



2008 Integrated Resource Plan Public Meeting

IRP Assumptions and Portfolio Development
Results

December 18, 2008



Pacific Power | Rocky Mountain Power | PacifiCorp Energy

Agenda

- Updated Load Forecast
- Capacity Load and Resource Balance
- Portfolio Modeling Set-up
- Portfolio Development Results

Remaining IRP Schedule - Update

Key Activities	Timeline/Milestone Dates
Scenario Development	04/01/08 - 6/23/08 (Update emailed 10/14/08)
Optimized Portfolio Development	Business Plan, 07/08/08 - 11/05/08* IRP scenario cases, 11/06/08 - 12/15/08 Incorporates 11/20/08 load forecast
Risk Analysis (stochastic production cost modeling)	11/12/08 - 01/07/09
IRP document development, 1st Draft	11/17/08 - 01/30/09
Action Plan Development	12/11/08 - 01/15/09
Public Review of IRP document 1st Draft	02/01/09 - 03/01/09
IRP filing	03/31/2009

* Business plan portfolio optimization captured a range of expected-case input assumption adjustments made throughout the business plan development cycle.



November 2008 Load Forecast

An Executive Summary

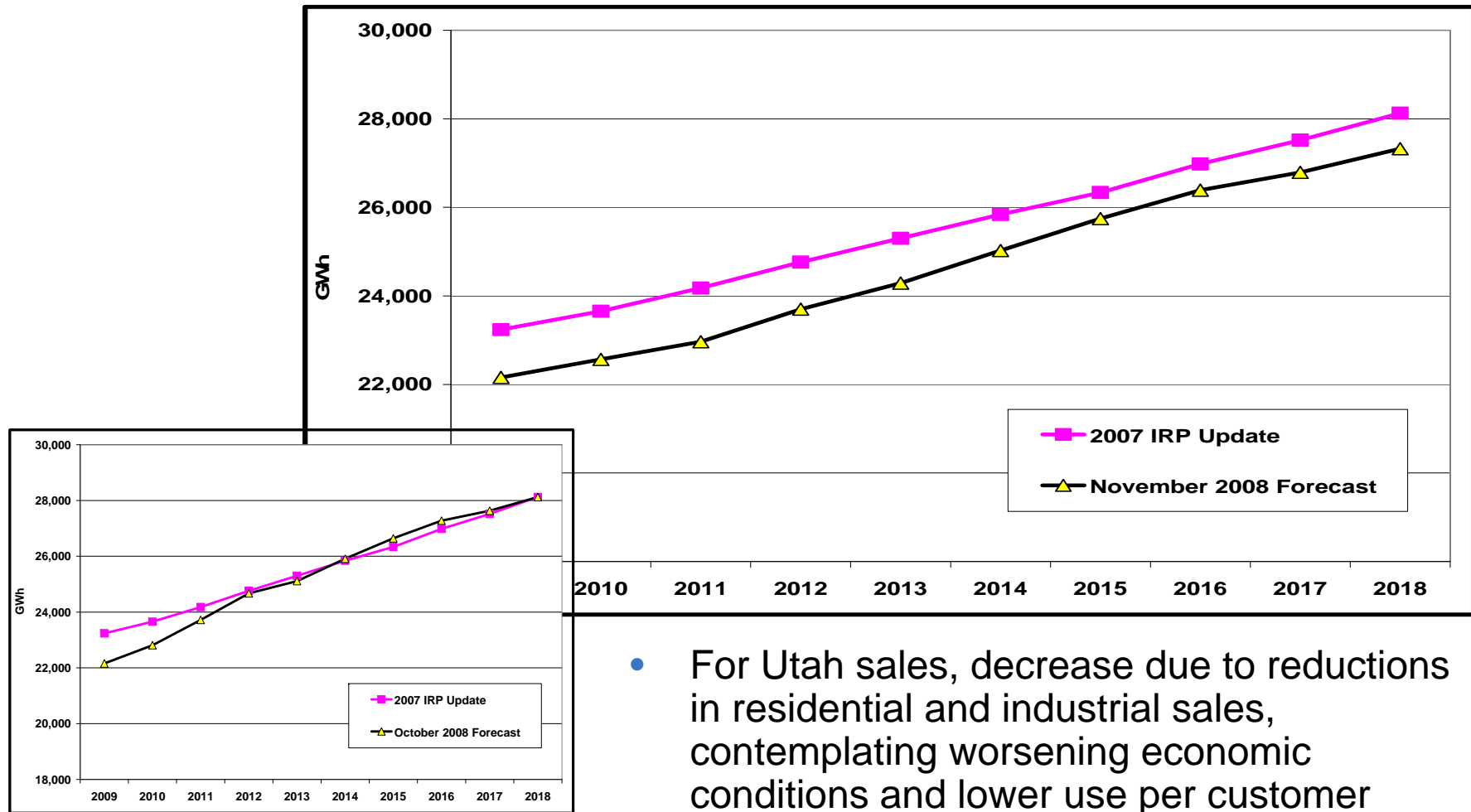


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What changed from November 12, 2008 call?

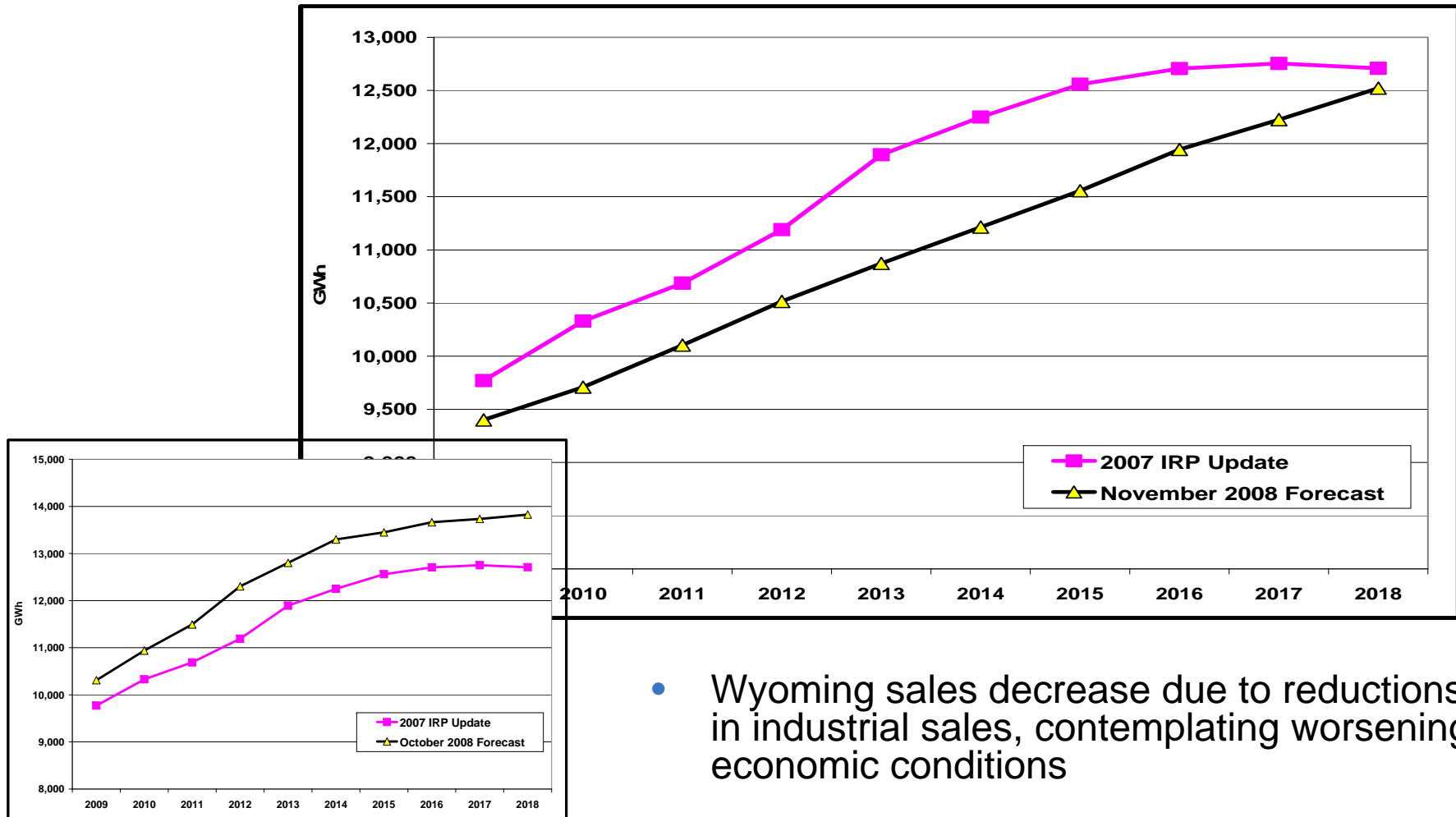
- The October sales forecast information provided in the November 12, 2008 teleconference has been updated with the November sales forecast. The November forecast is being used in the 2008 IRP analysis.
- Under stable economic conditions, the Company would normally prepare one load forecast per year. However, the economic conditions are currently very volatile and unstable, requiring the Company to update its load forecasts frequently to attempt to capture price and usage changes.
- In the November update, the forecast was further adjusted downward in the Industrial sector for Utah (2010 onwards) and Wyoming (2009 onwards) to reflect the our best estimate of recession impacts
 - In 2012, the forecast was reduced by 2.7 million MWh for energy and 412 MW for peak as compared to the October forecast

Utah: Retail Sales



- For Utah sales, decrease due to reductions in residential and industrial sales, contemplating worsening economic conditions and lower use per customer

Wyoming: Retail Sales



- Wyoming sales decrease due to reductions in industrial sales, contemplating worsening economic conditions



Load and Resource Balance

Stan Williams

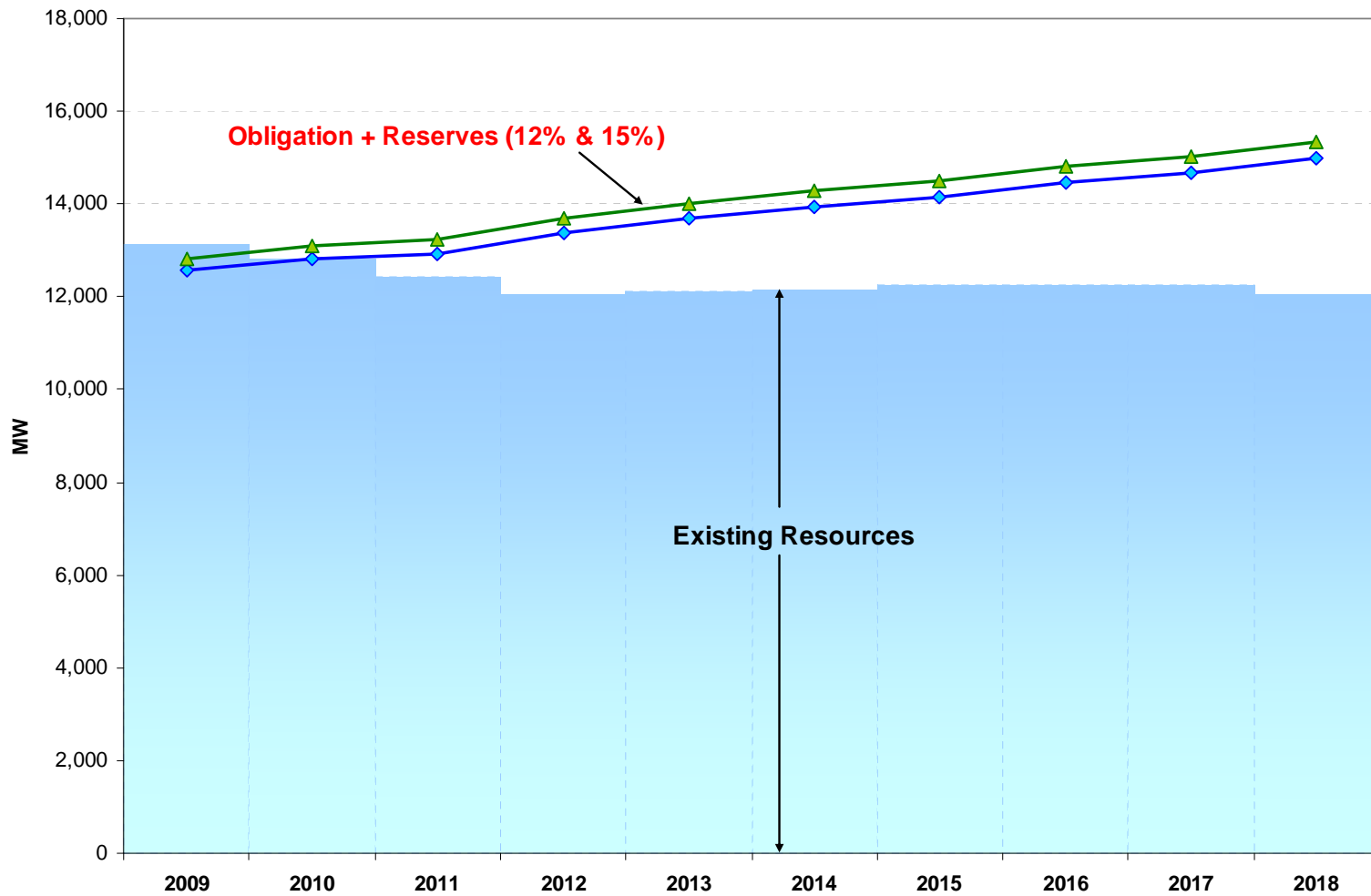


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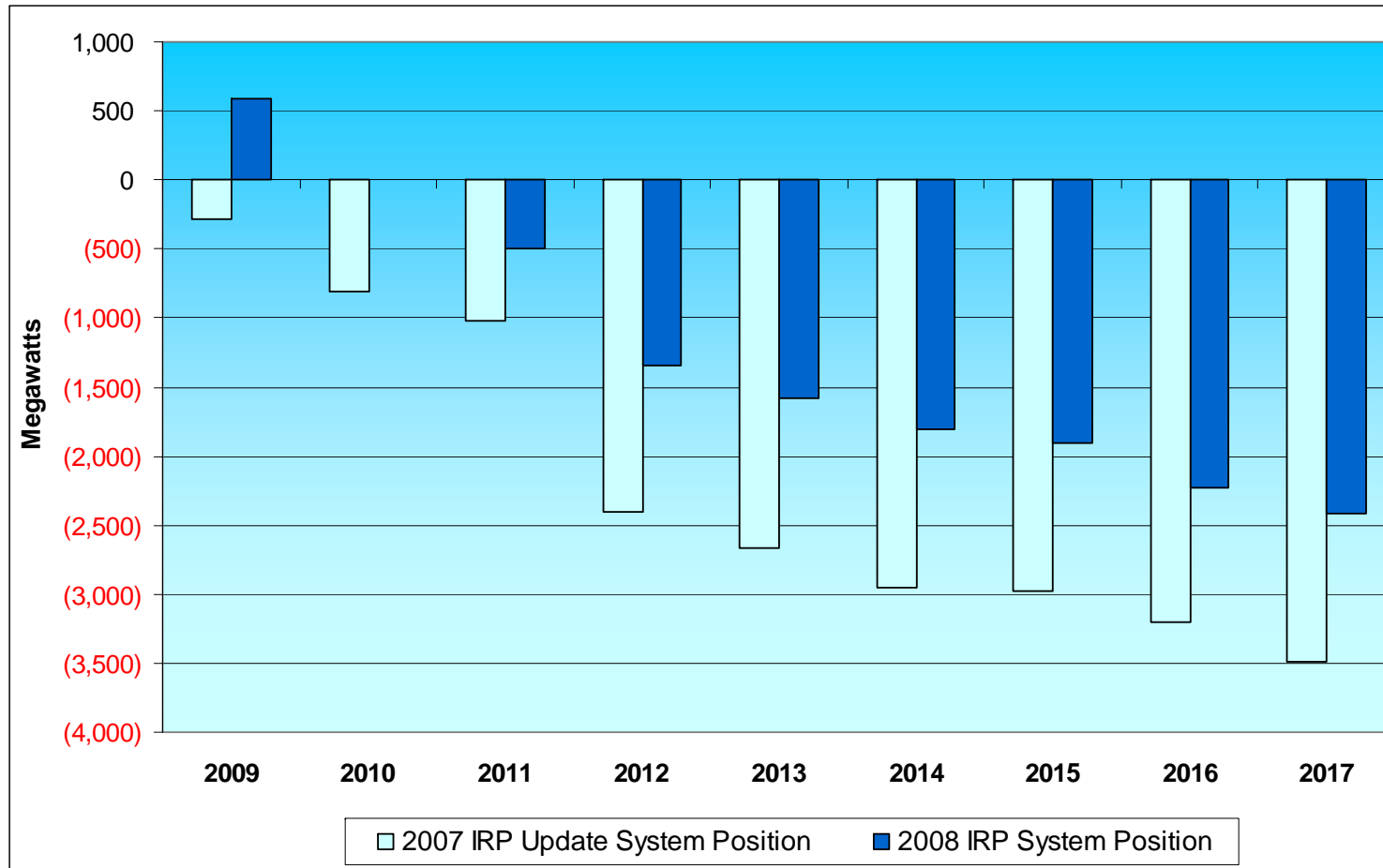
Load & Resource Assumptions

- 12% planning reserve margin
- Contracts existing as of 11/1/2008
- Lake Side 2 (607 MW) in 2012
- 162 MW coal plant turbine upgrades
 - Down from 202 MW identified in the 2007 IRP update
- 75 MW hydro turbine upgrades
- 205 MW curtailable load resources
- Firm planned wind projects
 - East Wind PPA (99 MW) in 2010
 - High Plains (99 MW) in 2009
 - West Wind PPA (45 MW in 2009 and 20 MW in 2010)
- Energy Gateway transmission upgrades
- Expiring Qualifying Facilities and Interruptibles extended until end of study period

System – Load & Resource Balance



System Position Comparison: 2008 IRP vs. 2007 IRP Update



- Position differences are due primarily to the addition of Chehalis, Lake Side 2, and load reductions attributable to new Federal Lighting standards.

Load & Resource Observations

- Resource deficit starts at 498 MW in 2011
 - Expiration of executed front office transactions
 - Increased load of 269 MW from 2010 to 2011 (2.6% growth)
- Deficit increases to 1,340 MW in 2012
 - Expiration of BPA Peaking contract
 - Increased load of 841 MW from 2009 to 2012 (2.7% avg. annual growth)
- Deficit increases to 2,930 MW in 2018
 - Increased load of 2,524 MW from 2009 to 2018 (2.5% avg. annual growth)



Portfolio Modeling Set-up

Pete Warnken

Capacity Expansion Model Set-up

- Simulation period is 2009-2028
- Final number of case definitions increased to 48
 - Additional 6 core cases with the October 20 price forecasts
 - Additional business plan portfolio with optimized renewables (Original business plan portfolio incorporates a fixed wind additions schedule developed by PacifiCorp's wind resource development team)
 - Two fewer planning reserve margin sensitivities (removed load growth and added CO2 tax as sensitivity variables)
- PacifiCorp's official business plan load forecast (November 20, 2008), used for all case runs
 - Backed out forecasted impact of new Federal lighting standards; necessary to avoid double-counting lighting efficiency gains attributable to efficiency measures included in the Class 2 DSM supply curves

Capacity Expansion Model Set-up

- Resource constraints
 - Wind: Annual system restriction of 500 MW added per year to reflect development and procurement impediments; increased to 750 MW when eastern segments of Energy Gateway West project are in place
 - Energy storage technologies (fuel cell, battery storage) limited to 5 MW for first-year availability to reflect pilot-to-full scale project phase-in
- Based on testing of distributed resources, solar attic fans and water heaters were excluded as resource options in developing case definition portfolios
 - Total potential is less than 2 MW, with quantities selected less than this
 - Will conduct sensitivity runs with these resources to supplement portfolio analysis

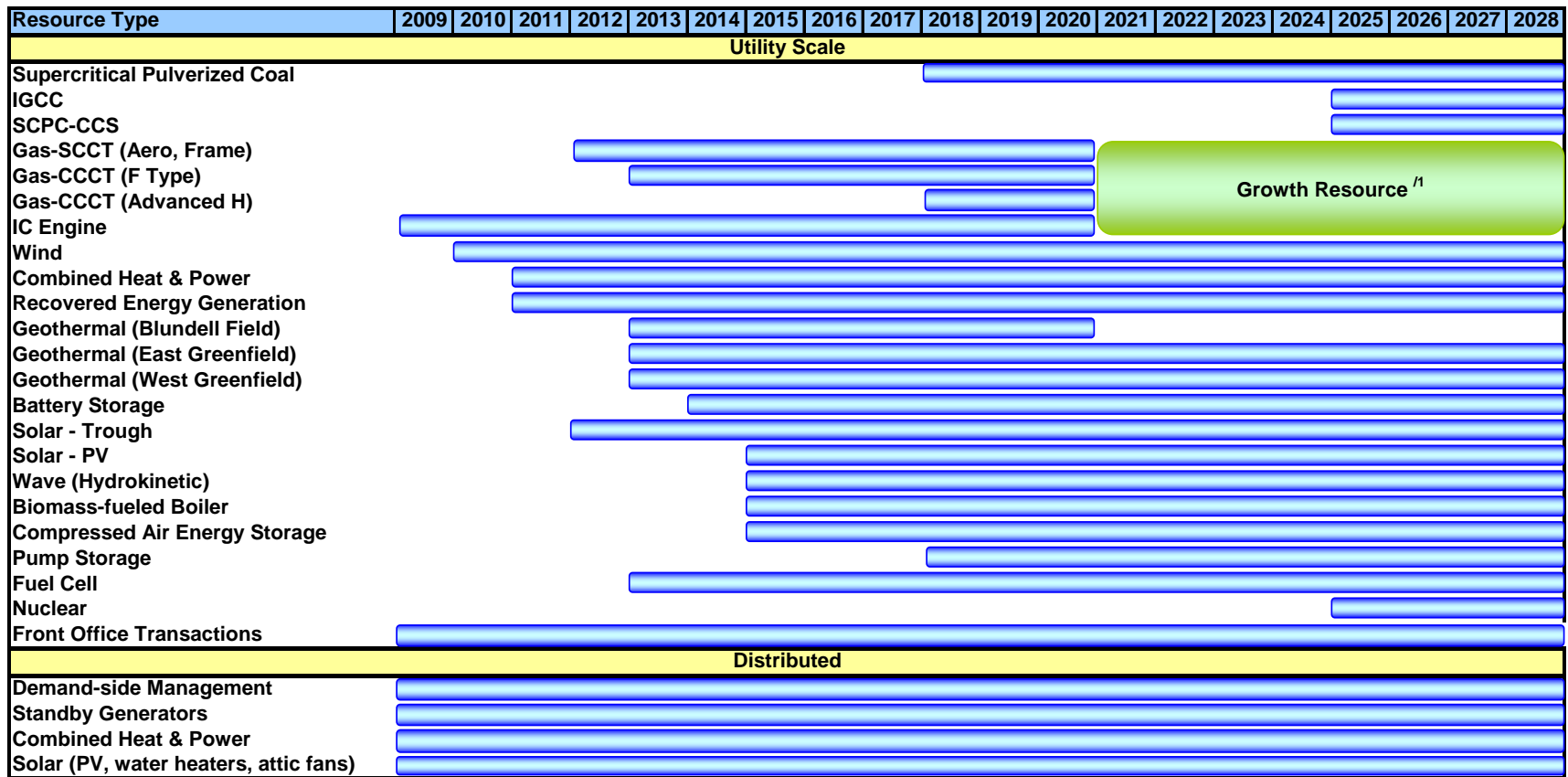
Capacity Expansion Model Set-up

- Front office transaction (forward firm market purchases) availability for all cases
 - Mid-Columbia third-quarter HLH or flat product:
 - 400 MW (only one product type can be selected in a given year)
 - California-Oregon Border third-quarter HLH or flat product:
 - 400 MW (only one product type can be selected in a given year)
 - Mona third-quarter HLH product:
 - 200 MW
 - Mead third-quarter HLH product:
 - 600 MW (available beginning in 2017)
 - Utah third-quarter HLH product:
 - 50 MW
 - West Main third-quarter HLH product:
 - 50 MW
 - Model allowed to select a variable amount up to the limits identified above

Capacity Expansion Model Set-up

- Representation of out-year resource options
 - Renewables, energy storage, coal (conventional and IGCC / CO2 removal retrofit with carbon capture and sequestration), nuclear, utility-scale CHP, and front office transactions available through 2028
 - Gas resources available through 2020
 - Growth resources available from 2021 through 2028
 - Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices
 - Model allowed to select a variable amount for annual load area balancing

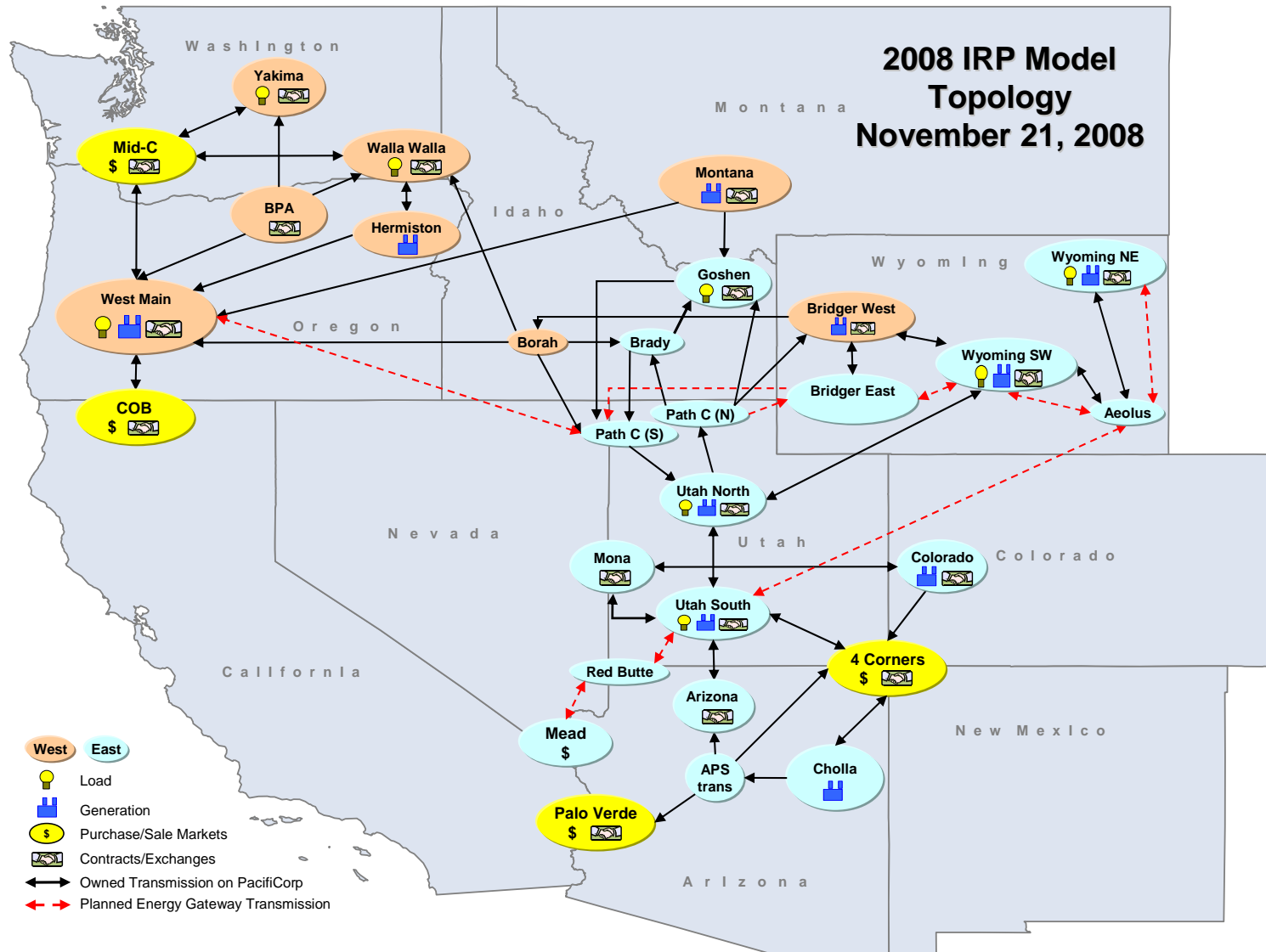
Resource Option Availability



¹⁷ Generic generation procured in a load area for a given year that is assumed to be acquired at costs equivalent to PacifiCorp's forward electricity market prices.

SCPC - Supercritical Pulverized Coal
 CCS - Carbon Capture & Sequestration
 PV - Photovoltaic
 IC - Internal Combustion
 IGCC - Integrated Gasification Combined Cycle

Transmission Topology



Transmission Options

- Three options included in all scenario cases:
 - Incremental addition to Energy Gateway West project
 - Path-C to West Main
 - 750 MW
 - 2015 assumed in-service date
 - Two west-side options, not associated with Energy Gateway
 - Walla Walla to West Main
 - 200 MW and 400 MW sizes, for total of 600 MW potential
 - 2014 assumed in-service date
- The capacity expansion model did not select any of these options



Portfolio Development Results



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Core Case Results

- 29 cases:
 - 4 CO2 tax levels: \$0 per ton, and \$45, \$70, \$100 per ton beginning in 2013 with escalation at PacifiCorp's corporate inflation rate assumption
 - Low/medium/high variations around two forward price curves (June 2008, October 2008)
 - Low/medium/high variations around November 20, 2008 load forecast (+/- 1.0 percentage point)
 - All assumed a 12% planning reserve margin

High Level Observations

- Gas resources selected under a relatively small set of scenario conditions: low gas prices; CO₂ tax at or under \$45/ton; high load growth
 - IC aero SCCT selected most often (14 out of 17 gas resources), typically in 2013 or 2016
 - CCCT selected only under high load growth cases
- Quantity of wind selected varies substantially, and increases as gas prices and/or the CO₂ tax increases
 - Only scenario with no additional wind was case 1 (\$0 CO₂ tax, low June 2008 FPC, low load growth)
 - Among the medium load growth cases, wind additions varied from a low of 941 MW to a high of 7,200 MW (high June 2008 FPC combined with \$70 or \$100 CO₂ tax)
 - East additions favored due to lower capital cost and higher wind quality relative to west-side resources

High Level Observations

- DSM
 - Additions within a relatively compact range: 1,645 MW to 2,293 MW for the 18 medium load growth cases
 - For Class 2 DSM, model favored relatively constant annual additions for the duration of the simulation period
 - For Class 1 DSM, model chose quantities in just one or two years, with most in one year, typically 2016, 2017, or 2018; west-side not chosen except in high load growth cases and case 29 (\$100 CO₂ tax and high Oct. FPC gas prices)
- Conventional supercritical coal selected in eight of the 29 core cases
 - Two of the three \$0 CO₂ tax cases
 - Two of the three high load growth cases with a \$45 CO₂ tax
 - Three of the medium load growth cases with high gas prices, including one with the \$70 CO₂ tax
 - One low load growth case with high gas prices and the \$45 CO₂ tax

High Level Observations

- Blundell 3 and west greenfield geothermal resources selected in most cases
- Distributed generation (DG) was selected in all cases
 - Ranges from 95 MW in cases 3 and 37 (high June FPC gas prices, and \$0 and \$70 CO2 tax levels, respectively) to 209 MW in case 6 (High load growth with low June FPC gas prices)
 - Highest amount of DG was selected in high load cases
 - Lowest amount of DG was selected in high gas cases
- Nuclear selected under higher CO2 tax and high gas price cases
- Solar (utility scale) and energy storage technology selection limited
 - Solar appears in case 15 (high load growth and high June FPC prices) and case 33 (“high cost outcome”)
 - CAES appears in case 12 (high load growth) and case 33 (“high cost outcome”); battery storage appears in case 12

Core Case Results – CO2 Tax Level

- CO2 tax impact on resource selection
 - \$0 CO2 tax (3 cases): Gas, supercritical coal, and wind dominate as resource selections
 - \$45 CO2 tax (12 cases): Wind, gas, and supercritical coal dominate as resource selections
 - \$70 CO2 tax (7 cases): Wind and existing CCS coal retrofits dominate as resource selections
 - \$100 CO2 tax (7 cases) - Wind, existing CCS coal retrofits, and nuclear dominate as resource selections

Core Case Results – Gas Price Variation

- Gas price variation impact on resource selection
 - Low June 2008 FPC (4 cases): Model preference for wind, gas, and market purchases
 - Low October 2008 FPC: (3 cases) - Model preference for wind, gas, and market purchases
 - Medium June 2008 FPC: (7 cases) - Model preference for wind, existing coal CCS retrofit, gas, and supercritical coal
 - Medium October 2008 FPC (3 cases) - Model preference for wind and existing coal CCS retrofit
 - High June 2008 FPC: (9 cases) - Model Preference for wind, supercritical coal, nuclear, and existing coal CCS retrofit
 - High October 2008 FPC (3 cases) - Model preference for wind, nuclear, supercritical coal, and existing coal CCS retrofit

Core Case Results – Load Growth

Load growth impact on resource selection

- Low (7 Cases)
 - Model Preference for wind, and existing coal retrofit with CCS
- Medium (19 Cases)
 - Model preference for wind, existing coal retrofit with CCS, nuclear, supercritical coal, and gas
- High (3 Cases)
 - Model Preference for wind, gas, supercritical coal, nuclear, and market purchase

Core Case Results by Time Period (Medium Load Growth)

- Near-term (2009-2013) resource selection patterns
 - Wind ranged from 99 to 2,099 MW
 - Added about 50 MW distributed generation and 500 MW DSM
 - Added 35 to 105 MW non-wind renewables
 - 100 to 200 MW 2011 Market Purchases, 600 to 900 MW in 2012 and 2013
- Mid-period (2014-2020) resource selection patterns
 - Little wind added with the \$0 CO₂ tax, except for the high gas case (2,708 MW)
 - Considerable wind added in higher CO₂ tax cases (1,450 to 5,200 MW)
 - IC Aero SCCT (261 MW) selected in low and medium gas price cases
 - About 700 MW DSM, 60 MW distributed generation in all cases
 - 600 to 790 MW supercritical coal in low CO₂ tax and high gas cases
 - Up to 120 MW non-wind renewables
 - Market purchases from 650 to 1,500 MW with largest in later years

Core Case Results by Time Period (Medium Load Growth)

- Out-year (2021-2028) resource selection patterns
 - About 800 MW DSM, 10 MW distributed generation
 - Small wind additions in few cases
 - Some clean coal (346 to 466 MW) with a \$45 CO₂ tax
 - 876 MW to 1,342 MW clean coal under \$70 and \$100 CO₂ tax
 - 1,600 MW nuclear with \$70 CO₂ and high gas
 - 3,200 MW nuclear with \$100 CO₂ except low gas
 - Heavy reliance on market purchases under low and medium gas prices cases (up to 1,700 MW per year)
 - Wide range in growth resource additions (up to 2,014 MW per year)

Sensitivity Case Results

- Real CO2 cost escalation with changing load growth (Cases 30 and 31)
 - In case 30 (medium gas), the model selected:
 - 5,498 MW of wind through 2028
 - A nuclear plant in 2025
 - Four CCS plants in 2025, three SPPC and one IGCC (earliest year available).
 - In case 31, (high gas), the model:
 - Selected one fewer CCS resource
 - Replaced the capacity using front office transactions
- National CO2 cap-and-trade policy (Case 32)
 - Inputs still under development; results not available
- High-cost outcome (Case 33)
 - Model selected:
 - Maximum amount of wind allowed through 2018: 10-year total - 6,013 MW; 20-year total - 7,463 MW
 - 1 SCCT frame, 1 CCCT H 2x1, 500 MW of solar, 790 MW of CAES
- Early clean base-load generation availability (Cases 34-37)
 - In cases 34 and 35:
 - \$45/ton CO2 tax did not cause the model to select any CCS resources
 - In cases 36 and 37:
 - \$70/ton CO2 tax caused the model to select CCS resources in 2020

Sensitivity Case Results

- High resource construction costs (Cases 38 and 39)
 - In case 38, (medium gas prices), the model relied heavily on front office transactions in the out years.
 - In case 39, (high gas prices), the model built:
 - coal plant in UT in 2018
 - more wind, especially in the first ten years.
 - The PVRR in case 39 was lower than for case 38 due to higher market sales of excess coal and wind capacity
- Oregon CO2 reduction targets (Case 40)
 - The model selected clean coal in 2025 and 2027
 - relied heavily on the market which doesn't come with a carbon penalty (model limitation)
- Alternative planning reserve margin levels (Cases 41-43)
 - When case 8 was run with a 15% PRM (Case 41), the PVRR increased by \$170 million
 - When case 17 was run with a 15% PRM (Case 42), the PVRR increased by \$214 million
 - When case 24 was run with a 15% PRM (Case 43), the PVRR increased by \$212 million

Sensitivity Case Results

- Alternative renewable policy assumptions (Cases 44 and 45)
 - Case 44 uses a high RPS requirement constraint
 - Reflects the system level of renewables needed to meet Oregon's allocated share based on current MSP protocols (a proxy for a Federal RPS requirement or more aggressive state requirements); the system-allocated renewable requirement reaches about 15% of system load by 2015 and 25% by 2025
 - With a high RPS requirement, the model selected wind, biomass, and geothermal resources to satisfy the requirement.
 - Case 45 assumes that the renewables PTC expires in 2013
 - The model selected a significantly lower amount of wind resources for the 20 year period (5,936 MW in case 44 vs. 1,160 MW in case 45)
 - The model built no new wind resources after the credit expired

Sensitivity Case Results

- Case 46 and 47 use business plan assumptions
 - Case 46 is nearly identical to the business plan in the first ten years
 - In the latter years, a coal plant and additional wind is selected to balance the system
 - In case 47, renewables are allowed to float in all years
 - In case 47, slightly more wind was selected; however, the major difference is that wind was selected earlier than in case 46

Sensitivity Case Results

- Class 3 DSM for peak load reduction (Case 48)
 - 114 MW was selected in the 20-year period; none after 2016
 - Largest resource selected was Utah critical peak pricing, 42 MW in 2014
 - When compared to Case 8, the model substitutes the Class 3 DSM for Class 2 DSM and standby generation



Appendix



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Capacity Load and Resource Balance Details

Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
East										
Thermal	5,983	5,998	6,025	6,662	6,662	6,674	6,675	6,683	6,684	6,459
Hydro	135	135	135	135	135	135	135	135	135	135
DSM	345	395	435	465	475	485	495	505	515	525
Renewable	157	157	157	157	157	157	154	154	154	154
Purchase	751	546	541	341	341	341	341	320	320	320
QF	151	151	151	151	151	151	151	151	151	151
Interruptible	237	237	237	237	237	237	237	237	237	237
Transfers	876	952	602	235	263	465	230	230	393	589
East Existing Resources	8,636	8,572	8,284	8,384	8,422	8,645	8,418	8,415	8,589	8,571
Load	6,757	6,949	7,150	7,404	7,643	7,779	8,029	8,303	8,491	8,696
Sale	781	768	758	747	745	745	745	745	659	659
East Obligation	7,538	7,717	7,908	8,151	8,388	8,524	8,774	9,048	9,150	9,355
Planning reserves	745	785	803	853	880	895	924	958	969	993
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	815	855	874	923	951	966	995	1,029	1,040	1,063
East Obligation + Reserves	8,352	8,572	8,781	9,074	9,339	9,490	9,769	10,077	10,190	10,418
East Position	284	1	(498)	(690)	(917)	(845)	(1,350)	(1,662)	(1,601)	(1,848)
East Reserve Margin	15.8%	12.0%	5.7%	3.5%	1.1%	2.1%	(3.4%)	(6.4%)	(5.5%)	(7.7%)
West										
Thermal	2,550	2,559	2,568	2,579	2,591	2,591	2,591	2,591	2,577	2,577
Hydro	1,315	1,218	1,216	980	1,009	1,046	1,157	1,150	1,149	1,146
DSM	-	-	-	-	-	-	-	-	-	-
Renewable	90	96	96	90	90	90	90	90	90	90
Purchase	1,310	1,203	753	115	144	111	111	111	111	139
QF	120	120	120	120	120	120	120	120	120	120
Transfers	(878)	(953)	(603)	(235)	(264)	(465)	(229)	(229)	(392)	(588)
West Existing Resources	4,507	4,242	4,150	3,649	3,691	3,492	3,840	3,833	3,654	3,483
Load	3,393	3,422	3,490	3,587	3,638	3,722	3,769	3,824	3,893	3,978
Sale	499	490	290	258	258	258	158	108	108	108
West Obligation	3,892	3,912	3,780	3,845	3,896	3,980	3,927	3,932	4,001	4,086
Planning reserves	310	325	363	448	450	464	458	459	467	474
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	316	332	370	454	457	471	464	465	473	480
West Obligation + Reserves	4,208	4,243	4,149	4,299	4,353	4,451	4,391	4,397	4,474	4,566
West Position	299	(1)	0	(650)	(662)	(958)	(551)	(564)	(820)	(1,082)
West Reserve Margin	19.7%	12.0%	12.0%	(4.9%)	(5.0%)	(12.1%)	(2.0%)	(2.4%)	(8.5%)	(14.5%)
System										
Total Resources	13,143	12,815	12,433	12,033	12,112	12,137	12,258	12,248	12,243	12,054
Obligation + Reserves (15%)	12,561	12,815	12,931	13,373	13,692	13,940	14,160	14,474	14,664	14,984
System Position	583	(0)	(498)	(1,340)	(1,579)	(1,803)	(1,902)	(2,226)	(2,421)	(2,930)
Reserve Margin	17.1%	12.0%	7.7%	0.8%	(0.9%)	(2.4%)	(3.0%)	(5.1%)	(6.4%)	(9.8%)

12% Planning Reserve Margin

Calendar Year	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
System										
Total Resources	13,143	12,815	12,433	12,033	12,112	12,137	12,258	12,248	12,243	12,054
Obligation + Reserves (15%)	12,824	13,092	13,222	13,698	14,024	14,280	14,505	14,828	15,023	15,351
System Position	319	(277)	(789)	(1,665)	(1,912)	(2,143)	(2,247)	(2,580)	(2,780)	(3,297)
Reserve Margin	17.8%	12.6%	8.2%	1.1%	(0.6%)	(2.1%)	(2.7%)	(4.9%)	(6.1%)	(9.5%)

15% Planning Reserve Margin

Utility-Scale Supply-Side Resource Options – East Side

	Installation Location	Technology	Average Capacity MW	Capital Cost Estimate in \$/kW (Average)	Annual Average Heat Rate HHV - Incl. Degradation	Var. O&M \$/MWh
East Side Options						
Coal						
Utah PC without Carbon Capture & Sequestration	Utah	PC Supercritical	600	2,934	9,106	0.96
Utah PC with Carbon Capture & Sequestration	Utah	PC Supercritical	526	5,306	13,087	6.71
Utah IGCC with Carbon Capture & Sequestration	Utah	IGCC - (2x1)	466	5,136	10,823	11.28
Wyoming PC without Carbon Capture & Sequestration	Wyoming	PC Supercritical	790	3,322	9,214	1.27
Wyoming PC with Carbon Capture & Sequestration	Wyoming	PC Supercritical	692	6,007	13,242	7.26
Wyoming IGCC with Carbon Capture & Sequestration	Wyoming	IGCC - (2x1)	456	5,816	11,047	13.52
Existing PC with Carbon Capture & Sequestration (500 MW)	Utah/Wyo	PC Subcritical Retrofit	(139)	1,319	14,372	6.71
Natural Gas (4500 feet elevation)						
Utility Cogeneration	Utah	Compressor Heat	10	5,076	4,974	23.29
Fuel Cell - Large (numbers do not change for West Side)	Utah	SOFC	5	1,794	7,262	0.03
SCCT Aero	Utah	SCCT - 3 x LM6000	118	1,126	9,773	5.63
Intercooled Aero SCCT	Utah	SCCT - 2 x LMS100	174	1,052	9,402	2.71
Intercooled Aero SCCT	Utah	SCCT - 3 x LMS100	261	1,052	9,402	2.71
Internal Combustion Engines	Utah	Natural Gas Engines	153	1,324	8,500	5.20
SCCT Frame (2 Frame "F")	Utah	SCCT - 2 - Frame F	302	747	11,659	4.47
CCCT (Wet "F" 1x1)	Utah	CCCT - "F" (1x1)	222	1,366	7,302	2.94
CCCT Duct Firing (Wet "F" 1x1)	Utah	"F" Duct Firing	50	558	8,869	0.39
CCCT (Wet "F" 2x1)	Utah	CCCT - "F" (2x1)	506	1,244	7,098	2.94
CCCT Duct Firing (Wet "F" 2x1)	Utah	"F" Duct Firing	64	628	8,557	0.39
CCCT (Dry "F" 2x1)	Utah	CCCT - "F" (2x1)	438	1,275	7,368	3.35
CCCT Duct Firing (Dry "F" 2x1)	Utah	"F" Duct Firing	98	644	8,950	0.11
CCCT (Wet "G" 1x1)	Utah	CCCT - "G" (1x1)	333	1,292	6,884	4.56
CCCT Duct Firing (Wet "G" 1x1)	Utah	"G" Duct Firing	72	547	9,021	0.36
CCCT Advanced (Wet)	Utah	"H" Technology	400	1,427	6,760	4.56
CCCT Advanced Duct Firing (Wet)	Utah	"H" Duct Firing	75	700	9,021	0.36
Renewables / Energy Storage / Nuclear / Other						
Wind	Wyoming	1.5 to 2.5 MW Turbines	100	2,462	n/a	-
East Side Geothermal (Blundell)	Utah	Dual flash or Binary	35	6,087	n/a	5.94
East Side Geothermal (Green field)	Utah	Dual flash or Binary	35	7,609	n/a	11.88
Battery Storage	Utah	Advanced Batteries	5	2,084	12,000	10.00
Pumped Storage	Nevada	Pumped Hydro	350	1,773	13,000	4.30
Compressed Air Energy Storage (CAES)	Wyoming	CAES	350	1,561	11,980	5.50
Recovered Energy Generation (CHP)	East	Organic Rankine	12	5,500	4,974	8.55
Nuclear	Idaho	Advanced - Fission	1,600	5,461	10,710	1.63
Solar Concentrating (PV) - 30% CF	Utah	Concentrating PV	10	6,520	n/a	-
Solar Concentrating (natural gas backup) - 25% solar	Utah	Concentrating PV	250	4,150	n/a	-
Solar Concentrating (thermal storage) - 30% solar	Utah	Thermal (trough)	250	4,650	n/a	-

Costs stated in 2008 dollars

Note: The capacity shown for retrofitting CCS on existing PC plants is a net change from current capacity (proportional to 500 MW). The heat rate is the total net plant heat rate based on a nominal 10,000 Btu/kWh without CCS.

Utility-Scale Supply-Side Resource Options – West Side

	Installation Location	Technology	Average Capacity MW	Capital Cost Estimate in \$/kW (Average)	Annual Average Heat Rate HHV - Incl. Degradation	Var. O&M \$/MWh
West Side Options						
Natural Gas(1,500 feet elevation)						
SCCT Aero	Northwest	SCCT - 3 x LM6000	130	1,024	9,773	5.12
Intercooled Aero SCCT	Northwest	SCCT - 3 x LMS100	287	956	9,402	2.46
Internal Combustion Engines	Northwest	Natural Gas Engines	168	1,204	8,500	5.20
SCCT Frame (2 Frame "F")	Northwest	SCCT - 2 - Frame F	338	679	11,659	4.07
CCCT (Wet "F" 1x1)	Northwest	CCCT - "F" (1x1)	244	1,242	7,302	2.67
CCCT Duct Firing (Wet "F" 1x1)	Northwest	"F" Duct Firing	55	507	8,869	0.36
CCCT (Wet "F" 2x1)	Northwest	CCCT - "F" (2x1)	557	1,131	7,098	2.67
CCCT Duct Firing (Wet "F" 2x1)	Northwest	"F" Duct Firing	70	570	8,557	0.36
CCCT (Wet "G" 1x1)	Northwest	CCCT - "G" (1x1)	367	1,175	6,884	4.14
CCCT Duct Firing (Wet "G" 1x1)	Northwest	"G" Duct Firing	80	497	9,021	0.33
CCCT Advanced (Wet)	Northwest	"H" Technology	440	1,297	6,760	4.14
CCCT Advanced Duct Firing (Wet)	Northwest	"H" Duct Firing	83	636	9,021	0.33
Renewables / Energy Storage						
Wind	Ore/Wash	1.5 to 2.5 MW Turbines	100	2,612	n/a	-
Biomass	Northwest	Boiler	50	3,347	10,979	0.96
West Side Geothermal (Green field)	Northwest	Dual flash or Binary	35	7,609	n/a	11.88
Compressed Air Energy Storage (CAES)	Northwest	CAES	385	1,561	11,980	5.00
Hydrokinetic (Wave) - 21% CF	Northwest	Floating Buoy	100	6,000	n/a	-

Costs stated in 2008 dollars

Forward Price Curves - Natural Gas (East /West)

