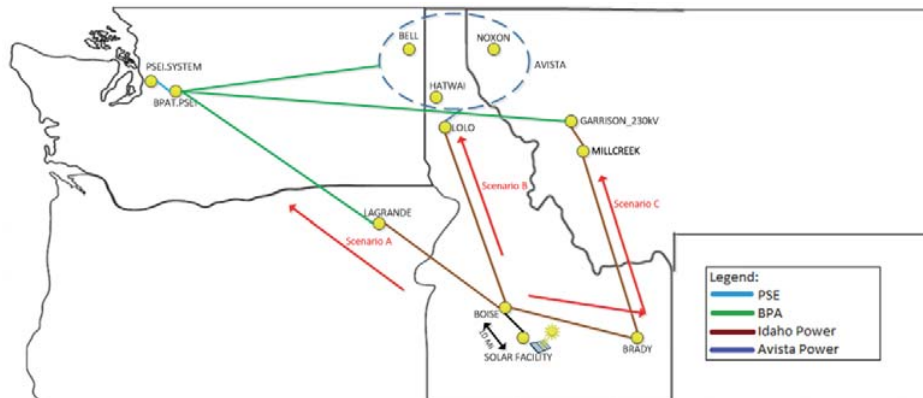


Cost and performance assumptions. Since PSE built the Wild Horse Solar Demonstration Project in 2007, installed costs for PV solar systems have declined considerably. According to the Solar Electric Industry Association, by the second quarter of 2016, utility fixed-tilt and tracking projects saw an average price of \$1.17 and \$1.30 per Watt_{dc}, respectively, and had reached approximately \$3.14 per Watt_{dc} for residential systems and \$2.19 per Watt_{dc} for commercial systems.²⁰

The EIA's *Annual Energy Outlook 2017* estimates capital costs for utility-scale PV solar systems to be approximately \$2,169 per kW_{ac}²¹ and solar thermal plants to be approximately \$3,908 per kW_{ac}.

For PSE's generic solar resource, we assumed it is located in eastern Washington and either connected to PSE's BA or connected to BPA and would only require one wheel. Washington solar has an estimated capacity factor of 27 percent, but a solar resource in Idaho has an estimated capacity factor of 30 percent; however, a solar resource located in Idaho would have to go through additional transmission to get to PSE. The solar in Idaho would interconnect to Idaho power, through BPA, then to PSE. This additional transmission will cost \$49.35/kw-yr with lines losses of 5.5 percent. Figure D-21 below is a description of the different transmission path options to get solar from Idaho to PSE.

Figure D-21: Washington Solar vs. Idaho Solar



20 | <http://www.seia.org/research-resources/solar-market-insight-report-2016-q3>

21 | PSE models generic solar resources as alternating current (ac) to recognize the cost of the conversion from dc to ac.



Wind Characteristics

Wind energy is the primary renewable resource that qualifies to meet RPS requirements in our region due to wind's technical maturity, reasonable lifecycle cost, acceptance in various regulatory jurisdictions and large "utility" scale compared to other technologies. However, it also poses challenges. Because of its variability, wind's daily and hourly power generation patterns don't necessarily correlate with customer demand; therefore, more flexible thermal and hydroelectric resources must be standing by to fill the gaps. This variability also makes wind power challenging to integrate into transmission systems. Finally, because wind projects are often located in remote areas, they frequently require long-haul transmission on a system that is already crowded and strained.

WASHINGTON, MONTANA AND OFFSHORE WIND. For this IRP, wind was modeled in three locations, eastern Washington, central Montana and offshore. Washington wind is located in BPA's balancing authority, so this wind only requires one transmission wheel through BPA to PSE. Montana wind, however, is outside BPA's balancing authority and will require four transmission wheels plus various system upgrades to deliver the power to PSE's service territory. The Judith Gap location was chosen because PSE was able to obtain data from that wind project for use in the analysis. Offshore wind would likely be located 22 miles off the coast of Washington near Grays Harbor. Offshore wind would require a marine cable to interconnect all the turbines and bring the power back to land. Once on land, it would require a transmission wheel through BPA to PSE.

Montana Wind Assumptions. The four scenarios PSE developed to determine the appropriate Montana wind costs to model in the IRP are labeled A through C in Figure D-24 and summarized in the table below it. Scenario A was modeled as the baseline. Scenario A looks at the cost to interconnect a 300 MW wind project at the Broadview substation using available transmission capacity from the retirement of Colstrip Units 1 & 2. Scenario B is the cost to interconnect a 300 MW wind project at the Colstrip substation using available transmission capacity from the retirement of Colstrip Units 1 & 2. Scenario C is the cost to interconnect 600 MW at the Broadview substation; 300 MW would use available transmission capacity from the retirement of Colstrip Units 1 & 2, the additional 300 MW would require constructing increased transmission capacity at the Broadview substation.



Figure D-22: Washington vs. Montana Wind, PSE Baseline Assumptions

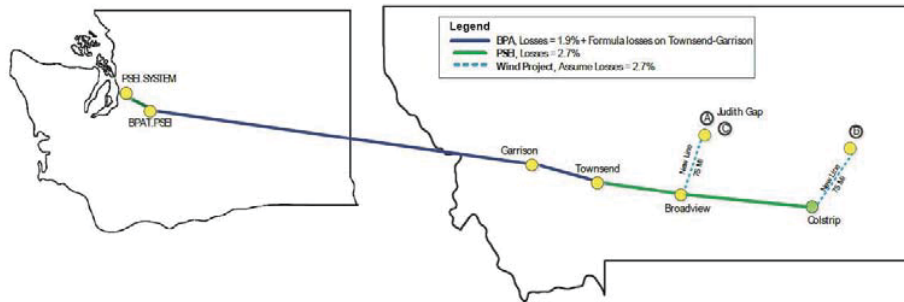


Figure D-23: Estimates of Interconnection Costs and Transmission Rates

| | OPTION | INTERCONNECTION COSTS (Millions \$) | TRANSMISSION RATES (\$/kW-yr) |
|---|--|-------------------------------------|---|
| A | Colstrip 1 & 2 Retired, 300 MW, 75 miles from Broadview Substation | \$52.2 | \$72.94 |
| B | Colstrip 1 & 2 Retired, 300 MW, 75 miles from Colstrip Substation | \$51.8 | \$72.94 |
| C | Colstrip 1 & 2 Retired, 600 MW, 75 miles from Broadview Substation | \$52.2 | \$72.94 + Impact of Capacity Increase on Rate |

NOTES

1. Interconnection cost is added to the total capital cost (\$/kw) of the wind project. See table D-22 for total cost of MT wind with interconnection costs.
2. Breakdowns of costs are listed below in table D-26.

There are many unknowns with the Montana transmission system. The shutdown of Colstrip units 1 & 2 will open up 300 MW of transmission to Washington. However, there could be transmission issues if the baseload resource is replaced with an intermittent resource. To count as a qualifying renewable resource under Washington’s RPS, wind outside the BPA footprint would have to be dynamically scheduled to match load. The assumptions for the scope and estimates of this study are listed below.

1. Transmission capacity available from the retirement of Colstrip Units 1 & 2 is currently unknown.
2. Costs to mitigate transmission impacts of retiring Colstrip Units 1 & 2 are currently unknown.
3. Interconnection costs and transmission facilities costs are estimates based on previous NorthWestern Energy (NWE) studies that assume Colstrip Units 1 & 2 are not retired.
4. Costs exclude costs to build generation.
5. Costs exclude overheads.



*Figure D-24: New Montana Wind Plant,
Breakdown of Estimates for Interconnection and Transmission Capital Costs*

| Assumptions for New Montana Wind Plant | Estimated Interconnection Costs (Millions) | Estimated Transmission Costs (Millions) |
|---|--|---|
| Scenario A: Colstrip 1 & 2 are retired, 300 MW Wind Plant (Broadview Substation) | | |
| New 75 mile 230kV line from Judith Gap to Broadview Substation (wood frame poles) | \$44.7 | |
| Broadview Substation upgrades to accommodate new 230kV line bay, assuming existing step-up transformer capacity is available ¹ | \$1.8 | |
| Fiber communication between Judith Gap and Broadview Substation | \$5.7 | |
| Other potential costs: Voltage support equipment, overdutied equipment, RAS, relay upgrades, communication upgrades, etc. ³ | Uncertain | Uncertain |
| Total Scenario A: | \$52.2 | - |
| Scenario B: Colstrip 1 & 2 are retired, 300 MW Wind Plant (Colstrip Substation) | | |
| New 75 mile 230kV line from Wind Farm to existing Colstrip Substation (Wood Frame Poles) | \$44.7 | |
| Colstrip Substation upgrades to accommodate new 230kV line bay, assuming existing step-up transformer capacity is available ² | \$1.4 | |
| Fiber for communications between Wind Farm and Colstrip Substation | \$5.7 | |
| Other Potential Costs: Voltage support equipment, overdutied equipment, RAS, relay upgrades, communication upgrades, etc. ³ | Uncertain | Uncertain |
| Total Scenario B: | \$51.8 | - |
| Scenario C: Colstrip 1 & 2 are retired, 600 MW Wind Plant (Broadview Substation) | | |
| New 75 mile 230kV line from Judith Gap to Broadview Substation (wood frame poles) | \$44.7 | |
| Broadview Substation upgrades to accommodate new 230kV line bay, assuming existing step-up transformer capacity is available ¹ | \$1.8 | |
| Fiber communication between Judith Gap and Broadview Substation | \$5.7 | |
| NWE Facility Study - Upgrades required from Broadview to Garrison to increase line capacity ⁴ | - | \$73 |
| Other potential costs: Voltage support equipment, overdutied equipment, RAS, relay upgrades, communication upgrades, etc. ³ | Uncertain | Uncertain |
| Total Scenario C: | \$52.2 | \$73 |

NOTES

1. Refer to NWE Facilities Interconnection Study for Project #207 completed in August 2016. This study assumes Colstrip 1 & 2 are not retired.
2. Refer to NWE Revised System Impact Study Report for Project #164 completed in January 2016. This study assumes Colstrip 1 & 2 are not retired.
3. Additional costs may be identified in an interconnection study or transmission service request that are currently unpredictable.
4. Refer to NWMT Transmission Service Request Facilities Study Report completed for Gaelectric LLC in January 2014 for additional 550 MW of capacity.



Figure D-25: Montana Wind Site Statistics

| ESTIMATED WIND CAPACITY | PERCENTAGE |
|------------------------------------|---------------|
| MT Wind Capacity Factor | 46.00% |
| Loss Factor | 7.30% |
| Wind Capacity Net of Losses | 42.64% |

Figure D-26: Montana Wind Transmission Rate Breakdown

| TRANSMISSION RATES | PERCENTAGE |
|---|----------------|
| Colstrip to Townsend (PSEI) | \$31.83 |
| Townsend to Garrison (BPA) | \$7.36 |
| Garrison to PSEI (BPA) ¹ | \$21.62 |
| Estimated Wind Integration Costs ² | \$12.12 |
| Impact of Capacity Increase on Rate | Uncertain |
| Total Transmission Rate | \$72.94 |

NOTES

1. BP-18 initial proposal, point-to-point (PTP) transmission plus scheduling
2. BP-18 initial proposal, Balancing Reserve rates

Land-based Wind

Wind turbine generator technology is mature and the dominant form of new renewable energy generation in the Pacific Northwest. While the basic concept of a wind turbine has remained generally constant over the last several decades, the technology continues to evolve, yielding larger towers, wider rotor diameters, greater nameplate capacity and increased wind capture (efficiency). Commercially available machines are in the 2.0 to 3.0 MW range with hub heights of 80 to 100²² meters and blade diameters topping out around 110 meters. These changes have come about largely because development of premium high-wind sites has pushed new development into less-energetic wind sites. The current generation of turbines is pushing the physical limits of existing transportation infrastructure. In addition, if nameplate capacity and turbine size continue to increase, the industry must explore creative solutions, such as concrete tower foundations poured on site.

Commercial availability. Recent tax law changes to provide incentives will drive demand in the short term. Greenfield development of a new wind facility requires approximately three to five years and consists of the following activities at a minimum: one to two years for development, permitting and major equipment lead-time, and one year for construction.

²² / One hundred meters is equivalent to 328 feet which is equivalent to a 30-story building.



Cost and performance assumptions. The cost for installing a wind turbine includes the turbine, foundation, roads and electrical infrastructure. Installed cost for a typical facility in the Northwest region is approximately \$2,000 per kW. The levelized cost of energy for wind power is a function of the installed cost and the performance of the equipment at a specific site, as measured by the capacity factor. The all-in levelized cost of energy ranges from \$43.0 to \$78.5 per MWh, which is very dependent on the quality of wind at the location.²³

Offshore Wind

Offshore winds tend to blow harder and more uniformly than on land. The potential energy produced from wind is directly proportional to the cube of the wind speed. As a result, increased wind speeds of only a few miles per hour can produce a significantly larger amount of electricity. For instance, a turbine at a site with an average wind speed of 16 mph would produce 50 percent more electricity than at a site with the same turbine and average wind speeds of 14 mph.

The wind turbine generators used in offshore environments include modifications to prevent corrosion. Additionally, their foundations must be designed to withstand the harsh environment of the ocean, including storm waves, hurricane-force winds, and even ice floes. The engineering and design of offshore wind facilities depends on site-specific conditions, particularly water depth, geology of the seabed and wave loading. Foundations for offshore wind fall into two major categories, fixed and floating, with a variety of styles for each category. The fixed foundation is a proven technology that is used throughout Europe. Monopiles are the preferred foundation type, which are steel piles driven into the seabed to support the tower and shell. Fixed foundations can be installed to a depth of 60 meters.

Roughly 90 percent of the U.S. wind energy resource occurs in waters too deep for current turbine technology, particularly on the West Coast. Engineers are working on new technologies, such as innovative floating wind turbines, that will transition wind power development to the harsher conditions associated with deeper waters.

All power generated by offshore wind turbines must be transmitted to shore and connected to the power grid. Each turbine is connected to an electric service platform (ESP) by a power cable. High voltage cables, typically buried beneath the sea bed, transmit the power collected from the wind turbines from the ESP to an onshore substation where the power is integrated into the grid.

23 / Source: http://www.eia.gov/outlooks/aeo/pdf/electricity_generation.pdf



Cost and performance assumptions. Offshore wind installations have higher capital costs than land-based installations per unit of generating capacity, largely because of turbine upgrades required for operation at sea and increased costs related to turbine foundations, balance of system infrastructure, interconnection and installation. In addition, one-time costs are incurred with the development of the infrastructure to support the offshore industry, such as vessels for turbine installation.

Currently in the United States, there are no large-scale, commercially operational offshore wind projects, and the first demonstration project was only recently installed in December 2016. As a result, capital cost estimates for large-scale U.S. installations are pure conjecture. Offshore wind would benefit from federal and state government mandates, renewable portfolio standards, subsidies and tax incentives to help jump-start the market. As the market develops, costs should decrease dramatically as experience is gained. In addition, as the technology develops, bigger units should be able to capture more wind and achieve greater economies of scale.²⁴

Commercial Availability. In Europe, offshore wind is a proven technology; there, 11 GW have been installed since 1991 and costs continue to decrease. On the other hand, the U.S. is just beginning the process of developing offshore wind. The first offshore wind installation in the U.S., the 30-MW Block Island demonstration project in Rhode Island, became operational in December 2016. However, thousands of megawatts of future development are currently in the planning stages, mostly in the Northeast and Mid-Atlantic regions. Projects are also being considered along the Great Lakes, the Gulf of Mexico and the Pacific Coast. The floating platforms required for deep water offshore wind are yet not commercially available.

²⁴ / http://www1.eere.energy.gov/wind/pdfs/national_offshore_wind_strategy.pdf; <http://www.nrel.gov/wind/offshore-energy-analysis.html>; <https://energy.gov/sites/prod/files/2015/09/f26/2014-2015-offshore-wind-technologies-market-report-FINAL.pdf>



Renewable Resources Not Modeled

FUEL CELLS. Fuel cells combine fuel and oxygen to create electricity, heat, water and other byproducts through a chemical process. Fuel cells have high conversion efficiencies from fuel to electricity compared to many traditional combustion technologies, on the order of 25 to 60 percent. In some cases, conversion rates can be boosted using heat recovery and reuse. Fuel cells operate and are being developed at sizes that range from watts to megawatts. Smaller fuel cells power items like portable electric equipment, larger ones can be used to power equipment, buildings or provide backup power. Fuel cells differ in the membrane materials used to separate fuels, the electrode and electrolyte materials used, operating temperatures and scale (size). Reducing cost and improving durability are the two most significant challenges to fuel cell commercialization. To be economical, fuel cell systems must be cost-competitive with, and perform as well as, traditional power technologies over the life of the system.²⁵

Provided that feedstocks are kept clean of impurities, fuel cell performance can be very reliable. They are often used as backup power sources for telecommunications and data centers, which require very high reliability. In addition, fuel cells are starting to be used for commercial combined heat and power applications, though mostly in states with significant subsidies or incentives for fuel cell deployment.

Commercial availability. Fuel cells have been growing in both number and scale, but they do not yet operate at large scale. According to the Department of Energy's report *State of the States: Fuel Cells in America 2016*,²⁶ there are fuel cell installations in 43 states, and more than 235 MW of large stationary (100 kW to multi-megawatt) fuel cells are currently operating in the U.S. The report further states that while California has the greatest number of stationary fuel cells, Connecticut (14.9 MW) and Delaware (30 MW) are home to the largest installations. In some states, incentives are driving fuel cell pricing economics to be competitive with retail electric prices, especially where additional value can be captured from waste heat. Currently, Washington state offers no incentives specific to fuel cells. The EIA's *Annual Energy Outlook 2017* estimates fuel cell capital costs to be approximately \$6,252 per kW.

²⁵ / U.S. Department of Energy, *Energy Efficiency and Renewable Energy, Fuel Cell Technologies Program*.
²⁶ / Source: U.S. Department of Energy's report, "State of the States: Fuel Cells in America 2016," dated November 2016 (<https://energy.gov/eere/fuelcells/downloads/state-states-fuel-cells-america-2016>).



GEOTHERMAL. Geothermal generation technologies use the natural heat under the surface of the earth to provide energy to drive turbine generators for electric power production. Geothermal energy production falls into four major types.

Dry Steam Plants use hydrothermal steam from the earth to power turbines directly. This was the first type of geothermal power generation technology developed.²⁷

Flash Steam Plants operate similarly to dry steam plants, but they use low-pressure tanks to vaporize hydrothermal liquids into steam. Like dry steam plants, this technology is best suited to high-temperature geothermal sources (greater than 182 degrees Celsius).²⁸

Binary-cycle Power Plants can use lower temperature hydrothermal fluids to transfer energy through a heat exchanger to a fluid with a lower boiling point. This system is completely closed-loop, no steam emissions from the hydrothermal fluids are released at all. The majority of new geothermal installations are likely to be binary-cycle systems due to the limited emissions and the greater number of potential sites with lower temperatures.²⁹

Enhanced Geothermal or “hot dry rock” technologies involve drilling deep wells into hot dry or nearly dry rock formations and injecting water to develop the hydrothermal working fluid. The heated water is then extracted and used for generation.³⁰

Geothermal plants typically run with high uptime, often exceeding 85 percent. However, plants sometimes do not reach their full output capacity due to lower than anticipated production from the geothermal resource.

Commercial availability. At the end of 2015, approximately 3.7 GW of geothermal generating capacity was online in the United States. Operating geothermal plants in the Northwest include the 28.5 MW Neal Hot Springs plant and the 15.8 MW Raft River plant in Idaho. An estimated 110 MW of planned capacity additions are in some stage of development in the Northwest, in Oregon and Idaho.³¹

²⁷ / <http://energy.gov/eere/geothermal/electricity-generation>

²⁸ / *Ibid.*

²⁹ / *Ibid.*

³⁰ / http://energy.gov/sites/prod/files/2014/02/f7/egs_factsheet.pdf

³¹ / *Geothermal Energy Association, 2016 Annual US & Global Geothermal Power Production Report.* ([http://www.geo-energy.org/reports/2016/2016 Annual US Global Geothermal Power Production.pdf](http://www.geo-energy.org/reports/2016/2016%20Annual%20US%20Global%20Geothermal%20Power%20Production.pdf)).

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The EIA's *Annual Energy Outlook 2017* estimates capital costs for geothermal resources to be approximately \$2,586. Because geothermal cost and performance characteristics are specific for each site, this represents the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located. Overall, site-specific factors including resource size, depth and temperature can significantly affect costs.

WASTE-TO-ENERGY TECHNOLOGIES. Converting wastes to energy is a means of capturing the inherent energy locked into wastes. Generally, these plants take one of the following forms.

Waste Combustion Facilities. These facilities combust waste in a boiler and use the heat to generate steam to power a turbine that generates electricity. This is a well-established technology, with 86 plants operating in the United States, representing 2,720 MW in generating capacity.³²

Waste Thermal Processing Facilities. This includes gasification, pyrolysis and reverse polymerization. These facilities add heat energy to waste and control the oxygen available to break down the waste into components without combusting it. Typically, a syngas is generated, which can be combusted for heat or to produce electricity. A number of pilot facilities once operated in the United States, but only a few remain today.

Landfill Gas And Municipal Wastewater Treatment Facilities. Most landfills in the United States collect methane from the decomposition of wastes in the landfill. Many larger municipal wastewater plants also operate anaerobic systems to produce gas from their organic solids. Both of these processes produce a low-quality gas with approximately half the methane content of natural gas. This low-quality gas can be collected and scrubbed to remove impurities or improve the heat quality of the gas. The gas can then be used to fuel a boiler for heat recovery, or a turbine or reciprocating engine to generate electricity. There were 650 landfill gas energy projects operating in 49 U.S. states in 2015. According to the U.S. EPA, these facilities, combined, were capable of providing 16 billion kWh of electricity and 99 billion cubic feet of landfill gas to end users, or enough energy to power nearly 1.3 million homes that year.³³

Commercial availability. Washington's RPS initially included landfill gas as a qualifying renewable energy resource, but excluded municipal solid waste. The passage of ESSB 5575 later expanded the definitions of wastes and biomass to allow some new wastes, such as food and yard wastes, to qualify as renewable energy sources.

³² / U.S. Environmental Protection Agency website. Retrieved from <http://www.epa.gov/waste/nonhaz/municipal/wtel/>, January 2015.

³³ / U.S. Environmental Protection Agency website. Retrieved from https://www.epa.gov/sites/production/files/2016-08/documents/green_power_from_landfill_gas.pdf, December 2016.

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Currently, several waste-to-energy facilities are operating in or near PSE's electric service area. Three waste facilities – the H.W. Hill Landfill Gas Project, the Spokane Waste-to-Energy Plant and the Emerald City facility – use landfill gas for electric generation in Washington state; combined, they produce up to 67 MW of electrical output. The H.W. Hill facility in Klickitat County is fed from the Roosevelt Regional Landfill and capable of producing a maximum capacity of 36.5 MW.³⁴ The Spokane Waste-to-Energy Plant processes up to 800 tons per day of municipal solid waste from Spokane County and is capable of producing up to 26 MW of electric capacity.³⁵ Emerald City uses landfill gas produced at the LRI Landfill in Pierce County to generate up to 4.5 MW of electricity. The facility became commercially operational in December 2013.³⁶ PSE purchases the electricity produced by the facility through a power purchase agreement under a Schedule 91 contract, which is discussed above.

The largest landfill in PSE's service territory, the Cedar Hills landfill, currently purifies its gas to meet pipeline natural gas quality; then they sell that gas to PSE rather than using it to generate electricity.

Cost and performance assumptions. Relatively few new waste combustion and landfill gas-to-energy facilities have been built since 2010, making it difficult to obtain reliable cost data. The EIA's *Annual Energy Outlook 2017* estimates municipal solid waste-to-energy costs to be approximately \$8,059 per kW.

In general, waste-to-energy facilities are highly reliable. They have used proven generation technologies and gained considerable operating experience over the past 30 years. Some variation of output from landfill gas facilities and municipal wastewater plants is expected due to uncontrollable variations in gas production. For waste combustion facilities, output is typically more stable, as the amount of input waste and heat content can be more easily controlled.

³⁴ / Phase 1 of the H.W. Hill facility consists of five reciprocating engines, which combined produce 10.5 MW. Phase 2, completed in 2011, adds two 10-MW combustion turbines, and a heat recovery steam generator and steam turbine for an additional 6 MW. Source: Klickitat PUD website. Retrieved from <http://www.klickitatpud.com/topicalMenu/about/powerResources/hwHillGasProject.aspx>, December 2016.

³⁵ / Spokane Waste to Energy website. Retrieved from <http://www.spokanewastetoenergy.com/WastetoEnergy.htm>, December 2016.

³⁶ / BioFuels Washington, LLC landfill gas to energy facility (later sold to Emerald City Renewables, LLC) solid waste permit (2014-2015) and permit application (2013), as posted to the Tacoma – Pierce County Health Department website. Retrieved from <http://www.tpchd.org/environment/waste-management/lri-landfill/>, December 2016.



WAVE AND TIDAL. The natural movement of water can be used to generate energy through the flow of tides or the rise and fall of waves.

Tidal Generation technology uses tidal flow to spin rotors that turn a generator. Two major plant layouts exist: barrages, which use artificial or natural dam structures to accelerate flow through a small area, and in-stream turbines, which are placed in natural channels. The Rance Tidal Power barrage system in France was the world's first large-scale tidal power plant. It became operational in 1966 and has a generating capacity of approximately 240 MW. The Sihwa Lake Tidal Power Station in South Korea is currently the world's largest tidal power facility. The plant was opened in late 2011 and has a generating capacity of approximately 254 MW. Other notably large tidal facilities include the 240 MW Swansea Bay Tidal Lagoon in the United Kingdom, the 86 MW MeyGen Tidal Energy Project in Scotland and the 20 MW Annapolis Royal Generating Station in Nova Scotia, Canada.³⁷

Wave Generation technology uses the rise and fall of waves to drive hydraulic systems, which in turn fuel generators. Technologies tested include floating devices such as the Pelamis and bottom-mounted devices such as the Oyster. The largest wave power plant in the world was the 2.25 MW Agucadoura Wave Farm off the coast of Portugal, which opened in 2008.³⁸ It has since been shut down because of the developer's financial difficulties.

In 2015, a prototype wave energy device developed by Northwest Energy Innovations was successfully launched and installed for grid-connected, open-sea pilot testing at the Navy's Wave Energy Test Site in Kaneohe Bay on the island of Oahu, Hawaii. According to the U.S. Department of Energy's web site, the 20-kilowatt Azura device is the nation's first grid-connected wave energy converter device.³⁹

Commercial availability. Since mid-2013, a number of significant wave and tidal projects and programs have slowed, stalled or shut down altogether. In general, wave and tidal resource development in the U.S. continues to face limiting factors such as funding constraints, long and complex permitting process timelines, relatively little experience with siting and the early-stage of the technology's development. FERC oversees permitting processes for tidal power projects, but

37 / Power Technology website. Retrieved from <http://www.power-technology.com/features/featuretidal-giants---the-worlds-five-biggest-tidal-power-plants-4211218>, April 2014.

38 / CNN website. Retrieved from <http://www.cnn.com/2010/TECH/02/24/wave.power.buoys/index.html>, February 2010.

39 / The U.S. Department of Energy website. Retrieved from <https://www.energy.gov/eere/articles/innovative-wave-power-device-starts-producing-clean-power-hawaii>, July 2015.



state and local stakeholders can also be involved. After permits are obtained, studies of the site's water resource and aquatic habitat must be made prior to installation of test equipment.

Currently, there are no operating tidal or wave energy projects on the West Coast. In late 2014, Snohomish PUD abandoned plans to develop a 1 MW tidal energy installation at the Admiralty Inlet.⁴⁰ Several years ago, Tacoma Power considered and later abandoned plans to pursue a project in the Tacoma Narrows.

Tidal and wave generation technologies are very early in development, making cost estimates difficult. Most developers have not produced more than one full-scale device, and many have not even reached that point. Few wave and tidal technologies have been in operation for more than a few years and their production volumes are limited, so costs remain high and the durability of the equipment over time is uncertain.

Demand-side Resource Costs and Characteristics

The demand-side resource alternatives considered include the following.

ENERGY EFFICIENCY MEASURES. This label is used for a wide variety of measures that result in a smaller amount of energy being used to do a given amount of work. Among them are building codes and standards that make new construction more energy efficient; retrofitting programs; appliance upgrades; and heating, ventilation and air conditioning (HVAC) and lighting changes.

DEMAND RESPONSE (DR). Demand response resources are comprised of flexible, price-responsive loads, which may be curtailed or interrupted during system emergencies or when wholesale market prices exceed the utility's supply cost.

DISTRIBUTED GENERATION. Distributed generation refers to small-scale electricity generators located close to the source of the customer's load.⁴¹

DISTRIBUTION EFFICIENCY (DE). This involves voltage reduction and phase balancing. Voltage reduction is the practice of reducing the voltage on distribution circuits to reduce energy

⁴⁰ / *The Seattle Times website. Retrieved from <http://www.seattletimes.com/seattle-news/snohomish-county-pud-drops-tidal-energy-project/>, October 2014.*

⁴¹ / *In this IRP distributed solar PV is not included in the demand-side resources. Instead, it is handled as a direct no-cost reduction to the customer load. Solar PV subsidies are driving implementation and the subsidies are not fully captured with by the Total Resource Cost (TRC) approach that is used to determine the cost-effectiveness of DSR measures. Under the TRC approach, distributed solar PV is not cost effective and so is not selected in the portfolio analysis. Treating solar as a no-cost load reduction captures the adoption of this distributed generation resource by customers and its impact on loads more accurately.*



consumption, as many appliances and motors can perform properly while consuming less energy. Phase balancing eliminates total current flow losses that can reduce energy loss.

GENERATION EFFICIENCY. This involves energy efficiency improvements at the facilities that house PSE generating plant equipment, and where the loads that serve the facility itself are drawn directly from the generator and not the grid. These loads are also called parasitic loads. Typical measures target HVAC, lighting, plug loads and building envelope end-uses.

CODES AND STANDARDS (C&S). No-cost energy efficiency measures that work their way to the market via new efficiency standards that originate from federal and state codes and standards.

Treatment of Demand-side Resource Alternatives

First, each demand-side measure was screened for technical potential. Screening for technical potential assumed that all energy and demand-saving opportunities could be captured regardless of cost or market barriers, so the full spectrum of technologies, load impacts and markets could be surveyed.

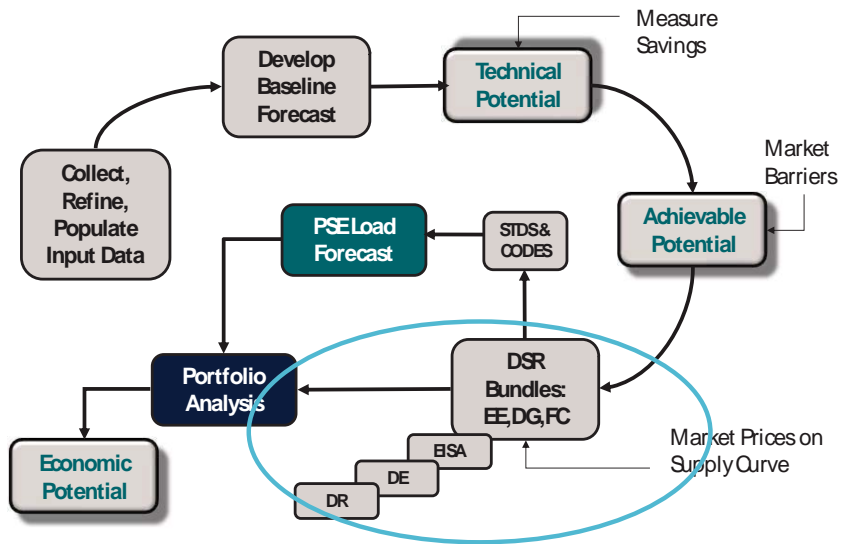
Second, market constraints were applied to estimate the achievable potential. To gauge achievability, we relied on customer response to past PSE energy programs, the experience of other utilities offering similar programs and the Northwest Power and Conservation Council's most recent energy efficiency potential assessment. For this IRP, PSE assumed achievable electric energy efficiency potentials of 85 percent in existing buildings and 65 percent in new construction.

Finally, the measures were combined into bundles based on levelized cost for inclusion in the portfolio optimization analysis. This methodology is consistent with the methodology used by the Northwest Power and Conservation Council.

Figure D-27 illustrates the methodology PSE used to assess demand-side resource potential in the IRP. Appendix J, Conservation Potential Assessment, contains a detailed discussion of the demand-side resource evaluation and development of the DSR bundles performed for PSE by Navigant.



Figure D-27: General Methodology for Assessing Demand-side Resource Potential



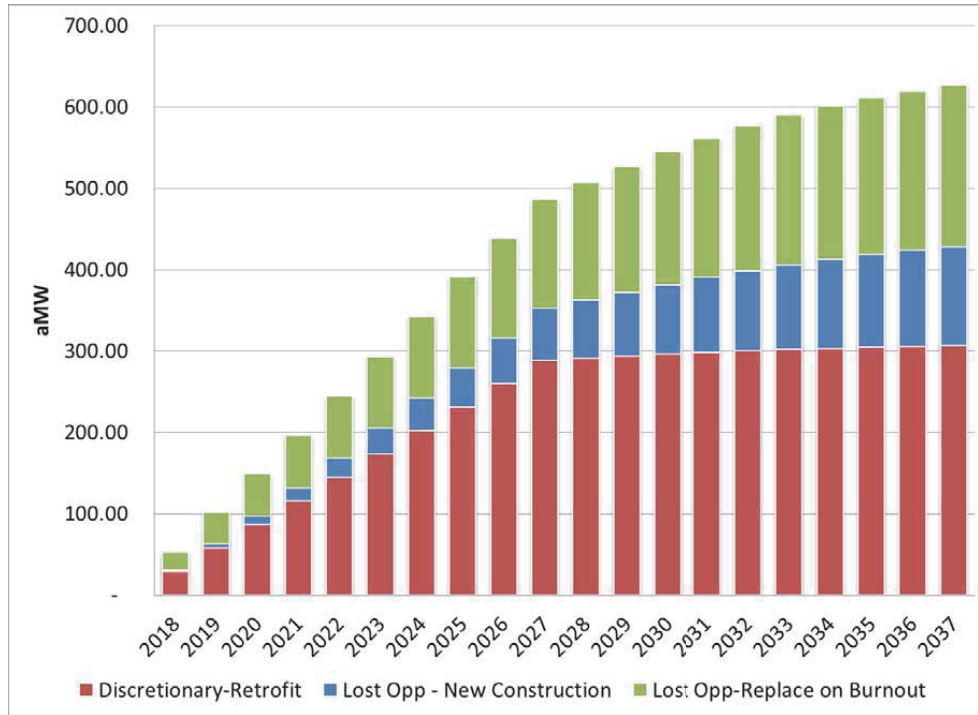
The following tables and charts summarize the results of the Navigant analysis of demand-side resources presented in Appendix J, Conservation Potential Assessment. Bundles 1 through 10 include energy efficiency, fuel conversion and distributed generation. Each bundle adds measures to the bundle that preceded it.

The savings potential for Bundles 1 through 10 consists of both discretionary and lost opportunity measures. Figure D-28 shows the proportion of discretionary versus lost opportunity measures in the bundles.

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Figure D-28: Discretionary versus Lost Opportunity Measures in Bundles 1 to 10



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Figure D-29: Annual Energy Savings (aMW)

| | Bundles (aMW) | | | | | | | | | | | |
|------|---------------|--------|--------|--------|--------|--------|--------|--------|--------|----------|-------|--------|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | DE | C&S |
| 2018 | 12.62 | 15.73 | 20.09 | 20.59 | 23.00 | 23.77 | 24.64 | 28.70 | 29.95 | 68.03 | 0.31 | 2.65 |
| 2019 | 35.90 | 45.23 | 58.06 | 59.55 | 66.83 | 69.13 | 71.75 | 84.08 | 87.83 | 203.64 | 0.93 | 10.05 |
| 2020 | 55.39 | 70.93 | 91.81 | 94.29 | 106.56 | 110.37 | 114.73 | 135.60 | 141.88 | 338.53 | 1.55 | 47.73 |
| 2021 | 72.34 | 94.08 | 122.80 | 126.28 | 143.65 | 148.96 | 155.04 | 184.84 | 193.66 | 474.11 | 2.18 | 84.77 |
| 2022 | 88.40 | 116.38 | 152.91 | 157.38 | 179.96 | 186.76 | 194.55 | 233.72 | 245.08 | 612.37 | 2.82 | 91.83 |
| 2023 | 103.93 | 138.16 | 182.32 | 187.80 | 215.68 | 223.92 | 233.34 | 281.81 | 295.67 | 749.69 | 3.45 | 97.21 |
| 2024 | 118.36 | 158.60 | 209.61 | 216.10 | 249.30 | 258.85 | 269.62 | 326.26 | 342.35 | 872.95 | 4.09 | 101.92 |
| 2025 | 131.74 | 177.85 | 235.12 | 242.63 | 281.14 | 291.90 | 303.78 | 367.76 | 385.87 | 985.30 | 4.73 | 106.35 |
| 2026 | 144.29 | 196.20 | 259.31 | 267.84 | 311.66 | 323.56 | 336.40 | 407.17 | 427.16 | 1,090.40 | 5.39 | 110.41 |
| 2027 | 155.90 | 213.49 | 281.78 | 291.33 | 340.46 | 353.39 | 366.98 | 443.56 | 465.23 | 1,183.85 | 6.07 | 114.68 |
| 2028 | 164.66 | 226.14 | 298.33 | 308.41 | 360.61 | 374.12 | 388.27 | 469.63 | 492.37 | 1,255.84 | 6.94 | 118.96 |
| 2029 | 170.70 | 234.34 | 309.32 | 319.45 | 372.48 | 386.12 | 400.72 | 486.07 | 509.36 | 1,310.00 | 7.93 | 122.42 |
| 2030 | 176.08 | 241.84 | 319.24 | 329.42 | 383.25 | 397.01 | 411.97 | 500.83 | 524.62 | 1,359.06 | 8.97 | 126.01 |
| 2031 | 180.66 | 248.35 | 327.60 | 337.82 | 392.43 | 406.23 | 421.43 | 512.99 | 537.11 | 1,398.32 | 9.95 | 130.86 |
| 2032 | 184.79 | 254.33 | 335.29 | 345.55 | 400.86 | 414.71 | 430.12 | 524.32 | 548.77 | 1,436.15 | 10.99 | 136.54 |
| 2033 | 188.48 | 259.75 | 342.29 | 352.57 | 408.53 | 422.42 | 438.02 | 534.77 | 559.55 | 1,472.34 | 12.04 | 142.10 |
| 2034 | 191.45 | 264.13 | 347.73 | 358.03 | 414.54 | 428.42 | 444.06 | 542.51 | 567.46 | 1,497.92 | 13.16 | 147.07 |
| 2035 | 193.89 | 267.75 | 352.13 | 362.44 | 419.42 | 433.26 | 448.86 | 548.52 | 573.57 | 1,517.34 | 14.21 | 152.01 |
| 2036 | 196.01 | 270.94 | 356.01 | 366.34 | 423.71 | 437.51 | 453.06 | 553.89 | 579.02 | 1,535.33 | 15.33 | 157.60 |
| 2037 | 197.86 | 273.75 | 359.48 | 369.82 | 427.51 | 441.27 | 456.77 | 558.75 | 583.94 | 1,552.18 | 16.45 | 163.34 |

Appendix D: Electric Resources



Figure D-30: Total December Peak Reduction (MW)

| | Bundles (MW) | | | | | | | | | | | |
|------|--------------|--------|-------|-------|-------|-------|-------|-------|-------|--------|-------|--------|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | DE | C&S |
| 2018 | 19.34 | 4.98 | 5.31 | 0.50 | 3.29 | 1.18 | 0.85 | 4.23 | 2.02 | 46.88 | 0.96 | 3.57 |
| 2019 | 52.89 | 14.08 | 13.15 | 1.50 | 9.93 | 3.18 | 1.95 | 9.23 | 5.29 | 106.24 | 1.93 | 13.52 |
| 2020 | 79.77 | 23.18 | 20.17 | 2.50 | 16.70 | 5.17 | 3.05 | 14.40 | 8.57 | 168.65 | 2.92 | 77.58 |
| 2021 | 102.34 | 32.31 | 26.76 | 3.50 | 23.61 | 7.14 | 4.15 | 19.97 | 11.82 | 234.33 | 3.92 | 142.53 |
| 2022 | 123.27 | 41.53 | 33.21 | 4.51 | 30.66 | 9.10 | 5.25 | 25.86 | 15.09 | 303.51 | 4.90 | 154.65 |
| 2023 | 143.27 | 50.80 | 39.44 | 5.52 | 37.84 | 11.02 | 6.28 | 31.73 | 18.28 | 372.34 | 5.90 | 163.31 |
| 2024 | 161.87 | 60.00 | 45.03 | 6.54 | 45.09 | 12.84 | 7.09 | 36.84 | 21.24 | 432.62 | 6.91 | 170.50 |
| 2025 | 179.44 | 69.40 | 50.62 | 7.56 | 52.40 | 14.64 | 7.84 | 42.23 | 24.19 | 494.52 | 7.92 | 177.30 |
| 2026 | 195.83 | 78.85 | 55.75 | 8.59 | 59.77 | 16.37 | 8.44 | 47.07 | 26.99 | 550.52 | 8.95 | 183.69 |
| 2027 | 211.28 | 88.43 | 60.60 | 9.62 | 67.19 | 18.07 | 8.96 | 51.63 | 29.71 | 603.92 | 10.12 | 190.11 |
| 2028 | 223.12 | 95.33 | 64.17 | 10.17 | 71.61 | 18.93 | 9.35 | 55.28 | 31.15 | 645.99 | 11.64 | 196.30 |
| 2029 | 231.47 | 99.57 | 66.62 | 10.22 | 73.00 | 19.00 | 9.68 | 58.29 | 31.40 | 680.14 | 13.20 | 201.54 |
| 2030 | 238.86 | 103.79 | 68.68 | 10.28 | 74.39 | 19.04 | 9.94 | 60.74 | 31.58 | 709.95 | 14.80 | 207.14 |
| 2031 | 245.33 | 107.87 | 70.34 | 10.32 | 75.73 | 19.05 | 10.12 | 62.63 | 31.68 | 734.88 | 16.46 | 214.19 |
| 2032 | 251.23 | 111.87 | 72.02 | 10.35 | 76.96 | 19.09 | 10.33 | 64.70 | 31.86 | 762.24 | 18.10 | 222.12 |
| 2033 | 256.25 | 115.54 | 73.34 | 10.38 | 78.04 | 19.10 | 10.46 | 66.21 | 31.97 | 783.98 | 19.76 | 230.08 |
| 2034 | 260.43 | 118.83 | 74.32 | 10.40 | 78.95 | 19.08 | 10.50 | 67.16 | 32.00 | 799.78 | 21.39 | 237.43 |
| 2035 | 263.99 | 121.81 | 75.19 | 10.42 | 79.67 | 19.06 | 10.50 | 67.99 | 32.04 | 813.75 | 23.14 | 244.51 |
| 2036 | 267.01 | 124.52 | 75.98 | 10.43 | 80.24 | 19.04 | 10.49 | 68.74 | 32.07 | 826.10 | 24.91 | 252.21 |
| 2037 | 269.60 | 127.01 | 76.70 | 10.45 | 80.68 | 19.02 | 10.47 | 69.42 | 32.11 | 837.20 | 26.77 | 260.33 |

Appendix D: Electric Resources



The DSR December peak reduction is based on the average of the very heavy load hours (VHLH). The VHLH method takes the average of the five-hour morning peak from hour ending 7 a.m. to hour ending 11 a.m. and the five-hour evening peak from hour ending 6 p.m. to hour ending 10 p.m. Monday through Friday. The system demand peaked during the evening hours and correspondingly the demand-side resource peaks were chosen to be coincident with those evening system peak hours.

*Figure D-31: Annual Costs (dollars in thousands)
(Codes and Standards has no cost and is considered a must-take bundle.)*

| Bundles (\$'000) | | | | | | | | | | | |
|------------------|-----------|----------|----------|---------|----------|----------|----------|-----------|----------|-------------|-------|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | DE |
| 2018 | \$13,617 | \$11,412 | \$24,380 | \$3,711 | \$25,096 | \$8,306 | \$10,447 | \$52,921 | \$19,392 | \$1,301,079 | \$467 |
| 2019 | \$23,349 | \$22,777 | \$47,179 | \$7,376 | \$49,369 | \$16,595 | \$20,820 | \$108,060 | \$38,877 | \$2,672,556 | \$467 |
| 2020 | \$110,203 | \$22,680 | \$44,324 | \$7,286 | \$47,919 | \$16,386 | \$20,634 | \$111,613 | \$39,152 | \$2,807,015 | \$467 |
| 2021 | \$119,200 | \$22,545 | \$42,551 | \$7,208 | \$47,330 | \$16,077 | \$20,418 | \$116,458 | \$39,054 | \$2,915,158 | \$467 |
| 2022 | \$33,207 | \$22,456 | \$41,758 | \$7,122 | \$46,933 | \$15,777 | \$20,183 | \$121,515 | \$38,852 | \$3,007,757 | \$467 |
| 2023 | \$25,668 | \$22,213 | \$40,169 | \$7,079 | \$45,935 | \$15,119 | \$19,192 | \$119,891 | \$37,815 | \$3,003,981 | \$467 |
| 2024 | \$19,873 | \$21,341 | \$35,632 | \$7,046 | \$44,531 | \$13,596 | \$15,896 | \$104,615 | \$33,496 | \$2,724,910 | \$467 |
| 2025 | \$15,827 | \$20,646 | \$32,029 | \$6,931 | \$42,870 | \$12,352 | \$12,857 | \$93,158 | \$29,974 | \$2,482,786 | \$467 |
| 2026 | \$12,764 | \$20,030 | \$29,264 | \$6,750 | \$41,155 | \$11,402 | \$10,728 | \$84,817 | \$27,341 | \$2,294,636 | \$467 |
| 2027 | \$10,501 | \$19,092 | \$25,293 | \$6,511 | \$39,378 | \$10,172 | \$8,278 | \$70,946 | \$23,601 | \$2,014,905 | \$545 |
| 2028 | \$7,290 | \$12,655 | \$18,444 | \$3,375 | \$22,356 | \$5,429 | \$6,096 | \$56,169 | \$14,552 | \$1,500,646 | \$701 |
| 2029 | \$4,576 | \$6,534 | \$12,562 | \$344 | \$6,067 | \$1,124 | \$4,554 | \$44,503 | \$6,847 | \$1,062,385 | \$701 |
| 2030 | \$3,979 | \$6,074 | \$10,499 | \$286 | \$5,661 | \$828 | \$3,579 | \$37,230 | \$5,736 | \$926,492 | \$701 |
| 2031 | \$3,283 | \$5,221 | \$7,689 | \$224 | \$5,052 | \$347 | \$2,277 | \$26,797 | \$3,766 | \$717,827 | \$701 |
| 2032 | \$2,791 | \$4,547 | \$6,395 | \$167 | \$4,296 | \$291 | \$1,799 | \$23,453 | \$3,349 | \$627,176 | \$701 |
| 2033 | \$2,312 | \$3,781 | \$5,326 | \$119 | \$3,445 | \$273 | \$1,427 | \$20,501 | \$3,003 | \$542,497 | \$701 |
| 2034 | \$1,689 | \$2,745 | \$3,287 | \$81 | \$2,576 | \$44 | \$594 | \$12,178 | \$1,511 | \$359,098 | \$701 |
| 2035 | \$1,195 | \$1,924 | \$2,045 | \$53 | \$1,789 | \$2 | \$212 | \$7,348 | \$769 | \$238,035 | \$701 |
| 2036 | \$814 | \$1,289 | \$1,423 | \$33 | \$1,129 | \$1 | \$115 | \$5,298 | \$534 | \$168,487 | \$701 |
| 2037 | \$472 | \$731 | \$846 | \$18 | \$600 | \$0 | \$51 | \$3,254 | \$312 | \$100,859 | \$701 |

Appendix D: Electric Resources



Demand response programs are organized into 5 categories. These include:

1. Direct Load Control (DLC)
2. Commercial and Industrial (C&I) Curtailment
3. Economic Demand Response
4. Residential Dynamic Pricing
5. C&I Dynamic Pricing

Figure D-32 describes the total December peak reduction achieved by each program, and Figure D-33 describes the costs for each program.

Figure D-32: Demand Response Programs, Total December Peak Reduction (MW)

| | Programs | | | | |
|------|----------|----|----|----|---|
| | 1 | 2 | 3 | 4 | 5 |
| 2018 | 9 | 5 | 2 | - | - |
| 2019 | 26 | 13 | 6 | - | - |
| 2020 | 52 | 26 | 10 | - | - |
| 2021 | 77 | 39 | 14 | - | - |
| 2022 | 85 | 42 | 15 | - | - |
| 2023 | 84 | 42 | 14 | 4 | 1 |
| 2024 | 85 | 42 | 14 | 12 | 2 |
| 2025 | 84 | 41 | 14 | 24 | 5 |
| 2026 | 84 | 41 | 14 | 36 | 7 |
| 2027 | 85 | 42 | 14 | 40 | 8 |
| 2028 | 85 | 41 | 14 | 40 | 8 |
| 2029 | 85 | 42 | 14 | 40 | 8 |
| 2030 | 86 | 42 | 15 | 40 | 8 |
| 2031 | 86 | 43 | 15 | 41 | 8 |
| 2032 | 87 | 43 | 15 | 41 | 8 |
| 2033 | 87 | 44 | 15 | 41 | 8 |
| 2034 | 88 | 44 | 15 | 41 | 9 |
| 2035 | 89 | 45 | 16 | 41 | 9 |
| 2036 | 90 | 46 | 16 | 42 | 9 |
| 2037 | 90 | 46 | 16 | 42 | 9 |

Appendix D: Electric Resources



Figure D-33: Demand Response Annual Costs (dollars in thousands)

| Programs (\$0'000) | | | | | |
|--------------------|----------|---------|---------|-----------|---------|
| | 1 | 2 | 3 | 4 | 5 |
| 2018 | \$1,945 | \$306 | \$390 | \$- | \$- |
| 2019 | \$4,567 | \$1,077 | \$836 | \$- | \$- |
| 2020 | \$7,007 | \$1,911 | \$868 | \$- | \$- |
| 2021 | \$7,743 | \$2,872 | \$634 | \$- | \$- |
| 2022 | \$4,129 | \$3,218 | \$44 | \$- | \$- |
| 2023 | \$2,136 | \$3,253 | \$(168) | \$909 | \$509 |
| 2024 | \$2,357 | \$3,309 | \$(150) | \$1,566 | \$778 |
| 2025 | \$2,295 | \$3,364 | \$(149) | \$2,126 | \$1,143 |
| 2026 | \$2,511 | \$3,463 | \$(123) | \$1,800 | \$1,138 |
| 2027 | \$2,648 | \$3,562 | \$(132) | \$(229) | \$324 |
| 2028 | \$4,809 | \$3,628 | \$379 | \$(1,272) | \$(103) |
| 2029 | \$7,462 | \$3,847 | \$972 | \$(1,330) | \$(93) |
| 2030 | \$10,261 | \$3,891 | \$1,124 | \$(1,284) | \$(95) |
| 2031 | \$10,847 | \$4,038 | \$911 | \$(1,333) | \$(100) |
| 2032 | \$6,663 | \$4,189 | \$183 | \$(1,353) | \$(107) |
| 2033 | \$4,193 | \$4,346 | \$(89) | \$(979) | \$393 |
| 2034 | \$4,557 | \$4,508 | \$(71) | \$(533) | \$720 |
| 2035 | \$4,523 | \$4,683 | \$(63) | \$(44) | \$1,207 |
| 2036 | \$4,949 | \$4,866 | \$(30) | \$52 | \$1,303 |
| 2037 | \$4,965 | \$5,035 | \$(59) | \$(1,007) | \$453 |



2017 PSE Integrated Resource Plan

Demand Forecasting Models

This appendix describes the econometric models used in creating the demand forecasts for PSE's 2017 IRP analysis.

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1. ELECTRIC BILLED SALES AND CUSTOMER COUNTS

PSE estimated use-per-customer (UPC) and customer count econometric equations using sample dates from a historical monthly data series that extends from January 1990 to December 2015; the sample dates varied depending on sector or class. Electric classes include residential, commercial, industrial, streetlights, resale and transport. The billed sales forecast is based on these estimated econometric equations, normal weather assumptions, rate forecasts, and forecasts of various economic and demographic inputs.

The UPC and customer count equations are defined as follows:

$$\begin{aligned}
 UPC_{c,t} &= f(RR_{c,t(k)}, W_{c,t}, EcoDem_{c,t(k)}, MD_m) \\
 CC_{c,t} &= f(EcoDem_{c,t(k)}, MD_m) \\
 MD_i &= \begin{cases} 1, & \text{Month} = i \\ 0, & \text{Month} \neq i \end{cases} \quad i \in \{1, 2, \dots, 12\} \\
 t &\in \{1, \dots, nobs\}
 \end{aligned}$$

$UPC_{c,t}$ = use (billed sales) per customer for class “c”, month “t”

$CC_{c,t}$ = customer counts for class “c”, month “t”

$t^{(k)}$ = the subscript $t^{(k)}$ denotes either a lag of “k” periods from “t” or a polynomial distributed lag form in “k” periods from month “t”

$RR_{c,t(k)}$ = effective real 12-month moving average of retail rates for class “c” in polynomial distributed lagged form

$W_{c,t}$ = class-appropriate weather variable; cycle-adjusted HDD/CDD using base temperatures of 65, 60, and 45 for HDD and 70 and 75 for CDD; cycle-adjusted HDDs/CDDs are created to fit consumption period implied by the class billing cycles

Appendix E: Demand Forecasting Models



$EcoDem_{c,t(k)}$ = class-appropriate economic and demographic variables; variables include income, household size, population, and employment levels or growth in polynomial distributed lagged form

MD_i = monthly dummy variable that is 1 when the month is equal to "i", and zero otherwise for "i" from 1 to 12

UPC is forecast monthly at a class level using several explanatory variables including weather, retail rates, monthly effects, and various economic and demographic variables such as income, household size and employment levels. Some of the variables, such as retail rates and economic variables, are added to the equation in a lagged or polynomial lagged form to account for both short-term and long-term effects of changes in these variables on energy consumption. Finally, depending on the equation, an ARMA(p,q) structure is imposed to acknowledge that future values of the predicted variables could be a function of its lag value or the lags of forecast errors.

Similar to UPC, PSE forecasts the customer count equations on a class level using several explanatory variables such as household population, total employment, or manufacturing employment. Some of the variables are also implemented in a lagged or polynomial distributed lag form to allow the impact of the variable to vary with time. Many of the customer equations use monthly customer growth as the dependent variable, rather than totals, to more accurately measure the impact of economic and demographic variables on growth, and to allow the forecast to grow from the last recorded actual value. ARMA(p,q) could also be imposed on certain customer counts equations.



The billed sales forecast for each customer class before new conservation is the product of the class UPC forecast and the forecasted number of customers in that class, as defined below.

$$Billed\ Sales_{c,t} = UPC_{c,t} \times CC_{c,t}$$

The billed sales and customer forecasts are adjusted for known, short-term future discrete additions and subtractions not accounted for in the forecast equations, such as major changes in energy usage by large customers. These adjustments may also include fuel and schedule switching by large customers. The forecast of billed sales is further adjusted for new programmatic conservation by class using the optimal conservation bundle from the most recent IRP.

Total billed sales in a given month are calculated as the sum of the billed sales across all customer classes:

$$Total\ Billed\ Sales_t = \sum_c Billed\ Sales_{c,t}$$

PSE estimates total system delivered loads by distributing monthly billed sales into each billing cycle for the month, then allocating the billing cycle sales into the appropriate calendar months using degree days as weights, and adjusting delivered sales for company own use and losses from transmission and distribution. This approach also enables computation of the unbilled sales each month.



2. ELECTRIC PEAK HOUR LOAD FORECASTING

Peak load forecasts are developed using econometric equations that relate observed monthly peak loads to weather-sensitive delivered loads for both residential and non-residential sectors. They also account for deviations of actual peak hour temperature from normal peak temperature for the month, day of the week effects, and unique weather events such as a cold snap or an El Niño season.

Based on the forecasted delivered loads, we use regression equations to estimate a set of hourly peak loads each month for the system based on three specific design temperatures: “Normal,” “Power Supply Operations” (PSO) and “Extreme.”

The “Normal” peak is based on the average temperature at the monthly peak during a historical time period, currently 30 years. The winter peaks are set at the highest Normal peak, which is currently the December peak of 23 degrees Fahrenheit. We estimated the PSO peak design temperatures to have a 1-in-20 year probability of occurring. These temperatures were established by examining the minimum temperature of each winter month during heavy load hours. An extreme value distribution function relating the monthly minimum temperature and the return probability was established. The analysis revealed the following design temperatures: 15 degrees Fahrenheit for January and February, 17 degrees Fahrenheit for November, and 13 degrees Fahrenheit for December. Finally, the “Extreme” peak design temperatures are estimated at 13 degrees Fahrenheit for all winter months.

Weather dependent loads are accounted for by the major peak load forecast explanatory variable, the difference between actual peak hour temperature and the average monthly temperature multiplied by system loads. The equations allow the impact of peak design temperature on peak loads to vary by month. This permits the weather-dependent effects of system delivered loads on peak demand to vary by season. The sample period for this forecast utilized monthly data from January 2002 to December 2015.

Appendix E: Demand Forecasting Models



In addition to the effect of temperature, peak load estimates account for the effects of several other variables, among them the portion of monthly system delivered loads that affects peak loads but is non-weather dependent; a dummy variable that accounts for large customer changes; and a day of the week variable. The functional form of the electric peak hour equation is

$$PkMW_t = \bar{\alpha}_{1,m} \cdot MD_i \cdot S_t + \bar{\alpha}_{2,m} \chi_1 \cdot \Delta T \cdot MD_i \cdot S_t + \beta_{1,d} DD_d + \delta_1 \cdot LT_t$$

where:

$$\chi_1 = \begin{cases} 1, & \text{Month} = 6,7,8 \\ 0, & \text{Month} \neq 6,7,8 \end{cases}$$

$$MD_i = \begin{cases} 1, & \text{Month} = i \\ 0, & \text{Month} \neq i \end{cases} \quad i \in \{1,2,\dots,12\}$$

$PkMW_t$ = monthly system peak hour load in MW

S_t = system delivered loads in the month in aMW

MD_i = monthly dummy variable

ΔT = deviation of actual peak hour temperature from monthly normal temperature

DD_d = day of the week dummy

LT_d = late hour of peak dummy, if the peak occurs in the evening

χ_1 = dummy variables used to put special emphasis on summer months to reflect growing summer peaks.

Appendix E: Demand Forecasting Models



To clarify the equation above, when forecasting we allow the coefficients for loads to vary by month to reflect the seasonal pattern of usage. However, in order to conserve space, we have employed vector notation. The Greek letters α_m , β_d , and δ_d denote coefficient vectors; there are also indicator variables that account for air conditioning load, to reflect the growing summer electricity usage caused by increased saturation of air conditioning.

The peak load forecast is further adjusted for the peak contribution of future conservation based on the optimal DSM bundle derived from the IRP.



3. GAS BILLED SALES AND CUSTOMER COUNTS

At the gas system level, PSE forecasts use-per-customer (UPC) and customer counts for each of the customer classes it serves. The gas classes include firm classes (residential, commercial, industrial, commercial large volume and industrial large volume), interruptible classes (commercial and industrial) and transport classes (commercial firm, commercial interruptible, industrial firm and industrial interruptible). Energy demand from firm, interruptible and transport classes is summed to form the 2017 IRP Gas Base Demand Forecast.

PSE estimated the following UPC and customer count econometric equations using sample dates from a historical monthly data series that extends from January 1990 to December 2015; the sample dates varied depending on sector or class. The gas billed sales forecast is based on the estimated equations, normal weather assumptions, rate forecasts, and forecasts of various economic and demographic inputs.

The UPC and customer count equations are defined as follows:

$$UPC_{c,t} = f(RR_{c,t(k)}, W_{c,t}, EcoDem_{c,t(k)}, MD_m)$$

$$CC_{c,t} = f(EcoDem_{c,t(k)}, MD_m)$$

$$MD_i = \begin{cases} 1, & \text{Month} = i \\ 0, & \text{Month} \neq i \end{cases} \quad i \in \{1, 2, \dots, 12\}$$

$$t \in \{1, \dots, nobs\}$$

$UPC_{c,t}$ = use (billed sales) per customer for class “c”, month “t”

$CC_{c,t}$ = customer counts for class “c”, month “t”

— $t(k)$ = the subscript $t(k)$ denotes either a lag of “k” periods from “t” or a polynomial distributed lag form in “k” periods from month “t”

$RR_{c,t(k)}$ = effective real retail rates for class “c” in polynomial distributed lagged form

Appendix E: Demand Forecasting Models



$W_{c,t}$ = class-appropriate weather variable; cycle-adjusted HDDs using the base temperature of 35 or 65; cycle-adjusted HDDs are created to fit consumption period implied by the class billing cycles

$EcoDem_{c,t(k)}$ = class-appropriate economic and demographic variables; variables include unemployment rate, household size, non-farm employment levels and growth, manufacturing employment levels and growth, and building permits. Economic and demographic variables may be used in lag form or in polynomial distributed lag form.

MD_i = monthly dummy variable that is 1 when the month is equal to "i", and zero otherwise for "i" from 1 to 12

UPC is forecast monthly at a class level using several explanatory variables including weather, retail rates, monthly effects, and various economic and demographic variables such as unemployment rate, non-farm employment and manufacturing employment. Some of the variables, such as retail rates and economic variables are added to the equation in a lagged or polynomial lagged form to account for both short-term and long-term effects of changes in these variables on energy consumption. Finally, depending on the equation, an ARMA(p,q) structure could be imposed to acknowledge that future values of the predicted variables could be a function of its lag value or the lags of forecast errors.

Similar to UPC, PSE forecasts the gas customer count equations on a class level using several explanatory variables such as household size, building permits, total employment and manufacturing employment. Some of the variables are also implemented in a lagged or polynomial distributed lag form to allow the impact of the variable to vary with time. Many of the customer equations use monthly customer growth as the dependent variable, rather than totals, to more accurately measure the impact of economic and demographic variables on growth, and to allow the forecast to grow from the last recorded actual value. ARMA(p,q) could also be imposed on certain customer counts equations. In addition, some of the smaller customer classes are not forecast using equations; instead, those current customer counts are held constant throughout the forecast period. This is done for the transport classes, industrial interruptible class and industrial large volume class. These classes have low customer counts and are not expected to change significantly over the forecast period.



The billed sales forecast for each customer class, before new conservation, is the product of the class UPC forecast and the forecasted number of customers in that class, as defined below.

$$Billed\ Sales_{c,t} = UPC_{c,t} \times CC_{c,t}$$

The gas billed sales and customer forecasts are adjusted for known, short-term future discrete additions and subtractions not accounted for in the forecast equations, such as major changes in energy usage by large customers. These adjustments may also include fuel and schedule switching by large customers. The forecast of billed sales is further adjusted for new programmatic conservation by class using the optimal conservation bundle from the most recent IRP.

Total billed sales in a given month are calculated as the sum of the billed sales across all customer classes:

$$Total\ Billed\ Sales_t = \sum_c Billed\ Sales_{c,t}$$

PSE estimates total gas system delivered loads by distributing monthly billed sales into each billing cycle for the month, then allocating the billing cycle sales into the appropriate calendar months using heating degree days as weights, and adjusting delivered sales for company own use and losses from distribution. This approach also enables computation of the unbilled sales each month.



4. GAS PEAK DAY LOAD FORECAST

Similar to the electric peaks, the gas peak day is assumed to be a function of weather-sensitive delivered sales, the deviation of actual peak day average temperature from monthly normal average temperature and other weather events. The following equation used monthly data from October 1993 to December 2014 to represent peak day firm requirements:

$$PkDThm_t = \bar{\alpha}_{1,m} Fr_t + \bar{\alpha}_{2,m} \Delta T_g \cdot Fr_t + \alpha_{3,m} EN + \alpha_{4,m} M_t + \alpha_{5,m} Sum + \alpha_{6,m} CSnp$$

$$W_{in} = \begin{cases} 1, & \text{Mont } h = 1, 2, 11, 12 \\ 0, & \text{Mont } h \neq 1, 2, 11, 12 \end{cases}$$

$$Smr = \begin{cases} 1, & \text{Mont } h = 6, 7, 8, 9 \\ 0, & \text{Mont } h \neq 6, 7, 8, 9 \end{cases}$$

where:

$PkDThm_t$ = monthly system gas peak day load in dekatherms

Fr_t = monthly delivered loads by firm customers

ΔT_g = deviation of actual gas peak day average daily temperature from monthly normal temperature

EN = dummy for when El Niño is present during the winter

M_t = dummy variable for month of the year

$CSnp$ = indicator variable for when the peak occurred within a cold snap period lasting more than one day, multiplied by the minimum temperatures for the day

As before, the Greek letters are coefficient vectors as defined in the electric peak section above.

This formula uses forecasted billed sales as an explanatory variable, and the estimated model weighs this variable heavily in terms of significance. Therefore, the peak day equation will follow a similar trend as that of the billed sales forecast with minor deviations based on the impact of other explanatory variables. An advantage of this process is that it helps estimate the contribution of distinct customer classes to peak loads.

Appendix E: Demand Forecasting Models



The design peak day used in the gas peak day forecast is a 52 heating degree day (13 degrees Fahrenheit average temperature for the day). This standard was adopted in 2005 after a detailed, cost-benefit analysis requested by the WUTC. The analysis considered both the value customers place on reliability of service and the incremental costs of the resources necessary to provide that reliability at various temperatures; it is presented in Appendix I of the 2005 LCP. We use projected delivered loads by class and this design temperature to estimate gas peak day load. PSE's gas planning standard covers 98 percent of historical peak events, and it is unique to our customer base, our service territory and the chosen form of energy.



5. MODELING UNCERTAINTIES IN THE LOAD FORECAST

Load forecasts are inherently uncertain, and to acknowledge this uncertainty, high and low load forecast scenarios are developed. To create high and low forecasts, uncertainty in both weather and long-term economic and demographic growth in the service territory were included.

The econometric load forecast equations depend on certain types of economic and demographic variables; these may vary depending on whether the equation is for customer counts or use per customer, and whether the equation is for a residential or non-residential customer class. In PSE's load forecast models, the key service area economic and demographic inputs are population, employment, unemployment rate, personal income, and building permits. These variables are inputs into one or more load forecast equations.

To develop the stochastic simulations of loads, a stochastic simulation of PSE's economic and demographic electric and gas models is performed to produce the distribution of PSE's economic and demographic forecast variables. Since these variables are also a function of key U.S. macroeconomic variables such as population, employment, unemployment rate, personal income, personal consumption expenditure index and long-term mortgage rates, we utilize the stochastic simulation functions in EViews¹ by providing the standard errors for the quarterly growth of key U.S. macroeconomic inputs into PSE's economic and demographic models. These standard errors were based on historical actuals from 1980 to 2015. The stochastic simulation of PSE's economic and demographic models from 1,000 draws provides the basis for developing the distribution of the relevant economic and demographic inputs for the load forecast models over the forecast period. Based on these draws, standard errors were estimated for PSE service area population, employment, unemployment rate, personal income and building permits for each year over the forecast horizon. In a similar manner, these standard errors were used in producing the 250 stochastic simulations of PSE's load forecasts within EViews.

¹ / EViews is a popular econometric, forecasting and simulation tool.

Appendix E: Demand Forecasting Models



Additionally, we introduced weather variability into these 250 stochastic simulations using weather between 1929 and 2015 by creating 87 weather scenarios, each with 20 consecutive years of weather data. For weather strips starting after 1996 there are not 20 years of consecutive weather data available. Therefore, after 2015 in the data series, the data wraps around to weather from January 1, 1989. The last weather scenario year starts in 2015. Random weather strips were assigned to each of the 250 stochastic simulations created with the economic and demographic model uncertainties to create the range of uncertainty used for both the gas and electric model.

The high and low load forecasts are defined in the IRP as the 95th and 5th percentile, respectively, of the 250 stochastic simulations of the loads based on uncertainties in the economic and demographic inputs and the weather inputs.



6. HOURLY ELECTRIC DEMAND PROFILE

Because temporarily storing large amounts of electricity is costly, the minute-by-minute interaction between electricity production and consumption is very important. For this reason, and for purposes of analyzing the effectiveness of different electric generating resources, an hourly profile of PSE electric demand is required.

We use our hourly (8,760 hours) load profile of electric demand for the IRP for the stochastic analysis in the Resource Adequacy Model (RAM), for our power cost calculation and for other AURORA analyses. The estimated hourly distribution is built using statistical models relating actual observed temperatures, recent load data and the latest customer counts.

Data

Actual hourly delivered electric loads between January 1, 1994 and December 31, 2015 were used to develop the statistical relationship between temperatures and loads for estimating hourly electric demand based on a representative distribution of hourly temperatures. Based on this relationship, PSE developed a representative distribution of hourly temperatures based on data from January 1, 1950 to December 31, 2015

Methodology for Distribution of Hourly Temperatures

The above temperature data were sorted and ranked to provide two separate data sets: For each year, a ranking of hourly temperatures by month, coldest to warmest, over 60 years was used to calculate average monthly temperature. A ranking of the times when these temperatures occurred, by month, coldest to warmest, was averaged to provide an expected time of occurrence. Next PSE found the hours most likely to have the coldest temperatures (based on observed averages of coldest-to-warmest hour times) and matched them with average coldest-to-warmest temperatures by month. Sorting this information into a traditional time series then provided a representative hourly profile of temperature.



Methodology for Hourly Distribution of Load

For the time period January 1, 1994 to December 31, 2015, PSE used the statistical hourly regression equation:

$$\hat{L}_h = \beta_{1,d} \cdot DD_d + \alpha_1 L_{h-1} + \alpha_2 \left(\frac{L_{h-2} + L_{h-3} + L_{h-4}}{3} \right) + (\alpha_{3,m} T_h + \alpha_{4,m} T_h^2) + \beta_{2,d} Hol + \alpha_5 P^{(1)}(h)$$

for hours from one to 24 to calculate load shape from the representative hourly temperature profile. This means that a separate equation is estimated for each hour of the day.

\hat{L}_h = Estimated hourly load at hour “h”

L_h = Load at hour “h”

L_{h-k} = Load “k” hours before hour “h”

T_h = Temperature at time “h”

T_h^2 = Squared hourly temperature at time “h”

$P^{(1)}(h)$ = 1st degree polynomial

Hol = NERC holiday dummy variables

All Greek letters again denote coefficient vectors.



F

2017 PSE Integrated Resource Plan

Regional Resource Adequacy Studies

The results and data from these three studies of regional load/resource balance were used in the preparation of the 2017 PSE IRP.

Contents

1. NORTHWEST POWER AND CONSERVATION COUNCIL (NPCC)

Pacific Northwest Power Supply Adequacy Assessment for 2021

Published September 27, 2016

(attached)

2. PACIFIC NORTHWEST UTILITIES CONFERENCE COMMITTEE (PNUCC)

Northwest Regional Forecast of Power Loads and Resources 2017-2026

Published April 2016

(attached)

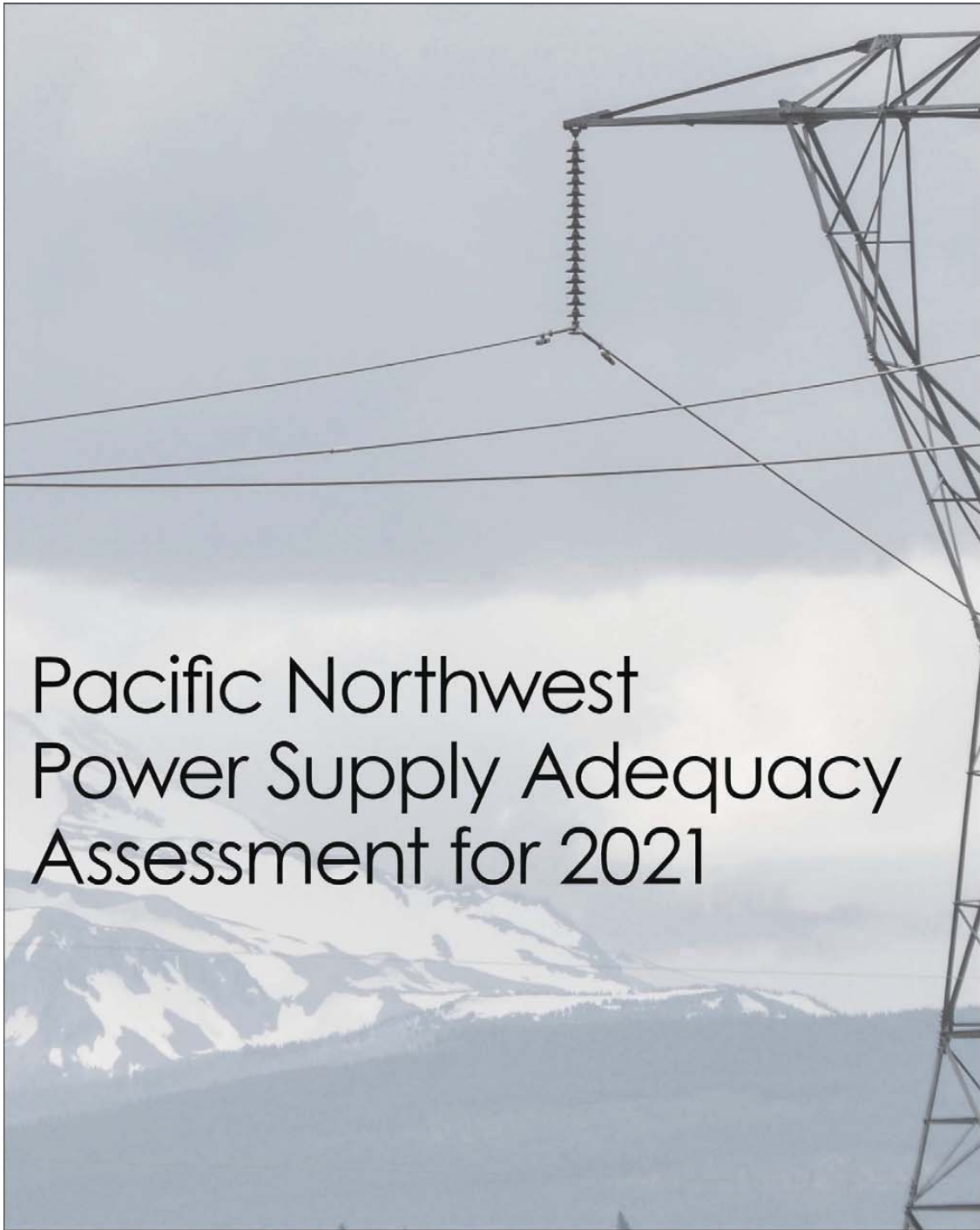
3. BONNEVILLE POWER ADMINISTRATION (BPA)

2016 Pacific Northwest Loads and Resources Study

Published December 22, 2016

Access this document at the following links:

- *Summary*
<https://www.bpa.gov/power/pgp/whitebook/2016/2016-WBK-Loads-and-Resources-Summary-20161222.pdf>
- *Energy Analysis*
<https://www.bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume-1-Energy-Analysis-20161222.pdf>
- *Capacity Analysis*
<https://www.bpa.gov/power/pgp/whitebook/2016/2016-WBK-Technical-Appendix-Volume%20-2-Capacity-Analysis-20161222.pdf>



Pacific Northwest Power Supply Adequacy Assessment for 2021



September 27, 2016
Document 2016-10



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FORWARD

This document summarizes the Northwest Power and Conservation Council's assessment of the adequacy of the power supply for the 2021 operating year (October through September). In 2011, the Council adopted the annual loss-of-load probability (LOLP) as the measure for power supply adequacy and set the maximum value at 5 percent. For a power supply to be deemed adequate, the likelihood (LOLP) of a shortfall (not necessarily an outage) occurring anytime in the year being examined cannot exceed 5 percent.

Other adequacy metrics that measure the size of potential shortages, how often they occur and how long they last, also provide valuable information to planners as they consider resource expansion strategies. This report provides that information along with other statistical data derived from Council analyses. The Council, with the help of the Resource Adequacy Advisory Committee, produced the data in the charts and tables.

The format and content of this report continue to be under development. We would like to know how useful this report is for you. For example, is the format appropriate? Would you like to see different types of output? Please send your comments, suggestions and questions to John Fazio at (jfazio@nwcouncil.org).

The Council is improving its adequacy model (GENESYS), in particular the hourly hydroelectric system dispatch simulation, and expects to complete the work by 2018. In addition, the Council has initiated a process to review its current adequacy standard. Staff and RAAC members have been asked to review the viability of the current metric (LOLP) and threshold (5 percent). This review should consider similar efforts going on in other parts of the United States, namely through the IEEE Loss-of-Load-Expectation Working Group and the North American Electric Reliability Corporation (NERC).

Cover photo courtesy of [SOAR Oregon](#).

EXECUTIVE SUMMARY

The Pacific Northwest's power supply should be adequate through 2020. However, with the planned retirements of four Northwest coal plants¹ by July of 2022, the system will no longer meet the Council's adequacy standard and will have to acquire nearly 1,400 megawatts of new capacity in order to maintain that standard. This result assumes that the region will meet the Council's energy efficiency targets, as identified in the Seventh Power Plan. Thus, it is imperative that we continue to implement cost-effective energy efficiency programs. Beyond energy efficiency, Northwest utilities have been steadily working to develop replacement resource strategies and have reported about 550 megawatts of planned generating capacity by 2021.² These strategies will include the next most cost-effective and implementable resources, which may include additional energy efficiency, demand response or new generating resources. The Council will reassess the adequacy of the power supply next year to monitor the region's progress in maintaining resource adequacy.

In 2011, the Northwest Power and Conservation Council adopted a regional adequacy standard to "provide an early warning should resource development fail to keep pace with demand growth." The standard deems the power supply to be inadequate if the likelihood of a power supply shortfall (referred to as the loss-of-load probability or LOLP) is higher than 5 percent. The LOLP for the region's power supply should stay under the 5 percent limit through 2020. In 2021, with the loss of 1,330 megawatts of capacity from the Boardman and Centralia 1 coal plants (slated to retire in December of 2020), the LOLP rises to 10 percent.³ In this scenario, the region will need a little over 1,000 megawatts of new capacity to maintain adequacy. Should the Colstrip 1 and 2 coal plants (307 megawatts committed to serve regional demand) also retire before 2021,⁴ the LOLP grows to just over 13 percent and the region's adequacy need grows to about 1,400 megawatts of new capacity.

These results are based on a stochastic analysis that simulates the operation of the power supply over thousands of different combinations of river flow, wind generation, forced outages, and temperatures. Since last year's assessment for 2021, which resulted in an 8 percent LOLP,

¹ Centralia 1 (670 megawatts) and Boardman (522 megawatts) are scheduled to retire by December 2020, Colstrip 1 and 2 (154 megawatts each) are to be retired no later than July of 2022 and Centralia 2 (670 megawatts) is expected to retire by 2025.

² From the Pacific Northwest Utility Conference Committee's 2016 Northwest Regional Forecast (NRF).

³ Boardman and Centralia 1 coal plants are scheduled to retire in December 2020. However, because the Council's operating year runs from October 2020 through September 2021, these two plants would be available for use during the first three months of the 2021 operating year. For this scenario, the LOLP is 7.6 percent. The Council must take into account the long-term effects of these retirements, and therefore uses the more generic study that has both plants out for the entire operating year.

⁴ Currently there is no indication that Colstrip plants 3 and 4 will be retired earlier than expected.

the region's load forecast has slightly decreased⁵ and no new resources have been added. This year's LOLP assessment for 2021 has grown to 10 percent because it included all regional balancing reserve requirements instead of only the federal system reserves assumed in last year's analysis.

The conclusions made above assume that future demand will stay on the Council's medium load forecast path and that only a fixed amount of imported generation from the Southwest is available. If demand growth were to increase rapidly and if the availability of imports were to drop, the LOLP could grow as high as 30 percent and the region's adequacy needs could grow to 2,600 megawatts or more. But these extreme cases are not very likely to occur.

Resource acquisition plans to bring the 2021 power supply into compliance with the Council's standard will vary depending on the types of new generating resources or demand reduction programs that are considered. In all likelihood, utilities will use some combination of new generation and load reduction programs to bridge the gap.

This analysis does not provide a strategy to maintain an adequate, efficient, economical, and reliable power supply. The Council's Seventh Power Plan outlines a resource strategy to ensure an adequate power supply for 2021.

Northwest utilities, as reported in the Pacific Northwest Utilities Conference Committee's 2016 Northwest Regional Forecast, show about 550 megawatts of planned generating capacity for 2021. However, these planned resources are not sited and licensed and are therefore not included in the 2021 adequacy assessment. As conditions change over the next few years, we expect utilities to revise their resource acquisition strategies to invest in new resources, which include energy efficiency and demand response.

⁵ This year's assessment included a hybrid load forecasting method that is different from past forecasts. This was done to insure that the load forecast used for the adequacy assessment was consistent with the one used for the development of the Council's Seventh Power Plan. The RAAC will evaluate this new load forecast in detail prior to next year's assessment for 2022.

THE COUNCIL'S RESOURCE ADEQUACY STANDARD

In 2011, the Northwest Power and Conservation Council adopted a regional adequacy standard to “provide an early warning should resource development fail to keep pace with demand growth.” The standard deems the power supply to be inadequate if the likelihood of a power supply shortfall five years in the future is higher than 5 percent.

The Council assesses adequacy using a stochastic analysis to compute the likelihood of a supply shortfall. It uses a chronological hourly simulation of the region's power supply over many different future combinations of stream flows, temperatures, wind generation patterns and forced generator outages. We only count existing generating resources, and those expected to be operational in the study year, along with targeted energy efficiency savings. The simulation also assumes a fixed amount of market resource availability, both from inside and outside of the region.

The power supply is deemed to be adequate if the likelihood of a shortfall (referred to as the loss of load probability or LOLP) is less than or equal to 5 percent. If the supply is deemed inadequate, the Council estimates how much additional capacity and energy generating capability is required to bring the system's LOLP back down to 5 percent. However, the standard is not intended to provide a resource-planning target because it assesses only one of the Council's criteria for developing a power plan. The Council's mandate is to develop a resource strategy that provides an adequate, efficient, economic and reliable power supply. There is no guarantee that a power supply that satisfies the adequacy standard will also be the most economical or efficient. Thus, the adequacy standard should be thought of as simply an early warning to test for sufficient resource development.

Because the computer model used to assess adequacy (GENESYS) cannot possibly take into account all contingency actions that utilities have at their disposal to avert an actual loss of service, a non-zero LOLP should not be interpreted to mean that real curtailments will occur. Rather, it means that the likelihood of utilities having to take extraordinary and costly measures to provide continuous service exceeds the tolerance for such events. Some emergency utility actions are captured in the LOLP assessment through a post-processing program that simulates the use of what the Council has termed “standby resources.”

Standby resources are demand-side actions and small generators that are not explicitly modeled in the adequacy analysis. They are mainly composed of demand response measures, load curtailment agreements and small thermal resources.

Demand response measures are typically expected to be used to help lower peak-hour demand during extreme conditions (e.g. high summer or low winter temperatures). These resources only have a capacity component and provide only a very limited amount of energy (i.e. they cannot be dispatched for more than a few hours at a time). The effects of demand response measures that have already been implemented are assumed to be reflected in the Council's load forecast.

New demand response measures that have no operating history and are therefore not accounted for in the load forecast are classified as part of the set of standby resources.

Load curtailment actions, which are contractually available to utilities to help reduce peak hour load, and small generating resources may also provide some energy assistance. However, they are not intended to be used often and are, therefore not modeled explicitly in the simulations. The energy and capacity capabilities of these non-modeled resources are aggregated along with the demand response measures mentioned above to define the total capability of standby resources. A post-processing program uses these capabilities to adjust the simulated curtailment record and calculate the final LOLP.

RECENT ADEQUACY ASSESSMENTS

Table 1 below illustrates the evolving nature of the effort to better quantify power supply adequacy. Since 1998, when the Council began using stochastic methods to assess adequacy, the power supply and, to some extent the methodology, have changed significantly, sometimes making it difficult to compare annual assessments. And, while this evolution is likely to continue, the Council believes that the current standard and methodology will be sufficiently stable to create a history of adequacy evaluations that can be used to record trends over time.

The Council recognizes that the power system of today is very different from that of 1980, when the Council was created by Congress. In particular, the ever increasing generation from variable energy resources, such as solar and wind, have added a greater band of uncertainty with regard to providing an adequate supply. This has led to a greater need in the ability to model hourly operations, especially for the hydroelectric system. Toward this end, the Council is currently in the process of redeveloping its adequacy model (GENESYS) to add more precision to the simulation of hydroelectric generation. The thrust of this effort is to improve the hourly operation simulation by adding a better representation of unit commitment, balancing reserve allocation and moving to a plant-specific hourly hydroelectric simulation (the current model simulates hourly hydroelectric generation in aggregate for the region). These enhancements, expected to be completed by 2018, could likely change the results in a significant way. It will require an extensive vetting effort to ensure that the results of the redeveloped model are a better representation of real-life operations. It will be important to identify the effects of the model enhancements to the resulting adequacy assessments and separate them from the effects of real load and resource changes.

Table 1: History of Adequacy Assessment

| Year Analyzed | Operating Year | LOLP | Observations |
|---------------|----------------|------|---|
| 2010 | 2015 | 5% | Was part of the Council's 6 th Power Plan |
| 2012 | 2017 | 7% | Imports decreased from 3,200 to 1,700 MW, load growth 150 aMW per year, only 114 MW of new thermal capacity |
| 2014 | 2019 | 6% | Load growth 120 aMW per year, over 600 MW new generating capacity, increased imports by 800 MW |
| 2015 | 2020 | 5% | Lower load forecast, 350 aMW of additional EE savings |
| 2015 | 2021 | 8% | <i>Early estimate (BPA INC/DEC only)</i> Loss of Boardman and Centralia 1 (~1,330 MW) |
| 2016 | 2021 | 10% | 2021 loads lower than last year's forecast regional INC/DEC reduces hydro peaking |
| 2016 | 2021 | 13% | Same as above but with Colstrip coal plants 1 and 2 retired (307 MW assigned to serve the region) |

2021 RESOURCE ADEQUACY ASSESSMENT

The Pacific Northwest's power supply is expected to be adequate through 2020. However, with the planned retirements of four Northwest coal plants by July of 2022, the system will no longer meet the Council's adequacy standard (LOLP at 13 percent) and will have to acquire nearly 1,400 megawatts of new capacity in order to reduce the LOLP to the 5 percent standard. This result assumes that the Council's energy efficiency targets, as identified in the Seventh Power Plan, will be achieved.

In 2021, with the loss of 1,330 megawatts of capacity from the Boardman and Centralia 1 coal plants (slated to retire in December of 2020), the LOLP rises to 10 percent.⁶ In this scenario, the region will need a little over 1,000 megawatts of new capacity to maintain adequacy. Should the Colstrip 1 and 2 coal plants (307 megawatts committed to serve regional demand) also retire

⁶ Boardman and Centralia 1 coal plants are scheduled to retire in December 2020. However, because the Council's operating year runs from October 2020 through September 2021, these two plants would be available for use during the first three months of the 2021 operating year. For this scenario, the LOLP is 7.6 percent. The Council must take into account the long-term effects of these retirements, and therefore uses the more generic study that has both plants out for the entire operating year.

before 2021, the LOLP grows to just over 13 percent and the region's adequacy need grows to about 1,400 megawatts of new capacity.

The conclusions made above assume that future demand will stay on the Council's medium load forecast path and that only a fixed amount of imported generation from the Southwest is available. If demand growth were to increase rapidly and if the availability of imports were to drop, the LOLP could grow as high as 26 percent and the region's adequacy needs could grow to 2,600 megawatts or more. But this extreme case is not very likely to occur.

Two future uncertainties not modeled explicitly in GENESYS are long-term (economic) load growth and variability of the out-of-region market supply. Long-term load growth is bounded by the Council's high and low load forecasts, which cover roughly 85 percent of the expected load range. Variation in SW market supply is influenced by future resource development in California and by the ability to transfer surplus energy into the Northwest.

By 2021, California is scheduled to retire 2,641 megawatts of its coastal water-cooled thermal power plants, and nearly 10,000 megawatts will either be retired or replaced over the next 10 years. In addition, in 2012 California lost 2,200 megawatts of San Onofre Nuclear Generating Station capacity.⁷ However, according to an Energy GPS report, California surplus is expected to greatly exceed the south-to-north intertie transfer capability during Northwest winter peak-load hours. Based on a look at historical monthly south-to-north transfer availability (BPA data), it appears that the maximum transfer capability hovers around 4,500 megawatts with a 95 percent chance of being at least 3,400 megawatts. The Council chose to set the maximum transfer capability from California into the Northwest to the 3,400 megawatt value.

In spite of the results of the Energy GPS survey of available California surplus, and supported by the Resource Adequacy Advisory Committee, the Council chose to limit California import availability to no more than 2,500 megawatts during peak hours in the winter and to 3,000 megawatts during off-peak hours year round. The on-peak imports are defined as a "spot market" resource, which can be acquired during the hour of need. The off-peak imports are defined as a "purchase ahead" resource, which can be acquired during the light-loads hours prior to an anticipated peak-hour shortfall.

To investigate the potential impacts of different combinations of economic load growth and California import availability, scenario analyses were performed. In one extreme case, with high load growth and no California import, the loss of load probability would be 26 percent. Fortunately, this scenario is not very likely. At the other end of extreme cases, with low load growth and maximum winter import availability, the loss of load probability drops to about 2 percent. Table 2 illustrates how LOLP changes as both long-term load growth and SW imports vary.

⁷ By 2025 the Diablo Canyon nuclear plant (2,200 megawatts) is expected to close.

Table 2: Load and SW Market Impacts to LOLP (121 MW new DR)

| Import | 3400 MW | 2500 MW | 1700 MW |
|-----------|---------|---------|---------|
| High Load | 22.1 | 24.2 | 26.2 |
| Med Load | 7.8 | 9.9 | 12.0 |
| Low Load | 1.9 | 3.7 | 5.6 |

Sensitivity Analysis

Sensitivity analyses are useful in helping to understand how results may change as particular input assumptions vary. We have already seen, in the section above, how LOLP changes as economic load growth and SW market assumptions vary. In this section, the sensitivity of LOLP to additional demand response and to a loss of gas supply is investigated.

Tables 3 and 4 show how LOLP changes as more demand response is added to the power supply.⁸ Studies run to produce the results in these tables are identical to those run to produce the results in Table 2, with the exception that more demand response was added to each. In Table 3, an additional 379 megawatts of demand response was added to all the studies (for a total of 500 megawatts of new demand response). In Table 4 an additional 1,136 megawatts (or a total of 1,257 megawatts) of new demand response was added. As evident in the results summarized in these tables, demand response can be a very effective resource toward maintaining an adequate supply. Studies using the Council's Regional Portfolio Model, during the development of the Seventh Power Plan, indicated that up to about 1,300 megawatts of new demand response resource could be cost effective relative to other options to maintain adequacy. Unfortunately, the infrastructure and experience needed to acquire that much new demand response is not as well developed as for energy efficiency programs, thus there remains uncertainty whether this level of new demand response would actually be implementable by 2021. The Council has encouraged utilities to continue to investigate and develop means to more easily acquire cost-effective demand response resources both for winter and summer needs.

⁸ It should be emphasized that demand response is exclusively a capacity provider with very limited energy contributions. As such, it may not be the best solution to offset longer-term curtailments (e.g. those that last over the 16 peak load hours of the day).

Table 3: Load and SW Market Uncertainty LOLP Map Existing (500 MW new DR)

| Import | 3400 MW | 2500 MW | 1700 MW |
|-----------|---------|---------|---------|
| High Load | 15.9 | 18.5 | 20.4 |
| Med Load | 5.5 | 7.7 | 9.5 |
| Low Load | 1.4 | 3.0 | 5.0 |

Table 4: Load and SW Market Uncertainty LOLP Map Existing (1,257 MW new DR)

| Import | 3400 MW | 2500 MW | 1700 MW |
|-----------|---------|---------|---------|
| High Load | 7.6 | 10.0 | 12.5 |
| Med Load | 2.6 | 4.7 | 6.7 |
| Low Load | 0.4 | 1.9 | 3.5 |

Table 5: Sensitivity – Loss of Gas Supply/Market Friction
(Loss of 650 MW IPP Resource)

| Import | Base Case | IPP Loss + 121 MW DR | IPP Loss + 500 MW DR | IPP Loss + 1257 MW DR |
|-----------|-----------|-------------------------|-------------------------|--------------------------|
| High Load | 24.2 | 30.0 | 23.1 | 13.3 |
| Med Load | 9.9 | 13.2 | 9.6 | 6.1 |
| Low Load | 3.7 | 5.4 | 4.5 | 2.9 |

Table 5 summarizes the sensitivity of LOLP to a loss of Northwest market supply due to a shortage of fuel (gas). The Northwest has about 3,000 megawatts (nameplate) of independent power producer (IPP) generating capability. Council adequacy assessments assume that all of that capability is available for Northwest use during winter months but only 1,000 megawatts is available during summer months (due to competition with SW utilities). These sensitivity studies examined how much the LOLP increases due to a loss of 650 megawatts of IPP generation during winter and about a 220 megawatt loss of IPP generation during summer.

As is evident in that table, a loss of Northwest market has a similar effect on LOLP (making it bigger) as does the loss of SW market supply. This type of analysis could also be thought of as a surrogate for a “market friction” sensitivity analysis. Market friction is commonly thought of as a decrease in market access due to transmission limitations or due to more conservative operations by utilities during periods of short supply (e.g. utilities may hold more generating capability in reserve during certain conditions) or a combination of both. This type of analysis will be important to investigate further for future adequacy assessments.

Monthly Analysis

Currently, the Council's adequacy standard sets a 5 percent maximum threshold for annual loss of load probability. This standard has been very useful in the past, especially compared to older deterministic methods, to aid the region in maintaining an adequate power supply. However, with the addition of more and more variable energy generation resources, such as wind and solar, and with the anticipated large increase in solar rooftop development, an annual metric may no longer be the best measure for adequacy. Figure 1 below shows the monthly LOLP values for both the reference case and the case with Colstrip 1 and 2 also retired. It is clear from this figure that the region has both winter and summer adequacy issues. For the reference case, the highest monthly LOLP values still appear mostly in winter but when the two Colstrip plants are also removed, the late summer LOLP value exceeds the winter month values.

It is important to differentiate by month (or at least by season) in order to find optimum resource acquisition strategies. For example, some demand response programs are only available in winter or in summer. It should be noted that the sum of monthly LOLP values will not equal the annual value because the annual value counts simulations with at least one curtailment event regardless of when it occurs. A simulation with multiple events, say one in January and one in August, would count the same for the annual LOLP value as a simulation with only a January event or only an August event. Monthly values for other adequacy metrics are summarized in that section of this report.

Figure 1: LOLP by Month

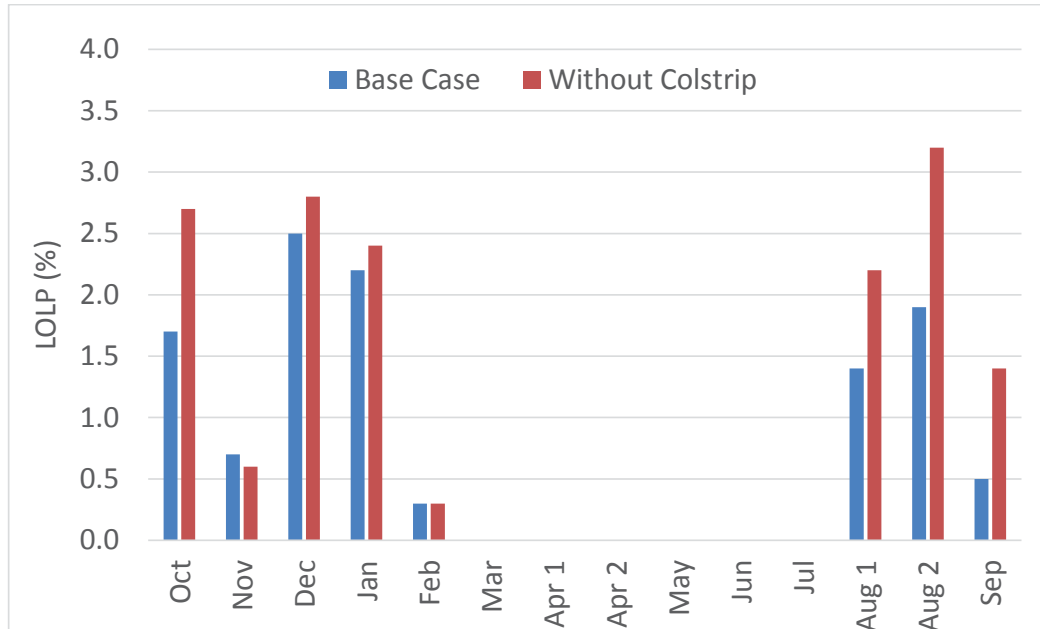


Table 6 summarizes the average monthly dispatch for groups of resources, namely wind, coal, gas, nuclear and SW market. This table shows the monthly dispatch for the reference case and for the case with the Colstrip 1 and 2 coal plant retirement and the difference. With the added loss of Colstrip 1 and 2, as expected, gas generation and SW market purchases go up to cover, as best they can, the loss of the coal generating capability. Obviously, the shift in the dispatch for these resources is not sufficient to offset the loss of the Colstrip plants as evident in the increase in curtailment events and the increase in the LOLP.

Table 6: Expected Resource Dispatch for 20219

| 2021 Base Case | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | AP2 | MAY | JUN | JUL | AU1 | AU2 | SEP |
|----------------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|
| Wind | 1203 | 1248 | 1201 | 1312 | 1296 | 1560 | 1767 | 1862 | 1751 | 1704 | 1571 | 1454 | 1342 | 1150 |
| Coal | 3254 | 2754 | 2861 | 2225 | 1828 | 1484 | 1557 | 801 | 467 | 670 | 1784 | 2862 | 3259 | 3533 |
| Gas | 2710 | 1184 | 1310 | 1356 | 1043 | 752 | 776 | 563 | 494 | 560 | 847 | 1596 | 2048 | 2439 |
| Nuclear | 1034 | 1039 | 1070 | 1075 | 1128 | 1076 | 1071 | 1066 | 1076 | 1053 | 1077 | 1067 | 1110 | 1055 |
| SW Market | 487 | 505 | 603 | 593 | 343 | 174 | 211 | 55 | 9 | 24 | 88 | 249 | 338 | 403 |

| 2021 No Colstrip | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | AP2 | MAY | JUN | JUL | AU1 | AU2 | SEP |
|------------------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|
| Wind | 1203 | 1248 | 1201 | 1312 | 1296 | 1560 | 1767 | 1862 | 1751 | 1704 | 1571 | 1454 | 1342 | 1150 |
| Coal | 3027 | 2561 | 2672 | 2054 | 1718 | 1410 | 1474 | 777 | 466 | 649 | 1679 | 2700 | 2986 | 3224 |
| Gas | 2895 | 1271 | 1409 | 1425 | 1093 | 785 | 819 | 574 | 495 | 571 | 898 | 1711 | 2197 | 2625 |
| Nuclear | 1034 | 1039 | 1070 | 1075 | 1128 | 1076 | 1071 | 1066 | 1076 | 1053 | 1077 | 1067 | 1110 | 1055 |
| SW Market | 524 | 569 | 674 | 648 | 383 | 202 | 240 | 64 | 10 | 28 | 99 | 277 | 375 | 440 |

| No Colstrip - Base | OCT | NOV | DEC | JAN | FEB | MAR | AP1 | AP2 | MAY | JUN | JUL | AU1 | AU2 | SEP |
|--------------------|------|------|------|------|------|-----|-----|-----|-----|-----|------|------|------|------|
| Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Coal | -227 | -193 | -189 | -171 | -110 | -74 | -83 | -24 | -1 | -21 | -105 | -162 | -273 | -309 |
| Gas | 185 | 87 | 99 | 69 | 50 | 33 | 43 | 11 | 1 | 11 | 51 | 115 | 149 | 186 |
| Nuclear | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| SW Market | 37 | 64 | 71 | 55 | 40 | 28 | 29 | 9 | 1 | 4 | 11 | 28 | 37 | 37 |

Curtailment Statistics

⁹ These studies for the 2021 operating year included no maintenance for the region's sole nuclear plant, which is in error. The 2-year maintenance schedule for the Columbia Generating Station has that plant out of service for about a 2 month period during odd years. So, these studies should have shown zero capability for nuclear during May and June. Since no curtailments are expected during these months, even with the shutdown of the nuclear plant, the resulting LOLP values would remain unchanged.

Sometimes, simply looking at simulation results can provide insight into the behavior of the power system. Table 7 below summarizes a few statistics for the curtailment events reported in our analysis. All adequacy studies were run with 6,160 simulations.

Besides looking at curtailment statistics, it may also be of great use to examine what conditions existed during the time of each shortfall. Thus, a record of all curtailment events along with the values for the four random variables used in the analysis will be provided in a separate spreadsheet (available on the Council's website). The four random variables displayed in the spreadsheet are;

- Water supply, as a percentage of monthly runoff volume
- Temperature, as a percentage of that day's historical temperature range
- Wind generation, based on historical wind capacity factors from BPA's wind fleet
- Forced outage conditions

Some attempts have been made to correlate shortfall events with the occurrence of certain temperatures, water conditions, wind generation patterns and forced outages, but unfortunately without much success. This is an area of study that is being explored further and may produce better results once the GENESYS model has been enhanced to model plant-specific hourly hydroelectric operations.

Table 7: 2021 Simulated Curtailment Statistics

| Statistic | | Units |
|--|--------|-------------|
| Number of simulations | 6,160 | Number |
| Simulations with a curtailment | 610 | Number |
| Loss of load probability (LOLP) | 10 | Percent |
| Number of curtailment events | 2,374 | Number |
| Number of events per year | 0.4 | Events/year |
| Average event duration | 11 | Hours |
| Average event magnitude | 12,700 | MW-hours |
| Average event peak curtailment | 1,200 | MW |
| Expected curtailed hours per year (LOLH) | 2.4 | Hours |
| Expected un-served energy (EUE) | 2,500 | MW-hours |
| Events with duration of 1 to 2 hours | 11 | Percent |
| Duration of 1 to 4 hours | 20 | Percent |
| Duration of 1 to 6 hours | 28 | Percent |
| Duration of 1 to 12 hours | 49 | Percent |
| Duration of 1 to 14 hours | 56 | Percent |
| Duration of 1 to 16 hours | 86 | Percent |
| Duration greater than 16 hours | 14 | Percent |
| Highest likely duration (15 to 16 hours) | 30 | Percent |

Figure 2 can be used to examine the likelihood for particular duration curtailment events. In that figure, the y-axis represents the duration for an event and the x-axis represents the probability of an event with that duration (or greater) of occurring. For example, in Figure 2 the 50th percentile duration (median value) is about 13 hours.¹⁰ This means that we expect a 50 percent chance of observing a curtailment event of 13 hours or more.

Figure 2: Curtailment Event Duration Probability

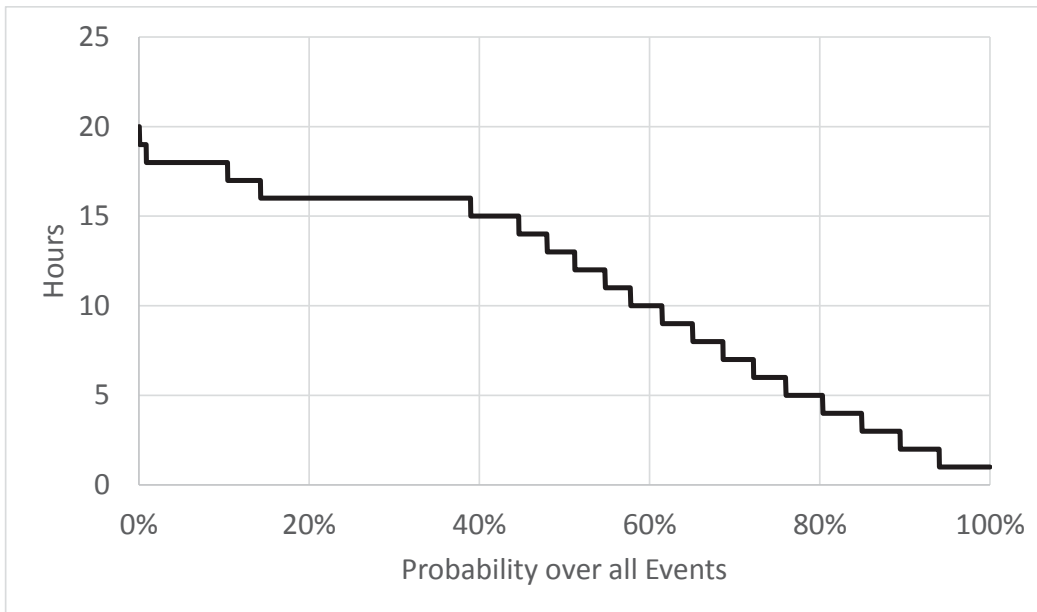


Figure 3 shows the same information in a different way. In that figure, the y-axis represents the percent of times that an event of particular duration occurs in the study. This is commonly referred to as a frequency distribution chart. For example, the most likely duration for an event is 16 hours. From Figure 3 a 16-hour duration event has about a 25 percent chance of occurring. The second most likely duration for an event is 18 hours. This result is not surprising since GENESYS will attempt to uniform any shortfall it sees across all the high-load hours of the day. Figure 4 shows the same information but the curtailment durations have been combined into 2-hour bins (as opposed to single hour bins in Figure 3). Figure 4 simply highlights the result that most event durations are between 15 and 18 hours. And, finally, Figure 5 provides more of a cumulative probability for event duration.

¹⁰ Note that the median duration is 13 hours while the average duration is 11 hours. This is because the distribution of event durations is not symmetric.

Figure 3: Event Duration Frequency (1-hour block incremental)

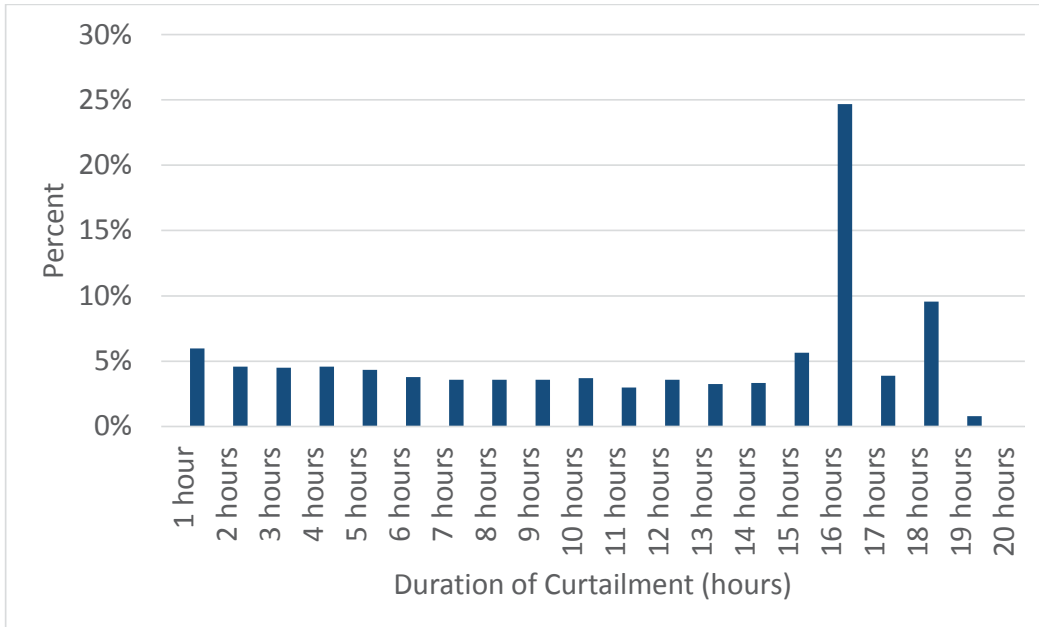


Figure 4: Event Duration Frequency (2-hour block incremental)

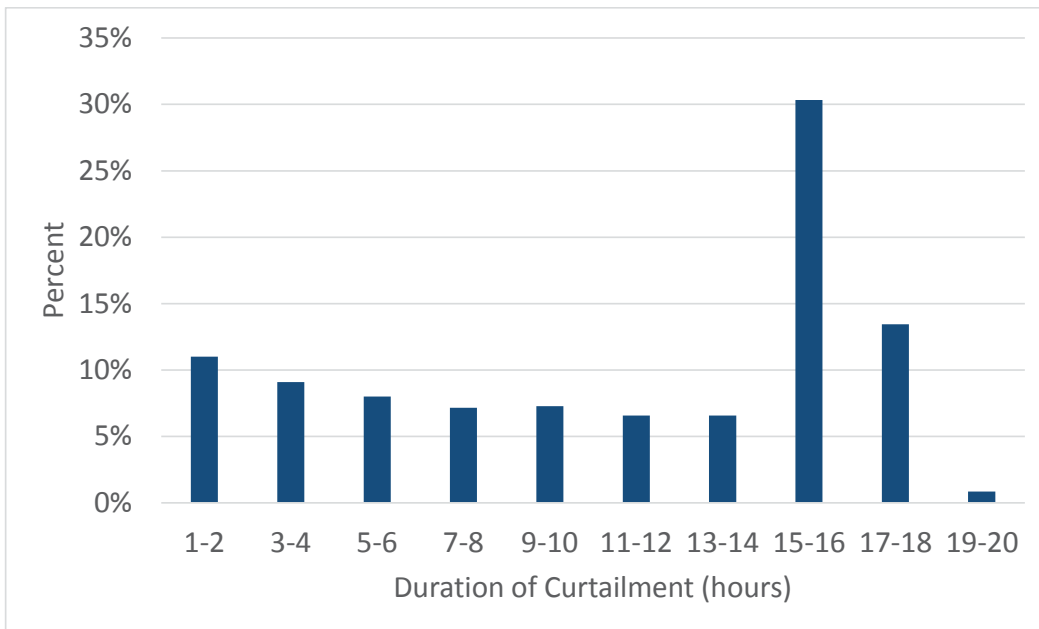
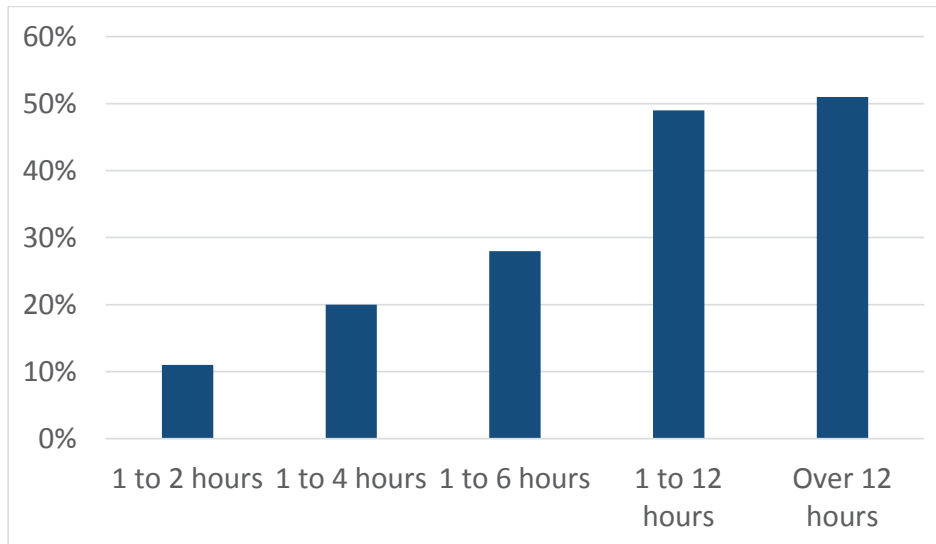


Figure 5: Event Duration Frequency (various time blocks)



The point at which these curves cross the horizontal axis would represent the LOLP except that these data were plotted prior to the implementation of standby resources.¹¹ By applying the effects of standby resources to the reference case results, the LOLP drops from a little over 13 percent down to the final value of 9.9 percent. In other words, if we could modify the curtailment record for that case to show the effects of standby resources, the resulting probability curve would shift down and cross the horizontal axis at 9.9 percent. Doing the same for the Colstrip retirement case drops the LOLP to a little over 13 percent.

Figure 6 displays the annual unserved energy probability over all games for both the reference case and the Colstrip retirement case. The total unserved energy for each of the 6,160 games is summed up and then sorted from highest to lowest. Those results are then graphed in Figure 6. The vertical axis represents the amount of annual unserved energy and the horizontal axis represents the likelihood of observing a particular amount of annual unserved energy or more. From Figure 6, without the effects of standby resources, it appears that there is about a 13 percent¹² chance of observing a game with at least one curtailment (this is where the curve in Figure 6 crosses the horizontal axis). The probability curve for the Colstrip retirement case crosses the horizontal axis at about 17.7 percent.

¹¹ This is a simplification of the actual process, which takes into account monthly results.

¹² Remember this result is prior to adding the effects of standby resources.

Figure 6: Annual Unserved Energy Probability

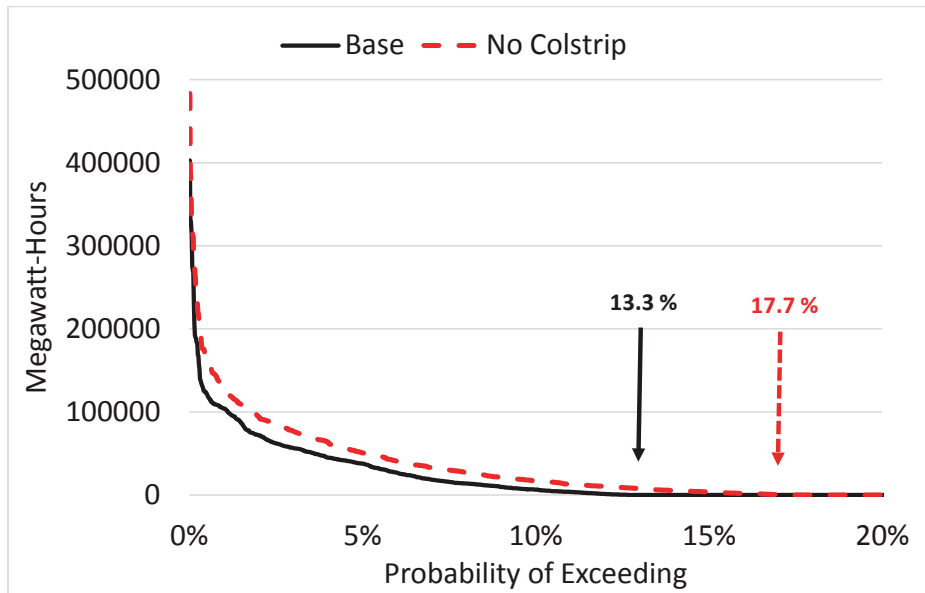


Figure 7a displays the worst-hour unserved energy probability for all games for both the reference case and the Colstrip retirement case. This figure is similar to Figure 6 but plots the worst (highest) single-hour unserved energy for each game, instead of the annual unserved energy. As expected, the probability curves in this figure cross the horizontal axis at the same percentage values as the curves in the annual unserved energy chart (Figure 6).

The curves in this figure can be used to estimate the amount of additional capacity needed to make the power supply adequate (not including the effects of standby resources). By looking at a blown-up section of Figure 7a, shown in Figure 7b, it becomes easier to see how much new capacity is required to shift the entire curve down so that it crosses the horizontal axis at the 5 percent Council adequacy limit. For the reference case, it requires a little over 1,800 megawatts of new capacity (simply draw a straight line up from the 5 percent point on the horizontal axis to the curve and then draw a straight line to the left to see where it would cross the vertical axis). Recall that these data have not been adjusted for standby resources, which contribute a little over 600 megawatts of capacity in winter. Thus, the estimate for required new capacity – in addition to the standby resource contribution – to maintain adequacy is about 1,200 megawatts. For the Colstrip retirement case, the needed amount of new capacity is about 1,500 megawatts. These values, however, are only estimates because they lump the curtailment events from all months together. Results from the more accurate analytical approach (which also include the effects of standby resources) show a need of about 1,040 megawatts and 1,400 megawatts of new capacity to maintain adequacy for the reference case and Colstrip retirement case, respectively.

It should be noted that it requires both new capacity and energy additions to move the 2021 LOLP down to the Council's 5 percent standard. Analysis indicates that the greatest need for the 2021 supply is addition of capacity, however, simply adding capacity with no energy will not result in an adequate supply. Each new resource has at least some energy providing capability, some more than others. For example, demand response programs can provide a lot of capacity but cannot be dispatched for long periods of time and therefore, provide only a very limited amount of energy. Wind resources, on the other hand, can provide a great deal of energy but can only be counted on to provide about 5 percent of their nameplate capacity toward peaking needs. This is why the Council uses its Regional Portfolio Model, which knows the energy and capacity contributions of all new resources, to develop a resource strategy that will lead to an adequate supply.

Figure 7a: Worst-Hour Unserved Energy Probability

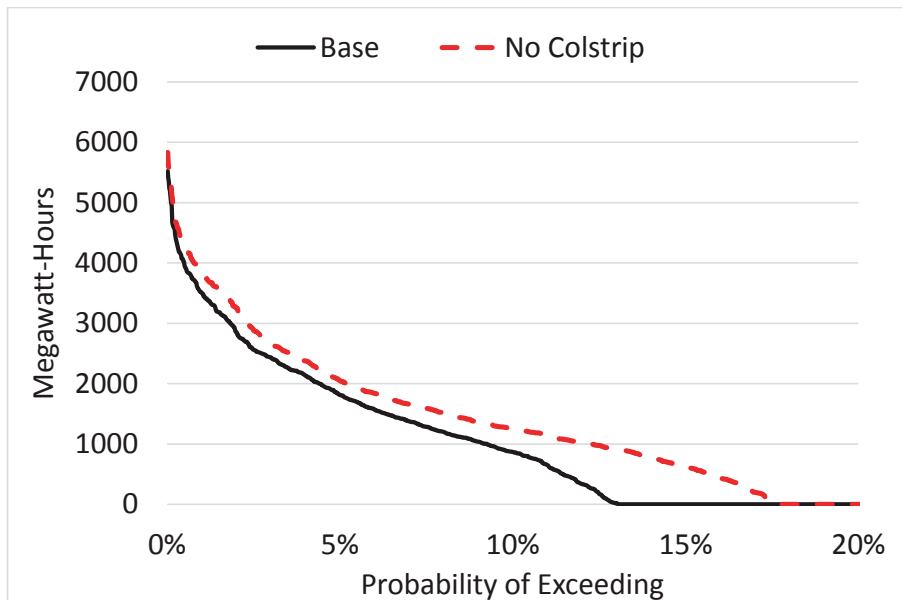
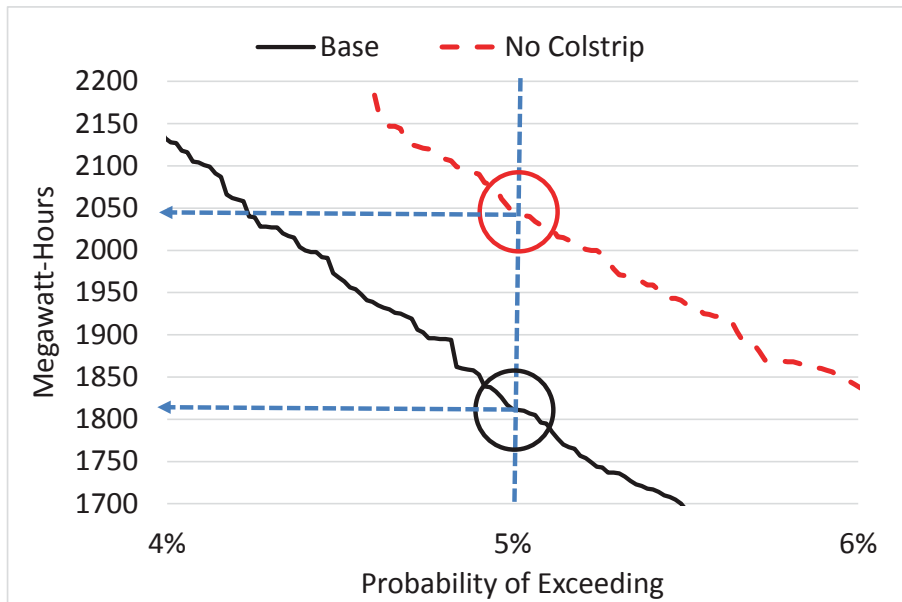


Figure 7b: Worst-Hour Unserved Energy Probability (Blow Up)



Other Adequacy Metrics

Other adequacy metrics help planners better understand the magnitude, frequency and duration of curtailments. These other metrics provide valuable information to planners as they consider resource expansion strategies. Table 8 below defines some of the more commonly used probabilistic metrics used to examine power supply adequacy and Table 9 provides the regional assessments of these metrics for 2017, 2019, 2020 and 2021.

While the Council has been using an annual LOLP metric to assess adequacy for nearly a decade, it became evident during the development of the Seventh Power Plan that monthly (or at least quarterly) values are essential to ensure a truly adequate supply. This is because resources can provide different energy and capacity contributions over each quarter. Also, the characteristics of potential shortfalls can vary by season. Thus, the Council's Regional Portfolio Model required quarterly adequacy reserve margins to develop more cost effective resource expansion strategies. The calculation of quarterly adequacy reserve margins requires quarterly adequacy targets. Recognizing this, the Council added an action item to reevaluate and amend its existing adequacy standard. Table 10 provides monthly values for LOLP and other adequacy metrics.

The North American Electric Reliability Corporation (NERC) instigated an adequacy assessment pilot program in 2012. It asked that each sub-region in the United States provide three adequacy measures; 1) expected loss of load hours, 2) expected unserved energy and 3) normalized expected unserved energy (EUE divided by load). This effort is a good first step toward standardizing how adequacy is assessed across the United States but it falls far short of

establishing adequacy thresholds for these metrics. It may, in fact, be impossible to set thresholds because power supplies can vary so drastically across regions.

Table 8: Adequacy Metric Definitions

| Metric | Description |
|---------------------------------|--|
| LOLP (%) | Loss of load probability = number of games with a problem divided by the total number of games |
| CVaR – Energy (MW-hours) | Conditional value at risk, energy = average annual curtailment for 5% worst games |
| CVaR – Peak (MW) | Conditional value at risk, peak = average single-hour curtailment for worst 5% of games |
| EUE (MW-hours) | Expected unserved energy = total curtailment divided by the total number of games |
| LOLH (Hours) | Loss of load hours = total number of hours of curtailment divided by total number of games |
| PGC (%) | Percent of games with curtailment prior to implementing standby resources |

Table 9: Annual Adequacy Metrics (Base Case)

| Metric | 2017 | 2019 | 2020 | 2021 | Units |
|----------------------|-------------|-------------|-------------|-------------|--------------|
| LOLP | 6.6 | 5.9 | 4.7 | 9.9 | Percent |
| CVaR - Energy | 99,000 | 59,200 | 50,589 | 46,378 | MW-hours |
| CVaR - Peak | 4,000 | 3,337 | 2,949 | 2,185 | MW |
| EUE | 5,000 | 3,000 | 2,536 | 2,482 | MW-hours |
| LOLH | 2.7 | 1.7 | 1.5 | 2.4 | Hours/year |
| PGC | 9.7 | 8.3 | 6.4 | 13.6 | Percent |

Table 10: Monthly Adequacy Metrics (Base Case)

| Month | LOLP Peak % | LOLP Energy % | Overall LOLP % | EUE MW-Hours | LOLH Hours |
|---------------|-------------|---------------|----------------|--------------|------------|
| Annual | 9.9 | 1.8 | 9.9 | 2,482 | 2.4 |
| Oct | 1.7 | 0.3 | 1.7 | 240 | 0.5 |
| Nov | 0.7 | 0.1 | 0.7 | 170 | 0.1 |
| Dec | 2.5 | 0.5 | 2.5 | 768 | 0.6 |
| Jan | 2.2 | 0.6 | 2.2 | 930 | 0.6 |
| Feb | 0.3 | 0.2 | 0.3 | 105 | 0.1 |
| Jul | 0 | 0 | 0 | 1 | 0 |
| Au1 | 1.4 | 0.2 | 1.4 | 102 | 0.2 |
| Au2 | 1.9 | 0.4 | 2 | 146 | 0.3 |
| Sep | 0.5 | 0.1 | 0.6 | 21 | 0.1 |

Assumptions

The methodology used to assess the adequacy of the Northwest power supply assumes a certain amount of reliance on non-utility supplies within the region and imports from California. The Northwest electricity market includes independent power producer (IPP) resources. The full capability of these resources, 2,943 megawatts, is assumed to be available for Northwest use during winter months. However, during summer months, due to competition with California utilities, the Northwest market availability is limited to 1,000 megawatts.

Other assumptions used for the 2021 adequacy assessment are shown in Table 11 through Table 15. Table 11 summarizes assumptions for load, energy efficiency savings and out-of-region market availability. Tables 12 and 13 provide the energy and capacity contributions for standby resources. Tables 14 and 15 provide the monthly incremental and decremental balancing reserves that were assumed. To the extent possible, the hydroelectric system was used to carry these reserves. Using the Council's hourly hydroelectric optimization program (TRAP model), a portion of the peaking capability and minimum generation at specific hydroelectric projects was reserved to support the within-hour balancing needs. Unfortunately, not all balancing reserves could be assigned to the hydroelectric system. The remaining reserves should be assigned to other resources but the current adequacy model does not have that capability. This is one of the major enhancements targeted in the GENESYS redevelopment process.

Table 11: Assumptions used for the 2021 Adequacy Assessment

| Item | Quarter 4 | Quarter 1 | Quarter 2 | Quarter 3 |
|---------------------|-----------|-----------|-----------|-----------|
| Mean Load (aMW) | 21,234 | 20,975 | 18,813 | 19,987 |
| Peak Load (MW) | 33,768 | 33,848 | 26,504 | 28,302 |
| DSI Load (aMW) | 338 | 338 | 338 | 338 |
| Mean EE (aMW) | 1,545 | 1,574 | 1,274 | 1,208 |
| Peak EE (MW) | 2,660 | 2,660 | 1,680 | 1,680 |
| Spot Imports (MW) | 2,500 | 2,500 | 0 | 0 |
| Purchase Ahead (MW) | 3,000 | 3,000 | 3,000 | 3,000 |

Table 12: Standby Resource Assumptions – Peak (MW)

| Item | Quarter 4 | Quarter 1 | Quarter 2 | Quarter 3 |
|------------------------------------|--------------|--------------|--------------|-------------------|
| Exist DR | 220 | 220 | 781 | 781 |
| Exist Emergency Gen | 266 | 266 | 266 | 266 |
| Total Existing | 486 | 486 | 1047 | 1047 |
| Planned DR | 121 | 121 | 0 | 0 |
| Total Exist + Planned | 607 | 607 | 1047 | 1047 |
| Min DR (from the RPM) | 379 | 379 | 468 | 468 ¹³ |
| Total Exist + Plan + Min | 986 | 986 | 1515 | 1515 |
| Expected DR (from RPM) | 1,136 | 1,136 | 1,178 | 1,178 |
| Total Exist + Plan + Expect | 1,743 | 1,743 | 2,225 | 2,225 |

¹³ These are existing summer demand response programs.

Table 13: Standby Resource Assumptions – Energy (MW-hours)

| Item | Quarter 4 | Quarter 1 | Quarter 2 | Quarter 3 |
|------------------------------------|----------------|----------------|----------------|----------------|
| Exist DR | 37,250 | 37,250 | 69,542 | 69,542 |
| Exist Emergency Gen | 5,800 | 5,800 | 5,800 | 5,800 |
| Total Existing | 43,050 | 43,050 | 75,342 | 75,342 |
| Planned DR | 6,050 | 6,050 | 0 | 0 |
| Total Exist + Planned | 49,100 | 49,100 | 75,342 | 75,342 |
| Min DR (from the RPM) | 18,950 | 18,950 | 23,400 | 23,400 |
| Total Exist + Plan + Min | 68,050 | 68,050 | 98,742 | 98,742 |
| Expected DR (from RPM) | 56,800 | 56,800 | 58,900 | 58,900 |
| Total Exist + Plan + Expect | 105,900 | 105,900 | 134,242 | 134,242 |

Table 14: Within-hour Balancing Reserves – Incremental (MW)

| Period | BPA Hydro | Non-BPA Hydro | Non-BPA Thermal ¹⁴ |
|--------------|-------------------|---------------|-------------------------------|
| October | 900 | 584 | 562 |
| November | 900 | 748 | 711 |
| December | 900 | 782 | 768 |
| January | 900 | 929 | 816 |
| February | 900 | 763 | 702 |
| March | 900 | 797 | 738 |
| April 1-15 | 400 | 719 | 672 |
| April 16-30 | 400 | 719 | 672 |
| May | 400 | 912 | 910 |
| June | 400 | 810 | 799 |
| July | 900 ¹⁵ | 750 | 958 |
| August 1-15 | 900 | 797 | 640 |
| August 16-31 | 900 | 797 | 640 |
| September | 900 | 716 | 662 |

¹⁴ These balancing reserves were not assigned for this analysis.

¹⁵ BPA's DEC reserve requirements of 400 megawatts extend through the end of July but the analysis in this report incorrectly assumed that the July reserve requirement was 900 megawatts. It was determined that rerunning all of the studies to include this correction was not warranted.

Table 15: Within-hour Balancing Reserves – Decremental (MW)

| Period | BPA Hydro | Non-BPA Hydro | Non-BPA Thermal |
|--------------|-----------|---------------|-----------------|
| October | 900 | 662 | 786 |
| November | 900 | 899 | 1,264 |
| December | 900 | 687 | 1,073 |
| January | 900 | 751 | 908 |
| February | 900 | 728 | 955 |
| March | 900 | 690 | 899 |
| April 1-15 | 900 | 713 | 942 |
| April 16-30 | 900 | 713 | 942 |
| May | 900 | 748 | 1,044 |
| June | 900 | 723 | 898 |
| July | 900 | 629 | 811 |
| August 1-15 | 900 | 609 | 872 |
| August 16-31 | 900 | 609 | 872 |
| September | 900 | 746 | 910 |

FUTURE ASSESSMENTS

The Council will continue to assess the adequacy of the region's power supply. This task is becoming more challenging because planners must now focus on satisfying not only winter energy needs but also summer energy needs and capacity needs year round. Continued development of variable generation resources, combined with changing patterns of electricity demand have added complexity to the task of successfully maintaining an adequate power supply. For example, regional planners have had to reevaluate methods to quantify and plan for balancing reserve needs. In light of these changes, the Council is in the process of enhancing its adequacy model to reflect real life operations and to address capacity issues.

Another emerging concern is the lack of access to supplies for some utilities due to insufficient transmission or due to other factors. For the current adequacy assessment, the Northwest

region is split into two subsections¹⁶ in which only the major east-to-west transmission lines are modeled. Similarly, only the major Canadian-U.S. and Northwest-to-Southwest interties are modeled. The Council is hoping to address these issues in future adequacy assessments.

Also, at some point, uncertainties surrounding the change in Canadian flood control operations in 2024 and the effects of a potentially renegotiated Columbia River Treaty will have to be addressed. But besides these issues, the Council's latest power plan identifies the following action items related to adequacy assessments:

- RES-8** Adaptive Management – Annual Resource Adequacy Assessments
- COUN-3** Review the regional resource adequacy standard
- COUN-4** Review the RAAC assumptions regarding availability of imports
- COUN-5** Review the methodology used to calculate the adequacy reserve margins used in the Regional Portfolio Model
- COUN-6** Review the methodology used to calculate the associated system capacity contribution values used in the Regional Portfolio Model
- COUN-8** Participate in and track WECC [adequacy] activities
- COUN-11** Participate in efforts to update and model climate change data
- ANLYS-4** Review and enhancement of peak load forecasting
- ANLYS-22** GENESYS Model Redevelopment
- ANLYS-23** Enhance the GENESYS model to improve the simulation of hourly hydroelectric system operations

Issues identified in 2016 by the Council's Resource Adequacy Advisory Committee to consider for next year's assessment include those listed below:

- Rec-1** Review methodology of the hybrid load forecast used for the 2021 adequacy assessment, in particular how peak loads are forecast
- Rec-2** Provide an hourly forecast for energy efficiency savings.
- Rec-3** Investigate how to incorporate uncertainty in EE savings into the adequacy assessments

¹⁶ The dividing line between the east and west areas of the region (for modeling purposes) is roughly the Cascade mountain range.

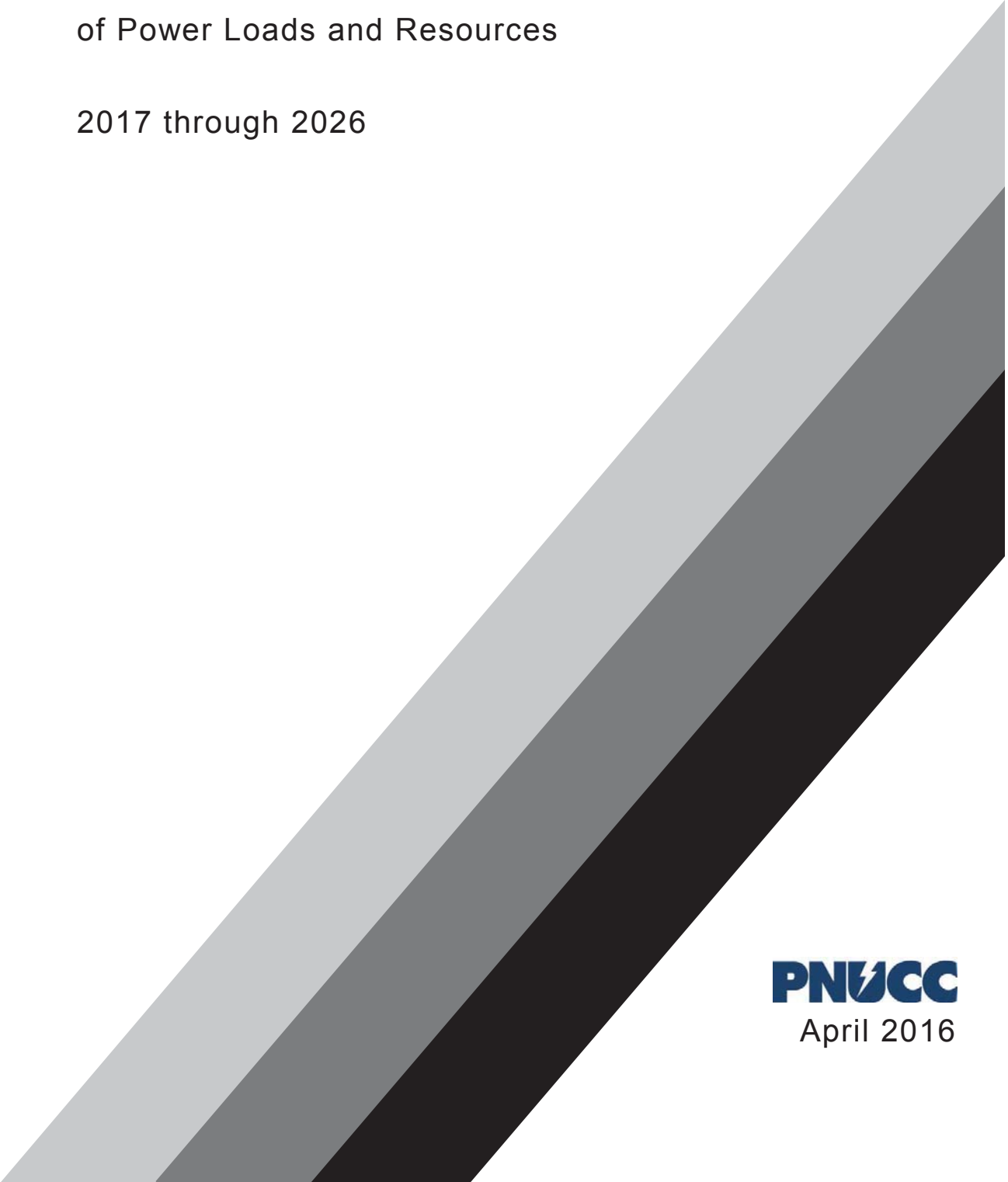
- Rec-4** Investigate availability of regional and extra-regional market supplies during periods of stress (supply shortages)
- Rec-5** Investigate the availability of fuel during periods of stress, especially for resources without firm fuel contracts.
- Rec-6** Investigate the availability of the interties that connect the NW with regions that may provide market supplies. Consider adding maintenance schedules and forced outages.
- Rec-7** Explore ways to incorporate the effects of climate change into the adequacy assessments. Should assessments only include the effects of recent temperature years or is there a way to adjust historic temperature profiles to account for climate change?
- Rec-8** Explore how an energy imbalance market might affect adequacy assessments. Investigate ways to incorporate an EIM into the analysis.
- Rec-9** Review the use of standby resources in the adequacy assessments, in particular how demand response is modeled. The algorithms in the standby resource post processor should be incorporated into the GENESYS model. DR should be dispatched based on price. How do we deal with existing DR, assuming that its impacts have been captured (somewhat) in the load forecast?

Not all of the action items and recommendations listed above will be addressed and resolved before the next adequacy assessment, which is tentatively scheduled for release in May of 2017. However, any enhancements that can be made and tested in time for the next assessment will be implemented. Thus, it continues to be important to isolate the effects of modeling changes on the LOLP from the effects of changes in loads and resources.

Northwest Regional Forecast

of Power Loads and Resources

2017 through 2026



PNWCC
April 2016

Special thanks to PNUCC System Planning Committee members and utility staff that provided us with this information.

Electronic copies of this report are available on the
PNUCC website
www.PNUCC.org

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2016 Northwest Regional Forecast

Executive Summary

The *Northwest Regional Forecast (Forecast)* is a compilation of Northwest utilities' expected loads and resources through 2026. This annual supply and demand snapshot serves as a barometer for the region's electric power system. Modest load growth expectations, PURPA renewables coming online, and aggressive energy efficiency acquisitions continue to be the theme for the Northwest power sector.

The *Forecast* examines the Northwest utilities' power picture at an aggregate level. Individual utilities have different load profiles, risk tolerance and challenges than the region as a whole. Still, looking at the big picture reveals trends in the Northwest energy world. And while winter peak continues to show the largest deficit using the *Forecast's* planning criteria, summer peak is a growing concern, especially if fewer non-firm resources are available in the summer as compared to winter.

Expected load growth remains low

Idled smelters keep loads down

In 2015 the Northwest's last aluminum giant, Alcoa, announced that it would be idling its regional smelters. The smelters operation is largely hinged on the global price of aluminum. Increased supply in China has pushed the commodity price to low levels in recent years.

This lost load has pulled down regional demand expectations for winter peak and annual energy. Summer forecasted loads start in-line with last year's forecast and then grow slightly faster.¹

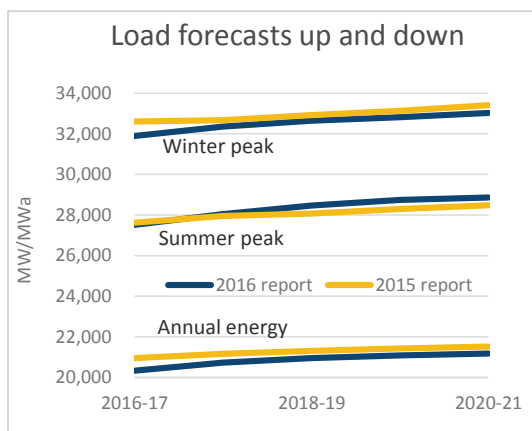


Figure 1

¹ The forecasted loads reflect expected (1-in-2) weather conditions and savings from projected energy efficiency efforts.

Varying degrees of growth across region

On average, regional annual energy load growth is projected at 0.7% per year through 2021. Winter peak load is also forecast at 0.7% while summer peak is 1%.

A look at annual energy load growth for individual utilities shows some of them forecasting growth in excess of 1% per year, whereas others are forecasting load decay. Utilities growing faster than 1% are typically a smaller utility expecting a significant new load.

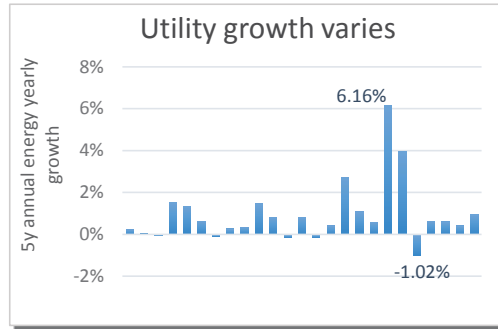


Figure 2

Reset on annual energy and winter peak

Looking at past reports, firm annual energy and winter peak requirement forecasts (load + contracted exports) have continued to start from a lower point than the previous year, implying decreasing need for annual energy and winter peak supply.

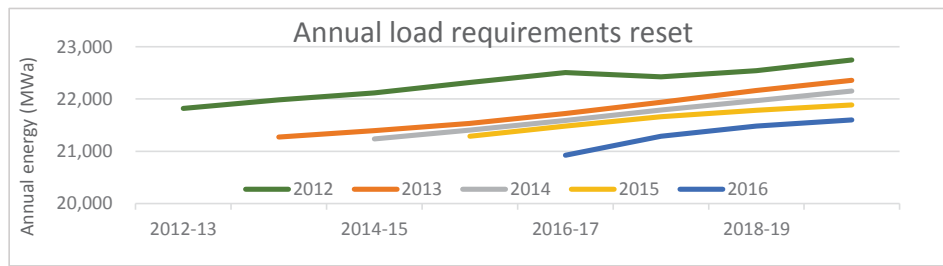


Figure 3

The starting point for the 2016 annual energy requirements forecast is down nearly 1,000 MWa from the 2012 *Forecast*. This trend is not found in the summer peak forecasts which continue to trend as expected.

Resource mix in transition

The firm power supply in the *Forecast* includes hydro at critical water levels, existing utility owned/contracted generating facilities, long-term imports and committed future resources. The *Forecast's* planning metrics do not include non-firm resources.

Wealth of carbon free resources

Largely thanks to the hydropower system, the Northwest has a wealth of CO₂ free power resources. The *Forecast* assumes critical water conditions for planning purposes, but in any given year the hydro system can generate significantly more power.

When the region has more precipitation and generates more hydropower, it relies less on other dispatchable resources, which are largely thermal. This in turn leads to lower CO₂ emissions. The hydro system's generation output under various water conditions, along with other firm carbon free resources stacked on top, are shown below.

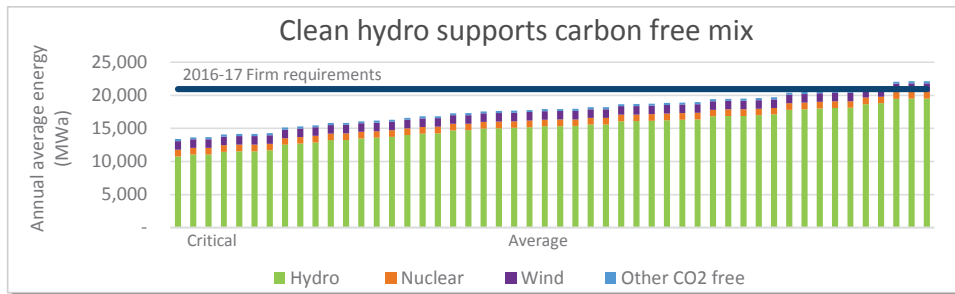


Figure 4

Hydro and thermal resources work together

Although the region's power system provides significant amounts of carbon free power, due to variations in hydro, wind and other CO₂ free resource generation, dispatchable thermal resources are relied upon to fill the gap, even during the highest of water years.

The shape of Northwest hydro generation and energy load varies month by month. During higher water years the extra hydro generation is largely found in the winter, spring and early summer months. In the late summer and early fall the difference in generation between critical and average water is less appreciable. This is largely due to the lack of storage on the Northwest's hydro system and the natural snowpack-driven, runoff pattern.

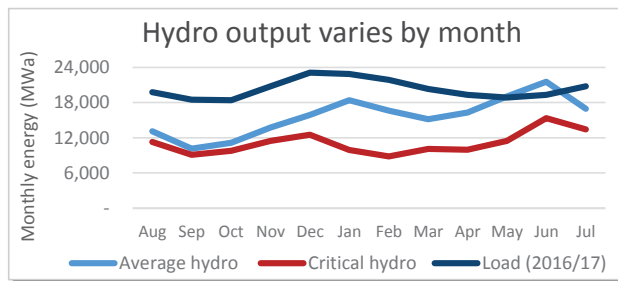


Figure 5

There are yearly and seasonal variations with wind in the Northwest as well. Wind production tends to be at its highest in the spring/early summer, which combined with hydro, can create a regional energy surplus in those months.

Region aggressively acquiring energy efficiency

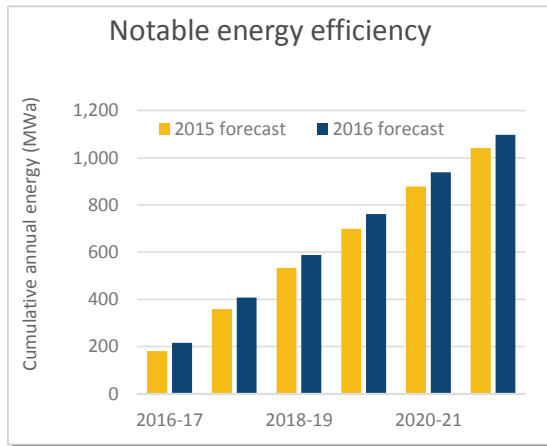


Figure 6

The *Forecast's* numbers show a region actively pursuing energy efficiency savings as a resource. One reason Northwest load growth has slowed is the thousands of megawatts of energy efficiency savings utilities and others have captured. Utilities expect to achieve additional annual electric energy savings of nearly 1,100 MWa in the next six years, slightly more than last year's *Forecast*. Once market transformation and codes and standards are accounted for this number will grow.

The sun also rises in the Northwest

Looking at committed resources, Idaho Power expects nearly 400 MW of nameplate capacity solar within the year via PURPA, and Portland General Electric's natural gas unit Carty is scheduled to be online in 2016. Some hydro system upgrades and PURPA wind in the next few years round out the picture.

In addition, around 2,000 MW of planned resources are identified by utilities to meet future demand. These projects have not been sited or licensed and thus, not included in the *Forecast's* load/resource tabulations. More details can be found in *Tables 8 and 9 Planned Resources* of the report.

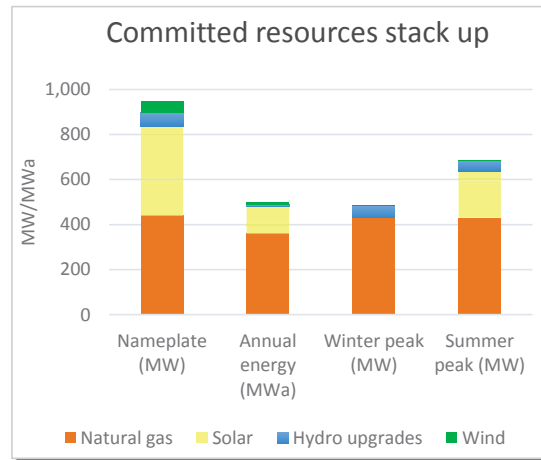


Figure 7

Demand response growing to meet peaks

Today, the Northwest has hundreds of megawatts of demand response on call. This resource is largely found in the eastern part of the region in the form of irrigation interruption. On the west side, utilities are eyeing this capacity resource as well, with nearly 150 MW of new winter programs scheduled to come on line in the next few years.

Resource retirements ahead

In the next decade over 2,000 MW of dispatchable capacity, in the form of coal units, are slated to retire. Up first are the planned retirements of Boardman and Centralia Unit 1, scheduled for the end of 2020. Further down the road Centralia Unit 2 is slated to go offline at the end of 2025, and Valmy has been dropped from Idaho Power’s preferred portfolio at the end of 2025 (although its retirement is not certain).

These retirements occur within the *Forecast’s* horizon. Resource availability for meeting peak capacity and energy needs could be impacted if these dispatchable units are not replaced with resources of similar operating characteristics.

Attention on peak needs

Winter peak is focus

Although winter peak need has been trending down the past five years, it remains the most acute need in this year’s *Forecast*. In 2012 the estimated one-hour peak need for January 2013 was about 3,000 MW. Today that gap is closer to 1,000 MW for January 2017 and grows to over 4,000 in 2021 based the *Forecast’s* planning criteria.² This 3,000 MW increase by 2021 is in part due to increased planning margins, expected load growth and the retirement of the Boardman power plant.

It is worth noting that the 2,000 MW decrease in need from 2013 to 2017 is due to a roughly 1,300 MW drop in firm obligations and a 700 MW increase in firm resources.³

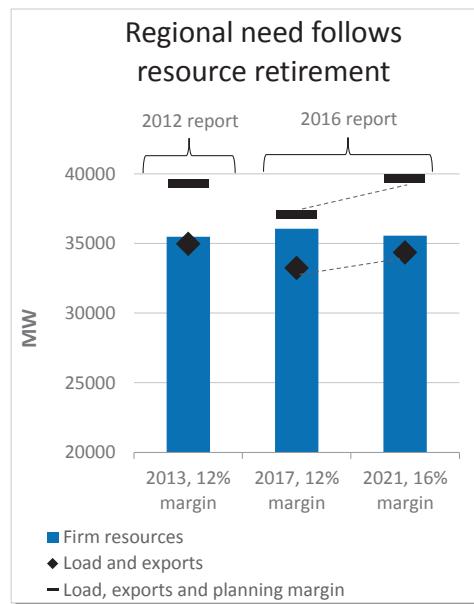


Figure 8

² 1-in-2 load, critical water, utility firm resources and contracts, and 12% planning margin growing 1% a year.

³ Power plant Carty (440 MW) and Port Westward 2 (220 MW) along with a reshuffling of a few contracts.

Assumptions can drive seasonal adequacy concerns

The assumptions for non-firm resources vary between organizations and can drive which season is of greatest concern.⁴ To help shed light on the potential for utilizing non-firm resources, this year's *Forecast* provides a bookend that shows how the firm power supply can be augmented if generation from independent power producers (IPPs), spot market imports, and additional hydropower (when water supply exceeds critical condition levels), are available.

A snapshot of the load/resource picture for winter and summer peak with a potential set of non-firm resources layered on is shown below. Firm resources come from the *Forecast*, assumptions for available generation from Northwest IPPs and market imports are from the Council's *2015 Resource Adequacy Assessment*, and the estimate of additional hydro generation from average water conditions is derived from the *2015 BPA White Book*.⁵ As noted, the season of greatest concern could be winter or summer depending on non-firm resource assumptions.

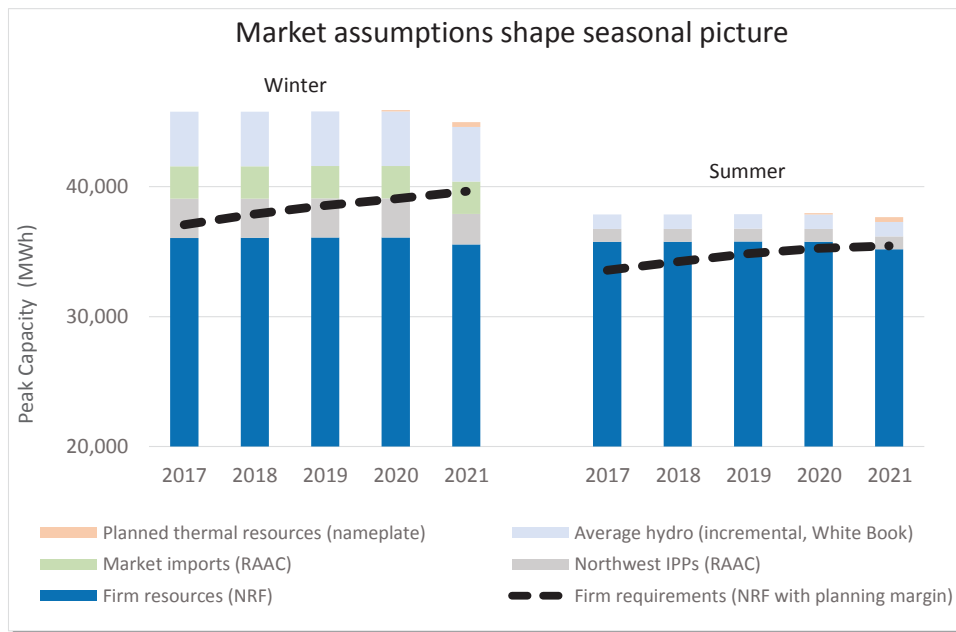


Figure 9

⁴ For example, BPA assumes full IPP availability year round, whereas the Council de-rates IPP's in the summer

⁵ Firm requirements include contracted exports and a planning margin that starts at 12% and grows 1% per year

Future is a little foggy

Load may not be business as usual

Although this report predicts slow load growth, there are a number of possible new loads that could increase the use of electricity in the Northwest. While some of these possible loads are already baked into the *Forecast's* figures, specific sectors could see greater than predicted growth. Additionally, the possibility of methanol plants in the Northwest could bring large scale industrial load growth to the region.

On the other hand, there are a number of programs that could pull load forecasts down further. These are factored into the report to some extent, but there is a chance they have been underestimated.

Public policy changing the power supply landscape

Although adequacy has been the driver behind some recent power plant builds in the Northwest, public policy, has played a large role as well. This will likely continue into the future with implementation of existing and new policies, and could change the needs of the power system.

State renewable portfolio standards have brought thousands of megawatts of variable energy resources to the Northwest and greater Western Interconnection. This has led to greater concerns regarding system flexibility. In addition, the retirement of Boardman and Centralia power plants, which are due in part to carbon driven public policy, may result in the construction of replacement resources.

Beyond existing policies there are additional rules and regulations on the drawing board on both a state and federal level. With each new policy there is a level of uncertainty until the policy is finalized and implements. Going forward PNUCC will continue to keep an eye on new policy developments and ensure members are aware of how they may impact the power system and need for power.

Reading the tea leaves

PNUCC is not the only organization that examines projected need for power. The Bonneville Power Administration and the Northwest Power & Conservation Council also conduct regular Northwest supply and demand studies. At a high level they both peg winter capacity as the area of chief concern.

BPA's 2015 White Book Regional Picture

The *BPA White Book* uses various methods to assess regional need for power, including critical water planning similar to the *Forecast*. One major difference between the White Book and the *Forecast* is the treatment of power supply from Northwest Independent Power Producers – the White Book “assumes that 100 percent of PNW regional uncommitted IPP generation is available to serve regional loads.”⁶

The *White Book* found the region to be constrained regarding January 120 hour capacity need starting in 2019, even with the inclusion of IPP resources.⁷ The *Forecast* does not have a 120 hour metric to compare. Looking at 1 hour capacity need, with all IPP resources available, the White Book sees a deficit starting in 2021.⁸ One key driver of the 2021 deficit is the retirement of Boardman and Centralia Unit 1.

Council's Resource Adequacy Advisory Committee 2015 Assessment

Each year the Council conducts a regional probabilistic five year out loss-of-load study with the goal of having a less than 5% annual chance of a supply based power outage. The *Assessment* for year 2020 also featured a six year outlook to examine the region after the coal unit retirements. They found a region that was adequate in year 2020, but inadequate in 2021, with the chief concern being winter capacity.⁹

⁶ Bonneville Power Administration, 2015 White Book Summary Document, Jan 2016, p. 37. IPPs are ~ 3,100 MW

⁷ Bonneville Power Administration, 2015 White Book Summary Document, p. 42

⁸ Bonneville Power Administration, 2015 White Book Technical Appendix – Volume 2, Capacity Analysis, p. 352

⁹ Northwest Power and Conservation Council, Pacific Northwest Power Supply Adequacy Assessment and State of the System Report, May 2015, p 11

Overview

Each year the *Northwest Regional Forecast* compiles utilities' 10-year projections of electric loads and resources which provide information about the region's need to acquire new power supply. The Forecast is a comprehensive look at the capability of existing and new electric generation resources, long-term firm contracts, expected savings from demand side management programs and other components of electric demand for the Northwest.

This report presents estimates of annual average energy, seasonal energy and winter and summer peak capability in Tables 1 through 4 of the *Northwest Region Requirements and Resources* section. These metrics provide a multi-dimensional look at the Northwest's need for power and underscore the growing complexity of the power system.

Northwest generating resources are shown by fuel type. Existing resources include those resources listed in Tables 5, 6, 10 and 11. *Table 5, Recently Acquired Resources* highlights projects and supply that became available most recently. *Table 6, Committed New Supply* lists those generating projects where construction has started, as well as contractual arrangements that have been made for providing power at a future time. *Table 10, Northwest Utility Generating Resources* is a comprehensive list of generating resources that make up the electric power supply for the Pacific Northwest that are utility-owned or utility contracted. *Table 11, Independent Owned Generating Resources* lists generating projects owned by independent power producers and located in the Northwest.

In addition, utilities have demand side management programs in place to reduce the need for generating resources. *Table 7, Demand Side Management Programs* provides a snapshot of utilities' expected savings from these programs for the next ten years. *Table 8, Planned Resources* is a compilation of what utilities have reported in their individual integrated resource plans to meet future need.

Planning Area

The Northwest Regional Planning Area is the area defined by the *Pacific Northwest Electric Power Planning and Conservation Act*. It includes: the states of Oregon, Washington and Idaho; Montana west of the Continental Divide; portions of Nevada, Utah, and Wyoming that lie within the Columbia River drainage basin; and any rural electric cooperative customer not in the geographic area described above, but served by BPA on the effective date of the *Act*.



Northwest Region Requirements and Resources

Table 1. Northwest Region Requirements and Resources – Annual Energy shows the sum of the individual utilities’ requirements and firm resources for each of the next 10 years. Expected firm load and exports make up the total firm regional requirements.

| Average Megawatts | 2016-17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 |
|--------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|----------------|
| Firm Requirements | | | | | | | | | | |
| Load ^{1/} | 20,332 | 20,733 | 20,951 | 21,077 | 21,171 | 21,319 | 21,437 | 21,575 | 21,695 | 21,835 |
| Exports | <u>590</u> | <u>555</u> | <u>531</u> | <u>524</u> | <u>519</u> | <u>468</u> | <u>463</u> | <u>459</u> | <u>450</u> | <u>445</u> |
| Total | 20,922 | 21,288 | 21,482 | 21,601 | 21,690 | 21,786 | 21,900 | 22,034 | 22,144 | 22,280 |
| Firm Resources | | | | | | | | | | |
| Hydro ^{2/} | 11,118 | 11,118 | 11,114 | 11,114 | 11,114 | 11,114 | 11,114 | 11,114 | 11,114 | 11,114 |
| Natural Gas | 4,238 | 4,267 | 4,304 | 4,277 | 4,254 | 4,226 | 4,250 | 4,243 | 4,248 | 4,242 |
| Renewables-Other | 214 | 213 | 213 | 212 | 210 | 206 | 204 | 204 | 204 | 203 |
| Solar | 94 | 129 | 129 | 129 | 129 | 129 | 129 | 129 | 129 | 123 |
| Wind | 1,294 | 1,294 | 1,294 | 1,294 | 1,291 | 1,221 | 1,204 | 1,191 | 1,178 | 932 |
| Cogeneration | 49 | 49 | 49 | 35 | 28 | 11 | 11 | 11 | 11 | 2 |
| Imports | 788 | 788 | 791 | 794 | 797 | 800 | 803 | 805 | 761 | 555 |
| Nuclear | 916 | 1,075 | 916 | 1,075 | 916 | 1,075 | 916 | 1,075 | 916 | 1,075 |
| Coal | <u>3,532</u> | <u>3,659</u> | <u>3,646</u> | <u>3,634</u> | <u>3,390</u> | <u>3,135</u> | <u>3,112</u> | <u>2,943</u> | <u>2,801</u> | <u>2,809</u> |
| Total | 22,244 | 22,591 | 22,455 | 22,563 | 22,128 | 21,917 | 21,742 | 21,715 | 21,361 | 21,055 |
| Surplus (Deficit) | 1,322 | 1,304 | 974 | 962 | 437 | 131 | (158) | (319) | (783) | (1,225) |

^{1/} Loads net of energy efficiency

^{2/} Firm hydro for energy is the generation expected assuming 1936-37 water conditions

Table 2. Northwest Region Requirements and Resources – 2016-2017 Monthly Energy
shows the monthly energy values for the 2016-2017 operating year.

| Average Megawatts | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Apr | May | Jun | Jul |
|--------------------------|--------------|--------------|--------------|--------------|--------------|----------------|----------------|--------------|--------------|--------------|--------------|--------------|
| Firm Requirements | | | | | | | | | | | | |
| Load ^{1/} | 19,754 | 18,518 | 18,408 | 20,773 | 23,110 | 22,885 | 21,895 | 20,323 | 19,339 | 18,857 | 19,337 | 20,801 |
| Exports | <u>851</u> | <u>716</u> | <u>530</u> | <u>516</u> | <u>518</u> | <u>518</u> | <u>518</u> | <u>516</u> | <u>515</u> | <u>527</u> | <u>615</u> | <u>738</u> |
| Total | 20,605 | 19,233 | 18,938 | 21,289 | 23,628 | 23,403 | 22,412 | 20,839 | 19,854 | 19,384 | 19,953 | 21,539 |
| Firm Resources | | | | | | | | | | | | |
| Hydro ^{2/} | 11,300 | 9,093 | 9,779 | 11,476 | 12,526 | 9,922 | 8,819 | 10,102 | 9,954 | 11,456 | 15,371 | 13,419 |
| Natural Gas | 4,447 | 4,302 | 4,029 | 4,244 | 4,694 | 4,638 | 4,222 | 4,042 | 3,559 | 3,594 | 4,155 | 4,364 |
| Renewables-Other | 221 | 222 | 215 | 216 | 214 | 201 | 211 | 213 | 203 | 204 | 206 | 212 |
| Solar | 33 | 32 | 23 | 22 | 59 | 45 | 64 | 97 | 125 | 148 | 165 | 177 |
| Wind | 1,297 | 1,205 | 1,198 | 1,114 | 1,189 | 1,194 | 1,159 | 1,482 | 1,421 | 1,400 | 1,504 | 1,359 |
| Cogeneration | 47 | 42 | 52 | 52 | 58 | 58 | 54 | 59 | 46 | 38 | 33 | 47 |
| Imports | 730 | 688 | 618 | 853 | 1,058 | 935 | 867 | 811 | 717 | 712 | 731 | 760 |
| Nuclear | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 1,075 | 347 | - | 971 |
| Coal | <u>3,844</u> | <u>3,394</u> | <u>3,323</u> | <u>3,599</u> | <u>3,783</u> | <u>3,730</u> | <u>3,770</u> | <u>3,555</u> | <u>2,965</u> | <u>2,696</u> | <u>3,408</u> | <u>3,777</u> |
| Total | 22,994 | 20,051 | 20,312 | 22,650 | 24,656 | 21,798 | 20,240 | 21,436 | 20,065 | 20,596 | 25,573 | 25,086 |
| Surplus (Deficit) | 2,389 | 818 | 1,375 | 1,361 | 1,028 | (1,606) | (2,172) | 597 | 211 | 1,211 | 5,620 | 3,547 |

^{1/} Loads net of energy efficiency

^{2/} Firm hydro for energy is the generation expected assuming 1936-37 water conditions

Table 3. Northwest Region Requirements and Resources – Winter Peak

The sum of the individual utilities' firm requirements and resources for the peak hour in January for each of the next 10 years are shown in this table. Firm peak requirements include a planning margin to account for planning uncertainties.

| Megawatts | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|-------------------------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|----------------|
| Firm Requirements | | | | | | | | | | |
| Load ^{1/} | 31,890 | 32,356 | 32,650 | 32,822 | 33,034 | 33,267 | 33,486 | 33,523 | 33,760 | 33,921 |
| Exports | 1,362 | 1,331 | 1,325 | 1,325 | 1,325 | 1,325 | 1,325 | 1,325 | 1,325 | 1,324 |
| Planning Margin ^{2/} | <u>3,827</u> | <u>4,206</u> | <u>4,571</u> | <u>4,923</u> | <u>5,285</u> | <u>5,655</u> | <u>6,028</u> | <u>6,369</u> | <u>6,752</u> | <u>6,784</u> |
| Total | 37,080 | 37,893 | 38,547 | 39,071 | 39,645 | 40,248 | 40,839 | 41,218 | 41,837 | 42,029 |
| Firm Resources | | | | | | | | | | |
| Hydro ^{3/} | 21,791 | 21,791 | 21,783 | 21,783 | 21,783 | 21,783 | 21,783 | 21,783 | 21,783 | 21,783 |
| Demand Response | 87 | 101 | 161 | 176 | 212 | 219 | 234 | 236 | 249 | 251 |
| Small Thermal & Misc. | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Natural Gas | 6,694 | 6,694 | 6,694 | 6,694 | 6,694 | 6,694 | 6,694 | 6,694 | 6,694 | 6,694 |
| Renewables-Other | 244 | 244 | 244 | 242 | 240 | 234 | 234 | 234 | 234 | 233 |
| Solar | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Wind | 222 | 222 | 222 | 222 | 222 | 203 | 205 | 204 | 201 | 186 |
| Cogeneration | 65 | 65 | 65 | 43 | 43 | 14 | 14 | 14 | 14 | 5 |
| Imports | 1,542 | 1,535 | 1,501 | 1,512 | 1,524 | 1,536 | 1,547 | 1,559 | 1,490 | 1,195 |
| Nuclear | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 |
| Coal | <u>4,287</u> | <u>4,287</u> | <u>4,287</u> | <u>4,287</u> | <u>3,715</u> | <u>3,711</u> | <u>3,709</u> | <u>3,709</u> | <u>3,709</u> | <u>3,709</u> |
| Total | 36,057 | 36,064 | 36,082 | 36,084 | 35,557 | 35,517 | 35,544 | 35,556 | 35,498 | 35,180 |
| Surplus (Need) | (1,022) | (1,830) | (2,465) | (2,986) | (4,088) | (4,731) | (5,295) | (5,661) | (6,340) | (6,849) |

| Potential Non-Firm Resources | MW | Source |
|------------------------------|-------|-----------------|
| Northwest IPPs | 3,000 | Council RAAC |
| Out of Region Imports | 2,500 | Council RAAC |
| Average Hydro | 4,200 | White Book est. |

^{1/} Expected (1-in-2) loads net of energy efficiency

^{2/} Planning margin is 12% in first year then grows 1% per year until reaching 20%

^{3/} Firm hydro for capacity is the generation expected assuming critical (8%) water condition

Table 4. Northwest Region Requirements and Resources – Summer Peak

This table shows the sum of the individual utilities' firm requirements and resources for a peak hour in August for each of the next 10 years. Firm peak requirements include a planning margin to account for planning uncertainties.

| Megawatts | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 |
|-------------------------------|---------------|---------------|---------------|---------------|---------------|---------------|---------------|----------------|----------------|----------------|
| Firm Requirements | | | | | | | | | | |
| Load ^{1/} | 27,521 | 28,040 | 28,466 | 28,747 | 28,858 | 29,039 | 29,168 | 29,394 | 29,633 | 29,891 |
| Exports | 1,876 | 1,878 | 1,783 | 1,777 | 1,777 | 1,477 | 1,477 | 1,477 | 1,470 | 1,461 |
| Planning Margin ^{2/} | <u>3,303</u> | <u>3,645</u> | <u>3,985</u> | <u>4,312</u> | <u>4,617</u> | <u>4,937</u> | <u>5,250</u> | <u>5,585</u> | <u>5,927</u> | <u>5,978</u> |
| Total | 32,700 | 33,563 | 34,234 | 34,836 | 35,252 | 35,452 | 35,895 | 36,456 | 37,029 | 37,331 |
| Firm Resources | | | | | | | | | | |
| Hydro ^{3/} | 21,896 | 21,896 | 21,888 | 21,888 | 21,888 | 21,888 | 21,888 | 21,888 | 21,888 | 21,888 |
| Demand Response | 405 | 407 | 408 | 410 | 410 | 410 | 416 | 428 | 428 | 428 |
| Small Thermal & Misc. | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 |
| Natural Gas | 6,148 | 6,148 | 6,148 | 6,148 | 6,148 | 6,148 | 6,148 | 6,148 | 6,148 | 6,148 |
| Renewables-Other | 245 | 245 | 245 | 245 | 244 | 242 | 236 | 236 | 236 | 235 |
| Solar | 38 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 | 202 |
| Wind | 224 | 224 | 224 | 224 | 223 | 223 | 205 | 205 | 203 | 185 |
| Cogeneration | 51 | 51 | 51 | 51 | 29 | 5 | 5 | 5 | 5 | 5 |
| Imports | 1,165 | 1,170 | 1,183 | 1,196 | 1,209 | 1,222 | 1,235 | 1,248 | 1,262 | 1,188 |
| Nuclear | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 | 1,120 |
| Coal | <u>4,290</u> | <u>4,287</u> | <u>4,287</u> | <u>4,287</u> | <u>4,287</u> | <u>3,715</u> | <u>3,711</u> | <u>3,709</u> | <u>3,709</u> | <u>3,709</u> |
| Total | 35,584 | 35,752 | 35,758 | 35,773 | 35,762 | 35,177 | 35,167 | 35,190 | 35,201 | 35,109 |
| Surplus (Need) | 2,884 | 2,189 | 1,525 | 937 | 509 | (276) | (729) | (1,266) | (1,828) | (2,222) |

| Potential Non-Firm Resources | MW | Source |
|------------------------------|-------|-----------------|
| Northwest IPPs | 1,000 | Council RAAC |
| Out of Region Imports | 0 | Council RAAC |
| Average Hydro | 1,100 | White Book est. |

^{1/} Expected (1-in-2) loads net of energy efficiency

^{2/} Planning margin is 12% in first year then grows 1% per year until reaching 20%

^{3/} Firm hydro for capacity is the generation expected assuming critical (8%) water condition

Northwest New and Existing Resources

Table 5. *Recently Acquired Resources* highlights projects that have most recently become available.

| Project | Fuel/Tech | Name plate (MW) | Winter Peak (MW) | Summer Peak (MW) | Energy (MWa) | Utility |
|-------------------------------|--------------|-----------------|------------------|------------------|--------------|------------------|
| W10 Transformer E Replacement | Hydro | 21 | 21 | 21 | | Grant County PUD |
| W09 Transformer E Replacement | Hydro | 23 | 23 | 23 | | Grant County PUD |
| W09 Generator E Replacement | Hydro | 21 | 21 | 21 | | Grant County PUD |
| Coffin Butte Resource Project | Landfill Gas | 6 | 6 | 6 | 5 | PGE via PURPA |
| Total | | 71 | 71 | 71 | 5 | |

Table 6. Committed New Supply lists contracts and generating projects where construction has started and that utilities are counting on to meet need. All supply listed in these tables are included in the regional analysis of power needs.

| Project | Date | Fuel/Tech | Name plate (MW) | Winter Peak (MW) | Summer Peak (MW) | Energy (MWa) | Utility |
|-------------------------------|---------|-------------|-----------------|------------------|------------------|--------------|---------------------------|
| Calligan Creek | Q1-2017 | Hydro | 6 | 6 | 2 | 2 | Snohomish County PUD |
| Clark Canyon Dam | Jun-17 | Hydro | 8 | 0 | 1 | | Idaho Power via PURPA |
| Hancock Creek | Q1-2018 | Hydro | 6 | 6 | 3 | 2 | Snohomish County PUD |
| North Gooding Main Hydro | May-17 | Hydro | 1 | 0 | 1 | 1 | Idaho Power via PURPA |
| W06 Generator Replacement | Jun-16 | Hydro | 9 | 9 | 9 | | Grant County PUD |
| W07 Transformer D Replacement | Nov-15 | Hydro | 21 | 21 | 21 | | Grant County PUD |
| W08 Transformer D Replacement | Nov-15 | Hydro | 12 | 12 | 12 | | Grant County PUD |
| Carty | Jul-16 | Natural Gas | 440 | 430 | 430 | 360 | Portland General Electric |
| American Falls Solar | Jan-16 | Solar | 20 | 0 | 11 | 5 | Idaho Power via PURPA |
| American Falls Solar II | Jan-16 | Solar | 20 | 0 | 11 | 5 | Idaho Power via PURPA |
| Arcadia Solar | Dec-16 | Solar | 5 | 0 | 3 | 3 | Idaho Power via PURPA |
| Boise City | Jul-16 | Solar | 40 | 0 | 21 | 12 | Idaho Power via PURPA |
| Evergreen Solar | Dec-16 | Solar | 10 | 0 | 5 | 5 | Idaho Power via PURPA |
| Fairway Solar | Dec-16 | Solar | 10 | 0 | 5 | 5 | Idaho Power via PURPA |
| Grand View Solar | Jul-16 | Solar | 80 | 0 | 42 | 22 | Idaho Power via PURPA |
| Grove Solar | Dec-16 | Solar | 10 | 0 | 5 | 2 | Idaho Power via PURPA |
| Hylite Solar | Dec-16 | Solar | 10 | 0 | 5 | 2 | Idaho Power via PURPA |
| Jamieson Solar | Dec-16 | Solar | 4 | 0 | 2 | 2 | Idaho Power via PURPA |
| John Day Solar | Dec-16 | Solar | 5 | 0 | 3 | 3 | Idaho Power via PURPA |
| Little Valley Solar | Dec-16 | Solar | 10 | 0 | 5 | 5 | Idaho Power via PURPA |
| Malheur River Solar | Dec-16 | Solar | 10 | 0 | 5 | 5 | Idaho Power via PURPA |
| Moore's Hollow Solar | Dec-16 | Solar | 10 | 0 | 5 | 5 | Idaho Power via PURPA |
| Mountain Home Solar | Dec-16 | Solar | 20 | 0 | 11 | 7 | Idaho Power via PURPA |
| Murphy Flat Power | Dec-16 | Solar | 20 | 0 | 11 | 5 | Idaho Power via PURPA |
| Old Ferry Solar | Dec-16 | Solar | 5 | 0 | 3 | 3 | Idaho Power via PURPA |
| Open Range Solar | Dec-16 | Solar | 10 | 0 | 5 | 2 | Idaho Power via PURPA |
| Orchard Ranch Solar | Dec-16 | Solar | 20 | 0 | 11 | 5 | Idaho Power via PURPA |
| Pocatello Solar I | Dec-16 | Solar | 20 | 0 | 10 | 6 | Idaho Power via PURPA |
| Railroad Solar | Dec-16 | Solar | 10 | 0 | 5 | 2 | Idaho Power via PURPA |
| RPS Solar | | Solar | 7 | | | | PacifiCorp |
| Simco Solar | Dec-16 | Solar | 20 | 0 | 11 | 5 | Idaho Power via PURPA |
| Thunderegg Solar | Dec-16 | Solar | 10 | 0 | 5 | 2 | Idaho Power via PURPA |
| Vale Solar | Dec-16 | Solar | 10 | 0 | 5 | 2 | Idaho Power via PURPA |
| Benson Creek Wind | Dec-16 | Wind | 10 | 1 | 1 | 2 | Idaho Power via PURPA |
| Durbin Creek Wind | Dec-16 | Wind | 10 | 1 | 1 | 2 | Idaho Power via PURPA |
| Jett Creek Wind | Dec-16 | Wind | 10 | 1 | 1 | 2 | Idaho Power via PURPA |
| Prospector Wind | Dec-16 | Wind | 10 | 1 | 1 | 3 | Idaho Power via PURPA |
| Willow Springs Wind Farm | Dec-16 | Wind | 10 | 1 | 1 | 2 | Idaho Power via PURPA |
| Total | | | 948 | 486 | 687 | 500 | |

Table 7. Demand Side Management Programs is a snapshot of the regional utilities' efforts to manage demand. The majority of the reported conservation savings are from utility programs. This table also shows cumulative existing plus new demand response programs reported by utilities.¹

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 |
|--------------------------------|---------|---------|---------|---------|---------|---------|---------|---------|---------|---------|
| Energy Efficiency (MWa) | | | | | | | | | | |
| Incremental | 216 | 193 | 179 | 174 | 177 | 159 | 159 | 154 | 149 | 141 |
| Cumulative | 216 | 408 | 588 | 762 | 939 | 1,097 | 1,256 | 1,410 | 1,560 | 1,700 |
| Demand Response (MW) | | | | | | | | | | |
| Winter (existing + new) | 87 | 101 | 161 | 176 | 212 | 219 | 234 | 236 | 249 | 251 |
| Summer (existing + new) | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 405 | 405 |

¹ Does not include any demand response in the Rocky Mountain Power territory
 PNUCC
 2016 Northwest Regional Forecast

Table 8. Planned Resources captures resources utilities have identified to meet their own needs. The table shows planned generating projects that are being counted on to meet the growing demand. This information is a compilation of what utilities have reported in their individual integrated resources plans. These resources are not included in the regional analysis of power needs.

| Project | Schedule | Fuel/Tech | Nameplate (MW) | Winter Peak (MW) | Summer peak (MW) | Energy (MWa) | Utility |
|----------------------------|----------|----------------------|----------------|------------------|------------------|--------------|----------------------|
| Nine Mile 1 & 2 | 2016 | Hydro | | 16 | 13 | | Avista Corp. |
| Shoshone Falls Upgrade | 2019 | Hydro | 49 | 2 | 9 | | Idaho Power |
| W03 Generator Replacement | 2016 | Hydro | 9 | 9 | 9 | | Grant County PUD |
| W04 Generator Replacement | 2017 | Hydro | 9 | 9 | 9 | | Grant County PUD |
| W 06 Generator Replacement | 2016 | Hydro | 9 | 9 | 9 | | Grant County PUD |
| W08 Generator Replacement | 2018 | Hydro | 9 | 9 | 9 | | Grant County PUD |
| Gas Peaker | 2020 | Natural Gas | 96 | 102 | 96 | 89 | Avista Corp. |
| Landfill Gas | 2020 | Methane/gas | 9 | | | 8 | Seattle City Light |
| Landfill Gas PPA | 2026 | Methane/gas | 10 | 9 | 9 | 9 | Snohomish County PUD |
| Peakers CT | 2021 | Natural Gas | 277 | 277 | 277 | | Puget Sound Energy |
| Peakers CT | 2025 | Natural Gas | 126 | 126 | 126 | | Puget Sound Energy |
| Gas CCCT | 2026 | Natural Gas | 286 | 286 | 306 | 265 | Avista Corp. |
| Gas CCCT | 2026 | Natural Gas | 577 | 577 | 577 | 476 | Puget Sound Energy |
| Thermal Plant Upgrades | 2021-25 | Natural Gas | | 38 | 38 | 35 | Avista Corp. |
| Winter Capacity PPA | 2021 | PPA | 75 | 75 | 0 | 25 | Snohomish County PUD |
| Community Solar Project | 2016 | Solar | 0 | 0 | 0 | 164 | Cowlitz PUD |
| Solar Project | 2017 | Solar | 3 | 3 | 3 | 1 | PNGC |
| Wind | 2023 | Wind | 206 | 16 | 16 | 71 | Puget Sound Energy |
| Wind | 2023 | Wind | 63 | | | 20 | Seattle City Light |
| Wind | 2024 | Wind | 220 | | | 70 | Seattle City Light |
| Wind | 2025 | Wind | 31 | | | 10 | Seattle City Light |
| Wind | 2026 | Wind | 78 | | | 25 | Seattle City Light |
| Biomass | 2023 | Wood waste/ cogen | 44 | | | 40 | Seattle City Light |
| Total | | | 2,185 | 1,562 | 1,505 | 1,307 | |

Table 9. Planned Resources Schedule (Cumulative Nameplate MW)

| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 |
|--------------|-----------|-----------|-----------|-----------|------------|------------|------------|------------|--------------|--------------|--------------|
| Hydro | 18 | 27 | 36 | 85 | 85 | 85 | 85 | 85 | 85 | 85 | 85 |
| Methane/gas | 0 | 0 | 0 | 0 | 9 | 9 | 9 | 9 | 9 | 9 | 19 |
| Natural Gas | 0 | 0 | 0 | 0 | 96 | 373 | 373 | 373 | 373 | 499 | 1,362 |
| PPA | 0 | 0 | 0 | 0 | 0 | 75 | 75 | 75 | 75 | 75 | 75 |
| Solar | 1 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 |
| Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 269 | 489 | 520 | 598 |
| Wood waste | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 44 | 44 | 44 | 44 |
| Total | 19 | 31 | 40 | 89 | 194 | 546 | 546 | 859 | 1,079 | 1,236 | 2,185 |

Table 10. Northwest Utility Generating Resources is a comprehensive list of utility-owned and utility contracted generating resources that make up those utilities electric power supply.

| Project | Owner | NW Utility | Nameplate (MW) |
|------------------------|-------------------------------|-------------------------------|----------------|
| HYDRO | | | 33,128 |
| Albeni Falls | US Corps of Engineers | Federal System (BPA) | 43 |
| Alder | Tacoma Power | Tacoma Power | 50 |
| American Falls | Idaho Power | Idaho Power | 92 |
| Anderson Ranch | US Bureau of Reclamation | Federal System (BPA) | 40 |
| Arena Drop | | Idaho Power | 0 |
| Arrowrock Dam | Clatskanie PUD/Irr Dist | Clatskanie PUD | 18 |
| B. Smith | PacifiCorp | PacifiCorp | 0 |
| Barber Dam | Enel North America | Idaho Power | 4 |
| Bell Mountain | PacifiCorp | PacifiCorp | 1 |
| Big Cliff | US Corps of Engineers | Federal System (BPA) | 18 |
| Big Sheep Creek | Everand Jensen | Avista Corp. | 0 |
| Birch Creek | Everand Jensen | Idaho Power | 0 |
| Birch Creek | PacifiCorp | PacifiCorp | 3 |
| Black Canyon Bliss Dam | PURPA | Idaho Power | 0 |
| Black Canyon | US Bureau of Reclamation | Federal System (BPA) | 10 |
| Black Canyon # 3 | Big Wood Canal Co. | Idaho Power | 0 |
| Black Creek Hydro | Black Creek Hydro, Inc. | Puget Sound Energy | 4 |
| Blind Canyon | Blind Canyon Hydro | Idaho Power | 2 |
| Bliss | Idaho Power | Idaho Power | 75 |
| Boise River Diversion | US Bureau of Reclamation | Federal System (BPA) | 2 |
| Bonneville | US Corps of Engineers | Federal System (BPA) | 1,102 |
| Boston Power | | PacifiCorp | |
| Boundary | Seattle City Light | Seattle City Light | 1,040 |
| Box Canyon | Pend Oreille County PUD | Pend Oreille County PUD | 70 |
| Box Canyon-Idaho | Richard Kaster | Idaho Power | 0 |
| Briggs Creek | Richard Kaster | Idaho Power | 1 |
| Brownlee | Idaho Power | Idaho Power | 585 |
| Burnside Hydro | | Other Public (BPA) | |
| Bypass | Bypass, Ltd. | Idaho Power | 10 |
| Cabinet Gorge | Avista Corp. | Avista Corp. | 265 |
| Calligan Creek | Snohomish County PUD | Snohomish County PUD | 6 |
| Calispel Creek | Pend Oreille County PUD | Pend Oreille County PUD | 1 |
| Canyon Springs | J.D. McCollum | Idaho Power | 0 |
| Carmen-Smith | Eugene Water & Electric Board | Eugene Water & Electric Board | 105 |
| Cascade | US Bureau of Reclamation | Idaho Power | 12 |
| CDM Hydro | PacifiCorp | PacifiCorp | 6 |
| Cedar Draw Creek | Crys. Sprgs. Hydro | Idaho Power | 2 |
| Cedar Falls, Newhalem | Seattle City Light | Seattle City Light | 20 |

| Project | Owner | NW Utility | Nameplate (MW) |
|-----------------------|-----------------------------|---------------------------|----------------|
| Central Oregon Siphon | | PacifiCorp | 5 |
| Chandler | US Bureau of Reclamation | Federal System (BPA) | 12 |
| Chelan | Chelan County PUD | Chelan County PUD | 59 |
| Chief Joseph | US Corps of Engineers | Federal System (BPA) | 2,457 |
| C. J. Strike | Idaho Power | Idaho Power | 83 |
| Clark Canyon Dam | PURPA | Idaho Power | 8 |
| Clear Lake | Idaho Power | Idaho Power | 3 |
| Clear Springs Trout | Clear Springs Trout | Idaho Power | 1 |
| Clearwater #1 | PacifiCorp | PacifiCorp | 15 |
| Clearwater #2 | PacifiCorp | PacifiCorp | 26 |
| Cline Falls | COID | PacifiCorp | 1 |
| COID | PacifiCorp | PacifiCorp | 7 |
| Copco #1 | PacifiCorp | PacifiCorp | 20 |
| Copco #2 | PacifiCorp | PacifiCorp | 27 |
| Cougar | US Corps of Engineers | Federal System (BPA) | 25 |
| Cove Hydro | | Other Public (BPA) | |
| Cowlitz Falls | Lewis County PUD | Federal (BPA) | 70 |
| Crystal Springs | Crystal Springs Hydro | Idaho Power | 2 |
| Curry Cattle Company | Curry Cattle Co. | Idaho Power | 0 |
| Curtis Livestock | PacifiCorp | PacifiCorp | 0 |
| Cushman 1 | Tacoma Power | Tacoma Power | 43 |
| Cushman 2 | Tacoma Power | Tacoma Power | 81 |
| Deep Creek | Gordon Foster | Avista Corp. | 0 |
| Derr Creek | Jim White | Avista Corp. | 0 |
| Detroit | US Corps of Engineers | Federal System (BPA) | 100 |
| Dexter | US Corps of Engineers | Federal System (BPA) | 15 |
| Diablo Canyon | Seattle City Light | Seattle City Light | 182 |
| Dietrich Drop | Enel North America | Idaho Power | 5 |
| Dry Creek | | PacifiCorp | 4 |
| D. Wiggins | | PacifiCorp | |
| Dworshak | US Corps of Engineers | Federal System (BPA) | 400 |
| Dworshak/ Clearwater | | Federal System (BPA) | |
| Eagle Point | PacifiCorp | PacifiCorp | 3 |
| East Side | PacifiCorp | PacifiCorp | 3 |
| Eight Mile Hydro | Eightmile Hydro Corporation | Idaho Power | 0 |
| Electron | Puget Sound Energy | Puget Sound Energy | 23 |
| Elk Creek | El Dorado Hydro | Idaho Power | 2 |
| Eltopia Branch Canal | SEOCBID | Muliple Utilities | 2 |
| Esquatzel Small Hydro | Green Energy Today, LLC | Franklin County PUD | 1 |
| Fall Creek | PacifiCorp | PacifiCorp | 3 |
| Falls Creek | | Other Public (BPA) | |
| Falls River | Marysville Hydro Partner | Idaho Power | 9 |
| Faraday | Portland General Electric | Portland General Electric | 37 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---------------------------|------------------------------|----------------------|----------------|
| Fargo Drop Hydro | Riverside Investments, LLC | Idaho Power | 1 |
| Farmers Irrigation | PacifiCorp | PacifiCorp | 3 |
| Faulkner Ranch | Faulkner Brothers Hydro Inc. | Idaho Power | 1 |
| Fish Creek | PacifiCorp | PacifiCorp | 11 |
| Fisheries Development Co. | Fisheries Devel. | Idaho Power | 0 |
| Foster | US Corps of Engineers | Federal System (BPA) | 20 |
| Frontier Technologies | PacifiCorp | PacifiCorp | 4 |
| Galesville Dam | PacifiCorp | PacifiCorp | 2 |
| Gem State Hydro | | Other Publics (BPA) | 23 |
| Geo-Bon No 2 | Enel North America, Inc. | Idaho Power | 1 |
| Georgetown Power | PacifiCorp | PacifiCorp | 0 |
| Gorge | Seattle City Light | Seattle City Light | 207 |
| Grand Coulee | US Bureau of Reclamation | Federal System (BPA) | 6,494 |
| Green Peter | US Corps of Engineers | Federal System(BPA) | 80 |
| Green Springs | US Bureau of Reclamation | Federal System (BPA) | 16 |
| Hailey CSPP | City of Hailey | Idaho Power | 0 |
| Hancock Creek | Snohomish County PUD | Snohomish County PUD | 6 |
| Hazelton A | SE Hazelton ALP | Idaho Power | 8 |
| Hazelton B | Hazelton Power Co. | Idaho Power | 8 |
| Head of U Canal | PURPA | Idaho Power | 1 |
| Hells Canyon | Idaho Power | Idaho Power | 392 |
| Hills Creek | US Corps of Engineers | Federal System (BPA) | 30 |
| Hood Street Reservoir | Tacoma Power | Tacoma Power | 1 |
| Horseshoe Bend | Horseshoe Bend Hydro | Idaho Power | 10 |
| Hungry Horse | US Bureau of Reclamation | Federal System (BPA) | 428 |
| Hutchinson Creek | STS Hydro | Puget Sound Energy | 1 |
| Ice Harbor | US Corps of Engineers | Federal System(BPA) | 603 |
| Idaho Falls - City Plant | | Federal System (BPA) | |
| Idaho Falls - Lower Plant | | Federal System (BPA) | |
| Idaho Falls - Upper Plant | | Federal System (BPA) | |
| Ingram Warm Springs | PacifiCorp | PacifiCorp | 1 |
| Iron Gate | PacifiCorp | PacifiCorp | 18 |
| Island Park | | Fall River REC | 5 |
| Jackson (Sultan) | Snohomish County PUD | Snohomish County PUD | 112 |
| James Boyd | | PacifiCorp | |
| Jim Ford Creek | Ford Hydro | Avista Corp. | 2 |
| Jim Knight | Big Wood Canal Co. | Idaho Power | 0 |
| John C. Boyle | PacifiCorp | PacifiCorp | 90 |
| John Day | US Corps of Engineers | Federal System(BPA) | 2,160 |
| John Day Creek | Dave Cereghino | Avista Corp. | 1 |
| John H Koyle | John H Koyle | Idaho Power | 1 |
| Joseph Hydro | | PacifiCorp | |
| Kasel-Witherspoon | Kasel & Witherspoon | Idaho Power | 1 |

| Project | Owner | NW Utility | Nameplate (MW) |
|----------------------------|-------------------------------|-------------------------------|----------------|
| Kerr | NorthWestern Corporation | NorthWestern Energy | 194 |
| Koma Kulshan | Koma Kulshan Associates | Puget Sound Energy | 11 |
| La Grande | Tacoma Power | Tacoma Power | 64 |
| Lacomb Irrigation | PacifiCorp | PacifiCorp | 1 |
| Lake Creek | | Other Publics (BPA) | |
| Lake Oswego Corp. | | Portland General Electric | 1 |
| Lateral No. 10 | Lateral 10 Ventures | Idaho Power | 2 |
| Leaburg | Eugene Water & Electric Board | Eugene Water & Electric Board | 16 |
| Lemolo #1 | PacifiCorp | PacifiCorp | 32 |
| Lemolo #2 | PacifiCorp | PacifiCorp | 33 |
| Lemoyne | John Lemoyne | Idaho Power | 0 |
| Libby | US Corps of Engineers | Federal System(BPA) | 525 |
| Lilliwaup Falls | | Other Public (BPA) | 1 |
| Little Falls | Avista Corp. | Avista Corp. | 32 |
| Little Goose | US Corps of Engineers | Federal System(BPA) | 810 |
| Little Wood | Little Wood Irr District | Idaho Power | 3 |
| Little Wood/Arkoosh | William Arkoosh | Idaho Power | 1 |
| Little Wood River Ranch II | PURPA | Idaho Power | 1 |
| Lloyd Fery | PacifiCorp | PacifiCorp | 0 |
| Long Lake | Avista Corp. | Avista Corp. | 70 |
| Lookout Point | US Corps of Engineers | Federal System (BPA) | 120 |
| Lost Creek | US Corps of Engineers | Federal System (BPA) | 49 |
| Lower Baker | Puget Sound Energy | Puget Sound Energy | 115 |
| Lower Granite | US Corps of Engineers | Federal System(BPA) | 810 |
| Lower Malad | Idaho Power | Idaho Power | 14 |
| Lower Monumental | US Corps of Engineers | Federal System(BPA) | 810 |
| Lower Salmon | Idaho Power | Idaho Power | 60 |
| Lowline #2 | Enel North America, Inc. | Idaho Power | 3 |
| Lowline Canal | S. Forks | Idaho Power | 3 |
| Lowline Midway | Idaho Power | Idaho Power | 8 |
| Lucky Peak | US Corps of Engineers | Seattle City Light | 113 |
| Magic Reservoir | Magic Reservoir Hydro | Idaho Power | 9 |
| Main Canal Headworks | SEOCBID | Multiple Utilities | 26 |
| Malad River | V. Ravenscroft | Idaho Power | 1 |
| Mayfield | Tacoma Power | Tacoma Power | 162 |
| McNary | US Corps of Engineers | Federal System(BPA) | 980 |
| McNary Fishway | US Corps of Engineers | Other Publics (BPA) | |
| Menwin | PacifiCorp | PacifiCorp | 136 |
| Meyers Falls | Hydro Technology Systems | Avista Corp. | 1 |
| Middlefork Irrigation | PacifiCorp | PacifiCorp | 3 |
| Mile 28 | Contractors Power Group Inc. | Idaho Power | 2 |
| Mill Creek (Cove) | City of Cove, OR | Idaho Power | 1 |
| Mill Creek | | Other Publics (BPA) | 1 |

| Project | Owner | NW Utility | Nameplate (MW) |
|------------------------|----------------------------|---------------------------|----------------|
| Milner | Idaho Power | Idaho Power | 59 |
| Minidoka | US Bureau of Reclamation | Federal System (BPA) | 28 |
| Mink Creek | PacifiCorp | PacifiCorp | 3 |
| Mitchell Butte | Owyhee Irrigation District | Idaho Power | 2 |
| Monroe Street | Avista | Avista Corp. | 15 |
| Mora Drop | Riverside LLC | Idaho Power | 2 |
| Morse Creek | | Port Angeles | 1 |
| Mossyrock | Tacoma Power | Tacoma Power | 300 |
| Mountain Energy | PacifiCorp | PacifiCorp | 0 |
| Mount Tabor | City of Portland | Portland General Electric | 0 |
| Moyie Springs | | Other Publics (BPA) | |
| Mud Creek/S&S | H.K. Hydro | Idaho Power | 1 |
| Mud Creek/White | Mud Creek Hydro | Idaho Power | 0 |
| N-32 Canal | Ranchers Irrig., Inc. | Idaho Power | 1 |
| Nicols Gap | PacifiCorp | PacifiCorp | 1 |
| Nicolson SunnyBar | PacifiCorp | PacifiCorp | 0 |
| Nine Mile | Avista Corp. | Avista Corp. | 26 |
| Nooksack | Puget Sound Hydro, LLC | Puget Sound Energy | 3 |
| North Fork | Portland General Electric | Portland General Electric | 41 |
| North Fork Sprague | PacifiCorp | PacifiCorp | 1 |
| Noxon Rapids | Avista Corp. | Avista Corp. | 466 |
| N.R. Rousch | PacifiCorp | PacifiCorp | 0 |
| Oak Grove | Portland General Electric | Portland General Electric | 51 |
| Odell Creek | PacifiCorp | PacifiCorp | 0 |
| O.J. Power | PacifiCorp | PacifiCorp | 0 |
| Opal Springs | PacifiCorp | PacifiCorp | 5 |
| Ormsby | | PacifiCorp | |
| Owyhee Dam | Owyhee Irrigation District | Idaho Power | 5 |
| Oxbow | Idaho Power | Idaho Power | 190 |
| Packwood | Energy Northwest | Multiple Utilities | 26 |
| Palisades | US Bureau of Reclamation | Federal System (BPA) | 177 |
| PEC Headworks | SEQCBID | Grant County PUD | 7 |
| Pelton | Portland General Electric | Multiple Utilities | 110 |
| Pelton Reregulation | Warm Springs Tribe | Portland General Electric | 19 |
| Phillips Ranch | Glen Phillips | Avista Corp. | 0 |
| Pigeon Cove | Pigeon Cove Power | Idaho Power | 2 |
| Portland Hydro-Project | City of Portland | Portland General Electric | 36 |
| Portneuf River | | PacifiCorp | 1 |
| Post Falls | Avista Corp. | Avista Corp. | 15 |
| Potholes East Canal 66 | SEQCBID | Multiple Utilities | 5 |
| Powerdale | PacifiCorp | PacifiCorp | 6 |
| Preston City | PacifiCorp | PacifiCorp | 0 |
| Priest Rapids | Grant County PUD | Multiple Utilities | 956 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---------------------|-------------------------------|-------------------------------|----------------|
| Pristine Springs | Pristine Springs, Inc | Idaho Power | 0 |
| Pristine Springs #3 | Pristine Springs, Inc | Idaho Power | 0 |
| Prospect #1 | PacifiCorp | PacifiCorp | 4 |
| Prospect #2 | PacifiCorp | PacifiCorp | 32 |
| Prospect #3 | PacifiCorp | PacifiCorp | 7 |
| Prospect #4 | PacifiCorp | PacifiCorp | 1 |
| Quincy Chute | SEQCBID | Grant County PUD | 9 |
| R.D. Smith | SEQCBID | Multiple Utilities | 6 |
| Reeder Gulch | | Other Publics (BPA) | 0 |
| Reynolds Irrigation | Reynolds Irrigation | Idaho Power | 0 |
| Rim View | Rim View Trout Co. | Idaho Power | 0 |
| River Mill | Portland General Electric | Portland General Electric | 19 |
| Rock Creek No. 1 | Rock Creek Joint | Idaho Power | 2 |
| Rock Creek No. 2 | Enel North America | Idaho Power | 2 |
| Rocky Brook | Mason County PUD #3 | Other Public (BPA) | 2 |
| Rock Island | Chelan County PUD | Multiple Utilities | 629 |
| Rocky Reach | Chelan County PUD | Multiple Utilities | 1,300 |
| Ross | Seattle City Light | Seattle City Light | 360 |
| Round Butte | Portland General Electric | Multiple Utilities | 247 |
| Roza | US Bureau of Reclamation | Federal System (BPA) | 13 |
| Sagebrush | Big Wood Canal Co. | Idaho Power | 0 |
| Sahko | Sahko | Idaho Power | 1 |
| Santiam | PacifiCorp | PacifiCorp | 0 |
| Schaffner | Lemhi Hydro Co. | Idaho Power | 1 |
| Sheep Creek | Glen Phillips | Avista Corp. | 2 |
| Shingle Creek | Willis D Deveny | Idaho Power | 0 |
| Shoshone II | Shorock Hydro | Idaho Power | 1 |
| Shoshone CSPP | Shorock Hydro, Inc. | Idaho Power | 0 |
| Shoshone Falls | Idaho Power | Idaho Power | 13 |
| Slide Creek | PacifiCorp | PacifiCorp | 18 |
| Smith Creek | Eugene Water & Electric Board | Eugene Water & Electric Board | 38 |
| Snake River Pottery | Snake River Pottery | Idaho Power | 0 |
| Snedigar Ranch | David Snedigar | Idaho Power | 1 |
| Snoqualmie Falls | Puget Sound Energy | Puget Sound Energy | 54 |
| Soda Creek | | Other Publics (BPA) | |
| Soda Springs | PacifiCorp | PacifiCorp | 11 |
| South Fork Tolt | Seattle City Light | Seattle City Light | 17 |
| Spokane Upriver | City of Spokane | Avista Corp. | 16 |
| Stauffer Dry Creek | | PacifiCorp | |
| Steffen Hydro | | Snohomish County PUD | |
| Stone Creek | Eugene Water & Electric Board | Eugene Water & Electric Board | 12 |
| Strawberry Creek | South Idaho Public Agency | Other Publics (BPA) | |
| Summer Falls | SEQCBID | Multiple Utilities | 92 |

| Project | Owner | NW Utility | Nameplate (MW) |
|--------------------|---------------------------------|-------------------------------|----------------|
| Swan Falls | Idaho Power | Idaho Power | 25 |
| Swift 1 | PacifiCorp | Multiple Utilities | 219 |
| Swift 2 | Cowlitz County PUD | Multiple Utilities | 0 |
| Sygitowicz | Cascade Clean Energy | Puget Sound Energy | 0 |
| TGS/Briggs | | PacifiCorp | |
| The Dalles | US Corps of Engineers | Federal System(BPA) | 1,807 |
| The Dalles Fishway | Northern Wasco Co. PUD | Northern Wasco Co. PUD | 5 |
| Thompson Falls | NorthWestern Corporation | NorthWestern Energy | 94 |
| Thousand Springs | Idaho Power | Idaho Power | 9 |
| Tiber Dam | Tiber Montana, LLC | Idaho Power | 8 |
| Toketee | PacifiCorp | PacifiCorp | 43 |
| Trail Bridge | Eugene Water & Electric Board | Eugene Water & Electric Board | 10 |
| Trout Company | Branch Flower Co. | Idaho Power | 0 |
| Tunnel #1 | Owyhee Irrig. Dist. | Idaho Power | 7 |
| Twin Falls | Idaho Power | Idaho Power | 53 |
| Twin Falls | Twin Falls Hydro Association LP | Puget Sound Energy | 20 |
| TW Sullivan | Portland General Electric | Portland General Electric | 15 |
| Upper Baker | Puget Sound Energy | Puget Sound Energy | 105 |
| Upper Falls | Avista Corp. | Avista Corp. | 10 |
| Upper Malad | Idaho Power | Idaho Power | 8 |
| Upper Salmon 1 & 2 | Idaho Power | Idaho Power | 18 |
| Upper Salmon 3 & 4 | Idaho Power | Idaho Power | 17 |
| Walla Walla | PacifiCorp | PacifiCorp | 2 |
| Wallowa Falls | PacifiCorp | PacifiCorp | 1 |
| Walterville | Eugene Water & Electric Board | Eugene Water & Electric Board | 8 |
| Wanapum | Grant County PUD | Multiple Utilities | 934 |
| Weeks Falls | So. Fork II Assoc. LP | Puget Sound Energy | 5 |
| Wells | Douglas County PUD | Multiple Utilities | 774 |
| West Side | PacifiCorp | PacifiCorp | 1 |
| White Water Ranch | White Water Ranch | Idaho Power | 0 |
| Wilson Lake Hydro | Wilson Pwr. Co. | Idaho Power | 8 |
| Woods Creek | Snohomish County PUD | Snohomish County PUD | 1 |
| Wynoochee | Tacoma Power | Tacoma Power | 13 |
| Yale | PacifiCorp | PacifiCorp | 134 |
| Yelm | | Other Publics (BPA) | 12 |
| Yakima-Tieton | PacifiCorp | PacifiCorp | 3 |
| Young's Creek | Snohomish County PUD | Snohomish County PUD | 8 |

| Project | Owner | NW Utility | Nameplate (MW) |
|------------------------------|---------------------------------|---------------------------|----------------|
| COAL | | | 5,496 |
| Boardman | Portland General Electric | Multiple Utilities | 642 |
| Colstrip #1 | PP&L Montana, LLC | Multiple Utilities | 330 |
| Colstrip #2 | PP&L Montana, LLC | Multiple Utilities | 330 |
| Colstrip #3 | PP&L Montana, LLC | Multiple Utilities | 740 |
| Colstrip #4 | NorthWestern Energy | Multiple Utilities | 805 |
| Jim Bridger #1 | PacifiCorp / Idaho Power | Multiple Utilities | 540 |
| Jim Bridger #2 | PacifiCorp / Idaho Power | Multiple Utilities | 540 |
| Jim Bridger #3 | PacifiCorp / Idaho Power | Multiple Utilities | 540 |
| Jim Bridger #4 | PacifiCorp / Idaho Power | Multiple Utilities | 508 |
| Valmy #1 | NV Energy / Idaho Power | Multiple Utilities | 254 |
| Valmy #2 | NV Energy / Idaho Power | Multiple Utilities | 267 |
| NUCLEAR | | | 1,230 |
| Columbia Generating Station | Energy Northwest | Federal System (BPA) | 1,230 |
| NATURAL GAS | | | 6,828 |
| Alden Bailey | Clatskanie PUD | Clatskanie PUD | 11 |
| Beaver | Portland General Electric | Portland General Electric | 516 |
| Beaver 8 | Portland General Electric | Portland General Electric | 25 |
| Bennett Mountain | Idaho Power | Idaho Power | 173 |
| Boulder Park | Avista Corp. | Avista Corp. | 25 |
| Carty | Portland General Electric | Portland General Electric | 440 |
| Chehalis Generating Facility | PacifiCorp | PacifiCorp | 517 |
| Coyote Springs I | Portland General Electric | Portland General Electric | 266 |
| Coyote Springs II | Avista Corp. | Avista Corp. | 287 |
| Danskin | Idaho Power | Idaho Power | 92 |
| Danskin 1 | Idaho Power | Idaho Power | 179 |
| Dave Gates | NorthWestern Energy | NorthWestern Energy | 150 |
| Encogen | Puget Sound Energy | Puget Sound Energy | 159 |
| Ferndale Cogen Station | Puget Sound Energy | Puget Sound Energy | 245 |
| Frederickson | EPCOR Power L.P./PSE | Multiple Utilities | 258 |
| Fredonia 1 & 2 | Puget Sound Energy | Puget Sound Energy | 208 |
| Fredonia 3 & 4 | Puget Sound Energy | Puget Sound Energy | 108 |
| Fredrickson 1 & 2 | Puget Sound Energy | Puget Sound Energy | 149 |
| Goldendale | Puget Sound Energy | Puget Sound Energy | 261 |
| Hermiston Generating P. | PacifiCorp/Hermiston Gen. Comp. | PacifiCorp | 469 |
| Kettle Falls CT | Avista Corp. | Avista Corp. | 7 |
| Lancaster Power Project | Avista Corp. | Avista Corp. | 270 |
| Langley Gulch | Idaho Power | Idaho Power | 319 |

| Project | Owner | NW Utility | Nameplate (MW) |
|-------------------------|---------------------------|---------------------------|----------------|
| Mint Farm Energy Center | Puget Sound Energy | Puget Sound Energy | 305 |
| Northeast A&B | Avista Corp. | Avista Corp. | 62 |
| Port Westward | Portland General Electric | Portland General Electric | 415 |
| Port Westward Unit 2 | Portland General Electric | Portland General Electric | 220 |
| Rathdrum 1 & 2 | Avista Corp. | Avista Corp. | 167 |
| River Road | Clark Public Utilities | Clark Public Utilities | 248 |
| Rupert (Magic Valley) | Rupert Illinois Holdings | Idaho Power | 10 |
| Sumas Energy | Puget Sound Energy | Puget Sound Energy | 121 |
| Whitehorn #2 & 3 | Puget Sound Energy | Puget Sound Energy | 149 |

COGENERATION

199

| | | | |
|----------------------------|-------------------------------|-------------------------------|----|
| Billings Cogeneration | Billings Generation, Inc. | NorthWestern Energy | 64 |
| Hampton Lumber | | Snohomish County PUD | 5 |
| International Paper Energy | Eugene Water & Electric Board | Eugene Water & Electric Board | 26 |
| James River - Camas | PacifiCorp | PacifiCorp | 52 |
| Simplot-Pocatello | PURPA | Idaho Power | 12 |
| Tasco-Nampa | Tasco | Idaho Power | 2 |
| Tasco-Twin Falls | Tasco | Idaho Power | 3 |
| Wauna (James River) | Western Generation Agency | Multiple Utilities | 36 |

RENEWABLES-OTHER

346

| | | | |
|-----------------------------|-----------------------------------|-------------------------------|----|
| Bettencourt B6 | Cargill | Idaho Power | 2 |
| Bettencourt Dry Creek | Cargill | Idaho Power | 2 |
| Big Sky West Dairy | Dean Foods Co. & AgPower Partners | Idaho Power | 2 |
| Bio Energy | | Puget Sound Energy | 1 |
| Bio Fuels, WA | | Puget Sound Energy | 5 |
| Biomass One | PacifiCorp | PacifiCorp | 25 |
| City of Spokane Waste | City of Spokane | Avista Corp. | 26 |
| Coffin Butte | Power Resources Cooperative | PNGC Power | 6 |
| Cogen Company | Prairie Wood Products Co-Gen Co. | Oregon Trail Coop | 8 |
| DR Johnson Lumber | PacifiCorp | PacifiCorp | 8 |
| Columbia Ridge Landfill Gas | Waste Management | Seattle City Light | 13 |
| Convanta Marion | Portland General Electric | Portland General Electric | 16 |
| Double A Digester | PURPA-Andgar Corp | Idaho Power | 5 |
| Dry Creek Landfill | Dry Creek Landfill Inc. | PacifiCorp | 3 |
| Edaleen Dairy | | Puget Sound Energy | 1 |
| Farm Power Tillamook | Tillamook PUD | Tillamook PUD | 1 |
| Fighting Creek | Kootenai Electric Co-op | Idaho Power | 3 |
| Flathead County Landfill | Flathead Electric Cooperative | Flathead Electric Cooperative | 2 |
| Four Mile Hill Geothermal | Calpine | Federal System (BPA) | 50 |
| Hidden Hollow Landfill | G2 Energy | Idaho Power | 3 |

| Project | Owner | NW Utility | Nameplate (MW) |
|----------------------------|--------------------------------|-------------------------------|----------------|
| Hooley Digester | Tillamook PUD | Tillamook PUD | 1 |
| H. W. Hill Landfill | Allied Waste Companies | Multiple Utilities | 11 |
| Interfor Pacific-Gilchrist | Midstate Electric Co-op | Midstate Electric Co-op | |
| Kettle Falls | Avista Corp. | Avista Corp. | 51 |
| Lynden | Farm Power | Puget Sound Energy | 1 |
| Mill Creek (Cove) | | Idaho Power | 1 |
| Neal Hot Springs | U.S Geothermal | Idaho Power | 23 |
| Olympic View 1&2 | Mason County PUD #3 | Mason County PUD #3 | 5 |
| Pine Products | PacifiCorp | PacifiCorp | 6 |
| Plum Creek NLSL | Plum Creek MDF | Flathead Electric Cooperative | 6 |
| Pocatello Wastewater | Idaho Power | Idaho Power | 0 |
| Portland Wastewater | City of Portland | Portland General Electric | 2 |
| Raft River 1 | US Geothermal | Idaho Power | 16 |
| Rainier Biogas | | Puget Sound Energy | 1 |
| Rexville | Farm Power | Puget Sound Energy | 1 |
| River Bend Landfill | McMinnville Water & Light | McMinnville Water & Light | 0 |
| Rock Creek Dairy | PURPA | Idaho Power | 4 |
| Seneca | Seneca Sustainable Energy, LLC | Eugene Water & Electric Board | 20 |
| Short Mountain | | Emerald PUD | 3 |
| Skookumchuck | | Puget Sound Energy | 1 |
| Smith Creek | | Puget Sound Energy | 0 |
| Stimson Lumber | Stimson Lumber | Avista Corp. | 7 |
| Stoltze Biomass | F.H. Stoltze Land & Lumber | Flathead Electric Coop | 3 |
| Tamarack | Idaho Power | Idaho Power | 5 |
| Van Dyke | | Puget Sound Energy | 0 |
| VanderHaak Dairy | VanderHaak Dairy, LLC | Puget Sound Energy | 0 |
| Whitefish Hydro | City of Whitefish | Flathead Electric Cooperative | 0 |
| SOLAR | | | 392 |

| | | | |
|-------------------------|----------------------|---------------------------|----|
| Ashland Solar Project | | BPA | - |
| American Falls Solar | PURPA | Idaho Power | 20 |
| American Falls Solar II | PURPA | Idaho Power | 20 |
| Arcadia Solar | PURPA | Idaho Power | 5 |
| Bellevue Solar | EDF Renewable Energy | Portland General Electric | 2 |
| Boise City Solar | PURPA | Idaho Power | 40 |
| Evergreen Solar | PURPA | Idaho Power | 10 |
| Fairway Solar | PURPA | Idaho Power | 10 |
| Finn Hill Solar | | Puget Sound Energy | 0 |
| Grand View Solar | PURPA | Idaho Power | 80 |
| Grove Solar | PURPA | Idaho Power | 10 |
| Hyline Solar Center | PURPA | Idaho Power | 10 |
| Island Solar | | Puget Sound Energy | 0 |

| Project | Owner | NW Utility | Nameplate (MW) |
|--------------------------|---------------------------|---------------------------|----------------|
| Jamieson Solar | PURPA | Idaho Power | 4 |
| John Day Solar | PURPA | Idaho Power | 5 |
| King Estate Solar | Lane County Electric Coop | Lane County Electric Coop | - |
| Little Valley Solar | PURPA | Idaho Power | 10 |
| Malhuer River Solar | PURPA | Idaho Power | 10 |
| Moore's Hollow Solar | PURPA | Idaho Power | 10 |
| Mountain Home Solar | PURPA | Idaho Power | 20 |
| Murphy Flat Power | PURPA | Idaho Power | 20 |
| Olds Ferry Solar | PURPA | Idaho Power | 5 |
| Open Range Solar Center | PURPA | Idaho Power | 10 |
| Orchard Ranch Solar | PURPA | Idaho Power | 10 |
| Pocatello Solar I | PURPA | Idaho Power | 20 |
| PacifiCorp RPS Solar | | PacifiCorp | 9 |
| PGE QF Solar Bundle | | Portland General Electric | |
| Railroad Solar Center | PURPA | Idaho Power | 10 |
| Simco Solar | PURPA | Idaho Power | 20 |
| Thunderegg Solar Center | PURPA | Idaho Power | 10 |
| Vale Air Solar Center | PURPA | Idaho Power | 10 |
| Wild Horse Solar Project | Puget Sound Energy | Puget Sound Energy | 1 |
| Yamhill Solar | EDF Renewable Energy | Portland General Electric | 1 |

WIND

4,491

| | | | |
|------------------------|-------------------------------|---------------------------|-----|
| 3Bar-G Wind | | Puget Sound Energy | 1 |
| Bennet Creek | Bennet Creek | Idaho Power | 21 |
| Benson Creek Wind | PURPA | Idaho Power | 10 |
| Big Top | Big Top LLC (QF) | PacifiCorp | 2 |
| Biglow Canyon - 1 | Portland General Electric | Portland General Electric | 125 |
| Biglow Canyon - 2 | Portland General Electric | Portland General Electric | 150 |
| Biglow Canyon - 3 | Portland General Electric | Portland General Electric | 174 |
| Burley Butte Wind Farm | PURPA | Idaho Power | 21 |
| Butter Creek Power | Butter Creek Power LLC | PacifiCorp | 5 |
| Camp Reed Wind Park | PURPA | Idaho Power | 23 |
| Cassia Wind Farm | Cassia Wind Farm | Idaho Power | 11 |
| Coastal Energy | CCAP | Grays Harbor PUD | 6 |
| Cold Springs | PURPA | Idaho Power | 23 |
| Combine Hills I | Eurus Energy of America | PacifiCorp | 41 |
| Combine Hills II | Eurus Energy of America | Clark Public Utilities | 63 |
| Condon Wind | Goldman Sachs & SeaWest NW | Federal System (BPA) | 25 |
| Desert Meadow Windfarm | PURPA | Idaho Power | 23 |
| Durbin Creek | PURPA | Idaho Power | 10 |
| Elkhorn Wind | Telocaset Wind Power Partners | Idaho Power | 101 |
| Foote Creek Rim 1 | PacifiCorp & EWEB | Multiple Utilities | 41 |

| Project | Owner | NW Utility | Nameplate (MW) |
|---------------------------------|-------------------------------|---------------------------|----------------|
| Foot Creek Rim 2 | PPM Energy | Federal System (BPA) | 2 |
| Foot Creek Rim 4 | PPM Energy | Federal System (BPA) | 17 |
| Fossil Gulch Wind | Idaho Power Company | Idaho Power | 11 |
| Four Corners Windfarm | Four Corners Windfarm LLC | PacifiCorp | 10 |
| Four Mile Canyon Windfarm | Four Mile Canyon Windfarm LLC | PacifiCorp | 10 |
| Golden Valley Wind Farm | PURPA | Idaho Power | 12 |
| Goodnoe Hills | PacifiCorp | PacifiCorp | 94 |
| Hammett Hill Windfarm | PURPA | Idaho Power | 23 |
| Harvest Wind | Summit Power | Multiple Utilities | 99 |
| Hay Canyon Wind | Hay Canyon Wind Project LLC | Snohomish County PUD | 101 |
| High Mesa Wind | PURPA | Idaho Power | 40 |
| Hopkins Ridge | Puget Sound Energy | Puget Sound Energy | 157 |
| Horseshoe Bend | Horseshoe Bend Wind Park LLC | Idaho Power | 9 |
| Hot Springs Wind | Hot Springs Wind | Idaho Power | 21 |
| Jett Creek | PURPA | Idaho Power | 10 |
| Judith Gap | Invenergy Wind, LLC | NorthWestern Energy | 135 |
| Klondike I | PPM Energy | Federal System (BPA) | 24 |
| Klondike II | PPM Energy | Portland General Electric | 75 |
| Klondike III | PPM Energy | Multiple Utilities | 221 |
| Knudson Wind | | Puget Sound Energy | 0 |
| Leaning Juniper 1 | PPM Energy | PacifiCorp | 101 |
| Lime Wind Energy | PURPA | Idaho Power | 3 |
| Lower Snake River 1 | Puget Sound Energy | Puget Sound Energy | 342 |
| Mainline Windfarm | PURPA | Idaho Power | 23 |
| Marengo | Renewable Energy America | PacifiCorp | 140 |
| Marengo II | PacifiCorp | PacifiCorp | 70 |
| Milner Dam Wind Farm | PURPA | Idaho Power | 20 |
| Moe Wind | Two Dot Wind | NorthWestern Energy | 1 |
| Nine Canyon | Energy Northwest | Multiple Utilities | 96 |
| Oregon Trail Windfarm | Oregon Trail Windfarm LLC | PacifiCorp | 10 |
| Oregon Trails Wind Farm | PURPA | Idaho Power | 14 |
| Pa Tu Wind Farm | Pa Tu Wind Farm, LLC | Portland General Electric | 9 |
| Pacific Canyon Windfarm | Pacific Canyon Windfarm LLC | PacifiCorp | 8 |
| Palouse Wind | Palouse Wind, LLC | Avista Corp. | 105 |
| Paynes Ferry Wind Park | PURPA | Idaho Power | 21 |
| Pilgrim Stage Station Wind Farm | PURPA | Idaho Power | 11 |
| Prospector Wind | PURPA | Idaho Power | 10 |
| Rockland Wind | PURPA | Idaho Power | 80 |
| Ryegrass Windfarm | PURPA | Idaho Power | 23 |
| Salmon Falls Wind Farm | PURPA | Idaho Power | 22 |
| Sand Ranch Windfarm | Sand Ranch Windfarm LLC | PacifiCorp | 10 |
| Sawtooth Wind | PURPA | Idaho Power | 21 |

| Project | Owner | NW Utility | Nameplate (MW) |
|--|---------------------------|---------------------------|----------------|
| Sheep Valley Ranch | Two Dot Wind | NorthWestern Energy | 1 |
| Spion Kop | | NorthWestern Energy | 40 |
| Stateline Wind | NextEra | Multiple Utilities | 300 |
| Swauk Wind | | Puget Sound Energy | 4 |
| Thousand Springs Wind | PURPA | Idaho Power | 12 |
| Three Mile Canyon | Momentum RE | PacifiCorp | 10 |
| Tuana Gulch Wind Farm | PURPA | Idaho Power | 11 |
| Tuana Springs Expansion | Cassia Gulch Wind Park | Idaho Power | 36 |
| Tucannon | Portland General Electric | Portland General Electric | 267 |
| Two Ponds Windfarm | PURPA | Idaho Power | 23 |
| Vansycle Ridge | ESI Vansycle Partners | Portland General Electric | 25 |
| Wagon Trail Windfarm | Wagon Trail Windfarm LLC | PacifiCorp | 3 |
| Ward Butte Windfarm | Ward Butte Windfarm LLC | PacifiCorp | 7 |
| Wheat Field Wind Project | Wheat Field Wind LLC | Snohomish County PUD | 97 |
| White Creek | White Creek Wind I LLC | Multiple Utilities | 205 |
| Wild Horse | Puget Sound Energy | Puget Sound Energy | 273 |
| Willow Springs Wind Farm | PURPA | Idaho Power | 10 |
| Wolverine Creek | Invenergy | PacifiCorp | 65 |
| Yahoo Creek Wind Park | PURPA | Idaho Power | 21 |
| SMALL THERMAL AND MISCELLANEOUS | | | 3 |
| Crystal Mountain | Puget Sound Energy | Puget Sound Energy | 3 |
| Total | | | 52,112 |

Table 11. *Independent Owned Generating Resources* is a comprehensive list of independently owned electric power supply located in the region. The nameplate values listed below show full availability. Some of these units have partial contracts (reflected in the load/resource tables) with Northwest utilities.

| Project | Owner | Nameplate (MW) |
|------------------------------|------------------------------------|----------------|
| COAL | | 1,340 |
| Centralia #1 | TransAlta | 670 |
| Centralia #2 | TransAlta | 670 |
| NATURAL GAS | | 2,125 |
| Grays Harbor (Satsop) | Invenergy | 650 |
| Hermiston Power Project | Hermiston Power Partners (Calpine) | 689 |
| Klamath Cogen Plant | Iberdrola Renewables | 502 |
| Klamath Peaking Units 1-4 | Iberdrola Renewables | 100 |
| March Point 1 | March Point Cogen | 80 |
| March Point 2 | March Point Cogen | 60 |
| COGENERATION | | 28 |
| Boise Cascade | | 9 |
| Freres Lumber | Evergreen BioPower | 10 |
| Rough & Ready Lumber | Rough & Ready | 1 |
| Warm Springs Forest Products | | 8 |
| RENEWABLES-OTHER | | 26 |
| Spokane MSW | City of Spokane | 23 |
| Treasure Valley | | 3 |
| WIND | | 3,403 |
| Big Horn | Iberdrola Renewables | 199 |
| Big Horn-Phase 2 | Iberdrola Renewables | 50 |
| Cassia Gulch | John Deere | 21 |
| Glacier Wind - Phase 1 | Naturener | 107 |
| Glacier Wind - Phase 2 | Naturener | 104 |
| Goshen North | Ridgeline Energy | 125 |
| Juniper Canyon - Phase 1 | Iberdrola Renewables | 151 |
| Horse Butte | | 58 |
| Kittitas Valley | Horizon | 101 |

| Project | Owner | Nameplate (MW) |
|--|-------------------------------------|----------------|
| Klondike IIIa | Iberdrola Renewables | 77 |
| Lava Beds Wind | PURPA | 18 |
| Leaning Juniper II-North | Iberdrola Renewables | 90 |
| Leaning Juniper II-South | Iberdrola Renewables | 109 |
| Linden Ranch | NW Wind Partners | 50 |
| Magic Wind Park | PURPA | 20 |
| Martinsdale Colony North | Two Dot Wind | 1 |
| Martinsdale Colony South | Two Dot Wind | 2 |
| Notch Butte Wind | PURPA | 18 |
| Pebble Springs Wind | Iberdrola Renewables | 99 |
| Rattlesnake Rd Wind (aka Arlington) | Horizon Wind | 103 |
| Shepards Flat Central | Caithness Energy | 290 |
| Shepards Flat North | Caithness Energy | 265 |
| Shepards Flat South | Caithness Energy | 290 |
| Star Point | Iberdrola Renewables | 99 |
| Stateline Wind | NextEra | 300 |
| Vancycle II (Stateline III) | NextEra | 99 |
| Vantage Wind | Invergy | 90 |
| Willow Creek | Invergy | 72 |
| Windy Flats | Cannon Power Group | 262 |
| Windy Point | Tuolumne Wind Project Authority | 137 |
| SMALL THERMAL AND MISCELLANEOUS | | 44 |
| Colstrip Energy LP Coal | Colstrip Energy Limited Partnership | 44 |
| Total | | 6,966 |

Report Procedures

This report provides an estimate of regional ‘need to acquire’ generating resources (Tables 1 - 4) using annual energy (August through July), monthly energy, winter peak-hour and summer peak-hour metrics. The peak need reflects information for January and August, as they present the greatest need for their respective seasons. These metrics provide a multi-dimensional look at the Northwest’s need for power and underscore the growing complexity of the power system.

This regional report reflects the summation of individual utilities’ forecasts. The larger utilities, in most cases, prepared their own projections. BPA provides much of the information for its smaller customers. Load (i.e. electricity demand), and resource information is included for the utilities listed in Table 12 at the end of this section. Procedures employed in preparing the regional load-resource comparisons of winter and summer peak and energy are described here. A list of definitions is included at the end of this section.

Load Estimate

Regional loads are the sum of loads estimated by the Northwest utilities and BPA for its federal agency customers, certain non-generating public utilities, and direct service industrial customers (DSI). Estimates are made for system peak and system energy loads. Load projections reflect network transmission and distribution losses, reductions in demand due to rising electricity prices, and the effects of appliance efficiency standards and energy building codes. Savings from demand-side management programs, such as energy efficiency, are also reflected in the regional load forecasts.

Energy Loads

A ten-year forecast of monthly firm energy loads is provided. This forecast reflects normal (1-in-2) weather conditions. The tabulated information includes the annual average load for the year forecast period as well as the monthly load for the first year of the report.

Peak Loads

Northwest regional peak loads are provided for each month of the ten year forecast period. The tabulated loads for winter and summer peak are the highest estimated 60-minute clock-hour average demand for that month, assuming normal (1-in-2) weather conditions. The regional firm peak load is the sum of the individual utility peak loads, and does not account for the fact that each utility may experience its peak load at a different hour than other Northwest utilities. Hence the

regional peak load is considered non-coincident. The federal system (BPA) firm peak load is adjusted to reflect a federal coincident peak among its many utility customers.

Federal System Transmission Losses

Federal System (BPA) transmission losses for both firm loads and contractual obligations are embedded in federal load. These losses represent the difference between energy generated by the federal system (or delivered to a system interchange point) and the amount of energy sold to customers. System transmission losses are calculated by BPA for firm loads utilizing the federal transmission system.

Planning Margin

In the derivation of regional requirements, a planning margin has been added to the load. This regional planning margin is equal to 12 percent of the total peak load for the first year of the planning horizon, increasing one percent per year to 20 percent and remaining at 20 percent thereafter. They are intended to cover, for planning purposes, operating reserves and all elements of uncertainty not specifically accounted for in determining loads and resources. These include forced-outage reserves, unanticipated load growth, temperature variations, hydro maintenance and project construction delays. An increasing reserve requirement reflects greater uncertainty about load levels and of achieving construction schedules in the future.

Demand-Side Management Programs

Savings from demand-side management efforts are reported in *Table 7. Demand Side Management Programs*. These estimates are the savings for the ten year study period and include expected future energy savings from existing and new programs in the areas of energy efficiency, distribution efficiency, some market transformation, fuel conversion, fuel switching, energy storage and other efforts that reduce the demand for electricity. These estimates reflect savings from programs that utilities fund directly, or through a third-party, such as the Northwest Energy Efficiency Alliance and Energy Trust of Oregon.

Demand response activity is reported in *Table 7* as well. The total load reduction reported is the cumulative sum of different utilities' agreements with their customers. Each program has its own characteristics and limitations.

Generating Resources

This report considers existing resources, committed new supply (including resources under construction), as well as planned resources. For the assessment of need only the existing and committed resources are reflected in the regional tabulations. In addition, only those generating resources (or shares) that are firmly committed to meeting Northwest loads are included in the regional analysis.

Hydro

Major hydro resource capabilities are estimated from a regional analysis using a computer model that simulates reservoir operation of past hydrologic conditions. The historical stream flow record used covers the 80-year period from August 1928 through July 2008.

Energy

The firm energy capability of hydro plants is the amount of energy produced during the operating year with the lowest 12-month average generation. The lowest generation occurred in 1936-37 given today's river operating criteria. The firm energy capability is the average of 12 months, August 1936 to July 1937. Generation for projects that are influenced by downstream reservoirs reflects the reduction due to encroachment.

Peak Capability

For this report the peak capability of the hydro system represents the maximum sustained hourly generation available to meet peak demand during the period of heavy load. Historically, a 50 hour sustained peak (10 hours/day for 5 days) has been reported.

The peaking capability of the hydro system maximizes available energy and capacity associated with the monthly distribution of streamflow. The peaking capability is the hydro system's ability to continuously produce power for a specific time period by utilizing the limited water supply while meeting power and non-power requirements, scheduled maintenance, and operating reserves (including wind reserves).

Computer models are used to estimate the operational hydro peaking capability of the major projects, based on their monthly average energy for 70 or 80 water conditions depending on the source of information. The peaking capability used for this report is the 8th percentile of the resulting hourly peak capabilities for January and August to indicate winter and summer peak capability respectively. These models shape the monthly hydro energy to maximize generation in the heavy load hours.

Columbia River Treaty

Since 1961 the United States has had a treaty with Canada that outlines the operation of U.S. and Canadian storage projects to increase the total combined generation. Hydropower generation in this analysis reflects the firm power generated by coordinating operation of three Canadian reservoirs, Duncan, Arrow and Mica with the Libby reservoir and other power facilities in the region. Canada's share of the coordinated operation benefits is called Canadian Entitlement. BPA and each of the non-Federal mid-Columbia project owners are obligated to return their share of the downstream power benefits owed to Canada. The delivery of the Entitlement is reflected in this analysis.

Downstream Fish Migration

Another requirement incorporated in the computer simulations is modified river operations to provide for the downstream migration of anadromous fish. These modifications include adhering to specific flow limits at some projects, spilling water at several projects, and augmenting flows in the spring and summer on the Columbia, Snake and Kootenai rivers. Specific requirements are defined by various federal, regional and state mandates, such as project licenses, biological opinions and state regulations.

Thermal and Other Renewable Resources

Thermal resources are reported in a variety of categories. Coal, cogeneration, nuclear, and natural gas projects are each totaled and reported as individual categories.

Renewable resources other than hydropower are categorized as solar, wind and other renewables and are each totaled and reported separately. Other renewables includes energy from biomass, geothermal, municipal solid waste projects and other miscellaneous projects.

All existing generating plants, regardless of size, are included in amounts submitted by each utility that owns or is purchasing the generation. The energy capabilities of plants are computed on annual planning equivalent availability factors submitted by the sponsors of the projects. The factors include allowance for scheduled maintenance (including refueling), forced outages and other expected operating constraints. Some small fossil-fuel plants and combustion turbines are included as peaking resources and their reported energy capabilities are only the amounts necessary for peaking operations. Additional energy potentially may be available from these peaking resources but is not included in the regional load/resource balance.

New and Future Resources

The latest activity with new and future resource developments, including expected savings from demand-side management are tabulated in this report. These resources are reported as *Recently Acquired*, *Committed New Supply* and *Planned Resources* to reflect the different stages of development.

Recently Acquired Resources

The *Recently Acquired Resources* reported in Table 5 have been acquired in the past year and are serving Northwest utility loads as of December 31, 2015. They are reflected as part of the regional firm needs assessment.

Committed New Supply

Committed New Supply reported in Table 6 includes those projects under construction or committed resources and supply to meet Northwest load that are not delivering power as of December 31, 2015. In this report, resources being built by utilities or resources where their output is firmly committed to utilities are included in the regional load-resource analysis. Future savings from committed demand-side management programs are reported in Table 7.

Planned Resources

Planned Resources presented in Table 8 include specific resources and/or blocks of generic resources identified in utilities' most current integrated resource plans. Projects specifically named in *Planned Resources* are not yet under construction as of December 31, 2015, but a firm commitment to construct or acquire the power has been made. These resources are not part of the regional analysis.

Contracts

Imports and exports include firm arrangements for interchanges with systems outside the region, as well as with third-party developers/owners within the region. These arrangements comprise firm contracts with utilities to the East, the Pacific Southwest and Canada. Contracts to and from these areas are amounts delivered at the area border and include any transmission losses associated with deliveries.

Short term purchases from Northwest independent power producers and other spot market purchases are considered non-firm contracts and not reflected in the tables that present the firm load/resource comparisons.

Table 12 Utilities included in the Northwest Regional Forecast

| | | |
|-----------------------------------|---------------------------------------|-----------------------------------|
| Albion, City of | Fall River Rural Electric Cooperative | Pacific County PUD #2 |
| Alder Mutual | Farmers Electric Co-op | PacifiCorp |
| Ashland, City of | Ferry County PUD #1 | Parkland Light & Water |
| Asotin County PUD #1 | Fircrest, Town of | Pend Oreille County PUD |
| Avista Corp. | Flathead Electric Cooperative | Peninsula Light Company |
| Bandon, City of | Forest Grove Light & Power | Plummer, City of |
| Benton PUD | Franklin County PUD | PNGC Power |
| Benton REA | Glacier Electric | Port of Seattle – SEATAC |
| Big Bend Electric Co-op | Grant County PUD | Portland General Electric |
| Blachly-Lane Electric Cooperative | Grays Harbor PUD | Puget Sound Energy |
| Blaine, City of | Harney Electric | Raft River Rural Electric |
| Bonners Ferry, City of | Hermiston, City of | Ravalli Co. Electric Co-op |
| Bonneville Power Administration | Heyburn, City of | Richland, City of |
| Burley, City of | Hood River Electric | Riverside Electric Co-op |
| Canby Utility | Idaho County L & P | Rupert, City of |
| Cascade Locks, City of | Idaho Falls Power | Salem Electric Co-op |
| Central Electric | Idaho Power | Salmon River Electric Cooperative |
| Central Lincoln PUD | Inland Power & Light | Seattle City Light |
| Centralia, City of | Kittitas County PUD | Skamania County PUD |
| Chelan County PUD | Klickitat County PUD | Snohomish County PUD |
| Cheney, City of | Kootenai Electric Co-op | Soda Springs, City of |
| Chewelah, City of | Lakeview L & P (WA) | Southside Electric Lines |
| City of Port Angeles | Lane Electric Cooperative | Springfield Utility Board |
| Clallam County PUD #1 | Lewis County PUD | Steilacoom, Town of |
| Clark Public Utilities | Lincoln Electric Cooperative | Sumas, City of |
| Clatskanie PUD | Lost River Electric Cooperative | Surprise Valley Elec. Co-op |
| Clearwater Power Company | Lower Valley Energy | Tacoma Power |
| Columbia Basin Elec. Co-op | Mason County PUD #1 | Tanner Electric Co-op |
| Columbia Power Co-op | Mason County PUD #3 | Tillamook PUD |
| Columbia REA | McCleary, City of | Troy, City of |
| Columbia River PUD | McMinnville Water & Light | Umatilla Electric Cooperative |
| Consolidated Irrigation Dist. #19 | Midstate Electric Co-op | Umpqua Indian Utility Co-op |
| Consumers Power Inc. | Milton, Town of | United Electric Cooperative |
| Coos-Curry Electric Cooperative | Milton-Freewater, City of | US Corps of Engineers |
| Coulee Dam, City of | Minidoka, City of | US Bureau of Reclamation |
| Cowlitz County PUD | Missoula Electric Co-op | Vera Water & Power |
| Declo, City of | Modern Electric Co-op | Vigilante Electric Co-op |
| Douglas County PUD | Monmouth, City of | Wahkiakum County PUD #1 |
| Douglas Electric Cooperative | Nespelem Valley Elec.Co-op | Wasco Electric Co-op |
| Drain, City of | Northern Lights Inc. | Weiser, City of |
| East End Mutual Electric | Northern Wasco Co. PUD | Wells Rural Electric Co. |
| Eatonville, City of | NorthWestern Energy | West Oregon Electric Cooperative |
| Ellensburg, City of | Ohop Mutual Light Company | Whatcom County PUD |
| Elmhurst Mutual P & L | Okanogan Co. Electric Cooperative | Yakama Power |
| Emerald PUD | Okanogan County PUD #1 | |
| Energy Northwest | Orcas Power & Light | |
| Eugene Water & Electric Board | Oregon Trail Co-op | |

Definitions

Annual Energy

Energy value in megawatts that represents the average of monthly values in a given year.

Average Megawatts

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

Biomass

Any organic matter which is available on a renewable basis, including forest residues, agricultural crops and waste, wood and wood wastes, animal wastes, livestock operation residue, aquatic plants, and municipal wastes.

Canadian Entitlement

Canada is entitled to one-half the downstream power benefits resulting from Canadian storage as defined by the Columbia River Treaty. Canadian entitlement returns estimated by Bonneville Power Administration.

Coal

This category of generating resources includes the region's coal-fired plants.

Cogeneration

Cogeneration is the technology of producing electric energy and other forms of useful energy (thermal or mechanical) for industrial and commercial heating or cooling purposes through sequential use of an energy source.

Combustion Turbines

These are plants with combined-cycle or simple-cycle natural gas-fired combustion turbine technology for producing electricity.

Committed Resources

This includes under construction projects and long-term power supply agreements that are committed but not yet producing power to meet Northwest load at the time of publication. This generation is included in the resources for calculating the regional load/resource balance.

Conservation

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with energy efficiency.

Demand Response

Control of load through customer/utility agreements that result in a temporary change in consumers' use of electricity in times of system stress.

Demand-side Management

Peak and energy savings from conservation/energy efficiency measures, distribution efficiency, market transformation, demand response, fuel conversion, fuel switching, energy storage and other efforts that that serve to reduce electricity demand.

Dispatchable Resource

A term referring to controllable generating resources that are able to be dispatched for a specific time and need.

Distribution Efficiency

Infrastructure upgrades to utilities' transmission and distribution systems that save energy by minimizing losses.

Encroachment

A term used to describe a situation where the operation of a hydroelectric project causes an increase in the level of the tailwater of the project that is directly upstream.

Energy Efficiency

Any reduction in electrical power consumption as a result of increases in the efficiency of energy use, production, or distribution. For the purposes of this report used synonymously with conservation.

Energy Load

The demand for power averaged over a specified period of time.

Energy Storage

Technologies for storing energy in a form that is convenient for use at a later time when a specific energy demand is greater.

Exports

Firm interchange arrangements where power flows from regional utilities to utilities outside the region or to non-specific, third-party purchasers within the region.

Federal System (BPA)

The federal system is a combination of BPA's customer loads and contractual obligations, and resources from which BPA acquires the power it sells. The resources include plants operated by the U.S. Army Corps of Engineers (COE), U.S. Bureau of Reclamation (USBR) and Energy Northwest. BPA markets the thermal generation from Columbia Generating Station, operated by Energy Northwest.

Federal Columbia River Power System (FCRPS)

Thirty federal hydroelectric projects constructed and operated by the Corps of Engineers and the Bureau of Reclamation, and the Bonneville Power Administration transmission facilities.

Firm Energy

Electric energy intended to have assured availability to customers over a defined period.

Firm Load

The sum of the estimated firm loads of private utility and public agency systems, federal agencies and BPA industrial customers.

Firm Losses

Losses incurred on the transmission system of the Northwest region.

Fuel Conversion

Consumers' efforts to make a permanent change from electricity to natural-gas or other fuel source to meet a specific energy need, such as heating.

Fuel Switching

Consumers' efforts to make a temporary change from electricity to another fuel source to meet a specific energy need.

Historical Streamflow Record

A database of unregulated streamflows for 80 years (July 1928 to June 2008). Data is modified to take into account adjustments due to irrigation depletions, evaporations, etc. for the particular operating year being studied.

Hydro Maintenance

The amount of energy lost due to the estimated maintenance required during the critical period. Peak hydro maintenance is included in the peak planning margin calculations.

Hydro Regulation

A study that utilizes a computer model to simulate the operation of the Pacific Northwest hydroelectric power system using the historical streamflows, monthly loads, thermal and other non-hydro resources, and other hydroelectric plant data for each project.

Imports

Firm interchange arrangements where power flows to regional utilities from utilities outside the region or third-party developer/owners of generation within the region.

Independent Power Producers (IPPs)

Non-utility entities owning generation that may be contracted (fully or partially) to meet regional load.

Intermittent Resource (a.k.a. Variable Energy Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Investor-Owned Utility (IOU)

A privately owned utility organized under state law as a corporation to provide electric power service and earn a profit for its stockholders.

Market Transformation

A strategic process of intervening in a market to accelerate the adoption of cost-effective energy efficiency.

Megawatt (MW)

A unit of electrical power equal to 1 million watts or 1,000 kilowatts.

Nameplate Capacity

A measure of the approximate generating capability of a project or unit as designated by the manufacturer.

Natural Gas-Fired Resources

This category of resources includes the region's natural gas-fired plants, mostly single-cycle and combined-cycle combustion turbines. It may include projects that are considered cogeneration plants.

Non-Firm Resources

Electric energy acquired through short term purchases of resources not committed as firm resources. This includes generation from hydropower in better than critical water conditions, independent power producers and imports from outside the region.

Non-Utility Generation

Facilities that generate power whose percent of ownership by a sponsoring utility is 50 percent or less. These include PURPA-qualified facilities (QFs) or non-qualified facilities of independent power producers (IPPs).

Nuclear Resources

The region's only nuclear plant, the Columbia Generating Station, is included in this category.

Operating Year

Twelve-month period beginning on August 1 of any year and ending on July 31 of the following year. For example, operating year 2017 is August 1, 2016 through July 31, 2017.

Other Publics (BPA)

Refers to the smaller, non-generating public utility customers whose load requirements are estimated and served by Bonneville Power Administration.

Peak Load

In this report the peak load is defined as one-hour maximum demand for power.

Planned Resources

Planned resources include generic, as well as specific projects, measures, and transactions that utilities have made some commitment to acquire and are in some stage of state site certification process. However, either not all licenses have been obtained, no commercial operation data has been specified, or the specifics of the transaction have not been finalized.

Planning Margin

A component of regional requirements that is included in the peak needs assessment to account for various planning uncertainties.

Private Utilities

Same as investor-owned utilities.

Publicly-Owned Utilities

One of several types of not-for-profit utilities created by a group of voters and can be a municipal utility, a public utility district, or an electric cooperative.

PURPA

Public Utility Regulatory Policies Act of 1978. The first federal legislation requiring utilities to buy power from qualifying independent power producers.

Renewables - Other

A category of resources that includes projects that produce power from such fuel sources as geothermal, biomass (includes wood, municipal solid-waste facilities), and pilot level projects including tidal and wave energy.

Requirements

For each year, a utility's projected loads, exports, and contracts out. Peak requirements also include the planning margin.

Small Thermal & Miscellaneous Resources

This category of resources includes small thermal generating resources such as diesel generators used to meet peak and/or emergency loads.

Solar Resources

Resources that produce power from solar exposure. This includes utility scale solar photovoltaic systems and other utility scale solar projects. This category does not include customer side distributed solar generation.

Thermal Resources

Resources that burn coal, natural gas, oil, diesel or use nuclear fission to create heat which is converted into electricity.

Variable Energy Resource (a.k.a. Intermittent Resource)

An electric generating source with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar and wind energy.

Wind Resources

This category of resources includes the region's wind powered projects.



G

2017 PSE Integrated Resource Plan

Wholesale Market Risk

This appendix updates the original wholesale market risk study presented in the 2015 PSE IRP.

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4. MONITORING WHOLESale MARKET RISK G-30

- *Do Additional Reliability Metrics Need to be Considered?*
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1. EXECUTIVE SUMMARY

Because PSE relies on more than 1,600 MW of wholesale market purchases to meet its current and forecasted energy and peak demand obligations, we must monitor regional resource adequacy issues closely and be prepared to modify our purchase strategy accordingly should changing conditions warrant.

For more than a decade, the Pacific Northwest region's large capacity surplus has kept wholesale power prices relatively low and made these existing resources a lower cost alternative to filling PSE's peak capacity need than building new generation. However, the long-term load/resource studies developed by the region's major energy organizations, NPCC, PNUCC and BPA,¹ while they differ in some details, generally point in the same direction: The current Pacific Northwest (PNW) energy and capacity surplus is expected to cross over to deficit at some point in the next decade unless new supply-side and/or demand-side resources are developed. Those studies are summarized in this chapter. Based upon current information, and assuming that all independently owned generation located within the PNW will be available to serve PNW peak loads, the region is forecast to transition from having a winter season capacity surplus of approximately 3,911 MW in 2017 to having a winter capacity deficit of approximately 2,014 MW in 2026.²

In response to the changing regional outlook, PSE presented its first analysis of wholesale market purchase risk in the 2015 IRP.³ For the 2017 IRP, we refine that analysis based on the updated long-term regional resource adequacy studies performed by NPCC, PNUCC and BPA.

Fortunately, recent evidence, particularly the updated 2017 NPCC *Pacific Northwest Power Supply Adequacy Assessment for 2021 and 2022* (which was not available in time for this analysis) suggests that the region is in the process of adding new resources – mainly in the form of additional investments in conservation – to fill this forecasted resource gap. In addition, regional utility load forecast growth rates are continuing to trend downwards, thereby also closing some of the projected gap. Also, the amount of power that can be reliably imported into the region

1 / *The Northwest Power and Conservation Council (NPCC or the Council), the Pacific Northwest Utilities Conference Committee (PNUCC) and the Bonneville Power Administration (BPA). These studies are included in Appendix F, Regional Resource Adequacy Studies.*

2 / *Based on information provided in BPA's 2016 Pacific Northwest Loads and Resources Study. The cited figures include 425 MW of long-term firm imports from California that are incorporated into the BPA Study plus an additional 3,400 MW of short-term imports from California that are assumed to be available to meet PNW winter peak loads.*

3 / *Prior to 2015, PSE IRP analyses assumed that wholesale market purchases were 100 percent reliable under all load/resource conditions. Although adequacy analyses conducted prior to 2015 had demonstrated that technically, regional capacity would be insufficient to meet firm loads in all circumstances, the region continued to pass capacity adequacy planning standards, so refining this wholesale purchase reliability assumption was not a high priority at the time.*

Appendix G: Wholesale Market Risk



during winter and summer peak load events may be higher than the figures currently being used in the NPCC's resource adequacy model. Finally, PSE's shift to a 5 percent LOLP metric in this IRP for its capacity planning standard (as opposed to the Value of Lost Load approach used in the 2015 IRP) has resulted in a higher level of reliability being assigned to wholesale market purchases.

While uncertainties remain, there are also reasons for increased confidence. So, while there is still some level of risk to PSE in relying on wholesale market purchases in order to meet resource need, this risk appears to be significantly reduced from the level presented in the 2015 IRP due to the reasons discussed above.

Figure G-1, summarizes the findings of PSE'S 2017 wholesale market risk analysis. It shows the peak capacity contribution of wholesale market purchases to PSE's portfolio starting in 2021.⁴ An important finding is that while wholesale market purchases are not 100 percent reliable, they are still expected to be highly reliable given current projected regional load/resource conditions for the winter of 2020-2021.

Figure G-1: Capacity Contribution of Wholesale Market Purchases

| Capacity Contribution of Wholesale Market Purchases | 2021 | |
|---|-------|-----------------|
| Market Reliance Capacity (MW) | 1,580 | |
| Effective Capacity Contribution | 1,568 | |
| Reduction in Capacity Contribution with Risk in Market Reliance | 12 | |
| Effective Load Carrying Capability (ELCC) | 99% | (= 1,568/1,580) |

It should be noted, however, that the reliability of wholesale market purchases would be expected to change as the PNW transitions from having large winter season capacity surpluses to potentially experiencing capacity deficits by 2026. Also, uncertainties remain, such as whether the region's forecasted conservation targets will actually be achieved and the specific timing of the early retirements of some of the region's coal-fired generating plants. Thus, it is important that PSE continue to closely monitor region's projected winter season load/resource balance and to update its assessment of the reliability of wholesale market purchases as conditions warrant.

⁴ / Additional details regarding the peak capacity contribution of wholesale market purchases are contained in Appendix N.



DESCRIPTION OF THE ANALYSIS. This analysis is designed to quantify the capacity value of wholesale market purchases in light of: 1) the 2015 & 2016 regional load/resource forecasts published by BPA and PNUCC, and 2) the 2016 regional resource adequacy assessment published by the NPCC. The goal is to better understand the physical and financial risk to PSE customers of reliance on wholesale market purchases to meet peak load needs under these forecasted regional conditions.

To accomplish this analysis, PSE aligned its Resource Adequacy Model (RAM) and Wholesale Market Curtailment Model (WCPM) with other regional reliability models in order to translate the regional load curtailment forecasts made by the NPCC's GENESYS model to PSE-level impacts. We then evaluated the capacity contribution of wholesale market purchases using the same methodology used to calculate capacity value for all other resources in this IRP, Expected Load Carrying Capacity (ELCC).⁵ Section 3 of this appendix explains the analysis in detail.

5 / ELCC refers to the peak capacity contribution of a resource relative to that of a gas-fired peaking plant. It is calculated as the change in capacity of a generic natural gas peaking plant that results from adding a different resource with any given energy production characteristics to the system while keeping the target reliability metric constant.



2. REGIONAL LOAD/RESOURCE FORECASTS

Overview

For a decade starting in the mid-2000s, the Pacific Northwest region experienced large energy and capacity surpluses. These surpluses were the result of a rush to build new generating capacity after the 2000-2001 west coast energy crisis, coupled with low natural gas prices, and followed by the subsequent slow-down of utility load growth. The resulting surpluses enabled many utilities, including PSE, to use wholesale market purchases to meet firm load obligations with a high degree of confidence in the reliability of both physical supply and reasonable prices.

Today, a different combination of forecasted circumstances could produce a capacity deficit in the region within the next 10 years. The primary factors contributing to this trend include the increasing need for balancing capacity as additional intermittent resources are added to the grid and planned generating plant retirements.

GROWTH IN INTERMITTENT RESOURCES. Renewable wind and solar plants have been the focus of most new construction in the region, primarily due to state-mandated renewable energy portfolio targets. The variability of these intermittent resources has substantially increased the region's need for balancing capacity.

COAL PLANT RETIREMENTS. Between 2019 and 2025, the Pacific Northwest will lose 2,489 MW of generating capacity and approximately 2,127 aMW of annual energy production as six coal-fired units are shut down: Valmy Unit 1 (137 MW Capacity)⁶, Boardman (585 MW capacity) and Centralia Unit 1 (730 MW capacity) in 2020; Colstrip Units 1 & 2 (307 MW combined capacity)⁷ in 2022; and Centralia Unit 2 in 2025 (730 MW capacity).

In particular, the region's ability to reliably meet firm winter season peak loads and operating reserve obligations could be a concern even after including all long-term and short-term imports available from California, as will be discussed below. This situation is especially critical for PSE since PSE is a winter season peaking utility.

⁶ / Idaho Power's 50 percent ownership of Valmy Unit 1 (137 MW) is dedicated to serving loads located in the PNW region while NV Energy's remaining 50 percent share is dedicated to serving loads outside the region.

⁷ / PSE's 50 percent ownership share of Colstrip Units 1 & 2 (307 MW) is dedicated to serving loads located in the PNW region while Talen Energy's remaining 50 percent share is dedicated to serving loads outside the region.



The long-term load/resource studies developed by NPCC, PNUCC and BPA differ in some details, but all of the forecasts point in the same direction: The current Pacific Northwest capacity surplus is projected to cross over to deficit at some point in the next decade unless new supply-side and/or demand-side resources are developed. These studies are summarized below, and copies or web links to the reports are included in Appendix F, Regional Resource Adequacy.

NPCC Regional Adequacy Studies for 2021

On September 27, 2016, the NPCC published its *Pacific Northwest Power Supply Adequacy Assessment for 2021*. This study focused on the region's ability to meet the peak load planning criteria adopted by the Council, which is a 5 percent loss of load probability (LOLP). These LOLP studies incorporated complex modeling of the region's hydroelectric resources and included IPP (independent power producer) plants located in the PNW, long-term and short-term power imports from California, and existing and announced demand-side management programs. Rather than producing traditional load/resource tables, the NPCC studies produced a series of regional PNW load-curtailement events that occur under different scenarios in 2021. These scenarios model varying levels of hydro and wind generation, regional loads and thermal plant forced outages.

The 2016 NPCC 2021 Base Case study indicates that in order for the PNW to meet the 5 percent LOLP planning standard, the region would need to add slightly over 1,000 MW of new firm, dispatchable generating capacity.

The NPCC's 2021 Base Case assumes the following conditions.

- That approximately 700 MW of "emergency" generating resources could be used (on an annual energy-limited basis) to help meet regional peak loads, including 300 MW of backup diesel generators owned by Portland General Electric (PGE) and 300 MW at the John Keys pumped storage plant.
- That the 650 MW Grays Harbor baseload CCCT plant located in the Puget Sound area could be fully utilized to meet regional peak load needs.
- That spot market power amounting to 2,500 MW could be imported from California during winter-season on-peak hours and 3,000 MW could be imported during winter season off-peak hours.



In addition to the Base Case, the 2016 NPCC 2021 adequacy analysis also includes a Colstrip Sensitivity study that incorporates the impacts of shutting down Colstrip Units 1 & 2 in 2021. Although these units will probably not be retired until mid-2022, advance knowledge of how this change will impact the region's need for new sources of firm capacity under the current NPCC planning standard will be useful to regional resource planners.

The 2016 NPCC 2021 Colstrip Sensitivity study indicates that in order for the PNW to meet the 5 percent LOLP planning standard, the region would need to add approximately 1,400 MW of new firm, dispatchable generating capacity.

2017 NPCC UPDATE

On July 11, 2017, the NPCC published its updated *Pacific Northwest Power Supply Adequacy Assessment for 2021 and 2022*, which shows an improved outlook relative to the 2016 assessment. In the 2017 NPCC study, the 2021 Base Case indicates that in order for the PNW to meet the 5 percent LOLP planning standard, the region would need to add 400 MW of new firm, dispatchable generating capacity. The reduction in the projected 2021 regional capacity deficit from the NPCC's previous 2016 assessment is due to several factors, including lower forecasted utility winter peak load forecasts and increased regional investments in conservation. This gives us increased confidence in the reliability of wholesale market purchases. However, the NPCC also cautions that normal variations in the loads and resource forecasts incorporated into the 2017 Adequacy Assessment could change the 400 MW of new generating capacity needed in 2021 to between 0 and 1,000 MW.

This IRP wholesale market risk study was based on the NPCC's 2016 assessment because the 2017 Assessment was not available in time to be used; therefore, the IRP analysis should be considered a conservative approach to assessing the peak capacity value of market purchases.



PNUCC Northwest Regional Forecast for 2017– 2026

PNUCC's annual *Northwest Regional Forecast of Power Loads and Resources* (the NRF) was published in April 2016 and covers the period 2017 – 2026. This analysis aggregates data from the region's electric utilities to produce region-wide load/resource projections over a 10-year time frame (net of conservation), with particular focus on annual energy and winter season capacity surpluses and/or deficits. The NRF also provides information on the amount of IPP generation located in the region that *may* be available to serve PNW firm loads.

There are several ways to look at the results of the 2016 NRF.

- The NRF 2021 forecast is based upon the utility-owned or controlled resources located within the PNW region that are known to be dedicated to serving firm PNW loads, plus 425 MW of long-term, firm purchased power agreement (PPA) imports from California; this results in a 4,800 MW deficit in 2021.
- When all IPP-owned generation located within the region is assumed to be available to serve PNW winter peak loads, the PNUCC 2021 winter capacity deficit is reduced to approximately 1,700 MW.
- When the NRF's 2021 winter capacity forecast is adjusted to include 3,400 MW of potentially available short-term imports – which PSE assumed in the Wholesale Purchase Containment Model (WPCM) – the 1,700 MW capacity deficit noted above changes to a 1,700 MW surplus.

While looking at surplus/deficit figures for the year 2021 is useful, it is even more important to recognize the long-term trend. Looking forward – based upon current information and assuming that all IPP generation will be available to serve PNW peak loads – the NRF forecasts that the region will transition from a 2017 winter season peak load surplus of approximately 2,010 MW to a peak load deficit of approximately 5,425 MW in 2026. When the NRF capacity forecast is adjusted to include 3,400 MW of short-term imports from California, the region would transition from a 2017 winter capacity surplus of 5,410 MW to a peak load deficit of approximately 2,025 MW in 2026.



BPA Loads and Resources Study for 2017– 2026

BPA published its *2015 Pacific Northwest Loads and Resources Study* in January 2016. This study provided detailed information on BPA's forecasted loads and resources as well as overall loads and resources for the entire region. The BPA study is similar to the PNUCC study, but there are some differences, particularly in the modeling of the PNW hydroelectric system and the inclusion of non-utility owned generation located in the PNW region.

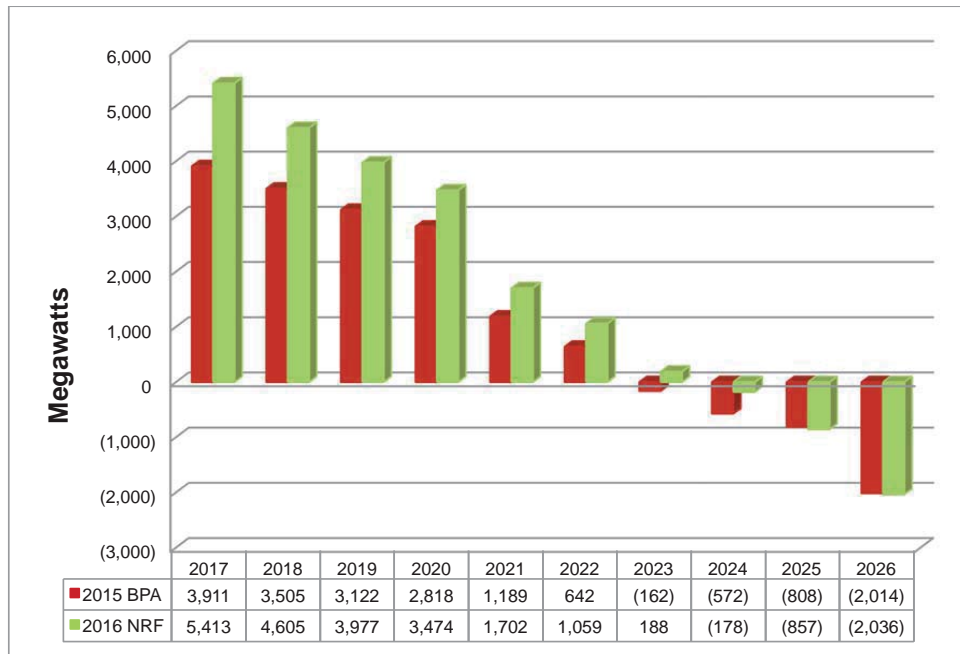
The BPA forecast used a 120-hour sustained hydro peaking methodology and assumed that all IPP generation located within the PNW is available to serve PNW peak loads. This figure includes 425 MW of long-term firm PPA imports from California, but it does not include any potentially available spot market imports.

- For 2021, the BPA study forecasts an overall regional winter peak load deficiency of 2,211 MW.
- When BPA's 2021 winter capacity forecast is adjusted to include 3,400 MW of potentially available short-term imports, the 2,211 MW capacity deficit noted above would change to a 1,189 MW surplus.
- Looking forward to 2026 – based upon current information and assuming that all IPP generation will be available to serve PNW peak loads – BPA's forecast shows that the region will transition from a 2017 winter season peak load surplus of approximately 511 MW to a peak load deficit of approximately 5,414 MW in 2026.
- When BPA's 2026 capacity forecasts are adjusted to include 3,400 MW of short-term imports from California – which PSE assumed in the WPCM – the region would transition from a 2017 winter capacity surplus of 3,911 MW to a peak load deficit of approximately 2,014 MW.

Again, the long-term winter capacity trend is perhaps more important than the exact surplus or deficit forecasted for 2021. The BPA forecast indicates, as does the PNUCC study, that the PNW is may experience larger winter capacity deficits over time. This long-term trend is illustrated in Figure G-2.



Figure G-2: 2016 PNUCC NRF Study/2015 BPA Study,
Pacific Northwest Winter Capacity Surplus/(Deficiency), 2017-2026
(Colstrip Units 1 & 2 retire in mid-2022.)



NOTES

1. The 2016 NRF winter capacity surplus/deficiency figures have been adjusted to include 3,400 MW of short-term imports from California and all available PNW IPP capacity.
2. The 2015 BPA winter capacity surplus/deficiency figures have been adjusted to include 3,400 MW of short-term imports from California.



3. WHOLESALE MARKET RELIABILITY ANALYSIS

PSE's Wholesale Purchase Strategy

PSE currently relies on up to approximately 1,722 MW of wholesale market purchases to meet its firm peak load obligations in the winter season. Figure G-3 compares the amount of wholesale market purchases that five PNW investor-owned utilities (IOUs) planned to use to meet forecasted 2021 peak loads (including reserve margins), according to their 2015 IRPs.

Figure G-3: Forecasted 2021 Seasonal Peak Wholesale Market Purchases by PNW Investor-owned Utilities

| Investor-owned Utility | Wholesale Purchases to Meet 2021 Seasonal Peak Load (MW) |
|---|--|
| Puget Sound Energy ⁴ | 1,722 |
| Avista ^{1,4} | 0 - 260 |
| Idaho Power ⁶ | 102 |
| PacifiCorp (East and West Systems) ³ | 1,670 |
| Portland General Electric ^{2,4} | 819 |

NOTES

1. Avista's loss of load analysis indicated that Avista could rely upon up to 260 MW of wholesale market purchases during some extreme peaking events.
2. PGE indicated that they intend to limit the amount of required winter peak spot purchases in 2021 to only 200 MW.
3. The PacifiCorp data includes both the PacifiCorp East (PACE) and PacifiCorp West (PACW) systems.
4. Puget, Portland General Electric and Avista are winter peaking utilities. In addition, the PacifiCorp West System is a winter-peaking Balancing Authority Area although the combined PacifiCorp West and East systems are summer peaking.
5. The figure cited for PacifiCorp is for the combined PACE and PACW systems for the summer of 2021. PacifiCorp's 2015 IRP Update did not provide winter 2021 peak information for the PACW System.
6. Idaho Power is a summer peaking utility. Idaho Power's wholesale purchases to meet peak load figure assumes that 390 MW of demand response is deployed.



When the regional surplus of energy and capacity began in the mid-2000s, PSE strategically positioned itself as “a buyer in a buyer’s market.” Instead of constructing new generating plants to meet load growth and replace the loss of long-term legacy PPAs, the company pursued an aggressive program of purchasing relatively lower cost energy and capacity in the wholesale marketplace. Again taking advantage of this position, the company acquired two baseload CCCT plants (Goldendale and Mint Farm) from their original owners at significant discounts from their original construction costs.

For many years, this strategy has been successful at achieving the lowest reasonable cost means of fulfilling customers’ energy needs. While PSE has long acknowledged that relying upon wholesale market purchases to meet a portion of its firm load obligations is not entirely a risk-free strategy, the region’s large (and relatively steady) capacity surplus acted to significantly mitigate this risk. However, the PNW energy markets are now in a state of transition due to many factors. These include: 1) a steady decline in the region’s forecasted capacity surplus across the next decade, 2) lower projected utility energy and peak load growth rates, 3) future greenhouse gas emission policies, 4) the impacts of new technology, and 5) shifting individual customer preferences. These factors combine to create a significant amount of uncertainty for PSE (and other regional utilities) regarding the preferred mix of supply-side and demand-side resources to economically and reliably meet its customers’ needs in the future.

Quantifying Wholesale Market Purchase Risk

Due to the changing landscape in the regional utility industry, PSE identified a need in the 2015 IRP to develop a new analytical tool to objectively quantify wholesale market purchase risk so that the company could continue to prudently monitor its wholesale purchase strategy and incorporate physical wholesale purchase risk into its IRP planning models. In response to this need, PSE developed the Wholesale Purchase Curtailment Model (WPCM) in the 2015 IRP using the following design criteria:

- Use existing analytical modeling tools whenever possible, including PSE’s LOLP/RAM and financial portfolio cost models.
- Use the results of publically available, region-wide load/resource studies as inputs to PSE’s IRP models when possible, primarily the NPCC and BPA LOLP studies for Operating Year 2021.
- “Sync up” the inputs and outputs of GENESYS, the NPCC and BPA LOLP model, with PSE’s LOLP model, the Resource Adequacy Model (RAM).



- Develop a methodology for translating the regional load curtailments forecast by the NPCC and BPA models into PSE-level impacts. (The result is the Wholesale Purchase Curtailment Model.)
- Incorporate regional load curtailments into PSE's RAM model by reducing the amount of wholesale market purchases PSE is able to import into its system.
- Include forced outage events at PSE-owned or jointly owned thermal plants shown in the NPCC and BPA LOLP models in PSE's RAM model in a consistent manner.
- Include the impact of scarcity in the wholesale power price forecasts used in PSE IRP financial models.

In 2015, this was new territory for both PSE and the Washington Utilities and Transportation Commission (WUTC or the Commission); none of the utilities under the Commission's jurisdiction had previously attempted to quantify physical wholesale market purchase risk in their IRP planning processes. In its review of PSE's 2015 IRP, the WUTC recognized PSE's model as "fundamentally sound" and a "reasonable means of modeling a difficult challenge." We have therefore continued to refine the WPCM for use in the 2017 IRP.

The following sections describe how PSE has integrated physical and financial wholesale market risks into its 2017 IRP modeling process.

Modeling Physical Supply Risk

Since PSE is a winter-peaking utility, winter peak load and winter resource capacity are its primary focus with regard to evaluating physical power supply risks. The company's main analytical tool for evaluating the reliability of power supply is its Resource Adequacy Model. To identify the frequency of potential outages under varying conditions, RAM performs a multi-simulation analysis that includes the impacts of variable loads, hydro generation, wind generation, generating plant forced outages (and repair times), and available short-term wholesale market imports. The RAM calculates several reliability metrics, including LOLP, EUE (expected unserved energy) and LOLH/LOLE (loss of load hours or loss of load expectation).

For the 2017 analysis, the following key refinements were incorporated into PSE's IRP models.

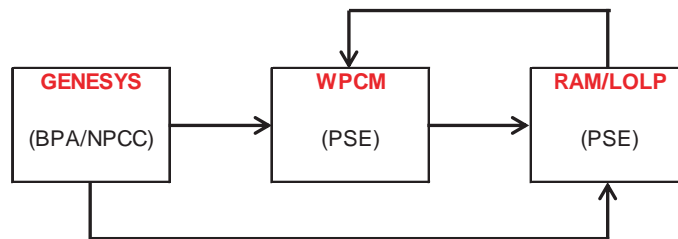
- A return to the 5 percent LOLP planning standard, as recommended by the Commission.
- Under some conditions, the amount of wholesale power available for PSE to purchase is limited to less than its maximum available Mid-C transmission capability of 1,722 MW.



- Limitations on PSE’s available supply of wholesale peaking capacity are tied to the regional load/resource conditions in the NPCC and BPA regional resource adequacy analyses using their GENESYS model.
- Specific hourly reductions to PSE’s wholesale market purchases are determined by PSE’s WPCM.

To accomplish this analysis, PSE modified its RAM model to incorporate the 2021 forecasts from the 2016 NPCC Resource Adequacy Study,⁸ the 2016 PNUCC Regional Forecast and the BPA 2015 Northwest Loads and Resources Study. As in 2015, PSE introduced into its RAM model the equivalent of forced outage events for PSE’s wholesale market purchases when regional deficit conditions are forecast. Figure G-4 illustrates the individual modeling tools utilized by PSE in this IRP to evaluate physical supply risk and how the inputs and outputs of these models are linked:

Figure G-4: Market Reliability Analysis Modeling Tools



The modeling steps illustrated in Figure G-5 are discussed in more detail in the following pages.

The GENESYS Model

The GENESYS model was developed by the NPCC and BPA to perform regional-level load and resource studies. GENESYS is a multi-scenario model that incorporates 80 different years of hydro conditions and 77 years of temperature conditions. When combined with thermal plant forced outages, mean time to repair those units, variable wind plant generation and available imports of power from outside the region, the model determines the PNW’s overall hourly capacity surplus or deficiency in each of 6,160 multi-scenario “simulations.” Since the GENESYS model includes all potentially available supplies of energy and capacity that could be utilized to

⁸ / The 2017 NPCC assessment was not published in time to use for this analysis.



meet PNW firm loads regardless of cost, a regional load-curtailement event will occur on any hour that has a capacity deficit.⁹

Since the PNW relies heavily upon hydroelectric generating resources to meet its winter peak load needs, GENESYS incorporates sophisticated modeling logic that attempts to minimize potential load curtailments by shaping the region's hydro resources to the maximum extent possible within a defined set of operational constraints. GENESYS also attempts to maximize the region's purchase of energy and capacity from California (subject to transmission import limits) utilizing both "purchase ahead" (i.e., forward purchases) and short-term purchases. GENESYS also incorporates a set of approximately 700 MW of energy-limited "emergency standby resources" that may be called upon to attempt to minimize PNW load-curtailement events; these resources include approximately 300 MW of backup diesel generation on PGE's system and 300 MW at the Bureau of Reclamation John W. Keys hydroelectric pumped storage plant.¹⁰

Regional Curtailment Events

PSE utilized the GENESYS model run from the 2016 NPCC Colstrip Sensitivity study to evaluate physical supply risk in this IRP.¹¹

The GENESYS Colstrip Sensitivity study incorporated the following key assumptions:

- PSE's 307 MW share of Colstrip Units 1 & 2 are removed in operating year 2021 (October 31, 2020 – September 30, 2021) before evaluating PNW load and resource conditions.
- Imports of short-term wholesale power from California during the winter season (November – February) were limited to 2,500 MW for on-peak hours and 3,000 MW for off-peak hours.
- The 650 MW Grays Harbor gas-fired CCCT plant was included as a firm resource in all months.¹²
- PGE's proposed 440 MW Carty 2 CCCT plant was not included in the analysis.¹³

9 / Operating reserve obligations (which include unit contingency reserves and intermittent resource balancing reserves) are included in the GENESYS model. A PNW load-curtailement event will occur if the total amount of all available resources (including imports) is less than the sum of firm loads plus operating reserves.

10 / The Bureau of Reclamation is currently limiting pump/generation operations at the Keys hydroelectric pumped storage plant to avoid excessive wear on the units and to meet its irrigation water delivery obligations.

11 / Support from NPCC staff was essential for this analysis – PSE is grateful for the assistance they provided and for help from the staff of PNUCC.

12 / The firmness of the natural gas supply for the Grays Harbor baseload CCCT plant has been an issue of concern for regional power supply planners, especially during the winter season. However, in November 2016, the owner/operator of the plant (Invenergy) indicated that it had secured an option on firm natural gas supplies for the plant for 2021; given this updated information, PSE's 2017 IRP analysis assumes that the plant would be available to provide firm capacity during all months of the year.

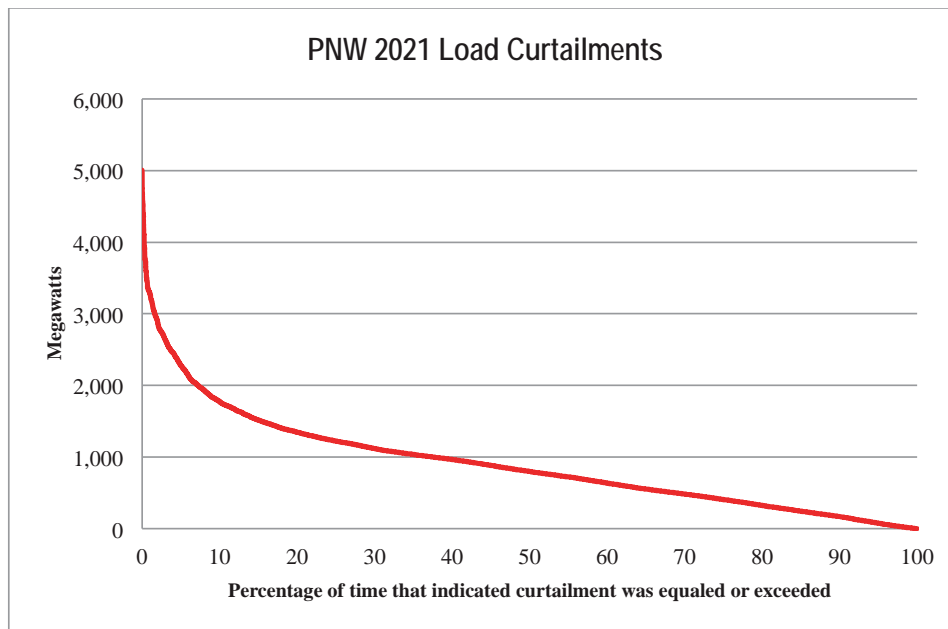
13 / At the present time, PGE's proposed Carty 2 plant does not meet the criteria established by the NPCC for inclusion in its long-term resource adequacy studies. (Proposed new plants must be both sited and licensed to be included in the adequacy analysis.)

Appendix G: Wholesale Market Risk



One of the outputs from this study is a set of all simulations in which there is a PNW-wide load-curtailement event of any magnitude on any given hour. The GENESYS Colstrip Sensitivity study output contained 35,937 hourly load curtailments for the PNW; these occurred in 1,039 of the 6,160 total simulations and ranged from 0.2 MW to 5,003 MW. This produced a region-wide LOLP of 16.9 percent (not including the emergency standby resources).¹⁴ When the 700 MW of emergency standby resources are included, the LOLP drops to slightly more than 13 percent. Figure G-5 illustrates the magnitude of PNW load curtailment events across the 35,937 hours that had curtailments greater than 0 MW.

Figure G-5: 2021 Pacific Northwest Load Curtailments
2016 NPCC Study, Colstrip Sensitivity Case



No adjustments were needed to the initial set of hourly PNW curtailments derived by GENESYS for use in this IRP, thanks to enhancements made since 2015 by NPCC and BPA staff to the hydro generation shaping logic incorporated into the GENESYS model.

¹⁴ / The impacts of PGE's backup generation and the Keys pumped storage plant are incorporated into the IRP analysis via the PGE and BPA peaking resources that are included in PSE's Wholesale Purchase Curtailment Model.



PSE Wholesale Market Reliability Scenarios

Using the hourly PNW load curtailments from the GENESYS study, PSE developed four Wholesale Market Reliability Scenarios to evaluate physical supply and financial risks. Scenario 1 assumes there is no wholesale market risk while Scenarios 2 through 4 incorporate market reliability – or the risk of interruption – consistent with the base assumptions for the resource additions, and fuel supply availability as used in the NPCC's 2016 Resource Adequacy Assessment for the winter of 2021. For all scenarios, PSE increased spot market imports to 3,400 MW, which is greater than the NPCC assumption of 2,500 MW for on-peak hours and 3,000 MW for off-peak hours. The four scenarios are described below.

SCENARIO 1: No wholesale market risk. This scenario assumes unlimited wholesale market supplies are available with no risk of interruption under any condition.

SCENARIO 2: NPCC 2016 assumptions, Colstrip sensitivity study

SCENARIO 3: NPCC 2016 assumptions, Colstrip sensitivity study + a new 227.5 MW peaker (with the output assigned to PSE).

SCENARIO 4: NPCC 2016 assumptions, Colstrip sensitivity study + 100 MW of new Columbia Gorge wind generation (with the output assigned to PSE).

PSE chose Wholesale Market Reliability Scenario 2 to evaluate resource adequacy impacts in the 2017 IRP.

The Wholesale Purchase Curtailment Model (WPCM)

As described earlier, the GENESYS model is configured to analyze conditions for the region as a whole, but it cannot determine which specific load-serving utility or utilities will bear all or a portion of a regional load-curtailment event. PSE developed the WPCM to link those regional events to their specific impacts on PSE's system and on PSE's ability to make wholesale market purchases to meet firm peak load and operating reserve obligations.

In essence, on an hourly basis, the WPCM translates a regional load-curtailment event into a reduction in PSE's wholesale market purchases (both measured in MW). In some cases, reductions in PSE's initial desired volume of wholesale market purchases could trigger a load-curtailment event in the PSE RAM.



The WPCM Computational Methodology

During a PNW-wide load-curtailement event, there is not enough physical power supply available in the region (including available imports from California) for all of the region's load-serving utilities to fully meet their firm loads plus operating reserve obligations. To mimic how the PNW wholesale markets would likely operate in such a situation, the WPCM uses a multi-step approach to "allocate" the regional capacity deficiency among the region's individual utilities. These individual capacity shortages are reflected via a reduction in each utility's forecasted level of wholesale market purchases.

The WPCM assumes that under PNW capacity shortage conditions:

1. all entities that need to purchase capacity in order to meet their own native load-serving obligations will be willing to purchase power up to the same threshold price,
2. all entities that need to purchase capacity in the PNW wholesale marketplace to meet their native load-serving obligations have equal opportunity and ability to locate and purchase needed capacity,¹⁵ and
3. any load-serving entity that manages to purchase more capacity than it needs to meet its load-serving obligations will re-sell the surplus capacity to other, still-deficient load-serving utilities.¹⁶

It should be noted that in actual operations, no central entity in the PNW is charged with allocating scarce supplies of energy and capacity to individual utilities during regional load-curtailement events (although Peak Reliability, as the Security Coordinator for the region, would be actively working with the region's utilities to maintain transmission system stability during such events). The PNW wholesale marketplace would, in effect, be the allocating mechanism as multiple parties attempt to enter into purchase and sale transactions under abnormal conditions. It is likely that forward market wholesale transactions would be partially curtailed or fully unwound to the extent allowed under the governing purchase/sale contracts. Furthermore the Western Systems Power Pool (WSPP) Agreement used for most wholesale power transactions in the PNW markets explicitly allows load-serving utilities to curtail or terminate firm Schedule C sales transactions to meet their own load-serving obligations.

¹⁵ / The WPCM does not incorporate potential transmission limitations that in practice might restrict one or more PNW load-serving utilities from purchasing some available capacity supplies.

¹⁶ / The WPCM assumes that the PNW wholesale power markets are perfectly efficient; i.e. that sellers are always able to sell 100 percent of their available capacity supplies and that no surplus capacity is left unsold due to the inability of purchasers and sellers to initiate purchase/sale transactions due to timing, credit or communication issues.

Appendix G: Wholesale Market Risk



(Appendix G of the 2015 IRP describes in detail how the Pacific Northwest wholesale power markets work and the impacts these processes could have during deficit conditions. It reviews the general PNW market structure, spot and forward wholesale power markets, key market characteristics, the WSPP Agreement and FERC price caps.)

The computational methodology incorporated into 2017 version of the WPCM is largely unchanged from the 2015 IRP version. The only logic modification made in the model was to address a situation where removals of large amounts of capacity from PSE's own resource portfolio (such as the early retirement of Colstrip Units 1 & 2) tended to understate the curtailments to PSE's Mid-C wholesale purchases as compared to the removal of the same amount of non-PSE capacity. This situation was addressed by allowing PSE to attempt to purchase wholesale power in quantities larger than its hourly Mid-C transmission import right; this additional PSE capacity need is termed the "PSE Excess Deficiency" in the WPCM.

The impact of this modification is to recognize that reductions in PSE's firm resource portfolio (such as the removal of Colstrip Units 1 & 2) increases PSE's wholesale purchase need while at the same time reducing the overall amount of capacity available for purchase in the PNW wholesale markets (in an amount equal to the PSE resource reduction). This, in turn, creates slightly increased PSE hourly wholesale purchase curtailments due to the increased competition among PNW utilities to make wholesale purchases from a smaller regional pool of available capacity.¹⁷

Regional Utility Load and Resource Inputs

Because the amounts of capacity that other load-serving entities in the region need to purchase in the wholesale marketplace has a direct impact on the amount of capacity that PSE would be able to purchase, it was necessary to assemble load and resource data for both the region as a whole and for many of its individual utilities, especially those that would be expected to purchase relatively large amounts of energy and capacity during winter peaking events.

For this analysis, PSE chose to use the capacity data contained in BPA's *2015 Pacific Northwest Loads and Resources Study* as an initial point of reference, because it contained useful differentiation at the regional level and because it treated individual utility data more consistently than other available sources. BPA's study tabulates forecasted loads and resources of non-BPA entities by class (IOUs, PUDs, municipalities, etc.), and it generally applies the same forecasting assumptions and methodologies to all regional utilities. In contrast, the computational methodologies used in individual utility IRPs can vary significantly.

¹⁷ / It should be noted that the reverse is also true; if PSE adds new firm resources to its portfolio, this would increase the overall supply of capacity in the PNW markets and thereby reduce the curtailments to PSE's wholesale purchases due to less competition for scarce capacity.

Appendix G: Wholesale Market Risk



Using the 2020-2021 capacity data contained in the 2015 BPA study and applying some general assumptions, PSE constructed winter 2021 load/resource tables for eight classes of market participants:

- | | |
|------------------------------|-----------------------------|
| 1. federal entities | 5. marketers |
| 2. cooperatives | 6. municipalities |
| 3. direct service industries | 7. public utility districts |
| 4. investor-owned utilities | 8. other |

From this data, PSE computed the surplus/deficiency positions for each of the eight entity classes under 2021 winter peaking conditions using BPA's 120-hour sustained hydro peaking case.

To create winter peak load/resource tables for the region's investor-owned utilities (several of which are large purchasers of wholesale energy and capacity), PSE assembled load and resource data from 2015 and 2016 IRPs to create winter 2021 peak load/resource tables for each utility. Forecasted winter 2021 peaking surplus/deficiencies were then determined for each of the following IOUs: PacifiCorp, PGE, Avista and Idaho Power.

PSE then trued up the 2021 winter peaking surplus/deficiencies between the 2015 BPA study, the IRPs of the above utilities and PSE's own 2017 IRP load/resource data to create a simplified model of the PNW wholesale market for use in the WPCM.¹⁸ Additional information and computational steps were required to incorporate PacifiCorp load/resource information into the model since PacifiCorp East (PACE) is a summer-peaking system and PacifiCorp West (PACW) is a winter-peaking system.¹⁹

The WPCM's input data also includes information regarding the IPP plants located within the region. For these plants, 100 percent of net winter season capacity was assumed to be available to meet PNW loads, as is the case in the BPA study. Idaho's surplus was also assumed to be available to meet PNW winter peak loads, since Idaho Power is a summer-peaking utility and its IRP indicated that it expects to have a moderate winter-season capacity surplus for 2021.

18 / In the 2015 IRP, PSE performed a series of preliminary sensitivity studies using varying amounts of PSE and other PNW utility winter surpluses and deficiencies to gauge the sensitivity of the WPCM's outcomes to the relative size and number of surplus and deficient utilities in the PNW region. The results of these studies indicated that utilities with small surpluses or deficiencies relative to PSE's average of approximately 1,600 MW, 2021 winter peak deficiency had very little (or no) impact on the level of PSE's computed wholesale purchase curtailments. It was therefore possible to significantly simplify the WPCM by aggregating the smaller utility capacity surpluses and deficits into one proxy "other" utility system. The 2017 version of the WPCM utilizes this same approach.

19 / Deriving winter 2020/21 load and resource information for the PACW system proved challenging given the fact that PacifiCorp overall is a summer-peaking system and PacifiCorp's 2015 IRP did not contain separate PACW and PACE load/resource tables under winter-peaking conditions. PSE therefore estimated PACW's winter 2021 peak load using a combination of the limited information contained in PacifiCorp's 2015 IRP and publically available historical load data from multiple FERC reports/filings including PacifiCorp's 2016 Triennial Market-Based Rate filing.

Appendix G: Wholesale Market Risk



In addition to deriving base winter 2021 surplus and deficiency values, PSE also computed a set of “sensitivity ratios” for PSE, PGE, BPA, PACW, other utilities, and the combination of the PNW IPPs and Idaho Power. The purpose of the sensitivity ratios is to scale each entity’s base surplus/deficiency (which was computed on a single-point deterministic basis) up or down to match the varying hourly PNW load-curtailed values from the GENESYS model. The sensitivity ratios are a measure of the relative size of each PNW entity and were computed as follows:

$$\text{Entity SR} = (\text{Entity ABS PK LD} + \text{Entity PK Res}) / (\text{PNW ABS PK LD} + \text{PNW PK Res})$$

Where:

Entity SR = Each Entity’s Sensitivity Ratio

Entity ABS PK LD = The Absolute Value of Each Entity’s 2021 Peak Load

Entity PK Res = Each Entity’s Total 2021 Peak Resources

PNW ABS PK LD = The Absolute Value of Total PNW 2021 Peak Loads

PNW PK Res = Total PNW 2021 Peak Resources

The sensitivity ratios were computed as a function of both load and resources since the multi-scenario GENESYS model varies both load and generation quantities; therefore, a regional PNW load-curtailed event could be the result of either a load-driven event, a generation-driven event or both.

The above computations yielded the base set of winter season surpluses and deficiencies and associated sensitivity ratios shown in Figure G-6 below:

Appendix G: Wholesale Market Risk



Figure G-6: WPCM Regional Utility Surplus/Deficiencies and Sensitivity Ratios for Winter 2021
Scenario 2 – 2016 NPCC Assumptions, Colstrip Sensitivity Study

| PNW Entity | Winter 2021 Peak Load(MW) | Winter 2021 Peak Resources (MW) | Net Peak Sur/(Def) (MW) | Sensitivity Ratio Absolute Value of Peak Load + Peak Resources |
|---------------------|---------------------------|---------------------------------|-------------------------|--|
| PSE | (6,334.0) | 4,050.0 | (2,284.0) | 0.147 |
| PGE | (4,126.0) | 3,307.0 | (819.0) | 0.106 |
| PACW | (4,032.6) | 3,095.0 | (937.6) | 0.102 |
| BPA | (10,861.0) | 9,841.0 | (1,020.0) | 0.295 |
| Other PNW Utilities | (8,309.4) | 8,044.0 | (265.4) | 0.233 |
| PNW IPPs + IPC | (2,704.0) | 5,512.0 | 2,808.0 | 0.117 |
| PNW IPPs | (265.0) | 2,445.0 | 2,180.0 | |
| Idaho Power | (2,439.0) | 3,067.0 | 628.0 | |
| Total | (36,367.0) | 33,849.0 | (2,518.0) | 1.00 |

NOTE: The PacifiCorp winter-season deficiency is for the PACW system only.

Allocation Methodology

For each hour that there is a PNW load-curtailement, the WPCM simulates how the five largest purchasers of winter season capacity in the PNW wholesale markets – PSE, PACW, PGE, BPA and all other utilities – would compete to purchase scarce supplies of capacity.

FORWARD MARKET ALLOCATIONS. The model assumes that each of the five large buyers purchases a portion of their base capacity deficit, as shown in Figure G-7, in the forward wholesale markets. Under most scenarios, each utility is able to purchase their target amount of capacity in these markets. This reduces the amount of remaining capacity available for purchase in the spot markets. If the wholesale market does not have enough capacity to satisfy all of the forward purchase targets, those purchases are reduced on a pro-rata basis based upon each utility's initial target purchase amount.



SPOT MARKET ALLOCATIONS. For spot market capacity allocation, each of the five large utility purchasers is assumed to have equal access to the PNW wholesale spot markets, including available imports from California. The spot market capacity allocation *is not* based on a straight pro-rata allocation, because in actual operations the largest purchaser (which is usually PSE) would not be guaranteed automatic access to a fixed percentage of its capacity need. Instead, all of the large purchasers would be aggressively attempting to locate and purchase scarce capacity from the exact same sources. Under deficit conditions, the largest of the purchasers would tend to experience the biggest MW shortfalls between what they need to buy and what they can actually buy. This situation is particularly true for small to mid-sized regional curtailments where the smaller purchasers may be able to fill 100 percent of their capacity needs but the larger purchasers cannot.

WPCM Outputs

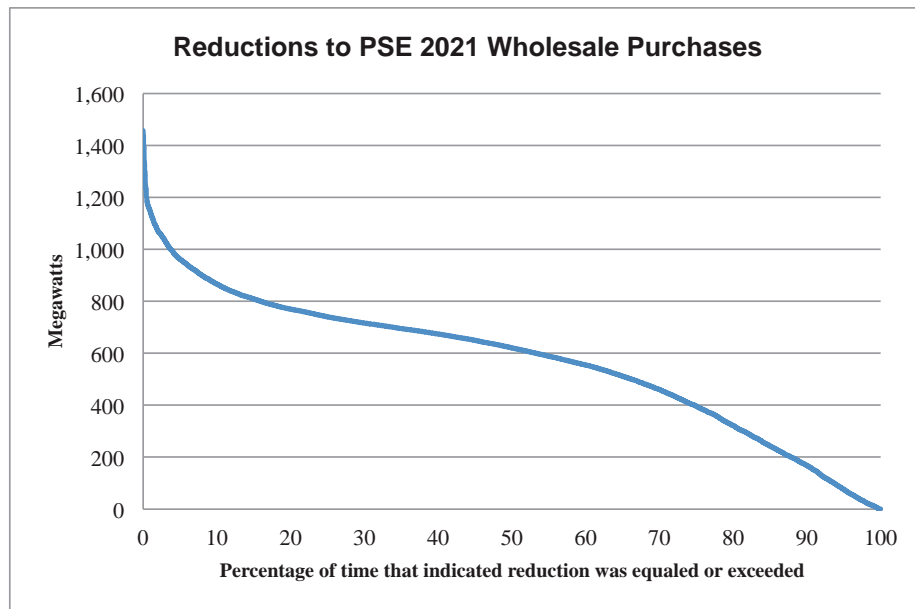
For each simulation and hour in which the NPCC GENESYS model determines there is PNW load-curtailment event, the WPCM model outputs the following PSE-specific information:

- PSE's initial wholesale market purchase amount (in MW), limited only by PSE's overall Mid-C transmission rights.
- The curtailment to PSE's market purchase amount (in MW) due to the PNW regional capacity shortage.
- PSE's final wholesale market purchase amount (in MW) after incorporating PNW regional capacity shortage conditions.



Figure G-7 illustrates the magnitude of the reductions in PSE’s wholesale market purchases across the 35,937 hours with PNW load curtailments greater than 0 MW in the NPCC’s 2016 Study (Colstrip Sensitivity Study).

Figure G-7: 2021 Reductions to PSE 2021 Wholesale Purchases due to PNW Load Curtailment Events



As discussed above, the amount of PSE’s wholesale purchase reductions is not a straight pro-rata calculation; rather, PSE’s percentage reduction in its initial target wholesale purchase amount varies depending upon

1. the magnitude of the PNW regional load-curtailment event, and
2. the capacity deficits of PSE and the other large capacity purchasers under each specific PNW load-curtailment event.

Appendix G: Wholesale Market Risk



Figure G-8 illustrates this point for several different magnitudes of hourly load-curtailement events from the same simulation of the NPCC's GENESYS model, for the Colstrip Sensitivity Study.

*Figure G-8: Hourly Load-curtailement Events
from the NPCC's GENESYS Model, Colstrip Sensitivity Study*

| Initial Hourly PSE Wholesale Purchase (MW) | PNW Load Curtailement Amount (MW) | Final Hourly PSE Wholesale Purchase (MW) | PSE Hourly Purchase Reduction (Percent) | PSE Share of PNW Load Curtailement (Percent) |
|--|-----------------------------------|--|---|--|
| 1,658.0 | (171.2) | 1,486.8 | 10.3% | 100.0% |
| 1,527.0 | (901.1) | 979.4 | 35.9% | 60.8% |
| 1,671.0 | (2,050.5) | 737.2 | 55.9% | 45.5% |
| 1,671.0 | (3,284.5) | 517.8 | 69.0% | 35.1% |
| 1,669.0 | (4,135.5) | 365.6 | 78.1% | 31.5% |
| 1,668.0 | (5,002.6) | 211.0 | 87.4% | 29.1% |



Summary of WPCM Results

Before incorporating wholesale purchase availability risk, PSE's average 2021 wholesale purchase amount was 1,587 MW during the 35,937 hours in the GENESYS Colstrip Sensitivity where there were PNW load curtailments. After incorporating wholesale purchase availability risk via the WPCM, PSE's average wholesale market purchases were reduced to only 1,016 MW – a 36 percent reduction in the average hourly amount of energy and capacity available for PSE to meet its firm winter peak load and reserve obligations. Furthermore, on some hours, PSE's wholesale purchases were reduced by as much as 88 percent from their original amounts; these large PSE wholesale purchase reductions tend to occur during the very large PNW load-curtailment events.

Summary results from the WPCM for each of the four Wholesale Market Reliability Scenarios are shown in Figure G-9.

Figure G-9: PSE Wholesale Market Purchases by Scenario

| Reliability Scenario | Initial Average PSE Wholesale Purchase (MW) | Final Average PSE Wholesale Purchase (MW) | Average Purchase Reduction (MW) | Average Purchase Reduction (Percent) |
|-----------------------------------|---|---|---------------------------------|--------------------------------------|
| 1. No Market Risk | 1,586.9 | 1,586.9 | 0.0 | 0 |
| 2. NPCC 2016 Colstrip Sensitivity | 1,586.9 | 1,016.4 | (570.5) | 36.0% |
| 3. NPCC 2016 + 227.5 new peaker | 1,589.4 | 1,040.2 | (549.2) | 34.6% |
| 4. NPCC 2016 + 100 MW new wind | 1,587.1 | 1,021.2 | (566.0) | 35.7% |



Linking the WPCM and RAM Models

PSE's RAM operates much like the GENESYS model, except that it is designed to analyze load/resource conditions for PSE's power system rather than the entire PNW region.²⁰ Like GENESYS, PSE's RAM is a multi-scenario model that varies a set of input parameters across 6,160 individual simulations, and the result of each simulation is PSE's hourly capacity surplus or deficiency. The loss of load probability (LOLP), expected unserved energy (EUE) and loss of load hours/expectations (LOLH/LOLE) for the PSE system is then computed across the 6,160 simulations.

One of the RAM input variables is the hourly wholesale market purchases that PSE imports into its system using its long-term Mid-C transmission rights. The initial set of hourly imports is computed as the difference between PSE's maximum import rights (which total approximately 2,300 MW in 2021) less the amount of transmission capability required to import generation from PSE's Wild Horse wind plant and PSE's contracted shares of the Mid-C hydro plants. To reflect regional deficit conditions, this initial set of hourly wholesale market imports is reduced on the hours when a PNW load-curtailment event is identified by the WCPM. The final set of hourly PSE wholesale imports from the WPCM is then used as a data input into the PSE RAM, and PSE's loss of load probability, expected unserved energy, and loss of load expectation are then determined. In this fashion, the LOLP, EUE and LOLH metrics determined in the RAM incorporate PSE's wholesale market reliance risk.

²⁰ / PSE's RAM is described in detail in Appendix N.



Calculating the Capacity Contribution of Wholesale Market Purchases

With the reliability of wholesale market purchases now reflected in PSE's RAM, we applied the same analytical process that we use for other resources to estimate the capacity value of wholesale market purchases. That is, just as PSE cannot count on the full nameplate capacity of a wind plant to meet peak capacity needs because the wind doesn't blow all the time, we cannot always count on the full amount of wholesale market purchases to meet our peak need, because the wholesale market is not perfectly reliable. To make this capacity value assessment, the 2017 IRP uses an effective load carrying capacity (ELCC) analysis.²¹ The results of this analysis are summarized in Figure G-10 for Scenario 2, the NPCC 2016 assumptions, Colstrip Sensitivity Study. The reason why the average purchase reduction of 36 percent in the WCPM model translates to a 99 percent ELCC is that those purchase reductions do not necessarily result in a PSE load curtailment in the RAM model when using a 5 percent LOLP planning standard. Under the LOLP metric, multiple PSE load curtailments that occur on different hours within the same simulation in the RAM only count as one failure. Therefore, a large number of curtailments to PSE's wholesale purchases that occur across many different hours in the same simulation can still result in a relatively high ELCC for wholesale purchases even though the average wholesale purchase curtailment percentage (36 percent in this case) is relatively large. The PNCC's updated 2017 regional adequacy study, which reflects larger regional investments in conservation and slowing regional load growth, increases our confidence in this result.

Figure G-10: Capacity Value of PSE's Wholesale Market Purchases

| For Scenario 2: NPCC 2016 Assumptions, Colstrip Sensitivity Study | Capacity | Capacity Needed to Maintain 5% LOLP | Effective Load Carrying Capacity |
|--|----------|--|---|
| PSE Wholesale Market Purchases (Using Available Mid-C Transmission Rights) | 1,580 MW | 12 MW | 99% |

²¹ / The ELCC analysis for PSE's wholesale market purchases and other resource types are discussed in Appendix N.



4. MONITORING WHOLESALE MARKET RISK

As has been previously discussed, the PNW utility industry is in a state of transition on many fronts. Some of the key issues that are currently impacting long-term utility load/resource planning efforts include: 1) a steady decline in the region's forecasted capacity surplus across the next decade, 2) lower projected utility energy and peak load growth rates, 3) potential future greenhouse gas emission policies, 4) the impacts of new technology, and 5) shifting individual customer preferences. These factors combine to create a significant amount of uncertainty for PSE (and other regional utilities) regarding the preferred mix of supply-side and demand-side resources to economically and reliably meet customers' needs in the future.

For many years, PSE has relied upon a strategy of purchasing relatively large amounts of power in the regional wholesale markets in order to achieve the lowest reasonable cost means of fulfilling customers' energy needs. However, as conditions continue to change, PSE must proactively monitor how these changes could impact its wholesale power purchase strategy and be prepared to modify this strategy in order to maintain a balance between the associated risks and benefits when compared against other supply-side and demand-side resource alternatives.

The following sections discuss several important issues that PSE will continue to actively monitor and/or discuss with other regional long-term planners so that we can reassess our wholesale power purchase strategy as changing conditions warrant.

Do additional reliability metrics need to be considered?

The NPCC's 2016 Resource Adequacy Assessment analyzed PNW regional electric reliability from the perspective of the LOLP planning metric developed by the Council and adopted by some utilities – including PSE. This planning standard requires utilities to have sufficient peaking resources available to fully meet their firm peak load and operating reserve obligations in 95 percent of simulated market conditions.

The LOLP metric measures the likelihood of having one or more regional load-curtailement events in a sample year, but it provides no information about the *frequency* of events within a simulation or the *magnitude* or *duration* of those events. The current LOLP metric does not take into account the size of regional load curtailments; i.e., a 1 MW curtailment and a 1,000 MW curtailment are treated equally when computing loss of load probability. In addition, the LOLP metric tends to understate reliability-related impacts associated with energy-limited resources such as hydro and demand response.



Several PNW utilities (including PSE) and NPCC staff have expressed interest in evaluating and potentially adopting additional metrics to provide regional resource planning stakeholders with a more complete picture of the region's ability to reliably meet peak load and reserve obligations.²²

- The Expected Unserved Energy (EUE) metric is a quantitative measure of the *magnitude* of load curtailments.
- The Loss of Load Expectation (LOLE) metric, also called the Loss of Load Hours (LOLH), provides information about the *duration* of the curtailment events.

PSE believes that the concept of supplementing and/or replacing the LOLP metric as a capacity planning standard deserves further attention; the company will therefore continue to pursue those discussions at the regional level before bringing the issue to the Commission.

Changes to Regional Load/Resource Forecasts

The amounts of energy and capacity that are forecast to be available for purchase in the future by PSE are closely related to the load/resource projections made by PSE and other regional utilities as part of their long-term planning processes. As utilities continue to refine their long-term load/resource studies – for example to incorporate new greenhouse gas emissions policies or the deployment of emerging technologies such as energy storage – assessments of the region's resource adequacy will change; this could either increase or decrease the region's need for new firm, dispatchable resources. Also, the potential range of new investments in conservation and demand response will continue to be updated (and hopefully narrowed) over time as well.

In addition, actions taken by regional entities other than PSE can have an indirect effect on PSE and its wholesale purchase strategy; for example, the decision by another PNW utility to develop new generation resources (to meet its own needs) may benefit PSE as well by increasing the supply and reliability of capacity available for purchase by PSE in the short-term wholesale markets.

PSE will continue to take a leadership role in PNW long-term planning forums in order to: 1) stay abreast of current trends, 2) actively work with the NPCC, BPA, PNUCC and other regional stakeholders to improve the accuracy of regional resource reliability assessments, and 3) maintain a safe, reliable and economic power system for the benefit of our customers and the region.

²² / The Council has initiated a process to review its current 5 percent LOLP adequacy standard. This review is expected to consider similar efforts going on in other parts of the United States, namely through the IEEE Loss-of-Load-Expectation Working Group and the North American Electric Reliability Corporation (NERC).



Energy and Capacity Imports from California

The high-voltage AC and DC interties that connect the Pacific Northwest with California were designed to facilitate large transfers of energy and capacity between the two regions. Imports and exports on these interties allow load-serving utilities to take advantage of seasonal load diversity, since California peaks in the summer and the Pacific Northwest (overall) peaks in the winter.

How much power from California will be available to import for meeting PNW winter peak loads in the future? This is a topic of great interest to the region's resource planners. Determining the amount of power that can reliably be imported from California under winter peak conditions is a complex exercise that involves modeling all of the loads and resources within the Western Electricity Coordinating Council (WECC) and all of the associated transmission line transfer path ratings. Recent BPA studies that have been vetted by several regional stakeholders (including the NPCC's Resource Adequacy Advisory Committee) have determined that up to 3,825 MW of energy and capacity could be imported from California under winter peaking conditions during on-peak hours.

Currently only 425 MW of imports from California are contracted for under long-term firm PPAs for the on-peak hours of the winter of 2020-2021. Of that amount, 300 MW is associated with PSE's power exchange agreement with PG&E. The remaining 3,400 MW of south-to-north intertie capability during the winter season is assumed to be available to import short-term supplies of wholesale power from California in order to help PNW load-serving utilities meet their winter peak load obligations.²³ Regional resource planners are continuing to assess the amounts of capacity that could reliably be imported from California to help meet PNW winter peak loads and will modify this conservative estimate if conditions warrant.

In addition, regional load/resource models may not fully incorporate the potential for outages and/or derates on the interties that interconnect the PNW with California. This is an especially important issue for PSE, since it relies upon 300 MW of firm imports from California to meet winter peak loads under the long-term PSE/PG&E Exchange Agreement. PSE will continue to assess whether we need to develop a forced outage rate for the PSE/PG&E Exchange Agreement in order to address this potential risk.

²³ / It should be noted that the assumed volume of short-term wholesale power imports from California during the summer season is 0 MW since: 1) California is a summer-peaking region, and 2) many load-serving entities in California typically purchase energy and capacity from the PNW to meet their summer peak load obligations.



Market Friction

The various PNW-level load/resource models used by the NPCC, PNUCC and BPA, as well as PSE's own RAM and WPCM models, assume that the wholesale markets always operate in an optimally efficient fashion. However, many real-world uncertainties and behaviors are difficult to incorporate into the models. For instance, during a severe winter cold weather event, the region's load-serving utilities would be expected to be very conservative with regard to meeting their statutory native load obligations. This could lead some utilities to forego making wholesale power sales in advance of the delivery hour, even though, after the fact, some surplus capacity may have been available. In addition, utilities operating energy-limited hydroelectric-based systems may not be willing to sell "surplus" water today if they think they may need that same increment of water at a future time to meet their own load-serving obligations. Incorporating this "market friction" impact could therefore result in more frequent and/or severe PNW load-curtailed events than the current set of models indicate.

CAISO Energy Imbalance Market

In late 2014, the California Independent System Operator (CAISO) expanded its centrally operated wholesale power markets to include a within-the-hour Energy Imbalance Market (EIM). The CAISO EIM is a voluntary, centrally-dispatched energy imbalance market that allows for the participation of loads and generating resources that are located in Balancing Authority Areas (BAAs) outside of the CAISO's own BAA.

PSE's application to join the CAISO EIM was approved by the FERC on September 30, 2016, and PSE commenced operations in the EIM on October 1, 2016. Currently, the EIM "footprint" is comprised of the following six BAAs: 1) CAISO, 2) PacifiCorp East, 3) PacifiCorp West, 4) Nevada Energy, 5) Arizona Public Service, and 6) PSE. In addition, PGE, Idaho Power and Seattle City Light are expected to join the EIM in late 2017, early 2018 and early 2019 respectively.

The primary focus of the EIM is to reduce the within-the-hour **energy-related** generation dispatch costs associated with the participants balancing load and resources in their respective BAAs; this is achieved by creating a larger "pool" of generating plants available to be re-dispatched within each hour based upon the combined energy imbalance need of all of the participants.

The CAISO EIM is currently not designed to be a **capacity balancing** market since each participating BAA operator must demonstrate that it has sufficient resources available to meet all



of its forecasted capacity obligations (including operating reserves) prior to the start of each delivery hour. However, should the EIM decide to form a capacity balancing market in the future, this may present new alternatives for PSE from a long-term capacity planning perspective.

Balancing Reserves for Intermittent Resources

The GENESYS model used to produce PNW-level load/resource studies now incorporates forecasts of the real-time balancing reserves for wind plants located within multiple PNW Balancing Authority Areas.²⁴ This is a significant enhancement from previous model versions; however, as additional wind and solar generating projects are developed within the region, these balancing capacity forecasts may need to be further refined, especially with regard to solar PV plants since little historical data currently exists for these types of facilities located in the PNW.

Fuel Supplies for Generating Plants

The firmness of generating plant fuel supplies are a concern for regional load/resource planners. Since the PNW is a heating-load-driven, winter-peaking region, demand for natural gas supplies tends to peak at the same time as the demand for electricity. A shortage of gas supply or limitations on gas pipeline capacity could lead to natural gas deliveries being curtailed to some gas-fired baseload and peaking plants. While many PNW gas-fired generating plants have backup fuel supplies (generally oil), at least one major plant – the 650 MW Grays Harbor CCCT plant – does not have an on-site backup fuel supply. As an independent power producer, the status of this plant's fuel supply is first and foremost a contractual issue between the plant's owner (Invenergy) and the entities that are purchasing power from the plant. However, since the NPCC's adequacy studies assume that all PNW IPP generating capacity will be available to meet regional peak loads, the firmness of the plant's fuel supply is a regional-level issue as well.

²⁴ / Earlier version of GENESYS, including the version utilized in PSE's 2015 IRP, only incorporated balancing capacity reserves for wind plants located within BPA's BAA.



H

2017 PSE Integrated Resource Plan

Operational Flexibility

This appendix summarizes the operational flexibility study performed for PSE by E3 Consulting for the 2017 IRP.

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1. OVERVIEW

A wide variety of conditions place demands on system flexibility. These include load fluctuations, integration of intermittent resources like wind, Balancing Authority obligations to integrate scheduled interchanges and unexpected events like forced outages. Balancing Authorities also require flexibility for maintaining contingency reserves to assist other balancing authorities that may have sudden needs for assistance in balancing loads.

This 2017 IRP analysis examines the issue of operational flexibility, specifically looking at the ability of PSE resources to balance load and variable energy resources such as wind on a sub-hourly basis. This analysis simulates the dispatch of PSE's existing portfolio in five-minute intervals using a two-stage production simulation model. It also compares how the portfolio's sub-hourly dispatch changes when potential new gas or storage resources are added.

The appendix is divided into five sections.

SYSTEM BALANCING discusses the role of balancing capacity, the Control Performance Standard 2 (CPS2) metric used to gauge PSE's ability to reliably balance the system and how PSE defines variability and uncertainty as they relate to balancing.

FLEXIBILITY SUPPLY AND DEMAND covers how PSE evaluates the availability of balancing capacity from PSE resources in light of the demands placed on the system for that capacity and discusses how that capacity is procured and deployed.

MODELING METHODOLOGY reviews the two models used to assess how PSE will meet its balancing obligations in 2018. The first model determines how to best set aside balancing reserves prior to an operating hour; the second simulates deployment of those reserves at 5-minute intervals.

Appendix H: Operational Flexibility



Finally, we present the analysis **RESULTS** and offer a **CONCLUSION AND NEXT STEPS**.

In addition to the current PSE portfolio, the analysis considered the independent addition of eight different gas-fired resources, as well as five storage resource configurations.

The results of this work indicate that, at PSE's current level of load and wind balancing needs, the current portfolio's existing resources are able to balance sub-hourly changes in load with only small and infrequent challenges. Adding the new resources to the simulation typically lowers the total system dispatch cost on an hourly basis. In addition, the new resources provide incremental sub-hourly cost savings related specifically to 5-minute dispatch (incremental to hourly savings) ranging from \$200,000 to \$900,000 per year, depending on the resource evaluated. Most of the flexible new resources considered create small reductions in the amount of sub-hourly flexibility challenges, but the relative differences are small due to the already low level of issues identified with the current portfolio. It is possible that if PSE assumed responsibility for balancing more wind resources, the sub-hourly flexibility issues could become more challenging.



2. SYSTEM BALANCING

The PSE Balancing Authority

A Balancing Authority (BA) is an entity that manages generation, transmission and load; it maintains load-interchange-generation balance within a geographic or electrically interconnected Balancing Authority Area (BAA), and it supports frequency in real time. The responsibility of the PSE Balancing Authority is to maintain frequency on its system and support frequency on the greater interconnection. To accomplish this, the PSE BA must balance load with generation on the system at all times. When load is greater than generation, a negative frequency error occurs. When generation is greater than load, a positive frequency error occurs. Small positive or negative frequency deviations are acceptable and occur commonly during the course of normal operations, but moderate to high deviations require corrective action by the BA. Large frequency deviations can severely damage electrical generating equipment and ultimately result in large-scale cascading power outages. Therefore, the primary responsibility of the BA is to do everything it can to maintain frequency so that load will be served reliably throughout the BAA.

The Area Control Error (ACE) metric has been used for many years to track the ability of a BA to meet its reliability obligation. ACE is the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency. It reflects the balance of generation, load and interchange. Balancing Authority ACE determines how much a BA needs to move its regulating generation units (both manually and automatically) to meet mandatory control performance standard requirements.

By properly managing its ACE, PSE meets several key objectives: it reliably serves its customers, it maintains regulatory compliance, and it minimizes frequency excursions originating within its own BA that could impact other BAs or Transmission Operators (TOP) within the interconnection. PSE's CPS2 metric sets a requirement for how far and often its system can stray from load and generation being in balance. CPS2 measures whether the average ACE stays within a given boundary over a 10-minute period; this is the L10 value. At least 90 percent of the 10-minute periods in each month must be within the +/- L10 boundary to meet the CPS2 requirement. The L10 value is provided to PSE by the North American Electric Reliability Corporation (NERC). The PSE system responds to ACE every four seconds to ensure that PSE's average CPS2 score exceeds the required 90 percent for compliance. CPS2 is a concrete benchmark for assessing system reliability, and it is one of the metrics used to determine the adequacy of PSE's portfolio in this analysis.

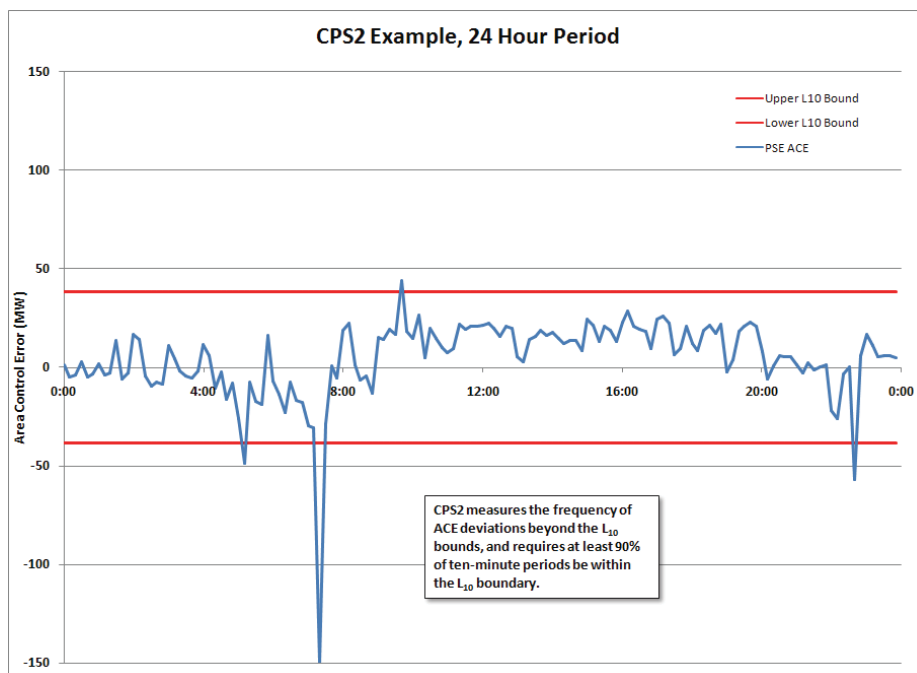
Appendix H: Operational Flexibility



BALANCING RESERVES refer to capacity held back on the PSE system to respond to negative and positive frequency errors. These can be incremental (INC) or decremental (DEC). Incremental capacity adds energy to the grid, decremental capacity reduces power to the grid. Balancing reserves can be in the form of regulating reserves, which are capable of adjusting dispatch to balance load within 5-minute time period, down to within one minute, and “load following” or “flexibility” reserves, which are often held to balance the variations of load and wind at a 5-minute level relative to an hourly ahead forecast.

CONTINGENCY RESERVES are also required in addition to balancing reserves; these are capacity reserved in spinning and non-spinning forms for managing a large negative frequency event such as a sudden loss of generation in PSE’s BA or a neighboring BA. Contingency reserves are used for the first hour of the event only.

Figure H-1: Example of Control Performance Standard 2





Impact of Variability and Uncertainty on System Volatility

VARIABILITY is the moment to moment, natural fluctuations in loads and generating resources and is always present on the electric system. **UNCERTAINTY** is the inability to perfectly predict the hourly values for loads and generating resources. **VOLATILITY** refers to the collective variability and uncertainty observed system-wide.

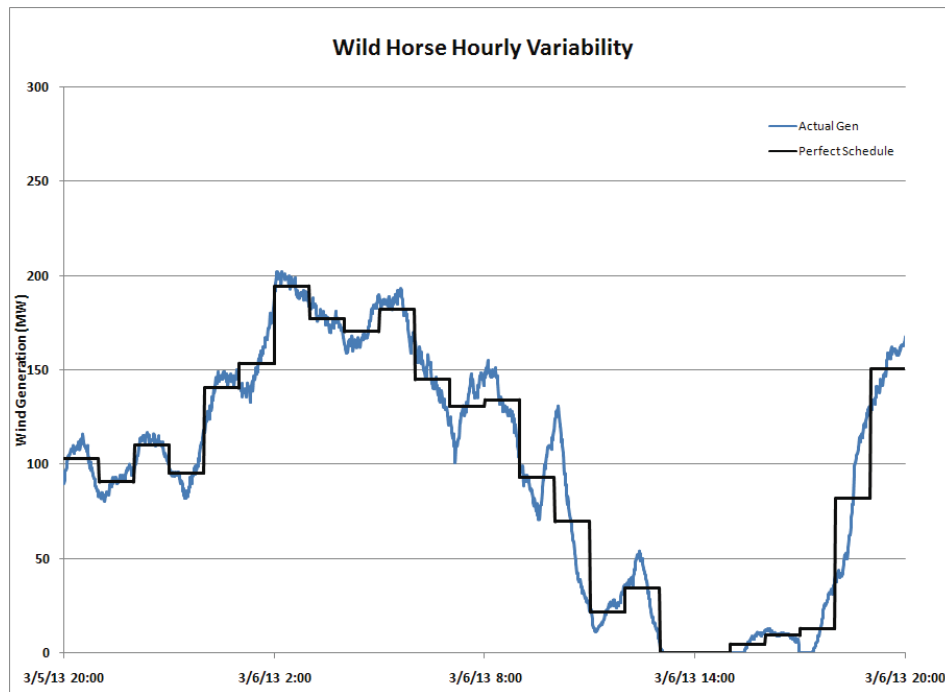
Understanding the distinction between variability and uncertainty is essential when discussing ways to manage and potentially reduce volatility across the entire PSE system. Variability is a smaller component of volatility than uncertainty. It is largely uncontrollable, since it is caused by random changes in loads, generating resource power output and fuel availability (such as wind). Uncertainty is the larger component of system volatility, but there are tools that can be used to reduce this uncertainty. For example, improvements in load and wind forecasting can increase the accuracy of load and wind generation schedules, reducing the need to provide balancing energy. Also, shortening scheduling windows can reduce the impact of both variability and uncertainty on system volatility.

Prior to October 2016, the PSE BA managed system volatility over 60-minute scheduling periods. To help address system flexibility needs PSE joined the voluntary, within-hour Energy Imbalance Market (EIM) operated by the California Independent System Operator (CAISO) effective October 1, 2016. At present, CAISO, PacifiCorp, NV Energy, and Arizona Public Service are the other EIM entities. Within the EIM, PSE is able utilize purchases and sales with the market to fulfill energy flexibility requirements on a 5-minute and 15-minute basis, but as a BA, PSE retains final responsibility for balancing its loads and resources. Due to the short time period of actual data regarding PSE's EIM experience and its effect on PSE's sub-hourly balance, this analysis for the 2017 IRP did not consider the EIM when evaluating sub-hourly dispatch. Future studies will reflect the impact of the EIM.



Figures H-2 through H-4 use a 24-hour period at the Wild Horse wind facility to illustrate examples of variability, uncertainty and volatility. In Figure H-2, the variability of Wild Horse is shown as the moment-to-moment generation relative to a perfect hourly schedule (a perfect hourly schedule equals the hourly average actual generation). It shows that even equipped with a perfect schedule, PSE must still manage fluctuations in wind generation within the hour, along with other deviations on the system.

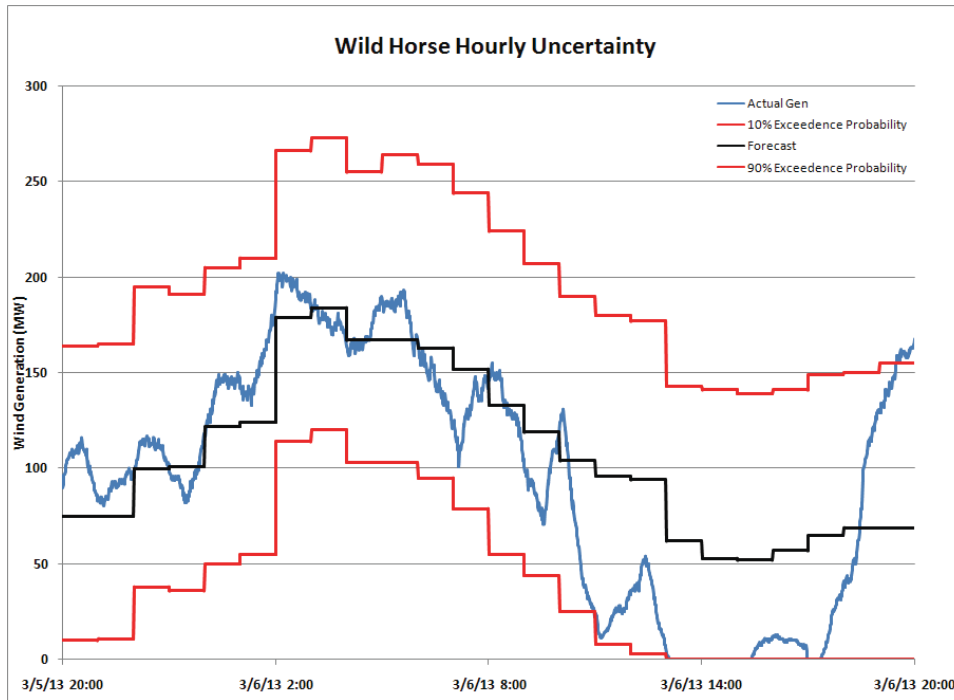
Figure H-2: Hourly Variability in Wind Generation





In reality, perfect foresight of wind generation or load for each upcoming operating hour is not possible. In Figure H-3, future wind generation is presented as an expected forecast for the next several hours, along with two additional forecasts that provide the probability of wind generation exceeding those values. At the 10 percent exceedence forecast, we would expect actual wind generation to be above this value only 10 percent of the time, whereas at the 90 percent exceedence forecast we would expect actual wind generation to be above this value 90 percent of the time. Actual wind generation may come in above or below the forecast, or, as is the case in HE 20 of March 6, 2013, it can exceed the forecasted bounds.

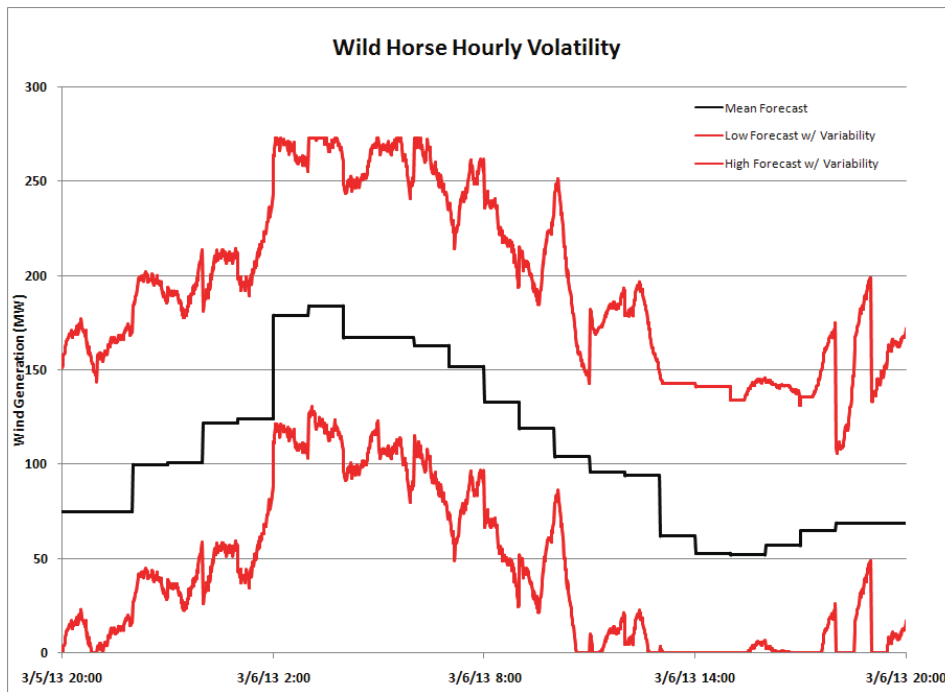
Figure H-3: Hourly Uncertainty in Wind Generation





The variability and uncertainty at Wild Horse are combined in Figure H-4 to illustrate the volatility that may be expected each hour. The actual variability observed around each perfect hour in Figure H-2 is imposed on the upper and lower probability forecasts from Figure H-3. It shows how PSE must balance potentially large blocks of energy related to forecast error (uncertainty) while simultaneously balancing within-hour fluctuations (volatility) in order to maintain system reliability. Addressing volatility from sources other than wind requires similar action on PSE's part.

Figure H-4: Hourly Volatility in Wind Generation





Managing Volatility

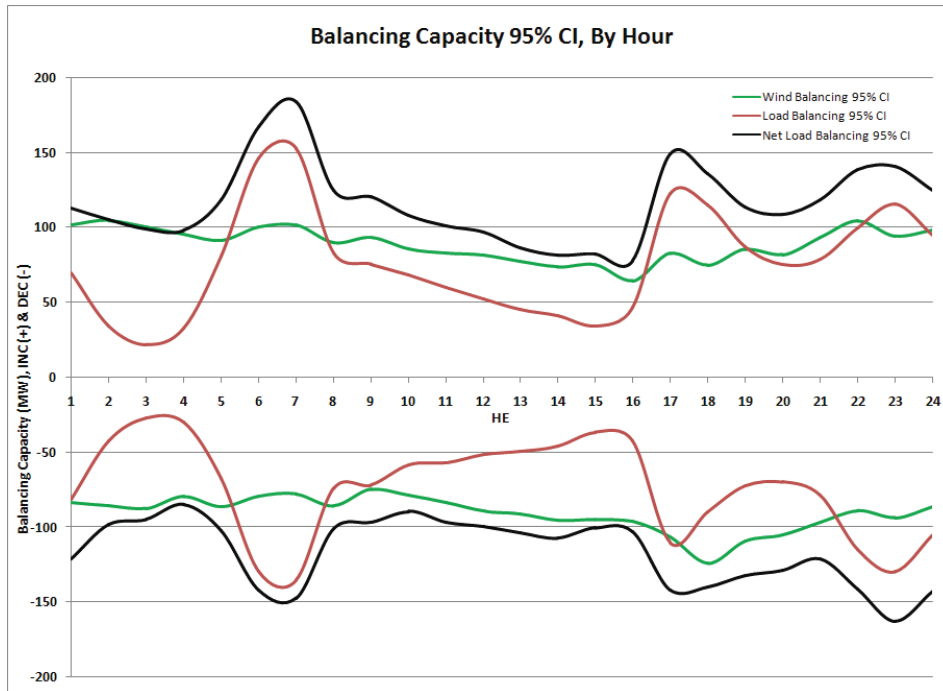
System volatility (variability and uncertainty) is managed with balancing reserves. Balancing reserves are generating capacity available to respond to changes in system conditions by either increasing generation (INC capacity) or decreasing generation (DEC capacity). The amount of balancing reserve capacity at PSE is determined by examining historical balancing capacity needs, and then establishing the amount of reserves necessary to cover 95 percent of the historical deviations in net load. This amount of balancing capacity is referred to as a 95 percent Confidence Interval level (95% CI) of reserves.

An overall 95 percent CI can be calculated that covers all time periods, but developing multiple 95 percent CIs can provide greater insight into balancing capacity needs. PSE develops 24 distinct 95 percent CIs for the entire day's operation. As Figure H-5 shows, the hourly 95 percent CI values can vary a great deal through the day for both load and wind resources. Large amounts of balancing capacity can be needed to manage strong load ramps to meet the 95 percent CI during morning and evening peaks.

For PSE wind resources, the 95 percent CI is more constant throughout the day, with a slight transition to more DEC capacity required in the evening hours and more INC capacity in the morning hours. The fixed range of potential wind generation, from 0 MW to full capacity, suggests the wind forecast can be a criterion for developing additional 95 percent CI. Taking the extremes, at a 0 MW wind forecast the only potential forecast error (forecast generation minus actual generation) PSE would need to balance is a negative error (forecast is less than actual generation), which would require only DEC capacity reserves. Conversely, when wind generation is forecast at full output, PSE would need to manage positive forecast errors only where the forecasted generation is greater than actual generation. In this case, INC capacity reserves are required.



Figure H-5: Hourly PSE Balancing Capacity at a 95 Percent Confidence Interval



It is important to note that contingency reserves are accounted for separate from balancing reserves. Contingency reserves are dedicated to addressing short-term reliability in the event of forced outages; they cannot be deployed to address hourly system volatility unless a qualifying event occurs, such as a unit tripping offline.



3. FLEXIBILITY SUPPLY AND DEMAND

System flexibility is the capability of PSE resources to manage system volatility over varying time periods, rates of change and overall magnitude. Flexibility is supplied by PSE generating resources, primarily PSE's share of the Mid-Columbia hydroelectric generating facilities (Mid-C), but also PSE's fleet of peaking and baseload gas-fired units. Flexibility demand is created by the volatility observed in load, generation and transmission curtailments, and the uncertainty inherent in predicting loads, wind generation and unexpected events. Load and wind volatility are the two primary drivers of the demand for flexibility on the PSE system. Regional consensus on flexibility metrics is still developing, but PSE has begun to try to quantify the flexibility supply it has available to meet demand.

Flexibility Supply

All resources provide some measure of flexibility; however, the ability of a resource to supply flexibility is constrained by unit-specific characteristics including availability, operational or environmental limitations, maximum and minimum operating range, and ramp rate. These characteristics, coupled with economic dispatch generation set points, affect PSE's total supply of system flexibility.

AVAILABILITY depends on whether the resource is online, the speed with which it can be dispatched if offline, and whether it is out of service due to planned maintenance or unplanned outage.

In terms of **OPERATIONAL LIMITATIONS**, the speed with which a resource can transition from offline to generating and synced to the system is a distinguishing feature of the resources needed to supply flexibility. Resources that take several hours to properly prepare for dispatch, like baseload gas units, are limited in their availability to respond to short-term system balancing needs.



RESOURCE RANGE refers to the physical and environmental (temperature) constraints that dictate the maximum and minimum levels at which a resource can generate. For any given resource, the difference between this maximum and minimum at any given time is referred to as its operating range. For conventional thermal resources, this range remains fairly constant, but the range for hydro resources changes dramatically during certain times of the year. A portion of PSE's capacity share of the Mid-C is available to meet PSE flexibility needs for most of the year, but during the spring runoff, high stream flows on the Columbia River reduce the available operating range on the Mid-C. At these times, hydro projects must generate at or near full capacity to avoid flowing excess water over spillways to meet water quality requirements for downstream fish migration. PSE's supply of flexibility is severely reduced at this time of year.

RESOURCE RAMP RATES describe the speed at which a unit can increase or decrease its generation. The ramp rate determines the ability of a resource to respond to all, some or none of the system's deviations. Slow ramp rates effectively limit the balancing capacity of a resource during a given time increment. A resource with a large operating range but very slow ramp rate may be insufficient to address sudden changes in load and wind generation, while a resource with a small operating range and faster ramp rate can quickly respond to system needs but may not be able to sustain such a rate for an extended period, so multiple resources may need to respond simultaneously.

Flexibility Demand

The demand for flexibility is created primarily by system volatility, the need to manage the scheduled interchange ramp period between hours and potential system contingencies.

Volatility

Continuous demands for flexibility are placed on the system by volatility – the variability of loads and generating resources that fluctuate from moment to moment combined with the uncertainty inherent in forecasting load and wind resources hour by hour.

PSE addresses the demand placed by all system loads and resources simultaneously, rather than responding to each deviation individually. The relationship between load and wind is especially important. Because wind generation serves system load, load and wind scheduling errors in the same direction offset each other. The BA does not need to respond to an increase in load if there is an equal increase in wind generation. Load and wind schedule deviations in opposite directions create greater demands on system balancing resources. On a probabilistic basis, the fact that PSE load and wind may often move in the same direction or at the same rate



places a smaller total demand for flexibility on PSE than if each were measured individually and then added together.

Scheduled Interchange

In addition to managing loads and resources throughout each operating hour, PSE's BA must integrate hourly imports and exports. This is known as a scheduled interchange. Little volatility is associated with scheduled interchanges (they are generally a flat, hourly amount of energy), but the magnitude of scheduled interchanges can vary each hour, often by several hundred megawatts. To accommodate these large changes, resources are ramped in over a 20-minute period beginning 10 minutes prior to the start of the operating hour and ending 10 minutes after. Even with planned ramps, integrating such large changes in power can be demanding, both in the range required of resources and the speed with which they must respond.

System Contingencies

Forced outages place significant demands for flexibility on the system because they create an immediate need for large increases in energy to replace the resource lost to the outage. Forced outages occur when a generating unit, transmission line or other facility becomes unavailable for unforeseen mechanical or reliability reasons.

PSE also faces forced outage-type events as other BAs manage their own system volatility. For example, all wind resources within the BPA BA, of which PSE has 500 MW, are subject to dispatcher instructions meant to address BPA's need for system flexibility at times when its system reserve capacity is exhausted. One notable BPA business practice is Dispatch Standing Order 216 (DSO-216). DSO-216 states that if wind plants are under-generating and BPA is supplying INC balancing reserves, BPA will have the ability to curtail transmission schedules for each plant, relative to the plant's actual generation. A schedule cut within the hour is like a forced outage in that the PSE BA must respond instantaneously to a potentially large loss of energy. In addition to wind schedule cuts, PSE's thermal resources located outside the company's BA can also be cut due to regional transmission congestion and maintenance requirements. Transmission congestion can mean within-hour schedule cuts of several hundred megawatts.



Procuring and Deploying Balancing Reserve Capacity

The balancing reserves required to manage system operations within every operating hour can be thought of in two stages, each of which are simulated in this analysis:

- In the day-ahead schedule (DA stage) PSE procures balancing reserve capacity ahead of the operating hour; and
- In real-time operations (RT stage), PSE deploys reserves and moves its generators to balance energy within the hour.

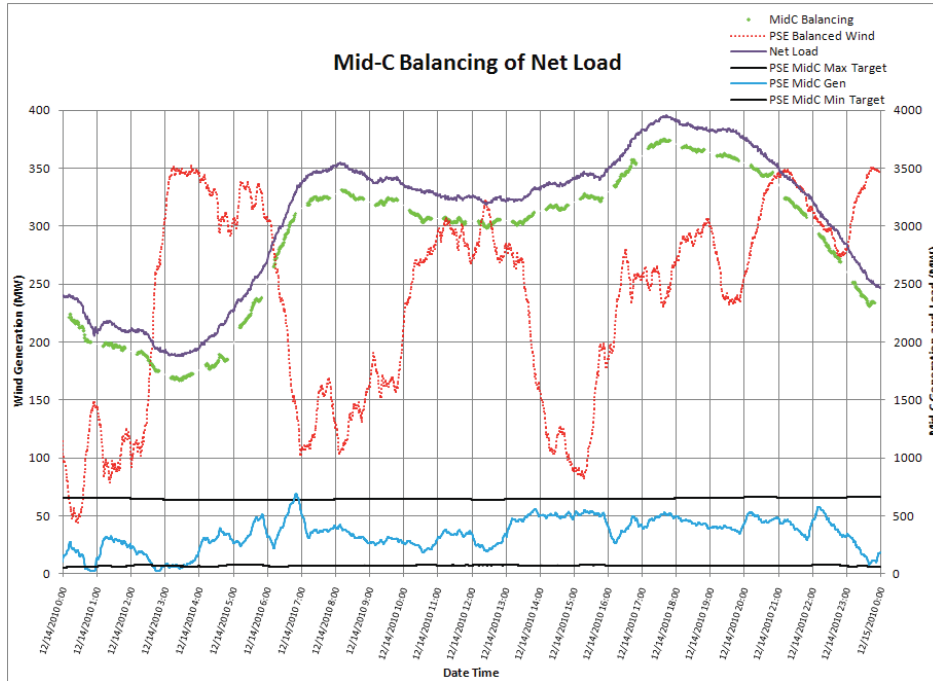
Procuring balancing capacity in the day-ahead stage ideally consists of positioning hydro assets to allow sufficient room to increase generation (INC capacity) or decrease generation (DEC capacity) as needed within the operating hour. Thermal resources (gas and coal) can also be dispatched to provide balancing capacity. It should be noted that procurement of the needed balancing reserve capacity does not always guarantee that sufficient flexibility is available to meet actual net load deviations on the system in real time. Meeting the demand for flexibility also requires unit ramp rates that can effectively deploy the capacity procured.

Figure H-6 depicts all aspects considered for balancing capacity and addressing system flexibility. In this 24-hour example, PSE's Mid-C generation is the source of balancing capacity. The moment-to-moment changes in net load (load minus wind generation) are represented by the purple trace. The blue line representing Mid-C generation is bounded by black minimum and maximum generation targets.

The green trace labeled "Mid-C Balancing" represents the slope (or rate of change) in Mid-C generation for each hour. It is presented just below the net load trace in order to highlight how the Mid-C generation is changing within the hour relative to the change in net load. This trace shows that during each hour, the Mid-C is responding in unison with changes in net load. The flexibility of the Mid-C is most evident during the 6:00 to 7:00 a.m. period as it manages an extreme load ramp of nearly 500 MW (over 8 MW per minute through the entire hour).



Figure H-6: Balancing of Net Load with Mid-C Generation



Note how the Mid-C reacts during the 20-minute schedule interchange period, from 5:50 to 6:10 am and from 6:50 to 7:10 am. During these periods Mid-C generation is being pushed down to accommodate new imports and to provide incremental balancing services for the next hour. In these instances, Mid-C frequently changes generation levels by 500 MWs over a 20-minute period (25 MW per minute ramp rate). No other resource in PSE’s fleet is capable of this combination of speed and range. This is why Mid-C hydro is such an important flexibility resource in PSE’s portfolio.



4. MODELING METHODOLOGY

This analysis focuses on whether PSE's portfolio has enough flexibility supply to meet its current system balancing needs on a 5-minute basis and how the cost of this balancing changes when different resources are added.

The flexibility analysis has two goals:

- 1. Identify Physical Needs, addressing these questions:**
 - Will PSE have adequate ramp up/down capability?
 - If not, PSE may need to add an additional dimension to its planning standard or operational guidelines to ensure PSE can meet its operational needs.

- 2. Reflect Sub-hourly Flexibility Analysis in Portfolio Analysis (Financial Impacts):**
 - Different resources have different sub-hourly operational capabilities.
 - Even if the portfolio has adequate flexibility, different resources can impact how the entire portfolio operates and also impact costs.
 - For example: Batteries could avoid dispatch of thermal plants for some ramping up and down.
 - A way to monetize those values is needed in order to incorporate these costs in the portfolio analysis, to ensure lowest reasonable cost decisions.



Model Framework and Input Methodology

PLEXOS is an hourly and sub-hourly chronological production simulation model that utilizes mixed-integer programming (MIP) to simulate unit commitment of resources at a day-ahead level, and then simulate the re-dispatch of these resources in real-time to match changes in supply and demand on a 5-minute basis. In more detail:

1. In the day-ahead schedule (DA stage)

- Utilities schedule resources on an hourly basis in the day-ahead market.
- On the next day, load and resources in every hour will probably deviate from the schedule.
- The portfolio must have the flexibility to adjust to those differences.
- Costs will be different than those predicted by the day-ahead schedule.

2. In real-time operations (RT stage)

- Within each hour, resources will ramp up and/or down.
- The day-ahead view alone will miss those cost impacts.

The Current Portfolio Case

For the sub-hourly cost analysis using PLEXOS, PSE, with support from its consultant E3, first created a Current Portfolio Case based on PSE's existing resources for the time period of this IRP analysis.

The Current Portfolio Case begins by creating a simulation that reflects a complete picture of PSE as a BA and PSE's connection to the market. This includes representation of PSE's BAA load and generation on a 5-minute basis, as well as contracts with neighboring BAs, and opportunities to make purchases and sales at the Mid-C trading hub in hourly increments.

Appendix H: Operational Flexibility



This simulation reflected all three types of reserve requirements:

- Contingency reserves, required to be equal to 3 percent of PSE load, and 3 percent of PSE generation. These include spinning reserves, which can be deployed within 10 minutes, and non-spinning reserves, which are available for up to a 60-minute period;
- Regulating up and down reserves, which must be able to adjust to movements in load and wind in a period of less than 5 minutes and down to sub-minute level; and
- Balancing up and down reserves (also termed flexibility reserves, or load following) which are used to address differences at the 5-minute level compared to the hour-ahead forecast.

For this analysis, PSE used actual 5-minute demand data from 2016 for load, scaled to the demand forecast for 2022. The analysis also uses 2016 actual 5-minute data for wind and run-of-river hydro in PSE's BA, and 2016 daily total Mid-C energy generation. PLEXOS then optimized the Mid-C generation within the day, allocating the daily total to different hours and 5-minute intervals.

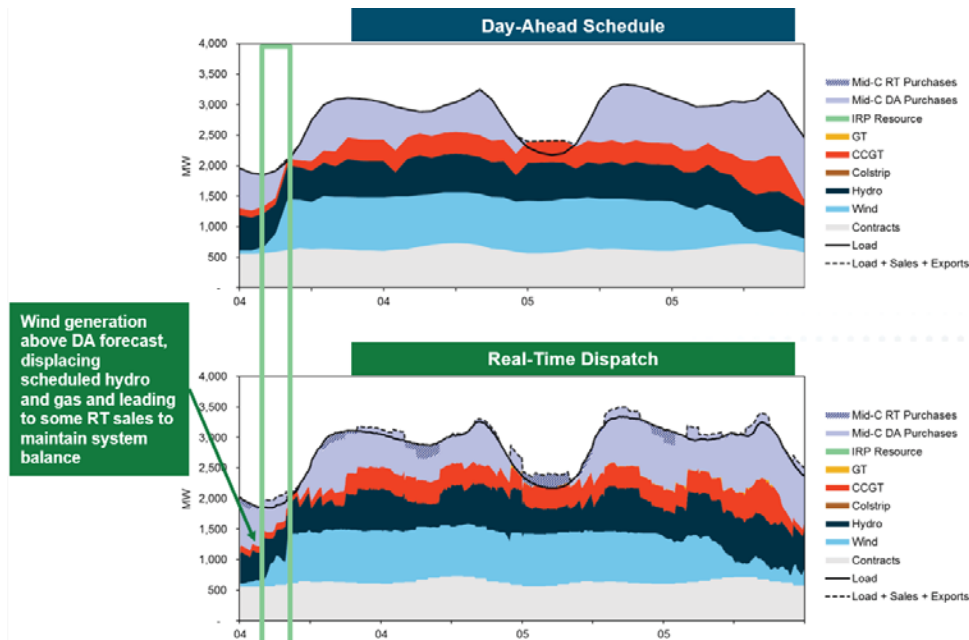
The analysis also used information consistent with PSE's 2017 IRP Base Scenario, including the base natural gas and CO₂ prices for generation and forecast Mid-C power prices from AuroraXMP for PSE hourly energy purchases and sales, which PLEXOS utilized when economic.

Figure H-7, below, illustrates the dispatch of PSE's system in the day-ahead and real-time stages over a two-day period, April 4 through April 5, 2022.

The highlighted area notes a time period of particularly high "downward deviation" of net load in the real-time stage compared to the day-ahead stage, because wind resources (in bright blue) were higher than expected in the first part of the hour. As a result, PSE's flexible resources respond in the real-time stage by reducing dispatch on hydro generation (dark blue), reducing gas dispatch (red area) and making real-time energy sales at Mid-C on an hourly basis. The shifts in generation required to accommodate these sub-hourly variations in real time may carry a cost resulting from the reduced efficiency of generation that is required to quickly adjust to balance the system.



Figure H-7: PSE System Dispatch, Day-ahead and Real-time



New Resource Cases

PSE tested the impact of a range of potential new resources, each of which is individually added to the current portfolio. If the dispatch cost of the portfolio with the new addition is lower than the Current Portfolio Case cost, the cost reduction is identified as a benefit of adding the new resource.



Modeling Assumptions and Limitations

Some key assumptions made in these modeling efforts should be noted.

- EIM participation by PSE was not included in this study, but may be included in future flexibility analyses.
- Contingency analysis of generators going offline in real-time (but not anticipated at the day-ahead stage) was not directly represented.
- Wind resources are modeled at the day-ahead level on an hourly basis using the 30-minute persistence forecast. This forecast uses, for each hour, the value of the wind output that occurs in the 5-minute interval 30 minutes prior to the operating hour.
- PSE load was modeled at the day-ahead level with perfect foresight of average conditions in the real-time stage.
- Balancing or “flexibility” reserves that were required to be held in the day-ahead stage are calculated on a month-hour basis based on the anticipated deviation of net load (PSE BAA load net of wind balanced by PSE) at the real-time 5-minute interval level compared to the day-ahead hourly value. These reserves, which average approximately 90 MW but can range up to 150 MW in some month-hour windows, are held as upward and downward room on thermal and hydro generators at the day-ahead stage, and “released” in the real-time stage. This means that the model can use the withheld generation capacity to increase or reduce energy output to respond to real-time changes in net load.



5. RESULTS

For this analysis, the real-time sub-hourly simulation shows a limited number of flexibility violations in upward and downward directions. The small size and frequency of flexibility issues reflect a relatively high amount of overall flexibility modeled for the PSE system from hydro and gas generation and hourly market transactions.

Most cases with potential generation resource additions show a small reduction in real-time flexibility issues and cost compared to already low level of flexibility issues in the Current Portfolio Case. IRP resource additions also provide small reductions in real-time dispatch costs compared to the Current Portfolio Case, with batteries providing highest value per kW.

Figure H-8 summarizes key details of the 13 new resources that were considered in the analysis, in addition to the Current Portfolio Case.

Figure H-8: Overview of Resource Additions Analyzed

| Description | Capacity (MW) | Heat Rate (Btu/kWh) | Energy Storage (MWh) | Roundtrip Efficiency (%) |
|------------------------------|---------------|---------------------|----------------------|--------------------------|
| 1x1 GE 7F.05 | 359 | 6,650 | - | - |
| 1x1 GE 7F.05 (Duct Firing) | 413 | 8,500 | - | - |
| 1x1 GE 7HA.01 | 405 | 6,515 | - | - |
| 1x1 GE 7HA.01 (Duct Firing) | 466 | 8,500 | - | - |
| 3x0 Wartsila 18V50SG | 55 | 8,425 | - | - |
| 6x0 Wartsila 18V50SG | 111 | 8,425 | - | - |
| 12x0 Wartsila 18V50SG | 222 | 8,425 | - | - |
| 1x0 GE LMS100PA | 114 | 8,986 | - | - |
| 2x0 GE LMS100PA | 228 | 8,986 | - | - |
| 1x0 GE 7F.05 | 239 | 9,823 | - | - |
| Li-Ion Battery 2-hr | 25 | - | 50 | 85% |
| Li-Ion Battery 4-hr | 25 | - | 100 | 85% |
| Flow Battery 4-hr | 25 | - | 100 | 75% |
| Flow Battery 6-hr | 25 | - | 150 | 75% |
| Pumped Storage Hydro | 25 | - | 250 | 81% |



Current Portfolio Case Results

Flexibility issues (defined as “violations” in the model) represent hours when the model faces constraints in moving resources upward or downward to follow load and wind. The model can include two categories of flexibility challenges.

- **Upward flexibility issues** occur in certain real-time 5-minute intervals, including times of implied unserved energy, shortage of ramping response or reserves, or positive area control error (ACE) compared to scheduled interchange with neighboring systems.
- **Downward flexibility issues** occur in real-time 5-minute intervals in which the model identifies excess energy (which indicates the potential need to curtail wind or hydro output), shortage of downward reserves, challenging downward ramping constraints, or negative ACE with neighboring BAs.

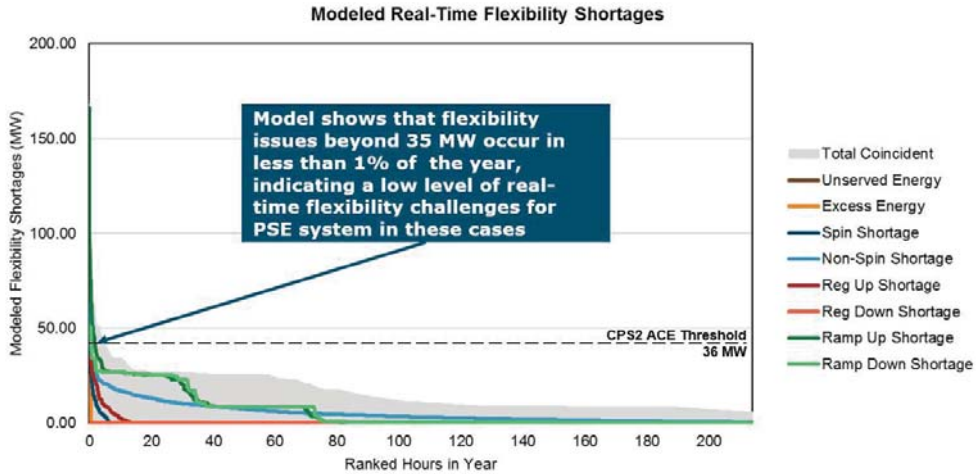
The day-ahead analysis did not result in any flexibility issues, indicating that PSE’s current portfolio has sufficient flexibility to balance on an hourly basis when conditions are well-known for the day, even while holding flexibility reserves.

In the real-time analysis, flexibility issues occurred but were relatively small. Some issues of very small magnitude may also be model-related noise rather than implying challenges that would actually appear in practice. The relatively small flexibility issues identified through PLEXOS modeling suggest there may be times when PSE could have ACE deviation from schedule or constrained reserves, but the small size of these deviations does not point to a need for procuring new resources.

Figure H-9 summarizes the size and frequency of flexibility issues identified when simulating the real-time stage for the Current Portfolio Case. The PLEXOS model shows flexibility issues occurring that are larger than 36 MW (the CPS2 L10 ACE threshold for PSE) in fewer than one percent of real-time 5-minute intervals in the year – with coincident issues occurring in fewer than 10 total hours per year.



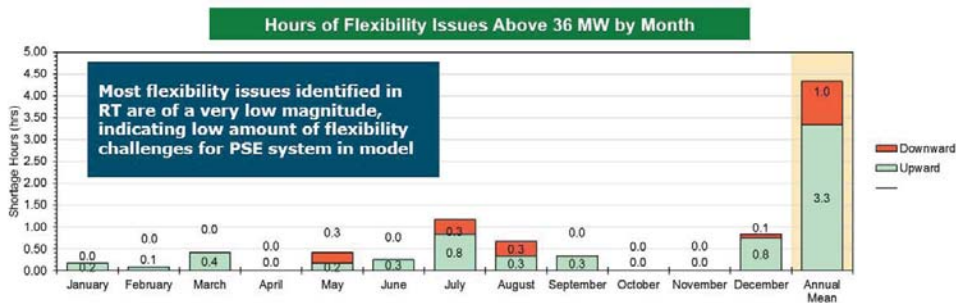
Figure H-9: Real-time Flexibility Shortages Modeled



Most of the flexibility issues shown above are still of a small magnitude (in MW) compared to PSE's 2,866 MW average load.

Figure H-10 summarizes the number of hours each month (in 5-minute intervals) in which upward or downward flexibility issues exceed 36 MW.

Figure H-10: Monthly Hours of Flexibility Issues above 36 MW



The flexibility issues occur in both the upward (green) and downward (red) direction across the year, most significantly in July, August and December – however, the frequency of these issues totals less than 5 hours. This represents less than 0.02 percent of PSE's total annual load.



New Resources Comparative Results

The figures below compare the frequency and total annual volume of flexibility issues that occur in real-time in the Current Portfolio Case, as well as in the separate simulations that include additional new resources. Figure H-11 shows that the number of hours of flexibility issues above the 36 MW threshold is lower in many of the cases with additional resources added compared to the Current Portfolio Case, though the relative size of the issues in each case is very close. Overall, the low level of flexibility issues in the Current Portfolio Case leaves little room for definite improvement in flexibility performance when adding new resources; as a result, all cases have similar performance. The small increase in some cases (including the 2x0 GE LMS 100PA case) is likely driven by changes in how generation across PSE’s portfolio is committed in the day-ahead stage. Because the day-ahead stage does not anticipate directly what will occur in the real-time stage, adding certain resources may cause price improvements in the day-ahead stage, but happen to set up a commitment that encounters marginally more issues in real-time.

Figure H-11: Annual Flexibility Shortage Hours, 36 MW Threshold

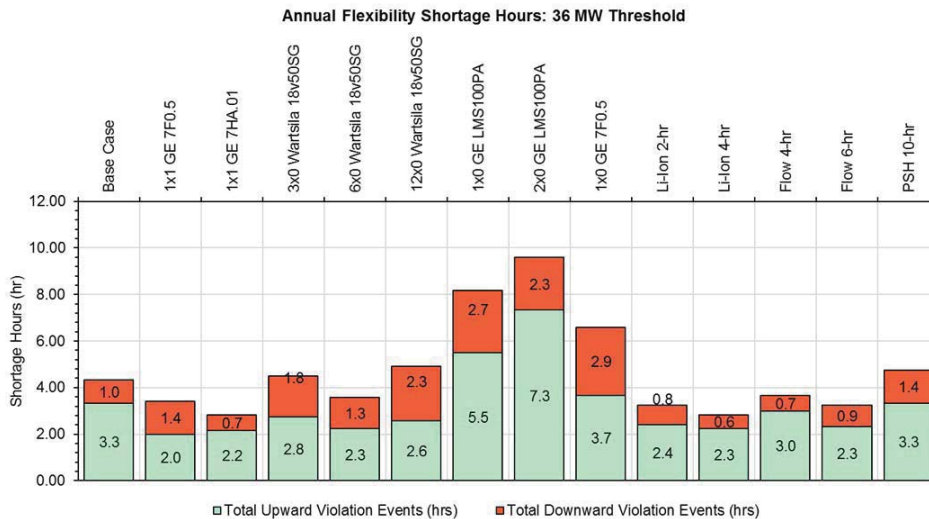
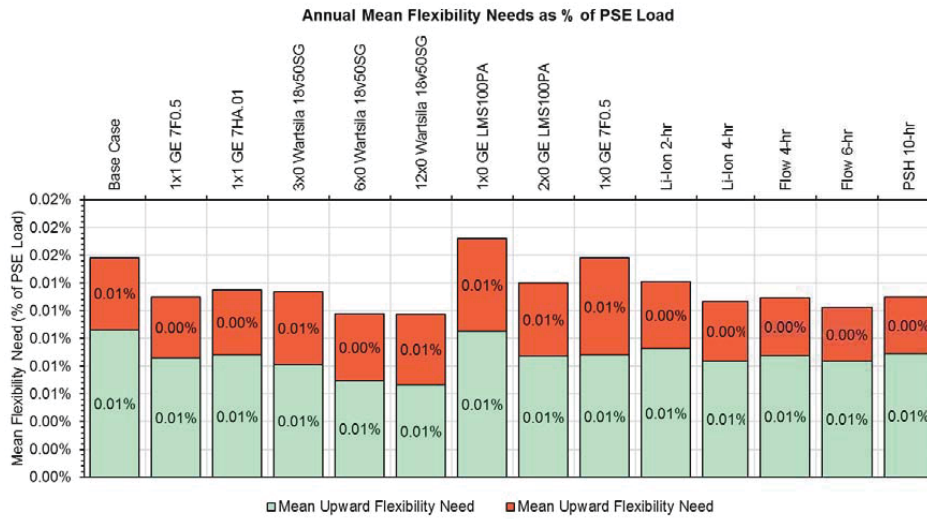


Figure H-12 presents the changes in impact on flexibility issues as a percentage of total PSE load across different portfolio resources. The Current Portfolio Case encounters upward or downward issues equivalent to less than 0.02 percent of total PSE system load. In most cases, new resources reduce the total annual volume of flexibility issues relative to the Current Portfolio Case, but the overall size of these differences is small due to the low starting level of flexibility issues in the Current Portfolio Case.

Appendix H: Operational Flexibility



Figure H12: Annual Mean Flexibility Needs as Percentage of PSE Load



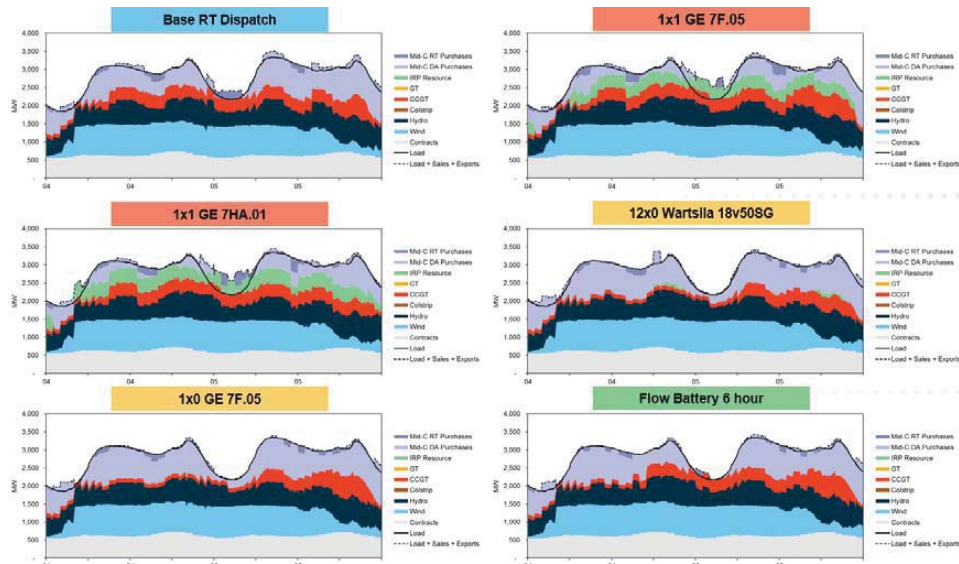


Sub-hourly Dispatch Cost Impact

Even in cases where adding new resources does not substantially change the total frequency of flexibility issues, new generators can improve the total variable cost of dispatching the portfolio to address flexibility movements at a sub-hourly level.

Figure H-13 illustrates how selected new resource additions (represented in green) move to address the real-time flexibility needs identified previously in the April 4, 2022 example.

Figure H-13: Real-time Impact of New Resources on Flexibility



The cost impact of these new resources can be represented by comparing the total portfolio cost (variable generation cost plus net purchases) across the different simulations.

Appendix H: Operational Flexibility



Figure H-14 presents the total annual cost by generation category for PSE's system (including energy purchases and sales at Mid-C) under the Current Portfolio Case (first column) and the different simulations that model resource additions.

Figure H-14: Total Annual Cost by Generation Category

| | | Real-Time System Cost for Each IRP Resource Addition Scenario(\$MM) | | | | | | | | | | | | | |
|--------------|-----------------|---|-------------|--------------|---------------------|---------------------|----------------------|----------------|----------------|-------------|------------|------------|------------|------------|------------|
| | | Base Portfolio | 1x1GE 7F0.5 | 1x1GE 7HA.01 | 3x0Wartsila 18v50SG | 6x0Wartsila 18v50SG | 12x0Wartsila 18v50SG | 1x0GE LMS100PA | 2x0GE LMS100PA | 1x0GE 7F0.5 | L-Hen 2-hr | L-Hen 4-hr | Flow 4-hr | Flow 6-hr | PSH 10-hr |
| Generation | Wind | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| | Hydro | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| | CCGT & Colstrip | 185 | 169 | 167 | 187 | 185 | 180 | 187 | 187 | 188 | 185 | 185 | 185 | 186 | 185 |
| | GT | 24 | 20 | 19 | 28 | 27 | 26 | 29 | 29 | 29 | 26 | 26 | 26 | 26 | 26 |
| | IRP Resource | - | 73 | 84 | 2 | 6 | 17 | 1 | 7 | 7 | - | - | - | - | - |
| | <i>Subtotal</i> | 222 | 275 | 282 | 229 | 231 | 236 | 230 | 236 | 237 | 224 | 224 | 224 | 225 | 224 |
| Mid-C | Purchases | 248 | 192 | 183 | 239 | 237 | 233 | 238 | 234 | 233 | 245 | 245 | 245 | 244 | 245 |
| | Sales | (22) | (36) | (38) | (26) | (28) | (31) | (27) | (30) | (29) | (24) | (24) | (24) | (24) | (25) |
| | <i>Subtotal</i> | 226 | 156 | 145 | 213 | 209 | 202 | 211 | 204 | 204 | 221 | 221 | 221 | 220 | 220 |
| Contracts | Aggregated | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 |
| | DSM | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | <i>Subtotal</i> | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 | 208 |
| Total | | 656 | 639 | 635 | 650 | 648 | 646 | 649 | 647 | 649 | 653 | 652 | 653 | 652 | 652 |

For example, the Current Portfolio Case shows a total dispatch cost of \$656 million (this includes generation fuel and CO₂ cost, variable operations and maintenance, and startup cost). In the second column, the addition of a baseload gas resource (1x1 CCCT) results in annual operating costs of \$73 million on the new plant, but this also displaces the dispatch (and cost) of other PSE resources. Adding the unit also reduces the volume and cost of PSE's annual energy purchases at Mid-C and increases PSE's sales.

In total, the new baseload gas generator results in a PSE variable dispatch cost of \$639 million, a reduction of \$17 million compared to the \$ 656 million cost with the Current Portfolio Case. These cost changes are characterized in subsequent columns for each of the new resources considered. It is important to note that the size of new resources covers a very wide range, from 25 MW batteries up to baseload gas plants of over 400 MW. Therefore, the total impact in \$/kW-yr may provide a more useful direct comparison across resources. Figure H-15 identifies the resulting cost changes in each scenario compared to the Current Portfolio Case, and also provides the estimated impact in \$/kW-yr.

Appendix H: Operational Flexibility



It is also important to note that, consistent with the current Clean Air Rule for the State of Washington, larger resources (including the baseload gas units in this study) incur a CO₂ adder on fuel costs; peaking resources in this study were assumed to be smaller than the threshold for the carbon rule, which may increase their relative dispatch in these cases.

Figure H-15: Cost Impact of Added Resources Compared to the Current Portfolio Case

| | | Total Real-Time System Cost Delta from Base Portfolio for Each IRP Resource Addition Scenario (\$MM) | | | | | | | | | | | | | |
|-----------------------------------|-----------------|--|--------------|---------------|----------------------|----------------------|-----------------------|-----------------|-----------------|--------------|--------------|--------------|--------------|--------------|-----------|
| | | Base Portfolio | 1x1 GE 7F0.5 | 1x1 GE 7HA.01 | 3x0 Wartsila 18v50SG | 6x0 Wartsila 18v50SG | 12x0 Wartsila 18v50SG | 1x0 GE LMS100PA | 2x0 GE LMS100PA | 1x0 GE 7F0.5 | L-Ion 2-hr | L-Ion 4-hr | Flow 4-hr | Flow 6-hr | PSH 10-hr |
| Generation | Wind | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Hydro | 12 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | CCGT & Colstrip | 185 | 169 | 167 | 187 | 185 | 180 | 187 | 187 | 188 | 185 | 185 | 185 | 186 | 185 |
| | GT | 24 | (4) | (5) | 4 | 4 | 3 | 6 | 5 | 6 | 2 | 2 | 3 | 2 | 2 |
| | IRP Resource | - | 73 | 84 | 2 | 6 | 17 | 1 | 7 | 7 | - | - | - | - | - |
| | <i>Subtotal</i> | 222 | 53 | 60 | 7 | 10 | 14 | 8 | 14 | 15 | 2 | 2 | 2 | 3 | 2 |
| Mid-C | Purchases | 248 | (56) | (64) | (8) | (10) | (15) | (9) | (13) | (14) | (3) | (3) | (3) | (4) | (3) |
| | Sales | (22) | (14) | (16) | (4) | (6) | (9) | (5) | (9) | (7) | (2) | (2) | (2) | (2) | (3) |
| | <i>Subtotal</i> | 226 | (69) | (81) | (13) | (17) | (24) | (15) | (22) | (22) | (5) | (5) | (5) | (6) | (5) |
| Contracts | Aggregated | 208 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | DSM | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | <i>Subtotal</i> | 208 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | 656 | (17) | (20) | (5) | (7) | (10) | (6) | (8) | (6) | (3) | (3) | (3) | (3) | (4) | |
| Levelized Delta (\$/kW-yr) | | (46) | (50) | (97) | (65) | (44) | (56) | (35) | (26) | (119) | (131) | (117) | (128) | (144) | |

Adding new resources reduces the total portfolio cost of generation to a varying extent; however, much of the cost reduction occurs at the day-ahead (hourly) simulation stage. These changes in generation cost typically overlap with the impact of the resource additions that PSE models in Aurora. The exception is storage resources, which PSE did not incorporate directly into the Aurora model due to limited parametrization; thus there is not an overlap of these portfolio costs impacts and Aurora results for the five storage resources listed.

For the resource additions, the cost impact related specifically to sub-hourly flexibility, can be isolated from the overall hourly impact of the new resources by comparing the change in portfolio cost of the real-time stage versus the day-ahead stage. These results are presented in Figure H-16.

Appendix H: Operational Flexibility



Figure H16: Cost Difference between Real-time Redispatch and Day-ahead Schedule for Each Resource Addition

| | | Real-Time Redispatch Cost from Day-Ahead Schedule for Each IRP Resource Addition Scenario (\$MM) | | | | | | | | | | | | | |
|-----------------------------------|-----------------|--|--------------|---------------|----------------------|----------------------|-----------------------|-----------------|-----------------|--------------|------------|------------|------------|------------|-------------|
| | | Base Portfolio | 1x1 GE 7F0.5 | 1x1 GE 7HA.01 | 3x0 Wartsila 18/50SG | 6x0 Wartsila 18/50SG | 12x0 Wartsila 18/50SG | 1x0 GE LMS10MPA | 2x0 GE LMS10MPA | 1x0 GE 7F0.5 | L1on 2-hr | L1on 4-hr | Flow 4-hr | Flow 6-hr | PSH 10-hr |
| Generation | Wind | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| | Hydro | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) |
| | CCGT & Colstrip | (5) | (5) | (5) | (5) | (4) | (4) | (4) | (4) | (5) | (6) | (5) | (6) | (5) | (5) |
| | GT | 5 | 4 | 4 | 7 | 6 | 6 | 6 | 6 | 8 | 6 | 6 | 6 | 6 | 6 |
| | IRP Resource | - | (1) | (2) | (0) | (1) | (0) | 0 | 0 | (2) | - | - | - | - | - |
| | <i>Subtotal</i> | <i>(0)</i> | <i>(2)</i> | <i>(3)</i> | <i>1</i> | <i>2</i> | <i>2</i> | <i>2</i> | <i>3</i> | <i>1</i> | <i>1</i> | <i>1</i> | <i>0</i> | <i>1</i> | |
| Mid-C | Purchases | 14 | 15 | 16 | 13 | 13 | 12 | 12 | 12 | 13 | 14 | 14 | 14 | 14 | 14 |
| | Sales | (14) | (13) | (13) | (15) | (16) | (15) | (15) | (15) | (14) | (15) | (14) | (15) | (14) | (15) |
| | <i>Subtotal</i> | <i>1</i> | <i>2</i> | <i>3</i> | <i>(2)</i> | <i>(3)</i> | <i>(3)</i> | <i>(3)</i> | <i>(4)</i> | <i>(1)</i> | <i>(1)</i> | <i>(1)</i> | <i>(1)</i> | <i>(1)</i> | |
| Contracts | Aggregated | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | (0) | 0 | (0) | (0) |
| | DSM | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| | <i>Subtotal</i> | <i>(0)</i> | <i>(0)</i> | <i>(0)</i> | <i>(0)</i> | <i>(0)</i> | <i>(0)</i> | <i>(0)</i> | <i>(0)</i> | <i>(0)</i> | <i>(0)</i> | <i>(0)</i> | <i>0</i> | <i>(0)</i> | <i>(0)</i> |
| Total | 0 | 0 | (0) | (1) | (1) | (1) | (1) | (1) | (0) | (0) | (0) | (0) | (0) | (0) | |
| Levelized Delta (\$/kW-yr) | | | 0 | (0) | (11) | (8) | (4) | (7) | (4) | (1) | (3) | (8) | (2) | (7) | (10) |

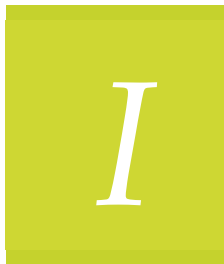
Overall, the impact of sub-hourly flexibility on portfolio costs with additional new resources produces smaller differences between cases – with the overall cost impact ranging from \$200,000 to \$900,000 per year. These flexibility differences are largest on a \$/kW-yr basis for smaller resources, representing, for instance, up to 10 percent of the total value identified for the 3x0 Wartsila internal combustion engine (\$11/kW-yr for sub-hourly flexibility, compared to \$97/kW-yr total value for addition to the PSE system). These costs can be considered incremental or additive to the hourly cost impact that PSE identified with its Aurora simulation. In addition, since the hourly cost impact of storage resources was not modeled in Aurora, the full storage cost impact from PLEXOS can instead be used.



6. CONCLUSION AND NEXT STEPS

The analysis indicates that PSE's current portfolio appears to have sufficient flexibility to balance the movements of load and wind in its BA on a 5-minute basis. The addition of new resources typically provides a small reduction in the frequency and magnitude of flexibility issues identified in the real-time stage at a 5-minute level. In addition, the additional resources typically provide modest incremental reductions in the variable cost of dispatching PSE's portfolio over the year on a 5-minute basis.

This two-stage PLEXOS simulation approach for modeling sub-hourly flexibility on the PSE system can be used to address a wide range of scenarios. Future analysis by PSE could evaluate the impact of PSE balancing a larger amount of wind resources internally to its BA, which could increase the demand for flexibility. This framework can also be used to examine the sub-hourly flexibility of fast-response demand response measures. In addition, PSE could model participation in the EIM market by including an opportunity to purchase and sell energy on a 5-minute basis in the real-time stage at an external market price.



2017 PSE Integrated Resource Plan

Regional Transmission Resources

This appendix reviews current regional transmission issues and efforts to address those issues.

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1. OVERVIEW

As the region's resources have grown in conjunction with increasing loads and renewable energy standards, the Pacific Northwest transmission system has not kept pace with expanding demands. As a result, the region experiences transmission constraints during various times of the year, sometimes resulting in curtailments of firm contractual transmission rights.

Existing flowgates and paths managed by the Bonneville Power Administration (BPA), which handles the majority of the region's high-voltage transmission, continue to experience congestion resulting in curtailment. The organization announced that it would perform a Transmission Service Request Study Process (TSEP) in 2017 to identify transmission projects required to grant new transmission service requests as part of its ongoing efforts to address these constraints.

ColumbiaGrid remains critical to the regional understanding of where future transmission reinforcements should occur and which projects or facilities will be most effective. This non-profit organization and its members have completed several studies and developed transmission reinforcement plans to help alleviate regional congestion. Members include PSE, Avista, BPA, Chelan County PUD, Grant County PUD, Seattle City Light, Snohomish County PUD and Tacoma Power.

Increasing levels of variable renewable energy in the region have also put pressure on Balancing Authorities to incorporate mechanisms that allow for scheduling shorter time intervals than traditional markets offer. PSE joined the Energy Imbalance Market (EIM) in October 2016. The EIM optimizes generator dispatch within and between EIM entities every 15 and 5 minutes. PSE expects positive performance and benefits from EIM; however, BPA has expressed concern that PSE's participation is impacting regional transmission usage.

Appendix I: Regional Transmission



Within the context of a regional transmission system with growing constraints, PSE has identified an opportunity to optimize the use of its transmission contracts with BPA. Originally, PSE acquired firm transmission for the entire output of Hopkins Ridge and the Lower Snake River wind farms consistent with our operating practice of holding firm transmission rights for our generating assets. However, as we have learned more about the operation of wind facilities and their contribution to capacity, we have determined that holding less firm transmission is in the best interests of our customers. Since wind is an intermittent resource, the facilities do not always operate at maximum output. By reassigning a portion of the firm delivery rights associated with each of these plants to Mid-C and making short-term firm transmission purchases when the wind facilities generate energy in excess of the firm transmission that remains dedicated to them, PSE can increase the amount of firm capacity it can use to access the Mid-C market. This opportunity uses transmission rights PSE already has on BPA's system in a way that will lower costs for PSE customers while retaining the ability to bring the wind energy to load.

These items will be discussed in more detail in the sections that follow.



2. THE PACIFIC NORTHWEST TRANSMISSION SYSTEM

Regional Constraints

BPA provides roughly 75 percent of the high-voltage transmission in the Pacific Northwest region. Historically, PSE and other regional utilities have relied on BPA's transmission system to deliver energy to serve retail customers. However, as the region's resource portfolios have grown in conjunction with increasing loads and renewable energy standards, the Pacific Northwest transmission system has not kept pace with the expanding demands. As a result, the region experiences transmission constraints during various times of the year, sometimes resulting in curtailments of firm contractual transmission rights.

The situation poses an operational challenge for PSE in particular, since PSE moves significant amounts of energy and capacity into the Puget Sound area from resources in eastern Washington (east of the Cascades) and from resources along the I-5 corridor.

Figure I-1 illustrates how power travels from remote resources, generally located south of Seattle and east of the Cascades, to PSE's service area. The thick, black bars represent BPA flowgates or paths, which often consist of several transmission lines or sets of parallel lines. The typical flow of winter peak power is indicated by the arrow symbol.

What is a constrained path?

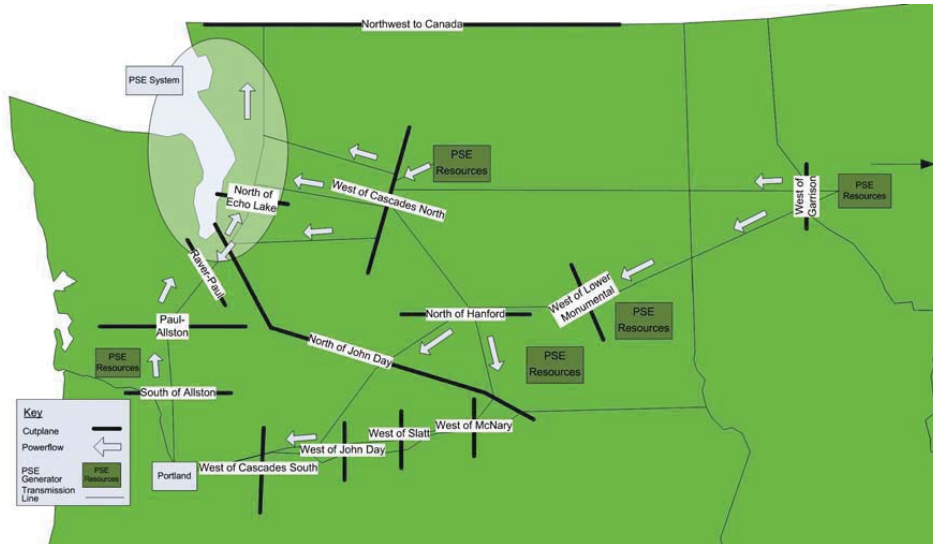
Constrained paths and flowgates are sets of transmission lines that are nearly "full." They have little capacity available to sell, which makes them vulnerable to congestion and curtailment.

What is curtailment?

Curtailments occur when scheduled transmission service must be reduced or canceled due to actual or simulated violation of constraints.



Figure I-1: BPA Transmission System Constraints on PSE Remote Resource Delivery



A summary of the most significant flowgates and paths shown in Figure I-1 are discussed below.

- The majority of energy from PSE’s eastern Washington resources flows across the constrained West of Cascades North flowgate and into the Puget Sound area. This flowgate is most constrained during heavy winter loading periods.
- A portion of the energy flowing from eastern Washington resources also flows over the West of Cascades South flowgate, and as it travels to loads in the Puget Sound area, it flows over the North of John Day and Raver – Paul flowgates. The West of Cascades South flowgate is most constrained during heavy winter loading periods, while the North of John Day and Raver – Paul flowgates are typically most constrained during heavy summer loading periods.
- Energy from PSE resources in Montana flow over the West of Garrison path.
- Congestion issues in the Puget Sound area are monitored by the North of Echo Lake flowgate. Generation support from PSE resources located in Skagit and Whatcom Counties is particularly important in reducing curtailment risk on this flowgate.
- Energy from PSE’s Lower Snake River Wind Project flows across the West of Lower Monumental flowgate.

Some paths are designed to operate close to their limits (like West of Garrison), others are not; this latter group presents areas of the system where PSE sees a particular importance in continuing to study, develop and possibly construct new transmission.



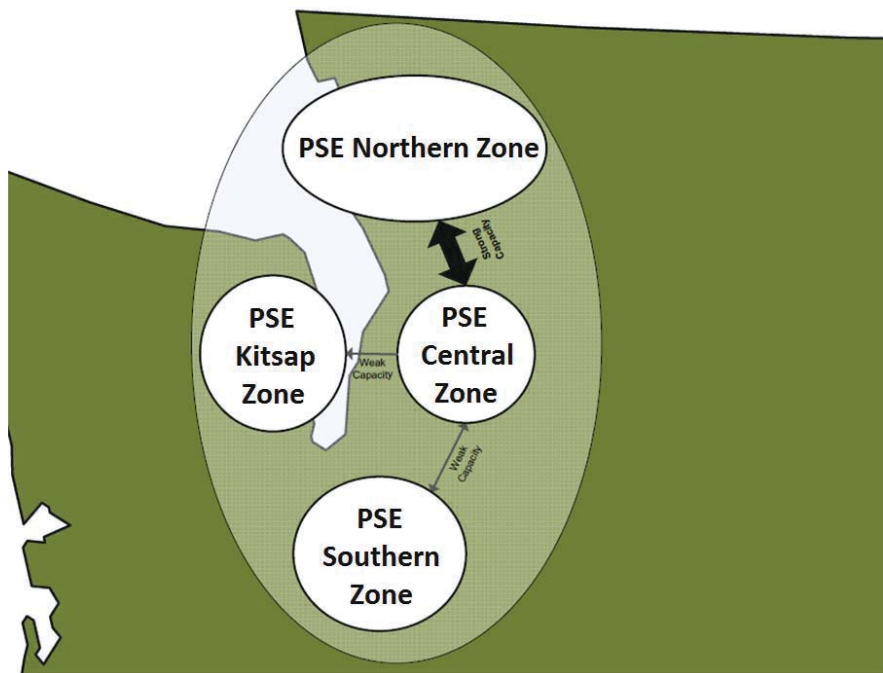
PSE Westside Transmission Constraints

Resources located west of the Cascades near PSE load centers and natural gas pipelines generally have fewer delivery constraints because this energy is typically delivered by the PSE-owned local transmission system. There is currently sufficient transmission capacity on PSE's westside system to move surplus energy produced in one part of the service territory to others. However, in certain areas, if new resources are added or imported, constraints could develop without transmission expansion.

Figure I-2 illustrates the PSE Westside Load Zones and transmission paths.

Figure I-2: Transmission System Constraints on PSE Internal Resource Delivery

PSE Westside Service Territory Load Zones



Appendix I: Regional Transmission



The illustration above divides PSE's service territory into four geographic load zones connected by different sets of PSE transmission facilities. The arrows indicate relative transmission capacity between the load areas; the thicker the arrow, the greater the transmission capacity.

- Capacity from the Central Zone to the Northern Zone is adequate in the near term. It is unlikely that new resources located in (or imported into) the Central Zone would cause PSE to experience limitations in moving energy from the Central to the Northern Zone in the ten-year time frame examined here.
- Transmission capacity from the Central to Southern Zone is more limited. Here, PSE could experience limitations in moving energy from the Central to the Southern Zone if new resources are added or imported in the next ten years.
- In the Kitsap Zone, PSE may begin to see transmission resource deficits in the long term unless new capacity is built or obtained between the Kitsap and the Central or Southern Zones.

PSE will consider purchased power agreements (PPAs), capacity constraints, the geographic location of PSE's loads and existing resources, and the physical delivery points of remote resources as we continue to analyze and study the potential locations of loads, resources and transmission.



3. PSE TRANSMISSION EFFORTS

PSE continues to participate with study teams and work with regional utility partners to solve congestion issues in the Pacific Northwest.

Participation with study teams like the ColumbiaGrid System Assessment groups has resulted in committed projects by PSE. The committed projects by PSE are:

- Alderton 230/115kV Transformer in Pierce County. A new 230/115 kV transformer at Alderton Substation in central Pierce County with a new 230 kV line from White River. This project is included in PSE's budget and the scheduled completion year is 2017.
- Woodland-Gravelly Lake 115kV Line. This project is in the design and construction phase and is a committed project with a scheduled completion year of 2025.

One of the committed projects by BPA is:

- Raver 500/230 kV transformer and a 230 kV line to Covington Substation. Addition of a 500/230 kV transformer at Raver and a 230 kV terminal at Raver for a Raver-Covington 230 kV line. This project will ensure increased transmission capability in the Puget Sound area.



4. BPA TRANSMISSION EFFORTS

TSR Study and Expansion Process

BPA is the primary option for acquiring contractual transmission in the Northwest. Historically this involved submitting an OASIS (Open Access Same-time Information System) transmission service request to BPA, but the agency now requires participation in its TSR Study and Expansion Process (TSEP), formerly known as Network Open Season (NOS). The TSEP process was designed to obtain financial commitments from transmission customers in advance of any new facility construction. For long-term transmission requests, the process uses cluster studies to analyze impacts and new transmission facility requirements on an aggregated basis. Commencing in 2008, and in accordance with Federal Energy Regulatory Commission (FERC) approval, BPA initiated an NOS process under its Open Access Transmission Tariff (OATT). The multi-step process began with the submission of Transmission Service Requests (TSR) by transmission customers. BPA responded with a Precedent Transmission Service Agreement (PTSA) that requires customers to pledge a security deposit equal to the charge for 12 months of transmission service at the tariff rate. The PTSA obligates the customer to take service for its TSR if BPA satisfies the following conditions:

- BPA determines that it can reasonably provide service for the TSR in the cluster at embedded cost rates, and
- BPA decides to construct the facilities required to provide the service after completing an environmental impact study.

2017 TSEP Study

In 2017, BPA will perform a TSEP Cluster Study that looks at 51 TSRs totaling 2,042 MW of incremental transmission service; these include several PSE transmission service requests. Results of this study, including potential transmission projects to support granting transmission requests, were shared by BPA on June 14, 2016. On May 17, 2017, BPA also announced their decision to not go ahead with their I-5 Corridor Reinforcement project. The study results showed that out of 7 TSRs, only 1 TSR was approved; the other TSRs needed additional system enhancements.



Past NOS Findings

Previously, BPA performed four NOS studies in 2008, 2009, 2010 and 2013. The 2009 and 2013 studies resulted in no new transmission projects. The 2008 and 2010 studies resulted in six new transmission projects. Study results and projects resulting from previous NOS studies can be found on the BPA website.

Wind Curtailments

Wind power plays a significant role in meeting the region's future energy needs and satisfying RPS requirements. In fact, approximately 5,000 MW of new renewable generation (primarily wind power) will be necessary to fulfill the combined RPS requirements of Washington and Oregon. To meet this increase, BPA must continue to build transmission lines and substations to deliver renewable electricity from new wind projects that are often located in remote areas. Integrating this amount of wind energy into the region's electrical grid poses many challenges, and BPA's role will certainly require innovative and cooperative approaches to manage the variability of wind power effectively. Current BPA efforts to manage wind energy include the following.

Dispatcher Standing Order (DSO) 216

DSO 216 enables BPA to either curtail generation schedules or limit generation to the scheduled amount when there is insufficient regulating capacity on the federal hydroelectric system. Regulating capacity is an ancillary service that BPA charges customers for integrating wind. However, that service is not always available, as shown by the historical frequency of DSO 216 curtailments. Curtailments may result in lost energy and/or renewable energy credits (RECs) without compensation.

Oversupply Management Protocol

Similar to DSO 216, BPA uses Oversupply Management Protocol to curtail wind energy, but in this case when there is an oversupply of hydroelectric and wind generation in the region. Curtailments may result in lost energy and/or RECs with compensation.

PSE's future resources – especially renewables – will most likely face tough economic and technical challenges, along with business uncertainties. Continuing to rely on BPA to integrate our wind resources has a limit, which means we must continue to look for alternatives to integrate wind either directly into our Balancing Authority (BA), or seek other innovative, lower-cost approaches.



BPA Transmission Planning and Attachment K¹ Projects

Through its various forums (Attachment K, Capital Investment Review, etc.), BPA is planning to construct the following projects:

- Raver 500/230 kV Transformer, expected energization 2017
- Monroe-Novelty 230kV Line Upgrade, proposed energization 2019
- Monroe 500kV Line Re-terminations, expected energization 2019

These projects increase reliability to Puget Sound area loads by decreasing potential Northern Intertie congestion across various seasons and conditions throughout the calendar year. These projects could also make new capacity available for PSE requests for transmission service from eastside generation alternatives to PSE loads.

¹ / PSE's current Attachment K document is available at http://www.oasis.oati.com/PSEI/PSEIdocs/PSE_Plan_2016_Final.pdf.
BPA's current Attachment K document is available at <https://www.bpa.gov/transmission/CustomerInvolvement/AttachmentK/Pages/default.aspx>



5. REGIONAL TRANSMISSION EFFORTS

Major Proposed Projects

Several major transmission projects are proposed for the Pacific Northwest. These projects may impact each other as well as existing Western Electricity Coordinating Council (WECC) paths. The WECC maintains a public transmission project database where project sponsors can post information and updates for their projects. The projects listed below can be found in the WECC database or at BPA's website. All are assumed to have some effect on the paths and flowgates that PSE uses to transmit energy from remote resources to load. Project names are followed by expected cost, completion date and current status.

- PacifiCorp's Gateway West: ~ \$2.7 billion, tentative completion date 2019 – 2024; final Supplemental Environmental Impact Statement issued by the Bureau of Land Management in October 2016.
- Idaho Power's Boardman to Hemingway: ~ \$900 million, tentative completion date 2022 or later; final Supplemental Environmental Impact Statement issued by the Bureau of Land Management in November 2016.
- PacifiCorp's Walla Walla – McNary 230 kV: cost unknown, construction estimated in 2017; tentative completion date 2017.



These projects are displayed in Figure I-3.

Figure I-3: Proposed Regional Transmission Projects



These projects bring three main benefits to the region:

1. access to significant incremental renewable resources in the northwestern states,
2. improvement in regional transmission reliability, and
3. new market opportunities for dealing with participants outside of the region.



ColumbiaGrid Efforts

ColumbiaGrid is a non-profit membership corporation formed in 2006 to improve the operational efficiency, reliability and planned expansion of the Pacific Northwest transmission grid. While ColumbiaGrid does not own transmission, PSE and other ColumbiaGrid members do own and operate an extensive network of transmission facilities. ColumbiaGrid's members are PSE, Avista, BPA, Chelan County PUD, Grant County PUD, Seattle City Light, Snohomish PUD and Tacoma Power.

ColumbiaGrid has had substantial responsibilities for transmission planning, reliability and other development services. These tasks are defined and funded through a series of "Functional Agreements" with members and other participants. Development of these agreements is carried out in an extensive public process. ColumbiaGrid processes stress transparency and encourage broad participation and interaction with stakeholders, including customers, transmission providers, states and tribes. It also provides a non-discriminatory forum for interested parties to receive and present pertinent information concerning the regional interconnected transmission system.

Planning and Expansion

ColumbiaGrid's planning and expansion efforts are intended to promote single-utility planning and expansion of the regional grid. The Planning and Expansion Functional Agreement (PEFA), which has been signed by all of ColumbiaGrid's members and three non-member participants (Cowlitz County PUD, Douglas County PUD and Enbridge, Inc.), defines the obligations under this program.

The PEFA charges ColumbiaGrid with answering three key questions concerning the transmission network: what should be built, who should build it and who should pay for it. ColumbiaGrid provides a number of services in this planning program, including performing annual transmission adequacy assessments, producing a Biennial Transmission Plan and identifying transmission needs. ColumbiaGrid also facilitates a coordinated planning process for the development of multi-party transmission system projects.

ColumbiaGrid's 2016 System Assessment serves as an input to the 2017 Biennial Transmission Expansion Plan. The Assessment highlights areas of the system that may be vulnerable to deficiencies in meeting reliability standards.² In support of the Biennial Plan, PSE participated in three study teams addressing specific regions: the Puget Sound Area Study Team (PSAST), the Wind Integration Study Team (WIST) and the Cross Cascades North Study Team.

² / The referenced plans and assessments can be found on ColumbiaGrid's web site at <http://www.columbiagrid.org/documents-search.cfm> by using the document search function.



Puget Sound Area Study Team (PSAST)

The ColumbiaGrid PSAST published its “Transmission Expansion Plan for the Puget Sound Area” in October 2010; in 2013, it issued the “Updated Transmission Expansion Plan for the Puget Sound Area to Support Summer North-to-South Transfers.” Since then, area utilities have continued to meet and develop additional scenarios to study. The PSAST projects have now been pulled into the ColumbiaGrid annual assessment and biennial expansion plan.

Wind Integration Study Team (WIST)

WIST was formed by the Northern Tier Transmission Group (NTTG) and ColumbiaGrid to facilitate the integration of renewable generation into the Northwest transmission grid. Its current focus is to study and address system constraints related to increased use of dynamic transfers for variable energy resources. The study team produced a set of reports in 2011 that confirmed the need for dynamic transfer capability limits, explored study methodologies and applied the methodology to several northwestern paths. Work continued through 2012 to quantify the dynamic transfer capability of Pacific Northwest paths and to help identify other dynamic transfer impacts on reliability.

While the Dynamic Transfer Capability Task Force is not currently meeting on a regular basis, ColumbiaGrid facilitated a Dynamic Transfer Capability study on the California – Oregon Intertie (COI) in late 2014 under a separate request by BPA.



Order 1000

The Federal Energy Regulatory Commission's Order 1000 requires transmission providers to:

- participate in a transmission planning process that evaluates alternatives that may resolve the region's transmission needs in a more cost-effective and efficient manner than local planning processes;
- have a methodology for cost allocation for such projects within the region; and
- consider public policy requirements in its planning process.

The Order further requires transmission providers to improve coordination across regional transmission planning processes by developing and implementing procedures for joint evaluation and sharing of information regarding both regional transmission needs and potential interregional transmission facilities. The Order also requires regions to have a common methodology for allocating costs of interregional projects.

PSE recognizes ColumbiaGrid as its regional planning entity. The ColumbiaGrid PEFA addresses many of the Order 1000 requirements for PSE, but an additional Order 1000 Functional Agreement has been created to address incremental changes to the PEFA planning process to ensure that it complies with regional planning requirements.

The Order 1000 Functional Agreement and corresponding changes to the Attachment K to PSE's OATT were filed with FERC on December 18, 2013 in response to FERC's June 20, 2013 Order regarding PSE's original compliance filing of October 11, 2012. On September 18, 2014, FERC issued an Order largely accepting the Order 1000 Functional Agreement filing with some additional modifications. A third compliance filing that addressed those modifications was made on November 17, 2014.

For the interregional portion of the order, PSE worked with ColumbiaGrid and the other regions in the western interconnection (the California Independent System Operator [CAISO], WestConnect and the Northern Tier Transmission Group) to develop the required common language for interregional coordination and cost allocation; this was filed with FERC on June 19, 2013. FERC issued an Order generally accepting the interregional language on December 18, 2014. While no further changes to the Order 1000 Functional Agreement or PSE's Attachment K are anticipated, a filing was made with FERC prior to February 18, 2015 to address changes made by the CAISO in response to the FERC's Interregional Order. PSE and ColumbiaGrid implemented the Order 1000 Agreement beginning with the 2015 ColumbiaGrid planning cycle.



Information regarding Order 1000 is available on the ColumbiaGrid website under Order 1000 at <https://www.columbiagrid.org/1000-overview.cfm>.

Energy Imbalance Market

Increasing levels of variable renewable energy in the region have put pressure on Balancing Authorities to incorporate mechanisms that allow for scheduling shorter time intervals and more optimized coordination than traditional bi-lateral hourly markets offer. The CAISO Energy Imbalance Market (“EIM”) is a sub-hourly market that efficiently addresses Balancing Authority imbalances by economic re-dispatch of participating generating resources and transfers between BAs.

PSE joined the Energy Imbalance Market (EIM) in October 2016. To establish its first EIM transfer path, PSE redirected a portion of its existing BPA point-to-point transmission contracts for use in the 5- to 15-minute balancing energy market. This path connects PSE and PacifiCorp West (PACW) entities for EIM market trades in both directions. Current members of the EIM also include Seattle City Light, Idaho Power Company, Arizona Public Service and NV Energy as well as the Balancing Authority of Northern California.

PSE’s participation in the EIM has triggered new regional transmission concerns and challenges. Because it is changing the transmission usage over BPA’s system, PSE’s EIM transactions are subject to the Dynamic Transfer Limits in BPA’s business practice. This requires that CAISO constrain PSE 5-minute generation dispatch in the EIM according to limits specified by BPA. These limits are meant to monitor BPA flowgates and maintain system reliability.

In the near future, PSE may establish additional EIM transfer paths as new entities join the market. These potential paths may or may not require additional BPA-contracted transmission; however, they will most likely impact physical usage of the BPA transmission system. PSE will continue to work with all stakeholders on these issues.

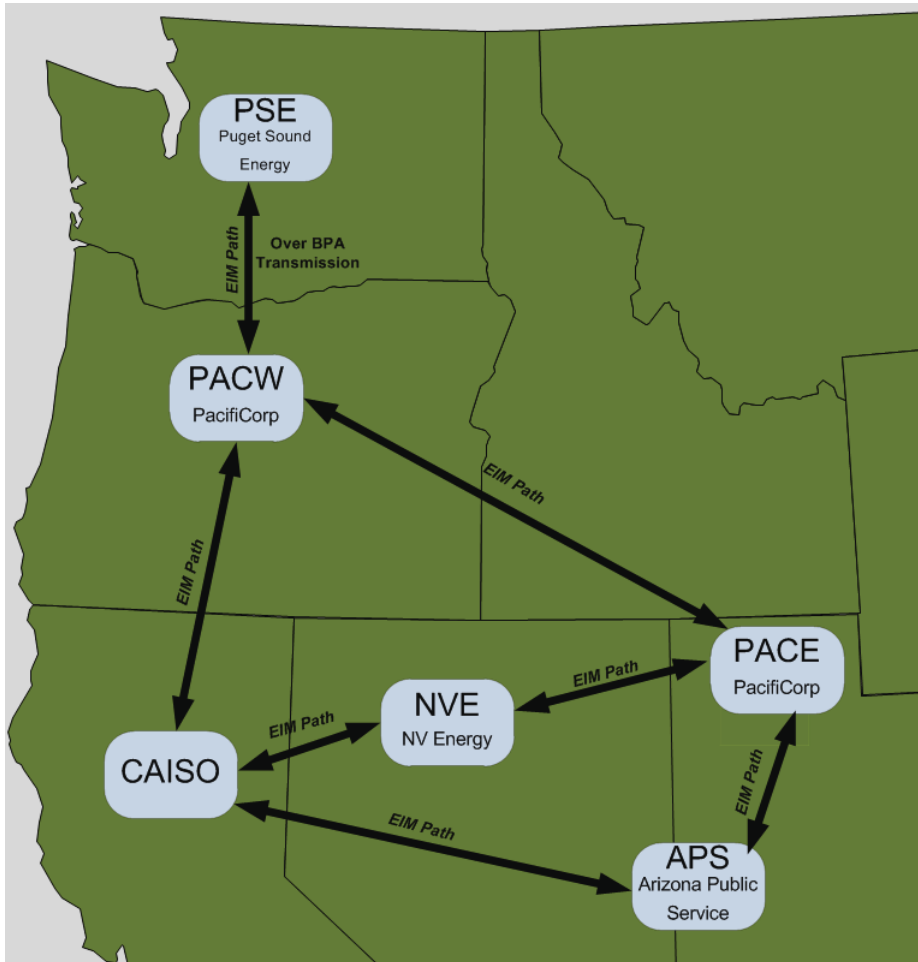
What is CAISO?

The California Independent System Operator (CAISO) is a non-profit Independent System Operator (ISO), serving California. The CAISO oversees the operation of California’s bulk electric power system, transmission lines, and the electricity market generated and transmitted by its member utilities.



Figure I-4 illustrates the existing transfer paths established between participating EIM entities.

Figure I-4: Established EIM Transfer Paths as of October 2016





6. TRANSMISSION REDIRECT OPPORTUNITIES

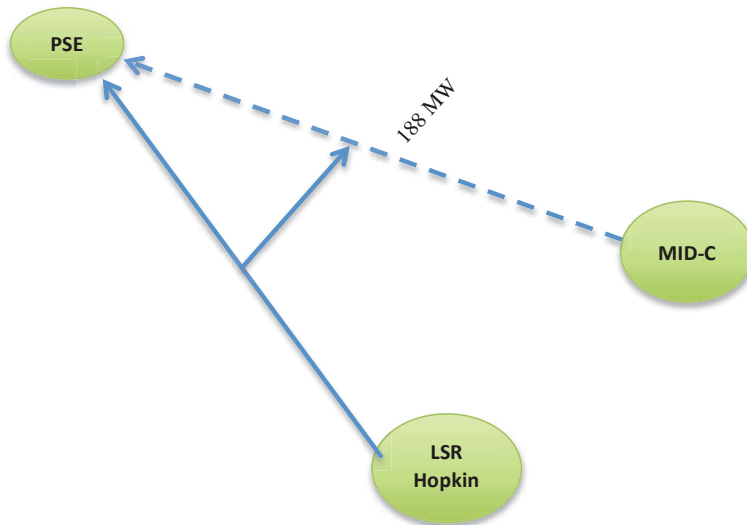
Lower Snake River (LSR) and Hopkins Ridge

For the winter peaking months of November through March, PSE is considering an opportunity to redirect a portion of LSR and Hopkins Ridge transmission to Mid-C to supplement additional firm capacity from Mid-C to PSE's load. PSE has determined that it can redirect 188 MW of LSR/Hopkins transmission to Mid-C, leaving 312 MW of firm transmission dedicated to those facilities. PSE would purchase short-term firm transmission when wind plant output exceeds the firm transmission dedicated to them. PSE is considering this redirect because:

- Additional firm capacity for the Mid-C Market increases PSE's flexibility for bringing energy to PSE's native load.
- 188 MW of redirected transmission capacity enables PSE to defer making a long-term generation decision.
- The output of Hopkins Ridge and LSE correlate poorly to PSE's peak load.
- The cost of short-term firm transmission to serve the wind farms when needed is significantly less than any other capacity resource.



Figure I-5: Illustration of Transmission Redirect to Mid-C from LSR/Hopkins



Legend:
— Firm Transmission from LSR + Hopkins
- - - Redirected Transmission to Mid-C for Winter Peak Months



Colstrip

The transfer capability of the existing Colstrip Transmission System after closure of Colstrip Units 1 & 2 will be determined by studies that have not yet been scoped and designed by the Colstrip Transmission System owners. PSE has begun working with NorthWestern Energy and the other Colstrip Transmission System owners on the design and staffing of these studies. It is anticipated that the studies will be overseen by the Colstrip Transmission System owners acting through the Transmission Committee under the Colstrip Transmission Agreement. The studies would typically include load flow, short circuit, transient, and voltage stability analyses. The transfer capability available on the Colstrip Transmission System for a new resource would be a function of, among other things, the type of new resource, its size and other characteristics, its location and the modifications made to the system to accommodate the new resource. Any modifications to the Colstrip Transmission System required by the introduction of any new resource would: 1) depend on the type of such new resource, its size and other characteristics, and its location, and 2) be identified in studies under the Open Access Transmission Tariffs of the Colstrip Transmission System owners (and the Colstrip Transmission Agreement) in response to requests for interconnection or transmission service on the Colstrip Transmission System. It would be speculative to identify any modifications to the Colstrip Transmission System for any new resource without knowing the size, characteristics and location of such new resource.



7. OUTLOOK AND STRATEGY

PSE needs to advocate for and participate in local and regional transmission projects that relieve congestion, increase transfer capacity and improve reliability for its electric customers. This can be accomplished through the following actions.

Participate in efforts focusing on relieving existing and future transmission congestion.

PSE should continue to participate in the planning of regional transmission projects that decrease congestion and curtailment risk, increase regional reliability and help maintain low power prices for its customers. PSE will pursue these opportunities through various forums, including ColumbiaGrid, BPA's TSEP process and Attachment K, and through its utility partners in the Puget Sound area. Because of our geographical location, PSE will focus on efforts to study and develop projects that relieve congestion on the West of Cascades North, North of Echo Lake and Raver – Paul flowgates.

Refine assessment of future internal transmission constraints related to westside generation alternatives.

PSE has begun to lay out the methodology for determining which internal transmission constraints may interfere with bringing new westside resource options to load. To the extent that PSE acquires incremental westside generation in the future, we will need to determine the quantitative and qualitative constraints involved in bringing that resource to load.

Identify opportunities to obtain additional transmission capacity necessary to deliver energy from eastside generation alternatives.

If PSE identifies cost-effective resources located east of the Cascades, we need to consider the means to build or acquire additional transmission service from those remote resources. PSE should continue to assess the quantitative and qualitative strengths and weaknesses of taking additional transmission service (through a BPA TSEP process) or obtaining physical transmission capacity. PSE will also continue to participate in ColumbiaGrid study groups that seek to refine which West of Cascades North transmission project is most beneficial to the region.



J

2017 PSE Integrated Resource Plan

Conservation Potential Assessment

The report developed for PSE by Navigant Consulting analyzes demand-side resources for the electric and gas sales analyses can be accessed and downloaded from the 2017 IRP links within PSE's website at:

<https://pse.com/aboutpse/EnergySupply/Documents/DSR-Conservation-Potential-Assessment.pdf>

Table of contents of the report provided below:

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2. DEMAND-SIDE RESOURCE POTENTIAL RESULTS
3. APPENDICES

- A. Measure Details, Abbreviations and Units
- B. Methodological Consistency with the Seventh Northwest Power Plan
- C. Distributed Generation Solar PV
- D. Energy Storage
- E. Demand Response
- F. Other Key Input Assumptions



K

2017 PSE Integrated Resource Plan

Colstrip

*This appendix describes the Colstrip generating plant ownership structure, governance agreements and history. It explains plant operations, the technology employed to minimize environmental impacts, and summarizes the rules and regulations that may impact the plant's future operation.*¹²

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1. THE CHANGING LANDSCAPE K-3

2. FACILITY DESCRIPTION K-4

- Governance
- History of Colstrip
- Plant Operations
- Coal Supply Agreements (CSAs)
- Requirements after Operations Cease

3. RECENT CONSENT DECREES K-12

- Administrative Order on Consent for Wastewater Ponds
- Consent Decree Related to AOC Litigation
- Consent Decree Related to New Source Review/Prevention of Significant Deterioration Litigation

(continued next page)

1 / Potential future CO₂ regulation is incorporated in the overall scenarios for the IRP since it impacts all thermal resources. Since Colstrip is included among these, CO₂ is not treated separately here.

2 / For discussion of the Colstrip sensitivities modeled in the 2017 IRP, see Chapter 6, Electric Analysis and Appendix N.



4. RECENT RULES & PROPOSED RULES K-14

- *Mercury and Air Toxics (MATS) Rule*
- *Regional Haze Rule*
- *Coal Combustion Residuals Rule*
- *Clean Air Act National Ambient Air Quality Standards (NAAQS)*



1. THE CHANGING LANDSCAPE

With six joint owners, Colstrip faces a changing landscape of evolving energy markets, new environmental regulation, potential carbon pricing, aging infrastructure, periodic litigation and potential owner valuation differences. As these factors influence Colstrip operations, PSE continually evaluates the asset, as we do all the assets within our portfolio.

As explained below, six partner companies own various shares of the Colstrip Plant. Talen Energy is one of PSE's partners in this ownership. Talen Energy and PSE each own 50 percent of Colstrip Units 1 & 2; Talen Energy also owns a 30 percent share of Unit 3. Talen Energy has experienced two significant corporate structure changes in recent years. In June 2015, Talen Energy was created from a restructuring of PPL Montana assets. Then in December 2016, Talen Energy was acquired by Riverstone Holdings, LLC, and Talen's Montana assets were moved to Talen Energy-MT as a subsidiary of Riverstone. For PSE, the recent change has created uncertainty concerning the future partnership viability for continued operations of Colstrip Units 1 & 2 and long-term planning for Colstrip Units 3 & 4.

Over the past few years, Colstrip has been the subject of litigation brought by the Sierra Club and Montana Environmental Information Center (MEIC) related to the Clean Air Act and by Earthjustice³ and MEIC related to the plant wastewater ponds. As the Clean Air Act litigation trial date approached, the owners were also considering economic factors related to market conditions, such as low natural gas prices, compliance with recent environmental regulation related to carbon emissions (the Clean Power Plan) and environmental regulations that could necessitate further environmental equipment installation on Colstrip Units (Regional Haze Rule). Based on this analysis, the owners determined to set a retirement date for Colstrip 1 & 2.

Upon further discussion with Sierra Club and MEIC, the Clean Air Act litigation was settled by an agreement to shut down Colstrip 1 & 2 no later than July 1, 2022. Additionally, the legal action brought by Earthjustice and MEIC related to the plant's wastewater ponds was also settled by an agreement based on the retirement of Colstrip 1 & 2 and the commitment to transition to a dry disposal system for coal combustion residuals from Colstrip 3 & 4 no later than July 1, 2022.

³ / Earthjustice is a nonprofit that represents Sierra Club and other nonprofit environmental organizations on legal issues. It was formerly the Sierra Club Legal Defense Fund.



2. FACILITY DESCRIPTION

The Colstrip generating plant supplies PSE customers with efficient, baseload power. Currently the facility supplies 18 percent of the energy needed to serve PSE's energy needs on an annual basis. The plant consists of four coal-fired steam electric plant units located in eastern Montana about 120 miles east of Billings. It was built in two phases.

- Units 1 & 2 began operation in 1975 and 1976, respectively. Each produces up to 307 megawatts (MW) net. PSE and Talen Energy (formerly PPL Montana) each own a 50 percent undivided interest in both units.
- Units 3 & 4 began operation in 1984 and 1986, respectively. Each produces up to 740 MW net. Six companies participate in the ownership of Units 3 & 4. PSE owns 25 percent each of Units 3 & 4, Portland General Electric (PGE) owns 20 percent of both units, Avista owns 15 percent of both units and PacifiCorp owns 10 percent of both units. Talen Energy owns 30 percent of Unit 3 and NorthWestern Energy owns 30 percent of Unit 4.

Figure K-1 summarizes ownership of the Colstrip plant.

Figure K-1: Colstrip Ownership Share by Unit and Owner

| Owner | | Unit 1 | Unit 2 | Unit 3 | Unit 4 | Ownership Total, MW | % of Total Plant |
|---------------------|---------|--------------|--------------|------------|------------|---------------------|------------------|
| Puget Sound Energy | % MW | 50% 153.5 | 50% 153.5 | 25% 185 | 25% 185 | 677 | 32.3% |
| Talen Energy | | 50% 153.5 | 50% 153.5 | 30% 222 | | 529 | 25.3% |
| NorthWestern Energy | | | | | 30% 222 | 222 | 10.6% |
| PGE | | | | 20% 148 | 20% 148 | 296 | 14.1% |
| Avista | | | | 15% 111 | 15% 111 | 222 | 10.6% |
| PacifiCorp | | | | 10% 74 | 10% 74 | 148 | 7.1% |
| Total | | 307 | 307 | 740 | 740 | 2094 | 100.0% |



The Colstrip Transmission System was built at the same time as Units 3 & 4. This transmission system consists of two single-circuit 500 kV transmission lines that run from the plant to an interconnection with the Bonneville Power Administration (BPA) in Townsend, Montana. It is owned by the five regulated utility owners of the power plant: PSE, NorthWestern Energy, PGE, Avista and PacifiCorp.

Governance

Colstrip owners are governed by two ownership agreements. The Units 1 & 2 Construction and Ownership Agreement executed in 1971, and the Colstrip Units 3 & 4 Ownership and Operation Agreement executed in 1981. There is a separate Operating and Maintenance Agreement for Units 1 & 2 and a separate Common Facilities Agreement.

Each agreement establishes an Owners Committee to guide operating decisions, and the agreements set forth several key conditions.

- Ownership is as “tenants in common,” without a right of partition, and the obligations of each owner are several and not joint.
- Assignment and ownership transfer to third parties is limited, with a right of first refusal for an existing owner to acquire any ownership offered for sale.
- The term of the agreements continues for as long as the units are used and useful or to the end of the period permitted by law.
- Each owner must provide enough fuel to operate its share of the units at minimum load.
- Failing to pay its share of project costs or failing to provide adequate fuel constitutes a default on the part of the owner.
- An owner must continue to pay its share of operating costs and coal costs until it has transferred its ownership to another entity.
- No single owner has the ability or right to shut down the plant, so to shut down and decommission any unit, all owners of that unit must unanimously agree.
- The ownership contracts do not establish a “put” right for any owner.

The Ownership and Operation and Agreement for Units 3 & 4 (O&O Agreement) specifies a voting structure to be used by the Owners Committee for approving annual budgets and other operating decisions. Both ownership agreements provide that the Owners Committee may not amend the agreement.

Appendix K: Colstrip



The operating agreements provide for a plant operator. The original agreements named Montana Power and subsequently its successor Talen Energy as Operator of all four units at the plant. The units are managed for daily operational purposes as a single facility with common costs split per ownership share. On May 23, 2016, Talen provided the other owners official notice (required by the O&O Agreement for Units 3 & 4) to terminate its operation of the plant within two years. However, in June 2017 Talen withdrew its operator resignation announcement, and will continue to operate all four Colstrip units.

A separate agreement governs ownership and operation of the Colstrip Transmission System. NorthWestern Energy is the immediate downstream transmission provider.

History of Colstrip

The Northern Pacific Railway established the town of Colstrip in 1924 at the northern end of the Powder River Basin to provide coal for its steam locomotives. The Powder River Basin is the single largest source of coal in the United States and is one of the largest deposits of coal in the world. At Colstrip, coal is mined from the Rosebud seam of the Fort Union Formation. The railroad shut down the mine in 1958 when it switched to diesel locomotives, and the Montana Power Company purchased the rights to the mine and the town in 1959. They resumed mining operations in the 1970s with plans to build coal-fired electrical plants.

In the 1960s, BPA forecast that available baseload hydroelectric power would be fully subscribed by its statutory preference customers, leaving none available for sale to PSE and other investor-owned utilities. Faced with this situation, PSE had to develop or contract for other sources of baseload energy. Developing a coal-fired generating plant at Colstrip, Montana, was the result. The adjacent Rosebud mine offered plentiful coal reserves that could be delivered to the generating plant without the need for costly rail facilities. Sharing the ownership and output of a two-unit plant with Montana Power Company (whose generating plants were later acquired by Talen Energy) made construction and operation more economical, and sharing the output of two units increased reliability compared to owning a single unit of similar size or a larger single-unit plant.

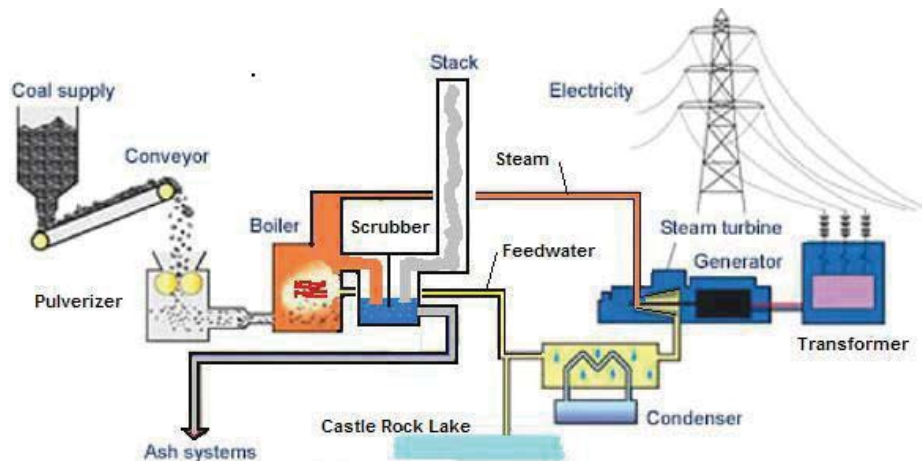
In the early 1970s, under the same forecast that the region's investor-owned utilities would soon lose access to BPA baseload hydro power, PSE and Montana Power Company began planning for Units 3 & 4 together with three other utilities. Construction of the two units began, but delays in obtaining the required Montana Major Facility Siting Act Certificate postponed their opening until 1984 and 1986 respectively. The 500 kV Colstrip Transmission System was constructed in tandem with Units 3 & 4.



Plant Operations

Each of the four Colstrip units consists of a fuel supply system, a coal-fired boiler, a steam turbine-generator, a cooling tower, step-up transformers, piping, and electric distribution and auxiliary equipment. Figure K-2 provides a simplified illustration of how each unit generates electricity.

Figure K-2: Colstrip Plant Operations Diagram



How Colstrip Generates Electricity

Coal from the Rosebud Mine is crushed into 3-inch chunks and transported to the generating plant on overland conveyors or in trucks where it is stored in piles at the plant site before being moved to silos in the boiler buildings. Coal travels through a pulverizer that grinds it to the consistency of talcum powder. The pulverized coal is then mixed with air and blown into the boiler. Inside the boiler, the coal and air mixture burns, releasing hot gases that convert water in boiler tubes to steam. The steam powers turbines connected to electric generators, which transform the mechanical energy from the turbine into electric energy.

Afterwards, the hot gases are drawn into the scrubbers, where they are cleaned before being exhausted through the stack. Bottom ash, the heavier of the two residuals, sinks to the bottom of the boiler where it is collected for treatment and storage. The lighter fly ash is pulled into the scrubbers with the flue gases, where it is captured for treatment and storage. The scrubbers also capture sulfur and mercury emitted from the coal during combustion.



Water for plant operations comes from the Yellowstone River. A 30-day supply is maintained in Castle Rock Lake, a man-made lake constructed as part of the plant facilities. As water enters the plant it is divided into two streams. The largest flows to the cooling towers where it replaces water lost from evaporation, the smaller flow is used for various processes including equipment cooling and scrubber system make-up. Water used in the boilers is demineralized before entering a closed-loop system that passes through the boiler and turbine system.

Environmental Impact Measures

Nearly every step of the process includes measures to reduce environmental impacts.

NITROGEN OXIDES (NO_x). Coal and air leaving the pulverizers passes through burner systems and over-fire air systems that cool the flame temperature and reduce the formation of NO_x. Units 1 & 2 use a second-generation low-NO_x combustion system with a close-coupled over-fire air injection. The newer Units 3 & 4 use a third-generation combustion system with separated over-fire air injection. Digital control systems installed on all four units further enhance NO_x emissions control. SmartBurn – an optimized combustion system that helps decrease the amount of nitrogen oxides formed during the combustion process – was installed in 2015 to Unit 2, 2016 to Unit 4, and 2017 to Unit 3 to further reduce NO_x emissions.

MERCURY. Coal contains mercury. To oxidize the mercury and enhance its capture, the coal is treated with a bromine solution before entering the boiler. Then, flue gases are treated with powdered activated carbon to capture the mercury before the gases enter the scrubbers; there, the activated carbon and mercury are removed along with other particulate matter.

SULFUR DIOXIDE (SO₂). Permit specifications limit the amount of sulfur in the coal fuel. Additionally, all four units remove sulfur dioxide from flue gases using wet alkali scrubbers. These scrubbers use the alkalinity of fly ash and/or hydrated lime to capture SO₂; then a water spray collects the fly ash and the mercury for further processing.



COAL COMBUSTION RESIDUALS (CCR). Two types of ash are produced by coal combustion. Bottom ash makes up 30 percent to 35 percent of the total. Fly ash makes up the remainder. The larger and heavier bottom ash falls into a water-filled trough in the bottom of the boiler; from there it is pumped to settling ponds on the plant site to dewater and then to permanent storage ponds. Some bottom ash is used as a construction material.

The smaller and lighter fly ash and other particulate matter (PM) passes into the scrubbers with the flue gases. The scrubbers use the fly ash's alkalinity and/or hydrated lime to capture SO₂ gases, and a water spray removes the fly ash and other PM. The resulting scrubber slurry is piped to storage ponds. Before final placement in the storage ponds, paste plants remove most of the water; the paste, which begins the process at about 65 percent solids, sets up like low-grade concrete after several days.

The original ash holding ponds at Colstrip were designed with highly impermeable clay liners to prevent slurry components from seeping into the groundwater. These conformed to the requirements of the Montana Major Facility Siting Act Certificate. Monitoring wells, installed prior to the start of operations, monitor the groundwater for any sign of possible contamination (pond water seepage), and capture wells pump impacted ground water back to the ponds.

Since 2000, projects have been and are being completed to control ash pond leakage, reduce migration of affected groundwater and to upgrade plant wastewater systems to allow increased recycling of water. In 2015, Colstrip completed a comprehensive master plan to address water and waste management at the facility to meet requirements under the CCR Rule and AOC. The plan covers a 25-year horizon and includes water reduction, treatment, water reuse, pond closures, post closure site monitoring and remediation.

ASH HOLDING POND SEEPAGE. Several years after the first slurry was placed into the stage one pond for Units 1 & 2 some of the monitoring wells began to show increases in groundwater constituents, such as dissolved salts, which could indicate that some of the ash constituents were migrating through the clay lining. In consultation with MDEQ (the Montana Department of Environmental Quality), Colstrip plant operators installed capture wells to capture affected groundwater and pump it back to the ponds to prevent affected water from leaving plant property, as well as additional monitoring wells. In addition to capture wells, existing ponds have been continually modified and additional storage cells have been installed over time utilizing newer, state-of-the-art lining methods including polymer liners, geo membranes and leak detection/collection systems.



Coal Supply Agreements (CSAs)

The coal supply for Colstrip Units 1 & 2 and Units 3 & 4 is established between the Colstrip Units 1 & 2 owners (buyers of coal) and Westmoreland Mining Co., and between Colstrip Units 3 & 4 owners (buyers of coal) and the Westmoreland Mining Co. The Units 1 & 2 agreement is titled “Coal Purchase and Sale Agreement,” and its term began January 1, 2010. PSE currently plans to purchase coal for Units 1 & 2 until July 1, 2022. For Units 3 & 4, the agreement is titled “Amended and Restated Coal Supply Agreement”; its term began January 1, 1998, and continues currently. PSE is currently in negotiations with the other Units 3 & 4 coal buyers and Westmoreland Mining Co. to extend the Units 3 & 4 coal purchase agreement.

The specific content of the CSAs is protected under contractual confidentiality language embedded within the agreement. However, in general terms the topics covered in the agreements are: sale and purchase of coal; dedication of coal reserves, and term; governance of the agreement; establishment of executive committee and mine operating committee; annual operating plan (mining plan); coal delivery, weighing and transportation; coal quality; coal price and payments; and final reclamation costs and obligations.

Requirements after Operations Cease

Potential Plant Demolition Obligations

The ownership agreements for both Units 1 & 2 and Units 3 & 4 are silent about a definite date for shutdown of the units. They address decommissioning or remediation costs only to the extent that costs remaining after equipment salvage are to be distributed based on ownership share. Currently there are no plans for decommissioning of the facility. The Montana legislature passed a bill in 2017 to require submission of a retirement plan.

Potential Mine Reclamation and Obligations

Colstrip receives its fuel from Westmoreland Mining Co., also located in Colstrip, Montana. Mining permits held by Westmoreland require development of reclamation plans and cost estimates for all areas disturbed by mining, and Westmoreland has provided surety bonds to the State of Montana to ensure that reclamation will occur. Plant owners reimburse Westmoreland for the cost of mine reclamation, including final reclamation work after coal deliveries cease, as part of the current costs paid for each ton of coal supplied.



AOC Wastewater Remediation Obligations

On August 3, 2012, Talen Energy and the Montana Department of Environmental Quality signed an Administrative Order of Consent Regarding Impacts from Wastewater Facilities (AOC). The AOC sets up a comprehensive program for investigation, interim response and remediation of any wastewater seepage or spills, and for closure of the holding ponds. Plans for closure of the wastewater ponds were submitted to the Montana Department of Environmental Quality in 2017. This plan will include requirements for wastewater pond closure which must be completed when plant operations cease. Refer to the section below titled “Recent Consent Decrees” for additional information on the AOC.

Coal Combustion Residuals (CCR) Pond Closure and Related Remediation Obligations

On April 17, 2015, the United States Environmental Protection Agency (EPA) published a final rule, effective October 19, 2015, that regulates Coal Combustion Residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The rule was initially self-implementing, but Congress passed a new statute in late 2016 authorizing EPA to either directly implement the CCR rule or allow states to implement the CCR Rule through state permit programs. The rule includes comprehensive requirements for closure of CCR wastewater ponds, as well as corrective action to remediate any impacts from CCR ponds. Refer to the section below titled “Rules and Proposed Rules” for additional information regarding the CCR rule.



3. RECENT CONSENT DECREES

Administrative Order on Consent for Wastewater Ponds

On August 3, 2012, Talen Energy and the Montana Department of Environmental Quality signed an Administrative Order of Consent Regarding Impacts from Wastewater Facilities (the AOC). The AOC sets up a comprehensive program for investigation, interim response and remediation of any wastewater seepage or spills, and closure of the holding ponds. For any area of the plant identified as a site where seepage or spills have occurred, the AOC provides for preparation of a Site Report. The Site Report must include a description of investigations performed to date in that area, results of modeling, details of pond construction and recommendations for additional characterization. After the Site Report for a given area is complete, a Site Characterization Work Plan, a Cleanup Criteria and Risk Assessment, a Remedy Evaluation Report, and if required, a Final Remediation Action Report will be completed and approved by the MDEQ. The AOC provides for public notice and comment on each report, and for response by MDEQ to substantive comments. Plans for closure of the wastewater ponds were submitted to the Montana Department of Environmental Quality in 2017. The plans include requirements for wastewater pond closure which must be completed when operations cease.

Consent Decree Related to AOC Litigation

In Fall 2012, two lawsuits were filed in Montana state court by the Montana Environmental Information Center and Earthjustice against the Montana Department of Environmental Quality pertaining to the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities entered into with PPL Montana, LLC (now Talen Montana), the plant operator. This litigation included a mandamus action and a petition for review. The petition for review was originally filed with Montana Board of Environmental Review, alleging that the Administrative Order on Consent Regarding Impacts Related to Wastewater Facilities is an improper enforcement action and violates Montanans' constitutional right to a clean and healthful environment. The Montana Department of Environmental Quality was the original defendant, but the operator of the Colstrip Steam Electric Generating Station intervened and removed the petition for review to Montana state court. Meanwhile, the mandamus action was dismissed in 2013.



The parties entered into settlement discussions and lodged a consent decree in state court in September 2016. Earthjustice and MEIC withdrew their claims in exchange for an agreement based on the retirement of Colstrip 1 & 2 and the commitment to transition to a dry disposal system for coal combustion residuals from Colstrip 3 & 4 no later than July 1, 2022.

Consent Decree Related to New Source Review/Prevention of Significant Deterioration Litigation

The Sierra Club and Montana Environmental Information Center filed a lawsuit in federal district court on March 6, 2013, alleging that the Colstrip Steam Electric Generating Station had violated the Clean Air Act by undertaking major repairs without a permit that would have required the installation of best available pollution control technology. Several amended complaints were filed, and at one point, plaintiffs alleged that 73 projects undertaken at the Colstrip Steam Electric Generating Station facility violated the Clean Air Act. Through amendment of the complaint and favorable court decisions, the number of claims was greatly reduced. Ultimately, claims related to two projects (one at Colstrip Unit 1 and one at Colstrip Unit 3) were set for trial in May 2016.

The parties entered into settlement discussions prior to the trial, and in July 2016, they entered into a consent decree which was filed in federal court. Under that decree Sierra Club and MEIC dropped all claims, and Colstrip Unit 1 & 2 owners agreed to cease operations of Units 1 & 2 no later than July 1, 2022. The owners also agreed to meet more stringent SO₂ and NO_x limits for Units 1 & 2 until closure in 2022.



4. RECENT RULES AND PROPOSED RULES

Mercury and Air Toxics (MATS) Rule

The EPA published the final Mercury and Air Toxics Standard to reduce air pollution from coal- and oil-fired power plants with a capacity equal to or greater than 25 megawatts in February 2012. The MATS rule establishes emissions limitations at coal-fired power plants for mercury (1.2 lbs per trillion British thermal units), and for acid gases and certain toxic heavy metals using a particulate matter surrogate (0.03 lb per million British thermal units [MMBtu]). Coal-fired generating units had until April 2015 to comply with MATS, and they could receive up to a one-year extension from state permitting authorities for the installation of controls if necessary.

On June 29, 2015, the United States Supreme Court held that the EPA failed to consider costs when deciding whether it was “appropriate and necessary” to regulate emissions of mercury and other hazardous air pollutants from power plants. The Supreme Court’s decision overturned a 2014 ruling by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit), which held that EPA’s decision not to consider costs in the initial stages of the MATS rulemaking process was reasonable. The Supreme Court remanded the decision on MATS back to the D.C. Circuit for further proceedings, so the full impact is not yet known.

The D.C. Circuit can either remand or vacate EPA’s decision. Under a remand, the MATS rule would remain in effect while EPA addresses the deficiencies outlined by the Supreme Court. If the court vacated the rule, EPA would have to start the entire rulemaking process over again. EPA and environmental groups have already signaled their intent to argue for remand. The D.C. Circuit’s decision is not expected for at least ten months, though industry petitioners may request expedited consideration.

The rule remains in effect while EPA addresses the deficiencies, but MDEQ granted Colstrip a one-year compliance extension until April 2016. Some investments for additional PM control by the Unit 1 & 2 scrubbers were required to comply with the heavy metals requirements of the MATS Rule. Installation of this equipment (sieve trays) on Units 1 & 2 scrubbers began in the second quarter of 2014 and was completed in the second quarter of 2016. This project brought Units 1 & 2 into compliance with the PM requirements of the MATS Rule. The Unit 3 & 4 scrubbers were already effective at keeping those units in compliance.



The mercury control system installed at Colstrip to meet a previous Montana mercury rule also meets the MATS requirements for mercury capture and removal. The existing scrubbers on all four units adequately remove acid gases covered by the rule. For more information on the MATS Rule, see <http://www.epa.gov/mats/actions.html>.

Regional Haze Rule

Established in 1999, the Regional Haze Program is a long-term (64-year) program administered by the U.S. EPA under federal law to improve visibility, or visual air quality, in 156 national parks and wilderness areas across the country. Specifically, the program requires EPA and the states to achieve natural-level visibility in all of the Class I areas in the country. Regional haze is not a health-based rule, rather it requires states to constantly decrease haze in certain scenic areas of the country over time according to a “Glide Path” in order to eliminate man-made impairment by 2064.

Every five years the Regional Haze Rule requires an updated progress report to show “reasonable progress” toward eliminating haze, and every ten years it requires a comprehensive updated plan for emission controls to keep emissions below the state’s established Glide Path. States can take on regional haze analysis directly and develop a State Implementation Plan (SIP), or states can defer to EPA to establish a Federal Implementation Plan (FIP) for their state. In 2006, Montana deferred to EPA to develop the FIP for the first ten-year phase of the program, 2008-2018.

Under Montana’s FIP, established in August 2012, EPA determined that Colstrip emissions impact at least two Class I areas within 300 kilometers, including the Theodore Roosevelt National Park and UL Bend National Wildlife Refuge. As a result, EPA determined that Colstrip Units 1 & 2 required additional emissions controls to meet additional sulfur dioxide and nitrogen oxide limits under the Regional Haze Rule. EPA determined that Colstrip 3 & 4 were exempt from requirements under the first ten-year phase. The Sierra Club filed an appeal of EPA’s FIP with the United States Court of Appeals for the Ninth Circuit (the Ninth Circuit) on November 15, 2012, and Talen Energy also filed an appeal as the Colstrip operator. The case was heard in 2014 and a final decision was issued by the Ninth Circuit on June 9, 2015, which determined that EPA had not adequately justified the need for two of the control technologies and remanded these two issues back to EPA for a re-do. EPA informally indicated that it will wait until the next Regional Haze review period to reissue an FIP. In July 2016, EPA proposed to delay the start of the new Regional Haze review from 2018 to 2021.



The ruling in no way affects the future planning periods for the Regional Haze Program or Montana's Glide Path. EPA's current assessment of Montana's Glide Path will require significant emission reductions to meet the natural visibility goal by 2064. Thus, additional emission reductions from current levels will be necessary in future ten-year planning periods beginning in the second planning period, which was set by the EPA in 2017 to begin July 31, 2021. The rule is subject to challenge in the D.C. Circuit at the moment, but no briefing schedule has been set.

Coal Combustion Residuals Rule

On April 17, 2015, the EPA published a final rule, effective October 19, 2015, that regulates coal combustion residuals (CCRs) under the Resource Conservation and Recovery Act, Subtitle D. The CCR rule addresses the risks from coal ash disposal (such as the leaking of contaminants into ground water, the blowing of contaminants into the air as dust and the catastrophic failure of coal ash containment structures) by establishing technical design, operation and maintenance, closure and post-closure care requirements for CCR landfills and surface impoundments, and corrective action requirements for any related leakage. The rule also sets out recordkeeping and reporting requirements including posting specific information related to CCR surface impoundments and landfills to a publicly-accessible website.

See <http://www2.epa.gov/coalash/coal-ash-rule>, and <http://www.gpo.gov/fdsys/pkg/FR-2015-04-17/pdf/2015-00257.pdf>.



Clean Air Act National Ambient Air Quality Standards (NAAQS)

Two types of national air quality standards are established by the Clean Air Act. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children and the elderly. Secondary standards set limits to protect public welfare, including protection against visibility impairment, damage to animals, crops, vegetation and buildings. These ambient level standards apply uniformly throughout the states. The Clean Air Act required EPA to set NAAQS for widespread pollutants from numerous and diverse sources considered harmful to public health and the environment. EPA has set NAAQS for six "criteria" pollutants; periodic review of the standards and the science on which they are based is required. Each time the NAAQS are revised, the states must evaluate whether any parts of the state exceed the standard (these are "non-attainment" areas). If a state contains any non-attainment areas, it must propose a plan and schedule to reduce emissions in order to achieve attainment approval by the EPA. Currently the Colstrip area of Montana is in attainment for all criteria pollutants. Reductions in Colstrip emissions for SO₂, NO_x and PM to meet the MATS Rule and the EPA FIP are expected to keep the area in attainment with any NAAQS revisions with no further actions required. For more information, go to <http://www.epa.gov/ttn/naaqs/criteria.html>.



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2017 PSE Integrated Resource Plan

Electric Energy Storage

This appendix describes PSE's experience with energy storage policy and technology, the services that energy storage can provide, and briefly reviews energy storage technologies and key development considerations.

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1. OVERVIEW

Electric energy storage (also simply called “energy storage”) encompasses a wide range of technologies that are capable of shifting energy usage from one time period to another. In this chapter, we discuss developments in newer forms of energy storage, mainly batteries.

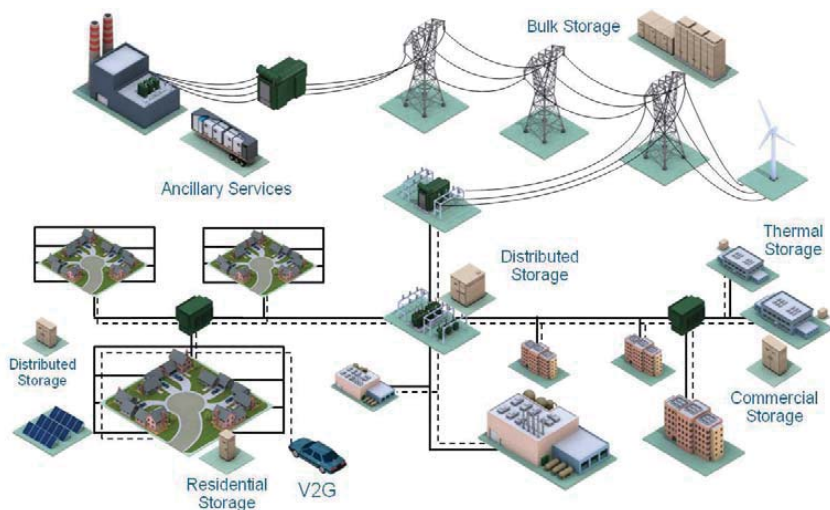
The most widespread traditional forms of energy storage include dams to hold water and underground or LNG storage for natural gas; however, dams must be built by rivers and underground storage requires special geologic formations. Batteries are different. They can be placed wherever needed and may be sized to fit. Evolving battery technologies could deliver important benefits to electric utilities and their customers, since the electric system currently operates on “just-in-time” delivery, which requires generation and load to be perfectly balanced at all times to ensure power quality and reliability. Strategically placed energy storage resources have the potential to increase the quality and efficiency of services provided by utilities. This includes being able to more effectively balance supply and demand, to provide backup power when primary sources are interrupted, to assist with the integration of intermittent renewable generation, and to delay costly upgrades and repair to the transmission and distribution grids. Energy storage is capable of benefiting all parts of the system – generation, transmission and distribution, and customers (see Figure L-1).

Throughout this appendix, energy storage resources will be described in terms of their nameplate power rating and their energy storage capacity. For example, a 10 MW/20 MWh storage system is capable of delivering 10 megawatts of AC power for two hours, for a total of 20 megawatt-hours of energy delivered to the grid (10MW x 2 hours = 20 MWhs). Systems can be as large as pumped hydropower facilities that provide hundreds of megawatts of power for many hours or as small as off-grid battery systems that support electric service for small, remote residences and facilities. This flexibility is one of its attractive qualities.

Appendix L: Electric Energy Storage



Figure L-1: Overview of Energy Storage Roles on the Electric Grid



Source: EPRI



PSE Experience

PSE has acquired considerable experience with energy storage technology, policy and services through research and pilot projects. The technology has been considered in both the 2013 and 2015 PSE Integrated Resource Plans.

PSE completed installation of its Glacier Battery Storage Project in the fall of 2016. This partnership with the Washington Department of Commerce is PSE's first grid-connected battery storage project. To ensure the safe operation of the 2 MW/4.4 MWh lithium-ion battery, PSE selected optimal technology and local energy storage service providers to upgrade substation, distribution and controls infrastructure. We continue to collaborate with project partners to study how battery storage can be used to improve the reliability of electricity for our customers. The Glacier Battery Storage Project is described in more detail at the end of this appendix.

In recent years, PSE has actively participated in the ongoing regulatory rulemaking process with the Washington Utilities and Transportation Commission (WUTC), other investor owned utilities (IOUs) and state and industry stakeholders, to help identify a viable model for energy storage in electric utility planning and procurement. The WUTC is currently examining these issues through Dockets UE-151069 and UE-161024. By properly valuing the unique flexibility of energy storage to act as either load or generation, PSE and other stakeholders continue to remove barriers to the inclusion of energy storage in traditional resource planning.

PSE also continues to monitor industry and technology developments associated with batteries and other energy storage technologies. Collaboration with other stakeholders involved in energy storage technology and services has been key to furthering standards for controls, communication and operation of energy storage. Recent industry developments and the implications they have for PSE are described in the following section.



Recent Industry Developments

The energy storage industry has made significant progress since PSE's 2015 IRP. Among the most notable developments are the following.

Policy and Regulatory Environment

Federal and state legislatures and regulatory bodies have used incentives, regulation and policy to reduce barriers to entry for energy storage. Specifically tailored policies have been designed to create frameworks for evaluating the costs and benefits of the technology and a broader market for its adoption. PSE continues to monitor other states' progress in this area, since well-crafted policy is crucial to optimal design of services and clear rules for operation.

- The second energy storage mandate in the U.S. was authorized in June 2015. Oregon House Bill 2193 required the state's investor-owned utilities (Portland Gas & Electric and PacifiCorp) to have a minimum of 5 MWh of energy storage in service by the end of 2019.
- Massachusetts launched the Energy Storage Initiative (ESI) in May 2015 to advance the energy storage segment of the state's clean energy industry.¹ Based on its funded research, ESI has advocated adding up to 600 MW of advanced energy storage technologies on the state's grid by 2025, which would result in over \$800 million in cost savings to ratepayers.² Subsequently, the Massachusetts state legislature passed bill H. 4568 in August 2016; this bill gave the Department of Energy Resources until the end of 2016 to decide whether or not to set a procurement target for electric companies to procure "viable and cost-effective energy storage systems."³ Adoption of such targets is expected by July 1, 2017. This legislation is the third energy storage mandate in the U.S.
- Arizona Public Service (APS) and Salt River Project (SRP) imposed residential demand charges that have made solar-plus-storage systems an increasingly viable option for customers in Arizona to reduce their peak electricity consumption from the grid.⁴
- Hawaiian Electric Company (HECO) closed its net energy metering program and introduced new tariffs to support customer interconnection of distributed energy resources to the grid in October 2015. While the newly introduced "self-supply" tariff would prevent exports of excess energy to the electric grid, it would ensure that

1 / Commonwealth of Massachusetts. *Energy and Environmental Affairs: Energy Storage Initiative*. <http://www.mass.gov/eea/energy-utilities-clean-tech/renewable-energy/energy-storage-initiative/>. Accessed 11/21/2016.

2 / Massachusetts Energy Storage Initiative Study. "State of Charge," September 2016. <http://www.mass.gov/eea/docs/doer/state-of-charge-report.pdf>. Accessed 11/17/2016.

3 / Ibid

4 / Greentech Media. "The Growing Opportunity for Residential Energy Storage in the US," 6/9/2016. <https://www.greentechmedia.com/articles/read/The-Growing-Opportunity-for-Residential-Energy-Storage-in-the-US>. Accessed 11/28/2016.

Appendix L: Electric Energy Storage



customers installing PV systems with energy storage are eligible for an expedited review and approval of their systems in areas of high PV penetration.⁵

- California continues to pass legislation to accelerate the adoption of energy storage resources. In October 2013, the California Public Utilities Commission (CPUC) adopted procurement targets in accordance with AB 2514 that order the three investor-owned state utilities – Pacific Gas and Electric Company (PG&E), Southern California Edison (SCE) and San Diego Gas & Electric (SDG&E) – to install 1,325 MW of storage capacity by 2024. Subsequently, in September 2016, AB 2868 directed utilities to deploy up to 500 MW of additional storage capacity, primarily grid-scale. Further, AB 1637 authorized the CPUC to double its budget for the Self Generation Incentive Program (SGIP) over the next three years, adding an additional \$249 million in funding for distributed energy resources. The revised SGIP will allocate 75 percent of program funds for energy storage, including 15 percent to residential projects.
- The state of New York embarked on Reforming the Energy Vision (REV) in 2015, tasking the state’s energy industry stakeholders to achieve a cleaner, more resilient and more affordable energy system by upgrading and reforming its infrastructure and business model framework. In response, several demonstration projects inspired by REV intend to integrate energy storage technology into New York’s current grid infrastructure. Further, New York City is trying to build upon the 96 MW of solar power installed since 2013 by setting new targets for both energy storage and solar capacity; this includes 100 MWh of energy storage by 2020 and 1 GW of solar capacity by 2030.⁶

Standards

Standards establish a level of quality, performance and reliability for energy storage; they dictate how energy storage systems interact with the grid and each other with regard to operation, communication and safety. PSE’s collaboration with stakeholders and adherence to industry-driven standards of operation are integral to designing reliable energy storage systems that are tailored to the unique demands of our grid and our customers.

- The Modular Energy Storage Architecture (MESA) Standards Group released the first draft of a protocol for communications between utility control centers and energy storage systems (ESS) in November 2016. The open, non-proprietary specification, referred to as MESA-ESS, provides a standard framework for utility-scale ESS data exchanges. PSE is a founding member of this group, which includes a national network of electric utilities and energy storage service providers.

5 / HECO. *Producing Clean Energy: Customer Self-Supply and Grid-Supply Programs*. <https://www.hawaiianelectric.com/clean-energy-hawaii/>. Accessed 11/29/2016.

6 / City of New York. “Climate Week: Solar Power In NYC Nearly Quadrupled Since Mayor de Blasio Took Office and Administration Expands Target,” 9/23/2016. <http://www1.nyc.gov/office-of-the-mayor/news/>. Accessed 11/21/2016.

Appendix L: Electric Energy Storage



- Underwriters Laboratories (UL) issued its first certification for a complete home energy storage system in November 2016. The UL 9540 certification was announced for Enphase Energy's AC Battery. Tesla's second-generation Powerwall and Powerpacks and UniEnergy Technologies (UET) ReFlex energy storage systems have also been UL 9540-certified, and other leading vendors are expected to follow.

Market Structure

The structure of specific energy markets defines the role of energy storage and how competitive it can be relative to other technology and programs, so it's important for PSE to monitor the market structures created by its utility and industry peers. Understanding these designs is critical to our contributions to local and regional efforts to establish transparent guidelines for the participation and compensation of energy storage services.

- The Pennsylvania-New Jersey-Maryland Interconnection (PJM) was the first independent system operator to offer higher payments for fast-responding assets, including energy storage.⁷ (The PJM is comprised of thirteen mid-Atlantic and Midwestern states.) This market design has been a major driver of storage development in the region. As a result, several energy storage projects are operating or under construction in order to take part in PJM's frequency regulation services market. Recent projects have included 31.5 MW of energy storage projects in Illinois and West Virginia (respectively) in 2015, and a 7 MW solar-plus-storage project in Ohio that was completed in 2016. The PJM Interconnect supported 74 percent of the utility-scale battery deployments in the U.S. from 2013 through Q3 2016.⁸
- Indianapolis Power and Light (IPL) began commercial operation of the first grid-scale, battery-based energy storage system in the fifteen-state Midcontinent Independent System Operator (MISO) in July of 2016. The 20 MW energy storage project was designed to deliver enhanced grid reliability and ancillary services, including frequency response, and to increase the ability to balance intermittent resources such as wind or solar energy.⁹ Removing barriers to energy storage market participation has become a higher priority in MISO stakeholder discussions since IPL's first energy storage project was placed in service.

⁷ / Greentech Media. "Faster Frequency Regulation Triples in PJM," 11/8/2013.

<https://www.greentechmedia.com/articles/read/faster-frequency-regulation-triples-in-pjm>. Accessed 11/22/2016.

⁸ / Greentech Media. "U.S. Energy Storage Monitor: Executive Summary, Q4 2016," 12/6/2016.

⁹ / IPL. "IPL Announces Commercial Operation of Battery-Based Energy Storage Array During White House Summit on Renewable Energy and Storage." https://www.iplpower.com/Our_Company/Newsroom/2016. Accessed 11/28/2016.



Major Procurement Efforts

Procurement efforts by energy industry stakeholders create a pipeline for energy storage development by setting targets for electric utilities and power-generating companies to find, acquire and develop an ever-increasing fleet of energy storage systems that meet the needs of the electric grid. These major procurements provide a valuable reference and benchmark that PSE can leverage in soliciting and selecting energy storage technology as solutions for grid services.

- The White House hosted a “Summit on Scaling Renewable Energy and Storage with Smart Markets” in June 2016 that brought together regulators, power companies, municipalities and energy developers to promote greater integration of flexible resources such as energy storage. The Obama administration also announced new executive actions and 33 state and private sector commitments to accelerate the integration of renewable energy and storage. Altogether, these totaled at least 1.3 GW of additional energy storage procurement or deployment in the next five years.¹⁰
- In summer 2016, Con Edison awarded contracts to ten service providers for an aggregate of 22 MW of peak demand reductions, including 897 kW of distributed battery storage by the summer of 2018.¹¹ The contracts were awarded as part of Con Edison’s proposed Neighborhood Program (formerly known as the Brooklyn Queens Demand Management plan); they were approved by New York state regulators in 2014, with the goal of deferring more than \$1 billion in substation upgrades.
- PG&E issued a request for offers (RFO) for up to 74 MW of energy storage resources in December 2014 pursuant to AB 2514 that drew applications totaling 5,000 MW of energy storage. PG&E subsequently announced contracts for 75 MW of energy storage. These included 20 MW of flywheels, 10 MW of zinc-air batteries and a collection of lithium-ion battery projects.¹²
- SCE’s first procurement of 250 MW of energy storage includes contracts for lithium-ion and thermal energy storage projects; the first deployment deadlines are scheduled for the end of 2016. The procurement was announced in November 2014 as part of the utility’s “Local Capacity Requirement” RFO to fulfill capacity required to meet established reliability criteria in targeted areas of SCE’s grid. In September 2016, SCE signed contracts for 125 MW of power that include an assortment of preferred renewable and

10 / The White House. “FACT SHEET: Obama Administration Announces Federal and Private Sector Actions on Scaling Renewable Energy and Storage with Smart Markets,” 6/16/2016. <https://www.whitehouse.gov/the-press-office/2016>. Accessed 12/7/2016.

11 / Utility Dive. “ConEd awards 22 MW of demand response contracts in Brooklyn-Queens project,” 8/8/2016. <http://www.utilitydive.com/news/coned-awards-22-mw-of-demand-response-contracts-in-brooklyn-queens-project/424034/>. Accessed 11/22/2016.

12 / PG&E. “PG&E Presents Innovative Energy Storage Agreements,” 12/2/2015. <https://www.pge.com/en/about/newsroom/newsdetails>. Accessed 11/22/2016.



- alternative technologies, including battery storage. The project, known as the “Preferred Resources Pilot,” will go online between 2019 to 2020 and test the capability of distributed resources and the grid to work together to reliably serve approximately 250,000 residential customers and 30,000 businesses in Orange County.¹³
- SDG&E announced in March 2016 that it is seeking up to 140 MW of new “preferred energy resources” to comply with AB 2514. These include energy storage and other renewable and distributed resources.¹⁴ Altogether, and based on targets set by AB 2514, SDG&E must procure at least 165 MW of energy storage by 2020.
 - HECO received more than 60 proposals for “one or more large-scale energy storage systems able to store 60 to 200 MW of energy storage for up to 30 minutes” in response to an RFP in early 2014. HECO is still working to file agreements with the HPUC, so the expectation for services from the storage devices has been pushed back to 2018.¹⁵

Commercial Deployments and Demonstration Projects

Deployments and demonstration projects utilize energy storage systems (in various scales, technology and configurations) to test the value and optimal use of energy storage on the grid. These specifically designed projects provide energy storage stakeholders with measurable data about services to use for study and analysis of the benefits of energy storage to customers and the grid. PSE monitors the progress of these projects and announcements closely in order to assess the opportunity for similar deployments and customer programs, as well as to guide the tailoring of unique configurations that can better address local obstacles to reliable grid operation.

- The U.S. installed 221 MW of energy storage resources in 2015, a 243 percent increase from 2014. Overall, total installed energy storage for 2016 is anticipated to finish at 260 MW, a 15 percent increase from 2015.¹⁶
- In Vermont, Green Mountain Power began to install its first residential customer-sited energy storage systems in May 2016. Sales of the 500 energy storage systems began in December 2015. Customers could lease a system, purchase a system directly for \$6,500, or purchase “shared access” that would result in a bill credit from the utility. These storage systems are intended for emergency backup power during multi-hour power outages.

13 / Edison International. “O.C. Pilot Tests Whether Clean Energy Resources Can Meet Growing Needs of Major Metro Area,” September 2016. <http://insideedison.com/stories/orange-county-pilot-tests-whether-clean-energy-resources-can-meet-major-metro-needs>. Accessed 11/22/2016.

14 / SDG&E. “SDG&E’s Energy Storage 201, “Procurement Plan Application,” 4/5/2016. <http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=10691>. Accessed 12/14/2016.

15 / Pacific Business News. “Hawaiian Electric pushes back major energy storage plan by a year,” 06/30/2015. <http://www.bizjournals.com/pacific/news/2015/06/30>. Accessed 11/28/ 2016.

16 / Greentech Media. U.S. Energy Storage Monitor, Q4 2016.

<https://www.greentechmedia.com/research/subscription/u.s.-energy-storage-monitor>. Accessed 12/6/2016.

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- Con Edison completed contracts for a distributed resources pilot program, known as the Virtual Power Plan, in 2016. This REV demonstration project will outfit 300 homes in Brooklyn and Queens with leased, high-efficiency solar panels and lithium-ion battery storage systems to explore the revenue streams made possible by software-enabled aggregation of energy storage.¹⁷
- In June 2016, the Arizona Corporation Commission (ACC) ordered APS to spend up to \$4 million to develop a residential battery storage program to facilitate energy storage technologies through demand response or load management. The two programs would be introduced as part of APS's energy efficiency "Demand Side Management Plan."¹⁸
- Texas municipal utilities Austin Energy (Austin, Tex.) and CPS Energy (San Antonio, Tex.) have ongoing pilot initiatives supported by the state. Austin Energy's SHINES program received a \$1 million award from the state of Texas in June 2015 to develop a pilot energy storage system paired with a community solar array, and another \$4.3 million award in February 2016 to pilot a technology platform supporting the integration of distributed energy resources.¹⁹ CPS Energy was awarded \$3 million in grants to kick off its solar-plus-storage program; this will be the largest energy storage system in Texas, and will shift clean energy peak demand periods when completed in 2018.²⁰
- PG&E announced the launch of multiple technology demonstration projects aimed at unlocking benefits at the edge of the grid in July of 2016. PG&E will demonstrate a distributed energy resource management system (DERMS) that includes installing and testing smart inverters and battery storage systems for up to 150 residential customers and 20 commercial customers. The battery storage systems used in the DERMS demonstration will evaluate whether customer-sited energy storage can be used to support the grid operationally during periods of high electric demand.²¹
- SDG&E has proposed a number of programs as part of the DER Integration Plan it filed with the CPUC in July of 2015. They include a pilot project leveraging residential energy storage and testing a new business model that would rely on third-party-owned distribution infrastructure; the goal is to find out if this could defer circuit upgrades. The pilot would also introduce an energy storage tariff rate.^{22, 23}

17 / New York State Department of Public Service. *Reforming the Energy Vision: Demonstration Projects*. <http://www3.dps.ny.gov/W/PSCWeb.nsf/All>. Accessed 11/21/2016.

18 / ACC. "Commission Approves Energy Efficiency Programs that Save APS Customers Money," 06/15/2016. <http://azcc.gov/Divisions/Administration/news/2016Releases>. Accessed 11/28/2016.

19 / Austin Energy. *Austin SHINES*. <http://austinenenergy.com/wps/portal/ae/green-power/austin-shines/austin-shines-innovations-energy-storage/>. Accessed 11/28/2016.

20 / CPS Energy. "CPS Newsroom: TCEQ awards CPS Energy \$3 million grant for solar battery storage program," 6/17/2016. <http://newsroom.cpsenergy.com>. Accessed 11/28/2016.

21 / PG&E. "PG&E Launches Distributed Energy Resource Projects Testing Technology to Unlock Benefits of the Grid," 7/12/2016. <https://www.pge.com/en/about/newsroom/newsdetails>. Accessed 11/22/2016.

22 / SDG&E. "Application of SDG&E (U 902 E) for Approval of Distribution Resources Plan," 7/1/2015. https://www.sdge.com/sites/default/files/regulatory/A_15-07-SDG&E_DRP_Application.pdf. Accessed 11/22/2016.

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- HECO has more than 17 energy storage projects underway or planned for Hawaii at the end of 2016. These projects are intended to (variously) provide grid services, maintain reliable service for customers and explore the technology's ability to support the use of more renewable energy.²⁴ In March 2016, HECO announced an agreement to launch a 10-unit pilot program to enable more customers to interconnect rooftop photovoltaic (PV) systems paired with energy storage systems on the island of Molokai.
- Avista continues to operate its 1 MW/3.2 MWh vanadium redox flow battery system at the Schweitzer Engineering Lab in Pullman, Wash. The \$7 million project included a \$3.2 million grant from the State of Washington's Clean Energy Fund. As of Q4 2016, the project is the largest vanadium redox flow battery storage project in operation in the U.S.
- Snohomish PUD's (SnoPUD) most recent energy storage project, MESA 2 is a 2.2 MW/8.8 MWh vanadium flow battery project located in Everett, Wash.; it is also funded in part by the State of Washington's Clean Energy Fund. Installation of the flow battery project was completed in early 2017.²⁵

23 / SDG&E. "Application of SDG&E (U 902 E) for Approval of Distribution Resources Plan," 7/1/2015. https://www.sdge.com/sites/default/files/regulatory/A_15-07-SDG&E_DRP_Application.pdf. Accessed 11/22/2016.

24 / HECO. Reliability: Energy Storage. <https://www.hawaiianelectric.com/clean-energy-hawaii/producing-clean-energy/other-routes-to-clean-energy/energy-storage>. Accessed 11/28/2016.

25 / Snohomish PUD. Current Energy Storage Projects.

<http://www.snopud.com/PowerSupply/energystorage/projects.ashx?p=2800>. Accessed 11/23/2016.



2. POTENTIAL ELECTRICITY STORAGE SERVICES

Terminology and definitions for energy storage grid services are not yet uniform, but the 2015 U.S. Department of Energy (DOE)/Electric Power Research Institute (EPRI) Electricity Storage Handbook provides the following list (Figure L-2).

Figure L-2: Energy Storage Grid Services²⁶

| | |
|--|---|
| Bulk Energy Services | Transmission Infrastructure Services |
| Electric Energy Time-shift (Arbitrage) | Transmission Upgrade Deferral |
| Electric Supply Capacity | Transmission Congestion Relief |
| Ancillary Services | Distribution Infrastructure Services |
| Regulation | Distribution Upgrade Deferral |
| Spinning, Non-spinning and Supplemental Reserves | Voltage Support |
| Voltage Support | Customer Energy Management Services |
| Black Start | Power Quality |
| Other Related Uses | Power Reliability |
| | Retail Electric Energy Time-shift |
| | Demand Charge Management |

Source: 2015 DOE/EPRI Electricity Storage Handbook in collaboration with NRECA

These applications, how they relate to PSE, and some of the potential challenges to adoption are described below. It is important to note that not all of the services described below have been demonstrated in residential, commercial or utility settings. The ability of a single storage resource to provide these services depends on many factors, among them:

1. minimum required energy storage power (kW or MW) and energy (kWh or MWh),
2. location requirements,
3. availability requirements (both frequency and duration), and
4. system performance characteristics (response time, ramp rate, etc.).

²⁶ / Sandia National Laboratories. DOE/EPRI 2015 Electricity Storage Handbook in Collaboration with NRECA; February 2015. <http://www.sandia.gov/ess/publications/SAND2015-1002.pdf>. Accessed 11/28/2016.

Appendix L: Electric Energy Storage



Moreover, using storage to provide multiple grid services can be complicated, since use for some services can exclude use for other services. For example, an energy storage system that provides transmission reliability service must reserve its storage capacity for contingency needs during certain time periods, rendering it unavailable for other uses during those periods. Detailed modeling is required to evaluate storage resources intended for multiple uses.

Bulk Energy Services

The term “bulk energy services” refers to all of the ways that energy storage is used to avoid the need to generate additional electricity.

Electric Energy Time-shift (Arbitrage)

In this application, storage resources stockpile energy for later use, typically charging when the cost of electricity is low and discharging when the cost of electricity is high. Alternatively, storage resources can provide similar time-shift services to accommodate excess generation when there is limited or no demand for it, typically from renewable resources such as wind or solar photovoltaic (PV). The stored energy can then be released when it's needed, enabling utilities to avoid renewable curtailments that would result in the loss of production tax credits (PTCs) and renewable energy credits (RECs).

Electric Supply Capacity

In this application, storage resources serve as generation supply capacity resources, similar to peaking plants. Historically, peak load demands – rather than economic conditions – have driven decisions on when to build new power plants. If energy storage can provide reliable peaking capacity, it may enable utilities to postpone or eliminate the need for new peaking power plants. PSE also refers to this service as “Energy Supply Capacity Value.”



Ancillary Services

Ancillary services are defined as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system."²⁷ In other words, these services support the reliable delivery of power and energy over the high voltage transmission system.

Regulation (or Frequency Response)

Regulation ensures the balance of electricity supply and demand at all times, particularly over short time frames (from seconds to minutes). Because energy storage can both charge and discharge power, it can help manage grid frequency. Many storage technologies can do this faster and more accurately than other regulating resources. Federal Energy Regulatory Commission (FERC) Order 755 requires that ISOs implement mechanisms to pay for regulation resources based on how responsive they are to control signals. Under the new rules, storage resources with high-speed ramping capabilities receive greater financial compensation than slower storage or conventional resources.

Spinning Reserves, Non-spinning Reserves and Supplemental Reserves

Generation capacity over and above customer demand is reserved for use in the event of contingency events like unplanned outages. "Spinning" reserves are generators that are turned on, idling, waiting for the signal to go and able to ramp up within 10 minutes. Many storage technologies can be synchronized to grid frequency through their power electronics, so they can provide a service equivalent to spinning reserves with minimal to zero standby losses (unlike the idling generators). Energy storage is also capable of providing non-spinning or supplemental reserves, but these services are easier for traditional generators to accomplish cost-effectively.

Voltage Support

This ancillary service is used to maintain transmission voltage within an acceptable range. Advanced power electronics give storage resources with four-quadrant inverters the capability to correct suboptimal or excessive voltage; however, a number of other devices are capable of providing voltage support at low cost, so the value of this service for energy storage is considered to be low.

²⁷ / U.S. Federal Energy Regulatory Commission 1995, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities*, Docket RM95-8-000, Washington, DC, March 29.

Appendix L: Electric Energy Storage



Black Start

This service, typically provided by generators, restores the electric grid following a blackout. While energy storage could theoretically provide this service, black start is of minimal value to PSE, because of its many other low-cost, black start-capable generation resources.

Other Related Uses

Additional services include firming of generation resources, typically wind and solar PV, either as a load following or load ramping support. Excess generation can be stored or released in response to rapid or randomly fluctuating load profiles. As a result, the storage resource can prolong output by flexibly addressing the delta between electric supply capacity and the variable load profile.

PSE's Open Access Transmission Tariff illustrates the relative cost for PSE to provide ancillary services:

Figure L-3: PSE Open Access Transmission Tariff ²⁸

| Service | Rate (\$/kW-yr) |
|-------------------------------------|-----------------|
| Reactive Supply and Voltage Control | \$0.07533 |
| Regulation and Frequency Response | \$126.00 |
| Operating Reserve – Spinning | \$111.00 |
| Operating Reserve – Supplemental | \$108.00 |

²⁸ / OATI OASIS. Puget Sound Energy, Inc.: Open Access Transmission Tariff; 09/01/2016. http://www.oatioasis.com/PSEI/PSEI/docs/2016-09-01_PSE_currently_effective_OATT.pdf. Accessed 11/28/2016.



Transmission Infrastructure Services

These services relate to reliability and economics; they enable the electric transmission system to operate more optimally and efficiently.

Transmission Investment Deferral

When a generation resource like energy storage or demand-side resources can cost-effectively defer capital expenditure in the transmission system, it's called "transmission investment deferral." Transmission resources are sized to handle peak capacity during normal operation with all elements in service, but it must be designed to meet capacity requirements even when portions of the network are out of service. It is possible to use energy storage to address capacity constraints created by periods of peak demand or specific contingencies; however, this is difficult due to the networked nature of the transmission system and storage specifications such as location, sizing, regulatory requirements and system controls. Also, deferring investment in transmission capacity projects is not always the best solution, since these projects usually increase system reliability, which is a valuable benefit. Radial transmission lines, where the battery could provide backup power, are an area where energy storage has more value for reliability.

Transmission Congestion Relief

This refers to using storage resources in a geographic area where locational marginal price (LMP) is jointly defined by the wholesale market price of energy and the amount of location-specific congestion in the electric system. The storage resource would optimize its dispatch based on an hourly LMP price signal. Locational marginal pricing was not modeled in prior versions of PSE's IRP since the Pacific Northwest did not use it. However, now that PSE has begun participating in the Energy Imbalance Market (EIM) administered by the California Independent System Operator (CAISO), storage resources can be assessed for their ability to be deployed downstream of congested transmission corridors where they can potentially discharge during congested periods and minimize congestion in the system. PSE studied energy storage as a potential solution to transmission congestion on the east side of King County, but it did not prove feasible. Chapter 8, Delivery Infrastructure Planning, contains a description of that study.



Distribution Infrastructure Services

These services support the physical infrastructure of the distribution system that connects distribution substations to customer meters.

Distribution Investment Deferral

This is similar to transmission investment deferral, but specific to the distribution system. To relieve overloaded distribution transformers, particularly high-cost substation transformers, energy storage can charge during low load periods and “peak shave” the highest load periods. This may postpone the need for a distribution investment. However, an energy storage system may be limited in its ability to deliver the operational flexibility and reliability improvements that traditional distribution infrastructure provides. For example, using storage to defer a new substation may make it harder to take existing substations offline for maintenance or in response to unplanned outages. For each candidate system, the tradeoffs between reliability, operational flexibility, capacity and cost need to be studied.

Distribution Voltage Support

This service maintains power voltage within acceptable bounds, as defined by ANSI standards (+/- 5 percent of nominal). A storage system could provide voltage support on distribution lines and support a conservation voltage reduction scheme, but the value of this service for energy storage is considered low, because other devices are capable of providing low-cost voltage support.

Customer Energy Management

Storage resources placed on the customer side of the meter can also provide direct benefits to customers, such as increased power quality, reliability, the ability to shift consumption to hours with lower energy rates and demand charges. Although not specifically included as part of this study, PSE has assessed each of these services and their potential application.

Power Quality

This service involves using energy storage to protect customers' on-site loads from short-duration events that affect the quality of power delivered by PSE. Energy storage could be used to address poor power quality to downstream customers, including variations in voltage magnitude or primary frequency, low power factors whereby voltage and current are excessively out of phase with each other, or poor harmonics (i.e., the presence of electric currents or voltages at frequencies other than the primary frequency). Instances of poor power quality can range from

Appendix L: Electric Energy Storage



seconds to a few minutes and the on-site energy storage would be able to monitor the utility power quality and discharges to smooth out disturbances and variations.

Power Reliability

Energy storage can support customer loads in the event of a total loss of power on the grid. During a power outage, the energy storage and customer loads will island and subsequently resynchronize with the utility when power is restored to the grid. The duration of time by which energy storage can mitigate a power outage depends on the energy capacity of the energy storage and the size of the load that it is providing with backup power.

Retail Electric Energy Time-shift

This service involves using energy storage to reduce a customer's overall cost of electricity. Customers could use their energy storage to charge during off-peak time periods when the retail price of electricity is low, then discharge the stored energy during on-peak time periods when the retail price of electricity increases. Since there are no time-of-use or real-time pricing tariffs in PSE's service territory, this service is not available to customers and was not considered further for this study or when assessing services from energy storage placed on the customer's side of the meter.

Demand Charge Management

This service can be used by customers to reduce their overall costs for electric service by reducing their demand during peak periods specified by the utility. As the peak demand can be assessed for the monthly demand charge during any 15-minute interval period, the energy storage must be able to reduce or limit load during all hours of a specified period of time and day. Tariffs will define the peak time of day and days when peak demand charges will be assessed (by kW, whereas the price for electric energy is measured per kWh). The tariffs will also define the time of day and days where no or low demand charges will be assessed, thus providing the optimal time for charging the energy storage. Pricing tariffs that include demand charges are applicable to non-residential customers and are therefore not further considered for residential customers.



3. ENERGY IMBALANCE MARKET

In October 2016, PSE became the third non-California utility to join the Energy Imbalance Market (EIM), a real-time wholesale energy market administered by the California Independent System Operator (CAISO). The EIM connects multiple balancing authorities and utilities operating in eight western states and enables participants to buy and sell power closer to the time that electricity is consumed. The real-time energy supply market enhances grid reliability, generates cost savings for its participants, supports the reduction of congestion on transmission lines and increases the diversity of generation resources.²⁹

As a participant, PSE's transmission system and generators operate on a 15-minute basis to serve either within PSE's own balancing authority area or on behalf of other EIM participants. As a result, PSE is able to reduce reserve obligations and associated costs with readily-available lower-cost resources available via the marketplace. Increased real-time visibility across neighboring grids also enhances PSE's efficient operation and the dispatch of its local generation resources.

Energy storage is a flexible resource that can potentially provide PSE with additional options for participating in the EIM. Primary options include bulk power supply and providing flexible ramping in the EIM. For bulk supply, stored electricity from pumped hydro and batteries (as modeled for the 2017 IRP or in a larger capacity) could be bid into the market. Alternatively, the fast-ramping capability of batteries could provide flexible ramping in the EIM. Storage may also allow PSE to optimize use of its own resources to meet balancing or other needs, thereby freeing up other resources to be provided into the EIM. PSE will look to include new resource types in the future, including storage. PSE may also be able to bid into forward markets in the future and provide the stored electricity as operating reserves for EIM participants seeking to optimize balancing and associated cost. PSE continues to research and analyze the capability of storage resources to qualify and compete as resources in the EIM market.

²⁹ / CAISO. EIM FAQ. <https://www.caiso.com/Documents/EIMFAQ.pdf>. Accessed 3/9/2017.



4. ENERGY STORAGE TECHNOLOGIES

Energy storage encompasses a wide range of technologies and resource capabilities, and these differ in terms of cycle life, system life, efficiency, size and other characteristics. A detailed description of how each technology works, its benefits and limitations, and where it has been deployed is presented in the 2015 PSE IRP in Appendix L. This brief summary focuses on how much of each general type of energy storage has been installed since the 2015 IRP.

Figure L-4: Energy Storage Technology Classes

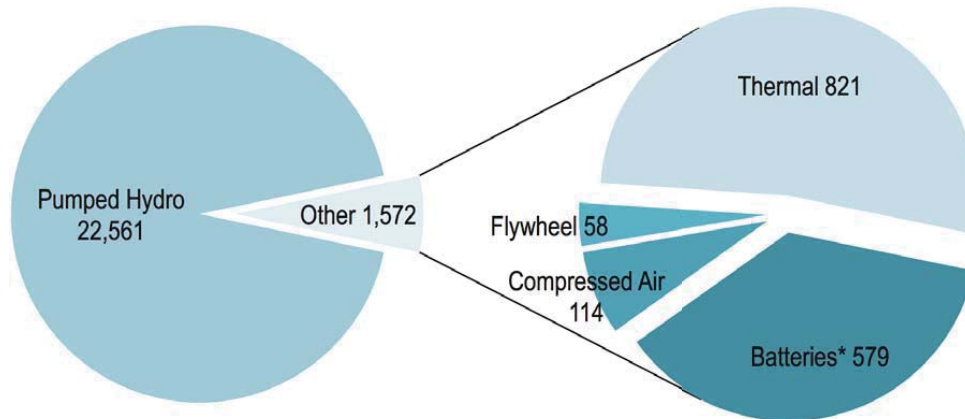
| Technology Class | Examples |
|----------------------------|---|
| Chemical Storage | Batteries |
| Mechanical Storage | Flywheels, Compressed Air |
| Thermal Storage | Ice, Molten Salt, Hot Water |
| Bulk Gravitational Storage | Pumped Hydropower, Advanced Rail/Gravitational Rail |

Although battery technology has attracted a great deal of industry attention in recent years, pumped hydro technology still supplies the majority of grid-connected energy storage in the U.S. today (93.5 percent) due to historical investment. The remaining categories combined comprise 6.5 percent of total installed operational capacity as of 2016, but 100 percent of operational capacity installed since 2013.

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Figure L-5: Installed U.S. Grid-connected Energy Storage in MW, by Technology, as of 11/2016 ³⁰



Batteries include lithium-ion, flow, sodium-based, nickel-based, lead acid, electrochemical capacitors and ultracapacitor batteries

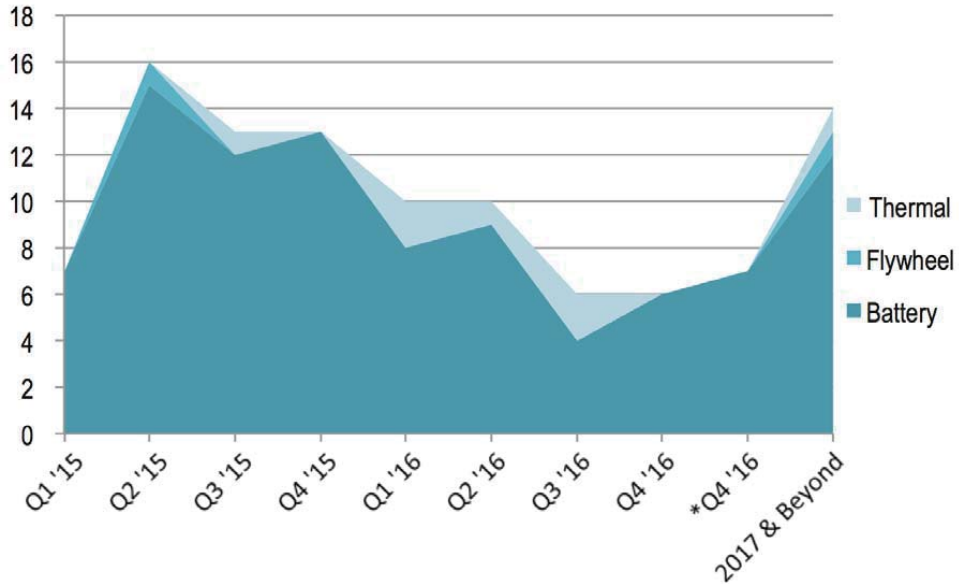
Recent installations and contracted or announced projects tracked by the DOE's energy storage database focus exclusively on battery, flywheel and thermal storage technology. The number of projects and grid-connected or contracted MW of energy storage are displayed in Figures L-6 and L-7, respectively.

³⁰ / U.S. Department of Energy Global Energy Storage Database (DOE GESDB), November 2016
<http://www.energystorageexchange.org>.

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Figure L-6: Number of U.S. Grid-connected Energy Storage Projects Installed or Contracted Since 2015, by Technology ³¹



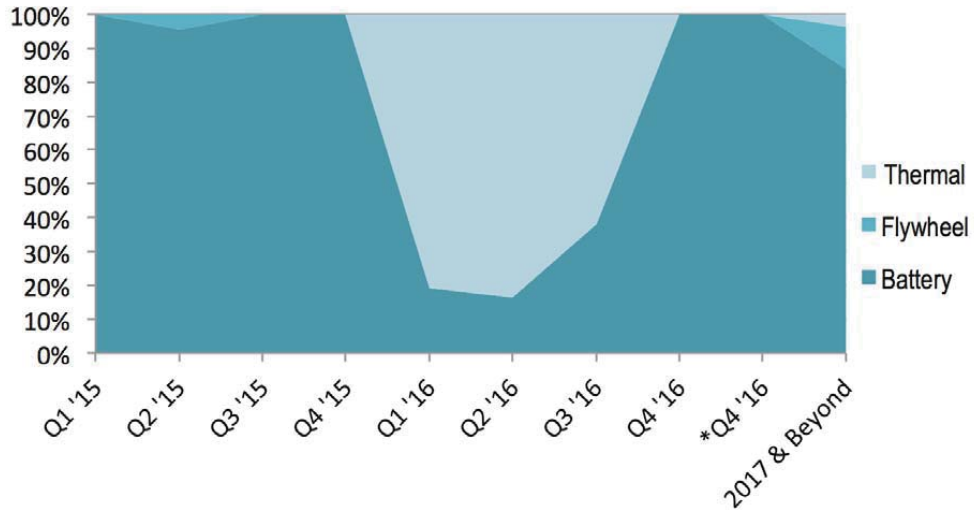
NOTE: Information from the DOE's energy storage database is as of 11/2016, therefore Figure L-6 separates the number of U.S. grid-connected energy storage projects installed as of 11/2016 and those projects anticipated to be installed by year-end 2016.

³¹ / U.S. Department of Energy Global Energy Storage Database (DOE GESDB), November 2016
<http://www.energystorageexchange.org>

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Figure L-7: Percentage Share of the MWs of U.S. Grid-connected Energy Storage Projects, Installed or Contracted Since 2015, by Technology ³²



NOTE: Information from the DOE's energy storage database is as of 11/2016, therefore Figure L-7 separates the number of U.S. grid-connected energy storage projects installed as of 11/2016 and those projects anticipated to be installed by year-end 2016.

³² / Ibid



5. DEVELOPMENT CONSIDERATIONS

The siting of an energy storage resource is an important consideration for development feasibility; it affects both costs and benefits. Some resources, like pumped hydro, must be located in areas with specific geology, water access and transmission lines. Natural gas combustion turbines have similar constraints, plus they face air emissions constraints in many locations as well. Many forms of storage, particularly batteries and ice energy, are more flexible when it comes to sizing and siting. Battery resources can be sized from as small as 1 kW to as large as 1,000 MW and sited at the customer's location or interconnected to the transmission system. Other factors may also limit where storage can be located, among them space availability, permitting and interconnection upgrade requirements. A few examples of different siting options for battery storage resources follow.



54 kW/54 kWh commercial customer-sited lithium-ion battery.



7 kW/14 kWh residential customer-sited lithium-ion battery.

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1 MW/2 MWh customer-sited lithium-ion battery.



1 MW/3.2 MWh distribution-connected vanadium redox flow battery.



Proposed 100 MW/400 MWh transmission-connected battery.



6. GLACIER PILOT PROJECT

In partnership with the Washington State Department of Commerce, PSE commissioned a battery storage pilot project in Glacier, a small town east of Bellingham, Wash. The project included the installation of a 2 MW/4.4 MWh lithium-ion battery system that was interconnected to the 12.5 kV distribution system near Glacier's existing substation during October 2016.



Glacier is served by a radial transmission and distribution line that runs along a heavily forested scenic highway, and the town experiences frequent and lengthy outages because of how challenging it is for repair crews to reach and repair the lines during storms. The project is funded in part by a \$3.8 million Smart Grid Grant from the Washington Department of Commerce; PSE's investment is estimated at \$7.4 million.³³

³³ / PSE. PSE Innovation Project: Glacier Battery Storage Project. <https://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Glacier-battery-storage-project.aspx>.

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The Glacier project tests three primary use cases:

- Outage mitigation
- System-wide peaking (supply capacity)
- System flexibility

Several project locations along PSE's electric grid were considered in addition to Glacier, including Baker River, Crystal Mountain, Frederickson, Lake Holm and Wild Horse. Similar to Glacier, each project site provided a combination of present issues, including a history of recurring outages and potential grid benefits that could result in measurable upgrades to reliability. Ultimately, Glacier was selected as the project site based on its superior combination of economic cost benefit, comparably lower development complexity and costs, and few other options to address the existing reliability concerns.

Pacific Northwest National Laboratories (PNNL) will conduct four to six months of testing and evaluation. Identifying the performance and economic benefits of the project will help PSE determine whether future applications of this technology are feasible and cost effective.

For more information on the Glacier Battery Storage project, please visit:

<http://pse.com/inyourcommunity/pse-projects/system-improvements/Pages/Glacier-battery-storage-project.aspx>.



2017 PSE Integrated Resource Plan

Washington Wind and Solar Costs

The attached report developed for PSE by DNV GL provides capital cost industry benchmarks for wind power and solar power project construction specific to the eastern Washington region.

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Notice and Disclaimer

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- *Project and Site Assumptions – Offshore Wind*
- *Results – Offshore Wind*

Washington State Wind and Solar Power Project Capital Cost Benchmarks

Puget Sound Energy, Inc.

Document No.: 10049032-HOU-T-01-B

Date: 28 April 2017





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Task and objective:

Provide capital cost industry benchmarks for wind power project and solar power project construction specific to the eastern Washington region.

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Reference to part of this report which may lead to misinterpretation is not permissible.

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1 INTRODUCTION

Puget Sound Energy, Inc. (“PSE” or the “Customer”) has requested DNV KEMA Renewables, Inc (DNV GL) provide capital cost industry benchmarks related to both a theoretical wind power plant and a theoretical solar power plant constructed in eastern Washington State. These benchmarks will allow the Customer to make informed investment decisions regarding future wind and solar power plant acquisition or development. In addition to the onshore wind power plant benchmarks, this document also includes comments regarding the increase in capital costs to be expected when considering an offshore wind power plant.

2 WIND POWER PLANT BENCHMARKS

This section presents high-level estimates for capital costs representative of a theoretical utility-size wind power project constructed in eastern Washington State (the “Theoretical Wind Project”).

2.1 Project and Site Assumptions – Onshore Wind


DNV GL used the following assumptions to define the Theoretical Wind Project and determine the numerical values for each cost category:

- Located in eastern Washington State;
- Total capacity of 100 MW;
- Land-use and zoning compatible with wind project development;
- Non-complex terrain (slopes and constraints);
- Reasonable access (not remote; accessible by State highways and County roads);
- Normal geotechnical conditions; and
- Equipped with modern size wind turbines. (i.e. 1.5 MW–3 MW)

All cost estimates presented herein are in 2017 dollars. The “low” and “high” cost estimates are meant to represent the expected range of costs for the Theoretical Wind Project and do not consider outliers (i.e., either extremely high or low data points) DNV GL has observed in its review of existing wind projects.

2.2 Methodology – Onshore Wind

DNV GL has used several sources to identify and estimate capital costs, excluding development costs, namely its proprietary cost database which includes actual and estimated component cost data for 399 wind energy projects located through the United States and Canada. For some cost categories, namely balance of plant (BoP) items, the database has been filtered to include projects constructed in the last 7 years and projects that are similar to the Theoretical Wind Project (i.e. Northwest US, modern turbines used, etc.).



It is noted that capital costs were observed to vary substantially from one project to another. For instance, turbine cost depends on model and options selected, and BoP costs are influenced by local material prices, labor rates, and equipment rental rates. Additionally, BoP costs can vary significantly from project to project, specifically civil costs (i.e., roads, foundations, crane pads) and electrical costs (i.e. collection system and interconnection), depending on location, site access considerations, and terrain.

The capital cost categories cover a broad range of EPC activities including:

- *Wind turbine generators.* This category includes the cost of all heavy crane work and labor necessary for procuring the wind turbines, including transport to the Theoretical Wind Project site, unloading, erection, wiring, and mechanical completion and turbine commissioning. DNV GL's project cost database indicates that turbine costs vary relatively little by region. However, turbine costs are dependent on options selected from the manufacturer such as control packages, monitoring services, warranty periods and other commercial terms.
- *Civil Balance of Plant.* This category includes costs related to the Theoretical Wind Project's civil BoP aspects including:
 - *Roads.* This category includes the costs, including material, equipment and labor, of new roads or road improvements, either public or private, and access roads to turbines. DNV GL has assumed that soils at the Theoretical Wind Project are appropriate for road building.
 - *Foundations.* This category includes costs of wind turbine and transformer foundations. DNV GL has assumed that soils at the Theoretical Wind Project are appropriate for foundation construction and a typical foundation design will be used.
 - *Crane pads.* This category includes costs of crane pads necessary for turbine erection. DNV GL has assumed that soils at the Theoretical Wind Project are appropriate for crane pad construction.
 - *O&M building.* This category covers the buildings and other infrastructure associated with operations and maintenance of the Theoretical Wind Project including any on-site staff offices, storage for spare parts and equipment, and shop space. Given the size of the Theoretical Wind Project, a separate O&M building may not be needed, and may depend on the turbine manufacturer's requirements and local operating staff presence. For the low end estimate, DNV GL has assumed that no O&M building would be built. For the high end estimate, DNV GL has assumed there would be one O&M building on site with between 1,000 and 3,000 square feet.
- *Electric Balance of Plant.* This category includes costs related to the Theoretical Wind Project's electrical BoP including:
 - *Collection system and pad-mount transformers.* This category includes costs associated with underground and overhead electrical collection systems, pad-mount transformers, and SCADA (including fiber network) installation. This category covers all of the electrical wiring and junction boxes required to transmit and regulate the flow of electricity throughout the Theoretical Wind Project, and the fiber optic cables necessary for communication. This cost is dependent on turbine density (i.e. turbine spacing).
 - *Substation and interconnection.* This category includes costs associated with the substation and interconnection (switchyard). Substations generally have switching, protection and control

equipment and one main power transformer and are used to interconnect the a wind project to the electric grid. Interconnection involves the infrastructure needed to link up the substation to the electric grid, including the cost of any new transmission lines or required network upgrades. The costs in this category are highly influenced by the interconnection voltage, the distance to point of interconnection, and the any grid upgrades required.

The following aspects of construction are included in equal proportions within the civil and electric BoP costs described above:

- *Permanent measurement towers.* Permanent measurement towers are used to monitor the wind regime for project operations and to monitor project performance. DNV GL has included cost estimates for zero (low end) to one 80 m, IEC-compliant measurement tower (high end).
- *Detailed engineering.* This category represents the work related to the mechanical design, electrical design, civil design, geotechnical engineering and foundation design, as well as preliminary submittal packages, issued-for-construction (IFC) drawings, and as-built drawings.
- *Construction management.* Management is required to organize and oversee the construction-related tasks involved with building a wind energy project, including cost-control, scheduling, site supervision, and environmental and safety compliance monitoring. Construction management can be performed in-house, by a third-party representative such as an independent engineer, or by the BoP EPC contractor.
- *Other costs.* This category covers BoP costs incurred by the Theoretical Wind Project that do not necessarily fit into of the categories above, such as reactive power compensation equipment.

It is important to note that the following costs are not included in this cost estimates provided: Owner's engineering, capital spares, contingency, financing or major grid upgrades.

2.3 Results – Onshore Wind

DNV GL estimates a total capital cost for the Theoretical Wind Project to range between M\$1.14/MW at the low end and M\$2.19/MW at the high end, as further detailed in Table 2-1 below.

Table 2-1 Capital cost estimates for the Theoretical Wind Project

| Capital Costs ¹ | Low (\$/kW) | Average (\$/kW) | High (\$/kW) |
|-----------------------------|----------------|--------------------|-----------------|
| Wind turbine generators | 860 | 1,080 | 1,510 |
| Civil Balance of Plant | 166 | 224 | 322 |
| Electrical Balance of Plant | 111 | 185 | 358 |
| Total | 1,137 | 1,489 | 2,191 |

1. Does not include owner's engineering, capital spares, contingency, financing or major grid upgrade costs.



3 SOLAR POWER PLANT BENCHMARKS

This section presents high-level estimates for capital costs representative of a theoretical utility-size solar power project constructed in eastern Washington State (the "Theoretical Solar Project").

3.1 Project and Site Assumptions – Solar

DNV GL used the following assumptions to define the Theoretical Solar Project and determine the numerical values for each cost category:

- Located in eastern Washington State;
- Total capacity of 20 MWac / 25 MWdc;
- Land-use and zoning compatible with solar project development;
- Non-complex terrain (slopes and constraints);
- Reasonable access (not remote; accessible by State highways and County roads);
- Normal geotechnical conditions; and
- Equipped with polycrystalline modules, central inverter, and typical single-axis tracker.

All cost estimates presented herein are in 2017 dollars.

3.2 Methodology - Solar

DNV GL has used several sources to identify and estimate capital costs, excluding development costs, including its solar project database which includes actual component cost data for solar projects located through the United States, and Greentech Media (GTM) Research Reports¹.

Capital costs can vary significantly by project, depending on items including, but not limited to: interconnection requirements, grid availability, transmission upgrades, land costs, environmental / permitting requirements, site access considerations, soil conditions, and terrain. Interconnection costs can vary based on the size of the facility. For example, a 10-20 MW distribution facility will require a Federal Energy Regulatory Commission (FERC) Small Generator interconnection process (IP) and will most likely have significantly lower costs, and less extensive distribution upgrade requirements, if any, compared to a Large Generator IP. BoP costs can vary from project to project, specifically civil costs (i.e., roads, foundations (i.e. frost heave and pile refusal considerations), and hydrology requirements) and electrical costs (i.e. AC collection system, dc/ac ratio).

¹ *PV Balance of Systems 2015: Technology Trends and Markets in the U.S. and Abroad*, dated August 2015, by GTM Research and *Q2 2016 Solar Executive Briefing*, dated July 2016, by GTM Research.

3.3 Results - Solar

DNV GL estimates a total capital cost for the Theoretical Solar Project to range between \$1.35/Wac at the low end and \$1.79/Wac at the high end, as further detailed in Table 3-1 below.

Table 3-1 Capital cost estimates for the Theoretical Solar Project

| Capital Costs ¹ | Low (\$/kWac) | Average (\$/kWac) | High (\$/kWac) |
|--|---------------|-------------------|----------------|
| Modules | 500 | 590 | 680 |
| Inverter and Skid | 60 | 85 | 110 |
| Structural BoP | 180 | 215 | 250 |
| DC Electrical BoP | 60 | 70 | 80 |
| AC Subsystem | 50 | 55 | 60 |
| Design, Engineering, Permit, Installation, Other | 555 | 555 | 610 |
| Total | 1,350 | 1,570 | 1,790 |

1. Does not include owner's engineering, capital spares, contingency, financing, substation, O&M building, interconnection or major grid upgrade costs.

For a fixed-tilt system, overall costs will decrease by approximately 10-15%. The major differences are due to decreased structural costs, labor and AC wiring.

4 OFFSHORE CAPITAL COST EXPECTATIONS

Given water depths and bathymetry in the Pacific Northwest, DNV GL expects any near-term offshore wind power project would most likely utilize floating structures to support turbines. Relative to onshore wind, floating offshore wind has significantly higher capital and operating costs but could allow for access to stronger and more consistent wind resources. Cost differences are driven by the following factors:

- *Wind turbine generators* – offshore wind turbines are generally similar to onshore wind turbines in overall architecture, but are typically much larger and designed for operations in a marine environment. While offshore wind turbine's cost per kW is closing in on onshore turbine cost, the cost of the first floating offshore wind turbines are high.
- *Substructure and mooring and anchoring system* – Floating offshore wind turbines are supported by floating support structures that are typically made of steel or concrete. Multiple design concepts are in various stages of development but generally fall into one of three design types: semi-submersibles, spars, or tension-leg platforms (TLPs). These support structures are moored to the seabed to maintain position of the unit.
- *Electrical BoP* – For large scale offshore wind farms, the turbines are typically connected to an offshore substation via a collector system consisting of array cables linking the turbine arrays to the substation. Power from the offshore project is then delivered to shore and to the grid via an export



cable. In comparison to a bottom fixed offshore project, the substation for a floating project will also need to be floating, and the infield cables will need to be dynamic.

- *Installation* – Offshore installation requires specialized equipment and workers trained for working in a marine environment. The offshore environment presents a range of hazards and risks that are not present onshore or are more easily managed. These conditions result in installation costs that are significantly greater for offshore wind projects relative to onshore wind projects.

4.1 Project and Site Assumptions – Offshore Wind

DNV GL used the following assumptions to define a theoretical utility-size offshore wind power project constructed offshore of Washington State (the “Theoretical Offshore Wind Project”):

- Located offshore of Washington State;
- Total capacity of 20-30 MW;
- Wind turbines are supported by floating support structures;
- No offshore substation is assumed due to the small size of the windfarm;
- Equipped with modern size offshore wind turbines. (i.e. 6 MW–8 MW)

All cost estimates presented herein are in 2017 dollars.

4.2 Results – Offshore Wind

Given the lack of any operating floating offshore wind projects in the United States and the limited experience with floating offshore wind globally, the cost estimates presented here are subject to a high level of uncertainty. The costs shown here are for a first of a kind pilot project with a relatively small number of turbines. Significant cost reduction can be achieved from the costs shown here with larger scale projects and the application of lessons learned after further advancement of the offshore industry in the United States.

Table 4-1 Capital cost estimates for the Theoretical Offshore Wind Project

| Capital costs | Low (\$/kW) | Average (\$/kW) | High (\$/kW) |
|-------------------------------------|--------------|-----------------|---------------|
| Wind turbine generators | 2,100 | 2,200 | 2,600 |
| Floating substructure and anchoring | 1,500 | 2,300 | 3,800 |
| Electrical Balance of plant | 300 | 700 | 900 |
| Installation | 1,100 | 2,000 | 3,200 |
| Other | 500 | 1,100 | 2,700 |
| Total | 5,500 | 8,300 | 13,200 |



2017 PSE Integrated Resource Plan

Electric Analysis

This appendix presents details of the methods and models employed in PSE's electric resource analysis and the data produced by that analysis.

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1. PORTFOLIO ANALYSIS METHODS

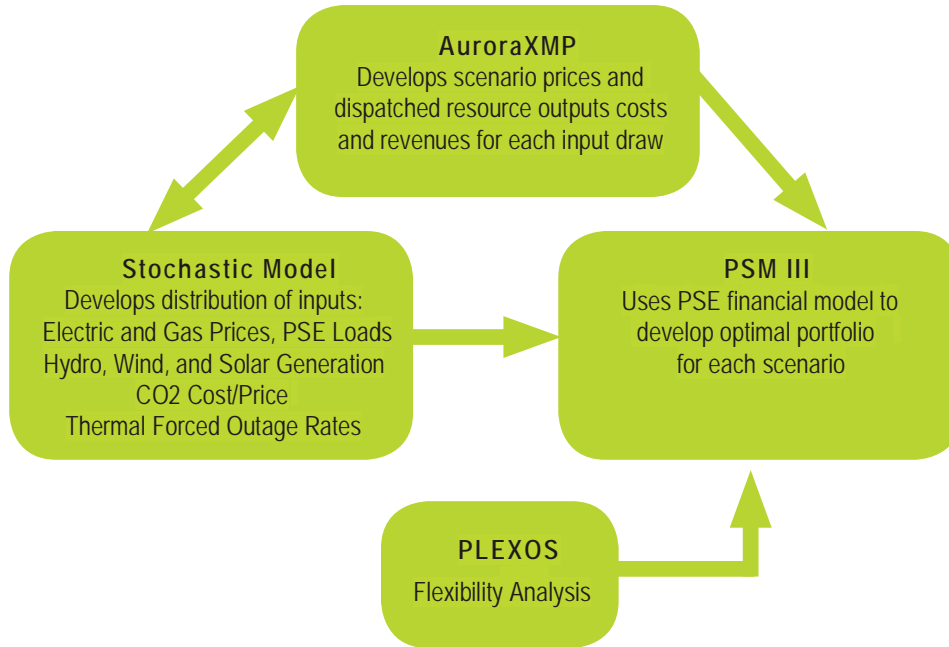
PSE uses four models for electric integrated resource planning: AURORA^{xmp},[®] PLEXOS, the Portfolio Screening Model III (PSM III), and a stochastic model. AURORA analyzes the western power market to produce hourly electricity price forecasts of potential future market conditions and resource dispatch. PLEXOS estimates the cost savings due to sub-hour operation for new generic resources. PSM III creates optimal portfolios and tests these portfolios to evaluate PSE's long-term revenue requirements for the incremental portfolio and risk of each portfolio. The stochastic model is used to create simulations and distributions for various variables. The following diagram shows the methods used to quantitatively evaluate the lowest reasonable cost portfolio.

Figure N-1 demonstrates how the four models are connected. The following steps are used to get to the least-cost portfolio for each of the scenarios and sensitivities.

1. Create Mid-C power prices in AURORA^{xmp} for each of the 14 scenarios.
2. Using the Base Scenario Mid-C prices from AURORA, run the flexibility analysis in PLEXOS to find the flexibility benefit for each of the generic supply-side resources.
3. Using the Mid-C price, dispatch PSE's resources to market for each scenario.
4. The plant dispatch and the flexibility benefit are then input into PSM III to create an optimal portfolio for each of the 14 scenarios and 13 sensitivities.
5. Develop stochastic variables around power prices, gas prices, CO₂ prices, hydro generation, wind generation, PSE loads and thermal plant forced outages.



Figure N-1: Electric Analysis Methodology

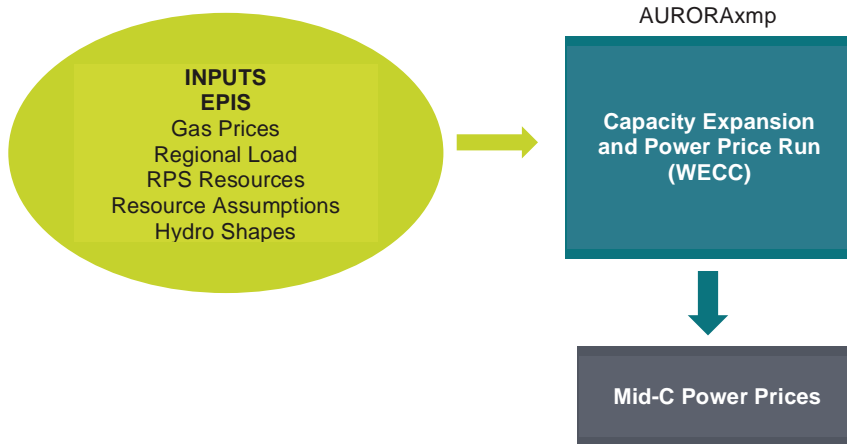




Developing Wholesale Power Prices

Figure N-2 illustrates PSE's process for creating wholesale market prices in AURORA.

Figure N-2: PSE IRP Modeling Process for AURORA Wholesale Power Prices



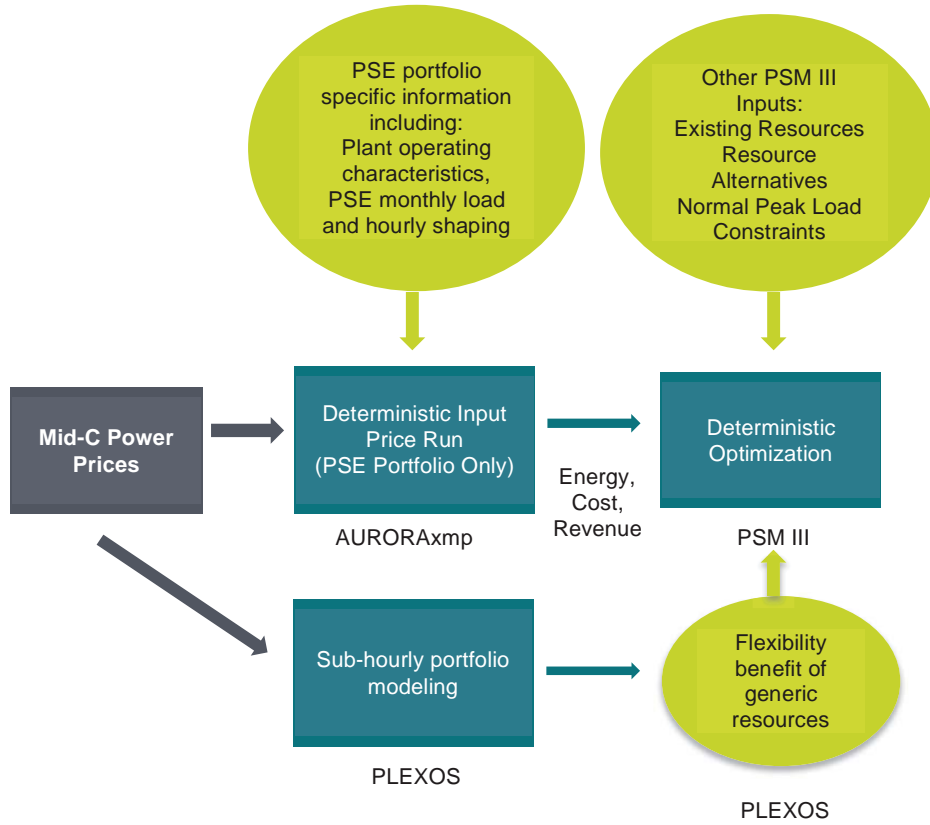
After all of the assumptions are collected and wholesale power prices have been created through AURORA, the next step is portfolio analysis.

Deterministic Portfolio Optimization Analysis

Figure N-3 illustrates PSE's process for creating the lowest cost portfolios through PSM III. Once the power prices are created in AURORA using the WECC-wide database, we use the Mid-C prices as an input to create an input price AURORA analysis. PSE's portfolio is isolated and then dispatched to the Mid-C prices. This AURORA analysis produces estimates of energy (MWh), variable costs including O&M, fuel price and CO₂ price (\$000), market revenue (\$000), and CO₂ emissions (tons) for all existing and generic resources. The Mid-C power prices are also input into PLEXOS to get the flexibility benefit of each supply-side resource. These results are used as inputs for PSM III to create the least-cost portfolio for a scenario using Frontline Systems' Risk Solver Platform optimization model.



Figure N-3: PSE IRP Modeling Process for Portfolio Optimization





Stochastic Risk Analysis

With stochastic risk analysis, we test the robustness of the candidate portfolios. In other words, we want to know how well the portfolio might perform under different conditions. The goal is to understand the risks of different candidate portfolios in terms of costs and revenue requirements. This involves identifying and characterizing the likelihood of bad events and the likely adverse impacts they may have on a given candidate portfolio.

For this purpose, we take the portfolio candidates (drawn from a subset of the lowest cost portfolios produced in the deterministic analysis) and run them through 250 simulations¹ that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO₂ prices. From this analysis, we can observe how risky the portfolio may be and where significant differences occur when risk is analyzed. The goal of the process is to find the set of resources with the lowest cost and the lowest risk.

Analysis Tools

A Monte Carlo approach is used to develop the stochastic inputs. Monte Carlo simulations are used to generate a distribution of resource outputs (dispatched to prices and must-take power), costs and revenues from AURORAxmp. These distributions of outputs, costs and revenues are then used to perform risk simulations in the PSM III model where risk metrics for portfolio costs and revenue requirements are computed to evaluate candidate portfolios.

Risk Measures

The results of the risk simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10 percent of outcomes (called TailVar90). This risk measure is the same as the risk measure used by the Northwest Power and Conservation Council (NPCC) in its power plans. Additionally, PSE looked at annual volatility by calculating the standard deviation of the year-to-year percent changes in revenue requirements. A summary measure of volatility is the average of the standard deviations across the simulations, but this can be described by its own distribution as well. It is important to recognize that this does not reflect actual expected rate volatility. The revenue requirement used for portfolio analysis does not include rate base and fixed-cost recovery for existing assets.

¹ / Each of the 250 simulations is for the twenty-year IRP forecasting period, 2018 through 2037.



2. PORTFOLIO ANALYSIS MODELS

The AURORA Dispatch Model

PSE uses the AURORA model to estimate the regional wholesale market price of power used to serve our core customer load. The model is described below in general terms to explain how it operates, with further discussion of significant inputs and assumptions.

The following text was provided by EPIS, Inc. and edited by PSE.

AURORA is a fundamentals-based program, meaning that it relies on factors such as the performance characteristics of supply resources and regional demand for power and transmission to drive the electric energy market using the logic of a production costing model. AURORA models the competitive electric market, using the following modeling logic and approach to simulate the markets: Prices are determined from the clearing price of marginal resources. Marginal resources are determined by “dispatching” all of the resources in the system to meet loads in a least-cost manner subject to transmission constraints. This process occurs for each hour that resources are dispatched. Resulting monthly or annual hourly prices are derived from that hourly dispatch.

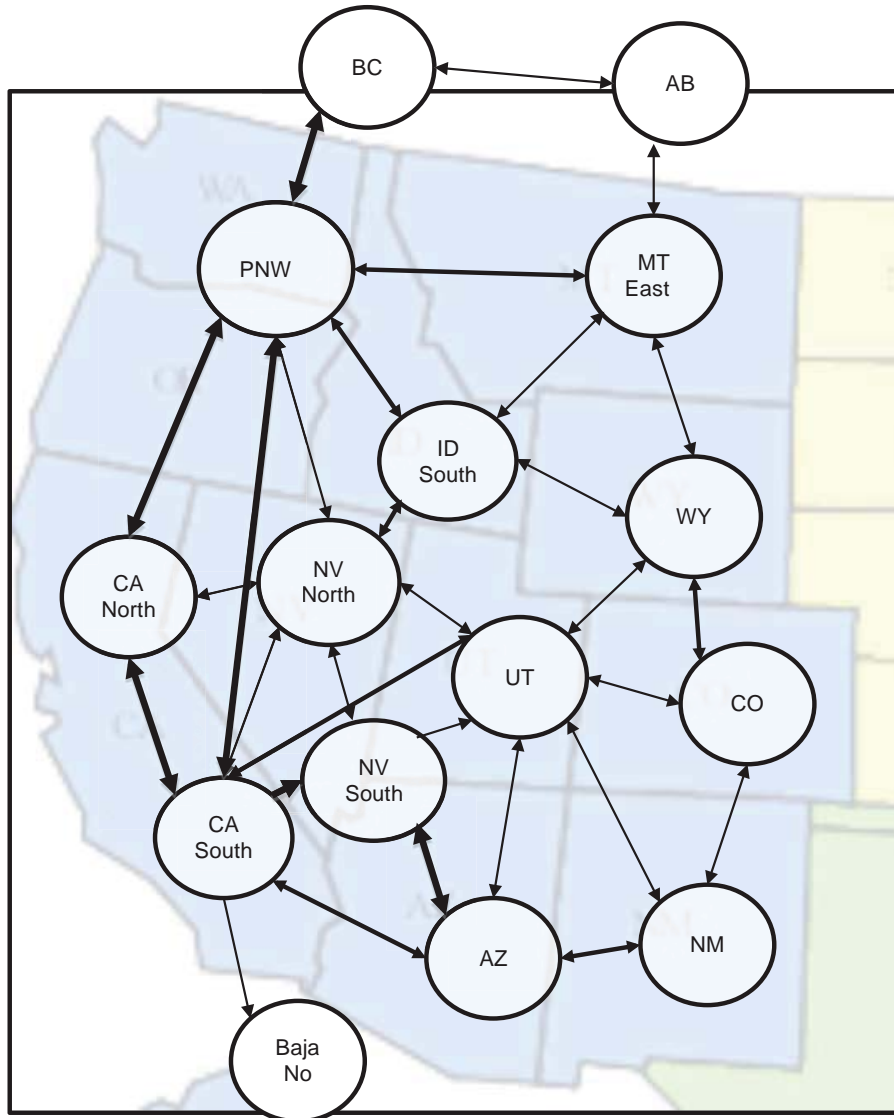
AURORA uses information to build an economic dispatch of generating resources for the market. Units are dispatched according to variable cost, subject to non-cycling and minimum-run constraints until hourly demand is met in each area. Transmission constraints, losses, wheeling costs and unit start-up costs are reflected in the dispatch. The market-clearing price is then determined by observing the cost of meeting an incremental increase in demand in each area. All operating units in an area receive the hourly market-clearing price for the power they generate.

AURORA estimates all market-clearing prices for the entire WECC, but the market-clearing price used in PSE's modeling is the Mid-Columbia hub, or Mid-C price.

Figure N-4 is a depiction of the AURORA system diagram used for the WECC dispatch. The lines and arrows in the diagram indicate transmission links between zones. The heavier lines represent greater capacity to flow power from one zone to another. The Pacific Northwest (PNW) Zone is modeled as the Mid-Columbia (Mid-C) wholesale market price. The Mid-C market includes Washington, Oregon, northern Idaho and western Montana.



Figure N-4: AURORA System Diagram





Long-run Optimization

AURORA also has the capability to simulate the addition of new generation resources and the economic retirement of existing units through its long-term optimization studies. This optimization process simulates what happens in a competitive marketplace and produces a set of future resources that have the most value in the marketplace. New units are chosen from a set of available supply alternatives with technology and cost characteristics that can be specified through time. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable, unless reserve margin targets are selected. (That is, when investors can recover fixed and variable costs with an acceptable return on investment.) AURORA uses an iterative technique in these long-term planning studies to solve the interdependencies between prices and changes in resource schedules.

PLEXOS/Flexibility Analysis

PLEXOS is used to estimate the impact of selected generic resources on system dispatch cost at a sub-hourly timeframe. PLEXOS is a sophisticated software platform that uses mathematical optimization combined with advanced handling and visualization to provide a high-performance, robust simulation system for electric power, water and gas. It is an hourly and sub-hourly chronological production simulation model which utilizes mixed-integer programming (MIP) to simulate electric power market, and to co-optimize energy and ancillary service provisions. The model first performs unit commitment and economic dispatch at a day-ahead level, and then re-dispatches these resources in real-time to match changes in supply and demand at a sub-hourly level.

For the IRP analysis, PSE utilizes a two-stage simulation approach to represent day-ahead schedule (DA stage) and real-time operations (RT stage) in PLEXOS. The DA stage determines unit commitment decision of PSE's generators on an hourly basis. Reserve requirements at the DA-stage include contingency reserves, regulation up and down reserves, and balancing up and down reserves. The RT stage runs for each 5-minute interval of the year. For each 5-minute interval, online resources will ramp up and/or down to meet the changes in demand and intermittent renewable resources within the hour. Quick-start peaker units can also be started or shut down in the RT stage.

To estimate the flexibility benefit of incremental resources, PLEXOS first runs the base case, which contains only PSE's current resource portfolio. Then, PLEXOS is run again with the addition of one new generic resource. The sub-hourly production cost result of the case with the base portfolio is then compared to the production cost of the case with the additional resource.



Any cost reduction to the portfolio is assumed to be attributed to the new resources. PSE tested each supply-side resource identified in the IRP and incorporated the flexibility benefit to the cost in the portfolio analysis. Except for storage resources, cost reductions that occur in the DA stage are assumed to overlap with PSE's economic evaluation of the resources using AURORA. To avoid double counting, only cost reductions provided at the RT stage (incremental to DA stage cost savings) are added to the portfolio analysis. Since storage resources were not evaluated using AURORA, the full PLEXOS-based cost savings for storage (jointly for the DA and RT stages) is included in the portfolio analysis.

Portfolio Screening Model III (PSM III)

PSM III is a spreadsheet-based capacity expansion model that the company developed to evaluate incremental costs and risks of a wide variety of resource alternatives and portfolio strategies. This model produces the least-cost mix of resources using a linear programming, dual-simplex method that minimizes the present value of portfolio costs subject to planning margin and renewable portfolio standard constraints.

The solver used for the linear programming optimization is Frontline Systems' Risk Solver Platform. This is an Excel add-in that works with the in-house financial model. Incremental costs include: a) the variable fuel cost and emissions for PSE's existing fleet, b) the variable cost of fuel emissions and operations and maintenance for new resources, c) the fixed depreciation and capital cost of investments in new resources, d) the booked cost and offsetting market benefit remaining at the end of the 20-year model horizon (called the "end effects"), and e) the market purchases or sales in hours when resource-dispatched outputs are deficient or surplus to meet PSE's need.

The primary input assumptions to the PSM are:

1. PSE's peak and energy demand forecasts,
2. PSE's existing and generic resources, their capacities and outage rates,
3. expected dispatched energy (MWh), variable cost (\$/MWh) and revenue (\$/MWh) from AURORAmp for existing contracts and existing and generic resources,
4. capital and fixed-cost assumptions of generic resources,
5. financial assumptions such as cost of capital, taxes, depreciation and escalation rates,
6. capacity contributions and planning margin constraints,
7. renewable portfolio targets, and
8. flexibility benefit from PLEXOS (\$/kw-yr)



Mathematical Representation of PSM III

The purpose of the optimization model is to create an optimal mix of new generic resources that minimizes the 20-year net present value of the revenue requirement plus end effects (or total costs) given that the portfolio meets the planning margin (PM) and the renewable portfolio standard (RPS), and subject to other various non-negativity constraints for the decision variables. The decision variables are the annual integer number of units to add for each type of generic resource being considered in the model. We may add one or two more constraints later on. The revenue requirement is the incremental portfolio cost for the 20-year forecast.

Let:

gn, gr – index for generic non-renewable and renewable resource at time t, respectively;
 xn, xr – index for existing non-renewable and renewable resource at time t, respectively;
 d(gn) – index for decision variable for generic non-renewable resource at time t;
 d(gr) - index for decision variable for generic renewable resource at time t;

AnnCapCost = annual capital costs at time t for each type of resource (the components are defined more fully in the Excel model);

VarCost = annual variable costs at time t for each type of resource (the components are defined more fully in the Excel model);

EndEff = end effects at T, end of planning horizon, for each type of generic resource only (the components are defined more fully in the Excel model);

ContractCost = annual cost of known power contracts;

DSRCost = annual costs of a given demand-side resources;

NetMktCost = Market purchases less market sales of power at time t;

RECSales = Sales of excess RCS over RPS-required renewable energy at time t

Cap = capacities of generic and existing resources, and DSR resources;

PM = planning margin to be met each t;

MWH = energy production from any resource type gn,gx,xn,xr at time t;

RPS = percent RPS requirement at time t;

PkLd = expected peak load forecast for PSE at time t;

EnLd = forecasted Energy Load for PSE at generator without conservation at time t;

LnLs = line loss associated with transmission to meet load at meter;

DSR = demand side resource energy savings at time t;

r = discount rate.

Appendix N: Electric Analysis



Annual revenue requirement (for any time t) is defined as:

$$RR_t = \sum_{gn} d(gn) * [AnnCapCost(gn) + VarCost(gn)] + \sum_{gr} d(gr) * [AnnCapCost(gr) + VarCost(gr)] + \sum_{xr} VarCost(xr) + \sum_{xr} VarCost(xr) + ContractCost + DSRCost + NetMktCost - RECSales.$$

The objective function for the model is the present value of RR to be minimized. This function is non-linear with integer decision variables.

$$PVRR = \sum_{t=1}^T RR_t * [1/(1+r)^t] + [1/(1+r)^{20}] * [\sum_{gn} d(gn) * EndEff(gn) + \sum_{gr} d(gr) * EndEff(gr)].$$

The objective function is subject to two constraints

CONSTRAINT #1. The planning margin was found using PSE's Resource Adequacy Model consistent with the 2015 Optimal Planning Standard. Details about the planning margin can be found later in this appendix. In the model, the planning margin is expressed as a percent, and it is used as a lower bound on the constraint. That is, the model must minimize the objective function while maintaining a minimum of this planning margin percent capacity above the load in any given year. Below is the mathematical representation of how the planning margin is used as a constraint for the optimization.

$$\sum_{gn} d(gn) * Cap(gn) + \sum_{gr} d(gr) * Cap(gr) + \sum_{xr} Cap(xr) + \sum_{xn} Cap(xn) \geq PkLd + PM \text{ for all } t;$$

CONSTRAINT #2. PSE is subject to the Washington state renewable target as stated in RCW 19.285. The load input for PSM is the load at generator, so that the company generates enough power to account for line loss and still meet customer needs. The RPS target is set to the average of the previous two years' load at meter less DSR. The model must minimize the objective function while maintaining a minimum of the total RECs needed to meet the state RPS. Below is the mathematical representation of how the RPS is used as a constraint for the optimization.



$$\sum_{gr} d(gr) * MWH(gr) + \sum_{xr} MWH(xr) \geq RPS * \frac{\sum_{t=2}^{t-1} (EnLd * (1 - LnLs) - DSR)}{2} \quad \text{for all } t;$$

$d(gn)$, $d(gr) \geq 0$, and are integer values for all t ,

Other restrictions include total build limits. For example, for the generic wind, 5 plants may be built in a year, for a total of 10 plants over the 20-year time horizon. In the comparison between east and west builds (relative to the Cascade mountain range), the westside natural gas plants were limited to a total of 1,000 MW over the 20 years for both peakers and baseload CCCT.

The model is solved using Frontline Systems' Risk Solver Platform software that provides various linear, quadratic, and nonlinear programming solver engines in Excel environments. Frontline Systems is the developer of the Solver function that comes standard with Excel. The software solves this non-linear objective function typically in less than a minute. It also provides a simulation tool to calculate the expected costs and risk metrics for any given portfolio.

End Effects

The IRP calculation of end effects includes the following: a) a revenue requirement calculation is made for the life of the plant, and b) replacement costs are added for plants that retire during end effects to put all proposals on equal footing in terms of service level.

REVENUE REQUIREMENT. Revenue requirement for end effects is based on the operational characteristics of the 20th year in the dispatch model and an estimate of dispatch, based on the last 5 years of AURORA dispatch. The revenue requirement calculation takes into account the return on ratebase, operating expenses, book depreciation and market value of the output from the plant. The operating expenses and market revenues are escalated at a standard escalation rate using an average of the last 5 years of AURORA dispatch as the starting point.



REPLACEMENT COSTS ON AN EQUIVALENT LIFE BASIS. To account for the differences in lives of projects the model includes a replacement resource at the end of the project life in the end effects period. Capacity resources are replaced with an equivalent type and amount of generic capacity resource, while renewable resources are replaced by an equivalent generic wind plant on a REC basis. The fixed capital cost of the replacement resource is added based on the estimated generic resource cost in the year of replacement on a level annual basis – equal annual costs until the end of the end-effects period. The variable cost, market revenue and fixed operations cost are included based on an estimate of the costs using the standard inflation factor and the dispatch from the last 5 years of AURORA dispatch. By adding replacements in end effects on a levelized cost basis, the model is creating equivalent lives for all the resources. The end-effects period extends 34 years beyond the initial 20-year planning horizon.

Monte Carlo Simulations for the Risk Trials

PSE utilized the 250 simulations from the stochastic model as the basis for the 1,000 risk trials. For each of the 1,000 trials, a simulation was chosen at random from the 250 simulations and the revenue requirement for the portfolio was calculated using all the outputs associated with that simulation (Mid-C power price, CO₂ cost/price, Sumas natural gas prices, hydro generation, wind generation and PSE load).

Stochastic Portfolio Model

The goal of the stochastic modeling process is to understand the risks of alternative portfolios in terms of costs and revenue requirements. This process involves identifying and characterizing the likelihood of bad events and the likely adverse impacts of their occurrence for any given portfolio. The modeling process used to develop the stochastic inputs is a Monte Carlo approach. Monte Carlo simulations are used to generate a distribution of resource energy output (dispatched to prices and must-take), costs and revenues from AURORA_{xmp}. These distributions of outputs, costs and revenues are then used to perform risk simulations in the PSM III model where risk metrics for portfolio costs and revenue requirements are computed to evaluate alternative portfolios. The stochastic inputs considered in this IRP are Mid-C power price, gas prices for Sumas hub, PSE loads, hydropower generation, wind generation, risk of CO₂ prices and thermal plant forced outages. This section describes how PSE developed these stochastic inputs.



Development of Monte Carlo Simulations for the Stochastic Variables

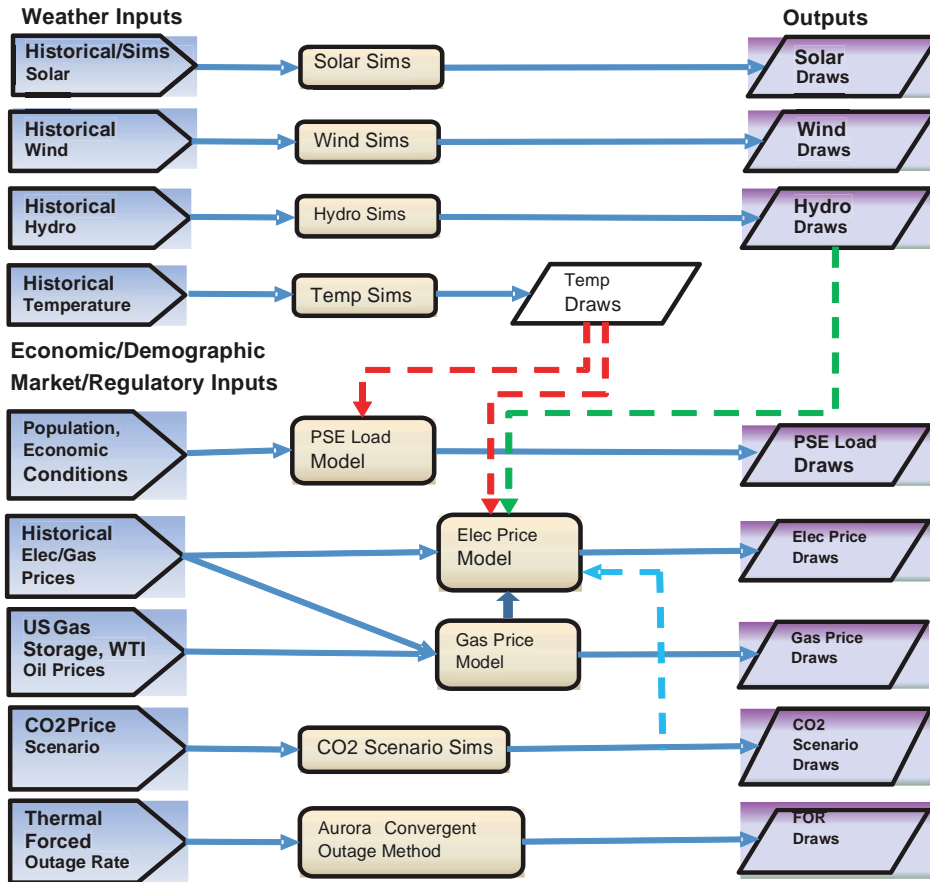
A key goal in the stochastic model is to be able to capture the relationships of major drivers of risks with the stochastic variables in a systematic way. One of these relationships, for example, is that variations in Mid-C power prices should be correlated with variations in Sumas gas prices, contemporaneously or with a lag. Another important aspect in the development of the stochastic variables is the imposition of consistency across simulations and key scenarios. This required ensuring, for example, that the same temperature conditions prevail for a load simulation and for a power price simulation. Figure N-5 shows the key drivers in developing these stochastic inputs. In essence, weather variables, long-term economic conditions and energy markets, and regulation determine the variability in the stochastic variables. Furthermore, two distinct approaches were used to develop the 250 Monte Carlo simulations for the inputs: a) loads and prices were developed using econometric analysis given their connection to weather variables (temperature and water conditions), key economic assumptions and the risks of CO₂ price policy, and b) temperature, hydro and wind variability were based directly on historical information assumed to be uniformly distributed, while the risks of a CO₂ prices were based on probability weights.

The econometric equations estimated using regression analysis provide the best fit between the individual explanatory values and maximize the predictive value of each explanatory variable to the dependent variable. However, there exist several components of uncertainty in each equation, including: a) uncertainty in the coefficient estimate, b) uncertainty in the residual error term, c) the covariate relationship between the uncertainty in the coefficients and the residual error, and d) uncertainty in the relationship between equations that are simultaneously estimated. Monte Carlo simulations utilizing these econometric equations capture these elements of uncertainty.

By preserving the covariate relationships between the coefficients and the residual error, we are able to maintain the relationship of the original data structure as we propagate results through time. For a system of equations, correlation effects between equations are captured through the residual error term. The logic of the linked physical and market relationships needs to be supported with solid benchmark results demonstrating the statistical match of the input values to the simulated data.



Figure N-5: Stochastic Model Diagram





PSE LOAD FORECAST. PSE developed a set of 250 Monte Carlo load forecast simulations by allowing two sets of variable inputs to vary for each simulation: weather and economic-demographic conditions. For each simulation there is no “normal” weather for the forecast horizon. Instead, the 250 simulations draw from 87 weather scenarios, or “weather strips,” each with 20 years of consecutive historical temperatures. The first weather strip is historical data starting in 1929 and continuing through 1948. The second weather strip starts in 1930 and continues through 1949. Weather strips starting after 1996 did not have 20 years of consecutive weather data available. Therefore, for each weather strip starting after 1996 the data series continues through 2015, then wraps around to weather from January 1, 1989 and continues from that point. Therefore, recent historical weather is oversampled in the weather scenarios. The temperatures were from two sets of data: a) 1929-1947 data from Portage Bay (near the University of Washington), and b) 1948-2015 data from SeaTac Airport. The heating degree days (HDDs) and cooling degree days (CDDs) were based on each weather strip run through the 20-year demand forecast model to get the impacts on monthly/hourly profiles and use per customer.

Monte Carlo simulations on economic and demographic inputs are based on historical standard errors of growth in macroeconomic and key regional inputs into the model such as population, employment and income. The stochastic simulation also accounts for the error distribution of the estimated customer counts and use-per-customer equations and the estimated equation parameters.

Why does PSE use different historical periods for different load analysis?

The Resource Adequacy Model (RAM) and the load forecasts in the scenario and stochastic portfolio analyses are done using different historical periods because these analyses are used for different types of planning.

The stochastic analysis performed by the RAM uses 80 years of historic weather and hydro conditions in addition to risks in market reliance, variability of wind generation and random forced outages in thermal plants. Because the risks in market reliance need to be consistent with the regional outlook where the 80 years of hydro conditions and 77 years of weather years were imposed, PSE’s Resource Adequacy Model was revised to account for these conditions in a consistent way.

The goal of the stochastic portfolio analysis is to examine the resource plans over a wide range of potential futures, knowing the region will not experience normal weather (load) and hydro conditions each year during the planning horizon, including variations in gas and electric prices, wind generation and thermal forced outages. In fact, most years may be abnormal in at least one of the aspects listed above. Understanding the strengths and weakness of each candidate



portfolio over a wide variety of potential futures is essential for a thorough analysis of each candidate portfolio. This stochastic portfolio model uses 83 weather years starting from 1929. While no correlations were imposed on weather and hydro conditions, each of these factors was correlated with prices and loads.

Figures N-6 and N-7 depict a graphical representation of the load forecast simulations for energy and peak.

Figure N-6: Load Forecast Simulations – Annual Energy (aMW)

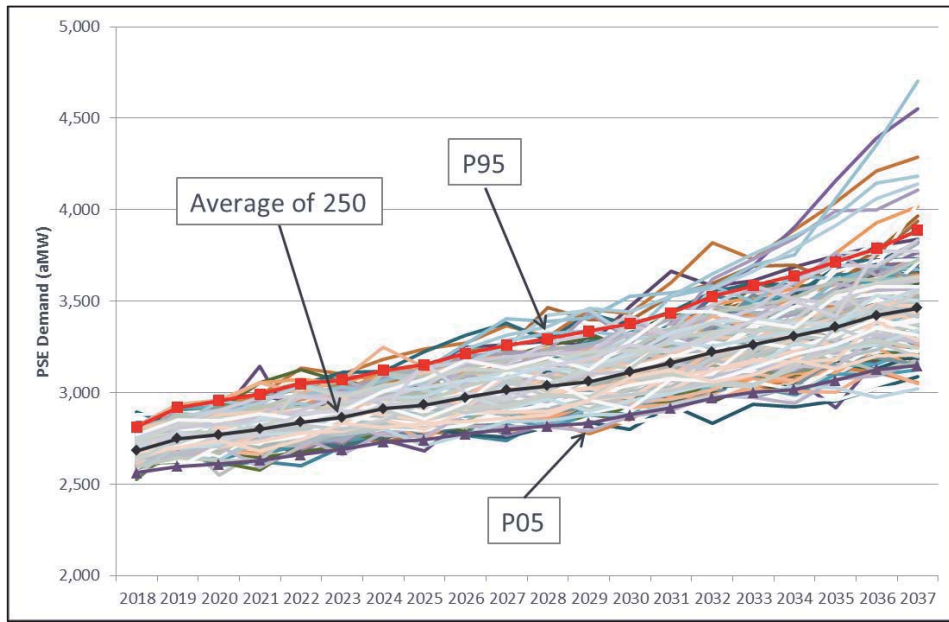
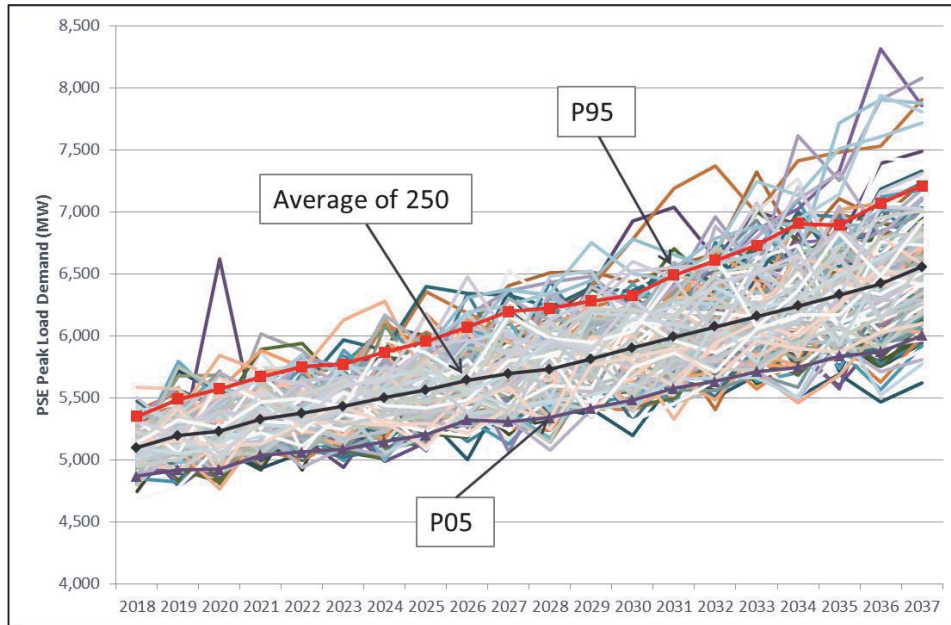




Figure N-7: Load Forecast Simulations – December 1-hour Peak (MW)



GAS AND POWER PRICES. The econometric relationship between prices and their explanatory variables is shown in the equations below:

Sumas Gas Price = $f(\text{US Gas Storage Deviation fr. 5 Yr Avg, Oil Price, Lagged Oil Price, Time Trend, Fracking Effects})$

Mid-C Power Price = $f(\text{Sumas Gas Price, Regional Temperature Deviation from Normal, Mid-C Hydro Generation, Day of Week, Holidays})$

A semi-log functional form is used for each equation. These equations are estimated simultaneously with one period autocorrelation using historical daily data from January 2005 to December 2016. The Fracking Effects in the Sumas gas price equation accounted for the impacts of fracking technology on the historical gas price series starting in 2010.

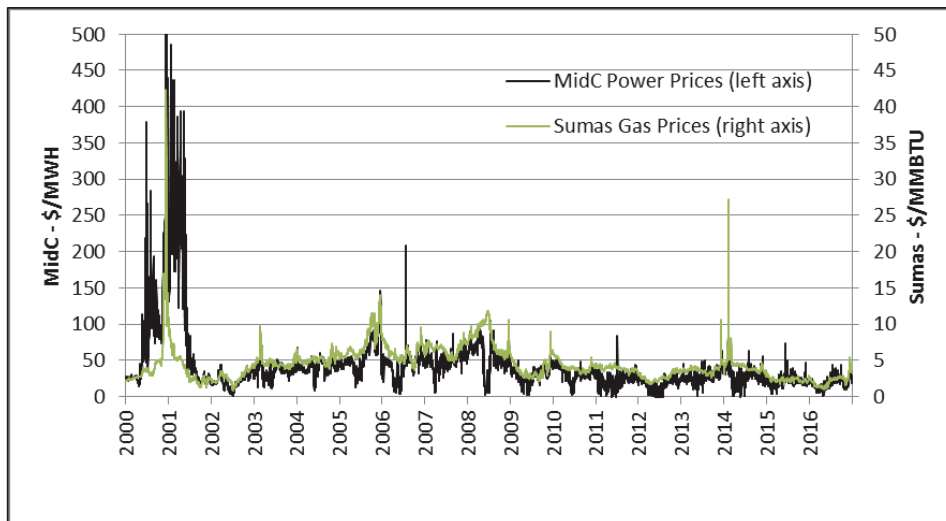
Monte Carlo simulations were obtained based on the error distributions of the estimated equations, oil price simulations, temperature simulations and hydro condition simulations. Gas price simulations were further adjusted so that the 10th percentile and 90th percentiles correspond to the low and high gas price scenarios, respectively, based on the rank leveled



price of each simulation. The price simulations were calibrated to ensure that the means of adjusted distributions are equal to the base case prices. Hourly power prices were then obtained using the hourly shape for the base case from AURORAxmp. Mid-C power price simulations in the presence of risks of CO₂ cost/price policies were adjusted based on the observed changes in power price forecasts from AURORAxmp model runs when CO₂ costs/prices were imposed at different levels. Mid-C power prices are generally higher when CO₂ costs/prices are included.

Figure N-8 shows the historical trends in daily Mid-C power price and Sumas gas price from 2000 through 2016, including the price spikes in late 2000 to early 2001 due to the California crisis.

Figure N-8: Historical Mid-C Power Price and Sumas Gas Price



The annual Sumas gas price simulations are shown in Figure N-9. The Annual Mid-C power price simulations are shown in Figure N-10.



Figure N-9: Annual Sumas Gas Price Simulations

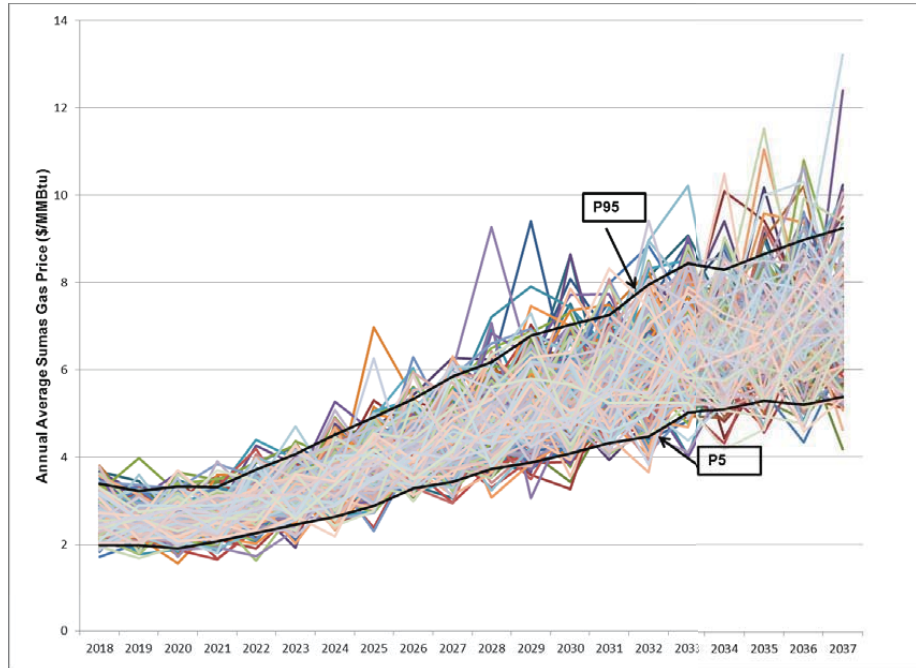
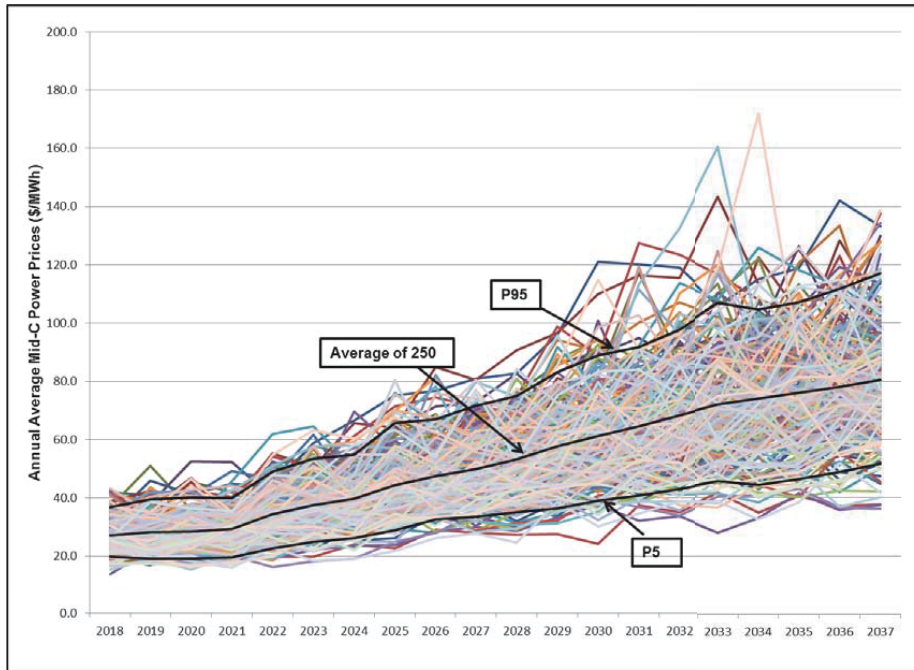




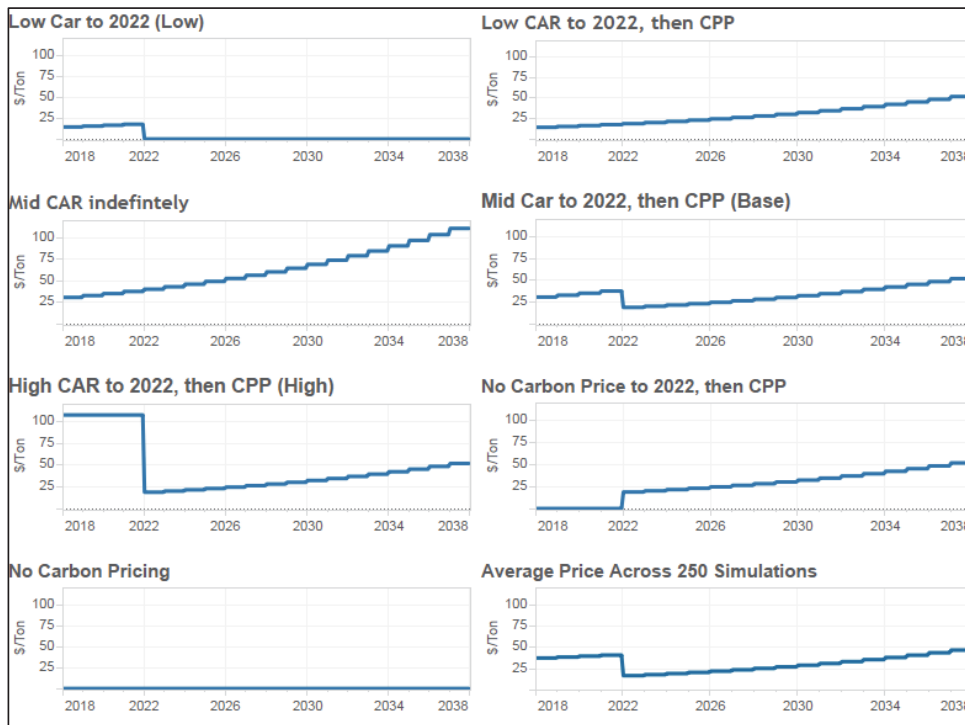
Figure N-10: Annual Mid-C Price Simulations





RISKS OF CO₂ PRICE. There exists significant uncertainty around future CO₂ policy, thus PSE modeled several different pricing paths as part of the IRP. Given the possible range of CO₂ price per ton assumed in the deterministic scenarios, as described in Chapter 4, equal probabilities were assigned to each of the 14 scenarios. Figure N-11 shows the annual CO₂ cost/price simulations with the weighted average of all simulations.

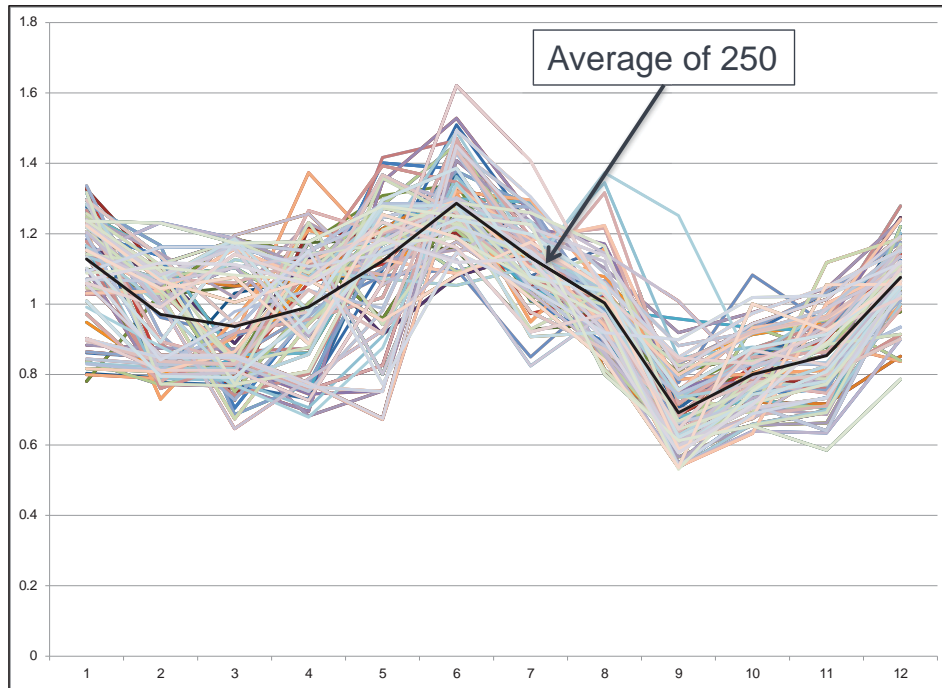
Figure N-11: Annual CO₂ Price Inputs, Weighted Average Simulation CO₂ Price





HYDRO GENERATION. Monte Carlo simulations for each of PSE's hydro projects were obtained using the 80-year historical Pacific Northwest Coordination Agreement Hydro Regulation data (1929-2008). Each hydro year is assumed to have an equal probability of being drawn in any given calendar year in the planning horizon. Capacity factors and monthly allocations are drawn as a set for each of the 250 simulations. A different set of 250 hydro simulations is applied for each year in the planning horizon. Figure N-12 shows the monthly flows/capacity factors for all five PSE contracted Mid-C projects. See Appendix D for discussion of which projects PSE has contracted.

Figure N-12: Monthly Capacity Factor for 5 Mid-C Hydro Projects





WIND GENERATION. As part of the IRP, PSE models what happens when potential new resources are introduced into PSE's existing portfolio. PSE generates, balances or purchases energy from five different existing wind farms within the region. These existing resources enable the IRP to draw upon four years (2012-2016) of actual simultaneous wind generation across farms. Although this seems sufficient, PSE's IRP models need 250 unique 8,760 hourly profiles, which exhibit the typical wind generation patterns, to test in portfolio stochastics. Since wind is an intermittent resource, one of the goals in developing the generation profile for each wind project considered in this IRP is to ensure that this intermittency is preserved. The other goals are to ensure that correlations across wind farms and the seasonality of wind generation are reflected. Thus, to form the 250 unique simulations, we sample a 24-hour day in a given month to form 250 series of 8,760 wind generation profiles. The distribution of the combined 250 simulations reflects the underlying observed distribution of monthly and hourly capacities, as well as observed cross-farm correlations.

Prior to the 2017 IRP, PSE had limited wind generation data to form stochastic wind profiles for new resources. Thus, PSE contracted with DNV GL to independently generate synthetic wind data, informed by their expertise in technical design and environmental operating conditions. DNV GL supplied PSE with 1,000 sets of 8,760 wind profiles ranging from 2000-2016. Sites and technologies modeled included offshore Washington wind, generic eastern Washington wind, generic Montana wind, and generic western Washington wind. For each resource, PSE randomly sampled annual profiles from over 17,000 possible profiles to form a set of 250 8,760 profiles for each resource.

Figure N-13 illustrates the frequency of the annual capacity factor for the generic wind project across all 250 simulations.



Figure N-13a: Wind Simulations, Frequency of Annual Capacity Factor for 250 Simulations for Generic Resources

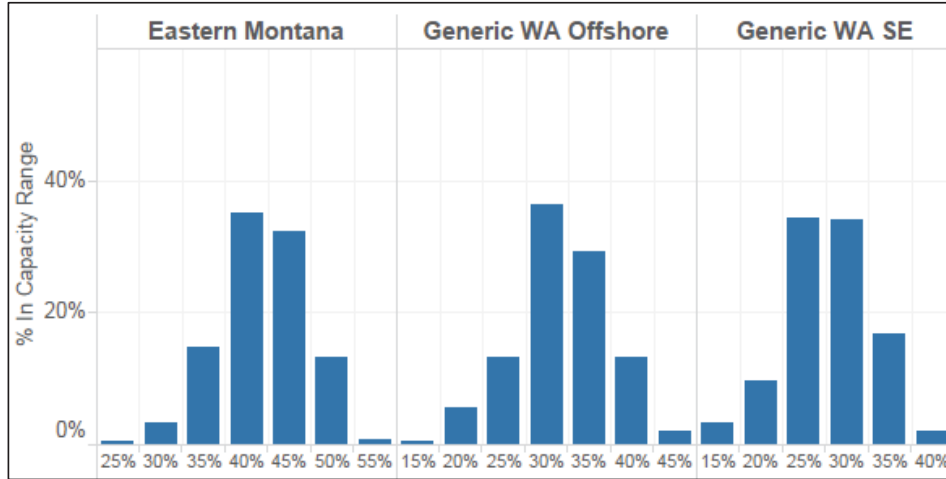


Figure N-13b: Wind Simulations, Box-Whisker Plot of Annual Capacity Factor for 250 Simulations for Generic Resources

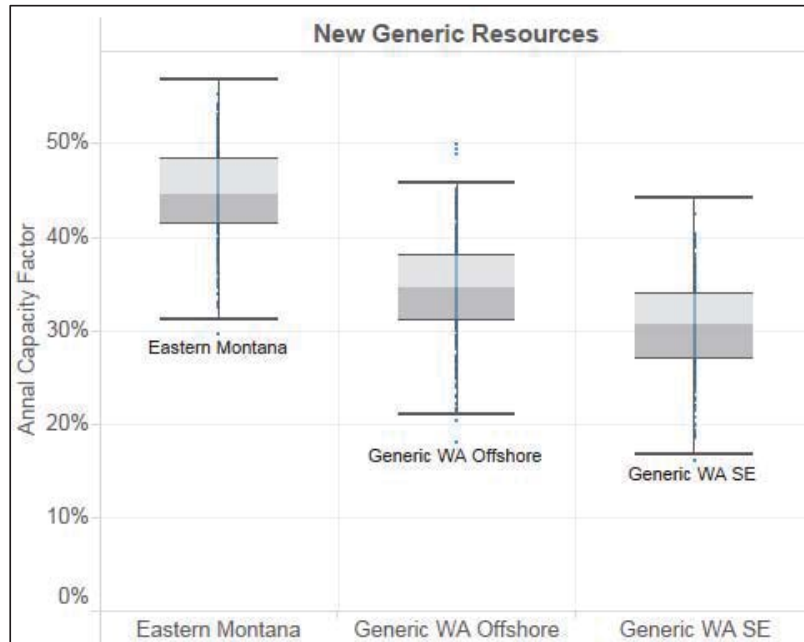




Figure N-14: Wind Simulations,
Sample Moments of 250 Simulations for Generic Resources

| Type | Resource | Mean | Standard Deviation | Min | Max | P25 | Median | P75 |
|---------|---------------------|-------|--------------------|-------|-------|-------|--------|-------|
| Generic | Eastern Montana | 44.6% | 4.9% | 29.6% | 56.9% | 41.3% | 44.6% | 48.3% |
| | Generic WA Offshore | 34.4% | 5.6% | 18.0% | 50.0% | 31.0% | 34.6% | 37.9% |
| | Generic Eastern WA | 30.4% | 5.0% | 16.0% | 44.1% | 26.9% | 30.6% | 33.8% |

THERMAL PLANT FORCED OUTAGES. “Convergent” outage method in AURORAmp is used to model unplanned outages (forced outage) for the thermal plants. This capability ensures the simulated outage rate is convergence to an input forced outage rate in every risk iteration. The actual timing of the outage, however, will change from iteration to iteration. The logic considers each unit’s forced outage rate and mean repair time. When the unit has planned maintenance schedule, the model will ignore those hours in the random outage scheduling. In other words, the hours that planned maintenance occurs is not accounted in forced outage rate.

AURORA Risk Modeling of PSE Portfolios

The economic dispatch and unit commitment capabilities of AURORAmp are utilized to generate the variable costs, outputs and revenues of any given portfolio and input simulations. The main advantage of using AURORAmp is its fast hourly dispatch algorithm for 20 years, a feature that is well known by the majority of Northwest utilities. It also calculates market sales and purchases automatically, and produces other reports such as fuel usage and generation by plant for any time slice. Instead of defining the distributions of the risk variables within AURORAmp, however, the set of 250 simulations for all of the risk variables (power prices, gas prices, CO₂ costs/prices, PSE loads, hydro generation and wind generation) are fed into the AURORAmp model. The thermal plant forced outage is simulated in AURORA at the same time as it is running the dispatch for the simulation. Given each of these input simulations, AURORAmp then dispatches PSE’s existing portfolio and all generic resources to market price. The results are then saved and passed on to the PSM III model where the dispatch energy, costs and revenues for each simulation are utilized to obtain the distribution of revenue requirements for each set of generic portfolio builds.



Risk Simulation in PSM III

In order to perform risk simulation of any given portfolio in PSM III, the distribution of the stochastic variables must be incorporated into the model. The base case 250 simulations of dispatched outputs, costs and revenues for PSE's existing and generic resources were fed into PSM III from AURORAxmp and the stochastic model as described above. Note that these AURORAxmp outputs have already incorporated the variability in gas and power prices, CO₂ price, PSE's loads, hydro and wind generation from the stochastic model. Frontline Systems' Risk Solver Platform Excel add-on allows for the automatic creation of distributions of energy outputs, costs and revenues based on the 250 simulations that PSM III can utilize for the simulation analysis. In addition, peak load distribution, consistent with the energy load distribution, was incorporated into the PSM III. Given these distributions, the risk simulation function in the Risk Solver Platform allowed for drawing 1,000 trials to obtain the expected present value of revenue requirements, TailVar90 and the volatility index for any given portfolio. In addition to computing the risk metrics for the present value of revenue requirements, risk metrics are also computed for annual revenue requirements and market purchased power costs. The results of the risk simulation are presented in Chapter 6 and in the "Outputs" section of this appendix.



3. KEY INPUTS AND ASSUMPTIONS

AURORA Inputs

Numerous assumptions are made to establish the parameters that define the optimization process. The first parameter is the geographic size of the market. In reality, the continental United States is divided into three synchronous regions, and limited electricity transactions occur between these regions. The western-most region, called the Western Electricity Coordinating Council (WECC), includes the states of Washington, Oregon, California, Nevada, Arizona, Utah, Idaho, Wyoming, Colorado and most of New Mexico and Montana. The WECC also includes British Columbia and Alberta, Canada, and the northern part of Baja California, Mexico. Electric energy can be traded along several paths in the WECC through these areas, but can only be traded to other interconnections via direct current tie lines.

For modeling purposes, the WECC is divided into 16 zones, primarily by state and province, except for California which has three zones and Nevada which has two areas. Oregon, Washington, Idaho north and Montana west are combined into one zone, which is used to represent Mid-C market. These zones approximate the actual market activity in the WECC.

All generating resources are included in the resource database, along with characteristics of each resource, such as its area, capacity, fuel type, efficiency and expected outages (both forced and unforced). The resource database assumptions are based on the EPIS North_American_DB_2016_v3 version produced in April 2016 with updates to include coal, NG plant retirements, and new WECC builds. See following sections for more details.

Many states in the WECC have passed statutes requiring Renewable Portfolio Standards (RPS) to support the development of renewable resources. Typically, an RPS state has a specific percentage of energy consumed that must come from renewable resources by a certain date (e.g., 10 percent by 2015). While these states have demonstrated clear intent for policy to support renewable energy development, they also provide pathways to avoid such strict requirements. Further details of these assumptions are discussed in the Section titled "Renewable Portfolio Standard (WECC)," below.



Water availability greatly influences the price of electric power in the Northwest. PSE assumes that hydropower generation is based on the average stream flows for the 80 historical years of 1929 to 2008. While there is also much hydropower produced in California and the Southwest (e.g., Hoover Dam), it does not drive the prices in those areas as it does in the Northwest. In those areas, the normal expected rainfall, and hence the average power production, is assumed for the model. For sensitivity analysis, PSE can vary the hydropower availability using the 80-year historical stream flows.

Electric power is transported between areas on high voltage transmission lines. When the price in one area is higher than it is in another, electricity will flow from the low-priced market to the high-priced market (up to the maximum capacity of the transmission system), which will move the prices closer together. The model takes into account two important factors that contribute to the price: First, there is a cost to transport energy from one area to another, which limits how much energy is moved; and second, there are physical constraints on how much energy can be shipped between areas. The limited availability of high voltage transportation between areas allows prices to differ greatly between adjacent areas. The 2017 IRP uses default transmission lines assumptions in EPIS's North_American_DB_2016_v3.

Regional Load Forecast

Load forecasts are created for each area. These forecasts include the base-year load forecast and an annual average growth rate. Since the demand for electricity changes over the year and during the day, monthly load shape factors and hourly load shape factors are included as well. All of these inputs vary by area: For example, the monthly load shape would show that California has a summer peak demand and the Northwest has a winter peak. For the 2017 IRP, load forecasts for Oregon, Washington, Montana and Idaho were based on the Northwest Power and Conservation Council (NPCC) 2016 regional forecast mid-term update load forecast, net of conservation.

Natural Gas Prices

For gas price assumptions, PSE uses a combination of forward market prices, fundamental forecasts acquired in November 2016 from Wood Mackenzie. Wood MacKenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international factors, as well as Canadian markets and liquefied natural gas (LNG) exports. Three gas price forecasts are used in the scenario analysis.

Appendix N: Electric Analysis

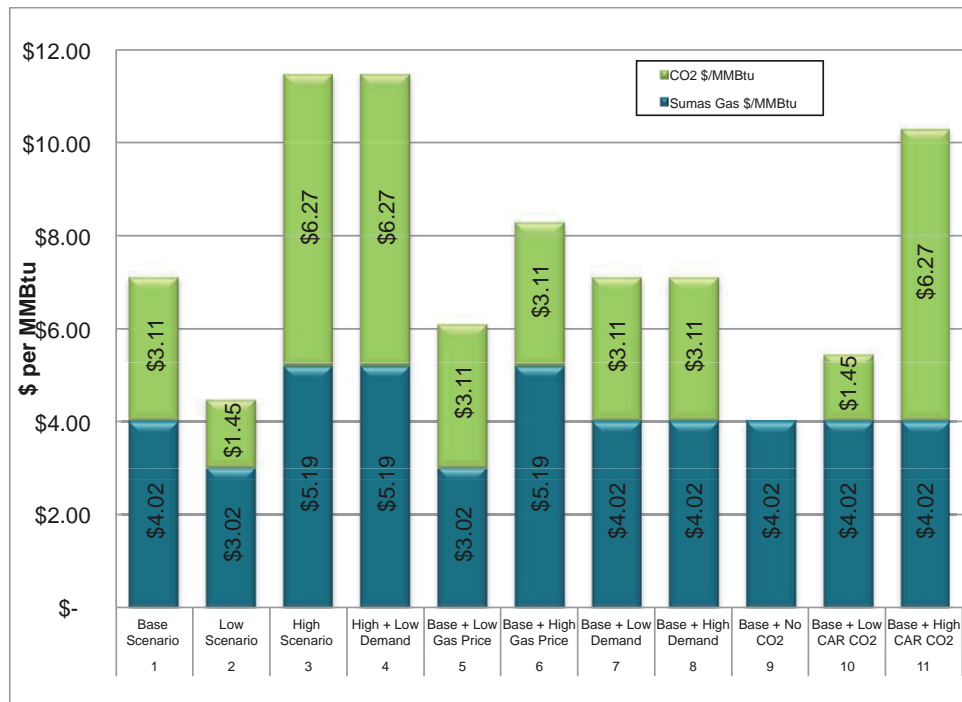


LOW GAS PRICES. These reflect Wood Mackenzie's long-term low price forecast for 2018-2037.

MID GAS PRICES. From 2018-2021, this IRP uses the three-month average of forward marks for the period ending November 27, 2016. Forward marks reflect the price of gas being purchased at a given point in time for future delivery. Beyond 2021, this IRP uses Wood Mackenzie long-run, fundamentals-based gas price forecasts. The 2017 IRP Base Scenario uses this forecast.

HIGH GAS PRICES. These reflect Wood Mackenzie's long-term high price forecast for 2018-2037.

Figure N-15: Levelized Gas Prices by Scenario
(Sumas Hub, 20-year levelized 2018-2037, nominal \$)





CO₂ Price

The carbon prices in this IRP reflect the range of potential impacts from several key pieces of carbon regulation. The two most important carbon regulations are reflected in the 2017 IRP. They are Washington state's Clean Air Rule (CAR) and the federal Environmental Protection Agency Clean Power Plan (CPP) rules. CAR regulations apply to both electric and gas utilities, and CPP regulations apply only to baseload electric resources. The annual CAR CO₂ prices modeled are presented in Figure N-16 and CPP CO₂ prices are presented in Figure N-17.

Mid CO₂ prices

The 2017 IRP Base Scenario uses this forecast.

MID CAR TO 2022 - \$30 PER TON IN 2018 TO \$111 PER TON IN 2037

CPP FROM 2022-2037 – \$19 PER TON IN 2022 TO \$52 PER TON IN 2037

CAR estimate is based on the Washington Dept. of Ecology's cost/benefit analysis of the CAR. CPP estimate is based on Wood MacKenzie's estimated CO₂ price for California AB32 and is applied WECC-wide as a CO₂ price to all existing and new baseload generating units affected under the CPP.

Low CO₂ prices

LOW CAR CO₂ PRICE TO 2022: \$15 PER TON IN 2018 TO \$51 PER TON IN 2037

NO CPP

CAR estimate is based on Wood MacKenzie's estimated CO₂ price for California.

High CO₂ Prices

HIGH CAR CO₂ PRICE TO 2022: \$108 PER TON IN 2018 TO \$108 PER TON IN 2037

CPP FROM 2022-2037: \$19 PER TON IN 2022 TO \$51 PER TON IN 2037

CAR estimate is based on PSE's fundamental REC price from the 2015 IRP. It reflects the difference between the levelized cost of power and the levelized cost of wind in the 2015 IRP. CPP estimate is based on Wood MacKenzie's estimated CO₂ price for California AB32.

Figure N-16: Annual CAR CO₂ Costs (Nominal \$/Ton)

| | Low | Base | High |
|------|-------|--------|--------|
| 2018 | 15.41 | 30.71 | 107.75 |
| 2019 | 16.59 | 32.87 | 107.75 |
| 2020 | 17.85 | 35.18 | 107.75 |
| 2021 | 19.22 | 37.64 | 107.75 |
| 2022 | - | 40.27 | 107.75 |
| 2023 | - | 43.09 | 107.75 |
| 2024 | - | 46.11 | 107.75 |
| 2025 | - | 49.34 | 107.75 |
| 2026 | - | 52.78 | 107.75 |
| 2027 | - | 56.48 | 107.75 |
| 2028 | - | 60.44 | 107.75 |
| 2029 | - | 64.67 | 107.75 |
| 2030 | - | 69.21 | 107.75 |
| 2031 | - | 74.06 | 107.75 |
| 2032 | - | 79.24 | 107.75 |
| 2033 | - | 84.78 | 107.75 |
| 2034 | - | 90.70 | 107.75 |
| 2035 | - | 97.05 | 107.75 |
| 2036 | - | 103.83 | 107.75 |
| 2037 | - | 111.09 | 107.75 |

Figure N-17: Annual CPP CO₂ Costs (Nominal \$/Ton)

| | Low | Mid |
|------|-----|-------|
| 2018 | - | 14.36 |
| 2019 | - | 15.37 |
| 2020 | - | 16.45 |
| 2021 | - | 17.60 |
| 2022 | - | 18.82 |
| 2023 | - | 20.14 |
| 2024 | - | 21.55 |
| 2025 | - | 23.06 |
| 2026 | - | 24.67 |
| 2027 | - | 26.40 |
| 2028 | - | 28.25 |
| 2029 | - | 30.23 |
| 2030 | - | 32.35 |
| 2031 | - | 34.62 |
| 2032 | - | 37.04 |
| 2033 | - | 39.63 |
| 2034 | - | 42.40 |
| 2035 | - | 45.37 |
| 2036 | - | 48.54 |
| 2037 | - | 51.93 |

Figure N-18a: CO₂ Prices by Scenario with CAR and CPP Combined

| | CO ₂ Price | Base ¹ | Low | High ² | Base No CO ₂ | Base + Low CAR CO ₂ | Base + High CAR CO ₂ |
|------|-----------------------|-------------------|------|-------------------|-------------------------|--------------------------------|---------------------------------|
| 2018 | CAR | 30.71 | 0.00 | 107.75 | 0 | 15.41 | 107.75 |
| 2019 | | 32.87 | 0.00 | 107.75 | 0 | 16.59 | 107.75 |
| 2020 | | 35.18 | 0.00 | 107.76 | 0 | 17.85 | 107.76 |
| 2021 | | 37.64 | 0.00 | 107.75 | 0 | 19.22 | 107.75 |
| 2022 | CPP | 18.82 | 0.00 | 18.82 | 0 | 18.82 | 18.82 |
| 2023 | | 20.14 | 0.00 | 20.14 | 0 | 20.14 | 20.14 |
| 2024 | | 21.56 | 0.00 | 21.56 | 0 | 21.56 | 21.56 |
| 2025 | | 23.06 | 0.00 | 23.06 | 0 | 23.06 | 23.06 |
| 2026 | | 24.67 | 0.00 | 24.67 | 0 | 24.67 | 24.67 |
| 2027 | | 26.40 | 0.00 | 26.40 | 0 | 26.4 | 26.4 |
| 2028 | | 28.25 | 0.00 | 28.25 | 0 | 28.25 | 28.25 |
| 2029 | | 30.23 | 0.00 | 30.23 | 0 | 30.23 | 30.23 |
| 2030 | | 32.35 | 0.00 | 32.35 | 0 | 32.35 | 32.35 |
| 2031 | | 34.62 | 0.00 | 34.62 | 0 | 34.62 | 34.62 |
| 2032 | | 37.04 | 0.00 | 37.04 | 0 | 37.04 | 37.04 |
| 2033 | | 39.63 | 0.00 | 39.63 | 0 | 39.63 | 39.63 |
| 2034 | | 42.40 | 0.00 | 42.40 | 0 | 42.4 | 42.4 |
| 2035 | | 45.37 | 0.00 | 45.37 | 0 | 45.37 | 45.37 |
| 2036 | | 48.54 | 0.00 | 48.54 | 0 | 48.54 | 48.54 |
| 2037 | | 51.93 | 0.00 | 51.93 | 0 | 51.93 | 51.93 |

NOTES

1. Scenarios Base + Low Gas, Base + High Gas, Base + Low Demand, and Base + High Demand have the same CO₂ prices as the Base Scenario.
2. Scenario High +Low Demand has the same CO₂ prices as the High Scenario.

Figure N-18b: CO₂ Prices by Scenario by Single CO₂ Policy

| | Base w/ CAR only | Base w/ CPP only | Base + All-thermal CO ₂ |
|------|------------------|------------------|------------------------------------|
| 2018 | 30.71 | 0.00 | 14.36 |
| 2019 | 32.87 | 0.00 | 15.37 |
| 2020 | 35.18 | 0.00 | 16.45 |
| 2021 | 37.64 | 0.00 | 17.60 |
| 2022 | 40.27 | 18.82 | 18.82 |
| 2023 | 43.09 | 20.14 | 20.14 |
| 2024 | 46.11 | 21.56 | 21.56 |
| 2025 | 49.34 | 23.06 | 23.06 |
| 2026 | 52.78 | 24.67 | 24.67 |
| 2027 | 56.48 | 26.40 | 26.40 |
| 2028 | 60.44 | 28.25 | 28.25 |
| 2029 | 64.67 | 30.23 | 30.23 |
| 2030 | 69.21 | 32.35 | 32.35 |
| 2031 | 74.06 | 34.62 | 34.62 |
| 2032 | 79.24 | 37.04 | 37.04 |
| 2033 | 84.78 | 39.63 | 39.63 |
| 2034 | 90.7 | 42.40 | 42.40 |
| 2035 | 97.05 | 45.37 | 45.37 |
| 2036 | 103.83 | 48.54 | 48.54 |
| 2037 | 111.09 | 51.93 | 51.93 |



Emission Standards/Coal-fired Power Plant Retirements

PSE added constraints on coal technologies to the AURORA model in order to reflect current political and regulatory trends. Specifically, no new coal builds were allowed in any state in the WECC. The EPIS's North_American_DB_2016_v3 database was used in this IRP, which includes planned coal power plant retirement. Planned retirements are shown in tables N-19 below.

Figure N-19: Planned Coal Retirements across the WECC (USA)

| Planned Coal Retirement (2017 -2037) | MW |
|---|--------------|
| Planned Retirement (Pacific Northwest, USA) | 2,575 |
| Planned Retirement (Rocky Mountain) | 1,139 |
| Planned Retirement (Southwest) | 1,040 |
| Total Planned Retirement | 4,754 |

Natural Gas-fired Power Plant Retirements

Planned natural gas power plant retirements by year and region are shown in table N-20 below. Most of the natural gas-fired power plants will retire before the end of 2025. Among the 7,459 MW retirements, 7,002 MW is in CA, which is due to Once-Through-Cooling (OTC) rules issued by the State Water Resources Board of California on May 4, 2010. The State Water Resources Board of California adopted a statewide water quality control policy on the use of Once-Through-Cooling (OTC) power plants (nuclear and non-nuclear facilities). This policy establishes requirements for the implementation of the Clean Water Act Section 316 (b), using best professional judgment in determining Best Technology Available (BTA) for cooling intake structures at existing coastal and estuarine plants.

Figure N-20: Planned Natural Gas Retirements in the WECC (USA)

| Planned Natural Gas Retirement (2017-2037) | MW |
|--|--------------|
| California | 7,002 |
| Pacific Northwest, USA | 0 |
| Rocky Mountain | 0 |
| Southwest | 457 |
| Total Planned Retirement | 7,459 |



WECC Builds

We used EPIS's North_American_DB_2016_v3 database, which includes a 128 MW new natural gas plant. We added 3,983 MW of new natural gas plant builds in WECC region, based on the data from the SNL Energy database² as of September 2016. The total new builds for gas plants from 2016 to 2037 is 4,111 MW. Few renewable resources are added after 2016 in the EPIS database. Since we have an RPS standard for each state in WECC, the renewable resources will be reflected by RPS requirement and added by AURORA as the result of the WECC capacity expansion run. Figure N-21 provides the natural gas new build capacity for each of the WECC sub-regions from 2016 to 2037.

Figure N-21: Planned New Builds in the WECC (USA)

| WECC Sub-region | NG Planned build (MW) |
|-------------------|-----------------------|
| Pacific Northwest | 460 |
| Rocky Mountain | 40 |
| California | 1,793 |
| Southwest | 1,818 |
| Total | 4,111 |

Renewable Portfolio Standard (WECC)

Renewable portfolio standards (RPS) currently exist in 29 states and the District of Columbia, including most of the states in the WECC and British Columbia. They affect PSE because they increase competition for development of renewable resources. Each state and territory defines renewable energy sources differently, sets different timetables for implementation, and establishes different requirements for the percentage of load that must be supplied by renewable resources.

To model these varying laws, PSE used the same method from the NPCC Seventh Power Plan. NPCC first identifies the applicable load for each state in the model and the renewable benchmarks of each state's RPS (e.g., 3 percent in 2015, then 15 percent in 2020, etc.). Then they apply those requirements to each state's load. No retirement of existing WECC renewable resources is assumed, which perhaps underestimates the number of new resources that need to be constructed. After existing and planned renewable energy resources are accounted for, "new" renewable energy resources are matched to the load to meet the applicable RPS. Following a review for reasonableness, these resources are created in the AURORA database. Technologies included wind, solar, biomass and geothermal.

² / SNL, which stands for Savings and Loan, is a company that collects and disseminates corporate, financial and market data on several industries including the energy sector (www.snl.com).

Appendix N: Electric Analysis



The table below includes a brief overview of the RPS for each state in the WECC that has one. The “Standard” column offers a summary of the law, as provided by the Lawrence Berkeley National Laboratory (LBNL), and the “Notes for AURORA Modeling” column includes a description of the new renewable resources created to meet the law.

Figure N-22: RPS Requirements for States in the WECC

| State | Standard (LBNL) | Notes for AURORA Modeling |
|------------------|---|---|
| Arizona | New Proposed RPS: 1.25% in 2006, increasing by 0.25% each year to 2% in 2009, then increasing by 0.5% a year to 5% in 2015, and increasing 1% a year to 14% in 2024, and 15% thereafter. Of that, 5% must come from distributed renewables in 2006, increasing by 5% each year to 30% by 2011 and thereafter. Half of distributed solar requirement must be from residential application; the other half from non-residential non-utility applications. No more than 10% can come from RECs, derived from non-utility generators that sell wholesale power to a utility. | Very little potential wind generation is available. Most of the requirement is met with central solar plants. The distributed solar (30%) is accounted for by assuming central renewable energy. |
| British Columbia | Clean renewable energy sources will continue to account for at least 90% of generation. 50% of new resource needs through 2020 will be met by conservation. | The assumption is that a majority of this need will be met by hydropower and wind. |
| California | IOUs must increase their renewable supplies by at least 1% per year starting January 1, 2003, until renewables make up 20% of their supply portfolios. The target now is to meet 20% level by 2010, with potential goal of 33% by 2020. IOUs do not need to make annual RPS purchases until they are creditworthy. CPUC can order transmission additions for meeting RPS under certain conditions. | The California Energy Commission created an outline of the necessary new resources by technology that could meet the 20% by 2010 goal. Technologies include wind, biomass, solar and geothermal in different areas of the state. The renewable energy resources identified in the outline were incorporated into the model. |
| Colorado | HB 1281 -Expands the definition of “qualifying retail utility” to include providers of retail electric services, other than municipally owned utilities, that serve 40,000 customers or less. Raises the renewable energy standard for electrical generation by qualifying retail utilities other than cooperative electric associations and municipally owned utilities that serve more than 40,000 customers to 5% by 2008, 10% by 2011, 15% by 2015, and 20% by 2020. Establishes a renewable energy standard for cooperative electric associations and municipally owned utilities that serve more than 40,000 customers of 1% by 2008, 3% by 2011, 6% by 2015, and 10% by 2020. Defines “eligible energy resources” to include recycled energy and renewable energy resources. | The primary resource for Colorado is wind. The 4% solar requirement is modeled as central power only. |
| Montana | 5% of sales (net of line losses) to retail customers in 2008 and 2009; 10% from 2010 to 2014; and 15% in 2015 and thereafter. At least 50 MW must come from community renewable energy projects during 2010 to 2014, increasing to 75 MW from 2015 onward. Utilities are to conduct RFPs for renewable energy or RECs and after contracts of at least 10 years in length, unless the utility can prove to the PSC the shorter-term contracts will provide lower RPS compliance costs over the long-term. Preference is to be given to projects that offer in-state employees or wages. | The primary source for Montana is wind. The community renewable resources are modeled as solar units of 50 MW then 25 MW. |

Appendix N: Electric Analysis

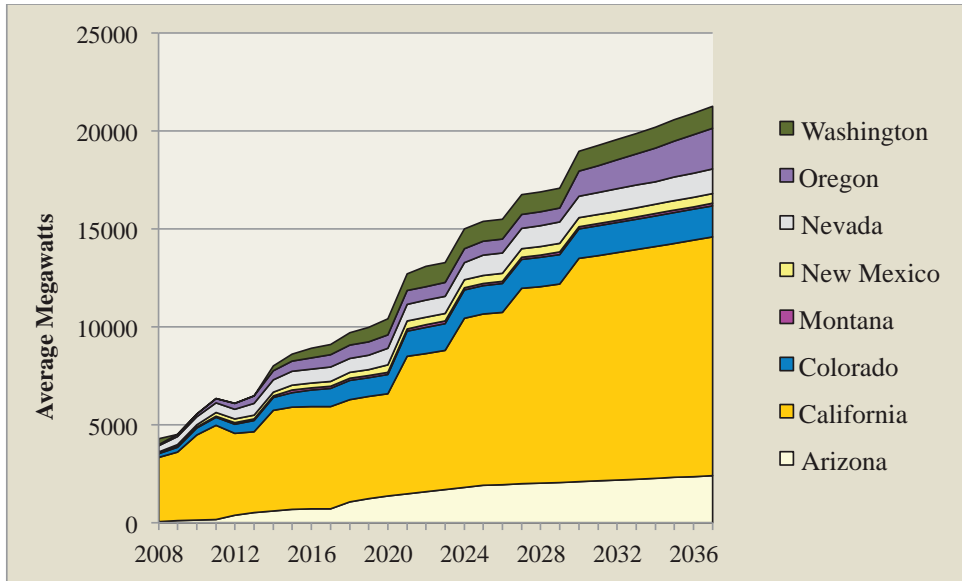


| State | Standard (LBNL) | Notes for AURORA Modeling |
|------------|--|---|
| Nevada | 6% in 2005 and 2006 and increasing to 9% by 2007 and 2008, 12% by 2009 and 2010, 15% by 2011 and 2012, 18% by 2013 and 2012, ending at 20% in 2015 and thereafter. At least 5% of the RPS standard must be from solar (PV, solar thermal electric, or solar that offsets electricity, and perhaps even natural gas or propane) and not more than 25% of the required standard can be based on energy efficiency measures. | The Renewable Energy Atlas shows that considerable geothermal energy and solar energy potential exists. For modeling the resources are located in the northern and southern part of the state respectively, with the remainder made up with wind. |
| New Mexico | Senate Bill 418 was signed into law in March 2007 and added new requirements to the state's Renewable Portfolio Standard, which formerly required utilities to get 10% of their electricity needs by 2011 from renewables. Under the new law, regulated electric utilities must have renewables meet 15% of their electricity needs by 2015 and 20% by 2020. Rural electric cooperatives must have renewable energy for 5% of their electricity needs by 2015, increasing to 10% by 2020. Renewable energy can come from new hydropower facilities, from fuel cells that are not fossil-fueled, and from biomass, solar, wind, and geothermal resources. | New Mexico has a relatively large amount of wind generation currently for its small population. New resources are not required until 2015, at which time they are brought in as wind generation. |
| Oregon | Senate Bill 1547 was signed into law in 2016. Large utility targets: 50% by 2040. Large utility sales represented 73% of total sales in 2002. Medium utilities 10% by 2025. Small utilities 5% by 2025. | We followed the NWPCC 6 th Power Plan assumption for REC banking in the state of Oregon. |
| Utah | Utah enacted The Energy Resource and Carbon Emission Reduction Initiative (S.B. 202) in March 2008. While this law contains some provisions similar to those found in renewable portfolio standards (RPSs) adopted by other states, certain other provisions in S.B. 202 indicate that this law is more accurately described as a renewable portfolio goal (RPG). Specifically, the law requires that utilities only need to pursue renewable energy to the extent that it is "cost-effective" to do so. Investor-owned utilities, municipal utilities and cooperative utilities must meet 20% of their 2025 adjusted retail electric sales. | |
| Washington | Washington state's RPS, I-937 (which became RCW 19.285) was passed in 2006 and requires 3% by 2012, 9% by 2016, 15% by 2020. Eligible resources include wind, solar, geothermal, biomass, tidal. Oregon officials have been discussing the need for an RPS. | Assumed any new generic renewables will meet the criteria for the extra 20% REC credit. |

In order to reflect RPS requirements in the 20-year planning horizon, renewable resource capacities were calculated, and they were treated as new resources in the AURORA resource table.



Figure N-23: RPS Builds Added to AURORA Database by State

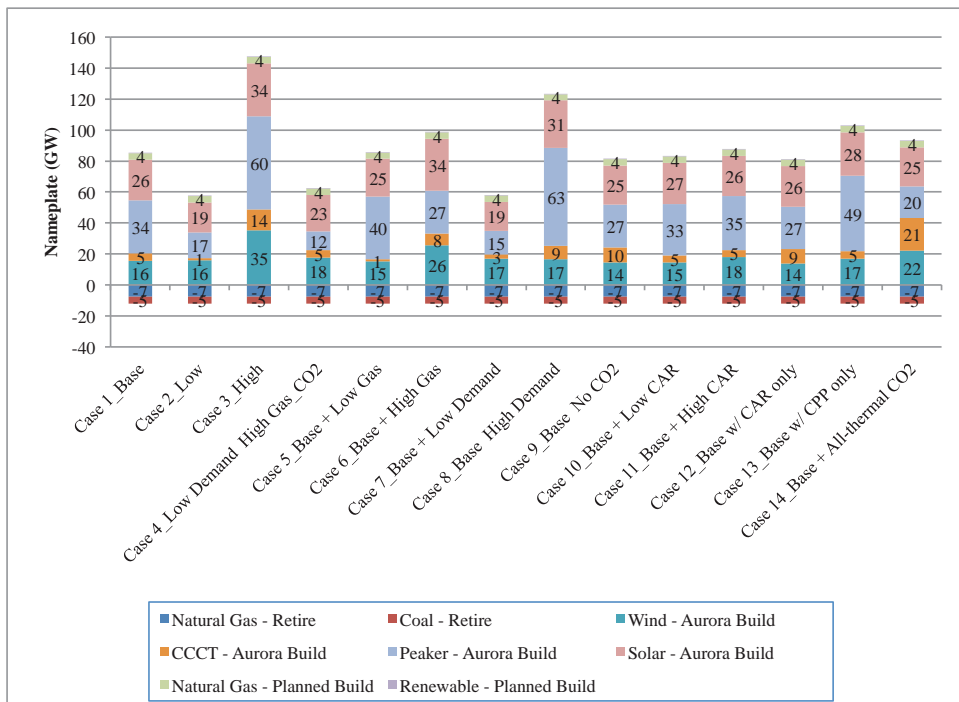




AURORA Builds

AURORA is able to run a long-term optimization model to choose a set of available supply to meet both energy needs and peak needs. New resources are built only when the combination of hourly prices and frequency of operation for a resource generate enough revenue to make construction profitable. Figure N-24 shows AURORAxmp builds in the 14 scenarios along with planned, retired and RPS capacity described above for both the U.S. and Canada WECC.

Figure N-24: WECC Total Builds/Retirements by 2037



Production Tax Credit Assumptions

The PTC is phased down over time: 100 percent in 2016, 80 percent in 2017, 60 percent in 2018 and 40 percent in 2019. A project must meet the physical test or show that 5 percent or more of the total cost of the project was paid during that year. For example, if a project began construction or paid 5 percent or more in costs in the year 2019, it will receive the 40 percent PTC even if the facility doesn't go online until 2022. The PTC is received over 10 years and is given as a variable rate in dollars per MWh.



Investment Tax Credit Assumptions (ITC)

The ITC is a one-time benefit based on the total capital cost invested in the project. The phase-down over time varies depending on the technology:

- Wind: 30 percent in 2016, 30 percent in 2017, 24 percent in 2018 and 18 percent in 2019;
- Solar: 30 percent 2016-2019, 26 percent in 2020 and 22 percent in 2021.

The ITC benefit is based on the year that construction begins. For example, if a wind project starts construction in 2016 but does not go online until 2018, it will receive a 30 percent tax credit based on the total capital cost. So, if the project cost \$300 million, then the developer will receive \$90 million in tax benefits.

Treasury Grant Assumptions

The Treasury Grant (Grant) is subsidy that amounts to 30 percent of the eligible capital cost for renewable resources; it also expired at the end of 2013. For projects placed in service in 2013, construction must have started in 2009, 2010 or 2011, and the project must meet eligibility criteria. This subsidy differs from the previous two in that it is a cash payment from the federal government, versus a tax credit. No extension of the Treasury Grant is assumed.

PSM III Inputs

Renewable Portfolio Standard (PSE)

The current PSE resources that meet the Washington state RPS include Hopkins Ridge, Wild Horse, Klondike III, Snoqualmie Upgrades, Lower Snake River I and Lower Baker Upgrades. The Washington state RPS also gives an extra 20 percent credit to renewable resources that use apprenticeship labor. That is, with the adder, a resource can contribute 120 percent to RCW 19.285. The PSE resources that can claim the extra 20 percent are Wild Horse Expansion, Lower Snake River I and Lower Baker Upgrades. For modeling purposes, we assume that the generic wind receives the extra 20 percent.

Discount Rate

We used the pre-tax weighted average cost of capital (WACC) from the 2017 General Rate Case of 7.74 percent nominal.



REC Price

The REC price starts at \$4.25 per MWh in 2018 and escalates to \$15.22 per MWh in 2037. The escalation rate is not uniform for the whole 20-year planning horizon. A major increase occurs in 2020 with an approximate 129.6 percent increase, corresponding to the RPS increase. All other years use a 2.5 percent escalation.

Inflation Rate

The 2017 IRP uses a 2.5 percent escalation for all assumptions unless otherwise noted. This is the long-run average inflation rate that the AURORAxmp model uses.

Transmission Inflation Rate

In 1996, the BPA rate was \$1.000 per kW per year and the estimated total rate in 2015 is \$1.798 per kW per year. Using the compounded average growth rate (CAGR) of BPA Point-to-Point (PTP) transmission service (including fixed ancillary service Scheduling Control and Dispatch) from 1996 to 2015, we estimated the nominal CAGR inflation rate to be 3.05 percent annually.

Gas Transport Inflation Rate

Natural gas pipeline rates are not updated often and recent history indicates that the rates are 0 percent. PSE has assumed zero inflation on pipeline rates because the major pipelines on which we operate have declining rate base and major expansions will be incrementally priced. Growth in cost of service from operating costs and maintenance capital additions are expected to be offset by declines due to depreciation.



Resource Adequacy Models and Planning Standard

The primary objective of PSE's capacity planning standard analysis is to determine the appropriate level of planning margin for the utility. Planning margin for capacity is, in general, defined as the level of generation resource capacity reserves required to provide a minimum acceptable level of service reliability to customers under peak load conditions. This is one of the key constraints in any capacity expansion planning model, because it is important to maintain a uniform reliability standard throughout the planning period in order to obtain comparable capacity expansion plans. The planning margin (expressed as a percent) is determined as:

Planning Margin = (Generation Capacity – Normal Peak Loads) / Normal Peak Loads,

Where Generation Capacity (in MW) is the resource capacity that meets the reliability standard established in a probabilistic resource adequacy model. This generation capacity includes existing and incremental capacity required to meet the reliability standard.

The planning margin framework allows for the derivation of multiple reliability/risk metrics (such as the likelihood, magnitude and duration of supply-driven customer outages) that, in turn, can be used to quantify the relative capacity contributions of different resource types towards meeting PSE's firm peak loads. These include thermal resources, variable energy resources such as wind, wholesale market purchases, and energy limited resources such as energy storage, demand response and backup fuel capacity.

PSE's Resource Adequacy Model (RAM)

PSE developed its probabilistic Resource Adequacy Model to quantify physical supply risks as PSE's portfolio of loads and resources evolves over time. This model provides the framework for establishing peak load planning standards, which in turn leads to the determination of PSE's capacity planning margin. The RAM is also utilized to compare the relative capacity contribution of intermittent supply-side resources that are subject to random production patterns and to express those contributions in equivalent terms (i.e. their effective load carrying capability or ELCC). Since PSE is a winter-peaking electric utility, its capacity planning standard and associated planning margin are based upon its forecasted ability to reliably meet winter season firm peak loads.



Consistency with Regional Resource Adequacy Assessments

Consistency with the NPCC's regional probabilistic GENESYS resource adequacy model is needed in order to ensure that the conditions under which the region may experience capacity deficits are properly reflected in PSE's modeling of its own loads, hydro and thermal resource conditions in the RAM. The PSE existing resources included in this analysis are Colstrip, Mid-Columbia purchase contracts and western Washington hydroelectric resources, several gas-fired plants (simple-cycle peakers and baseload combined-cycle combustion turbines), long-term firm purchased power contracts, several wind projects, and short-term wholesale (spot) market purchases up to PSE's available firm transmission import capability from the Mid-C. This reliance on market purchases requires that PSE's resource adequacy modeling adequately reflect regional adequacy conditions also.

The multi-scenario simulations made in PSE's resource adequacy model are consistent with the 6,160 simulations made in the NPCC's GENESYS model in terms of temperature, hydro conditions and thermal outage rates. In addition, PSE's RAM utilizes the same October 2020 – September 2021 study period as the regional GENESYS model.

The following sources of uncertainty were incorporated into PSE's multi-scenario RAM.

- 1. FORCED OUTAGE RATE FOR THERMAL UNITS.** Modeled as a combination of an outage event and duration of an outage event, subject to mean time to repair and total outage rate equal to the values used in GENESYS.
- 2. HOURLY SYSTEM LOADS.** Modeled as an econometric function of hourly temperature for the month, using the hourly temperature data for each of the 77 temperature years from 1929 to 2005 to preserve its chronological order, consistent with the GENESYS model.
- 3. MID-COLUMBIA AND BAKER HYDROPOWER.** PSE's RAM uses the same 80 hydro years, simulation for simulation, as the GENESYS model. PSE's Mid-Columbia purchase contracts and PSE's Baker River plants are further adjusted so that: 1) they are shaped to PSE load, and 2) they account for capacity contributions across several different sustained peaking periods (a 1-hour peak up to a 12-hour sustained peak). The 6,160 combinations of hydro and temperature simulations are consistent with the GENESYS model.



4. WHOLESALE MARKET PURCHASES. These inputs to the RAM are determined in the Wholesale Purchase Curtailment Model (WPCM) as explained in Appendix G. Limitations on PSE wholesale capacity purchases resulting from regional load curtailment events (as determined in the WPCM) utilize the same GENESYS model simulations as PSE's RAM.

5. WIND. Drawn randomly from historical hourly data for PSE's Wild Horse and Hopkins Ridge plants, but constrained for the following: 1) simulations of daily 24-hour wind profiles are made each month with each day having an equal probability of being chosen until all days in the month are populated to preserve seasonality; 2) simulations across wind farms are synchronized on a daily basis to preserve any correlations that may exist between Hopkins Ridge and Wild Horse; 3) PSE's Lower Snake River wind farm, which does not yet have a long-term generation data record, is assumed to have the same wind profile as Hopkins Ridge, with a 10-minute lag since it is located near Hopkins Ridge, and it is scaled to its nameplate capacity and pro-forma capacity factor.



Treatment of Operating Reserves in the RAM

PSE is required to maintain contingency reserves pursuant to the Northwest Power Pool (NWPP) reserve sharing agreement. Members are required to hold 3 percent of load and 3 percent of online dispatched generation in reserve, in case any member experiences an unplanned generating plant outage. In addition, half of the contingency reserves should be in spinning reserve capable of responding within ten minutes. In the event of an unplanned outage, NWPP members can call on the contingency reserves held by other members to cover the loss of the resource during the 60 minutes following the outage event. After the first 60-minute period, the member experiencing the outage must return to load-resource balance by either re-dispatching other generating units, purchasing power, or curtailing load. PSE's RAM reflects the value of contingency reserves to PSE by ignoring the first hour of a load curtailment, if a forced outage at one of PSE's generating plants causes loads to exceed available resources.

PSE's planning margin is calculated net of operating reserves, which are the sum of contingency reserves (as described above) and within-hour balancing resources. The total amount of contingency reserves and balancing reserves maintained by PSE can vary depending upon the magnitude of the resources and loads located in the PSE balancing authority area and the generating capacity needed to meet short-term system flexibility requirements.

Risk Metrics

The probabilistic resource adequacy model (RAM) allows for the calculation of several risk metrics including: 1) the loss of load probability (LOLP), which measures the likelihood of a load curtailment event occurring in any given simulation regardless of the frequency, duration and magnitude of the curtailment(s), 2) the expected unserved energy (EUE), which measures magnitude in MWh and is the sum of all unserved energy/load curtailments across all hours and simulations divided by the number of simulations, and 3) loss of load hours (LOLH) which measures outage duration and is the sum of the hours with load curtailments divided by the number of simulations. Capacity planning margins and the effective load carrying capability for different resources can be defined using any of these three risk metrics, once a planning standard has been established.



Determining PSE's Capacity Planning Margin

In this IRP, PSE adopts the reliability standard established for the Pacific Northwest region through the NW Regional Adequacy Forum.³ This standard utilizes the LOLP metric and establishes the 5 percent LOLP level as adequate for the region. This LOLP value is obtained by running the 6,160 scenarios through RAM, and calculating the LOLP metric for various capacity additions. As the generating capacity is incremented using a CT plant as the "typical" peaking plant, this results in a higher total capacity and lower LOLP. The process is repeated until the loss of load probability is reduced to the 5 percent LOLP. The incremental capacity plus existing resources is the generation capacity that determines the capacity planning margin.

Input Updates to the Resource Adequacy Model for the 2017 IRP

For the 2017 IRP resource adequacy study, the calculation of the resource capacity needed to meet the 5 percent LOLP standard excluded DSR since the optimal DSR amount will still be determined in the portfolio optimization model. In addition to the exclusion of DSR in the study, the following key updates to the RAM inputs were also made.

1. The load forecast was updated to reflect F16 assumptions; lower population growth rate, lower normal heating degree days because recent years have been much warmer than normal, and economic growth and modelling uncertainties introduced in the stochastic load simulations.
2. PSE's resource capacities were updated to reflect capacity changes in both hydro and thermal resources; slightly reduced capacities in PSE-owned hydro and slightly higher capacities in thermals due to upgrades to the combined-cycle peaking units.
3. The hourly draws of the existing PSE wind fleet were updated to include one more year of actual data.
4. Colstrip Units 1 & 2 are removed, consistent with the GENESYS model.
5. The version of GENESYS model used in the 2016 Resource Adequacy Assessment was introduced, with Colstrip 1 & 2 retirement, and winter SW imports increased to 3,400 MWs. Further details of the inputs into this version of GENESYS are discussed in Appendix G.
6. Updated forced outage rates for PSE thermals to be consistent with those filed in the most recent General Rate Case; the updated forced outage rates are slightly lower.

³ /A description of the NW Regional Adequacy Forum and the standards adopted can be found at <http://nwcouncil.org/energy/resource/Default.asp>



Impacts of Input Revisions to Incremental Capacity Needed to Meet 5 Percent LOLP

Figure N-25 shows the impacts of the key input revisions to the incremental capacity needed to meet the 5 percent LOLP.

Figure N-25: Impact of Key Input Revisions

| | Revisions | MW Needed for 5% LOLP Oct 2020 - Sep 2021 |
|------------------|--|---|
| 2015 IRP Base | Regional Market Reliance Assumptions: SW Imports = 3,500 (+550), Carty 2 = +440, Grays Harbor out (-650), 2015 IRP Base Load Forecast w/ DSM | -116 |
| | Remove DSR | 525 |
| 2017 IRP Updates | F16 loads, no DSR | 335 |
| | Update existing resource capacities | 300 |
| | Update wind draws | 300 |
| | Remove Colstrip 1 & 2 from PSE portfolio, consistent with GENESYS | 560 |
| | Regional Market: 2016 GENESYS, SW Imports = 3,400, No Carty 2, Grays Harbor in, Colstrip 1 & 2 out | 542 |
| | New forced outage rates draws for PSE thermal fleet | 550 |

The incremental capacity needed to achieve the 5 percent LOLP is 550 MW, on top of existing PSE resource capacity. This value is used in the calculation of planning margin below.



Calculation of Planning Margin and Resource Needs

PSE incorporates a planning margin in its description of resource need in order to achieve a 5 percent loss of load probability. The 5 percent LOLP is an industry standard resource adequacy metric used to evaluate the ability of a utility to serve its load, and one that is used by the Pacific Northwest Resource Adequacy Forum.⁴

Using the LOLP methodology, we determined that we need 123 MW of resources by 2020. In order to establish this need, we went through three steps.

1. Use PSE's resource adequacy model (RAM) to find the capacity need for the period October 2020 – September 2021. The RAM is consistent with GENESYS, the resource adequacy model used by the Northwest Power and Conservation Council (NPCC or the Council). In the NPCC's GENESYS, Colstrip 1 & 2 are retired during this time period, so Colstrip 1 & 2 were retired in RAM as well. With Colstrip 1 & 2 retired, PSE needs 503 MW of resources by December 2020.
2. Determine the planning margin for a 503 MW need, with Colstrip 1 & 2 retired. This comes to 13.5 percent.
3. Using the 13.5 percent planning margin, Colstrip 1 & 2 were added back to the 503 MW need because they do not retire until 2022, so the resulting need for October 2020 – September 2021 is 123 MW.

STEP 1: USE RAM TO FIND CAPACITY NEED. This analysis looked at the likelihood that load will exceed resources on an hourly basis over the course of a full year. Included are uncertainties around temperature impacts on loads before conservation, hydro conditions, wind, and forced outage rates (both their likelihood and duration), and uncertainties in market reliance based on the Council's regional adequacy model, GENESYS. Because of PSE's large reliance on the market, it is important that PSE's resource adequacy analysis is consistent with the regional assessment of resource adequacy. This is a Monte Carlo simulation that consists of 6,160 draws that model different temperature conditions, hydro conditions and thermal forced outage rate assumptions. Each of the draws and study year are consistent for both models. This analysis resulted in the need for 503 MWs of additional resources to achieve a 5 percent LOLP in the study year October 2020 – September 2021.⁵

STEP 2: DETERMINE PLANNING MARGIN. Figure N-26 shows the calculation of the planning margin to achieve the adequate level of reliability. Given that PSE has a winter peaking load, any capacity brought in to meet the planning margin in the winter is also

⁴ / See <http://www.nwccouncil.org/library/2008/2008-07.htm>

⁵ / The 503 MW need is before including additional cost-effective conservation. We need to establish resource need first, and then we determine how much of that need would cost effectively be met by conservation.



available to meet capacity in other seasons. The 503 MW need in December 2020 was calculated with Colstrip Units 1 & 2 retired, consistent with the NPCC GENESYS assumptions. The 503 MW capacity need translates to a 13.5 percent planning margin, not including reserves.

Figure N-26: Planning Margin Calculation

| | December 2020 w/o Colstrip 1 & 2 |
|---------------------------------------|----------------------------------|
| Peak Capacity Need from LOLP | 503 MW |
| Total Resources (No DSR) | 4,103 MW |
| Available Mid-C Transmissions | 1,714 MW |
| | 6,320 MW |
| Operating Reserves | (399) MW |
| | 5,921 MW |
| BPA Loss Return | (71) MW |
| Peak Need | 5,850 |
| Normal Peak Load | 5,156 |
| Planning Margin (Peak Need/Peak Load) | 13.5% |

STEP 3: DETERMINE RESOURCE NEED WITH COLSTRIP 1 & 2. Since Colstrip Units 1 & 2 do not retire till mid-2022, we add its capacity back into the calculation (that is, subtract it from the 503 MW capacity need). This results in a capacity need in December 2020 of 123 MW. See Figure N-27, below, for peak need calculation. This is the reverse of figure N-26, above. In Figure N-26, we were trying to find the planning margin. Now, we know the planning margin is 13.5 percent, so we have reversed the calculation to find the peak need.



Figure N-27: December Peak Need in 2020, with Colstrip 1 & 2

| | December 2020 w/ Colstrip 1&2 |
|-------------------------------------|-------------------------------|
| Peak Demand | 5,153 MW |
| Planning Margin | 13.5% |
| Normal Peak Load + PM | 5,836 MW |
| Operating Reserves | 415 MW |
| Total Capacity Need | 6,251 MW |
| Total Resources (No DSR) | (4,401) MW |
| Available Mid-C Transmissions | (1,731) MW |
| Total | 119 MW |
| Operating Reserves on new resources | 15 MW |
| Total Resource Deficit/(Surplus) | 123 MW |

Effective Load Carrying Capability of Resources

The effective load carrying capability (ELCC) of a resource represents the capacity credit assigned to that resource. It is implemented in RAM since this value is highly dependent on the load characteristics and the mix of resources owned by a given utility. The ELCC or the peak contribution of any given resource is therefore unique for that utility. In essence, the ELCC approach identifies, for each resource alternative, its capacity relative to that of a gas-fired peaking plant, that would yield the same level of reliability. For resources such as a wind, solar, thermal resources, wholesale market purchases, or other energy limited resources such as batteries, demand response programs, and backup fuel for thermal resources, the ELCC is expressed as a percentage of the equivalent gas peaker capacity.



The ELCC value of any resource, however, is also dependent on the reliability metric being used for evaluating the peak contribution of that resource. This is a function of the characteristics of the resource being evaluated, and more importantly, what each of the reliability metrics is counting. For example, a variable energy resource such as wind or solar with unlimited energy may show different ELCC values depending on which reliability metric is being used – LOLP or EUE. LOLP measures the likelihood of any deficit event for all draws, but it ignores the number of times that the deficit events occurred within each draw, and it ignores the duration and magnitude of the deficit events. EUE sums up all deficit MW hours across events and draws regardless of their duration and frequency expressed as average over the number of draws. In this study, we utilize LOLP as the reliability metric in estimating the ELCC of wind, solar and market purchases. However, we use EUE to determine the ELCC of energy-limited resources such as batteries, demand response and backup fuel for thermal plants, because LOLP is not able to distinguish the ELCC of batteries and demand response programs with different durations and call frequencies. EUE is also the reliability metric used to evaluate the ELCC of backup fuel storage since it is mainly limited by the total amount of storage.

WIND CAPACITY CREDITS. In order to implement the ELCC approach for wind in the RAM, the distribution of hourly generation for each of the existing and prospective wind farms was developed. These are described in the Stochastic Portfolio Model section of this appendix under the heading “Wind Generation.” For the existing wind farms, the wind distributions were derived based on historical wind outputs. For new wind farms such as Skookumchuk or generic wind farms out of Montana or Washington, the wind distributions developed by DNV GL were used. Given these distributions, the wind farms were added into the RAM incrementally to determine the reduction in peaking plant capacity needed to achieve the 5 percent LOLP level. The wind farm’s peak capacity credit is the ratio of the change in gas peaker capacity with and without the incremental wind capacity. The order in which the existing and prospective wind farms were added in the model follows the timeline of when these wind farms were acquired or about to be acquired by PSE: 1) Hopkins Ridge, 2) Wild Horse, 3) Klondike, 4) Lower Snake River, 5) Skookumchuck, which is a project currently under acquisition by PSE to serve its Green Direct customers, and finally 6) a generic wind resource expected to be located in eastern Montana, or a generic wind farm located in eastern Washington close to the Lower Snake River project, or a wind resource located offshore of Washington state. However, the ELCC values for the existing wind projects were not very different from each other, so a single ELCC value was assigned to the existing wind projects. Figure N-28 below shows the estimated peak capacity credit or ELCC of the wind resources included in this IRP.



Figure N-28: Peak Capacity Credit for Wind Resources

| Wind Resources | Capacity (MW) | Equivalent Peaker Capacity Change to Get Back to 5% LOLP(MW) | Peak Capacity Credit Based on 5% LOLP |
|---------------------------------------|---------------|--|---------------------------------------|
| Existing Wind | 823 | 90 | 11% |
| Skookumchuck Wind (DNV GL) | 131.1 | 53 | 40% |
| Generic Eastern Montana Wind (DNV GL) | 100 | 49 | 49% |
| Generic Washington Wind (DNV GL) | 100 | 16 | 16% |
| Generic WA Offshore Wind (DNV GL) | 100 | 51 | 51% |

SOLAR CAPACITY CREDIT. The approach used to derive the ELCC of solar is the same approach used for wind. The hourly solar draws were based on the historical outputs of the 0.5 MW solar farm located near the Wild Horse wind project, and the outputs of that project were scaled to a 50 MW solar farm. The solar capacity credit is shown in Figure N-29 below. As expected, solar does not contribute to peaks because it is usually not available when the system loads are peaking early in the morning and late in the evening.

Figure N-29: Peak Capacity Credit of Solar Resources

| Solar | Capacity (MW) | Equivalent Peaker Capacity Change to Get Back to 5% LOLP(MW) | Peak Capacity Credit Based on 5% LOLP |
|-------|---------------|--|---------------------------------------|
| Solar | 50 | 0 | 0% |



WHOLESALE MARKET PURCHASES CAPACITY CREDIT. With the reliability of wholesale market purchases now reflected in PSE's RAM, we applied the same analytical process to estimate the capacity value of wholesale market purchases using LOLP as the reliability metric. The uncertainty in PSE's wholesale market capacity purchase volumes is based on the outputs of WPCM as described in Appendix G, which in turn is highly dependent on the results of the GENESYS model inputs and assumptions. The additional peaker needed to reach the 5 percent LOLP after introducing uncertainty in market purchases divided by the total market purchase capacity (which is the total Mid-C transmission availability) is the percent reduction in the peak contribution of market purchases from 100 percent. The ELCC of market purchases is therefore one (1) minus this percent reduction in market purchase reliability. Given the regional outage outputs from the GENESYS model used in the 2016 adequacy assessment, market purchases contribute almost 100 percent to PSE's peak requirements.

Figure N-30: Peak Capacity Credit for Wholesale Market Purchases

| Market Purchases | Expected Capacity(MW) | Equivalent Peaker Capacity Change to Get Back to 5% LOLP(MW) | Peak Capacity Credit Based on 5% LOLP |
|------------------|-----------------------|--|---------------------------------------|
| Market Purchases | 1,580 | 12 | 99% |

BATTERY CAPACITY CREDIT. The estimated peak contribution of two types of batteries was modelled in RAM, each of which can be charged or discharged at a maximum of 25 MW per hour up to 4 hours duration when the battery is fully charged. When fully charged, each of the batteries can produce 100 MWh of energy continuously for 4 hours. Thus, the battery is energy limited. The two battery technologies are the lithium-ion battery with a round-trip efficiency of 85 percent, and the flow battery with a round-trip efficiency of 75 percent. The battery can be charged up to its maximum charge rate per hour only when there are no system outages and the battery is less than fully charged. The battery can be discharged up to its maximum discharge rate or just the amount of system outage, adjusted for its round-trip efficiency rating as long as there is a system outage and the battery is not empty.



As stated previously, the LOLP is not able to distinguish the impacts of the two types of batteries on system outages since it counts only draws with any outage event but not the magnitude, duration and frequency of events within each draw. Because of this, the capacity credit of batteries was estimated using the expected unserved energy (EUE). The analysis starts from a portfolio of resources that achieves a 5 percent LOLP, then the EUE from that portfolio is calculated. Each of the battery technologies is then added to the portfolio, which leads to lower EUE. The amount of peaker capacity taken out of the portfolio to achieve the EUE at 5 percent LOLP divided by the peak capacity of the battery after adding the battery determines the peak capacity credit or ELCC of the battery. Since the only difference between the two battery technologies is their round-trip efficiency, we should expect a lower peak capacity contribution or ELCC for the battery with the lower round-trip efficiency. The estimated peak contribution of the two types of batteries is shown in Figure N-31.

Figure N-31: Peak Capacity Credit for Battery Resources

| Battery | Capacity(MW) | Capacity Adjustment to Get EUE @ 5% LOLP(MW) | Peak Capacity Credit Based on EUE @ 5% LOLP |
|------------------------------------|--------------|--|---|
| Lithium-ion, 4Hr, 25MW max per hr | 25 | 22 | 88% |
| Flow Battery, 4Hr, 25MW max per hr | 25 | 19 | 76% |

DEMAND RESPONSE CAPACITY CREDIT. The capacity contribution of a demand response (DR) program is also estimated using EUE, since this resource is also energy limited like batteries. Even for similarly sized DR programs, each program is expected to have different capacity contribution estimates depending on how each one is designed in terms of its duration and frequency of calls within a day and season.

While using EUE as the risk metric in estimating the peak contribution or ELCC of DR, the analysis approach is slightly different and uses the following steps:

1. Calculate the EUE of the portfolio at 5 percent LOLP.
2. Remove 100 MW of peaker capacity and calculate the total incremental EUE from Step 1.
3. Implement a DR program with given attributes.
4. Calculate the reduction in incremental EUE due to the DR program.
5. The ELCC of the given DR program is the ratio of the reduction in incremental EUE (Step 4) and the total incremental EUE (Step 2).



Note that only the characteristics of the incremental EUE identified in Step 2 above is the benchmark that we use to determine the ELCC of a similarly sized (100 MW) DR program. The incremental outages as a result of removing 100 MW of peaker capacity can be described by the following characteristics: magnitudes (incremental MW deficits), frequency (how often bad events happen in a day/season), duration (length in hours of bad events) and time between bad events. The ELCC of a similarly sized DR program is therefore highly dependent in its ability to address these characteristics of the incremental outage events.

When PSE issued its initial RFP for DR, program designs were based on what was observed across the country where DR is to be called on once a day in a 4-hour period to avoid customer fatigue. However, this once-a-day DR program is more appropriate to areas that are typically summer peaking, since they experience only one peak per day. After the RFP, PSE considered further refinements to its program design to address the double-peak shape of PSE loads during typical winter season days. The charts below illustrate the double-peak nature of PSE's daily loads, and the impacts of removing 100 MW of peaker capacity from the portfolio.

Figure N-32: PSE Winter Season Double Peaks

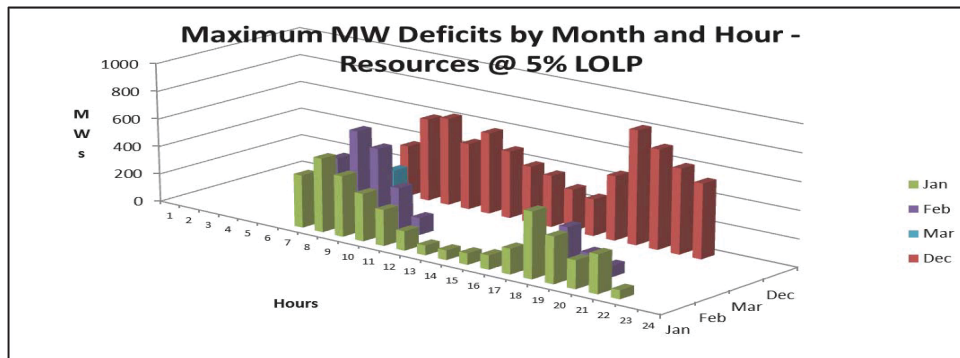
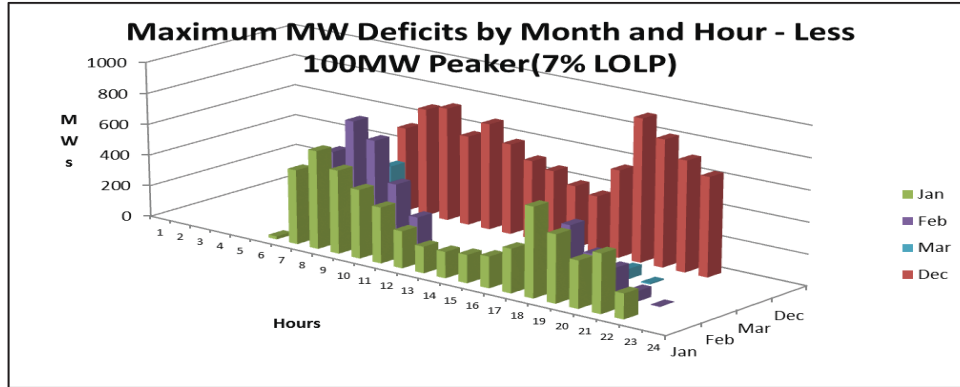




Figure N-33: PSE Winter Season Double Peaks, Minus 100 MW Peaker



When the 100 MW of peaker capacity is removed from the portfolio, not only are existing bad events made worse by higher MW deficits and longer outage durations, but new hours experience bad events as well. While not shown in these charts, the time in between bad events can be shorter also. To understand the effectiveness of DR program to meet peak loads, different combinations of DR parameters (duration in hours and call frequency within the day) are analyzed for their ability to mitigate the incremental outages resulting from the removal of a 100 MW peaker. The table below shows the ELCC or peak contribution of DR programs with different attributes, both duration the frequency of calls in a day. For the IRP, the DR program modeled was for a 3-hour maximum duration that can be called every 3 times a day or every 6 hours.

Figure N-34: Peak Capacity Credit for Demand Response Programs

| ELCC Estimates for Various DR Event Parameters(100MW) | | | | | |
|---|--|-----|-----|-----|-----|
| Duration(Hrs) | Call Frequency(Elapsed Hrs After Last Event) | | | | |
| | 4 | 6 | 8 | 12 | 24 |
| 2 | 63% | 61% | 57% | 49% | |
| 3 | 80% | 77% | 72% | 59% | |
| 4 | 90% | 85% | 80% | 65% | 53% |
| 5 | 94% | 89% | 84% | 68% | 55% |



BACKUP FUEL CAPACITY CREDIT. PSE has relied on spot gas supply to operate its fleet of peakers, combined with a 48-hour fuel oil backup in lieu of more expensive firm gas supply contracts, since the peakers have low capacity factors. Two key issues arise from this reliance on 48-hour fuel oil backup:

1. Is the current 48-hour fuel oil backup adequate to run the peakers if spot gas is not available for the season?
2. If backup fuel oil is used for the season, does PSE exceed the annual maximum run hours constraint of 300 hours required to meet air emission standards?

Currently, PSE stores about 48 hours of fuel oil backup for each peaker with the total amount varying depending on the capacity of the peaker. This enables the peaker to run for a cumulative 48 hours within the season without fuel replenishment since replenishment within the season is usually expensive. PSE's peaker fleet consists of Fredonia Units 1-4, Whitehorn Units 1 & 2, and Frederickson Units 1 & 2 for a total of 696 MW of maximum capacity (temperature adjusted). In PSE's RAM, these units are assumed to be supplied with gas from the spot market with no risks to their availability. To analyze the adequacy of the 48-hour fuel oil backup, we looked at the case in which the fuel oil backup is not available AND the market is unable to provide spot gas for the entire season. Under these circumstances the entire peaker fleet is not available in the resource adequacy model, which leads to more frequent and severe outage events. The MWhs of outages resulting from the absence of the peakers are then summed up for the season. Then, the sum of MWhs that the 48-hour fuel oil backup is able to provide is compared with the MWhs of outages resulting from the absent peakers in the resource adequacy model. If the MWhs from the 48-hour fuel oil backup is greater than the sum of MWhs from being unable to run the peakers, then we can conclude that the 48-hour fuel oil backup is adequate.

Note that the relevant MWh outages include only those from the incremental outages in the resource adequacy model, which results in some outage events 5 percent of the time since it is based on the 5 percent LOLP reliability standard. Also, to avoid inflating the MWh outages, this analysis included the impacts of conservation based on the 2015 IRP.

Since the resource adequacy model is also able to identify and count the incremental hours when new outage events occur, we also sum up all of the hours for the incremental outages to determine if this exceeds the maximum allowed run hours for fuel oil according to current air emission standards.



To determine if the results of the analysis are invariant to the scale of the capacity that is not available to meet resource adequacy, three scenarios were examined.

SCENARIO 1. Remove all existing peakers (696 MWs)

SCENARIO 2. Scenario 1, plus remove Colstrip Units 1 & 2 (298 MWs) and assume that peakers replace Colstrip 1 & 2 for a total of 994MWs

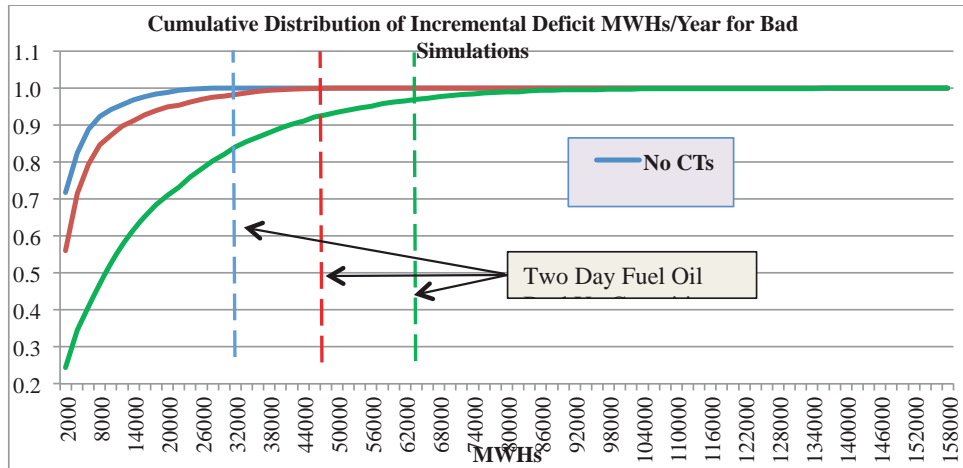
SCENARIO 3. Scenario 2, plus remove Colstrip 3 & 4 (359 MWs) and assume peakers replace Colstrip 3 & 4 for a total of 1,353 MWs

The resource adequacy model is run under each of the three scenarios and the resulting incremental outages are examined both for MWH outages and hours of outages. Because RAM is a stochastic model over 6,160 draws, both the MWH outages and hours of outages are presented as a cumulative distribution, and compared to the thresholds for the 48-hour fuel oil backup and maximum run hour constraints, respectively.

The chart below shows the cumulative distribution of MWHs resulting from the incremental outage events for each of the three scenarios. The higher the level of capacity that is unable to run due to the lack of gas supply, the greater the amount of deficit MWHs. This is shown by the rightward shift in the cumulative distribution curve. The vertical lines show the cumulative MWHs that the peakers are able to supply with the 48-hour fuel oil backup. For scenarios 1 and 2, where the peaker capacity level goes up to almost 1,000 MWs, the 48-hour fuel oil back is adequate to cover 100 percent of the deficit MWHs resulting from the incremental outage events. When the peaker capacity level that is not able to operate goes up to 1,353 MWs, the 48-hour fuel oil back is only able to cover about 97 percent of all the deficit MWHs. For PSE's current fleet of peakers, the study results show that the 48-hour fuel oil backup is adequate.



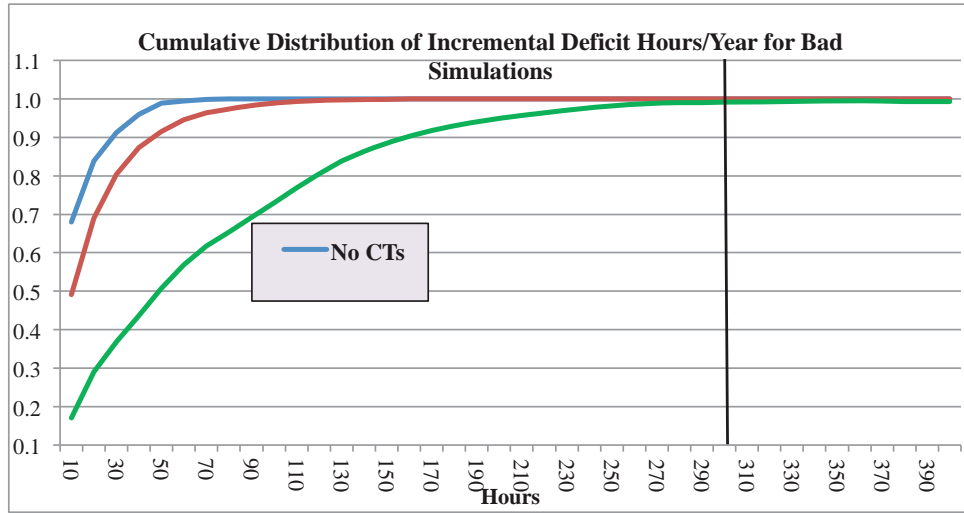
Figure N-35: Fuel Oil Backup, Cumulative Distribution of Incremental Deficits, MWh for Bad Simulations



The next chart displays the cumulative distribution of the run hours where incremental outage events occur for each of the three scenarios. Again, the higher the amount of peaker capacity that is not able to operate due to the lack of spot gas supply, the greater the amount of deficit events, so the cumulative distribution curve shifts to the right. The vertical line shows the 300 maximum run hours in a season required by current air emission standards. This chart illustrates that the maximum 300 run hours constraint is always greater than the 100 percent level of cumulative hours experiencing outage events for all of the scenarios tested in this study. This implies that for the existing PSE peaker fleet, or even with potential additions to the fleet, the 48-hour fuel oil backup meets the air emission standard for maximum run hours.



Figure N-36: Fuel Oil Backup, Run Hours Constraints





4. OUTPUTS: AVOIDED COSTS

AURORA Electric Prices and Avoided Costs

Consistent with WAC 480-107-055 (4), the schedules of estimated avoided costs in this section provide only general information about the costs of new power supplies – it should not be interpreted as a guaranteed contract price for electricity. This section includes estimated capacity costs consistent with the resource plan forecast, along with the different market price forecasts from AURORA. The two kinds of avoided costs – avoided capacity costs and avoided energy costs – are discussed below.

Avoided Capacity Costs

Within the category of avoided capacity costs, there are two types: avoided resource costs, and avoided supply-related costs.

AVOIDED CAPACITY RESOURCE COSTS: Avoided resource costs are directly related to avoiding acquisition of new capacity resources. The timing and cost of avoided capacity resources are tied directly to the resource plan. This represents the average cost of capacity additions (or average incremental costs) not marginal costs.

The indicative avoided capacity resource costs shown in Figure N-37, below, are “net” capacity costs, meaning that the energy or other resource values have been deducted, using the Base + CAR Only Scenario. For example, frame peakers can dispatch into market when the cost of running the plant is less than market, which creates a margin that flows back to reduce customers’ rates. The peaker costs shown in this table are net of those margins – they represent the cost of the plant that will not be covered by the energy market operations. The avoided peaker costs increase over time. This is to ensure a capacity resource acquired earlier in the planning horizon is credited with avoiding more expensive resources in the future. With batteries, we also deducted the sub-hourly flexibility value in the calculation of net avoided capacity cost. Before 2022, Figure 1-37 also includes the Avoided Short-term Supply-related Capacity Cost, which is described in the section below.



In addition to the avoided capacity cost expressed in \$/kW-yr, the capacity credit of different kinds of resources needs to be specified. After specifying the annual avoided capacity resource costs by year, Figure N-37 includes indicative adjustments to peak capacity value from the effective load carrying capability (ELCC) analysis in this IRP. The ELCC for a firm, dispatchable resource would be 100 percent, but different kinds of intermittent resources would have different peak capacity contributions. The capacity contributions used here are consistent with those described in Chapter 6.

AVOIDED SHORT-TERM SUPPLY-RELATED CAPACITY COSTS. PSE depends on short-term market purchases over existing firm transmission to meet a significant portion of our customers' peak capacity need. Annually, as PSE approaches the heating season, we examine how much of the peak need has already been covered by financial hedges to manage energy cost risk. To the extent that the capacity of those hedges falls short of covering the peak need, PSE will physically hedge most of the remaining capacity.

There are a variety of ways to cover this outstanding physical position. The easiest to conceptualize is a physical call-option contract, where PSE would pay a counter-party to provide energy during the winter at either a fixed or indexed price. The value is small – approximately \$0.10/kW-yr – based on recent market experience. Avoided Short-term Supply-related Capacity Cost applies to resources not delivered to PSE's system, but to a location where PSE has firm transmission to transmit the power to our customers. These avoided costs also apply during periods before PSE has a need for supply-side resources – see Figure N-38, Avoided Short-term Supply-related Capacity Costs, below.

Appendix N: Electric Analysis



Figure N-37: Indicative Avoided Capacity Resource Costs for Resources Delivered to PSE
(Base + CAR Only Scenario)

| | Capacity Resource Addition | Levelized Net Cost (\$/kw-yr) | Firm Resource ELCC = 100% (\$/kw-yr) | Wind Resource ELCC = 16% (\$/kw-yr) | Solar Resource ELCC = 1% (\$/kw-yr) |
|------|-------------------------------------|-------------------------------|--------------------------------------|-------------------------------------|-------------------------------------|
| 2018 | Avoided Energy Supply Capacity Cost | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2019 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2020 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2021 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2022 | Transmission Redirect | \$3.26 | \$3.26 | \$0.52 | \$0.03 |
| 2023 | Flow Battery-4 hr | \$93.00 | \$93.00 | \$14.88 | \$0.93 |
| 2024 | Flow Battery-4 hr | \$93.00 | \$93.00 | \$14.88 | \$0.93 |
| 2025 | Frame Peaker | \$80.00 | \$80.00 | \$12.80 | \$0.80 |
| 2026 | Frame Peaker | \$80.00 | \$80.00 | \$12.80 | \$0.80 |
| 2027 | Frame Peaker | \$80.48 | \$80.48 | \$12.88 | \$0.80 |
| 2028 | | \$80.48 | \$80.48 | \$12.88 | \$0.80 |
| 2029 | | \$80.48 | \$80.48 | \$12.88 | \$0.80 |
| 2030 | | \$80.48 | \$80.48 | \$12.88 | \$0.80 |
| 2031 | Frame Peaker | \$84.16 | \$84.16 | \$13.47 | \$0.84 |
| 2032 | | \$84.16 | \$84.16 | \$13.47 | \$0.84 |
| 2033 | | \$84.16 | \$84.16 | \$13.47 | \$0.84 |
| 2034 | Frame Peaker | \$88.31 | \$88.31 | \$14.13 | \$0.88 |
| 2035 | | \$88.31 | \$88.31 | \$14.13 | \$0.88 |
| 2036 | Frame Peaker | \$91.09 | \$91.09 | \$14.57 | \$0.91 |
| 2037 | | \$91.09 | \$91.09 | \$14.57 | \$0.91 |



*Figure N-38: Indicative Short-term Supply-related Avoided Capacity Costs
for Resources Not Delivered to PSE,
but to a Location from Which PSE Has Firm Transmission
(Base + CAR Only Scenario)*

| | Capacity Resource Addition | Levelized Net Cost (\$/kw-yr) | Firm Resource ELCC = 100% (\$/kw-yr) | Wind Resource ELCC = 16% (\$/kw-yr) | Solar Resource ELCC = 1% (\$/kw-yr) |
|------|-------------------------------------|-------------------------------|--------------------------------------|-------------------------------------|-------------------------------------|
| 2018 | Avoided Energy Supply Capacity Cost | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2019 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2020 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2021 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2022 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2023 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2024 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2025 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2026 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2027 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2028 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2029 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2030 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2031 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2032 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2033 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2034 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2035 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2036 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |
| 2037 | | \$0.10 | \$0.10 | \$0.02 | \$0.00 |



Avoided Energy Costs

All of the resources in PSE's resource plan are capacity resources, not energy resources. Redirected transmission, batteries and peakers all rely on market purchases for energy. Therefore, PSE's avoided energy costs are clearly avoiding Mid-C market purchases. Peakers are capable of generating energy, so they temper PSE's exposure to market prices, at least when market heat rates (the spread between natural gas prices and power prices) increase. This means using a forecast of market prices could tend to overstate avoided energy costs during some hours – but only for short periods.

The following tables include the forecast average monthly power prices and forecast average annual market power prices at Mid-C for all of the scenarios. The first table, Figure N-39, includes the Mid-C market prices forecast for the Base + CAR Only Scenario. This is the set of avoided energy costs PSE suggests would be the most informative for potential suppliers. While the future of the CAR is uncertain, it is a policy that is currently in effect.

Base Scenario prices are shown in the second table, Figure N-40. The Base Scenario includes CAR in the early years, but then transitions to the CPP in 2022, assuming the CPP is implemented as a WECC-wide cap and trade regulation that could significantly affect Mid-C prices. Whether the CPP will be implemented at all is highly uncertain. There are currently no serious efforts to develop a WECC-wide, interstate carbon market to implement the CPP. For any sizable power contracts, suppliers should not expect PSE would commit its customers to pay a market price for power that includes carbon prices associated with policies and regulatory structures that do not exist. The Base Scenario prices, however, are helpful in understanding the range of what market price could be in the future, along with the prices in all the other scenarios, which are included in the following tables.

Appendix N: Electric Analysis



Figure N-39: Forecast Mid-C Power Prices for Base + Mid CAR Only Scenario (Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|------|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| | MONTHS | | | | | | | | | | | | |
| 2018 | 31.15 | 30.89 | 28.82 | 24.41 | 21.65 | 21.62 | 27.89 | 30.19 | 29.94 | 28.71 | 27.51 | 28.55 | 27.61 |
| 2019 | 29.74 | 29.29 | 27.64 | 24.91 | 22.72 | 22.27 | 28.21 | 30.56 | 30.94 | 30.06 | 27.69 | 28.56 | 27.71 |
| 2020 | 29.43 | 29.29 | 27.73 | 24.87 | 22.28 | 22.85 | 28.93 | 31.15 | 32.15 | 32.05 | 29.66 | 29.67 | 28.34 |
| 2021 | 31.21 | 31.27 | 28.91 | 26.02 | 23.36 | 23.82 | 30.12 | 32.71 | 33.52 | 32.18 | 30.92 | 31.16 | 29.60 |
| 2022 | 32.93 | 33.33 | 30.47 | 28.53 | 26.57 | 27.44 | 33.04 | 35.96 | 36.82 | 35.98 | 34.72 | 33.90 | 32.47 |
| 2023 | 35.13 | 35.81 | 32.66 | 30.36 | 29.13 | 29.90 | 35.64 | 38.62 | 39.51 | 40.79 | 38.79 | 36.94 | 35.27 |
| 2024 | 37.01 | 38.62 | 35.08 | 32.71 | 31.51 | 31.58 | 37.99 | 41.65 | 42.97 | 42.20 | 39.46 | 39.45 | 37.52 |
| 2025 | 40.60 | 41.97 | 38.71 | 36.91 | 35.43 | 34.92 | 42.20 | 45.57 | 46.80 | 45.86 | 43.18 | 43.15 | 41.27 |
| 2026 | 44.87 | 46.21 | 43.40 | 39.90 | 37.40 | 38.11 | 45.93 | 49.72 | 50.61 | 51.14 | 47.81 | 46.97 | 45.17 |
| 2027 | 47.85 | 49.28 | 46.31 | 42.70 | 40.10 | 40.75 | 48.68 | 52.68 | 53.42 | 52.98 | 50.37 | 49.78 | 47.91 |
| 2028 | 50.87 | 51.89 | 48.99 | 46.13 | 44.44 | 43.97 | 51.72 | 56.10 | 56.36 | 56.78 | 54.59 | 52.87 | 51.23 |
| 2029 | 53.83 | 55.67 | 51.83 | 48.25 | 45.85 | 45.23 | 54.83 | 59.55 | 60.06 | 60.20 | 57.05 | 55.80 | 54.01 |
| 2030 | 56.83 | 58.50 | 53.86 | 50.80 | 47.73 | 46.09 | 57.40 | 61.82 | 63.06 | 62.38 | 59.30 | 59.14 | 56.41 |
| 2031 | 59.84 | 61.59 | 56.73 | 54.49 | 51.47 | 49.09 | 60.71 | 65.32 | 66.79 | 65.83 | 63.11 | 62.63 | 59.80 |
| 2032 | 63.34 | 64.33 | 60.11 | 56.58 | 52.37 | 52.84 | 63.69 | 69.04 | 70.32 | 70.13 | 68.21 | 66.37 | 63.11 |
| 2033 | 66.96 | 67.97 | 62.83 | 60.23 | 56.59 | 55.91 | 66.95 | 72.51 | 73.42 | 72.30 | 70.45 | 69.25 | 66.28 |
| 2034 | 69.65 | 70.23 | 64.08 | 61.88 | 59.32 | 56.67 | 68.85 | 74.71 | 75.56 | 74.83 | 73.17 | 71.72 | 68.39 |
| 2035 | 72.45 | 73.49 | 67.78 | 64.22 | 59.37 | 57.05 | 71.53 | 78.53 | 80.06 | 78.72 | 76.81 | 75.44 | 71.29 |
| 2036 | 75.00 | 76.00 | 69.85 | 66.30 | 60.46 | 58.88 | 73.76 | 80.59 | 83.10 | 80.47 | 78.50 | 78.47 | 73.45 |
| 2037 | 77.57 | 78.09 | 71.78 | 68.66 | 63.78 | 60.56 | 75.52 | 82.63 | 85.24 | 82.37 | 81.49 | 81.18 | 75.74 |

Appendix N: Electric Analysis



Figure N-40: Forecast of Mid-C Power Prices for Base Scenario (Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|------|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| | MONTHS | | | | | | | | | | | | |
| 2018 | 31.02 | 30.80 | 28.80 | 24.44 | 21.83 | 21.77 | 27.92 | 30.12 | 29.94 | 28.81 | 27.63 | 28.68 | 27.65 |
| 2019 | 29.82 | 29.36 | 27.64 | 24.89 | 22.78 | 22.48 | 28.21 | 30.47 | 31.04 | 30.12 | 27.79 | 28.66 | 27.77 |
| 2020 | 29.65 | 29.37 | 27.76 | 24.92 | 22.46 | 23.11 | 28.97 | 31.21 | 32.23 | 32.11 | 29.75 | 29.84 | 28.45 |
| 2021 | 31.43 | 31.38 | 28.97 | 26.04 | 23.42 | 23.91 | 29.94 | 32.61 | 33.57 | 32.44 | 31.12 | 31.31 | 29.68 |
| 2022 | 36.86 | 36.35 | 33.15 | 30.27 | 29.17 | 30.36 | 34.56 | 38.16 | 38.37 | 36.32 | 36.90 | 37.18 | 34.80 |
| 2023 | 38.30 | 38.27 | 35.68 | 32.95 | 31.11 | 33.17 | 37.01 | 41.00 | 41.18 | 41.00 | 40.35 | 39.74 | 37.48 |
| 2024 | 39.95 | 40.65 | 38.50 | 36.48 | 33.48 | 34.89 | 39.75 | 44.07 | 45.52 | 42.62 | 42.00 | 42.11 | 40.00 |
| 2025 | 43.29 | 43.78 | 41.95 | 40.32 | 37.43 | 38.84 | 43.41 | 48.14 | 49.55 | 46.50 | 45.63 | 45.85 | 43.72 |
| 2026 | 46.78 | 47.27 | 45.37 | 42.60 | 40.22 | 42.20 | 46.61 | 51.50 | 52.91 | 51.09 | 49.63 | 49.17 | 47.11 |
| 2027 | 49.92 | 50.38 | 48.56 | 46.20 | 43.10 | 45.12 | 49.52 | 54.85 | 56.04 | 53.38 | 52.66 | 52.29 | 50.17 |
| 2028 | 53.54 | 53.81 | 51.54 | 49.49 | 47.04 | 48.31 | 52.82 | 58.81 | 59.25 | 57.21 | 57.24 | 56.48 | 53.79 |
| 2029 | 57.70 | 58.41 | 55.22 | 52.61 | 49.40 | 50.86 | 56.19 | 62.59 | 64.07 | 61.98 | 61.07 | 60.47 | 57.55 |
| 2030 | 61.38 | 61.95 | 57.93 | 55.35 | 52.05 | 52.79 | 58.71 | 65.04 | 67.36 | 64.59 | 63.67 | 64.03 | 60.40 |
| 2031 | 64.56 | 65.10 | 61.56 | 58.92 | 55.73 | 56.28 | 62.52 | 68.72 | 71.35 | 68.61 | 67.88 | 68.02 | 64.10 |
| 2032 | 68.73 | 68.90 | 65.70 | 62.07 | 58.45 | 60.65 | 66.75 | 73.95 | 76.32 | 74.34 | 74.62 | 73.45 | 68.66 |
| 2033 | 72.80 | 73.42 | 69.49 | 65.82 | 62.44 | 63.56 | 70.21 | 78.06 | 79.97 | 77.20 | 77.80 | 77.14 | 72.33 |
| 2034 | 77.16 | 77.45 | 71.23 | 67.81 | 64.61 | 65.12 | 72.38 | 79.93 | 81.54 | 79.67 | 80.54 | 79.52 | 74.75 |
| 2035 | 79.13 | 79.93 | 74.68 | 70.86 | 66.07 | 66.59 | 74.95 | 83.57 | 85.48 | 83.61 | 84.61 | 83.04 | 77.71 |
| 2036 | 82.13 | 82.62 | 77.22 | 73.54 | 67.82 | 68.82 | 78.04 | 86.01 | 88.86 | 85.69 | 86.28 | 86.20 | 80.27 |
| 2037 | 85.20 | 85.67 | 80.17 | 76.30 | 71.24 | 71.19 | 81.19 | 88.68 | 91.90 | 88.48 | 89.74 | 89.39 | 83.26 |

Appendix N: Electric Analysis



Figure N-41: Forecast of Mid-C Power Prices for Base + No CO₂ Scenario (Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|------|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| | MONTHS | | | | | | | | | | | | |
| 2018 | 30.02 | 29.53 | 28.15 | 22.97 | 19.45 | 19.01 | 25.33 | 28.93 | 28.48 | 26.16 | 26.72 | 27.90 | 26.05 |
| 2019 | 28.79 | 28.19 | 26.87 | 23.78 | 20.29 | 19.49 | 25.55 | 29.33 | 29.12 | 26.73 | 26.90 | 27.88 | 26.08 |
| 2020 | 28.76 | 28.31 | 26.95 | 23.44 | 19.89 | 19.95 | 26.23 | 29.88 | 30.19 | 28.49 | 28.20 | 29.02 | 26.61 |
| 2021 | 30.17 | 29.51 | 27.98 | 24.12 | 20.68 | 20.66 | 27.04 | 31.20 | 31.02 | 28.48 | 29.03 | 30.27 | 27.51 |
| 2022 | 31.71 | 31.34 | 29.51 | 27.25 | 24.16 | 24.09 | 30.31 | 34.21 | 33.85 | 31.52 | 31.88 | 32.48 | 30.19 |
| 2023 | 33.02 | 33.10 | 31.17 | 29.32 | 26.89 | 27.06 | 32.81 | 36.73 | 36.22 | 35.97 | 35.70 | 35.40 | 32.78 |
| 2024 | 34.96 | 35.31 | 32.78 | 31.78 | 29.55 | 29.27 | 35.36 | 39.42 | 39.81 | 37.85 | 37.34 | 37.79 | 35.10 |
| 2025 | 38.67 | 38.81 | 36.46 | 35.60 | 32.97 | 31.98 | 39.08 | 43.44 | 43.81 | 41.81 | 41.22 | 41.77 | 38.80 |
| 2026 | 42.70 | 43.15 | 40.25 | 38.42 | 34.33 | 33.93 | 42.31 | 47.33 | 47.68 | 46.99 | 45.42 | 45.09 | 42.30 |
| 2027 | 45.72 | 46.05 | 43.11 | 41.43 | 36.83 | 36.49 | 45.12 | 50.22 | 50.42 | 49.11 | 47.95 | 47.83 | 45.02 |
| 2028 | 48.67 | 48.99 | 45.65 | 44.22 | 40.79 | 39.36 | 48.10 | 53.39 | 53.13 | 52.59 | 51.46 | 50.73 | 48.09 |
| 2029 | 51.58 | 52.47 | 48.84 | 46.73 | 42.57 | 41.56 | 50.71 | 56.60 | 57.10 | 56.12 | 54.32 | 53.88 | 51.04 |
| 2030 | 54.78 | 55.17 | 51.28 | 49.00 | 44.06 | 42.44 | 52.28 | 59.03 | 60.06 | 58.90 | 56.82 | 57.37 | 53.43 |
| 2031 | 57.81 | 58.36 | 54.34 | 52.08 | 47.40 | 45.23 | 55.31 | 62.10 | 63.49 | 62.19 | 60.66 | 60.96 | 56.66 |
| 2032 | 61.29 | 61.26 | 57.81 | 54.15 | 48.76 | 49.00 | 58.80 | 65.34 | 66.70 | 66.18 | 65.68 | 64.73 | 59.97 |
| 2033 | 64.88 | 65.05 | 60.54 | 57.63 | 52.68 | 51.53 | 61.60 | 68.43 | 69.54 | 68.30 | 68.11 | 67.58 | 62.99 |
| 2034 | 67.58 | 67.44 | 61.66 | 59.04 | 54.94 | 52.25 | 63.06 | 70.35 | 71.51 | 70.85 | 70.55 | 69.90 | 64.93 |
| 2035 | 70.48 | 70.71 | 65.55 | 61.13 | 55.28 | 53.14 | 65.18 | 73.69 | 75.84 | 74.97 | 74.37 | 73.81 | 67.85 |
| 2036 | 72.98 | 73.00 | 67.43 | 62.78 | 56.50 | 54.63 | 67.35 | 75.53 | 78.59 | 76.82 | 76.26 | 76.68 | 69.88 |
| 2037 | 75.17 | 75.37 | 69.42 | 64.96 | 59.20 | 56.33 | 68.80 | 77.26 | 80.50 | 78.68 | 79.13 | 79.07 | 71.99 |

Appendix N: Electric Analysis



Figure N-42: Forecast of Mid-C Power Prices for Low Scenario (Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|------|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| | MONTHS | | | | | | | | | | | | |
| 2018 | 25.96 | 25.60 | 23.78 | 19.94 | 17.25 | 17.49 | 23.19 | 25.38 | 24.51 | 22.53 | 21.95 | 23.53 | 22.59 |
| 2019 | 24.22 | 23.66 | 22.18 | 19.99 | 17.93 | 17.51 | 22.22 | 24.97 | 24.61 | 22.95 | 21.79 | 22.66 | 22.06 |
| 2020 | 23.54 | 23.35 | 21.81 | 19.48 | 16.97 | 17.54 | 22.28 | 24.94 | 25.18 | 23.71 | 22.53 | 22.95 | 22.02 |
| 2021 | 23.63 | 23.55 | 22.24 | 19.55 | 17.41 | 18.13 | 22.64 | 25.38 | 25.27 | 23.31 | 22.73 | 24.02 | 22.32 |
| 2022 | 24.32 | 24.21 | 22.30 | 20.56 | 18.24 | 18.15 | 23.20 | 27.45 | 26.55 | 23.66 | 24.61 | 25.58 | 23.24 |
| 2023 | 26.13 | 26.06 | 24.29 | 22.17 | 20.18 | 20.30 | 25.16 | 29.31 | 28.48 | 26.98 | 27.73 | 27.67 | 25.37 |
| 2024 | 27.41 | 27.81 | 25.94 | 24.13 | 21.85 | 21.89 | 26.90 | 31.06 | 31.12 | 28.18 | 29.29 | 30.21 | 27.15 |
| 2025 | 30.46 | 31.05 | 29.82 | 28.05 | 25.29 | 24.81 | 30.46 | 34.92 | 35.55 | 32.73 | 33.45 | 33.51 | 30.84 |
| 2026 | 34.05 | 35.03 | 32.62 | 29.06 | 25.96 | 26.12 | 31.99 | 37.16 | 37.87 | 35.43 | 35.32 | 34.70 | 32.94 |
| 2027 | 35.07 | 36.08 | 33.09 | 29.96 | 26.61 | 26.53 | 32.32 | 37.95 | 38.53 | 35.94 | 36.27 | 35.59 | 33.66 |
| 2028 | 36.17 | 37.12 | 34.35 | 31.31 | 28.13 | 27.40 | 33.41 | 39.44 | 39.67 | 37.39 | 37.82 | 36.81 | 34.92 |
| 2029 | 37.23 | 39.03 | 35.81 | 32.08 | 28.83 | 28.69 | 34.79 | 41.43 | 42.47 | 40.15 | 39.12 | 38.37 | 36.50 |
| 2030 | 38.99 | 40.72 | 37.67 | 33.87 | 30.46 | 29.57 | 36.05 | 43.04 | 45.18 | 42.40 | 41.36 | 40.97 | 38.36 |
| 2031 | 41.87 | 43.85 | 40.76 | 37.32 | 33.55 | 31.96 | 39.26 | 46.22 | 48.84 | 45.93 | 45.06 | 44.69 | 41.61 |
| 2032 | 44.87 | 46.58 | 42.67 | 39.31 | 34.73 | 35.02 | 42.25 | 49.09 | 51.15 | 48.97 | 49.32 | 47.65 | 44.30 |
| 2033 | 47.01 | 48.21 | 43.74 | 40.73 | 36.74 | 36.09 | 43.72 | 51.12 | 52.72 | 49.74 | 50.54 | 49.28 | 45.80 |
| 2034 | 48.76 | 49.60 | 43.64 | 40.40 | 37.32 | 35.23 | 43.33 | 51.28 | 53.47 | 50.84 | 51.39 | 49.83 | 46.26 |
| 2035 | 49.53 | 51.35 | 45.55 | 40.36 | 36.11 | 34.46 | 43.45 | 52.91 | 56.34 | 53.26 | 53.39 | 51.34 | 47.34 |
| 2036 | 50.47 | 52.24 | 46.21 | 40.66 | 36.21 | 34.70 | 44.38 | 53.25 | 57.99 | 54.06 | 53.64 | 52.61 | 48.04 |
| 2037 | 51.66 | 53.53 | 47.07 | 41.76 | 37.92 | 35.33 | 45.52 | 54.25 | 59.37 | 55.11 | 55.40 | 53.89 | 49.23 |

Appendix N: Electric Analysis



Figure N-43: Forecast of Mid-C Power Prices for High Scenario (Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|--------|--------|--------|-------|-------|-------|-------|-------|--------|--------|--------|--------|--------|-------|
| MONTHS | | | | | | | | | | | | | |
| 2018 | 32.31 | 32.56 | 30.28 | 25.62 | 23.69 | 23.74 | 29.94 | 32.27 | 32.20 | 30.90 | 30.32 | 31.20 | 29.59 |
| 2019 | 41.92 | 40.94 | 35.03 | 31.00 | 28.17 | 26.93 | 34.00 | 36.80 | 36.73 | 36.23 | 34.20 | 34.72 | 34.72 |
| 2020 | 36.58 | 36.41 | 33.28 | 29.23 | 26.94 | 27.17 | 33.80 | 36.39 | 37.14 | 37.10 | 35.62 | 35.34 | 33.75 |
| 2021 | 38.57 | 38.20 | 34.02 | 29.75 | 27.53 | 27.97 | 34.52 | 37.50 | 38.19 | 37.09 | 38.06 | 39.07 | 35.04 |
| 2022 | 44.24 | 43.09 | 39.48 | 36.25 | 35.35 | 36.91 | 41.54 | 45.64 | 45.88 | 44.63 | 47.20 | 48.30 | 42.38 |
| 2023 | 49.55 | 49.02 | 45.00 | 41.05 | 40.10 | 41.57 | 47.16 | 51.34 | 51.33 | 51.75 | 52.46 | 51.75 | 47.67 |
| 2024 | 50.78 | 51.39 | 47.45 | 43.97 | 41.41 | 42.29 | 48.98 | 53.95 | 54.54 | 52.13 | 52.81 | 53.94 | 49.47 |
| 2025 | 57.86 | 58.33 | 54.47 | 51.66 | 48.65 | 49.19 | 56.77 | 61.85 | 62.16 | 59.97 | 60.48 | 61.17 | 56.88 |
| 2026 | 61.59 | 62.17 | 57.18 | 53.19 | 50.25 | 51.63 | 59.15 | 64.78 | 65.52 | 64.43 | 64.23 | 63.98 | 59.84 |
| 2027 | 63.93 | 64.21 | 59.15 | 55.80 | 52.04 | 53.26 | 61.45 | 67.31 | 67.47 | 64.80 | 66.11 | 66.08 | 61.80 |
| 2028 | 68.90 | 68.56 | 63.57 | 59.44 | 56.47 | 56.30 | 65.47 | 71.88 | 70.89 | 69.17 | 71.06 | 70.83 | 66.05 |
| 2029 | 78.86 | 79.54 | 72.52 | 67.75 | 64.63 | 65.39 | 74.76 | 82.11 | 82.23 | 81.29 | 83.93 | 84.59 | 76.47 |
| 2030 | 85.47 | 86.13 | 79.57 | 76.08 | 73.18 | 73.51 | 82.48 | 89.32 | 90.99 | 90.09 | 96.50 | 97.42 | 85.06 |
| 2031 | 86.03 | 86.37 | 80.97 | 78.14 | 74.72 | 74.97 | 83.78 | 90.44 | 92.33 | 91.20 | 96.70 | 98.16 | 86.15 |
| 2032 | 89.54 | 88.96 | 83.71 | 80.38 | 76.08 | 78.71 | 86.96 | 94.20 | 95.86 | 95.52 | 99.54 | 99.27 | 89.06 |
| 2033 | 93.80 | 93.13 | 88.86 | 85.53 | 82.00 | 82.93 | 91.29 | 99.10 | 101.04 | 100.27 | 113.90 | 114.02 | 95.49 |
| 2034 | 99.89 | 99.32 | 91.98 | 88.37 | 85.00 | 84.21 | 93.31 | 100.91 | 102.74 | 100.99 | 104.05 | 103.25 | 96.17 |
| 2035 | 98.68 | 98.63 | 94.90 | 87.31 | 82.45 | 82.06 | 91.33 | 100.03 | 102.67 | 100.49 | 100.08 | 99.66 | 94.86 |
| 2036 | 101.30 | 100.90 | 96.81 | 89.25 | 84.16 | 84.41 | 93.75 | 101.53 | 105.27 | 102.25 | 101.26 | 102.40 | 96.94 |
| 2037 | 103.96 | 103.20 | 98.79 | 91.65 | 87.41 | 86.79 | 95.95 | 103.88 | 107.59 | 104.46 | 104.28 | 105.01 | 99.41 |

Appendix N: Electric Analysis



Figure N-44: Forecast of Mid-C Power Prices for Low Demand + High Gas CO₂ Scenario
(Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|--------|-------|-------|-------|-------|-------|-------|-------|--------|--------|--------|--------|--------|-------|
| MONTHS | | | | | | | | | | | | | |
| 2018 | 29.44 | 29.57 | 28.53 | 24.73 | 21.37 | 20.85 | 27.85 | 30.78 | 30.79 | 28.79 | 28.26 | 28.73 | 27.47 |
| 2019 | 38.30 | 37.85 | 33.26 | 29.87 | 25.51 | 24.34 | 31.46 | 34.98 | 35.07 | 33.62 | 31.78 | 32.22 | 32.36 |
| 2020 | 33.12 | 33.01 | 31.64 | 27.93 | 23.96 | 23.65 | 30.66 | 34.41 | 34.84 | 34.05 | 32.57 | 32.74 | 31.05 |
| 2021 | 33.90 | 33.73 | 32.11 | 28.23 | 24.09 | 23.96 | 31.32 | 35.49 | 35.85 | 33.67 | 33.36 | 35.06 | 31.73 |
| 2022 | 41.07 | 40.07 | 37.73 | 34.90 | 33.67 | 34.87 | 39.04 | 42.92 | 43.12 | 40.92 | 43.56 | 44.23 | 39.68 |
| 2023 | 45.55 | 45.41 | 42.34 | 39.54 | 38.27 | 38.84 | 43.91 | 47.96 | 48.12 | 47.91 | 48.90 | 47.88 | 44.55 |
| 2024 | 46.56 | 47.16 | 44.15 | 41.36 | 39.43 | 40.03 | 44.72 | 49.05 | 50.24 | 48.05 | 49.12 | 49.39 | 45.77 |
| 2025 | 52.72 | 53.52 | 50.10 | 48.02 | 45.36 | 45.41 | 51.65 | 55.91 | 57.26 | 55.87 | 56.11 | 56.10 | 52.34 |
| 2026 | 55.29 | 55.99 | 52.08 | 49.16 | 46.31 | 47.65 | 53.10 | 57.54 | 59.02 | 58.09 | 58.26 | 57.67 | 54.18 |
| 2027 | 57.17 | 57.56 | 53.58 | 51.10 | 48.20 | 48.87 | 54.45 | 59.02 | 60.10 | 58.24 | 59.74 | 59.33 | 55.61 |
| 2028 | 61.36 | 61.34 | 57.55 | 54.36 | 51.81 | 51.01 | 57.16 | 62.61 | 63.35 | 61.60 | 64.07 | 63.30 | 59.13 |
| 2029 | 70.12 | 71.17 | 65.44 | 61.67 | 58.42 | 58.84 | 66.31 | 72.15 | 73.89 | 73.61 | 76.34 | 75.32 | 68.61 |
| 2030 | 75.76 | 77.49 | 71.49 | 67.99 | 65.19 | 65.09 | 73.46 | 79.02 | 81.70 | 82.16 | 86.66 | 85.70 | 75.98 |
| 2031 | 77.59 | 78.70 | 73.68 | 70.82 | 68.22 | 67.10 | 75.89 | 81.52 | 84.38 | 84.47 | 87.88 | 87.29 | 78.13 |
| 2032 | 81.42 | 81.79 | 76.51 | 72.78 | 69.27 | 70.87 | 79.80 | 86.58 | 89.63 | 89.96 | 92.08 | 89.38 | 81.67 |
| 2033 | 85.66 | 86.18 | 81.45 | 77.11 | 74.02 | 74.81 | 84.20 | 91.81 | 95.31 | 94.83 | 104.80 | 102.54 | 87.73 |
| 2034 | 91.98 | 92.68 | 85.40 | 81.47 | 79.29 | 77.77 | 88.08 | 95.61 | 98.59 | 96.98 | 97.37 | 94.91 | 90.01 |
| 2035 | 92.18 | 93.51 | 88.95 | 83.27 | 79.19 | 77.66 | 88.68 | 96.62 | 100.48 | 98.42 | 95.43 | 93.26 | 90.64 |
| 2036 | 95.18 | 96.30 | 91.55 | 85.51 | 81.29 | 80.36 | 91.52 | 99.27 | 104.11 | 100.57 | 97.02 | 96.31 | 93.25 |
| 2037 | 98.25 | 99.19 | 94.35 | 88.61 | 85.22 | 83.04 | 94.16 | 102.12 | 107.21 | 103.56 | 100.34 | 99.33 | 96.28 |

Appendix N: Electric Analysis



Figure N-45: Forecast of Mid-C Power Prices for Base + Low Gas Scenario (Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|------|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| | MONTHS | | | | | | | | | | | | |
| 2018 | 26.85 | 26.34 | 24.14 | 20.03 | 18.05 | 18.40 | 24.36 | 26.49 | 25.94 | 25.14 | 23.08 | 24.14 | 23.58 |
| 2019 | 25.47 | 25.14 | 22.63 | 20.08 | 18.61 | 18.60 | 24.05 | 26.25 | 26.51 | 25.77 | 23.45 | 23.86 | 23.37 |
| 2020 | 24.96 | 25.11 | 22.21 | 19.71 | 17.85 | 18.81 | 24.17 | 26.47 | 27.38 | 27.34 | 24.50 | 24.16 | 23.56 |
| 2021 | 25.29 | 25.45 | 22.89 | 19.98 | 18.40 | 19.21 | 24.24 | 26.98 | 27.97 | 26.82 | 25.16 | 25.29 | 23.97 |
| 2022 | 31.24 | 30.55 | 28.13 | 25.30 | 23.46 | 24.94 | 28.83 | 32.97 | 33.59 | 31.40 | 32.23 | 32.52 | 29.60 |
| 2023 | 33.42 | 33.05 | 30.35 | 27.70 | 25.32 | 27.13 | 31.29 | 35.63 | 35.72 | 35.55 | 35.46 | 34.52 | 32.09 |
| 2024 | 34.40 | 35.17 | 33.04 | 30.14 | 26.69 | 27.90 | 33.59 | 38.20 | 39.26 | 36.73 | 36.50 | 37.04 | 34.05 |
| 2025 | 37.18 | 38.19 | 37.14 | 34.91 | 31.42 | 32.81 | 38.19 | 42.46 | 44.01 | 40.89 | 40.21 | 40.62 | 38.17 |
| 2026 | 41.05 | 41.80 | 39.81 | 36.45 | 33.60 | 35.46 | 40.09 | 44.65 | 46.35 | 43.83 | 42.88 | 42.21 | 40.68 |
| 2027 | 42.84 | 43.41 | 41.04 | 37.98 | 34.81 | 36.71 | 41.54 | 46.44 | 47.51 | 44.52 | 44.36 | 43.41 | 42.05 |
| 2028 | 44.47 | 45.06 | 42.64 | 39.93 | 37.20 | 38.30 | 43.42 | 49.03 | 49.01 | 46.64 | 46.39 | 45.45 | 43.96 |
| 2029 | 46.35 | 47.19 | 44.69 | 41.85 | 38.18 | 39.68 | 45.69 | 51.55 | 52.60 | 49.92 | 48.65 | 47.72 | 46.17 |
| 2030 | 49.25 | 49.90 | 47.57 | 44.49 | 40.85 | 42.14 | 48.59 | 54.46 | 56.29 | 52.62 | 51.01 | 51.35 | 49.04 |
| 2031 | 52.99 | 53.49 | 51.45 | 48.89 | 44.88 | 45.76 | 52.97 | 58.50 | 60.51 | 56.63 | 55.29 | 55.85 | 53.10 |
| 2032 | 56.62 | 57.34 | 54.18 | 51.24 | 46.91 | 49.38 | 56.46 | 62.43 | 63.60 | 60.76 | 60.10 | 59.68 | 56.56 |
| 2033 | 59.13 | 59.32 | 55.80 | 53.16 | 48.63 | 50.79 | 58.05 | 64.43 | 65.34 | 62.39 | 62.16 | 61.88 | 58.42 |
| 2034 | 62.02 | 61.61 | 55.92 | 53.34 | 49.65 | 50.65 | 58.35 | 65.45 | 65.86 | 62.55 | 63.11 | 62.43 | 59.24 |
| 2035 | 62.73 | 62.69 | 57.66 | 53.83 | 49.82 | 50.61 | 59.44 | 67.73 | 68.61 | 64.69 | 64.87 | 64.01 | 60.56 |
| 2036 | 63.86 | 63.75 | 58.77 | 54.91 | 50.65 | 51.60 | 61.02 | 68.51 | 70.44 | 64.94 | 65.00 | 65.56 | 61.58 |
| 2037 | 65.06 | 64.79 | 59.60 | 56.13 | 52.68 | 52.75 | 62.00 | 69.62 | 71.31 | 65.61 | 66.54 | 66.73 | 62.74 |

Appendix N: Electric Analysis



Figure N-46: Forecast of Mid-C Power Prices for Base + High Gas Scenario (Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|------|--------|-------|-------|-------|-------|-------|-------|--------|--------|--------|--------|--------|-------|
| | MONTHS | | | | | | | | | | | | |
| 2018 | 30.61 | 30.45 | 28.94 | 24.76 | 22.31 | 22.20 | 28.41 | 30.62 | 30.53 | 29.54 | 28.61 | 29.17 | 28.01 |
| 2019 | 39.40 | 38.47 | 33.60 | 30.01 | 26.85 | 25.62 | 32.32 | 34.72 | 35.09 | 34.66 | 32.41 | 33.22 | 33.03 |
| 2020 | 34.31 | 34.10 | 32.24 | 28.42 | 25.70 | 25.76 | 32.11 | 34.54 | 35.34 | 35.40 | 33.61 | 33.57 | 32.09 |
| 2021 | 35.35 | 35.54 | 32.74 | 29.15 | 26.38 | 26.56 | 32.91 | 35.62 | 36.67 | 35.93 | 35.49 | 36.19 | 33.21 |
| 2022 | 42.21 | 41.06 | 38.00 | 35.14 | 33.97 | 35.40 | 39.04 | 43.41 | 43.88 | 42.07 | 45.17 | 45.86 | 40.43 |
| 2023 | 47.21 | 46.73 | 43.48 | 39.99 | 38.89 | 39.88 | 44.42 | 48.95 | 49.01 | 49.22 | 50.09 | 49.29 | 45.60 |
| 2024 | 48.15 | 48.69 | 45.91 | 42.62 | 40.31 | 40.77 | 45.92 | 50.88 | 51.94 | 49.97 | 50.77 | 51.17 | 47.26 |
| 2025 | 54.61 | 55.30 | 52.15 | 49.45 | 46.44 | 47.12 | 53.28 | 58.08 | 59.10 | 57.17 | 57.82 | 58.04 | 54.05 |
| 2026 | 57.36 | 57.93 | 54.46 | 50.32 | 47.87 | 49.20 | 54.95 | 60.19 | 61.59 | 60.29 | 60.21 | 59.77 | 56.18 |
| 2027 | 59.48 | 59.81 | 56.41 | 52.70 | 49.86 | 50.88 | 56.81 | 62.40 | 63.51 | 61.13 | 62.12 | 61.55 | 58.05 |
| 2028 | 63.94 | 63.83 | 60.44 | 56.23 | 54.12 | 53.50 | 60.48 | 66.80 | 66.97 | 65.03 | 66.56 | 65.83 | 61.98 |
| 2029 | 73.47 | 74.28 | 68.98 | 64.28 | 61.94 | 62.81 | 69.98 | 76.82 | 78.14 | 77.31 | 79.69 | 78.99 | 72.22 |
| 2030 | 79.76 | 81.18 | 76.00 | 72.47 | 69.44 | 70.24 | 77.63 | 84.33 | 87.22 | 86.68 | 91.41 | 91.00 | 80.61 |
| 2031 | 80.57 | 81.63 | 77.58 | 74.54 | 71.33 | 71.95 | 79.51 | 86.15 | 88.89 | 88.03 | 91.94 | 91.89 | 82.00 |
| 2032 | 84.28 | 84.41 | 80.72 | 77.34 | 72.73 | 75.14 | 83.20 | 90.82 | 93.28 | 92.80 | 95.08 | 93.76 | 85.30 |
| 2033 | 88.46 | 89.07 | 86.13 | 81.95 | 77.58 | 79.03 | 87.62 | 96.01 | 98.70 | 97.65 | 108.68 | 107.28 | 91.51 |
| 2034 | 95.27 | 96.06 | 89.83 | 85.58 | 81.87 | 81.59 | 91.02 | 99.02 | 101.62 | 99.50 | 100.74 | 98.90 | 93.42 |
| 2035 | 94.59 | 95.71 | 91.75 | 85.02 | 80.51 | 80.16 | 90.33 | 98.86 | 102.30 | 99.60 | 97.27 | 95.93 | 92.67 |
| 2036 | 96.81 | 97.85 | 93.40 | 86.74 | 81.90 | 82.10 | 92.27 | 99.98 | 104.35 | 101.16 | 98.18 | 98.21 | 94.41 |
| 2037 | 99.42 | 99.76 | 95.10 | 89.17 | 84.86 | 83.86 | 93.76 | 101.85 | 106.15 | 103.09 | 100.85 | 100.53 | 96.53 |

Appendix N: Electric Analysis



Figure N-47: Forecast of Mid-C Power Prices for Base + Low Demand Scenario
(Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| MONTHS | | | | | | | | | | | | | |
| 2018 | 30.29 | 30.13 | 28.60 | 24.42 | 20.92 | 20.60 | 27.37 | 29.84 | 29.88 | 28.19 | 27.14 | 28.08 | 27.12 |
| 2019 | 28.93 | 28.59 | 27.31 | 24.88 | 21.86 | 20.89 | 27.64 | 30.22 | 30.56 | 28.81 | 27.25 | 27.76 | 27.06 |
| 2020 | 28.60 | 28.33 | 27.30 | 24.49 | 20.79 | 20.96 | 27.81 | 30.55 | 31.30 | 30.50 | 28.53 | 29.01 | 27.35 |
| 2021 | 30.10 | 29.90 | 28.46 | 25.42 | 21.48 | 21.70 | 28.77 | 31.99 | 32.40 | 29.94 | 29.32 | 30.18 | 28.30 |
| 2022 | 36.13 | 35.67 | 32.68 | 29.99 | 28.97 | 30.05 | 34.81 | 38.11 | 37.90 | 35.37 | 36.32 | 36.53 | 34.38 |
| 2023 | 37.53 | 37.53 | 35.00 | 32.34 | 31.09 | 32.99 | 37.41 | 40.62 | 40.60 | 39.76 | 39.69 | 39.17 | 36.98 |
| 2024 | 39.20 | 39.99 | 37.46 | 35.22 | 32.93 | 34.44 | 39.56 | 43.32 | 44.39 | 41.66 | 41.13 | 41.26 | 39.21 |
| 2025 | 42.45 | 43.09 | 40.68 | 39.19 | 36.74 | 38.11 | 43.06 | 46.82 | 48.22 | 45.76 | 44.51 | 44.55 | 42.76 |
| 2026 | 45.73 | 46.30 | 44.05 | 41.35 | 39.32 | 41.16 | 46.02 | 50.06 | 51.29 | 49.93 | 48.46 | 47.81 | 45.96 |
| 2027 | 48.56 | 49.16 | 46.77 | 44.17 | 42.01 | 43.85 | 48.51 | 52.52 | 53.71 | 51.77 | 50.98 | 50.50 | 48.54 |
| 2028 | 51.96 | 52.22 | 49.73 | 47.80 | 45.47 | 46.92 | 51.43 | 55.84 | 56.49 | 55.16 | 55.42 | 54.32 | 51.90 |
| 2029 | 55.53 | 56.55 | 52.97 | 50.30 | 47.48 | 49.29 | 54.47 | 59.38 | 60.69 | 59.30 | 58.91 | 57.86 | 55.23 |
| 2030 | 58.86 | 59.54 | 55.03 | 52.36 | 49.85 | 50.47 | 56.56 | 60.96 | 63.13 | 61.82 | 60.98 | 60.68 | 57.52 |
| 2031 | 62.08 | 62.74 | 58.55 | 55.87 | 53.03 | 53.60 | 60.14 | 64.81 | 67.31 | 65.65 | 65.06 | 64.80 | 61.13 |
| 2032 | 66.01 | 66.52 | 62.55 | 59.15 | 55.29 | 57.72 | 64.16 | 69.64 | 72.15 | 71.17 | 71.54 | 69.89 | 65.48 |
| 2033 | 70.29 | 71.17 | 66.67 | 63.23 | 59.41 | 60.94 | 67.93 | 73.97 | 76.65 | 74.50 | 74.84 | 73.37 | 69.41 |
| 2034 | 74.17 | 74.84 | 68.69 | 65.89 | 62.19 | 62.69 | 70.43 | 76.66 | 78.87 | 76.94 | 77.85 | 76.05 | 72.11 |
| 2035 | 76.62 | 77.53 | 72.47 | 68.54 | 64.35 | 65.13 | 73.84 | 80.86 | 83.96 | 81.74 | 82.20 | 80.27 | 75.63 |
| 2036 | 79.91 | 80.81 | 75.42 | 70.92 | 66.17 | 67.31 | 77.33 | 84.00 | 87.68 | 83.99 | 84.18 | 83.51 | 78.44 |
| 2037 | 83.28 | 84.03 | 78.20 | 73.86 | 69.64 | 70.16 | 80.75 | 87.49 | 90.81 | 86.86 | 87.97 | 86.77 | 81.65 |

Appendix N: Electric Analysis



Figure N-48: Forecast of Mid-C Power Prices for Base + High Demand Scenario
(Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| MONTHS | | | | | | | | | | | | | |
| 2018 | 32.80 | 32.76 | 30.05 | 25.25 | 23.29 | 23.32 | 29.25 | 31.23 | 30.95 | 29.95 | 29.24 | 30.50 | 29.05 |
| 2019 | 32.00 | 31.38 | 28.82 | 25.95 | 24.26 | 24.07 | 29.49 | 31.63 | 31.98 | 31.44 | 29.70 | 30.64 | 29.28 |
| 2020 | 32.19 | 31.53 | 28.68 | 25.74 | 23.53 | 24.37 | 29.98 | 32.21 | 32.96 | 33.19 | 31.52 | 31.88 | 29.81 |
| 2021 | 34.84 | 34.00 | 30.36 | 26.87 | 24.71 | 25.62 | 31.34 | 33.97 | 34.66 | 33.66 | 33.79 | 34.37 | 31.52 |
| 2022 | 39.79 | 38.52 | 35.42 | 31.93 | 30.75 | 32.17 | 36.97 | 41.27 | 41.72 | 39.39 | 39.88 | 40.13 | 37.33 |
| 2023 | 41.21 | 40.82 | 37.73 | 34.33 | 33.06 | 35.03 | 39.76 | 44.26 | 44.68 | 44.71 | 44.40 | 43.02 | 40.25 |
| 2024 | 43.08 | 44.18 | 40.53 | 38.02 | 35.37 | 36.93 | 43.12 | 48.20 | 49.52 | 46.63 | 45.22 | 46.15 | 43.08 |
| 2025 | 48.04 | 48.83 | 43.92 | 42.55 | 39.85 | 40.90 | 47.49 | 52.77 | 54.38 | 51.46 | 49.85 | 50.88 | 47.58 |
| 2026 | 52.75 | 53.35 | 48.02 | 44.95 | 42.82 | 44.62 | 51.21 | 57.30 | 58.74 | 56.62 | 55.36 | 54.79 | 51.71 |
| 2027 | 56.87 | 57.19 | 52.09 | 48.80 | 46.13 | 47.76 | 54.82 | 61.38 | 62.14 | 59.13 | 58.77 | 58.69 | 55.31 |
| 2028 | 58.96 | 58.65 | 54.39 | 52.00 | 49.65 | 50.55 | 57.77 | 64.13 | 63.45 | 61.68 | 62.09 | 61.63 | 57.91 |
| 2029 | 63.41 | 64.21 | 58.67 | 55.23 | 52.51 | 53.31 | 61.59 | 69.04 | 68.71 | 66.41 | 65.22 | 65.77 | 62.01 |
| 2030 | 66.72 | 67.10 | 61.21 | 57.98 | 55.01 | 55.16 | 63.78 | 71.05 | 71.73 | 68.93 | 68.18 | 69.67 | 64.71 |
| 2031 | 70.49 | 70.82 | 64.95 | 61.57 | 58.68 | 58.64 | 67.50 | 74.55 | 75.81 | 72.62 | 72.58 | 73.94 | 68.51 |
| 2032 | 75.15 | 74.69 | 69.39 | 65.23 | 61.90 | 63.55 | 72.41 | 79.88 | 80.43 | 77.73 | 79.33 | 79.33 | 73.25 |
| 2033 | 78.91 | 78.60 | 72.92 | 69.53 | 66.49 | 66.91 | 76.08 | 83.37 | 83.69 | 80.00 | 82.25 | 82.67 | 76.78 |
| 2034 | 82.17 | 81.54 | 74.19 | 71.18 | 68.51 | 68.56 | 77.49 | 85.11 | 84.86 | 82.37 | 84.88 | 84.97 | 78.82 |
| 2035 | 85.42 | 85.24 | 78.42 | 73.96 | 70.38 | 70.41 | 80.00 | 89.38 | 89.70 | 86.51 | 88.66 | 89.29 | 82.28 |
| 2036 | 87.63 | 87.23 | 80.56 | 76.20 | 72.06 | 72.68 | 82.77 | 90.91 | 92.43 | 88.42 | 90.37 | 91.96 | 84.44 |
| 2037 | 90.57 | 90.10 | 83.72 | 79.68 | 75.69 | 75.76 | 86.06 | 93.92 | 95.20 | 91.47 | 93.95 | 94.97 | 87.59 |

Appendix N: Electric Analysis



Figure N-49: Forecast of Mid-C Power Prices for Base + Low CAR CO₂ Scenario
(Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| MONTHS | | | | | | | | | | | | | |
| 2018 | 31.22 | 30.82 | 28.92 | 24.26 | 21.71 | 21.39 | 26.66 | 29.39 | 28.89 | 27.11 | 27.50 | 28.73 | 27.22 |
| 2019 | 29.77 | 29.12 | 27.66 | 24.75 | 22.73 | 22.04 | 26.78 | 29.66 | 29.64 | 28.32 | 27.73 | 28.60 | 27.23 |
| 2020 | 29.58 | 29.33 | 27.71 | 24.86 | 22.36 | 22.70 | 27.49 | 30.39 | 30.78 | 30.00 | 29.58 | 29.82 | 27.88 |
| 2021 | 31.27 | 30.86 | 28.91 | 25.97 | 23.40 | 23.67 | 28.67 | 31.70 | 31.77 | 30.15 | 30.67 | 31.23 | 29.02 |
| 2022 | 37.43 | 36.59 | 33.74 | 30.77 | 29.64 | 31.11 | 35.49 | 39.42 | 39.73 | 37.57 | 37.57 | 37.64 | 35.56 |
| 2023 | 38.66 | 38.60 | 35.99 | 33.37 | 31.72 | 33.83 | 37.89 | 42.33 | 42.51 | 42.72 | 41.57 | 40.19 | 38.28 |
| 2024 | 40.33 | 41.16 | 38.86 | 37.03 | 34.10 | 35.57 | 40.89 | 45.79 | 47.21 | 44.40 | 42.74 | 42.71 | 40.90 |
| 2025 | 44.03 | 44.51 | 42.35 | 40.81 | 38.21 | 39.74 | 45.00 | 50.01 | 51.86 | 49.00 | 46.64 | 46.64 | 44.90 |
| 2026 | 47.39 | 48.00 | 45.79 | 43.07 | 40.81 | 43.02 | 48.22 | 53.39 | 55.45 | 53.88 | 51.00 | 50.02 | 48.34 |
| 2027 | 50.92 | 51.41 | 49.09 | 46.83 | 43.88 | 46.11 | 51.23 | 56.87 | 58.73 | 56.25 | 54.01 | 53.26 | 51.55 |
| 2028 | 54.64 | 54.92 | 52.06 | 50.03 | 47.69 | 49.23 | 54.65 | 61.03 | 62.00 | 60.20 | 58.41 | 57.42 | 55.19 |
| 2029 | 58.72 | 59.45 | 55.82 | 53.15 | 50.27 | 51.69 | 57.86 | 64.91 | 66.79 | 64.96 | 61.92 | 60.99 | 58.88 |
| 2030 | 62.28 | 62.85 | 58.53 | 55.72 | 52.83 | 53.74 | 60.33 | 67.09 | 69.90 | 66.74 | 64.64 | 64.69 | 61.61 |
| 2031 | 65.64 | 66.07 | 61.96 | 59.11 | 56.47 | 57.07 | 64.15 | 70.81 | 73.74 | 70.71 | 68.77 | 68.78 | 65.27 |
| 2032 | 69.60 | 69.91 | 66.25 | 62.66 | 59.08 | 61.20 | 68.22 | 75.68 | 78.44 | 76.29 | 75.48 | 74.09 | 69.74 |
| 2033 | 74.18 | 74.52 | 70.13 | 66.41 | 63.29 | 64.04 | 71.59 | 79.74 | 82.14 | 78.90 | 78.52 | 77.86 | 73.44 |
| 2034 | 78.29 | 78.48 | 71.87 | 68.56 | 65.46 | 66.20 | 74.04 | 82.25 | 83.90 | 81.15 | 81.31 | 80.25 | 75.98 |
| 2035 | 80.10 | 80.70 | 75.21 | 71.36 | 67.11 | 68.21 | 76.87 | 85.97 | 88.17 | 85.56 | 85.27 | 83.90 | 79.04 |
| 2036 | 83.28 | 83.78 | 77.88 | 74.41 | 69.13 | 70.59 | 80.32 | 88.63 | 91.63 | 87.69 | 87.08 | 87.18 | 81.80 |
| 2037 | 86.45 | 87.07 | 80.89 | 77.25 | 72.84 | 73.28 | 83.65 | 91.60 | 94.77 | 90.68 | 90.74 | 90.46 | 84.97 |

Appendix N: Electric Analysis



Figure N-50: Forecast of Mid-C Power Prices for Base + High CAR CO₂ Scenario
(Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| MONTHS | | | | | | | | | | | | | |
| 2018 | 31.29 | 31.01 | 28.97 | 24.43 | 21.84 | 21.83 | 28.03 | 30.57 | 30.32 | 28.98 | 27.61 | 28.72 | 27.80 |
| 2019 | 29.82 | 29.31 | 27.55 | 24.82 | 22.82 | 22.45 | 28.45 | 31.06 | 31.47 | 30.16 | 27.82 | 28.69 | 27.87 |
| 2020 | 29.65 | 29.31 | 27.70 | 24.85 | 22.40 | 23.09 | 29.24 | 31.80 | 32.76 | 32.40 | 29.77 | 29.74 | 28.56 |
| 2021 | 31.39 | 31.40 | 28.97 | 26.00 | 23.53 | 23.98 | 30.26 | 33.32 | 34.41 | 32.42 | 31.00 | 31.31 | 29.83 |
| 2022 | 37.39 | 36.41 | 33.51 | 30.59 | 29.57 | 31.08 | 35.39 | 39.00 | 39.37 | 37.17 | 37.34 | 37.47 | 35.36 |
| 2023 | 38.47 | 38.54 | 35.95 | 33.33 | 31.47 | 33.74 | 37.67 | 41.88 | 42.11 | 42.16 | 41.19 | 40.11 | 38.05 |
| 2024 | 40.30 | 41.06 | 38.89 | 36.73 | 33.86 | 35.34 | 40.60 | 45.16 | 46.59 | 44.04 | 42.29 | 42.50 | 40.61 |
| 2025 | 43.66 | 44.22 | 42.32 | 40.52 | 37.90 | 39.56 | 44.49 | 49.25 | 51.05 | 48.24 | 46.10 | 46.30 | 44.47 |
| 2026 | 47.20 | 47.79 | 45.51 | 42.78 | 40.62 | 42.85 | 47.63 | 52.55 | 54.63 | 53.04 | 50.47 | 49.55 | 47.89 |
| 2027 | 50.54 | 50.83 | 48.78 | 46.30 | 43.52 | 45.73 | 50.51 | 55.84 | 57.59 | 55.08 | 53.30 | 52.74 | 50.90 |
| 2028 | 53.97 | 54.26 | 51.65 | 49.65 | 47.21 | 48.97 | 53.70 | 59.87 | 60.47 | 58.86 | 57.93 | 56.96 | 54.46 |
| 2029 | 58.22 | 58.83 | 55.45 | 52.83 | 49.86 | 51.45 | 57.29 | 64.00 | 65.65 | 63.60 | 61.47 | 60.61 | 58.27 |
| 2030 | 61.97 | 62.40 | 58.19 | 55.71 | 52.64 | 53.61 | 59.90 | 66.53 | 69.03 | 65.97 | 64.34 | 64.34 | 61.22 |
| 2031 | 65.01 | 65.49 | 61.63 | 59.00 | 55.99 | 56.92 | 63.54 | 70.25 | 73.09 | 69.82 | 68.53 | 68.45 | 64.81 |
| 2032 | 69.24 | 69.31 | 65.84 | 62.32 | 58.97 | 61.06 | 67.94 | 75.25 | 77.63 | 75.31 | 75.02 | 73.86 | 69.31 |
| 2033 | 73.66 | 73.90 | 69.79 | 66.05 | 62.77 | 64.12 | 71.21 | 79.18 | 81.20 | 78.00 | 78.10 | 77.36 | 72.94 |
| 2034 | 77.84 | 78.10 | 71.48 | 68.18 | 65.02 | 65.65 | 73.48 | 81.79 | 82.69 | 80.10 | 80.75 | 79.84 | 75.41 |
| 2035 | 79.88 | 80.58 | 75.04 | 71.12 | 66.71 | 67.62 | 76.14 | 85.17 | 87.32 | 84.88 | 84.96 | 83.68 | 78.59 |
| 2036 | 82.22 | 82.79 | 77.05 | 73.47 | 68.16 | 69.25 | 78.75 | 86.47 | 89.74 | 86.04 | 86.26 | 86.37 | 80.55 |
| 2037 | 85.57 | 85.66 | 80.12 | 76.28 | 71.66 | 71.96 | 81.82 | 89.54 | 92.70 | 88.77 | 89.51 | 89.46 | 83.59 |

Appendix N: Electric Analysis



Figure N-51: Forecast of Mid-C Power Prices for Base + CPP only Scenario (Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|------|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| | MONTHS | | | | | | | | | | | | |
| 2018 | 30.00 | 29.55 | 28.20 | 23.04 | 19.54 | 19.10 | 25.48 | 28.99 | 28.58 | 26.40 | 26.66 | 27.96 | 26.12 |
| 2019 | 28.81 | 28.13 | 26.90 | 23.86 | 20.37 | 19.55 | 25.71 | 29.32 | 29.17 | 26.78 | 26.86 | 27.91 | 26.11 |
| 2020 | 28.86 | 28.23 | 26.80 | 23.43 | 20.01 | 19.99 | 26.30 | 29.93 | 30.19 | 28.65 | 28.24 | 29.08 | 26.64 |
| 2021 | 30.26 | 29.62 | 28.00 | 24.24 | 20.82 | 20.86 | 27.26 | 31.27 | 31.10 | 28.53 | 29.14 | 30.36 | 27.62 |
| 2022 | 36.82 | 36.32 | 33.05 | 30.23 | 29.18 | 30.37 | 34.57 | 38.06 | 38.09 | 36.35 | 36.81 | 37.12 | 34.75 |
| 2023 | 38.15 | 38.28 | 35.58 | 32.78 | 31.04 | 33.10 | 36.96 | 40.91 | 40.83 | 40.61 | 40.13 | 39.63 | 37.33 |
| 2024 | 39.92 | 40.63 | 38.46 | 36.54 | 33.47 | 34.92 | 39.83 | 43.87 | 45.27 | 42.34 | 41.93 | 41.96 | 39.93 |
| 2025 | 43.12 | 43.71 | 41.96 | 40.18 | 37.56 | 38.83 | 43.71 | 48.14 | 49.13 | 46.13 | 45.33 | 45.63 | 43.62 |
| 2026 | 46.75 | 47.14 | 45.19 | 42.53 | 40.26 | 42.17 | 46.73 | 51.35 | 52.44 | 50.87 | 49.36 | 48.93 | 46.98 |
| 2027 | 49.82 | 50.27 | 48.49 | 46.16 | 43.33 | 45.10 | 49.67 | 54.64 | 55.50 | 53.06 | 52.49 | 52.15 | 50.06 |
| 2028 | 53.36 | 53.65 | 51.44 | 49.52 | 47.04 | 48.26 | 52.89 | 58.50 | 58.59 | 56.88 | 57.02 | 56.38 | 53.63 |
| 2029 | 57.32 | 58.01 | 55.00 | 52.55 | 49.48 | 51.12 | 56.28 | 62.36 | 63.18 | 61.06 | 60.72 | 60.19 | 57.27 |
| 2030 | 60.95 | 61.36 | 57.59 | 55.24 | 52.10 | 52.88 | 58.39 | 64.35 | 66.20 | 63.56 | 63.31 | 63.54 | 59.96 |
| 2031 | 63.97 | 64.57 | 61.07 | 58.66 | 55.50 | 56.16 | 62.12 | 67.91 | 70.00 | 67.38 | 67.45 | 67.52 | 63.52 |
| 2032 | 68.25 | 68.21 | 65.33 | 61.63 | 58.29 | 60.67 | 66.66 | 72.93 | 75.08 | 73.22 | 73.92 | 72.96 | 68.10 |
| 2033 | 72.38 | 72.71 | 69.27 | 65.47 | 62.44 | 63.47 | 69.97 | 76.68 | 78.53 | 75.99 | 76.91 | 76.65 | 71.71 |
| 2034 | 76.34 | 76.39 | 70.62 | 67.82 | 64.39 | 64.85 | 71.95 | 78.54 | 80.25 | 78.07 | 79.54 | 78.76 | 73.96 |
| 2035 | 78.23 | 78.62 | 73.92 | 70.57 | 65.77 | 66.41 | 74.31 | 81.74 | 83.79 | 81.80 | 83.47 | 82.31 | 76.75 |
| 2036 | 80.76 | 81.13 | 76.44 | 72.87 | 67.46 | 68.38 | 77.02 | 83.46 | 86.42 | 83.42 | 84.92 | 85.23 | 78.96 |
| 2037 | 83.81 | 83.66 | 79.23 | 75.51 | 70.41 | 70.61 | 79.70 | 85.88 | 89.02 | 85.72 | 88.04 | 88.12 | 81.64 |

Appendix N: Electric Analysis



Figure N-52: Forecast of Mid-C Power Prices for Base + All-thermal CO₂ Scenario
(Nominal \$/MWh)

| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | Ave |
|--------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|-------|
| MONTHS | | | | | | | | | | | | | |
| 2018 | 34.78 | 34.55 | 32.77 | 26.83 | 25.55 | 26.69 | 30.88 | 34.15 | 33.42 | 31.94 | 31.73 | 33.15 | 31.37 |
| 2019 | 34.16 | 33.61 | 31.76 | 28.06 | 26.31 | 27.14 | 31.42 | 34.98 | 35.28 | 33.64 | 32.78 | 33.83 | 31.91 |
| 2020 | 35.16 | 34.29 | 31.88 | 27.64 | 26.09 | 28.13 | 32.69 | 36.13 | 37.23 | 36.65 | 35.06 | 35.26 | 33.02 |
| 2021 | 36.55 | 35.96 | 33.12 | 28.76 | 27.30 | 29.13 | 33.67 | 37.73 | 38.79 | 36.58 | 36.29 | 36.60 | 34.21 |
| 2022 | 38.38 | 38.03 | 35.41 | 32.69 | 30.45 | 32.08 | 36.31 | 41.14 | 42.12 | 40.14 | 39.04 | 38.80 | 37.05 |
| 2023 | 39.90 | 40.05 | 37.88 | 35.03 | 32.66 | 34.65 | 39.00 | 43.98 | 45.11 | 45.39 | 43.39 | 41.53 | 39.88 |
| 2024 | 42.00 | 42.97 | 40.58 | 38.59 | 35.32 | 36.58 | 42.22 | 47.66 | 49.84 | 47.13 | 44.07 | 43.98 | 42.58 |
| 2025 | 45.59 | 46.82 | 43.85 | 42.93 | 39.48 | 40.87 | 46.59 | 52.34 | 54.75 | 51.78 | 48.33 | 48.26 | 46.80 |
| 2026 | 49.10 | 50.15 | 46.96 | 44.56 | 42.01 | 44.18 | 49.60 | 55.48 | 58.25 | 56.57 | 52.80 | 51.22 | 50.07 |
| 2027 | 52.56 | 53.49 | 50.60 | 48.02 | 45.20 | 47.21 | 52.66 | 59.25 | 61.69 | 58.61 | 55.57 | 54.42 | 53.27 |
| 2028 | 56.25 | 57.00 | 53.72 | 51.51 | 48.97 | 50.35 | 56.23 | 63.47 | 65.08 | 62.74 | 60.29 | 58.75 | 57.03 |
| 2029 | 60.52 | 61.73 | 57.69 | 54.51 | 51.60 | 53.07 | 59.77 | 67.56 | 70.29 | 67.80 | 64.02 | 62.44 | 60.92 |
| 2030 | 64.18 | 65.38 | 60.47 | 57.37 | 54.26 | 55.40 | 62.46 | 69.94 | 73.90 | 70.10 | 66.50 | 66.15 | 63.84 |
| 2031 | 67.70 | 68.75 | 64.21 | 60.99 | 57.91 | 58.77 | 66.68 | 74.13 | 78.12 | 74.29 | 71.07 | 70.54 | 67.76 |
| 2032 | 71.12 | 71.63 | 67.46 | 63.67 | 60.32 | 62.52 | 70.18 | 78.07 | 81.90 | 78.73 | 77.15 | 75.36 | 71.51 |
| 2033 | 75.61 | 76.66 | 71.63 | 67.74 | 64.12 | 65.89 | 73.93 | 82.56 | 85.95 | 81.51 | 80.59 | 79.21 | 75.45 |
| 2034 | 79.73 | 80.20 | 73.28 | 70.00 | 67.04 | 68.11 | 76.37 | 85.26 | 88.07 | 84.61 | 83.68 | 82.01 | 78.20 |
| 2035 | 81.68 | 83.15 | 77.00 | 72.18 | 68.50 | 69.86 | 78.91 | 88.70 | 92.21 | 89.20 | 87.56 | 85.32 | 81.19 |
| 2036 | 84.26 | 85.21 | 78.69 | 74.65 | 70.21 | 71.87 | 81.28 | 90.32 | 94.63 | 90.20 | 88.67 | 88.44 | 83.20 |
| 2037 | 87.33 | 88.06 | 81.53 | 77.62 | 73.25 | 74.27 | 83.89 | 92.94 | 96.97 | 92.41 | 91.97 | 91.55 | 85.98 |



5. OUTPUTS: SCENARIO ANALYSIS RESULTS

Expected Portfolio Costs – Scenarios

This table summarizes the expected costs of the different portfolios.

*Figure N-53: Revenue Requirements for Optimal Portfolio with Expected Inputs for the Scenarios
Expected Cost for Portfolios*

| Scenario | NPV to 2018 (\$Millions) | | | | | |
|------------------------|--------------------------|-------------------------------|---------------|-----------------------|-------------|-------------|
| | Expected Portfolio Cost | Net Market Purchases/ (Sales) | DSR Rev. Req. | Incremental Rev. Req. | End Effects | REC Revenue |
| Resource Plan | 11,994 | 4,687 | 618 | 6,351 | 354 | (16) |
| Base | 11,981 | 4,664 | 569 | 6,396 | 364 | (11) |
| Low | 8,611 | 1,970 | 423 | 5,692 | 531 | (4) |
| High | 15,398 | 5,240 | 700 | 9,041 | 520 | (103) |
| High + Low Demand | 11,769 | 5,006 | 572 | 5,959 | 280 | (48) |
| Base + Low Gas Price | 10,772 | 4,187 | 423 | 5,767 | 399 | (5) |
| Base + High Gas Price | 13,269 | 5,131 | 621 | 7,290 | 348 | (122) |
| Base + Low Demand | 10,701 | 4,393 | 569 | 5,425 | 325 | (10) |
| Base + High Demand | 13,755 | 3,979 | 621 | 8,806 | 382 | (33) |
| Base No CO2 | 10,446 | 670 | 618 | 8,982 | 181 | (5) |
| Base + Low CO2 w CPP | 11,932 | 4,112 | 569 | 6,971 | 303 | (23) |
| Base + High CO2 | 11,976 | 4,408 | 569 | 6,686 | 337 | (23) |
| Base + CAR only | 10,732 | 5,590 | 621 | 4,089 | 441 | (9) |
| Base + CPP Only | 11,875 | 4,176 | 569 | 6,741 | 401 | (11) |
| Base + All-thermal CO2 | 12,664 | 3,976 | 621 | 7,700 | 390 | (23) |

Appendix N: Electric Analysis



Figure N-54: Annual Revenue Requirements for Optimal Portfolio (\$Millions)

| | Resource Plan | Base | Low | High | High + Low Demand | Base + Low Gas Price | Base + High Gas Price | Base + Low Demand |
|----------------------|---------------|---------------|--------------|---------------|-------------------|----------------------|-----------------------|-------------------|
| 2018 | 730 | 728 | 647 | 787 | 696 | 683 | 732 | 693 |
| 2019 | 777 | 773 | 670 | 903 | 767 | 715 | 823 | 729 |
| 2020 | 876 | 869 | 765 | 988 | 846 | 812 | 905 | 822 |
| 2021 | 890 | 883 | 774 | 1,006 | 852 | 824 | 918 | 830 |
| 2022 | 973 | 962 | 707 | 1,187 | 920 | 885 | 1,004 | 867 |
| 2023 | 941 | 957 | 664 | 1,203 | 926 | 881 | 1,039 | 860 |
| 2024 | 962 | 968 | 690 | 1,218 | 948 | 881 | 1,082 | 863 |
| 2025 | 1,007 | 989 | 692 | 1,272 | 980 | 922 | 1,124 | 877 |
| 2026 | 1,038 | 1,045 | 673 | 1,351 | 1,011 | 954 | 1,181 | 900 |
| 2027 | 1,095 | 1,079 | 666 | 1,369 | 1,012 | 961 | 1,186 | 922 |
| 2028 | 1,151 | 1,134 | 683 | 1,417 | 1,051 | 998 | 1,226 | 968 |
| 2029 | 1,240 | 1,222 | 731 | 1,665 | 1,207 | 1,065 | 1,409 | 1,042 |
| 2030 | 1,298 | 1,303 | 789 | 1,849 | 1,352 | 1,146 | 1,588 | 1,113 |
| 2031 | 1,459 | 1,439 | 921 | 2,029 | 1,521 | 1,288 | 1,705 | 1,267 |
| 2032 | 1,688 | 1,683 | 1,056 | 2,310 | 1,749 | 1,498 | 1,956 | 1,475 |
| 2033 | 1,744 | 1,779 | 1,101 | 2,514 | 1,843 | 1,564 | 2,124 | 1,562 |
| 2034 | 1,835 | 1,842 | 1,098 | 2,582 | 1,883 | 1,573 | 2,176 | 1,618 |
| 2035 | 1,927 | 1,943 | 1,122 | 2,607 | 1,955 | 1,603 | 2,202 | 1,732 |
| 2036 | 1,981 | 1,995 | 1,191 | 2,720 | 2,015 | 1,593 | 2,293 | 1,748 |
| 2037 | 2,023 | 2,042 | 1,175 | 2,812 | 2,053 | 1,594 | 2,331 | 1,786 |
| 20-yr NPV | 11,640 | 11,617 | 8,081 | 14,879 | 11,489 | 10,373 | 12,921 | 10,376 |
| End Effects | 354 | 364 | 531 | 520 | 280 | 399 | 348 | 325 |
| Expected Cost | 11,994 | 11,981 | 8,611 | 15,398 | 11,769 | 10,772 | 13,269 | 10,701 |

Appendix N: Electric Analysis



Figure N-55: Annual Revenue Requirements for Optimal Portfolio (\$Millions) Cont.

| | Base + High Demand | Base No CO2 | Base + Low CO2 w CPP | Base + High CO2 | Base + CAR only | Base + CPP Only | Base + All Thermal CO2 |
|----------------------|--------------------|---------------|----------------------|-----------------|-----------------|-----------------|------------------------|
| 2018 | 775 | 698 | 721 | 729 | 689 | 696 | 818 |
| 2019 | 834 | 743 | 765 | 774 | 735 | 738 | 869 |
| 2020 | 938 | 839 | 862 | 870 | 831 | 832 | 968 |
| 2021 | 985 | 850 | 874 | 884 | 844 | 842 | 988 |
| 2022 | 1,108 | 824 | 965 | 965 | 841 | 962 | 958 |
| 2023 | 1,070 | 833 | 959 | 959 | 837 | 956 | 959 |
| 2024 | 1,120 | 837 | 983 | 982 | 840 | 968 | 996 |
| 2025 | 1,169 | 871 | 1,001 | 999 | 882 | 988 | 1,041 |
| 2026 | 1,241 | 926 | 1,055 | 1,053 | 901 | 1,044 | 1,077 |
| 2027 | 1,282 | 947 | 1,089 | 1,086 | 925 | 1,078 | 1,120 |
| 2028 | 1,344 | 987 | 1,144 | 1,140 | 961 | 1,134 | 1,175 |
| 2029 | 1,450 | 1,056 | 1,230 | 1,226 | 1,051 | 1,220 | 1,293 |
| 2030 | 1,505 | 1,091 | 1,309 | 1,306 | 1,118 | 1,300 | 1,354 |
| 2031 | 1,708 | 1,238 | 1,443 | 1,439 | 1,236 | 1,434 | 1,539 |
| 2032 | 1,994 | 1,479 | 1,683 | 1,680 | 1,437 | 1,678 | 1,760 |
| 2033 | 2,072 | 1,491 | 1,771 | 1,768 | 1,507 | 1,775 | 1,824 |
| 2034 | 2,159 | 1,516 | 1,837 | 1,833 | 1,559 | 1,835 | 1,917 |
| 2035 | 2,278 | 1,584 | 1,940 | 1,939 | 1,639 | 1,934 | 2,015 |
| 2036 | 2,355 | 1,723 | 1,996 | 1,987 | 1,801 | 1,984 | 2,101 |
| 2037 | 2,455 | 1,732 | 2,042 | 2,034 | 1,821 | 2,029 | 2,145 |
| 20-yr NPV | 13,373 | 10,265 | 11,628 | 11,639 | 10,292 | 11,474 | 12,273 |
| End Effects | 382 | 181 | 303 | 337 | 441 | 401 | 390 |
| Expected Cost | 13,755 | 10,446 | 11,932 | 11,976 | 10,732 | 11,875 | 12,664 |



Incremental Portfolio Builds by Year – Scenarios

Figure N-56: Incremental Portfolio Builds by Year (nameplate MW)

Resource Plan Forecast

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 266 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | - | - | 50 | - | 41 | 3 |
| 2024 | - | - | - | - | - | 112 | 25 | - | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 11 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | 239 | - | - | - | - | - | - | 35 | 5 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0 |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 478 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | 25 | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 59 | - | - | - | 19 | 1 |
| 2034 | - | - | 239 | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | - | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,912 | - | - | 486 | 25 | 50 | - | 714 | 148 |
| Winter | 188 | - | 1,912 | - | - | - | 15 | 38 | - | 714 | 114 |

Appendix N: Electric Analysis



Figure N-57: Incremental Portfolio Builds by Year (nameplate MW)

Base Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | 239 | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | - | - | - | 38 | 8 |
| 2025 | - | - | - | - | - | - | - | - | - | 37 | 12 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 4 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0 |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0.0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 0.5 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 20 | 0.5 |
| 2032 | - | - | - | - | - | 25 | - | 25 | - | 20 | 0.5 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 0.3 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0.4 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 16 | 0.4 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 0.7 |
| 2037 | - | - | 63 | - | - | 25 | - | - | - | 16 | 0.2 |
| Total | 188 | - | 1,975 | - | - | 486 | - | 50 | - | 714 | 58 |
| Winter | 188 | - | 1,975 | - | - | - | - | 38 | - | 714 | 45 |

Appendix N: Electric Analysis



Figure N-58: Incremental Portfolio Builds by Year (nameplate MW)
Base + No CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 50 | - | 41 | 3 |
| 2024 | - | - | - | - | - | 29 | 50 | - | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 11 |
| 2026 | - | 413 | - | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 5 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0.0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1.4 |
| 2031 | - | 413 | - | - | - | 32 | - | - | - | 20 | 1.2 |
| 2032 | - | 413 | - | - | - | - | - | - | - | 20 | 1.4 |
| 2033 | - | - | - | - | - | 72 | - | - | - | 19 | 0.6 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0.9 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1.1 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 16 | 1.8 |
| 2037 | - | - | 18 | - | - | 26 | - | - | - | 16 | 0.6 |
| Total | 188 | 1,652 | 257 | - | - | 484 | 50 | 50 | - | 714 | 148 |
| Winter | 188 | - | - | - | - | - | 30 | 38 | - | 714 | 114 |



Figure N-59: Incremental Portfolio Builds by Year (nameplate MW)
Low Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | DR |
|--------------------|-----------------------|------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 26 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 51 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 98 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 95 | 3 |
| 2022 | - | - | - | - | - | - | - | - | - | 41 | 1 |
| 2023 | - | - | - | - | - | 47 | - | - | - | 36 | 5 |
| 2024 | - | - | - | - | - | 172 | - | - | - | 34 | 9 |
| 2025 | - | - | - | - | - | - | - | - | - | 33 | 14 |
| 2026 | - | - | 239 | - | - | - | - | 25 | - | 32 | 14 |
| 2027 | - | - | - | - | - | - | - | - | - | 31 | 5 |
| 2028 | - | - | - | - | - | 50 | - | - | - | 26 | 0 |
| 2029 | - | - | - | - | - | - | - | 25 | - | 19 | 0.1 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 18 | 0.7 |
| 2031 | - | - | 478 | - | - | 26 | - | - | - | 19 | 0.6 |
| 2032 | - | - | - | - | - | - | - | - | - | 19 | 0.7 |
| 2033 | - | - | 239 | - | - | 49 | - | - | - | 18 | 0.4 |
| 2034 | - | - | - | - | - | - | - | - | - | 16 | 0.5 |
| 2035 | - | - | - | - | - | - | - | - | - | 15 | 0.6 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 15 | 0.8 |
| 2037 | - | - | 60 | - | - | 25 | - | - | - | 15 | 0.4 |
| Total | 188 | 413 | 1,255 | - | - | 369 | - | 50 | - | 658 | 67 |
| Winter | 188 | 413 | 1,255 | - | - | - | - | 38 | - | 658 | 52 |

Appendix N: Electric Analysis



Figure N-60: Incremental Portfolio Builds by Year (nameplate MW)
High Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | DR |
|--------------------|-----------------------|----------|--------------|----------|------------|------------|---------------------|-------------------|----------------------|------------|------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 30 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 58 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 105 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 101 | 29 |
| 2022 | - | - | 478 | - | - | 261 | - | - | - | 46 | 9 |
| 2023 | - | - | - | - | 300 | - | - | - | - | 42 | 3 |
| 2024 | - | - | - | - | - | 214 | - | - | - | 40 | 8 |
| 2025 | - | - | - | - | - | - | - | - | - | 38 | 11 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 37 | 12 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 37 | 5 |
| 2028 | - | - | - | - | - | - | - | - | - | 29 | 0 |
| 2029 | - | - | 239 | - | - | - | - | - | - | 21 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1.4 |
| 2031 | - | - | 717 | - | - | - | - | - | - | 20 | 1.2 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1.4 |
| 2033 | - | - | 239 | - | - | - | - | - | - | 19 | 0.6 |
| 2034 | - | - | 239 | - | - | - | - | - | - | 17 | 0.9 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1.1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1.8 |
| 2037 | - | - | 7 | - | - | 25 | - | 25 | - | 16 | 0.6 |
| Total | 188 | - | 2,875 | - | 300 | 500 | - | 50 | - | 728 | 148 |
| Winter | 188 | - | 2,875 | - | 136 | - | - | 38 | - | 728 | 114 |

Appendix N: Electric Analysis



Figure N-61: Incremental Portfolio Builds by Year (nameplate MW)
High + Low Demand Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | DR |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | - | - | - | - | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 190 | - | - | - | 41 | 5 |
| 2024 | - | - | - | - | - | 285 | - | - | - | 38 | 9 |
| 2025 | - | - | - | - | - | - | - | - | - | 37 | 14 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 14 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 5 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0 |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0.1 |
| 2030 | - | - | - | - | - | - | - | 66 | - | 20 | 0.7 |
| 2031 | - | - | 717 | - | - | - | - | - | - | 20 | 0.6 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 0.7 |
| 2033 | - | - | - | - | - | - | - | - | - | 19 | 0.4 |
| 2034 | - | - | - | - | - | - | - | 25 | - | 17 | 0.5 |
| 2035 | - | - | 239 | - | - | - | - | - | - | 16 | 0.6 |
| 2036 | - | - | 239 | - | - | - | - | - | - | 16 | 0.8 |
| 2037 | - | - | 141 | - | - | 25 | - | - | - | 16 | 0.4 |
| Total | 188 | - | 1,575 | - | - | 500 | - | 91 | - | 714 | 67 |
| Winter | 188 | - | 1,575 | - | - | - | - | 69 | - | 714 | 52 |

Appendix N: Electric Analysis



Figure N-62: Incremental Portfolio Builds by Year (nameplate MW)

Base + Low Gas Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | DR |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 26 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 51 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 98 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 95 | 3 |
| 2022 | - | - | 239 | - | - | 50 | - | - | - | 41 | 1 |
| 2023 | - | - | - | - | - | 222 | - | - | - | 36 | 5 |
| 2024 | - | - | - | - | - | 35 | - | - | - | 34 | 9 |
| 2025 | - | - | - | - | - | - | - | 29 | - | 33 | 14 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 32 | 14 |
| 2027 | - | - | - | - | - | - | - | - | - | 31 | 5 |
| 2028 | - | - | - | - | - | 46 | - | - | - | 26 | 0 |
| 2029 | - | - | - | - | - | 25 | - | - | - | 19 | 0.1 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 18 | 0.7 |
| 2031 | - | - | 239 | - | - | 26 | - | - | - | 19 | 0.6 |
| 2032 | - | - | - | - | - | - | - | 54 | - | 19 | 0.7 |
| 2033 | - | - | 239 | - | - | 74 | - | - | - | 18 | 0.4 |
| 2034 | - | - | - | - | - | - | - | - | - | 16 | 0.5 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 15 | 0.6 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 15 | 0.8 |
| 2037 | - | - | 70 | - | - | 27 | - | - | - | 15 | 0.4 |
| Total | 188 | - | 1,982 | - | - | 504 | - | 108 | - | 658 | 67 |
| Winter | 188 | - | 1,982 | - | - | - | - | 82 | - | 658 | 52 |

Appendix N: Electric Analysis



Figure N-63: Incremental Portfolio Builds by Year (nameplate MW)

Base + High Gas Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | DR |
|--------------------|-----------------------|----------|--------------|----------|------------|------------|---------------------|-------------------|----------------------|------------|------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | 300 | - | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 435 | - | - | - | 38 | 10 |
| 2025 | - | - | - | - | - | - | - | 26 | - | 37 | 13 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0 |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0.1 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 1.5 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 20 | 1.4 |
| 2032 | - | - | - | - | - | - | - | 25 | - | 20 | 1.5 |
| 2033 | - | - | 239 | - | - | - | - | - | - | 19 | 0.7 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1.1 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 16 | 1.2 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1.9 |
| 2037 | - | - | 62 | - | - | 25 | - | - | - | 16 | 0.7 |
| Total | 188 | - | 1,735 | - | 300 | 500 | - | 76 | - | 714 | 157 |
| Winter | 188 | - | 1,735 | - | 136 | - | - | 58 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-64: Incremental Portfolio Builds by Year (nameplate MW)

Base + Low Demand Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | DR |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | - | - | - | - | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 190 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 64 | - | - | - | 38 | 8 |
| 2025 | - | - | - | - | - | - | - | - | - | 37 | 12 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 4 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0 |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 0.5 |
| 2031 | - | - | 478 | - | - | 25 | - | - | - | 20 | 0.5 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 0.5 |
| 2033 | - | - | - | - | - | 47 | - | 63 | - | 19 | 0.3 |
| 2034 | - | - | - | - | - | - | - | 39 | - | 17 | 0.4 |
| 2035 | - | - | 239 | - | - | - | - | - | - | 16 | 0.4 |
| 2036 | - | - | 239 | - | - | - | - | - | - | 16 | 0.7 |
| 2037 | - | - | 141 | - | - | 25 | - | - | - | 16 | 0.2 |
| Total | 188 | - | 1,575 | - | - | 351 | - | 102 | - | 714 | 58 |
| Winter | 188 | - | 1,575 | - | - | - | - | 78 | - | 714 | 45 |

Appendix N: Electric Analysis



Figure N-65: Incremental Portfolio Builds by Year (nameplate MW)
Base + High Demand Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | DR |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | 239 | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | 239 | - | - | - | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 190 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 64 | - | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | (0.1) |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0.1 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1.5 |
| 2031 | - | - | 717 | - | - | 25 | - | 25 | - | 20 | 1.4 |
| 2032 | - | - | 239 | - | - | - | - | - | - | 20 | 1.5 |
| 2033 | - | - | - | - | - | 47 | - | - | - | 19 | 0.7 |
| 2034 | - | - | 239 | - | - | - | - | - | - | 17 | 1.1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1.2 |
| 2036 | - | - | 478 | - | - | - | - | 25 | - | 16 | 1.9 |
| 2037 | - | - | 135 | - | - | 25 | - | - | - | 16 | 0.7 |
| Total | 188 | - | 3,003 | - | - | 351 | - | 75 | - | 714 | 157 |
| Winter | 188 | - | 3,003 | - | - | - | - | 57 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-66: Incremental Portfolio Builds by Year (nameplate MW)
Base + Low CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | 239 | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 200 | - | - | - | 38 | 8 |
| 2025 | - | - | - | - | - | - | - | - | - | 37 | 12 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 4 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0 |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0.0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 0.5 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 20 | 0.5 |
| 2032 | - | - | - | - | - | - | - | 25 | - | 20 | 0.5 |
| 2033 | - | - | 239 | - | - | - | - | - | - | 19 | 0.3 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0.4 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 16 | 0.4 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 0.7 |
| 2037 | - | - | 63 | - | - | 25 | - | - | - | 16 | 0.2 |
| Total | 188 | - | 1,975 | - | - | 490 | - | 50 | - | 714 | 58 |
| Winter | 188 | - | 1,975 | - | - | - | - | 38 | - | 714 | 45 |

Appendix N: Electric Analysis



Figure N-67: Incremental Portfolio Builds by Year (nameplate MW)
Base + High CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | 239 | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 200 | - | - | - | 38 | 8 |
| 2025 | - | - | - | - | - | - | - | - | - | 37 | 12 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 4 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0 |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0.0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 0.5 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 20 | 0.5 |
| 2032 | - | - | - | - | - | - | - | 25 | - | 20 | 0.5 |
| 2033 | - | - | 239 | - | - | - | - | - | - | 19 | 0.3 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0.4 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 16 | 0.4 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 0.7 |
| 2037 | - | - | 63 | - | - | 25 | - | - | - | 16 | 0.2 |
| Total | 188 | - | 1,975 | - | - | 490 | - | 50 | - | 714 | 58 |
| Winter | 188 | - | 1,975 | - | - | - | - | 38 | - | 714 | 45 |

Appendix N: Electric Analysis



Figure N-68: Incremental Portfolio Builds by Year (nameplate MW)
Base + Mid CAR only Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | 114 | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 90 | - | - | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0 |
| 2029 | - | - | - | - | - | - | - | 50 | - | 20 | 0.1 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 1.5 |
| 2031 | - | - | 239 | - | - | 32 | - | - | - | 20 | 1.4 |
| 2032 | - | - | - | - | - | - | - | - | 41 | 20 | 1.5 |
| 2033 | - | - | 239 | - | - | 73 | - | - | - | 19 | 0.7 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1.1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1.2 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1.9 |
| 2037 | - | - | 73 | - | - | 25 | - | - | - | 16 | 0.7 |
| Total | 188 | - | 1,859 | - | - | 486 | - | 50 | 41 | 714 | 157 |
| Winter | 188 | - | 1,859 | - | - | - | - | 38 | 41 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-69: Incremental Portfolio Builds by Year (nameplate MW)
Base + CPP Only Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | 239 | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | - | - | - | 38 | 8 |
| 2025 | - | - | - | - | - | - | - | - | - | 37 | 12 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 4 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0.0 |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0.0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 0.5 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 20 | 0.5 |
| 2032 | - | - | - | - | - | 25 | - | 25 | - | 20 | 0.5 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 0.3 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0.4 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 16 | 0.4 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 0.7 |
| 2037 | - | - | 63 | - | - | 25 | - | - | - | 16 | 0.2 |
| Total | 188 | - | 1,975 | - | - | 486 | - | 50 | - | 714 | 58 |
| Winter | 188 | - | 1,975 | - | - | - | - | 38 | - | 714 | 45 |

Appendix N: Electric Analysis



Figure N-70: Incremental Portfolio Builds by Year (nameplate MW)
Scenario: Base + All Thermal CO₂

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | - | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | 0 |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0.1 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1.5 |
| 2031 | - | 413 | - | - | - | - | - | - | - | 20 | 1.4 |
| 2032 | - | - | - | - | - | 25 | - | - | - | 20 | 1.5 |
| 2033 | - | - | - | - | - | 63 | - | - | 25 | 19 | 0.7 |
| 2034 | - | - | 239 | - | - | - | - | - | - | 17 | 1.1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1.2 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 16 | 1.9 |
| 2037 | - | - | 70 | - | - | 25 | - | - | - | 16 | 0.7 |
| Total | 188 | 826 | 1,026 | - | - | 486 | - | 75 | 25 | 714 | 157 |
| Winter | 188 | 826 | 1,026 | - | - | - | - | 57 | 25 | 714 | 121 |



Portfolio CO₂ Emissions – Scenarios

Figure N-71: Total Portfolio CO₂ Emissions
Emission PSE Portfolio - All (Millions Tons)

| | Resource Plan | Base | Low | High | High + Low Demand | Base + Low Gas Price | Base + High Gas Price | Base + Low Demand |
|------|---------------|-------|-------|-------|-------------------|----------------------|-----------------------|-------------------|
| 2018 | 12.30 | 12.30 | 10.58 | 13.10 | 11.94 | 11.18 | 12.31 | 11.92 |
| 2019 | 12.02 | 12.02 | 10.16 | 13.90 | 12.61 | 10.80 | 13.13 | 11.45 |
| 2020 | 11.64 | 11.64 | 9.57 | 13.27 | 11.84 | 10.34 | 12.40 | 10.90 |
| 2021 | 11.17 | 11.17 | 9.66 | 12.34 | 10.91 | 10.37 | 11.52 | 10.47 |
| 2022 | 5.87 | 6.06 | 8.53 | 8.61 | 6.82 | 5.25 | 7.41 | 5.08 |
| 2023 | 6.09 | 6.12 | 8.17 | 9.09 | 7.27 | 5.18 | 7.88 | 5.48 |
| 2024 | 6.23 | 6.27 | 7.89 | 8.67 | 6.81 | 5.24 | 7.32 | 5.36 |
| 2025 | 6.85 | 6.86 | 8.25 | 9.44 | 7.54 | 5.53 | 8.01 | 5.92 |
| 2026 | 7.28 | 7.33 | 8.27 | 9.40 | 7.67 | 5.75 | 8.20 | 6.35 |
| 2027 | 7.55 | 7.57 | 8.05 | 9.30 | 7.44 | 5.69 | 8.13 | 6.38 |
| 2028 | 7.73 | 7.73 | 8.41 | 9.94 | 7.84 | 5.84 | 8.66 | 6.56 |
| 2029 | 8.14 | 8.14 | 8.34 | 9.98 | 7.89 | 6.09 | 8.63 | 6.86 |
| 2030 | 8.24 | 8.30 | 8.39 | 9.67 | 7.88 | 6.23 | 8.59 | 6.71 |
| 2031 | 8.65 | 8.66 | 8.82 | 10.04 | 8.21 | 6.62 | 8.87 | 7.14 |
| 2032 | 9.42 | 9.42 | 9.27 | 10.44 | 8.60 | 7.37 | 9.25 | 7.87 |
| 2033 | 9.58 | 9.63 | 9.57 | 10.79 | 8.90 | 7.23 | 9.59 | 8.07 |
| 2034 | 9.52 | 9.53 | 9.52 | 10.73 | 8.72 | 7.52 | 9.49 | 7.93 |
| 2035 | 9.49 | 9.49 | 9.88 | 11.01 | 8.97 | 7.96 | 9.66 | 8.15 |
| 2036 | 7.64 | 7.64 | 7.31 | 8.27 | 6.19 | 8.27 | 6.77 | 6.39 |
| 2037 | 7.81 | 7.83 | 7.45 | 8.51 | 6.26 | 8.47 | 6.76 | 6.58 |



Figure N-72: Total Portfolio CO₂ Emissions
Emission PSE Portfolio - All (Millions Tons)

| | Base + High Demand | Base No CO2 | Base + Low CO2 w CPP | Base + High CO2 | Base + CAR only | Base + CPP Only | Base + All Thermal CO2 |
|------|--------------------|-------------|----------------------|-----------------|-----------------|-----------------|------------------------|
| 2018 | 13.05 | 12.66 | 12.31 | 12.33 | 12.24 | 12.68 | 7.62 |
| 2019 | 12.96 | 12.31 | 12.02 | 12.06 | 11.95 | 12.36 | 7.43 |
| 2020 | 12.59 | 11.83 | 11.63 | 11.65 | 11.53 | 11.91 | 6.82 |
| 2021 | 12.09 | 11.69 | 11.18 | 11.20 | 11.08 | 11.76 | 6.76 |
| 2022 | 7.92 | 10.28 | 6.65 | 6.46 | 9.66 | 6.04 | 6.84 |
| 2023 | 7.96 | 9.82 | 6.61 | 6.42 | 9.31 | 6.05 | 6.82 |
| 2024 | 7.97 | 9.85 | 6.54 | 6.42 | 9.40 | 6.16 | 6.97 |
| 2025 | 8.64 | 10.17 | 7.16 | 7.02 | 9.59 | 6.85 | 7.53 |
| 2026 | 9.18 | 9.38 | 7.64 | 7.49 | 8.44 | 7.34 | 7.59 |
| 2027 | 9.42 | 9.22 | 7.86 | 7.61 | 8.30 | 7.54 | 7.78 |
| 2028 | 9.71 | 9.55 | 8.12 | 7.91 | 8.70 | 7.77 | 8.00 |
| 2029 | 9.86 | 9.53 | 8.35 | 8.22 | 8.75 | 8.04 | 8.18 |
| 2030 | 9.94 | 9.73 | 8.46 | 8.38 | 8.94 | 8.20 | 8.28 |
| 2031 | 10.64 | 10.37 | 8.85 | 8.73 | 9.45 | 8.57 | 8.96 |
| 2032 | 11.52 | 11.00 | 9.60 | 9.48 | 10.05 | 9.32 | 9.39 |
| 2033 | 11.88 | 11.28 | 9.87 | 9.72 | 10.34 | 9.48 | 9.56 |
| 2034 | 11.75 | 11.21 | 9.87 | 9.71 | 10.21 | 9.28 | 9.45 |
| 2035 | 11.78 | 11.37 | 9.85 | 9.73 | 10.39 | 9.28 | 9.39 |
| 2036 | 9.63 | 8.71 | 7.94 | 7.67 | 7.64 | 7.37 | 7.22 |
| 2037 | 10.08 | 8.79 | 8.21 | 7.86 | 7.72 | 7.52 | 7.22 |



6. OUTPUTS: SENSITIVITY ANALYSIS RESULTS

Expected Portfolio Costs – Sensitivities

This table summarizes the expected costs of the different sensitivity analysis.

Figure N-73: Annual Revenue Requirements for Sensitivities (\$Millions)

| Sensitivity | NPV to 2018 (\$Millions) | | | | | |
|-----------------------------|--------------------------|-------------------------------|---------------|-----------------------|---------------------|-------------|
| | Expected Portfolio Cost | Net Market Purchases/ (Sales) | DSR Rev. Req. | Incremental Rev. Req. | Generic End Effects | REC Revenue |
| Retire Colstrip 2018 Base | 11,944 | 4,853 | 572 | 6,163 | 370 | (13) |
| Retire Colstrip 2018 No CO2 | 10,456 | 839 | 618 | 8,821 | 181 | (5) |
| Retire Colstrip 2025 Base | 11,766 | 5,091 | 572 | 5,772 | 344 | (13) |
| Retire Colstrip 2025 No CO2 | 10,647 | 656 | 621 | 9,252 | 123 | (5) |
| Retire Colstrip 2030 Base | 11,833 | 4,893 | 572 | 6,025 | 356 | (13) |
| Retire Colstrip 2030 No CO2 | 10,462 | 695 | 621 | 9,006 | 144 | (5) |

Appendix N: Electric Analysis



Figure N-74: Annual Revenue Requirements for Sensitivities (\$Millions)

| Sensitivity | NPV to 2018 (\$Millions) | | | | | |
|-----------------------------------|--------------------------|------------------------------|---------------|-----------------------|---------------------|-------------|
| | Expected Portfolio Cost | Net Market Purchases/(Sales) | DSR Rev. Req. | Incremental Rev. Req. | Generic End Effects | REC Revenue |
| Retire Encogen Base | 11,975 | 4,695 | 621 | 6,365 | 304 | (11) |
| Retire Ferndale Base | 12,013 | 4,611 | 572 | 6,505 | 337 | (11) |
| Retire Goldendale Base | 11,971 | 4,652 | 621 | 6,390 | 318 | (11) |
| Retire Mint Farm Base | 11,974 | 4,652 | 621 | 6,394 | 318 | (11) |
| Retire Sumas Base | 11,977 | 4,695 | 621 | 6,355 | 317 | (11) |
| Retire Encogen No CO2 | 10,721 | 2,211 | 621 | 7,374 | 519 | (5) |
| Retire Ferndale No CO2 | 10,787 | 2,207 | 621 | 7,402 | 562 | (5) |
| Retire Goldendale No CO2 | 10,782 | 2,195 | 621 | 7,404 | 566 | (5) |
| Retire Mint Farm No CO2 | 10,805 | 2,195 | 621 | 7,406 | 588 | (5) |
| Retire Sumas No CO2 | 10,795 | 2,207 | 621 | 7,406 | 565 | (5) |
| Retire Encogen All Thermal CO2 | 12,668 | 3,584 | 621 | 8,143 | 343 | (23) |
| Retire Ferndale All Thermal CO2 | 12,702 | 3,508 | 621 | 8,242 | 353 | (23) |
| Retire Goldendale All Thermal CO2 | 12,663 | 3,508 | 621 | 8,235 | 322 | (23) |
| Retire Mint Farm All Thermal CO2 | 12,664 | 3,508 | 621 | 8,229 | 329 | (23) |
| Retire Sumas All Thermal CO2 | 12,665 | 3,584 | 621 | 8,129 | 355 | (23) |

Appendix N: Electric Analysis



Figure N-75: Annual Revenue Requirements for Sensitivities (\$Millions)

| Sensitivity | NPV to 2018 (\$Millions) | | | | | |
|-----------------------------|--------------------------|------------------------------|---------------|-----------------------|---------------------|-------------|
| | Expected Portfolio Cost | Net Market Purchases/(Sales) | DSR Rev. Req. | Incremental Rev. Req. | Generic End Effects | REC Revenue |
| No New Thermal | 13,343 | 4,881 | 748 | 6,709 | 1,045 | (39) |
| High Thermal Cost | 12,194 | 4,736 | 621 | 6,409 | 440 | (11) |
| Energy Storage Battery | 11,988 | 4,699 | 618 | 6,325 | 357 | (12) |
| Energy Storage Pumped Hydro | 11,996 | 4,718 | 618 | 6,316 | 355 | (11) |
| Battery ITC | 12,055 | 4,736 | 621 | 6,378 | 331 | (11) |
| EV Load | 12,343 | 4,781 | 569 | 6,600 | 408 | (15) |
| No DSR | 12,536 | 5,229 | - | 6,883 | 441 | (17) |
| Extended DSR | 11,894 | 4,637 | 704 | 6,251 | 312 | (11) |
| DSR Discount Rate | 11,999 | 4,709 | 516 | 6,425 | 360 | (11) |
| MT Wind - 150 MW | 12,016 | 4,704 | 621 | 6,344 | 360 | (14) |
| MT Wind 175MW | 12,023 | 4,692 | 621 | 6,354 | 373 | (17) |
| MT Wind - 300 MW | 12,063 | 4,598 | 569 | 6,532 | 404 | (39) |
| Hopkins Ridge Repowering | 12,021 | 4,664 | 569 | 6,397 | 403 | (11) |
| Wild Horse Repowering | 12,023 | 4,693 | 621 | 6,347 | 375 | (14) |
| Add 300 MW Solar | 12,027 | 4,432 | 569 | 6,717 | 383 | (74) |
| No Transmission Redirect | 12,108 | 4,646 | 621 | 6,477 | 374 | (11) |
| More Conservation | 12,145 | 4,431 | 1,230 | 6,181 | 314 | (10) |



Figure N-76: Annual Revenue Requirements for Sensitivities (\$Millions)

| | Retire Colstrip 2018 Base | Retire Colstrip 2018 No CO2 | Retire Colstrip 2025 Base | Retire Colstrip 2025 No CO2 | Retire Colstrip 2030 Base | Retire Colstrip 2030 No CO2 |
|----------------------|---------------------------|-----------------------------|---------------------------|-----------------------------|---------------------------|-----------------------------|
| 2018 | 733 | 709 | 740 | 716 | 727 | 697 |
| 2019 | 797 | 760 | 786 | 760 | 773 | 742 |
| 2020 | 861 | 826 | 881 | 857 | 867 | 836 |
| 2021 | 879 | 840 | 893 | 867 | 881 | 846 |
| 2022 | 945 | 836 | 958 | 842 | 944 | 828 |
| 2023 | 920 | 817 | 956 | 846 | 940 | 830 |
| 2024 | 959 | 837 | 979 | 855 | 963 | 839 |
| 2025 | 1,001 | 870 | 1,021 | 889 | 1,005 | 870 |
| 2026 | 1,034 | 926 | 1,017 | 1,000 | 1,039 | 924 |
| 2027 | 1,072 | 949 | 1,032 | 999 | 1,076 | 947 |
| 2028 | 1,144 | 989 | 1,073 | 1,031 | 1,149 | 989 |
| 2029 | 1,231 | 1,056 | 1,156 | 1,090 | 1,240 | 1,062 |
| 2030 | 1,289 | 1,091 | 1,233 | 1,138 | 1,299 | 1,110 |
| 2031 | 1,445 | 1,239 | 1,362 | 1,280 | 1,400 | 1,320 |
| 2032 | 1,678 | 1,479 | 1,628 | 1,463 | 1,617 | 1,459 |
| 2033 | 1,756 | 1,492 | 1,716 | 1,570 | 1,707 | 1,554 |
| 2034 | 1,836 | 1,517 | 1,772 | 1,576 | 1,764 | 1,563 |
| 2035 | 1,931 | 1,585 | 1,862 | 1,632 | 1,855 | 1,622 |
| 2036 | 1,984 | 1,723 | 1,923 | 1,651 | 1,938 | 1,668 |
| 2037 | 2,032 | 1,732 | 2,005 | 1,690 | 2,020 | 1,710 |
| 20-yr NPV | 11,574 | 10,274 | 11,422 | 10,525 | 11,477 | 10,317 |
| End Effects | 370 | 181 | 344 | 123 | 356 | 144 |
| Expected Cost | 11,944 | 10,456 | 11,766 | 10,647 | 11,833 | 10,462 |

Appendix N: Electric Analysis



Figure N-77: Annual Revenue Requirements for Sensitivities (\$Millions)

| | Retire Encogen Base | Retire Ferndale Base | Retire Goldendale Base | Retire Mint Farm Base | Retire Sumas Base | Retire Encogen No CO2 | Retire Ferndale No CO2 | Retire Goldendale No CO2 |
|----------------------|---------------------|----------------------|------------------------|-----------------------|-------------------|-----------------------|------------------------|--------------------------|
| 2018 | 730 | 728 | 730 | 730 | 730 | 698 | 698 | 698 |
| 2019 | 777 | 773 | 777 | 777 | 777 | 743 | 743 | 743 |
| 2020 | 876 | 869 | 876 | 876 | 876 | 839 | 839 | 839 |
| 2021 | 890 | 883 | 891 | 891 | 890 | 850 | 850 | 850 |
| 2022 | 942 | 962 | 942 | 942 | 942 | 824 | 824 | 824 |
| 2023 | 946 | 957 | 946 | 946 | 946 | 825 | 825 | 821 |
| 2024 | 971 | 969 | 971 | 971 | 971 | 835 | 835 | 829 |
| 2025 | 1,015 | 1,015 | 1,015 | 1,015 | 1,015 | 870 | 870 | 865 |
| 2026 | 1,044 | 1,046 | 1,044 | 1,044 | 1,044 | 876 | 876 | 873 |
| 2027 | 1,085 | 1,083 | 1,085 | 1,085 | 1,085 | 907 | 907 | 906 |
| 2028 | 1,139 | 1,137 | 1,139 | 1,139 | 1,139 | 950 | 950 | 950 |
| 2029 | 1,253 | 1,250 | 1,253 | 1,253 | 1,253 | 1,049 | 1,049 | 1,049 |
| 2030 | 1,310 | 1,304 | 1,310 | 1,310 | 1,310 | 1,088 | 1,088 | 1,088 |
| 2031 | 1,458 | 1,449 | 1,472 | 1,472 | 1,461 | 1,233 | 1,234 | 1,249 |
| 2032 | 1,707 | 1,704 | 1,696 | 1,699 | 1,698 | 1,420 | 1,449 | 1,432 |
| 2033 | 1,791 | 1,797 | 1,780 | 1,784 | 1,783 | 1,457 | 1,486 | 1,502 |
| 2034 | 1,846 | 1,857 | 1,836 | 1,839 | 1,839 | 1,533 | 1,532 | 1,542 |
| 2035 | 1,947 | 1,955 | 1,929 | 1,930 | 1,941 | 1,627 | 1,627 | 1,620 |
| 2036 | 1,998 | 2,005 | 1,981 | 1,981 | 1,993 | 1,774 | 1,776 | 1,773 |
| 2037 | 2,036 | 2,050 | 2,018 | 2,019 | 2,032 | 1,795 | 1,811 | 1,796 |
| 20-yr NPV | 11,671 | 11,677 | 11,653 | 11,656 | 11,660 | 10,202 | 10,225 | 10,216 |
| End Effects | 304 | 337 | 318 | 318 | 317 | 519 | 562 | 566 |
| Expected Cost | 11,975 | 12,013 | 11,971 | 11,974 | 11,977 | 10,721 | 10,787 | 10,782 |

Appendix N: Electric Analysis



Figure N-78: Annual Revenue Requirements for Sensitivities (\$Millions)

| | Retire Mint Farm No CO2 | Retire Sumas No CO2 | Retire Encogen All Thermal CO2 | Retire Ferndale All Thermal CO2 | Retire Goldendale All Thermal CO2 | Retire Mint Farm All Thermal CO2 | Retire Sumas All Thermal CO2 |
|----------------------|----------------------------|------------------------|--------------------------------------|---------------------------------------|---|--|------------------------------------|
| 2018 | 698 | 698 | 818 | 818 | 818 | 818 | 818 |
| 2019 | 743 | 743 | 869 | 869 | 869 | 869 | 869 |
| 2020 | 839 | 839 | 968 | 968 | 968 | 968 | 968 |
| 2021 | 850 | 850 | 988 | 988 | 989 | 989 | 988 |
| 2022 | 824 | 824 | 958 | 958 | 958 | 958 | 958 |
| 2023 | 821 | 825 | 959 | 959 | 959 | 959 | 959 |
| 2024 | 825 | 835 | 996 | 996 | 996 | 992 | 996 |
| 2025 | 862 | 870 | 1,041 | 1,041 | 1,041 | 1,038 | 1,041 |
| 2026 | 869 | 876 | 1,077 | 1,077 | 1,077 | 1,075 | 1,077 |
| 2027 | 903 | 907 | 1,120 | 1,120 | 1,120 | 1,116 | 1,117 |
| 2028 | 947 | 950 | 1,175 | 1,175 | 1,175 | 1,172 | 1,172 |
| 2029 | 1,047 | 1,049 | 1,293 | 1,293 | 1,293 | 1,291 | 1,290 |
| 2030 | 1,086 | 1,088 | 1,354 | 1,354 | 1,354 | 1,352 | 1,352 |
| 2031 | 1,247 | 1,237 | 1,536 | 1,599 | 1,597 | 1,594 | 1,528 |
| 2032 | 1,435 | 1,452 | 1,826 | 1,813 | 1,807 | 1,806 | 1,820 |
| 2033 | 1,509 | 1,488 | 1,874 | 1,862 | 1,855 | 1,854 | 1,869 |
| 2034 | 1,556 | 1,535 | 1,930 | 1,919 | 1,912 | 1,917 | 1,926 |
| 2035 | 1,628 | 1,628 | 2,030 | 2,039 | 2,039 | 2,046 | 2,026 |
| 2036 | 1,780 | 1,777 | 2,115 | 2,134 | 2,133 | 2,139 | 2,112 |
| 2037 | 1,804 | 1,812 | 2,156 | 2,174 | 2,173 | 2,179 | 2,159 |
| 20-yr NPV | 10,218 | 10,230 | 12,325 | 12,348 | 12,341 | 12,335 | 12,311 |
| End Effects | 588 | 565 | 343 | 353 | 322 | 329 | 355 |
| Expected Cost | 10,805 | 10,795 | 12,668 | 12,702 | 12,663 | 12,664 | 12,665 |

Appendix N: Electric Analysis



Figure N-79: Annual Revenue Requirements for Sensitivities (\$Millions)

| | No New Thermal | High Thermal Cost | Energy Storage Battery | Energy Storage Pumped Hydro | Battery ITC | EV Load | No DSR |
|----------------------|----------------|-------------------|------------------------|-----------------------------|---------------|---------------|---------------|
| 2018 | 737 | 730 | 730 | 730 | 730 | 729 | 698 |
| 2019 | 791 | 777 | 777 | 777 | 777 | 775 | 721 |
| 2020 | 891 | 876 | 876 | 876 | 876 | 872 | 741 |
| 2021 | 906 | 890 | 890 | 890 | 890 | 886 | 754 |
| 2022 | 956 | 942 | 942 | 942 | 957 | 970 | 953 |
| 2023 | 979 | 955 | 946 | 948 | 951 | 965 | 978 |
| 2024 | 976 | 974 | 962 | 968 | 972 | 985 | 1,036 |
| 2025 | 1,005 | 1,025 | 1,006 | 1,013 | 1,018 | 1,032 | 1,063 |
| 2026 | 1,127 | 1,061 | 1,036 | 1,042 | 1,048 | 1,074 | 1,130 |
| 2027 | 1,153 | 1,095 | 1,094 | 1,083 | 1,089 | 1,118 | 1,177 |
| 2028 | 1,194 | 1,149 | 1,149 | 1,138 | 1,144 | 1,199 | 1,255 |
| 2029 | 1,299 | 1,270 | 1,238 | 1,252 | 1,259 | 1,289 | 1,389 |
| 2030 | 1,380 | 1,326 | 1,297 | 1,310 | 1,316 | 1,347 | 1,452 |
| 2031 | 1,607 | 1,476 | 1,458 | 1,457 | 1,465 | 1,512 | 1,623 |
| 2032 | 1,842 | 1,736 | 1,687 | 1,686 | 1,719 | 1,747 | 1,861 |
| 2033 | 1,949 | 1,790 | 1,756 | 1,779 | 1,785 | 1,852 | 1,960 |
| 2034 | 2,033 | 1,847 | 1,847 | 1,837 | 1,843 | 1,919 | 2,031 |
| 2035 | 2,141 | 1,964 | 1,937 | 1,929 | 1,978 | 2,024 | 2,131 |
| 2036 | 2,294 | 2,029 | 1,991 | 1,983 | 2,027 | 2,074 | 2,193 |
| 2037 | 2,358 | 2,077 | 2,033 | 2,025 | 2,063 | 2,122 | 2,253 |
| 20-yr NPV | 12,299 | 11,755 | 11,631 | 11,641 | 11,724 | 11,935 | 12,095 |
| End Effects | 1,045 | 440 | 357 | 355 | 331 | 408 | 441 |
| Expected Cost | 13,343 | 12,194 | 11,988 | 11,996 | 12,055 | 12,343 | 12,536 |

Appendix N: Electric Analysis



Figure N-80: Annual Revenue Requirements for Sensitivities (\$Millions)

| | Extended DSR Potential | DSR Discount Rate | MT Wind 150 MW | MT Wind 175 MW | MT Wind 300 MW |
|----------------------|------------------------|-------------------|----------------|----------------|----------------|
| 2018 | 730 | 723 | 730 | 730 | 728 |
| 2019 | 777 | 764 | 777 | 777 | 773 |
| 2020 | 876 | 870 | 876 | 876 | 869 |
| 2021 | 890 | 885 | 890 | 890 | 883 |
| 2022 | 942 | 957 | 965 | 970 | 990 |
| 2023 | 953 | 951 | 930 | 930 | 947 |
| 2024 | 973 | 964 | 947 | 948 | 947 |
| 2025 | 1,017 | 994 | 996 | 997 | 997 |
| 2026 | 1,046 | 1,049 | 1,029 | 1,030 | 1,028 |
| 2027 | 1,082 | 1,083 | 1,063 | 1,064 | 1,063 |
| 2028 | 1,147 | 1,142 | 1,130 | 1,122 | 1,126 |
| 2029 | 1,269 | 1,233 | 1,245 | 1,238 | 1,239 |
| 2030 | 1,322 | 1,314 | 1,304 | 1,298 | 1,293 |
| 2031 | 1,451 | 1,449 | 1,449 | 1,446 | 1,438 |
| 2032 | 1,695 | 1,696 | 1,720 | 1,717 | 1,725 |
| 2033 | 1,744 | 1,793 | 1,787 | 1,787 | 1,788 |
| 2034 | 1,796 | 1,855 | 1,852 | 1,852 | 1,854 |
| 2035 | 1,879 | 1,950 | 1,987 | 1,988 | 1,991 |
| 2036 | 1,886 | 2,003 | 2,037 | 2,039 | 2,042 |
| 2037 | 1,919 | 2,051 | 2,081 | 2,083 | 2,087 |
| 20-yr NPV | 11,581 | 11,639 | 11,655 | 11,650 | 11,659 |
| End Effects | 312 | 360 | 360 | 373 | 404 |
| Expected Cost | 11,894 | 11,999 | 12,016 | 12,023 | 12,063 |

Appendix N: Electric Analysis



Figure N-81: Annual Revenue Requirements for Sensitivities (\$Millions)

| | Hopkins Ridge Repowering | Wild Horse Repowering | Add 300 MW Solar | No Transmission Redirect | More Conservation |
|----------------------|--------------------------|-----------------------|------------------|--------------------------|-------------------|
| 2018 | 728 | 718 | 728 | 729 | 777 |
| 2019 | 773 | 771 | 773 | 777 | 870 |
| 2020 | 869 | 866 | 869 | 876 | 964 |
| 2021 | 883 | 880 | 883 | 890 | 978 |
| 2022 | 970 | 965 | 962 | 965 | 1,015 |
| 2023 | 967 | 955 | 997 | 958 | 1,002 |
| 2024 | 976 | 970 | 994 | 979 | 998 |
| 2025 | 995 | 1,010 | 1,007 | 1,024 | 1,033 |
| 2026 | 1,050 | 1,043 | 1,057 | 1,054 | 1,054 |
| 2027 | 1,083 | 1,078 | 1,086 | 1,086 | 1,074 |
| 2028 | 1,138 | 1,137 | 1,136 | 1,151 | 1,102 |
| 2029 | 1,226 | 1,247 | 1,220 | 1,265 | 1,187 |
| 2030 | 1,306 | 1,307 | 1,299 | 1,321 | 1,264 |
| 2031 | 1,411 | 1,462 | 1,431 | 1,462 | 1,391 |
| 2032 | 1,668 | 1,699 | 1,671 | 1,717 | 1,629 |
| 2033 | 1,767 | 1,772 | 1,764 | 1,784 | 1,715 |
| 2034 | 1,831 | 1,856 | 1,824 | 1,841 | 1,773 |
| 2035 | 1,933 | 1,950 | 1,923 | 1,957 | 1,859 |
| 2036 | 1,987 | 2,002 | 1,972 | 2,005 | 1,910 |
| 2037 | 2,035 | 2,047 | 2,017 | 2,052 | 1,955 |
| 20-yr NPV | 11,618 | 11,647 | 11,644 | 11,733 | 11,831 |
| End Effects | 403 | 375 | 383 | 374 | 314 |
| Expected Cost | 12,021 | 12,023 | 12,027 | 12,108 | 12,145 |



Incremental Portfolio Builds by Year – Sensitivities

Figure N-82: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2018, Base Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 5 |
| 2024 | - | - | - | - | - | 123 | - | 21 | - | 38 | 9 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 14 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 14 |
| 2027 | - | - | - | - | - | - | 8 | 4 | - | 35 | 5 |
| 2028 | - | - | 239 | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 478 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 73 | - | - | - | 19 | 0 |
| 2034 | - | - | 239 | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1 |
| 2037 | - | - | 76 | - | - | 25 | - | - | - | 16 | 0 |
| Total | 188 | - | 1,988 | - | - | 487 | 8 | 25 | - | 714 | 67 |
| Winter | 188 | - | 1,988 | - | - | - | 5 | 19 | - | 714 | 52 |

Appendix N: Electric Analysis



Figure N-83: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2018, No CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 50 | - | 41 | 3 |
| 2024 | - | - | - | - | - | 29 | 50 | - | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 11 |
| 2026 | - | 413 | - | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 5 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | 413 | - | - | - | 32 | - | - | - | 20 | 1 |
| 2032 | - | 413 | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 18 | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | 1,652 | 257 | - | - | 484 | 50 | 50 | - | 714 | 148 |
| Winter | 188 | 1,652 | 257 | - | - | - | 30 | 38 | - | 714 | 114 |

Appendix N: Electric Analysis



Figure N-84: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2025, Base Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 5 |
| 2024 | - | - | - | - | - | 123 | - | 21 | - | 38 | 9 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 14 |
| 2026 | - | - | 717 | - | - | - | - | - | - | 36 | 14 |
| 2027 | - | - | - | - | - | - | 8 | 4 | - | 35 | 5 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 73 | - | - | - | 19 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | 239 | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2037 | - | - | 80 | - | - | 25 | - | - | - | 16 | 0 |
| Total | 188 | - | 1,992 | - | - | 487 | 8 | 25 | - | 714 | 67 |
| Winter | 188 | - | 1,992 | - | - | - | 5 | 19 | - | 714 | 52 |

Appendix N: Electric Analysis



Figure N-85: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2025, No CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 29 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | 826 | - | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | 25 | - | 20 | 2 |
| 2031 | - | 413 | - | - | - | 32 | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | 413 | - | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | - | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | - | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | 1,652 | 239 | - | - | 484 | 25 | 75 | - | 714 | 157 |
| Winter | 188 | 1,652 | 239 | - | - | - | 15 | 57 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-86: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2030, Base Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 5 |
| 2024 | - | - | - | - | - | 123 | - | 21 | - | 38 | 9 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 14 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 14 |
| 2027 | - | - | - | - | - | - | 8 | 4 | - | 35 | 5 |
| 2028 | - | - | 239 | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 717 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 73 | - | - | - | 19 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | 239 | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2037 | - | - | 76 | - | - | 25 | - | - | - | 16 | 0 |
| Total | 188 | - | 1,988 | - | - | 487 | 8 | 25 | - | 714 | 67 |
| Winter | 188 | - | 1,988 | - | - | - | 5 | 19 | - | 714 | 52 |

Appendix N: Electric Analysis



Figure N-87: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2030, No CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 29 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | 413 | - | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | 25 | - | 20 | 2 |
| 2031 | - | 826 | - | - | - | 32 | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | 413 | - | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | - | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | - | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | 1,652 | 239 | - | - | 484 | 25 | 75 | - | 714 | 157 |
| Winter | 188 | 1,652 | 239 | - | - | - | 15 | 57 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-88: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Encogen, Base Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 28 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 478 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | 25 | - | 56 | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | 30 | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 73 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,985 | - | - | 486 | 25 | 164 | - | 714 | 157 |
| Winter | 188 | - | 1,985 | - | - | - | 15 | 125 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-89: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Ferndale, Base Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | 239 | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 5 |
| 2024 | - | - | - | - | - | 108 | - | - | - | 38 | 9 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 14 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 14 |
| 2027 | - | - | - | - | - | - | 25 | - | - | 35 | 5 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 478 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | 25 | - | 60 | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1 |
| 2037 | - | - | 80 | - | - | 25 | - | - | - | 16 | 0 |
| Total | 188 | - | 2,231 | - | - | 486 | 25 | 85 | - | 714 | 67 |
| Winter | 188 | - | 2,231 | - | - | - | 15 | 64 | - | 714 | 52 |

Appendix N: Electric Analysis



Figure N-90: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Goldendale, Base Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 28 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 717 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | 25 | - | - | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 43 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 2,194 | - | - | 486 | 25 | 78 | - | 714 | 157 |
| Winter | 188 | - | 2,194 | - | - | - | 15 | 59 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-91: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Mint Farm, Base Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 28 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 717 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | 25 | - | - | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 48 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 2,199 | - | - | 486 | 25 | 78 | - | 714 | 157 |
| Winter | 188 | - | 2,199 | - | - | - | 15 | 59 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-92: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Sumas, Base Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 28 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 478 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | 25 | - | 25 | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | 29 | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 73 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,985 | - | - | 486 | 25 | 132 | - | 714 | 157 |
| Winter | 188 | - | 1,985 | - | - | - | 15 | 101 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-93: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Encogen, No CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 29 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | 25 | 35 | 6 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 478 | - | - | 32 | - | 30 | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | 239 | - | - | - | - | - | 25 | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | 76 | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 11 | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,923 | - | - | 484 | 25 | 80 | 126 | 714 | 157 |
| Winter | 188 | - | 1,923 | - | - | - | 15 | 61 | 123 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-94: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Ferndale, No CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 29 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | 25 | 35 | 6 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 478 | - | - | 32 | - | 30 | - | 20 | 1 |
| 2032 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | 25 | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | 76 | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 123 | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | - | 2,035 | - | - | 484 | 25 | 80 | 126 | 714 | 157 |
| Winter | 188 | - | 2,035 | - | - | - | 15 | 61 | 123 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-95: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Goldendale, No CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | 25 | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 29 | - | 28 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 717 | - | - | 32 | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 43 | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | - | 2,194 | - | - | 484 | 25 | 53 | - | 714 | 157 |
| Winter | 188 | - | 2,194 | - | - | - | 15 | 40 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-96: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Mint Farm, No CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | 25 | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 29 | - | - | 26 | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 717 | - | - | 32 | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 48 | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | - | 2,199 | - | - | 484 | 25 | 25 | 26 | 714 | 157 |
| Winter | 188 | - | 2,199 | - | - | - | 15 | 19 | 26 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-97: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Sumas, No CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 29 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | 25 | 35 | 6 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 478 | - | - | 32 | - | 30 | - | 20 | 1 |
| 2032 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | 25 | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | 76 | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 123 | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | - | 2,035 | - | - | 484 | 25 | 80 | 126 | 714 | 157 |
| Winter | 188 | - | 2,035 | - | - | - | 15 | 61 | 123 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-98: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Encogen, All Thermal CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 200 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | 413 | - | - | - | - | - | - | 28 | 20 | 1 |
| 2032 | - | 413 | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | - | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 66 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | 1,239 | 783 | - | - | 490 | 25 | 75 | 28 | 714 | 157 |
| Winter | 188 | 1,239 | 783 | - | - | - | 15 | 57 | 27 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-99: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Ferndale, All Thermal CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 200 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | 826 | - | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | - | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | 68 | 16 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | 44 | 16 | 2 |
| 2037 | - | - | 93 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | 1,239 | 810 | - | - | 490 | 25 | 75 | 112 | 714 | 157 |
| Winter | 188 | 1,239 | 810 | - | - | - | 15 | 57 | 110 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-100: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Goldendale, All Thermal CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 200 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | 826 | - | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | - | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | 77 | 16 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | 44 | 16 | 2 |
| 2037 | - | - | 93 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | 1,239 | 810 | - | - | 490 | 25 | 75 | 122 | 714 | 157 |
| Winter | 188 | 1,239 | 810 | - | - | - | 15 | 57 | 119 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-101: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Mint Farm, All Thermal CO₂ Scenario

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 200 | - | - | 32 | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | 826 | - | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | - | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | 85 | 16 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | 44 | 16 | 2 |
| 2037 | - | - | 93 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | 1,239 | 810 | - | - | 490 | - | 50 | 161 | 714 | 157 |
| Winter | 188 | 1,239 | 810 | - | - | - | - | 38 | 158 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-102: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Sumas All Thermal CO₂

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 200 | 25 | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | 25 | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | 413 | - | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | 413 | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | - | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 63 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | 1,239 | 780 | - | - | 490 | 25 | 50 | 25 | 714 | 157 |
| Winter | 188 | 1,239 | 780 | - | - | - | 15 | 38 | 25 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-103: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: No New Thermal

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|------------|-----------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 30 | 15 |
| 2019 | - | - | - | - | - | - | - | - | - | 58 | 30 |
| 2020 | - | - | - | - | - | - | - | - | - | 105 | 43 |
| 2021 | - | - | - | - | - | - | - | - | - | 101 | 41 |
| 2022 | - | - | - | - | - | 35 | - | - | - | 46 | 13 |
| 2023 | - | - | - | - | 300 | - | - | - | - | 42 | 4 |
| 2024 | - | - | - | - | - | - | - | - | - | 40 | 9 |
| 2025 | - | - | - | - | - | - | - | 25 | - | 38 | 13 |
| 2026 | - | - | - | - | - | - | 25 | 125 | 201 | 37 | 15 |
| 2027 | - | - | - | - | - | - | 25 | - | 12 | 37 | 6 |
| 2028 | - | - | - | - | - | - | - | - | 11 | 29 | 0 |
| 2029 | - | - | - | - | - | - | - | - | 76 | 21 | 0.5 |
| 2030 | - | - | - | - | - | - | - | - | 83 | 20 | 2.1 |
| 2031 | - | - | - | - | - | - | - | - | 336 | 20 | 1.9 |
| 2032 | - | - | - | - | - | - | - | - | 78 | 20 | 2.0 |
| 2033 | - | - | - | - | - | - | - | - | 79 | 19 | 1.3 |
| 2034 | - | - | - | - | - | - | - | - | 80 | 17 | 1.6 |
| 2035 | - | - | - | - | - | - | - | - | 87 | 16 | 1.8 |
| 2036 | - | - | - | - | - | - | - | - | 465 | 16 | 2.6 |
| 2037 | - | - | - | - | - | 25 | - | - | 104 | 16 | 1.1 |
| Total | 188 | - | - | - | 300 | 60 | 50 | 150 | 1,612 | 728 | 203 |
| Winter | 188 | - | - | - | 136 | - | 30 | 114 | 1582 | 728 | 156 |



Figure N-104: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Higher Thermal Cost

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 52 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | - | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | 25 | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | (0) |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 239 | - | - | - | - | - | 33 | 20 | 1 |
| 2032 | - | - | 239 | - | - | 25 | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 63 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | 88 | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 86 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,759 | - | - | 486 | 25 | 77 | 120 | 714 | 157 |
| Winter | 188 | - | 1,759 | - | - | - | 15 | 59 | 118 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-105: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Energy Storage – Battery

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 50 | - | 41 | 3 |
| 2024 | - | - | - | - | - | 112 | 25 | - | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 11 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | 239 | - | - | - | - | - | - | 35 | 5 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0.0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1.4 |
| 2031 | - | - | 478 | - | - | - | - | - | - | 20 | 1.2 |
| 2032 | - | - | - | - | - | 25 | - | - | - | 20 | 1.4 |
| 2033 | - | - | - | - | - | 59 | - | - | - | 19 | 0.6 |
| 2034 | - | - | 239 | - | - | - | - | - | - | 17 | 0.9 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1.1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1.8 |
| 2037 | - | - | - | - | - | 25 | - | - | - | 16 | 0.6 |
| Total | 188 | - | 1,912 | - | - | 486 | 25 | 50 | - | 714 | 148 |
| Winter | 188 | - | 1,912 | - | - | - | 15 | 38 | - | 714 | 114 |

Appendix N: Electric Analysis



Figure N-106: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Energy Storage - Pumped Storage

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | - | 50 | 41 | 3 |
| 2024 | - | - | - | - | - | 108 | - | 25 | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 11 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 5 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | (0.1) |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0.0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1.4 |
| 2031 | - | - | 353 | - | - | - | - | - | - | 20 | 1.2 |
| 2032 | - | - | - | - | - | 25 | - | - | - | 20 | 1.4 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 0.6 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0.9 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1.1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1.8 |
| 2037 | - | - | 71 | - | - | 25 | - | - | - | 16 | 0.6 |
| Total | 188 | - | 1,858 | - | - | 486 | - | 50 | 50 | 714 | 148 |
| Winter | 188 | - | 1,858 | - | - | - | - | 38 | 50 | 714 | 114 |

Appendix N: Electric Analysis



Figure N-107: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Battery ITC

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | - | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 239 | - | - | - | - | 37 | - | 20 | 1 |
| 2032 | - | - | 239 | - | - | 25 | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 63 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | 113 | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 73 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,746 | - | - | 486 | - | 200 | - | 714 | 157 |
| Winter | 188 | - | 1,746 | - | - | - | - | 152 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-108: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Electric Vehicle Load

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | 239 | - | - | 52 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 221 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 148 | - | - | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 12 |
| 2026 | - | - | 239 | - | - | - | - | 25 | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | 25 | - | 35 | 4 |
| 2028 | - | - | 239 | - | - | - | - | - | - | 28 | (0) |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 478 | - | - | - | - | - | - | 20 | 0 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 85 | - | - | - | 19 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0 |
| 2035 | - | - | - | - | - | - | - | - | 34 | 16 | 0 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1 |
| 2037 | - | - | 102 | - | - | 25 | - | - | - | 16 | 0 |
| Total | 188 | - | 2,253 | - | - | 530 | - | 50 | 34 | 714 | 58 |
| Winter | 188 | - | 2,253 | - | - | - | - | 38 | 33 | 714 | 45 |

Appendix N: Electric Analysis



Figure N-109: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: No DSR

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|----------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | - | - |
| 2019 | - | - | - | - | - | - | - | - | - | - | - |
| 2020 | - | - | - | - | - | - | - | - | - | - | - |
| 2021 | - | - | - | - | - | - | - | - | - | - | - |
| 2022 | - | - | 239 | - | - | 114 | - | 27 | - | - | - |
| 2023 | - | - | - | - | - | 197 | 25 | 54 | - | - | - |
| 2024 | - | - | 239 | - | - | 191 | - | - | - | - | - |
| 2025 | - | - | - | - | - | - | - | - | - | - | - |
| 2026 | - | - | 478 | - | - | - | - | - | - | - | - |
| 2027 | - | - | - | - | - | - | - | - | - | - | - |
| 2028 | - | - | - | - | - | - | - | - | - | - | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | - | - |
| 2030 | - | - | - | - | - | - | - | - | - | - | - |
| 2031 | - | - | 478 | - | - | - | - | - | - | - | - |
| 2032 | - | - | - | - | - | - | - | - | - | - | - |
| 2033 | - | - | 239 | - | - | 90 | - | - | - | - | - |
| 2034 | - | - | - | - | - | - | - | - | - | - | - |
| 2035 | - | - | - | - | - | - | - | - | - | - | - |
| 2036 | - | - | 478 | - | - | - | - | - | - | - | - |
| 2037 | - | - | 87 | - | - | 25 | - | - | - | - | - |
| Total | 188 | - | 2,477 | - | - | 616 | 25 | 81 | - | - | - |
| Winter | 188 | - | 2,477 | - | - | - | 15 | 61 | - | - | - |

Appendix N: Electric Analysis



Figure N-110: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Extended DSR Potential

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 47 | - | 41 | 4 |
| 2024 | - | - | - | - | - | 109 | - | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | 25 | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 36 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 35 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 35 | 2 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 37 | 1 |
| 2032 | - | - | 239 | - | - | - | - | - | - | 37 | 1 |
| 2033 | - | - | - | - | - | 49 | - | - | - | 37 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 37 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 37 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 37 | 2 |
| 2037 | - | - | 28 | - | - | 25 | - | - | - | 38 | 1 |
| Total | 188 | - | 1,701 | - | - | 449 | 25 | 72 | - | 886 | 157 |
| Winter | 188 | - | 1,701 | - | - | - | 15 | 55 | - | 886 | 121 |

Appendix N: Electric Analysis



Figure N-111: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: DSR Discount Rate

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 28 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 55 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 101 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 97 | 3 |
| 2022 | - | - | 239 | - | - | 45 | - | - | - | 43 | 1 |
| 2023 | - | - | - | - | - | 224 | - | - | - | 39 | 4 |
| 2024 | - | - | - | - | - | 113 | - | - | - | 36 | 8 |
| 2025 | - | - | - | - | - | - | - | 25 | - | 35 | 12 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 34 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 34 | 4 |
| 2028 | - | - | - | - | - | - | - | - | - | 27 | (0) |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2032 | - | - | - | - | - | 25 | - | 29 | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 16 | 0 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1 |
| 2037 | - | - | 67 | - | - | 25 | - | - | - | 16 | 0 |
| Total | 188 | - | 1,979 | - | - | 494 | - | 79 | - | 693 | 58 |
| Winter | 188 | - | 1,979 | - | - | - | - | 60 | - | 693 | 45 |

Appendix N: Electric Analysis



Figure N-112: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: MT Wind - 150 MW

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|------------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | 150 | - | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 33 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 98 | - | - | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | 25 | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 239 | - | - | - | - | 25 | - | 20 | 1 |
| 2032 | - | - | 239 | - | - | 25 | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 56 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | 109 | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 73 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,746 | - | 150 | 237 | - | 159 | - | 714 | 157 |
| Winter | 188 | - | 1,746 | - | 68 | - | - | 121 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-113: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: MT Wind - 175 MW

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|------------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | 175 | - | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | - | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 106 | - | - | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 239 | - | - | - | - | 31 | - | 20 | 1 |
| 2032 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 66 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | 113 | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 73 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,746 | - | 175 | 197 | - | 144 | - | 714 | 157 |
| Winter | 188 | - | 1,746 | - | 86 | - | - | 109 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-114: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: MT Wind - 300 MW

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|------------|-----------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | - | - | 300 | - | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | - | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | - | - | - | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 12 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 4 |
| 2028 | - | - | - | - | - | - | - | 25 | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 239 | - | - | - | - | 29 | - | 20 | 0 |
| 2032 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | - | - | - | - | 19 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0 |
| 2035 | - | - | - | - | - | - | - | 113 | - | 16 | 0 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1 |
| 2037 | - | - | 74 | - | - | 25 | - | - | - | 16 | 0 |
| Total | 188 | - | 1,747 | - | 300 | 25 | - | 168 | - | 714 | 58 |
| Winter | 188 | - | 1,747 | - | 136 | - | - | 128 | - | 714 | 45 |

Appendix N: Electric Analysis



Figure N-115: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Hopkins Ridge Repowering

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | 239 | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | - | - | - | 38 | 8 |
| 2025 | - | - | - | - | - | - | - | - | - | 37 | 12 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 4 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2032 | - | - | - | - | - | 25 | - | 25 | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 16 | 0 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1 |
| 2037 | - | - | 67 | - | - | 25 | - | - | - | 16 | 0 |
| Total | 188 | - | 1,979 | - | - | 486 | - | 50 | - | 714 | 58 |
| Winter | 188 | - | 1,979 | - | - | - | - | 38 | - | 714 | 45 |

Appendix N: Electric Analysis



Figure N-116: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Wild Horse Repowering

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|-----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | 21 | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 25 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 217 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 122 | - | 5 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | 5 | 7 | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | 14 | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 478 | - | - | - | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | 239 | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 58 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,970 | 21 | - | 462 | 5 | 25 | - | 714 | 157 |
| Winter | 188 | - | 1,970 | 3 | - | - | - | 19 | - | 714 | 121 |

Appendix N: Electric Analysis



Figure N-117: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Add 300 MW Solar

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 2 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 4 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 4 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 3 |
| 2022 | - | - | 239 | - | - | 40 | - | - | - | 45 | 1 |
| 2023 | - | - | - | - | - | 525 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | - | - | - | 38 | 8 |
| 2025 | - | - | - | - | - | - | - | - | - | 37 | 12 |
| 2026 | - | - | 478 | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 4 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2032 | - | - | - | - | - | 25 | - | 25 | - | 20 | 1 |
| 2033 | - | - | 239 | - | - | 63 | - | - | - | 19 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 0 |
| 2035 | - | - | - | - | - | - | - | 25 | - | 16 | 0 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 1 |
| 2037 | - | - | 67 | - | - | 25 | - | - | - | 16 | 0 |
| Total | 188 | - | 1,979 | - | - | 786 | - | 50 | - | 714 | 58 |
| Winter | 188 | - | 1,979 | - | - | - | - | 38 | - | 714 | 45 |

Appendix N: Electric Analysis



Figure N-118: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: No Transmission Redirect

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | 239 | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 4 |
| 2024 | - | - | - | - | - | 108 | - | 25 | - | 38 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 36 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 6 |
| 2028 | - | - | - | - | - | - | - | 25 | - | 28 | - |
| 2029 | - | - | 239 | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 2 |
| 2031 | - | - | 239 | - | - | - | - | - | 25 | 20 | 1 |
| 2032 | - | - | 239 | - | - | 25 | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 63 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | 239 | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | - | 239 | - | - | - | - | - | 64 | 16 | 2 |
| 2037 | - | - | 93 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 2,005 | - | - | 486 | - | 50 | 89 | 714 | 157 |
| Winter | 188 | - | 2,005 | - | - | - | - | 38 | 87 | 714 | 121 |

Appendix N: Electric Analysis



Figure N-119: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: More Conservation

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|----------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 36 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 67 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 114 | 30 |
| 2021 | - | - | - | - | - | 25 | - | - | - | 110 | 29 |
| 2022 | - | - | - | - | - | - | - | - | - | 56 | 9 |
| 2023 | - | - | - | - | - | 221 | - | - | - | 51 | 4 |
| 2024 | - | - | - | - | - | 78 | - | - | - | 48 | 10 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 47 | 13 |
| 2026 | - | - | 239 | - | - | - | - | - | - | 46 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 45 | 6 |
| 2028 | - | - | - | - | - | - | - | - | - | 34 | - |
| 2029 | - | - | - | - | - | - | - | 51 | - | 23 | 0 |
| 2030 | - | - | 239 | - | - | - | - | - | - | 22 | 2 |
| 2031 | - | - | 239 | - | - | - | - | - | - | 22 | 1 |
| 2032 | - | - | - | - | - | 25 | - | 41 | - | 22 | 1 |
| 2033 | - | - | 239 | - | - | 58 | - | - | - | 20 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 18 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2036 | - | - | 478 | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 72 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | - | 1,745 | - | - | 431 | - | 92 | - | 830 | 157 |
| Winter | 188 | - | 1,745 | - | - | - | - | 70 | - | 830 | 121 |



Portfolio CO₂ Emissions – Sensitivities

Figure N-120: Total Portfolio CO₂ Emissions
Emission PSE Portfolio - Sensitivity (Millions Tons)

| | Retire Colstrip 2018 Base | Retire Colstrip 2018 No CO2 | Retire Colstrip 2025 Base | Retire Colstrip 2025 No CO2 | Retire Colstrip 2030 Base | Retire Colstrip 2030 No CO2 |
|------|---------------------------------|-----------------------------------|---------------------------------|-----------------------------------|---------------------------------|-----------------------------------|
| 2018 | 12.30 | 12.66 | 12.05 | 12.66 | 12.30 | 12.90 |
| 2019 | 12.02 | 9.66 | 11.71 | 12.31 | 12.02 | 12.61 |
| 2020 | 11.64 | 9.49 | 11.31 | 11.83 | 11.64 | 12.15 |
| 2021 | 11.17 | 9.14 | 10.96 | 11.69 | 11.17 | 11.89 |
| 2022 | 6.03 | 9.11 | 6.72 | 10.28 | 6.03 | 9.68 |
| 2023 | 6.09 | 9.82 | 7.37 | 9.82 | 6.09 | 8.65 |
| 2024 | 6.22 | 9.85 | 7.74 | 9.85 | 6.22 | 8.43 |
| 2025 | 6.84 | 10.17 | 8.50 | 10.17 | 6.84 | 8.63 |
| 2026 | 7.27 | 9.38 | 7.69 | 6.39 | 7.27 | 9.24 |
| 2027 | 7.51 | 9.22 | 7.95 | 6.45 | 7.51 | 9.05 |
| 2028 | 7.73 | 9.55 | 8.14 | 6.54 | 7.73 | 9.38 |
| 2029 | 8.14 | 9.53 | 8.59 | 6.74 | 8.14 | 9.32 |
| 2030 | 8.24 | 9.73 | 8.79 | 6.91 | 8.24 | 9.50 |
| 2031 | 8.65 | 10.37 | 9.19 | 7.35 | 6.24 | 7.34 |
| 2032 | 9.44 | 11.00 | 10.13 | 8.05 | 7.03 | 7.93 |
| 2033 | 9.58 | 11.28 | 10.28 | 8.24 | 7.13 | 8.25 |
| 2034 | 9.53 | 11.21 | 10.17 | 8.40 | 7.29 | 8.42 |
| 2035 | 9.49 | 11.37 | 10.22 | 8.53 | 7.45 | 8.53 |
| 2036 | 7.65 | 8.71 | 8.27 | 8.71 | 7.63 | 8.69 |
| 2037 | 7.84 | 8.79 | 8.44 | 8.79 | 7.82 | 8.76 |



Figure N-121: Total Portfolio CO₂ Emissions
Emission PSE Portfolio - Sensitivity (Millions Tons)

| | Retire Encogen Base | Retire Ferndale Base | Retire Goldendale Base | Retire Mint Farm Base | Retire Sumas Base |
|------|---------------------|----------------------|------------------------|-----------------------|-------------------|
| 2018 | 12.30 | 12.30 | 12.30 | 12.30 | 12.30 |
| 2019 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 |
| 2020 | 11.64 | 11.64 | 11.64 | 11.64 | 11.64 |
| 2021 | 11.17 | 11.17 | 11.17 | 11.17 | 11.17 |
| 2022 | 6.03 | 6.06 | 6.03 | 6.03 | 6.03 |
| 2023 | 6.09 | 6.12 | 6.09 | 6.09 | 6.09 |
| 2024 | 6.23 | 6.27 | 6.23 | 6.23 | 6.23 |
| 2025 | 6.85 | 6.89 | 6.85 | 6.85 | 6.85 |
| 2026 | 7.28 | 7.32 | 7.28 | 7.28 | 7.28 |
| 2027 | 7.52 | 7.56 | 7.52 | 7.52 | 7.52 |
| 2028 | 7.70 | 7.73 | 7.70 | 7.70 | 7.70 |
| 2029 | 8.14 | 8.18 | 8.14 | 8.14 | 8.14 |
| 2030 | 8.24 | 8.29 | 8.24 | 8.24 | 8.24 |
| 2031 | 8.65 | 8.65 | 8.59 | 8.79 | 8.57 |
| 2032 | 9.41 | 9.42 | 9.39 | 9.62 | 9.34 |
| 2033 | 9.62 | 9.63 | 9.63 | 9.91 | 9.56 |
| 2034 | 9.53 | 9.54 | 9.52 | 9.81 | 9.45 |
| 2035 | 9.49 | 9.50 | 9.45 | 9.74 | 9.42 |
| 2036 | 7.65 | 7.66 | 7.61 | 7.89 | 7.58 |
| 2037 | 7.84 | 7.86 | 7.80 | 8.10 | 7.77 |



Figure N-122: Total Portfolio CO₂ Emissions
Emission PSE Portfolio - Sensitivity (Millions Tons)

| | Retire Encogen No CO2 | Retire Ferndale No CO2 | Retire Goldendale No CO2 | Retire Mint Farm No CO2 | Retire Sumas No CO2 |
|------|--------------------------|---------------------------|-----------------------------|----------------------------|------------------------|
| 2018 | 12.90 | 12.90 | 12.90 | 12.90 | 12.90 |
| 2019 | 12.61 | 12.61 | 12.61 | 12.61 | 12.61 |
| 2020 | 12.15 | 12.15 | 12.15 | 12.15 | 12.15 |
| 2021 | 11.89 | 11.89 | 11.89 | 11.89 | 11.89 |
| 2022 | 9.68 | 9.68 | 9.68 | 9.68 | 9.68 |
| 2023 | 8.65 | 8.65 | 8.65 | 8.65 | 8.65 |
| 2024 | 8.43 | 8.43 | 8.43 | 8.43 | 8.43 |
| 2025 | 8.63 | 8.63 | 8.63 | 8.63 | 8.63 |
| 2026 | 9.01 | 9.01 | 9.01 | 9.01 | 9.01 |
| 2027 | 8.82 | 8.82 | 8.82 | 8.82 | 8.82 |
| 2028 | 9.14 | 9.14 | 9.14 | 9.14 | 9.14 |
| 2029 | 9.10 | 9.10 | 9.10 | 9.10 | 9.10 |
| 2030 | 9.30 | 9.30 | 9.30 | 9.30 | 9.30 |
| 2031 | 9.76 | 9.59 | 9.63 | 9.68 | 9.71 |
| 2032 | 10.14 | 9.97 | 10.01 | 10.07 | 10.09 |
| 2033 | 10.42 | 10.26 | 10.33 | 10.49 | 10.38 |
| 2034 | 10.38 | 10.18 | 10.27 | 10.39 | 10.32 |
| 2035 | 10.54 | 10.34 | 10.42 | 10.48 | 10.48 |
| 2036 | 7.79 | 7.58 | 7.65 | 7.71 | 7.72 |
| 2037 | 7.82 | 7.63 | 7.70 | 7.73 | 7.77 |



Figure N-123: Total Portfolio CO₂ Emissions
Emission PSE Portfolio - Sensitivity (Millions Tons)

| | Retire Encogen All Thermal CO2 | Retire Ferndale All Thermal CO2 | Retire Goldendale All Thermal CO2 | Retire Mint Farm All Thermal CO2 | Retire Sumas All Thermal CO2 |
|------|-----------------------------------|------------------------------------|--------------------------------------|-------------------------------------|---------------------------------|
| 2018 | 7.62 | 7.62 | 7.62 | 7.62 | 7.62 |
| 2019 | 7.43 | 7.43 | 7.43 | 7.43 | 7.43 |
| 2020 | 6.82 | 6.82 | 6.82 | 6.82 | 6.82 |
| 2021 | 6.76 | 6.76 | 6.76 | 6.76 | 6.76 |
| 2022 | 6.84 | 6.84 | 6.84 | 6.84 | 6.84 |
| 2023 | 6.82 | 6.82 | 6.82 | 6.82 | 6.82 |
| 2024 | 6.97 | 6.97 | 6.97 | 6.97 | 6.97 |
| 2025 | 7.53 | 7.53 | 7.53 | 7.53 | 7.53 |
| 2026 | 7.59 | 7.59 | 7.59 | 7.59 | 7.59 |
| 2027 | 7.78 | 7.78 | 7.78 | 7.78 | 7.78 |
| 2028 | 8.00 | 8.00 | 8.00 | 8.00 | 8.00 |
| 2029 | 8.18 | 8.18 | 8.18 | 8.18 | 8.18 |
| 2030 | 8.28 | 8.28 | 8.28 | 8.28 | 8.28 |
| 2031 | 8.92 | 8.70 | 9.61 | 9.61 | 8.92 |
| 2032 | 9.61 | 9.26 | 9.96 | 9.96 | 9.60 |
| 2033 | 9.78 | 9.50 | 10.08 | 10.08 | 9.76 |
| 2034 | 9.68 | 9.37 | 9.99 | 9.99 | 9.66 |
| 2035 | 9.62 | 9.19 | 10.00 | 10.00 | 9.61 |
| 2036 | 7.48 | 7.07 | 7.84 | 7.84 | 7.45 |
| 2037 | 7.49 | 7.07 | 7.86 | 7.86 | 7.45 |



Figure N-124: Total Portfolio CO₂ Emissions
Emission PSE Portfolio - Sensitivity (Millions Tons)

| | No New Thermal | High Thermal Cost | Energy Storage Battery | Energy Storage Pumped Hydro | Batteries ITC | EV Load | No DSR |
|------|----------------|-------------------|------------------------|-----------------------------|---------------|---------|--------|
| 2018 | 12.30 | 12.30 | 12.30 | 12.30 | 12.30 | 12.30 | 12.35 |
| 2019 | 12.01 | 12.02 | 12.02 | 12.02 | 12.02 | 12.02 | 12.15 |
| 2020 | 11.63 | 11.64 | 11.64 | 11.64 | 11.64 | 11.64 | 11.84 |
| 2021 | 11.15 | 11.17 | 11.17 | 11.17 | 11.17 | 11.17 | 11.42 |
| 2022 | 6.01 | 6.03 | 6.03 | 6.03 | 6.03 | 6.05 | 6.30 |
| 2023 | 5.90 | 6.09 | 6.09 | 6.09 | 6.09 | 6.12 | 6.43 |
| 2024 | 6.12 | 6.23 | 6.23 | 6.23 | 6.23 | 6.23 | 6.60 |
| 2025 | 6.69 | 6.85 | 6.85 | 6.85 | 6.85 | 6.86 | 7.26 |
| 2026 | 7.07 | 7.28 | 7.28 | 7.28 | 7.28 | 7.29 | 7.79 |
| 2027 | 7.31 | 7.52 | 7.55 | 7.52 | 7.52 | 7.53 | 8.08 |
| 2028 | 7.48 | 7.70 | 7.73 | 7.70 | 7.70 | 7.74 | 8.28 |
| 2029 | 7.89 | 8.14 | 8.14 | 8.14 | 8.14 | 8.15 | 8.75 |
| 2030 | 7.95 | 8.24 | 8.24 | 8.24 | 8.24 | 8.27 | 8.89 |
| 2031 | 8.25 | 8.61 | 8.65 | 8.63 | 8.61 | 8.68 | 9.33 |
| 2032 | 9.03 | 9.42 | 9.42 | 9.40 | 9.42 | 9.46 | 10.13 |
| 2033 | 9.21 | 9.58 | 9.57 | 9.62 | 9.58 | 9.66 | 10.35 |
| 2034 | 9.06 | 9.47 | 9.52 | 9.50 | 9.47 | 9.55 | 10.28 |
| 2035 | 9.01 | 9.43 | 9.49 | 9.46 | 9.43 | 9.52 | 10.26 |
| 2036 | 7.01 | 7.58 | 7.64 | 7.61 | 7.58 | 7.68 | 8.44 |
| 2037 | 7.11 | 7.77 | 7.81 | 7.80 | 7.77 | 7.88 | 8.66 |



Figure N-125: Total Portfolio CO₂ Emissions
Emission PSE Portfolio - Sensitivity (Millions Tons)

| | Extended DSR Potential | DSR Discount Rate | MT Wind 150 MW | MT Wind 175 MW | MT Wind 300 MW |
|------|------------------------|-------------------|----------------|----------------|----------------|
| 2018 | 12.30 | 12.30 | 12.30 | 12.30 | 12.30 |
| 2019 | 12.02 | 12.03 | 12.02 | 12.02 | 12.02 |
| 2020 | 11.64 | 11.66 | 11.64 | 11.64 | 11.64 |
| 2021 | 11.17 | 11.18 | 11.17 | 11.17 | 11.17 |
| 2022 | 6.03 | 6.08 | 5.90 | 5.87 | 5.74 |
| 2023 | 6.09 | 6.14 | 6.09 | 6.08 | 5.95 |
| 2024 | 6.23 | 6.29 | 6.24 | 6.23 | 6.17 |
| 2025 | 6.85 | 6.89 | 6.86 | 6.85 | 6.78 |
| 2026 | 7.28 | 7.36 | 7.28 | 7.27 | 7.21 |
| 2027 | 7.52 | 7.60 | 7.53 | 7.52 | 7.45 |
| 2028 | 7.68 | 7.77 | 7.70 | 7.69 | 7.63 |
| 2029 | 8.10 | 8.18 | 8.15 | 8.14 | 8.07 |
| 2030 | 8.17 | 8.34 | 8.25 | 8.24 | 8.17 |
| 2031 | 8.51 | 8.70 | 8.61 | 8.60 | 8.53 |
| 2032 | 9.31 | 9.46 | 9.42 | 9.43 | 9.36 |
| 2033 | 9.44 | 9.67 | 9.58 | 9.58 | 9.56 |
| 2034 | 9.29 | 9.57 | 9.47 | 9.47 | 9.45 |
| 2035 | 9.21 | 9.53 | 9.43 | 9.43 | 9.41 |
| 2036 | 7.32 | 7.68 | 7.58 | 7.58 | 7.56 |
| 2037 | 7.45 | 7.87 | 7.77 | 7.77 | 7.75 |



Figure N-126: Total Portfolio CO₂ Emissions
Emission PSE Portfolio - Sensitivity (Millions Tons)

| | Hopkins Ridge Repowering | Wild Horse Repowering | Add 300 MW Solar | No Transmission Redirect | More Conservation |
|------|--------------------------|-----------------------|------------------|--------------------------|-------------------|
| 2018 | 12.30 | 12.30 | 12.30 | 12.30 | 12.29 |
| 2019 | 12.02 | 12.02 | 12.02 | 12.02 | 11.97 |
| 2020 | 11.64 | 11.63 | 11.64 | 11.64 | 11.56 |
| 2021 | 11.17 | 11.15 | 11.17 | 11.17 | 11.04 |
| 2022 | 6.06 | 6.02 | 6.06 | 6.06 | 5.90 |
| 2023 | 6.12 | 6.09 | 5.92 | 6.12 | 5.94 |
| 2024 | 6.27 | 6.22 | 6.06 | 6.27 | 6.08 |
| 2025 | 6.86 | 6.84 | 6.65 | 6.89 | 6.66 |
| 2026 | 7.33 | 7.27 | 7.12 | 7.32 | 7.07 |
| 2027 | 7.57 | 7.51 | 7.36 | 7.56 | 7.29 |
| 2028 | 7.73 | 7.69 | 7.52 | 7.73 | 7.44 |
| 2029 | 8.14 | 8.13 | 7.94 | 8.18 | 7.85 |
| 2030 | 8.30 | 8.23 | 8.09 | 8.29 | 7.99 |
| 2031 | 8.66 | 8.64 | 8.45 | 8.66 | 8.34 |
| 2032 | 9.42 | 9.43 | 9.21 | 9.47 | 9.11 |
| 2033 | 9.63 | 9.58 | 9.43 | 9.63 | 9.32 |
| 2034 | 9.53 | 9.53 | 9.32 | 9.52 | 9.20 |
| 2035 | 9.49 | 9.49 | 9.29 | 9.54 | 9.15 |
| 2036 | 7.64 | 7.65 | 7.44 | 7.64 | 7.30 |
| 2037 | 7.83 | 7.83 | 7.63 | 7.84 | 7.48 |



7. STOCHASTIC ANALYSIS RESULTS

Figure N-127: Revenue Requirement with Input Simulations – 1,000 Trials

| Expected Portfolio Cost (\$Millions) | Risk Simulation - 1000 Trials | | | | | | | |
|--------------------------------------|-------------------------------|--------------------------------|--------------------------------|--------|------------------|--------------------------|----------------|------------------------------|
| | Resource Plan | Base Portfolio (Frame Peakers) | Base + No CO2 Portfolio (CCCT) | No DSR | Add 300 MW Solar | No Transmission Redirect | No New Thermal | More Conservation (Bundle 5) |
| Minimum | 7.46 | 7.19 | 8.29 | 6.84 | 6.93 | 7.17 | 9.92 | 7.92 |
| 1st Quartile (P25) | 10.09 | 10.03 | 10.55 | 10.34 | 10.06 | 10.12 | 12.06 | 10.31 |
| Mean | 10.57 | 10.52 | 11.13 | 10.84 | 10.54 | 10.62 | 12.69 | 10.81 |
| Median (P50) | 10.60 | 10.55 | 11.19 | 10.89 | 10.60 | 10.66 | 12.70 | 10.82 |
| 3rd Quartile (P75) | 11.14 | 11.08 | 11.71 | 11.42 | 11.09 | 11.18 | 13.44 | 11.36 |
| TVar90 | 11.84 | 11.79 | 12.50 | 12.18 | 11.80 | 11.89 | 14.65 | 12.06 |
| Maximum | 12.89 | 12.80 | 13.33 | 13.03 | 12.61 | 12.86 | 16.34 | 13.15 |



8. CARBON ABATEMENT ANALYSIS RESULTS

Expected Portfolio Costs – Carbon Abatement

This table summarizes the expected costs of the different carbon abatement analysis.

*Figure N-128: Revenue Requirements for Optimal Portfolio with Expected Inputs for the Scenario
Expected Cost for All Portfolios*

| Scenario | NPV to 2018 (\$Millions) | | | | | |
|---|--------------------------|-------------------------------|---------------|-----------------------|---------------------|-------------|
| | Expected Portfolio Cost | Net Market Purchases/ (Sales) | DSR Rev. Req. | Incremental Rev. Req. | Generic End Effects | REC Revenue |
| Add 300 MW Wind No CO2 | 10,841 | 738 | 618 | 9,163 | 328 | (5) |
| Add 300 MW Solar No CO2 | 10,523 | 657 | 618 | 9,115 | 142 | (9) |
| 50%RPS | 11,707 | (37) | 618 | 10,364 | 794 | (32) |
| CAR Cap on WA CCCT | 10,562 | 1,393 | 420 | 8,839 | (82) | (9) |
| Additional Conservation – Incremental | 10,645 | 358 | 1,230 | 8,908 | 156 | (6) |
| Additional Conservation – All | 26,971 | (889) | 20,927 | 6,858 | 112 | (37) |
| Early Retirement of Colstrip 3&4 ¹ | 10,647 | 656 | 621 | 9,252 | 123 | (5) |

NOTE

1. This is the same portfolio as “Retire Colstrip 2025 No CO₂,” in Figure N-73.

Appendix N: Electric Analysis



Figure N-129: Annual Revenue Requirements for Optimal Portfolio (\$Millions)

| | Add 300 Wind No CO2 | Add 300 Solar No CO2 | 50% RPS | Cap Gas | Additional Conservation Incremental | Additional Conservation All | Early Retirement of Colstrip 3&4 |
|----------------------|---------------------|----------------------|---------------|---------------|-------------------------------------|-----------------------------|----------------------------------|
| 2018 | 698 | 698 | 698 | 691 | 745 | 1,987 | 716 |
| 2019 | 743 | 743 | 743 | 723 | 836 | 3,376 | 760 |
| 2020 | 839 | 839 | 839 | 822 | 927 | 3,569 | 857 |
| 2021 | 850 | 850 | 850 | 839 | 938 | 3,656 | 867 |
| 2022 | 824 | 824 | 894 | 899 | 899 | 3,678 | 842 |
| 2023 | 894 | 886 | 884 | 897 | 885 | 3,613 | 846 |
| 2024 | 890 | 884 | 960 | 903 | 870 | 3,318 | 855 |
| 2025 | 916 | 907 | 965 | 913 | 896 | 3,057 | 889 |
| 2026 | 966 | 955 | 1,003 | 972 | 940 | 2,813 | 1,000 |
| 2027 | 983 | 971 | 1,013 | 999 | 947 | 2,534 | 999 |
| 2028 | 1,018 | 996 | 1,062 | 1,034 | 955 | 1,974 | 1,031 |
| 2029 | 1,084 | 1,063 | 1,142 | 1,110 | 1,010 | 1,527 | 1,090 |
| 2030 | 1,118 | 1,097 | 1,186 | 1,153 | 1,108 | 1,405 | 1,138 |
| 2031 | 1,262 | 1,242 | 1,342 | 1,292 | 1,174 | 1,314 | 1,280 |
| 2032 | 1,446 | 1,480 | 1,527 | 1,492 | 1,410 | 1,379 | 1,463 |
| 2033 | 1,559 | 1,490 | 1,696 | 1,573 | 1,430 | 1,295 | 1,570 |
| 2034 | 1,575 | 1,513 | 1,678 | 1,601 | 1,450 | 1,114 | 1,576 |
| 2035 | 1,640 | 1,579 | 1,712 | 1,678 | 1,501 | 1,028 | 1,632 |
| 2036 | 1,774 | 1,716 | 1,822 | 1,815 | 1,637 | 1,093 | 1,650 |
| 2037 | 1,778 | 1,722 | 1,844 | 1,823 | 1,647 | 1,042 | 1,690 |
| 20-yr NPV | 10,514 | 10,381 | 10,913 | 10,643 | 10,489 | 26,859 | 10,525 |
| End Effects | 328 | 142 | 794 | (82) | 156 | 112 | 123 |
| Expected Cost | 10,841 | 10,523 | 11,707 | 10,562 | 10,645 | 26,971 | 10,647 |



Incremental Portfolio Builds by Year – Carbon Abatement

Figure N-130: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Add 300 MW Wind No CO₂

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | - | - | 41 | 3 |
| 2024 | - | - | - | - | - | 29 | - | 25 | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 11 |
| 2026 | - | 413 | - | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 5 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | 413 | - | - | - | 32 | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | - | - | 25 | - | 20 | 1 |
| 2033 | - | 413 | - | - | - | 72 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | - | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | 1,652 | 239 | - | - | 484 | - | 50 | - | 714 | 148 |
| Winter | 188 | 1,652 | 239 | - | - | - | - | 38 | - | 714 | 114 |

Appendix N: Electric Analysis



Figure N-131: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Add 300 MW Solar No CO₂

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 225 | - | 50 | - | 41 | 3 |
| 2024 | - | - | - | - | - | 90 | 50 | - | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 11 |
| 2026 | - | 413 | - | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 5 |
| 2028 | - | - | - | - | - | - | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | - | - | - | - | 20 | 1 |
| 2031 | - | 413 | - | - | - | 32 | - | - | - | 20 | 1 |
| 2032 | - | 413 | - | - | - | - | - | - | - | 20 | 1 |
| 2033 | - | - | - | - | - | 73 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 18 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | 1,652 | 257 | - | - | 486 | 50 | 50 | - | 714 | 148 |
| Winter | 188 | 1,652 | 257 | - | - | - | 30 | 38 | - | 714 | 114 |

Appendix N: Electric Analysis



Figure N-132: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: 50% Washington RPS

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|--------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 29 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 57 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 103 | 30 |
| 2021 | - | - | - | - | - | - | - | - | - | 99 | 29 |
| 2022 | - | - | - | - | - | 435 | - | - | - | 45 | 9 |
| 2023 | - | - | - | - | - | 224 | - | 50 | - | 41 | 3 |
| 2024 | - | - | - | - | - | 579 | 50 | - | - | 38 | 8 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 37 | 11 |
| 2026 | - | 413 | - | - | - | - | - | - | - | 36 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 35 | 5 |
| 2028 | - | - | - | - | - | 184 | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | 157 | - | - | - | 20 | 0 |
| 2030 | - | - | - | - | - | 149 | - | - | - | 20 | 1 |
| 2031 | - | 413 | - | - | - | 172 | - | - | - | 20 | 1 |
| 2032 | - | - | - | - | - | 174 | - | 25 | - | 20 | 1 |
| 2033 | - | 413 | - | - | - | 780 | - | - | - | 19 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 16 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | - | - | - | 231 | - | - | - | 16 | 1 |
| Total | 188 | 1,652 | 239 | - | - | 3,086 | 50 | 75 | - | 714 | 148 |
| Winter | 188 | 1,652 | 239 | - | - | - | 30 | 57 | - | 714 | 114 |

Appendix N: Electric Analysis



Figure N-133: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: CAR Cap on WA CCCT Plants

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 26 | - |
| 2019 | - | - | - | - | - | - | - | - | - | 51 | - |
| 2020 | - | - | - | - | - | - | - | - | - | 98 | - |
| 2021 | - | - | - | - | - | - | - | - | - | 95 | - |
| 2022 | - | 413 | - | - | - | 50 | - | - | - | 41 | - |
| 2023 | - | - | - | - | - | 222 | - | - | - | 36 | 5 |
| 2024 | - | - | - | - | - | 93 | - | - | - | 34 | 10 |
| 2025 | - | - | - | - | - | - | - | - | - | 33 | 14 |
| 2026 | - | 413 | - | - | - | - | - | - | - | 32 | 14 |
| 2027 | - | - | - | - | - | - | - | - | - | 31 | 5 |
| 2028 | - | - | - | - | - | - | - | - | - | 26 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 19 | 0 |
| 2030 | - | - | - | - | - | 25 | - | 25 | - | 18 | 0 |
| 2031 | - | 413 | - | - | - | - | - | - | - | 19 | 0 |
| 2032 | - | - | - | - | - | 25 | - | 25 | - | 19 | 0 |
| 2033 | - | 413 | - | - | - | 65 | - | - | - | 18 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 16 | 0 |
| 2035 | - | - | - | - | - | - | - | - | - | 15 | 0 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 15 | 1 |
| 2037 | - | - | - | - | - | 25 | - | - | - | 15 | 0 |
| Total | 188 | 2,065 | - | - | - | 505 | - | 50 | - | 658 | 51 |
| Winter | 188 | 2,065 | - | - | - | - | - | 38 | - | 658 | 39 |

Appendix N: Electric Analysis



Figure N-134: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Additional Conservation – Incremental (Bundle 5)

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 36 | 11 |
| 2019 | - | - | - | - | - | - | - | - | - | 67 | 21 |
| 2020 | - | - | - | - | - | - | - | - | - | 114 | 30 |
| 2021 | - | - | - | - | - | 25 | - | - | - | 110 | 29 |
| 2022 | - | - | - | - | - | - | - | - | - | 56 | 9 |
| 2023 | - | - | - | - | - | 221 | - | - | - | 51 | 4 |
| 2024 | - | - | - | - | - | 25 | - | - | - | 48 | 10 |
| 2025 | - | - | - | - | - | - | 25 | 50 | 28 | 47 | 13 |
| 2026 | - | 413 | - | - | - | - | - | - | - | 46 | 15 |
| 2027 | - | - | - | - | - | - | - | - | - | 45 | 6 |
| 2028 | - | - | - | - | - | 35 | - | - | - | 34 | - |
| 2029 | - | - | - | - | - | - | - | - | 37 | 23 | 0 |
| 2030 | - | 413 | - | - | - | - | - | - | - | 22 | 2 |
| 2031 | - | - | - | - | - | 30 | - | - | - | 22 | 1 |
| 2032 | - | 413 | - | - | - | - | - | - | - | 22 | 1 |
| 2033 | - | - | - | - | - | 69 | - | - | - | 20 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 18 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 16 | 2 |
| 2037 | - | - | 60 | - | - | 25 | - | - | - | 16 | 1 |
| Total | 188 | 1,652 | 60 | - | - | 430 | 25 | 50 | 65 | 830 | 157 |
| Winter | 188 | 1,652 | 60 | - | - | - | 15 | 38 | 63 | 830 | 121 |

Appendix N: Electric Analysis



Figure N-135: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Additional Conservation – All (Bundle 10)

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|------------|--------------|----------|----------|-----------|---------------------|-------------------|----------------------|--------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 93 | - |
| 2019 | - | - | - | - | - | - | - | - | - | 140 | - |
| 2020 | - | - | - | - | - | - | - | - | - | 190 | - |
| 2021 | - | - | - | - | - | - | - | - | - | 190 | - |
| 2022 | - | - | - | - | - | - | - | - | - | 139 | - |
| 2023 | - | - | - | - | - | 72 | - | - | - | 134 | 4 |
| 2024 | - | - | - | - | - | - | - | - | - | 121 | 8 |
| 2025 | - | - | - | - | - | - | - | - | - | 122 | 12 |
| 2026 | - | - | - | - | - | - | - | - | - | 113 | 12 |
| 2027 | - | - | - | - | - | - | - | - | - | 109 | 4 |
| 2028 | - | - | - | - | - | - | - | - | - | 83 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 61 | (0) |
| 2030 | - | - | - | - | - | - | - | - | - | 55 | 0 |
| 2031 | - | 413 | - | - | - | - | - | - | - | 49 | 0 |
| 2032 | - | - | - | - | - | - | - | - | - | 52 | 0 |
| 2033 | - | - | - | - | - | - | - | - | - | 44 | 0 |
| 2034 | - | - | - | - | - | - | - | - | - | 35 | 0 |
| 2035 | - | - | - | - | - | - | - | - | - | 32 | 0 |
| 2036 | - | 413 | - | - | - | - | - | - | - | 30 | 0 |
| 2037 | - | - | - | - | - | 25 | - | 50 | - | 28 | 0 |
| Total | 188 | 826 | - | - | - | 97 | - | 50 | - | 1,820 | 42 |
| Winter | 188 | 826 | - | - | - | - | - | 38 | - | 1,820 | 32 |

Appendix N: Electric Analysis



Figure N-136: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Early Retirement of Colstrip 3 & 4

| Annual Builds (MW) | Transmission Redirect | CCCT | Frame Peaker | WA Wind | MT Wind | Solar | Li-Ion 2-hr Battery | Flow 4-hr Battery | Pumped Storage Hydro | DSR | Demand Response |
|--------------------|-----------------------|--------------|--------------|----------|----------|------------|---------------------|-------------------|----------------------|------------|-----------------|
| 2018 | 188 | - | - | - | - | - | - | - | - | 38 | 8 |
| 2019 | - | - | - | - | - | - | - | - | - | 73 | 16 |
| 2020 | - | - | - | - | - | - | - | - | - | 126 | 23 |
| 2021 | - | - | - | - | - | - | - | - | - | 121 | 22 |
| 2022 | - | - | - | - | - | 40 | - | - | - | 52 | 7 |
| 2023 | - | - | - | - | - | 225 | - | 25 | - | 44 | 3 |
| 2024 | - | - | - | - | - | 29 | 25 | 25 | - | 46 | 7 |
| 2025 | - | - | 239 | - | - | - | - | - | - | 47 | 10 |
| 2026 | - | 826 | - | - | - | - | - | - | - | 47 | 11 |
| 2027 | - | - | - | - | - | - | - | - | - | 40 | 4 |
| 2028 | - | - | - | - | - | 60 | - | - | - | 28 | - |
| 2029 | - | - | - | - | - | - | - | - | - | 20 | - |
| 2030 | - | - | - | - | - | - | - | 25 | - | 21 | 1 |
| 2031 | - | 413 | - | - | - | 32 | - | - | - | 21 | 1 |
| 2032 | - | - | - | - | - | - | - | - | - | 21 | 1 |
| 2033 | - | 413 | - | - | - | 72 | - | - | - | 20 | 1 |
| 2034 | - | - | - | - | - | - | - | - | - | 18 | 1 |
| 2035 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2036 | - | - | - | - | - | - | - | - | - | 17 | 1 |
| 2037 | - | - | - | - | - | 26 | - | - | - | 16 | 1 |
| Total | 188 | 1,652 | 239 | - | - | 484 | 25 | 75 | - | 834 | 121 |
| Winter | 188 | 1,652 | 239 | - | - | - | 15 | 57 | - | 834 | 121 |



Change in WECC Emissions by Resource Type

Figure N-137: Change in WECC Emissions by Resource Type
Carbon Abatement: 50% Washington RPS

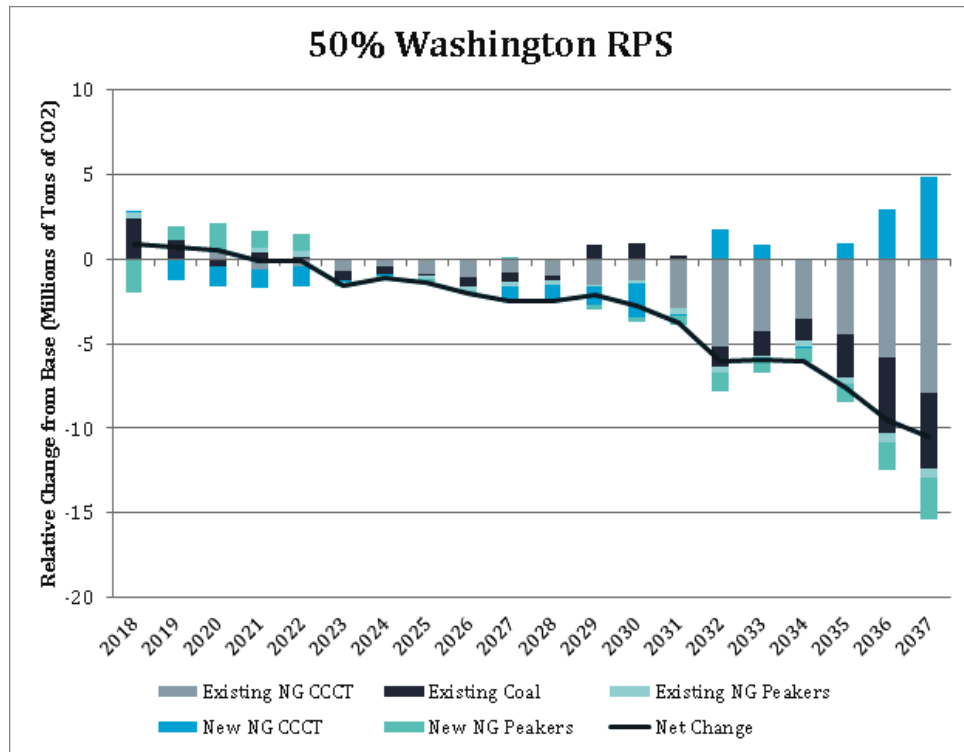




Figure N-138: Change in WECC Emissions by Resource Type
Carbon Abatement: Add 300 MW Solar

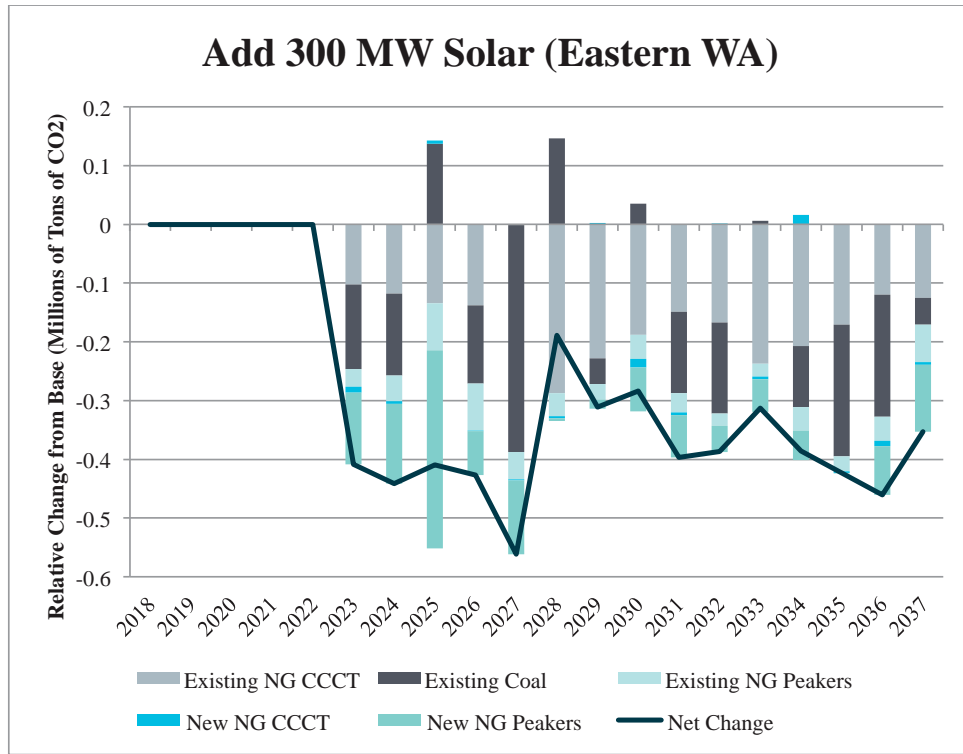




Figure N-139: Change in WECC Emissions by Resource Type
Carbon Abatement: Add 300 MW Wind

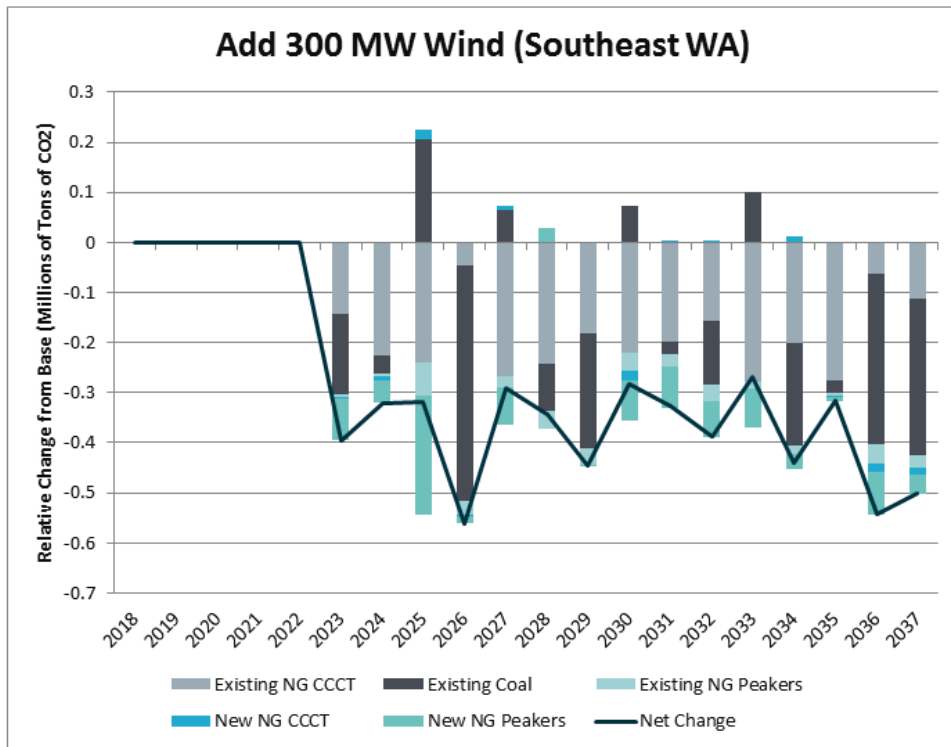




Figure N-140: Change in WECC Emissions by Resource Type
Carbon Abatement: CAR Cap on WA CCCT

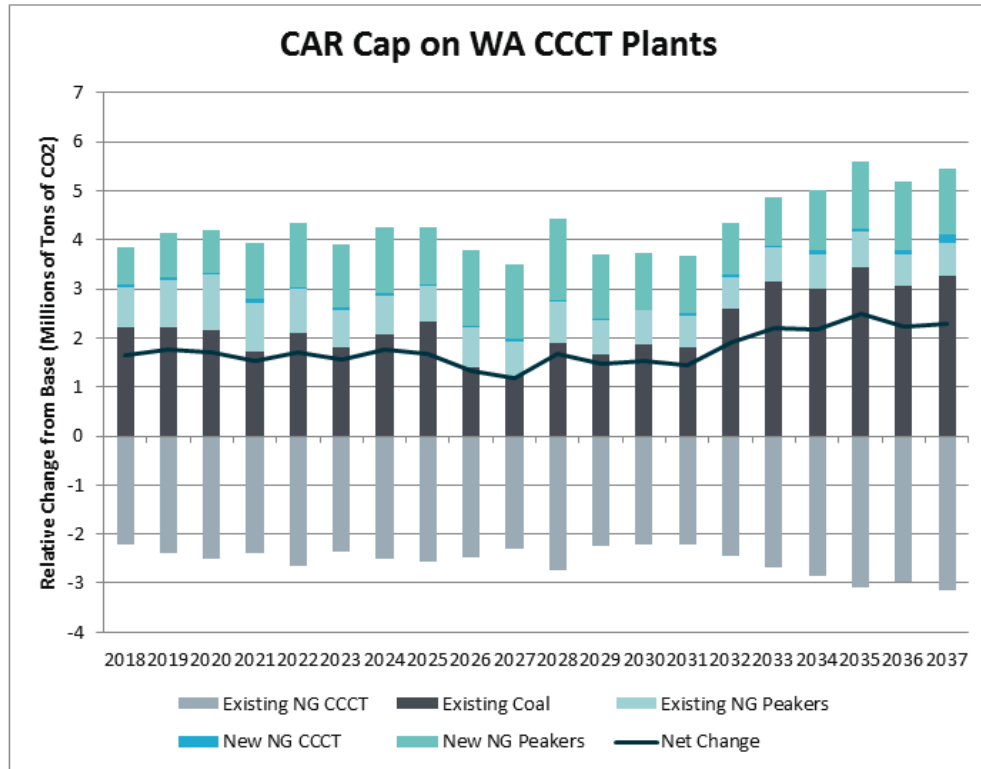




Figure N-141: Change in WECC Emissions by Resource Type
Carbon Abatement: Additional Conservation - Incremental

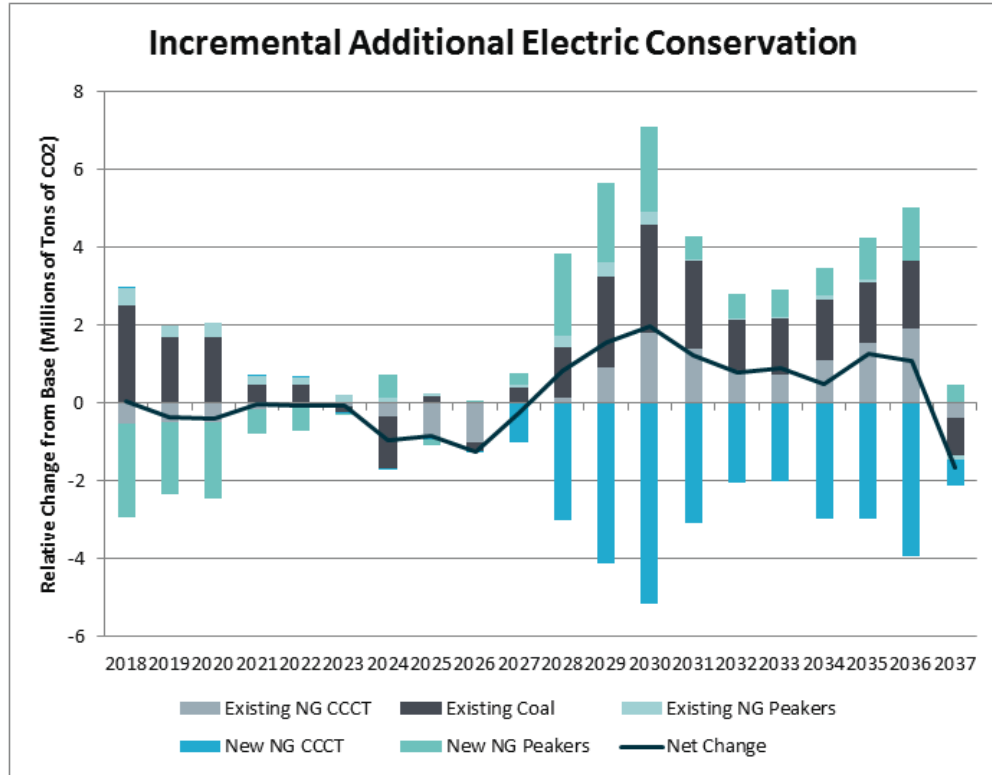




Figure N-142: Change in WECC Emissions by Resource Type
Carbon Abatement: Additional Conservation – All

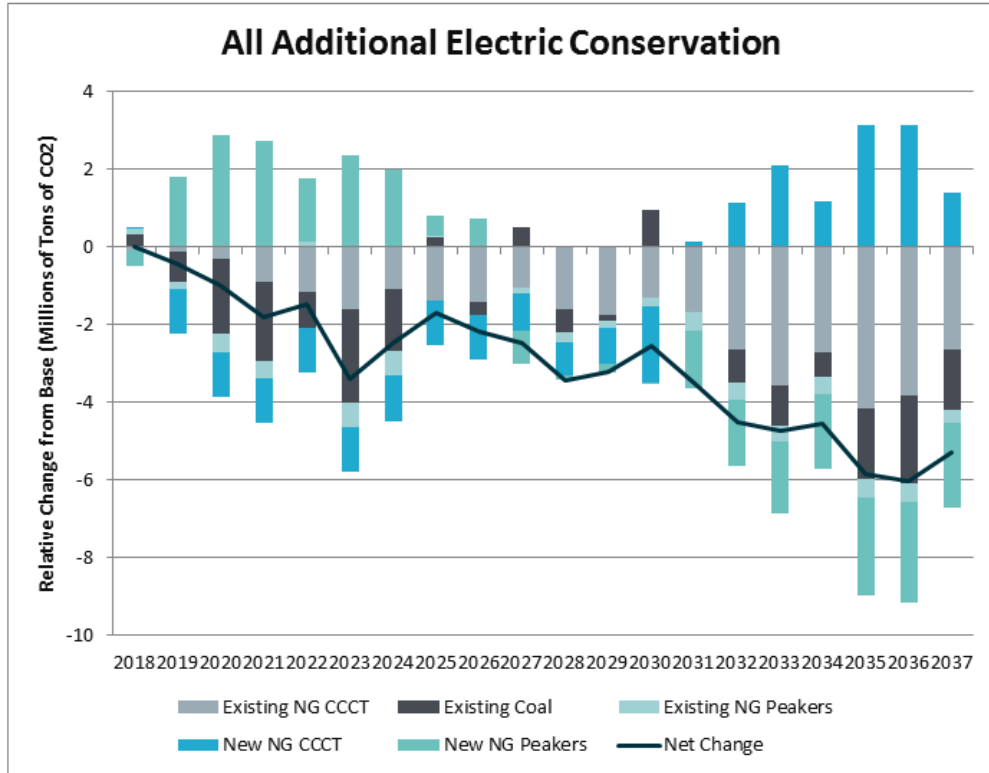
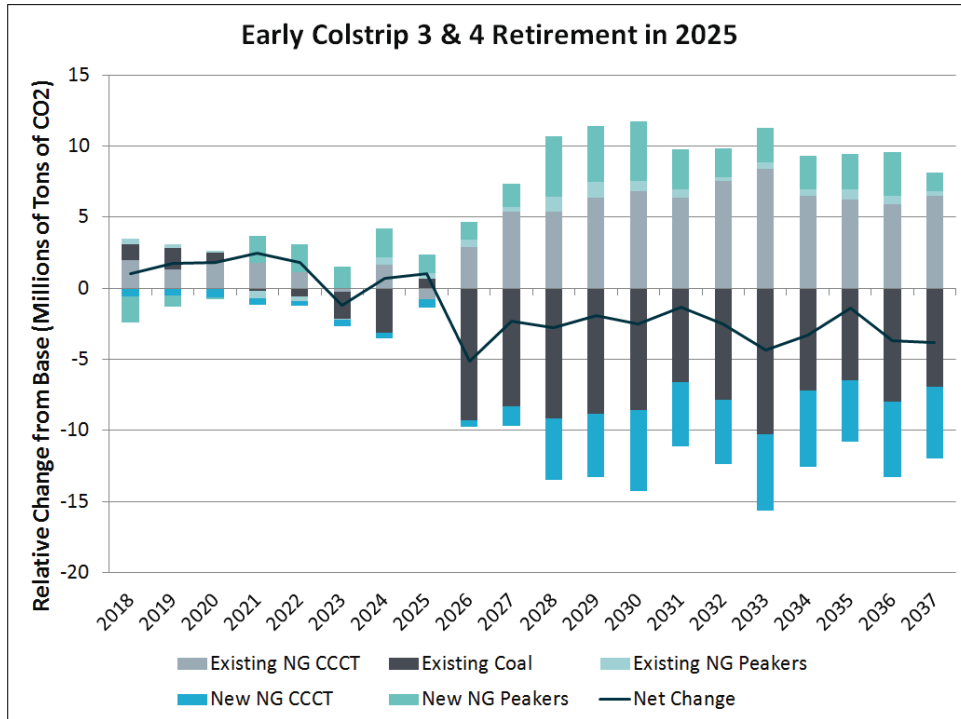




Figure N-143: Change in WECC Emissions by Resource Type

Carbon Abatement: Early Retirement of Colstrip 3 & 4





Gas Portfolio CO₂ Emissions – Carbon Abatement

Figure N-144: Total Portfolio CO₂ Emissions
Emission PSE Portfolio – Carbon Abatement Gas (Millions Tons)

| | Base No CO2 | Base No CO2 + 2 more DSR | Base No CO2 + all DSR |
|------|-------------|--------------------------|-----------------------|
| 2018 | 5.63 | 5.63 | 5.62 |
| 2019 | 5.68 | 5.68 | 5.65 |
| 2020 | 5.75 | 5.75 | 5.70 |
| 2021 | 5.77 | 5.77 | 5.70 |
| 2022 | 5.79 | 5.79 | 5.70 |
| 2023 | 5.85 | 5.85 | 5.74 |
| 2024 | 5.93 | 5.92 | 5.79 |
| 2025 | 5.94 | 5.93 | 5.78 |
| 2026 | 5.98 | 5.97 | 5.80 |
| 2027 | 6.01 | 6.00 | 5.81 |
| 2028 | 6.08 | 6.07 | 5.87 |
| 2029 | 6.13 | 6.12 | 5.90 |
| 2030 | 6.20 | 6.19 | 5.95 |
| 2031 | 6.27 | 6.26 | 6.01 |
| 2032 | 6.38 | 6.36 | 6.10 |
| 2033 | 6.42 | 6.41 | 6.14 |
| 2034 | 6.50 | 6.48 | 6.20 |
| 2035 | 6.58 | 6.57 | 6.28 |
| 2036 | 6.70 | 6.68 | 6.38 |
| 2037 | 6.76 | 6.74 | 6.43 |



9. INCREMENTAL COST OF RENEWABLE RESOURCES

According to RCW 19.285, certain electric utilities in Washington must meet 15 percent of their retail electric load with eligible renewable resources by the calendar year 2020. The annual target for the calendar year 2012 was 3 percent of retail electric load, and for 2016, it was 9 percent. However, if the incremental cost of those renewable resources compared to an equivalent non-renewable is greater than 4 percent of its revenue requirement, then a utility will be considered in compliance with the annual renewable energy target in RCW 19.285. The law states it this way: “The incremental cost of an eligible renewable resource is calculated as the difference between the levelized delivered cost of the eligible renewable resource, regardless of ownership, compared to the levelized delivered cost of an equivalent amount of reasonably available substitute resources that do not qualify as eligible renewable resources.”

Analytic Framework

This analysis compares the revenue requirement cost of each renewable resource with the projected market value and capacity value at the time of the renewable acquisition. There may be other approaches to calculating these costs – such as using variable costs from different kinds of thermal plants instead of market. However, PSE’s approach is most reasonable because it most closely reflects how customers will experience costs; i.e., PSE would not dispatch a peaker or CCCT with the ramping up and down of a wind farm without regard to whether the unit is being economically dispatched. For example, a peaker will not be economically dispatched often at all, so capacity from the thermal plant and energy from market is the closest match to actual incremental costs – and that is the point of this provision in the law – a to ensure customers don’t pay too much. This, “contemporaneous” with the decision-making aspect of PSE’s approach, is important. Utilities should be able to assess whether they will exceed the cost cap before an acquisition, without having to worry about ex-post adjustments that could change compliance status. The analytical framework here reflects a close approximation of the portfolio analysis used by PSE in resource planning, as well as in the evaluation of bids received in response to the company’s request for proposals (RFP).



“Eligible Renewable Resources”

Figure N-145: Resources that Meet RCW 19.285 Definition of Eligible Renewable Resources

| | Nameplate (MW) | Annual Energy (aMW) | Commercial Online Date | Market Price/Peaker Assumptions | Capacity Credit Assumption |
|----------------------|----------------|---------------------|------------------------|---------------------------------|----------------------------|
| Hopkins Ridge | 149.4 | 53.3 | Dec-05 | 2004 RFP | 20% |
| Wild Horse | 228.6 | 73.4 | Dec-06 | 2006 RFP | 17.20% |
| Klondike III | 50 | 18 | Dec-07 | 2006 RFP | 15.60% |
| Hopkins Infill | 7.2 | 2.4 | Dec-07 | 2007 IRP | 20% |
| Wild Horse Expansion | 44 | 10.5 | Dec-09 | 2007 IRP | 15% |
| Lower Snake River I | 342.7 | 102.5 | Apr-12 | 2010 Trends | 5% |
| Snoqualmie Upgrades | 6.1 | 3.9 | Mar-13 | 2009 Trends | 95% |
| Lower Baker Upgrades | 30 | 12.5 | May-13 | 2011 IRP Base | 95% |
| Generic Solar 2022 | 266 | 70.8 | Jan-22 | 2017 IRP Base | 0% |
| Generic Solar 2024 | 112 | 29.8 | Jan-24 | 2017 IRP Base | 0% |
| Generic Solar 2032 | 25 | 6.7 | Jan-32 | 2017 IRP Base | 0% |
| Generic Solar 2033 | 59 | 15.7 | Jan-33 | 2017 IRP Base | 0% |
| Generic Solar 2037 | 25 | 6.6 | Jan-37 | 2017 IRP Base | 0% |

Equivalent Non-renewable

The incremental cost of a renewable resource is defined as the difference between the levelized cost of the renewable resource compared to an equivalent non-renewable resource. An equivalent non-renewable is an energy resource that does not meet the definition of a renewable resource in RCW 19.285, but is equal to a renewable resource on an energy and capacity basis. For the purpose of this analysis, the cost of an equivalent non-renewable resource has three components:

1. **Capacity Cost:** There are two parts of capacity cost. First is the capacity in MW. This would be the nameplate for a firm resource like biomass, or the assumed capacity of a wind plant. Second is the \$/kW cost, which we assumed to be equal to the cost of a peaker.



2. **Energy Cost:** This was calculated by taking the hourly generation shape of the resource, multiplied by the market price in each hour. This is the equivalent cost of purchasing the equivalent energy on the market.
3. **Imputed Debt:** The law states the non-renewable must be an “equivalent amount,” which includes a time dimension. If PSE entered into a long-term contract for energy, there would be an element of imputed debt. Therefore, it is included in this analysis as a cost for the non-renewable equivalent.

For example, Hopkins Ridge produces 466,900 MWh annually. The equivalent non renewable is to purchase 466,900 MWh from the Mid-C market and then build a 30 MW (149.4*20 percent = 30) peaker plant for capacity only. With the example, the cost comparison includes the hourly Mid-C price plus the cost of building a peaker, plus the cost of the imputed debt. The total revenue requirement (fixed and variable costs) of the non-renewable is the cost stream – including end effects – discounted back to the first year. That net present value is then levelized over the life of the comparison renewable resource.

Cost of Renewable Resource

Levelized cost of the renewable resource is more direct. It is based on the proforma financial analysis performed at the time of the acquisition. The stream of revenue requirement (all fixed and variable costs, including integration costs) are discounted back to the first year – again, including end effects. That net present value is then levelized out over the life of the resource/contract. The levelized cost of the renewable resource is then compared with the levelized cost of the equivalent non-renewable resource to calculate the incremental cost.

The following is a detailed example of how PSE calculated the incremental cost of Wild Horse. It is important to note that PSE’s approach uses information contemporaneous with the decision making process, so this analysis will not reflect updated assumptions for capacity, capital cost, or integration costs, etc.

Eligible Renewable: Wild Horse Wind Facility

Capacity Contribution Assumption: $228.6 * 17.2\% = 39$ MW



1. Calculate Wild Horse revenue requirement.

Figure N-146 is a sample of the annual revenue requirement calculations for the first few years of Wild Horse, along with the NPV of revenue requirement.

Figure N-146: Calculation of Wild Horse Revenue Requirement

| (\$ Millions) | 20-yr NPV | 2007 | 2008 | ... | 2025 |
|-------------------------------------|------------|-------|-------|-----|-------|
| Gross Plant | | 384 | 384 | ... | 384 |
| Accumulative depreciation (Avg.) | | (10) | (29) | ... | (355) |
| Accumulative deferred tax (EOP) | | (20) | (56) | ... | (7) |
| Rate base | | 354 | 299 | ... | 22 |
| After tax WACC | | 7.01% | 7.01% | ... | 7.01% |
| After tax return | | 25 | 21 | ... | 2 |
| Grossed up return | | 38 | 32 | ... | 2 |
| PTC grossed up | | (20) | (20) | ... | - |
| Expenses | | 16 | 16 | ... | 22 |
| Book depreciation | | 19 | 19 | ... | 19 |
| Revenue required | 370.9 | 53 | 48 | ... | 44 |
| End effects | 4.6 | | | | |
| Total revenue requirement | 375 | | | | |



2. Calculate revenue requirement for equivalent non-renewable: Peaker capacity.

Capacity = 39 MW

Capital Cost of Capacity: \$462/KW

Figure N-147: Calculation of Peaker Revenue Requirement

| (\$ Millions) | 20-yr NPV | 2007 | 2008 | ... | 2025 |
|----------------------------------|-----------|-------|-------|-----|-------|
| Gross Plant | | 18 | 18 | ... | 18 |
| Accumulative depreciation (Avg.) | | (0) | (1) | ... | (10) |
| Accumulative deferred tax (EOP) | | (0) | (0) | ... | (3) |
| Rate base | | 18 | 17 | ... | 5 |
| After tax WACC | | 7.01% | 7.01% | ... | 7.01% |
| After tax return | | 1 | 1 | ... | 0 |
| Grossed up return | | 2 | 2 | ... | 0 |
| Expenses | | 1 | 1 | ... | 2 |
| Book depreciation | | 1 | 1 | ... | 1 |
| Revenue required | 32 | 4 | 4 | ... | 3 |
| End effects | 2 | | | | |
| Total revenue requirement | 34 | | | | |



3. Calculate revenue requirement for equivalent non-renewable: Energy

Energy: 642,814 MWh

For the market purchase, we used the hourly power prices from the 2006 RFP plus a transmission adder of \$1.65/MWh in 2007 and escalated at 2.5 percent.

Figure N-148:: Calculation of Energy Revenue Requirement

| Month | Day | Hour | 20-yr NPV | 2007 | ... | 2025 |
|----------------------------------|------|------|-----------|--------------------------|-----|--------------------------|
| 1 | 1 | 1 | | 49 MW * \$59/MW = \$2891 | ... | 49 MW * \$61/MW = \$2989 |
| 1 | 1 | 2 | | 92 MW * \$60/MW = \$5520 | ... | 92 MW * \$63/MW = \$5796 |
| ... | | ... | | ... | ... | ... |
| 12 | 31 | 24 | | 13 MW * \$59/MW = \$767 | ... | 13 MW * \$65/MW = \$845 |
| (\$Millions) | | | | | | |
| Cost of Market | | | | 36 | ... | 41 |
| Imputed Debt | | | | 1 | ... | 0 |
| Total Revenue Requirement | | | 285 | 37 | ... | 41 |



4. Incremental cost

The table below is the total cost of Wild Horse less the cost of the peaker and less the cost of the market purchases for the total 20-year incremental cost difference of the renewable to an equivalent non-renewable.

Figure N-149: 20-yr Incremental Cost of Wild Horse

| (\$ Millions) | 20-yr NPV |
|---|-----------|
| Wild Horse | 375 |
| Peaker | 34 |
| Market | 285 |
| 20-yr Incremental Cost of Wild Horse | 56 |

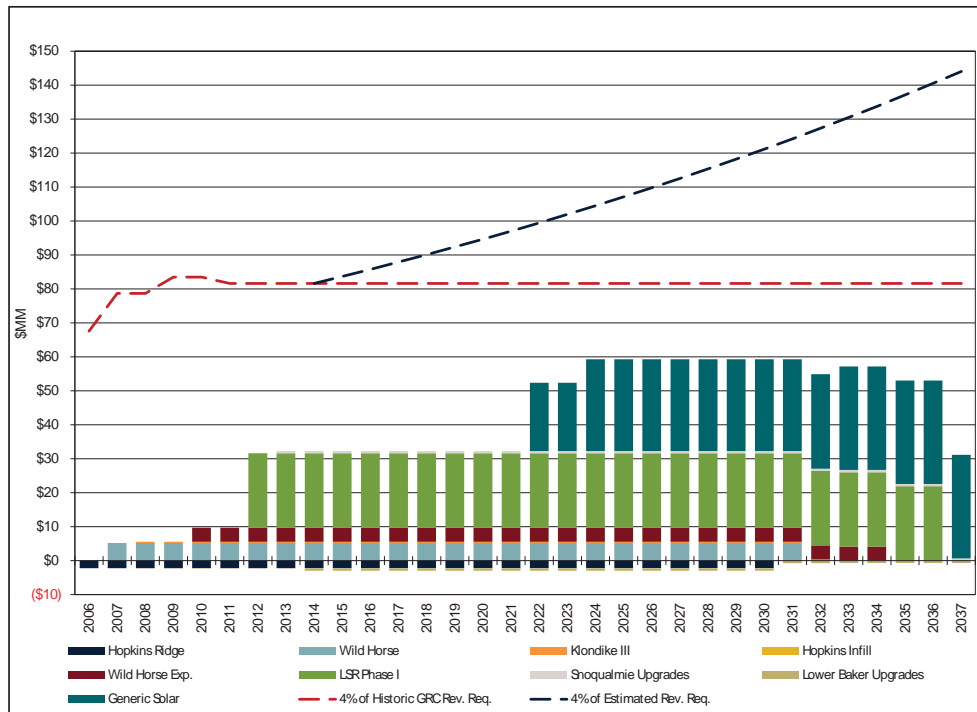
We chose to spread the incremental cost over 25 years since that is the depreciable life of a wind project used by PSE. The payment of \$56 Million over 25 years comes to \$5.2 Million per year using the 7.01 percent discount rate.



Summary Results

Each renewable resource that counts towards meeting the renewable energy target was compared to an equivalent non-renewable resource starting in the same year and leveled over the book life of the plant: 25 years for wind power and 40 years for hydroelectric power. Figure N-150 presents results of this analysis for existing resources and projected resources. This demonstrates PSE expects to meet the physical targets under RCW 19.285 without being constrained by the cost cap. A negative cost difference means that the renewable was lower-cost than the equivalent non-renewable, while a positive cost means that the renewable was a higher cost.

Figure N-150: Equivalent Non-renewable 20-year Levelized Cost Difference Compared to 4% of 2011 GRC Revenue Requirement + 2014 PCORC Adjustment



Appendix N: Electric Analysis



As the chart reveals, even if the company's revenue requirement were to stay the same for the next 10 years, PSE would still not hit the 4 percent requirement. The estimated revenue requirement uses a 2.5 percent assumed escalation from the company's current revenue requirement.



2017 PSE Integrated Resource Plan

Gas Analysis

This appendix presents details of the methods and model employed in PSE's gas sales resource analysis and the data produced by that analysis.

Contents

1. ANALYTICAL MODEL O-2
 - SENDOUT
 - Resource Alternative Assumptions
 - Scenarios and Sensitivities Analyzed
2. ANALYSIS RESULTS O-8
3. PORTFOLIO DELIVERED GAS COSTS O-39



1. ANALYTICAL MODEL

To model gas resources and alternatives for both long-term planning and gas resource acquisition activities, PSE uses a gas portfolio model (GPM). The GPM used in this IRP is SENDOUT[®] from ABB, a widely used software tool that helps identify the long-term least-cost combination of resources to meet stated loads. Other regional utilities that provide natural gas services, such as Avista, Cascade Natural Gas, and FortisBC, use the SENDOUT model. SENDOUT Version 14.3.0 was used for this analysis.

SENDOUT

SENDOUT is an integrated tool set for gas resource analysis that models the gas supply network and the portfolio of supply, storage, transportation and demand-side resources (DSR) to meet demand requirements.

SENDOUT can operate in two modes: For a defined planning period, it can determine the optimal set of resources to minimize costs; or, for a defined portfolio, it can determine the least-cost dispatch to meet demand requirements for that portfolio. SENDOUT solves both problems using a linear program (LP) to determine how a portfolio of resources (energy efficiency, supply, storage and transport), including associated costs and contractual or physical constraints, should be added and dispatched to meet demand in a least-cost fashion. The linear program considers thousands of variables and evaluates tens of thousands of possible solutions in order to generate a solution. A standard planning-period dispatch considers the capacity level of all resources as given, and therefore performs a variable-cost dispatch. A resource-mix dispatch can look at a range of potential capacity and size resources, including their fixed and variable costs.

Demand-side Resources (Energy Efficiency)

SENDOUT provides a comprehensive set of inputs to model a variety of energy efficiency programs. Costs can be modeled at an overall program level or broken down into a variety of detailed accounts. The impact of efficiency programs on load can be modeled at the same detail level as demand. SENDOUT has the ability to determine the most cost-effective size of energy efficiency programs on an integrated basis with supply-side alternatives in a long-run resource mix analysis.



Gas Supply

SENDOUT allows a system to be supplied by either long-term gas contracts or short-term spot market purchases. Specific physical and contractual constraints can be modeled on a daily, monthly, seasonal or annual basis, such as maximum flow levels and minimum flow percentages. SENDOUT uses standard gas contract costs; the rates may be changed on a monthly or daily basis.

Storage

SENDOUT allows storage sources (either leased or company-owned) to serve the system. Storage input data include the minimum or maximum inventory levels, minimum or maximum injection and withdrawal rates, injection and withdrawal fuel loss, to and from interconnects, and the period of activity (i.e., when the gas is available for injection or withdrawal). There is also the option to define and name volume-dependent injection and withdrawal percentage tables (ratchets), which can be applied to one or more storage sources.

Transportation

SENDOUT provides the means to model transportation segments to define flows, costs and fuel loss. Flow values include minimum and maximum daily quantities available for sale to gas markets or for release. Cost values include standard fixed and variable transportation rates, as well as a per-unit cost generated for released capacity. Seasonal transportation contracts can also be modeled.



Demand

SENDOUT allows the user to define multiple demand areas and it can compute a demand forecast by class based on weather. The demand input is segregated into two components: 1) base load, which is not weather dependent, and 2) heat load, which is weather dependent. Both factors are further computed as a function of customer counts. The heat load factor is estimated by dividing the remaining non-base portion of the load by historical monthly average heating degree days (HDD) and monthly forecasted customer counts to derive energy per HDD per customer. The demand is input into SENDOUT on a monthly basis and includes the customer forecast, the baseload factors and the heat load factors computed over the entire 20-year demand forecast period.

As discussed, the gas system load is dependent on the weather pattern. The 2017 IRP used the most recent 30 years of data ending in 2016 to estimate the historical normal HDDs for each month. This monthly average HDD was then used to find an actual month that most closely matches this average. (Using an actual month produces a better distribution of daily temperatures for the representative month than simply using daily average temperatures.) In this way, months were selected to match the monthly average HDDs and a 12-month weather year was constructed for use in the IRP study. Finally, the gas analysis uses a design day peak standard of 52 HDD.¹ This design peak day demand value is manually inserted into the historical peak month, which is December for this 2017 IRP.

¹ / The design day peak standard of 52 Heating Degree Days was established in PSE's 2005 IRP, Appendix I, Gas Planning Standard.



Resource Alternatives Assumptions

Figure O-1 summarizes resource costs and modeling assumptions for the pipeline alternatives considered in the IRP, and Figure O-2 summarizes resource costs and modeling assumptions for storage alternatives.

Figure O-1: Prospective Pipeline Alternatives Available

| Alternative | From/To | Capacity Demand (\$/Dth/Day) | Variable Commodity (\$/Dth) | Fuel Use (%) | Earliest Available | Comments |
|---|-----------------------------|------------------------------|-----------------------------|--------------|--------------------|---|
| Short Term NWP TF-1 | Sumas to PSE | 0.38 | 0.08 | 1.9 | Nov. 2018 | Potential available in marketplace from third parties from Nov. 2018-Nov. 2020. |
| Incremental NWP - Backhaul | I-5 to PSE | 0.28 | 0.08 | 1.9 | Nov. 2021 | Requires NWP Sumas South Expansion; Demand Charge Winter Only Rate |
| Westcoast + NWP Expansions | Station 2 to PSE | 0.52 + 0.56 | 0.05 + 0.08 | 1.6 + 1.9 | Nov. 2021 | Westcoast expansion coupled with NWP expansion |
| Fortis BC / Westcoast (KORP) + NWP Expansions | Kingsgate to PSE via Sumas | 0.42 + 0.56 | 0.05 + 0.08 | 1.6 + 1.9 | Nov. 2021 | Prospective projects & estimated project cost - Requires NGTL and Foothills |
| NGTL (Nova) Pipeline | AECO to Alberta / BC border | 0.16 | 0 | 0 | Nov. 2021 | Prospective projects & estimated project cost. |
| Foothills Pipeline | Alberta / BC Border | 0.097 | 0 | 1 | Nov. 2021 | Uncontracted capacity is available - Requires NGTL |
| GTN Pipeline | Kingsgate to Stanfield | 0.177 | 0.044 | 1.4 | Nov. 2021 | Uncontracted capacity is available - Requires NGTL and Foothills. |
| Cross Cascades | Stanfield to PSE | 0.8 | 0.005 | 2 | Nov. 2022 | Prospective project & estimated project cost - Requires GTN Backhaul or NGTL/Foothills/GTN. |
| GTN "Backhaul" | Malin to Stanfield | 0.21 | 0.005 | 0 | Nov. 2022 | Uncontracted capacity is available |
| Tacoma LNG Distribution Upgrade | Tacoma LNG to PSE | 0.23 | 0 | 0 | Nov. 2021 | Upgrade of the distribution system to connect the LNG plant to the PSE system |



Figure O-2: Prospective Storage Alternatives Available

| Alternative | Storage Capacity (MDth) | Maximum Withdrawal Capacity (MDth/day) | Days of Full Withdrawal (days) | Max. Injection Capacity (MDth/day) | Earliest Available | Comments |
|----------------|-------------------------|--|--------------------------------|------------------------------------|--------------------|---|
| Mist Expansion | 1,000 | 50 | 20 | 20 | Nov. 2022 | Prospective project, estimated size and costs, confidential |
| Swarr | 90 | 30 | 3 | - | Nov. 2018 | Existing plant requiring Upgrades |

Scenarios and Sensitivities Analyzed

Eleven scenarios were analyzed for the gas sales portfolio using the SENDOUT model. The assumptions used to create those scenarios are described in detail in Chapter 4, Key Analytical Assumptions, and summarized briefly below in Figure O-3.

Figure O-3: 2017 IRP Scenarios

| | Scenario Name | Gas Price | CO ₂ Price | Demand |
|----|---------------------------------------|-----------|-----------------------|--------|
| 1 | Low Scenario | Low | Low | Low |
| 2 | Base Scenario | Mid | Mid | Mid |
| 3 | High Scenario | High | High | High |
| 4 | High + Low Demand | High | High | Low |
| 5 | Base + Low Gas Price | Low | Mid | Mid |
| 6 | Base + High Gas Price | High | Mid | Mid |
| 7 | Base + Low Demand | Mid | Mid | Low |
| 8 | Base + High Demand | Mid | Mid | High |
| 9 | Base + Low Demand | Mid | None | Mid |
| 10 | Base + Low CAR CO ₂ price | Mid | Low | Mid |
| 11 | Base + High CAR CO ₂ price | Mid | High | Mid |



Four sensitivity analyses were also run through the SENDOUT model to isolate the effect a single resource has on the portfolio:

1. DEMAND SIDE RESOURCES

BASELINE: All cost-effective DSR per RCW 19.285.

SENSITIVITY > No DSR, all future resource needs met with supply-side resources.

2. ALTERNATE RESIDENTIAL CONSERVATION DISCOUNT RATE

BASELINE: All demand-side resources evaluated using the weighted average cost of capital (WACC) assigned to PSE.

SENSITIVITY > Evaluate residential DSR using an alternate discount rate. The WACC is still applied to the commercial and industrial energy efficiency measures.

3. RESOURCE ADDITION TIMING OPTIMIZATION

BASELINE: Swarr and LNG distribution expansions are built starting in 2019 and 2021 respectively, and offered every two years in the model.

SENSITIVITY > Swarr and LNG distribution expansions are allowed every year starting in 2019 and 2021 respectively.

4. ADDITIONAL GAS CONSERVATION

BASELINE: All cost-effective DSR per RCW 19.285.

SENSITIVITY > Add two more demand-side bundles above the cost-effective demand-side bundles chosen as cost-effective.



2. ANALYSIS RESULTS

The optimal portfolios of supply- and demand-side resources for each of the scenarios and sensitivities were identified using SENDOUT. The cumulative resources added in each of the gas sales scenarios for the winter periods 2018-19, 2022-23, 2026-27, 2030-31 and 2032-33 are shown in Figures O-4 through O-8. Graphs of the resource additions for each of the scenarios are shown in Figures O-9 thru O-18. Resource additions for the each of the two sensitivities are shown in Figures O-19 and O-20.

Figure O-4: Gas Sales Scenario Cumulative Resource Additions for 2021-22 (MDth/day)

| Peak Day Capacity MDth/day (2021-22) | Base | Low | High | High + Low Demand | Base + Low Gas | Base + High Gas | Base + Low Demand | Base + High Demand | Base + No CO2 | Base + Low CAR CO2 | Base + High CAR CO2 |
|--------------------------------------|-----------|----------|------------|-------------------|----------------|-----------------|-------------------|--------------------|---------------|--------------------|---------------------|
| NWP Additions + Westcoast | - | - | 88 | - | - | - | - | 75 | - | - | - |
| Short Term NWP | - | - | - | - | - | - | - | - | - | - | - |
| Cross Cascades - AECO | - | - | - | - | - | - | - | - | - | - | - |
| Cross Cascades - Malin | - | - | - | - | - | - | - | - | - | - | - |
| Swarr | - | - | 30 | - | - | - | - | 30 | - | - | - |
| LNG Distribution Upgrade | - | - | 16 | - | - | - | - | 16 | - | - | - |
| Mist | - | - | - | - | - | - | - | - | - | - | - |
| DSR (Incl Standard Bundle) | 14 | 8 | 19 | 15 | 14 | 15 | 8 | 17 | 8 | 8 | 15 |
| Total | 14 | 8 | 153 | 15 | 14 | 15 | 8 | 138 | 8 | 8 | 15 |

Appendix O: Gas Analysis



Figure O-5: Gas Sales Scenario Cumulative Resource Additions for 2025-26 (MDth/day)

| Peak Day Capacity MDth/day (2025-26) | Base | Low | High | High + Low Demand | Base + Low Gas | Base + High Gas | Base + Low Demand | Base + High Demand | Base + No CO2 | Base + Low CAR CO2 | Base + High CAR CO2 |
|--------------------------------------|-----------|-----------|------------|-------------------|----------------|-----------------|-------------------|--------------------|---------------|--------------------|---------------------|
| NWP Additions + Westcoast | - | - | 116 | - | - | - | - | 100 | 16 | 16 | - |
| Short Term NWP | - | - | - | - | - | - | - | - | - | - | - |
| Cross Cascades - AECO | - | - | - | - | - | - | - | 42 | - | - | - |
| Cross Cascades - Malin | - | - | 66 | - | - | - | - | 34 | - | - | - |
| Swarr | 30 | - | 30 | - | 30 | 30 | - | 30 | 30 | 30 | 30 |
| LNG Distribution Upgrade | - | - | 16 | - | - | - | - | 16 | - | - | - |
| Mist | - | - | - | - | - | - | - | - | - | - | - |
| DSR (Incl Standard Bundle) | 31 | 16 | 43 | 32 | 31 | 32 | 17 | 38 | 16 | 17 | 32 |
| Total | 61 | 16 | 271 | 32 | 61 | 62 | 17 | 260 | 62 | 63 | 62 |

Appendix O: Gas Analysis



Figure O-6: Gas Sales Scenario Cumulative Resource Additions for 2029-30 (MDth/day)

| Peak Day Capacity MDth/day (2029-30) | Base | Low | High | High + Low Demand | Base + Low Gas | Base + High Gas | Base + Low Demand | Base + High Demand | Base + No CO2 | Base + Low CAR CO2 | Base + High CAR CO2 |
|--------------------------------------|------------|-----------|------------|-------------------|----------------|-----------------|-------------------|--------------------|---------------|--------------------|---------------------|
| NWP Additions + Westcoast | 53 | - | 197 | - | 53 | 51 | - | 192 | 81 | 80 | 51 |
| Short Term NWP | - | - | - | - | - | - | - | - | - | - | - |
| Cross Cascades - AECO | - | - | - | - | - | - | - | 42 | - | - | - |
| Cross Cascades - Malin | - | - | 75 | - | - | - | - | 34 | - | - | - |
| Swarr | 30 | - | 30 | - | 30 | 30 | - | 30 | 30 | 30 | 30 |
| LNG Distribution Upgrade | 16 | - | 16 | - | 16 | 16 | - | 16 | 16 | 16 | 16 |
| Mist | - | - | - | - | - | - | - | - | - | - | - |
| DSR (Incl Standard Bundle) | 48 | 25 | 65 | 49 | 48 | 49 | 27 | 58 | 25 | 26 | 49 |
| Total | 147 | 25 | 383 | 49 | 147 | 146 | 27 | 372 | 152 | 152 | 146 |

Appendix O: Gas Analysis



Figure O-7: Gas Sales Scenario Cumulative Resource Additions for 2033-34 (MDth/day)

| Peak Day Capacity MDth/day (2033-34) | Base | Low | High | High + Low Demand | Base + Low Gas | Base + High Gas | Base + Low Demand | Base + High Demand | Base + No CO2 | Base + Low CAR CO2 | Base + High CAR CO2 |
|--------------------------------------|------------|-----------|------------|-------------------|----------------|-----------------|-------------------|--------------------|---------------|--------------------|---------------------|
| NWP Additions + Westcoast | 133 | - | 310 | - | 133 | 51 | - | 305 | 170 | 170 | 130 |
| Short Term NWP | - | - | - | - | - | - | - | - | - | - | - |
| Cross Cascades - AEEO | - | - | - | - | - | 83 | - | 42 | - | - | - |
| Cross Cascades - Malin | - | - | 75 | - | - | - | - | 34 | - | - | - |
| Swarr | 30 | - | 30 | - | 30 | 30 | - | 30 | 30 | 30 | 30 |
| LNG Distribution Upgrade | 16 | - | 16 | - | 16 | 16 | - | 16 | 16 | 16 | 16 |
| Mist | - | - | - | - | - | - | - | - | - | - | - |
| DSR (Incl Standard Bundle) | 65 | 35 | 85 | 67 | 66 | 67 | 37 | 77 | 35 | 36 | 67 |
| Total | 244 | 35 | 516 | 67 | 245 | 247 | 37 | 504 | 251 | 252 | 243 |

Appendix O: Gas Analysis



Figure O-8: Gas Sales Scenario Cumulative Resource Additions for 2037-38 (MDth/day)

| Peak Day Capacity MDth/day (2033-34) | Base | Low | High | High + Low Demand | Base + Low Gas | Base + High Gas | Base + Low Demand | Base + High Demand | Base + No CO2 | Base + Low CAR CO2 | Base + High CAR CO2 |
|--------------------------------------|------------|-----------|------------|-------------------|----------------|-----------------|-------------------|--------------------|---------------|--------------------|---------------------|
| NWP Additions + Westcoast | 133 | - | 310 | - | 133 | 51 | - | 305 | 170 | 170 | 130 |
| Short Term NWP | - | - | - | - | - | - | - | - | - | - | - |
| Cross Cascades - AECO | - | - | - | - | - | 83 | - | 42 | - | - | - |
| Cross Cascades - Malin | - | - | 75 | - | - | - | - | 34 | - | - | - |
| Swarr | 30 | - | 30 | - | 30 | 30 | - | 30 | 30 | 30 | 30 |
| LNG Distribution Upgrade | 16 | 16 | 16 | - | 16 | 16 | 16 | 16 | 16 | 16 | 16 |
| Mist | - | - | - | - | - | - | - | - | - | - | - |
| DSR (Incl Standard Bundle) | 82 | 44 | 103 | 84 | 82 | 84 | 46 | 95 | 44 | 46 | 84 |
| Total | 261 | 60 | 534 | 84 | 261 | 264 | 62 | 522 | 260 | 262 | 260 |



Figure O-9: Base Scenario Optimal Portfolio – Gas Sales

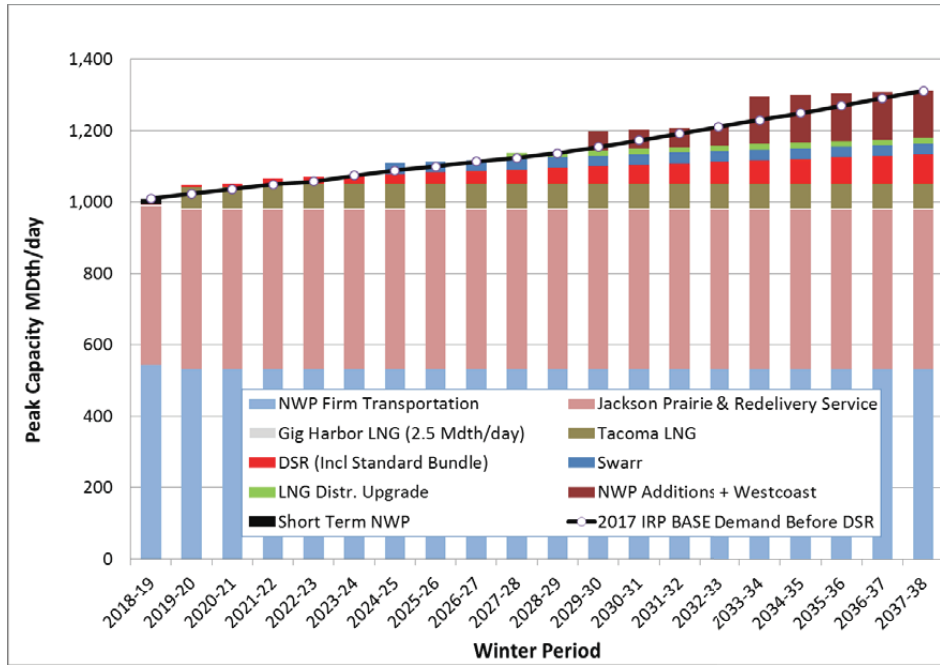




Figure O-10: Low Scenario Optimal Portfolio – Gas Sales

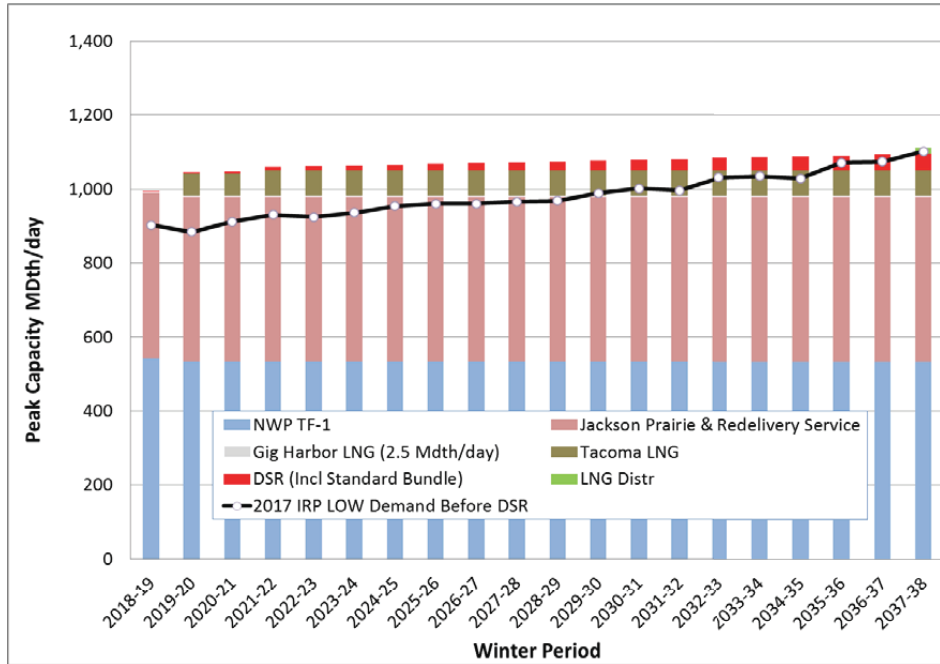




Figure O-11: High Scenario Optimal Portfolio – Gas Sales

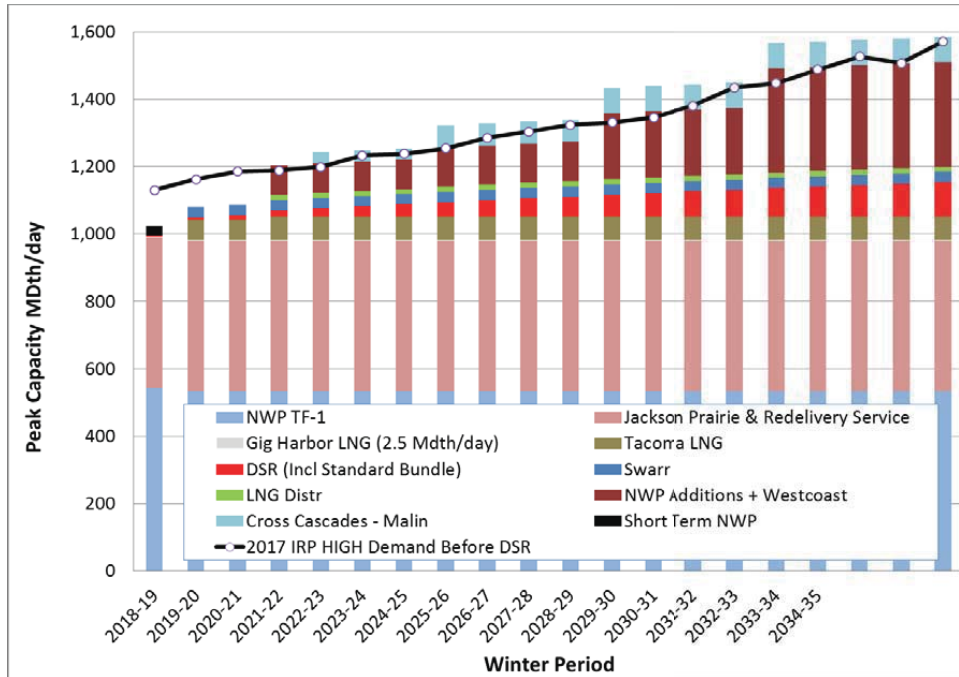




Figure O-12: High + Low Demand Optimal Portfolio – Gas Sales

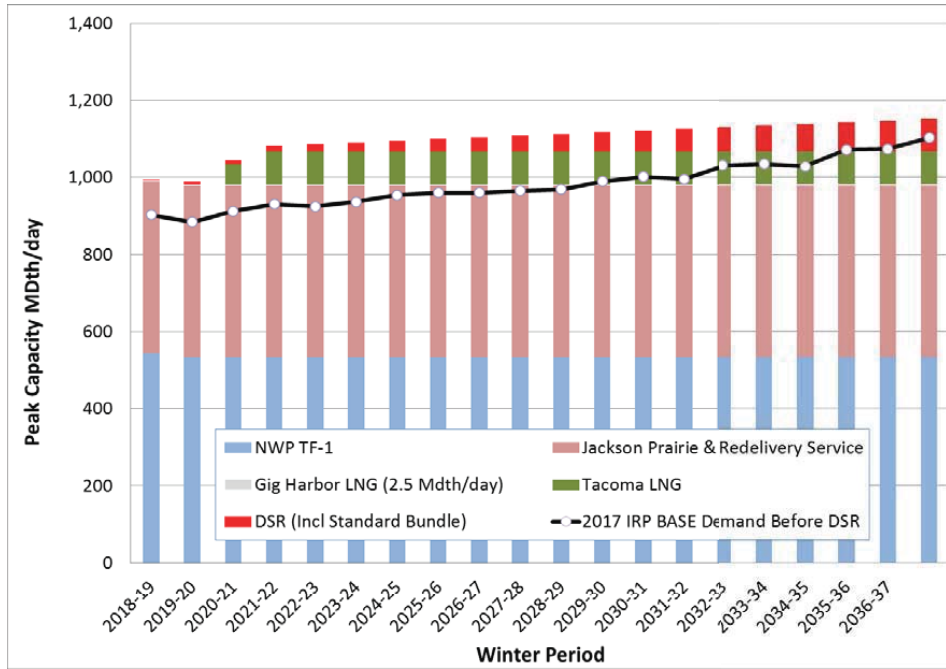




Figure O-13: Base + Low Gas Price Scenario Optimal Portfolio – Gas Sales

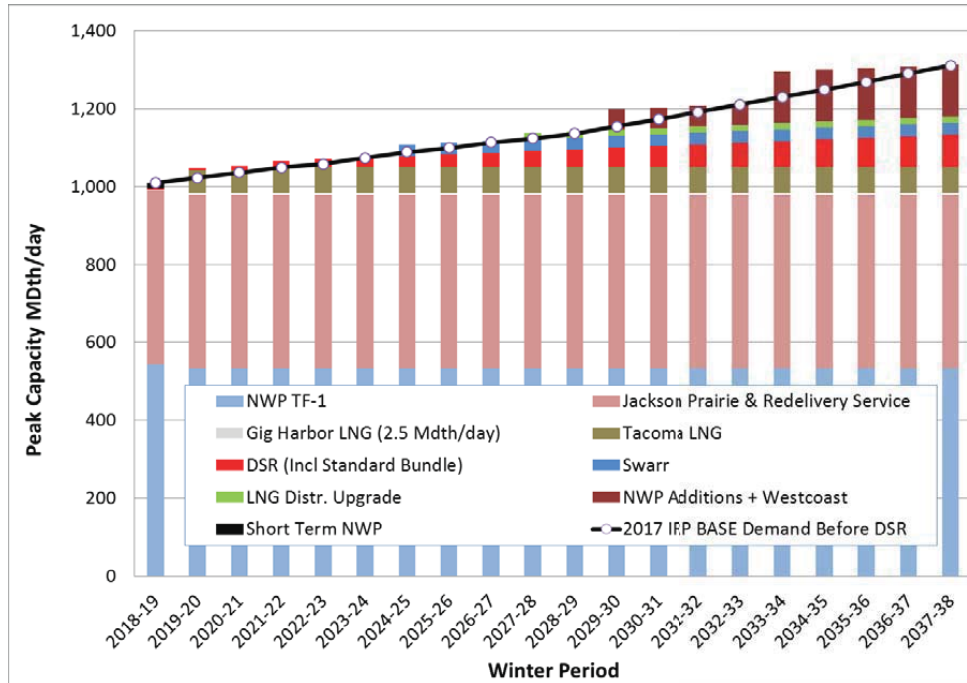




Figure O-14: Base + High Gas Price Optimal Portfolio – Gas Sales

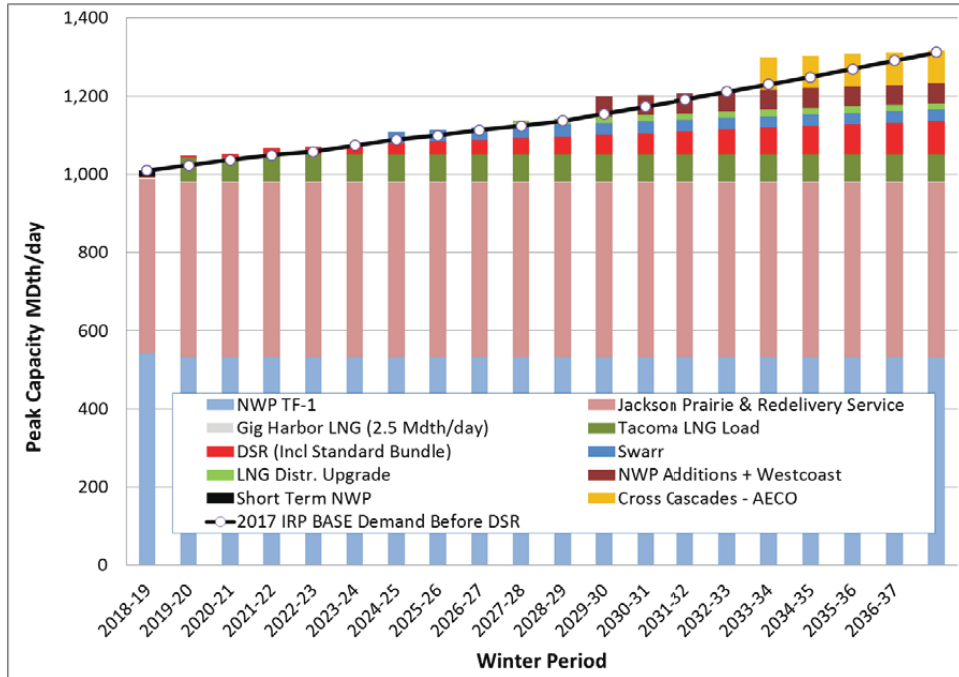




Figure O-15: Base + Low Demand Optimal Portfolio – Gas Sales

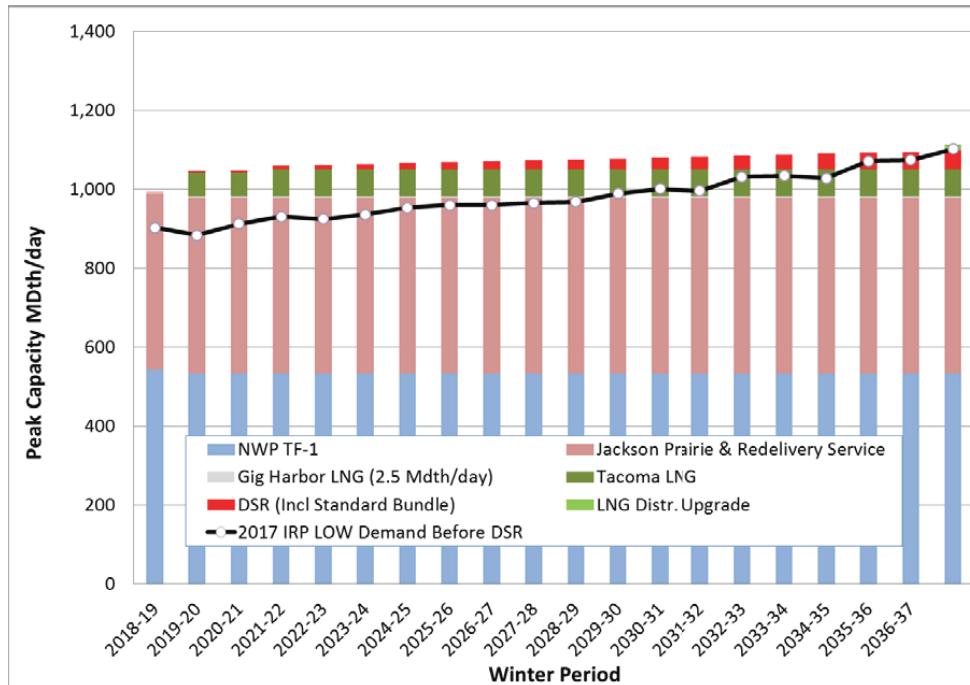




Figure O-16: Base + High Demand Optimal Portfolio – Gas Sales

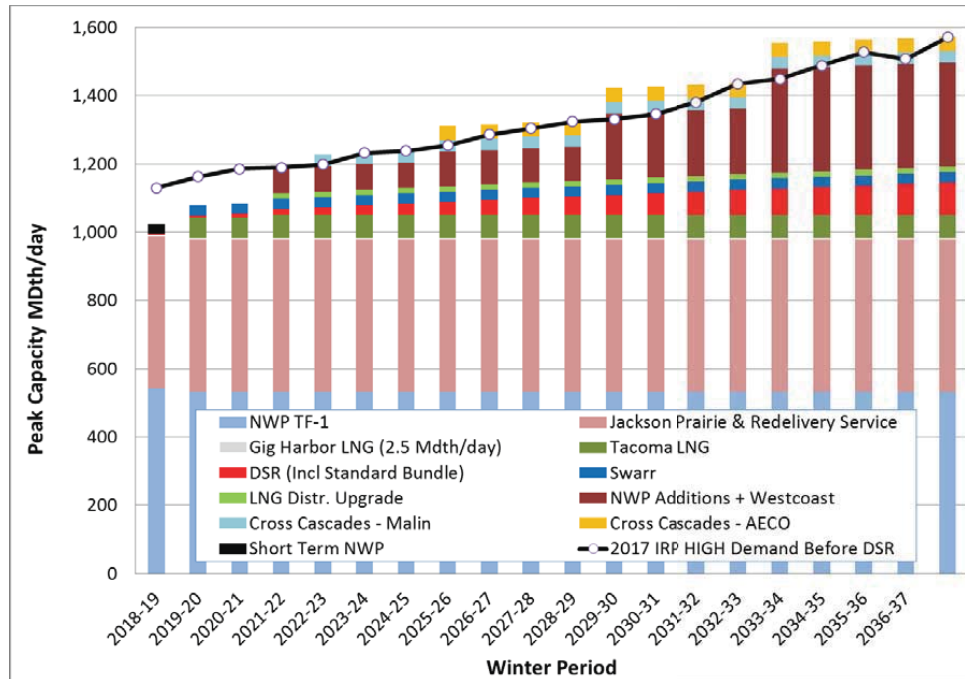




Figure O-17: Base + No CO₂ Optimal Portfolio – Gas Sales

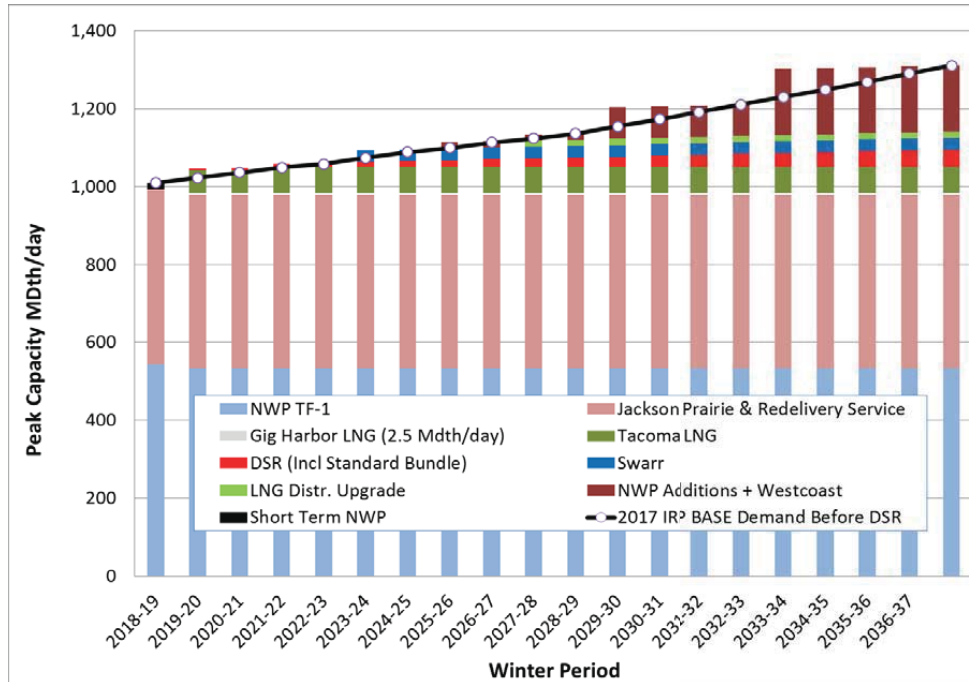




Figure O-18: Base + Low CAR CO₂ price Optimal Portfolio – Gas Sales

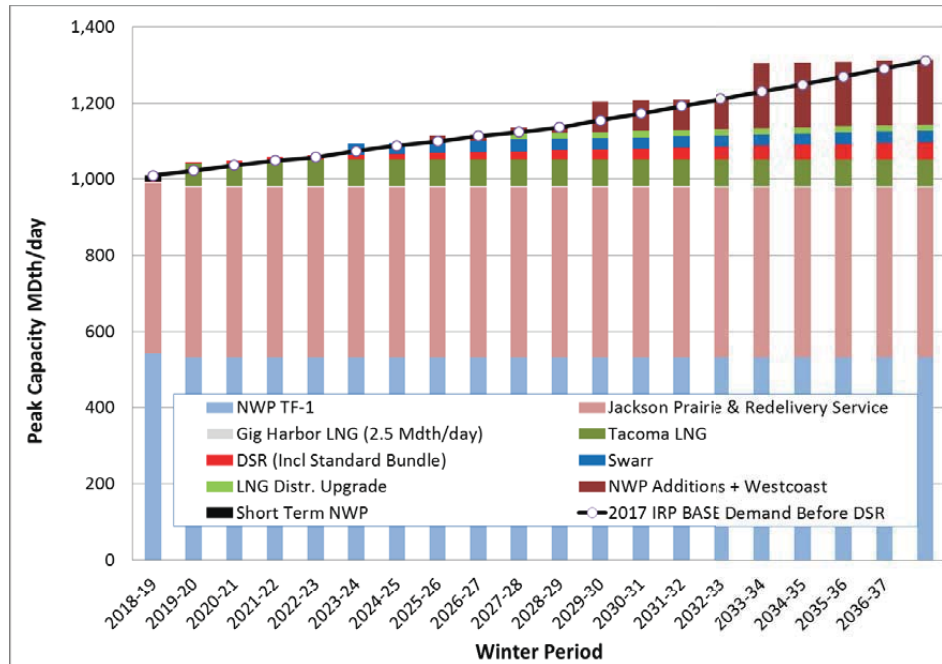




Figure O-19: Base + High CAR CO₂ price Optimal Portfolio – Gas Sales

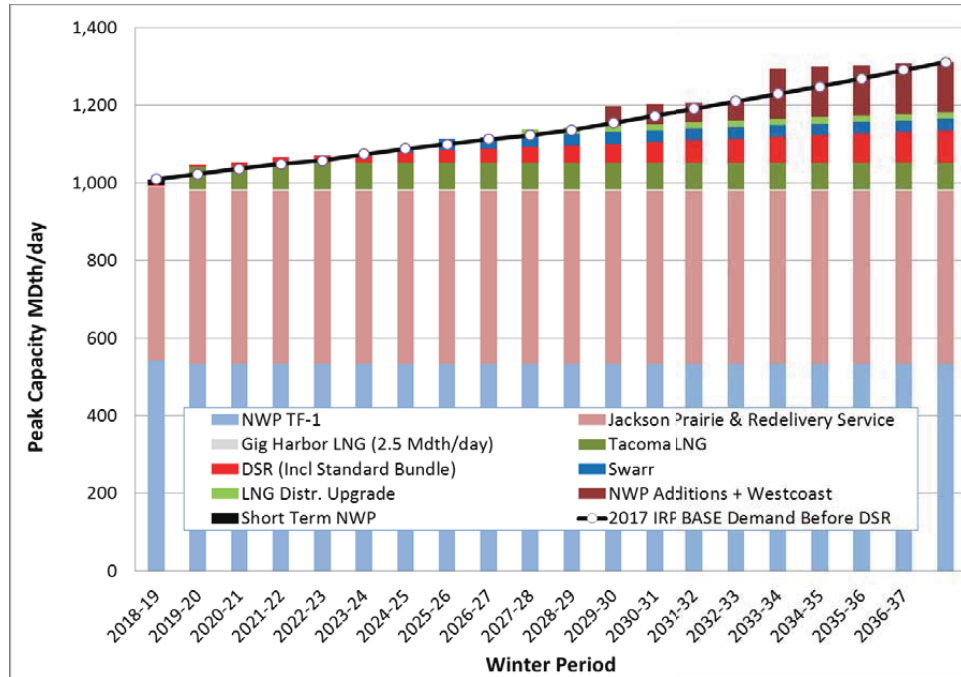




Figure O-20: Alternate Discount Rate Sensitivity
Gas Sales Cumulative Resource Additions (MDth/day)

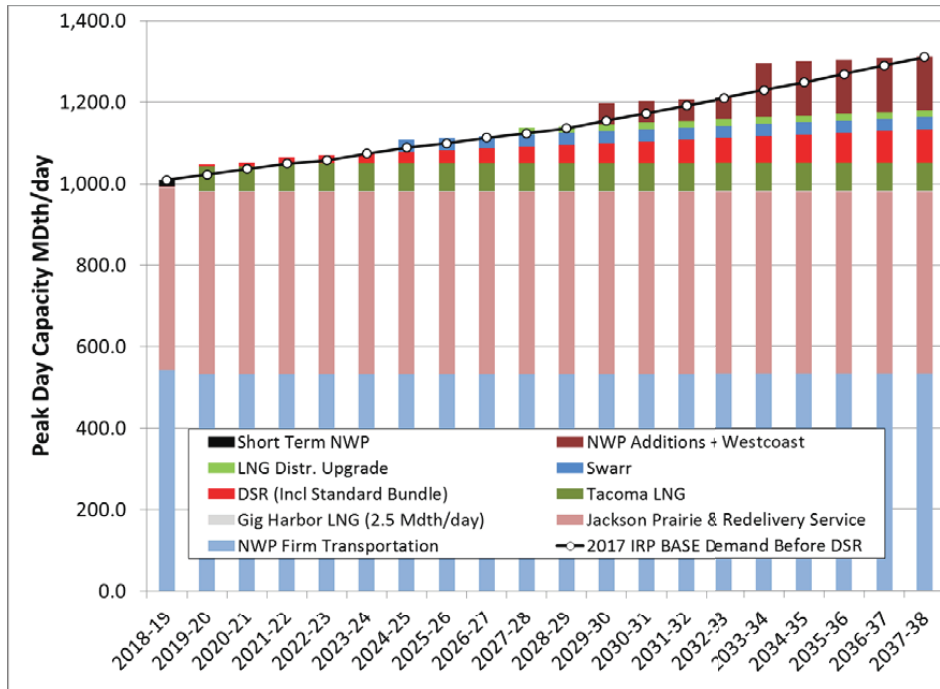




Figure O-21: PSE-controlled Resource Timing Sensitivity
Gas Sales Cumulative Resource Additions (MDth/day)

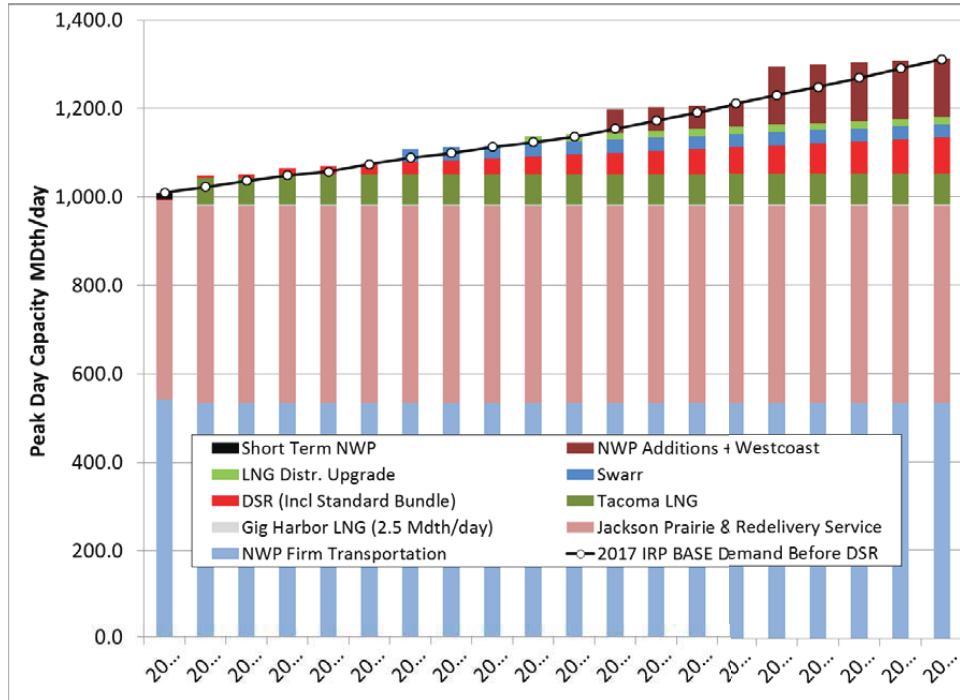




Figure O-22: Scenario Portfolio Capacity Expansion Results – Base (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | 15 | | | | | | 2 |
| 2019-20 | | | | | | | | 6 |
| 2020-21 | | | | | | | | 10 |
| 2021-22 | | | | | | | | 14 |
| 2022-23 | | | | | | | | 18 |
| 2023-24 | | | | | | | | 22 |
| 2024-25 | | | | | 30 | | | 27 |
| 2025-26 | | | | | 30 | | | 31 |
| 2026-27 | | | | | 30 | | | 35 |
| 2027-28 | | | | | 30 | 16 | | 40 |
| 2028-29 | | | | | 30 | 16 | | 44 |
| 2029-30 | 53 | | | | 30 | 16 | | 48 |
| 2030-31 | 53 | | | | 30 | 16 | | 52 |
| 2031-32 | 53 | | | | 30 | 16 | | 56 |
| 2032-33 | 53 | | | | 30 | 16 | | 61 |
| 2033-34 | 133 | | | | 30 | 16 | | 65 |
| 2034-35 | 133 | | | | 30 | 16 | | 69 |
| 2035-36 | 133 | | | | 30 | 16 | | 73 |
| 2036-37 | 133 | | | | 30 | 16 | | 78 |
| 2037-38 | 133 | | | | 30 | 16 | | 82 |

Appendix O: Gas Analysis



Figure O-23: Scenario Portfolio Capacity Expansion Results – Low (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|-----------|------|----------------------------|
| 2018-19 | | | | | | | | 1 |
| 2019-20 | | | | | | | | 3 |
| 2020-21 | | | | | | | | 6 |
| 2021-22 | | | | | | | | 8 |
| 2022-23 | | | | | | | | 10 |
| 2023-24 | | | | | | | | 12 |
| 2024-25 | | | | | | | | 14 |
| 2025-26 | | | | | | | | 16 |
| 2026-27 | | | | | | | | 19 |
| 2027-28 | | | | | | | | 21 |
| 2028-29 | | | | | | | | 23 |
| 2029-30 | | | | | | | | 25 |
| 2030-31 | | | | | | | | 28 |
| 2031-32 | | | | | | | | 30 |
| 2032-33 | | | | | | | | 33 |
| 2033-34 | | | | | | | | 35 |
| 2034-35 | | | | | | | | 37 |
| 2035-36 | | | | | | | | 39 |
| 2036-37 | | | | | | | | 42 |
| 2037-38 | | | | | | 16 | | 44 |

Appendix O: Gas Analysis



Figure O-24: Scenario Portfolio Capacity Expansion Results – High (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|-----------|------|----------------------------|
| 2018-19 | | 30 | | | | | | 3 |
| 2019-20 | | | | | 30 | | | 8 |
| 2020-21 | | | | | 30 | | | 14 |
| 2021-22 | 88 | | | | 30 | 16 | | 19 |
| 2022-23 | 88 | | | 33 | 30 | 16 | | 25 |
| 2023-24 | 88 | | | 33 | 30 | 16 | | 30 |
| 2024-25 | 88 | | | 33 | 30 | 16 | | 37 |
| 2025-26 | 116 | | | 66 | 30 | 16 | | 43 |
| 2026-27 | 116 | | | 66 | 30 | 16 | | 49 |
| 2027-28 | 116 | | | 66 | 30 | 16 | | 55 |
| 2028-29 | 116 | | | 66 | 30 | 16 | | 60 |
| 2029-30 | 197 | | | 75 | 30 | 16 | | 65 |
| 2030-31 | 197 | | | 75 | 30 | 16 | | 70 |
| 2031-32 | 197 | | | 75 | 30 | 16 | | 75 |
| 2032-33 | 197 | | | 75 | 30 | 16 | | 80 |
| 2033-34 | 310 | | | 75 | 30 | 16 | | 85 |
| 2034-35 | 310 | | | 75 | 30 | 16 | | 90 |
| 2035-36 | 310 | | | 75 | 30 | 16 | | 94 |
| 2036-37 | 310 | | | 75 | 30 | 16 | | 99 |
| 2037-38 | 310 | | | 75 | 30 | 16 | | 103 |

Appendix O: Gas Analysis



Figure O-25: Scenario Portfolio Capacity Expansion Results – High + Low Demand (MDth)

| Winter Period | NWP Additions + Westcoast | NWP + KORP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | PSE LNG Project | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|------------|-----------------------|------------------------|-------|-----------------|------|----------------------------|
| 2018-19 | | | | | | | | 2 |
| 2019-20 | | | | | | | | 6 |
| 2020-21 | | | | | | | | 11 |
| 2021-22 | | | | | | | | 15 |
| 2022-23 | | | | | | | | 19 |
| 2023-24 | | | | | | | | 23 |
| 2024-25 | | | | | | | | 27 |
| 2025-26 | | | | | | | | 32 |
| 2026-27 | | | | | | | | 37 |
| 2027-28 | | | | | | | | 41 |
| 2028-29 | | | | | | | | 45 |
| 2029-30 | | | | | | | | 49 |
| 2030-31 | | | | | | | | 54 |
| 2031-32 | | | | | | | | 58 |
| 2032-33 | | | | | | | | 63 |
| 2033-34 | | | | | | | | 67 |
| 2034-35 | | | | | | | | 72 |
| 2035-36 | | | | | | | | 76 |
| 2036-37 | | | | | | | | 80 |
| 2037-38 | | | | | | | | 84 |

Appendix O: Gas Analysis



Figure O-26: Scenario Portfolio Capacity Expansion Results – Base + Low Gas (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | 15 | | | | | | 2 |
| 2019-20 | | | | | | | | 6 |
| 2020-21 | | | | | | | | 10 |
| 2021-22 | | | | | | | | 14 |
| 2022-23 | | | | | | | | 19 |
| 2023-24 | | | | | | | | 23 |
| 2024-25 | | | | | 30 | | | 27 |
| 2025-26 | | | | | 30 | | | 31 |
| 2026-27 | | | | | 30 | | | 36 |
| 2027-28 | | | | | 30 | 16 | | 40 |
| 2028-29 | | | | | 30 | 16 | | 44 |
| 2029-30 | 53 | | | | 30 | 16 | | 48 |
| 2030-31 | 53 | | | | 30 | 16 | | 53 |
| 2031-32 | 53 | | | | 30 | 16 | | 57 |
| 2032-33 | 53 | | | | 30 | 16 | | 61 |
| 2033-34 | 133 | | | | 0 | 16 | | 66 |
| 2034-35 | 133 | | | | 0 | 16 | | 70 |
| 2035-36 | 133 | | | | 0 | 16 | | 74 |
| 2036-37 | 133 | | | | 0 | 16 | | 78 |
| 2037-38 | 133 | | | | 0 | 16 | | 82 |

Appendix O: Gas Analysis



Figure O-27: Scenario Portfolio Capacity Expansion Results – Base + High Gas (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | 15 | | | | | | 2 |
| 2019-20 | | | | | | | | 6 |
| 2020-21 | | | | | | | | 11 |
| 2021-22 | | | | | | | | 15 |
| 2022-23 | | | | | | | | 19 |
| 2023-24 | | | | | | | | 23 |
| 2024-25 | | | | | 30 | | | 27 |
| 2025-26 | | | | | 30 | | | 32 |
| 2026-27 | | | | | 30 | | | 37 |
| 2027-28 | | | | | 30 | 16 | | 41 |
| 2028-29 | | | | | 30 | 16 | | 45 |
| 2029-30 | 51 | | | | 30 | 16 | | 49 |
| 2030-31 | 51 | | | | 30 | 16 | | 54 |
| 2031-32 | 51 | | | | 30 | 16 | | 58 |
| 2032-33 | 51 | | | | 30 | 16 | | 63 |
| 2033-34 | 51 | | 83 | | 30 | 16 | | 67 |
| 2034-35 | 51 | | 83 | | 30 | 16 | | 72 |
| 2035-36 | 51 | | 83 | | 30 | 16 | | 76 |
| 2036-37 | 51 | | 83 | | 30 | 16 | | 80 |
| 2037-38 | 51 | | 83 | | 30 | 16 | | 84 |

Appendix O: Gas Analysis



Figure O-28: Scenario Portfolio Capacity Expansion Results – Base + Low Demand (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | | | | | | | 1 |
| 2019-20 | | | | | | | | 4 |
| 2020-21 | | | | | | | | 6 |
| 2021-22 | | | | | | | | 8 |
| 2022-23 | | | | | | | | 10 |
| 2023-24 | | | | | | | | 12 |
| 2024-25 | | | | | | | | 15 |
| 2025-26 | | | | | | | | 17 |
| 2026-27 | | | | | | | | 20 |
| 2027-28 | | | | | | | | 22 |
| 2028-29 | | | | | | | | 24 |
| 2029-30 | | | | | | | | 27 |
| 2030-31 | | | | | | | | 29 |
| 2031-32 | | | | | | | | 32 |
| 2032-33 | | | | | | | | 34 |
| 2033-34 | | | | | | | | 37 |
| 2034-35 | | | | | | | | 39 |
| 2035-36 | | | | | | | | 41 |
| 2036-37 | | | | | | | | 44 |
| 2037-38 | | | | | | 16 | | 46 |

Appendix O: Gas Analysis



Figure O-29: Scenario Portfolio Capacity Expansion Results – Base + High Demand (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | 30 | | | | | | 2 |
| 2019-20 | | | | | 30 | | | 7 |
| 2020-21 | | | | | 30 | | | 12 |
| 2021-22 | 75 | | | | 30 | 16 | | 17 |
| 2022-23 | 75 | | | 34 | 30 | 16 | | 22 |
| 2023-24 | 75 | | | 34 | 30 | 16 | | 27 |
| 2024-25 | 75 | | | 34 | 30 | 16 | | 32 |
| 2025-26 | 100 | | 42 | 34 | 30 | 16 | | 38 |
| 2026-27 | 100 | | 42 | 34 | 30 | 16 | | 43 |
| 2027-28 | 100 | | 42 | 34 | 30 | 16 | | 48 |
| 2028-29 | 100 | | 42 | 34 | 30 | 16 | | 53 |
| 2029-30 | 192 | | 42 | 34 | 30 | 16 | | 58 |
| 2030-31 | 192 | | 42 | 34 | 30 | 16 | | 63 |
| 2031-32 | 192 | | 42 | 34 | 30 | 16 | | 67 |
| 2032-33 | 192 | | 42 | 34 | 30 | 16 | | 72 |
| 2033-34 | 305 | | 42 | 34 | 30 | 16 | | 77 |
| 2034-35 | 305 | | 42 | 34 | 30 | 16 | | 81 |
| 2035-36 | 305 | | 42 | 34 | 30 | 16 | | 86 |
| 2036-37 | 305 | | 42 | 34 | 30 | 16 | | 90 |
| 2037-38 | 305 | | 42 | 34 | 30 | 16 | | 95 |

Appendix O: Gas Analysis



Figure O-30: Scenario Portfolio Capacity Expansion Results – Base + No CO₂ (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | 16 | | | | | | 1 |
| 2019-20 | | | | | | | | 3 |
| 2020-21 | | | | | | | | 6 |
| 2021-22 | | | | | | | | 8 |
| 2022-23 | | | | | | | | 10 |
| 2023-24 | | | | | 30 | | | 12 |
| 2024-25 | | | | | 30 | | | 14 |
| 2025-26 | 16 | | | | 30 | | | 16 |
| 2026-27 | 16 | | | | 30 | | | 19 |
| 2027-28 | 16 | | | | 30 | 16 | | 21 |
| 2028-29 | 16 | | | | 30 | 16 | | 23 |
| 2029-30 | 81 | | | | 30 | 16 | | 25 |
| 2030-31 | 81 | | | | 30 | 16 | | 28 |
| 2031-32 | 81 | | | | 30 | 16 | | 30 |
| 2032-33 | 81 | | | | 30 | 16 | | 33 |
| 2033-34 | 170 | | | | 30 | 16 | | 35 |
| 2034-35 | 170 | | | | 30 | 16 | | 37 |
| 2035-36 | 170 | | | | 30 | 16 | | 39 |
| 2036-37 | 170 | | | | 30 | 16 | | 42 |
| 2037-38 | 170 | | | | 30 | 16 | | 44 |

Appendix O: Gas Analysis



Figure O-31: Scenario Portfolio Capacity Expansion Results – Base + Low CAR CO₂ (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | 16 | | | | | | 1 |
| 2019-20 | | | | | | | | 3 |
| 2020-21 | | | | | | | | 6 |
| 2021-22 | | | | | | | | 8 |
| 2022-23 | | | | | | | | 10 |
| 2023-24 | | | | | 30 | | | 12 |
| 2024-25 | | | | | 30 | | | 15 |
| 2025-26 | 16 | | | | 30 | | | 17 |
| 2026-27 | 16 | | | | 30 | | | 20 |
| 2027-28 | 16 | | | | 30 | 16 | | 22 |
| 2028-29 | 16 | | | | 30 | 16 | | 24 |
| 2029-30 | 80 | | | | 30 | 16 | | 26 |
| 2030-31 | 80 | | | | 30 | 16 | | 29 |
| 2031-32 | 80 | | | | 30 | 16 | | 31 |
| 2032-33 | 80 | | | | 30 | 16 | | 34 |
| 2033-34 | 170 | | | | 30 | 16 | | 36 |
| 2034-35 | 170 | | | | 30 | 16 | | 39 |
| 2035-36 | 170 | | | | 30 | 16 | | 41 |
| 2036-37 | 170 | | | | 30 | 16 | | 44 |
| 2037-38 | 170 | | | | 30 | 16 | | 46 |

Appendix O: Gas Analysis



Figure O-32: Scenario Portfolio Capacity Expansion Results – Base + High CAR CO₂ (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | 15 | | | | | | 2 |
| 2019-20 | | | | | | | | 6 |
| 2020-21 | | | | | | | | 11 |
| 2021-22 | | | | | | | | 15 |
| 2022-23 | | | | | | | | 19 |
| 2023-24 | | | | | | | | 23 |
| 2024-25 | | | | | 30 | | | 27 |
| 2025-26 | | | | | 30 | | | 32 |
| 2026-27 | | | | | 30 | | | 37 |
| 2027-28 | | | | | 30 | 16 | | 41 |
| 2028-29 | | | | | 30 | 16 | | 45 |
| 2029-30 | 51 | | | | 30 | 16 | | 49 |
| 2030-31 | 51 | | | | 30 | 16 | | 54 |
| 2031-32 | 51 | | | | 30 | 16 | | 58 |
| 2032-33 | 51 | | | | 30 | 16 | | 63 |
| 2033-34 | 130 | | | | 30 | 16 | | 67 |
| 2034-35 | 130 | | | | 30 | 16 | | 72 |
| 2035-36 | 130 | | | | 30 | 16 | | 76 |
| 2036-37 | 130 | | | | 30 | 16 | | 80 |
| 2037-38 | 130 | | | | 30 | 16 | | 84 |



Figure O-33: Scenario Portfolio Capacity Expansion Results –
Alternate Discount Rate Sensitivity (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | 15 | | | | | | 2 |
| 2019-20 | | | | | | | | 6 |
| 2020-21 | | | | | | | | 10 |
| 2021-22 | | | | | | | | 14 |
| 2022-23 | | | | | | | | 18 |
| 2023-24 | | | | | | | | 22 |
| 2024-25 | | | | | 30 | | | 27 |
| 2025-26 | | | | | 30 | | | 31 |
| 2026-27 | | | | | 30 | | | 35 |
| 2027-28 | | | | | 30 | 16 | | 40 |
| 2028-29 | | | | | 30 | 16 | | 44 |
| 2029-30 | 53 | | | | 30 | 16 | | 48 |
| 2030-31 | 53 | | | | 30 | 16 | | 52 |
| 2031-32 | 53 | | | | 30 | 16 | | 56 |
| 2032-33 | 53 | | | | 30 | 16 | | 61 |
| 2033-34 | 133 | | | | 30 | 16 | | 65 |
| 2034-35 | 133 | | | | 30 | 16 | | 69 |
| 2035-36 | 133 | | | | 30 | 16 | | 73 |
| 2036-37 | 133 | | | | 30 | 16 | | 78 |
| 2037-38 | 133 | | | | 30 | 16 | | 82 |



Figure O-34: Scenario Portfolio Capacity Expansion Results –
Timing Sensitivity for LNG Distribution (MDth)

| Winter Period | NWP Additions + Westcoast | Short Term NWP | Cross Cascades - AECO | Cross Cascades - Malin | Swarr | LNG Distr. Upgrade | Mist | DSR (Incl Standard Bundle) |
|---------------|---------------------------|----------------|-----------------------|------------------------|-------|--------------------|------|----------------------------|
| 2018-19 | | 15 | | | | | | 2 |
| 2019-20 | | | | | | | | 6 |
| 2020-21 | | | | | | | | 10 |
| 2021-22 | | | | | | | | 14 |
| 2022-23 | | | | | | | | 18 |
| 2023-24 | | | | | | | | 22 |
| 2024-25 | | | | | 30 | | | 27 |
| 2025-26 | | | | | 30 | | | 31 |
| 2026-27 | | | | | 30 | | | 35 |
| 2027-28 | | | | | 30 | 16 | | 40 |
| 2028-29 | | | | | 30 | 16 | | 44 |
| 2029-30 | 53 | | | | 30 | 16 | | 48 |
| 2030-31 | 53 | | | | 30 | 16 | | 52 |
| 2031-32 | 53 | | | | 30 | 16 | | 56 |
| 2032-33 | 53 | | | | 30 | 16 | | 61 |
| 2033-34 | 133 | | | | 30 | 16 | | 65 |
| 2034-35 | 133 | | | | 30 | 16 | | 69 |
| 2035-36 | 133 | | | | 30 | 16 | | 73 |
| 2036-37 | 133 | | | | 30 | 16 | | 78 |
| 2037-38 | 133 | | | | 30 | 16 | | 82 |



3. PORTFOLIO DELIVERED GAS COSTS

The average delivered portfolio cost for the gas sales scenarios are shown graphically in Chapter 7. They are presented below in tabular form in Figure O-22. Note however, these costs represent the cost of gas delivered to PSE's system; they do not include distribution system costs.

Figure O-35: Portfolio Delivered Gas Costs (\$/Dth)

| Year | Base | Low | High | High + Low Demand | Base + Low Gas | Base + High Gas | Base + Low Demand | Base + High Demand | Base + No CO2 | Base + Low CAR CO2 | Base + High CAR CO2 |
|------|------|------|------|-------------------|----------------|-----------------|-------------------|--------------------|---------------|--------------------|---------------------|
| 2018 | 6.2 | 5.7 | 13.2 | 13.8 | 6.5 | 8.5 | 6.3 | 6.0 | 4.2 | 5.2 | 10.9 |
| 2019 | 6.0 | 5.5 | 12.9 | 13.2 | 6.5 | 8.8 | 6.2 | 5.8 | 4.0 | 4.8 | 10.4 |
| 2020 | 6.1 | 5.3 | 13.6 | 13.8 | 6.2 | 9.3 | 6.3 | 5.9 | 3.9 | 4.9 | 10.4 |
| 2021 | 6.3 | 5.6 | 13.5 | 13.7 | 6.7 | 9.5 | 6.5 | 6.2 | 4.1 | 5.2 | 10.5 |
| 2022 | 6.7 | 5.9 | 13.6 | 13.7 | 7.1 | 9.4 | 6.9 | 6.7 | 4.2 | 5.3 | 10.6 |
| 2023 | 6.9 | 6.2 | 13.8 | 13.8 | 7.3 | 9.9 | 7.5 | 7.2 | 4.5 | 5.7 | 11.0 |
| 2024 | 7.7 | 6.7 | 14.4 | 14.6 | 8.0 | 10.4 | 8.1 | 7.9 | 4.8 | 6.2 | 11.2 |
| 2025 | 8.1 | 6.9 | 14.3 | 14.2 | 8.1 | 11.1 | 8.4 | 8.3 | 5.1 | 6.5 | 11.6 |
| 2026 | 8.6 | 7.4 | 15.8 | 15.7 | 8.9 | 12.2 | 8.9 | 8.9 | 5.5 | 7.0 | 11.9 |
| 2027 | 9.2 | 7.8 | 16.0 | 15.8 | 9.5 | 12.4 | 9.6 | 9.5 | 5.9 | 7.3 | 12.2 |
| 2028 | 9.7 | 8.4 | 16.1 | 15.9 | 10.0 | 13.1 | 10.1 | 10.0 | 6.1 | 7.9 | 12.5 |
| 2029 | 10.3 | 8.4 | 16.3 | 16.1 | 10.3 | 13.3 | 10.7 | 10.5 | 6.5 | 8.2 | 12.8 |
| 2030 | 10.9 | 8.8 | 16.7 | 16.4 | 11.0 | 14.1 | 10.9 | 11.1 | 6.7 | 8.6 | 13.2 |
| 2031 | 11.4 | 9.1 | 16.9 | 16.8 | 11.2 | 14.7 | 11.7 | 11.7 | 7.0 | 9.1 | 13.4 |
| 2032 | 12.0 | 9.2 | 16.9 | 16.7 | 11.7 | 14.9 | 12.3 | 12.3 | 7.3 | 9.5 | 13.7 |
| 2033 | 12.3 | 9.3 | 17.3 | 17.0 | 11.9 | 15.5 | 12.9 | 12.8 | 7.5 | 9.8 | 13.9 |
| 2034 | 13.2 | 10.0 | 17.9 | 17.5 | 13.0 | 16.5 | 13.4 | 13.3 | 7.7 | 10.2 | 14.1 |
| 2035 | 13.6 | 10.2 | 18.3 | 17.7 | 13.6 | 17.3 | 14.1 | 14.1 | 8.1 | 10.8 | 14.5 |
| 2036 | 14.4 | 10.7 | 18.7 | 18.2 | 14.1 | 18.1 | 14.7 | 14.7 | 8.2 | 11.1 | 14.6 |
| 2037 | 14.9 | 11.1 | 18.9 | 18.2 | 14.4 | 18.4 | 15.1 | 15.2 | 8.4 | 11.5 | 14.8 |



P

2017 PSE Integrated Resource Plan

Gas-fired Resource Costs

The attached report developed for PSE by Black & Veatch presents generic order-of-magnitude cost and performance estimates and other plant characteristics for natural gas-fired power plant options.

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- A. Full Thermal Performance Estimates for Supply-side Options
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 - F. Wartsila Recommended Maintenance Intervals

FINAL REPORT

CHARACTERIZATION OF SUPPLY SIDE OPTIONS

Natural Gas-Fired Options

B&V PROJECT NO. 192143
B&V FILE NO. 40.1100

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PREPARED FOR



Puget Sound Energy

12 JANUARY 2017



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1.0 Introduction

Puget Sound Energy (PSE) is currently developing information that will be used to complete the next iteration of the company's Integrated Resource Plan (IRP). PSE has tasked Black & Veatch to characterize current, competitive natural gas-fired power plant options. These options will be considered as supply-side options (SSOs) within the upcoming IRP.

1.1 BACKGROUND

In 2012 on behalf of PSE, Black & Veatch developed the 2012 Gas-Fired Power Plant Characteristics report, which presented generic order-of-magnitude cost and performance estimates and other plant characteristics for natural gas-fired power plant options. The 2012 report was updated by Black & Veatch in 2014. In 2016, PSE has again requested that Black & Veatch provide current characteristics for relevant SSOs to be considered in the current IRP process.

1.2 OBJECTIVE

The objective of this report is to provide a general overview of the commercially available baseload and peaking gas-fired SSOs. This overview includes order-of-magnitude estimates of performance and cost for Greenfield installations as well as peaking unit additions at an existing PSE generating facility.

1.3 APPROACH

As with prior reports, the information and data presented herein are intended to be preliminary, screening-level characteristics suitable for the initial evaluation of multiple SSOs. In the event that a particular SSO is deemed cost-competitive or selected for further investigation, these estimates may be refined in subsequent stages of planning and development.

The screening-level performance and cost estimates have been developed based on experience with similar generation options, including both recent studies and recent project installations executed by Black & Veatch. Where applicable, Black & Veatch has incorporated recent performance and cost data provided by major equipment Original Equipment Manufacturers (OEMs). This information has been adjusted using engineering judgment to provide values that are considered representative for potential projects that may be implemented by PSE within its service territory.

1.4 REPORT ORGANIZATION

Following this Introduction, this report is organized as follows:

- Section 2.0 – Study Basis and General Assumptions
- Section 3.0 – Gas-Fired Generation Option Descriptions
- Section 4.0 – Summary of Performance and Emission Estimates
- Section 5.0 – Summary of Capital and O&M Cost Estimates

- Appendix A – Full Thermal Performance Estimates for Supply-Side Options
- Appendix B – Air-Cooled Design Considerations
- Appendix C – Supplemental HRSG Duct Firing
- Appendix D – Peaking Plant Backup Fuel
- Appendix E – Capital and O&M Cost Estimates for Brownfield Projects
- Appendix F – Wartsila Recommended Maintenance Intervals

2.0 Study Basis and General Assumptions

In support of its current IRP effort, PSE has selected to characterize eight gas-fired SSOs, including two (2) combined cycle options and six (6) simple cycle options. Combined cycle options would operate as Baseload units, while simple cycle options would operate as Peaking units.

Combined cycle options selected for consideration by PSE include:

- **Combined Cycle A:** GE 7F.05 combustion turbine generator (CTG) in a 1x1 configuration
- **Combined Cycle B:** GE 7HA.01 CTG in a 1x1 configuration

Simple cycle options selected for consideration by PSE include:

- **Peaking Plant A:** Wartsila 18V50SG reciprocating internal combustion engine (RICE) in a 3x0 configuration
- **Peaking Plant B:** Wartsila 18V50SG RICE in a 6x0 configuration
- **Peaking Plant C:** Wartsila 18V50SG RICE in a 12x0 configuration
- **Peaking Plant D:** GE LMS100PA+ CTG in a 1x0 configuration
- **Peaking Plant E:** GE LMS100PA+ CTG in a 2x0 configuration
- **Peaking Plant F:** GE 7F.05 CTG in a 1x0 configuration

The options are similar to combined cycle and peaking plant options characterized in 2014. Combined cycle options (Combined Cycles A and B) utilize current, commercial large frame CTGs as the prime mover for the facility. Peaking plant options include facilities employing reciprocating engines (Peaking Plants A, B and C), aeroderivative CTGs (Peaking Plants D and E); and large frame CTGs (Peaking Plant F).

The selected gas turbine SSOs are assumed to employ turbines supplied by General Electric (GE), while the selected reciprocating engine SSOs are assumed to employ engines supplied by Wartsila. These assumptions were made to provide a consistent comparison within these technology classes. Identification of these OEMs is not intended to be an implicit recommendation or final technology selection. In the event that a given SSO may be selected for development, it is recommended that PSE consider all qualified technology suppliers. For example, if PSE elected to investigate large frame CTG options in subsequent stages of planning and development, it is recommended that PSE consider combustion turbine options offered by GE, Mitsubishi Hitachi Power Systems and Siemens.

2.1 DESIGN BASIS FOR SUPPLY SIDE OPTIONS

Design basis parameters for the selected SSOs are summarized for combined cycle options in Table 2-1 and for peaking plant options in Table 2-2.

Table 2-1 Design Basis Parameters for Combined Cycle SSOs

| OPTION ID | SUPPLY-SIDE OPTION | PLANT CONFIGURATION | DUTY | AVERAGE AMBIENT NET OUTPUT (MW) | ANNUAL CAPACITY FACTOR (%) | ANNUAL NUMBER OF STARTS |
|-----------|--------------------|--|----------|---------------------------------|----------------------------|-------------------------|
| CC-A | 1x1 GE 7F.05 | Combustion Turbine: GE 7F.05 Inlet Air Cooling: None HRSG: Triple Pressure, Reheat Duct Firing: None Emissions Control: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower | Baseload | 359 | 80 | 70 |
| CC-B | 1x1 GE 7HA.01 | Combustion Turbine: GE 7HA.01 Inlet Air Cooling: None HRSG: Triple Pressure, Reheat Duct Firing: None Emissions Control: SCR, CO catalyst Steam Turbine: Condensing System Heat Rejection: Wet Cooling Tower | Baseload | 405 | 80 | 70 |

Table 2-2 Design Basis Parameters for Peaking Plant SSOs

| OPTION ID | SUPPLY-SIDE OPTION | PLANT CONFIGURATION | DUTY | AVERAGE AMBIENT NET OUTPUT (MW) | ANNUAL CAPACITY FACTOR (%) | ANNUAL NUMBER OF STARTS |
|-----------|-----------------------|---|---------|---------------------------------|----------------------------|-------------------------|
| PP-A | 3x0 Wartsila 18V50SG | Recip. Engine: Wartsila 18V50SG Emissions Control: SCR, CO catalyst Heat Rejection: Closed-Loop Radiator | Peaking | 55 | 5 | 100 |
| PP-B | 6x0 Wartsila 18V50SG | Recip. Engine: Wartsila 18V50SG Emissions Control: SCR, CO catalyst Heat Rejection: Closed-Loop Radiator | Peaking | 111 | 5 | 100 |
| PP-C | 12x0 Wartsila 18V50SG | Recip. Engine: Wartsila 18V50SG Emissions Control: SCR, CO catalyst Heat Rejection: Closed-Loop Radiator | Peaking | 222 | 5 | 100 |
| PP-D | 1x0 GE LMS100PA+ | Comb. Turbine: GE LMS100PA+ Emissions Control: SCR, CO catalyst Heat Rejection: Wet Cooling Tower | Peaking | 114 | 6 | 100 |
| PP-E | 2x0 GE LMS100PA+ | Comb. Turbine: GE LMS100PA+ Emissions Control: SCR, CO catalyst, Heat Rejection: Wet Cooling Tower | Peaking | 227 | 6 | 100 |
| PP-F | 1x0 GE 7F.05 | Combustion Turbine: GE 7F.05 Inlet Air Cooling: None Emissions Control: SCR, CO catalyst Heat Rejection: Std Package (Dry) | Peaking | 239 | 2 | 100 |

2.2 GENERAL SITE ASSUMPTIONS

In addition to the design basis parameters shown in Table 2-1 and Table 2-2, general site assumptions employed by Black & Veatch for these SSOs include the following:

- The site has sufficient area available to accommodate construction activities including, but not limited to, office trailers, lay-down, and staging.
- The plant will not be located on environmentally or culturally sensitive lands. The project site will require neither mitigation nor remediation.
- Pilings are assumed under major equipment, and spread footings are assumed for all other equipment foundations.
- All buildings will be pre-engineered unless otherwise specified.
- Construction power is available at the boundary of the site.
- Potable, Service and Fire water will be supplied from the local water utility.
- Cooling water, if required, will be supplied from the local water utility.
- Wastewater disposal will utilize local sewer systems.
- Natural gas pressure at the site boundary is assumed to be about 400 psi.
 - At this delivery pressure, all frame combustion turbine (i.e., 7F.05 and 7HA.01) and aeroderivative combustion turbine (i.e., LMS100PA+) options will require fuel gas compression.
 - Reciprocating engine-based options will not require fuel gas compression.
- Costs for transmission lines and switching stations are included as part of the owner's cost estimate.

2.3 CAPITAL COST ESTIMATING BASIS

Screening-level capital cost estimates were developed for each of the SSOs evaluated. The capital cost estimates were developed based on Black & Veatch's experience on projects either serving as engineering, procurement, and construction (EPC) contractor or as owner's engineer (OE). Capital cost estimates are market-based; based on recent and on-going experiences. The market-based numbers were adjusted based on technology and configuration to arrive at capital cost estimates developed on a consistent basis and reflective of current market trends.

Rather than develop capital cost estimates based on a "bottoms up" methodology, the estimates presented herein have been developed using recent historical and current project pricing and then adjusted to account for differences in region, project scope, technology type, and cycle configuration. The basic process flow is as follows:

- **Leverage** in-house database of project information from EPC projects recently completed and currently being executed as well as EPC pursuits currently being bid and our knowledge of the market from an owner's engineer perspective to produce a list of potential reference projects based primarily on technology type and cycle configuration.

- **Review** differences in region and scope.
- **Exclude** references which differ significantly from study basis.
- **Adjust.** The remaining references are broken down into several cost categories and further adjusted to account for differences such as major equipment pricing, labor, and commodities escalation.
- **Scale.** Remaining reference projects are compared and a scaling curve is generated. That scaling curve forms the basis for the screening-level capital cost estimates and is ultimately used to arrive at the EPC capital cost estimate.

The estimate process described above maximizes the value of past experiences and reduces bias resulting from project outliers such as differences in scope and location with the objective of providing current market pricing for generic power projects in PSE's service territory.

Capital cost estimates presented in Section 5.0 are based on Greenfield site development under fixed, lump sum EPC contracting. Cost estimates are on a mid-year 2016 US dollars basis. EPC cost estimates are based on Black & Veatch's knowledge of current market trends. Financing fees, interest during construction, land, outside-the-fence infrastructure, and taxes are considered to be "Owner Costs" and need to be added to the EPC cost estimates to arrive at a total installed cost. For this study, the allowance for Owner's costs is assumed to be 30 percent. A more comprehensive listing of potential owner costs is presented in Table 2-3.

Table 2-3 Potential Owner’s Costs for Power Generation Projects

| | |
|--|---|
| <p><u>Project Development</u></p> <ul style="list-style-type: none"> • Site selection study • Land purchase/rezoning for greenfield sites • Transmission/gas pipeline right-of-way • Road modifications/upgrades • Demolition • Environmental permitting/offsets • Public relations/community development • Legal assistance • Provision of project management <p><u>Spare Parts and Plant Equipment</u></p> <ul style="list-style-type: none"> • Combustion and steam turbine materials, supplies and parts • HRSG and/or boiler materials, supplies and parts • SCR and CO catalyst materials, supplies and parts • Balance-of-plant equipment/tools • Rolling stock • Plant furnishings and supplies • Recip. engine materials, supplies and parts <p><u>Plant Startup/Construction Support</u></p> <ul style="list-style-type: none"> • Owner’s site mobilization • O&M staff training • Initial test fluids and lubricants • Initial inventory of chemicals and reagents • Consumables • Cost of fuel not recovered in power sales • Auxiliary power purchases • Acceptance testing • Construction all-risk insurance | <p><u>Owner’s Contingency</u></p> <ul style="list-style-type: none"> • Owner’s uncertainty and costs pending final negotiation: <ul style="list-style-type: none"> • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreements (i.e., interconnection contract costs) <p><u>Owner’s Project Management</u></p> <ul style="list-style-type: none"> • Preparation of bid documents and the selection of contractors and suppliers • Performance of engineering due diligence • Provision of personnel for site construction management <p><u>Taxes/Advisory Fees/Legal</u></p> <ul style="list-style-type: none"> • Taxes • Market and environmental consultants • Owner’s legal expenses • Interconnect agreements • Contracts (procurement and construction) • Property <p><u>Utility Interconnections</u></p> <ul style="list-style-type: none"> • Natural gas service • Gas system upgrades • Electrical transmission (including switchyard) • Water supply • Wastewater/sewer <p><u>Financing (may be included in fixed charge rate)</u></p> <ul style="list-style-type: none"> • Financial advisor, lender’s legal, market analyst, and engineer • Interest during construction • Loan administration and commitment fees • Debt service reserve fund |
|--|---|

2.4 NON-FUEL OPERATING & MAINTENANCE COST ESTIMATING BASIS

Black & Veatch developed non-fuel operations and maintenance (O&M) cost estimates for each option under consideration. Non-fuel O&M cost estimates were developed as representative estimates based on (1) previous Black & Veatch experience with projects of similar design and scale, and (2) relevant vendor information available to Black & Veatch. Non-fuel O&M cost estimates were categorized into Fixed O&M and Non-fuel Variable O&M components:

- Fixed O&M costs include labor, routine maintenance and other expenses (i.e., training, property taxes, insurance, office and administrative expenses).
- Non-fuel Variable O&M costs include outage maintenance (including the costs associated with Long Term Service Agreements [LTSAs] or other maintenance agreements), parts and materials, water usage, chemical usage and equipment.
- Non-fuel Variable O&M costs exclude the cost of fuel (i.e., natural gas).

Additional assumptions regarding O&M cost estimates include the following:

- Plant staffing assumptions are summarized in Table 2-4 for Greenfield options.
- Labor rates for O&M staff were assumed based on information provided by PSE and Black & Veatch experience with similar facilities in the Pacific Northwest.
- All plant water consumption (including cooling water) was assumed to be sourced from a nearby water utility. Water rates were assumed as follows:
 - Monthly basic fixed charge of \$1209.05.
 - Rate for first 100 ccf (100 cubic feet) of water consumed per month: \$3.95 per ccf.
 - Rate for quantity greater than 100 ccf per month: \$2.31 per ccf.
- Cost for additional plant consumables based on information provided by PSE and Black & Veatch experience with similar facilities in the region.
- All non-fuel O&M cost estimates are presented in 2016 dollars.

Table 2-4 Plant Staffing Assumptions for Greenfield Options

| ID | OPTION | GREENFIELD STAFFING (FTEs) |
|------|-----------------------|----------------------------|
| CC-A | 1x1 GE 7F.05 | 17 |
| CC-B | 1x1 GE 7HA.01 | 17 |
| PP-A | 3x0 Wartsila 18V50SG | 9 |
| PP-B | 6x0 Wartsila 18V50SG | 9 |
| PP-C | 12x0 Wartsila 18V50SG | 12 |
| PP-D | 1x0 GE LMS100PA+ | 9 |
| PP-E | 2x0 GE LMS100PA+ | 9 |
| PP-F | 1x0 GE 7F.05 | 9 |

3.0 Gas-Fired Generation Option Descriptions

As noted in Section 2.0, PSE has selected to characterize SSOs that employ the following gas-fired generation prime mover technologies:

- GE 7F.05 CTG
- GE 7HA.01 CTG
- Wartsila 18V50SG reciprocating engine
- GE LMS100PA+ CTG

These gas-fired options are described in the following subsections.

3.1 GE 7F.05

3.1.1 Technology Overview

The 7F.05 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 3-stage axial turbine, and 14-can-annular dry low NO_x (DLN) combustors. The 7F.05 is GE's 5th generation 7FA machine; the latest advancements integrated into the 7F.05 design include a redesigned compressor and three variable stator stages and a variable inlet guide vane for improved turndown capabilities. GE's 7F fleet of over 800 units has over 33 million operating hours.

Key attributes of the GE 7F.05 include the following:

- High availability.
- 40 MW/min ramp rate.
- Start to 200 MW in 10 minutes, full load in 11 minutes (excluding purge).
- Natural gas interface pressure requirement of 435 psig.
- Dual fuel capable.
- DLN combustion with CTG NO_x emissions of 9 ppm on natural gas.
- Capable of turndown to 45 percent of full load.
- High exhaust temperature increases the difficulty of implementing post-combustion NO_x emissions controls (i.e., SCR).

3.1.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for the following configurations:

- **CC-A:** a 1x1 combined cycle natural gas-fired GE 7F.05 combustion turbine facility.
- **PP-F:** a simple cycle (1x0) natural gas-fired GE 7F.05 combustion turbine facility.

Relevant assumptions employed in the development of performance and cost parameters for 7F.05 options include the following:

- For the CC-A option:
 - The power plant would consist of a single GE 7F.05 CTG, located outdoors in a weather-proof enclosure; the CTG would be close-coupled to a three-

- pressure HRSG. Ancillary CTG skids would also be located outdoors in weather-proof enclosures.
 - An axial flow reheat condensing steam turbine would accept steam from the HRSG at three pressure levels. The steam turbine would be located within a building.
 - A wet surface condenser and mechanical draft counterflow cooling tower would reject STG exhaust heat to atmosphere.
 - To reduce NO_x and carbon monoxide (CO) emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would be located within the HRSG in a temperature region conducive to the SCR catalyst.
 - A generation building would house electrical equipment, balance of plant controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- For the PP-F option:
 - The power plant would consist of a single GE 7F.05 CTG, located outdoors in a weather-proof enclosure. Ancillary CTG skids would also be located outdoors in weather-proof enclosures.
 - To reduce NO_x and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would include purge/tempering air for startup and to reduce CTG exhaust temperature to within the operational limits of the SCR catalyst.
 - A generation building would house electrical equipment, balance of plant controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
 - Natural gas compression (to approximately 500 psia) has been assumed for 7F.05 options.

3.2 GE 7HA.01

3.2.1 Technology Overview

The GE 7HA.01 is an air cooled heavy frame CTG with a single shaft, 14-stage axial compressor, 4-stage axial turbine, and 12-can-annular DLN combustors. The 7HA.01 has a single inlet guide vane stage and three variable stator vane stages to vary compressor geometry for part load operation. The 7HA.01 and the scaled-up 7HA.02 represent the largest and most advanced heavy frame CTG technologies from GE. (GE also offers 50 Hz versions, the 9HA.01 and 9HA.02.) The compressor design is scaled from GE's 7F.05 and 6F.01 (formally 6C) designs. The 7HA.01 employs the DLN 2.6+ AFS (Axial Fuel Staged) fuel staging combustion system which allows for high firing temperatures and improved gas turbine turndown while maintaining emissions guarantees; providing stable operations; and allowing for increased fuel variability.

The 7HA.01 and the 7HA.02 are the newest combustion turbine technologies offered by GE. The first shipments of the 7HA.01 are expected in 2016 (to Chubu Electric's Nishi-Nagoya thermal power plant in Nagoya City, Japan). GE has more than 16 orders of its HA CTG technology to date.

Key attributes of the GE 7HA.01 include the following:

- High availability.
- CTG 50 MW/min ramp rate.
- Capable of turndown to approximately 30 percent of full load (ambient temperature dependent).
- Natural gas interface pressure requirement of about 540 psig.
- Dual fuel capable.
- DLN combustion with CTG NO_x emissions of 25 ppm on natural gas.

3.2.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for:

- **CC-B:** a 1x1 combined cycle natural gas-fired GE 7HA.01 combustion turbine facility.

Relevant assumptions employed in the development of performance and cost parameters for the 1x1 7HA.01 option include the following:

- The power plant would consist of a single GE 7HA.01 CTG, located outdoors in a weather-proof enclosure; the CTG would be close-coupled to a three-pressure HRSG. Ancillary CTG skids would also be located outdoors in weather-proof enclosures.
- An axial flow reheat condensing steam turbine would accept steam from the HRSG at three pressure levels. The steam turbine would be located within a building.
- A wet surface condenser and mechanical draft counterflow cooling tower would reject STG exhaust heat to atmosphere.
- To reduce NO_x and CO emissions, a SCR system with oxidation catalyst would be utilized. The SCR system would be located within the HRSG in a temperature region conducive to the SCR catalyst.
- A generation building would house electrical equipment, balance of plant controls, water treatment equipment, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compression (to approximately 600 psia) has been assumed for this option.

3.3 WARTSILA 18V50SG

3.3.1 Technology Overview

Wartsila's 18V50SG reciprocating engine is a turbocharged, four-stroke spark-ignited natural gas engine. Unlike dual fuel reciprocating engines, the SG does not require liquid pilot fuel during startup and to maintain combustion. The 18V50SG utilizes 18 cylinders in a "V" configuration. Each cylinder has a bore diameter of 500 millimeters (19-11/16 inches) and a stroke of 580 millimeters (22-13/16 inches). Each engine operates at a shaft speed of 514 revolutions per minute. These engines employ individual cylinder computer controls and knock sensors for precise control of the combustion process, enabling the engine to operate more efficiently while minimizing emissions. There have been more than sixty 18V50SG engines sold to date with initial commercial operations starting in 2013.

For this characterization, it is assumed that engine heat is rejected to the atmosphere using an air-cooled heat exchanger, or "radiator." An 18V50SG power plant utilizing air cooled heat exchangers requires very little makeup water as the engines do not typically utilize inlet cooling for power augmentation or water injection for NO_x reduction.

Key attributes of the Wartsila 18V50SG include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- 5 minutes to full power (excluding purge).
- Capable of turndown to 25 percent of full load.
- Minimal power plant footprint.
- Low starting electrical load demand.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 75 psig.
- Not dual fuel capable.

While the 18V50SG does not provide dual fuel capability, the diesel variation of the engine, the 18V50DF model, does provide dual fuel capability. In diesel mode, the main diesel injection valve injects the total amount of light fuel oil as necessary for proper operation. In gas mode, the combustion air and the fuel gas are mixed in the inlet port of the combustion chamber, and ignition is provided by injecting a small amount of light fuel oil (less than one percent by heat input). The injected light fuel oil ignites instantly, which then ignites the air/fuel gas mixture in the combustion chamber. During startup, the 18V50DF must operate in diesel mode until the engine is up to speed; once up to speed, the unit may operate in gas mode.

Wartsila offers a standard, pre-engineered six-engine configuration for the 18V50SG and the 18V50DF, sometimes referred to as a "6-Pack". The 6-Pack configuration has a net generation output of approximately 110 MW and ties the six engines to a single bus and step-up transformer. This configuration provides economies of scale associated with the balance of plant systems (e.g., step-up transformer and associated switchgear) and reduced engineering costs.

3.3.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for the following configurations:

- **PP-A:** 3x0 (simple cycle) natural gas-fired Wartsila 18V50SG RICE facility.
- **PP-B:** 6x0 (simple cycle) natural gas-fired Wartsila 18V50SG RICE facility.
- **PP-C:** 12x0 (simple cycle) natural gas-fired Wartsila 18V50SG RICE facility.

Relevant assumptions employed in the development of performance and cost parameters for 7F.05 options include the following:

- For the PP-A option:
 - The facility would consist of three (3) Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- For the PP-B option:
 - The facility would consist of six (6) Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- For the PP-C option:
 - The facility would consist of twelve (12) Wartsila 18V50SG reciprocating engines, arranged as slide along units and co-located in a common engine hall.
- For all three 18V50SG options:
 - The engine hall would be one of a number of rooms within a generation building. The generation building would also include space for electrical equipment, engine controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
 - An SCR system with oxidation catalyst would be utilized to minimize NO_x and CO emissions.
 - Engine heat is rejected to atmosphere by way of a closed loop radiators. The use of these radiators would make water consumption rates of the Wartsila engines negligible.
- No natural gas compression has been assumed for 18V50SG options.

3.4 GE LMS100PA+

3.4.1 Technology Overview

The LMS100 is an intercooled aeroderivative CTG with two compressor sections and three turbine sections. Compressed air exiting the low-pressure compressor section is cooled in an air-to-water intercooler heat exchanger prior to admission to the high-pressure compressor section. A mixture of compressed air and fuel is combusted in a single annular combustor. Hot flue gas then enters the two-stage high-pressure turbine. The high-pressure turbine drives the high-pressure

compressor. Following the high-pressure turbine is a two-stage intermediate pressure turbine, which drives the low-pressure compressor. Lastly, a five-stage low-pressure turbine drives the electric generator. Major intercooler components include the inlet and outlet scrolls and associated ductwork to/from the intercooler and the intercooler. Nitrogen oxides (NO_x) emissions are minimized utilizing water injection (for the LMS100PA+) or the use of Dry Low Emission (DLE) combustion technology (for the LMS100PB+).

Many of the major components from the LMS100 are based on engine applications with extensive operating hours. The low-pressure compressor section is derived from the first six stages of GE's MS6001FA heavy-duty CTG compressor. The high-pressure compressor is derived from GE's CF6-80C2 aircraft engine and strengthened to withstand a pressure ratio of approximately 41:1. The single annular combustor and high pressure turbine are derived from GE's LM6000 aeroderivative turbine and CF6-80C2 and CF6-80E2 aircraft engines.

Key attributes of the GE LMS100PA include the following:

- High full- and part-load efficiency.
- Minimal performance impact at hot-day conditions.
- High availability.
- 50 megawatt per minute (MW/min) ramp rate.
- 8 minutes to full power (excluding purge).
- Capable of turndown 25 percent of full load.
- Ability to cycle on and off without impact of maintenance costs or schedule.
- Natural gas interface pressure requirement of 850 pounds per square inch gauge (psig).
- Dual fuel capable.

The LMS100 is available in a number of configurations. Major variations include an intercooler heat rejection to atmosphere using dry cooling methods and dry low emissions (DLE) in lieu of water injected combustion for applications when water availability is limited.

GE has recently introduced the LMS100PA+ and LMS100PB+, which provide increased turbine output and a reduced net plant heat rate relative to the LMS100PA and LMS100PB models.

3.4.2 Technology-Specific Assumptions

Cost and performance characteristics have been developed for the following configurations:

- **PP-D:** a 1x0 simple cycle natural gas-fired LMS100PA+ combustion turbine facility.
- **PP-E:** a 2x0 simple cycle natural gas-fired LMS100PA+ combustion turbine facility.

Relevant assumptions employed in the development of performance and cost parameters for the LMS100PA+ options include the following:

- For the PP-D (1x0) option:
 - The power plant would consist of a single GE LMS100PA CTG, located outdoors in a weather-proof enclosure.

- For the PP-E (2x0) option:
 - The power plant would consist of two GE LMS100PA CTGs, located outdoors in a weather-proof enclosure.
- To reduce NO_x and CO emissions, selective catalytic reduction (SCR) systems with oxidation catalyst would be utilized. The SCR system would include purge/tempering air for startup and when CTG exhaust temperature approaches the operational limits of the SCR catalyst.
- Intercooler heat is rejected to atmosphere by way of wet mechanical draft cooling towers.
- A generation building would house electrical equipment, balance of plant controls, mechanical equipment, warehouse space, offices, break area, and locker rooms.
- Natural gas compression (to approximately 925 psia) has been assumed for LMS100PA+ options. Natural gas compressors would be housed in a prefabricated weather-proof enclosure.

4.0 Summary of Performance and Emission Characteristics

For each of the SSOs considered in this study, Black & Veatch has developed estimates of unit performance and emissions (when firing pipeline-quality natural gas). Performance estimates were prepared for each SSO at three load points: gas turbine or engine baseload (i.e., 100% Load), intermediate (75%) load, and minimum emissions compliance load (MECL). These estimates were developed considering ambient conditions consistent with locations in the PSE service territory. A summary of the ambient conditions considered for performance estimates is presented in Table 4-1.

Table 4-1 Ambient Conditions for SSO Characterizations

| AMBIENT CONDITION | SITE ELEVATION (FT ABOVE MSL) | BAROMETRIC PRESSURE (PSIA) | DRY BULB TEMPERATURE (° F) | RELATIVE HUMIDITY (%) |
|-------------------|-------------------------------|----------------------------|----------------------------|-----------------------|
| Typical Low | 30 | 14.68 | 23 | 40 |
| Annual Average | 30 | 14.68 | 51 | 75 |
| ISO Conditions | 0 | 14.70 | 59 | 60 |
| Typical High | 30 | 14.68 | 88 | 30 |

4.1 THERMAL PERFORMANCE AND EMISSIONS ESTIMATES

A summary of unit full load (New and Clean) performance and stack emissions estimates at average day conditions is presented in Table 4. Additional performance cases at full load and part load for three ambient conditions and at ISO conditions are provided in Appendix A of this document. Also included are indicative degradation curves based on generic data, provided by the original equipment manufacturers for past projects.

Combined cycle performance estimates are based on the use of a combination of a surface condenser and wet mechanical draft cooling tower for rejecting heat from the steam bottoming cycle to atmosphere. Performance estimates for simple cycle LMS100PA+ options also utilize wet mechanical draft cooling towers for rejecting heat to atmosphere. Performance estimates for Wartsila 18V50SG options assume that these engines utilize closed-loop radiators (rather than a wet cooling method). A discussion of the performance and cost impacts associated with designing combined cycle and peaking plants with dry cooling heat rejection systems is included in Appendix B.

Combined cycle performance estimates do not include supplemental HRSG duct firing. A discussion of the performance and cost impacts associated with designing combined cycle plants with supplemental HRSG duct firing for increased plant net output is included in Appendix C.

Table 4-2 Full Load (New and Clean) Performance and Stack Emission Estimates at Average Day Conditions

| ID | OPTION | NET PLANT OUTPUT (MW) | NET PLANT HEAT RATE (BTU/kWh, HHV) | NO _x EMISSIONS | | CO ₂ EMISSIONS (LB/HR) |
|------|-----------------------|-----------------------|------------------------------------|---------------------------|---------|-----------------------------------|
| | | | | (PPM) ⁽²⁾ | (LB/HR) | |
| CC-A | 1x1 GE 7F.05 | 359.1 | 6,520 | 2.0 | 16.8 | 269,300 |
| CC-B | 1x1 GE 7HA.01 | 405.1 | 6,410 | 2.0 | 18.7 | 298,500 |
| PP-A | 3x0 Wartsila 18V50SG | 55.5 | 8,260 | 5.0 | 7.5 | 53,600 |
| PP-B | 6x0 Wartsila 18V50SG | 111.0 | 8,260 | 5.0 | 14.9 | 107,100 |
| PP-C | 12x0 Wartsila 18V50SG | 222.0 | 8,260 | 5.0 | 29.9 | 214,200 |
| PP-D | 1x0 GE LMS100PA+ | 113.7 | 8,810 | 2.5 | 9.0 | 115,100 |
| PP-E | 2x0 GE LMS100PA+ | 227.3 | 8,810 | 2.5 | 18.0 | 230,200 |
| PP-F | 1x0 GE 7F.05 | 239.0 | 9,630 | 2.5 | 20.7 | 264,600 |

Notes:

1. All values based on ambient conditions of 51°F and relative humidity of 75%.
2. NO_x emissions on a ppm basis are presented as ppmvd @15% O₂.

4.2 OPERATIONAL CHARACTERISTICS

Operational characteristics for the selected SSOs are presented in this section, including the following parameters:

- Ramp rate, between full load and minimum emission compliant load (MECL)
- Minimum run time upon startup
- Minimum down time upon shutdown
- Start time, to full load
- Loads achievable within 10 minutes (for units with start time greater than 10 minutes)
- Preliminary estimate of startup fuel consumption
- Preliminary estimate of startup net electrical production

4.2.1 Ramping and Run Time Parameters

Ramp rates, minimum run time and minimum downtime are presented for the selected SSOs in Table 4-3.

- Ramp rates are based on capability of each machine to change load between full load and MECL (Minimum Emissions Compliant Load).

- Minimum run time is estimated from the time of generator breaker closure to generator breaker opening. This value is assumed to be limited by CEMS calibration/reporting period. For combined cycle options, minimum run time includes 60 minute allowance for hot start. A longer minimum run time may be required for other start events (i.e., cold start or warm start).
- Minimum downtime is estimated from the time of generator breaker opening to generator breaker closure. These values assume purge and turning gear operation are achieved within one hour.

Table 4-3 Ramp Rate, Minimum Run Time and Minimum Down Time Parameters for SSOs

| ID | OPTION | CTG/ENGINE RAMP RATE ⁽¹⁾ (MW/MIN) | MINIMUM RUN TIME ⁽²⁾ (MINUTES) | MINIMUM DOWNTIME ⁽³⁾ (MINUTES) |
|------|-----------------------|--|---|---|
| CC-A | 1x1 GE 7F.05 | 40 | 120 | 60 |
| CC-B | 1x1 GE 7HA.01 | 50 | 120 | 60 |
| PP-A | 3x0 Wartsila 18V50SG | 42 | 60 | 60 |
| PP-B | 6x0 Wartsila 18V50SG | 84 | 60 | 60 |
| PP-C | 12x0 Wartsila 18V50SG | 168 | 60 | 60 |
| PP-D | 1x0 GE LMS100PA+ | 50 | 60 | 60 |
| PP-E | 2x0 GE LMS100PA+ | 100 | 60 | 60 |
| PP-F | 1x0 GE 7F.05 | 40 | 60 | 60 |

Notes:

1. Ramp Rate based on capability of machine to change load between Full Load and MECL (Minimum Emissions Compliant Load).
2. Minimum Run Time estimated from the time of generator breaker closure to generator breaker opening. This value is assumed to be limited by CEMS calibration/reporting period. For combined cycle options, minimum run time includes 60 minute allowance for hot start. A longer minimum run time may be required for other start events (i.e., cold start or warm start).
3. Minimum Downtime estimated from the time of generator breaker opening to generator breaker closure. These values assume purge and turning gear operation are achieved within one hour.

4.2.2 Unit Start Parameters

Start times are defined as the time required for gas-fired turbines and engines to achieve CTG/RICE full load output from start initiation. Simple cycle CTG and RICE units do not typically have start times that vary depending on the time the unit had previously been offline. However, start times for combined cycle units (and other units that employ steam cycle equipment) do depend upon the time the unit had previously been online. Therefore, start times for combined cycle units may be classified as follows:

- **Hot start:** a start following a shutdown period of less than 8 hours.
- **Warm start:** a start following a shutdown period of 8 – 48 hours.
- **Cold start:** a start following a shutdown period of 48 – 72 hours.
- **Ambient start:** a start following a shutdown period of greater than 72 hours.

Combined cycle unit start times are mainly driven by steam temperature control capabilities and STG warming requirements. Combined cycle CTG and STG start times and ramp rates can be reduced using a number of proven cycle design methods such as integration of auxiliary steam boilers, HRSG stack dampers, steam final point attemperation, and enhanced CTG starting systems.

During the startup period, simple cycle and combined cycle options will consume fuel and electricity and will also produce some quantity of electricity. The amount of fuel consumed and electricity consumed and produced during a startup will impact production costs. After syncing the generator to the grid, the unit will immediately begin generating electricity. If the “Net Electricity Produced” value is positive, then the unit is expected to have produced more electricity than it has consumed.

For both simple cycle and combined cycle options, Table 4-4 presents estimates of start times and estimates of fuel consumption and net electricity production during start up. Combined cycle startup estimates shown in Table 4-4 are based on a hot start and conventional steam cycle designs with no fast start features. Combined cycle starts occurring after longer shutdown periods will require additional time (and fuel) to achieve CTG full load. For example, if the start time under a “hot start” condition is 90 minutes (excluding purge), then the start times under warm, cold and ambient start conditions (excluding purge) would be 150 minutes, 210 minutes and 330 minutes, respectively.

Table 4-4 Startup Parameters for SSOs

| ID | OPTION | START TIME ⁽¹⁾ (MINUTES) | LOAD ACHIEVABLE IN 10 MINUTES ⁽²⁾ (MW) | FUEL CONSUMPTION ⁽³⁾ (MBTU, HHV) | NET ELECTRICITY PRODUCED ⁽⁴⁾ (MWh) |
|------|-----------------------|--|--|--|--|
| CC-A | 1x1 GE 7F.05 | 90 | 24 | 1,000 | 75 |
| CC-B | 1x1 GE 7HA.01 | 90 | 28 | 1,090 | 85 |
| PP-A | 3x0 Wartsila 18V50SG | 5 | n/a | 25 | 2 |
| PP-B | 6x0 Wartsila 18V50SG | 5 | n/a | 50 | 4 |
| PP-C | 12x0 Wartsila 18V50SG | 5 | n/a | 100 | 7 |
| PP-D | 1x0 GE LMS100PA+ | 8 | n/a | 42 | 3 |
| PP-E | 2x0 GE LMS100PA+ | 8 | n/a | 84 | 6 |
| PP-F | 1x0 GE 7F.05 | 11.5 | 200 | 121 | 7 |

Notes:

1. Start Time estimates exclude any time allotted for exhaust system purge. Start Time for combined cycle options are based on a hot start and conventional steam cycle designs with no fast start features.
2. For options with start times greater than 10 minutes, Achievable Load represents the load able to be provided within 10 minutes of initiating start of the unit. Wartsila 18V50SG and GE LMS100PA+ are able to achieve full load in less than 10 minutes.
3. Fuel Consumption is the total fuel energy required during startup period
4. Net Electricity Produced is total energy produced during startup period.

5.0 Summary of Capital and Non-Fuel O&M Cost Estimates

Black & Veatch developed order-of-magnitude capital and nonfuel O&M cost estimates for generic Greenfield gas-fired power plants constructed within the state of Washington, based on the SSOs under consideration in this study. Estimates are based on similar studies and project experience and adjusted using engineering judgment.

Along with capital cost estimates, Black & Veatch has also developed estimates of project duration for installation of the selected facilities and incremental cash flows over the duration of project installation.

5.1 INSTALLED CAPITAL COST ESTIMATES

Estimates of capital costs for Greenfield options are presented in Table 5-1. The scope of the cost estimates presented end at the high-side of the generator step-up transformers. Additional costs, including utility interconnections considered outside-the-fence, project development, and project financing are not included in the EPC cost estimates. For each of the considered options, Black & Veatch has included an allowance equal to 30 percent of the EPC capital cost to account for these additional costs, including owner's costs. These additional costs will be discussed in further detail below.

The cost estimates presented are for power plants capable of operating on natural gas fuel only. Having a secondary fuel source for backup, such as diesel fuel, will require additional equipment, systems, and major equipment design accommodations. A discussion of the design and cost impacts associated with designing a peaking plant with backup fuel operation capabilities is included in Appendix D.

Capital costs for development of projects at brownfield locations (i.e., unit additions at existing power generation facilities) are discussed in Appendix E.

Table 5-1 Summary of Capital Cost Estimates (for Greenfield Options)

| ID | OPTION | AVERAGE DAY NET OUTPUT ⁽¹⁾ (MW) | ESTIMATED EPC COST (\$'000) | OWNER'S COST ALLOWANCE ⁽²⁾ (\$'000) | TOTAL OVERNIGHT CAPITAL COST | |
|------|-----------------------|---|--------------------------------|---|------------------------------|---------|
| | | | | | (\$'000) | (\$/kW) |
| CC-A | 1x1 GE 7F.05 | 359.1 | 388,000 | 116,400 | 504,400 | 1,405 |
| CC-B | 1x1 GE 7HA.01 | 405.1 | 449,000 | 134,700 | 583,700 | 1,440 |
| PP-A | 3x0 Wartsila 18V50SG | 55.5 | 61,000 | 18,300 | 79,300 | 1,430 |
| PP-B | 6x0 Wartsila 18V50SG | 111.0 | 116,000 | 34,800 | 150,800 | 1,360 |
| PP-C | 12x0 Wartsila 18V50SG | 222.0 | 218,000 | 65,400 | 283,400 | 1,275 |
| PP-D | 1x0 GE LMS100PA+ | 113.7 | 105,000 | 31,500 | 136,500 | 1,200 |
| PP-E | 2x0 GE LMS100PA+ | 227.3 | 176,000 | 52,800 | 228,800 | 1,005 |
| PP-F | 1x0 GE 7F.05 | 239.0 | 105,000 | 31,500 | 136,500 | 570 |

Notes:

1. Average day net output based on ambient conditions of 51°F and relative humidity of 75%.
2. Owner's Cost Allowances are assumed to be equivalent to 30% of Overnight EPC Costs.

As shown in Table 5-1, Black & Veatch has included an allowance equal to 30 percent of the estimated EPC capital cost for each of the options to account for owner’s costs and escalation. These additional costs typically range from 20 to 50 percent of the overnight EPC cost and are generally higher for a Greenfield site than a Brownfield site.

Table 5-2 includes a breakdown of typical components of the owner’s and escalation cost allowance. This table is presented as an example only to provide PSE with a general understanding of the relative impact of major owner’s cost components and escalation. Potential types of owner’s costs, including project development and outside-the-fence costs, are presented in Table 2-3.

Table 5-2 Example Owner’s Cost and Escalation Breakdown

| Cost Component | % of Owner’s + Escalation Costs |
|--|---------------------------------|
| Utility Interconnections | 25% |
| Owner’s Contingency | 25% |
| Interest During Construction | 20% |
| Escalation | 10% |
| Project Development | 10% |
| Other | 10% |
| Total of Owner’s and Escalation | 100% |

As evidenced in Table 5-2, outside-the-fence utility interconnections are typically a large component of owner’s costs. In addition, earthwork costs can vary significantly depending on soil conditions, impediments, and site terrain. While earthwork is generally placed in the EPC contractor’s scope, it is something that can increase project costs above generic Greenfield cost projection. Table 5-3 includes an example of typical values used in Black & Veatch site selection studies to give PSE an understanding of costs associated with major items that influence siting.

Table 5-3 Representative Unit Costs for Outside-the-Fence Utility Interconnections and Siting Considerations

| Siting Consideration | Unit | Unit Cost |
|--|----------------------------------|--------------------|
| Earthwork | \$/cubic yard of earth displaced | 7.50 |
| Water Pipeline | \$/mile | 500,000 to 750,000 |
| Transmission Line | \$/mile | 1,000,000 |
| Natural Gas Pipeline | \$/mile | 1,800,000 |
| Roads | \$/mile | 250,000 |
| Note: 1. Costs presented are specific to a combined cycle project and do not include any interconnection costs. | | |

Expected project durations for activities starting with development of the EPC specification through the commercial operation date (COD) of the power plant are presented in Table 5-4. Activities not included in the expected project duration include permitting and other activities required prior to EPC specification development. A typical duration for EPC specification development, bidding, negotiation, and award is 7 to 10 months. Incremental cash flows are also presented in Table 5-4. Cash flows are expressed as a percentage of the overnight EPC Cost portion spent during the Expected Project Duration, from EPC award to COD. For example, for the 1x1 GE 7F.05 option, the project has an expected duration of 36 months, and the EPC contractor is expected to expend 62 percent of budget at the end of the 3/6 portion of the project, which is the project mid-way point, 18 months into the project.

Table 5-4 Project Durations and Expenditure Patterns for SSOs

| ID | OPTION | EPC SPEC DEVELOPMENT TO CONTRACT AWARD ⁽¹⁾ (MONTHS) | EXPECTED PROJECT DURATION ⁽²⁾ (MONTHS) | INCREMENTAL CASH FLOWS ⁽³⁾ (1/6, 2/6, 3/6, 4/6, 5/6, 6/6) |
|------|-----------------------|--|---|--|
| CC-A | 1x1 GE 7F.05 | 7 to 10 | 36 | 10, 20, 32, 23, 13, 2 |
| CC-B | 1x1 GE 7HA.01 | 7 to 10 | 36 | 10, 20, 32, 23, 13, 2 |
| PP-A | 3x0 Wartsila 18V50SG | 7 to 10 | 24 | 14, 25, 33, 19, 7, 2 |
| PP-B | 6x0 Wartsila 18V50SG | 7 to 10 | 24 | 14, 25, 33, 19, 7, 2 |
| PP-C | 12x0 Wartsila 18V50SG | 7 to 10 | 24 | 14, 25, 33, 19, 7, 2 |
| PP-D | 1x0 GE LMS100PA+ | 7 to 10 | 28 | 14, 25, 33, 19, 7, 2 |
| PP-E | 2x0 GE LMS100PA+ | 7 to 10 | 28 | 14, 25, 33, 19, 7, 2 |
| PP-F | 1x0 GE 7F.05 | 7 to 10 | 28 | 14, 25, 33, 19, 7, 2 |

Notes:

1. Permitting and other activities required prior to EPC specification development are not included in EPC Spec Development to Contract Award period.
2. Expected Contract Duration represents the number of months from EPC contract award to COD.
3. Incremental Cash Flows represent the percentage of total capital cost expended across six time increments between EPC contract award to COD.

5.2 NON-FUEL O&M COST ESTIMATES

Estimates of O&M costs for Greenfield options are presented in Table 5-5. Variations in O&M costs for projects sited at brownfield locations are discussed in Appendix E.

Table 5-5 Summary of O&M Cost Estimates (for Greenfield Options)

| ID | OPTION | AVERAGE DAY NET OUTPUT ⁽¹⁾ (MW) | ANNUAL CAPACITY FACTOR (%) | ANNUAL NUMBER OF STARTS | ANNUAL NET GENERATION (MWh) | ANNUAL FIXED O&M | | ANNUAL VARIABLE O&M | |
|------|-----------------------|--|----------------------------|-------------------------|-----------------------------|------------------|------------|---------------------|----------|
| | | | | | | (\$000) | (\$/kW-yr) | (\$000) | (\$/MWh) |
| CC-A | 1x1 GE 7F.05 | 359.1 | 80 | 70 | 2,517,000 | 2,915 | 8.1 | 6,270 | 2.5 |
| CC-B | 1x1 GE 7HA.01 | 405.1 | 80 | 70 | 2,839,000 | 2,970 | 7.3 | 6,750 | 2.4 |
| PP-A | 3x0 Wartsila 18V50SG | 55.5 | 5 | 100 | 24,300 | 1,340 | 24.1 | 210 | 8.6 |
| PP-B | 6x0 Wartsila 18V50SG | 111.0 | 5 | 100 | 48,600 | 1,420 | 12.8 | 390 | 8.0 |
| PP-C | 12x0 Wartsila 18V50SG | 222.0 | 5 | 100 | 97,200 | 1,940 | 8.7 | 760 | 7.8 |
| PP-D | 1x0 GE LMS100PA+ | 113.7 | 6 | 100 | 59,800 | 1,390 | 12.2 | 610 | 10.2 |
| PP-E | 2x0 GE LMS100PA+ | 227.3 | 6 | 100 | 119,500 | 1,480 | 6.5 | 1,210 | 10.1 |
| PP-F | 1x0 GE 7F.05 | 239.0 | 2 | 100 | 41,900 | 1,540 | 6.4 | 965 | 23.0 |

Notes:

1. Average day net output based on ambient conditions of 51°F and relative humidity of 75%.

For purposes of bidding into certain power markets, Variable O&M (VOM) costs may be required to be provided as follows:

- Operations (including chemicals and consumables), in terms of \$/MWh
- Corrective maintenance, in terms of \$/MWh
- Major maintenance, in terms of \$/hour (for combined cycle units) or \$/start (for peaking units)

Based on the estimates of non-fuel O&M costs listed in Table 5-5, Black & Veatch has developed a breakout of VOM as shown in Table 5-6.

Table 5-6 Breakout of Annual Non-fuel Variable O&M Costs

| ID | OPTION | OPERATIONS COSTS ⁽¹⁾ | | CORRECTIVE MAINT. COSTS | MAJOR MAINTENANCE COSTS ⁽³⁾ | | |
|------|-----------------------|---------------------------------|----------|-------------------------|--|---------|------------|
| | | (\$000) | (\$/MWh) | | (\$000) | (\$/hr) | (\$/start) |
| CC-A | 1x1 GE 7F.05 | 2,350 | 0.93 | Note (2) | 3,915 | 560 | n/a |
| CC-B | 1x1 GE 7HA.01 | 2,650 | 0.93 | | 4,095 | 580 | n/a |
| PP-A | 3x0 Wartsila 18V50SG | 50 | 2.06 | | 155 | 350 | n/a |
| PP-B | 6x0 Wartsila 18V50SG | 80 | 1.65 | | 310 | 710 | n/a |
| PP-C | 12x0 Wartsila 18V50SG | 140 | 1.44 | | 625 | 1,430 | n/a |
| PP-D | 1x0 GE LMS100PA+ | 170 | 2.81 | | 445 | 850 | n/a |
| PP-E | 2x0 GE LMS100PA+ | 315 | 2.61 | | 890 | 1,690 | n/a |
| PP-F | 1x0 GE 7F.05 | 40 | 0.95 | | 925 | n/a | 9,250 |

Notes:

1. Operations Costs include chemicals and consumables but do not include fuel.
2. Corrective Maintenance Costs are assumed to be primarily associated with unscheduled maintenance costs or maintenance costs associated with forced outages. These costs are included within Black & Veatch estimates of Major Maintenance Costs, but are not distinguished within Major Maintenance Costs.
3. Major Maintenance Costs include scheduled and/or forced outage maintenance and costs associated with Long Term Service Agreements (LTSAs).

Periodically, power generation units must be taken offline to perform inspections and potentially replace worn components. Maintenance intervals recommended by the Original Equipment Manufacturer (OEM) for these inspections and corresponding maintenance provide an indication of operational reliability of the units. Manufacturer-recommended maintenance intervals for each SSO are presented in Table 5-7. Wartsila recommended maintenance activities were provided by the manufacturer and are included in Appendix G of this document. For the combined cycle options, it is anticipated that major maintenance activities for the steam turbine

and other plant equipment would be scheduled during CTG maintenance outages to minimize impacts to plant availability.

Table 5-7 CTG/RICE Manufacturer Recommended Maintenance Intervals

| ID | OPTION | COMBUSTION INSPECTION | HOT GAS PATH INSPECTION ⁽¹⁾ | MAJOR INSPECTION ⁽²⁾ |
|--|-----------------------|-------------------------|--|---------------------------------|
| CC-A | 1x1 GE 7F.05 | 16,000 FFH/ 1,250 FS | 32,000 FFH/ 1,250 FS | 64,000 FFH/ 2,500 FS |
| CC-B | 1x1 GE 7HA.01 | n/a | 25,000 FFH/ 900 FS | 50,000 FFH/ 1,800 FS |
| PP-A | 3x0 Wartsila 18V50SG | See Appendix D | | |
| PP-B | 6x0 Wartsila 18V50SG | | | |
| PP-C | 12x0 Wartsila 18V50SG | | | |
| PP-D | 1x0 GE LMS100PA+ | n/a | 25,000 AFH | 50,000 AFH |
| PP-E | 2x0 GE LMS100PA+ | n/a | 25,000 AFH | 50,000 AFH |
| PP-F | 1x0 GE 7F.05 | 16,000 FFH/ 1,250 FS | 32,000 FFH/ 1,250 FS | 64,000 FFH/ 2,500 FS |
| Abbreviations: AFH: Actual Fired Hours FFH: Factored Fired Hour FS: Factored Starts | | | | |
| Notes: 1. Hot Gas Path Inspection scope of work includes Combustion Inspection scope of work. 2. Major Inspections scope of work includes Hot Gas Path Inspection scope of work. | | | | |

Appendix A. Full Thermal Performance Estimates for Supply-Side Options

| <p>Project Sound Energy 13145 Preliminary Performance Summary May 27, 2016 - Rev A</p> | | | | | | | | | | | | | |
|--|-------------------------------|--------------------------|---------------------|---------------------------|--------------------------|---------------------|--------------------------------|-------------------------------|-----------------------|---------------------------|--------------------------|---------------------|---------------------|
| Section # | Description | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 1 | 20 deq F 100% CTG Load | 23 deq F 75% CTG Load | 23 deq F MECL | 51 deq F 100% CTG Load | 51 deq F 75% CTG Load | 51 deq F MECL | 80 Conditions 100% CTG Load | 80 Conditions 75% CTG Load | 80 Conditions MECL | 88 deq F 100% CTG Load | 88 deq F 75% CTG Load | 88 deq F MECL | 88 deq F MECL |
| CTG Configuration | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 |
| Heat Rejection System | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower |
| Relative Humidity | 30 | 30 | 40 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 | 30 |
| Ambient Pressure | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 |
| CTG Load | 100 | 75 | 45 | 100 | 75 | 45 | 100 | 75 | 45 | 100 | 75 | 45 | 45 |
| CTG Load Level | 100 | 75 | 45 | 100 | 75 | 45 | 100 | 75 | 45 | 100 | 75 | 45 | 45 |
| NEW & CLEAN PERFORMANCE | | | | | | | | | | | | | |
| Stack CTG Output (each) | 242,741 | 183,355 | 110,133 | 242,741 | 183,355 | 110,133 | 242,027 | 183,000 | 109,812 | 227,232 | 170,492 | 102,295 | 102,295 |
| Number of Gas Turbines in Operation | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Stack CTG Output | 242,741 | 183,355 | 110,133 | 242,741 | 183,355 | 110,133 | 242,027 | 183,000 | 109,812 | 227,232 | 170,492 | 102,295 | 102,295 |
| Stack CTG Output (each) | 242,741 | 183,355 | 110,133 | 242,741 | 183,355 | 110,133 | 242,027 | 183,000 | 109,812 | 227,232 | 170,492 | 102,295 | 102,295 |
| CTG Heat Input (MW) (each) | 2,095 | 1,639 | 1,209 | 2,111 | 1,639 | 1,210 | 2,110 | 1,638 | 1,209 | 2,207 | 1,555 | 1,181 | 1,181 |
| CTG Heat Input (HHV) (each) | 2,324 | 1,816 | 1,363 | 2,342 | 1,819 | 1,347 | 2,341 | 1,818 | 1,341 | 2,207 | 1,725 | 1,288 | 1,288 |
| Coal Plant Auxiliary Power | 5,910 | 7,778 | 6,911 | 5,166 | 8,134 | 7,082 | 9,181 | 8,136 | 7,100 | 8,934 | 7,974 | 7,072 | 7,072 |
| NET PLANT PERFORMANCE | | | | | | | | | | | | | |
| Net Plant Output | 390,654 | 271,408 | 186,629 | 399,116 | 274,276 | 187,257 | 360,243 | 274,604 | 186,920 | 346,505 | 260,655 | 178,059 | 178,059 |
| Net Plant Heat Rate (HHV) | 5,974 | 6,031 | 6,883 | 5,877 | 5,977 | 6,484 | 5,857 | 5,862 | 6,465 | 5,942 | 5,965 | 6,520 | 6,520 |
| Net Plant Heat Rate (LHV) | 5,718 | 5,775 | 6,627 | 5,672 | 5,772 | 6,279 | 5,650 | 5,655 | 6,231 | 5,728 | 5,751 | 6,306 | 6,306 |
| Net Plant Efficiency (HHV) | 51.5% | 51.0% | 46.7% | 52.3% | 51.5% | 47.4% | 52.5% | 51.6% | 47.6% | 52.6% | 51.6% | 47.2% | 47.2% |
| Net Plant Efficiency (LHV) | 51.5% | 51.0% | 46.7% | 52.3% | 51.5% | 47.4% | 52.5% | 51.6% | 47.6% | 52.6% | 51.6% | 47.2% | 47.2% |
| REGULATED PERFORMANCE | | | | | | | | | | | | | |
| Net Plant Output Degradation Factor | | | | | | | | | | | | | |
| Net Plant Heat Rate Degradation Factor | | | | | | | | | | | | | |
| See Degradation Worksheet | | | | | | | | | | | | | |
| STACK EMISSIONS (PER UNIT) | | | | | | | | | | | | | |
| NOx | ppmv @ 15% O2 lb/MWh (HHV) | 2 0.0072 | 2 0.0072 | 2 0.0072 | 2 0.0072 | 2 0.0072 | 2 0.0072 | 2 0.0072 | 2 0.0072 | 2 0.0072 | 2 0.0072 | 2 0.0072 | 2 0.0072 |
| | lb/hr | 16.7 | 13 | 9.8 | 16.8 | 13.1 | 10.8 | 13 | 9.6 | 15.9 | 12.4 | 9.3 | 9.3 |
| SO | ppmv @ 15% O2 lb/MWh (HHV) | 2 0.0044 | 2 0.0044 | 2 0.0044 | 2 0.0044 | 2 0.0044 | 2 0.0044 | 2 0.0044 | 2 0.0044 | 2 0.0044 | 2 0.0044 | 2 0.0044 | 2 0.0044 |
| | lb/hr | 10.2 | 7.9 | 6 | 10.2 | 8 | 10.2 | 7.9 | 5.9 | 9.7 | 7.5 | 5.6 | 5.6 |
| CO2 | lb/hr | 257,277 | 208,866 | 156,766 | 259,307 | 209,168 | 269,224 | 208,798 | 154,215 | 253,806 | 198,386 | 148,124 | 148,124 |
| WATER CONSUMPTION (PER UNIT) | | | | | | | | | | | | | |
| Cooling Tower Makeup Water (5 COC) | GPM | 940 | 762 | 692 | 1,152 | 906 | 1,239 | 985 | 831 | 1,488 | 1,248 | 1,095 | 1,095 |
| Steam Cycle Makeup Water (2% of Flow) | GPM | 27 | 22 | 18 | 28 | 22 | 28 | 23 | 18 | 28 | 22 | 18 | 18 |
| CTG Water Injection | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| <p>1) PERFORMANCE IS PRELIMINARY. NO GUARANTEE IS MADE.</p> <p>2) CTG performance is based on data from GT Pro from May 2016.</p> <p>3) The fuel gas is unheated and is assumed to be supplied at 80F.</p> <p>4) No inlet conditioning applied.</p> <p>5) HRS, STG and Heat Rejection System used using GT Pro software.</p> <p>6) HRS, STG and Heat Rejection System selected by GT Pro software.</p> <p>7) STG Last Stage Blade geometry selected by GT Pro software.</p> <p>8) Condenser Pressure designed to be 1.38 inches HgA at design (100%) conditions.</p> <p>9) Condenser Water Flow Rate (CWR) is based on condenser design, as calculated by Black & Veatch.</p> <p>10) Emission flow rate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PMW rates provided by GE.</p> <p>11) SFC designed to reduce stack NOx to 2.0 ppmv @ 15% O2.</p> | | | | | | | | | | | | | |

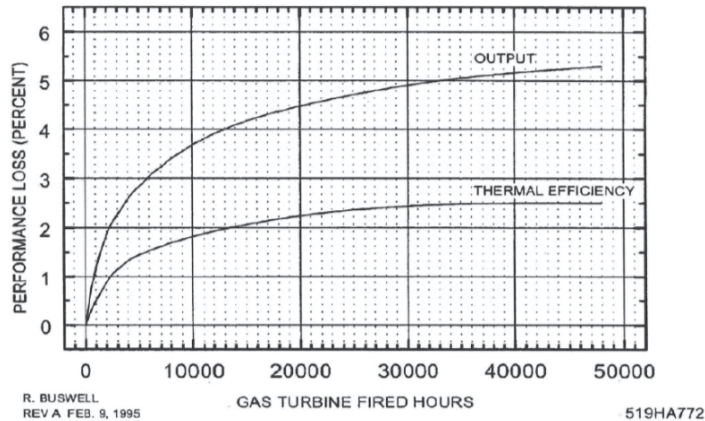


GE Power Systems

EXPECTED GAS TURBINE PLANT PERFORMANCE LOSS FOLLOWING NORMAL MAINTENANCE AND OFF-LINE COMPRESSOR WATER WASH

THE AGED PERFORMANCE EFFECTS REPRESENTED BY THESE CURVES ARE BASED ON THE FOLLOWING:

- * PERFORMANCE IS RELATIVE TO THE GUARANTEE LEVEL.
- * ALL GAS TURBINE PLANT EQUIPMENT SHALL BE OPERATED AND MAINTAINED IN ACCORDANCE WITH GE'S RECOMMENDED PROCEDURES FOR OPERATION, PREVENTIVE MAINTENANCE, INSPECTION AND BOTH ON-LINE AND OFF-LINE CLEANING.
- * ALL OPERATIONS SHALL BE WITHIN THE DESIGN CONDITIONS SPECIFIED IN THE RELEVANT TECHNICAL SPECIFICATIONS.
- * A DETAILED OPERATIONAL LOG SHALL BE MAINTAINED FOR ALL RELEVANT OPERATIONAL DATA, TO BE AGREED TO AMONGST THE PARTIES PRIOR TO COMMENCEMENT OF CONTRACT.
- * GE TECHNICAL PERSONNEL SHALL HAVE ACCESS TO PLANT OPERATIONAL DATA, LOGS, AND SITE VISITS PRIOR TO CONDUCTING A PERFORMANCE TEST. THE OWNER WILL CLEAN AND MAINTAIN THE EQUIPMENT. THE DEGREE OF CLEANING AND MAINTENANCE WILL BE DETERMINED BASED ON THE OPERATING HISTORY OF EACH UNIT, ATMOSPHERIC CONDITIONS EXPERIENCED DURING THE PERIOD OF OPERATION, THE PREVENTIVE AND SCHEDULED MAINTENANCE PROGRAMS EXECUTED, AND THE RESULTS OF THE GE INSPECTION.
- * THE GAS TURBINE WILL BE SHUT DOWN FOR INSPECTION AND OFF-LINE COMPRESSOR WATER WASH AS A MINIMUM IMMEDIATELY PRIOR TO PERFORMANCE TESTING TO DETERMINE PERFORMANCE LOSS. THE GAS TURBINE PERFORMANCE TEST SHALL OCCUR WITHIN 100 FIRED HOURS OF THESE ACTIONS.
- * DEMONSTRATION OF GAS TURBINE PLANT PERFORMANCE SHALL BE IN ACCORDANCE WITH TEST PROCEDURES WHICH ARE MUTUALLY AGREED UPON.



Notes:

1. Degradation curves based on generic GE 7FA data from 2/9/1995.

| Project Sound Energy Number 132143 141 of 716.0 Preliminary Performance Summary May 27, 2016 - Rev A | | NEW & CLEAN PERFORMANCE | | | | | | | | | | |
|--|--|-------------------------|------------------------|----------------------|------------------------|----------------------|------------------------|------------------------|----------------------|------------------------|------------------------|----------------------|
| Section # | Description | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 | 1x1 |
| | | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower | Mech. Cooling Tower |
| | | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 |
| | | 63.0 | 63.0 | 63.0 | 63.0 | 63.0 | 63.0 | 63.0 | 63.0 | 63.0 | 63.0 | 63.0 |
| | | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 | 100 |
| | | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas |
| | | | | | | | | | | | | |
| NEW & CLEAN PERFORMANCE | | | | | | | | | | | | |
| Stack CO2 Output (each) | | 289,135 | 216,861 | 98,306 | 285,100 | 102,638 | 281,301 | 218,976 | 95,642 | 252,668 | 189,501 | 76,900 |
| Number of Gas Turbines in Operation | | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Stack CO2 Output | | 289,135 | 216,861 | 98,306 | 285,100 | 102,638 | 281,301 | 218,976 | 95,642 | 252,668 | 189,501 | 76,900 |
| Stack CO2 Output (MW) | | 2,355 | 1,863 | 787 | 2,340 | 875 | 2,309 | 1,823 | 769 | 2,117 | 1,628 | 627 |
| GT Heat Input (MW) (each) | | 2,613 | 2,061 | 884 | 2,596 | 1,272 | 2,363 | 2,023 | 821 | 2,349 | 1,862 | 703 |
| GT Heat Input (MW) (each) | | 10,874 | 9,479 | 7,424 | 11,088 | 7,817 | 10,987 | 9,755 | 7,699 | 10,525 | 9,380 | 7,533 |
| GT Plant Auxiliary Power | | | | | | | | | | | | |
| NET PLANT PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output | | 403,042 | 319,614 | 168,009 | 405,115 | 173,652 | 401,250 | 318,136 | 164,830 | 398,562 | 283,755 | 139,843 |
| Net Plant Heat Rate (HHV) | | 5,843 | 5,294 | 6,783 | 5,776 | 6,693 | 5,756 | 5,891 | 6,075 | 5,745 | 5,912 | 6,910 |
| Net Plant Heat Rate (LHV) | | 5,843 | 5,294 | 6,783 | 5,776 | 6,693 | 5,756 | 5,891 | 6,075 | 5,745 | 5,912 | 6,910 |
| Net Plant Efficiency (HHV) | | 58.4% | 57.6% | 50.5% | 59.1% | 51.7% | 59.3% | 58.1% | 51.1% | 59.4% | 57.7% | 49.4% |
| Net Plant Efficiency (LHV) | | 52.6% | 51.9% | 45.5% | 53.3% | 46.0% | 53.4% | 52.3% | 46.1% | 53.5% | 52.0% | 44.5% |
| REGULATED PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output Degradation Factor | | | | | | | | | | | | |
| Net Plant Heat Rate Degradation Factor | | | | | | | | | | | | |
| STACK EMISSIONS (PER UNIT) | | | | | | | | | | | | |
| NOx | ppmv @ 15% O2 lb/MWh (HHV) lb/hr | 0.0072 18.8 18.7 | 0.0072 14.8 14.7 | 0.0072 9.1 9.1 | 0.0072 18.7 18.7 | 0.0072 9.2 9.2 | 0.0072 18.5 18.5 | 0.0072 14.6 14.6 | 0.0072 8.8 8.8 | 0.0072 18.9 18.9 | 0.0072 13.4 13.4 | 0.0072 7.7 7.7 |
| SO | ppmv @ 15% O2 lb/MWh (HHV) lb/hr | 0.0044 11.5 11.5 | 0.0044 9.1 9.1 | 0.0044 5.5 5.5 | 0.0044 11.4 11.4 | 0.0044 5.6 5.6 | 0.0044 11.3 11.3 | 0.0044 8.9 8.9 | 0.0044 5.4 5.4 | 0.0044 11.1 11.1 | 0.0044 8.2 8.2 | 0.0044 4.7 4.7 |
| CO2 | lb/hr | 300,486 | 237,040 | 144,988 | 298,548 | 146,293 | 294,677 | 232,358 | 140,376 | 270,163 | 216,059 | 133,931 |
| WATER CONSUMPTION (PER UNIT) | | | | | | | | | | | | |
| Cooling Tower Makeup Water (5 COC) | GPM | 1,038 | 858 | 632 | 1,246 | 722 | 1,318 | 1,078 | 772 | 1,246 | 1,320 | 1,094 |
| Steam Cycle Makeup Water (2% of Flow) | GPM | 30 | 24 | 17 | 31 | 18 | 30 | 25 | 17 | 29 | 24 | 16 |
| GT Water Injection | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

1) PERFORMANCE IS BASED ON DATA FROM GT PRO FROM MAY 2016
2) CTG PERFORMANCE IS BASED ON DATA FROM GT PRO FROM MAY 2016
3) The fuel gas is unheated and is assumed to be supplied at 8. F.
4) No water conditioning applied.
5) HISS, STG and Heat Rejection System used using GT Pro software.
6) HISS, STG and Heat Rejection System selected by GT Pro software.
7) STG Last Stage Blade Geometry selected by GT Pro software.
8) Condenser Pressure designed to be 1.38 inches HgA at design (15.8) conditions.
9) Condenser Pressure designed to be 1.38 inches HgA at design (15.8) conditions.
10) Emission flow rate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PMW rates provided by GE.
11) SFC designed to reduce stack NOx to 2.0 ppmv @ 15% O2.

| RW Project Number 132143 Preliminary Performance Summary May 27, 2016 - Rev A | Engine Sound Energy | | | | | | | | | | | |
|---|--|---------------------------|-----------------------|----------------------------|---------------------------|-----------------------|----------------------------------|---------------------------------|------------------------|----------------------------|---------------------------|-----------------------|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Case # | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Description | 23 deg F 100% RICE Load | 23 deg F 75% RICE Load | 23 deg F MECL | 51 deg F 100% RICE Load | 51 deg F 75% RICE Load | 51 deg F MECL | ISO Conditions 100% RICE Load | ISO Conditions 75% RICE Load | ISO Conditions MECL | 88 deg F 100% RICE Load | 88 deg F 75% RICE Load | 88 deg F MECL |
| ICCE Configuration | 3x0 | 3x0 | 3x0 | 3x0 | 3x0 | 3x0 | 3x0 | 3x0 | 3x0 | 3x0 | 3x0 | 3x0 |
| Ambient Temperature | 23 | 23 | 23 | 51 | 51 | 51 | 59 | 59 | 59 | 88 | 88 | 88 |
| Relative Humidity | 40 | 40 | 40 | 75 | 75 | 75 | 60 | 60 | 60 | 80 | 80 | 80 |
| Altitude | 148 | 148 | 148 | 148 | 148 | 148 | 148 | 148 | 148 | 148 | 148 | 148 |
| Responsible Engine Model | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG |
| Fuel | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas |
| Load Level | 100 | 75 | 25 | 100 | 75 | 25 | 100 | 75 | 25 | 100 | 75 | 25 |
| NEW & CLEAN PERFORMANCE | | | | | | | | | | | | |
| Stress RICE Output (each) | 18,817 | 14,118 | 4,621 | 18,817 | 14,118 | 4,621 | 18,817 | 14,118 | 4,621 | 18,817 | 14,118 | 4,621 |
| Sum of Engines in Operation | 56,451 | 42,354 | 13,863 | 56,451 | 42,354 | 13,863 | 56,451 | 42,354 | 13,863 | 56,451 | 42,354 | 13,863 |
| RICE Heat Input (HHV) (each) | 137.6 | 108.0 | 43.0 | 137.6 | 108.0 | 43.0 | 137.6 | 108.0 | 43.0 | 137.6 | 108.0 | 43.0 |
| RICE Heat Input (HHV) (each) | 137.6 | 108.0 | 43.0 | 137.6 | 108.0 | 43.0 | 137.6 | 108.0 | 43.0 | 137.6 | 108.0 | 43.0 |
| Load Plant Auxiliary Power | 867 | 741 | 485 | 867 | 741 | 485 | 867 | 741 | 485 | 867 | 741 | 485 |
| NET PLANT PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output | 53,604 | 41,613 | 13,378 | 53,604 | 41,613 | 13,378 | 53,604 | 41,613 | 13,378 | 53,604 | 41,613 | 13,378 |
| Net Plant Heat Input (HHV) | 5,259 | 4,135 | 1,378 | 5,259 | 4,135 | 1,378 | 5,259 | 4,135 | 1,378 | 5,259 | 4,135 | 1,378 |
| Net Plant Heat Input (HHV) | 4,239 | 3,296 | 1,070 | 4,239 | 3,296 | 1,070 | 4,239 | 3,296 | 1,070 | 4,239 | 3,296 | 1,070 |
| Net Plant Efficiency (HHV) | 46.0% | 43.8% | 35.4% | 45.9% | 43.8% | 35.4% | 45.8% | 43.8% | 35.3% | 45.6% | 43.5% | 35.3% |
| Net Plant Efficiency (HHV) | 41.2% | 39.5% | 31.9% | 41.3% | 39.5% | 31.9% | 41.3% | 39.4% | 31.8% | 41.1% | 39.2% | 31.8% |
| DEGRADED PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output (Degradation Factor) | | | | | | | | | | | | |
| Net Plant Heat Input (Degradation Factor) | | | | | | | | | | | | |
| Net Plant Heat Input (Degradation Factor) | | | | | | | | | | | | |
| STACK EMISSIONS (PER UNIT) | | | | | | | | | | | | |
| NOx | ppmvd @ 15% O2 lb/AMbu (HHV) lb/hr | 5.0 0.016 2.49 | 5.0 0.015 0.71 | 5.0 0.016 0.71 | 5.0 0.016 2.49 | 6.0 0.015 0.71 | 5.0 0.016 2.49 | 5.0 0.018 2.10 | 6.0 0.015 0.71 | 5.0 0.016 2.49 | 5.0 0.018 2.10 | 6.0 0.015 0.71 |
| CO | ppmvd @ 15% O2 lb/AMbu (HHV) lb/hr | 15.0 0.033 4.39 | 15.0 0.043 4.39 | 15.0 0.043 4.39 | 15.0 0.033 4.39 | 15.0 0.043 4.39 | 15.0 0.033 4.39 | 15.0 0.036 4.39 | 15.0 0.043 4.39 | 15.0 0.033 4.39 | 15.0 0.036 4.39 | 15.0 0.043 4.39 |
| CO2 | lb/hr | 17,830 | 14,006 | 5,381 | 17,830 | 14,006 | 5,381 | 17,830 | 14,006 | 17,830 | 14,006 | 5,381 |
| WATER CONSUMPTION (PER UNIT) | | | | | | | | | | | | |
| Cooling Tower Makeup Water (5 COC) | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| Steam Cycle Makeup Water (2% of Flow) | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| Engine Water Injection | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

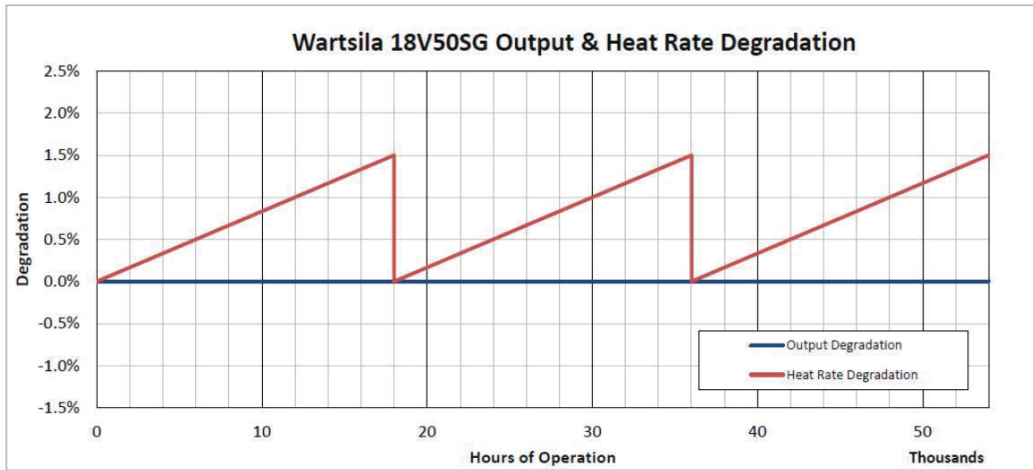
1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.
2) Engine performance is based on data obtained from Wartsila in April 2016.
3) The fuel gas is unheated and is assumed to be supplied at 80 °F.
4) The ambient conditions are assumed to be 23 deg F, 40% RH, and 148 ft altitude.
5) Auxiliary power consumption assumes a 3-engine power block.
6) SCR designed to reduce stack NOx to 5.0 ppmvd @ 15% O2 at full load.
7) Wartsila engines assumed to employ air-cooled radiators for heat rejection.

| RW Project Number 132343 Preliminary Performance Summary May 27, 2016 - Rev A Case # Description | NEW & CLEAN PERFORMANCE | | | | | | | | | | | |
|---|--|-----------------------|----------------------------|---------------------------|-----------------------|----------------------------------|---------------------------------|-------------------------|----------------------------|---------------------------|-----------------------|-----------------------|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| 23 deg F 75% RICE Load | 23 deg F 100% RICE Load | 23 deg F MIECL | 51 deg F 100% RICE Load | 51 deg F 75% RICE Load | 51 deg F MIECL | ISO Conditions 100% RICE Load | ISO Conditions 75% RICE Load | ISO Conditions MIECL | 88 deg F 100% RICE Load | 88 deg F 75% RICE Load | 88 deg F MIECL | |
| 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | 600 | |
| 23 | 23 | 23 | 51 | 51 | 51 | 59 | 59 | 59 | 88 | 88 | 88 | |
| 40 | 40 | 40 | 79 | 79 | 79 | 60 | 60 | 60 | 88 | 88 | 88 | |
| 148 | 148 | 148 | 178 | 178 | 178 | 148 | 148 | 148 | 198 | 198 | 198 | |
| Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | Wartsila 18V450SG | |
| Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | |
| 100 | 75 | 25 | 100 | 75 | 25 | 100 | 75 | 25 | 100 | 75 | 25 | |
| 14,118 | 14,118 | 4,621 | 18,817 | 14,118 | 4,621 | 18,817 | 14,118 | 4,621 | 18,817 | 14,118 | 4,621 | |
| 84,708 | 84,708 | 27,206 | 112,902 | 84,708 | 27,206 | 112,902 | 84,708 | 27,206 | 112,902 | 84,708 | 27,206 | |
| 108.0 | 108.0 | 43.0 | 137.6 | 108.0 | 43.0 | 137.6 | 108.0 | 43.0 | 137.6 | 108.0 | 43.0 | |
| 119.8 | 119.8 | 47.7 | 152.7 | 119.8 | 47.7 | 152.7 | 119.8 | 47.7 | 152.7 | 119.8 | 47.7 | |
| 1,684 | 1,684 | 970 | 2,652 | 1,684 | 970 | 2,652 | 1,684 | 970 | 2,652 | 1,684 | 970 | |
| 11,208 | 8,226 | 26,756 | 10,983 | 8,226 | 26,756 | 110,970 | 83,099 | 26,728 | 10,918 | 8,200 | 26,672 | |
| 10,207 | 8,038 | 10,207 | 8,206 | 8,038 | 10,207 | 8,206 | 8,038 | 10,219 | 8,206 | 8,038 | 10,201 | |
| 46.0% | 43.8% | 35.4% | 45.9% | 43.8% | 35.4% | 45.8% | 43.8% | 35.3% | 45.6% | 43.5% | 35.3% | |
| 41.2% | 39.5% | 31.9% | 41.3% | 39.5% | 31.9% | 41.3% | 39.4% | 31.8% | 41.1% | 39.2% | 31.8% | |
| SEVERE DEGRADATION WORKSHEET | | | | | | | | | | | | |
| Net Plant Output (Degradation Factor) | | | | | | | | | | | | |
| Net Plant Heat Rate (Degradation Factor) | | | | | | | | | | | | |
| STACK EMISSIONS (PER UNIT) | | | | | | | | | | | | |
| NOx | ppmvd @ 15% O2 lb/AMbu (HHV) lb/hr | 5.0 0.016 2.49 | 5.0 0.016 2.49 | 6.0 0.015 0.71 | 5.0 0.016 2.49 | 5.0 0.016 2.49 | 5.0 0.016 2.49 | 5.0 0.016 2.49 | 5.0 0.016 2.49 | 5.0 0.016 2.49 | 5.0 0.016 2.49 | 6.0 0.015 0.71 |
| CO | ppmvd @ 15% O2 lb/AMbu (HHV) lb/hr | 15.0 0.033 4.39 | 15.0 0.033 4.39 | 15.0 0.043 2.03 | 15.0 0.036 4.39 | 15.0 0.033 4.39 | 15.0 0.036 4.39 | 15.0 0.043 2.03 | 15.0 0.033 4.39 | 15.0 0.033 4.39 | 15.0 0.033 4.39 | 15.0 0.043 2.03 |
| CO2 | lb/HR | 17,830 | 17,830 | 5,381 | 17,830 | 17,830 | 14,006 | 5,381 | 17,830 | 14,006 | 5,381 | 17,830 |
| WATER CONSUMPTION (PER UNIT) | | | | | | | | | | | | |
| Cooling Tower Makeup Water (5 COC) | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| Steam Cycle Makeup Water (2% of Flow) | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| Engine Water Injection | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| 1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY. 2) Engine performance is based on data obtained from Wartsila in April 2016. 3) The fuel gas is unheated and is assumed to be supplied at 80 °F. 4) Ambient conditions are assumed to be 75 °F, 60% RH, and 10.2 m/s wind speed. 5) Auxiliary power consumption is assumed to be 3% of engine power block. 6) SCR designed to reduce stack NOx to 5.0 ppmvd @ 15% O2 at full load. 7) Wartsila engines assumed to employ air-cooled radiators for heat rejection. | | | | | | | | | | | | |

| Flight Sound Energy 12x VertiStar 150S6G Preliminary Performance Summary May 27, 2016 - Rev A | | | | | | | | | | | | |
|--|---------------------------|--------------------------|-----------------|---------------------------|--------------------------|-----------------|--------------------------------|-------------------------------|----------------------|---------------------------|--------------------------|-----------------|
| Revision # | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Description | 50 kts F 100% RCE Load | 75 kts F 75% RCE Load | 50 kts F MEL | 51 kts F 100% RCE Load | 51 kts F 75% RCE Load | 51 kts F MEL | 50 Conditions 100% RCE Load | 50 Conditions 75% RCE Load | 50 Conditions MEL | 50 kts F 100% RCE Load | 50 kts F 75% RCE Load | 50 kts F MEL |
| RCE Configuration | 1200 | 1200 | 1200 | 1200 | 1200 | 1200 | 1200 | 1200 | 1200 | 1200 | 1200 | 1200 |
| Relative Humidity | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| Ambient Pressure | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.70 | 14.70 | 14.70 | 14.68 | 14.68 | 14.68 |
| Wind-Propagating Engine Model | Vert-14.68-0506 | Vert-14.68-0506 | Vert-14.68-0506 | Vert-14.68-0506 | Vert-14.68-0506 | Vert-14.68-0506 | Vert-14.70-0506 | Vert-14.70-0506 | Vert-14.70-0506 | Vert-14.68-0506 | Vert-14.68-0506 | Vert-14.68-0506 |
| Load Level | 100 | 75 | 25 | 100 | 75 | 25 | 100 | 75 | 25 | 100 | 75 | 25 |
| NEW & CLEAN PERFORMANCE | | | | | | | | | | | | |
| Gross RCE Output (each) | 18,217 | 14,118 | 4,621 | 18,217 | 14,118 | 4,621 | 18,217 | 14,118 | 4,621 | 18,217 | 14,118 | 4,621 |
| Number of Engines in Operation | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 |
| RCE Heat Input (LHV) (each) | 3,397 | 156,046 | 43,0 | 3,397 | 156,046 | 43,0 | 3,397 | 156,046 | 43,0 | 3,397 | 156,046 | 43,0 |
| RCE Heat Input (HHV) (each) | 132.7 | 119.8 | 47.7 | 132.7 | 119.8 | 47.7 | 132.7 | 119.8 | 47.7 | 132.7 | 119.8 | 47.7 |
| Total Plant Auxiliary Power | 3,397 | 2,985 | 1,941 | 3,397 | 2,985 | 1,941 | 3,397 | 2,985 | 1,941 | 3,397 | 2,985 | 1,941 |
| NET PLANT PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output | 22,247 | 16,651 | 5,261 | 22,247 | 16,651 | 5,261 | 22,247 | 16,651 | 5,261 | 22,247 | 16,651 | 5,261 |
| Net Plant Heat Rate (LHV) | 8,239 | 8,639 | 10,707 | 8,239 | 8,639 | 10,707 | 8,239 | 8,639 | 10,707 | 8,239 | 8,639 | 10,707 |
| Net Plant Heat Rate (HHV) | 46.0% | 43.8% | 35.4% | 46.0% | 43.8% | 35.4% | 46.0% | 43.8% | 35.4% | 46.0% | 43.8% | 35.4% |
| Net Plant Efficiency (LHV) | 41.2% | 39.3% | 31.7% | 41.2% | 39.3% | 31.7% | 41.2% | 39.3% | 31.7% | 41.2% | 39.3% | 31.7% |
| DEGRADED PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output (Degradation Factor) | 22,247 | 16,651 | 5,261 | 22,247 | 16,651 | 5,261 | 22,247 | 16,651 | 5,261 | 22,247 | 16,651 | 5,261 |
| Net Plant Heat Rate (LHV) (Degradation Factor) | 8,239 | 8,639 | 10,707 | 8,239 | 8,639 | 10,707 | 8,239 | 8,639 | 10,707 | 8,239 | 8,639 | 10,707 |
| Net Plant Efficiency (LHV) (Degradation Factor) | 41.2% | 39.3% | 31.7% | 41.2% | 39.3% | 31.7% | 41.2% | 39.3% | 31.7% | 41.2% | 39.3% | 31.7% |
| STACK EMISSIONS (PER UNIT) | | | | | | | | | | | | |
| NOx | 5.0 | 5.0 | 6.0 | 5.0 | 5.0 | 6.0 | 5.0 | 5.0 | 6.0 | 5.0 | 5.0 | 6.0 |
| | 0.016 | 0.018 | 0.015 | 0.016 | 0.018 | 0.015 | 0.016 | 0.018 | 0.015 | 0.016 | 0.018 | 0.015 |
| | 2.49 | 2.18 | 0.71 | 2.49 | 2.18 | 0.71 | 2.49 | 2.18 | 0.71 | 2.49 | 2.18 | 0.71 |
| CO | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 | 15.0 |
| | 0.033 | 0.036 | 0.043 | 0.033 | 0.036 | 0.043 | 0.033 | 0.036 | 0.043 | 0.033 | 0.036 | 0.043 |
| | 4.97 | 4.35 | 2.03 | 4.97 | 4.35 | 2.03 | 4.97 | 4.35 | 2.03 | 4.97 | 4.35 | 2.03 |
| CO2 | 17,250 | 14,006 | 5,581 | 17,250 | 14,006 | 5,581 | 17,250 | 14,006 | 5,581 | 17,250 | 14,006 | 5,581 |
| WATER CONSUMPTION (PER UNIT) | | | | | | | | | | | | |
| Cooling Tower Makeup Water (G COC) | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| Steam Cycle Makeup Water (2% of flow) | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| Engine Water Injection | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.
2) Engine performance is based on data obtained from VertiStar in April 2016.
3) Auxiliary power estimate assumes a 3-engine power block.
4) SCE designed to reduce stack NOx to 50 ppmw @ 15% O2 at full load.
5) VertiStar engines assumed to employ pre-cooled oxidizers for NOx reduction.

Puget Sound Energy
B&V Project Number 192143
Wartsila 18V50SG Degradation Curve



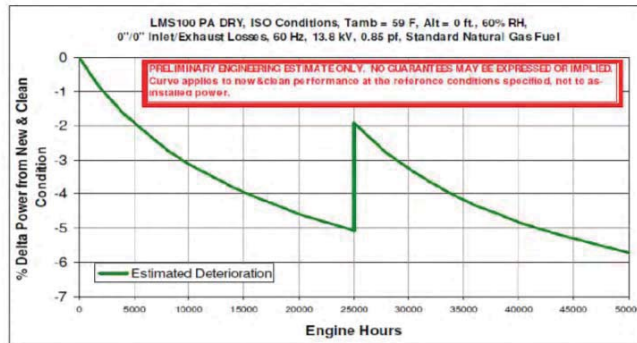
Notes:

1. Degradation curves based on e-mail from Wartsila on 11/7/2012.

| Project Sound Energy 100% GE LMS100PA+ Preliminary Performance Summary May 27, 2016 - Rev A | | | | | | | | | | | | |
|--|--|--------------------------|-------------------|---------------------------|--------------------------|-------------------|---------------|--------------|-------------------------|---------------------------|--------------------------|-------------------|
| Section # | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Description | 23 deg F 75% CTG Load | 23 deg F 75% CTG Load | 23 deg F MISCL | 51 deg F 100% CTG Load | 51 deg F 75% CTG Load | 51 deg F MISCL | 100% CTG Load | 75% CTG Load | ISO Conditions MISCL | 88 deg F 100% CTG Load | 88 deg F 75% CTG Load | 88 deg F MISCL |
| CTG Configuration | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 |
| Ambient Temperature | 23 | 23 | 23 | 51 | 51 | 51 | 51 | 51 | 51 | 88 | 88 | 88 |
| Relative Humidity | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| CTG Model | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ | GE LMS100PA+ |
| CTG Fuel | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas |
| CTG Load Level | 100 | 75 | 25 | 100 | 75 | 25 | 100 | 75 | 25 | 100 | 75 | 25 |
| NEW & CLEAN PERFORMANCE | | | | | | | | | | | | |
| Stress CTG Output (each) | 114,920 | 86,191 | 28,730 | 185,508 | 87,360 | 29,127 | 117,000 | 87,750 | 29,250 | 112,423 | 84,316 | 28,108 |
| Stress CTG Output (each) - in Operation | | | | | | | | | | | | |
| Stress CTG O/E | 229,841 | 172,381 | 57,460 | 233,016 | 174,760 | 58,253 | 234,000 | 175,500 | 58,499 | 224,846 | 168,632 | 56,216 |
| CTG Heat Input (LHV) (each) | 887 | 711 | 351 | 902 | 720 | 355 | 908 | 724 | 356 | 886 | 706 | 349 |
| CTG Heat Input (HHV) (each) | 984 | 789 | 389 | 1,001 | 799 | 393 | 1,008 | 803 | 395 | 984 | 783 | 387 |
| Cost Plant Investment (each) | 5,816 | 4,673 | 2,036 | 5,884 | 4,731 | 2,078 | 5,939 | 4,784 | 2,083 | 5,777 | 4,631 | 2,029 |
| NET PLANT PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output (LHV) | 29,225 | 19,708 | 34,694 | 27,332 | 17,001 | 35,471 | 23,829 | 13,767 | 35,711 | 20,289 | 14,001 | 33,466 |
| Net Plant Output (HHV) | 32,800 | 21,800 | 38,400 | 30,000 | 19,000 | 37,000 | 25,000 | 14,000 | 36,000 | 21,000 | 15,000 | 34,000 |
| Net Plant Heat Rate (LHV) | 4,791 | 3,652 | 14,242 | 4,807 | 3,602 | 14,184 | 4,829 | 3,602 | 14,189 | 4,871 | 3,650 | 14,177 |
| Net Plant Heat Rate (HHV) | 4,816 | 3,678 | 14,266 | 4,832 | 3,628 | 14,208 | 4,856 | 3,628 | 14,213 | 4,880 | 3,676 | 14,204 |
| Net Plant Efficiency (LHV) | 34.8% | 40.3% | 24.0% | 34.8% | 38.3% | 26.7% | 42.3% | 38.7% | 28.1% | 42.3% | 39.7% | 28.2% |
| Net Plant Efficiency (HHV) | | | | | | | | | | | | |
| DEGRADED PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output Degradation Factor | | | | | | | | | | | | |
| Net Plant Heat Rate Degradation Factor | | | | | | | | | | | | |
| STACK EMISSIONS (PER UNIT) | | | | | | | | | | | | |
| NOx | 2.5 ppmvd @ 15% O2 lb/1000 ft ³ | 2.5 0.009 | 2.5 0.009 | 2.5 0.009 | 2.5 0.009 | 2.5 0.009 | 2.5 0.009 | 2.5 0.009 | 2.5 0.009 | 2.5 0.009 | 2.5 0.009 | 2.5 0.009 |
| SO | 6 ppmvd @ 15% O2 lb/1000 ft ³ | 6 0.031 | 6 0.031 | 6 0.031 | 6 0.031 | 6 0.031 | 6 0.031 | 6 0.031 | 6 0.031 | 6 0.031 | 6 0.031 | 6 0.031 |
| CO2 | 113,201 lb/hr | 99,675 | 44,787 | 115,109 | 91,896 | 45,233 | 115,884 | 92,313 | 45,412 | 113,088 | 90,949 | 45,488 |
| WATER CONSUMPTION (PER UNIT) | | | | | | | | | | | | |
| Boiling Tower Makeup Water (5 COCI) | 175 | 128 | 40 | 209 | 157 | 55 | 215 | 165 | 60 | 235 | 184 | 72 |
| Steam Cycle Makeup Water (2% of flow) | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| CTG Water Injection | 58 | 42 | 15 | 55 | 28 | 11 | 56 | 40 | 13 | 53 | 27 | 12 |

1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.
2) CTG performance is based on data from GE APPS from May 2016
3) Water injection to control CTG NOx to 25 ppm @ 15% O2
4) The fuel supply pressure is assumed to be 400 psig at the site boundary
5) The fuel supply pressure is assumed to be 400 psig at the site boundary
6) No inlet conditioning applied.
7) Auxiliary loads estimated by GE Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
8) SDCR is based on in-house calculations and indicative PPM rates provided by GE
9) SDCR designed to reduce stack NOx to 2.5 ppmvd @ 15% O2.

Power Deterioration for LMS100 PA Dry at ISO Conditions



GE Proprietary Information

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Heat Rate Deterioration for LMS100 PA Dry at ISO Conditions



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Notes:

1. Degradation curves based on generic GE LMS100PA data from 7/8/2008.

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|---|--------------------------------|--------------------------|-------------------|---------------------------|--------------------------|-------------------|---------------|---------------|-------------------------|---------------------------|--------------------------|-------------------|
| Section # | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 |
| Description | 23 deg F 75% CTG Load | 23 deg F 75% CTG Load | 23 deg F MISCL | 51 deg F 100% CTG Load | 51 deg F 75% CTG Load | 51 deg F MISCL | 100% CTG Load | 100% CTG Load | ISO Conditions MISCL | 88 deg F 100% CTG Load | 88 deg F 75% CTG Load | 88 deg F MISCL |
| CTG Configuration | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 | 1x0 |
| Ambient Temperature | 23 | 23 | 23 | 51 | 51 | 51 | 51 | 51 | 59 | 88 | 88 | 88 |
| Relative Humidity | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 |
| Plant Pressure | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.68 | 14.70 | 14.70 | 14.70 | 14.68 | 14.68 | 14.68 |
| CTG Model | GE 7F 05 | GE 7F 05 | GE 7F 05 | GE 7F 05 | GE 7F 05 | GE 7F 05 | GE 7F 05 | GE 7F 05 | GE 7F 05 | GE 7F 05 | GE 7F 05 | GE 7F 05 |
| CTG Fuel | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas | Natural Gas |
| CTG Load Level | 100 | 100 | 45 | 100 | 75 | 45 | 100 | 100 | 45 | 100 | 75 | 45 |
| NEW & CLEAN PERFORMANCE | | | | | | | | | | | | |
| Stress CTG Output (each) | 244,740 | 188,555 | 110,133 | 242,391 | 181,798 | 109,076 | 240,860 | 186,646 | 108,387 | 227,576 | 170,682 | 102,409 |
| Stress CTG Output (each) - Conditions in Operation | | | | | | | | | | | | |
| Stress CTG Input | 242,740 | 188,555 | 110,133 | 242,391 | 181,793 | 109,076 | 240,860 | 186,646 | 108,387 | 227,576 | 170,682 | 102,409 |
| CTG Heat Input (MW) (each) | 2,079 | 1,626 | 1,221 | 2,074 | 1,617 | 1,202 | 2,066 | 1,616 | 1,195 | 2,066 | 1,546 | 1,153 |
| CTG Heat Input (MMBtu/h) (each) | 2,306 | 1,804 | 1,355 | 2,301 | 1,794 | 1,333 | 2,292 | 1,786 | 1,286 | 2,296 | 1,715 | 1,280 |
| Cost Plant Auxiliary Power | 3,430 | 2,921 | 2,620 | 3,412 | 2,901 | 2,612 | 3,393 | 2,884 | 2,601 | 3,381 | 2,874 | 2,592 |
| NET PLANT PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output (MW) | 241,311 | 180,384 | 107,713 | 238,979 | 178,336 | 105,664 | 237,400 | 177,696 | 105,980 | 224,275 | 167,808 | 100,047 |
| Net Plant Output (MMBtu/h) | 2,846 | 2,164 | 1,284 | 2,834 | 2,148 | 1,270 | 2,826 | 2,142 | 1,270 | 2,818 | 2,139 | 1,261 |
| Net Plant Heat Rate (MMBtu/MWh) | 9,558 | 9,992 | 12,975 | 9,631 | 10,031 | 12,901 | 9,633 | 10,051 | 12,550 | 9,837 | 10,220 | 12,700 |
| Net Plant Efficiency (MW) % | 39.6% | 37.9% | 30.1% | 39.3% | 37.8% | 30.3% | 39.2% | 37.7% | 30.3% | 38.9% | 37.1% | 29.6% |
| Net Plant Efficiency (MMBtu) % | 35.7% | 34.2% | 27.1% | 35.4% | 34.0% | 27.3% | 35.4% | 34.0% | 27.3% | 34.7% | 33.4% | 26.7% |
| DEGRADED PERFORMANCE | | | | | | | | | | | | |
| Net Plant Output Degradation Factor | | | | | | | | | | | | |
| Net Plant Heat Rate Degradation Factor | | | | | | | | | | | | |
| STACK EMISSIONS (PER UNIT) | | | | | | | | | | | | |
| NOx | ppmv @ 15% O2 lb/MMBtu (MM) | 2.5 0.059 | 2.5 0.059 | 2.5 0.059 | 2.5 0.059 | 2.5 0.059 | 2.5 0.059 | 2.5 0.059 | 2.5 0.059 | 2.5 0.059 | 2.5 0.059 | 2.5 0.059 |
| SO | ppmv @ 15% O2 lb/MMBtu (MM) | 2.5 0.065 | 2.5 0.065 | 2.5 0.065 | 2.5 0.065 | 2.5 0.065 | 2.5 0.065 | 2.5 0.065 | 2.5 0.065 | 2.5 0.065 | 2.5 0.065 | 2.5 0.065 |
| CO2 | lb/MWh | 265,219 | 207,467 | 155,751 | 264,643 | 206,300 | 153,837 | 263,573 | 152,459 | 253,696 | 197,206 | 147,137 |
| WATER CONSUMPTION (PER UNIT) | | | | | | | | | | | | |
| Boiling Tower Makeup Water (5 COCI) | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| Steam Cycle Makeup Water (2% of flow) | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |
| CTG Water Injection | GPM | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

1) PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.
 2) CTG performance is based on data from GTP Web from May 2016.
 3) The fuel gas is unheated and is assumed to be supplied at 80° F.
 4) The plant is assumed to be operating at 50% load. The auxiliary power is assumed to be 400 psm at this site boundary.
 5) No heat conditioning applied.
 6) No heat conditioning applied.
 7) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch.
 8) Emission (lb/MMBtu) estimates based on Black & Veatch in-house calculations and indicative PMV rates provided by GE.
 9) SOx designed to reduce stack NOx to 1.5 ppmv @ 15% O2.

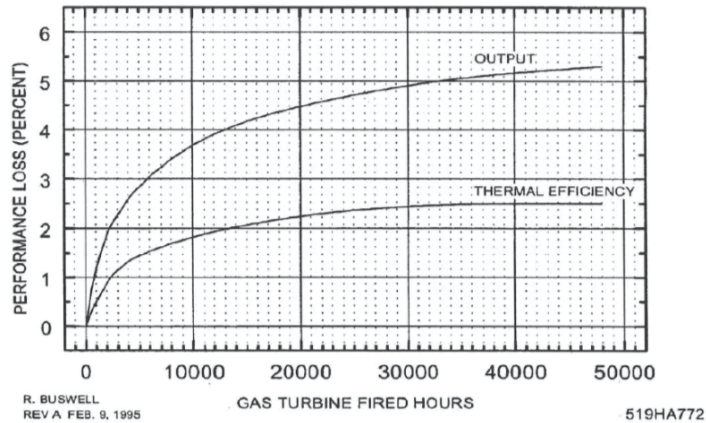


GE Power Systems

EXPECTED GAS TURBINE PLANT PERFORMANCE LOSS FOLLOWING NORMAL MAINTENANCE AND OFF-LINE COMPRESSOR WATER WASH

THE AGED PERFORMANCE EFFECTS REPRESENTED BY THESE CURVES ARE BASED ON THE FOLLOWING:

- PERFORMANCE IS RELATIVE TO THE GUARANTEE LEVEL.
- ALL GAS TURBINE PLANT EQUIPMENT SHALL BE OPERATED AND MAINTAINED IN ACCORDANCE WITH GE'S RECOMMENDED PROCEDURES FOR OPERATION, PREVENTIVE MAINTENANCE, INSPECTION AND BOTH ON-LINE AND OFF-LINE CLEANING.
- ALL OPERATIONS SHALL BE WITHIN THE DESIGN CONDITIONS SPECIFIED IN THE RELEVANT TECHNICAL SPECIFICATIONS.
- A DETAILED OPERATIONAL LOG SHALL BE MAINTAINED FOR ALL RELEVANT OPERATIONAL DATA, TO BE AGREED TO AMONGST THE PARTIES PRIOR TO COMMENCEMENT OF CONTRACT.
- GE TECHNICAL PERSONNEL SHALL HAVE ACCESS TO PLANT OPERATIONAL DATA, LOGS, AND SITE VISITS PRIOR TO CONDUCTING A PERFORMANCE TEST. THE OWNER WILL CLEAN AND MAINTAIN THE EQUIPMENT. THE DEGREE OF CLEANING AND MAINTENANCE WILL BE DETERMINED BASED ON THE OPERATING HISTORY OF EACH UNIT, ATMOSPHERIC CONDITIONS EXPERIENCED DURING THE PERIOD OF OPERATION, THE PREVENTIVE AND SCHEDULED MAINTENANCE PROGRAMS EXECUTED AND THE RESULTS OF THE GE INSPECTION.
- THE GAS TURBINE WILL BE SHUT DOWN FOR INSPECTION AND OFF-LINE COMPRESSOR WATER WASH, AS A MINIMUM, IMMEDIATELY PRIOR TO PERFORMANCE TESTING TO DETERMINE PERFORMANCE LOSS. THE GAS TURBINE PERFORMANCE TEST SHALL OCCUR WITHIN 100 FIRED HOURS OF THESE ACTIONS.
- DEMONSTRATION OF GAS TURBINE PLANT PERFORMANCE SHALL BE IN ACCORDANCE WITH TEST PROCEDURES WHICH ARE MUTUALLY AGREED UPON.



Notes:

1. Degradation curves based on generic GE 7FA data from 2/9/1995.

Appendix B. Air-Cooled Design Considerations

Combined cycle power plants and some peaking power plants require large heat rejection systems for proper operation. For a combined cycle power plant with adequate water supply and water discharge capacity, the combination of a surface condenser and wet mechanical draft cooling tower is the most common method of rejecting heat from a steam bottoming cycle to atmosphere. This method of heat rejection allows for a low steam turbine exhaust pressure and temperature, which results in a greater thermal efficiency of the bottoming cycle. However, water losses for this heat rejection method are high compared to alternative, dry cooling methods. For example, operation of the 1x1 7F.05 combined cycle option (CC-A) would require approximately 1,000 to 1,500 gpm of water during full load operation, depending on ambient conditions.

In areas where water conservation is a high priority or water discharge is not available, air cooled condensers (ACCs) are usually employed. Water losses with an ACC-based heat rejection system are minimal. This method of heat rejection is more expensive in terms of capital cost than a surface condenser and wet mechanical draft cooling tower. Also, the steam turbine exhaust pressure and temperature are typically higher with an ACC, which results in a lower bottoming cycle efficiency compared to wet cooling methods.

O&M costs required to maintain an air cooled condenser are higher than the costs required to maintain a surface condenser and wet mechanical draft cooling tower. However, the cost savings in water treatment chemicals would likely offset the additional maintenance cost. Table B-1 provides a summary comparison for a typical combined cycle operating during hot day conditions. The performance difference during average day conditions would be reduced.

Table B-1 Typical Combined Cycle Wet versus Dry Cooling Comparison

| | WET SURFACE CONDENSER/ WET MECHANICAL DRAFT COOLING TOWER | AIR COOLED CONDENSER |
|---------------------|--|-----------------------------|
| Capital Cost | BASE | +5 percent |
| Net Plant Output | BASE | -1.5 percent |
| Net Plant Heat Rate | BASE | +1.5 percent |

Some peaking plants also rely on large heat rejection systems for proper operation. GE's LMS100 combustion turbine uses a compressor intercooler to cool air leaving the low pressure compressor prior to entering the high pressure compressor. Using an air cooled intercooler loop is possible but results in a much greater hot day performance impact. A summary comparison for an LMS100 operating during typical hot day conditions is presented in Table B-2.

Table B-2 Typical GE LMS100 Wet versus Dry Cooling Comparison

| | WET MECHANICAL DRAFT COOLING TOWER | AIR COOLED HEAT EXCHANGER |
|---------------------|------------------------------------|---------------------------|
| Capital Cost | BASE | +3 to +5 percent |
| Net Plant Output | BASE | -5 to -10 percent |
| Net Plant Heat Rate | BASE | +1 to +3 percent |

Wartsila’s 18V50SG also relies on a large heat rejection system, mainly for engine jacket cooling. Unlike the LMS100 or a combined cycle’s bottoming cycle, the temperatures required are not as stringent. Therefore, the performance impact associated with an air cooled heat exchanger is not nearly as great. However, space requirements for heat rejection equipment may be a concern. The footprint of an air cooled heat exchanger for a single Wartsila 18V50SG engine is roughly 100 feet by 100 feet, which is approximately the space required for the engine itself. One solution would be to locate the air cooled heat exchangers on top of the engine hall. Wartsila has done this as EPC contractor for projects outside the US. However, this approach will result in increased engine hall building costs. Below is a summary comparison for 18V50SG operating during typical hot day conditions.

Table B-3 Typical Wartsila 18V50SG Wet versus Dry Cooling Comparison

| | WET MECHANICAL DRAFT COOLING TOWER | AIR COOLED HEAT EXCHANGER |
|---------------------|------------------------------------|---------------------------|
| Capital Cost | BASE | +2 percent |
| Net Plant Output | BASE | -1 percent |
| Net Plant Heat Rate | BASE | +1 percent |

Appendix C. Supplemental HRSG Duct Firing

Supplementary HRSG duct firing is often incorporated into an HRSG design as it allows for increased steam production and resulting increased steam turbine output. Supplemental HRSG duct firing can range from a small amount which allows for constant steam turbine output over the ambient temperature range (i.e., duct firing makes up for the loss in exhaust energy from the combustion turbine at high ambient temperatures) up to a 25 percent increase in net plant output. The burners used for supplementary firing are generally installed in the HRSG, downstream of the final superheater/reheater heat transfer surfaces. The duct burner system consists of pressure reducing station(s); main fuel supply system(s); fuel metering; pilot fuel supply system; cooling air system; augmenting air supply systems; burner elements; flame holders/stabilizers; baffles, scanners; igniters; and piping between associated skids and the HRSG. View ports for visually monitoring the duct burners are provided in the ductwork downstream of burners by the HRSG Supplier. Additionally, skid mounted components for fuel supply, cooling air, and burner management systems are also furnished.

The SCR and oxidation catalysts, as appropriate, can be designed to maintain stack emissions due to the additional contribution of emissions from supplemental duct firing.

To accommodate the additional steam production, the HRSG and steam turbine generator must be designed accordingly. Given that the steam turbine in a combined cycle application is operated in a sliding pressure mode, the unfired throttle pressure will be lower than a comparable combined cycle design with no duct firing capability.

Boiler feed and condensate pump capacity must also be increased to address both fired and steam turbine bypass operation. A fired design, while firing, will result in an increased auxiliary load. Auxiliary loads while in unfired mode may represent a larger percentage of total plant load due to the over-sizing of the balance of plant (BOP) systems to meet fired conditions. In addition, the heat rejection system capacity may be increased to handle the additional heat load when fired while maintaining both desired level of performance and steam turbine backpressure (below alarm limits).

Performance and cost impacts associated with supplemental HRSG duct firing vary greatly with equipment selection. Below are some cost and performance highlights that are typical for supplemental HRSG duct firing designs for utility-scale combined cycle applications:

- **Capital Cost** – The incremental cost associated with a revised HRSG design, larger steam turbine, larger pumps, and associated BOP systems and equipment would be about \$300 to \$400 per kilowatt of increased net output, on an overnight EPC cost basis. For example, installing the required duct firing systems to provide an increase of 30 MW in steam cycle output would cost approximately \$10 million. Considering total capital costs, adding supplemental HRSG duct firing capability to a nominal, un-fired 300 MW-net plant design (and raising the net output to a total of 330 MW) would increase the cost of the combined cycle facility from approximately \$300 million to \$310 million, on an overnight EPC cost basis.

- **Net Plant Output** – Employing supplemental HRSG duct firing can result in a total net plant output increase of up to about 25 percent if the HRSG is heavily fired. A 10 to 20 percent increase is common.
- **Net Plant Heat Rate** – The incremental net heat rate for supplemental HRSG duct firing is about 8,000 to 9,000 Btu/kWh (HHV). When operating the plant with the CTG(s) at full load and not utilizing the duct burners, the plant heat rate will be impacted slightly because the bottoming cycle would be operating at part-load. This would typically result in about 0.5 percent increase in heat rate. In sliding pressure operation, the steam turbine throttle pressure will be lower. In addition, the steam turbine would only be operating at part load, below its maximum rated output which generally corresponds with the most efficient steam turbine operating conditions.

Appendix D. Peaking Plant Backup Fuel

A backup fuel source can be utilized to increase peaking plant availability and allow for generation to continue during natural gas supply disruptions. Natural gas supply disruptions may occur during peak winter months when residential gas demand is high, among other reasons. The most predominant source of backup fuel is No. 2 distillate fuel, also referred to as diesel fuel. Power plant design, equipment selection, and cost implications associated with constructing a facility with the capability of operating on diesel fuel as a backup fuel source are presented below.

In order to accommodate diesel fuel operating capability, the CTG or RICE package configuration or even model selection will be impacted. For a CTG, model availability might not change but the CTG package will require special design features to accommodate two fuels. These features generally will have no impact on plant output and efficiency while the plant is operating on natural gas but will result in additional equipment and cost. For example, the GE 7F.05 CTG will require a dual fuel package consisting of dual fuel combustors and associated ancillary equipment. While operating on diesel fuel, CTG efficiency will be worse and output will be impacted, either up or down depending on the specific CTG model and dual fuel package limitations. In addition, CTGs utilize water injection for controlling NO_x emissions while operating on diesel fuel. NO_x water injection rates are often high and CTG water quality specifications call for demineralized water, which can be expensive to produce. NO_x water injection requirements are typically anywhere from 0.6 to 1.2 lb water per lb of diesel fuel but vary greatly depending on the CTG model selected.

For reciprocating engines, model availability can be impacted. For example, the Wartsila 18V50SG reciprocating engine (considered in this study) is not capable of dual fuel operation. Instead, the Wartsila 18V50DF dual fuel reciprocating engine would be the Wartsila model offering closest in size and efficiency. The 18V50DF engine has a 9 percent lower output and 3 percent lower efficiency (about 100 Btu/kWh-HHV higher heat rate) than the 18V50SG engine and requires a small amount of diesel fuel consumption (1 percent or less of total fuel input) when operating on natural gas as a primary fuel. Reciprocating engines do not require NO_x water injection but rather rely on the SCR system for NO_x reductions.

In addition to CTG and reciprocating engine considerations, additional balance of plant systems and equipment would be required to accommodate fuel delivery, storage, forwarding and, in the case of CTGs, demineralized water production, storage, and forwarding. Below is a summary list of plant features required to support diesel fuel operation:

- Diesel truck unloading pad.
- Diesel truck unloading pumps.
- Truck hookups.
- Field erected diesel storage tanks.
- Secondary containment (typically in the form of lined and bermed containment areas in which the tanks are located).
- Diesel fuel forwarding pumps.
- Associated piping and valves.

In addition, the yard fire protection system and foam suppression system will need to be expanded due to the additional fuel oil tanks. A demineralized water production and storage system to support water injection for NO_x control will be required. Demineralized water production could be accomplished using demineralized water production trailers and associated trailer parking pads, hookups, and booster pumps as a more economical solution if trailers are readily available and if diesel fuel operation is expected to be limited. For the GE LMS100PA+ CTG, a demineralization system would already be in place (a cost savings on the order of \$500,000 per CTG). Additional associated balance of plant facilities such as roads, electrical supply and distribution, foundations, and excavation will also be required. The all-in incremental capital cost impact of constructing a single GE 7F.05 CTG-based peaking power plant with diesel fuel backup capabilities would be approximately \$15 million, including three days diesel fuel storage and a demineralized water production and storage system but excluding initial diesel fuel inventory.

Appendix E. Capital and O&M Cost Estimates for Brownfield Projects

Adding new peaking units at an existing PSE generating facility is expected to result in both capital and O&M cost savings compared to constructing equivalent units at Greenfield sites. To help PSE quantify the potential cost savings, Black & Veatch developed brownfield unit addition estimate variants for the following options:

- PP-B: 6x0 Wartsila 18V50SG
- PP-D: 1x0 GE LMS100PA+
- PP-F: 1x0 GE 7F.05

Potential Capital Cost Savings

Assuming sufficient capacity is available at existing facilities, capital cost savings may be possible for power plant facilities and supporting infrastructure such as (but not necessarily limited to) natural gas supply, transmission, water treatment, water storage, site fire protection, buildings, and roads. A breakdown of these line items and rough potential cost savings values are presented in Table E-1.

Table E-1 Potential Capital Cost Savings

| COST ITEM | EXPECTED COST SAVINGS VERSUS GREENFIELD | MEAN VALUE |
|--|---|--------------------------------------|
| Utility Interconnections | \$4 – 10M+ | \$7M |
| Demineralized Water Treatment & Storage (1) | \$2 – 4M | \$3M |
| Buildings | \$2 – 4M | \$3M |
| Site Access Roads | \$3 – 5M | \$4M |
| Total Expected Cost Savings | \$9 – 23M+ | \$14M \$17M⁽¹⁾ |
| Notes: | | |
| 1. Only applicable to the PP-D: 1x0 GE LMS100PA+ option. | | |

To illustrate the potential cost savings, a summary of brownfield capital cost estimates, using the applicable mean values, are summarized in Table E-3.

Potential O&M Cost Savings

The primary difference in O&M costs for Brownfield projects (relative to Greenfield projects) is in reduced fixed labor costs, as the operation of additional units at an existing facility requires only an incremental increase in plant staff. Plant staffing assumptions for Brownfield projects are listed in Table E-2. Estimates of O&M costs for brownfield cases are summarized in Table E-4.

Table E-2 Plant Staffing Assumptions for Brownfield Options

| ID | OPTION | PLANT STAFFING | |
|------|----------------------|-------------------|-------------------|
| | | GREENFIELD (FTEs) | BROWNFIELD (FTEs) |
| PP-B | 6x0 Wartsila 18V50SG | 9 | 5 |
| PP-D | 1x0 GE LMS100PA+ | 9 | 5 |
| PP-F | 1x0 GE 7F.05 | 9 | 5 |

Table E-3 Summary of Capital Cost Estimates for Brownfield Options

| ID | OPTION | AVERAGE DAY NET OUTPUT ⁽¹⁾ (MW) | GREENFIELD TOTAL CAPITAL COST | | BROWNFIELD TOTAL CAPITAL COST | |
|------|----------------------|--|-------------------------------|---------|-------------------------------|---------|
| | | | (\$000) | (\$/kW) | (\$000) | (\$/kW) |
| PP-B | 6x0 Wartsila 18V50SG | 111.0 | 150,800 | 1,360 | 136,800 | 1,230 |
| PP-D | 1x0 GE LMS100PA+ | 113.7 | 136,500 | 1,200 | 119,600 | 1,050 |
| PP-F | 1x0 GE 7F.05 | 239.0 | 136,500 | 570 | 122,500 | 510 |

Notes:

1. Average day net output based on ambient conditions of 51°F and relative humidity of 75%.

Table E-4 Summary of O&M Cost Estimates for Brownfield Options

| ID | OPTION | AVERAGE DAY NET OUTPUT ⁽¹⁾ (MW) | GREENFIELD ANNUAL FIXED O&M | | BROWNFIELD ANNUAL FIXED O&M | |
|------|----------------------|--|-----------------------------|------------|-----------------------------|------------|
| | | | (\$000) | (\$/kW-yr) | (\$000) | (\$/kW-yr) |
| PP-B | 6x0 Wartsila 18V50SG | 111.0 | 1,420 | 12.8 | 850 | 7.7 |
| PP-D | 1x0 GE LMS100PA+ | 113.7 | 1,390 | 12.2 | 803 | 7.1 |
| PP-F | 1x0 GE 7F.05 | 239.0 | 1,540 | 6.4 | 990 | 4.1 |

Notes:

1. Average day net output based on ambient conditions of 51°F and relative humidity of 75%.

Appendix F. Wartsila Recommended Maintenance Intervals

04. Maintenance schedule

V2

Regular maintenance of the engine should be performed according to the maintenance schedule. Regular maintenance helps to avoid malfunction of the engine and increases its lifespan.

The actual operating conditions and the quality of the fuel used have a large impact on the recommended maintenance intervals. Because of the difficulty in anticipating the engine operating conditions encountered in the field, the maintenance intervals stated in the schedule are for guidance only.



Note!

During the warranty period, the maintenance intervals must not be exceeded.

If there is any sign indicating the need for a maintenance operation in advance of the scheduled time, prudent industry practice dictates that the maintenance operation be performed. Likewise, if an inspection or observation reveals wear of any part or use beyond the prescribed tolerances, the part should be replaced immediately.

In some cases, the fuel quality used affects the length of the maintenance intervals.

For maintenance instructions, see the references given in the schedule. See also the turbocharger instructions and other equipment manufacturer's instructions.

04.1. Basic maintenance principles

V1

- Observe utmost cleanliness and order during all maintenance work.
- Before dismantling, check that all concerned systems are drained and the pressure released.
- After dismantling, immediately cover the lubricating oil, fuel oil and air holes with tape, plugs, clean cloth or similar means.
- When exchanging a worn-out or damaged part provided with an identification mark stating cylinder or bearing number, mark the new part with the same number on the same spot. Enter every exchange in the engine log along with the clearly stated reason for the exchange.

Maintenance schedule

- Always renew all gaskets, sealing rings and O-rings at maintenance work.



Note!

The O-rings in the cooling water system must not be lubricated with oil based lubricants, use soap or similar.

- After reassembling, check that all screws and nuts are tightened and locked (as required).
- If any welding is performed on the engine, disconnect the electronic equipment according to the welding instructions. Keep the return connection near the welding point.
- Consider that well cleaned oil spaces (oil sump and camshaft spaces) spare the oil pump and oil filter.

04.2.

Before starting maintenance work

v4

Do the following before starting to do any maintenance work on the engine (unless it can be done with the engine running):

- Ensure that the automatic start of the engine and all concerned circulation pumps (for instance, lubrication oil, cooling water and fuel) are disconnected.
- Close the starting air shut-off valve located before the main starting valve. Drain the engine starting air system to avoid engine damage and/or personal injury.
- To avoid accidental turning of the engine, secure the generator breaker or disengage the gear box.



Warning!

Accidental turning of the engine may cause engine damages and/or personal injury.

- Disconnect the power supply if electrical components will be removed.

04.3. Maintenance intervals

04.3.1. Daily routine inspections

V1

| Part or system | Maintenance task | See |
|----------------------------------|--|------------|
| Gas system | Inspect the gas system for leakage using a hand held gas detector. | Chapter 17 |
| Oil mist detector (if installed) | Observe normal operation. | |
| Pneumatic system | Drain condensated water. | Chapter 21 |

04.3.2. Every second day

V1

| Part or system | Maintenance task | See |
|---------------------------|---|------------|
| Automatic pre-lubrication | Check the operation of automatic pre-lubrication. Replace parts, if necessary. | Chapter 03 |

04.3.3. Once a week

V1

| Part or system | Maintenance task | See |
|----------------|--|------------|
| Start process | Test start. (if the engine is on stand-by) | Chapter 03 |



Note!

The maintenance task is irrespective of the engine being in operation or not.

04.3.4. Every second week

V1

| Part or system | Maintenance task | See |
|----------------|---|--------------------------|
| Start process | Check water quality. Check content of additives. | Chapter 19 Chapter 02 |



Note!

The maintenance task is irrespective of the engine being in operation or not.

Maintenance schedule

04.3.5. Interval: 50 operating hours

V1

| Part or system | Maintenance task | See |
|---------------------------------|--|--------------------------|
| Air cooler(s) | Check draining of the air cooler(s). Check that the draining pipes are open. Check if there is any leakage. | Chapter 15 Chapter 03 |
| Automation | Check and record all operating values. | Chapter 03 |
| Cooling water system | Check the water level in the expansion tank(s). Check the static pressure in the engine cooling circuits. Inspect that the ventilation (de-aerating) of the expansion tank is working. | Chapter 19 |
| Gas and lubricating oil filters | Check pressure drop indicators. Replace filter cartridges if high pressure drop is indicated. | Chapter 17 Chapter 18 |
| Turbocharger | Clean the compressor by injecting water. | Chapter 15 |
| Valve mechanism | Check the valve clearances after 50 running hours in new and overhauled engines. | Chapter 12 Chapter 06 |

04.3.6. Interval: 500 operating hours

V1

| Part or system | Maintenance task | See |
|----------------------------------|--|------------|
| Centrifugal filter | Clean centrifugal filter(s). Clean more often, if necessary. Remember to open the valve before the filter after cleaning. | Chapter 18 |
| Charge air cooler | Measure the pressure drop over charge air cooler(s) using U-gauge or tool no. 848051. | Chapter 15 |
| Lubricating oil | In a new installation or after changing to a new lubricating oil brand, take oil samples for analysis. | Chapter 02 |
| Oil mist detector (if installed) | Inspect the functioning. See manufacturer's instructions. | |
| Wastegate valve | Inspect the functioning. | Chapter 15 |
| By-pass valve (if installed) | Inspect the functioning. | Chapter 15 |

Maintenance schedule

04.3.7. Interval: 1000 operating hours

V1

| Part or system | Maintenance task | See |
|--------------------------------------|---|------------|
| Air filter (on-built) | Remove the turbocharger air filter(s). Clean according to manufacturer's instructions. Clean more often, if necessary. | Chapter 15 |
| Electrical lubricating oil pump | Regrease pre-lubricating pump under running condition. | Chapter 18 |
| Engine fastening bolts | Inspect the tightening of engine fastening bolts on new installations. | |
| Gas filter Engine mounted | Clean gas filter cartridges. The engine mounted filter can be cleaned by pressurised air from inside. Replace cartridge, if necessary. (The cartridge must be replaced earlier if the pressure difference indicator shows very high pressure drop.) Clean the filter housing outside and inside. Follow intervals for the filter at 4000 operating hours. | Chapter 17 |
| Gas filter On gas regulating unit | Replace the filter cartridge. Clean the filter housing outside and inside. Follow intervals for the filter at 4000 operating hours or when the pressure difference indicator shows pressure drop higher than 0.5 bar. | Chapter 17 |

04.3.8. Interval: 2000 operating hours

V1

| Part or system | Maintenance task | See |
|----------------------------------|--|--------------------------|
| Automation | Check the functioning of the safety system. Check the functioning of the sensors for the alarm system and automatic stop devices. | Chapter 23 Chapter 01 |
| Gas system | Perform the leak test. | Chapter 17 |
| Ignition system | Replace spark plugs if the engine is running more or less continuously. (Maintenance intervals can be shorter if the engine is started/stopped daily or more often.) Clean and check the condition of the ignition coil on plug if the engine is running more or less continuously. Replace O-rings. | Chapter 16 |
| Lubricating oil filter | Inspect and clean lubricating oil filter. (It must be cleaned earlier if the pressure difference indicator shows very high pressure drop.) Drain the filter housings. Clean the wire gauze and filter housing. | Chapter 18 |
| Oil mist detector (if installed) | Replace fresh air filter. See manufacturer's instructions. | |
| Valves | Check yoke and valve clearances. | Chapter 12 Chapter 06 |
| Valve rotators | Check valve rotators visually. | Chapter 12 Chapter 06 |

04.3.9. Interval: 4000 operating hours

v2

| Part or system | Maintenance task | See |
|--------------------------------------|--|--------------------------|
| Air cooler(s) | Clean the charge air cooler(s). (Cleaning interval is based on the cooling performance of the air cooler.) Perform the pressure test. Look carefully for corrosion. Measure the pressure difference over the charge air cooler before and after cleaning using U-gauge. | Chapter 15 |
| Automation | Check connectors and cables. Check mounting and connections. Apply contact lubricant to contact surfaces. Check tightness of connections. Check condition of cables, wires and cable glands. Replace damaged connectors and cables. | Chapter 23 |
| Camshaft | Inspect contact faces of the camshaft. Check the contact faces of the cams and tappet rollers. Check that the rollers rotate. Rotate the engine with the turning gear. | Chapter 14 Chapter 03 |
| Crankshaft | Check crankshaft alignment using form no. 4611V005. It is not necessary to perform an alignment check if the engine is mounted on rubber. | Chapter 11 |
| Flexible coupling Vulkan-Rato-S/R | Inspect the flexible coupling visually. See manufacturer's instructions. | |
| Flexible coupling | Check the alignment of flexible coupling using form no. WV98V041. | |
| Flexible mounting (if used) | Check the alignment . Check compression of the thrust rubber elements. Inspect according to maintenance instructions for resilient installation. See technical documents. | |
| Gas filter | Replace gas filter cartridges. (The cartridge must be replaced earlier if the pressure difference indicator shows very high pressure drop.) Clean the filter housing outside and inside. | Chapter 17 |
| Gas filter On gas regulating unit | Replace gas filter cartridges. (The cartridge must be replaced earlier if the pressure difference indicator shows pressure drop higher than 0.5 bar.) Clean the filter housing outside and inside. | Chapter 17 |
| Wastegate | Check the wastegate valve and the actuator. Change the positioner pilot valve. | Chapter 15 |

Maintenance schedule

04.3.10. Interval: 6000 operating hours

V1

| Part or system | Maintenance task | See |
|---------------------------|---|------------|
| Flexible pipe connections | Inspect flexible pipe connections. Renew, if necessary. | |
| Exhaust manifold | Inspect expansion bellows. Replace parts, if necessary. Inspect supports of the exhaust system. | Chapter 20 |

04.3.11. Interval: 8000 operating hours

V1

| Part or system | Maintenance task | See |
|----------------|---|------------|
| Automation | Check wiring condition inside the cabinets and boxes. Check for wear of insulation, loose terminations, loose wires and leakages. Check wear of cable insulation, breakages, loose cable glands, connectors, holders and loose grounding shields. Check for loose grounding straps and corrosion. Check sensors, actuators, solenoids etc. for leakages, physical damages. Check signal/measurement also where applicable. Check soft dampers condition if its flattened, worn out or broken. Check if the electrical displays/meters are dark or broken. Check electronic modules visually for damages, leakages or smoke residuals. Rectify, improve or replace the equipment, if necessary. | Chapter 23 |

04.3.12. Interval: 9000 operating hours

V1

| Part or system | Maintenance task | See |
|------------------|---|------------|
| Prechamber | Check prechamber tip for possible wear or cracks. | Chapter 16 |
| Prechamber valve | Clean the prechamber valve. Check the prechamber valve for wear. Renew parts, if necessary. | Chapter 16 |

Maintenance schedule

04.3.13. Interval: 12000 operating hours

V1

| Part or system | Maintenance task | See |
|--------------------------------------|---|------------|
| Air filter (in pneumatic systems) | Clean the filter. Clean the filter cartridge and replace , if necessary. Clean the filter housing outside and inside. | Chapter 21 |
| Flexible pipe connections | Renew flexible pipe connections. Depending on the condition of the connection and the target of usage, these pipe connections can be used even for longer. | |
| Oil mist detector (if installed) | Replace the oil mist detector supply air filter. See manufacturer's instructions. | |
| Turbocaharger(s) | Dismount and clean. Inspect and assess the shaft and the bearing parts. Clean the compressor casings. Check for any crack ,erosion or corrosion. Clean nozzle ring and check for any crack or erosion. Measure and note the axial clearance. If the clearance is out of tolerance, contact the engine manufacturer. See manufacturer's instructions. | Chapter 15 |
| Turbocharger(s) ABB TPL- chargers | Inspect the turbocharger bearings. Replace the bearings at 36000 hours at the latest , if necessary. See manufacturer's instructions. | Chapter 15 |
| Turning device | Grease the drive shaft of the turning device. | Chapter 11 |
| Wastegate | General overhaul of the wastegate valve and the actuator. Change the positioner pilot valve. | Chapter 15 |

04.3.14. Interval: 18000 operating hours

V1

| Part or system | Maintenance task | See |
|-----------------------|--|--------------------------|
| Air cooler(s) | Clean the charge air cooler(s). Clean more often, if necessary. (Cleaning interval is based on the cooling performance of the cooler.) | Chapter 15 |
| Camshaft driving gear | Inspect intermediate gears. Inspect teeth surfaces and running pattern. Replace parts, if necessary. | Chapter 13 Chapter 06 |
| Connecting rods | Inspect big end bearing, one/bank. Dismantle the big end bearing. Inspect mating surfaces. If defects are found, open all big end bearings. Renew bearing shells, if necessary. Refer measurement record 4611V008 and 4611V003. | Chapter 11 Chapter 06 |
| Connecting rods | Check small end bearing and piston pin, one/bank. If defects are found, open all and renew if needed. Refer measurement record 4611V004. | Chapter 11 Chapter 06 |

Maintenance schedule

| Part or system | Maintenance task | See |
|----------------------------------|--|--------------------------|
| Crankshaft | Inspect main bearings. Inspect one main bearing. If in a bad condition, check/change all main bearings. Note the type of bearing in use and do the inspection accordingly. | Chapter 10 Chapter 06 |
| Crankshaft | Check thrust bearing clearance. Check axial clearance. | Chapter 11 Chapter 06 |
| Cylinder heads | Overhaul of cylinder head. Dismantle and clean the under side, inlet and exhaust valves and ports. Inspect cooling spaces and clean, if the deposits are thicker than 1 mm. If cylinder head cooling water spaces are dirty, check also the cooling water spaces in liners and engine block and clean them all, if the deposits are thicker than 1 mm. Improve the cooling water treatment. Grind all seats and the valves. Inspect the valve rotators. Check rocker arms. Replace O-rings in the valve guides. Replace O-rings at the bottom of the cylinder head screws at every overhaul. Replace the knocking sensors. Check the starting valves. Renew parts, if necessary. | Chapter 12 Chapter 14 |
| Cylinder liners | Inspect the cylinder liners. Measure the bore using form no. 5010V001. Replace liner if wear limits are exceeded. Hone the liners. Check the deposits from cooling bores. If the deposits are thicker than 1 mm, clean the cooling bores. Renew the anti-polishing ring. | Chapter 10 Chapter 06 |
| Engine fastening bolts | Check tightening of the engine fastening bolts. | Chapter 07 |
| Gas admission valves Woodward | Replace the main gas admission valves. In installations where connectors are used, replace the female connector also. Send gas admission valves to the engine manufacturer for reconditioning. | Chapter 17 |
| Gas system | Replace sealings in pipe connections. Check sealing faces for wear and corrosion. Perform the leak test. | Chapter 17 |
| Hydraulic jack | Check the functioning. Replace O-rings in the hydraulic jack if they are leaking when lifting the main bearing cap. | Chapter 10 |
| Ignition system | Replace ignition coil on the plug. | Chapter 16 |
| Pistons | Check the cooling gallery deposit, one piston/bank. If the deposit exceeds 0.3 mm, open all piston tops. Inspect the piston skirt. Clean lubricating oil nozzles. | Chapter 11 |

Maintenance schedule

| Part or system | Maintenance task | See |
|----------------------------------|--|--|
| Pistons, piston rings | Inspect pistons and replace piston rings. Pull, inspect and clean. Check the height of the piston ring grooves using form no. 4611V009 and 4611V002. Check the retainer rings of the gudgeon pins. Replace complete set of piston rings. Note the running-in programme. | Chapter 11 Chapter 06 Chapter 03 |
| Prechamber | Replace the prechamber tip. Check all the parts of prechamber. | Chapter 16 |
| Prechamber valve | Replace the prechamber valve. | Chapter 16 |
| Turning device | Change lubricating oil in the turning device. | Chapter 02 |
| Vibration damper Viscous type | Take oil sample from vibration damper for analysis. | Chapter 14 |

04.3.15. Interval: 24000 operating hours

V1

| Part or system | Maintenance task | See |
|---|---|--------------------------|
| Automation | Replace drive electronics. (CCM modules on engine control system) The drive electronics must be replaced every 10th year at the latest. | Chapter 23 |
| Automation | Replace vibration dampers used in the control system cabinets, enclosures and modules. Replace the vibration dampers every 24000 operating hours or every four years depending on whichever comes first. | |
| Exhaust manifold | Renew the expansion bellows between exhaust pipe sections, after the cylinder head and before the turbocharger. | Chapter 20 |
| Flexible coupling (Oil supply from the engine) | Check the flexible coupling. Dismantle and check flexible coupling according to manufacturer's recommendations. | |
| HT- water pump | Inspect HT-water pump. Dismantle and check. Renew bearings and shaft sealing. | Chapter 19 |
| HT- water pump driving gear | Inspect HT-water pump driving gear. Replace parts, if necessary. | Chapter 19 Chapter 06 |
| HT- water thermostatic valve | Clean and inspect HT- water thermostatic valve. Clean and check the thermostatic element, valve cone-casing, and sealings. | Chapter 19 |
| LT- water pump | Inspect LT-water pump. Dismantle and check. Renew bearings and shaft sealing. | Chapter 19 |
| LT- water pump driving gear | Inspect LT-water pump driving gear. Replace parts, if necessary. | Chapter 19 Chapter 06 |
| LT- water thermostatic valve | Clean and inspect LT- water thermostatic valve. Clean and check the thermostatic element, valve cone-casing, indicator pin and sealings. | Chapter 19 |

Maintenance schedule

| Part or system | Maintenance task | See |
|--------------------------------------|--|--------------------------|
| Lubricating oil pump | Inspect lubricating oil pump. Renew bearings. Renew shaft sealing. | Chapter 18 |
| Lubricating oil pump driving gear | Inspect lubricating oil pump driving gear. Replace parts, if necessary. | Chapter 18 Chapter 06 |
| Lubricating oil thermostatic valve | Clean and inspect lubricating oil thermostatic valve. Clean and check the thermostatic element, valve cone-casing and sealings. | Chapter 18 |
| Main starting valve | General overhaul of the main starting valve. Replace worn parts. | Chapter 21 |
| Turbocharger(s) ABB TPL- chargers | Inspect turbocharger parts. Inspect and replace nozzle ring , turbine diffuser/cover ring , if necessary. See manufacturer's instructions. | Chapter 15 |

04.3.16. Interval: 32000 operating hours

V1

| Part or system | Maintenance task | See |
|------------------------|---|------------|
| Turbocharger Napier | Check rotor balance every 32000 hours or every 4 years. See manufacturer's instructions. | Chapter 15 |

04.3.17. Interval: 36000 operating hours

V1

| Part or system | Maintenance task | See |
|-----------------|---|--------------------------|
| Air cooler(s) | Renew the charge air cooler(s). | Chapter 15 |
| Camshaft | Inspect camshaft bearing bush, one/bank. If defects are found, inspect all including driving end and thrust bearing. Renew, if necessary. Refer measurement record 4610V003. | Chapter 14 Chapter 06 |
| Connecting rods | Replace big end bearing. Replace big end bearing shells. Inspect mating surfaces. Measure the big end bore using form no. 4611V008 and 4611V003. | Chapter 11 Chapter 06 |
| Connecting rods | Replace the small end bearings. Replace the small end bearing shells. | Chapter 11 Chapter 06 |
| Crankshaft | Renew main bearing shells. Renew main bearing shells, flywheel bearings and thrust bearing halves. | Chapter 10 Chapter 06 |
| Crankshaft | Inspect the crankshaft for wear. Renew the crankshaft seal. | Chapter 11 |

Maintenance schedule

| Part or system | Maintenance task | See |
|--|--|--|
| Cylinder head | Renew inlet and exhaust valve seats only if wear limits have exceeded or leaks are detected. Renew inlet and exhaust valves. Renew valve rotators and valve guides. | Chapter 12 |
| Cylinder liners | Clean cylinder liner cooling water spaces. Replace the liner O-rings at every overhaul. | Chapter 10 |
| Elastic coupling in camshaft driving end | General overhaul of the elastic coupling. The elastic coupling must be opened only by the authorized personnel. Contact the engine manufacturer. | Chapter 07 |
| Exhaust manifold | Renew exhaust pipe support plates. | Chapter 20 |
| Intermediate gear | Renew thrust bearing of the intermediate gear. Renew bearing bushes of the intermediate gear. | Chapter 13 |
| Piston | Inspect the piston cooling gallery, all cylinders. Clean , if necessary. | Chapter 11 |
| Prechamber | Replace the prechamber. | Chapter 16 |
| Starting air distributor | General overhaul of starting air distributor. Renew worn parts. | Chapter 21 |
| Valve mechanism | Check bearing clearances in the tappets and rocker arms, one/cylinder. Dismantle one rocker arm assembly for inspection. Proceed with other rocker arm bearings if defects are found. Renew valve tappet roller bearing bushes. | Chapter 12 Chapter 14 Chapter 06 |
| Vibration damper in camshaft free end (spring type, optional) | Dismantle the damper and check its condition. The damper must be opened only by the authorized personnel. Contact the engine manufacturer. | Chapter 07 Chapter 14 |
| Vibration damper in crankshaft free end (spring type, optional) | Dismantle the damper and check its condition. The damper must be opened only by the authorized personnel. Contact the engine manufacturer. | Chapter 07 Chapter 11 |

04.3.18. Interval: 48000 operating hours

v1

| Part or system | Maintenance task | See |
|---------------------------------------|--|------------|
| Automation | Replace measuring electronics and all the modules on engine control system. The measuring electronics must be replaced every 10th year at the latest. | Chapter 23 |
| Charge air bellow | Renew expansion bellow(s) between the turbocharger and air inlet box. | Chapter 20 |
| Turbocharger | Replace rotor and rotating parts. (Lifetime dependent of operating conditions). See manufacturer's instructions. | Chapter 15 |
| Turbocharger(s) ABB TPL - chargers | Inspect turbocharger gas- inlet/outlet casings. Replace the gas- inlet/outlet casings, if necessary. See manufacturer's instructions. | Chapter 15 |

04.3.19. Interval: 72000 operating hours

V1

| Part or system | Maintenance task | See |
|-----------------------------|---|--------------------------|
| Camshaft bearings | Renew camshaft bearings. Renew camshaft driving end bearing bush and camshaft thrust bearings. | Chapter 13 Chapter 14 |
| Cylinder heads | Renew cylinder heads. | Chapter 12 |
| Flexible mounting (if used) | Renew rubber elements. See technical documents. | |
| Piston | Renew pistons and gudgeon pins. | Chapter 11 |
| Valve mechanism | Renew rocker arm bearing bushes. | Chapter 12 Chapter 14 |