2017 PSE Integrated Resource Plan

Appendices A-P

November 2017

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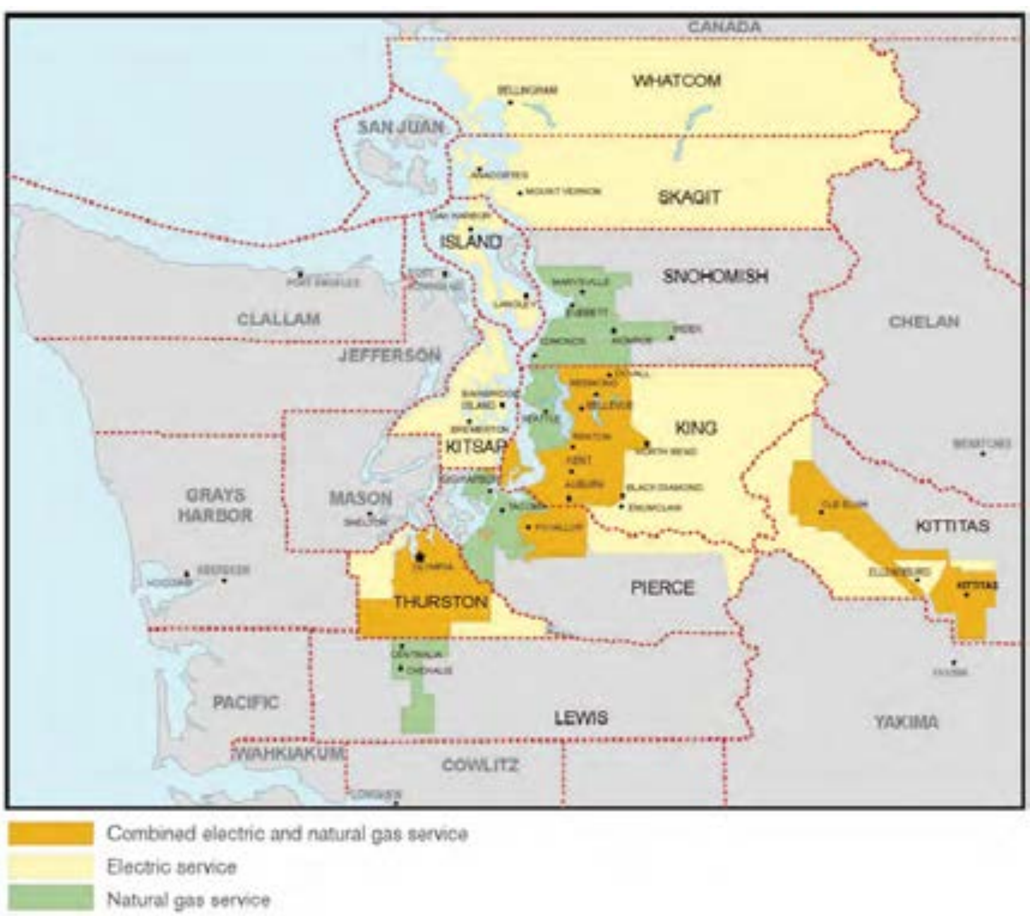
PSE PUGET SOUND ENERGY

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.



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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 appied 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.

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
CO2	carbon dioxide
CO2e	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.

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 industies
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 MtCO2 per year.

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

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
MMtCO2e	million metric tons of CO2 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
NO2	nitrogen dioxide
NOS	Network Open Season, a BPA transmission planning process

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 spies 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)

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 asses physical resource adequacy.

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 enteringinto 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

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
SO2	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 CO2 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.

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

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

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

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 (NWEC)
- 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

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
WAC 480-100-238 (3) (a) 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
WAC 480-100-238 (3) (b) 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
WAC 480-100-238 (3) (c) 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
WAC 480-100-238 (3) (d) 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
WAC 480-100-238 (3) (e) 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

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-100-238 (3) (f) 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.	Chapter 2, Resource Plan Decisions
WAC 480-100-238 (3) (g) 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
WAC 480-100-238 (3) (h) A report on the utility's progress towards implementing the recommendations contained in its previously filed plan.	Appendix B, Legal Requirements and Other Reports
WAC 480-100-238 (4) 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.	2017 Integrated Resource Plan Work Plan filed with the WUTC July 14, 2016, and Updated Work Plan filed April 7, 2017
WAC 480-100-238 (5) 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.	Appendix A, Public Participation
RCW 19.280.030 (e) 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.	Appendix H, Operational Flexibility Overgeneration events are not applicable to PSE.

Figure B-2: Natural Gas Utility Integrated Resource Plan Regulatory Requirements

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-90-238 (3) (a) 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
WAC 480-90-238 (3) (b) 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
WAC 480-90-238 (3) (c) An assessment of conventional and commercially available nonconventional gas supplies.	Chapter 7, Gas Analysis Appendix O, Gas Analysis
WAC 480-90-238 (3) (d) An assessment of opportunities for using company-owned or contracted storage.	Chapter 7, Gas Analysis Appendix O, Gas Analysis
WAC 480-90-238 (3) (e) An assessment of pipeline transmission capability and reliability and opportunities for additional pipeline transmission resources.	Chapter 7, Gas Analysis Appendix O, Gas Analysis
WAC 480-90-238 (3) (f) 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
WAC 480-90-238 (3) (g) 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
WAC 480-90-238 (3) (h) 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
WAC 480-90-238 (3) (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

Statutory or Regulatory Requirement	Chapter and/or Appendix
WAC 480-90-238 (4) 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.	2017 Integrated Resource Plan Work Plan filed with the WUTC July 14, 2016, and Updated Work Plan filed April 7, 2017
WAC 480-90-238 (5) 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.	Appendix A, Public Participation

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 Explaination
Order 5-1(4) Model the availability of transmission to import Montana wind energy resources.	Chapter 6, Electric Analysis
Order 5-2 (4) 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
Order 5-1 (5) 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
Order 5-2 (5) 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
Order 5-3 (5) 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
Order 5-4 (5) 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.
Order 5-5 (5) 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

Order 01 request	Chapter and/or Appendix or Explaination
Order 5-6 (5) PSE will include a sensitivity that examines whether changing the discount rate for conservation impacts cost effectiveness of conservation.	Chapter 4, Key Analytical Assumptions Chapter 6, Electric Analysis
Order 5-7 (5) 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.	Appendix M, Washington Wind and Solar Costs Appendix P, Gas-fired Resource Costs
Order 5-8 (6) 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.	Chapter 4, Key Analytical Assumptions Chapter 6, Electric Analysis
Order 5-9 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: • 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.	Chapter 8, Delivery Infrastructure Planning

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 RFP[1] 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.

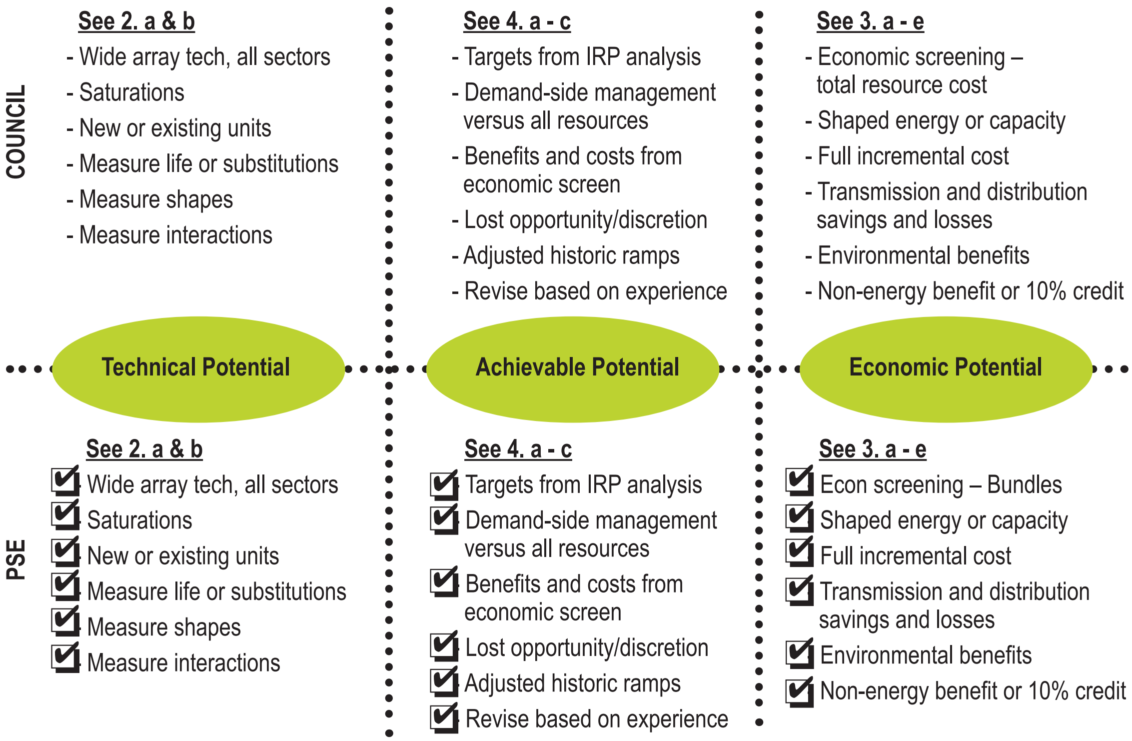
3. OTHER REPORTS

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

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.

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		
Period	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

C

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.

Contents

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 PM2.5, 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.

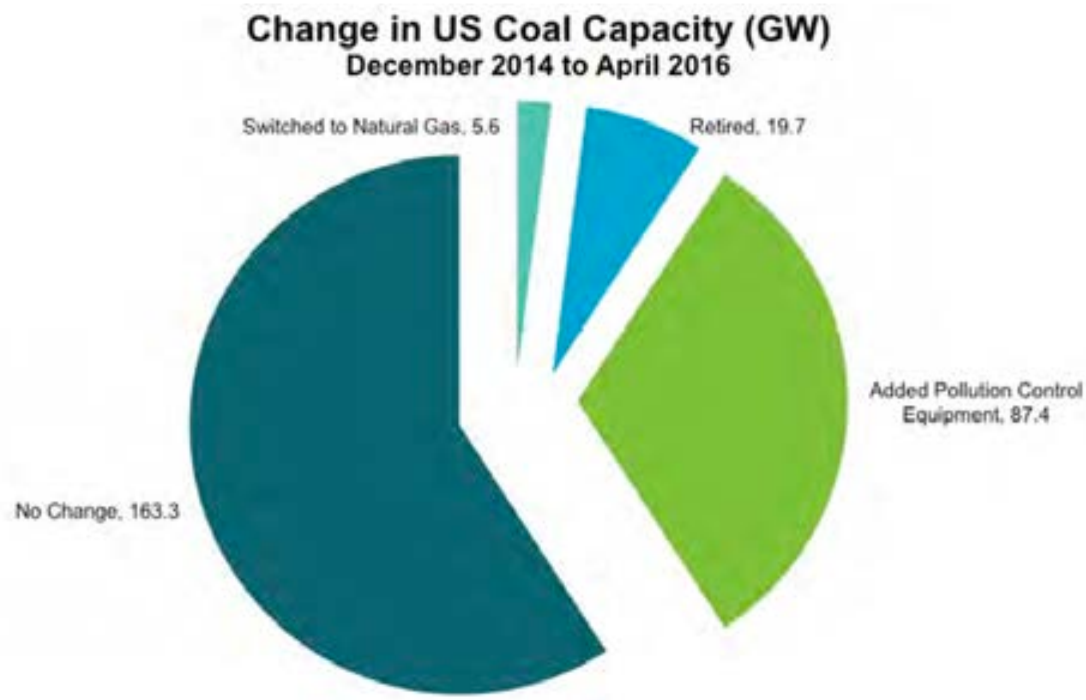
1 / Appendix K, Colstrip, describes Colstrip's compliance with the MATS rule.

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.

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 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/epafinalactononmontanaregionahazeplan.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 (SO_2), 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 (CO_2) 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 CO_2 per megawatt hour (MWh); for natural gas combined-cycle sources; limits would be set at 1,000 to 1,100 lb CO_2 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 CO_2 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 CO_2 per MWh, which is achievable with the latest combined-cycle technology. New coal power plants can emit no more than 1,400 lbs CO_2 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 CO_2 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 CO_2 reductions to the EPA one to three years following issuance of the final rule.

In the October 2015 final version of the rule, the CO_2 goal for Montana became 26 percent more stringent than the draft version, and the CO_2 goal for Washington became 35 percent less stringent. By 2030 Montana must reduce CO_2 emissions from coal plants from 20.5 million tons of CO_2 to 11.3 million tons of CO_2, which is a 45 percent reduction in CO_2 emissions. For reference, Colstrip Units 1, 2, 3 and 4 combined emit 18 million tons of CO_2.

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 (CO_2e)[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 "CO_2 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 CO_2 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 CO_2 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 CO_2 emissions by 15 percent or more.

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 CO_2 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 CO_2 equivalent per year ($MMtCO_2e$ per year). Starting in 2020, the threshold is reduced every 3 years until it reaches 70,000 $MMtCO_2e$ 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 $MMtCO_2e$ 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 $MtCO_2e$ 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.

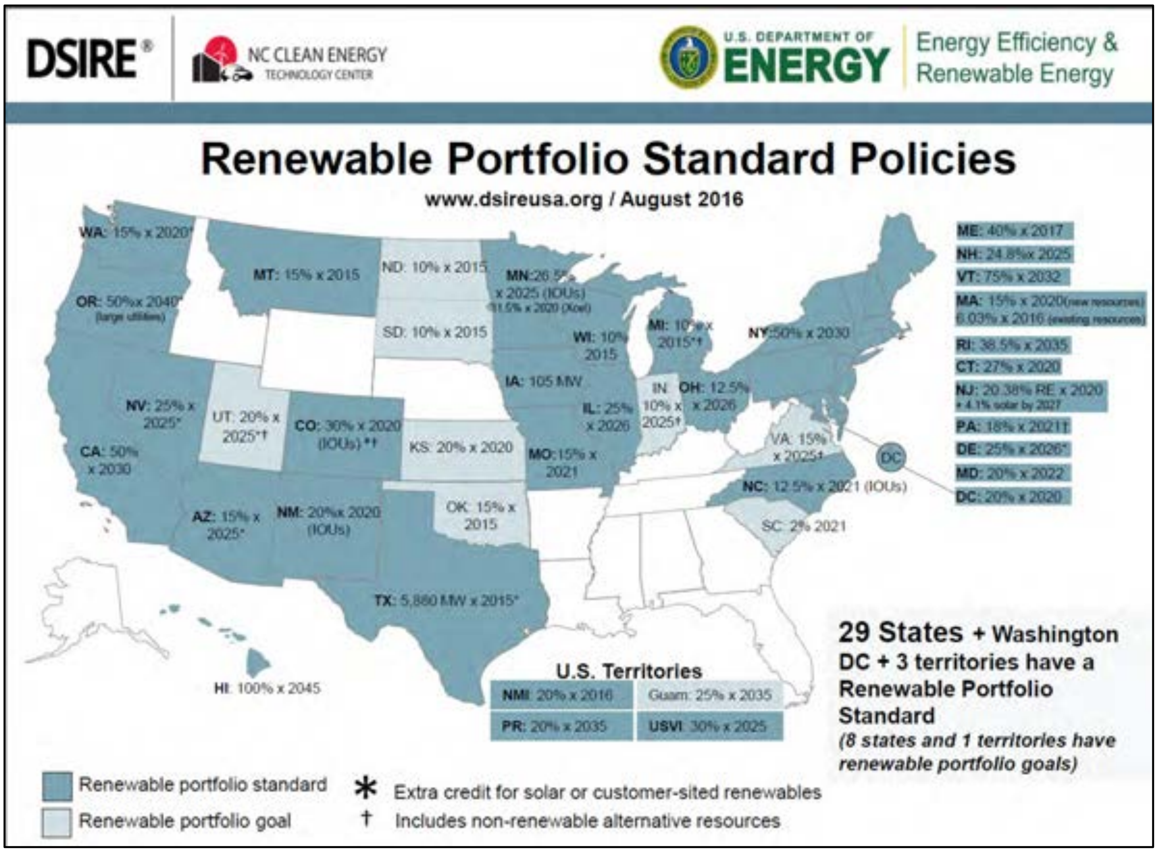
Renewable Portfolio Standards (RPS)

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.

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.*

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; Muni-cipal 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.

D

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]

Contents

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 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 report[2] 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.

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.

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.

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 MWhs 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.

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."

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.

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:

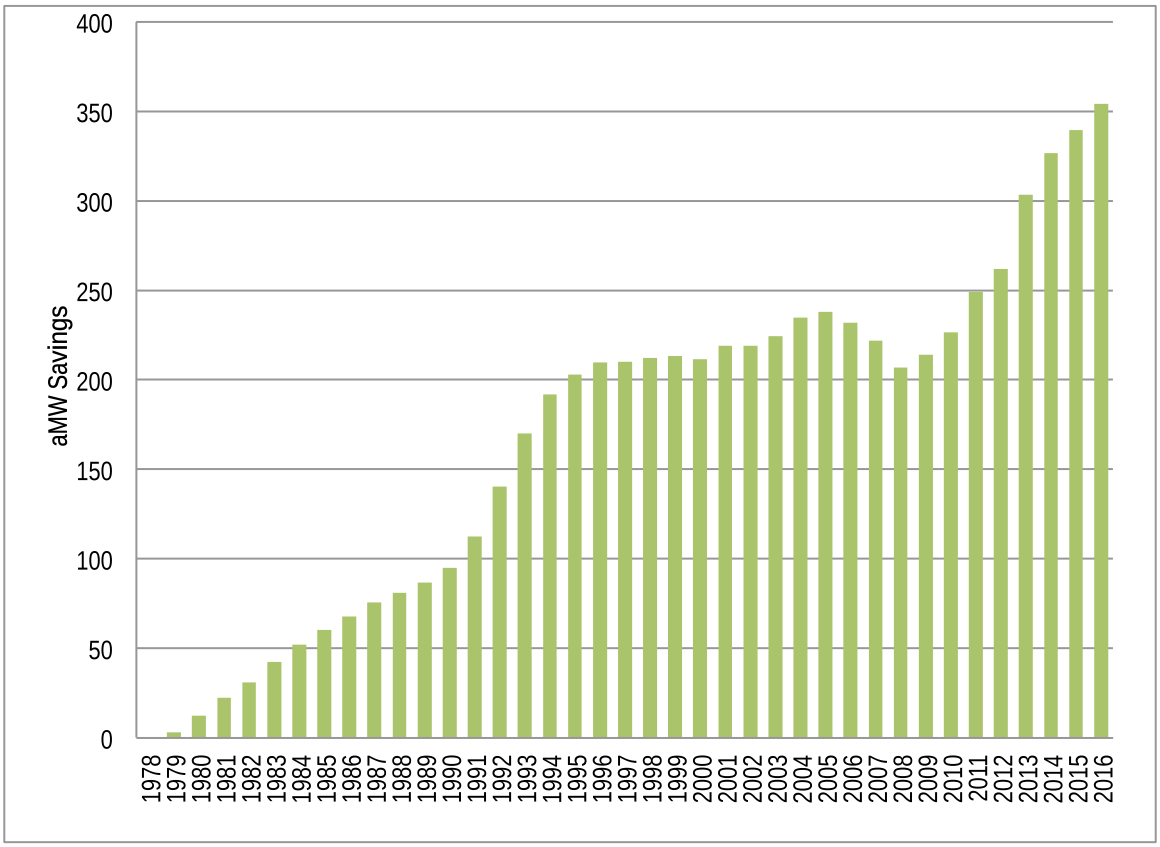
- **ENERGY EFFICIENCY**, implemented by PSE's Customer Energy Management group
- **FUEL CONVERSION**, implemented by PSE's Customer Energy Management group
- **DISTRIBUTION EFFICIENCY**, managed by the System Planning department
- **GENERATION EFFICIENCY**, evaluated by PSE's Customer Energy Management 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.*

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.

Figure D-9: PSE 2014-15 Electric Energy Efficiency Program Savings – Targeted versus Actual[8]

	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 loads[9] 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

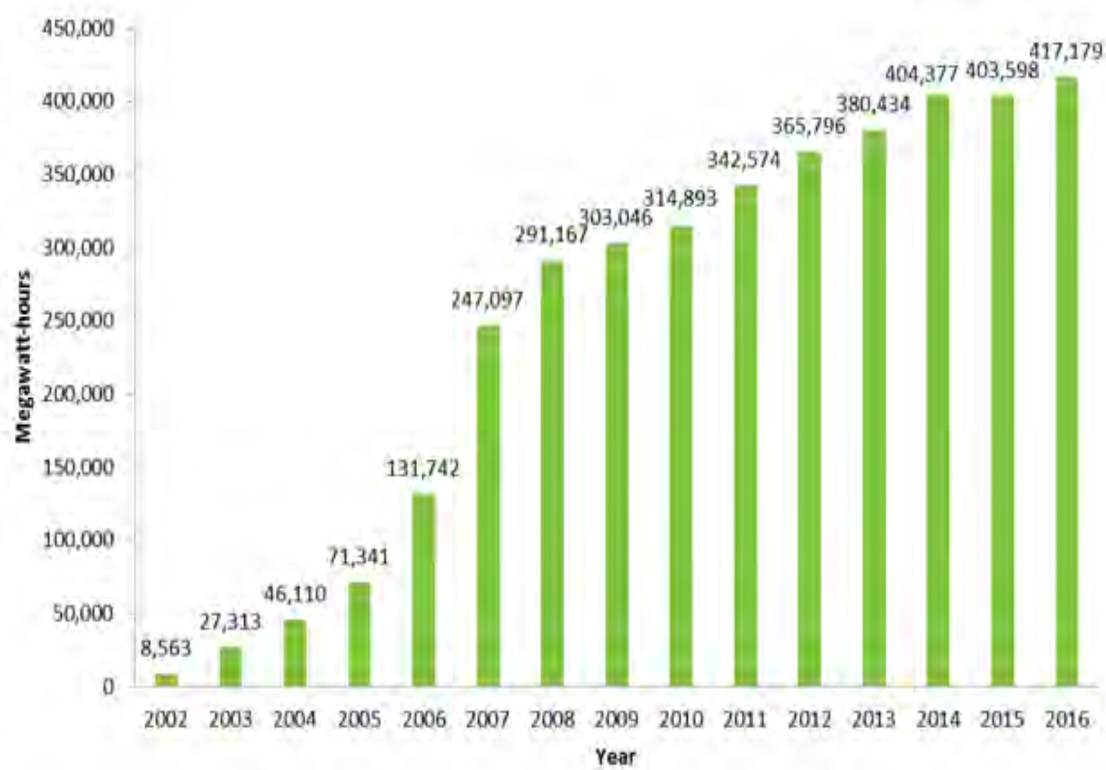
Launched in 2001, PSE's Green Power Program allows customers to voluntarily purchase retail electric energy from qualified renewable energy resources. In 2009, we began working to increase participation in the program with 3Degrees, a third-party renewable energy credits (REC) broker that has developed 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."

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.

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.

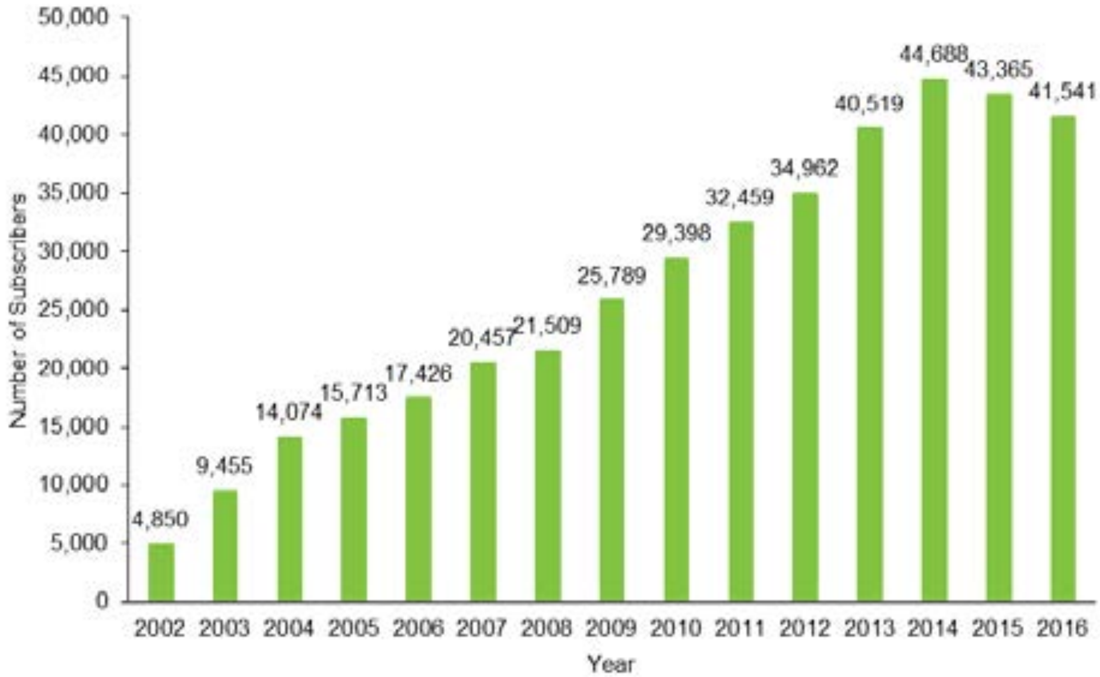
In 2015, PSE issued a RFQ that resulted in competitively awarding REC contracts to the Bonneville Environmental Foundation, Port of Tillamook Bay and 3Degrees to help supply the balance of our Green Power Program portfolio needs for up to two years, beginning in 2016. Pricing for these Pacific Northwest 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.

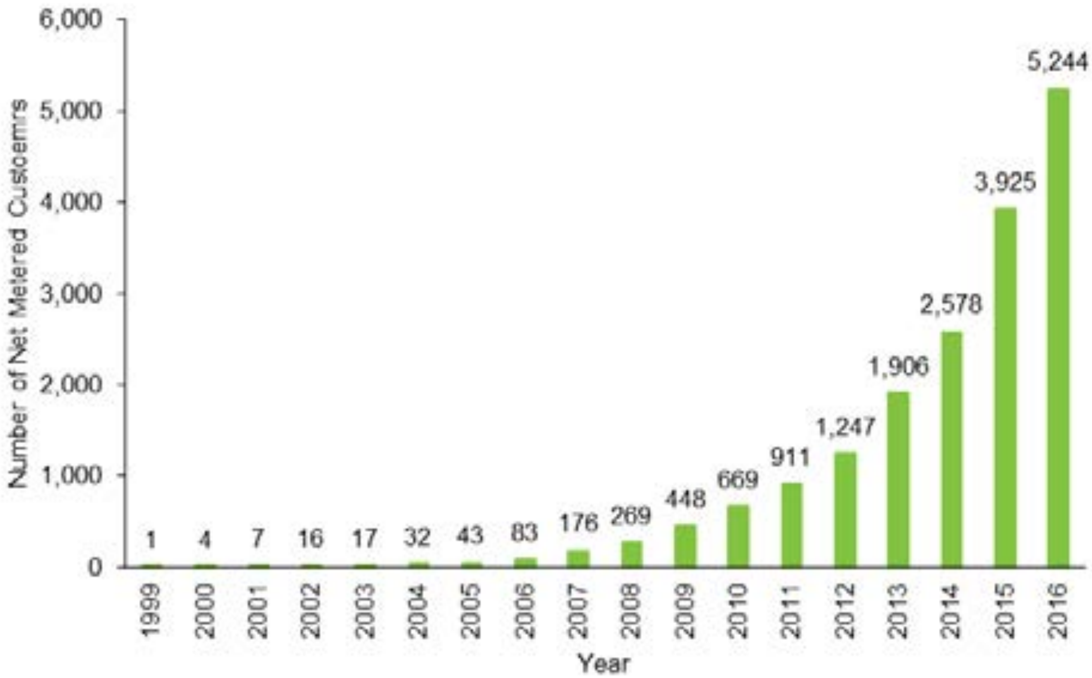
Customer Renewables Programs

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.

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.

Figure D-15: Generic Gas Resource Cost Assumptions

GENERIC GAS RESOURCES		BASELOAD GAS		PEAKERS					
2016 $	UNITS	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. CO_2 emissions reflect natural gas as the main source of fuel under normal operating conditions. In the event that the gas pipeline is constrained, the CO_2 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 duel fueled reciprocating engines when operating with natural gas as the primary fuel is not captured in the emission rates.

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.

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 CO_2).

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.

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 Europe[15] and The Linde Group[16] 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.

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 form 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 than 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 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.

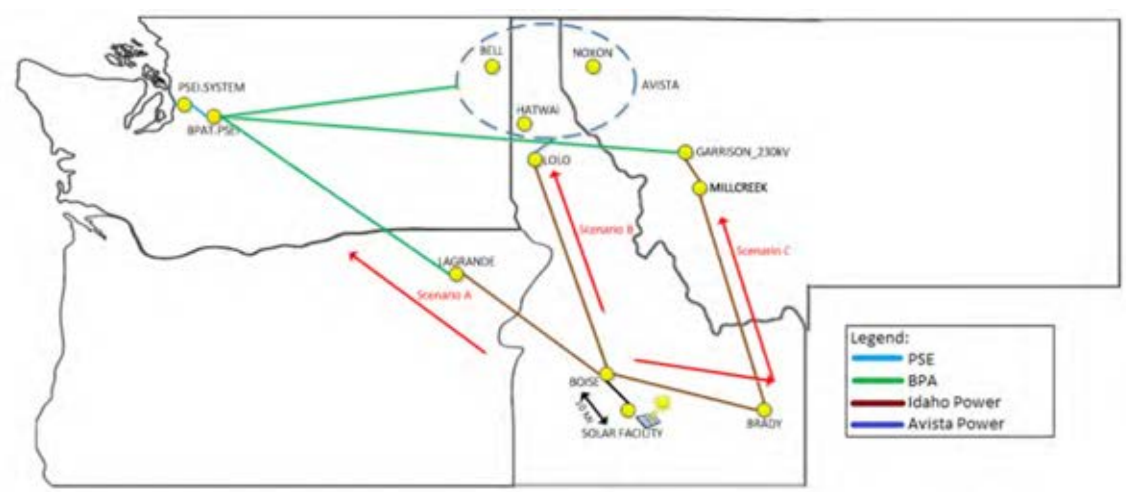
17 / Solar is installed at direct current (dc).
18 / Solar Electric Industry Association (SEIA), Q2 2016, http://www.seia.org/research-resources/solar-industry-data.
19 / Ibid.

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

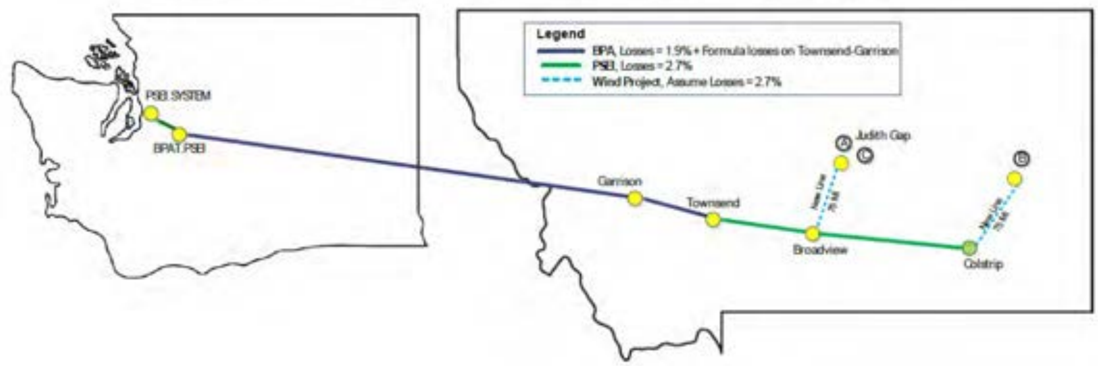


Figure D-23: Estimates of Interconnection Costs and Transmission Rates

	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 capcital 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 Esimates 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 initital 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 100[22] 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 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]

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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).

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.

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32 / U.S. Environmental Protection Agency website. Retrieved from http://www.epa.gov/waste/nonhaz/municipal/wte/, 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.

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

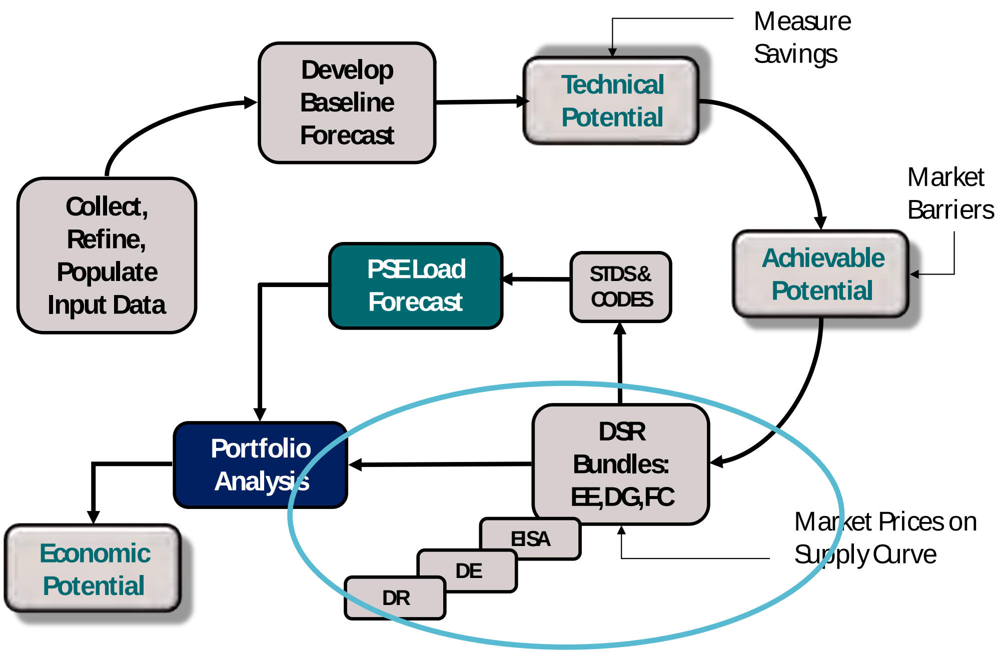
First, each demand-side measure was screened for technical potential. Screening for technical potential assumed that all energy and demand-saving opportunities could be captured regardless of cost or market barriers, so the full spectrum of technologies, load impacts and markets could be surveyed.

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.

Figure D-28: Discretionary versus Lost Opportunity Measures in Bundles 1 to 10

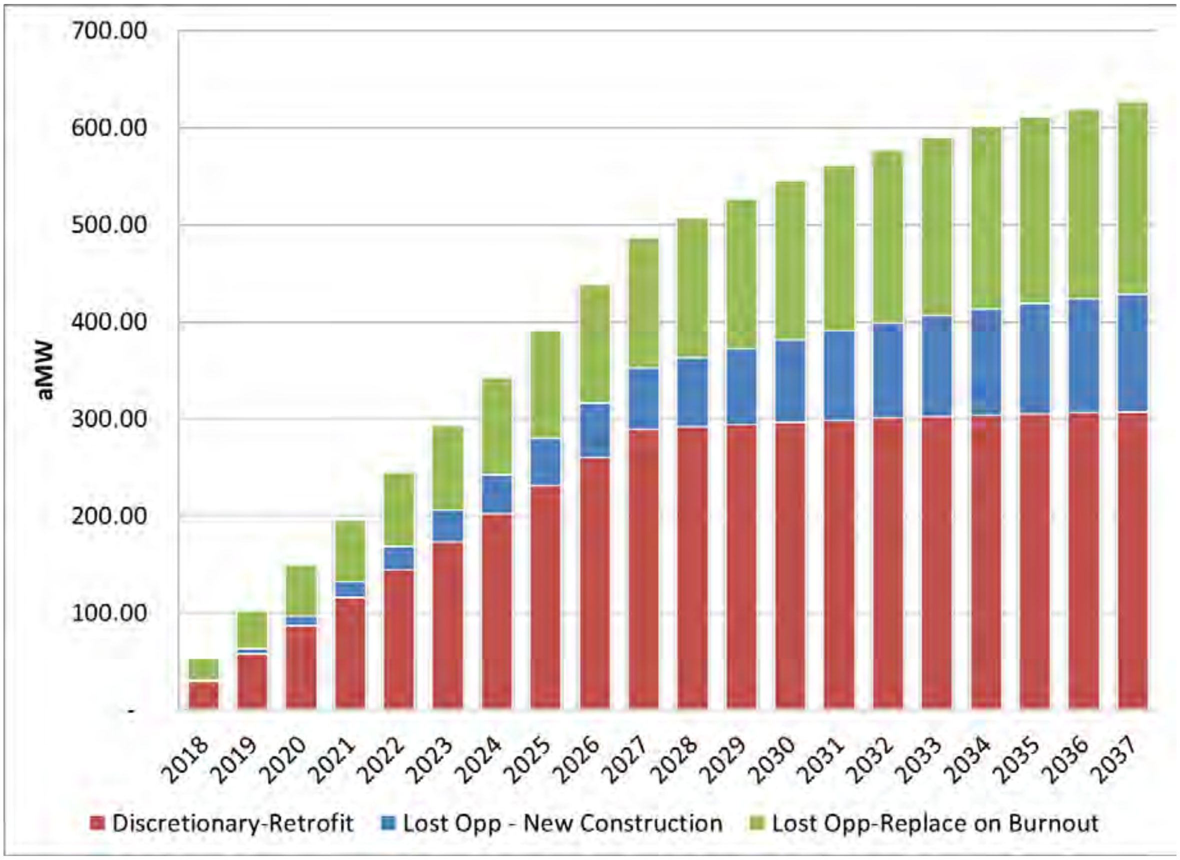


Figure D-29: Annual Energy Savings (aMW)

	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

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

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

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

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

E

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.

Contents

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:

$$UPC_{c,t} = f(RR_{c,t(k)}, W_{c,t}, EcoDem_{c,t(k)}, MD_m)$$
$$CC_{c,t} = f(EcoDem_{c,t(k)}, MD_m)$$
$$MD_i = \begin{cases} 1, Month = i \\ 0, Month \neq i \end{cases} \quad i \in \{1,2,\ldots 12\}$$
$$t \in \{1,\ldots,nobs\}$$

$UPC_{c,t}$ = 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 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

$EcoDem_{c,t(k)}$ = 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.

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

$$PkMW_t = \vec{\alpha}_{1,m} \cdot MD_i \cdot S_t + \vec{\alpha}_{2,m}\chi_1 \cdot \Delta T \cdot MD_i \cdot S_t + \beta_{1,d} DD_d + \delta_1 \cdot LT_t$$

where:

$$\chi_1 = \begin{cases} 1, & Month = 6,7,8 \\ 0, & Month \neq 6,7,8 \end{cases}$$

$$MD_i = \begin{cases} 1, Month = i \\ 0, Month \neq i \end{cases} \quad i \in \{1,2,.....12\}$$

$PkMW_t$ = 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.

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:

$$UPC_{c,t} = f(RR_{c,t(k)}, W_{c,t}, EcoDem_{c,t(k)}, MD_m)$$

$$CC_{c,t} = f(EcoDem_{c,t(k)}, MD_m)$$

$$MD_i = \begin{cases} 1, Month = i \\ 0, Month \neq i \end{cases} \quad i \in \{1,2,\ldots 12\}$$

$$t \in \{1,\ldots,nobs\}$$

$UPC_{c,t}$ = 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

$W_{c,t}$ = 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:

$$PkDThm_t = \vec{\alpha}_{1,m} Fr_t + \vec{\alpha}_{2,m} \Delta T_g \cdot Fr_t + \alpha_{3,m} EN + \alpha_{4,m} M_t + \alpha_{5,m} Sum + \alpha_{6,m} Csnp$$

$$Win = \begin{cases} 1, & Month = 1,2,11,12 \\ 0, & Month \neq 1,2,11,12 \end{cases}$$

$$Smr = \begin{cases} 1, & Month = 6,7,8,9 \\ 0, & Month \neq 6,7,8,9 \end{cases}$$

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.

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 EViews[1] 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.*

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:

$$\hat{L}_h = \vec{\beta}_{1,d} \cdot DD_d + \alpha_1 L_{h-1} + \alpha_2 \left(\frac{L_{h-2} + L_{h-3} + L_{h-4}}{3} \right) + \left(\vec{\alpha}_{3,m} T_h + \vec{\alpha}_{4,m} T_h^2 \right) + \vec{\beta}_{2,d} Hol + \alpha_5 P^{(1)}(h)$$

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)

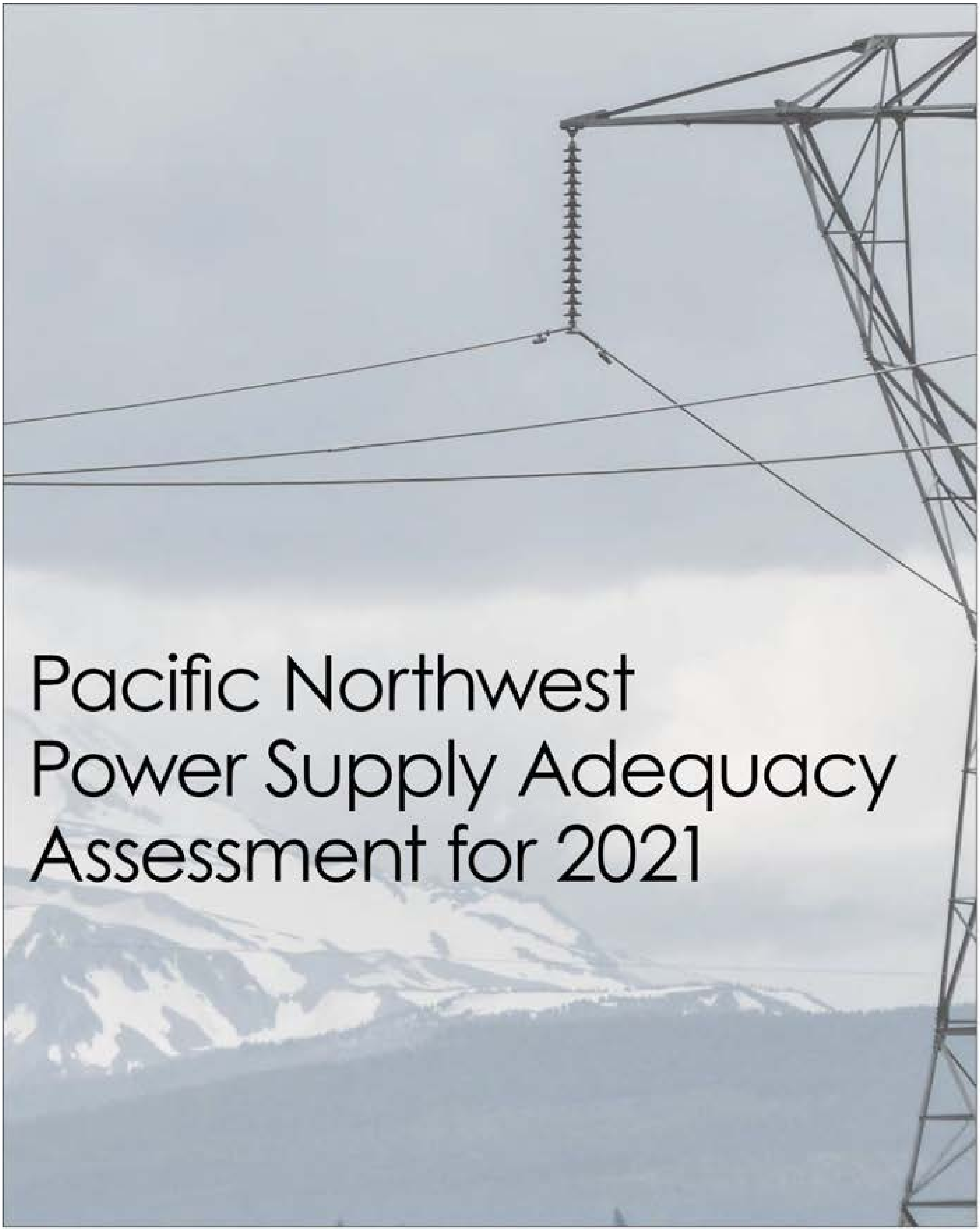
3. BONNEVILLE POWER ADMINISTRATION (BPA)

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

Northwest **Power** and **Conservation** Council

CONTENTS

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 plants[1] 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 decreased[5] 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 6th 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%	*Early estimate (BPA INC/DEC only)* 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

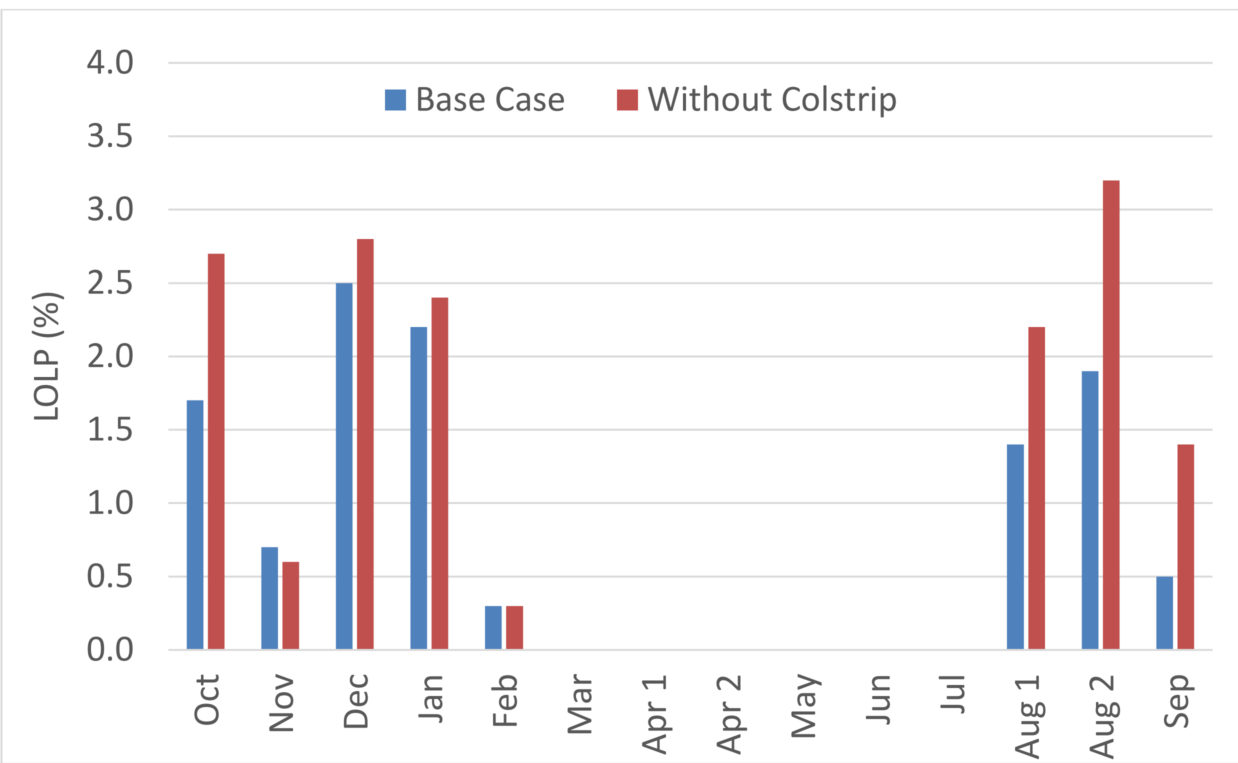


Table 6 summarizes the average monthly dispatch for groups of resources, namely wind, coal, gas, nuclear and SW market. This table shows the monthly dispatch for the reference case and for the case with the Colstrip 1 and 2 coal plant retirement and the difference. With the added loss of Colstrip 1 and 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 2021[9]

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

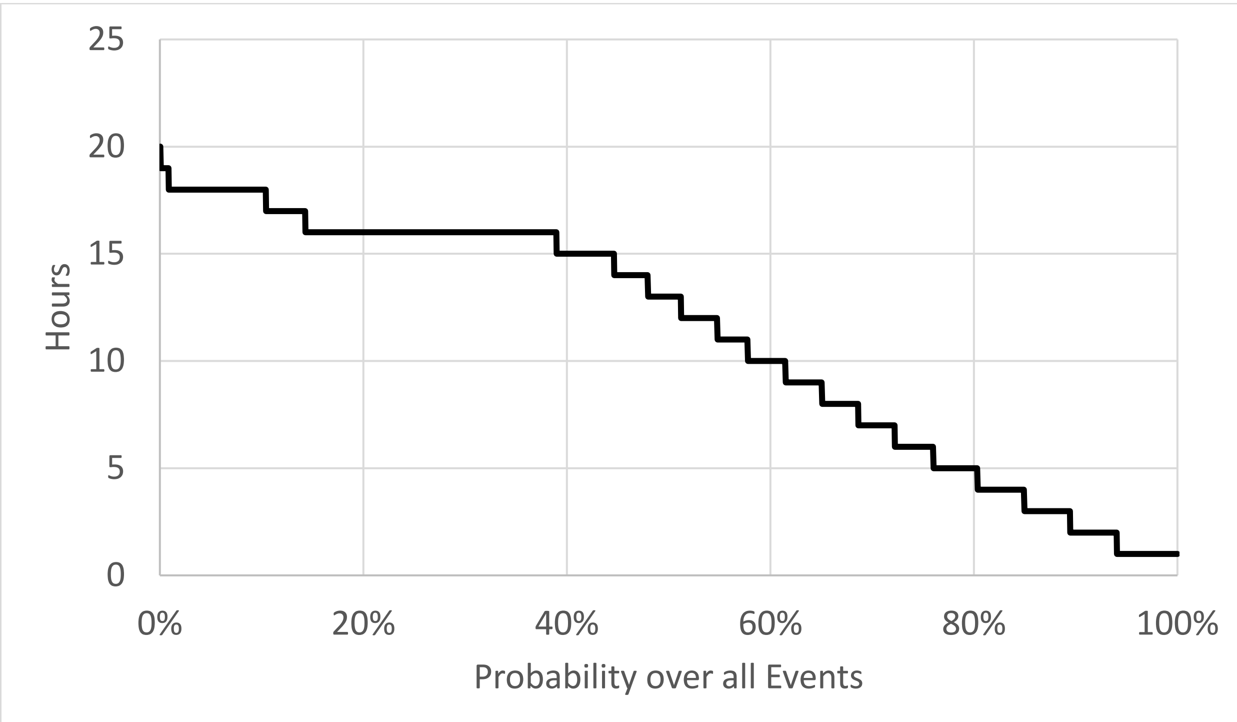


Figure 3 shows the same information in a different way. In that figure, the y-axis represents the percent of times that an event of particular duration occurs in the study. This is commonly referred to as a frequency distribution chart. For example, the most likely duration for an event is 16 hours. 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)

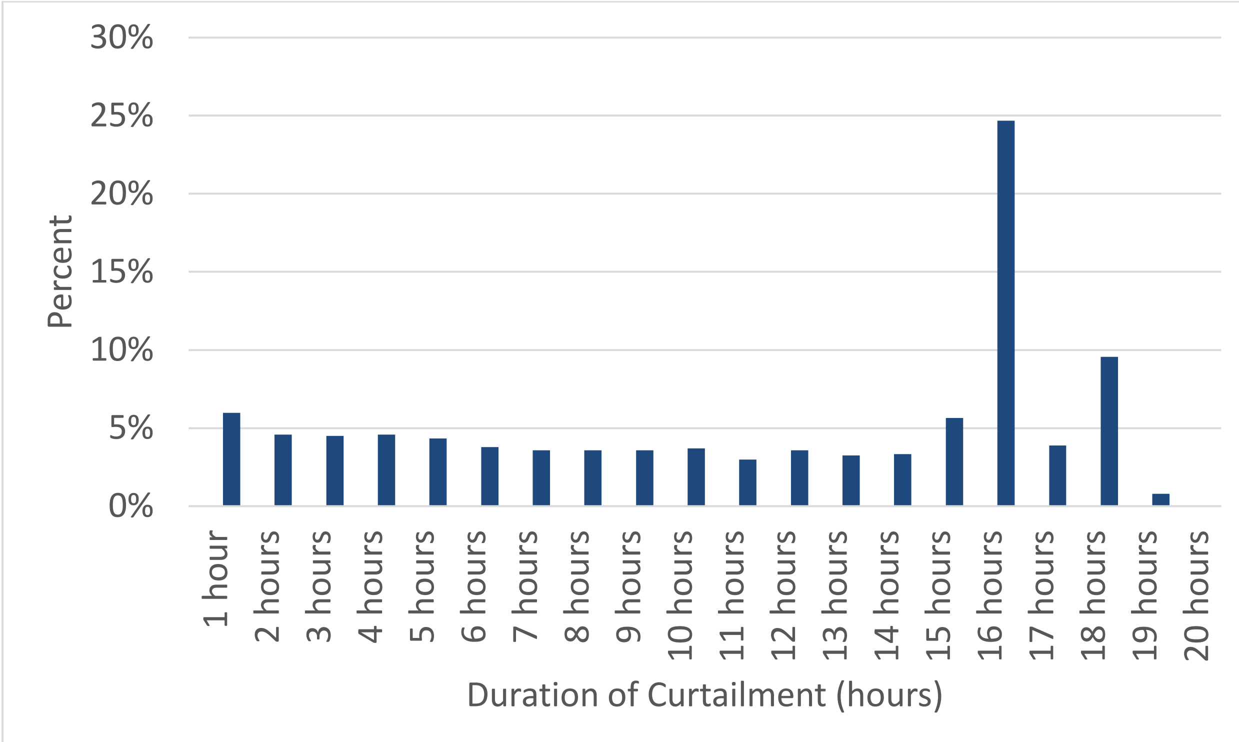


Figure 4: Event Duration Frequency (2-hour block incremental)

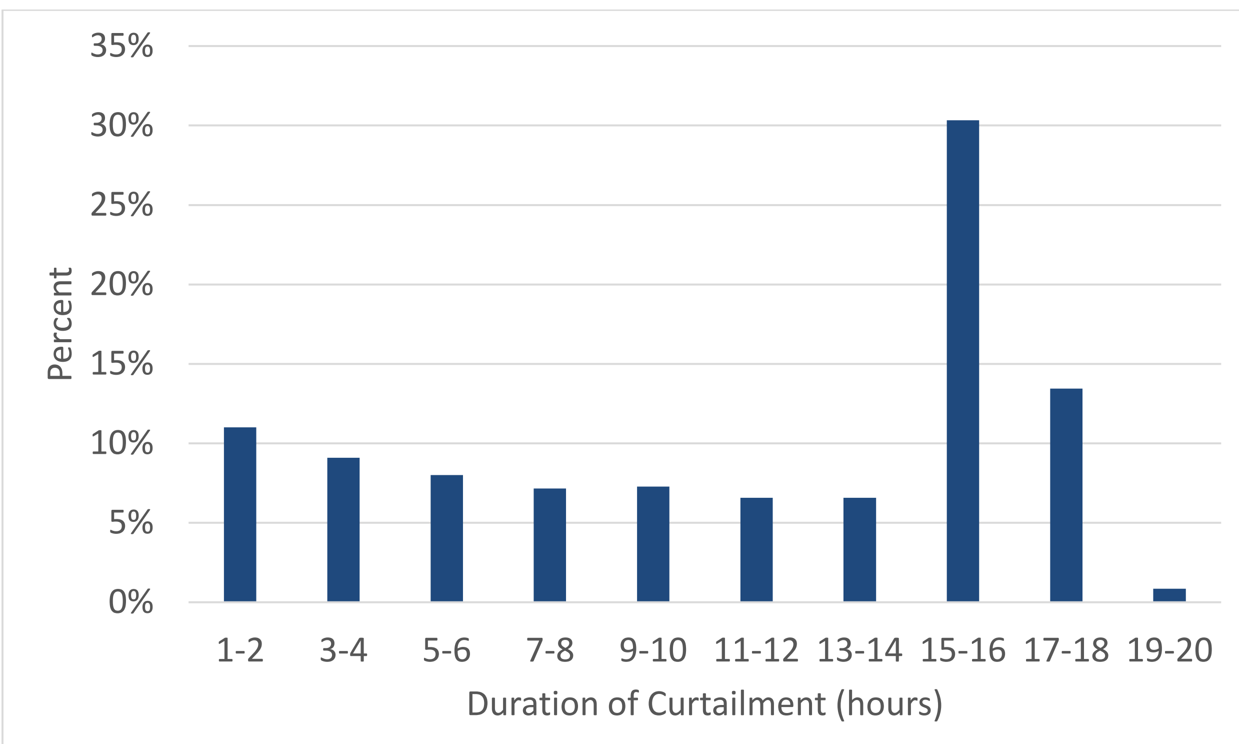
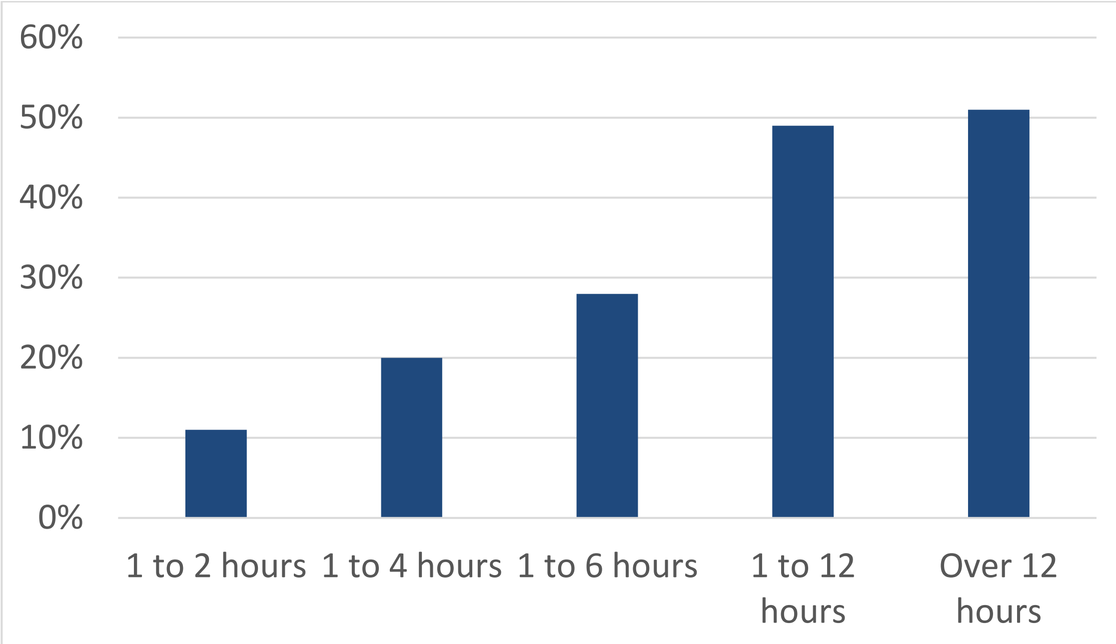


Figure 5: Event Duration Frequency (various time blocks)



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 shows 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 <u>annual</u> 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 percent[12] 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.

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[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

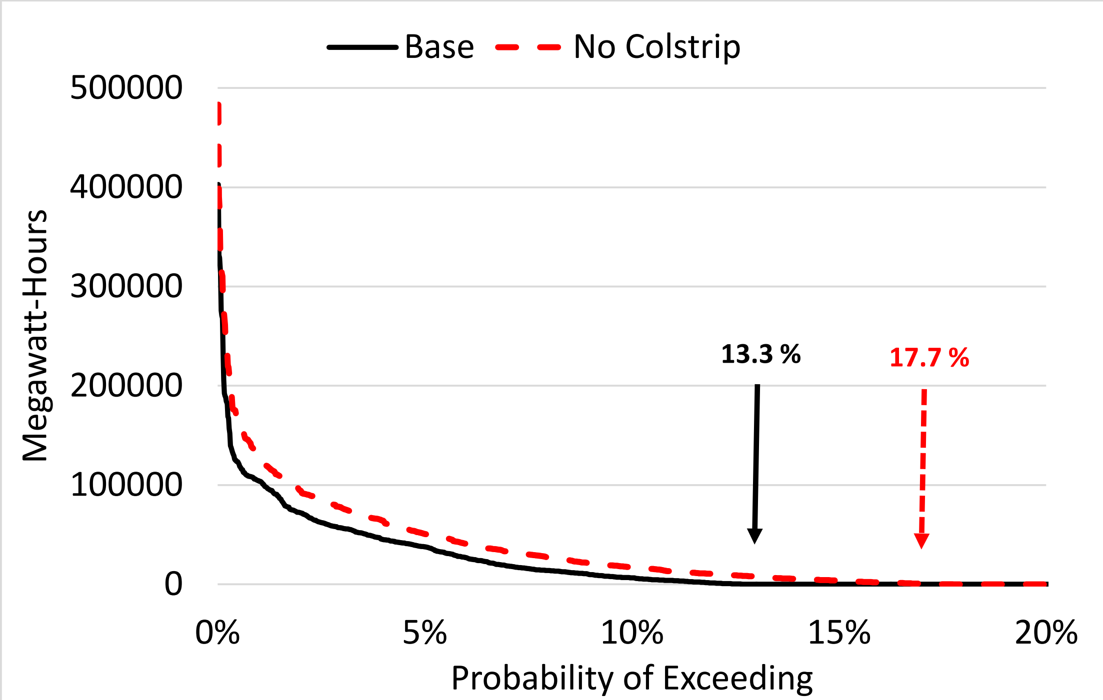


Figure 7a displays the <u>worst-hour</u> unserved energy probability for all games for both the reference case and the Colstrip retirement case. This figure is similar to Figure 6 but plots the worst (highest) single-hour unserved energy for each game, instead of the annual unserved energy. As expected, 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

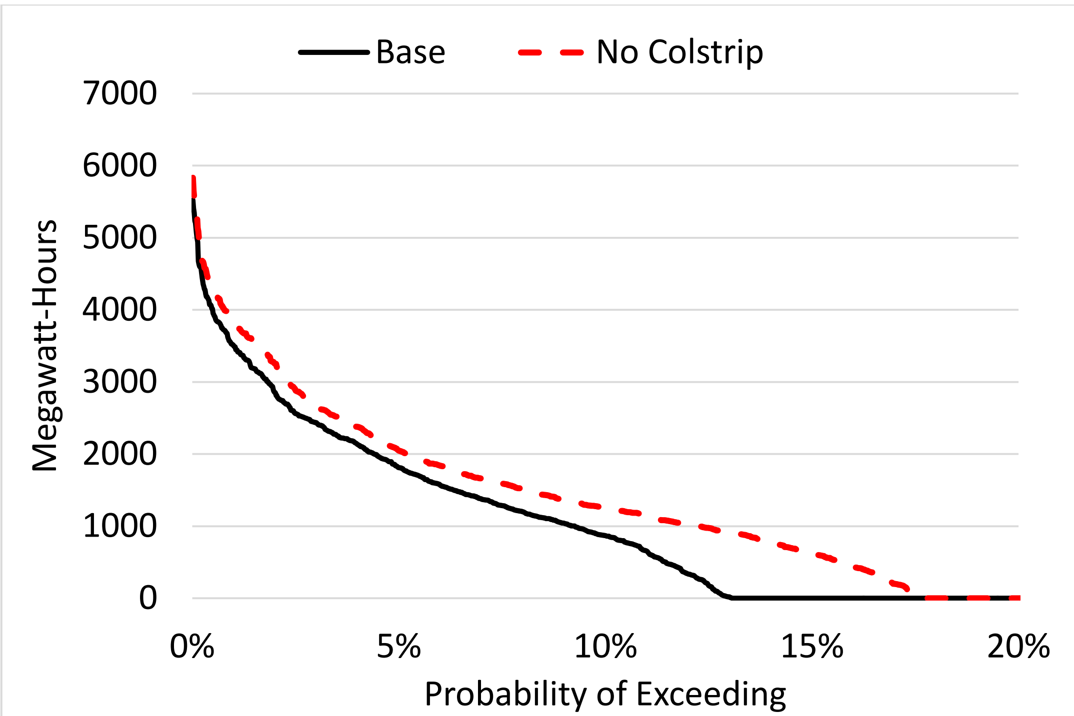
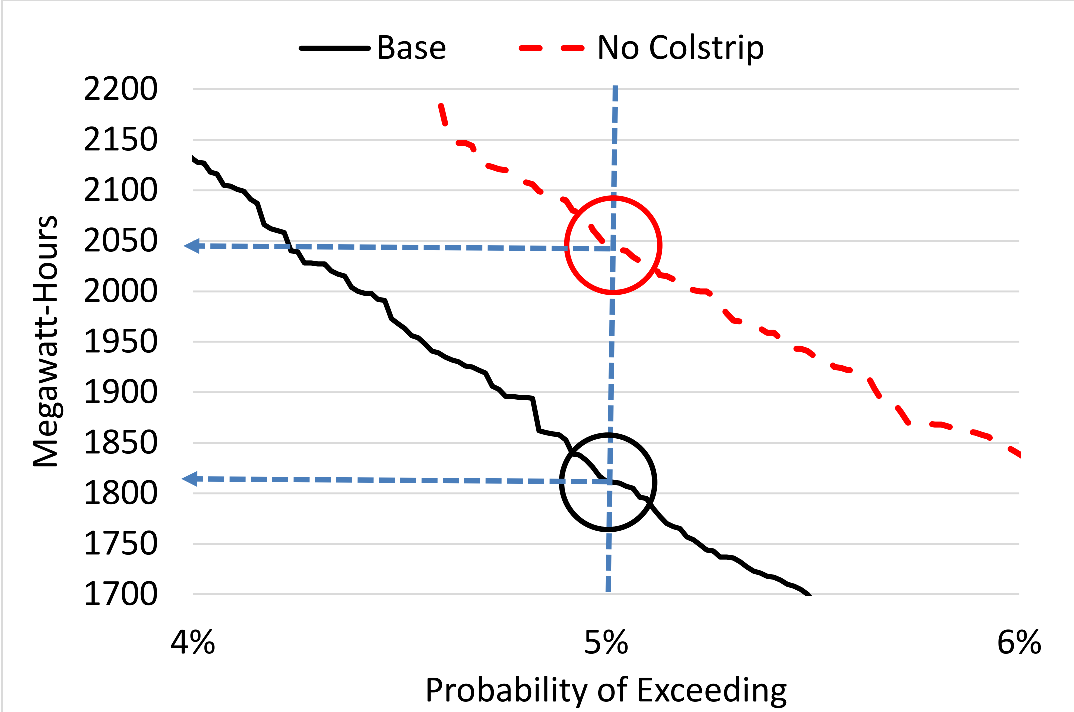


Figure 7b: Worst-Hour Unserved Energy Probability (Blow Up)



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 subsections[16] 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.

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Northwest Regional Forecast

of Power Loads and Resources

2017 through 2026

PNUCC

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

101 SW Main Street, Suite 1605

Portland, OR 97204

503.294.1259

Table of Contents

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]

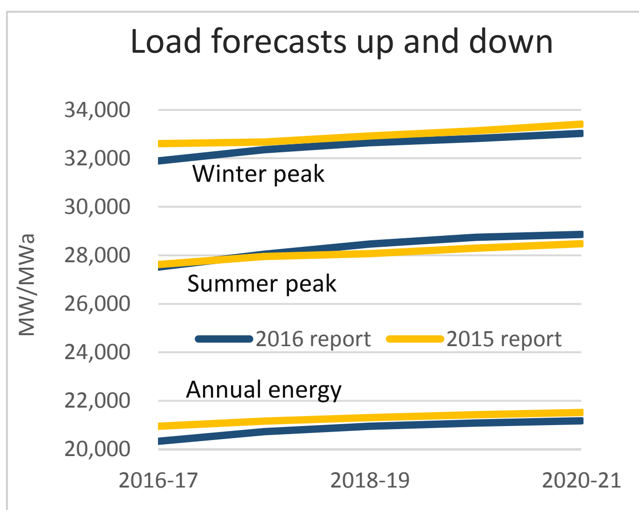

Figure 1

[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.

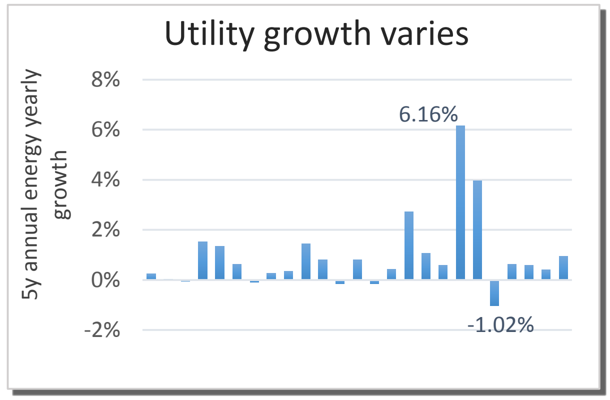

Figure 2

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.

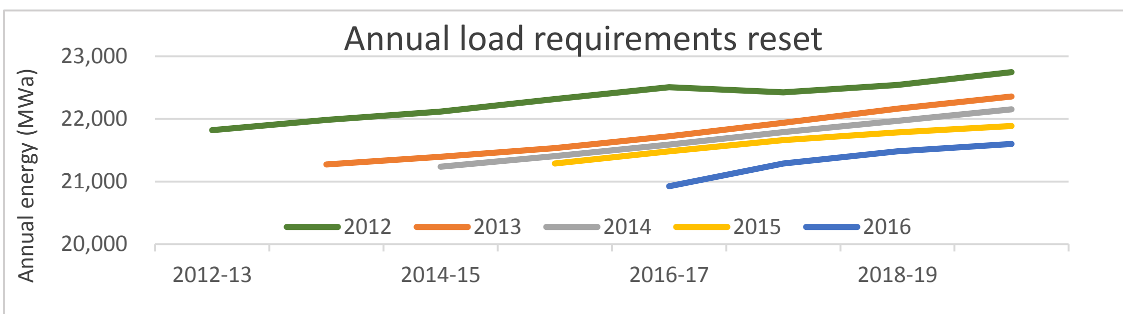

Figure 3

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 CO_2 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 CO_2 emissions. The hydro system's generation output under various water conditions, along with other firm carbon free resources stacked on top, are shown below.

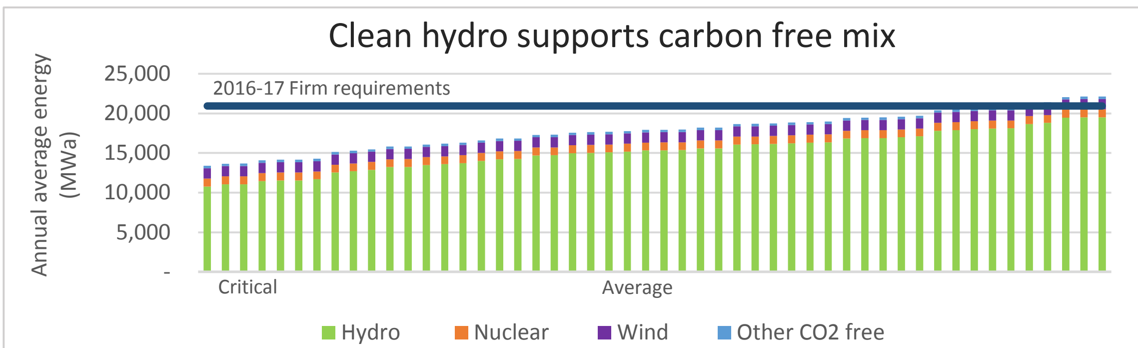

Figure 4

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 CO_2 free resource generation, dispatchable thermal resources are relied upon to fill the gap, even during the highest of water years.

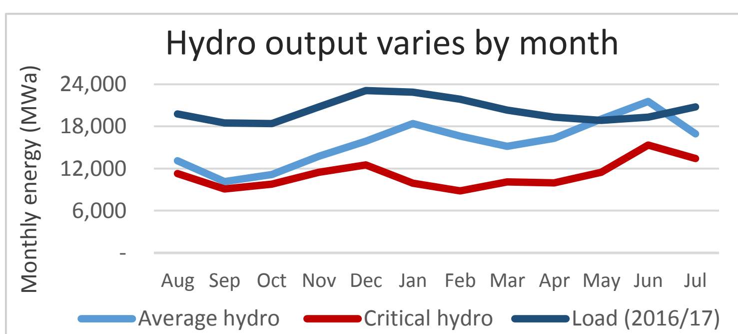

Figure 5

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.

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

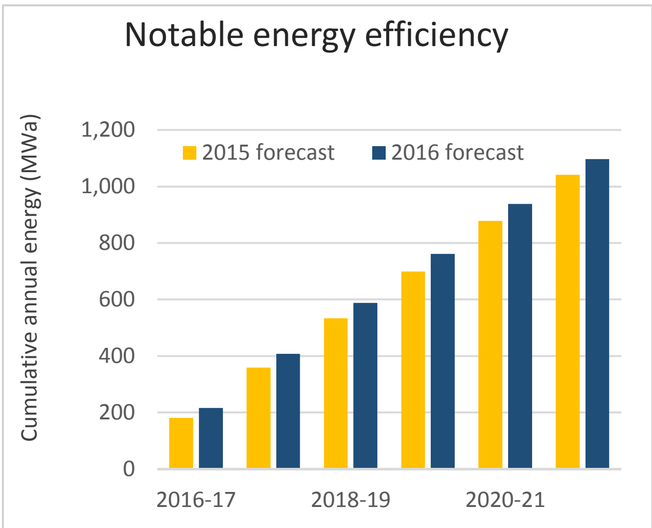

Figure 6

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.

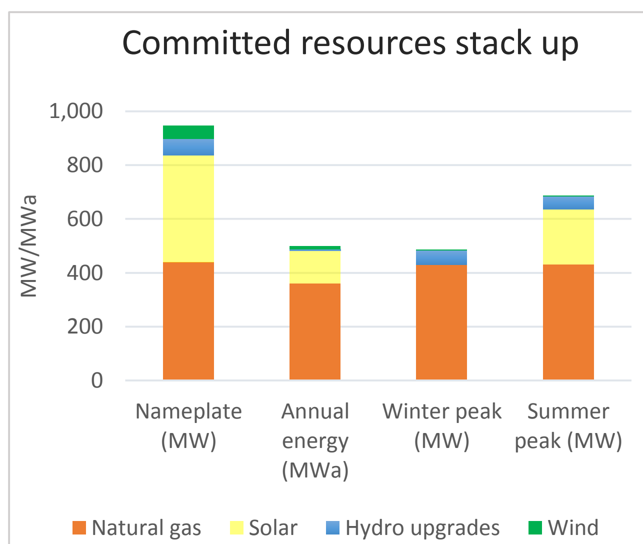

Figure 7

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.

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.

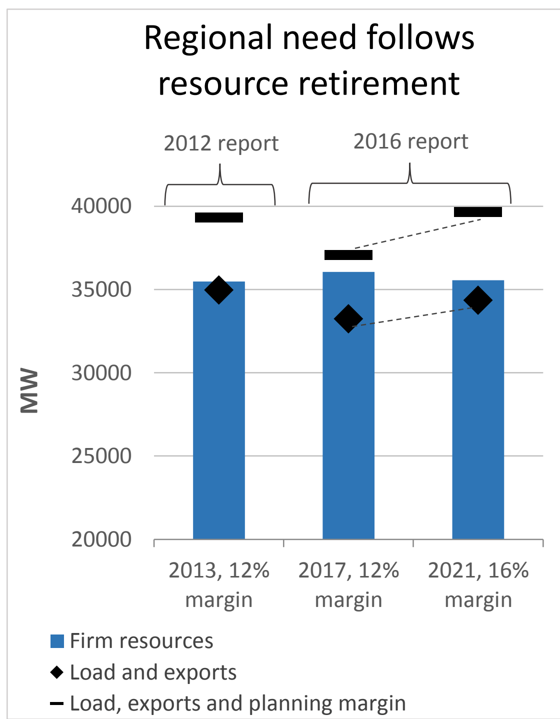

Figure 8

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]

[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.

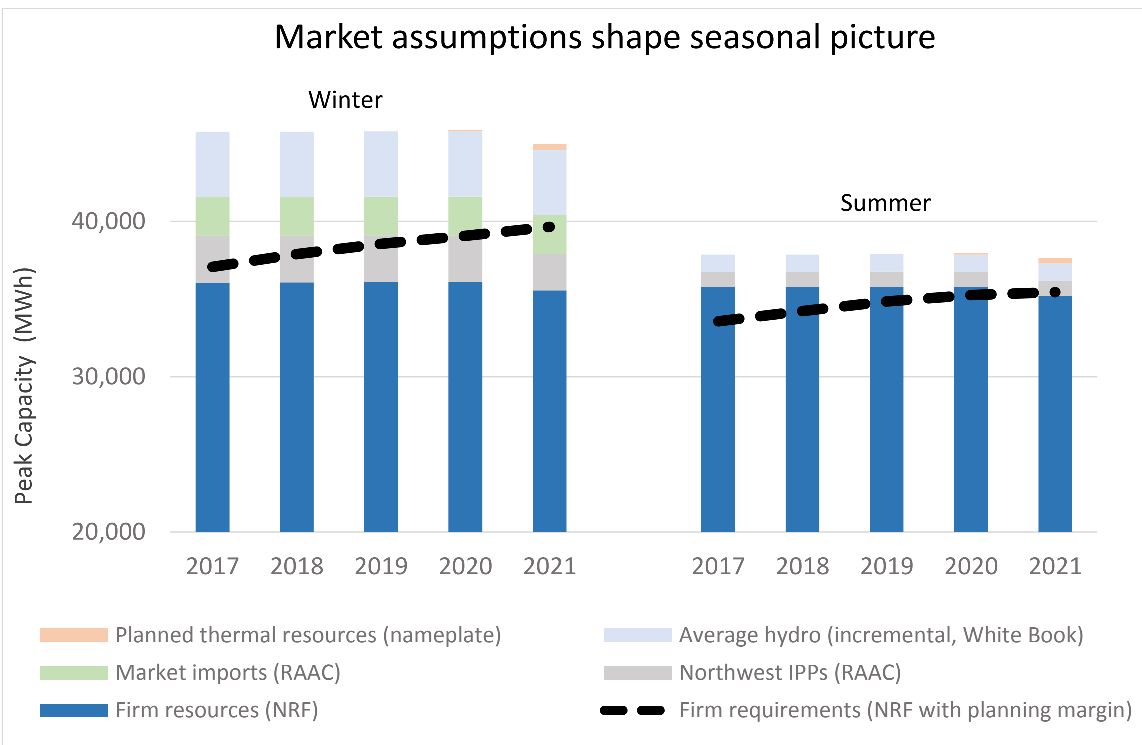

Figure 9

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[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 *Assessmen*t 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]

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[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	590	555	531	524	519	468	463	459	450	445
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	3,532	3,659	3,646	3,634	3,390	3,135	3,112	2,943	2,801	2,809
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	851	716	530	516	518	518	518	516	515	527	615	738
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	3,844	3,394	3,323	3,599	3,783	3,730	3,770	3,555	2,965	2,696	3,408	3,777
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/]	3,827	4,206	4,571	4,923	5,285	5,655	6,028	6,369	6,752	6,784
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	4,287	4,287	4,287	4,287	3,715	3,711	3,709	3,709	3,709	3,709
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/]	3,303	3,645	3,985	4,312	4,617	4,937	5,250	5,585	5,927	5,978
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	4,290	4,287	4,287	4,287	4,287	3,715	3,711	3,709	3,709	3,709
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
Hyline 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
Moores Hallow 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

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	SEQCBID	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	SEQCBID	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)	
Merwin	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	Ftathead 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
Moores Hallow 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 Solor 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)
Foote Creek Rim 2	PPM Energy	Federal System (BPA)	2
Foote 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	Invenergy	90
Willow Creek	Invenergy	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
Alder Mutual
Ashland, City of
Asotin County PUD #1
Avista Corp.
Bandon, City of
Benton PUD
Benton REA
Big Bend Electric Co-op
Blachly-Lane Electric Cooperative
Blaine, City of
Bonners Ferry, City of
Bonneville Power Administration
Burley, City of
Canby Utility
Cascade Locks, City of
Central Electric
Central Lincoln PUD
Centralia, City of
Chelan County PUD
Cheney, City of
Chewelah, City of
City of Port Angeles
Clallam County PUD #1
Clark Public Utilities
Clatskanie PUD
Clearwater Power Company
Columbia Basin Elec. Co-op
Columbia Power Co-op
Columbia REA
Columbia River PUD
Consolidated Irrigation Dist. #19
Consumers Power Inc.
Coos-Curry Electric Cooperative
Coulee Dam, City of
Cowlitz County PUD
Declo, City of
Douglas County PUD
Douglas Electric Cooperative
Drain, City of
East End Mutual Electric
Eatonville, City of
Ellensburg, City of
Elmhurst Mutual P & L
Emerald PUD
Energy Northwest
Eugene Water & Electric Board
Fall River Rural Electric Cooperative
Farmers Electric Co-op
Ferry County PUD #1
Fircrest, Town of
Flathead Electric Cooperative
Forest Grove Light & Power
Franklin County PUD
Glacier Electric
Grant County PUD
Grays Harbor PUD
Harney Electric
Hermiston, City of
Heyburn, City of
Hood River Electric
Idaho County L & P
Idaho Falls Power
Idaho Power
Inland Power & Light
Kittitas County PUD
Klickitat County PUD
Kootenai Electric Co-op
Lakeview L & P (WA)
Lane Electric Cooperative
Lewis County PUD
Lincoln Electric Cooperative
Lost River Electric Cooperative
Lower Valley Energy
Mason County PUD #1
Mason County PUD #3
McCleary, City of
McMinnville Water & Light
Midstate Electric Co-op
Milton, Town of
Milton-Freewater, City of
Minidoka, City of
Missoula Electric Co-op
Modern Electric Co-op
Monmouth, City of
Nespelem Valley Elec.Co-op
Northern Lights Inc.
Northern Wasco Co. PUD
NorthWestern Energy
Ohop Mutual Light Company
Okanogan Co. Electric Cooperative
Okanogan County PUD #1
Orcas Power & Light
Oregon Trail Co-op
Pacific County PUD #2
PacifiCorp
Parkland Light & Water
Pend Oreille County PUD
Peninsula Light Company
Plummer, City of
PNGC Power
Port of Seattle – SEATAC
Portland General Electric
Puget Sound Energy
Raft River Rural Electric
Ravalli Co. Electric Co-op
Richland, City of
Riverside Electric Co-op
Rupert, City of
Salem Electric Co-op
Salmon River Electric Cooperative
Seattle City Light
Skamania County PUD
Snohomish County PUD
Soda Springs, City of
Southside Electric Lines
Springfield Utility Board
Steilacoom, Town of
Sumas, City of
Surprise Valley Elec. Co-op
Tacoma Power
Tanner Electric Co-op
Tillamook PUD
Troy, City of
Umatilla Electric Cooperative
Umpqua Indian Utility Co-op
United Electric Cooperative
US Corps of Engineers
US Bureau of Reclamation
Vera Water & Power
Vigilante Electric Co-op
Wahkiakum County PUD #1
Wasco Electric Co-op
Weiser, City of
Wells Rural Electric Co.
West Oregon Electric Cooperative
Whatcom County PUD
Yakama Power

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.

Contents

(continued next page)

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.

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-curtailment 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

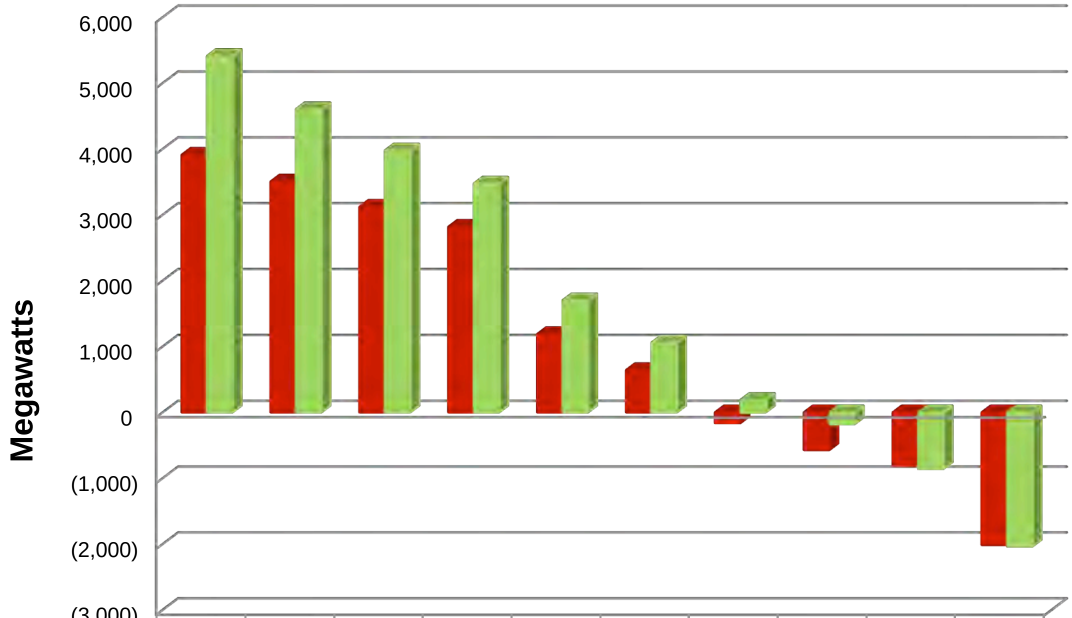
BPA published its *2015 Pacific Northwest Loads and Resources Study* in January 2016. This study provided detailed information on BPA's forecasted loads and resources as well as overall loads and resources for the entire region. The BPA study is similar to the PNUCC study, but there are some differences, 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.)



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
2015 BPA	3,911	3,505	3,122	2,818	1,189	642	(162)	(572)	(808)	(2,014)
2016 NRF	5,413	4,605	3,977	3,474	1,702	1,059	188	(178)	(857)	(2,036)

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 quantity 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).

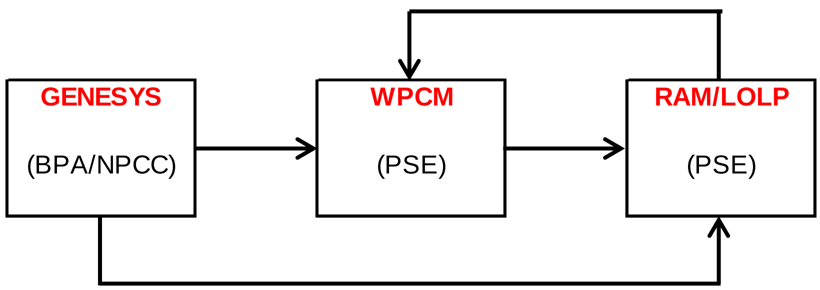
For the 2017 analysis, the following key refinements were incorporated into PSE's IRP models.

- 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-curtailment 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-curtailment 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]

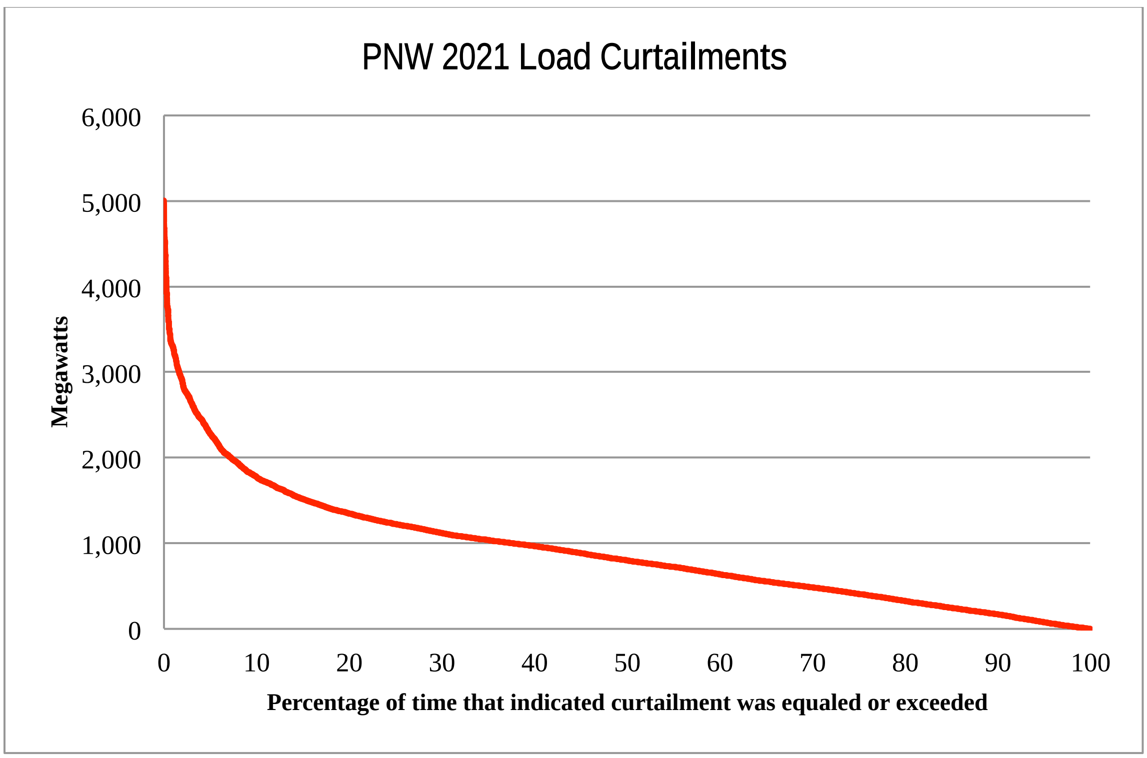
The GENESYS Colstrip Sensitivity study incorporated the following key assumptions:

- 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-curtailment 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.)

One of the outputs from this study is a set of all simulations in which there is a PNW-wide load-curtailment 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 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-curtailment 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-curtailment 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 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.

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
2. cooperatives
3. direct service industries
4. investor-owned utilities
5. marketers
6. municipalities
7. public utility districts
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.

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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.

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-curtailment values from the GENESYS model. The sensitivity ratios are a measure of the relative size of each PNW entity and were computed as follows:

Entity SR = (Entity ABS PK LD + Entity PK Res)/(PNW ABS PK LD + 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-curtailment 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:

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-curtailment, 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.

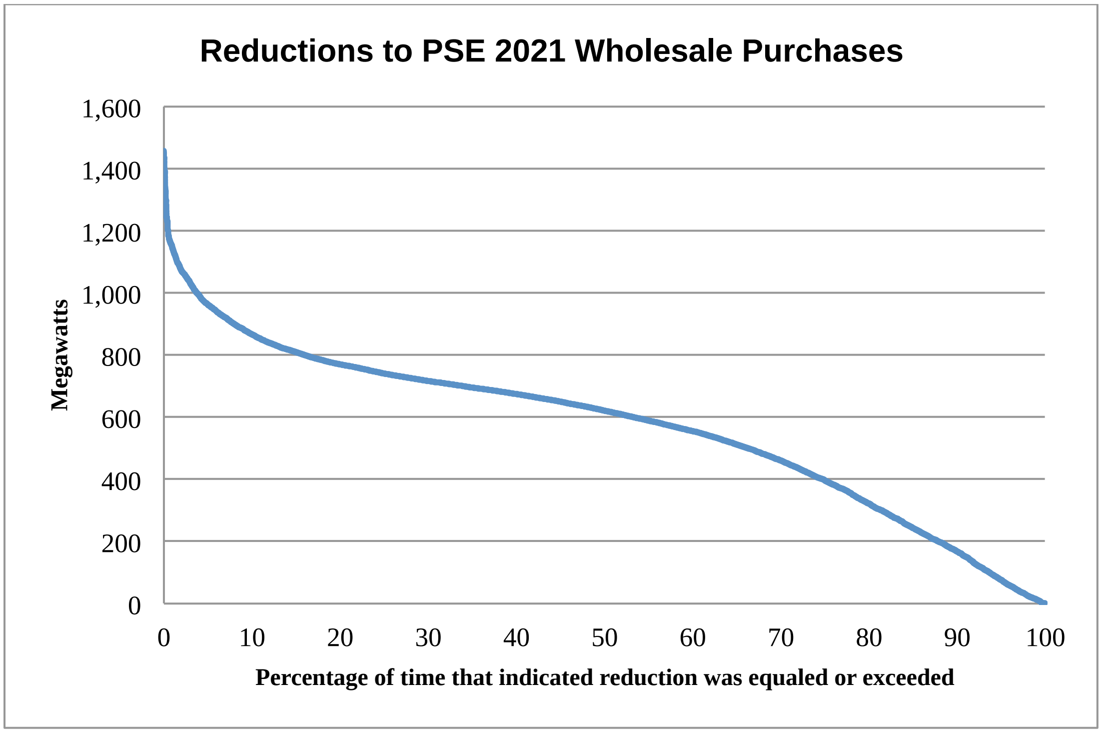
WPCM Outputs

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.

Figure G-8 illustrates this point for several different magnitudes of hourly load-curtailment events from the same simulation of the NPCC's GENESYS model, for the Colstrip Sensitivity Study.

Figure G-8: Hourly Load-curtailment Events
from the NPCC's GENESYS Model, Colstrip Sensitivity Study

Initial Hourly PSE Wholesale Purchase (MW)	PNW Load Curtailment Amount (MW)	Final Hourly PSE Wholesale Purchase (MW)	PSE Hourly Purchase Reduction (Percent)	PSE Share of PNW Load Curtailment (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-curtailment 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-curtailment 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.

Contents

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.

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.

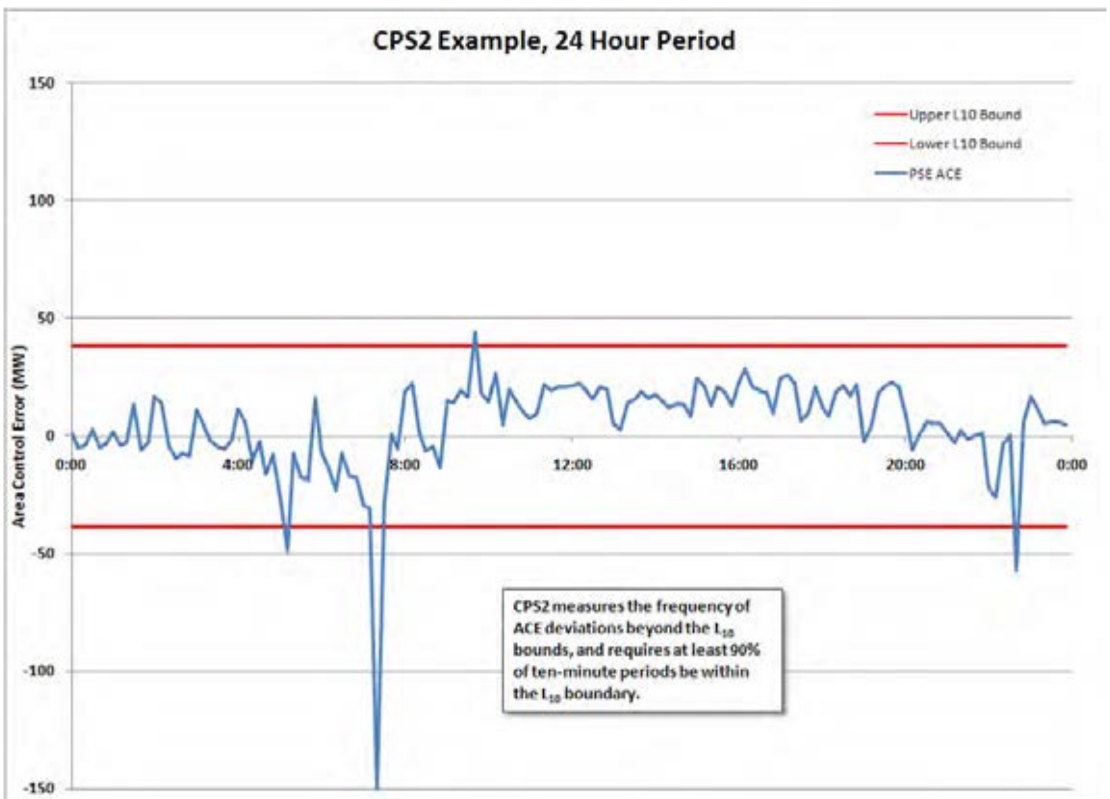
The Area Control Error (ACE) metric has been used for many years to track the ability of a BA to meet its reliability obligation. ACE is the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency. It reflects the balance of generation, load and 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.

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

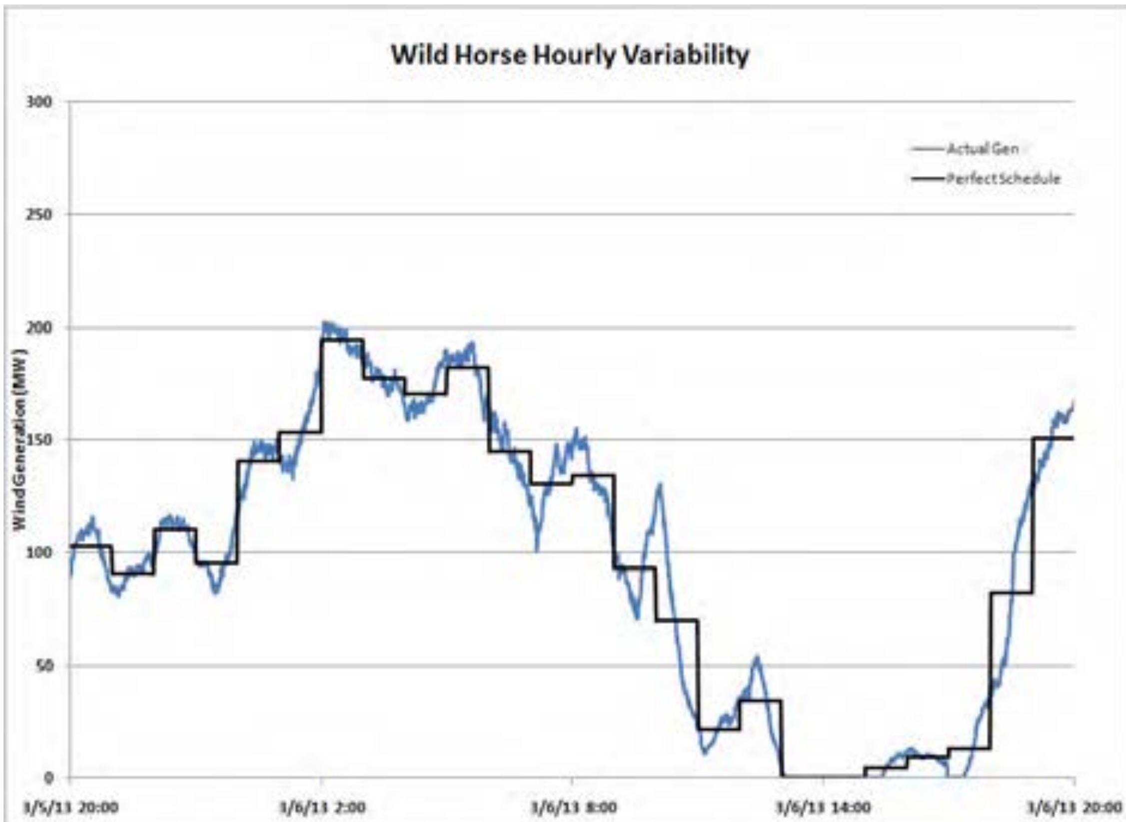
VARIABILITY is the moment to moment, natural fluctuations in loads and generating resources and is always present on the electric system. **UNCERTAINTY** is the inability to perfectly predict the hourly values for loads and generating resources. **VOLATILITY** refers to the collective variability and 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.

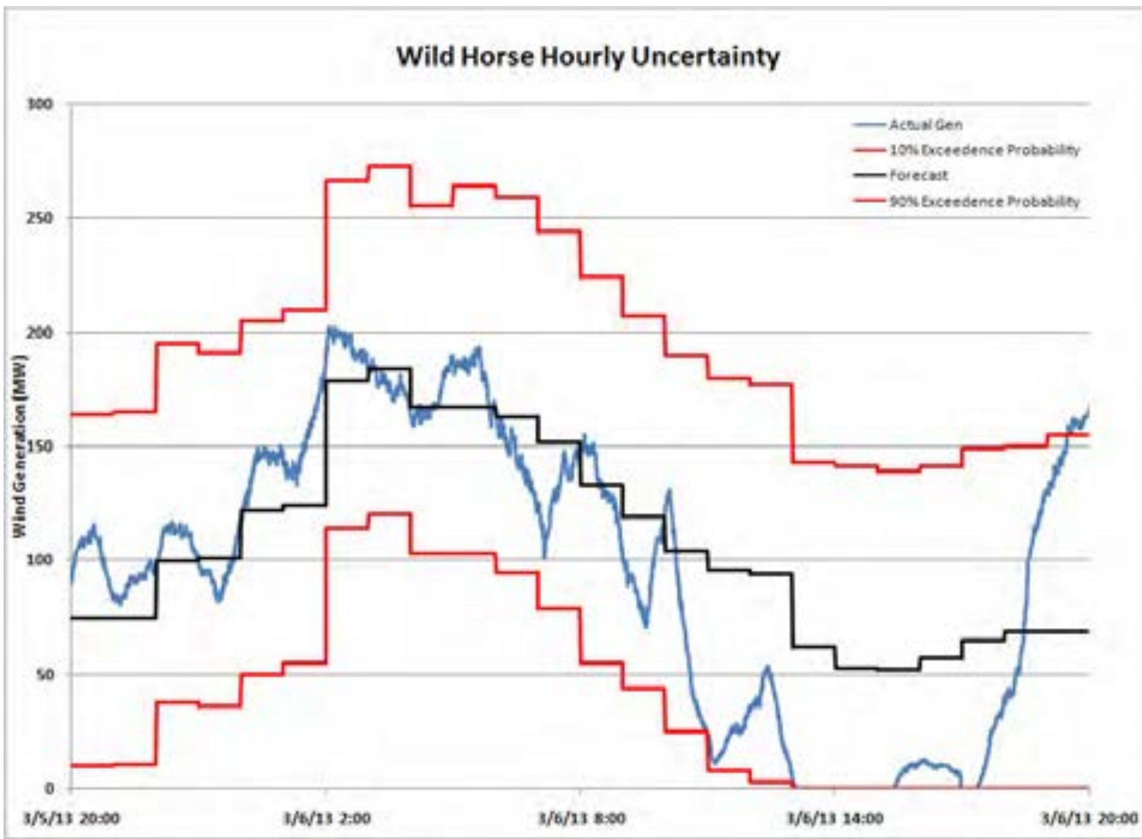
Figures H-2 through H-4 use a 24-hour period at the Wild Horse wind facility to illustrate examples of variability, uncertainty and volatility. In Figure H-2, the variability of Wild Horse is shown as the moment-to-moment generation relative to a perfect hourly schedule (a perfect hourly schedule equals 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



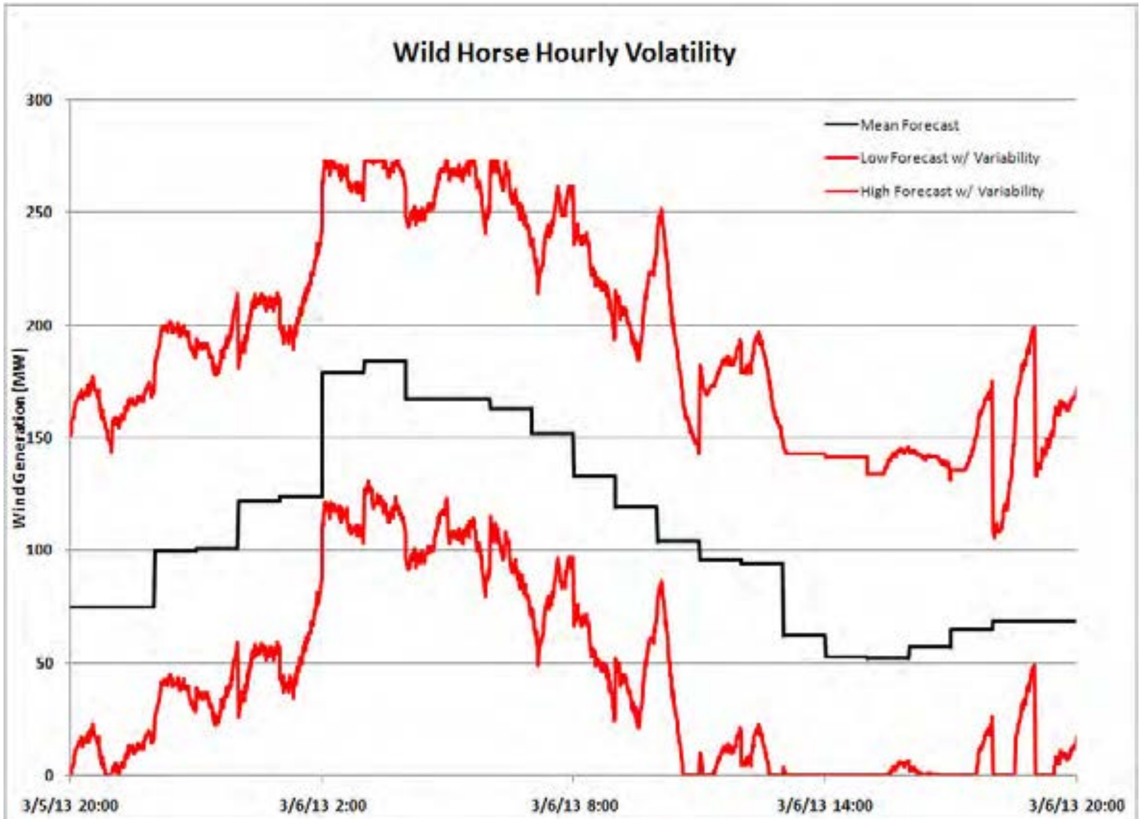
In reality, perfect foresight of wind generation or load for each upcoming operating hour is not possible. In Figure H-3, future wind generation is presented as an expected forecast for the next several hours, along with two additional forecasts that provide the probability of wind generation exceeding 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



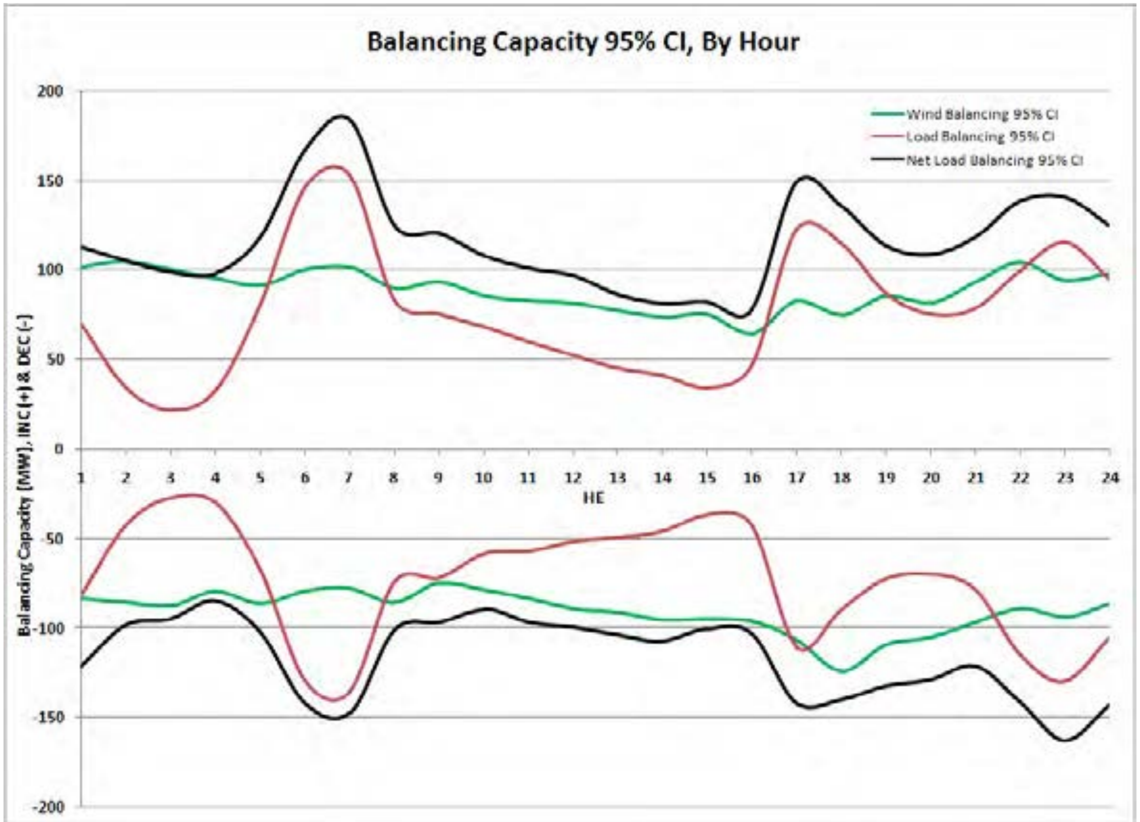
Managing Volatility

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:

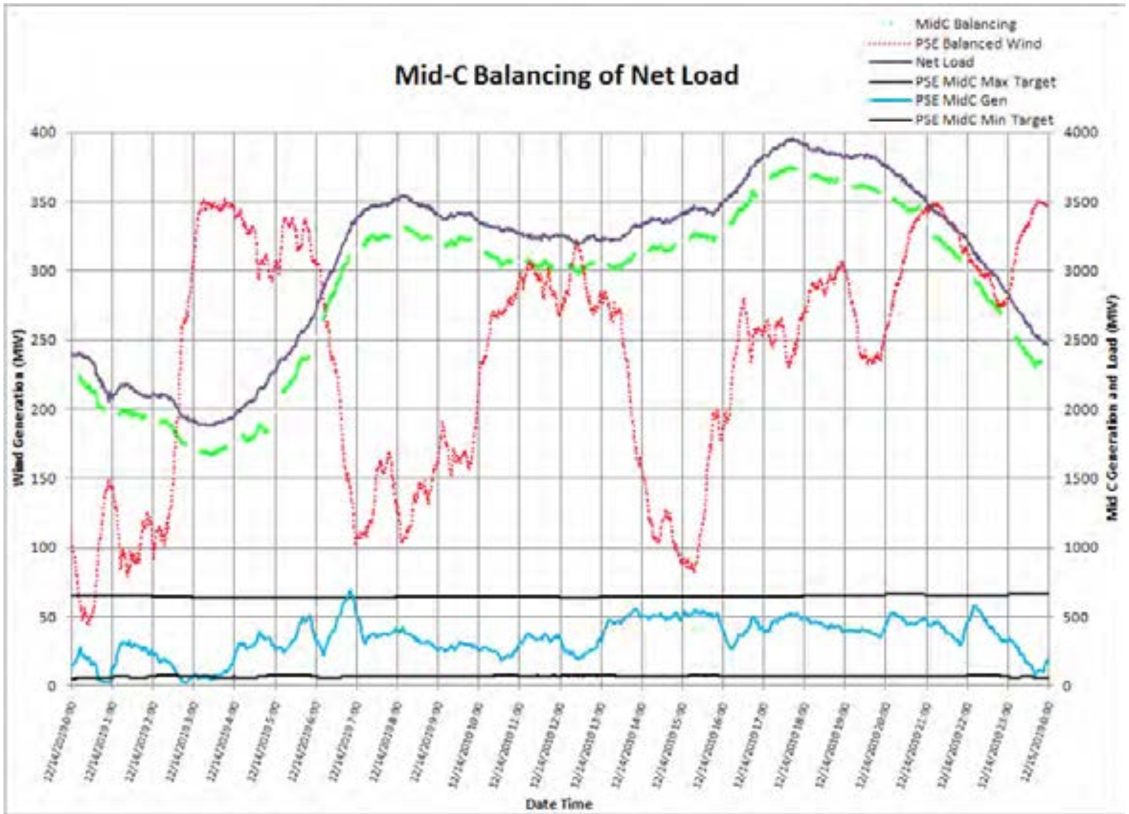
- In the day-ahead schedule (DA stage) PSE procures balancing reserve capacity ahead of the operating hour; and
- In real-time operations (RT stage), PSE deploys reserves and moves its generators to balance energy within the hour.

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.

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.

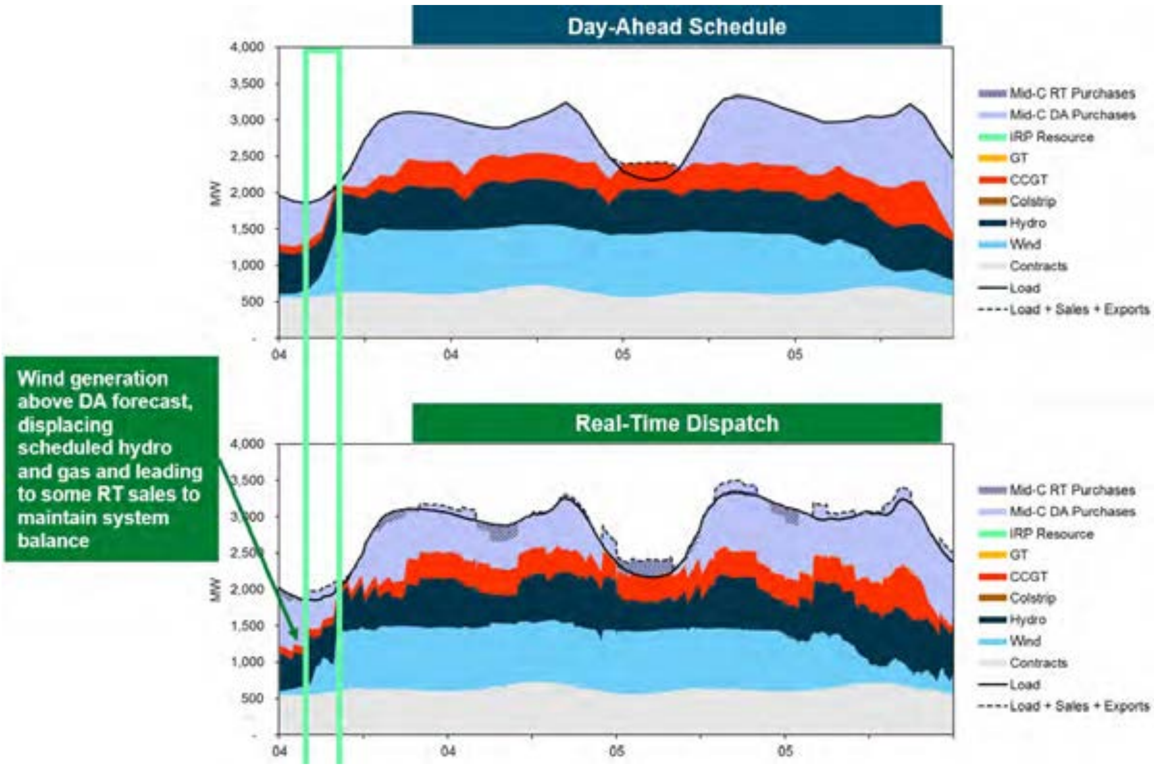
For this analysis, PSE used actual 5-minute demand data from 2016 for load, scaled to the demand forecast for 2022. The analysis also uses 2016 actual 5-minute data for wind and run-of-river hydro in PSE's BA, and 2016 daily total Mid-C energy generation. PLEXOS then optimized the Mid-C generation within 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 CO_2 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.

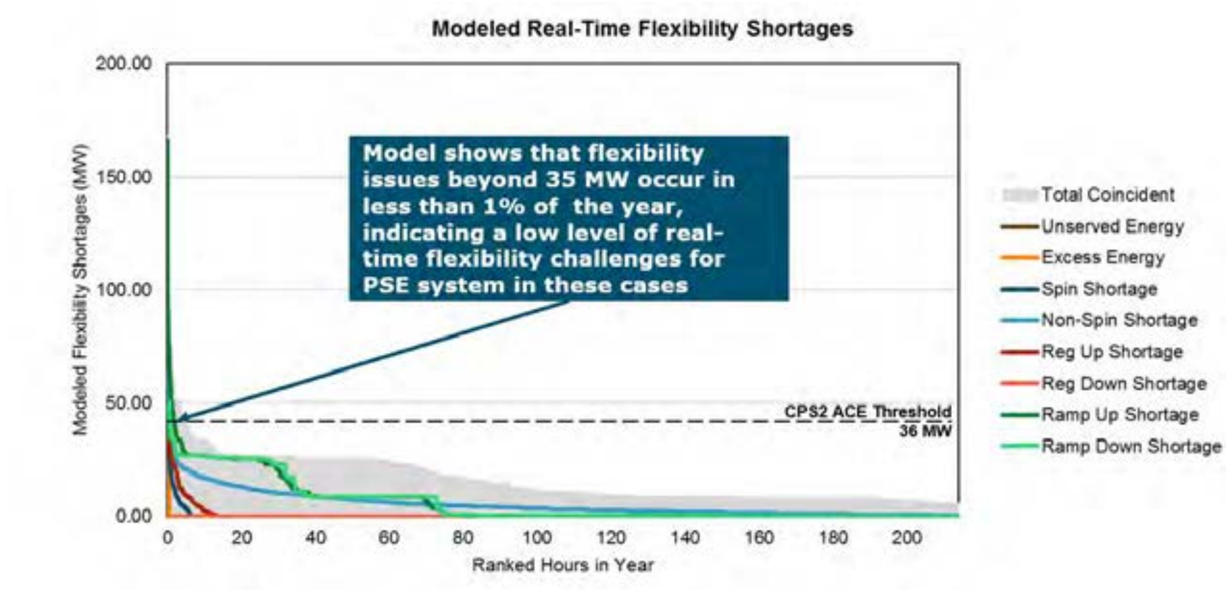
- **Upward flexibility issues** occur in certain real-time 5-minute intervals, including times of implied unserved energy, shortage of ramping response or reserves, or positive area control error (ACE) compared to scheduled interchange with neighboring systems.
- **Downward flexibility issues** occur 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.

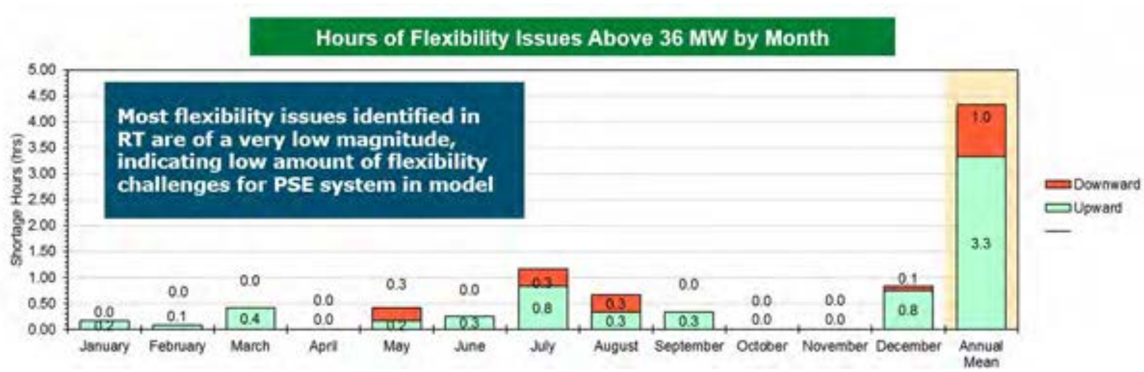
Figure H-9: Real-time Flexibility Shortages Modeled



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

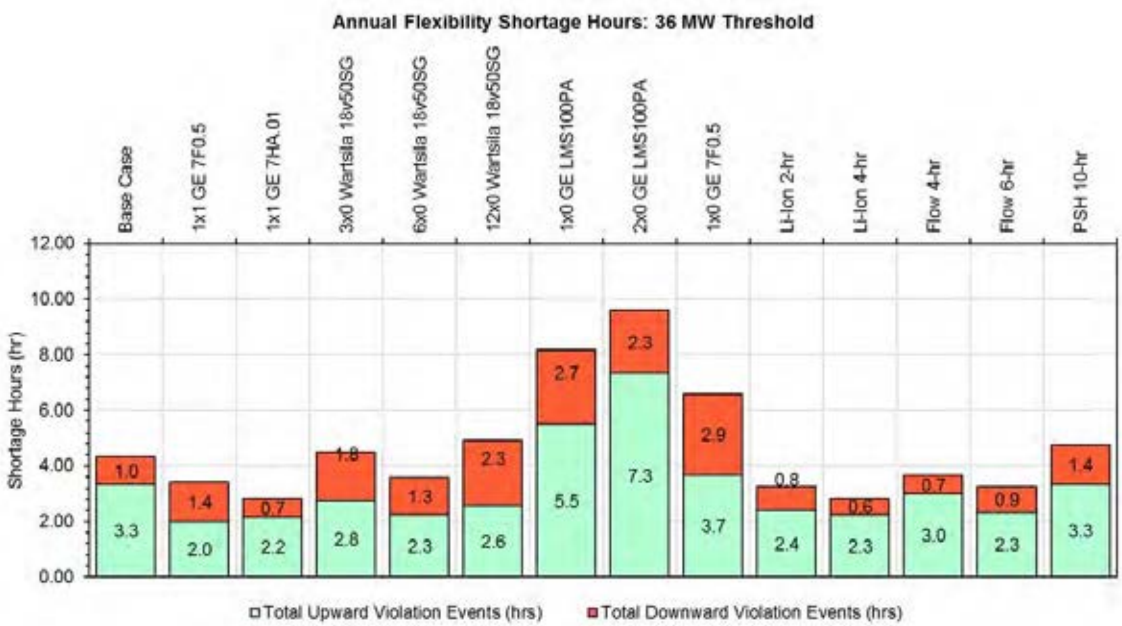
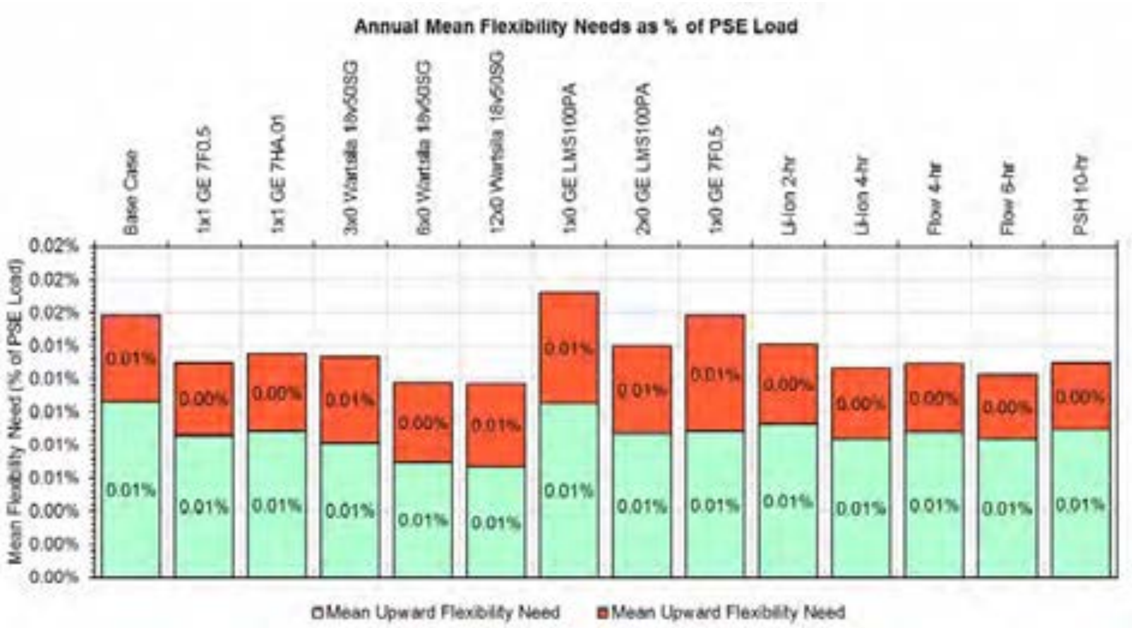


Figure H-12 presents the changes in impact on flexibility issues as a percentage of total PSE load across different portfolio resources. The Current Portfolio Case encounters upward or downward issues equivalent to less than 0.02 percent of total PSE system load. In most cases, new resources reduce the 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.

Figure H12: Annual Mean Flexibility Needs as Percentage of PSE Load

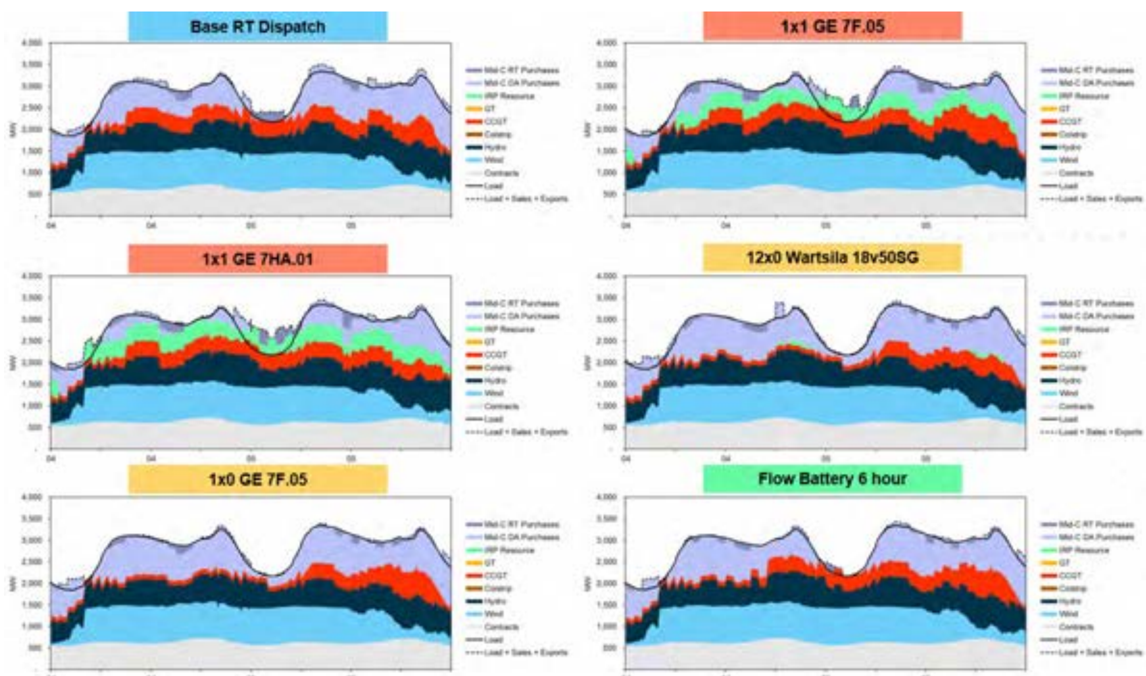


Sub-hourly Dispatch Cost Impact

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.

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	1x1 GE 7F9.5	1x1 GE 7HA.01	3x0 Wartsila 18V50SG	6x0 Wartsila 18V50SG	12x0 Wartsila 18V50SG	1x0 GE LMS100PA	2x0 GE LMS100PA	1x0 GE 7F9.5	Li-Ion 2-hr	Li-Ion 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	187	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	-	-	-	-	-
	Subtotal	*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)
	Subtotal	*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	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Subtotal	*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 CO_2 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.

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 CO_2 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 7F8.5	1x1 GE 7HA.01	3x3 Wartsila 18v50SG	6x3 Wartsila 18v50SG	12x0 Wartsila 18v50SG	1x0 GE LMS100PA	2x0 GE LMS100PA	1x0 GE 7F8.5	Li-Ion 2-hr	Li-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	-	-	-	-	-
	Subtotal	*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)
	Subtotal	*226*	*(69)*	*(81)*	*(13)*	*(17)*	*(24)*	*(15)*	*(22)*	*(22)*	*(5)*	*(5)*	*(5)*	*(6)*	*(3)*
Contracts	Aggregated	208	0	0	0	0	0	0	0	0	0	0	0	0	0
	DSM	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Subtotal	*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.

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 ($MM)		Base Portfolio	1x1 GE 7F6.5	1x1 GE 7HA.01	3x0 Wartsila 18V50SG	6x0 Wartsila 18V50SG	12x0 Wartsila 18V50SG	1x0 GE LMS100PA	2x0 GE LMS100PA	1x0 GE 7F6.5	Li-Ion 2-hr	Li-Ion 4-hr	Flow 4-hr	Flow 6-hr	PSH 10-hr
Generation	Wind	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	Hydro	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
	CCGT & Colstrip	(5)	(5)	(5)	(5)	(4)	(4)	(4)	(4)	(5)	(6)	(5)	(6)	(5)	(5)
	GT	5	4	4	7	6	6	6	8	8	6	6	8	6	6
	IRP Resource	-	(1)	(2)	(0)	(1)	(0)	0	0	(2)	-	-	-	-	-
	Subtotal	*(0)*	*(2)*	*(3)*	*1*	*2*	*2*	*2*	*3*	*1*	*1*	*1*	*1*	*0*	*1*
Mid-C	Purchases	14	15	16	13	13	12	12	12	13	14	14	14	14	14
	Sales	(14)	(13)	(13)	(15)	(16)	(15)	(15)	(15)	(14)	(15)	(14)	(15)	(14)	(15)
	Subtotal	*1*	*2*	*3*	*(2)*	*(3)*	*(3)*	*(3)*	*(4)*	*(1)*	*(1)*	*(1)*	*(1)*	*(1)*	*(1)*
Contracts	Aggregated	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	0	(0)	(0)
	DSM	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Subtotal	*(0)*	*(0)*	*(0)*	*(0)*	*(0)*	*(0)*	*(0)*	*(0)*	*(0)*	*(0)*	*(0)*	*0*	*(0)*	*(0)*
Total		0	0	(0)	(1)	(1)	(1)	(1)	(1)	(0)	(0)	(0)	(0)	(0)	(0)
Levelized Delta ($/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.

I

2017 PSE Integrated Resource Plan

Regional Transmission Resources

This appendix reviews current regional transmission issues and efforts to address those issues.

Contents

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.

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.

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 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.

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.

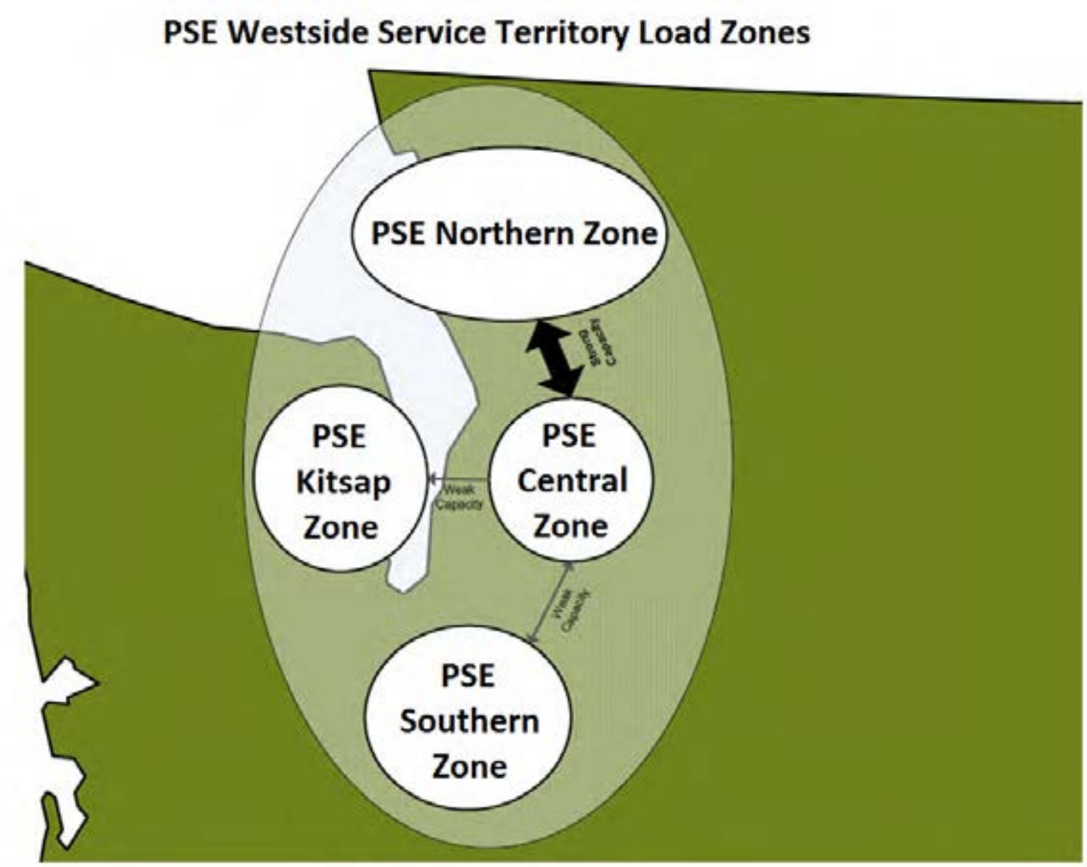
Some paths are designed to operate close to their limits (like West of Garrison), others are not; this latter group presents areas of the system where PSE sees a particular importance in continuing to study, develop and possibly construct new transmission.

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



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 K[1] 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

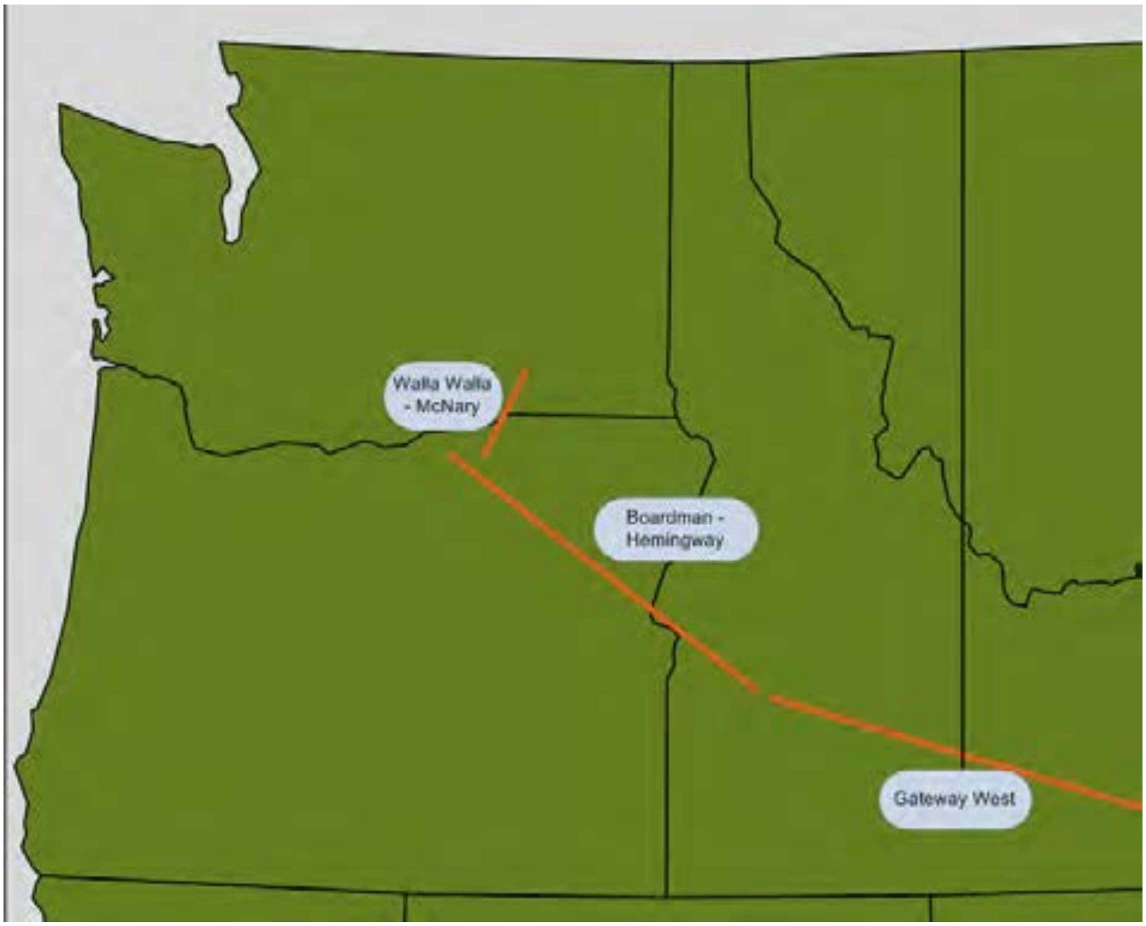
Major Proposed Projects

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

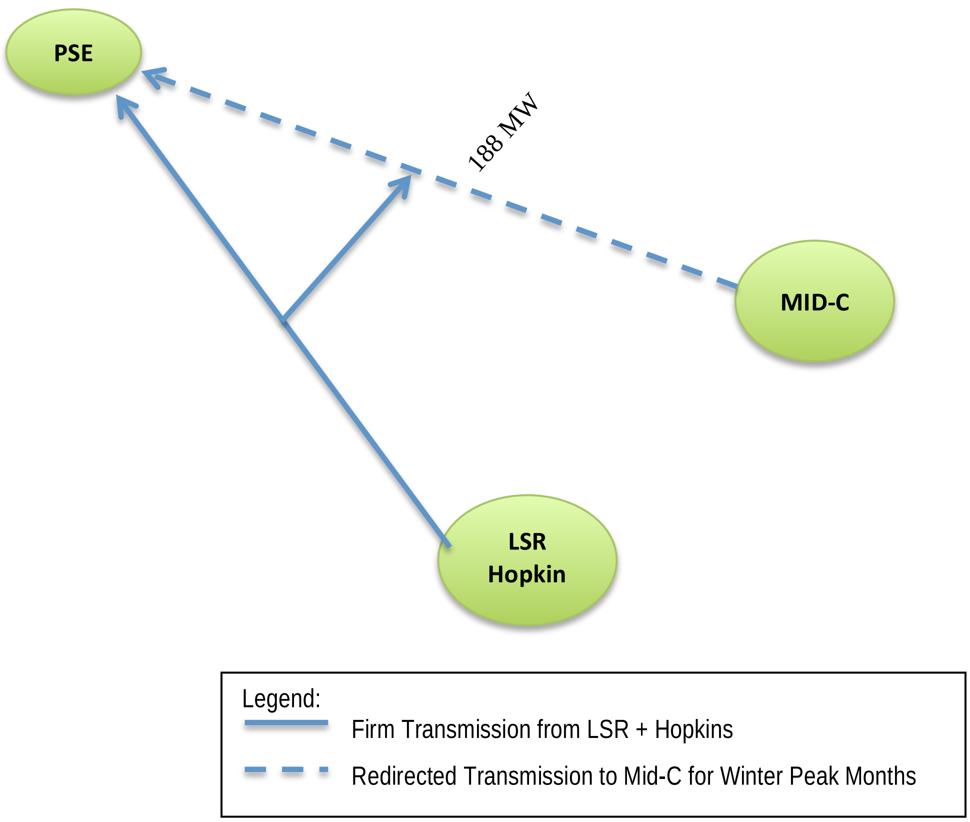
6. TRANSMISSION REDIRECT OPPORTUNITIES

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



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.

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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:

Contents

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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. [1][2]

Contents

(continued next page)

1 / Potential future CO_2 regulation is incorporated in the overall scenarios for the IRP since it impacts all thermal resources. Since Colstrip is included among these, CO_2 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.

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 Earthjustice[3] 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.

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.

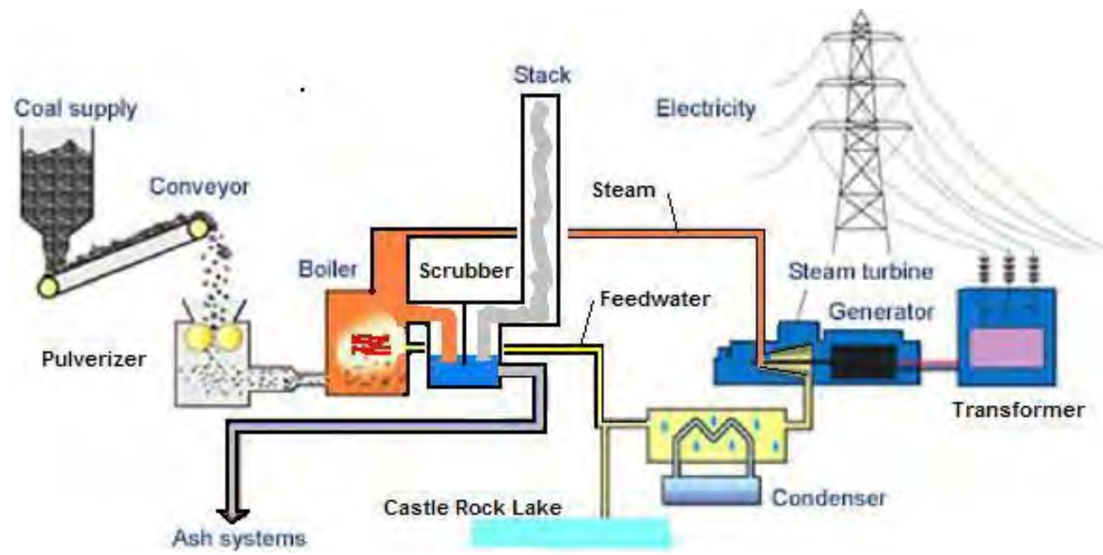
In the 1960s, BPA forecast that available baseload hydroelectric power would be fully subscribed by its statutory preference customers, leaving none available for sale to PSE and other investor-owned utilities. Faced with this situation, PSE had to develop or contract for other sources of baseload energy. 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 though 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 (SO_2). 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 SO_2; 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 SO_2 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 SO_2 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 SO_2, 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.

Contents

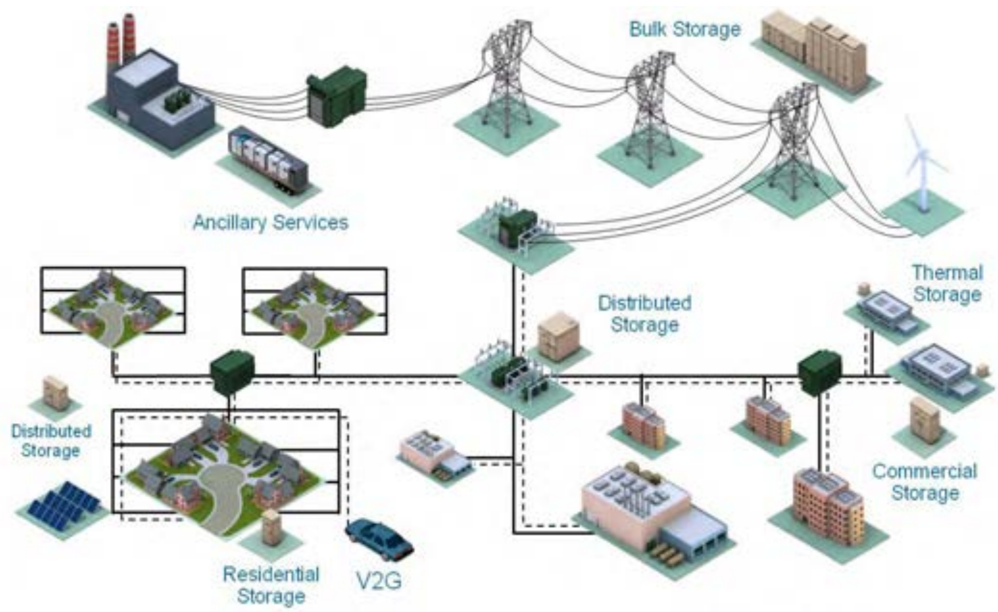
1. OVERVIEW

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.

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 Massashusetts. 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.

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.

- 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 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 atorage 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.

- 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]

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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://austinenergy.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.

- 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]

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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 Services[26]

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.

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.

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/PSEIdocs/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 reliabiliy.

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 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 enegy 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

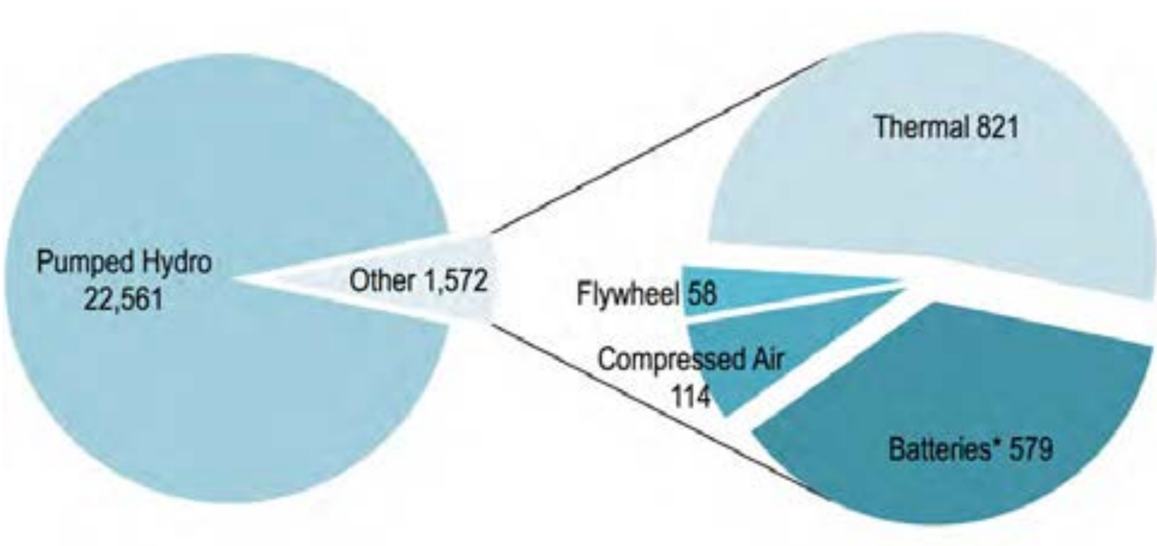
Energy storage encompasses a wide range of technologies and resource capabilities, and these differ in terms of cycle life, system life, efficiency, size and other characteristics. A detailed description of how each technology works, its benefits and limitations, and where it has been deployed is presented 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.

Figure L-5: Installed U.S. Grid-connected Energy Storage in MW, by Technology, as of 11/2016 [30]

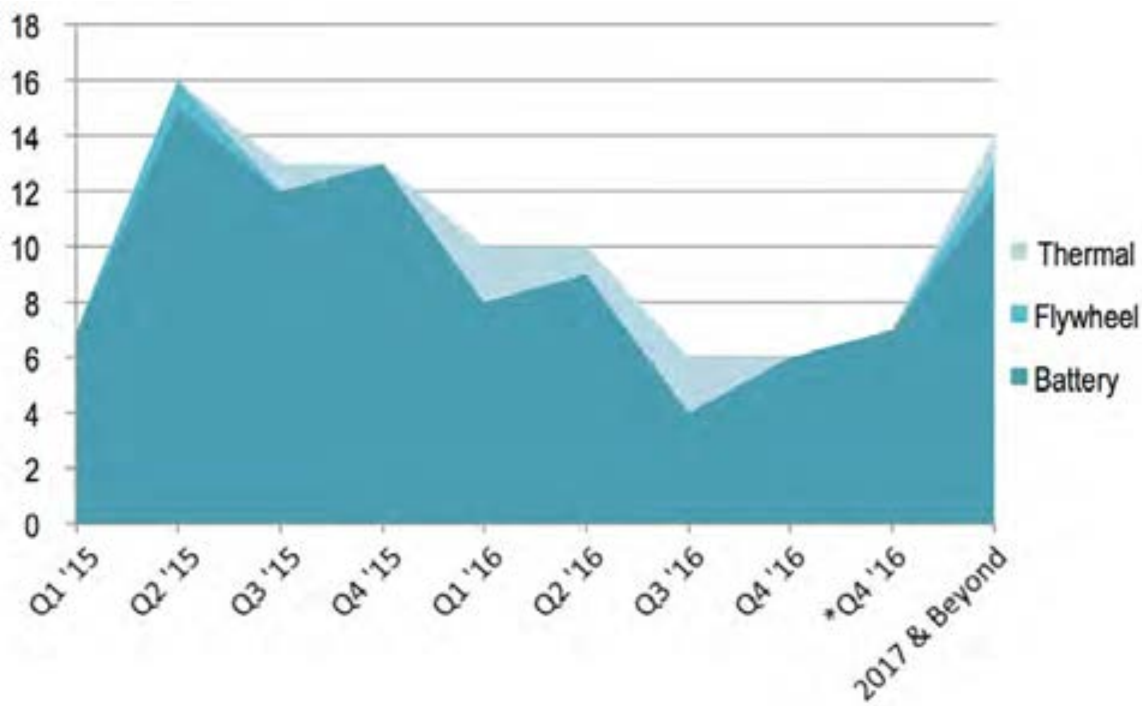


Batteries include lithium-ion, flow, sodium-based, nickel-based, lead acid, electrochemical capacitors and ultracapacitor batteries

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.

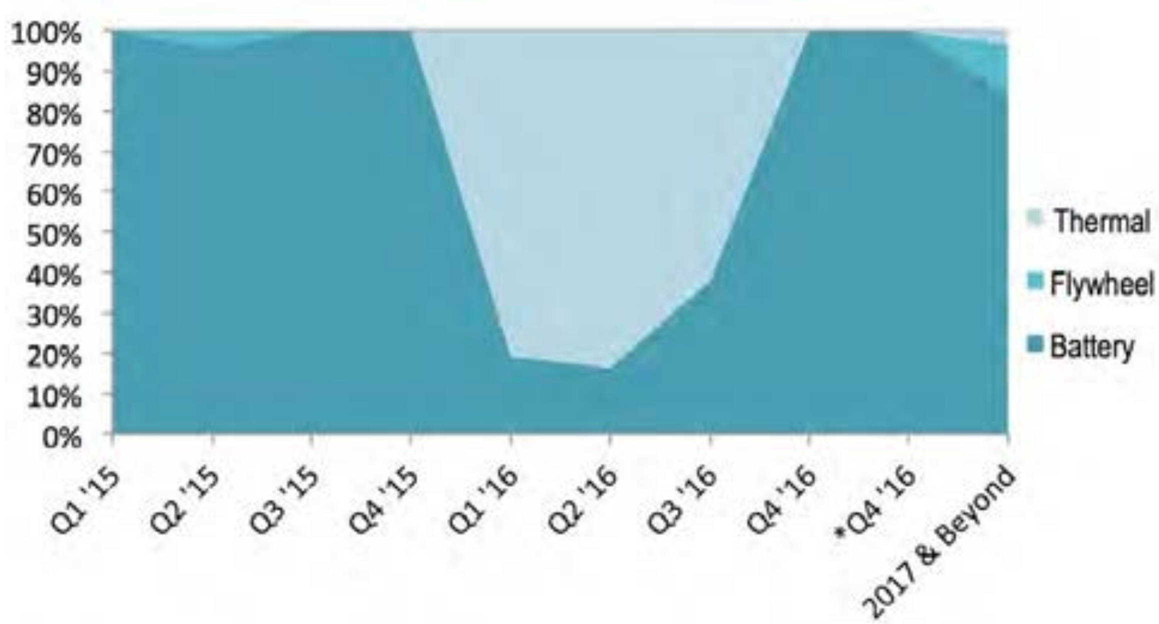
Figure L-6: Number of U.S Grid-connected Energy Storage Projects Installed or Contracted Since 2015, by Technology[31]



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

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.

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.

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.

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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.

Contents

DNV·GL

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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Project name:	CAPEX benchmarking	DNV GL - Energy
Report title:	Washington State Wind and Solar Power Project Capital Cost Benchmarks	Advisory Americas
		1501 4th Avenue, Suite 900
Customer:	Puget Sound Energy, Inc., PO Box 97034 Bellevue, 98009-9734	Seattle, WA 98101 USA
		Tel: 206-387-4200
		Enterprise No.: 26-2535197
Contact person:	Michele Kvam	
Date of issue:	28 April 2017	
Project No.:	10049032	
Document No.:	10049032-HOU-T-01	
Issue:	B	
Status:	FINAL	

Task and objective:

Provide capital cost industry benchmarks for wind power project and solar power project construction specific to the eastern Washington region.

Prepared by:	Verified by:	Approved by:
D. Pardo Project Manager, Development & Engineering Services	M. Drunsic Offshore lead, Americas	J. Frye Senior Project Manager, Development & Engineering Services
M. Heffernan Senior Engineer, Solar Due Diligence	A. Abatzis Senior Solar Consultant	

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Keywords:
Onshore wind, offshore wind, solar, CAPEX, benchmark

Reference to part of this report which may lead to misinterpretation is not permissible.

Issue	Date	Reason for Issue	Prepared by	Verified by	Approved by
A	19 Apr 2017	DRAFT	D. Pardo, M. Heffernan, M. Ebbesen	R. Abatzis, M. Drunsic	J. Frye
B	28 Apr 2017	FINAL			

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 Reports[1].

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**

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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.

Contents

(continued next page)

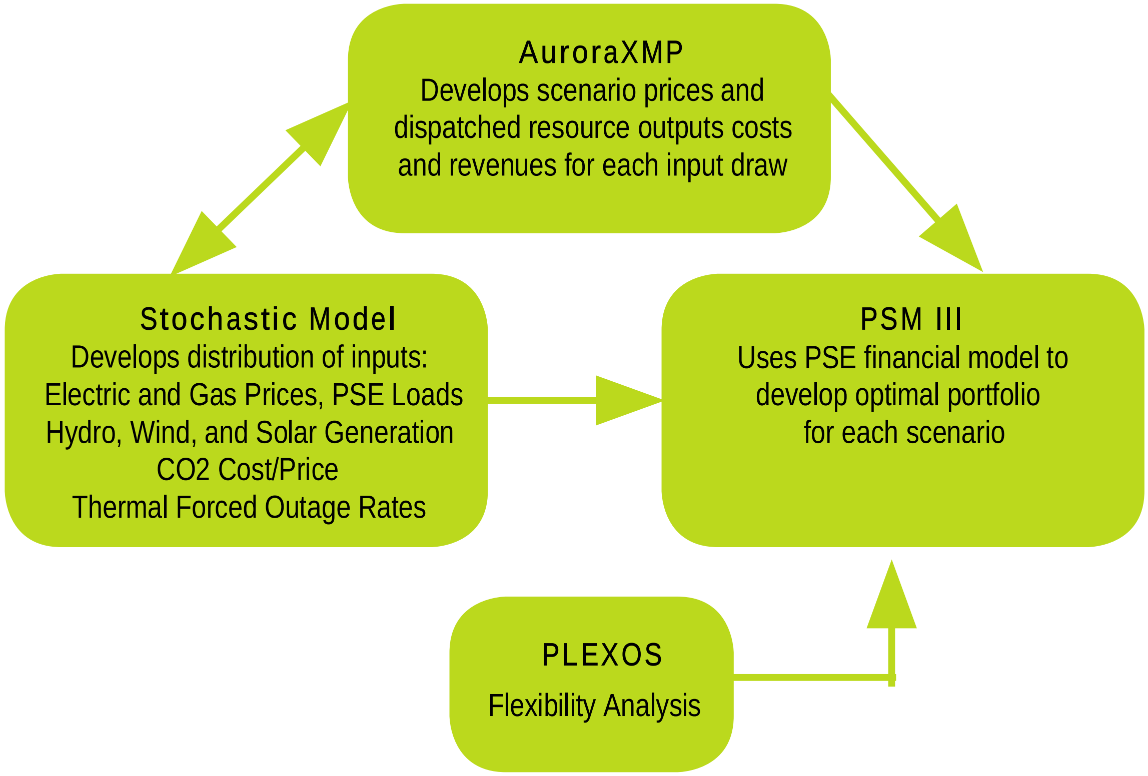
1. PORTFOLIO ANALYSIS METHODS

PSE uses four models for electric integrated resource planning: AURORAxmp,® 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 AURORAxmp 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, CO_2 prices, hydro generation, wind generation, PSE loads and thermal plant forced outages.

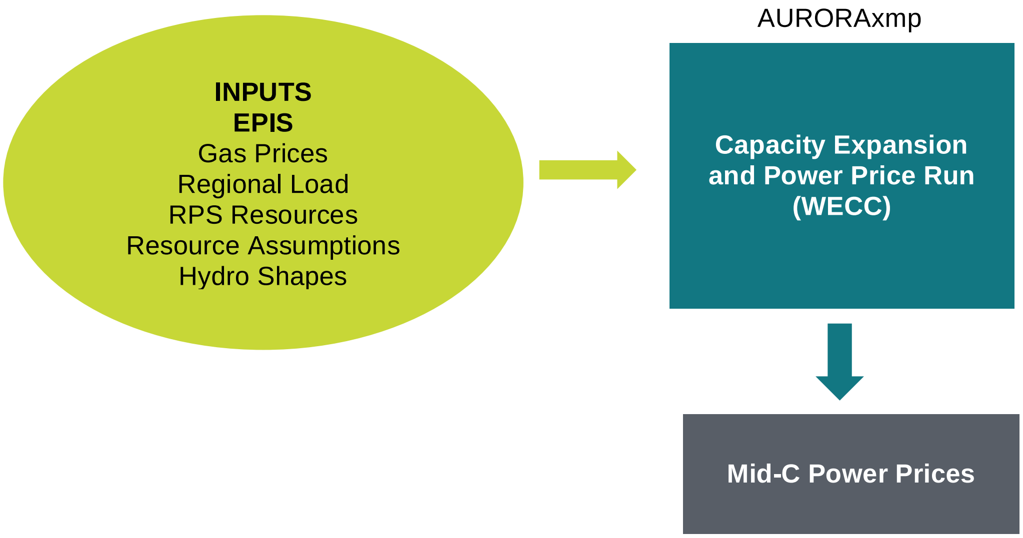
Figure N-1: Electric Analysis Methodology



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

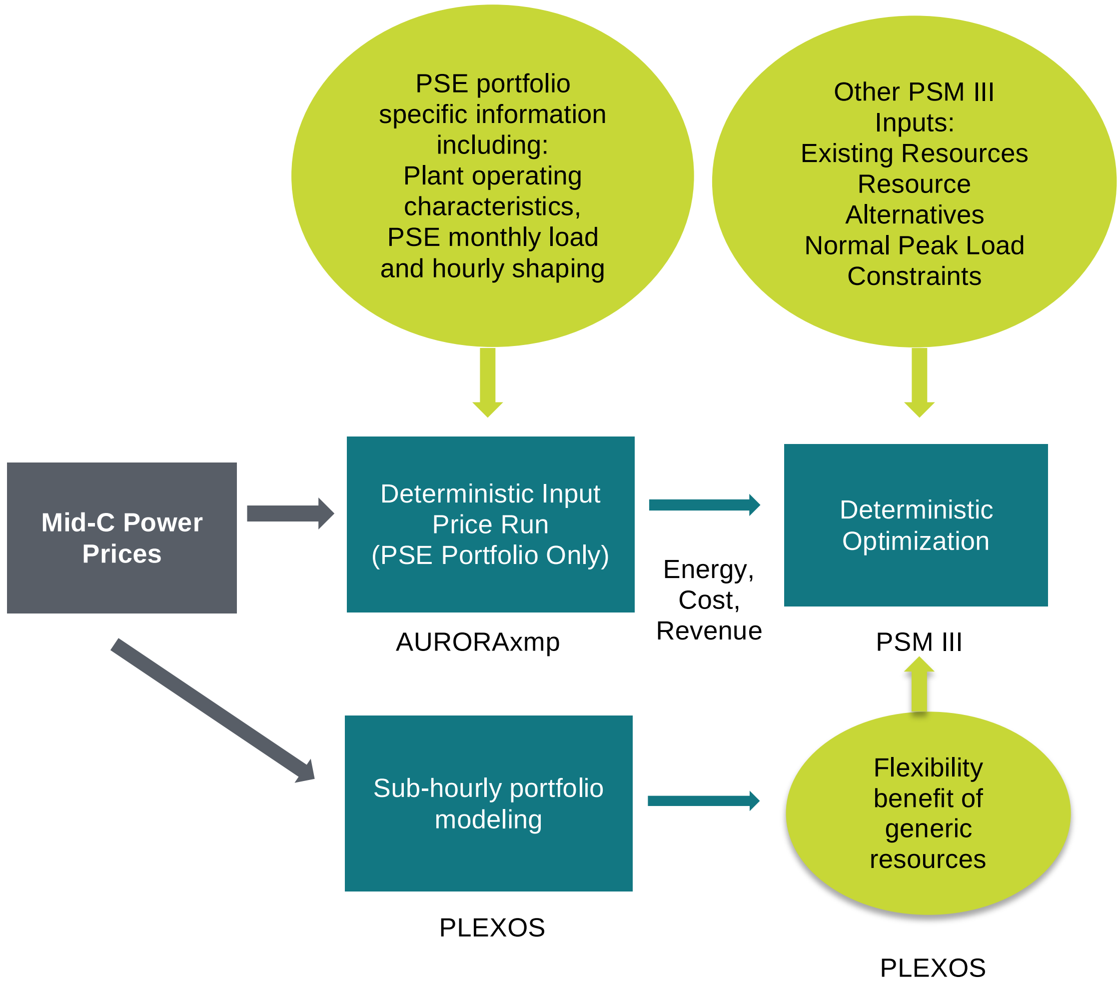


After all of the assumptions are collected and wholesale power prices have been created through AURORA, the next step is portfolio analysis.

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 CO_2 price ($000), market revenue ($000), and CO_2 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 simulations[1] that model varying power prices, gas prices, hydro generation, wind generation, load forecasts (energy and peak), plant forced outages and CO_2 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 ANLAYSIS 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.

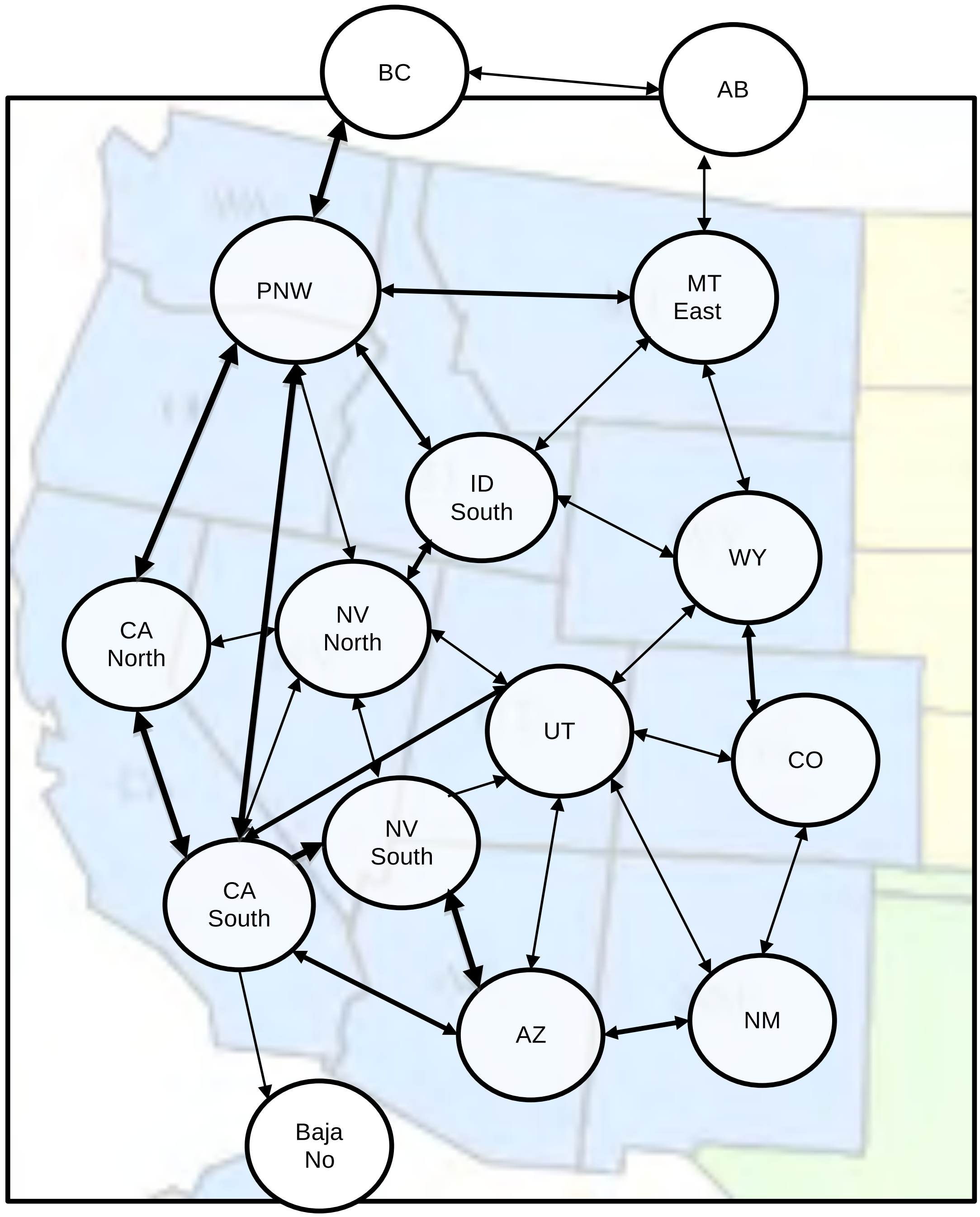
The following text was provided by EPIS, Inc. and edited by PSE.

> 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 ($000) and revenue ($000) from AURORAxmp for existing contracts and existing and generic resources,
4. capital and fixed-cost assumptions of generic resources,
5. financial assumptions such as cost of capital, taxes, depreciation and escalation rates,
6. capacity contributions and planning margin constraints,
7. renewable portfolio targets, and
8. flexibility benefit from PLEXOS ($/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.

Annual revenue requirement (for any time t) is defined as:

$$RR_t = \sum_{gn} d(gn)*[AnnCapCost(gn) + VarCost(gn)] + \sum_{gr} d(gr)*[AnnCapCost(gr) + VarCost(gr)] +$$

$$\sum_{xn} VarCost(xn) + \sum_{xr} VarCost(xr) + ContractCost + DSRCost + NetMktCost - RECSales.$$

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.

$$\sum_{gr} \text{d(gr)*MWH(gr)} + \sum_{xr} \text{MWH(xr)} \geq \text{RPS*} \frac{\sum_{t-2}^{t-1} (\text{EnLd} * (1 - \text{LnLs}) - \text{DSR})}{2} \quad \text{for all t;}$$

d(gn), d(gr) ≥ 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, CO_2 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 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 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 CO_2 prices and thermal plant forced outages. This section describes how PSE developed these stochastic inputs.

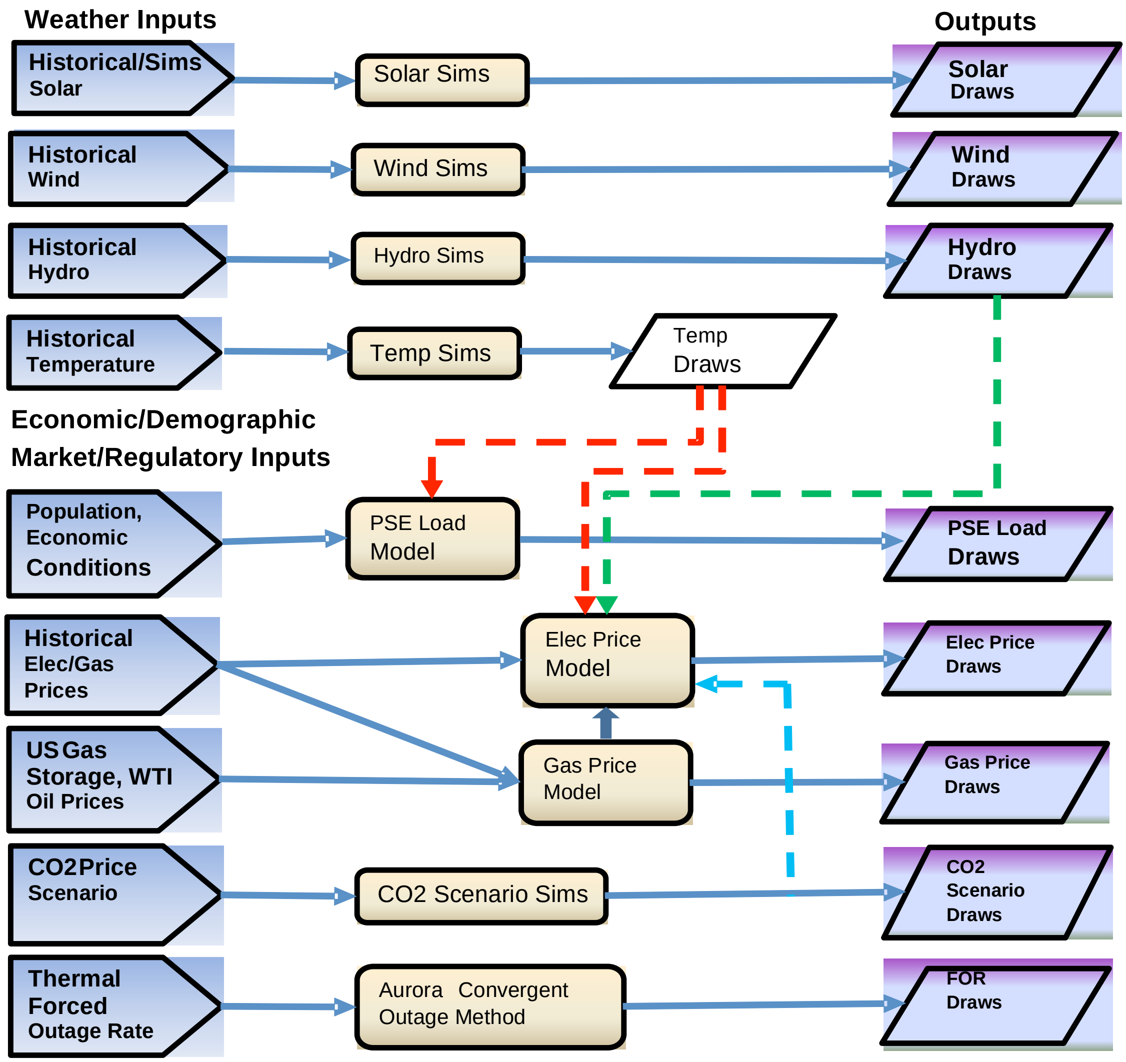
Development of Monte Carlo Simulations for the Stochastic Variables

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 CO_2 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 CO_2 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)

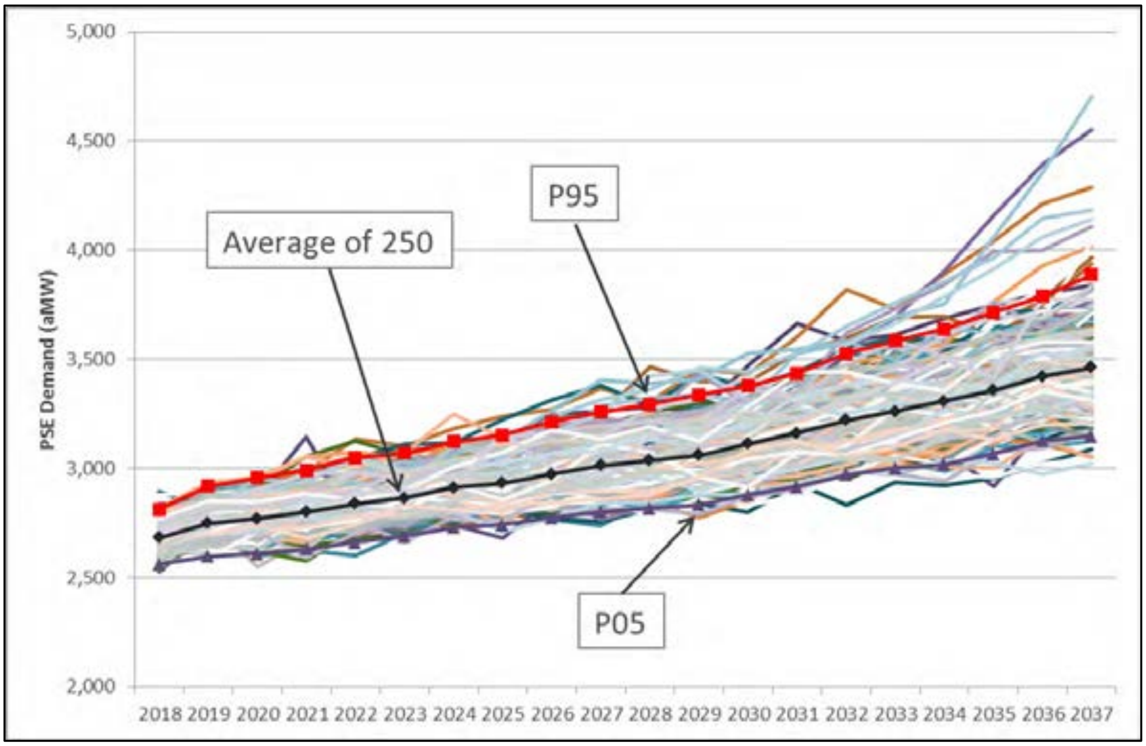
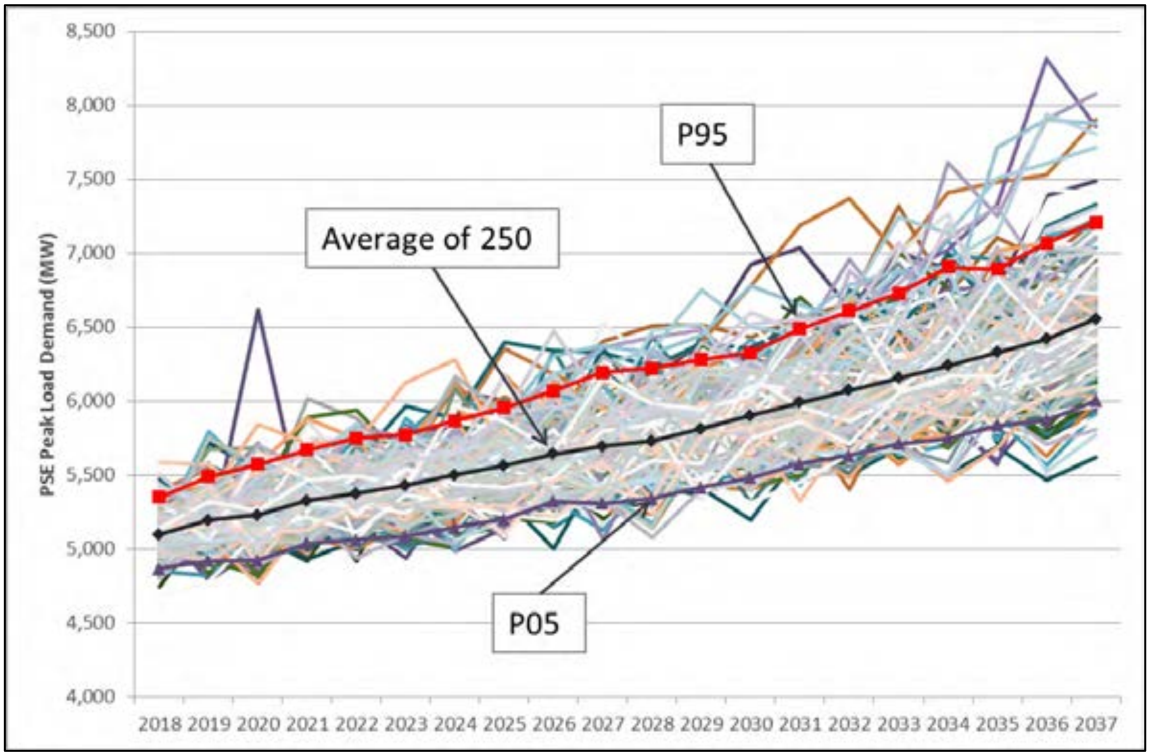


Figure N-7: Load Forecast Simulations – December 1-hour Peak (MW)



GAS AND POWER PRICES. The econometric relationship between prices and their explanatory variables is shown in the equations below:

Sumas Gas Price = f(US Gas Storage Deviation fr. 5 Yr Avg, Oil Price, Lagged Oil Price, Time Trend,Fracking Effects)

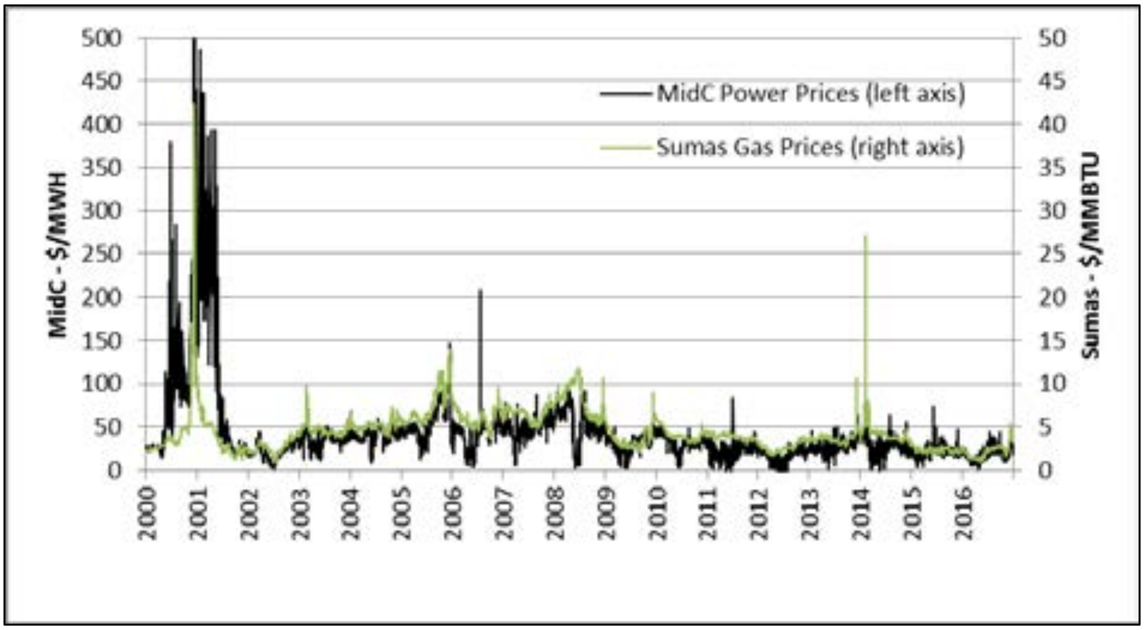
Mid-C Power Price = f(Sumas Gas Price, Regional Temperature Deviation from Normal, Mid-C Hydro Generation, Day of Week, Holidays)

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 levelized 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 CO_2 cost/price policies were adjusted based on the observed changes in power price forecasts from AURORAxmp model runs when CO_2 costs/prices were imposed at different levels. Mid-C power prices are generally higher when CO_2 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

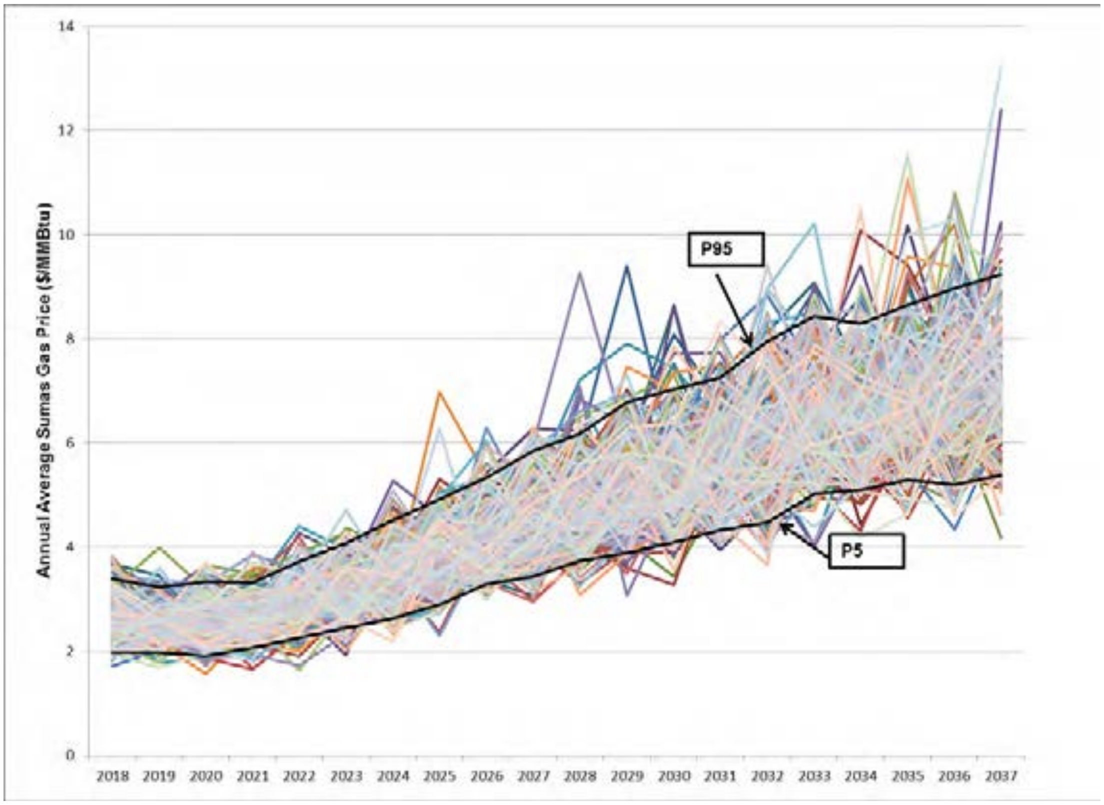
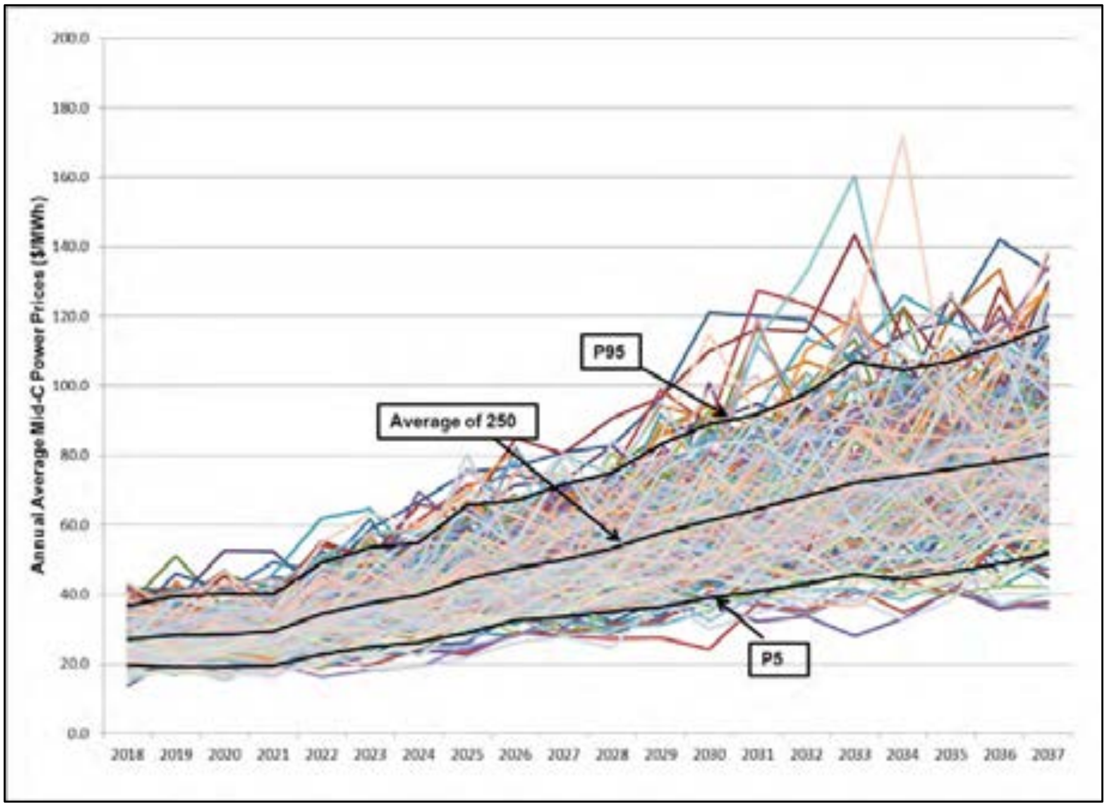
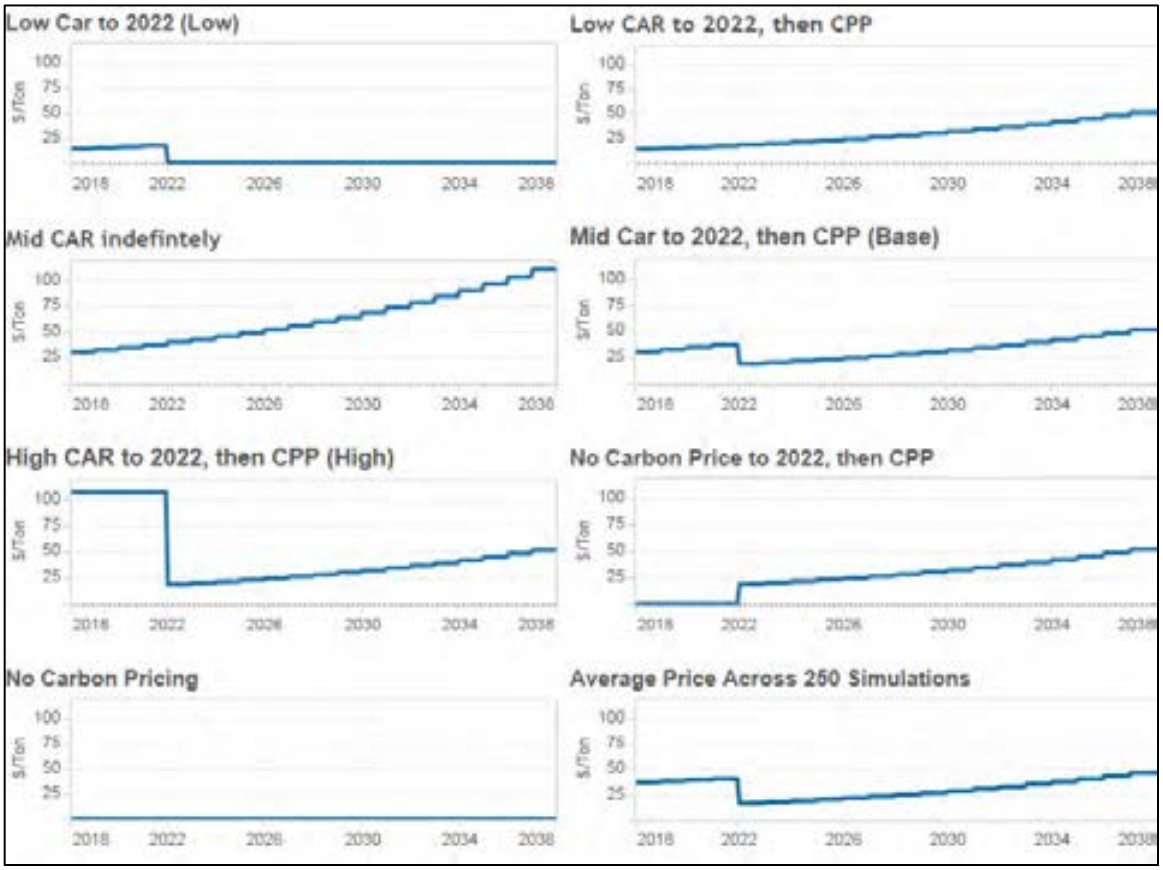


Figure N-10: Annual Mid-C Price Simulations



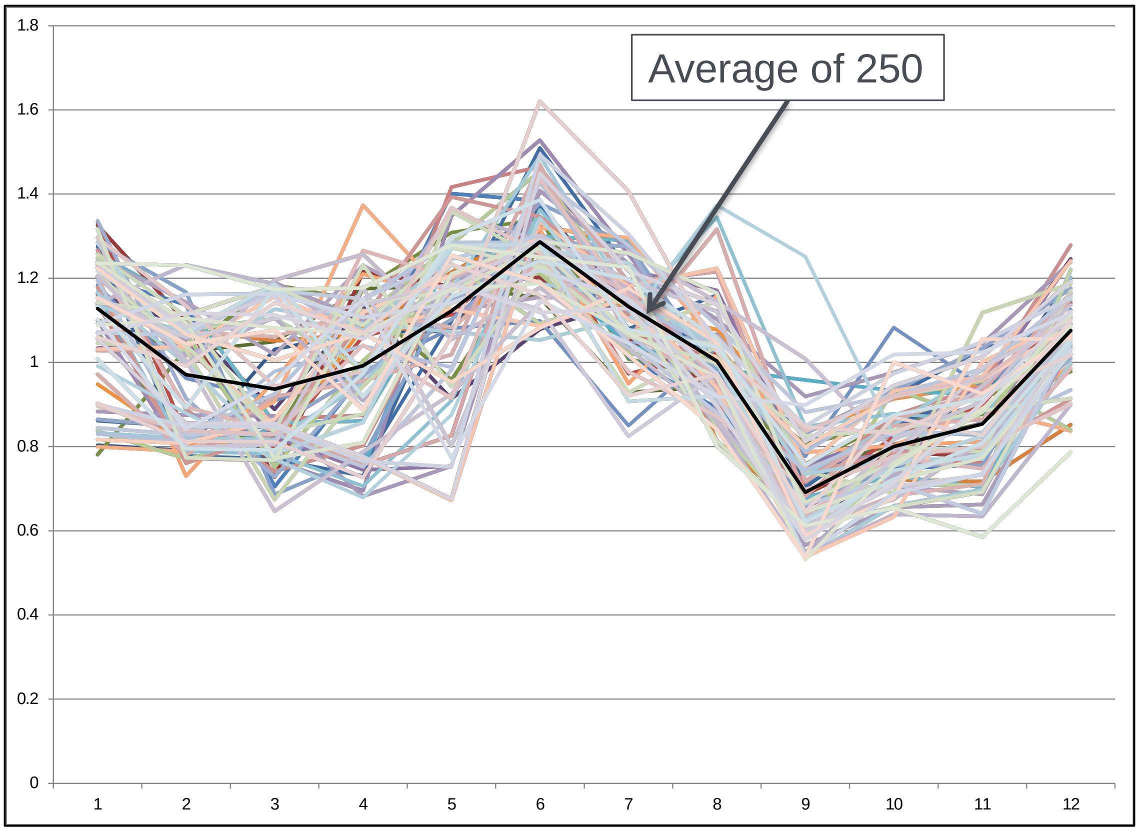
RISKS OF CO_2 PRICE. There exists significant uncertainty around future CO_2 policy, thus PSE modeled several different pricing paths as part of the IRP. Given the possible range of CO_2 price per ton assumed in the deterministic scenarios, as described in Chapter 4, equal probabilities were assigned to each of the 14 scenarios. Figure N-11 shows the annual CO_2 cost/price simulations with the weighted average of all simulations.

Figure N-11: Annual CO_2 Price Inputs, Weighted Average Simulation CO_2 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

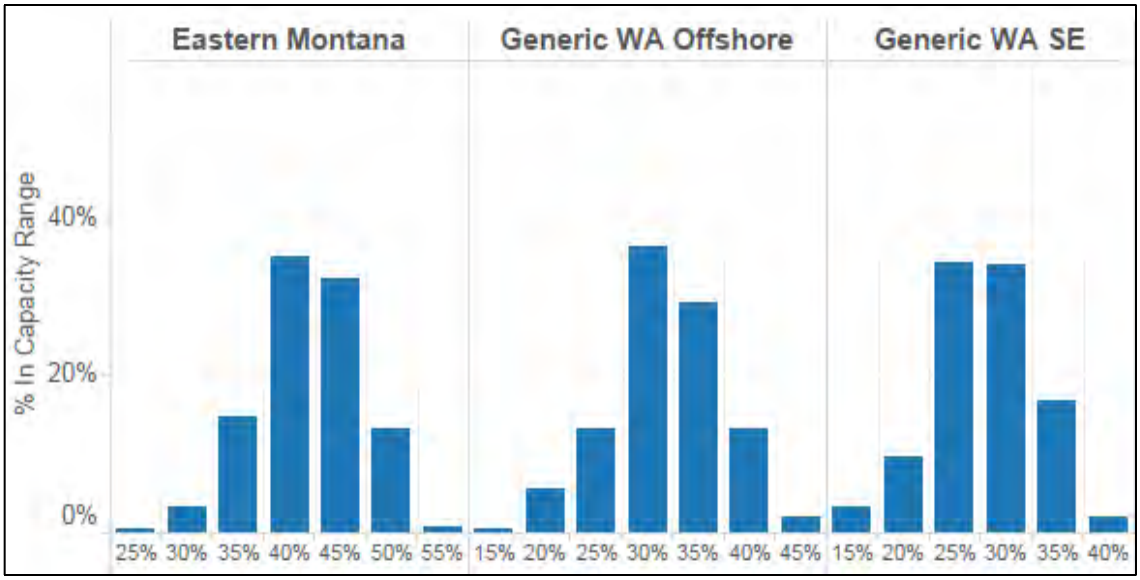


Figure N-13b: Wind Simulations, Box-Whisker Plot of Annual Capacity Factor
for 250 Simulations for Generic Resources

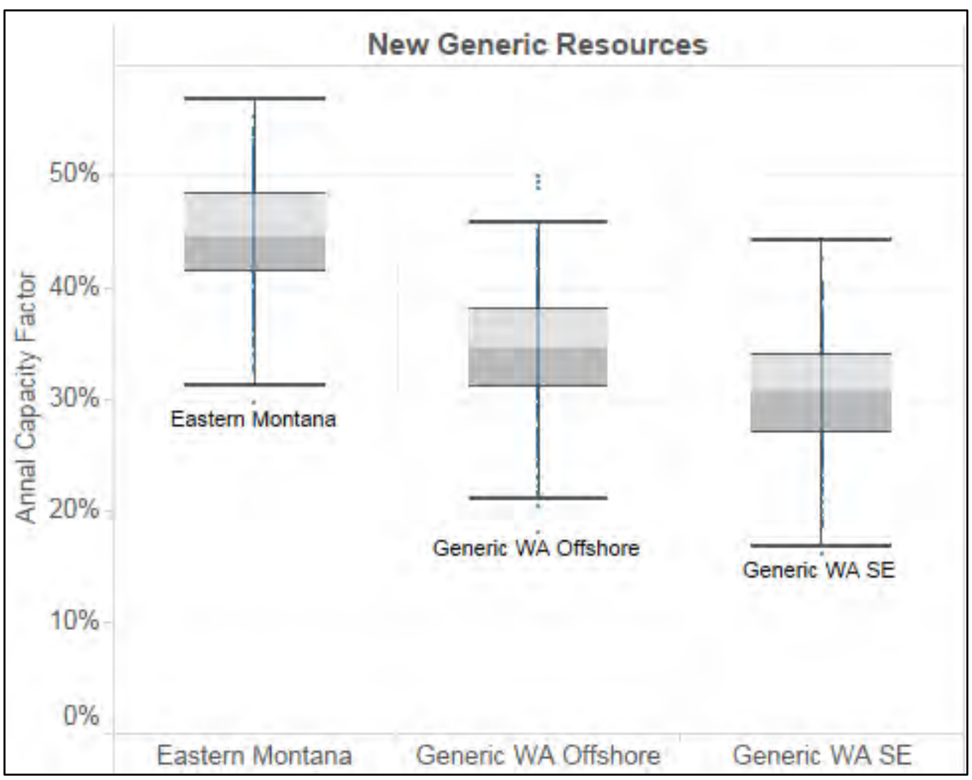


Figure N-14: Wind Simulations,
Sample Moments of 250 Simulations for Generic Resources

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 AURORAxmp 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 AURORAxmp are utilized to generate the variable costs, outputs and revenues of any given portfolio and input simulations. The main advantage of using AURORAxmp 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 AURORAxmp, however, the set of 250 simulations for all of the risk variables (power prices, gas prices, CO_2 costs/prices, PSE loads, hydro generation and wind generation) are fed into the AURORAxmp 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, AURORAxmp 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, CO_2 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

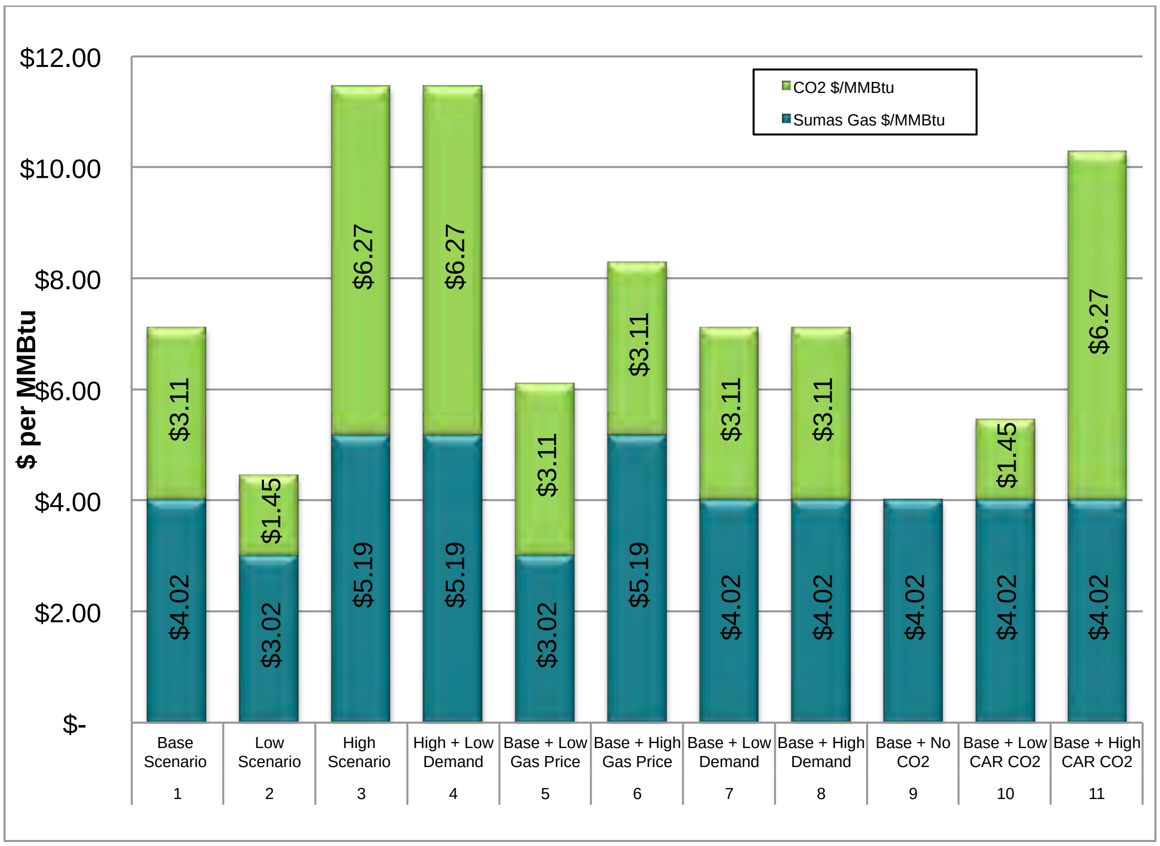
For gas price assumptions, PSE uses a combination of forward market prices, fundamental forecasts acquired in November 2016 from Wood Mackenzie. Wood MacKenzie is a well-known macroeconomic and energy forecasting consultancy whose gas market analysis includes regional, North American and international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

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 $)



CO_2 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 CO_2 prices modeled are presented in Figure N-16 and CPP CO_2 prices are presented in Figure N-17.

Mid CO_2 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 CO_2 price for California AB32 and is applied WECC-wide as a CO_2 price to all existing and new baseload generating units affected under the CPP.

Low CO_2 prices

LOW CAR CO_2 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 CO_2 price for California.

High CO_2 Prices

HIGH CAR CO_2 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 CO_2 price for California AB32.

Figure N-16: Annual CAR CO_2 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 CO_2 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: CO_2 Prices by Scenario with CAR and CPP Combined

	CO2 Price	Base[1]	Low	High[2]	Base No CO2	Base + Low CAR CO2	Base + High CAR CO2
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 CO_2 prices as the Base Scenario.
2. Scenario High +Low Demand has the same CO_2 prices as the High Scenario.

Figure N-18b: CO_2 Prices by Scenario by Single CO_2 Policy

	Base w/ CAR only	Base w/ CPP only	Base + All-thermal CO2
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 database[2] 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).

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.

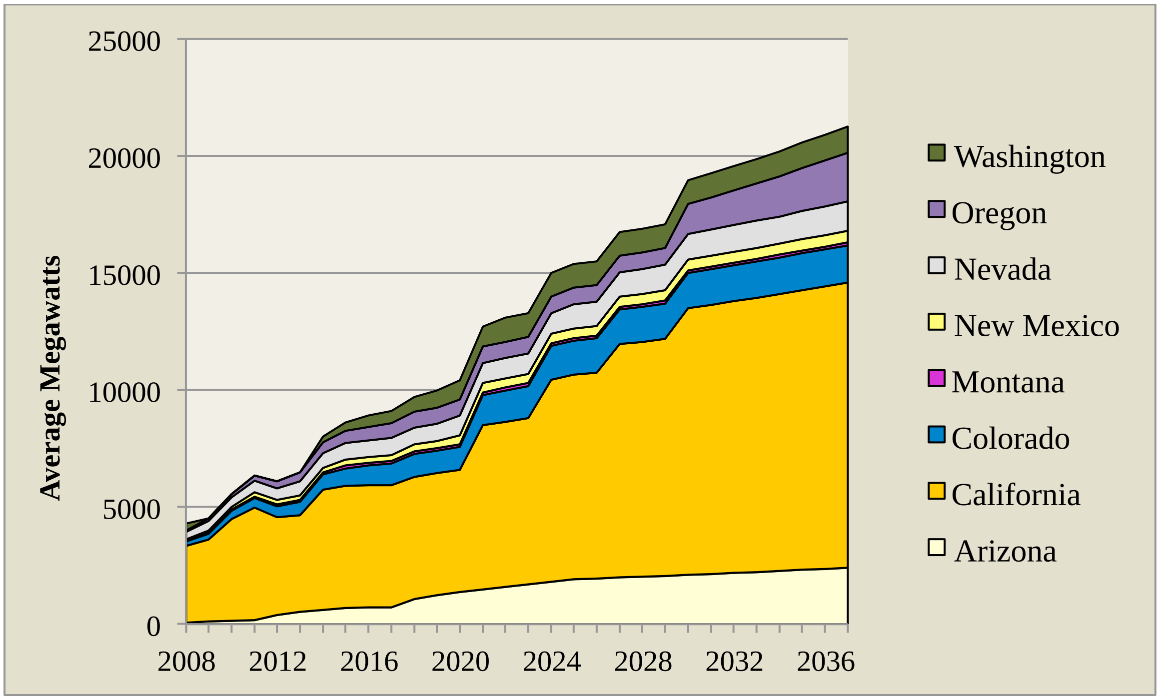
Figure N-22: RPS Requirements for States in the WECC

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.

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 6th 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.

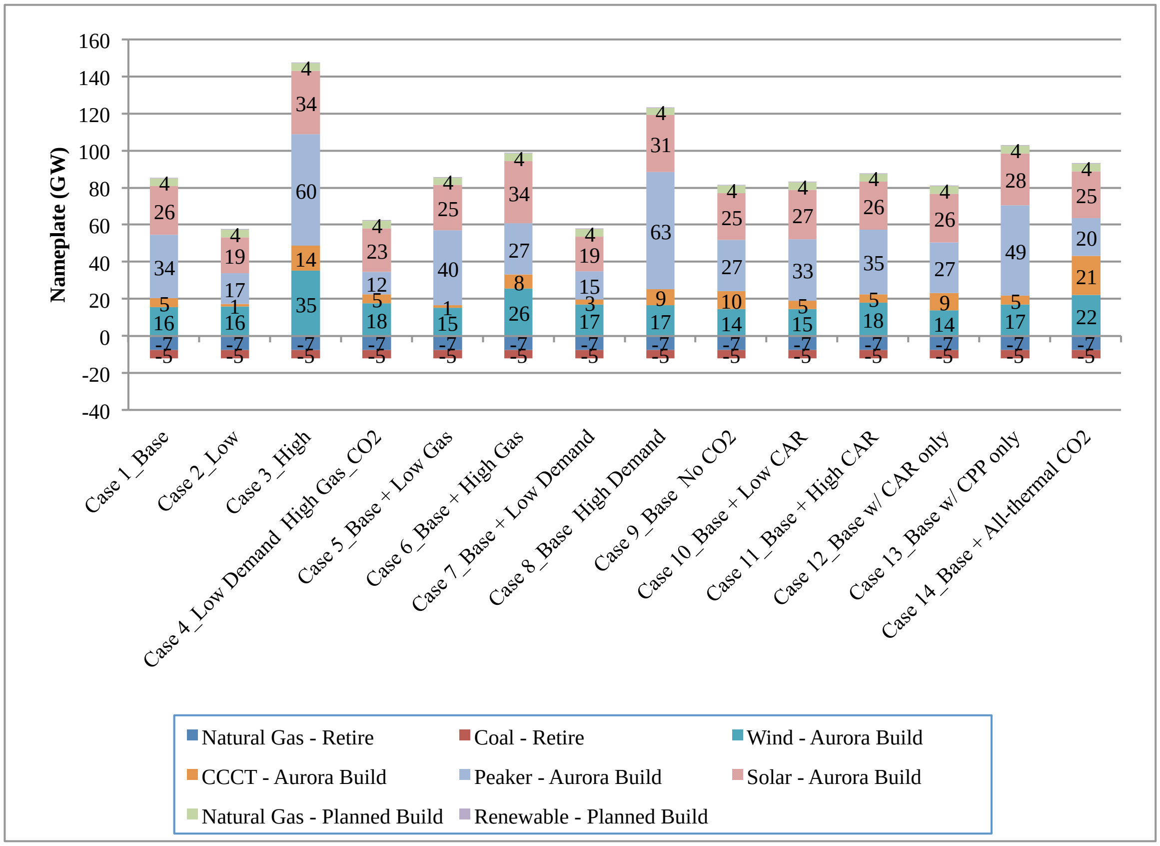
Figure N-23: RPS Builds Added to AURORA Database by State



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
2017 IRP Updates	Remove DSR	525
	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.nwcouncil.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

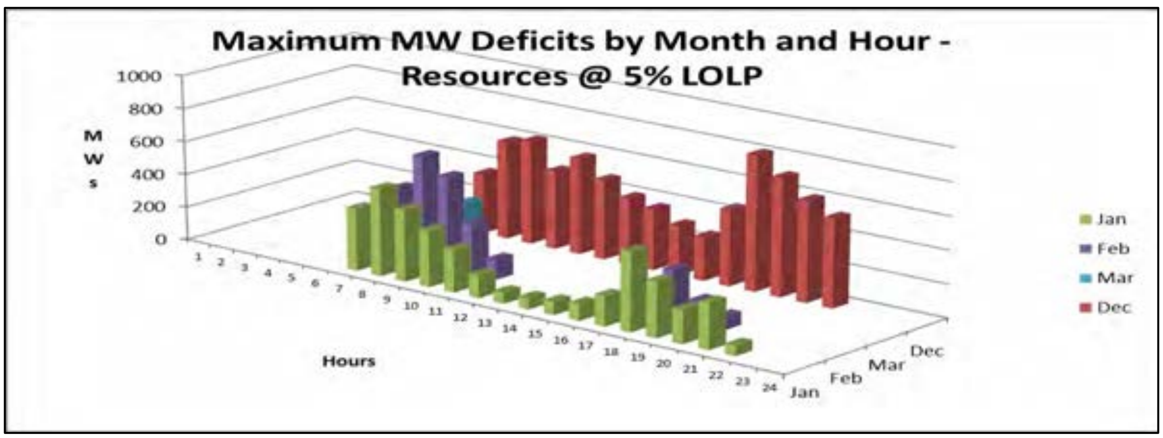
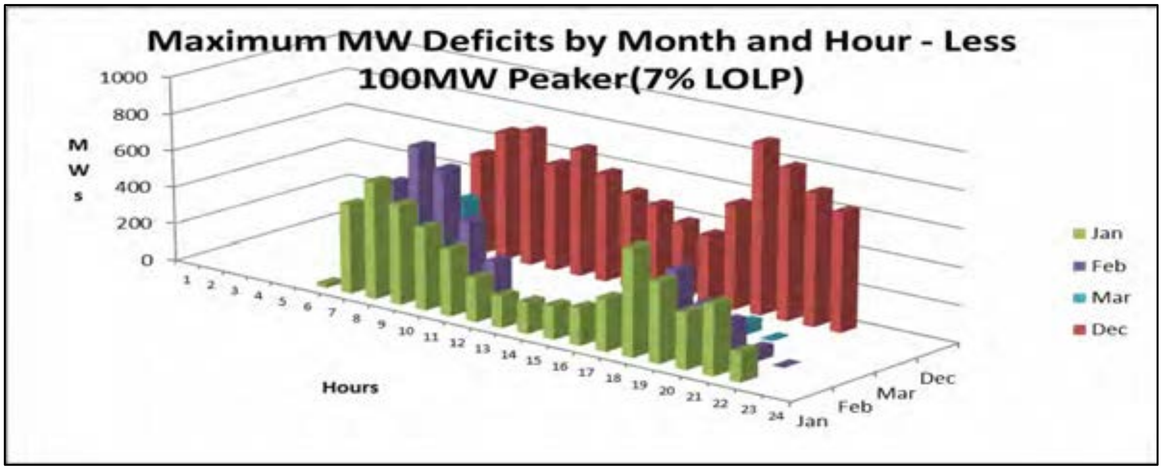


Figure N-33: PSE Winter Season Double Peaks, Minus 100 MW Peaker



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)					
	Call Frequency(Elapsed Hrs After Last Event)				
Duration(Hrs)	**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.

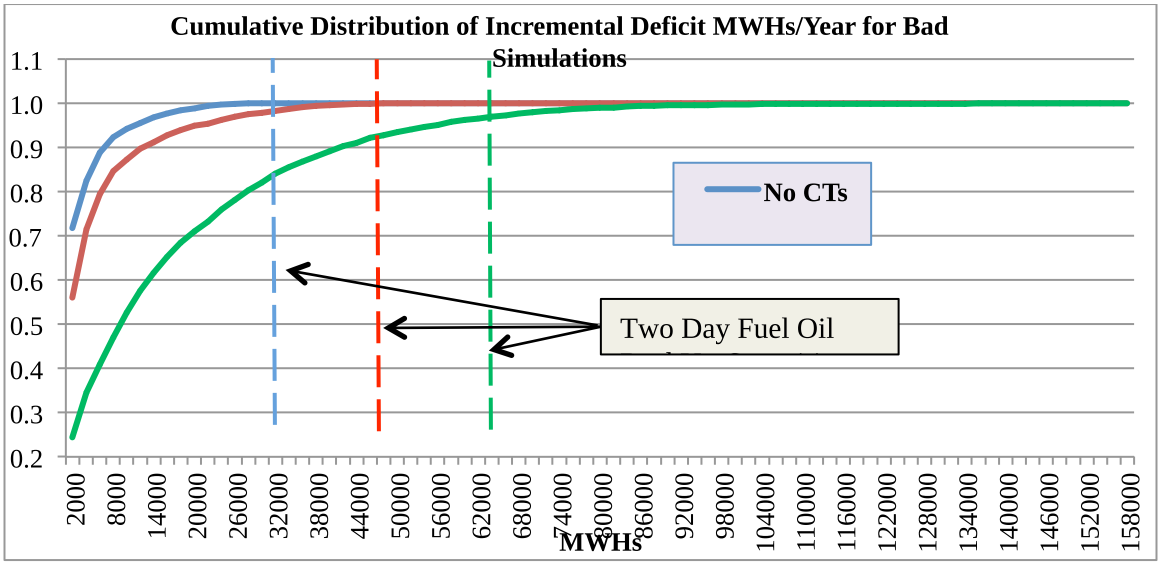
To determine if the results of the analysis are invariant to the scale of the capacity that is not available to meet resource adequacy, three scenarios were examined.

> **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.

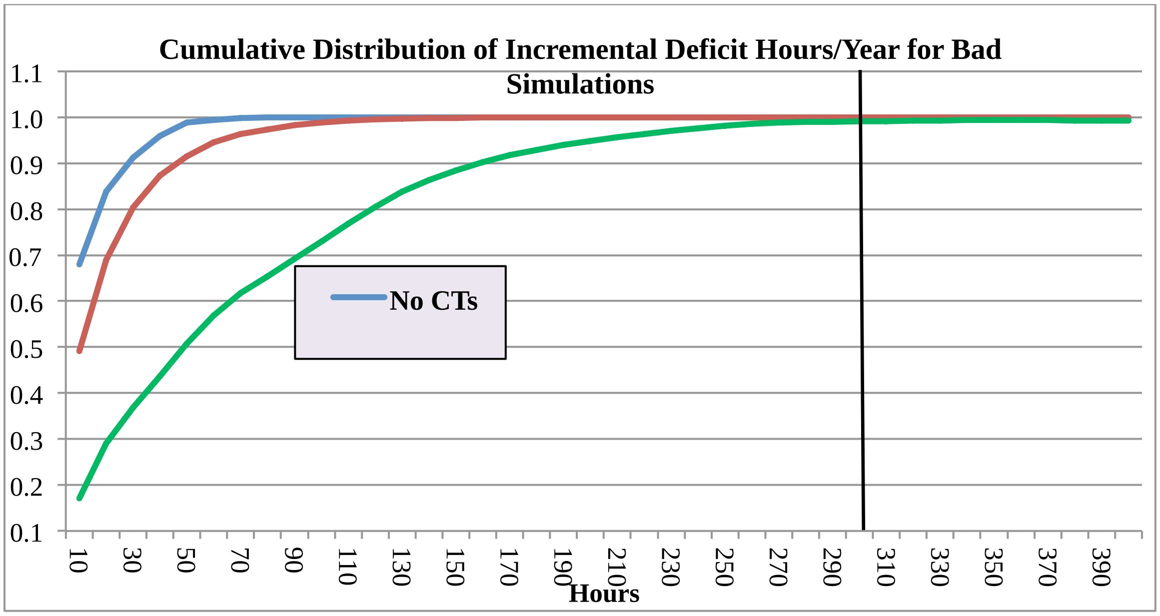
The chart below shows the cumulative distribution of MWHs resulting from the incremental outage events for each of the three scenarios. The higher the level of capacity that is unable to run due to the lack of gas supply, the greater the amount of deficit MWHs. This is shown by the rightward shift in 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.

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.

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

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

Figure N-41: Forecast of Mid-C Power Prices for Base + No CO_2 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

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

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

Figure N-44: Forecast of Mid-C Power Prices for Low Demand + High Gas CO_2 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

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

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

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

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

Figure N-49: Forecast of Mid-C Power Prices for Base + Low CAR CO_2 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

Figure N-50: Forecast of Mid-C Power Prices for Base + High CAR CO_2 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

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

Figure N-52: Forecast of Mid-C Power Prices for Base + All-thermal CO_2 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)

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**

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**

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**

Figure N-58: Incremental Portfolio Builds by Year (nameplate MW)
Base + No CO_2 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**

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**

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**

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**

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**

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**

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**

Figure N-66: Incremental Portfolio Builds by Year (nameplate MW)
Base + Low CO_2 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**

Figure N-67: Incremental Portfolio Builds by Year (nameplate MW)
Base + High CO_2 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**

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**

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**

Figure N-70: Incremental Portfolio Builds by Year (nameplate MW)
Scenario: Base + All Thermal CO_2

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 CO_2 Emissions – Scenarios

Figure N-71: Total Portfolio CO_2 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 CO_2 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)

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)

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**

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**

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**

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**

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**

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**

Figure N-83: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2018, No CO_2 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**

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**

Figure N-85: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2025, No CO_2 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**

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**

Figure N-87: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Colstrip 2030, No CO_2 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**

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**

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**

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**

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**

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**

Figure N-93: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Encogen, No CO_2 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**

Figure N-94: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Ferndale, No CO_2 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**

Figure N-95: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Goldendale, No CO_2 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**

Figure N-96: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Mint Farm, No CO_2 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**

Figure N-97: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Sumas, No CO_2 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**

Figure N-98: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Encogen, All Thermal CO_2 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**

Figure N-99: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Ferndale, All Thermal CO_2 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**

Figure N-100: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Goldendale, All Thermal CO_2 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**

Figure N-101: Incremental Portfolio Builds by Year (nameplate MW)
Sensitivity: Retire Mint Farm, All Thermal CO_2 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**

Figure N-102: Incremental Portfolio Builds by Year (nameplate MW)

Sensitivity: Retire Sumas All Thermal CO_2

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**

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**

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**

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**

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**

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**

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**	**-**	**-**	**-**

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**

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**

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**

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**

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**

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**

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**

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**

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**

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 CO_2 Emissions – Sensitivities

Figure N-120: Total Portfolio CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2 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 CO_2" in Figure N-73.

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 CO_2

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**

Figure N-131: Incremental Portfolio Builds by Year (nameplate MW)
Carbon Abatement: Add 300 MW Solar No CO_2

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**

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**

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**

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**

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**

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

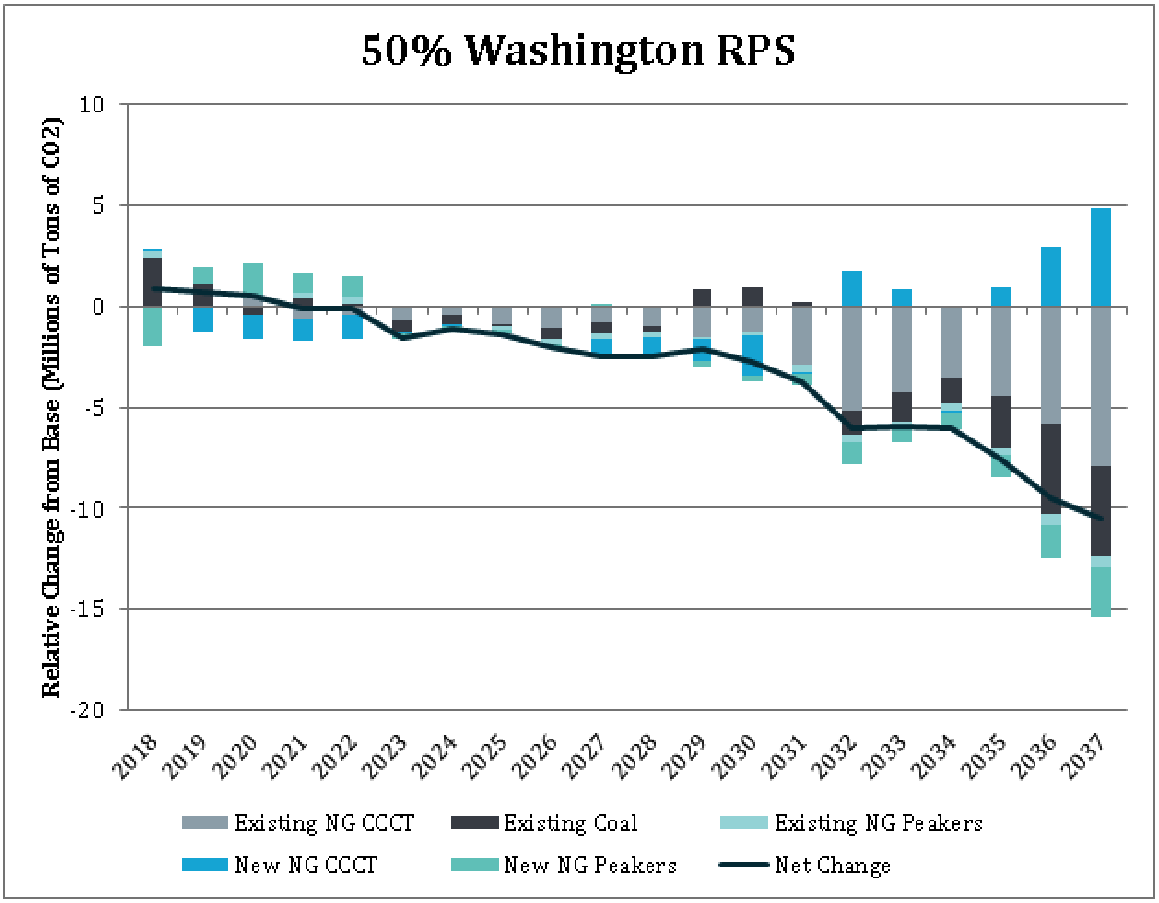


Figure N-138: Change in WECC Emissions by Resource Type

Carbon Abatement: Add 300 MW Solar

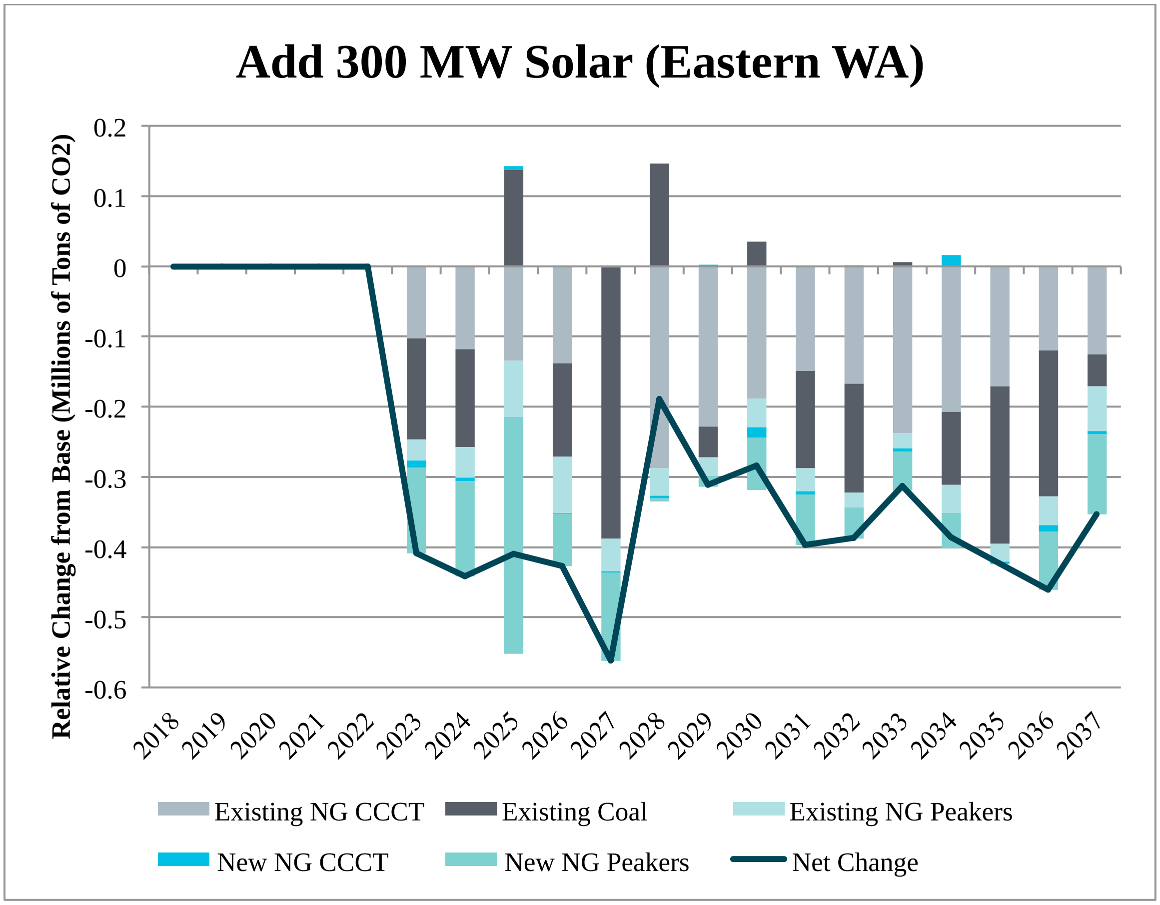


Figure N-139: Change in WECC Emissions by Resource Type

Carbon Abatement: Add 300 MW Wind

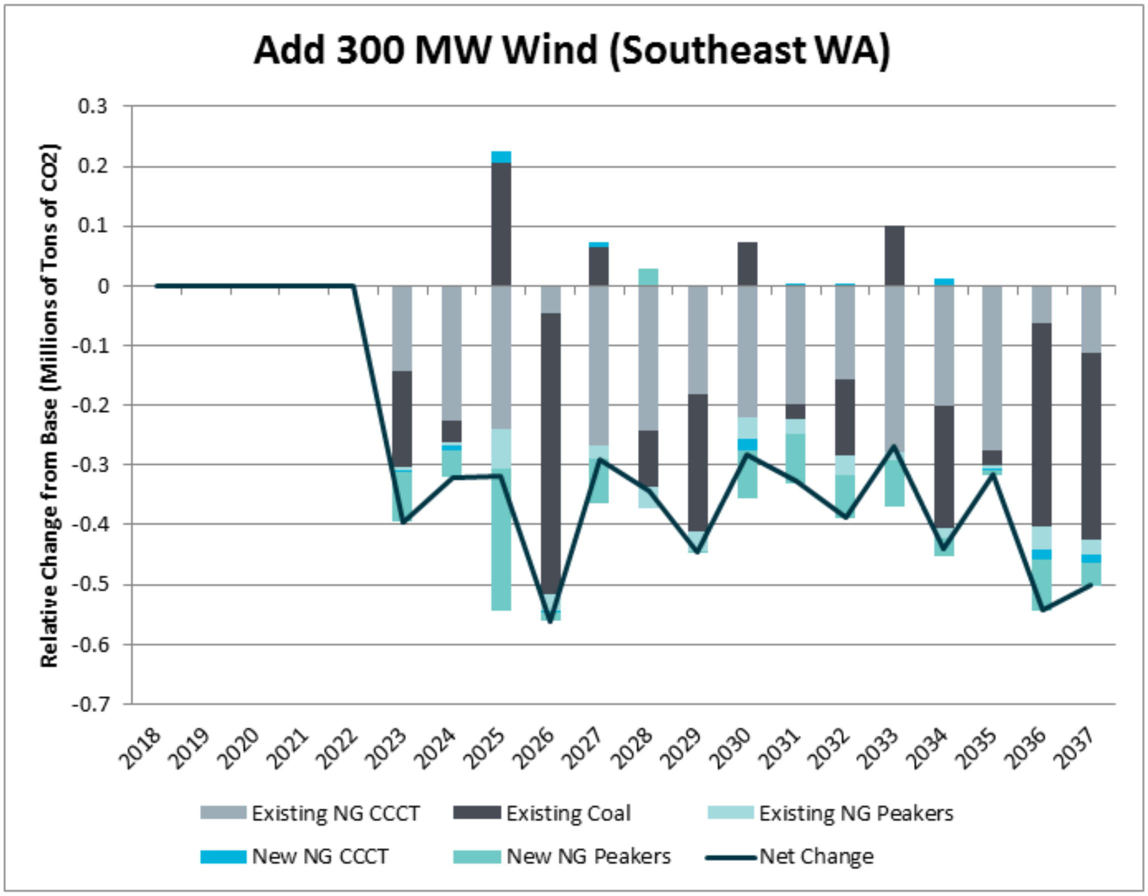


Figure N-140: Change in WECC Emissions by Resource Type

Carbon Abatement: CAR Cap on WA CCCT

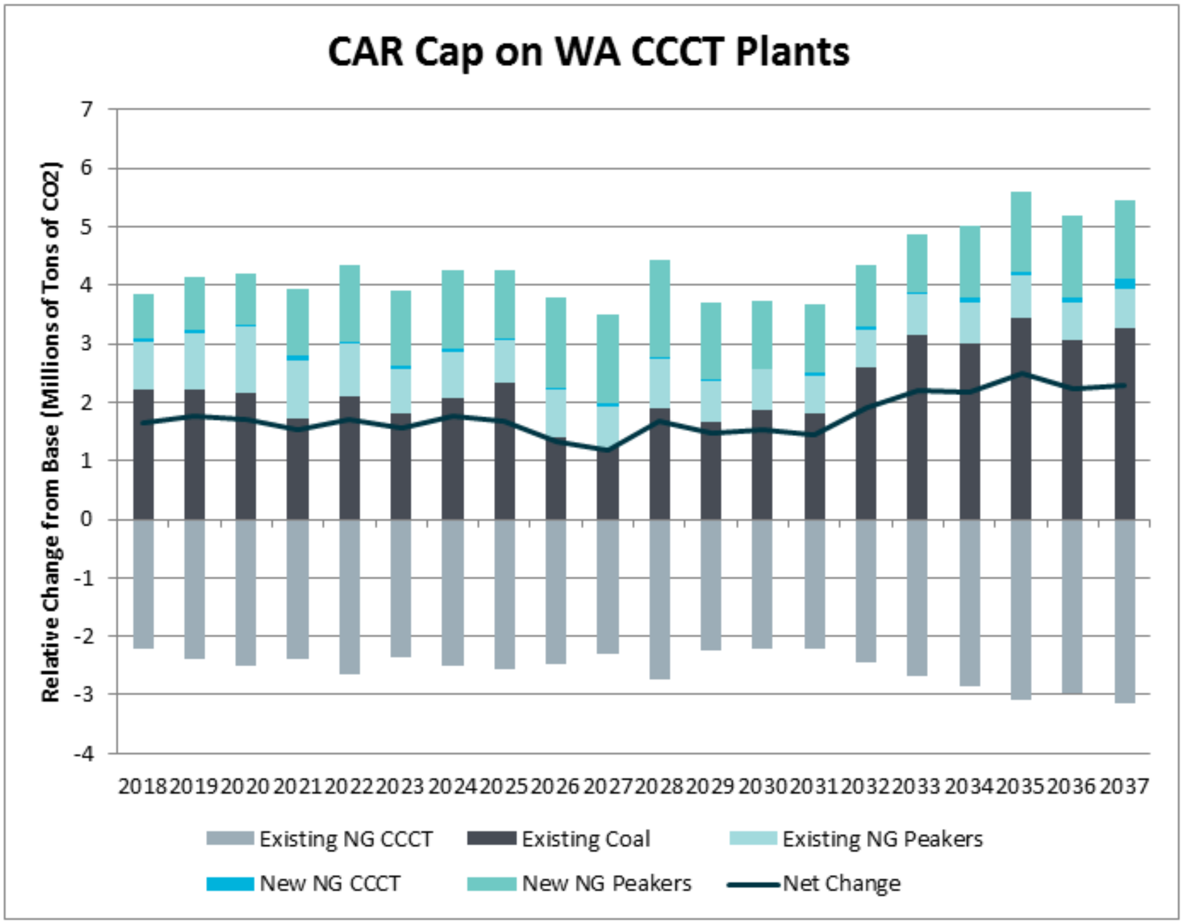


Figure N-141: Change in WECC Emissions by Resource Type

Carbon Abatement: Additional Conservation - Incremental

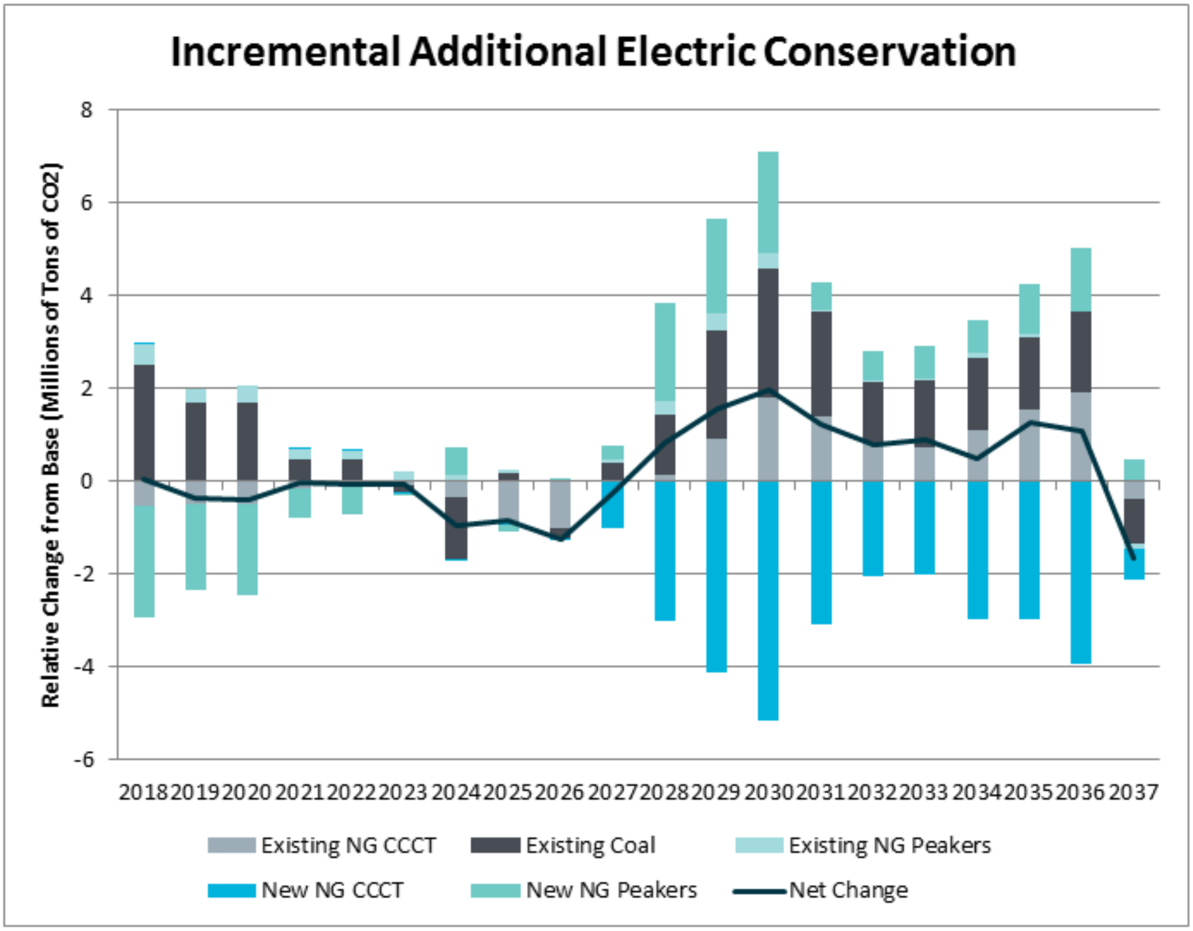


Figure N-142: Change in WECC Emissions by Resource Type

Carbon Abatement: Additional Conservation – All

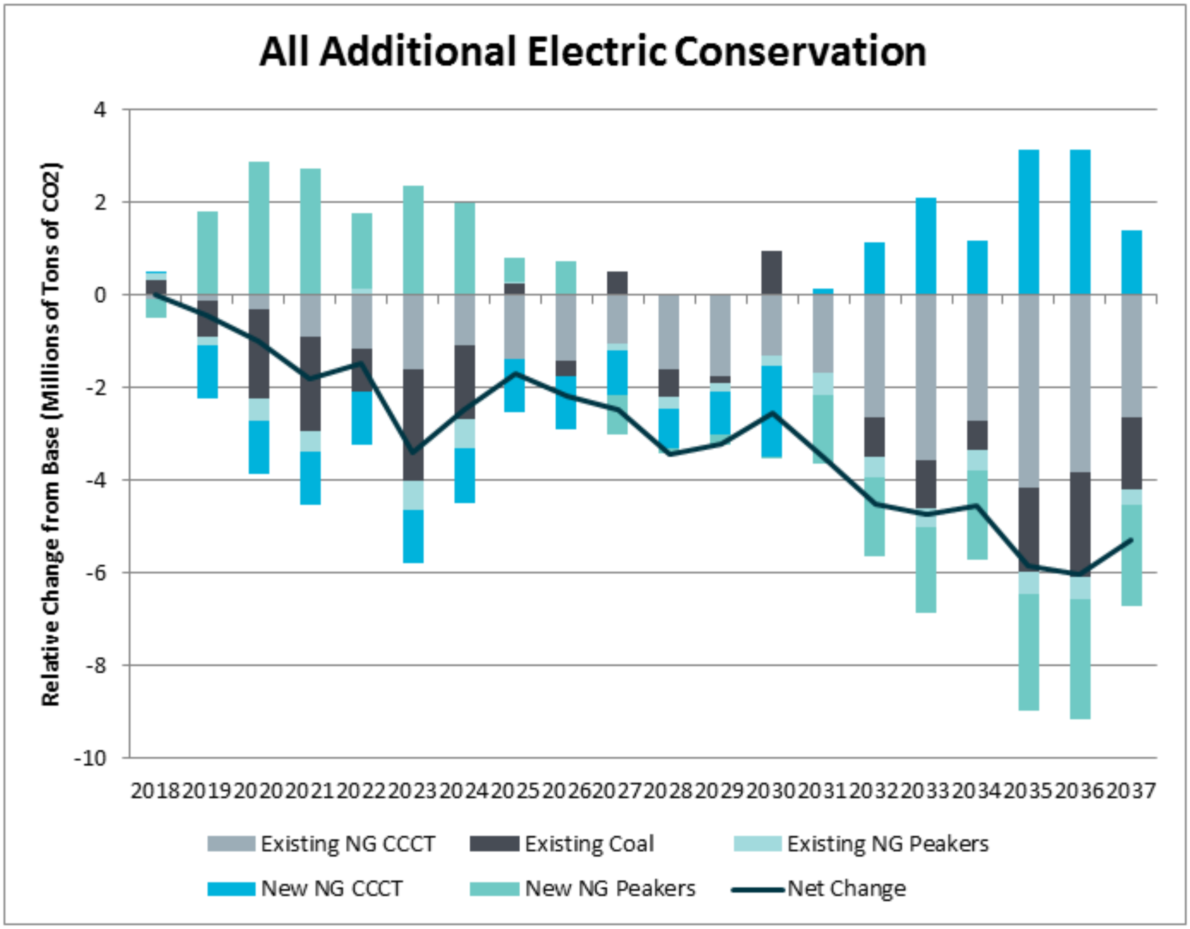
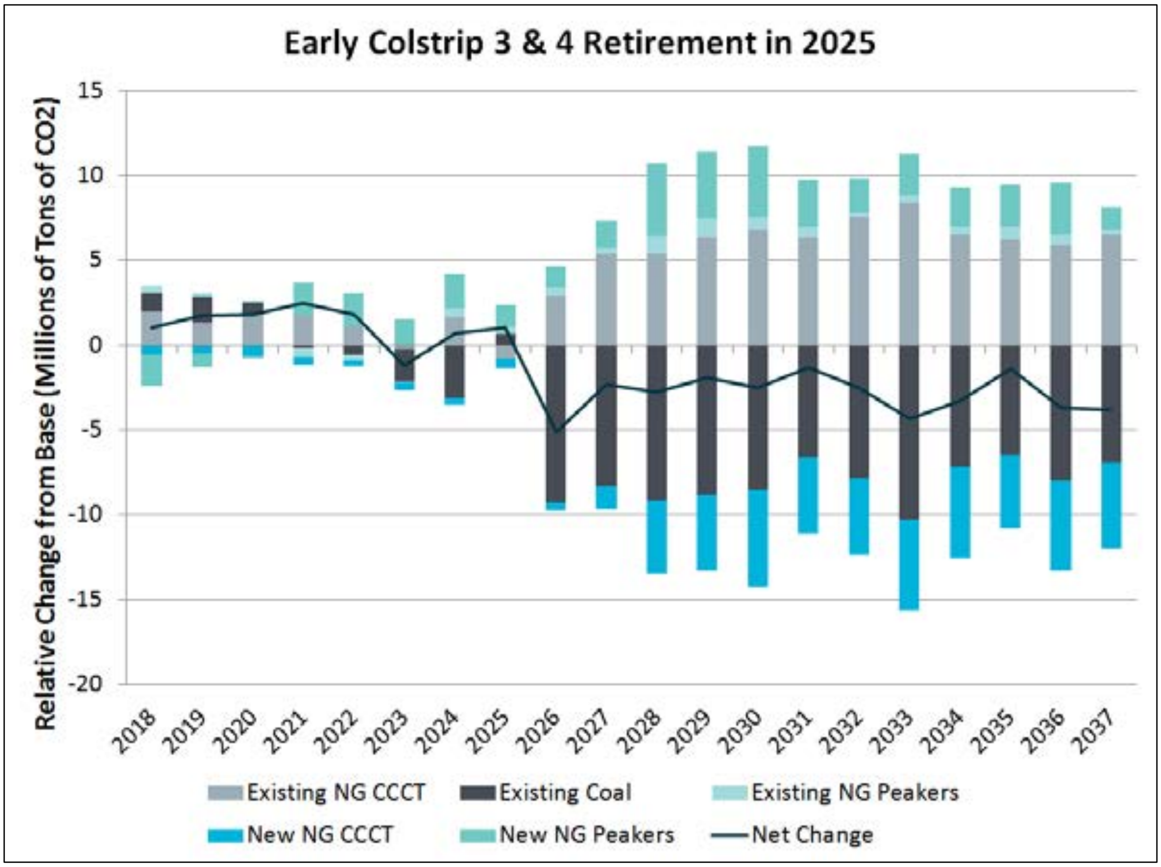


Figure N-143: Change in WECC Emissions by Resource Type

Carbon Abatement: Early Retirement of Colstrip 3 & 4



Gas Portfolio CO_2 Emissions – Carbon Abatement

Figure N-144: Total Portfolio CO_2 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

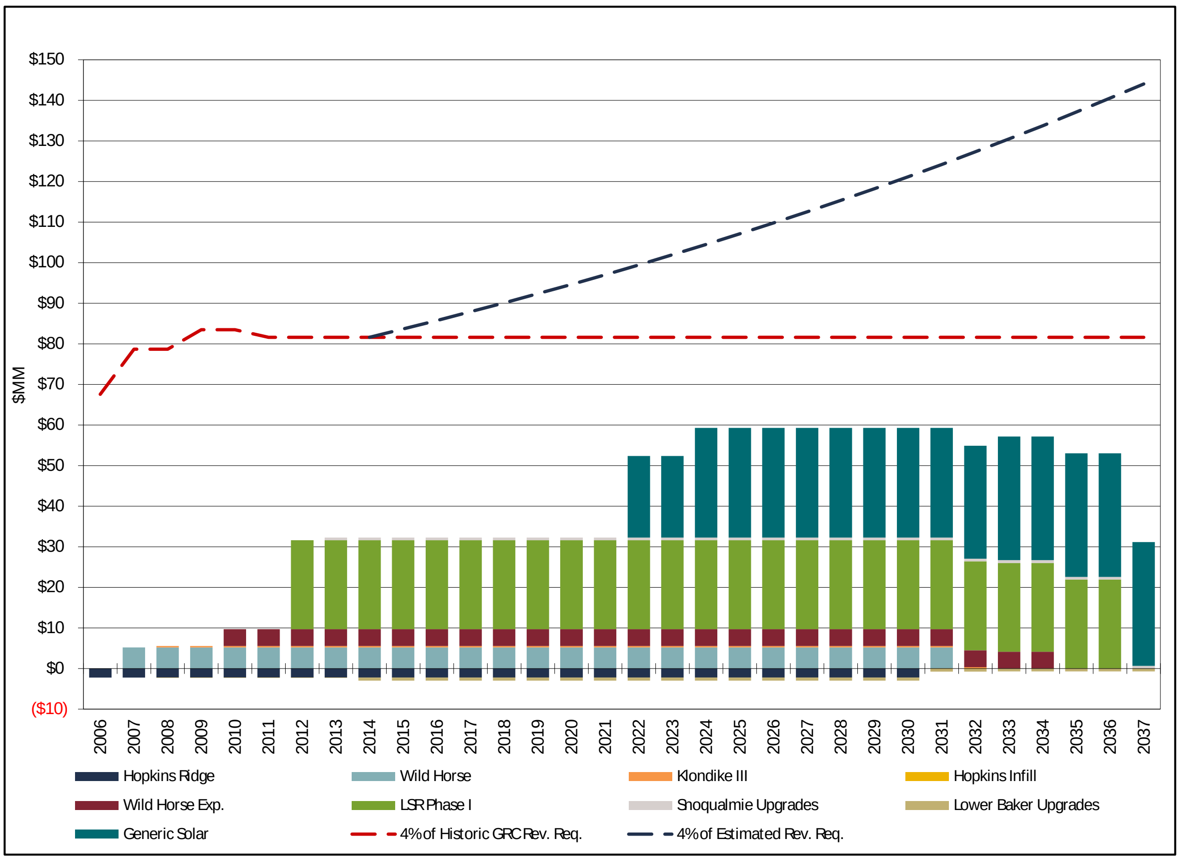
($ Millions)	20-yr NPV
Wild Horse	375
Peaker	34
Market	285
20-yr Incremental Cost of Wild Horse	**56**

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 levelized over the book life of the plant: 25 years for wind power and 40 years for hydroelectric power. Figure N-150 resents 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



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.

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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

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

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

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

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 - 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
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

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

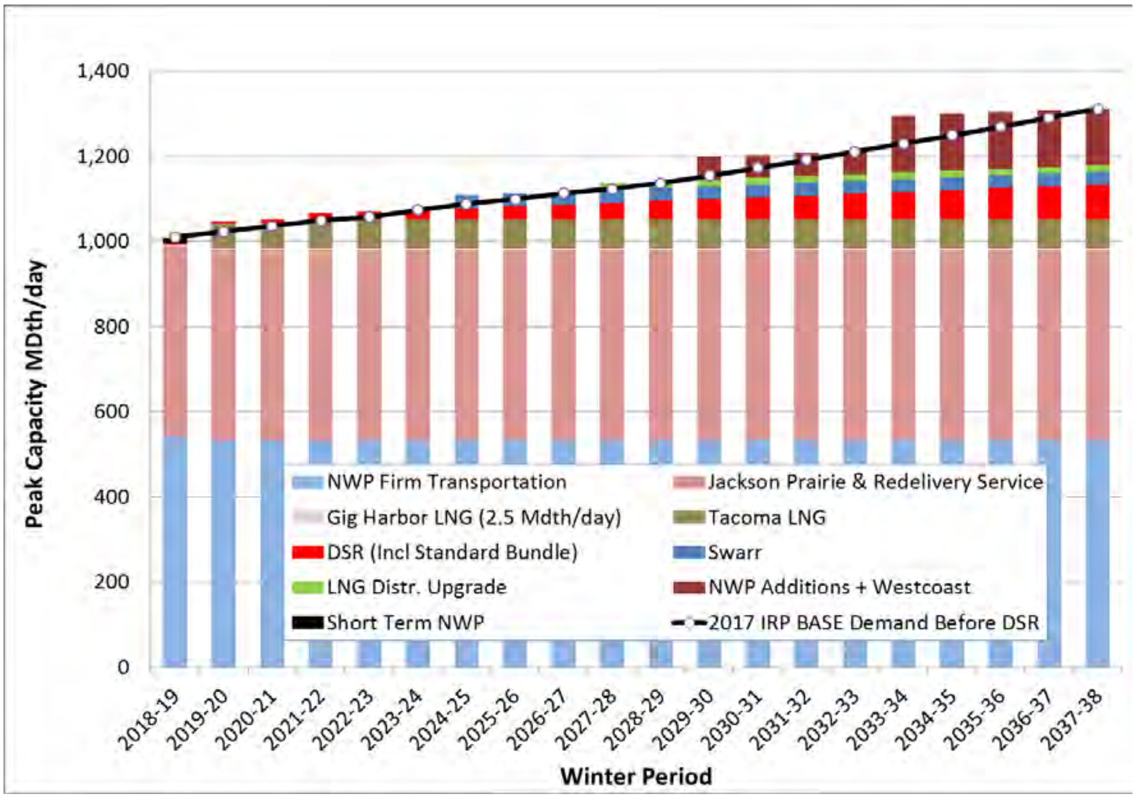


Figure O-10: Low Scenario Optimal Portfolio – Gas Sales

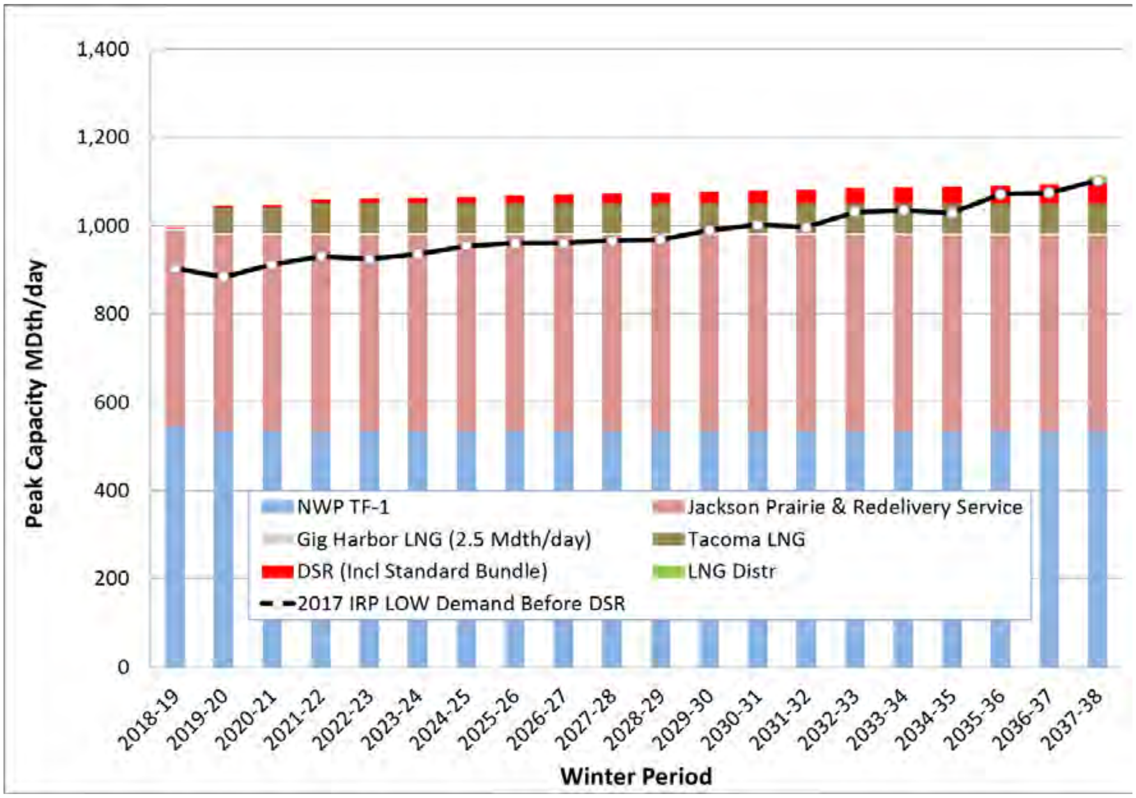


Figure O-11: High Scenario Optimal Portfolio – Gas Sales

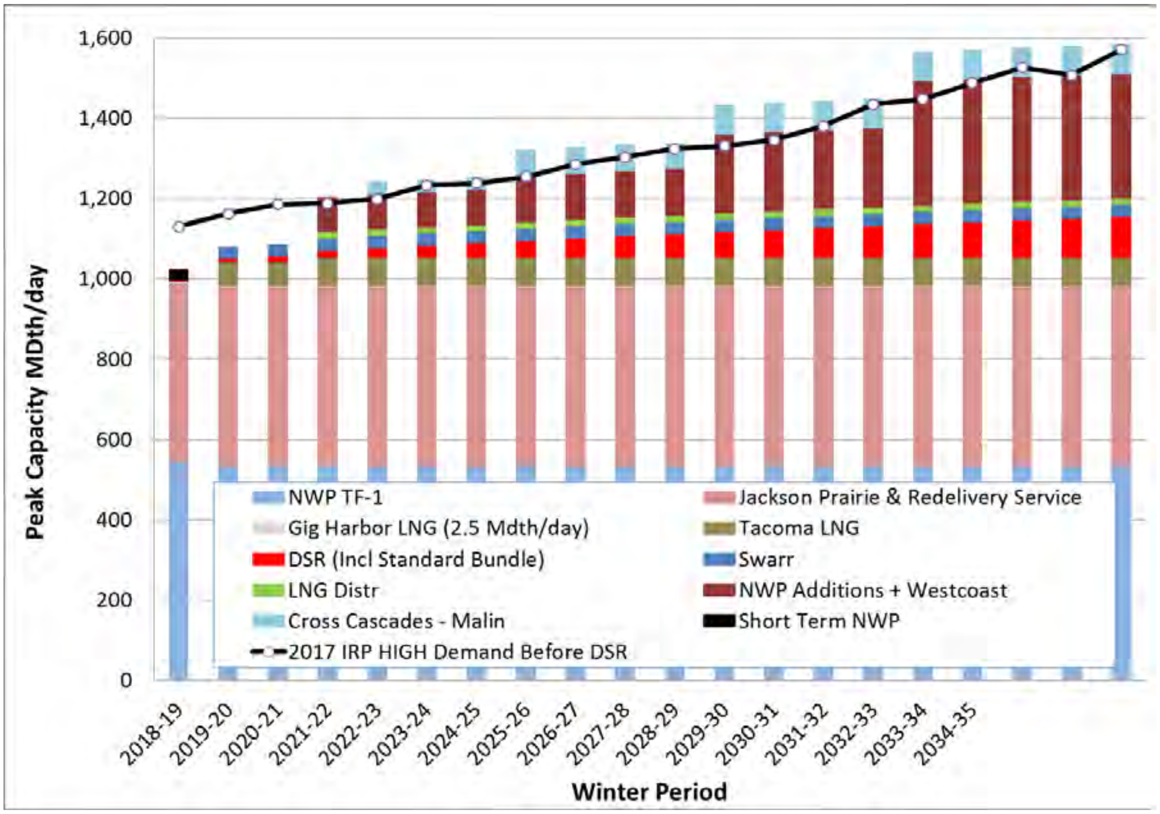


Figure O-12: High + Low Demand Optimal Portfolio – Gas Sales

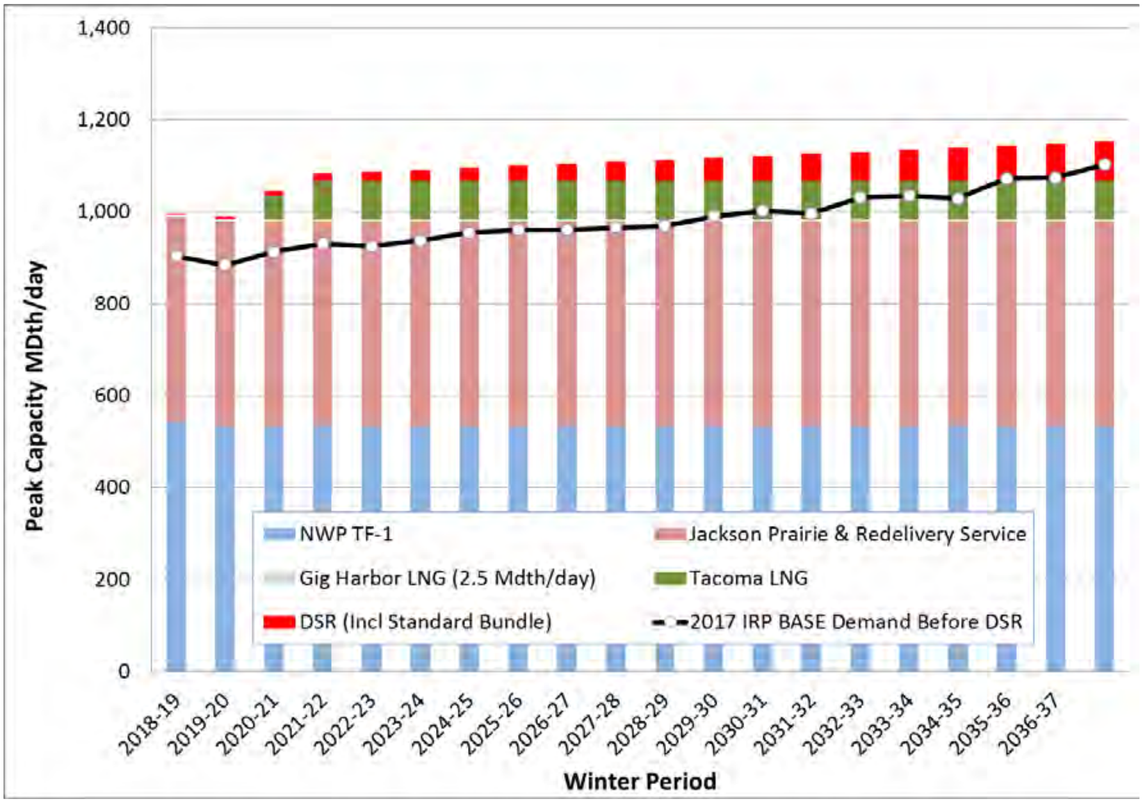


Figure O-13: Base + Low Gas Price Scenario Optimal Portfolio – Gas Sales

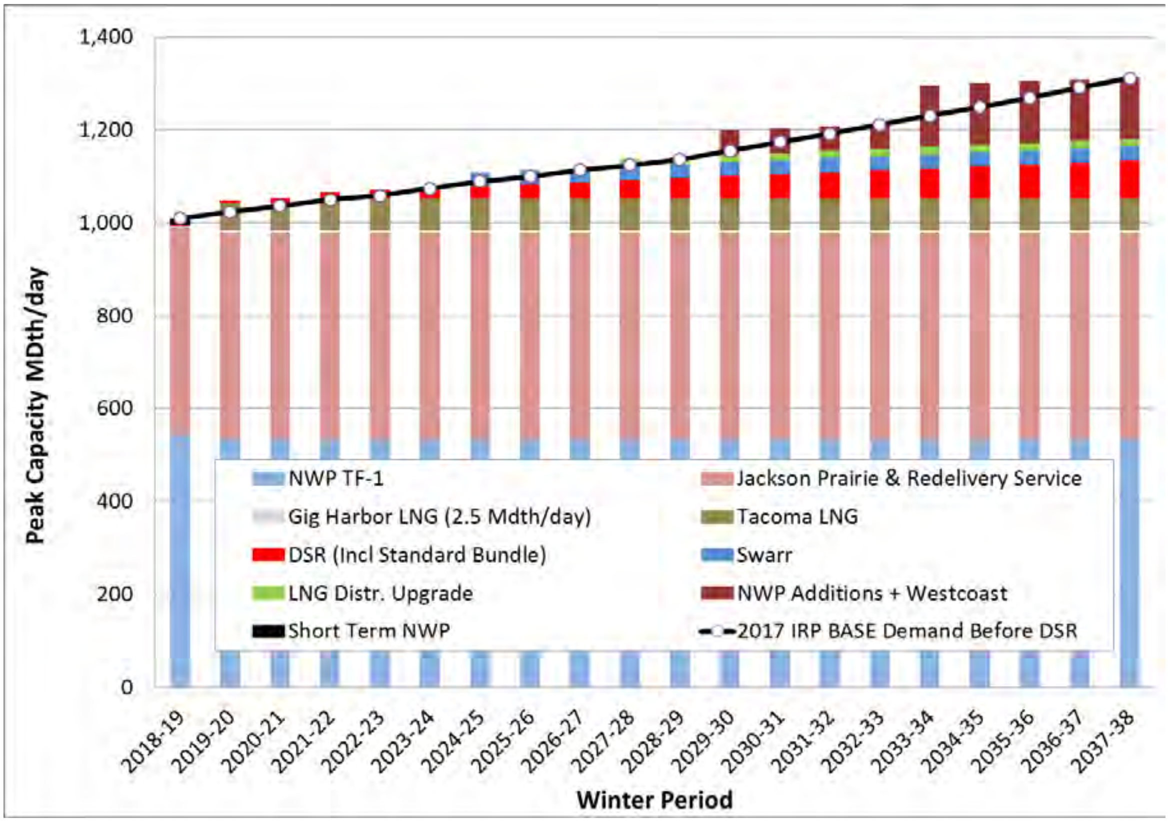


Figure O-14: Base + High Gas Price Optimal Portfolio – Gas Sales

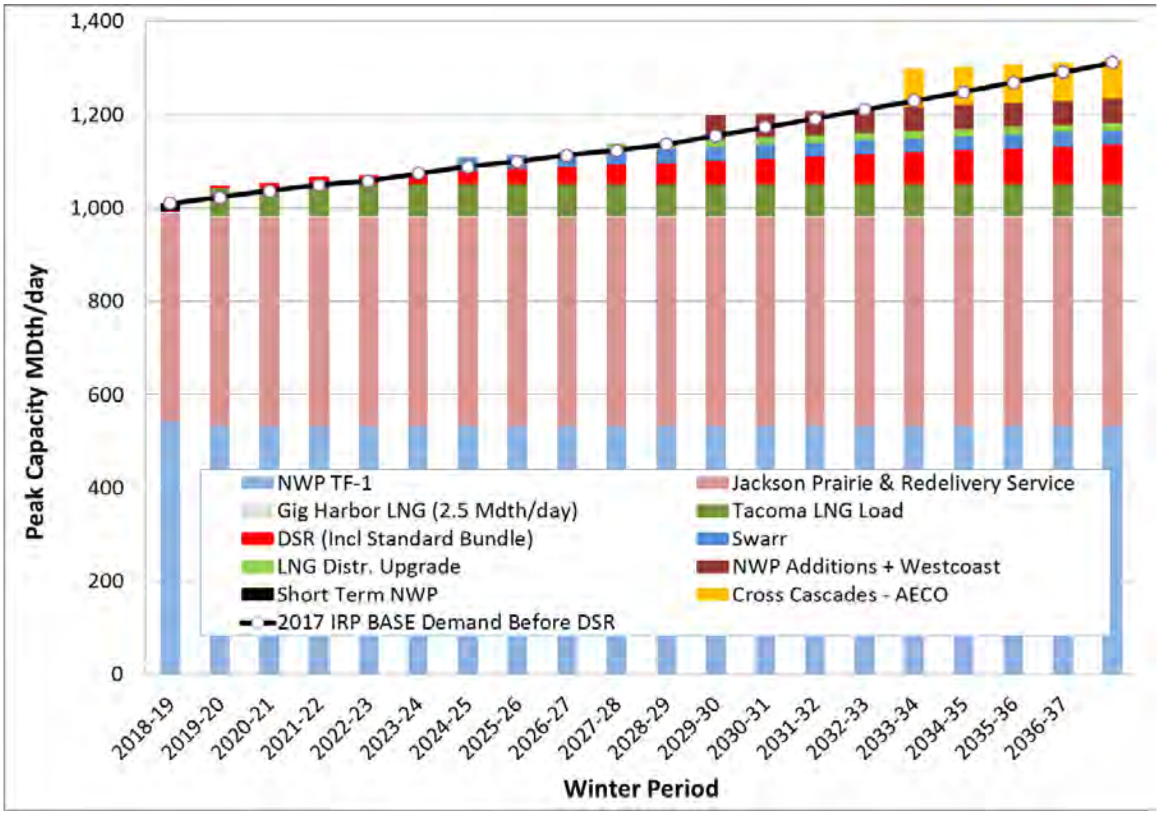


Figure O-15: Base + Low Demand Optimal Portfolio – Gas Sales

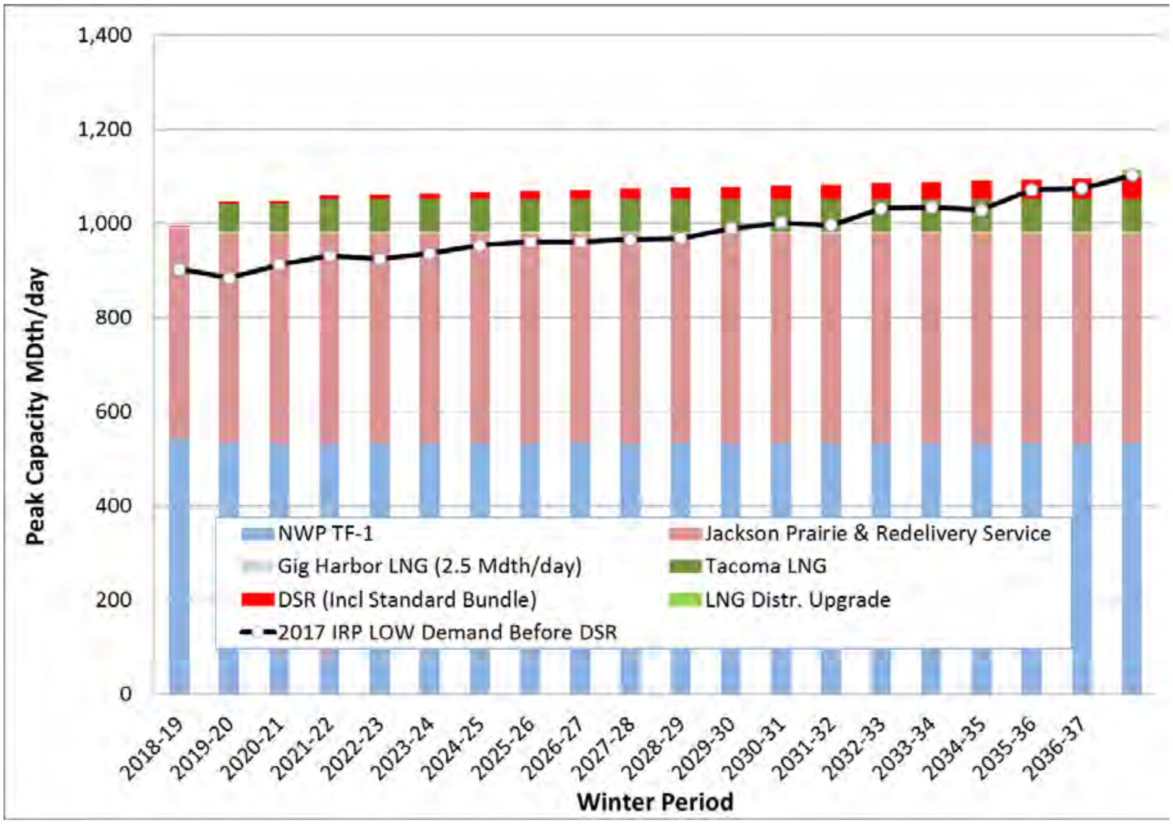


Figure O-16: Base + High Demand Optimal Portfolio – Gas Sales

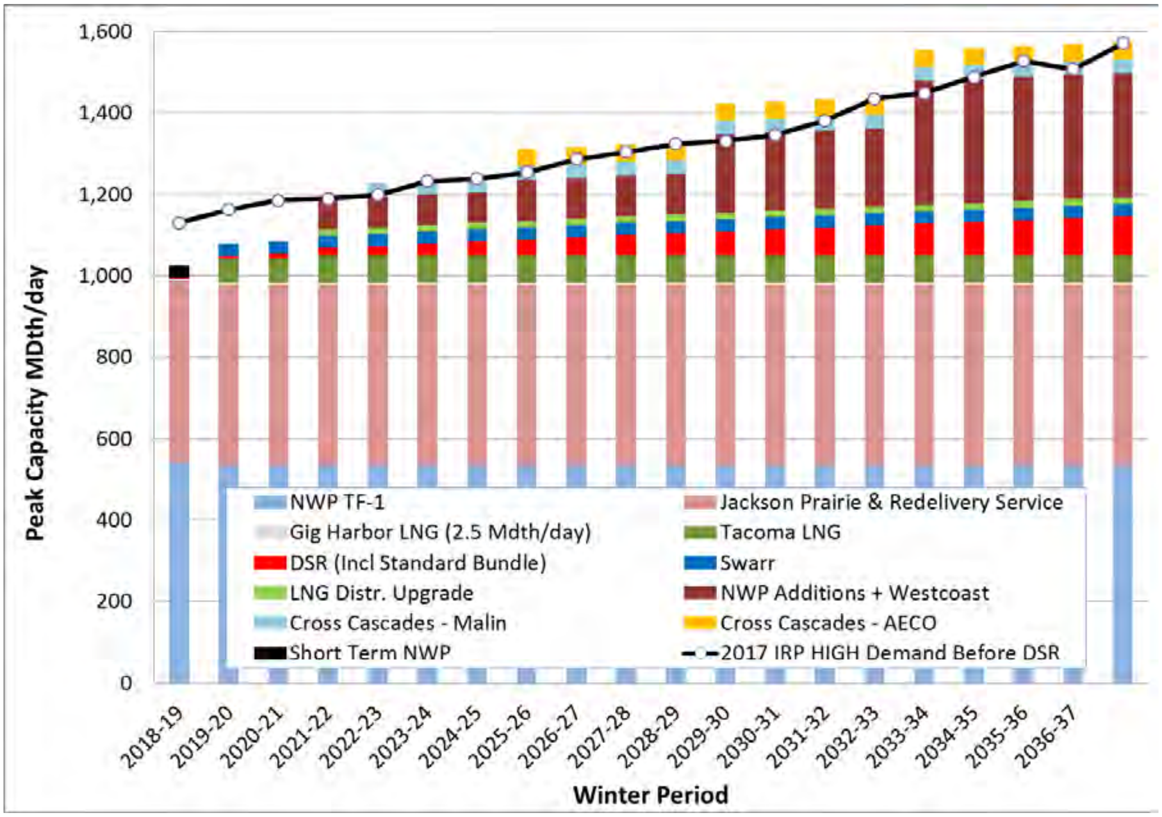


Figure O-17: Base + No CO_2 Optimal Portfolio – Gas Sales

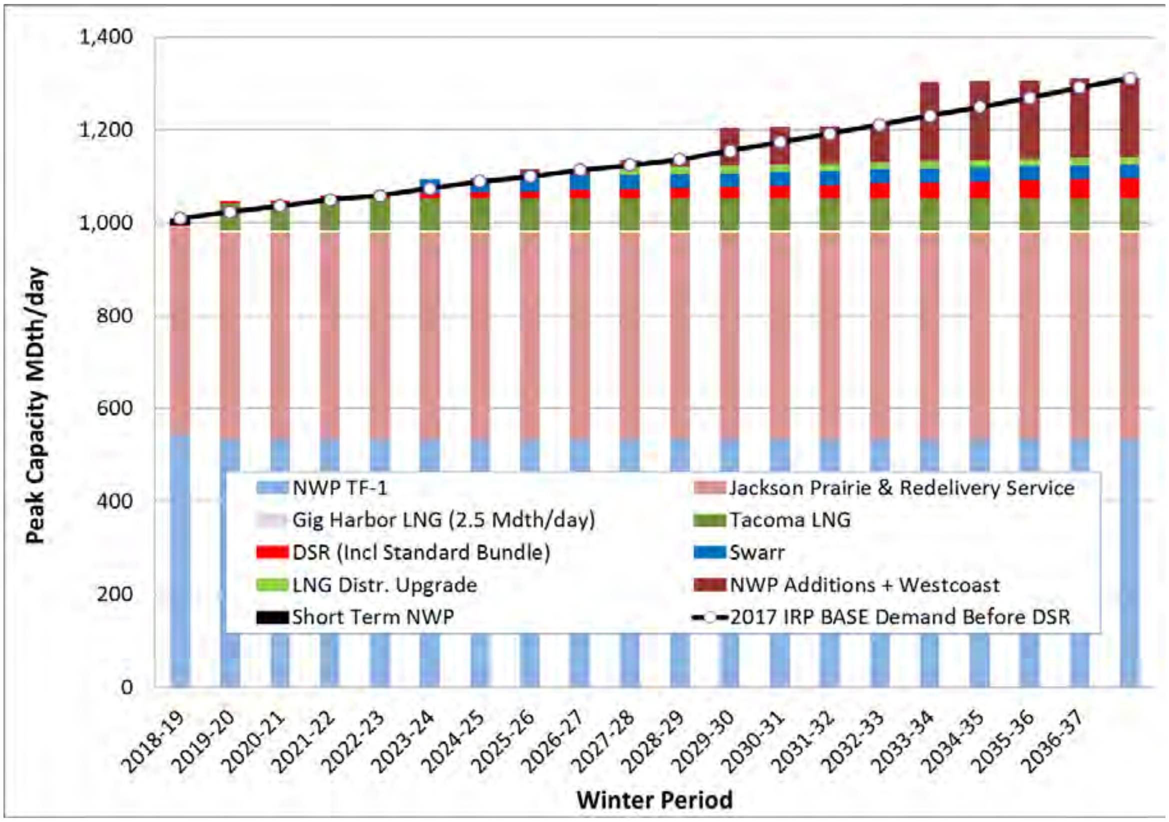


Figure O-18: Base + Low CAR CO_2 price Optimal Portfolio – Gas Sales

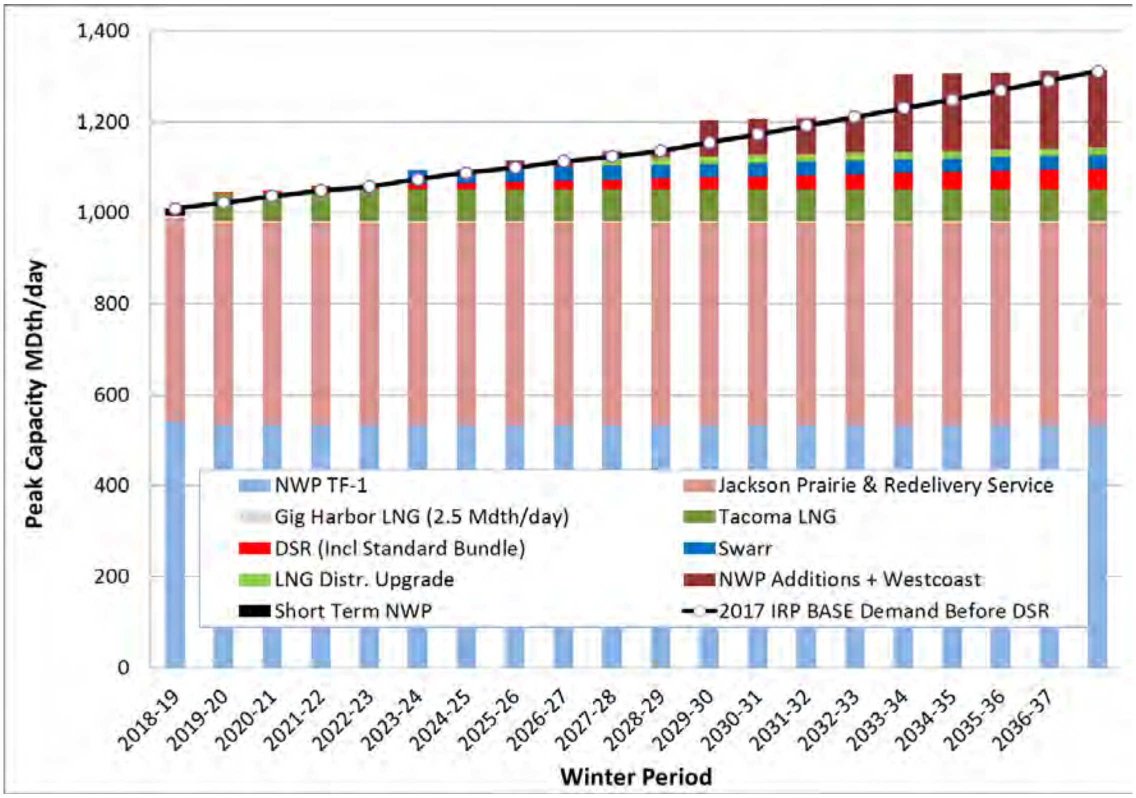


Figure O-19: Base + High CAR CO_2 price Optimal Portfolio – Gas Sales

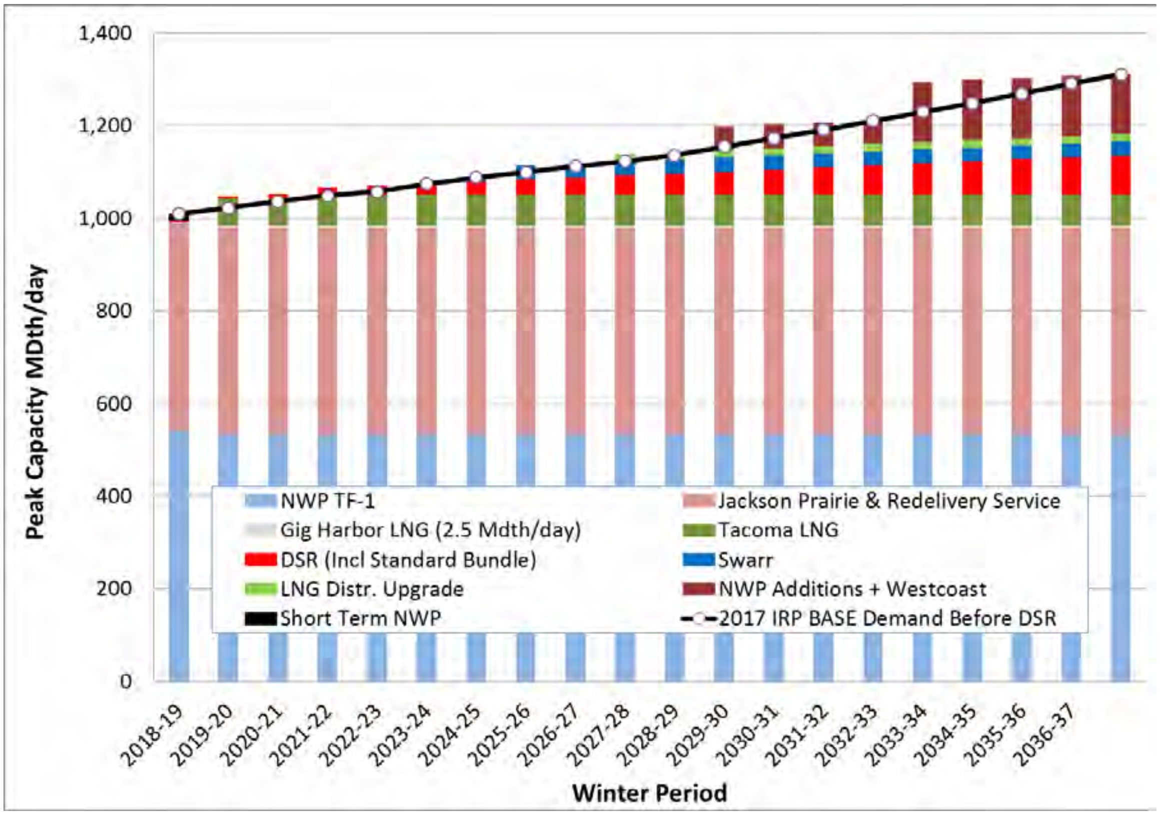


Figure O-20: Alternate Discount Rate Sensitivity
Gas Sales Cumulative Resource Additions (MDth/day)

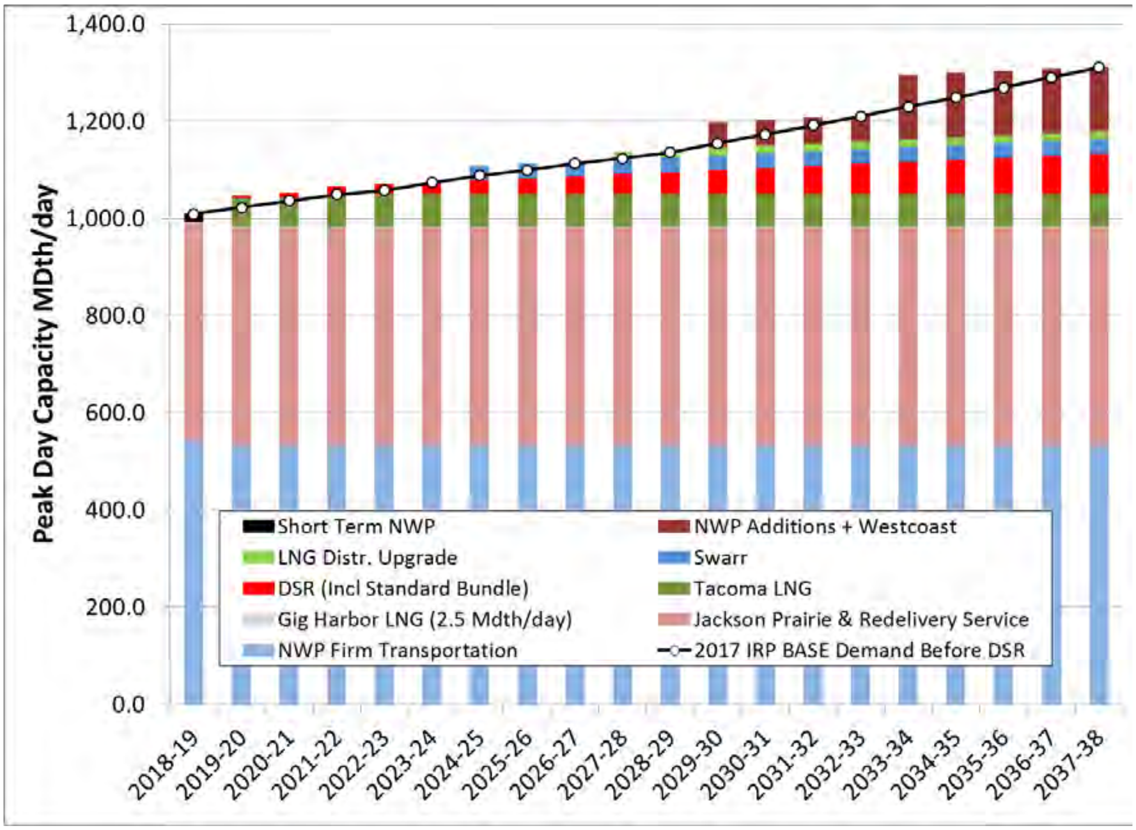


Figure O-21: PSE-controlled Resource Timing Sensitivity
Gas Sales Cumulative Resource Additions (MDth/day)

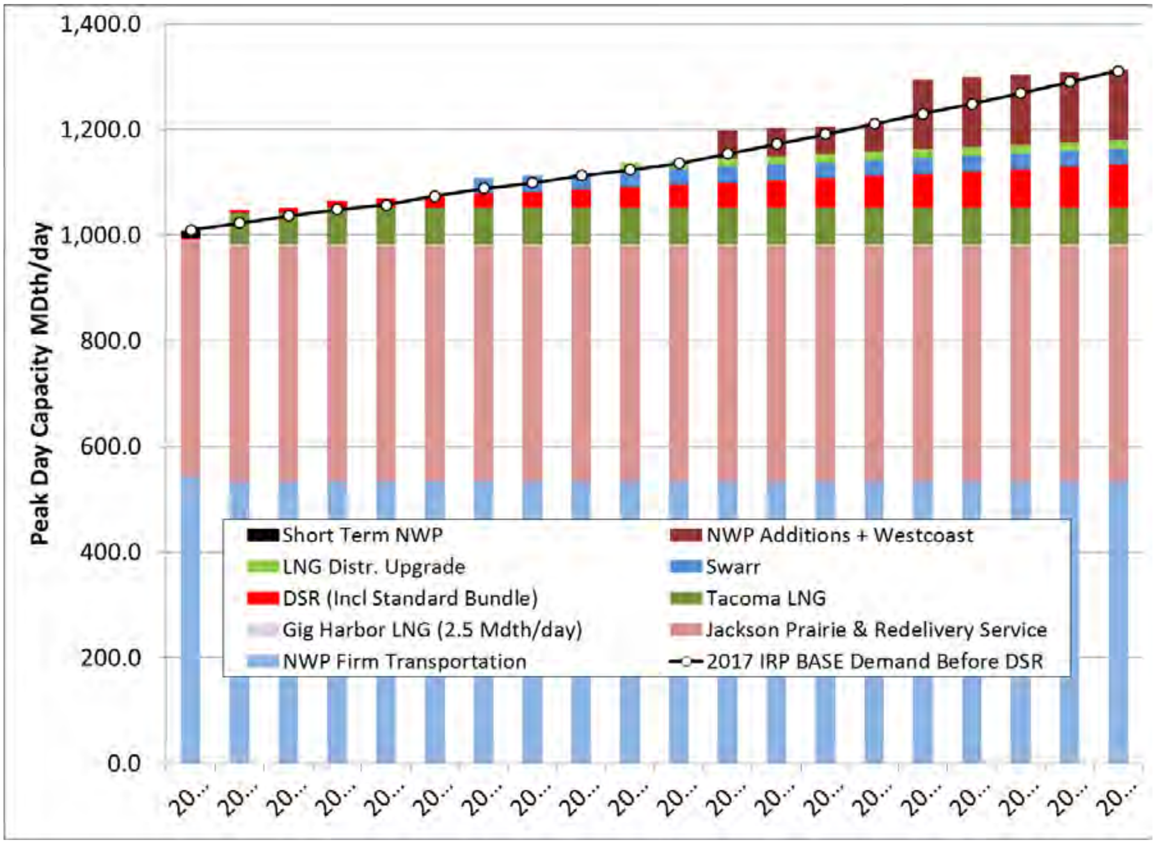


Figure O-22: Scenario Portfolio Capacity Expansion Results – Base (MDth)

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

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

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

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

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

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

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

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

Figure O-30: Scenario Portfolio Capacity Expansion Results – Base + No CO_2 (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

Figure O-31: Scenario Portfolio Capacity Expansion Results – Base + Low CAR CO_2 (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

Figure O-32: Scenario Portfolio Capacity Expansion Results – Base + High CAR CO_2 (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 RateSensitivity (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.

Contents

FINAL REPORT

CHARACTERIZATION OF SUPPLY SIDE OPTIONS

Natural Gas-Fired Options

B&V PROJECT NO. 192143
B&V FILE NO. 40.1100

PREPARED FOR

Puget Sound Energy

12 JANUARY 2017

Table of Contents

LIST OF TABLES

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

Project Development
• 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
 	
Spare Parts and Plant Equipment
• 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
 	
Plant Startup/Construction Support
• 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
	Owner's Contingency
	• Owner's uncertainty and costs pending final negotiation:
	  ◦ Unidentified project scope increases
	  ◦ Unidentified project requirements
	  ◦ Costs pending final agreements (i.e., interconnection contract costs)
	
	Owner's Project Management
	• Preparation of bid documents and the selection of contractors and suppliers
	• Performance of engineering due diligence
	• Provision of personnel for site construction management
	
	Taxes/Advisory Fees/Legal
	• Taxes
	• Market and environmental consultants
	• Owner's legal expenses
	• Interconnect agreements
	• Contracts (procurement and construction)
	• Property
	
	Utility Interconnections
	• Natural gas service
	• Gas system upgrades
	• Electrical transmission (including switchyard)
	• Water supply
	• Wastewater/sewer
	
	Financing (may be included in fixed charge rate)
	• 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 NOx 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 NOx 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 NOx 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 NOx 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 vain 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 NOx 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 NOx 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 NOx 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 NOx 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. NOx emissions on a ppm basis are presented as ppmvd @15% O_2.

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 CONSUMP-TION(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

Puget Sound Energy
B&V Project Number 192143
1x1 GE 7F.05
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	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
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	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	75	45	100	75	45	100	75	45	100	75	45
NEW & CLEAN PERFORMANCE													
Gross CTG Output (each)	kW	244,741	183,555	110,133	244,741	183,555	110,133	244,027	183,020	109,812	227,322	170,492	102,295
Number of Gas Turbines in Operation		1	1	1	1	1	1	1	1	1	1	1	1
Gross CTG Output	kW	244,741	183,555	110,133	244,741	183,555	110,133	244,027	183,020	109,812	227,322	170,492	102,295
Gross Steam Turbine Output	kW	114,823	95,629	83,207	123,542	98,853	84,156	125,397	99,570	84,297	122,118	98,137	82,836
CTG Heat Input (LHV) (each)	MBtu/h	2,095	1,637	1,229	2,111	1,639	1,214	2,110	1,636	1,209	1,989	1,555	1,161
CTG Heat Input (HHV) (each)	MBtu/h	2,324	1,816	1,363	2,342	1,819	1,347	2,341	1,816	1,341	2,207	1,725	1,288
Total Plant Auxiliary Power	kW	8,910	7,776	6,711	9,166	8,134	7,032	9,181	8,136	7,190	8,934	7,974	7,072
NET PLANT PERFORMANCE													
Net Plant Output	kW	350,654	271,408	186,629	359,116	274,275	187,257	360,243	274,454	186,920	340,505	260,655	178,059
Net Plant Heat Rate (LHV)	Btu/kWh	5,974	6,031	6,583	5,877	5,977	6,484	5,857	5,962	6,466	5,842	5,965	6,520
Net Plant Heat Rate (HHV)	Btu/kWh	6,629	6,692	7,305	6,522	6,632	7,195	6,499	6,616	7,175	6,483	6,619	7,235
Net Plant Efficiency (LHV)	%	57.1%	56.6%	51.8%	58.1%	57.1%	52.6%	58.3%	57.2%	52.8%	58.4%	57.2%	52.3%
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%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
	lb/hr	16.7	13	9.8	16.8	13.1	9.7	16.8	13	9.6	15.9	12.4	9.3
CO	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2
	lb/MBtu (HHV)	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044
	lb/hr	10.2	7.9	6	10.2	8	5.9	10.2	7.9	5.9	9.7	7.5	5.6
CO2	lb/hr	267,277	208,866	156,766	269,307	209,168	154,928	269,224	208,784	154,215	253,806	198,386	148,124
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	940	762	692	1,152	906	766	1,239	985	831	1,488	1,248	1,095
Steam Cycle Makeup Water (2% of Flow)	GPM	27	22	18	28	22	18	28	23	18	28	22	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

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) No inlet conditioning applied
5) No HRSG duct firing applied.
6) HRSG, STG and Heat Rejection System sized using GT Pro software
7) STG Last Stage Blade geometry selected by GT Pro software.
8) Condenser Pressure designed to be 1.88 inches HgA at design (88 F) conditions
9) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
10) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
11) SCR designed to reduce stack NOx to 2.0 ppmvd @15% O2

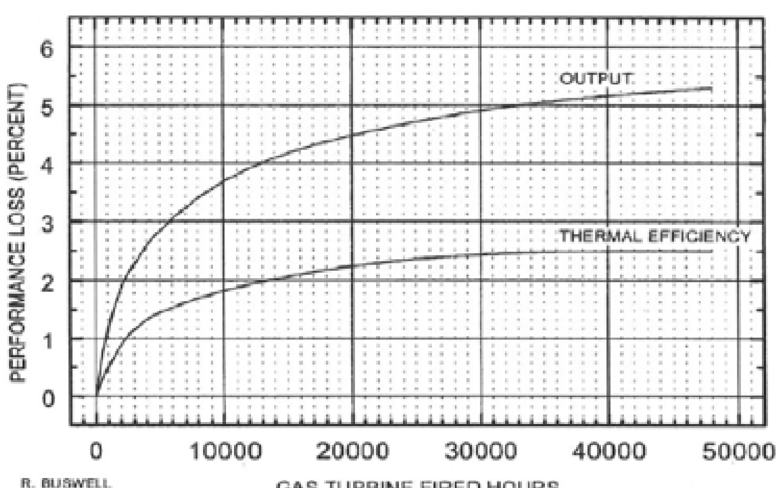
Puget Sound Energy
B&V Project Number 192143
1x1 7F.05 Degradation Curve

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.



R. BUSWELL
REV A FEB. 9, 1995

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Notes:

1. Degradation curves based on generic GE 7FA data from 2/9/1995.

Puget Sound Energy **B&V Project Number 192143** **1x1 GE 7HA.01** **Preliminary Performance Summary** **May 27, 2016 - Rev A**													
Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	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
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	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 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01	GE 7HA.01
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	34	100	75	36	100	75	34	100	75	30
NEW & CLEAN PERFORMANCE													
Gross CTG Output (each)	kW	289,135	216,851	98,306	285,100	213,825	102,636	281,301	210,976	95,642	252,668	189,501	75,800
Number of Gas Turbines in Operation		1	1	1	1	1	1	1	1	1	1	1	1
Gross CTG Output	kW	289,135	216,851	98,306	285,100	213,825	102,636	281,301	210,976	95,642	252,668	189,501	75,800
Gross STG Output	kW	124,782	106,233	77,127	131,063	109,045	78,832	130,936	108,915	76,876	126,419	103,635	71,675
CTG Heat Input (LHV) (each)	MBtu/h	2,355	1,858	1,136	2,340	1,842	1,147	2,309	1,823	1,100	2,117	1,678	967
CTG Heat Input (HHV) (each)	MBtu/h	2,613	2,061	1,261	2,596	2,044	1,272	2,563	2,023	1,221	2,349	1,862	1,073
Total Plant Auxiliary Power	kW	10,874	9,470	7,424	11,048	9,798	7,817	10,987	9,755	7,699	10,525	9,380	7,533
NET PLANT PERFORMANCE													
Net Plant Output	kW	403,042	313,614	168,009	405,115	313,072	173,652	401,250	310,136	164,820	368,562	283,755	139,943
Net Plant Heat Rate (LHV)	Btu/kWh	5,843	5,924	6,763	5,776	5,883	6,603	5,756	5,878	6,675	5,745	5,912	6,910
Net Plant Heat Rate (HHV)	Btu/kWh	6,484	6,573	7,505	6,409	6,527	7,326	6,387	6,522	7,407	6,375	6,560	7,668
Net Plant Efficiency (LHV)	%	58.4%	57.6%	50.5%	59.1%	58.0%	51.7%	59.3%	58.1%	51.1%	59.4%	57.7%	49.4%
Net Plant Efficiency (HHV)	%	52.6%	51.9%	45.5%	53.3%	52.3%	46.6%	53.4%	52.3%	46.1%	53.5%	52.0%	44.5%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2
	lb/MBtu (HHV)	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
	lb/hr	18.8	14.8	9.1	18.7	14.7	9.2	18.5	14.6	8.8	16.9	13.4	7.7
CO	ppmvd @ 15% O2	2	2	2	2	2	2	2	2	2	2	2	2
	lb/MBtu (HHV)	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044	0.0044
	lb/hr	11.5	9.1	5.5	11.4	9.0	5.6	11.3	8.9	5.4	10.3	8.2	4.7
CO2	lb/hr	300,486	237,040	144,988	298,548	234,987	146,293	294,677	232,583	140,376	270,163	214,059	123,391
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	1,038	858	632	1,246	1,002	722	1,318	1,078	772	1,546	1,320	1,004
Steam Cycle Makeup Water (2% of Flow)	GPM	30	24	17	31	25	18	30	25	17	29	24	16
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

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) No inlet conditioning applied.
5) No HRSG duct firing applied.
6) HRSG, STG and Heat Rejection System sized using GT Pro software.
7) STG Last Stage Blade geometry selected by GT Pro software.
8) Condenser Pressure designed to be 1.88 inches HgA at design (88 F) conditions.
9) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
10) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
11) SCR designed to reduce stack NOx to 2.0 ppmvd @15% O2.

Puget Sound Energy
B&V Project Number 192143
3x Wartsila 18V50SG
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
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
RICE Configuration	-	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0	3x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
Reciprocating Engine Model	-	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG
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													
Gross RICE Output (each)	kW	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621
Number of Engines in Operation		3	3	3	3	3	3	3	3	3	3	3	3
Gross RICE Output	kW	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 (LHV) (each)	MBtu/h	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)	MBtu/h	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7
Total Plant Auxiliary Power	kW	847	741	485	960	741	485	1,016	805	499	1,242	1,059	527
NET PLANT PERFORMANCE													
Net Plant Output	kW	55,604	41,613	13,378	55,491	41,613	13,378	55,435	41,549	13,364	55,209	41,295	13,336
Net Plant Heat Rate (LHV)	Btu/kWh	7,425	7,785	9,650	7,440	7,785	9,650	7,448	7,797	9,660	7,479	7,845	9,680
Net Plant Heat Rate (HHV)	Btu/kWh	8,239	8,639	10,707	8,256	8,639	10,707	8,264	8,652	10,719	8,298	8,705	10,741
Net Plant Efficiency (LHV)	%	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)	%	41.4%	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 Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0
	lb/MBtu (HHV)	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015
	lb/hr	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	ppmvd @ 15% O2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	lb/MBtu (HHV)	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043
	lb/hr	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	lb/hr	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	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
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	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	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 8𝐶° F.
4) No inlet conditioning applied
5) Auxiliary power estimate 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

Puget Sound Energy
B&V Project Number 192143
6x Wartsila 18V50SG
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
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
RICE Configuration	-	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0	6x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
Reciprocating Engine Model	-	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG
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													
Gross RICE Output (each)	kW	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621
Number of Engines in Operation		6	6	6	6	6	6	6	6	6	6	6	6
Gross RICE Output	kW	112,902	84,708	27,726	112,902	84,708	27,726	112,902	84,708	27,726	112,902	84,708	27,726
RICE Heat Input (LHV) (each)	MBtu/h	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)	MBtu/h	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7
Total Plant Auxiliary Power	kW	1,694	1,482	970	1,919	1,482	970	2,032	1,609	998	2,484	2,118	1,054
NET PLANT PERFORMANCE													
Net Plant Output	kW	111,208	83,226	26,756	110,983	83,226	26,756	110,870	83,099	26,728	110,418	82,590	26,672
Net Plant Heat Rate (LHV)	Btu/kWh	7,425	7,785	9,650	7,440	7,785	9,650	7,448	7,797	9,660	7,479	7,845	9,680
Net Plant Heat Rate (HHV)	Btu/kWh	8,239	8,639	10,707	8,256	8,639	10,707	8,264	8,652	10,719	8,298	8,705	10,741
Net Plant Efficiency (LHV)	%	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)	%	41.4%	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 Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0
	lb/MBtu (HHV)	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015
	lb/hr	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	ppmvd @ 15% O2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	lb/MBtu (HHV)	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043
	lb/hr	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	lb/hr	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	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
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	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	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 8(° F.
4) No inlet conditioning applied
5) Auxiliary power estimate 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

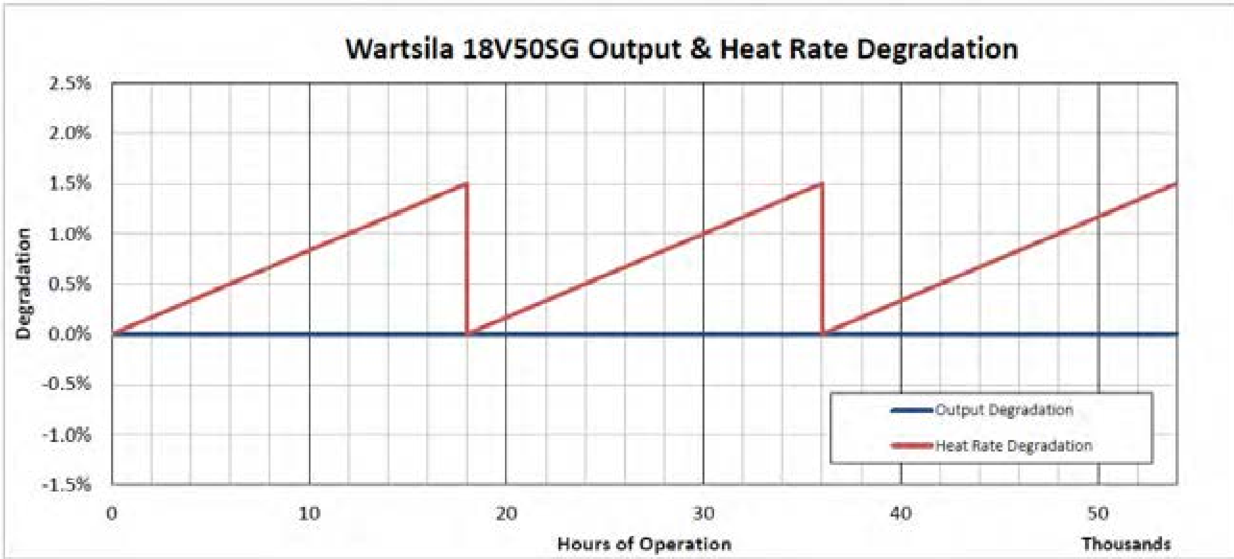
Puget Sound Energy
B&V Project Number 192143
12x Wartsila 18V50SG
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
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
RICE Configuration	-	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0	12x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	14.68	14.68	14.68	14.68	14.68	14.68	14.70	14.70	14.70	14.68	14.68	14.68
Reciprocating Engine Model	-	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG	Wartsila 18V50SG
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													
Gross RICE Output (each)	kW	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621	18,817	14,118	4,621
Number of Engines in Operation		12	12	12	12	12	12	12	12	12	12	12	12
Gross RICE Output	kW	225,804	169,416	55,452	225,804	169,416	55,452	225,804	169,416	55,452	225,804	169,416	55,452
RICE Heat Input (LHV) (each)	MBtu/h	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)	MBtu/h	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7	152.7	119.8	47.7
Total Plant Auxiliary Power	kW	3,387	2,965	1,941	3,839	2,965	1,941	4,064	3,219	1,996	4,968	4,235	2,107
NET PLANT PERFORMANCE													
Net Plant Output	kW	222,417	166,451	53,511	221,965	166,451	53,511	221,740	166,197	53,456	220,836	165,181	53,345
Net Plant Heat Rate (LHV)	Btu/kWh	7,425	7,785	9,650	7,440	7,785	9,650	7,448	7,797	9,660	7,479	7,845	9,680
Net Plant Heat Rate (HHV)	Btu/kWh	8,239	8,639	10,707	8,256	8,639	10,707	8,264	8,652	10,719	8,298	8,705	10,741
Net Plant Efficiency (LHV)	%	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)	%	41.4%	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 Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0	5.0	5.0	6.0
	lb/MBtu (HHV)	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015	0.016	0.018	0.015
	lb/hr	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	ppmvd @ 15% O2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
	lb/MBtu (HHV)	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043	0.033	0.036	0.043
	lb/hr	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	lb/hr	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581	17,850	14,006	5,581
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	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
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	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	n/a

#DIV/0!

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) No inlet conditioning applied.
5) Auxiliary power estimate 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.

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.

Puget Sound Energy
B&V Project Number 192143
1x GE LMS100PA+
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	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 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													
Gross CTG Output (each)	kW	114,920	86,191	28,730	116,508	87,380	29,127	117,000	87,750	29,250	112,423	84,316	28,108
Number of Gas Turbines in Operation		1	1	1	1	1	1	1	1	1	1	1	1
Gross CTG Output	kW	114,920	86,191	28,730	116,508	87,380	29,127	117,000	87,750	29,250	112,423	84,316	28,108
CTG Heat Input (LHV) (each)	MBtu/h	887	711	351	902	720	355	908	724	356	886	706	349
CTG Heat Input (HHV) (each)	MBtu/h	984	789	389	1,001	799	393	1,008	803	395	984	783	387
Total Plant Auxiliary Power	kW	2,823	2,351	1,397	2,856	2,374	1,406	2,869	2,381	1,409	2,803	2,330	1,390
NET PLANT PERFORMANCE													
Net Plant Output	kW	112,098	83,840	27,332	113,651	85,006	27,721	114,131	85,369	27,841	109,620	81,986	26,718
Net Plant Heat Rate (LHV)	Btu/kWh	7,914	8,477	12,842	7,938	8,473	12,789	7,958	8,475	12,786	8,086	8,608	13,054
Net Plant Heat Rate (HHV)	Btu/kWh	8,782	9,406	14,249	8,808	9,402	14,191	8,830	9,404	14,187	8,972	9,552	14,484
Net Plant Efficiency (LHV)	%	43.1%	40.3%	26.6%	43.0%	40.3%	26.7%	42.9%	40.3%	26.7%	42.2%	39.6%	26.1%
Net Plant Efficiency (HHV)	%	38.9%	36.3%	24.0%	38.7%	36.3%	24.1%	38.7%	36.3%	24.1%	38.0%	35.7%	23.6%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor		**See Degradation Worksheet**											
Net Plant Heat Rate Degradation Factor													
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
	lb/hr	8.8	7.1	3.5	9.0	7.2	3.6	9.0	7.2	3.6	8.8	7.1	3.5
CO	ppmvd @ 15% O2	6	6	6	6	6	6	6	6	6	6	6	6
	lb/MBtu (HHV)	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131
	lb/hr	12.9	10.3	5.1	13.1	10.5	5.2	13.2	10.5	5.2	12.9	10.3	5.1
CO2	lb/hr	113,201	90,675	44,787	115,109	91,896	45,233	115,884	92,313	45,412	113,083	90,049	44,488
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	175	128	40	207	157	55	215	165	60	235	184	72
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	n/a
CTG Water Injection	GPM	58	42	15	55	39	13	56	40	13	53	37	12

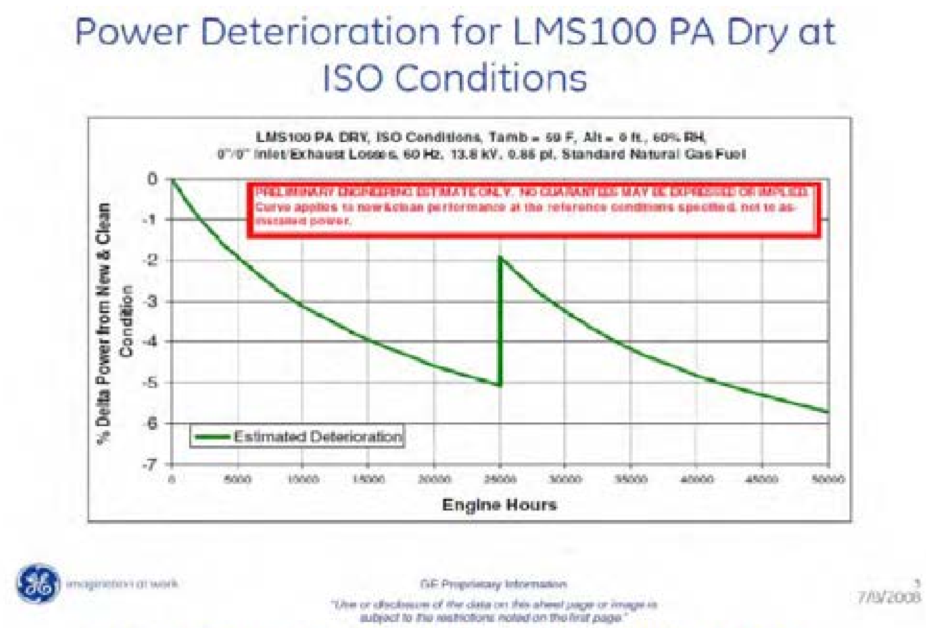
1) **PERFORMANCE IS PRELIMINARY. NO GUARANTEES APPLY.**
2) CTG performance is based on data from GE APPS from May 2016
3) Water injection to control CTG NOx to 25 ppm @15% O2
4) The fuel gas is unheated and is assumed to be supplied at 8C° F.
5) The fuel supply pressure is assumed to be 400 psia at the site boundary
6) No inlet conditioning applied
7) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
8) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
9) SCR designed to reduce stack NOx to 2.5 ppmvd @15% O2.

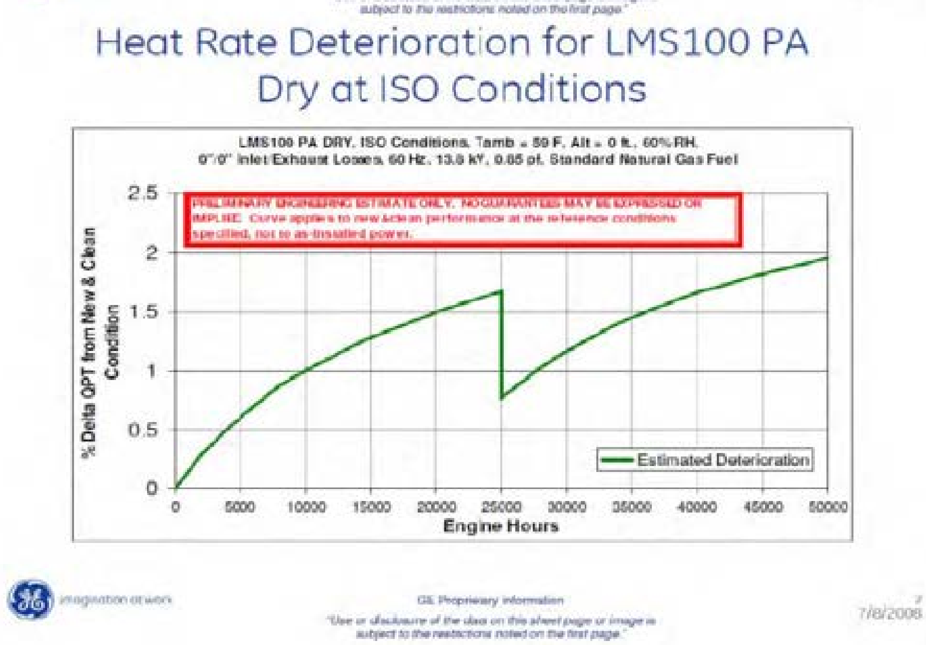
Puget Sound Energy
B&V Project Number 192143
2x GE LMS100PA+
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	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 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													
Gross CTG Output (each)	kW	114,920	86,191	28,730	116,508	87,380	29,127	117,000	87,750	29,250	112,423	84,316	28,108
Number of Gas Turbines in Operation		2	2	2	2	2	2	2	2	2	2	2	2
Gross CTG Output	kW	229,841	172,381	57,460	233,016	174,760	58,253	234,000	175,501	58,499	224,846	168,632	56,216
CTG Heat Input (LHV) (each)	MBtu/h	887	711	351	902	720	355	908	724	356	886	706	349
CTG Heat Input (HHV) (each)	MBtu/h	984	789	389	1,001	799	393	1,008	803	395	984	783	387
Total Plant Auxiliary Power	kW	5,616	4,673	2,766	5,684	4,719	2,782	5,709	4,734	2,788	5,577	4,631	2,750
NET PLANT PERFORMANCE													
Net Plant Output	kW	224,225	167,708	54,694	227,332	170,041	55,471	228,291	170,767	55,711	219,269	164,001	53,466
Net Plant Heat Rate (LHV)	Btu/kWh	7,913	8,476	12,835	7,937	8,472	12,783	7,957	8,474	12,779	8,085	8,607	13,047
Net Plant Heat Rate (HHV)	Btu/kWh	8,781	9,405	14,242	8,807	9,400	14,184	8,829	9,402	14,180	8,971	9,550	14,477
Net Plant Efficiency (LHV)	%	43.1%	40.3%	26.6%	43.0%	40.3%	26.7%	42.9%	40.3%	26.7%	42.2%	39.7%	26.2%
Net Plant Efficiency (HHV)	%	38.9%	36.3%	24.0%	38.8%	36.3%	24.1%	38.7%	36.3%	24.1%	38.0%	35.7%	23.6%
DEGRADED PERFORMANCE													
Net Plant Output Degradation Factor Net Plant Heat Rate Degradation Factor		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
	lb/hr	8.8	7.1	3.5	9.0	7.2	3.6	9.0	7.2	3.6	8.8	7.1	3.5
CO	ppmvd @ 15% O2	6	6	6	6	6	6	6	6	6	6	6	6
	lb/MBtu (HHV)	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131	0.0131
	lb/hr	12.9	10.3	5.1	13.1	10.5	5.2	13.2	10.5	5.2	12.9	10.3	5.1
CO2	lb/hr	113,201	90,675	44,787	115,109	91,896	45,233	115,884	92,313	45,412	113,083	90,049	44,488
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	GPM	175	128	40	207	157	55	215	165	60	235	184	72
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	n/a
CTG Water Injection	GPM	58	42	15	55	39	13	56	40	13	53	37	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 gas is unheated and is assumed to be supplied at 80° F.
5) The fuel supply pressure is assumed to be 400 psia at the site boundary
6) No inlet conditioning applied
7) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
8) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
9) SCR designed to reduce stack NOx to 2.5 ppmvd @15% O2.

Puget Sound Energy
B&V Project Number 192143
1x0 GE LMS100PA Degradation Curve





Notes:

1. Degradation curves based on generic GE LMS100PA data from 7/8/2008.

Puget Sound Energy
B&V Project Number 192143
1x GE 7F.05
Preliminary Performance Summary
May 27, 2016 - Rev A

Case #		1	2	3	4	5	6	7	8	9	10	11	12
Revision #		1	1	1	1	1	1	1	1	1	1	1	1
Description		23 deg F 100% CTG Load	23 deg F 75% CTG Load	23 deg F MECL	51 deg F 100% CTG Load	51 deg F 75% CTG Load	51 deg F MECL	ISO Conditions 100% CTG Load	ISO Conditions 75% CTG Load	ISO Conditions MECL	88 deg F 100% CTG Load	88 deg F 75% CTG Load	88 deg F MECL
CTG Configuration	-	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0	1x0
Ambient Temperature	F	23	23	23	51	51	51	59	59	59	88	88	88
Relative Humidity	%	40	40	40	75	75	75	60	60	60	30	30	30
Ambient Pressure	psia	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	75	45	100	75	45	100	75	45	100	75	45
NEW & CLEAN PERFORMANCE													
Gross CTG Output (each)	kW	244,740	183,555	110,133	242,391	181,793	109,076	240,860	180,645	108,387	227,576	170,682	102,409
Number of Gas Turbines in Operation		1	1	1	1	1	1	1	1	1	1	1	1
Gross CTG Output	kW	244,740	183,555	110,133	242,391	181,793	109,076	240,860	180,645	108,387	227,576	170,682	102,409
CTG Heat Input (LHV) (each)	MBtu/h	2,079	1,626	1,221	2,074	1,617	1,202	2,066	1,610	1,195	1,988	1,546	1,153
CTG Heat Input (HHV) (each)	MBtu/h	2,306	1,804	1,355	2,301	1,794	1,333	2,292	1,786	1,326	2,206	1,715	1,280
Total Plant Auxiliary Power	kW	3,430	2,971	2,420	3,412	2,957	2,412	3,400	2,949	2,407	3,301	2,874	2,362
NET PLANT PERFORMANCE													
Net Plant Output	kW	241,311	180,584	107,713	238,979	178,836	106,664	237,460	177,696	105,980	224,275	167,808	100,047
Net Plant Heat Rate (LHV)	Btu/kWh	8,614	9,005	11,333	8,679	9,040	11,266	8,700	9,058	11,274	8,866	9,210	11,527
Net Plant Heat Rate (HHV)	Btu/kWh	9,558	9,992	12,575	9,631	10,031	12,501	9,653	10,051	12,510	9,837	10,220	12,790
Net Plant Efficiency (LHV)	%	39.6%	37.9%	30.1%	39.3%	37.8%	30.3%	39.2%	37.7%	30.3%	38.5%	37.1%	29.6%
Net Plant Efficiency (HHV)	%	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		**See Degradation Worksheet**											
STACK EMISSIONS (PER UNIT)													
NOx	ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009	0.009
	lb/hr	20.7	16.2	12.2	20.7	16.1	12	20.6	16	11.9	19.8	15.4	11.5
CO	ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5
	lb/MBtu (HHV)	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055	0.0055
	lb/hr	12.6	9.9	7.4	12.6	9.8	7.3	12.5	9.8	7.2	12.1	9.4	7
CO2	lb/hr	265,219	207,467	155,751	264,643	206,260	153,337	263,573	205,355	152,459	253,696	197,206	147,137
WATER CONSUMPTION (PER UNIT)													
Cooling Tower Makeup Water (5 COCs)	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
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	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	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.
5) The fuel supply pressure is assumed to be 400 psia at the site boundary
6) No inlet conditioning applied
7) Auxiliary loads estimated by GT Pro software. Includes auxiliary load for fuel gas compression, as calculated by Black & Veatch
8) Emission flowrate (lb/hr) estimates based on Black & Veatch in-house calculations and indicative PPM rates provided by GE
9) SCR designed to reduce stack NOx to 2.5 ppmvd @15% O2.

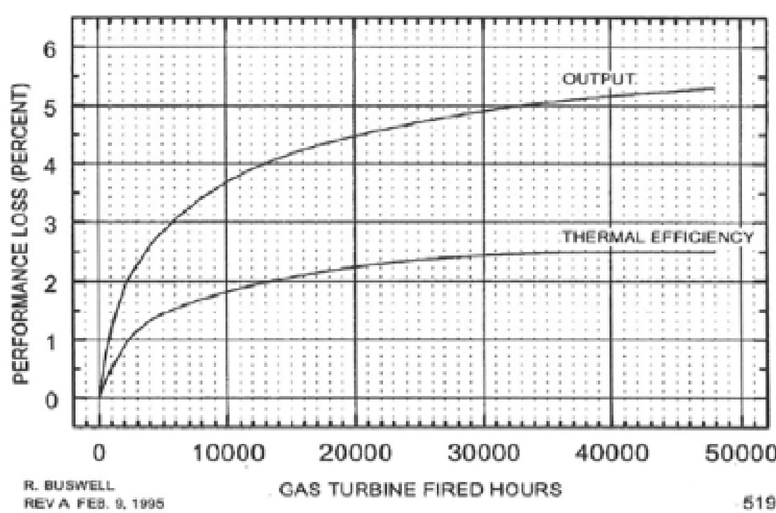
Puget Sound Energy
B&V Project Number 192143
1x0 GE 7F.05 Degradation Curve

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.



R. BUSWELL
REV A FEB. 9, 1995

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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 <u>$300 to $400 per kilowatt of increased net output, on an overnight EPC cost basis.</u> 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, <u>on an overnight EPC cost basis</u>.

- **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 NOx emissions while operating on diesel fuel. NOx water injection rates are often high and CTG water quality specifications call for demineralized water, which can be expensive to produce. NOx 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 NOx water injection but rather rely on the SCR system for NOx 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 NOx 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.

- 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.

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

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

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

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

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

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

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

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