ELECTRIC ANALYSIS

Contents

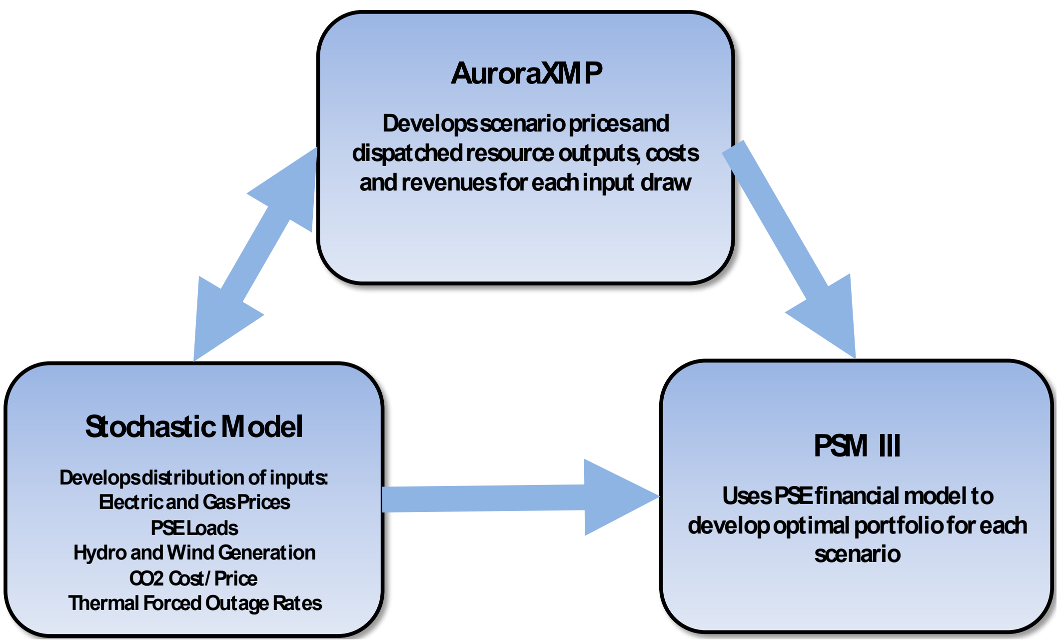
This appendix presents details of the methods and models employed in PSE's electric resource analysis, and the data produced by that analysis.

PORTFOLIO ANALYSIS METHODS

PSE uses three models for electric integrated resource planning: AURORAxmp,® 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. 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 three models are connected. We first start with the AURORAxmp to develop power prices. Once the power prices are developed, we create a dispatch for PSE's portfolio to use in the PSM III model. PSM III is a linear programming model that is used to find the lowest cost resource plan for each scenario developed in AURORA. Next, we develop stochastic variables around power prices, gas prices, CO_2 prices, hydro generation, wind generation, PSE loads, and thermal plant forced outages.

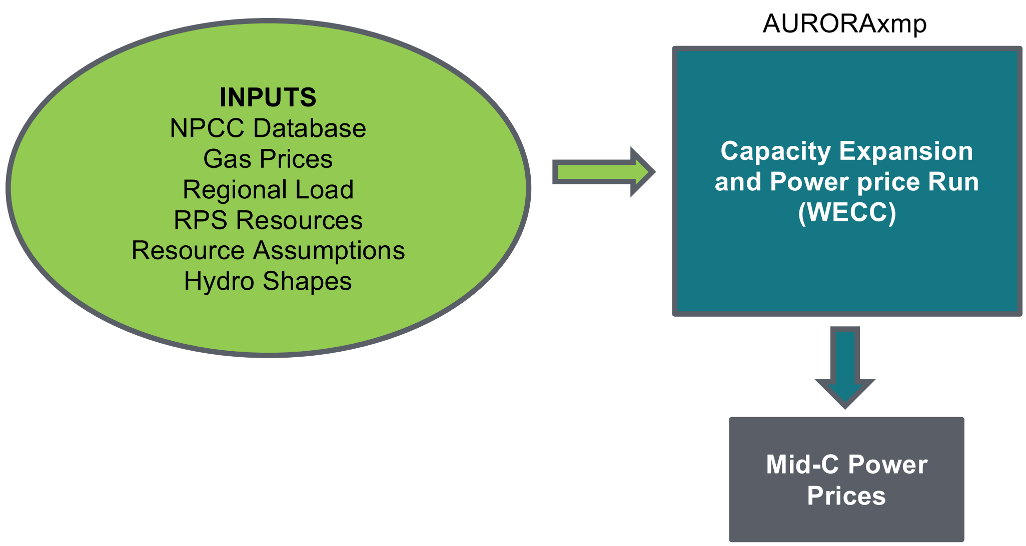
Figure N-1: Electric Analysis Methodology



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

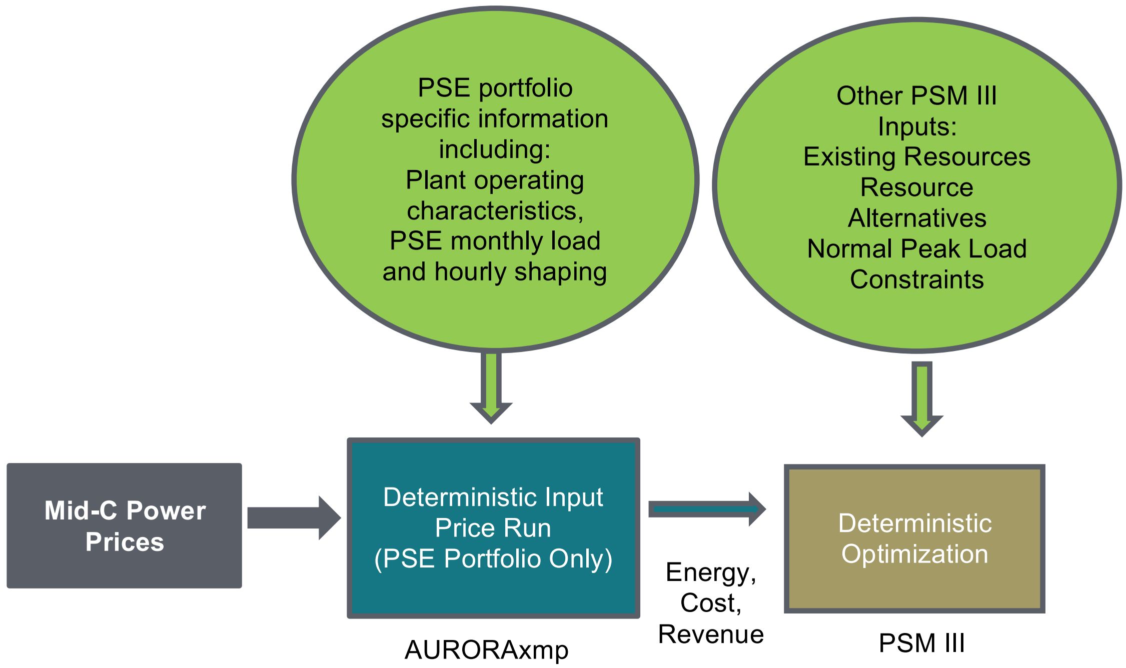


After all of the assumptions are collected and wholesale power prices have been created through AURORA, the next step is portfolio analysis.

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 the existing and generic resources. 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. For example, in the deterministic analysis for this IRP, the frame peaker was lowest cost resource addition in the Base Scenario portfolio, but many other scenarios included the CCCT in the lowest cost portfolio. When we perform the stochastic analysis, we find that the CCCT reduces the portfolio's risk, because it provides a benefit to the portfolio in many of the simulations; by running the stochastic analysis, we learn that balancing the portfolio with both peakers and CCCT plants is the better option. 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, 2016 through 2035.*

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.

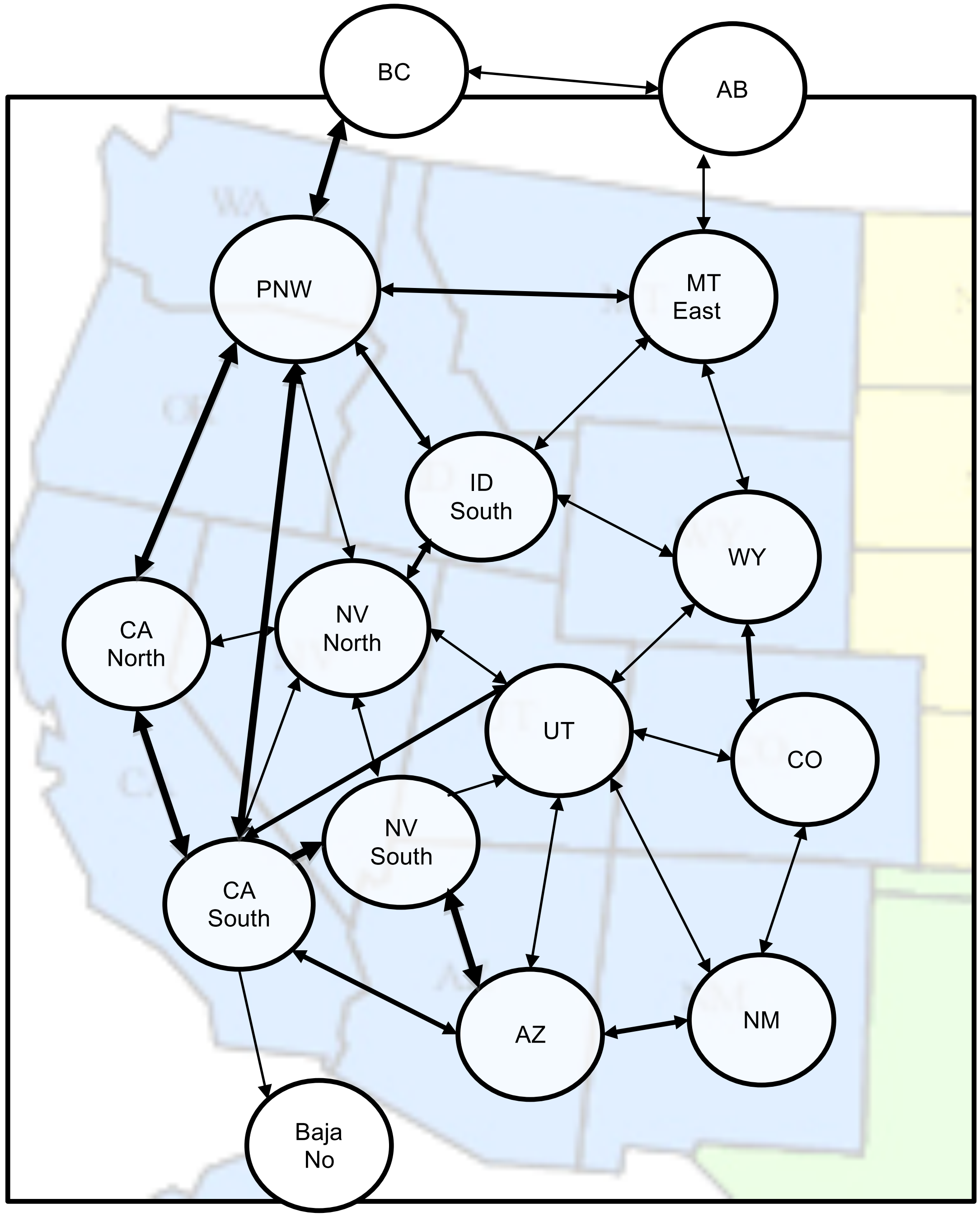
The following text was provided by EPIS, Inc. and edited by PSE.

> 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.

Portfolio Screening Model III

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

The solver used for the linear programming optimization is Frontline 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, and
7. renewable portfolio targets.

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 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 neededED 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 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

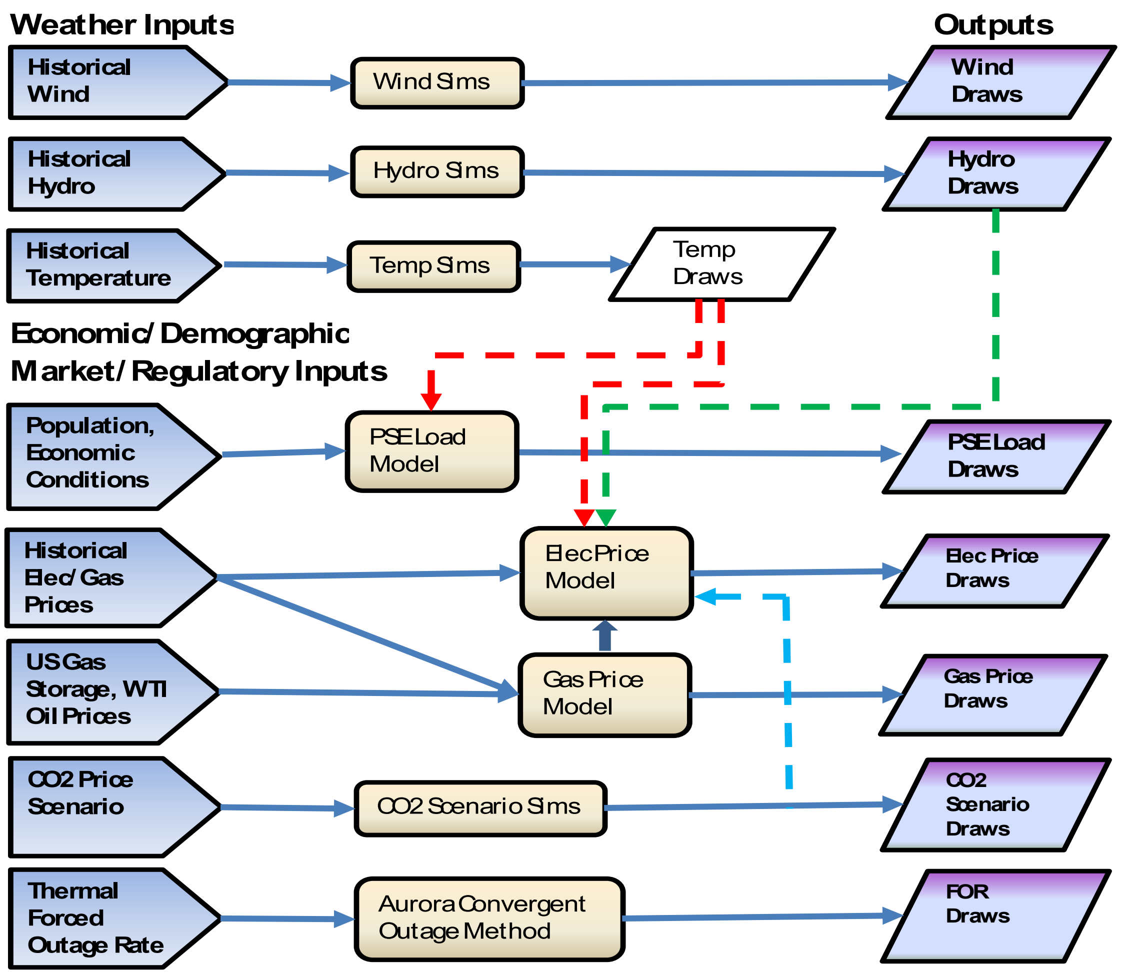
The goal of the stochastic modeling process is to understand the risks of alternative portfolios in terms of costs and revenue requirements. This process involves identifying and characterizing the likelihood of bad events and the likely adverse impacts of their occurrence for any given portfolio. The 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. The 250 unique annual temperature profiles were created synthetically. For each temperature profile, an annual hourly temperature shape was selected randomly from the 76 years worth of hourly shapes. Temperature simulations used were from two sets of data: a) 1929-1947 data from Portage Bay (near UW), and b) 1948-2005 data from SeaTac Airport. The heating degree days (HDDs) and cooling degree days (CDDs) were based on each temperature year simulation run through the demand forecast model to get the impacts on month/hourly profiles and use-per-customer. By this process, PSE is able to create an infinite amount of unique temperature profiles to test possible load outcomes. For the current IRP, 250 annual temperature profiles were generated. 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 were correlated with prices and loads.

The load forecast used in the deterministic portfolio scenario analysis is based on "normal" weather, where normal weather is defined as the average of the most recent last 30 years of weather data. The goal of this analysis is to use "normal" weather to forecast future loads, assuming the region experiences average weather each year. Loads forecast with "normal" weather were used in the base case scenarios of the portfolio analysis. PSE had hoped to explore different definitions of normal for the load forecast in this IRP, such as using the last 15 years instead of 30 years, but did not have time. The primary impact would be to change expected "normal" load, which may or may not have an impact on peak capacity need, but could impact renewable resource need, because it is a function of MWh energy sales.

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)

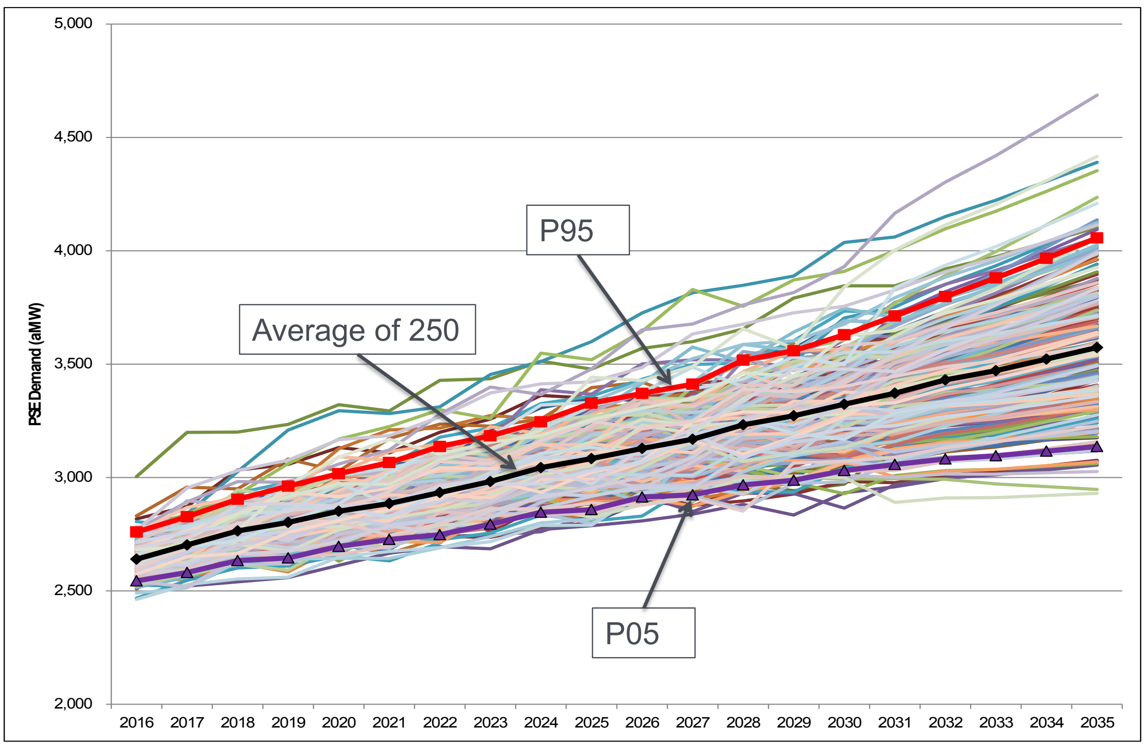
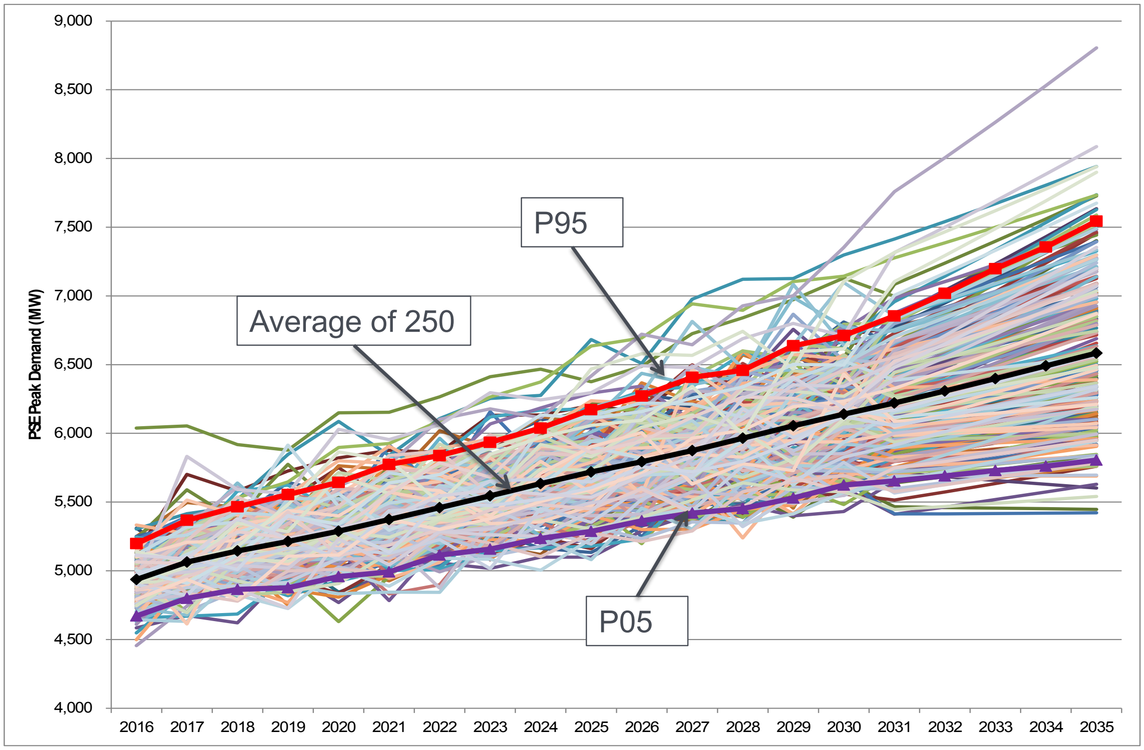


Figure N-7: Load Forecast Simulations – December 1-hour Peak (MW)



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)

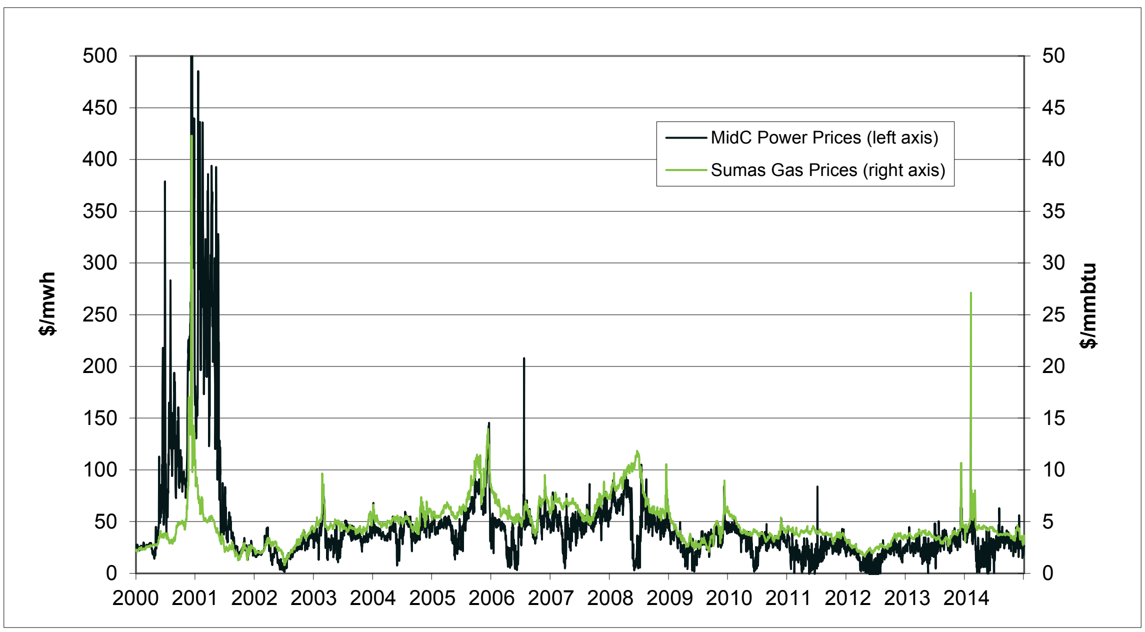
Mid-C Power Price = f(Sumas Gas Price, Regional Temperature Deviation from Normal, Mid-C Hydro Generation, Day of Week, Holidays)

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 2003 to December 2014. 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. The temperature simulations are consistent with those drawn for the load forecast, while the hydro simulations are consistent with those drawn directly from the 70-year historical hydro data as described below. 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 to 2010 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

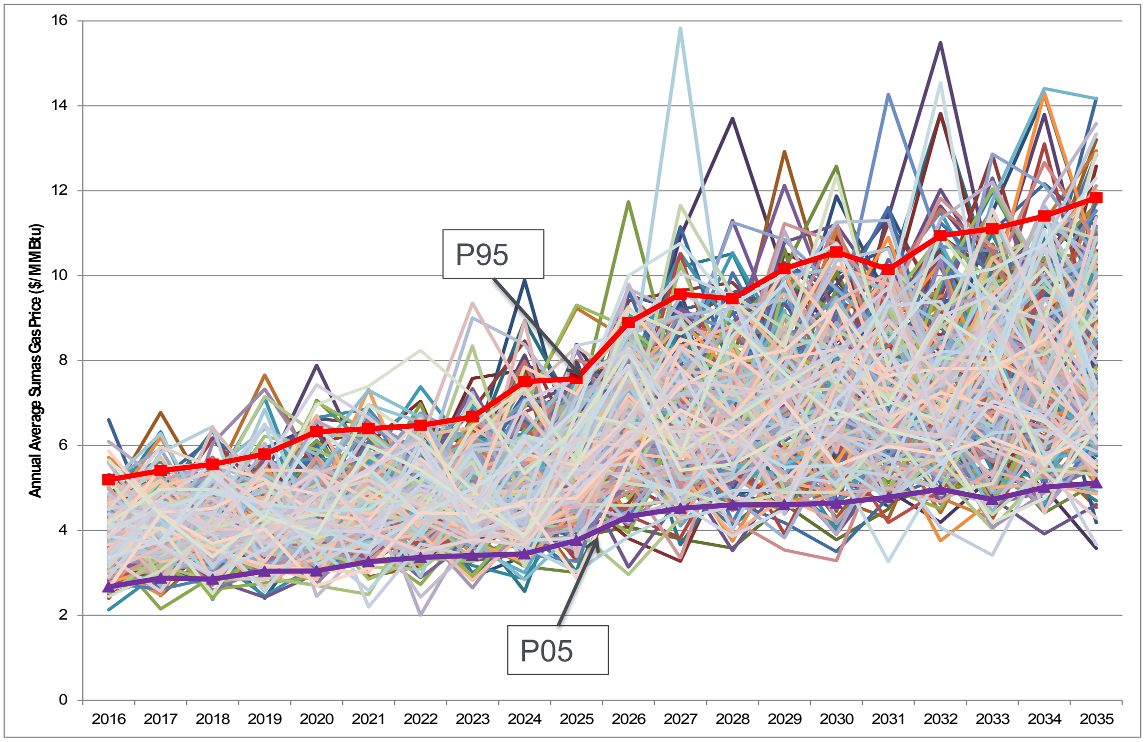
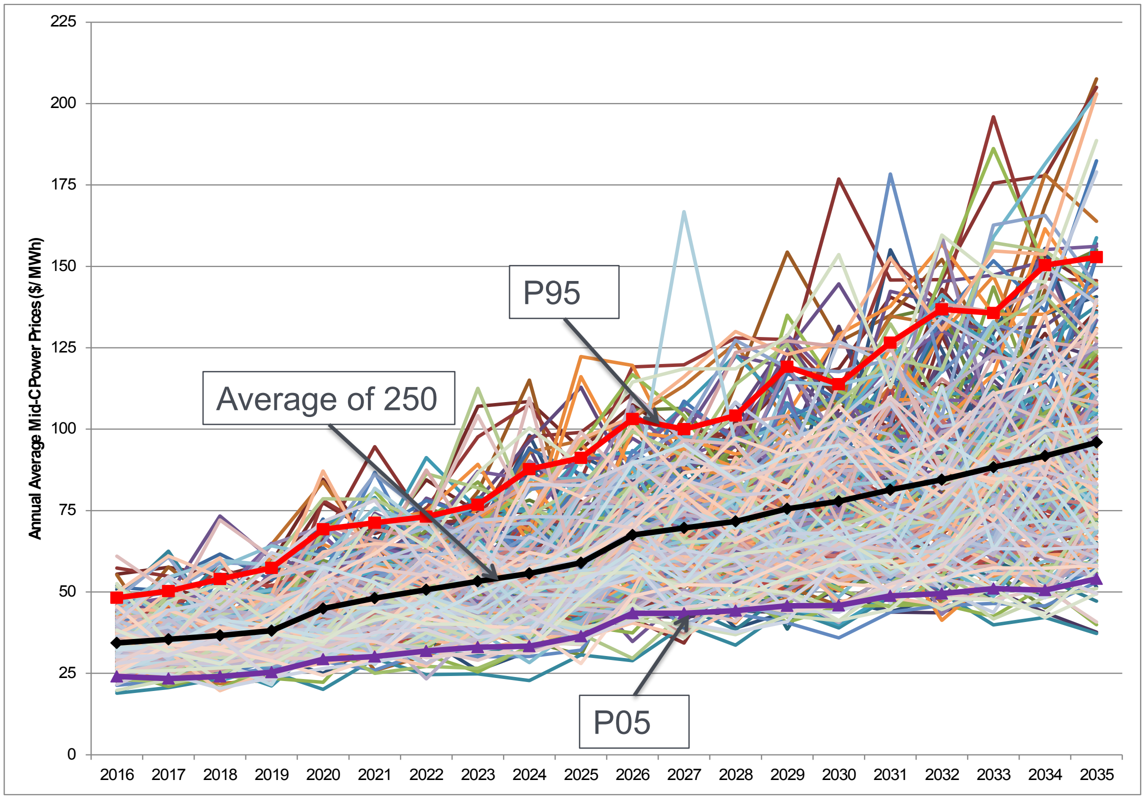
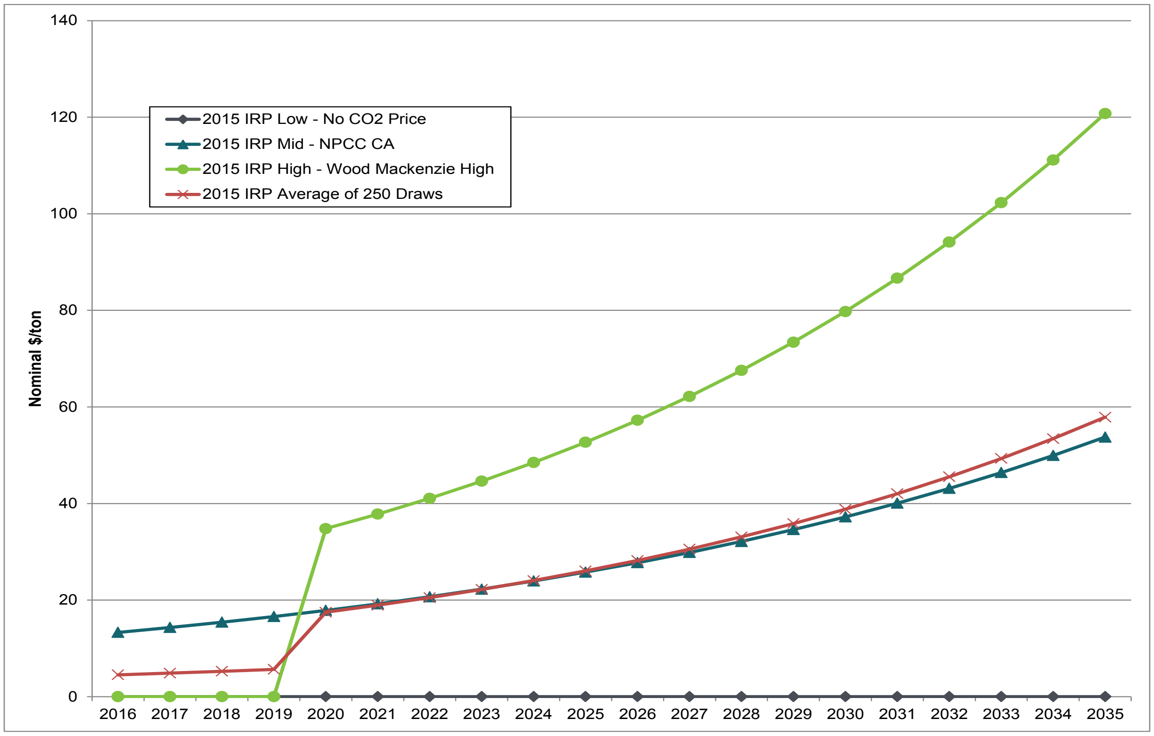


Figure N-10: Annual Mid-C Price Simulations



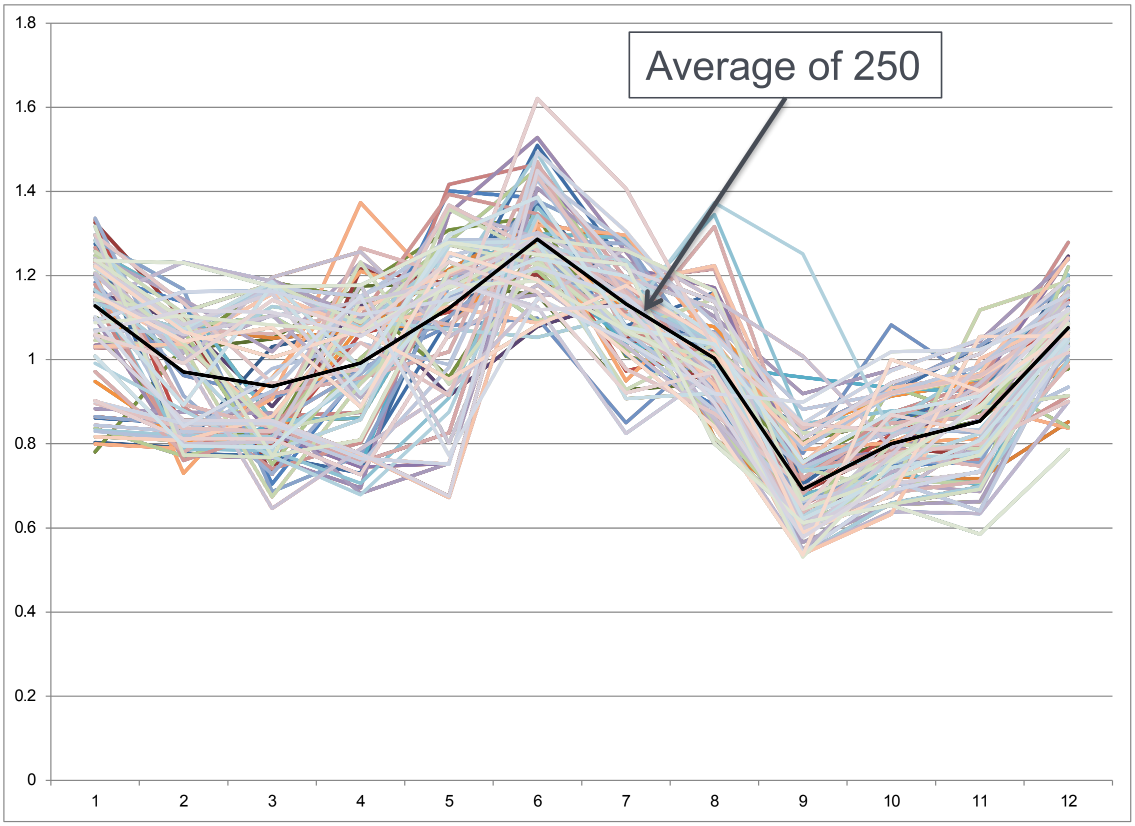
RISKS OF CO_2 PRICE. Because of the changes in legislative agenda in the last 2-3 years, there was greater uncertainty about whether a CO_2 policy would be implemented in the future. As a result, the risk of a CO_2 policy was modeled differently in this IRP. Given the possible range of CO_2 price per ton assumed in the deterministic scenarios as described in Chapter 4 and later in this appendix, subjective probabilities were assigned to each of these price scenarios representing their likelihood of being implemented. The three scenarios and their respective probabilities are No CO_2 – 33.3 percent, Mid CO_2 – 33.3 percent, and High CO_2 – 33.3 percent. The assigned probabilities still imply that there is greater than 50 percent chance of a positive CO_2 cost/price being imposed in the future for this risk study. Figure N-11 shows the annual CO_2 cost/price simulations with the weighted average of all simulations.

Figure N-11: Annual Mid-C Price Simulations with Weighted CO_2 Inputs



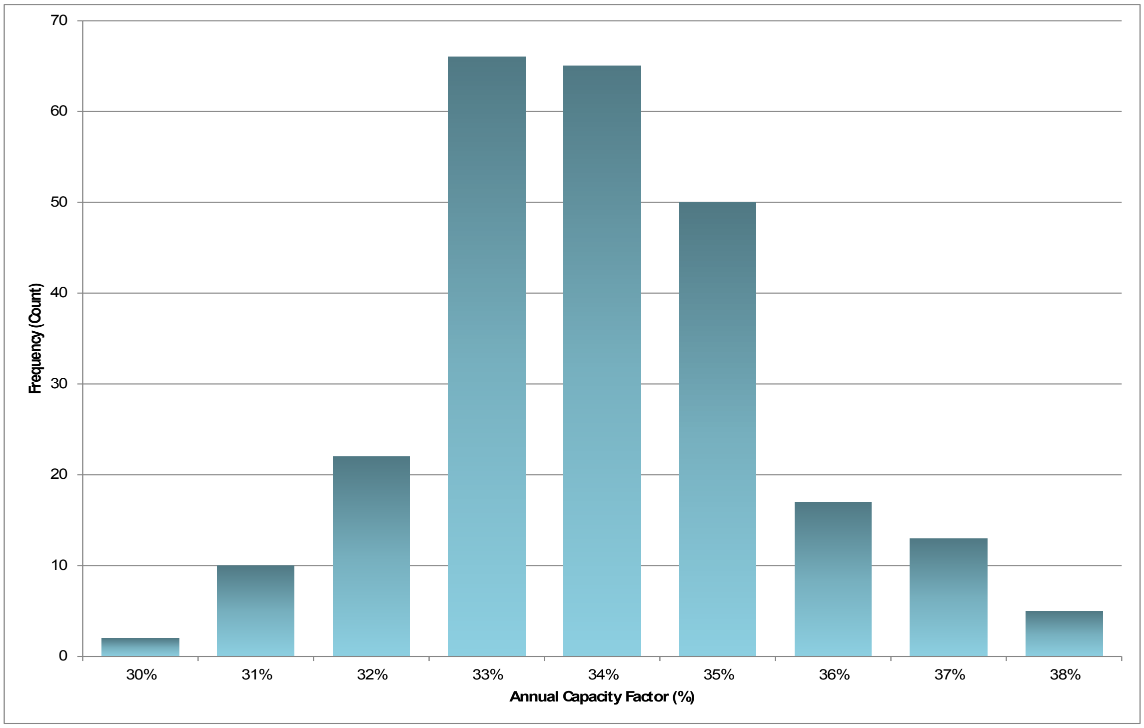
HYDRO GENERATION. Monte Carlo simulations for each of PSE's hydro projects were obtained using the 80-year historical Pacific Northwest Coordination Agreement Hydro Regulation data (1929-2008). Each hydro year is assumed to have an equal probability of being drawn in any given calendar year in the planning 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. 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. The wind distributions were derived from 9 years of historical data from Hopkins Ridge and Wild Horse. Given the limited historical data that is available to generate the 250 hourly wind profiles, 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. Since simulations for each month are based only on daily profiles within each month, the seasonality of wind generation is also preserved. Finally, simulations across wind farms are synchronized on a daily basis to preserve any correlations that may exist between Hopkins Ridge and Wild Horse. The Lower Snake River wind farm only has 2 years of operating data, so the data was filled out with the same wind profile as Hopkins Ridge, with a lag since it is located near Hopkins Ridge, and scaled to its nameplate capacity and pro-forma capacity factor. Finally, the generic wind farm is assumed to have a wind profile distribution similar to that of Hopkins Ridge and Lower Snake River, scaled to a 100 MW capacity. Again, a different set of 250 simulations is used for each of the calendar years in the planning horizon to ensure that there is also weather variation across years. Figure N-13 illustrates the frequency of the annual capacity factor for the generic wind project across all 250 simulations.

Figure N-13: Generic Washington Wind Simulations,
Frequency of Annual Capacity Factor for 250 Simulations



THERMAL PLANT FORCED OUTAGES. A new addition to the stochastic modeling for the 2015 IRP is simulation of the unplanned outages (forced outages) for the thermal plants for both existing and generic plants. This was modeled using the “Frequency Duration” outage method in AURORAxmp. The frequency duration outage method allows units to fail or return to service at any time-step within the simulation, not just at the beginning of a month or a day. The frequency and duration method assumes units are either fully available or completely out of service. The inputs needed are forced outage rate (FOR) and mean time to repair (MTTR) which is used to compute the mean time to fail. This data is based on the 5-year historical operations of the existing thermal plants. This method is for risk studies and does not guarantee to meet the FOR in one year, but the 250 simulations will average to the FOR. This results in different random outages each year.

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.

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 regions, and electricity is not traded 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 is traded and transported to and from these foreign areas, but is not traded with Texas, for example.

For modeling purposes, the WECC is divided into 16 areas, primarily by state and province, except for California which has three areas, Nevada which has two areas, and Oregon, Washington, Idaho and Montana, which combined have three areas. These areas approximate the actual economic areas in terms of market activity and transmission. The databases are organized by these areas and the economics of each area is determined uniquely.

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 EPIS's 2012.01 version produced in January 2012 with updates to include coal plant retirements, new WECC builds not included in the database and the California Once-Through-Cooling (OTC) plant retirements. 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. EPIS updates the model to include known upgrades (e.g., Path 15 in California) but the model does not add new transmission "as needed."

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 2015 IRP, load forecasts for Oregon, Washington, Montana and Idaho were based on the Northwest Power and Conservation Council (NPCC) 2013 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 2014 from Wood Mackenzie, and forecasts developed by the NPCC. 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. The NPCC focuses on energy planning issues in the Northwest region. Four gas price forecasts are used in the scenario analysis:

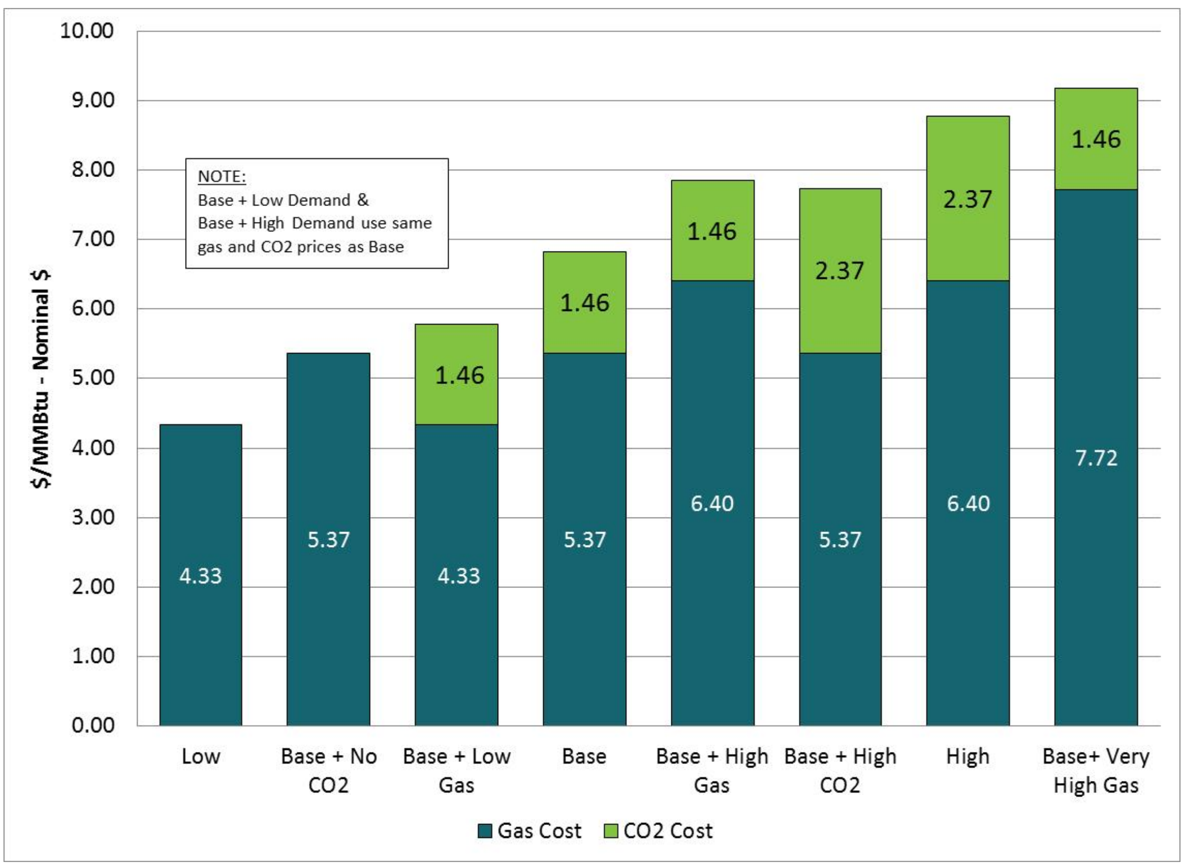
LOW GAS PRICES. These reflect Wood Mackenzie's long-term low price forecast for 2016-2035.

MID GAS PRICES. From 2016-2019, this IRP uses the three-month average of forward marks for the period ending November 14, 2014. Forward marks reflect the price of gas being purchased at a given point in time for future delivery. Beyond 2019, this IRP uses Wood Mackenzie long-run, fundamentals-based gas price forecasts. The Base Scenario uses this forecast.

HIGH GAS PRICES. These reflect Wood Mackenzie's long-term high price forecast for 2016-2035.

VERY HIGH GAS PRICES. This forecast reflects the NPCC high gas price forecast developed in July 2014.

Figure N-14: Levelized Gas Prices by Scenario
(Sumas Hub, 20-year levelized 2016-2035, nominal $)



CO_2 Price. To model uncertainty around CO_2 prices, PSE developed the following estimates as inputs. These estimates reflect the potential for CO_2 price regulation and how that might affect resource decisions, rather than incorporating the societal cost of carbon emissions as an externality. The annual CO_2 prices modeled are presented in Figure N-15.

NO FEDERAL CO_2 PRICE. $0 PER TON. The lowest CO_2 price used in the 2015 IRP assumes no federal CO_2 price, but does include an NPCC forecast of California CO_2 prices based on the California Global Warming Solutions Act of 2006 (AB32).[2] This CO_2 price is applied to power plants located in California.

MID CO_2 PRICE. $13 PER TON IN 2016 TO $54 PER TON IN 2035. This estimate is based on NPCC's estimated CO_2 price for California AB32 and is applied as a federal CO_2 price to all resources.

HIGH CO_2 PRICE. $35 PER TON IN 2020 TO $120 PER TON IN 2035. This estimate of federal CO_2 price comes from the Wood Mackenzie high gas price forecast; California CO_2 price are increased to match federal CO_2 price.

2 / *See Appendix C, Environmental Matters, for more details on the California Global Warming Solutions Act.*

Figure N-15: Annual CO_2 Costs (Nominal $/Ton)

	Low	Base	High
2016	-	13.31	-
2017	-	14.32	-
2018	-	15.41	-
2019	-	16.59	-
2020	-	17.85	34.79
2021	-	19.22	37.80
2022	-	20.68	41.07
2023	-	22.26	44.62
2024	-	23.96	48.48
2025	-	25.78	52.68
2026	-	27.75	57.23
2027	-	29.86	62.18
2028	-	32.14	67.56
2029	-	34.59	73.41
2030	-	37.23	79.76
2031	-	40.07	86.65
2032	-	43.12	94.15
2033	-	46.41	102.29
2034	-	49.95	111.14
2035	-	53.76	120.76

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 Northwest Power and Conservation Council Sixth Power Plan database was used in this IRP, which includes planned coal power plant retirement. We also added 1,860 MW coal retirement based on coal retirement report from SNL Energy as of Oct. 2014. In addition, the High, Base + Low Gas Price, and Base + High CO_2 Scenarios were allowed to retire coal power plants economically in AURORA. In these three cases, low natural gas prices or high CO_2 prices tended to lower the capacity factor of coal power plants. Therefore, coal power plants which had less than a 40 percent capacity factor were allowed to retire in AURORA's long-term run. Planned retirements and AURORA-assumed retirements are shown in tables N-16 and N-17 below.

Figure N-16: Planned Coal Retirements across WECC

Planned Coal Retirement (2014 -2035)	MW
Planned Retirement (California)	1,555
Planned Retirement (Pacific Northwest, USA)	2,079
Planned Retirement (Pacific Northwest, CAN)	3,949
Planned Retirement (Rocky Mountain)	1,425
Planned Retirement (Southwest)	608
Total Planned Retirement	**9,616**

Figure N-17: Assumed Coal Retirements across WECC

Assumed Coal Retirement (2014 -2035)	MW
Assumed coal Retirement (High)	7,036
Assumed coal Retirement (Base + Low Gas)	7,245
Assumed coal Retirement (Base + High CO2)	7,432

Natural Gas-fired Power Plant Retirements. Planned natural gas power plant retirements by year and region are shown in table N-18 below. Most of the natural gas-fired power plants will retire before the end of 2025. Among the 10,869 MW retirements, 9,164 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. We followed the retirement/replacement schedule of the CA OTC plants from the WECC Transmission Expansion Planning Policy Committee (TEPPC) 2022 Common Case and Los Angeles Department of Water and Power (LADWP) Implementation Plan April 2011.

Figure N-18: Planned Natural Gas Retirements in WECC

Planned Nature Gas Retirement	MW
Planned Retirement (California)	9,164
Planned Retirement (Pacific Northwest, USA)	0
Planned Retirement (Pacific Northwest, CAN)	1,065
Planned Retirement (Rocky Mountain)	65
Planned Retirement (Southwest)	575
Total Planned Retirement	10,869

WECC Builds. We used the NPCC's draft 7 power plan database, but added 1,619 MW of new natural gas plant builds in WECC region, based on the data from the SNL Energy database[3] as of September 2014. Figure N-19 provides the new build capacity for each of the WECC sub-regions.

Figure N-19: Planned New Builds in WECC

MW Nameplate	California	Pacific Northwest (USA)	Pacific Northwest (CAN)	Southwest	Rocky Mountain	Total
Solar	1,694	-	-	624	110	2,428
Other Renewables	49	732*	1,421	-	-	2,202
Wind	19	267	445	-	250	981
Thermal	5,989	1,212	1,125	242	1,330	9,898
Total	7,751	2,210	2,991	866	1,690	15,508

**732 MW is the upgraded capacity for Wanapum*

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 areview for reasonableness, these resources are created in the AURORA database. Technologies included wind, solar, biomass and geothermal.

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.

3 / 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).

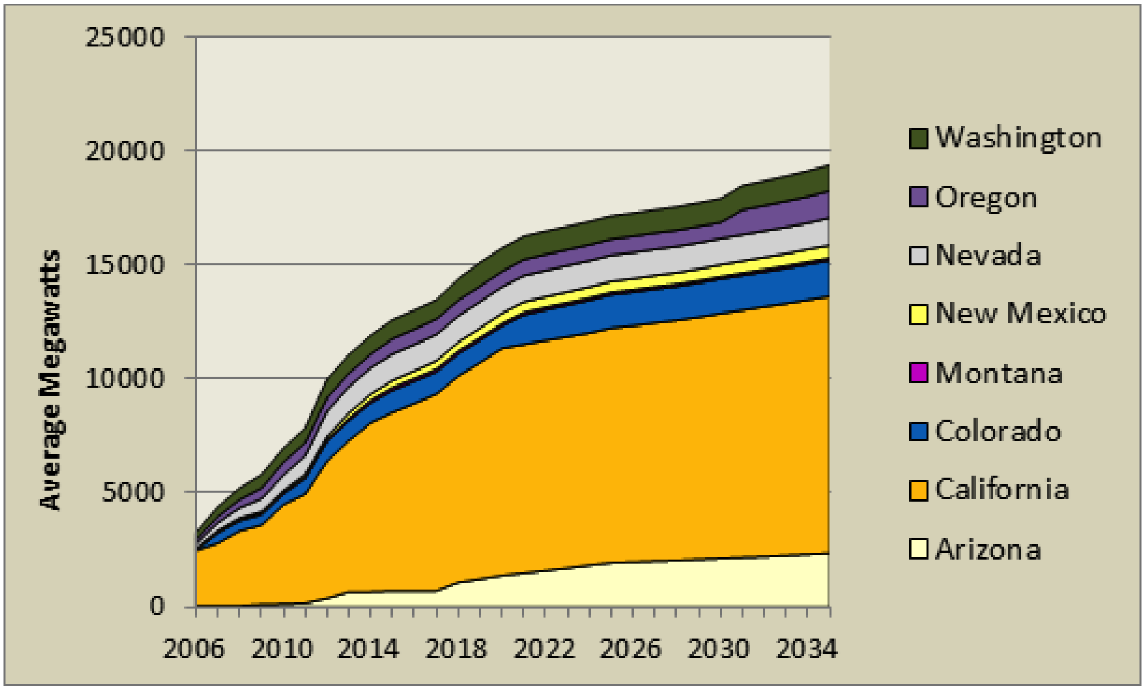
Figure N-20: RPS Requirements for States in WECC

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	Large utility targets: 5% in 2011, 15% in 2015, 20% in 2020 and 25% in 2025. Large utility sales represented 73% of total sales in 2002. Medium utilities 10% by 2025. Small utilities 5% by 2025.	We followed the 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 RPS: 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.

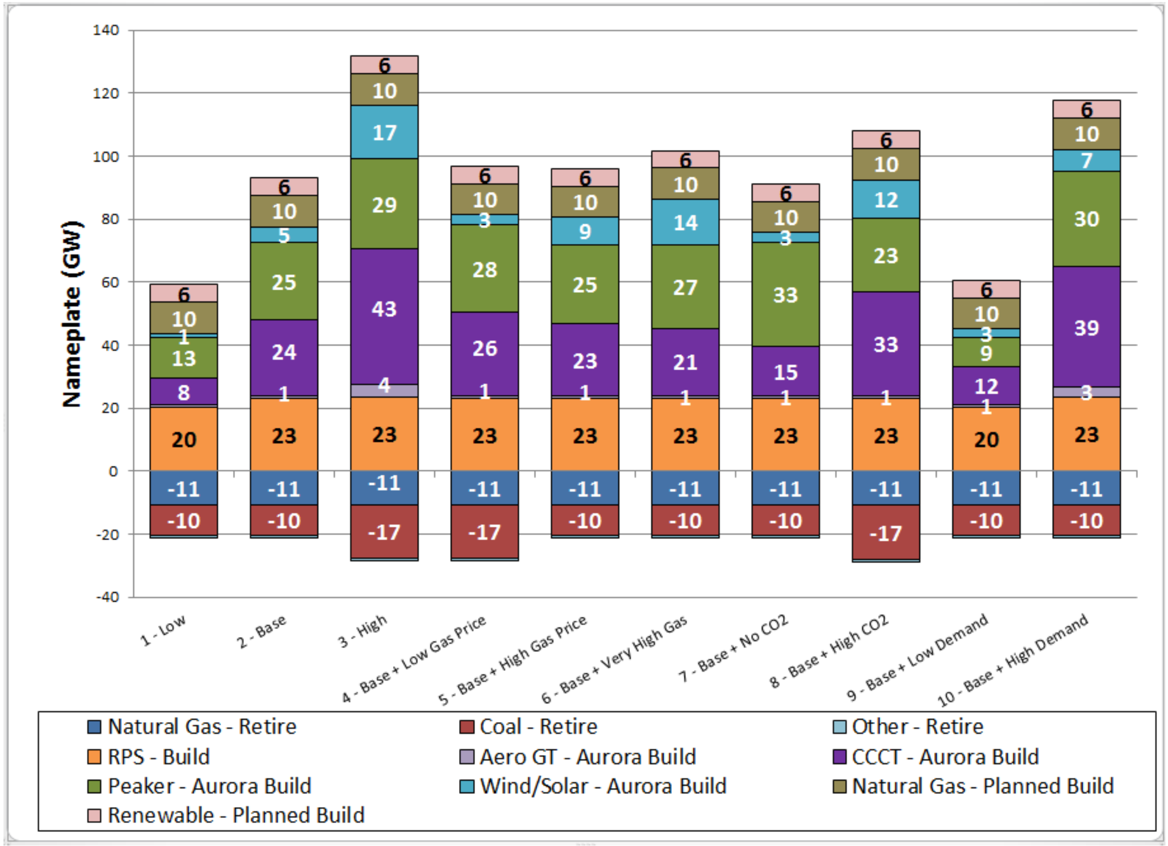
In order to reflect RPS requirements in the 20-year planning horizon, renewable resource capacities were calculated and they were treated as new resources in the AURORA resource table.

Figure N-21: 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-21 shows AURORAxmp builds in 10 scenarios along with planned, retired and RPS capacity described above for both the U.S. and Canada WECC.

Figure N-22: WECC Total Builds/Retirements by 2035



Production Tax Credit Assumptions. The Production Tax Credit (PTC) is a subsidy identified in the American Recovery and Reinvestment Act of 2009 (ARRA) for production of renewable energy. In January 2013, the American Taxpayer Relief Act of 2012 (H.R. 6, Sec. 407) removed the "placed in service dates" for eligibility and replaced this language with "begins construction in 2013." Currently, the PTC amounts to approximately $22 (in 2012 dollars) per MWh for 10 years of production after a project is placed into service. The PTC is indexed for inflation. The Base Scenario assumes no further PTCs are available for new resource development as of 2014.

Investment Tax Credit Assumptions. The Investment Tax Credit (ITC) currently amounts to 30 percent of the eligible capital cost for renewable resources; it expires at the end of 2013. These scenarios assume no extension of ITCs.

Treasury Grant Assumptions. The Treasury Grant (Grant) is subsidy that amounts to 30 percent of the eligible capital cost for renewable resources; it also expires 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 2013 Expedited Rate Filing (ERF) of 7.77 percent nominal or 6.7 percent after-tax.

REC Price. The REC price starts at $4.25 per MWh in 2016 and escalates to $14.85 per MWh in 2035. The escalation rate is not uniform for the whole 20-year planning horizon. A major increase occurs in 2020 with an approximate 124 percent increase, corresponding to the RPS increase. All other years use a 2.5 percent escalation.

Inflation Rate. The 2015 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 have been increasing at approximately 1.25 percent annually.

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 (measured in MW) is determined as:

Planning Margin = (Generation Capacity – Normal Peak Loads)/Normal Peak Loads.

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 (thermal, wind, energy storage, wholesale market purchases, etc.) towards meeting PSE's firm peak loads.

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 supply-side resources that are subject to random production patterns and to express those contributions in equivalent terms (i.e. incremental capacity equivalents or ICE). 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.

In previous IRPs, PSE has treated its reliance on wholesale market purchases as a known and firm capacity resource in its resource adequacy model; in other words, wholesale market purchases were assumed to be available in any amount at any time. This assumption was primarily based upon the NW Regional Resource Adequacy Forum's finding that the Pacific Northwest had adequate resources available to meet the region's peak load planning standard for approximately the next five to seven year period. However, with the impending closure of the 585 MW Boardman coal plant and the 730 MW Centralia Unit 1 in 2020 followed by the closure of the 730 MW Centralia Unit 2 in 2025, the Northwest Power and Conservation Council's Resource Adequacy Advisory Committee has determined that the region could be capacity deficient in the winter of 2020-21 based upon the results of the Council's GENESYS regional resource adequacy model. Given this assessment, PSE updated its resource adequacy model to make it more consistent with the assumptions incorporated into the NPCC's regional resource adequacy model, especially with respect to assumptions regarding the firmness of PSE's wholesale market purchases under peak load conditions. Appendix G provides a more detailed discussion of how the market reliance-related inputs into PSE's resource adequacy model were developed.

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 resources included in this analysis are Colstrip, Mid-Columbia purchase contracts and western Washington hydroelectric resources, several gas-fired plants (simple-cycle and combined-cycle combustion turbines), long-term firm purchased power contracts, several wind projects, and short-term wholesale (i.e., "spot") market purchases up to PSE's available firm transmission import capability from the Mid-C.

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, and 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. Loads are further adjusted for conservation savings where the weather-sensitive savings vary by the temperature simulation.

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) to 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 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 on-line dispatched generation in reserve, in case any member experiences an unplanned generating plant outage. 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, 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 duration and is the sum of the hours with load curtailments divided by the number of simulations. Capacity planning margins and incremental capacity equivalents 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. As described in Chapters 2 and 6, this IRP utilizes a new planning standard that optimizes the value of reliability to customers while incorporating wholesale market purchase risk.[4] The 2015 Optimal Planning Standard utilizes the expected unserved energy (EUE) since this metric provides a quantifiable measure (in MWh) of the magnitude of load curtailment events, which in turn serves as the basis for determining the financial impacts of outages on PSE's customers through a value of lost load (VOLL) computation. By comparison, the 2013 planning standard utilized a LOLP target metric (which provides no information about either the magnitude or duration of customer curtailment events), and furthermore, it did not incorporate wholesale market purchase risk.[5]

Value of Lost Load. Value of lost load (VOLL) is utilized in the 2015 Optimal Planning Standard to determine the optimal EUE target for the PSE system based upon an evaluation of the cost of adding generating resources to increase service reliability compared to the cost to customers of potential outages. In other words, VOLL quantifies the benefit to customers of experiencing a higher level of electric service reliability, so that it can be compared to the cost of providing that level of reliability.

4 / Subsequent references to the "2015 Optimal Planning Standard" in this Appendix infer that wholesale market purchase risk is incorporated into the standard.
5 / Subsequent references to the "2013 Planning Standard" in this Appendix infer that wholesale market purchase risk is not incorporated into the standard.

VOLL is typically derived from customer surveys. A well-designed survey is sometimes difficult to implement since the cost/value placed on an electric service interruption by a customer could be biased by a number of factors, plus these values could change over time and/or be seasonal in nature. Also, different types of customers (i.e. industrial, commercial, residential) are likely to have significantly different assessments of the value of avoiding a service interruption.

Notwithstanding the above issues, VOLL is a critical input for electric utilities in determining the appropriate EUE-based target for long-term peak load planning. A lower EUE target implies a smaller magnitude and lower expected frequency of load curtailments and therefore a higher level of reliability, but this condition can only be achieved by investing in additional capacity resources. Increasing investment to achieve higher system reliability must be balanced against the benefits that customers gain from a reduced probability of load curtailments. The point where the incremental benefits of increasing reliability (the marginal benefits) equals the associated incremental costs (marginal costs) of adding more firm capacity determines the “correct” or “optimal” EUE target level.

VOLL for the PSE System. The value of lost load for PSE was derived from the US Department of Energy’s (DOE) Interruption Cost Estimator (ICE Calculator) which was based on the Lawrence Berkeley Laboratory study titled “Updated Value of Service Reliability for Electric Utility Customers in the United States," by Michael J. Sullivan, Ph.D., Josh Schellenberg, and Marshall Blundell, Nexant, Inc., Ernest Orlando Lawrence Berkeley National Laboratory LBNL-6941E, June 2009. This study provided estimates of interruption costs per customer for each event and length of outage duration by customer class (residential, small commercial and industrial, medium and large commercial and industrial), for each of the states in the U.S. The challenge for PSE was in converting these customer class outage cost estimates – as reported on a per MW loss basis by outage duration – into aggregated system-wide metrics for use in the RAM (which analyzes the PSE system as a whole and not by individual customer class). However, the DOE’s ICE Calculator provides a mechanism for estimating the average annual energy consumption by customer class. Coupled with PSE’s assumptions about load factors and customer class contribution to peak load,[6] one can calculate a per-customer peak load contribution (measured in kW), averaged across all customer classes. This value was then used to compute the expected number of PSE customers affected by a given load curtailment event.

Next, an average interruption cost per event across all customer types was calculated for each event duration as identified in DOE’s ICE Calculator (i.e., durations of 1 hour, 2 hours,…, 8 hours and above). In performing these computations, we applied the interruption cost for the 8 hours and above duration for any event with duration of 8 or more hours. The interruption costs by

6 / Customer Peak Load Shares – from the PSE Rate Department’s “Peak Contribution by Rate Class, Dec 2010” customer class in Washington State were inflation adjusted to the 2020 study period. To obtain an average interruption cost across all customer classes, we used PSE's estimated customer class contribution to winter peak load shares. This average interruption cost per event by duration reflects customers' value of lost load since this is the cost that would be avoided in the absence of a load outage. For each duration length, this value is multiplied by the unserved energy for each curtailment event. Figure N-22 below shows the VOLL for an average PSE customer for a one-hour outage duration.

Figure N-23: Interruption Cost Calculation of an Average PSE Customer per Event of One-hour Duration

Customer Type	Number of Customers	Per Customer InterrCost per Event - 2011$	Per Customer InterrCost per AvgKW/Hr - 2011$	Implied Avg KW per Yr(Flat)	PSE Load Factors	Peak KW/Yr	PSE Peak Shares	Avg Peak per Yr per Cust, KW
	Year End 2020	**1HR Duration**	**1HR Duration**					
Medium&Large C&I	10,889	$4,122.40	$27.80	148.3	1.47	218	0.2	43.6
Small Comm&Ind	126,531	$758.90	$179.70	4.2	1.42	6	0.1	0.6
Residential	1,060,975	$2.80	$1.90	1.5	2.05	3	0.7	2.1
All Customers	1,198,395	**$120.06**	$38.76	3.1	1.71	5.3		**46.3**
Interr Cost Aver Per Cust per Hr($2020)		**$149.94**						

The implied 2020 per customer interruption cost from Figure N-22 is $3.24 per kWh (equal to $149.94 per customer for a one-hour outage event divided by an average peak load of 46.3 kW per customer). The hourly per-customer interruption cost increases as the duration of the outage increases, but at a declining rate, and it declines slightly after the duration exceeds 7 hours.

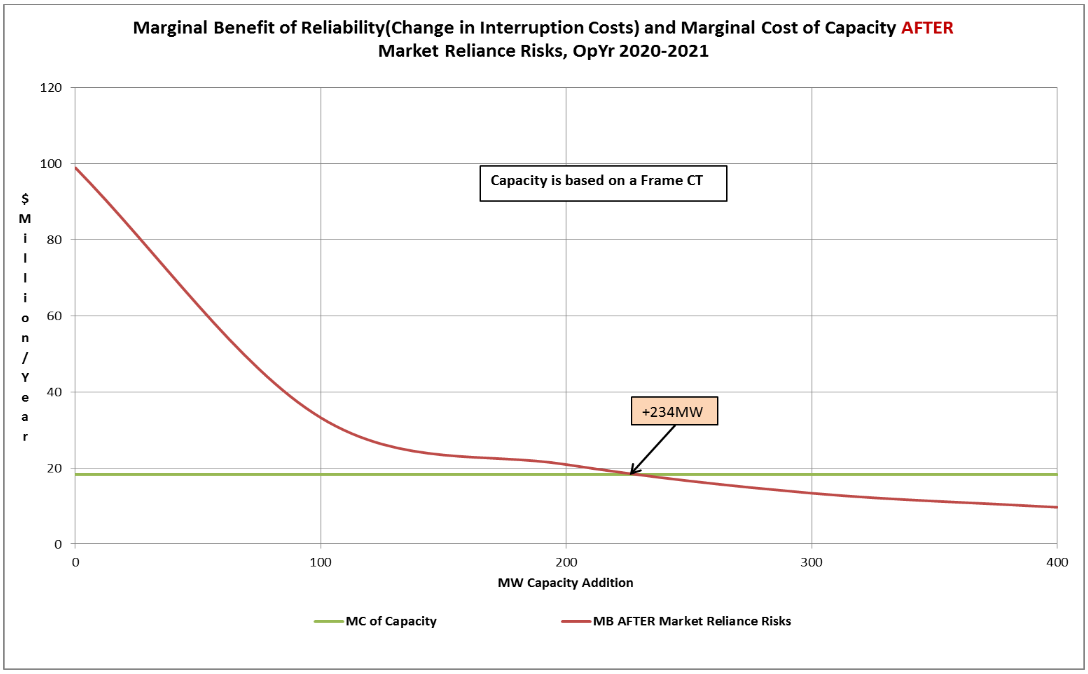
Optimizing Customer Reliability Benefits. The customer value of lost load is summed across all curtailment events in the year, and then averaged over 6,160 simulations to get the expected annual value of lost load for any given level of EUE. As we add gas-fired peaking plants to PSE's portfolio in increments of 100 MW, service reliability increases which results in lower calculated levels of EUE and VOLL. The reduction in the VOLL (measured in dollars) for the PSE system as new capacity is added to the portfolio is the marginal benefit of reliability. The relationship between the annual value of lost load and lower EUE (i.e., increasing reliability) as new peaking plant capacity is added can be shown as a downward sloping curve; alternatively, the incremental benefit of increasing reliability is positive but a declining function of the added capacity.

In this study, to achieve different levels of EUE, a gas-fired simple-cycle CT is added to the system since previous IRPs have shown this is the cheapest generation technology available to meet PSE's peak load needs. The present value of the net costs[7] of the incremental peaking plant is levelized over its life and the life of a replacement peaker to obtain an annualized peaker cost on a per MW basis, expressed in 2020 dollars. These costs were obtained from PSE's PSM model using 2015 IRP assumptions. Given these costs, an upward sloping curve is derived showing the relationship between annual costs of the total peaking capacity added and the associated EUE levels for PSE's system. The incremental cost of increasing reliability, however, is a flat line since the annualized cost per MW of adding additional peaking capacity is constant.

Figure N-24 shows the marginal benefit and marginal cost of reliability as new generating capacity is added and reliability is increased (and EUE declines) before and after incorporating wholesale market purchase risk. The intersection points of the horizontal cost line and the downward sloping benefit curves determines the optimal level of EUE since these points represent the minimum total costs of reliability (VOLL + resource costs). Reflecting wholesale market purchase risk in the study results in more occurrences and higher volumes of PSE load curtailments, therefore the value of lost loads in this case is higher. Consequently, the marginal benefit of increasing reliability by adding capacity is higher compared to ignoring wholesale market purchase risks. Thus, PSE's optimal level of capacity additions, based on its customers' value of lost load, is higher after reflecting wholesale market purchase risk.

7 / Net cost = fixed costs + variable costs – revenue + end effects + replacement costs

Figure N-24: Customer VOLL Optimal Capacity Additions



The VOLL-based optimal capacity additions imply different EUE levels compared to the 5 percent LOLP standard that was used in the 2013 IRP. Because the 5 percent LOLP target utilized in the 2013 Planning Standard does not account for the optimal level of customer reliability, the EUEs implied are higher (which indicates lower reliability) as compared to the EUEs obtained by the 2015 Optimal Planning Standard in which customers' VOLL and the costs of increasing reliability are accounted for. Figure N-25 compares the 2013 Planning Standard, the 2013 Planning Standard with wholesale market risk, and the 2015 Optimal Planning Standard.

Figure N-25: Comparison of the 2013 Planning Standard, the 2013 Planning Standard with Wholesale Market Risk, and the 2015 Optimal Planning Standard

	LOLP	EUE (MWh)	Planning Margin	2021 Capacity Added (MW)	Expected VOLL ($mill/yr)	TVar90 VOLL ($mill/yr)
2013 Planning Standard	5%*	26	13%	(150)	86	858
2013 Planning Standard with Market Risk	5%*	50	13.8%	(117)	169	1,691
2015 Optimal Planning Standard	1%	10.9*	20.0%	234	39	385

** Target Metric*

Figure N-25 also shows the different risk metrics for the different planning standards. The following key conclusions can be derived from these results.

1. After reflecting wholesale market risk, the change in capacity needed to maintain the 2013 Planning Standard's 5 percent LOLP target is small (from -150 MW to -117 MW); however, this is because the LOLP target focuses only the frequency or likelihood of load curtailments. Expected unserved energy (EUE) more than doubles, from 26 MWh to 50 MWh, indicating a significant increase the magnitude of potential load curtailments. Note that PSE's portfolio is surplus under the 5 percent LOLP target, hence, the negative capacity adjustments needed to maintain this standard.

2. The EUEs implied by the 2013 Planning Standard's 5 percent LOLP target are higher than those based on customers' optimal value of reliability because the 5 percent LOLP target ignores the additional benefits and costs of higher or lower levels of customer reliability .

3. The change in planning margin is small between the 2013 Planning Standard and the 2013 Planning Standard with market risk case since the change in capacity needed to maintain the 5 percent LOLP is small (33 MW=(-117 MW - -150 MW).

4. Figure N-24 also shows the expected VOLL and the TailVar90 of VOLL for the 2013 Planning Standard, the 2013 Planning Standard with wholesale market risk, and the 2015 Optimal Planning Standard. The expected VOLLs under the 2013 Planning Standard and the 2013 Planning Standard with market risk (5 percent LOLP) are always higher than the 2015 Optimal Planning Standard (customer optimal level of reliability).. This is because the EUEs from the 2013 Planning Standard and 2013 Planning Standard with market risk are higher, or the implied customer reliability levels are lower. The change in the

TailVar90 also shows the potential magnitude of further risk reduction as a result of adopting the customer optimal reliability metric.

5. The gross benefit to PSE's customers of increasing reliability under the 2015 Optimal Planning Standard – by adding 234 MW of gas-fired CT generating capacity to PSE's resource portfolio and reducing annual EUE from 50 MWh to 10.9 MWh – is $130 million per year, while the cost associated with the added capacity is $63 million per year. The net benefit to customers of increasing reliability is therefore $67 million per year. As discussed, this represents the economically efficient point where marginal benefits equals marginal costs; adding more or less new capacity to the portfolio would result in a lower level of net benefits to customers.

While the 2015 Optimal Planning Standard adopted by PSE in this IRP includes wholesale market purchase risk by definition, it may also be instructive to view the risk metrics of an alternate case that does not include the impacts of market risk. These metrics are summarized in Figure N-25. Note, by ignoring wholesale market risk, the VOLL and capacity additions need to maintain a 3 MWh EUE are both significantly understated, which is apparent when comparing to Figure N-25, above.

Figure N-26: 2015 Optimal Planning Standard without Wholesale Market Risk

	LOLP	EUE(MWh)	Planning Margin	2021 Capacity Need (MW)	Expected VOLL $mill/yr	TVar90 VOLL $mill/yr
2015 Optimal Planning Standard without Market Risk	1.7%	**3**	17.7%	97	10	96
	Target Metrics					

The following key conclusions can be derived from the results shown in Figures N-25 and N-26:

1. Before reflecting wholesale market purchase risk in the 2015 Optimal Planning Standard but still accounting for customers' benefits and costs of reliability (by linking customer interruption costs to VOLL and the resource costs associated with increasing reliability) leads to a lower EUE (from 26 MWh to 3 MWh) and lower LOLP (from 5.0 percent to 1.7 percent). The EUE of 3 MWh is associated with the optimal capacity addition of 97 MW as indicated in Figure N-26.

2. After reflecting wholesale market purchase risk, the optimal EUE for the 2015 Planning Standard is higher because the higher levels of risk require higher expenditures to maintain the desired reliability. Thus, the optimal EUE level rises from 3 MWh to 10.9 MWh. (10.9 MWh of EUE is obtained by adding 234 MW of capacity to the existing portfolio.) At the optimal EUE levels, the associated LOLPs are lower than 5 percent (1.7 percent for the 2015 Optimal Planning Standard excluding wholesale market risks and 1.0 percent for the 2015 Optimal Planning Standard).

3. For the 2015 Optimal Planning Standard (which is based upon the optimal EUE level), the capacity addition needed to obtain the customer optimal reliability level is 137 MW higher (= 234 MW – 97 MW) than in the 2015 Optimal Planning Standard without wholesale market risk case. Therefore, the planning margin rises from 17.7 percent to 20.0 percent (referenced to 2021 conditions).

Incremental Capacity Equivalents of Resources. The incremental capacity credits assigned to PSE's existing and prospective resources were developed by applying the incremental capacity equivalent (ICE) approach[8] in the RAM. In essence, the ICE approach identifies the equivalent capacity of a gas-fired peaking plant that would yield the same customer optimal EUE level as the capacity of a different resource such as a wind farm, energy storage facility, Colstrip or wholesale market purchases using PSE's available firm Mid-C transmission import rights. The ratio of the equivalent gas peaker capacity to the alternative resource capacity is the incremental capacity equivalent (ICE); this value represents the capacity credit assigned to the alternative resource. For the 2015 IRP, ICE was calculated for existing and new wind projects, the Colstrip plant, and for wholesale market purchases.

8 / The ICE approach is similar to the equivalent load carrying capability (ELCC) approach, except that the numeraire is a peaker instead of load in the case of ELCC.

WIND CAPACITY. In order to implement the ICE 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 this Appendix in the Stochastic Portfolio Model section under the heading "Wind Generation." Given these distributions, the wind farms were incrementally added into the RAM to determine the reduction in peaking plant capacity needed to achieve the optimal EUE level. The ratio of the change in gas peaker capacity with and without the incremental wind capacity is that wind farm's capacity credit. The order in which the existing and prospective wind farms were added in the model follows the timeline 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, and 5) a generic wind resource expected to be located in southeast Washington close to the Lower Snake River project. However, the ICE values for the existing wind projects were not very different from each other so a single ICE value was assigned to all these wind projects.

COLSTRIP CAPACITY. The ICE for PSE's ownership share of Colstrip Units 1-4 (which have an aggregate nameplate capacity of 657 MW) was similarly calculated. PSE's share of the Colstrip plant was taken out of the resource stack, which resulted in a higher level of EUE. Peakers were then added to replace Colstrip until the customer-optimal EUE levels were achieved. The ratio of the additional peaker MW to PSE's total Colstrip capacity is its capacity credit; this value reflects the fact that the Colstrip units have historically had a higher forced outage rate than a generic gas-fired peaking plant.

WHOLESALE MARKET PURCHASES CAPACITY. 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.

To calculate the ICE of wholesale market purchases we started with a portfolio that produces the RAM results needed to achieve the planning standard target; the 2015 Optimal Planning Standard used in this IRP results in an optimal EUE level of 10.9 MWh. This involved a three-step process:

1. Introduce uncertainty in PSE's wholesale market capacity purchase volumes based upon the outputs of the WPCM as described in Appendix G. The regional resource configuration used for this step is reflected in Wholesale Market Reliability Scenario 7: NPCC's May 2015 assumptions + PGE Carty 2 + 475 MW additional CA imports, minus the 650 MW Grays Harbor plant.
2. Re-run the RAM to identify the impact on EUE. The EUE that reflects wholesale purchase risk is greater than the EUE computed under the assumption that PSE can purchase up to 1,666 MW of firm capacity in the regional wholesale markets at all times.
3. Calculate the amount of gas-fired peaking plant capacity needed to restore the system to the target level of EUE.

Summary of Resource Capacity Contributions. The table in Figure N-27 compares the incremental capacity equivalence of resources calculated using the 2013 Planning Standard (based on a 5 percent LOLP target and ignoring wholesale market risk) and the 2015 Optimal Planning Standard (which utilizes the EUE metric and includes market risk).

Figure N-27: Incremental Capacity Equivalent (ICE) Values/Capacity Credits

	2013 Planning Standard	2015 Optimal Planning Standard		
Resource Type	ICE	Nameplate Capacity (MW)	Capacity Needed to Maintain Optimal EUE	ICE
Baseline: Natural Gas Peaker	**100%**			**100%**
1) Existing Wind (Cumulative = 822MW)	12%	822	76	9%
2) New Wind (SE Washington = 100MW)*	8%	100	8	8%
3) Colstrip	92%	657	591	90%
4) Available Mid-C Transmission (Wholesale Market Purchases)	100%	1,666	269	84%

The ICE values/capacity credits from Figure N-27 are used in PSE's portfolio selection model. The above results are highly dependent on PSE's resource mix, load characteristics and projected distributions of wind generation.

Adjusted Planning Margin. Applying a 20.0 percent planning margin (as shown in Figure N-24 for the 2015 Optimal Planning Standard) to PSE's forecasted 2021 winter peak load yields a planning margin value of 1,059 MW. While this computation yields a numerically correct result for 2021, we recognized that applying the 20.0 percent figure in subsequent years might overstate PSE's planning margin, due to the fact that the 269 MW ICE adjustment shown in Figure N-26 for wholesale market purchases would not be expected to increase over time at PSE's peak load growth rate. Therefore, the planning margin was adjusted from a single 20.0 percent value to 13.7 percent plus a fixed 269 MW capacity adjustment (where the 269 MW figure reflects the wholesale market purchase risk component). This two-stage adjusted planning margin yields the same 1,059 MW value for 2021; this result is shown in Figure N-28.

Figure N-28: Calculation of PSE's 2021 Planning Margin

	Option A	Option B
Planning Margin (% of Normal Peak Load)	20%	13.7%
Wholesale Market Purchase Risk Adjustment	0 MW	269 MW
Total Capacity Above Normal Peaker	1,059 MW	1,059 MW

This planning margin and the ICE value for wholesale market purchases is expected to vary each year, as we update our information about regional resource adequacy.

OUTPUTS

AURORA Electric Prices and Avoided Costs

The series of tables below shows the AURORA price forecasts for each of the 10 scenarios. Consistent with WAC 480-107-055, this schedule of estimated Mid-Columbia (Mid-C) power prices is intended to provide only general information to potential bidders about the avoided costs of power supply. It does not provide a guaranteed contract price for electricity.

Figure N-29: Monthly Flat Mid-C Prices (Nominal $/MWh)

Base Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	38.86	39.60	38.08	33.85	32.42	33.28	35.75	38.02	40.17	40.01	40.20	38.98	37.43
2017	40.37	40.89	39.35	35.04	34.66	34.84	36.76	39.26	41.29	41.48	41.64	40.54	38.84
2018	41.82	42.65	40.77	36.66	34.20	34.88	38.22	40.83	43.30	43.21	43.00	42.68	40.19
2019	43.60	44.40	42.34	37.93	36.57	36.53	39.87	42.57	45.45	45.66	44.99	44.83	42.06
2020	45.16	46.20	44.28	40.38	37.22	38.63	41.82	44.57	47.80	47.86	47.58	46.77	44.02
2021	47.73	49.45	47.06	42.96	40.85	41.76	44.59	47.61	51.33	51.28	51.15	49.71	47.12
2022	50.20	51.87	49.05	44.93	41.95	43.52	46.87	50.46	53.51	54.35	54.10	52.23	49.42
2023	53.05	54.13	50.67	46.48	45.16	45.55	48.84	52.52	55.28	56.39	56.13	54.59	51.57
2024	55.89	57.10	53.36	49.19	45.48	46.55	51.35	54.94	58.27	59.02	57.83	57.11	53.84
2025	57.67	59.14	56.18	51.23	48.95	49.26	53.51	57.77	62.23	62.35	61.60	61.12	56.75
2026	64.41	66.87	64.75	59.25	53.98	56.74	61.65	66.39	72.28	72.57	71.93	69.49	65.03
2027	70.01	72.53	65.76	59.90	56.89	58.24	62.79	68.02	73.50	73.43	73.39	70.78	67.10
2028	71.27	73.96	67.64	61.17	57.10	59.34	64.62	70.20	75.11	76.36	75.55	72.72	68.75
2029	74.21	76.56	71.71	64.99	61.94	62.14	67.91	73.67	79.34	79.44	77.84	77.00	72.23
2030	77.32	80.17	73.55	66.72	61.36	63.27	70.21	75.46	81.90	81.88	80.47	80.53	74.40
2031	79.60	82.28	76.08	69.16	66.11	66.69	72.65	78.17	83.75	84.06	83.50	82.81	77.07
2032	82.12	84.52	78.63	71.21	65.16	68.68	75.54	81.11	86.54	86.78	86.74	85.30	79.36
2033	85.53	87.80	81.70	73.42	71.16	71.91	78.57	84.71	89.69	90.78	90.26	88.16	82.81
2034	89.41	91.44	85.23	77.61	72.72	74.84	82.28	87.94	92.89	94.59	93.75	91.98	86.22
2035	92.62	94.90	88.68	81.43	77.45	77.38	85.53	91.56	96.10	96.80	96.13	95.84	89.53

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Low Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	28.49	28.25	25.65	24.40	22.77	22.59	25.96	29.02	30.18	29.81	29.56	28.96	27.14
2017	30.34	30.22	28.27	26.25	26.41	26.28	28.81	32.17	32.97	32.82	32.62	31.99	29.93
2018	30.53	30.74	28.94	26.47	25.27	25.67	28.77	32.64	33.69	33.18	32.91	33.12	30.16
2019	30.93	31.09	28.98	26.86	26.11	25.30	28.64	32.05	33.67	32.95	32.08	32.54	30.10
2020	33.46	33.43	30.68	28.34	26.21	26.84	29.84	33.72	35.73	34.57	34.26	34.50	31.80
2021	35.81	36.30	32.29	29.55	28.07	28.60	31.61	35.82	37.61	36.95	36.89	36.45	33.83
2022	36.32	36.86	34.03	30.61	28.07	29.39	32.99	37.30	39.36	38.96	39.31	39.04	35.19
2023	35.08	35.41	32.38	28.98	27.27	27.02	30.85	35.34	36.87	36.66	37.09	36.19	33.26
2024	37.41	38.09	34.44	31.31	27.68	28.30	33.87	38.24	41.01	40.97	40.22	39.38	35.91
2025	40.00	40.72	36.85	33.68	31.17	31.09	35.84	40.63	43.71	43.05	43.18	43.08	38.58
2026	41.22	41.90	39.66	36.18	31.93	33.76	38.60	43.50	46.34	45.36	45.41	44.66	40.71
2027	44.53	45.15	40.09	36.39	33.59	34.67	39.10	44.33	46.60	45.56	46.38	45.29	41.81
2028	45.35	45.92	41.07	36.62	33.04	34.90	40.03	45.65	47.30	46.83	47.75	46.59	42.59
2029	48.06	48.48	44.09	39.13	36.92	37.06	42.61	49.14	51.09	50.12	49.80	50.17	45.56
2030	48.35	48.64	43.40	38.92	34.78	35.92	42.33	48.56	50.94	49.63	49.86	51.00	45.19
2031	50.15	49.77	44.93	40.96	37.93	38.44	43.90	50.84	53.45	51.43	50.36	50.38	46.88
2032	52.47	51.96	46.70	42.81	38.33	40.51	46.16	53.63	55.57	53.46	53.07	52.47	48.93
2033	54.43	54.13	48.89	44.35	41.97	42.88	47.88	56.25	57.93	55.83	55.39	54.57	51.21
2034	56.97	56.32	50.86	46.02	41.98	44.34	50.05	58.49	60.08	58.40	58.03	56.80	53.19
2035	59.54	59.00	53.12	48.02	45.56	45.88	52.07	61.23	63.65	61.42	59.87	59.72	55.75

Monthly Flat Mid-C Prices
(Nominal $/MWh)

High Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	36.58	36.16	32.78	31.62	30.79	31.19	33.94	37.20	38.30	38.62	37.88	37.27	35.19
2017	38.41	38.14	35.98	33.91	35.11	35.17	37.89	41.45	41.58	41.82	41.39	40.83	38.47
2018	41.62	41.96	39.73	36.38	36.19	36.86	40.60	45.10	45.66	45.69	45.24	45.54	41.71
2019	48.10	48.32	45.09	41.90	42.14	41.51	46.30	50.61	51.78	51.11	49.57	50.59	47.25
2020	64.40	65.39	61.97	58.21	55.61	57.27	61.45	64.76	67.54	67.79	66.04	65.58	63.00
2021	68.36	70.56	65.10	60.74	59.14	60.47	64.20	67.91	71.58	72.34	70.09	68.52	66.59
2022	69.03	70.62	66.80	62.32	59.03	60.99	65.24	69.32	73.68	74.23	72.75	70.07	67.84
2023	71.59	72.91	68.80	64.69	63.20	64.07	67.54	71.59	75.56	77.07	74.67	72.81	70.38
2024	74.61	76.34	72.51	68.27	63.80	65.16	70.44	74.95	79.19	80.03	77.21	76.49	73.25
2025	81.03	83.46	78.97	74.42	71.23	71.75	77.40	82.30	88.17	88.12	85.45	83.01	80.44
2026	87.42	90.11	87.16	82.31	76.53	79.07	85.20	90.18	97.88	97.46	95.15	91.84	88.36
2027	95.57	99.32	91.51	85.97	82.94	83.72	88.84	94.87	101.79	102.06	100.39	96.10	93.59
2028	99.64	103.19	95.01	88.67	83.22	85.59	92.61	98.67	106.02	107.29	104.91	100.25	97.09
2029	103.97	107.23	100.48	93.20	89.50	89.29	97.11	104.03	110.82	111.03	107.37	106.81	101.74
2030	109.33	113.47	104.35	97.49	90.80	92.26	102.24	109.06	116.90	117.25	113.05	112.91	106.59
2031	114.55	118.50	109.66	102.03	96.87	97.26	107.12	114.13	123.36	123.71	115.31	114.50	111.42
2032	120.73	125.57	115.91	107.20	98.76	101.93	112.08	120.96	130.45	130.70	123.29	120.93	117.37
2033	127.15	132.06	121.39	112.00	107.23	108.18	118.25	128.31	137.19	138.34	130.33	127.90	124.03
2034	135.45	140.15	128.55	118.08	109.94	113.25	125.81	135.67	145.03	147.30	138.72	135.49	131.12
2035	142.63	147.79	135.90	123.96	118.49	117.99	132.44	143.26	153.40	155.14	144.80	144.44	138.35

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + No CO_2 Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	34.57	34.49	32.45	28.48	27.56	28.37	31.29	34.37	35.30	34.90	35.11	34.63	32.63
2017	35.36	35.18	33.41	29.03	29.67	29.47	31.85	35.25	35.89	35.75	36.33	35.80	33.58
2018	36.56	36.59	34.41	30.25	29.27	29.60	32.93	36.65	37.79	37.15	37.02	37.24	34.62
2019	37.66	37.62	35.17	31.72	31.08	30.28	33.75	37.56	39.35	38.89	38.35	38.77	35.85
2020	39.12	39.12	36.49	33.32	31.35	32.13	35.64	39.49	41.44	40.73	40.80	40.62	37.52
2021	41.57	42.00	39.02	35.72	34.43	35.57	38.92	43.05	44.49	44.01	44.37	43.78	40.58
2022	43.78	44.23	40.76	37.42	35.59	37.55	41.05	45.85	46.66	46.40	47.07	46.20	42.71
2023	46.24	46.19	42.14	38.59	38.33	39.25	42.55	47.49	47.76	48.26	49.42	48.26	44.54
2024	48.78	48.76	44.34	40.96	38.73	39.60	44.89	49.59	50.77	50.65	50.40	50.76	46.52
2025	50.08	49.66	46.31	43.05	41.37	41.77	47.07	51.91	54.60	54.24	53.51	54.34	48.99
2026	56.50	57.31	54.90	50.77	46.84	50.16	55.96	61.05	64.53	64.11	64.00	62.30	57.37
2027	61.66	62.79	55.53	51.20	49.09	51.48	56.62	62.43	65.17	64.63	65.39	63.36	59.11
2028	62.21	63.26	56.34	51.48	49.03	51.94	57.90	63.86	65.70	66.02	67.05	64.58	59.95
2029	65.37	65.60	59.85	54.89	53.25	54.50	61.07	67.69	69.99	69.80	69.17	69.02	63.35
2030	67.81	68.16	60.46	56.15	52.67	55.13	63.24	69.03	71.46	71.54	71.12	72.30	64.92
2031	69.67	69.47	62.73	57.88	55.90	57.54	65.26	71.85	74.11	73.85	74.16	74.41	67.24
2032	71.93	71.68	65.06	59.64	55.60	59.87	67.10	74.48	76.80	75.69	77.96	76.60	69.37
2033	74.33	74.38	66.98	61.24	60.23	62.66	69.18	77.44	79.32	78.45	80.90	79.07	72.01
2034	77.13	76.88	69.21	62.98	60.43	63.86	71.10	80.05	81.25	81.03	83.23	81.33	74.04
2035	79.84	80.20	72.10	65.50	64.33	65.10	73.72	82.88	84.73	83.74	84.66	85.05	76.82

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + High CO_2 Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	34.60	34.56	32.65	28.56	27.76	28.50	31.48	34.54	35.58	34.97	35.31	34.75	32.77
2017	35.48	35.39	33.57	29.18	29.64	29.47	32.16	35.53	36.09	35.87	36.47	35.97	33.74
2018	36.69	36.80	34.54	30.29	29.36	29.61	33.12	37.02	38.11	37.53	37.28	37.58	34.83
2019	37.78	37.89	35.48	31.70	30.86	30.30	34.23	38.03	39.78	39.31	38.72	39.14	36.10
2020	55.03	56.05	53.66	49.00	45.78	47.09	50.84	54.09	58.49	58.75	56.97	55.84	53.47
2021	57.66	59.59	56.29	51.59	49.47	50.48	53.86	57.61	61.84	62.50	60.78	59.11	56.73
2022	60.94	63.03	59.36	54.82	51.18	53.04	57.46	61.57	65.94	66.43	64.59	62.79	60.10
2023	64.96	66.45	62.16	57.51	55.89	56.26	60.43	64.44	69.18	70.62	68.67	66.38	63.58
2024	68.85	70.30	65.75	60.84	56.46	57.52	63.90	67.65	72.17	73.40	71.12	70.07	66.50
2025	72.28	74.68	70.12	64.76	62.02	62.67	68.45	73.42	78.73	79.39	76.67	75.63	71.57
2026	79.48	82.25	79.38	73.71	68.18	70.59	77.33	82.41	88.90	89.14	86.59	83.90	80.15
2027	85.69	88.64	81.77	75.50	72.32	73.15	79.79	85.60	91.38	91.23	89.47	86.73	83.44
2028	88.97	92.90	84.83	77.78	72.79	74.72	83.05	89.37	94.83	95.74	93.60	90.46	86.59
2029	93.14	96.71	90.47	82.39	78.96	78.80	87.64	94.27	100.12	100.28	96.94	96.29	91.33
2030	98.25	101.72	93.87	85.99	79.10	81.23	91.27	97.93	104.24	104.81	101.66	101.97	95.17
2031	102.76	105.96	98.66	89.61	85.51	86.03	95.33	102.52	109.23	109.05	106.13	105.90	99.72
2032	107.46	111.28	103.90	93.68	86.01	89.54	99.54	108.19	115.58	114.96	112.59	110.50	104.44
2033	112.66	116.81	108.49	97.52	94.16	95.14	105.45	114.70	122.01	122.12	118.83	115.68	110.30
2034	117.90	121.81	113.21	101.26	94.94	98.44	109.84	120.33	127.83	129.09	124.86	121.54	115.09
2035	123.34	129.28	119.04	106.26	102.35	102.94	115.27	126.95	135.86	135.65	130.42	128.12	121.29

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + Low Gas Price Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	34.79	35.39	32.66	30.60	28.79	29.52	31.91	34.54	36.80	36.99	36.21	34.96	33.60
2017	37.06	37.46	35.90	33.61	32.98	33.26	35.63	37.88	39.55	39.93	39.28	38.31	36.74
2018	37.56	38.75	37.18	34.23	32.57	32.91	36.25	38.86	40.42	40.81	40.32	39.92	37.48
2019	38.82	39.99	37.89	35.11	33.90	33.86	36.95	39.53	41.55	41.99	40.73	40.19	38.38
2020	42.09	43.11	40.59	37.45	34.63	35.89	39.29	41.86	44.39	44.36	43.56	42.77	40.83
2021	44.76	46.78	42.73	39.11	37.51	38.02	40.95	44.10	47.55	48.21	47.02	45.39	43.51
2022	46.44	48.44	44.84	40.77	38.03	39.66	43.27	47.20	50.46	51.09	50.02	48.82	45.75
2023	46.23	47.81	44.67	40.52	39.17	39.51	42.67	45.95	49.18	50.54	49.00	46.67	45.16
2024	49.08	50.99	47.71	43.37	39.69	41.50	46.42	50.25	54.06	54.78	52.96	51.07	48.49
2025	52.95	55.42	51.24	46.79	44.75	45.16	49.20	53.40	57.80	58.13	56.55	55.23	52.22
2026	54.23	56.66	54.30	49.93	45.77	47.53	51.85	55.23	61.24	61.82	59.62	57.37	54.63
2027	58.45	60.85	56.02	51.62	49.53	49.69	53.61	57.28	62.71	62.94	61.03	58.71	56.87
2028	60.28	62.85	58.12	53.83	49.70	51.48	55.92	59.78	64.88	66.32	63.73	60.77	58.97
2029	63.85	66.85	62.78	57.38	55.36	55.19	59.46	64.11	69.35	69.73	66.93	65.64	63.06
2030	65.30	67.40	63.17	58.55	53.91	55.70	60.98	64.96	70.24	70.69	67.65	67.66	63.85
2031	67.73	69.70	65.44	60.54	57.71	58.40	63.21	66.74	72.46	73.24	69.01	67.41	65.97
2032	70.96	73.03	68.60	63.52	58.36	60.55	65.36	70.14	76.21	77.15	73.10	70.57	68.96
2033	74.49	76.29	71.71	65.94	63.29	63.92	68.86	73.65	80.38	81.25	76.82	74.17	72.56
2034	78.43	80.19	74.92	68.67	63.84	66.03	72.20	77.07	84.43	85.02	80.90	78.11	75.82
2035	81.73	84.14	78.76	71.73	68.39	68.08	74.85	80.86	87.02	87.84	83.64	82.37	79.12

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + High Gas Price Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	39.06	39.61	36.76	34.77	33.36	34.18	36.56	39.06	40.97	41.43	40.80	39.79	38.03
2017	41.38	41.57	39.80	37.47	37.80	37.94	40.33	42.79	44.25	44.63	44.15	43.12	41.27
2018	44.25	45.19	43.36	40.19	38.98	39.70	43.26	46.62	48.12	48.46	47.77	47.56	44.46
2019	50.35	51.33	48.33	45.09	44.92	44.77	48.23	51.99	53.95	53.78	52.71	52.84	49.86
2020	54.35	55.48	51.32	47.90	45.66	47.12	50.95	54.95	58.02	57.49	56.69	55.82	52.98
2021	58.43	60.82	54.61	50.48	49.08	49.96	53.37	57.75	61.29	61.90	60.54	58.92	56.43
2022	58.01	59.17	55.03	50.28	47.49	49.58	53.21	57.86	61.35	61.72	62.15	59.37	56.27
2023	60.11	61.17	56.54	51.63	50.35	51.17	54.36	58.75	62.63	63.52	63.77	61.75	57.98
2024	62.69	64.01	59.43	54.61	50.74	52.23	57.41	61.57	65.94	66.72	65.63	64.56	60.46
2025	66.67	68.69	64.64	59.62	57.20	57.98	62.20	67.23	73.22	72.98	71.95	69.70	66.01
2026	72.71	75.11	71.93	66.21	61.04	64.03	69.56	75.13	81.39	81.34	80.88	78.06	73.12
2027	79.33	83.37	74.72	68.56	65.27	66.97	71.78	77.83	83.74	83.86	83.96	80.58	76.66
2028	80.82	83.68	75.76	69.14	64.59	66.99	72.95	79.74	84.08	85.32	85.64	82.25	77.58
2029	84.27	86.04	80.26	72.85	69.38	69.71	76.16	83.01	88.73	88.66	87.63	86.87	81.13
2030	86.09	89.20	81.14	74.17	68.03	70.94	78.85	84.65	90.75	90.51	89.99	89.27	82.80
2031	88.10	90.31	83.00	75.61	72.32	73.96	80.49	86.80	92.52	91.82	86.96	87.38	84.11
2032	91.73	94.21	87.17	78.90	72.88	76.75	84.36	91.04	96.54	96.30	91.48	91.28	87.72
2033	94.94	97.41	90.15	81.61	77.98	80.37	87.60	94.56	99.87	99.82	94.68	94.09	91.09
2034	99.24	101.47	94.38	85.04	79.41	83.32	91.63	99.02	104.44	104.43	98.92	98.03	94.94
2035	103.18	106.01	98.07	88.90	84.90	86.52	95.47	103.04	108.48	107.47	102.37	102.86	98.94

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + Very High Gas Price Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	45.70	46.33	41.95	39.50	38.74	39.61	42.24	45.02	47.00	47.61	47.00	45.37	43.84
2017	46.33	46.95	44.19	41.31	42.25	42.59	45.07	48.19	49.90	50.56	50.23	48.89	46.37
2018	47.40	48.87	46.57	42.90	41.96	42.58	46.40	50.46	52.25	52.80	52.11	51.49	47.98
2019	51.56	52.71	49.44	46.32	45.95	45.44	49.39	53.38	55.82	55.63	54.61	54.21	51.21
2020	55.41	56.28	52.73	48.92	46.25	47.86	52.11	56.22	59.38	58.57	58.07	57.01	54.07
2021	61.38	63.09	57.12	52.62	50.97	52.38	56.11	61.03	63.82	64.00	63.06	61.46	58.92
2022	64.77	64.82	60.72	55.57	52.58	55.46	59.39	65.18	67.34	66.99	68.36	65.63	62.23
2023	66.91	67.96	64.08	58.84	58.82	59.77	63.75	69.53	71.79	72.67	73.30	72.12	66.63
2024	74.07	75.36	69.61	63.92	60.57	60.00	66.72	72.94	74.79	74.22	74.30	76.08	70.21
2025	75.73	76.72	70.89	65.65	64.38	64.93	71.17	77.91	81.66	80.41	79.44	78.72	73.97
2026	77.66	80.01	76.35	69.70	64.43	68.12	74.69	80.32	85.90	85.61	83.43	82.14	77.36
2027	85.90	87.50	79.61	72.78	69.45	72.62	78.37	85.21	90.65	90.42	88.86	86.57	82.33
2028	91.49	91.11	82.99	75.00	71.90	76.12	82.93	91.40	94.51	96.10	96.59	93.28	86.95
2029	95.13	95.93	89.53	80.79	78.69	80.34	88.63	97.45	102.07	102.44	100.10	98.67	92.48
2030	97.29	100.22	94.30	86.20	80.61	83.94	93.79	102.16	108.30	107.61	105.59	103.22	96.94
2031	103.94	104.64	98.28	89.18	86.43	88.93	98.15	105.76	112.61	112.56	108.31	108.11	101.41
2032	109.89	110.95	104.58	94.82	88.27	94.48	104.26	113.18	119.83	119.98	116.67	114.75	107.64
2033	116.81	117.15	110.08	98.89	96.61	100.70	110.18	119.58	125.87	126.56	123.36	120.79	113.88
2034	123.72	123.57	116.22	103.44	99.98	105.87	116.91	126.23	133.31	134.14	130.49	127.33	120.10
2035	130.42	131.51	123.50	110.38	106.96	110.77	123.36	133.36	141.26	140.71	135.84	135.46	126.96

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + Low Demand Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	37.33	38.04	36.51	32.77	30.75	32.00	34.78	37.00	38.80	38.95	38.95	37.45	36.11
2017	38.54	39.27	37.81	33.73	33.05	33.41	35.78	38.19	39.95	40.28	40.33	38.99	37.44
2018	39.86	40.75	39.11	35.04	32.52	33.58	37.15	39.53	41.71	41.66	41.48	40.73	38.59
2019	41.48	42.50	40.77	36.22	34.47	34.73	38.54	41.04	43.81	43.75	43.31	42.57	40.27
2020	43.32	44.05	42.61	38.04	34.45	36.27	40.05	42.91	45.81	45.74	45.58	44.59	41.95
2021	45.47	47.00	44.64	40.59	38.14	39.23	42.65	45.97	48.58	48.45	48.54	47.26	44.71
2022	47.67	49.18	46.52	42.24	38.84	40.54	44.72	48.48	50.77	50.80	50.94	49.63	46.69
2023	50.31	51.53	48.15	43.43	42.06	42.69	46.36	50.06	52.27	52.93	53.06	51.85	48.72
2024	52.68	54.06	50.37	45.76	41.88	42.75	48.40	52.10	54.78	55.16	54.80	53.96	50.56
2025	54.60	55.82	52.47	47.53	45.36	45.98	50.55	54.45	58.42	58.44	58.13	57.74	53.29
2026	59.88	62.49	59.51	54.21	48.91	52.00	58.00	62.15	67.33	67.14	66.78	64.60	60.25
2027	64.40	67.00	60.58	54.84	51.87	53.38	58.93	63.38	68.17	67.96	67.89	65.48	61.99
2028	65.51	68.23	62.21	55.68	51.50	53.99	60.20	64.59	69.27	69.93	69.89	67.10	63.18
2029	68.52	70.63	65.90	58.37	56.02	55.75	62.97	68.24	72.71	72.97	72.07	70.78	66.24
2030	71.04	73.51	66.81	59.99	54.82	56.73	65.01	69.53	74.78	74.71	74.45	73.71	67.92
2031	74.40	76.22	70.00	63.34	60.58	61.11	67.91	73.46	78.51	77.63	78.16	77.23	71.54
2032	77.09	79.12	72.66	64.94	58.81	63.03	71.18	77.03	81.24	80.87	81.74	80.34	74.00
2033	80.27	82.37	76.07	67.94	65.63	65.95	74.03	80.34	84.35	84.07	85.11	83.26	77.45
2034	84.28	86.04	79.24	71.31	66.34	69.18	77.73	83.98	87.85	88.02	88.81	86.54	80.78
2035	87.28	89.79	82.77	74.54	71.87	72.10	80.83	87.67	91.96	90.91	91.23	90.07	84.25

Monthly Flat Mid-C Prices
(Nominal $/MWh)

Base + High Demand Scenario

	1	2	3	4	5	6	7	8	9	10	11	12	Ave
2016	39.94	40.63	39.07	34.82	33.42	34.34	36.50	38.91	40.75	41.27	41.36	39.90	38.41
2017	41.48	41.94	40.63	36.28	35.66	36.02	37.71	40.14	42.03	42.76	42.83	41.64	39.93
2018	42.78	43.51	41.80	37.89	35.70	36.21	38.90	41.48	44.02	44.04	43.99	43.63	41.16
2019	44.74	45.31	43.54	39.59	37.76	37.79	40.70	43.40	46.43	46.80	46.07	45.92	43.17
2020	46.43	47.18	45.63	41.69	38.89	39.98	42.82	45.47	48.78	48.95	48.72	47.95	45.21
2021	49.07	50.84	48.21	44.44	42.34	43.19	45.61	48.74	52.74	53.16	52.95	51.04	48.53
2022	51.64	53.66	50.43	46.70	43.62	44.93	48.18	51.72	55.68	56.50	56.08	53.76	51.08
2023	54.57	56.17	52.22	48.31	46.96	47.06	50.24	53.84	57.50	58.80	58.26	55.88	53.32
2024	57.31	58.95	55.01	51.01	47.03	47.76	52.57	56.08	60.11	60.95	59.60	58.39	55.40
2025	59.43	61.54	57.74	53.39	50.84	51.28	55.39	59.06	64.50	64.88	63.80	62.63	58.71
2026	66.61	70.11	66.98	61.86	56.58	59.14	63.84	68.17	75.12	75.83	75.12	71.88	67.60
2027	72.39	75.88	68.37	63.10	59.69	60.98	65.07	69.63	76.43	77.23	77.06	73.07	69.91
2028	73.95	78.06	70.22	64.41	59.76	61.96	67.38	71.89	78.71	80.66	79.77	75.39	71.85
2029	76.56	80.04	74.21	67.57	64.13	64.61	70.23	75.17	81.33	82.19	81.23	79.85	74.76
2030	79.65	83.47	75.62	69.71	64.06	66.06	72.86	77.30	84.30	85.18	83.91	83.75	77.16
2031	82.24	85.95	78.88	72.75	69.67	70.24	75.70	80.20	88.14	88.74	87.85	85.69	80.50
2032	84.48	87.85	81.61	75.07	69.97	72.49	77.72	82.87	90.53	91.28	91.32	87.55	82.73
2033	87.86	91.13	84.21	78.24	75.74	76.26	80.91	86.61	93.98	95.14	94.44	90.40	86.24
2034	91.12	94.12	87.37	81.35	77.52	79.07	84.53	89.65	97.12	99.41	97.64	93.86	89.40
2035	94.31	98.05	91.18	84.63	82.08	81.35	87.40	92.88	99.19	100.96	99.58	97.87	92.46

Electric Integrated Portfolio Results–2013 Planning Standard

This table summarizes the expected costs of the different portfolios.

Figure N-30: Revenue Requirements for Optimal Portfolio with Expected Inputs for the Scenarios

Expected Cost for All Portfolios, 2013 Planning Standard

Scenario	NPV to 2016 ($Millions)						
	Expected Portfolio Cost	Net Market Purchases/ (Sales)	DSR Rev. Req.	Generic Rev. Req.	Generic End Effects	Variable Cost of Existing	REC Revenue
Base	$12,277	$4,267	$990	$1,235	$838	$4,956	($11)
Low	$7,200	$1,561	$942	$565	$388	$3,756	($12)
High	$17,591	$2,088	$993	$8,104	$620	$5,885	($98)
Base + Low Gas	$11,568	$2,528	$990	$2,296	$796	$4,967	($11)
Base + High Gas	$12,899	$4,713	$990	$1,235	$808	$5,163	($11)
Base + Very High Gas	$13,656	$5,444	$1,210	$1,296	$641	$5,091	($24)
Base + No CO2	$9,924	$1,056	$990	$2,286	$729	$4,873	($11)
Base + High CO2	$13,501	$3,961	$1,170	$3,467	$483	$4,444	($24)
Base + Low Demand	$9,757	$3,908	$942	$596	$328	$4,000	($16)
Base + High Demand	$15,548	$3,295	$1,337	$3,840	$1,350	$5,744	($22)

Figure N-31: Revenue Requirements for Optimal Portfolio with Expected Inputs for the Sensitivities

Expected Cost for All Portfolios, 2013 Planning Standard

Scenario	NPV to 2016 ($Millions)						
	Expected Portfolio Cost	Net Market Purchases / (Sales)	DSR Rev. Req.	Generic Rev. Req.	Generic End Effects	Variable Cost of Existing	REC Revenue
No DSR	$14,208	$5,474	$0	$3,791	$1,400	$4,956	($16)
All CCCT	$12,471	$2,818	$1,210	$3,499	$776	$4,956	($13)
Mix CCCT & Frame	$12,363	$3,368	$990	$3,059	$815	$4,956	($11)
East Side Plant	$12,171	$2,459	$1,210	$3,558	$626	$4,956	($13)
Battery 2023	$12,374	$4,185	$1,170	$2,076	$877	$4,956	($14)
Battery 2023 flex	$12,277	$4,185	$1,170	$1,980	$852	$4,956	($14)
80MW PS	$12,478	$4,267	$990	$2,274	$1,009	$4,956	($11)
200MW PS	$12,915	$4,376	$691	$2,907	$1,392	$4,956	($18)
75MW Recip	$12,263	$4,267	$993	$2,057	$822	$4,956	($11)
75MW Recip 2023	$12,282	$4,242	$993	$2,106	$802	$4,956	($16)
224MW Recip 2023	$12,354	$4,267	$993	$2,148	$853	$4,956	($11)
MT 40%	$12,503	$3,936	$990	$2,630	$884	$4,956	($11)
MT 45%	$12,483	$3,927	$967	$2,644	$883	$4,956	($12)
MT 50%	$12,474	$3,936	$927	$2,663	$881	$4,956	($11)
MT 55%	$12,462	$3,927	$929	$2,660	$882	$4,956	($12)
Max PV	$12,211	$4,203	$990	$2,073	$838	$4,956	($12)
Wind Carbon*	$12,654	$3,920	$990	$2,798	$923	$4,956	($11)
Wind Re-Opt*	$12,624	$3,920	$990	$2,768	$926	$4,956	($11)
Solar Carbon*	$12,875	$4,057	$990	$2,881	$1,017	$4,956	($11)
DSR E Carbon*	$12,340	$4,202	$1,146	$2,046	$841	$4,956	($11)
DSR F Carbon*	$12,336	$4,183	$1,146	$2,060	$839	$4,956	($11)
DSR G Carbon*	$12,345	$4,090	$1,439	$1,875	$765	$4,956	($15)

**Results shown are for the total portfolio NPV. Chapter 6 sensitivity is just the 25-yr NPV.*

Figure N-32: Annual Revenue Requirements for Optimal Portfolio ($Millions)
2013 Planning Standard

	Base	Low	High	Base + Low Gas	Base + High Gas	Base + Very High Gas	Base + No CO2	Base + High CO2	Base + Low Demand	Base + High Demand
2016	720	526	659	679	722	789	606	617	667	794
2017	767	572	816	743	784	844	645	660	705	894
2018	812	599	876	784	843	892	680	696	744	975
2019	802	580	900	767	855	888	668	686	727	952
2020	856	620	1,269	826	919	951	709	1,000	775	1,051
2021	855	601	1,356	824	922	963	694	1,006	767	1,028
2022	910	641	1,470	881	964	1,031	737	1,074	813	1,146
2023	996	609	1,568	936	1,045	1,090	809	1,158	809	1,256
2024	1,063	641	1,617	1,020	1,112	1,188	862	1,298	903	1,288
2025	1,084	695	1,723	1,046	1,156	1,225	868	1,353	908	1,377
2026	1,228	648	1,953	1,106	1,312	1,349	968	1,545	964	1,532
2027	1,302	658	2,055	1,280	1,403	1,447	1,121	1,627	1,000	1,598
2028	1,414	677	2,264	1,331	1,515	1,570	1,152	1,702	1,037	1,777
2029	1,530	793	2,515	1,444	1,639	1,777	1,224	1,854	1,190	1,903
2030	1,597	799	2,633	1,477	1,705	1,875	1,260	2,046	1,238	1,990
2031	1,765	850	2,858	1,564	1,858	2,025	1,332	2,182	1,330	2,242
2032	1,830	859	3,031	1,627	1,944	2,195	1,360	2,298	1,365	2,373
2033	1,931	880	3,322	1,779	2,049	2,375	1,477	2,413	1,418	2,608
2034	2,016	897	3,522	1,850	2,147	2,498	1,521	2,520	1,463	2,726
2035	2,130	907	3,757	1,927	2,276	2,629	1,554	2,643	1,506	2,862
20-yr NPV	11,439	6,812	16,971	10,771	12,091	13,015	9,195	13,018	9,429	14,198
End Effects	838	388	620	796	808	641	729	483	328	1,350
Expected Cost	12,277	7,200	17,591	11,568	12,899	13,656	9,924	13,501	9,757	15,548

Figure N-33: Annual Revenue Requirements for Sensitivities ($Millions)
2013 Planning Standard

	No DSR	All CCCT	Mix CCCT & Frame	Gas Plant Location	Battery 2023	Battery 2023 flexibility	80MW PS	200MW PS	75MW Recip	75MW Recip 2023	224MW Recip 2023
2016	653	732	720	732	730	730	720	707	721	721	721
2017	702	784	767	784	781	781	767	748	767	767	767
2018	772	831	812	831	827	827	812	788	812	812	812
2019	775	824	802	824	819	819	802	777	803	803	803
2020	819	880	856	880	874	874	856	821	856	856	856
2021	911	881	855	881	874	874	855	829	856	856	856
2022	987	937	910	937	929	929	910	872	911	911	911
2023	1,145	989	996	989	983	969	976	1,026	996	970	1,010
2024	1,196	1,129	1,063	1,113	1,048	1,034	1,043	1,066	1,063	1,062	1,076
2025	1,292	1,148	1,084	1,133	1,119	1,105	1,116	1,165	1,084	1,132	1,097
2026	1,549	1,271	1,228	1,243	1,218	1,204	1,258	1,270	1,228	1,270	1,240
2027	1,608	1,333	1,410	1,304	1,332	1,317	1,332	1,372	1,302	1,318	1,314
2028	1,730	1,412	1,464	1,382	1,385	1,371	1,389	1,432	1,414	1,376	1,426
2029	1,865	1,521	1,577	1,489	1,497	1,482	1,560	1,552	1,530	1,549	1,542
2030	2,028	1,694	1,641	1,644	1,617	1,602	1,627	1,680	1,597	1,617	1,609
2031	2,114	1,801	1,749	1,752	1,730	1,715	1,736	1,782	1,765	1,728	1,776
2032	2,202	1,859	1,814	1,810	1,791	1,776	1,802	1,857	1,830	1,853	1,841
2033	2,366	1,950	1,971	1,899	1,948	1,933	1,963	2,006	1,931	1,954	1,942
2034	2,475	2,026	2,053	1,975	2,029	2,014	2,047	2,098	2,016	2,038	2,026
2035	2,615	2,105	2,137	2,053	2,110	2,095	2,132	2,192	2,131	2,124	2,140
20-yr NPV	12,808	11,695	11,548	11,545	11,497	11,425	11,469	11,523	11,441	11,480	11,501
End Effects	1,400	776	815	626	877	852	1,009	1,392	822	802	853
Expected Cost	14,208	12,471	12,363	12,171	12,374	12,277	12,478	12,915	12,263	12,282	12,354

Annual Revenue Requirements for Sensitivities ($Millions)
2013 Planning Standard

	MT 40%	MT 45%	MT 50%	MT 55%	Max PV	Wind Carbon	Solar Carbon	Wind Re-Opt	DSR E Carbon	DSR F Carbon	DSR G Carbon
2016	720	720	719	719	720	720	720	720	730	731	761
2017	767	767	764	765	767	767	767	767	780	781	814
2018	812	809	808	808	811	812	812	812	825	827	860
2019	802	801	796	797	801	802	802	802	817	818	853
2020	856	845	850	850	854	856	856	856	863	874	908
2021	855	853	850	851	853	939	960	939	872	875	909
2022	910	897	905	906	908	985	1,005	984	916	932	964
2023	1,052	1,051	1,045	1,045	992	1,061	1,081	1,061	1,010	1,007	988
2024	1,108	1,108	1,101	1,101	1,058	1,121	1,140	1,121	1,076	1,073	1,053
2025	1,170	1,169	1,163	1,163	1,078	1,136	1,155	1,136	1,095	1,092	1,124
2026	1,247	1,270	1,292	1,263	1,220	1,269	1,290	1,269	1,225	1,215	1,186
2027	1,369	1,364	1,359	1,357	1,293	1,340	1,361	1,340	1,288	1,278	1,300
2028	1,421	1,417	1,411	1,409	1,404	1,450	1,470	1,396	1,425	1,414	1,354
2029	1,532	1,529	1,577	1,577	1,517	1,562	1,583	1,564	1,536	1,525	1,465
2030	1,654	1,651	1,641	1,641	1,583	1,627	1,647	1,629	1,598	1,586	1,586
2031	1,760	1,757	1,747	1,747	1,748	1,791	1,812	1,735	1,711	1,756	1,698
2032	1,822	1,820	1,809	1,810	1,811	1,854	1,875	1,858	1,830	1,816	1,759
2033	1,979	1,978	1,966	1,967	1,908	1,951	1,972	1,955	1,927	1,911	1,905
2034	2,059	2,058	2,046	2,046	1,989	2,032	2,054	2,035	2,008	1,991	1,997
2035	2,141	2,139	2,127	2,127	2,100	2,143	2,165	2,146	2,118	2,102	2,078
20-yr NPV	11,619	11,599	11,592	11,580	11,373	11,732	11,858	11,698	11,499	11,496	11,580
End Effects	884	883	881	882	838	923	1,017	926	841	839	765
Expected Cost	12,503	12,483	12,474	12,462	12,211	12,654	12,875	12,624	12,340	12,336	12,345

Figure N-34: Revenue Requirement with Input Simulations – 1,000 Trials
2013 Planning Standard

Expected Portfolio Cost ($Millions)	Risk Simulation - 1000 Trials			
	Base_All Frame Peaker	All CCCT	Mix CCCT & Frame	No DSR
Minimum	$7,358	$7,360	$7,291	$8,822
1st Quartile (P25)	$9,738	$9,506	$9,506	$11,363
Mean	$11,129	$10,858	$10,899	$12,932
Median (P50)	$11,123	$10,901	$10,921	$12,931
3rd Quartile (P75)	$12,385	$11,874	$12,027	$14,337
TVar90	$14,445	$13,778	$13,932	$16,480
Maximum	$16,078	$15,466	$15,643	$18,366
Base Deterministic	$12,277	$12,471	$12,363	$14,208

Figure N-35: Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Scenarios: Base, Base +High Gas Price

Sensitivity: Max PV

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	41
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	43
2021	-	-	-	-	-	-	62	2
2022	-	-	-	-	25	-	66	12
2023	-	228	100	-	-	-	56	2
2024	-	-	100	-	-	-	55	3
2025	-	-	-	-	-	-	53	2
2026	-	455	-	-	-	-	27	2
2027	-	-	100	-	-	-	27	2
2028	-	228	-	-	-	-	27	3
2029	-	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	23	2
2031	-	228	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	80	24	2
Total	-	1,138	300	15	25	80	906	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Scenarios: Low, Base + Low Demand

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	62	12
2018	-	-	-	-	-	-	66	42
2019	-	-	-	-	-	-	63	14
2020	-	-	-	-	-	-	77	44
2021	-	-	-	-	-	-	60	2
2022	-	-	-	-	-	-	64	13
2023	-	-	-	-	-	-	55	2
2024	-	-	-	-	-	-	54	3
2025	-	-	200	-	-	-	51	2
2026	-	228	-	-	-	-	26	2
2027	-	-	-	-	-	-	27	2
2028	-	-	-	-	-	-	27	3
2029	-	228	-	-	-	-	23	2
2030	-	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	26	2
2032	-	-	-	-	-	-	32	2
2033	-	-	-	-	-	-	29	2
2034	-	-	-	-	-	-	24	2
2035	-	-	-	-	-	-	24	2
Total	-	455	200	-	-	-	888	174

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Scenario: High

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	385	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	42
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	44
2021	-	-	300	-	-	-	62	2
2022	-	-	300	-	-	-	66	13
2023	385	-	-	-	-	-	56	2
2024	-	-	-	-	-	-	55	3
2025	-	-	-	-	-	-	53	2
2026	385	-	-	-	-	-	27	2
2027	-	-	-	-	-	-	27	2
2028	385	-	-	-	-	-	27	3
2029	-	-	400	-	-	-	23	2
2030	-	-	-	-	-	-	23	2
2031	385	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	385	-	-	-	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	2,312	-	1,000	-	-	-	906	174

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Scenarios: Base + Low Gas Price, Base + No CO_2
Sensitivity: Mix CCCT & Peaker

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	41
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	43
2021	-	-	-	-	-	-	62	2
2022	-	-	-	-	25	-	66	12
2023	-	228	100	-	-	-	56	2
2024	-	-	100	-	-	-	55	3
2025	-	-	-	-	-	-	53	2
2026	385	-	-	-	-	-	27	2
2027	385	-	100	-	-	-	27	2
2028	-	-	-	-	-	-	27	3
2029	-	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	228	-	15	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	771	455	300	15	25	-	906	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Scenario: Base + Very High Gas Price

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	77	18
2017	-	-	-	-	-	-	66	12
2018	-	-	-	-	-	-	71	41
2019	-	-	-	-	-	-	69	14
2020	-	-	-	-	-	-	84	43
2021	-	-	-	-	-	-	68	2
2022	-	-	-	-	-	-	72	12
2023	-	-	200	-	-	-	61	2
2024	-	228	-	-	-	-	59	3
2025	-	-	-	-	-	-	58	2
2026	-	455	-	-	-	-	28	2
2027	-	-	-	-	-	-	30	2
2028	-	-	100	-	-	-	29	3
2029	-	228	-	-	-	-	25	2
2030	-	-	-	-	-	-	25	2
2031	-	-	-	-	-	-	29	2
2032	-	-	300	-	-	-	35	2
2033	-	228	-	-	-	-	31	2
2034	-	-	-	-	-	-	26	2
2035	-	-	-	-	-	-	25	2
Total	-	1,138	600	-	-	-	968	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Scenario: Base + High CO_2

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	77	18
2017	-	-	-	-	-	-	66	12
2018	-	-	-	-	-	-	70	41
2019	-	-	-	-	-	-	68	14
2020	-	-	-	-	-	-	82	43
2021	-	-	-	-	-	-	66	2
2022	-	-	-	-	-	-	70	12
2023	-	-	300	-	-	-	60	2
2024	385	-	-	-	-	-	58	3
2025	-	-	-	-	-	-	56	2
2026	385	-	-	-	-	-	28	2
2027	-	-	-	-	-	-	30	2
2028	-	-	-	-	-	-	29	3
2029	-	-	-	-	-	-	25	2
2030	385	-	-	-	-	-	25	2
2031	-	-	-	-	-	-	29	2
2032	-	-	100	-	-	-	35	2
2033	-	-	-	-	-	-	31	2
2034	-	-	-	-	-	-	26	2
2035	-	-	-	-	-	-	25	2
Total	1,156	-	400	-	-	-	956	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Scenario: Base + High Demand

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	77	24
2017	-	228	-	-	25	-	66	12
2018	-	-	-	-	-	-	70	67
2019	-	-	-	-	75	-	68	14
2020	-	-	-	-	-	-	82	77
2021	-	-	-	-	100	-	66	3
2022	-	-	200	-	100	-	70	13
2023	-	228	200	-	-	-	60	3
2024	-	-	-	-	-	-	58	4
2025	-	228	-	-	-	-	56	3
2026	385	-	-	-	-	-	28	3
2027	-	-	-	-	-	-	30	3
2028	385	-	-	-	-	-	29	4
2029	-	-	-	-	-	-	25	3
2030	-	-	-	-	-	-	25	3
2031	385	-	-	-	-	-	29	3
2032	-	-	100	-	-	-	35	3
2033	385	-	-	-	-	-	31	3
2034	-	-	-	-	-	-	26	3
2035	-	-	-	-	-	-	25	3
Total	1,542	683	500	-	300	-	956	254

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + Colstrip 1 & 2 Retired*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	MT Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	-	79	35
2021	-	-	-	-	-	-	-	62	2
2022	-	-	-	-	-	50	-	66	2
2023	-	228	100	-	-	-	-	56	2
2024	-	-	100	-	-	-	-	55	2
2025	-	-	-	-	-	-	-	53	2
2026	-	683	-	-	-	-	-	27	2
2027	-	-	100	100	-	-	-	27	2
2028	-	-	-	100	-	-	-	27	2
2029	-	228	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	-	27	2
2032	-	-	-	100	-	-	-	32	2
2033	-	228	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	-	24	2
Total	0	1,366	300	300	15	50	0	906	148

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + Colstrip All 4 Units Retired*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	MT Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	-	67	41
2019	-	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	-	79	43
2021	-	-	-	-	-	-	-	62	2
2022	-	-	-	-	-	25	-	66	12
2023	-	228	100	-	-	-	-	56	2
2024	-	-	100	-	-	-	-	55	3
2025	-	-	-	-	-	-	-	53	2
2026	771	228	-	-	-	-	-	27	2
2027	-	-	100	100	-	-	-	27	2
2028	-	-	-	100	-	-	-	27	3
2029	-	228	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	-	27	2
2032	-	-	-	100	-	-	-	32	2
2033	-	228	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	-	24	2
Total	771	910	300	300	15	25	0	906	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Low + Colstrip 1&2 Retired*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	MT Wind	Biomass	Solar	Battery	DSR	DR
2016	-	-	-	-	-	-	-	73	6
2017	-	-	-	-	-	-	-	59	0
2018	-	-	-	-	-	-	-	62	26
2019	-	-	-	-	-	-	-	59	1
2020	-	-	-	-	-	-	-	72	35
2021	-	-	-	-	-	-	-	55	1
2022	-	-	-	-	-	-	-	58	1
2023	-	-	-	-	-	-	-	50	1
2024	-	-	-	-	-	-	-	49	1
2025	-	-	200	-	-	-	-	46	1
2026	-	683	-	-	-	-	-	24	1
2027	-	-	-	-	-	-	-	24	1
2028	-	-	-	-	-	-	-	25	1
2029	-	228	-	-	-	-	-	21	1
2030	-	-	-	-	-	20	-	21	1
2031	-	-	-	-	-	-	-	20	1
2032	-	-	-	-	-	-	-	26	1
2033	-	-	-	-	-	20	-	23	1
2034	-	-	-	-	-	-	-	20	1
2035	-	-	-	-	-	-	-	19	1
Total	0	910	200	0	0	40	0	808	84

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Low + Colstrip All 4 Units Retired*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	MT Wind	Biomass	Solar	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	6
2017	-	-	-	-	-	-	-	62	0
2018	-	-	-	-	-	-	-	66	28
2019	-	-	-	-	-	-	-	63	1
2020	-	-	-	-	-	-	-	77	42
2021	-	-	-	-	-	-	-	60	1
2022	-	-	-	-	-	-	-	64	11
2023	-	-	-	-	-	-	-	55	1
2024	-	-	-	-	-	-	-	54	2
2025	-	-	200	-	-	-	-	51	1
2026	-	910	-	-	-	-	-	26	1
2027	-	-	-	-	-	-	-	27	1
2028	-	-	-	-	-	-	-	27	1
2029	-	228	-	-	-	-	-	23	1
2030	-	-	-	-	-	-	-	23	1
2031	-	-	-	-	-	-	-	26	1
2032	-	-	-	-	-	-	-	32	1
2033	-	-	-	-	-	-	-	29	1
2034	-	-	-	-	-	-	-	24	1
2035	-	-	-	-	-	-	-	24	1
Total	0	1,138	200	0	0	0	0	888	108

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *High + Colstrip 1&2 Retired*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	MT Wind	Biomass	Solar	Battery	DSR	DR
2016	-	-	-	-	-	-	-	77	18
2017	385	-	-	-	-	-	-	66	12
2018	-	-	-	-	-	-	-	71	41
2019	-	-	-	-	-	-	-	69	14
2020	-	-	-	-	-	-	-	84	43
2021	-	-	-	-	-	-	-	68	2
2022	-	-	300	-	-	-	-	72	12
2023	385	-	-	-	-	-	-	61	2
2024	-	-	-	-	-	-	-	59	3
2025	-	-	-	-	-	-	-	58	2
2026	385	-	-	500	-	-	-	28	2
2027	-	-	-	-	-	-	-	30	2
2028	385	-	100	-	-	-	-	29	3
2029	-	-	100	-	-	-	-	25	2
2030	-	-	-	-	-	-	-	25	2
2031	385	-	-	-	-	-	-	29	2
2032	-	-	-	-	-	-	-	35	2
2033	385	-	-	-	-	-	-	31	2
2034	-	-	-	-	-	-	-	26	2
2035	-	-	-	-	-	-	-	25	2
Total	2,312	0	500	500	0	0	0	968	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *High + Colstrip All 4 Units Retired*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	MT Wind	Biomass	Solar	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	385	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	-	67	42
2019	-	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	-	79	44
2021	-	-	300	-	-	-	-	62	2
2022	385	-	-	-	-	-	-	66	13
2023	-	-	-	-	-	-	-	56	2
2024	-	-	-	-	-	-	-	55	3
2025	-	-	-	-	-	-	-	53	2
2026	771	-	-	500	-	-	-	27	2
2027	-	-	-	-	-	-	-	27	2
2028	385	-	100	-	-	-	-	27	3
2029	-	-	100	-	-	-	-	23	2
2030	-	-	-	-	-	-	-	23	2
2031	385	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	-	32	2
2033	385	-	-	-	-	-	-	29	2
2034	-	-	-	-	-	-	-	25	2
2035	-	-	-	-	15	-	-	24	2
Total	2,698	0	500	500	15	0	0	906	174

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + No DSR*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	33	-
2017	-	-	-	-	75	-	15	-
2018	-	228	-	-	-	-	13	-
2019	-	-	-	-	-	-	11	-
2020	-	-	-	-	50	-	27	-
2021	-	228	-	-	-	-	10	-
2022	-	-	100	-	75	-	11	-
2023	-	228	200	-	-	-	9	-
2024	-	-	-	-	-	-	9	-
2025	-	228	-	-	-	-	6	-
2026	-	455	100	-	-	-	7	-
2027	-	-	-	-	-	-	6	-
2028	-	228	-	-	-	-	8	-
2029	-	-	-	-	-	-	5	-
2030	-	228	100	-	-	-	6	-
2031	-	-	-	-	-	-	3	-
2032	-	-	-	-	-	-	5	-
2033	-	228	-	-	-	-	6	-
2034	-	-	-	-	-	-	4	-
2035	-	-	-	-	-	80	4	-
Total	-	2,048	500	-	200	80	197*	-

**197 MW reflects the no cost codes and standards bundle*

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivities: *Base + All CCCT, Base + Gas Plant Location (East side)*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	77	18
2017	-	-	-	-	-	-	66	12
2018	-	-	-	-	-	-	71	41
2019	-	-	-	-	-	-	69	14
2020	-	-	-	-	-	-	84	43
2021	-	-	-	-	-	-	68	2
2022	-	-	-	-	-	-	72	12
2023	-	-	200	-	-	-	61	2
2024	385	-	-	-	-	-	59	3
2025	-	-	-	-	-	-	58	2
2026	385	-	-	-	-	-	28	2
2027	-	-	-	-	-	-	30	2
2028	-	-	100	-	-	-	29	3
2029	-	-	-	-	-	-	25	2
2030	385	-	-	-	-	-	25	2
2031	-	-	-	-	-	-	29	2
2032	-	-	-	-	-	-	35	2
2033	-	-	-	15	-	-	31	2
2034	-	-	-	-	-	-	26	2
2035	-	-	-	-	-	-	25	2
Total	1,156	-	300	15	-	-	968	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + 80 MW Pump Storage*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Pumped Storage	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	41
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	43
2021	-	-	-	-	-	-	62	2
2022	-	-	-	-	25	-	66	12
2023	-	-	100	-	-	80	56	2
2024	-	-	100	-	-	-	55	3
2025	-	228	-	-	-	-	53	2
2026	-	455	-	-	-	-	27	2
2027	-	-	100	-	-	-	27	2
2028	-	-	-	-	-	-	27	3
2029	-	228	-	-	-	-	23	2
2030	-	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	228	-	15	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	-	1,138	300	15	25	80	906	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + 200 MW Pump Storage*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Pumped Storage	DSR	DR
2016	-	-	-	-	-	-	73	18
2017	-	-	-	-	-	-	59	12
2018	-	-	-	-	-	-	62	39
2019	-	-	-	-	-	-	59	14
2020	-	-	-	-	-	-	72	35
2021	-	-	-	-	-	-	55	2
2022	-	-	-	-	25	-	58	2
2023	-	-	200	-	75	200	50	2
2024	-	-	-	-	-	-	49	2
2025	-	228	100	-	-	-	46	2
2026	-	228	-	-	-	-	24	2
2027	-	228	-	-	-	-	24	2
2028	-	-	-	-	-	-	25	2
2029	-	-	-	-	-	-	21	2
2030	-	228	-	-	-	-	21	2
2031	-	-	100	-	-	-	20	2
2032	-	-	-	-	-	-	26	2
2033	-	228	-	-	-	-	23	2
2034	-	-	-	-	-	-	20	2
2035	-	-	-	-	-	-	19	2
Total	0	1,138	400	0	100	200	808	148

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivities: *Base + Battery 2023, Base + Battery 2023 Flexibility*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	77	18
2017	-	-	-	-	-	-	66	12
2018	-	-	-	-	-	-	70	41
2019	-	-	-	-	-	-	68	14
2020	-	-	-	-	-	-	82	43
2021	-	-	-	-	-	-	66	2
2022	-	-	-	-	-	-	70	12
2023	-	-	100	-	-	80	60	2
2024	-	-	100	-	-	-	58	3
2025	-	228	-	-	-	-	56	2
2026	-	228	100	-	-	-	28	2
2027	-	228	-	-	-	-	30	2
2028	-	-	-	-	-	-	29	3
2029	-	-	-	-	-	-	25	2
2030	-	228	-	-	-	-	25	2
2031	-	-	-	-	-	-	29	2
2032	-	-	-	-	-	-	35	2
2033	-	228	-	15	-	-	31	2
2034	-	-	-	-	-	-	26	2
2035	-	-	-	-	-	-	25	2
Total	-	1,138	300	15	-	80	956	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + 75 MW Recip*

Annual Builds (MW)	CCCT	Frame Peaker	Recip Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	-	67	42
2019	-	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	-	79	44
2021	-	-	-	-	-	-	-	62	2
2022	-	-	-	-	-	25	-	66	13
2023	-	228	-	100	-	-	-	56	2
2024	-	-	-	100	-	-	-	55	3
2025	-	-	-	-	-	-	-	53	2
2026	-	455	-	-	-	-	-	27	2
2027	-	-	-	100	-	-	-	27	2
2028	-	228	-	-	-	-	-	27	3
2029	-	-	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	-	23	2
2031	-	228	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	-	32	2
2033	-	-	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	-	25	2
2035	-	-	75	-	-	-	-	24	2
Total	0	1,138	75	300	15	25	0	906	174

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + 75 MW Recip 2023*

Annual Builds (MW)	CCCT	Frame Peaker	Recip Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	-	67	42
2019	-	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	-	79	44
2021	-	-	-	-	-	-	-	62	2
2022	-	-	-	-	-	25	-	66	13
2023	-	-	75	100	-	-	-	56	2
2024	-	-	-	200	-	-	-	55	3
2025	-	228	-	-	-	-	-	53	2
2026	-	455	-	-	-	-	-	27	2
2027	-	-	-	-	-	-	-	27	2
2028	-	-	-	-	-	-	-	27	3
2029	-	228	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	-	27	2
2032	-	228	-	-	-	-	-	32	2
2033	-	-	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	-	24	2
Total	0	1138	75	300	15	25	0	906	174

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + 224 MW Recip 2023*

Annual Builds (MW)	CCCT	Frame Peaker	Recip Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	-	67	42
2019	-	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	-	79	44
2021	-	-	-	-	-	-	-	62	2
2022	-	-	-	-	-	25	-	66	13
2023	-	-	224	100	-	-	-	56	2
2024	-	-	-	100	-	-	-	55	3
2025	-	-	-	-	-	-	-	53	2
2026	-	455	-	-	-	-	-	27	2
2027	-	-	-	100	-	-	-	27	2
2028	-	228	-	-	-	-	-	27	3
2029	-	-	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	-	23	2
2031	-	228	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	-	32	2
2033	-	-	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	80	24	2
Total	0	910	224	300	15	25	80	906	174

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + MT Wind 40%*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	MT Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	-	67	41
2019	-	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	-	79	43
2021	-	-	-	-	-	-	-	62	2
2022	-	-	-	-	-	25	-	66	12
2023	-	-	100	300	-	-	-	56	2
2024	-	-	100	-	-	-	-	55	3
2025	-	228	-	-	-	-	-	53	2
2026	-	228	-	-	-	-	-	27	2
2027	-	228	100	-	-	-	-	27	2
2028	-	-	-	-	-	-	-	27	3
2029	-	-	-	-	-	-	-	23	2
2030	-	228	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	-	32	2
2033	-	228	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	-	24	2
Total	0	1,138	300	300	15	25	0	906	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + MT Wind 45%*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	WT Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	-	79	35
2021	-	-	-	-	-	-	-	62	2
2022	-	-	-	-	-	50	-	66	2
2023	-	-	100	300	-	-	-	56	2
2024	-	-	100	-	-	-	-	55	2
2025	-	228	-	-	-	-	-	53	2
2026	-	228	100	-	-	-	-	27	2
2027	-	228	-	-	-	-	-	27	2
2028	-	-	-	-	-	-	-	27	2
2029	-	-	-	-	-	-	-	23	2
2030	-	228	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	-	32	2
2033	-	228	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	-	24	2
Total	0	1,138	300	300	15	50	0	906	148

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + MT Wind 50%*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	WT Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	6
2017	-	-	-	-	-	-	-	64	0
2018	-	-	-	-	-	-	-	67	28
2019	-	-	-	-	-	-	-	64	1
2020	-	-	-	-	-	-	-	79	42
2021	-	-	-	-	-	50	-	62	1
2022	-	-	-	-	-	75	-	66	11
2023	-	-	100	300	-	-	-	56	1
2024	-	-	100	-	-	-	-	55	2
2025	-	228	-	-	-	-	-	53	1
2026	-	455	-	-	-	-	-	27	1
2027	-	-	100	-	-	-	-	27	1
2028	-	-	-	-	-	-	-	27	1
2029	-	228	-	-	-	-	-	23	1
2030	-	-	-	-	-	-	-	23	1
2031	-	-	-	-	-	-	-	27	1
2032	-	-	-	-	-	-	-	32	1
2033	-	228	-	-	15	-	-	29	1
2034	-	-	-	-	-	-	-	25	1
2035	-	-	-	-	-	-	-	24	1
Total	0	1,138	300	300	15	125	0	906	108

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + MT Wind 55%*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	WT Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	6
2017	-	-	-	-	-	-	-	64	0
2018	-	-	-	-	-	-	-	67	29
2019	-	-	-	-	-	-	-	64	1
2020	-	-	-	-	-	-	-	79	43
2021	-	-	-	-	-	50	-	62	1
2022	-	-	-	-	-	75	-	66	12
2023	-	-	100	300	-	-	-	56	1
2024	-	-	100	-	-	-	-	55	2
2025	-	228	-	-	-	-	-	53	1
2026	-	228	100	-	-	-	-	27	1
2027	-	228	-	-	-	-	-	27	1
2028	-	-	-	-	-	-	-	27	1
2029	-	228	-	-	-	-	-	23	1
2030	-	-	-	-	-	-	-	23	1
2031	-	-	-	-	-	-	-	27	1
2032	-	-	-	-	-	-	-	32	1
2033	-	228	-	-	15	-	-	29	1
2034	-	-	-	-	-	-	-	25	1
2035	-	-	-	-	-	-	-	24	1
Total	0	1,138	300	300	15	125	0	906	110

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + Wind Carbon*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	41
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	43
2021	-	-	300	-	-	-	62	2
2022	-	-	-	-	25	-	66	12
2023	-	228	100	-	-	-	56	2
2024	-	-	100	-	-	-	55	3
2025	-	-	-	-	-	-	53	2
2026	-	455	-	-	-	-	27	2
2027	-	-	100	-	-	-	27	2
2028	-	228	-	-	-	-	27	3
2029	-	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	23	2
2031	-	228	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	80	24	2
Total	-	1,138	600	15	25	80	906	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + Wind Carbon (re-optimized)*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	41
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	43
2021	-	-	300	-	-	-	62	2
2022	-	-	-	-	-	-	66	12
2023	-	228	100	-	-	-	56	2
2024	-	-	100	-	-	-	55	3
2025	-	-	-	-	-	-	53	2
2026	-	455	-	-	-	-	27	2
2027	-	-	100	-	-	-	27	2
2028	-	-	-	-	-	-	27	3
2029	-	228	-	-	-	-	23	2
2030	-	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	228	-	-	-	-	32	2
2033	-	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	80	24	2
Total	-	1,138	600	15	-	80	906	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + Solar Carbon*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	Solar	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	-	67	41
2019	-	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	-	79	43
2021	-	-	-	-	300	-	-	62	2
2022	-	-	-	-	-	25	-	66	12
2023	-	228	100	-	-	-	-	56	2
2024	-	-	100	-	-	-	-	55	3
2025	-	-	-	-	-	-	-	53	2
2026	-	455	-	-	-	-	-	27	2
2027	-	-	100	-	-	-	-	27	2
2028	-	228	-	-	-	-	-	27	3
2029	-	-	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	-	23	2
2031	-	228	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	-	32	2
2033	-	-	-	15	-	-	-	29	2
2034	-	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	80	24	2
Total	-	1,138	300	15	300	25	80	906	172

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + DSR E Carbon*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	77	18
2017	-	-	-	-	-	-	66	12
2018	-	-	-	-	-	-	70	39
2019	-	-	-	-	-	-	68	14
2020	-	-	-	-	-	-	82	35
2021	-	-	-	-	-	-	66	2
2022	-	-	-	-	25	-	70	2
2023	-	228	100	-	-	-	60	2
2024	-	-	100	-	-	-	58	2
2025	-	-	-	-	-	-	56	2
2026	-	455	-	-	-	-	28	2
2027	-	-	-	-	-	-	30	2
2028	-	228	100	-	-	-	29	2
2029	-	-	-	-	-	-	25	2
2030	-	-	-	-	-	-	25	2
2031	-	-	-	-	-	-	29	2
2032	-	228	-	-	-	-	35	2
2033	-	-	-	15	-	-	31	2
2034	-	-	-	-	-	-	26	2
2035	-	-	-	-	-	80	25	2
Total	-	1,138	300	15	25	80	956	148

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + DSR F Carbon*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	77	6
2017	-	-	-	-	-	-	66	0
2018	-	-	-	-	-	-	71	28
2019	-	-	-	-	-	-	69	1
2020	-	-	-	-	-	-	84	42
2021	-	-	-	-	25	-	68	1
2022	-	-	-	-	50	-	72	11
2023	-	228	100	-	-	-	61	1
2024	-	-	100	-	-	-	59	2
2025	-	-	-	-	-	-	58	1
2026	-	455	-	-	-	-	28	1
2027	-	-	-	-	-	-	30	1
2028	-	228	100	-	-	-	29	1
2029	-	-	-	-	-	-	25	1
2030	-	-	-	-	-	-	25	1
2031	-	228	-	-	-	-	29	1
2032	-	-	-	-	-	-	35	1
2033	-	-	-	15	-	-	31	1
2034	-	-	-	-	-	-	26	1
2035	-	-	-	-	-	80	25	1
Total	-	1,138	300	15	75	80	968	108

Incremental Portfolio Builds by Year (nameplate MW), 2013 Planning Standard

Sensitivity: *Base + DSR G Carbon*

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	82	18
2017	-	-	-	-	-	-	72	12
2018	-	-	-	-	-	-	76	42
2019	-	-	-	-	-	-	74	14
2020	-	-	-	-	-	-	90	44
2021	-	-	-	-	-	-	74	2
2022	-	-	-	-	-	-	78	13
2023	-	-	100	-	-	-	66	2
2024	-	-	100	-	-	-	64	3
2025	-	228	-	-	-	-	63	2
2026	-	228	100	-	-	-	28	2
2027	-	228	-	-	-	-	31	2
2028	-	-	-	-	-	-	29	3
2029	-	-	-	-	-	-	25	2
2030	-	228	-	-	-	-	25	2
2031	-	-	-	-	-	-	29	2
2032	-	-	-	-	-	-	36	2
2033	-	228	-	-	-	-	31	2
2034	-	-	-	15	-	-	26	2
2035	-	-	-	-	-	-	25	2
Total	-	1,138	300	15	-	-	1,023	174

Figure N-35: Total Portfolio CO_2 Emissions, 2013 Planning Standard Emission PSE Portfolio - All (Millions Tons)

	Low	Base	High	Base + Low Gas Price	Base + High Gas Price	Base + Very High Gas Price	Base + No CO2	Base + High CO2	Base + Low Demand	Base + High Demand
2016	10.89	10.14	12.34	9.08	10.36	11.24	11.69	11.60	9.32	11.10
2017	11.57	10.12	12.89	9.42	11.11	11.78	12.24	12.13	9.18	11.25
2018	11.53	10.18	12.96	9.23	11.38	11.75	12.28	12.14	9.11	11.28
2019	11.25	9.93	12.89	8.61	11.63	11.69	12.13	11.95	8.68	10.98
2020	11.42	9.97	10.64	9.00	11.77	11.79	12.29	6.26	8.62	11.11
2021	11.37	10.09	10.16	9.19	11.72	11.81	12.35	6.02	8.80	11.32
2022	11.18	10.01	8.48	9.08	11.32	11.70	12.34	5.92	8.52	10.98
2023	11.05	9.91	7.96	7.94	11.26	11.70	12.41	5.57	8.31	10.72
2024	11.15	9.91	7.43	8.12	11.13	11.83	12.42	5.56	7.92	10.83
2025	10.58	9.90	8.76	9.15	11.13	11.30	11.86	5.73	8.34	10.98
2026	9.42	9.90	9.15	9.16	10.10	10.01	10.50	6.38	8.60	10.78
2027	9.54	9.89	9.00	8.97	10.13	10.17	10.57	5.85	8.48	10.91
2028	9.53	9.78	8.86	8.91	10.13	10.11	10.69	5.83	8.25	11.00
2029	9.81	10.09	8.08	9.33	10.48	10.44	11.07	5.93	8.36	11.28
2030	9.92	9.99	7.78	8.69	10.51	10.55	11.27	6.22	8.22	11.38
2031	9.91	9.93	7.84	7.95	10.47	10.51	11.32	6.34	8.16	11.58
2032	10.01	9.77	7.95	7.82	10.47	10.30	11.61	6.28	7.85	11.56
2033	10.01	9.72	8.21	7.71	10.49	10.39	11.74	6.39	7.66	11.87
2034	9.92	9.59	8.38	7.76	10.32	10.35	11.78	6.43	7.39	11.76
2035	10.06	9.47	8.53	7.45	10.38	10.57	12.08	6.49	7.04	11.66

Emission PSE Portfolio, Sensitivity - All (Millions Tons), 2013 Planning Standard

	No DSR	Bundle E	Bundle F	Bundle G
2016	10.19	10.14	10.14	10.13
2017	10.27	10.11	10.11	13.20
2018	10.45	10.17	10.17	13.28
2019	10.33	9.92	9.91	13.10
2020	10.48	9.95	9.94	13.20
2021	10.71	10.06	10.05	13.31
2022	10.63	9.98	9.97	13.14
2023	10.53	9.87	9.86	13.06
2024	10.75	9.86	9.85	13.07
2025	10.84	9.85	9.84	12.39
2026	10.81	9.84	9.83	9.64
2027	10.94	9.94	9.92	9.74
2028	10.86	9.71	9.70	9.63
2029	11.22	10.02	10.00	9.93
2030	11.05	9.91	9.89	9.82
2031	11.03	9.84	9.83	9.76
2032	10.89	9.69	9.67	9.60
2033	10.90	9.64	9.62	9.59
2034	10.80	9.50	9.49	9.42
2035	10.72	9.38	9.36	9.29

Figure N-36: Emission PSE Portfolio - WA (Millions Tons), 2013 Planning Standard

	Low	Base	High	Base + Low Gas Price	Base + High Gas Price	Base + Very High Gas Price	Base + No CO2	Base + High CO2	Base + Low Demand	Base + High Demand
2016	1.33	0.74	2.29	1.65	1.03	0.49	1.19	1.19	0.51	1.06
2017	1.27	0.66	3.08	1.51	0.80	0.38	1.07	1.08	0.42	0.95
2018	0.98	0.61	2.66	1.31	0.61	0.40	1.10	1.12	0.36	0.90
2019	1.07	0.75	2.69	1.66	0.64	0.48	1.20	1.27	0.44	1.15
2020	1.06	0.84	1.45	1.65	0.57	0.51	1.36	1.66	0.50	1.20
2021	1.33	1.19	1.76	1.82	0.80	0.75	2.06	1.76	0.63	1.71
2022	1.10	1.29	2.19	1.58	0.88	0.81	2.36	1.89	0.66	1.83
2023	1.37	1.28	3.33	2.22	0.98	0.79	2.54	1.97	0.63	1.88
2024	0.89	1.32	3.18	1.79	0.98	0.99	2.75	2.88	0.63	1.85
2025	0.78	1.06	2.94	1.63	0.80	0.77	2.30	2.84	0.49	1.60
2026	1.20	0.98	3.44	2.60	0.85	0.71	3.03	3.24	0.37	2.32
2027	1.20	0.96	3.58	3.53	0.85	0.71	3.99	3.20	0.37	2.33
2028	1.20	1.01	5.00	3.61	0.82	0.61	4.24	3.35	0.36	3.37
2029	1.06	1.00	4.81	3.39	0.86	0.63	4.41	3.25	0.35	3.14
2030	1.25	1.03	5.05	3.66	0.79	0.59	4.59	4.11	0.32	3.19
2031	1.70	1.02	6.77	3.89	0.79	0.46	5.03	4.25	0.41	4.37
2032	2.00	1.01	6.82	3.92	0.82	0.51	5.25	4.25	0.44	4.19
2033	2.10	1.08	7.71	4.01	0.73	0.47	5.46	4.39	0.47	5.24
2034	2.36	1.08	7.78	3.98	0.70	0.45	5.63	4.31	0.52	5.19
2035	2.54	0.96	7.70	3.90	0.65	0.43	5.87	4.31	0.50	5.16

Electric Integrated Portfolio Results–2015 Optimal Planning Standard

This table summarizes the expected costs of the different portfolios.

Figure N-37: Revenue Requirements for Optimal Portfolio with Expected Inputs for the Scenario, 2015 Optimal Planning Standard

Expected Cost for All Portfolios

Scenario	NPV to 2016 ($Millions)						
	Expected Portfolio Cost	Net Market Purchases / (Sales)	DSR Rev. Req.	Generic Rev. Req.	Generic End Effects	Variable Cost of Existing	REC Revenue
Base	$12,789	$3,790	$967	$2,104	$980	$4,956	($11)
Low	$7,669	$1,550	$1,082	$780	$516	$3,756	($16)
High	$17,991	$2,431	$1,134	$7,866	$747	$5,885	($76)
Base + Low Gas	$12,038	$2,991	$967	$2,132	$990	$4,967	($11)
Base + High Gas	$13,411	$4,713	$967	$1,584	$993	$5,163	($11)
Base + Very High Gas	$14,180	$5,459	$1,186	$1,622	$844	$5,091	($23)
Base + No CO2	$10,379	-$190	$967	$3,965	$775	$4,873	($11)
Base + High CO2	$13,948	$3,071	$967	$4,841	$641	$4,444	($17)
Base + Low Demand	$10,204	$3,882	$967	$835	$537	$4,000	($16)
Base + High Demand	$16,091	$3,410	$916	$4,419	$1,617	$5,744	($18)

Figure N-38: Annual Revenue Requirements for Optimal Portfolio ($Millions)
2015 Optimal Planning Standard

	Base	Low	High	Base + Low Gas	Base + High Gas	Base + Very High Gas	Base + No CO2	Base + High CO2	Base + Low Demand	Base + High Demand
2016	720	533	666	679	722	789	605	606	669	773
2017	767	574	773	743	783	844	645	646	709	874
2018	809	631	864	782	841	890	678	679	746	919
2019	801	585	888	766	853	886	667	667	730	967
2020	845	660	1,281	816	909	941	699	972	770	1,012
2021	902	610	1,375	871	969	1,010	789	1,080	771	1,083
2022	945	638	1,422	916	999	1,066	816	1,131	805	1,137
2023	1,042	616	1,615	982	1,091	1,165	849	1,188	813	1,322
2024	1,108	718	1,665	1,066	1,157	1,235	899	1,262	906	1,353
2025	1,180	752	1,775	1,142	1,252	1,291	1,004	1,415	963	1,440
2026	1,323	705	2,011	1,200	1,354	1,410	1,096	1,625	1,012	1,613
2027	1,395	717	2,149	1,270	1,497	1,503	1,143	1,713	1,100	1,664
2028	1,450	735	2,351	1,321	1,553	1,657	1,171	1,786	1,135	1,843
2029	1,620	852	2,596	1,490	1,677	1,808	1,241	1,938	1,230	1,973
2030	1,685	859	2,712	1,525	1,799	1,907	1,377	2,049	1,278	2,062
2031	1,792	910	2,933	1,614	1,893	2,115	1,438	2,277	1,370	2,333
2032	1,857	919	3,105	1,678	1,978	2,268	1,458	2,373	1,404	2,439
2033	2,015	940	3,395	1,831	2,083	2,392	1,507	2,489	1,483	2,678
2034	2,098	957	3,594	1,904	2,241	2,520	1,544	2,599	1,525	2,799
2035	2,181	967	3,828	1,980	2,340	2,683	1,569	2,724	1,565	2,945
20-yr NPV	11,808	7,153	17,244	11,048	12,418	13,336	9,604	13,307	9,668	14,474
End Effects	980	516	747	990	993	844	775	641	537	1,617
Expected Cost	12,789	7,669	17,991	12,038	13,411	14,180	10,379	13,948	10,204	16,091

Figure N-39: Incremental Portfolio Builds by Year (nameplate MW)
2015 Optimal Planning Standard

Base, Base + Low Gas Price

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	-	228	-	-	50	-	62	2
2022	-	-	-	-	100	-	66	2
2023	-	228	100	-	-	-	56	2
2024	-	-	100	-	-	-	55	2
2025	-	228	-	-	-	-	53	2
2026	385	-	-	-	-	-	27	2
2027	-	-	100	-	-	-	27	2
2028	-	-	-	-	-	-	27	2
2029	-	228	-	-	-	-	23	2
2030	-	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	228	-	15	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	385	1,138	300	15	150	-	906	148

Incremental Portfolio Builds by Year (nameplate MW), 2015 Optimal Planning Standard

Base + High Gas Price

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	-	228	-	-	50	-	62	2
2022	-	-	-	-	100	-	66	2
2023	-	228	100	-	-	-	56	2
2024	-	-	100	-	-	-	55	2
2025	-	228	-	-	-	-	53	2
2026	-	228	-	-	-	-	27	2
2027	-	228	100	-	-	-	27	2
2028	-	-	-	-	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	-	228	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	-	-	15	-	-	29	2
2034	-	228	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	-	1,593	300	15	150	-	906	148

Incremental Portfolio Builds by Year (nameplate MW), 2015 Optimal Planning Standard

Base + Very High Gas Price

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	77	18
2017	-	-	-	-	-	-	66	12
2018	-	-	-	-	-	-	71	39
2019	-	-	-	-	-	-	69	14
2020	-	-	-	-	-	-	84	35
2021	-	228	-	-	25	-	68	2
2022	-	-	-	-	75	-	72	2
2023	-	228	100	-	-	-	61	2
2024	-	-	100	-	-	-	59	2
2025	-	-	100	-	-	-	58	2
2026	-	455	-	-	-	-	28	2
2027	-	-	-	-	-	-	30	2
2028	-	228	-	-	-	-	29	2
2029	-	-	-	-	-	-	25	2
2030	-	-	-	-	-	-	25	2
2031	-	228	-	-	-	-	29	2
2032	-	-	200	-	-	-	35	2
2033	-	-	-	-	-	-	31	2
2034	-	-	-	-	-	-	26	2
2035	-	-	-	-	-	80	25	2
Total	-	1,366	500	-	100	80	968	148

Incremental Portfolio Builds by Year (nameplate MW), 2015 Optimal Planning Standard Low

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	24
2017	-	-	-	-	-	-	62	12
2018	-	-	-	-	-	-	66	65
2019	-	-	-	-	-	-	63	14
2020	-	-	-	-	-	-	77	69
2021	-	-	-	-	-	-	60	3
2022	-	-	-	-	-	-	64	3
2023	-	-	-	-	-	-	55	3
2024	-	-	200	-	-	-	54	3
2025	-	228	-	-	-	-	51	3
2026	-	228	-	-	-	-	26	3
2027	-	-	-	-	-	-	27	3
2028	-	-	-	-	-	-	27	3
2029	-	228	-	-	-	-	23	3
2030	-	-	-	-	-	-	23	3
2031	-	-	-	-	-	-	26	3
2032	-	-	-	-	-	-	32	3
2033	-	-	-	-	-	-	29	3
2034	-	-	-	-	-	-	24	3
2035	-	-	-	-	-	-	24	3
Total	-	683	200	-	-	-	888	230

Incremental Portfolio Builds by Year (nameplate MW), 2015 Optimal Planning Standard

Base + Low Demand

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	-	-	-	-	-	-	62	2
2022	-	-	-	-	-	-	66	2
2023	-	-	-	-	-	-	56	2
2024	-	-	200	-	-	-	55	2
2025	-	228	-	-	-	-	53	2
2026	-	228	-	-	-	-	27	2
2027	-	228	-	-	-	-	27	2
2028	-	-	-	-	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	-	-	-	-	80	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	-	683	200	-	-	80	906	148

Incremental Portfolio Builds by Year (nameplate MW), 2015 Optimal Planning Standard

Base + No CO_2

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	385	-	-	-	-	-	62	2
2022	-	-	-	-	-	-	66	2
2023	-	-	100	-	-	-	56	2
2024	-	-	100	-	-	-	55	2
2025	385	-	-	-	-	-	53	2
2026	385	-	-	-	-	-	27	2
2027	-	-	100	-	-	-	27	2
2028	-	-	-	-	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	385	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	-	-	15	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	1,542	-	300	15	-	-	906	148

Incremental Portfolio Builds by Year (nameplate MW), 2015 Optimal Planning Standard

Base + High CO_2

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	385	-	-	-	-	-	62	2
2022	-	-	-	-	-	-	66	2
2023	-	-	100	-	-	-	56	2
2024	-	-	100	-	-	-	55	2
2025	385	-	-	-	-	-	53	2
2026	385	-	-	-	-	-	27	2
2027	-	-	100	-	-	-	27	2
2028	-	-	-	-	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	-	-	100	-	-	-	23	2
2031	385	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	-	-	-	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	1,542	-	400	-	-	-	906	148

Incremental Portfolio Builds by Year (nameplate MW), 2015 Optimal Planning Standard High

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	DSR	DR
2016	-	-	-	-	-	-	75	24
2017	-	228	-	-	75	-	64	12
2018	-	-	-	-	50	-	67	65
2019	-	-	100	-	100	-	64	14
2020	-	-	-	-	25	-	79	69
2021	385	-	-	-	25	-	62	3
2022	-	-	-	-	50	-	66	3
2023	385	-	300	-	-	-	56	3
2024	-	-	-	-	-	-	55	3
2025	-	-	-	-	-	-	53	3
2026	385	-	-	-	-	-	27	3
2027	-	-	200	-	-	-	27	3
2028	385	-	-	-	-	-	27	3
2029	-	-	400	-	-	-	23	3
2030	-	-	-	-	-	-	23	3
2031	385	-	-	-	-	-	27	3
2032	-	-	-	-	-	-	32	3
2033	385	-	-	-	-	-	29	3
2034	-	-	-	-	-	-	25	3
2035	-	-	-	-	-	-	24	3
Total	2,312	228	1,000	-	325	-	906	230

Incremental Portfolio Builds by Year (nameplate MW), 2015 Optimal Planning Standard

Base + High Demand

Annual Builds (MW)	CCCT	Frame Peaker	WA Wind	Biomass	PBA	Battery	Solar	DSR	DR
2016	-	-	-	-	-	-	-	75	18
2017	-	228	-	-	75	-	-	62	12
2018	-	-	-	-	75	-	-	66	39
2019	-	228	-	-	-	-	-	63	14
2020	-	-	-	-	-	-	-	77	35
2021	-	228	-	-	50	-	-	60	2
2022	-	-	-	-	75	-	-	64	2
2023	-	228	400	-	-	-	-	55	2
2024	-	-	-	-	-	-	-	54	2
2025	-	228	-	-	-	-	-	51	2
2026	385	-	-	-	-	-	-	26	2
2027	-	-	-	-	-	-	-	27	2
2028	385	-	-	-	-	-	-	27	2
2029	-	-	-	-	-	-	-	23	2
2030	-	-	-	-	-	-	-	23	2
2031	385	-	100	-	-	-	-	26	2
2032	-	-	-	-	-	-	-	32	2
2033	385	-	-	-	-	-	-	29	2
2034	-	-	-	-	-	-	-	24	2
2035	-	-	-	-	-	-	20	24	2
Total	1,542	1,138	500	-	275	-	20	888	148

Figure N -40: Emission PSE Portfolio - All (Millions Tons), 2015 Optimal Planning Standard

	Low	Base	High	Base + Low Gas Price	Base + High Gas Price	Base + Very High Gas Price	Base + No CO2	Base + High CO2	Base + Low Demand	Base + High Demand
2016	10.89	10.14	12.34	9.08	10.36	11.24	11.69	11.60	9.31	11.10
2017	11.57	10.12	12.95	9.42	11.11	11.78	12.24	12.14	9.18	11.26
2018	11.53	10.18	12.99	9.23	11.38	11.75	12.28	12.15	9.11	11.29
2019	11.25	9.93	12.79	8.61	11.63	11.69	12.13	11.97	8.67	11.00
2020	11.42	9.97	10.51	9.00	11.77	11.79	12.29	6.28	8.61	11.14
2021	11.37	10.09	10.39	9.19	11.72	11.81	12.33	6.20	8.79	11.36
2022	11.18	10.01	9.01	9.08	11.32	11.70	12.33	6.12	8.50	11.26
2023	11.05	9.91	8.16	7.94	11.26	11.82	12.40	5.98	8.30	10.78
2024	10.92	9.91	7.62	8.12	11.13	11.83	12.40	5.69	7.90	10.90
2025	10.58	9.90	8.96	9.15	11.13	11.18	11.84	6.06	8.32	11.05
2026	9.42	9.92	9.36	9.16	10.10	9.90	10.50	6.70	8.58	10.86
2027	9.54	9.91	9.00	8.94	10.13	10.05	10.57	6.09	8.46	10.99
2028	9.53	9.81	8.86	8.87	10.13	10.11	10.70	6.09	8.23	11.09
2029	9.81	10.11	8.08	9.29	10.48	10.44	11.08	6.18	8.34	11.38
2030	9.92	10.02	7.77	8.65	10.51	10.55	11.26	6.20	8.20	11.48
2031	9.91	9.96	7.84	7.90	10.47	10.51	11.33	6.53	8.13	11.58
2032	10.01	9.83	7.94	7.74	10.47	10.42	11.67	6.59	7.82	11.67
2033	10.01	9.80	8.20	7.62	10.49	10.50	11.80	6.71	7.63	11.98
2034	9.92	9.67	8.38	7.66	10.32	10.46	11.85	6.75	7.36	11.88
2035	10.06	9.56	8.53	7.34	10.38	10.68	12.13	6.82	7.01	11.77

Emission PSE Portfolio - WA (Millions Tons), 2015 Optimal Planning Standard

	Low	Base	High	Base + Low Gas Price	Base + High Gas Price	Base + Very High Gas Price	Base + No CO2	Base + High CO2	Base + Low Demand	Base + High Demand
2016	1.33	0.74	2.29	1.65	1.03	0.49	1.19	1.19	0.51	1.06
2017	1.27	0.66	2.28	1.51	0.80	0.38	1.07	1.08	0.42	0.95
2018	0.98	0.61	1.96	1.31	0.61	0.40	1.10	1.12	0.36	0.90
2019	1.07	0.75	1.97	1.66	0.64	0.48	1.20	1.27	0.44	1.15
2020	1.06	0.84	0.91	1.65	0.57	0.51	1.36	1.66	0.50	1.20
2021	1.33	1.19	1.87	1.82	0.80	0.75	2.79	2.65	0.63	1.71
2022	1.10	1.29	2.28	1.58	0.88	0.81	3.15	2.79	0.66	1.83
2023	1.37	1.28	3.37	2.22	0.98	0.79	3.39	2.88	0.63	1.88
2024	0.89	1.32	3.22	1.79	0.98	0.99	3.63	2.86	0.63	1.85
2025	0.78	1.06	3.03	1.63	0.80	0.77	3.95	3.74	0.49	1.60
2026	1.20	1.61	3.53	2.60	0.85	0.71	4.66	4.09	0.37	2.32
2027	1.20	1.60	3.67	2.63	0.85	0.71	4.81	4.04	0.37	2.33
2028	1.20	1.66	5.05	2.72	0.82	0.61	5.08	4.21	0.36	3.37
2029	1.06	1.66	4.86	2.52	0.86	0.63	5.26	4.07	0.35	3.14
2030	1.25	1.71	5.08	2.79	0.79	0.59	6.35	4.11	0.32	3.19
2031	1.70	1.74	6.78	2.95	0.79	0.46	6.98	5.12	0.41	4.37
2032	2.00	1.71	6.83	3.00	0.82	0.51	7.24	5.12	0.44	4.19
2033	2.10	1.82	7.74	3.08	0.73	0.47	7.47	5.27	0.47	5.24
2034	2.36	1.84	7.80	3.06	0.70	0.45	7.66	5.17	0.52	5.19
2035	2.54	1.73	7.72	2.99	0.65	0.43	7.92	5.18	0.50	5.16

Candidate Resource Strategy Results

This table summarizes the expected costs of the different candidate resource strategies.

Figure N-41: Revenue Requirements for Optimal Portfolio with Expected Inputs for the Scenario Expected Cost for All Portfolios

Scenario	NPV to 2016 ($Millions)						
	Expected Portfolio Cost	Net Market Purchases / (Sales)	DSR Rev. Req.	Generic Rev. Req.	Generic End Effects	Variable Cost of Existing	REC Revenue
1 - All Frame Peaker	$12,531	$4,251	$967	$2,371	$911	$4,956	($14)
2 - Early Recip Peaker	$12,620	$4,251	$967	$2,460	$922	$4,956	($14)
3 - Early CCCT/Thermal Mix	$12,729	$3,259	$967	$3,561	$962	$4,956	($14)
4 - All CCCT	$12,761	$2,501	$967	$4,351	$921	$4,956	($14)
5 - Mix CCCT & Frame Peaker	$12,627	$3,456	$967	$3,262	$921	$4,956	($14)
6 - Add 300 MW Wind in 2021	$12,798	$3,903	$967	$3,051	$978	$4,956	($79)

Figure N-42 : Annual Revenue Requirements for Optimal Portfolio ($Millions)

	1 - All Frame Peaker	2 - Early Recip Peaker	3 - Early CCCT/Thermal Mix	4 - All CCCT	5 - Mix CCCT & Frame Peaker	6 - Add 300 MW Wind in 2021
2016	720	720	720	720	720	720
2017	767	767	767	767	767	767
2018	809	809	809	809	809	809
2019	801	801	801	801	801	801
2020	845	845	845	845	845	845
2021	912	926	925	925	912	981
2022	953	967	965	965	953	1,013
2023	1,029	1,042	1,040	1,040	1,029	1,079
2024	1,067	1,080	1,077	1,077	1,067	1,111
2025	1,116	1,129	1,127	1,287	1,116	1,154
2026	1,239	1,251	1,270	1,321	1,314	1,266
2027	1,340	1,352	1,379	1,368	1,362	1,363
2028	1,432	1,444	1,469	1,457	1,452	1,453
2029	1,546	1,558	1,581	1,569	1,565	1,563
2030	1,663	1,675	1,696	1,691	1,679	1,677
2031	1,771	1,782	1,801	1,796	1,786	1,781
2032	1,835	1,846	1,864	1,858	1,849	1,843
2033	1,983	1,994	2,022	2,011	2,004	1,987
2034	2,067	2,078	2,103	2,089	2,086	2,066
2035	2,153	2,163	2,186	2,171	2,168	2,148
20-yr NPV	11,620	11,698	11,767	11,840	11,707	11,820
End Effects	911	922	962	921	921	978
Expected Cost	12,531	12,620	12,729	12,761	12,627	12,798

Figure N-43: Revenue Requirement with Input Simulations – 1,000 Trials

Expected Portfolio Cost ($Millions)	Risk Simulation - 1000 Trials					
	1 - All Frame Peaker	2 - Early Recip Peaker	3 - Early CCCT/Thermal Mix	4 - All CCCT	5 - Mix CCCT & Frame Peaker	6 - Add 300 MW Wind in 2021
Minimum	$7,604	$8,214	$7,815	$7,549	$7,554	$7,554
1st Quartile (P25)	$9,974	$10,378	$10,008	$9,710	$9,767	$10,326
Mean	$11,343	$11,782	$11,392	$10,993	$11,138	$11,582
Median (P50)	$11,371	$11,791	$11,413	$11,052	$11,179	$11,605
3rd Quartile (P75)	$12,586	$13,052	$12,499	$12,048	$12,243	$12,638
TVar90	$14,589	$15,014	$14,412	$13,856	$14,147	$14,576
Maximum	$16,275	$16,750	$16,103	$15,545	$15,875	$16,188
Base Deterministic	$12,531	$12,620	$12,729	$12,761	$12,627	$12,798

Figure N-44: Incremental Portfolio Builds by Year (nameplate MW)

Option 1 - All Frame Peaker Portfolio

Annual Builds (MW)	CCCT	Frame Peaker	Recip Peaker	WA Wind	Biomass	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	-	277	-	-	-	-	62	2
2022	-	-	-	-	-	-	66	2
2023	-	-	-	206	-	-	56	2
2024	-	-	-	-	-	-	55	2
2025	-	126	-	-	-	-	53	2
2026	-	363	-	-	-	-	27	2
2027	-	214	-	-	-	-	27	2
2028	-	-	-	131	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	-	206	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	228	-	-	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	-	1,413	-	337	-	-	906	148

Incremental Portfolio Builds by Year (nameplate MW)

Option 2 - Early Recip Peaker

Annual Builds (MW)	CCCT	Frame Peaker	Recip Peaker	WA Wind	Biomass	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	-	-	277	-	-	-	62	2
2022	-	-	-	-	-	-	66	2
2023	-	-	-	206	-	-	56	2
2024	-	-	-	-	-	-	55	2
2025	-	126	-	-	-	-	53	2
2026	-	363	-	-	-	-	27	2
2027	-	214	-	-	-	-	27	2
2028	-	-	-	131	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	-	206	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	228	-	-	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	-	1,136	227	337	-	-	906	148

Incremental Portfolio Builds by Year (nameplate MW)

Option 3 - Early CCCT/Thermal Mix

Annual Builds (MW)	CCCT	Frame Peaker	Recip Peaker	WA Wind	Biomass	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	277	-	-	-	-	-	62	2
2022	-	-	-	-	-	-	66	2
2023	-	-	-	206	-	-	56	2
2024	-	-	-	-	-	-	55	2
2025	-	126	-	-	-	-	53	2
2026	385	-	-	-	-	-	27	2
2027	-	-	207	-	-	-	27	2
2028	-	-	-	131	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	-	206	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	-	225	-	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	662	332	432	337	-	-	906	148

Incremental Portfolio Builds by Year (nameplate MW)

Option 4 - All CCCT

Annual Builds (MW)	CCCT	Frame Peaker	Recip Peaker	WA Wind	Biomass	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	277	-	-	-	-	-	62	2
2022	-	-	-	-	-	-	66	2
2023	-	-	-	206	-	-	56	2
2024	-	-	-	-	-	-	55	2
2025	703	-	-	-	-	-	53	2
2026	-	-	-	-	-	-	27	2
2027	-	-	-	-	-	-	27	2
2028	-	-	-	131	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	206	-	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	228	-	-	-	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	1,414	-	-	337	-	-	906	148

Incremental Portfolio Builds by Year (nameplate MW)

Option 5 - Mix CCCT & Frame Peaker

Annual Builds (MW)	CCCT	Frame Peaker	Recip Peaker	WA Wind	Biomass	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	-	277	-	-	-	-	62	2
2022	-	-	-	-	-	-	66	2
2023	-	-	-	206	-	-	56	2
2024	-	-	-	-	-	-	55	2
2025	-	126	-	-	-	-	53	2
2026	577	-	-	-	-	-	27	2
2027	-	-	-	-	-	-	27	2
2028	-	-	-	131	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	-	206	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	228	-	-	-	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	805	609	-	337	-	-	906	148

Incremental Portfolio Builds by Year (nameplate MW)

Option 6 - Add 300 MW Wind in 2021

Annual Builds (MW)	CCCT	Frame Peaker	Recip Peaker	WA Wind	Biomass	Battery	DSR	DR
2016	-	-	-	-	-	-	75	18
2017	-	-	-	-	-	-	64	12
2018	-	-	-	-	-	-	67	39
2019	-	-	-	-	-	-	64	14
2020	-	-	-	-	-	-	79	35
2021	-	253	-	300	-	-	62	2
2022	-	-	-	-	-	-	66	2
2023	-	-	-	206	-	-	56	2
2024	-	-	-	-	-	-	55	2
2025	-	126	-	-	-	-	53	2
2026	-	363	-	-	-	-	27	2
2027	-	214	-	-	-	-	27	2
2028	-	-	-	131	-	-	27	2
2029	-	-	-	-	-	-	23	2
2030	-	206	-	-	-	-	23	2
2031	-	-	-	-	-	-	27	2
2032	-	-	-	-	-	-	32	2
2033	-	228	-	-	-	-	29	2
2034	-	-	-	-	-	-	25	2
2035	-	-	-	-	-	-	24	2
Total	-	1,389	-	637	-	-	906	148

Figure N - 45: Emission PSE Portfolio - All (Millions Tons)

	1 - All Frame Peaker	2 - Early Recip	3 - Early CCCT/Thermal Mix	4 - All CCCT	5 - Mix CCCT & Frame Peaker	6 - Add 300 MW Wind in 2021
2016	10.14	10.14	10.14	10.14	10.14	10.14
2017	10.12	10.12	10.12	10.12	10.12	10.12
2018	10.18	10.18	10.18	10.18	10.18	10.18
2019	9.93	9.93	9.93	9.93	9.93	9.93
2020	9.97	9.97	9.97	9.97	9.97	9.97
2021	10.09	10.09	10.10	10.10	10.09	9.75
2022	10.01	10.01	10.03	10.03	10.01	9.68
2023	9.79	9.79	9.81	9.81	9.79	9.45
2024	9.90	9.90	9.92	9.92	9.90	9.56
2025	9.90	9.90	9.92	9.97	9.90	9.57
2026	9.89	9.89	9.93	9.95	9.92	9.56
2027	9.99	9.99	10.03	10.05	10.02	9.66
2028	9.74	9.74	9.80	9.82	9.78	9.41
2029	10.05	10.05	10.10	10.13	10.09	9.72
2030	9.95	9.95	10.01	10.06	10.00	9.62
2031	9.88	9.88	9.95	10.01	9.94	9.56
2032	9.73	9.73	9.84	9.92	9.82	9.42
2033	9.72	9.72	9.85	10.00	9.87	9.41
2034	9.59	9.59	9.74	9.90	9.76	9.28
2035	9.47	9.47	9.63	9.81	9.66	9.17

Emission PSE Portfolio - WA (Millions Tons)

	1 - All Frame Peaker	2 - Early Recip	3 - Early CCCT/Thermal Mix	4 - All CCCT	5 - Mix CCCT & Frame Peaker	6 - Add 300 MW Wind in 2021
2016	0.74	0.74	0.74	0.74	0.74	0.74
2017	0.66	0.66	0.66	0.66	0.66	0.66
2018	0.61	0.61	0.61	0.61	0.61	0.61
2019	0.75	0.75	0.75	0.75	0.75	0.75
2020	0.84	0.84	0.84	0.84	0.84	0.84
2021	1.19	1.19	1.67	1.67	1.19	1.19
2022	1.29	1.29	1.78	1.78	1.29	1.29
2023	1.28	1.28	1.80	1.80	1.28	1.28
2024	1.32	1.32	1.82	1.82	1.32	1.32
2025	1.06	1.06	1.52	2.84	1.06	1.06
2026	0.98	0.98	2.06	2.63	1.93	0.98
2027	0.96	0.96	2.02	2.56	1.91	0.96
2028	1.01	1.01	2.10	2.69	1.98	1.01
2029	1.00	1.00	2.10	2.68	1.98	1.00
2030	1.03	1.03	2.15	3.14	2.05	1.03
2031	1.02	1.02	2.22	3.26	2.09	1.02
2032	1.01	1.01	2.18	3.20	2.06	1.01
2033	1.08	1.08	2.32	3.81	2.64	1.08
2034	1.08	1.08	2.36	3.92	2.68	1.08
2035	0.96	0.96	2.26	3.83	2.59	0.96

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 is 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."[9]

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).

9 / RCW 19.285.050 (1) (a) (b)

"Eligible Renewable Resources"

Figure N-46: Resources that meet RCW 19.285 definition of Eligible Renewable Resource

	Nameplate (MW)	Annual Energy (aMW)	Commercial Online Date	Market Price/ Peaker Assumptions	Capacity Credit Assumption
Hopkins Ridge	149.4	53.3	Dec 2005	2004 RFP	20%
Wild Horse	228.6	73.4	Dec 2006	2006 RFP	17.2%
Klondike III	50	18.0	Dec 2007	2006 RFP	15.6%
Hopkins Infill	7.2	2.4	Dec 2007	2007 IRP	20%
Wild Horse Expansion	44	10.5	Dec 2009	2007 IRP	15%
Lower Snake River I	342.7	102.5	Apr 2012	2010 Trends	5%
Snoqualmie Upgrades	6.1	3.9	Mar 2013	2009 Trends	95%
Lower Baker Upgrades	30	12.5	May 2013	2011 IRP Base	95%
Generic Wind 2023	206	71	Jan 2023	2015 IRP Base	8%
Generic Wind 2028	131	45	Jan 2028	2015 IRP Base	8%

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 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-47 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-47: 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-48: 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-49: 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.

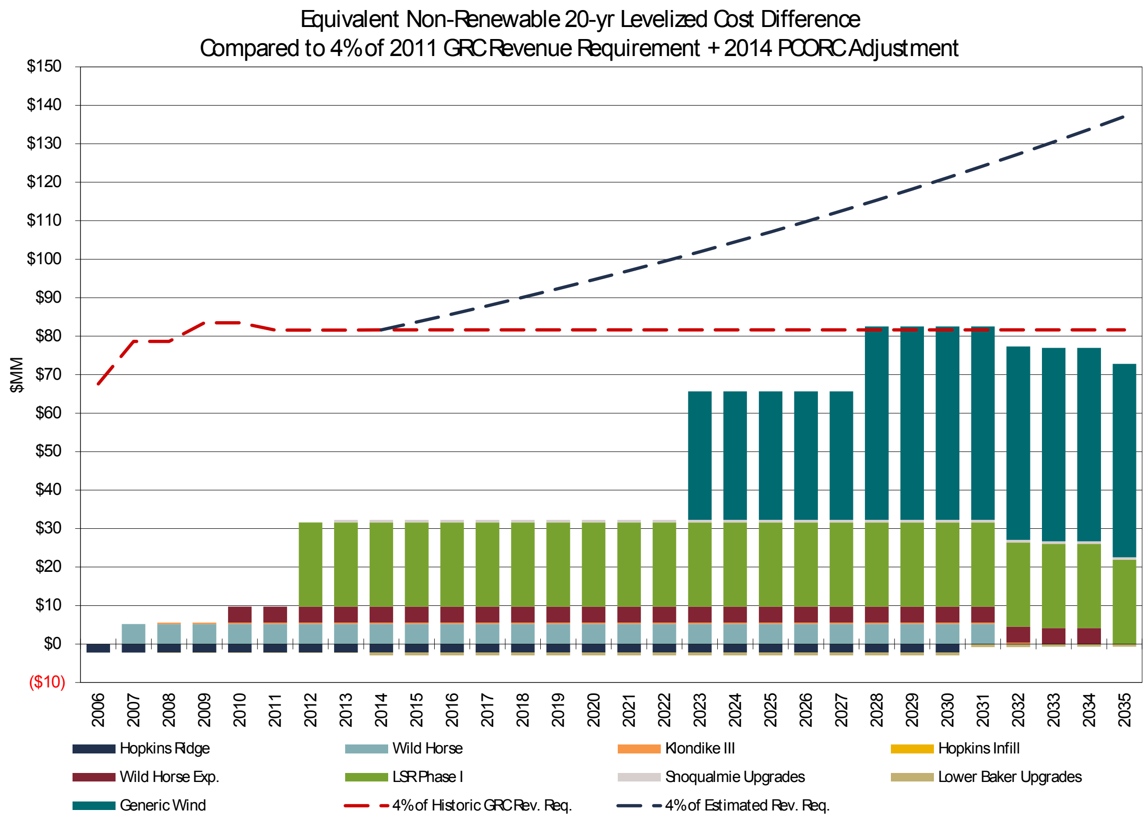
Figure N-50: 20-yr Incremental Cost of Wild Horse

($ 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/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-51 presents results of this analysis for existing resources and projected resources. This demonstrates PSE expects to meet the physical targets under RCW 19.285 without being constrained by the cost cap. A negative cost difference means that the renewable was lower-cost than the equivalent non-renewable, while a positive cost means that the renewable was a higher cost.

Figure N-51: 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.