Electric Analysis

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

1. Methods and Models

2. Data

1. Methods and Models

I. Methods

A. Planning Adjustment for Energy Efficiency Screening

PSE's planning team has developed a process that will directly incorporate demand resources into our portfolio analysis, as depicted in the diagram titled "2007 IRP Process" on page I-5 of this appendix. Integrating demand resources into our initial portfolio analysis achieves the kind of integrated resource planning called for in the rules set forth by the Washington Utilities and Transportation Commission (WUTC). It also allows us to examine the risk impacts of demand resources.

Demand resources are bundled into a manageable number of resources to effectively integrate them into the portfolio analysis. Bundling is performed using Quantec's cost effectiveness screening model, using a portfolio-based avoided cost approach. Quantec's model is capable of examining the benefit of demand resources based on hourly demands and hourly prices over a 20-year period, which amounts to more than 175,000 hourly data points for each of the 1700+ individual demand-resource measures.

i. Hourly "Prices" for Bundling and New Planning Adjustment Factor

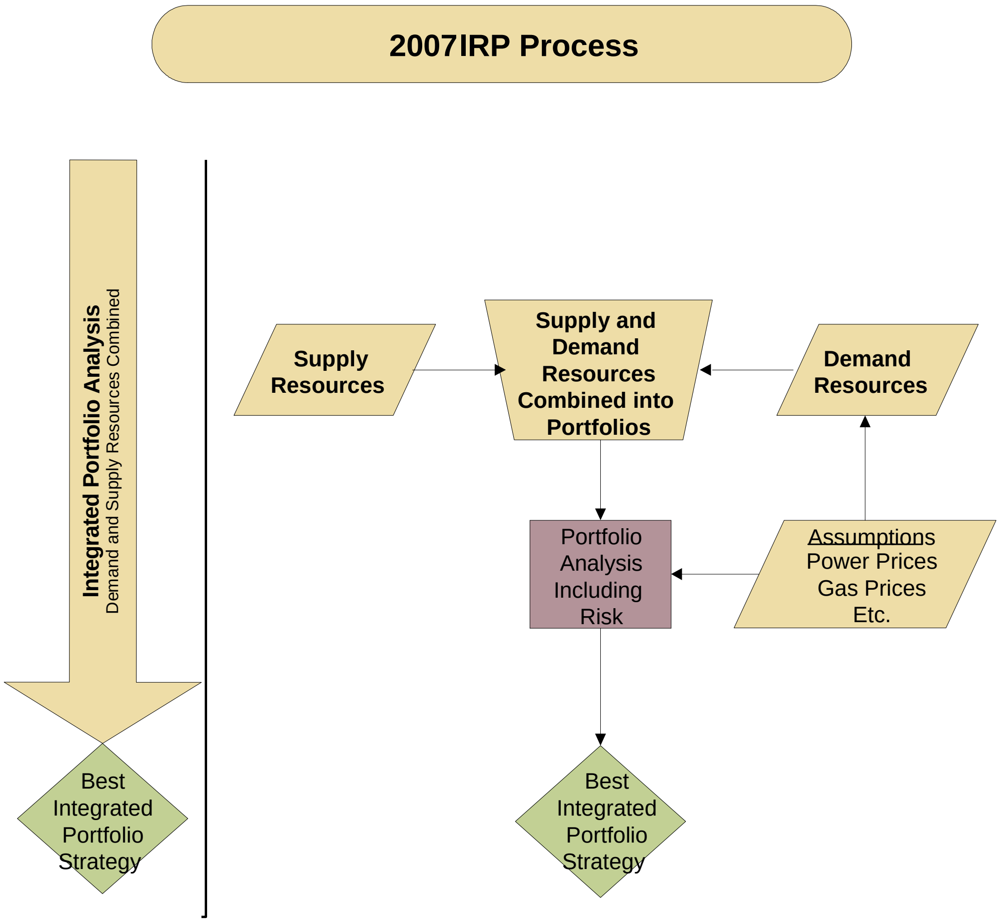
The hourly prices PSE provides to Quantec are based on Aurora price forecasts, and include adjustments consistent with PSE's cost effectiveness screening model. These include T&D benefits, system benefits charge, and line loss reduction. PSE has developed an additional adjustment called the "planning adjustment."

Our long-term planning standard calls for the Company to meet projected average energy requirements within each month of the year. It should be noted that this is not the same as stating that PSE will acquire resources as long as their cost is less than spot market (an approach more indicative of an energy marketer than a utility obligated to serve and manage risk). This IRP analysis indicates the incremental cost of PSE's 2005 LCP resource strategy is approximately 40% more costly than if the Company were to rely purely on spot market power. The "planning adjustment" is based on the portfolio strategy from the 2005 LCP, but with updated technology costs and characteristics, fuel prices, and power prices to reflect 2007 IRP assumptions. The difference between levelized spot prices and the levelized cost of the portfolio strategy is the planning adjustment. This adjustment provides a better estimate of the value energy efficiency would have in PSE's portfolio. For evaluating Demand Response, PSE provided Quantec an annual levelized cost of capacity resources. The all-in levelized number is calculated using $36.77 per KWyear, escalating annually during the first period of 2008 through 2013, and a levelized $90 per KW-year during the 2014 to 2027 period.

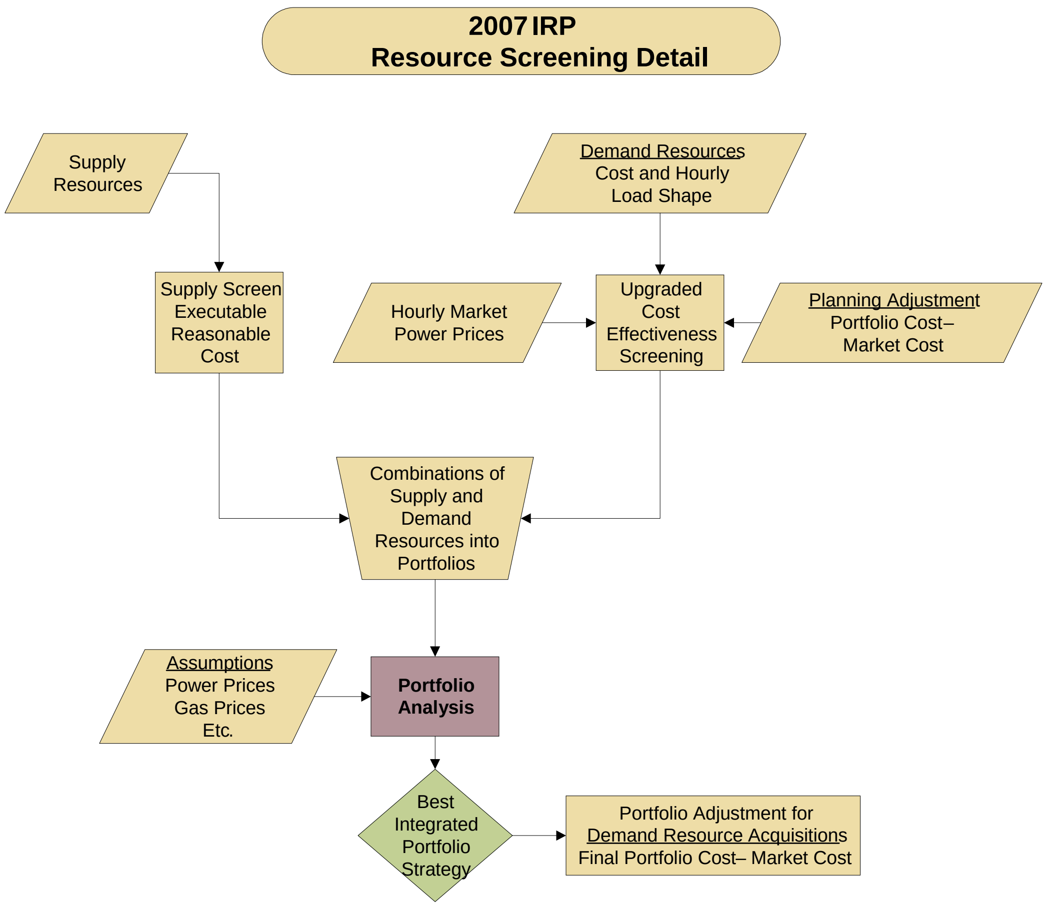
B. Diagrams of Process

PSE uses two models for integrated resource planning: AURORAxmp and the Portfolio Screening Model (PSM). AURORA analyzes the western power market to produce hourly electricity price forecasts of potential future market conditions, as described in Chapter 3. PSM tests electric supply and demand portfolios to evaluate PSE's long-term revenue requirements for the incremental portfolio. The followings diagrams show the methods used to quantitatively evaluate the lowest reasonable cost portfolio.

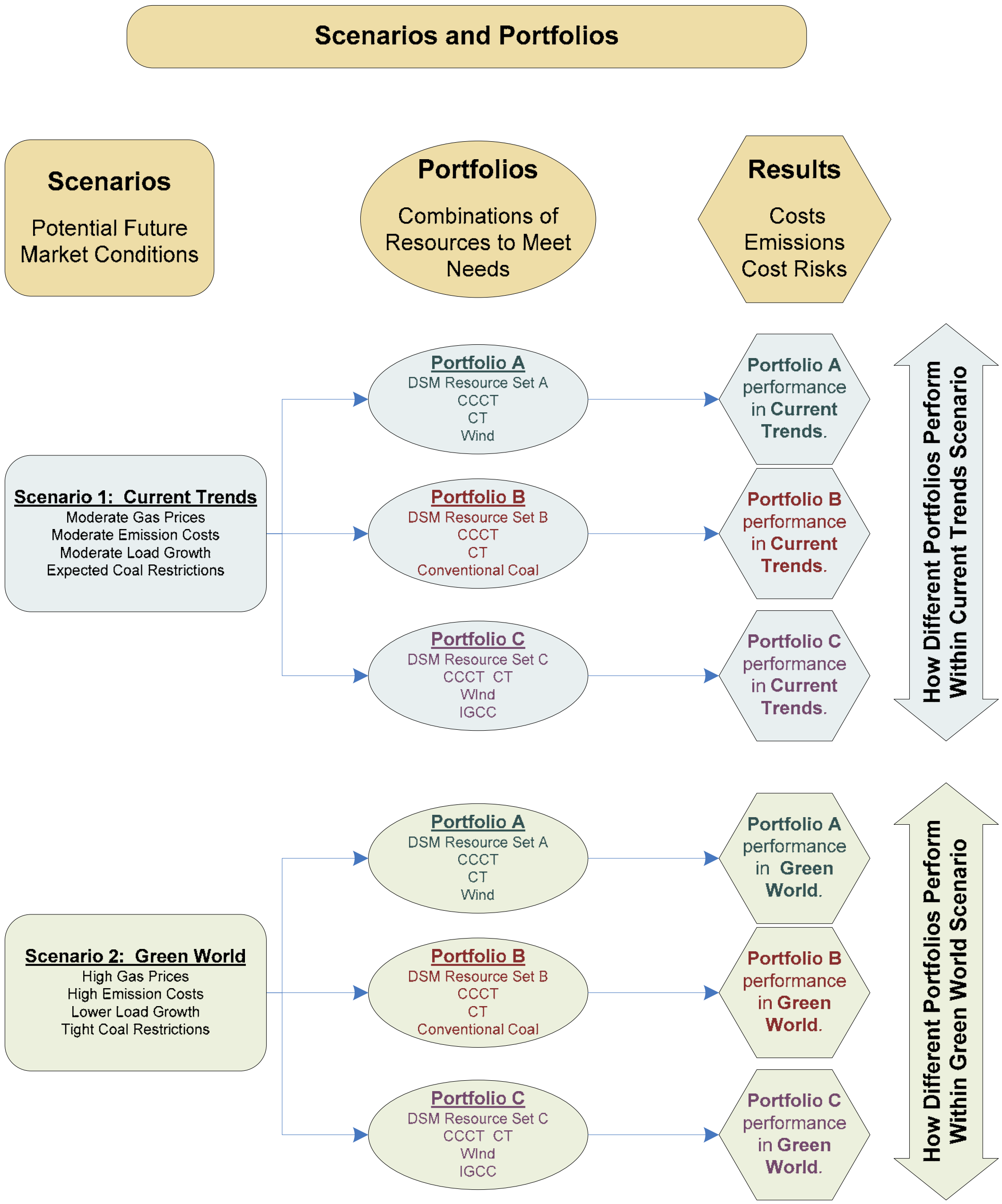
i. 2007 IRP Process



ii. Resource Screening



iii. Electric Resource Analysis



C. Risk Analysis

i. Scenarios

A description of the six scenarios can be found in Chapter 3, section 1, *Electric Analysis Components*. The monthly price output from these scenarios can be found in section 2 of this appendix.

ii. Portfolios

Below is a description of all 12 portfolios and the name that corresponds to the tables in section 2 of this appendix.

The key definitions and assumptions help to further define the portfolios:

- **Renewables**. Meet Washington's Renewable Portfolio Standards (RPS) of 3% by 2012, 9% by 2016 and 15% by 2020, and PSE's goal of 10% by 2013 with wind and biomass plants. In 2008, PSE meets slightly less than 5% of load with current wind resources (Wild Horse and Hopkins Ridge).
- **More Renewables**. Increase renewable energy development to 20% by 2017.
- **PBAs.** Power Bridging agreements used to balance energy need with short-term annual energy purchases that bridge the gap to long lead resources, limited to 500 MW.

Portfolio	Summary Description
1. Aggressive Gas	PSE meets Washington state RPS targets with wind and biomass plants. All other thermal requirements are met by gas-fired CCCT. No near-term PBAs.
1a. Early PBA Aggressive Gas	PSE meets Washington state RPS targets with wind and biomass plants. All other thermal requirements are met by gas-fired CCCT. PBAs used near-term.
2. Early IGCC	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT and IGCC capacity which is brought onine by 2014. A second IGCC plant comes online by 2020. PBAs used throughout.
3. Late IGCC	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT, and IGCC capacity (with no CCS) brought on line by 2020. PBAs used throughout.
3a. Early PBA Late IGCC	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT, and IGCC capacity (with no CCS) brought online by 2021. PBAs used near-term.
4. Max IGCC	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT and as many IGCC plants as PSE can bring online subject to the constraint of not exceeding more than 500 MW PBA at any time. First IGCC online in 2014, with the next online in 2016.
5. Late IGCC with CCS	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT and IGCC with CCS capacity brought online by 2021. No near-term PBAs
5a. Early PBA Late IGCC with CCS	Existing Washington state RPS targets are met with wind and biomass plants. Thermal requirements are met by gas-fired CCCT and IGCC with CCS capacity brought online by 2021. PBAs used near-term
6. Aggressive Renewables	PSE meets Washington state RPS targets with wind and biomass plants. All other thermal requirements are met by gas-fired CCCT through 2017. Increased reliance on wind post-2018 in amount sufficient to offset thermal energy additions. PBAs used near-term.
7. More Renewables with Gas	PSE increases its renewables to meet 20% of load by 2017. All other thermal requirements are met by gas-fired CCCT.
8. More Renewables and IGCC with CCS	PSE increases its renewables to meet 20% of load by 2017. All other thermal requirements are met by gas-fired CCCT and IGCC with CCS capacity brought online by 2021.
9. Last IRP Portfolio	PSE meets Washington state RPS targets with wind and biomass plants. All other future load requirements met using the same portfolio construction as the 2005 IRP. Thermal requirements met by CCCT and Conventional Coal brought online by 2016.

iii. Probabilistic Analysis of Risk Factors

In addition to using scenarios to assess risk, this 2007 IRP continues to assess portfolio uncertainty through probabilistic Monte Carlo modeling in the Portfolio Screening model. It relies on Monte Carlo analysis to consider four uncertainty factors: market prices for natural gas, market prices for power, wind generation variability, and hydroelectric generation availability.

iv. Risk Measures

The results of the Monte Carlo simulation allow PSE to calculate portfolio risk. Risk is calculated as the average value of the worst 10% of outcomes. This risk measure is the same as the risk measure used by NWPCC in its Fifth Power Plan. Additionally, we looked at annual volatility by measuring year to year changes in revenue requirements. Then we calculated the standard deviation of those year to year changes. The final measure of volatility is the average of the standard deviation across the simulations. 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.

II. Models

A. The AURORA Dispatch Model

i. Overview

PSE uses the AURORA model to estimate the market price of power used to serve its 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, regional demand for power, and transmission, which drive the electric energy market. 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.

ii. 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.

iii. Use of Reserve Margin Targets

During the summer of 2006, EPIS, Inc. released a new version of AURORAxmp, along with an input database that included the necessary inputs to perform long-term studies using planning reserve margin targets. The model builds resources to meet target reserve margins and estimates the "capacity price payments necessary to support the marginal entrants supplying capacity to the system."[1]

PSE uses reserve margin targets at the pool level, which consists of the Northwest Power Pool territory. The overall pool reserve margin target is 15%. PSE tested capacity pool reserve margins at 0%, 5%, and 15%. A pool reserve margin of 15% best mitigated summer price spreads without increasing average prices unreasonably. Many U.S. regions plan for at least a 15% reserve margin.

Existing units that cannot generate enough revenue to cover their variable and fixed operating costs over time are identified and become candidates for economic retirement. To reflect the timing of transition to competition across all areas, the rate at which existing units can be retired for economic reasons is constrained in these studies for a number of years.

B. Portfolio Screening Model

The Portfolio Screening Model (PSM) is a Microsoft Excel-based hourly dispatch simulation model the Company developed to evaluate incremental cost and risk for a wide variety of resource alternatives and portfolio strategies. The PSM calculates the

[1] EPIS, Inc., "Long-Term Studies Using Reserve Margins," from AURORAxmp electronic documentation, December 2005.

incremental portfolio costs of resources required to serve load. Incremental cost includes: (i) the variable fuel cost and emissions for PSE's existing fleet, (ii) the variable cost of fuel emissions and operations and maintenance for new resources, (iii) the fixed depreciation and capital cost of investments in new resources, (iv) the book cost and offsetting market benefit remaining at the end of the 20-year model horizon, and (v) the market purchases or sales in hours when resources are deficient or surplus to PSE's need.

PSM is a modeling tool that can

(i) quickly evaluate and compare results for a wide range and large number of alternative resource strategies;
(ii) calculate variable costs for all resources, including existing and new resources, as well as fixed costs for new resources (AURORA does not address fixed costs for new resources added to a utility's portfolio);
(iii) perform probabilistic analyses of several key uncertainty factors, including multiple correlations among uncertainty factors; and
(iv) address other topics, such as end effects for resource alternatives that have varying lives.

The primary input assumptions to the PSM are

(i) PSE's existing portfolio,
(ii) projected gas and power prices,
(iii) costs of generic resources,
(iv) financial assumptions such as cost of capital and escalation rates,
(v) variability of prices, and
(vi) a generic resource mix.

2. Data

I. Key Inputs and Assumptions

A. 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 21 areas primarily by state and province, except for California which has eight areas, Nevada which has two areas, and Oregon and Washington which are combined. 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.

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.

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). Previously, the generating resource landscape experienced few changes; however, numerous plants are now under construction and many more are in the planning stage. PSE uses current knowledge of Northwest resources, and utilizes EPIS, Henwood, public sources (e.g., Cal-ISO, CEC, etc.) and private contacts to update the over 3,000 electric power resources in the West. The model incorporates resources that are under construction with expected online dates; however, because of uncertainties caused by numerous factors, PSE includes only new plants that will be completed by 2008.

Power Plants under Construction

Plant	Location	Fuel	Capacity (MW)	Online Date
Spring Canyon	CO	Wind	60	1/1/2006
Galena Geothermal	NV	Geothermal	20	11/14/2005
Stillwater 11	NV	Geothermal	26	12/31/2007
Nevada Solar One	NV	Solar	3.1	12/1/2006
Argonne Mesa	NM	Wind	90	12/1/2006
Caprock Wind	NM	Wind	80	5/1/2005
White Creek	WA	Wind	100	12/1/2007
Klondike Wind III	OR	Wind	247.5	12/2/2007
Gross Hydroelectric Reservoir Project	CO	Hydro	7.6	5/1/2007
Mint Farm Power Station	WA	Gas	285	6/1/2007
Allen GT2	NV	Gas	75	6/1/2006
Horseshoe Bend (Great Falls) Ranch Pit Wind	MT	Wind	9	3/1/2006
Hidden Hollow	ID	Landfill Gas	3	4/1/2006
Desert Peak 2	NV	Geothermal	15	6/1/2006
Soderglen	AB	Wind	70.5	8/1/2006
Kettles Hill WF 1-30 (Pincher Creek)	AB	Wind	63	7/31/2006
China Creek	BC	Hydro	6.5	1/1/2006
Brilliant Expansion	BC	Hydro	120	8/1/2006
Chin Chute Wind Power Project	AB	Wind	30	10/30/2006
Furry Creek Hydro Project	BC	Hydro	11	6/1/2004
Richard Burdett Geothermal	NV	Geothermal	30	11/14/2005
Miller Creek	BC	Hydro	33	3/1/2003

Many states in the WECC have passed statutes requiring Renewable Portfolio Standards (RPS) to support the development of renewable resources. Typically an RPS states that a specific percentage of energy consumed must be from renewable resources by a certain date (e.g., 10% 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.

Coal prices were adopted from the August 2006 Global Insight price forecasts.

Water availability greatly influences the price of electric power in the Northwest. PSE assumes that hydro power generation is based on the average stream flows for the 50 historical years of 1929 to 1978. While there is also much hydro power 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 hydro power availability, or combine a past year's water flow to a future year's needs.

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."

B. Production Tax Credit and Renewable Portfolio Standard

i. Production Tax Credit Assumptions

Current federal production tax credit (PTC) legislation is effective through December 31, 2008. For modeling purposes, we continued PTCs at the current rate of $19 per MWh through 2009, and drop to a $10 per MWh credit in 2010 and 2011, representing a 50% probability that the PTCs will be extended for another two years. The PTCs are still assumed to be given to a project for 10 years after it is placed into service. The inflation adjuster will also be dropped. This suggestion allows for continued support for renewable energy while recognizing the fact that wind, in particular, has been heavily subsidized for a number of years. Another factor is the increasing number of states that have Renewable Portfolio Standards, which also leads to greater renewable energy capacity. While this may be a reasonable assumption, there is great uncertainty with respect to future PTCs and PSE will need to conduct additional sensitivity analyses for specific renewable resource proposals. Both wind and biomass receive the PTC; however, open-loop biomass only receives a partial PTC credit. For the purpose of modeling, we assumed open-looped Biomass is credited with half of the PTC.

ii. Renewable Portfolio Standard

As described above, a number of states in the WECC have Renewable Portfolio Standards, which determines the percentage of load that must be served with renewable resources. Each state has different rules regarding the definition of renewable energy sources, the timing of the standards, and the percentage of load that must be met.

In order to model these varying laws, we first need a load forecast for each state. The benchmarks of each RPS (e.g. 3% in 2015, then 5% in 2020) are identified and applied to the load forecast. After existing and expected renewable energy resources are accounted for, new renewable energy resources are matched to the load to meet the RPS. With internal and external review for reasonableness, these resources are created in the AURORA data base.

Important sources of information include: the AURORA data base for long run state load forecasts; summaries of the state RPSs from Lawrence Berkeley National Laboratory; and renewable resource potential for each state from the “Renewable Energy Atlas of the West.” Existing and expected renewable resources were identified in the AURORA data base, and updated with information from the Renewables Northwest Project and Global Energy Decisions' "New Entrants" data base.

New Mexico - The RPS requires 5% of retail sales to be renewable by 2006. RPS requirements increase by at least 1% a year, and utilities must reach 10% by January 1, 2011 and thereafter.

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.

State	Standard (LBNL)	Notes for AURORA Modeling
Arizona	New Proposed RPS: 1.25% in 2006, increasing by 0.25% each year to 2.00% 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.
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 20% requirement must be reached no later than 2017, but utilities may not have to meet the requirement if SBC funds are exhausted before the requirement is met: costs of renewables over a to-be-determined market price must be paid for by the state's SBC fund. Although not required, major push 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 and location that could meet the 20% by 2017 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	Utilities that serve over 40,000 customers must have 3% of their electricity from eligible renewable energy from 2007 through 2010; 6% from 2011 through 2014; and 10% in 2015 and beyond. New and existing renewables are eligible. At least 4% of the RPS standard must be met by	The primary resource for Colorado is wind. The 4% solar requirement is modeled as central power only.

	solar, with half of the solar requirement from on-site solar systems. Utilities acquire renewables or RECs via competitive bidding.	
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.
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	The Public Regulation Commission (PRC) passed an RPS rule on December 17, 2002, but the Legislature passed legislation in 2004 that is equivalent to the PRC rule. The RPS requires 5% of retail sales to be renewable by 2006. RPS requirements increase by at least 1% a year, and utilities must reach 10% by January 1, 2011 and thereafter.	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 - Washington	Proposed 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, and the governor has proposed 25% by 2025.	The loads and existing renewable resources for Oregon and Washington were combined and the proposed Washington RPS was applied to the combined area. While the Washington RPS is yet to be voted on, it is expected to pass and some RPS legislation is expected from Oregon in the future. Further, the wind resources along the Columbia River may be in either state, but the model has them in Oregon. Modeled resources also included biomass in each state and geothermal in Oregon.

C. Generic Resource Costs and Characteristics

Generic Resource Costs	Units	CCCT 2008	SCCT 2008	Wind 2008	Coal SCPC 2008	IGCC 2008	IGCC + CCS 2008	Biomass 2008	Geothermal 2008
Capacity	*MW*	250 (40 DF)	100	150	500	500	500	40	25
Capital Cost	*$/KW*	1,050	990	2,000	2,600	3,001	4,295	2,200	3,449
O&M - Fixed	*$/kW-yr*	21	7	43	25	35	42	175	132
O&M - Variable	*$/MWh*	3	4	2	5	3	4	0	2
Availability	*%*	95%	95%	30%	90%	85%	85%	85%	95%
Heat Rate - GT	*Btu/kWh*	7,000	8,934	n/a	9,000	8,655	9,848	14,000	n/a
Heat Rate - Duct Firing	*Btu/kWh*	9,100	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Fuel Price	*$/MMBtu*	n/a	n/a	n/a				incl in FO&M	n/a
Fixed Gas Transportation	*$/Dth per day*	$0.50	$0.18	n/a	n/a	n/a	n/a		n/a
Fuel Basis Differential	*$/MWh*	$2.69	$3.43	n/a	n/a	n/a	n/a		n/a
Fuel Basis Differential - DF	*$/MWh*	$3.22						n/a	n/a
Electric Transmission - Fixed	*$/kW-yr*	$14.9	$4.0	$24.1	$97.5	$50.7	$50.7	$14.9	$68.54
Electric Transmission - Variable	*$/MWh*	$1.0	$0.0	$7.2	$1.4	$1.8	$1.8	$1.0	$1.78
Fixed Transmission Build	*$/kW-yr*	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed	inlc in Fixed
Transmisssion Zone (% split)		1 & 2 (50%)	1 (100%)	3 (100%)	5 (100%)	2, 3 & 5 (33%)	2, 3 & 5 (33%)	1 & 2 (50%)	4 (100%)
Emissions:									
CO_2	*ton/GWh*	385 (501 DF)	491	n/a	957	920	0		
SO_2	*ton/GWh*	0.04 (0.06 DF)	0.05	n/a	0.32	0.3	0.3		
NOX	*ton/GWh*	0.00	0.00	n/a	0.56	0.13	0.13		
Hg									
Fixed Gas Transportation	*$/kW-yr*	30.66	4.70						

D. Wind Capacity Credit

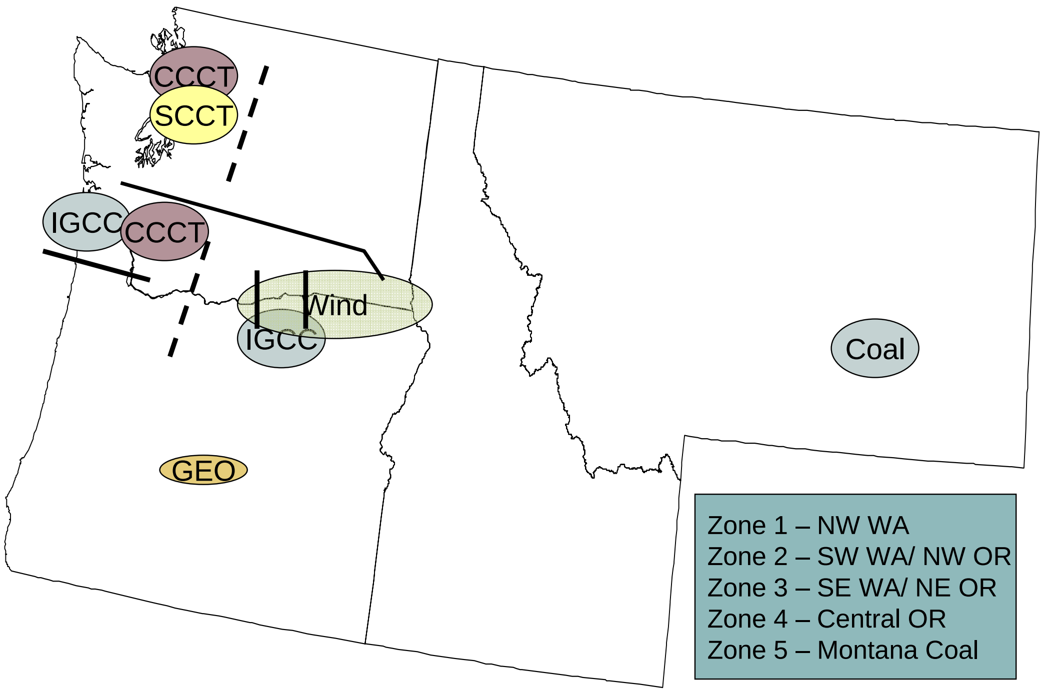
For the 2007 IRP, PSE is using 15% of plant name plate capacity for wind capacity credit when evaluating wind resources. We adopted the current recommendation that is being evaluated by the Pacific Northwest Resource Adequacy Forum in its pilot capacity adequacy standard, which was presented to the NWPCC on October 18, 2006.

E. Wind Profile

The following table provides information on zone 3 wind projects (see section F for zones). The January shape for peak capacity was derived by taking the average of these wind projects.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave	Factor
Avg % Energy (Zone 3)	29%	23%	43%	33%	40%	39%	40%	35%	32%	31%	27%	28%	400%	0.25
	7.1%	5.9%	10.8%	8.2%	9.9%	9.8%	10.1%	8.7%	8.0%	7.8%	6.8%	7.1%	100%	8.3%
Monthly aMW Factor	0.85	0.70	1.29	0.98	1.19	1.18	1.21	1.04	0.96	0.94	0.81	0.85	1.00	

F. Diagram of Transmission Zones



G. Monte Carlo Input Assumptions

The annual variability of power and gas prices, as well as the correlation between these variables, has been updated. Based on conversations with Horizon Wind Energy and with Global Energy Concepts, LLC, we updated the annual variability to 10%. The variability of hydroelectric generation and correlation with power prices was held at the same values used in the 2003 and 2005 Least Cost Plans.

The following table shows the Monte Carlo input assumptions.

	Variability and Distribution	Correlations		
		Gas Price	**Power Price**	**Hydro**
Gas Price	47% Log normal	1.0	.96	
Power Price	37% Log normal	.96	1.0	-.54
Mid-C Hydro	8% Normal		-.54	1.0
West Side Hydro	12% Normal		-.54	1.0
Wind	10% Normal			

II. Output

A. Aurora Electric Prices

Below is a series of tables with the AURORA price forecasts for the different scenarios.

Monthly Flat Mid-C Prices

(Nominal $/MWH)

Current Trends (CT)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.69	73.27	63.13	47.96	44.90	46.06	57.75	60.62	59.84	57.44	67.51	64.31	59.29
2009	65.35	70.62	60.67	46.52	42.55	43.51	54.19	56.98	57.22	54.37	66.34	61.55	56.65
2010	62.48	68.23	58.03	43.27	40.75	43.04	52.21	55.13	54.41	53.01	66.05	59.82	54.70
2011	61.34	67.06	56.98	41.67	38.99	41.16	49.12	53.14	52.69	51.58	64.91	57.83	53.04
2012	63.68	67.38	55.84	51.71	49.82	50.47	59.16	61.36	61.74	62.79	77.81	62.17	60.33
2013	64.89	68.59	56.87	53.55	51.15	50.51	60.61	63.78	64.69	63.40	74.77	64.56	61.45
2014	65.55	68.21	56.94	55.00	52.21	52.73	62.31	64.52	67.06	65.99	77.35	66.55	62.87
2015	64.77	66.79	56.61	54.91	52.41	53.77	62.32	64.59	67.25	66.23	77.54	65.99	62.77
2016	63.86	66.14	56.24	54.20	52.84	53.82	61.69	64.63	66.87	66.90	81.18	66.18	62.88
2017	67.44	67.79	58.63	57.29	55.97	57.08	66.00	68.34	69.72	71.71	86.03	69.00	66.25
2018	68.46	69.80	60.86	59.75	57.40	56.86	66.72	70.48	71.70	71.64	85.78	71.09	67.54
2019	71.50	71.38	62.15	62.66	59.77	58.96	70.10	73.39	74.76	75.53	89.82	75.22	70.44
2020	71.83	70.86	62.23	62.15	59.16	60.13	68.98	71.40	74.79	74.55	90.76	75.54	70.20
2021	76.30	75.98	67.04	63.78	58.56	58.83	67.57	70.40	73.59	73.89	96.33	82.08	72.03
2022	78.97	78.68	69.32	65.79	60.57	61.61	69.77	73.26	75.59	77.08	99.46	84.02	74.51
2023	81.78	80.50	71.15	67.43	62.97	63.11	72.29	75.82	77.17	80.33	102.85	85.50	76.74
2024	84.93	84.71	74.25	71.83	65.34	64.37	74.70	79.40	81.17	82.16	103.38	90.52	79.73
2025	86.92	87.47	76.67	73.41	66.83	66.87	77.67	80.66	83.94	84.76	106.81	93.33	82.11
2026	89.68	89.99	78.97	75.48	68.11	69.65	79.33	82.70	86.32	87.35	110.67	95.61	84.49
2027	92.28	92.60	82.29	77.96	69.99	72.71	82.33	85.87	88.74	90.17	115.79	98.53	87.44

Green World (GW)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.08	72.35	62.31	47.52	44.08	44.70	57.30	60.24	59.25	56.91	66.83	63.68	58.60
2009	65.51	70.57	60.56	46.77	42.62	43.52	54.70	57.42	57.09	54.32	65.96	61.18	56.69
2010	64.43	66.60	56.33	54.20	50.90	53.23	65.05	67.10	66.70	65.17	81.81	66.70	63.18
2011	64.05	65.76	56.18	54.30	51.83	53.43	65.06	67.92	67.39	66.15	84.61	66.36	63.59
2012	67.25	68.68	57.21	58.54	58.28	58.87	70.55	71.91	69.17	72.07	89.80	68.54	67.57
2013	67.44	69.62	58.60	59.99	58.61	57.96	70.92	73.74	73.13	72.10	85.97	70.43	68.21
2014	68.61	70.02	58.70	62.17	60.95	61.48	74.62	76.40	75.81	75.57	89.57	72.49	70.53
2015	68.28	69.03	58.86	63.42	61.79	63.79	76.41	77.73	77.25	76.98	91.17	72.73	71.45
2016	69.03	68.82	59.12	64.50	62.61	65.10	77.09	80.29	77.60	78.58	96.76	74.28	72.81
2017	71.44	70.78	61.31	67.42	67.38	68.80	82.54	84.99	81.11	84.26	103.29	77.31	76.72
2018	73.75	73.63	64.62	71.43	70.03	69.15	85.19	88.69	84.63	86.08	104.18	80.89	79.36
2019	76.11	74.82	65.92	74.93	74.25	73.21	91.19	92.68	88.43	90.73	110.00	84.82	83.09
2020	78.10	74.00	65.88	75.78	73.54	74.56	92.06	92.91	88.56	91.14	113.51	87.19	83.94
2021	79.34	76.90	68.29	78.35	75.91	78.05	95.79	96.84	92.67	95.13	120.93	90.03	87.35
2022	82.09	79.16	70.45	80.92	79.40	82.11	97.43	100.14	94.82	99.79	124.53	91.88	90.23
2023	84.69	81.18	72.04	82.35	82.49	84.31	100.71	102.22	96.34	103.13	129.59	94.28	92.78
2024	88.12	85.30	76.13	87.32	85.30	83.95	104.62	106.58	101.95	105.51	129.00	99.72	96.13
2025	90.51	87.58	77.73	88.74	86.05	86.63	106.29	106.68	104.21	107.99	132.67	103.23	98.19
2026	93.14	89.95	79.89	90.29	88.81	90.10	109.13	109.28	106.72	110.47	137.14	105.34	100.86
2027	95.75	93.09	83.01	93.53	92.26	94.02	112.28	113.75	110.22	114.36	143.38	108.35	104.50

Low Growth (LG)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.08	72.35	62.31	47.52	44.08	44.70	57.30	60.24	59.25	56.91	66.83	63.68	58.60
2009	65.20	69.54	59.96	46.00	42.80	43.91	54.28	57.08	56.69	53.97	65.45	60.54	56.29
2010	61.41	66.44	56.21	42.77	40.37	42.58	52.06	54.44	53.81	52.18	64.40	58.58	53.77
2011	59.90	64.79	55.91	41.25	38.96	40.72	49.40	52.14	51.37	50.14	63.35	56.38	52.02
2012	55.14	57.16	47.31	44.56	43.40	44.32	51.67	52.34	52.51	53.90	67.53	53.54	51.95
2013	53.58	56.82	46.81	44.14	42.07	42.57	50.11	51.80	53.60	52.78	62.36	53.44	50.84
2014	53.42	55.63	45.96	44.12	42.67	43.31	50.79	51.78	54.16	53.65	63.45	54.01	51.08
2015	52.16	54.58	45.19	44.31	42.74	44.36	51.11	52.08	54.71	53.95	63.47	52.91	50.96
2016	51.57	53.46	45.03	44.15	43.23	44.74	51.20	53.11	54.28	54.66	66.82	53.25	51.29
2017	52.06	52.26	44.62	44.63	44.35	46.13	52.50	53.58	54.19	56.27	68.53	53.23	51.86
2018	53.35	53.97	46.62	46.32	45.41	45.97	53.66	54.97	56.09	56.51	68.96	55.34	53.10
2019	55.90	55.61	47.77	48.79	47.99	47.99	56.55	57.61	58.82	59.49	72.75	58.68	55.66
2020	55.78	55.23	48.01	49.52	47.07	49.08	57.08	57.90	58.85	60.18	74.20	58.96	55.99
2021	56.82	57.10	49.67	50.96	48.91	51.04	58.47	59.62	60.51	62.30	78.36	60.93	57.89
2022	59.00	58.30	50.75	51.81	50.68	52.43	59.85	61.90	62.15	64.43	80.68	62.14	59.51
2023	60.37	59.25	51.93	52.61	52.35	53.88	61.03	62.80	62.82	66.76	83.18	63.05	60.84
2024	62.03	62.24	54.04	55.17	53.60	53.71	62.95	64.29	65.73	67.63	83.05	65.92	62.53
2025	63.73	63.59	55.40	56.43	54.37	55.84	64.30	65.06	67.84	69.83	85.30	68.47	64.18
2026	65.42	65.00	56.68	57.77	55.91	57.68	64.92	65.81	69.37	71.38	88.05	70.20	65.68
2027	67.07	66.48	58.63	59.11	57.01	59.00	66.40	68.00	71.16	73.39	91.48	71.89	67.47

Robust Growth (RG)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.91	73.79	63.18	48.43	44.50	46.01	58.16	60.84	60.40	57.80	67.96	64.47	59.54
2009	66.05	71.55	61.09	47.53	43.45	44.82	55.53	58.01	57.75	54.97	66.81	62.04	57.47
2010	65.79	67.97	56.59	55.18	51.57	52.78	64.02	66.84	66.71	65.47	82.47	67.24	63.55
2011	64.96	66.87	56.00	55.05	52.29	52.94	63.57	66.74	66.04	65.88	83.34	66.48	63.35
2012	66.16	67.59	56.55	57.14	55.59	56.21	66.54	69.05	67.61	69.72	86.89	66.75	65.48
2013	66.84	68.00	57.79	59.70	57.33	56.82	68.92	72.21	71.43	71.41	84.87	69.28	67.05
2014	67.83	68.66	58.00	61.90	60.25	60.57	72.82	75.07	74.95	74.91	88.85	71.74	69.63
2015	68.52	68.67	58.77	63.94	61.93	63.84	76.14	77.93	77.07	77.23	92.09	72.80	71.58
2016	69.70	68.89	59.66	65.34	63.82	65.11	77.67	81.53	78.51	80.54	98.60	75.41	73.73
2017	72.81	70.80	61.86	68.70	68.08	69.16	82.82	85.77	81.79	85.60	104.61	78.31	77.53
2018	74.96	73.87	65.11	72.25	70.77	69.03	84.78	88.57	85.05	87.71	105.73	82.01	79.99
2019	78.01	76.24	66.71	76.20	74.00	72.79	90.49	93.13	89.75	93.04	112.28	87.30	84.16
2020	78.50	75.57	66.44	76.30	73.01	74.47	90.83	91.34	89.29	92.90	115.30	88.95	84.41
2021	80.04	77.68	68.80	78.63	76.19	77.83	94.10	96.15	93.27	97.18	122.70	92.30	87.91
2022	84.31	81.73	71.89	82.13	81.15	83.46	99.64	103.72	97.61	103.18	130.41	96.63	92.99
2023	87.46	83.51	73.96	84.29	83.92	84.98	103.07	105.86	98.97	107.29	134.79	98.85	95.58
2024	91.54	88.54	77.25	89.63	86.75	85.37	107.03	111.49	106.22	110.21	134.79	105.03	99.49
2025	93.60	90.44	79.44	91.38	87.95	88.94	109.02	110.44	108.24	113.25	138.26	107.69	101.55
2026	96.37	93.74	82.38	94.21	90.32	92.95	111.63	113.33	111.98	116.42	143.78	110.99	104.84
2027	98.74	96.33	85.20	97.24	94.70	97.39	116.25	120.35	115.19	120.70	151.06	113.06	108.85

Technology Improvement

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.69	73.27	63.13	47.96	44.90	46.06	57.75	60.62	59.84	57.44	67.51	64.31	59.29
2009	65.81	71.15	60.62	46.99	43.17	44.63	54.74	57.30	57.58	54.70	66.91	61.80	57.12
2010	63.05	67.96	58.70	43.78	41.36	43.95	52.71	55.34	55.17	53.41	66.34	60.05	55.15
2011	60.90	66.06	56.54	41.78	39.23	41.24	49.35	52.40	52.45	51.40	64.83	57.74	52.83
2012	64.62	67.42	55.94	52.57	50.44	51.10	60.02	61.96	61.94	63.44	78.54	63.50	60.96
2013	65.92	68.52	57.40	54.67	51.91	51.92	61.48	63.66	64.38	63.41	74.62	65.35	61.94
2014	66.42	68.33	56.85	55.67	53.52	53.87	63.00	64.30	65.72	65.15	76.47	66.65	63.00
2015	66.29	68.31	57.10	56.77	54.10	55.12	64.18	65.35	66.68	66.28	77.69	66.84	63.73
2016	66.08	67.52	57.16	56.78	54.33	55.58	63.76	66.31	66.13	66.83	81.06	67.65	64.10
2017	68.94	69.44	59.09	59.58	57.72	58.57	67.33	69.26	68.77	70.91	85.47	70.18	67.10
2018	70.39	71.76	62.07	61.34	59.00	58.61	68.04	70.93	70.62	71.45	85.64	72.48	68.53
2019	73.24	73.85	63.51	64.78	62.01	61.10	71.05	73.39	73.47	75.03	89.97	76.09	71.46
2020	74.12	73.36	63.54	65.44	61.29	62.25	72.70	73.46	73.37	75.51	92.24	77.50	72.06
2021	79.21	79.48	69.08	66.62	59.95	61.45	70.63	71.71	72.13	74.19	97.26	83.99	73.81
2022	82.09	82.83	72.19	69.02	62.60	64.10	72.50	74.96	74.59	77.59	100.93	86.49	76.66
2023	85.23	85.49	75.05	71.12	65.42	66.42	74.98	77.06	76.92	81.66	105.15	88.77	79.44
2024	88.54	89.99	78.54	75.04	67.90	66.98	77.16	79.90	80.83	82.74	105.47	93.26	82.20
2025	90.28	92.54	80.19	77.06	69.16	69.52	79.57	81.24	83.61	84.80	108.66	95.87	84.38
2026	92.29	94.82	82.55	78.62	71.04	71.73	81.23	82.84	85.60	86.49	111.48	97.26	86.33

Escalating costs

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Ave
2008	68.69	73.27	63.13	47.96	44.90	46.06	57.75	60.62	59.84	57.44	67.51	64.31	59.29
2009	65.30	70.07	60.32	46.60	42.85	44.03	54.23	56.91	56.80	54.16	66.06	60.84	56.51
2010	61.79	67.82	58.12	42.88	40.48	42.58	51.26	53.96	54.35	52.63	66.27	59.52	54.31
2011	60.62	65.86	56.99	41.28	38.86	41.18	48.83	52.08	52.09	51.18	64.66	57.14	52.56
2012	63.41	66.68	55.52	51.42	49.90	50.66	59.58	61.09	61.07	62.72	77.71	62.07	60.15
2013	64.87	68.28	57.24	53.64	50.78	51.11	61.23	63.12	64.81	63.54	75.58	64.77	61.58
2014	65.15	67.65	57.00	54.70	52.35	53.05	62.35	63.85	66.13	65.45	77.35	66.51	62.63
2015	64.61	66.86	56.13	54.69	52.62	53.90	62.77	64.26	66.50	65.87	77.87	65.54	62.63
2016	63.86	66.12	55.96	54.16	53.00	54.46	62.45	65.12	65.99	66.51	81.13	66.12	62.91
2017	67.05	68.07	58.25	57.03	56.60	57.32	66.41	68.37	68.66	71.24	86.20	68.43	66.14
2018	68.08	69.54	60.26	58.91	57.17	57.11	66.87	70.03	70.52	71.42	85.85	70.83	67.22
2019	70.36	71.37	61.58	61.99	59.68	59.79	69.95	72.44	73.45	74.47	89.98	74.59	69.97
2020	70.46	70.26	61.35	61.94	59.06	60.21	70.39	71.59	72.99	74.32	90.96	74.65	69.85
2021	75.41	75.20	66.37	63.27	57.85	59.20	68.33	69.86	71.78	73.12	95.57	80.56	71.38
2022	77.58	77.82	68.32	64.91	60.62	61.14	69.56	72.25	73.21	75.55	98.28	82.01	73.44
2023	80.75	80.02	70.58	66.54	62.85	63.41	72.24	74.84	74.80	79.34	102.46	84.00	75.99
2024	83.77	84.86	74.27	70.81	64.92	63.94	75.23	77.88	79.06	81.06	103.05	89.30	79.01
2025	84.95	87.06	75.95	72.64	66.25	66.36	77.17	78.75	81.65	82.99	105.04	91.40	80.85
2026	88.60	90.06	78.84	75.23	67.75	69.62	79.78	81.34	84.88	86.03	110.24	94.73	83.92
2027	90.68	92.53	81.71	77.09	69.79	72.01	81.79	84.06	87.40	88.98	114.77	97.05	86.49

B. Electric Demand-Side Screening Results

The results in the following tables were part of the bundles provided by Quantec. See Appendix K for a discussion of Quantec's methodology and analysis.

	Annual Energy Savings (aMW)				
	Bundle 1 Current Trends	Bundle 2 CT+25% AC	Bundle 3 CT-10% AC	Bundle 4 Low Growth	Bundle 5 Green World
2008	29.4	29.7	26.9	27.2	30.1
2009	59.6	60.4	54.7	55.2	61.1
2010	90.8	91.9	83.1	84.2	92.8
2011	123.2	124.1	113.2	113.7	125.4
2012	156.5	157.6	144.6	144.1	159.3
2013	190.1	191.1	177.0	174.8	193.2
2014	225.5	226.4	210.4	206.7	228.6
2015	260.5	261.6	243.5	238.6	263.9
2016	295.4	298.4	276.5	271.5	299.0
2017	329.7	334.7	309.0	304.4	333.6
2018	340.3	348.1	320.2	315.4	344.9
2019	350.9	361.2	331.3	325.8	356.1
2020	361.5	374.0	342.3	336.2	368.1
2021	372.2	387.0	353.5	346.4	380.0
2022	383.9	400.6	365.5	357.0	392.3
2023	395.9	414.3	377.4	367.5	404.9
2024	407.4	427.0	388.5	377.3	416.8
2025	418.0	439.5	398.9	386.3	427.8
2026	428.5	451.9	409.3	395.3	439.0
2027	439.0	464.5	419.9	404.4	450.0

January Energy Savings (aMW)					
	Bundle 1 Current Trends	Bundle 2 CT+25% AC	Bundle 3 CT-10% AC	Bundle 4 Low Growth	Bundle 5 Green World
2008	35.9	36.5	32.7	32.7	37.0
2009	72.8	74.1	66.3	66.2	74.8
2010	111.1	112.8	100.9	101.0	113.7
2011	150.8	152.2	138.4	136.3	153.3
2012	191.1	192.7	176.8	172.6	194.1
2013	230.7	232.2	215.8	208.3	233.9
2014	272.2	273.8	255.9	245.2	275.5
2015	314.2	316.6	296.5	283.0	317.8
2016	356.9	363.2	337.4	323.6	360.6
2017	398.2	408.2	377.0	363.6	402.0
2018	409.7	424.0	389.3	376.3	414.2
2019	420.5	438.3	400.6	387.5	425.8
2020	431.5	452.3	412.2	398.6	438.9
2021	445.8	469.5	426.6	412.1	454.9
2022	459.8	485.7	440.5	424.7	469.8
2023	473.6	501.4	453.7	436.4	484.4
2024	486.8	515.7	465.7	447.0	498.0
2025	497.0	528.0	474.9	454.8	508.4
2026	509.8	543.1	487.3	465.5	522.0
2027	524.0	559.5	501.4	477.5	536.4

Total December Peak Reduction (MW)					
	Bundle 1 Current Trends	Bundle 2 CT+25% AC	Bundle 3 CT-10% AC	Bundle 4 Low Growth	Bundle 5 Green World
2008	63.7	64.9	59.0	58.7	65.1
2009	133.5	136.0	124.4	123.5	136.3
2010	214.5	217.5	200.1	199.2	218.0
2011	307.3	310.1	290.2	285.1	310.7
2012	405.7	408.8	386.5	377.7	409.5
2013	483.3	486.4	463.7	449.1	487.1
2014	538.7	542.9	517.8	498.2	542.8
2015	602.9	608.8	580.7	557.2	607.7
2016	669.7	683.5	645.8	621.0	674.7
2017	734.8	756.0	709.0	683.1	739.9
2018	750.7	778.7	725.7	701.9	757.0
2019	775.1	808.2	750.3	725.9	782.6
2020	789.2	826.5	764.5	741.1	799.8
2021	811.0	853.1	785.1	761.9	824.1
2022	833.3	879.2	806.1	780.5	847.8
2023	857.8	906.9	828.4	799.5	873.9
2024	885.3	934.8	852.0	821.8	902.2
2025	907.3	958.8	870.6	838.8	924.5
2026	922.6	976.4	883.8	851.8	941.1
2027	946.7	1002.6	906.3	873.1	965.5

Total Costs (Thousands $)					
	Bundle 1 Current Trends	Bundle 2 CT+25% AC	Bundle 3 CT-10% AC	Bundle 4 Low Growth	Bundle 5 Green World
2008	$88,508	$97,372	$70,869	$66,563	$93,142
2009	$89,183	$99,721	$70,806	$67,650	$94,701
2010	$94,339	$103,818	$72,787	$72,278	$98,158
2011	$102,741	$108,930	$92,248	$74,844	$104,220
2012	$105,913	$113,030	$96,448	$78,468	$110,927
2013	$103,127	$106,935	$97,095	$72,932	$105,441
2014	$112,808	$118,105	$102,636	$79,549	$113,971
2015	$125,074	$135,956	$113,815	$92,964	$128,301
2016	$127,691	$164,748	$114,059	$111,660	$130,533
2017	$127,404	$168,006	$113,115	$113,481	$129,355
2018	$54,615	$96,886	$49,684	$57,174	$62,701
2019	$58,880	$93,870	$53,513	$56,811	$72,548
2020	$74,530	$101,216	$65,707	$64,720	$95,499
2021	$81,843	$100,341	$65,671	$62,636	$94,341
2022	$100,630	$120,617	$83,962	$80,808	$110,275
2023	$116,080	$142,289	$100,214	$89,057	$130,205
2024	$113,439	$136,875	$96,994	$87,036	$127,287
2025	$96,764	$131,528	$80,368	$71,247	$106,187
2026	$100,172	$130,932	$86,198	$74,811	$115,158
2027	$104,700	$128,956	$88,324	$75,463	$110,277

C. Electric Integrated Portfolio Results

Static Results from PSM using DSM Bundle 1 (Current Trends)

Portfolio	1	1a	2	3	3a	4	5	5a	6	7	8	9	
	Aggressive Gas	**Early PBA Aggressive Gas**	**Early IGCC**	**Late IGCC**	**Early PBA Late IGCC**	**Max IGCC**	**Late IGCCwCCS**	**Early PBA Late IGCCwCCS**	**Aggresive Renewables**	**More Renew w Gas**	**More Renew w IGCCwCCS**	**Last IRP Portfolio**	
Current Trends	$14,561	$14,506	$14,614	$14,502	$14,389	$14,616	$14,682	$14,626	$15,556	$14,891	$15,041	$14,685	*Millions $*
	$57.71	$57.49	$57.92	$57.48	$57.03	$57.93	$58.19	$57.97	$61.66	$59.02	$59.61	$58.20	*$/MWh*
	4	3	5	2	1	6	8	7	12	10	11	9	*Rank*
Green World	$17,710	$17,664	$18,355	$18,059	$17,916	$18,685	$17,536	$17,490	$18,282	$17,869	$17,751	$18,303	*Millions $*
	$72.55	$72.36	$75.19	$73.98	$73.39	$76.54	$71.84	$71.65	$74.89	$73.20	$72.71	$74.98	*$/MWh*
	4	3	11	8	7	12	2	1	9	6	5	10	*Rank*
Low Growth	$13,286	$13,230	$13,788	$13,492	$13,379	$14,077	$13,673	$13,616	$14,678	$13,752	$14,152	$13,816	*Millions $*
	$54.43	$54.20	$56.48	$55.27	$54.81	$57.67	$56.01	$55.78	$60.13	$56.33	$57.97	$56.60	*$/MWh*
	2	1	8	4	3	10	6	5	12	7	11	9	*Rank*
Robust Growth	$16,511	$16,457	$16,064	$16,152	$16,079	$15,786	$16,366	$16,316	$17,073	$16,685	$16,592	$16,177	*Millions $*
	$62.25	$62.04	$60.56	$60.89	$60.62	$59.51	$61.70	$61.51	$64.37	$62.90	$62.55	$60.99	*$/MWh*
	9	8	2	4	3	1	7	6	12	11	10	5	*Rank*
Technology Improvement	$14,166	$14,083	$14,049	$13,980	$13,903	$13,954	$14,160	$14,086	$14,851	$14,427	$14,456	$14,294	*Millions $*
	$56.15	$55.82	$55.68	$55.41	$55.11	$55.31	$56.12	$55.83	$58.86	$57.18	$57.30	$56.65	*$/MWh*
	8	5	4	3	1	2	7	6	12	10	11	9	*Rank*
Escalating Costs	$14,384	$14,329	$14,526	$14,398	$14,270	$14,571	$14,504	$14,449	$14,827	$14,634	$14,784	$14,543	*Millions $*
	$57.01	$56.79	$57.57	$57.06	$56.56	$57.75	$57.48	$57.27	$58.77	$58.00	$58.59	$57.64	*$/MWh*
	3	2	7	4	1	9	6	5	12	10	11	8	*Rank*

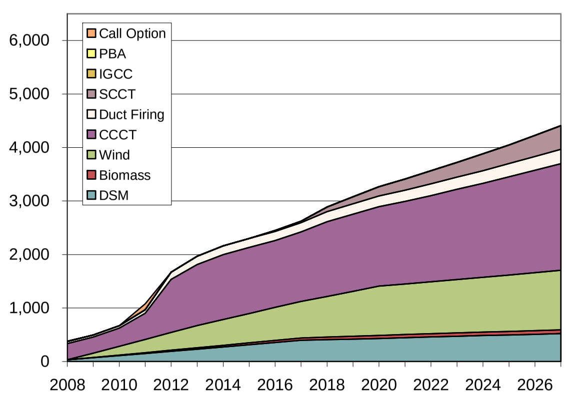
"Least Cost" Portfolio
Second "Least Cost" Portfolio
Third "Least Cost" Portfolio

Portfolio: Aggressive Gas
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	299		40	152	501	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	40		5	20	68	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	6	(6)									0	0%
Call Option				107	(107)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	381	116	172	408	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	99	45	43	62	67	73	68	82	78	78	1,992	45%
SCCT	60	46	42	34	35	33	40	31	44	49	441	10%
IGCC											0	0%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	13	6	6	8	9	10	9	11	10	11	269	6%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs											0	0%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($640)	($361)	($590)	($413)	($849)	($587)
Cost of Power Purchase	$3,160	$5,515	$2,617	$4,546	$2,465	$3,274
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$7,741	$6,674	$6,994	$8,184	$8,255	$7,492
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$432	$285	$612	$208	$291	$388
Expected Cost	$14,561	$17,710	$13,286	$16,511	$14,166	$14,384
Expected Cost $/MWh	$57.71	$72.55	$54.43	$62.25	$56.15	$57.01

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

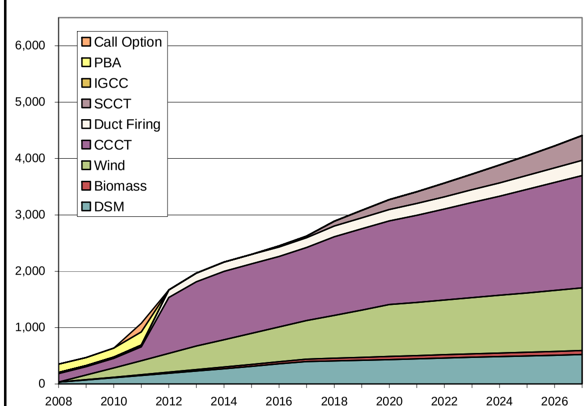
Mean	$14,400
Average of 10 Worst	$15,361
Annual Volatility	30%

Portfolio: Early PBA Aggressive Gas
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	746	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	101	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	(233)						0	0%
Call Option				153	(153)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	99	45	43	62	67	73	68	82	78	78	1,992	45%
SCCT	60	46	42	34	35	33	40	31	44	49	441	10%
IGCC											0	0%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	13	6	6	8	9	10	9	11	10	11	269	6%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs											0	0%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($650)	($371)	($602)	($419)	($865)	($597)
Cost of Power Purchase	$3,016	$5,366	$2,471	$4,387	$2,307	$3,125
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$7,830	$6,775	$7,086	$8,290	$8,346	$7,585
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$442	$295	$622	$214	$292	$398
Expected Cost	$14,506	$17,664	$13,230	$16,457	$14,083	$14,329
Expected Cost $/MWh	$57.49	$72.36	$54.20	$62.04	$55.82	$56.79

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

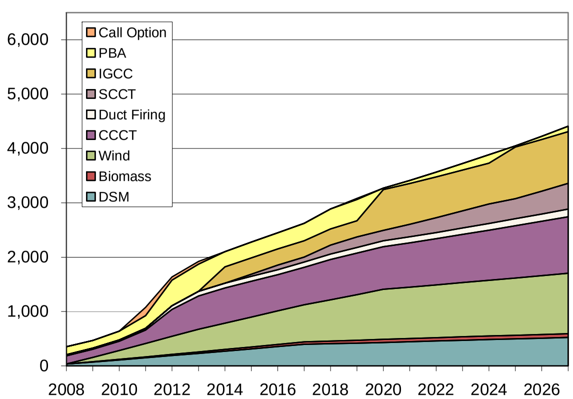
Mean	$14,342
Average of 10 Worst	$15,263
Annual Volatility	29%

Portfolio: Early IGCC
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	251	117	37	10	8	23	692	26%
SCCT								40	42	11	93	4%
IGCC							300				300	11%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	34	16	5	1	1	3	93	4%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	238	29	(220)	10	8	22	320	12%
Call Option				153	(93)	(7)	(52)				0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	560	285	181	174	173	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	50	23	21	31	34	37	34	41	39	39	1,039	24%
SCCT	70	29		39	41	40	46	8	51	57	475	11%
IGCC			450					200			950	22%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	7	3	3	4	5	5	5	6	5	5	140	3%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	47	22	(363)	30	32	34	33	(131)	37	37	98	2%
Call Option		21	(21)								0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($661)	($408)	($630)	($409)	($854)	($613)
Cost of Power Purchase	$2,057	$3,547	$1,616	$3,176	$1,678	$2,125
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,978	$9,024	$8,327	$9,443	$9,077	$8,831
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$371	$593	$822	($131)	$143	$366
Expected Cost	$14,614	$18,355	$13,788	$16,064	$14,049	$14,526
Expected Cost $/MWh	$57.92	$75.19	$56.48	$60.56	$55.68	$57.57

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

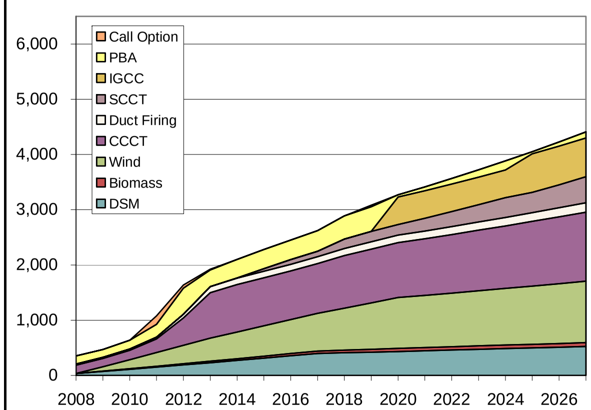
Mean	$14,508
Average of 10 Worst	$15,357
Annual Volatility	22%

Portfolio: Late IGCC
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	251	328	37	10	8	23	902	34%
SCCT							3	43	42	11	99	4%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	34	44	5	1	1	3	122	5%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	238	(171)	35	10	8	22	375	14%
Call Option				153	(93)	(46)	(13)				0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	560	285	178	177	173	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	50	23	21	31	34	37	34	41	39	39	1,250	28%
SCCT	70	21		40	41	39	47	8	51	57	474	11%
IGCC			500					200			700	16%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	7	3	3	4	5	5	5	6	5	5	169	4%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	47	22	(405)	29	32	35	32	(131)	37	37	110	2%
Call Option		29	(29)								0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($653)	($386)	($614)	($408)	($858)	($602)
Cost of Power Purchase	$2,300	$4,007	$1,833	$3,490	$1,828	$2,379
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,627	$8,335	$7,866	$9,157	$8,860	$8,453
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$359	$505	$753	($72)	$146	$350
Expected Cost	$14,502	$18,059	$13,492	$16,152	$13,980	$14,398
Expected Cost $/MWh	$57.48	$73.98	$55.27	$60.89	$55.41	$57.06

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

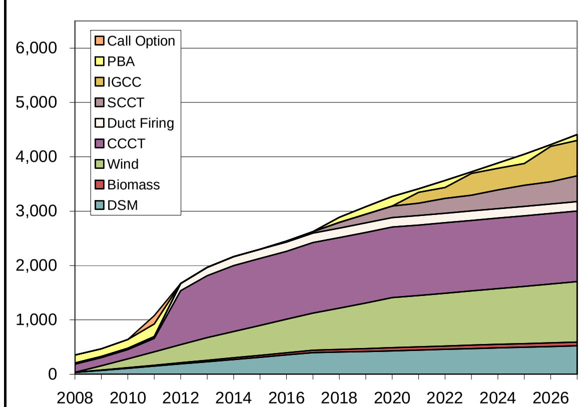
Mean	$14,373
Average of 10 Worst	$15,213
Annual Volatility	24%

Portfolio: Early PBA Late IGCC
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	746	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	101	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	(233)						0	0%
Call Option				153	(153)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT											1,297	29%
SCCT	79	54	50	16	48	16	53	46	21	64	473	11%
IGCC				200		200			250		650	15%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing											175	4%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	94	43	41	(112)	64	(100)	65	78	(139)	74	108	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($641)	($369)	($595)	($405)	($842)	($589)
Cost of Power Purchase	$2,763	$4,853	$2,254	$4,081	$2,171	$2,858
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,186	$7,482	$7,466	$8,631	$8,545	$7,987
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$213	$352	$602	($213)	$25	$197
Expected Cost	$14,389	$17,916	$13,379	$16,079	$13,903	$14,270
Expected Cost $/MWh	$57.03	$73.39	$54.81	$60.62	$55.11	$56.56

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

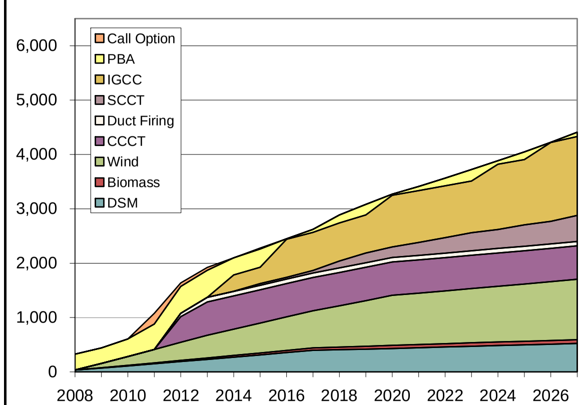
Mean	$14,296
Average of 10 Worst	$15,225
Annual Volatility	27%

Portfolio: Max IGCC
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT					471	142					613	23%
SCCT							3	30		15	48	2%
IGCC							300		400		700	27%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing					64	19					83	3%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	290	(6)	38	144	29	5	(184)	19	(324)	44	55	2%
Call Option				198	(134)	(12)	(52)	16	(16)		0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	326	116	165	471	560	285	178	177	173	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT											613	14%
SCCT	79	54	13	45	48	47	15	46	21	64	479	11%
IGCC			250				250		250		1,450	33%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing											83	2%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	94	43	(172)	59	64	69	(147)	78	(139)	74	78	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($700)	($456)	($678)	($443)	($880)	($654)
Cost of Power Purchase	$1,770	$3,081	$1,351	$2,836	$1,465	$1,822
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$9,381	$9,746	$8,858	$9,759	$9,332	$9,275
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$297	$716	$893	($351)	$33	$311
Expected Cost	$14,616	$18,685	$14,077	$15,786	$13,954	$14,571
Expected Cost $/MWh	$57.93	$76.54	$57.67	$59.51	$55.31	$57.75

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

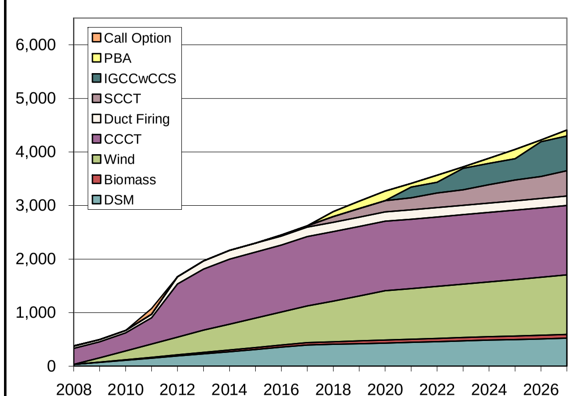
Mean	$14,628
Average of 10 Worst	$15,508
Annual Volatility	19%

Portfolio: Late IGCC with CCS
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	299		40	152	501	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCCwCCS											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	40		5	20	68	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	6	(6)									0	0%
Call Option				107	(107)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	381	116	172	408	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT											1,297	29%
SCCT	79	54	50	16	48	16	53	46	21	64	473	11%
IGCCwCCS				200		200			250		650	15%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing											175	4%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	94	43	41	(112)	64	(100)	65	78	(139)	74	108	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($631)	($359)	($584)	($398)	($825)	($579)
Cost of Power Purchase	$2,905	$4,941	$2,399	$4,239	$2,331	$3,006
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,263	$7,401	$7,538	$8,689	$8,583	$8,022
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$277	($45)	$666	($148)	$68	$237
Expected Cost	$14,682	$17,536	$13,673	$16,366	$14,160	$15
Expected Cost $/MWh	$58.19	$71.84	$56.01	$61.70	$56.12	$57.48

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

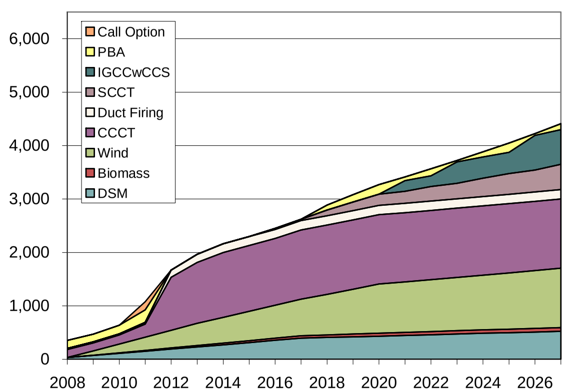
Mean	$14,586
Average of 10 Worst	$15,559
Annual Volatility	29%

Portfolio: Early PBA Late IGCC with CCS
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	746	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCCwCCS											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	101	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	(233)						0	0%
Call Option				153	(153)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT											1,297	29%
SCCT	79	54	50	16	48	16	53	46	21	64	473	11%
IGCCwCCS				200		200			250		650	15%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing											175	4%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	94	43	41	(112)	64	(100)	65	78	(139)	74	108	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($641)	($369)	($596)	($405)	($842)	($589)
Cost of Power Purchase	$2,762	$4,791	$2,252	$4,080	$2,171	$2,857
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,350	$7,505	$7,631	$8,794	$8,677	$8,115
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$287	($35)	$676	($138)	$77	$247
Expected Cost	$14,626	$17,490	$13,616	$16,316	$14,086	$14,449
Expected Cost $/MWh	$57.97	$71.65	$55.78	$61.51	$55.83	$57.27

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

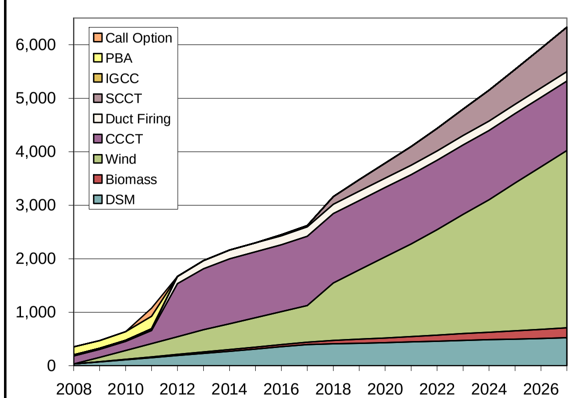
Mean	$14,530
Average of 10 Worst	$15,457
Annual Volatility	28%

Portfolio: Aggressive Renewables
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	149		20	76	746	148	74	20	17	46	1,297	49%
SCCT									20	7	26	1%
IGCC											0	0%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	101	20	10	3	2	6	175	7%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	(233)						0	0%
Call Option				153	(153)						0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	592	298	195	136	152	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT											1,297	20%
SCCT	116	72	66	69	73	74	79	77	88	93	833	13%
IGCC											0	0%
Wind	390	222	219	216	239	261	245	289	276	276	3,315	52%
Duct Firing											175	3%
Biomass	21	13	12	12	13	14	13	16	15	15	186	3%
PBAs											0	0%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	8%
Total	539	317	308	311	339	362	350	391	391	398	6,330	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($742,576)	($400,424)	($672,633)	($532,027)	($987,142)	($681,450)
Cost of Power Purchase	$2,695,490	$4,667,559	$2,197,627	$3,977,317	$2,121,598	$2,788,234
PPA Revenue Requirement	$980,107	$980,107	$980,107	$980,107	$980,107	$980,107
Generic Revenue Requirement	$8,877,237	$7,934,763	$8,204,274	$9,283,697	$9,146,116	$8,352,464
Variable Cost of Existing Fleet	$2,888,053	$4,617,739	$2,672,777	$3,004,881	$3,024,359	$2,837,233
End Effects	$857,909	$482,359	$1,295,839	$359,427	$566,169	$550,533
Expected Cost	$15,556,221	$18,282,102	$14,677,992	$17,073,403	$14,851,208	$14,827,121
Expected Cost $/MWh	$61.66	$74.89	$60.13	$64.37	$58.86	$58.77

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

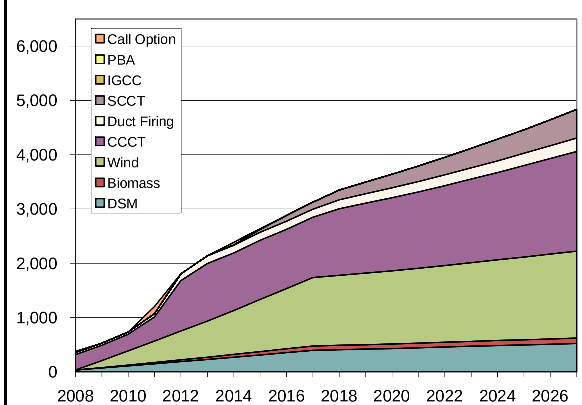
Mean	$15,472
Average of 10 Worst	$16,419
Annual Volatility	26%

Portfolio: More Renewables with Gas
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW)										2008-2017 Total Additions	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	MW	Percent
CCCT	283		24	136	485	132		32		19	1,110	35%
SCCT							5	48	54	22	129	4%
IGCC											0	0%
Wind		129	132	133	135	136	145	149	150	152	1,261	40%
Duct Firing	38		3	18	65	18		4		3	150	5%
Biomass		8	8	8	8	8	9	9	9	9	79	3%
PBAs	21	(21)					46	(36)	(10)		0	0%
Call Option				133	(131)	(2)					0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	13%
Total	378	153	206	468	603	331	247	249	246	245	3,127	100%

	Supply Additions (Nameplate Capacity in MW)										2008-2027 Total Additions	
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	MW	Percent
CCCT	115	61	60	59	64	70	65	79	74	75	1,834	38%
SCCT	52	37	33	35	37	34	42	32	46	51	529	11%
IGCC											0	0%
Wind	28	28	30	30	34	37	37	38	39	39	1,602	33%
Duct Firing	16	8	8	8	9	9	9	11	10	10	248	5%
Biomass	2	2	2	2	2	2	2	2	2	2	100	2%
PBAs											0	0%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	11%
Total	223	148	143	149	160	167	169	173	185	192	4,836	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($698)	($388)	($633)	($473)	($932)	($641)
Cost of Power Purchase	$2,866	$4,979	$2,353	$4,170	$2,252	$2,970
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,371	$7,376	$7,678	$8,789	$8,781	$8,059
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$485	$305	$702	$214	$322	$428
Expected Cost	$14,891	$17,869	$13,752	$16,685	$14,427	$14,634
Expected Cost $/MWh	$59.02	$73.20	$56.33	$62.90	$57.18	$58.00

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

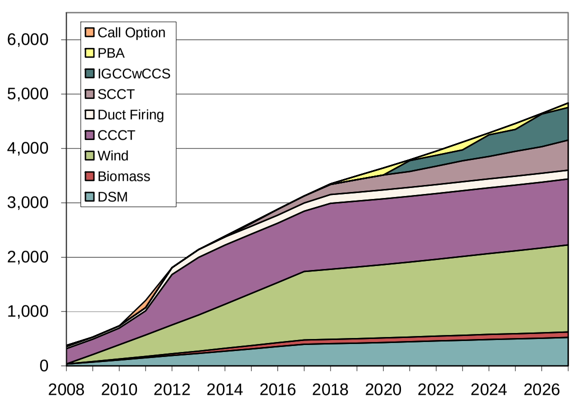
Mean	$14,753
Average of 10 Worst	$15,664
Annual Volatility	29%

Portfolio: More Renewables with IGCC w CCS
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW) 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2008-2017 Total Additions MW	Percent
CCCT	283		24	136	485	132	32			19	1,109	35%
SCCT								53	54	22	129	4%
IGCCwCCS											0	0%
Wind		129	132	133	135	136	145	149	150	152	1,261	40%
Duct Firing	38		3	18	65	18	4			3	150	5%
Biomass		8	8	8	8	8	9	9	9	9	79	3%
PBAs	21	(21)					16	(6)	(10)		0	0%
Call Option				133	(131)	(2)					0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	13%
Total	378	153	206	468	603	331	248	248	246	245	3,126	100%

	Supply Additions (Nameplate Capacity in MW) 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2008-2027 Total Additions MW	Percent
CCCT	101										1,210	25%
SCCT	54	49	44	17	49	47	24	47	29	65	554	11%
IGCCwCCS				200			200		200		600	12%
Wind	28	28	30	30	34	37	37	38	39	39	1,602	33%
Duct Firing	14										163	3%
Biomass	2	2	2	2	2	2	2	2	2	2	100	2%
PBAs	14	58	57	(114)	61	67	(108)	75	(99)	71	82	2%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	11%
Total	223	148	143	149	160	167	169	173	185	192	4,835	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($693)	($388)	($632)	($461)	($913)	($637)
Cost of Power Purchase	$2,670	$4,522	$2,187	$3,932	$2,153	$2,764
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,811	$7,976	$8,148	$9,204	$9,055	$8,507
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$384	$42	$795	($68)	$157	$332
Expected Cost	$15,041	$17,751	$14,152	$16,592	$14,456	$14,784
Expected Cost $/MWh	$59.61	$72.71	$57.97	$62.55	$57.30	$58.59

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

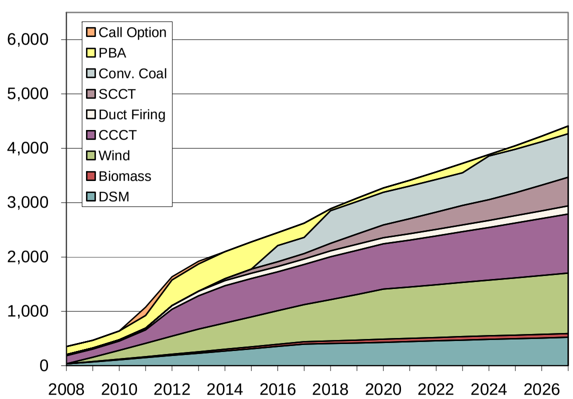
Mean	$15,902
Average of 10 Worst	$15,457
Annual Volatility	27%

Portfolio: Last IRP Portfolio
DSM Bundle: Current Trends

	Supply Additions (Nameplate Capacity in MW) 2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2008-2017 Total Additions MW	Percent
CCCT	149		20	76	251	117	74	21	8	23	739	28%
SCCT							35	41	12	11	100	4%
Conv. Coal									300		300	11%
Wind		80	83	84	85	85	65	67	67	67	683	26%
Duct Firing	20		3	10	34	16	10	3	1	3	100	4%
Biomass		5	5	5	5	5	4	4	4	4	43	2%
PBAs	148	(6)	19	72	238	29			(262)	22	260	10%
Call Option				153	(93)	(7)	(52)				0	0%
DSM	36	37	38	40	40	40	41	42	43	41	398	15%
Total	354	116	169	439	560	285	178	177	173	172	2,622	100%

	Supply Additions (Nameplate Capacity in MW) 2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2008-2027 Total Additions MW	Percent
CCCT	50	23	21	31	34	37	34	41	39	39	1,087	25%
SCCT	40	50	46	40	41	39	27	38	51	57	529	12%
Conv. Coal	300						200				800	18%
Wind	77	79	82	23	26	28	28	29	29	29	1,112	25%
Duct Firing	7	3	3	4	5	5	5	6	5	5	147	3%
Biomass	5	5	5	1	2	2	2	2	2	2	69	2%
PBAs	(223)	22	20	29	32	35	(148)	39	37	37	140	3%
Call Option											0	0%
DSM	12	11	11	14	14	14	13	10	13	14	524	12%
Total	266	192	189	143	153	159	161	164	176	183	4,408	100%

Capacity MW (Cumulative Additions)



Static Results for Each Scenario

(20-Year NPV in Millions $)	Current Trends	Green World	Low Growth	Robust Growth	Technology Improvement	Escalating Cost
Revenue from Power Sales	($668)	($402)	($631)	($419)	($868)	($618)
Cost of Power Purchase	$2,105	$3,725	$1,672	$3,233	$1,703	$2,175
PPA Revenue Requirement	$980	$980	$980	$980	$980	$980
Generic Revenue Requirement	$8,896	$8,802	$8,218	$9,362	$9,132	$8,708
Variable Cost of Existing Fleet	$2,888	$4,618	$2,673	$3,005	$3,024	$2,837
End Effects	$484	$581	$904	$16	$321	$461
Expected Cost	$14,685	$18,303	$13,816	$16,177	$14,294	$14,543
Expected Cost $/MWh	$58.20	$74.98	$56.60	$60.99	$56.65	$57.64

Dynamic Results - 100 Trials
(Current Trends Scenario in Millions $)

Mean	$14,618
Average of 10 Worst	$15,438
Annual Volatility	22%

Total Emissions Intensity for Each Portfolio

Total Rate (lbs CO2/MWh)

	Aggressive Gas	Early PBA Aggressive Gas	Early IGCC	Late IGCC	Early PBA Late IGCC	Max IGCC	Late IGCC with CCS	Early PBA Late IGCC with CCS	Aggressive Renewables	More Renewables with Gas	More Renewables IGCC w CCS	Last IRP Portfolio
2008	965	973	973	973	973	981	965	973	973	966	966	973
2009	928	937	937	937	937	946	928	937	937	922	922	937
2010	927	937	937	937	937	946	927	937	937	916	916	937
2011	870	884	884	884	884	897	870	884	884	852	852	884
2012	880	879	898	898	879	899	880	879	879	855	855	898
2013	852	852	882	870	852	882	852	852	852	823	823	882
2014	848	847	936	867	847	938	848	847	847	813	811	877
2015	814	813	901	833	813	904	814	813	813	768	768	843
2016	802	801	887	821	801	962	802	801	801	747	747	893
2017	810	810	889	826	810	963	810	810	810	745	745	895
2018	783	782	867	804	787	943	788	787	749	725	726	933
2019	776	776	858	797	782	934	783	782	728	725	729	924
2020	772	772	930	879	781	972	781	781	712	728	734	919
2021	768	767	922	871	811	963	726	726	688	723	679	909
2022	773	773	925	876	819	967	735	735	675	728	688	914
2023	771	770	922	874	851	965	687	687	652	726	690	911
2024	760	760	910	863	842	993	681	681	624	716	634	936
2025	756	756	937	890	840	989	683	682	599	712	636	931
2026	764	763	943	897	887	1,034	637	636	589	719	601	937
2027	754	753	929	885	877	1,019	634	634	563	710	599	923