2015 Integrated Resource Plan

Public Input Meeting 4

September 25-26, 2014

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Rocky Mountain Power
Pacific Power
PacifiCorp Energy

Agenda

Day 1

- Introductions
- Stochastic Modeling & Portfolio Selection Process
- Portfolio Development Cases
- *Lunch Break (1/2 hour) 11:30 PT/12:30 MT*
- Smart Grid Update
- Conservation Voltage Reduction

Day 2

- Anaerobic Digester Study
- Modeling for Confidential Volume 3
- *Lunch Break (1/2 hour) 11:30 PT/12:30 MT*
- Planning Reserve Margin Results
- Resource Capacity Contribution Results
- Wind Integration Cost Results

2015 Integrated Resource Plan

Stochastic Modeling & Portfolio Selection Process

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Stochastic Modeling Scope

- PacifiCorp evaluates stochastic risk of resource portfolios using Planning and Risk (PaR)

- Stochastic variables
  - Load (short-term volatility)
  - Market prices (power and gas, including FOTs – short-term volatility)
  - Hydro availability and thermal outages

- Core case portfolios will be analyzed in PaR
  - PacifiCorp may omit portfolios that are essentially identical to others

- PacifiCorp will target running sensitivity case portfolios in PaR, time permitting

PaR Scenarios

2013 IRP PaR Scenarios	2015 IRP PaR Scenarios
• Zero CO_2, Medium Natural Gas • Base CO_2, Medium Natural Gas • High CO_2, Medium Natural Gas	• Low Natural Gas • Medium Natural Gas • High Natural Gas • Medium Natural Gas, High CO_2

- With anticipated regulation of CO_2 emissions under EPA's proposed 111(d) rule, PaR modeling scenarios will focus on stochastic risk among three different natural gas price scenarios (and associated power prices)
  - Gas price and associated electric prices are pending completion of the September 2014 official forward price curve
  - New Aurora model with ability to capture emission rate constraints was recently released
  - Specific natural gas and electricity price forecasts will be shared with stakeholders within the next couple of weeks

- In response to stakeholder comments, the cost and stochastic risk of portfolios will also be tested in a PaR run assuming high CO_2 prices, starting at approximately $22/ton in 2020 and rising to approximately $162/ton by 2034

Stochastic Portfolio Measures

- Cost
  - Stochastic mean PVRR
  - Risk-adjusted mean PVRR (consolidated cost/risk indicator)
    - Expected-value cost of low probability outcomes
    - Stochastic mean + 5% of the 95th percentile of the variable production cost PVRR
  - Customer rate impacts
    - Real levelized portfolio costs are adjusted to nominal dollars and year-on-year change in costs are reported
- Risk
  - Upper-tail mean PVRR (average of 5-highest cost iterations)
  - 5th and 95th percentile PVRR
  - Standard deviation of PVRR costs
- Supply Reliability
  - Average annual energy not served (ENS)
  - Upper-tail ENS

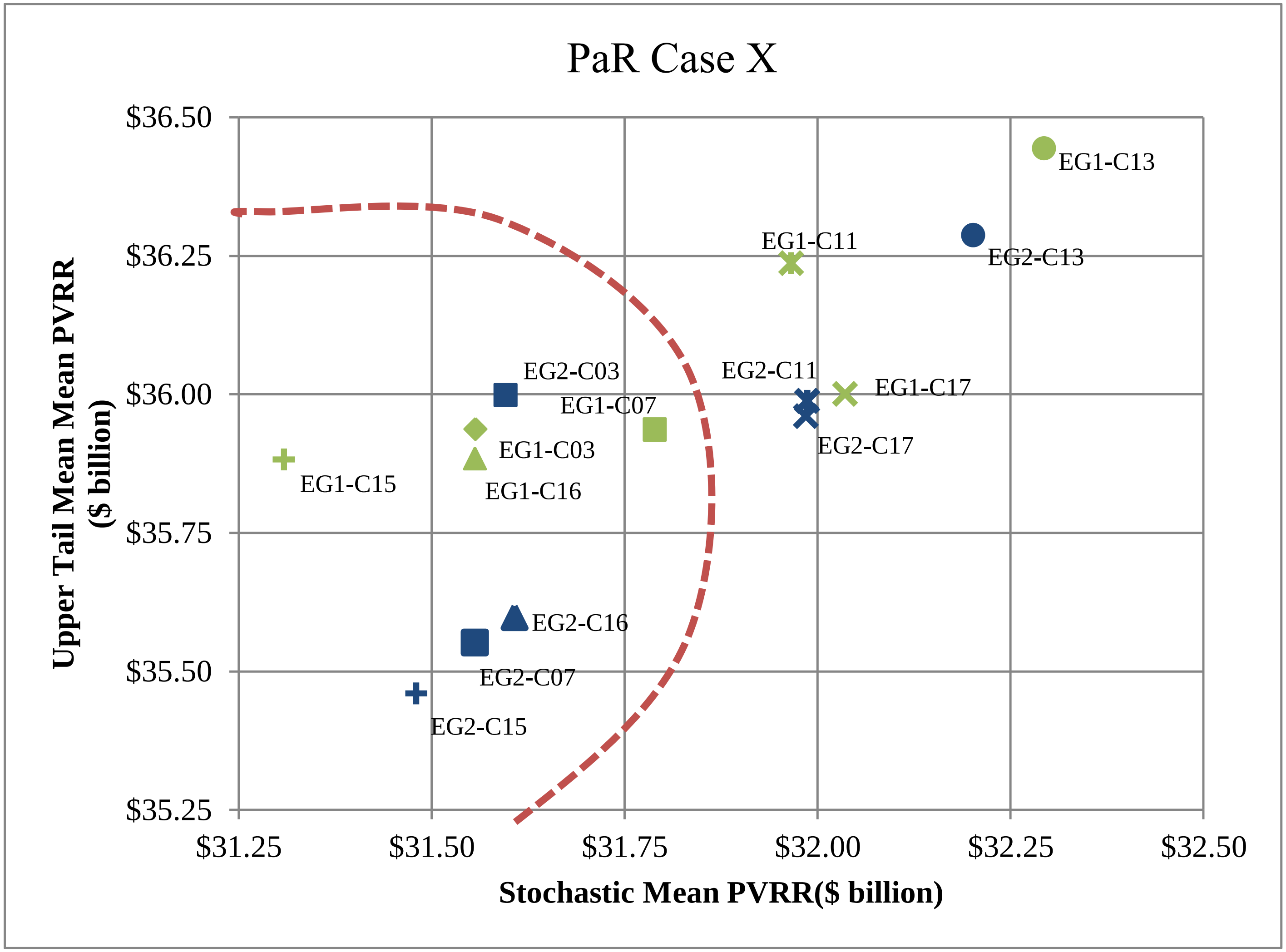
Preferred Portfolio Selection Process: Pre- and Initial Screening

- Pre-screening (as required)
  - Removes outlier portfolios with mean PVRR and upper-tail mean PVRR are clear cost and/or risk outliers in relation to other portfolios

- Initial screening
  - Identify the portfolio with lowest mean PVRR to establish a cost and risk threshold calculated as 2% of the least-cost portfolio*
  - Identify portfolios that fall within the threshold amount as compared to the least cost portfolio (mean PVRR)
  - Identify portfolios that fall within the threshold amount as compared to the least risk portfolio (upper tail mean PVRR)
  - Select portfolios that fall within the least cost *<u>and</u>* least risk thresholds among *<u>any</u>* PaR scenario

*PacifiCorp may modify the threshold percentage so as to not be either overly restrictive

Illustrative Examples of Initial Screening Scatter Plots



Preferred Portfolio Selection Process: Final Screening and Selection

- Final screening
  - Primary metric
    - Risk-adjusted PVRR ranking (for each PaR study) = primary metric for final screening
  - Other considerations
    - Cumulative CO_2 emissions
    - ENS (stochastic mean and upper tail)
    - Resource diversity
    - Customer rate impacts
- Preliminary selection based on final screening results
- Final selection based on additional analysis, as required, to further refine identification of a least cost and least risk preferred portfolio





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Portfolio Development Cases

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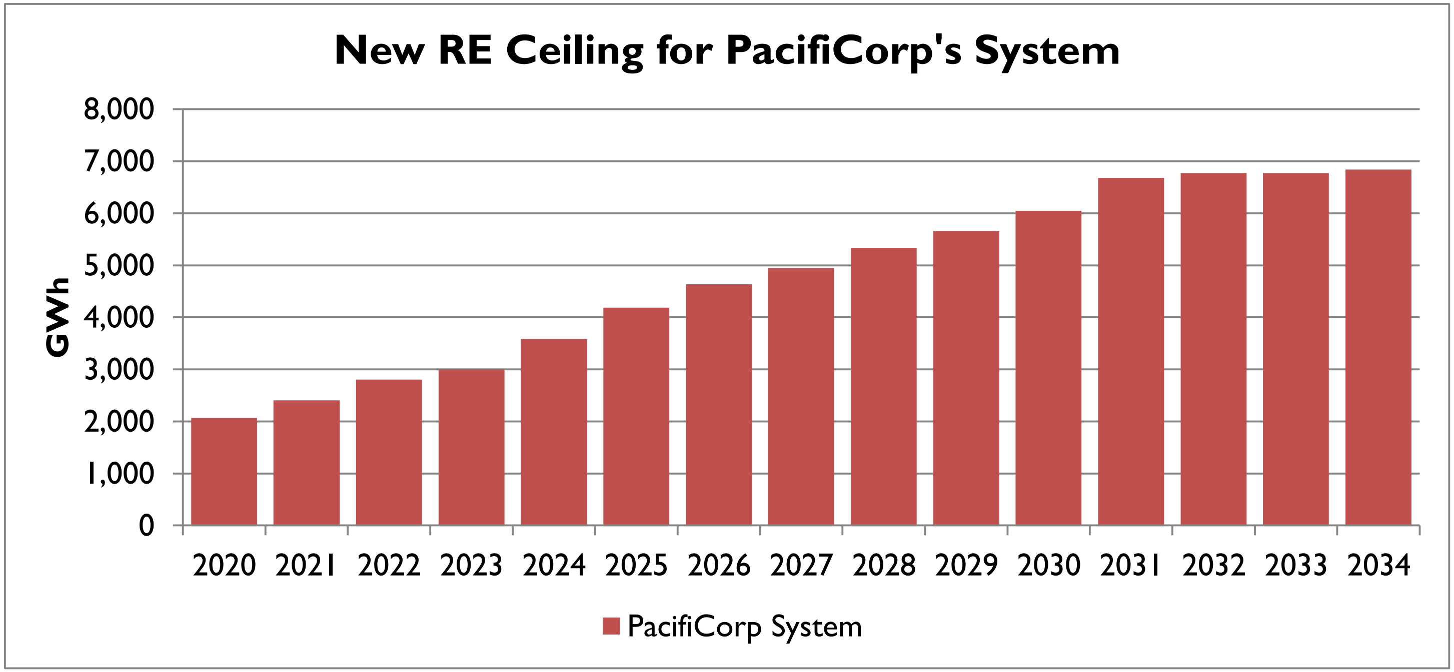
Portfolio Development Case Updates

- Updated after reviewing stakeholder comments and recommendations
  - PacifiCorp appreciates the constructive feedback
  - Many comments accompanied with detailed information and discussion supporting very specific recommendations
  - Comments and recommendations have been mindful of schedule and scope
- Summary of core case updates
  - Three 111(d) compliance strategies among two different emission rate policy definitions (replaces gas price scenarios in *portfolio development process only*)
  - Clarification of assumed 111(d) treatment for new natural gas combined cycle (NGCC) units by case
  - One case combining a CO_2 price with 111(d) emission rate targets
  - Removed the QF core case (previously C14), which would not be a candidate for preferred portfolio selection
- Summary of sensitivity case updates
  - Replaced placeholder for Oregon Guideline 8d & 8c sensitivity with a sensitivity case defined with high CO_2 prices and 111(d) emission rate targets
  - Two utility scale solar trigger point sensitivities (costs yet to be defined)

Portfolio Development Case Matrix and Stakeholder Comments

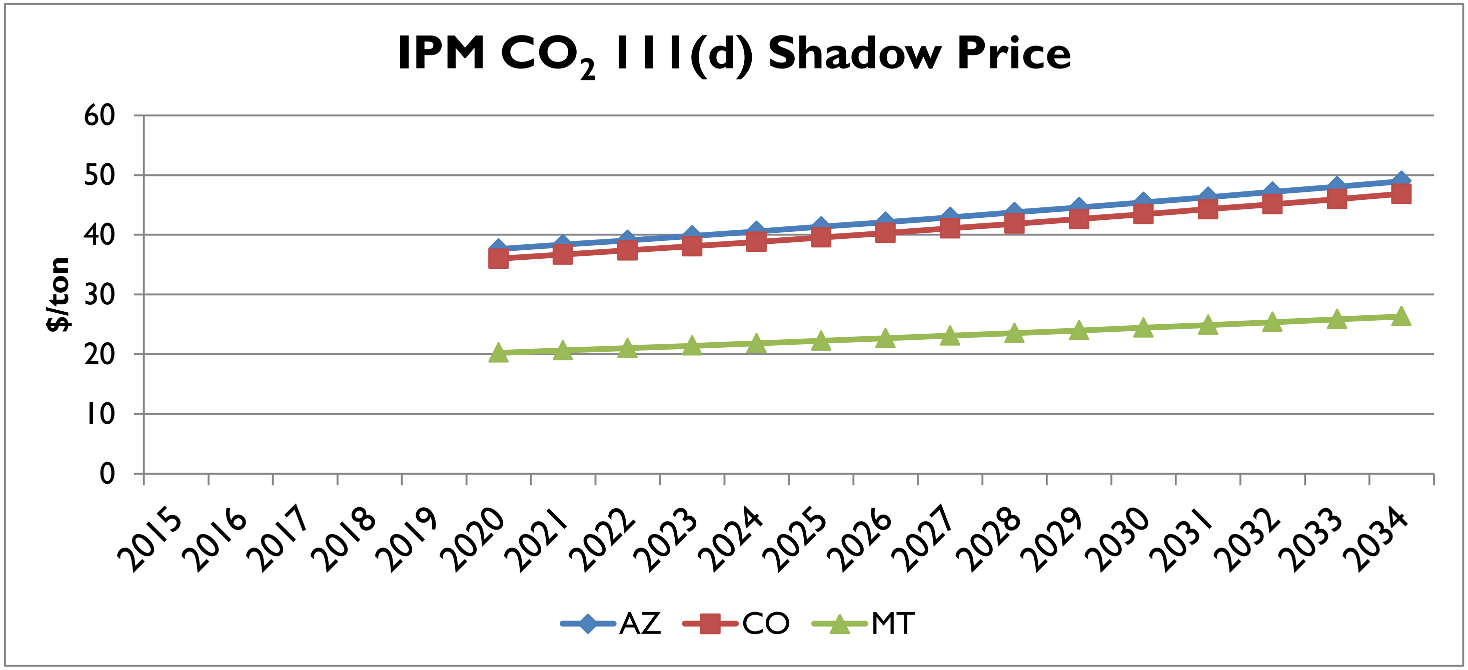
- See "Portfolio Development and Comment Log" handout
- See updated "Portfolio Development Matrix" handout
- See "111(d) Compliance Strategy" handout

Renewable Ceiling for 111(d) Compliance (Cases C04 and C07)



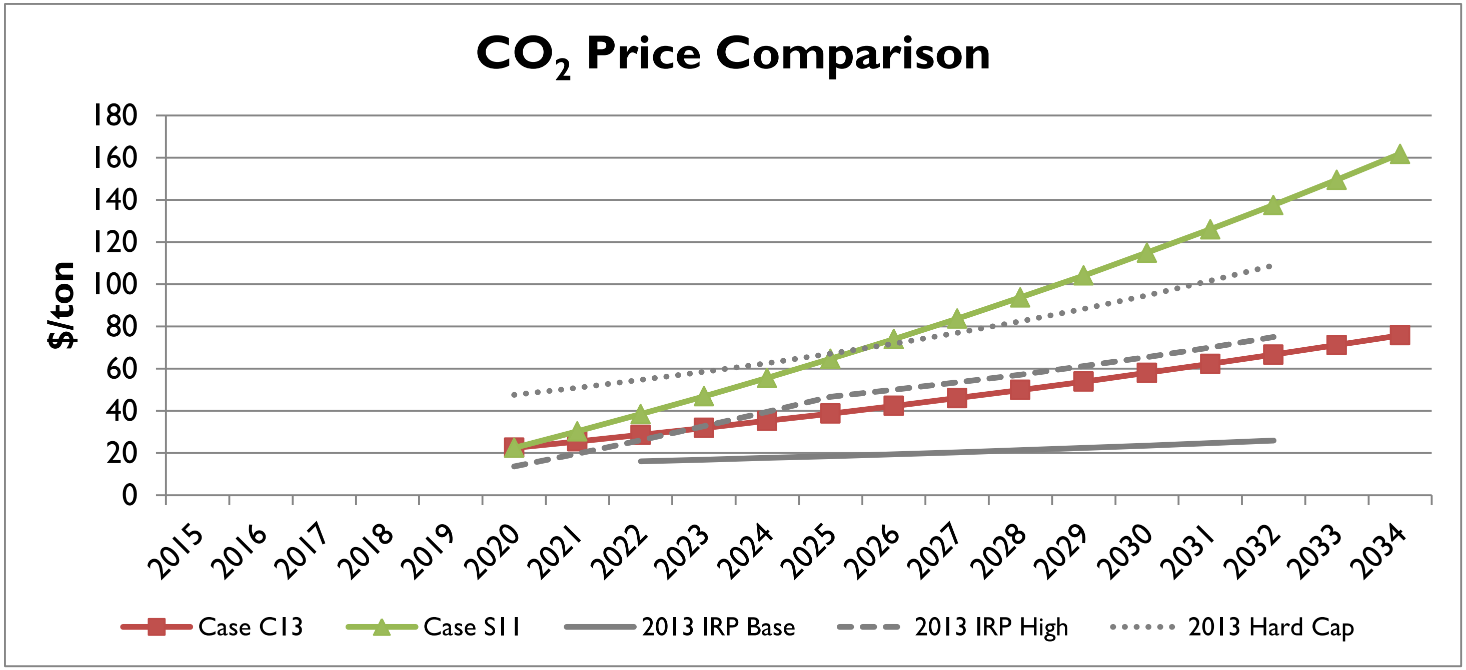
- Compliance strategies for cases C04 and C07 will rely more heavily on new renewable generation
- New renewables will be added, beyond those that are economic and beyond those required for state RPS compliance, up to the levels assumed in EPA's calculation of state emission rate goals applied to PacifiCorp's system as a percentage of retail sales
- For illustrative purposes only, the volume of new renewables shown above equates to approximately 785 MW in 2020, rising to approximately 2,600 MW by 2034 assuming an average capacity factor of 30%

Levelized CO_2 Shadow Price for 111(d) Compliance in CO, AZ, and MT



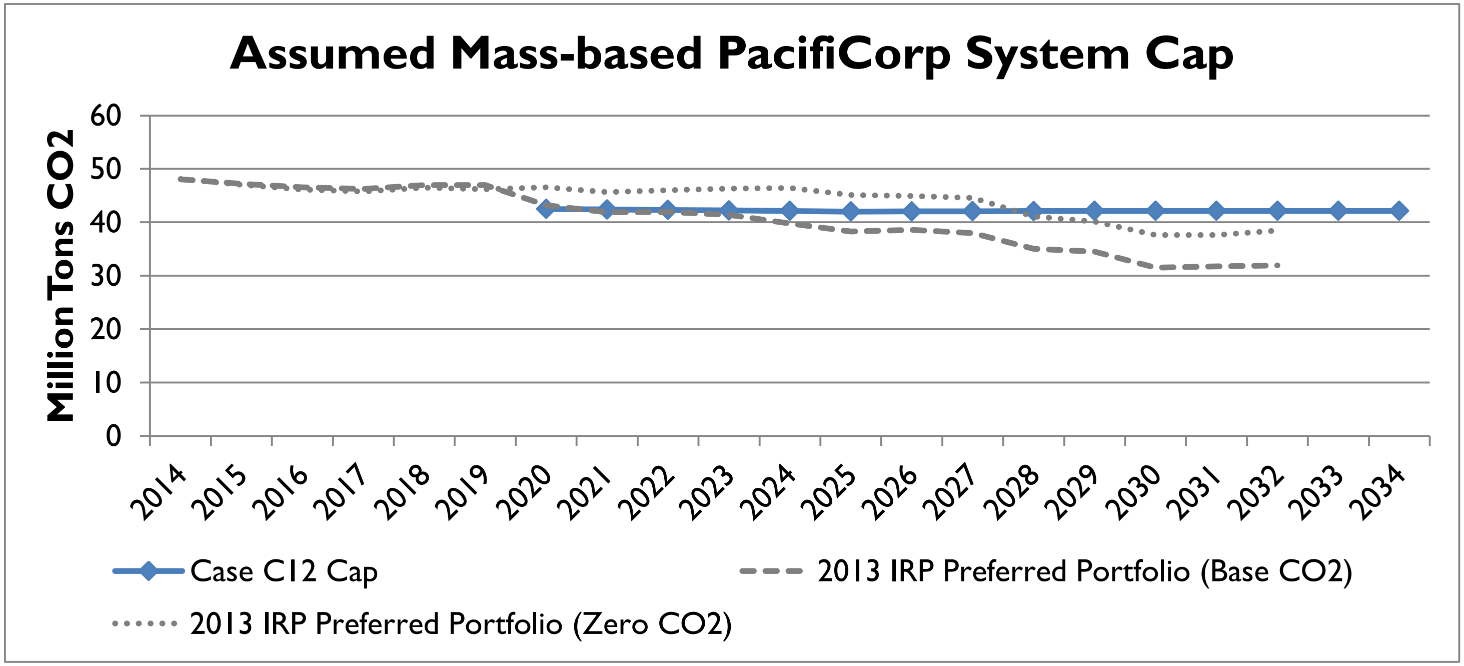
- IPM reports a CO_2 shadow price from state 111(d) emission rate constraints
- Cases C05, C06, and C07 will apply the above CO_2 price to emissions from Cholla 4 (AZ), Craig and Hayden (CO), and Colstrip 3&4 (MT) as proxy 111(d) compliance costs for emissions from these generating units, which are located in states in which PacifiCorp does not have retail load

CO_2 Prices (Cases C13 and S11)



- 2015 IRP cases C13 and S11 will include CO_2 price assumptions in addition to 111(d) emission rate targets
- In addition to low, medium, and high natural gas prices paired with 111(d) emission rate targets, PacifiCorp will use CO_2 prices paired with medium natural gas prices from case S11 when modeling all core case portfolios in PaR

Mass Cap (Case C12)



- Calculation of the mass-based cap is based on state emissions from EPA's 111(d) modeling run
- State emissions under 111(d) from 2020 through 2030 are allocated to PacifiCorp's system via its pro-rata share of 2012 fossil emissions within each state
- Comparison to 2013 IRP preferred portfolio results are based on PaR runs and shown for comparison purposes only





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Smart Grid Update

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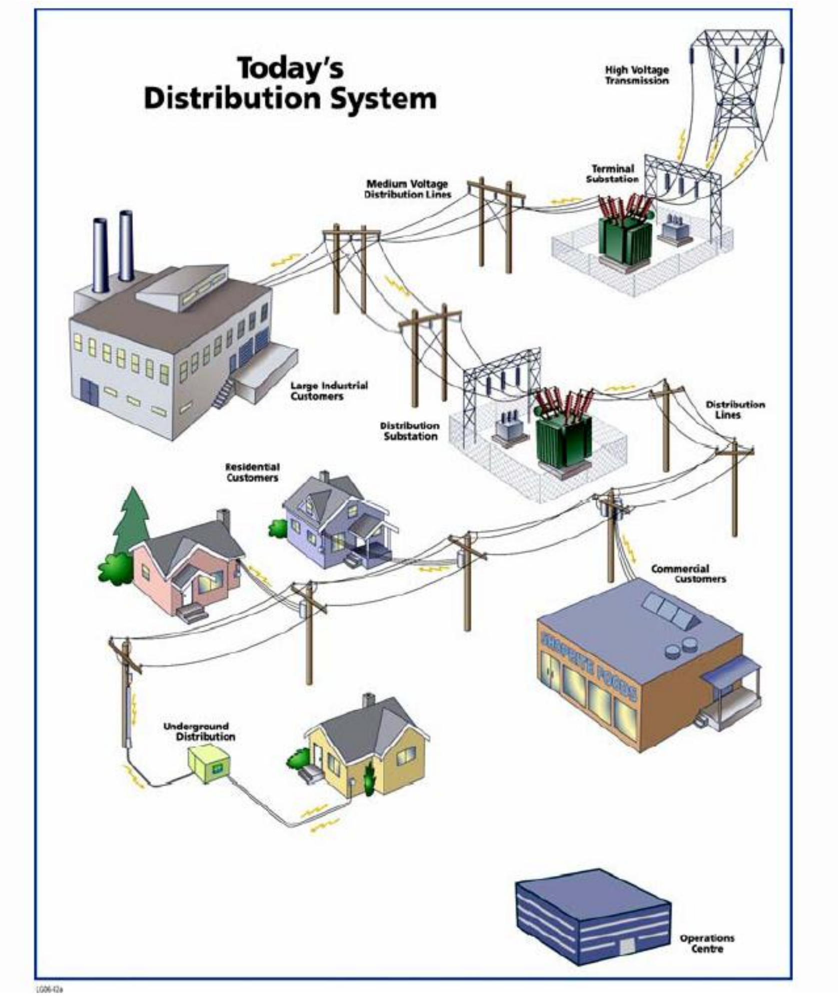
PacifiCorp Smart Grid History

- PacifiCorp has researched smart grid for many years
- Smart grid department reports and monitors industry
- State commission report requirements
  - Discuss company's smart grid plans and activities
  - Supply financial business cases for a six state smart grid
  - Filing schedule
    - Washington - every even year
    - Utah - yearly
    - Wyoming - yearly
    - Oregon - yearly

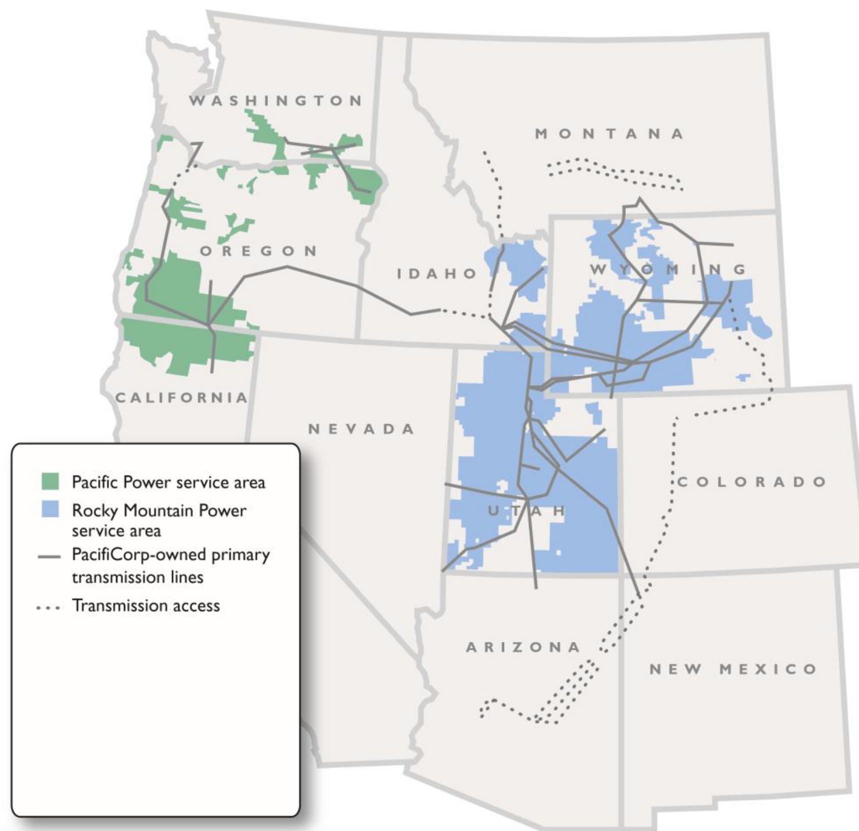
Today's Electrical System



- Human intervention is a large part of how the system is operated today.
- The "smart grid" will enable equipment to automatically perform tasks by using data and logic to make decisions.

About PacifiCorp

- Customers 1.8 million
- Employees 6,000
- Territory 136,000 sq. mi.
- Distribution
  - ✓873 Substations
  - ✓63,000 Line Miles
- Transmission
  - ✓371 Substations
  - ✓16,200 Line Miles

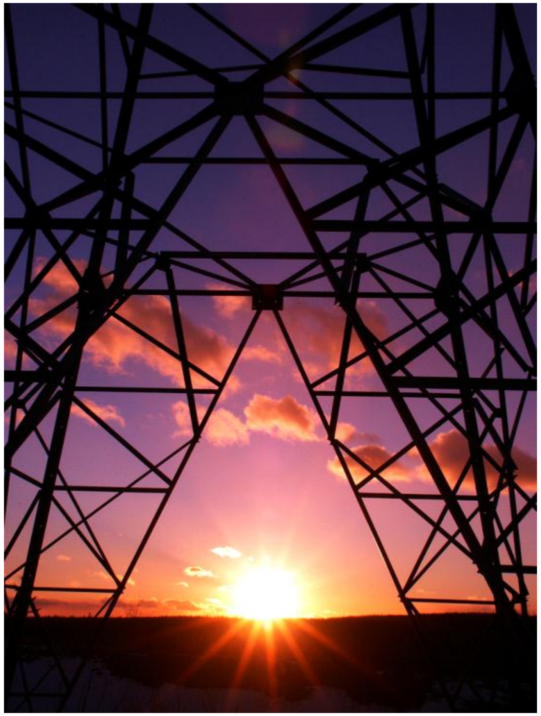


Major Components of "Smart Grid"

- Advanced Metering System
- Demand Response
- Direct Load Control
- Distributed Generation
- Workforce Automation Tools
- Substation Automation
- Outage Management System
- Asset Utilization
- Distribution Management System
- Transmission Synchrophasors

Defining "Smart Grid" for PacifiCorp

- Advanced Metering System
- Demand Response
  - Home Area Networks
- Distribution Management System
  - Interactive Volt-Var Optimization
    - Conservation Voltage Reduction
    - Capacitor Bank Maintenance
  - Centralized Energy Storage
- Outage Management System
  - Fault Detection, Isolation and Restoration
- Transmission Synchrophasors



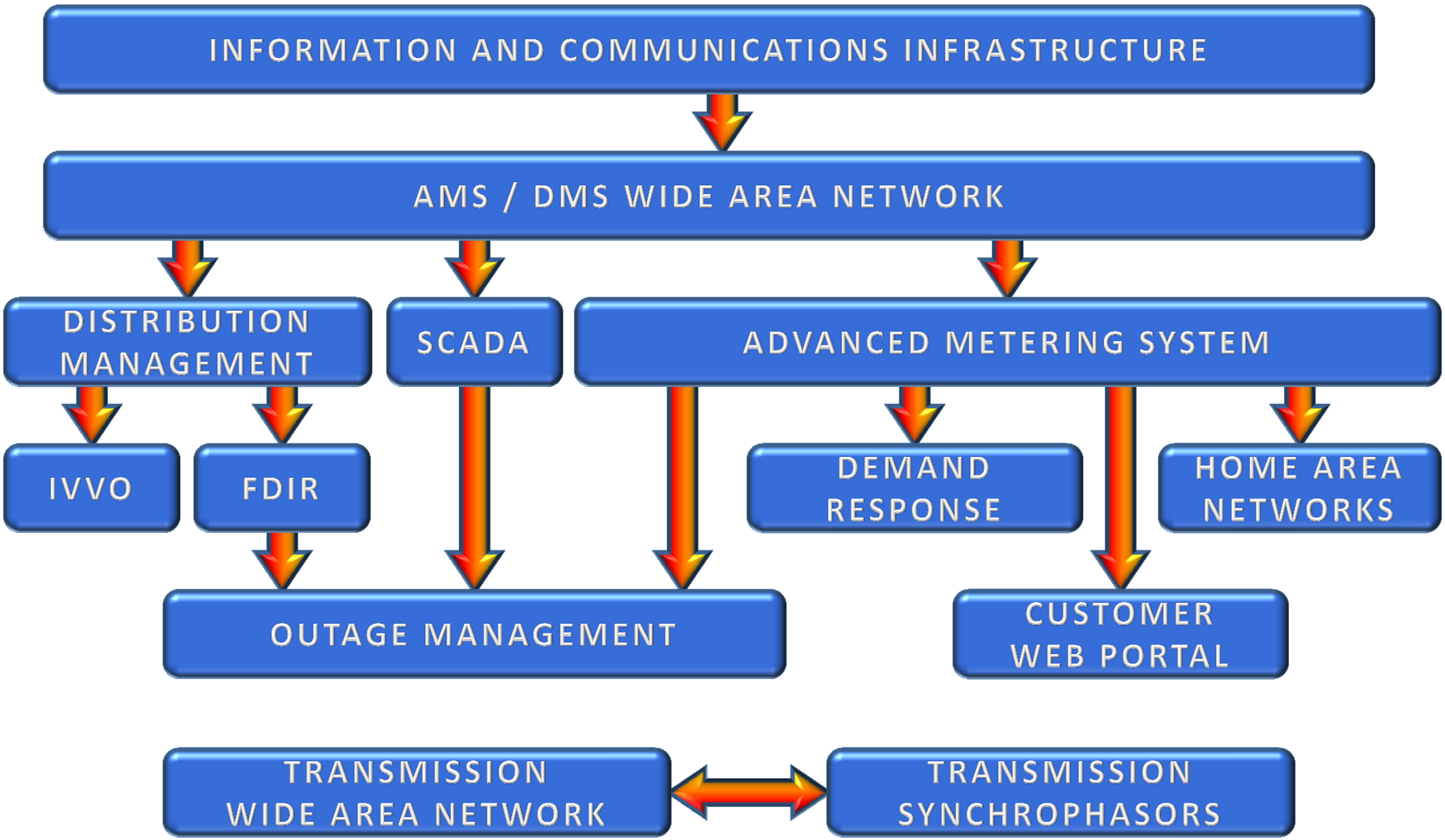
Functionalities Not Included

- Distributed Generation
  - Electric Vehicles, Solar and Wind
- Direct Load Control
  - Smart Appliances and Thermal Storage
- Substation Automation
  - Self-Healing Networks (fully redundant)
- Asset Utilization
  - Engineering Planning and Design
- Workforce Automation

IT and Communication Infrastructure

- Robust two-way communication networks
  - High-speed, secure and extremely-reliable networks
- Available for critical applications
- Prioritize and react to the data received
- Manage and archive massive amounts of data
  - 45 million meter reads per day
  - 5 million “IVVO reads” per day
  - Continuous SCADA and PMU reads

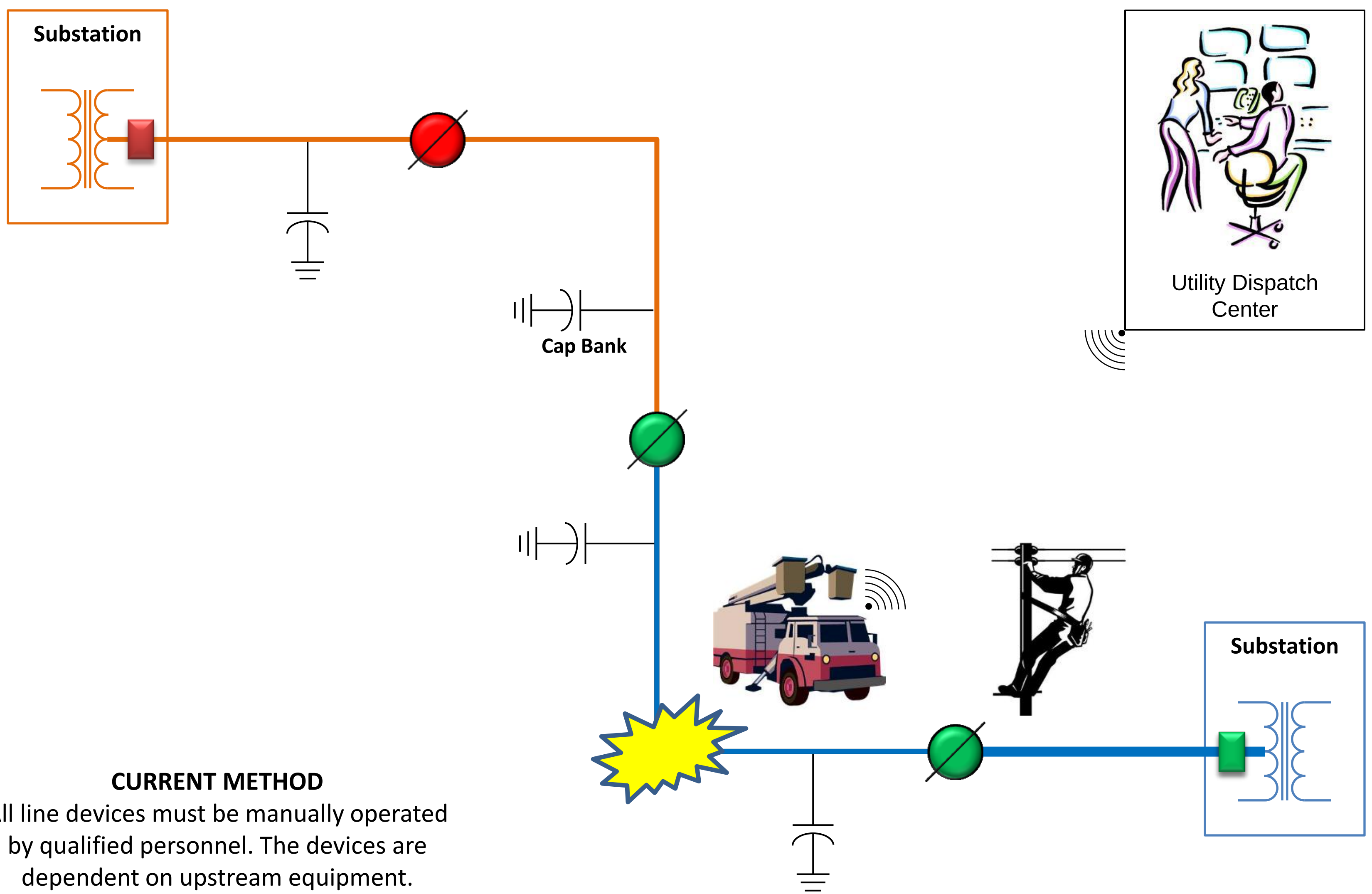
Technology Dependencies



Distribution Management System

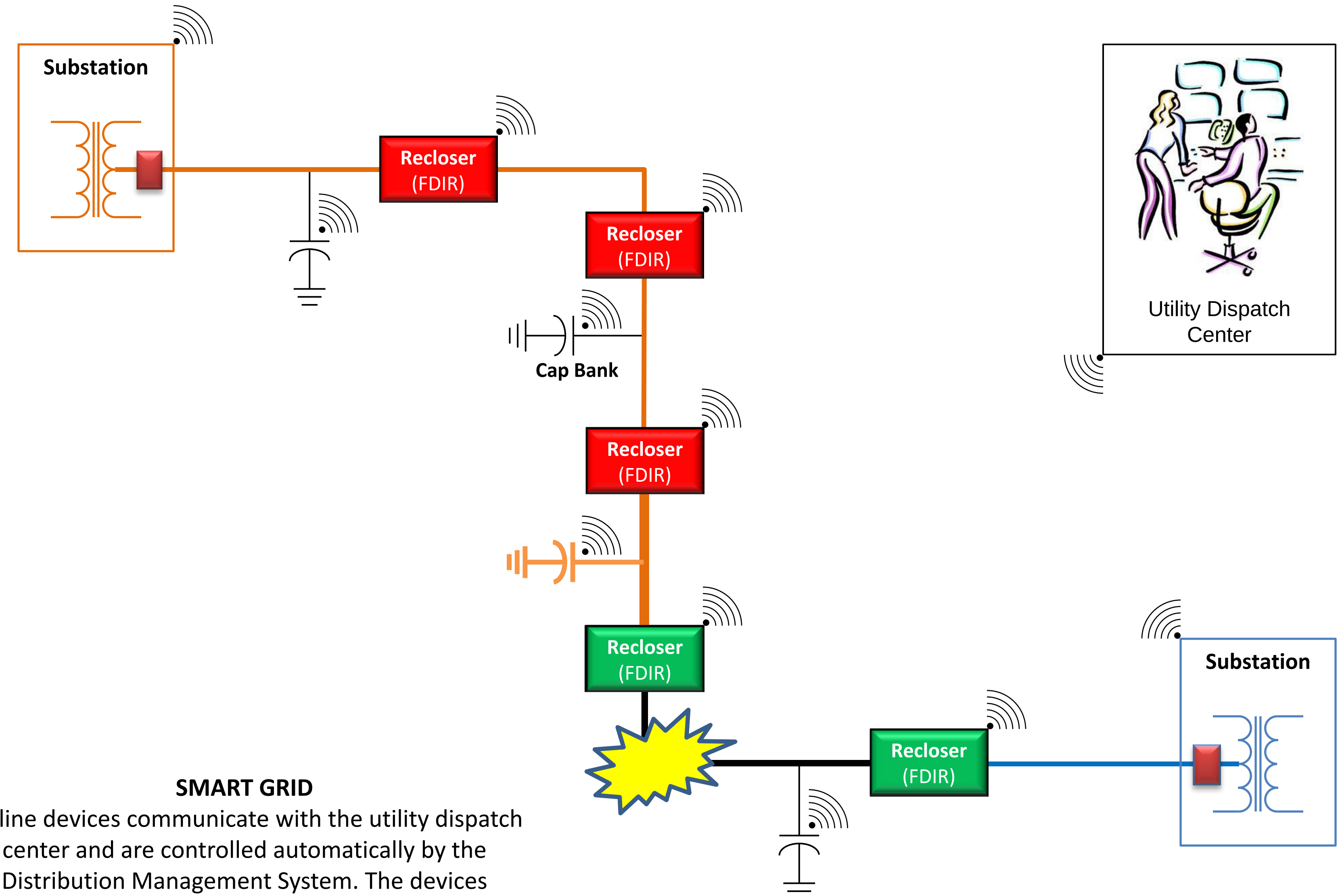
- Interactive Volt-Var Optimization (IVVO)
  - "Intelligent" Capacitor Banks and Regulators
  - Improved Voltage Regulation
  - Reduced Distribution System Losses
  - Makes the system run better
- Fault Detection, Isolation and Restoration (FDIR)
  - "Smart" Reclosers and Faulted Circuit Indicators
  - Reduced Customer Minutes Interrupted
  - Improved Circuit Reliability

Current Distribution Management



CURRENT METHOD
All line devices must be manually operated by qualified personnel. The devices are dependent on upstream equipment.

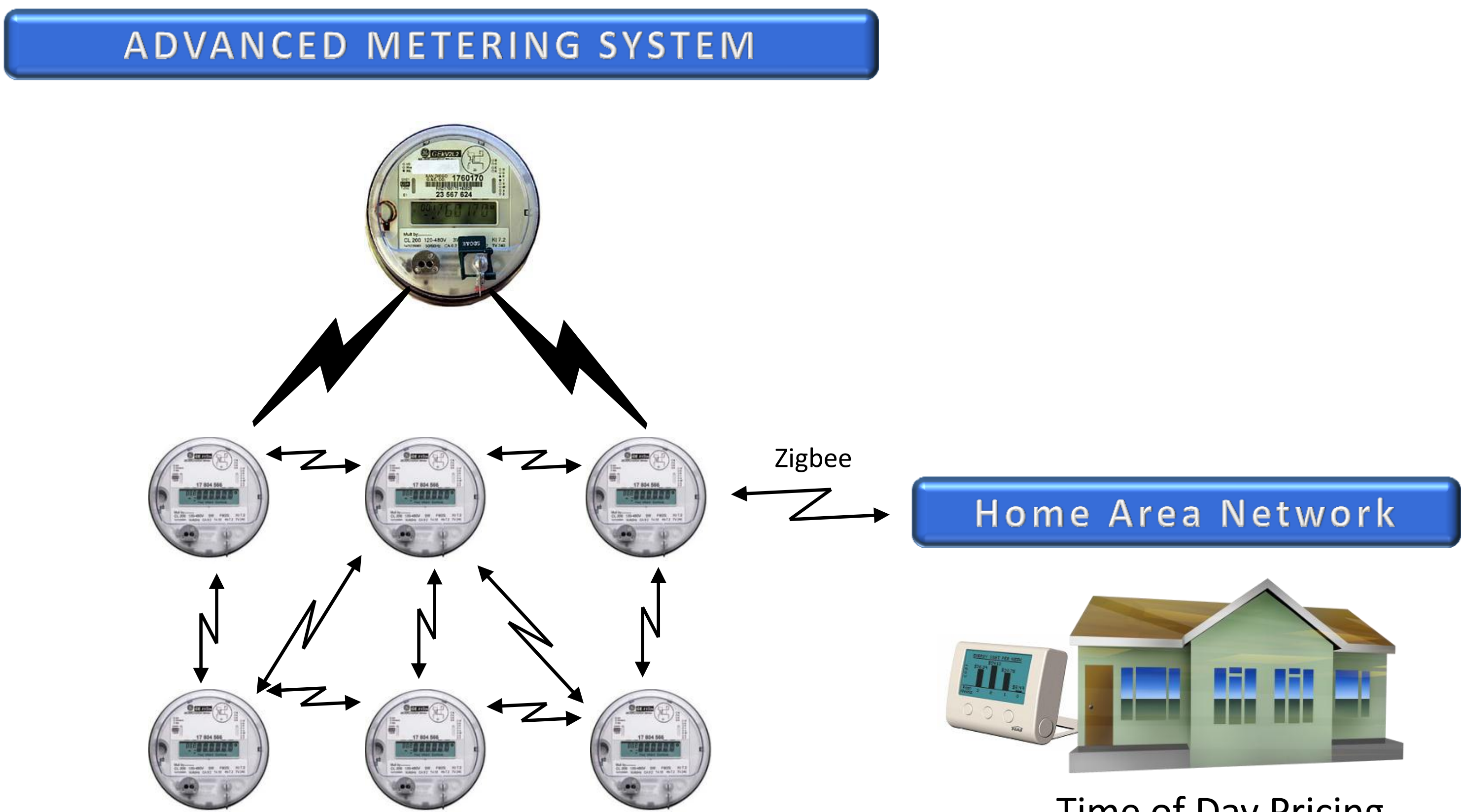
Smart Grid Distribution Management



SMART GRID
All line devices communicate with the utility dispatch center and are controlled automatically by the Distribution Management System. The devices are no longer dependent on upstream equipment.

Advanced Metering and Demand Response

– Supports Pricing Options



Time of Day Pricing Required

Smart Grid Business Cases

Case	AMS	DR	DMS	FDIR	IVVO	CES	TSP
1	X						
2	X	X					
3			X	X			
4			X		X		
5			X	X	X	X	
6	X	X	X	X	X	X	X

Estimated Costs and Benefits

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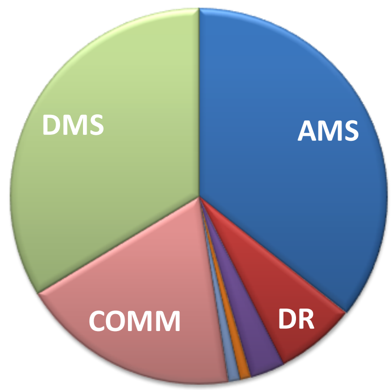
Case 6 - PacifiCorp Smart Grid Project

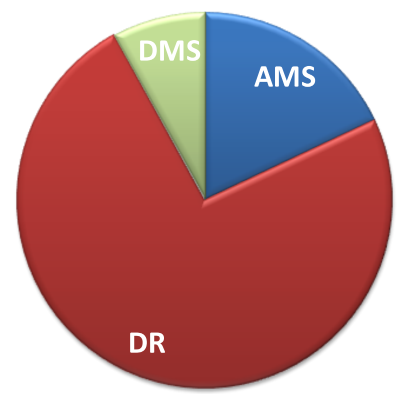
Smart Grid Financial Summary (thousands of dollars)

	CapEx Costs			Annual OpEx Costs			Annual Benefits		
Information Technology	$	-	1%	$	-	3%			
Communications Infrastructure	$	-	19%	$	-	28%			
AMS / DMS Wide Area Network		-			-				
Distribution SCADA Network		-			-				
Advanced Metering System	$	-	36%	$	-	11%	$	-	18%
Meter Reading Savings		-			-			-	
Field Collection Savings		-			-			-	
Estimated Billing Savings		-			-			-	
Reduction in Energy Theft		-			-			-	
Meter System Losses		-			-			-	
Demand Response	$	-	7%	$	-	16%	$	-	74%
Energy Cost Savings		-			-			-	
Capacity Cost Savings		-			-			-	
Avoided Cool Keeper Costs		-			-			-	
Distribution Management	$	-	34%	$	-	29%	$	-	8%
Distribution Management System		-			-			-	
Interactive Volt/Var Optimization		-			-			-	
Fault Detection Isolation Restoration		-			-			-	
Centralized Energy Storage					-			-	
Outage Management	$	-	-	$	-	-	$	-	-
Call Center Savings		-			-			-	
Trouble Dispatching Savings		-			-			-	
Trouble Investigation Savings		-			-			-	
Transmission Synchropasors	$	-	3%	$	-	4%			
Smart Grid Business Unit	$	-		$	-				
Customer Education Program	$	-	1%	$	-	-			
TOTAL COSTS and SAVINGS	$	-		$	-		$	-	

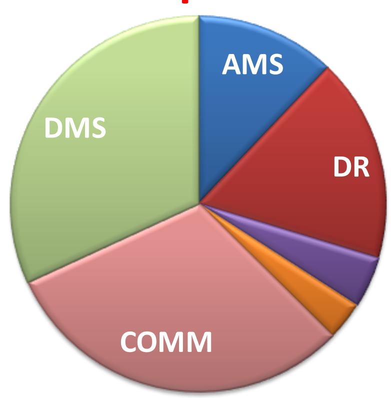
CapEx



Benefits



OpEx



Smart Grid Projects

- Company deployed smart grid projects (mandated or cost effective)
  - Dynamic Line Rating Project
    - Instead of re-conductor lines – technology applied that determines real time loading limits
    - 230kV Miners Platte line (completed)
    - 345kV West of Populus line (in progress)
  - Transmission Synchrophasor Project
    - Install transmission line phase measurement devices in eight transmission substations – shows corridor phase irregularities
    - WECC funded project – other utilities involved

Smart Grid Projects (cont.)

- Cannon Beach Substation - Low cost scada
  - Cellular communication remote terminal unit installed to communicate station energization status
- Coolkeeper Load Control (SLC)
  - Directly control customer air conditioner load for summer curtailment events
  - Upgraded for two-way communications recently
- Communicating Faulted Circuit Indicators (CFCI)
  - Installation of 48 CFCIs on 5 distribution circuits
  - Ongoing sensor validation and cost/benefit analysis; Expected Spring 2015

Smart Grid Projects (cont.)

- Conservation Voltage Reduction (CVR) Pilot
  - Four circuits had equipment installed to lower voltage for efficiency savings
  - Efficiency goals were not achieved
- Oregon Advanced Metering Strategy Project
  - Investigated applicable technologies for AMI, AMR and hybrid solutions
  - Request for proposal issued; will obtain accurate pricing for business case analysis
  - Management to review business case for next steps

Challenges

- Standards and Interoperability
- Security of Customer and Company Data
- Distributed Generation
  - Protection Schemes
  - Electric Vehicles
- Customer Communication
- Customer Participation

Hurdles for PacifiCorp Smart Grid

- Low Energy Prices
- Large Financial Investment
  - Company Infrastructure
  - Customer Expenses





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Conservation Voltage Reduction

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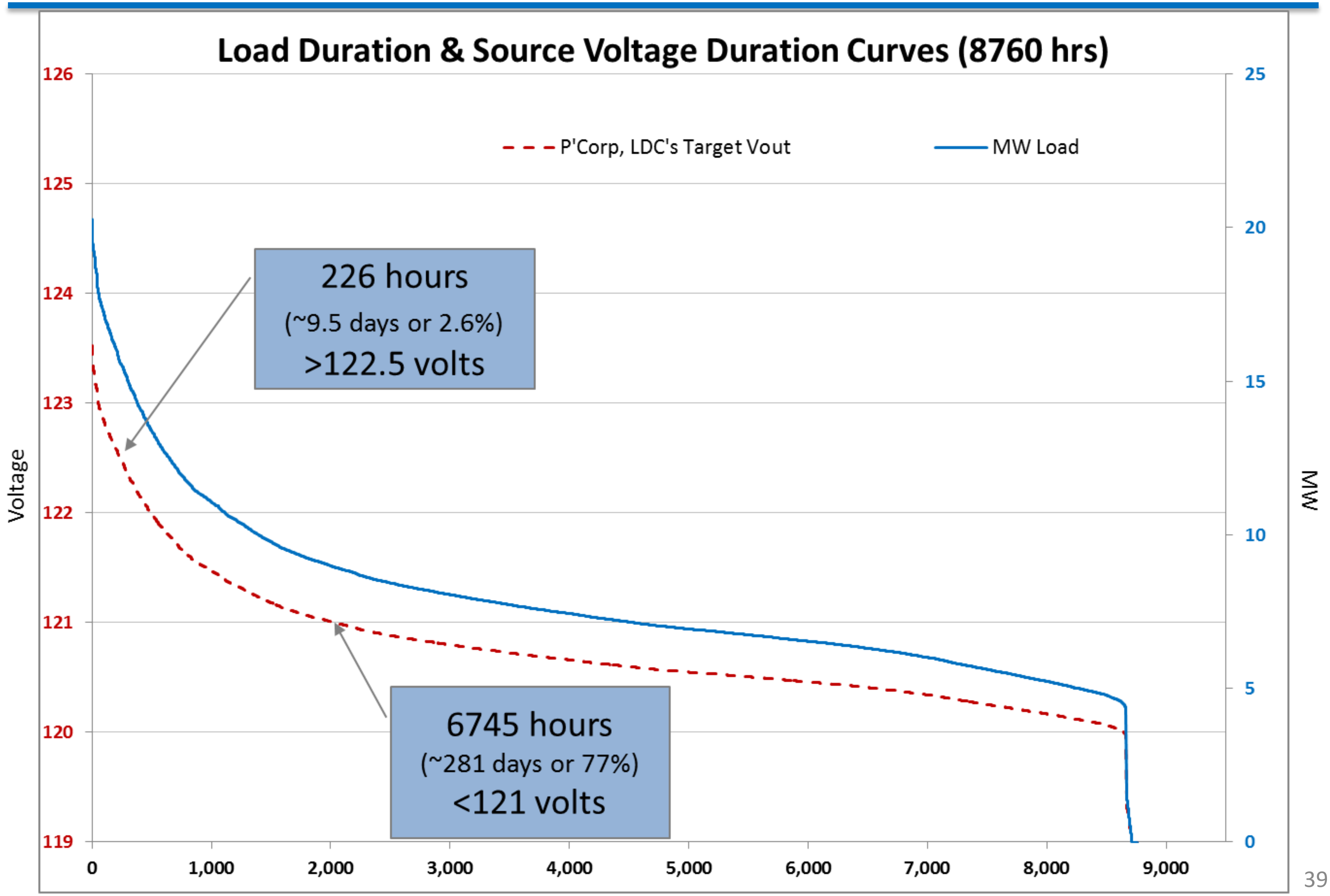
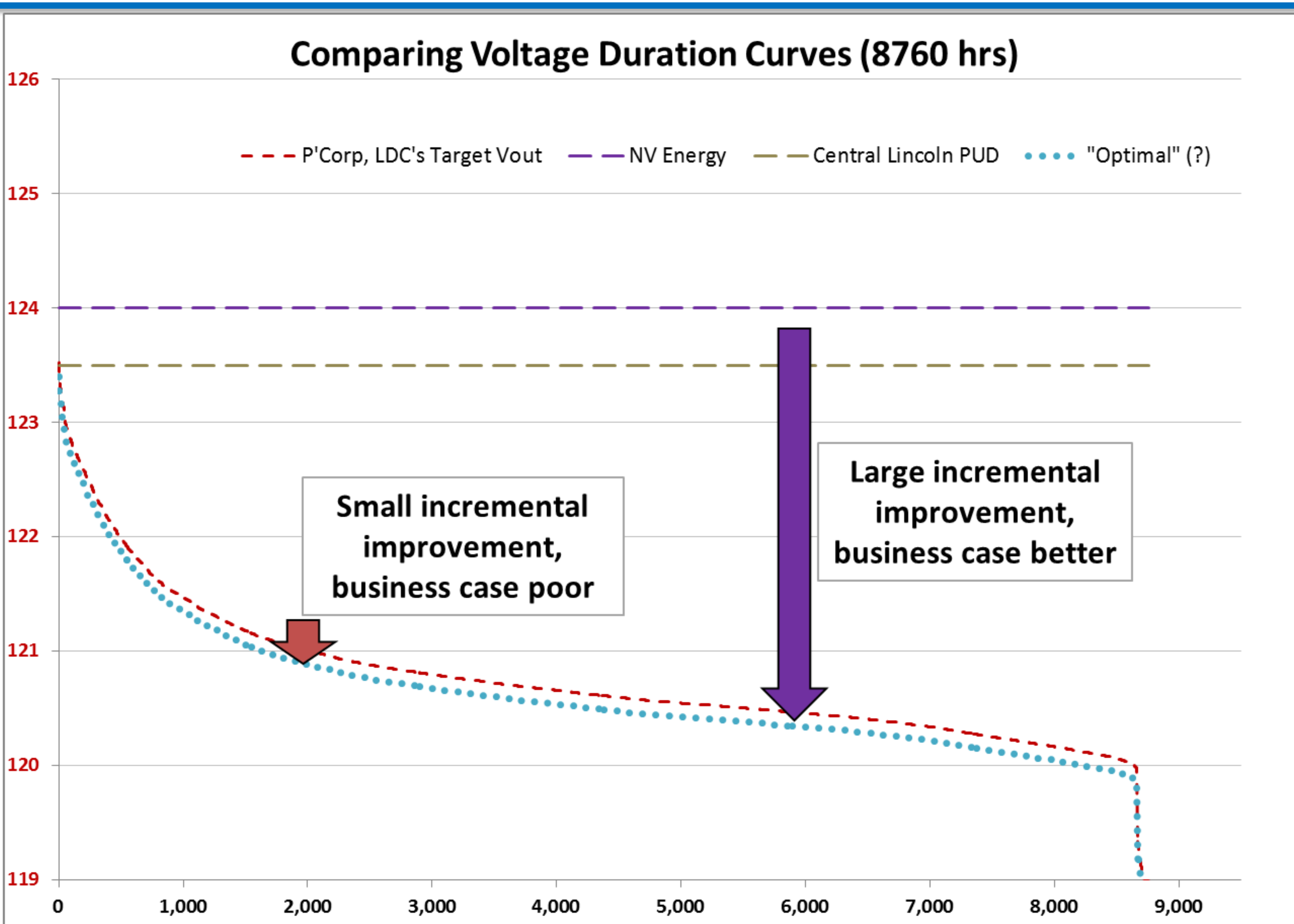
CVR/IVVO Update

- Voltage Management Options
- PacifiCorp Practices
- Recent Developments

Voltage Management Options

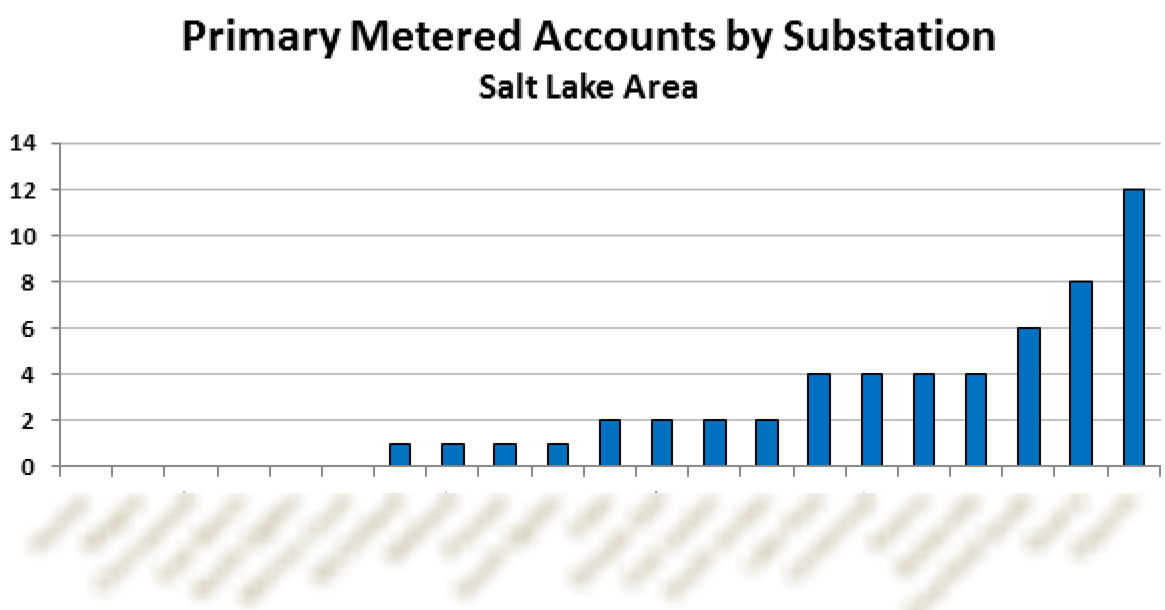


Voltage Management Options

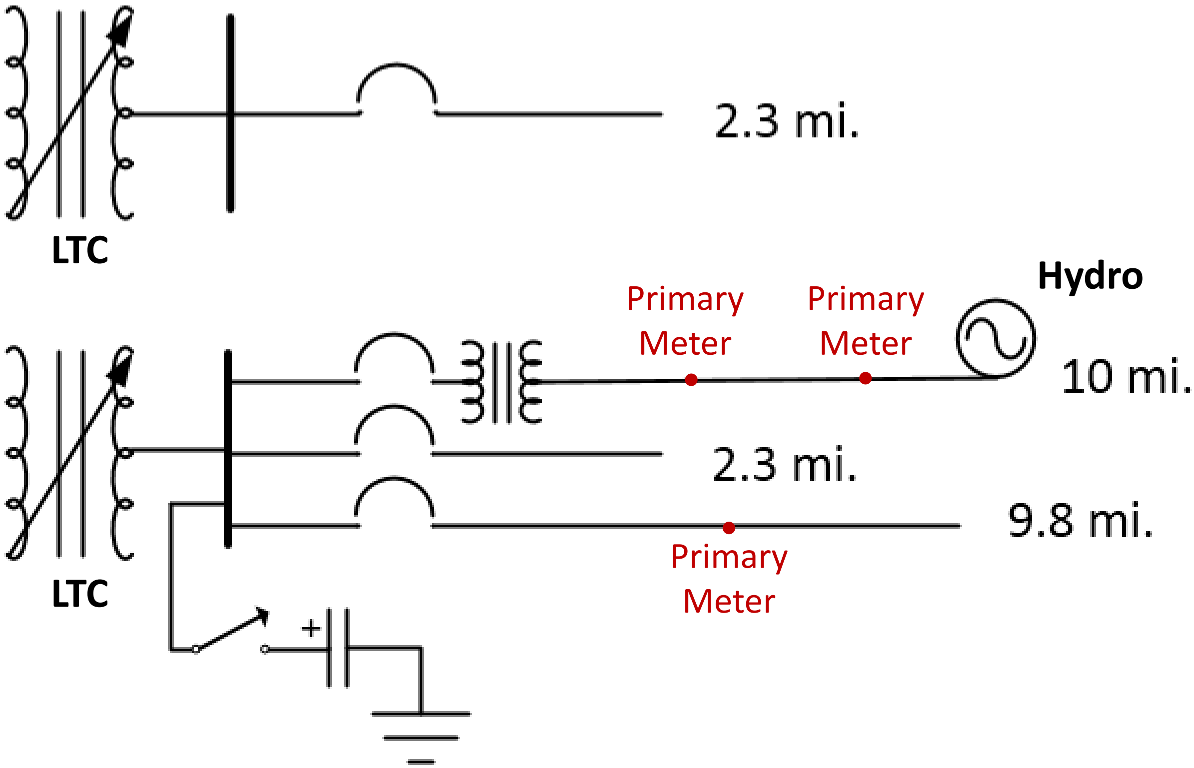


PacifiCorp Practices

- Stocky, energy dense circuits can be seen as good CVR candidates, but…
- Primary metered accounts require at least 97.5% (not 95%) nominal voltage, per ANSI C84
- PacifiCorp has many primary metered customers



PacifiCorp Practices



Simple! Lower the LTC set point.

Not so simple!

Recent Developments

- Researching AMI business case, other utilities' efforts
- RTF is evaluating its CVR protocols and may change scope
- NEETRAC's research shows significant decline in CVR factor over eight hours
- Persistence and savings measurement accuracy answers can be elusive
- Moving to new power flow application
- Continuing the discussion within Smart Grid





2015
Integrated Resource Plan

Anaerobic Digester Study

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Anaerobic Digesters – Washington State Service Territory

Basis for Study

- Excerpt from Washington Utility Commission IRP Acknowledgement Order:

  "Regarding anaerobic digesters, the Commission believes that PacifiCorp's modeling in the IRP process did not address adequately the Commission's 2011 request for the Company to analyze the potential for this technology in its Washington service territory. Digesters are potentially a reliable source of cost-effective baseload power for the Company, a revenue stream for Washington farmers, and a mechanism to significantly reduce dairy waste. …We expect a rigorous analysis of the potential for this form of generation in the next IRP cycle."

Anaerobic Digester Study

Summary

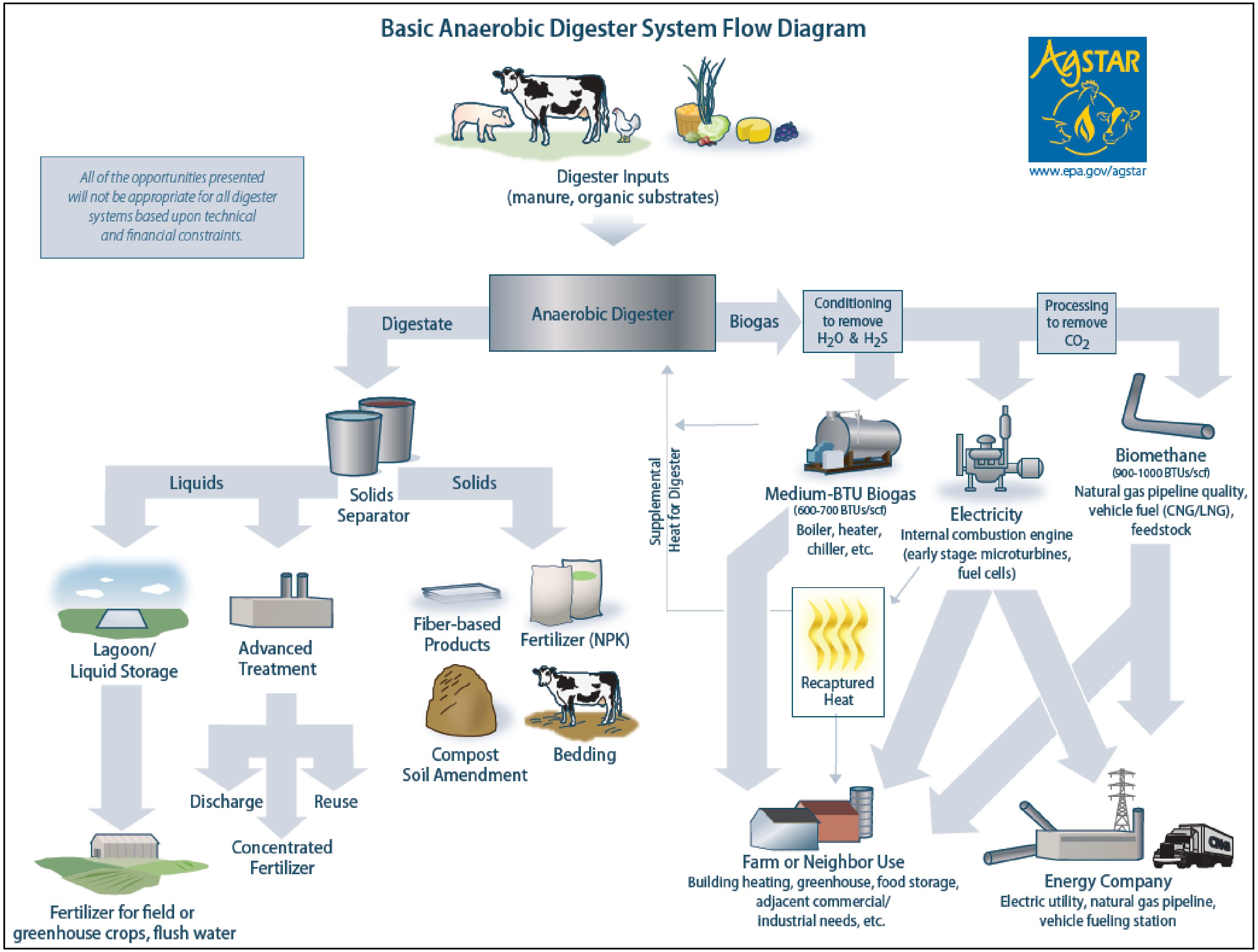
- 2014 Anaerobic Digester Study (see link below)
- Purpose: Assess the magnitude of power generation potential from dairy waste in State of Washington in PacifiCorp Service Territory
  - Study focus: Dairy operations and electric power production
  - Methodology
    - Identify both quantity and sizes of dairies
    - Identify biogas potential
    - Identify power generation potential
  - Power generation source: biogas fired in reciprocating engines
- http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Anaerobic_Digesters_Resource_Assessment_06-24-2014.pdf

Anaerobic Digesters – Washington State Service Territory Study

- Solicited proposals from:
  - Harris Group
  - HDR
  - Navigant
- Contract awarded to Harris Group based on:
  - Project experience
  - Project plan
  - Price

State of Washington

What is Anaerobic Digestion?



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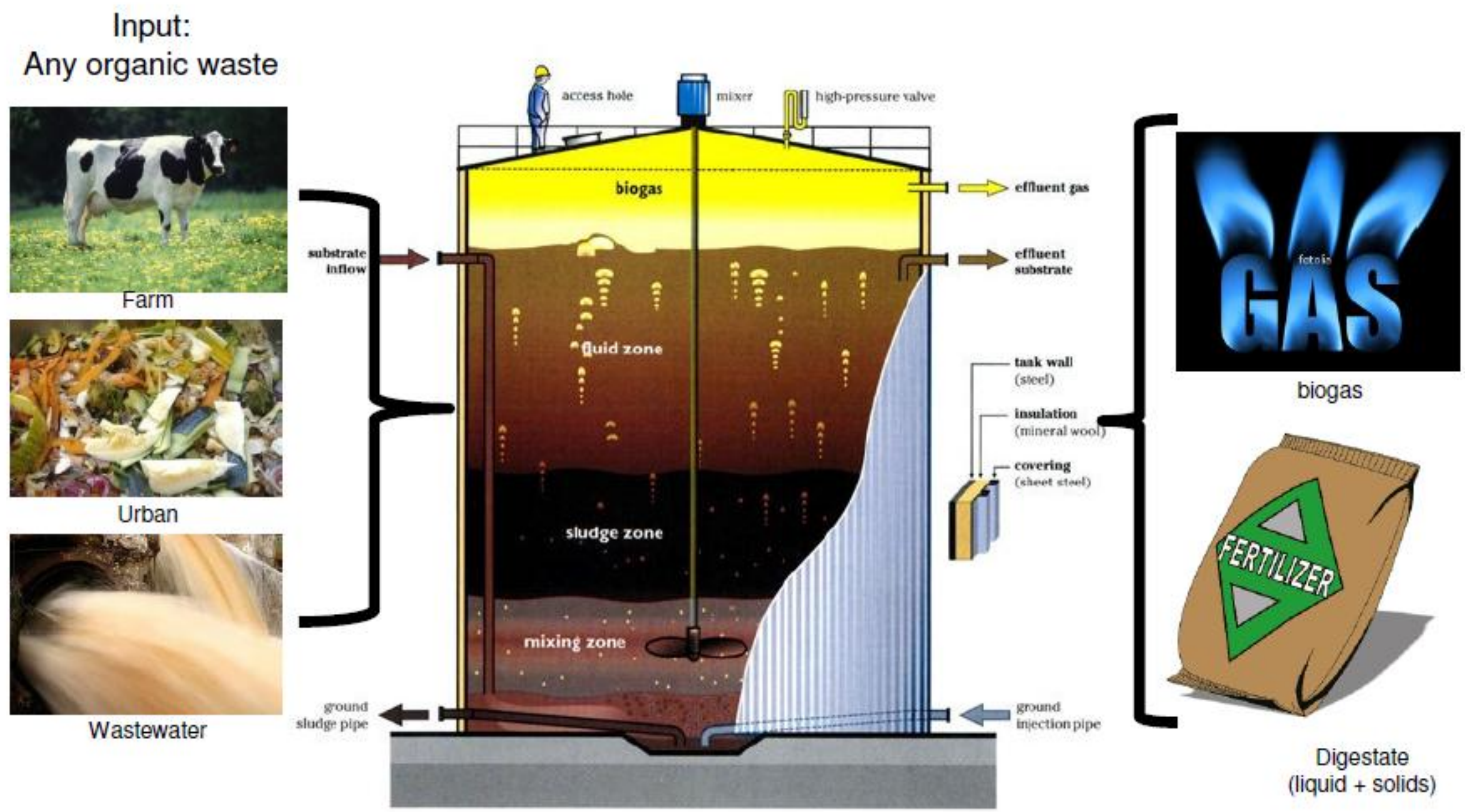
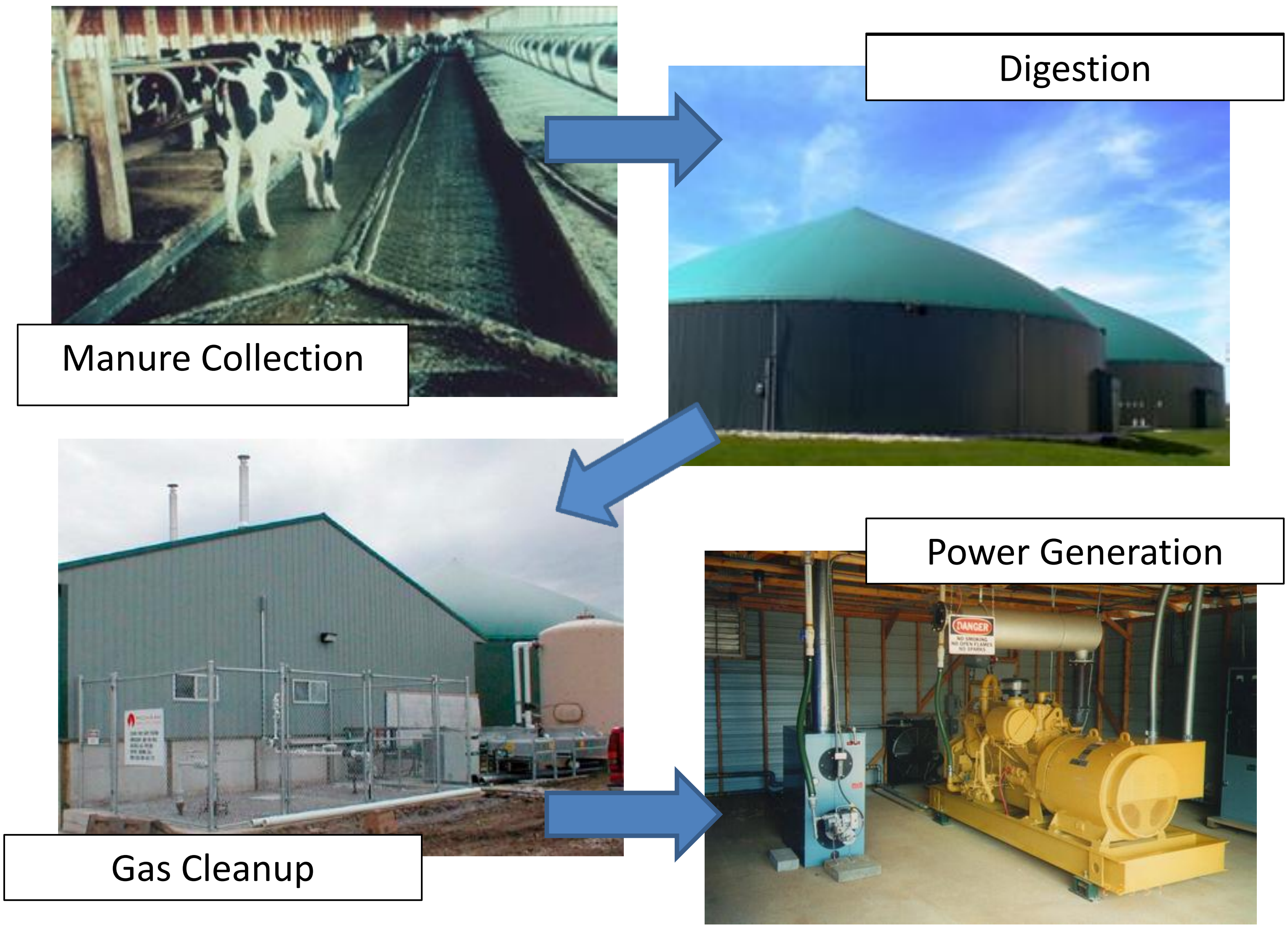
Anaerobic Digester Technology



www.americanbiogascouncil.org

State of Washington

Process Flow Diagram



Biogas Characteristics

Pressure (less than 1 psig)

Composition:

- Methane (CH_4): 55 to 60 %
- Carbon Dioxide (CO_2): 40 to 45 %
- Nitrogen (N_2): 0.4 to 1.2 %
- Oxygen (O_2): 0.0 to 0.4%
- Hydrogen Sulfide (H_2S): 0.02 to 0.4%
- Saturated with water

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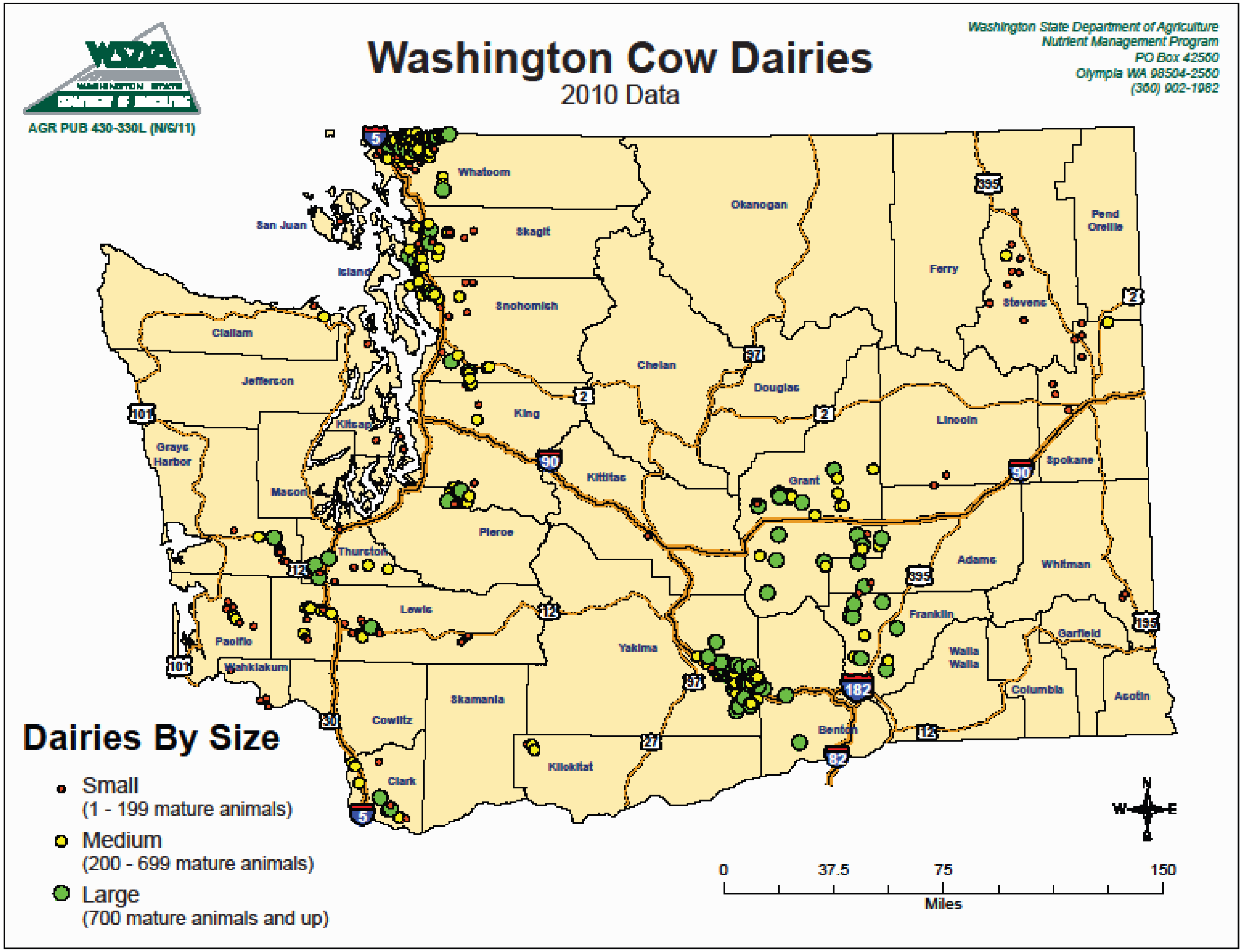
Cow Dairies

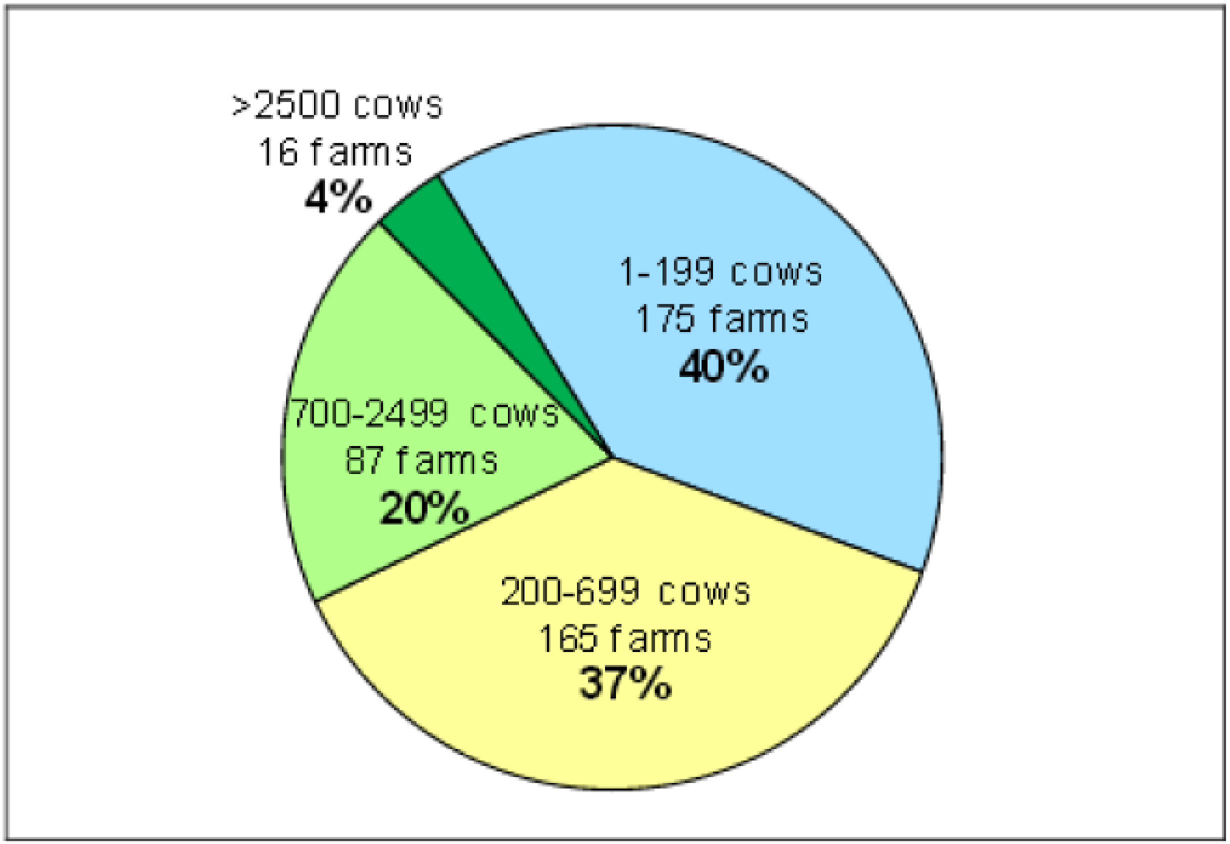


Anaerobic Digester Study

Dairy Farm Size Distribution

Dairy Size Distribution in Washington

Source: WSDA, 2010 Registration



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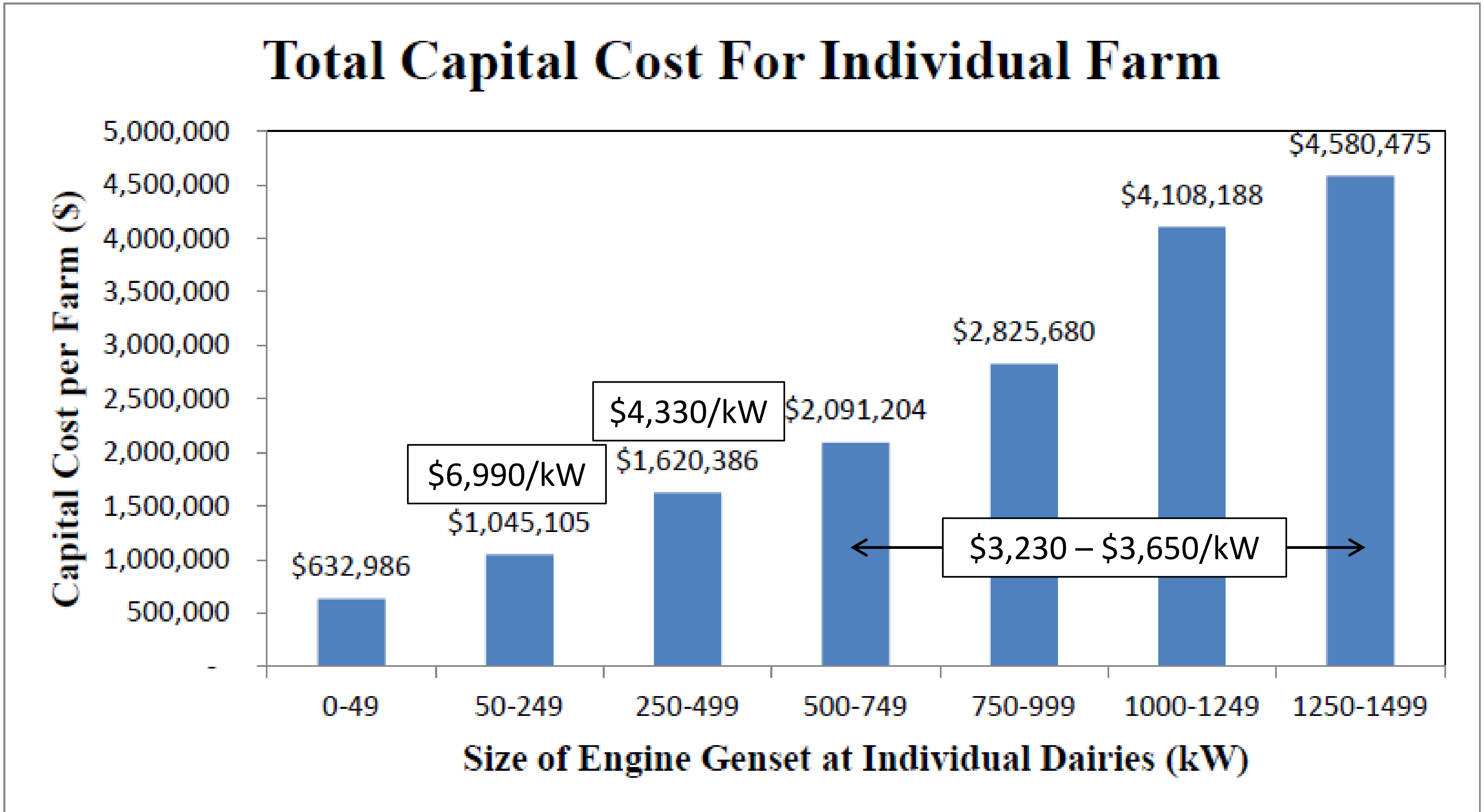
Estimated Power Production

Table 3-5: Electrical Power Production Ranges by Dairy Size

Mature Cows	Number of Dairies	Minimum Power (kW)	Maximum Power (kW)	Average Power (kW)
38 to 199	2	8	38	23
200 to 699	15	47	151	99
700 to 1699	22	143	248	246
1700 to 2699	11	322	520	421
2700 to 3699	2	576	779	677
3700 to 4699	4	679	894	787
5700 to 6839	2	1,102	1,345	1,221
6840 and above	2	1,242	1,509	1,375
Total:	60	15,971	26,576	21,273

State of Washington
Anaerobic Digester Study



Anaerobic Digester Study
Summary Results

- Major dairy resources in PacifiCorp service territory are in Yakima County
- Estimated total available capability: 16 - 27 megawatts
  - Avoided CO_2e emissions: 341,000 to 565,000 tons per year
- Estimated total available capability (>500 kW): 10.2 megawatts
  - Avoided CO_2e emissions: 217,000 tons per year
- Estimated capital costs: $3,000-3,500 per kilowatt (500 kW and greater)
- Estimated O&M costs: $9-10/MWh
- Estimated capacity factor: 92%

Anaerobic Digester Study

General Conclusions

- Resource potential is relatively small
- Consolidation of dairies (or dairy waste) needed to form larger digester facilities to develop economically viable projects
- Recent experience indicates that current avoided costs make project economics unattractive
  - RECs & carbon offsets are other factors
  - DeRuyter Dairy switches from power generation to selling synthetic natural gas
    - "And it's worth many times more than the electricity that can be produced by a digester" (Dan Evans, Promus Energy)
- Expectation is that economic projects will be brought forward through qualifying facility power purchase agreements





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Modeling for Confidential Volume 3

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Volume III Analysis

- Confidential PVRR(d) analysis of emission controls/compliance alternatives required for existing coal units

- Focus on compliance decisions that fall within the 2015 IRP Action Plan window
  - Wyodak SCR (2019)
  - Naughton 3 Natural Gas Conversion (2018) vs. early retirement year-end 2017
  - Dave Johnston 3 SCR (2019) vs. Firm Retirement (2027)
  - Cholla 4 (2018)

Model Runs for Wyodak

Base Compliance Alternative Analysis

	Wyodak	Dave Johnston 1	Dave Johnston 2	Dave Johnston 3	Dave Johnston 4
SCR	SCR (3/4/2019)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Early Retirement	Retire (3/4/2019)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
Gas Conversion	Conversion (6/1/2019)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)

Inter-temporal (IT) Scenario Analysis

	Wyodak	Dave Johnston 1	Dave Johnston 2	Dave Johnston 3	Dave Johnston 4
IT-1	SNCR (3/4/2019), Retire (12/31/2030)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
IT-2	Conversion (6/1/2022)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
IT-3	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)

Fleet Trade-Off (FT) Scenario Analysis

	Wyodak	Dave Johnston 1	Dave Johnston 2	Dave Johnston 3	Dave Johnston 4
FT-1	No SCR	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)
FT-2	No SCR	Conversion (6/1/2022), Retire (12/31/2027)	Conversion (6/1/2022), Retire (12/31/2027)	Retire (12/31/2027)	Retire (12/31/2027)

Scope of Other Studies

- Naughton Unit 3 Runs
  - Gas conversion, on-line June 1, 2018
  - Early retirement by December 31, 2017
- Dave Johnston Unit 3 Runs
  - Installation of SCR by March 4, 2019
  - No SCR, early retirement by December 31, 2027
- Cholla Unit 4 Runs
  - Installation of SCR by January 4, 2018
  - Early retirement by December 31, 2017
  - Natural gas conversion, on-line June 1, 2018
  - Others (to be discussed in confidential filing)

2015
Integrated Resource Plan

Planning Reserve Margin Results

PacifiCorp
Rocky Mountain Power
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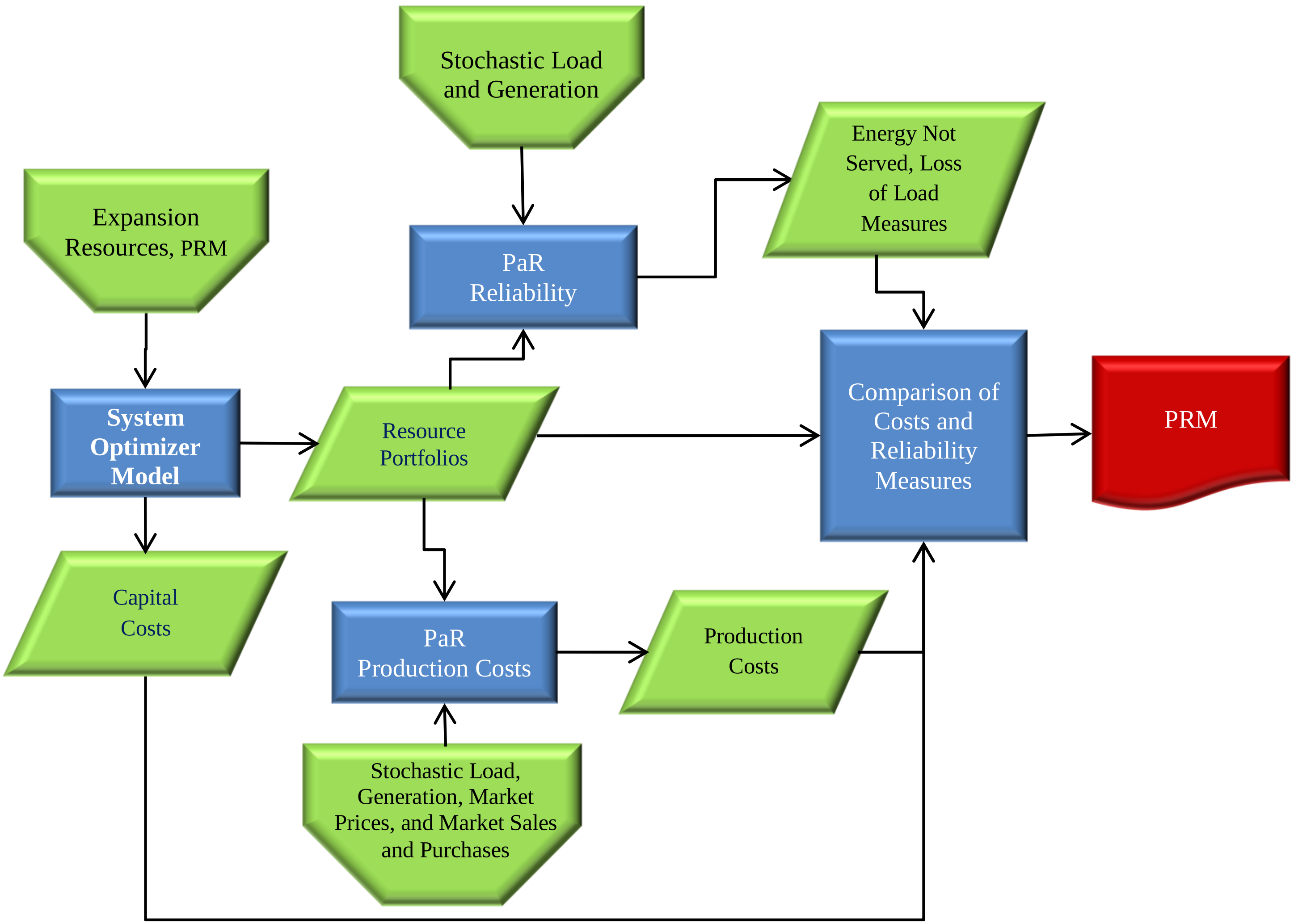
PacifiCorp Energy

Overview of Planning Reserve Margin

- The planning reserve margin (PRM), represented as a percentage of coincident peak load, is used to ensure there are sufficient resources to reliably serve customers over time
- Planning to a reserve margin ensures sufficient capacity is available to meet both near-term and longer-term uncertainties:
  - Contingency reserves (near-term)
  - Regulating margin reserves (near-term)
  - Changes & availability of resources (near-term and long-term)
  - Changes in customer load (near-term and long-term)
- Planning reserve margins of 10% to 20% are studied in the System Optimizer (SO) and Planning and Risk (PaR) models
  - 11 SO runs, 22 PaR runs
  - SO runs determine the resource portfolio for each planning reserve margin level
  - One set of PaR runs simulates the reliability of the resource portfolio
  - Another set of PaR runs determines the production costs of the portfolio

Workflow

- PRM is determined by four studies.



Major Inputs

- SO model
  - Base data from 2013 IRP Update
  - Incremental Class 2 demand side management (DSM) resources, which reduce load
  - Gas-fired resources, which provide flexibility to meet system peak load and energy requirements
- PaR (reliability model)
  - Resource portfolios from SO for each PRM level
  - Stochastic parameters for load and resource availability
- PaR (production cost model)
  - Resource portfolio from SO for each PRM level
  - Stochastic parameters for load and resource availability, as well as for market prices for natural gas and electricity
  - System balancing sales and purchases allow economic dispatch to minimize production costs

Resource Additions by PRM

- 11 SO runs, one for each assumed PRM
- Study period: 2014-2032 to minimize the impact of solving resource needs for only the near future
- All expansion plans included at least the addition of one 420 MW of CCCT plant, 976 MW of SCCT capacity, and between approximately 1,000 – 1,100 MW of DSM resources that provide between 358 MW and 424 MW of capacity at the time of system peak

PRM (%)	DSM Maximum (MW)	DSM Capacity at System Peak (MW)	SCCT (MW)	CCCT (MW)	Total (MW)
10	1,029	372	976	420	1,768
11	1,017	363	1,157	420	1,940
12	1,020	365	1,259	420	2,045
13	1,032	375	1,259	420	2,055
14	1,017	363	1,440	420	2,224
15	1,043	384	1,440	420	2,244
16	1,010	358	1,602	420	2,380
17	1,065	397	1,612	420	2,428
18	1,017	363	1,793	420	2,576
19	1,107	424	1,793	420	2,637
20	1,096	416	1,996	420	2,832

Reliability Measures

- Study period: 2017, which is the first year that a gas-fired resource could be added
- Reliability measures:
  - Expected unserved energy
  - Number of hours when the system has loss of load events, LOLH
  - Loss of Load Episodes

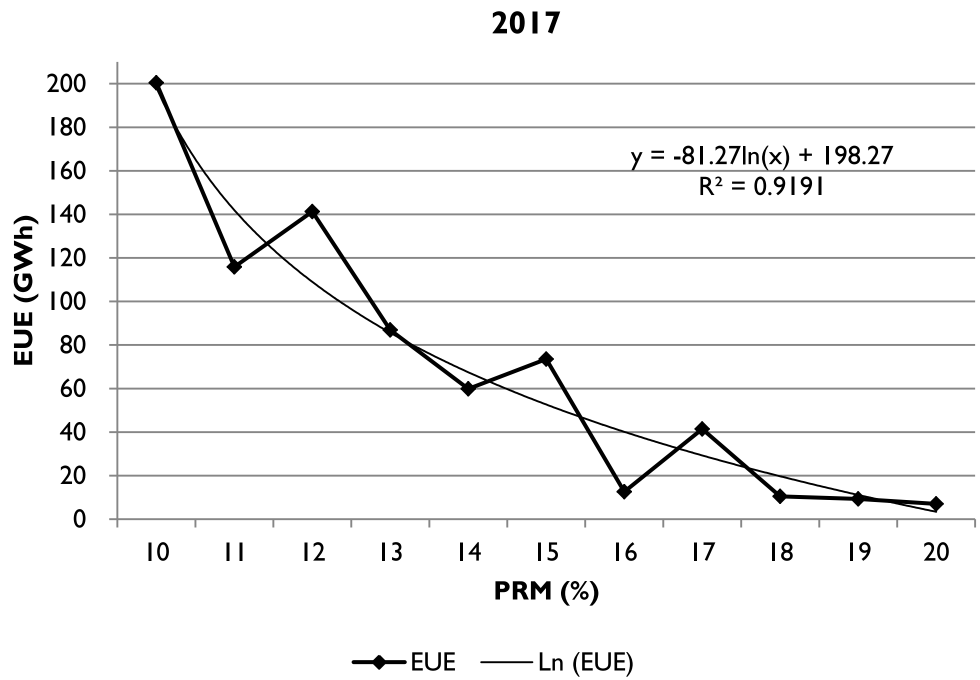
PRM (%)	Simulated Energy not Served (GWh)	LOLH (Hour)	Loss of Load Episodes
10	301	2.60	0.87
11	183	2.03	0.74
12	197	1.78	0.50
13	122	1.51	0.43
14	84	1.24	0.35
15	98	1.19	0.30
16	32	0.34	0.20
17	68	0.46	0.18
18	17	0.30	0.12
19	17	0.40	0.18
20	13	0.27	0.12

Reliability Measures, cont.

- Participating in NWPP reserve sharing allows PacifiCorp to receive energy contingency reserves from other participants in the pool for the first hour after a resource outage.
- Modeled energy not served is reduced by number of outage episode

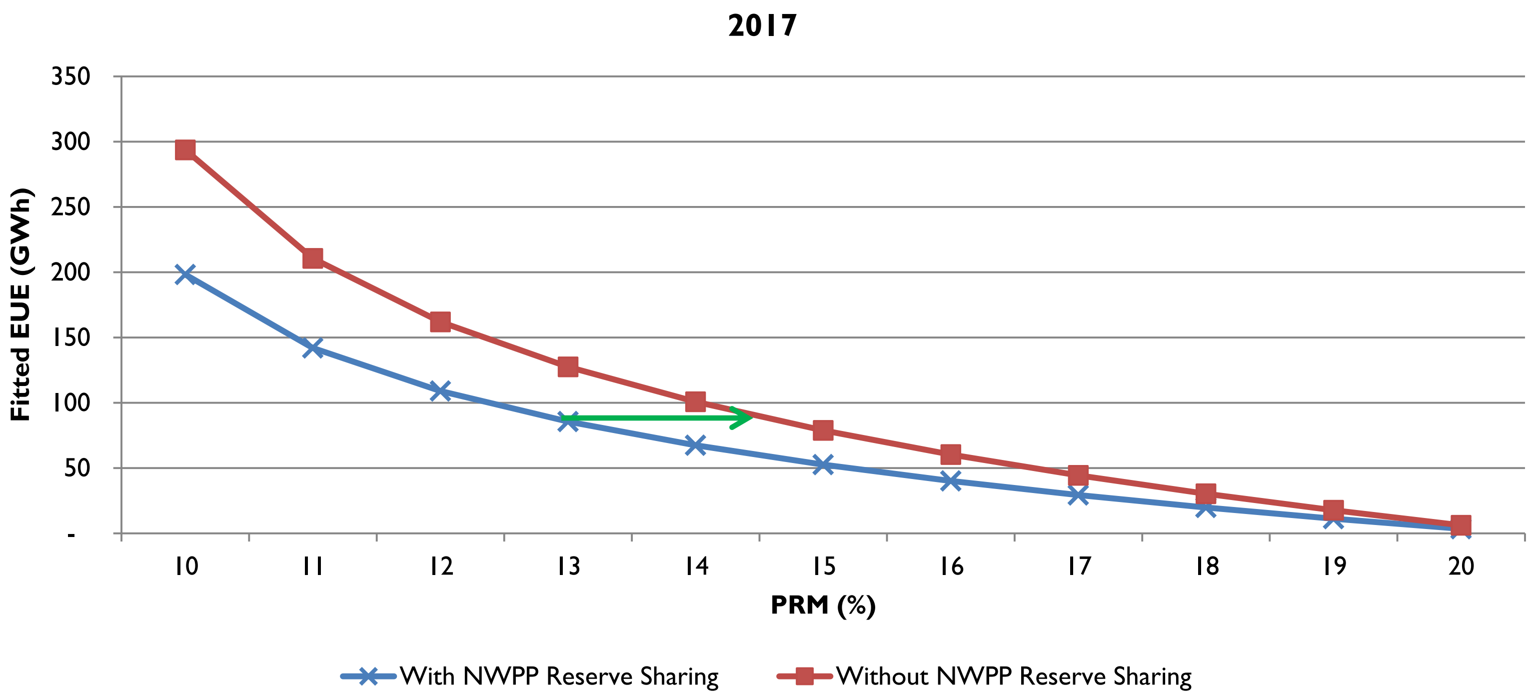
PRM (%)	Simulated Energy Not Served (GWh)	Simulated Expected Loss of Load Hours	Simulated Loss of Load Episodes	Energy Served through Reserve Sharing (GWh)	EUE (GWh)	LOLH
	G	H	O	R= (G / H) * O	N = G - R	H - O
10	301	2.60	0.87	100	200	1.73
11	183	2.03	0.74	67	116	1.29
12	197	1.78	0.50	56	141	1.27
13	122	1.51	0.43	35	87	1.08
14	84	1.24	0.35	24	60	0.89
15	98	1.19	0.30	25	73	0.89
16	32	0.34	0.20	19	13	0.13
17	68	0.46	0.18	27	41	0.28
18	17	0.30	0.12	7	10	0.18
19	17	0.40	0.18	8	9	0.22
20	13	0.27	0.12	6	7	0.15

EUE by Planning Reserve Margin Level



- As expected, EUE trends downward with higher PRMs
- The anomalous break in trend at specific PRM levels (12%, 15%, and 17%) is driven by the blocky nature of resource additions in the 2017 study period, which can lead to an effective planning reserve margin level that is slightly higher than the target PRM

EUE by Planning Reserve Margin Level, cont.



- Amount of fitted expected unserved energy is reduced by reserve reduction that would be available through NWPP reserve sharing
- Expected unserved energy at 13% PRM is equivalent to approximately 14.5% without the reserve sharing

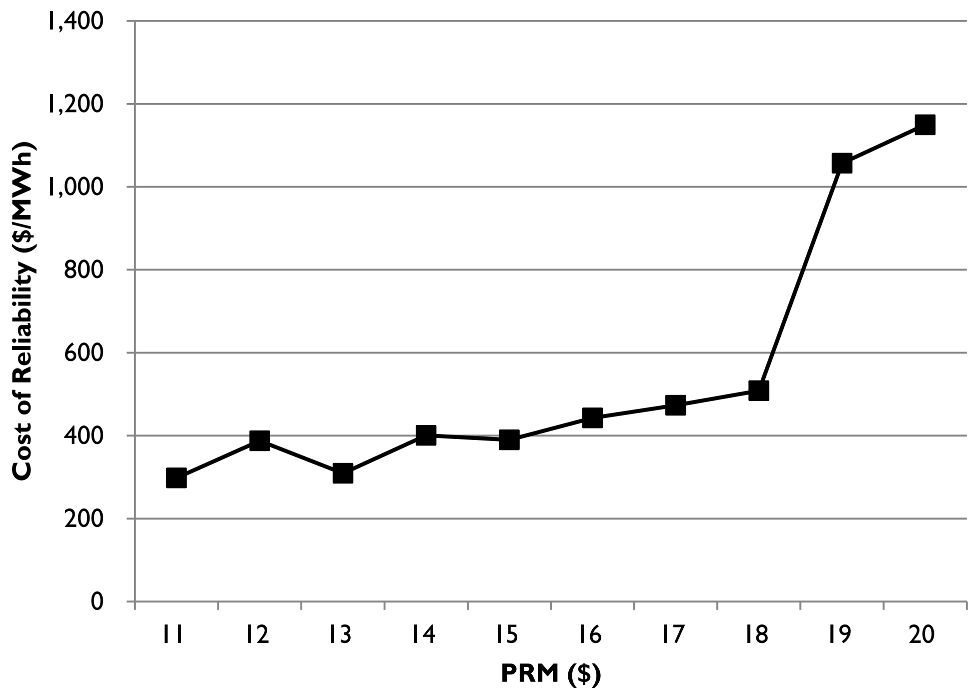
Total Costs by Planning Reserve Margin Level

- Levelized fixed costs of the expansion resources from SO
- Production variable costs of resources dispatched to meet load obligations from PaR Model

PRM (%)	Production Cost ($m)	DSM Costs ($m)	Capital Cost ($m)	Total ($m)
10	$1,292	$34	$237	$1,564
11	$1,292	$32	$256	$1,581
12	$1,289	$33	$277	$1,599
13	$1,288	$35	$276	$1,599
14	$1,289	$32	$295	$1,616
15	$1,287	$39	$295	$1,621
16	$1,289	$31	$314	$1,634
17	$1,285	$45	$314	$1,644
18	$1,289	$32	$333	$1,655
19	$1,284	$143	$334	$1,762
20	$1,284	$141	$363	$1,788

Selection of PRM for 2015 IRP

- The incremental cost of reliability rises between 15% and 18% PRM levels, and increases dramatically at PRM levels above 19%
- PRMs below13% would not sufficiently cover the need to carry short-term operating reserves (contingency and regulating margin) and longer-term uncertainties (extended resource/transmission outages and changed in customer load)
- With these considerations, PacifiCorp will maintain a13% PRM in the 2015 IRP



2015 Integrated Resource Plan

Resource Capacity Contribution Results

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Wind & Solar Capacity Contribution

- PacifiCorp has updated its wind and solar capacity contribution study for the 2015 IRP
- The methodology is based on a National Renewable Energy Laboratory ("NREL") report on Effective Load Carrying Capability (ELCC) approximation methods
- The methodology (the "CF Approximation Method") relies upon weighted hourly loss of load probability (LOLP) statistics based on the reliability model used in PacifiCorp's planning reserve margin study at the 13% planning reserve margin level
- Based on in its review of the literature, PacifiCorp will adopt the capacity contribution results from this study when developing resource portfolios for the 2015 IRP

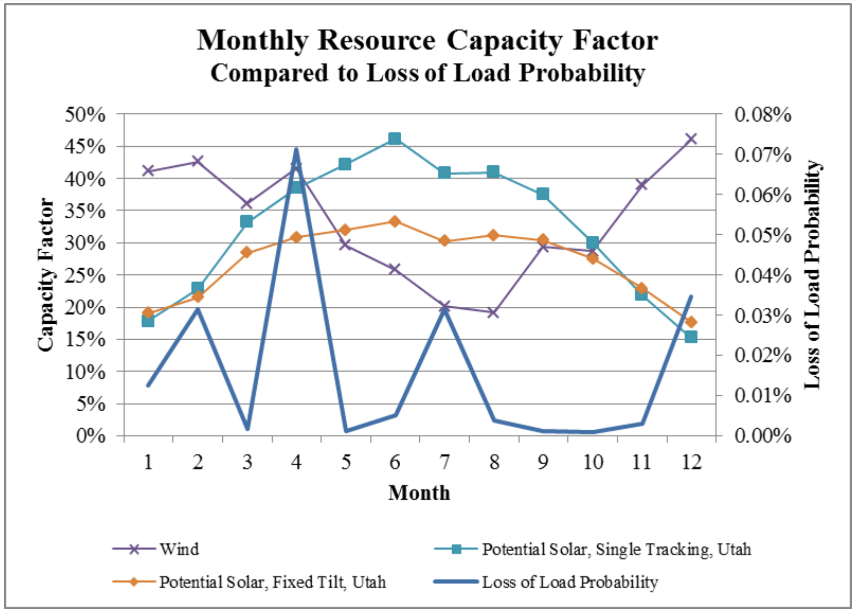
CF Approximation Method

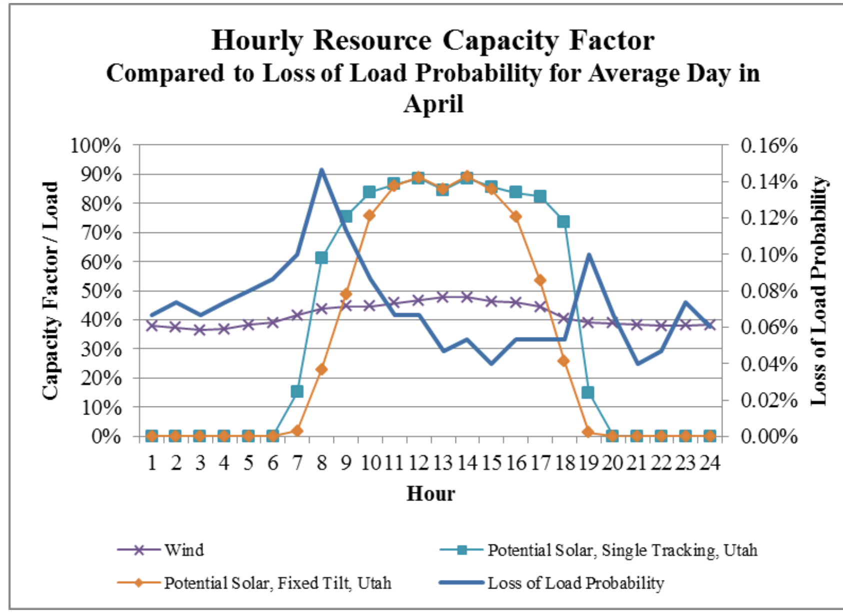
- Approximation of the computationally intensive Effective Load Carrying Capability (ELCC) method
- 500-iteration hourly PaR run (reliability model used in the planning reserve margin study)
- Each hour's LOLP is calculated, with weighting factors calculated by dividing each hour's LOLP to the total LOLP in the 2017 study year
- Capacity contribution calculated as the sum of hourly weighted capacity factors for each resource type
  - Wind
  - Proxy solar (fixed & tracking) in Milford, UT
  - Proxy solar (fixed & tracking) in Lakeview, OR

Wind and Solar Capacity Contribution Results

	Wind	Solar PV					
		OR Fixed Tilt	UT Fixed Tilt	Average Fixed Tilt	OR Single Axis Tracking	UT Single Axis Tracking	Average Single Axis Tracking
2013 IRP (90% probability among top 100 Load Hours)	4.2%	13.6%					
2015 IRP (CF Approximation)	18.1%	32.2%	34.1%	33.1%	36.7%	39.1%	37.9%

Sample of LOLP and Capacity Factor Data





- Seasonal distribution of LOLP shows highest time periods in spring (maintenance period), summer (July peak loads), and winter (December – February)
- Among April hours, LOLP events peak during morning and evening ramp periods





2015 Integrated Resource Plan

Wind Integration Cost Results

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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.

Benefits of Energy Imbalance Market

- Energy and Environmental Economics, Inc. (E3) estimates that the reduction in PacifiCorp's flexible reserve requirements based on transfer capability between California ISO and PacifiCorp under energy imbalance market (EIM) is approximately as follows:

Transfer capability (MW)	Reduction of Flexible reserves in PacifiCorp (MW)
100	19
400	78
800	103

- For purposes of the 2014 WIS and its subsequent use in the 2015 IRP, PacifiCorp assumes a transfer capability of ~330 MW, which leads to a reduction in flexible reserves of ~65 MW.
- Reduction in flexible reserves is applied to west side of PacifiCorp's system
  - ~330 MW of transfer capability is from Malin in California ISO to the California Oregon Border (COB) in Southern Oregon, both on PacifiCorp-owned transmission and transmission rights acquired from the Bonneville Power Administration
  - Reduction in reserves is applied on hourly basis and is limited by the regulation margin in the hour

Determination of Integration Costs in the 2014 WIS

- Seven studies to determine the intra-hour and inter-hour integration costs

PaR Model Simulation	Forward Term	Load	Wind Profile	Incremental Reserve	Day-ahead Forecast Error	Comments
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						
System Balancing Cost Runs						
3	2015	2013 Day-ahead Forecast	2013 Day-ahead Forecast	Yes	None	Commit units based on day-ahead load forecast, and day-ahead wind forecast
4	2015	2013 Actual	2013 Actual	Yes	For Load and Wind	Apply commitment from Simulation 3
5	2015	2013 Actual	2013 Day-ahead Forecast	Yes	None	Commit units based on actual Load, and day-ahead wind forecast
6	2015	2013 Actual	2013 Actual	Yes	For Wind	Apply commitment from Simulation 5
7	2015	2013 Actual	2013 Actual	Yes	None	Commit units based on actual Load, and actual wind forecast
Load System Balancing Cost = System Cost from PaR Simulation 4, which uses the unit commitment from Simulation 3 based on day-ahead forecast load (and day-ahead wind) less System Cost from PaR Simulation 6, which uses the unit commitement from Simulation 5 based on actual load (and day-ahead wind)						
Wind System Balancing Cost = System Cost from PaR Simulation 6, which uses the unit commitment from Simulation 5 based on day-ahdead wind (and actual load) less System Cost from PaR Simulation 7, which commits units based on actual wind (and actual load)						

Determination of Wind Integration Costs in the 2012 WIS

- Studies performed in the 2012 WIS:

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	No	None
2	2015	2015 Load Forecast	Expected Profile	Yes	None
Regulating Margin Cost = System Cost from PaR Simulation 2 less System Cost from PaR Simulation 1					
System Balancing Cost Runs					
3	2015	2013 Day-ahead Forecast	2013 Day-ahead Forecast	Yes	None
4	2015	2013 Actual	2013 Day-ahead Forecast	Yes	For Load
5	2015	2013 Actual	2013 Actual	Yes	For Load and Wind
Load System Balancing Cost = System Cost from PaR simulation 4 (which uses the unit commitment from Simulation 3) less system cost from PaR simulation 3					
Wind System Balancing Cost = System Cost from PaR simulation 5 (which uses the unit commitment from Simulation 4) less system cost from PaR simulation 4					

- As compared to the 2012 WIS, 2014 WIS added two studies to isolate the impact of volume changes from day-ahead forecast to actual, for both load and wind generation.

Wind Integration Costs

- 2014 WIS wind integration costs as compared to 2012 WIS results:

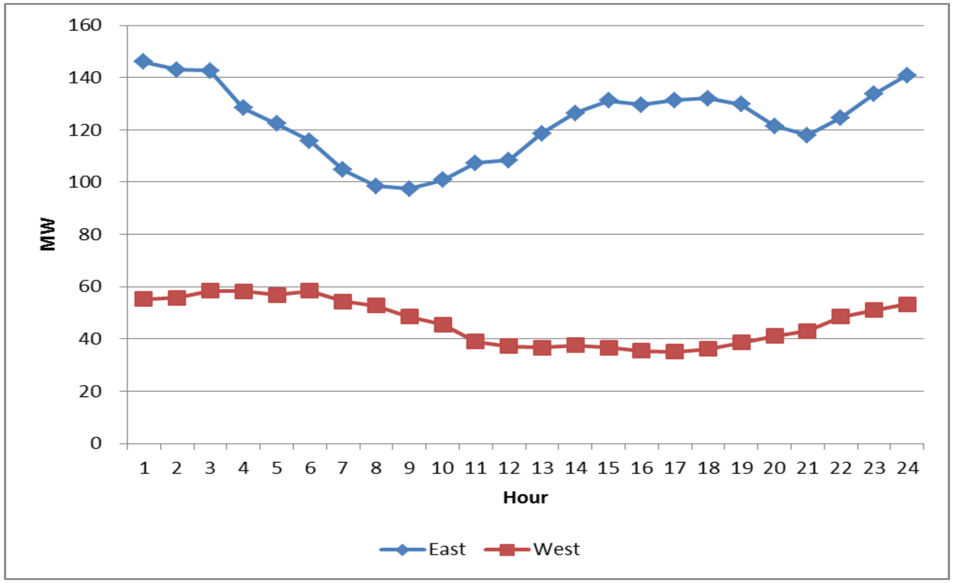
$/MWh	2012 WIS Monthly Avg. Regulation Reserves (2012$)	2014 WIS Hourly Regulation Reserves (2015$)
Regulating Margin	$2.19	$2.35
System Balancing	$0.36	$0.71
Total Wind Integration Costs	**$2.55**	**$3.06**

- Reserves are modeled on hourly basis in the 2014 WIS, as opposed to on monthly basis as in the 2012 WIS.
- For the SO studies, $3.06/MWh will be added to the costs of potential wind resources, and $0.77/MWh (25% of $3.06/MWh) will be added to the costs of potential solar resources.
- For PaR studies, additional reserves from the WIS will be included as operating reserve requirements.

2014 WIS Hourly vs. Monthly Reserves

$/MWh	2014 WIS Hourly Reserves	2014 WIS Monthly Reserves
Regulating Margin	$2.35	$1.66
System Balancing	$0.71	$0.74
Total Wind Integration Costs	**$3.06**	**$2.40**

- Modeling reserves on hourly basis, more reserves are shifted from relatively lower-priced hours to relatively higher-priced hours.



2012 WIS and 2014 WIS Costs Using Monthly Reserves

$/MWh	2012 WIS Monthly Avg. Regulation Reserves (2012$)	2014 WIS Monthly Avg. Regulation Reserves (2015$)
Regulating Margin	$2.19	$1.66
System Balancing	$0.36	$0.74
Total Wind Integration Costs	**$2.55**	**$2.40**

- Compared with 2012 WIS, the regulating margin cost is lower, mainly due to addition of the Lake Side 2 gas-fired plant:
  - A sensitivity study without Lake Side 2 shows that the regulating margin costs would change from $1.66/MWh to $2.65/MWh .
- Integration costs are higher due to higher market prices for gas and electricity

	PV HLH ($/MWh)	PV LLH ($/MWh)	Opal Gas ($/MMBtu)
2012 WIS	$37.05	$25.74	$3.43
2014 WIS	$39.13	$29.31	$3.88

Affect of EIM on Wind Integration Costs

$/MWh	2012 WIS (2012$)	2014 WIS Monthly Regulation Reserves Net of EIM Reserve Benefits (2015$)	2014 WIS, Monthly Regulation Reserves Without EIM Reserve Benefits (2015$)
Regulating Margin	$2.19	$1.66	$1.87
System Balancing	$0.36	$0.74	$0.74
Total Wind Integration Costs	**$2.55**	**$2.40**	**$2.61**

- Based on assumed estimates of EIM's benefits in reducing reserve requirements, wind integration costs are reduced by $0.21/MWh.
- Changes in reserve requirements does not impact system balancing costs.

Sensitivity 3: Differentiation of Regulating and Following Reserves

- In its review of the 2012 WIS, the TRC suggested the Company consider differentiating regulating and following reserves for analysis in PaR
- Combined Reserve Requirement:

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

- Split Reserve Requirement:

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

	Combined (MW)		Regulating		Following		Total (MW)	
	West	East	West	East	West	East	West	East
Jan	238	400	107	196	211	354	318	550
Feb	212	363	100	182	187	318	287	500
Mar	219	357	97	179	202	313	299	492
Apr	240	422	123	224	208	362	331	586
May	192	400	84	205	180	348	264	553
Jun	183	462	70	240	179	393	249	633
Jul	219	427	88	180	206	391	294	572
Aug	220	428	90	188	206	388	296	576
Sep	210	392	100	171	188	361	287	533
Oct	153	335	75	159	131	301	206	461
Nov	301	438	165	228	249	375	414	603
Dec	274	433	122	216	251	375	373	592

- Amount of total reserve is significantly higher and inconsistent with Company's operations, and consequently, PacifiCorp has not calculated costs for this sensitivity.

Reminder - Upcoming Meetings

- November 14
  - EIM Update
  - Portfolio Results
- January 29, 2015
  - Confidential Coal Analysis
  - Stochastic Results
  - Sensitivity Analysis Results
  - Preferred Portfolio and Action Plan
- February 26, 2015
  - Final Report

Note: meeting topics are tentative and subject to change.