Northwest Power and Conservation Council

April 27, 2011

MEMORANDUM

TO: Power Committee

FROM: Massoud Jourabchi

SUBJECT: Overview of PacifiCorp 2011 Integrated Resource Plan (IRP)

PacifiCorp filed its 2011 IRP with state regulatory commissions on March 31, 2011. The filing will initiate the state processes for acknowledgment in Idaho, Oregon, Utah, Washington and Wyoming. PacifiCorp IRP manager Peter Warnken will briefly present the process, major assumptions and key findings.

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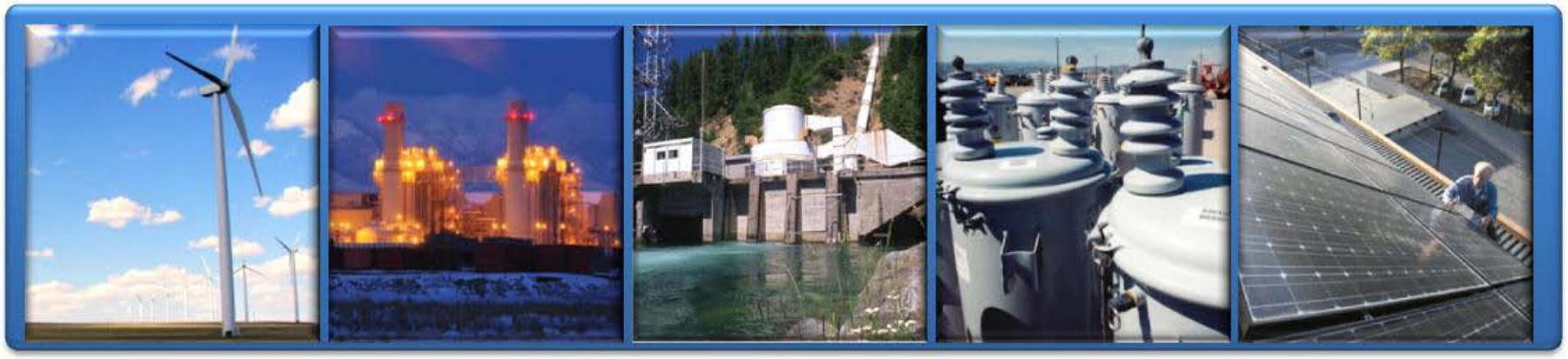


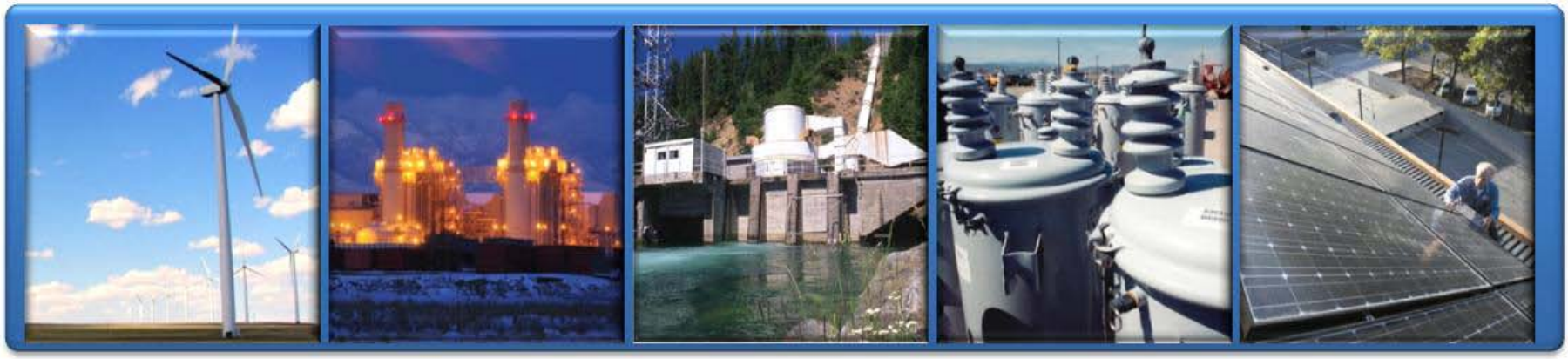
2011
Integrated Resource Plan Overview

Northwest Power and Conservation Council

May 5, 2011

PACIFICORP

Rocky Mountain Power
Pacific Power
PacifiCorp Energy



IRP Results

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Key Drivers for the 2011 IRP

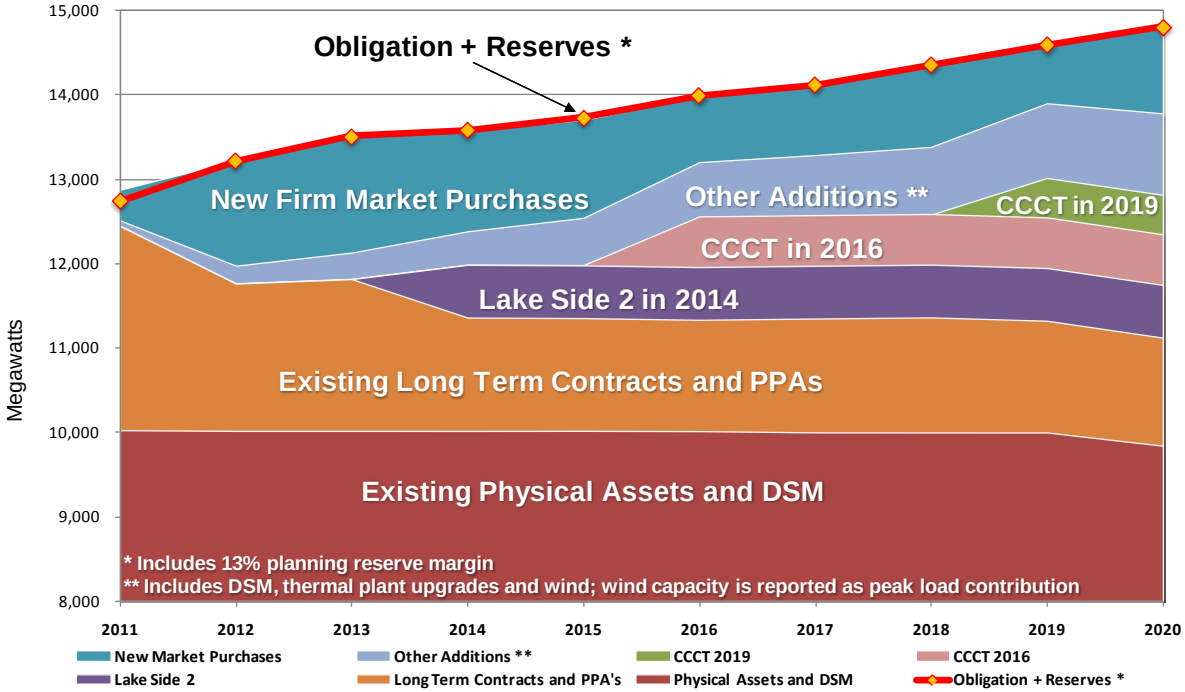
- Decreases in projected natural gas and wholesale electricity prices relative to the forecasts prepared in 2008 and 2009, Favor natural gas fueled resources and market purchases.
- Loss of momentum in federal efforts to develop comprehensive federal energy and climate change compliance requirements contribute to continued uncertainty regarding the long-term investment climate for clean energy technologies. Nevertheless, public and legislative support for clean energy policies at the state level remains robust.
- Continued aggressive efforts by the U.S. Environmental Protection Agency to regulate electric utility plant emissions, including greenhouse gases, criteria pollutants, and other emissions.
- Expectations for a more favorable economic environment than assumed in 2009 accompanied by load growth in such areas as data centers and natural resource extraction.
- Progress and challenges in planning for, permitting, and building the Energy Gateway transmission project, coupled with the potential for state-specific cost recovery issues.
- Near-term procurement activities, including the planned acquisition of a gas-fired combined-cycle combustion turbine plant in Utah with a 2014 in-service date.

2011 IRP Preferred Portfolio

Resource	Capacity (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	Total, 20-year
Combined Cycle CT	-	-	-	625	-	597	-	-	475	-	-	-	-	-	-	-	-	-	-	-	1,697
Coal Plant Turbine Upgrades	12	19	6	-	-	18	-	8	-	-	2	-	-	-	-	-	-	-	-	-	65
Wind, Wyoming	-	-	-	-	-	-	-	300	300	200	200	200	200	200	100	100	100	100	100	-	2,100
CHP - Biomass	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	104
DSM Load Control, Class 1	6	70	57	20	97	-	-	-	-	-	-	-	-	-	-	-	-	5	-	-	255
DSM Energy Efficiency, Class 2	108	114	110	118	122	124	126	120	122	125	125	134	133	139	140	146	136	135	141	145	2,563
Oregon Solar Programs	4	4	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	19
Micro Solar - Water Heating	-	4	4	4	4	4	4	4	-	-	-	-	-	-	-	-	-	-	-	-	30
Front Office Transactions	350	1,240	1,429	1,190	1,149	775	822	967	695	995	700	750	750	750	750	750	750	750	750	750	N/A
Growth Resources	-	-	-	-	-	-	-	-	-	-	11	95	201	250	546	717	863	975	1,150	1,265	N/A

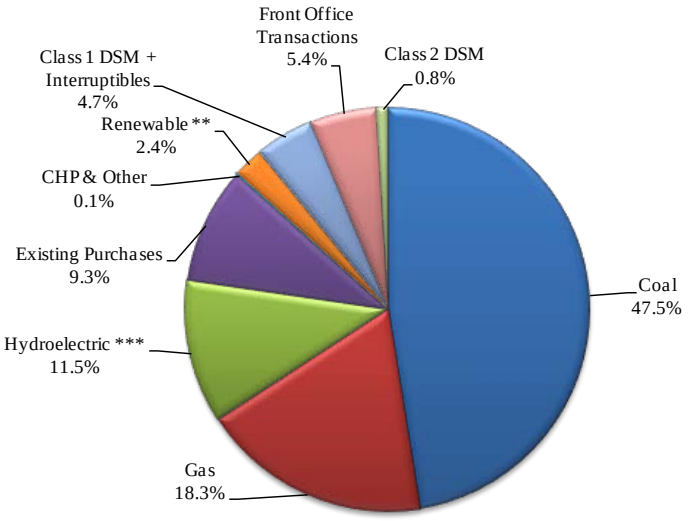
Note: Front office transaction (firm market purchases) and growth resources reflect one-year transaction periods, and are not additive. Growth resources are similar to front office transactions, but are located in load areas as opposed to being purchased at market hubs, and represent generic capacity needed to meet planning reserve margins in the latter half of the IRP planning period.

Addressing PacifiCorp's Peak Capacity Deficit for 2011-2020

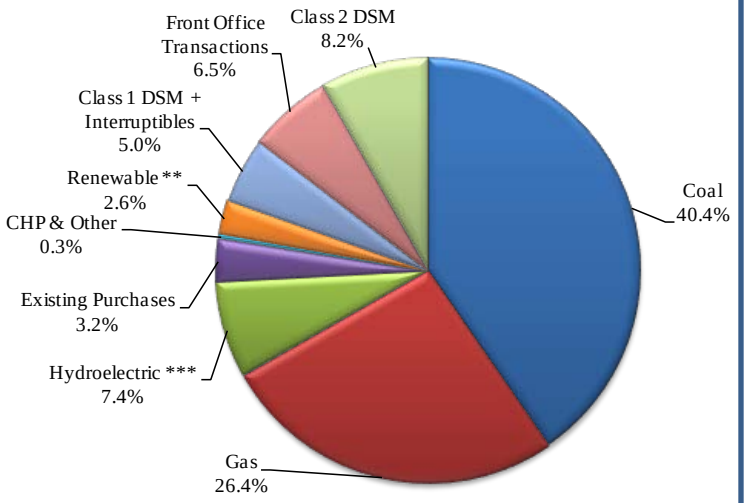


Resource Capacity Mix, 2011 versus 2020

2011 Capacity Mix*



2020 Capacity Mix*



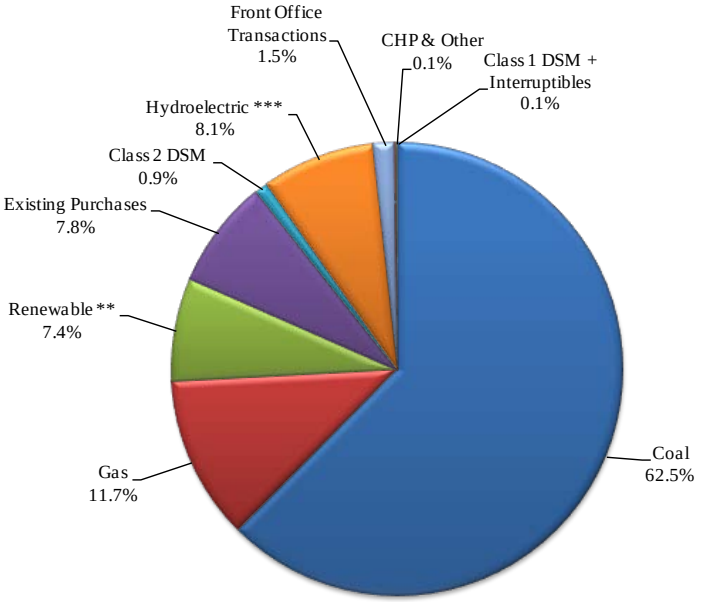
* The capacity mix reflects available capacity at the time of system peak; the peak capacity contribution for wind is about 13.5% of installed capacity. Forecasted installed wind capacities for 2011 and 2020 are 2,005 MW and 2,855 MW, respectively.

** Renewable resources include wind, solar, and geothermal.

*** Hydroelectric resources include owned, PURPA Qualifying Facilities, and contract purchases.

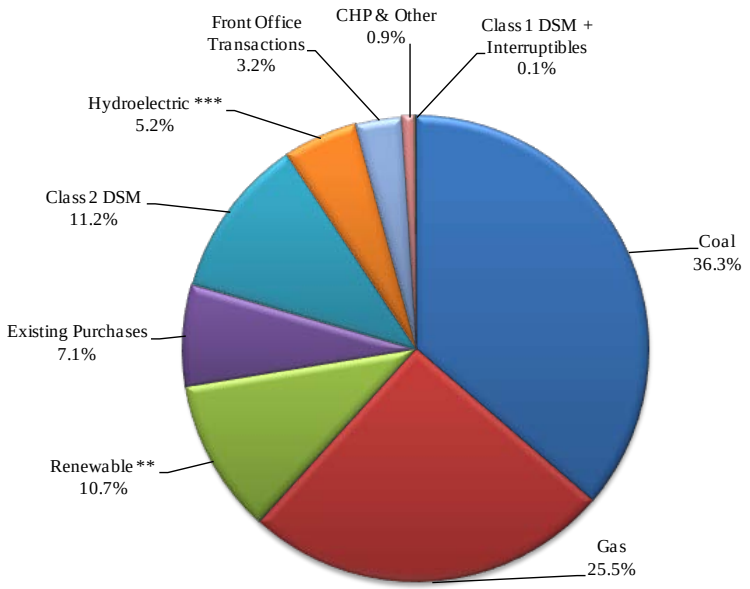
Resource Energy Mix, 2011 versus 2020

2011 Energy Mix*



2020 Energy Mix*

$24 CO_2 Tax (nominal dollars)



* Energy mix expressed in megawatt-hours.

** Renewable resources include wind, solar, and geothermal.

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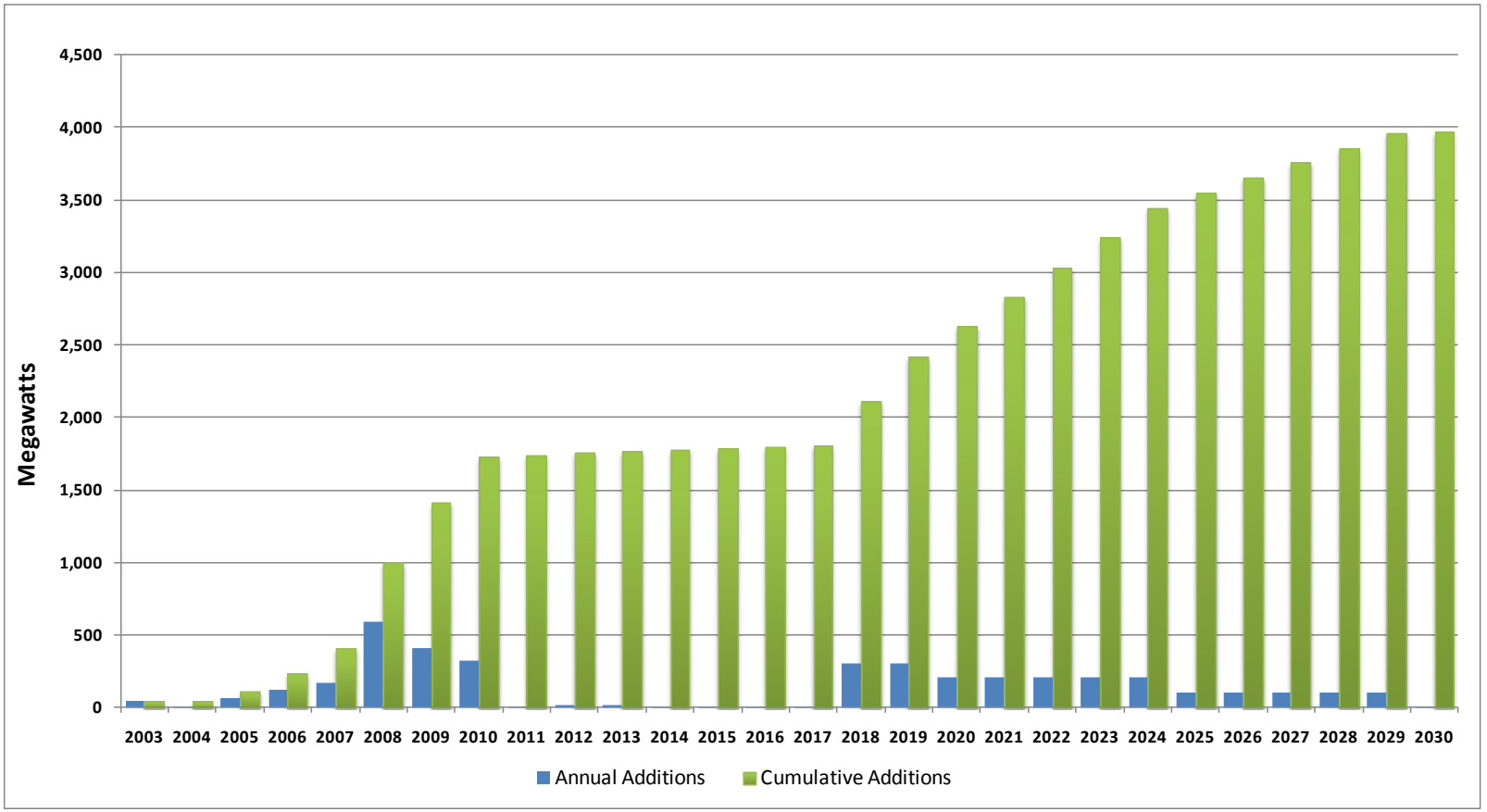
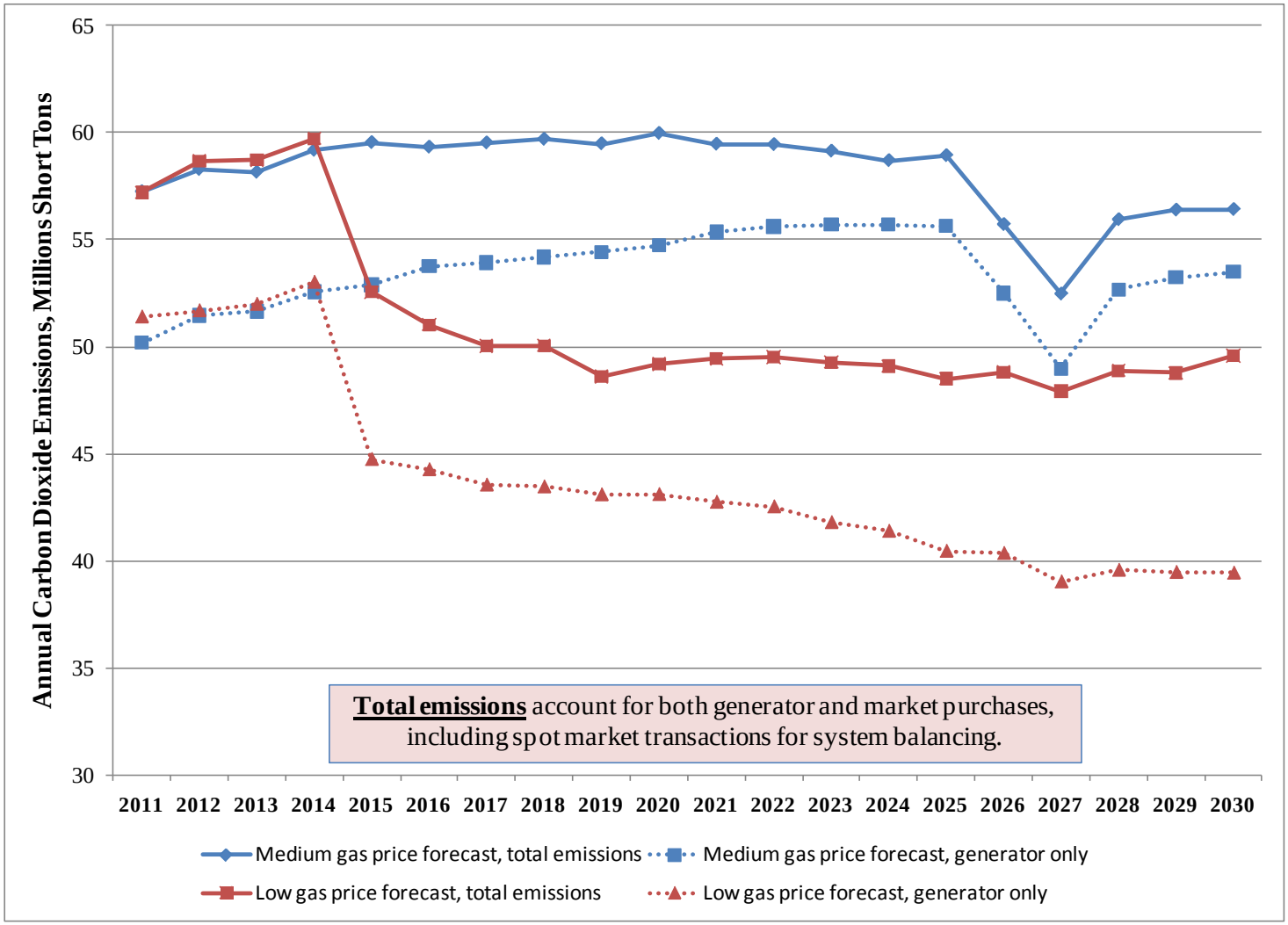
Annual and Cumulative Renewable Capacity Additions, 2003-2030

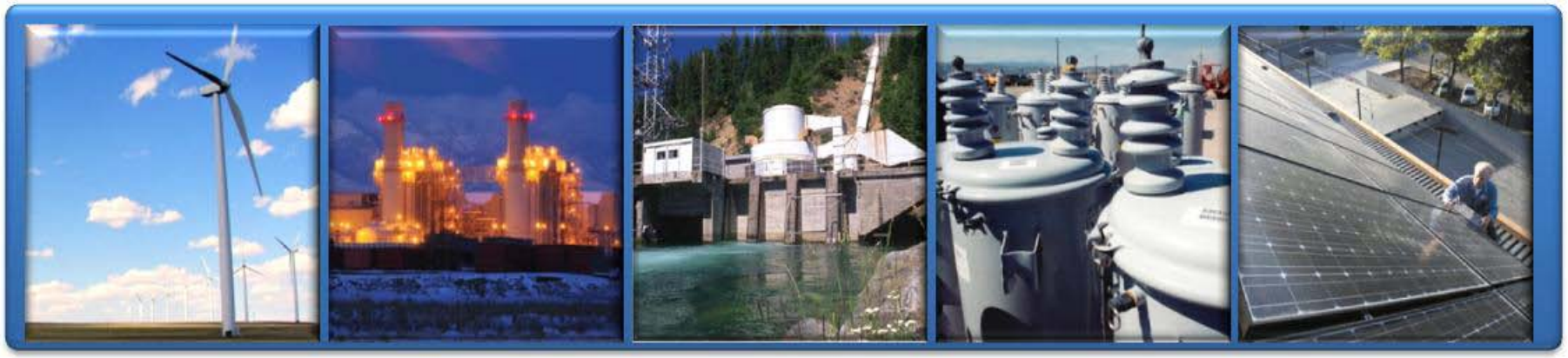
- Cumulative installed renewables capacity represents 19% of total installed capacity by 2020; 25% by 2030



Carbon Dioxide Emissions Trend

Based on nominal $19/ton CO_2 Tax beginning in 2015





IRP Methodology

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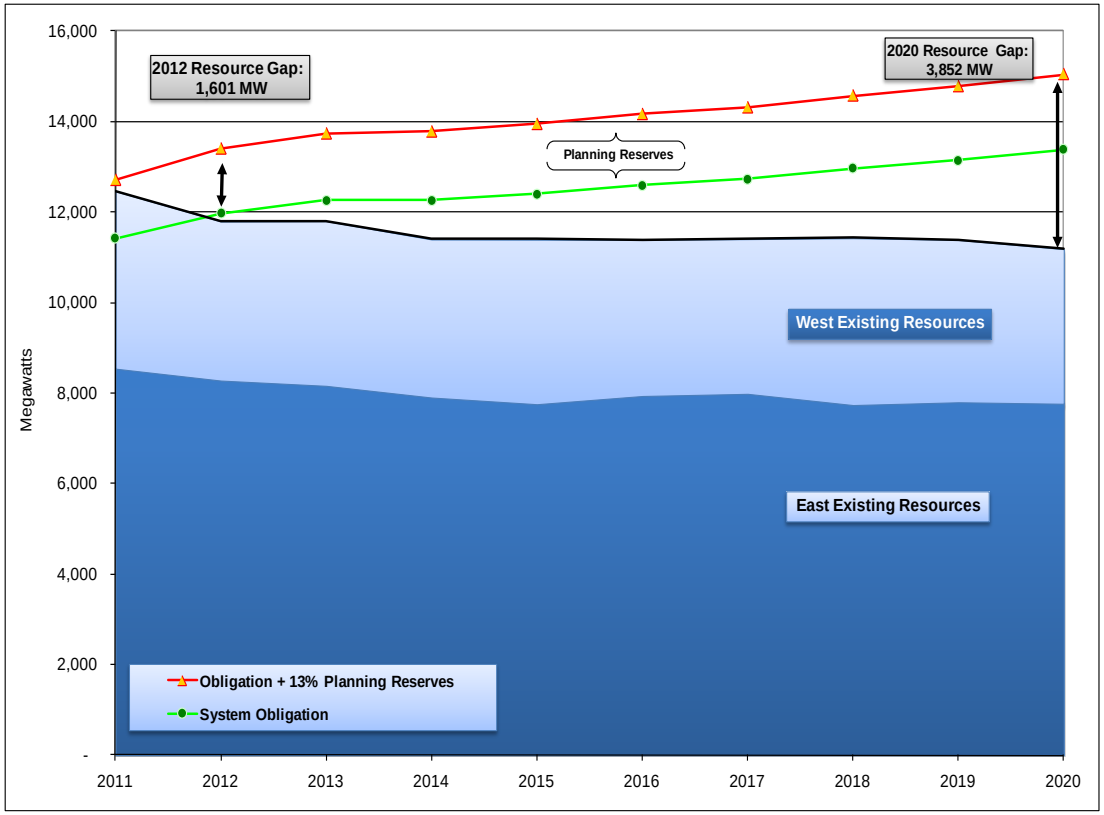
2011 IRP Modeling Approach - Steps

- Determine capacity need via Load and Resource Balance

Capacity planning criterion: capacity must meet or exceed coincident system hourly peak load plus firm sales ("obligation") plus 13% planning reserve margin for every year



	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
System										
Total Resources	12,468	11,802	11,810	11,404	11,399	11,397	11,412	11,433	11,395	11,192
System Obligation	11,497	11,973	12,264	12,256	12,403	12,595	12,728	12,961	13,145	13,376
Reserves (based on 13% target)	1,297	1,430	1,470	1,522	1,542	1,569	1,582	1,611	1,633	1,668
Obligation + 13% Planning Reserves	12,794	13,403	13,735	13,778	13,945	14,164	14,310	14,572	14,777	15,044
System Position	(326)	(1,601)	(1,925)	(2,373)	(2,546)	(2,767)	(2,898)	(3,139)	(3,383)	(3,852)

2011 IRP Modeling Approach - Steps

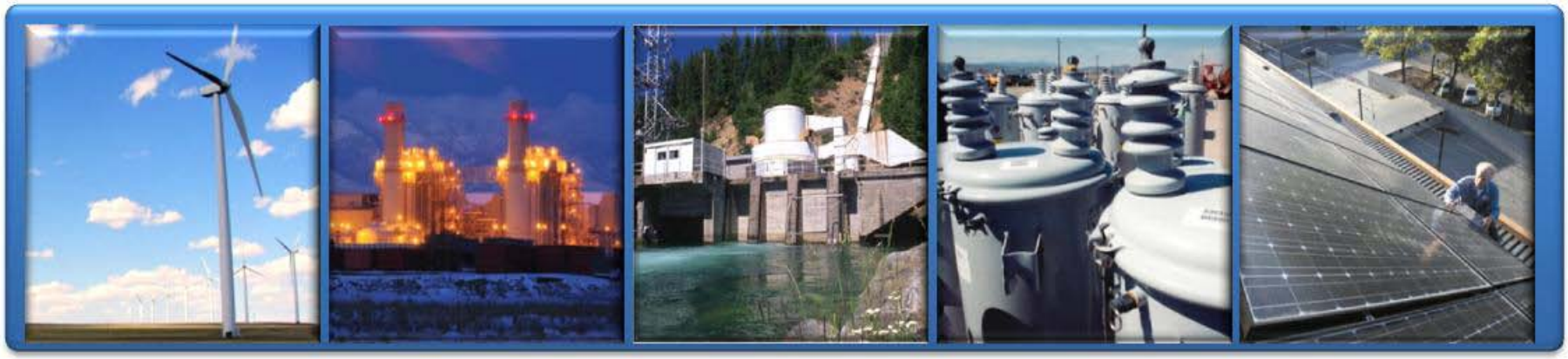
- Use capacity expansion optimization tool, *System Optimizer*, to develop alternative resource portfolios that meet capacity, energy, and resource-related state regulatory requirements, based on numerous input scenarios
- Monte Carlo production cost modeling of each portfolio (100 simulations resulting in 100 distinct portfolio costs) – accounts for stochastic behavior of loads, prices, and plant availability
- Select top-performing portfolios based on simulations with alternative CO_2 tax levels
  - Best combinations of low average and upper-tail portfolio costs

2011 IRP Modeling Approach - Steps

- Final screen: compare other performance metrics, including risk-adjusted cost, 10-year customer rate impact, CO_2 emissions, supply reliability, etc.
- Select top three portfolios and simulate with *System Optimizer* given different deterministic cost assumptions (deterministic risk assessment)
- Select top-performing portfolio

2011 IRP Modeling Approach - Steps

- Preferred portfolio determination
  - Evaluate top portfolio based on resource-specific acquisition risks
    - Geothermal resource development costs ("dry hole" risk)
    - Preferred wind schedule for meeting regulatory compliance requirements, address public policy goals, mitigate fuel price risk
    - Timing of next major thermal resource (after Lake Side 2 CCCT acquired in 2014)
  - Refine preferred portfolio resources and re-optimize with System Optimizer to ensure that capacity reserve margins are met for every year



Key IRP Inputs/Assumptions

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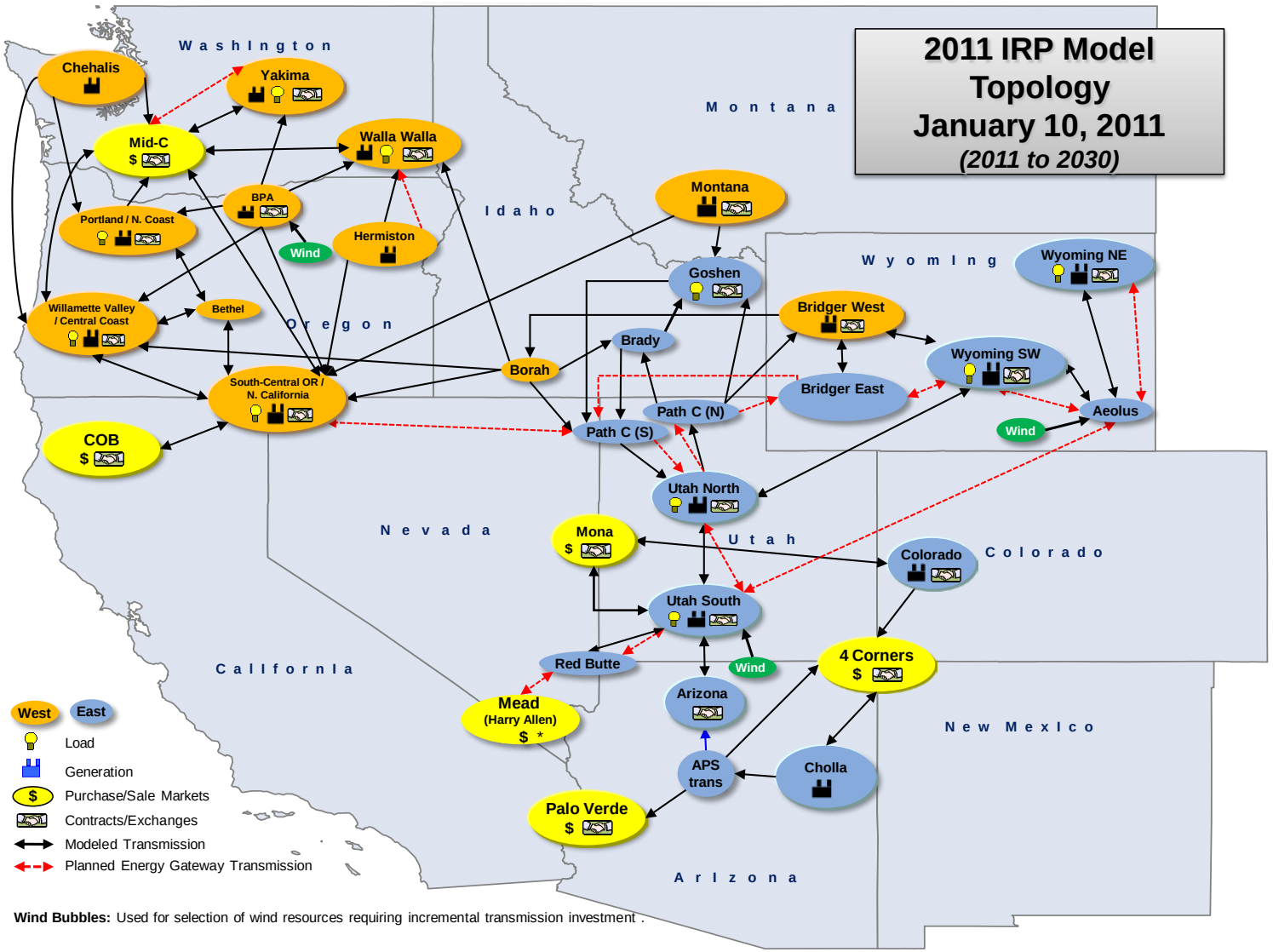
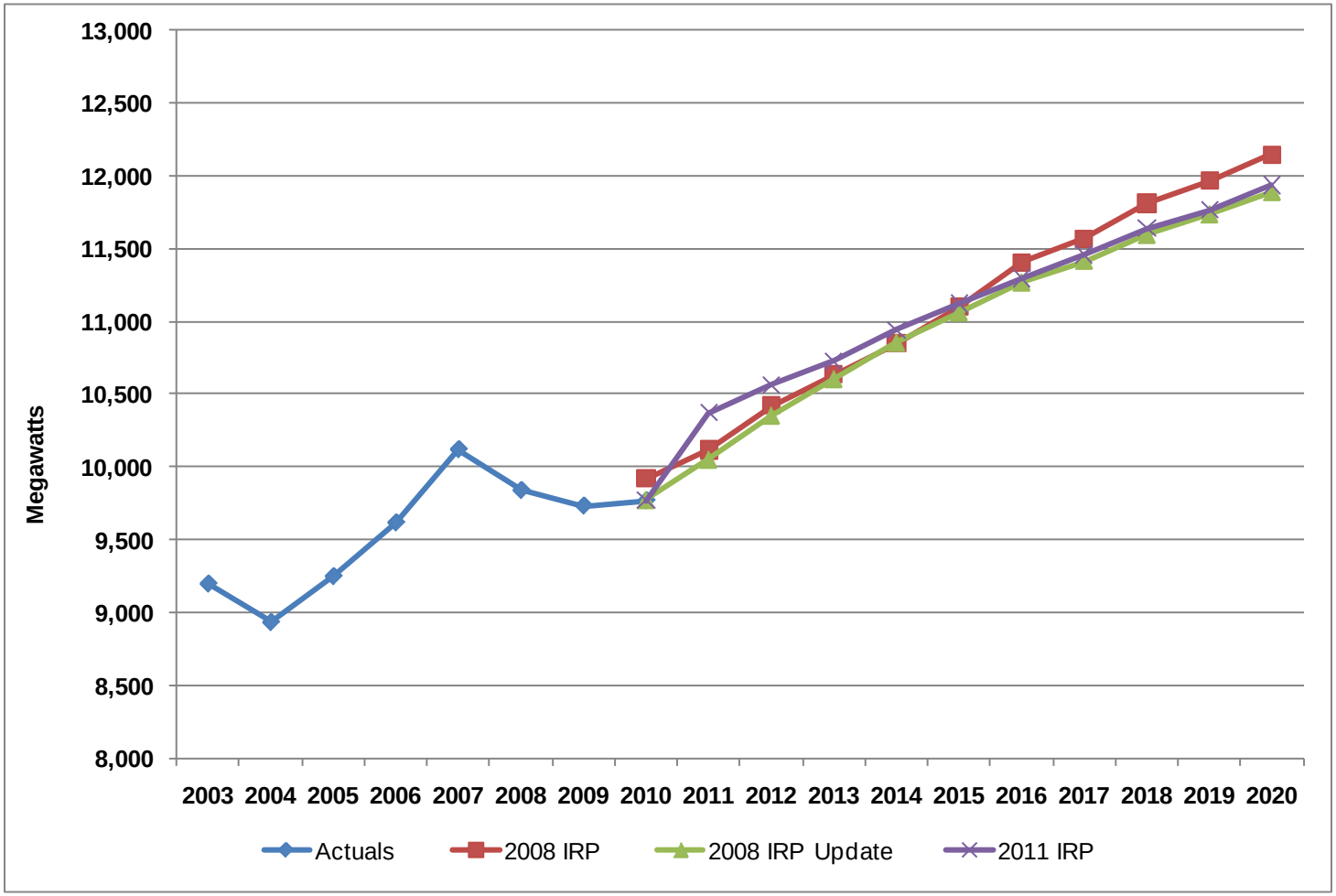
Transmission System Model Topology



Wind Bubbles: Used for selection of wind resources requiring incremental transmission investment .

Load Forecast - Comparison



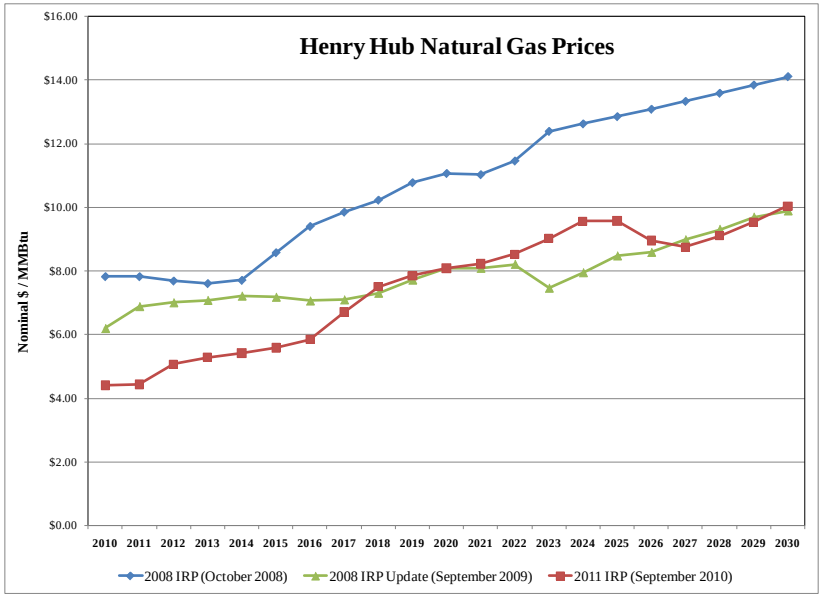
Natural Gas Price Forecast Scenarios

- Three underlying forecasts—High, Medium, Low—support development of scenario forecasts reflecting CO_2 prices and other IRP input assumptions

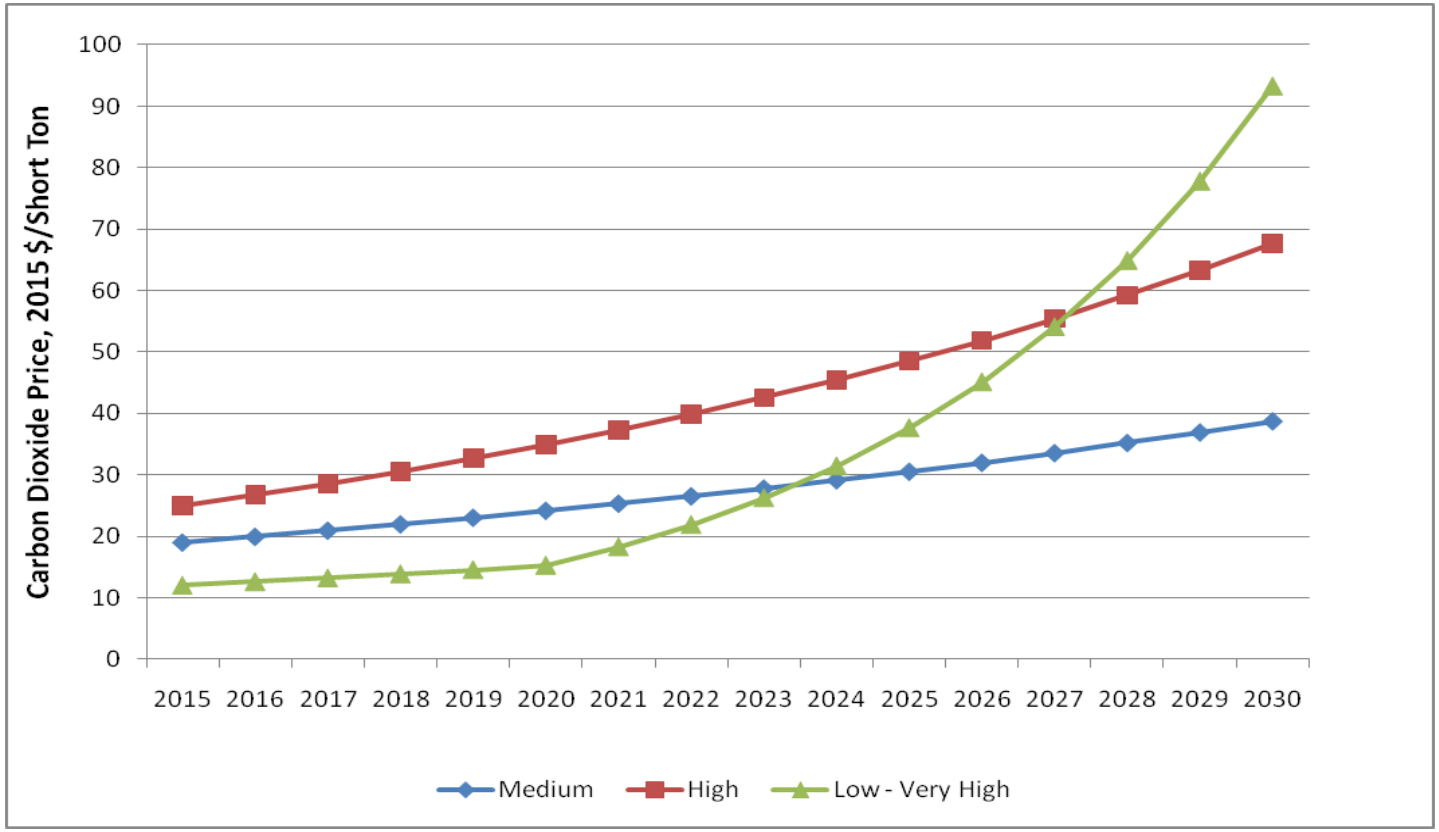
Henry Hub Natural Gas Price Forecast Summary (nominal $/MMBtu)

Forecast Name	2011	2015	2020	2025	2030
High	$4.41	$8.41	$10.99	$14.55	$15.97
Medium	$4.41	$7.43	$8.09	$9.58	$10.04
Low	$4.41	$4.79	$5.70	$6.75	$7.41

- Gas price forecasts significantly lower than those produced for the 2008 IRP and 2008 IRP Update



Carbon Dioxide Price Scenarios



- Also modeled CO_2 emissions physical hard cap scenarios
  - Base – 15% below 2005 emission levels by 2020, and 80% by 2050
  - Oregon – 10% below 1990 emission levels by 2020, and 80% below by 2050