



2015 Integrated Resource Plan

Public Input Meeting 3

August 7-8, 2014

PACIFICORP
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

Agenda

Day 1

- Introductions
- Supply-Side Resources
  - Includes Energy Storage Study
- *Lunch Break (1/2 hour) 11:30 PT/12:30 MT*
- Needs Assessment
- Distributed Generation Study
- Plant Efficiency Study

Day 2

- Portfolio Development
- Wind Integration
- *Lunch Break (1/2 hour) 11:30 PT/12:30 MT*
- Planning Reserve Margin
- Wind & Solar Capacity Contribution

August 26 Conference Call

2015 Integrated Resource Plan

Supply-Side Resources

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Supply Side Resources Discussion Outline

- Background
  - Data sources
  - General assumptions
  - Supply Side Resources table format changes since 2012
- Resource Update and Overview
  - Coal
  - Gas
  - Renewables
    - Wind
    - Solar
    - Geothermal
  - Energy Storage
  - Nuclear

Background

- Data sources
  - Third-party performance and cost estimates
  - Publicly available data
  - Recent projects
- General assumptions
  - 2014 dollars
  - Capacities and costs adjusted to "proxy site" elevations
  - Capital costs based on "greenfield" sites for gas-fueled resources
  - Capital costs include:
    - Direct: costs: Engineering-Procure-Construct (EPC) "overnight construction" costs to in-service year; includes sales taxes, insurance and contractor's contingency
    - Owner's costs: Development, permitting, project management/engineering, water, "outside the fence" linears, land, legal costs, interconnection, capital spares and owner's contingency
    - Owner's financial costs: Allowance for Funds Used During Construction (AFUDC), capital surcharge and capitalized property taxes
- Supply Side Resources (SSR) table format changes since 2012 - Elevation assumptions for new resources – impact on combustion turbine based resources

Coal Resources

NSPS & Input Assumptions

- New coal currently not considered a viable option
- Proposed greenhouse gas (GHG) New Source Performance Standards (NSPS) for fossil-fueled electric plants proposed in September 2013
  - New coal-fueled units: 1,100 lbs CO_2 per gross megawatt-hour over a 12-month operating period
  - New natural gas-fueled combined cycle plants larger than 850 MMBtu/hour: 1,000 lbs CO_2 per gross megawatt-hour over a 12-month operating period
- Coal resource costs escalated from 2012 SSR
- 2025: carbon capture and sequestration (CCS) for supercritical pulverized coal (SCPC) or integrated gasification combined cycle (IGCC) available

Coal & Gas Resources

Implications - Proposed NSPS GHG Standards

- Coal-fueled resources - requires some level of carbon capture and sequestration CCS to meet the standard
- Gas-fueled resources - existing technology combined cycle plants can meet the proposed GHG standard without CCS
- The requirement for CCS essentially eliminates coal for new generating resources for utilities
- North American coal-fueled CCS projects:
  - Enhanced oil recovery is the CO_2 sink
  - Rely on federal funding or incentives
  - Have experienced cost overruns, and in most cases, significant

Coal Resources

Kemper County IGCC

- 65% CO_2 capture (enhanced oil recovery)
- 582 MW (natural gas); 524 MW (lignite)
- Natural gas combined cycle portion tested
- Still in construction; target in-service: May 2015
- $5.5 billion! ($9,450 per kilowatt of gas capacity)
- Original budget: $2.4 billion

Coal Resources

SaskPower Boundary Dam Unit 3

- Post-combustion CO_2 capture – amine based
- 90% CO_2 capture (enhanced oil recovery)
- Retrofit of a coal-fired plant
- 160 MW gross, 110 MW net
- $1.3 (US) billion ($11,818 per kilowatt)
- In-service: July? 2014

Input Assumptions

- Modified proxy elevations to reflect generic locations:
  - 5,050’ is the base case (“reference case”) elevation
  - Eliminated 4,250’ elevation (Salt Lake City)
  - Added 3,000’ elevation (Oregon)
- Engineer-procure-construct (EPC) capital cost estimates prepared by Black & Veatch in 2012 were escalated to 2014$
- Updated major equipment costs (combustion turbines, power island equipment, reciprocating engines)
- Updated performance in cases where applicable:
  - Resources based on “F” class combustion turbines
  - Internal combustion (IC) engines
- O&M costs reflect a combination of escalated 2012 costs and updated costs provided by original equipment manufacturers

Gas Resources

Design Basis & Owner's Cost Updates

- Design basis in the SSR for gas-fueled resources is dry cooling. Wet-cooled options removed (though wet cooling is a repowering option for existing coal)
- Previous SSR costs for gas resources assumed costs for project development, external linears (gas and transmission interconnections), land, water, development and project management on a brownfield basis
- Proposed SSR costs applies a generic greenfield development approach. This increases overall project costs for the first resource at a site by $17- 24 million depending on technology and resource size
- Note: actual development costs will be site specific

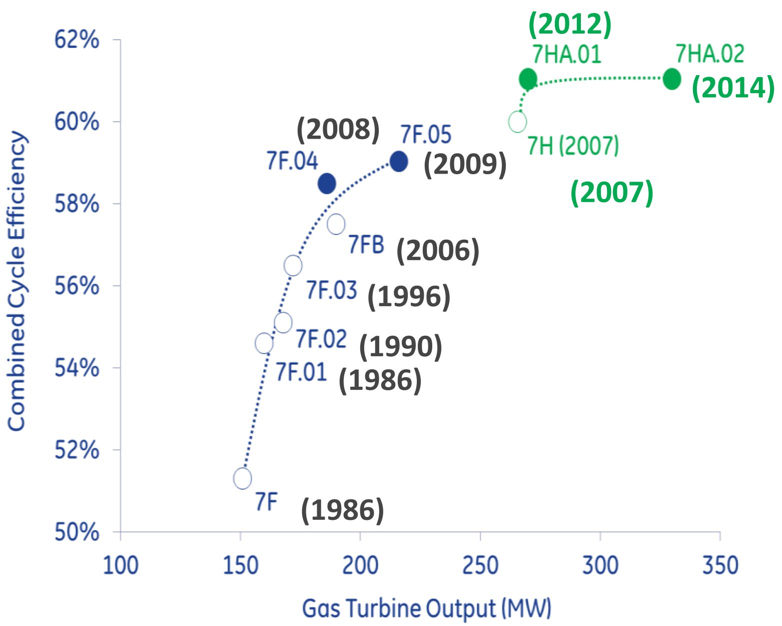
Market Changes

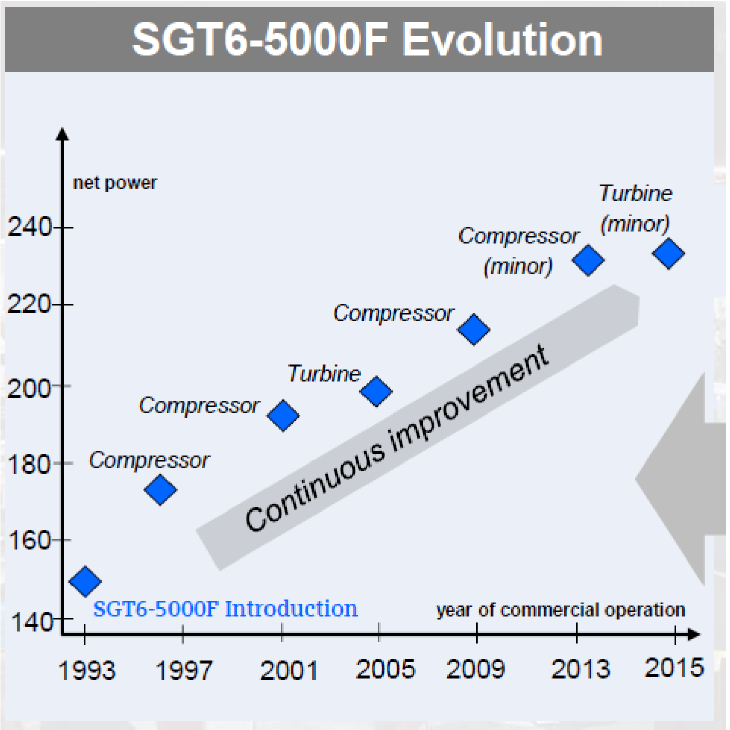
Wartsila 18V50SG engines, 18 MW

- Further development and deployment of flexible resources (both combined cycle and peaking facilities):
  - Fast startup times and ramping capability
  - Decreased startup emissions
  - Lower minimum load capability while maintaining emissions compliance
  - High efficiency
  - Durations between planned outages extended
  - Reciprocating engines are serious alternatives

Gas Turbine Manufacturers' Update

- GE & Siemens turbine evolution ("F" class, 60 Hz)





Gas Resources

Market Update

Dominion's Warren County, 3x1 MHI GAC, 1329 MW

- Domestic gas-fueled power generation equipment sales over 2012-2014 period have been soft
- Black & Veatch predicts power sector demand for gas to grow by 2.57% annually (403 GW of new capacity before 2038)[1]
- Another prediction: commitments for new gas will remain modest pending clarity on recently promulgated and proposed EPA rules that impact existing coal plants. Result: slight to moderate domestic growth in combustion turbine sales

[1] "Building a World of Difference, 2013 Energy Market Outlook and Industry Trends," Black & Veatch, July 2013

Gas Resources

Performance and Cost ($2014)

Resource	Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency
SCCT Aero x3	3,000	151	2015	4	2019	40	1,285	3.26	10.58	9,738
Intercooled SCCT Aero x1	3,000	95	2015	4	2019	40	1,619	3.24	17.14	8,867
SCCT Frame "F" x1	3,000	200	2015	4	2019	40	839	7.49	8.64	9,781
IC Recips x 6	3,000	109	2015	4	2019	40	1,503	8.05	17.79	8,135
CCCT Dry "F", 2x1	3,000	578	2015	6	2021	30	995	1.26	5.40	6,637
CCCT Dry "F", DF, 2x1	3,000	101	2015	6	2021	35	755	0.11	0.00	9,561
CCCT Dry "G/H", 2x1	3,000	710	2015	6	2021	40	912	2.33	4.82	6,667
CCCT Dry "G/H", DF, 2x1	3,000	96	2015	6	2021	40	636	0.09	0.00	7,504
CCCT Dry "J", Adv 1x1	3,000	411	2015	5	2020	40	956	2.11	7.57	6,495
CCCT Dry "J", DF, Adv 1x1	3,000	43	2015	5	2020	40	481	0.10	0.00	8,611
SCCT Aero x3	5,050	140	2015	4	2019	30	1,391	3.48	11.41	9,739
Intercooled SCCT Aero x1	5,050	88	2015	4	2019	30	1,753	3.46	18.44	8,867
SCCT Frame "F" x1	5,050	185	2015	4	2019	35	908	8.27	9.31	9,781
IC Recips x6	5,050	109	2015	4	2019	35	1,503	8.05	17.79	8,135
CCCT Dry "F", 1x1	5,050	265	2015	5	2020	40	1,152	1.60	11.19	6,667
CCCT Dry "F", DF, 1x1	5,050	48	2015	5	2020	40	539	0.09	0.00	7,864
CCCT Dry "F", 2x1	5,050	534	2015	6	2021	40	1,077	1.36	5.80	6,637
CCCT Dry "F", DF, 2x1	5,050	101	2015	6	2021	40	755	0.11	0.00	9,561
CCCT Dry "G/H", 1x1	5,050	327	2015	5	2020	40	996	2.77	9.89	6,698
CCCT Dry "G/H", DF, 1x1	5,050	48	2015	5	2020	40	604	0.10	0.00	8,452
CCCT Dry "G/H", 2x1	5,050	656	2015	6	2021	40	987	2.51	5.18	6,667
CCCT Dry "G/H", DF, 2x1	5,050	96	2015	6	2021	40	636	0.09	0.00	7,504
CCCT Dry "J", Adv 1x1	5,050	380	2015	5	2020	40	1,035	2.34	8.58	6,495
CCCT Dry "J", DF, Adv 1x1	5,050	43	2015	5	2020	40	481	0.10	0.00	8,611
Molten Carbonate Fuel Cell	5,050	5	2015	2	2017	20	5,106	10.10	8.82	8,061

Renewable Resources

Major Changes

- Wind: turbine designs have changed resulting in higher capacity factors in a wider range of wind regimes. Turbine design improvements have led to higher net capacity factor estimates in the SSR for Utah and Wyoming locations.

- Solar: includes thermal and photovoltaic (PV). Replaced 2 MW solar PV with 5 MW solar PV

- Geothermal: updated costs based on previous geothermal resources study, updated PPA price

- Capital cost estimates do not include investment tax credits

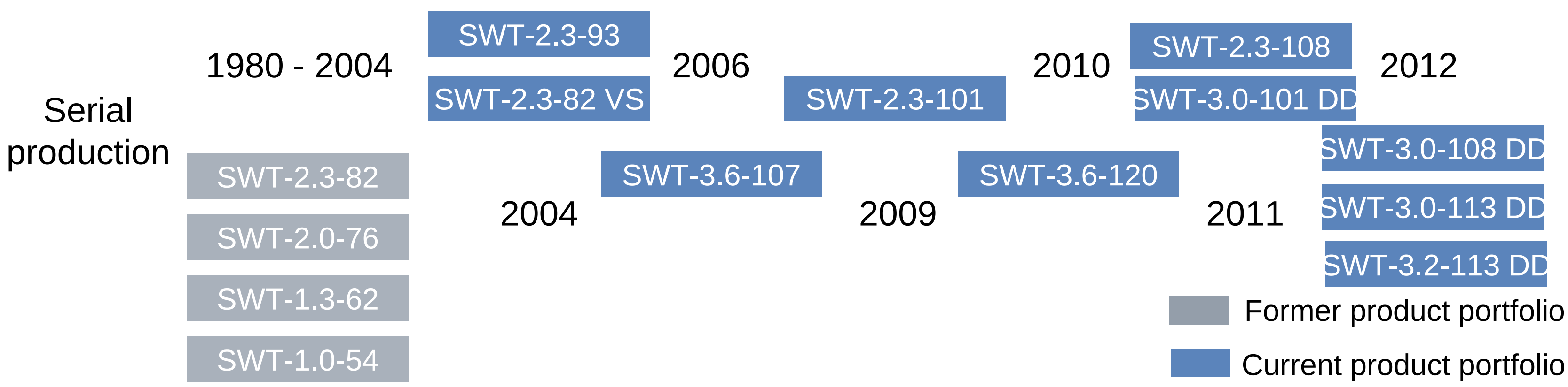
Input Assumptions

- A proxy 2 MW wind turbine size is used in the SSR to represent a range of typical wind turbine sizes currently available
- The type, size and spacing of wind turbines depend on the site specific wind characteristics
- Capital cost estimates are based on current turbine pricing information from leading manufacturers; overall project costs based upon actual development and construction costs

Wind Turbine Manufacturers' Update

- Manufacturers are designing wind turbines with longer blade lengths and shape factors to maximize energy production for lower wind speeds
- Designers are able to improve capacity factors by choosing wind turbines and turbine options matched to the wind regime of their site
- Manufacturers have developed farm-based controls to increase overall energy production

Siemens Wind Turbines – Mega Watt Rating – Rotor Diameter (Meters)



Solar Resources

Photo Voltaic Update

Agua Caliente Solar Plant, 290 MW_{AC}

- In December 2013 an update to the Black & Veatch study was completed for both 5 & 50 MW solar PV (both fixed tilt and single axis tracking)
- Removed thin film resource option from SSR
- Owner's costs assumptions used by B&V study were reduced
- An additional mid-year cost reduction was applied
- System interconnection costs were included
- Increased the size of small utility scale photovoltaic resources for the SSR from 2 MW_{AC} to 5 MW_{AC}
- **Capital costs range from $1.86 to $2.00 per watt (DC basis)**

Solar Resources

Renewable Resources Update: Solar PV

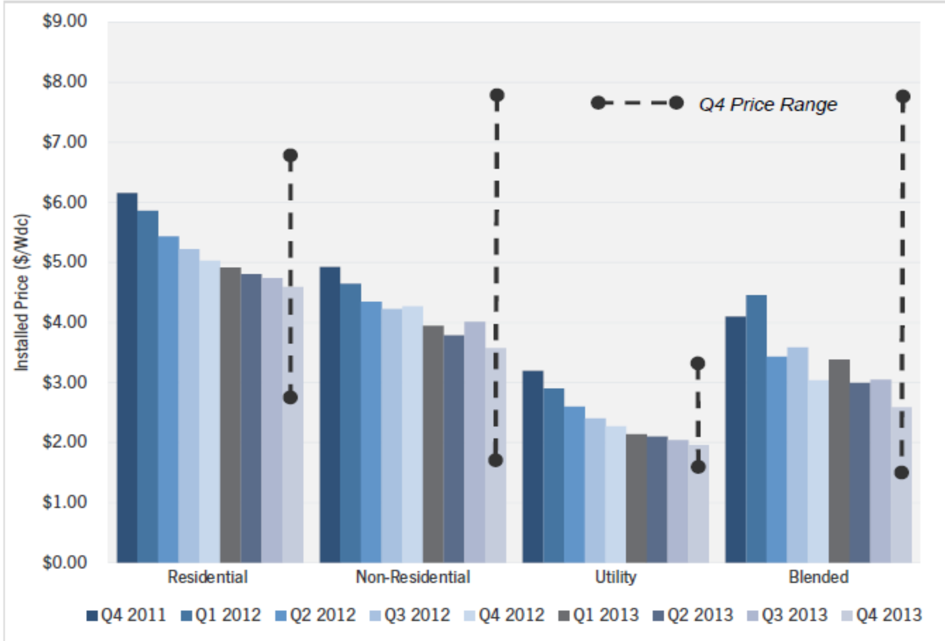


Figure 2.12, "US Solar Market Insight Report", 2013 Year-In-Review, Executive Summary, GTM Research

- Price declines in photovoltaic panels seen during the past few years are beginning to level off
- Global production and demand for solar panels reached equilibrium in 2014 at about 45-50 GW. Global production was nearly twice as high as demand two years ago
- In June 2014 the US Department of Commerce announced preliminary duties between18% and 35% on Chinese PV solar products imported into the US
- China is contesting US duties on solar panels at the World Trade Organization which adds further uncertainty to future panel prices in the US
- Lessons learned from European experience may drive down soft costs

Renewable Resources Update: Solar PV

Cost Breakdown of a Fixed Tilt 50 MW AC Photovoltaic Solar Project in Utah			
Item	**Cost**	**Unit**	**Responsibility**
Modules	596	$/kW DC	EPC
Mounting Structure	280	$/kW DC	EPC
Inverter	185	$/kW DC	EPC
Balance of Systems	211	$/kW DC	EPC
Site Preparation	129	$/kW DC	EPC
Installation Labor	211	$/kW DC	EPC
Land Purchase	9	$/kW DC	Owner
Interconnection	23	$/kW DC	Owner
Project Management	95	$/kW DC	Owner
AFUDC & Capital Surcharge	116	$/kW DC	Owner
Cost Subtotal	**1,855**	**$/kW DC**	
Conversion from DC to AC	137.25%		
Cost Total in AC	**2,546**	**$/kW AC**	

Renewable Resources Update: Solar PV

Cost Breakdown of a Single Axis 50 MW AC Photovoltaic Solar Project in Utah

Item	Cost	Unit	Responsibility
Modules	596	$/kW DC	EPC
Mounting Structure	358	$/kW DC	EPC
Inverter	189	$/kW DC	EPC
Balance of Systems	226	$/kW DC	EPC
Site Preparation	138	$/kW DC	EPC
Installation Labor	243	$/kW DC	EPC
Land Purchase	12	$/kW DC	Owner
Interconnection	24	$/kW DC	Owner
Project Management	102	$/kW DC	Owner
AFUDC & Capital Surcharge	125	$/kW DC	Owner
Cost Subtotal	**2,012**	**$/kW DC**	
Conversion from DC to AC	134.30%		
Cost Total in AC	**2,702**	**$/kW AC**	

Solar Resources

Solar PV - Future Costs

Utah 50 MW Solar Cost Glide Path

Based upon B&V 2013 Solar Report

	Fixed Tilt	Single Axis Tracking
Year 1	$2,545	$2,702
Year 2	98.4%	98.4%
Year 3	96.8%	96.8%
Year 4	95.2%	95.2%
Year 5	93.6%	93.6%
Year 6	92.0%	92.0%
Year 7	90.4%	90.4%
Year 8	88.8%	88.8%
Year 9	87.2%	87.2%
Year 10	85.5%	85.5%

Concentrating Solar Power Update

Ivanpah Concentrating Solar Plant, 377 MW_{AC},

- Concentrating Solar Power (CSP)
  - Site-specific to locations with high direct normal insolation
  - CSP development has been impacted by reduced PV pricing and project risk factors associated with CSP
  - Photovoltaic technology continues to be preferable to CSP technologies based on costs, capital risk and resource opportunity
  - Permitting challenges lie ahead for solar power towers
  - For the 2015 IRP, 2012 SSR cost estimates were escalated to 2014$

Geothermal Resources

Renewable Resources Update

Blundell Geothermal Plant, 33 MW

- Geothermal capital costs are based upon previous studies of geothermal within or near Company's service territory
- Studies indicate adding generation capacity at the Blundell geothermal plant is an option that has lower costs and fewer risks than developing a new greenfield site
- Company is currently conducting a multi-year reservoir study to assess the Roosevelt Hot Springs geothermal reservoir and expansion capability
- Geothermal has significantly greater development and capital risk than wind or solar
- For IRP modeling purposes, the assumption is made that geothermal resources are priced as a PPA to mitigate greenfield geothermal development risk. PPA price is based on publicly available data for recent geothermal projects.

Renewables Resources

Performance and Cost Summary (2014$)

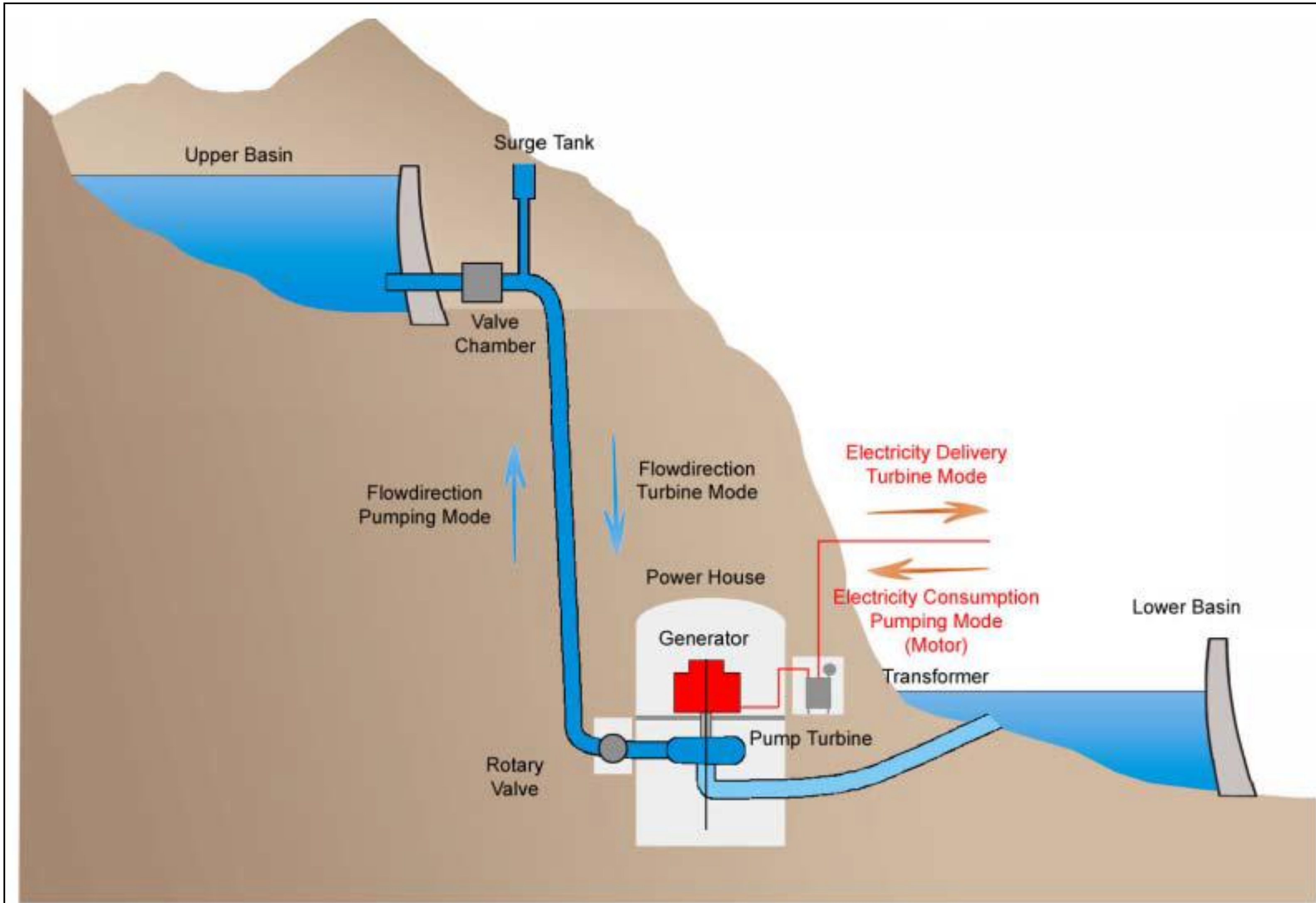
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)
Geothermal	Blundell Dual Flash 90% CF	5,000	35	2015	4	2019	40	5,748	1.30	106.79
Geothermal	Greenfield Binary 90% CF	5,000	43	2015	6	2021	40	7,396	1.30	165.63
Geothermal	Generic Geothermal PPA 90% CF	5,000	30	2015	1	2016	20	n/a	93.46	n/a
Wind	2.0 MW turbine 29% CF WA/OR	1,500	100	2015	5	2020	30	2,135	0.00	34.46
Wind	2.0 MW turbine 31% CF UT/ID	4,500	100	2015	5	2020	30	2,188	0.00	34.46
Wind	2.0 MW turbine 43% CF WY	6,500	100	2015	5	2020	30	2,156	0.66	34.46
Solar	PV Poly-Si Fixed Tilt 26.5% AC CF (1.37 MWdc/Mwac) UT	5,000	5.4	2015	2	2017	25	3,080	0.00	33.50
Solar	PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT	5,000	5.4	2015	2	2017	25	3,261	0.00	37.20
Solar	PV Poly-Si Fixed Tilt 26.5% AC CF (1.37 MWdc/Mwac) UT	5,000	50.4	2015	3	2018	25	2,546	0.00	30.90
Solar	PV Poly-Si Single Tracking 31.6% AC CF (1.34 MWdc/Mwac) UT	5,000	50.4	2015	3	2018	25	2,702	0.00	34.88
Solar	PV Poly-Si Fixed Tilt 25.4% AC CF (1.34 MWdc/Mwac) OR	4,000	50.4	2015	3	2018	25	2,659	0.00	31.32
Solar	PV Poly-Si Single Tracking 29.2% AC CF (1.34 MWdc/Mwac) OR	4,000	50.4	2015	3	2018	25	2,829	0.00	35.47
Solar	CSP Trough w Natural Gas	5,000	100	2015	4	2019	30	5,826	0.00	66.19
Solar	CSP Tower 24% CF	5,000	100	2015	4	2019	30	5,549	0.00	66.19
Solar	CSP Tower Molten Salt 30% CF	5,000	100	2015	4	2019	30	6,657	0.00	66.19

Energy Storage Options

- 2014 HDR study (update); link below
  - Pumped Storage
    - Focused on three projects in various stages of development
    - West side and east side options
  - Battery Storage
    - Lithium-ion: small / expensive on a $/MWh basis
    - Sodium-sulfur: larger / expensive / still in development
    - Redox flow: small / unique applications / expensive
  - Compressed Air Energy Storage (CAES)
  - Advanced flywheels: low energy storage capability
- http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Energy_Storage-Screening-Study-July2014.pdf

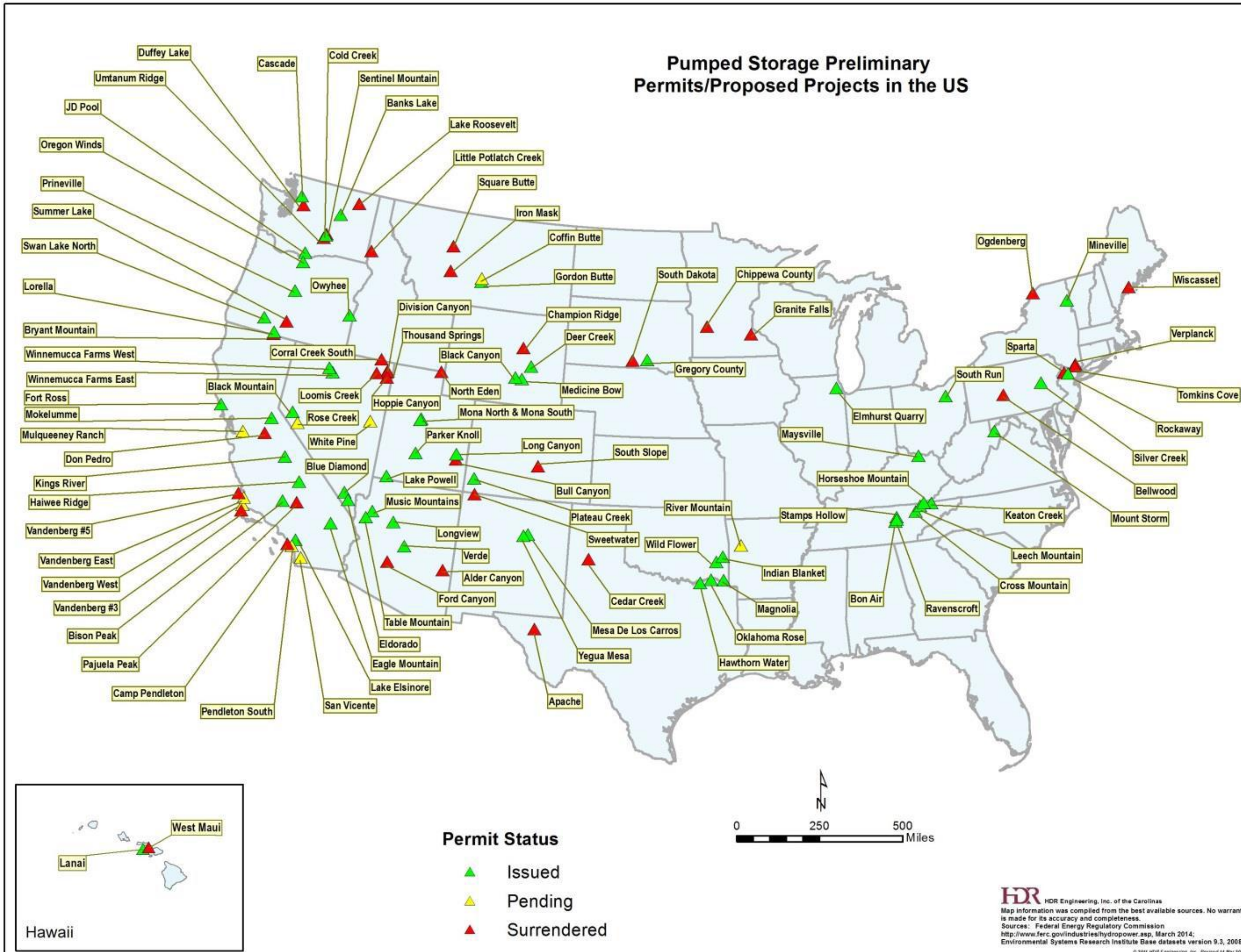
Energy Storage

Pumped Storage Schematic



Energy Storage

Proposed Pumped Storage Projects in US



Energy Storage

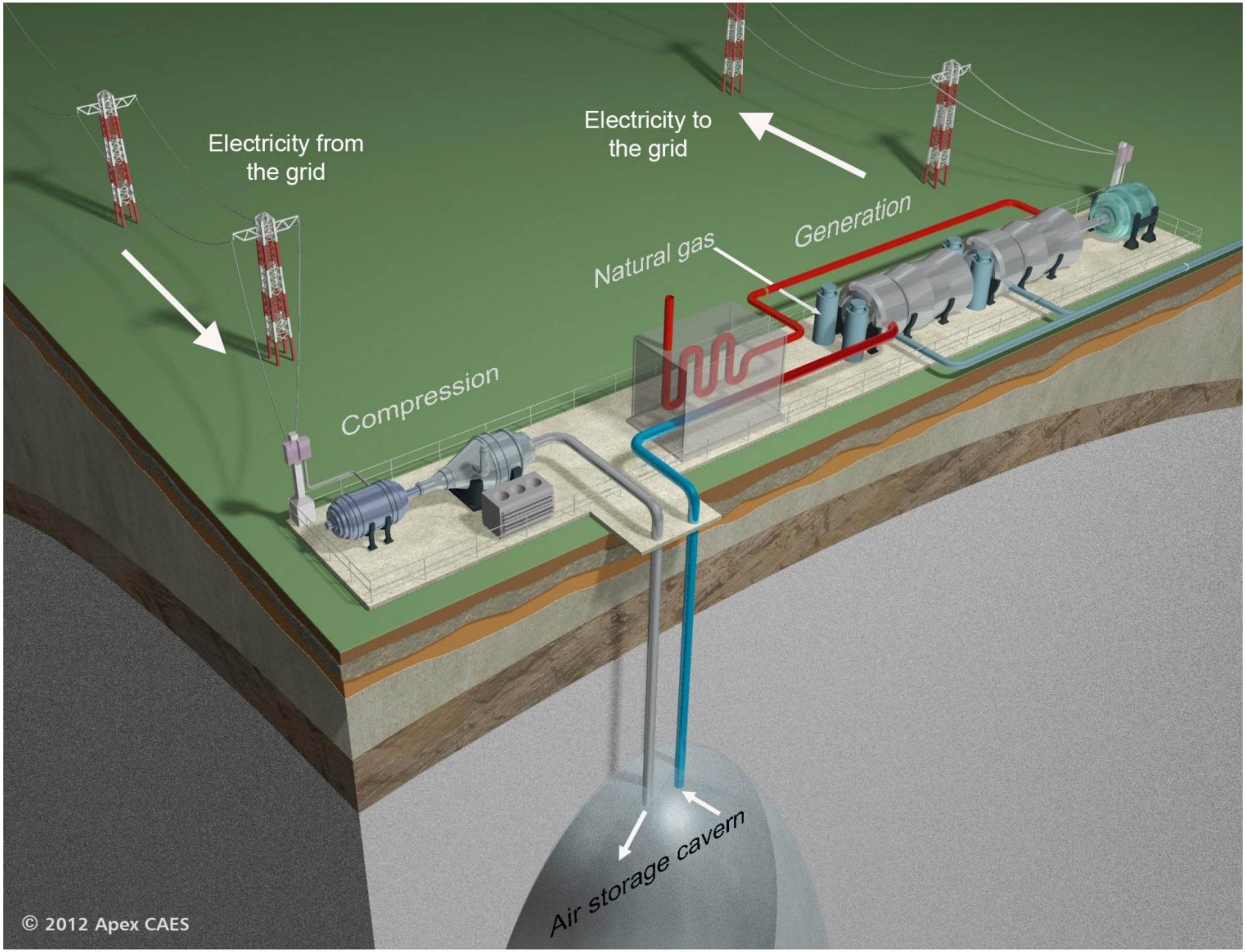
Pumped Storage Proxy Site – West Side

- Swan Lake North, Oregon
  - Capacity: 600 MW
  - Energy Storage: 5,280 MWh
  - Ramp rate: 6,000 MW/hr
  - Overall round trip efficiency: 77.5%
  - Commercial Operation Date: 2022

Pumped Storage Proxy Site – East Side

- Black Canyon, Wyoming
  - Capacity: 584 MW
  - Energy Storage: 5,550 MWh
  - Ramp rate: 6,000 MW/hr
  - Overall round trip efficiency 77.5%
  - Commercial Operation Date: 2022

Compressed Air Energy Storage (CAES)

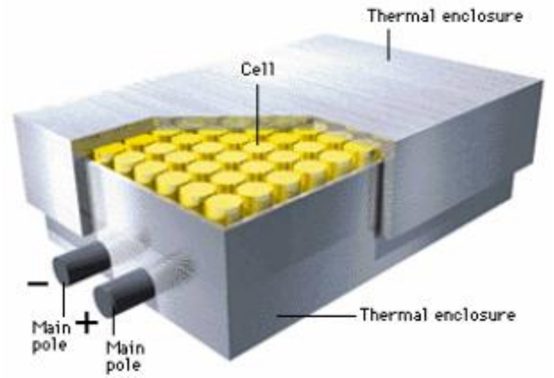


Energy Storage

CAES Proxy Site – Central Utah

- Magnum Energy (salt dome), transmission connection at Mona, UT
  - Stored compressed air is delivered to a series of combustion turbines, fired with natural gas
  - Capacity: Up to 1200 MW
  - Capacity (SSR) 300 MW
  - Energy storage: Up to 2 days
  - Energy storage (SSR) 8 hours
  - Heat rate (Btus/kWh, HHV) 4,390
  - Ramp rate: 8,000 MW/hr
  - Overall round trip efficiency 83.5% (excl. fuel)
  - Commercial availability: 2019

Battery Update



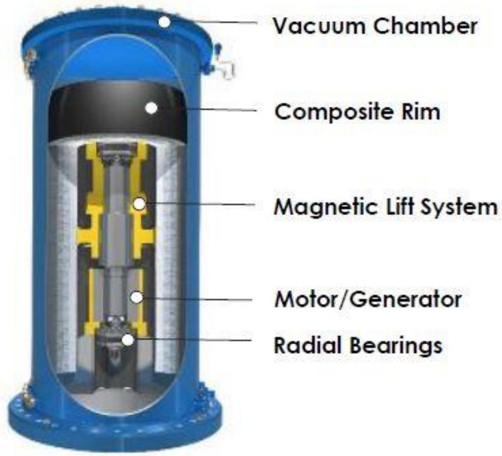
- Battery Storage
  - Batteries considered in this SSR:
    - Lithium Ion (Li-ion)
    - Sodium Sulfur (NaS)
    - Vanadium RedOx (VRB)
  - Still an expensive energy storage option
  - Not all operating characteristics remain constant throughout the life of a battery
  - Each of the battery technologies still have inherent technology risks

Energy Storage
Flywheel Update

- Advanced Flywheels
  - Best used for regulating voltage and frequency.

Beacon has the highest energy flywheel in commercial operation.

- ~7' tall, 3' in diameter
- 2,500 pound rotor mass
- Spins up to 16,000 rpm
- Max power rating 190 kW, 30 kWh/charge
- Lifetime throughput is over 4,375 MWh
- Capable of charging or discharging at full rated power without restriction
- Beacon flywheel technology is protected by over 60 patents



Energy Storage

Performance and Cost Summary ($2014)

	Flywheel	Li-Ion	NAS	VRB	Dry Cell	Pumped Storage	CAES
System Cost ($/kWh)	$ 29,040	$ 1,310	$ 611	$ 739	$ 478	N/A	N/A
($/kW)	$ 2,400	$ 9,432	$ 4,400	$ 5,324	$ 3,440	$ 2,862	$ 2,300
Rated System (MW)	20	1	1	1	1	600	1,200
Rated Capacity (hrs)	0.083	7.2	7.2	7.2	7.2	8.8	48
	(5 minutes)						

Nuclear Resources

Advanced Large Reactor Update

Vogtle Plant, under construction

- Advanced large reactor (similar to Plant Vogtle 3 & 4 currently under construction by Southern Company)
  - Westinghouse AP1000: 1,117 MW each
  - Similar technology to that being proposed by Blue Castle for a facility near Green River, Utah
  - Capital cost for Vogtle 3 & 4: $16.5+? bn (~$7,400 per kilowatt)
  - In service dates: 2017 & 2018
  - SSR Availability: 2025

Nuclear Resources

Small Modular Reactor (SMR) Update

- The SMR designs use varying degrees of "first-of-a-kind" (FOAK) design concepts
- On a cost per kilowatt basis, initial capital cost are estimated to be comparable to large nuclear plants
- Design Certification Application approval is at least 6 years away
- Combined Operating License applicant must address site-specific differences
- Will continue to monitor SMR development

SMR Proxy Technology - NuScale

- SMR's: NuScale Power (Reactor) Module
  - Capacity: 45 MW / module
  - Minimum power: 10%
  - Ramp rate up: 3% / minute
  - Ramp rate down: 10% / minute
  - Water consumption:
    - Once-through 300 gpm
    - Wet cooling tower 540 gpm

Nuclear Resources

Performance and Cost Summary ($2014)

Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Resource Availability Year	Total Implementation Time (yrs)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency
Nuclear	Advanced Fission	5,000	2,200	2015	10	2025	40	6,705	9.64	88.75	10,710
Nuclear	Small Modular Reactor x 12	5,000	518	2023	8	2031	40	5,438	8.62	32.94	10,710

True or False?





2015 Integrated Resource Plan

Needs Assessment

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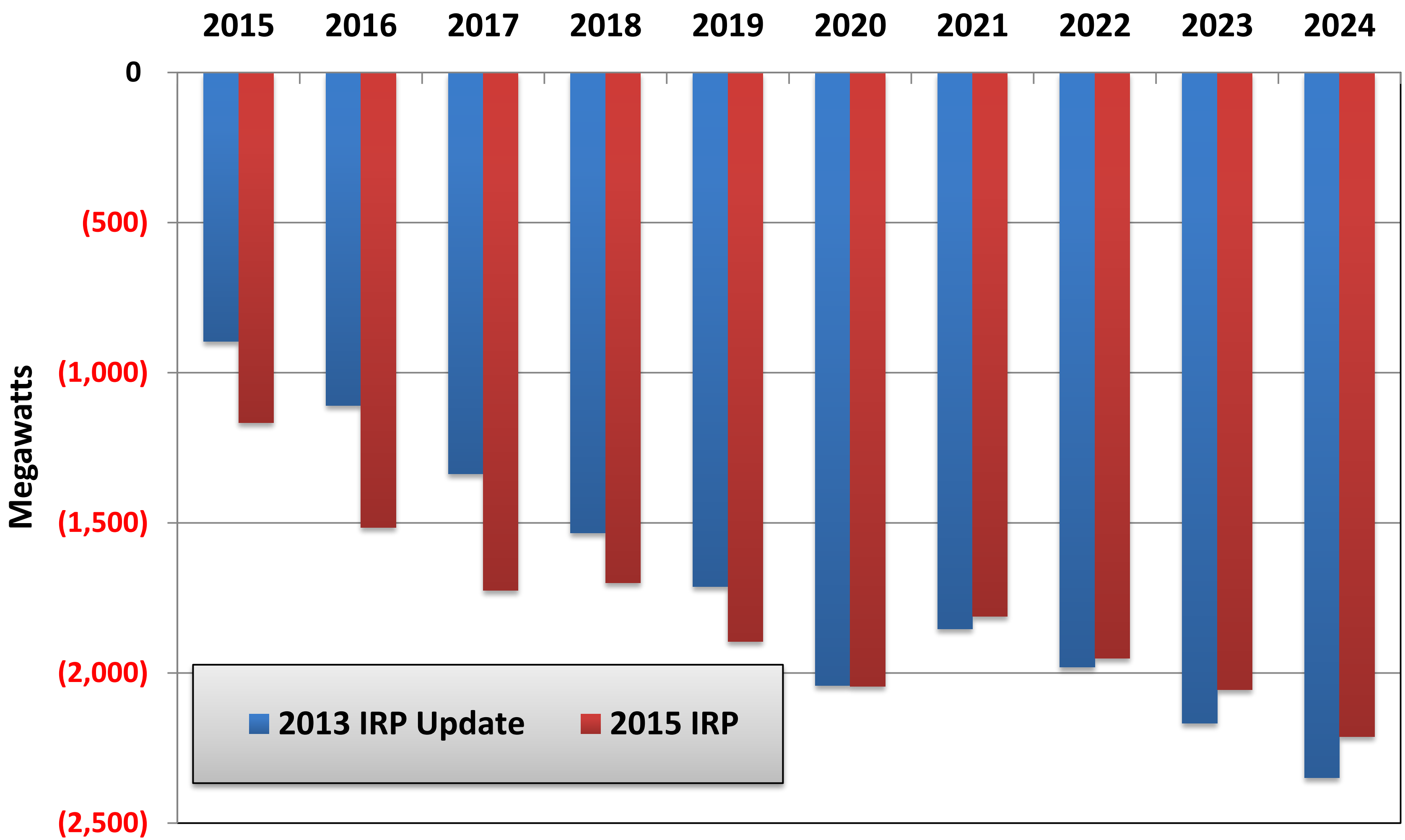
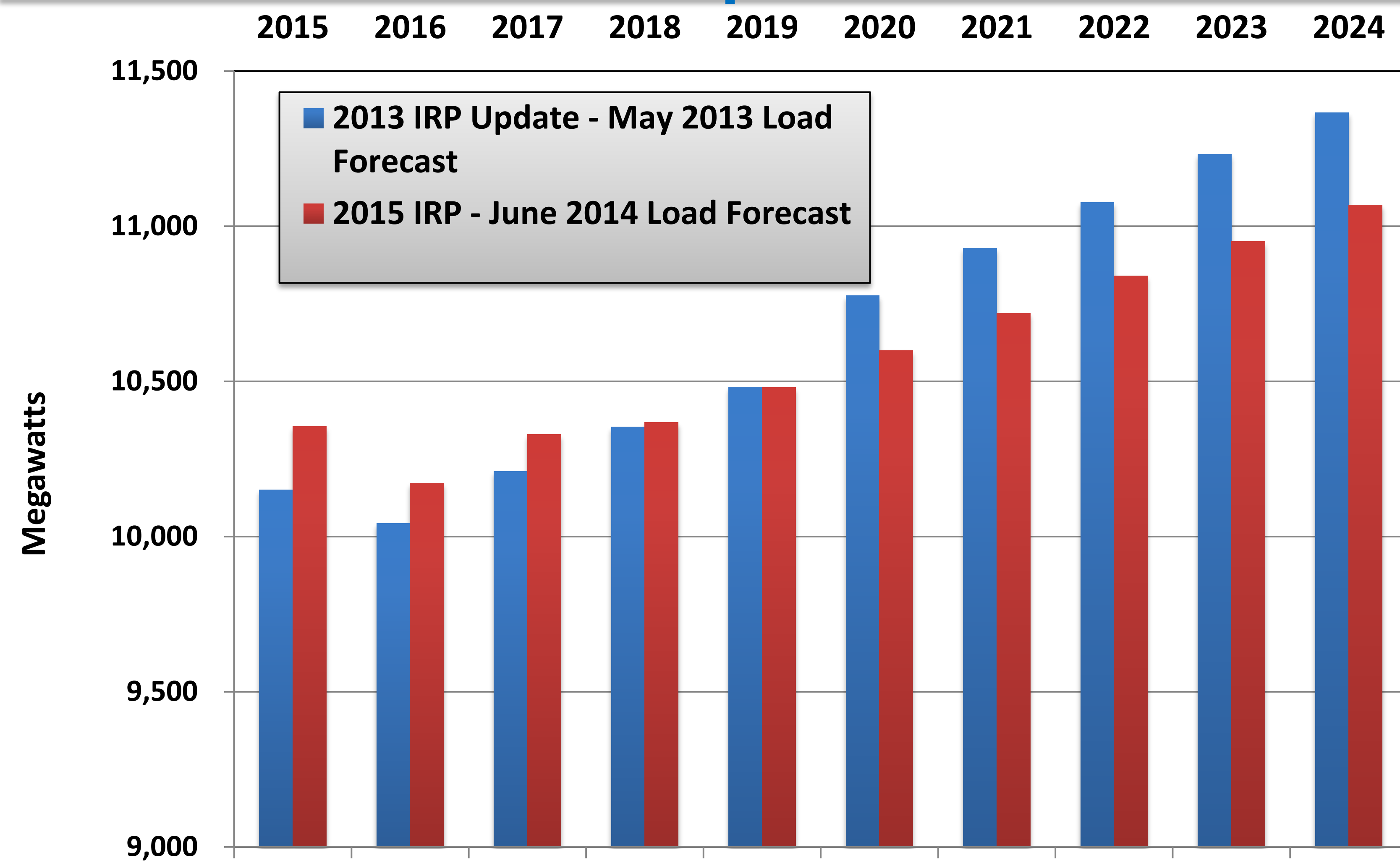
System Capacity Position Comparison
2015 IRP vs 2013 IRP Update



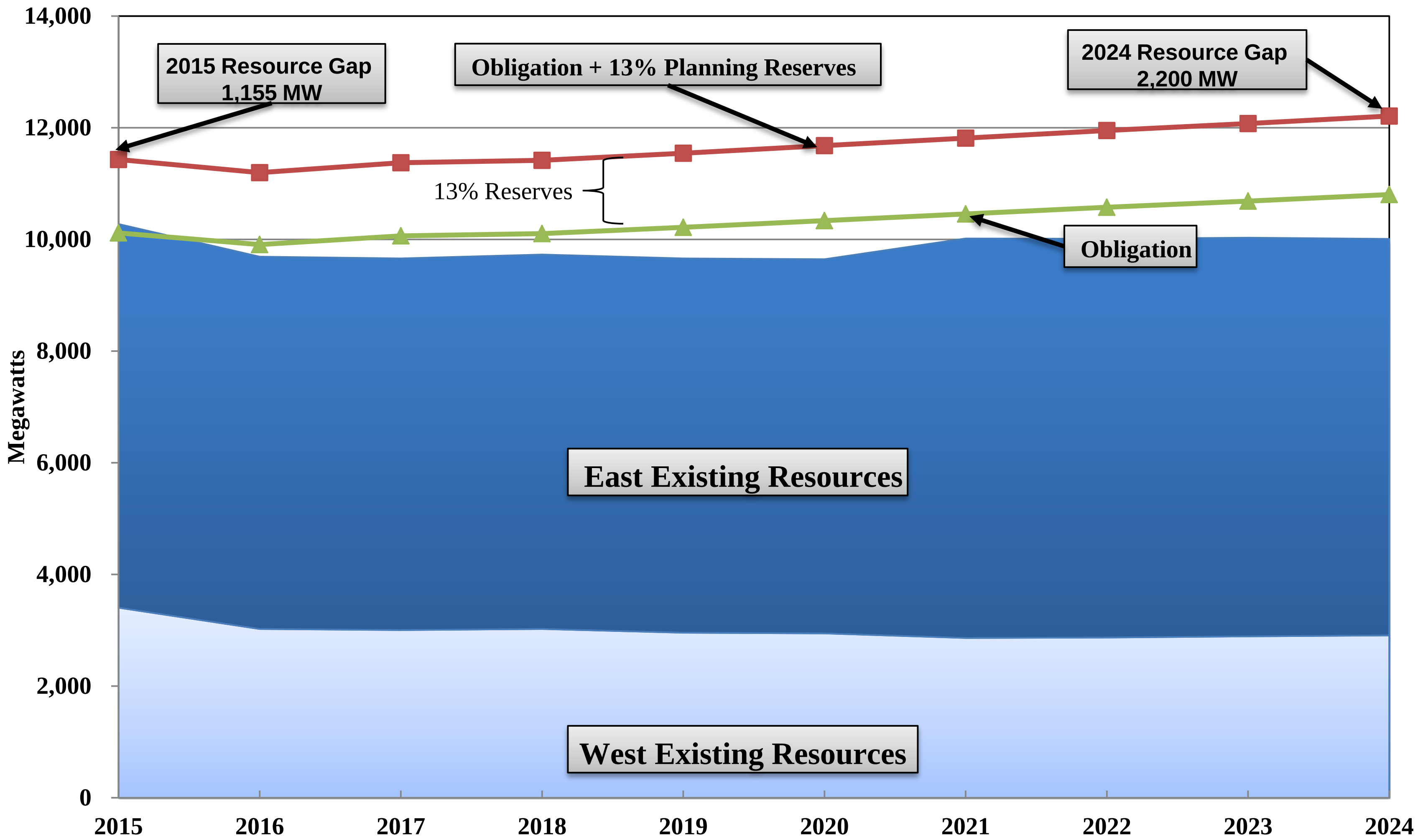
Peak Load Comparison
2015 IRP vs 2013 IRP Update



Resource/Reserve Changes
2015 IRP vs 2013 IRP Update

- Load Changes
  - In the near term, peak load is higher - up by an average of 117 MW between 2015 and 2018
  - In the out years, peak load is lower – down an average of 201 MW between 2019 and 2024
- Resource Changes
  - Total resources reduced by an average of 138 MW
    - Hermiston PPA expires in 2016 reducing resources by 227 MW
    - Hydro capacity down an average of 12 MW as a result of updated forecasts
    - Peak contribution factor for wind revised to 5.0% from 4.0% resulting in an increase in peak resource availability by about 20 MW
    - New executed solar QF contracts and increase in solar peak contribution (previously 13.6% for all solar increasing to 14.5% for fixed tilt and 28.5% for single axis tracking) results in an increase of peak resource availability of about 28 MW by 2017
    - Cancellation of two QF wind projects decreased peak resource availability by 6 MW, which is partially offset by the addition of three smaller wind QF's which increases peak resource availability by 1.5 MW
    - Gadsby 1 re-rated to 64 MW up from 57 MW.
    - Peak contribution factor for existing class 1 DSM was changed from 100% of nameplate to 106% of nameplate resulting in an increase to resource of 20 MW
    - Peak contribution factor for firm sales, purchase contracts, and interruptibles was decreased from 113% to 106% resulting in an average decrease in 28 MW

System Position Chart



Capacity Load and Resource Balance

(13% Planning Reserve Margin)

Calendar Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
East										
Thermal	6,379	6,376	6,376	6,426	6,426	6,426	6,426	6,418	6,418	6,418
Hydroelectric	113	111	111	111	111	111	111	111	111	90
Renewable	95	100	100	100	100	98	97	97	94	94
Purchase	627	406	300	299	299	299	272	272	272	272
Qualifying Facilities	85	104	122	122	122	122	120	116	116	66
Class 1 DSM	349	349	349	349	349	349	349	349	349	349
Sale	(737)	(737)	(662)	(662)	(662)	(662)	(182)	(182)	(182)	(150)
Non-Owned Reserves	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)
East Existing Resources	**6,873**	**6,670**	**6,657**	**6,706**	**6,706**	**6,704**	**7,154**	**7,143**	**7,140**	**7,102**
East Total Resources	**6,873**	**6,670**	**6,657**	**6,706**	**6,706**	**6,704**	**7,154**	**7,143**	**7,140**	**7,102**
Load	7,147	6,970	7,092	7,101	7,189	7,279	7,375	7,438	7,549	7,615
Interruptible	(149)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)	(175)
Existing Class2 DSM	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)
East obligation	**6,940**	**6,738**	**6,860**	**6,869**	**6,957**	**7,047**	**7,142**	**7,206**	**7,317**	**7,382**
Planning Reserves (13%)	902	876	892	893	904	916	929	937	951	960
East Reserves	**902**	**876**	**892**	**893**	**904**	**916**	**929**	**937**	**951**	**960**
East Obligation + Reserves	**7,842**	**7,613**	**7,751**	**7,762**	**7,862**	**7,963**	**8,071**	**8,142**	**8,268**	**8,342**
East Position	**(969)**	**(943)**	**(1,095)**	**(1,056)**	**(1,156)**	**(1,260)**	**(917)**	**(1,000)**	**(1,128)**	**(1,240)**
East Reserve Margin	(1.0%)	(1.0%)	(3.0%)	(2.4%)	(3.6%)	(4.9%)	0.2%	(0.9%)	(2.4%)	(3.8%)
West										
Thermal	2,500	2,256	2,252	2,252	2,252	2,252	2,252	2,248	2,243	2,243
Hydroelectric	781	774	755	779	729	731	646	624	656	650
Renewable	43	43	43	43	43	43	43	24	24	22
Purchase	189	21	23	23	6	6	6	6	6	6
Qualifying Facilities	101	91	91	86	86	72	72	72	68	68
Class 1 DSM	0	0	0	0	0	0	0	0	0	0
Sale	(207)	(158)	(157)	(156)	(157)	(157)	(153)	(101)	(102)	(77)
Non-Owned Reserves	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)	(3)
West Existing Resources	**3,403**	**3,023**	**3,004**	**3,023**	**2,955**	**2,943**	**2,862**	**2,869**	**2,891**	**2,908**
West Total Resources	**3,403**	**3,023**	**3,004**	**3,023**	**2,955**	**2,943**	**2,862**	**2,869**	**2,891**	**2,908**
Load	3,209	3,202	3,237	3,267	3,291	3,321	3,346	3,403	3,401	3,454
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)
West obligation	**3,177**	**3,171**	**3,205**	**3,235**	**3,259**	**3,289**	**3,314**	**3,371**	**3,369**	**3,423**
Planning Reserves (13%)	413	412	417	421	424	428	431	438	438	445
West Reserves	**413**	**412**	**417**	**421**	**424**	**428**	**431**	**438**	**438**	**445**
West Obligation + Reserves	**3,590**	**3,583**	**3,622**	**3,655**	**3,683**	**3,716**	**3,745**	**3,809**	**3,807**	**3,868**
West Position	**(187)**	**(560)**	**(618)**	**(633)**	**(727)**	**(773)**	**(883)**	**(940)**	**(916)**	**(960)**
West Reserve Margin	7.1%	(4.7%)	(6.3%)	(6.6%)	(9.3%)	(10.5%)	(13.6%)	(14.9%)	(14.2%)	(15.0%)
System										
Total Resources	10,277	9,693	9,660	9,729	9,661	9,647	10,016	10,012	10,031	10,010
Obligation	10,117	9,908	10,065	10,104	10,216	10,336	10,456	10,577	10,686	10,805
Reserves	1,315	1,288	1,308	1,314	1,328	1,344	1,359	1,375	1,389	1,405
Obligation + Reserves	11,432	11,196	11,373	11,417	11,544	11,680	11,816	11,952	12,075	12,210
System Position	(1,155)	(1,504)	(1,713)	(1,689)	(1,883)	(2,033)	(1,800)	(1,940)	(2,045)	(2,200)
Reserve Margin	1.6%	(2.2%)	(4.0%)	(3.7%)	(5.4%)	(6.7%)	(4.2%)	(5.3%)	(6.1%)	(7.4%)

Line Item Differences
2015 IRP less 2013 IRP Update

Calendar Year	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
East										
Thermal	(81)	(78)	(78)	(28)	(28)	(28)	(28)	(36)	(36)	(30)
Hydroelectric	3	(14)	(14)	(11)	(14)	(14)	(14)	(14)	(14)	(15)
Renewable	13	18	18	18	18	16	16	16	15	15
Purchase	(35)	(19)	(12)	(13)	(13)	(13)	(11)	(11)	(11)	(11)
Qualifying Facilities	2	11	29	29	29	29	28	28	28	28
DSM	20	20	20	20	20	20	20	20	20	20
Sale	1	1	1	1	1	1	1	1	1	4
Non-Owned Reserves	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**(77)**	**(62)**	**(37)**	**15**	**12**	**10**	**11**	**4**	**3**	**12**
Load	217	178	176	73	56	(116)	(142)	(197)	(208)	(253)
Interruptible	10	11	11	11	11	11	11	11	11	11
Existing Class2 DSM	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)	(57)
East obligation	**169**	**132**	**130**	**27**	**10**	**(162)**	**(189)**	**(243)**	**(254)**	**(300)**
East Reserves	**65**	**60**	**60**	**46**	**44**	**22**	**18**	**11**	**10**	**4**
East Obligation + Reserves	**233**	**191**	**189**	**73**	**54**	**(140)**	**(170)**	**(232)**	**(244)**	**(296)**
East Position	**(310)**	**(253)**	**(227)**	**(58)**	**(43)**	**150**	**181**	**236**	**247**	**308**
East Reserve Margin	(3.7%)	(3.0%)	(2.4%)	(0.1%)	0.2%	2.6%	2.8%	3.5%	3.6%	4.3%
West										
Thermal	(24)	(250)	(251)	(251)	(251)	(251)	(251)	(252)	(254)	(254)
Hydroelectric	6	(0)	(19)	32	(1)	(3)	5	(28)	4	4
Renewable	5	5	5	5	5	5	5	3	3	3
Purchase	(1)	(0)	2	2	3	3	3	3	3	3
Qualifying Facilities	15	15	15	15	15	1	1	1	1	1
DSM	0	0	0	0	0	0	0	0	0	0
Sale	(0)	(1)	(1)	(0)	0	(0)	(0)	(1)	(0)	(0)
Non-Owned Reserves	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
West Existing Resources	**0**	**(232)**	**(249)**	**(198)**	**(230)**	**(246)**	**(238)**	**(275)**	**(244)**	**(244)**
Load	(12)	(49)	(57)	(58)	(58)	(62)	(67)	(39)	(74)	(44)
Interruptible	0	0	0	0	0	0	0	0	0	0
Existing Class2 DSM	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)	(32)
West obligation	**(44)**	**(80)**	**(89)**	**(90)**	**(90)**	**(93)**	**(98)**	**(71)**	**(106)**	**(75)**
West Reserves	**(6)**	**(10)**	**(12)**	**(12)**	**(12)**	**(12)**	**(13)**	**(9)**	**(14)**	**(10)**
West Obligation + Reserves	**(50)**	**(91)**	**(100)**	**(102)**	**(102)**	**(105)**	**(111)**	**(80)**	**(120)**	**(85)**
West Position	**50**	**(142)**	**(149)**	**(96)**	**(128)**	**(141)**	**(127)**	**(195)**	**(125)**	**(159)**
West Reserve Margin	1.5%	(4.8%)	(5.0%)	(3.4%)	(4.4%)	(4.8%)	(4.5%)	(6.2%)	(4.4%)	(5.1%)
System										
Total Resources	(76)	(294)	(287)	(183)	(218)	(236)	(227)	(271)	(241)	(232)
Obligation	125	51	41	(63)	(80)	(255)	(287)	(314)	(360)	(375)
Reserves	59	49	48	35	32	10	5	2	(4)	(6)
Obligation + Reserves	184	100	89	(29)	(47)	(246)	(281)	(313)	(364)	(381)
System Position	(260)	(395)	(376)	(155)	(171)	9	54	41	123	149
Reserve Margin	(2.2%)	(3.5%)	(3.2%)	(1.1%)	(1.3%)	0.2%	0.6%	0.4%	1.1%	1.3%

2015 Integrated Resource Plan

Distributed Generation Study

Navigant

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2015
Integrated Resource Plan

Plant Efficiency Study

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Plant Efficiency Improvement Action Items

2013 IRP Update for Action Item 6 in 2013 IRP:

Activity	Status
Production efficiency studies have been conducted to satisfy requirements of the Washington I-937 Production Efficiency Measure that have identified categories of cost effective production efficiency opportunity.	
1. By the end of the first quarter of 2014, complete an assessment of the plant efficiency opportunities identified in the Washington I-937 studies that might be applicable to other wholly owned generation facilities.	1. The Company has completed a multi-plant analysis of potential energy conservation opportunities at wholly owned generation facilities. The "Energy Analysis Report" is included as Appendix C to the 2013 IRP Update.
2. Prior to initiating modeling efforts for the 2015 IRP, determine a multi-state "total resource cost test" evaluation methodology to address regulatory recovery among states with identified capital expenditures.	2. The evaluation methodology for a multi-state "total resource cost test" of plant efficiency projects is consistent with the methodology applied to other production capital projects.
3. Prior to initiating modeling efforts for the 2015 IRP, present to IRP stakeholders in a public input meeting the Company's recommended approach to analyzing cost effective production efficiency resources in the 2015 IRP.	3. As stated above, the Company will present to IRP stakeholders the analysis methodology consistent with evaluating production capital projects.

Plant Efficiency Study

- Definition of Production Energy Efficiency (EE)
  - Only applicable to wholly owned generating units
  - Applies to reduction in station auxiliary power consumption
  - Does not include increased generation capacity

- Washington I-937
  - Meeting Washington I-937 requirements provided insight into identifying the types of production EE projects with a potential for economic benefit

- Activities completed to date to identify and screen potential production EE projects:
  - Visited each plant to conduct EE audits
  - Evaluated data gathered to screen for project potential

- What was included in 2013 IRP Update
  - Energy Analysis Report (including supporting workpapers)

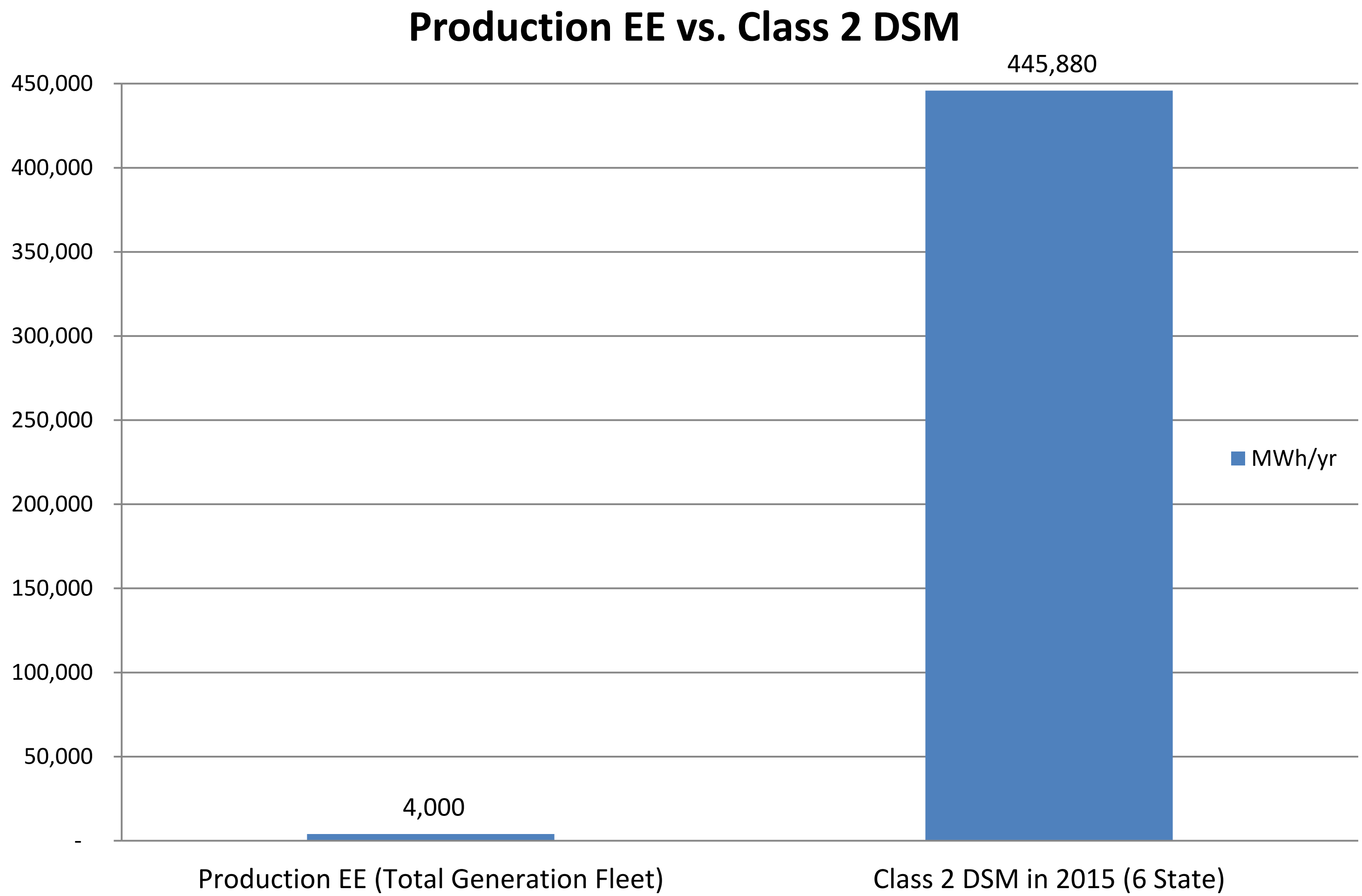
Plant Efficiency Study

- Company experience from I-937 studies revealed that cost effective opportunities at generation facilities are limited to minor systems and equipment.
  - Major equipment and systems do not typically provide enough energy savings to offset the high costs of installation
- Other utilities that have conducted EE audits for I-937 have come to similar conclusions for projects worth pursuing at generation facilities.
  - Potential project examples
    - Lighting controls
    - Compressor runtime coordination and dew point controls
    - Reverse Osmosis pump speed controls (under 20hp motors typically)
    - Condensate Pumps (not available at all plants and not as cost-effective due to high cost of upgrades)

Plant Efficiency Study

- PacifiCorp is committed to pursuing all cost-effective energy efficiency upgrades within the generation fleet.
  - The Company does upgrade to more energy efficient designs at end of life replacement of current equipment
- Production EE represents a small fraction of the overall Company EE as shown on the following graph.

Plant Efficiency Study – Comparison of EE



Points of consideration

- Production EE available <.5 aMW (4,000/8,760)
- Class 2 DSM, 2015 amount selected in 2013 IRP > 51 aMW (445,880/8,760)
- Production EE less than 1% available in initial year
- Production EE single year impact, Class 2 DSM shown is 2015 incremental value, additional potential in future years.

Plant Efficiency Study – Comparison of EE

- Plant EE Opportunities
  – Potential volume limited
  – Relatively minimal impact to system load/resource balancing optimization
- Plant EE selection
  – Evaluated on a stand alone basis as part of PacifiCorp's standard budgeting and planning activities
  – Not included as a "resource" for "System Optimizer" modeling

Production Efficiency Economic Evaluation Methodology

- Production EE projects will be capitalized and placed in rate base, unlike retail DSM projects, which are funded annually through a DSM tariff rider and do not get rate base treatment

- Because budget capital is not unlimited, Production EE projects will compete for capital the same as other production capital projects

- Production EE projects will be evaluated and economically justified through the thermal project evaluation model using a methodology similar to other production projects…Present Value Revenue Requirement differential (PVRR(d)) as measured at the production level

- Revenue Requirement includes operating benefits and costs, fuel, depreciation, return, income taxes and property taxes

Production Efficiency Economic Evaluation Methodology (cont.)

- Project evaluations will include fully loaded capital cost:
  - Direct Costs
  - Allowance for Funds Used During Construction (AFUDC)
  - Capital Surcharge
  - Contingency
  - Escalation to in-service date
  - Proposed new equipment will require stocking of critical spare parts which will be added to the installed cost of the project
  - Additional costs in project management from the plant or engineering support offices will need to be accounted for in the installation of the project
- Evaluation period will be the shorter of proposed new equipment life or remaining plant depreciation life.

Production Efficiency Economic Evaluation Methodology (cont.)

- Project evaluations will include associated increases or decreases due to incremental operation and maintenance cost
  - More sophisticated equipment usually results in increased O&M costs
  - Proposed new equipment will be evaluated to determine if reliability issues will increase or decrease costs

- Production EE benefits should be evaluated based on the energy characteristics unique to the production resource

- Additional energy savings that would result in increased MWh delivered to the GRID is valued using forward price curve

- Available energy savings that would not increase MWh delivered to the GRID would be measured as an incremental fuel savings as less fuel would be needed to meet the same net plant output

- The evaluation point is at the production facility; therefore, no incremental or decremental T&D cost is included

Timeline

- Potential projects to be screened for economics using Total Resource Cost (TRC) test methodology
- Projects passing screen to be summarized in 2015 IRP, including results from TRC screening.
- Projects meeting all tests will be scheduled for installation.





2015 Integrated Resource Plan

Portfolio Development

Sensitivity Analysis

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Regional Haze Scenarios

Reference Scenario (Stringent Regional Haze)

- Forced installation of controls for known, reasonably expected, and hypothetical stringent Regional Haze compliance obligations where agency action has not yet been taken; utilizes current depreciable life when shutdown is modeled as alternate compliance approach

Scenario RH-1

- Fleet-trade & inter-temporal scenario reflecting potential negotiated outcomes across the fleet; agency/regulator/litigant/joint owner perspectives on acceptability have not been determined

Scenario RH-2

- Fleet-trade & inter-temporal scenario reflecting potential negotiated outcomes across the fleet falling somewhere between the Reference Scenario and Scenario RH-1; agency/regulator/litigant/joint owner perspectives on acceptability have not been determined

Underlying Assumptions

- Fleet-trade & inter-temporal scenarios attempt to provide alternative environmental benefits that would be viewed as reasonable compliance alternatives by agencies and consider remaining depreciable life of assets, where practical

- Fleet-trade & inter-temporal scenarios consider alignment with future Regional Haze planning periods and anticipated compliance deadlines for other emerging environmental regulations where information is reasonably available

- Fleet-trade & inter-temporal scenarios attempt to recognize existing long-term commitments, ownership structures, and current environmental compliance position of individual units/facilities where those inputs would impact economic assessment of alternatives

- Fleet-trade & inter-temporal scenarios are intended to provide insight into potential alternate compliance approaches that may best serve customers while also addressing environmental compliance obligations; agency/regulator/litigant/joint owner perspectives on acceptability have not been determined nor are final outcomes expected to directly align with the scenarios assessed

Regional Haze Scenarios: Reference (C01-R)

Coal Unit	Description	Coal Unit	Description
Carbon 1	Shut Down Apr 2015	Hunter 1	SCR by Dec 2021
Carbon 2	Shut Down Apr 2015	Hunter 2	SCR by Dec 2021
Cholla 4	SCR by Dec 2017	Hunter 3	SCR by Dec 2024
Colstrip 3	SCR by Dec 2023	Huntington 1	SCR by Dec 2022
Colstrip 4	SCR by Dec 2022	Huntington 2	SCR by Dec 2022
Craig 1	SCR by Aug 2021	Jim Bridger 1	SCR by Dec 2022
Craig 2	SCR by Jan 2018	Jim Bridger 2	SCR by Dec 2021
Dave Johnston 1	Shut Down Dec 2027	Jim Bridger 3	SCR by Dec 2015
Dave Johnston 2	Shut Down Dec 2027	Jim Bridger 4	SCR by Dec 2016
Dave Johnston 3	SCR by Mar 2019, Shut Down Dec 2027	Naughton 1	Shut Down by Dec 2029
Dave Johnston 4	Shut Down Dec 2027	Naughton 2	Shut Down by Dec 2029
Hayden 1	SCR by Jun 2015	Naughton 3	Conversion by Jun 2018; Shut Down by Dec 2029
Hayden 2	SCR by Jun 2016	Wyodak	SCR by Mar 2019

Regional Haze Scenarios: RH-1

Coal Unit	Description	Coal Unit	Description
Carbon 1	Shut Down Apr 2015	Hunter 1	SCR by Dec 2021
Carbon 2	Shut Down Apr 2015	Hunter 2	Shut Down by Dec 2032
Cholla 4	Conversion by Jun 2029	Hunter 3	SCR by Dec 2024
Colstrip 3	SCR by Dec 2023	Huntington 1	Shut Down by Dec 2036
Colstrip 4	SCR by Dec 2022	Huntington 2	Shut Down by Dec 2021
Craig 1	SCR by Aug 2021	Jim Bridger 1	Shut Down by Dec 2023
Craig 2	SCR by Jan 2018	Jim Bridger 2	Shut Down by Dec 2032
Dave Johnston 1	Shut Down Mar 2019	Jim Bridger 3	SCR by Dec 2015
Dave Johnston 2	Shut Down Dec 2027	Jim Bridger 4	SCR by Dec 2016
Dave Johnston 3	Shut Down Dec 2027	Naughton 1	Shut Down by Dec 2029
Dave Johnston 4	Shut Down Dec 2032	Naughton 2	Shut Down by Dec 2029
Hayden 1	SCR by Jun 2015	Naughton 3	Conversion by Jun 2018; Shut Down by Dec 2029
Hayden 2	SCR by Jun 2016	Wyodak	Shut Down by Dec 2039

Regional Haze Scenarios: RH-2

Coal Unit	Description	Coal Unit	Description
Carbon 1	Shut Down Apr 2015	Hunter 1	SCR by Dec 2021
Carbon 2	Shut Down Apr 2015	Hunter 2	Shut Down by Dec 2024
Cholla 4	Conversion by Jun 2025	Hunter 3	SCR by Dec 2024
Colstrip 3	SCR by Dec 2023	Huntington 1	Shut Down by Dec 2024
Colstrip 4	SCR by Dec 2022	Huntington 2	Shut Down by Dec 2021
Craig 1	SCR by Aug 2021	Jim Bridger 1	Shut Down by Dec 2023
Craig 2	SCR by Jan 2018	Jim Bridger 2	Shut Down by Dec 2028
Dave Johnston 1	Shut Down Mar 2019	Jim Bridger 3	SCR by Dec 2015
Dave Johnston 2	Shut Down Dec 2023	Jim Bridger 4	SCR by Dec 2016
Dave Johnston 3	Shut Down Dec 2027	Naughton 1	Shut Down by Dec 2029
Dave Johnston 4	Shut Down Dec 2032	Naughton 2	Shut Down by Dec 2029
Hayden 1	SCR by Jun 2015	Naughton 3	Conversion by Jun 2018; Shut Down by Dec 2029
Hayden 2	SCR by Jun 2016	Wyodak	Shut Down by Dec 2032

Risk Analysis

- Stochastic risk analysis (September public input meeting)
  - Mean PVRR
  - Risk-adjusted mean PVRR
  - Energy Not Served (ENS)

- Deterministic risk analysis (Challenges with 111(d) framework)

- Trigger point analyses
  - Solar Costs
  - CO_2 scenario (Oregon Guideline 8c: "The utility should identify at least one CO_2 compliance scenario, which if anticipated now, would lead to or 'trigger' the selection of a portfolio of resources that is substantially different from the preferred portfolio."

- Acquisition path analysis
  - Assessment of portfolio results among core cases and sensitivities used to describe how changes in the planning environment affect changes in the resource plan.





2015
Integrated Resource Plan

Wind Integration

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Agenda

- Overview of 2012 Wind Integration Study (WIS)
- Overview & Outcome of 2014 WIS
  - Regulating Margin
  - Component Reserves
- Reasons Why Reserve Requirements Change
  - Increased Installed Wind Capacity
  - Impact of Volatility on Reserve Requirements
- Determination of Wind Integration Costs
  - Modeling Regulating & Following in 2014 WIS
  - Wind Integration Costs
- Description and Impact of Energy Imbalance Market (EIM)

Overview of 2012 Wind Integration Study

- Based on 2011 actual data
- Methodology reviewed by Technical Review Committee (TRC)
- Annual Reserve Requirements, MW*

	West BAA	East BAA	Combined
Load-Only Regulating Margin	147	247	394
Incremental Wind Regulating Margin	54	131	185
Total Regulating Margin	**202**	**378**	**579**

- Wind Integration Costs, 2012$ per MWh of Wind Generation

Regulating Margin Cost ($/MWh)	System Balancing Cost ($/MWh)	Wind Integration Cost ($/MWh)
$2.19	$0.36	$2.55

*Reserve requirements are derived from actual load and wind generation data from 2011

Overview of 2014 Wind Integration Study

- Incorporate data from 2012 and 2013
  - Additional 10-min interval data of existing load and wind projects.
  - Additional 417 MW of wind projects since the 2012 WIS:
    - 222 MW of new wind projects that came online in 2012 in PacifiCorp's east balancing authority area (BAA)
    - 195 MW of existing wind projects (Goodnoe Hills and Leaning Juniper) that were electrically moved from Bonneville Power Administration's BAA to PacifiCorp's west BAA.
  - Once Energy Imbalance Market goes live (October 2014), additional data will become available that will be used to inform future wind integration studies.
- Studies to compute wind integration costs used for IRP modeling are being finalized, will be shared & reviewed with the TRC
- PacifiCorp will present wind integration cost results during the August 26, 2014 conference call

Regulating Margin Results

- Regulating margin is the incremental amount of reserves required to maintain reliability of the system, in addition to contingency reserves.
- The WIS focuses only on the up reserve portion of regulating margin.

		West BAA	East BAA	Combined
2011	Load-Only Regulating Margin	147	247	394
(2012 WIS)	Incremental Wind Regulating Margin	54	131	185
	Total Regulating Margin	202	378	579
2012	Load-Only Regulating Margin	141	259	400
(2014 WIS)	Incremental Wind Regulating Margin	77	129	206
	Total Regulating Margin	217	388	606
2013	Load-Only Regulating Margin	166	275	441
(2014 WIS)	Incremental Wind Regulating Margin	55	130	186
	Total Regulating Margin	222	405	626

- Compared with the 2011 values from the 2012 wind integration study:
  - Total regulating margin increased by approximately 27 MW (4.7%) in 2012 and 47 MW (additional 3.3%) in 2013.
- Regulating margin results have been sent to the TRC.

Component Reserves

- Regulating margin includes ramping, regulating and following reserves to deal with deviations of load and wind from forecasts.
- Regulating margin is determined as:

$$RM = Max(\sqrt{Load\ Following^2 + Load\ Regulating^2 + Wind\ Following^2 + Wind\ Regulating^2} - L_{10}, 0) + Ramp$$

Average MW	2011		2012		2013	
Reserve	West	East	West	East	West	East
Load Following	87	151	89	163	107	180
Load Regulating	94	159	88	161	102	167
Wind Following	76	158	96	187	81	193
Wind Regulating	70	161	79	161	63	166
Ramp	52	76	51	79	52	79
L10	-33.41	-47.88	-33.41	-47.88	-33.41	-47.88
Total Regulating Margin*	**202**	**378**	**217**	**388**	**222**	**405**

* The sum of the component reserves does not equal the Regulating Margin because the formula above is applied to 10-minute intervals while the above component reserves are annual averages across each year.

- L_{10} represents a bandwidth of acceptable deviation prescribed by WECC between the net scheduled interchange and the net actual electrical interchange on the Company's BAAs.
- The fluctuation in component reserves is due to changes in actual data that impact operational forecasts of reserve requirements, and deviations between actual and operational forecast reserve requirements.

Reserve Requirement

- Differences between 2014 WIS and 2012 WIS include:
  - 47 MW (8.0%) increase in total reserves from 579 MW in 2011 to 626 MW in 2013
  - 417 MW (20%) increase in wind capacity from 2,135 MW in 2011 to 2,552 MW in 2013
  - Reserves for wind remain relatively flat changing from 185 MW in 2011 to 186 MW in 2013

- Increase in total reserve requirements reflects different levels of volatility in actual load and wind generation, which can impact reserve requirements in two ways:
  - Operational forecasts of reserve requirements
  - Deviation between the actual and operational forecast reserve requirements

Wind Reserves as a % of Wind Capacity

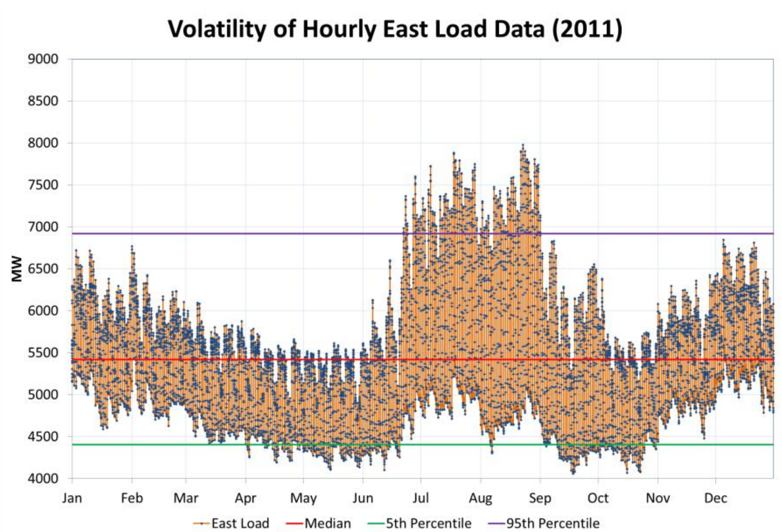
- Amount of reserves as percentages of wind capacity varies slightly from year to year.

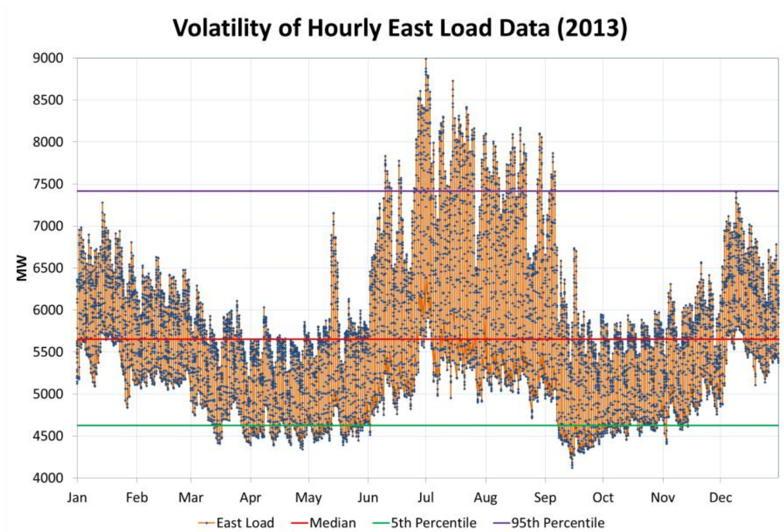
West	Incremental Wind Reserves (MW)	Wind Capacity (MW)	%
2011	50	599	8%
2012	71	794	9%
2013	51	794	6%

East	Incremental Wind Reserves (MW)	Wind Capacity (MW)	%
2011	126	1,536	8%
2012	123	1,759	7%
2013	123	1,759	7%

Volatility of Wind and Load

- "Volatility of Wind and Load" is illustrated by the Standard Error of the changes in actual wind and load data from one hour to the next.
- For example, load volatility in the East is illustrated in the figures below:
  - 2011 East load in the 2012 WIS vs. 2013 East load in the 2014 WIS
  - Median load is higher
  - 95th percentile of the load is also higher





Costs to Integrate Wind

- Wind integration costs reflect production costs associated with:
  - Additional reserves to integrate wind generation in order to maintain reliability of the system (costs of intra-hour reserve requirements)
  - Differences between day-ahead forecast wind generation and actual wind generation (system balancing costs)
- Wind integration costs are being determined using the Planning and Risk (PaR) model, which simulates production costs by dispatching resources to meet load and reserve obligations.
- Types of reserves modeled in PaR
  - Regulating reserves (up reserves only)
  - Spinning reserves
  - Following reserves (up reserves only)
  - Non-spinning reserves

Costs to Integrate Wind, Intra-Hour

- Two studies are being used to determine the intra-hour costs for incremental regulating margin reserves.

PaR Model Simulation	Forward Term	Load	Wind Profile	Incremental Reserve	Day-ahead Forecast Error
Regulating Margin Reserve Cost Runs					
1	2015	2015 Load Forecast	Expected Profile	Load	None
2	2015	2015 Load Forecast	Expected Profile	Load and Wind	None
Regulating Margin Cost = System Cost from PaR Simulation 2 less System Cost from PaR Simulation 1					

TRC Sensitivity: Differentiation of Regulating and Following Reserves

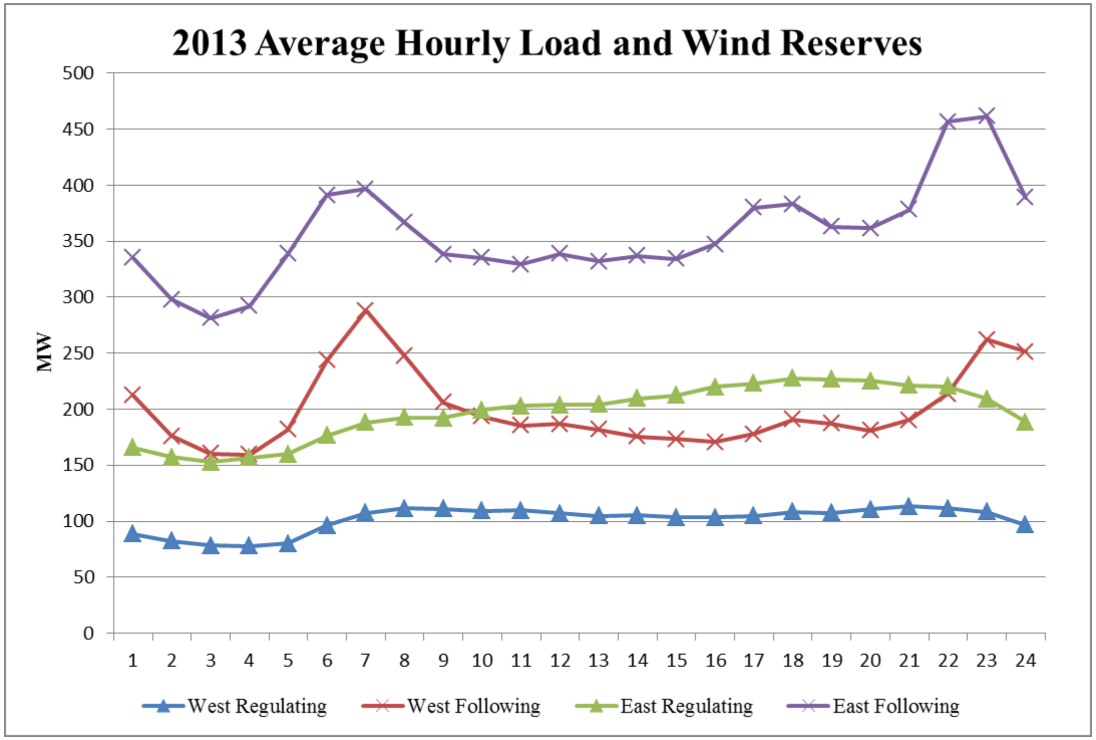
- Differentiating reserve requirements by Regulating and Following categories allows PaR modeling to reflect differentiation in resource capabilities

$$RM = \sqrt{Load\ Regulating^2 + Wind\ Regulating^2} - L_{10} + \sqrt{Load\ Following^2 + Wind\ Following^2} + \text{Ramp}$$

	Combined (MW)		Regulating		Following		Total (MW)	
	West	East	West	East	West	East	**West**	**East**
Jan	180	327	107	196	153	281	**260**	**476**
Feb	155	291	100	182	130	246	**230**	**428**
Mar	168	289	97	179	151	246	**248**	**425**
Apr	194	360	122	224	162	300	**284**	**524**
May	146	333	84	205	134	282	**218**	**487**
Jun	139	373	70	240	135	303	**205**	**543**
Jul	154	318	88	181	141	282	**229**	**462**
Aug	164	323	90	188	150	284	**240**	**471**
Sep	161	311	99	171	139	280	**239**	**451**
Oct	105	268	75	160	83	234	**158**	**394**
Nov	250	365	165	228	198	303	**363**	**531**
Dec	218	357	122	216	195	299	**317**	**516**

TRC Sensitivity: Modeling of Hourly Reserve Requirements

- Modeling reserves on hourly basis to reflect changes in reserve requirements as wind and load generation vary
- An example of hourly regulating and following reserves in the East and West is illustrated in the figure below



Energy Imbalance Market (EIM)

- EIM is an energy balancing market that optimizes generator dispatch between PacifiCorp and California ISO every five minutes via the existing real-time dispatch market functionality.

- Scheduled to go live October 1, 2014

- Currently no data exists to model EIM impacts on wind integration reserve requirements and costs. Modeling of EIM impacts is expected to be included in the subsequent studies when data become available.

- Based on E3 study, PacifiCorp could see ~19 MW reduction in regulating reserves per 100 MWs of intertie made available to EIM by PacifiCorp.
  - Capacity of intertie nomination offered by PacifiCorp to EIM is currently in discussion.

Proposed Benefits of EIM

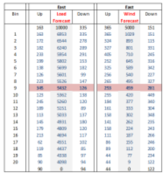
- Proposed benefits of EIM, per Energy and Environmental Economics ("E3") study*…
  - *Interregional dispatch savings:* 5-minute dispatch efficiency will reduce "transactional friction" (e.g., transmission charges) and alleviate structural impediments currently preventing trade between the two systems;
  - *Intraregional dispatch savings*: PacifiCorp generators will dispatch more efficiently through the ISO's automated system (nodal dispatch software), including benefits from more efficient transmission utilization;
  - *Reduced flexibility reserves* by aggregating the two systems' load, wind, and solar variability and forecast errors;
  - *Reduced renewable energy curtailment* by allowing BAs to export or reduce imports of renewable generation when it would otherwise need to be curtailed.

*Energy and Environmental Economics, Inc., "Pacificorp-ISO Energy Imbalance Market Benefits", March 13, 2013

Expected Impact of EIM on Regulating Margin

PACIFICORP

Determine Regulating Margin Reserves Based on WIS Results



California ISO

Determine Flexible Ramping Requirements for PacifiCorp and CAISO, Separately and Combined

California ISO

"Diversity Benefit"

PACIFICORP

Realize "Diversity Benefit" and Reflect Reduction in Regulating Margin Reserves





2015 Integrated Resource Plan

Planning Reserve Margin

PACIFICORP
Rocky Mountain Power
Pacific Power
PacifiCorp Energy

Overview of Stochastic Parameters

- Stochastic parameters are used to generate stochastic inputs for risk analysis of resource portfolios
- Parameters updated by third party independent consultant, using historical PacifiCorp data from 2010 to 2013
- Stochastic parameters include volatility, mean reversion and correlation among variables
  - Load by transmission bubbles by season
    - 2015 IRP change: Portland split out from Oregon/California
  - Electricity & natural gas market prices by market by season
    - 2015 IRP change: Short term volatilities with mean reversion used for full tenor of forward price curve. No long term volatility.
  - Availability of hydro generation by season
    - 2015 IRP change: seasonal hydro shocks.
  - Thermal generation outages

Short Term Volatility Comparison 2013 vs 2015

- Volatility is a measure of variation in time-series that is observed over time.

2013 IRP S.T Volatility Parameter in Daily %

Load

	Utah	Oregon-California
Winter	2.60%	4.10%
Summer	4.50%	3.80%

Electricity Market Prices

	PV	Mid C
Winter	10.50%	8.50%
Summer	9.40%	11.80%

Gas Prices

	East Gas	West Gas
Winter	5.90%	5.50%
Summer	4.20%	3.50%

2015 IRP S.T Volatility Parameters in Daily %

Load

	Utah	Oregon-California
Winter	2.01%	4.45%
Summer	4.52%	3.65%

Electricity Market Prices

	PV	Mid-C
Winter	6.20%	17.77%
Summer	9.10%	47.69%

Gas Prices

	East Gas	West Gas
Winter	4.84%	6.31%
Summer	2.89%	2.92%

Short Term Mean Reversion Comparison 2013 vs 2015

- Mean reversion represents the speed at which the distributed variable will return to its seasonal expectation.

2013 IRP S.T Mean Reversion Parameter in Daily

Load

	Utah	Oregon-California
Winter	0.23	0.26
Summer	0.14	0.28

Electricity Market Prices

	PV	Mid C
Winter	0.40	0.44
Summer	0.42	0.29

Gas Prices

	East Gas	West Gas
Winter	0.40	0.46
Summer	0.29	0.38

2015 IRP S.T Mean Reversion Parameter in Daily

Load

	Utah	Oregon-California
Winter	0.33	0.23
Summer	0.26	0.24

Electricity Market Prices

	PV	Mid-C
Winter	0.09	0.28
Summer	0.29	0.94

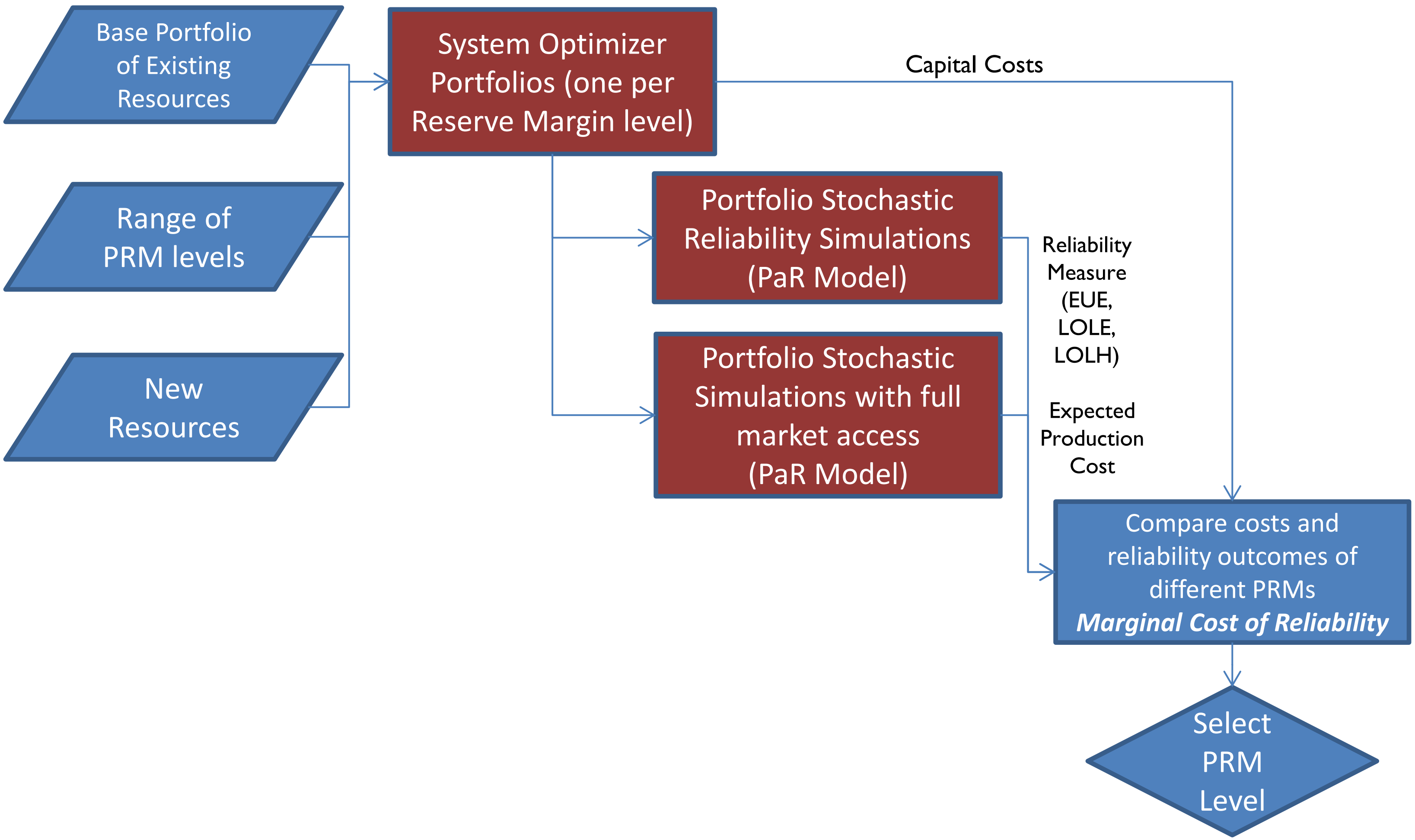
Gas Prices

	East Gas	West Gas
Winter	0.06	0.09
Summer	0.06	0.07

Overview of Planning Reserve Margin

- Planning reserve margin is the additional amount of capacity that the Company needs to build beyond coincident system peak load to maintain system reliability
- Planning reserve margins of 10% to 20% are studied using the System Optimizer model (SO) and Planning and Risk model (PaR)
  - 11 SO runs, 22 PaR runs.
  - SO runs determine the resource portfolio given an input planning reserve margin level
  - One set of PaR runs simulates the reliability of the resource portfolio, reliability-based outputs used to measure loss of load probability (LOLP)
  - Another set of PaR runs determines the production costs of the portfolio
- Stochastic parameters are applied to vary inputs to PaR studies
  - Load, hydro and thermal availability for the reliability studies
  - Load, hydro, thermal availability, and market prices for production cost studies

Planning Reserve Magin Study Components and Workflow



*EUE = Expected Unserved Energy; LOLE = Loss of Load Episodes; LOLH = Loss of Load Hours

Planning Reserve Margin Study – Reliability Metrics

- Expected unserved energy (EUE)
  - Gross (prior to accounting for NW Power Pool reserve sharing)
  - Net (after accounting for NW Power Pool reserve sharing)
  - NW Power Pool reserve sharing method assumes PacifiCorp receives energy from other participants for the first hour after a loss of load event
- Expected loss of load episodes (LOLE)
  - One event in 10 years translates into 0.1 LOLE per year
  - Does not measure duration or magnitude
- Expected loss of load hours (LOLH)
  - One day in 10 years translates into 2.4 LOLH per year
  - Does not measure the number or magnitude of occurrences
- Marginal cost of reliability informs selection of the planning reserve margin
- The 2015 IRP planning reserve margin study is being finalized – results will be made available and reviewed during the August 26, 2014 conference call

2015 Integrated Resource Plan

Resource Capacity Contribution

PacifiCorp

Rocky Mountain Power
Pacific Power
PacifiCorp Energy

Wind & Solar Capacity Contributions

- Resource planning to ensure sufficient capacity at time of coincident system peak.
- In assessing the capacity contribution of wind & solar resources, PacifiCorp is implementing two methodologies.
  - Peak Capacity Contribution method calculates resource capacity factors during top 100 actual load hours.
  - Annual Capacity Contribution approximation method based on National Renewable Energy Laboratory ("NREL") report, is a loss of load weighted average of capacity factor calculation (consistent with Utah PSC order, Docket No. 12-035-100).

Peak Capacity Contribution Method

- Capacity contribution is based on aligning the hourly generation with top 100 summer load hours
  - Calculation based upon level of generation that can be counted on 90% of time during the top 100 summer load hours.
  - Average of results for 4 years are used (2010-2013).
  - All existing owned and non-owned wind on system used.
  - Estimated shapes for solar at Milford, UT and Lakeview, OR were used and results between the two sites were averaged.

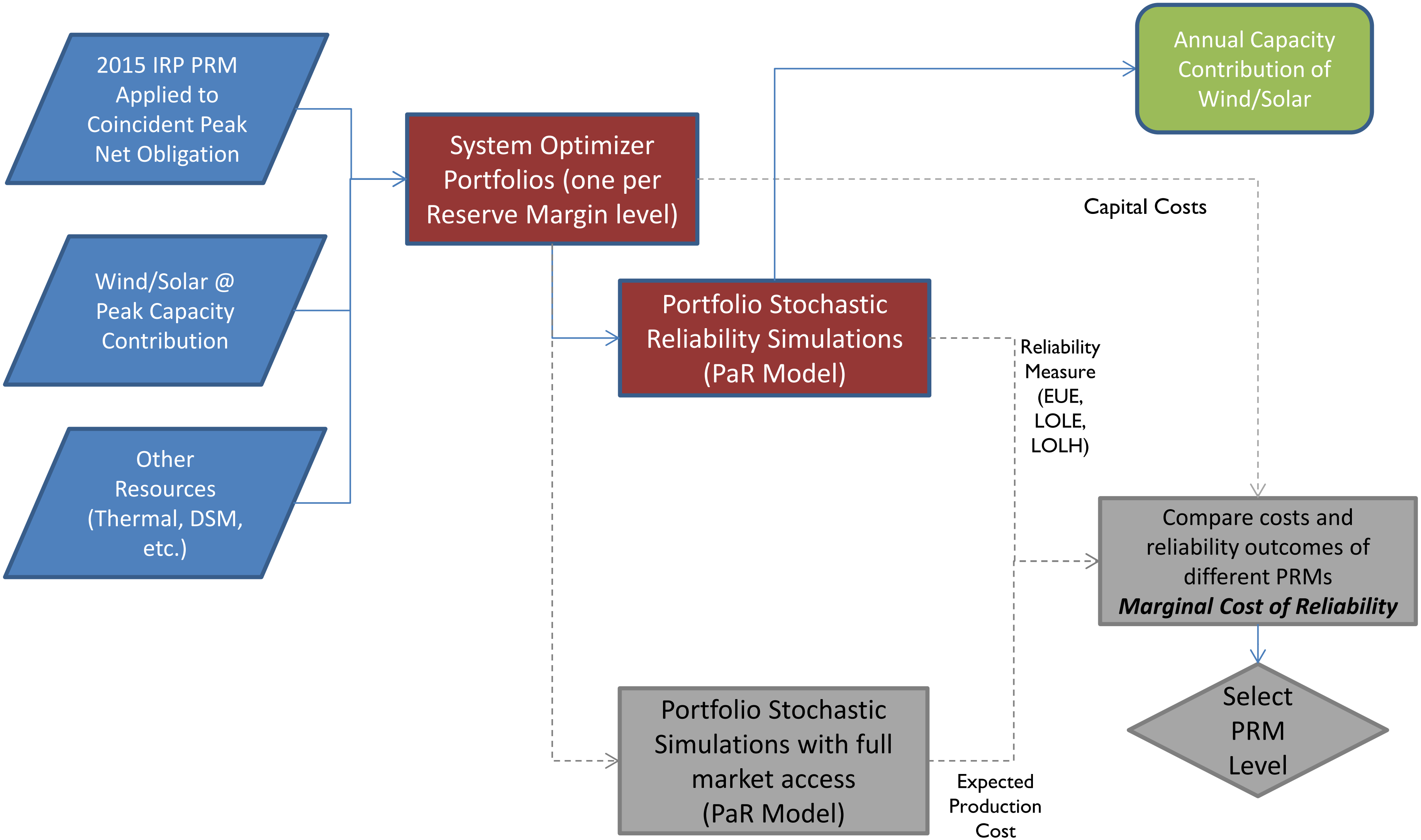
Peak Capacity Contribution Results

- Peak Capacity Contribution Results:

Technology	Wind	Solar PV Fixed Tilt	Solar PV Single Axis Tracking
2015 IRP Values	5.0%	14.5%	28.5%
2013 IRP Update Values	4.0%	13.6%	

- Results prepared for Single Axis Tracking and Fixed Tilt Solar technologies (previously only fixed tilt shapes were evaluated)
- The wind peak capacity contribution value has increased due to higher capacity factor wind projects coming online in recent years – the 5% figure equals that assumed in the Northwest Power and Conservation Council (6th Power Plan, Chapter 12)
- Peak Capacity Contribution results will be used for assessing resource need in System Optimizer for the 2015 IRP

Relationship Between Peak and Annual Capacity Contribution Values



Capacity Factor Approximation Method

- Annual capacity contribution of wind and solar resources is determined by weighting capacity factors calculated during the highest 10% LOLP hours.
  - Method is consistent with approach outlined in the NREL Report.
  - Approximation of the computationally intensive Effective Load Carrying Capability (ELCC) method.
  - 500-iteration hourly PaR run from the planning reserve margin study is being used as the basis for the analysis.
  - Each hour's LOLP is calculated, with weighting factors calculated by dividing each hour's LOLP by the total LOLP in 2017.
  - Total weighted hourly capacity contribution values during highest 10% of LOLP hours are summed to derive the annual capacity contribution values for wind & solar (Milligan and Parsons' study referenced in the NREL Report finds 10% of hours is typically sufficient to approximate ELCC approach).
  - Study results are being finalized, results will be made available and reviewed during the August 26, 2014 conference call

Reminder - Upcoming Meetings

- August 26 (Conference Call)
  - Price Curve Scenarios
  - Planning Reserve Margin Results
  - Capacity Contribution Results
  - Wind Integration Cost Results
- September 25-26
  - Stochastic Modeling
  - EIM Update
  - Smart Grid Update
  - Anaerobic Digester Study
  - Sensitivities/Risk Analysis
- October 27
  - Portfolio Results
- January 15, 2015
  - Confidential Coal Analysis
  - Stochastic Results
  - Sensitivity Analysis Results
  - Preferred Portfolio and Action Plan
- February 18, 2015
  - Final Report

Note: meeting topics are tentative and subject to change.